2019 ANNUAL PERFORMANCE REPORT

CENTER FOR OFFSHORE SAFETY

SEPTEMBER 2020

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LETTER FROM COS DIRECTOR RUSSELL HOLMES

Entering its second decade, the Center for Offshore Safety (COS) was established to advance safety, environmental protection, operational integrity, and risk management on the Outer Continental Shelf (OCS). While this is only my first year as the Director of COS, I've been quickly impressed by how this mission is embodied by our members and their continual commitment to improving safety through reporting and sharing performance information.

The 2019 Annual Performance Report provides shared learnings to industry to help improve performance, enhance safety and environmental protection, and meet the world's growing energy needs. This report also shows areas where industry continues to improve – including zero major oil spills reported to us this year and zero Level 1 Loss of Well Control Incidents for the fifth year in a row. That is certainly news worth acknowledging.

However, our goal is and always has been zero incidents. While this annual report is focused on data, I am mindful that each safety and fatality statistic represents our industry colleagues and friends and serves as a solemn reminder that our work is never done. We report on these incidents to provide transparency and hope that the information shines light on where and how we can improve safety across all operations to reach this important goal.

While this has been a challenging year for America and our industry, we are focused on our long-term strategy and the future as well. COS is utilizing the Bureau of Safety and Environmental Enforcement (BSEE) Safety and Environment Management Systems (SEMS) audit results (included in the report) to compile tools to enable industry operators to establish, implement and maintain company management systems that advance safety and environmental performance. I'm hopeful that this will be exceedingly useful to our members as we look towards the future.

Safety is our core value, with continual improvement our constant goal. The global pandemic in 2020 has called on every industry, including the U.S. offshore natural gas and oil industry, to come together to combat the virus while maintaining our commitments to safe operations and meeting the world's energy needs in the face of increasing complex challenges.

As I look forward to 2021 and beyond, I am encouraged by the continued commitment of our members to the COS mission and energized by the prospect of greater data integration and utilization to identify new opportunities for good practices to support our industry. I thank all COS members for their contributions to and participation in this annual report and for their ongoing dedication to continual improvement through safety and environmental management systems.

Sincerely,

Russell Holmes

COS Director

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COMMONLY USED ACRONYMS

API — American Petroleum Institute

APR — Annual Performance Report

ASP — Audit Service Provider

ASQ — American Society for Quality

BSEE — Bureau of Safety and Environmental Enforcement

COS — Center for Offshore Safety

DART — Days Away from Work, Restricted Work, and Job-Transfer Injury and Illness Frequency

GoM — Gulf of Mexico

HVLE — High Value Learning Event

IADC — International Association of Drilling Contractors

IMCA — International Marine Contractors Association

LFI — Learning from Incidents and HVLE

MIT — Maintenance, Inspection, and Testing

MOC — Management of Change

MSRC — Marine Spill Response Corporation

NOIA — National Ocean Industries Association

OCS — Outer Continental Shelf

OMSA — Offshore Marine Service Association

OOC — Offshore Operators Committee

PSE — Process Safety Event

RIIF — Recordable Injury and Illness Frequency

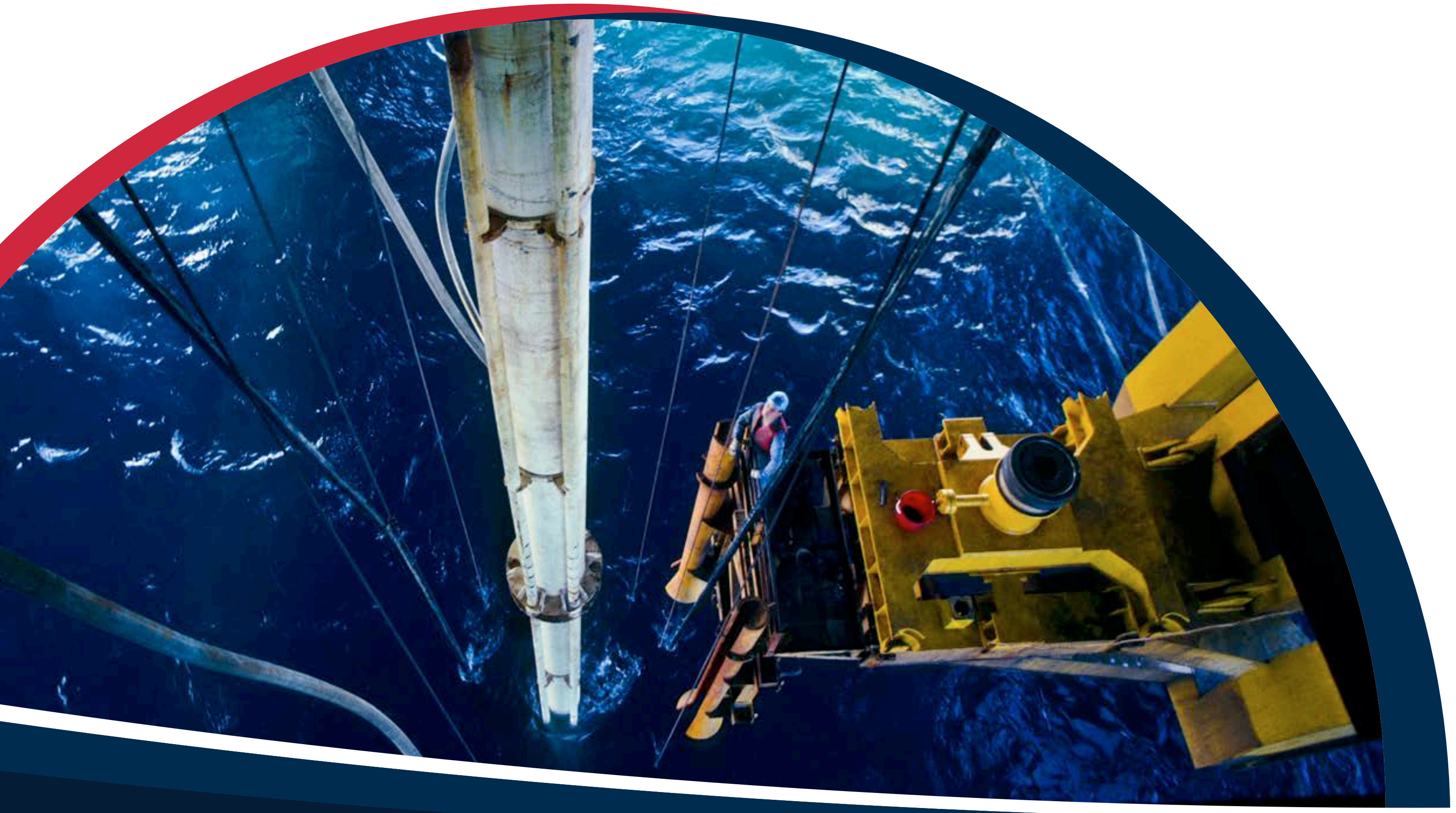
SEMS — Safety and Environmental Management System

SPI — Safety Performance Indicator

SPIP — Safety Performance Indicator Program

WCI — Well Control Incident

WPCS — Well Pressure Containment System



1.0 COS MEMBERS AND PARTICIPANTS

COS MEMBERS

Operators	Rig Contractors	Service Companies	Associations
Anadarko/Oxy	Helmerich & Payne	Baker Hughes	ASQ
BHP	Seadrill Americas	Halliburton	IADC
BP E&P	Valaris	Oceaneering	IMCA
Chevron USA		Schlumberger	MSRC
Equinor		SubSea7	NOIA
ExxonMobil			OMSA
Fieldwood			OOC
Hess			OPITO
Murphy E&P			
Shell International E&P			
TOTAL E&P			

Eleven Operators and seven Rig Contractors and Service Companies shared SPI data for use in this APR.

COS members listed above as Associations do not provide data.

2.0 INTRODUCTION

The Center for Offshore Safety (COS) is designed to promote the highest level of safety for offshore drilling, completions, and operations through leadership and effective management systems addressing communication, teamwork, and independent third-party auditing and certification. COS enables operational excellence in part by enhancing and continuously improving industry's safety and environmental performance and stimulating cooperation within industry to share learnings. In the context of this report, the term safety is inclusive of personal safety, process safety, health, security, and the environment.

This COS Annual Performance Report (APR) provides information shared by its members under the following COS programs:

- Safety Performance Indicators (SPI), and
- Learning from Incidents and Events (LFI)

The COS member data provided through the LFI and SPI programs enable continual improvement of performance-based management systems.

The SPI originated from major hazard bow ties, developed within COS, that cover both process safety and personal safety. The information can be used for driving improvement and, when effectively acted upon, contribute to reducing risk of major incidents by identifying weaknesses in barriers intended to prevent the occurrence or recurrence of incidents and mitigate consequences. The scope of the SPI data covers COS member wells, projects, and production facilities and operations in the U.S. Outer Continental Shelf (OCS).

The data collected via the SPI program ranges from SPI 1 (fatality, injury to five or more from a single incident, loss of well control, etc.) and SPI 2 (injury to four or less from a single incident, direct damage ≥ $25,000, etc.) to SPI 10 (dropped objects potential results). The full list of SPI collected by COS can be found in section 4.1 of this report.

The LFI program covers the same scope, but also allows for the submittal of data for incidents and events which occur outside the U.S. OCS. The main objective of the LFI program is to provide COS members a mechanism for sharing information from incidents that meet the criteria for an SPI 1 or SPI 2, as well as High Value Learning Events (HVLE).

Publication of SPI and LFI Program data began in 2014, reflecting 2013 performance. Reporting is voluntary and data confidentiality is maintained through a process administered by an independent 3rd-party before submittal to COS.

For this APR, in addition to SPI and LFI data, anonymized Safety and Environmental Management System (SEMS) Audit data for 47 regulatorily required SEMS Audits completed between April 2017 and December 2019 was supplied to COS by the Bureau of Safety and Environmental Enforcement (BSEE). This is unlike previous years, where data for the APR was collected only from COS Operator members. Identifying information was removed by BSEE prior to sharing the data to ensure confidentiality and reduce any bias.

As provided, the information was organized by SEMS element and finding categories (Non-Conformances, Areas of Concern, Opportunities for Improvements, Good Practices). In addition, an expert group applied further analytical methodologies to identify trends, cross-element issues, and other insights into industry performance.

Specific definitions for these are provided in Appendix 1

3.0 EXECUTIVE SUMMARY

ABOUT THE REPORT

The Center for Offshore Safety (COS) Annual Performance Report (APR) for 2019 provides an accounting of safety-related incidents and events at facilities operating in the U.S. Outer Continental Shelf (OCS).

Members voluntarily present data for the APR to support COS' mission to provide the highest level of safety for the U.S. offshore natural gas and oil industry. Through the report, COS can identify areas of improvement in the management of risk through safety management systems for the operation of offshore wells, projects, and production facilities in the U.S. OCS.

Member data in the report comes from two key COS programs: the Safety Performance Indicators program, or SPI, and the Learning from Incidents and Events program, or LFI. Both programs identify and monitor areas where the industry can improve safety in the U.S. OCS. While COS maintains a database of all data collected, beginning with 2013 data, the data in the APR reflects the most recent 5-years' data.

In addition to the SPI and LFI data, this year's APR also includes an analysis of 47 regulatorily required SEMS audits completed between 2017-2019. This analysis of SEMS audit reports, which includes both COS member and non-member data, provides insight into the maturity levels of SEMS programs throughout the U.S. OCS. These insights will help COS and industry determine where to focus safety efforts for continual improvement.

This yearly performance report is an example of COS' commitment to open communication and transparency of safety information, to building collaboration, communication, and sharing regarding safety in and between the industry, regulators and the public.

KEY FINDINGS FROM 2019 DATA

- There were zero incidents reported for 2019 which included injuries to 5 or more people, greater than $1 million direct damage costs, or oil spills to water greater than 10,000 gallons.
- Three of the four fatalities reported for the U.S.OCS in 2019 were from two incidents reported by COS member companies.
- The report shows there were zero Level 1 or Level 2 well control incidents for 2019.
- The 23 reported SPI 2 mechanical lifting incidents was a sharp increase from the eight reported in 2018 and 16 reported in 2017.
- Of the 37 SPI 1 and SPI 2 incidents reported, 9 incidents (24%) involved equipment failure as a contributing factor.
- For the 43 U.S. OCS incidents reported to the LFI Program, the three areas most frequently identified for improvement were: Operating Procedures or Safe Work Practices; Quality of Hazard Mitigation; and Quality of Task Execution.
- Four SEMS elements accounted for 55% of the cited Non-Conformances: Assurance of Quality and Mechanical Integrity, Safe Work Practices, Hazards Analysis, and Operating Procedures.
- Five SEMS elements accounted for 56% of the cited Areas for Concern: Safe Work Practices, Assurance of Quality and Mechanical Integrity, Hazards Analysis, Management of Change, and Operating Procedures.
- The data reported for 2019 represents over 44-million Operator and Contractor work hours in the U.S. OCS. This is a slight increase of more than 3 million hours from the hours reported for 2018.

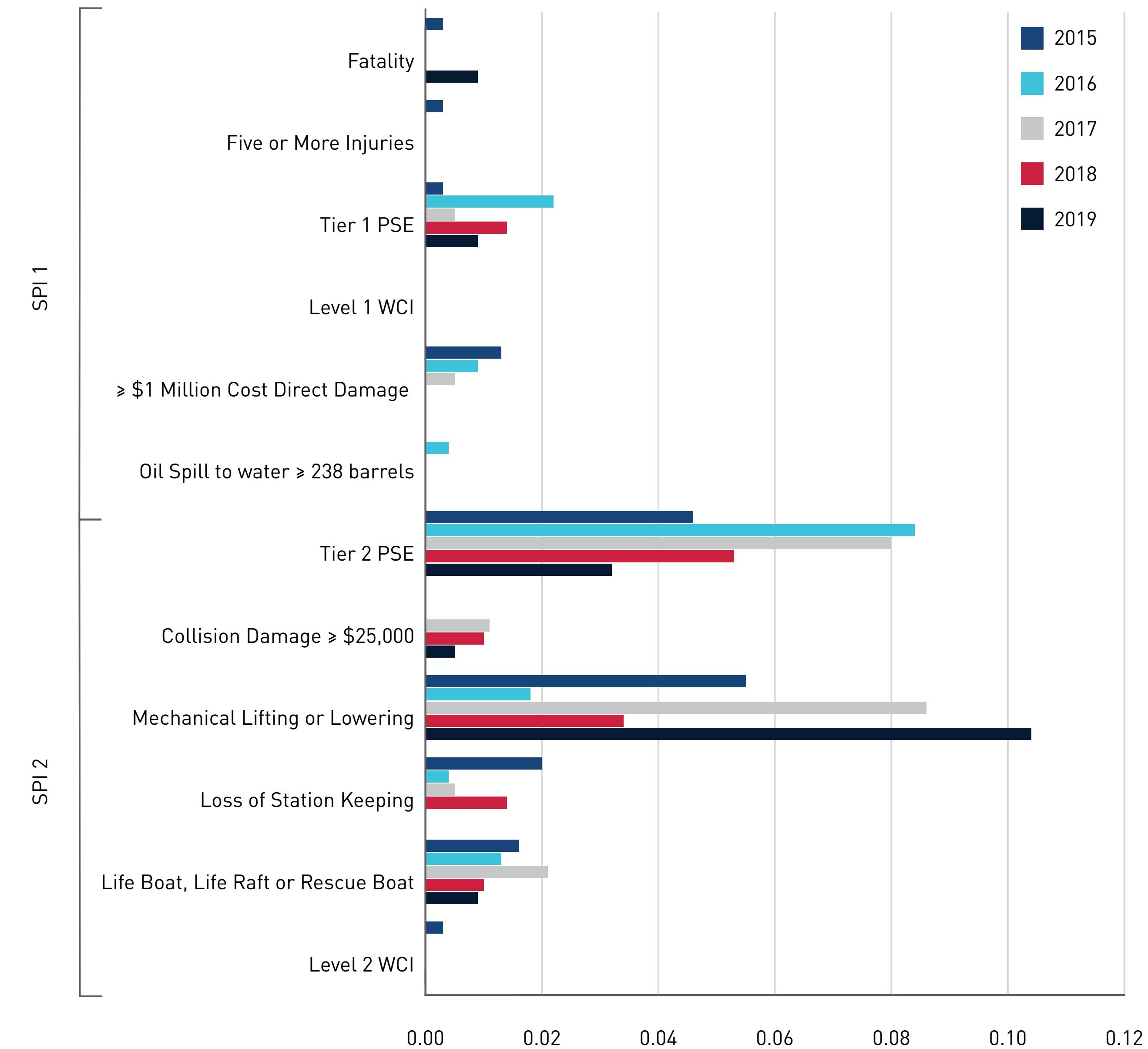
3.1 SPI DATA SUMMARY

Operator members reported four **SPI 1** incidents for 2019, as compared to three for 2018. The four **SPI 1** were two incidents involving at least one **Fatality (SPI 1A)** and two incidents that were **Tier 1 Process Safety Events (PSE) (SPI 1C)**. Zero **SPI 1** incidents involving **≥ Five Injuries in a Single Incident (SPI 1B)**, **Level 1 Well Control Incidents (WCI) (SPI 1D)**, **≥ $1 Million Cost Direct Damage (SPI 1E)**, or **Oil Spills to Water ≥ 238 bbl. (SPI 1F)** were reported for 2019.

Operator members also reported 33 **SPI 2** incidents for 2019, as compared to 25 for 2018. The reported consequences were seven **Tier 2 PSE (SPI 2A)**, one incident resulting in **Collision Damage > $25,000 (SPI 2B)**, 23 **Mechanical Lifting or Lowering Incidents (SPI 2C)**, and two **Life Boat, Life Raft, or Rescue Boat Events (SPI 2E)**. No incidents resulting in a **Loss of Station Keeping (SPI 2D)** or **Level 2 WCI (SPI 2F)** were reported for 2019.

The frequency of SPI 1 and SPI 2 incidents for 2015-2019 are shown in Figure 3.1. Additional details for SPI 1 and SPI 2, and remaining SPI, can be found in Section 4 of this report.

FIGURE 3.1: SPI 1 and SPI 2 Incident Frequency



Center for Offshore Safety Annual Performance Report

3.2 LFI DATA SUMMARY

The effectiveness of this program is dependent on active participation by COS members to facilitate maximum learning opportunities through:

- Timely sharing of quality information from incidents and HVLE that meet the reporting criteria; and
- Reviewing submitted incidents and HVLE, along with other data in this report, to identify and implement applicable learnings appropriate to different levels and functions within their own organizations.

The LFI data presented in this report includes information from 52 LFI submittals received for the 2019 reporting year, with 43 of the reported incidents and HVLE occurring in the U.S. OCS, four occurring in U.S. Onshore/State Waters, and five occurring at international locations. To support COS' mission to promote the highest level of safety for the U.S. offshore natural gas and oil industry, the charts and graphs presented in this report are focused on incidents and events that occurred in the U.S. OCS. A review of the 2019 reporting year LFI data (U.S. OCS only) identified the top reported activity types as:

- Mechanical Lifting or Lowering (32.6%)
- Drilling Operations – Normal, Routine (20.9%)
- Maintenance, Inspection and Testing (14.0%)
- Production Operations – Normal, Routine (11.6%)

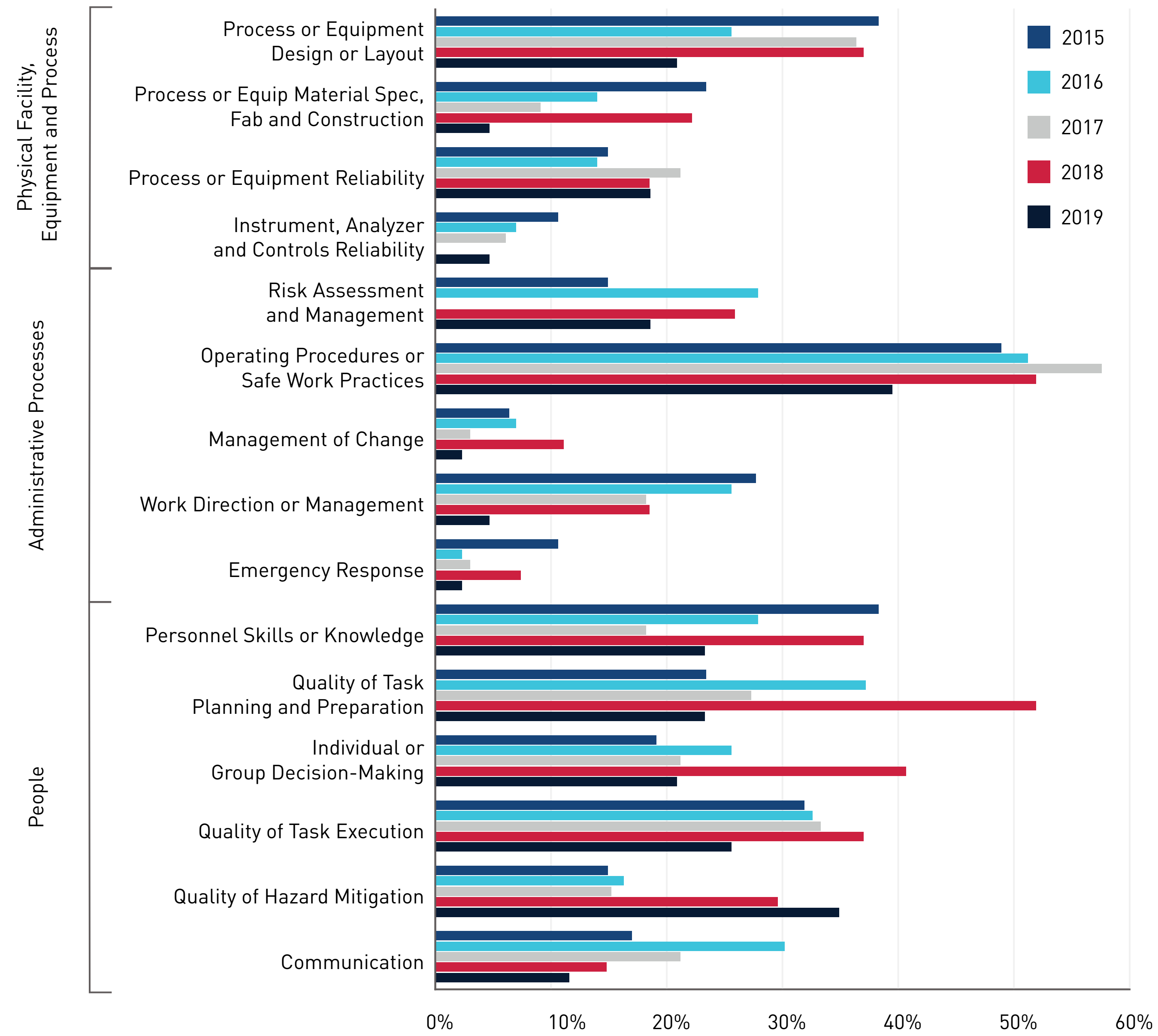
In addition to the topics mentioned above, the top three Areas for Improvement (AFI) identified for 2019 were:

- Operating Procedures or Safe Work Practices (39.5%)
- Quality of Hazard Mitigation (34.9%)
- Quality of Task Execution (25.6%)

Consistently, Operating Procedures or Safe Work Practices has been the most frequently identified AFI. However, the 39.5% reported for 2019 is the lowest for the seven years of COS LFI data.

Additional LFI data, as well as selected incident reports and learnings, are covered in Section 5 of this report.

FIGURE 3.2: Areas for Improvement Distribution (U.S. OCS only)



NOTE - LFI submittals typically identify more than one AFI for any given incident. The graph above illustrates the percent of times an AFI was identified relative to the number of LFI forms submitted for U.S. OCS. Because the number of AFI exceeds the number of LFI forms, the sum of the percentages will be > 100%.

3.3 SEMS AUDIT DATA SUMMARY

For the 47 SEMS audit reports submitted to BSEE from 2017-2019, 214 Non-Conformances, 187 Areas of Concern, and 153 Opportunities for Improvement were identified. Typically, Non-Conformances and Areas of Concern represent either less than satisfactory fulfillment of a requirement, or a requirement that is only marginally being met but could lead to a non-conformity if additional actions are not taken. Of note:

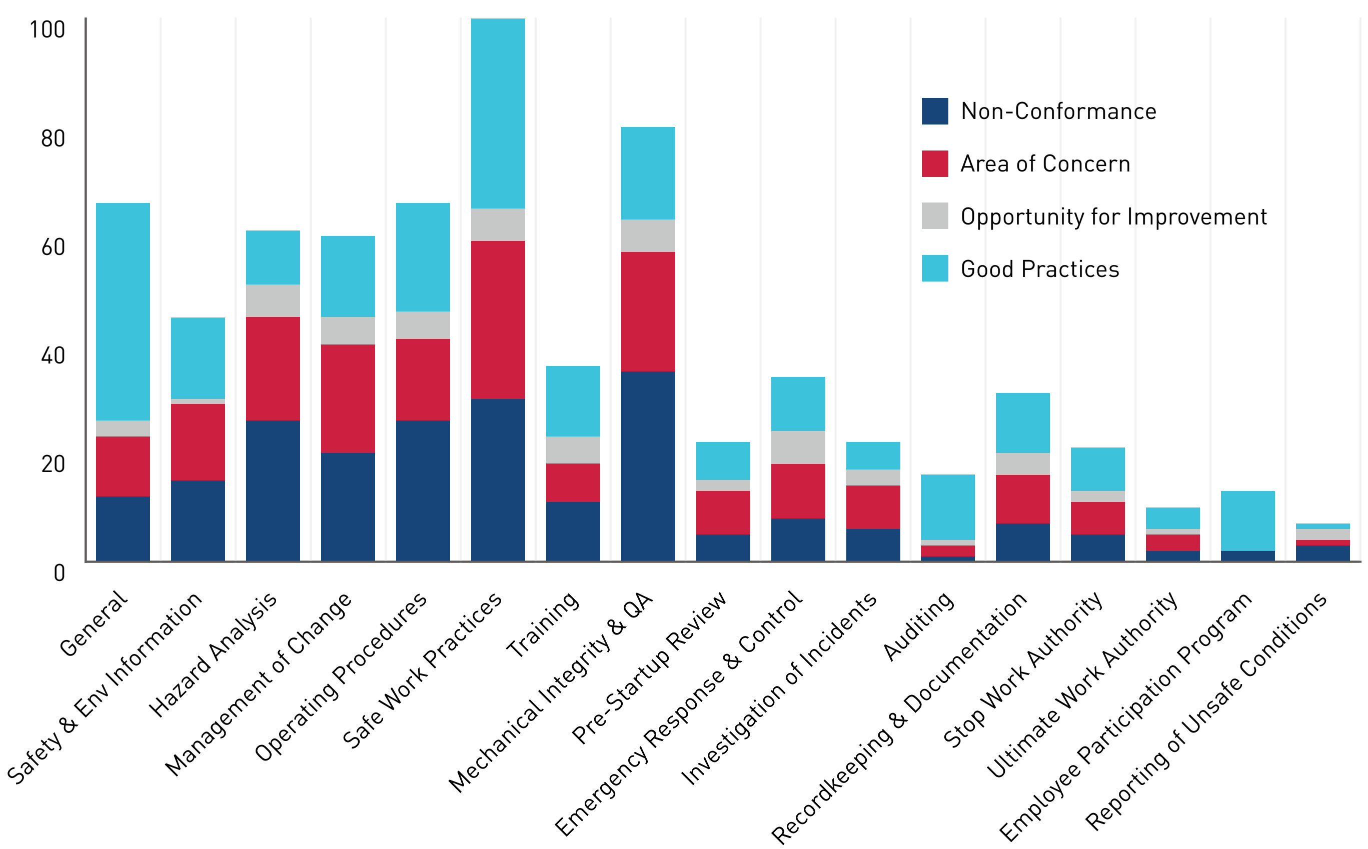
- Four SEMS Elements account for 55% of the Non-Conformances – Assurance of Quality and Mechanical Integrity, Safe Work Practices, Hazards Analysis, and Operating Procedures
- Five SEMS elements accounted for 56% of the cited Areas for Concern: Safe Work Practices, Assurance of Quality and Mechanical Integrity, Hazards Analysis, Management of Change, and Operating Procedures

In addition, 234 Good Practices were also identified; these were analyzed separately to identify learnings. Over 90% of the Good Practices identified were statements of conformance indicating functional and effective areas within SEMS. Every SEMS Element had at least one Good Practice identified.

