PETROLEUMSTILSYNET

Investigation report

Report	
Report title **Revised report of the investigation of Neptune Energy's production drilling with stuck string and consequent blocked BOP on *Deepsea Yantai* on the Gjøa field**	Activity number 027153050 405008005

Security grading		
☑ Public	☐ Restricted	☐ Strictly confidential
☐ Not publicly available	☐ Confidential	

Involved	
Teams T-2 T-F	Approved by/date 28 May 2021
Members of the investigation team Roar Sognnes Øyvind Tuntland Vebjørn Nygaard	Investigation leader Eigil Sørensen

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List of abbreviations and terms

AoC	Acknowledgement of compliance
BOP	Blowout preventer
CCS	Continuous circulation system
DLS	Dogleg severity – change in well direction over a distance of 30 metres
DP	Drill pipe
ECD	Equivalent circulating density
ESD	Equivalent static density
Fish	Equipment lost downhole
HSE	Health, safety and the environment
HTO	Human, technology, organisation
LMRP	Lower marine riser package
LCM	Lost circulation material
mMD	Metres measured depth
MOC	Management of change
mTVD	Metres total vertical depth
NCS	Norwegian continental shelf
OWS	Odfjell Well Service
PSA	Petroleum Safety Authority Norway
Ram	Safety valve in the BOP
RSS	Rotary steerable systems
sg	Specific gravity: mud density expressed in kilograms per litre
Sub	Short component in the drillstring
TD	Total depth
TVDRT	True vertical depth from rotary table

1 Summary

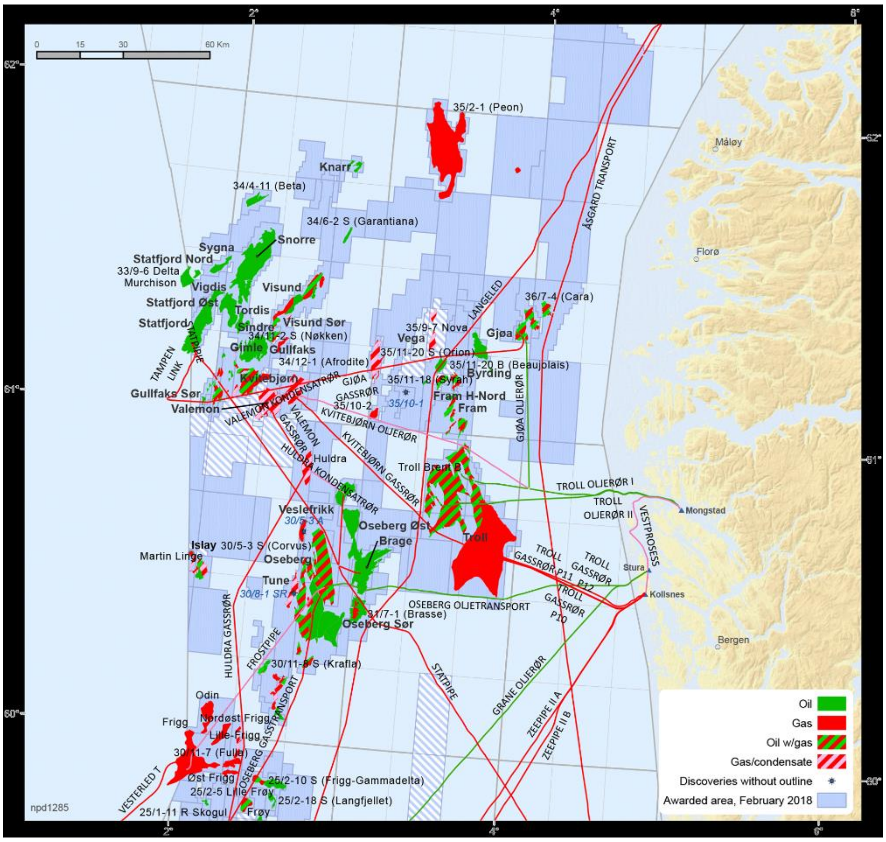

Figure 1 Map of the Gjøa area. Source: Norskpetroleum.no

Neptune Energy (Neptune) was drilling production well 35/9-G-4 H in the P1 segment of the Gjøa field with the *Deepsea Yantai* mobile drilling facility owned by Odfjell Drilling (Odfjell) on 2 September 2020 when the well incident occurred. At that time, the well had been drilled to total depth (TD) in the 12 ¼-inch section, a few metres into the top of the reservoir. The drillstring was being tripped out when it became stuck in the formation at a depth of 2 582 metres. Efforts to free the string caused it to part and a 150-metre section of drill pipe (DP) fell into the well alongside the remaining lower part of the string. This left two DP sections stuck through the blowout preventer (BOP) and blocking its safety valves. As a consequence, the function of primary and secondary barriers was unclear for a long time, until the well was secured through cementing 30 days after the incident occurred.

The Petroleum Safety Authority Norway decided to investigate the incident and a letter notifying Neptune and Odfjell of this was sent on 13 October 2020.

Four nonconformities were identified by the investigation.

2 Background information

2.1 Description of organisation and facility

2.1.1 Neptune

Neptune is a private and independent company involved in exploration for and production of oil and gas, with a regional focus on the North Sea, North Africa and Asia/Pacific. Established in 2015, its head office is in London, UK.

Interests are held by Neptune in seven producing fields on the Norwegian continental shelf (NCS), from Snøhvit in the Barents Sea to Gudrun in the southern part of Norway's North Sea sector. These include Gjøa, where Neptune is the operator.

About half the group's total production and reserves are in Norway. It ranks in production terms as the fifth largest producer on the NCS.

Discovered in 1989, Gjøa is an oil and gas field in the northern part of Norway's North Sea sector. Statoil was the development operator, but the production operatorship was transferred to Neptune when the field came on stream.

Remaining reserves in Gjøa were estimated at 297 million barrels of oil equivalent (mmboe) at 1 January 2021. Gas accounts for more than 65 per cent of total reserves.

To reduce the decline in Gjøa's output, several new development projects are under way to utilise its production capacity. The Gjøa P1 project involves an extension of the existing reservoir in the northern part of the field. Well 35/9-G-4 H is part of this development.

The Gjøa P1 project organisation for drilling, well and subsurface is presented in figure 2 below.

