ExproSoft

# Final REPORT

## Title: Loss of Well Control Occurrence and Size Estimators, Phase I and II

CLIENT:
BSEE

Authors:
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| Report no. | Version | Date |
| --- | --- | --- |
| ES201471/2 | Final Report 04-May 2017 | 04-May 2017 |

| REPORT | | | | |
|---|---|---|---|---|
| Client: | BSEE | | | |
| SUBJECT: | Loss of Well Control Occurrence and Size Estimators, Phase I and II | | | |
| Distribution: | Name | | Company | |
| | Dr. Elaine Kleiner, COR | | BSEE | |

| Classification | Project no | Version no | Date | No. of pages |
|---|---|---|---|---|
| Open | ES201471 | Final report | 04.05.2017 | 200 |

| Prepared by: | Reviewed by: | Approved by: |
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## SUMMARY

*Loss of Well Control* (LOWC) events reported in the *SINTEF Offshore Blowout Database* for the period 2000–2015 are carefully studied in this report. The events are classified with respect to the operational phases: exploration drilling, development drilling, workover activities, well completion activities, production, wireline and abandoned wells.

Information about the individual LOWC events pertaining to the following issues is sought:

- Equipment failures
- Human errors
- Testing of equipment prior to incident
- Observation of well kicks
- Violation of rules and regulations

Information sources that are part of the SINTEF database system are reviewed together with several other sources, with a special focus on BSEE's *eWell* system.

Well kicks from the US GOM OCS in the period 2011–2015 are identified through a systematic review of the *Well Activity Reports* (WAR) in the BSEE *eWell* system.

The report describes, categorizes, and analyzes the observed LOWC events for the period 2000–2015, and compares the LOWC frequencies in the US GoM with other regulated areas.

This report overrides the previous Phase I report. This report is the combined final report from Phase I and Phase II.



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# GLOSSARY OF ACRONYMS AND DEFINITIONS

| | | |
|---|---|---|
| ANP | - | Agência Nacional do Petróleo (Brazilian) |
| APD | - | Application for Permit to Drill |
| BHA | - | Bottom Hole Assembly |
| BOEM | - | Bureau of Ocean Energy Management |
| BOEMRE | - | Bureau of Ocean Energy Management, Regulation and Enforcement |
| BOP | - | Blowout Preventer |
| BSEE | - | Bureau of Safety and Environmental Enforcement |
| BSR | - | Blind-shear Ram |
| DP | - | Drill-pipe |
| EDS | - | Emergency Disconnect Situation |
| ESD | - | Emergency Shut Down |
| ESP | - | Electrical Submersible Pump |
| FIV | - | Formation Isolation Valve |
| FTC | - | Failed To Close |
| FTO | - | Failed To Open |
| GoM | - | Gulf of Mexico |
| HP | - | High Pressure |
| HPHT | - | High Pressure High Temperature |
| HSE | - | Health and Safety Executive (UK) |
| LCP | - | Leakage in Closed Position |
| LMRP | - | Lower Marine Riser Package |
| LOWC | - | Loss of Well Control |
| LPR | - | Lower Pipe Ram |
| LWD | - | Logging While Drilling |
| MD | - | Measured Depth |
| MMS | - | Mineral Management Service |
| MPR | - | Middle Pipe Ram |
| MSL | - | Mean Sea Level |
| MTBB | - | Mean Time Between Blowouts |
| MTTF | - | Mean Time To Failure |
| MTTR | - | Mean Time To Repair |
| NPD | - | Norwegian Petroleum Directorate |
| OCS | - | Outer Continental Shelf |
| PC | - | Premature Closure |
| PSA | - | Petroleum Safety Authority (Norway) |
| QA | - | Quality Assurance |
| ROV | - | Remotely Operated Vehicle |
| SCSSV | - | Surface Controlled Subsurface Safety Valve |
| TD | - | Total Depth |
| TVD | - | True Vertical Depth |
| UPR | - | Upper Pipe Ram |
| WP | - | Working Pressure |
| WR | - | Wireline Retrievable |

The following categories for the spill size have been used:

- < 10 bbls = very small
- 10 - 50 bbls = small
- 50 - 500 bbls = medium
- 500 - 5,000 bbls = large
- 5,000 - 50,000 bbls = very large
- > 50,000 bbls = gigantic

**BSEE definition for *Loss of Well Control*:**

- Uncontrolled flow of formation or other fluids. The flow may be to an exposed formation (an underground blowout) or at the surface (a surface blowout).
- Flow through a diverter
- Uncontrolled flow resulting from a failure of surface equipment or procedures

**SINTEF Offshore Blowout Database definitions**

**Blowout definition:** A blowout is an incident where formation fluid flows out of the well or between formation layers after all the predefined technical well barriers or the activation of the same have failed.

**Well release definition:** The reported incident is a well release if oil or gas flowed from the well from some point were flow was not intended and the flow was stopped by use of the barrier system that was available on the well at the time the incident started.

**Shallow gas definition:** Any gas zone penetrated before the BOP has been installed. Any zone penetrated after the BOP is installed is not shallow gas (typical Norwegian definition of shallow gas).

**Categories and subcategories for LOWC incidents in the SINTEF Offshore Blowout Database**

| Main | Category | Sub category | Comments/Example |
|---|---|---|---|
| Blowout and well release | Blowout (surface flow) | 1. Totally uncontrolled flow, from a deep zone | Totally uncontrolled incidents with surface/subsea flow. |
| | | 2. Totally uncontrolled flow, from a shallow zone | Typically the diverter system fails. |
| | | 3. Shallow gas "controlled" subsea release only | Typical incident for e.g. riserless drilling is performed when the well starts to flow. The rig is pulled away. |
| | Blowout (underground flow) | 4. Underground flow only | |
| | | 5. Underground flow mainly, limited surface flow | The limited surface flow will be incidents where a minor flow has appeared, and typically the BOP has been activated to shut the surface flow. |
| | Well release | 6. Limited surface flow before the secondary barrier was activated | Typical incident will be with flow through the drill pipe and the shear ram is activated. |
| | | 7. Tubing blown out of well, then the secondary barrier is activated | Typical incident occurring during completion or workover. Shear ram is used to close the well after the tubing has been blown out of the well. |
| | Diverted well release | 8. Shallow gas controlled flow (diverted) | All incidents where the diverter system functioned as intended. |
| | Unknown | Unknown | Unknown may be selected for both the category and the subcategory. |

**Deep and shallow zone LOWC events**

- *Shallow zone LOWC event* - A LOWC event that occurs before the BOP has been installed on the wellhead
- *Deep zone LOWC* – A LOWC event that occurs after the BOP has been landed on the wellhead

**Deepwater and shallow water definition**

- *Deepwater* – Water depth deeper than 600 meters
- *Shallow water* – Water depth less than 600 meters

**Deep well and normal well definition**

- *Deep well* - A well with a total depth deeper than 4,000 mTVD
- *Normal well* - A well with a total depth less than 4,000 mTVD

**HPHT well definitions**

**US definition**

According to 30 CFR 250.807 HPHT means when one or more of the following well conditions exist:

1) The completion of the well requires completion equipment or well control equipment assigned a pressure rating greater than 15,000 psig or a temperature rating greater than 350 degrees Fahrenheit (°F);

2) The maximum anticipated surface pressure or shut-in tubing pressure is greater than 15,000 psig on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead; or

3) The flowing temperature is equal to or greater than 350 degrees Fahrenheit (°F) on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead.

**HPHT definition is used in this report**

- *HPHT well* – A well with expected shut-in pressure exceeding 69 MPa (10,000 psi), or a static bottom hole temperature higher than 150 °C (302 F)

**Areas of operation**

The following areas of operations are used in the report;

- *US GoM OCS*
- *Regulated area include:* UK, Norway, Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark and Brazil
- *Rest of the world:* All countries/areas not mentioned above

# EXECUTIVE SUMMARY

## *Overview*

The Phase I objective was to update offshore loss of well control (LOWC) frequency information for the period 2006-2014 for the US Gulf of Mexico and Pacific OCS, North Sea, Canada, Brazil, and Australian offshore regions and other areas with a comparable regulatory regime. When working with the Phase I the period was extended to 2000–2014 to get a more comprehensive data set to evaluate.

The work with Phase II of the project was started in October 2016. The Phase II Objective has been to update offshore loss of well control frequency information for the period 2015, and merge the results with the Phase I results. Further, the LOWC incidents experienced during the production phase and wireline operations for the period 2000 – 2015 have been added and analyzed.

In Phase II of the project 39 new LOWC events were added to the LOWC experience, so the total number of LOWCs increased from 117 to 156. They were; one shallow gas incident during development drilling, one abandoned well incident, 26 production incidents, seven wireline incidents, and four incidents where the operational phase is unknown.

This report includes all information from the previous Phase I report, in addition to the added information. This report therefore overrides the previous Phase I report. This report is the combined final report from Phase I and Phase II.

*Loss of Well Control* (LOWC) events reported in the *SINTEF Offshore Blowout Database* for the period 2000–2015 are carefully studied in this report. The events are classified with respect to the following operational phases:

- Exploration drilling
- Development drilling
- Workover activities
- Well completion activities
- Production
- Wireline
- Abandoned wells

The drilling LOWC events have further been grouped in:

- *Shallow zone LOWC event* - A LOWC event that occur before the BOP has been installed on the wellhead
- *Deep zone LOWC* – A LOWC event that occur after the BOP has been landed on the wellhead

The descriptions of the individual LOWC events in the SINTEF database have been reviewed in order to extract detailed information about the following issues:

- Equipment failures

- Human errors
- Testing of equipment prior to incident
- Observations of well kicks
- Violations of rules and regulations

The study is based on data from the SINTEF database, but is supplemented by other worldwide sources of information, with special focus on the BSEE *eWell* system.

Well kicks in the US GOM OCS for the period 2011–2015 are identified through a systematic review of the *Well Activity Reports* (WARs) in the BSEE *eWell* system.

A risk model has been developed for estimating the US GoM risk related to LOWC events.

The report describes, categorizes, and analyzes the observed LOWC events for the period 2000–2015, and compares the LOWC frequencies in the US GoM with other areas of the world. In addition, the future LOWC risk in the US GOM is assessed.

The following areas of operations are used in the report;

- *US GoM OCS*
- *Regulated area:* UK, Norway, Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark and Brazil
- *Rest of the world:* All countries/areas not mentioned above

Table 1.1 shows an overview of the number of LOWC events for the various areas and the operational phases for the period 2000–2015.

*Table 1.1 Area-specific overview of the number of LOWC events that occurred during different operational phases (2000–2015).*

| Area | | Dev. drilling | Expl. Drilling | Unk. Drilling | Compl-etion | Work-over | Production | | Wire-line | Aband-oned well | Un-known | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | External cause* | No ext. cause* | | | | |
| US GOM OCS | | 16<br>19.5 % | 24<br>29.3 % | | 3<br>3.7 % | 21<br>25.6 % | 5<br>6.1 % | 7<br>8.5 % | 3<br>3.7 % | 3<br>3.7 % | | 82 |
| Regu-lated areas | UK & Norwegian waters | 4<br>15.4 % | 3<br>11.5 % | | 5<br>19.2 % | 5<br>19.2 % | | 3<br>11.5 % | 4<br>15.4 % | 1<br>3.8 % | 1<br>3.8 % | 26 |
| | Netherlands. Canada East Coast. Australia. US Pacific OCS. Denmark. Brazil | 2<br>22.2 % | 3<br>33.3 % | | | 3<br>33.3 % | | | | | 1<br>11.1 % | 9 |
| Rest of the world | | 9<br>23.1 % | 5<br>12.8 % | 4<br>10.3 % | 2<br>5.1 % | 4<br>10.3 % | 7<br>17.9 % | 4<br>10.3 % | | 2<br>5.1 % | 2<br>5.1 % | 39 |
| Total | | 31<br>19.9 % | 35<br>22.4 % | 4<br>2.6 % | 10<br>6.4 % | 33<br>21.2 % | 12<br>7.7 % | 14<br>9.0 % | 7<br>4.5 % | 6<br>3.8 % | 4<br>2.6 % | 156 |

* External causes are typical; storm, military activity, ship collision, fire and earthquake.

More than 50% of the LOWC events come from the US GoM OCS, which is the most mature area with the highest activity. Approximately 45% of the LOWC events occurred during drilling and 21% during workovers, and 17% during production. Approximately 50% of the drilling LOWC events were shallow events.

From a risk perspective, a *blowout (surface flow)* from a "deep" zone has the highest potential for consequences. Table 1.2 presents an overview of the LOWC main categories for the regulated areas, including the US GoM OCS 2000–2015.

*Table 1.2 Overview of LOWC main categories for the regulated areas including the US GoM OCS 2000–2015.*

| Main category [1] | Deep zone LOWCs | | | Shallow zone LOWCs | | |
|---|---|---|---|---|---|---|
| | Regulated area | US GoM OCS | Total | Regulated area | US GoM OCS | Total |
| Blowout (surface flow) | 8 | 30 | 38 | 4 | 12 | 16 |
| Blowout (underground flow) | 1 | 3 | 4 | | | |
| Diverted well release | | 2 | 2 | 2 | 8 | 10 |
| Well release | 20 | 25 | 45 | | 2 | 2 |
| **Total** | **29** | **60** | **89** | **6** | **22** | **28** |

Thirty-eight *blowouts (surface flow)* from a "deep" zone were identified.

## *Fatalities Related to LOWC Events*

In total, 13 fatalities occurred in the regulated areas including the US GoM OCS for all operations included. Table 1.3 shows the total number of LOWC events versus the number of fatalities in regulated areas, including US GoM OCS 2000–2015.

*Table 1.3 Total number of LOWC events versus the number of fatalities in regulated areas, including US GoM OCS 2000–2015.*

| Main Category | No. of LOWC events/Fatalities | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Development drilling | | Exploration drilling | | Com-pletion | Work-over | Prod-uction | Wire-line | Aband-oned well | Un-known | Total |
| | Deep zone | Shallow zone | Deep zone | Shallow zone | | | | | | | |
| Blowout (surface flow) | 3 / 0 | 10 / 0 | 10 / 12 | 6 / 0 | 2 / 0 | 11 / 0 | 8 / 0 | 1 / 0 | 2 / 0 | 1 / 0 | 54 / 12 |
| Blowout (underground flow) | 1 / 0 | / | 3 / 0 | / | / | / | / | / | / | / | 4 / 0 |
| Diverted well release | / | 6 / 0 | 1 / 0 | 4 / 0 | 1 / 0 | / | / | / | / | / | 12 / 0 |
| Well release | 2 / 0 | / | 4 / 0 | 2 / 0 | 5 / 0 | 18 / 1 | 7 / 0 | 6 / 0 | 2 / 0 | 1 / 0 | 47 / 1 |
| Total | 6 / 0 | 16 / 0 | 18 / 12 | 12 / 0 | 8 / 0 | 29 / 1 | 15 / 0 | 7 / 0 | 4 / 0 | 2 / 0 | 117 / 13 |

One LOWC event caused 11 fatalities (Deepwater Horizon) and two LOWC events also occurring in the US GoM OCS, caused one fatality. Twelve fatalities comes from *blowout (surface flow)* incidents and one during a *well release*.

In the period 2000 -2015 there have been LOWC events in the rest of the world with several fatalities. The two most serious ones occurred in Azerbaijan 2015, 32 fatalities and Mexico 2007, 23 fatalities. Both these events occurred in the production phase, and the personnel died during evacuation. In addition there were three more LOWC events with a total of six fatalities.

In total there were 74 fatalities worldwide in the period 2000 – 2015 associated to LOWCs.

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[1] The LOWC events are classified into the following main categories:

- *Blowout (surface flow)*
- *Blowout (underground flow)*
- *Well release*
- *Diverted well release*

In the period 1980–1999, 186 LOWC events occurred in the regulated areas including the US GoM OCS during the same phases of operation. For this period 58 fatalities occurred. One LOWC in Brazil (Enchova) in 1984 caused 37 fatalities. All died when a cable for the lifeboat snapped during lowering. The remaining 21 died in eight different LOWC incidents

For the period 1980 – 1999 there were some LOWCs incidents with several fatalities. One in China in 1980 during exploration drilling that caused 70 fatalities (rig Bohai 3). One in Saudi Arabia in 1980 during exploration drilling that caused 19 fatalities due to inhaling $H_2S$ (rig Ron Tappmaier). Further, in 1980, for one drilling incident in the Nigerian delta it was claimed that 180 civilians died due to the pollution (Rig Sedco 135C).

There were further, 10 more LOWC incidents in rest of the world that caused in total 33 fatalities for the period 1980 – 1999.

In total there were 360 fatalities worldwide in the period 1980 – 1999 associated to LOWCs.

## *Pollution from LOWC Events*

Three of the deep zone drilling LOWC events that occurred in 2000–2015 in the US GoM OCS and the regulated areas caused a major pollution. These accidents occurred in 2009, 2010, and 2011.

- 2009 – Australia, Montara: A total volume of 29,600 barrels 4,800 $m^3$, or 66 $m^3$ per day.
- 2010 – USA, Macondo: 8,000 $m^3$ a day in 85 days, in total 680,000 $m^3$, or 4,250,000 bbls
- 2011 – Brazil, Frade field: 600 bbls per day or 3,700 bbls in total.

The spill from the Macondo blowout was 140 times larger than the Montara blowout and 1,150 times larger than the Frade blowout in terms of amount of oil released. These incidents caused large media attention, high direct costs, and loss of reputation for the involved parties.

In addition there is one event that occurred in 2004 and is still ongoing. A storm created an underwater landslide that toppled the Mississippi Canyon 20A production platform. The daily leak rate is limited to a few barrels, but the cumulative leak over 12 - 13 years caused this LOWC to be categorized as very large. The total volume leaked over this period has been estimated to be between 6,000 – 25,000 barrels.

In 2001 a spill occurred in Brazil. The total volume was estimated to 150 barrels. For this spill the phase of operation was unknown. In 2002 a 350 bbls spill to the sea from a producing well occurred in the US GoM OCS.

Further, one drilling LOWC event in 2000 caused a release of 150–200 barrels of crude oil (Mississippi Canyon 584). Further, an abandoned well spilled 62 barrels before being controlled in 2010.

For workovers and completions, some LOWC events were listed with minor pollution. These spills were not severe. Typically, a few gallons of oil entered the water or a limited sheen was reported. None of these incidents were regarded as important pollution events.

In the period 1980–1999, none of the LOWC events in the US GoM OCS, Norway, or UK caused any significant pollution incident.

## Ignition

Table 1.4 shows the number of ignited LOWC events and the ignition time.

*Table 1.4 Ignition of LOWC events in the regulated areas including the US GoM OCS 2000–2015.*

| Main category | Ignition time grouped | Development drilling | | Exploration drilling | | Compl-etion | Work-over | Prod-uction | Wire-line | Abando-ned well | Unknown | Total | Distri-bution % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Deep | Shallow | Deep | Shallow | | | | | | | | |
| Blowout (surface flow) | Immediate ignition | | | 2 | | | | 1 | | 1 | | 4 | 7.4 % |
| | 5 min - 1 hour | | 1 | | | | | | | | | 1 | 1.9 % |
| | 6 - 24 hours | | | | | 1 | | | | | | 1 | 1.9 % |
| | More than 24 hours | 1 | 1 | | | | | | | | | 2 | 3.7 % |
| | No ignition | 2 | 8 | 8 | 6 | 1 | 11 | 7 | 1 | 1 | 1 | 46 | 85.2 % |
| | Total | 3 | 10 | 10 | 6 | 2 | 11 | 8 | 1 | 2 | 1 | 54 | 100.0 % |
| Blowout (undergro-und flow) | No ignition | 1 | | 3 | | | | | | | | 4 | 100.0 % |
| | Total | 1 | | 3 | | | | | | | | 4 | 100.0 % |
| Diverted well release | No ignition | | 6 | 1 | 4 | 1 | | | | | | 12 | 100.0 % |
| | Total | | 6 | 1 | 4 | 1 | | | | | | 12 | 100.0 % |
| Well release | Immediate ignition | | | 1 | | | 1 | | | | | 2 | 4.3 % |
| | No ignition | 2 | | 3 | 2 | 5 | 17 | 7 | 6 | 2 | 1 | 45 | 95.7 % |
| | Total | 2 | | 4 | 2 | 5 | 18 | 7 | 6 | 2 | 1 | 47 | 100.0 % |
| Total all | | 6 | 16 | 18 | 12 | 8 | 29 | 15 | 7 | 4 | 2 | 117 | |

Eight (8.5%) of the 117 LOWC events ignited. Eight (14.8%) of the *blowout (surface flow)* and two (4.3%) of the *well releases* ignited. *Blowout (surface flow)* may ignite immediately or delayed, whereas *well releases* typically have a short duration and, if igniting, it ignites immediately.

## Material Losses to Rig Caused by LOWC Events

Table 1.5 gives an overview of the installation damage related to LOWC events in the regulated areas including the US GoM OCS 2000–2015.

*Table 1.5 Installation damage of LOWC events in regulated areas including US GoM OCS 2000–2015.*

| Main category | Consequence Class | Development drilling | | Exploration drilling | | Comp-letion | Work-over | Prod-uction | Wire-line | Abando-ned well | Un-known | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Deep | Shallow | Deep | Shallow | | | | | | | |
| Blowout (surface flow) | Total loss | 1 | | 1 | | 1 | | 1 | | | | 4 |
| | Severe | | 1 | | | | | | | 1 | | 2 |
| | Damage | | 1 | | | | 1 | 1 | | | | 3 |
| | Small | 1 | | 2 | | | | 1 | | | | 4 |
| | No | 1 | 8 | 6 | 5 | 1 | 10 | 5 | 1 | 1 | 1 | 39 |
| | Unknown | | | 1 | 1 | | | | | | | 2 |
| | Total | 3 | 10 | 10 | 6 | 2 | 11 | 8 | 1 | 2 | 1 | 54 |
| Blowout (underground flow) | No | 1 | | 2 | | | | | | | | 3 |
| | Unknown | | | 1 | | | | | | | | 1 |
| | Total | 1 | | 3 | | | | | | | | 4 |
| Diverted well release | No | | 6 | 1 | 4 | 1 | | | | | | 12 |
| | Total | | 6 | 1 | 4 | 1 | | | | | | 12 |
| Well release | Severe | | | 1 | | | | | | | | 1 |
| | Damage | | | | | | 1 | | | | | 1 |
| | Small | | | | | | 3 | | | | | 3 |
| | No | 2 | | 3 | 2 | 5 | 13 | 7 | 5 | 2 | 1 | 40 |
| | Unknown | | | | | | 1 | | 1 | | | 2 |
| | Total | 2 | | 4 | 2 | 5 | 18 | 7 | 6 | 2 | 1 | 47 |
| Total all | | 6 | 16 | 18 | 12 | 8 | 29 | 15 | 7 | 4 | 2 | 117 |

Most LOWC events lead to minor consequences for the installations. Four of the 117 events in Table 1.5 are categorized as *total loss* after the LOWC event, and three are listed with severe damage.

## *LOWC Causes*

Equipment failures and human errors are frequently involved in LOWC events. Table 1.6 shows a summary of the causal factors.

*Table 1.6 LOWC causal factors summary*

| Type of operation | Primary barrier failure | Distri-bution | Well kick observation | Distri-bution | Gas handling | Distri-bution |
|---|---|---|---|---|---|---|
| Shallow gas bottom fixed installation | Unexpected high well pressure | 42 % | | | Diverted, no problem | 44 % |
| | While cement setting | 27 % | | | Diverter failed or not in place | 30 % |
| | Other | 31 % | | | Other/unknown | 24 % |
| Shallow gas floating installation | Unexpected high well pressure | 42 % | | | Subsea release | 75 % |
| | While cement setting | 27 % | | | Other/unknown | 25 % |
| | Other | 31 % | | | | |
| Deep zone drilling floating | **Primary barrier failure** | | **Well kick observation** | | **Secondary barrier (Blowout (surface Flow))** | |
| | Loss of hydrostatic control | 100% | Late kick observation | 38 % | BOP failed | 50 % |
| | | | In time kick observation | 38 % | Formation broke down | 25 % |
| | | | Unknown | 24 % | Poor cement | 25 % |
| Deep zone drilling fixed | **Primary barrier failure** | | Late kick observation | 38 % | Wellhead area leak | 33 % |
| | Loss of hydrostatic control | 100% | In time kick observation | 38 % | BOP not in place | 22 % |
| | | | Unknown | 24 % | BOP failed after closure | 11 % |
| | | | | | Casing failed | 11 % |
| | | | | | Other | 22 % |
| Workover, killed wells | **Primary barrier failure** | | **Well kick observation** | | **Secondary barrier (Blowout (surface Flow))** | |
| | Unexpected high well pressure/too low mud weight | 28 % | Late kick observation | 78 % | Casing leak | 27 % |
| | Trapped gas | 22 % | In time kick observation | 11 % | Casing and tubing leaked | 18 % |
| | Swabbing, losses, unknown | 22 % | Unknown | 11 % | Casing and X-mas tree leaked | 9 % |
| | Well plug failure | 11 % | | | Wellhead failed | 18 % |
| | Tubing parted | 6 % | | | Kelly valve not available | 18 % |
| | Unknown | 6 % | | | Failed to close BOP | 9 % |
| Workover, live wells | **Primary barrier failure** | | | | **Secondary barrier (Blowout (surface Flow))** | |
| | SCSSV /storm choke failure | 36 % | | | Casing leak | 27 % |
| | Tubing leakage/parted | 36 % | | | Casing and tubing leaked | 18 % |
| | Snubbing equipment failure | 18 % | | | Casing and X-mas tree leaked | 9 % |
| | Tubing plug failure | 9 % | | | Wellhead failed | 18 % |
| | | | | | Kelly valve not available | 18 % |
| | | | | | Failed to close BOP | 9 % |
| Completion | **Primary barrier failure** | | **Well kick observation** | | **Secondary barrier (Blowout (surface Flow))** | |
| | Loss of hydrostatic control | 100% | Late kick observation | 87 % | Failed to close BOP | 100 % |
| | | | Unknown | 13 % | | |
| Production | **Primary barrier failure** | | | | **Secondary barrier (Blowout (surface Flow))** | |
| | SCSSV failed | 75% | | | X-mas tree failed, external load | 40% |
| | Tubing leak | 25% | | | X-mas tree failed, wear and tear | 30% |
| | | | | | Casing/cement/formation | 30% |
| Wireline | **Primary barrier failure** | | | | **Secondary barrier (Blowout (surface Flow))** | |
| | Stuffing box/lubricator failure | 100% | | | Wireline BOP failure | 50% |
| | | | | | X-mas tree failed | 50% |

Shallow zone incidents typically occur due to unexpected high well pressure or while the cement is setting. For a bottom fixed installation, most incidents are diverted without problems. In some cases the diverter is not in place, because it has been nippled down.

For the deep zone drilling incidents, the well may kick for various reasons. Approximately 50% of the kicks were detected late. For floating drilling *blowout (surface flow)* LOWC events, the BOP failed to close in 50% of the incidents, and the formation and/or the cement failed for the remaining. For bottom fixed drilling, leaks developed below the BOP in one third of the incidents, and the BOP was nippled down for installing casing seals in 22% of the incidents.

For workovers in killed wells, the kicks were caused by unexpected high pressure or trapped gas in 50% of the incidents. The majority of kicks were observed late. For the workover LOWC events in live wells, the SCCSV or tubing failed in 72% of the incidents. For more than 50% of the incidents that resulted in a *blowout (surface flow),* a casing leak was involved.

Workovers are frequently performed in old wells. Equipment failures are therefore more likely in these operations than in other well operations.

Nearly all kicks during completion that led to a LOWC event were detected late. A BOP failure is typical involved in completion *blowout (surface flow)* LOWC events.

For a *blowout (surface flow)* LOWC to occur in a producing well it will most likely occur as a combination of a failure in the X-mas tree or wellhead area and a SCSSV failure. The X-mas tree may have a degradation or being destroyed by storm or another external force.

For a *blowout (surface flow)* LOWC to occur during a wireline operation a leak in sthe lubricator or the stuffing box in combination with a wireline BOP failure seems to be the most likely cause.

Humans are important in the occurrence and development of LOWC events, and human errors have contributed to many of the LOWC events. Personnel skills and proper procedures and practices are always important.

### Well Kicks

In killed wells, all LOWC events start with a well kick. During the study an investigation of the US GoM OCS kick occurrences in wells spudded in the period 2011–2015 was performed. In this period, the frequency of kicks in the US GoM OCS was high compared to other comparable areas.

Figure 1.1 gives an overview of kick data from various data sources.

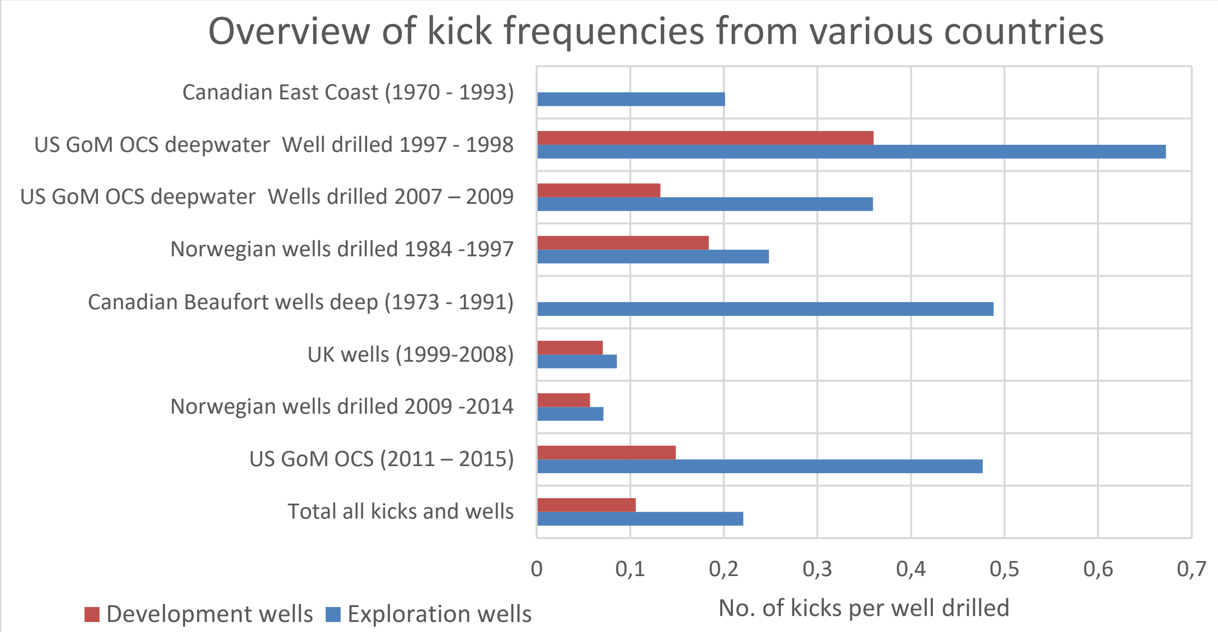


*Figure 1.1 Overview of kick frequencies.*

By comparing the US GoM OCS 2011–2015 kick frequency with the most recent statistics from Norway and the UK, the kick frequency is significantly higher in the US GoM OCS. Compared with the Norwegian kick frequency for 1984–1997, however, the kick frequency in the US GoM OCS for development wells is in the same order of magnitude.

It is not known why the observed kick frequency in the US GoM OCS is so much higher than the most recent data from UK and Norway. There may be several reasons, including:

1. UK and Norwegian data is based on well kicks reported to the authorities. The operators may not report all the well kicks to the authorities.
2. Many US GoM wells are extremely deep and takes a long time to drill. This increases the probability of having a kick due to the increased exposure time.
3. US GoM OCS may be a more complicated area to drill due to different formations. Narrow margins between pore pressure and fracture gradient constitute a typical problem that causes many kicks.
4. Some of the shallow water drilling in the US GoM OCS may be drilled with less advanced instrumentation.
5. There may be different requirements for drilling personnel qualifications in the US GoM OCS as compared to Norway and the UK.
6. The well control policies with respect to mud weight and casing program may be different.

### *Comparison of US GoM OCS LOWC Frequencies vs. Other Regulated Areas*

Table 1.7 and Table 1.8 compare the drilling LOWC event frequencies in the regulated areas and the US GoM OCS.

*Table 1.7 Development Drilling LOWC event frequency comparison US GoM OCS and regulated areas, 2000–2015.*

| Deep or shallow zone | Main category | Regulated area | | | US/GOM OCS | | | US GoM OCS vs. Regulated areas |
|---|---|---|---|---|---|---|---|---|
| | | No. of LOWCs | No. of wells drilled | LOWC frequency per 1000 wells drilled | No. of LOWCs | No. of wells drilled | LOWC frequency per 1000 wells drilled | |
| Deep | Blowout (surface flow) | 1 | 8,156 | 0.12 | 2 | 6,288 | 0.32 | 2.59 |
| | Blowout (underground flow) | | | | 1 | | 0.16 | - |
| | Diverted well release | | | | | | | - |
| | Well release | 1 | | 0.12 | 1 | | 0.16 | 1.30 |
| | Total | 2 | | 0.25 | 4 | | 0.64 | 2.59 |
| Shallow | Blowout (surface flow) | 3 | | 0.37 | 7 | | 1.11 | 3.03 |
| | Diverted well release | 1 | | 0.12 | 5 | | 0.80 | 6.49 |
| | Well release | | | | | | | - |
| | Total | 3 | | 0.37 | 12 | | 1.91 | 5.19 |
| Total | | 6 | | 0.74 | 16 | | 2.54 | 3.46 |

*Table 1.8 Exploration Drilling LOWC event frequency comparison between the US GoM OCS and the regulated areas, 2000–2015.*

| Deep or shallow zone | Main category | Regulated area | | | US GoM OCS | | | US GoM OCS vs. Regulated areas |
|---|---|---|---|---|---|---|---|---|
| | | No. of LOWCs | No. of wells drilled | LOWC frequency per 1000 wells drilled | No. of LOWCs | No. of wells drilled | LOWC frequency per 1000 wells drilled | |
| Deep | Blowout (surface flow) | 1 | 3,998 | 0.25 | 9 | 3,971 | 2.27 | 9.06 |
| | Blowout (underground flow) | 1 | | 0.25 | 2 | | 0.50 | 2.01 |
| | Diverted well release | | | | 1 | | 0.25 | - |
| | Well release | 2 | | 0.50 | 2 | | 0.50 | 1.01 |
| | Total | 4 | | 1.00 | 14 | | 3.53 | 3.52 |
| Shallow | Blowout (surface flow) | 1 | | 0.25 | 5 | | 1.26 | 5.03 |
| | Diverted well release | 1 | | 0.25 | 3 | | 0.76 | 3.02 |
| | Well release | | | | 2 | | 0.50 | - |
| | Total | 2 | | 0.50 | 10 | | 2.52 | 5.03 |
| Total | | 6 | | 1.50 | 24 | | 6.04 | 4.03 |

Table 1.7 and Table 1.8 show that the total LOWC event frequency in the US GoM OCS is significantly higher than in the comparable regulated areas for both development and exploration drilling.

The LOWC event type with the highest risk is the *blowout (surface flow)* type incident. Nine such events occurred in the US GoM OCS exploration wells and only one in the regulated areas. Approximately the same number of wells were drilled in the US GoM OCS and the regulated areas.

Table 1.9 compares the workover LOWC event frequencies in the UK and Norway, and the US GoM OCS.

*Table 1.9 Workover LOWC event frequency comparison between US GoM OCS and UK and Norway, 2000–2015.*

| Main category | UK & Norwegian waters | | | US GoM OCS | | | US GoM OCS vs. Norway and UK |
|---|---|---|---|---|---|---|---|
| | No. of LOWCs | Number of well years in service | LOWC frequency per 10,000 well years in service | No. of LOWCs | Number of well years in service | LOWC frequency per 10,000 well years in service | |
| Blowout (surface flow) | 1 | 47,683 | 0.21 | 9 | 77,843 | 1.16 | 5.51 |
| Well release | 4 | | 0.84 | 12 | | 1.54 | 1.84 |
| Total | 5 | | 1.05 | 21 | | 2.70 | 2.57 |

The LOWC event frequency during workovers is significantly higher in the US GoM OCS than in in the Norwegian and UK waters combined, when measuring by the number of well years in service.

The frequency of well workovers may be higher in the US GoM OCS due to in average older wells that require more frequent workovers. In addition, many of the US GoM workovers have been carried out in wells with poor barriers due to aging. Many of the workover LOWC events occurred in wells that have been temporary abandoned for long periods.

Table 1.10 compares the completion LOWC event frequencies in the UK and Norway and the US GoM OCS.

*Table 1.10 Completion LOWC event frequency comparison between US GoM OCS and UK and Norway, 2000–2015.*

| Main category | UK & Norwegian waters | | | US GoM OCS | | | US GoM OCS vs. Norway and UK |
|---|---|---|---|---|---|---|---|
| | No. of LOWCs | Number of well completions | Frequency per 1000 wells completed | No. of LOWCs | Number of well completions | Frequency per 1000 wells completed | |
| Blowout (surface flow) | 1 | 5,305 | 0,19 | 1 | 5,004 | 0,20 | 1.05 |
| Diverted well release | | | | 1 | | 0,20 | - |
| Well release | 4 | | 0,75 | 1 | | 0,20 | 0.27 |
| Total | 5 | | 0,94 | 3 | | 0,60 | 0.64 |

The LOWC event frequency during completion is lower in the US GoM OCS than in the Norwegian and UK waters combined, when measured by the number of well completions carried out. It should here be noted that the total number of completion LOWC events is low such that the statistical uncertainty of this conclusion is high.

Table 1.11 compares the production LOWC event frequencies in the UK and Norway and the US GoM OCS.

*Table 1.11 Production LOWC frequency comparison US GoM OCS and UK and Norway, 2000–2015*

| Main category | UK & Norwegian waters | | | US/GOM OCS | | | | | | US GoM OCS vs. Norway and UK |
|---|---|---|---|---|---|---|---|---|---|---|
| | No. of LOWCs | Number of well years in service | LOWC frequency per 10,000 well years in service | No. of LOWCs | | Number of well years in service | LOWC frequency per 10,000 well years in service | | | |
| | No external load | | No external load | No external load | External load | | No external load | External load | Total | |
| Blowout (surface flow) | | 47,683 | | 3 | 5 | 77,843 | 0.39 | 0.64 | 1.03 | - |
| Well release | 3 | | 0.63 | 4 | | | 0.51 | 0.00 | 0.51 | 0.82 |
| Total | 3 | | 0.63 | 7 | 5 | | 0.90 | 0.64 | 1.54 | 2.45 |

The LOWC event frequency during production is significantly higher in the US GoM OCS than in in the Norwegian and UK waters combined, when measuring by the number of well years in service.

Many of the LOWC events in the US GoM OCS are caused by external causes as storm, and collisions. These types of LOWCs are not observed in the Norwegian and UK waters. The strong hurricanes and the small shallow water installations causes these types of events. If disregarding these events the LOWC frequencies becomes more similar.

Table 1.12 compares the wireline LOWC event frequencies in the UK and Norway and the US GoM OCS.

*Table 1.12 Wireline LOWC frequency comparison US GoM OCS and UK and Norway, 2000–2015*

| Main category | UK & Norwegian waters | | | US GoM OCS | | | US GoM OCS vs. Norway and UK |
|---|---|---|---|---|---|---|---|
| | No. of LOWCs | Number of well years in service | LOWC frequency per 10,000 well years in service | No. of LOWCs | Number of well years in service | LOWC frequency per 10,000 well years in service | |
| Blowout (surface flow) | 1 | 47,683 | 0.21 | | 77,843 | | |
| Well release | 3 | | 0.63 | 3 | | 0.39 | 0.61 |
| Total | 4 | | 0.84 | 3 | | 0.39 | 0.46 |

The LOWC event frequency during wireline is lower in the US GoM OCS than in in the Norwegian and UK waters combined, when measuring by the number of well years in service.

There are relatively few wireline LOWC events in the database..

### *LOWC Risk*

Figure 1.2 shows a pie chart with the estimated contribution from the various phases of operation to the large spill probability based on a 2015 activity level.

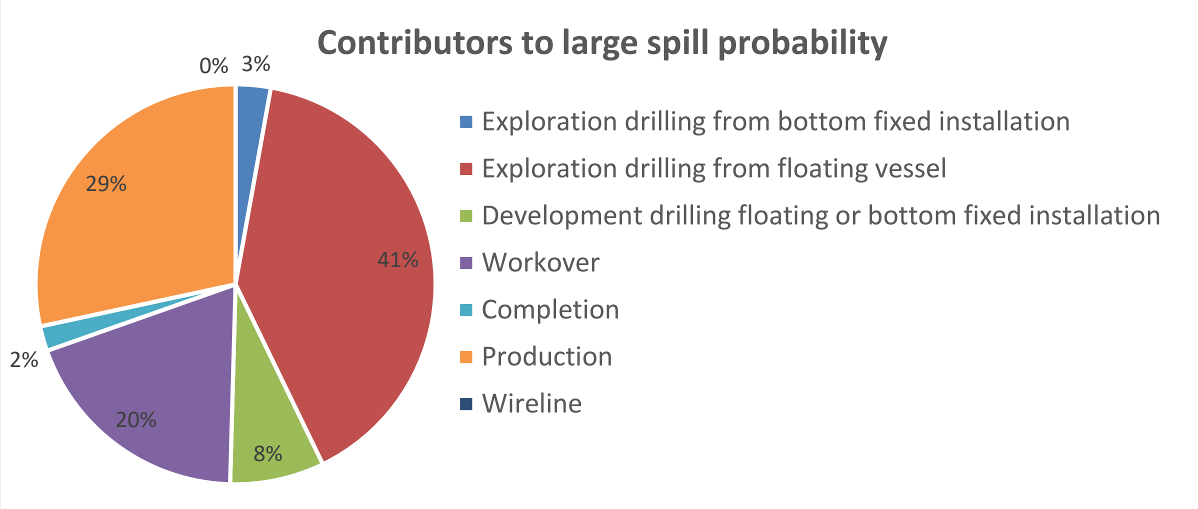


*Figure 1.2 The contributors to the large spill probability.*

Should there be a large spill caused by a LOWC event, the risk analysis indicates that with around a 40% probability, it will occur during exploration drilling from a floater. The proportion from a producing well is close to 30%, and from a workover event is around 20%. If there should occur a large spill during production it is likely to be caused by an external load as a hurricane.

It can be expected that 3.5% of the LOWC events will result in a total loss of the installation. With the estimated number of LOWC events for a five-year period in the US GoM OCS, there is a 46% probability that a total loss incident shall occur in a five-year period. Most LOWC events cause no or minor damages to the installation.

There are few LOWC events with fatalities. Occasionally a LOWC may cause several fatalities. Based on the average numbers, one to two fatalities caused by LOWC events can be expected in a five-year period in the US GoM OCS.

One LOWC event can be expected to ignite in a five-year period.

### LOWC Risk Reduction Discussion

The main contributors to the risk are the *blowout (surface flow)* accidents. These incidents have the largest accident potential with respect to fires, loss of lives, spill to the surroundings, and damage to material assets.

In general, by reducing the kick frequency the LOWC event frequency will be reduced. The kick frequencies in the US GoM OCS are high, as shown in Figure 1.1, page 17. A reduction of the kick frequency will reduce the LOWC event frequency. If assuming that a kick frequency reduction of 50% in drilling operations will reduce the LOWC event frequency in drilling with 50%, the total risk for the US GoM OCS will be reduced.

Table 1.13 shows the effect of reducing the drilling kick frequency with 50% when assuming a five-year period with an annual activity levels as in 2015.

*Table 1.13 Sensitivity analysis, effect of reducing of drilling kick frequency with 50%*

| Activity type | Risk results | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Material damages | | | | Large spill probability |
| | | | | Total Loss | Severe | Damage | Small-/no | |
| Exploration drilling from bottom fixed installation | 0.075 | 0.007 | 0.011 | 0.0035 | 0.0018 | 0.0027 | 0.0665 | 0.0026 |
| Exploration drilling from floating vessel | 1.509 | 0.138 | 0.181 | 0.0559 | 0.0408 | 0.0547 | 1.3578 | 0.0367 |
| Development drilling floating or bottom fixed installation | 0.688 | 0.059 | 0.087 | 0.0287 | 0.0153 | 0.0224 | 0.6218 | 0.0070 |
| Workover | 4.559 | 0.401 | 0.490 | 0.1447 | 0.1278 | 0.1640 | 4.1227 | 0.0352 |
| Completion | 0.264 | 0.017 | 0.021 | 0.0065 | 0.0051 | 0.0068 | 0.2454 | 0.0040 |
| Production | 2.605 | 0.294 | 0.404 | 0.1287 | 0.0828 | 0.1150 | 2.2788 | 0.0521 |
| Wireline | 0.651 | 0.028 | 0.014 | 0.0000 | 0.0139 | 0.0139 | 0.6236 | 0.0000 |
| Total risk with 50% reduced kick frequency drilling events | 10.351 | 0.944 | 1.208 | 0.368 | 0.287 | 0.379 | 9.317 | 0.138 |
| Result from Base Case Table 17.14 | 12.62 | 1.15 | 1.49 | 0.46 | 0.34 | 0.46 | 11.36 | 0.18 |
| *Risk reduction compared to base case* | 18.0 % | 17.9 % | 18.9 % | 20.0 % | 15.6 % | 17.6 % | 18.0 % | 23.3 % |

Table 1.13 shows that by reducing the drilling kick frequency the total LOWC risk in the US GoM OCS risk will be reduced with around 20%.

Another important factor with respect to drilling LOWC events is the kick detection. For approximately 50% of the deep zone drilling LOWC events, the kick was not observed before the well was flowing to the surroundings. If these kicks had been observed in time, the LOWC events would most likely not have occurred.

For most of the well completion kicks and the workover kicks in killed wells, late kick detection is a common factor.

Efforts to improve the kick detection during drilling, completion, and workover activities will in most cases give a corresponding reduction in the LOWC event frequency.

For workovers, it is especially important to be prepared that the barrier situation and the pressures in the well that shall be worked over may be different than expected.

The highest risk contribution from producing wells stems from LOWC incidents caused by hurricanes. When a hurricane damages the topside barriers, the quality of the downhole barriers as tubing, packer, and SCSSV is important.

Wireline incidents have a small impact on the total risk because there were few events and the events normally have small consequences..

The abandoned wells have not been included in the risk model, and the risk is difficult to quantify. In the period 2000–2015, LOWC events from these well types did not cause any significant damage. The number of temporary abandoned wells in the whole world is large. Many of these wells have been temporary abandoned for many years. The risk related to LOWC events from the temporary abandoned wells will increase unless a significant effort is put in to permanently plug and abandon these wells.

# PREFACE

The evaluation, analysis and calculations performed are based on a number of assumptions, limitations, and definitions of system and environmental boundaries, all of which are stated further in the report or in its references. ExproSoft will accept no liability for conclusions being made by readers of the report. Caution should always be taken when using the results from this report further, so that decisions are not made on an erroneous basis.

# INTRODUCTION

Based on BSEE Broad Agency Announcement (BAA) Number: E15PS00092, ExproSoft submitted a White Paper with the Title "Loss of Well Control Occurrence and Size Estimators".

In June 2015, ExproSoft received a request for proposal (E15PS00092), and in July 2015 Exprosoft submitted a proposal to BSEE.

Exprosoft was awarded the contract in September 2015, and the Phase I of the work was kicked off on September 30, 2015

The Phase I objective was to update offshore loss of well control (LOWC) frequency information for the period 2006-2014 for the US Gulf of Mexico and Pacific OCS, North Sea, Canada, Brazil, and Australian offshore regions and other areas with a comparable regulatory regime. When working with the Phase I the period was extended to 2000–2014 to get a more comprehensive data set to evaluate.

The Project has had the following main activities:

Activity 1: Qualify loss of well control in accordance with 30 CFR 250.188(a) (3) definition
Activity 2: Group the loss of well control occurrences
Activity 3: Determine for each loss of well control if, when, and how the flow was stopped
Activity 4: Statistical analysis of the LOWC data categories
Activity 5: Causal analysis
Activity 6: Coherent risk evaluation methodology
Activity 7: Analysis and reporting

The work with Phase II of the project was started in October 2016. The Phase II objective has been to update offshore loss of well control frequency information for the period 2015, and merge the results with the Phase I results. Further, the LOWC incidents experienced during the production phase and wireline operations for the period 2000 – 2015 have been added and analyzed.

In Phase II of the project 39 new LOWC events were added to the LOWC experience, so the total number of LOWCs increased from 117 to 156. They were; one shallow gas incident during development drilling, one abandoned well incident, 26 production incidents, seven wireline incidents, and four incidents where the operational phase is unknown.

This report includes all information from the previous Phase I report, in addition to the information added in association with the Phase II work. This report therefore overrides the previous Phase I report. This report is the combined final report from Phase I and Phase II.

# MAIN CHANGES FROM PHASE I REPORT

The main changes in this report vs. the Phase I report are:

Three new sections have been included:

Section 9, Production LOWC Events, page 94
Section 10, Wireline LOWC Events, page 108
Section 12, Unknown Phase LOWC Events, page 113

Further, the reference period from 2000 – 2014 to 2000 – 2015, so all the tables in Section 2 Exposure Data, page 33, has been changed.

Because the exposure data has been changed all tables and figures in the report where LOWC frequencies are included has been updated.

Section 4, Overview of LOWC Data, page 41, has been updated to include the 39 added LOWCs in this report.

Changes have been performed to reflect the 39 added LOWCs in the following sections:

Section 13, LOWC Characteristics, page 114
Section 14, LOWC Consequences, page 131
Section 15, LOWC Causal Factors, page 142

Section 16, Well kick experience, page 160, has been updated with the additional sub section Annualized Kick Frequencies, page 172.

Section 17, LOWC Risk Analysis, page 179, has been updated with the new phases of operations, updated frequencies for all phases of operation and the year 2015 have been used as a reference for future activity level.

No major changes has been done in the following sections:

Section 5, Shallow Zone Drilling LOWC events, page 47
Section 6, Deep Zone drilling LOWC Events, page 55
Section 7, Workover LOWC Events, page 70
Section 8, Completion LOWC events, page 86
Section 11, Abandoned Well LOWC Events, page 111

# 1 MAIN DATA SOURCE FOR LOWC DATA

The main data source for the LOWC data has been the *SINTEF Offshore Blowout Database* [7]. The *SINTEF Offshore Blowout Database* was initiated in 1984.

By December 2016, the following companies were sponsoring the database:

1. Statoil
2. Aker BP ASA
3. Safetec Nordic A/S
4. Total E&P Norge AS
5. Lloyd's Register Consulting
6. Shell Global Solutions International
7. DNV GL AS
8. Lilleaker Consulting a.s.
9. Eni Norge AS
10. ConocoPhillips Norge
11. Acona Flow Technology AS
12. Proactima
13. Maersk Drilling
14. Akvaplan-niva as

## 1.1 DATABASE STRUCTURE

### 1.1.1 INCIDENT CATEGORY AND SUB-CATEGORY

The following main definitions have been utilized when categorizing the blowouts/well releases in categories and sub-categories.

**Blowout definition**
NPD came up with a blowout definition in their proposal for the new regulations. ("Aktivitetsforskriften, eksternt høringsutkast av 3.7.2000, høringsfrist 3.11.2000");

A blowout is an incident where formation fluid flows out of the well or between formation layers after all the predefined technical well barriers or the activation of the same have failed.

The definition has however not become a part of the final new NPD regulation, but remains the database blowout definition.

**Well release definition:** The reported incident is a well release if oil or gas flowed from the well from some point were flow was not intended and the flow was stopped by use of the barrier system that was available on the well at the time the incident started.

The current BSEE definition for *Loss of Well Control* means [11]:

- Uncontrolled flow of formation or other fluids. The flow may be to an exposed formation (an underground blowout) or at the surface (a surface blowout).

- Flow through a diverter
- Uncontrolled flow resulting from a failure of surface equipment or procedures

**Shallow gas definition:** Any gas zone penetrated before the BOP has been installed. Any zone penetrated after the BOP is installed is not shallow gas (typical Norwegian definition of shallow gas).

All shallow gas incidents in the database have at the extent possible been categorized according *to the typical Norwegian definition of shallow gas.*

The IADC Lexicon [22] define shallow gas as; *Gas pockets or entrapped gas below impermeable layers at shallow depth.*

For many of the incidents the description of the incident in the source is insufficient, and some assumptions have to be made.

The *categories* and *subcategories* utilized when classifying the incidents in the *SINTEF Offshore Blowout Database* are shown in Table 1.1.

The SINTEF database categorizes the incidents in blowouts and well releases. All the incidents fall in the category LOWC that are used by BSEE.

*Table 1.1 Main categories and subcategories for the LOWC incidents in the SINTEF Offshore Blowout database*

| Main | Category | Sub category | Comments/Example |
|---|---|---|---|
| Blowout and well release | Blowout (surface flow) | 1. Totally uncontrolled flow, from a deep zone | Totally uncontrolled incidents with surface/subsea flow. |
| | | 2. Totally uncontrolled flow, from a shallow zone | Typically the diverter system fails |
| | | 3. Shallow gas "controlled" subsea release only | Typical incident for e.g. riserless drilling is performed when the well starts to flow. The rig is pulled away |
| | Blowout (underground flow) | 4. Underground flow only | |
| | | 5. Underground flow mainly, limited surface flow | The limited surface flow will be incidents where a minor flow has appeared, and typically the BOP has been activated to shut the surface flow |
| | Well release | 6. Limited surface flow before the secondary barrier was activated | Typical incident will be with flow through the drill pipe and the shear ram is activated |
| | | 7. Tubing blown out of well, then the secondary barrier is activated | Typical incident occurring during completion or workover. Shear ram is used to close the well after the tubing has been blown out of the well. |
| | Diverted well release | 8. Shallow gas controlled flow (diverted) | All incidents where the diverter system functioned as intended. |
| | Unknown | Unknown | Unknown may be selected for both the category and the subcategory |

### 1.1.2 *BLOWOUT/WELL RELEASE DESCRIPTIONS*

The database contains 51 different fields describing each blowout/well release. The various fields are grouped in six different groups. They are:

1. Category and location
2. Well description
3. Present operation
4. Blowout causes
5. Blowout Characteristics
6. Other

*Category and location*
Includes information related to the incident category (blowout vs. well release), offshore installation such as location, operator, installation name and type, and water depth.

Well description
Includes well and casing depths, last casing size, mud weight, bottom hole- and shut in pressure, GOR, formation age and rock type.

Present operation
Includes the phase (exploration drilling, development drilling, workover etc.), the operation presently carried out (for example casing running) and the present activity (for example cementing).

Blowout causes
Include external cause (stating if an external cause contributed to the incident), loss of the primary barrier, loss of the secondary barrier (describing how primary and secondary barrier were lost) and human error. It should be noted that the field regarding human error in general holds low quality information. Human errors are frequently masked. A field named North Sea requirements highlights if the development of the blowout could have been avoided if North Sea type equipment had been used (for instance in other parts of the world a blind-shear ram is not required in surface BOP stacks).

Blowout characteristics
Twelve fields are included comprising flow-path, flow medium, flow-rate (low quality), release point, ignition type, time to ignition, lost production (low quality), duration, fatalities, consequence class, material loss and pollution.

Other
In the *Other* group, five fields are included. They are control method, remarks (includes a description of the incident), data quality (includes an evaluation of the source data quality), last revision date, and references.

### *1.1.3 EXPOSURE DATA*

The various areas represented with exposure data area shown in Table 1.2.

*Table 1.2 Overview of exposure data included in the database*

| Country | Drilling exposure data | Production exposure data |
|---|---|---|
| US GoM OCS | Yes | Yes |
| Norway | Yes | Yes |
| United Kingdom | Yes | Yes |
| The Netherlands | Yes | No |
| Canada East Coast | Yes | No |
| Australia | Yes | No |
| US Pacific | Yes | Yes |
| Denmark | Yes | No |

The exposure data for drilling is number of wells drilled each year within the various categories.

Exposure data during production is presented as number of well years in service.

The format of the exposure data varies between the different areas because the various sources present the exposure data differently.

## 1.2 Phase of Operation

Each of the blowout/well releases in the database is categorized in the phase of operation they occurred. The various phases are selected to avoid comparing blowout causes, frequencies, and consequences in which there are important differences. The distinction between various phases is important when working with risk analyses and/or evaluating risk-reducing measures. One of the main criteria for grouping blowouts according to main operational phases is the blowout barriers present during the various phases. Other criteria are format of exposure data and differences in frequencies experienced in the various phases. Table 1.3 shows the phases of operation used in the database.

*Table 1.3 Phase of operation*

| Description | Remarks |
|---|---|
| Exploration drilling | Exploration drilling, includes wildcats and appraisal wells |
| *Development drilling* | *Development drilling* |
| Unknown drilling | When it is not known whether it is development drilling or exploration drilling |
| Completion | Activities associated to well completion activities |
| Production | Production, injection, closed in wells |
| Workover | Workover activities, not including wireline operations |
| Wireline | Wireline operations in connection with a production/injection well, not wireline operations carried out as a part of well drilling, well completion or well workover |
| Abandoned well | Wells that have been permanently or temporary abandoned or have been plugged for a long period |
| Unknown | Unknown |

*Exploration drilling* is drilling to find hydrocarbons or to determine the extent of a field. When this drilling takes place the *knowledge of the geology and formation is relatively low* compared with development drilling.

*Development drilling* is drilling of production or injection wells. The *knowledge of the formation is higher* than for exploration drilling.

In principle, drilling a development well is identical to drilling an exploration well. Nevertheless, mainly due to the increased reservoir knowledge, the historical blowout frequency for development drilling is lower than it is for exploration drilling. This is the main reason for making a distinction between development and exploration drilling.

*Shallow gas* blowouts occur when drilling at shallow depths, and closing in the well with a blowout preventer (BOP) is impossible due to inadequate formation strength, i.e., it is a *single barrier situation*. The single barrier is the hydrostatic pressure from the mud column. “Deep” blowouts obviously occur deeper than shallow gas blowouts. Normally the BOP, the casing, and the formation are the secondary barriers, in addition to the hydrostatic pressure from the mud column, which is the primary barrier.

## 1.3 North Sea Specific Requirements

The intention with the field North Sea Specific requirements is to identify blowout/well release incidents that likely would have been prevented in North Sea operations because the procedures or equipment utilized when the incident occurred are different from North Sea equipment or procedures.

Table 1.4 presents the coding used for this field.

*Table 1.4 North Sea requirements*

| Description |
|---|
| Yes |
| No, no shear ram |
| No, BOP not North Sea standard |
| No, two barrier principle not followed |
| Sometimes not relevant, BOP removed to install casing seal |
| Unknown |
| Not evaluated |

## 1.4 Quality of LOWC Data

The blowout information fed into the database has various origins. The best blowout descriptions are from blowout investigation reports (public, company, or insurance reports), while the blowout descriptions with the lowest quality are from small notices in magazines. Even in the investigation reports, several crucial facts may be missing, like cause of kick, ignition source, and ongoing activity. This means that the information in these data fields is not specifically stated in the sources.

In total, 156 LOWC events are included for the period 2000–2015. Table 1.5 presents an overview of the source data quality for all these 156 LOWC events. The criteria for the data quality evaluation are listed in the *Users' Manual* for the *SINTEF Offshore Blowout Database* [7].

*Table 1.5 Quality of the source data in the SINTEF Offshore Blowout Database (2000–2015)*

| Area[2] | | Data Quality | | | | | |
|---|---|---|---|---|---|---|---|
| | | Very good | Good | Fair | Low | Very low | Total |
| US GoM OCS | | 27<br>32.9 % | 18<br>22.0 % | 20<br>24.4 % | 11<br>13.4 % | 6<br>7.3 % | 82 |
| Regulated area | UK & Norwegian waters | 2<br>7.7 % | 3<br>11.5 % | 5<br>19.2 % | 12<br>46.2 % | 4<br>15.4 % | 26 |
| | The Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark, and Brazil | 3<br>33.3 % | 1<br>11.1 % | 1<br>11.1 % | 3<br>33.3 % | 1<br>11.1 % | 9 |
| Rest of the World | | 1<br>2.6 % | 4<br>10.3 % | 3<br>7.7 % | 11<br>28.2 % | 20<br>51.3 % | 39 |
| Total | | 33<br>21.2 % | 26<br>16.7 % | 29<br>18.6 % | 37<br>23.7 % | 31<br>19.9 % | 156 |

Eighty-two LOWC events are reported in the US GoM OCS, 26 in the UK and Norway, nine come from other regulated areas, and the remaining 39 from the rest of the world.

Table 1.5 shows that the best quality source information data comes from the US GoM OCS.

In general, the oil business would benefit if companies were more open about why blowouts occurred. Identifying means to reduce the blowout probability would then be easier. However, it is the author's opinion that oil companies and drilling contractors dislike that their blowouts become publicly known, because this leads to a bad reputation that may hurt the business. Further, the people directly involved in the well operations when control was lost frequently mask their own and their colleagues' mistakes for various reasons. They may, for example, be afraid of losing their jobs, reducing their further career prospects, or being prosecuted after the incident. These are well-known phenomena from all types of accidents, and have negative influences on future accident prevention.

In general, identifying LOWC events that have occurred in the US GoM OCS is easier than identifying those in Norway and the UK. This is because in the US GoM OCS all offshore incidents must be reported to BSEE (Former MMS). BSEE stores this information, and provides access to the public. Furthermore, BSEE also releases public investigation reports more often. Short descriptions of the incidents may be downloaded from the BSEE homepage. LOWC events in Norway and UK are identified from information coming from HSE and PSA, press releases, newspapers, magazine articles, etc. The key LOWC information cannot be found in place. Most oil companies worldwide are reluctant to distribute internal documents regarding the various blowouts.

The *SINTEF Offshore Blowout Database* covers most of the blowouts in the UK waters, Norwegian waters, and the US GoM OCS, but several blowouts from other parts of the world are believed to be missing. Blowouts not included from Norway, UK and the US GoM are

[2] The following areas of operations are used in the report;

- *US GoM OCS*
- *Regulated area include:* UK, Norway, Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark and Brazil
- *Rest of the world:* All countries/areas not mentioned above

typically blowouts that have never been reported other than in internal company files. It is likely that several underground blowouts have never been reported. Further, it is likely that some shallow gas blowouts and other minor blowouts are not included, because they have not been reported in any public sources.

When using the blowout database, it is always important to bear in mind that the quality of blowout data is highly variable.

# 2 EXPOSURE DATA

## 2.1 Exposure Data for US GoM OCS, UK and Norway

Table 2.1 shows overall number of wells drilled, as listed in the *SINTEF Offshore Blowout Database*, for the UK waters, Norwegian waters, and the US GoM OCS.

*Table 2.1 Wells drilled in the US GoM OCS, UK and Norwegian waters (2000–2015)*

| Year | US GoM OCS | | UK | | Norway | | Total | |
|---|---|---|---|---|---|---|---|---|
| | Exploration | Development | Exploration | Development. | Exploration | Development. | Exploration | Development. |
| 2000 | 441 | 940 | 61 | 225 | 27 | 188 | 529 | 1,353 |
| 2001 | 411 | 851 | 59 | 286 | 39 | 201 | 509 | 1,338 |
| 2002 | 309 | 634 | 45 | 260 | 22 | 168 | 376 | 1,062 |
| 2003 | 354 | 541 | 45 | 207 | 26 | 165 | 425 | 913 |
| 2004 | 363 | 553 | 64 | 167 | 17 | 139 | 444 | 859 |
| 2005 | 355 | 457 | 78 | 228 | 14 | 150 | 447 | 835 |
| 2006 | 413 | 359 | 70 | 202 | 28 | 149 | 511 | 710 |
| 2007 | 301 | 316 | 111 | 165 | 32 | 153 | 444 | 634 |
| 2008 | 267 | 299 | 105 | 170 | 56 | 138 | 428 | 607 |
| 2009 | 147 | 174 | 64 | 131 | 66 | 163 | 277 | 468 |
| 2010 | 80 | 174 | 62 | 130 | 46 | 127 | 188 | 431 |
| 2011 | 81 | 186 | 42 | 122 | 52 | 125 | 175 | 433 |
| 2012 | 123 | 236 | 53 | 122 | 43 | 130 | 219 | 488 |
| 2013 | 117 | 237 | 44 | 120 | 59 | 166 | 220 | 523 |
| 2014 | 107 | 223 | 32 | 126 | 57 | 162 | 196 | 511 |
| 2015 | 102 | 108 | 33 | 131 | 56 | 189 | 191 | 428 |
| **Total** | **3,971** | **6,288** | **968** | **2,792** | **640** | **2,513** | **5,579** | **11,593** |

Approximately 61% of the total number of wells drilled have been drilled in the US GoM OCS, 22% offshore UK, and the remaining 17% offshore Norway.

Figure 2.1 shows the annual drilling trend for US GoM OCS, UK, and Norway.

