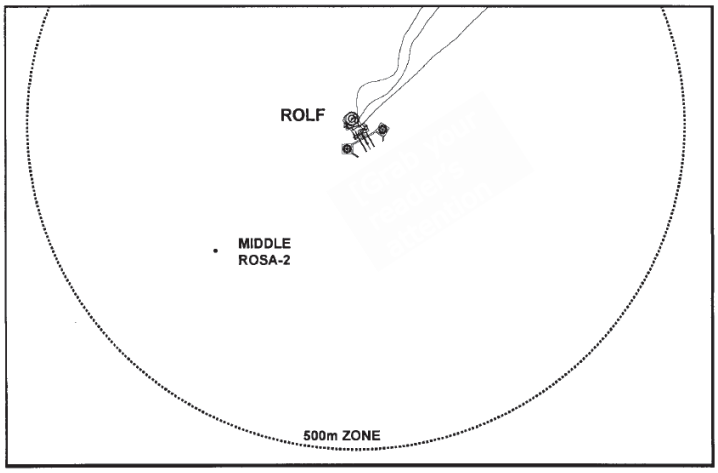
Programme under review by the Danish Energy Agency



MIDDLE ROSA-02 WELL

WELL STATUS REVIEW AND PROPOSED P&A

TOTALENERGIES E&P DANMARK A/S

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Signature List

Middle Rosa-2 Well Status Review and Proposed P&A Plan: DOE-13-2027 Rev0

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A. Executive Summary

Middle Rosa-2 is an old exploration well that was decommissioned in 1983 and gas bubbles have been observed at the seafloor level since this date. It is suspected that a channel in the 13-3/8" x 20" annular cement may be acting as a conduit allowing biogenic methane gas from the shallow Pliocene sands to escape.

This document, through a review of the subsurface, the original well decommissioning phase 2 (AB2) as per OEUK guidelines and subsequent remediation operations demonstrate that;

1. The Ekofisk reservoir remains isolated.
2. The Upper Lark does not represent a zone with flow potential.
3. The final well decommissioning phase 3 (AB3) of the well will stop the leak while maintaining the existing reservoir isolation.

Having assessed the history/trend of the gas bubbles, the present well status, and compared the associated risks of a rig-based abandonment versus that of a vessel-based abandonment, the recommendation based on ALARP evaluation is to complete the P&A with an intervention vessel as this operation carries a significantly lower risk of a loss of primary containment (LOPC) and the potential harm such an event could have on people, assets and the environment.

The proposed approach will ensure that the well will be left in a permanent safe condition, with the Ekofisk reservoir isolated, the Upper Lark not requiring individual isolation, and the shallow biogenic methane pathway remediated.

The table below outlines the P&A requirements regarding the proposed actions governed by the evidence.

P&A requirement	Conclusion	Evidence	Proposed action
Ekofisk isolation	Already isolated	Pressure test, plug, CBL, biogenic sample, no deeper flow	No re-entry proposed
Upper Lark isolation	Not a Zone with Flow Potential for abandonment purposes	Porosity/permeability, water saturation, lack of sustained pressure support	No additional barrier proposed
Pliocene shallow methane	Shallow biogenic gas pathway through well to be remediated	Gas sample, leak path, declining leak rate	Replace TA Cap, verify no bubbles, cement, cut conductor

B. Introduction

Middle Rosa-2 is located 200m from the Rolf platform in what is now known as the Rolf field.

It was an appraisal well drilled from a jack up rig utilising an Vetco MLS system so that in the event that the well encountered economic reserves, it could be plugged to isolate any porous/permeable zones, the tieback casing strings backed out and recovered from the MLS and the conductor string severed above the seabed to leave a stump in place to aid re-entry.

Middle Rosa-2 was drilled and subsequently decommissioned as per OEUK phase 2 (AB2) in 1983 with all casing strings recovered from the Vetco Mudline System (MLS), and the conductor stump left above the seabed.

During the well test, an annular pressure of 250psi was observed to build up in the 13-3/8" x 20" annulus and following the subsequent plugging of the well, a continuous leak of gas has been observed to be coming from the 13-3/8" x 20" annulus.

Attempts to seal off the gas leak by installing a 20" Temporary Abandonment (TA) Cap were only partially successful due to a leaking check valve in the TA cap. A net guard was placed on top of the conductor stump and the rig departed the location with the leaking 20" TA Cap left in place in the well.

The source of the leaking gas is the Pliocene sands formation which are located just below the 20" casing shoe and the gas is leaking through a suspected cement channel within the 13-3/8" x 20" annulus and is then being released at the 13-3/8" mudline hanger.

For Middle Rosa-2 to be permanently abandoned (OEUK phase 3), the gas leak through the well needs to be stopped before all structures above the mudline are removed.

C. Well Status

Middle Rosa-2 was decommissioned as per OEUK phase 2 (AB2) in 1983 and once the 3 cement plugs were set, the 9-5/8", 13-3/8" and 20" tieback casings were backed out of the MLS and recovered, and a TA Cap installed in the 20" tieback profile. The TA Cap was fully engaged however a gas tight seal could not be achieved through the BPV or the threads. The 9-5/8", 13-3/8" and 20" tieback threads have been exposed to the environment since 1983.

The well has been inspected periodically since being decommissioned to establish if the source of the gas leak would naturally deplete. There has been a significant reduction in leak rate between 2016 and 2023 after installing a funnel to the net deflector which results in a more accurate reading. The latest measured methane release rate is very low. For scale, it is significantly below the Article 14(8) repair threshold for offshore subsea components under the EU Methane Regulation, 17 g/hr, approximately 600l/day. (see figure below).

In 2012, a sample of the leaking gas was collected and analysed, confirming that it was 99.6% methane (biogenic and of shallow origin) and not from the Ekofisk reservoir.

The well was intervened upon and inspected in 2016, 2017 and 2018 by an intervention vessel as part of the annual rigless Plug and Abandon (P&A) campaigns.

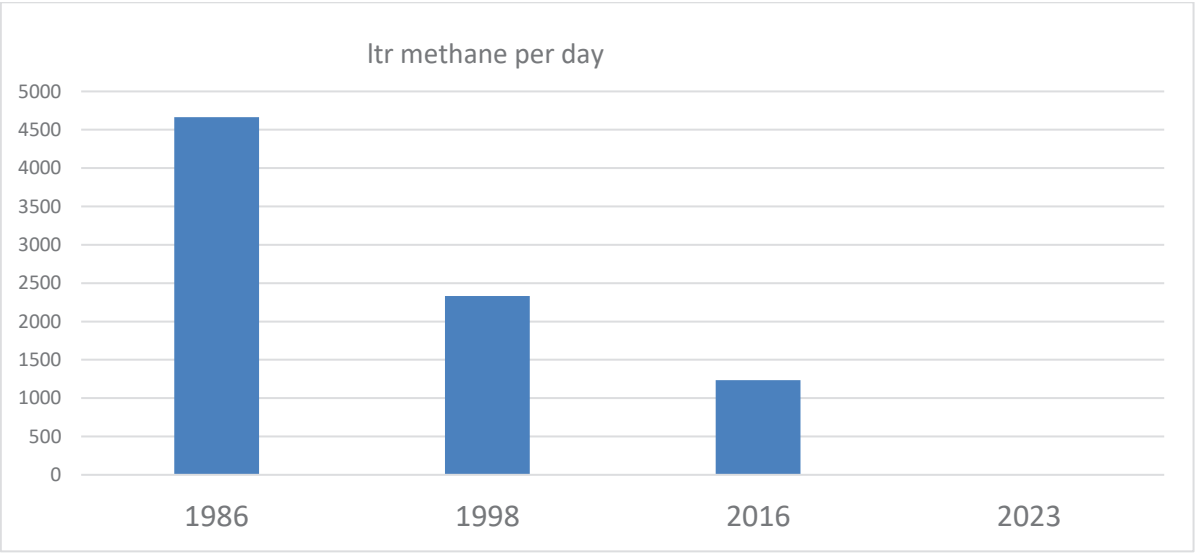
Between 2016 and 2018 the leak rate has been steady at approximately 1ltr/min at seabed.

In 2018, the leaking 20" TA Cap was removed from the well and it was confirmed that the gas is emanating from the 20" x 13-3/8" annulus only.

In 2021, a modified 20" TA Cap with a thread seal and check valve to prevent hydraulic lock and a net deflector with a funnel guide to improve gas sampling were installed, however the leak persisted through the defective check valve. An ROV inspection in 2022 and 2023 recorded leak rates between 0.02 and 0.05 ltr/hr which is a significant reduction compared to previous measurements and signifies that the source is limited and depleting.

The well currently has the modified TA Cap with leaking check valve and net deflector installed on top of the conductor stump.

The current Well Status Drawing has been included as Appendix 1 and a schematic of the Vetco MLS has been included as Appendix 2.



Methane Emission Measurements from Middle Rosa-2

D. Relevant Information from the drilling of Middle Rosa-2

Note: All MDRT are based on the original RTE of 131ft

Having driven the 30" conductor, the 26" hole section was drilled to ca. 1,200 ft with 8.8ppg mud with losses of 2 bbls/min being recorded from 870ft. The 20" casing was run and cemented with 300 bbl of contaminated cement circulated out of the well at surface during the displacement. In order to ensure that the 20" tieback casing could be backed out and recovered at a later stage, 1-3/4" skinny pipe was run in the annulus between the 20" casing and the conductor to a depth of 300ft MDRT (ca. 30ft below the 20" casing hanger) and the cement in the annulus from this depth was circulated out.

The 17-1/2" hole section was drilled to ca. 3,100ft MDRT, initially with 9ppg mud and losses of 100 bbl/hr occurring as soon as the 20" casing shoe was drilled out as clay with intermittent sand stringers were drilled. The mud weight was increased to 9.2ppg once losses were manageable with LCM and was further increased to 10.2ppg mud from 2,500ft and 10.3ppg mud prior to running the 13-3/8" casing. Whilst RIH, the 13-3/8" casing became stuck prior to reaching the land off point. Attempts to free the casing were unsuccessful and so it was cemented in place with the 13-3/8" hanger not fully landed within the 20" hanger. It was originally reported that the 13-3/8" hanger was set 2ft higher than it was designed to but during the downhole inspection in 2018, it was confirmed that the 13-3/8" hanger is only 2-3" higher than designed.

The 13-3/8" casing was cemented to the mudline and after the displacement, the washports on the 13-3/8" running tool were opened and excess cement was circulated out from above the washports (to ensure that the 13-3/8" tieback casing could be backed out and recovered from the MLS during the subsequent abandonment).

The 13-3/8" casing string also contained an inflatable, external packer which was inflated during the pressure test of the casing after the cement job.

The 12-1/4" hole section was drilled down to and through the Ekofisk Chalk reservoir and down into the Zechstein before the 9-5/8" was run and cemented.

The 9-5/8" casing string included a stage collar above the 13-3/8" casing shoe to allow a 2-stage cement job to be performed. After the 1st stage cement job, the stage collar was opened and mud which was contaminated with cement was circulated up from above the stage collar. The 2nd stage cement job was then performed.

The 8-1/2" hole section was drilled to Well TD at 6,786ft (175ft below 9-5/8" shoe) before an EZSV was set above the 9-5/8" shoe and the open hole section squeezed full of cement.

In preparation for perforating the 9-5/8" casing during the planned well test of the Ekofisk reservoir, a CBL log was run from 5,000ft to the casing shoe at 6,611ft. The CBL log interpretation performed in 2012 has been included as Appendix 10.

A production packer was installed above the top Ekofisk and a 3-1/2" completion string run and stabbed into the packer.

The Ekofisk was perforated, and a well test performed over the interval. Upon completion of the first well test, the 9-5/8" casing was perforated over 2 additional intervals and a well test performed of the 3 intervals. During the PBU period of the 2nd well test, an annular pressure of ca. 250psi was observed to be building up in the 13-3/8" x 20" annulus.

A summary of the casing cement jobs on Middle Rosa-2 has been included as Appendix 3.

E. Subsurface Input for P&A

Subsurface has reviewed three zones of interest in the context of well abandonment.

1. Ekofisk Fm Chalk (Primary reservoir)
2. Diatomaceous Mudstone of the Upper Lark Fm
3. Pliocene Sand (Shallow overburden)

Based on integrated analysis of subsurface data (CPI logs, seismic and offset wells) the Ekofisk Fm this is being retained as the only "zone to be individually isolated". The analysis below shows that the Upper Lark Diatomaceous mudstone does not constitute a flowzone. The shallow Pliocene Sand interval which contains biogenic gas is also not considered for isolation following review of seismic, mud log and induction log data (see section below).

1: Ekofisk Chalk

Top Ekofisk Chalk is at 6,255 ft MDRT* / 5,805 ft TVDSS

Ekofisk Chalk pressure is 3,952 psi (12.5 ppg EMW)

Minimum Plug Setting Depth: 4,721 ft MDRT* / 4,590 ft TVDSS

*All MDRT are based on the original RTE of 131ft

Maximum estimated wellhead pressure

If existing cement plugs are removed and communication to main reservoir established:

- 3,372psi (3,952psi pressure at top Ekofisk with 0.1 psi/ft gas gradient)
- Should the Ekofisk isolation plug and intermediate cement plug have failed, and the well has been evacuated to gas below the surface cement plug, the maximum pressure below the surface cement plug could be 3,418psi at 710ft MDRT (92.6ppg EMW).

If existing cement plugs are not removed and reservoir remains isolated:

- 695 psi (790 psi pressure at Pliocene sand interval with 0.1 psi/ft gas gradient).
- Pliocene sands considered to be normally pressured at 8.65ppg EMW, giving an estimated formation pressure of 540psi at 1,200ft TVDRT. With a gas gradient to the mudline, the maximum anticipated wellhead pressure would be 445psi. The 250psi annular pressure which was originally observed has been added to the estimated formation pressure to ensure that the Well barrier element (TA Cap) is able to withstand this maximum pressure.

2: Diatomaceous Mudstone of the Upper Lark Fm Description

The Lark formation is widespread across the Danish Central Graben. By around 2013 it was acknowledged that the Upper Lark was diatomaceous in nature. Prior to that it was generally described as a claystone on mud logs, however, with the advent of SEM Microscopy it was noticed that this part of the Middle Miocene overburden contained diatoms and could be classified as a diatomaceous mudstone. When first deposited diatoms are constituted by Opal-A. With burial, in situ transformation of biogenetic opal-A to diagenetic opal-CT occurs over an interval of 10s to 100s of meters with a relative timing that is largely controlled by the bulk composition of individual strata and maximum temperature reached. Particularly, smectitic clay content retards the transformation.

In the DK sector the uppermost part of Upper Lark is preserving relatively high porosities, associated with content of untransformed Opal A at depth's of 4,500 – 5,000 ft below msl. Below the upper zone with high porosity typically a degree of diagenetic alteration is seen.

This transformation is relatively deep and seems to be a consequence of the high clay content.

Once the lithological composition of the Upper Lark was better understood it also became possible to apply the right petrophysical analysis, and this gave further insights to the properties of this rock. In concert with mud-logs it was possible to subdivide into two populations:

a) A population containing some biogenic gas in the pores which basin modelling tools ascribe to being self-sourced from the Upper Lark itself.
b) A population containing some oil, which basin modelling ascribes to being sourced from the much deeper Upper Jurassic Source Rock of the Farsund Fm, and via accentuated Chalk structures has leaked up into the Upper Lark.

As suggested these two populations correlate with the degree of chalk structuration:

a) is found above gentler chalk structures (fx Roar, Tyra, Halfdan)
b) is found above the most accentuated chalk structures that are typically heavily induced by underlying salt structures (fx Svend, Dagmar and **Rolf**). In the context of this document, we are focusing on Rolf and the Middle Rosa Structure.

Appendix 6 shows a structure map of Top Upper Lark across the Middle Rosa Structure.

The structure map shows the presence of a collapsed central area on the Crest, that is surrounded to the SW and SE by two elevated areas. The log signature from the wells penetrating the crestal collapse area (like MR2) varies significantly from the wells penetrating the SE High (like Rolf-4). No wells penetrate the SW high mostly configured in the German Sector. This difference can be seen from the well section shown on Appendix 7. The porosity difference between the Rolf wells can also be observed from porosity histograms of the Upper Lark interval from each well also shown on appendix 7.

Note, for MR2 only a very small proportion of the porosity is above 35 PU, in contrast to Rolf-4 that has porosities up to 50 PU. Comparing the mean porosity values the delta between the two wells is ~20 PU (48-28) PU, which could be an indication that a very large proportion of the crestal collapse area has gone through the Opal A to Opal CT transition. It can also be observed from the Well panel that Rolf-5, which is intermediate in position between MR2 and Rolf-4 at its intersection with the Top Upper Lark, that the well seems to have gone through a partial conversion exhibiting a bi-modal porosity distribution on the histogram.

The difference between the wells in porosity distribution is related to the structural position. Appendix 9 shows a 3D view of the Upper Lark Structure with interpreted faults. These faults have played a major role in setting up the difference in porosity loss. Fault movement has facilitated transmission of hotter fluids to the collapse area, advancing the diagenetic alteration. In addition, the faults have the potential to be a hindrance to fluid flow between the low porosity zones and the preserved porosity zones.

In the context of this document, it is key to consider the flow potential of the Upper Lark Diatomaceous mudstone, and since 2015 a porosity-permeability relationship has been developed from data available across the Danish and Southern Norwegian sector. These two areas have several things in common. The diatomaceous Upper Lark layer is present, Chalk reservoirs tend to be dominant, and there tends to be few Paleocene sands present in which oil can accumulate if it leaks out of the chalk.

The compiled data are shown in Appendix 8, together with a plot showing Free Fluid Volume versus Total porosity, based on a Nuclear Magnetic Resonance log recorded across the Upper Lark above the Valhall Field.
The combined conclusion from these two x-plots can be summarized with the following statements

- Below 35 PU fluids are not movable
- At 40 PU, permeability is extremely low around 0.05 mD

Hence, with MR2 porosity distribution as noted above it can be deducted that the flow potential from Upper Lark diatomaceous mudstone interval is extremely low.

Arguably the distance from MR2 to Rolf-4, which could have some flow potential from this interval, is not very large, however, as mentioned the fault separating the crestal collapse area from the SW High is likely presenting a barrier to flow limiting the chance of MR2 being connected to a zone with more flow potential. The interpreted faults are shown on Appendix 9 together with a structural model cross section depicting the situation.
In essence the Upper Lark diatomaceous mudstone is deemed not a Zone with Flow Potential for abandonment purposes in MR2. Hydrocarbons are present but not connected to mobility at field scale.