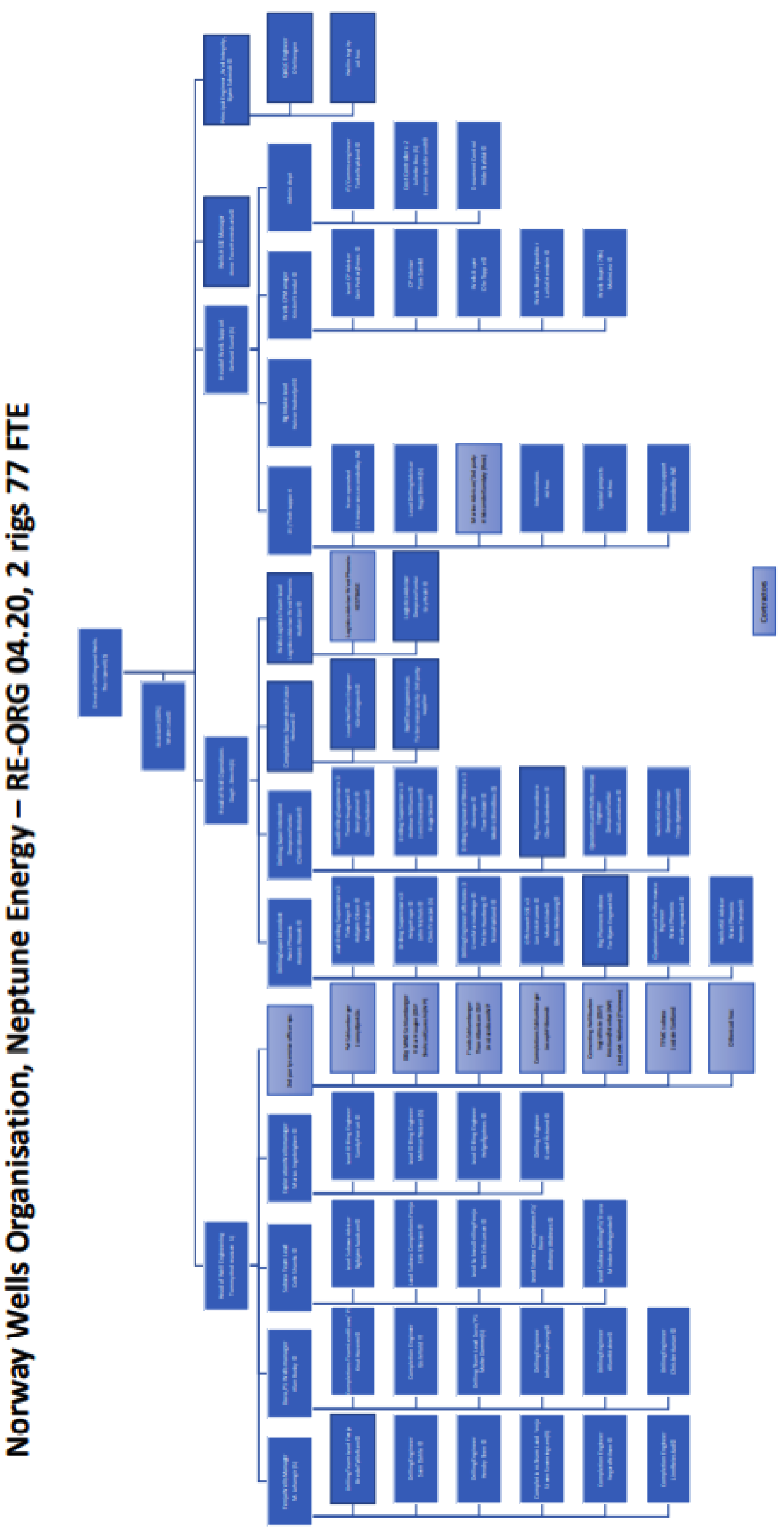

Figure 2 Chart of the Gjøa P1 project organisation for drilling, well and subsurface. Source: Neptune activity programme Gjøa P1 35/9-G-4 H.

2.1.2 Odfjell

Figure 3 Deepsea Yantai. *Source: odfjelldrilling.com.*

Odfjell is a Norwegian drilling contractor with its head office in Bergen, with *Deepsea Yantai* as one of the newest drilling facilities in its fleet of five such units. The company is also engaged in drilling on fixed facilities and provides services such as running casing through its Odfjell Well Service (OWS) department.

Deepsea Yantai is a sixth-generation GM4D type and Odfjell's first mobile facility to this design. It was built in 2014 at Yantai CIMC Raffles. The facility is designed to operate in water depths down to 1 200 metres.

Configured to maintain position with DP 3, it has a full mooring spread for operations in waters from 70 to 500 metres deep. Its cargo capacity is 4 000 tonnes under all operating conditions, and the facility is winterised for the Arctic environment.

A modern drilling system includes a 1 ½ derrick to permit a number of simultaneous operations. The drilling package incorporates a drawworks with built-in heave compensation.

An acknowledgement of compliance (AoC) for *Deepsea Yantai* was issued on 31 October 2019.

The facility began a drilling campaign for Neptune in October 2019.

2.2 Equipment involved

2.2.1 Continuous circulation system (CCS)

The industry utilises various CCSs involving different equipment and methods. Using such systems provides a steady dynamic downhole pressure with the drilling mud.

In traditional drilling, the string is composed of many individual lengths of DP. Every time a DP length is added to the string, the mud pumps must be shut down. That reduces pressure in the well by removing the dynamic pressure, leaving the remaining static weight of the mud column to maintain downhole pressure.

Maintaining a steady bottomhole pressure in a well is particularly important when drilling out downhole sections where narrow margins exist between loss of mud, influx from the formation or formation collapse. In this section of the well, narrow margins existed between loss of mud and formation collapse.

Schlumberger owns the CCS in use on *Deepsea Yantai*. Hired in via OWS and Odfjell, this was a newly developed solution which had been used once before outside Norway being adopted for the Gjøa well.

The system primarily comprised short circulation tubes with valves – known as CCS subs – as well as a CCS clamp on the drill floor which is closed over the subs in order to continue pumping mud whilst making up a new section of DP, and a CCS manifold connected to the standpipe manifold for access to the mud system.

Once incorporated between the DPs, the CCS subs became part of the string with the same external diameter as the DPs. Internally, the subs had a moveable sleeve which slid over openings in the DPs in order to open or close these, and an inner flapper valve to prevent mud backflow. The CCS subs had tool joints with 50 API NC threads, which were made up with a torque of 38 kNm.

Figure 4 A CCS sub installed in the string with the clamp for circulation ready for installation.

*Source: Odfjell Drilling/*Deepsea Yantai.

2.2.2 Drill pipe

The DP used was five-inch S-135 with NC-50 DSTJ tool joints made up to 62 kNm. Originally, the 12 ¼-inch section was due to be drilled with a 5 7/8-inch string. However, this was changed when the decision was taken to use the CCS.

2.2.3 Blowout preventer (BOP)

The BOP was an NOV Shaffer NXT, Class 7, 15K, with two annular preventers and five rams. One of the latter was 5 7/8 inches fixed.

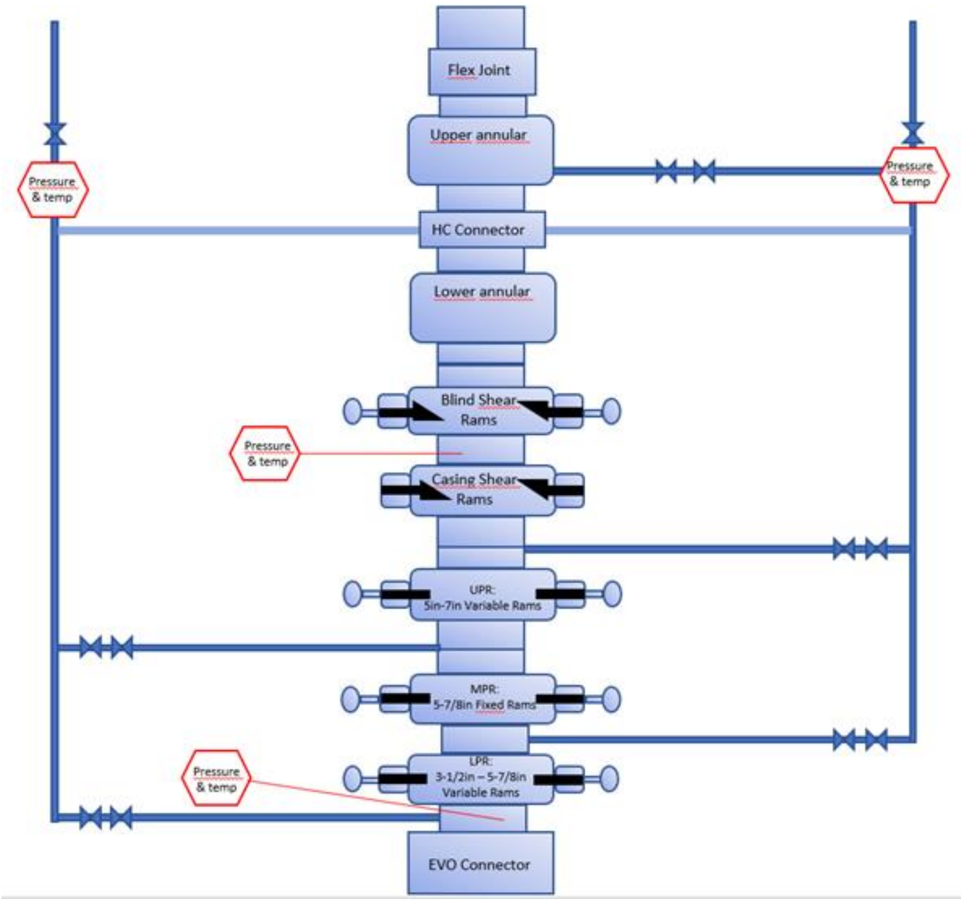

Figure 5 BOP configuration. Source: BOP configuration risk analysis- Deepsea Yantai.

2.3 Position before the incident

Well 35/9-G-4 H was planned as the first oil producer in developing the P1 segment of Gjøa in production licence 153. See the map in figure 6. Segments P2, P3 and P4 on the southern part of the field, in production licence 153B, had previously been drilled and completed for production in 2009-12.

