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Investigation report

Investigation report	
Investigation of a well control incident in well 31/3-Q-21 BY1H T5 \BY2H T2 on the Troll field involving the Deepsea Bollsta drilling facility	Activity number 001085040-Equinor 405010009-Odfjell Drilling 350000009-Baker Hughes

Classification	
☒Unclassified	☐Exempt from publication

Parties involved	
Team A-1 A-3	Approved by / date [redacted] (A-1) [redacted] (A-3) 22.04.2026
Investigation group participants [redacted]	Investigation leader [redacted]

Photo 1 Deepsea Bollsta (source: Odfjell Drilling)

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1 Summary

On 23 September 2025, a well control incident occurred during the permanent plugging and abandonment (PP&A) of well 31/3-Q-21 BY1H T5 \BY2H T2 on the Troll field. The incident occurred during the cutting of a 13 ⅜″ casing at 510 m RKB, 160 m below the seabed. The work was being carried out from the Deepsea Bollsta semi-submersible drilling facility, operated by Odfjell Drilling. Equinor is the operator of the field. At the time of the incident, there were 114 people on board the facility.

Prior to the cutting operation, wireline logging was performed to assess the quality of the cement and the potential presence of gas behind the 13 ⅜″ casing. The log was interpreted to indicate that the cement had sufficient barrier properties and that there was no free gas in the annulus behind the 13 ⅜" casing. Based on this interpretation, the well-cutting operation was planned and carried out without closing the annular preventer on the BOP.

The cutting operation began at approx. 03:50 when the cutting blades in the string were activated. At approx. 03:58, a movement was detected on the facility, which was interpreted as a successful cut. Because drilling fluid with a higher specific gravity than the fluid in the well was behind the casing, a pressure differential arose. This pressure differential meant that a slight backflow was expected after the cut.

Shortly after the cut, however, water and gas gushed uncontrollably up through the rotary table on the drill floor and into the shaker room. The flow caused the gas to spread rapidly to several areas of the facility. Readings on several gas detectors triggered the general alarm, an emergency shutdown (ESD 1) and ignition source disconnection.

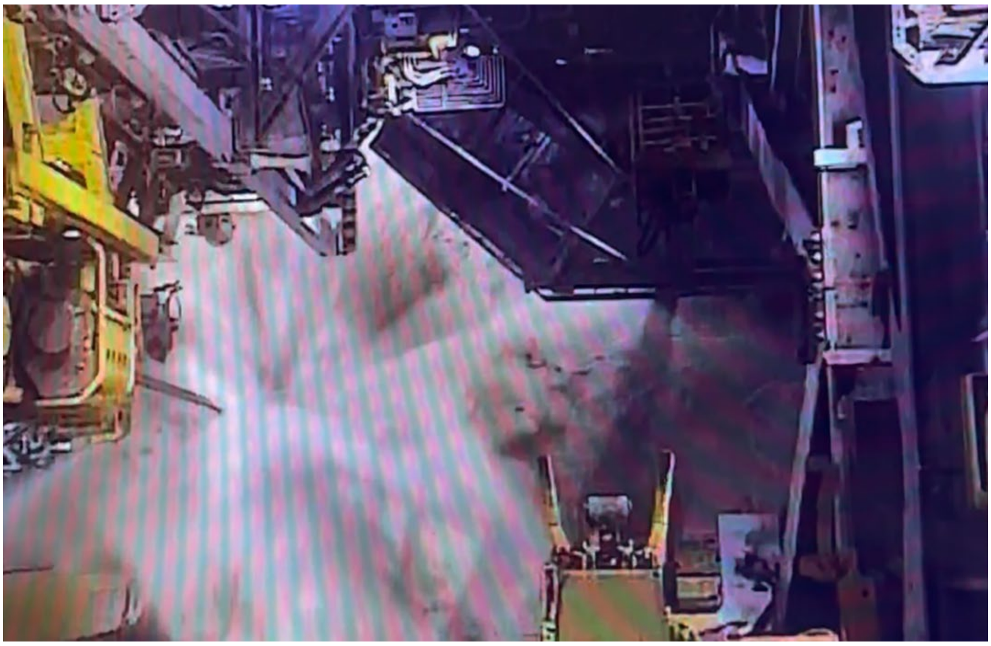

Photo 2 Still image from a video showing outflow onto the drill floor, viewed from above (source: Odfjell Drilling)

At the time of the incident, there were six people in the driller's cabin on the drill floor and two people in the room behind the driller's cabin. The drilling crew implemented well control measures by activating the diverter system and the annular preventer on the BOP shortly after observing the flow. The well was thus closed in. One person who was in the shaker room sustained minor injuries. There was also material damage in the shaker room, including several doors and parts of the HVAC system.

The direct cause of the incident was that gas from the reservoir, which had accumulated behind a 13 ⅜" casing, was released when the casing was cut. The investigation shows that this was due to a failure in the well's outer barrier.

The investigation detected various non-conformities concerning:

- Inadequate well barrier design
- Inadequate quality assurance during the calibration of equipment for logging the 13 ⅜" casing
- Use of technology that was not qualified for well barrier assessments
- Inadequate formulation of requirements (SR-126590) in the well integrity manual (TR3507)
- Absence of well barriers during cutting operation
- Noise level in the driller's cabin during well control operation
- Inadequate sharing of information about barriers and barrier impairments
- Separation of HVAC 1 and HVAC 2 rooms
- Failure to use differential pressure data
- Lack of maintenance of differential pressure gauges
- Inadequate formulation of requirements in the well control manual
- Inadequate updating of technical documentation

One improvement point was also identified.

- Handling of hazard and accident situations

The incident had the potential to cause a major accident. Under slightly different circumstances, the gas could have ignited, which could have resulted in serious injury or loss of life, as well as significant damage to the facility.

Key learning points:

- Uncertainty regarding well barrier components must be addressed through conservative operational decisions.
- Technology used for barrier verification must be suitable for the purpose.
- Changes in operational practices must be risk assessed and incorporated into the management system.
- Barriers must be assessed based on their function in the specific situation.

- A shared understanding of risk requires clear communication of uncertainty.
- Ensure that the negative pressure in the shaker room meets the requirements, but is not so low as to prevent a quick and efficient evacuation.
- Ensure adequate separation of classified and unclassified areas in such a way as to prevent the spread of gas in scenarios where the release of large quantities of gas could lead to pressure buildup in rooms.

2 Background information

The Troll field is a gas and oil field in the northern part of the North Sea, approximately 65 kilometres west of Kollsnes near Bergen. Troll has two main structures: Troll East and Troll West. The field covers an area of 750 square kilometres in blocks 31/2, 31/3, 31/5, and 31/6 in the North Sea. Water depth in the area is approximately 350 metres. The Troll field was discovered in 1979 and contains vast gas reserves; it is also one of the largest oil-producing fields on the Norwegian Continental Shelf. The original plan for development and operation (PDO) was approved in 1986. The field came on stream in 1995 (source: www.norskpetroleum.no).

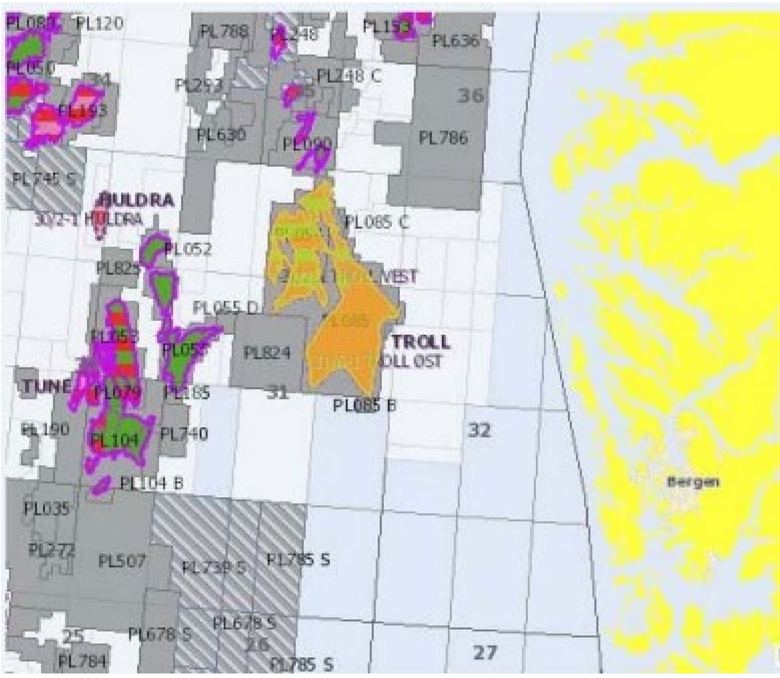

Photo 3 Location of the Troll field (source: Sodir)

2.1 Suppliers involved

Baker Hughes is Equinor's main service provider (MSP) of drilling and well services at Troll. The scope of work includes downhole drilling tools, cementing, completion solutions, drilling and completion fluids, logging while drilling, wireline logging, pumping and well cleaning operations. The MSP has, in principle, been awarded all work within the aforementioned categories; however, in cases where technical requirements cannot be fully met, or where the operator believes there are significant opportunities for efficiency gains, they will select equipment and services from suppliers other than the MSP. These other suppliers are often referred to as "preferred suppliers."

Archer was selected as the “preferred supplier” for services related to the cutting and pulling of casing in the well in question.

2.2 Well 31/3-Q-21 BY1H T5 \BY2H T2 (Q-21)

Well Q-21 was drilled in three separate phases in 2001, 2004 and 2007-2008. The original exploration well, Q-21 H, was drilled in 2001 using Scarabeo 6, and the reservoir zones were permanently plugged and abandoned before the well was prepared for a future sidetrack. In 2004, an MLT production well, Q-21 AY1H/AY2H T2, was drilled from a 13 ⅜ casing shoe, this time using West Venture. Well paths AY1/AY2 were plugged back in 2007 by West Venture. Two cement plugs were then installed on the inside of the 13 ⅜” casing before the casing was cut and pulled from the well. A new sidetrack, with two branches, was drilled from a cement plug just below the 20” casing, and two multilateral oil producers, Q-21 BY1H T5 and BY2H T2, were drilled into the reservoir. This drilling operation was carried out using Deepsea Trym. The upper completion installation was performed by Songa Dee. The BY1H well path included four technical sidetracks in the Fensfjord reservoir, while the BY2H well path included one technical sidetrack in the Sognefjord reservoir. All sidetracks were drilled to verify fluid contacts and stratigraphy. The well was in production until 2011 and has been shut in since then.

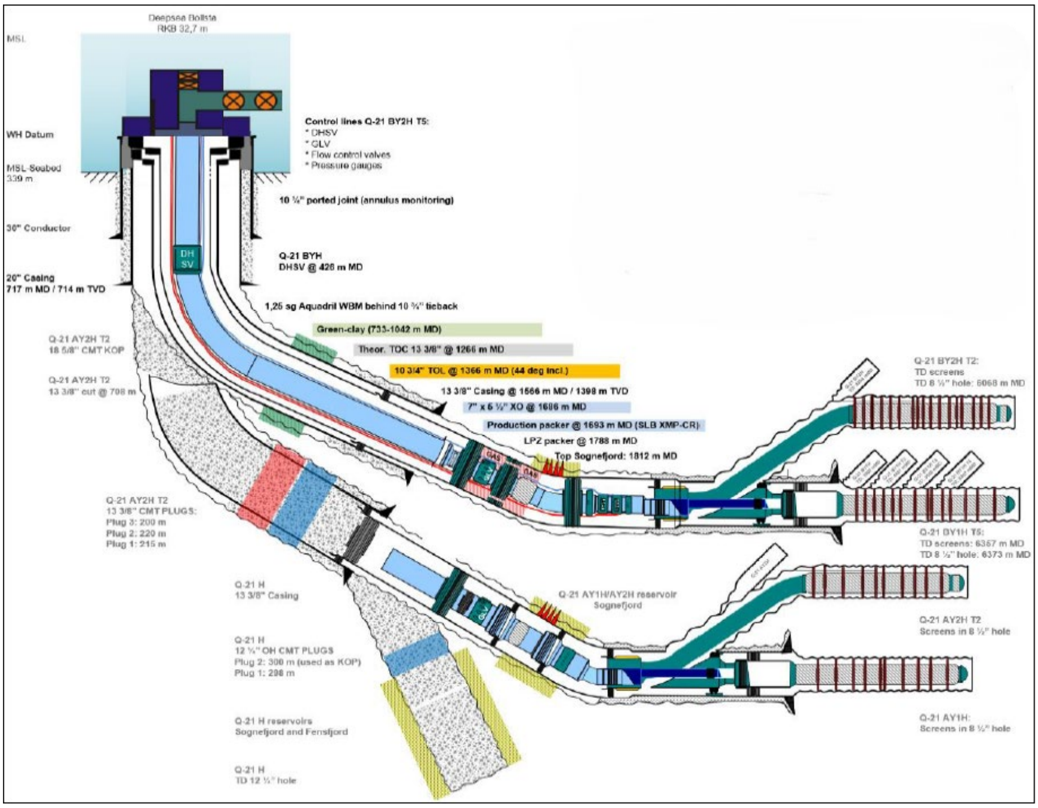

Figure 1 Sketch of the well prior to the plugging operation (source: Equinor)

2.3 Description of facility and organisation

Deepsea Bollsta is a semi-submersible drilling rig designed for offshore petroleum operations in challenging climatic and maritime conditions. The vessel was designed by Moss Maritime based on the CS60E concept and was completed in 2019 by Hyundai Heavy Industries in South Korea. It has been operated by Odfjell Drilling since 1 September 2022, and received an acknowledgement of compliance from Havtil on 9 May 2025. Deepsea Bollsta was previously operated by Seadrill. The facility is specifically designed for drilling operations on the Norwegian Continental Shelf.

Deepsea Bollsta was renamed Deepsea Bergen in March 2026.

At the time of the incident in question, the facility was under contract to Equinor to perform permanent plugging (PP&A) of two subsea wells, 31/3-Q-21 BY1H and 31/2-X-23 Y1H, on the Troll field.

Photo 4 The Deepsea Bollsta drilling facility (source: Odfjell Drilling)

2.4 Situation before the incident

A few days before the incident, wireline logging had been performed to verify the cement behind the 13 ⅜" casing. According to the documents received, the purpose of the logging was to:

1) verify that there was sufficient barrier-grade cement in the annulus,
2) assess any corrosion, and
3) determine whether there was gas behind the casing.

The operation immediately prior to the incident consisted of verifying the cement plug that had been set in the 13 ⅜" casing and simultaneously performing the cut at 510 m RKB. A bottom-hole assembly equipped with both a drill bit and cutting blades was used to perform the tagging and dressing of the cement plug, as well as to cut the casing. The actual cutting of the casing was planned as the final part of this operation.

2.5 Abbreviations and terms

Table 1 Abbreviations and descriptions

Abbreviations and terms	**Explanation**
Annular preventer	Annulus valve on the BOP

AoC	Acknowledgement of Compliance (SUT in Norwegian)
APS	Automatic Protection System
barg	The standard unit of pressure is the bar. When pressure is specified as overpressure relative to the external atmosphere, it is given in barg
BOP	Blowout Preventer
BHA	Bottom Hole Assembly
BY1H / BY2H	Well path (sidetrack) in well Q-21
CBL	Cement Bond Log
C1	Methane
C5	Pentane
CC	Cement channel
CCL	Casing Collar Locator
CCTV	Closed Circuit Television
C&E	Cause and Effect diagram
CORA	Consequence and Risk Analysis
DAL	Design Accidental Load
DCR	Driller's Control Room
DF	Drill Floor
DSHA	Defined situations of hazard and accident
Diverter	A diverter pipe, used to direct gas in risers to the open air away from the facility.
DOP	Detailed Operation Plan
DP	Dynamic Positioning
Dressing	Low-weight drilling to verify the hardness of the cement
EDS	Emergency Disconnect System
ESD	Emergency Shutdown ESD1 A and ESD1 B refer to ignition source disconnection of different groups of non-critical equipment.
F&G	Fire & Gas System
FiFi	Firefighting on standby vessels
Flow paddle	Flow meter designed with a hinged vane
FPP	Free Pipe Pass (calibration section in logging)
HC	Hydrocarbon
HVAC	Heating, Ventilation and Air Conditioning
HXT	Horizontal Xmas Tree (horizontal valve tree on the seabed)
ICMS	Integrated Control and Monitoring System
IMR	Inspection, Maintenance and Repair (vessel)
LEL	Lower Explosive Limit
MD	Measured Depth
Moonpool	The area underneath the drill floor on a semi-submersible drilling rig

MSP	Main Service Provider (primary drilling and well service provider)
OC-P&A	Operations Centre – Plugging & Abandonment (onshore)
P&A / PP&A	Plug and Abandon / Permanent Plugging and Abandonment
PAGA	Public Address & General Alarm
POB	Persons On Board
PS-30 slips	Hydraulically operated mechanical pipe grip that secures and supports drill pipes in the rotary table during handling
RKB	Rotary Kelly Bushing (reference for depth measurement)
SIMOPS	Simultaneous Operations
SUT	See AoC
Tagging	Weighing with the drill string
Tie-back	Casing string installed back from a liner hanger to the wellhead
Trip tank	A fluid reservoir used to monitor the level of small amounts of fluid in the well while running pipes in and out of the well
TVD	True Vertical Depth
UEL	Upper Explosive Limit
ULTeX	Ultrasonic logging tool for cement evaluation (acoustic impedance)
WBS	Well Barrier Schematics

3 Havtil's investigation

Havtil was notified by Equinor at 09:11 on 23 September 2025.

Havtil decided to launch an investigation into the incident on 24 September 2025.

Composition of the investigation group:
[redacted] drilling and well technology
[redacted], process integrity
[redacted] drilling and well technology

The investigation team was established on Wednesday, 24 September and travelled out to Deepsea Bollsta on Thursday, 25 September. Two inspections were conducted, covering the shaker room and adjacent areas, the drill floor, the HVAC rooms and the moonpool area. A total of 20 interviews were conducted with personnel from Equinor, Odfjell Drilling, Baker Hughes and Archer Offshore.
Following the on-board inspection, a further 23 interviews were conducted.

A meeting was also held with Odfjell Drilling to investigate alarm responses on various gas detectors and differential pressure gauges on the facility.