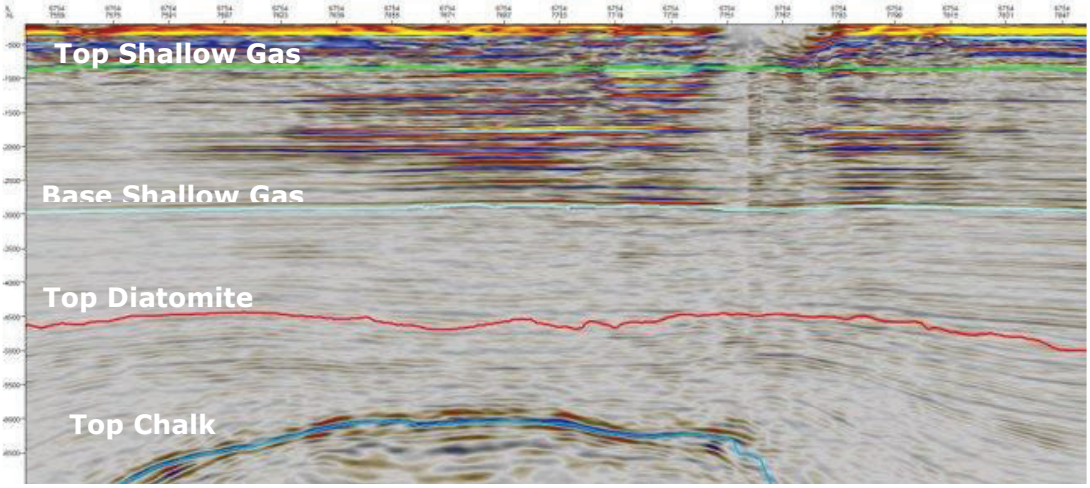
3 Pliocene Sands Description

In Middle Rosa-2, the Pleistocene / Pliocene sands are located at 1,200ft MDRT (1,069ft TVDSS), which is just below the 20" casing shoe at 1,190ft MDRT.

The Pliocene and Pleistocene succession in the Danish Central Graben forms the uppermost part of the overburden and consists predominantly of unconsolidated to poorly consolidated marine clays/shales, with interbedded sands, silts deposited as part of deltaic sequences overlain by locally glaciogenic deposits. The interval becomes sandier upwards, particularly within Pleistocene glacial and glacio-marine sequences.

From regional understanding and drilling experience, these shallow layers are known to be hydrostatic across the Danish sector (estimated to be 8.65ppg EMW). The sands have been observed to be partially gas bearing, where this is found, this gas is also hydrostatic. The seismic plot below shows the shallow gas distribution above the labelled "Base shallow Gas" horizon, however the strength of the seismic amplitudes are not indicative of the gas saturation level in the individual sands, as it takes very little gas saturation to get a strong signal (even residual gas gives a strong signal). When comparing the logs across this section with the seismic it becomes evident that the sections consists of multiple leaky reservoir-seal pairs.

As observed on the mudlog (appendix 4), the Pliocene sands are overlain by a sequence of interbedded clays and sands. The formation just above the shallowest gas occurrence (appendix 5) provides the seal strength to hold back a very short column of gas. Given the depositional environment and the observations above, this seal is unlikely to be laterally consistent and away from the well leak paths are likely present, and as such the Pliocene sands are not considered necessary to isolate during abandonment.



Seismic plot for Rolf Field

F. Current Decommissioning Status Review

Middle Rosa-2 was decommissioned (AB2 as per OEUK) with the reservoir isolated and all the required cement plugs installed. A combination plug of 416 ft was set as a dual barrier below the minimum setting depth for the Ekofisk reservoir (4,721 ft MDRT). The annular cement adjacent to this plug was logged and 192 ft of bonding was identified. It should be noted that the annular cement barrier is a competent seal to the Ekofisk reservoir. To comply with OEUK guidelines, a risk assessment on re-entering the well and remediating this annular cement was performed. The result from the RA makes the re-entry not reasonably practicable by OEUK guidelines definition.

A 413 ft intermediate cement plug was placed to form a rock-to-rock barrier across the 13-3/8" shoe. This plug is considered a barrier between the over pressured shales and Pliocene formation.

Finally, a shallow plug was placed to act as an environmental plug prior to installing the TA Cap and moving off the well. The well in its current state complies with OEUK well decommissioning Phase 2 (AB2). This plan which remediates the bubbling and removal of the conductor will make the well comply with OEUK well decommissioning phase 3 (AB3).

Given the time that the well was left in the AB2 abandoned phase and subsequent casing deration, well re-entry is not recommended.

Ekofisk Isolation

On completion of the well test, the well was displaced to 13.5ppg kill weight mud and flow checked static. The production test string was recovered, leaving the production packer in place. Should the well have been re-entered at some point in the future, the existing production packer potentially could have been re-used once the abandonment plugs had been drilled out.

An EZSV was set 150 ft above the production packer with cement squeezed approximately 100 ft below it and a 416 ft cement plug placed on top. Squeezing cement below the EZSV is done to ensure the EZSV could be drilled out in future, if required, in a controlled manner.

The cement slurry used for the abandonment plug was 16 ppg Class G with some retarder (same recipe described in the dry hole abandonment procedure).

The combination abandonment plug and casing above were pressure tested with 2,000psi to verify that the reservoir was fully isolated.

The internal abandonment plug to the Ekofisk was set between 6,050 ft and 5,534 ft. At the time of the original abandonment, this 416 ft cement plug was considered sufficient to be classified as the isolation barrier to the main Ekofisk reservoir.

As per the recent Subsurface review of Middle Rosa-2, the minimum plug setting depth for the Ekofisk isolation plug is at 4,721 ft thus the combination plugs fulfil the requirement of a dual barrier to the Ekofisk formation.

The interpretation of the 9-5/8" CBL has identified an annular cement over the plugged interval of 192 ft and risk assessed as per OEUK guidelines to be ALARP.

The CBL interpretation performed in 2012 has been included as Appendix 10.

The CBL interpretation was reviewed again in 2021 with a CBL reading of less than 30mV being considered to represent intervals with a good annular bond. On this basis, the cumulative column of cement with good annular bond has been assessed to be as follows:

- Barrier to the Ekofisk reservoir (interval 6,050 ft – 5,534 ft) there is 192 ft (58.5 m) of good annular cement

The CBL interpretation performed in 2021 has been included in 1:500 scale as Appendix 11.

The result of this interpretation identifies 192 ft of bonded annular cement adjacent to the internal combination plug. This falls only marginally short of the required length of 200 ft and was assessed identifying the operational risks vs benefits to risks of loss of primary containment and concluded as being ALARP as per OEUK guidelines. Also, considering that the measured methane leaking from the well is biogenic concludes that these barriers effectively isolate the Ekofisk reservoir.

Upper Lark Isolation

At the time of the original abandonment in 1983, the Upper Lark was not considered to be a permeable formation which required to be isolated from surface. As such, no plugs were placed in the interval where an isolation plug would have been required.

In compliance with the requirements at the time and with the main Ekofisk reservoir fully isolated, an intermediate cement plug was set across the previous casing shoe interval. A 413 ft cement plug was set from 3,346 ft (224 ft below the 13-3/8" shoe) to 2,933 ft (189 ft above the 13-3/8" shoe) with TOC reaching ca. 53 ft above the 9-5/8" stage collar. This plug serves as an isolation between the over pressured shales and the shallower Pliocene formation.

The 9-5/8" casing was cemented as a 2-stage operation. Since the second stage of the 9-5/8" cement job was performed as a cased hole operation, the bond of the annular cement above the stage collar is considered good.

Environmental Plug

In compliance with the requirements at the time, an environmental/surface cement plug was set over the interval 710 ft-395 ft (just below the 30" conductor shoe).

Once the surface cement plug had been set, the well was displaced to seawater above the plug.

The plug was not verified during the original abandonment, although it was tagged at 395 ft MDRT with an 8.835" drill collar on wire as part of the 2018 well intervention operations.

Tieback casing recovery and TA Cap installation

Having set the 3 planned abandonment plugs, the well was considered to be fully isolated and the 9-5/8", 13-3/8" and 20" tieback casings were all backed out from their respective MLS hangers and recovered to the rig.

Due to the sustained annular pressure in the 13-3/8" x 20" annulus, a 20" TA Cap (complete with back pressure valve (BPV)) was installed into the 20" tieback profile. If the TA Cap had been fully engaged into the tieback profile with the 2 seal rings correctly positioned and the BPV able to provide a gas tight seal, the pressure from the 13-3/8" x 20" annulus would have been contained below the TA Cap (See Appendix N 12).

Whilst waiting to sever the conductor, it was observed that gas bubbles had started to leak from the well. Upon investigation it was confirmed that they were emanating from the TA Cap mandrel, indicating that the BPV was unable to provide a gas tight seal.

The TA Cap was recovered and the primary and back up TA Caps were run, interchangeably, ca. 20 times with the leak from the BPV remaining after each installation attempt. The conductor was severed and the well left with a leaking TA Cap in place.

Eventually a TA Cap was modified by removing the original BPV components and welding a drill pipe float valve onto the underside the TA Cap. The addition of the float valve ensured that gas would not be able to pass through and leak via the mandrel, but this also meant that the TA Cap could not be installed in a vented position and any pressure which built up below the cap as it is screwed in, could impact the installation.

The modified TA Cap was installed in the 20" tieback profile but could only be partially made up with the string moving down only 2" during make up, rather than the 3-1/2" that would have occurred if the TA cap had been fully made up.

With the modified TA Cap partially installed in the tieback threads, gas bubbles were observed to be leaking from the top of the 20" casing hanger (where the non-engaged TA Caps threads were visible)

A schematic of the modified TA Cap in the partially installed position has been included as Appendix 14.

Having reviewed the position of the seal rings with the TA Cap only partially installed, neither of the seal rings were positioned against a seal face and therefore the gas was able to pass through the threads and continue to leak from the well.

It is likely that as the TA Cap was being installed, at the point where the seal rings contacted a seal face, the pressure below the TA Cap built up instantly and caused hydraulic lockout, which prevented the TA Cap from being made up any further.

Having exhausted all possible solutions for sealing off the gas leak with the 20" TA Cap, the decision was made to leave the well with the gas leak continuing and make no further attempts to stop the leak.

As such, the modified 20" TA Cap was left in place and the 30" conductor was severed 10ft above the mudline and a net guard placed on top of the conductor stump.

The DEA was contacted at the time of the abandonment and gave approval for the rig to depart the location with no further attempts being made to prevent the gas leak.

An agreement was made with the DEA at the time that the well would be periodically inspected to establish if the source zone for the leak was able to deplete naturally.

Well Inspections 1983-2012

As per this agreement with the DEA, Middle Rosa-2 was visually inspected by ROV or divers every ca. 3 years since the well was temporarily abandoned.

Due to the design of the original net guard, it was not possible to accurately measure the leak rate from the well and therefore it was not possible to verify of the leak rate had changed over this period.

In 2012, a sample of the gas leaking from the well was collected by divers and was analysed to be biogenic methane gas, confirming that the source of the leak was not the reservoir.

Well Inspections 2016-2018

In 2016, the well was inspected and a custom-made net guard was installed over the conductor stump which was designed to act as a funnel and included a single vent hole which allowed for the leak rate to be accurately measured.

The leak rate has remained steady at ca. 1ltr/min at the mudline between 2016 and 2018.

In 2017, an attempt was made to verify the pressure below the TA Cap prior to removing it from the well. As this was not possible, operations to remove the TA Cap were suspended and the net guard was reinstalled.

A Conductor Stripping Assembly (CSA) with POS-SET connector was run and installed onto the 30" stump. The TA Cap retrieval tool was deployed on drill pipe and latched onto the TA Cap. The annular within the CSA, was then closed around the drill pipe and the pressure below the CSA was monitored with no pressure build-up observed and so the TA Cap was backed out. No significant increase in leak rate from the well, nor pressure build up was

observed once the TA Cap had been released from the MLS.

The CSA was removed by cutting the conductor just below the POS-SET connector (leaving a 5.6 ft conductor stick up) and the TA Cap was recovered to the vessel.

The threads on 20", 13-3/8" and 9-5/8" hangers were inspected with a downhole camera and observed to be free of any significant damage however most recent inspections showed the threads not suitable to be used for subsequent tie-backs. The gas leak was confirmed to be emanating from 13-3/8" x 20" annulus, with no indications of flow from the other annuli or from within the 9-5/8" casing.

The well was drifted, using an 8.835" drift assembly, tagging cement at 153 ft below the seabed before the net deflector was reinstalled and the leak rate confirmed to still be 1ltr/min at the mudline.

Temporary Abandonment Summary

- Ekofisk reservoir was fully isolated with a 416ft (157m) internal cement plug
- An intermediate cement plug was placed in the 9-5/8" casing across the 13-3/8" casing shoe interval to isolate the over pressured shales and for future re-entry.
- No flow has been observed from the 9-5/8" x 13-3/8" annulus or from inside the 9-5/8" casing itself. This confirms that the existing internal plugs and the annular cement in the 9-5/8" x 13-3/8" annulus are fully isolating both the Ekofisk and Upper Lark.
- An environmental/surface plug was set close to the seabed, however below the ML hangers.
- The 9-5/8", 13-3/8" and 20" tieback threads have been exposed to the environment since the original abandonment in 1983. ROV visuals do not show evidence of thread degradation however since the threads have been exposed for this period, sealing cannot be guaranteed.
- With the 20" TA Cap only partially made up, the 2 seal rings on the TA Cap were not positioned against a seal face and so a conduit past the threads allowed the gas to continue to leak.

In 2018, the leaking 20" TA Cap was removed from the well and it was confirmed that the gas is emanating from the 20" x 13-3/8" annulus only.

In 2021, a modified 20" TA Cap was installed, however the leak persisted through the check valve modification.

The well currently has the modified TA Cap with leaking check valve and net deflector installed on top of the conductor stump.

The TA Cap supplier has since conducted various tests on the check valve and concluded that the leak path was via a dowty body seal and the design was modified with a new seal arrangement and successfully factory tested.

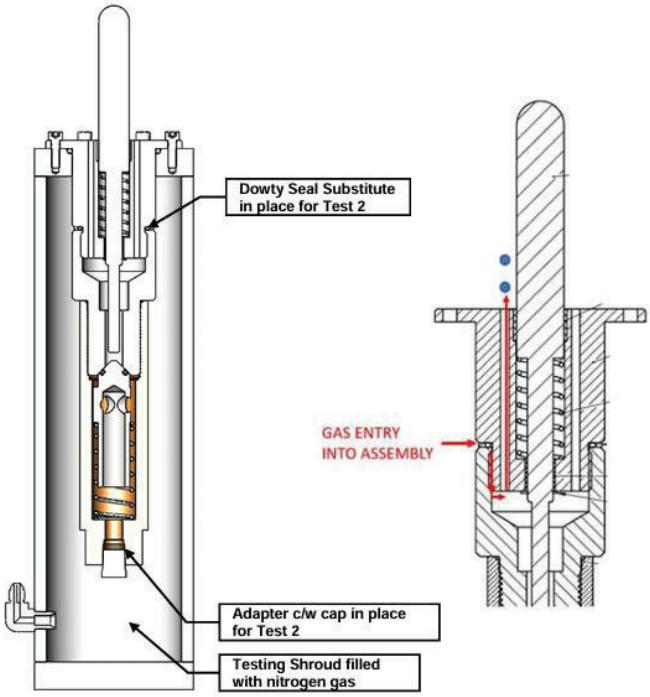


Fig. Factory test setup for TA-Cap Check Valve

G. Relevant OEUK Well Decommissioning Guidelines Issue 7 (November 2022)

OEUK guidelines were followed in assessing the current well status and proposing this final decommissioning plan.

Relevant **OEUK Guidelines** followed:

- **Section 2: Evaluation of Zones with Flow Potential**
    - Well decommissioning planning requires the assessment of potential flow from subsurface formations in terms of environmental and safety risk, and resource impacts. Well barriers may need to be placed to isolate geological formations that have flow potential. The magnitude and duration of flow from individual formations penetrated by the well is a key input to the assessment of the requirement for the well barriers. The extent of measures to mitigate possible consequences of flow potential should be considered in an approach which maintains that, so far as is reasonably practicable, there can be no unplanned escape of fluids from the well. This approach should ensure that the magnitude of potential flow that could result is balanced against the safety and environmental risks, complexity and chance of success of extended well operations to mitigate the risk of flow via placement of additional barriers and other well decommissioning activity.
- **Section 3.4. Length of Barriers**
    - All depths are Measured Depth (MD) unless otherwise stated
- **Section 3.4.1 Cement**

  A permanent cement barrier should consist of:

    - A cement column of typically a minimum 100 ft measured depth (MD) of good cement above zone of flow potential, whether inside or outside the casing.
    - Internal cement adjacent to the annular good cement of typically 100 ft MD of overlap, above zone of flow potential. Annular good cement may consist of discrete sections of good cement, cumulatively added together to total 100ft MD. The internal cement must fully overlap this cumulative interval.

      Note 1: Where distinct zones with flow potential are less than 100 ft MD apart, then the maximum practical column of good cement should be placed between the zones.

      Note 2: The operator may set limits on minimum lengths of discrete sections of good annular cement via ALARP assessment (e.g. based on leakage risk assessment and/or industry experience).

  When a combination barrier is chosen to replace two permanent barriers, it should have:

    - A cement column of typically a minimum 200 ft MD of good cement.

- Internal cement adjacent to the annular good cement over a cumulative distance of 200 ft MD.

  A reduction in the lengths stated above should only be used if a rigorous risk assessment process has been followed, which demonstrates that the additional time, trouble and cost required to set a 100 / 200 ft barrier are grossly disproportionate to the further risk reduction achieved in setting these barriers. Thereby demonstrating that the risks of a leak associated with a barrier less than 100 / 200 ft are ALARP.

H. Abandonment of Middle Rosa-2 in line with OEUK Guidelines

The plan for the Middle Rosa-2 well is to complete the abandonment in line with OEUK Decommissioning Guidelines. Thus, the following well status would need to be verified:

- Upper Lark flow potential – Proven to be unlikely to flow as per **section E,** thus no barrier requirement for this zone as per **OEUK guideline section 2**.
- Ekofisk internal combination plug set adjacent to an annular barrier of 192 ft which is confirmed to be positively sealing the flow zone. **OEUK guideline 3.4.1** states that the combination barrier requires 200 ft MD of good cement however a reduction in length can be justified with a risk assessment and proof that the reasonably practicable approach demonstrates that the additional time, trouble and cost is disproportionate to further risk reduction in resetting the barriers. Thereby demonstrating that the risks of a leak associated with a barrier just short of 200 ft is ALARP.

Therefore, it is concluded that the cement plugs do not need remedial work when compared to the provisions of OEUK guidelines and the AB2 well abandonment status. The risk assessment (Appendix 15) outlined the risks of re-entering the well. Risk #4 –"Unable to test the HP Riser against the 9-5/8" casing to the required pressure", could not be mitigated to an acceptable level. Since this is a requirement to confirm containment to prevent an LOPC event, it is deemed reasonable to consider the Ekofisk barrier plugs and the associated AB2 status are ALARP.