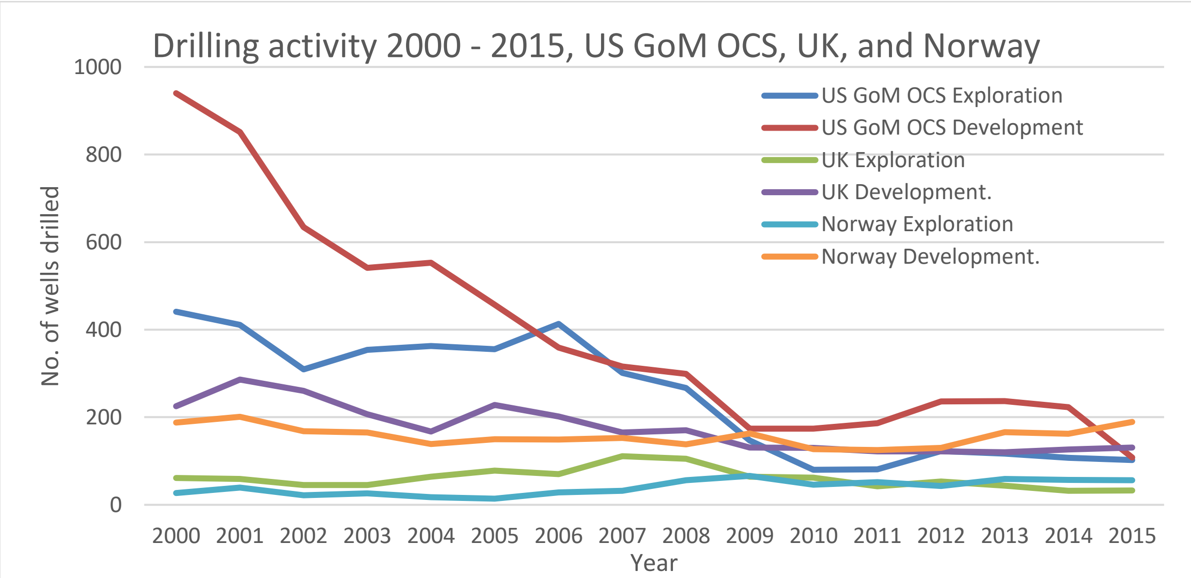


*Figure 2.1 Drilling trend*

There has been a decline in drilling during the period 2000–2015. The largest relative decline is in the US GoM OCS, while in Norway the drilling activity has been fairly stable over the period.

Table 2.2 shows completed wells, as listed in the *SINTEF Offshore Blowout Database*, for the UK waters, Norwegian waters, and the US GoM OCS.

*Table 2.2 Completed wells in the US GoM OCS, UK and Norwegian waters 2000–2015 [7]*

| Spud year | US GoM OCS | UK | Norway | Total |
|---|---|---|---|---|
| 2000 | 805 | 225 | 188 | 1218 |
| 2001 | 654 | 286 | 201 | 1141 |
| 2002 | 449 | 260 | 168 | 877 |
| 2003 | 423 | 207 | 165 | 795 |
| 2004 | 454 | 167 | 139 | 760 |
| 2005 | 360 | 228 | 150 | 738 |
| 2006 | 365 | 202 | 149 | 716 |
| 2007 | 288 | 165 | 153 | 606 |
| 2008 | 259 | 170 | 138 | 567 |
| 2009 | 145 | 131 | 163 | 439 |
| 2010 | 135 | 130 | 127 | 392 |
| 2011 | 136 | 122 | 125 | 383 |
| 2012 | 148 | 122 | 130 | 400 |
| 2013 | 132 | 120 | 166 | 418 |
| 2014 | 163 | 126 | 162 | 451 |
| 2015 | 88 | 131 | 189 | 408 |
| Total | 5,004 | 2,792 | 2,513 | 10,309 |

Approximately 49 % of the total number of completed wells is from the US GoM OCS, 27% from UK and the remaining 23% from Norway.

Table 2.3 shows active production and injection wells, as listed in the *SINTEF Offshore Blowout Database*, for the UK waters, Norwegian waters, and the US GoM OCS.

*Table 2.3 Active production and injection wells in the US GoM OCS, UK and Norwegian waters 2000–2015 [7]*

| Year | US GoM OCS | | | | United Kingdom | | | | Norway | | | | Total | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Production wells | | | Inje-ction wells | Production wells | | | Inject-ion wells | Production wells | | | Inje-ction wells | Production wells | | | Inject-ion wells |
| | Oil | Gas/-cond | Total | | Oil | Gas/-cond | Total | | Oil | Gas/-cond | Total | | Oil | Gas/-cond | Total | |
| 2000 | 3,313 | 3,308 | 6,621 | 291 | 1,027 | 784 | 1,769 | 382 | 787 | 110 | 897 | 259 | 5,127 | 4,160 | 9,287 | 932 |
| 2001 | 3,239 | 3,217 | 6,456 | 259 | 953 | 740 | 1,676 | 382 | 813 | 116 | 929 | 266 | 5,005 | 4,056 | 9,061 | 907 |
| 2002 | 3,109 | 2,993 | 6,102 | 234 | 943 | 618 | 1,649 | 382 | 820 | 133 | 953 | 257 | 4,872 | 3,832 | 8,704 | 873 |
| 2003 | 3,086 | 3,043 | 6,129 | 235 | 867 | 643 | 1,566 | 382 | 849 | 127 | 976 | 261 | 4,802 | 3,869 | 8,671 | 878 |
| 2004 | 2,599 | 2,804 | 5,403 | 234 | 777 | 586 | 1,432 | 382 | 848 | 129 | 977 | 264 | 4,224 | 3,589 | 7,812 | 880 |
| 2005 | 1,505 | 1,977 | 3,482 | 210 | 685 | 538 | 1,289 | 382 | 831 | 123 | 954 | 269 | 3,021 | 2,704 | 5,725 | 861 |
| 2006 | 2,323 | 2,457 | 4,780 | 216 | 622 | 453 | 1,170 | 382 | 863 | 133 | 996 | 278 | 3,808 | 3,138 | 6,946 | 876 |
| 2007 | 2,691 | 2,597 | 5,288 | 202 | 624 | 429 | 1,122 | 382 | 886 | 141 | 1027 | 282 | 4,201 | 3,235 | 7,437 | 866 |
| 2008 | 1,860 | 1,560 | 3,420 | 198 | 583 | 430 | 1,068 | 382 | 910 | 150 | 1,060 | 285 | 3,353 | 2,194 | 5,548 | 865 |
| 2009 | 2,429 | 2,005 | 4,434 | 173 | 556 | 346 | 964 | 382 | 1,078 | 165 | 1,243 | 317 | 4,063 | 2,577 | 6,641 | 872 |
| 2010 | 2,462 | 1,875 | 4,337 | 154 | 519 | 362 | 905 | 382 | 1,123 | 170 | 1,293 | 317 | 4,104 | 2,431 | 6,535 | 853 |
| 2011 | 2,560 | 1,614 | 4,174 | 121 | 433 | 279 | 743 | 382 | 1,099 | 178 | 1,277 | 346 | 4,092 | 2,102 | 6,194 | 849 |
| 2012 | 2,471 | 1,398 | 3,869 | 108 | 373 | 292 | 640 | 382 | 1,201 | 196 | 1,397 | 367 | 4,045 | 1,862 | 5,906 | 857 |
| 2013 | 2,466 | 1,154 | 3,620 | 97 | 336 | 273 | 583 | 382 | 1,302 | 215 | 1,517 | 389 | 4,104 | 1,616 | 5,720 | 868 |
| 2014 | 2,481 | 1,042 | 3,523 | 93 | 326 | 264 | 575 | 382 | 1,404 | 231 | 1,635 | 410 | 4,211 | 1,522 | 5,733 | 885 |
| 2015 | 2,454 | 835 | 3,289 | 91 | 388 | 257 | 645 | 382 | 1,485 | 173 | 1,658 | 419 | 4,327 | 1,265 | 5,592 | 892 |
| Total | 41,048 | 33,879 | 74,927 | 2,916 | 10,012 | 7,294 | 17,796 | 6,112 | 16,299 | 2,490 | 18,789 | 4,986 | 67,359 | 44,152 | 111,512 | 14,014 |

Approximately 68 % of the total number of active wells comes from the US GoM OCS, 16% from UK and the remaining 16% from Norway.

## 2.2 Drilling Exposure Data from Various Countries

The *SINTEF Offshore Blowout Database* [7] includes drilling exposure data from other areas. These are offshore wells in the Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark and Brazil.

Table 2.4 shows overall number of wells drilled, as listed in the *SINTEF Offshore Blowout Database*, in the Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark, and Brazil.

*Table 2.4 Wells drilled in the other regulated areas (Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark, and Brazil)*

| Year | Dutch | | Canada E. Coast | | Australia | | US Pacific OCS | | Denmark | | Brazil | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Expl. | Dev. | Expl. | Dev. | Expl. | Dev. | Expl. | Dev. | Expl. | Dev. | Expl. | Dev. | Expl. | Dev. |
| 2000 | 12 | 9 | 12 | 38 | 70 | 31 | 0 | 13 | 17 | 11 | 41 | 65 | 152 | 167 |
| 2001 | 19 | 12 | 6 | 20 | 60 | 32 | 0 | 16 | 17 | 26 | 99 | 77 | 201 | 183 |
| 2002 | 19 | 13 | 8 | 33 | 57 | 47 | 0 | 21 | 9 | 25 | 83 | 63 | 176 | 202 |
| 2003 | 11 | 13 | 9 | 31 | 79 | 39 | 0 | 18 | 11 | 23 | 92 | 56 | 202 | 180 |
| 2004 | 13 | 6 | 2 | 33 | 61 | 49 | 0 | 20 | 10 | 15 | 80 | 50 | 166 | 173 |
| 2005 | 5 | 8 | 7 | 33 | 80 | 52 | 0 | 23 | 4 | 11 | 53 | 59 | 149 | 186 |
| 2006 | 12 | 16 | 13 | 25 | 66 | 59 | 0 | 17 | 4 | 18 | 59 | 63 | 154 | 198 |
| 2007 | 7 | 12 | 4 | 14 | 72 | 63 | 0 | 12 | 4 | 15 | 58 | 58 | 145 | 174 |
| 2008 | 11 | 13 | 3 | 13 | 92 | 111 | 0 | 5 | 7 | 11 | 58 | 58 | 171 | 211 |
| 2009 | 10 | 11 | 2 | 15 | 83 | 75 | 0 | 7 | 2 | 14 | 61 | 75 | 158 | 197 |
| 2010 | 9 | 12 | 9 | 13 | 62 | 56 | 0 | 8 | 2 | 7 | 83 | 82 | 165 | 178 |
| 2011 | 9 | 15 | 8 | 8 | 46 | 26 | 0 | 3 | 3 | 5 | 110 | 76 | 176 | 133 |
| 2012 | 9 | 11 | 2 | 8 | 36 | 53 | 0 | 8 | 2 | 3 | 90 | 99 | 139 | 182 |
| 2013 | 6 | 10 | 5 | 12 | 23 | 43 | 0 | 5 | 3 | 5 | 45 | 107 | 82 | 182 |
| 2014 | 13 | 11 | 3 | 10 | 31 | 40 | 0 | 1 | 6 | 5 | 42 | 99 | 95 | 166 |
| 2015 | 12 | 11 | 7 | 3 | 13 | 46 | 0 | 1 | 1 | 12 | 26 | 66 | 59 | 139 |
| Total | 177 | 183 | 100 | 309 | 931 | 822 | 0 | 178 | 102 | 206 | 1,080 | 1,153 | 2,390 | 2,851 |

There are no production exposure data from these areas in the *SINTEF Offshore Blowout Database*, except for US Pacific OCS.

## 2.3 Water Depth Related Drilling Exposure US GoM OCS

Table 2.5 presents the water depth specific number of exploration and development wells drilled in the US GoM OCS, 2000–2015.

*Table 2.5 Exploration and development wells drilled in the US GoM OCS vs. water depth 2000–2015*

| Well type | Spud year | Number of wells drilled within water depth range (m) | | | | | | | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | <50 | 50-100 | 100-200 | 200-400 | 400-600 | 600-1,000 | 1,000-1,500 | 1,500-2,000 | 2,000-2,500 | 2,500-3,000 | >3,000 | |
| | 2000 | 446 | 302 | 48 | 42 | 8 | 24 | 60 | 9 | 1 | | | 940 |
| | 2001 | 417 | 225 | 69 | 35 | 17 | 23 | 36 | 23 | 6 | | | 851 |
| | 2002 | 303 | 146 | 22 | 35 | 9 | 24 | 76 | 11 | 9 | | | 635 |
| | 2003 | 308 | 90 | 33 | 20 | 8 | 18 | 49 | 12 | 1 | 2 | | 541 |
| | 2004 | 329 | 105 | 33 | 15 | 8 | 15 | 13 | 16 | 19 | | | 553 |
| | 2005 | 244 | 135 | 21 | 12 | 14 | 19 | 10 | 1 | | 1 | | 457 |
| | 2006 | 202 | 73 | 17 | 9 | 8 | 6 | 36 | 6 | 2 | | | 359 |
| Devel-opment wells | 2007 | 153 | 71 | 28 | 3 | 6 | 13 | 10 | 7 | 25 | | | 316 |
| | 2008 | 154 | 73 | 41 | | 3 | 10 | 15 | | | 3 | | 299 |
| | 2009 | 67 | 33 | 19 | | 3 | 12 | 22 | 6 | 11 | 1 | | 174 |
| | 2010 | 88 | 52 | 8 | 5 | 1 | 7 | 6 | 3 | 2 | 2 | | 174 |
| | 2011 | 93 | 62 | 6 | 5 | 3 | 2 | 13 | 2 | 1 | | | 187 |
| | 2012 | 113 | 67 | 4 | | 3 | 14 | 21 | 9 | 4 | 1 | | 236 |
| | 2013 | 103 | 75 | 8 | | 7 | 11 | 18 | 6 | 7 | 2 | | 237 |
| | 2014 | 92 | 70 | 5 | 5 | 8 | 14 | 19 | 7 | 2 | 1 | | 223 |
| | 2015 | 32 | 36 | 3 | 5 | 1 | 5 | 13 | 4 | 9 | | | 108 |
| | Total | 3,144 | 1,615 | 365 | 191 | 107 | 217 | 417 | 122 | 99 | 13 | | 6,290 |
| | 2000 | 215 | 91 | 18 | 9 | 12 | 34 | 34 | 9 | 17 | 2 | | 441 |
| | 2001 | 167 | 56 | 26 | 18 | 7 | 39 | 55 | 24 | 16 | 3 | | 411 |
| | 2002 | 149 | 48 | 8 | 7 | 12 | 23 | 25 | 17 | 17 | 3 | | 309 |
| | 2003 | 176 | 62 | 17 | 9 | 8 | 19 | 29 | 21 | 6 | 6 | 1 | 354 |
| | 2004 | 174 | 45 | 18 | 19 | 8 | 22 | 27 | 21 | 17 | 12 | | 363 |
| | 2005 | 179 | 47 | 15 | 9 | 7 | 27 | 38 | 17 | 10 | 6 | | 355 |
| | 2006 | 217 | 47 | 15 | 11 | 11 | 30 | 40 | 22 | 19 | 1 | | 413 |
| Explor-ation wells | 2007 | 123 | 56 | 6 | 3 | 8 | 41 | 28 | 21 | 14 | 1 | | 301 |
| | 2008 | 120 | 26 | 12 | 5 | 2 | 23 | 37 | 22 | 16 | 3 | 2 | 268 |
| | 2009 | 52 | 7 | 3 | 2 | 1 | 18 | 25 | 20 | 19 | | | 147 |
| | 2010 | 33 | 7 | 2 | 1 | | 9 | 12 | 6 | 9 | 1 | | 80 |
| | 2011 | 18 | 5 | 4 | | | 13 | 16 | 8 | 15 | 1 | | 80 |
| | 2012 | 19 | 12 | 1 | | 3 | 28 | 13 | 29 | 16 | 2 | | 123 |
| | 2013 | 28 | 9 | 1 | 2 | | 9 | 17 | 29 | 17 | 5 | | 117 |
| | 2014 | 19 | 8 | 1 | 1 | 2 | 2 | 27 | 31 | 9 | 7 | | 107 |
| | 2015 | | 2 | | | 4 | 3 | 41 | 39 | 10 | 4 | | 103 |
| | Total | 1,689 | 528 | 147 | 96 | 85 | 340 | 464 | 336 | 227 | 57 | 3 | 3,972 |
| Total all wells | | 4,833 | 2,143 | 512 | 287 | 192 | 557 | 881 | 458 | 326 | 70 | 3 | 10,262 |

## 2.4 Drilling Exposure Subsea vs. Surface BOPs US GoM OCS

Information about the type of drilling installation type used cannot be deduced from [8]. However, BSEE publish APDs (Application for Permit to Drill) as a part of their public *eWell* reporting system [10]. In these APDs, the drilling installation types planned to be used and the water depths are listed. Based on the drilling installation type the BOP type to be used for the drilling can be deducted. This information has been combined with the BOEM Borehole file [8] to establish an estimated overview of the number of wells drilled with surface and subsea BOPs. The key field used is the water depth.

Table 2.6 shows the estimated number of wells drilled with surface and subsea BOPs vs. water depth for exploration and development wells (US GoM OCS, 2000–2015).

*Table 2.6 Estimated number of wells drilled with subsea vs. surface BOPs, US GoM OCS 2000–2015*

| Type of drilling | BOP type | Water depth grouped (m) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | < 50 | 50 - 100 | 100 - 200 | 200 - 400 | 400 - 600 | 600 - 1,000 | 1,000 - 1,500 | 1,500 - 2,000 | 2,000 - 2,500 | 2,500 - 3,000 | >3,000 | Total | Distri-bution |
| Devel-opment | Subsea | 8 | 0 | 10 | 24 | 46 | 113 | 265 | 107 | 99 | 13 | 0 | 684 | 10.9 % |
| | Surface | 3,136 | 1,615 | 355 | 167 | 61 | 104 | 152 | 15 | 0 | 0 | 0 | 5,606 | 89.1 % |
| | Total | 3,144 | 1,615 | 365 | 191 | 107 | 217 | 417 | 122 | 99 | 13 | | 6,290 | 100.0 % |
| Explor-ation | Subsea | 0 | 0 | 72 | 96 | 80 | 316 | 438 | 334 | 227 | 57 | 3 | 1,622 | 40.8 % |
| | Surface | 1,689 | 528 | 75 | 0 | 5 | 24 | 26 | 2 | 0 | 0 | 0 | 2,350 | 59.2 % |
| | total | 1,689 | 528 | 147 | 96 | 85 | 340 | 464 | 336 | 227 | 57 | 3 | 3,972 | 100.0 % |
| Total | Subsea | 8 | 0 | 82 | 120 | 126 | 430 | 702 | 440 | 326 | 70 | 3 | 2,307 | 22.5 % |
| | Surface | 4,825 | 2,143 | 430 | 167 | 66 | 127 | 179 | 18 | 0 | 0 | 0 | 7,955 | 77.5 % |
| | Total | 4,833 | 2,143 | 512 | 287 | 192 | 557 | 881 | 458 | 326 | 70 | 3 | 10,262 | 100.0 % |

Nearly 90% of all the development wells and 60% of the exploration wells are drilled with surface BOPs. In total 22 % of the wells are drilled with subsea BOPs and 78% with surface BOPs.

# 3 LOWC BARRIERS

Maintaining well control is important during all well operational phases. Failure to maintain well control will result in a LOWC event, which may cause severe damage to material assets, the environment, and loss of human lives.

The Petroleum Safety Authority Norway (PSA) [20] has specific regulations related to well barriers during drilling [21]. To fulfill the Norwegian barrier requirements the NORSOK Standard D010r4 [19] is normally followed.

The Norwegian regulation is focusing on the two-barrier principle. In general, the two-barrier principle is followed in both the UK and the US GoM OCS also, even though this is not explicitly stated in their respective regulations. A well barrier is an item that, by itself, prevents flow of well fluids from the well to the surroundings.

The two independent barriers are usually referred to as the *primary* and the *secondary* barrier envelopes. The primary barrier is normally the barrier closest to the potential source of the flow (a reservoir).

For operations in a *killed* well, the hydrostatic pressure from the drilling mud is regarded as the primary barrier, and the BOP, wellhead, drill pipe, casing, etc. are regarded as the secondary barrier envelope. In a *production* or *injection* well, the primary barrier envelope would typically be the packer that seals off the annulus, the tubing below the SCSSV, and the SCSSV. The secondary barrier envelope would then be the tubing above the SCSSV, the X-mas tree main flow side, the casing/wellhead, and the annulus side of the X-mas tree.

For a completion or workover operation, the barriers will change during the operation. For certain parts of the operation the barriers will be similar to the drilling barriers. For other parts of the operation the barriers will be mechanical only, similar to the barriers that exist in the production phase.

Strictly, when drilling the top-hole of the well before the BOP has been installed on the wellhead there is a one-barrier situation. A mechanical device cannot close in the well. If the well should start flowing in this situation, the well fluids would be diverted for a bottom fixed installation and released on the seafloor for a floating operation.

Whenever the well is controlled by a hydrostatic pressure a LOWC event will always be initiated by a well kick, i.e. the hydrostatic pressure becomes lower than the pore pressure for some reason. When the kick occurs, the well control is regained by activating the secondary barrier, and circulating the well with a higher density drilling mud.

If failing to activate the secondary barrier a LOWC event will occur. The time from when the kick occurs until it is observed is an important factor. This will affect the size of the hydrocarbon influx and the flow in the annulus of the well. The flow rate in the annulus is not a design criterion for the BOP. The BOP will close if the flow rate is low, but may fail to close if the flow rate is high. Therefore, an early kick detection will increase the success probability with respect to closing in a well. A fast shut-in of the well will reduce the kick size and make it less likely that subsurface leaks occur.

Typical secondary barrier failures are (US GoM exploration drilling since 1980 – 2015):

- BOP closes late for some reason causing limited release.
- BOP fails to close or fails after closure.
- Some dry BOPs lack blind shear ram and thereby cannot cut tubular and seal the well.
- Wellheads where the BOP needs to be nippled down to energize the casing seals after the casing has been cemented have caused flow when BOP is not present.
- Jack-up type casing heads and casing spools with associated holding bolts and valves.
- Inadequate casing program, underground flow, and flow outside casing.
- Casing leaks due to not good enough casing design.

Table 3.1 presents the various barrier types. They are grouped according to their functions, how they are operated, and how barrier failures are observed. The barriers listed in Table 3.1 are only examples; several other barriers exist.

*Table 3.1 Some Typical Well Barriers*

| Barrier type | Description | Example |
|---|---|---|
| Operational barrier | A barrier that functions while the operation is carried out. A barrier failure will be observed when it occurs. | Drilling mud, stuffing box |
| Active barrier (Standby barriers) | An external action is required to activate the barrier. Barrier failures are normally observed during regular testing. | BOP, X-mas tree, SCSSV |
| Passive barrier | A barrier in place that functions continuously without any external action. | Casing, tubing, kill fluid, well packer |
| Conditional barrier | A barrier that is either not always in place or not always capable of functioning as a barrier. | Stabbing valve (WR-SCSSV) |

Since oil and gas well drilling is an international business there are not too many differences with respect to barriers in drilling in regulated areas.

Regarding testing of casing and BOPs, the US GoM OCS regulation and the Norwegian regulations are similar.

# 4 OVERVIEW OF LOWC DATA

## 4.1 When and Where do LOWC events Occur?

This section presents an overview of the LOWC events that are included in the *SINTEF Offshore Blowout Database* for the period 2000–2015.

The *SINTEF Offshore Blowout Database* includes 622 LOWC events worldwide (January 2016), and is constantly being updated. Offshore blowouts from as far back as 1957 are included. Of these 643 LOWC events, 156 were experienced in the period from 2000–2015.

## 4.2 During what Operational Phases do LOWC Events Occur?

Table 4.1 shows an overview of all the listed LOWC events in the database for the period 2000 - 2005 and 2006 - 2015 subdivided in operational phases (operational phases are explained in Section 1.2, page 29).

*Table 4.1 Number of LOWC events experienced during different operational phases (2000–2015)*

| Period | Development Drilling | Exploration drilling | Unk. drilling | Compl-etion | Work-over | Produ-ction | Wireline | Aband-oned well | Un-known | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| 2000 - 2005 | 20<br>27.0 % | 16<br>21.6 % | 2<br>2.7 % | 7<br>9.5 % | 13<br>17.6 % | 7<br>9.5 % | 5<br>6.8 % | 2<br>2.7 % | 2<br>2.7 % | 74 |
| 2006 - 2015 | 11<br>13.4 % | 19<br>23.2 % | 2<br>2.4 % | 3<br>3.7 % | 20<br>24.4 % | 19<br>23.2 % | 2<br>2.4 % | 4<br>4.9 % | 2<br>2.4 % | 82 |
| Total | 31<br>19.9 % | 35<br>22.4 % | 4<br>2.6 % | 10<br>6.4 % | 33<br>21.2 % | 26<br>16.7 % | 7<br>4.5 % | 6<br>3.8 % | 4<br>2.6 % | 156 |

The 2016 LOWC statistics is yet not completed, but some few incident have been identified. They are:

- Underground blowout during exploration drilling in May 2016 in 2009 meters (6590 ft) of water, US GoM OCS,
- Shallow water flow during exploration drilling in June 2016 in 1289 meters (4228 ft) of water, US GoM OCS,
- Blowout and fire during workover in September 2016, Gunashli well in the Caspian sea in Azerbaijan
- Well release during workover in October 2016 in the Norwegian Troll field. Down hole barriers failed when pulling the tubing from the well.

Table 4.2 shows an overview of number of LOWC events for the various areas and the operational phases for the period 2000–2015.

*Table 4.2 Area-specific overview of number of LOWC events that occurred during different operational phases (2000–2015)*

| Area[3] | Dev. drilling | Expl. drilling | Unk. drilling | Compl-etion | Work-over | Production | | Wire-line | Aband-oned well | Un-known | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | External cause* | No ext. cause* | | | | |
| US GOM OCS | 16<br>19.5 % | 24<br>29.3 % | 0.0 % | 3<br>3.7 % | 21<br>25.6 % | 5<br>6.1 % | 7<br>8.5 % | 3<br>3.7 % | 3<br>3.7 % | | 82 |
| UK & Norwegian waters | 4<br>15.4 % | 3<br>11.5 % | | 5<br>19.2 % | 5<br>19.2 % | | 3<br>11.5 % | 4<br>15.4 % | 1<br>3.8 % | 1<br>3.8 % | 26 |
| Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark, Brazil | 2<br>22.2 % | 3<br>33.3 % | | | 3<br>33.3 % | | | | | 1<br>11.1 % | 9 |
| Rest of the world | 9<br>23.1 % | 5<br>12.8 % | 4<br>10.3 % | 2<br>5.1 % | 4<br>10.3 % | 7<br>17.9 % | 4<br>10.3 % | | 2<br>5.1 % | 2<br>5.1 % | 39 |
| Total | 31<br>19.9 % | 35<br>22.4 % | 4<br>2.6 % | 10<br>6.4 % | 33<br>21.2 % | 12<br>7.7 % | 14<br>9.0 % | 7<br>4.5 % | 6<br>3.8 % | 4<br>2.6 % | 156 |

* External causes are typical; storm, military activity, ship collision, fire and earthquake.

When reading Table 4.2 it is important to note that the data from rest of the world in general has lower quality than the data from the other areas.

The relatively high number of well workover LOWC events in US GoM OCS area indicates that the number of workovers in that area is high.

It should further be noted that external loads caused approximately 50% of the production blowouts.

## 4.3 Countries Represented with LOWC Events in the Database

Table 4.3 shows the countries represented with LOWC events in the database for the period 2000–2015.

[3] The following areas of operations are used in the report;

- *US GoM OCS*
- *Regulated area:* UK, Norway, Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark and Brazil
- *Rest of the world:* All countries/areas not mentioned above

*Table 4.3 Countries represented with LOWC events in the SINTEF Offshore Blowout Database (2000–2015)*

| Country | Development drilling | | Exploration drilling | | Unknown drilling | | Comp-letion | Work-over | Prod-uction | Wireline | Abandoned well | Un-known | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Deep | Shallow | Deep | Shallow | Deep | Shallow | | | | | | | |
| Australia | 1 | | 1 | | | | | | | | | | 2 |
| Azerbaijan | | | 1 | 1 | | | | | 2 | | | | 4 |
| Brazil | | | 2 | | | | | | | | | 1 | 3 |
| Brunei | | | | | | | | 1 | | | | | 1 |
| China | 1 | | | | | | | | 1 | | | | 2 |
| Egypt | 1 | | | | 1 | 1 | | | | | | | 3 |
| India | | 1 | | | | | | | | | 1 | | 2 |
| Indonesia | 3 | 1 | | 1 | | | | | | | 1 | | 6 |
| Iran | | | | | | | | | | | | 1 | 1 |
| Mexico | | | | | | | 1 | | 1 | | | | 2 |
| Netherlands | | | | | | | | 1 | | | | | 1 |
| Nigeria | | | 1 | | | 1 | | | | | | | 2 |
| Norway | | | | 2 | | | 1 | 1 | | | | | 4 |
| Saudi Arabia | | | | | | | | | 1 | | | | 1 |
| Trinidad | | | 1 | | 1 | | | | | | | | 2 |
| UK | 1 | 3 | 1 | | | | 4 | 4 | 3 | 4 | 1 | 1 | 22 |
| US GoM OCS | 4 | 12 | 14 | 10 | | | 3 | 21 | 12 | 3 | 3 | | 82 |
| US Alaska State | | | | | | | | 1 | | | | | 1 |
| US Pacific OCS | | 1 | | | | | | 2 | | | | | 3 |
| US GoM State | 1 | | | | | | 1 | 2 | 6 | | | 1 | 11 |
| Venezuela | 1 | | | | | | | | | | | | 1 |
| Total | 13 | 18 | 21 | 14 | 2 | 2 | 10 | 33 | 26 | 7 | 6 | 4 | 156 |

For the period 2000–2015, 52% of the LOWC events come from the US GoM OCS. Further, 45% of the LOWC events occurred during drilling, 21% during workovers, and 17% during production.

## 4.4 Well Categories in Drilling

Most offshore LOWC events occurred during well drilling (see Section 4.1, page 41). Wells are generally classified as:

- Exploration
- Development

In Norway, *exploration wells* are classified into two groups:
- *Wildcats* (wells drilled in an unproved area)
- *Appraisal wells* (wells drilled following a discovery to determine the extent of an oil or gas field)

In the UK, only wildcats are regarded as exploration wells, while appraisal wells form a separate category.

In the US, exploration wells include both wildcats and appraisal wells.

This report classifies appraisal wells and wildcats as exploration wells (as per the US classification).

A *development well* is a well drilled within a proven area of an oil or gas reservoir to a depth of a stratigraphic horizon known to be productive.

Drilling blowouts may occur at nearly all well depths. In some wells, very shallow gas pockets have been observed. In terms of well control, shallow gas blowouts are different from blowouts stemming from deeper zones of the well. The drilling blowouts described in this report are divided in two main types:

- Shallow gas blowouts
- "Deep" blowouts

All drilling blowouts that are not regarded as shallow gas blowouts are classified as "deep" blowouts. The definition of shallow gas is shown on page 27.

## 4.5 North Sea Requirements

As explained in Section 1.1.1 on page 26 the incidents in the *SINTEF Offshore Blowout database* have been categorized in blowouts and well releases. BSEE categorizes both blowouts and well releases as LOWCs.

Table 4.4 shows an overview of the number of drilling blowouts/well releases, the associated main category, sub category, and if there were any factors important for the incident that were not according to "North Sea Requirements".

*Table 4.4 Overview of the number of incidents main categories, sub categories, and accordance with North Sea Requirements for LOWC events in the period 2000–2015 worldwide*

| Main category (Table 1.1, p. 27) | Sub category (see Table 1.1, p. 27) | **According to North Sea Requirements?** (Table 1.4 p. 30) | Dev. drlg | Expl. drlg | Unk. drlg | Comp-letion | Work-over | Prod-uction | Wire-line | Aband-oned well | Un-known | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Blowout (surface flow) | Shallow gas "controlled" subsea release only | Yes | | 1 | | | | | | | | 1 |
| | Totally uncontrolled flow, from a deep zone | No, no acoustic backup BOP control system | | 2 | | | | | | | | 2 |
| | | No, no shear ram | | 1 | | | 2 | | | | | 3 |
| | | No, two barrier principle not followed | 1 | | | | | 2 | | | | 3 |
| | | Not evaluated | | | | | | 4 | | | | 4 |
| | | Sometimes not relevant, BOP removed to install casing seal | 2 | 1 | | | | | | | | 3 |
| | | Unknown | 3 | 1 | 1 | 2 | 2 | 5 | | 2 | 1 | 17 |
| | | Yes | 3 | 8 | 1 | 2 | 9 | 6 | 1 | 2 | 1 | 33 |
| | Totally uncontrolled flow, from a shallow zone | Sometimes not relevant, BOP removed to install casing seal | 1 | 1 | | | | | | | | 2 |
| | | Unknown | 1 | 2 | | | | | | | | 3 |
| | | Yes | 10 | 4 | 2 | | | | | | | 16 |
| | Unknown | Not evaluated | | | | | | 1 | | | 1 | 2 |
| | **Total** | | **21** | **21** | **4** | **4** | **13** | **18** | **1** | **4** | **3** | **89** |
| Blowout (underground flow) | Underground flow only | Yes | 1 | 3 | | | | | | | | 4 |
| | **Total** | | 1 | 3 | | | | | | | | 4 |
| Diverted well release | Other | Yes | | 1 | | 1 | | | | | | 2 |
| | Shallow gas controlled flow (diverted) | Yes | 6 | 4 | | | | | | | | 10 |
| | **Total** | | 6 | 5 | | 1 | | | | | | 12 |
| Unknown | Unknown | Unknown | | | | | 1 | | | | | 1 |
| | Total | | | | | | 1 | | | | | 1 |
| Well release | Limited surface flow before the secondary barrier was activated | No, no shear ram | | | | | 1 | | | | | 1 |
| | | Unknown | 1 | | | | | | | | | 1 |
| | | Yes | 2 | 4 | | 5 | 15 | 8 | 6 | | 1 | 41 |
| | Other | Yes | | 1 | | | | | | 2 | | 3 |
| | Shallow gas "controlled" subsea release only | Yes | | 1 | | | | | | | | 1 |
| | String blown out of well, then the secondary barrier | Yes | | | | | 3 | | | | | 3 |
| | **Total** | | 3 | 6 | | 5 | 19 | 8 | 6 | 2 | 1 | 50 |
| **Total** | | | **31** | **35** | **4** | **10** | **33** | **26** | **7** | **6** | **4** | **156** |

Three of the *blowout (surface flow)* incidents and one of the *well releases* may have been avoided if the surface BOP stack had included a blind shear ram and not a blind ram only. In the BSEE new final rule (Federal Register / Vol. 81, No. 83 / Friday, April 29, 2016 / Rules and Regulations) paragraph 250.733 there is a requirement that all surface BOPs shall include a blind shear ram. In the previous rule, there was only a requirement of a blind ram or a blind shear ram. When looking back on LOWC events that occurred before the year 2000 the lack of blind shear rams in surface BOPs caused LOWC events more often than in the present dataset. It is believed that most surface BOPs in the US GoM OCS already have blind shear rams installed.

Five of the incidents occurred while the BOP was nippled down to energize a casing seal. These are incidents where the surface BOP is removed from the wellhead after cementing of the casing. The flow starts when the BOP is removed while the cement is setting.

For two of the incidents an acoustic subsea BOP backup system may have prevented the incident from occurring, or reduced the consequences of the incident. The new BSEE regulation has significantly more requirements related to subsea BOP emergency systems than before the Deepwater Horizon accident. These systems, if installed, may have prevented these incidents.

For the production LOWC events some of the incidents categorized with unknown may seem to be events where the wells have not had a SCSSV. These events typically stems from "non regulated areas".

# 5 SHALLOW ZONE DRILLING LOWC EVENTS

When drilling the shallow section of the well (before the BOP is landed on the wellhead), there is normally only one LOWC barrier, the drilling fluid. Diverter systems, which should lead the gas away from the installation, are installed in most cases. Some bottom-supported drilling platforms are not equipped with diverter systems, when shallow gas is not expected. The definition used for shallow zone in this report is shown on page 27.

Floating vessels do normally drill the shallow sections of the well without a riser. This means that the diverter systems are normally not used when drilling the shallow section of the well from a floating vessel. The vessel will be moved away from the well in case a shallow gas LOWC represents a danger for the vessel.

When drilling without a riser, the drilling fluid is usually seawater with a density of 1030 kg/m$^3$ (8.6 lb./gallon). Mud, which has to be disposed on the seafloor, is usually not used. This limits the hydrostatic pressure in the well, and thereby increases the LOWC probability.

The exact spud location is frequently based on experience from previous wells drilled nearby and seismic surveys, which helps to avoid drilling into shallow gas pockets. Experience, however, proves that the probability of failing to predict shallow gas pockets is high. This was a larger problem in the 80's, but the LOWC events experienced indicate that this is still a problem.

## 5.1 SHALLOW ZONE LOWC EXPERIENCE

Shallow zone LOWC events occur during drilling. The shallow gas experience presented in this section is based on worldwide incidents in the period 2000–2015. Thirty-four shallow gas LOWC events have been recorded. Table 5.1 lists the various installation and well types.

*Table 5.1 Shallow zone LOWC events experienced for various installation vs. main well type (2000–2015 worldwide)*

| Installation type | Main incident category | Sub Category | Dev. drlg | Expl. drlg | Unk. drlg | Total |
|---|---|---|---|---|---|---|
| Jack-up | Blowout (surface flow) | Totally uncontrolled flow, from a shallow zone | 8 | 3 | | 11 |
| | Diverted well release | Shallow gas controlled flow (diverted) | 4 | 4 | | 8 |
| | Total | | 12 | 7 | | 19 |
| Semisubmersible | Blowout (surface flow) | Shallow gas "controlled" subsea release only | | 1 | | 1 |
| | | Totally uncontrolled flow, from a shallow zone | 2 | 2 | 2 | 6 |
| | Total | | 2 | 3 | 2 | 7 |
| Drillship | Blowout (surface flow) | Totally uncontrolled flow, from a shallow zone | | 1 | | 1 |
| | Well release | Other | | 1 | | 1 |
| | | Shallow gas "controlled" subsea release only | | 1 | | 1 |
| | Total | | | 3 | | 3 |
| Jacket | Blowout (surface flow) | Totally uncontrolled flow, from a shallow zone | 1 | 1 | | 2 |
| | Diverted well release | Shallow gas controlled flow (diverted) | 2 | | | 2 |
| | Total | | 3 | 1 | | 4 |
| Barge | Blowout (surface flow) | Totally uncontrolled flow, from a shallow zone | 1 | | | 1 |
| | Total | | 1 | | | 1 |
| Total | | | 18 | 14 | 2 | 34 |

Shallow gas releases from LOWC events occurring when drilling with drillship and semisubmersibles are normally released on the sea floor. The risk for the installation will depend on the water depth and the gas flow rate. In deepwater the gas will pose limited danger for an installation. Some gas will dissolve in the water and the gas that comes to the surface (if any) will be released in a large area so an explosive mixture of gas and air will not be formed. In shallow water shallow gas released on the seafloor can represent a danger.

For jacket and jack-ups, the shallow gas is typically lead back to the installation and diverted overboard. As long as the shallow gas is diverted properly, the explosion risk is low. However, experience shows that in some cases the large gas flow, which normally is mixed with sand, erodes the diverter lines and causes them to leak. This was a larger problem in the 80's and 90's than to day. One of the jack-ups drilled the top-hole without a riser. The gas then came back to the rig through the seawater and the rig could not move away.

Three of the shallow gas LOWC events ignited, two in the US GoM OCS and one in Indonesia. All three occurred on a jack-up. One ignited immediately, one after half an hour and one after 26 hours. None caused fatalities.

These events do not cause severe pollution.

Figure 5.1 and Figure 5.2 show the annual LOWC frequency and the associated regression lines for shallow zone LOWC events from 2000–2015 for development and exploration drilling in the US GoM OCS, UK and Norway.

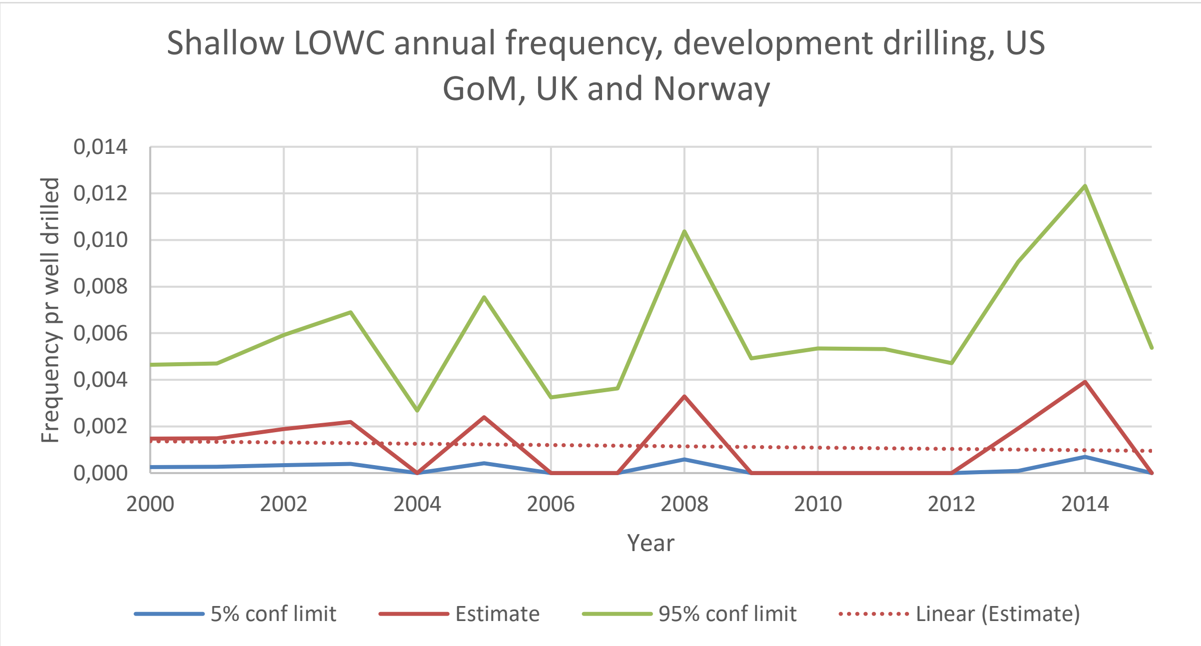


*Figure 5.1 Annual frequency for shallow zone LOWC events during development drilling and the associated trend line*

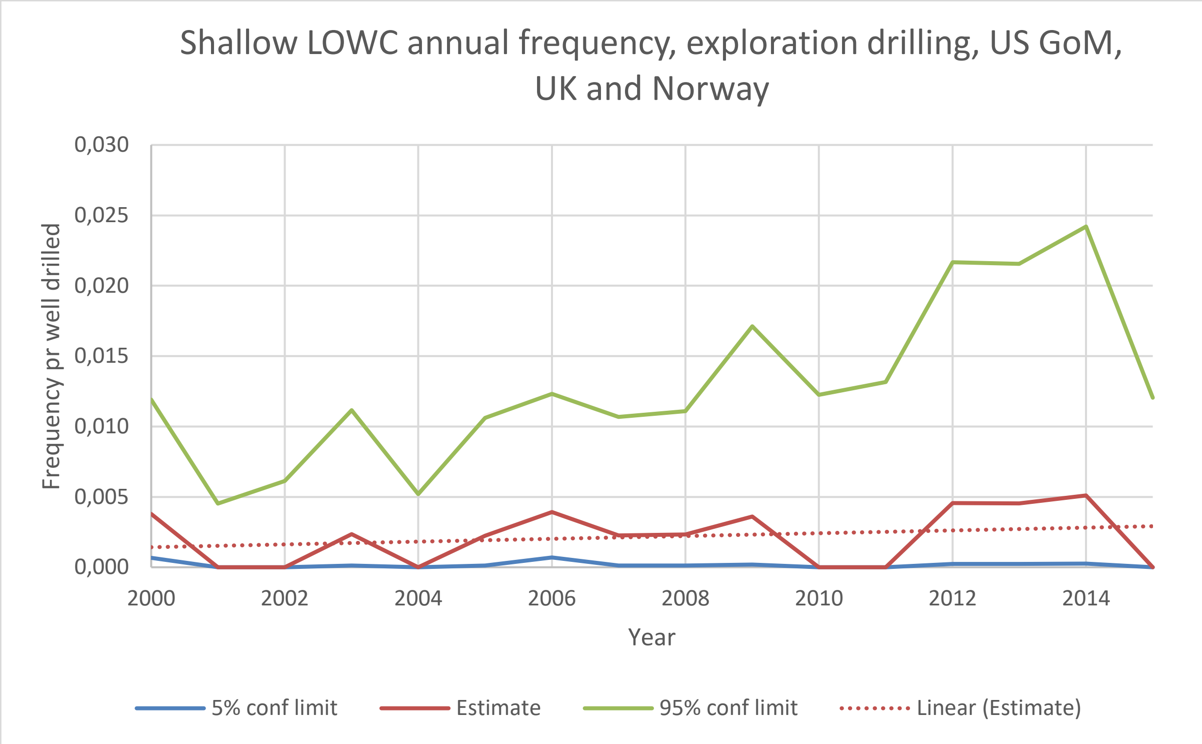


*Figure 5.2 Annual frequency for shallow zone LOWC events during exploration drilling and the associated trend line*

The linear trend lines in Figure 5.1 and Figure 5.2 indicate a slight increase for shallow zone LOWC frequency for exploration drilling, and no trend for development and drilling. The statistical uncertainty is, however, large due to few occurrences, so it cannot be concluded that there is any trend.

In the late 1980's, the industry put major emphasis into shallow gas blowout risk reduction means. These efforts mainly focused on diverter systems, riserless drilling, and handling procedures. Earlier studies have shown that this focus has reduced the frequency and consequences of shallow zone LOWC incidents.

Table 5.2 shows the operations and activities in progress when the shallow gas LOWC events occurred.

*Table 5.2 Operations and activities in progress when the shallow gas LOWC events occurred (world-wide 2000–2015)*

| Activity ⇩ / Operation ⇨ | Drilling activity | Casing running | Other/unknown operations. | Total |
|---|---|---|---|---|
| Actual drilling | 11 | | | 11 |
| Tripping out | 2 | | | 2 |
| Coring | 1 | | | 1 |
| Circulating | 1 | | | 1 |
| Casing running | | 1 | | 1 |
| Cementing casing | | 3 | | 3 |
| Wait on cement | | 7 | | 7 |
| Wait on weather | | | 1 | 1 |
| Unknown | 4 | | 3 | 7 |
| Total | 19 | 11 | 4 | 34 |

56% of the shallow zone LOWC events occurred during operation related to making new hole (drilling activity), 29% occurred in association with casing running operations, and the remaining incidents during other operations.

Most LOWC events occurred during actual drilling and waiting on cement to harden.

### 5.1.1 *SHALLOW ZONE LOWC CAUSES*

Table 5.3 lists the experienced causes for shallow zone LOWC events.

*Table 5.3 Primary and "secondary barrier" failure listed in the database for the worldwide shallow zone LOWC events during drilling (2000–2015)*

| Loss of primary barrier | | Loss of "secondary barrier" | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Diverted - no problem | Failed to operate diverter | Diverter failed after closure | Drilling without riser | Diverter not in place | Fracture at csg shoe | Casing leak & Poor cement | Formation breakdown | Not relevant | Other/ Unknown | Total |
| Too low hydro-static head | Unexpected high well pressure/too low mud weight | 6 | | | 5 | | 1 | | | 1 | 2 | 15 |
| | Swabbing | 1 | | 1 | | | | | | | | 2 |
| | Annular losses | 2 | | | 1 | | | | | | | 3 |
| | While cement setting | 1 | 1 | 2 | 1 | 2 | | 1 | 1 | | | 9 |
| | Unknown why | | | | 1 | | | | | | | 1 |
| Poor cement | | | | 1 | | | | | | 1 | | 2 |
| Unknown | | | | | | | | | | | 2 | 2 |
| **Total** | | 10 | 1 | 4 | 8 | 2 | 1 | 1 | 1 | 2 | 4 | 34 |

As seen from Table 5.3, experience shows that the shallow zone LOWC events primary barrier failures are related to *too low hydrostatic head*.

*Unexpected high well pressure / too low mud weight* is the most common cause for losing the hydrostatic control of the well. In many cases seismic results or experience from drilling neighbor wells indicate that the risk of shallow gas is negligible, so shallow gas is not expected. The shallow section of a well is frequently drilled with seawater as the drilling fluid, and slightly over-pressured gas accumulations may initiate flow.

These incidents have typically been diverted with no problems (for bottom-supported rigs) or released to the seafloor for floating drilling without a riser. Floating vessels may move away from the location if the gas flow becomes too high.

One of these LOWC events occurred on a jack-up rig in UK waters where they were drilling the shallow section of the well without a riser. The shallow geo-hazard assessment erroneously defined the risk of shallow gas to be negligible. The water depth was 90 meters (295 ft.). A significant disturbance of gas breaking out on sea surface was observed around the perimeter of the rig to some 100m. In such cases, the gas cannot be diverted and the jack-up could not be moved away. They pumped mud and managed to control the well.

Another frequent cause is *flow after cementing*. These LOWC events typically occur after the casing has been run and cemented. The most vulnerable period for the cement is immediately after placement and prior to its setting. It is during this time that cement, while developing gel strength, becomes self-supporting and loses its hydrostatic pressure. This hydrostatic pressure loss is responsible for the well reaching an underbalanced condition, which can lead to gas invasion. Slurries must be designed with the goal of minimizing this vulnerable time when an underbalanced condition exists.

So-called gas-tight cements were introduced in the late 80's to reduce this problem. How commonly gas-tight cements are used and the effect of this is not known to the author.

Important factors to focus on to reduce the possibility of such events are:

- Awareness of shallow gas
- Continuously monitoring the annulus for fluid level or fluid gain
- Waiting time for cement to cure
- Utilize lower fluid loss cement slurry to avoid flow after cementing
- Hold nominal pressure on annulus while waiting on cement to harden

The MMS issued three safety alerts concerning annular flow in association with cementing of casing [12] in 2003 - 2005. The recommendations from these safety alerts are listed below:

Safety Alert No. 210 January 8, 2003
It has been concluded in part by the MMS investigation of this event that the well control problem was probably caused by the regression of the cement density to a seawater gradient and/or the formation of a channel because of the delay in pumping cement. MMS stresses the importance of and recommends pumping cement as soon as possible after landing casing and circulating at least one casing volume.

Safety Alert No. 216 October 22, 2003

1. For each well, the operators and contractors should conduct a review of the contingency procedures to be followed in the event of annular flow after cementing. Before using the diverter to hold back pressure after cementing, detailed planning is recommended,

including identification of maximum pressure to be held, method of monitoring and measuring pressure, and how that pressure will be diverted if necessary.
2. The operators and contractors should ensure the contingency procedures are clearly disseminated to all rig supervisors and any personnel who could be involved in emergency decision making.
3. The operators and drilling contractors should ensure all supervisory personnel are fully trained in diverter operations specific to each rig, including pressure limits and control mechanisms, under all circumstances.
4. The operators should review cementing practices and procedures for shallow casing strings and adopt best cementing practices that provide the most protection from annular flow after cementing.

Safety Alert No. 226 January 28, 2005 (comes from a "deep" blowout that occurred in 2004)
1. Close examination of all logs, especially prior to cementing, is recommended to ensure no unexpected shallow zones are productive. Adjustment of the cementing program is recommended if such zones are identified.

Three of the shallow gas drilling LOWC events were caused by *annular losses*. Annular losses occur when the hydrostatic pressure from the mud column exceeds the formation fracture gradient. This causes fluid to enter the formation, and possibly, the well to kick.

One LOWC event was caused by swabbing and two by poor cement.

### *5.1.2 EQUIPMENT FAILURES CONTRIBUTION TO SHALLOW ZONE LOWC RISK.*

For non-floating installations, diverter systems are normally used to lead the gas overboard to avoid damage and danger of an explosion or fire. In some occasions, shallow gas blowouts have been closed in. Closing in shallow gas greatly increases the chances for a blowout to occur outside the casing, and cratering, which again, in a worst case, may cause a bottom-supported platform to tilt and capsize.

More alternatives are available for floating drilling structures than for bottom-supported drilling installations. These are:

- Diverter systems
- Disconnecting riser and pull off
- Drilling without riser

When drilling without a riser or disconnecting the riser, the hydrostatic pressure from the seawater will reduce the flow. In the 80's some few rigs used subsea diverters as well in addition to the rig diverter system. By using subsea diverters the gas may be diverted subsea, and thereby not be brought back to the rig. Subsea diverters were also used to some extent to close in the wells for short periods.

Today bottom supported rigs typically use diverter systems, while floating rigs are drilling the top hole without a riser.

Table 5.3, page 50 shows that for 15 of the shallow zone LOWC events the diverter system was in use, and for two it was nippled down to install casing seal and/or wellhead. For 10 of the incidents the diverting functioned as intended, and for five the diverter system failed.

The five incidents where the diverter system did not function as intended were:

- Diverter line eroded due to the flow of gas and sand.
- Leaking of gas past the diverter flowline seals, probably over pressured because the diverter was in test mode and could not be operated.
- Diverter leak through in closed position.
- Diverter leak through in closed position.
- Failed to close the diverter because a 1.5" grout sting was running through the diverter.

Further:

- For one incident a boat plug in the subsea wellhead port blew out (two other ports had shut off valves).
- For another incident the casing cement failed one month after the casing was set and cemented.
- For one incident listed with a failed casing, they cut a hole in the 30-inch casing to wash cement from the 18 5/8-inch by 30-inch annulus. The well started to flow through the hole.

Seven LOWC events resulted in a "controlled" subsea release. These incidents occur when drilling without a riser. For the experienced incidents the pump rate was typically increased to kill the well dynamically, alternatively the rigs were winched off the location to avoid the gas exposure.

For the *formation breakdown* LOWC the diverter was closed to control the pressure and allow the cement to cure. After a while, gas came to surface around other wells.

For the *Not relevant* incident, the cement failed and the well flowed outside the casing.

## 5.2 Human Errors in Shallow Zone LOWC Events

The human role is considered important in the occurrence and development of LOWC events.. Human errors are believed to have contributed to many of the incidents without being explicitly stated in the information source. The skill of the personnel and proper procedures and practices will always be important.

The following human errors were found from the verbal description of the various LOWC events:

- Drilled with a jack-up without a riser *(could not divert the shallow gas or move the rig away from the well).*
- Personnel should be aware of that the diverter *test mode* could not be overridden from the remote panel *(could thereby not operate the diverter).*
- While drilling, gas slowly came up the drive pipe through the drill pipe annulus. They decided to weight up the mud and drill ahead *(should have controlled the well before continuing drilling).*
- The operator did not inform properly about shallow gas hazard to involved parties.

- Cement program was not properly designed.
- Otherwise, general observation from many of the incidents is that the geo-hazard analyses did not foresee any shallow gas problem, but shallow gas was present anyway.
- Shallow gas hazards from neighbor wells are from time to time not considered when planning a well.

The drilling plans and the personnel should always be prepared for the possibility that shallow gas may occur.

# 6 DEEP ZONE DRILLING LOWC EVENTS

All drilling LOWC events *not* classified as shallow zone LOWC events are classified as *"deep"* LOWC events (See Shallow gas definition, page 27).

## 6.1 WELL BARRIERS IN DEEP ZONE DRILLING

The main difference in LOWC barriers (when drilling the deeper part of the well compared to the shallow part) is that two blowout barriers exist during "deep" drilling. The primary barrier is the drilling mud, and the secondary barriers are the mechanical devices designed for closing in the well annulus (a BOP) or the drill pipe (kelly valve or similar) in addition to the casing and cement.

When a mechanical barrier is activated during a kick situation, the well pressurizes. This requires that the formation fracture gradient is sufficiently high so that the pressure can be confined until the hydrostatic control is regained. If the formation fracture gradient is too low, an underground blowout or a blowout outside the casing may result.

A brief description of the secondary barriers during drilling is given below. Blowout barriers in general are also briefly discussed in Section 3*, page 39*, along with several textbooks, among them [17] and [18].

During normal drilling, the secondary barriers are the blowout preventers (BOPs), drill string, formation, cement, wellhead and the casing. The BOPs are typically located subsea for floating installations and topside for bottom-supported installations. BOPs are mainly used for closing in the well annulus, but most BOPs also include a blind-shear ram used for shearing the drill pipe and sealing the well. The annulus is usually sealed by closing an annular or a pipe ram preventer. The blind-shear ram preventer, is regarded as an emergency device. Closing this preventer will significantly complicate the operation required to regain the hydrostatic control of the well.

If the well kicks through the drill pipe when the drill pipe is connected to the mud system (i.e., not when the pipe is disconnected for tripping or adding an extra stand or joint), the pressure may be closed in by a valve located in the drill string flow path. For drilling rigs with a rotary table, this will be a kelly valve. For drilling rigs with a topdrive, a remote controlled valve inside the topdrive will close the drill string flow path. If the drill pipe is disconnected from the topdrive when the well kicks, the kelly valve or the topdrive has to be stabbed in the pipe against the well flow to be able to stop the flow. If this does not succeed, the blind-shear ram preventer has to be activated.

Many drilling operators also use a check valve in the drill string near the drill bit (frequently referred to as a float valve), which closes if the well flows through the drill string. Some operators decide not to install such a valve from time to time for various reasons.

The drill string, formation, cement, wellhead and the casing are passive barriers that do not have to be activated in a kick situation.

One or more of the secondary barriers may not be available. This may be because the barrier itself failed (e.g., leakage in a wellhead connector), failed to activate (e.g., failed to close the BOP), or specific operations made the barriers unavailable (e.g., BOP nippled down to energize the casing seals). If the secondary barriers are unavailable and a kick occurs, the kick may develop to a LOWC event.

For other operations some of the barriers may be unavailable, e.g., when running drill collars through the BOP, the blind-shear ram or pipe ram preventers cannot be used. When the drill pipe is out of the hole, the blind-shear ram is normally used to stop the well flow. Annular preventers may, however, also be used for this purpose, but only in an emergency.

The secondary barriers described above are the "normal" secondary barriers when drilling is in progress. During some specific operations, different secondary barriers are used (i.e., when performing a production test on an exploration well or when running a wireline through the drill pipe).

After a kick is closed-in by the secondary barriers, the main goal is to re-establish hydrostatic control of the well. Several different methods exist to re-establish the hydrostatic control. The selection of method is related to the specific situation and the company's well control policy. The various methods applied, together with advantages and disadvantages, are described in several textbooks, among them [17] and [18].

## 6.2 Deep Zone Drilling LOWC Experience

The experience presented in this section is based on the *SINTEF Offshore Blowout Database* [7] for the period 2000–2015 worldwide. A total of 36 *deep zone drilling* LOWC events have been recorded. Table 6.1 lists the various installation types, incident categories, and well types.

*Table 6.1 Deep zone drilling LOWC events experienced for various installation vs. main well type worldwide (2000–2015)*

| Installation type and main incident category | Sub category | Number of LOWCs Dev. drlg | Expl. drlg | Unknown drlg | Total |
|---|---|---|---|---|---|
| **JACK-UP** | | | | | |
| Blowout (surface flow) | Totally uncontrolled flow, from a deep zone | 3 | 8 | 1 | 12 |
| Blowout (underground flow) | Underground flow only | 1 | 2 | | 3 |
| Well release | Limited surface flow before the secondary barrier was activated | 2 | | | 2 |
| **Total** | | 6 | 10 | 1 | 17 |
| **SEMISUBMERSIBLE** | | | | | |
| Blowout (surface flow) | Totally uncontrolled flow, from a deep zone | | 3 | 1 | 4 |
| Blowout (underground flow) | Underground flow only | | 1 | | 1 |
| Well release | Limited surface flow before the secondary barrier was activated | | 2 | | 2 |
| **Total** | | | 6 | 1 | 7 |
| **DRILLSHIP** | | | | | |
| Blowout (surface flow) | Totally uncontrolled flow, from a deep zone | | 1 | | 1 |
| Diverted well release | Other | | 1 | | 1 |
| Well release | Limited surface flow before the secondary barrier was activated | | 2 | | 2 |
| **Total** | | | 4 | | 4 |
| **JACKET** | | | | | |
| Blowout (surface flow) | Totally uncontrolled flow, from a deep zone | 2 | 1 | | 3 |
| Well release | Limited surface flow before the secondary barrier was activated | 1 | | | 1 |
| **Total** | | 3 | 1 | | 4 |
| **BARGE** | | | | | |
| Blowout (surface flow) | Totally uncontrolled flow, from a deep zone | 4 | | | 4 |
| **Total** | | 4 | | | 4 |
| **TOTAL ALL** | | 13 | 21 | 2 | 36 |

As seen from Table 6.1, 21 of the LOWC events occurred in exploration drilling and 13 in development drilling. For the two last incidents, it was not possible to identify in what type of well the LOWC event occurred.

Approximately 48% of the "deep" LOWC events occurred on jack-ups, while 19% occurred on semisubmersibles. The remaining 33 % occurred on drillships, barges and jackets.

Figure 6.1 and Figure 6.2 shows the annual LOWC frequency and the associated regression lines for deep zone LOWC events from 2000–2015 for development and exploration drilling in US GoM OCS, Norway, and UK.

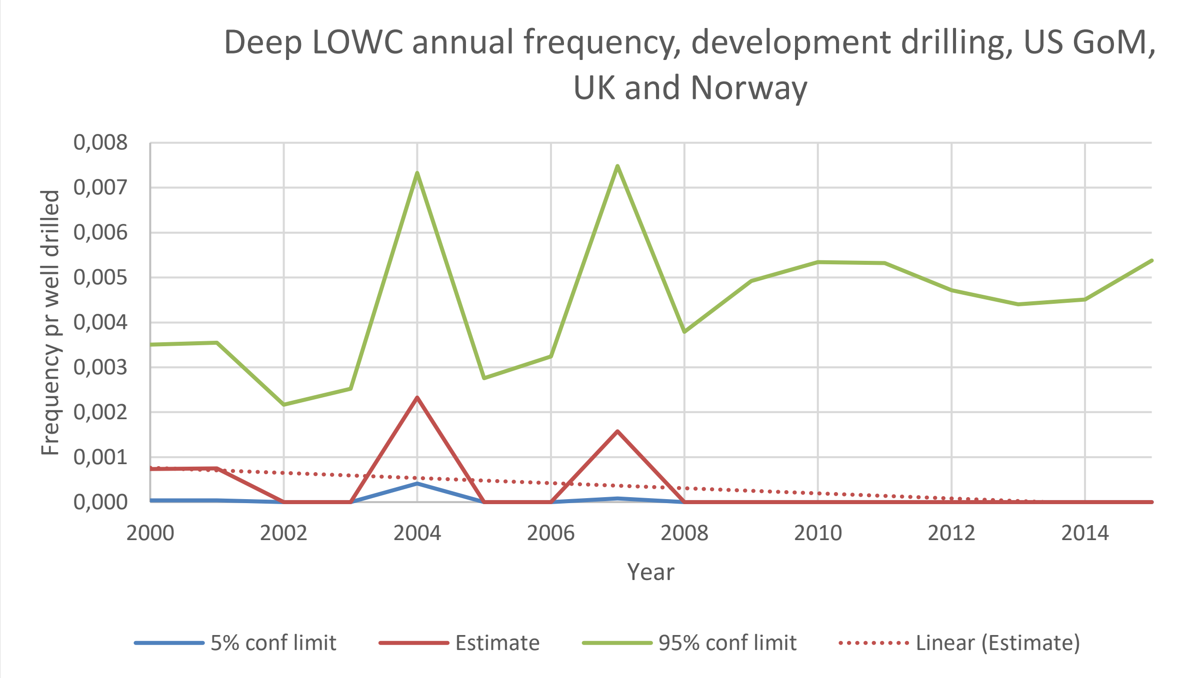


*Figure 6.1 Annual frequency for deep zone LOWC events during development drilling and the associated trend line*

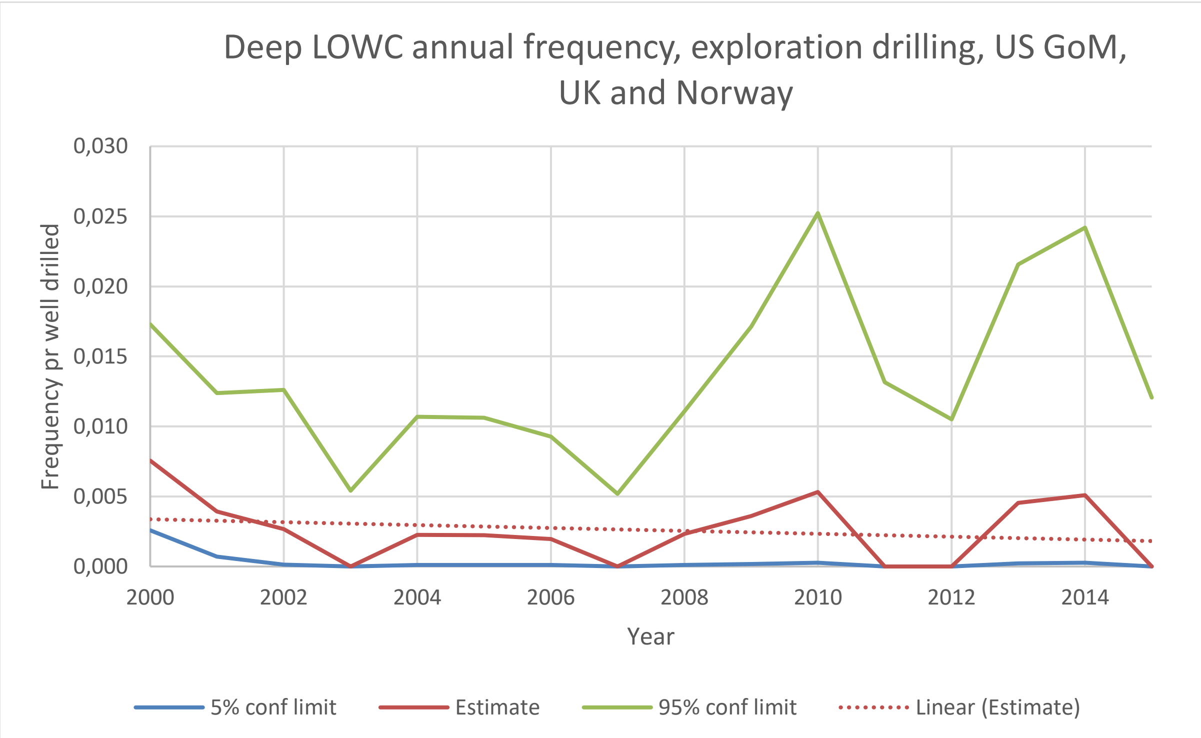


*Figure 6.2 Annual frequency for deep zone LOWC events during exploration drilling and the associated trend line*

Figure 6.1 and Figure 6.2 show that the statistical uncertainty is largely due to few occurrences. It cannot be concluded that there is any statistical significant trend. The statistical uncertainties increases during the period due to reduced drilling.

