



Investigation report

Report

Report title Hydrocarbon leak on Oseberg A on 17 June 2013	Activity number 001053028
---	------------------------------

Security grading

<input checked="" type="checkbox"/> Public	<input type="checkbox"/> Restricted	<input type="checkbox"/> Strictly confidential
<input type="checkbox"/> Not publicly available	<input type="checkbox"/> Confidential	

Summary

A hydrocarbon leak occurred on Oseberg A on 17 June 2013.

Oseberg A was in normal operation when the incident occurred. One of the operations under way was gas injection in well B-41, while well B-45 was producing to the test separator. B-41 and B-45 are tandem wells.

Unstable flow (slugging) from B-45 caused the test manifold to shut down as a result of high pressure. Because B-41 and B-45 are tandem wells, gas injection was not sufficiently isolated from the test manifold, which meant that pressure in the manifold was further increased by the injection system. Pressure from the manifold was bled off to the flare. This caused a hole to be eroded in the blowdown line.

The central control room received the first gas alarm at about 07.04. Immediately afterwards, plant operators confirmed the presence of gas in the module.

Manual level 2.0 emergency shutdown (ESD) was activated by the control room at 07.06. This disconnected ignition sources, shut down, and initiated pressure blowdown of the process plant. Because the leak occurred in the flare system, gas continued to flow out into the module until the blowdown was completed.

The emergency response organisation mobilised and personnel mustered.

About 85kg of gas was released. The initial leak rate was roughly 0.1kg/s.

Nobody was injured in the incident. Production was shut down for four days.

The potential consequences are considered to have been explosion and fire, confined to the module where the incident occurred. Had there been personnel in the immediate vicinity of the leak point, lives could have been lost.

Involved

Main group T-1	Approved by/date Kjell Marius Auflem
Members of the investigation team Ove Hundseid, Eirik Duesten	Investigation leader Øyvind Lauridsen

Contents

1	Summary	3
2	Introduction	5
3	Course of events	6
4	Direct and underlying causes	10
	4.1 Direct causes	10
	4.2 Underlying causes	10
	4.2.1 Erosion as a consequence of sand production	10
	4.2.2 Connection point of pressure blowdown line to test manifold	10
	4.2.3 Position of orifice plate in relation to pipe bend	11
	4.2.4 Ensuring good working practice	12
5	Actual and potential consequences of the incident	13
	5.1 Actual consequences	13
	5.2 Potential consequences of the actual leak	13
	5.2.1 Probability of ignition	13
	5.2.2 Consequences of an explosion	14
	5.2.3 Consequences of a fire	14
6	Observations	16
	6.1 Nonconformities	16
	6.1.1 Inadequate overpressure protection of the test manifold	16
	6.1.2 Lack of risk assessment in using the equalising and blowdown system for gas injection	17
	6.1.3 Inadequate work processes for operating wells and process plant	17
	6.1.4 Deficiencies in the inspection programme	18
	6.1.5 Design deficiencies for dealing with sand production	18
	6.2 Improvement points	19
	6.2.1 Sand strategy	19
	6.2.2 Presentation of detector height above deck level	19
	6.3 Other observations	20
	6.3.1 Use of sledgehammer when opening a valve	20
	6.3.2 Securing the incident site	20
	6.3.3 Fire and explosion strategy	20
	6.3.4 Well design pressure	20
	6.3.5 Loss of main power	21
	6.3.6 Mustering and debriefing	21
	6.3.7 Statoil's investigation report	21
7	Barriers which have functioned	21
8	Discussion of uncertainties	22
9	Appendices	23

1 Summary

Course of events

A hydrocarbon leak occurred on Oseberg A, part of the Oseberg field centre, on 17 June 2013.

Oseberg A was in normal operation when the incident occurred. One of the operations under way was gas injection in well B-41, while well B-45 was producing to the test separator. B-41 and B-45 are tandem wells – in other words, they are connected to the same branch and valve on the test and production manifold.

Unstable flow alternating between gas and fluids (slugging) from B-45 caused the test manifold to shut down as a result of high pressure. Because B-41 and B-45 are tandem wells, gas injection was not sufficiently isolated from the test manifold, which meant that pressure in the manifold was further increased by the injection system. This was observed by the control room operator, who opened the blowdown line to the flare from the test manifold in order to bleed off the pressure.

The central control room received the first gas alarm at about 07.04 and asked plant operators to go and check in the M module to see if gas was present there. Two operators entered at the mezzanine level and observed a quantity of “gas” as a cloud high up in the module. A third operator entered the M module immediately afterwards and notified the control room by radio that gas was present. They then evacuated the area.

Manual level 2.0 emergency shutdown (ESD) was activated by the control room from the critical alarm panel at 07.06. This disconnected ignition sources, shut down, and initiated pressure blowdown of the process plant. Because the leak occurred in the flare system, gas continued to escape until the blowdown was completed.

The emergency response organisation was mobilised and personnel mustered.

Direct and underlying causes

Wells on the Oseberg field centre began to produce sand around 2000. They are tested with the test separator to identify the acceptable rate of flow for sand production. Sand is accordingly produced into the system during well testing. The test manifold’s blowdown line is unfavourably designed with regard to sand production:

- its connection to the manifold means that sand can accumulate in the line
- a 90° bend positioned directly downstream from the line’s orifice plate means that sand carried in the gas stream hits the outer wall of the bend at very high speed.

This caused sand erosion, which led to a hole being eroded in connection with the pressure blowdown on 17 June 2013.

The main reason why this was able to develop over time and eventually cause a gas leak was that no adequate review of the plant has been conducted to verify that it could handle sand production.

Actual consequences

Based on Statoil's calculations, 85kg of gas and less than 15l of oil were released. The initial leak rate was roughly 0.1kg/s.

Nobody was injured in the incident. Production was shut down for four days.