The RA outlining the risks and challenges of re-entering the well and remediating the cement barriers is shown in Appendix 15. The result of the RA denotes that remediating is not reasonably practicable since a structurally safe connection to the well cannot be guaranteed. Few conclusions of the RA of the main risks are as below.

The CSA POS-Grip (fig. below) is not recommended, as a pressure tight connection cannot be guaranteed for the full well intervention to remediate the cement plugs due to conductor corrosion.





CSA POS-Grip Conductor Connector

The 9-5/8" casing strength has been downgraded to 1,538 psi, using the Immersion Zone, Submerged corrosion prediction case (0.1-0.2 mm/year), which is below the expected chalk reservoir pressure of 3,000 psi. This increases the risk of loss of primary containment (LOPC).

Since the casings have been downgraded too, directly reconnecting via the casing threads is also not recommended.

As per OEUK guidelines section 2, well re-entry possibility of success is low.

The SLB 9-5/8" CRS system was analysed with the following challenges identified.

- The tool needs to be able to swallow the 9-5/8" casing. The outer annulus of this casing therefore needs to be clean of debris/ cement.
- The 9-5/8" casing & 13-5/8" casing to be cut, allowing access.
- Casing strength, condition and uniformity will also be key as the casing is hydroformed (inflated) to anchor into the CRS tool. Should there be any damage / imperfection in the 9-5/8" casing it will not form the necessary seal.

Should the CRS not be able to swallow/connect to the 9-5/8" casing an internal packer could be run to establish a pressurized connection to the well. This internal packer would result in a restricted ID which would prevent remedial operations being conducted such as Section Milling / PWC.

As per OEUK guidelines section 2, well re-entry possibility of success is low. Refer to RA in Appendix 15 **Item Ref-3**.

Proving that the current barriers in place are compliant and re-entry is not reasonably practicable, the plan is to stop the current leak by replacing the leaking TA Cap, monitor for leaks, place competent cement on top of the TA Cap and sever the conductor at the seabed.

A schematic demonstrating Middle Rosa-2 if P&A'd as planned is in full compliance with OEUK Guidelines has been included as Appendix 13.

I. TEPDK Experience with vessel-based P&A

TEPDK has previously completed 5 vessel-based P&A campaigns between 2013 and 2018, with 26 legacy wells (either exploration or appraisal wells which were previously temporarily abandoned) fully plugged and abandoned and the conductor stumps severed. Middle Rosa-2 has also been inspected and intervened upon to remove the 20" TA Cap as part of these previous campaigns.

The scope of work of the previous vessel-based P&A campaigns included:

- Well flushing, cleaning, and inspection
- TA Cap recovery
- Casing cutting and pulling
- Surface cement plug installation
- Conductor severance and recovery
- Seabed clearance

Based on the challenges and risks associated with performing a rig-based P&A of Middle Rosa-2, consideration was given for what scope of work could be safely completed with a P&A vessel.

The main considerations when evaluating the possibility of performing a vessel-based P&A on Middle Rosa-2 were as follows:

- Leaking gas is verified to be biogenic methane gas and is not from the Ekofisk formations – indicating that the existing isolations to these formations are holding.
- No pressure build-up observed from existing leak – verifying that leak source is a normally pressured formation.
- All of the sealing faces within the MLS have been exposed to the environment for 38 years which is likely to have caused corrosion which would impact the sealing ability.

Having consulted several companies which specialise in performing vessel-based abandonment operations, it was proposed that a mechanical barrier be installed in the well to prevent the gas leak and to place a cement plug on top of the mechanical barrier which will provide the long-term isolation required.

The proposed scope of work for a vessel-based P&A for Middle Rosa-2 is as follows:

1. Arrive at Middle Rosa-02 location and verify gas leak rate with ROV.
2. Inspect and remove net guard from well and wet store same on seabed.
3. Clean and inspect TA-Cap and wellbore with down hole camera.
4. Recover TA cap and inspect at surface.
5. RIH TA cap c/w with check/float valve and seals installed. Make up TA cap to MLS.
6. Release TA Cap Running Tool to allow check valve to close.
7. Observe well with ROV to verify that gas leak is isolated (bubbles).
8. Recover TA Cap RT.
9. Circulate 30" x 20" annulus clean using cement stinger and place balanced cement plug on top of existing annular cement to the top of the conductor stump.
10. Flush in hole with cement stinger to 3ft below top of conductor.
11. POOH with cement stinger, circulate clean and recover to vessel.
12. WOC whilst observing well for gas leak with ROV
13. Tag cement plug to verify cement has set.
14. Cut Conductor at seabed.
15. Complete as left survey around well center.
16. Depart location.

A Well status drawing on completion of the proposed vessel-based P&A has been included in Appendix 13.

J. Modifications to the 20" TA Caps

TEPDK have previously recovered three 20" TA Caps from exploration wells as part of the vessel-based P&A campaigns (including the TA Cap recovered in 2018 on Middle Rosa-2).

These TA Caps were modified so that they can be re-installed as part of the proposed vessel-based operation. There are also two TA Cap running tools which were purchased for the previous campaigns which were modified as required. The planned modifications were as follows:

- Lower lip guide and lower seal ring grove removed from the base of the TA Cap threaded section (to reduce the risk of mechanical interference between the TA Cap and the 13-3/8" casing hanger)
- Lower section of the TA Cap main body machined to allow for the installation of a metal crush ring (metal to metal) seal above the original upper seal ring grove. Two metal crush ring seals will be available:
    - A small (37mm) crush ring which will seal against the top of the 20" hanger if the TA Cap is fully made up into the 20" hanger
    - A large (81mm) crush ring which will seal against the top of the 20" hanger if the TA Cap cannot be fully made up into the 20" hanger
- Original BPV /modified drill pipe float valve removed, and TA Cap mandrel annulus plugged to prevent flow.
- Check valve installed in the top of the TA Cap (which can be held open during TA Cap installation to allow the cap to be run in a vented position). This check valve is spring loaded and will close as soon as the plunger is no longer held down.
- Sleeve welded onto the outside of the TA Cap running tool, which when connected to the TA cap will depress the check valve plunger and allow the cap to be in the vented position (once the running tool is released from the TA Cap and the sleeve lifted, the plunger will lift and the check valve close).

Details of the modifications done to the TA-Caps are shown in the figure below and have been included as Appendix 14.

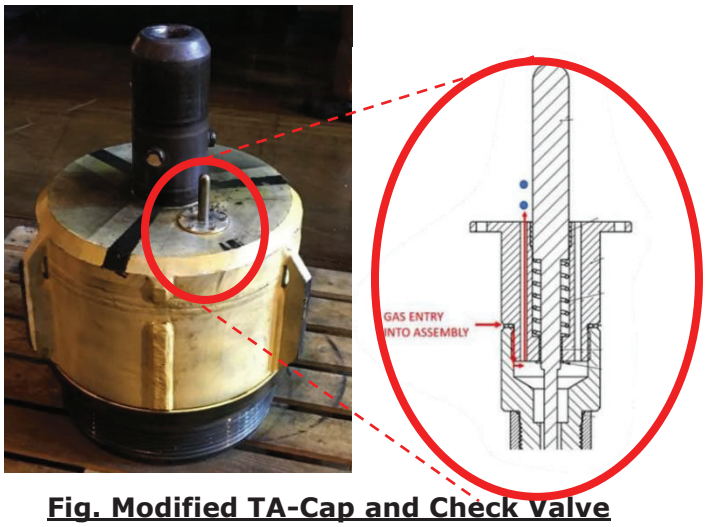


Fig. Modified TA-Cap and Check Valve

K. Risks and Method of abandoning Middle Rosa-2 with a vessel

Risks

The operational risks associated with a vessel-based abandonment of Middle Rosa-2 have been identified as follows:

- Leaking gas (methane) from the well reaches the vessel
- 20" MLS threads are damaged during TA Cap installation
- Unable to establish gas tight seal with TA Cap in 20" MLS profile (unable to proceed with cementing operation)
- Gas leak returns during cement plug placement

An assessment of these operational risks was carried out in January 2021 and the results of this Risk Assessment are discussed in **Section I** of this document.

Method

A vessel-based abandonment would allow for Middle Rosa-2 to be abandoned in line with OEUK Guidelines as follows:

1. Cement Barriers

   All cement barriers would remain as is since they comply with the OEUK guidelines and remediating them has been proven not to be reasonably practicable.

2. Seabed clearance

To maximise the length of the surface cement plug/barrier to the Pliocene sands, the cement would be brought up to inside the conductor stump above the seabed. After an agreed period and when it's apparent that the isolation of the Pliocene sands has been successful and no leak has returned, the stump would be severed at the mudline using a diamond wire saw.

Risk – seabed scour results in the conductor stump protruding above the mudline in the future.

These additional risks will be included in the full risk assessment of the proposed vessel-based operation and will be included as part of the main programme.

L. Comparative Risk Assessment (Rig vs Vessel-based P&A)

In January 2021, a comparative Risk Assessment (RA) was completed when the main risks of a limited rig-based P&A on Middle Rosa-2 were compared to the main risks of a vessel-based P&A.

For the purposes of the comparative RA, the assumption was made that the existing/historical isolations of the Ekofisk and Upper Lark formations are sufficient and that no operations to re-abandon these intervals will be required.

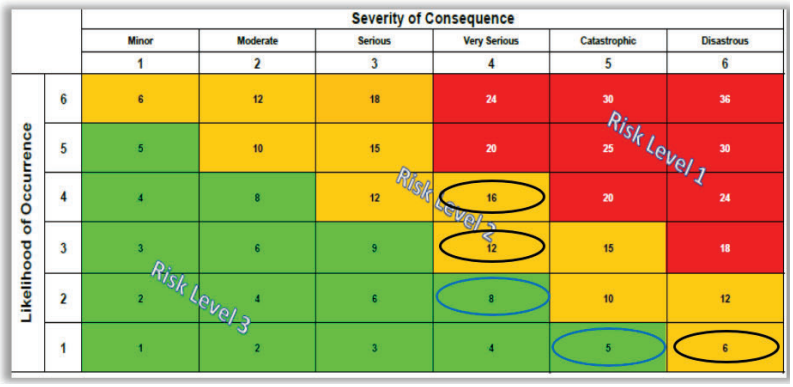
As a result, the scope considered for the rig-based operation did not include drilling out the existing intermediate cement plug over the 13-3/8" casing shoe interval and therefore the risks associated with intentionally establishing communication to the reservoir and the associated hydrocarbons were not considered.

The results of the comparative Risk Assessment have been included as Appendix 16.

The table below highlights the main residual risks for the 2 types of operation.

Rig Based Operation – Residual Risk

Vessel Based Operation – Residual Risk



The main residual risks from the rig-based operation were as follows:

Hazardous Event: Unable to establish integrity with tieback casing string

Residual Risk: Material Loss (Likelihood 4, Severity 4) due to the amount of time potentially lost spent trying to establish integrity into one of any of the 5 thread profiles.

Hazardous Events: Attempts to verify the integrity of the tieback string with pressure testing results in the existing barriers (isolation plugs or annular cement) being damaged and reservoir hydrocarbons and pressure being released.

Drill out existing surface cement plug with reservoir hydrocarbons and pressure below the cement plug being released.

Section milling 13-3/8" casing over the 20" casing shoe interval which results in pressures and vibrations being transmitted into the well which results in the existing barriers (isolation plugs or annular cement) being damaged and reservoir hydrocarbons and pressure being released.

Residual Risks: Personnel Safety (Likelihood 1, Severity 6) due to the risk of reservoir hydrocarbons leaking from the well and travelling up through the conductor string to the rig.

Hazardous Event: Drill out existing surface cement plug with reservoir hydrocarbons and pressure below the cement plug being released.

Residual Risk: Material Loss (Likelihood 3, Severity 4) due to the risk of damage to the rig should there be a large accumulation of hydrocarbons and/or high pressure just below the surface cement plug (insufficient depth to have a column of kill fluid sufficient to control well and potential volumes released greater than if existing isolations are damaged to start to leak)

The main residual risks from the vessel-based operation were as follows:

Hazardous Event: Install temporary barrier (such as TA Cap) within 20" threaded profile but failing to prevent gas leak

Residual Risk: Material Loss (Likelihood 2, Severity 4) due to the amount of time and costs associated with mobilising a vessel to the location and being unable to proceed with setting the cement plug.

Hazardous Event: Channel forms in cement whilst setting balanced plug and gas continues to leak from the well

Residual Risk: Material Loss (Likelihood 1, Severity 5) due to the amount of time and costs associated with mobilising a vessel to the location and potentially having to circulate out the cement and remove the temporary barrier and develop an alternative solution (to be completed during a separate operation)

RA Assessment Summary

The comparative RA only focussed on the operational risks of the 2 possible methodologies (rig-based P&A vs vessel-based P&A) and did not consider the risks associated with isolating the Pliocene sands just below the mudline as part of a vessel-based operation.

From an operational point of view, the significant residual risks associated with a rig-based P&A include risks to personnel, assets and the environment due to the risk of releasing high pressured, reservoir hydrocarbons from the well with the environmental riser providing a conduit straight back to the rig and with a low likelihood of being able to establish and/or verify a high pressure seal with the tieback casing, there is also a risk that any reservoir hydrocarbons escaping from the well, could leak into the environment.

From an operational point of view, the significant residual risk associated with a vessel-based P&A is related to material loss only.

Environmental risks from a vessel-based P&A were not considered to be significant risks during the operation as the leak is non-reservoir, methane gas which has been verified to have depleted and has no significant pressure build up. As the leak has been continuous for 38 years, should the methane continue to leak throughout the operation or after the operation has been suspended, the risk to the environment, the vessel and personnel has been considered to be minimal.

Based on the outcome of the comparative RA and the compliance with OEUK Guidelines the plan is to pursue the vessel-based P&A in preference to the rig-based solution.

M. Conclusion

The review of the Middle Rosa-2 well involved a detailed study of the original drilling and P&A Operations, subsequent monitoring and remediation efforts as well as the geology of the formations intersected by the well.

The periodic monitoring and interventions on the well can be summarised as follows:

- 2012: Gas sample collected and found to be biogenic in nature.
- 2016: P&A vessel fitted a net deflector with a vent installed on the conductor for a more accurate measurement of the declining leak rate (0.9 ltr/min). A camera inspection confirmed the leak from the 13-3/8" x 20" annulus.
- 2021: A modified 20" TA Cap was installed into the mud line system 20" hanger. Bubbles observed leaking from the check valve mounted to the TA Cap.
- 2022 & 2023: ROV surveys found bubbles of biogenic gas (0.02-0.05 lrt/hr) coming from the check valve. For scale, this rate is far below the Article 14(8) repair threshold for offshore subsea components under the EU Methane Regulation; however, this comparison is included only as a contextual benchmark and not as the applicable legal basis for the well.

The periodic monitoring confirms that the gas bubbling is on a declining trend.

The latest Subsurface study of the Upper Lark concluded that this formation cannot be classified as zone with flow potential as per the OEUK Guidelines for Well Decommissioning Issue 7, November 2022.

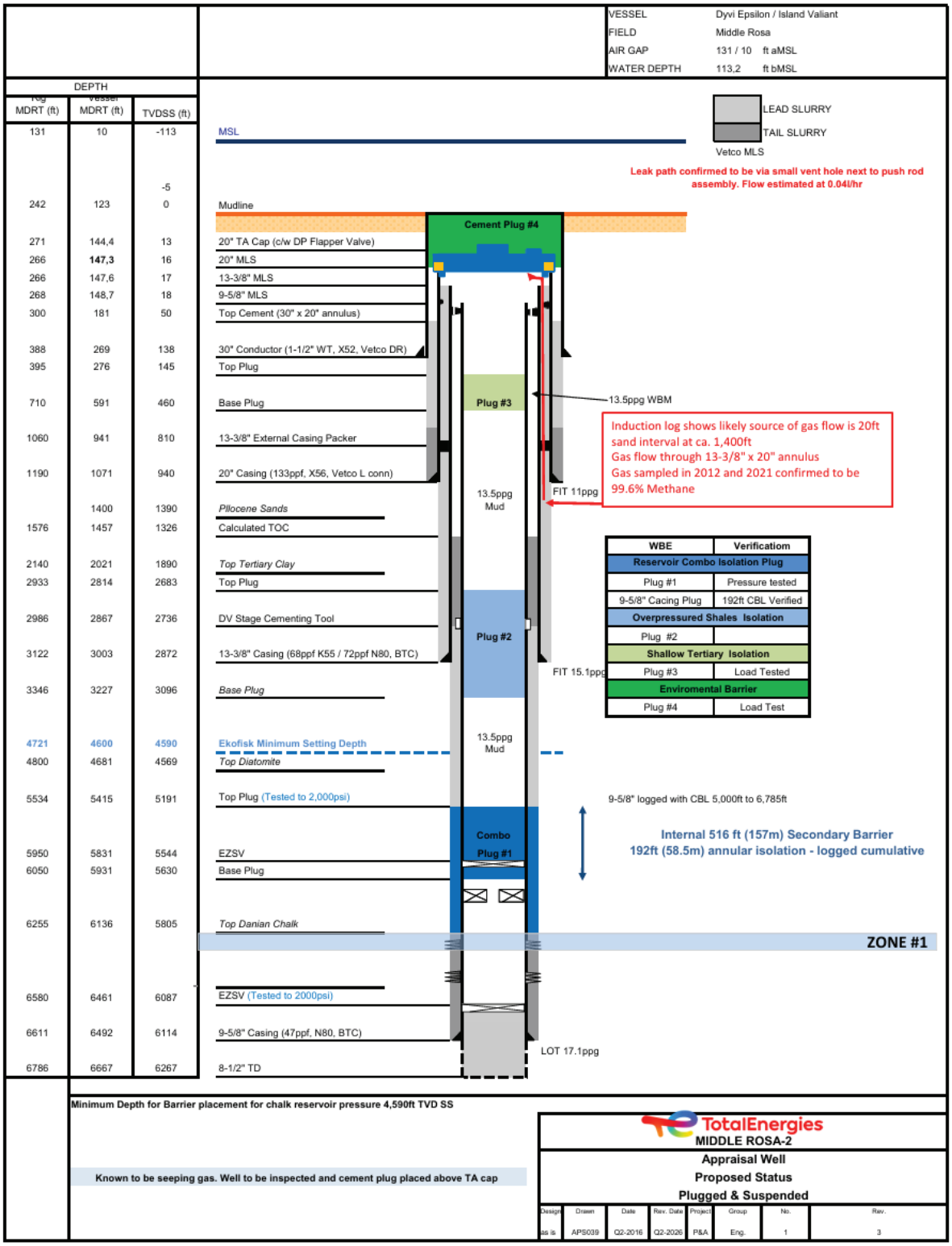
The Subsurface study results confirms that the only zone with flow potential is the Ekofisk reservoir which is proven to be isolated in line with the OEUK guidelines. Secondly the analysis of the gas bubbles captured concluded that it is biogenic in nature and on a declining trend confirming that the Ekofisk reservoir is isolated.