Figure 3.3 shows the distribution of the count of Non-Conformances, Areas of Concern, Opportunities for Improvement, and Good Practices as reported by SEMS Elements.

Additional SEMS Audit results, including an analysis of findings per SEMS maturity phases, can be found in Section 6 of this report.

FIGURE 3.3: Findings by SEMS Element and Finding Type



3.4 COS ACCOMPLISHMENTS FOR 2019-2020

The COS APR is published in September each year. Below are highlights of COS activities and accomplishments since the publication of last year's APR through September 2020.

3.4.1 SEMS AUDIT SERVICE PROVIDER (ASP) ACCREDITATION PROGRAM

In accordance with the Memorandum of Understanding signed in 2015, COS is currently the only accreditation body authorized by BSEE to accredit SEMS ASP pursuant to 30 CFR 250, Subpart S.

As of the writing of this report, six (6) ASP have been fully accredited:

- ABS Quality Evaluations
- CICS-Americas
- DNV GL Business Assurance
- ERM Certification and Verification Services
- Gulf Tech
- M&H Auditing

A list of accredited ASP is maintained at https://www.centerforoffshoresafety.org/

3.4.2 SEMS AUDIT AND CERTIFICATE PROGRAM

SEMS Certificates demonstrate that an organization has satisfactorily completed a Safety and Environmental Management System (SEMS) audit conducted by an accredited ASP and meets the requirements of API Recommended Practice 75 Version 3.

As of the publication of this APR, the following COS member companies have successfully attained or re-attained a COS SEMS Certificate:

- Anadarko Petroleum Corporation
- BHP Billiton Petroleum
- BP E&P, Inc.
- Cameron International
- Chevron U.S.A, Inc. (Deepwater Assets)
- Cobalt International Energy, LP
- ConocoPhillips Company
- Equinor U.S.A E&P, Inc
- ExxonMobil Production Company
- Helmerich & Payne International Drilling Co.
- Hess Corporation
- Marathon Oil Company
- Murphy E&P, Co.
- Noble Energy
- Shell E&P Co.
- Pacific Drilling Services, Inc.
- Schlumberger
- Statoil Gulf Services, LLC.

A list of COS member certificates is maintained at https://www.centerforoffshoresafety.org/

In early 2020, COS modified procedures for SEMS Certificates to allow non-COS member companies to obtain COS SEMS Certificates. The modified procedures also allow operations outside the U.S. OCS to obtain SEMS Certificates.

The updated procedures, COS-2-05 Requirements for COS SEMS Certificates, are available for download at https://www.centerforoffshoresafety.org/

3.4.3 COS SAFETY LEADERSHIP AWARD

The winners of the 2019 COS Safety Leadership Awards were:

ExxonMobil—Safe Choice: Empowering Workers to Enhance Human Performance, and
Baker Hughes, a GE Company—Enhanced Augmented/Mixed Reality and Process Safety Applications

COS will be announcing the winners of the 2020 COS Safety Leadership Award at the 8th Annual COS Safety Forum, November 10-11 – Virtual event.

3.4.4 COS PUBLICATIONS & WEBINARS

COS published a suite of new and updated documents in April 2020 aimed at improving the quality and consistency of SEMS Audits. In addition to the SEMS Audit documents, COS also published Guidance for Developing and Managing Procedures.

These documents are all available for free download via the COS website – www.CenterforOffshoreSafety.org. The new and updated documents are:

- COS-1-06 Guidance for Developing a SEMS Audit Plan, 1st edition
- COS-1-07 Guidance for Developing a SEMS Corrective Action Plan, 1st edition
- COS-1-08 SEMS Audit Report Format and Guidance, 1st edition
- COS-2-03 SEMS Auditing Requirements, 2nd edition
- COS-2-05 Requirements for a COS SEMS Certificate, 1st edition
- COS-3-06 Guidance for Developing and Managing Procedures

COS held the following webinars in 2020 with the purpose of educating the industry on the published good practices.

- COS Webinar: Audit Good Practice, April 21, 2020
- COS Webinar: Annual Performance Report for the 2019 Reporting Year, September 24, 2020
- COS Webinar: Guidance for Developing and Managing Procedures, September 30, 2020

3.4.5 COS SAFETY SHARES

As part of the COS commitment to the mission of promoting safe operations by sharing industry knowledge, COS created the COS Safety Shares Program. In August 2020 COS added 10 new Safety Shares to its library of available Shares:

- COS2019004 Staging Materials Near Handrail Results in Dropped Object
- COS2019005 Lifting Eye Unexpectedly Came Free
- COS2019009 Stored 2500 Pound Elevator Links Descend 69" to Deck
- COS2019013 Offshore Worker Stops Work and Prevents Potential Process Safety Incident
- COS2019015 Coiled Tubing Failure During Pressure Test
- COS2019016 Loss of Flare Purge Results in Detonations
- COS2019018 Helicopter Operations Rotor Wash Hazard
- COS2019031 Rigger Lifted from Boat by Tagline
- COS2019033 Human Error Prompts Human Performance Correction
- COS2019035 Dropped Counterweight

A complete list of COS Safety Shares are publicly available at www.centerforoffshoresafety.org, with more under development.

4.0 SAFETY PERFORMANCE INDICATORS

4.1 INTRODUCTION

COS members share Safety Performance Indicator (SPI) data with COS through the SPI Program. Reporting is voluntary and data confidentiality is maintained through a process administered by a 3rd-party before submittal to COS. COS maintains a full record of data collected beginning with 2013 data. The data reported in this APR represents the five most recent years – 2015-2019. A normalization factor for work hours is utilized to enable year-to-year comparisons. A list of SPI collected is presented in Figure 4.1 below.

FIGURE 4.1: Safety Performance Indicators (SPI)

SPI 1 is the frequency of incidents that resulted in one or more of the following:

A. Fatality
B. Five or more injuries in a single incident
C. Tier 1 process safety event
D. Level 1 Well Control Incident - Loss of well control
E. ≥ $1 million direct cost from damage to or loss of facility / vessel / equipment
F. Oil spill to water ≥ 10,000 gallons (238 barrels)

SPI 2 is the frequency of incidents that do not meet the SPI 1 definition but have resulted in one or more of the following:

A. Tier 2 process safety event
B. Collision resulting in property or equipment damage > $25,000
C. Mechanical Lifting or Lowering Incident
D. Loss of station keeping resulting in a drive off or drift off
E. Life boat, life raft, rescue boat event
F. Level 2 Well Control Incident - Multiple Barrier Systems Failures and Challenges

SPI 3 is the number of SPI 1 and SPI 2 incidents that involved failure of one or more pieces of equipment as a contributing factor

SPI 4 is the frequency of crane or personal/ material handling operations incident

SPI 5 is the percentage of planned critical maintenance, inspection and testing (MIT) completed on time. Planned critical MIT deferred with a formal risk assessment and appropriate level of approval is not considered overdue

SPI 6 is number of work-related fatalities

SPI 7 is the frequency of days away from work, restricted work, and job-transfer injuries and illnesses (DART)

SPI 8 is the frequency of recordable injuries and illnesses (RIIF)

SPI 9 is the frequency of oil spills to water ≥ 1 barrel

SPI 10 is the severity potential of incidents involving a dropped object

SPI 1-5 are based on structured assessments of major hazards facing the offshore industry. SPI 6-9 are indicators historically reported by industry and are not directly related to the structured assessment work. SPI 10 is new for the 2019 reporting year and is based on the severity-potential calculator developed by *DROPSOnline*.[2]

Certain characteristics of the data reported for SPI 1 and SPI 2 incidents limit some aspects of the analysis and trending. An incident may have consequences that meet both SPI 1 and SPI 2 definitions but are not counted in both classifications. The higher consequence drives the classification. For example, a collision that results in > $1 Million Direct Damage Cost meets the SPI 1E definition, but also meets the SPI 2B consequence of Collision Resulting in > $25,000 in Damage. However, to prevent the duplication of data, per the SPI program structure, it is only counted as an SPI 1E incident and not an SPI 2B collision.

Although definitions used for some of the SPI are the same or similar to regulatory definitions, the numbers in this report will not necessarily match regulatory data due to this report being based on COS member company data and not all companies operating in the U.S. OCS.

4.2 SUMMARY

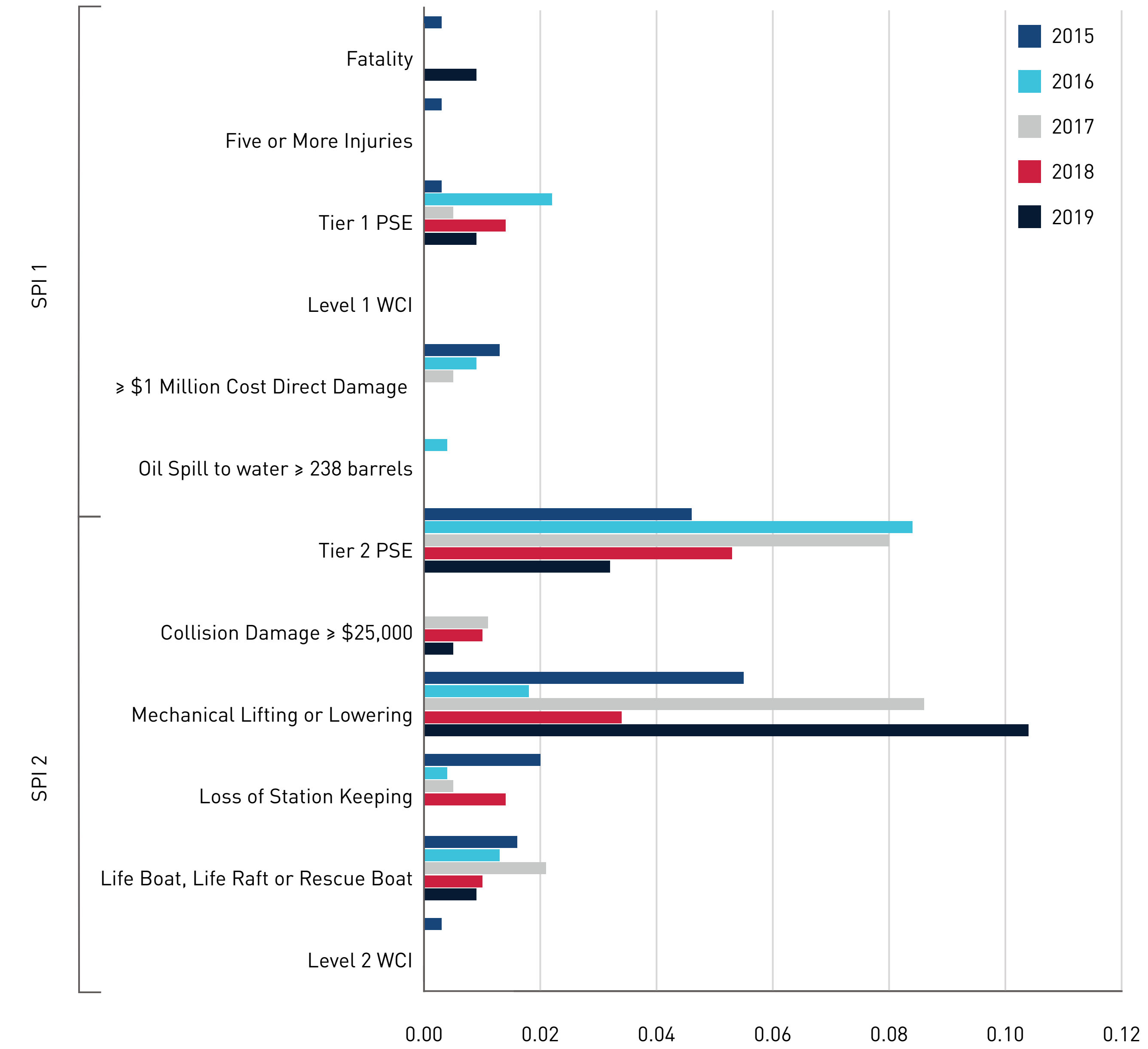
This report provides COS member data for 2015-2019. The data reported for 2019 represents over 44-million Operator and Contractor work hours in the U.S. OCS. This is a slight increase of more than 3 million hours from the hours reported for 2018. Work hours are reported only by Operators for work occurring within 500 meters of their facilities.

Reporting Year	COS OCS Work Hours (Millions)
2015	61
2016	45
2017	37
2018	41
2019	**44**

The frequency of all SPI 1 and SPI 2 incidents are shown below in Figure 4.2; specific definitions for the SPI are presented in Appendix 2.

[2] *Dropped Objects Prevention Scheme Online* www.dropsonline.org

FIGURE 4.2: SPI 1 and SPI 2 Incident Frequency



Operator members reported four **SPI 1** incidents for 2019, as compared to three for 2018. The four **SPI 1** were two incidents involving at least one **Fatality (SPI 1A)** and two incidents that were **Tier 1 PSE (SPI 1C)**. Zero SPI 1 incidents involving **≥ Five Injuries in a Single Incident (SPI 1B)**, **Level 1 Well Control Incidents (WCI) (SPI 1D)**, **≥ $1 Million Cost Direct Damage (SPI 1E)**, or **Oil Spills to Water ≥ 238 bbl. (SPI 1F)** were reported for 2019.

Operator members also reported 33 **SPI 2** incidents for 2019, as compared to 25 for 2018. The reported consequences were seven **Tier 2 PSE (SPI 2A)**, one incident resulting in **Collision Damage > $25,000 (SPI 2B)**, 23 **Mechanical Lifting or Lowering Incidents (SPI 2C)**, and **two Life Boat, Life Raft, or Rescue Boat Events (SPI 2E)**. No incidents resulting in a **Loss of Station Keeping (SPI 2D)** or **Level 2 WCI (SPI 2F)** were reported for 2019.

The seven **Tier 2 PSE (SPI 2A)** reported in 2019, was down from 11 in 2018, 15 in 2017, and 19 in 2016. The seven reported for 2019 is the lowest since COS started collecting data in 2013.

The one incident reported for 2019 involving **Collision Damage ≥ $25,000 (SPI 2B)** was down from two reported each year for 2017-2018.

As stated above, there were 23 incidents involving **Mechanical Lifting or Lowering (SPI 2C)**; a significant increase from the seven reported for 2018 and 16 reported for the 2017. In addition to the data reported by COS Operator members, COS Contractor members reported two incidents involving **Mechanical Lifting or Lowering (SPI 2C)**.

The reporting of zero **Loss of Station Keeping Resulting Drive Off or Drift Off (SPI 2D)** incidents for 2019 is lower as compared to three for 2018 and one for 2017.

The two **Life Boat, Life Raft, or Rescue Boat Events (SPI 2E)** was the same as reported for 2018 and lower compared to four for 2017.

Of the 37 total **SPI 1** and **SPI 2** incidents reported by Operators for 2019, nine involved **Failure of Equipment as a Contributing Factor (SPI 3)**, or 24%. The most frequently cited equipment type for 2019, with 5 incidents reporting failure as a contributing factor, was Mechanical Lifting Equipment/Personnel Transport Systems.

The 2019 frequency of **Incidents Involving Cranes or Personnel/Material Handling (SPI 4)** was the highest reported from 2013-2019. The 2019 frequency was 0.620, compared to 0.187 for the prior year. For clarification, work hours are used to determine frequency and not the total number of lifts.

For Operators' **SPI 5 data (Percentage of Planned Critical Maintenance Completed on Time)**, the combined average for 2019 was 93.8%. This is a decrease from the average of 97.3% reported for 2018.

Additionally, for Contractors that shared **SPI 5 data**, the combined average for 2019 was 97.3%, which represents an increase from the average of 93.9% reported for 2018.

Three **Fatalities (SPI 6)** were reported for 2019. Including this 2019 data, a total of four (4) fatalities have been reported to COS in seven years of collecting data.

The combined **Days Away from Work, Restricted Work and Transfer of Duty Rate (DART) (SPI 7)** reported for 2019 was 0.244 which is a decrease as compared to the 0.268 reported for 2018. This rate remains higher when compared with 2014-2017.

The combined **Recordable Injury and Illness Frequency (RIIF) (SPI 8)** reported for 2019 was 0.448, lower than the 0.474 reported for 2018 and 0.488 reported for 2017, but higher than the rates for 2014-2016.

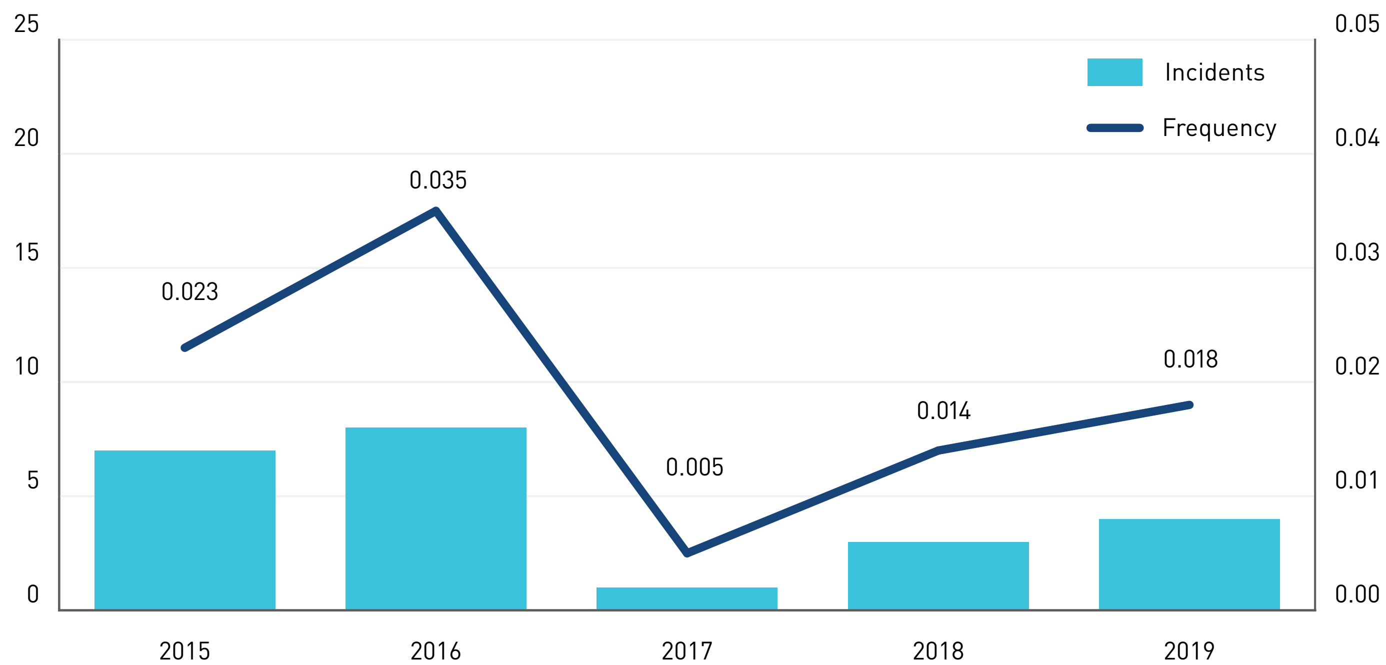
COS members reported one **Oil Spill to Water ≥ One Barrel (SPI 9)** for 2019, compared to five for 2018 and two for 2017. The frequency was 0.005 for 2019, compared to 0.024 in 2018 and 0.011 in 2017. This is the lowest number reported to COS for SPI 9 in seven years of data.

4.3 SPI 1 RESULTS AND TRENDS

SPI 1 is the frequency of incidents that resulted in one or more of the following:

A. Fatality
B. Five or more injuries in a single incident
C. Tier 1 Process Safety Event
D. Level 1 Well Control Incident - Loss of Well Control
E. ≥ $1 million direct cost from damage to or loss of facility/vessel/equipment
F. Oil Spill to Water ≥ 10,000 gallons (238 barrels)

FIGURE 4.3: SPI 1 Incident Count and Frequency



- Participating Operator members reported four **SPI 1** for 2019, as compared to three for 2018.
- The four **SPI 1** incidents reported for 2019 combined for a frequency of 0.018.

FIGURE 4.4: SPI 1 Incident Count per Sub-Group

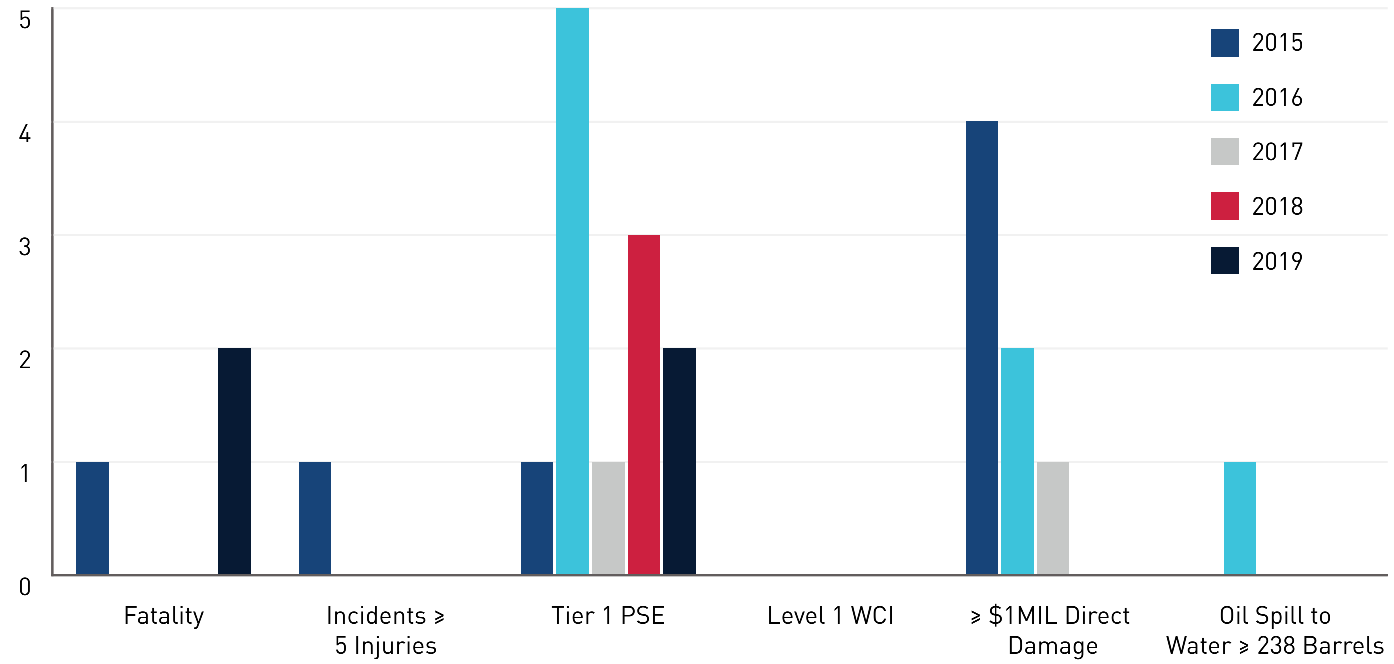
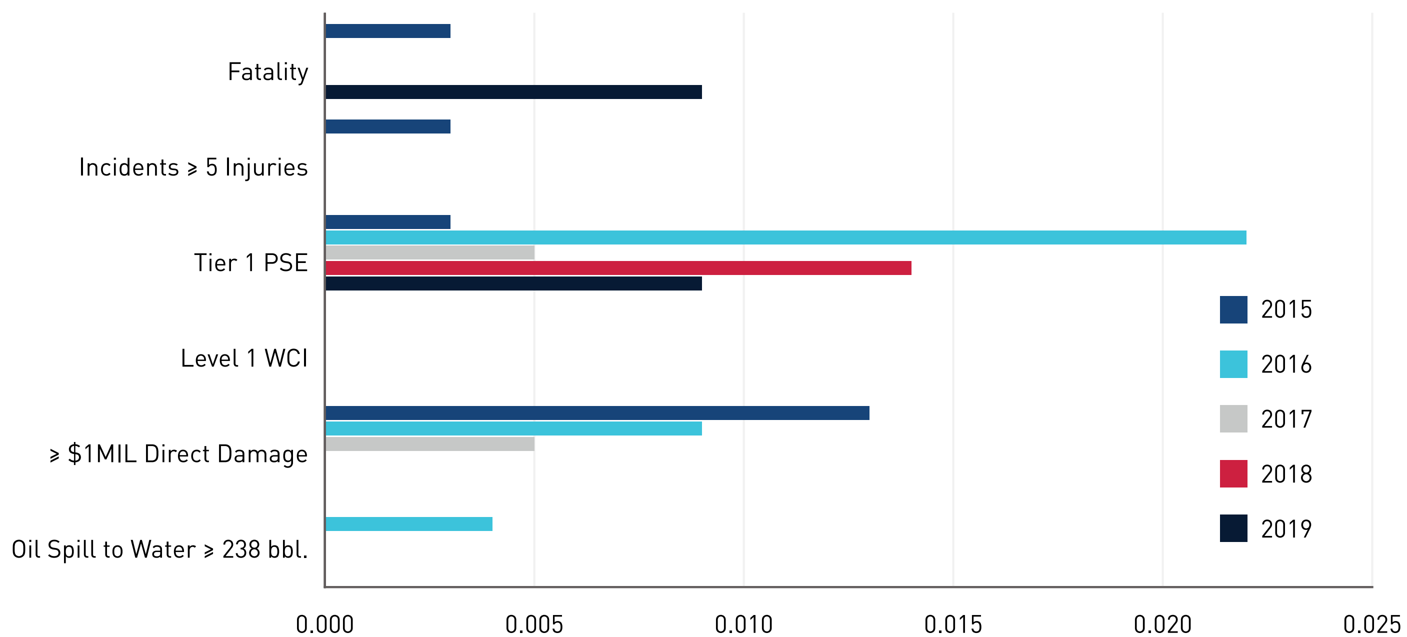


FIGURE 4.5: SPI 1 Incident Frequency per Sub-Group



- The four **SPI 1** incidents were two incidents involving a **Fatality (SPI 1A)** and two that resulted in a **Tier 1 PSE (SPI 1C)**.
- Zero **SPI 1** incidents involving **≥ Five Injuries in a Single Incident (SPI 1B)**, **Level 1 Well Control Incidents (SPI 1D)**, **≥ $1 Million Cost Direct Damage (SPI 1E)**, or **Oil Spills to Water ≥ 238 bbl. (SPI 1F)** were reported for 2019.
- 2019 marks the fifth year in a row with COS Operators reporting zero **Level 1 Well Control Incidents.**

4.4 SPI 2 RESULTS AND TRENDS

SPI 2 is the frequency of incidents that do not meet the SPI 1 definition but have resulted in one or more of the following:

A. Tier 2 process safety event

B. Collision resulting in property or equipment damage > $25,000

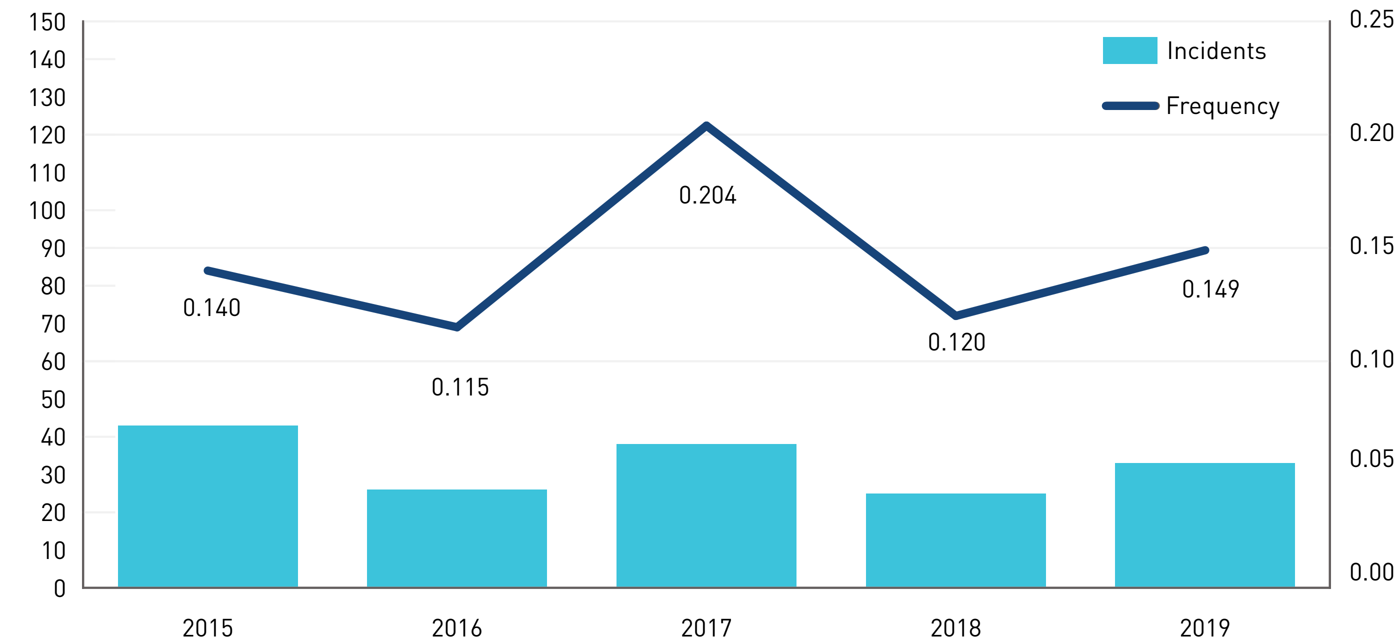
C. Mechanical Lifting or Lowering Incident

D. Loss of station keeping resulting in a drive off or drift off

E. Life boat, life raft, rescue boat event

F. Level 2 Well Control Incident - Multiple Barrier Systems Failures and Challenges

FIGURE 4.6: SPI 2 Incident Count and Frequency



- Participating members reported 33 **SPI 2** for 2019, as compared to 25 for 2018, and 38 for 2017.