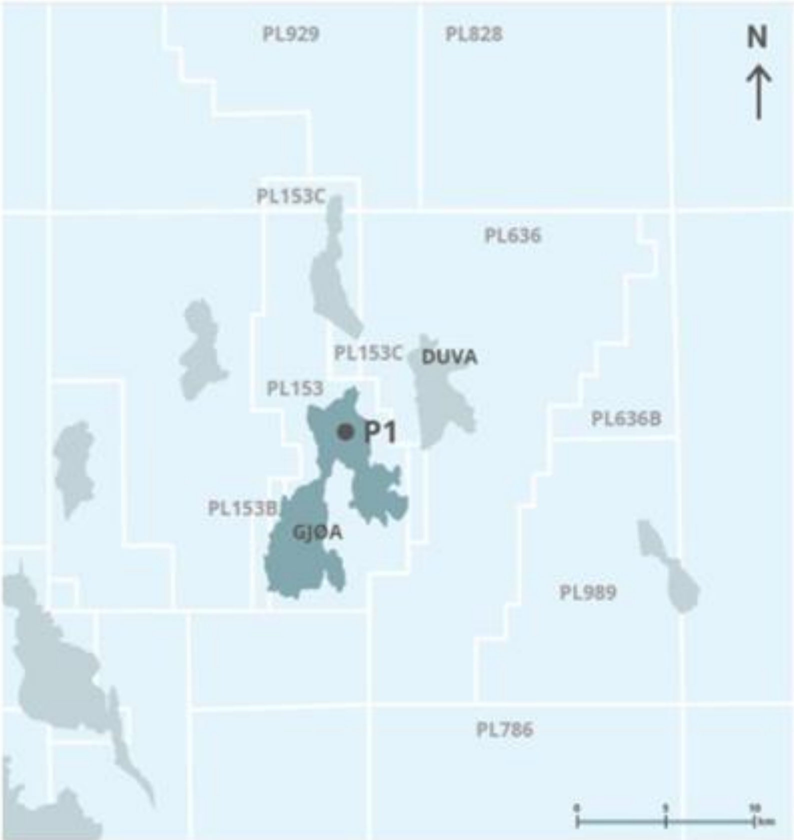

Figure 6 Gjøa P1 location map. Source: Neptune – activity programme Gjøa P1 35/9-G-4 H.

Two appraisal wells had been drilled during the spring and summer of 2020 in the relevant P1 segment of Gjøa with *Deepsea Yantai*. Substantial challenges had been experienced, with drilling problems related to formations above the reservoir. These problems prompted a desire to make changes to drilling plans for the G-4 well.

After G-4 had been spudded in mid-August 2020, progress was largely as planned until the first drilling problems arose in the 12 ¼-inch section on 5 September 2020 with a big loss of mud.

It had been necessary to wait on weather briefly in early September, but conditions were thereafter favourable for many weeks. Operational weather conditions appear to have been good in the area until November (source: www. Yr.no).

2.3.1 Well planning and design

2.3.1.1 Concept select report

The Gjøa P1 concept select report for developing the P1 structure on Gjøa was signed and approved by Neptune in July 2018.

According to this document, the overall strategy for P1 well design was that Gjøa P1 wells would feature simple, reliable, robust and well-proven solutions. These would build on experience, lessons learnt and established standards from existing Gjøa wells. See the D&W report for gate 1 and the Gjøa main drilling and completion programme.

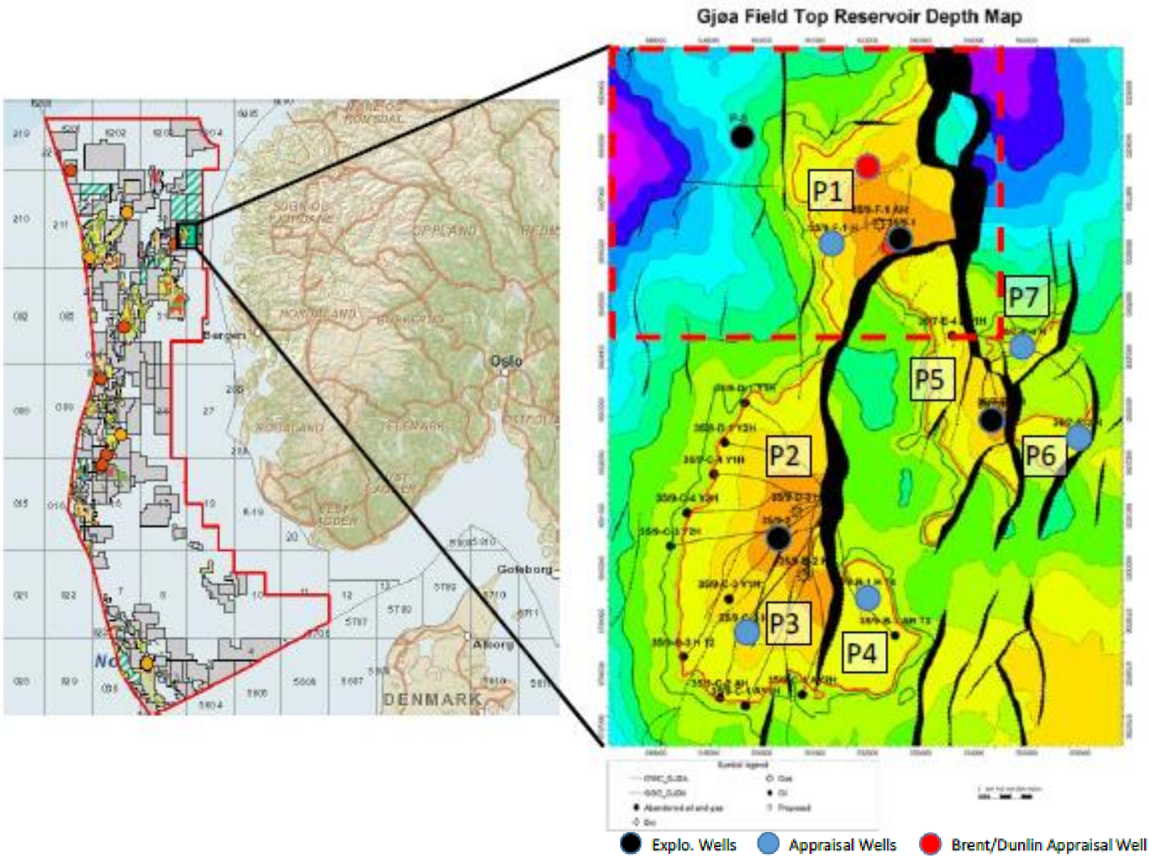

Figure 7 Location of Gjøa and its P1 segment. Source: Neptune – Gjøa P1 concept select report, rev 2.

The following guidance for well design was provided in the concept select report:

- 13 3/8-inch casing would be set above the weak zone in the Kyrre formation at the 1 800-2 000 mTVDRT interval
    - casing and casing shoe should cope with gas-lift and reservoir pressure
- 9 5/8-inch x 10 ¾-inch production liner would be set at the top of the Fensfjord reservoir at 2 120 mTVDRT
- 9 5/8-inch x 10 ¾-inch production liner cement would not go right up to the 13 3/8-inch casing shoe in order to avoid an enclosed B annular volume between the 9 5/8-inch x 10 ¾-inch production casing and the 13 3/8-inch casing
- the well's B annulus was to be monitored.

Furthermore, it was specified that the recommended practice for the well path's angle in the overburden was a maximum inclination of 55°.

Unstable formations were flagged as a geological risk in the 12 ¼-inch section, with such consequences as well collapse, stuck string and technical sidetracking.

Recommended measures were to drill with adequate mud weight and to use best-practice drilling procedures.

The following well and well-related risks were identified as the most important for concept selection:

- monitoring/bleeding off from the B annulus
- drilling in depleted reservoir
- long reservoir sections in oil production wells.

Furthermore, the report emphasised the risk of developing a project culture where changes were made without a formal management of change (MOC) process, with such consequences as HSE incidents, delays and/or increased costs.

2.3.1.2 Drilling programme

The first operational phase in developing the Gjøa P1 structure was carried out in the spring and summer of 2020 with the drilling of appraisal wells 35/9-15 S/15 A and 35/9-15 BT2. Experience from these and other nearby wells played a key role in the detailed planning of the G-4 H well.

Approval of the drilling programme for the well was given in early July 2020. This was complemented by the subsequent hole section guidelines and mud weight selection report, which were signed later the same month.

The G-4 H well was planned with a standard four-string casing design to the top of the reservoir. A reservoir section was also to be drilled. See the well design drawing in figure 8. Plans called for the well to be completed with 6 5/8-inch sandscreens installed in the open hole in the 8 ½-inch reservoir section.