Table 6.2 shows the countries and the years the various deep zone drilling LOWC events occurred.

*Table 6.2 Countries where deep zone drilling LOWC events were experienced vs. main well type worldwide (2000–2015)*

| Year | Country | Development drilling | Exploration drilling | Unknown drilling | Total |
|---|---|---|---|---|---|
| 2000 | US GoM OCS | 1 | 4 | | 5 |
| 2001 | Trinidad | | 1 | | 1 |
| | UK | | 1 | | 1 |
| | US GoM OCS | 1 | 1 | | 2 |
| 2002 | Indonesia | 1 | | | 1 |
| | Trinidad | | | 1 | 1 |
| | US GoM OCS | | 1 | | 1 |
| 2003 | Indonesia | 1 | | | 1 |
| | US GoM State water | 1 | | | 1 |
| | Venezuela | 1 | | | 1 |
| 2004 | Egypt | 1 | | 1 | 2 |
| | US GoM OCS | 2 | 1 | | 3 |
| 2005 | US GoM OCS | | 1 | | 1 |
| 2006 | US GoM OCS | | 1 | | 1 |
| 2007 | Brazil | | 1 | | 1 |
| | Indonesia | 1 | | | 1 |
| | UK | 1 | | | 1 |
| 2008 | US GoM OCS | | 1 | | 1 |
| 2009 | Australia | 1 | | | 1 |
| | US GoM OCS | | 1 | | 1 |
| 2010 | Australia | | 1 | | 1 |
| | US GoM OCS | | 1 | | 1 |
| 2011 | Brazil | | 1 | | 1 |
| | China | 1 | | | 1 |
| 2012 | Nigeria | | 1 | | 1 |
| 2013 | Azerbaijan | | 1 | | 1 |
| | US GoM OCS | | 1 | | 1 |
| 2014 | US GoM OCS | | 1 | | 1 |
| Total | | 13 | 21 | 2 | 36 |

Table 6.2 shows that 50 % (18) of the observed deep zone drilling LOWC events occurred in the US GoM OCS, and the remaining 18 in the rest of the world. Table 2.1 and Table 2.4, page 36 shows the areas of the world where there exist public drilling statistics. These areas are regulated areas where the operations are carried out similarly to the US GoM OCS operations. The regulated areas includes Norway, UK, the Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark, and Brazil. For the remaining countries, there are no known drilling statistics, and LOWC frequencies cannot be established.

The total number of wells drilled in the regulated areas are in the same order of magnitude as for the US GoM OCS, but only six deep zone LOWC events have been observed in these areas. The average frequency for drilling LOWC events in the regulated areas was 60 % of the US GoM OCS frequency for development wells and 25% for exploration wells. Poorer reporting, different well control philosophy, different equipment, different formations and/or statistical uncertainty may cause this difference.

Table 6.3 presents the operations and activities in progress when the blowouts occurred for exploration and development drilling.

*Table 6.3 Operations and activities in progress when the deep zone drilling LOWC events occurred*

| Area | Main category | Operation ⇒ / Activity ⇓ | Drilling activity | | Casing Running | | Other operations | | Unknown | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Dev. drlg | Expl. drlg | Dev. drlg | Expl. drlg | Dev. drlg | Expl. drlg | Dev. drlg | Expl. drlg | Unk. drlg | |
| US GoM OCS | Blowout (surface flow) | Actual drilling | | 3 | | | | | | | | 3 |
| | | Circulating | | | | 1 | | 1 | | | | 2 |
| | | Casing running | | | | 1 | | | | | | 1 |
| | | Cementing casing | | | | 1 | | | | | | 1 |
| | | Wait on cement | | | 1 | | | | | | | 1 |
| | | Cement squeeze | | | | 1 | | | | | | 1 |
| | | Install BOP | | | 1 | | | | | | | 1 |
| | | Nipple down BOP | | | | | | 1 | | | | 1 |
| | | Total | | 3 | 2 | 4 | | 2 | | | | 11 |
| | Blowout (under-ground flow) | Actual drilling | | 2 | | | | | | | | 2 |
| | | Logging | 1 | | | | | | | | | 1 |
| | | Total | 1 | 2 | | | | | | | | 3 |
| | Diverted well release | Circulating | | 1 | | | | | | | | 1 |
| | | Total | | 1 | | | | | | | | 1 |
| | Well release | Actual drilling | 1 | | | | | | | | | 1 |
| | | Circulating | | 1 | | | | 1 | | | | 2 |
| | | Total | 1 | | | | | 1 | | | | 2 |
| | **Total** | | **2** | **7** | **2** | **4** | | **3** | | | | **18** |
| Regula-ted area | Blowout (surface flow) | Actual drilling | | 1 | | | | | | | | 1 |
| | | Well suspended | | | | | 1 | | | | | 1 |
| | | Total | | 1 | | | 1 | | | | | 2 |
| | Blowout (under-ground flow) | Actual drilling | | 1 | | | | | | | | 1 |
| | | Total | | 1 | | | | | | | | 1 |
| | Well release | Circulating | 1 | | | | | 1 | | | | 2 |
| | | Pull/drill out well plugs | | 1 | | | | | | | | 1 |
| | | Total | 1 | 1 | | | | 1 | | | | 3 |
| | **Total** | | **1** | **3** | | | **1** | **1** | | | | **6** |
| Remain-ing countries | Blowout (surface flow) | Actual drilling | 1 | | | | | | | | | 1 |
| | | Wait on cement | | | 1 | | | | | | | 1 |
| | | Killing | | | | | | | | 1 | | 1 |
| | | Unknown | | | | | | | 4 | 2 | 2 | 8 |
| | | Total | 1 | | 1 | | | | 4 | 3 | 2 | 11 |
| | Well release | Unknown | | | | | | | 1 | | | 1 |
| | | Total | | | | | | | 1 | | | 1 |
| | **Total** | | **1** | | **1** | | | | **5** | **3** | **2** | **12** |
| *Total* | | | *4* | *10* | *3* | *4* | *1* | *4* | *5* | *3* | *2* | *36* |

From Table 6.3, it can be seen that for the US GoM OCS and the regulated areas approximately 50% of the deep zone drilling LOWC events occurred when making a new hole, and approximately 25% in association with running casing and cement. For the remaining countries, there are many unknowns with respect to the ongoing operations when the LOWC events occurred.

For the US GoM OCS and the regulated areas, 13 of the 24 LOWC events were categorized as *blowout (surface flow)*. The remaining 11 were categorized as either a *blowout (underground flow)* or a *well release*. For the remaining countries, 11 out 12 LOWC events were categorized as *blowout (surface flow)*.

## 6.3 Deep Zone Drilling LOWC Causes

This section focuses on the causes of "deep" drilling LOWC events. Since two barriers normally should be present while drilling, this section is focused on the causes of losing the primary barrier, mainly the hydrostatic control of the well, and the secondary barriers, mainly the wellhead located barriers, the casing, the formation and drill string.

### *6.3.1 Loss of the Primary and Secondary Barriers*

When the primary barrier is lost during drilling, a well kick results. In terms of well control, it is important to detect the well kick as soon as possible in order to close in the well with a minimum influx. Small influxes are easier to handle than large influxes.

The ability to detect kicks has gradually improved since the 1980's, but still kicks are observed late. The control of the flow and pit volumes are the most important kick detection parameters. Computers are used for real time analysis of drilling data to improve the early kick detection. One problem may be that when drilling, the personnel sometimes believe too much in the well drilling plan and sophisticated computer systems and do not read the signals from the well.

If the secondary barrier fails to activate or activates late a LOWC event will occur.

Table 6.4 lists the experienced primary and secondary barrier failure causes for the kicks resulting in "deep" drilling LOWC events for US GoM OCS and regulated areas (Norway, UK, the Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark, and Brazil).

*Table 6.4 Primary and secondary barrier failure causes for "deep" drilling LOWC events in the US GoM OCS and the regulated areas (2000–2015).*

| Primary barrier failure | | Secondary barrier failure | LOWC Id | Rig type | Dev. drlg | Expl. drlg | Total |
|---|---|---|---|---|---|---|---|
| **Blowout (surface flow)** | | | | | | | |
| Too low hydrostatic head | Too low mud weight | Casing head failed | 459 | Jack-up | | 1 | 1 |
| | Gas cut mud | Poor cement | 516 | Semisub | | 1 | 1 |
| | Improper fill up, annular losses, packer leakage | Wellhead failed | 564 | Jack-up | | 1 | 1 |
| | Disconnected riser | Failed to close BOP | 464 | Semisub | | 1 | 1 |
| | Unexpected high well pressure | Formation breakdown | 619 | Drillship | | 1 | 1 |
| | Reservoir depth uncertainty | String safety valve failed | 481 | Jack-up | | 1 | 1 |
| | | Inner casing failed | 524 | Jacket | 1 | | 1 |
| | While cement setting | BOP failed after closure | 463 | Jack-up | | 1 | 1 |
| | | BOP/diverter not in place | 460 | Jack-up | 1 | | 1 |
| | | | 465 | Jack-up | | 1 | 1 |
| | | Wellhead failed | 550 | Jack-up | | 1 | 1 |
| Casing plug failure | | Failed to close BOP | 611 | Semisub | | 1 | 1 |
| | | Not relevant (only one barrier) | 590 | Jack-up | 1 | | 1 |
| **Total** | | | | | **3** | **10** | **13** |
| **Blowout (underground flow)** | | | | | | | |
| Too low hydrostatic head | Unexpected high well pressure | Poor cement, casing leakage | 629 | Jack-up | | 1 | 1 |
| | | Formation breakdown | 605 | Jack-up | | 1 | 1 |
| | | | 622 | Semisub | | 1 | 1 |
| | Unknown why | Formation breakdown | 580 | Jack-up | 1 | | 1 |
| **Total** | | | | | **1** | **3** | **4** |
| **Diverted well release** | | | | | | | |
| Too low hyd. Head - unknown why | | Failed to close BOP | 608 | Drillship | | 1 | 1 |
| **Total** | | | | | | **1** | **1** |
| **Well release** | | | | | | | |
| Too low hydrostatic head | Too low mud weight | Failed to close BOP | 595 | Jack-up | 1 | | 1 |
| | Trapped gas | | 583 | Drillship | | 1 | 1 |
| | Unknown why | Diverted - no problem | 538 | Semisub | | 1 | 1 |
| | Unexpected high well pressure | Not sufficient frictional backpressure | 532 | Semisub | | 1 | 1 |
| | | Failed to close BOP | 645 | Drillship | | 1 | 1 |
| | | Unknown | 502 | Jacket | 1 | | 1 |
| **Total** | | | | | **2** | **4** | **6** |
| **Total all** | | | | | **6** | **18** | **24** |

The individual LOWC events are commented a bit further down. Here some overall findings are discussed.

It should be noted that well kicks are fairly normal. They are normally detected in a timely manner and handled properly so an LOWC event will not be the outcome.

The frequency of well kicks varies highly depending on many factors. Kicks are discussed in Section 15.8, page 158.

**Loss of the primary barrier**

For one LOWC event a spurious disconnect of the riser caused the event. The well was in 678 meters (2,223 ft.) of water and did not have a riser margin. The well kicked because the riser was disconnected. When disconnecting the riser the main BOP control was also lost (loss of secondary barrier). With the actual BOP setup the primary and the secondary barriers were not independent. Today all US subsea BOPs have emergency functions and/or alternative control systems so the occurrence of such an event is far less likely.

Further, four LOWC events occurred while the cement was setting after running casing. These LOWC events typically occur after the casing has been run and cemented. The most vulnerable period for the cement is immediately after placement and prior to its setting. It is during this time that cement, while developing gel strength, becomes self-supporting and loses its hydrostatic pressure. This hydrostatic pressure loss is responsible for the well reaching an underbalanced condition, which can lead to gas invasion. This type of primary barrier failures are common for the shallow events as well. The blowout database shows that this has been a problem in the 80's and 90's as well.

For the *Unexpected high well pressure,* the reservoir was over-pressurized due to water injection. Assumed reservoir pressure was 3,700 psi, actual pressure was between 4,003 psi and 4,176 psi.

The two incidents categorized with casing plug failure as cause for loss of the primary barrier are the well-known Deepwater Horizon and the Montara blowouts. In both cases the wells were cemented and assumed safe. For the Montara blowout this was the only barrier in the well, while for the Deepwater Horizon blowout a series of human and technical failures caused the well to blow out.

Further, one *well release* was caused by trapped gas. Gas was trapped below the annular BOPs after an EDS situation. While circulating gas out, a leak occurred at the shale shakers, causing an accumulation of gas below the rig floor area, which was followed by an explosion and fire.

Of the ***secondary barrier failures*** for the drilling LOWC events *Failed to close BOP* occurred six times. Two events were categorized as *blowout (surface flow)*, the Deepwater Horizon (ID 611) where the BOP did not close is one. The other was an incident where the LMRP (Lower Marine Riser Package) spuriously disconnected, and thereby was unable to operate the BOP (ID 464). For a *diverted well release* the BOP was closed late, after gas had reached the riser. For the three *well releases* also the BOP was closed late allowing a limited release of hydrocarbons.

For one *blowout (surface flow),* the BOP developed a leak in the annular preventer during well control operations.

For two *blowout (surface flow),* the BOP was not in place. It was removed to install a casing seal.

For one incident, they failed to close the drill string safety valve (kelly valve) and the BOP did not have a blind shear ram.

Otherwise, wellhead and casing head failed for three *blowout (surface flow)* LOWC events. This equipment is below the BOP, so when this equipment fails the well cannot be closed in by the BOP.

In addition poor cement, inner casing failed, and formation breakdown have been listed as secondary barrier for *blowout (surface flow)* LOWC events.

For the *blowout (underground flow)* LOWC events, casing leak, formation breakdown or cementing or a combination of these are typical secondary barrier failures.

### 6.3.2 BRIEF LOWC DESCRIPTIONS

**Blowout surface flow**

1. (ID 459) The crew shut in the BOP in a timely manner. The *10 ¾ inch casing head by 16 inch casing head spool began leaking*, and caught fire. This spool was located approximately 20 feet below the BOP.
2. (ID 516) While making a connection, the crew observed that the well was flowing. They shut the well in. While they were circulating the mud, the hole started losing returns. The crew spotted three lost return pills, and reciprocated the drill pipe. While they were attempting to strip off bottom, the shut-in casing pressure dropped, and they noticed gas bubbles at the surface.
3. (ID 564) Four gland nut/hold down pins in the wellhead that were used to secure the wear bushing in the wellhead profile needed to be backed out to pull the wear bushing. A rig crew member apparently backed out one of the gland nuts too far. This coincided with an unanticipated well flow from an apparent down-hole failure, and one gland nut dislodged and fell overboard. The well immediately began to flow from the casing valve below the gland nut.
4. (ID 464) The riser was accidentally disconnected and the well kicked immediately due to lack of riser margin. The control of the BOP was lost when the riser disconnected (The BOP did not have auto-shear, ROV controls, or acoustic backup system)
5. (ID 619) The reservoir was over-pressurized due to water injection. Assumed reservoir pressure was 3,700 psi, actual pressure was between 4,003 psi and 4,176 psi. The formation broke down and oil appeared on the seafloor 20 hours after the kick was observed.
6. (ID 481) The well flowed through the drill pipe after the floorhands had set the slips (no float in the drill pipe). Stabbed drill floor safety valve but failed to turn it to closed position. Attempted to stab the kelly, but the mud flow was too strong and too hot. The BOP did not have a blind shear ram.
7. (ID 524) The well had been drilled to more than 3,000 m when annulus pressure was observed. An unexpected shallow zone at 1,615 m (5,300 ft.) was the cause of the blowout. It was indicated that this zone had been charged during a kick that took place earlier. One pressure indicator failed, the other was ignored. When exposed to 3,000 psi, the surface casing failed below its rated burst pressure of 3,450 psi because of heavy wear in the casing that was not detected.
8. (ID 463) When the pressure from the kick increased to 1,900 psi, the annular preventer started leaking. Bled off pressure, but the annular started leaking again at 1,200 psi.
9. (ID 460) The BOP was removed to install the casing seal. Gas and mud began flowing from the base of the wellhead through a gap in the base plate flange that connects the drive pipe to the surface casing.
10. (ID 465) The crew picked up the BOP stack to cut the casing and install the tree, when the well started flowing through the 10 3/4 inch by 7 5/8 inch annulus. They attempted to reset the BOP stack, but a line parted and the stack fell and damaged the flange. The crew lifted, reset, bolted the stack, and then closed the rams. The flange began leaking. The pressure built to 1,700 psi after 20 minutes, with dry gas to the surface.

11. (ID 550) The casing hanger lock down dogs blew out of the port/forward quadrant of the 16" wellhead, giving an uncontrolled release of mud, water, and cement through a 1 1/4" threaded port to a distance of 50-75' out away from the rig.
12. (ID 611) There was a bad cement job and a failure of the shoe track barrier at the bottom of the well, which let hydrocarbons from the reservoir into the production casing. There were failures in well control procedures and in the blowout preventer so the BOP failed to close. The kick was not detected before the well flowed to the drill floor.
13. (ID 590) The H1 Well was left in an unprotected state (and relying on an untested primary barrier) while the rig proceeded to complete other planned activities as part of batch drilling operations at the Montara wellhead platform. When the downhole barrier failed, the well started to flow.

**Underground blowout**

14. (ID 629) Five days after a kick was experienced an underground flow was observed. The 18" liner seal failed and the cement between the surface liner and conductor failed. Diagnostic procedures indicated an underground migration from the bottom of the well (8,261 feet) to another sand formation at approximately 1,100 feet. Only gas flowed.
15. (ID 605) This is an incident with very limited information. It was reported by MMS in 2008.
16. (ID 622) Production casing shoe set at 2,829 m. Drilled into gas bearing formation and a gas kick was recorded at 4,602 m. Well was shut in and the formation 100 m below the shoe broke down - underground blow out. Well control operations were complicated by hydrate blockage in the choke and kill lines and drill pipe. The well was P&A after 38 days.
17. (ID 580) They were logging while drilling (LWD) when an underground gas flow occurred in the well. Well depth 19,820 ft. TVD

**Diverted well release**

18. (ID 608) The kick was not detected before the gas was in the riser. The BOP was therefore closed late. The diverter was closed and the riser gas with some mud was diverted overboard.

**Well release**

19. (ID 595) They were circulating out a kick and seemed to have control. Observed the well through choke, well static, annular was opened and a 2nd bottoms up was circulated, an increase in flow was observed as bottoms up came up. The BOP was closed too late and the gas expansion at surface dislodged the hole cover.
20. (ID583) An emergency disconnect due to a blackout caused the loss of station keeping. Upon returning to the well, it was confirmed that gas was trapped below the BOP. While circulating gas out, a leak occurred at the shale shakers, causing an accumulation of gas below the rig floor area, which was followed by an explosion and fire. Personnel ignored the gas alarms in the shale shaker area.
21. (ID 538) While drilling a kick was detected. When the well was considered stabilized the annular was opened and circulating a gas bubble entered the riser and it was necessary to put the well on the diverter. This resulted in the discharge of approximately 160 barrels (bbl.) of drilling fluid into offshore waters. Of the 160 bbl. discharged, it is estimated that approximately 11 bbl. was entrained crude oil.
22. (ID 532) When drilling out cement plug that was set between 180 and 300 meters inside the 10 3/4" casing. The bit depth at the time of the incident was 214 m. During the above

operation using a 9 ½" bit, and after having just made a connection, the driller was about to continue with drilling out the cement, when the drill string was hydraulically forced out of the hole. This resulted in the drill pipe being buckled in the derrick between the top drive and the rotary table.

23. (ID 645) The rig had been drilling at a depth of 15,902 feet and increasing the weight of the mud in the well from 11.8 ppg. to 12.0 ppg. when the incident occurred. The crew first recognized the gas influx when the flow out of the well increased by 41%. The kick was already in the riser. An influx of approximately 238 barrels was detected within two minutes. The drill crew spaced out the drill pipe and shut the well in utilizing the Upper Annular. During the kick, it was estimated that a total of 55 barrels of mud had been discharged onto the rig floor.
24. (ID 502) The drill string penetrated a salt body, which caused a kick. During kill operations a sudden discharge of drilling fluid occurred, resulting in synthetic fluid being discharged into the water.

## 6.4 Human Errors in Deep Zone Drilling LOWC Events

The human role is considered important in the occurrence and development of LOWC events.. Human errors are believed to have contributed to many of the incidents without being explicitly stated in the information source. The skill of the personnel and proper procedures and practices will always be important.

Of the 24 “deep” LOWC events in the US GoM OCS and the regulated areas human errors involved have been investigated. Table 6.5 shows the human errors involved in deep well drilling LOWC events, alongside the time from the kick is observed until the fluids are flowing from the well.

*Table 6.5 Human errors in deep zone drilling LOWC events (2000–2015, US GoM OCS and the regulated areas)*

| LOWC ID | Time from kick to event | Human Error |
|---|---|---|
| 459 | Unknown | Unknown |
| 463 | > 6 hrs. | The casing was not centralized, and could not be worked during cementing because the brakes on the draw works overheated while running the casing. After the cementing job was complete, the crew's calculations indicated channeling. |
| 460 | Unknown | Unknown |
| 465 | 0 | No obvious |
| 550 | 0 | No obvious |
| 516 | 1 day | Unknown |
| 564 | 0 | Yes removed gland nut/hold down pin from the wellhead flange |
| 464 | 0 | A modification on BOP controls were carried out when the reservoir was exposed. No risk evaluation was carried out. The maintenance personnel accidentally activated the LMRP disconnect |
| 619 | 20 hours from kick observed until oil was observed on the sea surface. | No direct, but not following regulations and internal procedures, used too low kick tolerance |
| 481 | 0 | Failure of the driller to recognize the indications that the well was flowing when the kelly was broken from the drill string. The string safety valve (TIW) was not tested regular and could not be closed |
| 524 | 5 | Did not properly evaluate ditch magnet recovery of metal, probable rig misalignment |
| 611 | 0 | Accepted cement job that should have been rejected. Failed to observe kick before well was flowing |
| 590 | 0 | When the rig had departed from the well to undertake other work, not one well control barrier in the well had been satisfactorily tested and verified, and one barrier that should have been installed was missing. In other words, the well was suspended without regard to the company's own Well Construction Standards or sensible oilfield practice. |
| 629 | 5 days | No obvious |
| 605 | Unknown | Unknown |
| 622 | Unknown | Unknown |
| 580 | Unknown | Unknown |
| 608 | 0 | Failed to observe kick before it was in the riser |
| 595 | 5 hours (assumed) | Likely observed kick late, BOP closed late |
| 583 | 0 | Yes, seems the crew did not pay attention to gas alarm in the shale shaker area and gas was allowed to accumulate before it exploded |
| 538 | 2.5 days | Yes according to MMS, did not sweep stack sufficiently after kick before opening annular |
| 532 | 0 | Likely, seems not to have anticipated gas when drilling out shallow cement plug |
| 645 | 0 | Observed kick late, 55 bbl. of mud on the drill floor before the BOP was closed |
| 502 | Some hours | Unknown |

For 11 of the 24 drilling LOWC events the kick was not observed before fluid was flowing out of the well. For nine LOWC events, the kick was observed in time to close in the well, and for four it is unknown.

Many of these late observations are related to lack of attention, but some are also related to the procedures followed. One typical example is that after the casing has been cemented and the preset time for the cement to set has ended, the surface BOP is nippled down to cut casing/energize casing seals. In the period the BOP is disconnected, the well starts to flow.

For some incidents the personnel have jeopardized the secondary barrier by mistake.

For some, several human errors and poor procedures result in the LOWC event.

More human errors than those listed above have probably been present, but they have not been reported in the source material for the LOWC events.

## 6.5 Equipment Failures in Deep Zone Drilling LOWC Events

Equipment failures are frequently involved in deep zone drilling LOWC events. Table 6.6 shows the equipment failures in deep zone drilling LOWC events.

*Table 6.6 Equipment failures in deep zone drilling LOWC events (2000–2015, US GoM OCS and the regulated areas)*

| LOWC main category | LOWC ID | Rig type | Secondary barrier failure | Equipment failure |
|---|---|---|---|---|
| Blowout (surface flow) | 459 | Jack-up | Casing head failed | The 10 ¾ inch casing head by 16 inch casing head spool began leaking |
| | 516 | Semisub | Poor cement | Cement/casing |
| | 564 | Jack-up | Wellhead failed | Liner hanger packer, wellhead flange |
| | 464 | Semisub | Failed to close BOP | No (Controls disconnected by human error) |
| | 619 | Drillship | Formation breakdown | No |
| | 481 | Jack-up | String safety valve failed | Failed to close TIW valve, three men was not able to apply enough torque (There were no blind shear ram in the BOP, this was not a requirement) |
| | 524 | Jacket | Inner casing failed | The two primary gauges failed simultaneously and returned a false reading of pressure decline. Casing bursted below its rated burst pressure of 3,450 psi because of heavy wear in the casing that was not detected. |
| | 463 | Jack-up | BOP failed after closure | The pressure increased to 1,900 psi, and the annular preventer began leaking gas |
| | 460 | Jack-up | BOP/diverter not in place | Gas and mud began flowing from the base of the wellhead through a gap in the base plate flange that connects the drive pipe to the surface casing. |
| | 465 | Jack-up | BOP/diverter not in place | The wellhead flange began leaking after reattaching the BOP because it was damaged during the reattach operation |
| | 550 | Jack-up | Wellhead failed | Casing hanger lock down dogs blew out of the port/forward quadrant of the 16" wellhead, giving an uncontrolled release of mud, water, and cement through a 1 1/4" threaded port to a distance of 50-75' out away from the rig, |
| | 611 | Semisub | Failed to close BOP | BOP failed to shear and close, LMRP failed to disconnect |
| | 590 | Jack-up | Not relevant, one barrier only | Cemented casing shoe failed |
| Blowout (under-ground flow) | 629 | Jack-up | Poor cement, casing leakage | 18" liner seal failed, cement between the surface liner and conductor failed |
| | 605 | Jack-up | Formation breakdown | No |
| | 622 | Semisub | Formation breakdown | No |
| | 580 | Jack-up | Formation breakdown | No |
| Diverted well release | 608 | Drillship | Failed to close BOP | No (closed late) |
| Well release | 595 | Jack-up | Failed to close BOP | No (closed late) |
| | 583 | Drillship | Failed to close BOP | No (closed late) |
| | 538 | Semisub | Diverted - no problem | No |
| | 532 | Semisub | Not sufficient frictional backpressure | No |
| | 645 | Drillship | Failed to close BOP | No (closed late) |
| | 502 | Jacket | Unknown | No |

As seen from Table 6.6 equipment failures are mostly involved in the LOWC events categorized as *blowout (surface flow)*. There is a large variety of equipment failures that have been observed. The failures that occur in the wellhead or in the equipment as spools etc. below the BOP are difficult to handle. There will be no mechanical way to close the leak in.

In less serious LOWC events, there are few equipment failures involved in deep zone drilling.

# 7 WORKOVER LOWC EVENTS

Although most offshore blowouts occur during drilling, if disregarding the shallow drilling incidents, approximately the same number of LOWC events occur during workovers as during drilling (Table 4.3, page 43).

The US GoM OCS and the North Sea (UK and Norway) are mature areas. There are many producing wells with a long history of production. These wells will from time to time need to be worked over.

Workover blowouts typically occur in wells that are cased down to the productive zone, and may cause severe pollution if the well control is lost. If the well blows out, the content of the flow seen topside is dependent on whether the well is perforated in an oil, condensate, or gas zone.

A well workover is a well overhaul/repair operation that normally involves complete or partial pulling of the production tubing. Snubbing, coiled tubing and wireline operations are frequently carried out as a part of the workover operation.

The primary barrier in workover operations may be the hydrostatic control of the well (killed well), as for drilling, alternatively a mechanical barrier (live well), depending on how the workover is carried out and the progress of the workover operation.

- During workovers, a productive zone is exposed nearly all the time (i.e., a flow is possible). For drilling, a productive zone is exposed only for a short duration of the total drilling period.
- Solids-free workover fluids are usually used during workovers. A mud filter cake, which during drilling acts as a seal against the formation, will not be created. This means that during workovers there are normally continuous losses to the formation.
- In a workover, the well can be closed in with higher pressures than during drilling because formation breakdowns on shallow casing shoes are less likely to occur.
- Bullheading is a kill method that has a high success probability for workover kicks, compared to drilling kicks.
- In workovers, there is less knowledge about the casing condition, because the casing strings have been in the well for a period, and may have deteriorated.
- Normally a change in fluid density is not required to circulate out workover kicks as opposed to drilling kicks.

## 7.1 WORKOVER LOWC EXPERIENCE

The experience presented in this section is based on the *SINTEF Offshore Blowout Database* [7] for the period 2000–2015 worldwide. A total of 33 workover LOWC events have been recorded. Table 7.1 lists the various installation types and incident categories where LOWC events have been experienced.

*Table 7.1 Workover LOWC events experienced for various installation vs. main well type worldwide (2000–2015)*

| **Installation type and main incident category** | **Sub category** | Number of LOWCs |
|---|---|---|
| **JACKET** | | |
| Blowout (surface flow) | Totally uncontrolled flow, from a deep zone | 11 |
| Well release | Limited surface flow before the secondary barrier was activated | 10 |
| | String blown out of well, then the secondary barrier | 1 |
| Total | | 22 |
| **JACK-UP** | | |
| Blowout (surface flow) | Totally uncontrolled flow, from a deep zone | 1 |
| Well release | Limited surface flow before the secondary barrier was activated | 2 |
| | String blown out of well, then the secondary barrier | 2 |
| Total | | 5 |
| **SEMISUBMERSIBLE** | | |
| Well release | Limited surface flow before the secondary barrier was activated | 1 |
| Total | | 1 |
| **TENSION LEG** | | |
| Blowout (surface flow) | Totally uncontrolled flow, from a deep zone | 1 |
| Total | | 1 |
| **BARGE** | | |
| Well release | Limited surface flow before the secondary barrier was activated | 2 |
| Total | | 2 |
| **UNKNOWN** | | |
| Well release | Limited surface flow before the secondary barrier was activated | 1 |
| Unknown | Unknown | 1 |
| Total | | 2 |
| **TOTAL ALL** | | 33 |

Table 7.1 shows that 67% of the workover LOWC events occurred on jackets, while 15% occurred on jack-ups. The remaining 18% occurred on semisubmersibles, tension leg, barges and unknown.

Of the 33 workover LOWC events, 13 were classified as *blowout (surface flow).*

Table 7.2 shows the countries and the years the various workover LOWC events occurred.

*Table 7.2 Countries where workover LOWC events were experienced world-wide (2000–2015)*

| Year | Country | Number of LOWCs |
|---|---|---|
| 2000 | US California OCS | 1 |
| 2001 | Brunei | 1 |
| | UK | 1 |
| | US GoM OCS | 3 |
| 2002 | US Alaska State | 1 |
| | US GoM OCS | 1 |
| 2003 | US GoM OCS | 1 |
| 2004 | Norway | 1 |
| | UK | 1 |
| | US California OCS | 1 |
| | US GoM OCS | 1 |
| 2006 | US GoM OCS | 1 |
| 2007 | UK | 2 |
| | US GoM OCS | 3 |
| 2008 | US GOM State Waters | 1 |
| | US GoM OCS | 3 |
| 2009 | US GoM OCS | 1 |
| 2010 | Netherlands | 1 |
| | US GOM State Waters | 1 |
| 2011 | US GoM OCS | 2 |
| 2012 | US GoM OCS | 3 |
| 2013 | US GoM OCS | 1 |
| 2014 | US GoM OCS | 1 |
| Total | | 33 |

Table 7.2 shows that 64 % (21) of the workover LOWC events occurred in the US GoM OCS, and the remaining 12 in the rest of the world.

Figure 7.1 shows the annual workover LOWC frequency per well year in service (injectors and producers) and the associated regression lines for workover LOWC events from 2000–2015.

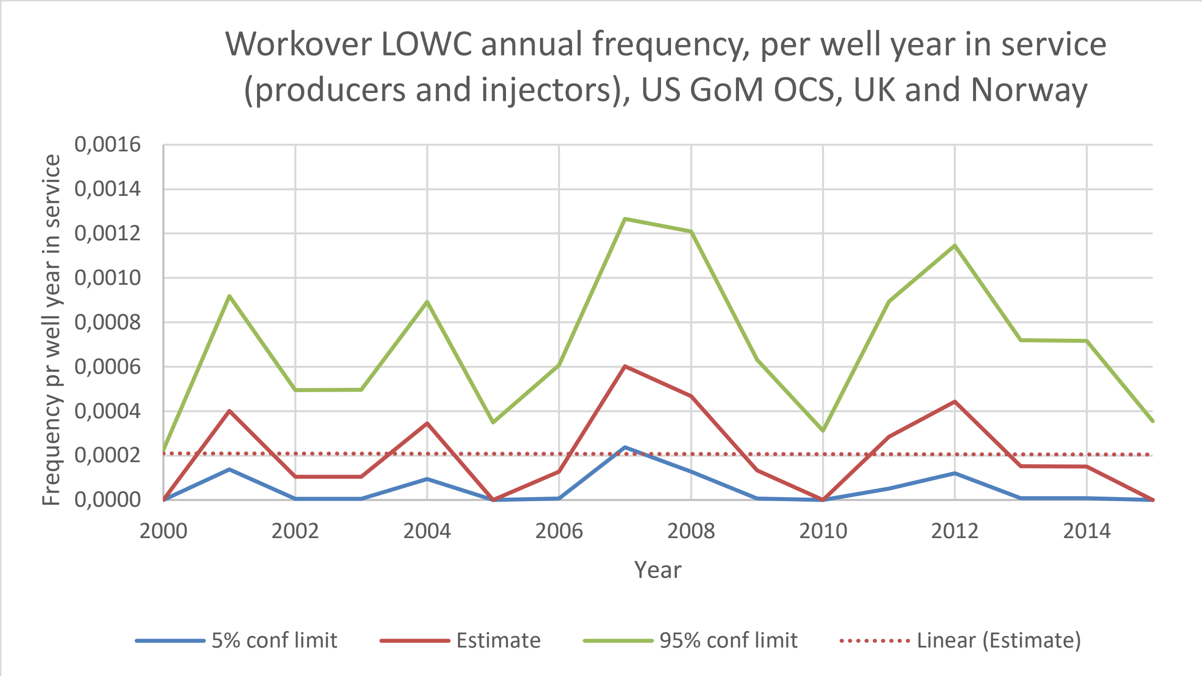


*Figure 7.1 Annual frequency for workover LOWC events and the associated regression line*

Figure 7.1 shows that there is a large variation from year to year. It cannot be concluded that there is any statistical significant trend. The trend line indicates that there is no trend. The statistical uncertainties increases during the period due to a reduction in active wells.

Table 7.3 presents the operations and activities in progress when the workover LOWC events occurred.

*Table 7.3 Operations and activities in progress when the workover LOWC events occurred (2000–2015 worldwide)*

| Area | Main category | Operation → / Activity ↓ | Pull well equip. | Aband-on well | Coil tub-ing | Install equip. | Circu-lating | Perfor-ating | Snub-bing | Run cas-ing | Temp. plug-ged | Wire-line | Unk-nown | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| US GoM OCS | Blowout (surface flow) | Pull tubing | 2 | | | | | | | | | | | 2 |
| | | Cleaning well | | | 1 | | 1 | | | | | | | 2 |
| | | Pull coiled tubing | | | 1 | | | | | | | | | 1 |
| | | Coiled tubing operations | | 1 | | | | | | | | | | 1 |
| | | Other | | 2 | | | | | | | | | | 2 |
| | | Unknown | | 1 | | | | | | | | | | 1 |
| | | Total | 2 | 4 | 2 | | 1 | | | | | | | 9 |
| | Well release | Actual drilling | | 1 | | | | | | | | | | 1 |
| | | Circulating | | | | | | 1 | | | | | | 1 |
| | | Install BOP | | 1 | | | | | | | | | | 1 |
| | | Pull/drill out well plugs | 2 | | | | | | | | | 1 | | 3 |
| | | Pull tubing | 1 | 2 | | | | | | | | | | 3 |
| | | Cleaning well | | | 1 | | | | | | | | | 1 |
| | | Run wireline | | | | | | | | | | 1 | | 1 |
| | | Run coiled tubing | | | 1 | | | | | | | | | 1 |
| | | Total | 3 | 4 | 2 | | | 1 | | | | 2 | | 12 |
| | Total | | 5 | 8 | 4 | | 1 | 1 | | | | 2 | | 21 |
| UK & Norw-egian waters | Blowout (surface flow) | Pulling casing | 1 | | | | | | | | | | | 1 |
| | | Total | 1 | | | | | | | | | | | 1 |
| | Well release | Pulling casing | 1 | | | | | | | | | | | 1 |
| | | Pull/drill out well plugs | | | | | | | | | 1 | | | 1 |
| | | Pull tubing | 2 | | | | | | | | | | | 2 |
| | | Total | 3 | | | | | | | | 1 | | | 4 |
| | Total | | 4 | | | | | | | | 1 | | | 5 |
| Rest of the world | Blowout (surface flow) | Tripping out | 1 | | | | | | | | | | | 1 |
| | | Circulating | | | | | | | | 1 | | | | 1 |
| | | Maintenance surface equipment | | | | 1 | | | | | | | | 1 |
| | | Total | 1 | | | 1 | | | | 1 | | | | 3 |
| | Unk-nown | Stimulating | | | | | | | | | | | 1 | 1 |
| | | Total | | | | | | | | | | | 1 | 1 |
| | Well release | Pull/drill out well plugs | 1 | | | | | | | | | | | 1 |
| | | Snubbing in | | | | | | | 1 | | | | | 1 |
| | | Maintenance surface equipment | | | | 1 | | | | | | | | 1 |
| | | Total | 1 | | | 1 | | | 1 | | | | | 3 |
| | Total | | 2 | | | 2 | | | 1 | 1 | | | 1 | 7 |
| Total | | | 11 | 8 | 4 | 2 | 1 | 1 | 1 | 1 | 1 | 2 | 1 | 33 |

From Table 7.3, it can be seen for 11 of the workover LOWC events the operation was pulling well equipment. Eight of the LOWC events were related to abandoning the well and four related to coil tubing operations. Also for at least three of the incidents, where the operations were abandon well or coil tubing, they were actually pulling equipment from the well when the incident occurred. Several of the incidents, where the operation was abandon well, occurred in old wells that had been temporary abandoned or plugged for longer periods.

For the US GoM OCS nine of the 21 LOWC events were categorized as *blowout (surface flow)*. The remaining 12 were categorized as a *well release*. For Norway and UK one of the workover LOWC events was categorized as a *blowout (surface flow)*. The remaining 11 were categorized as a *well release*. For the rest of the world three were categorized as *blowout (surface flow),* three as a *well release*, and one was categorized as unknown.

## 7.2 Workover LOWC Causes

This section focuses on the causes of the workover LOWC events. Since two barriers normally should be present during workover, this section is focused on the causes of losing the primary barrier and the secondary barriers. The primary barrier in workover operations may be the hydrostatic control of the well (killed well) or a mechanical barrier (live well), depending on how the workover is carried out and the progress of the workover operation.

### *7.2.1 Loss of the Primary and Secondary Barriers*

When the well is controlled by the hydrostatic pressure, the loss of the primary barrier is a well kick. As for drilling incidents, it is important to detect the well kick as soon as possible in order to close in the well with a minimum influx. If the secondary barrier fails to activate, or activates late, a workover LOWC event will occur.

Table 7.4 lists the experienced primary and secondary barrier failure causes for the workover LOWC events in the US GoM OCS and the regulated areas (Norway, UK, the Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark, and Brazil).

*Table 7.4 Primary and secondary barrier failure causes for workover LOWC events in the US GoM OCS and the regulated areas.*

| Primary barrier failure | | Secondary barrier failure | LOWC Id | Well Status | Install-ation type | No. of LOWCs |
|---|---|---|---|---|---|---|
| **Blowout (surface flow)** | | | | | | |
| Too low hyd. head | Too low mud weight | String safety valve not available | 621 | Killed | Jacket | 1 |
| | | Tubing leak and casing leak | 591 | Killed | Jacket | 1 |
| | Annular losses | Wellhead failed | 539 | Killed | Jacket | 1 |
| | Unknown why | String safety valve not available | 480 | Killed | Jacket | 1 |
| | Swabbing | Casing leakage | 542 | Killed | Tension leg | 1 |
| | Unexpected high well pressure | Failed to close BOP | 520 | Killed | Jacket | 1 |
| Tubing to annulus leakage | | Wellhead failed | 525 | Live | Jacket | 1 |
| | | Outer casing an inner casing failed | 631 | Live | Jacket | 1 |
| SCSSV/storm choke failure | | X-mas tree failed and casing leakage | 606 | Live | Jacket | 1 |
| | | Tubing to annulus leak and casing leak | 593 | Live | Jacket | 1 |
| Unknown | | Casing leakage | 613 | Killed | Jacket | 1 |
| **Total** | | | | | | **11** |
| **Well release** | | | | | | |
| Too low hyd. head | Trapped gas | Failed to close BOP | 571 | Killed | Semisub | 1 |
| | | | 576 | Killed | Barge | 1 |
| | | | 627 | Killed | Jacket | 1 |
| | | | 477 | Killed | Jack-up | 1 |
| | Unknown why | BOP failed after closure (coil tubing) | 623 | Killed | Jacket | 1 |
| | Swabbing | Unknown | 597 | Killed | Jacket | 1 |
| SCSSV/storm choke failed | | X-mas tree failed | 643 | Live | Jacket | 1 |
| Unexpected high well pressure | | Failed to close BOP | 598 | Killed | Jacket | 1 |
| | | | 620 | Killed | Jack-up | 1 |
| Tubing plug failure | | Wireline BOP/ lubricator failed | 585 | Live | Jacket | 1 |
| | | Failed to close BOP | 475 | Killed | Jacket | 1 |
| Snubbing equipment failure | | Failed to close BOP | 618 | Live | Unknown | 1 |
| Packer plug failure | | Failed to close BOP | 531 | Killed | Jacket | 1 |
| Tubing parted | | Failed to close BOP | 558 | Live | Jacket | 1 |
| | | | 574 | Killed | Jack-up | 1 |
| Tubing to annulus leakage | | Failed to close BOP | 584 | Live | Jack-up | 1 |
| SCSSV/storm choke failure | | X-mas tree failed | 478 | Live | Jacket | 1 |
| Snubbing equipment failure | | Outer casing failed | 506 | Live | Jacket | 1 |
| **Total** | | | | | | **18** |
| **Total all** | | | | | | **29** |

The individual LOWC events are commented a bit further down. Here are some overall findings discussed.

**Blowout (surface flow)**
***Loss of the primary barrier***
For six of the 11 *blowout (surface flow)* LOWC incidents the hydrostatic pressure became too low.

Four of the *blowout (surface flow)* LOWC incidents occurred in live wells being worked over. For two of them the tubing leaked and for two the SCSSV leaked. The last incident occurred in a temporary abandoned well that they were working over to permanently plug. The cause of the primary barrier failure is unknown.

**Loss of the secondary barrier *blowout (surface flow)***
Four of these 11 *blowout (surface flow)* LOWC incidents were in wells that should be permanently abandoned.

For the two *string safety valve not available*, the valve was not in a ready state to be stabbed into the string. For one the BOPs did not have a blind shear ram, for the other the well was isolated with the blind shear ram after a period of time.

For the *failed to close BOP,* the BOP did not have a blind shear ram

For the first *tubing to annulus leak and casing leak* second barrier failure, severe corrosion in the tubing and casing caused the barrier failure.

For the second *tubing to annulus leak and casing leak* second barrier failure, they accidentally cut two holes with a hole saw during toppled well P&A.

For one *casing leak,* a scab liner in the well had been pulled, opening a known casing leak, when the well kicked the casing leaked to shallow formation that again released gas to the seafloor.

For the other *casing leak,* natural gas bubbled to surface outside the well during plugging operations. The conductor casing was heavily corroded.

For the *outer and inner casing failed,* the well control was lost due to leaks in the tubing, production casing, and surface casing to an unsealed annulus

For one of the *wellhead leaked* incidents, a wellhead service technician removed a 1.5" diameter lockdown pin and packing-gland from the wellhead, ruining the barrier.

For the other *wellhead leaked,* a failed plastic injector port, together with a missing wellhead seal assembly, allowed for the LOWC event to occur.

For the *X-mas tree and casing leak* secondary barrier failure, while installing the hot tap tool on the number 2 tubing string (Short String) the well started flowing gas out the X-mas tree 200 feet away from the vessel.

**Well releases**
For the majority of the 18 workover LOWC events categorized as *well release* there was no equipment failure involved for the secondary barrier. Typically, the BOP or another available barrier was closed and the situations were controlled after hydrocarbons had been leaking to the surroundings for a limited period.

### *7.2.2 BRIEF LOWC EVENT DESCRIPTIONS*

**Blowout surface Flow**
1. (ID 621) The rig was pulling 2 7/8" tubing out of the well, the well started flowing and wellbore fluids spewed out to a height of 30-40 feet in the air. Failed to stab the TIW valve because the hoist was unavailable at the time. Shut in well with blind shear ram.

2. (ID 591) While conducting P/A operations the well kicked when washing the perforations. Holes in the tubing and all of the casing strings had developed from corrosion, which in turn exposed the gas with oil to open atmosphere. The weight of the system was overrated for the patch job and the patch failed.
3. (ID 539) A wellhead service technician removed a 1.5" diameter lockdown pin and packing-gland from the wellhead. Removal of this pin circumvented the blowout prevention system (BOP) and provided an exit point for wellbore fluids. While doing so they stopped pumping seawater for a 20 - 40 minutes period. Losses caused the well to kick. Gas and oil were released. Seawater was pumped into the well at a high rate through the kill line. After approximately 2.5 hours, the rate of leakage subsided enough to allow the installation of a valve assembly into the 1.5" opening.
4. (ID 480) While washing over a gravel pack assembly using a 2-7/8 inch work string, the rig crew experienced a kick. Well control operations were initiated by bullheading into the well. Pressure rose to 4,200 psig. The pressure safety valve (PSV) located on the mud pump relieved, allowing a mixture of formation sand, gas, oil, and completion fluid to escape. The PSV should relieve at 5,000 psi, but relieved prematurely. The BOP did not have a blind shear ram.
5. (ID 542) During a sidetrack in 1995, a scab liner was set due to severe casing wear and holes in the 9 5/8" casing at 1,400m TVD. The well was worked over in 2004 due to a tubing to annulus communication. After cutting the scab liner, they started to pull it. The well was flow-checked several times and the well seemed static. Then they observed flow and closed the annular preventer. The pressure increased for a short while before it fell. They then observed losses and opened the annular preventer and pumped mud. The pressure increased again and the BOP was closed. Gas was observed visually and by detectors coming up from the sea. The sea surface "boiled”. After the incident, it was estimated that the gas flow rate was 20-30 kg/s. Craters of some meters in diameter were observed at the sea floor. They had limited amount of mud on the platform and mud supply was impossible due to the gas flowing through the sea surface. After having mixed mud from the available well fluid chemicals, this was pumped into the well, and the well was stabilized.
6. (ID 520) The objective of the workover was to replace parted tubing and return the well to production of gas from the "P" sand. The "P" sand had been pressure depleted and the workover employed light-weight fluid. When preparations to begin recovering the tubing down to a suspected break or part at about 1,900 ft. were initiated, high pressure was then unexpectedly observed to be abruptly rising on the tubing and production casing annulus. When the pressure reached approximately 6,150 psi, the tubing hanger and approximately 600 feet of tubing were suddenly ejected from the well through the BOP's. Subsequently, the well flowed out of control through the BOP stack. Attempts to control the well with the BOP's were unsuccessful because of the tubing lodged across the BOP stack. The BOP stack was not equipped with blind shear rams. The flow ceased and the Well bridged over after some hours.
7. (ID 525) The well that had been shut-in for approximately 10 year prior to the incident. The intention was to work over the well to re-start the production from the well. Coiled tubing equipment was rigged-up and run in hole. Nitrogen was injected down the tubing to wash and clean out the sand. As the intended target depth was neared, the well started to flow. Wellhead pressure rapidly rose to 2,300 psi after the choke manifold was closed. Thereafter nitrogen was observed leaking from around the wellhead, below the BOP stack. The injection fitting port on the wellhead that is used to inject a plastic energizer for the wellhead seal assembly failed. The failed port, together with a missing wellhead seal assembly, allowed for the LOWC event.

8. (ID 631) During a Temporary Abandonment (TA) procedure in 2013, while attempting to pull a tubing plug, unexpected pressure was encountered. Well control was lost due to leaks in the tubing, production casing, and surface casing to an unsealed annulus. Light sheens were observed before the well was killed. The well was drilled in 1970. The last production from the well was in 1999. The well has since been plugged.
9. (ID 606) P&A operations were being conducted. The number 1 tubing string (Long String) had been tapped and it was shut-in with 1,800 psi. While installing the hot tap tool on the number 2 tubing string (Short String) the well started flowing gas out the X-mas tree 200 feet away from vessel. Gas was coming up out of the #1 tubing string (long string) up the various casing strings and out the casing valves. The flow was strictly gas and no sheen. After the gas flow ceased, the well was killed.
10. (ID 593) The wellbore was bent over near the mud line and the wellhead was inaccessible in the structure's debris field. The casing strings and production tubing string should be hot tapped approximately 7-10 feet below the mudline in an excavation surrounding the well. Successfully installed the 4-inch hole-saw and began to saw a 4-inch hole in the 7 5/8 inch casing. By accident, he cut into the 2 7/8 inch production tubing. He then observed uncontrolled gas bubbling from the hole-saw apparatus. This created a gas plume approximately 30 feet in diameter at the surface. Hot tapped the 2 7/8 inch production tubing and pumped 8.6 ppg. seawater into the production tubing until the well was killed.
11. (ID 613) Conductor casing corroded. Well had not been in production for 21 years when the operator was in the process of permanently plugging its associated non-producing natural gas wells when workers spotted what appeared to be natural gas bubbling to the surface near the platform. Bubbling and discolored water near the platform was observed, possibly a mixture of sediment from the ocean floor, gas, and formation water. Oil was not believed to be present other than in small amounts of condensate. Well control procedures from the platform were successful in stopping the flow of natural gas from the well.

**Well release**

12. (ID 571) Whilst pumping up, at 400 psi, the seal assembly prematurely released and unexpected gas behind the seal assembly evacuated the seawater in the riser on to the drill floor. There was a fire at the riser/rotary table interface, which lasted for between 2 and 5 minutes. The well was shut in and the rig floor deluge was activated.
13. (ID 576) When retrieving an RTTS packer a gas bubble had formed below the packer, which was set at 500 ft. measured depth. When the packer was released, the trapped gas was released, pushing the 9.1 ppg. workover fluid above it through the rotary. Closed the annular preventer.
14. (ID 627) Cut the tubing string above the DX plug. Ran an overshot. Several attempts were made to open the equalizing port on the DX plug using wireline tools. Reports indicated, in error, that the equalizing ports had opened and pressure was equalized above and below the plug. They then failed to pull plug free from the profile. An external cutter was run to cut the tubing below the DX plug. After approximately 4 minutes of cutting, the tubing parted and the well began to flow resulting in the work string being ejected from the well. The annular and pipe rams were closed in order to bring the well under control. Approximately 809 feet of work string had been ejected before the blind shear rams were closed and the work string sheared.
15. (ID 477) The driller began pulling on the tubing and working the pipe up and down. Eventually the tubing parted, and 500 feet of tubing and the master bushing from the rotary table were blown from the hole into the derrick. The crew evacuated the rig floor, and activated the BOP from a remote location. The well was shut-in by closing the blind rams.

The crew commenced well control operations. The BOP had no shear ram, but that did not affect the result of the incident.

16. (ID 623) During Coil tubing (CT) operations the well started venting gas near the bottom of the CT injector allowing the 6,850 psi of well pressure to escape around the CT pipe without restriction. BOP was closed to seal off the well. When picking the pipe up to clear stripper, the stripper rubber was coming out in pieces with it, indicating that the stripper had lost seal integrity and become gas cut leading to the unwanted release of well pressure.
17. (ID 597) While pulled out of hole with 5 ½" completion with 9 5/8" packer the packer pulled tight and began swabbing fluid. Oil was noticed on top of the header box and trip tank. The trip tank level was kept down to contain the slight amount of oil. Pumped down 5 ½" tubing 5 bpm, 0 psi. Shut down pumping operation, continued to pull 5 ½ " tubing. A quantity of gas and approximately 5 bbl. water/oil mixture, (estimated approximately 10% oil) released onto BOP deck area.
18. (ID 643) A dynamic positioned offshore supply vessel had a cement pump staged on board that was connected to the well production tree with rigid high pressure lines. The vessel lost station keeping while conducting well operations. There were no emergency disconnect coupling within the piping from the vessel to the well that would allow a quick disconnect. As the vessel moved off location, the well production tree was severed at the wellhead flange and fell overboard. The well was secured by closing the downhole safety valve and by installing a temporary flange cap on the tubing head. An estimated area of 300 ft. by 50 ft. of oil was spilled into the offshore waters.
19. (ID 598) While milling out a bridge plug on a well, without warning, the drill pipe instantaneously and uncontrollably ascended out from the well. A section of drill pipe parted. The two sections of drill pipe were locked in place with one section being attached to the top drive and the other remaining on the hole. It was estimated that 18 meters pipe was forced up the hole. As this well was a plugged and cemented previous water injector well, there was no release of hydrocarbons. The BOP was closed after some pipe had blown out of the well.
20. (ID 620) The well had been temporarily abandoned (TA) in two years prior to the re-entry to begin P&A operations. All existing plugs, including the surface plug, were successfully tested. During the P&A operations, pressure encountered below the bridge plug, ejected 385 feet of work string and the bottom-hole assembly out of the wellbore before the blind shear rams of the BOP sealed the well.
21. (ID 585) A wireline BOP and lubricator were ejected from the wellhead into the Gulf of Mexico during an attempt to retrieve a wireline DX plug from the production tubing. The accident resulted in severe facial injuries to the wireline operator. The plug was set at 505 ft.
22. (ID 475) The crew experienced an uncontrolled flow from the well after releasing a bridge plug during a well workover operation. The flow lasted about 20 seconds, and consisted of approximately 10 barrels of water and 15 barrels of oil. About one gallon of oil sprayed overboard. The BOP was used to shut-in the well.
23. (ID 618) During snubbing operations of a velocity string into a live well, the string was ejected from the well and landed vertically 4 m from the hydraulic workover tower. The pipe penetrated the helideck side netting, passed through two grating decks, struck a structural member and main deck plating and then ruptured a methanol injection flange outlet on the gas export pipeline, which resulted in an uncontrolled gas release.
24. (ID 531) Tubing was cut @ 17,130 ft. when pulling tubing freed and picked up 18 ft. when fluid influx commenced. The annular BOP was closed, but fluids escaped to drill floor with delay in activating internal top drive BOP. The internal BOP was closed and well made

safe. It appear that the tubing was not completely cut and during the pulling process, a packer was pulled. This resulted in brine release into the derrick.

25. (ID 558) The tubing was being stripped out of the hole by using a hydraulic rig (casing jacks) when the tubing became stuck. An attempt was made by the operator representative to pull the tubing when the tubing parted. The parted tubing was forced upward, causing the top slips to be ejected from the top bowl of the casing jacks. The ejected slips fatally struck the operator representative as he attempted to evacuate the immediate area. The well was then secured by closing the BOP's from the accumulator control unit.
26. (ID 574) Began operations of pulling on the production tubing in an attempt to pull the seals from the production packer located at 10,830 feet. The hanger pulled free of the wellhead with 54 kips. Pulling continued to 80 kips (string weight) and stopped. Pulling continued at 10 kips increments up to 110 kips and stopped. The seals were anticipated to release between 83 to 85 kips. When the seals failed to release the operator began working the pipe from 60 kips to 110 kips with no success. When the operator pulled 120 kips and stopped, the tubing parted at a depth of approximately 4,300 feet. Because the tubing parted at 4,300 feet, there was not enough hydrostatic head to contain the well bore pressure. The 4,300 feet of tubing was being ejected when the BOP was activated, closing the pipe rams and the annular preventers, thus stopping the ejection of tubing and containing the pressure in the annulus. The BOP did not have a blind shear ram.
27. (ID 584) Immediately after perforating the long string tubing well began to flow through the BOPs. Flow could not be controlled through dual rams. Decision was made to close blind shear rams to shut in the well. Sheared off 2 strings of 2 3/8-inch 4.7lbs tubing; electric line and perforation gun left in long string. Rams could not seal around dual string due to SCSSV control lines.
28. (ID 478) The subsurface safety valve was leaking when testing the valve. Thinking that the valve had trash in it, the crew pumped five barrels of water downhole to clean the valve. The supervisor instructed the crew to cycle the valve three times and close it. At this time, the valve appeared to hold. When the coil tubing bottom hole assembly (BHA) was lowered into the well, the BHA tagged the closed surface safety valve, which was closed by mistake. When the surface safety valve was opened, the BHA was blown out of the lubricator and into the water. It was later determined that the surface safety valve was cycled three times and then closed instead of the subsurface safety valve. This led the supervisor to believe that the subsurface safety valve was holding. After the incident, the operators discovered that the needle valve on the subsurface safety valve was closed. The control line had pressure on it, so this caused the downhole valve to be blocked open.
29. (ID 506) The crew was rigging up a snubbing unit on a dual completion wellhead in preparation to plug and abandon the well when the surface casing failed to support the weight of the BOP stack and collapsed. This resulted in the wellhead shifting downward 10 to 16 inches causing the dual crossover offset spool to crack at the weld. One of the completions was blinded off prior to nippling up the BOP stack, but the other was open. Because of the crack in the spool, there was a release of less than one gallon of fluid lasting approximately 30 seconds. The crew secured the well by closing the secondary lower master valve. Investigation showed that the surface casing failed due to corrosion.

## 7.3 Human Errors in Workover LOWC Events

The human role is considered important in the occurrence and development of LOWC events. Human errors are believed to have contributed to many of the incidents without being explicitly stated in the information source. The skill of the personnel and proper procedures and practices will always be important.

Of the 29 workover LOWC events in the US GoM OCS and the regulated areas, human errors have been investigated. Table 7.5 shows the human errors involved in workover LOWC events, alongside the time from the kick is observed until the fluids are flowing from the well. It has also been noted if the well was controlled by a hydrostatic pressure (killed) or if the well was live when the LOWC events occurred.

*Table 7.5 Human errors in workover LOWC events (2000–2015, US GoM OCS and the regulated areas)*

| LOWC ID | Well Status | Time from kick to event | Human Error |
|---|---|---|---|
| ***Blowout (surface flow)*** | | | |
| 621 | Killed | 0 | Failed to maintain the proper mud weight of 9 ppg. to control the well. (Mud Engineer noticed condensate or oil mixed with the returns in the trip-tank but failed to stop the operation or re-weigh the mud entering the well as 2 7/8" tubing was being pulled.)<br><br>The TIW valve was not in the ready state to be stabbed due to the unavailability of the hoist |
| 591 | Killed | Unknown | No obvious |
| 539 | Killed | 0 | Removed tubing hanger lock down pins (jeopardized the secondary barrier, and stopped pumping seawater (caused the kick). |
| 480 | Killed | 8 hours | The TIW valve was not ready to be stabbed |
| 542 | Killed | 6 hours | The non-conformities relate to failure on the part of both individuals and groups in company and with the drilling contractor. The non-conformities occurred at several levels in the organization on land and on the facility.<br>A scab-liner had sealed the leak in the casing. When pulling the scab-liner the leak was re-opened (secondary barrier). |
| 520 | Killed | 0 | No obvious |
| 525 | Live | a short while, not immediately | (1) failure to inspect and maintain equipment,<br>(2) failure to conduct a Job Safety Analysis (JSA) for workover activities,<br>(3) failure to provide clear and specific instructions to contracted personnel, and<br>(4) failure to communicate with the contracted operator of the lease. |
| 631 | Live | 0 | • Failure to research all wellbore and well production records *to determine wellbore conditions before permitting the abandonment* work. A site specific hazard analysis could have prevented this incident<br>• Failure to confirm pressure integrity of production casing before pulling the plug. Held 300 psi external on June 27, 2013.<br>• Lack of communication between all parties involved including contractor to contractor, contractors and company men, company men and ERT staff, ERT and BSEE.<br>• Lack of clear supervisory authority |
| 606 | Killed | 0 | No obvious |
| 593 | Live | 0 | Should have stopped work due to uncertainty related to hole saw cutting depth |
| 613 | Killed | 0 | No obvious |
| ***Well releases*** | | | |
| 571 | Killed | 0 | No obvious |
| 576 | Killed | 0 | Yes, should have closed annular preventer prior to releasing the RTTS packer |
| 627 | Killed | 0 | Yes, failed to realize the pressure over the DX plug was not equalized |
| 477 | Killed | 0 | Torn off tubing |
| 623 | Killed | 0 | No obvious |
| 597 | Killed | Unknown | Unknown |
| 643 | Live | 0 | No obvious |
| 598 | Killed | 0 | Unknown |
| 620 | Killed | 0 | The Operator did not take additional precautions, such as, conducting a hazard analysis for potential pressure below the plug |
| 585 | Live | 0 | Yes, did not equalize over plug (used wrong tool), did not test wireline BOP, |
| 475 | Killed | 0 | Seems they have not considered the possibility that there may be pressure below a tubing plug |
| 618 | Live | 0 | The investigation identified systemic failures in the management of HWO snubbing units by contractor. Major gaps were identified in equipment maintenance, operating procedures, |

| LOWC ID | Well Status | Time from kick to event | Human Error |
|---|---|---|---|
| | | | competence assurance and supervision. |
| 531 | Killed | 0 | Unknown |
| 558 | Live | 0 | • The operator exceeded the yield strength of the tubing causing it to part and (calculation was wrong).<br>• Since there were pressure in the well, a snubbing unit should have been used and not casing jacks.<br>• The operator made operational decisions on the platform without consulting offsite managers. His decisions and actions placed the platform, personnel, and environment in constant threat from a potential loss of well control, and resulted in a brief loss of well control, pollution, and a fatal accident.<br>• The investigation report also blames the management for lack of control |
| 574 | Killed | 0 | No obvious |
| 584 | Live | 0 | No obvious |
| 478 | Live | 0 | Closed wrong valve. The surface safety valve was cycled three times and then closed instead of the subsurface safety valve. This led the supervisor to believe that the subsurface safety valve was holding. The operators discovered that the needle valve on the subsurface safety valve was closed. The control line had pressure on it, so this caused the downhole valve to be blocked open |
| 506 | Live | 0 | No obvious |

For wells that are live there will not be a kick warning. When equipment fails, well fluids are flowing out immediately. A secondary barrier is then normally activated to end the flow to surroundings. When the activation of the secondary barrier is successful, the LOWC event has a short duration and it is categorized as a *well release* and not a blowout. Eight of the *well releases* and three of the *blowout (surface flow)* occurred in live wells, while the remaining occurred in killed wells.

For 14 of the 18 workover LOWC events that had the well status killed the kick was not observed before the well was flowing out to the surroundings. For two of the remaining they failed to control the kick after some hours of kick killing operations. For two the time from kick to the LOWC event was unknown.

Human errors were identified in 15 of the 29 workover LOWC events. It is likely that there have been more human errors as well but they cannot be identified from the LOWC descriptions and data sources.

Some of the human errors are related to poor planning of the operations. The possible risks have not been properly considered. Others are related to equipment that did not function due to lack of maintenance or that was not accessible.

Some are also related to faulty operations, as jeopardizing a barrier by mistake, closing or opening the wrong valve, tearing off the tubing by using too much force, not performing operations in a safe manner. These types of events can be caused by poor planning or by procedures not being followed.

## 7.4 Equipment Failures in Workover LOWC Events

Equipment failures are frequently involved in workover LOWC events. Table 7.6 shows the equipment failures in workover LOWC events.