The investigation team used the STEP methodology for incident mapping.

3.1 Mandate of the investigation group

The following mandate was approved for Havtil's investigation group:

a. *Determine the scope and course of the incident (using a systematic review that typically describes timeline and events).*
b. *Assess the actual and potential consequences of*
    1. *Harm sustained by people, property and the environment.*
    2. *The incident's potential for harm to people, property and the environment.*
c. *Assess direct and underlying causes.*
d. *Identify regulatory non-conformities and improvement points (and internal requirements)*
e. *Discuss and describe any uncertainties/unclear issues*
f. *Consider barriers that did function (i.e. barriers that helped to prevent a hazard from developing into an accident, or barriers that mitigated the consequences of an accident.)*
g. *Assess the company's own investigation report*
h. *Prepare a report and cover letter (including, if appropriate, suggestions for the use of sanctions) according to the template*
i. *Recommend – and normally contribute to – further follow-up*

4 Description of technical systems and internal requirements

4.1 Internal technical requirements in Equinor TR3507

TR (Technical Requirement) 3507 is Equinor's internal technical requirements document that establishes minimum requirements for well integrity in offshore well operations throughout the well's lifecycle.
According to the company, the purpose of this document is to define minimum well integrity requirements for offshore wells at Equinor. The target audience for this document is all personnel and/or organisations involved in the planning and execution of offshore drilling, completion and well intervention activities.

TR 3507 is based on FR03 Drilling and Well.

FR (Functional Requirements) documents describe the overall requirements and principles that the organisation must fulfil, and they form the basis for more detailed technical requirements and guidelines (such as TR documents).

At the time of the incident, the document described the following requirements for operations that were scheduled to be performed: "*For operations with a risk of exposure of HC in combination with insufficient BOP activation time, the BOP shall be closed upfront the operation*".

4.2 Logging tool

According to documents received from Baker Hughes, the ULTeX™ logging tool is an ultrasonic wireline logging tool that combines evaluation of cement quality and casing integrity in a single logging operation. The tool uses a rotating transducer that transmits and receives ultrasonic signals to achieve a 360° survey of the casing. The technology makes it possible to detect channels, inadequate cement bonding, as well as wear, ovality and corrosion on the casing, and provides high-resolution data that supports the assessment of the well's barrier integrity and zone isolation.

4.3 Casing cutter

According to Archer, Samurai® is a hydraulic, ball-activated cutting tool for large casing pipes (from 9 ⅝" and up).
The tool allows for circulation and pumping through the string, without the cutting blades being activated until the ball is positioned, which provides the flexibility to combine cutting with other operations such as cementing or the installation of permanent barriers.

Samurai® has a large internal cross-section that allows for high circulation rates, and can be used to perform multiple cuts during the same operation.

Photo 5 Samurai cutting tool for casing (source: Archer Oiltools)

4.4 The diverter system

The diverter is integral to the riser system and is a component of the well control system. The system typically consists of several valves and overboard lines, which allow for rapid redirection of the well stream in the event of an unexpected kick, usually to a predefined overboard discharge line. When the diverter system is activated, a preselected valve to the overboard line opens, while the valves to the trip tank and/or the return flow line to the shaker room are closed. Packing elements are installed around the drill pipe, and an additional hydraulic seal is activated in the slip joint to ensure controlled diversion. The diverter system is not designed to withstand high well pressures like a BOP. It is used solely to divert the well flow away from the facility in a well control situation where hydrocarbons have entered the riser above the BOP.

The purpose of the diverter system is to protect personnel and the facility by diverting hydrocarbons away from the drilling area and potential ignition sources, thereby reducing the likelihood of an explosive atmosphere forming.

Photo 6 The diverter system on Deepsea Bollsta (source: Havtil)

4.5 PS-30 slips

The PS-30 slips is a hydraulically operated mechanical pipe grip used on the drill floor to hold and support the drill pipe in the rotary table when the pipe is not under tension or when it needs to be relieved of tension. The gripping elements in the slips consist of wedge-shaped segments with teeth that grip the pipe and transfer the load to the rotary table, ensuring that the pipe remains secure during operations such as connecting, disconnecting or handling the bottomhole assembly (BHA) and drill pipe. This equipment is an important part of the lifting and pipe-securing system in drilling operations. The slips used on Deepsea Bollsta weighed 5 tonnes.

Photo 7 PS-30 slips mounted on the rotary table (source: Havtil)

4.6 Shaker room and shakers

The shaker room is the area of the drilling installation where solid particles in drilling mud returning from the well are separated out using vibrating screens (shakers). The drilling fluid is normally returned from the well through the return flow line via the gumbo and header box, passing through the shakers before being collected in tanks for further treatment and recycling.

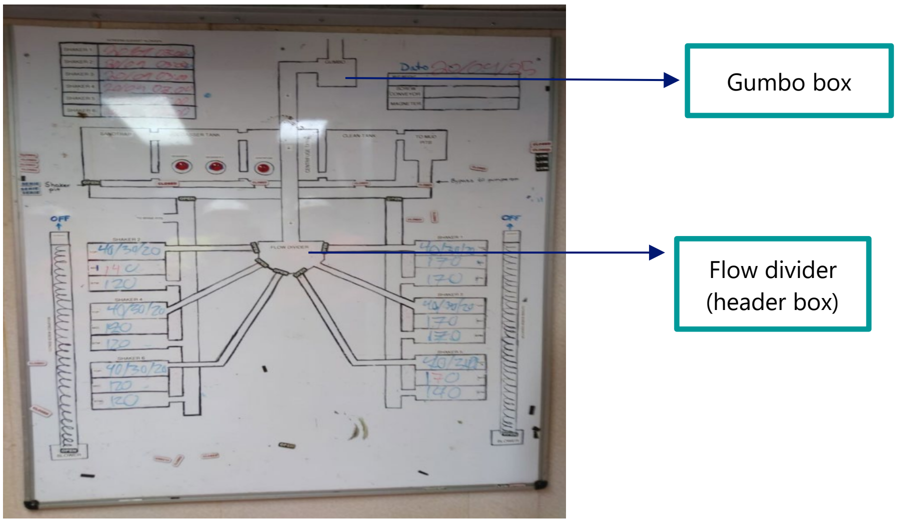

Photo 8 Outline sketch of Gumbo box and Flow divider (source: Havtil)

The room is classified as a potentially explosive area, since gas may be carried along with the return flow from the well.

4.7 Gas detection

Point gas detectors using infrared sensing have been installed in the shaker areas and on the drill floor. Detectors are placed at strategic locations near equipment where leaks are likely to occur. In addition, detectors have been installed in the exhaust ducts. Detectors detect gas at the point where the detector is installed, which means that the gas must physically come into contact with the detector in order to be measured.

According to the document "Deepsea Bollsta - HSE CASE FOR AoC," the gas detection system has the following alarm levels:

- High alarm (AlarmH):
  - HVAC detection: 8% LEL,
  - Detection in areas: 20% LEL
- High-High Alarm (AlarmHH):
  - HVAC detection: 16% LEL,
  - Detection in areas: 40% LEL

In the event of gas detection, the following procedure applies for confirmed gas detection:

- For zones where more than one gas detector is installed:
  - Two detectors ≥ 20% LEL (for HVAC detection: 8% LEL)
  - One detector at ≥ 20% LEL (for HVAC detection: 8% LEL) and one detector in failure condition (in areas where two detectors are installed).
  - One detector ≥ 20% (HVAC 8%), not checked out within two minutes.
  - One detector ≥ 40% LEL (for HVAC detection: 16% LEL)
- For zones where only one gas detector is installed:

- One detector ≥ 40% LEL (for HVAC detection: 16% LEL)
- One detector ≥ failure condition + 2 minutes for PAGA activation

Confirmed gas detection in the shaker areas triggers, among other things, a visual and audible alarm in the control room, as well as a general alarm (PAGA) in the installation. Confirmed gas detection on the drill floor (naturally ventilated area) also triggers ESD1 (in the alarm log and C&E, the descriptions ESD1 A and ESD1 B are used), resulting in the shutdown of non-critical equipment.

4.7.1 Gas detection during the incident

Three gas detectors have been installed in the shaker room on A Deck, in addition to one gas detector in the exhaust duct (ventilation system). A gas detector has also been installed in the adjacent room, Screen Store, and one gas detector in the exhaust duct in the adjacent room, Screen Cleaning Room. Figure 2 shows an overview of the gas detectors, which detectors triggered an alarm, and the order in which the detectors triggered an H/HH alarm during the incident.

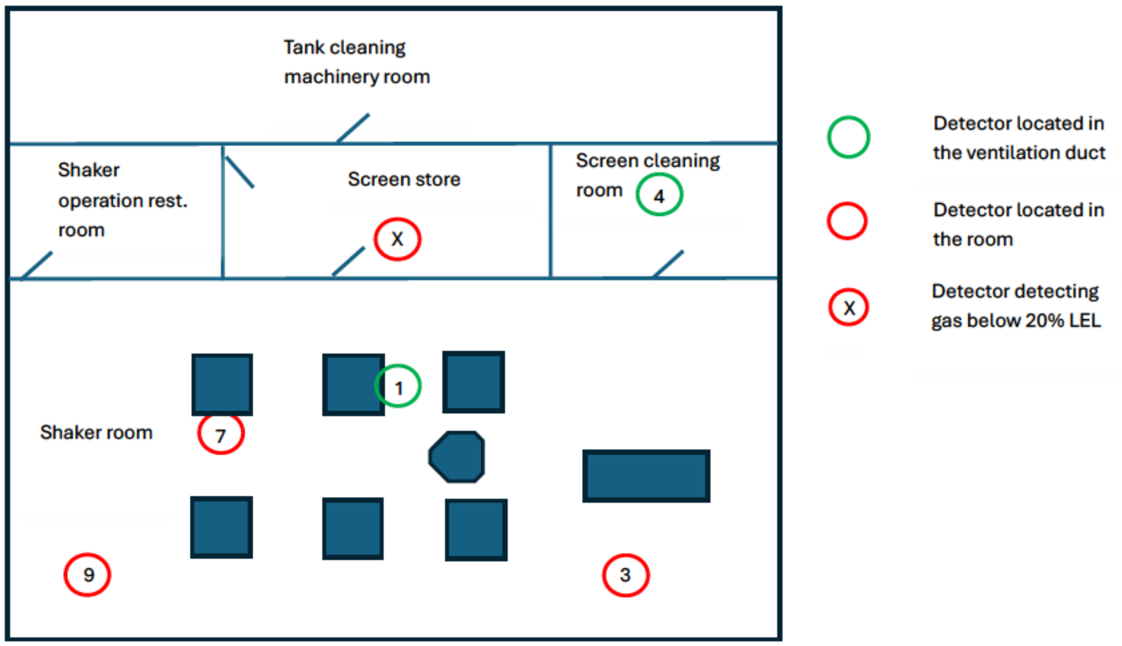

Figure 2 Overview of gas detectors in the shaker room and adjacent rooms on A Deck. The detectors are numbered according to the order in which they triggered the H/HH alarm (see Table 2) (source: Odfjell Drilling)

Figure 3 shows the trend in readings from the gas detectors in the shaker room and adjacent areas.
There are no gas detectors installed on B Deck (one level above the shakers, but in the same area). At 03:58:20, the first detector triggered an H/HH alarm (detector 1, located in the exhaust duct in the shaker room). Several of the detectors registered readings above 100% LEL. The gas detector in the Screen Store (detector X) detected gas, but not at a concentration high enough to trigger an H alarm (gas detection below 20% LEL).

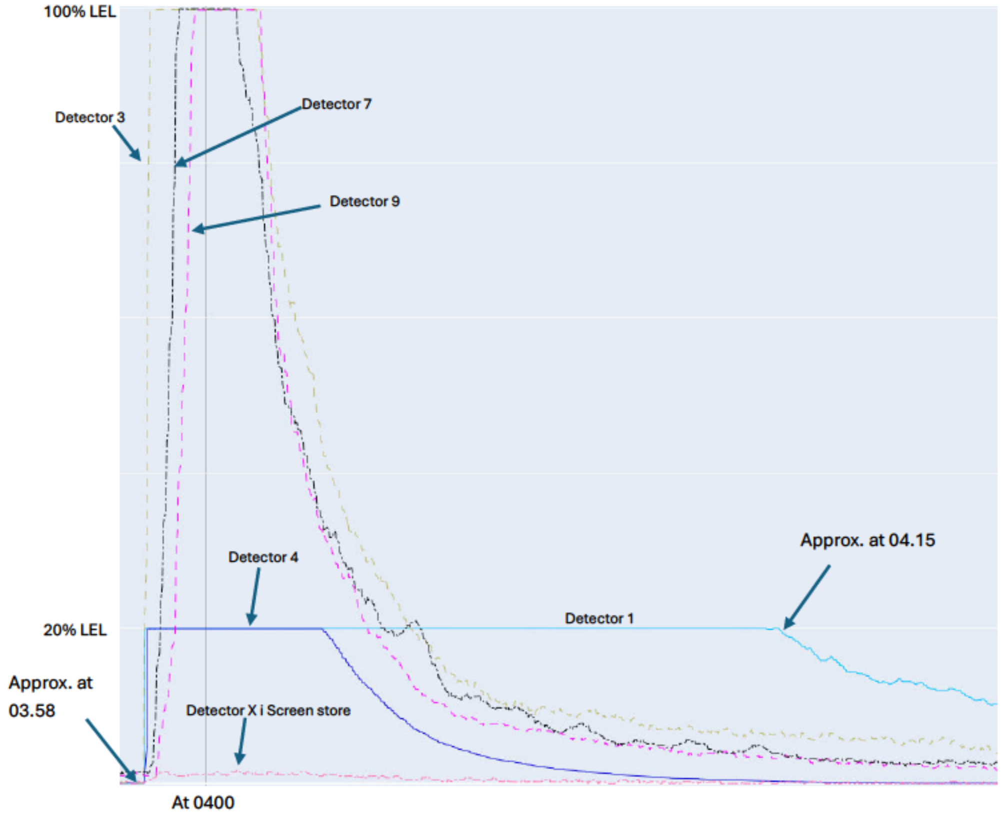

Figure 3 Gas detector readings in the shaker room and adjacent area (source: Odfjell Drilling)

Below the shaker room is the Lower Part Shale Shaker. There is a steel deck between the shaker room and the Lower Part Shale Shaker. Four gas detectors were installed in the Lower Part Shale Shaker, as shown in Figure 4, which indicates the order in which the detectors triggered an alarm.

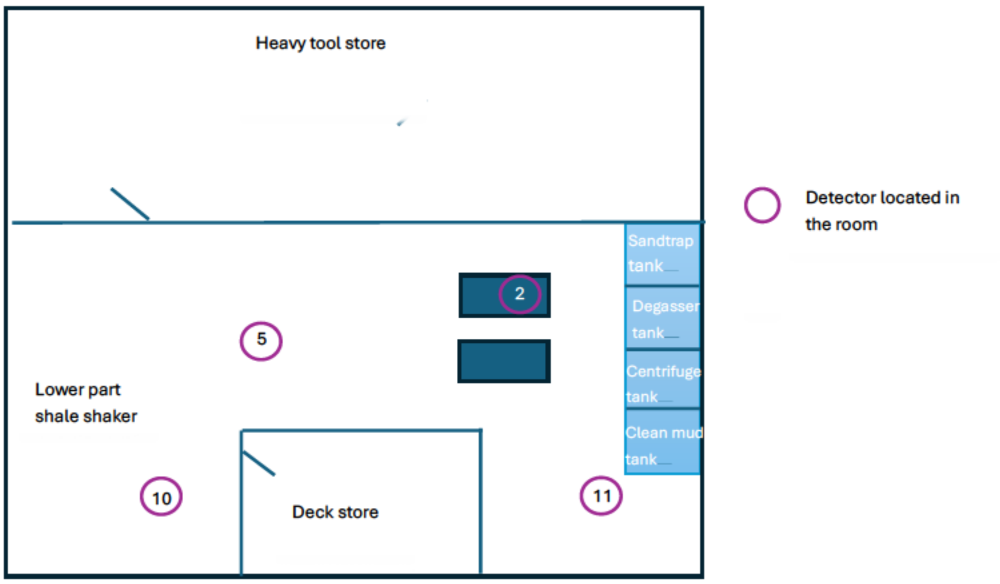

Figure 4 Overview of gas detectors in the Lower Part Shale Shaker. The detectors are numbered according to the order in which they triggered an H/HH alarm (see Table 2) (source: Odfjell Drilling)

Figure 5 shows the trend in gas detector readings measured in the Lower Part Shale Shaker. Detector 2 registered a reading above 100% LEL during the incident. Detectors 10 and 11 triggered only an H alarm (the reading was above 20% LEL but below 40% LEL).

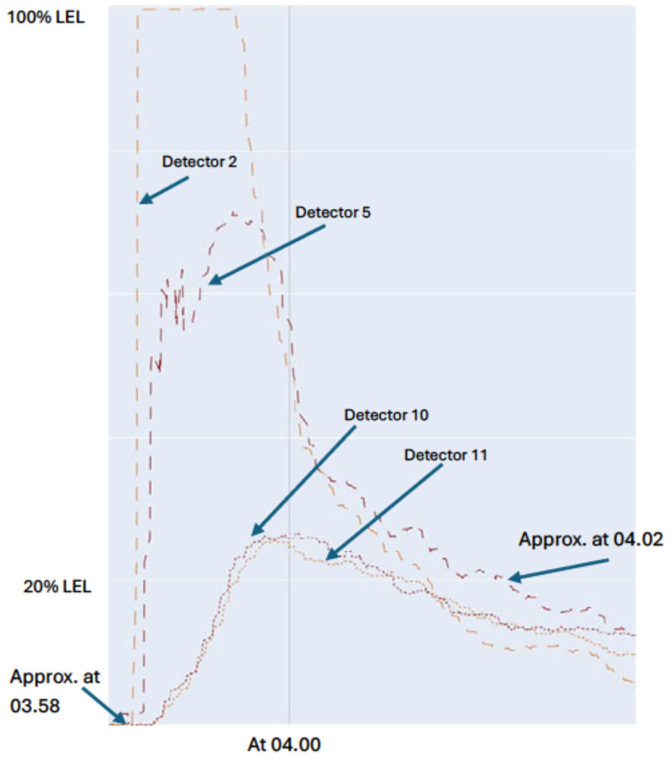

Figure 5 Gas detector readings in the Lower Part Shale Shaker. (source: Odfjell Drilling)

There is a gas detector under the drill floor near the overboard lines and the return flow line to the shaker room (Figure 6). The detector was no. 6 in the order of detecting gas, and gas detection was confirmed (HH alarm) at 03:58:29, triggering ESD 1 (A/B) with the disconnection of ignition sources from non-critical equipment at 03:58:30. Figure 7 shows the trend in measured gas detector readings. For a period of time, the reading was above 100% LEL.