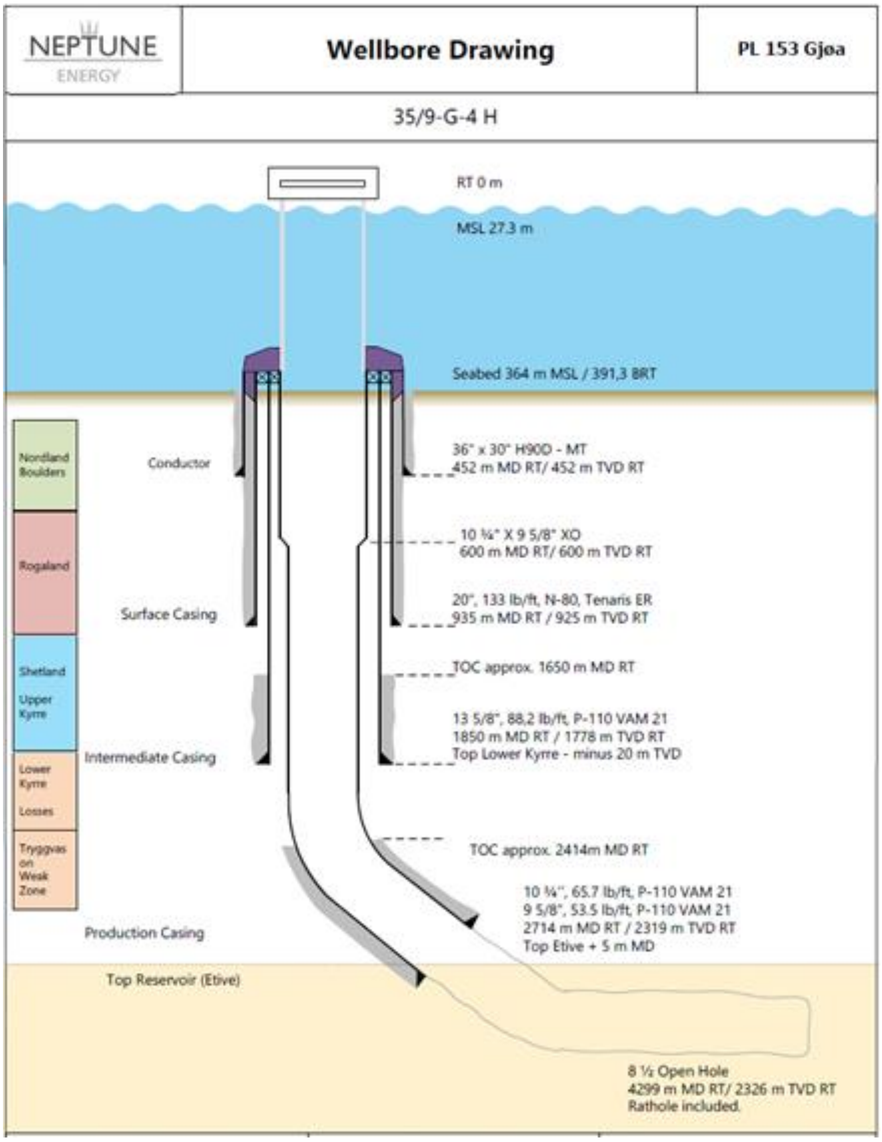

Figure 8 . Wellbore drawing. Source: Neptune Energy – hole section guidelines Gjøa P1 35/9-G-4 H.

As the well diagram shows, the following sections and setting depths were planned for casing down to the top of the reservoir:

- 36-inch section and 30-inch conductor casing to 452 mTVD/452 mMD
- 26-inch section and 20-inch casing to 925 mTVD/935 mMD
- 17 ½-inch section and 13 3/8-inch x 13 5/8-inch casing to 1 850 mTVD/1 878 mMD
- 12 ¼-inch section and 9 5/8-inch x 10 ¾-inch production liner to 2 319 mTVD/2 714 mMD.

Plans called for the 13 3/8-inch x 13 5/8-inch casing to be installed at the top of the lower Kyrre formation, where it was to be cemented with a gas-tight cement to 200 metres above the casing shoe.

It was planned to drill a 12 ¼-inch section of about 860 metres with 5 7/8-inch DP from 1 858 mMD to five metres into the top of the reservoir at a total depth (TD) of 2 714 mMD. Forecasts indicated a zone of +/- 450 metres with a weak formation in the upper part of the section and another of +/- 60 metres just above the reservoir with substantial collapse pressure.

Maximum pore pressure for the section was predicted to be 1.03 sg, a minimum fracturing pressure of 1.27 sg was expected in the weak-formation zone and a maximum formation collapse pressure of 1.24 sg was anticipated in the zone just above the top of the reservoir.

Schlumberger's around-the-clock 3D geomechanical real-time service was to be used during drilling to optimise estimates for pore, collapse and fracturing pressures.

The section was to be drilled with a standard rotary steerable system (RSS), and initially with an oil-based mud of 1.12 sg equivalent static density (ESD) which would be increased to 1.15 sg ESD before drilling the formation with higher collapse pressure. Well-path inclination was to be built from 20° to 81°, with a maximum 3.0° dogleg severity (DLS).

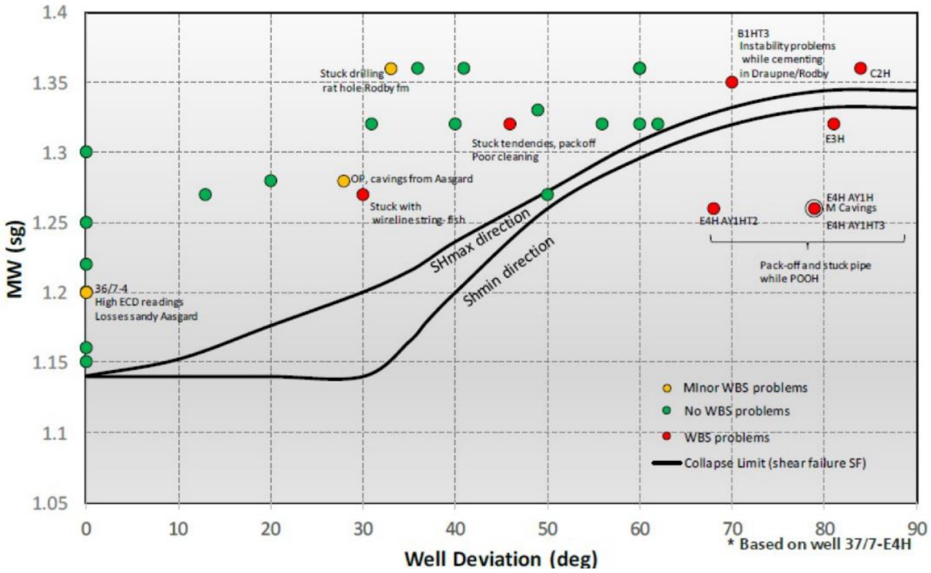

Figure 9 Åsgard inclination versus MW offset experience plot. Source: Neptune Energy – activity programme Gjøa P1 35/9-G-4 H.

Two of the main risks identified for drilling the section were loss of mud in the weak zone and formation collapse with a subsequent stuck string in the zone immediately above the reservoir.

Measures planned to reduce the risk of loss were:

- LCM in the mud before drilling into the weak zone
- limit ECD during drilling to a maximum of 1.21 sg.

Measures planned to reduce the risk of formation collapse were:

- accept maximum five per cent formation collapse, estimated at 1.135 sg ESD
- drill section of higher collapse pressure with a minimum of 1.15 sg ESD.

2.3.2 Contingency plans

Should the challenges posed by loss or formation collapse become substantial, a contingency plan was to set the TD shallow, but below the weak zone. The 12 ¼-inch section would thereafter be opened to 14 inches for setting a 10 ¾-inch production liner. The plan was consequently to drill a 9 5/8-inch x 12 ¼-inch hole section from the 10 ¾-inch shoe to a TD of five metres into the top of the reservoir, and then install an 8 5/8-inch expanding liner.