*Table 7.6 Equipment failures in workover LOWC events (2000–2015, US GoM OCS and the regulated areas)*

| LOWC Id | Well Status | Secondary barrier failure | Equipment failure |
|---|---|---|---|
| **Blowout (surface flow)** | | | |
| 621 | Killed | String safety valve not available | No (operational error) |
| 591 | Killed | Tubing leak and casing leak | Tubing and casings leaked due to corrosion (well originally drilled in 1969) |
| 539 | Killed | Wellhead failed | No (operational error) |
| 480 | Killed | String safety valve not available | The PSV should relieve at 5,000 psi, but relieved prematurely on 4,200 psi |
| 542 | Killed | Casing leakage | Casing leaked (leak sealed by scab liner, scab liner was removed) |
| 520 | Killed | Failed to close BOP | The tubing hanger hold-down pins failed. This failure was due to a design flaw. The ejection of hanger and tubing and loss of control were caused by this design flaw. |
| 525 | Live | Wellhead failed | The injection fitting port on the wellhead failed. The failed port, together with a missing/failed wellhead seal assembly, allowed for the LOWC. The seal was corroded. the well had been closed for 10 years before the workover |
| 631 | Live | Outer casing an inner casing failed | Leaks in the tubing, production casing, and surface casing to an unsealed annulus. Corrosion was not mentioned, but this was a very old well that had been plugged for more than 10 years. |
| 606 | Live | X-mas tree failed and casing leakage | SCSSV failed to close (well toppled by hurricane) |
| 593 | Live | Tubing to annulus leak and casing leak | DHSV likely failed to close or were leaking (well toppled by hurricane) |
| 613 | Killed | Casing leakage | Conductor casing corroded. Well had been closed in for 21 years |
| **Well release** | | | |
| 571 | Killed | Failed to close BOP | The seal assembly prematurely released and unexpected gas behind the seal assembly evacuated the sea water in the riser to the drill floor (BOP closed late) |
| 576 | Killed | Failed to close BOP | No (closed late) |
| 627 | Killed | Failed to close BOP | Equalizing port on the DX plug failed to open. The tubing overshot packoff was leaking, resulting in the loss of pressure into the casing annulus. The pressure drop was assumed to be going into the formation; thus, giving a false indication that the pressure was equalized. Failed to pull DX plug. When tubing below plug was cut well flowed. (BOP closed late) |
| 477 | Killed | Failed to close BOP | Tubing torn off (BOP closed late) |
| 623 | Killed | BOP failed after closure (coil tubing) | Coiled tubing stripper rubber was coming out in pieces indicating that the stripper had lost seal integrity and become gas cut, leading to release of well pressure |
| 597 | Killed | Unknown | Unknown |
| 643 | Live | X-mas tree failed | DP failed on service boat tearing off the X-mas tree. No emergency disconnect coupling within the hard line between the service boat and the X-mas tree. SCSSV closed after control line was drained. |
| 598 | Killed | Failed to close BOP | No (closed late) |
| 620 | Killed | Failed to close BOP | No (closed late) |
| 585 | Live | Wireline BOP/ lubricator failed | Wireline BOP and Lubricator were ejected from the wellhead into the Gulf of Mexico, the connector probably failed. The wireline BOP was not tested before the operation |
| 475 | Killed | Failed to close BOP | No (closed late) |
| 618 | Live | Failed to close BOP | No (closed late) |
| 531 | Killed | Failed to close BOP | No (top drive IBOP closed late) |
| 558 | Live | Failed to close BOP | Ruptured tubing (due to over tension) (BOP closed late) |
| 574 | Killed | Failed to close BOP | Tubing parted due to tension. The max. pull was calculated at 70% (using the API recommended factor of 1.80) of the maximum yield or 133 kips. The tubing parted at 120 kips, which was 63% of the maximum yield. Laboratory tests indicate the parted tubing was the result of fatigue cracking and wall thinning. (BOP closed late) |
| 584 | Live | Failed to close BOP | No (blind shear ram closed late) |
| 478 | Live | X-mas tree failed | None (X-mas tree valve was opened by mistake) |
| 506 | Live | Outer casing failed | Surface casing failed to support the weight of the BOP stack and collapsed. This resulted in the wellhead shifting downward 10 to 16 inches causing the dual crossover offset spool to crack at the weld. Failure caused by corrosion. (well was originally drilled in the mid 60's) |

For many of the incidents there have been equipment failures. For six of the workover LOWC events corrosion was mentioned as the direct cause for the equipment failure. There are probably more of the incidents where corrosion plays a role.

Some of the equipment failures are caused by human errors, as for instance over-tensioning the tubing.

For most of the *blowout (surface flow)* incidents, there were equipment failures involved.

Four of the *blowout (surface flow)* incidents occurred in wells that they were performing plug and abandon operations in. (LOWC Id 591, 593, 606, and 613). One well was drilled in 1969 (Id 591), two were in wells toppled by hurricane (Id 593 and 606), and one was in a well that had been closed in for 21 years (Id 613). These are wells where the well barrier situation is uncertain.

For Id 525 the well had been closed for 10 years before the workover, and for ID 631 the well had been plugged for 10 years. These are also wells where the well barrier situation is uncertain.

The equipment failures experienced in workovers are to a large degree caused by aging, especially equipment in the wells. A proper verification of the status of the well prior to the workover, with respect to the barriers in the well, the surface barriers, in addition to an evaluation of potential pressures in the well will always be important in workovers.

# 8 COMPLETION LOWC EVENTS

Completion blowouts occur during well completion activities. Well completion activities involve installing equipment or undertaking operations required to produce a well after the drilling is completed. This usually includes preparation for and running of the production tubing, and installation of the X-mas tree. If the wells, for instance, are gravel-packed, or are in any other ways prepared before running the tubing, this is regarded as a part of the completion activities.

The complexity of a well completion varies significantly; some are simple, while others are complex. The complexity will vary from field to field and from operator to operator. Complexity is mainly dependent on the reservoir, the oil company's preferences and requirements, and the government requirements.

The complexity depends on whether there are:

- gravel-pack, sand screens
- dual or single completions
- artificial lift (now or later)
- non-corrosive equipment
- equipment for downhole chemical injection
- dual/single downhole safety valve
- annulus safety valve
- multi zones
- smart wells
- horizontal or highly deviated wells
- etc.

In this report, no distinctions have been made regarding the equipment included in the various well completions. This is because the information required to make such distinctions is not available and the total number of completion blowouts is low.

## 8.1 COMPLETION LOWC EXPERIENCE

The experience presented in this section is based on the *SINTEF Offshore Blowout Database* [7] for the period 2000–2015 worldwide. Ten completion LOWC events have been identified. Table 8.1 lists the various installation types and incident categories where LOWC events have been experienced.

*Table 8.1 Completion LOWC events experienced for various installation vs. main well type worldwide (2000–2015)*

| Installation type and main incident category | Sub category | Number of LOWCs |
|---|---|---|
| **JACKET** | | |
| Blowout (surface flow) | Totally uncontrolled flow, from a deep zone | 1 |
| Well release | Limited surface flow before the secondary barrier was activated | 1 |
| Total | | 2 |
| **JACK-UP** | | |
| Blowout (surface flow) | Totally uncontrolled flow, from a deep zone | 2 |
| Total | | 2 |
| **SEMISUBMERSIBLE** | | |
| Diverted well release | Other | 1 |
| Well release | Limited surface flow before the secondary barrier was activated | 2 |
| Total | | 3 |
| **TENSION LEG** | | |
| Well release | Limited surface flow before the secondary barrier was activated | 2 |
| Total | | 2 |
| **BARGE** | | |
| Blowout (surface flow) | Totally uncontrolled flow, from a deep zone | 1 |
| Total | | 1 |
| **TOTAL ALL** | | 10 |

Table 8.1 shows that completion blowouts occur on all type of installations.

Of the 10 completion LOWC events, four were classified as *blowout (surface flow),* while the remaining were classified as a *well release* or a *diverted well release.*

Table 8.2 shows the countries and the years the various completion LOWC events occurred.

*Table 8.2 Countries where completion LOWC events were experienced world-wide (2000–2015)*

| Year | Country | Number of LOWCs |
|---|---|---|
| 2000 | Mexico | 1 |
| | Norway | 1 |
| 2001 | UK | 1 |
| | US GoM OCS | 1 |
| 2002 | UK | 1 |
| 2003 | UK | 1 |
| | US GoM State waters | 1 |
| 2009 | UK | 1 |
| | US GoM OCS | 1 |
| 2013 | US GoM OCS | 1 |
| Total | | 10 |

Table 8.2 shows that 30 % (3) of the workover LOWC events occurred in the US GoM OCS, 40% (4) in the UK and 10% (1) in Norway. The remaining two were observed in US GoM State waters and in Mexico.

Figure 8.1 shows the annual completion LOWC frequency per well year in service (injectors and producers) and the associated regression lines for completion LOWC events from 2000–2015.

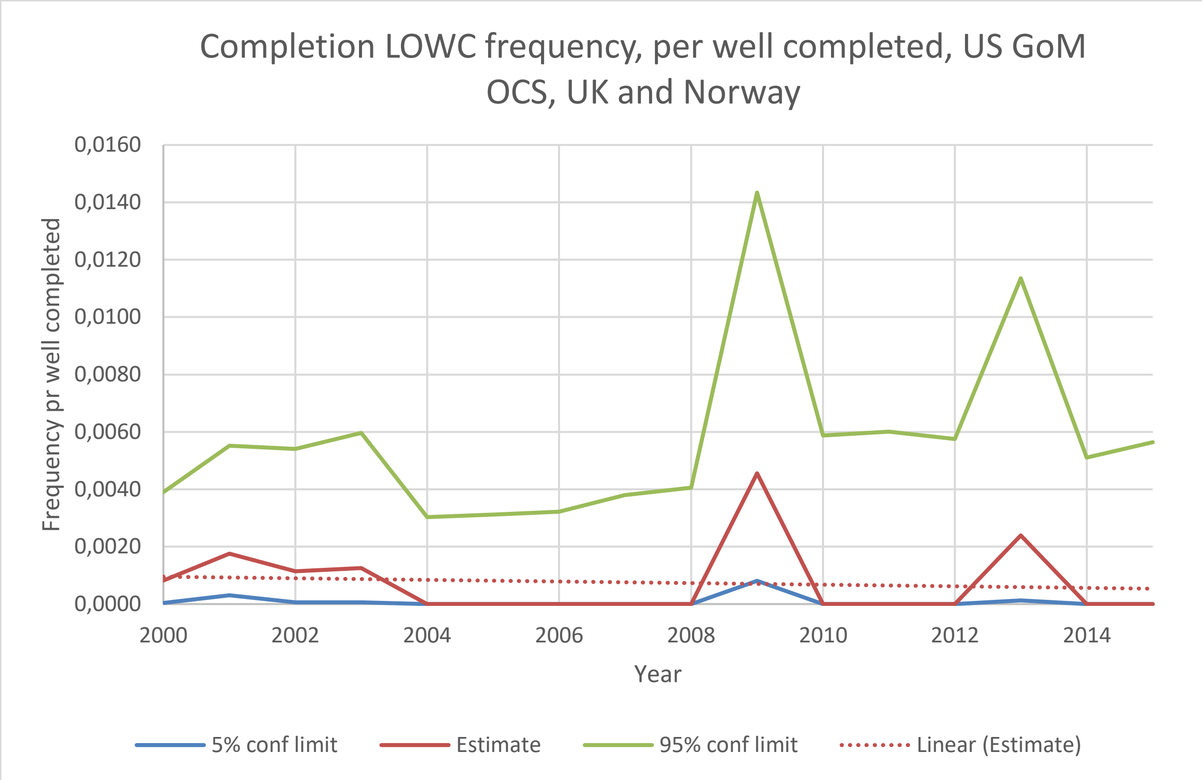


*Figure 8.1 Annual frequency for completion LOWC events and the trend line*

Figure 8.1 shows that there is a large variation from year to year. It cannot be concluded that there is any statistical significant trend. The trend line indicates no trend. The statistical uncertainties increases during the period due to a reduction in number of completions.

Table 8.3 presents the operations and activities in progress when the completion LOWC events occurred.

*Table 8.3 Operations and activities in progress when the completion LOWC events occurred (2000–2015 worldwide)*

| Area | Main category | Operation ⇨ / Activity ⇩ | Pull well equip-ment | Run well equip-ment | Install equip-ment | Perfor-ating | Drilling activity | Circulat-ing | Un-known | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| US GoM OCS | Blowout (surface flow) | Tripping out | | | | 1 | | | | 1 |
| | Diverted well release | Circulating | | | | 1 | | | | 1 |
| | Well release | Tripping in | | | | 1 | | | | 1 |
| | Total | | | | | 3 | | | | 3 |
| UK and Norway | Blowout (surface flow) | Cleaning well | | | 1 | | | | | 1 |
| | Well release | Pull tubing | 1 | | | | | | | 1 |
| | | Gravel pack | | | 1 | | | | | 1 |
| | | Cleaning well | | | | | | 1 | | 1 |
| | | Maintenance well equipment | | 1 | | | | | | 1 |
| | Total | | 1 | 1 | 2 | | | 1 | | 5 |
| Rest of the world | Blowout (surface flow) | Actual drilling | | | | | 1 | | | 1 |
| | | Unknown | | | | | | | 1 | 1 |
| | Total | | | | | | 1 | | 1 | 2 |
| Total all | | | 1 | 1 | 2 | 3 | 1 | 1 | 1 | 10 |

From Table 8.3, it can be seen that for the three completion LOWC events occurring in the US GoM OCS, they were in the process of perforating the well when the incident occurred. Two of them resulted in a *well release* and the third in a *blowout (surface flow).* This third one was the Walter Oil & Gas blowout on Hercules 265 that occurred in 2013.

For the five UK and Norwegian incidents a variety of operations were going on.

## 8.2 COMPLETION LOWC CAUSES

This section focuses on the causes of the workover LOWC events. Since two barriers normally should be present during completion activities, this section is focused on the causes of losing the primary barrier and the secondary barriers. The primary barrier in completion operations is normally the hydrostatic control of the well. It may in some cases be a mechanical barrier, depending on how the completion is carried out and the progress of the completion operation. For all the completion LOWC events observed from 2000 to 2015, the primary barrier was the hydrostatic control of the well.

### *8.2.1 LOSS OF THE PRIMARY AND SECONDARY BARRIERS*

When the primary barrier is lost during completion, a well kick results. As for drilling incidents, it is important to detect the well kick as soon as possible in order to close in the well with a minimum influx. If the secondary barrier fails to activate, or activates late, a completion LOWC event will occur.

Table 8.4 lists the experienced primary and secondary barrier failure causes for the kicks resulting in LOWC events for US GoM OCS and regulated areas (Norway, UK, the Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark, and Brazil).

*Table 8.4 Primary and secondary barrier failure causes for completion LOWC events in the US GoM OCS and the regulated areas.*

| **Primary barrier failure** | | **Secondary barrier failure** | **LOWC Id** | **No. of LOWCs** |
|---|---|---|---|---|
| **Blowout (surface flow)** | | | | |
| Too low hyd. head | Too low mud weight | Failed to close BOP | 632 | 1 |
| | Unknown why | | 569 | 1 |
| **Total** | | | | 2 |
| **Diverted well release** | | | | |
| Too low hyd. head - trapped gas | | Failed to close BOP | 607 | 1 |
| **Total** | | | | 1 |
| **Well release** | | | | |
| Too low hyd. head | Annular losses | Failed to stab Kelly valve | 573 | 1 |
| | Unknown why | Failed to close BOP | 568 | 1 |
| | Swabbing | String safety valve failed | 470 | 1 |
| | | Failed to close BOP | 501 | 1 |
| Packer plug failure | | Failed to close BOP | 614 | 1 |
| **Total** | | | | 5 |
| **Total all** | | | | 8 |

The individual LOWC events are commented a bit further down. Here some overall findings are discussed.

Two *blowout (surface flow)* incidents were observed during completions. One occurred in the UK (ID 569) while the other was the Walter Oil & Gas blowout on Hercules 265 in 2013 (ID 632). For both these events, the BOP failed to close. For the Walter incident, the flow through the BOP became too high before the BOP was activated. The BOP would not close against the flow. For the UK incident, the drill pipe was pushed out of the hole by well pressure, causing it to buckle and split above the drill floor. Drilling fluid was released from the split drill pipe. The driller then activated the shear rams but they failed to shear the pipe and the flow from the drill pipe, although reduced, continued.

For the *diverted well release,* the BOP was closed late and gas entered the riser. The riser was then diverted.

For three of the *well release* incidents, they observed the kick late. One kicked through the drill pipe and they failed to stab the kelly valve before they closed the blind ram. For two incidents the BOP was closed late due to the late kick observation.

For one *well release,* the screens were across the BOP when the well kicked. It took some time until they had dropped the screens and could close the BOP. For the last *well release,* the kelly was opened with pressure below it. Some gas was released before the well was closed in.

### *8.2.2 BRIEF LOWC DESCRIPTIONS*

**Blowout (surface flow)**

1. (ID 632) The well had recently been perforated. After tripping out of the hole for approximately 4.5 hours, the well suddenly began flowing. The pressure built up rapidly and because mud discharge at the end of the work string, and high flowing pressure, the safety valve could not set. Attempts to control the well by closing the BOP annular from the rig-floor failed due to the annular flow. Minutes later, attempts to activate the BOP pipe rams and blind shear rams from a remote station failed as well. As a result, the well flowed uncontrolled at rates estimated to be up to 400 million cubic feet of natural gas per day for three days before bridging. The flow of gas ignited after 13 hours and the fire destroyed the platform and production equipment, and damaged the MODU. The uncontrolled well required the drilling of a depletion-relief well to regain complete control.
2. (ID 569) During completion operations, the lower completion sand screens had been run and set. Cleaning of the subsea wellhead was in progress when the driller noticed a large increase in flow from the well and closed the BOP pipe rams. Drill pipe was pushed out of the hole by well pressure and causing it to buckle and split above the drill floor. Drilling fluid was released from the split drill pipe. The driller then activated the shear rams but the pipe failed to shear and the flow from the drill pipe, although reduced, continued.

**Diverted well release**

3. (ID 607) For the *diverted well release*, they had just perforated and reverse circulated the well. They then observed a 10 barrel kick in the pits. The subsea BOP was closed too late and the well continued to flow after the BOP was closed due to gas in the riser. The master rotary bushing was blown out of the rotary table onto its side on the rig floor. The well was then put on the diverter. They failed to observe kick before it was in the riser.

**Well releases**.

4. (ID 573) The well was an ESP (Electrical Submersible Pump) Producer. Completion tubular were being pulled from the well, with 300 ft. remaining. The well was losing approximately 20 bbls per hour of 10.5 ppg. brine. Having laid down a joint, flow of crude/calcium chloride brine started from the tubing and an attempt to stab a safety valve by the rig crew was made but increasing flow prevented this. The BOP blind/shear rams were then closed to secure the well.
5. (ID 568) The kick was observed late. They were in the process of running a dual string. They used time to drop the string before closing the blind shear ram. In this period, gas was released at the surface.
6. (ID 470) The kelly valve was opened without any evaluation of the situation. Total estimated volume of gas released was 10 to 20 Sm3 before the well was closed in again.
7. (ID 501) Screens were across the BOPs when the kick was observed. BOPs were closed after the screens were dropped in the well and the flow stopped.
8. (ID 614) The formation isolation valve was set and tested. Thereafter the well was displaced and the mud returns were pumped directly to the reserve pits where they could not be measured. When reducing the pump rate the well started to unload mud to the drill floor. At this point, the well was closed with the BOP. This incident has similarities with the Deepwater Horizon accident, but here they managed to close the BOP after some release.

## 8.3 Human Errors in Completion LOWC Events

The human role is considered important in the occurrence and development of LOWC events. Human errors are believed to have contributed to many of the incidents without being explicitly stated in the information source. The skill of the personnel and proper procedures and practices will always be important.

Of the eight completion LOWC events in the US GoM OCS and the regulated areas, human errors have been investigated. Table 8.5 shows the human errors involved in completion LOWC events, alongside the time from the kick is observed until the fluids are flowing from the well. It has also been noted if the well was controlled by a hydrostatic pressure (killed), or if the well was live when the LOWC events occurred.

*Table 8.5 Human errors in completion LOWC events (2000–2015, US GoM OCS and the regulated areas)*

| LOWC ID | Well Status | Time from kick to event | Human Error |
|---|---|---|---|
| ***Blowout (surface flow)*** | | | |
| 632 | Killed | 0 | 1. Observed kick late.<br>2. Did not consider heating effect of water based mud, reducing density and causing kick. |
| 569 | Killed | 0 | Drilling fluid was pumped overboard from the well bypassing on board fluid level monitoring equipment while the well was open to the reservoir. Therefore the kick was observed late |
| ***Diverted well release*** | | | |
| 607 | Killed | 0 | Failed to observe kick before it was in the riser |
| ***Well release*** | | | |
| 573 | Killed | 0 | Observed kick late. |
| 568 | Killed | Short/zero | Realized late that the well was flowing |
| 470 | Killed | 0 | The kelly cock was opened without any evaluation of the situation. Indirect causes: Wrong interpretation of signals from the well. Forgot to open the kelly cock. Not a proper handover during crew change |
| 501 | Killed | Unknown | Unknown |
| 614 | Killed | 0 | During the cleanup and displacement, mud returns were routed to the reserve pits. As a result, volumes could not be monitored on the active pit system. There were indications of an increase in flow out in the rate of mud returns to the pit room during displacement, but this was expected due to the increased pump rate. After ten minutes at a higher pump rate, the rate was reduced to allow the pit room to resolve the increasing flow issues. At this point, the well began to flow, unloading mud onto the drill floor. |

All the completion LOWC events occurred in killed wells. For the majority of these LOWC events the kicks were not observed before the well was flowing to the surroundings.

Human errors were identified in seven of the eight completion LOWC events.

Typically, the human errors were related to poor planning of the operations, lack of attention, or that the possible risks had not been properly considered.

Keeping control of the fluid coming out of the well vs. the fluid pumped in is utmost important in kick detection. For ID 569 and ID 614 they had no ability to control of the volume coming out of the well, similar to the Deepwater Horizon incident.

## 8.4 Equipment Failures in Completion LOWC Events

Table 8.6 shows the equipment failures in completion LOWC events.

*Table 8.6 Equipment failures in completion LOWC events (2000–2015, US GoM OCS and the regulated areas)*

| LOWC Id | Well Status | Secondary barrier failure | Equipment failure |
|---|---|---|---|
| **Blowout (surface flow)** | | | |
| 632 | Killed | Failed to close BOP | No (BOPs are not designed to close when the well is flowing) |
| 569 | Killed | Failed to close BOP | Blind shear ram failed to shear pipe |
| **Diverted well release** | | | |
| 607 | Killed | Failed to close BOP | No (closed late) |
| **Well release** | | | |
| 573 | Killed | Failed to stab Kelly valve | No |
| 568 | Killed | Failed to close BOP | No (closed late) |
| 470 | Killed | String safety valve failed | No (opened valve with pressure below) |
| 501 | Killed | Failed to close BOP | No (screen were across the BOP, had to be dropped before closing BOP) |
| 614 | Killed | Failed to close BOP | BOP closed late, downhole isolation packer and formation isolation valve (FIV) failed, causing the kick |

There are few equipment failures observed in completion activities. This is likely because the equipment in the wells during completions is new equipment. The failure of the secondary barrier is typically caused by late detection and not the equipment that is failing. The exceptions are the blind shear ram that failed to shear the tubing (Id 569) and the incident where the formation isolation valve failed. This valve was inflow tested just before the incident.

# 9 PRODUCTION LOWC EVENTS

Production blowouts occur from production or injection wells, which may be in service (producing/injecting) or closed in by mechanical well barriers.

For a blowout to occur in a production well, at least one primary and one secondary barrier have to fail. During production both the *primary and secondary barriers are mechanical barriers.* In a *flowing* well, the barriers closest to the reservoir are usually regarded as the primary barrier. This would typically be the packer that seals off the annulus, the tubing below the SCSSV, and the SCSSV. The secondary barriers would then be the tubing above the SCSSV, the Xmas tree main flow side, the casing/wellhead, and the annulus side of the Xmas tree.

## 9.1 PRODUCTION LOWC EXPERIENCE

The SINTEF Offshore Blowout Database includes 26 LOWC incidents from 2000 - 2015 during the production phase. Twelve of these stems from the US GoM OCS and three from UK. Further, six of the events stems from the US GoM state water.

Out of these 26 LOWC incidents, external load "caused" 12. The most typical external loads are storm, fires and ship collisions.

External loads did not cause blowouts for the other operational phases (drilling, completion, workover, and wireline) in the US GoM OCS and the North Sea for the stated period. The remaining 14 production blowouts originated from "normal" causes.

Table 9.1 shows an overview of when and where the production blowouts have been experienced in the period 2000 – 2015.

*Table 9.1 When and where the production blowouts have been experienced (2000–2015)*

| Incident year | Country | No external cause | External cause | Total |
|---|---|---|---|---|
| 2000 | US GoM state waters | 1 | 1 | 2 |
| 2002 | Saudi Arabia | | 1 | 1 |
| | US GoM OCS | 1 | 1 | 2 |
| 2003 | US GoM OCS | 1 | | 1 |
| 2004 | US GoM OCS | | 1 | 1 |
| 2007 | Mexico | | 1 | 1 |
| | Uk | 1 | | 1 |
| | US GoM state waters | | 1 | 1 |
| | US GoM OCS | 1 | | 1 |
| 2008 | Azerbaijan | 1 | | 1 |
| | Uk | 1 | | 1 |
| | US GoM state waters | | 1 | 1 |
| | US GoM OCS | 1 | 1 | 2 |
| 2009 | US GoM OCS | | 1 | 1 |
| 2010 | US GoM state waters | | 1 | 1 |
| | US GoM OCS | 1 | | 1 |
| 2011 | China | 1 | | 1 |
| | US GoM OCS | 1 | | 1 |
| 2013 | Uk | 1 | | 1 |
| 2015 | Azerbaijan | | 1 | 1 |
| | US GoM state waters | 1 | | 1 |
| | US GoM OCS | 1 | 1 | 2 |
| Total | | 14 | 12 | 26 |

### 9.1.1 PRODUCTION LOWCS WITH EXTERNAL CAUSES

An external cause normally only damages the topside barrier. For a *blowout (surface flow)* to occur, the downhole barrier also has to fail. Consequently, an external cause will not be the single blowout cause, except for wells that are not equipped with a downhole safety valve. Typically, the external force damages the wellhead/X-mas tree barriers of an active well, and the downhole barrier fails to activate, leaks, or are not installed in the first place, causing the blowout.

Table 9.2 shows the installation type and external cause for world-wide production LOWC events (2000–2015).

*Table 9.2 Installation type and external cause for production LOWC events experienced world-wide (2000–2015)*

| Main Category | Installation type | External object | Fire/-explosion | Ship collision | Storm | Total |
|---|---|---|---|---|---|---|
| Blowout (surface flow) | Jacket | 2 | 1 | 1 | 4 | 8 |
| | Satellite | | | 3 | | 3 |
| | Unknown | | | 1 | | 1 |
| | Total | 2 | 1 | 5 | 4 | 12 |

All the 12 LOWCs that were caused by an external cause resulted in a *blowout (surface flow)*. The incidents caused by a ship collision normally occur in shallow waters.

Table 9.3 shows a brief overview of production LOWCs caused by an external force.

*Table 9.3 Overview of production blowouts caused by external force worldwide (2000 – 2015).*

| LOWC id | Year | Country | Water Depth (m) | External Cause | Description | Poll-ution | Spill volume | Duration | **Fatalitie** |
|---|---|---|---|---|---|---|---|---|---|
| 563 | 2000 | US GoM State waters | <50 | Ship collision | Unidentified vessel struck well | Small | Totally around 20 bbls were spilled. Small amount on sea surface. Not recoverable | 6 hours | 0 |
| 517 | 2002 | US GoM OCS | <50 | Storm | Hurricane damage bent wellhead 15 degrees | Medium | An estimated 350 barrels of crude oil was released, creating a dark brown slick 6 miles long by 50 yards wide. Recovered 145 barrels of the crude oil spilled. The estimated unrecovered oil released was 205 barrels. | 2 days | 0 |
| 511 | 2002 | Saudi Arabia | <50 | External object | Jack-up rig leg collapsed and fell over a well | Large | Massive oil spill reported | Un-known | 3 |
| 646 | 2004 | US GoM OCS | 100 - 200 | Storm/-mudslide | Platform destroyed by an underwater mudslide triggered by Hurricane Ivan and toppled the platform. | Large | In 2014 the daily volume of oil discharging fluctuated between a low of less than one barrel of oil to a high of 55 barrels. Average daily oil volume on the sea surface over seven months were over 2 barrels | More than 10 years still ongoing | 0 |
| 561 | 2007 | US GoM State waters | <50 | Ship collision | Unidentified vessel struck well | Large | More than 7000 bbls of waxy condensate crude oil with an API of 35 | 4 days | 0 |
| 567 | 2007 | Mexico | <50 | External object | Storm caused oscillating movements in the jack-up. The cantilever of the unit damaged part of well assembly on the fixed platform. The X-mas tree was torn off the wellhead. | Large | 69 m3 a/day for 54 days = 3700 m3 (24 000 bbls) | 54 days | 23 died, life craft being capsized by adverse weather |
| 588 | 2008 | US GoM State waters | **<50** | Ship collision | Unidentified vessel struck well | Medium | 3000 gallons of oil, plus gas | 28 days | 0 |
| 592 | 2008 | US GoM OCS | <50 | Storm | Damaged by Hurricane Ike in September 2008 | No | Gas leak | 12 hours | 0 |
| 594 | 2009 | US GoM OCS | 50 - 100 | Storm | Failed during Hurricane Ike in September 2008 | No | 2.44 bbl. of condensate over a 7 days' period. 50 feet diameter plume of bubbling gas at the surface of the water | 6 days | 0 |
| 615 | 2010 | US GoM State waters | <50 | Ship collision | Struck by a tug boat | Medium | At a 33 bbl./day rate, nearly 100 bbl. of oil would have been released into the environment after three days. Field observers suggest such a volume is consistent with the oil seen during overflights. | 6 days | 0 |
| 648 | 2015 | US GoM OCS | <50 | Ship collision | Platform hit by ship | Small | Minor sheening and gas bubbling. | 50 days | 0 |
| 669 | 2015 | Azer-baijan | 50 - 100 | Fire/-explosion | Platform was damaged due a fire caused by a damaged subsea gas pipeline | Un-known | Oil and gas was blowing initially. The oil seems to have burned up. Only gas was flowing after the fire was put out | 70 days | 32, life boat fell from platform to the sea. Damaged after hitting piles of the platform |

Four of the five incidents that occurred in the US GoM OCS were caused by damages from hurricanes. The last one, that occurred in 15 meters of water, were caused by a boat collision. One US GoM OCS incident from 2004 is still not under control. The hurricane is believed to cause an underwater land slide that toppled the platform, and broke all the conductors. It is unknown how many of the 24 wells that developed a leak. The cumulative amount of oil released is high, even if the daily rate in 2014 was claimed to be only 2 barrels in average. Some sources claim that more than a million gallons (24,000 barrels) of oil has been released over a 12-year period. For another US GoM OCS incident, 350 barrels of oil was released during a two-day blowout. For the remaining three US GoM OCS incidents the oil spills were limited.

Four external cause LOWC incidents occurred in the US GoM State waters. All incidents were caused by a boat collision. For three of them the boats were not been identified. Typical for these incidents are that the wells are close to land and marshlands. Relatively small amounts of oil will cause damage to the environment and wild life. For one of these incident 7,000 barrels of oil was spilled. Two of the spills were around 100 barrels, and one was reported with minor sheening and gas bubbles. It is suspected that for some of these wells the well did not include a DHSV, i.e. a single barrier situation.

The three remaining incidents occurred in Saudi Arabia in 2002, Mexico in 2007, and in Azerbaijan in 2015. The Saudi Arabian incident occurred when a jack-up collapsed and the jack-up fell over a well and damaged the X-mas tree. The Mexican incident occurred during a severe storm. The storm caused a jack-up rig to oscillate when drilling a development well. The movement of the jack-up rig caused that the X-mas tree of the neighbor well was stricken and damaged, and started to leak. For the Azerbaijan incident, a gas pipeline developed a leak just below an installation due to a storm. The gas ignited and the fire destroyed the integrity of the platform located X-mas trees. Multiple wells were blowing out.

All these three incidents caused multiple fatalities. For the Mexico and Azerbaijan LOWC event in total 55 persons died. For both these accidents the personnel died in association with the evacuation. For the Saudi Arabian LOWC event three persons died for unknown reasons.

All these incidents released oil. For the Azerbaijan incident, it seems that the majority of oil burned initially, what happened later with respect to oil spill is not reported. For the Saudi Arabian incident, a massive oil spill was reported. The Mexican well spilled 69 m3 a/day for 54 days, in total 3700 m3 or 24 000 bbls. The oil was reported to pollute beaches.

It is suspected that a DHSV was not installed in any of these three LOWC.

#### *9.1.2 PRODUCTION LOWCS WITH "NORMAL" CAUSES*

Table 9.4 shows the main category and the installation type for the 14 worldwide production LOWC events not caused by an external force world-wide (2000–2015).

*Table 9.4 Installation type and external cause for production LOWC events experienced world-wide (2000–2015)*

| Main Category | Installation type | No external cause |
|---|---|---|
| Blowout (surface flow) | Jacket | 5 |
| | Unknown | 2 |
| Well release | Jacket | 5 |
| | Subsea prod | 2 |
| Total | | 14 |

Table 9.5 shows a brief overview of production LOWCs not caused by an external force.

*Table 9.5 Production LOWC events experienced for various installation vs. main well type worldwide (2000–2015)*

| Id | Year | Country | Main category | Water depth grouped (m) | Loss of primary barrier | Loss of secondary barrier | Poll-ution | Spill volume | Duration |
|---|---|---|---|---|---|---|---|---|---|
| 560 | 2000 | US GoM state water | Blowout (surface flow) | Unknown | Unknown | Unknown | Large (because close to shore) | Oil and sheen east of the facility, approx. 70 bbl were observed on the sea surface. Marshes near the blow-out site were impacted to a much greater extent. An estimated 100 x 150 yds. of marsh were heavily oiled. | Unknown |
| 519 | 2002 | US GoM OCS | Blowout (surface flow) | 1) <50 | SCSSV/storm choke failure (ESD failed to activate) | X-mas tree failure | Small | Approximately 21 gallons of condensate. A barely visible sheen on the water. | 12 hours |
| 521 | 2003 | US GoM OCS | Well release | 2) 50 - 100 | SCSSV/storm choke failure (closed late) | X-mas tree failure | Small | Approximately one gallon of condensate. Mostly gas was released | 6 hours |
| 577 | 2007 | US GoM OCS | Blowout (surface flow) | 1) <50 | Tubing leakage | Inner casing failed, fracture at csg shoe | Small | Only gas | 79 days |
| 596 | 2007 | Uk | Well release | 1) <50 | SCSSV/storm choke failure (closed late) | Unknown | No | Gas | Unknown |
| 578 | 2008 | US GoM OCS | Blowout (surface flow) | 1) <50 | SCSSV/storm choke failure | X-mas tree failure | No | Gas | 3 days |
| 617 | 2008 | Azerbaijan | Blowout (surface flow) | 3) 100 - 200 | Poor cement | Flow outside casing | No | Gas | 20 days |
| 653 | 2008 | Uk | Well release | 3) 100 - 200 | Unknown | Wellhead failed | Small | Only *some* oil went to sea, of the 20 tons released (140 barrels) | 10 hours |
| 612 | 2010 | US GoM OCS | Well release | 2) 50 - 100 | SCSSV/storm choke failure | X-mas tree failure | No | Gas only, unknown rate | 6 mins |
| 624 | 2011 | US GoM OCS | Well release | 4) 200 - 400 | SCSSV/storm choke failure | X-mas tree failure | Small | Leakage lasted likely 4-6 days. Sheen approx. 1/2 mile long by 100 yards. Spill amount calculated as 1 gallon | Unknown |
| 649 | 2011 | China | Blowout (surface flow) | 1) <50 | Formation breakdown | Formation breakdown | Medium | Event resulted in the release of approximately 113 barrels (18cubic meters) of crude oil. | 17 days |
| 652 | 2013 | Uk | Well release | 1) <50 | SCSSV failure (closed late when observed leak) | X-mas tree failed | No | Only gas, leaked for one hour and 18 minutes | 1.3 hours |
| 647 | 2015 | US GoM state water | Blowout (surface flow) | Unknown | Unknown | Casing leakage | Small | 37 gallons | Unknown |
| 672 | 2015 | US GoM OCS | Well release | 2) 50 - 100 | Tubing plug and tubing leakage | Inner and outer casing failed | Small | Estimated 0.67 gallons of oil leaked into the waters | Unknown |

Seven of the 12 LOWC events have been categorized as a *blowout (surface flow)*, while the remaining five have been categorized as a *well release*.

Seven of the incidents (three *blowout (surface flow)* and four *well releases*) stems from the US GoM OCS. Three *well releases* stems from the UK, two *blowout (surface flow)* stems from US GoM state waters, one from China, and one from Azerbaijan.

For the majority of LOWCs firstly there is a surface leak in the X-mas tree, and then the SCSSV fails to close. For others, tubing leaks, casing leaks, multiple casing leaks, and formation breakdown were observed.

None of these incidents caused fatalities and none of them ignited. Some of the incidents caused release of oil to the sea. The worst one seems to have been an incident in US GoM State waters in 2000, where the Marshes near the blow-out site were impacted. There were also a couple of other LOWC incidents where 100 - 200 barrels were released to the sea.

### *9.1.3 PRODUCTION LOWC TRENDS*

Figure 9.1 shows the annual production LOWC frequency per well year in service (injectors and producers) and the associated regression lines for production LOWC events from 2000–2015, when including the external cause LOWCs.

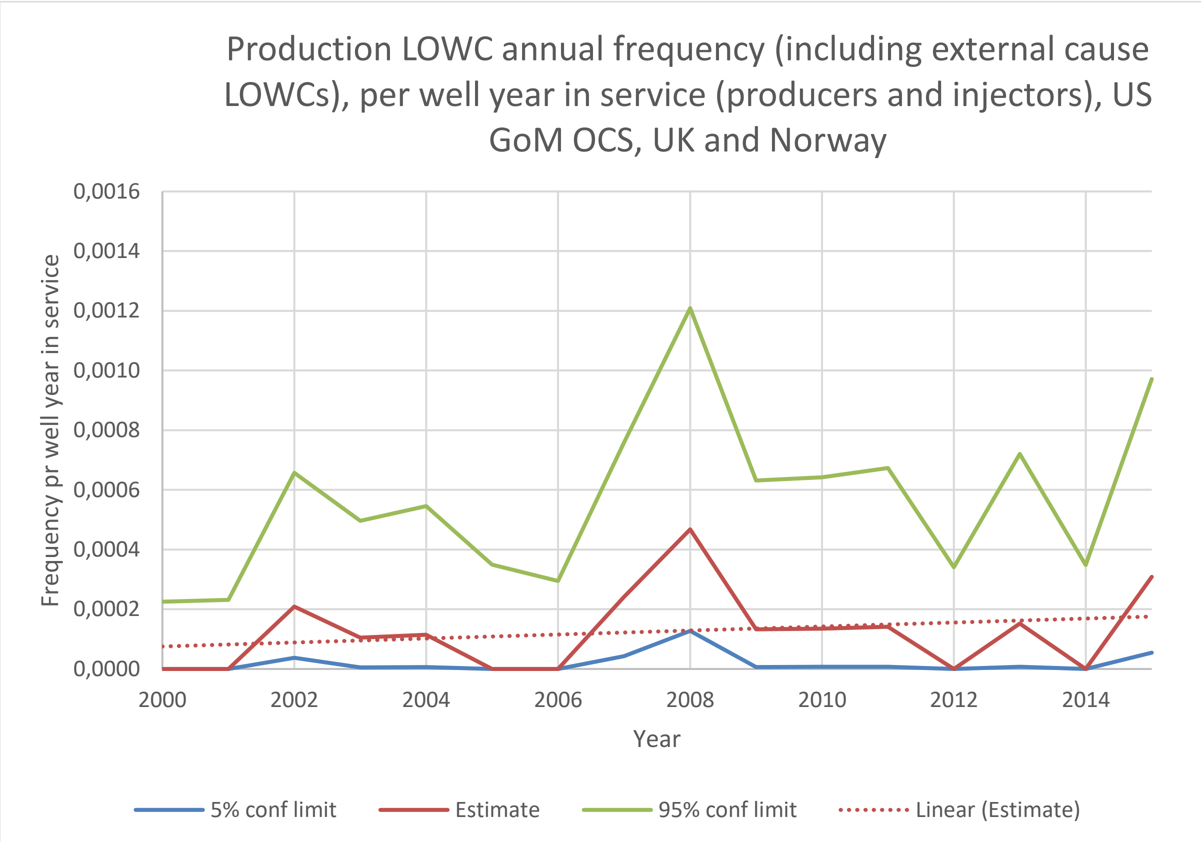


*Figure 9.1 Annual frequency for production LOWC events and the trend line, US GoM OCS, UK and Norway, 2000 – 2015, including the external causes LOWCs*

Figure 9.2 shows the annual production LOWC frequency per well year in service (injectors and producers) and the associated regression lines for production LOWC events from 2000–2015, when <u>not</u> including the external causes LOWCs.

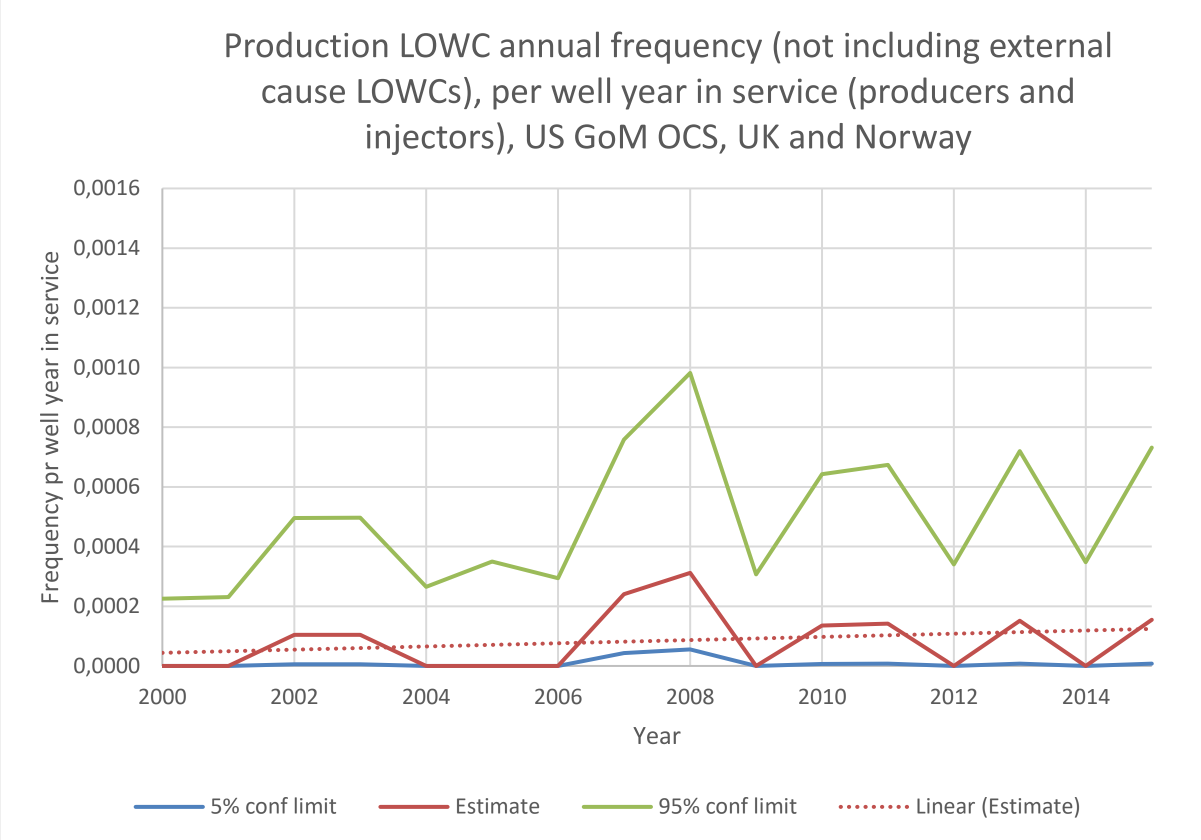


*Figure 9.2 Annual frequency for production LOWC events and the trend line, US GoM OCS, UK and Norway, 2000 – 2015, including the external causes LOWCs*

Figure 9.1 and Figure 9.2 shows that there are variations from year to year. The trend lines indicate an increasing LOWC incident frequency for both the figures, but it cannot be concluded that there is any statistical significant trend.

#### *9.1.4 BRIEF LOWC DESCRIPTIONS*

## LOWC events with external causes

**Blowout (surface flow)**

1. (ID 563) An unknown vessel collided with a production platform. One of the platform's wells was damaged when it flowed oil, water, and gas into the Gulf of Mexico. Primary indications were that a shipping vessel damaged the well X-mas tree (producing 35 b/d), causing a flow of fluid to flow into the sea. Oil was free flowing as a 20' gusher. The well bridged over after six hours and was later capped and brought under control. The remainder of the field was unaffected. Damage to the wellhead was minimal. Throughout the day, overflights reported seeing mostly sheens. Light sheens were reported to make land-fall in marshes. Several patches of recoverable oil were identified south of the release in a convergence area; skimmers were directed to this area. Total recoverable oil as reported by USCG observers was only 60 gallons.

2. (ID 517) The uncontrolled flow from Well No. 14 was caused by hurricane damage that decapitated the well and bent the wellhead at 15 degrees. The loss of the wellhead caused differential flow across the storm choke. The storm choke failed to contain the pressure over time and was at some point released from its settings and ejected from the wellhead. While the mechanism that caused the choke to fail is not known, the most likely explanation is that the slips of the choke were cut by grit carried by seepage around the choke body, ultimately releasing the choke and allowing the well to flow uncontrolled. An estimated 350 barrels of crude oil was released, creating a dark brown slick 6 miles long by 50 yards wide. A Fast Response Unit was dispatched which recovered approximately 145 barrels of the crude oil spilled. The estimated volume of unrecovered oil released is 205 barrels.
3. (ID 511) Arabian Drilling Company's independent leg jack-up rig Arabdrill 19, collapsed and sank offshore Saudi Arabia following an accident that occurred as the rig was being positioned over a Khafji field producing well. Sources at the scene said "the rig fell when one leg buckled". When the rig collapsed the production tree was sheared, resulting in a blowout that ultimately sank the rig. The operator mobilized the Arabdrill 17 to drill a relief. Several crewmen were injured but there were no fatalities. Another source reports that the accident caused 3 fatalities and several injuries (unknown how many). Extensive efforts were initiated to contain the massive oil spill and prevent a huge ecological disaster in the region, since the damaged well heads were leaking oil, gas and H2S.
4. (ID 646) It seems Hurricane Ivan created waves that triggered an underwater mudslide and toppled Taylor's platform. The rig stood roughly 10 miles off Louisiana's coast in approximately 475 feet of water, and buried its cluster of 28 wells under mounds of sediment. It may seem that the leak rate has gradually increased since 2004. The multi-agency effort has worked continuously to prevent and control the discharge, improve the effectiveness of containment around the leaking oil, and mitigate environmental impacts. Platform deck and subsea debris has been removed. Nine of the 25 impacted wells have been intervened. In 2014 the daily volume of oil discharging from the MC-20 site has fluctuated between a low of less than one barrel of oil to a high of 55 barrels. The average reported daily oil volume on the sea surface over the past seven months has been over 2 barrels.
5. (ID 561) An unidentified vessel hit a wellhead of a newly completes well and damaged it. The well was yet not in production. Crude oil leaked out in the Bayou Perot. More than 7,000 bbls of waxy condensate crude oil with an API of 35 was released. 3,200 feet of oil containment boom was deployed to prevent the oil from spreading. The winds pushed the oil along the western shore of Bayou Perot into the bayou, creating large areas of silver to rainbow sheens and areas of yellow oil that have escaped the containment boom placed along the shoreline. Most of the oil stranded on mudflats and in shallow canals with little or no water. It seems likely that the well was completed without a SCSSV.
6. (ID 567) The incident occurred on a 3 well jacket. Well Kab 101 and Kab 121 were producing while well Kab 103 were being perforated by the jack-up rig Usumacinta. Around noon adverse meteorological conditions with gusts of wind up to 130 km/hr and waves of 6 to 8 meters, which caused oscillating movements in the Usumacinta jack-up drilling rig that resulted in the cantilever of the unit striking part of well assembly on the fixed platform Kab 101, resulting in an escape of oil and gas from the well Kab 123. The X-mas tree was torn off the wellhead. Evacuation procedures activated, involving life rafts and support of the stand-by vessel the Morrison Tide. The extremely adverse weather prevented the crews being rescued from life craft and the use of helicopters. In total 23

persons died because a life craft being capsized by adverse weather. The flow was mainly gas and approximately 430 bbls of oil per day. In none of the articles and Pemex press release reviewed has a Down hole safety valve been mentioned. This may indicate that the well did not have a DHSV. The blowout ignited 22 days after it occurred, probably from a spark generated by the well control operation. The fire was extinguished the day after. The blowout reignited 10 days later. They removed some the drillfloor and derrick on the jack-up to get better access for well control and then they also were able to control the fire. The well was finally capped after 54 days. Oil had polluted the beaches.

7. (ID 588) An unidentified vessel struck and oil well. After the incident, the well's guard structure was missing, and the wellhead was submerged below the waterline. The Coast Guard reported that "initial investigators observed oil and natural gas bubbling 10 feet into the air, and nearly 3,000 gallons of crude oil flowed into the Grand Bayou Blue, which feeds into the Bayou Lafourche.

   The Louisiana Department of Natural Resources inspected the well the day after the incident and found that the well was deficient, noting that the "well had no storm choke" and "no nav-aid lights."

   There was used more than 3,300-feet of containment boom. Cleanup costs totaled $ 2.5 million.

   Well was plugged with three cement plugs after 28 days.

8. (ID 592) The platform had been shut down because of hurricane Ike. The platform was in the process of returning to production. Upon opening the SCSSVs, gas leaks were detected from Wells G-1, G-3 and G-4. The leaks occurred from two locations on the wellheads, including: the flange connection located immediately above the tubing head and the flange connection just above the wellhead spacer piece.

   The operator closed the SCSSVs to control the gas leaks. Well G-4's SCSSV would not fully close/seal. Thus, gas leaked uncontrolled from Well G-4's tree flange connection located immediately above the tubing head bonnet that was damaged by the hurricane.

   Gas flowed/escaped through the loose mating surfaces of the ring gaskets and grooves. Well G-4 was then opened to the flare to minimize the gas leakage. The tubing pressure dropped to about 50 psi. After several hours of flowing the G-4 well to the flare, it's SCSSV fully closed/sealed.

   On the following day, successful repair procedures were initiated on the wellheads. Hurricane Ike forces acted on the wellhead flange studs, causing the studs to stretch beyond their elastic limit. This resulted in loss of seal integrity of the tree flange connections. All leaks were repaired by changing out the studs, nuts, and ring gaskets on wells G-1, G-3, and G-4.

9. (ID 594) The C platform had been toppled during hurricane Ike. The wells were found to be bent over or "kinked" at approximately 30' above the seafloor.

   A 50' diameter plume of bubbling gas was observed at the surface of the water above the toppled platform. Some condensate was also released. The wells' conductors bend downward from horizontal at an angle of about 20 degrees and the well heads were found in an accessible location about 10' - 15' above the seafloor.

   The wellheads of C-9 was found to be sheared off in the bodies of the master valves immediately above the tubing head flange where the release of condensate and gas occurred from. The SCSSV that was successfully tested with a report of zero leakage in 3 months earlier.

One theory was that the control line had been squeezed and opened the SCSSV.

The well was secured after six days by removing the sheared off master valve and then replacing the broken valve with a new valve assembly.

10. (ID 615) A tug boat struck the wellhead. Escaping oil and gas in the form of an orange and brown mist was reaching up to 100 feet in the air. This well was close to important marshes in the Barataria Bay area,

    Heavy drilling fluids was pumped into the wellbore to stop the flow of hydrocarbons from the well. Then a new valve was installed on top of the wellhead to permanently seal it. The blowout lasted for 6 days.

    60,200 feet of containment boom and 14,080 feet of sorbent boom was used in an effort to corral the oil spill. Additionally, 213 personnel and 47 oil skimmers, boats and barges were also used.

11. (ID 648) An offshore supply vessel struck an unmanned production platform located at South Timbalier 27 IA. Ninety percent of the structure was destroyed because of the collision and subsequent fire.

    Three vessels in the area responded and assisted in extinguishing the fire. Prior to the accident there were three producing gas lift wells on the structure, with an average total daily production of 92 barrels of oil, 93 barrels of water, and 115 million cubic feet of gas per day.

    During the first 1-2 weeks, immediately following the accident, inspectors routinely flew over the site to monitor minor sheening and gas bubbling. The wells were secured after 50 days.

12. (ID 669) A fire broke out in the northern part of platform No. 10 at the western section of the Gunashli oilfield in Azerbaijan, operated by SOCAR. The fire started when a high-pressure subsea gas pipeline was damaged in a heavy storm. Because of the fire, the platform, which had been in service since 1984, partially collapsed. Fire spread to several oil and gas wells. Production at all 28 wells (24 oil wells and 4 gas wells) connected to the platform was suspended, pipelines connecting the platform to the shore were closed, and electricity to the platform was cut off. Before the accident, the platform produced 920 tons (6,000- 7,000 barrels) of oil and 1.08 million cubic meters (38 million cubic feet) of gas per day. About 60% of the oil produced by SOCAR was transported through this platform. At the time of the accident, 63 workers were on the platform.

    People went missing when a life boat with 34 people on board fell from the platform into the sea and was damaged after hitting piles of the platform. The oil fires at the well were put out after 14 days, but the gas wells continue to burn. The fire ceased in mid-February 2016. The platform was a total loss. The platform was renovated and production restarted in July 2016.

## LOWC events with no external causes

### Blowout (surface flow)

1. (ID 560) A fisherman reported a 20' gusher of oil from the Bay DeChene Oil and Gas Field. The USCG was notified and NOAA was asked to provide technical support. At first light,

A USCG overflight observed oil and sheen east of the facility and estimated that approximately 70 bbl. were observed (much less than initially predicted). The facility was shut in by the operator. Most of the oiling was reported as sheens, but marshes near the blow-out site, were impacted to a much greater extent.

2. (ID 519) A Platform Operator was flying to Ship Shoal Block 239, Platform A, when he spotted a watery spray blowing up from the platform. They then flew to Ship Shoal Block 233. He then took a boat to Ship Shoal Block 239, Platform A. When arriving, he activated the ESD station. and thereby closed the SCSSV in Well A-12. Then he closed the manual master valve. The well had produced approximately 12 hours open to the atmosphere. Approximately 21 gallons of condensate were released during the incident which produced a barely visible sheen on the water. The ESD control system was later tested. It was found that the needle valve for the flowline sensing line was stopped up with sand and a small piece of metal. It was also found that the final relay in the TSE logic in the panel was stuck. This malfunctioning relay is what caused the TSE loop to not close the SCSSV.

3. (ID 577) An operator representative reported gas leaking at the mud line at Main Pass, Block 91, Platform A (MP 91A). No pollution was visible. It was determined the source of the gas was Well A-1. The well had a leak in the tubing for a long period. The annulus pressure was 23% of the minimum internal yield pressure of the 9 5/8-inch production casing. The casing pressure breached the production casing, the pressure was more than sufficient to break down the shoe of the 16-inch surface casing. It is not known how, where or why the failure occurred in the 9 5/8-inch production casing.

   Numerous attempts were made to kill the well without success. Before they had managed to kill the well a storm came and the platform was evacuated. The platform structure was found toppled/sunk while returning from storm evacuation.

   Then a relief well was drilled intersecting the well bore. The well was killed with 525 bbls of mud and abandoned with 203 bbls of cement 79 days after the blowout occurred.

   The evidence does not provide the necessary information to indicate definitely how or why failure occurred, however, had the casing pressure been reported as necessary, timely intervention measures may have prevented the loss of well control.

4. (ID 578) A contract wireline company was performing routine scaling operations on the well to repair a leaking surface controlled subsurface safety valve (SCSSV). The operator decided to perform an acid job to reduce the amount of scale around the SCSSV after several attempts to remove the scale with a wireline unit were not successful. The personnel pumped approximately 100 gallons of 1 percent hydrochloric acid (HCL) into the well and allowed it to soak overnight. The day after the acid job the personnel re-entered the well to perform more scraping. A seal ring on the bottom flange below the master valve began to leak and dry gas was released into the atmosphere.

   Since the SCSSV was not operable and the leak was below the master valve, the operator was not able to prevent the escape of natural gas. The platform was evacuated shortly after the event. The well was secured three days later by installing a back-pressure valve in the tree and replacing the ring gasket.

   The incident was caused by a leaking SCSSV, severely corroded ring gasket, and the performance of an acid job possibly accelerating the failure of the ring gasket.

5. (ID 617) This is an incident that has been reported as a blowout through WikiLeaks information. As far as we can see the operator has not referred to this as a blowout, but the

Operator's Annual Report 2008 states the following from the incident; On 17 September 2008, a subsurface gas release occurred below the Central Azeri platform in Azerbaijan.

As a precautionary measure, all personnel (211 workers) on the platform were safely transferred onshore. Another WikiLeaks document said the operator believed the gas leak was linked to a bad cementing job.

6. (ID 649) Oil was observed on the surface of the water near PL19 3 Wellhead Platform B in China. The source of the seep was identified to be an existing geological fault that opened slightly due to pressure from water injection into a subsurface reservoir during production activities. The operator discontinued the water injection and began de-pressuring the reservoir. 17 days after the incident was observed the reservoir pressure was reduced to a point that the fault closed, isolating the reservoir from the surface and stopping the seepage.
7. (ID 647) The source of the discharge was a leak that developed on the surface casing of a saltwater injection well. Initial sheen was estimated to 37 gallons based on sheen calculations from an overflight.

**Well release**

8. (ID 521) The lead operator recorded the tubing pressure from a gauge located in the tree cap of Well A-2. He then left the platform without removing the pressure gauge or installing a plug in the needle valve. The lead operator also left the crown valve (swab valve) open. The O-ring in the tree cap failed while the platform was unattended, allowing gas and condensate to be vented into the atmosphere. While conducting a morning check, an operator observed the well blowing natural gas out of the well cap. Personnel from a nearby platform were sent by boat to the facility, and they activated the boat dock ESD. The well stopped flowing approximately 30 seconds after the ESD was activated. The master, wing and crown valves were then closed. An investigation revealed that Well A-2 was blowing out at the hammer type cap located on top of the wellhead. The gas was coming from a bleed-off hole (weep hole) on the hammer type cap. The cap gasket was pinched, allowing gas to flow. Approximately one gallon of condensate was spilled into the Gulf.
9. (ID 596) The wells incident was reported by field standby vessel. Bubbles coming to surface with a 10m dispersion radius at the location of a subsea wellhead structure. After identifying the well that leaked, the well was shut in and the gas release stopped.
10. (ID 653) Fractured wellhead weld point. The leak was controlled by applying a hose to the opposite side of the wellhead from the crack to reduce the pressure and divert the oil back into production.

    This successfully reduced the pressure to such an extent that the leak from the crack stopped at around after 10 hours. The majority of leak went to the bund in the module with some going to sea. A VR plug was inserted and the wellhead made safe. The bund was pumped out and the module cleaned. One source stated that 320 kg was released. A news article stated that 20 tons of oil leaked. It is not stated in the source, but it seems the leak was fed by the annulus.
11. (ID 612) When looking outside the living quarters, the operator heard a gas leak and observed a large gas cloud in the area where the test separator was located. The operator headed to the well bay to insure all wells had been shut-in. He noticed that all wells shut-in except for A-15.

The Operator then manually closed the wing valve and the gas leak stopped. Large amounts of sand were observed in the area around damaged piping.

A range charts showed that the well flow had begun to increase. It is believed the choke was once again "cut out". The PSV began to relieve at some point as flow increased. The source of the leak was found to be the A-15 flowline PSV discharge piping as it was cut out at two 90 degree "elbow" sections.

The PSH and PSL located on the flowline were found to have sensing lines plugged with sand and therefore did not function. A report stated the SSV of the A-15 well was found to have large amounts of sand, which was believed to be responsible for the A-15 SSV failing to actuate to the closed position.

12. (ID 624) Re-manning the facility following the T.S. Lee evacuation. The crew exited the aircraft and was walking down the stairway to the quarters when they noticed a sheen approx. 1/2-mile-long by 100 yards coming from the facility. The crew then noticed that liquids were coming out the Flare Boom. They proceeded downstairs to investigate and found two wells had failed to ESD.

    The wells were manually shut in and the source was contained. The spill estimate released to the water was based on sheen size present in the water was calculated as 1 gallon. Several additional gallons were also released and covering significant portions of the platform and rig. Several cleaning crews were brought out to clean the facility. The facility remained shut in until the cleaning crew was finished.

13. (ID 652) A supply boat observed an area of 150 to 200m wide showing signs of disturbances. Bubbling water could be observed on the center of this area. Production tree upper flow spool was replaced by divers. It was estimated that 1571 kg gas released.
14. (ID 672) A production operator was making his morning rounds and found gas and oil leaking from a well. The gas and oil was leaking through a hole in the 20-inch drive pipe at the +10-bell guide and from the 20 inch x 10 ¾ inch annulus from below the well head base plate. The operator reported an estimated 0.67 gallons of oil leaked into the waters of the Gulf of Mexico.

    The well was a dual completion with a long string and the short string. The short string was plugged in 2014 at the packer level because the short string tubing was leaking to the annulus.

    The well was closed in before the incident because of some surface equipment failure. This increased the reservoir pressure. The buildup of reservoir shut-in pressure caused the pump through plugs in short string to fail allowing reservoir shut-in pressure/gas and oil to enter the deteriorated short string that again leaked to the well annulus. A leak in the 7 5/8-inch production casing allowed reservoir shut-in pressure/gas and oil to build in the 7 5/8-inch and 10 ¾ inch annulus. A leak in the 10 ¾ inch surface casing +-10ft below the well head allowed reservoir gas and oil to enter the non-pressure holding 20-inch casing finding open leak paths to the atmosphere

## 9.2 Human Errors in Production LOWC Events

The human role is considered important in the occurrence and development of LOWC events. Human errors are believed to have contributed to many of the incidents without being explicitly stated in the information source. The skill of the personnel and proper procedures and practices will always be important.

### 9.2.1 LOWC EVENTS WITH EXTERNAL CAUSES

For five of the 12 LOWC events with external causes a ship or a boat collided with the wellhead. This will in many cases be regarded as a human error, although it will mainly be the ship personnel. It has however been mentioned that that lightening has been missing on the structures, making them difficult to see when it is dark. These types of small unmanned structures in shallow water should be enlightened. Such structures should also clearly be marked on all maps and navigation devices.

Some of these wells have not been equipped with and SCSSV. All wells that may be exposed to external forces should have an SCSSV.

Otherwise it cannot be identified what role human errors have had for the development of the rest of the LOWC events caused by external forces.

### 9.2.2 LOWC EVENTS WITHOUT EXTERNAL CAUSES

For nine of the 14 LOWCs without external causes a direct human error that had impact on the event could not be identified. For the remaining five, human errors may seem to have been contributed to the occurrence of the incidents.

For one *blowout (surface flow)* (ID 577) the well had had a leak in the tubing for a long period. The annulus pressure was 23% of the minimum internal yield pressure of the 9 5/8-inch production casing. The casing pressure was not reported as necessary, timely intervention measures may have prevented the loss of well control.

For another *blowout (surface flow)* (ID 649) the source of the seep was an existing geological fault that opened slightly due to pressure from water injection into a subsurface reservoir during production activities. 17 days after the incident was observed the reservoir pressure was reduced to a point that the fault closed.

For a *well release* (ID 521), after a tubing pressure measurement the operator left the platform without removing the pressure gauge or installing a plug in the needle valve and left the crown valve (swab valve) open. The O-ring in the tree cap failed while the platform was unattended, allowing gas and condensate to be vented into the atmosphere.

For another *well release* (ID 653) it seems that the well had been allowed to have an annulus pressure due to a down hole leak. When a fracture in the wellhead weld point occurred, the annulus started to leak oil to the surroundings. A source states that 20 tons of oil leaked, another states 320 kg.

For a third *well release* (ID 624) two wells had failed to ESD prior to evacuating the platform due to a storm warning. This was not observed before re-manning the platform some days later. It seems that the personnel did not verify that all wells were properly isolated prior to evacuating the platform

# 10 WIRELINE LOWC EVENTS

Wireline LOWC events occur during wireline operations in production or injection wells. Wireline operations are also frequently performed during well workovers, well drilling or well completions. Blowouts that occur during these operations are not regarded as wireline blowouts.

During wireline operations, a stuffing box/lubricator and/or a wireline BOP located on top of the X-mas tree is normally the primary barrier. If the well cannot be controlled by those means, the wireline is dropped or cut before the X-mas tree is closed to control the well.

## 10.1 Wireline LOWC Experience

The experience presented in this section is based on the *SINTEF Offshore Blowout Database* [7] for the period 2000–2015 worldwide. The database includes seven LOWC incidents from 2000 - 2015 during the wireline phase. Three of these stem from the US GoM OCS and four from the UK. This type of LOWC events have not be identified in any other areas. It is likely that such events have occurred in other areas as well but they have not reached the public domain due to lack of reporting and low consequences. Table 10.1 shows some key parameters for the wireline LOCW incidents.

*Table 10.1 Wireline LOWC Incidents, some key parameters*

| ID | Year | Sub Category | Country | Water Depth | Installation type | Well status | Poll-ution | Spill volume | Duration | Fatali-ties | Ignition |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Blowout (surface flow)*** | | | | | | | | | | | |
| 530 | 2000 | Totally uncontrolled flow, from a deep zone | UK | 3) 100 - 200 | Light intervention vessel | Alive | No | Gas | 4 hrs 45 min | 0 | No |
| ***Well release*** | | | | | | | | | | | |
| 515 | 2001 | Limited surface flow before the secondary barrier was activated | US GoM OCS | 1) <50 | Jacket | Alive | No | Gas | 5 mins | 0 | No |
| 552 | 2003 | | US GoM OCS | 1) <50 | Satellite | Alive | No | Gas with H2S | 5 mins | 0 | No |
| 572 | 2001 | | UK | 2) 50 - 100 | Jacket | Alive | No | Only gas | 5 mins | 0 | No |
| 642 | 2014 | | US GoM OCS | 2) 50 - 100 | Jacket | Alive | No | Gas, very small | 1 min | 0 | No |
| 651 | 2014 | | UK | 3) 100 - 200 | Jacket | Alive | No | Estimated oil release 900 - 950kg (Not to sea). | 1 min | 0 | No |
| 656 | 2000 | | UK | 3) 100 - 200 | Jacket | Alive | No | 3350 kg gas in 2 minutes | 2 mins | 0 | No |

None of the wireline LOWC incidents caused any severe accidents, no fatalities, no ignition, and no pollution of the sea. Most of the incidents were categorized as *well rel*eases, that typically have a short duration. One incident was categorized as a *blowout (surface flow)*. For this case the wireline BOP failed to stop the flow.

Below a brief description of the various LOWC events is given.

1. (ID 530) A leak occurred on a wireline lubricator at the stuffing box during the setting of an electric line bridge plug. Wireline BOP's were closed but failed to stop the leak. The leak continued for nearly 5 hrs. when the BOP's eventually sealed.