The proposed intervention removes the remaining shallow biogenic methane emission pathway while avoiding intrusive operations that could compromise demonstrated existing deep barriers to the Ekofisk reservoir.

TotalEnergies concludes that the safest and ALARP assessed way forward to complete the remaining Abandonment phase of the Middle Rosa-2 well is with the use of an Intervention vessel to replace the current TA Cap, place cement on top and cut the conductor at seabed. This plan aligns with OEUK Guidelines for Well Decommissioning.

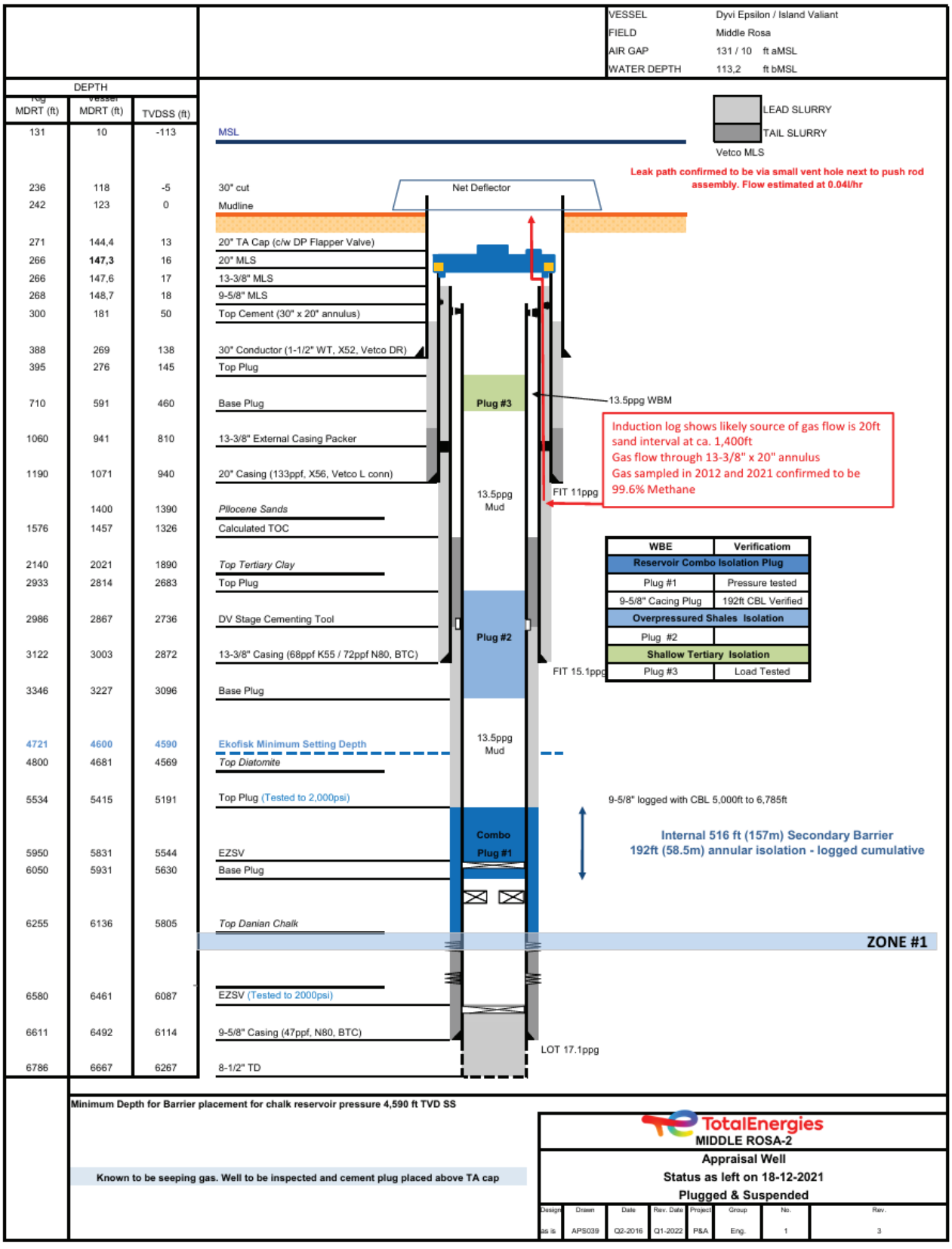
This is a tool and technique which TEP DK has been used successfully on 26 previous wells and removes the risk of a loss of primary containment. The final well status with barriers to the flow potential zone is shown below.

Proposed Barrier Diagram

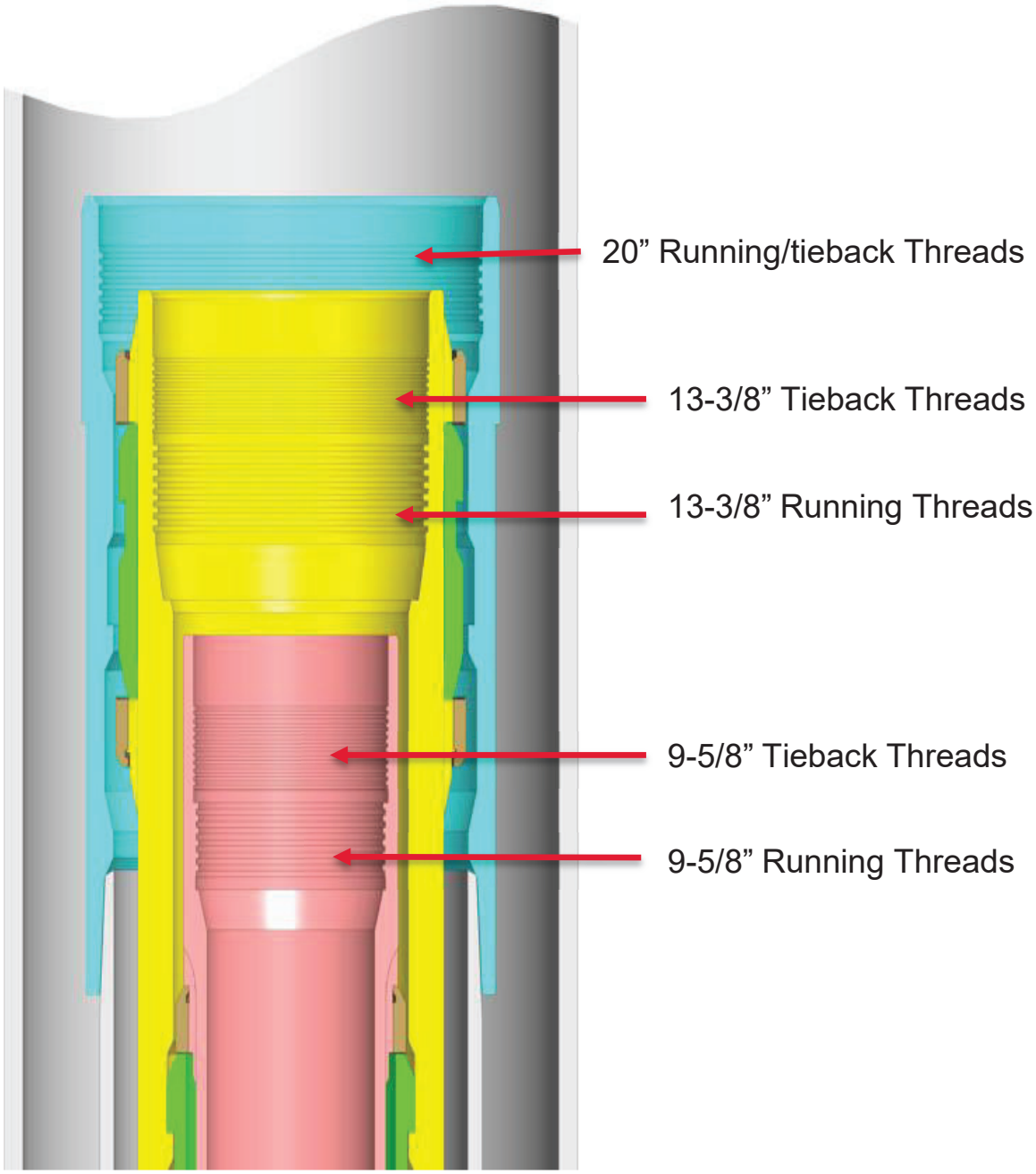


N. APPENDICES

N.1 Current Well Status Drawing



N.2 Vetco Type IV Mudline Suspension System



Actual configuration of MLS on Middle Rosa-2 (13-38” hanger sitting 2” higher than designed)

N.3 Cement Job Review

20" Cement Job

Planned TOC: Back into 30" shoe (146ft MD BML)

Volume pumped: 1200 sxs, 13 ppg lead and 1000 sxs, 16 ppg tail

Losses/Returns during cement job: 300 bbls contaminated cement at surface

Losses after displacement: None reported

Estimated final TOC: 58 ft MD BML – based on displacement depth and annulus cleanout

Comments: Circulated cement out in annulus with 1-1/4" tubing from 300 ft MDRT (58 ft BML) to ensure TOC below 20" hanger depth.

13-3/8" Cement Job

Planned TOC: Back to 13-3/8" hanger (31ft MD BML)

Volume pumped: 1450 sxs, 13 ppg lead and 1000 sxs, 16 ppg tail

Plug bumped: Yes and casing tested to 2,000psi

Losses/Returns during cement job: None reported

Losses after displacement: None reported

Estimated final TOC: 31ft MD BML – 13-3/8" hanger depth

Comments: Slurry displaced to mudline and the washports were opened and excess cement circulated out of annulus above hanger. 13-3/8" casing became stuck whilst RIH and was cemented in place with 13-3/8" casing hanger sitting ca. 2-3" high.

9-5/8" Cement Job

Planned TOC: Back into 13-3/8" shoe (1700ft MD BML)

Primary Stage Job - Volume pumped: 100 sxs, 14.5ppg "scavenger" cement, 800 sxs, 14.5 ppg Class G lead and 800 sxs, 15.4 ppg tail

Secondary Stage Job - Volume pumped: 400 sxs, 16 ppg

Plug(s) bumped: Yes and casing tested to 4,600psi

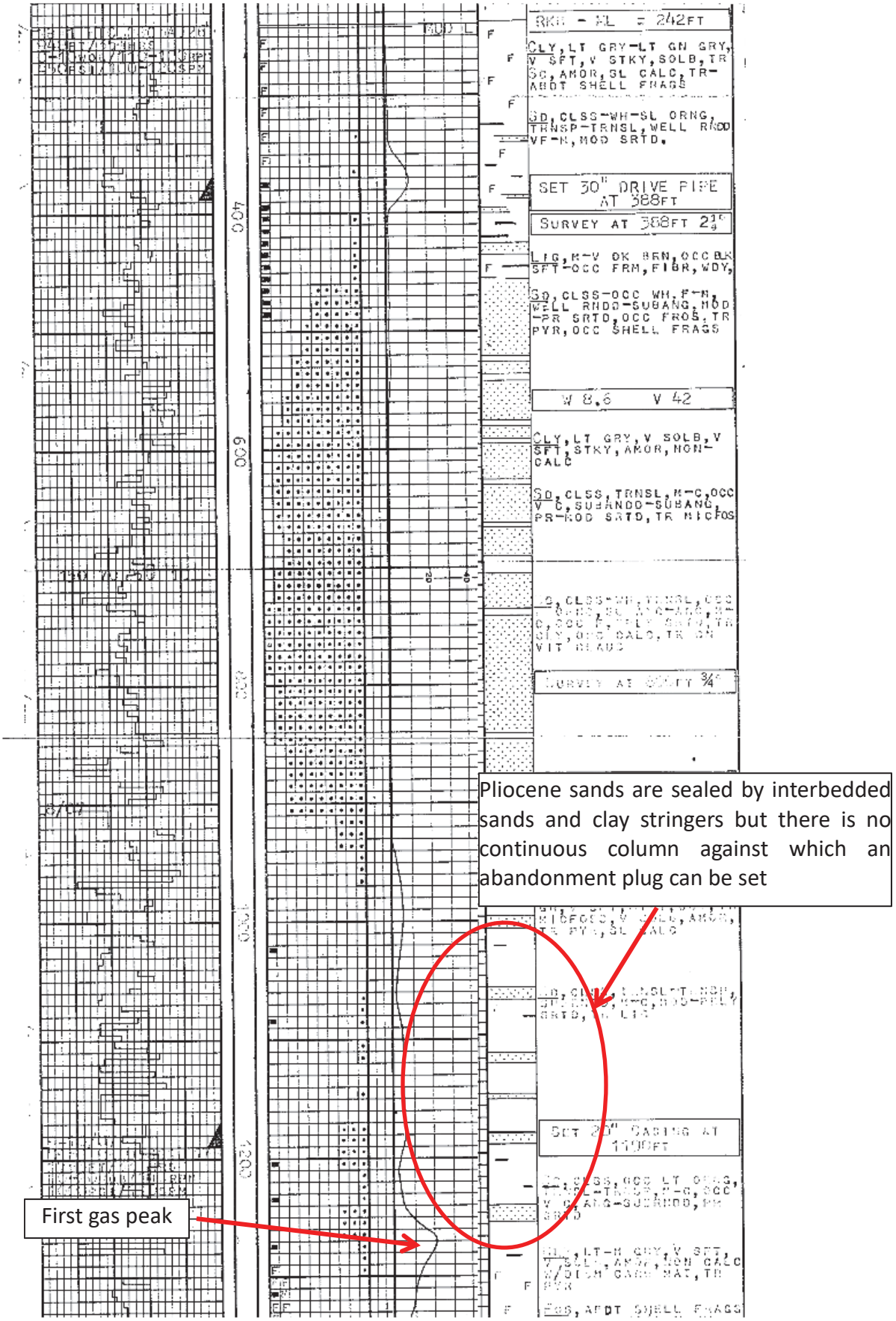
Losses/Returns during cement job: None reported

Losses after displacement: None reported

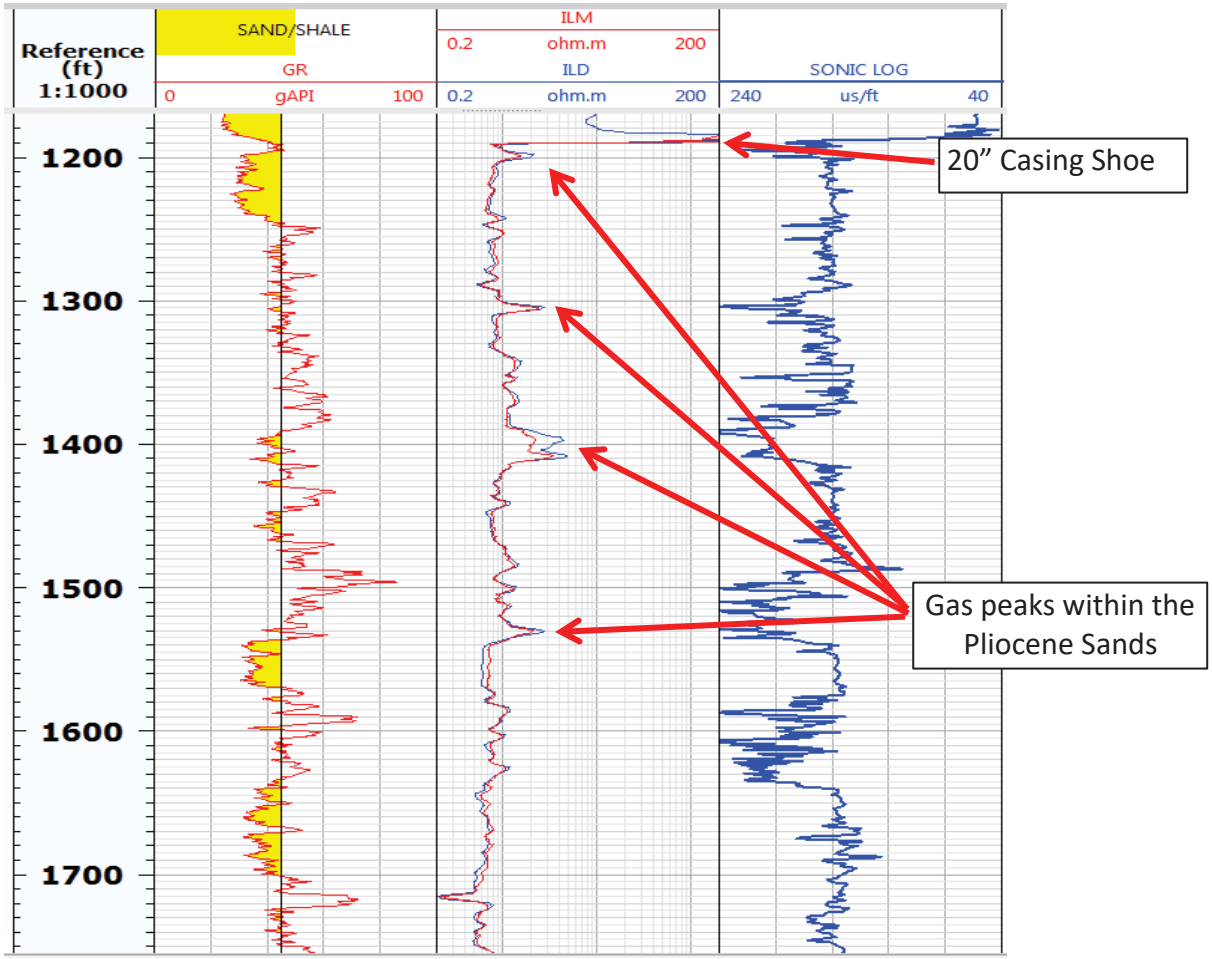
Estimated final TOC: 1,334ft MD BML – secondary stage through DV stage cementing tool

Comments: A CBL log was taken on the 9-5/8" casing between 5,000ft and 6,611ft which indicated a partial bond for over the logged interval.