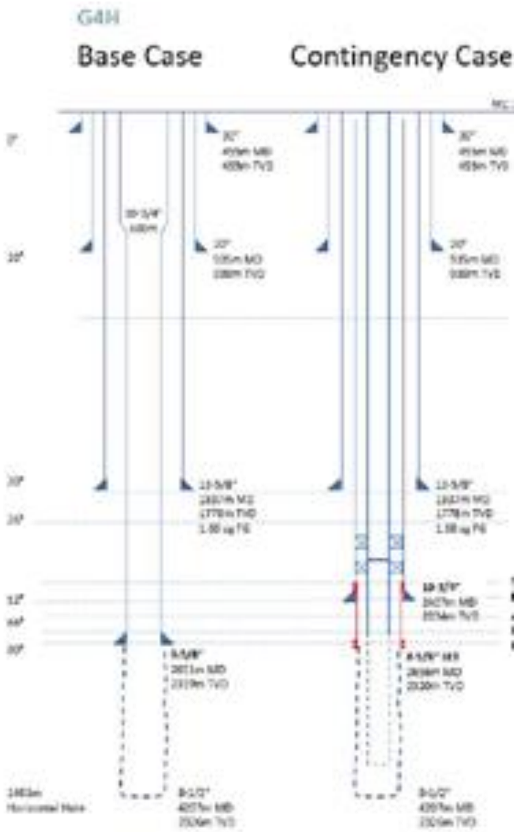

Figure 10 Alternative casing design. Source: Neptune Energy – activity programme Gjøa P1 35/9-G-4 H.

Another option was to use Schlumberger's CCS, if it became available through Odfjell, for drilling the final 300-400 metres to TD. This was a measure to reduce the risk of formation collapse.

It was later decided to adopt the CCS.

The day before the incident, the crew had experienced a big loss of mud in the 12 ¼-inch section and carried out three cement jobs to strengthen the well. Great attention was devoted to avoiding a new mud loss, and a constant ECD could be maintained by using the CCS when connecting new DPs.

Fourteen days before the incident, five-inch DPs with CCS subs were made up and placed ready in the derrick. The CCS subs had tool joints with 50 API NC threads which were made up with a torque of 38 kNm. This introduced a weaker link in the upper part of the drillstring, which otherwise consisted of five-inch DPs featuring NC-50 DSTJ tool joints with a torque of 62 kNm.

The whiteboard in the driller's control room which provides an overview of the capacity of the string's components was not updated with the weaker tool joints on the CCS subs.

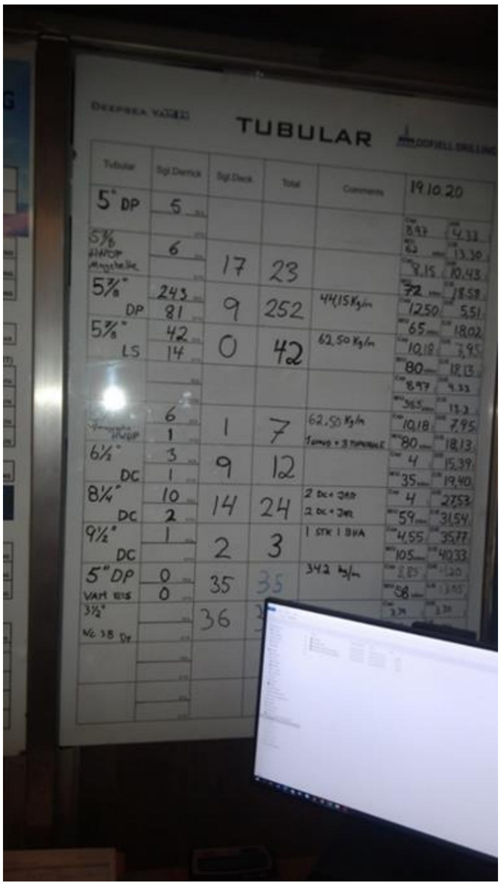

Figure 11: Whiteboard in the driller's control room which provides an overview of the capacity of the string's components. Source: Neptune Energy.

3 The PSA's investigation

Investigation team:
Eigil Sørensen, drilling and well (investigation leader)
Roar Sognnes, drilling and well
Øyvind Tuntland, drilling and well
Vebjørn Nygaard, drilling and well (onshore part)

The Petroleum Safety Authority Norway (PSA) decided to investigate the incident and a letter announcing this was sent to both companies (Neptune og Odfjell) on 13 October 2020. It was decided to wait until normalisation work had been completed and until the crew involved had returned after their time ashore before initiating the investigation with a visit to the facility.

Relevant documents were received before departure to *Deepsea Yantai*. Three members of the PSA team went offshore from 23-26 October 2020 and conducted interviews with relevant personnel as well as inspecting the drilling area. Some photographic material was also assembled.

Further interviews with onshore personnel were conducted from 2-27 November. The Covid 19 position called for customisation, and Neptune organised interviews with onshore personnel using suitable premises in the Quality Hotel Pond at Forus.

4 Course of events and normalisation

4.1 Course of events

Deepsea Yantai arrived at the relevant well location on Gjøa in mid-August and spudded well 35/9-G-4 H on 16 August 2020. The first three sections were drilled without significant problems.

Soon after drilling out of the 13 5/8-inch casing shoe at 1 848 mMD and roughly 250 metres into the new formation, a substantial mud loss occurred in the well on 5 September 2020. A weak zone had been anticipated, and compensating measures were initiated with several rounds of mixing and pumping LCM. Drilling continued, but the mud loss persisted at up to 50 cubic metres per hour. After verification of weak formation strength, it was decided to cement the weak section in order to fill fractures in the area around the hole wall and improve formation strength.

The cement was then drilled out of the well and drilling continued. New problems with big mud loss arose, and it was decided to do another cementing operation in the hole. The cement was once again drilled out, with the loss significantly reduced. Nevertheless, the formation strength achieved was unsatisfactory and a third cementing operation was conducted before continuing to drill towards the 12 ¼-inch section's TD at 2 670 metres MD.

Since zones with a higher collapse pressure were expected in the section's lower formations, the drilling window would be limited. See figure 9. Drilling operations were therefore halted and the hole circulated several times during drilling of the final metres of the section.

CCS was adopted before drilling into the zone with high collapse pressure.

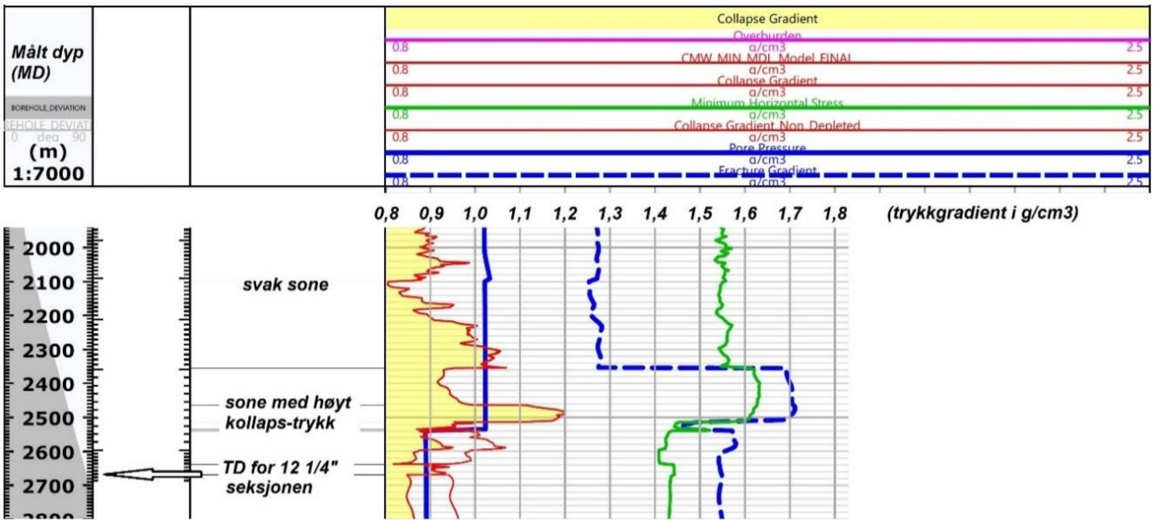

Figure 12 Edited figure showing in part the pore and collapse pressures in the relevant part of the well. Source: Neptune Energy – activity programme Gjøa P1 35/9-G-4 H.

The section's TD at 2 670 metres was reached at 19.00 on 19 September 2020, when the hole then had an inclination of about 77°. Here, the hole was again circulated clean while the guidelines for the 12 ¼-inch section specified that the mud weight was to be increased to a minimum of 1.15 sg in order to avoid a hole collapse of more than five per cent. That would compensate for ceasing to pump while tripping out the string and therefore failing to obtain the extra bottomhole pressure created by the CCS during drilling. Mud weight was increased from 1.10 sg to 1.11 sg before starting to trip out the string with the assistance of slight lubrication.