FIGURE 4.7: SPI 2 Incident Count per Sub-Group

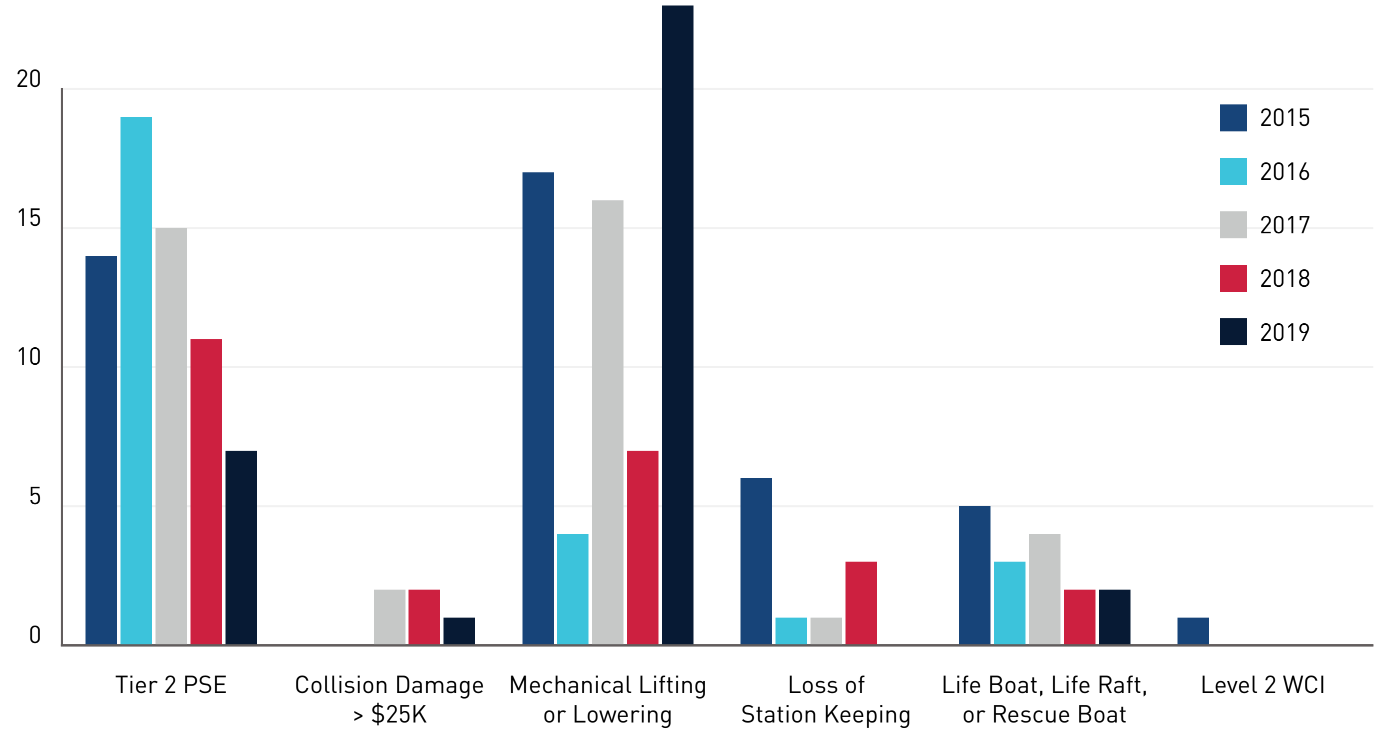
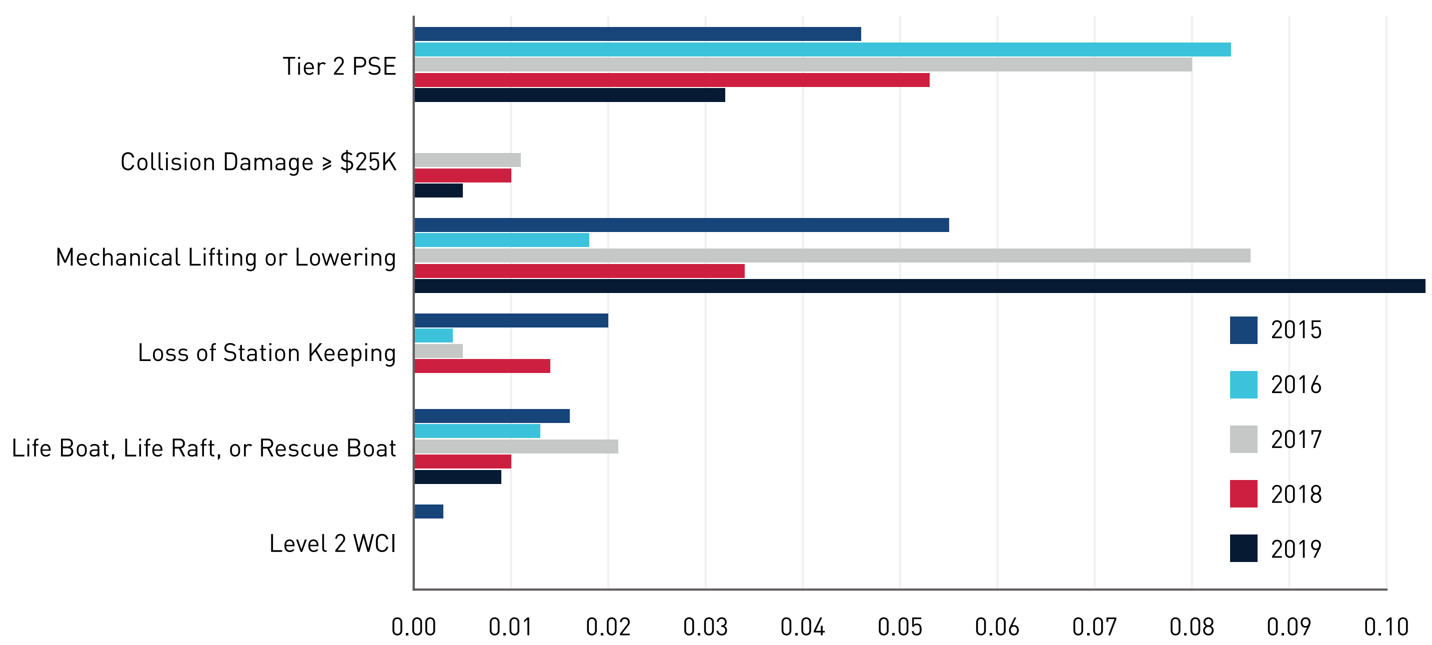


FIGURE 4.8: SPI 2 Incident Frequency per Sub-Group



- Of the 33 **SPI 2** reported for 2019, the consequences were seven **Tier 2 PSE (SPI 2A)**, one incident resulting in **Collision Damage > $25,000 (SPI 2B)**, 23 **Mechanical Lifting or Lowering Incidents (SPI 2C)**, and two **Life Boat, Life Raft, or Rescue Boat Events (SPI 2E)**.
- 2019 marks the fourth year in a row with COS Operators reporting zero **Level 2 Well Control Incidents.**
- The seven **Tier 2 PSE** reported for 2019 is down from the 11 reported in 2018 and 15 in 2017. The frequency indicates an improvement trend from 2016 to 2019.
- The one incident reported for 2019 involving **Collision Damage ≥ $25,000 (SPI 2B)**, was down from the two each reported for 2018 and 2017.
- The 23 incidents involving **Mechanical Lifting or Lowering (SPI 2C)** reported for 2019 was a significant increase from the seven reported for 2018 and 16 reported for 2017. Of the 23 incidents reported for this SPI, 10 (43%) were reported by a single Operator. Three Operators reported four **SPI 2C** incidents; each of these four Operators accounts for 17% of the total incidents.
- Two **Life Boat, Life Raft, or Rescue Boat Events (SPI 2E)** were reported for 2019, the same as reported for 2018.

4.5 TIER 1 AND TIER 2 PROCESS SAFETY EVENT CONSEQUENCES

Tier 1 and Tier 2 PSE are determined by assessing the consequences of a loss of primary containment (LOPC) event against defined thresholds (see Appendix 2). If it meets or exceeds a threshold, then it is classified as either a Tier 1 PSE or a Tier 2 PSE, but not both. In 2014, participating COS members began sharing consequence data for reported Tier 1 and Tier 2 PSE.

Consequence data was collected for the two Tier 1 PSE (SPI 1C) shared for 2019, with the following consequences:

- One PSE Resulting in a Worker Days Away from Work Injury
- One PSE Resulting in a Non-Toxic Material Release
- One PSE Resulting in an Outdoor Release

Consequence data was collected for six of the seven Tier 2 PSE (SPI 2A) reported for 2019, with the following consequences:

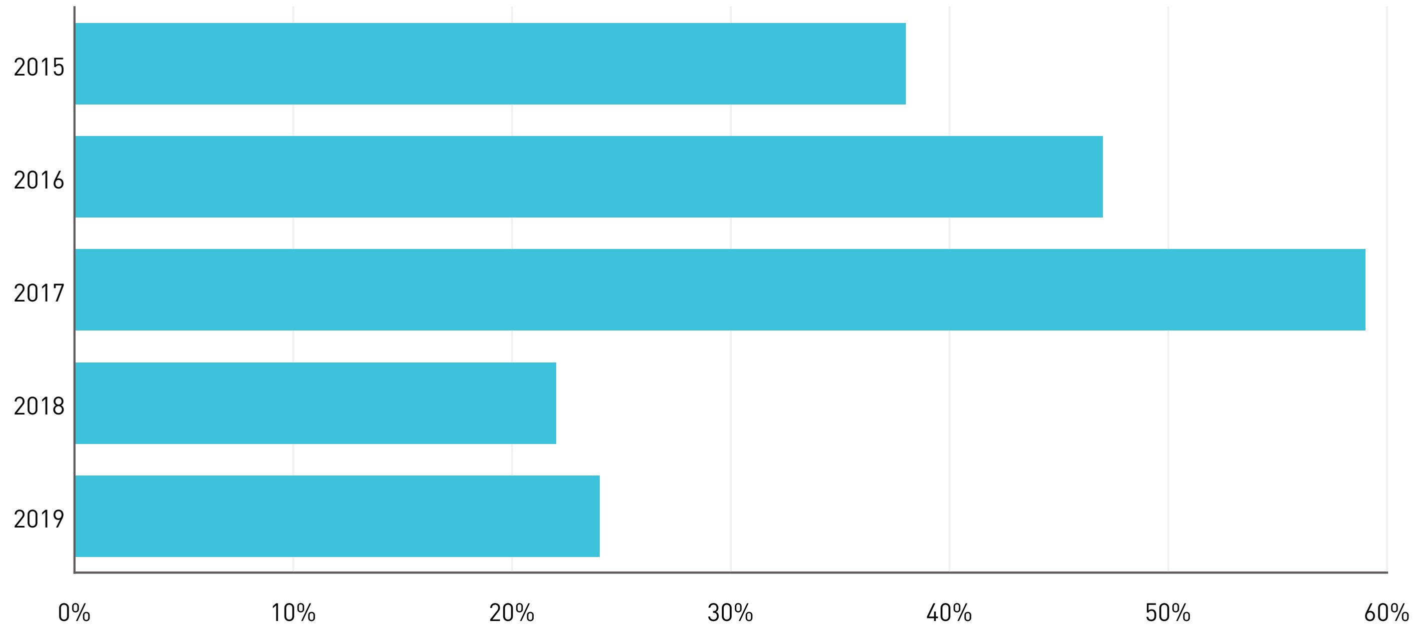
- One PSE Resulting in a Pressure Relief Device (PRD) Discharge Directly to Atmosphere
- One PSE Resulting in a PRD Discharge Directly to Downstream Destructive Device
- One PSE Resulting in a PRD Discharge to an Unsafe Location
- One PSE Resulting in a PRD Discharge with a Consequence of an On-Site Shelter-In-Place
- Six PSE Resulting in a Non-Toxic Material Release
- Six PSE Resulting in an Outdoor Release

Note – The total count of PSE consequences may be greater than the number of incidents reported, as one incident can have multiple consequences.

4.6 SPI 3 RESULTS AND TRENDS

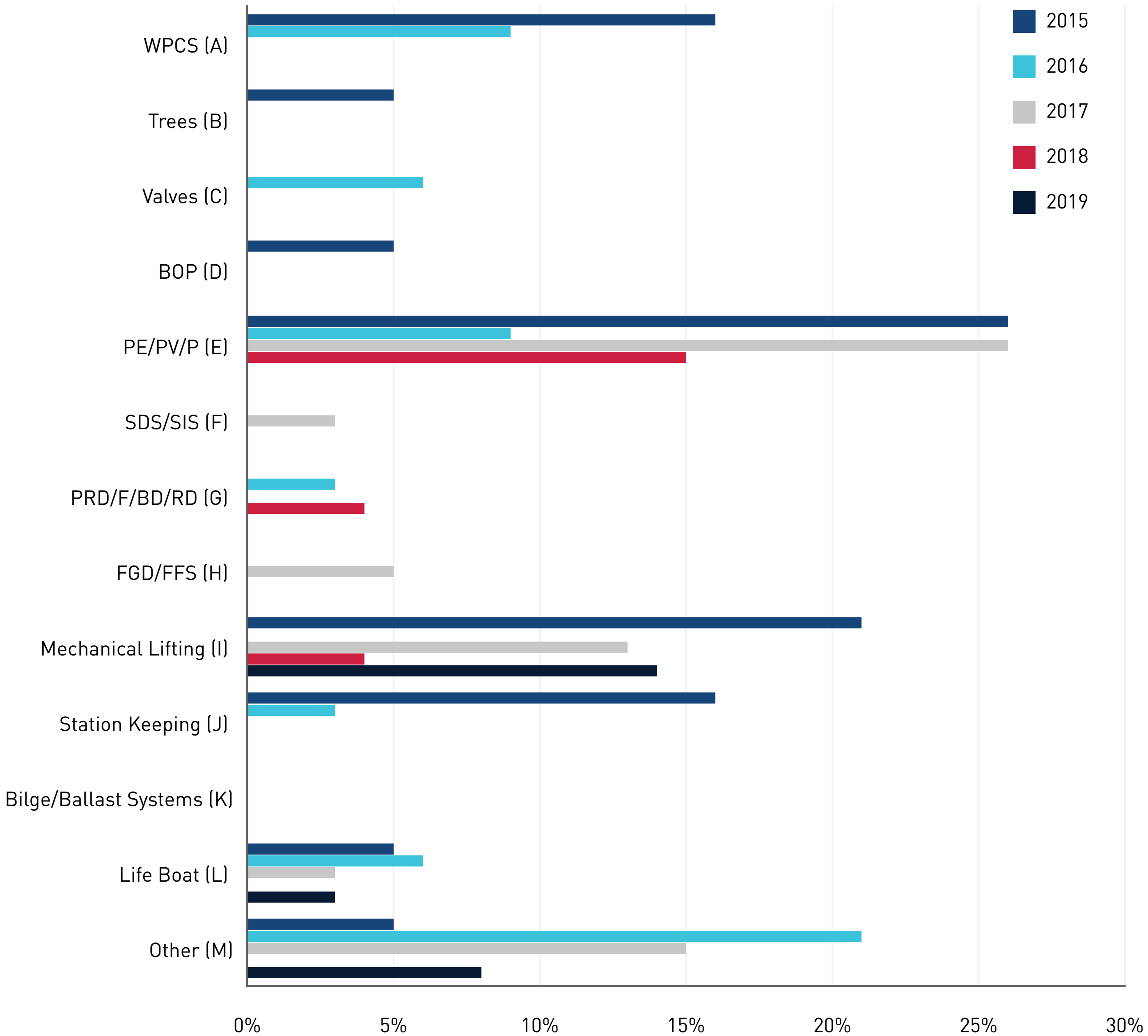
SPI 3 is the number of SPI 1 and SPI 2 incidents that involved failure of one or more pieces of equipment as a contributing factor.

FIGURE 4.9: Equipment Failure as Contributing Factor



- Of the 37 SPI 1 and SPI 2 incidents reported for 2019, nine involved failure of equipment as a contributing factor (SPI 3), or 24%. This is a slight increase over the 22% reported for 2018.

FIGURE 4.10: SPI 3 Failure Rates Contributing to SPI 1 and SPI 2 Incidents – by Equipment Category[3]



- The most frequently cited category for SPI 3 for 2019 was Mechanical Lifting Equipment/Personnel Transport Systems (I).
- The other two equipment types reported as contributing factors for 2019 were Life Boat/Life Raft/Rescue Boat/Launch and Recovery Systems (L) and Other (M).

[3] *Specific definitions and descriptions of the equipment categories are presented in Appendix 3.*

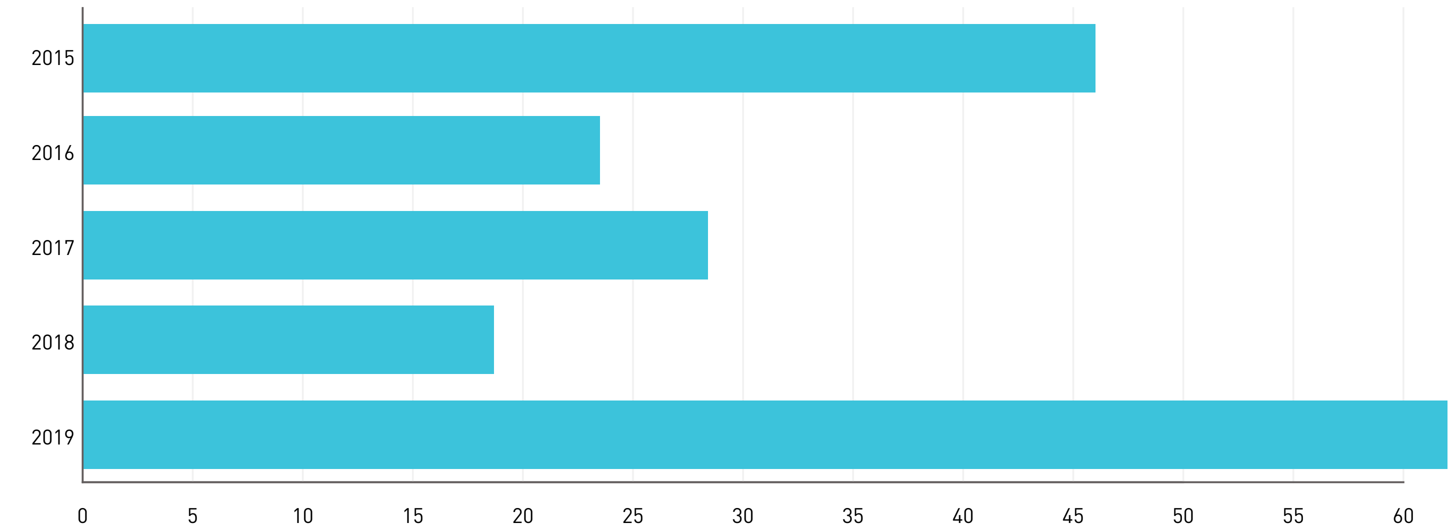
FIGURE 4.11: SPI 3 Incident Counts by Equipment Type

Equipment	2015 Failures (Count)	2016 Failures (Count)	2017 Failures (Count)	2018 Failures (Count)	2019 Failures (Count)
A - Well Pressure Containment System (WPCS)	3	3	0	0	0
B - Christmas Trees	1	0	0	0	0
C - Downhole Safety Valves (Valves)	0	2	0	0	0
D - Blowout Preventers and Intervention Systems (BOP)	1	0	0	0	0
E - Process Equipment/Pressure Vessels/Piping (PE/PV/P)	5	3	10	4	0
F - Shutdown Systems/Automated Safety Instrumented Systems (SDS/SIS)	0	0	1	0	0
G - Pressure Relief Devices/Flares/Blowdown/ Rupture Disks (PRD/F/B/RD)	0	1	0	1	0
H - Fire/Gas Detection and Fire Fighting Systems (FGD/FFS)	0	0	2	0	0
I - Mechanical Lifting Equipment/Personnel Transport Systems	4	0	5	1	5
J - Station Keeping Systems	3	1	0	0	0
K - Bilge/Ballast Systems	0	0	0	0	0
L - Life Boat/Life Raft/Rescue Boat/Launch and Recovery Systems	1	2	1	0	1
M - Other	1	7	6	0	3

4.7 SPI 4 RESULTS AND TRENDS

SPI 4 is the frequency of crane or personnel/material handling operations incident.

FIGURE 4.12: SPI 4 Crane or Personnel / Material Handling Frequency



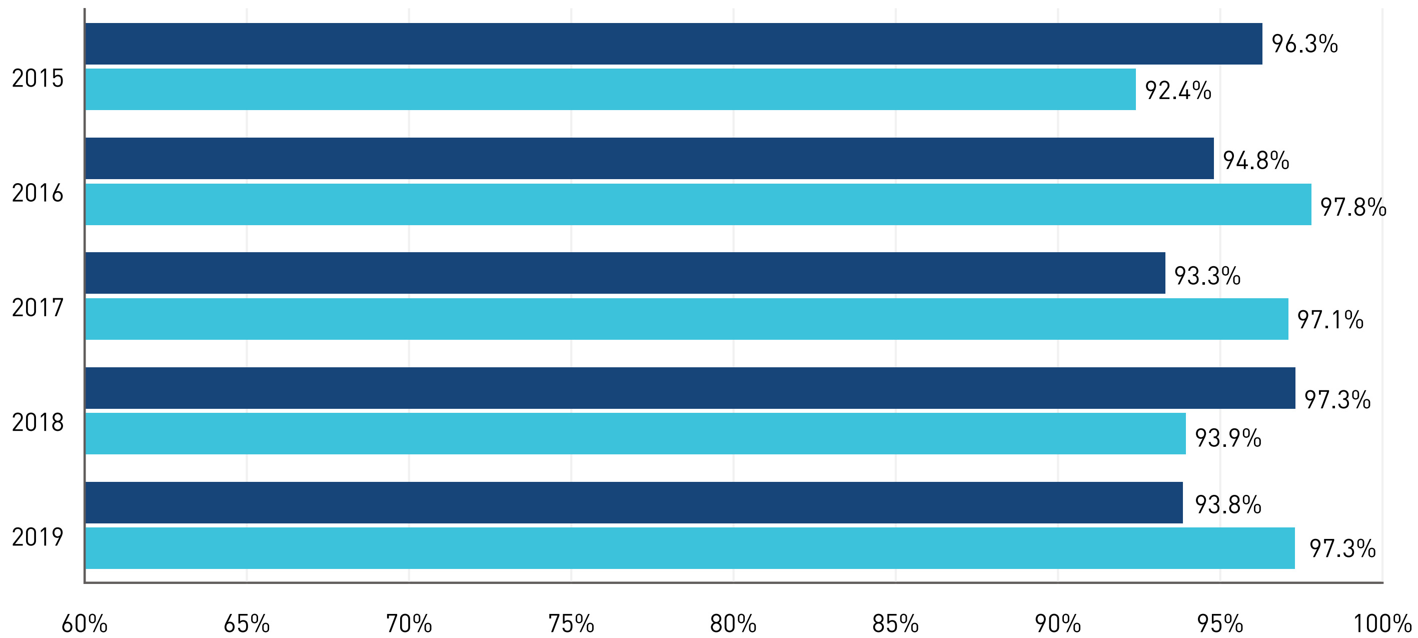
- The 2019 frequency of incidents Involving Cranes or Personnel/Material Handling (SPI 4) was the highest reported from 2015-19.
- 137 incidents Involving Cranes or Personnel/Material Handling (SPI 4) were reported for 2019; a significant increase from the 39 reported for 2018 and 53 reported for 2017. Of the 137 incidents reported for SPI 4, 74%, or 102, were reported by two Operators.

	2015	2016	2017	2018	2019
Count	108	53	53	39	137
Rate	0.460	0.235	0.284	0.187	0.620

4.8 SPI 5 RESULTS AND TRENDS

SPI 5 is the percentage of planned critical maintenance, inspection and testing (MIT) completed on time. Planned critical MIT deferred with a formal risk assessment and appropriate level of approval is not considered overdue.

FIGURE 4.13: Percentage of Planned Critical MIT Completed on Time



- For Operators' SPI 5 data (Percentage of Planned Critical Maintenance Completed on Time), the combined average for 2019 was 93.8%, ranging from 72.7% to 100%. This is a decrease from the data reported for 2018 (average 97.3%, ranging from 71.1% to 100.0%).
- For Contractors, the combined average for 2019 was 97.3%, ranging from 94.6% to 100%, which represents an increase from the data reported for 2018 (average 93.9%, ranging from 60.3% to 100%).
- SPI 5 data, when combined for Operators and Contractors, was 94.9% for 2019, which represents a decrease compared to 96.7% reported for 2018.

Note – each company defines what maintenance, inspection and testing tasks qualify as "critical".