2. (ID 515) The crew had run in the hole with a tool string to begin logging when a leak developed in a connection between the wireline pump-in sub and a 2-inch molded "Y". The leak could not be isolated from the wellbore without shutting in the gate valve on the tree. All non-essential personnel were evacuated from the jack-up boat and the platform, and the electrical wireline was retrieved. After the tools were above the SCSSV, the pressure was bled to 0 psi into the production system. When the BOP’s and the pump-in sub were dismantled, the crew found that a seal was cut out.

3. (ID 552) It seems that they prepared for wireline job to install a plug in the well. The needle valve which accessed the downhole chemical injection line, had a check valve installed at the end. When the construction personnel attempted to back out the check valve, the autoclave needle valve came off the seat. This resulted in gas from the wellbore being released into the atmosphere. Cudd Pressure Control personnel tightened the autoclave connection eliminating the leak. No $H_2S$ detected in escaping gas at wellhead.

   The probable causes of the incident were the following: 1) the failure of the construction operator to properly remove the plug from the autoclave valve, 2) a lack of company supervision during the operation, and 3) a failure of the operator to implement the $H_2S$ contingency plan. Damage is estimated at $400.

4. (ID 572) The wireline riser was installed onto the well swab valve with the BOPs and lubricator positioned above on the top deck. When retrieving a tool during wireline operations for inspection/redress the operator encountered a sudden overpull when the odometer indicated the tool was still registering 153 ft below the swab valve. Simultaneously the wire parted at surface and exited out of the lubricator stuffing box and the tool string plus wire fell back down the well. Gas then started to escape to the open atmosphere from the 1/8" orifice on stuffing box left by the wire when the stuffing box BOP also failed to operate. The pressure in the well at the time was 697 psi. Wind conditions at the time was 12 knots from a direction of 200 deg. The Schlumberger operator took immediate action and the blow out preventers closed within 30sec.

5. (ID 642) While preparing to drop a wireline cutter, the wireline BOP that was closed around the wire failed and gas was briefly discharged to atmosphere for +/- 10 seconds. The gate valve beneath the lubricator was closed to cut the wire and secure the well. There were no injuries, fires or pollution.

6. (ID 651) Initial detection visual by driller. Further fixed system detection identified dispersion. Activation of BOP well control was manual. Full platform shutdown was initiated manually. The operator estimated the amount of oil released to be between 900 - 950kg. Several unknown factors mean that the size of the release cannot be accurately determined. Release drained down from Rig Floor to BOP Deck, then into Eggboxes/Well Bay

7. (ID 656) During rig-up slick line, system was about to be flushed through to pressure test BOP's. At this point the wireline BOP's were open, with no lubricator fitted. The well was isolated on the swab valve and upper master valve. The swab valve on the Xmas tree was opened to fill the system with water. The operator on the drill floor noticed what is assumed to be some trapped pressure between the swab valve and the upper master valve being vented on the drill floor.

   He should then function the BOP's to closed position, but inadvertently opened the upper master valve to the open position instead. As the swab valve was open, this allowed well pressure to vent up the riser onto the drill floor.

The platform GPA was triggered by a gas release on the drill floor at this point. The personnel at the Xmas tree closed in the swab valve immediately to isolate the well. The operator on the drill floor contacted the personnel in the wellheads and returned to the control panel. He realized his error and dumped the opening pressure to the upper master valve, and functioned the BOP's to the closed position.

## 10.2 Human Errors in Wireline LOWC Events

The human role is considered important in the occurrence and development of LOWC events. Human errors are believed to have contributed to many of the incidents without being explicitly stated in the information source. The skill of the personnel and proper procedures and practices will always be important.

For two of the seven wireline LOWC events human errors were identified.

For the ID 552, when preparing for a wireline job, the construction operator di not properly remove the plug from the autoclave valve, casing a leak from the chemical injection line to the surroundings.

For ID 656, when preparing for a slick line operation, the operator by mistake opened the upper master valve (the swab valve was also open), when he should have closed the wireline BOP.

Human errors may have been involved in other of the incidents as well, but they have not been mentioned in the source material.

## 10.3 Equipment Failures in Wireline LOWC Events

For four of the LOWC incidents equipment failures occurred, for one it is unclear, and for the two last incidents it seems that human errors caused the incidents.

For ID 530 a leak occurred on a wireline lubricator at the stuffing box during the setting of a Schlumberger electric line bridge plug. The wireline BOP's were then closed but failed to stop the leak.

For ID 515 a leak developed in a connection between the wireline pump-in sub and a 2-inch molded "Y". Closed X-mas tree gate valve to isolate the leak. After dismantling the crew found that a seal was cut

For ID 572 the wire parted at surface and exited out of the lubricator stuffing box and the tool string plus wire fell back down the well. Then the stuffing box BOP also failed. X-mas tree valves were then closed

For ID 642 the wireline BOP failed to seal around the wireline. Cut the wire and secured the well with X-mas tree valves

# 11 ABANDONED WELL LOWC EVENTS

There are five LOWC events in the database for the period 2000–2015 from wells categorized as abandoned wells. Wells that are temporary abandoned, permanently abandoned, and long-time plugged wells are regarded as abandoned wells.

Table 11.1 shows an overview of the abandoned wells LOWC events.

*Table 11.1 Overview of LOWC events in abandoned wells 2000–2015*

| LOWC ID | Year | Country | Water depth (m) | When abandoned | Description |
|---|---|---|---|---|---|
| 484 | 2000 | US GoM OCS | 15 | Temporary abandoned | The cement job on well No. D-5 annuli failed and allowed gas to migrate up through the cement into the annular void of the well and into the atmosphere, when working on the neighbor well. Hot slag from welding operations on the adjacent D-6 well caisson fell down into the annulus D-5 annuli and ignited. The fire lasted for 27 hours |
| 513 | 2002 | Indonesia | 1,676 | Well was recently plugged and abandoned | A thin hydrocarbon sheen near a deepwater well site was observed. Unknown duration |
| 609 | 2009 | US GoM OCS | 1,884 | Well was P&A in 2008 | The well was temporary abandoned in 2006 and permanently abandoned in June 2008. Estimated the flow to 5.6 barrels a day. During killing operations, it was found that the flow was through the casing. The flow from the well lasted for more than a month. Total release estimated to 62 barrels by the operator |
| 610 | 2007 | US GoM OCS | 16.5 | Permanent plugged and abandoned in 1997 | In November 2007, it was discovered that the well was bubbling. Well was dead when the initial bubble appeared. While investigating the source of the bubble the old plugged and abandoned well bridged off and stopped flowing. |
| 626 | 2012 | UK | 46.3 | Reservoir had been plugged for a year | This was the UK Elgin blowout. The well main reservoir had been plugged for a year. The gas and condensate were believed to originate from a rock formation located above the reservoir that contained gas and condensate that may have migrated. The casing fractured at a pressure below the design pressure. Casing was corroded. Flow was stopped after 53 days Production resumed 9 months later. The flow was condensate and gas. Pollution was negligible. Gas and condensate dispersed or evaporated. |
| 633 | 2012 | India | 260 | Well had been temporary abandoned for 10 years | The well was temporarily abandoned with two bridge plugs and a horizontal subsea X-mas tree. It is not known if the X-mas tree had any crown plugs or if it was left with only a debris cap. One source states that there were some condensate on the sea surface, all others refer to this as a gas blowout. A capping stack was made for the purpose and used for ending the flow. The blowout lasted for 84 days. |

LOWC events in abandoned wells do occur. There is reason to believe that more of these types of events will be seen in the future. There are many wells in the North Sea and in the US GoM OCS that are temporary abandoned and longtime shut in. In regulated areas in the rest of the world the number of such wells is assumingly on the same level. In other areas with less regulation the relative number of such wells may be even higher.

As the workover section shows, Section 7, page 70 many LOWC events occur during abandoning operations. Further, many of these comes from wells that have been temporary abandoned or shut in for a long period. Entering these wells is difficult due to the uncertainties related to the conditions of the barriers and unanticipated well pressures.

The BOMR 5010 borehole list [8] includes a *status* field and a *status date* field for the individual wells. *Permanently Abandoned* and *Temporarily Abandoned* are among the status categories that can be selected. A version of this file from June 26, 2016 has been downloaded. From this file, Table 11.2 has been generated.

*Table 11.2 Permanently Abandoned and Temporarily Abandoned wells in the US GoM OCS (based on 5010 borehole file [8] downloaded June 2016 including all wells drilled in all times)*

| Latest well status reported (period/year) | Development wells | | Exploration well | | Cumulative exploration and development wells | |
|---|---|---|---|---|---|---|
| | Permanently Abandoned | Temporarily Abandoned | Permanently Abandoned | Temporarily Abandoned | Permanently Abandoned | Temporarily Abandoned |
| 1948 - 1979 | 1,817 | 76 | 4,249 | 7 | 6,066 | 83 |
| 1980 - 1989 | 1,932 | 119 | 2,649 | 29 | 10,647 | 231 |
| 1990 - 1999 | 2,897 | 311 | 2,295 | 70 | 15,839 | 612 |
| 2000 - 2009 | 4,007 | 896 | 1,921 | 162 | 21,767 | 1,670 |
| 2010 | 787 | 228 | 188 | 24 | 22,742 | 1,922 |
| 2011 | 800 | 242 | 198 | 20 | 23,740 | 2,184 |
| 2012 | 615 | 330 | 182 | 43 | 24,537 | 2,557 |
| 2013 | 377 | 493 | 205 | 49 | 25,119 | 3,099 |
| 2014 | 439 | 413 | 187 | 50 | 25,745 | 3,562 |
| 2015 | 322 | 263 | 137 | 76 | 26,204 | 3,901 |
| 2016 | 101 | 58 | 45 | 16 | 26,350 | 3,975 |
| Total | 14,094 | 3,429 | 12,256 | 546 | | |

The accuracy of the status data in the borehole list is unknown, but Table 11.2 indicates that many wells have been temporarily abandoned for many years. The table indicates that 83 wells have been temporarily abandoned since before 1980, and that 612 have been temporary abandoned before the year 2000. The past six years the number of temporary abandoned wells has increased with around 1,000. As per June 2016, nearly 4,000 wells are temporary abandoned in the US GoM OCS.

In addition to these temporary abandoned wells, many producing wells are closed in or plugged for some reasons. The OgorA file [9] for January 2016, lists in total 1,595 non-producing oil completions and 1,380 non-producing gas completions. There is reason to believe that many of these wells have been closed in for a long period of time.

There is a huge back-log related to temporary abandoned wells in the whole world. Unless this back-log is reduced, the probability of blowouts from these wells will increase.

# 12 UNKNOWN PHASE LOWC EVENTS

For two LOWC events, one occurred in Brazil (Platform P-7) in 2001, and one in UK (Forties Echo) in 2008, the operational phase could not be determined based on the source description. Both incidents occurred on production installations.

Both these events caused release of oil to the sea.

The UK LOWC incident has been categorized as a *well release*.

ID 655. Drill crew responded to this incident by completing the nipple up of the double ram BOP. This was installed in 20 mins, bolts were torqued up and shear rams closed. By this action the well was closed off. Well was then monitored for some hours and no further gas bubbles came to surface, no pressure increase was recorded. Approximately spill area on sea surface: 10m x 500m. The source stated a duration of one minute and a spill of 200 kg (1-2 barrels).

The Brazilian LOWC Incident has been categorized as a *blowout (surface flow).*
ID 483. It seems they had been testing the well when something went wrong, and pipes were spilling to the sea. The spill volume has been estimated to 13,000 (80 barrels) liter and 25,000 liters(150 barrels).The duration of the Brazilian spill is unknown.

# 13 LOWC CHARACTERISTICS

## 13.1 LOWCs Flow Paths and Release Points

A LOWC event may flow to the surroundings through various flow paths. Figure 13.1 shows an overview of the leak paths for the 117 LOWC events from the "regulated" area (US GoM OCS, Norway, UK, the Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark, and Brazil).

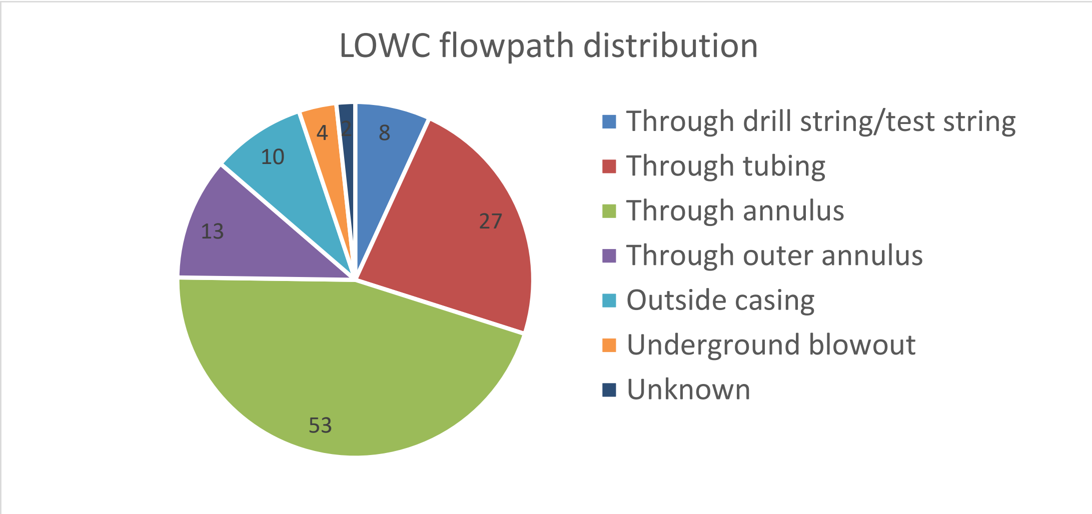


*Figure 13.1 LOWC flow paths 2000–2015, regulated areas including US GoM OCS*

Approximately 45% of the LOWC event's flow came through the well annulus, 23 % came through the tubing, 11% in-between casings, 7% through the drillstring, and the remaining came outside casing and the remaining outside the casing or an underground flow.

More detailed overviews of the flow paths and release points for the various operational phases and main vessel type are shown in Table 13.1, Table 13.2, Table 13.3, Table 13.4, and Table 13.5.

*Table 13.1 LOWC event flow paths and release points, shallow zone incidents, 2000–2015, regulated areas including US GoM OCS*

| Phase | Main category | Release point | Leak path: Through annulus | Through outer annulus | Outside casing | Total |
|---|---|---|---|---|---|---|
| **Bottom fixed** | | | | | | |
| Development drilling | Blowout (surface flow) | Diverter syst.leak | | 1 | | 1 |
| | | Diverter syst.leak-main diverter | 1 | 1 | | 2 |
| | | Drill floor | 1 | | | 1 |
| | | From wellhead | | 2 | | 2 |
| | | Subsea - outside casing | | | 2 | 2 |
| | Diverted well release | Diverted | 6 | | | 6 |
| | Total | | 8 | 4 | 2 | 14 |
| Exploration drilling | Blowout (surface flow) | Diverter syst.leak-main diverter | 1 | | | 1 |
| | | From wellhead | | 2 | | 2 |
| | Diverted well release | Diverted | 4 | | | 4 |
| | Total | | 5 | 2 | | 7 |
| **Floating vessel** | | | | | | |
| Development drilling | Blowout (surface flow) | Subsea wellhead | 2 | | | 2 |
| | Total | | 2 | | | 2 |
| Exploration drilling | Blowout (surface flow) | Subsea wellhead | 3 | | | 3 |
| | Well release | Subsea - outside casing | | 1 | | 1 |
| | | Subsea wellhead | 1 | | | 1 |
| | Total | | 4 | 1 | | 5 |
| TOTAL ALL | | | 19 | 7 | 2 | 28 |

Most shallow zone LOWC events have their final flow-path through the well bore annulus. Either the flow is diverted without any problems, the diverter system fails, or the flow is released through the subsea wellhead.

*Table 13.2 LOWC event flow paths and release points, <u>bottom fixed installation</u>, deep zone incidents during drilling, completion, workover, and wireline operations, 2000–2015, regulated areas including US GoM OCS*

| Phase | Main category | Release point | Flow path | | | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Through drill string | Through tubing | Through annulus | Through outer annulus | Outside casing | Under-ground blowout | Unknown | |
| Develop-ment drilling | Blowout (surface flow) | From wellhead | | | | 2 | | | | 2 |
| | | Subsea wellhead | | | 1 | | | | | 1 |
| | Blowout (underground flow) | No surface flow | | | | | | 1 | | 1 |
| | Well release | Drill floor - through rotary | | | 1 | | | | | 1 |
| | | Unknown | | | | | | | 1 | 1 |
| | Total | | | | 2 | 2 | | 1 | 1 | 6 |
| Explorat-ion drilling | Blowout (surface flow) | BOP valve outlet | | | 1 | | | | | 1 |
| | | Drill floor - top of drill string | 1 | | | | | | | 1 |
| | | From wellhead | | | 2 | 2 | | | | 4 |
| | Blowout (under-ground flow) | No surface flow | | | | | | 2 | | 2 |
| | Total | | 1 | | 3 | 2 | | 2 | | 8 |
| Comp-letion | Blowout (surface flow) | Drill floor | | | 1 | | | | | 1 |
| | | Drill floor - through rotary | 1 | | | | | | | 1 |
| | Well release | Drill floor - through rotary | | | 1 | | | | | 1 |
| | | Drill floor - top of tubing | 1 | | | | | | | 1 |
| | | Shaker room | 1 | | | | | | | 1 |
| | Total | | 3 | | 2 | | | | | 5 |
| Work-over | Blowout (surface flow) | Drill floor - top of tubing | | 2 | | | | | | 2 |
| | | From wellhead | | | 2 | | | | | 2 |
| | | From x-mas tree | | 1 | | | | | | 1 |
| | | Mud room | 1 | | | | | | | 1 |
| | | Subsea - outside casing | | | | | 4 | | | 4 |
| | | Subsea wellhead | | 1 | | | | | | 1 |
| | Well release | BOP valve outlet | | | 3 | | | | | 3 |
| | | Drill floor - through rotary | | | 8 | | | | | 8 |
| | | Drill floor - top of drill string | 1 | 1 | | | | | | 2 |
| | | Drill floor - top of tubing | | 1 | | | | | | 1 |
| | | From above x-mas tree | | 1 | | | | | | 1 |
| | | From wellhead | | 1 | | | | | | 1 |
| | | From x-mas tree | | | 1 | | | | | 1 |
| | Total | | 2 | 8 | 14 | | 4 | | | 28 |
| Wireline | Blowout (surface flow) | Drillfloor - through rotary | | | | 1 | | | | 1 |
| | Well release | Drillfloor | | 2 | | | | | | 2 |
| | | Drillfloor -Wireline stuffing box/BOP | 1 | | | | | | | 1 |
| | | From above X-mas tree | | 2 | | | | | | 2 |
| | | From X-mas tree | | 1 | | | | | | 1 |
| | Total | | 1 | 5 | | 1 | | | | 7 |
| TOTAL ALL | | | 7 | 13 | 21 | 5 | 4 | 3 | 1 | 54 |

For workover and completion LOWC events, many have the flow path through the tubing or the drill string.

*Table 13.3 LOWC flow paths and release points, floating vessel deep zone incidents, 2000–2015, regulated areas including US GoM OCS*

| Phase | Main category | Release point | Flow path: Through drill string | Through annulus | Outside casing | Underground blowout | Un-known | Total |
|---|---|---|---|---|---|---|---|---|
| Exploration drilling | Blowout (surface flow) | Drill floor - through rotary, subsea BOP | | 1 | | | | 1 |
| | | Subsea - outside casing | | | 2 | | | 2 |
| | | Subsea BOP | | 1 | | | | 1 |
| | Blowout (underground flow) | No surface flow | | | | 1 | | 1 |
| | Diverted well release | Drill floor - through rotary | | 1 | | | | 1 |
| | Well release | Diverted | | 1 | | | | 1 |
| | | Drill floor - through rotary | | 2 | | | | 2 |
| | | Shaker room | | 1 | | | | 1 |
| | Total | | | 7 | 2 | 1 | | 10 |
| Comp-letion | Diverted well release | Diverted | | 1 | | | | 1 |
| | Well release | Drill floor - through rotary | 1 | 1 | | | | 2 |
| | Total | | 1 | 2 | | | | 3 |
| Work-over | Well release | Drill floor - through rotary | | 1 | | | | 1 |
| | Total | | | 1 | | | | 1 |
| TOTAL ALL | | | 1 | 10 | 2 | 1 | | 14 |

Most of the deep zone LOWC events for floating vessels have their final flow-path through the well bore annulus.

*Table 13.4 LOWC flow paths and release points, for abandoned well incidents, 2000–2015, regulated areas including US GoM OCS*

| Installation type | Main category | Release point | Flow path: Through annulus | Through outer annulus | Outside casing | Total |
|---|---|---|---|---|---|---|
| Abandoned wellhead | Well release | Subsea wellhead | 2 | | | 2 |
| Bottom fixed | Blowout (surface flow) | From wellhead | | 1 | 1 | 2 |
| TOTAL ALL | | | 2 | 1 | 1 | 4 |

*Table 13.5 LOWC flow paths and release points, for producing well incidents, 2000–2015, regulated areas including US GoM OCS*

| Installation type | Main category | Release point | Through tubing | Through outer annulus | Outside casing | Unknown | Total |
|---|---|---|---|---|---|---|---|
| No external cause | | | | | | | |
| Bottom fixed | Blowout (surface flow) | From x-mas tree | 2 | | | | 2 |
| | | Subsea - outside casing | | | 1 | | 1 |
| | Well release | From wellhead | | 1 | | 1 | 2 |
| | | From x-mas tree | 2 | | | | 2 |
| | | Unknown | 1 | | | | 1 |
| | Total | | 5 | 1 | 1 | 1 | 8 |
| Subsea X-mas tree | Well release | Subsea x-mas tree | 2 | | | | 2 |
| | Total | | 2 | | | | 2 |
| Total LOWC with NO external cause | | | 7 | 1 | 1 | 1 | 10 |
| LOWC with external cause | | | | | | | |
| Bottom fixed | Blowout (surface flow) | From wellhead | 1 | | | | 1 |
| | | From x-mas tree | 2 | | | | 2 |
| | | Subsea wellhead | 2 | | | | 2 |
| | Total | | 5 | | | | 5 |
| TOTAL ALL | | | 12 | 1 | 1 | 1 | 15 |

All the production LOWC incidents with external causes occurred on bottom fixed installations and had the flow path through the tubing.

*Table 13.6 LOWC flow paths and release points, for unknown phase well incidents, 2000–2015, regulated areas including US GoM OCS*

| Main Category | Flow path | | Total |
|---|---|---|---|
| | Through test string | Through annulus | |
| Blowout (surface flow) | 1 | | 1 |
| Well release | | 1 | 1 |
| Total | 1 | 1 | 2 |

## 13.2 LOWCs Duration

The LOWC events have a highly variable duration. In general, *well releases* have a short duration, while *blowout (surface flow)* and underground blowouts have a longer duration. Table 13.7 shows an overview of the LOWC duration for the various phases of operation and LOWC types.

*Table 13.7 LOWC duration 2000–2015, regulated areas including US GoM OCS*

| Phase | Deep or shallow zone | Duration grouped | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | T ≤10 mins | 10min < T ≤ 40min | 40min < T ≤ 2 hrs | 2 hrs < T ≤ 12 hrs | 12 hrs < T ≤ 2 days | 2 days < T ≤ 5 days | T > 5 days | Un-known | Total |
| **Blowout (surface flow)** | | | | | | | | | | |
| Development drilling | Deep | | | 1 | | | | 1 | 1 | 3 |
| | Shallow | | 1 | 2 | 1 | 2 | 2 | 1 | 1 | 10 |
| Exploration drilling | Deep | | | | 1 | 1 | 1 | 3 | 4 | 10 |
| | Shallow | | | 1 | 1 | | | 2 | 2 | 6 |
| Completion | | | | | | | 1 | | 1 | 2 |
| Workover | | 1 | | | 3 | 3 | 1 | 1 | 2 | 11 |
| Production (no external cause) | | | | | 1 | | 1 | 1 | | 3 |
| Production (external cause) | | | | | 1 | 1 | | 3 | | 5 |
| Wireline | | | | | 1 | | | | | 1 |
| Abandoned well | | | | | | | | 1 | 1 | 2 |
| Unknown | | | | | | | | | 1 | 1 |
| **Total** | | 1 | 1 | 4 | 9 | 7 | 6 | 13 | 13 | 54 |
| **Blowout (underground flow)** | | | | | | | | | | |
| Development drilling | Deep | | | | | | | | 1 | 1 |
| Exploration drilling | Deep | | | | | | | 2 | 1 | 3 |
| **Total** | | | | | | | | 2 | 2 | 4 |
| **Diverted well release** | | | | | | | | | | |
| Development drilling | Shallow | | 2 | 2 | 1 | 1 | | | | 6 |
| Exploration drilling | Deep | 1 | | | | | | | | 1 |
| | Shallow | 1 | | | 2 | 1 | | | | 4 |
| Completion | | | 1 | | | | | | | 1 |
| **Total** | | 2 | 3 | 2 | 3 | 2 | | | | 12 |
| **Well release** | | | | | | | | | | |
| Development drilling | Deep | 2 | | | | | | | | 2 |
| Exploration drilling | Deep | 4 | | | | | | | | 4 |
| | Shallow | | | | | 1 | | 1 | | 2 |
| Completion | | 4 | 1 | | | | | | | 5 |
| Workover | | 15 | 1 | 1 | | | | | 1 | 18 |
| Production (no external cause) | | 1 | | 1 | 2 | | | | 3 | 7 |
| Wireline | | 6 | | | | | | | | 6 |
| Abandoned well | | | | | | | | 1 | 1 | 2 |
| Unknown | | 1 | | | | | | | | 1 |
| **Total** | | 33 | 2 | 2 | 2 | 1 | | 2 | 5 | 47 |
| **TOTAL ALL** | | **36** | **6** | **8** | **14** | **10** | **6** | **17** | **20** | **117** |

## 13.3 How the LOWCs Flow were Stopped

LOWC events may be stopped by various means. The mean for stopping the flow will depend on the LOWC event. Some stop by themselves (bridging or depletion). In the worst case a relief well may be required to stop the flow. Figure 13.2 shows the methods used to stop the LOWC events.

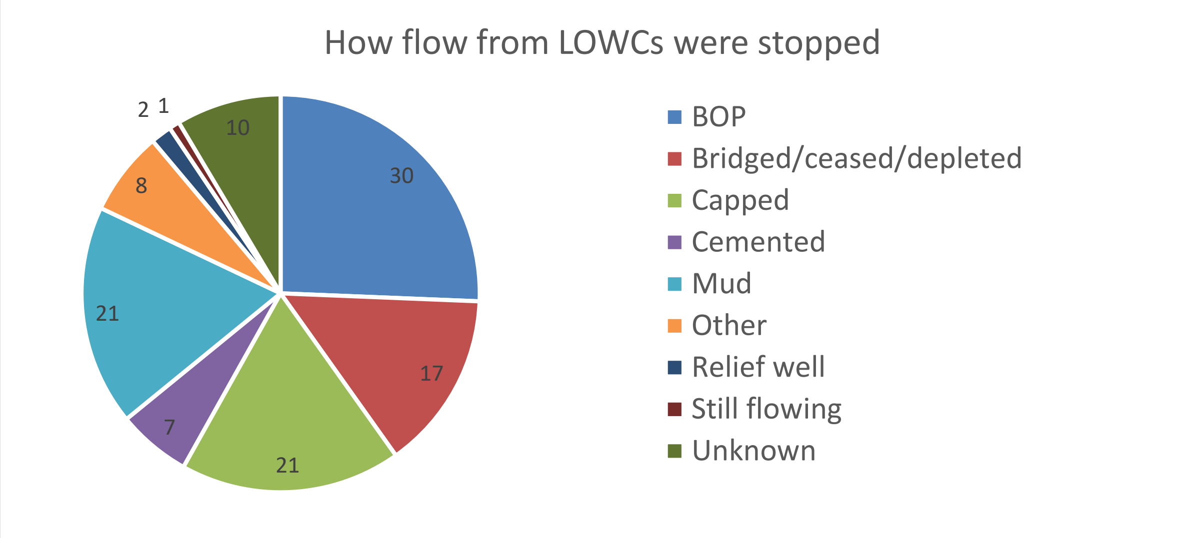


*Figure 13.2 Control methods for LOWC events 2000–2015, regulated areas including US GoM OCS*

Most of the LOWC events were controlled by the BOP, pumping mud, bridging, or they were capped. For two of the 117 LOWC events a relief well was needed to stop the surface flow. For others relief wells may have been started or used to finally secure the well, but not to stop the flow to surroundings. One LOWC that occurred in 2004 due to a hurricane is still flowing. The selected method to be used will always depend on the situation.

A more detailed overview of how the LOWC events were stopped for the various phases of operation and LOWC types is shown in Table 13.8.

*Table 13.8 How the LOWC events are stopped for the various phases of operation and LOWC types, 2000–2015, regulated areas*

| Main Category | Control method | Phase of operation | | | | | | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Development drilling | | Exploration drilling | | Comp-letion | Work-over | Produ-ction | Wire-line | Aban-doned well | Un-known | |
| | | Deep | Shallow | Deep | Shallow | | | | | | | |
| Blowout (surface flow) | BOP | | | 1 | | | 1 | | 1 | | | 3 |
| | Bridged/ceased/depleted | 1 | 4 | 4 | 1 | 1 | 1 | | | | | 12 |
| | Capped | 1 | 1 | 3 | | | 3 | 3 | | | | 11 |
| | Cemented | | 2 | 1 | | | | | | | | 3 |
| | Mud | | 3 | 1 | 4 | | 6 | | | 1 | | 15 |
| | Other | | | | | | | 1 | | | | 1 |
| | Relief well | 1 | | | | | | 1 | | | | 2 |
| | Unknown | | | | 1 | 1 | | 2 | | 1 | 1 | 6 |
| | Still flowing | | | | | | | 1 | | | | 1 |
| | Total | 3 | 10 | 10 | 6 | 2 | 11 | 8 | 1 | 2 | 1 | 54 |
| Blowout (under-ground flow) | Cemented | | | 2 | | | | | | | | 2 |
| | Unknown | 1 | | 1 | | | | | | | | 2 |
| | Total | 1 | | 3 | | | | | | | | 4 |
| Diverted well release | BOP | | | 1 | | 1 | | | | | | 2 |
| | Bridged/ceased/depleted | | 2 | | 1 | | | | | | | 3 |
| | Mud | | 3 | | 3 | | | | | | | 6 |
| | Unknown | | 1 | | | | | | | | | 1 |
| | Total | | 6 | 1 | 4 | 1 | | | | | | 12 |
| Well release | BOP | 1 | | 4 | | 5 | 12 | | 3 | | | 25 |
| | Bridged/ceased/depleted | | | | | | 1 | | | 1 | | 2 |
| | Capped | | | | | | 4 | 3 | 2 | | 1 | 10 |
| | Cemented | | | | 1 | | | | | 1 | | 2 |
| | Other | | | | 1 | | 1 | 4 | 1 | | | 7 |
| | Unknown | 1 | | | | | | | | | | 1 |
| | Total | 2 | | 4 | 2 | 5 | 18 | 7 | 6 | 2 | 1 | 47 |
| Total | | 6 | 16 | 18 | 12 | 8 | 29 | 15 | 7 | 4 | 2 | 117 |

For the *blowout (surface flow)* and *diverted well release* LOWC events the most common methods to stop the events are either that, the well stops to flow by itself (bridging), by pumping mud, or capped. For the *well releases*, the most common way the flow is stopped is by the BOP. The flow from the two LOWC events that were stopped by a relief well were one development drilling LOWC event in Australia in 2009 and one production LOWC event in the US GoM OCS in 2007.

## 13.4 LOWC Flow Medium and Spill

Table 13.9 shows an overview of the LOWC flow medium for the incidents 2000–2015 in regulated areas including US GoM OCS.

*Table 13.9 LOWC events flow medium as listed in the database for 2000–2015 in regulated areas including US GoM OCS*

| Main Category | Flow Medium | Phase of operation | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Development drilling | Exploration drilling | Completion | Workover | Production | Wireline | Abandoned well | Unknown | Total |
| Blowout (surface flow) | Condensate, Gas (deep) | | | | 3 | | | 1 | | 4 |
| | Condensate, Gas (deep), water | | | | | 1 | | | | 1 |
| | Gas (deep) | 1 | 3 | 2 | 4 | 4 | 1 | | | 15 |
| | Mud | | 1 | | | | | | | 1 |
| | Oil | | 1 | | | 2 | | | 1 | 4 |
| | Oil, Gas (deep), Condensate | 1 | | | | | | | | 1 |
| | Oil, Gas (deep) | | 2 | | 4 | 1 | | | | 7 |
| | Oil, Gas (deep), Mud | | 1 | | | | | | | 1 |
| | Oil, Gas (deep), Water | 1 | | | | | | | | 1 |
| | Shallow gas | 7 | 6 | | | | | 1 | | 14 |
| | Shallow gas, Mud | 2 | | | | | | | | 2 |
| | Shallow, unknown fluid | 1 | | | | | | | | 1 |
| | Unknown | | 1 | | | | | | | 1 |
| | Water | | 1 | | | | | | | 1 |
| | Total | 13 | 16 | 2 | 11 | 8 | 1 | 2 | 1 | 54 |
| Blowout (underground flow) | Gas (deep) | 1 | 2 | | | | | | | 3 |
| | Unknown | | 1 | | | | | | | 1 |
| | Total | 1 | 3 | | | | | | | 4 |
| Diverted well release | Gas (deep), Mud | | 1 | 1 | | | | | | 2 |
| | Mud | | 1 | | | | | | | 1 |
| | Shallow gas | 1 | 3 | | | | | | | 4 |
| | Shallow gas, Mud | 2 | | | | | | | | 2 |
| | Shallow gas, Water | 3 | | | | | | | | 3 |
| | Total | 6 | 5 | 1 | | | | | | 12 |
| Well release | Condensate, Gas (deep) | | | | | 1 | | | | 1 |
| | Gas (deep) | 1 | 1 | 2 | 7 | 3 | 5 | 1 | | 20 |
| | Gas (deep), Mud | | 1 | | | | | | | 1 |
| | Mud | | | 1 | 4 | | | | | 5 |
| | Oil | | | | 1 | 2 | | 1 | 1 | 5 |
| | Oil, Gas (deep) | | | | 1 | 1 | 1 | | | 3 |
| | Oil, Gas (deep), Mud | | 1 | 1 | | | | | | 2 |
| | Oil, Gas (deep), Water | | | | 1 | | | | | 1 |
| | Oil, Water | | | 1 | 1 | | | | | 2 |
| | Shallow gas, Water | | 1 | | | | | | | 1 |
| | Unknown | 1 | 1 | | 3 | | | | | 5 |
| | Water | | 1 | | | | | | | 1 |
| | Total | 2 | 6 | 5 | 18 | 7 | 6 | 2 | 1 | 47 |
| Total | | 22 | 30 | 8 | 29 | 15 | 7 | 4 | 2 | 117 |

Fourteen of the 54 *blowout (surface flow)* events included oil as a part of the flow medium, while five included condensate (grey shaded). In addition, thirteen of the *well releases* were listed with oil as a part of the flow (grey shaded), and one condensate. Gas is nearly always a part of the flow.

Table 13.10 shows a simplified version of Table 13.9, where the flow medium has been grouped in accordance with the worst component of the flow with respect to environmental issues.

*Table 13.10 LOWC events grouped flow medium for 2000–2015 in regulated areas including US GoM OCS*

| Main category | Flow medium grouped | Development drilling | Exploration drilling | Comp-letion | Work-over | Prod-uction | Wireline | Abandoned well | Un-known | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Blowout (surface flow) | Oil | 2 | 4 | | 4 | 3 | | | 1 | 14 |
| | Condensate | | | | 3 | 1 | | 1 | | 5 |
| | Gas | 1 | 3 | 2 | 4 | 4 | | | | 14 |
| | Shallow event | 10 | 6 | | | | | 1 | | 17 |
| | Mud or water | | 2 | | | | | | | 2 |
| | Unknown | | 1 | | | | 1 | | | 2 |
| | Total | 13 | 16 | 2 | 11 | 8 | 1 | 2 | 1 | 54 |
| Blowout (underground flow) | Gas | 1 | 2 | | | | | | | 3 |
| | Unknown | | 1 | | | | | | | 1 |
| | Total | 1 | 3 | | | | | | | 4 |
| Diverted well release | Gas | | 1 | 1 | | | | | | 2 |
| | Shallow event | 6 | 3 | | | | | | | 9 |
| | Mud or water | | 1 | | | | | | | 1 |
| | Total | 6 | 5 | 1 | | | | | | 12 |
| Well release | Oil | | 1 | 2 | 4 | 3 | 1 | 1 | 1 | 13 |
| | Condensate | | | | | 1 | | | | 1 |
| | Gas | 1 | 2 | 2 | 7 | 3 | 4 | 1 | | 20 |
| | Shallow event | | 1 | | | | | | | 1 |
| | Mud or water | | 1 | 1 | 4 | | | | | 6 |
| | Unknown | 1 | 1 | | 3 | | 1 | | | 6 |
| | Total | 2 | 6 | 5 | 18 | 7 | 6 | 2 | 1 | 47 |
| Total | | 22 | 30 | 8 | 29 | 15 | 7 | 4 | 2 | 117 |

All LOWC incidents where oil or condensate is a part of the flow medium have been reviewed with respect to the amount of spill from the well based on the description of the incident. The flows have further been categorized in spill size.

The following categories for the spill size have been used;

- < 10 bbls = very small
- 10 – 50 bbls = small
- 50 – 500 bbls = medium
- 500 – 5,000 bbls = large
- 5,000 – 50,000 bbls = very large
- > 50,000 bbls = gigantic

Table 13.11 shows a short description of the spills with size categories, alongside some key data.

*Table 13.11 Overview of oil and condensate spill size from LOWC events, 2000–2015, regulated areas including US GoM OCS*

| Main cate-gory | Flow Medium Type | LOWC ID | Country | Phase | Year | Spill description | Spill size category |
|---|---|---|---|---|---|---|---|
| Blow-out (surface flow) | Condensate, Gas (deep) | 520 | US GoM OCS | Workover | 2003 | 1 MMcf of gas and 10 barrels of condensate were blown out of the well with the uncontrolled gas flow, most of which is assumed to have spilled into the ocean. A light, broken, streaky sheen measuring approximately 2 miles by ½ mile was visible the next morning | Very small |
| | | 525 | US GoM OCS | Workover | 2004 | The Operator did estimate approximately 5 gallons of condensate went into the water. | Very small |
| | | 626 | UK | Abandoned well | 2012 | Much gas and some condensate. The condensate created a scattered sheen that evaporated. The estimated flow rate was around 2 kg/s gas for 53 days. | Small |
| | | 631 | US GoM OCS | Workover | 2013 | Light sheen | Very small |
| | | 519 | US GoM OCS | Production | 2002 | Approximately 21 gallons of condensate were released during the incident which produced a barely visible sheen on the water | Very small |
| | Oil | 483 | Brazil | Unknown | 2001 | Calculated the volume to be some 25,000 liters (150 bbls) | Medium |
| | | 517 | US GoM OCS | Production | 2002 | An estimated 350 barrels of crude oil was released, creating a dark brown slick 6 miles long by 50 yards wide. | Medium |
| | | 619 | Brazil | Expl.drlg | 2011 | 600 bbls per day or 3,700 bbls in total. | Large |
| | | 646 | US GoM OCS | Production | 2004 | Are still leaking oil. In 2014 the daily volume of oil discharging as fluctuated between a low of less than one barrel of oil to a high of 55 barrels, average 2 bbls a day. The cumulative release over 14 years is very large. Average sheen size of 8 square miles | Very large |
| | Oil, Gas (deep) | 463 | US GoM OCS | Expl.drlg | 2000 | Gas and oil, unknown rate. Oil collected in DOT tanks | Very small |
| | | 480 | US GoM OCS | Workover | 2001 | The spill amount was determined to be 1.56 gallons. All attempts to recover any amount of oil were unsuccessful because of the small amount and area of coverage. | Very small |
| | | 539 | US Pacific OCS | Workover | 2004 | A spill of approximately 3 gallons of crude oil went into the ocean. | Very small |
| | | 591 | US GoM OCS | Workover | 2008 | Oil and gas unknown volume | Small |
| | | 611 | US GoM OCS | Expl.drlg | 2010 | 8,000 m3 a day in 85 days, 680,000 m3, or 4,250,000 bbls | Gigantic |
| | | 621 | US GoM OCS | Workover | 2012 | An estimated 9.34 gallons of oil was determined to have entered the Gulf waters. | Very small |
| | | 648 | US GoM OCS | Production | 2015 | Minor sheening and gas bubbling. | Very small |
| | Oil, Gas (deep), Conden-sate | 524 | US GoM OCS | Dev.drlg | 2004 | A sheen was observed trailing from the platform with pollution estimated to be 5.4 barrels (bbl) condensate and oil. | Very small |
| | Oil, Gas (deep), Mud | 464 | US GoM OCS | Expl.drlg | 2000 | 150-200 barrels of crude oil from the wellbore and approximately 806 barrels of synthetic mud | Medium |
| | Oil, Gas (deep), Water | 590 | Australia | Dev.drlg | 2009 | A total volume of 29,600 barrels 4,800 m3, or 66 m3 per day | Very large |
| Well release | Condensate, Gas (deep) | 521 | US GOM OCS | Production | 2003 | Approximately one gallon of condensate was spilled into the Gulf. Mostly gas was released | Very small |
| | Oil | 609 | US GoM OCS | Abandoned well | 2009 | 5.1 barrels oil per day, 62 barrels in total (10 m3) | Medium |
| | | 624 | US GOM OCS | Production | 2011 | Sheen approx. 1/2 mile long by 100 yards. Estimated 1 gallon released to the water. | Very small |
| | | 643 | US GoM OCS | Workover | 2014 | Estimated area of 300 ft. by 50 ft. of oil was in the water | Very small |
| | | 653 | UK | Production | 2008 | 20 tonnes of oil (140 barrels), some going to sea | Small |
| | | 655 | UK | Unknown | 2008 | 188 kg oil | Very small |
| | Oil, Gas (deep) | 627 | US GoM OCS | Workover | 2012 | Seems only to have been gas, but the well was producing oil 3 years before | Very small |
| | | 651 | UK | Wireline | 2014 | Estimated the amount of oil released to be between 900 - 950kg | Very small |
| | | 672 | US GOM OCS | Production | 2015 | Estimated 0.67 gallons of oil leaked into the waters | Very small |
| | Oil, Gas (deep), Mud | 538 | US GoM OCS | Expl.drlg | 2004 | Riser gas, mud, and approximately 11 bbls was entrained crude oil | Very small |
| | | 614 | UK | Completion | 2009 | Approximately three barrels of oil-based mud and the equivalent 0.9 tons of oil lost to sea | Very small |
| | Oil, Gas (deep), Water | 597 | UK | Workover | 2007 | Slight amount of oil | Very small |
| | Oil, Water | 475 | US Pacific OCS | Workover | 2000 | 10 barrels of water and 15 barrels of oil. About one gallon of oil sprayed overboard. | Small |
| | | 573 | UK | Completion | 2003 | Approximately 2 bbl of crude/brine was spilled on the drill floor | Very small |

The majority of the spills are small or very small. One oil spill is categorized as gigantic and it is the Deepwater Horizon blowout in 2010. The Montara blowout in 2009 is categorized as very large, and the Frade Blowout in 2011 is characterized as large. These events occurred during drilling operations. In addition there is one event that occurred in 2004 and is still ongoing. A storm created an underwater landslide that toppled the Mississippi Canyon 20A production platform. The daily leak rate is limited to some barrels, but the cumulative leak over 12 - 13 years caused this LOWC to be categorized as very large. The total volume leaked over this period has been estimated to be between 6,000 – 25,000 barrels.

Figure 13.3 shows the spill size distribution for spills with release of oil or condensate.

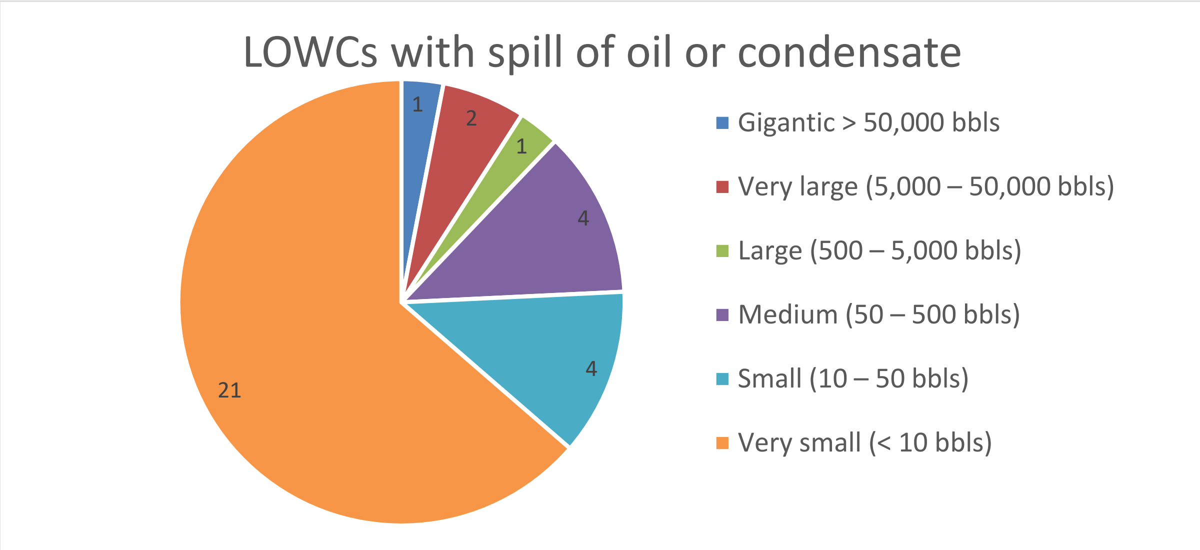


*Figure 13.3 Spill size distribution for LOWC spills with release of oil or condensate*

## 13.5 Water Depth when LOWCs Occurred

Figure 13.4 shows an overview of number of LOWC occurrences within the various water depth ranges.

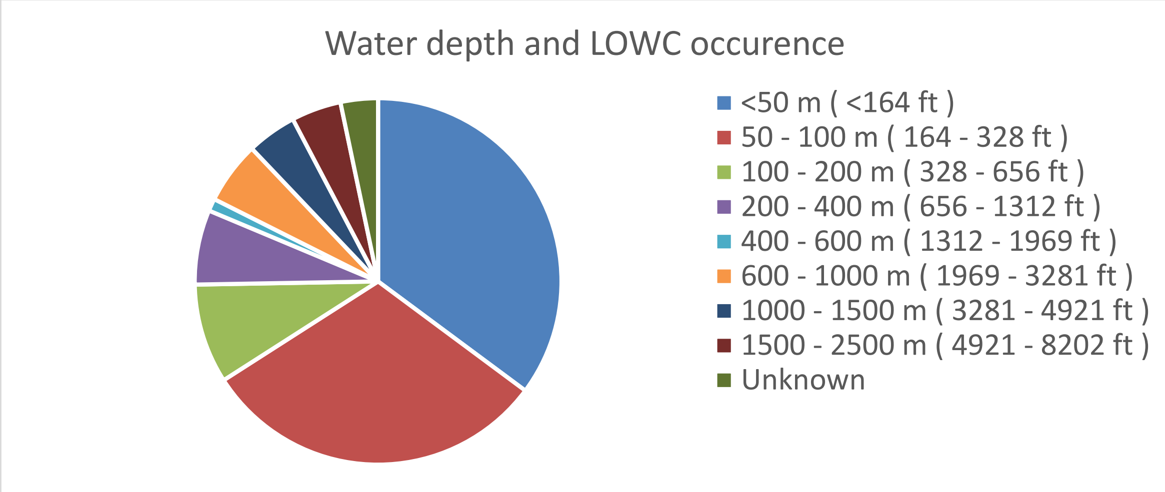


*Figure 13.4 Water depth and number of LOWC occurrences, regulated areas including US GoM OCS 2000–2015*

The majority (75%) of LOWC events occurred in water depths less than 200 m (656 ft.).

Table 13.12 shows the water depth related number of LOWC events for the various phases of operation.

*Table 13.12 Water depth related number of LOWC events for the various phases of operation, regulated areas including US GoM OCS 2000–2015*

| Water Depth Grouped | Phase | | | | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|
| | Develop-ment drilling | Explor-ation drilling | Comp-letion | Work-over | Prod-uction | Wire-line | Aband-oned well | Un-known | |
| <50 m (<164 ft.) | 3 | 11 | 2 | 14 | 8 | 2 | 3 | | 43 |
| 50 - 100 m (164 - 328 ft.) | 15 | 4 | 2 | 7 | 4 | 2 | | 1 | 35 |
| 100 - 200 m (328 - 656 ft.) | 2 | 3 | 1 | 3 | 2 | 3 | | | 14 |
| 200 - 400 m (656 – 1,312 ft.) | 2 | | 1 | 3 | 1 | | | 1 | 8 |
| 400 - 600 m (1,312 – 1,969 ft.) | | | 1 | | | | | | 1 |
| 600 - 1000 m (1,969 – 3,281 ft.) | | 4 | 1 | | | | | | 5 |
| 1000 - 1500 m (3,281 – 4,921 ft.) | | 4 | | | | | | | 4 |
| 1500 - 2500 m (4,921 – 8,202 ft.) | | 3 | | | | | 1 | | 4 |
| Unknown | | 1 | | 2 | | | | | 3 |
| Total | **22** | **30** | **8** | **29** | **15** | **7** | **4** | **2** | **117** |

The majority of deepwater LOWC events (> 600 m/ 1,969 ft.) have occurred during exploration drilling.

Table 13.13 shows the water depth related number of LOWC events for the various LOWC categories.

*Table 13.13 Water depth related number of LOWC events for the various LOWC categories, regulated areas including US GoM OCS 2000–2015*

| Water Depth Grouped | Main category | | | | |
|---|---|---|---|---|---|
| | Blowout (surface flow) | Blowout (underground flow) | Diverted well release | Well release | Total |
| <50 m (<164 ft.) | 24 | 2 | 4 | 13 | 43 |
| 50 - 100 m (164 - 328 ft.) | 17 | 1 | 4 | 13 | 35 |
| 100 - 200 m (328 - 656 ft.) | 6 | | 1 | 7 | 14 |
| 200 - 400 m (656 – 1,312 ft.) | 3 | | 1 | 4 | 8 |
| 400 - 600 m (1,312 – 1,969 ft.) | | | | 1 | 1 |
| 600 - 1000 m (1,969 – 3,281 ft.) | 2 | | 2 | 1 | 5 |
| 1000 - 1500 m (3,281 – 4,921 ft.) | 1 | 1 | | 2 | 4 |
| 1500 - 2500 m (4,921 – 8,202 ft.) | 1 | | | 3 | 4 |
| Unknown | | | | 3 | 3 |
| Total | **54** | **4** | **12** | **47** | **117** |

## 13.6 WELL DEPTH WHEN LOWCS OCCURRED

Figure 13.5 shows an overview of the distribution LOWC occurrences within the various well depth ranges. Primarily it has been sought for the TVD, but for some incidents only the MD has been given. In those cases, the MD is used.

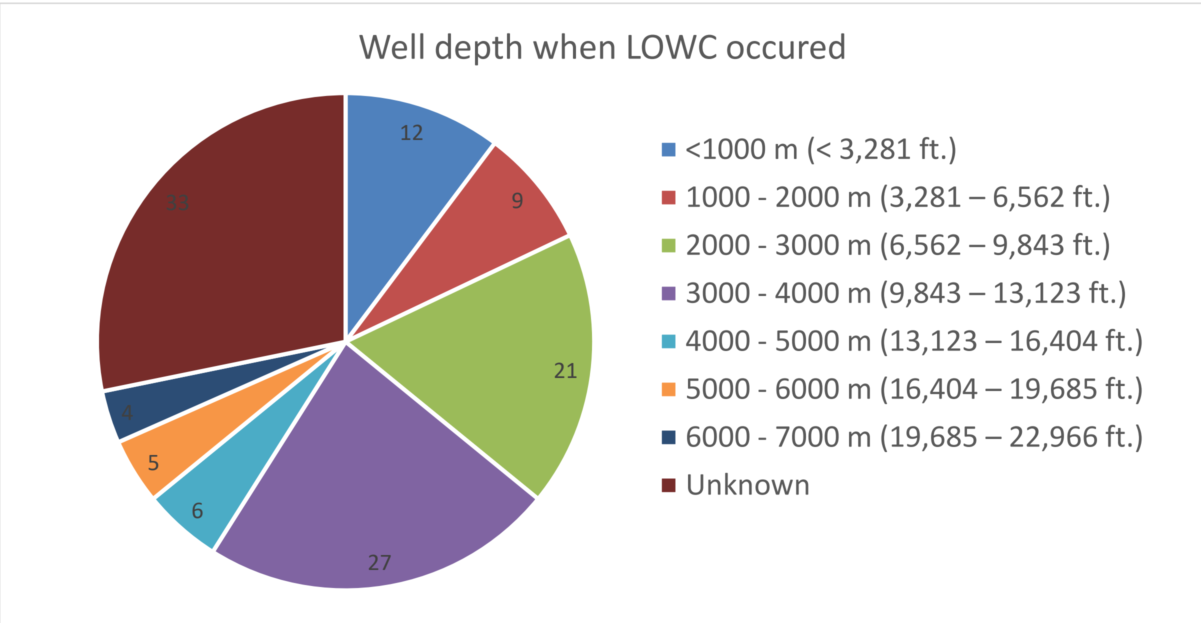


*Figure 13.5 Well depth when LOWC events occurred and distribution of occurrences, regulated areas including US GoM OCS 2000–2015*

The well depth is unknown for 28% of the LOWC occurrences. If disregarding the LOWC events with an unknown depth, 57% occurred between 2,000 and 4,000 meters, 25% in less than 2,000 meter, and 18 % between 4,000 and 6,000 meter.

Table 13.14 shows the number of LOWC events for the various well depth groups and the various phases of operation.

*Table 13.14 Well depth related number of LOWC events for the various phases of operation, regulated areas including US GoM OCS 2000–2015*

| Well depth grouped | Phase | | | | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|
| | Develop-ment drilling | Explor-ation drilling | Comp-letion | Work-over | Prod-uction | Wire-line | Aband-oned well | Un-known | |
| <1000 m (< 3,281 ft.) | 8 | 4 | | | | | | | 12 |
| 1000 - 2000 m (3,281 – 6,562 ft.) | 4 | 3 | | 1 | 1 | | | | 9 |
| 2000 - 3000 m (6,562 – 9,843 ft.) | 1 | 7 | 2 | 6 | 4 | 1 | | | 21 |
| 3000 - 4000 m (9,843 – 13,123 ft.) | 2 | 3 | 3 | 11 | 6 | 1 | 1 | | 27 |
| 4000 - 5000 m (13,123 – 16,404 ft.) | | 3 | 1 | 2 | | | | | 6 |
| 5000 - 6000 m (16,404 – 19,685 ft.) | | 2 | | 1 | | | 2 | | 5 |
| 6000 - 7000 m (19,685 – 22,966 ft.) | 2 | | | | | 1 | 1 | | 4 |
| Unknown | 5 | 8 | 2 | 8 | 4 | 4 | | 2 | 33 |
| Total | 22 | 30 | 8 | 29 | 15 | 7 | 4 | 2 | 117 |

A large proportion of the drilling LOWC events occur shallow in the well.

Table 13.15 shows the number of LOWC events for the various LOWC categories and the well depth.

*Table 13.15 Well depth related number of LOWC events for the various LOWC categories, regulated areas including US GoM OCS 2000–2015*

| Well depth grouped | Main category | | | | Total |
|---|---|---|---|---|---|
| | Blowout (surface flow) | Blowout (underground flow) | Diverted well release | Well release | |
| <1000 m (< 3,281 ft.) | 5 | | 7 | | 12 |
| 1000 - 2000 m (3,281 – 6,562 ft.) | 7 | | | 2 | 9 |
| 2000 - 3000 m (6,562 – 9,843 ft.) | 11 | 1 | | 9 | 21 |
| 3000 - 4000 m (9,843 – 13,123 ft.) | 17 | | | 10 | 27 |
| 4000 - 5000 m (13,123 – 16,404 ft.) | | 2 | 1 | 3 | 6 |
| 5000 - 6000 m (16,404 – 19,685 ft.) | 4 | | | 1 | 5 |
| 6000 - 7000 m (19,685 – 22,966 ft.) | | 1 | | 3 | 4 |
| Unknown | 10 | | 4 | 19 | 33 |
| Total | 54 | 4 | 12 | 47 | 117 |

## 13.7 LOWCs that Come from Main Reservoir

A LOWC event during drilling may occur at any depth in a well. Drilling LOWC events that do not come from the main reservoir are unlikely to cause large releases of hydrocarbons.

In general, it can be assumed that:

- Shallow zone LOWC events will not come from the main reservoir.
- Workovers and completion LOWC events will likely come from the main reservoir.
- Deep zone drilling LOWC events may come from the main reservoir or accumulations of hydrocarbons higher up in the well.

It has been investigated how many of the deep zone drilling LOWC events that come from the main reservoir. For this investigation, only the US GoM OCS LOWC events have been reviewed. For the deep zone drilling LOWC events from the other areas, there is not enough background information to evaluate the individual incidents.

To perform this evaluation various sources have been reviewed:

- The description of the LOWC events in the *SINTEF Offshore Blowout Database* [7]
- The 5010 borehole file [8]
- *eWell* WAR descriptions [10]

It has been looked at:

- The description of the LOWC to see if there is specific references to the reservoir.
- TD of the well vs. the well depth when the LOWC occurred.
- If well was sidetracked and deepened after the LOWC.
- Type of casing in the well when the incident occurred.

Based on this it has been concluded if the flow stemmed from the reservoir or not for the individual LOWC events.

There were in total 18 deep zone drilling LOWC events from the US GoM OCS for the period 2000–2015.

The result from this evaluation is presented in Table 13.16.

*Table 13.16 Origin of well flow, deep zone drilling LOWC events US GoM OCS, 2000–2015*

| Origin of flow | Main category | Phase of operation | | Total |
|---|---|---|---|---|
| | | Development drilling | Exploration drilling | |
| Reservoir | Blowout (surface flow) | | 5 | 5 |
| | Blowout (underground flow) | 1 | 1 | 2 |
| | **Total** | **1** | **6** | **7** |
| Not reservoir | Blowout (surface flow) | 2 | 4 | 6 |
| | Blowout (underground flow) | | 1 | 1 |
| | Diverted well release | | 1 | 1 |
| | Well release | 1 | 2 | 3 |
| | **Total** | **3** | **8** | **11** |
| **Total** | | **4** | **14** | **18** |

From Table 13.16 it can be seen that seven of the 18 deep zone drilling LOWC events came from the reservoir, while the remaining 11 did not.

## 13.8 Well Depth when Kick Occurred vs. Total Well Depth

A well kick may occur at any depth in the well. Section 16.5, page 167 presents kick data from the US GoM OCS. For these kicks, the depth when the kick occurred has been compared with the total depth of the well.

It is reasonable to believe that most kicks occurring prior to reaching the target reservoir will have a limited flow potential. Large oil releases are unlikely from these hydrocarbon deposits.

Figure 13.6 and Figure 13.7 show the well depth when the kick occurred vs. the total well depth for kicks occurring in US GoM OCS wells spudded in the period 2011 – 2015.

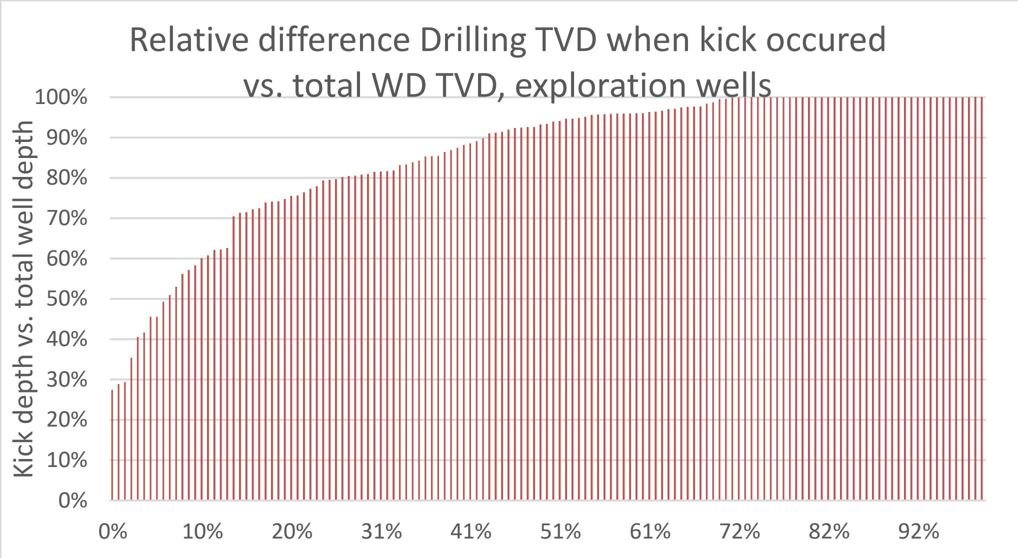


*Figure 13.6 Kick depth vs. total well depth US GoM exploration wells spudded 2011 - 2015*

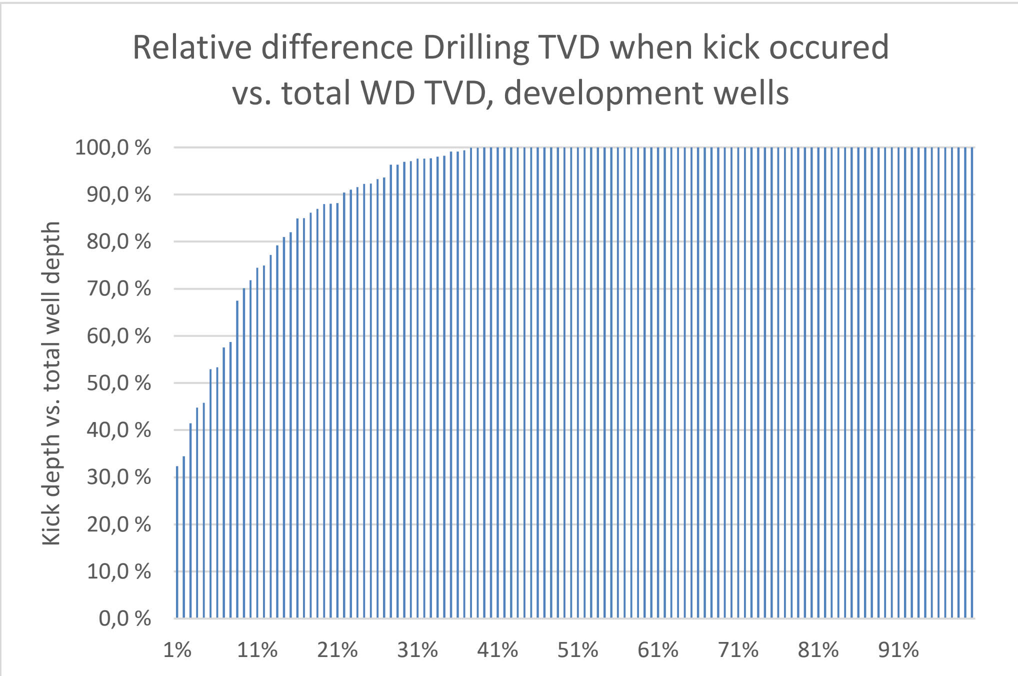


*Figure 13.7 Kick depth vs. total well depth US GoM development wells spudded 2011 - 2015*

A large proportion of the well kicks occur before the wells have reached the reservoir. The proportion is larger than indicated in Figure 13.6 and Figure 13.7, because some of the kicks cause that the wells are abandoned. It has not been estimated how many of the kicks caused the wells to be plugged and abandoned.

# 14 LOWC CONSEQUENCES

This section focuses on the consequences related to the experienced LOWC events. The data comes from US GoM OCS and other regulated areas. The other regulated areas include Norway, UK, the Netherlands, Canada East Coast, Australia, US Pacific OCS, Denmark, and Brazil.

The LOWC consequences have focused on:

- Fatalities
- Pollution
- Ignition
- Material losses to rig

The first subsection presents an overview of the data while the remaining present some more details related to the various phases of operation and LOWC category.

## 14.1 Overview of Experienced Consequences

**Fatalities**

In total 13 fatalities were observed in the regulated areas including the US GoM OCS for all operations included in the period 2000 - 2015.

*Table 14.1 Total number of LOWC events vs. number of fatalities in regulated areas including US GoM OCS 2000–2015*

| Main Category | No. of LOWC events/Fatalities | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Development drilling | | Exploration drilling | | Com-pletion | Work-over | Prod-uction | Wire-line | Aband-oned well | Un-known | Total |
| | Deep zone | Shallow zone | Deep zone | Shallow zone | | | | | | | |
| Blowout (surface flow) | 3 / 0 | 10 / 0 | 10 / 12 | 6 / 0 | 2 / 0 | 11 / 0 | 8 / 0 | 1 / 0 | 2 / 0 | 1 / 0 | 54 / 12 |
| Blowout (underground flow) | 1 / 0 | / | 3 / 0 | / | / | / | / | / | / | / | 4 / 0 |
| Diverted well release | / | 6 / 0 | 1 / 0 | 4 / 0 | 1 / 0 | / | / | / | / | / | 12 / 0 |
| Well release | 2 / 0 | / | 4 / 0 | 2 / 0 | 5 / 0 | 18 / 1 | 7 / 0 | 6 / 0 | 2 / 0 | 1 / 0 | 47 / 1 |
| Total | 6 / 0 | 16 / 0 | 18 / 12 | 12 / 0 | 8 / 0 | 29 / 1 | 15 / 0 | 7 / 0 | 4 / 0 | 2 / 0 | 117 / 13 |

One LOWC event caused 11 fatalities and two LOWC events caused one fatality. Twelve fatalities comes from *blowout (surface flow)* incidents and one during a *well release*.