N.4 Middle Rosa-2 Mudlog

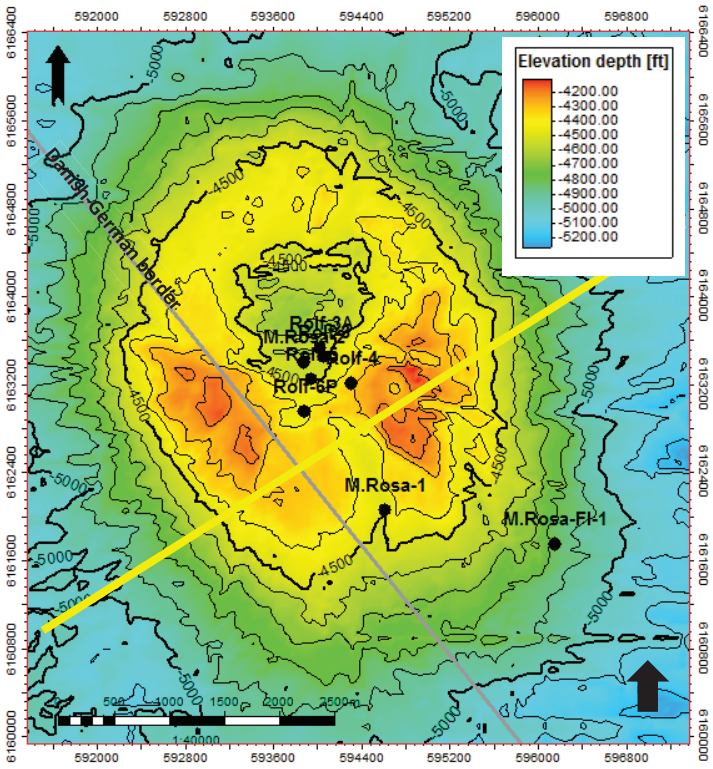


N.5 Middle Rosa-2 Induction log below 20” shoe



N.6 Top Upper Lark Depth Structure map

Top Upper Lark Structure map (ft)



Well distances at Top Upper Lark:

Rolf-4 to Rolf-5: 380 m

Rolf-4 to Rolf-3: 355 m

Rolf-4 to M. Rosa-2: 473 m

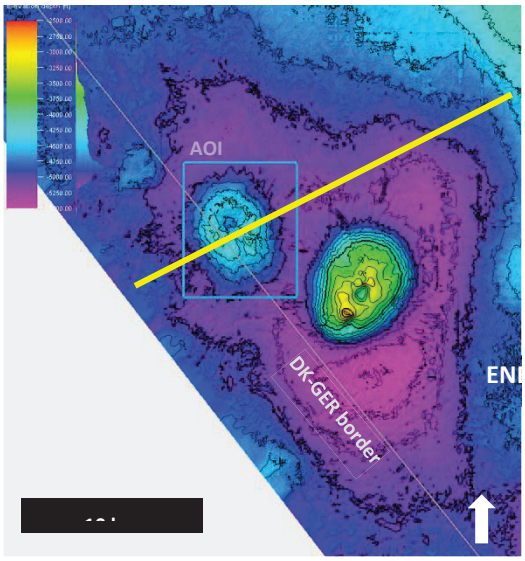
Rolf-4 to M. Rosa-1: 1163 m

Rolf-4 to M. Rosa Fl-1: 2365 m

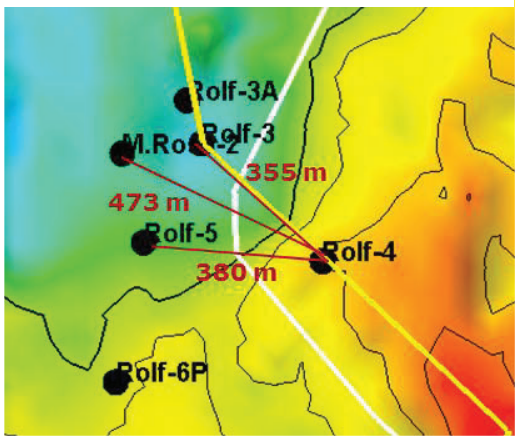
Rolf-5 to M. Rosa-2: 200 m

Rolf-3 to M Rosa-2: 170 m

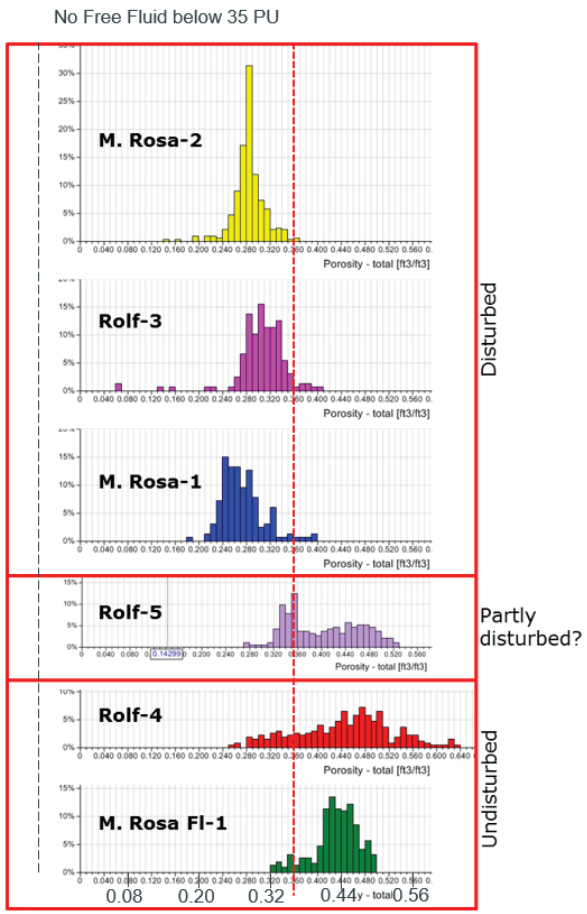
Top Upper Lark Regional Structure map (ft)



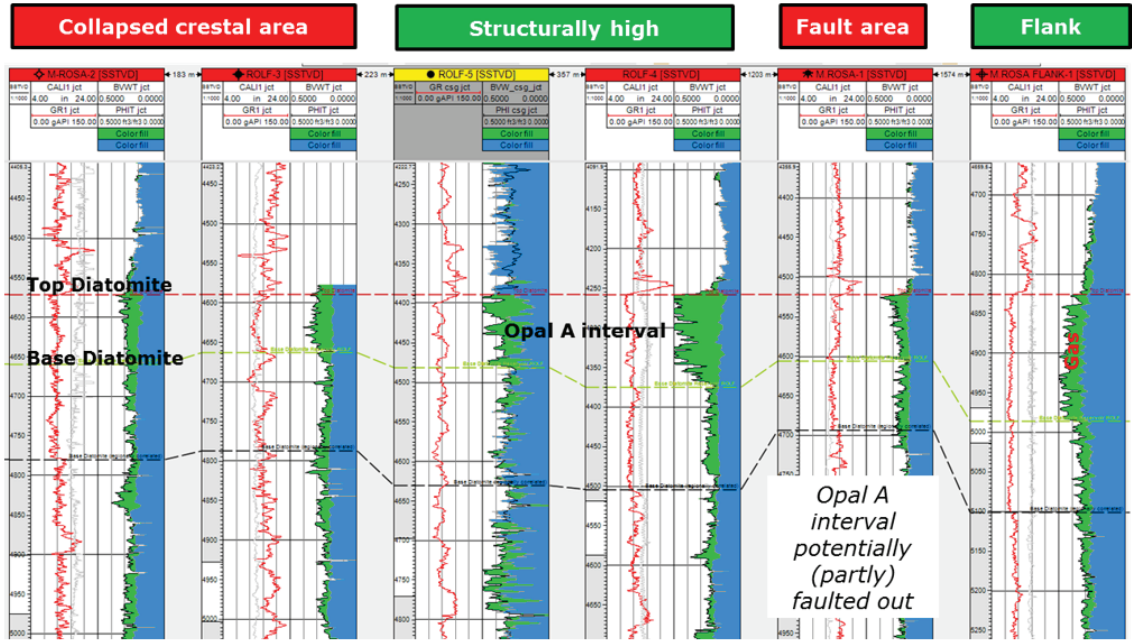
Zoom in at crestal well positions



Histograms for all six Rolf Wells:

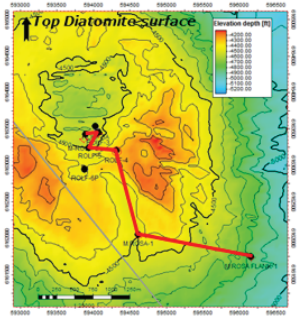


Wells – correlation panel flattened on Top Diatomite

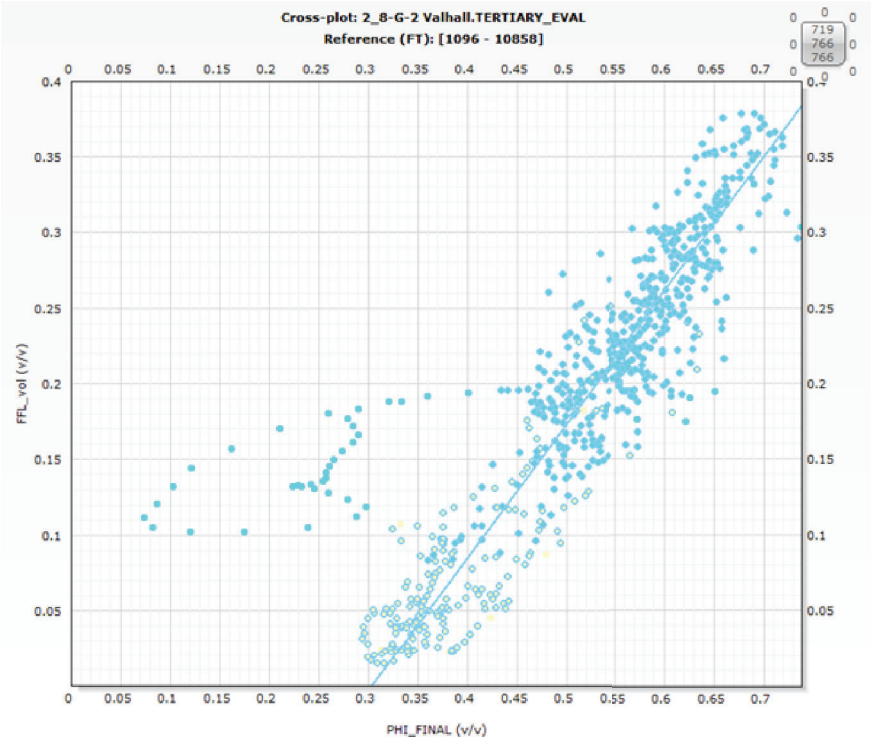


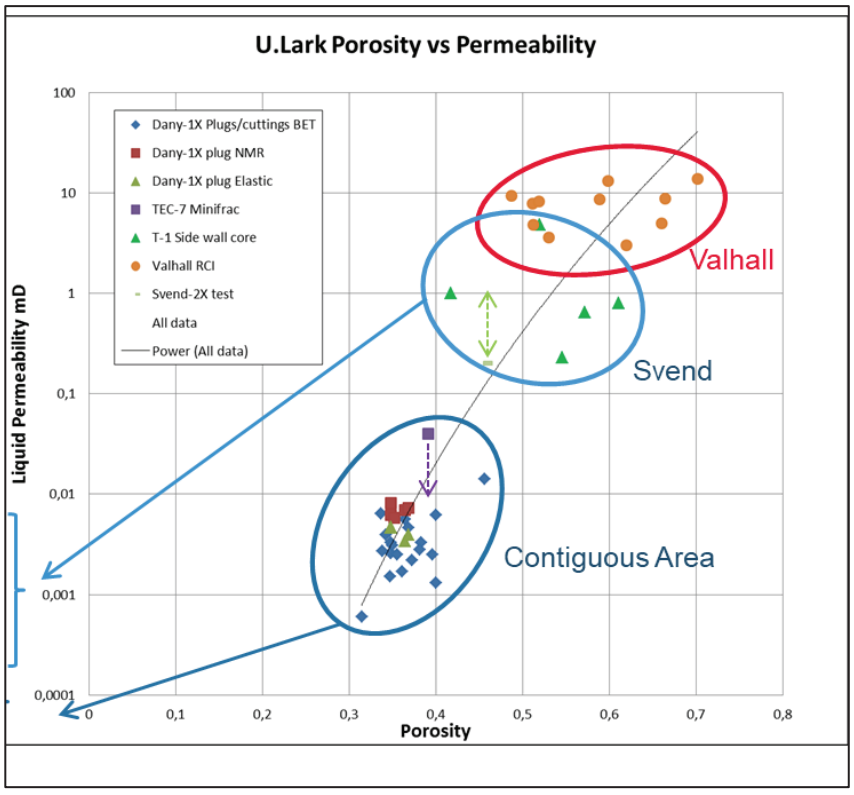
Porosity data:

- *Six Rolf wells with log data (Rolf-5 recently acquired via cased hole logging)*
- *Interval picked with confident top and less confident base pick.*
- *Two groupings based on porosity histograms that can relate to disturbed/Opal CT and undisturbed areas (Opal A)*