4.9 SPI 6–9 RESULTS AND TRENDS

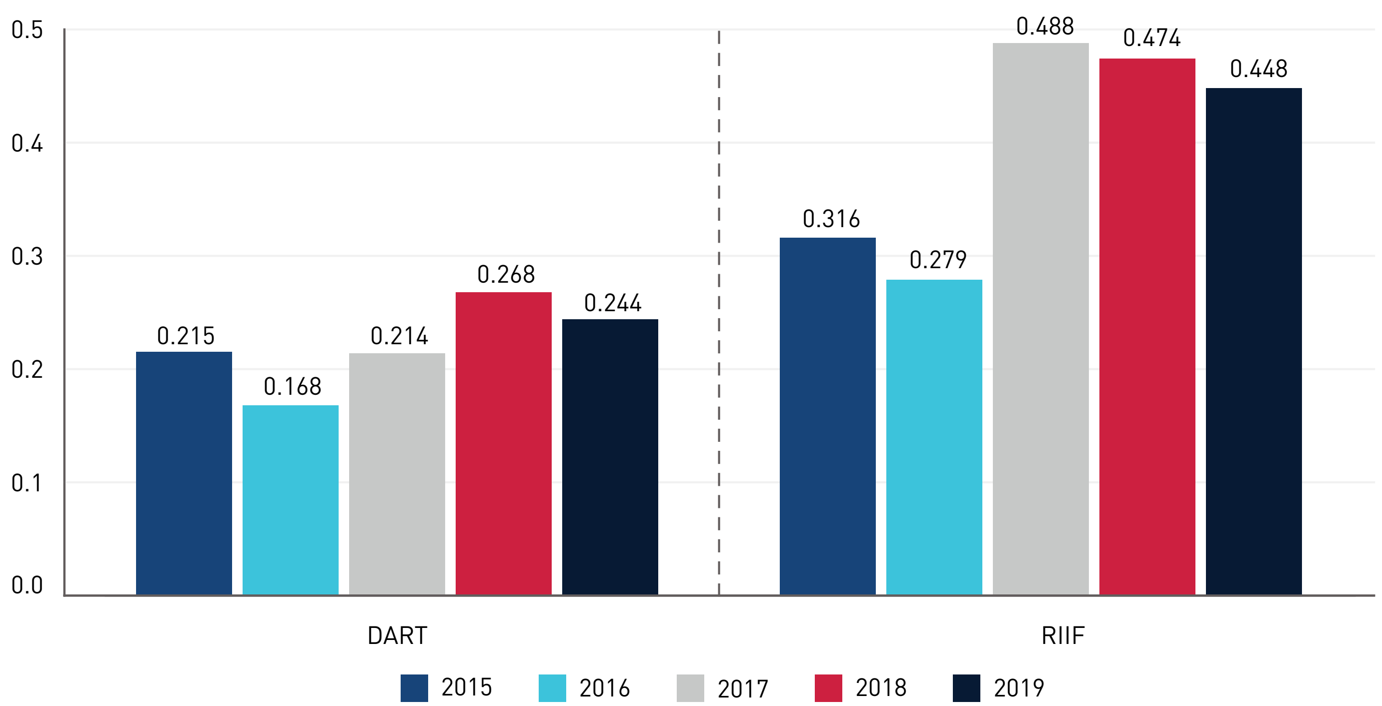
SPI 6 is the number of work-related fatalities

SPI 7 is the frequency of days away from work, restricted work, and job-transfer injuries and illnesses (DART)

SPI 8 is the frequency of recordable injuries and illnesses (RIIF)

SPI 9 is the frequency of oil spills to water ≥ 1 barrel

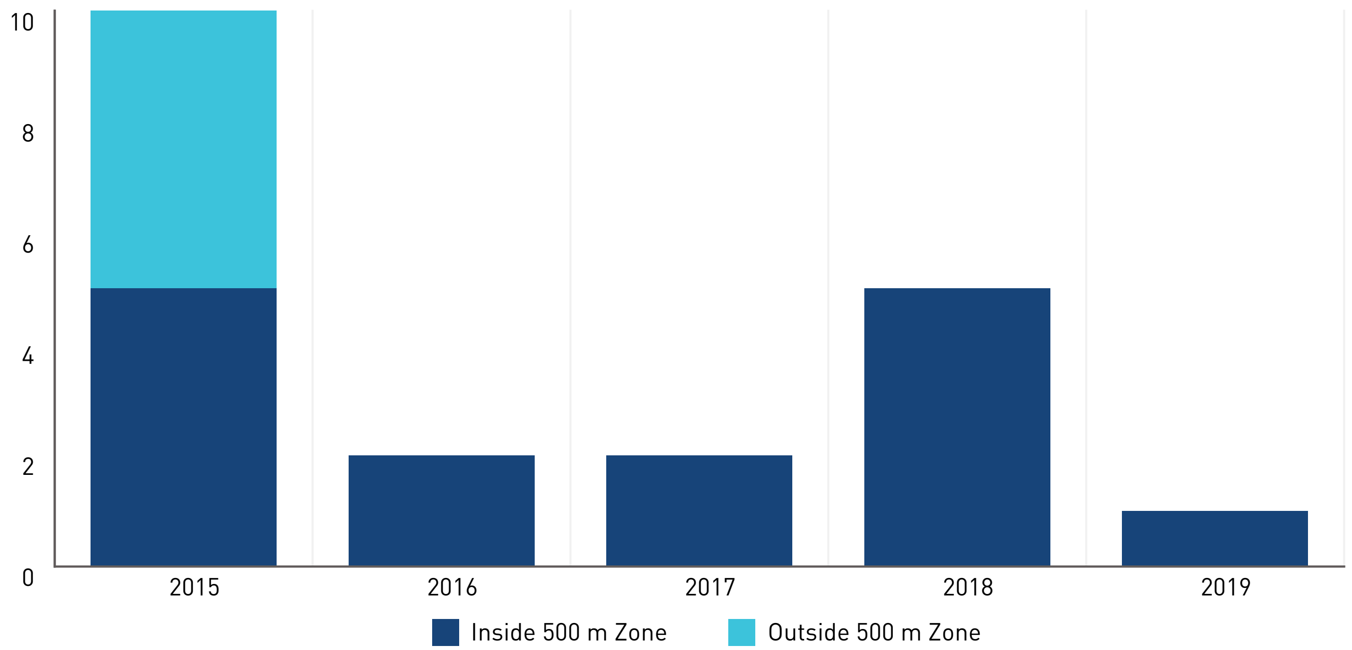
FIGURE 4.14: SPI DART and RIIF Chart[4]



- Three Fatalities (SPI 6) were reported for 2019. A total of four Fatalities have been reported to COS in the seven years of reporting.
- The combined Days Away from Work, Restricted Work and Transfer of Duty Rate (DART) (SPI 7) reported for 2019 was 0.244 which is a decrease from 0.268 reported in 2018.
- The combined Recordable Injury and Illness Frequency (RIIF) (SPI 8) reported for 2019 was 0.448 which is a decrease from 0.474 reported in 2018.

[4] *NOTE – For 2017, although 10 Operators submitted both DART and RIIF data, the chart only reflects the data from 9 Operators. There was an unresolved discrepancy in one Operator's data where the RIIF was lower than the DART, which is an impossibility (as all DART are also RIIF). Including this data would not change the rates significantly and does not affect the conclusions in this report.*

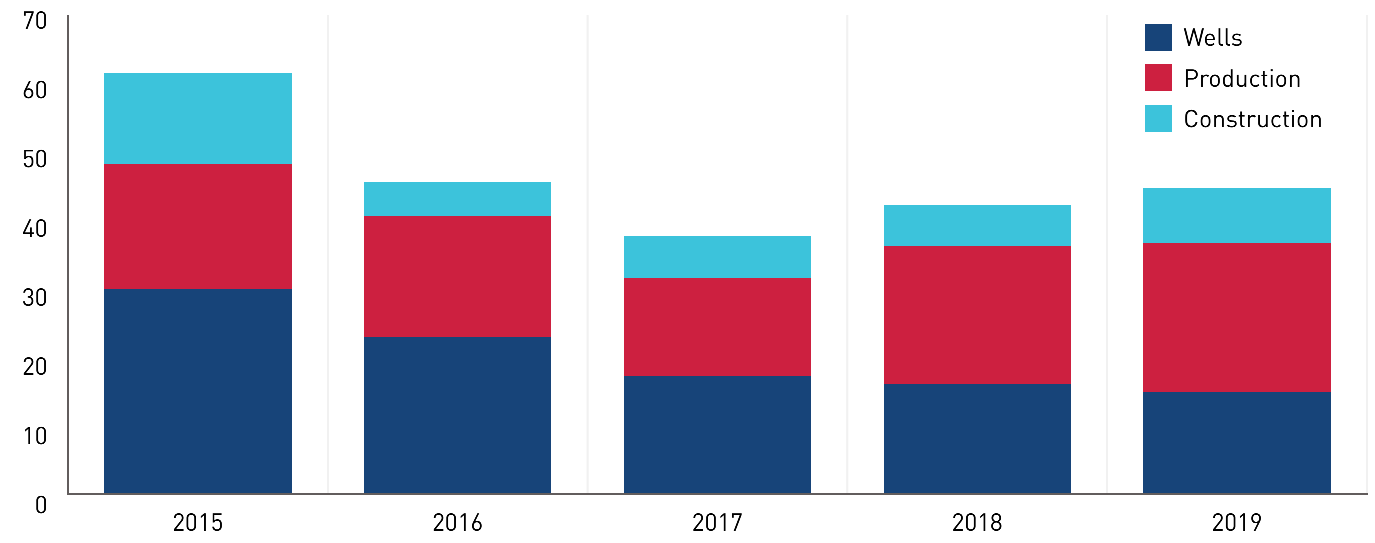
FIGURE 4.15: Oil Spill to Water Count



- One Oil Spill to Water ≥ One Barrel (SPI 9) was reported for 2019, compared to five in 2018 and two in 2017. The frequency was 0.005 for 2019 compared to 0.024 in 2018 and 0.011 in 2017.

4.10 NORMALIZATION FACTOR (WORK HOURS)

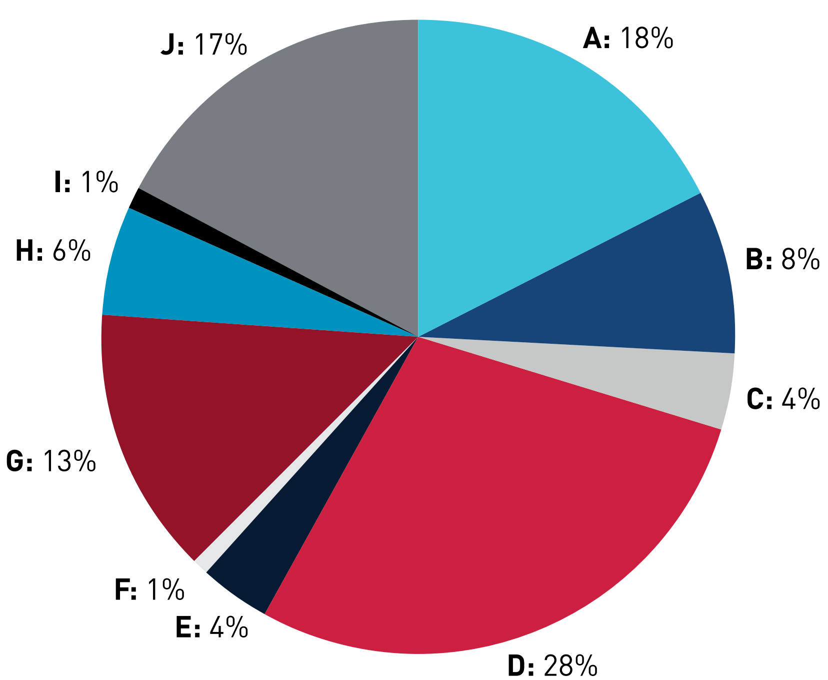
FIGURE 4.16: Work Hours (Millions) by Operation Type



- The data reported for 2019 represents more than 44-million Operator and Contractor work hours in the U.S. OCS. This is a slight increase over hours reported for 2018 and 2017.
- Work hours, for both Operators and Contractors, are reported only by Operators for work occurring within 500 meters of their facilities.

Year	2015	2016	2017	2018	2019
COS U.S. OCS Work Hours (Millions)	61	45	37	41	44

FIGURE 4.17: Work Hours by Company

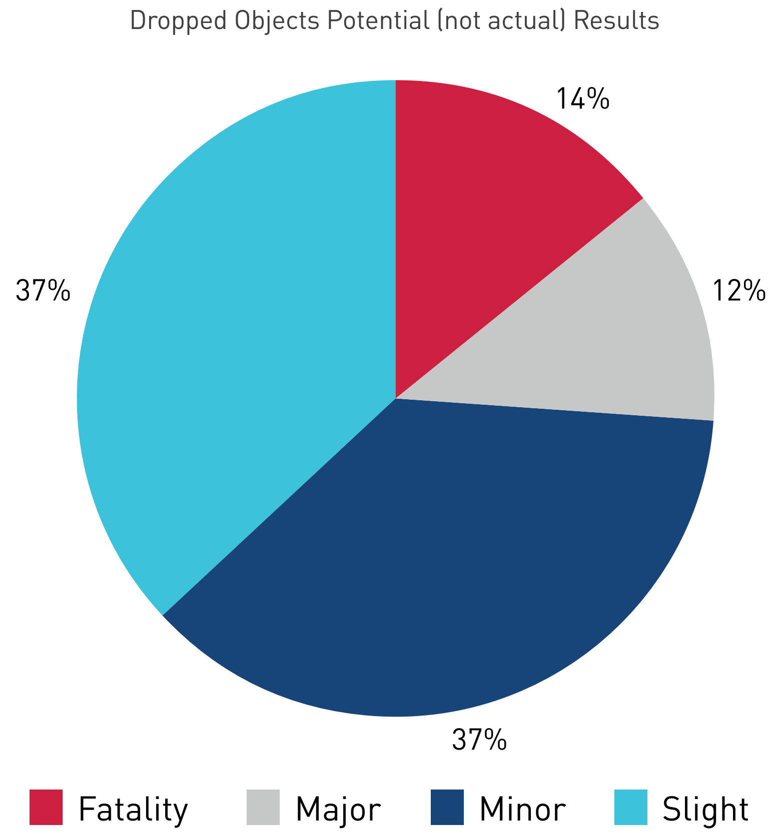


- Four COS Operators account for 76% of the total work hours reported by COS members. One COS Operator member reported zero work hours for the U.S. OCS for 2019 and is therefore not represented here.

4.11 SPI 10 RESULTS

SPI 10 is the severity potential of incidents involving a dropped object

FIGURE 4.18: Dropped Objects Potential



- Based on observations in previous COS annual reports, COS began collecting Dropped Object Potential (SPI 10) information from members for the first time for the 2019 reporting year.
- SPI 10 represents the potential, not actual, results of incidents involving a dropped object. A total of 266 reported dropped object incidents were reported for 2019. Of these 266 incidents, 14% had the potential to result in a fatality, 12% had the potential to result in a major injury, 37% had the potential to result in a minor injury, and 37% had the potential to result in a slight injury.
- The definitions for potential fatality, potential major, potential minor and potential slight are based on those developed by the DROPSOnline network. Additional details can be found in Appendix 2.

5.0 LEARNING FROM INCIDENTS AND HIGH-VALUE LEARNING EVENTS

5.1 INTRODUCTION

The Learning from Incidents and Events (LFI) Program was established to provide a means for COS members to share and learn from incidents and High Value Learning Events (HVLE) that occur in offshore operations. Reporting is voluntary and data confidentiality is maintained through a process administered by a 3rd-party before submittal to COS.

While COS maintains a full record of data collected beginning with 2013 data, the data reported in this APR represents the five most recent years. The LFI section of this report provides an analysis and comparison of the SPI 1, SPI 2, and HVLE LFI data submitted for reporting years 2015-2019 and includes learnings from the 2019 reporting year data that can be shared within companies to potentially prevent recurrence of similar or more severe incidents.

The data are comprised of the reported learnings from SPI 1 and SPI 2 incidents, as well as those from HVLE. A summary of the definitions for SPI 1, SPI 2, and HVLE are presented in Figure 5.1 below.

FIGURE 5.1: Description of SPI 1, SPI 2 and HVLE

SPI 1 is the frequency of incidents that resulted in one or more of the following:

A. Fatality
B. Five or more injuries in a single incident
C. Tier 1 process safety event
D. Level 1 Well Control Incident - Loss of well control
E. ≥ $1 million direct cost from damage to or loss of facility / vessel / equipment
F. Oil spill to water ≥ 10,000 gallons (238 barrels)

SPI 2 is the frequency of incidents that do not meet the SPI 1 definition but have resulted in one or more of the following:

A. Tier 2 process safety event
B. Collision resulting in property or equipment damage > $25,000
C. Mechanical Lifting or Lowering Incident
D. Loss of station keeping resulting in drive off or drift off
E. Life boat, life raft, rescue boat event
F. Level 2 Well Control Incident - Multiple Barrier Systems Failures and Challenges

HVLE is an event that may be considered by a COS member or the industry for use as a reference in process hazard analyses, management of change, project design, risk assessment, inspection, operating procedures review and / or training.

The submitted data include 3 key fields:

- **Description of the Incident or HVLE:** A brief explanation of activities, conditions, and acts leading up to, during and after the incident or HVLE, including sufficient details to facilitate clear understanding.
- **Areas for Improvement:** A selection of pre-determined general categories and subcategories. Submitters had the option to add comments to provide further clarity and content.
- **Lessons Learned:** Companies outlined their incident investigation conclusions with the goal being to reduce the likelihood of similar incidents

Within the Areas for Improvement (AFI) fields, submitters choose from three general categories and 15 sub-categories. Multiple AFI can be selected for a single incident or event. The three general categories are:

- **Physical Facility, Equipment, and Process:** Enhancements in the quality of the physical process and equipment design, layout, material specification, fabrication, or construction were highlighted for improvement
- **Administrative Processes:** Enhancements in the quality, scope, or structure of administrative processes for managing various aspects of work execution were highlighted for improvement
- **People:** Enhancements to the personnel actions linked to the execution of work tasks were highlighted for improvement

5.2 SUMMARY

The effectiveness of this program is dependent on active participation by COS members to facilitate maximum learning opportunities through:

- Timely sharing of quality information from incidents and HVLE that meet the reporting criteria; and
- Reviewing submitted incidents and HVLE, along with other data in this report, to identify and implement applicable learnings appropriate to different levels and functions within their own organizations.

The LFI data presented in this report includes information from 52 LFI submittals received for the 2019 reporting year, with 43 of the reported incidents and HVLE occurring in the U.S. Outer Continental Shelf, four occurring in U.S. Onshore/State Waters, and five occurring at international locations (refer to Figure 5.2 below). To support COS' mission to promote the highest level of safety for the U.S. offshore natural gas and oil industry, the charts and graphs presented in this section of the report represent incidents and events that occurred in the U.S. OCS (refer to Figure 5.3 below). Section 5.3 Learnings includes International and U.S. Onshore/State Waters incidents in addition to those which occurred on the U.S. OCS.

FIGURE 5.2: Incident Location (All Submittals)

Location	2015	2016	2017	2018	2019
U.S. OCS	47	43	33	27	**43**
U.S. Onshore / State Waters*	2	1	12	4	**4**
International	0	17	8	0	**5**
TOTAL	49	61	53	31	**52**

NOTE - The U.S. Onshore/State Waters category was new for 2017 data reporting. U.S. Onshore/State Waters statistics for prior years were generated from submittal content.

FIGURE 5.3: Incident Category Distribution per Submittal Type (U.S. OCS Only)

Year	2015	2016	2017	2018	2019
COS SPI 1	7	5	0	2	**1**
COS SPI 2*	21	17	8	11	**10**
HVLE	19	21	25	14	**32**
TOTAL	47	43	33	27	**43**

**Note – The definition of SPI 2C "Incidents involving Mechanical Lifting or Lowering" was modified for reporting years 2015 and beyond to include minimum thresholds to qualify as an SPI 2C. The previous broader definition has been retained as SPI 4.*

A review of the 2019 reporting year LFI data (U.S. OCS only) identified the top reported activity types as:

- Mechanical Lifting or Lowering (32.6%)
- Drilling Operations – Normal, Routine (20.9%)
- Maintenance, Inspection and Testing (14.0%)
- Production Operations – Normal, Routine (11.6%)

In addition to the topics mentioned above, the top three AFI identified for 2019 were:

- Operating Procedures or Safe Work Practices (39.5%)
- Quality of Hazard Mitigation (34.9%)
- Quality of Task Execution (25.6%)

Across all seven reporting years, Operating Procedures or Safe Work Practices was the most frequently identified AFI, as shown in Figures 5.4 and 5.5. However, the 39.5% reported for 2019 is the lowest for the seven years of COS LFI data.

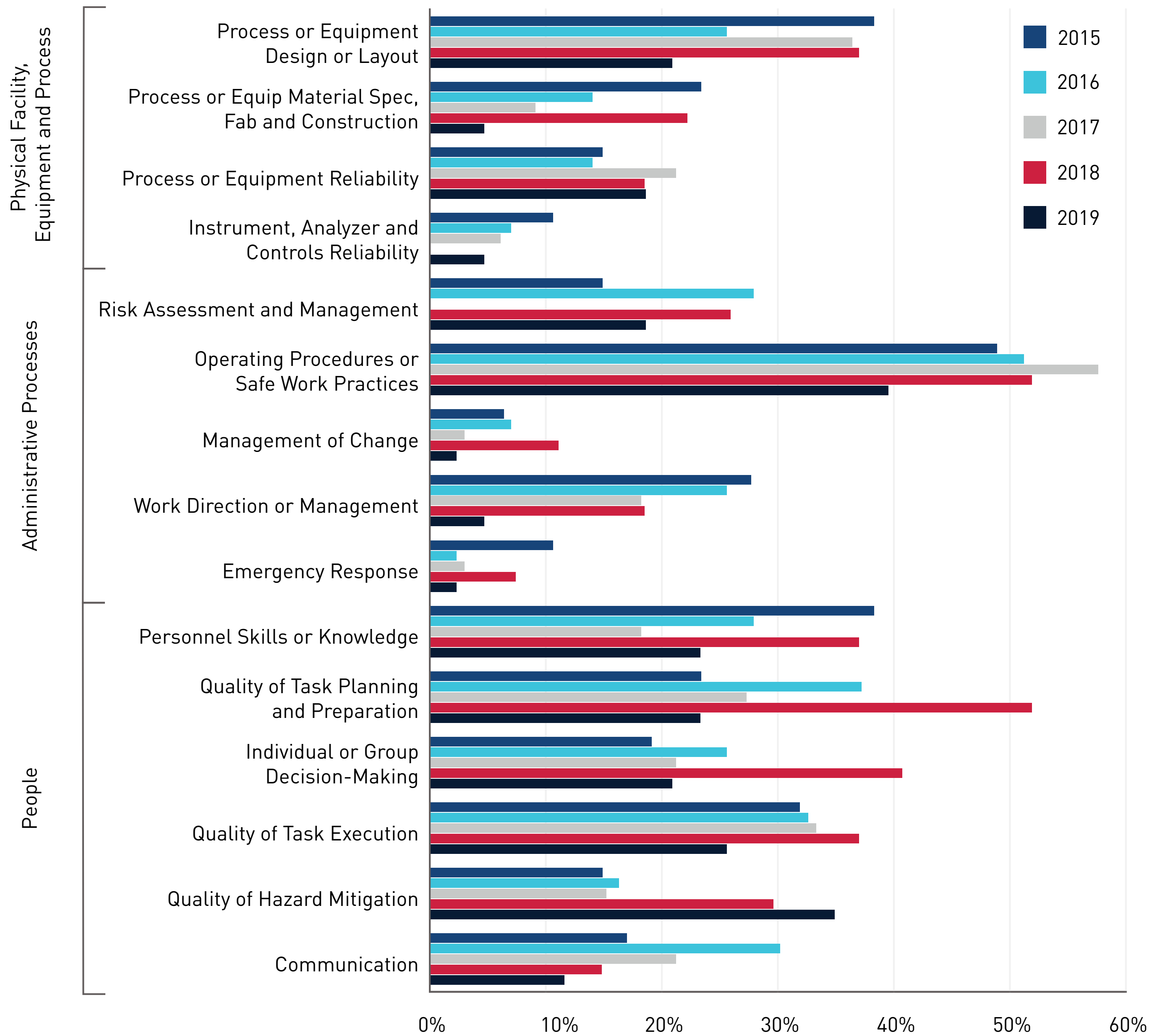
Additional review of the 2019 data identified the following as common threads through many of the LFI submittals:

- Mechanical Lifting or Lowering
- Dropped Objects
- Process Safety Events

FIGURE 5.4: Area for Improvement Distribution (OCS Only)

Area for Improvement	2015	2016	2017	2018	2019	5-yr Avg
Operating Procedures or Safe Work Practices	48.9%	51.2%	57.6%	51.9%	39.5%	**49.8%**
Quality of Task Planning and Preparation	23.4%	37.2%	27.3%	51.9%	23.3%	**32.6%**
Quality of Task Execution	31.9%	32.6%	33.3%	37.0%	25.6%	**32.1%**
Process or Equipment Design or Layout	38.9%	25.6%	36.4%	37.0%	20.9%	**31.6%**
Personnel Skills or Knowledge	38.3%	27.9%	18.2%	37.0%	23.3%	**28.9%**
Individual or Group Decision-Making	19.1%	25.6%	21.2%	40.7%	20.9%	**25.5%**
Quality of Hazard Mitigation	14.9%	16.3%	15.2%	29.6%	34.9%	**22.2%**
Communication	17.0%	30.2%	21.2%	14.8%	11.6%	**19.0%**
Work Direction or Management Process	27.7%	25.6%	18.2%	18.5%	4.7%	**18.9%**
Risk Assessment and Management Process	14.9%	27.9%	0.0%	25.9%	18.6%	**17.5%**
Process or Equipment Reliability	14.9%	14.0%	21.2%	18.5%	18.6%	**17.4%**
Process or Equipment Material Specification, Fabrication and Construction	23.4%	14.0%	9.1%	22.2%	4.7%	**14.7%**
Management of Change Process	6.4%	7.0%	3.0%	11.1%	2.3%	**6.0%**
Instrument, Analyzer and Controls Reliability	10.6%	7.0%	6.1%	0.0%	4.7%	**5.7%**
Emergency Response Process	10.6%	203%	3.0%	7.4%	2.3%	**5.1%**

FIGURE 5.5: Areas for Improvement Distribution (U.S. OCS only, Chart)



NOTE - LFI submittals typically identify more than one AFI for any given incident. The graph above illustrates the percent of times an AFI was identified relative to the number of LFI forms submitted for U.S. OCS. Because the number of AFI exceeds the number of LFI forms, the sum of the percentages will be > 100%.

For 2019, the largest changes in AFI selection from the prior reporting year were:

- Quality of Task Planning and Preparation decreased from 51.9% to 23.3%
- Operating Procedures or Safe Work Practices decreased from 51.9% to 39.5%
  - This is a significant decrease from previous years, and the lowest reported over the seven years of COS data collection.
- Individual or Group Decision-Making decreased from 40.7% to 20.9%
- Work Direction or Management decreased from 18.5% to 4.7%
  - This is a significant decrease from previous years. The 5-year average for this AFI is 18.9%.
- Process or Equipment Design or Layout decreased from 37% to 20.9%
- Process or Equipment Material Specification, Fabrication and Construction decreased from 22.2% to 4.7%.
- Quality of Hazard Mitigation increased from 29.6% to 34.9%
  - This is more than double the average percentage reported for 2014-2017 (14.6%)

5.3 2019 LEARNINGS

As noted in Section 5.2, Mechanical Lifting or Lowering, Dropped Objects, and Process Safety Events were the most frequent incident consequences reported in the 2019 LFI data.

The charts and graphs earlier in this section reflected data for U.S. OCS incidents and HVLE only. In addition to these U.S. OCS LFI submittals, the following sections may include learnings from U.S. Onshore / State Waters and International incidents and HVLE.

5.3.1 MECHANICAL LIFTING OR LOWERING (INCLUDING DROPPED OBJECTS DURING A MECHANICAL LIFT)

Nineteen of the 52 LFI submittals listed the primary activity type at the time of the incident or HVLE as Mechanical Lifting or Lowering for 2019. For these incidents, the most frequently cited AFI were:

- Operating Procedures and Safe Work Practices
- Quality of Task Execution
- Risk Assessment and Management

The following incident descriptions and learnings are excerpted examples relating to Mechanical Lifting or Lowering:

- **Incident Description** – "The incident occurred following the installation of a subsea jumper (pipe connector used to transport production fluids between two subsea components) from a marine support vessel. A spreader bar was used to lower the jumper into its final position. After setting the jumper in place, the spreader bar was kept at around 100 ft above the sea bed using the vessel crane to clear subsea assets. Then, the vessel initiated a move to a 'safe-overboarding zone', where the spreader bar could be recovered to the surface. During this process, a downline (either the crane wire or Remote Operated Vehicle (ROV) umbilical) contacted and severed a polyester section of the platform's mooring line. A second mooring line was also contacted, but ROV inspections confirmed that only marine growth had been removed and the integrity of this mooring line was not compromised."

  Learnings: "Lack of written procedures /standardized practices for communicating and verifying vessel moves within the spar's mooring pattern led to selecting an incorrect safe-overboarding zone, which put the vessel in a trajectory that crossed one of the platform mooring line clusters.

  The survey navigation display of in-water assets was unclear; and the labelling conventions used for vessel waypoints resulted in naming two safe over-boarding zones with the same name. This contributed to the selection of a safe over-boarding zone which was not appropriate for the location where the job was being executed.

  The incident occurred after three major milestones in the installation were completed, and the only remaining job was to recover equipment to the surface and transfer it to a support vessel. The investigation team identified that the degree of alertness shifted, which contributed to the incident.

  Implement Automatic Barriers – It is recommended to implement an automated Hazard Alarm on the survey navigation screen when vessel enters a marked exclusion zone and add an automated Hazard Alarm to respond when vessel proposed path intersects water column assets.

  It is recommended to implement an assurance process for vessel operations and formalize the assurance responsibilities for Company representatives onboard Contractor vessels.