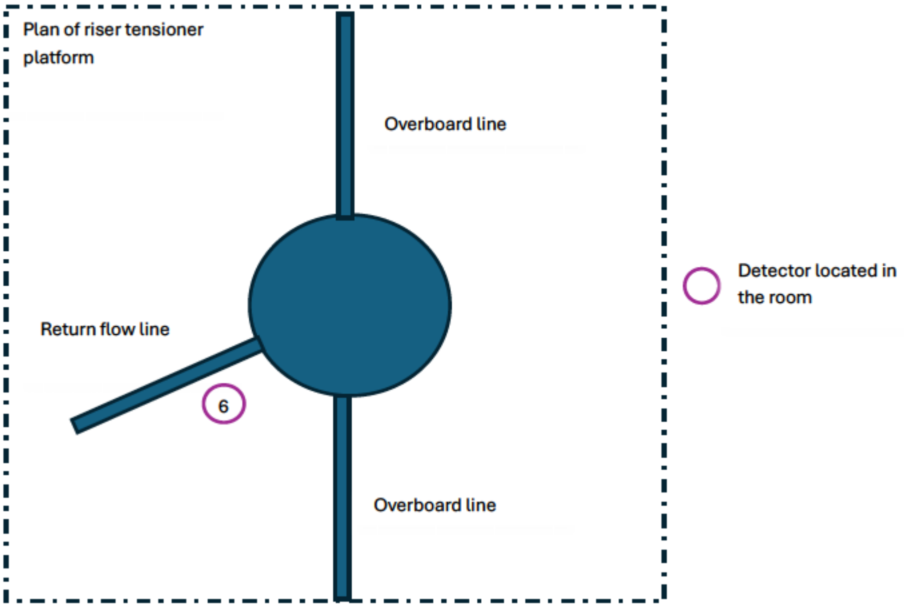

Figure 6 Overview of gas detector in the area underneath the drill floor (source: Odfjell Drilling)

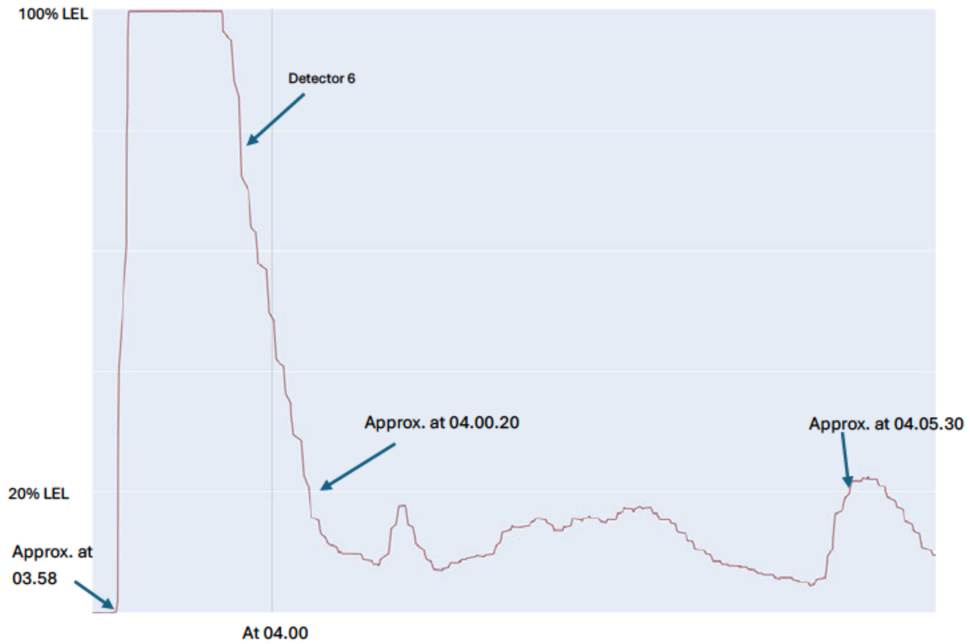

Figure 7 Readings from gas detector underneath the drill floor during the incident. (source: Odfjell Drilling)

The instrument in Photo 9 shows a flapper valve, which is installed on the return flow line to the shaker room. During the incident, the instrument came loose, resulting in an open hole in the return flow line located in the area underneath the drill floor.

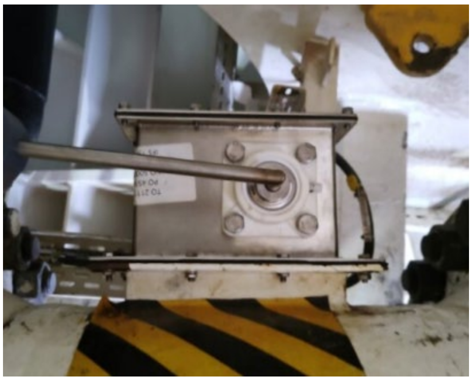

Photo 9 Flapper valve on the return flow line to the shakers (source: Havtil)

Four gas detectors were installed on the drill floor in the area near the rotary table, as shown in Figure 8. A detector (detector 8) triggered an H/HH alarm at 03:58:47. This detector registered a reading above 100% LEL. Two other detectors in the area detected gas, but the levels were not high enough to trigger an alarm (i.e., below 20% LEL).

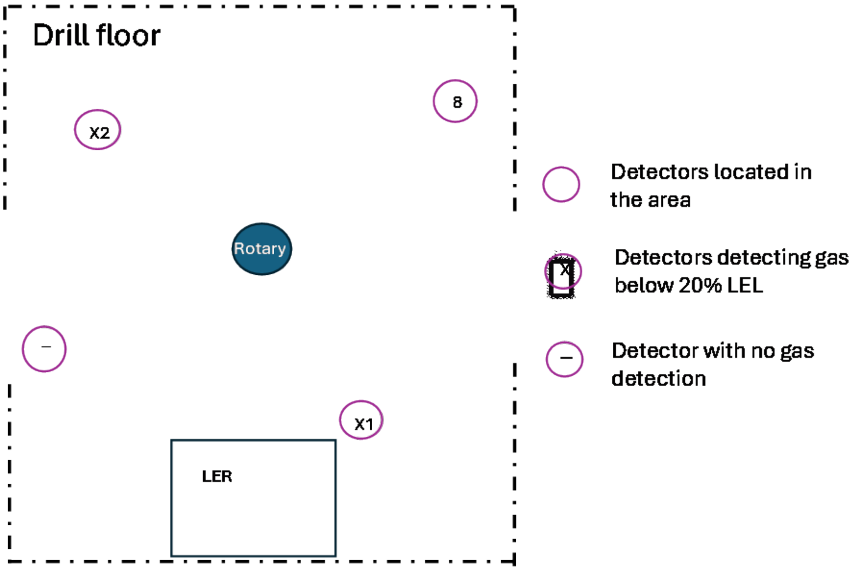

Figure 8 Overview of gas detectors on the drill floor. The detectors are numbered according to the order in which they triggered the H/HH alarm (see Table 2) (source: Odfjell Drilling)

Figure 9 shows the trend in readings from the gas detectors on the drill floor.

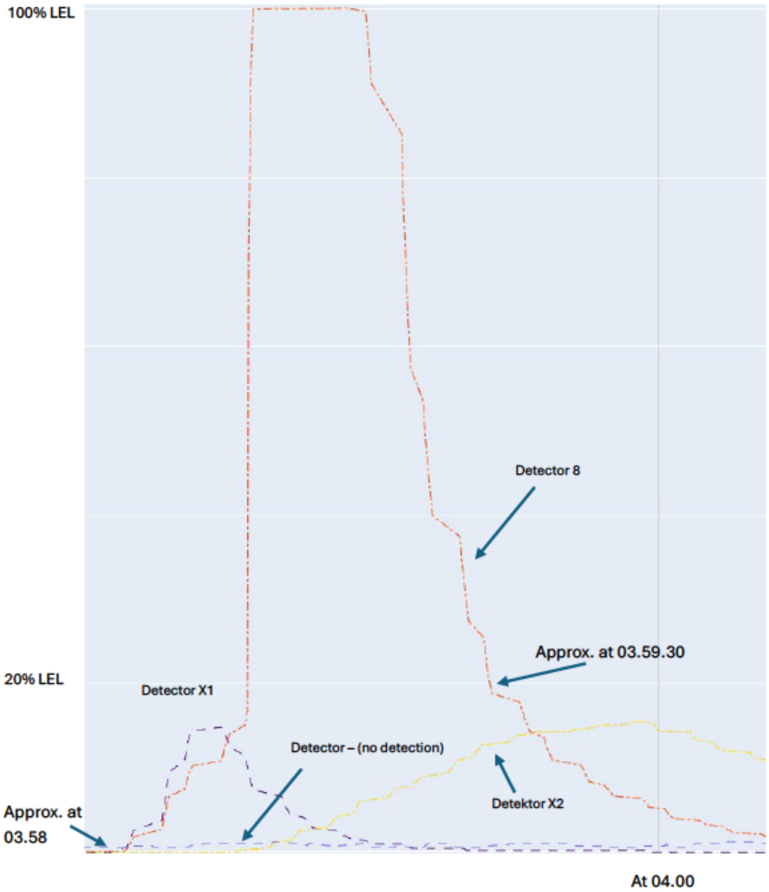

Figure 9 Gas detector readings on the drill floor during the incident. (source: Odfjell Drilling)

Table 2 shows the order and time of the gas detectors triggering alarm levels H and HH during the incident. This information is taken from the alarm log.

Table 2 Order and time of gas detection alarm levels H and HH

Detector no.	Location	Detection	Time when the detector first triggered alarm per the alarm log
1	Shale Shaker Room Exhaust Duct	Alarm H	03:58:20
		Alarm HH	03:58:20
2	Lower Part Shale Shaker	Alarm H	03:58:21
		Alarm HH	03:58:22
3	Shale Shaker Room Starboard	Alarm H	03:58:22
		Alarm HH	03:58:25
4	In Screen Cleaning Room Exhaust Duct	Alarm H	03:58:23
		Alarm HH	03:58:23
5		Alarm H	03:58:28

	Lower Part Shale Shaker	Alarm HH	03:58:31
6	Underneath Drill Floor	Alarm H	03:58:28
		Alarm HH	03:58:29
7	Shale Shaker Room	Alarm H	03:58:54
		Alarm HH	03:58:54
8	Drill Floor Port	Alarm H	03:58:47
		Alarm HH	03:58:47
9	Shale Shaker Room Starboard	Alarm H	03:59:08
		Alarm HH	03:59:16
10	Lower Part Shale Shaker	Alarm H	03:59:18
		Alarm HH	
11	Lower Part Shale Shaker	Alarm H	03:59:23
		Alarm HH	

The description of detector readings in the various zones provides only an indication of the gas/air mixture at the specific location where the gas detector is installed (as mentioned earlier, the gas must physically come into contact with the detector in order to be measured). There were gas mixtures in other parts of the shaker areas, the drill floor and underneath the drill floor where no gas detectors were installed. In addition to the gas detectors mentioned above, there were also several other detectors on the facility that detected gas, but not at levels high enough to trigger an alarm (below 20% LEL/8% LEL HVAC).

For a flammable gas to ignite, the mixture of flammable gas and air must fall within the lower and upper explosive limits (between 100% LEL and UEL). If the mixture of flammable gas and air is below the LEL or above the UEL, it will not ignite. Several of the detectors that triggered an alarm during the incident registered readings above the lower explosive limit (i.e., above 100% LEL). During the investigation, we were informed that it was the gas from the reservoir (including C1, ref. 5.3.1) that was released during the incident. For methane (C1), there is a risk of ignition and explosion between approximately 4.4% and 17.0% by volume (see Figure 10).

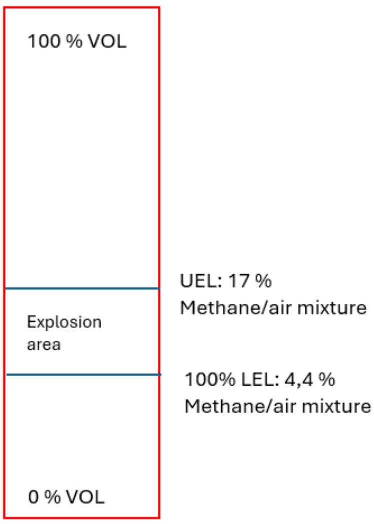

Figure 10 Sketch illustrating the lower and upper explosive limits and the explosion range for methane (C1) (source: Havtil)

We have received data showing the readings from the various gas detectors on the facility (as shown in Figure 3, Figure 5, Figure 7 and Figure 9). The trends show only detected gas concentrations up to 100% LEL for detectors located in the various areas, and for some gas detectors in exhaust ducts, up to 20% LEL. A total of six gas detectors located in the shaker room, the "Lower part shaker room," the "Drill floor" and "Underneath the drill floor" detected gas levels above 100% LEL over a period of time (see Figure 11). Figure 11 shows only the approximate time period during which the various detectors were above the lower explosive limit (above 100% LEL→). The time during which the gas mixture was within 100% LEL and UEL will be slightly shorter, since the gas concentration above the upper explosive limit is included in the calculation of this time. As mentioned earlier, the gas-air mixture is only flammable between the lower and upper explosive limits (between 100% LEL and UEL). The trend shows that the three detectors located in the shaker room (detectors 3, 7, and 9 on A Deck) have readings above 100% LEL for in excess of one minute simultaneously. Based on the location and readings from the three detectors, it is estimated that the gas cloud covered large parts of the room.

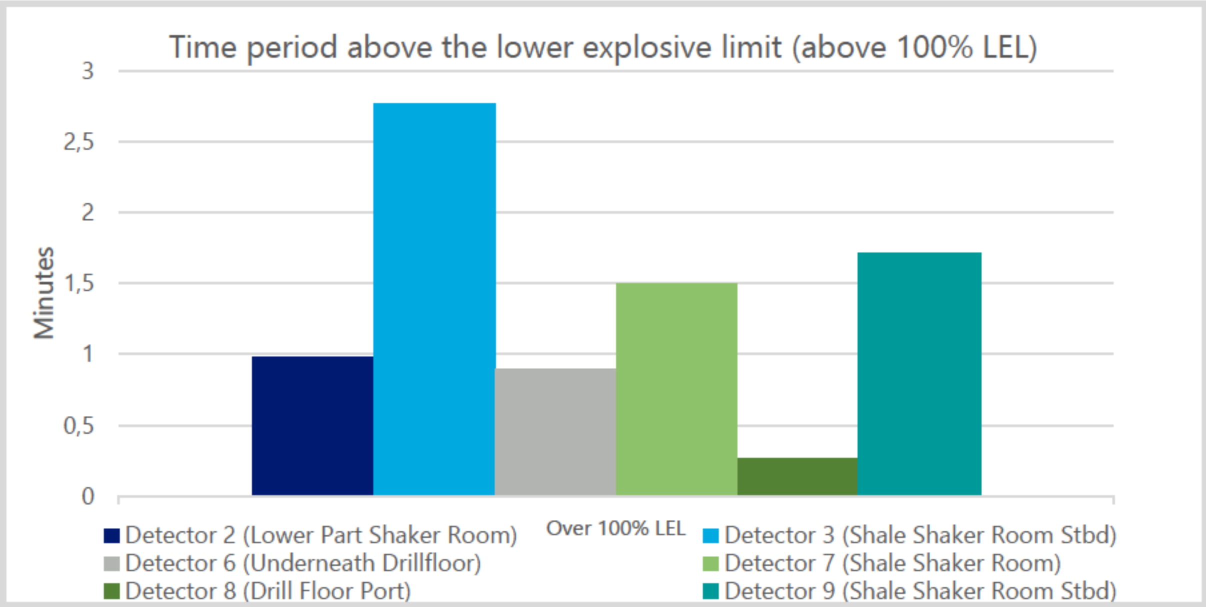

Figure 11 Overview of the time periods during which the various detectors that detected gas above 100% LEL were above the lower explosive limit (above 100% LEL). (source: Odfjell Drilling)

Detector 1, located in the exhaust duct in the shaker room, and detector 4, located in the exhaust duct in the Screen Cleaning Room, detected gas at 20% LEL over an extended period (the maximum detection range for these detectors was set to 20% LEL); see Figure 12. If the detectors had been configured to measure concentrations above 20% LEL, they would most likely have recorded concentrations above the lower explosive limit (100% LEL) for an extended period. Detector 1 was the detector that detected gas for the longest period of time compared to the other detectors. Gas readings exceeded 20% LEL for approximately 16.5 minutes. Detector 4 registered readings above 20% LEL for approximately 4.5 minutes.