Potential consequences

The potential consequences are considered to have been explosion and fire, confined to the module where the incident occurred. Had there been personnel in the immediate vicinity of the leak point, lives could have been lost.

Nonconformities

Five nonconformities were identified by the investigation:

- inadequate overpressure protection of the test manifold
- lack of risk assessment in using the equalising and blowdown system for gas injection
- inadequate work processes for operating wells and process plant
- deficiencies in the inspection programme
- design deficiencies for dealing with sand production.

2 Introduction

Pressure blowdown of the test manifold on the Statoil-operated Oseberg A facility was initiated at 06.58 on 17 June 2013. This caused a hydrocarbon leak in the pressure blowdown line, which was detected at 07.04. Gas was eventually detected in several modules on the main deck.

The Petroleum Safety Authority Norway (PSA) resolved on the same day to conduct its own investigation of the incident, with departure for Oseberg A on the afternoon of 18 June 2013.

Composition of the investigation team:

- Eirik Duesten, structural integrity
- Ove Hundseid, process integrity
- Øyvind Lauridsen, investigation leader, organisational safety

The investigation has been conducted through interviews with personnel in the land-based and offshore organisation, assessment of governing documents, Statoil's own investigation report and a verification on Oseberg A – including examination of the incident site. Use has also been made of analyses and reports commissioned by Statoil's investigation team. Statoil has made good provision for our conduct of the investigation.

Mandate for the investigation:

Clarify the scope and course of the incident, with emphasis on the safety, working environment and emergency response aspects.

- a. *Assess the actual and potential consequences:

 1. *harm caused to people, material assets and the environment*
 2. *the incident's potential for harm to people, material assets and the environment.**
- b. *Assess direct and underlying causes, with the emphasis on human, technical, organisational (HTO) and operational conditions from a barrier perspective.*
- c. *Discuss and describe possible uncertainties/unclear aspects.*
- d. *Identify nonconformities and improvement points related to the regulations (and internal requirements).*
- e. *Discuss barriers which have functioned. (In other words, barriers which has helped to prevent a hazard developing into an accident or which have reduced the consequences of an accident.)*
- f. *Assess the player's own investigation report (our assessments are communicated at a meeting or by letter).*
- g. *Assess the incident in light of improvement initiatives implemented by Statoil to reduce hydrocarbon leaks.*
- h. *Prepare a report and covering letter (possibly with proposals for the use of reactions) in accordance with established templates.*
- i. *Recommend – and contribute to – further follow-up.*

3 Course of events

This chapter describes the incident and its time line, including relevant history.

The Oseberg field centre embraces the Oseberg A, B and D platforms, which are tied together by bridges at the southern end of the Oseberg field.

Oseberg A is a concrete structure with process equipment and living quarters, while **Oseberg B** is supported by a steel jacket and has drilling, production and injection equipment. **Oseberg D** is a steel platform with gas processing and export equipment.



Figure 1 The Oseberg field centre. Source: Statoil.no.

The incident occurred in process module M02. See Figure 2



Figure 2 Process module M. The photograph is taken from Statoil's investigation report. The arrow has been superimposed to show where the leak occurred in M02.



Figure 3 Model of process module M. The photograph is taken from Statoil's investigation report. The arrow has been superimposed to show where the leak occurred in M02.

Course of events

Injecting gas in wells (bullheading) became common in 1995.

Around 2000, certain wells began to experience sand problems and some measures were then taken in the form of studies and sand detectors.

14 June 2013: It was decided to inject gas in well B-41, which was accordingly placed in equalising mode. Bullheading began on 15 June 2013.

17 June 2013: The test separator and test separator manifold shut down at 01.10 when they experienced high pressure. Pressure in the test manifold was bled off through the bleed valve before the test separator was brought back into operation at 01.30.

06.54: A high pressure alarm was given for the test separator and manifold, and the latter shut down a few seconds later because of high pressure following a slug from B-45. The high pressure alarm was at 24 barg, while the high pressure shutdown was at 26 barg. Pressure reached 59.3 barg in the test manifold. The master and wing valves also closed on B-41 and B-45, which were both connected to the test separator.

06.57: Pressure in the test manifold continued to rise because of gas leaking from the injection manifold, which did not shut down. The pressure rise came mainly from leakage through the choke valve, while some may have derived from leaking Rotork valves.

06.58: The bleed valve was opened to bleed off pressure in the test separator manifold.

About 07.04: The central control room received the first gas alarm and plant operators were asked to check the presence of gas in the M module. Two operators entered at the mezzanine level and observed a quantity of gas as a thick cloud high up in the module. A third operator entered the M module at the main deck immediately afterwards and confirmed to the control room by radio that gas was present.

07.04-07.09: 21 gas detectors in the M04 main deck, M03 main deck, M02 main deck and M01 main deck areas registered alarms of 10% lower explosion limit (LEL). Since they were all below 20% LEL, automatic shutdown was not activated.

07.06: The control room activated manual level 2.0 emergency shutdown (ESD) from the critical alarm panel. All the wells were thereby shut in by wing and master valves.

07.07: The muster alarm was activated.

07.07: The emergency response centre lost main power for 20 seconds.

About 07.07.30. The incident was reported over the PA system.

About 07.07.30: The first meeting in the emergency response centre began.

07.07: The control room initiated manual pressure blowdown of process system B with four separators and manifold.

07.08: Firewater deluge was initiated in the M04 mezzanine area from the control room.

07.10. Two pairs of line gas detectors on the top deck registered 10% LEL. The gas was now distributed over large parts of the process modules.

07.10: The control room initiated manual pressure blowdown of process system A with four separators and manifold.

07.09: A first detector recorded 20% LEL in the M02 main deck area, followed by another at 07.11, when firewater deluge was initiated by the logic controller in the relevant area. That also meant automatic activation of ESD 2.1.