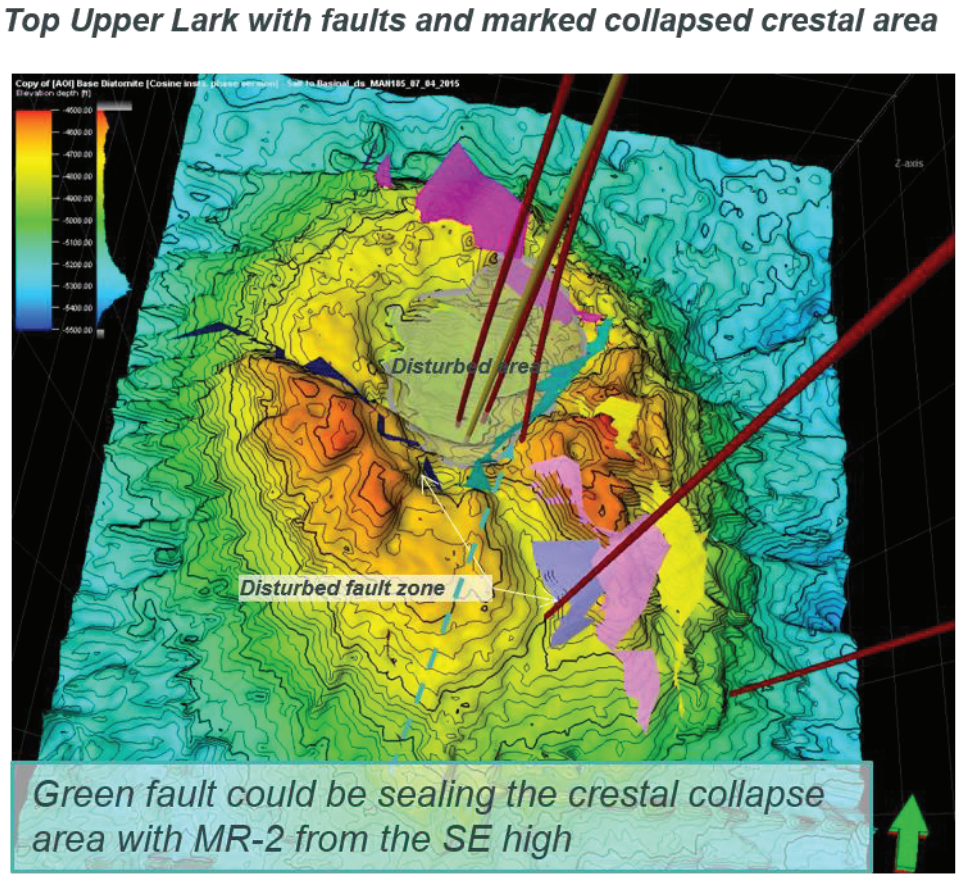


N.8 Porosity-Free Fluid volume X-plot & Porosity-Permeability x-plot



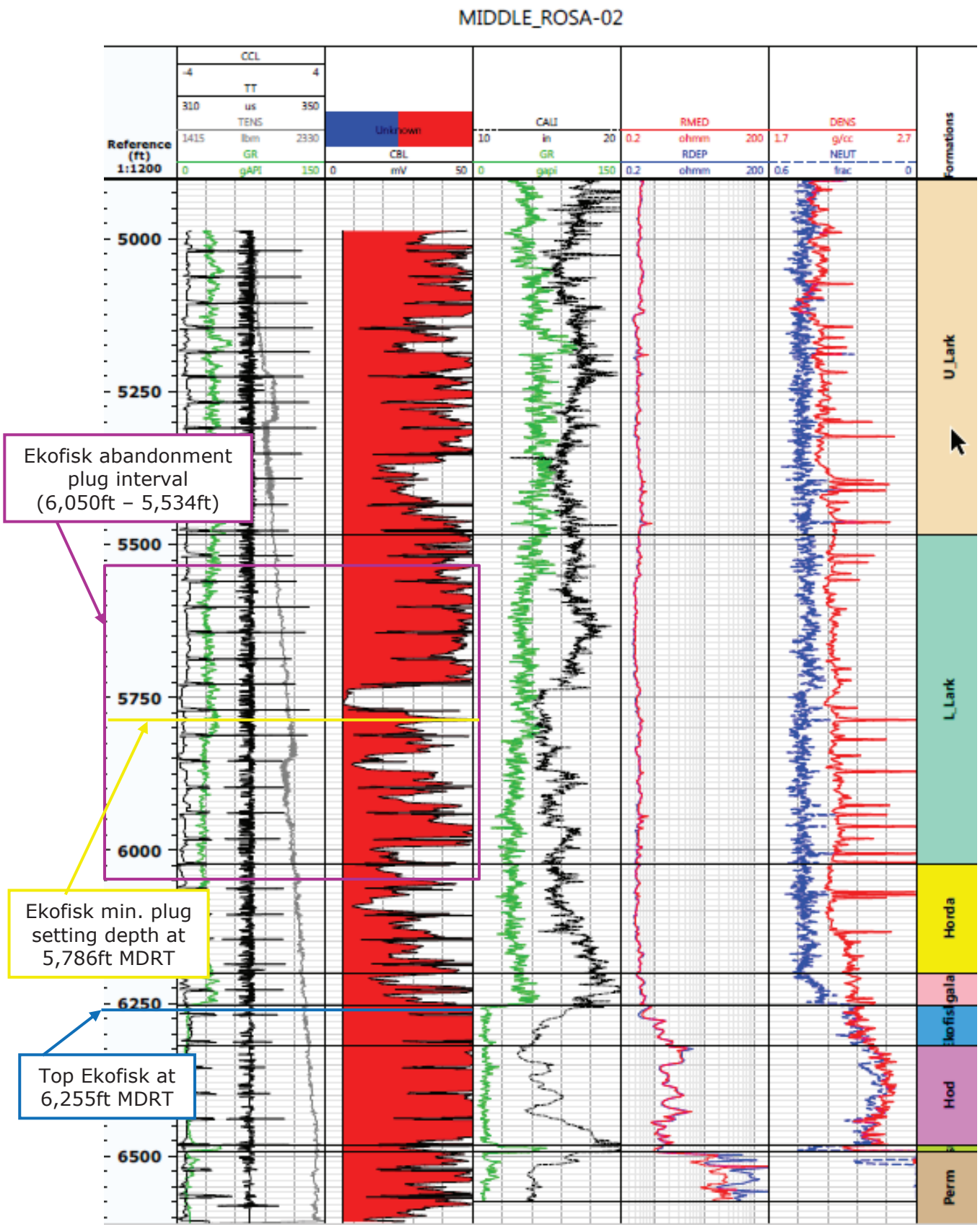


N.9 Top Upper Lark 3D structure with faults



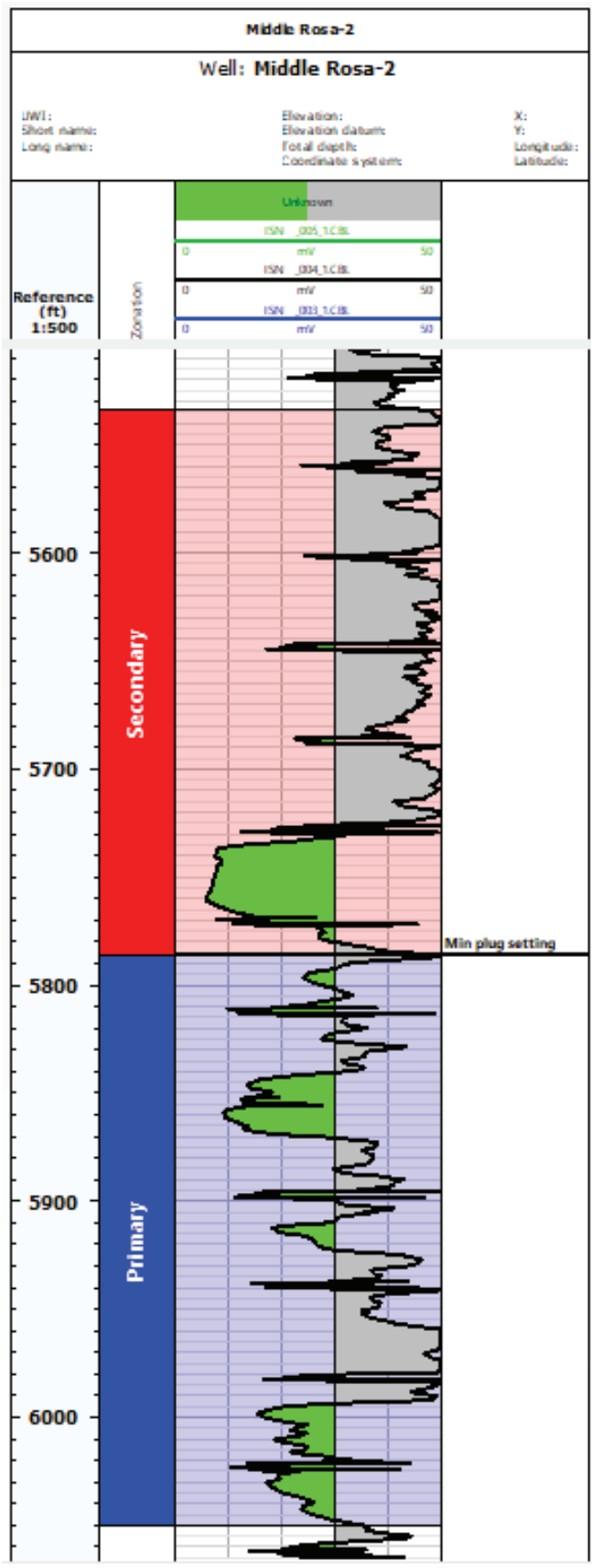
Disturbed areas (collapsed crestal area with MR2 and fault zone at Ml Rosa-1) have wells with marked lower porosities than wells from less to undisturbed areas (Rolf-4)

N.10 9-5/8" casing CBL interpretation from 2012



N.11 9-5/8" casing CBL interpretation from 2021 (1:500)

CBL response of <30mV considered to represent bonded annular cement (highlighted in green)



Cumulative colum
over Secondary Ba
reservoir (ZONE#

60ft / 18.3m

5,534 ft – 5,786 ft
(252 ft / 76.8m)

is

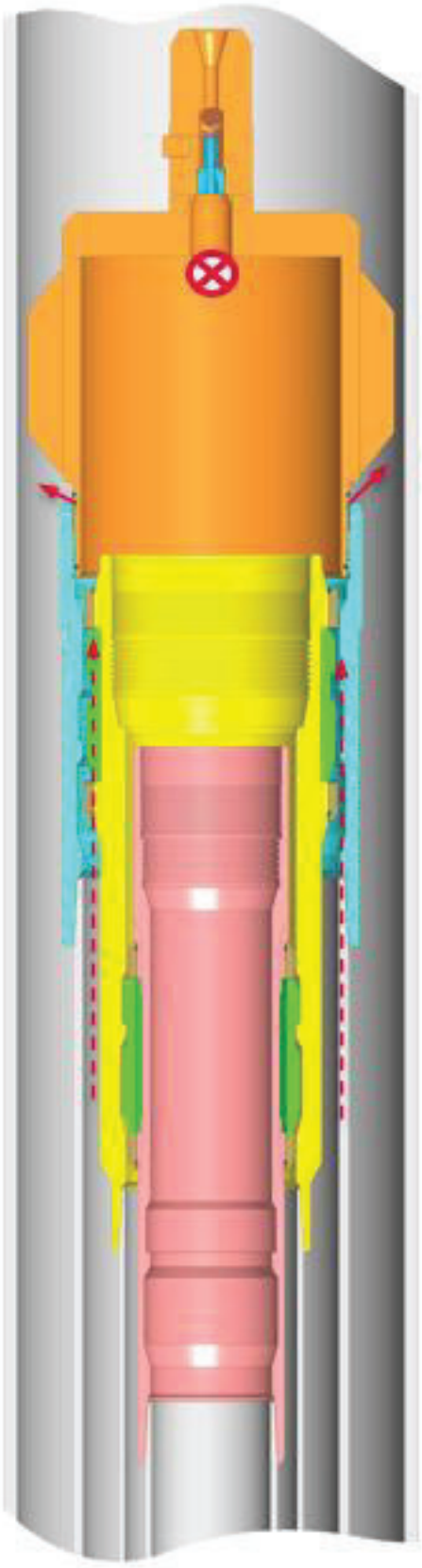
5,786 ft – 6,050 ft
(264 ft / 80.5m)

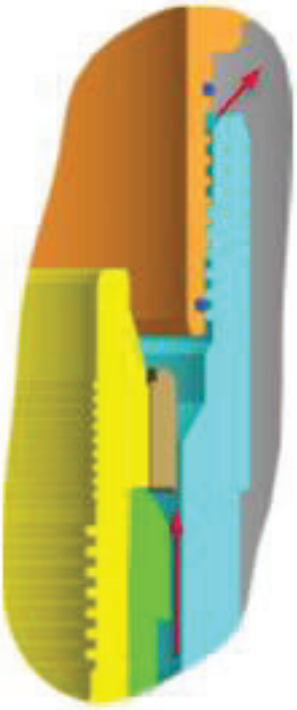
Cumulative column of bonded cement over Primary Barrier to Ekofisk reservoir (ZONE#1) (6,050ft-5,786ft) is:

132ft / 40.2m

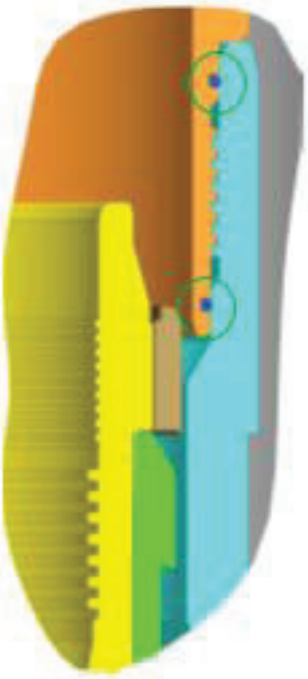
N.12 Original 20” TA Cap installation drawing

Schematic showing the original TA Cap installation into the 20” tieback threads on Middle Rosa-2.



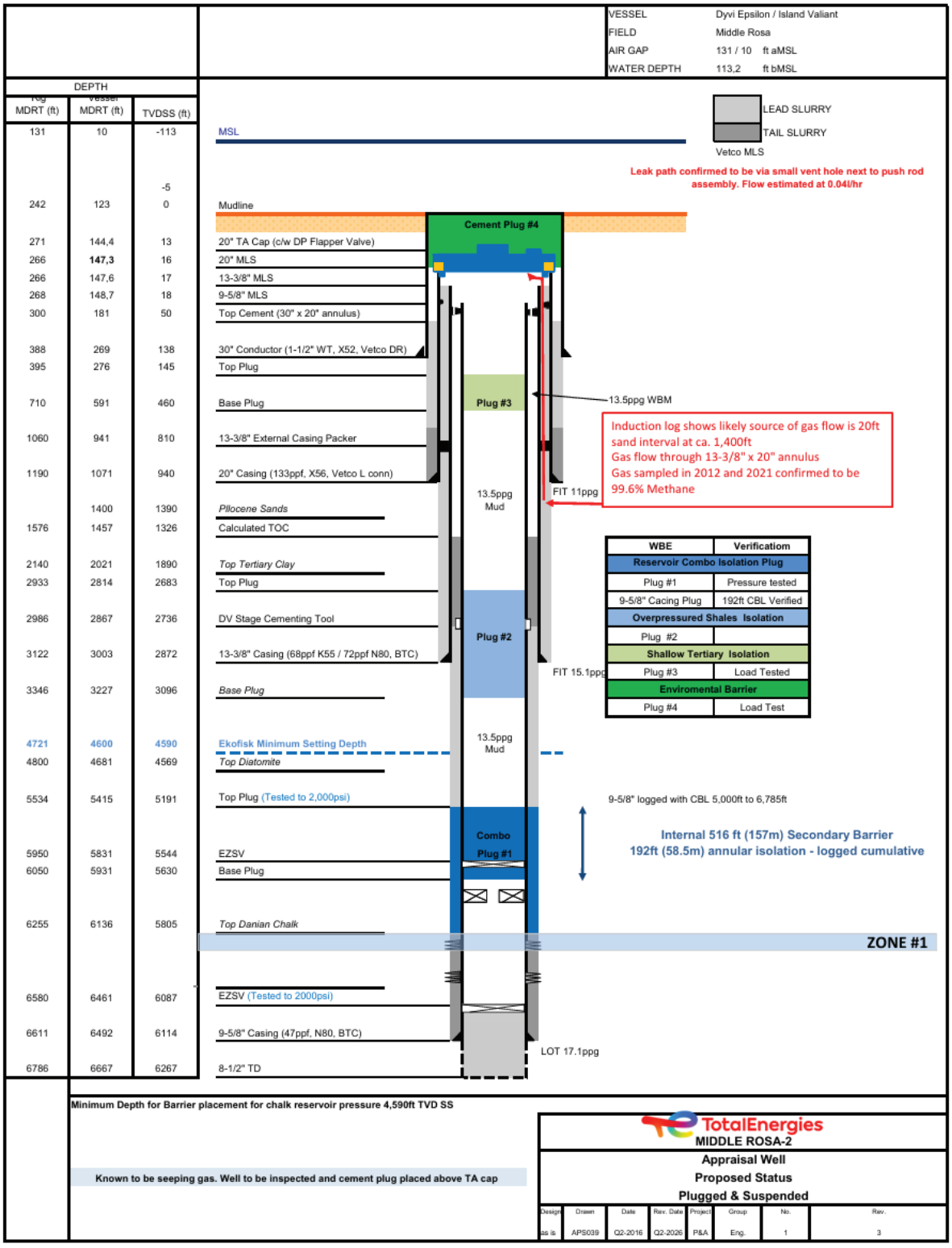


Actual position of the upper and lower seal rings (dark blue) with the 20” TA Cap only partially engaged



Designed position of the upper and lower seal rings (dark blue) if the 20” TA Cap was fully engaged

N.13 P&A of Middle Rosa-2 in compliance with OEUK Guidelines

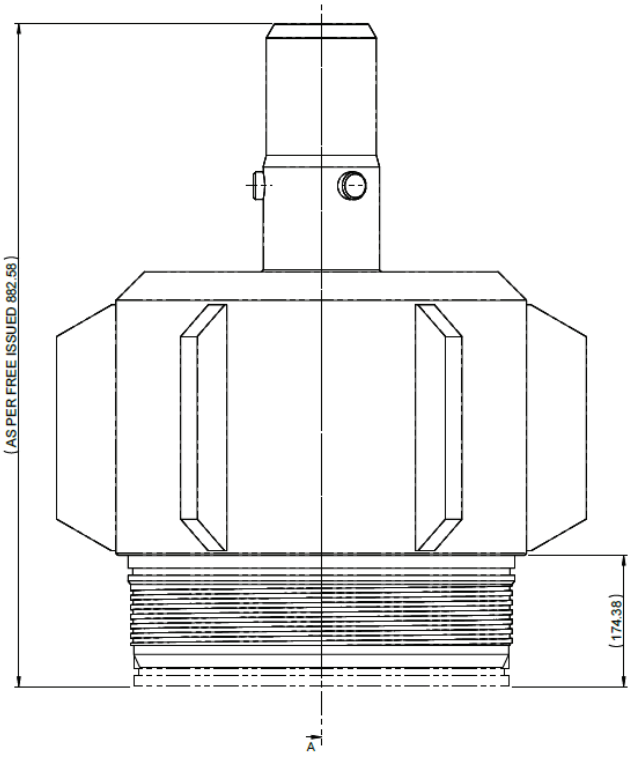


MDRT (ft)	MDRT (ft)	TVDSS (ft)	
131	10	-113	MSL
		-5	
242	123	0	Mudline
271	144,4	13	20" TA Cap (c/w DP Flapper Valve)
266	**147,3**	16	20" MLS
266	147,6	17	13-3/8" MLS
268	148,7	18	9-5/8" MLS
300	181	50	Top Cement (30" x 20" annulus)
388	269	138	30" Conductor (1-1/2" WT, X52, Vetco DR)
395	276	145	Top Plug
710	591	460	Base Plug
1060	941	810	13-3/8" External Casing Packer
1190	1071	940	20" Casing (133ppf, X56, Vetco L conn)
	1400	1390	*Pliocene Sands*
1576	1457	1326	Calculated TOC
2140	2021	1890	*Top Tertiary Clay*
2933	2814	2683	Top Plug
2986	2867	2736	DV Stage Cementing Tool
3122	3003	2872	13-3/8" Casing (68ppf K55 / 72ppf N80, BTC)
3346	3227	3096	*Base Plug*
4721	4600	4590	Ekofisk Minimum Setting Depth
4800	4681	4569	*Top Diatomite*
5534	5415	5191	Top Plug (Tested to 2,000psi)
5950	5831	5544	EZSV
6050	5931	5630	Base Plug
6255	6136	5805	*Top Danian Chalk*
6580	6461	6087	EZSV (Tested to 2000psi)
6611	6492	6114	9-5/8" Casing (47ppf, N80, BTC)
6786	6667	6267	8-1/2" TD

Design	Drawn	Date	Rev. Date	Project	Group	No.	Rev.
as is	APS039	Q2-2016	Q2-2026	P&A	Eng.	1	3

N.14 TA Cap Modifications 2018 onwards

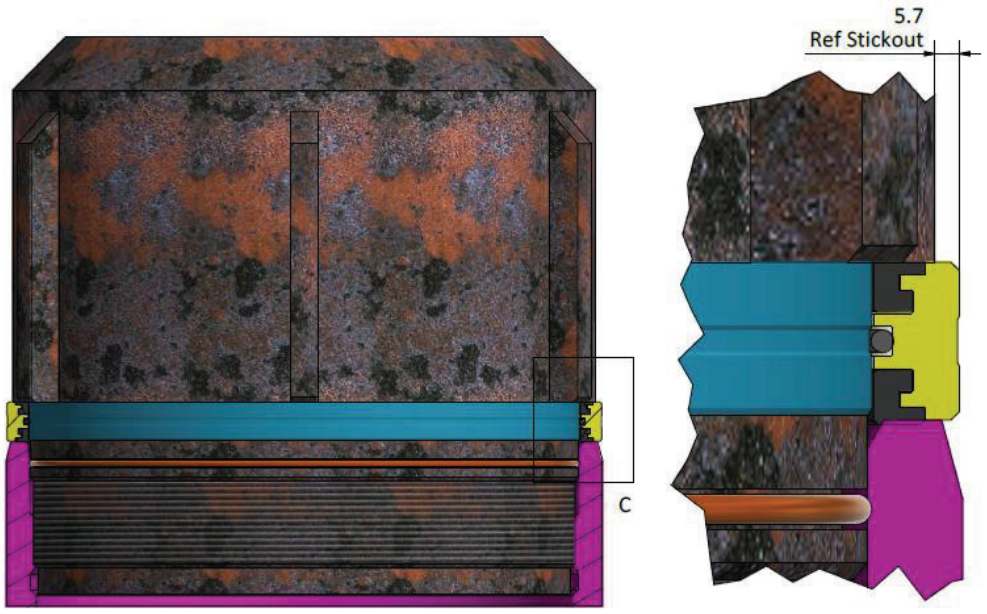
Lower lip guide and lower seal ring grove removed from the base of the TA Cap threaded section (to reduce the risk of mechanical interference between the TA Cap and the 13-3/8" casing hanger)



Lower section of the TA Cap main body machined to allow for the installation of a metal crush ring (metal to metal) seal above the original upper seal ring grove.



A small (37mm) crush ring which will be installed and will establish a metal-to-metal seal against the top of the 20” hanger if the TA Cap is fully made up into the 20” hanger. An original style O-ring will also be run in the TA Cap ring groove with the crush ring providing a back-up seal to the O-ring.