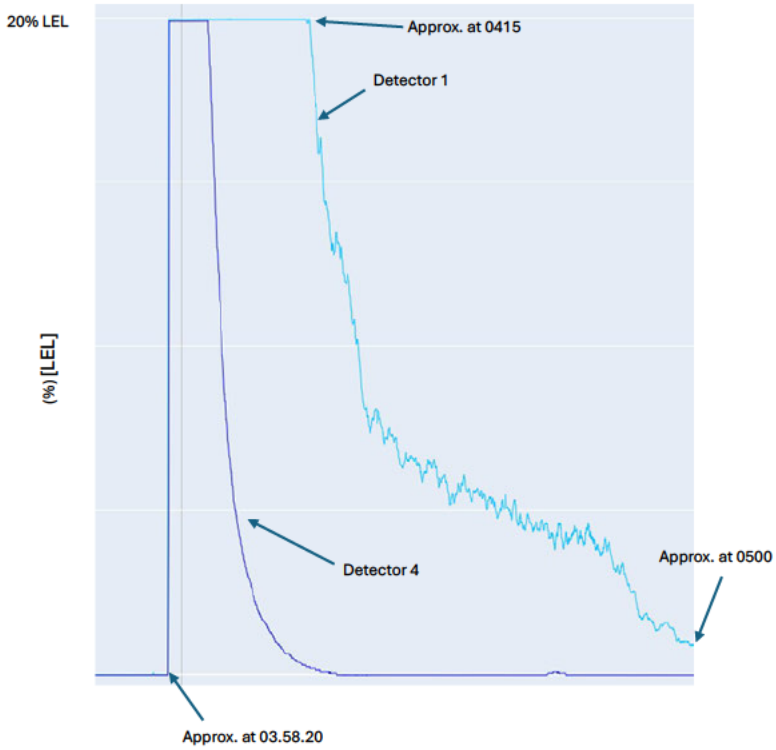

Figure 12 Detector 1, located in the exhaust duct in the shaker room, and detector 4, located in the exhaust duct in the Screen Cleaning Room, detected gas levels above 20% LEL for an extended period. (source: Odfjell Drilling data)

During the incident, there was a period of time (as shown in Figure 11), when there was an explosive mixture (above 100% LEL) in the shaker room, the "Lower Part Shaker Room," "Underneath drill floor," and the drill floor that could have ignited upon contact with an ignition source. In the investigation, we did not analyse how the gas mixture most likely spread throughout the facility or what the concentration (air/gas) of the mixture was during the course of the incident. There were gas mixtures in other parts of the shaker areas, the drill floor and underneath the drill floor where no gas detectors were installed. We do not have data on the volume of gas or the concentration of the gas mixture in these areas. There is therefore uncertainty regarding the extent of the gas cloud in the shaker area and other areas, as well as the period during which the gas cloud in these areas may have been flammable. During the incident, there may have been an explosive gas mixture present for longer and at a completely different time, in areas not covered by gas detectors.

Several of the areas mentioned are enclosed spaces with reduced ventilation. Enclosure means that the gas mixture will not be ventilated away as quickly (compared to areas with natural ventilation), and large gas clouds may form. Larger gas clouds will result in higher explosion pressures. In addition, large clouds will also be exposed to more potential ignition sources, resulting in a higher probability of ignition of the flammable gas mixture. Figure 9 shows that detector 8, which is located in a naturally ventilated area on the drill deck, exceeds 100% LEL for a short period, while the detectors located in enclosed areas show elevated gas concentrations over a longer period.

4.8 Emergency shutdown (ESD)

The emergency shutdown system on the facility is designed to prevent hazard and accident situations from occurring, as well as to limit the consequences should an accident occur. The system consists of various shutdown levels, including APS, ESD 2 and ESD 1. ESD 1 is the lowest shutdown level and is activated automatically upon confirmed fire or gas detection in a naturally ventilated area, manually by pressing the ESD push buttons, or as a cascade effect of a higher ESD level being activated. ESD 1 leads to actions such as isolation of non-critical equipment in naturally ventilated areas (welding rods, temporary equipment, etc.). In Odfjell Drilling's alarm log and C&E, the terms ESD1 A and ESD1 B are used.

4.8.1 Emergency shutdown during the incident

Detector 6, located underneath the drill floor, triggered an HH alarm (confirmed gas detection) at 03:58:29, which in turn triggered a signal to activate ESD 1. According to the alarm log, an alarm indicating the activation of ESD 1 (Inter Trip to ESD 1A/1B Non-Critical Equipment) was triggered at 03:58:30.

4.9 HVAC and ignition source control

<u>Differential pressure and area classification</u>
The ventilation system (mechanical) shall help establish and maintain a pressure differential between defined classified areas where explosive atmospheres may occur (Zone 0*, Zone 1*, and Zone 2*) and unclassified areas. The purpose is to prevent the unwanted spread of gas between areas with different probabilities of a flammable atmosphere.

According to the performance standard for ignition source control, the creation of a pressure differential between areas may serve the following purposes:

- Overpressure in a lower-risk area:
  Prevent airflow from areas with a higher probability of a flammable atmosphere (e.g., Zone 1) to adjacent areas with a lower probability (e.g., Zone 2 or unclassified areas). This is achieved by establishing and maintaining a defined positive pressure in the area with the lowest probability of a flammable atmosphere, so that airflow always moves from a lower to a higher risk level.
- Negative pressure in high-risk areas:
  Prevent air from classified areas (e.g., Zone 1) from entering adjacent areas with a lower classification (e.g., Zone 2) by establishing and maintaining a defined negative pressure in the area with a higher probability of a flammable atmosphere.

To monitor and verify that differential pressure requirements are maintained, differential pressure gauges have been installed between the relevant areas.

* Zone 0: Areas where explosive atmospheres are present continuously or for long periods of time.
Zone 1: Areas where an explosive atmosphere is likely to occur under normal operating conditions.
Zone 2: Areas where explosive atmospheres occur only exceptionally and for short periods of time.

The performance standard for ignition source isolation requires that any loss of differential pressure relative to an adjacent unclassified area or an area with a lower classification be monitored, and that an alarm be triggered after 30 seconds.

The shaker room is a potentially explosive area (classified area) designated as Zone 1. The shaker room must maintain negative pressure relative to adjacent areas. A differential pressure gauge has been installed in the Screen Cleaning Room, with a measuring point in the Tank Cleaning Machinery Room, and a differential pressure gauge has been installed in the Screen Store, with a measuring point in the shaker room. Figure 13, which shows the A Deck, outlines the design principles for differential pressure and zone classification in the shaker room and adjacent areas. The differential pressures listed are taken from the drawing "HVAC D&ID Machinery Area Hazardous System – Shale Shaker and Mud Pits".

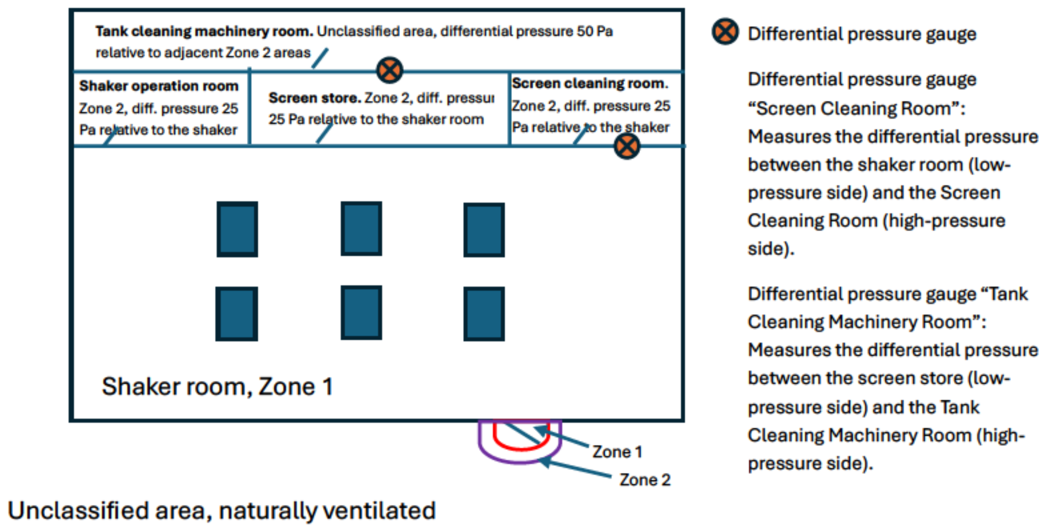

Figure 13 Overview of area classification and defined differential pressures for the shaker room and adjacent rooms on A Deck. (source: Odfjell Drilling)

On B Deck (which is the same module as the shaker room) are the HVAC1 room and the HVAC2 room. One differential pressure gauge has been installed in the shaker room, with a measuring point in the HVAC1 room, and one differential pressure gauge has been installed in HVAC1, with a measuring point in HVAC2. The design principles for differential pressure and zone classification on B Deck are shown in

Figure 14. The differential pressures listed are taken from the drawing HVAC D&ID Machinery Area Hazardous System – Shale Shaker and Mud Pits.

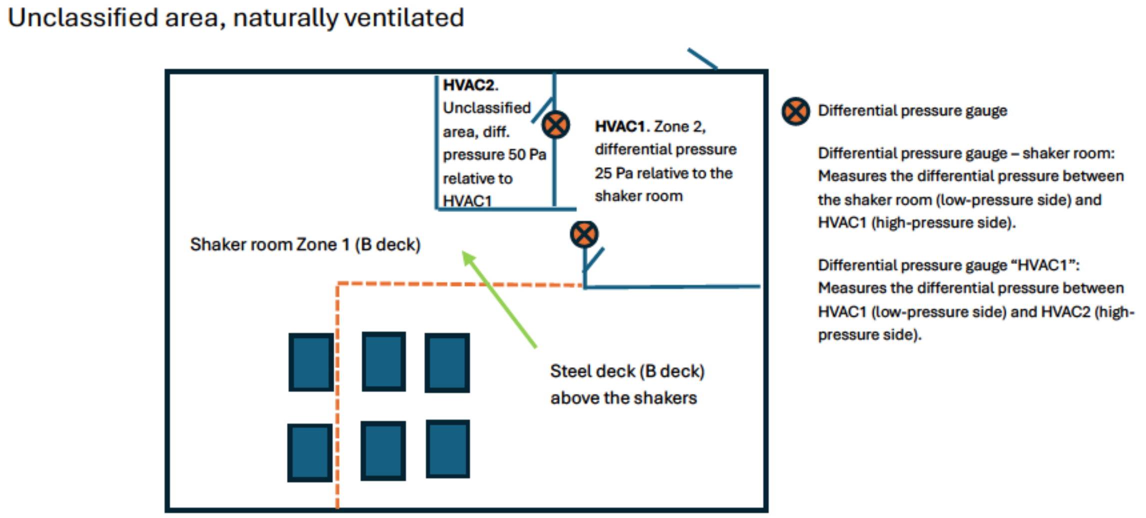

Figure 14 Overview of area classification and defined differential pressures for the shaker room and adjacent rooms on A Deck. (source: Odfjell Drilling)

On the deck below (Upper Deck) is the Lower Part Shale Shaker; see Figure 15. One differential pressure gauge has been installed in the Lower Part Shale Shaker, with a measuring point in the Deck Store. The differential pressures listed are taken from the drawing HVAC D&ID Machinery Area Hazardous System – Shale Shaker and Mud Pits. As mentioned previously, there is a steel deck between the shaker room and the Lower Part Shale Shaker.

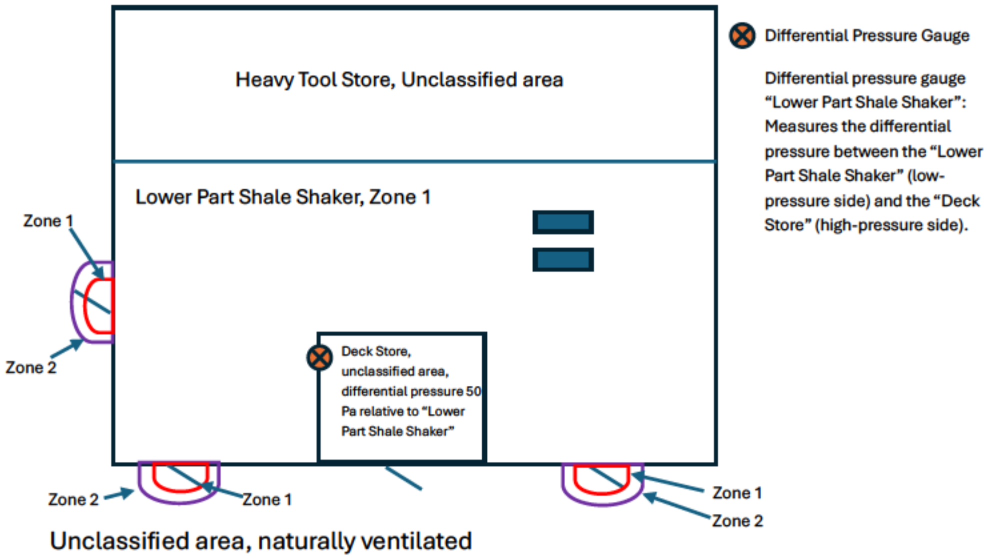

Figure 15 Overview of area classification and defined differential pressures for the Lower Part Shale Shaker and adjacent rooms on the Upper Deck. (source: Odfjell Drilling).

Towards the end of the investigation, we were informed that the reported negative pressure values in the shaker room and the Lower Part Shale Shaker were incorrect under the current design principles (email dated 16 January 2026). Our investigation report includes the differential pressure values specified in the drawing HVAC D&ID

Machinery Area Hazardous System – Shale Shaker and Mud Pits that were in effect at the time of the incident (i.e., -25 Pa negative pressure in the shaker room relative to the adjacent Zone 2 room and -50 Pa negative pressure in the Lower Part Shale Shaker).

Design principles for ventilation fans in shaker rooms
Among other things, the ventilation system is intended to help reduce the likelihood of flammable gas mixtures forming on board the facility by supplying sufficient air to dilute the gas mixture or vent the gas away. The regulations governing the construction of mobile facilities require that mechanical ventilation in potentially explosive areas ensure a minimum of 12 air changes per hour.

According to the documents received (HSE Case for AoC), the shaker room is equipped with two ventilation fans (2 x 100% capacity), one of which is in operation and provides adequate ventilation to, among other areas, the shaker room, the Shaker Monitoring Room and the airlocks in those areas. In addition, there is an exhaust system consisting of two exhaust fans. One of the exhaust fans is normally in operation, while the other is designed to start up either in the event of a fan malfunction or if gas is detected in the shaker room, in order to ventilate the gas out of the room.

Design principles for ignition source disconnection
Confirmed gas detection on the drill floor (naturally ventilated area), ESD1 (A/B), triggers ignition source disconnection of non-critical equipment. Electrical equipment in the shaker room (Zone 1) and adjacent areas (Zone 2) is certified for use in classified areas (Zone 1, Zone 2) and will not be disconnected in the event of gas detection in these areas.

The HVAC 2 room is an unclassified area. During normal operation, the room is protected by positive pressure and a gas damper that closes in the event of confirmed gas detection in the air intake. Equipment in this room is not disconnected in the event of ESD 1 A/B.

4.9.1 HVAC and ignition source control during the incident

We have received data showing the differential pressure in the affected areas before and during the incident; see Table 3

Table 3 Overview of differential pressure requirements (taken from HVAC D&ID for Shale Shaker and Mud Pits) and differential pressure measured before and during the incident.

Differential pressure trend	Requirements	Before the incident (the period of approximately 30 minutes prior to the incident)	Approximate time period and corresponding differential pressure during the course of the incident, derived from trends		Remarks
Measures the	-25 Pa	≤ -210 Pa*	03:58:25 - 03:58:26	From ≤ -210 Pa* to +1.2 Pa	The negative pressure is significantly lower than

<table>
<tr><td rowspan="2">differential pressure between the Shaker Room (low-pressure side) and HVAC1 (high-pressure side)</td><td rowspan="2">negative pressure in the Shaker Room relative to HVAC 1</td><td rowspan="2"></td><td>03:58:26 - 03:58:45</td><td>Approx. +1.2 Pa (differential pressure is not measured above this level)</td><td rowspan="2">requirements both before and during the incident.

Incident: The differential pressure between the Shaker Room and HVAC 1 is close to zero. This indicates that the door to the HVAC 1 room has been opened.

* The maximum measurement range of the differential pressure gauge is -210 Pa

An alarm was triggered in the control room indicating a loss of negative pressure during the incident (i.e., the barrier was not intact).</td></tr>
<tr><td>03:58:45 -</td><td>Varies between approx. +1.2 Pa and -4/-5 Pa</td></tr>
<tr><td rowspan="4">Screen Store

Measures the differential pressure between the Screen Store (low-pressure side) and the Tank Cleaning Machinery Room (high-pressure side)</td><td rowspan="4">-50 Pa negative pressure in the Screen Store (Zone 2) relative to the Tank Cleaning Machinery Room, which is an unclassified area</td><td rowspan="4">Varies between approx. -67 Pa and -88 Pa</td><td>03:58:24 - 03:58:25</td><td>From ≤ -210 Pa* to +1.2 Pa</td><td rowspan="4">During the incident, the negative pressure drops to -210 Pa and remains low throughout the course of the incident.

*The maximum measurement range of the differential pressure gauge is -210 Pa

No alarm was triggered for a loss of negative pressure during the incident (as there is a 30-second delay before the alarm triggers)</td></tr>
<tr><td>03:58:25 - 03:58:34</td><td>Approx. +1.2 Pa</td></tr>
<tr><td>03:58:34 - 03:58:43</td><td>From +1.2 Pa to ≤ -210 Pa</td></tr>
<tr><td>03:58:43 -</td><td>≤ -210 Pa*</td></tr>
<tr><td rowspan="4">Screen Cleaning Room

Measures the differential pressure between the Shaker Room (low-pressure side) and the Screen Cleaning Room (high-pressure side)</td><td rowspan="4">-25 Pa negative pressure in the Shaker Room relative to the Screen Cleaning Room</td><td rowspan="4">≤ -210 Pa*</td><td>03:58:23 - 03:58:25</td><td>≤ -210 Pa*</td><td rowspan="4">The pressure was significantly below the specified requirement both before and during the incident.