07.12: Firewater deluge was initiated in the M04 main deck area from the control room.

About 07.12: The joint rescue coordination centre, search and rescue helicopters, other helicopters in the area and standby ships were notified.

07.15 The control room failed to open EV-0054 between Oseberg D and Oseberg A.

About 07.20: It became clear that lifeboat crew were lacking for lifeboat 3.

07.29: According to the alarm log, firewater deluge was activated in the M03 main deck area.

About 07.32: Personnel on board (POB) overview completed for all 308 people aboard.

07.42: Pressure blowdown ended on Oseberg A, with pressure below 0.01 barg.

08.29: Pressure began to fall in the gas pipeline between Oseberg A and Oseberg D, the last segment under pressure, after maintenance personnel had succeeded in opening the blowdown valve.

08.59: Pressure blowdown of the facility was completed.

About 09.15: Muster terminated and platform normalised.

4 Direct and underlying causes

4.1 Direct causes

Slugging in well B45 produced an unintended shutdown of the test manifold/separator. Because of simultaneous bullheading in tandem well B-41 and because a leaking choke valve was the only barrier to the test manifold, a pressure build-up occurred in the manifold.

Leakage through Rotork manifold valves from other wells could also have contributed to pressure build-up in the test manifold.

The emergency blowdown valve was used as an operational valve to reduce pressure in the manifold.

An inappropriate connection point for the pressure blowdown line on the test manifold meant that sand accumulated in the pressure blowdown line.

An inappropriate design with an orifice plate before a pipe bend meant the formation of a jet containing sand which struck the pipe bend and eroded a hole.

4.2 Underlying causes

4.2.1 Erosion as a consequence of sand production

Sand production has been an issue on Oseberg A since the 2000s. Extensive work was then carried out, including an upgrade of the sand detection system, calculations of expected sand production, erosion rates and a review of the inspection programme.

The philosophy for sand production is that it will not occur in producing wells. In other words, the wells will not produce more than one gram of sand per second. The control room receives an alarm if sand production exceeds this limit, and the well must then be choked down until a “sand-free” rate is achieved. The test manifold is used to test the well in order to establish this rate. Sand will accordingly be produced into the manifold as the production rate is adjusted. During pressure blowdown and testing of the manifold’s pressure blowdown valve, sand produced into the manifold has been carried along and caused erosion in the pressure blowdown line. Two features designed into the pressure blowdown system are very unfavourable with regard to sand production from the wells, and are described in the sections below.

4.2.2 Connection point of pressure blowdown line to test manifold

The pressure blowdown line has an unfortunate connection to the manifold, which means that sand produced into the manifold accumulates in the line. Such lines are normally connected at a high point 90° on the piping segment to be blown down, so that the flow bled off to the flare consists of gas. This also helps to reduce the volume of sand which accompanies the gas into the flare system.

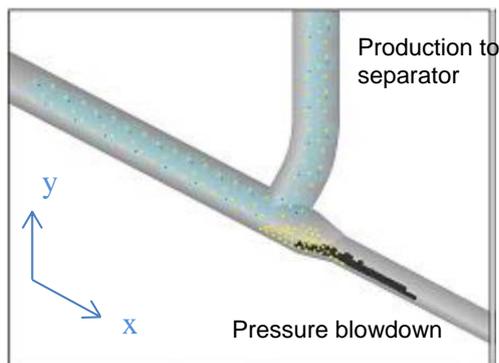


Figure 4 Connection of the pressure blowdown line. Source: Statoil's investigation report.

4.2.3 Position of orifice plate in relation to pipe bend

Because the orifice plate intended to limit the gas flow rate to the flare is positioned directly before a 90° bend, the jet from the plate has imparted very high velocity to the sand before it hits the bend. That has caused a hole to be eroded in the bend, as shown in the diagram and photograph below.

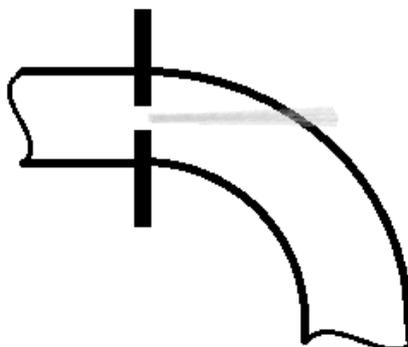


Figure 5 Simplified diagram for orifice plate and bend.



Figure 6 Hole eroded in the bend. Photo: Statoil.

Through interviews, we have been informed that the pressure blowdown valve is used regularly to blow down the test manifold. The data we have received make it difficult to obtain an overall view of how often the pressure blowdown valve is utilised in operations. According to Statoil's investigation report, however, it is used about 40 times a year.

4.2.4 Ensuring good working practice

Adequate work processes have not been established for operation of the wells and the process plant. As a result, the pressure blowdown line was utilised operationally without this use being assessed for sand production and inspection requirements. See nonconformity 6.1.3. There was also a lack of risk assessment, as noted with nonconformity 6.1.2.

5 Actual and potential consequences of the incident

5.1 Actual consequences

Based on Statoil's calculations, 85kg of gas and less than 15l of oil were released. Some of the oil accompanied water from the deluge system into the sea. Small quantities of oil were observed on the deck after the deluge had been shut off, but it cannot be established whether this derived from the leak. The leak occurred in module M02. Gas also spread to modules M03, M04 and M10.

Production was shut down for four days as a result of the incident.

The incident occurred around 07.00, and no work permits were active on Oseberg A.

Material damage was confined to the pipe bend where a hole was eroded.

5.2 Potential consequences of the actual leak

This section provides an assessment of the potential consequences of the actual leak which occurred on 17 June.