In the period 1980–1999, 186 LOWC events occurred in the regulated areas including the US GoM OCS during the same phases of operation. For this period 58 fatalities occurred. One LOWC in Brazil (Enchova) in 1984 caused 37 fatalities. All died when a cable for the lifeboat snapped during lowering. The remaining 21 died in eight different LOWC incidents

There have been LOWC events in the rest of the world with several fatalities in the period 2000 -2015. Table 14.2 shows an overview of the number of LOWC events and the number of fatalities for the various phases of operation.

*Table 14.2 Total number of LOWC events vs. number of fatalities in the rest of the world, 2000–2015*

| Main Category | No. of LOWC events/Fatalities | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Development drilling | | Exploration drilling | | Unknown drilling | | Com-pletion | Work-over | Prod-uction | Wire-line | Aband-oned well | Un-known | Total |
| | Deep zone | Shallow zone | Deep zone | Shallow zone | Deep zone | Shallow zone | | | | | | | |
| Blowout (surface flow) | 6 / 1 | 2 / 0 | 3 / 2 | 2 / 0 | 2 / 0 | 2 / 0 | 2 / 0 | 2 / 0 | 11 / 58 | / | 2 / 0 | 2 / 0 | 36 / 61 |
| Blowout (underground flow) | / | / | / | / | / | / | / | / | / | / | / | / | / |
| Diverted well release | / | / | / | / | / | / | / | / | / | / | / | / | / |
| Well release | 1 / 0 | / | / | / | / | / | / | 1 / 0 | / | / | / | / | 2 / 0 |
| Unknown | / | / | / | / | / | / | / | 1 / 0 | / | / | / | / | 1 / 0 |
| Total | 7 / 1 | 2 / 0 | 3 / 2 | 2 / 0 | 2 / 0 | 2 / 0 | 2 / 0 | 4 / 0 | 11 / 58 | 0 / 0 | 2 / 0 | 2 / 0 | 39 / 61 |

Five of the LOWC events in the rest of the world involved fatalities. Two occurred during drilling and three during the production phase. The three production LOWCs that involved fatalities were;

- Azerbaijan 2015, 32 fatalities during evacuation.
- Mexico 2007, 23 fatalities during evacuation
- Saudi Arabia 2007, three persons died for unknown reasons

For the period 1980 – 1999 there were some LOWCs incidents with several fatalities. One in China in 1980 during exploration drilling that caused 70 fatalities (rig Bohai 3). One in Saudi Arabia in 1980 during exploration drilling that caused 19 fatalities due to inhaling $H_2S$ (rig Ron Tappmaier). Further, in 1980, for one drilling incident in the Nigerian delta it was claimed that 180 civilians died due to the pollution (Rig Sedco 135C).

There were further, 10 more LOWC incidents in rest of the world that caused in total 33 fatalities for the period 1980 – 1999.

**Pollution**

Table 13.11, page 124 shows all LOWC events with oil and condensate spills in the period 2000–2015 in the US GoM OCS and the regulated areas.

Three of the deep zone drilling LOWC events that occurred in 2000–2015 in the US GoM OCS and the regulated areas caused a major pollution. These accidents occurred in 2009, 2010, and 2011.

- 2009 – Australia, Montara: A total volume of 29,600 barrels 4,800 $m^3$, or 66 $m^3$ per day.
- 2010 – USA, Macondo: 8,000 $m^3$ a day in 85 days, in total 680,000 $m^3$, or 4,250,000 bbls
- 2011 – Brazil, Frade field: 600 bbls per day or 3,700 bbls in total.

The spill from the Macondo blowout was 140 times larger than the Montara blowout and 1,150 times larger than the Frade blowout in terms of amount of oil released. These incidents caused large media attention, high direct costs, and loss of reputation for the involved parties.

In addition there is one event that occurred in 2004 and is still ongoing. A storm created an underwater landslide that toppled the Mississippi Canyon 20A production platform. The daily leak rate is limited to some barrels, but the cumulative leak over 12 - 13 years caused this LOWC to be categorized as very large. The total volume leaked over this period has been estimated to be between 6,000 – 25,000 barrels.

In 2001 a spill occurred in Brazil. The total volume was estimated to 150 barrels. For this spill the phase of operation was unknown. In 2002 a 350 bbls spill to the sea from a producing well occurred in the US GoM OCS.

Further, one drilling LOWC event in 2000 caused a release of 150–200 barrels of crude oil (Mississippi Canyon 584). Further, an abandoned well spilled 62 barrels before being controlled in 2010.

For workovers and completions, some LOWC events were listed with minor pollution. These spills were not severe. Typically, some few gallons of oil entered the water or a limited sheen was reported. None of these incidents were regarded as important pollution events.

In the period 1980–1999, none of the LOWC events in the US GoM OCS, Norway, or UK caused any significant pollution incident.

### Ignition

Table 14.3 shows the number of ignited LOWC events and the ignition time.

*Table 14.3 Ignition of LOWC events in regulated areas including US GoM OCS 2000–2015*

| Main category | Ignition time grouped | Development drilling | | Exploration drilling | | Compl-etion | Work-over | Prod-uction | Wire-line | Abando-ned well | Unknown | Total | Distri-bution % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Deep | Shallow | Deep | Shallow | | | | | | | | |
| Blowout (surface flow) | Immediate ignition | | | 2 | | | | 1 | | 1 | | 4 | 7.4 % |
| | 5 min - 1 hour | | 1 | | | | | | | | | 1 | 1.9 % |
| | 6 - 24 hours | | | | | 1 | | | | | | 1 | 1.9 % |
| | More than 24 hours | 1 | 1 | | | | | | | | | 2 | 3.7 % |
| | No ignition | 2 | 8 | 8 | 6 | 1 | 11 | 7 | 1 | 1 | 1 | 46 | 85.2 % |
| | Total | 3 | 10 | 10 | 6 | 2 | 11 | 8 | 1 | 2 | 1 | 54 | 100.0 % |
| Blowout (undergro-und flow) | No ignition | 1 | | 3 | | | | | | | | 4 | 100.0 % |
| | Total | 1 | | 3 | | | | | | | | 4 | 100.0 % |
| Diverted well release | No ignition | | 6 | 1 | 4 | 1 | | | | | | 12 | 100.0 % |
| | Total | | 6 | 1 | 4 | 1 | | | | | | 12 | 100.0 % |
| Well release | Immediate ignition | | | 1 | | | 1 | | | | | 2 | 4.3 % |
| | No ignition | 2 | | 3 | 2 | 5 | 17 | 7 | 6 | 2 | 1 | 45 | 95.7 % |
| | Total | 2 | | 4 | 2 | 5 | 18 | 7 | 6 | 2 | 1 | 47 | 100.0 % |
| Total all | | 6 | 16 | 18 | 12 | 8 | 29 | 15 | 7 | 4 | 2 | 117 | |

Eight (8.5%) of the 117 LOWC events ignited. Eight (14.8%) of the *blowout (surface flow)* and two (4.3%) of the *well releases* ignited. *Blowout (surface flow)* may ignite immediately or delayed, whereas *well releases* typically have a short duration and, if igniting, it ignites immediately.

### Material losses to rig

Table 14.4 gives an overview of the installation damages related to LOWC events.

*Table 14.4 Installation damages of LOWC events in regulated areas including US GoM OCS 2000–2015*

| Main category | Consequence Class | Development drilling | | Exploration drilling | | Comp-letion | Work-over | Prod-uction | Wire-line | Abando-ned well | Un-known | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Deep | Shallow | Deep | Shallow | | | | | | | |
| Blowout (surface flow) | Total loss | 1 | | 1 | | 1 | | 1 | | | | 4 |
| | Severe | | 1 | | | | | | | 1 | | 2 |
| | Damage | | 1 | | | | 1 | 1 | | | | 3 |
| | Small | 1 | | 2 | | | | 1 | | | | 4 |
| | No | 1 | 8 | 6 | 5 | 1 | 10 | 5 | 1 | 1 | 1 | 39 |
| | Unknown | | | 1 | 1 | | | | | | | 2 |
| | Total | 3 | 10 | 10 | 6 | 2 | 11 | 8 | 1 | 2 | 1 | 54 |
| Blowout (underground flow) | No | 1 | | 2 | | | | | | | | 3 |
| | Unknown | | | 1 | | | | | | | | 1 |
| | Total | 1 | | 3 | | | | | | | | 4 |
| Diverted well release | No | | 6 | 1 | 4 | 1 | | | | | | 12 |
| | Total | | 6 | 1 | 4 | 1 | | | | | | 12 |
| Well release | Severe | | | 1 | | | | | | | | 1 |
| | Damage | | | | | | 1 | | | | | 1 |
| | Small | | | | | | 3 | | | | | 3 |
| | No | 2 | | 3 | 2 | 5 | 13 | 7 | 5 | 2 | 1 | 40 |
| | Unknown | | | | | | 1 | | 1 | | | 2 |
| | Total | 2 | | 4 | 2 | 5 | 18 | 7 | 6 | 2 | 1 | 47 |
| Total all | | 6 | 16 | 18 | 12 | 8 | 29 | 15 | 7 | 4 | 2 | 117 |

Most LOWC events lead to minor consequences for the installations. Four of the 117 events in Table 14.4 are categorized as *total loss* after the LOWC event, and three are listed with severe damage.

## 14.2 Shallow Zone Drilling LOWCs

A total of 27 shallow zone LOWC events were observed in the regulated areas including US GoM OCS in shallow gas in the period 2000–2015.

**Fatalities**

No fatalities were experienced related to shallow gas in regulated areas including US GoM OCS in the period 2000–2015.

**Pollution**

None of the LOWC events caused any significant pollution, only gas, formation water, and drilling mud was spilled.

**Ignition**

Table 14.5 shows an overview of the experienced ignition for the shallow zone LOWC events in regulated areas including US GoM OCS in in the period 2000–2015.

*Table 14.5 Experienced ignition of shallow gas LOWC events in regulated areas including US GoM OCS 2000–2015*

| **Main category** | **Ignition time grouped** | | | | **Total** |
|---|---|---|---|---|---|
| | Drilling without riser | Drilling with riser | | | |
| | No ignition | No ignition | 5 min - 1 hour | More than 24 hours | |
| Blowout (surface flow) | 6 | 8 | 1 | 1 | 16 |
| | 37.5 % | 50.0 % | 6.3 % | 6.3 % | 100.0 % |
| Diverted well release | | 10 | | | 10 |
| | | 100.0 % | | | 100.0 % |
| Well release | 2 | | | | 2 |
| | 100.0 % | | | | 100.0 % |
| Total | 8 | 18 | 1 | 1 | 28 |
| | 28.6 % | 64.3 % | 3.6 % | 3.6 % | 100.0 % |

Two of the 28 LOWC events ignited. Both these LOWC events occurred during *blowout (surface flow)* when drilling with a riser, i.e. from a fixed installation. When drilling without a riser, shallow zone LOWC events rarely ignites. In deepwater the gas will pose no danger for an installation. Some gas will dissolve in the water and the gas that comes to the surface (if any) will be released in a large area so an explosive mixture of gas and air will not be formed. In shallow water, shallow gas released on the seafloor may cause a danger. Successfully diverted LOWC events rarely ignite.

**Material losses to rig**

Only the two ignited LOWC events caused significant damage to the installation. For one the damage to the rig and platform was estimated to be two million dollars (2002). For the other the derrick and substructure of the rig collapsed onto the platform, but no cost was listed in the investigation report (2000).

In the period 1980 – 2000, a total of 72 shallow gas LOWC events occurred in the regulated areas including US GoM OCS. Seven of these ignited and two of the ignited LOWC events caused fatalities. One in Norway (1985) causing one fatality and one in the US GoM OCS back in 1980 causing six fatalities.

## 14.3 Deep Zone Drilling LOWCs

A total of 24 deep zone drilling LOWC events were observed in the regulated areas including US GoM OCS in the period 2000–2015.

**Fatalities**

Two of the 24 LOWC events involved fatalities in the regulated areas including US GoM OCS in the period 2000–2015. One LOWC caused 11 fatalities and the other caused one fatality. Both these LOWC events were *blowout (surface flow*). The accident with 11 fatalities was the Deepwater Horizon accident. The persons immediately died in the explosion. For the other fatal accident (2001), there was no ignition. The person did not evacuate with the others and disappeared, and the body was never found.

If looking at the deep zone drilling LOWC events in the period 1980 until 1999 there were in to total 47 LOWC events. Four LOWC events involved fatalities. These were *blowout (surface* *flow)* LOWC events that ignited. Two with a single fatality, one with four fatalities, and one with five fatalities. All the LOWC events that involved fatalities occurred in the 80's.

**Pollution**
Three of the 24 LOWC events caused major pollution accidents:

- Australia, Montara; A total volume of 29,600 barrels 4,800 m3, or 66 m3 per day (2009)
- USA, Macondo: 8,000 m3 a day in 85 days, 680,000 m3, or 4,250,000 bbls (2010)
- Brazil, Frade field: 600 bbls per day or 3,700 bbls in total (2011)

For the Australian LOWC event, only one barrier was present. When this barrier failed the well flow could not be stopped. For the Brazilian LOWC event, water injection had increased the formation pressure to above the natural formation pressure. The formation broke down in association with a kick occurrence. Oil was released through the formation to the sea floor.

In addition, one LOWC event in 2000 caused a release of 150-200 barrels of crude oil. The LMRP was accidentally disconnected when drilling in the reservoir. They managed to re-connect the LMRP after some hours.

If looking at the LOWC events from 1980–1999 none had a significant release of crude oil. Only one of the deep zone drilling LOWC events had a significant release of condensate. That was the Vinland blowout in 1984 offshore the east coast of Canada. The flow rate was estimated to be 48 cubic meters/day (300 bbls a day) of condensate and 2 million cubic meter of gas per day. The flow rate was observed to diminish throughout the course of the blowout. The blowout lasted for 10 days. Sea surface spill was not mentioned in the data sources, indicating that the condensate was evaporated/diluted rather fast. It was bad weather in the area through the first days of the incident.

Table 13.11, page 124 shows all drilling LOWC events with oil and condensate spills in the period 2000–2015 in the US GoM OCS and the regulated areas.

**Ignition**

Table 14.6 shows an overview of the experienced ignition for the deep zone drilling LOWC events in regulated areas including US GoM OCS in in the period 2000–2015.

*Table 14.6 Experienced ignition of deep zone drilling LOWC events in regulated areas including US GoM OCS 2000–2015*

| Main category | Ignition time grouped | | | Total |
|---|---|---|---|---|
| | No ignition | Immediate ignition | More than 24 hours | |
| Blowout (surface flow) | 10 | 2 | 1 | 13 |
| | 76.9 % | 15.4 % | 7.7 % | 100.0 % |
| Blowout underground flow | 4 | | | 4 |
| | 100.0 % | | | 100.0 % |
| Diverted well release | 1 | | | 1 |
| | 100.0 % | | | 100.0 % |
| Well release | 5 | 1 | | 6 |
| | 83.3 % | 16.7 % | | 100.0 % |
| Total | 20 | 3 | 1 | 24 |
| | 83.3 % | 12.5 % | 4.2 % | 100.0 % |

Of the 24 deep zone drilling LOWC events four ignited. Three of these four were *blowout (surface flow)* LOWC events, and the forth one was a *well release* LOWC. Three of the four incidents ignited immediately.

For the period 1980 to 1999, a total of 47 LOWC events occurred during drilling. Of these 47 incidents, eight ignited. All of them were *blowout (surface flow)* incidents. In total 25% of the *blowout (surface flow)* LOWC events ignited.

### Material losses to rig

For two of the LOWC events in regulated areas including US GoM OCS in in the period 2000–2015 the installation was damaged beyond repair. One was the Deepwater Horizon rig that sank because of the fire. The second one was the West Atlas Jack-up (used for Montara operations) in Australia that was condemned.

For one *well release* LOWC, the rig was severely damaged. This was for a well drilled in Brazil in 2007. The rig was inoperable for 11 months after the incident, before it was repaired. For the remaining incidents, the damages were small.

## 14.4 Workover LOWCs

A total of 29 workover LOWC events were observed in the regulated areas including US GoM OCS in the period 2000–2015.

### Fatalities

One workover LOWC caused a fatality. During a *well release,* the tubing was blown out of the well causing the slips to fatally strike the operators representative.

If looking at the workover LOWC events in the period 1980 until 1999 there were in to total 31 LOWC events. Two LOWC events involved fatalities. One *blowout (surface flow)* LOWC event ignited and caused two fatalities. The other one was an unignited *well release* where the tubing used for removing the back pressure valve jumped and the rotary bushing inserts were blown out. One of these inserts hit and killed a person.

**Pollution**
Ten of the 28 workover LOWC events were listed with some pollution. These spills were not severe. Typically, they were listed with some few gallons that had entered the water or a limited sheen was reported. For none of the incidents the pollution was regarded as an important issue.

Table 13.11, page 124 shows all workover LOWC events with oil and condensate spills in the period 2000–2015 in the US GoM OCS and the regulated areas.

If looking at the 31 workover LOWC events from 1980–1999 in US GoM OCS, Norway and the UK, the same type of spills are observed, typically small and some sheen observed on the sea surface.

**Ignition**
Table 14.7 shows an overview of the experienced ignition for the workover LOWC events in regulated areas including US GoM OCS in in the period 2000–2015.

*Table 14.7 Experienced ignition of workover LOWC events in regulated areas including US GoM OCS 2000–2015*

| Main category | Ignition time grouped | | Total |
|---|---|---|---|
| | No ignition | Immediate ignition | |
| Blowout (surface flow) | 11 | | 11 |
| | 100.0 % | | |
| Well release | 17 | 1 | 18 |
| | 94.4 % | 5.6 % | |
| Total | 28 | 1 | 29 |
| | 96.6 | 3.4 % | |

Of the 29 workover LOWC events, only one ignited. This incident was a *well release* LOWC that ignited immediately.

**Material losses to rig**

For three of the incidents there were minor damages to the installation. For the Norwegian Snorre blowout, there was no significant damage to the installation, but it took several months before the field could be restarted.

## 14.5 Completion LOWCs

Eight completion LOWC events were observed in the regulated areas including US GoM OCS in the period 2000–2015.

**Fatalities**

None of the completion LOWC events caused fatalities.

If looking at the completion LOWC events in the period 1980 until 1999 there were in total 13 LOWC events. None of the LOWC events involved fatalities.

**Pollution**

None of the eight completion LOWC events were listed with pollution.

If looking at the 13 completion LOWC events from 1980–1999, two of them were listed with small pollution. Both reported a light sheen.

**Ignition**

Table 14.8 shows an overview of the experienced ignition for the completion LOWC events in regulated areas including US GoM OCS in the period 2000–2015.

*Table 14.8 Experienced ignition of completion LOWC events in regulated areas including US GoM OCS 2000–2015*

| Main category | Ignition time grouped | | Total |
|---|---|---|---|
| | No ignition | 6 – 24 hours | |
| Blowout (surface flow) | 1 | 1 | 11 |
| | 50.0 % | 50.0 % | 100.0 % |
| Diverted well release | 1 | | 1 |
| | 100.0 % | | 100.0 % |
| Well release | 5 | | 5 |
| | 100.0 % | | 100.0 % |
| Total | 7 | 1 | 28 |
| | 87.5% | 12.5% | 100.0 % |

Of the eight completion LOWC events only one ignited. This incident was the Walter Oil & Gas blowout on Hercules 265 in 2013. The blowout ignited after 13 hours. The flow rate was estimated to be 400 million cubic feet per day (115 kg/s). The platform was damaged beyond repair, and Hercules received 50 million US Dollars from the insurance company.

None of the other completion LOWC events caused significant damage to the installation.

## 14.6 Production LOWCs

Fifteen production well LOWC events were observed in the regulated areas including US GoM OCS in the period 2000–2015. Five of these events were caused by an external force (storm, collision, fire, etc.).

**Fatalities**

None of the production well LOWC events caused fatalities.

**Pollution**

For eight of the 15 events, some pollution to the sea surface was observed. Six these releases were small or very small. One was categories as medium and one as very large. The very large spill has been going one for many years. The flowrate is low, but the cumulative amount of oil spilled is high. For the medium spill an estimated 350 barrels of crude oil was released.

**Ignition**

One of the incidents ignited. This was an event where a boat hit an unmanned structure and ignited immediately. Ninety percent of the structure was destroyed because of the collision and subsequent fire.

## 14.7 Wireline LOWCs

Seven wireline LOWC events were observed in the regulated areas including US GoM OCS in the period 2000–2015. Most of the incidents were categorized as *well releases*, that typically have a short duration. One incident was categorized as a *blowout (surface flow)*. For this case the wireline BOP failed to stop the gas flow.

**Fatalities**

None of the wireline LOWC events caused fatalities.

**Pollution**

None of the LOWC events caused pollution to the sea surface. For one some oil was released, but it was collected on the rig.

**Ignition**

None of the LOWC incidents ignited.

## 14.8 Abandoned Wells LOWCs

Four abandoned well LOWC events were observed in the regulated areas including US GoM OCS in the period 2000–2015.

**Fatalities**

None of the abandoned well LOWC events caused fatalities.

**Pollution**

One incident caused a gas release. One incident (Elgin) released mostly gas, but some condensate. The condensate created a scattered sheen that evaporated. The estimated flow rate was around 2 kg/s for 53 days. For the third incident oil seeped from the abandoned wellhead at an initial estimated rate of 5.1 barrels a day. The total volume spilled during the 32 days' release was estimated to 62 barrels (10 $m^3$). For the forth incident some gas leaked and allowed gas to migrate up through the cement into the annular void of the well and into the atmosphere, when working on the neighbor well.

**Ignition**

One of the incidents ignited immediately. The fire lasted for 27 hours and made damages to the installation.

For the other LOWC incidents there were no damages to the installations. The Elgin and Franklin was however closed in for one year. The production rate from the field was around 70,000 barrels a day.

## 14.9 Unknown Phase LOWCs

Two *Unknown Phase* LOWC event was observed in the regulated areas including US GoM OCS in the period 2000–2015. One was categorized as a *well release,* and the other as a *blowout (surface flow)*.

**Fatalities**

None of the *Unknown Phase* LOWC events caused fatalities.

**Pollution**

Both incidents caused a spill to sea. For one it was very small. For the other the release was in the range of 80 – 150 barrels.

**Ignition**

None of the incident ignited.

There were no damages to the installations.

# 15 LOWC CAUSAL FACTORS

The causal factor in this section stems from LOWC events that have occurred in the regulated areas including the US GoM OCS for the period 2000 – 2015.

## 15.1 Shallow Zone LOWC

The experience related to shallow zone LOWC events is presented in Section 5. The intention with this subsection is to identify the most common causes related to shallow zone LOWC events as well as the most frequent sequences of events leading to LOWC.

For shallow gas, the only barrier against flow is the hydrostatic pressure from the mud. If the hydrostatic control of the well is lost it will result in a LOWC. Shallow flows cannot normally be closed in because the fracture gradient at the casing shoe will normally be low, and a BOP is not set on the wellhead.

For floating vessels, the shallow gas is released on the sea floor because there is no riser between the wellhead and the rig. For fixed installation, the gas will normally be diverted away from the rig.

### *15.1.1 Shallow Zone Kick Causes*

Figure 15.1 shows a distribution of the shallow zone kick causes.

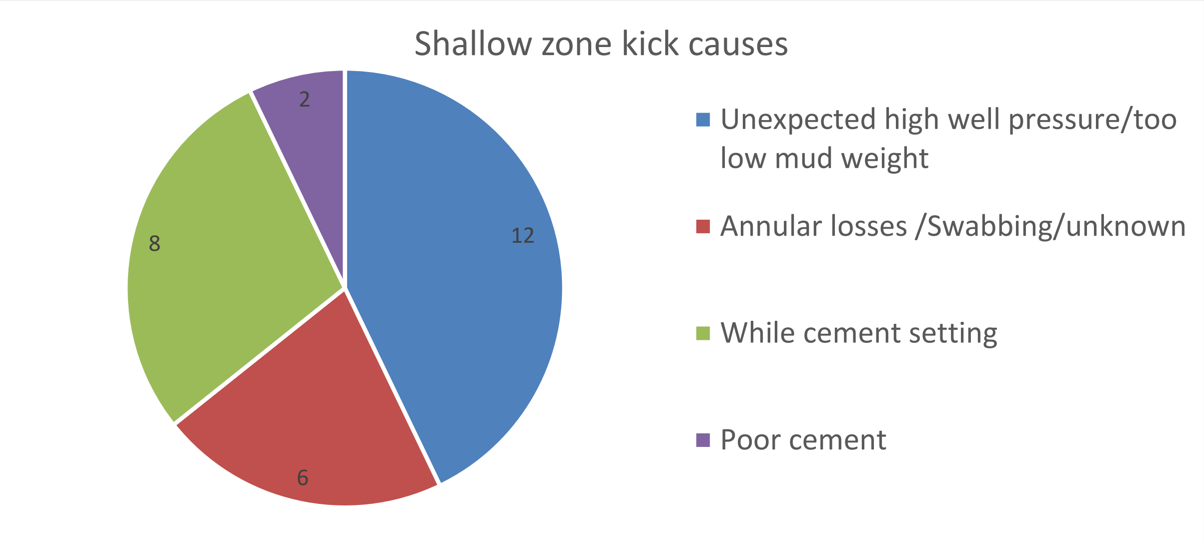


*Figure 15.1 Shallow zone kick causes*

Unexpected high well pressure and flow after cementing are the two most frequent causes for the shallow flows.

The shallow section of a well is frequently drilled with seawater as the drilling fluid; slightly over pressured gas accumulations may initiate a flow. For several of the incidents shallow gas was not expected to be present, because geo-hazard analysis did not foresee any shallow gas problem. Shallow gas experience from nearby wells are not always considered. The risk of shallow gas has not always been properly communicated to the involved parties.

For some cases, the cement program was not properly designed. The flow while cement is setting cases confirm that.

Important factors to focus on to reduce the possibility of flow after cementing are:

- Awareness of shallow gas.
- Continuously monitoring the annulus for fluid level or fluid gain.
- Waiting time for cement to cure.
- Utilize lower fluid loss cement slurry to avoid flow after cementing.
- Hold nominal pressure on annulus while waiting on cement.

### 15.1.2 HANDLING OF SHALLOW ZONE LOWCS

The handling of shallow gas LOWC events is separated in two pie charts. Figure 15.2 shows shallow flow handling, when drilling without a riser and Figure 15.3 shows the shallow flow handling, when drilling with a riser.

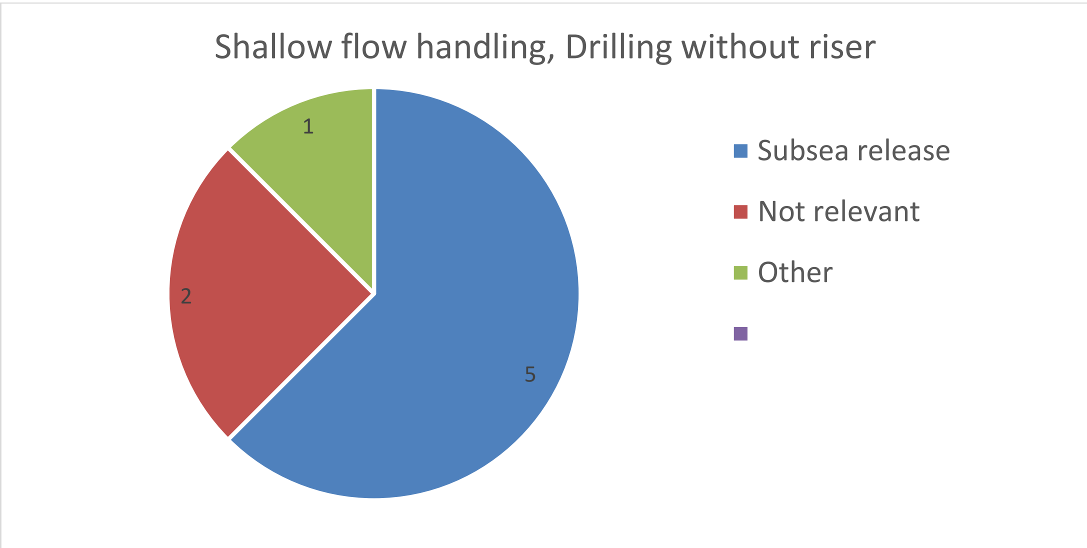


*Figure 15.2 Shallow zone flow handling, drilling without a riser*

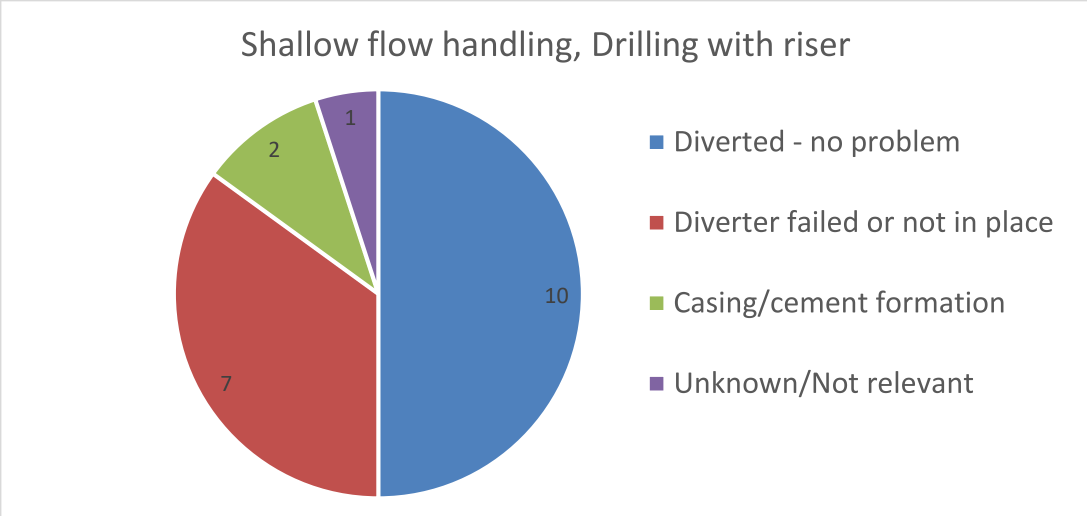


*Figure 15.3 Shallow zone flow handling, drilling with a riser*

Release at the seafloor for floating installations and diverted release for bottom fixed installations are the normal outcomes of shallow gas flow.

For a large proportion of the diverted incidents, the diverters failed to function as intended. Two incidents occurred because the diverter was nippled down, one because the diverter was inoperable due to a human error, and in three cases there was a leak in the diverter or diverter flange. Only one incident caused a diverter line to erode and leak. Diverter line leaks due to erosion were far more frequent in the period 1980–1999, indicating that the diverter systems have improved.

## 15.2 Deep zone drilling

A deep zone drilling LOWC event will always start with a well kick. If failing to close in the well when it kicks it will result in a LOWC event. It should be noted that well kicks are fairly normal. They are normally detected in a timely manner and handled properly so an LOWC event will not be the outcome. Well kick occurrences are discussed in Section 15.8, page 158.

### *15.2.1 Kick observation*

For 11 of the 24 drilling LOWC events the kick was not observed before fluid was flowing out of the well. For nine the kick was observed in time to close in the well, and for four it is unknown when the kick was observed. Figure 15.4 shows a pie diagram for the kick observation.

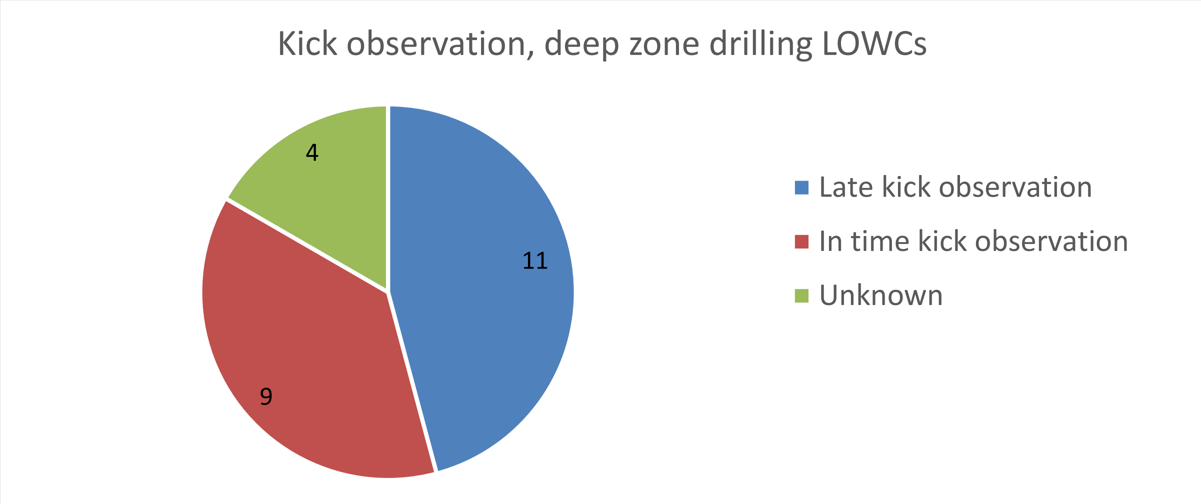


*Figure 15.4 Kick observation in deep zone drilling LOWC events*

Many of these late observations are related to lack of attention, but some are also related to the procedures followed. One typical example is that after the casing has been cemented and the preset time for the cement to harden has ended, the surface BOP is nippled down to cut casing/energize casing seals, and the well starts to flow when the BOP is disconnected. This may be caused by too short waiting time, but other factors as cement type used and problems during cementing may contribute to these types of incidents.

### 15.2.2 CAUSES FOR SECONDARY BARRIER FAILURES

For the 11 LOWC incidents categorized as *blowout (underground flow), diverted well release, and well release* typically there were no equipment failures involved. For the *blowout (underground flow),* typically the formation broke down.

For the *well releases type* LOWC events the most typical was that the BOP was closed late because the kick was detected late. After the BOP was closed, the situations were controlled.

For the 13 *blowout (surface flow)* LOWC incidents equipment failures were involved in most of them. Four of these incident occurred on drillships and semisubmersibles, eight on jack-ups and one on a jacket.

Since the floating vessels have a subsea BOP and the jack-ups and jackets have a surface BOP these have been separated when evaluating the secondary barrier failures for deep zone drilling *blowout (surface flow)* LOWC events.

Figure 15.5 and Figure 15.6 shows pie diagrams for equipment failure in deep zone drilling *Blowout (surface flow.)*

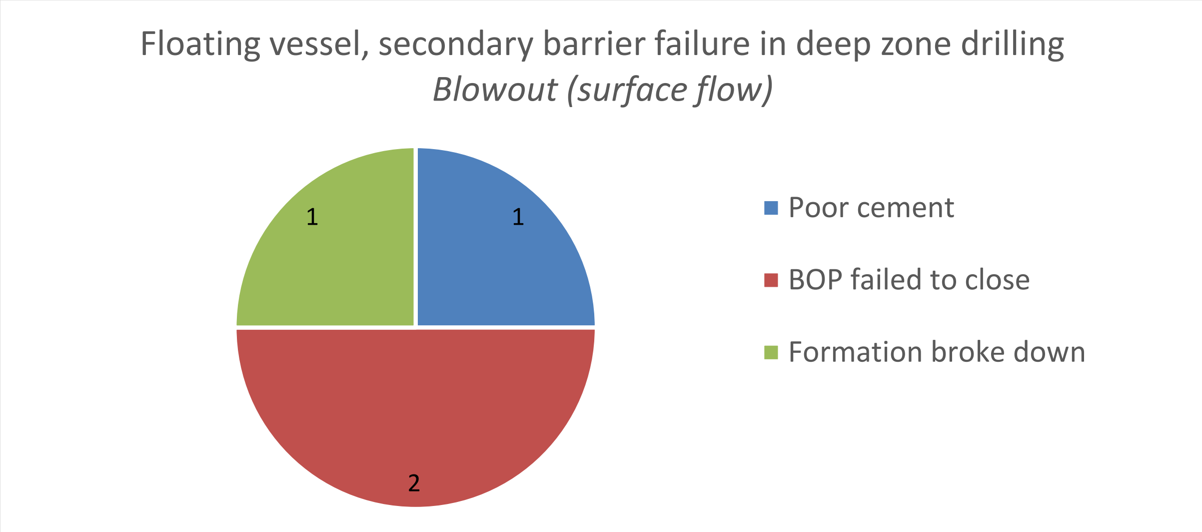


*Figure 15.5 Floating vessel, equipment failure in deep zone drilling blowout (surface flow)*

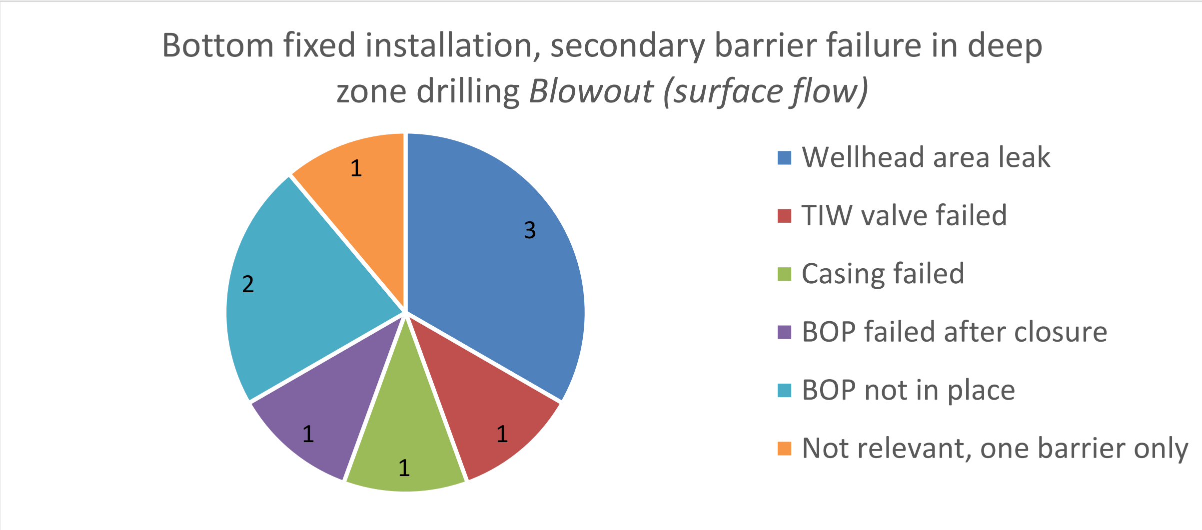


*Figure 15.6 Bottom fixed vessel, equipment failure in deep zone drilling blowout (surface flow)*

For the floating vessels (Figure 15.5) the BOP failed to close in two occasions. One was the Deepwater Horizon incident and the other was an incident where the LMRP was disconnected by a mistake, and thereby the BOP control was lost and the well kicked. Both incidents were in deepwater. The second incident would likely not occur in the US GoM OCS today because of the required autoshear function in the subsea BOPs. For the Deepwater Horizon the BOP failed to close. The investigation indicated that the pipe had been misaligned within the BOP, and the blind shear ram therefore did not cut the pipe and seal the well.

The increased requirements for subsea BOPs in the US GoM OCS will likely reduce the possibility that a subsea BOP fails to close in an emergency.

The poor cement/formation blowout occurred in 2002. While they were attempting to strip off bottom, the shut-in casing pressure dropped, and they noticed gas bubbles at the surface. The cause of the poor cement was not mentioned in the source.

The formation break down blowout occurred in Brazil in 2011. The reservoir was over pressured by water injection. When drilling in the reservoir and taking a kick the well flowed through a fault opened by the over pressure to the sea floor. A similar incident occurred in China in 2011.

For the bottom fixed installations (Figure 15.6), three of the LOWC events occurred because leaks developed in the wellhead area below the BOP during a kick. One of the leaks was caused by a human error. The two others were regular leaks. These types of leaks are not observed for wells drilled with subsea BOPs.

Two blowouts occurred when the BOP was not in place after cementing the casing. The BOP was nippled down to cut casing or energize casing seals. These are incidents not observed for wells with subsea BOPs.

For the BOP failed after closure, the annular preventer began leaking gas during the well control operation.

In one case, they failed to close the TIW valve (kelly valve), three men were not able to apply enough torque. The valve had not been regularly tested. The BOP did not include a blind shear ram so the well could not be sealed off.

For one LOWC event the casing burst below its rated burst pressure because of heavy wear in the casing that was not detected.

The not relevant incidents is the Montara LOWC event in Australia. The well did not have a secondary barrier. When the primary barrier (an untested cement plug) failed, the blowout occurred.

## 15.3 Completion

This section focuses on the causes of the completion LOWC events. Since two barriers normally should be present during completion operations, this section is focused on the causes of losing the primary barrier and the secondary barrier. The primary barrier in completion operations is normally the hydrostatic control of the well. In some cases, the primary barrier may be a mechanical barrier, depending on how the completion is carried out and the progress of the completion operation.

### *15.3.1 Causes for the primary barrier failures*

All the completion LOWC events in the US GoM and the regulated areas occurred in killed wells.

Figure 15.7 shows the kick observation time in completion LOWC events.

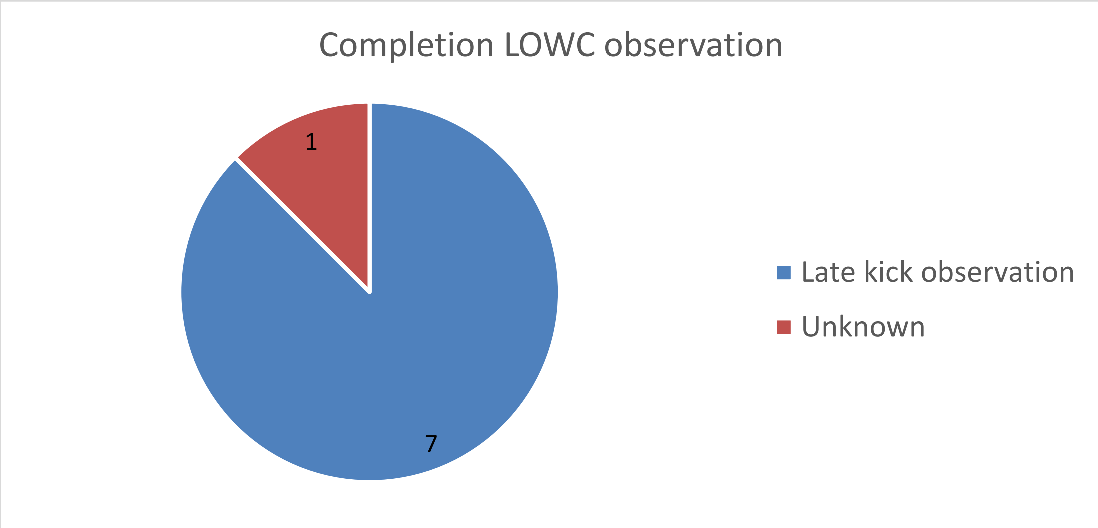


*Figure 15.7 Kick observation in completion LOWC events*

For seven of the eight completion LOWC events the kick was not observed before the well was flowing out to the surroundings.

The late kick detection may be caused by lack of attention, but such incidents are also caused by unforeseen conditions in the well.

Keeping control of the fluid coming out of the well vs. the fluid pumped in is utmost important in kick detection. For two of the LOWC events they had no control of the volume coming out of the well. The fluid was pumped overboard or to the reserve pits without measuring the volume.

Figure 15.8 shows an overview of the causes for the loss of the primary barrier during completions LOWC events.

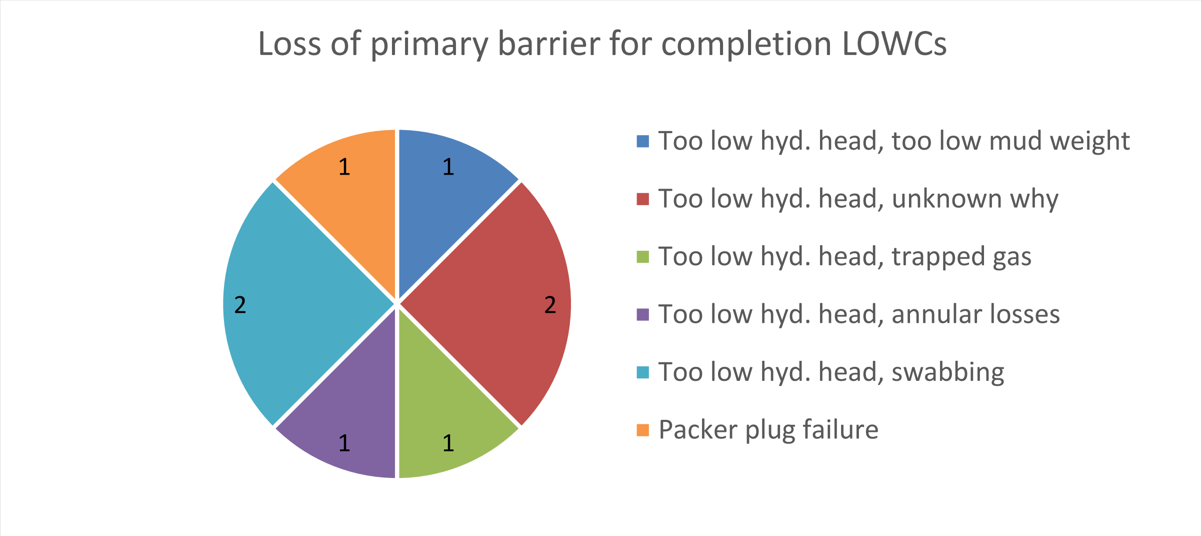


*Figure 15.8 Cause for the primary barrier losses in completion LOWC events*

As for drilling, there are several different causes for losing the hydrostatic control of the well during completion operations. For one incident it was a downhole isolation packer and a formation isolation valve (FIV) that failed, causing the kick. This valve was inflow tested just before the incident.

### 15.3.2 CAUSES FOR THE SECONDARY BARRIER FAILURES

Figure 15.9 shows the causes for loss of secondary barrier for completion LOWC events

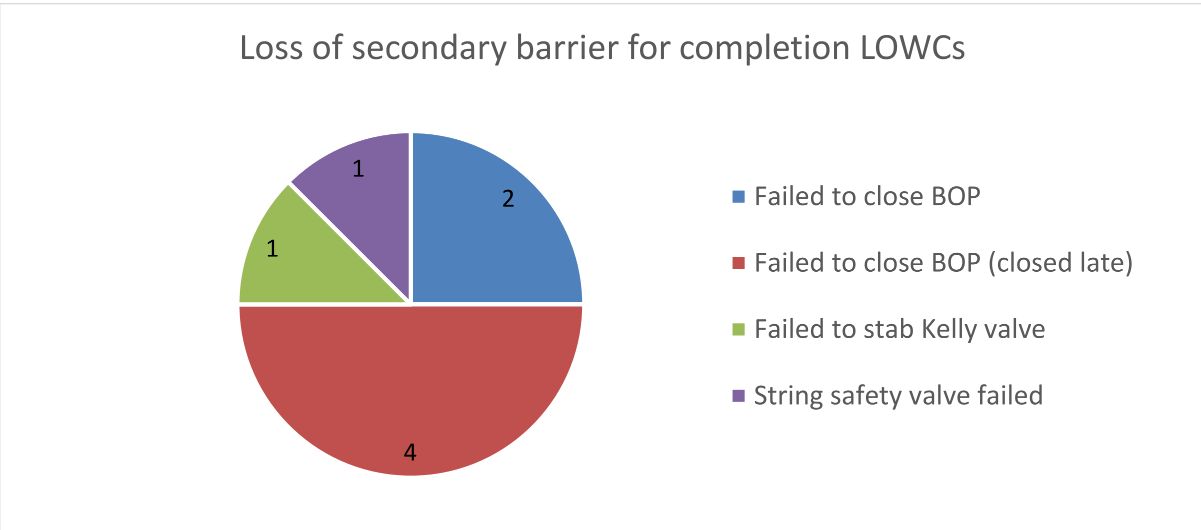


*Figure 15.9 Loss of secondary barrier for completion LOWC events*

Few equipment failures are observed during completion LOWC events. This is likely because the equipment in the wells during completions is new equipment. The failure of the secondary barrier is typically caused by too late detection of the kicks and not the equipment that is failing.

There are two exceptions. In one incident the blind shear rams failed to shear the tubing. For the other incident, first a recently tested formation isolation valve failed, then when attempting to close the BOP the flow through the BOP was too high. API 16A has no requirements related to BOP closure under dynamic flowing conditions. Most BOPs are therefore not designed or tested to close and seal under high rate flowing conditions.

For the string safety valve failed case, the valve was opened by mistake with pressure below.

## 15.4 Workover

In well workover operations the well may be controlled by the hydrostatic pressure from the drilling fluid (killed wells), or mechanical barriers only (live wells).

Human errors were identified in 15 of the 29 workover LOWC events that occurred in the regulated areas including the US GoM OCS. It is likely that there have been more human errors as well, but they cannot be observed from the LOWC descriptions and data sources.

Some of the human errors were related to poor planning of the operations. The possible risks were not properly considered.

Others were related to equipment that would not function due to lack of maintenance or that was not accessible.

In addition, some were related to faulty operations, as jeopardizing a barrier by mistake, closing or opening the wrong valve, tearing off the tubing by using too much force, not performing operations in a safe matter. Poor planning or that procedures are not followed can cause these types of events.

### *15.4.1 Causes for Primary Barrier Failures*

Eleven LOWC events occurred in live wells, three categorized as *blowout (surface flow)* and eight categorized as *well releases*. The remaining 18 LOWC events occurred in killed wells, seven categorized as *blowout (surface flow)* and 11 categorized as *well releases*. Eleven LOWC events occurred in live wells. Eighteen LOWC events occurred in killed wells. Figure 15.10 shows a pie diagram for the workover LOWC observation.

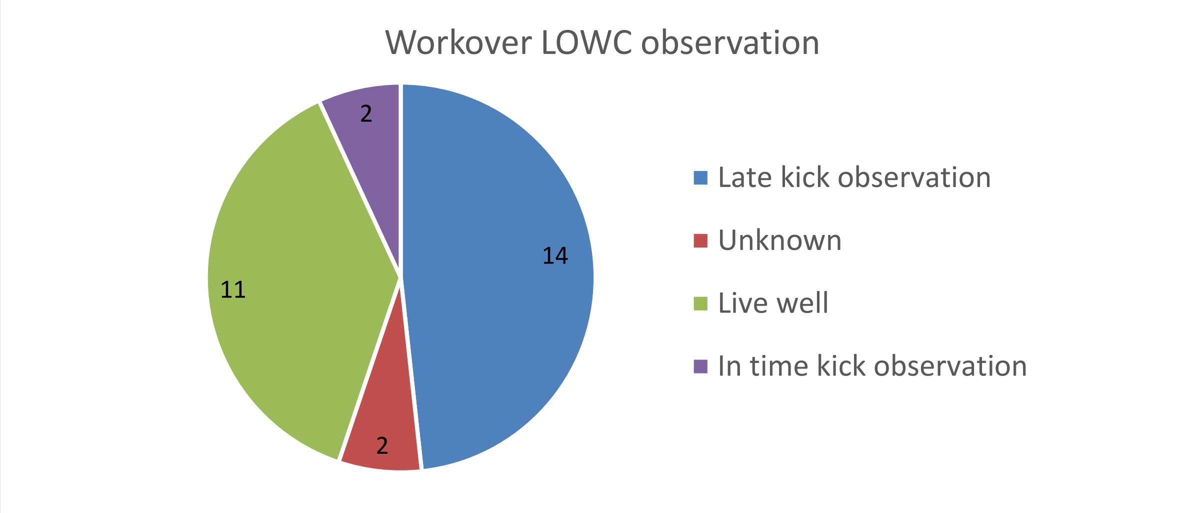


*Figure 15.10 Workover LOWC observation*

For the 11 LOWC events that occurred in live wells the LOWC events were observed as a leak of hydrocarbons to the surroundings.

For 14 of the 18 workover LOWC events that had the well status killed the kick was not observed before the well was flowing out to the surroundings. For two of the remaining they failed to control the kick after some hours of kick killing operations. For two the time from kick to event was unknown.

The late kick detection in many of the cases may be caused by lack of attention, but such incidents are also caused by unforeseen conditions in the well. Barriers may be in failed conditions, equipment is stuck, and pressures may be trapped. A thorough planning prior to workovers will always be important.

Figure 15.11 shows an overview of the causes for the loss of the primary barrier in killed wells.

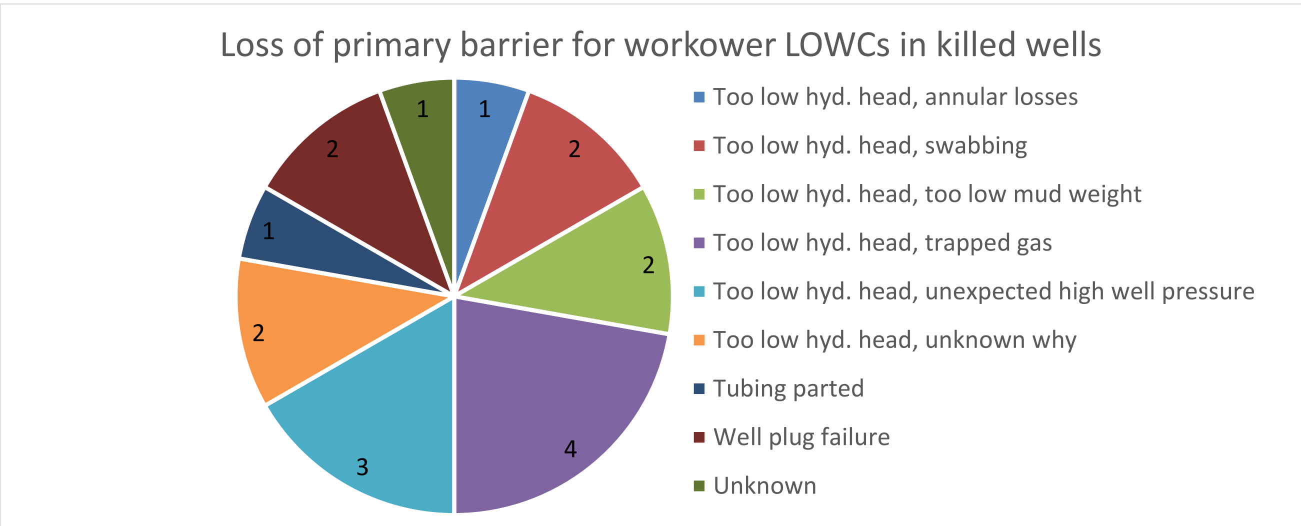


*Figure 15.11 Loss of primary barrier in killed wells*

Four of the kicks (22%) were caused by trapped gas in the well. For some of the others trapped gas may have contributed to the kick, for instance unexpected high well pressure incidents. Otherwise, the reason for the kicks are similar to drilling kicks. Swabbing, annular losses and too low mud weight are listed as causes for the kick. Further, for two of the incidents well plugs failed and for one the tubing parted.

Figure 15.12 shows an overview of the causes for the loss of the primary barrier in live wells.

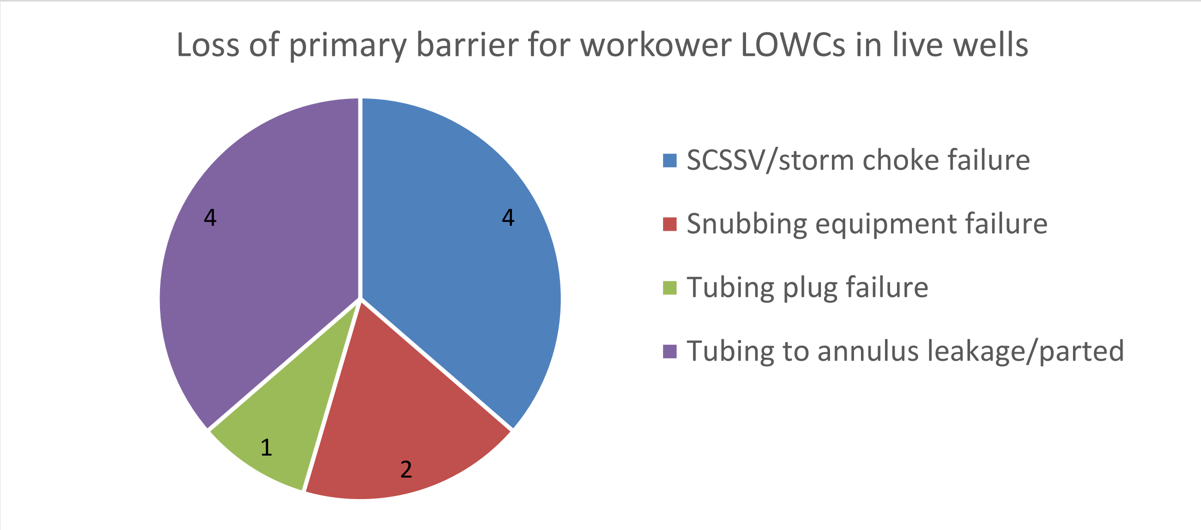


*Figure 15.12 Loss of primary barrier in live wells*

For the live wells the major causes for loss of the primary barrier during a workover were that the SCSSV failed or the tubing failed.

### 15.4.2 CAUSES FOR SECONDARY BARRIER FAILURES

For the 18 workover LOWC events categorized as *well release,* there were typically not any equipment failures involved for the secondary barrier. Typically, the BOP or another available barrier was closed and the situations were controlled after hydrocarbons had been leaking to the surroundings for a limited period.

For the 11 *blowout (surface flow)* incidents, equipment failures were involved in most of the incidents. None of these incidents occurred on a floating installation.

Figure 15.13 shows pie diagrams for equipment failure in workover *blowout (surface flow)* LOWC events.

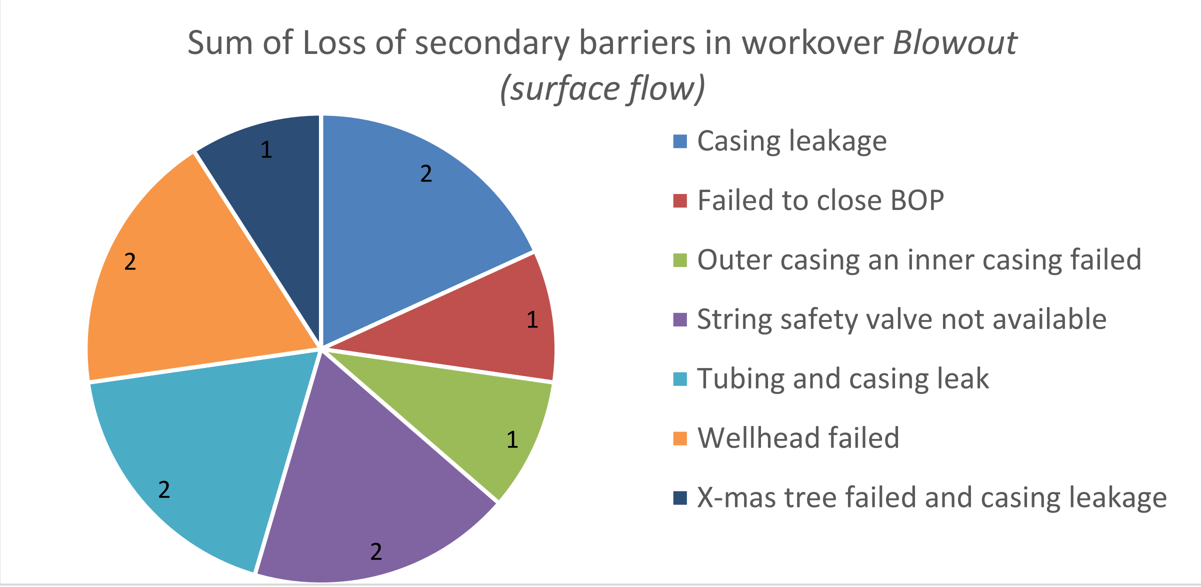


*Figure 15.13 Sum of Loss of secondary barriers in workover blowout (surface flow)*

Four of these 11 *blowout (surface flow)* events were in wells that should be permanently abandoned.

For the two *string safety valve not available*, the valve was not in a ready state to be stabbed into the string. For one the BOPs did not have a blind shear ram, for the other the well was isolated with the blind shear ram after a while.

For the *failed to close BOP,* the BOP did not have a blind shear ram.

For one *tubing and casing leak* secondary barrier failure, severe corrosion in the tubing and casing caused the barrier failure.

For the other *tubing to annulus leak and casing leak* secondary barrier failure, they accidentally cut two holes with a hole saw during toppled well P&A.

For one *casing leak* a scab-liner in the well had been pulled, opening a known casing leak path. When the well kicked, the casing leaked out this leak path.

For the other *casing leak* natural gas bubbled to surface outside the well during plugging operations. The conductor casing was heavily corroded.

For the *outer and inner casing failed*, well control was lost due to leaks in the tubing, production casing, and surface casing to an unsealed annulus.

For one of the *wellhead leaked* incidents a wellhead service technician removed a 1.5"diameter lockdown pin and packing-gland from the wellhead ruining the barrier.

For the other *wellhead leaked* a failed plastic injector port, together with a missing wellhead seal assembly, allowed for the LOWC event to occur.

For the *X-mas tree and casing leak* while installing the hot tap tool on the number 2 tubing string (Short String) the well started flowing gas out the X-mas tree 200 feet.

## 15.5 Production

This section concerns the causes of the production LOWC events. Since two barriers should be present during production operations, this section is focused on the causes of losing the primary barrier and the secondary barrier. During production both the *primary and secondary barriers are mechanical barriers.* In a *flowing* well, the barriers closest to the reservoir are usually regarded as the primary barrier. This would typically be the packer that seals off the annulus, the tubing below the SCSSV, and the SCSSV. The secondary barriers would then be the tubing above the SCSSV, the Xmas tree main flow side, the casing/wellhead, and the annulus side of the Xmas tree.

A large proportion of the production LOWC incidents are caused by an external load. The most typical external loads are storm, fires and ship collisions. It is, however, important to note that an external load normally only ruins the topside barrier. To experience a blowout, the downhole barrier also must fail. So, an external load will not be the single blowout cause. Typically, the external load ruins the wellhead/X-mas tree barriers of an active well (secondary barrier), and the downhole barrier (primary barrier) then fails to activate or is leaking.

In the regulated areas including the US GoM OCS the wells will have a down hole safety valve (SCSSV). This is not the case for many other areas of the world.

### *15.5.1 Causes for the primary barrier failures*

Figure 15.14 shows the primary barriers failures in the production phase LOWC events.

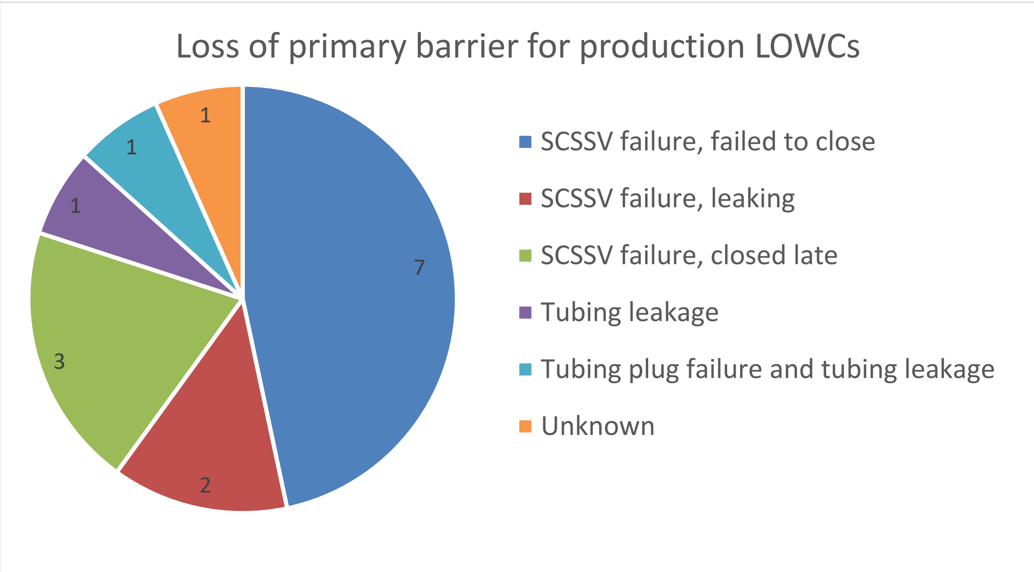


*Figure 15.14 Loss of primary barrier in production phase LOWC events*

Most of the primary barrier failures involves the SCSSV. The *failed to close* incidents may be related to the controls, the ESD, the valve itself, sand in the well, or scale. The *closed late* incidents are typically incidents where the valve is closed after the release on surface is observed.

### 15.5.2 CAUSES FOR SECONDARY BARRIER FAILURES

Figure 15.15 shows the secondary barriers failures in the production phase LOWC events.