*The maximum measurement range of the differential pressure gauge is -210 Pa

No alarm was triggered for a loss of negative pressure during the incident (as there is a 30-second delay before the alarm triggers)</td></tr>
<tr><td>03:58:25 - 03:58:34</td><td>Approx. +1.2 Pa</td></tr>
<tr><td>03:58:34 - 03:58:43</td><td>From +1.2 Pa to -210 Pa*</td></tr>
<tr><td>03:58:43 -</td><td>≤ -210 Pa*</td></tr>
<tr><td rowspan="3">B Deck HVAC Room

Measures the differential pressure</td><td rowspan="3">-50 Pa negative pressure in HVAC 1 relative to HVAC 2</td><td rowspan="3">Varies between approx. -65 Pa and -80 Pa</td><td>03:58:25 - 03:58:27</td><td>From -81 Pa to approx. +1.3 Pa</td><td rowspan="3">During the incident: The differential pressure between HVAC 1 and HVAC 2 is close to zero. This indicates that there has been a significant flow of air between the rooms (through the door),</td></tr>
<tr><td>03:58:27 - 03:58:38</td><td>Approx. +1.3 Pa</td></tr>
<tr><td>03:58:38 -</td><td>Varies between approx. 0 Pa and -6/7 Pa</td></tr>
</table>

between HVAC 1 (low-pressure side) and HVAC 2 (high-pressure side)					or that the door may have opened. An alarm was triggered indicating a loss of negative pressure during the incident (i.e., the barrier was compromised).
Lower Part Shale Shaker Measures the differential pressure between the Lower Part Shale Shaker (low-pressure side) and the Deck Store (high-pressure side)	-50 Pa negative pressure in the Lower Part Shale Shaker relative to the Deck Store	Varies greatly between approx. -100 Pa and -160 Pa	03:58:21 - 03:58:30	From -151 Pa to +1.3 Pa	The negative pressure is significantly lower than the specified requirement. During the incident, the negative pressure drops to -210 Pa* and remains low throughout the course of the incident. *The maximum measurement range of the differential pressure gauge is -210 Pa
			03:58:30 - 03:58:39	Approx. +1.3 Pa	
			03:58:39 - 03:58:42	From +1.2 Pa to ≤ -210 Pa*	
			03:58:42 -	≤ -210 Pa* The negative pressure stabilises at ≤ -210 Pa*	

<u>Loss of differential pressure (negative pressure) between rooms</u>

The differential pressure gauge between the shaker room and HVAC 1 triggered an alarm indicating a loss of differential pressure (negative pressure) at 03:58:48, and the differential pressure gauge between HVAC 1 and HVAC 2 triggered an alarm at 03:58:48. Subtracting 30 seconds (the 30-second delay before the alarm sounds) gives the differential pressure drop between the shaker room and HVAC 1, and between HVAC 1 and HVAC 2 at 03:58:18. Figure 17 and Table 3 show that the differential pressure between the Shaker Room (Zone 1) and HVAC 1 (Zone 2) was close to zero during the incident (prior to the incident, the negative pressure in the shaker room was ≤ -210 Pa* relative to HVAC 1). This may indicate that there was a significant airflow through the door between these two rooms, and that the door to the HVAC 1 room may have opened during the incident. Next to HVAC 1 (Zone 2) is the HVAC 2 room (unclassified area). Prior to the incident, HVAC 1 had a negative pressure of between approximately -65 Pa and -80 Pa relative to HVAC 2. The pressure difference between the rooms was close to zero during the incident (see Figure 17), indicating that there was a significant airflow

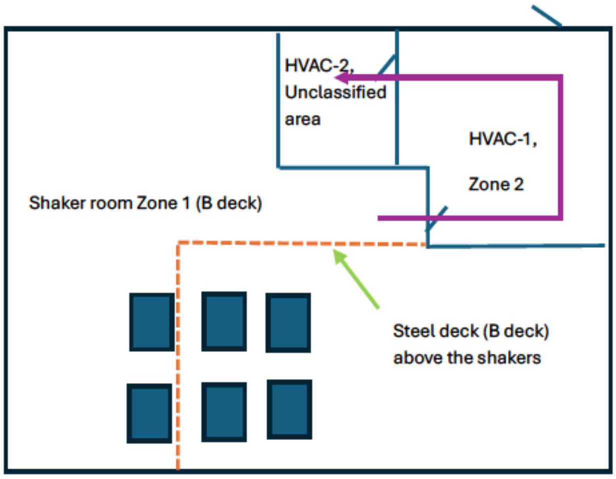

Figure 16 Differential pressure measurements during the incident show that there was significant airflow/opening (indicated in the figure by a purple arrow) in the door between the shaker room and HVAC 1, but also further on in the door between HVAC 1 and HVAC 2. (source: Odfjell Drilling)

through the door between these two rooms, and that the door to the HVAC 2 room may have opened during the incident (see Figure 16).

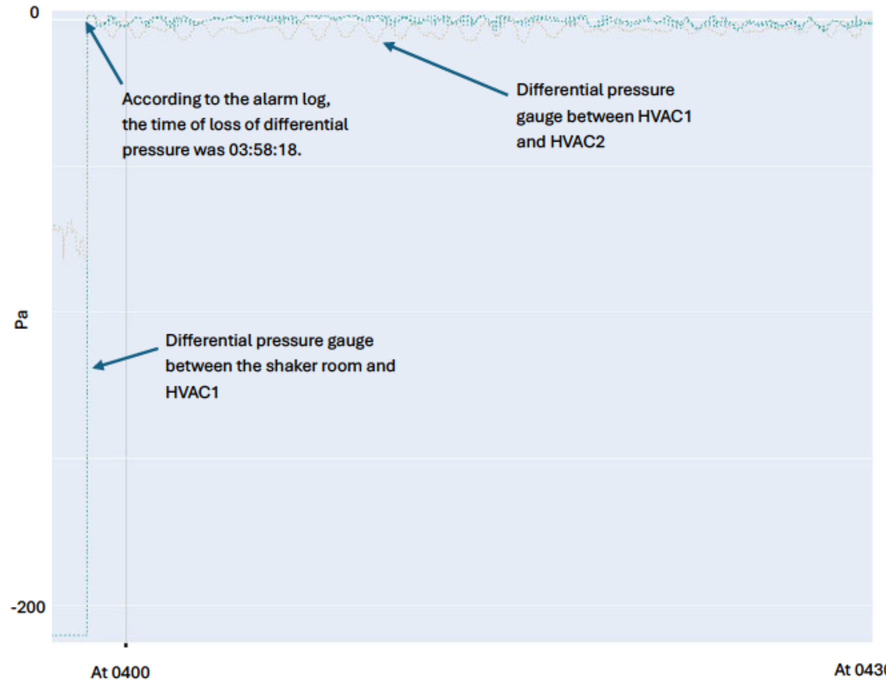

Figure 17 Trend in differential pressure measurements between the shaker room and HVAC 1, and between HVAC 1 and HVAC 2. (source: Odfjell Drilling)

As described, there may have been significant airflow from the shaker room to the HVAC 1 room and on to the HVAC 2 room, which is an unclassified area (see Figure 16). The equipment in the HVAC 2 room is not disconnected in the event of ESD 1 A/B and is not ATEX equipment. There may have been potential ignition sources in the HVAC 2 room that could have ignited a flammable gas mixture in the room. There are no gas detectors installed in HVAC 1 or HVAC 2, so it is unclear what the gas/air mix was in this area.

Low negative pressure in the shaker room

Table 3 shows that, prior to the incident, there was a significant difference between the required differential pressure (-25 Pa negative pressure in the shaker room) and the measured differential pressure between the shaker room and the Screen Room, and between the shaker room and HVAC 1. Prior to the incident, the negative pressure in the shaker room was lower than or equal to -210 Pa (the trend from the differential pressure gauge does not show a differential pressure lower than -210 Pa, so it is unclear how low the differential pressure actually was).

Doors are required to open outwards from rooms with negative pressure. If the negative pressure in a room is too low, it can prevent or hinder evacuation from the room, as the doors are pulled inward toward the area of negative pressure and thus become difficult to open. During the investigation, we were informed that, at the time of the incident, it was difficult to open the door from the shaker room into the Shaker Operation Restroom. The differential pressure between the Shaker Operation

Restroom and the shaker room corresponds to the differential pressure between the shaker room and the Screen Cleaning Room, i.e., a negative pressure of ≤ -210 Pa in the shaker room. The person who was in the shaker room when the incident occurred ran back to the Shaker Operation Restroom when large amounts of liquid began pouring out of the shakers and the header box. According to the CCTV camera in the shaker room, this occurred at approximately 03:58:10 The person struggled to open the door leading into the Shaker Operation Restroom. He managed to open it by springing it open. When the door opened, he stumbled into the Shaker Operation Restroom and sustained minor injuries. Just as the door opened, a panel fell from the ceiling of the room. As mentioned earlier, the alarm log shows a loss of differential pressure between the shaker room and HVAC 1, and between HVAC 1 and HVAC 2, at 03:58:18 (which indicates that the doors into HVAC 1 and HVAC 2 opened at that time). This was most likely caused by the pressure wave that occurred during the incident. This pressure wave may have helped the person to open the door to the Shaker Operation Restroom.

According to the alarm log, the standby exhaust fan from the mud pits and the shaker room started up at 03:58:28, following the confirmed detection of gas in the shaker room. This was in accordance with the HVAC design principles described earlier. One supply fan and two exhaust fans were in operation from that point on. The additional exhaust fan caused the negative pressure in the shaker room to decrease further compared to the level prior to the incident (≤ -210 Pa).

<u>Damage to fire doors in the shaker room and adjacent rooms</u>
Several fire doors were damaged, with the door panels being warped or dented. The door lock kept the doors locked, but for the doors to HVAC 1 and HVAC 2, based on differential pressure measurements, it appears that the door lock did not keep the doors in the closed position during the incident. Photo 10 shows some of the damage to fire doors: The photo on the left shows the door to the Shaker Operation Restroom from the Screen Store. The photo second from the left shows the door into the Screen Store from the shaker room. Photos 3 and 4 from the left show the door into HVAC 1 from the shaker room. The photo on the right shows the door from HVAC 1 to HVAC 2.

Photo 10 Examples of damage to doors in the shaker room and adjacent areas where door panels are warped or dented (source: Havtil)

<u>Damage to ventilation ducts in the shaker room</u>

Several ventilation ducts were damaged, but only the exhaust ducts sustained visible damage. The ducts are made of steel and are not designed to withstand high pressure. Two of the damaged exhaust ducts were located near the header box and the gumbo box. During the incident, the systems were subjected to loads exceeding their design capacity, causing pressurised fluid to leak from the header box and the gumbo box (see Photo 11), which may have caused damage to the two associated exhaust ducts (see Photo 12). An alternative explanation could be the pressure difference between the exhaust ducts and the shaker room. During normal operation, there is negative pressure in the exhaust ducts. During the incident, the pressure in the shaker room increased significantly, and the pressure difference between the ducts and the room may have caused the ducts to implode.

Photo 11 The gumbo box is shown at the top and the header box below (source: Havtil)

Photo 12 Exhaust ducts in the shaker room that were damaged during the incident (source: Havtil)

Photo 13 shows the exhaust duct from the Shale Shaker House & Lower Part Shale Shaker located in HVAC 1 (the room adjacent to the shaker room) on B Deck. The trend in the differential pressure between the HVAC 1 room and the shaker room suggests that the door to the HVAC 1 room opened during the incident (differential pressure between the shaker room and the HVAC 1 room was close to zero). The

Photo 13 Imploded exhaust duct from the Shale Shaker House & Lower Part Shale Shaker located in HVAC 1 (source: Havtil)

exhaust duct shown in the photo has imploded/collapsed inward, probably due to the significant pressure difference between the room and the duct during the incident.

4.9.2 Maintenance of differential pressure gauges

A quarterly function test has been established to verify the overpressure/underpressure barrier between overpressure-protected rooms (TBAMI test – Function test of
HVAC transmitters).

During the inspection, we were informed that three differential pressure gauges lacked a maintenance programme to verify the barrier and were therefore not included in this function test. This applied to differential pressure gauges between:

- Shaker Room and Screen Cleaning Room
- Screen Store and Tank Cleaning Room
- HVAC1 and HVAC2

The differential pressure gauges were last verified on 30 April 2025, as part of the AoC process for Deepsea Bollsta.

4.10 CCTV cameras

CCTV cameras have been installed on the facility for surveillance in various areas. Several CCTV cameras were installed in the shaker room and on the drill floor, and one camera was installed near the relevant overboard line.

4.10.1 CCTV cameras during the incident

During the incident, several cameras had not been set to record. Only two of the cameras in the shaker room were recording.

The clocks on the various CCTV cameras did not show the correct time (the time had not been synchronised with the other security systems).

4.11 Risk assessment of the shaker room

The document “Design Accidental Load Appendix A – The Detailed Analysis and Strength Assessment under Gas Explosion for the Shale Shaker Room” contains an assessment of the structural integrity of the shaker room in an explosion scenario. A total of eight scenarios with varying degrees of gas filling (from 9.5% to 99.4%) were conducted to calculate explosion loads (see Table 4). Taking into account the HVAC system in the shaker room (exhaust fans above the shakers designed to prevent gas in the mud from escaping into the room), a 50% gas filling is considered a conservative gas leak scenario.

Table 4 Overview of gas filling of the shaker room and overpressure resulting from ignition of gas cloud (source: Odfjell Drilling)

Gas cloud size [m3]	Gas filling ratio of the shale shaker room [%]	Pick overpressure [barg]	Duration time [sec]
166	9.5	0.28	2.0
338	19.3	0.44	2.0
542	31.0	0.55	2.0
726	41.5	0.68	2.5
864	49.4	0.79	2.5
1014	57.9	0.91	2.5
1262	72.1	1.55	2.5
1740	99.4	2.78	2.5

Assessments of structural integrity were conducted at 41.5%, 57.9%, and 72.1% gas filling. Scenarios with gas filling levels of 41.5% and 57.9% fall within the acceptance criteria related to structural strength. At gas filling of 72.1%, both local cracks and global buckling will occur in the structure, which could lead to the complete collapse of the shaker room.

The trend in gas detector readings in the shaker room shows that all three detectors located in the shaker room (detectors 3, 7, and 9 on A Deck) have readings above 100% LEL for in excess of one minute simultaneously (ref. chap. 4.7.1). Based on the location and readings from the three detectors, the gas cloud may have covered large parts of the room; see Figure 18.

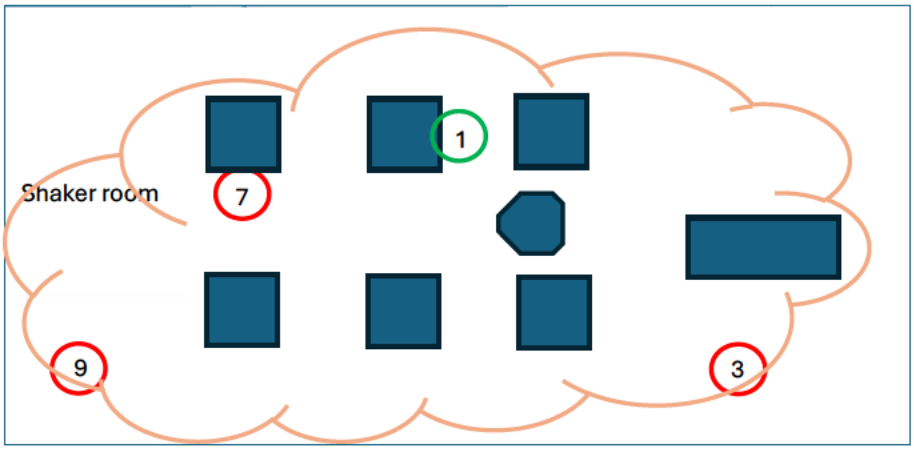

Figure 18 Sketch of the possible size of the gas cloud (over 100% LEL) in the shaker area during the incident (source: Havtil)

Based on readings from the gas detectors (indications of gas filling/gas cloud during the incident), as well as an assessment of explosion loads/structural integrity for a scenario with 72.1% gas filling, it is considered plausible that the shaker room could have developed both cracks and global buckling – which in turn could have resulted in a total collapse of the shaker room if the gas cloud had ignited. According to the Design Accidental Load (DAL) Specification (FOR 2620), the shaker room is deemed capable of withstanding an internal explosion with an overpressure of 0.7 barg. Most probably, the overpressure from an ignited gas cloud that formed in the shaker room during the incident would have been higher than this pressure (ref. Table 4 where a gas filling of 72.1% results in an overpressure of 1.55 barg). This is not an incident that the shaker room on Deepsea Bollsta is designed to withstand.

The document "Main Report Operational CORA for Deepsea Bollsta" states that the entire shaker area is located above the main deck as a freestanding module. This means that the shaker room is not considered part of the facility's structural integrity. An explosion in the shaker area would therefore not compromise the overall structural integrity of the facility.

5 Sequence of events

5.1 Previous activity

For information on well design and the situation prior to the incident, see chap. 2.2 and chap. 2.4.

The overall plan for plugging the wells was to install two barrier plugs in the Sognefjord and Fensfjord reservoirs, as well as one barrier plug in Shetland (see chap. 10). The two planned barrier plugs in Sognefjord and Fensfjord were to be placed between 1,150 m and 1,300 mMD, and were also intended to cover the Shetland formation, which lies between 1,668 m and 1,674 mMD (1,456 m TVD).

Before operations began using Deepsea Bollsta, the well was secured with a deep plug in the 10 ¾" liner just above the production packer, and a shallower plug in the tubing hanger.

After Deepsea Bollsta's initial arrival on the field and the successful connection of the BOP/riser on the HXT, the upper completion string was pulled out of the well. Subsequently, the 10 ¾" liner/tie-back was relogged due to uncertainty regarding the quality of previous assessments. A 1,400-meter timelock plug was then set, along with a shallower (390-metre) plug in a 10 ¾" tie-back.

The HXT was then picked up by an IMR vessel.

5.2 The incident

On Deepsea Bollsta's second arrival (18 September 2025), the BOP was installed on the wellhead. The shallowly set plug was then pulled out, after which the 10 ¾" tie-back was cut at 1,353 mMD and pulled out of the well. After the pull, 13 ⅜" of casing cement was logged using a Baker Hughes ULTeX™/CBL from 1,348 m up to the wellhead.

Logging of the 13 ⅜" casing cement was carried out between 18:15 on 21 September and 01:45 on 22 September. A so-called Free Pipe Pass (FPP) was performed in the interval from 500 to 600 metres. FPP is a calibration of the logging equipment based on an interval where the casing is not in contact with cement or the formation. Such calibration is intended to ensure that zones containing cement or formation rock behind the casing can be distinguished from zones containing fluid or gas. The calibration interval is selected based on information regarding the theoretical top of the cement outside the casing, and adjustments are made to account for any precipitation of weighting material from the drilling fluid. The calibration method is not designed to distinguish between zones containing liquid and zones containing gas.