  Improve Offshore Installation Procedures – It is recommended to (1) Standardize data exchange format of Companies infrastructure drawings files (.dwg) to make known hazards obvious (i.e., seafloor assets, in-water column assets, and surface assets); (2) Contractors to provide project-specific safe work location, safe ingress/egress routes and vessel transit routes; and (3) Contractors to provide a written protocol for making vessel moves with downlines in the water column while working in the 500m zone or within mooring pattern of a Facilities/Vessels with in-water assets (e.g., mooring lines, risers, etc.)."*

- **Incident Description** – "Crew was lifting a 13 ¾" by 42.6 ft. long (98.58 PPF for a total weight of 4205 lbs.) joint of casing from the catwalk machine to the rotary when the end of the joint being lifted released from the lift nubbin. The casing joint fell to the rig floor striking the lifting arm and the tongs on the way down and came to rest on the catwalk machine and casing tongs. The nearest person was approximately 6 ft. away located in a designated safe zone. The lift nubbin remained in the single joint elevators, 33.7 ft from the floor. Nobody was injured nor in the path of the casing as it fell."

  Learnings: "Work package failed to list steps to change from 13-5/8" to 13-3/4" casing or identify the use of different size lift nubbins. Contractor's JSA did not identify the 13-5/8" to 13-3/4" nubbin size as a potential hazard nor did they assign clear roles and responsibilities to business parties involved.

  Floor hand stopped the work and requested for verification of the nubbin fit on joint #3 from Thread Specialist. The Thread Specialist inspector did not identify the 13-5/8" lift nubbin as the incorrect size for the 13-3/4" casing joint #3 before resuming operations.

  Future work packages to highlight the change of casing sizes and assign specific responsibility for swapping out all lifting gear and removing the undersized lifting gear from the floor (error proof).

  Revise JSAs to include all potential hazards and mitigations (e.g., clear color coding) when lifting equipment with multiple sizes and managing multiple sizes of lifting gear. Clear roles and responsibilities will be assigned. Additional focus and safeguards shall be added when using lifting gear with similar tolerances (i.e., 13-5/8" and 13-3/4").

  Develop guidance on the different types of stopping the job, and under whose authority different types of stops can be re-started."

- **Incident Description** – "Personnel were conducting a heavy lift from the contracted work boat. The load was raised from the boat to the platform into its landing position. As the load was being lowered into position, witnesses stated that they observed the load contact the landing area then heard a noise and saw one of the composite sheaves fail and shatter into pieces. One of the pieces weighing approximately 16 lbs. fell approximately 140 ft to the top deck of the platform striking one drilling employee (IP #1) in the right forearm and right foot. Another drilling employee (IP #2) who was standing next to IP #1 was struck on the left hand."

  Learnings: "The equipment failure occurred due to deterioration within internal seals, compromising the integrity of the bearing assembly. There was also a bearing grease seal failure due to deformation and side loading of the sheave assembly. The age of the sheave/bearing, fatigue, and corrosion of the sheave bearing also contributed to the incident.

  Corrosion/Fatigue of the outer bearing race coupled with mild side loading during the heavy lift caused the sheave assembly failure. The loads seen by the sheave when realigning the mud tank are unknown due to the friction involved with no load indicator recording on the crane.

  During the investigation it was observed that OEM and distributor followed industry guidance in terms of preventive maintenance program. A preventive maintenance system should be highly effective in detecting impending failures in the dynamic components of the crane. However, the current maintenance plan is not adequate to detect this type of failure. Operator plans to incorporate a defined detailed sheave inspection program, at 5-year intervals, with consideration to replace the sheave at no more than 10-year intervals."

- **Incident Description** – "While rigging a centralizer plate using the well bay crane, the lifting eye assembly unexpectedly came free from the plate while under approximately 800lbs of lifting pressure. This caused the lifting eye to travel upwards approximately 30' then downwards and land on the grating below. The lifting eye remained attached to the crane rigging (lifting eye attached to the single leg nylon sling attached to the crane's wire rope). The lifting eye weighs 6.6lbs."

  Learnings: "Legacy procedures not aligned with manufacturer recommendations. Procedures do not specify to torque to Swivel Hoist Rings specifications. Swivel Hoist Rings have proper torqueing specification identified on each ring. Crews complete this task from memory.

  The hazards of Swivel Hoist Ring breaking free during the lift was not recognized or discussed during the JSA by personnel conducting the task. Cone of exposure was not addressed during the JSA.

  Crews routinely complete a "pull test" of the Swivel Hoist Rings prior to attempting the centralizer lift. According to witness statements, this was completed by crews but did not identify that one ring was not properly tightened through proper torqueing according to OEM specifications.

  QA/QC requirement will be established for any customer-owned offshore equipment / tools on site and maintained by field inspection(s), calibration(s), or certification(s).

  A two points lift is recommended during the lifting of each quadrant of the centralizer operation procedure. A diagram will be updated in the procedure to reflect dual lifting points and turn buckle areas.

  Held a Safety Stand Down with employees to discuss the hazards of selecting the wrong installation equipment, how to verify the correct selection was chosen during the visual inspection/installation, and proper tools to be used during the installation of swivel hoist rings."

- **Incident Description** – "Picking up 4" heavy-weight drill pipe singles AD accidentally hit elevator unlatch button on joystick instead of float button and dropped a joint of drill pipe to the floor. Unlatch button requires being pressed twice for actuation/unlatch of elevator. When elevator unlatched joint dropped, and the pin end struck the rotary. Subsequently, the joint fell across the rotary towards the handrails at the east side of the drill floor. The box end of the joint landed approximately two feet from the handrail. Four members of the drill crew were at or near the rotary when the joint fell."

  Learnings: "The joystick was identifiable by sight but not by feel. The Elevator release button on the joystick was fitted with a tactile device to allow the Operator to readily identify the Elevator Release Button by feel alone, and to increase the Operators awareness of differentiating the control buttons."

5.3.2 STATIC DROPPED OBJECTS

Sixteen of the 52 LFI submittals included Static Dropped Objects as an actual or potential consequence for 2019. For these incidents, the most frequently reported AFI were:

- Operating Procedures and Safe Work Practices
- Quality of Hazard Mitigation

The following incident descriptions and learnings are excerpted examples of learnings for Static Dropped Objects:

- **Incident Description** – "A worker was attaching a shipping label to a wash sub located on a horizontal storage rack in the pipe rack area. While the worker was attaching the label, the 18' elevator links stored above the wash sub shifted, and one end of the links descended to the deck. The worker was within 24 inches of the elevator links but was able to retreat without any injuries. The elevator links weigh 2,500 lbs each and fell 69 inches. Drops calculator potential outcome is fatality."

  Learnings: "The rack was too wide for the 18' length of the elevator links. The rack used in this event is intended for storage of 22' length elevator links. Tripping Pipe operations on the rig floor causes vibrations to the area (theorized to be what initiated movement of the elevator links).

  The storage rack is in a well-travelled area, but personnel did not recognize unsafe condition. A lack of formal guidance requiring identification and use of approved storage arrangements for the elevator links resulted in crews placing equipment in areas of opportunity and normalization of risk.

  Develop specific storage arrangement for elevator links that are appropriate for length and weight that prevent bail from becoming unstable and falling.

  Survey locations for other similar equipment that may pose a drops risk if improperly stored and establish approved designated storage arrangements.

  Storage racks, shelving, etc. with the potential to be loaded beyond capacity should be labeled with the safe working limit to prevent overloading."

- **Incident Description** – "The work crew had completed activities in the bottom of the forward hull column and began to ascend the hull ladder system one at a time utilizing a climb assist system. As a worker ascended the lower hull ladder to mid-level another worker at the hull bottom approached the base of the ladder to determine progress. While looking up the ladder column, the worker saw an object falling and moved out of the way prior to impact. The object was the climb assist system's 15-pound counterweight which came off the system when the worker at the top of the ladder disconnected. The counterweight fell approximately 105 feet and landed at the base of ladder."

  Learnings: "Counterweight connections were all found to be hand tightened which allowed for the weight to be disconnected without tools.

  The worker was new to the equipment and had received formal classroom and hands-on training, but the worker did not disconnect correctly.

Apply thread locker and wrench tighten the carabiner attaching the counterweight to the hoist cable. In addition, add secondary retaining connection to prevent disconnection.

Strengthen training program to include: increased awareness of potential for dropped objects when disconnecting equipment, protocol for communicating secured disconnect completed, and clear procedure for dismounting from system.

A red zone was painted at the base of the hull ladders and additional red zone procedures were implemented."

- **Incident Description** – "While preforming a routine scaffolding activity, a scaffolding crew inadvertently dropped a 2" X 4" board weighing 5.6 pounds while staging near a handrail on the Generator Module Upper Deck. The worker was staging the board when it dropped through the handrail opening falling approximately 40 feet below to the Generator Module Lower Deck landing in an egress walkway."

  Learnings: "There were no personnel present in the area at the time of the incident. However, there was potential for personnel to be in the Generator Module Lower Deck location because of no barricades being in place.

  Inadequate process in place for assessing hazards and re-validating JSA when crew moves to a new job site. Consequences of staging material near hand rails not recognized.

  Incorporate hazard review procedure for Scaffold Crews. This review will be performed prior to starting work at each job site and will be documented on the Revalidation sheet of the Work pack.

  Establish expectation across organization that the assigned operation representative will inspect every scaffolding construction and demolition location that requires working at heights or some other high-risk activity and complete Pre-Work Checks and Verifications for each location.

  Prohibit stacking material next to handrails unless deemed absolutely necessary by onsite supervision. If deemed necessary, the policy will reflect a list of mitigations that must be met before staging is allowed."

- **Incident Description** – "During helicopter operations on a support vessel which was stationed outside of the 500m safety zone, a rotor wash from a helicopter caused the protective lid of the helo restart box weighing 21.3 lbs. to lift and fall approximately 75 ft. into the water on the starboard side of the vessel. Per normal operations, no personnel were in the vicinity of the helideck during helicopter final approach."

  Learnings: "Aviation Risk is predominantly focused on aircraft crash, and the threat of hazardous rotor wash has not been included in any formal risk assessment. Multiple leadership teams missed opportunities to learn from previous internal and external events, and improvements in industry practices.

  The investigation identified multiple opportunities for the organization to learn from past internal and external similar events. Despite repeated risk assessments, risk reviews, deep dives, etc., neither Operator, the Support Vessel Contractor, or the Aircraft Operator identified rotor wash as a significant hazard.

  Aviation efforts, including internal risks and controls and external industry, are focused predominantly on preventing and mitigating risks associated with aircraft crash, and with good reason. However, it is clear that aircraft operations also pose risks to personnel on the ground at final approach and take-off who may be in the line of fire."

5.3.3 PROCESS SAFETY EVENTS (PSE)

Twelve of the 52 LFI submittals described PSE and listed either Energy Isolation or Maintenance, Inspection & Testing as the primary activity type at the time of the incident or HVLE for 2019. For these incidents, the most frequently reported AFI were:

- Process or Equipment Design or Layout
- Operating Procedures and Safe Work Practices

The following incident descriptions and learnings are excerpted examples of learnings for PSE:

- **Incident Description** – "Contract Valve Technician and Employee were performing valve maintenance. Isolation in place for maintenance included Open Bleed Points upstream and downstream of the valve, confirming zero pressure on either side of the valve. Valve was also manually opened and closed to release potential trapped pressure in the valve body and placed in the closed position. After removal of the gear actuator and bolts to the stem were then removed. The Employee stood back, and Valve Technician used a wedge to unseat the stem. Unforeseen trapped pressure in the valve body ejected the stem upward and away from personnel, landing behind the valve in the skid. No personnel were injured, and no other equipment was damaged as a result of the event"

  Learnings: "A Pressure gauge on the valve was inadvertently mistaken as the internal pressure of the valve. The bleed port was not labeled.

  Contract company stated this is a known occurrence in a controlled environment and failed to inform their technicians or other companies. Installation, Maintenance and Operating Instructions Guidelines not in the manufacturer's manual.

  Confirm Zero Pressure on the Valve Body of all PBV Trunnion Valves utilizing Bleed Ports, Valve Actuation, and if needed placing Bleeds onto Valve Body Seat Grease Fittings to ensure potential trapped pressure confirmed and release is controlled.

  Ensure to share information with the field when there is a potential for trapped pressure in controlled environments."

- **Incident Description** – "During an outage, work was conducted to replace a section of pipe. This work was scheduled to happen on night shift on [date redacted]. At about (time of day), the fuel gas coalescers were de-pressured per the isolation/deisolation plan (IDP), although the liquids in the filters were not drained. The isolation was purged with nitrogen, followed by testing lower explosive limit (LEL) in preparation for cold-cutting. Testing showed high LELs, which were incorrectly attributed to passing valves in the isolation. In preparation to expand the isolation, the High Pressure (HP) system was de-pressured to atmospheric conditions. On the morning of [date redacted], the day shift worked to trouble-shoot the isolation. They were unaware that the HP system was depressured to atmosphere the previous evening. The fuel gas scrubber was isolated and de-pressured to expand the isolation envelope. The fuel gas scrubber supplies gas to both the flare pilots and the flare purge. This loss of purge gas resulted in a flammable mixture in the flare that was ignited by the flare pilots leading to detonation events. A temporary nitrogen supply was connected to purge the flare and to extinguish the pilots which stopped the detonation."

  Learnings: "Flare Design does not include source for independent purge back-up. The alarm was without action: there is no prescribed action for this alarm. Lack of reliable flame detection extended the trouble-shooting duration which allowed the detonation events to continue for over two hours.

  Engineer and install an independent back-up purge source to improve overall reliability. Evaluate automating back-up system response instead of relying on Operator intervention.

Update Relief System Site Operating Procedure to include an Operator response for low flow purge alarm. Update Relief and Flare System Operating Manual to describe the importance of maintaining a continuous minimum flare purge gas rate.

The incident was caused when loss of purge gas allowed for air ingress into the flare, resulting in a flammable mixture that was ignited by the flare pilots, leading to detonation events. This was due to the belief that isolation valves were passing. The fuel gas scrubber was de-pressured, which removed the source of purge gas. Personnel appeared to have a lack of understanding of the importance of maintaining a continuous calculated purge gas flow to the flare.

Insufficient leadership on night shift before the incident and inadequate shift handover to dayshift contributed to lack of understanding and adequate risk assessment of plant altering decisions."

- **Incident Description** – "Subsea team commenced with the troubleshooting of a Subsea Blowout Preventer (BOP) to identify the source of a leak. After isolating all the functions at the BOP panel, except for critical connections, the system pressure still did not stabilize. A plan was developed to verify and rule out the possibility of the leak coming from a hotline, since it had recently been spliced during the previous well. A discussion was had between the Subsea Supervisor and the Subsea Engineer (SE) that when the hotline is isolated on the surface, it vents the fluid from the hotline back into the Hydraulic Power Unit (HPU) mixing tank which may result in the overflow of the tank. The SE made the decision to transfer fluid from the HPU mixed tank to an offline HPU mixing tank to attempt to make room. After the transfer was completed, the SE estimated there still wasn't enough room in the mixing tank to complete the fluid dump, so an artificial drain line was attached to existing tubing to relieve the BOP fluid from the hotline when isolated. The SE routed the hose out of the HPU room with the intention of draining the fluid to the deck below. Once the hotline valve was closed, the fluid began to flow from the hose. The fluid was pressurized at 5,000 psi from the hotline. The SE was attempting to restrain the hose but was unsuccessful due to pressure and it slipped out of his hands striking him on the forehead and the right side of his neck."

Learnings: "Initiate an MOC to install a permanent mixed tank drain connection on Main and Offline HPU mixing tanks. Include an updated engineering drawing as part of the MOC process.

Modify procedure for transferring BOP fluid from HPU mixing tanks to include steps on how to lower/drain the HPU mixing tank volumes after the proposed MOC has been completed. Update title of the procedure to reflect the management of fluid.

Because this was troubleshooting activity, those involved did not recognize a change in the work plan.

Prior to connection of the hose to the Main HPU mix tank, work management requirements were not followed including risk assessment, permit to work, and energy isolation. Team misjudged force of the back pressure releasing through restricted nozzle and high-pressure hazard was not recognized.

SE performed a similar pressure bleed off on a different system on a previous rig without incident, was trying to avoid potential risk of a loss of primary containment on HPU tank from an overfill, which had occurred previously, did not see any other option(s) to complete the task, and self-imposed motivation to complete BOP troubleshooting in efficient manner during down time."

- **Incident Description** – "While the team was pressure testing the Coiled Tubing (CT) Stripper to 12,500 psi using seawater with 2" Coiled Tubing across the BOP, the pressure suddenly bled off and the CT ejected from the Blowout Preventer (BOP) stack and eventually came to rest hanging over the starboard side of the vessel. The Tubing Guide Roller Assembly (TGRA) was broken off in the ejection process and fell to sea."

Learnings: "Evaluate an engineering control to prevent test/operating pressures being applied which generate forces in excess of gripper pressure setting. Confirm effect of slip setting on coil properties.

The test pressure used during this operation was the highest historically used with this type of CT within GoM operations. This was not highlighted as a risk during the planning process and it was also higher than required for the operation to be conducted.

The CT ejected from the Injector Head Grippers due to an incorrectly set Linear Beam Pressure on the Injector Head Gripper Blocks. The ejection occurred in part because of a lack of operational procedures for determining and setting appropriate Linear Beam Pressure for the intended operation. A good practice of setting the Connector against the Stripper Ram Blocks when pressure testing (to mechanically prevent slippage of the coil through the stripper) was not implemented and not documented in the procedure for the task. Develop specific contractor operational procedures that include Linear Beam Pressure setting protocols. This would include a calculation of the pressure required for the greatest potential force that may be generated during the operation. Document the standards to be used in calculating of pressures to be used during pressure testing.

The Coiled Tubing was found to have parted in tension at the Connector. No damage or markings from the Injector Head Grippers were found on the exterior of the CT. The CT slid through the locked Injector Head Grippers at a rate fast enough to not register on the depth counter. The Connector impacted the CT Stripper with such force that the CT was pinched, creating a weak point in the CT that instantly lead to the tensile failure right above the Connector. The Sidewinder Stripper Rams Blocks were damaged beyond repair but no other damage to the BOP stack components occurred."

6.0 SEMS AUDITS

6.1 BACKGROUND

BSEE issued its Workplace Safety Rule, also known as the Safety and Environmental Management Systems (SEMS) regulations, in October 2010, requiring all Operators operating in the U.S. Outer Continental Shelf (OCS) to develop, implement and audit a SEMS. The SEMS Audits are meant to verify that companies have established, implemented, and maintained a SEMS throughout their U.S. OCS operations, as well as to identify areas where the companies are improving or are deficient. Operators were required to complete the first round of audits by November 15, 2013, and additional audits at least every three years thereafter. This meant that for most Operators, the second round of audits was completed by the end of 2016 and the third round by the end of 2019.

COS commenced both a SEMS Certificate program and an Audit Service Provider (ASP) Accreditation Program in October 2012 to support its mission of improving safety and environmental performance and in conjunction with the SEMS regulatory requirements. The COS SEMS Certificate Program was established to recognize COS member companies who conducted their SEMS audits and completed their Corrective Action Plan (CAP), if applicable, to the satisfaction of the ASP. The Audit Service Provider Accreditation Program was established to create a consistent, standardized set of requirements for ASP and their auditors to increase confidence in and effectiveness of the audits. The program documents can be found on the COS website (http://www.centerforoffshoresafety.org).

Subsequent changes to the SEMS regulatory requirements (a.k.a. SEMS II) in April 2013 led to additional requirements regarding stop work authority, ultimate work authority, employee participation, and reporting of unsafe conditions. Additional requirements regarding SEMS auditing were also added including: incorporating selected COS documents, the need for an Accreditation Body to accredit Audit Service Providers, and requiring all SEMS Audits conducted after June 2015 to be directed by an accredited ASP. COS is currently the only recognized Accreditation Body; as such, all regulatory required SEMS Audits must be conducted by a COS-accredited ASP.

In 2014, COS requested COS Operator members share results of their SEMS Audits from the first round. This data was analyzed to identify performance trends and learning opportunities. These conclusions, along with the underlying data, were reported publicly in the COS APR in 2014. In 2017, COS again requested COS Operator members to share the results of their second round of SEMS Audits. The information requested was more extensive to better identify trends and learnings. Also, where appropriate, the results of both rounds were compared to identify additional trends in longer-term performance.

6.2 SEMS AUDIT DATA BY CLASSIFICATION TYPE

For the 47 SEMS audit reports submitted to BSEE from 2017-2019, 214 Non-Conformances, 187 Areas of Concern, and 153 Opportunities for Improvement were identified. Typically, Non-Conformances and Areas of Concern represent either less than satisfactory fulfillment of a requirement, or a requirement that is only marginally being met but could lead to a non-conformity if additional actions are not taken. Of note:

- Four SEMS Elements account for 55% of the Non-Conformances – Assurance of Quality and Mechanical Integrity, Safe Work Practices, Hazards Analysis, and Operating Procedures.
- Five SEMS elements accounted for 56% of the cited Areas for Concern: Safe Work Practices, Assurance of Quality and Mechanical Integrity, Hazards Analysis, Management of Change, and Operating Procedures.

In addition, 234 Good Practices were also identified; these were analyzed separately to identify learnings. Over 90% of the Good Practices identified were statements of conformance indicating functional and effective areas within SEMS. Every SEMS Element had at least one Good Practice identified.

Figure 6.1 shows the distribution of the count of Non-Conformances, Areas of Concern, Opportunities for Improvement, and Good Practices as reported by SEMS Elements. Figure 6.2 is the same data represented in table form.

FIGURE 6.1: Findings by SEMS Element and Finding Type (graph)

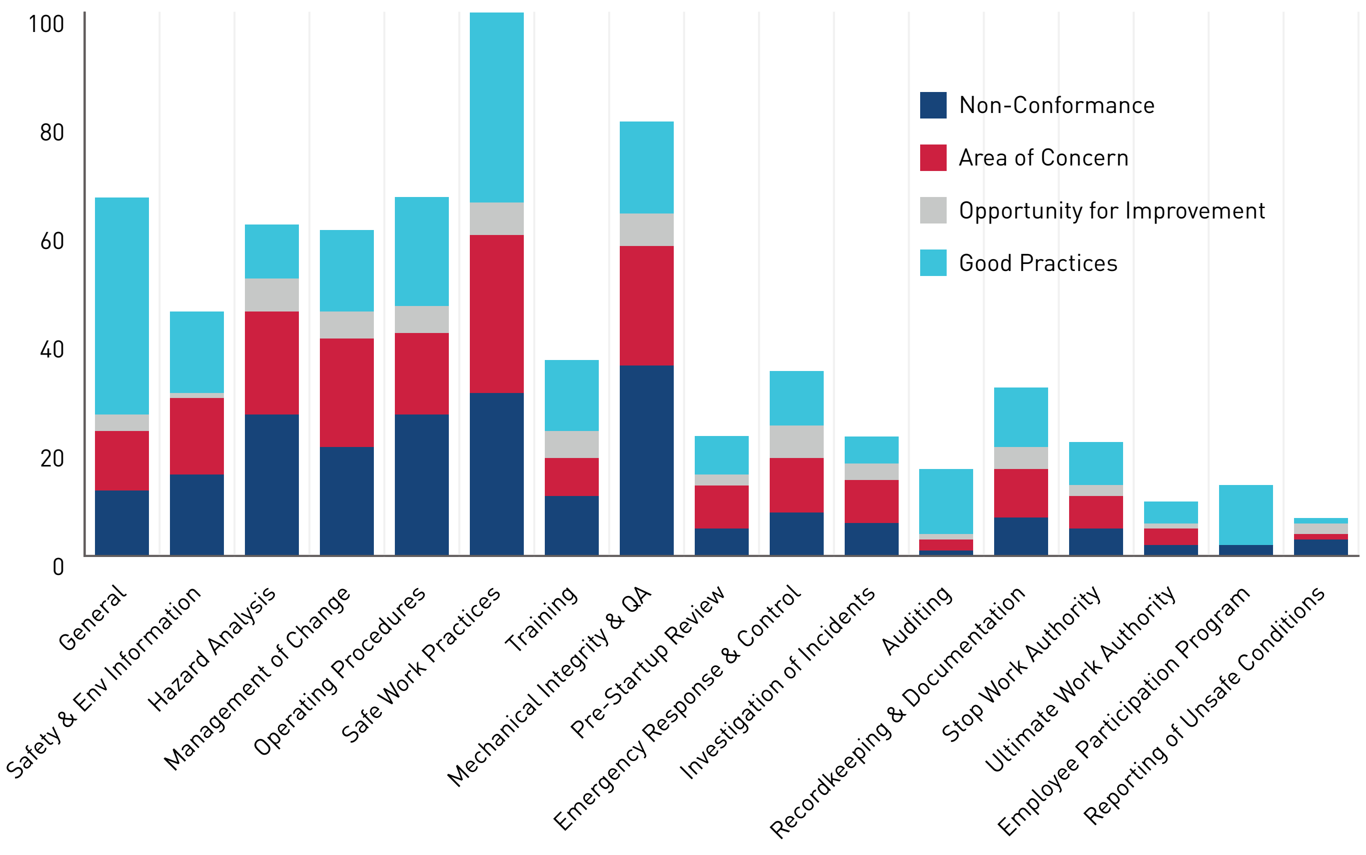


FIGURE 6.2: Findings by SEMS Element and Finding Type (table)

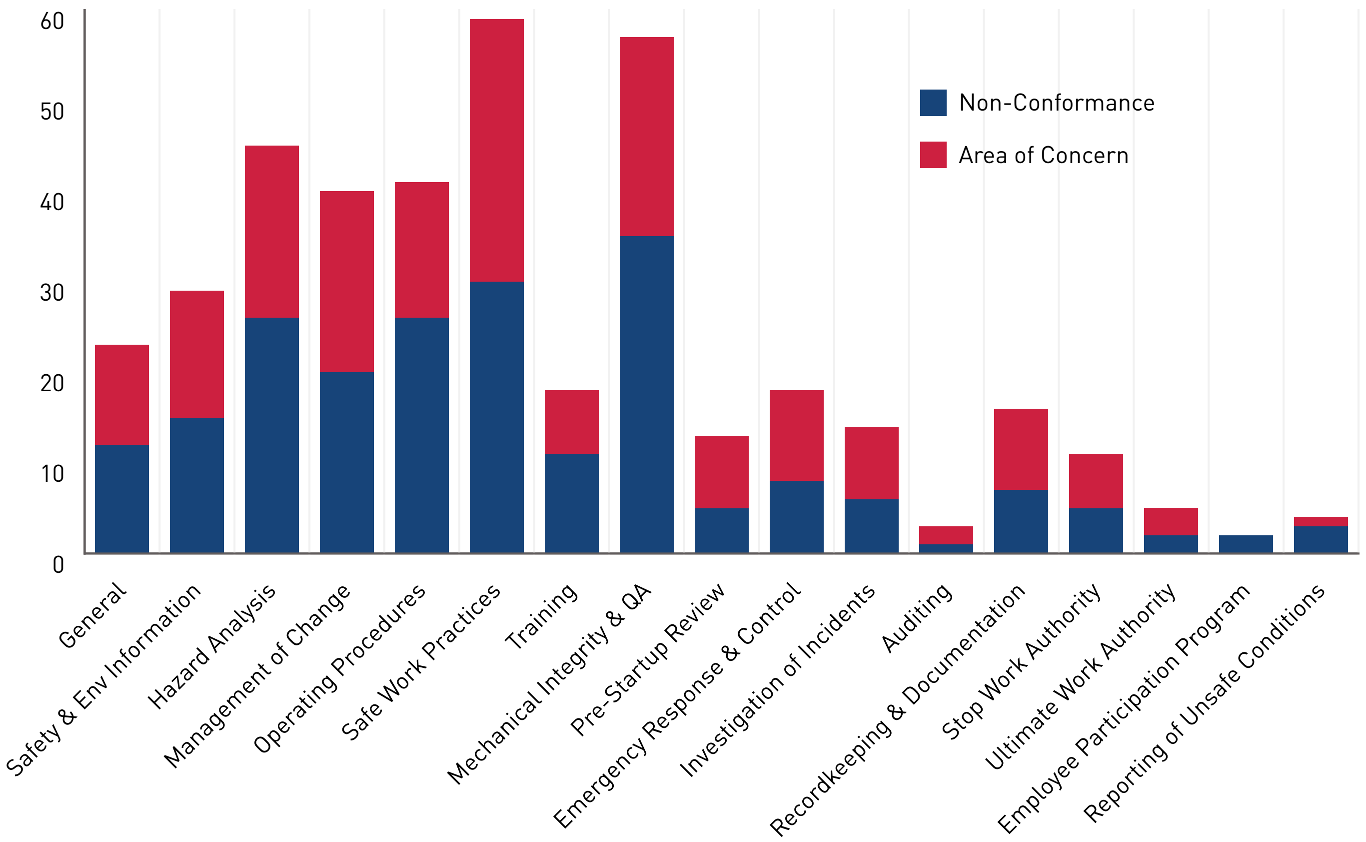
Element	Non-Conformance	Area of Concern	Opportunity for Improvement	Good Practices
General	12	11	3	40
Safety and Environmental Information	15	14	1	15
Hazard Analysis	26	19	6	10
Management of Change	20	20	5	15
Operating Procedures	26	15	5	20
Safe Work Practices	30	29	6	35
Training	11	7	5	13
Mechanical Integrity	35	22	6	17
Pre-Startup Review	5	8	2	7
Emergency Response and Control	8	10	6	10
Investigation of Incidents	6	8	3	5
Auditing	1	2	1	12
Recordkeeping and Documentation	7	9	4	11
Stop Work Authority	5	6	2	8
Ultimate Work Authority	2	3	1	4
Employee Participation Program	2	0	0	11
Reporting of Unsafe Working Conditions	3	1	2	1

6.3 SEMS AUDIT DATA BY SEMS MATURITY

As stated before, Non-Conformances and Areas of Concern typically represent either less than satisfactory fulfillment of a requirement, or a requirement that is only marginally being met but could lead to a non-conformity if additional actions are not taken. As such, further analysis of these findings may help industry more sustainably and collaboratively close gaps and improve SEMS performance. Figure 6.3 shows the breakdown of Non-Conformances and Areas of Concern distributed by SEMS Element.