It soon became clear that the string was being held back to some extent by the formations or by accumulated cuttings. After tripping out 88 metres of the string, it was no longer possible to continue. The decision was taken to go in towards the bottom again while pumping and trying to reduce the downhole problems. However, similar problems were encountered in trying to get down towards the bottom.

Efforts were made during the night to move the string and pump mud in an attempt to improve the downhole position. It proved possible to achieve some circulation for periods, and the mud weight was increased to 1.13 sg. However, the downhole problems persisted and it was difficult to attain good continuous circulation. Great rotation resistance was also encountered at times.

The downhole problems worsened on the morning of 20 September 2020 and the string appeared to be more or less stuck, while circulation opportunities were variable. At times, the well was more or less packed off. At about 08.30, it was decided to increase the rotational torque in the string a step at a time in order to get it free and out of the hole. At 09.05, it suddenly became clear that the string had parted. When the free section of the string had been pulled to the drill floor, the parting was found to have occurred only 35 metres below the drill floor. One of the CCS pipe tool joints had spun/twisted off.

Efforts to locate the end which remained in the hole found that it was not at the expected depth. The top of the string remaining the well proved to be at 187 metres. It was then suspected that the string had parted at several points and that one or more of its sections had dropped towards and into the BOP. An assessment of geometries in the BOP, wellhead and the upper part of the casing established that it was very likely that two or more DP sections were stuck in the BOP. It eventually became clear that at least one of the tool joints which had parted further down the string had spun/twisted off between DPs in addition to the uppermost parting from a CCS sub tool joint.

At that time, the barrier position in the well was unclear. It was assumed that the mud in the well provided a satisfactory overbalance as the primary barrier, but this could not longer be confirmed.

Opportunities for activating the BOP rams to secure the well with the secondary barrier were unclear. With two or more DPs through the BOP, neither the pipe rams nor the annular preventers could tighten around the string. It was also unclear whether the shear rams could cut and seal if two or more DPs were stuck in the BOP.

The well would be open to the seabed through the BOP, but with only one – unverifiable – primary barrier if the weather was to worsen and require disconnection of the lower marine riser package (LMRP).

4.2 Normalisation after the incident

The incident occurred on 20 September 2020 and operation was back under a new plan on 20 October 2020, when the last cement plug was set up to and inside the 13 5/8-inch casing and the well had been secured.

Confusion prevailed after the incident. The barrier position was unclear, with at least one further section of five-inch DP through the BOP – a "fish", or equipment which has dropped or loosened in the well. The well was partly open down to the reservoir.

Since a 35-metre section had been pulled out after the string parted, and the top of fish number one was at 187 metres, the remaining DP section (fish number two) dropped into the well had to be 153 metres long or further parted into several more sections. It was assumed that the DP sections which fell inside the riser would have stopped on top of the wellhead/13 5/8-inch casing at 385 metres. The top of fish number two was also found at 277 metres under the drill floor. This should indicate that a minimum of three fish were standing in the riser and through the BOP.

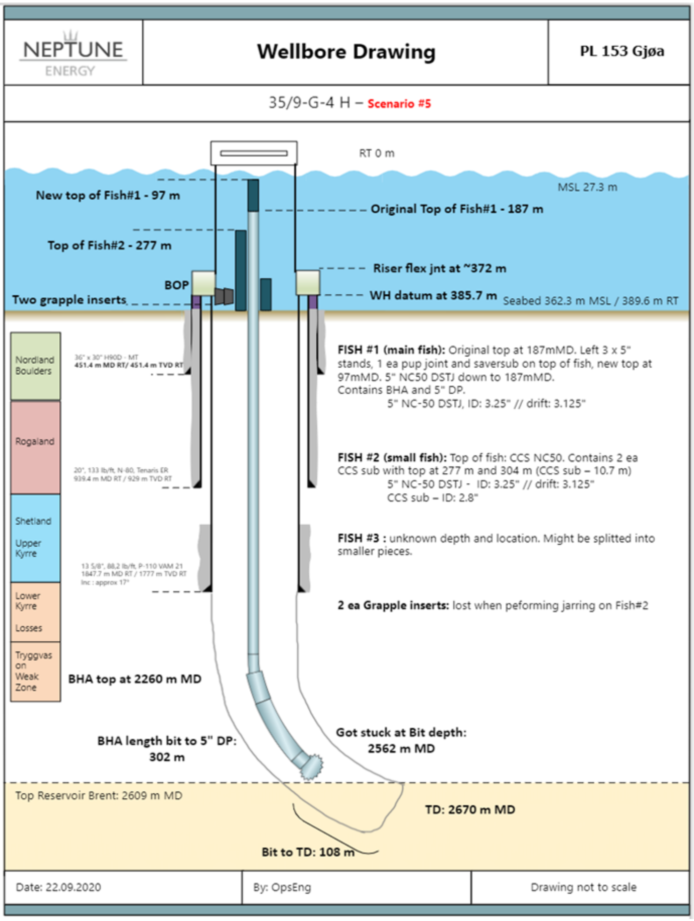

Figure 13: Well status 22 September 2020, where the perception was that the second dish stopped on top of the wellhead. This meant that three fish were assumed to exist. Source: Neptune Energy.

With this understanding of the position, a successful shearing test was conducted in Houston by NOV with three DPs in a similar shear ram on 25 September 2020.

At the same time, uncertainty prevailed over the primary barrier and whether pack-off existed to the reservoir. Neptune had an overshot made with additional packing in order to be able to connect to fish number one and maintain integrity when running wireline and when pumping down the string through fish number one.

A wireline operation was used to perforate the string above the point where it was stuck down the well, and then cementing out into the annulus and up the 12 ¼-inch hole right to the 13 5/8-inch casing. That would substantially reduce the risk of a blowout, and was therefore done during normalisation. After 30 days, the well had been plugged up to the 13 5/8-inch casing.

Full barrier testing of the cement plugs was not possible, but they were pressure-tested to the extent possible. The tests which could be conducted gave satisfactory results, and a planned disconnection of the BOP was carried out at a later point in the operations on the well.

An ultrasonic tool was run on 4 October 2020 and confirmed two fish.

The second fish was pulled to the surface on 6 October 2020. It had landed inside the 13 3/8-inch casing and driven with great force down past five tool joints on fish number one. With each tool joint passed by the lowest joint on fish number two, the 13 5/8-inch casing was expanded and rolled to an oval shape. The second fish was found to have driven 45 metres below the wellhead, into the 13 5/8-inch casing.

A five-inch DP has tool joints with an external diameter of about 16.5 centimetres (two sets of joints are about 33 centimetres), while the internal diameter of a 13 5/8-inch casing is about 31.5 centimetres. See figure 14, which shows a deformed casing rolled out.

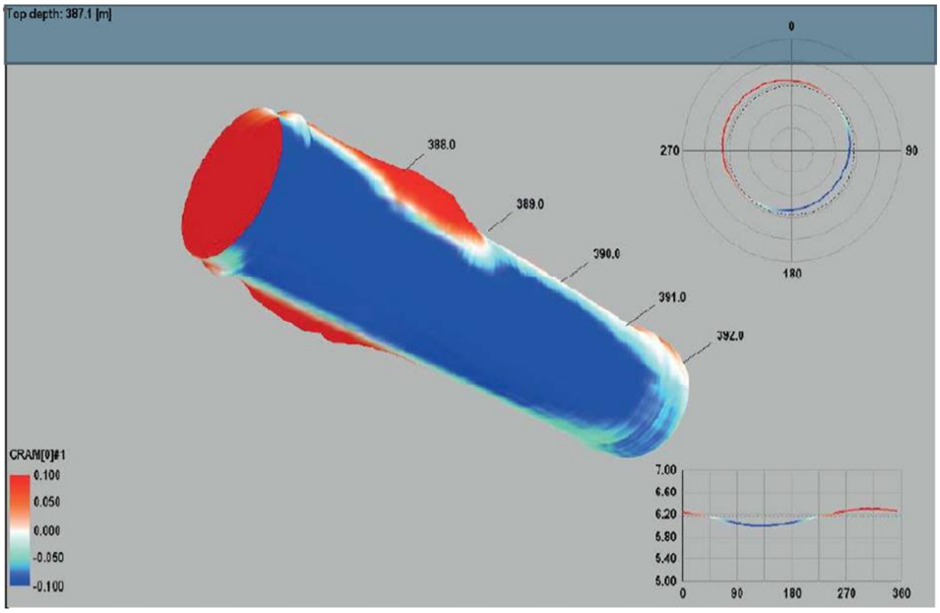

Figure 14 3-D wellcad over the 387-392 metre interval showing casing deformation. Source: Neptune Energy.