The first attempt to calibrate the equipment resulted in a significant deviation from the quality parameters. Based on discussions between Baker Hughes logging personnel and an Equinor representative, the correction factor for casing ovality was changed. Despite this adjustment, the measurements were still just outside the quality range. Equinor nevertheless concluded that the measurements were acceptable and could be used in further analysis of the cement's barrier quality and the presence of gas in the annulus.
The subsequent interpretation concluded that the cement was of good quality in the intervals 1,317 m - 1,333 m and 1,205 m - 1,233 m, according to the report from Equinor " (Troll 31/3-Q-21 BY1HT5 Deepsea Bollsta ULTeX-CBL-GR-CCL 13 3/8'' Casing September 2025 Annular Bond and Casing Conditions Interpretation Report)".

It was also concluded that there was a fluid-filled interval behind the casing from 372 m to 647 m, but that there was no gas behind the 13 ⅜" casing.
Based on this, it was decided to install a double cement plug inside the 13 ⅜" casing, thereby establishing two barrier envelopes in both the Sognefjord/Fensfjord and Shetland formation reservoirs. At 18:15 on 22 September, the cementing equipment had been removed from the well. They waited about eight hours for the cement to set, and went back into the well with equipment for tagging/dressing the cement and cutting the casing at 02:15 on 23 September.

The cement on the inside of the 13 ⅜" casing was encountered at 1,172.4 m and drilled through to 1,173.8 m at 60 rpm and 3000 lpm. The plug was then tagged and verified at 10 tonnes at a depth of 1,173.8 metres. The equipment string was then pulled up so that the blades on the Archer cutting equipment were positioned at 510 m. Reference pressures were recorded at 1,500 lpm and 2,000 lpm before a steel ball was dropped into the string to activate the cutting equipment at 03:30. The cutting operation was initiated at approx. 03:50 and at approx. 3:58 a movement was detected on the facility, which was interpreted as a successful cut. Shortly thereafter, an outflow of drilling fluid and gas was observed rising through the rotary table on the drill floor. Drilling fluid and gas also flowed into the shaker room.

At the time of the incident, there were six people in the driller's cabin to observe and assist with the cutting operation. In addition, there were two people in the room behind the driller's cabin. In the shaker room, one person was physically present to monitor the expected increase in flow from the well and, if necessary, start the shakers. The person ran back to the Shaker Operation Restroom when large amounts of liquid began pouring out of the shakers from the header box (at approx. 03:58:10; see chap. 4.9.1). The person struggled to open the door leading into the Shaker Operation Restroom. He managed to open it by "springing" it, sustaining minor injuries in the process.

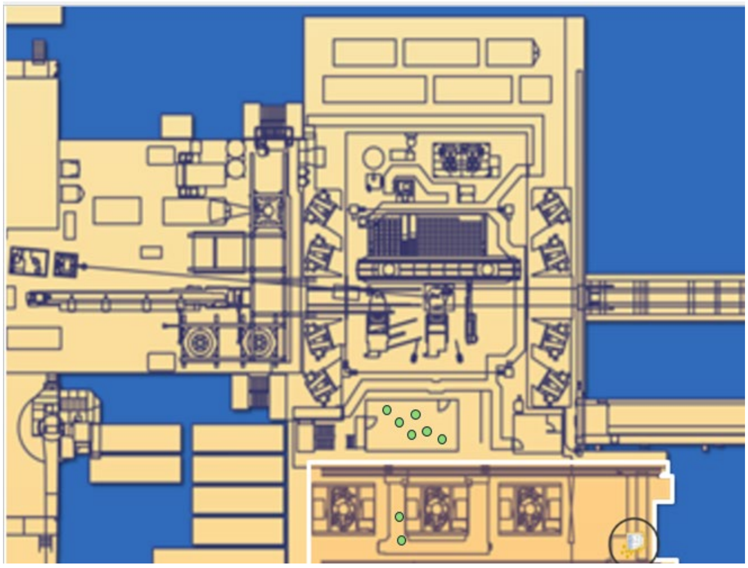

Figure 19 Floor plan of the drill deck showing the location of personnel during the incident.

The floor plan in figure 19 shows the location of personnel during the incident. Green dots indicate where personnel were located on the drill floor at the time of the incident.

At 03:58:18, a simultaneous loss of differential pressure occurred between the shaker room and HVAC1, and between HVAC1 and HVAC2, most likely due to the pressure wave that occurred during the incident.

At 03:58:20, the first of several gas detection alarms in the shaker areas was triggered and displayed in the control room. The general alarm was automatically activated at

03:58:22. It was quickly determined that the alarm was caused by an actual gas incident on the facility, and an announcement was made over the PA system stating: "We have a gas alarm…."

At 03:58:29, an alarm was received confirming gas detection in the naturally ventilated area (underneath the drill floor), which subsequently triggered the automatic activation of ESD 1 A/B at 03:58:30.

Interviews with personnel in the driller's cabin indicate that several alarms were triggered simultaneously during the incident, including gas alarms, a general alarm, a dynamic positioning (DP) alarm, and other system alarms. The alarms caused high noise levels in the driller's cabin and hindered effective verbal communication among the crew. Furthermore, the interviews reveal that alarm noise and the simultaneous use of a radio channel posed challenges for radio communication between personnel in the driller's cabin and other personnel on board (including the person in the shaker room). This made it difficult to understand and convey messages during the initial phase of the incident.

Interviews and available documentation further show that, shortly after noticing drilling fluid on the drill floor (rotary table), personnel initiated activation of the diverter system, and that the annular preventer on the BOP was activated to close a few seconds later.

The diverter system was activated six seconds before the annular preventer on the BOP. The closure times for these are 26 and 45 seconds, respectively. Based on this, it is estimated that the annular preventer closed 19 seconds (45–26+6 sec.) after the packing element in the diverter system. The diverter system shutdown sequence begins with the opening of a preselected valve leading to the overboard discharge line. Next, the valve leading to the return flow line (to the shaker room) is closed, and finally, the packing elements that seal around the string are activated (see chap. 4.4).

It was reported that the slips (PS-30), which was positioned on the rotary table around the drill string, was lifted off the rotary table due to the pressure of the fluid flow against the drill floor. The pressure changes that occurred when the fluid flow was directed towards both the drill floor and the shaker room caused the slips to move up and down and slightly in the plane of rotation around the work string.

CCTV images show liquid and gas flowing through the diverter pipe into the sea. The recordings also show that the flow of liquid and gas went higher than the fingerboard level on the derrick. Video footage from the shaker room, along with the extent of the damage in the area, indicates that a significant amount of energy was released in this area.

According to the Emergency Board, Full POB+1 was reported at 04:10, and at 04:16, Full POB was reported.

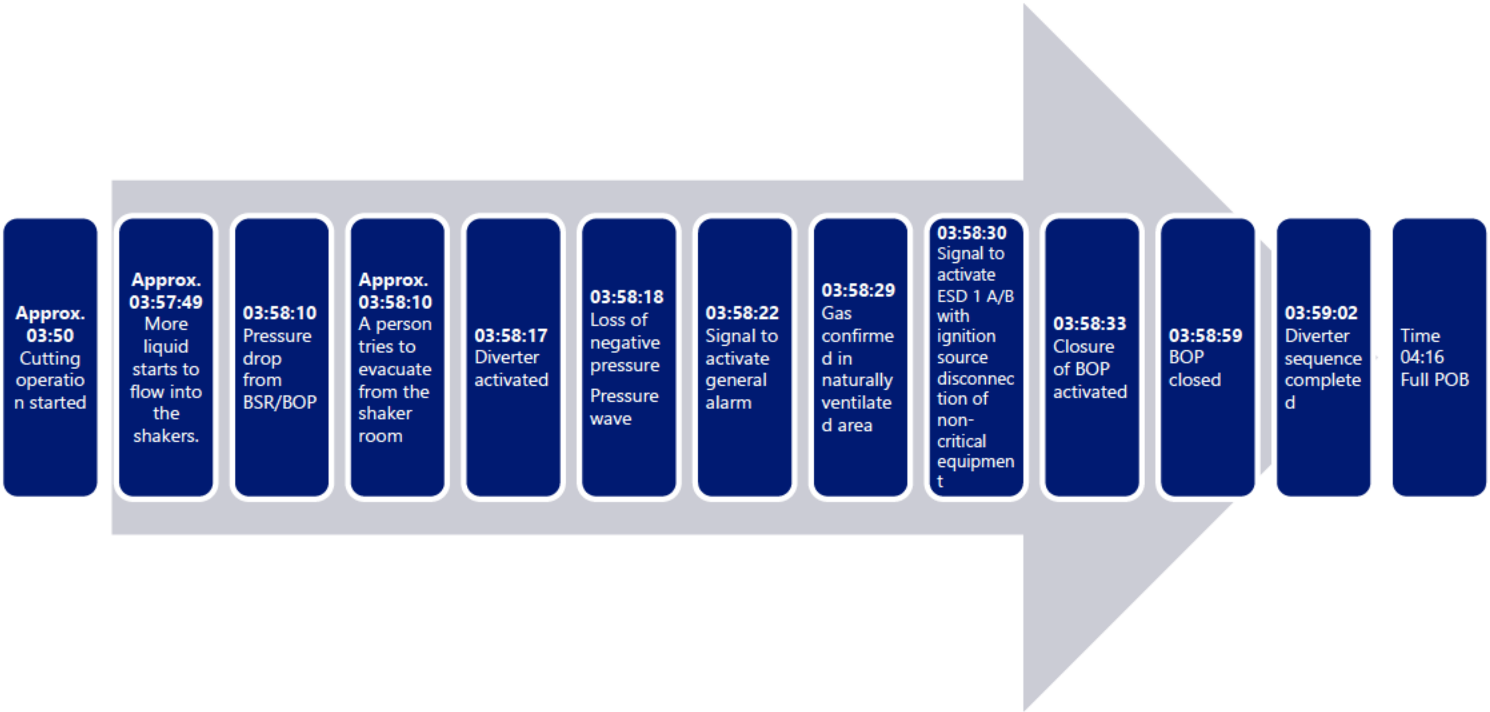

Figure 20 Overview of situations/actions during the course of events, including times (source: Odfjell Drilling)

23.09.2025	**Incident element**	**Additional Information**
Approx. 03:57:49	More liquid than expected is starting to flow into the shakers.	Information obtained from the CCTV camera in the shaker room. The exact time is somewhat uncertain, as the camera's clock was not set correctly.
03:58:10	Records a pressure drop from 37.5 bar to -3.71 bar on the pressure transmitter from the BSR/BOP	Cameron event logger. A significant change in hydrostatic pressure was recorded, likely due to gas displacing drilling fluid in the riser and parts of the well.
Approx. 03:58:10	Fluid floods/bursts the header box in the shaker room. A person in the shaker room tries to evacuate to the Shaker Operation Restroom	Information obtained from the CCTV camera in the shaker room. The exact time is somewhat uncertain, as the camera's clock was not set correctly.

23.09.2025	Incident element	Additional Information
03:58:17	Activation of the diverter closure sequence from the driller's cabin.	Cameron event logger. Manual operation
03:58:18	Loss of differential pressure between the Shaker Room (Zone 1) and HVAC 1 (Zone 2).	Alarm list The alarm went off at 03:58:48, due to a 30-second delay.
03:58:18	Loss of differential pressure between HVAC 1 (Zone 2) and HVAC 2 (unclassified).	Alarm log The alarm went off at 03:58:48, due to a 30-second delay.
03:58:20	First gas detector in H/HH alarm in the Shale Shaker Room Exhaust Duct.	Alarm log Confirmed gas detection in the shaker room triggers the Gas Alarm PAGA
03:58:21	New gas detector in H alarm in the Lower Part Shale Shaker. A second later, the detector went into HH alarm.	Alarm log Confirmed gas detection in the Lower Part Shale Shaker.
03:58:22	Signal to activate the general alarm on the facility (Gas Alarm to PAGA A)	Alarm log Confirmed gas detection triggers a signal to activate the general alarm on the facility.
03:58:22	New gas detector in H alarm in the shaker room. Three seconds later, the detector went into HH alarm.	Alarm log
03:58:23	New gas detector in H/HH alarm in the Screen Cleaning Room Exhaust Duct.	Alarm log Confirmed gas detection in the Screen Cleaning Room Exhaust Duct.
03:58:24	Signal to close the valve on the return flow line to the shaker	Cameron event logger.
03:58:28	The standby exhaust fan from the Mud Pits and Shale Shaker Room starts up.	Alarm log

23.09.2025	Incident element	Additional Information
03:58:28	New gas detector in H alarm in the Lower Part Shale Shaker. Three seconds later, the detector went into HH alarm (confirmed gas detection).	Alarm log
03:58:28	New gas detector in H alarm underneath the drill floor. One second later, the detector went into HH alarm (confirmed gas detection).	Alarm log Confirmed gas detection in a naturally ventilated area (Underneath Drill Floor) triggers the activation of ESD 1 A/B, thereby causing ignition source disconnection of non-critical equipment in naturally ventilated areas
03:58:30	Signal to activate ESD 1A with ignition source disconnection of non-critical equipment in naturally ventilated areas	Alarm log
03:58:31	Signal to activate ESD 1B with ignition source disconnection of non-critical equipment in naturally ventilated areas	Alarm log
03:58:33	Activates closure of the annular preventer on the BOP	Cameron event logger. Manual operation
03:58:45	New gas detector in H alarm in the shaker room. Nine seconds later, the detector went into HH alarm.	Alarm log
03:58:46	Registers pressure drop from 11.0 bar to -30.2 bar on the LPR/BOP	Cameron event logger.
03:58:47	New gas detector in H/HH alarm at Drill Floor Port.	Confirmed gas detection on the drill floor.

23.09.2025	Incident element	Additional Information
03:58:59	Estimated closure time of the annular preventer on the BOP	Cameron event logger. Based on the last BOP test
03:59:02	Estimated time for completion of the diverter closure sequence	Cameron event logger. Based on the most recent test
03:59:08	New gas detector in H alarm in the shaker room. Nine seconds later, the detector went into HH alarm.	Alarm log
03:59:18	New gas detector in H alarm in the Lower Part Shale Shaker.	Alarm log
03:59:23	New gas detector in H alarm in the Lower Part Shale Shaker.	Alarm log
04:10	Full POB + 1	Information from the board in the emergency response room.
04:16	Full POB	Information from the board in the emergency response room.

Table 5 Sequence of events: CCTV cameras, alarms, and sensors (source: Odfjell Drilling)

5.3 Potential of the incident

5.3.1 Actual consequences

The actual consequence of the incident was that one person who was in the shaker room sustained minor injuries.

In addition, gas and water leaked onto the drill floor, into the shaker room and into the external environment. Based on information from the rig, it is estimated that 22 cubic metres of fresh water were released into the sea.

At least 930 kg of thermogenic gas were released into the air. Analyses conducted by Equinor indicate that the gas consists of a mixture of methane (85%), ethane (10%), and propane (5%). There is uncertainty regarding the origin of the gas and, consequently, its volume (see chap. 10).

The incident also caused material damage to the drill floor and the shaker room, including deformation of doors and damage to HVAC ducts.

5.3.2 Potential consequences

The incident had the potential to cause a major accident. Uncontrolled release of gas behind the 13 ⅜" casing, with subsequent release onto the drill floor and into the shaker room, could – under slightly different circumstances – have resulted in ignition and an explosion. Such an incident would have entailed a high risk of serious injury or loss of life, as well as extensive damage to the facility.

Trends from differential pressure gauges indicate significant airflow from the shaker room to the HVAC 1 room and onward to the HVAC 2 room, which is an unclassified area (see chap. 4.9.1 and Figure 17). The equipment in the HVAC 2 room is not disconnected in the event of ESD 1 A/B and is not ATEX equipment. There may have been potential ignition sources in the HVAC 2 room that could have ignited a flammable gas mixture in the room. There are no gas detectors installed in HVAC 1 or HVAC 2, so it is unclear what the gas/air mix was in this area.

If a flammable gas mixture in the shaker areas had ignited, this could have caused cracks and widespread buckling, which in turn could have led to the complete collapse of the shaker room. However, the entire shaker area is located above the main deck as a freestanding module and is therefore not considered part of the facility’s structural integrity. An explosion in the shaker area would therefore not have compromised the overall structural integrity of the facility (see chap. 4.11).

6 Direct and underlying causes

6.1 Direct causes

The direct cause of the incident was the presence of gas behind the casing, which was released during the cutting operation. In addition, adequate barriers had not been put in place to prevent the flow of large quantities (930 kg, source: Equinor; see also chap. 10) of gas to the surface.

6.2 Underlying causes

The investigation shows that the incident had several underlying causes related to technical, operational and organisational factors.

6.2.1 Gas behind the casing due to a lack of barriers in respect of the reservoir

Following the incident, perforation and circulation were performed under the seal assembly, before it was pulled from the well. The measure was implemented to reduce the risk of uncontrolled release of residual gas under the seal assembly.

During discussions on board, it emerged that chromatographic analyses of gas vented after perforation under the seal assembly for the 13 ⅜″ casing, revealed the presence of heavier hydrocarbon components originating from the reservoir. This indicates that gas has migrated up from the reservoir, through the annular cement, and that the external well barriers have therefore failed to fulfil their established functional requirements.

An investigation and available documentation show that the cement behind the 10 ¾″ liner was not of barrier quality and therefore could not function as a barrier against reservoir pressure.

The 13 ⅜″ casing was installed and cemented in 2007. In accordance with requirements, it was decided to log the cement behind the 13 ⅜″ casing using ULTeX™/DAL to verify barrier quality. Above the cement outside the 13 ⅜″ casing, a layer of green clay was also identified, which was believed to have crept in and settled around the casing.

Confirmed presence of reservoir gas behind the 13 ⅜″ casing indicated possible leakage paths from the reservoir and up through the cement behind the 13 ⅜″ casing, either between the cement and the casing, or between the cement and the formation.

6.2.2 Calibration of logging tools

Prior to the cement and gas logging operations, a so-called Free Pipe Pass (FPP) was performed. The purpose of calibration in a free pipe section is to establish the most accurate acoustic impedance possible for the fluid present, for use in logging, by calibrating against a known annular impedance in the free pipe section. This is intended to facilitate the creation of a log that can be used for interpretation without the need for post-processing, thereby reducing the time required to complete the interpretation. Furthermore, the calibration should help distinguish between zones containing cement or a creeping formation and fluid behind the casing. The calibration range is selected based on information regarding the theoretical top of the cement behind the casing, and adjustments are made to account for any precipitation of weighting material from the drilling fluid.