Please note, to make this report more readable and user-friendly, the term "Deficiency" shall be used throughout the rest of this section to encompass both Non-Conformances and Areas of Concern.

FIGURE 6.3: Deficiencies by SEMS Element



In reviewing the data, it was determined that different analytical methods could add additional value and help identify useful insights. One option, using the methodology outlined in COS-3-03 Guidelines for SEMS Maturity Self-Assessments, was to analyze the data to better understand in what phase of SEMS maturity breakdowns occurred. For the purposes of this report, this analysis was done by a small group of audit and SEMS subject matter experts to identify trends, cross-element issues, and other insights into industry performance.

The methodology followed was:

- Every Deficiency was analyzed to understand if the issue was in the Establish, Implement, or Maintain maturity phase of the SEMS.
- The Implement phase was further broken down to understand if the issue was in the actual implementation of the requirement or in its documentation (policy, practice, procedure, etc.):
  - Implement means to put the requirement into action.
  - Document means to appropriately document the action, update necessary documents, and allow appropriate access to documents.
- Multiple maturity phases could be chosen for a single Deficiency if it was warranted; this resulted in 491 selections for the 401 Deficiencies analyzed.
  - For example, both Implementation and Documentation would have been chosen where personnel were noted using an outdated procedure because they did not have access to the updated procedure.

To make it easier to align, understand, and communicate, the below was used as shorthand:

- Establish – Do you say what you do?
- Implement
  - Implement – Do you do what you say?
  - Document – Do you document what you do, update documents appropriately, and provide access to the right people?
- Maintain – Do you confirm your SEMS is working as designed and review and act when you say you will?

Figure 6.4 shows the distribution by the SEMS Maturity phase that was determined as needing improvement. Figure 6.5 further breaks down this data and shows it by SEMS element.

FIGURE 6.4: Overall Distribution of Deficiencies by SEMS Maturity Phase

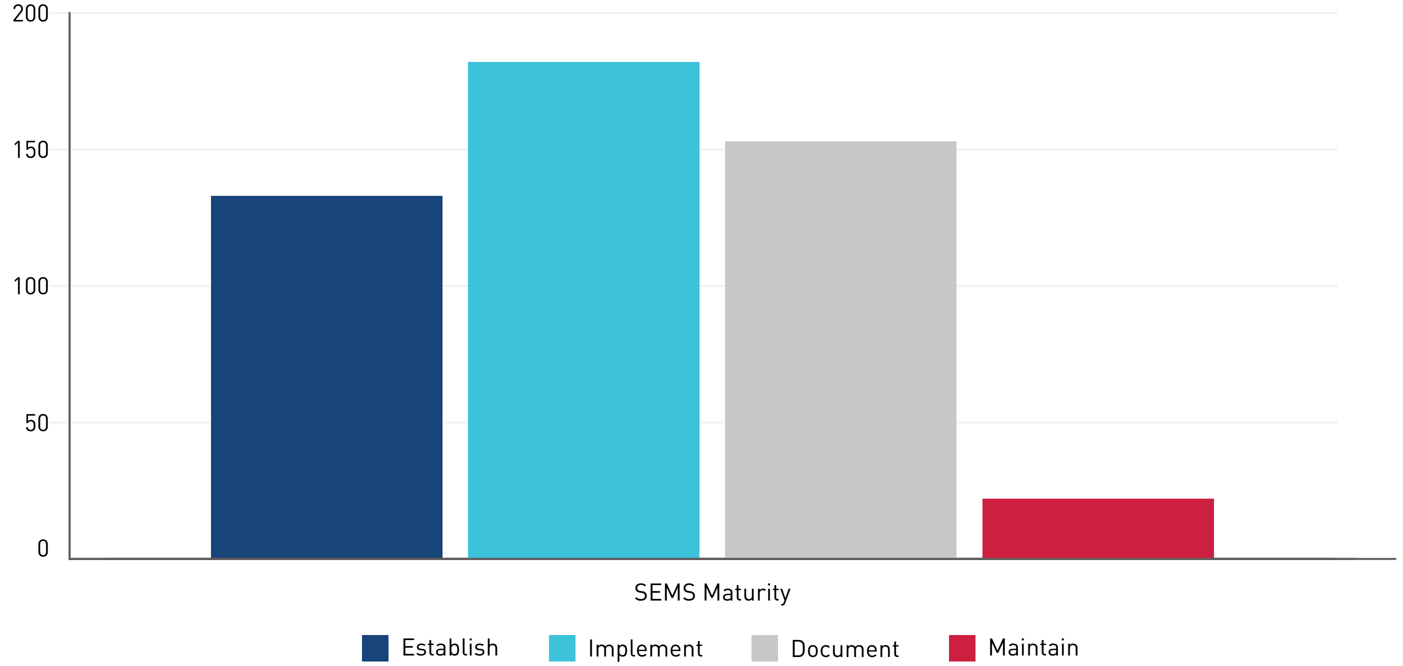
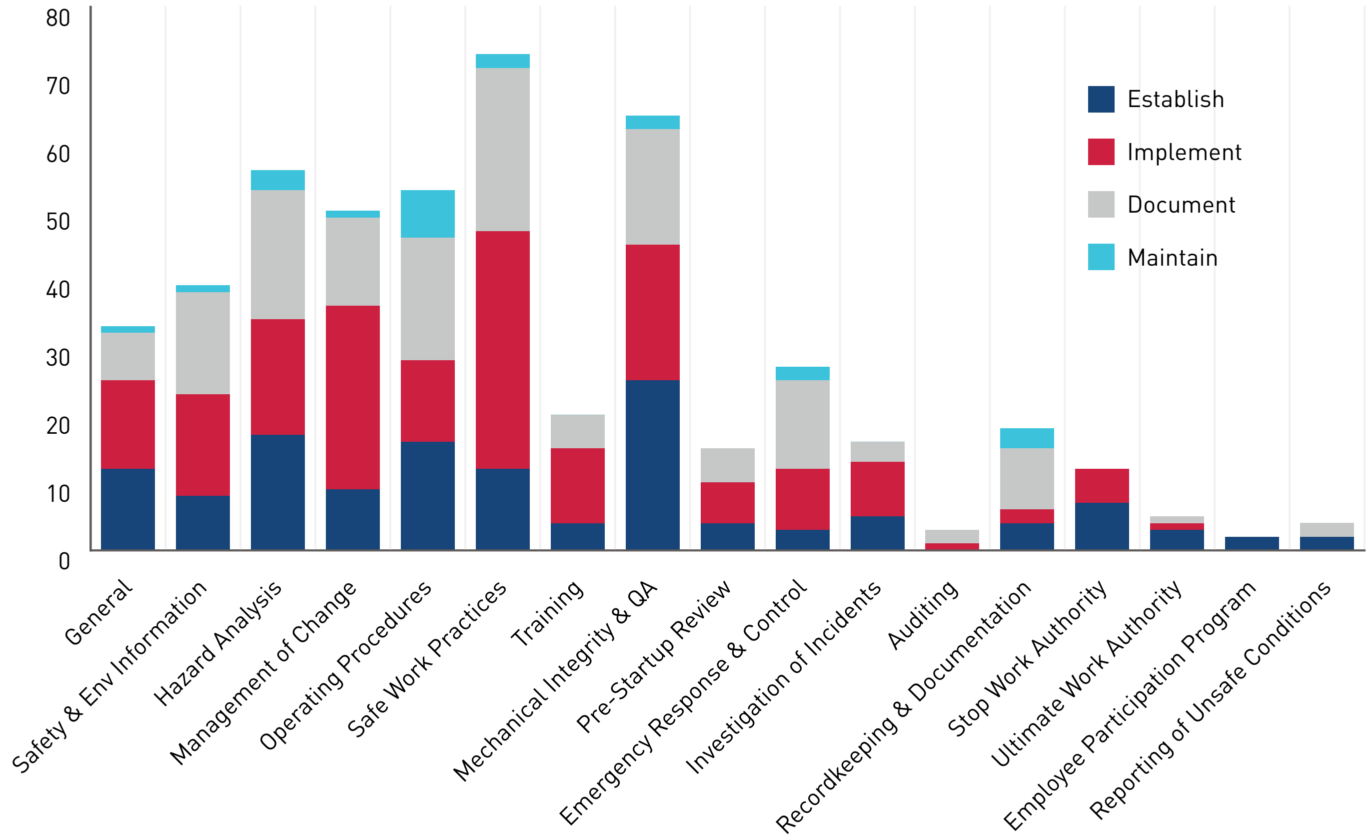


FIGURE 6.5: Deficiencies by SEMS Maturity Phase per SEMS Element



The analysis identified that:

- 27% of Deficiencies were determined to be in the Establish phase and typically represented issues with:
  - Processes missing requirements (e.g., training checklists not including all necessary training, Bridging Agreements not including all company requirements, etc.),
  - Process missing (e.g., no assurance process for review of JSA, maintenance procedures not developed for all critical equipment, etc.),
  - Unclear or inconsistent expectations (e.g., company's requirements for contractors unclear, additional definition needed on how to document action closure, etc.).
- 37% of Deficiencies were determined to be in the Implement phase and typically represented issues with:
  - Executing work as designed (e.g., not always using required checklists, incomplete work, using the wrong tools, etc.),
  - Inconsistencies in the execution of work processes (e.g., inadequate information on initial drawings, inconsistent use of processes, incomplete training, etc.).
- 31% of Deficiencies were determined to be in the Document phase and typically represented issues with:
  - Lack of access to current documents (e.g., use of outdated drawings, up-to-date procedures not being accessible from the platform, etc.),

- Illegible or incomplete documents and records (e.g., illegible chemical labels, not recording analysis and critique of emergency drills for improvement opportunities, incomplete records of management reviews, etc.).

- 4% of Deficiencies were determined to be in the Maintain phase and typically represented issues with:
  - Not reviewing and/or updating documents per a defined schedule (e.g., not reviewing procedures per company requirements, etc.).

6.4 SEMS AUDITS – INSIGHTS

Based on the provided SEMS Audit data, there were five SEMS Elements that encompassed more than 50% of the Deficiencies. These five elements were further analyzed for additional insights and to identify common themes; these elements were:

- Hazards Analysis
- Management of Change
- Operating Procedures
- Safe Work Practices
- Assurance of Quality and Mechanical Integrity of Critical Equipment

The results of the analysis and selected findings, as well as common themes, for each of these SEMS Elements are included below. Please note that that multiple phases of SEMS Maturity could be chosen for a Deficiency.

6.4.1 HAZARD ANALYSIS

- There were 26 Non-Conformances and 19 Areas of Concern for Hazards Analysis, which represented 12% of all Non-Conformances and 10% of all Areas of Concern.
- The top SEMS maturity phases noted for improvement in Hazards Analysis were Document (34%), followed by Establish (30%) and Implement (30%).
- Further textual analysis of the Deficiencies identified the following common themes:
  - 27% (12 of 45) involved the Hazards Analysis process missing specific regulatory requirements and/or company expectations; lack of these led to incomplete or missing communication, lack of specific revalidation schedules, and/or reliance on institutional memory over a more systematic and sustainable process.
  - 16% (7 of 45) involved issues in Job Safety Analysis (JSA) processes, including inconsistent application of JSA and inconsistent direction on how and when to complete a JSA.
  - 13% (6 of 45) specifically indicated issues in performing Hazard Analyses per a defined schedule, including lack of Hazards Analysis for facilities and overdue / not current HAZOPs being used in decision making.

6.4.2 MANAGEMENT OF CHANGE

- There were 20 Non-Conformances and 20 Areas of Concern for Management of Change, which represented 9% of all Non-Conformances and 11% of all Areas of Concern.
- The top SEMS Maturity phases noted for improvement in Management of Change were Implement (54%), followed by Document (26%) and Establish (18%).
- Further textual analysis of the Deficiencies identified the following common themes:
  - 35% (14 of 40) involved inconsistent implementation of the process, such as evidence being found that MOC process requirements were not uniformly implemented.
  - 35% (14 of 40) involved the MOC process or procedure missing specific regulatory requirements and/or company expectations; the lack of the MOC process requirement led to missing required MOC steps or not completing MOC for required changes.
  - 30% (12 of 40) involved incorrect or missing documentation; these issues typically involved documentation that could not be found at the time of the audit or inaccurate/incomplete documentation of MOC closure actions and follow-up.

6.4.3 OPERATING PROCEDURES

- There were 26 Non-Conformances and 15 Areas of Concern for Operating Procedures, which represented 12% of all Non-Conformances and 8% of all Areas of Concern.
- The top SEMS maturity phases noted for improvement were Document (34%), followed by Establish (30%) and Implement (23%).
- Further textual analysis of the Deficiencies identified the following common themes:
  - 46% (19 of 41) involved inconsistent or incomplete reviews of procedures, including reviews that did not occur per schedule, reviews that did not occur in the prescribed manner, and/or a lack of systemic process to review procedures.
  - 12% (5 of 41) involved inaccurate procedures, primarily involving procedures that were outdated or legacy procedures from other companies that were not updated to current company standards.
  - 12% (5 of 41) involved chemical inventory sheets, including issues where procedures were not updated with current chemicals or procedures did not explicitly address hazards from chemicals to be used in the execution of that procedure.

6.4.4 SAFE WORK PRACTICES

- There were 30 Non-Conformances and 29 Areas of Concern for Safe Work Practices, which represented 14% of all Non-Conformances and 16% of all Areas of Concern.
- The top SEMS maturity phases noted for improvement were Implement (48%), followed by Document (33%) and Establish (16%).
- Further textual analysis of the Deficiencies identified the following common themes:
  - 41% (24 of 59) involved inconsistent implementation of Safe Work Practices; the majority of these issues involved irregular adherence to company polices and requirements by personnel.
  - 36% (21 of 59) involved incorrect or missing documentation; the majority of these issues involved incorrect or missing Safety Data Sheets (SDS) or Hot Work Permit documentation.
  - 19% (11 of 59) involved chemicals; the majority of these involved incorrect, incomplete, or missing SDS or incorrect or incomplete storage of these chemicals.

6.4.5 ASSURANCE OF QUALITY AND MECHANICAL INTEGRITY OF CRITICAL EQUIPMENT

- There were 35 Non-Conformances and 22 Areas of Concern for Assurance of Quality and Mechanical Integrity, which represented 16% of all Non-Conformances and 12% of all Areas of Concern.
- The top SEMS Maturity phases noted for improvement were Establish (39%), followed by Implement (31%) and Document (27%).
- Further textual analysis of the Deficiencies identified the following common themes:
  - 35% (20 of 57) involved the process missing specific regulatory requirements and/or company expectations; this lack led to missing required maintenance and/or an inability to compliantly prioritize equipment maintenance and integrity work.
  - 33% (19 of 57) involved inconsistent or incomplete documentation; these issues typically involved documentation that could not be found at the time of the audit or inaccurate/incomplete documentation of inspection results.
  - 23% (13 of 57) involved a procedure that was missing or incomplete at the time of the audit; this is different from "process missing" in that there was evidence of a Mechanical Integrity process, but specific required procedures were incomplete or unaccounted for.
  - 21 % (12 of 57) involved issues with tracking and/or assuring that the required maintenance, inspections, or verifications had been completed as scheduled; these issues typically were either around a lack of systematic ways to track and assure action items or around a lack of a plan to track and assure asset integrity actions

6.5 SEMS AUDITS – GOOD PRACTICES

234 Good Practices were identified in the 2017-2019 SEMS Audit data provided. 93% of the Good Practices identified were statements of conformance indicating a functional and effective SEMS. Further analysis identified 17 Good Practices as being potentially helpful to share across the wider industry. The most noteworthy of these are included below based on the applicability to the wider industry and/or the uncommon nature of the practice.

6.5.1 SAFE WORK PRACTICE AND CONTRACTOR SELECTION

- Tabbed organization of the Active SDS book by usage (e.g., paints) enabling quick access, paired with diligent attention to maintaining the book.

6.5.2 TRAINING

- Use of a drilling simulator when training contracted drilling personnel.
- Use of photographs to incorporate hazards identification into JSA training, behavior-based safety, safe work practices, stop work authority and reporting unsafe work.

6.5.3 EMERGENCY RESPONSE AND CONTROL

- The Emergency Drill Procedure requires the manned facilities to cover a new potential emergency each month.
- Incorporating BSEE Safety Alerts into master action list to be conducted offshore (e.g., use of Stokes Litters incorporated into emergency drills).

APPENDIX 1 – DEFINITIONS

Note: please reference **Appendix 2: SPI Definitions and Metrics** for detail on the SPI, their minimum-release threshold values, and specific normalization factors for each SPI. Please reference **Appendix 3: Equipment Definitions** for specific definitions of equipment.

Barrier: A constraint on a hazard that reduces the probability of an incident or its consequences. There are two types of barriers: Prevention and Mitigation.

Concern: A condition that marginally meets requirements but could lead to a non-conformity if sufficient controls are not in place to maintain the management system.

Consequence: The harm that could result from an incident.

Contractor: An individual, partnership, firm or corporation retained by the Owner or Operator to perform work or to provide supplies or equipment. The term Contractor shall also include subcontractors.

Deepwater: Exploration and production activity occurring in 1000 feet or deeper water depth.

Established: Management system or component is in place, and documented if required by regulation or by the company.

Facility: All types of offshore structures permanently or temporarily attached to the seabed (mobile offshore drilling units, floating production systems, floating production, storage and offloading facilities, tension-leg platforms, and spars) used for exploration, development, production, and transportation activities for in the OCS, including pipelines regulated by the Department of Interior (DOI).

Formation Fluid: The subterranean fluid trapped by a reservoir formation; can include natural gas, liquid and vapor petroleum hydrocarbons, and interstitial water.

Good Practice: A SEMS-related practice that has been identified as being exemplary and one that could potentially benefit others in the industry by being shared.

Hazard: Types of chemical, thermal, toxic, kinetic, or potential energy with the ability to cause harm to people, the environment, or facilities.

High Value Learning Event: An event that may be considered by a COS member or the industry for use as a reference in process hazard analyses, management of change, project design, risk assessment, inspection, operating procedure review, and/or training. An HVLE should meet one or more of the following criteria:

A. Identify a previously unknown risk, situation, operational or mechanical hazard, or critical equipment failure.
B. Identify a previously unknown combination of factors that resulted in an unexpected condition or event.
C. Identify a routine operation or activity that created a previously unidentified risk or consequence.
D. Identify a situation where established industry designs, controls or procedures led to prevent an event (e.g., well kick, loss of wall thickness).
E. An event that is part of a pattern in industry events which could indicate that certain hazardous conditions are not well understood.

Implemented: Management system or component is put into effect or action.

Incident: A work-related event that has one or more consequences.

Loss of Primary Containment (LOPC): An unplanned or uncontrolled release of material from primary containment.

Maintained: Management system or component continues to work as designed, is checked, and corrections or adjustments are made, if required.

Major Hazard: A Hazard that can reasonably be foreseen as having the potential to cause a SPI 1 consequence.

Mitigation Barrier: Barrier to the right of the top event in a bow tie that can reduce or minimize the probability of a consequence. For example, active fire protection is a mitigation barrier.

Non-conformity: Less than satisfactory fulfillment of a requirement.

Operator: The individual, partnership, firm, or corporation having control or management of operations on the leased area or a portion thereof. The Operator may be a lessee, designated agent of the lessee(s), or holder of operating rights under an approved operating agreement.

Opportunity for Improvement: A condition that meets requirements, but based on auditor experience and knowledge, can be more effectively implemented using a modified approach or using good practices.

Prevention Barrier: Barrier to the left of the top event in a bow tie that can prevent or reduce the probability of a top event occurrence. For example, a safety instrumented system is a prevention barrier.

Production: Production covers offshore natural gas and oil production activities including flow lines and pipelines.

Projects: Projects include all offshore construction activities.

Safety Performance Indicator: A measurement that provides insights into the strength of barriers. SPI are inclusive of those that measure performance with respect to protection of personnel, the environment, and offshore facilities and property.

Safety Performance Indicator Program: A program developed, implemented and continually improved through which SPI are established, collected, analyzed and reported for specific safety issues of concern so that actions can be taken by relevant stakeholders to improve safety performance.

Wells: Wells include all offshore exploration, appraisal and production drilling, wireline, completion, workover, and intervention activities.

APPENDIX 2 – SPI DEFINITIONS & METRICS

SPI No.	SPI Definition	SPI Metric	Reporting Entity

SPI 1	Frequency of work-related incidents resulting in one or more of the following consequences:
	A. Fatality: One or more fatalities.
	B. Injury to 5 or more persons in a single Incident
	C. Tier 1 Process Safety Event: (API RP 754 Tier 1 Process Safety Event) An unplanned or uncontrolled release of any material, including non-toxic and non-flammable materials (e.g., steam, hot condensate, nitrogen, compressed CO2, compressed air), from a process that results in one or more of the consequences listed below:
	▪ an employee, contractor or subcontractor "days away from work" injury and/or fatality;
	▪ a hospital admission and/or fatality of a third-party;
	▪ an officially declared community evacuation or community shelter-in-place;
	▪ a fire or explosion resulting in greater than or equal to $25,000 of direct cost to the Company;
	▪ a pressure release device (PRD) discharge to atmosphere whether directly or via a downstream destructive device that results in one or more of the following four consequences:
	  ▪ liquid carryover
	  ▪ discharge to a potentially unsafe location
	  ▪ an onsite shelter-in-place
	  ▪ public protective measures
	  ▪ and a PRD discharge quantity greater than the threshold quantities in Table A-C in any one-hour period; or
	▪ A release of material greater than the threshold quantities described in Tables A-C in any one-hour period.
		# of SPI 1 incidents/ total work hours * 200,000	COS Operator for all incidents within the 500-meter zone and for incidents to direct employees while offshore
			COS Contractor for incidents outside the 500-meter zone while offshore

SPI No.	SPI Definition	SPI Metric	Reporting Entity
	D. Level 1 Well Control Incident: Loss of well control ▪ Uncontrolled flow of formation or other fluids resulting in: ▪ Seabed/surface release. ▪ Underground communication to another formation or well. ▪ Includes shallow water flows that result in damage or loss of facilities/equipment ▪ Excludes planned shallow gas mitigation operations. E. $1 million or greater direct cost from damage to or loss of facility / vessel / equipment (excludes costs associated with downtime or production loss). F. Oil spill to water > 10,000 gallons (238 barrels)		
SPI 2	Frequency of work-related incidents that do not meet the definition of a SPI 1 incident but have resulted in one or more of the following: A. Tier 2 Process Safety Event: (API RP 754 Tier 2 Process Safety Event) An unplanned or uncontrolled release of any material, including non-toxic and non-flammable materials (e.g., steam, hot condensate, nitrogen, compressed CO_2, compressed air), from a process that results in one or more of the consequences listed below and is not reported as a Tier 1 PSE: ▪ An employee, contractor or subcontractor recordable injury; ▪ A fire or explosion resulting in greater than or equal to $25,000 of direct cost to the Company; ▪ A pressure release device (PRD) discharge to atmosphere whether directly or via a downstream destructive device that results in one or more of the following four consequences: ▪ liquid carryover ▪ discharge to a potentially unsafe location ▪ an onsite shelter-in-place ▪ public protective measures ▪ and a PRD discharge quantity greater than the threshold quantity in Tables D-F in any one-hour period; or ▪ a release of material greater than the threshold quantities described in Tables D-F in any one-hour period.	# of SPI 2 incidents/ total work hours * 200,000	COS Operator for all incidents within the 500-meter zone and for incidents to direct employees while offshore COS Contractor for incidents outside the 500-meter zone while offshore

SPI No.	SPI Definition	SPI Metric	Reporting Entity
	B. Collision that results in property or equipment damage > $25,000 C. Incident Involving Mechanical Lifting A mechanical lifting (or lowering) incident that results in one or more of the following consequences. Mechanical lifting includes lifts of an asset or personnel (personnel transfer and man-riding). Consequences: ▪ Four or less recordable injuries in a single incident that occurs during the lift ▪ Between $25,000 and $1 million direct damage to or loss of an asset (including the load itself) ▪ A loss of primary containment of a material meeting a Tier 2 Process Safety Event threshold quantity ▪ A dropped load that strikes live process equipment ▪ Not included: ▪ Lifting incident resulting only in a first aid injury ▪ Lifting incident resulting only in direct damage to an asset (including the load itself) < $25,000 ▪ Lifting incident resulting only in a slipped load ▪ Dropped load or object into the water valued at < $25,000 ▪ Manual lifting incidents D. Loss of station keeping resulting in drive off or drift off defined as a malfunction or improper operation of the dynamic positioning system E. Life boat, life raft, or rescue boat event that resulted in a recordable injury or equipment damage or malfunction during life boat, life raft, or rescue boat operations or that take it out of service. F. Level 2 Well Control Incident One barrier system within the well design failed and other barrier system(s) either failed or were challenged beyond design capacity resulting in an influx without uncontrolled flow.		