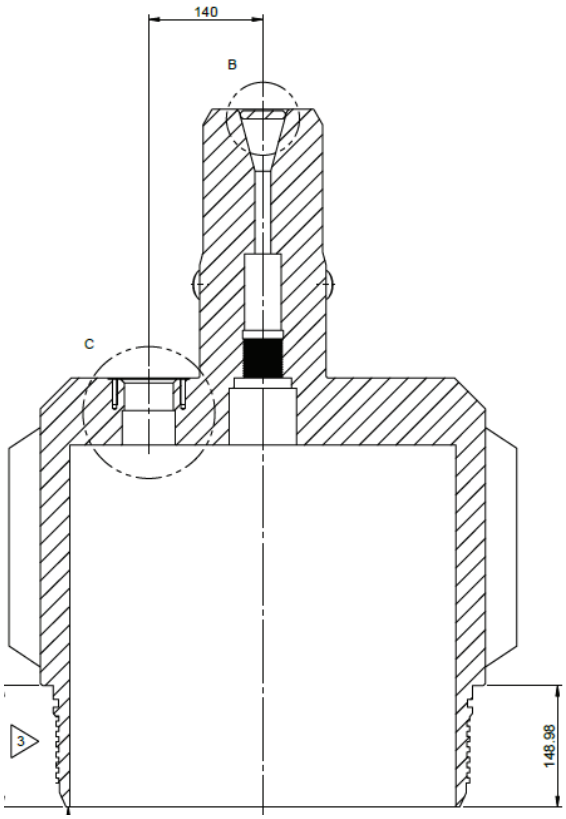
Detail C
Smaller Ring to work in conjunction with existing O-Ring

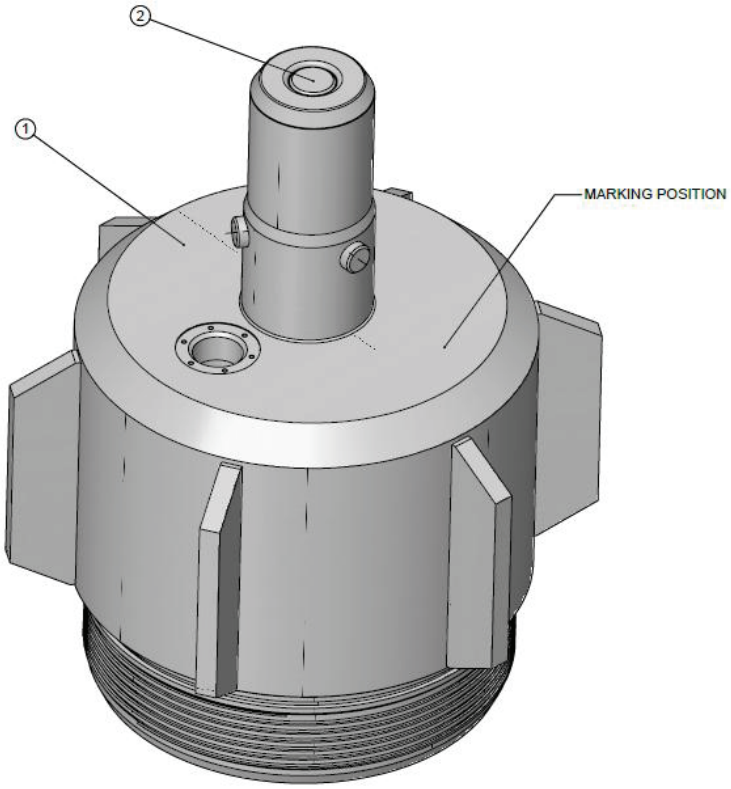
A large (81mm) crush ring which will seal against the top of the 20” hanger if the TA Cap cannot be fully made up into the 20” hanger. This assumes the TA Cap can only be partially made up and the original ring groove cannot be positioned against the hanger seal face. The crush ring will provide a metal-to-metal seal but this will be the only seal.



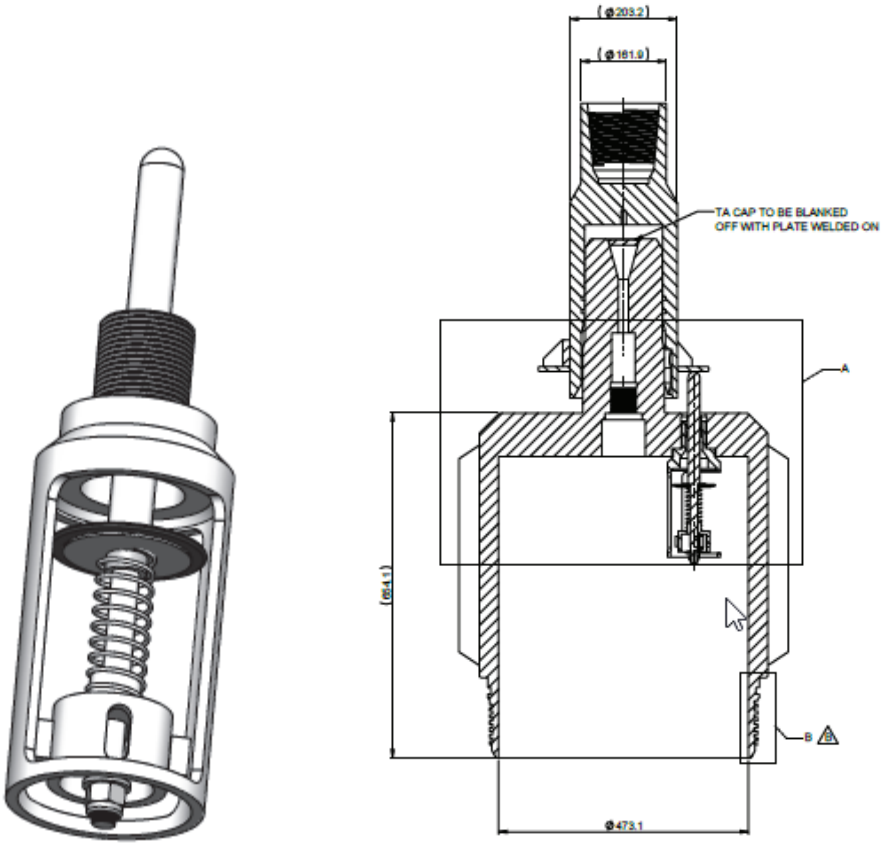
Detail B
Larger Ring to take over sealing from existing O-Ring

Original BPV/modified drill pipe float valve removed, and TA Cap mandrel plugged to prevent flow. Hole bored in TA Cap top to allow for check valve installation.

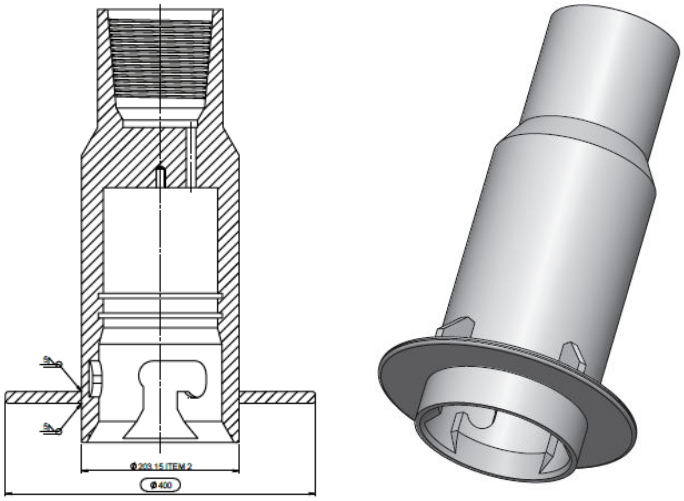




Check valve installed in the top of the TA Cap (which can be held open during TA Cap installation to allow the cap to be run in a vented position). This check valve is spring loaded and will close as soon as the plunger is no longer held down.



Sleeve welded onto the outside of the TA Cap running tool, which when connected to the TA cap will depress the check valve plunger and allow the cap to be in the vented position (once the running tool is released from the TA Cap and the sleeve lifted, the plunger will lift and the check valve close).



N.15 Middle Rosa 2 Re-entry Risk Assessment

Site:	Middle Rosa -02	Synergi No.:		Doc. No.	
Platform:	Subsea Well	System:		Revision:	00
Title:	Risk Assessment for P&A Operations for Middle Rosa -02			Date Raised	

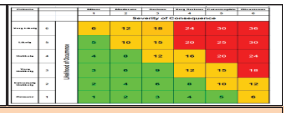
NOTE: If scenario requires new revision or update to Risk Assessment, add new revision of whole Risk Assessment workbook. **PREVIOUS REVISIONS OF RISK ASSESSMENT MUST BE HELD ON FILE AND NOT DELETED.**

Ref	Hazard/Anomoly/Threat	Probable Causes	Potential Consequences	Existing Controls/safeguards (During Normal Operation)	Risk classification	Initial Risk assumptions	Initial Risk (Probability & Severity) P	S	IR	*Note: Measures can be listed in any constructive order.* Compensatory Measures to Reduce Risk	Residual Risk assumptions	Residual Risk (Probability & Severity) P	S	RR	Major Integrity Threat	*Note: Actions can be listed in any constructive order* Corrective Actions
1	**Leave as is** Leak to surface of hydrocarbon from the Upper Lark (diatomaceous Mudstone)	Insufficient abandonment plug length to hold the formation pressure at depth, thus allow the pressure from the Upper Lark (diatomaceous Mudstone) to come in contact with a formation too weak to support/contain the formation pressure.	Hydrocarbon release at surface due to broaching	Majority of Wells abandoned between 1975-1990 in Danish Waters used the methodology for abandoning Wells as used in MR2. No leak seen in last 43 years from the Upper Lark formation. **Long term inflow test.** The Upper Lark (Diamtic Mudstone) as an ultra low permeability zone with limited connectivity and non-movable fluids, based on the available evidence. **Data does not support or demonstrate a sustained flow potential.**	Human									NA		Re-enter well (additional risk) and replace current cement plug across the 13-3/8" shoe with one that fully meets CURRENT OEUK standards.
					Environment	Minor pollution, remote possibility, Has never occurred in DUC.	1	2	L3 - 2	No measures in place		1	2	L3 - 2		Perform Broaching Study to confirm a breach would not reach the surface
					Material									NA		
					Media									NA		
					Production									NA		
2	**Re-enter Well** Unable to Tieback to cut 30" conductor.	Corroded conductor after 43 years exposed to SW Structural too weak to support a 30" CP to surface	Unable to install environmental riser to allow acces to Well	Successfuly connected short section POSI-grip connector 6 years ago during Intervention Vessel campaign. Structural analysis of strength and fatigue exposure to CP to confirm acceptability	Human						No measures in place				NA		
					Environment									NA		Send ROV to inspect conductor before rig arrival to ascertain corroison damage
					Material	Corrosion has caused engagement issues before, several days delay	4	3	L2 - 12	Perform CP structual strength & fatigue analysis.		2	3	L3 - 6		Perform CP structual strength & fatigue analysis. *Ongoing*
					Media									NA		
					Production									NA		
3	**Re-enter Well** Unable to run 9-5/8" SLB casing re-connect system	Debris / cement in 13-3/8" x 9-5/8" annulus Corroded Casing reducing strength and inability to form casing to reconnect system	Unable to acheive enough swallow to engage system Cannot create HP connection due to poor casing condition	Logs suggest no cement behind casing at cut depth to allow sufficient swallow of casing Run internal packer which will reduce ID of well entry but allow access to the wellbore. This restricted ID will limit remediation operation such as section milling, if undertaken.	Human						No measures in place				NA		Utilisation of rubbliser to breakdown annulus blockage.
					Environment									NA		Pilot milling 9-5/8" casing / hanger until clear to clean out annulus. Use of a overshot mill to clear annulus.
					Material	Reconnect system running stopped by the smallest debris / settlement in annulus, often seen in old wells, requirement to use alternative connection method, week or more to recover.	4	4	L2 - 16			3	4	L2 - 12		Run log for 9-5/8" casing to determine strength and cement / debris in annulus
					Media									NA		Cut additional length of casing to provide new starting point for CRS connection
					Production									NA		Have internal packer ready to allow access to wellbore.
4	**Re-enter Well** Unable to test HP riser against 9-5/8" casing to required pressure	Corroison of casing after 43 years submerged - 18% corrosion (best case) = **4,506 psi casing** strength - 70% corrosion (feasible) = **1,538 psi casing** strength Exposure to Chalk reservoir preesure = **3,000 psi.**	Inability to safely drillout cement plugs as tested well barrier cannot prevent Leak Of Primary Containment (LOPC)	None	Human						No measures in place				NA		Run a log before pressure testing to ensure structural integrity of 9-5/8" casing
					Environment	Environmental consequences due to casing failure	2	4	L3 - 8			2	4	L3 - 8		
					Material	Inability to access well, long delays	5	4	L1 - 20			5	4	L1 - 20	MIT	Not able to proceed if test fails.
					Media									NA		
					Production									NA		
5	**Re-enter Well** Communication to Chalk reservoir after removing internal cement plugs	Failed deep abandonment plug Kick to surface ***9-5/8" Casing not strong enough to contain kick due to feasible corroison values***	Injury of personnel Release of hydrocarbons to environment	The 9-5/8" casing (Primary barrier system) ONLY tested to 2,000 psi in 1983. Exposure to Chalk reservoir could see pressures as high as **3,000 psi.**	Human	Injuries due to hydrocabon release to surface	2	5	L2 - 10	Conduct P/T to 3,000 psi before re-entry BOPs on 9-5/8" Kill weight fluids		2	4	L3 - 8		Run a log before pressure testing to ensure structural integrity of 9-5/8" casing
					Environment	Significant pollution potential	2	4	L3 - 8			1	4	L3 - 4		Prepare for kick when cement plug drilled out.
					Material									NA		Have kill mud ready incase kick is taken
					Media									NA		Complete GEO studies for relief well location
					Production									NA		
6	**Re-enter Well** Section Milling / PWC	Poor annular cement quaility shown on log requires remediation, which subsequently breaks existing cement bonds.	Release of minor hydrocarbons due to loss of cement in annulus during section milling - opening up a conduit into the 13-3/8" casing annulus	30" environment riser is not pressure containing but will capture minor leaks from 13-3/8" annulus The Upper Lark (Diamtic Mudstone) as an ultra low permeability zone with limited connectivity and non-movable fluids, based on the available evidence. **Data does not support or demonstrate a sustained flow potential**	Human	Minor hydrocarbons into the 30" CP annulus	2	1	L3 - 2	Overbalanced fluid in wellbore (but not guaranteed in annulus)		1	1	L3 - 1		Prepare for kick when milling / perforating
					Environment	Moderate pollution	2	2	L3 - 4			2	2	L3 - 4		
					Material									NA		

Ref	Hazard/Anomoly/Threat	Probable Causes	Potential Consequences	Existing Controls/safeguards (During Normal Operation)	Risk classification	Initial Risk assumptions	(Probability & Severity) P	S	IR	Compensatory Measures to Reduce Risk	Risk assumptions	(Probability & Severity) P	S	RR	Integrity Threat	Corrective Actions
					Media									NA		
					Production									NA		
7	**Risk of Well status degradation due to intervention operations** Damage to existing structure / barriers	Re-entry into ageing well. Corrosion of casings, damage to casing & cement bonding due operational mechanical impact due to drilling, section milling, pressure testing etc. leading to unforseeable damage and reduction of well integrity compared to current well status	Increase risk of Hydrocarbon release over time due to damage to current established barriers	None.	Human									NA		
					Environment	Higher likelihood and potential for additional environmental exposure	2	3	L3 - 6			2	3	L3 - 6		
					Material									NA		
					Media									NA		
					Production									NA		
8					Human									NA		
					Environment									NA		
					Material									NA		
					Media									NA		
					Production									NA		
Guidance Notes	Give a clear description of what is the Hazard or Anomoly or Threat	List the known causes or probable causes for this scenario	what are the actual or possible consequences from this scenario if no action is taken (immediate consequences and potential escalation)	List any existing controls etc which are in place during normal operation (procedures, safety systems etc)	Human	Explain how many people could be injured or killed and reasons why.			L3 - 0	What compensatory (mitigation) measures have been put into place, and are proven to work, to reduce the risk. Compensatory measures are to be listed in any constructive order. NOTE: compensatory measures that are not already implemented at the time of the risk assessment should be consider as ACTIONS in Synergi	Explain why compensatory measures will reduce risk			L3 - 0		State what is required to return the scenario to NORMAL SITUATION (ie, repairs to be completed, replacement components to be installed etc)
					Environment	Explain what could be the damage/effect on the ENVIRONMENT and over what period of time. (worst case scenario)			L3 - 0					L3 - 0		
					Material	Explain what equipment will be impacted and estimated cost to rectify/replace (ie damage to crane/structure/piping)			L3 - 0					L3 - 0		
					Media	What would be the MEDIA reaction			L3 - 0					L3 - 0		
					Production	What could be the overall effect on production and over what time frame			L3 - 0					L3 - 0		

N.16 Rig-based vs Vessel-based P&A Comparative Risk Assessment

Rig Based P&A

Title: Abandonment of Mid Rosa 2 Using a Jack Up Rig P&A Vessel **File : Middle Rosa 02** **Author : L102879** **Date : 28-01-2021** **Revision : 1_1**	**Installation: Jack-Up Rig or P&A Vessel** **Operation / System : Mid-Rosa 02 Abandonment** **Task / Sub-system :** **1) P&A with Jack up Rig** **2) P&A with Vessel**	

1.0 Risk Assesment for the Abandonment of Mid Rosa-2 Using a Jack-Up Rig

Background:

- Middle Rosa-2 was drilled as an appraisal well from a JU rig and was subsequently temporary abandoned in 1983. Bubbles were observed to be emanating from the well. DEA informed about bubbling from well and approval given for rig to depart. Well inspected every 2-3 year, as per agreement with DEA.
- Gas samples taken in 2012 confirmed that the gas is not from reservoir.
- Custom net deflector installed (2016) on conductor stump with single vent hole (to aid accurate leak rate measurement)
- A P&A Vessel visited location in 2018. Pressure build up from leak confirmed to be less than 50psi (accuracy of subsea gauge questionable but PBU observed to be between 0 psi and 50psi). No increase in pressure or large release of trapped gas observed when TA Cap released or annular opened.
- In 2018 the condition of tieback threads found to be better than expected with minimal sediment/marine growth. Downhole camera confirmed the leak path to be the 13-3/8" x 20" annulus.
- Leak rate confirmed to be ca. 1ltr/min at seabed.