5.2.1 Probability of ignition

None of the gas detectors detected gas in an explosive mixture. In other words, the leak was not large enough to provide a sufficiently high concentration of gas to reach an explosive mixture where the gas detectors were installed. However, areas will exist around the leak where an explosive mixture occurred. In this case, these appear to have been confined to the immediate vicinity of the leak site. Simulations conducted by Statoil indicate that an explosive concentration of about 1cu.m occurred close to the leak point. Figure 7 presents the simulation of the leak. Since the detectors were primarily positioned high up in the module, however, the motion and concentration of the gas cloud before it reached the detectors are uncertain. Data from tests reported to the trends in risk level in the petroleum activity (RNNP) study show that gas detector reliability on Oseberg A is poor. The failure frequency in 2012 was six times higher than the average for the Norwegian continental shelf (NCS) that year. The process area is a classified area, which is basically not supposed to contain ignition sources exposed to gas. But the possibility of faults in electrical equipment cannot be excluded in the area around the leak point, which could result of the presence in ignition sources. However, the probability of ignition is regarded as low.

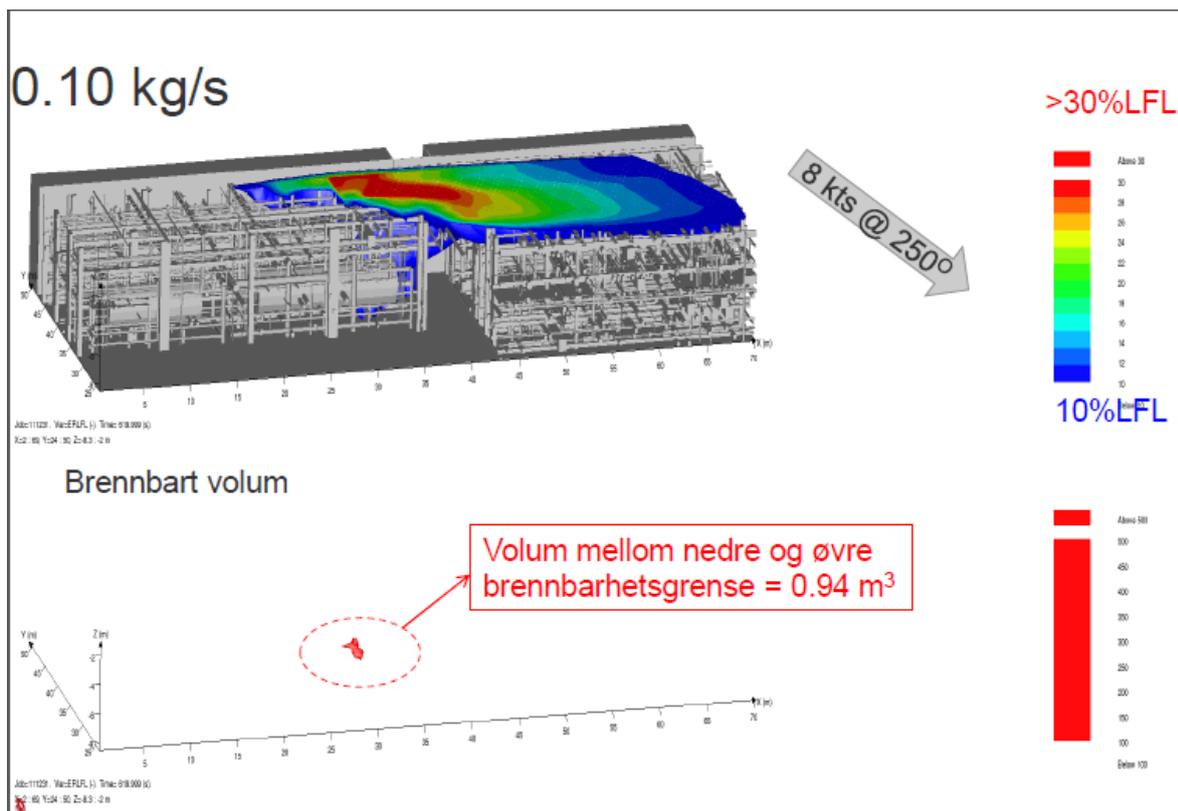


Figure 7 Simulation of gas emissions based on detector activation. The figure is taken from Statoil's investigation report. (Key: Ignitable volume; Volume between upper and lower ignitable limits = 0.94cu.m.)

5.2.2 Consequences of an explosion

The consequences of an explosion are uncertain because the volume of gas involved in an explosive mixture is unclear. However, Statoil's simulation indicates a volume of about 1cu.m, which is not sufficient to produce an explosion capable of causing further damage and gas leaks in the process plant.

No people were present in the module when the leak occurred, but the alarm reaction team was sent into the module to check the seriousness of the incident. Had the incident led to an explosion, a potential for loss of life would have existed. The timing of the incident must be characterised as arbitrary, and there could have been personnel in the area.

5.2.3 Consequences of a fire

Had the gas ignited, the result would have been a jet fire at a rate of 0.1kg/s with a duration of 10-15 minutes. Since the leak occurred in the flare system, a fire would have been supplied with gas throughout the period until the pressure blowdown was completed after about 30 minutes.