SPI No.	SPI Definition	SPI Metric	Reporting Entity
SPI 3	Number of SPI 1 and SPI 2 incidents that involved failure of one or more of equipment as a contributing factor. COS Equipment categories: G. Well pressure containment system H. Christmas trees I. Downhole safety valves J. Blow out preventer and intervention systems K. Process equipment/pressure vessels, piping L. Automated safety instrumented systems / shutdown systems M. Pressure relief devices, flare, blowdown, rupture disks N. Fire/gas detection and fire-fighting systems O. Mechanical lifting equipment/personnel transport systems P. Station keeping systems Q. Bilge/ballast systems R. Life boat, life rafts, rescue boats, launch and recovery systems S. Other	Number of SPI 1 and 2 incidents involving failure of equipment / total number of SPI 1 and 2 incidents * 100	COS Operator for all incidents within the 500-meter zone and for incidents to direct employees while offshore COS Contractor for incidents outside the 500-meter zone while offshore
SPI 4	Crane or personnel/material handling incidents defined as a failure of the crane itself (e.g., the boom, cables, winches, ball ring), other lifting apparatus (e.g., air tuggers, chain pulls), the rigging hardware (e.g., slings, shackles, turnbuckles), or the load (e.g., striking personnel, dropping the load, damaging the load, damaging the facility). Reference MMS NTL 2008-G17.	Number of incidents as defined by MMS NTL 2008-G17 / total work hours * 200,000	COS Operator for all incidents within the 500-meter zone and for incidents to direct employees while offshore

SPI No.	SPI Definition	SPI Metric	Reporting Entity
SPI 5	Number of planned critical maintenance, inspections and tests completed on time. A planned task can be deferred if a proper risk assessment was completed and approved, and a new due date set. It is up to each company to define critical equipment	Number of critical mainte-nance, inspections and tests tasks completed on time / number of critical mainte-nance, inspections and tests tasks planned (expressed as a %)	COS Owner of Equipment
SPI 6	Number of work-related fatalities	Number of work-related fatalities	COS Operator when within the 500-meter zone and for direct employees while offshore COS Contractor when outside the 500-meter zone while offshore

SPI No.	SPI Definition	SPI Metric	Reporting Entity
SPI 7	Number of DART injuries and illnesses. BSEE defines DART injuries or illnesses as those that resulted in "Days Away from work, Restricted duty, and Job Transfer' outcomes.	# DART / total work hours * 200,000	COS Operator when within the 500-meter zone and for direct employees while offshore (same as reported on BSEE-0131 Form)
SPI 8	Number of recordable injuries and illnesses	Number of recordable injuries and illnesses/ total work hours * 200,000	COS Operator when within the 500-meter zone and for direct employees while offshore (same as reported on BSEE-0131 Form)
SPI 9	Number of spills greater or equal to 1 barrel that enter the water	Number of spills > 1 barrel / total work hours * 200,000	COS Operator for all spills within the 500-meter zone COS Contractor for spills outside the 500-meter zone while offshore

SPI No.	SPI Definition	SPI Metric	Reporting Entity
SPI 10	Potential severity of dropped object incidents. Aligning with the categories established by DROPSOnline.org, the potential may fall into one of the following four categories: • FATALITY: Death resulting from an injury or trauma • MAJOR: A Lost Time Incident (LTI). Non-fatal traumatic injury that causes any loss of time from work beyond the day or shift it occurred. Also referred to as Day Away from Work Case (DAFWC). • MINOR: A Recordable Incident. A work-related injury that does not involve death, day(s) away from work, restricted work or job transfer, and where the employee receives medical treatment beyond first aid. • SLIGHT: A First-aid Case. Limited or no injury. Treatment may be limited to first-aid.	Number of dropped objects in each category / total number of dropped objects reported.	COS Operator for all drops within the 500-meter zone COS Contractor for drops outside the 500-meter zone while offshore
Work Hours	For offshore workers, the hours worked are calculated on a 12-hour work day. Work hours are collected in the following categories: • Total U.S. OCS construction workforce hours inside 500 meters • Total U.S. OCS well workforce hours inside 500 meters • Total U.S. OCS production workforce hours inside 500 meters • Total U.S. OCS workforce hours inside 500 meters	Total Workforce Hours for the various categories	COS Operator when within the 500-meter zone (same as reported on BSEE-0131 Form)

TABLE A – Tier 1 Process Safety Events - Non-toxic Material Release Threshold Quantities for LOPC

LOPC is a recordable when release is 'acute', i.e. equals or exceeds a threshold quantity in any one-hour period.

Material Hazard Classification (with examples)	Outdoor Release	Indoor Release
Flammable Gases – e.g. • methane, ethane, propane, butane, • natural gas, • ethyl mercaptan	500 kg (1,100 lb)	250 kg (550 lb)
Flammable Liquids with Boiling Point < or equal to 35˚C (95˚F) and Flash Point < 23˚C (73˚F) – e.g. • liquefied petroleum gas (LGP), • liquefied natural gas (LNG), • isopentane	500 kg (1,100 lb)	250 kg (550 lb)
Flammable Liquids with Boiling Point > 35˚C (95˚F) and Flash Point < 23˚C (73˚F) – e.g. • gasoline, toluene, xylene, • condensate, • methanol, • > 15 API Gravity crude oils (unless actual flashpoint available)	1,000 kg (2,200 lb) or 7 barrels	500 kg (1,100 lb) or 3.5 barrels
Combustible Liquids with Flash Point > 23˚C (73˚F) and < or equal to 60˚C (140˚F) – e.g. • diesel, most kerosenes, • < 15 API Gravity crude oils (unless actual flashpoint available)	2,000 kg (4,400 lb) or 14 barrels	1,000 kg (2,200 lb) or 7 barrels
Liquids with flash point > 60˚C (140˚F) released at a temperature at or above its flash point – e.g. • asphalts, molten sulphur, • ethylene glycol, propylene glycol, • lubricating oil	2,000 kg (4,400 lb) or 14 barrels	1,000 kg (2,200 lb) or 7 barrels
Liquids with flash point > 60 ˚C (140˚F) released at a temperature below its flash point – e.g. • asphalts, molten sulphur, • ethylene glycol, propylene glycol, • lubricating oil	Not Applicable	Not Applicable

TABLE B – Tier 1 Process Safety Events - Toxic Material Release Threshold Quantities for LOPC

LOPC is a recordable when release is 'acute', i.e. equals or exceeds a threshold quantity in any one-hour period.

Material Hazard Classification (with examples)	Outdoor Release	Indoor Release
TIH Hazard Zone A materials - includes • acrolein (stabilized), • bromine	5 kg (11 lb)	2.5 kg (5.5 lb)
TIH Hazard Zone B materials- includes: • hydrogen sulphide (H2S), • chlorine (Cl2)	25 kg (55 lb)	12.5 kg (27.5 lb)
TIH Hazard Zone C materials- includes: • sulphur dioxide (SO2), • hydrogen chloride (HCl)	100 kg (220 lb)	50 kg (110 lb)
TIH Hazard Zone D materials- includes: • ammonia (NH3), • carbon monoxide (CO)	200 kg (440 lb)	100 kg (220 lb)
Other Packing Group I Materials – includes: • aluminum alkyls, • some liquid amines, • sodium cyanide, • sodium peroxide, • hydrofluoric acid (> 60% solution)	500 kg (1,100 lb)	250 kg (550 lb)
Other Packing Group II Materials – includes: • aluminum chloride, • phenol, • calcium carbide, • carbon tetrachloride • some organic peroxides • hydrofluoric acid (< 60% solution)	1,000 kg (2,200 lb) or 7 barrels	500 kg (1,100 lb) or 3.5 barrels

TABLE C – Tier 1 Process Safety Events - Other Material Release Threshold Quantities for LOPC

LOPC is a recordable when release is "acute," i.e. exceeds a threshold quantity in any one-hour period.

Material Hazard Classification (with examples)	Outdoor Release	Indoor Release
Other Packing Group III Materials – includes: • sulphur, • lean amine, • calcium oxide, • activated carbon, • chloroform, • some organic peroxides, • sodium fluoride, • sodium nitrate	2,000 kg (4,400 lb) or 14 barrels	1,000 kg (2,200 lb) or 7 barrels
Strong Acids or Bases - includes: • sulphuric acid, hydrochloric acid, • sodium hydroxide (caustic), • calcium hydroxide (lime)	2,000 kg (4,400 lb) or 14 barrels	1,000 kg (2,200 lb) or 7 barrels
Moderate Acids or Bases- includes: • diethylamine (corrosion inhibitor)	None	None

TABLE D – Tier 2 Process Safety Events - Non-toxic Material Release Threshold Quantities for LOPC

LOPC is a recordable when release is 'acute', i.e. equals or exceeds a threshold quantity in any one-hour period.

Material Hazard Classification (with examples)	Outdoor Release	Indoor Release
Flammable Gases – e.g. • methane, ethane, propane, butane, • natural gas, • ethyl mercaptan	50 kg (110 lb)	25 kg (55 lb)
Flammable Liquids with Boiling Point < or equal to 35˚C (95˚F) and Flash Point < 23˚C (73˚F) – e.g. • liquefied petroleum gas (LGP), • liquefied natural gas (LNG), • isopentane	50 kg (110 lb)	25 kg (55 lb)
Flammable Liquids with Boiling Point > 35˚C (95˚F) and Flash Point < 23˚C (73˚F) – e.g. • gasoline, toluene, xylene, • condensate, • methanol, • > 15 API Gravity crude oils (unless actual flashpoint available)	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel
Combustible Liquids with Flash Point > 23˚C (73˚F) and < or equal to 60˚C (140˚F) – e.g. • diesel, most kerosenes, • < 15 API Gravity crude oils (unless actual flashpoint available)	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel
Liquids with flash point > 60˚C (140˚F) released at a temperature at or above its flash point – e.g. • asphalts, molten sulphur, • ethylene glycol, propylene glycol, • lubricating oil	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel
Liquids with flash point > 60 ˚C (140˚F) released at a temperature below its flash point – e.g. • asphalts, molten sulphur, • ethylene glycol, propylene glycol, • lubricating oil	1,000 kg (2,200 lb) or 10 barrels	500 kg (1,100 lb) or 5 barrels

TABLE E – Tier 2 Process Safety Events - Toxic Material Release Threshold Quantities for LOPC

LOPC is a recordable when release is "acute," i.e. exceeds a threshold quantity in any one-hour period.

Material Hazard Classification (with examples)	Outdoor Release	Indoor Release
TIH Hazard Zone A materials - includes • acrolein (stabilized), • bromine	0.5 kg (1 lb)	0.25 kg (0.5 lb)
TIH Hazard Zone B materials- includes: • hydrogen sulphide (H2S), • chlorine (Cl2)	2.5 kg (5.5 lb)	1.3 kg (2.8 lb)
TIH Hazard Zone C materials- includes: • sulphur dioxide (SO2), • hydrogen chloride (HCl)	10 kg (22 lb)	5 kg (11 lb)
TIH Hazard Zone D materials- includes: • ammonia (NH3), • carbon monoxide (CO)	20 kg (44 lb)	10 kg (22 lb)
Other Packing Group I Materials – includes: • aluminum alkyls, • some liquid amines, • sodium cyanide, • sodium peroxide, • hydrofluoric acid (> 60% solution)	50 kg (110 lb)	25 kg (55 lb)
Other Packing Group II Materials – includes: • aluminium chloride, • phenol, • calcium carbide, • carbon tetrachloride • some organic peroxides • hydrofluoric acid (< 60% solution)	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel

TABLE F – Tier 2 Process Safety Events - Other Material Release Threshold Quantities for LOPC

LOPC is a recordable when release is 'acute', i.e. exceeds a threshold quantity in any one-hour period.

Material Hazard Classification (with examples)	Outdoor Release	Indoor Release
Other Packing Group III Materials – includes: • sulphur, • lean amine, • calcium oxide, • activated carbon, • chloroform, • some organic peroxides, • sodium fluoride, • sodium nitrate	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel
Strong Acids or Bases - includes: • sulphuric acid, hydrochloric acid, • sodium hydroxide (caustic), • calcium hydroxide (lime)	100 kg (220 lb) or 1 barrel	50 kg (110 lb) or 0.5 barrel
Moderate Acids or Bases- includes: • diethylamine (corrosion inhibitor)	1,000 kg (2,000 lb) or 10 barrels	500 kg (1,000 lb) or 5 barrels

APPENDIX 3 – EQUIPMENT DEFINITIONS

Equipment	Equipment Definition
Well Pressure Containment System	The casing and wellhead (with cement support and isolation where applicable) and tubing, tubing hardware and tubing hanger represent the equipment are located below the BOP or Christmas Tree, and comprise the "well pressure containment system", and as such represent the ability to contain pressure when a BOP or Christmas Tree has been closed.
Christmas Trees	Equipment attached to the uppermost connection of the wellhead or tubing spool to contain wellbore fluids in both the tubing and in the annular space between the casing and tubing during producing operations. The subsea tree may provide locations where nitrogen and chemical additives can be injected into the annulus or tubing string. The tree consists of assembled equipment that includes a wellhead connector, valves, choke, tree cap, and control system to operate the various components.
Downhole Safety Valves	• Downhole safety valve: A device installed in a well below the wellhead with the design function to prevent uncontrolled well flow when actuated, e.g., SSCSV or SCSSV. • Subsurface controlled subsurface safety valve (SSCSV): An SSSV actuated by the pressure characteristics of the well. • Surface controlled subsurface safety valve (SCSSV): An SSSV controlled from the surface by hydraulic, electric, mechanical, or other means.
Blow Out Preventer and Intervention Systems	Equipment installed on the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and the tubulars, in the tubulars or in an open hole during well drilling, completion, and testing operations. For the purposes of SPI data collection, this also includes pressure control equipment used in intervention operations, such as wireline and coiled tubing BOPs, lubricators, etc.
Process Equipment, Pressure Vessels and Piping	• Process Equipment/Pressure Vessel: A container associated with drilling, production, gathering, transportation, and treatment of liquid petroleum, natural gas, natural gas liquids, associated salt water (brine) designed to withstand internal or external pressure above ambient conditions. This definition includes containers used for pressurized storage of toxic and hazardous chemicals. • Piping System: An assembly of interconnected pipes that are used to convey, distribute, mix, separate, discharge, meter, control, or snub flows of hydrocarbons or toxic and hazardous chemicals.

Equipment	Equipment Definition
Automated Safety Instrumented Systems / Shutdown Systems	• Automated Safety Instrumented System - a system implementing one or more safety functions, with specified safety integrity level(s), that detect abnormal process conditions and take automatic, necessary actions to achieve or maintain a safe state for the process with respect to a hazardous event. • Shutdown Systems - a system of manual stations that, when activated, will initiate the shutting in (isolation and cessation) of all process stations of a platform production process and all support equipment for the process. May also be integrated with Fire and Gas Detection systems for automatic initiation.
Pressure Relief Devices, Flare Systems, Blowdown Systems, Rupture Disks	• Pressure Relief Device – A device actuated by inlet static pressure and designed to open during emergency or abnormal conditions to prevent a rise of internal fluid pressure in excess of a specified design value. The device also may be designed to prevent excessive internal vacuum. The device may be a pressure relief valve, a non-reclosing pressure relief device, or a vacuum relief valve. • Flare System – used to safely dispose of relief gases in an environmentally compliant manner through the use of combustion. • Blowdown System - a collection of controls, valves and pipes that allow controlled depressurization of liquid or gas pressure contained within a process, piping, or pressure vessel to reduce or eliminate pressure induced stresses during a time of potential heat weakening of vessels and piping, as well as a reduction of the inventory of fuel present on the facility. • Rupture Disk – A pressure containing, pressure and temperature sensitive element of a rupture disk device. A rupture disk device is a non-reclosing pressure relief device actuated by static differential pressure between the inlet and outlet of the device and designed to function by the bursting of a rupture disk. A rupture disk device includes a rupture disk and a rupture disk holder.

Equipment	Equipment Definition
Fire and Gas Detection and Fire Fighting Systems	• Manual fire alarms (pull stations), call stations, and audible alarms / beacons • Automatic Fire Detection Systems - The primary function of an automatic fire detection system is to alert personnel of the existence of a fire condition and to allow rapid identification of the location of the fire. The detection system(s) may be used to automatically activate emergency alarms, initiate Emergency Shutdown (ESD), isolate fuel sources, start fire water pumps, shut-in ventilation systems, and activate fire extinguishing systems such as gaseous agents, dry chemical, foam or water. The types of fire detectors commonly used on offshore platforms are as follows: ▪ Flame Detectors - e.g., Infrared (IR) Detectors, Ultraviolet (UV) Flame Detectors, Combination (IR/UV) ▪ Heat Detectors – e.g., Fusible Plugs or links, Heat-pneumatic or Theronistor Sensors, Rate of Rise Detectors, Fixed Temperature Detectors ▪ Products of Combustion / Smoke Detectors – e.g., Ionization Detector, Photoelectric Detector • Gas Detection System – The primary function of a fixed gas detection system is to alert personnel to the presence of flammable gases, toxic gases, or a combination of both. ▪ Flammable Gas Detection – designed to respond to a broad range of hydrocarbon gases / vapors (e.g., methane, ethane, propane and vapors from the evaporation of hydrocarbon liquids). The predominant sensors for flammable gas detection in general, normally occupied spaces are the infrared (IR) sensor or the catalytic bead sensor. ▪ Toxic Gas Detection – many gas detection systems include both flammable gas and toxic gas detection for hydrogen sulfide, sulfur dioxide, and fluorine in the same system. The semiconductor and electrochemical sensors are most commonly used for the detection of the toxic gases. ▪ Excludes portable gas monitoring instruments. • Fixed fire-fighting systems include the following: fire water pumps & drivers, distribution piping, fire hoses, stations, and nozzles, water spray systems / monitors, foam systems (fixed or portable), dry chemical systems, gaseous systems (e.g., CO2, Halon, FM-200 & FE-13, Inergen), and water mist / fine water spray systems. • Fire water systems are installed on offshore platforms to provide exposure protection, control of burning, and/or extinguishment of fires. The basic components of a fire water system are the fire water pump, the distribution piping, the hose / nozzle, and deluge / sprinkler system. Additives such as foaming agents may be included to aid in extinguishing flammable liquid fires. • Excludes portable fire extinguishers

Equipment	Equipment Definition
Mechanical Lifting Equipment / Personnel Transport Equipment	• Crane (includes base mounted drum winches) - a type of machine, generally equipped with a hoist, wire ropes or chains, and sheaves, that can be used both to lift and lower materials and to move them horizontally. Includes: ▪ Boom chords, foot pins, hoist (hydraulics and brakes), lift cylinder, sheave assembly, stops, tip extension or jib, pendant lines ▪ Counterweights ▪ Gantry, mast or A-frame pins ▪ Hook block ▪ Overhaul ball ▪ Main hoist (hydraulics and brakes) ▪ Auxiliary hoist (hydraulics or brakes) ▪ Pedestal or crane base ▪ Load management system (MIPEG, CCM-7000 etc.) ▪ Crane safety system (anti two block, high & low angle kick outs) • Top Drive - a device used on a drilling rig to actually rotate the drill pipe in order to drill the well. Includes main drill line hoist (hydraulics or brakes), crown-o-matic, top drive track, assembly rollers or wheels and bearings, hydramatics or hydromatics. • Pipe racking system (PRS) including main hoist (hydraulics or brakes), track, hydraulic system, claws or fingers. • Drawworks, Air Hoists, Tuggers • Chain fall - a type of hoist with a chain attached to a fixed raised structure or beam and used to lift very heavy objects. Includes clutch, brake and sprocket. • Rigging Accessories including hooks, chains, shackles, slings (below the hook), wire rope, D-ring, elevators, bails

Equipment	Equipment Definition
Station Keeping Systems	The station keeping systems for a floating structure are typically a single point mooring, a spread mooring, vertical tension legs, or a dynamic positioning (DP) system. • Single point mooring components may include but not limited to: hoisting system, hawser, swivels, roller bearings, risers, u-joint connectors, counter weights, chain, chain table, wire rope, synthetic rope, connecting hardware, clump weight, buoy, and anchor. • Spread mooring components: winch / windlass, chain jack, brakes, power, fairlead, wire rope, synthetic rope, connecting hardware, clump weight, buoy, and anchor • Vertical tension leg moorings are used by TLPs (tension leg platforms) and are comprised of: mooring tendons, seafloor foundations • Dynamic positioning system consists of components and systems acting together to achieve reliable position keeping capability. The dynamic-positioning system includes the power system (power generation and power management), thruster system and dynamic positioning control system.
Bilge/Ballast Systems	The vessel structure, machinery, piping, or controls related to ballast movement, watertight integrity and stability.
Life Boat, Life Rafts, Rescue Boats and Launch and Recovery Systems	• Life Boat / Survival craft is a craft capable of sustaining the lives of person in distress from the time of abandoning the ship. • Rescue boat is a boat designed to rescue persons in distress and to marshal survival craft. • A life raft is an inflatable appliance which depends upon non-rigid, gas filled chambers for buoyancy and which is normally kept not inflated until ready for use. • Launch and Recovery Systems - systems used to deploy or retrieve a lifeboat, life raft, or rescue boat. Components may include but not limited to: winch, fall wire (lifting wire), sheaves (pulleys), davits, davit arms, connecting hardware, secondary securing method (gripes, safety pendants), cradle, lifting points, releasing hook(s), brake, brake release, power source to winch / davit / davit arm, free fall railing.

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APPENDIX 5 – LFI CATEGORY DESCRIPTIONS

Site Type: The primary site where the incident or event occurred. Only one selection can be made.

- Aircraft
- Diving Vessel
- Drilling Rig on Production Facility
- Fixed Production Facility
- Floating Production Facility
- Floating Storage and Offloading Facility
- Mobile Offshore Drilling Unit
- Offshore Supply or Support Vessel
- Offshore Construction Vessel
- Seismic Vessel
- Subsea Production System
- Other

Operation Type: The primary operation that was underway at the time of the incident or event. Only one selection can be made.

- Aviation
- Marine-diving, seismic, transportation, rig moves, etc.
- Production-petroleum/natural gas production, flow lines, pipe lines
- Decommissioning
- Projects-includes offshore construction activities
- Wells-exploration, appraisal/production drilling, wireline, completion, workover, abandonment, intervention activities
- Other

Activity Type: The primary (most closely linked to incident or event) activity that was occurring at the time of the incident or event. Only one selection can be made.

- Confined Space Entry
- Diving
- Drilling Operations - Normal, Routine
- Energy Isolation
- Emergency Response (Actual or Drill)
- Helicopter Flight
- Helicopter Landing or Take-Off
- Hot Work
- Maintenance, Inspection and Testing
- Marine Vessel - In-Transit
- Marine Vessel - Station Keeping
- Material Transfer or Displacement
- Mechanical Lifting or Lowering
- Production Operations - Normal, Routine
- Simultaneous Operations
- Start-up or Shut-down Operations
- Working at Height
- Other

Areas for Improvement: All of the Areas for Improvement that apply to the incident or event being shared. The Areas for Improvement cover three general categories: Physical Process and Equipment; Administrative Process; or People. Multiple Areas for Improvement can be selected across the general categories.

5.11.1 Physical Facility, Equipment and Process
Select one or more of the following AFI when enhancements in the quality of the physical process and equipment design, layout, material specification, fabrication, or construction were highlighted for improvement, including:

5.11.1.1 Process or Equipment Design or Layout – Select this AFI if the design or layout of the process or equipment was highlighted for improvement. Include cases where issues with the design or layout were significant contributors to subsequent human actions.

5.11.1.2 Process or Equipment Material Specification, Fabrication and Construction – Select this AFI if the quality and compatibility of the material specification, fabrication or construction of the process or equipment, prior to its use was highlighted for improvement, including process or equipment provided by vendors or third parties on a permanent or temporary basis. This category includes the use of defective parts or equipment, or improper installation.

5.11.1.3 Process or Equipment Reliability – Select this AFI if the ability of the process or equipment to function without defects or breakdown was highlighted for improvement, including improvement in maintenance, inspection, testing and operating requirements.

5.11.1.4 Instrument, Analyzer and Controls Reliability – Select this AFI if the ability of instrumentation, analyzers, and control systems, including software, to function without defects or breakdown was highlighted for improvement including improvement in maintenance, inspection, testing and operating requirements.

5.11.2 Administrative Processes
Select one or more of the following AFI when enhancements to the quality, scope or structure of administrative processes for managing various aspects of work execution were highlighted for improvement. Note - If the identified gap was related to "failure to follow" Administrative Processes, do NOT select these categories. Instead, use the appropriate category in Section 5.11.3 People.

5.11.2.1 Risk Assessment and Management – Select this AFI if the process for systematic identification and evaluation of potentially significant risks was identified for improvement. This includes but is not limited to HAZOPS, facility hazard assessments, and Job Safety Analysis (JSA).

5.11.2.2 Operating Procedures or Safe Work Practices – Select this AFI if the improvement opportunity involves creating or modifying operating procedures or safe work practices to prevent recurrence. This includes specific operations, maintenance, testing, contractor selection or other procedures and practices.

5.11.2.3 Management of Change – Select this AFI if the process for identifying, approving, and managing significant technical, administrative, or organizational changes was identified for improvement. Specific improvement areas may include MOC use not required (but should have been), MOC review incomplete or incorrect, or MOC actions not completed (e.g., drawings not updated).

5.11.2.4 Work Direction or Management – Select this AFI if the process for directing work activities or managing the number or types of work allowed at a given time or location was identified for improvement. This includes but is not limited to permit-to-work, simultaneous operations and supervision of the area or work team.

5.11.2.5 Emergency Response – Select this AFI if the capability or processes for responding to a situation to prevent the escalation of incident or event consequences was identified for improvement. This category includes opportunities related to emergency preparedness, such as access to equipment and trained personnel, insufficient or absence of drills, etc.

5.11.3 People
Select one or more of the following AFI when enhancements to the personnel actions linked to the execution of work tasks were highlighted for improvement, including:

5.11.3.1 Personnel Skills or Knowledge – Select this AFI if personnel knowledge of the relevant tasks, or the ability of personnel to execute the task correctly and safely, was identified for improvement. This category includes gaps in training (e.g., not required, not completed, or training needs improvement), assessment/verification (not performed, needs improvement, etc.), or remediation (not required, not completed, etc.).

5.11.3.2 Quality of Task Planning and Preparation – Select this AFI if personnel planning and preparation of the task prior to initiating the activity were identified for improvement, including team actions such as reviewing procedures, and completing JSAs, toolbox talks, or job walkthroughs. Note – this category will most often apply when appropriate procedures were in place, but personnel failed to follow them in the pre-work planning phase.

5.11.3.3 Individual or Group Decision-Making – Select this AFI if decisions made by one or more people involved in the execution of the task were identified for improvement. This may be selected only if personnel involved in the task had sufficient skills and knowledge, but chose to execute the task in a manner different than the documented procedure or practice.

5.11.3.4 Quality of Task Execution – Select this AFI if the quality or thoroughness of executing the intended task procedure or practice was highlighted for improvement. This applies where the person or personnel were attempting to follow the prescribed procedures or practices, but errors or incomplete execution contributed to the incident or event.

5.11.3.5 Quality of Hazard Mitigation – Select this AFI if a person or personnel either failed to put in place barriers or the quality, number, or location of barriers were insufficient to mitigate the potential impacts of relevant hazards was highlighted for improvement.

5.11.4.6 Communication – Select this AFI if the effectiveness of communication was identified for improvement. This includes communication between team members and between the team and other individuals or groups. Also included are difficulties with language or terminology.

5.12 Additional Comments
Enter Areas for Improvement that were identified in areas outside the Physical Facility, Equipment and Process; Administrative Processes; and People categories described above. A detailed description of the identified improvements should be included. Also, any additional description of "Other" Site, Operation or Activity Types could be included in this Additional Comments section. This input cell is limited to 750 characters. The first use of an acronym should always be preceded by the term for which it is used.