In well Q-21, gas, not liquid, was present from the wellhead down to approx. 648 metres. The result was that the tool was calibrated against a medium that was not present. As a result, the subsequent logging data was incorrect, which in turn led to the casing being cut without the BOP being closed.

6.2.3 Use of technology and methods that were not qualified for the purpose

Equinor used an acoustic impedance wireline log to assess the possible presence of hydrocarbons behind the 13 ⅜" casing. The investigation revealed that Equinor had not qualified the use of this method for identifying hydrocarbons.

Furthermore, it emerged during the interviews that the use of the log for the purpose of cutting casing with an open BOP was not in accordance with Equinor's internal requirements (TR3507) regarding the closure of the BOP prior to operations where there is a risk of hydrocarbons being present, combined with insufficient activation time for the BOP. The breach of this requirement stemmed from differing interpretations of the requirement's wording.

Casing can be cut by rotating a tool string from the surface or by using a motor downhole in the drill string, below the BOP. Rotation from the surface in combination with a closed BOP could result in damage to the BOP packing elements. This can be avoided by using a so-called annular swivel, which acts as a roller bearing between the tool string and the BOP. It would therefore have been entirely possible to cut the casing with the BOP closed, but that would have required additional components in the tool string.

6.2.4 Planning of cutting operation

The investigation revealed that neither the primary nor the secondary barrier elements in the well were able to perform their intended function. Fluid in the well (drilling fluid) was defined as the primary barrier element, while the BOP was defined as the secondary barrier element.

The fluid in the well had a specific gravity of 1.0 sg, while the estimated fluid in the annulus behind the 13 ⅜" casing had a specific gravity of 1.3 sg. This meant that the primary barrier could not perform its function.

The distance from the planned cut at 510 m RKB to the BOP was approximately 160 m. The normal closure time for the annular preventer on the BOP is approximately 45 seconds, which meant that it was effectively impossible to close it before the flow of fluid and gas had passed through the BOP and reached the surface. This meant that the secondary barrier was also unable to fulfil its intended function.

During the interviews, it emerged that Equinor's planning organisation was unaware of previous observations on the Troll field of gas behind the 13 ⅜" casing. The planning of the cutting operation was therefore largely based on the assumption that there was no gas behind the casing. As a result of this assumption, equipment needed to perform cutting operations using well control equipment, including cutting with the BOP closed, was not included in the planning phase.

6.2.5 Changes over time in operational practices related to casing cutting with an open BOP

Around the turn of the millennium, it was standard practice to seal off the annulus around the drill string when cutting a casing. This was achieved, among other things, through the use of an annular preventer swivel, which allows the rubber element of the annular preventer to be sealed around the drill string during the actual cutting operation. On floating facilities, this could be implemented in combination with a marine swivel.

Furthermore, a motor in the bottom-hole string could be used to rotate the cutting tool, while the drill string was kept stationary without rotation, with the annular preventer element closed.

However, these methods require additional preparation and result in more time spent running tools down the well. In addition, the solutions were not always compatible with combined operations (combination strings).
Equinor's increased focus on efficient execution and time savings in operations may have contributed to changes in practice, including reduced use of a closed BOP during casing cutting.

6.2.6 Fragmented communication and distributed situational awareness

Although gas behind the casing was identified as a potential risk during the planning of the operation, the descriptions in the activity programme, risk analyses and DOPs, when considered together with information the investigation team obtained through interviews, suggest that there was a shared perception from early in the planning phase that the risk of gas behind the 13 ⅜" casing was low (ref. chap. 6.2.4).

The following factors may have shaped this shared situational understanding:

- The risk matrix attached to the activity programme included only one risk related to logging and cutting of the 13 ⅜" casing. The identified risk related to the possibility of being unable to identify barrier-grade cement behind the casing, with the potential consequences this could have for re-establishing the cement barrier. The risk of gas behind the casing was not included in the matrix. It also appears that the plan was to pull the 13 ⅜" seal assembly with the BOP closed, in the event of gas under the seal assembly. Although the risk had been identified, the implications of making the actual cut at 510 m, with a short distance for gas migration to the surface/facility, were not fully appreciated.
- Furthermore, the activity programme included no WBSs showing the status of the well at the time of Deepsea Bollsta's arrival. The well in question had an orange barrier status, which means that the well had only one barrier. The operational barrier diagrams were also not attached to the activity programme, but were only available via a link. More detailed information about the condition of the well could have enabled personnel from the drilling contractor and other contractors to fully understand the risk profile during the planning phase.

- There is uncertainty regarding the personnel's understanding of the criticality of gas logging in the annulus. It is unclear whether all involved parties were aware of the secondary purpose of the logging. It is also questionable whether the significance and implications of the log were adequately communicated, and whether Baker Hughes personnel with operational roles in the logging operation fully understood that the log and its interpretation would determine whether the cutting operations should be carried out with or without the annular preventer on the BOP activated. Furthermore, it is unclear whether everyone understood that it would be too late to close the annular preventer in the event of a kick, given the short distance from the cut to the BOP on the seabed.
- A review of documents and interviews shows that operations on Deepsea Bollsta prior to the incident proceeded more smoothly and quickly than planned. As a result, the detailed planning of upcoming operations fell behind schedule. The complexity of the activity, combined with multiple possible outcomes based on the logging of both the 10 3/4" tie-back and the 13 ⅜" casing, resulted in a large number of alternative plans. This may have contributed to the high number of DOPs in circulation, and to the fact that the responsible personnel did not have sufficient time and capacity to review each individual DOP with the necessary critical eye.
  During the interviews, it emerged that Equinor requires the DOP to be finalised and ready for review by the offshore organisation no later than two days before the scheduled activity. However, a review of documents and interviews reveals that at least four different DOPs were reviewed and signed between the offshore organisation and offshore personnel on Deepsea Bollsta during the Monday preceding the incident. Several of these concerned the upcoming operations.
- When the DOP concerning cement tagging and cutting of the casing was reviewed, it was concluded, as expected, that the annulus was gas-free based on the logging data. When the issue of cutting without a closed BOP was raised during this review, the prevailing understanding was therefore that the annulus was gas-free. Risks associated with potential sources of error in the log and the need for additional safeguards were accordingly not discussed in detail.

There was general consensus regarding a gas-free annulus. The pace of the operation, combined with the need to keep up with the schedule, may have contributed to risk factors that could have been identified and addressed being overlooked by the senior personnel on board.

7 Emergency response

The emergency response was initiated immediately after the gas detectors triggered an alarm, and the general alarm was activated in accordance with established procedures. Coordination between the drilling crew and the rest of the emergency response team appeared to be effective, and the well was shut in shortly after the flow was observed on the drill floor. However, given the short distance between the cutting point and the BOP, combined with the BOP's activation time, there was no time to activate the BOP before the fluid and gas reached the facility.

The following factors have been identified where established emergency response requirements were not fully met:

- The standby/FiFi vessel was not mobilised in accordance with the applicable emergency response plan.
- The POB check was not performed within 12 minutes, as specified in the internal requirements of the Deepsea Bollsta emergency response plan.

8 Observations

Havtil's observations are generally divided into two categories:

Non-conformity: Observations where we *prove* the existence of a breach/non-compliance with respect to the regulations.

Improvement point: Observations where we *believe we have seen a* breach/non-compliance with respect to the regulations, but do not have sufficient information to be able to prove it.

8.1 Non-conformities

8.1.1 Inadequate well barrier design

Non-conformity:
Equinor had not ensured that the well barrier element in the annulus between the 13 ⅜" casing and the formation (the cement barrier) prevented uncontrolled flow of hydrocarbons into the annulus of the well.

Rationale:
Detected presence of gas behind the 13 ⅜" casing indicates that the well's outer barrier element did not function as intended. The cement barrier in the annulus did not prevent the migration of hydrocarbons from the reservoir. During interviews, it emerged that chromatographic analyses of gas vented after perforation under the wellhead before pulling of the seal assembly for the 13 ⅜" casing, revealed the presence of heavier hydrocarbon components originating from the reservoir. This

indicates leakage through the annular barrier and that the barrier element did not meet the requirements for the barrier function.

Requirements:
Facilities Regulations, section 48(2) concerning well barriers, with ref. to para 1.

8.1.2 Inadequate quality assurance during the calibration of equipment for logging the 13 ⅜" casing

Non-conformity:
Equinor had not ensured that the procedure for calibrating the logging tool used for logging the cement behind the 13 ⅜" casing fulfilled its intended function.

Rationale
Calibration of the logging tool was subject to a generic standard operating procedure prepared by Baker Hughes in collaboration with Equinor, as well as Baker Hughes's operations supervisor for ULTeX.

According to the procedure, calibration must be performed in a zone with liquid behind the casing to ensure accurate differentiation between cement, formation and liquid. However, the logging tool was calibrated in a section where there was gas behind the casing.

The calibration process in the procedure establishes the criteria for interpreting different levels of acoustic impedance. If a gas zone is incorrectly defined as a liquid zone during calibration, this could lead to an incorrect interpretation of subsequent logging data.

Based on information provided by Equinor, during the planning phase an erroneous assumption was made regarding the presence of liquid behind the casing in the 500-metre to 600-metre interval where the FPP was carried out. An expected acoustic impedance value of 1.6 MRayls was entered into the ULTeX logging tool software. The actual measured values for acoustic impedance were lower than expected.

The procedure defined quality ranges for acoustic impedance measurements to identify errors related to equipment, assumptions or calibration. Although the acoustic impedance measurements during the calibration process fell outside these quality ranges on two occasions (see chap. 5.2), this was not followed up. Nevertheless, the measurements were accepted and used by the operator as a basis for further interpretation of the log data.

Requirements:
Activities Regulations, section 24(2) concerning procedures

8.1.3 Use of technology that was not qualified for identification of gas

Non-conformity:
Equinor had not qualified the use of acoustic impedance wireline logging for assessing the presence of gas in the annulus on the Troll field.

Rationale:
Equinor used acoustic impedance wireline logging as a basis for assessing the presence or absence of gas behind the 13 ⅜" casing. The investigation shows that the technology had not been qualified or validated by the company for detecting gas in an annulus. Despite this, the technology was a key factor in the planning and execution of cutting casing without a closed annular preventer in the BOP. The necessary criteria and processes for qualifying, testing and verifying the technology prior to use had not been established. The company was therefore unable to document that the technology met the health, safety and environmental requirements.

Requirements:
Facilities Regulations, section 9 concerning qualification and use of new technology and new methods.

8.1.4 Inadequate formulation of requirements (SR-126590) in the well integrity manual (TR3507)

Non-conformity:
Equinor had not ensured that requirement SR-126590 was designed and applied in such a way that it fulfilled its intended functions in connection with the planning and execution of cutting operations.

Rationale:
TR3507 is Equinor's internal technical requirements document for well integrity and is based on FR03 Drilling and Well (see chap. 4.1). The document determines binding minimum requirements for the planning and execution of offshore well operations.

TR3507 states that, for operations involving a risk of hydrocarbon exposure, combined with insufficient BOP activation time, the annular preventer on the BOP must be closed prior to the operation. The text of TR3507 - SR-126590 reads: "*For operations with a risk of exposure of HC in combination with insufficient BOP activation time, the BOP shall be closed upfront the operation*".

In interviews with personnel involved in the design and quality assurance of TR3507, it emerged that the intent of the requirement was that the BOP should always be closed prior to shallow cutting operations.

In interviews with users of the requirement, it emerged that SR-126590 was interpreted to mean that, if the cement bond log did not show gas behind the casing, the risk of hydrocarbons being present was considered eliminated. The personnel involved therefore concluded that the existing barriers were sufficient.
During the interviews, it emerged that, historically, no gas had been observed behind the 13 ⅜" casing on previous wells on the Troll field, and that, consequently, no equipment for cutting the casing with the BOP closed was ordered during the planning phase. As a result, the requirement for a closed BOP annular preventer in SR-126590 was not addressed during the planning or execution of the operation.

Requirements:
Activities Regulations, section 24(2) concerning procedures.

8.1.5 Missing well barriers during cutting operation

Non-conformity:
Equinor had not ensured that well barriers were in place when the cutting operation was carried out.

Rationale:
Based on the documentation received, it was known that the liquid in the well (the primary barrier) was not heavy enough to counterbalance the expected pressure on the outside of the casing. In reality, the pressure on the outside of the casing was significantly higher than expected.

The casing was cut at 510 m RKB. The BOP was on the seabed, approximately 160 metres above the cut. When gas began flowing into the well, it was not possible, due to the short distance, to close the BOP in time to prevent gas from reaching the surface at the facility.

As a result of this situation, the cutting activity was carried out without any barriers.

Requirements:
Activities Regulations, section 85(1) concerning well barriers.

8.1.6 Noise level in the driller's cabin during well control operation

Non-conformity:
Odfjell Drilling had not ensured that the necessary internal and external communication was maintained when alarms were triggered in the driller's cabin during the handling of the well control situation.

Rationale:

Interviews with personnel in the driller's cabin indicate that several alarms were triggered simultaneously during the incident, including gas alarms, a general alarm, a dynamic positioning (DP) alarm, and other system alarms. The alarms caused high noise levels in the driller's cabin and hindered effective verbal communication among the personnel. Furthermore, the interviews reveal that alarm noise and the simultaneous use of a single radio channel posed challenges for radio communication between personnel in the driller's cabin and other personnel on board (including the person in the shaker room). This made it difficult to understand and convey messages during the initial phase of the incident.

Requirements:
Activities Regulations, section 80(1) concerning communication, with ref. to the Activities Regulations, section 77 concerning the handling of hazard and accident situations.

8.1.7 Inadequate sharing of information about barriers and barrier impairments

Non-conformity:
Equinor had not ensured that the necessary information about the barrier status of the well was communicated to the relevant users in connection with the planning and execution of the cutting operation.

Rationale:

Due to the lack of conclusive data from the 10 ¾" cement logging conducted in 2008, the well was classified as orange (one barrier intact and one compromised or unverified). Information about the well's barrier status was not included in the activity programme.

- The well barrier schematics (WBSs) attached to the DOPs signed by the operational managers on the facility depicted the fluid column in the well as the primary barrier against the outside environment. This conflicts with information in the DOP stating that backflow was expected due to uncertainty regarding the specific gravity of the mud behind the casing. Furthermore, the BSR (Blind Shear Ram) on the BOP was depicted as a secondary barrier, even though it could not be closed in time to fulfil its intended function (ref. chap. 8.1.5)

Information regarding the barrier situation and impairments was not presented and communicated in a clear manner to the users of the information.

Requirements:
Management Regulations, section 15(2) concerning information

8.1.8 Separation of HVAC 1 and HVAC 2 rooms

Non-conformity:
Odfjell Drilling had not ensured that the shaker area, which contains drilling fluid that can emit gas, was separated from HVAC 1 and HVAC 2 in a way that prevented the spread of gas.

Rationale:
The shaker room is a potentially explosive area (classified area) designated as Zone 1. The shaker room must maintain negative pressure relative to adjacent areas (see chap. 4.9 and Figure 22). Adjacent to the shaker room is the HVAC 1 room, which is a potentially explosive area classified as Zone 2. During normal operation, the room has positive pressure relative to the shaker room. Adjacent to HVAC 1 is HVAC 2, which is an unclassified area. During normal operation, the room is protected by positive pressure and a gas damper that closes in the event of confirmed gas detection in the air intake. The equipment in this room is not disconnected in the event of ESD 1 A/B. There is no ATEX equipment in the room.

During the incident, data from differential pressure gauges indicate that a simultaneous loss of differential pressure occurred between:

- the HVAC 1 room and the shaker room. Under Odfjell Drilling's design principles, there is a requirement for positive pressure of 25 Pa in HVAC 1 relative to the shaker room (see Table 3). The shaker room is a Zone 1 area and has a door that opens into the HVAC 1 room, which is a Zone 2 area.
- the HVAC 2 room and the HVAC 1 room. Under Odfjell Drilling's design principles, there is a requirement for positive pressure of 50 Pa in HVAC 2 relative to HVAC 1 (see Table 3). The HVAC 1 room is a Zone 2 area and has a door that opens into the HVAC 2 room, which is an unclassified area.

The simultaneous loss of differential pressure between the shaker room and HVAC 1, and between HVAC 1 and HVAC 2, allowed the gas/air mixture to penetrate into an unprotected area (HVAC 2 without positive pressure), which contained ignition sources (non-ATEX equipment) and which did not shut down in the event of gas detection in the shaker area.

Requirements:
Framework Regulations, section 3 concerning the application of maritime regulations in the offshore petroleum activities, with ref. to the Norwegian Maritime Authority's Regulations concerning precautionary measures against fire and explosion on mobile offshore units, section 24 concerning Gas hazard/system, para 1

8.1.9 Failure to use differential pressure data

Non-conformity:
Odfjell Drilling had not ensured that data on differential pressure in the shaker room was used to monitor technical and operational conditions.

Rationale:
Data on the differential pressure (negative pressure) in the shaker room relative to adjacent rooms is available in order to monitor the required negative pressure in the shaker room. In accordance with Odfjell Drilling's design principles (ref. Table 3), the shaker room, which is classified as Zone 1, must maintain a negative pressure of -25 Pa relative to adjacent areas with a lower classification than Zone 1 (Zone 2 and unclassified areas).

The data had not been used to check whether the negative pressure was too low. Excessively negative pressure can lead to:

- doors being difficult to open, which can prevent a quick and safe evacuation of the area,
- smoke spread between areas, door integrity, and the ability to carry out effective manual firefighting operations being adversely affected.

Trends in differential pressure show that the negative pressure in the shaker room was lower than -210 Pa (differential pressure is not measured below -210 Pa) both before and during the incident (ref. Table 3).

In an interview, it emerged that it was difficult to open the door from the shaker room into the Shaker Operation Restroom during the incident. The person who was in the shaker room when the incident occurred struggled to open the door and escape to an adjacent area.

Requirements:
Management Regulations, section 19(a) concerning the collection, processing and use of data

8.1.10 Lack of maintenance of differential pressure gauges

Non-conformity:
Odfjell Drilling had not established a maintenance programme to systematically prevent failure modes that could pose a safety risk for three differential pressure gauges that monitor overpressure/underpressure between rooms.