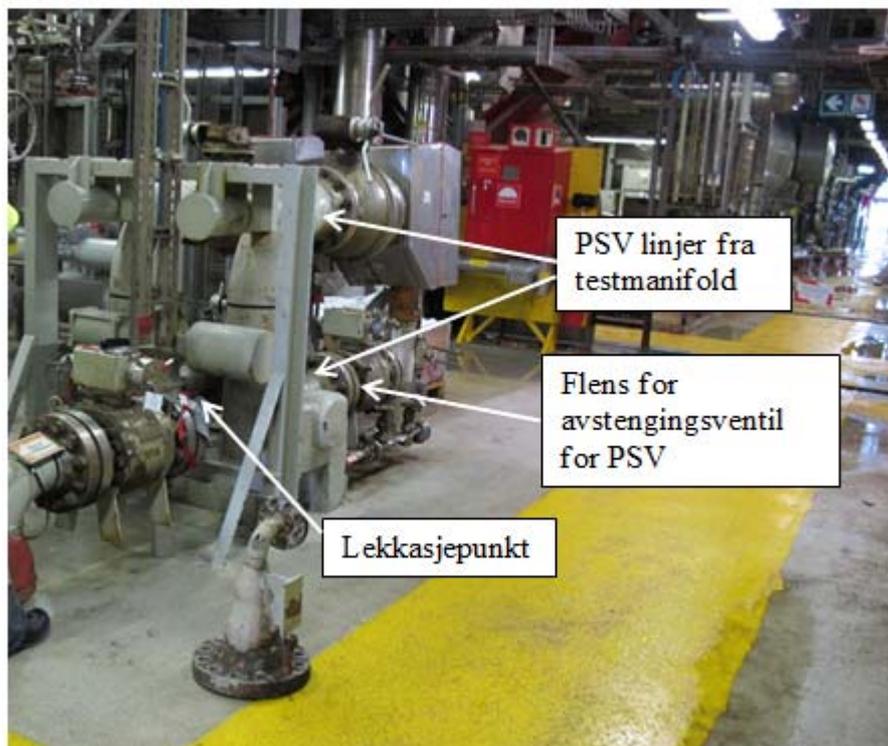


Figure 8 Pressure safety valve (PSV) in the immediate vicinity of the leak point.
 (Key: PSV lines from test manifold; Flange for shutdown valve for PSV; Leak point.)

The safety valves for the test manifold are located in the immediate vicinity of the leak point and would have been exposed to a jet fire. Figure 8 presents the layout. The flange on the shutdown valve for the upstream PSV would have been particularly exposed because it is not provided with passive fire protection. A jet fire could have caused leaks and a further supply of gas to the fire until the test manifold had been blown down. The consequences of leaks in the lines upstream and downstream of the PSVs are uncertain. However, we take the view that the probability of escalation out of the module would be low because pressure blowdown in the module functioned as intended.

6 Observations

The PSA's observations fall generally into three categories:

- nonconformities: observations where the PSA believes that regulations have been breached
- improvement points: observations where deficiencies are found, but insufficient information is available to establish a breach of the regulations
- other observations.

6.1 Nonconformities

6.1.1 Inadequate overpressure protection of the test manifold

Nonconformity

In connection with gas injection (bullheading) in well B-41 at the same time as well B-45 was being produced to the test separator, primary protection against overpressure was not established in the test manifold.

Grounds

Wells B-41 and B-45 are connected by a common (manual Rotork) valve to the test separator, and are accordingly called tandem wells. See the diagram below.

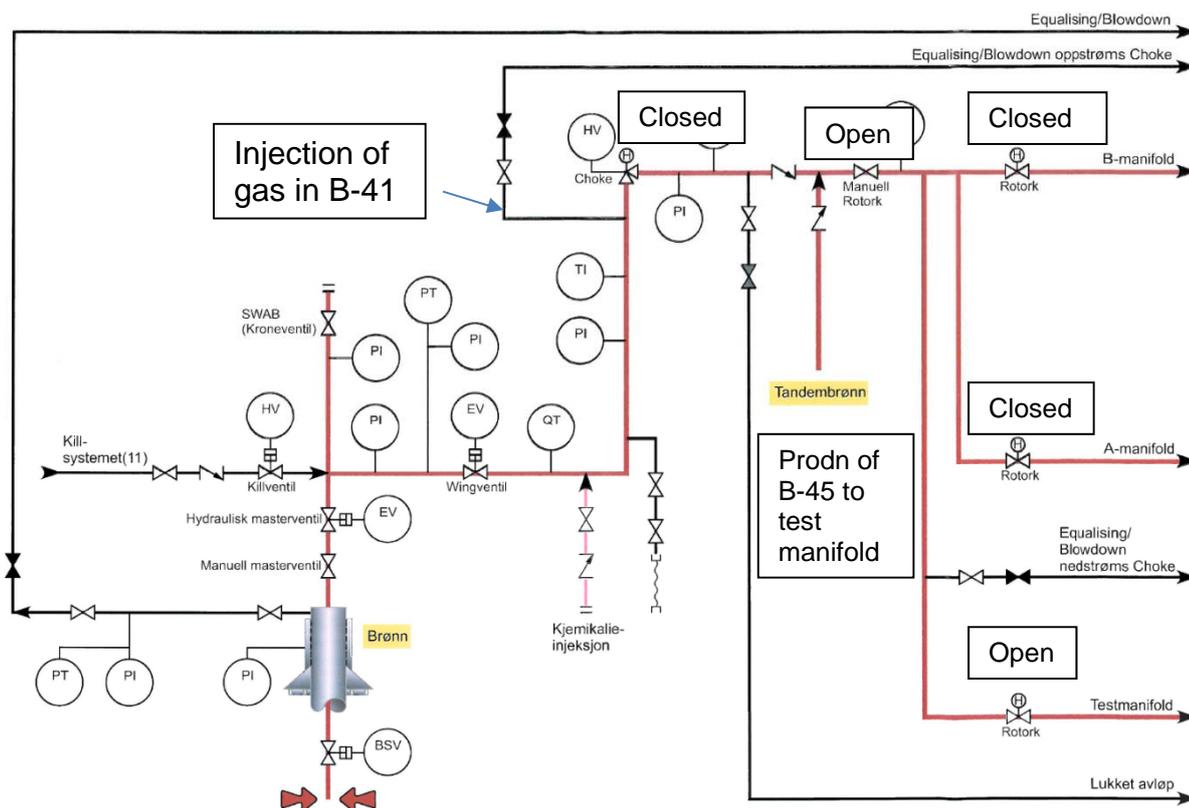


Figure 9 Layout for tandem wells B-41 and B-45.