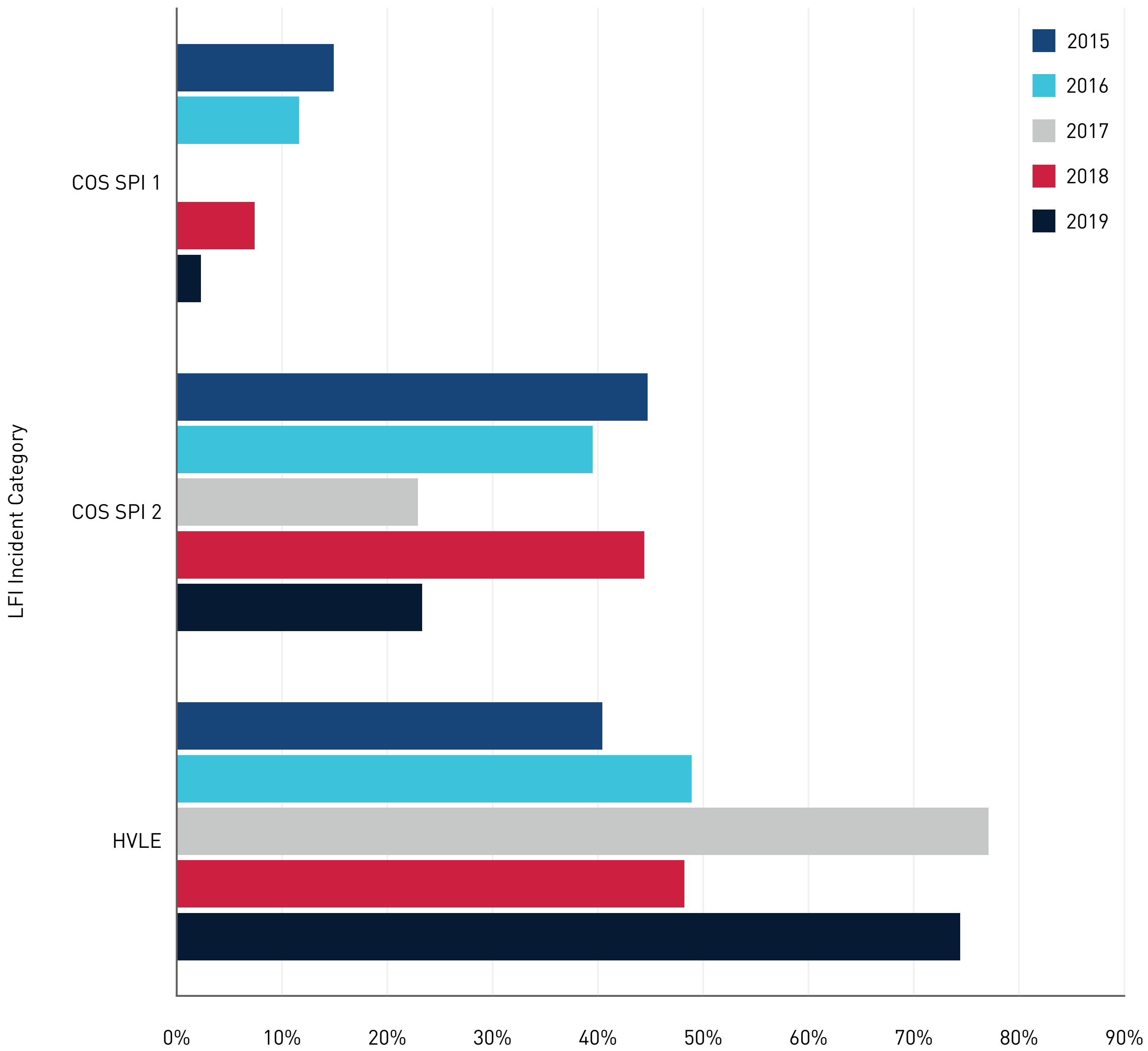
5.13 Lessons Learned
Enter a description with sufficient content to explain the context of the incident, lessons learned, and actions taken to reduce the likelihood of a recurrence. These may include equipment, processes and/or human factors. Lessons Learned and actions taken should be directly related to the areas for improvement listed above. This input cell is limited to 750 characters. The first use of an acronym should always be preceded by the term for which it is used.

APPENDIX 6 – LFI DATA CHARTS (U.S. OCS DATA)

Refer to the charts listed in this appendix for additional details on the distribution of incidents and HVLE across reporting fields contained in the LFI Report Form (and not previously displayed in the body of the report). The following charts are contained in this Appendix:

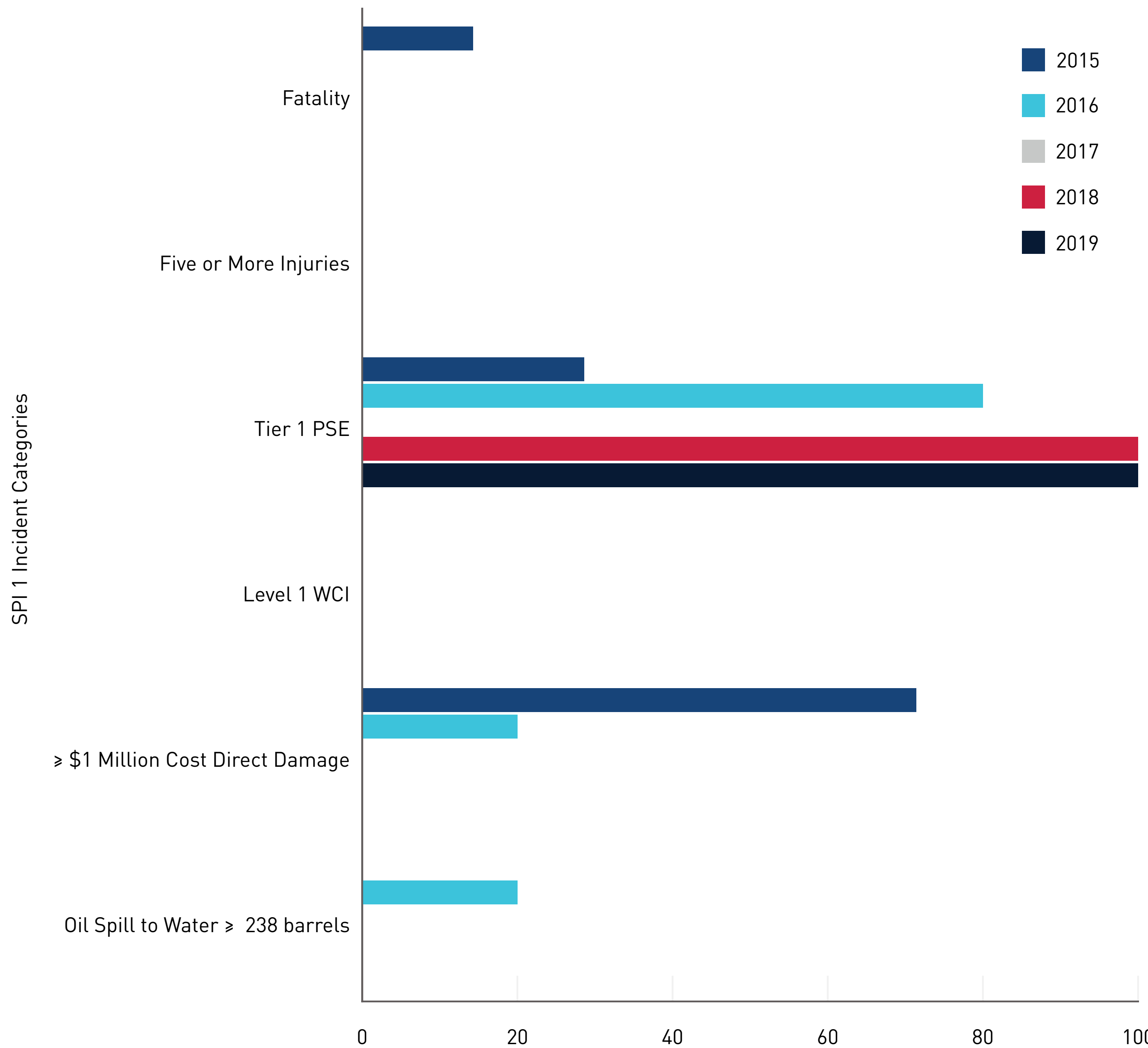
- **Chart 1:** LFI Incident and HVLE Category Distribution
- **Chart 2:** LFI SPI 1 Incident Distribution
- **Chart 3:** LFI SPI 2 Incident Distribution
- **Chart 4:** LFI Incident and HVLE Site Type Distribution
- **Chart 5:** LFI Incident and HVLE Operation Type Distribution
- **Chart 6:** LFI Incident and HVLE Activity Type Distribution
- **Chart 7:** LFI SPI 2C (Mechanical Lifting or Lowering) AFI Distribution
- **Chart 8:** Process Safety (Tier 1 and Tier 2) AFI Distribution

CHART 1: LFI Incident and HVLE Category Distribution (U.S. OCS only)



• Number of occurrences represented above (by year): 2015 = 47, 2016 = 43, 2017 = 33, 2018 = 27, 2019 = 43

CHART 2: LFI SPI 1 Incident Distribution (U.S. OCS only)



[1] *This chart depicts the number of SPI 1 consequences divided by the total number of SPI 1 LFI submitted in the given year. The total percentage in a given year can exceed 100% when multiple consequences occur for one incident.*

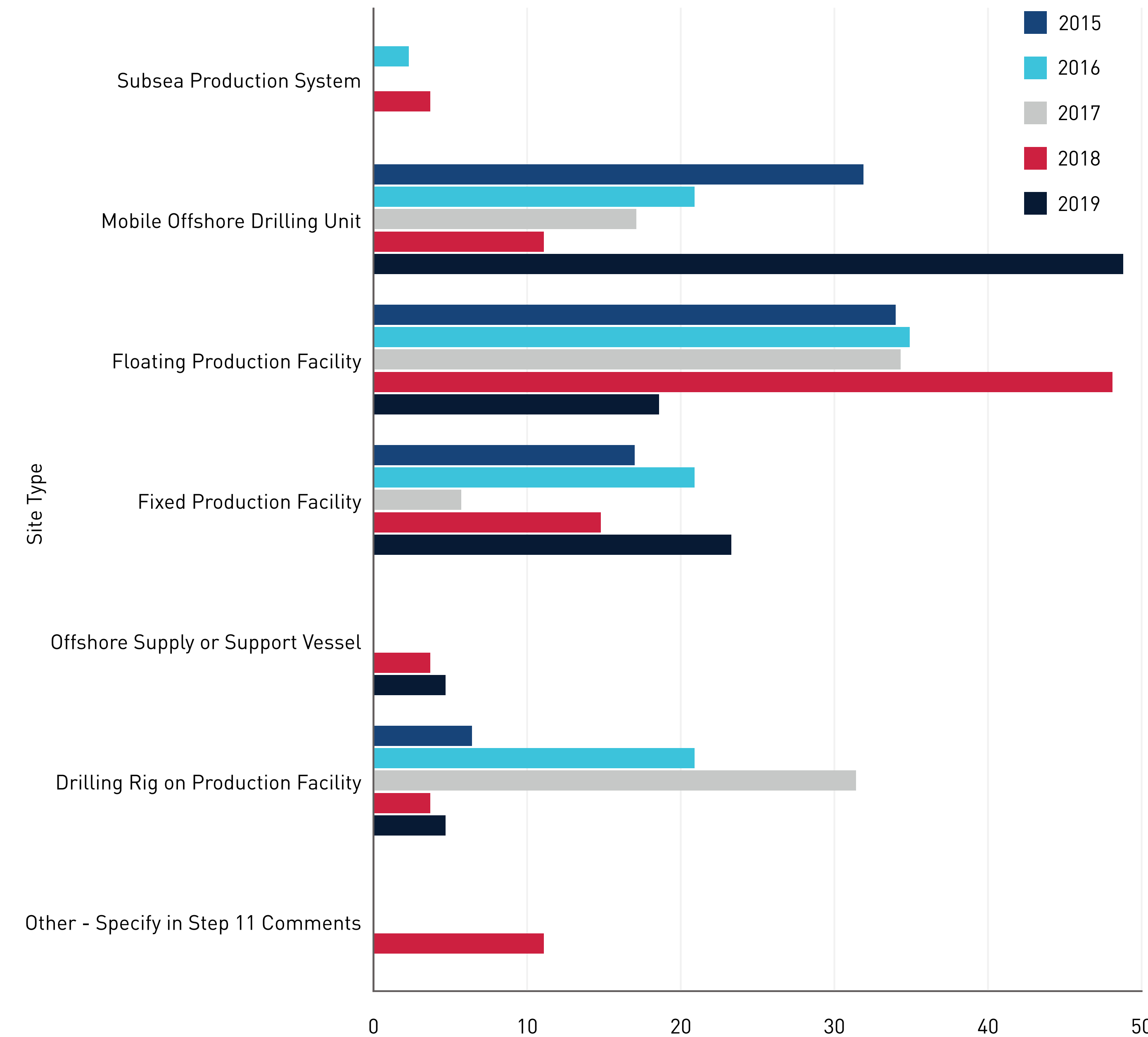
• Number of occurrences represented above (by year): 2015 = 8, and 2016 = 6, 2017 = 0, 2018 = 2, 2019 = 1

CHART 3: LFI SPI 2 Incident Distribution (U.S. OCS only)

[1] *This chart depicts the number of SPI 2 consequences divided by the total number of SPI 2 LFI submitted in the given year. The total percentage in a given year can exceed 100% when multiple consequences occur for one incident.*

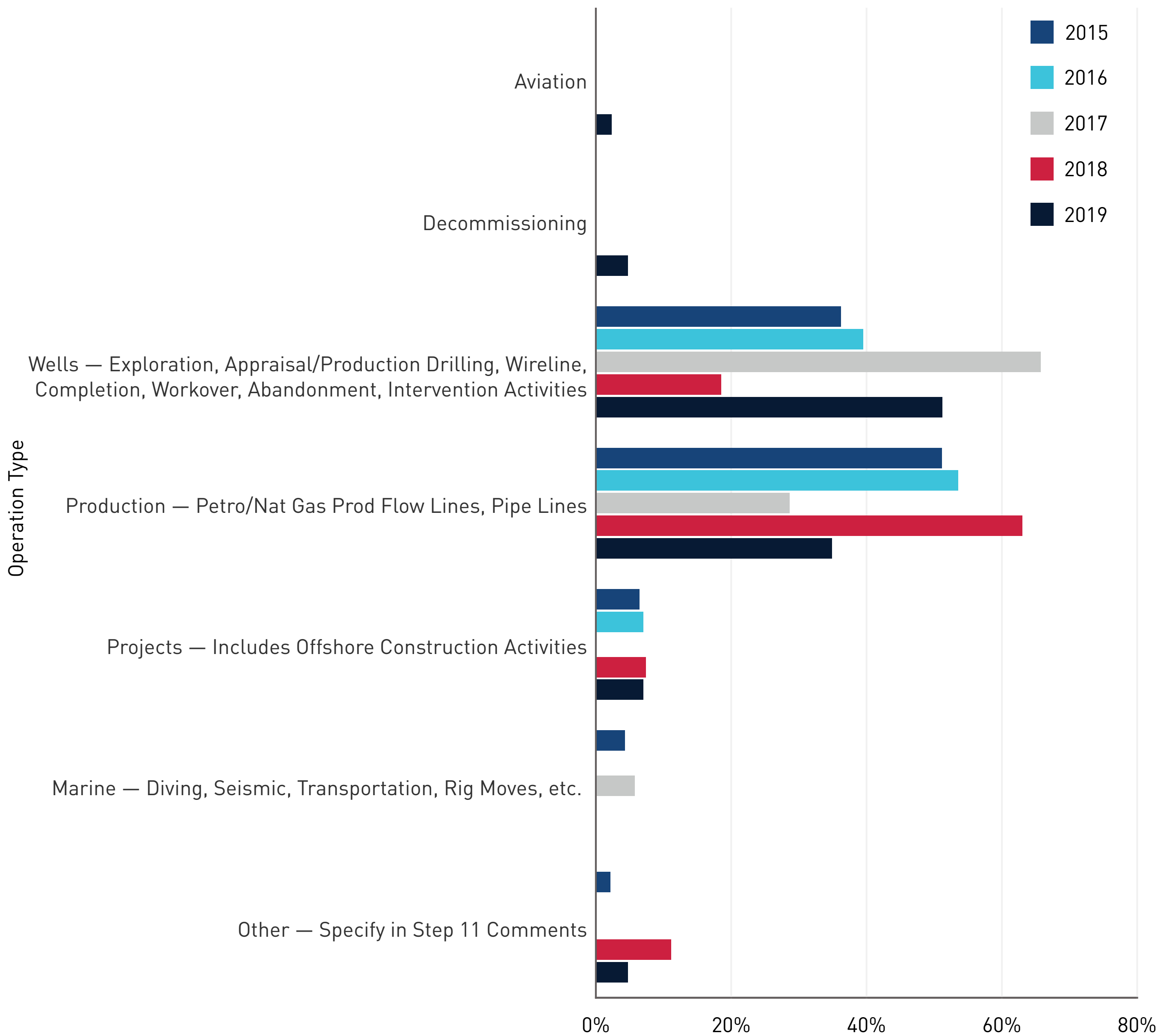
- Number of occurrences represented above (by year): 2015 = 22, 2016 = 17, 2017 = 8, 2018 = 11, 2019 = 10

CHART 4: LFI Incident and HVLE Site Type Distribution (U.S. OCS only)



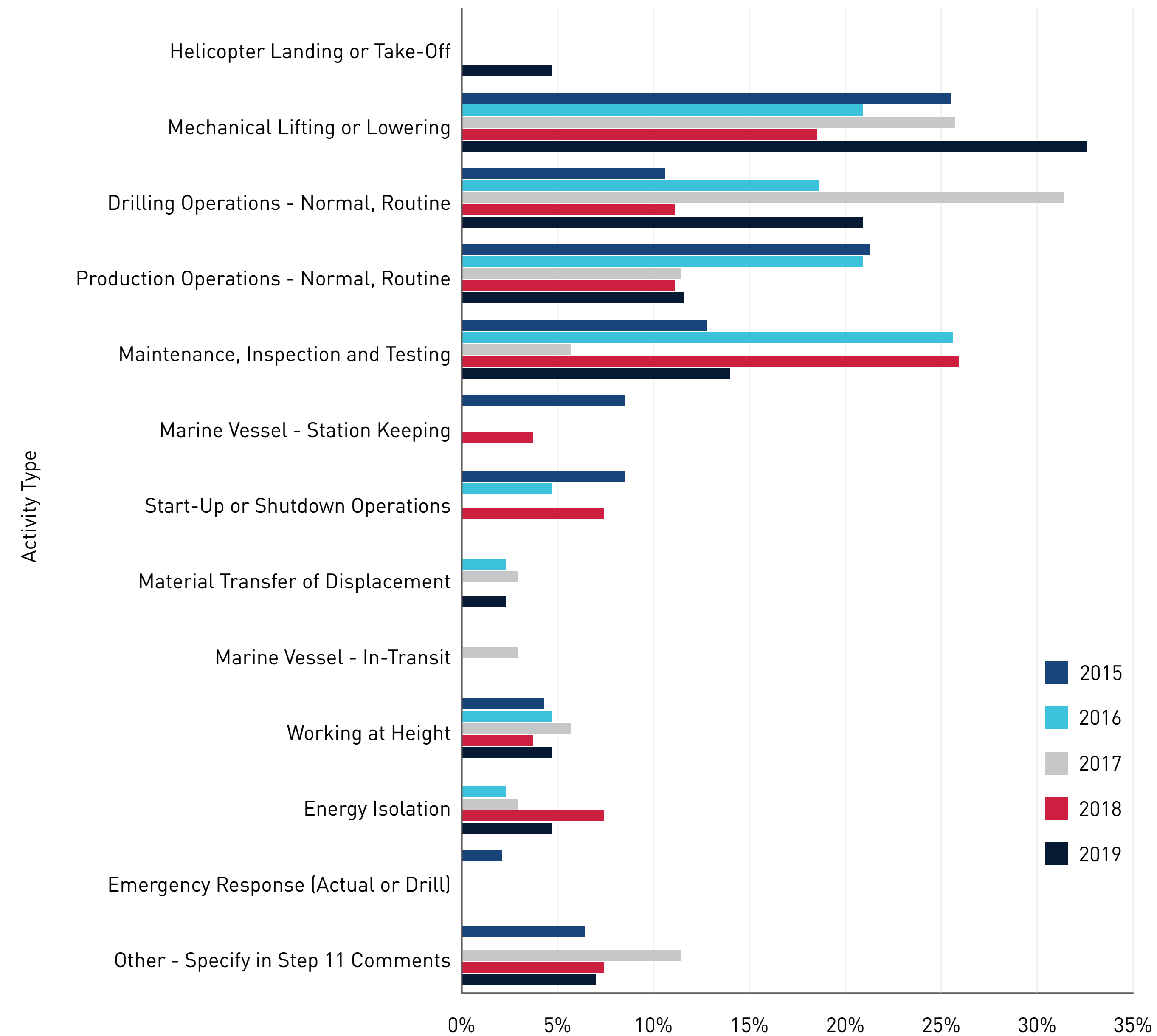
- Number of occurrences represented above (by year): 2015 = 47, 2016 = 43, 2017 = 33, 2018 = 27, 2019 = 43

CHART 5: LFI Incident and HVLE Operation Type Distribution (U.S. OCS only)



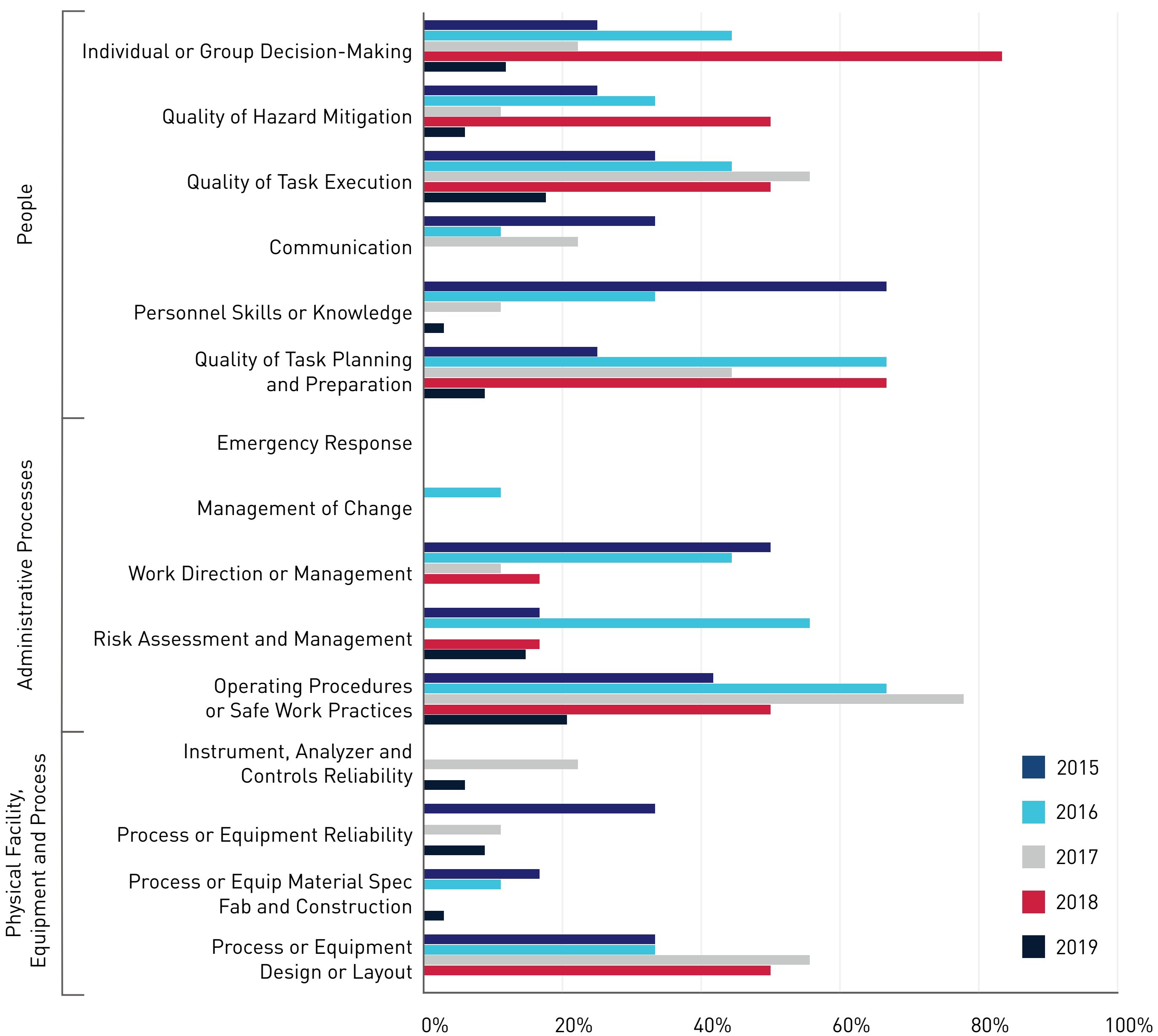
- Number of occurrences represented above (by year): 2015 = 47, 2016 = 43, 2017 = 33, 2018 = 27, 2019 = 43

CHART 6: LFI Incident and HVLE Activity Type Distribution (U.S. OCS only)



- Number of occurrences represented above (by year): 2015 = 47, 2016 = 43, 2017 = 33, 2018 = 27, 2019 = 43
- This chart presents the primary activity for each event (LFI Submittals identify only one activity for each event). Secondary activities are not captured in this chart (e.g., Mechanical Lifting or Lowering during Maintenance Inspection and Testing).

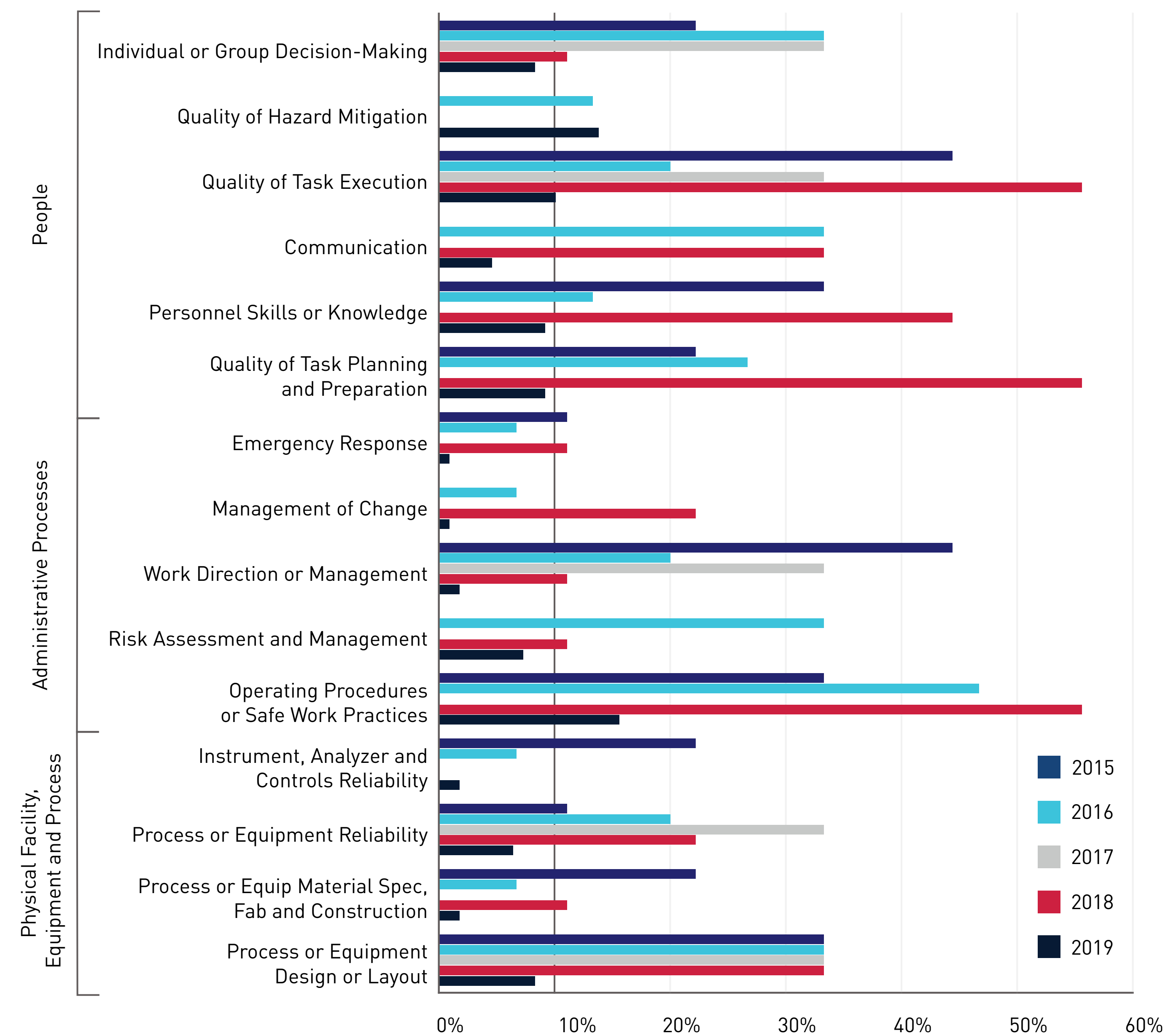
CHART 7: Mechanical Lifting or Lowering AFI Distribution (AFI selection per total number of Mechanical Lifting or Lowering Activity submittals) (U.S. OCS only)



[2] *This chart depicts the number of Mechanical Lifting or Lowering Activity AFI selected divided by the total number of Mechanical Lifting or Lowering Activity LFI submittals in the given year.*

- Number of incidents represented above (by year): 2015 = 12, 2016 = 9, 2017 = 9, 2018 = 6, 2019 = 13

CHART 8: Process Safety (Tier 1 and Tier 2) AFI Distribution (AFI selection per total number of PSE submittals) (U.S. OCS only)



[1] *This chart depicts the number of AFI selected divided by the total number of PSE submittals in the given year.*

- Number of Process Safety LFI Forms represented above: 2015 = 9, 2016 = 15, 2017 = 3, 2018 = 9, 2019 = 4