During the normalisation period, 22 trips were run in the hole with fishing equipment and 18 for wireline operations.

After normalisation of the incident, the 13 5/8-inch casing was pulled out before drilling a sidetrack from the well below the 20-inch casing.

*Figure 15 The lowest tool joint on fish number two, which dropped in below the wellhead. Shows marks of having passed tool joints on the way down past fish number one. Source: Odfjell Drilling/*Deepsea Yantai.

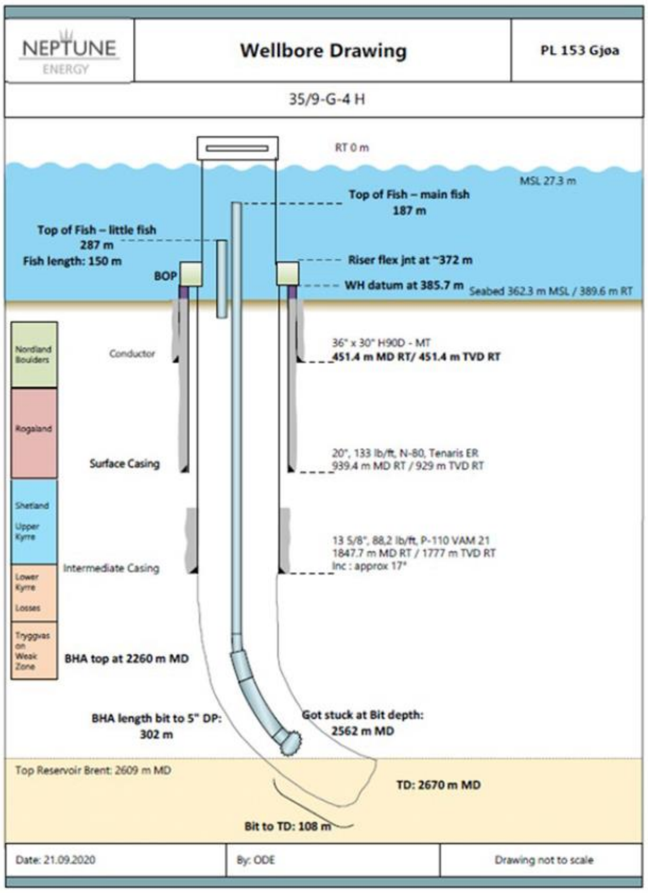

Figure 16 Diagram of fish through the BOP. Source : Neptune Energy.

5 Potential of the incident

5.1 Actual consequences

The mud column from the bottom of the well up to the facility (the primary barrier) had an overbalance with a limited margin when the incident occurred. After the string had parted, it was nevertheless no longer possible to maintain and verify the condition of the primary barrier through circulation and measuring mud density.

After the string parted and one or more DP sections (fish number two) dropped into the BOP (secondary barrier) alongside a DP section which remained from the bottom up through the BOP (fish number one), it was uncertain whether any of the BOP rams could shut the well. Whether the two shear rams could cut and possibly seal was unclear, and the rams and annular preventers could not be relied on to seal around two or more DP sections through the BOP.

The well appeared to be stable, but its barrier status could not be confirmed for a long time after the incident. Normalisation operations concentrated on clarifying and re-establishing barriers. Weather conditions were favourable, so that these operations could be executed as they were planned.

Normalisation and the changes to plans following the incident meant a substantial loss of time and to some extent postponed production. Costs related to the incident were estimated at several hundred million kroner and involved more than 30 days of lost progress.

5.2 Potential consequences

The section of the string, fish number two, which parted out and dropped alongside the string stuck in the hole, incorporated several CCS subs. In different circumstances, one of these subs could have ended up on a level with a shear ram and prevented cutting of the string.

In weather conditions with high waves, it might have been necessary to disconnect the riser from the BOP to avoid damage to the riser system and facility. The well could have been standing open to the sea through the BOP. The actual disconnection could have been a challenging operation, since it might not have been possible to cut the DPs standing in the BOP. It would subsequently have been necessary to use remotely-operated vehicles with equipment for cutting and cleaning DPs from the top of the BOP before being able to reconnect the riser and LMRP to the well. This could have been a lengthy operation. However, weather conditions were favourable for several weeks after the incident, so that disconnection was not needed during the incident and the well had been further secured by cementing.

Had the incident been long-lasting, the properties of the static mud in the well might have changed. Were hydrocarbons to rise in an open well, the primary barrier might no longer have provided an overbalance.

The established procedure for work in the red zone had the potential to cause personal injuries in the event of leaks in the CCS subs. According to the procedure, roughnecks were to close a possible leak in a CCS sub using sledgehammers. That increased the risk of personal injury, since personnel might be forced to work on a pressurised system in the drill floor's red zone.

6 Direct and underlying causes

6.1 Direct causes

6.1.1 Mud weight lower than the formation's estimated collapse pressure

Mud weight was not increased sufficiently to prevent formation collapse before disconnecting the CCS when tripping out the string. It emerged from geological forecasts and the latest plans for drilling the 12 ¼-inch section that a mud weight higher than the one in the hole should have been circulated in when starting to trip out the string after reaching the section's TD.

It emerged from interviews on the facility and from operational personnel on land that misunderstanding had occurred over the scope of the mud-weight increase required before tripping out.

Several versions of the detailed operational procedure (DOP) for the 12 ¼-inch section were drawn up because various problems arose along the way. The first was lost circulation, with subsequent setting of cement plugs and cementing to seal and strengthen the formation. Then came the need to correct the hole direction before the final DOP was prepared only days before reaching the section's TD. The operational plans described the risk of hole collapse in the lower part of the section, in line with the concept select report of 24 July 2018, the activity programme for the well of 1 July 2020 and the DOP, based on the hole section guidelines – Gjøa P1 35/9 – G-4 H – 12 ¼-inch. This risk was described as requiring a minimum mud weight of 1.15 sg. Using that weight already created a risk of a five per cent hole collapse, without mechanisms being described for how hole collapse was envisaged being limited to five per cent. The specified mud weight was achieved during drilling though the use of the CCS, but this system was disconnected before tripping out at TD. The mud weight should have increased to at least 1.15 sg as described in the guidelines for the 12 ¼-inch section.

In reality, significantly greater attention was paid to avoiding loss in the higher formations than to maintaining sufficient mud weight to avoid hole collapse in the lower parts of the section. This emerged from interviews as a clear reason why the purpose of using the CCS during drilling appeared to have been forgotten to some extent, and why the mud weight was not increased to the value described in the drilling programme and guidelines for the hole section. Several interviewees also asserted that misunderstandings prevailed over the specific requirements for mud weight before tripping out the string at TD.

6.1.2 Drillstring above BOP composed of joints with varying torque

The string parted and sections of it dropped to prevent closure of BOP rams and opportunities to maintain mud as the primary barrier.

It is highly likely that the string's composition, with joints high up its length tightened to different torques, contributed to its parting at several points and thereby to creating more than one fish in the hole. The result was that the functional ability of the secondary barrier (BOP) to shut the well became unclear.

The use of weaker joints high up the string followed from the introduction of the CCS. These weak joints were not noted on the driller's overview whiteboard or in the CCS procedure. This was limited to drilling with the CCS after the string was made up and installed in the derrick.

6.1.3 Torque on joints was exceeded

Efforts were made to free the struck string by increasing its rotational torque beyond the level the joints were made up to and intended for. The string parted on 20 September 2020 during a stepped increase in rotational torque to the maximum level the DPs were tightened to. The lower torque used for the CCS subs was forgotten during this operation, since it was not noted on the driller's whiteboard.

6.2 Underlying causes

6.2.1 Experience transfer from earlier wells on Gjøa

Experience from drilling the same formations in several earlier wells on Gjøa is described in an overall manner in a concept select report of 24 July 2018 as part of preparations for producing the drilling programme for the G-4 well, among other activities. The incident shows that key risks identified in that report were not adequately taken into account in planning the well design The risk assessments and assumptions which underpinned the chosen casing programme and the resulting drilling window in the 12 ¼-inch segment failed to deal with the various challenges experienced during earlier drilling operations in the same formations.