At the same time as well B-45 was connected to the test separator, gas was injected in well B-41. This was done via the equalising and blowdown manifold, which is connected to the well upstream of the production choke. Because well B-45 was connected to the test separator, this configuration meant that the choke was the only barrier between the injection gas and the test manifold. The latter has a design pressure of 75barg, while the injection system has no

automatic shutdown function until the pressure reaches 233 barg. In the event of erroneous opening or a leak in the choke, no shutdown function will accordingly be available for the manifold which prevents overpressure as required by the regulations.

A shutdown function for high pressure is installed on the test manifold, but this only closes the wing and master valves on the tandem wells and accordingly does not affect a connection to the equalising and blowdown manifold.

Requirements

Section 82, subsection 2 of the facilities regulations, see chapter 7.3 on process safety equipment and functions in the regulations for production and auxiliary systems on production installations for exploitation of petroleum resources etc issued by the Norwegian Petroleum Directorate on 3 April 1978 with subsequent amendments of 1 July 1980, see also section 34 of the facilities regulations on process safety systems.

6.1.2 Lack of risk assessment in using the equalising and blowdown system for gas injection

Nonconformity

No review to assess risk and ensure that the system accords with regulatory requirements can be documented when using the equalising and blowdown system for gas injection.

Grounds

During our investigation, we have been informed that gas injection was conducted earlier by connecting to the wells via the kill line on the Xmas tree. Use of the kill line for gas injection is described in the system and operations (SO) manual. The practice has subsequently been changed so that the equalising and blowdown system is also used. This is less time-consuming operationally because new connections do not have to be made on the Xmas trees, since only existing valves in the process plant need to be operated.

Use of the equalising and blowdown system for gas injection is not described in the SO manual (see also nonconformity **Feil! Fant ikke referanseilden.**). Nor can it be documented that a risk assessment for using the system for gas injection has been conducted.

Requirements

Section 11 of the management regulations on the basis for making decisions and decision criteria, and sections 27 and 30 of the activities regulations on critical activities and safety clearance of activities respectively.

6.1.3 Inadequate work processes for operating wells and process plant

Nonconformity

Adequate work processes have not been established for operating wells and process plant.

Grounds

It emerged from interviews with personnel in the operations organisation and a review of documents that work processes have not been established or updated for:

- using the equalising and blowdown system for gas injection
- starting up wells in low pressure mode after a shutdown

- bleeding off pressure in the test manifold
- dealing with slugging
- bullheading of tandem wells.

Several of these activities form part of normal operations and have been pursued for a number of years without procedures being prepared or updated. Statoil presented the importance of a uniform operational and organisational model in 2008 (ref: 20081209 *Description of standardised operations model for UPN, case documents for UPN SU ver 1.ppt*). See also the *Statoil Book* on governing documentation and the A standard. Goals for standardised operations on the NCS are also described, with the emphasis on similar working methods, minimal variations in operating models and other points related to management, experience transfer and form of organisation. The document *Organisation, leadership and management for UPN operations* specifies the following: “That all operational or technical changes are first adopted after the solution has been approved by the technical system/technical discipline manager” and “operational documents are available”.

Requirements

Sections 8 and 13 of the management regulations on internal requirements and work processes respectively, and section 24 of the activities regulations on procedures.

6.1.4 Deficiencies in the inspection programme

Nonconformity

The inspection programme for the test manifold’s pressure blowdown line is deficient.

Grounds

No inspection is conducted with the pressure blowdown line from the test manifold, including the bend where a hole was eroded. We were told in interviews that the pressure blowdown valve upstream of the bend is frequently tested. The pressure blowdown valve is also opened to reduce high pressure in the manifold. According to information from Statoil, the line has been used about 40 times over the past year. In other words, it is used regularly without any assessment of the need for changes in the inspection programme. Nor have analyses been conducted or change orders issued in connection with the use of the pressure blowdown valve as a pressure bleed valve.

Requirements

Sections 45 and 47 of the activities regulations on maintenance and maintenance programmes respectively, section 21 of the management regulations on follow-up.

6.1.5 Design deficiencies for dealing with sand production

Nonconformity

The pressure blowdown system for the test manifold is not suitable for wells with sand production.

Grounds

The wells on Oseberg are tested against the test separator to identify the sand-free production rate. This means that sand is produced into the test manifold during testing. Branches from the manifold are so designed that sand is conducted into and accumulates in the pressure blowdown line. The positioning of the orifice plate directly upstream from a 90° bend means very high erosion rates in the bend from the sand in the system. Generally speaking, flow rates in the flare system are very high during a pressure blowdown, and also give sand in the system an erosion potential downstream from the bend.

Facilities on Oseberg A were not originally designed for sand production. Changes to the design assumptions have not been adequately followed up.

In our audits of Statoil, we have been informed that a project has been initiated to prepare plant-specific barrier strategies and area-specific performance requirements (see audit of barrier management in Statoil – activity 001000141). In our view, the incident would have been prevented if these were in place in accordance with the regulatory requirements.

Requirements

Section 25 of the activities regulations on use of facilities and section 5 of the management regulations on barriers.

6.2 Improvement points

6.2.1 Sand strategy

Improvement point

Documentation of the sand strategy for the Oseberg field centre could be improved.

Grounds

No document has been produced to describe the sand strategy for the Oseberg field centre. Work on this has begun but not been completed. The practice has been established that the wells will be *sand-free* in operation – in other words, produce less than 1g/s, but a complete strategy for the facility has not been produced. We also refer to nonconformity **Feil! Fant ikke referanseilden.**

Requirements

Sections 5 and 6 of the management regulations on barriers and management of health, safety and the environment respectively.