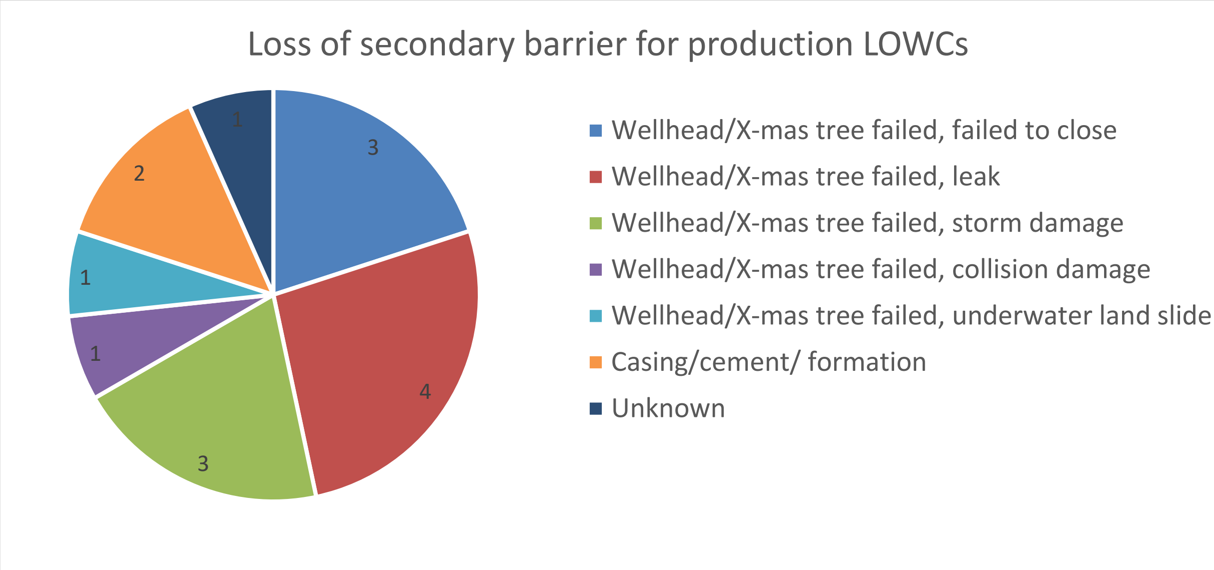


*Figure 15.15 Loss of secondary barrier in production phase LOWC events*

The wellhead or X-mas tree has some sort of failure in most of the production phase LOWC incident. Either valves fail to close or there is a leak. The leak may be caused by normal wear and tear failures, or as a result of an external load.

## 15.6 WIRELINE

All wireline LOWCs occurred in live wells. During wireline operations, a stuffing box/lubricator and/or a wireline BOP located on top of the X-mas tree is normally the primary barrier. If the well cannot be controlled by those means, the wireline is dropped or cut before the X-mas tree is closed to control the well.

### 15.6.1 CAUSES FOR THE PRIMARY BARRIER FAILURES

Figure 15.16 shows the primary barriers failures in the wireline LOWC events.

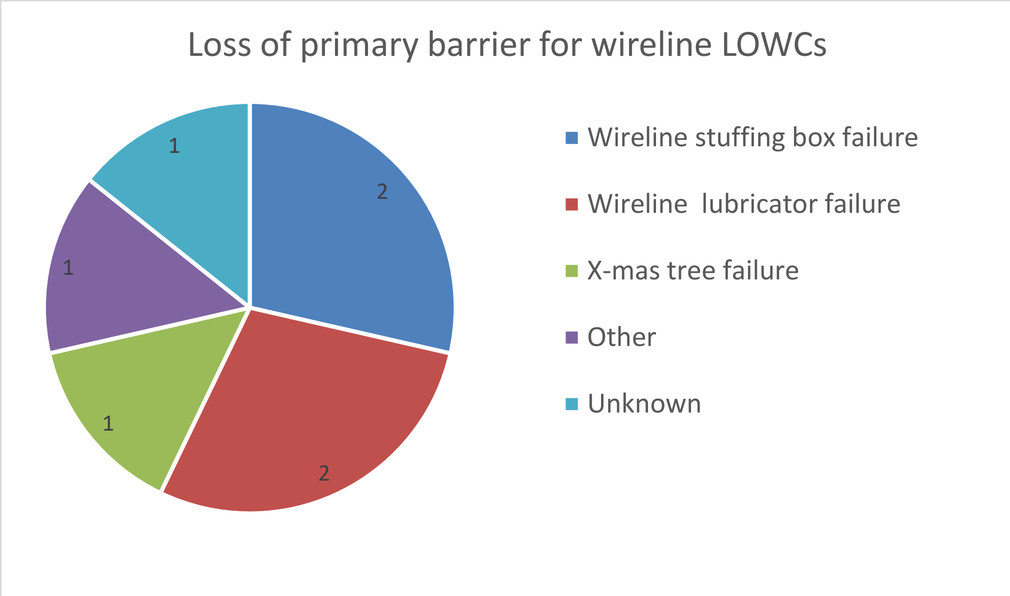


*Figure 15.16 Loss of primary barrier in wireline LOWC events*

Wireline stuffing box and wireline lubricator were involved in four of the seven events.

### *15.6.2 CAUSES FOR SECONDARY BARRIER FAILURES*

Figure 15.17 shows the secondary barriers failures in the wireline LOWC events.

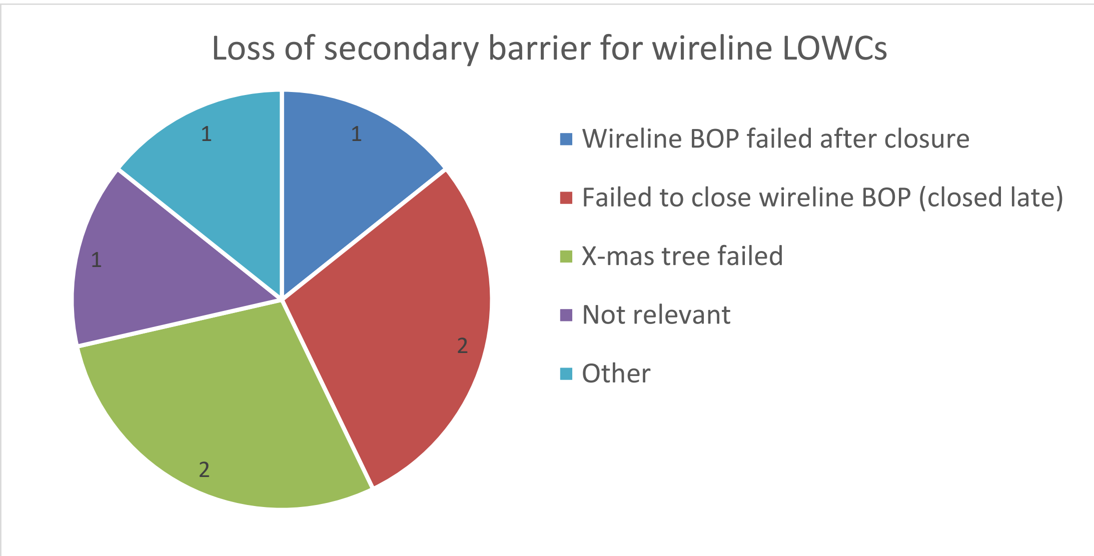


*Figure 15.17 Loss of secondary barrier in wireline LOWC events*

*For the case were the wireline failed after closure the incident resulted in a blowout (surface flow) event.* For the other events the release had a relatively short duration and were categorized as a well release.

## 15.7 CAUSAL FACTORS SUMMARY

Equipment failures and human errors are frequently involved in LOWC events. Table 15.1 shows a summary of the causal factors discussed in this section.

*Table 15.1 Causal factors summary*

| Type of operation | Primary barrier failure | Distri-bution | Well kick observation | Distri-bution | Gas handling | Distri-bution |
|---|---|---|---|---|---|---|
| Shallow gas bottom fixed installation | Unexpected high well pressure | 42 % | | | Diverted, no problem | 44 % |
| | While cement setting | 27 % | | | Diverter failed or not in place | 30 % |
| | Other | 31 % | | | Other/unknown | 24 % |
| Shallow gas floating installation | Unexpected high well pressure | 42 % | | | Subsea release | 75 % |
| | While cement setting | 27 % | | | Other/unknown | 25 % |
| | Other | 31 % | | | | |
| Deep zone drilling floating | **Primary barrier failure** | | **Well kick observation** | | **Secondary barrier (Blowout (surface Flow))** | |
| | | | Late kick observation | 38 % | BOP failed | 50 % |
| | Loss of hydrostatic control | 100% | In time kick observation | 38 % | Formation broke down | 25 % |
| | | | Unknown | 24 % | Poor cement | 25 % |
| Deep zone drilling fixed | **Primary barrier failure** | | Late kick observation | 38 % | Wellhead area leak | 33 % |
| | | | In time kick observation | 38 % | BOP not in place | 22 % |
| | Loss of hydrostatic control | 100% | Unknown | 24 % | BOP failed after closure | 11 % |
| | | | | | Casing failed | 11 % |
| | | | | | Other | 22 % |
| Workover, killed wells | **Primary barrier failure** | | **Well kick observation** | | **Secondary barrier (Blowout (surface Flow))** | |
| | Unexpected high well pressure/too low mud weight | 28 % | Late kick observation | 78 % | Casing leak | 27 % |
| | Trapped gas | 22 % | In time kick observation | 11 % | Casing and tubing leaked | 18 % |
| | Swabbing, losses, unknown | 22 % | Unknown | 11 % | Casing and X-mas tree leaked | 9 % |
| | Well plug failure | 11 % | | | Wellhead failed | 18 % |
| | Tubing parted | 6 % | | | Kelly valve not available | 18 % |
| | Unknown | 6 % | | | Failed to close BOP | 9 % |
| Workover, live wells | **Primary barrier failure** | | | | **Secondary barrier (Blowout (surface Flow))** | |
| | SCSSV /storm choke failure | 36 % | | | Casing leak | 27 % |
| | Tubing leakage/parted | 36 % | | | Casing and tubing leaked | 18 % |
| | Snubbing equipment failure | 18 % | | | Casing and X-mas tree leaked | 9 % |
| | Tubing plug failure | 9 % | | | Wellhead failed | 18 % |
| | | | | | Kelly valve not available | 18 % |
| | | | | | Failed to close BOP | 9 % |
| Completion | **Primary barrier failure** | | **Well kick observation** | | **Secondary barrier (Blowout (surface Flow))** | |
| | Loss of hydrostatic control | 100% | Late kick observation | 87 % | Failed to close BOP | 100 % |
| | | | Unknown | 13 % | | |
| Production | **Primary barrier failure** | | | | **Secondary barrier (Blowout (surface Flow))** | |
| | SCSSV failed | 75% | | | X-mas tree failed, external load | 40% |
| | Tubing leak | 25% | | | X-mas tree failed, wear and tear | 30% |
| | | | | | Casing/cement/formation | 30% |
| Wireline | **Primary barrier failure** | | | | **Secondary barrier (Blowout (surface Flow))** | |
| | Stuffing box/lubricator failure | 100% | | | Wireline BOP failure | 50% |
| | | | | | X-mas tree failed | 50% |

Shallow zone incidents typically occur due to unexpected high well pressure or while the cement is setting. For a bottom fixed installation, most incidents are diverted without problems. In some cases, the diverter is not in place, because it has been nippled down.

For the deep zone drilling incidents, the well may kick for various reasons. Approximately 50% of the kicks were detected late. For floating drilling *blowout (surface flow)* LOWC events, the BOP failed to close in 50% of the incidents, and the formation and cement failed for the remaining. For bottom fixed drilling, leaks developed below the BOP in one third of the incidents, and the BOP was nippled down for installing casing seals in 22% of the incidents.

For workovers in killed wells, the kicks were caused by unexpected high pressure or trapped gas in 50% of the incidents. The majority of kicks were observed late. For the workover LOWC events in live wells, the SCCSV or tubing failed in 72% of the incidents. For more than 50% of the incidents that resulted in a *blowout (surface flow),* a casing leak was involved.

Workovers are frequently performed in old wells. Equipment failures are therefore more likely in these operations than in other well operations.

Nearly all kicks during completion that led to a LOWC event were detected late. A BOP failure is typical involved in completion *blowout (surface flow)* LOWC events.

For a *blowout (surface flow)* LOWC to occur in a producing well it will most likely occur as a combination of a failure in the X-mas tree or wellhead area and a SCSSV failure. The X-mas tree may have a degradation or being destroyed by storm or another external force.

For a *blowout (surface flow)* LOWC to occur during a wireline operation a leak in the lubricator or the stuffing box in combination with a wireline BOP failure seems to be the most likely cause.

## 15.8 Violation of Rules and Regulations

Violations of rules and regulations are from time to time described in LOWC investigation reports, but many times they are not. There are likely many more violations of rules and regulations than described in the investigation reports. The investigation reports focus on describing what went wrong and why things went wrong, but not pointing back to the specific rules and regulations that were breached. Below relevant breaches of rules and regulations identified in the 2000–2015 LOWC events are briefly listed.

The described violations are often of a general character such as:

- Failure to prevent pollution of offshore waters from the well control incident.
- Failure to perform all operations in a manner that ensured complete well control and that resulted in a sustained and uncontrolled flow of hydrocarbon fluids to surface.
- Failed to protect health, safety, property, and the environment. Did not perform all operations in a safe and workmanlike manner.
- Failed to take necessary precautions to keep the well under control at all times.
- Did not complete the well in a manner, which protected against harm or damage to life, property, natural resources, the national security, or the environment.
- Polluted the waters.
- Failure to maintain the casing in a safe condition.

More specific violations listed were:
- Failure to comply with regulatory requirement at 30 CFR 250.618(c) W/L lubricator not being tested prior to RIH to pull the DX plug.

- Failed to design and implement a fluid program to prevent the loss of well control.
- Failure to perform the JSA meeting prior to operation.
- Failure to utilize Stop Work Authority in order to stop job when operations varied from approved procedure.
- Failed to exercise Stop Work Authority and verify the depth of the hole-saw after the diver expressed concerns regarding which string of pipe he was cutting.
- The Inquiry found that at the time the well was suspended, not one well control barrier complied with Operator's own Well Construction Standards (or, importantly, with sensible oilfield practice).
- Operator conducted its operations in a manner that was clearly contrary to Brazilian regulations, heightening the risk of the drilling of the well that gave rise to the accident.
- Operator failed to carry out an analysis in conformity with Brazilian regulations, even ignoring its own risk management procedures (Risk and Uncertainty Management Standard - RUMS of July 26, 2011, and the Single Well CPDEP Roadmap).
- Failure to conduct operations according to the approved permit.
- The safety valve was not readily available for insertion into the work string.
- Ignored alarms.
- Failure to follow approved procedure.

## 15.9 Test of Equipment Prior to LOWC

It has been sought to find information about testing of the relevant equipment prior to the LOWC events. Information has been sought in the LOWC source material and also the BSEE Well Activity Report system [10].

Information about equipment testing prior to a LOWC event is normally not included in LOWC descriptions. Only detailed investigation reports may have this information.

No incidents have been found where the regular BOP has not been tested in time prior to an incident. From time to time BSEE grant a waiver to postpone a BOP test. Such waivers are granted in cases where the ongoing operations make it impossible to test the BOP within the preset time.

For other equipment, a missing wireline BOP test was noted prior to a LOWC event, which has been observed. The wireline BOP failed and caused the LOWC. For another incident the 9⅝" cemented casing shoe had not been pressure tested in accordance with the company's well construction standards. This caused a major blowout.

For workover LOWC events, it has also been mentioned that the equipment and well barriers have not been properly tested or evaluated before operation.

There are some examples that kelly valve type equipment has not been tested and maintained regularly and therefore has failed when needed.

# 16 WELL KICK EXPERIENCE

## 16.1 Kick Frequencies from Various Areas

A blowout during drilling operations will start with a well kick. A low kick frequency will thereby also reduce the LOWC probability. For some type of wells, it will be more likely to experience a kick than for others.

A general perception is that there are more frequent kicks in:

- HPHT wells vs. normally pressurized wells.
- Exploration wells vs. development wells.
- Exploration wildcats vs. exploration appraisal wells.
- Very deep wells vs. normal depth wells.

Various studies have revealed that some factors significantly affect the kick frequency (Section 16.2). The most significant factor is the margin between the fracture gradient and the pore pressure of a well. Further, uncertainty about the pore pressure typically causes many kicks.

When there is a low margin between the fracture gradient and the pore pressure, it is more likely to experience a kick. Factors like:

- too low mud weight
- losses
- swabbing
- gas cut mud

may more likely cause a well to kick. Many of the HPHT wells and deepwater wells drilled have this low margin, and thereby the kick frequency in such wells is high. The high pressure itself in a HPHT well does not seem to be a problem as long as the margin between the pore pressure and the fracture gradient is high.

In addition, the overall well control policies and the competency of the personnel and the organization will influence the kick frequency.

## 16.2 Kick Statistics from Previous Studies

Kick statistics are not commonly available in the public domain. Table 16.1 shows an overview of the kick frequencies. These data stem from various studies [5], [6], [3], and [4].

*Table 16.1 Drilling kick frequencies*

| Drilling dataset | | | No. of kicks | No. of wells | Kick frequency per well drilled | Shallow gas kick included |
|---|---|---|---|---|---|---|
| Canadian East Coast (1970 - 1993), Exploration wells [**5**] | | | 55 | 273 | 0.20 | Yes |
| US GoM OCS deepwater | Explorat-ion wells | Well drilled 1997 - 1998) [**3**] | 39 | 58 | 0.67 | No |
| | | Wells drilled 2007 – 2009 [**4**] | 74 | 206 | 0.36 | No |
| | | TOTAL | 113 | 264 | 0.43 | No |
| | Develop-ment wells | Well drilled 1997 - 1998) [**3**] | 9 | 25 | 0.38 | No |
| | | Wells drilled 2007 – 2009 [**4**] | 7 | 53 | 0.13 | No |
| | | TOTAL | 16 | 78 | 0.21 | No |
| Norwegian, Wells drilled 1984 -1997 [**6**] | Explorat-ion wells | Normal (Well depth < 4000m TVD) | 39 | 416 | 0.09 | No |
| | | Deep (Well depth > 4000m TVD, not incl. HPHT) | 36 | 111 | 0.32 | No |
| | | HPHT wells | 68 | 49 | 1.39 | No |
| | | TOTAL | 143 | 576 | 0.25 | No |
| | Development wells | | 272 | 1,478 | 0.19 | No |
| Canadian Beaufort wells deep (1973 - 1991), Exploration wells, [5] | | | 42 | 86 | 0.49 | No |

**Canadian East Coast (1970 - 1993)**. These kick data originally stem from the Alberta Energy and Utilities Board in Canada. A total of 55 kicks (included shallow kicks) were experienced during drilling these 273 wells. This corresponds to a frequency of one kick every fifth well.

**US GoM OCS deepwater (1997 - 1998).** This frequency is based on kick data collected by SINTEF/ExproSoft in [3]. The kick frequency in this dataset was high. The main reason for the high kick frequency is the low limit between the pore pressure and the fraction pressure. Many of the US GoM *deepwater wells* are *deep wells* and *HPHT wells*.

**Norwegian offshore (1984 -1997).** The majority of the kick data was originally collected through a Ph. D. work [15]. The frequencies are based on wells drilled in Norway during the period 1984 - 1997. The exploratory wells are typically drilled in water depths ranging from 50 to 400 meters. The majority of the exploratory wells are drilled with semisubmersible rigs while the development wells are mostly drilled from jackets or concrete structures.

**Canadian Beaufort wells deep (1973 - 1991**). The kick data is based on a spreadsheet extracted from the Canadian EUB and Downloaded Well files from Northwest Territories, Geoscience Office (2007).

The kick frequency for these wells was high. Some of the wells experienced many kicks - one well as many as 10. For many of the wells that experienced a kick the pore pressures of the wells were rather high. Several of the wells have to be regarded as high pressure wells. Fourteen kicks occurred when drilling with mud weights above 1,800 kg/m$^3$. These kicks occurred in five different wells.

The causes of kicks were: *Too low mud weight/unexpected high pore pressure* for 75% of the kicks, *Swabbing* was listed as cause for 17% of the kicks. It should be noted that for none of the kicks that occurred *loss of circulation* was the initial kick cause. It should further be noted that for many of the wells the mud weight was increased quite significantly to kill the well. This means that it would have been possible to drill most of the wells with a significantly higher mud weight, indicating a high margin between the pore pressure and the fracture gradient for most of the wells.

It may also have been the case that when drilling many of these wells they were “drilling for kicks”. This way of drilling will result in many kick occurrences. “Drilling for kick” is not a normal practice anymore.

## 16.3 RECENT ESTABLISHED KICK STATISTICS

A search for more recent public domain kick data has been made. Some kick data from the UK for the period 1999-2008 has been published [1]. The UK drilling activity can be found at the UK Oil and Gas Authority web page [13]. By combining the UK kick and well drilling information, overall kick frequencies were established for the period 1999 – 2008. The kick frequencies are presented in Section 16.3.1.

Kick data from the Norwegian sector for the period 2000 – 2015, published by Petroleum Safety Authority (PSA), has been made available for generating general statistics. The Norwegian kick frequencies are presented in Section 16.3.2.

### *16.3.1 UK KICK FREQUENCIES*

The kick data from the UK [1] has been processed and combined with drilling activity data information to establish overall kick frequencies. No detailed kick information exists in the data.

*Table 16.2 Exploration and appraisal drilling kick frequencies UK 1999 -2008 (shallow gas kicks included)*

| Area | No. of wells (not incl. sidetracks) | No. of sidetracks | No. of wells incl. sidetracks | No. of kicks | Kick frequency (per well drilled, incl sidetracks) | Mean time between kicks (no. of wells incl sidetracks) | Kick frequency (per well drilled, ***not*** incl sidetracks) | Mean time between kicks (no. of wells ***not*** incl sidetracks) |
|---|---|---|---|---|---|---|---|---|
| Southern North Sea | 114 | 16 | 130 | 22 | 0.169 | 5.9 | 0.193 | 5.2 |
| Central North Sea | 341 | 109 | 450 | 36 | 0.080 | 12.5 | 0.106 | 9.5 |
| Northern North Sea | 161 | 53 | 214 | 4 | 0.019 | 53.5 | 0.025 | 40.3 |
| West of England/Wales | 9 | 1 | 10 | 6 | 0.600 | 1.7 | 0.667 | 1.5 |
| West of Shetland | 47 | 11 | 58 | 6 | 0.103 | 9.7 | 0.128 | 7.8 |
| Total | 673 | 189 | 862 | 74 | 0.086 | 11.6 | 0.110 | 9.1 |

*Table 16.3 Development drilling kick frequencies UK 1999 -2008 (shallow gas kicks included)*

| Area | No. of wells (not incl. side-tracks) | No. of side-tracks | No. of wells incl. sidetracks | No. of kicks | Kick frequency (per well drilled, incl sidetracks) | Mean time between kicks (no. of wells incl sidetracks) | Kick frequency (per well drilled, ***not*** incl sidetracks) | Mean time between kicks (no. of wells ***not*** incl sidetracks) |
|---|---|---|---|---|---|---|---|---|
| Southern North Sea | 265 | 131 | 396 | 67 | 0.169 | 5.9 | 0.253 | 4.0 |
| Central North Sea | 961 | 460 | 1,421 | 69 | 0.049 | 20.6 | 0.072 | 13.9 |
| Northern North Sea | 763 | 280 | 1,043 | 74 | 0.071 | 14.1 | 0.097 | 10.3 |
| West of England/Wales | 49 | 23 | 72 | 1 | 0.014 | 72.0 | 0.020 | 49.0 |
| West of Shetland | 109 | 41 | 150 | 7 | 0.047 | 21.4 | 0.064 | 15.6 |
| Total | 2,147 | 935 | 3,082 | 218 | 0.071 | 14.1 | 0.102 | 9.8 |

Five of the kicks were shallow gas kicks. It is not stated how many shallow gas kicks that were observed in development wells and exploration wells.

The average kick frequency in exploration wells and development wells are 0.103 and 0.071 kicks per well drilled when regarding sidetracks as separate wells. The source [1] states that 27 of the kicks occurred in *HPHT wells*. A total of 82 *HPHT wells* were drilled. It is not specifically stated, but it seems the majority of the *HPHT wells* were development wells.

The study concluded that most of the kicks were directly related to geological conditions and mostly to conditions that were difficult to detect before drilling. Other geological related incidents included challenges in cementing casing and maintaining mud weight between influx and losses. According to [1] a significant, though minor, proportion of the incidents were due to human errors.

### *16.3.2 NORWEGIAN KICK FREQUENCIES*

The Petroleum Safety Authority (PSA) in Norway published Norwegian kick statistics from the year 2000 in the project “Trends in risk level in the petroleum activity (RNNP)” [2]. PSA was requested to provide access to descriptions of the individual kicks so the data could be analyzed further.

The drilling kicks occurring in 2009 and later kicks have been re-categorized and analyzed. The kicks that occurred before 2009 did not include a kick description and the focus has therefore been on the kicks occurring from 2009 through 2014.

For the period 2009 – 2014, 109 kicks were reported in Norwegian wells. Forty-nine of these kicks occurred during exploration drilling and 60 during development drilling. Of the 49 exploration well kicks, 26 were shallow kicks (kicks occurring before the BOP was installed) and 23 kicks occurred after the BOP was installed. Of the 60 development drilling kicks, 10 were shallow kicks and 50 deep kicks.

Table 16.4 shows the annual kick occurrence and the associated number of wells drilled

*Table 16.4 Norwegian kick frequencies for exploration and development wells (2009 - 2014)*

| Year | Exploration drilling | | | Development drilling | | |
|---|---|---|---|---|---|---|
| | No. of kicks | No. of wells spudded | Kick frequency pr. well | No. of kicks | No. of wells spudded | Kick frequency pr. well |
| 2009 | 3 | 66 | 0.045 | 13 | 166 | 0.078 |
| 2010 | 2 | 46 | 0.043 | 13 | 126 | 0.103 |
| 2011 | 3 | 52 | 0.058 | 7 | 125 | 0.056 |
| 2012 | 4 | 43 | 0.093 | 7 | 130 | 0.054 |
| 2013 | 3 | 59 | 0.051 | 3 | 166 | 0.018 |
| 2014 | 8 | 57 | 0.140 | 7 | 162 | 0.043 |
| Total | 23 | 323 | 0.071 | 50 | 875 | 0.057 |

As seen the exploration drilling frequency is a bit higher than the development drilling kick frequency. It should be noted that seven of the development drilling kicks were associated with completion activities and two with workover activities.

The exploration well kicks occurred in 94 exploration appraisal wells and 229 exploration wildcat wells. These exploration wells and the kicks have further been categorized into;

- deep wells (>4,000m)
  - Normal pressure and temperature well
  - HPHT well, and
  - HT wells
- normal depth wells (<4,000m)
  - Normal pressure and temperature well
  - HPHT well, and
  - HT wells

Table 16.5 shows an overview of kick frequency for the various types of exploration wells.

*Table 16.5 Exploration well kick frequency, Norwegian waters, 2009 - 2014*

| | Appraisal well | Wildcat | | | | | | Total |
|---|---|---|---|---|---|---|---|---|
| | | Well depth <4000 m | | Well depth >4000 m | | | Total | |
| | | a) Normal press. and temp. | b) HT (>150 Celsius) | a) Normal press. and temp | b) HT (>150 Celsius) | c) HPHT | | |
| Number of kicks | 1 | 10 | | 5 | 2 | 5 | 22 | 23 |
| Number of wells drilled | 94 | 180 | 2 | 27 | 14 | 6 | 229 | 323 |
| Kick frequency per well | 0.011 | 0.056 | | 0.185 | 0.143 | 0.833 | 0.096 | 0.071 |
| MTBK (Mean Time between kick (wells) | 94.0 | 18.0 | | 5.4 | 7.0 | 1.2 | 10.4 | 14.0 |

The overall wildcat kick frequency is one kick in every 10 wells. For *HPHT wells* the kick frequency is high, nearly one kick on average per well drilled. *Deep wells* (>4,000 m) have a higher kick frequency than *normal wells* (<4,000m). The kick frequency for a *normal* wildcat well is one kick every 18 wells drilled.

All wells, except 10, were drilled in water depths less than 450 meter. Ten wells were drilled in water depths ranging from 650 to 1,452 meters. No kick was observed for any of these *deepwater wells*.

PSA categorizes kicks according to severity. One of the kicks was categorized as a serious well control incident, while the remaining 22 were categorized as a regular well control incidents.

## 16.4 Comparison of Kick Statistics

Table 16.6 shows an overview of the kick frequencies observed for the different well types and periods.

*Table 16.6 Kick frequencies, old and recent statistic compiled (based on Table 16.1, Table 16.2, Table 16.3, Table 16.4, and Table 16.5.)*

| DATASET | | | No. of kicks | No. of wells | Kick frequency per well drilled: 5% conf limit | Kick frequency per well drilled: Estimate | Kick frequency per well drilled: 95% conf limit | Shall kick included |
|---|---|---|---|---|---|---|---|---|
| Canadian East Coast (1970 - 1993), Exploration wells [5] | | | 55 | 273 | 0.159 | 0.201 | 0.252 | Yes |
| US GoM OCS deepwater | Exploration wells | Well drilled 1997 - 1998 [3] | 39 | 58 | 0.506 | 0.672 | 0.878 | No |
| | | Wells drilled 2007 – 2009 [4] | 74 | 206 | 0.293 | 0.359 | 0.436 | |
| | | TOTAL | 113 | 264 | 0.364 | 0.428 | 0.500 | |
| | Development wells | Well drilled 1997 - 1998 [3] | 9 | 25 | 0.188 | 0.360 | 0.628 | |
| | | Wells drilled 2007 – 2009 [4] | 7 | 53 | 0.062 | 0.132 | 0.248 | |
| | | TOTAL | 16 | 78 | 0.129 | 0.205 | 0.312 | |
| Norwegian wells drilled 1984 -1997 [6] | Exploration, Appraisal | Normal (Well depth < 4000m TVD) | 15 | 121 | 0.076 | 0.124 | 0.191 | No |
| | | Deep (Well depth > 4000m TVD, not incl. HPHT) | 7 | 24 | 0.137 | 0.292 | 0.548 | |
| | | HPHT wells | 4 | 5 | 0.273 | 0.800 | 1.831 | |
| | | Total | 26 | 150 | 0.121 | 0.173 | 0.241 | |
| | Exploration, Wildcats | Normal (Well depth < 4000m TVD) | 24 | 295 | 0.056 | 0.081 | 0.114 | |
| | | Deep (Well depth > 4000m TVD, not incl. HPHT) | 29 | 87 | 0.238 | 0.333 | 0.454 | |
| | | HPHT wells | 64 | 44 | 1.169 | 1.455 | 1.791 | |
| | | Total | 117 | 426 | 0.234 | 0.275 | 0.320 | |
| | TOTAL exploration | | 143 | 576 | 0.215 | 0.248 | 0.285 | |
| | Development wells | | 272 | 1,478 | 0.166 | 0.184 | 0.203 | |
| Canadian Beaufort wells deep (1973 - 1991), Exploration wells, [5] | | | 42 | 86 | 0.371 | 0.488 | 0.632 | No |
| UK wells (1999-2008) [1] | Exploration wells | | 74 | 862 | 0.070 | 0.086 | 0.104 | Yes |
| | Development wells | | 218 | 3,082 | 0.063 | 0.071 | 0.079 | |
| Norwegian wells drilled 2009 -2014 [2] | Exploration, Appraisal | Normal (Well depth < 4000m TVD) | 1 | 94 | 0.001 | 0.011 | 0.050 | No |
| | Exploration, Wildcat | Normal (Well depth < 4000m TVD) | 10 | 182 | 0.030 | 0.055 | 0.093 | |
| | | Deep (Well depth > 4000m TVD, not incl. HPHT) | 7 | 41 | 0.080 | 0.171 | 0.321 | |
| | | HPHT wells | 5 | 6 | 0.328 | 0.833 | 1.752 | |
| | | Total | 22 | 229 | 0.065 | 0.096 | 0.137 | |
| | TOTAL exploration | | 23 | 323 | 0.049 | 0.071 | 0.101 | |
| | Development wells | | 50 | 875 | 0.045 | 0.057 | 0.072 | |
| **All exploration well** | | | **450** | **2,384** | **0.174** | **0.189** | **0.204** | No and yes |
| **All development wells** | | | **556** | **5,513** | **0.094** | **0.101** | **0.108** | |
| **All wells and kicks** | | | **1,006** | **7,897** | **0.121** | **0.127** | **0.134** | |

When adding up all the kicks and wells drilled, a kick frequency of one kick per five wells drilled is observed for exploration wells and one kick every 10 wells for development wells.

The kick frequencies varies a lot for the different well types, areas and periods during which the data was collected. Some type of wells have a high probability of kick while others have a low probability.

In *HPHT wells* and the *deepwater* US GoM OCS wells there is typically a narrow margin between the pore pressure and the fracture gradient. These wells are kick prone because the mud overbalance has to be low. Factors like slightly higher pore pressures than anticipated, formation depth uncertainties, swabbing, gas cut mud will more likely cause a kick to occur than in a well where a large mud overbalance is used. These wells are also more likely to develop losses.

The well kill operations will also be more difficult for these wells. Kill mud weight has to be carefully selected, kill fluid rates need to be low to reduce friction and increased bottom hole pressure and losses.

The kick frequency for the Beaufort wells were also high. The main reason for the high frequency is believed to be that they at that time were "drilling for kicks". The well and kick data for those kicks indicate that the margin between the pore pressure and the fracture gradient was large for most of the kicks observed.

From both the Norwegian exploration well kick data sets it is observed that normally pressured *deep wells* (TD > 4,000m) are more kick prone than normally pressured shallow wells (TD < 4,000m).

When comparing the Norwegian dataset from 1984 - 1997 with the dataset from 2009 – 2014, the average kick frequency for exploration wells has decreased from 0.248 kicks per well (one per four wells drilled) to 0.071 kicks per well (one per 14 wells drilled). The high number of HPHT kicks that was observed in the period 1984 – 1997 may partly explain this. When comparing the development wells kick, the kick frequency has decreased from one kick every $10^{th}$ well to one kick every $19^{th}$ well.

## 16.5 US GoM OCS Kick Statistics (for wells spudded 2011-2015)

BSEE does not capture kick information from the US GoM OCS activity systematically. The BSEE *eWell* system has a specific part that reports significant events. One of the possible significant events is well kick. Through the study [4], it was observed that approximately 50 % of the kicks were reported as a significant event, while the remaining 50% were not. This is however not a description of the kick, only stating that within a specific week a kick occurred.

The kicks in this section have been identified from the verbal description in the BSEE *eWell* WAR (Well Activity Reports) for wells spudded in the period 2011-2015. Ninety-nine of these kicks were listed as a significant event in *eWell* (2011-2013), while the remaining kicks have been identified by reviewing the description of the operations in WAR.

The complete Well Activity Reports (WAR) Database [10] was downloaded 10th of March 2016. This data was combined with the data in the BSEE Borehole file [8] to extract the WAR for all wells spudded in the US GoM OCS in the period 2011 – 2015.

In order to identify WARs that may include kicks several search and filter operations were carried out. The following key words were used to identify potential WAR that included a kick:

- Kick, Gain, Flow, Well started flowing, Well started to flow, SIDP, SICP, SIDDP, Balloon, Shut in, Well control, Strip, Diverted, Gas in riser, well kill, kill well, Bullhead, Drillers method, Influx, Wait and weight

The WARs identified through the key word search have been evaluated to identify those WARs that describe a well kick. There is likely some inaccuracy in the data. There are probably several kicks that have not been identified, and some of the incidents identified as a kick may not be a kick.

### *16.5.1 About the Kick Data Collected*

Below are some key information related to the kicks identified from WAR.

1. Only included wells spudded in the period 2011 – 2015.
2. Only included wells where a verbal description of the operation is included in the WAR.
3. Total number of spudded wells in the period 1,519.
4. Total number of spudded wells in the period with a verbal description of the operation is included in the WAR 1,121.
5. Total number of WARs 12,784.
6. Total number of operational days; 82,008 (based on a WAR count, including one relief well not included in the analysis. This relief well experienced a kick).
7. A WAR duration is 7 days or less.
8. A kick has been identified in 307 of the 12,784 WARs.
9. A kick may be reported in subsequent WARs (1, 2, and up to 5 WARs).
10. A WAR has in many cases included more than one kick.
11. Several wells have more than one kick.
12. Total number of kicks observed = 266 kicks (including 1 relief well kick).

13. Total 184 wells experienced one or more kicks:
    a. 131 wells experienced 1 kick
    b. 35 wells experienced 2 kicks
    c. 9 wells experienced 3 kick
    d. 6 wells experienced 4 kicks
    e. 1 well experienced 6 kicks
    f. 1 well experienced 7 kicks

### 16.5.2 LOWC AND KICKS

For the wells spudded in the period 2011-2015, nine LOWC events are listed in the *SINTEF Offshore Blowout Database* [7]. Only seven of these nine were found in the WAR. For the two remaining LOWC events there was no description of the activities in the WAR (not all wells have such a description).

For the seven identified in WAR, five were related to shallow flow before the BOP was installed on the wellhead, and two happened after the BOP was installed on the wellhead.

These nine LOWC events were all **drilling or completion incidents**. All of these events started with a kick because, for some reason, the mud weight could not control the pore pressure.

There are in addition seven LOWC incidents in the database for the period 2011 – 2015, but these incidents occurred in wells that were spudded before 2011. They were all **workover incidents**. Such incidents may start with a kick or a mechanical barrier failure.

In the subsequent pages, the kick statistics are presented. It should be noted that shallow zone incidents (before the BOP has been landed on the wellhead) are also included in the statistics.

### 16.5.3 KICK FREQUENCIES AND WELL DEPTH

Table 16.7 and Table 16.8 show the well kick frequencies for development and exploration wells. The wells have further been categorized in total well depth.

*Table 16.7 Development wells kick frequencies US GoM OCS, wells spudded 2011 - 2015*

| Well depth grouped | Deep well (>4,000 mTVD) | Normal well (<4,000 mTVD) | Dev total |
|---|---|---|---|
| Number of wells spudded | 157 | 664 | 821 |
| Number of drilling days | 18,110 | 33,537 | 51,647 |
| Number of kicks | 44 | 78 | 122 |
| Number of wells with kicks | 33 | 61 | 94 |
| Kick frequency per well | 0.28 | 0.12 | 0.15 |
| Kick frequency per 1000 days in operation | 2.43 | 2.33 | 2.36 |
| Mean time between kicks (MTBK), wells | 3.57 | 8.51 | 6.73 |
| Mean time between kicks (MTBK), days | 412 | 430 | 423 |
| Percentage number of wells with kicks | 21.0 % | 9.2 % | 11.4 % |

*Table 16.8 Exploration wells kick frequencies US GoM OCS, wells spudded 2011 - 2015*

| Well depth grouped | Deep well (>4,000 mTVD) | Normal well (<4,000 mTVD) | Expl total |
|---|---|---|---|
| Number of wells spudded | 215 | 85 | 300 |
| Number of drilling days | 25,624 | 4,606 | 30,230 |
| Number of kicks | 111 | 32 | 143 |
| Number of wells with kicks | 69 | 20 | 89 |
| Kick frequency per well | 0.52 | 0.38 | 0.48 |
| Kick frequency per 1000 days in operation | 4.33 | 6.95 | 4.73 |
| Mean time between kicks (MTBK), wells | 1.94 | 2.66 | 2.10 |
| Mean time between kicks (MTBK), days | 231 | 144 | 211 |
| Percentage number of wells with kicks | 32.1 % | 23.5 % | 29.7 % |

The data shows that the kick frequency for development wells is in average 1 kick per every 6.7 well drilled, and for exploration wells, 1 kick every 2.2 wells drilled. When comparing with the total kick frequencies in Table 16.6, page 165 it has to be concluded that the overall kick frequencies for development wells and exploration wells in the US GoM OCS for the period 2011 – 2015 seem high. For exploration wells the kick frequency per well drilled is approximately 2.5 times higher and frequency for development well kicks is approximately 1.5 times higher.

It can further be noted that, as expected, the kick frequency per well drilled in the deep wells (TVD > 4,000 m = 13,123 ft.) is higher than the kick frequency in normal wells (TVD < 4,000 m).

The drilling of a deep well normally takes more time than drilling a normal well. If comparing the kick frequency per 1,000 days in operation it is seen that it is approximately the same for deep and normal wells in development drilling and lower for deep wells than for normal wells in exploration drilling.

### *16.5.4 KICK FREQUENCIES AND WATER DEPTH*

For the purpose of this study, drilling in deeper water than 600 m (1,969 ft.) has been regarded as deepwater drilling, and drilling in water depths less than 600 m for shallow water drilling. Table 16.9 and Table 16.10 show the well kick frequencies for development and exploration wells in deepwater vs. shallow water.

*Table 16.9 Development wells, deepwater vs. shallow water*

| Water depth grouped | <600 m | >600 m | Dev total |
|---|---|---|---|
| Number of wells spudded | 699 | 122 | 821 |
| Number of drilling days | 37,203 | 14,444 | 51,647 |
| Number of kicks | 95 | 27 | 122 |
| Number of wells with kicks | 71 | 23 | 94 |
| Kick frequency per well | 0.14 | 0.22 | 0.15 |
| Kick frequency per 1000 days in operation | 2.55 | 1.87 | 2.36 |
| Mean time between kicks (MTBK), wells | 7.36 | 4.52 | 6.73 |
| Mean time between kicks (MTBK), days | 392 | 535 | 423 |
| Percentage number of wells with kicks | 10.2 % | 18.9 % | 11.4 % |

*Table 16.10 Exploration wells, deepwater vs. shallow water*

| Water depth grouped | <600 m | >600 m | Expl total |
|---|---|---|---|
| Number of wells spudded | 110 | 190 | 300 |
| Number of drilling days | 9,440 | 20,790 | 30,230 |
| Number of kicks | 61 | 82 | 143 |
| Number of wells with kicks | 33 | 56 | 89 |
| Kick frequency per well | 0.55 | 0.43 | 0.48 |
| Kick frequency per 1000 days in operation | 6.46 | 3.94 | 4.73 |
| Mean time between kicks (MTBK), wells | 1.80 | 2.32 | 2.10 |
| Mean time between kicks (MTBK), days | 155 | 254 | 211 |
| Percentage number of wells with kicks | 30.0 % | 29.5 % | 29.7 % |

The shallow water kick frequency per well drilled is lower than in deepwater for development drilling. For exploration drilling the kick frequency per well drilled is lower in deepwater drilling than in shallow water drilling. If looking at the kick frequency per 1,000 drilling days it is lower in deepwater drilling than in shallow water drilling both for development drilling and exploration drilling.

### *16.5.5 KICK FREQUENCIES AND WELL DEPTH WHEN KICK OCCURRED*

The WAR includes information related to the well depth for the specific week the report describes. This depth is referring to the depth at the end of the WAR period. This depth has been used as the well depth when the kick occurred. In many cases this is 100 % correct, while in other cases the drilling may have progressed a bit since the kick was controlled.

It has been selected to establish a frequency based on the number of drilling days within the various drilling depth ranges. A kick occurrence rate for the various drilling depths cannot be measured as a kick frequency per well drilled.

Table 16.11 and Table 16.12 shows the drilling TVD when the kick occurred for development and exploration drilling.

*Table 16.11 Development Drilling TVD when kick occurred*

| Drilling TVD Grouped (ft.) | <5,000 ft. | 5,000 – 10,000 ft. | 10,000 – 15,000 ft. | 15,000 - 20,000 ft. | 20,000 - 25,000 ft. | 25,000 – 30,000 ft. | >30,000 ft. | No depth listed | Total |
|---|---|---|---|---|---|---|---|---|---|
| Number of kicks | 7 | 53 | 37 | 16 | 8 | 1 | | | 122 |
| Number of drilling days in the various depth groups | 6,515 | 18,859 | 15,385 | 5,950 | 3,193 | 1,060 | | 685 | 51,647 |
| Kick frequency per 1000 days in operation | 1.07 | 2.81 | 2.40 | 2.69 | 2.51 | 0.94 | | | 2.36 |

*Table 16.12 Exploration Drilling TVD when kick occurred*

| Drilling TVD Grouped (ft.) | <5,000 ft. | 5,000 – 10,000 ft. | 10,000 - 15,000 ft. | 15,000 - 20,000 ft. | 20,000 - 25,000 ft. | 25,000 - 30,000 ft. | >30,000 ft. | No depth listed | Total |
|---|---|---|---|---|---|---|---|---|---|
| Number of kicks | 4 | 21 | 37 | 24 | 35 | 18 | 4 | | 143 |
| Number of drilling days in the various depth groups | 1,217 | 3,927 | 6,618 | 7,459 | 5,010 | 4,478 | 1,221 | 300 | 30,230 |
| Kick frequency per 1000 days in operation | 3.29 | 5.35 | 5.59 | 3.22 | 6.99 | 4.02 | 3.28 | | 4.73 |

For development wells, the kick frequency per 1,000 days seems fairly independent of the well depth. For exploration wells the highest kick frequency per 1,000 days drilled is for well depths between 20,000 to 25,000 ft. Thereafter well depths between 5,000 to 15,000 feet. The depth range from 15,000 to 20,000 ft. and from 25,000 to 30,000 ft. have a lower kick frequency per 1,000 days drilled.

#### 16.5.6 KICK FREQUENCIES AND BOP TYPE

Subsea BOPs are typically used for floating drilling and surface BOPs are typically used for drilling with a bottom fixed platform, including Spars and TLPs.

Floating rigs move due to the waves, making pit level control more difficult than on a bottom fixed installation. On the other hand, many of the floating rigs have more advanced kick detection systems than the jack-ups.

From a kick control perspective it is better with a surface BOP because the kick is easier to observe before it reaches the BOP. Kick circulation is easier because the kill and choke lines are short and that reduces friction. Higher pump rate can frequently be used.

Table 16.13 and Table 16.14 show the BOP type used when the kick occurred for development and exploration drilling. Bottom fixed installations typically use surface BOPs while floating installations typically use subsea BOP. The wells have been sorted in deep wells and normal depth wells.

*Table 16.13 Development wells and BOP type*

| Well depth grouped | Dry BOP | | Subsea BOP | | Dev total |
|---|---|---|---|---|---|
| | Deep well (>4,000 mTVD) | Normal well (<4,000 mTVD) | Deep well (>4,000 mTVD) | Normal well (<4,000 mTVD) | |
| Number of wells spudded | 84 | 648 | 73 | 16 | 821 |
| Number of drilling days | 8,150 | 32,015 | 9,960 | 1,522 | 51,647 |
| Number of kicks | 22 | 75 | 22 | 3 | 122 |
| Number of wells with kicks | 15 | 58 | 18 | 3 | 94 |
| Kick frequency per well | 0.26 | 0.12 | 0.30 | 0.19 | 0.15 |
| Kick frequency per 1000 days in operation | 2.70 | 2.34 | 2.21 | 1.97 | 2.36 |
| Mean time between kicks (MTBK), wells | 3.82 | 8.64 | 3.32 | 5.33 | 6.73 |
| Mean time between kicks (MTBK), days | 370 | 427 | 453 | 507 | 423 |
| Percentage number of wells with kicks | 17.9 % | 9.0 % | 24.7 % | 18.8 % | 11.4 % |

*Table 16.14 Exploration wells and BOP type*

| Well depth grouped | Dry BOP | | Subsea BOP | | Expl total |
|---|---|---|---|---|---|
| | Deep well (>4,000 mTVD) | Normal well (<4,000 mTVD) | Deep well (>4,000 mTVD) | Normal well (<4,000 mTVD) | |
| Number of wells spudded | 50 | 60 | 166 | 24 | 300 |
| Number of drilling days | 6,832 | 3,066 | 18,792 | 1,540 | 30,230 |
| Number of kicks | 36 | 24 | 75 | 8 | 143 |
| Number of wells with kicks | 16 | 16 | 54 | 3 | 89 |
| Kick frequency per well | 0.72 | 0.40 | 0.45 | 0.33 | 0.48 |
| Kick frequency per 1000 days in operation | 5.27 | 7.83 | 3.99 | 5.19 | 4.73 |
| Mean time between kicks (MTBK), wells | 1.39 | 2.50 | 2.21 | 3.00 | 2.10 |
| Mean time between kicks (MTBK), days | 190 | 128 | 251 | 193 | 211 |
| Percentage number of wells with kicks | 32.0 % | 26.7 % | 32.5 % | 12.5 % | 29.7 % |

For the development wells the kick frequency per well is a bit higher for wells drilled with subsea BOPs than with dry BOPs. The kick frequencies per 1,000 days in operation are similar.

For the exploration wells the kick frequency is lower for subsea BOPs than for surface BOPs when measuring both per well drilled and per 1,000 days in operation.

### *16.5.7 ANNUALIZED KICK FREQUENCIES*

Table 16.15 shows kick data for the individual years.

*Table 16.15 Annualized kick frequencies*

| Well type | Water depth grouped | Number of wells drilled and kicks observed | Spud year | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | 2011 | 2012 | 2013 | 2014 | 2015 | Total |
| Devel-opment | <600 m | Number of wells spudded | 168 | 186 | 191 | 112 | 42 | 699 |
| | | Number of kicks | 28 | 13 | 35 | 8 | 11 | 95 |
| | | Kick frequency per well spudded | 0,17 | 0,07 | 0,18 | 0,07 | 0,26 | 0,14 |
| | >600 m | Number of wells spudded | 17 | 44 | 37 | 20 | 4 | 122 |
| | | Number of kicks | 4 | 13 | 5 | 5 | | 27 |
| | | Kick frequency per well spudded | 0,24 | 0,30 | 0,14 | 0,25 | 0,00 | 0,22 |
| | Total | Number of wells spudded | 185 | 230 | 228 | 132 | 46 | 821 |
| | | Number of kicks | 32 | 26 | 40 | 13 | 11 | 122 |
| | | Kick frequency per well spudded | 0,17 | 0,11 | 0,18 | 0,10 | 0,24 | 0,15 |
| Explor-ation | <600 m | Number of wells spudded | 26 | 35 | 38 | 11 | 0 | 110 |
| | | Number of kicks | 15 | 24 | 22 | | | 61 |
| | | Kick frequency per well spudded | 0,58 | 0,69 | 0,58 | 0,00 | | 0,55 |
| | >600 m | Number of wells spudded | 48 | 64 | 61 | 14 | 3 | 190 |
| | | Number of kicks | 26 | 28 | 25 | 3 | | 82 |
| | | Kick frequency per well spudded | 0,54 | 0,44 | 0,41 | 0,21 | 0,00 | 0,43 |
| | Total | Number of wells spudded | 74 | 99 | 99 | 25 | 3 | 300 |
| | | Number of kicks | 41 | 52 | 47 | 3 | | 143 |
| | | Kick frequency per well spudded | 0,55 | 0,53 | 0,47 | 0,12 | 0,00 | 0,48 |
| Total | | Number of wells spudded | 259 | 329 | 327 | 157 | 49 | 1121 |
| | | Number of kicks | 73 | 78 | 87 | 16 | 11 | 265 |
| | | Kick frequency per well spudded | 0,28 | 0,24 | 0,27 | 0,10 | 0,22 | 0,24 |

Table 16.15 shows that the majority of the kick data stems from wells spudded in the period 2011 to 2013. This is mainly because less WAR reports exist for 2014 and 2015. The table is based on data in the WAR Database [10] that was downloaded 10$^{th}$ of March 2016. For the years 2011 to 2013 more than 90% of the wells spudded were included in the WAR database,

for 2014 and 2015, 48% and 25% were included. In addition the drilling activity was lower in 2015 than the previous years (Table 2.1, page 33.).

## 16.6 Comparison of US GoM Kick Frequency vs. Other Statistics

Table 16.16 shows an overview of all the kick data available.

*Table 16.16 Kick frequencies, old and recent statistic compiled (based on Table 16.6, Table 16.7, and Table 16.8)*

| DATASET | | | No. of kicks | No. of wells | Kick frequency per well drilled: 5% conf limit | Estimate | 95% conf limit | Shall kick included |
|---|---|---|---|---|---|---|---|---|
| Canadian East Coast (1970 - 1993), Exploration wells [5] | | | 55 | 273 | 0.159 | 0.201 | 0.252 | Yes |
| US GoM OCS deepwater | Exploration wells | Well drilled 1997 - 1998 [3] | 39 | 58 | 0.506 | 0.672 | 0.878 | No |
| | | Wells drilled 2007 – 2009 [4] | 74 | 206 | 0.293 | 0.359 | 0.436 | |
| | | TOTAL | 113 | 264 | 0.364 | 0.428 | 0.500 | |
| | Development wells | Well drilled 1997 - 1998 [3] | 9 | 25 | 0.188 | 0.360 | 0.628 | |
| | | Wells drilled 2007 – 2009 [4] | 7 | 53 | 0.062 | 0.132 | 0.248 | |
| | | TOTAL | 16 | 78 | 0.129 | 0.205 | 0.312 | |
| Norwegian wells drilled 1984 -1997 [6] | Exploration, Appraisal wells | Normal (Well depth < 4000m TVD) | 15 | 121 | 0.076 | 0.124 | 0.191 | No |
| | | Deep (Well depth > 4000m TVD, not incl. HPHT) | 7 | 24 | 0.137 | 0.292 | 0.548 | |
| | | HPHT wells | 4 | 5 | 0.273 | 0.800 | 1.831 | |
| | | Total | 26 | 150 | 0.121 | 0.173 | 0.241 | |
| | Exploration, Wildcats | Normal (Well depth < 4000m TVD) | 24 | 295 | 0.056 | 0.081 | 0.114 | |
| | | Deep (Well depth > 4000m TVD, not incl. HPHT) | 29 | 87 | 0.238 | 0.333 | 0.454 | |
| | | HPHT wells | 64 | 44 | 1.169 | 1.455 | 1.791 | |
| | | Total | 117 | 426 | 0.234 | 0.275 | 0.320 | |
| | TOTAL exploration | | 143 | 576 | 0.215 | 0.248 | 0.285 | |
| | Development wells | | 272 | 1,478 | 0.166 | 0.184 | 0.203 | |
| Canadian Beaufort wells deep (1973 - 1991), Exploration wells, [5] | | | 42 | 86 | 0.371 | 0.488 | 0.632 | No |
| UK wells (1999-2008) [1] | | Exploration wells | 74 | 862 | 0.070 | 0.086 | 0.104 | Yes |
| | | Development wells | 218 | 3,082 | 0.063 | 0.071 | 0.079 | |
| Norwegian wells drilled 2009 -2014 [2] | Exploration, Appraisal | Normal (Well depth < 4000m TVD) | 1 | 94 | 0.001 | 0.011 | 0.050 | No |
| | Exploration, Wildcat | Normal (Well depth < 4000m TVD) | 10 | 182 | 0.030 | 0.055 | 0.093 | |
| | | Deep (Well depth > 4000m TVD, not incl. HPHT) | 7 | 41 | 0.080 | 0.171 | 0.321 | |
| | | HPHT wells | 5 | 6 | 0.328 | 0.833 | 1.752 | |
| | | Total | 22 | 229 | 0.065 | 0.096 | 0.137 | |
| | TOTAL exploration | | 23 | 323 | 0.049 | 0.071 | 0.101 | |
| | Development wells | | 50 | 875 | 0.045 | 0.057 | 0.072 | |
| US GoM OCS (2011 – 2015) | Exploration wells | Normal (Well depth < 4000m TVD) | 32 | 85 | 0.274 | 0.376 | 0.506 | Yes |
| | | Deep (Well depth > 4000m TVD | 111 | 215 | 0.438 | 0.516 | 0.604 | |
| | | Total | 143 | 300 | 0.413 | 0.477 | 0.548 | |
| | Development wells | Normal (Well depth < 4000m TVD) | 78 | 664 | 0.096 | 0.117 | 0.142 | |
| | | Deep (Well depth > 4000m TVD | 44 | 157 | 0.215 | 0.280 | 0.360 | |
| | | Total | 122 | 821 | 0.127 | 0.149 | 0.173 | |
| **All exploration well** | | | 593 | 2,684 | 0.206 | 0.221 | 0.236 | No and yes |
| **All development wells** | | | 600 | 5,670 | 0.099 | 0.106 | 0.113 | |
| **All wells and kicks** | | | 1,193 | 8,354 | 0.136 | 0.143 | 0.150 | |

The frequency of kicks in the US GoM OCS for the period 2011 – 2015 is high compared to other areas. If comparing this US GoM OCS data with the most recent data from Norway (2009 -2014) and UK (1999 -2008) there is a statistically significant difference. The Norwegian and UK data sets are similar.

Figure 16.1 shows a graphical overview of the overall kick data from the various data sources.

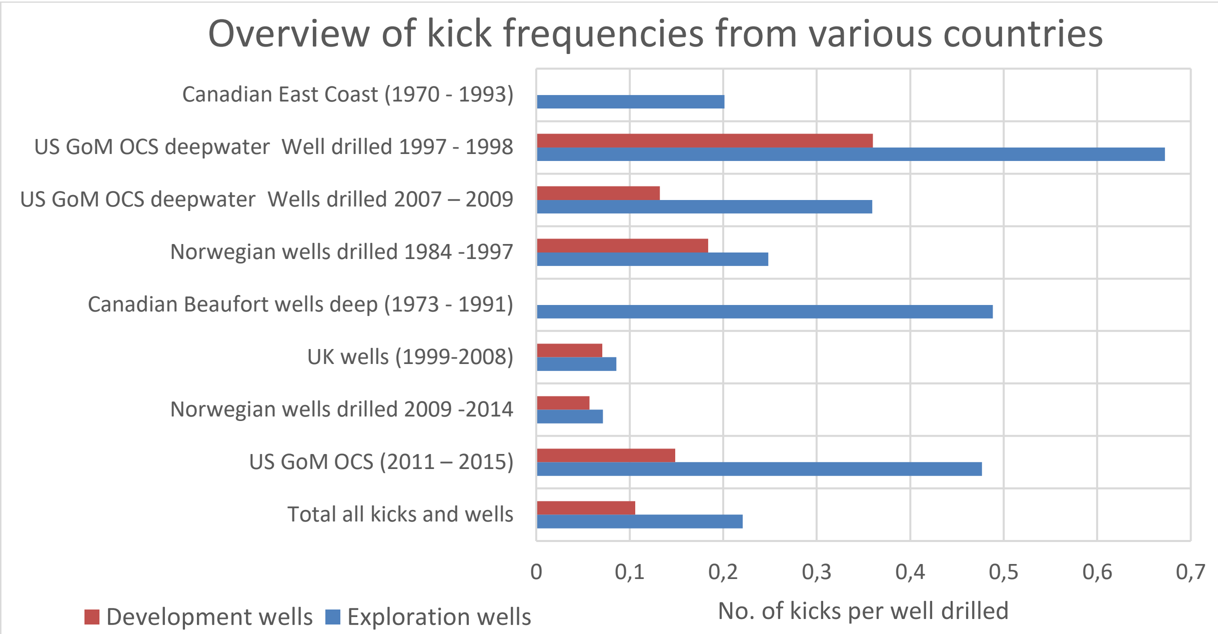


*Figure 16.1 Overview of kick frequencies*

By comparing the US GoM OCS 2011–2015 kick frequency with the most recent statistics from Norway and the UK, the kick frequency is significantly higher in the US GoM OCS. Compared with the Norwegian kick frequency for 1984–1997, however, the kick frequency in the US GoM OCS is in the same order of magnitude.

It is not known why the observed kick frequency in the US GoM OCS is so much higher than the most recent data from UK and Norway. There may be several reasons, including:

1. UK and Norwegian data is based on well kicks reported to the authorities. The operators may not report all the well kicks to the authorities.
2. Many US GoM wells are extremely deep and take a long time to drill. This increases the probability of having a kick due to the increased exposure time.
3. US GoM OCS may be a more complicated area to drill due to different formations. Narrow margin between pore pressure and fracture gradient constitutes a typical problem that causes many kicks.
4. Some of the shallow water wells in the US GoM OCS may be drilled with less advanced instrumentation.
5. There may be different requirements for drilling personnel qualifications in the US GoM OCS as compared to Norway and the UK.
6. The well control policies with respect to mud weight and casing program may be different.

## 16.7 Kick Causes

### 16.7.1 Kick Causes Discussion

A detailed review and categorizing of the US GoM OCS 2011 – 2015 kicks has not been carried out. This will require significant work effort and is not a part of the study scope.

When evaluating causes of kicks, it is very important to note that there are two main factors that influence the occurrence of a kick;

- Well control policy
- Local well conditions

If wells can be drilled with a high mud overbalance, kicks will be less likely than if wells are drilled with a low overbalance. Factors like slightly higher pore pressures than anticipated, formation depth uncertainties, swabbing, and gas cut mud will less likely cause a kick to occur than if the well is drilled with a low mud overbalance.

It is in general assumed that when drilling with a high mud overbalance the rate of penetration will be lower. This means that increasing the mud weight will be costly.

For some wells, the local well conditions do not make it possible to drill with a high overbalance due to a limited margin between the pore pressure and formation fracture gradient. For these wells a low overbalance has to be selected. In some cases running an extra casing may eliminate the problem. But adding an extra casing may on the other hand cause that the well target cannot be reached. Adding an extra casing will also cause additional costs.

HPHT wells in the North Sea and many deepwater wells in the US GoM OCS typically have a low margin between the pore- and fracture gradient. These wells are expected to cause more frequent kicks than in wells where a large margin between the pore- and fracture gradient exist

The casing program selected may also affect how large the mud overbalance can be, and thereby the probability of kicks.

In 2001 SINTEF/ExproSoft completed a deepwater kick study for MMS [3]. In 2012 Exprosoft completed another study related to deepwater kicks and BOP reliability [4] for BSEE. Both these report are available from the BSEE web page.

The kick causes were coarsely evaluated based on the description of the events in both these studies. The kick causes were listed as shown in Table 16.17 and Table 16.18.

*Table 16.17 Kick causes for US GoM OCS deepwater (1997 – 1998) kicks [3]*

| Kick cause | No. of kicks | Distribution |
|---|---|---|
| Losses | 7 | 17.9 % |
| Swab | 5 | 12.8 % |
| Unexpected high pore pressure/too low mud weight | 27 | 69.2 % |
| **Total** | **39** | **100.0 %** |

*Table 16.18 Kick causes for US GoM OCS deepwater (2007 – 2009) kicks [4]*

| Kick cause | No. of kicks | Distribution |
|---|---|---|
| Losses | 4 | 5.4 % |
| Other | 5 | 6.8 % |
| Swab | 9 | 12.2 % |
| Unexpected high pore pressure/too low mud weight | 52 | 70.3 % |
| Unknown | 4 | 5.4 % |
| **Total** | **74** | **100.0 %** |

For many of the kicks listed with too low mud weight, gas cut mud was a part of the problem. The occurrence of swabbed in kicks will also be influenced by a low mud weight.

Based on the limited incident descriptions for the Norwegian exploration wells drilled 2009 – 2014 [2] a coarse review of the exploration kick causes was performed. The results show the same distribution of causes as for the US GoM deepwater kicks. Table 16.19 shows an overview of the kick causes for the Norwegian exploration wells.

*Table 16.19 Exploration well kick causes, Norwegian waters, 2009 - 2014*

| Kick Cause | No. of kicks | % distribution |
|---|---|---|
| Unexpected high pore pressure/too low mud weight | 19 | 83 % |
| Swabbing | 3 | 13 % |
| Losses | 1 | 4 % |
| **Total** | **23** | 100 % |

### *16.7.2 KICK AND DEVIATED WELLS*

It has been investigated to see if the kick occurrence rate is higher in deviated wells than in vertical wells for the US GoM OCS kicks identified. Each WAR [10] lists the MD and the TVD for the activity the WAR describes. The deviation have been measured as the MD/TVD for the specific point in the well and not the angle. The various depths have been grouped in ranges for both the kicks and the drilling exposure days. Table 16.20 shows the results from this analysis.

*Table 16.20 Kick frequency vs. well deviation*

| MD vs. TVD Grouped (for each war) | Development wells | | | | Exploration wells | | | | Total | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Sum of days in operation | Distribu-tion (%) | No. of kicks | Kick frequency per 1000 days in operation | Sum of days in operation | Distribu-tion (%) | No. of kicks | Kick frequency per 1000 days in operation | Sum of days in operation | Distribut-ion (%) | No. of kicks | Kick frequency per 1000 days in operation |
| less than 110% | 29,570 | 57.3 % | 80 | 2.71 | 26,786 | 88.6 % | 132 | 4.93 | 56,356 | 68.8 % | 212 | 3.76 |
| 110 - 120% | 9,450 | 18.3 % | 17 | 1.80 | 1,820 | 6.0 % | 7 | 3.85 | 11,270 | 13.8 % | 24 | 2.13 |
| 120 - 130% | 5,502 | 10.7 % | 9 | 1.64 | 569 | 1.9 % | | | 6,071 | 7.4 % | 9 | 1.48 |
| 130 - 140% | 1,872 | 3.6 % | 3 | 1.60 | 583 | 1.9 % | 3 | 5.15 | 2,455 | 3.0 % | 6 | 2.44 |
| 140 - 150% | 1,208 | 2.3 % | 2 | 1.66 | 150 | 0.5 % | 1 | 6.67 | 1,358 | 1.7 % | 3 | 2.21 |
| 150-200% | 2,467 | 4.8 % | 9 | 3.65 | 22 | 0.1 % | | | 2,489 | 3.0 % | 9 | 3.62 |
| 200- 250% | 770 | 1.5 % | 2 | 2.60 | | 0.0 % | | | 770 | 0.9 % | 2 | 2.60 |
| more than 250% | 123 | 0.2 % | | | | 0.0 % | | | 123 | 0.2 % | 0 | 0.00 |
| Unknown | 685 | 1.3 % | | | 300 | 1.0 % | | | 985 | 1.2 % | 0 | 0.00 |
| Total | 51,647 | 100.0 % | 122 | 2.36 | 30,230 | 100.0 % | 143 | 4.73 | 81,877 | 100.0 % | 265 | 3.24 |

When looking at the results in Table 16.20 it is observed that the majority of drilling and the majority of well kicks stem from the nearly vertical part of the well. It can also be observed that there does not seem to be any relation between the deviation and the frequency of kicks per 1,000 drilling days.

### 16.7.3 KICK AND STUCK PIPE

Stuck pipe is from time to time a complication in association with a kick. Table 16.21 shows an overview of number of stuck pipe incidents for the US GoM OCS (2011 - 2015).