The chosen well design provided a very narrow drilling window between the expected collapse pressure in the deeper formations and possible loss zones higher up the same section. Introducing the CCS during the summer was an attempt to compensate to some extent for the narrow window. The contingency plan in the well design, with an expanding liner to seal the weak zone from possible collapse zones deeper in the same section, was probably not as ready to be mobilised as the plan appeared to suggest. Operational criteria for initiating this plan also seemed unclear.

Few of those with key roles in the drilling operation had experience from the wells drilled earlier on Gjøa in 2009-12. The concept select report of 24 July 2018 identified the threat of collapse in the hole section as one of the main risks. This was covered in both the G-4 well programme and the hole section guidelines – Gjøa P1 35/9 - G-4 H - 12 ¼-inch, and included in the detailed operational plans for the section. Nevertheless, it was not given a prominent place in the description of the planned operational stages for this part of the well. On the contrary, there were constant descriptions and reminders of the upper limits for mud weight to avoid loss in the higher zones. Specific descriptions of the minimum mud-weight requirements to avoid hole collapse in connection with disconnecting the CCS and tripping out at TD were not clearly presented in the final operational procedures. It emerged from interviews that decisions taken in operational meetings just before tripping out on the requirements for increasing mud weight appear to have been misunderstood.

6.2.2 Well design

Several of the production wells drilled in other parts of Gjøa during 2009-11 experienced problems very similar to the downhole condition in the G-4 well before the string parted on 20 September 2020.

Issues related to a narrow drilling window between a loss zone requiring a low mud weight as opposed to deeper formations with a collapse pressure which required a higher mud weight emerge from drilling reports on earlier Gjøa wells. The PSA team understood that this was also experienced to some extent in the P1 well drilled in the same area in the spring of 2020.

The design for the G-4 well revealed a low level of learning compared with designs for earlier wells on Gjøa.

6.2.3 Pressure of time

The problems experienced with the P1 appraisal well arose at the same time as planning for the G-4 well was in its final stages, with little time to make a necessary reassessment of the G-4 plans. Pre-ordered equipment and services set clear restrictions on possible changes to the G-4 well design. A contingency plan was produced in case the problems in the expected weak zone could not be resolved to provide a sufficient drilling window to reach TD in the 12 ¼-inch section. Nevertheless, genuine opportunities to implement the contingency plan appeared to be limited. Activating this solution was discussed, and criteria for execution were set. Given the planned operational measures, cement jobs and the CCS, the assessment was that the contingency solution would not be required.

7 Observations

The PSA's observations fall generally into two categories.

- Nonconformities: this category embraces observations where the PSA has identified breaches of the regulations.
- Improvement points: these relate to observations where deficiencies are seen, but insufficient information is available to establish a breach of the regulations.

7.1 Nonconformities

7.1.1 Insufficient use of change management (Neptune)

Nonconformity

Insufficient action was taken to ensure that the management of change (MOC) procedure was applied in order to fulfil its intended function, and so that issues related to HSE were comprehensively and adequately identified.

Grounds

- It emerged from the document review and interviews that drilling challenges in the appraisal wells for the P1 segment prompted amendments to the G-4 well programme which were not subject to an MOC process.
- Use of the CCS was decided without initiating an MOC process with associated risk assessment of the restrictions this imposed.
    - The consequences of weak joints high up the string were not risk-assessed.
    - The consequences of a possible stuck string when using the CCS were not risk-assessed.
- No MOC process was implemented when changing the mud weight from the G-4 well programme for the lower part of the 12 ¼-inch section.

Requirements

Section 24, paragraph 2 of the activities regulations on procedures

Section 11, paragraph 1 of the management regulations on the basis for making decisions and decision criteria

7.1.2 Lack of robustness in well planning (Neptune)

Nonconformity

Solutions chosen in planning the well had insufficient effect on reducing risk, and insufficient risk analyses were conducted to provide a decision basis for determining operational conditions and limitations.

Grounds

- The well was planned with a marginal drilling operation window. It emerged from the investigation that this window became narrower than stipulated in the original plan without these limitations prompting significant operational adjustments, such as implementing an alternative casing design.
- It emerged from interviews that implementing an alternative casing design with an expanding 8 5/8-inch liner would be demanding and fairly unrealistic because of the Covid-19 position. No risk assessment related to these conditions was conducted.
- It emerged from interviews and detailed procedures that the risk of mud loss was given priority over the threat of formation collapse. The latter was not taken sufficiently into account in the well planning.
- Experience from earlier wells – see figure 9 – shows that the chosen mud weight could not be considered sufficient to avert wellbore collapse.
- Experience from earlier well designs concerning the choice of depth for setting casing was not taken sufficiently into account.

Requirements

Section 4, paragraph 1 of the management regulations on risk reduction
Section 17, paragraph 4, litera f of the management regulations on risk analyses and emergency preparedness assessments

7.1.3 Inadequate processes for experience transfer (Neptune and Odfjell)

Nonconformity

Information acquired was not processed and communicated to the relevant users at the right time.

Grounds

- Adequate communication of field-specific information was not ensured when operationalising the well plans. The operator had few personnel in its drilling organisation with experience of similar drilling challenges on Gjøa.
- It emerged from interviews that substantial challenges in the previous well meant limited time was available for processing experiences from that operation and transferring them to detailed plans for the G-4 well.
- The make-up torque for the CCS subs was not processed and included in the operational procedure or entered on the driller's whiteboard which showed string capacities and limitations.

Requirement

Section 15, paragraph 2 of the management regulations on information

7.1.4 CCS not qualified in accordance with applicable requirements (Neptune and Odfjell)

Nonconformity
New technology was adopted without the criteria for its use being developed sufficiently to HSE meet requirements.

Grounds

- The CCS added several weak links high up the string, which were not adequately assessed.
- Information on torque for the CCS subs was not included in operational procedures.
- The CCS created a need for more red-zone work on the drill floor, which was not adequately assessed.
    - Hitting the sub carefully with a sledgehammer until its valve closes was prescribed, for example, for dealing with a leak in a CCS sub. “It is important not to stand in front of the valve opening when hitting with the sledgehammer”. See the procedure *Rig-up CCS & operation of CCS* (L4-MODU-DSY-B-WI-378N).
- Little assessment was made of the risk of using the CCS in relation to hole problems such as stuck string.

Requirement
Section 9 of the facilities regulations on qualification and use of new technology and new methods, see section 89 of the activities regulations on remote operation of pipes and work strings.

7.2 Improvement points

No improvement points were identified by the investigation.

8 Barriers which have functioned

When the incident occurred, it became clear that the primary barrier (mud) was no longer verifiable and the secondary barrier (BOP) was affected by the DPs (fishes) stuck through it, which might prevent it from functioning.

Work was immediately initiated to clarify the weakening of the barriers. Neptune ordered a new cutting test for DPs to verify that the shear rams in the type of BOP used on *Deepsea Yantai* could still cut with several DPs through the BOP. After three days, the BOP supplier confirmed that it would be possible to cut three DPs by activating the most powerful shear ram in the BOP. This was therefore verified as a possibility for securing the well if the weather worsened and the riser had to be disconnected before normalisation was completed.

However, good weather meant the riser did not need to be disconnected before the normalisation operations had been completed after 30 days.

9 Discussion of uncertainties

Neptune and Odfjell initiated detailed studies into possible causes of the partings which occurred in the string and caused a section to come loose and drop into the well, so that it became stuck through the BOP together with the remainder of the main string.

Two joints could have failed as the result of a double spin-off or a combination of spin-off and twist-off, allowing 150 metres of string to drop into the BOP. But determining the exact mechanism which caused two partings high up the string seems to be difficult. The PSA team's investigation has not given emphasis to how the string might part in the way it did.

Although the CCS subs were involved in one of the partings in the string, the system clearly functioned as intended during the actual drilling operation.

Introducing a weak link/joint high up the string is not normal practice. This is usually done lower down the string, as in bottomhole assemblies and tapered strings.

10 Assessment of players' investigation report

The joint Neptune/Odfjell report *Deepsea Yantai – Parted Drillstring Incident Investigation* was received by the PSA on 3 March 2021. It seems to be thorough and well-founded. Most of its findings on causes correspond by and large with those made by the PSA team, and it also addresses parting mechanisms in the string via several different investigations based on detailed analyses of the two joints which failed and possible failure modes which instigated the partings.

11 Appendices

A: The following documents have been used in the investigation
B: Overview of personnel interviewed