6.2.2 Presentation of detector height above deck level

Improvement point

The presentation of detector height on the fire and gas display in the control room could be improved.

Grounds

In the event of gas alarms in the control room, the operator is unable to form a quick picture of whether the gas is high or low in the module. They must refer to a separate folder in the control room. This is an inappropriate method, since a quick response to gas alarms by the operator is important for limiting the scope of a possible gas leak and for informing plant

operators where the gas is located. Detector height is shown on safety detection and alarm layout drawings, which are apparently little known or used in the central control room.

Requirement

Section 21 of the facilities regulations on the human-machine interface and information presentation.

6.3 Other observations

6.3.1 Use of sledgehammer when opening a valve

It was explained that problems arose in opening EV-0054 on the line between Oseberg D and Oseberg A. The mechanic who was called in used a sledgehammer to get the actuator to move. That was done with full pressure in the line. This approach is not included in any procedure and has the potential to harm people and material assets. We have been informed that this valve has caused problems since 2006 and has subsequently been treated at regular intervals. It opened when the gas release system was tested on 1 June 2013, but the position indicator showed it had not reached the open position. Test results for the pressure blowdown valve from Oseberg D reported to the RNNP show that the failure rate is 3.5 times higher than the expected level in the industry.

6.3.2 Securing the incident site

When we arrived on Oseberg, the area where the incident had taken place was cordoned off and washed. Drains had been cleaned and the bend disassembled. It is significantly more difficult to envisage the incident and how things have happened during an incident when cleaning and disassembly have occurred. Photographs were taken, but it turned out that these did not cover all relevant angles.

6.3.3 Fire and explosion strategy

We have been informed that no fire and explosion strategy has been produced for the Oseberg field centre, but that one is under preparation. Explosion calculations have been made, while probabilistic fire simulations are under way. Where the latter are concerned, however, the regulations require that each fire area must be able to withstand the highest fire load which could occur regardless of frequency. In other words, no opportunity exists to use probabilistic fire simulations to reduce the fire resistance of the fire areas.

6.3.4 Well design pressure

A well design pressure is shown on the well barrier diagrams. This could be understood as the pressure the well is designed to withstand. However, it is defined as the highest pressure which can arise in the well with the gas-filled column down to the reservoir, also known as the maximum shut-in pressure in Norsok D-010. Conversations with personnel in the operations organisation revealed different interpretations of how the well design pressure was defined. It was also understood as the highest pressure the well was designed for, like the way the term “design pressure” is used for process equipment.

6.3.5 Loss of main power

The main power supply on the facility was lost in the transition from fuel gas to diesel oil, so that the emergency response centre lost power. This has happened before. Statoil has carried out in-depth studies and is following this up as a separate issue.

6.3.6 Mustering and debriefing

The bridge between Oseberg B and A was closed as a result of the incident, so personnel on Oseberg B could not muster at the lifeboats on A. The crew of lifeboat 3 on Oseberg A were on Oseberg B when the incident occurred. However, lifeboat 3 was mustered after a while by people present who by chance had lifeboat crew qualifications.

It took 25 minutes before POB were confirmed. Statoil's internal requirement for the Oseberg field centre is 18 minutes. RNNP data show that muster time in 2012 averaged 20.7 minutes (24 drills). This means that the average is higher than the requirement, and four of the drills had muster times in excess of 25 minutes.

No systematic review has been conducted of lessons learnt from dealing with the incident by the emergency response leadership and others in the emergency response organisation. Nor has a systematic debriefing been conducted for the personnel, so that feedback to personnel has only been provided by certain managers.

However, feedback from those we have spoken to about the emergency response leadership's handling of the incident has been positive.

6.3.7 Statoil's investigation report

Statoil's investigation has been conducted at level two of the corporate audit function (COA INV). The description of the incident and of the direct and underlying causes of the incident largely coincides with our data and assessments. Where the actual consequences are concerned, we take note of the assessments made and the calculations commissioned by Statoil's investigation team (see also chapter 8 on uncertainties). With regard to the potential consequences, we do not agree with Statoil's assessments. Statoil writes that the leak occurred away from walkways. In our view, the leak point was oriented towards the walkway and the gas has probably flowed out into the latter, and personnel could have been present in the area. Statoil considers the probability for fire and explosion to be small, given that ignition source disconnection functioned and there were no other ignition sources in the area. In our view, the timing of the incident was arbitrary, and the presence of ignition sources could not be excluded. In its investigations, Statoil should consider the consequences of ignition with a view to identifying possible vulnerabilities on its facilities. See section 20 of the management regulations on registration, review and investigation of hazard and accident situations.

7 Barriers which have functioned

We have not identified barriers which failed other than those mentioned above.

8 Discussion of uncertainties

We have not carried out our own calculations of gas volume and the extent of the gas cloud. We have relied on Statoil's own calculations, and have not verified these. The calculations reflect the incident as we perceive it on the basis of the data we have had access to.