Reference	Task / Sub-system	Hazardous event	Possible causes	Potential consequences	Cat.	Initial risk			Existing prevention (to avoid possible causes)	Planned correction (to limit potential consequences)	Actions/comments/remark	Residual risk		
						F	S	R				F	S	R
1.1	Move rig to the location	- Existing barriers are no longer holding or fail during the rig move onto location - Other gas breakouts in the vicinity of the well - Explosion or Fire at surface. - Personnel breathing in gas.	- Gas to surface from leak at sea bed. - Gas rate to surface increased prior to or during move onto location. - Damage by Previously passing Vessels has exasperated the leak - Spud can collides with conductor stump during move onto location damaging existing barriers	- Injury to personnel on the rig - Damage to Rig - Punch through occurance resulting to some rig damage	PS	2	6		- A Jack-up rig has previously been on location - Well located within the Rolf 500 m zone - Modern net deflector fitted in 2016 - 20m Sample cores taken July 2020 not showing gas - Most of the gas would be absorbed by the sea water. Existing water depth is 40m with most being being dissolved.	- Surface location to be 'eye-balled' in calm weather for any indications of deterioration or increase in the leak rate. - Surface gas release contingency planning - Gas monitors on rig. - Suitable weather window specified for rig move to ensure collision risk is reduced - Use of anchors to mitigate collision with the conductor	- Well releasing gas bubbles since 1983. - Leak accepted by DEA, and regular inspections carried out by MOG. - Existing leak sampled and gas analysis indicated 99.6% Methane, thus it is assumed to come from a sand below the 20" shoe, not the reservoir. - Initial PBU in A-section in 1983 recorded to be 250psi but pressure observed to build to less than 50psi in 2018 indicating the source formation has depleted - Leak rate last confirmed to be ca. 1ltr/min at seabed with no visible bulles observed at sea level (gas dispersed over water column) - No flow observed from 9-5/8" casing or B-section during inspection in 2018 indicating that integrity of existing cement plugs and B-section annular cement is good. - Existing surface cement plug tagged at 153ft BML in 2018 **ACTION: Reverse engineer gas leak flow rate required to cause an explosive atmosphere at surface.**	1	6	
					EI	3	3					2	3	
					ML	2	6					1	6	
					MR	2	6					1	6	
1.2	Move rig to the location	- Conductor stump damaged/Bent during move onto location	- Conductor stump damaged by previously passing Vessel - Spud can of rigs collides with conductor stump during move in - Object dropped from rig damage conductor stump	- Unable to access / abandon well - Unable to tieback environmental riser (conductor string)	PS				- Well is placed within Rolf 500 m zone and so no trawlers should have been in area - Modern net deflector installed over stump in 2016 - Location visited and condition of net guard and stump verified in 2017, 2018 and 2019.	- Suitable rig move weather window to be used to ensure move onto location is controlled - Surface abandonment as a last option if cannot get access	Option to inspect location with an ROV prior to rig arriving on location if deemed necessary Based on a rig time cost of 2<-10< Million			
					EI									
					ML	4	5					2	5	
					MR									
1.3	Pre-loading Rig on location	Spud cans punch through seabed during pre-loading	- Soil may be weakened due to shallow interval having been depleted over 37 years of leaking - Area known to have shallow gas anomlies which may have ingressed into the shallow formations	- Damage to rig - Injury to personnel	PS				- A Jack-up rig has previously been on location - Original rig location selected to avoid shallow gas anomolies identifed on seismic - CPT's were taken at the location in July 2020 down to 20m with no gas observed during the operation	- Suitable rig move weather window to be used to ensure move onto location is controlled	- CPT's taken over 4 boreholes in July 2020 down to 20m depth and SSA identified high risk of punch through for this location during pre-loading. - Considered likely that high risk of punchthrough applies due to considering winter conditions and risk of punch through during summer conditions would be more favourable. - Assessment of risk of punch through may be reduced if an advanced numerical analysis is performed on the data. - If operations are planned for summer months due to increased risk of punch through during wiinter weather conditions, any significant operational delays may result in the operation running into winter months when the rig cannot stand on the location.			
					EI									
					ML	2	5					1	5	
					MR									
1.4	Picking up and recovering Net Guard	- Unable to remove net deflector/guard; - Debris falls into well whilst lifting net guard - Handling recovered net guard on the rig	- Deflector disintegrating - Debris picked up with net guard drops off whilst picking up - Debris sitting in recovery tool slot preventing access to recovery tool	- Unable to access conductor - MLH tieback threads damaged and unable to tieback with integrity - Possible injury to personnel handling the recovered net guard at surface	PS	3	3		- Net guard is modern design which was installed in 2016. - Net guard was lifted off and replaced in 2017 and twice in 2018 without any issues. - Well was observed with an ROV in 2019 with no obvious damage observed - Well is located within Rolf 500m zone so limited number of vessels have been in the area since last inspection	- WROV can be used to attach slings and recover net guard - WROV can inspect net guard and remove any debris prior to lifting - Recovery tool can flush pocket on net guard prior to engaging	- Net guard has a DP deployed recovery tool which can use a J-slot to engage net guard for recovery - Net Guard has dimensions of ca. 4m x 4m and weighs 2900kg in air.	1	3	
					EI									
					ML	2	3					1	3	
					MR									
1.5	Install 30" conductor on stump as an environmental riser	- Conductor stump is damaged trying to stab connector tool onto stump - Unable to establish environmental riser	- Conductor stump deformed and unable swallow with connector	- Subsequent operations to be performed in open water with tieback casings exposed to currents - Additional time and cost to operation from trying to establish environmental riser	PS				- POS-SET connector installed on stump in 2018 confirming that connector is not oval or heavily corroded. - Conductor stump prepared (including grinding chamfer) with WROV in 2018 for subsequent POS-SET connector installation - Connector fitted with chamfered sleeve to help guide connector over stump.	- ROV to observe operation and ensure connector does not collide with stump - Operational weather window picked to limit movement of conductor string whilst RIH - ROV can be used to guide connector tool over stump	- Riser analysis to be performed for conductor string plus tieback strings in case open water operations are required - Conductor tieback tool cannot be released and conductor must be severed with diamond wire saw below to recover tieback tool and environmental riser. - There is only sufficient stump remaining (5.6ft) for one more attempt to tieback to conductor. If operations are not successful, there will not be an option for a second rig based P&A.			
					EI									
					ML	4	4					2	4	
					MR									

1.6	Install tieback casing string between rig and MLH	- Unable to establish integrity with tieback casing string - Attempts to verify integrity of the tieback string with pressure, damage the existing abandonment plugs	- 9-5/8" and 13-3/8" threads have been unprotected for 37 years - 20" threads had a TA Cap installed 1983-2018 but TA Cap installed ca. 20 times whilst trying to establish a seal. Leak path past 20" threads for 35 years. - Pressure test applied to verify tieback string integrity will be applied against existing barriers (plugs and annular cement)	- Extra rig days required trying to find which tieback tool can establish integrity - Unable to verify integrity of connection at MLH (operations involving removing existing barriers cannot be completed unelss verified integrity is established) - Only surface cement plug can be set above existing plugs if integrity of tieback string cannot be established and verified (same P&A as can be done with a vessel) - Attempts to verify integrity of tieback tools with pressure tests could break down existing barriers in result in a leak of reservoir fluids (without integrity being established) - Conduit to the rig	PS	2	6		- Reservoir isolated with primary plug consisting of EZSV with 100ft cement squeezed below and 416ft cement plug placed on top which was later tagged and tested to 2,000psi. Additionally there was a second plug placed over the 13-3/8" shoe and a surface cement plug set beneath the 30" conductor shoe. Surface plug was tagged in 2018 and position verified. - 9-5/8" cement job was done as a staged cement job - Threads visually inspected with downhole camera in 2018 and no severe damage observed. - Threads to be jetted/cleaned with a brush and inspected prior to running tieback tools	- Option to manufacture running and tieback tools for both 9-5/8" and 13-3/8" hangers plus 20" tieback tool to give 5 options for tying back the well - Re-enforce kick awareness. - Divertor connected - Only surface cement plug can be set above existing plugs if integrity of tieback string cannot be established and verified (same P&A as can be done with a vessel)	- Bridge plug/RTTS can be installed inside 9-5/8" casing if tying back to 9-5/8 threads to prevent pressure being applied to internal cement plugs - If only 9-5/8" tieback string integrity can be confirmed, containment will be lost when the 9-5/8" casing is cut and recovered (any breakdown in existing barriers during subsequent section milling operation would likely be completed without pressure containment.	1	6	
					EI	3	3						3	3	
					ML	5	4						4	4	
					MR										
1.7	Drill out existing upper cement plug.	- Well blows out as pressure and HC below plug expands when plug drilled out - Explosion/Fire from HC to surface - HC leak at tieback connection and are released into the sea	- Reservoir HC and trapped presssure present below the surface plug are released resulting in HC at surface - Tieback thread integrity fails or 9-5/8" casing above plug leaks when exposed to pressure from reservoir	- Oil and gas flow to surface (Injury to personnel and loss of rig) - Oil and Gas leak to environment	PS	2	6		- Reservoir isolated with primary plug consisting of EZSV with 100ft cement squeezed below and 416ft cement plug placed on top which was later tagged and tested to 2,000psi. Additionally there was a second plug placed over the 13-3/8" shoe.	- Kill weight mud to be available to be pumped in the event that well starts to flow - Increased awareness of risk of drilling out existing cement plugs - Well control drills	Insufficient column of kill weight fluid can be held above cement plug to balance reservoir pressure if well has been evacuated to gas below existing surface plug.	1	6	
					EI	3	3						3	3	
					ML	4	4						3	4	
					MR										
1.8	Cut and pull 9-5/8" casing from above TOC	- Unable to cut and pull 9 5/8"	- Annular cement present above cut depth.	- Extra rig days required attempting to recover casing - Casing recovered from a shallower depth and subsequent remediation performed shallower as a result - Potentially required to section mill through 9-5/8 "and 13-3/8" annulus in order to remediate A-section annular cement	PS				- Theoretical 9-5/8" TOC ca. 300ft below 20" shoe/planned recovery depth. - Second stage cement job was done in cased hole with no risk of losses or OH excess required	- Section milling can be moved to a shallower depth if required	- Due to shallow depth of source formation (just below 20" shoe) no formal minimum plugging depth exists and so moving the section milling and subsequent plug shallower is possible (although increases risk of cement bypassing the 20" shoe (underground blowout))			
					EI										
					ML	4	3						3	3	
					MR										
1.9	Install 13-3/8" bridge plug and section mill 60m window in 13-3/8" casing	- Leak rate increases as annular cement in A-section is removed - Section milling operation causes existing barriers to break down and reservoir fluids to released - Section milling operation suffers delays	- Existing annular cement may be restricting annular leak which will be removed as part of section milling operation - Milling operation results in vibration and pressures which results in existing barriers to break down - Production of Swarf from Milling slows operation down (surface handling constraints)	- Reservoir hydrocarbons released into the sea or on the rig - Placing cement plug with increased flow rate may be unable to achieve isolation - Extra rig days required attempting to rectify operational issues	PS	2	6		- 13-3/8" bridge plug to be installed above 9-5/8" casing stump to act as base to section milled plug but also provide additional isolation to the reservoir and B-section annular cement. - Combined 60m section milled interval selected to reduce the number of miling runs required	- Gas monitors on rig. - Clean hole best practices - Plug verification practices - Good cement isolation practices	Milling and recementing is a high risk operation on that well, but the only option to re-establish annular integrity without drilling a relief well, which is considered to be even more risky.	1	6	
					EI	3	3						3	3	
					ML	4	3						3	3	
					MR										
1.10	Set balanced cement plug to isolate shallow flow zone	Cement fails to isolate shallow gas bearing formation (leak continues)	- Unable to set/test plug - Loss of cement - Gas continues to flow as cement sets creating channel through cement plug	Gas leak continues and operations must be repeated	PS				- Limited pressure can be held above cement plug to suppress gas from flowing whilst cement sets	- Gas monitors on rig. - Clean hole best practices - Plug verification practices - Good cement isolation practices - Complete additonal section milling and barrier placement operation - Underreamer to formation to ensure good bond after section millling. - Use high density Viscous Gel to prevent slumping - Using an inflatable packer below milled interval	- Milling and recementing is a high risk operation on that well, but the only option to re-establish annular integrity without drilling a relief well, which is considered to be even more risky. - Performing section milling operation will still leave the option to cure the losses with a cement plug set above the casing hangers (the proposed vessel based solution)			
					EI										
					ML	4	4						3	4	
					MR										
1.11	Sever 30" conductor ca. 10ft BML and recover stump and clear seabed.	- Gas leak returns once the conductor has been severed	- Remediation work failed to isolate the leak paths long term	- Further remediation options are very limited once conductor stump has been removed - Might not be able to recover stump	PS					- Plan short term monitoring programme to gauge success. - Potential to not cut the conductor and to leave for future vessel cut and retreival	- Post operational monitoring requirtemets to be defined - Possibly mobilise a P&A vessel to perform severance and seabed clearance after a certain period of time.			
					EI										
					ML	4	5						3	5	
					MR	4	5						2	5	

Vessel-based P&A

Reference	Task / Sub-system	Hazardous event	Possible causes	Potential consequences	Cat.	Initial risk F	Initial risk S	Initial risk R	Existing prevention (to avoid possible causes)	Planned correction (to limit potential consequences)	Actions/comments/remark	Residual risk F	Residual risk S	Residual risk R
2.0 Risk Assesment for the Abandonment of Mid Rosa-2 Using a P&A Vessel														
2,1	Move Vessel onto the location with gas bubble leaking at seabed	- Explosion or Fire at surface. - Personnel breathing in gas.	- Gas to surface from leak at sea bed. - Gas rate to surface increases. - Damage by Previously passing Vessels has exasperated the leak	- Injury to personnel on the vessel - Damage to vessel - Unable to access location to abandon well	PS				- A P&A Vessel has previously been on location - Vessel can leave if required - Leak rate has been previously confirmed to be steady in 2016, 2017, and 2018 - Well within Rolf 500 m zone - Modern net deflector in place (2016)	- Surface location to be 'eye-balled' in calm weather for any indications of deteriation or increase in the leak rate. - ROV inspection of the area pior to commcement of the operation. - Surface gas release contingency planning - No minimum days commitment	- Well releasing gas bubbles since 1983 - Leak accepted by DEA with regular inspections carried out by MOG. - Gas analysis indicated 99.6% methane, thus it is assumed to come from a sand below the 20" shoe, not the reservoir. - Leak rate last confirmed to be ca. 1ltr/min at seabed and steady from 2016-2018.			
					EI									
					ML	3	3					2	3	
					MR									
2,2	Picking up and recovering Net Guard	- Unable to remove net deflector/guard; - Debris falls into well whilst lifting net guard - Handling recovered net guard on the rig	- Deflector disintegrating - Debris picked up with net guard drops off whilst picking up	- Unable to access conductor - MLH tieback threads damaged and unable to install temporary seal	PS				- Net guard is modern design which was built and installed in 2016. - Net guard was lifted off and reinstalled in 2017 and twice in 2018 without any issues. - Well was inspected with an ROV in 2019 with no obvious damage observed - Well is located within Rolf 500m zone so limited number of vessels have been in the area since last inspection	- WROV can be used to attach slings and recover net guard - WROV can inspect net guard and remove any debris prior to lifting	- Net Guard has dimensions of ca. 4m x 4m and weighs 2900kg in air but can be lifted safely on to the deck of the P&A vessel using the crane.			
					EI									
					ML	2	3					1	3	
					MR									
2,3	Install Temp. barrier in 20" threads	- Gas leak not isolated - Temporary cap becomes stuck during installation	- Tieback threads are worn out from previous flow - Threads are damaged during installation due to vessel motion during operation	- Faliure to arrest bubbling. - Temporary Cap does not seal gas but cannot be recovered - Cement slurry has to be set with gas flow continuing	PS				- 20" tieback threads inspected in 2018 and no obvious damage to thread profile observed - Original recovered TA Cap available for modification and/or inspection when designing Temporary Barrier	- Walkaway before pumping cement and go back to the 'drawing board'	- Risk of damage threads that could impair rig access			
					EI									
					ML	3	4					2	4	
					MR									
2,4	Place balanced cement plug	- Unsuccessful Operation - Channel forms in cement plug during setting - Cement flash sets in cement hose during pumping - Breakdown of temporarily installed cementing spread on vessel	- Gas flow is not prevented prior to setting plug - Cement slurry purposely designed to set quickly due to being set in open water at seabed	- Future access impeded. - Faliure to arrest bubbling. - Cement job abandoned due to failure of equipment or plugged off cement hose	PS				- Surface cement plugs have been set on 27 wells with a vessel during previous P&A Campaigns - Cementing spread fully tested upon installation at quayside to ensure it is working - Cement slurry optimised to negate the impact of gas migration during setting - Perform dummy cement job - Use of good cement practices and volume calculations	- Back up cementing hose reel onboard vessel - If gas migration is observed with ROV upon displacement, consider flushing cement out and repeat operation. '- Walkaway and go back to the 'drawing board'	Assumed gas has stopped due to TA cap isolation			
					EI									
					ML	2	5					1	5	
					MR									
2,5	Sever 30" conductor at mudline and recover stump and clear seabed.	- Gas leak returns once the conductor has been severed	- Severance operation disturbs newly installed cement plug and channel is created - Remediation work failed to isolate the leak paths long term	- Further remediation options are very limited once conductor stump has been removed	PS					- Explore cutting of conductor first before cementing - Explore the use of a temp. funnel - Plan short term monitoring programme to gauge success. - Explore the option of leaving 'as is' or a shorter stump if DEA/DWEA approval is forthcoming	- Option to sever conductor at seabed prior to perform cement job - Post operational monitoring requirtemets to be defined - Possibly mobilise a P&A vessel to perform severance and seabed clearance after a certain period of time. - Evaluate the use of a capping stack clamp to tie back riser to the surface and RIH with CT to cement (DFA (B?) 99 Last done 2003 - Old slot 10)			
					EI									
					ML	2	5					1	5	
					MR									

Title: Well Integrity Engineer	Title: Senior Decommissioning Engineer	Title: Decommisioning Team Leader	Title: WI & Abandonments Manager	Title: Drilling & Well Engineering Manager
Name / Signature / IGG George KARDAN Digitally signed by George KARDAN Date: 2021.02.05 15:32:42 +01'00'	Name / Signature / IGG Andrew SUTCLIFFE J0513570 Digitally signed by: Andrew SUTCLIFFE J0513570 DN: CN = Andrew SUTCLIFFE J0513570 C = FR O = TOTAL OU = TOTAL AUTHENTIFICATION INTERNE Date: 2021.02.05 15:41:55 +01'00'	Name / Signature / IGG David MOLONY Digitally signed by: David MOLONY DN: CN = David MOLONY C = FR O = TOTAL OU = TOTAL SIGNATURE INTERNE Date: 2021.02.05 18:38:46 +01'00'	Name / Signature / IGG Stephen Patterson Digitally signed by Stephen Patterson Date: 2021.02.05 15:57:49 +01'00'	Name / Signature / IGG Michael TURNER Digitally signed by Michael TURNER Date: 2021.02.08 07:48:49 +01'00'
Title: Drilling Superintendent	Title: Senior Technical Safety Engineer	Title: DSO Senior Integrity Specialist	Title:	Title:
Name / Signature / IGG John Laurence Simpson Digitally signed by John Laurence Simpson Date: 2021.02.06 10:17:30 +01'00'	Name / Signature / IGG Christoffer BRANDT J0515276 CN = Christoffer BRANDT J0515276 C = FR O = TOTAL OU = TOTAL AUTHENTIFICATION INTERNE 2021.02.08 07:59:57 +01'00'	Name / Signature / IGG Philip WODKA Signient digitalt af: Philip WODKA DN: CN = Philip WODKA C = FR O = TOTAL OU = TOTAL SIGNATURE INTERNE Dato: 2021.02.05 16:52:07 +01'00'	Name / Signature / IGG	Name / Signature / IGG