*Table 16.21 Number of stuck pipe incidents US GoM OCS (2011 - 2015) based on WAR*

| **Well depth grouped** | **Development wells** | **Exploration wells** | Total |
|---|---|---|---|
| Number of wells spudded | 821 | 300 | 1,121 |
| Number of drilling days | 51,647 | 30,230 | 81,877 |
| Number of stuck pipe incidents | 286 | 162 | 448 |
| Number of wells with stuck pipe incidents | 225 | 99 | 324 |
| Stuck pipe incident frequency per well | 0.35 | 0.54 | 0.40 |
| Stuck pipe incident frequency per 1000 days in operation | 5.54 | 5.36 | 5.47 |
| Mean time Between Stuck pipe incident frequency, wells | 2.87 | 1.85 | 2.50 |
| Mean time Between Stuck pipe incident frequency, days | 181 | 187 | 183 |
| Percentage number of wells with Stuck pipe | 27.4 % | 33.0 % | 28.9 % |

For 47 of the WARs both a kick and a stuck pipe incident are occurring within the same week. This represents 17.7% of the kicks and 10.5% of the stuck pipe incidents.

These WARs have been read more closely and it was found that for 25 of these kick incidents the well kicked before the pipe became stuck. For 12 of these incidents the pipe became stuck before the well kicked. For the remaining incidents the stuck pipe and kick were not found to be related.

There are rather many kicks that also involves stuck pipe. It does however not seem that stuck pipe frequently causes the well to kick.

Some other stuck pipe findings;

- The frequency of stuck pipe incidents ***per well drilled*** is some higher in exploration wells compared to development wells.
- The frequency of stuck pipe incidents ***per day in operation*** is the same in exploration wells compared to development wells.
- Deep wells (> 4,000mTVD) have more stuck pipe incidents than Normal wells (<4,000mTVD).
- There does not seem to be any relation between the water depth and the stuck pipe incident frequency.
- Stuck pipe may occur at any well depth.
- There seems not to be any strong relation between drilling TVD and stuck pipe occurrences. It may seem that in the drilling depth range between 25,000 – 30,000 ft. the occurrence of stuck pipe is higher than the other depth ranges for exploration drilling. This was not observed for development drilling.

A kick may occur at any depth. Many of the kicks occurred far from the TD of the well. These kicks will typically not have the potential to cause a large release of oil, but release of gas may cause danger for the personnel and the installations.

# 17 LOWC RISK ANALYSIS

The experience with LOWC events and well kicks is discussed in the previous section of this report. Exposure data related to no of wells drilled, completed, and wells in productions is presented in Section 2, page 33. This section focus on risk related to the various operations, well types, water depths, and vessel types (floating or fixed).

The LOWC risk can be measured by several measures. In this report the measures used are:

- Fatalities
- Pollution
- Ignition
- Material losses to rig

Risk is in general a function of the frequency of an event and the consequence of an event.

## 17.1 Experienced Risk

### *17.1.1 US GOM OCS LOWC FREQUENCIES VS. REGULATED AREAS*

Table 17.1 and Table 17.2 compare the drilling LOWC event frequencies in the regulated areas and the US GoM OCS.

*Table 17.1 Development Drilling LOWC frequency comparison US GoM OCS and regulated areas, 2000–2015*

| Deep or shallow zone | Main category | Regulated area | | | US/GOM OCS | | | US GoM OCS vs. Regulated areas |
|---|---|---|---|---|---|---|---|---|
| | | No. of LOWCs | No. of wells drilled | LOWC frequency per 1000 wells drilled | No. of LOWCs | No. of wells drilled | LOWC frequency per 1000 wells drilled | |
| Deep | Blowout (surface flow) | 1 | 8,156 | 0.12 | 2 | 6,288 | 0.32 | 2.59 |
| | Blowout (underground flow) | | | | 1 | | 0.16 | - |
| | Diverted well release | | | | | | | - |
| | Well release | 1 | | 0.12 | 1 | | 0.16 | 1.30 |
| | Total | 2 | | 0.25 | 4 | | 0.64 | 2.59 |
| Shallow | Blowout (surface flow) | 3 | | 0.37 | 7 | | 1.11 | 3.03 |
| | Diverted well release | 1 | | 0.12 | 5 | | 0.80 | 6.49 |
| | Well release | | | | | | | - |
| | Total | 3 | | 0.37 | 12 | | 1.91 | 5.19 |
| Total | | 6 | | 0.74 | 16 | | 2.54 | 3.46 |

*Table 17.2 Exploration Drilling LOWC frequency comparison US GoM OCS and regulated areas, 2000–2015*

| Deep or shallow zone | Main category | Regulated area | | | US GoM OCS | | | US GoM OCS vs. Regulated areas |
|---|---|---|---|---|---|---|---|---|
| | | No. of LOWCs | No. of wells drilled | LOWC frequency per 1000 wells drilled | No. of LOWCs | No. of wells drilled | LOWC frequency per 1000 wells drilled | |
| Deep | Blowout (surface flow) | 1 | 3,998 | 0.25 | 9 | 3,971 | 2.27 | 9.06 |
| | Blowout (underground flow) | 1 | | 0.25 | 2 | | 0.50 | 2.01 |
| | Diverted well release | | | | 1 | | 0.25 | - |
| | Well release | 2 | | 0.50 | 2 | | 0.50 | 1.01 |
| | Total | 4 | | 1.00 | 14 | | 3.53 | 3.52 |
| Shallow | Blowout (surface flow) | 1 | | 0.25 | 5 | | 1.26 | 5.03 |
| | Diverted well release | 1 | | 0.25 | 3 | | 0.76 | 3.02 |
| | Well release | | | | 2 | | 0.50 | - |
| | Total | 2 | | 0.50 | 10 | | 2.52 | 5.03 |
| Total | | 6 | | 1.50 | 24 | | 6.04 | 4.03 |

Table 17.1 and Table 17.2 show that the total LOWC event frequency in the US GoM OCS is significantly higher than in the comparable regulated areas for both development and exploration drilling.

The LOWC event type with the highest risk is the *blowout (surface flow)* type incident. Nine such events occurred in the US GoM OCS exploration wells and only one in the regulated areas. Approximately the same number of wells were drilled in the US GoM OCS and the regulated areas.

Causes for drilling LOWC events are discussed in Section 15, page 142.

Table 17.3 compares the completion LOWC event frequencies in the UK and Norway and the US GoM OCS.

*Table 17.3 Completion LOWC frequency comparison US GoM OCS and UK and Norway, 2000–2015*

| Main category | UK & Norwegian waters | | | US GoM OCS | | | US GoM OCS vs. Norway and UK |
|---|---|---|---|---|---|---|---|
| | No. of LOWCs | Number of well completions | Frequency per 1000 wells completed | No. of LOWCs | Number of well completions | Frequency per 1000 wells completed | |
| Blowout (surface flow) | 1 | 5,305 | 0,19 | 1 | 5,004 | 0,20 | 1.05 |
| Diverted well release | | | | 1 | | 0,20 | - |
| Well release | 4 | | 0,75 | 1 | | 0,20 | 0.27 |
| Total | 5 | | 0,94 | 3 | | 0,60 | 0.64 |

The LOWC event frequency during completion is lower in the US GoM OCS than in the Norwegian and UK waters combined, when measured by the number of well completions carried out. It should here be noted that the total number of completion LOWC events is low such that the statistical uncertainty of this conclusion is high.

Table 17.4 compares the workover LOWC event frequencies in the UK and Norway, and the US GoM OCS.

*Table 17.4 Workover LOWC frequency comparison US GoM OCS and UK and Norway, 2000–2015*

| Main category | UK & Norwegian waters | | | US GoM OCS | | | US GoM OCS vs. Norway and UK |
|---|---|---|---|---|---|---|---|
| | No. of LOWCs | Number of well years in service | LOWC frequency per 10,000 well years in service | No. of LOWCs | Number of well years in service | LOWC frequency per 10,000 well years in service | |
| Blowout (surface flow) | 1 | 47,683 | 0.21 | 9 | 77,843 | 1.16 | 5.51 |
| Well release | 4 | | 0.84 | 12 | | 1.54 | 1.84 |
| Total | 5 | | 1.05 | 21 | | 2.70 | 2.57 |

The LOWC event frequency during workovers is significantly higher in the US GoM OCS than in in the Norwegian and UK waters combined, when measuring by the number of well years in service.

The frequency of well workovers may be higher in the US GoM OCS due to in average older wells that require more frequent workovers. In addition, many of the US GoM workovers have been carried out in wells with poor barriers due to aging. Many of the workover LOWC events occurred in wells that have been temporary abandoned for long periods.

Table 17.5 compares the production LOWC event frequencies in the UK and Norway and the US GoM OCS.

*Table 17.5 Production LOWC frequency comparison US GoM OCS and UK and Norway, 2000–2015*

| Main category | UK & Norwegian waters | | | US/GOM OCS | | | | | | US GoM OCS vs. Norway and UK |
|---|---|---|---|---|---|---|---|---|---|---|
| | No. of LOWCs | Number of well years in service | LOWC frequency per 10,000 well years in service | No. of LOWCs | | Number of well years in service | LOWC frequency per 10,000 well years in service | | | |
| | No external load | | No external load | No external load | External load | | No external load | External load | Total | |
| Blowout (surface flow) | | 47,683 | | 3 | 5 | 77,843 | 0.39 | 0.64 | 1.03 | - |
| Well release | 3 | | 0.63 | 4 | | | 0.51 | 0.00 | 0.51 | 0.82 |
| Total | 3 | | 0.63 | 7 | 5 | | 0.90 | 0.64 | 1.54 | 2.45 |

The LOWC event frequency during production is significantly higher in the US GoM OCS than in in the Norwegian and UK waters combined, when measuring by the number of well years in service.

Many of the LOWC events in the US GoM OCS are caused by external causes as storm, and collisions. These type of LOWCs are not observed in the Norwegian and UK waters. The strong hurricanes and the small shallow water installations causes these types of events. If disregarding these events the LOWC frequencies becomes more similar.

Table 17.6 compares the wireline LOWC event frequencies in the UK and Norway and the US GoM OCS.

*Table 17.6 Wireline LOWC frequency comparison US GoM OCS and UK and Norway, 2000–2015*

| Main category | UK & Norwegian waters | | | US GoM OCS | | | US GoM OCS vs. Norway and UK |
|---|---|---|---|---|---|---|---|
| | No. of LOWCs | Number of well years in service | LOWC frequency per 10,000 well years in service | No. of LOWCs | Number of well years in service | LOWC frequency per 10,000 well years in service | |
| Blowout (surface flow) | 1 | 47,683 | 0.21 | | 77,843 | | |
| Well release | 3 | | 0.63 | 3 | | 0.39 | 0.61 |
| Total | 4 | | 0.84 | 3 | | 0.39 | 0.46 |

The LOWC event frequency during wireline is lower in the US GoM OCS than in in the Norwegian and UK waters combined, when measuring by the number of well years in service.

There are relatively few wireline LOWC events in the database.

### 17.1.2 DEEPWATER VS. SHALLOW WATER DRILLING

Table 17.7 and Table 17.8 show the LOWC frequency vs. water depth for development and exploration drilling. Water depths deeper than 600 m (1,969 ft.) have been considered as deepwater.

*Table 17.7 Development drilling LOWC frequency comparison shallow water vs. deepwater, US GoM OCS 2000–2015*

| Main category | Development drilling | | | | | | Water depth <600 m vs. >600m |
|---|---|---|---|---|---|---|---|
| | Water depth < 600m (1,969 ft.) | | | Water depth > 600m (1,969 ft.) | | | |
| | No. of LOWCs | No. of wells drilled | Frequency per 1,000 wells drilled | No. of LOWCs | No. of well drilled | Frequency per 1,000 wells drilled | |
| ***Deep zone incidents*** | | | | | | | |
| Blowout (surface flow) | 2 | 5,422 | 0.37 | 0 | 868 | 0.00 | - |
| Blowout (underground flow) | 1 | | 0.18 | 0 | | 0.00 | - |
| Diverted well release | | | 0.00 | 0 | | 0.00 | - |
| Well release | 1 | | 0.18 | 0 | | 0.00 | - |
| Total | 4 | | 0.74 | 0 | | 0.00 | - |
| ***Shallow zone incidents*** | | | | | | | |
| Blowout (surface flow) | 7 | 5,422 | 1.29 | 0 | 868 | 0.00 | - |
| Diverted well release | 5 | | 0.92 | 0 | | 0.00 | - |
| Well release | | | 0.00 | 0 | | 0.00 | - |
| total | 12 | | 2.21 | 0 | | 0.00 | - |
| Total all | 16 | | 2.95 | 0 | | 0.00 | - |

No deepwater LOWC events have been observed for development wells, while 16 have been observed for the shallow water drilling. The number of wells drilled is also far higher in shallow water.

*Table 17.8 Exploration drilling LOWC frequency comparison shallow water vs. deepwater, US GoM OCS 2000–2015*

| Main category | Exploration drilling | | | | | | Water depth <600m vs. >600m |
|---|---|---|---|---|---|---|---|
| | Water depth < 600m (1,969 ft.) | | | Water depth > 600m (1,969 ft.) | | | |
| | No. of LOWCs | No. of well drilled | Frequency per 1,000 wells drilled | No. of LOWCs | No. of well drilled | Frequency per 1,000 wells drilled | |
| ***Deep zone incidents*** | | | | | | | |
| Blowout (surface flow) | 7 | 2,545 | 2.75 | 2 | 1,427 | 1,40 | 196 % |
| Blowout (underground flow) | 2 | | 0.79 | | | 0,00 | - |
| Diverted well release | | | 0.00 | 1 | | 0,70 | 0 % |
| Well release | | | 0.00 | 2 | | 1,40 | 0 % |
| Total | 9 | | 3.54 | 5 | | 3,50 | 101 % |
| ***Shallow zone incidents*** | | | | | | | |
| Blowout (surface flow) | 4 | 2,545 | 1.57 | 1 | 1,427 | 0,70 | 224 % |
| Diverted well release | 3 | | 1.18 | | | 0,00 | - |
| Well release | | | 0.00 | 2 | | 1,40 | 0 % |
| Total | 7 | | 2.75 | 3 | | 2,10 | 131 % |
| Total all | 16 | | 6.29 | 8 | | 5,61 | 112 % |

For exploration drilling, the experienced total LOWC frequency is on the same level for shallow water as for deepwater. If looking at the most serious LOWC events, *blowout (surface flow)* type incidents, the observed frequency is higher in shallow water than in deepwater.

### *17.1.3 SURFACE BOP VS. SUBSEA BOPS*

Bottom fixed installations typically use surface BOPs while floating installations typically use subsea BOPs. Table 17.9 and Table 17.10 shows the LOWC frequency for bottom fixed vs. floating installations for development and exploration drilling.

*Table 17.9 Development drilling LOWC frequency comparison bottom fixed vs. floating vessel, US GoM OCS 2000–2015*

| Main category | Development drilling | | | | | | Bottom fixed vs. floating |
|---|---|---|---|---|---|---|---|
| | Bottom fixed | | | Floating | | | |
| | No. of LOWCs | No. of wells drilled | Frequency per 1,000 wells drilled | No. of LOWCs | No. of well drilled | Frequency per 1,000 wells drilled | |
| ***Deep zone incidents*** | | | | | | | |
| Blowout (surface flow) | 2 | 5,606 | 0.36 | | 684 | 0.00 | - |
| Blowout (underground flow) | 1 | | 0.18 | | | 0.00 | - |
| Well release | 1 | | 0.18 | | | 0.00 | - |
| Total | 4 | | 0.71 | | | 0.00 | - |
| ***Shallow zone incidents*** | | | | | | | |
| Blowout (surface flow) | 7 | 5,606 | 1.25 | | 684 | 0.00 | - |
| Diverted well release | 5 | | 0.89 | | | 0.00 | - |
| Total | 12 | | 2.14 | | | 0.00 | - |
| Total all | 16 | | 2.85 | 0 | | 0.00 | - |

*Table 17.10 Exploration drilling LOWC frequency comparison bottom fixed vs. floating vessel, US GoM OCS 2000–2015*

| Main category | Exploration drilling | | | | | | Bottom fixed vs. floating |
|---|---|---|---|---|---|---|---|
| | Bottom fixed | | | Floating | | | |
| | No. of LOWCs | No. of well drilled | Frequency per 1,000 wells drilled | No. of LOWCs | No. of well drilled | Frequency per 1,000 wells drilled | |
| ***Deep zone incidents*** | | | | | | | |
| Blowout (surface flow) | 6 | | 2.55 | 3 | | 1.85 | 138 % |
| Blowout (underground flow) | 2 | | 0.85 | | | 0.00 | |
| Diverted well release | | 2,350 | 0.00 | 1 | 1,622 | 0.62 | 0 % |
| Well release | | | 0.00 | 2 | | 1.23 | 0 % |
| Total | 8 | | 3.40 | 6 | | 3.70 | 92 % |
| ***Shallow zone incidents*** | | | | | | | |
| Blowout (surface flow) | 3 | | 1.28 | 2 | | 1.23 | 104 % |
| Diverted well release | 3 | | 1.28 | | | 0.00 | |
| Well release | | 2,350 | 0.00 | 2 | 1,622 | 1.23 | |
| Total | 6 | | 2.55 | 4 | | 2.47 | 104 % |
| Total all | 14 | | 5.96 | 10 | | 6.17 | 97 % |

There are fairly few development wells drilled from a floating unit, and no LOWC events have been observed. Approximately eight times as many development wells have been drilled from bottom fixed units, and in total 16 LOWC events have been observed.

For exploration drilling the LOWC frequency for floating units and bottom fixed units are similar.

When combing all the LOWC events in Table 17.9 and Table 17.10 with the kick frequency in Table 16.13, page 171 and Table 16.14, page 172 an estimate for experiencing a LOWC per well kick can be established for a floating vs. bottom fixed installation. The experience from exploration drilling and development drilling have been merged. The results are shown in Table 17.11.

*Table 17.11 Number of kicks per LOWC floating vs. bottom fixed drilling*

| Type of installation | All drilling LOWCs (2000–2015) | | | All drilling kicks (2011 – 2015) | | | No. of kicks per LOWCs |
|---|---|---|---|---|---|---|---|
| | No. of LOWCs | Total no. of well drilled | LOWC frequency per well drilled | Total no. of drilling kicks | No. of wells spudded | Kick frequency per well spudded | |
| Bottom fixed | 30 | 7,956 | 0.00377 | 157 | 842 | 0.18646 | 49 |
| Floating units | 10 | 2,306 | 0.00434 | 108 | 279 | 0.38710 | 89 |

Table 17.11 assumes that the kick frequency for the period 2011 – 2015 will be representative for the period 2000–2015.

Table 17.11 indicates that one out of 49 kicks on a bottom fixed installation results in a LOWC and one out of 89 kicks on a floater results in a LOWC.

From a risk perspective the LOWC type *blowout (surface flow)* from a deep zone is the LOWC type with the highest risk. When combing the deep zone *blowout (surface flow)* LOWC events in Table 17.9 and Table 17.10 with the kick frequency in Table 16.13, page 171 and Table 16.14, page 172 an estimate for that a well kick shall develop to a deep zone *blowout (surface flow)* has been established for a floating vs. a bottom fixed installation. The experience from exploration drilling and development drilling have been merged.

The results are shown in Table 17.12.

*Table 17.12 Number of kicks per blowout (surface flow) LOWC floating vs. bottom fixed drilling*

| Type of installation | All drilling LOWCs (2000–2015) No. of LOWCs | Total no. of well drilled | LOWC frequency per well drilled | All drilling kicks (2011 – 2015) Total no. of drilling kicks | No. of wells spudded | Kick frequency per well spudded | No. of kicks per LOWCs |
|---|---|---|---|---|---|---|---|
| Bottom fixed | 8 | 7,956 | 0.00101 | 157 | 842 | 0.18646 | 185 |
| Floating units | 3 | 2,306 | 0.00130 | 108 | 279 | 0.38710 | 298 |

Table 17.12 indicates that one out of 185 kicks on a bottom fixed installation results in a *blowout (surface flow)* type LOWC and one out of 298 kicks on a floater results in a *blowout (surface flow)* type LOWC.

### *17.1.4 PROBABILITY OF OIL SPILLS LARGER THAN 500 BLLS*

Acute large oil spills have occurred on three occasions in regulated areas including US GoM OCS in the period 2000–2015 as discussed in section 13.4, page 121. These all occurred during drilling. In addition an incident that occurred in 2004 is still not under control. The flow rate from this incident is, however, low but the cumulative amount over a 12 – 13 year period causes that this spill is qualified as a very large oil spill.

**Probability for Drilling LOWC events with an oil spill larger than 500 bbls**
The three spills all occurred during drilling, they are:

- 2009 – Australia, Montara: A total volume of 29,600 barrels 4,800 $m^3$, or 66 $m^3$ per day.
- 2010 – USA, Macondo: 8,000 $m^3$ a day in 85 days, in total 680,000 $m^3$, or 4,250,000 bbls
- 2011 – Brazil, Frade field: 600 bbls per day or 3,700 bbls in total.

These incidents caused large media attention, high direct cost and loss of reputation for the involved parties.

If relying on these three incidents and the number of wells drilled in the period 2000–2015 (Table 2.1, page 33 and Table 2.4, page 36) in the US GoM OCS and the regulated areas, the probability of a large oil spill will be;

- Exploration drilling; 2 blowouts / 7,969 wells drilled = 1 blowout / 3,985 wells drilled, or 0.025% per well drilled[4]
- Development drilling; 1 blowout / 14,444 wells drilled , or 0.007% per well drilled

One of three deep zone development drilling blowouts *(surface flow)* and two of 10 deep zone exploration drilling Blowouts *(surface flow)* caused a large spill.

[4] Statoil said the statistical probability of a blow-out, an uncontrolled oil spill from a well, was 0.014 percent - or one for every 7,100 exploration wells in the Norwegian Barents Sea (www.Rigzone.com

If looking further back in time, no drilling blowouts with large oil spills occurred in the US GoM OCS and the regulated areas in the period 1980–1999. Number of wells drilled in this period:

- 15,388 exploration wells [7]
- 21,727 development wells [7]

If adding this to the exposure data the experienced frequency for the period 1980 – 2015 for US GoM and the regulated areas will be;

- Exploration drilling; 2 blowouts / 23,357 wells drilled = 1 blowout /11,679 wells drilled
- Development drilling; 1 blowout / 36,171 wells drilled

When looking at the period 1980 – 2015 for US GoM and the regulated areas, one of 10 deep zone development drilling *blowout (surface flow)* incidents and two of 27 deep zone exploration drilling *blowouts (surface flow)* caused a large spill.

It seems reasonable to base a large spill probability on the period 1980 – 2015 for US GoM and the regulated areas. It can then be assumed that 3 of 37, or 8.1%, of the deep zone drilling *blowout (surface flow)* incidents will cause a large release.

If looking further back in time to the 70's none of the drilling blowouts caused large pollution in the US GoM and regulated areas, but one workover blowout, one blowout during production, and one wireline blowout did.

Although there has been no large releases from workover and completion LOWC events observed in the period 1980 to 2015 for the US GoM OCS and the regulated areas this probability cannot be ruled out. Such incidents have been observed in other areas of the world and in other periods.

**Probability for Workover LOWC events with large spill**
As input for the analysis, it has been assumed that 0.5 *blowout (surface flow)* workover LOWC incidents with a large release have been observed for all workover activities in the period 1980 - 2015 in the US GoM OCS, Norway and UK. The *SINTEF Offshore Blowout Database* [7] shows that 28 *blowout (surface flow)* LOWC events occurred in this period during workover activities. Under this assumption it can be expected that one of every 56 (or 1.8%) *blowout (surface flow)* LOWC events during workover will involve a large release.

**Probability for Completion LOWC events with large spill probability**
As input for the analysis, it has been assumed that 0.5 *blowout (surface flow)* completion LOWC incidents with a large release have been observed for all completion activities in the period 1980 until 2015 in the US GoM OCS and the regulated areas. The *SINTEF Offshore Blowout Database* [7] shows that 11 *blowout (surface flow)* LOWC events occurred in this period during well completion activities. Under this assumption it can be expected that one of every 22 (or 4.5%) *blowout (surface flow)* LOWC events during completion will involve a large release.

**Probability for Production LOWC events with large spill probability**

As input for the analysis, it has been assumed that 0.7 *blowout (surface flow)* production LOWC incidents with a large release have been observed for all production activities in the period 1980 - 2015 in the US GoM OCS, Norway and UK.

No acute large oil spill has occurred during production, but an incident that occurred in 2004 is still not under control. The daily leak rate is limited to around 2 barrels, but the cumulative leak over 12 - 13 years caused this LOWC to be categorized as very large. The total volume leaked over this period has been estimated to be between 6,000 – 25,000 barrels. The incident was caused by an underwater landslide caused by a hurricane.

When looking at the period from 1980 – 1999 no large oil spills have occurred in the production phase in the US GoM OCS, Norway and UK.

The *SINTEF Offshore Blowout Database* [7] shows that 23 *blowout (surface flow)* LOWC events occurred in this period during well production. Under this assumption it can be expected that one of every 33 (or 3.0%) *blowout (surface flow)* LOWC events during production will involve a large and acute release.

**Probability for Wireline LOWC events with large spill probability**
As input for the analysis, it has been assumed that the probability of a large leak from a wireline *blowout (surface flow)* event is the same as for a workover *blowout (surface flow)* event, i.e. 1.8%.

## 17.2 Risk Model for Prediction of Future Risk

To predict the future risk related to LOWC events in the US GoM OCS, the LOWC experience from the past in the US GoM and the regulated areas have been used in combination with a predicted activity level.

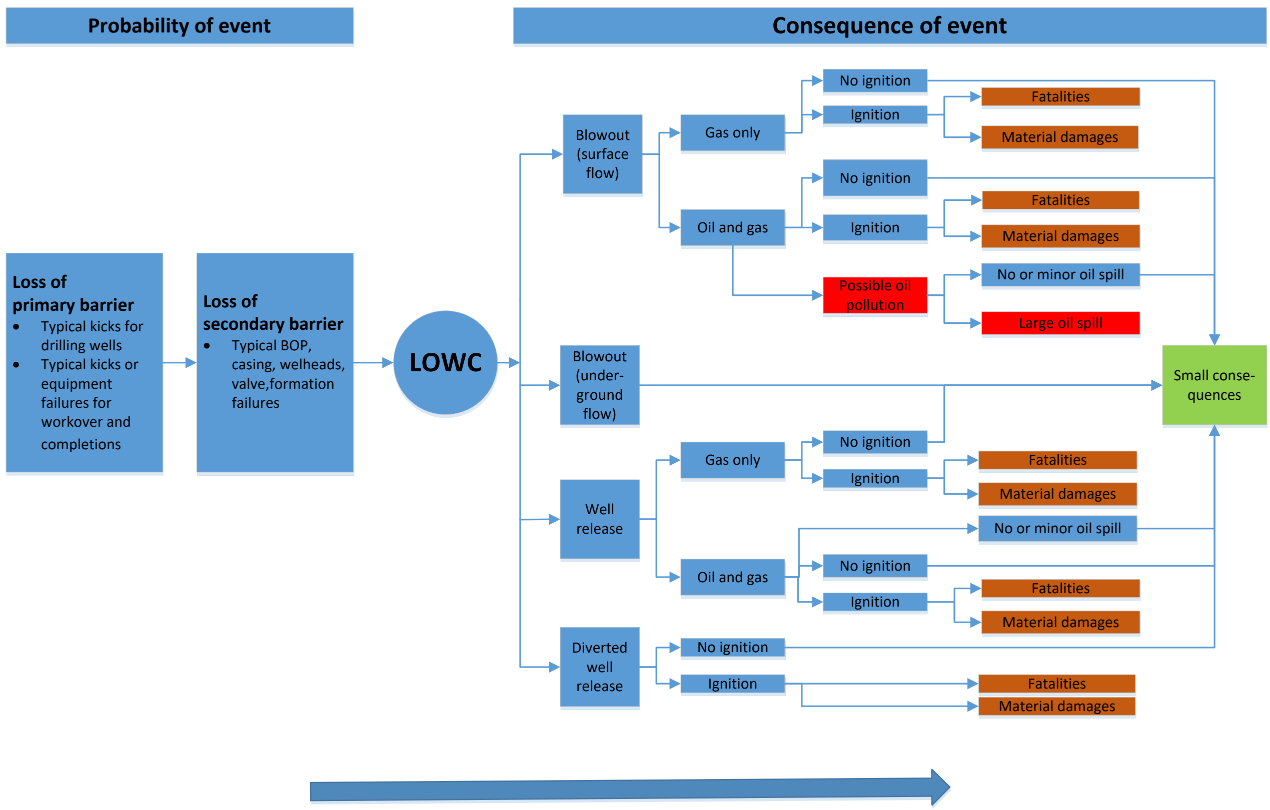


*Figure 17.1 Risk model used for predicting the risk*

As discussed in this report LOWC events may originate from many causes and create a large variety of consequences. Most LOWC events have small consequences, but some have very severe consequences.

For the overall risk results the experience from US GOM OCS has been used with respect to the frequency of the LOWC events, while a combination of the US GoM OCS and the regulated areas has been used for assessing the consequences of the LOWC events.

Spreadsheets have been used to perform the calculations. The three main spreadsheets with input data and references to where the data is taken from are shown in Appendix 1 to this report.

The first spreadsheet shows a five year LOWC risk that has been predicted mainly based on the 2000–2015 US GoM OCS experience.

For the second spreadsheet, a five year LOWC risk has been predicted based on the 2000–2015 US GoM OCS and regulated areas experience.

The third spreadsheet has been used to verify the risk model by calculating the risk for the period 2000–2015 and comparing with the experienced events in the database.

For the risk assessment, a five-year period has been assumed. The US GoM OCS activity for this five-year period is based on the 2015 activity level. Table 17.13 shows the estimated activity for a five-year period

*Table 17.13 Estimated US GoM OCS activity for a five year period, based on the 2015 activity (from Table 2.1, Table 2.2, Table 2.3, and Table 2.6)*

| Activity type | Activity level |
|---|---|
| Exploration drilling from bottom fixed installation (Number of wells drilled) | 25 |
| Exploration drilling from floating vessel (Number of wells drilled) | 490 |
| Development drilling floating or bottom fixed installation (Number of wells drilled) | 540 |
| Workover (Number of well years in service) | 16,900 |
| Completion (Number of wells completed) | 440 |

## 17.3 Estimated Risk Level in US GoM OCS for a Five-Year period

Table 17.14 shows the overall result from the risk analysis for US GoM in a five-year period based on an annual activity level as in 2015.

*Table 17.14 Overall risk analysis result US GoM OCS a five-year period, <u>input frequencies based on US GoM OCS 2000–2015</u>, annual activity level based on US GoM OCS 2015*

| **Activity type** | **Risk results** | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Material damages | | | | Large spill probability |
| | | | | Total Loss | Severe | Damage | Small-/no | |
| Exploration drilling from bottom fixed installation | 0.149 | 0.014 | 0.021 | 0.0071 | 0.0035 | 0.0053 | 0.1330 | 0.0052 |
| Exploration drilling from floating vessel | 3.018 | 0.275 | 0.361 | 0.1118 | 0.0815 | 0.1095 | 2.7156 | 0.0734 |
| Development drilling floating or bottom fixed installation | 1.376 | 0.118 | 0.174 | 0.0574 | 0.0305 | 0.0449 | 1.2436 | 0.0140 |
| Workover | 4.559 | 0.401 | 0.490 | 0.1447 | 0.1278 | 0.1640 | 4.1227 | 0.0352 |
| Completion | 0.264 | 0.017 | 0.021 | 0.0065 | 0.0051 | 0.0068 | 0.2454 | 0.0040 |
| Production | 2.605 | 0.294 | 0.404 | 0.1287 | 0.0828 | 0.1150 | 2.2788 | 0.0521 |
| Wireline | 0.651 | 0.028 | 0.014 | 0.0000 | 0.0139 | 0.0139 | 0.6236 | 0.0000 |
| Total all | 12.62 | 1.15 | 1.49 | 0.46 | 0.34 | 0.46 | 11.36 | 0.18 |

Table 17.14 shows that the expected value for the number of LOWC events for a five-year period is 12.6. This means that 12 to 13 LOWC events can be expected to occur in a five-year period.

It should be noted that the reduced drilling activity in the US GoM OCS is reflected in the risk model, causing that the relative risk contribution from drilling LOWC events is reduced compared to workover and the production phase where the activity is assumed to be more stable.

Table 17.14, further indicates that there is a probability of a large spill in in this five-year period of 18%. A large spill includes spills with a total release above from 500 barrels to millions of barrels.

Figure 17.2 shows a pie chart with the estimated contribution from the various phases of operation to the large spill probability based on a 2015 activity level.

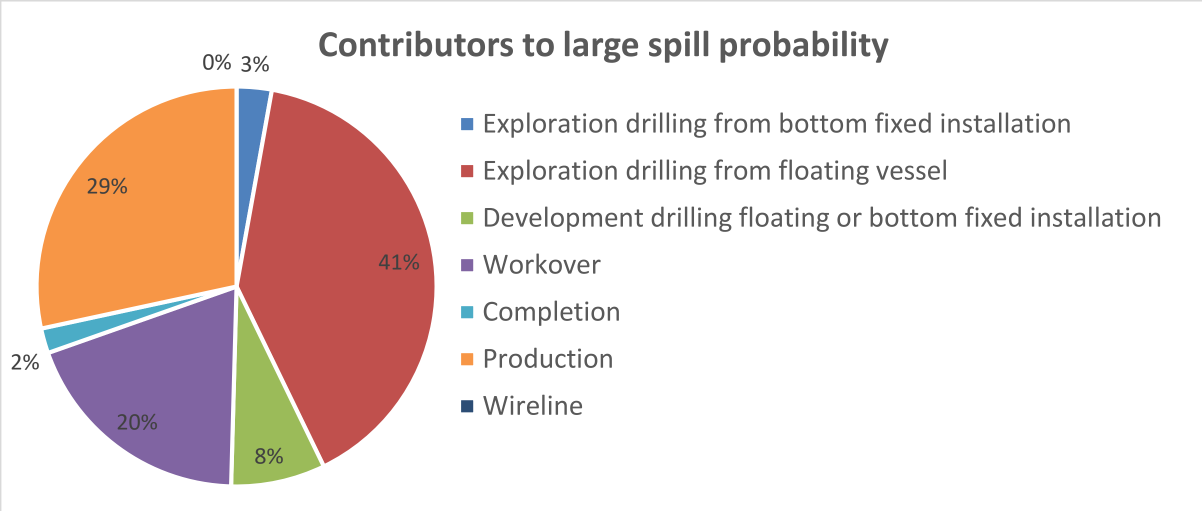


*Figure 17.2 The contributors to the large spill probability based on a 2015 activity level.*

Should there be a large spill caused by a LOWC event, the risk analysis indicates that with around a 40% probability, it will occur during exploration drilling from a floater. The proportion from a producing well is close to 30%, and from a workover event is around 20%. If there should occur a large spill during production it is likely to be caused by an external load as a hurricane.

It can be expected that 3.5% of the LOWC events will result in a total loss of the installation. With the estimated number of LOWC events for a five-year period in the US GoM OCS, there is a 46% probability that a total loss incident shall occur in a five-year period. Most LOWC events cause no or minor damages to the installation.

There are few LOWC events with fatalities. Occasionally a LOWC may cause several fatalities. Based on the average numbers, one to two fatalities caused by LOWC events can be expected in a five-year period in the US GoM OCS.

One LOWC event can be expected to ignite in a five-year period.

If assuming that the LOWC frequencies from the regulated areas and the GoM combined will be representative for the five-year risk estimate for the US GoM OCS, Table 17.15 shows the risk.

*Table 17.15 Overall risk analysis result, US GoM OCS for a five-year period, input frequencies based on US GoM OCS and regulated areas combined, 2000–2015*

| Activity type | Risk results | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Material damages | | | | Large spill probability |
| | | | | Total Loss | Severe | Damage | Small-/no | |
| Exploration drilling | 1.94 | 0.170 | 0.238 | 0.077 | 0.047 | 0.066 | 1.750 | 0.052 |
| Development drilling | 0.82 | 0.075 | 0.110 | 0.036 | 0.020 | 0.029 | 0.738 | 0.009 |
| Workover | 3.50 | 0.292 | 0.345 | 0.100 | 0.096 | 0.121 | 3.184 | 0.024 |
| Completion | 0.34 | 0.022 | 0.024 | 0.006 | 0.008 | 0.009 | 0.318 | 0.004 |
| Production | 2.02 | 0.200 | 0.259 | 0.080 | 0.060 | 0.080 | 1.800 | 0.032 |
| Wireline | 0.94 | 0.055 | 0.047 | 0.010 | 0.022 | 0.025 | 0.886 | 0.002 |
| Total all | 9.57 | 0.813 | 1.023 | 0.308 | 0.252 | 0.329 | 8.676 | 0.124 |

When basing the input frequencies on a combination of the US GoM OCS and the regulated areas the estimated risk becomes lower because the LOWC frequencies are lower in the regulated areas than in the US GoM. For all the risk measures, the risk is reduced to 67% – 76%.

## 17.4 Risk Model Verification

To verify the risk model used, the total activity in the US GoM OCS for the period 2000–2015 has been fed into the model. Table 17.16 shows the US GoM OCS activity for the period 2000–2015.

*Table 17.16 The US GoM OCS activity for the period 2000–2015 (from Table 2.1, Table 2.3, and Table 2.6)*

| Activity type | Activity level |
|---|---|
| Exploration drilling from bottom fixed installation (Number of wells drilled) | 2,350 |
| Exploration drilling from floating vessel (Number of wells drilled) | 1,622 |
| Development drilling Floating or bottom fixed installation (Number of wells drilled) | 6,288 |
| Workover (Number of well years in service) | 77,843 |
| Completion (Number of wells completed) | 5,004 |

Table 17.17 shows the comparison of the risk result from the risk model and from a count in the *SINTEF Offshore Blowout Database*.

*Table 17.17 Risk model verification, input frequencies based on US GoM OCS 2000–2015, activity level 2000–2015*

| Result type | Risk comparison | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | No. of LOWCs | No. of ignited events | No. of fatalities | Material damages | | | | Large spill probability |
| | | | | Total Loss | Severe | Damage | Small-/no | |
| Risk calculated with risk model | 79.03 | 7.15 | 9.65 | 3.04 | 2.05 | 2.81 | 71.13 | 1.34 |
| Count from SINTEF Offshore Blowout Database | 79 | 6 | 13 | 3 | 1 | 3 | 72 | 1 |

Table 17.17 shows that the results from the risk model corresponds well with the incident count from the *SINTEF Offshore Blowout Database*.

## 17.5 Risk Matrices

To illustrate the risk level for the future activities in the US GoM OCS two risk matrices have been established. The frequency and the consequences in the risk matrices are based on the results in this Section 17.3, page 189, and some coarse evaluations.

The color codes used are based on the authors subjective opinion. A red color code indicates a high risk, a yellow indicates a medium risk, and green indicates a low risk. The **X** indicates the predicted LOWC risk level for the US GoM OCS activities combined. The phases of operation included are exploration drilling, development drilling, workover- and completion activities.

Figure 17.3 shows a risk matrix for oil spills caused by LOWCs and Figure 17.4 shows a risk matrix for fatalities caused by LOWCs.

| Probability | LOWC consequence (Spill size) | | | | | |
|---|---|---|---|---|---|---|
| | No or insignificant spill | Minor spill (10 - 50 bbls) | Medium spill (50 -500 bbls) | Large spill (500 – 5,000 bbls) | Very large spill (5,000 - 50,000 bbls) | Gigantic spill (>50,000 bbls) |
| More frequent than once a year | X | | | | | |
| 1 - 5 times in 5 year | | X | | | | |
| 1 - 4 times in 20 year | | | | | | |
| 1- 4 times in 80 year | | | X | | | |
| 1 - 2 times in 160 year | | | | X | X | X |
| less than once in 160 year | | | | | | |

*Figure 17.3 Risk matrix LOWC oil spill for the US GoM OCS*

| Probability | LOWC consequence (No. of fatalities) | | | | |
|---|---|---|---|---|---|
| | No fatalities | 1 fatality | 1- 5 fatalities | 5 - 20 fatalities | More than 20 fatalities |
| More frequent than once a year | X | | | | |
| 1 - 5 times in 5 year | | | | | |
| 1 - 4 times in 20 year | | | | | |
| 1- 4 times in 80 year | | X | X | | |
| 1 - 2 times in 160 year | | | | X | |
| less than once in 160 year | | | | | X |

*Figure 17.4 Risk matrix LOWC fatalities for the US GoM OCS*

## 17.6 LOWC Risk Reduction Discussion

The main contributors to the risk are the *blowout (surface flow)* accidents. These incidents have the largest accident potential with respect to fires, loss of lives, spill to the surroundings, and damage to material assets.

In general, by reducing the kick frequency the LOWC event frequency will be reduced. The kick frequencies in the US GoM OCS are high, as shown in Figure 16.1, page 174. A reduction of the kick frequency will reduce the LOWC event frequency. If assuming that a kick frequency reduction of 50% in drilling operations will reduce the LOWC event frequency in drilling with 50%, the total risk for the US GoM OCS will be reduced.

Table 17.18 shows the effect of reducing the drilling kick frequency with 50% when assuming a five-year period with an annual activity levels as in 2015.

*Table 17.18 Sensitivity analysis, effect of reducing of drilling kick frequency with 50%*

| **Activity type** | **Risk results** | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Material damages | | | | Large spill probability |
| | | | | Total Loss | Severe | Damage | Small-/no | |
| Exploration drilling from bottom fixed installation | 0.075 | 0.007 | 0.011 | 0.0035 | 0.0018 | 0.0027 | 0.0665 | 0.0026 |
| Exploration drilling from floating vessel | 1.509 | 0.138 | 0.181 | 0.0559 | 0.0408 | 0.0547 | 1.3578 | 0.0367 |
| Development drilling floating or bottom fixed installation | 0.688 | 0.059 | 0.087 | 0.0287 | 0.0153 | 0.0224 | 0.6218 | 0.0070 |
| Workover | 4.559 | 0.401 | 0.490 | 0.1447 | 0.1278 | 0.1640 | 4.1227 | 0.0352 |
| Completion | 0.264 | 0.017 | 0.021 | 0.0065 | 0.0051 | 0.0068 | 0.2454 | 0.0040 |
| Production | 2.605 | 0.294 | 0.404 | 0.1287 | 0.0828 | 0.1150 | 2.2788 | 0.0521 |
| Wireline | 0.651 | 0.028 | 0.014 | 0.0000 | 0.0139 | 0.0139 | 0.6236 | 0.0000 |
| Total risk with 50% reduced kick frequency drilling events | 10.351 | 0.944 | 1.208 | 0.368 | 0.287 | 0.379 | 9.317 | 0.138 |
| Result from Base Case Table 17.14 | 12.62 | 1.15 | 1.49 | 0.46 | 0.34 | 0.46 | 11.36 | 0.18 |
| *Risk reduction compared to base case* | 18.0 % | 17.9 % | 18.9 % | 20.0 % | 15.6 % | 17.6 % | 18.0 % | 23.3 % |

Table 17.18 shows that by reducing the drilling kick frequency the total LOWC risk in the US GoM OCS risk will be reduced with around 20%.

Another important factor with respect to drilling LOWC events is the kick detection. For approximately 50% of the deep zone drilling LOWC events, the kick was not observed before the well was flowing to the surroundings. If these kicks had been observed in time, the LOWC events would most likely not have occurred.

For most of the well completion kicks and the workover kicks in killed wells, late kick detection is a common factor.

Efforts to improve the kick detection during drilling, completion, and workover activities will in most cases give a corresponding reduction in the LOWC event frequency.

For workovers, it is especially important to be prepared that the barrier situation and the pressures in the well that shall be worked over may be different than expected.

The highest risk contribution from producing wells stems from LOWC incidents caused by hurricanes. When a hurricane damages the topside barriers, the quality of the downhole barriers as tubing, packer, and SCSSV is important.

Wireline incidents have a small impact on the total risk.

The abandoned wells have not been included in the risk model, and the risk is difficult to quantify. In the period 2000–2015, LOWC events from these well types did not cause any significant damage. The number of temporary abandoned wells in the whole world is large. Many of these wells have been temporary abandoned for many years. The risk related to LOWC events from the temporary abandoned wells will increase unless a significant effort is put in to permanently plug and abandon these wells.

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# APPENDIX 1, RISK ANALYSES SPREADSHEETS

In the subsequent pages three spreadsheets are shown presenting input data and results from the main risk calculations.

1. Frequencies based on US GoM OCS 2000–2015. Consequences mainly based on US GoM OCS and regulated areas 2000–2015, assumed 5 years of activity equal to 2015 activity level.
2. Frequencies and Consequences based on US GoM OCS and regulated areas 2000–2015, assumed 5 years of activity equal to 2015 activity level.
3. Risk model verification, Frequencies based on US GoM OCS 2000–2015. Consequences mainly based on US GoM OCS and regulated areas 2000–2015, All US GoM activities 2000–2015.

## Frequencies based on US GoM OCS 2000–2015. Consequences mainly based on US GoM OCS and regulated areas 2000–2015, assumed 5 year activity level based on 2015

| Offshore activity | | | INPUT DATA | | | | | | | | | Risk results | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Type of drilling | Deep or shallow zone | Main category | LOWC frequency per well drilled (Table 17.10) (US GOM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of exploration wells | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Exploration drilling from bottom fixed installation | Deep | Blowout surface flow | 0.00255 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 8.10 % | 25 | 0.064 | 0.009 | 0.014 | 0.0047 | 0.0024 | 0.0035 | 0.0531 | 0.0052 |
| | | Blowout (underground flow) | 0.00085 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 25 | 0.021 | 0 | 0 | 0 | 0 | 0 | 0.0213 | 0 |
| | | Diverted well release | 0 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 25 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Well release | 0 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 25 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Shallow | Blowout surface flow | 0.00128 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 0 % | 25 | 0.032 | 0.005 | 0.007 | 0.0024 | 0.0012 | 0.0018 | 0.0267 | 0 |
| | | Blowout (underground flow) | 0.00128 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 25 | 0.032 | 0 | 0 | 0 | 0 | 0 | 0.0320 | 0 |
| | | Diverted well release | 0 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 25 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Well release | 0.00000 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 25 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | SuM | | 0.00596 | | | | | | | | SuM | 0.149 | 0.014 | 0.021 | 0.0071 | 0.0035 | 0.0053 | 0.1330 | 0.0052 |
| Exploration drilling from floating vessel | Deep | Blowout surface flow | 0.00185 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 8.10 % | 490 | 0.907 | 0.134 | 0.201 | 0.0671 | 0.0336 | 0.0504 | 0.7554 | 0.0734 |
| | | Blowout (underground flow) | 0 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 490 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.00062 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 490 | 0.304 | 0 | 0 | 0 | 0 | 0 | 0.3038 | 0 |
| | | Well release | 0.00123 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 490 | 0.603 | 0.026 | 0.013 | 0 | 0.0128 | 0 | 0.5771 | 0 |
| | Shallow | Blowout surface flow | 0.00123 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 0 % | 490 | 0.603 | 0.089 | 0.134 | 0.0446 | 0.0223 | 0.0335 | 0.5023 | 0 |
| | | Blowout (underground flow) | 0 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 490 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 490 | 0.000 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0 |
| | | Well release | 0.00123 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 490 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| | SuM | | 0.00616 | | | | | | | | SuM | 3.018 | 0.275 | 0.361 | 0.1118 | 0.0815 | 0.1095 | 2.7156 | 0.0734 |
| Operation | Deep or shallow zone | Main category | LOWC frequency per well drilled (Table 17.9) (US GOM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Material damages (Table 14.4) Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of development wells | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Material damages Total Loss | Severe | Damage | Small /no | Large spill probability |
| Development drilling Floating or bottom fixed installation | Deep | Blowout surface flow | 0.00032 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 8.10 % | 540 | 0.173 | 0.026 | 0.039 | 0.0128 | 0.0064 | 0.0096 | 0.1444 | 0.0140 |
| | | Blowout (underground flow) | 0.00016 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 540 | 0.087 | 0 | 0 | 0 | 0 | 0 | 0.0866 | 0 |
| | | Diverted well release | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 540 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Well release | 0.00016 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 540 | 0.087 | 0.004 | 0.002 | 0 | 0.0018 | 0 | 0.0829 | 0 |
| | Shallow | Blowout surface flow | 0.00111 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 0 % | 540 | 0.602 | 0.089 | 0.134 | 0.0446 | 0.0223 | 0.0334 | 0.5013 | 0 |
| | | Blowout (underground flow) | | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 540 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.00079 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 540 | 0.428 | 0 | 0 | 0 | 0 | 0 | 0.4283 | 0 |
| | | Well release | | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 540 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | SuM | | 0.00255 | | | | | | | | SuM | 1.376 | 0.118 | 0.174 | 0.0574 | 0.0305 | 0.0449 | 1.2436 | 0.0140 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.4) (US GOM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of well years in service | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Workover | | Blowout surface flow | 0.000116 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 1.80 % | 16,900 | 1.954 | 0.289 | 0.434 | 0.1447 | 0.0724 | 0.1086 | 1.6283 | 0.0352 |
| | | Blowout (underground flow) | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Well release | 0.000154 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 16,900 | 2.605 | 0.112 | 0.055 | 0 | 0.0554 | 0 | 2.4944 | 0 |
| | SuM | | 0.000270 | | | | | | | | SuM | 4.559 | 0.401 | 0.490 | 0.1447 | 0.1278 | 0.1640 | 4.1227 | 0.0352 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.3) (US GoM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of completed wells | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Completion | | Blowout surface flow | 0.000200 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 4.50 % | 440 | 0.088 | 0.013 | 0.020 | 0.0065 | 0.0033 | 0.0049 | 0.0733 | 0.0040 |
| | | Blowout (underground flow) | 0.000000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 440 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.000200 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 440 | 0.088 | 0 | 0 | 0 | 0 | 0 | 0.0879 | 0 |
| | | Well release | 0.000200 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 440 | 0.088 | 0.004 | 0.002 | 0 | 0.0019 | 0 | 0.0842 | 0 |
| | SuM | | 0.000600 | | | | | | | | SuM | 0.264 | 0.017 | 0.021 | 0.0065 | 0.0051 | 0.0068 | 0.2454 | 0.0040 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.5) (US GOM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of well years in service | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Production | | Blowout surface flow | 0.000103 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 3.00 % | 16,900 | 1.737 | 0.257 | 0.386 | 0.1287 | 0.0643 | 0.0965 | 1.4474 | 0.0521 |
| | | Blowout (underground flow) | 0.000000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.000000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0.000 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0 |
| | | Well release | 0.000051 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 16,900 | 0.868 | 0.037 | 0.018 | 0 | 0.0185 | 0 | 0.8315 | 0 |
| | SuM | | 0.000154 | | | | | | | | SuM | 2.605 | 0.294 | 0.404 | 0.1287 | 0.0828 | 0.1150 | 2.2788 | 0.0521 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.6) (US GOM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of well years in service | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Wireline | | Blowout surface flow | 0.000000 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 1.80 % | 16,900 | 0.000 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Blowout (underground flow) | 0.000000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.000000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0.000 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0 |
| | | Well release | 0.000039 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 16,900 | 0.651 | 0.028 | 0.014 | 0 | 0.0139 | 0 | 0.6236 | 0 |
| | SuM | | 0.000039 | | | | | | | | SuM | 0.651 | 0.028 | 0.014 | 0.0000 | 0.0139 | 0.0139 | 0.6236 | 0.0000 |
| | | | | | | | | | | | | | | | Material damages | | | | |
| | | | | | | | | | | **US GoM OCS five year period risk** | | No of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| | | | | | | | | | | | Total all | 12.623 | 1.148 | 1.486 | 0.456 | 0.345 | 0.459 | 11.363 | 0.184 |

## Frequencies and Consequences based on US GoM OCS and regulated areas 2000–2015, assumed 5 year activity level based on 2015

| Offshore activity | | | INPUT DATA | | | | | | | | | Risk results | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Type of drilling | Deep or shallow zone | Main category | LOWC frequency per well drilled (Table 17.2) (US, UK & Norwegian frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Material damages (Table 14.4) Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of exploration wells | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Material damages Total Loss | Severe | Damage | Small /no | Large spill probability |
| Exploration drilling Floating or bottom fixed installation | Deep | Blowout surface flow | 0.00125 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 8.10 % | 515 | 0.646 | 0.096 | 0.144 | 0.0479 | 0.0239 | 0.0359 | 0.5385 | 0.0523 |
| | | Blowout (underground flow) | 0.00038 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 515 | 0.194 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.1939 | 0.0000 |
| | | Diverted well release | 0.00013 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 515 | 0.065 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0646 | 0.0000 |
| | | Well release | 0.00050 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 515 | 0.259 | 0.011 | 0.006 | 0.0000 | 0.0055 | 0.0055 | 0.2475 | 0.0000 |
| | Shallow | Blowout surface flow | 0.00075 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 0 % | 515 | 0.388 | 0.057 | 0.086 | 0.0287 | 0.0144 | 0.0215 | 0.3231 | 0.0000 |
| | | Blowout (underground flow) | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 515 | 0 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Diverted well release | 0.00050 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 515 | 0.259 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.2585 | 0.0000 |
| | | Well release | 0.00025 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 515 | 0.129 | 0.006 | 0.003 | 0.0000 | 0.0028 | 0.0028 | 0.1238 | 0.0000 |
| | SuM | | 0.00376 | | | | | | | | SUM | 1.94 | 0.170 | 0.238 | 0.077 | 0.047 | 0.066 | 1.750 | 0.052 |
| Operation | Deep or shallow zone | Main category | LOWC frequency per well drilled Table 17.1) (US, UK & Norwegian frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Material damages (Table 14.4) Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of development wells | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Material damages Total Loss | Severe | Damage | Small /no | Large spill probability |
| Development drilling Floating or bottom fixed installation | Deep | Blowout surface flow | 0.00021 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 8.10 % | 540 | 0.112 | 0.017 | 0.025 | 0.0083 | 0.0042 | 0.0062 | 0.0935 | 0.0091 |
| | | Blowout (underground flow) | 0.00007 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 540 | 0.037 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0374 | 0.0000 |
| | | Diverted well release | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 540 | 0.000 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Well release | 0.00014 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 540 | 0.075 | 0.003 | 0.002 | 0.0000 | 0.0016 | 0.0016 | 0.0716 | 0.0000 |
| | Shallow | Blowout surface flow | 0.00069 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 0 % | 540 | 0.374 | 0.055 | 0.083 | 0.0277 | 0.0138 | 0.0208 | 0.3115 | 0.0000 |
| | | Blowout (underground flow) | | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 540 | 0 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Diverted well release | 0.00042 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 540 | 0.224 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.2243 | 0.0000 |
| | | Well release | | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 540 | 0.000 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | SuM | | 0.00152 | | | | | | | | SUM | 0.82 | 0.075 | 0.110 | 0.036 | 0.020 | 0.029 | 0.738 | 0.009 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.4) (US, UK & Norwegian frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of well years in service | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Workover | | Blowout surface flow | 0.000080 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 1.80 % | 16,900 | 1.346 | 0.199 | 0.299 | 0.0997 | 0.0499 | 0.0748 | 1.1219 | 0.0242 |
| | | Blowout (underground flow) | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0.000 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Diverted well release | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0.000 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Well release | 0.000127 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 16,900 | 2.154 | 0.093 | 0.046 | 0.0000 | 0.0458 | 0.0458 | 2.0625 | 0.0000 |
| | SuM | | 0.000207 | | | | | | | | SuM | 3.50 | 0.292 | 0.345 | 0.100 | 0.096 | 0.121 | 3.184 | 0.024 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.3) (US, UK & Norwegian frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of completed wells | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Completion | | Blowout surface flow | 0.000194 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 4.50 % | 440 | 0.085 | 0.013 | 0.019 | 0.0063 | 0.0032 | 0.0047 | 0.0711 | 0.0038 |
| | | Blowout (underground flow) | 0.000000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 440 | 0.000 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Diverted well release | 0.000097 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 440 | 0.043 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0427 | 0.0000 |
| | | Well release | 0.000485 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 440 | 0.213 | 0.009 | 0.005 | 0.0000 | 0.0045 | 0.0045 | 0.2043 | 0.0000 |
| | SuM | | 0.000776 | | | | | | | | SuM | 0.34 | 0.022 | 0.024 | 0.006 | 0.008 | 0.009 | 0.318 | 0.004 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.5) (US, UK & Norwegian frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of well years in service | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Production | | Blowout surface flow | 0.000064 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 3.00 % | 16,900 | 1.077 | 0.159 | 0.239 | 0.0798 | 0.0399 | 0.0598 | 0.8976 | 0.0323 |
| | | Blowout (underground flow) | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0.000 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Diverted well release | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0.000 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Well release | 0.000056 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 16,900 | 0.942 | 0.041 | 0.020 | 0.0000 | 0.0201 | 0.0201 | 0.9023 | 0.0000 |
| | SuM | | 0.000119 | | | | | | | | SuM | 2.02 | 0.200 | 0.259 | 0.080 | 0.060 | 0.080 | 1.800 | 0.032 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.6) (US, UK & Norwegian frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level five year period (Table 17.13), no. of well years in service | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Wireline | | Blowout surface flow | 0.000008 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 1.80 % | 16,900 | 0.135 | 0.020 | 0.030 | 0.0100 | 0.0050 | 0.0075 | 0.1122 | 0.0024 |
| | | Blowout (underground flow) | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0.000 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Diverted well release | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 16,900 | 0.000 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Well release | 0.000048 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 16,900 | 0.808 | 0.035 | 0.017 | 0.0000 | 0.0172 | 0.0172 | 0.7734 | 0.0000 |
| | SuM | | 0.000056 | | | | | | | | SUM | 0.94 | 0.055 | 0.047 | 0.010 | 0.022 | 0.025 | 0.886 | 0.002 |
| | | | | | | | | | | | | | | | Material damages | | | | |
| | | | | | | | | | | US GoM OCS five year period risk | | No of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| | | | | | | | | | | | Total all | 9,57 | 0,813 | 1,023 | 0,308 | 0,252 | 0,329 | 8,676 | 0,124 |

## RISK MODEL VERIFICATION. Frequencies based on US GoM OCS 2000–2015. Consequences mainly based on US GoM OCS and regulated areas 2000–2015. US GoM activities 2000–2015

| Offshore activity | | | INPUT DATA | | | | | | | | | Risk results | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Type of drilling | Deep or shallow zone | Main category | LOWC frequency per well drilled (Table 17.10) (US GOM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level 2000-2015 (Table 17.16), no. of exploration wells | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Exploration drilling from bottom fixed installation | Deep | Blowout surface flow | 0.00255 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 8.10 % | 2,350 | 5.993 | 0.887 | 1.332 | 0.4439 | 0.2219 | 0.3329 | 4.9938 | 0.4854 |
| | | Blowout (underground flow) | 0.00085 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 2,350 | 1.998 | 0 | 0 | 0 | 0 | 0 | 1.9975 | 0 |
| | | Diverted well release | 0 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 2,350 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Well release | 0 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 2,350 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Shallow | Blowout surface flow | 0.00128 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 0 % | 2,350 | 3.008 | 0.445 | 0.668 | 0.2228 | 0.1114 | 0.1671 | 2.5067 | 0 |
| | | Blowout (underground flow) | 0.00128 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 2,350 | 3.008 | 0 | 0 | 0 | 0 | 0 | 3.0080 | 0 |
| | | Diverted well release | 0 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 2,350 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Well release | 0.00000 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 2,350 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | SuM | | 0.00596 | | | | | | | | **SuM** | 14.006 | 1.332 | 2.000 | 0.6667 | 0.3334 | 0.5000 | 12.5059 | 0.4854 |
| Exploration drilling from floating vessel | Deep | Blowout surface flow | 0.00185 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 8.10 % | 1,622 | 3.001 | 0.444 | 0.667 | 0.2223 | 0.1111 | 0.1667 | 2.5006 | 0.2431 |
| | | Blowout (underground flow) | 0 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 1,622 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.00062 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 1,622 | 1.006 | 0 | 0 | 0 | 0 | 0 | 1.0056 | 0 |
| | | Well release | 0.00123 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 1,622 | 1.995 | 0.086 | 0.042 | 0 | 0.0424 | 0 | 1.9102 | 0 |
| | Shallow | Blowout surface flow | 0.00123 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 0 % | 1,622 | 1.995 | 0.295 | 0.443 | 0.1478 | 0.0739 | 0.1108 | 1.6626 | 0 |
| | | Blowout (underground flow) | 0 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 1,622 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 1,622 | 0.000 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0 |
| | | Well release | 0.00123 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 1,622 | 2 | 0 | 0 | 0 | 0 | 0 | 2 | 0 |
| | SuM | | 0.00616 | | | | | | | | **SuM** | 9.992 | 0.911 | 1.195 | 0.3701 | 0.2699 | 0.3624 | 8.9891 | 0.2431 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | Deep or shallow zone | Main category | LOWC frequency per well drilled (Table 17.9) (US GOM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level 2000-2015 (Table 17.16), no. of development wells | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Development drilling Floating or bottom fixed installation | Deep | Blowout surface flow | 0.00032 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 8.10 % | 6,288 | 2.018 | 0.299 | 0.448 | 0.1494 | 0.0747 | 0.1121 | 1.6813 | 0.1634 |
| | | Blowout (underground flow) | 0.00016 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 6,288 | 1.009 | 0 | 0 | 0 | 0 | 0 | 1.0088 | 0 |
| | | Diverted well release | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 6,288 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Well release | 0.00016 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 6,288 | 1.009 | 0.043 | 0.021 | 0 | 0.0215 | 0 | 0.9658 | 0 |
| | Shallow | Blowout surface flow | 0.00111 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 0 % | 6,288 | 7.005 | 1.037 | 1.557 | 0.5189 | 0.2595 | 0.3892 | 5.8377 | 0 |
| | | Blowout (underground flow) | | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 6,288 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.00079 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 6,288 | 4.988 | 0 | 0 | 0 | 0 | 0 | 4.9878 | 0 |
| | | Well release | | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 6,288 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | SuM | | 0,00255 | | | | | | | | **SuM** | 16,028 | 1,379 | 2,027 | 0,6684 | 0,3556 | 0,5227 | 14,4813 | 0,1634 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.4) (US GOM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level 2000-2015 (Table 17.16), no. of well years in service | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Workover | | Blowout surface flow | 0.000116 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 1.80 % | 77,843 | 9.000 | 1.332 | 2.000 | 0.6667 | 0.3333 | 0.5000 | 7.5000 | 0.1620 |
| | | Blowout (underground flow) | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 77,843 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.00000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 77,843 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Well release | 0.000154 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 77,843 | 12.000 | 0.516 | 0.255 | 0 | 0.2553 | 0 | 11.4894 | 0 |
| | SuM | | 0.000270 | | | | | | | | **SuM** | 21.000 | 1.848 | 2.255 | 0.6667 | 0.5887 | 0.7553 | 18.9894 | 0.1620 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.3) (US GoM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level 2000-2015 (Table 17.16), no. of completed wells | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Completion | | Blowout surface flow | 0.000200 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 4.50 % | 5,004 | 1.000 | 0.148 | 0.222 | 0.0741 | 0.0370 | 0.0556 | 0.8333 | 0.0450 |
| | | Blowout (underground flow) | 0.000000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 5,004 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.000200 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 5,004 | 1.000 | 0 | 0 | 0 | 0 | 0 | 1.0000 | 0 |
| | | Well release | 0.000200 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 5,004 | 1.000 | 0.043 | 0.021 | 0 | 0.0213 | 0 | 0.9574 | 0 |
| | SuM | | 0.000600 | | | | | | | | **SuM** | 3.000 | 0.191 | 0.243 | 0.0741 | 0.0583 | 0.0768 | 2.7908 | 0.0450 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.5) (US GOM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level 2000-2015 (Table 17.16), no. of well years in service | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Production | | Blowout surface flow | 0.000103 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 3.00 % | 77,843 | 8.000 | 1.184 | 1.778 | 0.5926 | 0.2963 | 0.4444 | 6.6667 | 0.2400 |
| | | Blowout (underground flow) | 0.000000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 77,843 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.000000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 77,843 | 0.000 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0 |
| | | Well release | 0.000051 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 77,843 | 4.000 | 0.172 | 0.085 | 0 | 0.0851 | 0 | 3.8298 | 0 |
| | SuM | | 0.000154 | | | | | | | | **SuM** | 12.000 | 1.356 | 1.863 | 0.5926 | 0.3814 | 0.5296 | 10.4965 | 0.2400 |
| | | | | | | Material damages (Table 14.4) | | | | | | | | | Material damages | | | | |
| Operation | | Main category | LOWC frequency per well year in service (Table 17.6) (US GOM OCS frequencies) | Ignition probability per LOWC (Table 14.3) | Fatalities per LOWC (Table 14.1) | Total Loss | Severe | Damage | Small /no | Large spill probability per LOWC (Section 17.1.4) | US GoM OCS activity level 2000-2015 (Table 17.16), no. of well years in service | No. of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| Wireline | | Blowout surface flow | 0.000000 | 14.8 % | 0.22 | 7.4 % | 3.7 % | 5.6 % | 83.3 % | 1.80 % | 77,843 | 0.000 | 0.000 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | | Blowout (underground flow) | 0.000000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 77,843 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | Diverted well release | 0.000000 | 0.0 % | 0.00 | 0.0 % | 0.0 % | 0.0 % | 100.0 % | 0 % | 77,843 | 0.000 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0 |
| | | Well release | 0.000039 | 4.3 % | 0.02 | 0.0 % | 2.1 % | 2.1 % | 95.7 % | 0 % | 77,843 | 3.000 | 0.129 | 0.064 | 0 | 0.0638 | 0 | 2.8723 | 0 |
| | SuM | | 0.000039 | | | | | | | | **SuM** | 3.000 | 0.129 | 0.064 | 0.0000 | 0.0638 | 0.0638 | 2.8723 | 0.0000 |
| | | | | | | | | | | | | | | | Material damages | | | | |
| | | | | | | | | | | **US GoM OCS five year period risk** | | No of LOWCs to expect | No. of ignited events to expect | No. of fatalities to expect | Total Loss | Severe | Damage | Small /no | Large spill probability |
| | | | | | | | | | | | Total all | 79.03 | 7.15 | 9.65 | 3.04 | 2.05 | 2.81 | 71.13 | 1.34 |