9 Appendices

A: The following documents have been utilised in the investigation

- /1/ Statoil's mandate for investigation of an undesirable emission incident with a gas leak on the Oseberg field centre OSF 17062013 -3
- /2/ Organisation chart, Oseberg business unit 13/832-6
- /3/ E-mail 17 June 13 "TASK FORCE - 25EV0054" 13/832-7-1
- /4/ Investigation report on the loss of main power with consequent gas leaks in the well area (well B-30) and process area (M02) 13/832-7-2
- /5/ System and control diagrams for the test manifold and test separator 13/832-7-3
- /6/ Extract from Siemen's log 13/832-7-4
- /7/ Minutes of welcome meeting, week 24 – PV 13/832-7-5
- /8/ L-OSF-14965 - low-pressure production via test separator 13/832-7-6
- /9/ Safety detection and alarm layout diagrams 13/832-7-7
- /10/ Hand-drawn overview of detector layout M02 13/832-7-8
- /11/ Well barrier schematics B-41 & B-45 13/832-7-9
- /12/ Plot from relevant pressure transmitters 13/832-7-10
- /13/ Status manifold valves 13/832-7-11
- /14/ OSB system 13: overview diagram of platform wells 13/832-7-12
- /15/ Extract from governing document: supplement to emergency preparedness on the NCS – Oseberg field centre 13/832-7-13
- /16/ Extract from Siemens log received from CCR 13/832-7-14
- /17/ Graphs of gas detectors and pressure graphs received from CCR 13/832-7-15
- /18/ Organisation chart, Oseberg field centre at 17 June 2013 13/832-7-16
- /19/ Photographs of the displays in the emergency response centre for the OSF 13/832-7-17
- /20/ Cause and effect diagram for shutdown level 4.1 and test manifold and subsea wells 13/832-7-18
- /21/ Extract from SAP related to BDV 13/832-7-19
- /22/ P&IDs for wells with associated test manifold and test separator 13/832-7-20
- /23/ ISO drawing pipe bend 13/832-7-21
- /24/ WP 17 June 2013 13/832-7-22
- /25/ Synergi 1364712, loss of main power 13/832-7-23
- /26/ Synergi 1364701 25-EV-0054 failed to open with ESD 13/832-7-24
- /27/ SAP 227102191774-25EV 0054, indicator fails 13/832-7-25
- /28/ Synergi 1364798 Reduced functionality of firefighting equipment in the area around the gas leak site, M03 main deck 17/6 13/832-7-26
- /29/ Actions following gas leak 17 June 13 13/832-7-27
- /30/ PUB overview 16 June 2013 18:54 13/832-7-28
- /31/ Overview staffing DV day/night 13/832-7-29
- /32/ Shift report CCR, shift staffing, log date: 16 June 2013 13/832-7-30
- /33/ Registered incident report in connection with gas leak in M02 OSA 17 June 2013 13/832-7-32
- /34/ Overview of WPs M01-M04 13/832-7-33
- /35/ Inspection report conducted after incident 13/832-7-34
- /36/ Presentation with photographs of hole in pipe bend before disassembly 13/832-7-35
- /37/ Inspection in connection with gas leak 17 June 2013 13/832-7-36
- /38/ Emergency response report Oseberg field centre 13/832-7-37
- /39/ PDP actions related to B-41 and B-45 13/832-9-2
- /40/ L-OSF-15257 – use of kill system 13/832-9-3

- /41/ Oseberg field centre production plan, week 25: 14-20 June 13/832-9-4
- /42/ OM01.01.02.01 – Implement continuous production optimisation 13/832-9-5
- /43/ Doc no TNE PRT HSET ST-10003 condition monitoring of technical safety (TTS) Oseberg field centre 13/832-11-2
- /44/ 250713 Response to questions in connection with PSA investigation 13/832-11-3
- /45/ 060913 Information from task in PDP. Well B-41 13/832-14-2
- /46/ 060913 Information from task in PDP. Well B-45 252402 13/832-14-2
- /47/ 060913 Local practice. Eq-bl.d system 252403 13/832-14-2
- /48/ 060913 Local practice. Kill system 252404 13/832-14-2
- /49/ 060913 Maximum pressure for bullheading 252405 13/832-14-2
- /50/ 060913 Sand production generally on OSF – information for the internal investigation team 252406 13/832-14-2
- /51/ 060913 Well status 252407 13/832-14-2
- /52/ 060913 Rates 252408 13/832-14-2
- /53/ 060913 Rates 12.6.2013 252409 13/832-14-2
- /54/ 060913 Startup 252410 13/832-14-2
- /55/ 12 B-41 – startup attempt after long shut-in 13/832-14-2
- /56/ Answers to questions from the PSA 120913 255141 13/832-18-2
- /57/ 120913 Well trend B-41 255142 13/832-18-3
- /58/ 120913 Well trend B-41 x 255143 13/832-18-4
- /59/ 120913 Plot 255144 13/832-18-5
- /60/ Startup criteria B-30 (and possibly B-41) after gas leak 120913 – information on task well B-30 and B-41 to the PSA 255145 13/832-18-6
- /61/ Log showing whether pressure blowdown valve 13-EV-804 has been open or closed 120913 - Log (open closed) pressure blowdown valve 13-EV-804 to the PSA 255146 13/832-18-7
- /62/ 120913 Bullheading of well to the PSA 13/832-18-8
- /63/ Information in connection with the investigation of emission on Oseberg A 17062013 255151 13/832-19-1
- /64/ Number of times the valve (13-EV-804) has been in the open position with simultaneous pressure on the test manifold 255152 13/832-19-2
- /65/ 200913 ISO drawings of the pressure blowdown line's connection to the test manifold 255153 13/832-19-3
- /66/ 200913 PID PZVs 13/832-19-4
- /67/ A DPN L2 2013-12 Investigation report – gas leak owing to erosion in pipe bend 13/832-20-1
- /68/ 141013 Handout PSA 2 October 13 Presentation gas leak OSF 17062013KBP-04 13/832-20-2
- /69/ 141013 Minutes from meeting 2 October 2013 13/832-3
- /70/ Follow-up of actions after meeting 2 October 2013 Oseberg – concerning emission incident Oseberg A 17 June 2013 13/832-21
- /71/ 20081209 Description of standardised operations model for UPN, case documents for UPN SU ver r 1.ppt
- /72/ *Statoil Book*, version 3.1, 2013
- /73/ E-mail from Statoil, 13 December 2013
- /74/ OMC01-004 - UPN operations – organisation, leadership and management, Rev 3.1
Revision date: 26 April 2013