Rationale:
During the inspection, information was provided that three differential pressure gauges lacked a maintenance programme for verifying the barrier. The three differential pressure gauges were not included in the functional test (TBAMI test – Function test of HVAC transmitters). This applied to differential pressure gauges between:

- Shaker Room and Screen Cleaning Room

- Screen Store and Tank Cleaning Room
- HVAC1 and HVAC2

Requirements:
Activities Regulations, section 47(1) concerning maintenance programmes.

8.1.11 Inadequate formulation of requirements in the well control manual

Non-conformity:
Odfjell Drilling had not ensured that the requirement (5-20 Retrieve seal assembly & cut casing) in the well control manual (L3-MODU-ALL-DO-MA-005-WELL CONTROL MANUAL) was formulated in such a way that it fulfilled its intended functions in connection with the planning and execution of cutting operations.

Rationale:
The wording of Odfjell Drilling's requirement regarding the cutting of casing (5-20 Retrieve seal assembly & cut casing) was unclear.

The requirement stated that:
"*Cutting casing with open BOP can be done with a risk assessment, if some of the compensating measures below are in place:*

- *Cement is logged and proven hydraulic bonding or annulus*
- *logged and verified free of gas.*
- *Seal assembly retrieved prior of cut casing.*
- *Deep cut*"

The requirement could be interpreted in different ways, as it did not specify how many of the criteria had to be met.

Interviews revealed that, over time, Odfjell Drilling had aligned itself with the operator's requirements regarding well control.

When the DOP for cutting casing was reviewed prior to signing by senior offshore personnel, questions were raised about the procedure. In the ensuing discussion, logging and subsequent interpretation (gas-free annulus) were highlighted as a verification method, and the conclusion was that Odfjell's requirements had also been met.

If Odfjell Drilling had had a clear requirement for shallow casing cuts, this could have prompted a genuine review of the procedure, which in turn could have prevented the incident from occurring.

Requirements:
Activities Regulations, section 85(1) concerning well barriers.

8.1.12 Inadequate updating of technical documentation

Non-conformity:
Odfjell Drilling had not ensured that the technical operating documentation related to HVAC and differential pressure was up to date.

Rationale:
During the investigation, we identified the following errors and discrepancies in the technical operating documentation related to HVAC and differential pressure:

a) The drawing "HVAC D&ID Machinery Area Hazardous System – Shale Shaker and Mud Pits" was missing information indicating the fire separation between the "Screen Store (Zone 2)" and the "Tank Cleaning Machinery Room (Non-Haz area)."
b) The drawings "HVAC D&ID Machinery Area Hazardous System – Shale Shaker and Mud Pits" and "Hazardous Area Plan A Deck" contain incorrect values for the differential pressure between "Shale Shaker Room (Zone 1)" and "Screen Cleaning Room (Zone 2)". The differential pressure is 25 Pa according to the drawings, which does not match the differential pressure stated by Odfjell Drilling in their email of 16 January 2026
c) The drawing "Hazardous Area Plan Upper Deck" includes an incorrect value for negative pressure in the "Lower Part Shale Shaker (Zone 1)". The negative pressure is -50 Pa according to the drawing, which does not match the negative pressure stated by Odfjell Drilling in their email of 16 January 2026

Requirements:
Activities Regulations, section 20(b) concerning the start-up and operation of facilities

8.2 Improvement points

8.2.1 Handling of hazard and accident situations

Improvement point:
Odfjell Drilling does not appear to have ensured that the necessary measures, in the form of mobilisation of a firefighting vessel and a POB check on Deepsea Bollsta, were implemented as quickly as possible during the well control incident on 23 September 2025.

Rationale:
In interviews it emerged that, immediately after the gas detections were confirmed, a general alarm was activated in accordance with procedures, but a standby/FF vessel was not mobilised in accordance with the applicable emergency response plan.

Interviews and a document review (emergency response board) revealed that it took 21 minutes for personnel to be accounted for during the muster following the general/gas alarm triggered by the well control incident on 23 September 2025. The performance requirement in Deepsea Bollsta's governing document was 12 minutes.

Requirements:
Activities Regulations, section 77(b) and 77(c) concerning the handling of hazard and accident situations

9 Barriers that did function

- The diverter system was activated and functioned, but only after some of the liquid and gas flow had already escaped through the rotary table
- The drilling crew shut in the well using the diverter valve and annular preventer on the BOP.
- The red zone, serving as a barrier, was observed, as there was no one on the drill floor within the restricted area.
- Ignition source control: In this incident, the system for shutting down equipment in the event of gas detection appears to have functioned as intended and reduced the likelihood of ignition.
- The exhaust fan in the shaker room started running
- Gas detection worked
- ESD worked as intended
- PAGA

10 Discussion concerning uncertainties

- There is uncertainty regarding the choking effect that the 5-tonne PS-30 slips had on the flow of liquid. Liquids and gases will flow along the path of least resistance. The weight of the PS-30 slips and the constriction it creates may have directed the flow towards the shaker room.
  Another possible explanation for why the liquid flowed towards the shaker room could be the order of activation of the various components of the diverter system. If the packing element against the drill floor was activated before the flowline to the shaker room was shut off, this would have had an impact.
  It cannot therefore be determined whether the backflow of water and gas into the shaker room was caused by the PS-30 slips, the activation sequence of the diverter system, or a combination of these factors.

- There is uncertainty regarding the extent of the gas mixture in the various areas, as well as how long the mixture remained within an explosive area. There were gas mixtures in other parts of the shaker areas, the drill floor and underneath the drill floor where no gas detectors were installed. During the incident, there may have been an explosive gas mixture present for longer/at a different time, in areas not covered by gas detectors.

- Differential pressure measurements indicate that there was airflow from the shaker room to the HVAC1 room and from the HVAC1 room to the HVAC2 room (an unclassified area where equipment is not disconnected in the event of ESD1). There are no gas detectors in the HVAC 1 and HVAC 2 rooms, so it is unclear what gas-air mixture these areas were exposed to.

- The clocks on the various CCTV cameras did not show the correct time (the time had not been synchronised with the other safety systems). In addition, the timings in the received trends for gas detection and differential pressure are not sufficiently precise. The times listed in the report (based on this information) are therefore not entirely precise compared to actual time.

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11 Assessment of the company's investigation report

Equinor decided to launch a level-3 investigation on 25 September 2025, in order to understand the causes of the incident and prevent it from recurring. Equinor based its choice of methodology on DW 901 ("Handling of quality deviations"). It is our assessment that the incident should have been embedded and investigated at a higher level within Equinor.

Havtil received the report on 2 March 2026.

The in-depth investigation, conducted by Equinor with participants from Odfjell Drilling and Baker Hughes, has identified both direct and underlying causes of the incident. The report is presented in a thorough and well-organised manner.

The report provides little insight into why there have been so many breaches of the company's governing documents, and why management has failed to ensure compliance with procedures.

Equinor considers the risk of further escalation into a fire or explosion to be unlikely. The assessments are based on the company's guidelines for assessing the severity of fire and explosion risks (GL0604) and the definition of the expression "slightly different circumstances." As Equinor describes it, there is uncertainty surrounding several factors, including the extent of the gas cloud, the presence of gas in HVAC 2, and the presence of potential ignition sources. Our investigation indicates that there was significant airflow from the shaker room to the HVAC 1 room and on to the

HVAC 2 room. There are no gas detectors installed in HVAC 1 or HVAC 2, so it is unclear what the gas/air mix was in this area. In Havtil’s assessment, there may have been potential ignition sources in the HVAC 2 room that could have ignited a flammable gas mixture in the room.

Equinor's investigation report states that gas detection in the shaker area (mechanically ventilated/enclosed area) triggers ESD 1, which shuts down non-critical equipment. Our report is based on the principle that ESD 1 with ignition source disconnection is activated upon confirmed gas detection in a naturally ventilated area (in the case of this incident, this refers to confirmed gas detection beneath the drill floor). This is in accordance with the facility’s C&E (a diagram showing various causes/events and their subsequent actions/effects) for the relevant areas.

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1	Risk register for the activity of cutting the 13 3/8-inch casing
2	Bha tegning av Samurai kutter.pdf
3	ULTEX CALIBRATIONS MAIN 13 38 JA-514942 - Instrument configuration
4	24615459 M150 - (DOP15) - Log 13 3 8 casing bond log (WL) (1)
5	NO 31 3-Q-21 BY1H M160 - DOP16 - Set 13 3 8 PP A cement plug w 4'' stinger
6	NO 31 3-Q-21 BY1H M165 - (DOP16A) - RIH 13 3 8'' Dress-tag BHA w 13 3 8 casing cutter.pdf
7	ULTEX CALIBRATIONS MAIN 13 38 JA-514942 - Instrument configuration
8	VEDLEGG NR 01 - DBO - PICTURES POST EVENT 23.09.2025 - DOCS-2686036
9	VEDLEGG NR 29 - DBO - 3S-7102-001 - GENERAL ARRANGEMENT FOR CCTV SYSTEM - SHT 1 - REV. Z1 - DATO 17.02.2017 - DOCS-2686065
10	VEDLEGG NR 30 - DBO - 3S-7102-001 - GENERAL ARRANGEMENT FOR CCTV SYSTEM - SHT 3 - REV. Z1 - DATO 17.02.2017 - DOCS-2686066
11	VEDLEGG NR 31 - DBO - 3S-7102-001 - GENERAL ARRANGEMENT FOR CCTV SYSTEM - SHT 4 - REV. Z1 - DATO 17.02.2017 - DOCS-2686067
12	VEDLEGG NR 32 - DBO - 3S-7102-001 - GENERAL ARRANGEMENT FOR CCTV SYSTEM - SHT 5 - REV. Z1 - DATO 17.02.2017 - DOCS-2686068
13	VEDLEGG NR 33 - DBO - 3S-7102-001 - GENERAL ARRANGEMENT FOR CCTV SYSTEM - SHT 6 - REV. Z1 - DATO 17.02.2017 - DOCS-2686069
14	VEDLEGG NR 34 - DBO - 102-55 550-102-S-XD-001 - GENERAL ARRANGEMENT FOR CCTV SYSTEM - REV. Z1 - DATO 02.17.2017 - DOCS-2686070
15	VEDLEGG NR 02 - DBO - EVENT LOG FROM KONGSBERG ICMS - DOCS-2686037
16	VEDLEGG NR 03 - DBO - LAYOUT TEGNING FOR GAS DETEKTORER - DOCS-2686038
17	VEDLEGG NR 04 - DBO - 550-811-S-XD-001 - GENERAL ARRANGEMENT OF FIRE &GAS SYSTEM - REV. Z2 - DATO 02.17.2017 - DOCS-2686039
18	VEDLEGG NR 05 - DBO - INHIBITATION LOG - DOCS2686040
19	VEDLEGG NR 07 - DBO - GAS DETECTOR ALARM HISTORY - DOCS-2686042
20	VEDLEGG NR 06 - DBO - 850-811250-EN-R - OPERATING MANUAL GD10
21	VEDLEGG NR 22 - DBO - D&ID WITH RED LINE DBO - REV. 23.09.25 - DOCS-2686057
22	Confirmation that standby fan(s) started to reduce potential explosion pressure, and which action lead to start of fans
23	VEDLEGG NR 08 - DBO - FANS RUNNING 23.09.2025 - DOCS-2686043
24	VEDLEGG NR 09 - DBO - 550-812-S-XR-001 - DBO FIRE AND GAS CAUSE AND EFFECT CHART - REV. 15 - DATO 14.05.2025 - DOCS-2686044
25	VEDLEGG NR 10 - DBO - 550-812-S-XR-001 - DBO ESD CAUSE AND EFFECT CHART - REV. 15 - DATO 14.05.2025 - DOCS-2686045
26	VEDLEGG NR 11 - DBO - DIFFERENTIAL PRESSURE RECORDINGS - REV. 2 - DOCS-2686046
27	VEDLEGG NR 12 - DBO - 00813-0100-4001 - ROSEMOUNT 3051 PRESSURE TRANSMITTER - REV. WC - DATO OCTOBER 2022 - DOCS-2686047

28	VEDLEGG NR 23 - DBO - 550-105-C-LA-525 - LIST OF CERTIFICATES FOR FIRE CLASS DOOR - REV. 0 - DATO 23.02.2015 - DOCS-2686058
29	VEDLEGG NR 24 - DBO - 550-105-C-VB-526 - TYPE CERTIFICATES FOR FIRE CLASS DOOR - REV. 0 - DATO 27.02.2015 - DOCS-2686059
30	VEDLEGG NR 25 - DBO - 7C-8105-031 - CLASS DOOR LIST - REV. Z1 - DATO 12.02.2014 - DOCS-2686060
31	VEDLEGG NR 26 - DBO - MEDB00000TY - A60 DOUBLE LEAF HINGED DOOR TYPE HB-HH - REV 2 - DATO 11.03.2021 - DOCS-2686061
32	VEDLEGG NR 27 - DBO - HB-H A-60 - ETO DATASHEET - DATO 30.04.2025 - DOCS-2686062
33	VEDLEGG NR 28 - DBO - MEDB000069F - DRAFT A60 HINGED DOORTY
34	VEDLEGG NR 13 - DBO - WEATHER OBSERVARIONS AND RIG HEADING 22-230925 - DOCS-2686048
35	VEDLEGG NR 14 - DBO - STORMGEO TROLL Q-21 2025092215 - DOCS-2686049
36	VEDLEGG NR 35 - DBO - 7S-7142-057 - DESIGN ACCIDENTAL LOAD (DAL) VERIFICATION - REV. Z1 - DATO 17.02.2017 - DOCS-2686144
37	VEDLEGG NR 36 - DBO - 7S-7142-036 - DESIGN ACCIDENTAL LOAD (DAL) SPECIFICATION - REV. Z1 - DATO 17.02.2017 - DOCS-2686182
38	VEDLEGG NR 15 - DBO - TIME CALCULATIONS FOR CCTV RECORDINGS - DOCS-2686050
39	VEDLEGG NR 16 - DBO - CMS-22587 - DBO OFFSHORE ORG CHART - DOCS-2686051
40	VEDLEGG NR 17 - DBO - L4-MODU-DBO-B-PR-314 - HANDLING OF GAS IN RISER DEEP WATER - REV. 3 - DATO 30.09.2024 - DOCS-2686052
41	VEDLEGG NR 18 - DBO - WSOG - TROLL Q-21 - DOCS2686053
42	VEDLEGG NR 19 - DBO - EMERGENCY BOARD - DOCS268605
43	VEDLEGG NR 20 - DBO - 6H0096-09.1-H-JC-0001-01-4 - DAGSRAPPORT - DOCS-2686055
44	VEDLEGG NR 21 - DBO - DOOR INSPECTION - JOB CLOSE REPORT - DOCS-2686056
45	VEDLEGG NR 39 - DBO - 550-326-P-XB-001 - TRIP TANK SYSTEM - REV. A - DATO 22.12.2021 - DOCS-2686286
46	VEDLEGG NR 40 - DBO - X-262123-126-01 - SOFTWARE FUNCTIONAL DESIGN SPECIFICATION - REV 07 - DATO 19.05.2021 - DOCS-2686292
47	VEDLEGG NR 41 - DBO - 501075-U-XE-0003-001 - NO 313- Q-21 - BOP OPERATIONAL STACK UP DRAWING - REV 03 - DATO 03.06.2025 - DOCS-2686294
48	VEDLEGG NR 42 - DBO - X-262123-126-01 - EDS ONLY - REV 08 - DATO 07.08.2025 - DOCS-2686299
49	TEAMS correspondence between Baker Hughes wireline logging and the shift engineer for the cased hole logging group
50	Standard Operating Procedures applicable to Baker Hughes' wireline services for Equinor
51	24615459 M150 - (DOP15) - Log 13 3 8 casing bond log (WL).pdf
52	CHIL (Cased Hole Integrity Logging) Submit Request Confirmation Section ID: 5842

52	Daily Report - 24615149 - 2025-09-18.pdf
53	Daily Report - 24615149 - 2025-09-19.pdf
54	Daily Report - 25311671 - 2025-09-20.pdf
55	Daily Report - 25311671 - 2025-09-21.pdf
56	Daily Report - 25311671 - 2025-09-22.pdf
57	Daily Report - 25311671 - 2025-09-23.pdf
58	Daily Report - 25311671 - 2025-09-24.pdf
59	Daily Report - 25311671 - 2025-09-25.pdf
60	Daily Report - 25311671 - 2025-09-26.pdf
61	FINAL Well control bridging document DS Bollsta - 2025 Signed.pdf
62	NO 31 3-Q-21 BY1H M70 - (DOP07) - Log 10 3 4 liner tieback bond log (WL) (1).pdf
63	Equinor etterspurt dokumentasjon (002) S.docx
64	Troll PP&A Q-21 - Info til Havtil - 2025.10.10
65	DW200 - DW200 - Workover and PP&A offshore
66	DW201 - Assess feasibility of workover and permanent P A
67	DW202 - Develop and select concept
68	DW203 - Plan well in detail
69	Annular Bond and Casing Conditions Interpretation Report - 31/3-Q-21 BY1HT5 Troll
70	Troll PP A - Summary of log requests to CHLG - Vedr Deepsea Bollsta - Brønnkontrollhendelse
71	DBO - Deepsea Bollsta - Brønnhendelse på Deepsea Bollsta - Havtil - Tilsvar - Versjon 1 - dato 03.10.2025 - Doc
72	Requested Information - Equinor Troll Deepsea Bollsta - Investigation - Well Control Incident 23092025 - Is Equinor considering any immediate changes to the execution of similar operations, based on what has been uncovered so far? What assessments have been made regarding further work on the well?
73	Information requested from Odfjell Drilling – Questions regarding the well incident – Equinor Troll Deepsea Bollsta – Investigation – Well control incident – Is Odfjell Drilling considering any immediate changes to the execution of similar operations, based on what has been uncovered so far? What assessments have been made regarding further work on the well?
74	Information requested from Baker Hughes – Questions regarding the well incident – Equinor Troll Deepsea Bollsta – Investigation – Well control incident – Is Baker Hughes considering any immediate changes to the execution of similar operations, based on what has been uncovered so far? What assessments have been made regarding further work on the well?
75	Annular Bond and Casing Conditions Interpretation Report - 31/3-Q-21 BY1HT5 Troll
76	Troll PP A - Summary of log requests to CHLG – Ordering of log services