Geological constraints on hydrocarbon contacts in the greater Norne area

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Thesis for Master degree

Basin and Reservoir Studies

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June 2018

Abstract

The understanding of the geological constraints on the position of fluid contacts is important for the evaluation of the remaining resources on the Norwegian Continental Shelf. Different mechanisms can lead to filled, underfilled or overfilled traps. This can greatly affect the in-place volumes of hydrocarbons in a prospect.

The study investigates the position of hydrocarbon water contacts and spill points in 10 individual structures situated on the western edge of the Nordland Ridge and on the Dønna Terrace.

A detailed geological mapping of the reservoirs in the area was conducted by the interpretation of high resolution 3D-seismic data. Available data from exploration wells was utilized to estimate shale smear factors for critical faults, investigate formation pressures and determine the depths of hydrocarbon-water contacts.

The high overpressures in the Cretaceous Reservoirs on the Dønna Terrace falls on a pressure gradient defined for overpressured structures on Haltenbanken, and some of the structures are most likely underfilled. The structures included in the commonly accepted Norne fill-spill route, are all in pressure communication with the surface. Most of the traps are filled to spill, but some are overfilled relative to their structural spill point.

The Cretaceous reservoirs on the Dønna Terrace has probably leaked either through cap rock failure or fault reactivation. The Norne fill-spill route is confirmed as the most likely model for the structures suggested to be on this migration route. Sealing faults are in some locations critical for the fill spill route to work.

Acknowledgements

The study was conducted at the Department of Earth Science at the University of Bergen.

First of all I would like to thank my main supervisor Christian Hermanrud for extremely rapid, constructive feedback and for always being available for guidance and discussion of ideas. A special thanks goes to Equinor ASA and PSG (Petroleum Geo-Services) for providing the 3D-seismic data. I would also like to thank all members of the PESTOH group for valuable and interesting discussions. Thanks to Jhon Meyer Munos Barrera for valuable tips on seismic interpretation. I would like to express my gratitude to my fellow students for the past years, especially Sander Hofker Berg, Jarle Thorsen Haugland, Anders Hågenvik, Mads André Meland, Tor Naustdal Helgheim and the rest of the Grotten crew for all academic and non-academic disussions.

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1. Introduction

Large volumes of oil and gas have been discovered and produced from the Norwegian Continental Shelf (NCS). The early discoveries were often accumulations in relatively obvious structural traps that could be seen in poor resolution seismic data. As the most evident traps were drilled years ago, the development of new methods, technology and play models are essential to the industry. Recent years exploration activity has proven that there still are considerable resources yet to be found. The estimate of the Norwegian Petroleum Directorate is that about 47% of the remaining resources on the NCS have not yet been proven (NPD, 2018). A lot of the structures are filled to their structural spill point, but underfilled and overfilled structures occur, as well as dry structures. The overfilled traps can frequently be explained by fault sealing, while the dry and underfilled traps may be caused by limited charge or leakage. The understanding of the geological constraints on fluid contacts is important for the evaluation of the remaining resources on the Norwegian Continental Shelf.

General knowledge of hydrocarbon trapping mechanisms has been available for a long time. The commonly accepted fill-spill model described by Gussow (1954), which also explains the differential entrapment of oil and gas, yields hydrocarbon accumulation down to a spill point from where the hydrocarbons migrate further up-dip. However, deviations from this model, in the form of overfilled and underfilled traps, occur.

Accumulations in fault related structural traps are very common in extensional settings. The faults and fault patterns can impede or alter fluid migration (Caine et al., 1996, Randolph and Johnson, 1989). Sealing faults controlled by the mechanisms of shale smear, cataclasis and/or diagenesis can lead to overfilled structures (Watts, 1987, Yielding et al., 1997, Lindsay et al., 1993, Færseth, 2006).

Underfilled structures as a result of leakage has been documented in several areas (Wiprut and Zoback, 2002, Wiprut and Zoback, 2000, Gartrell et al., 2003, Georgescu, 2013, Sollie, 2015). Hermanrud and Nordgård Bolås (2002) investigated leakage from overpressured reservoirs on the Haltenbanken, comparing them to overpressured structures in the North Sea. They found that the pore pressures in the Haltenbanken wells fall on a well-defined pressure gradient with depth. It is proposed that the pore pressures could not get any higher than their present value, and that the stress state at the time resulted in vertical cap rock leakage.

The areas on the western edge of the Nordland Ridge and on the Dønna Terrace, west of the Nordland Ridge have been open for exploration since the 1980's. The 10B consession round in 1986 was focused on this area. Earlier, 6 dry wells had been drilled on the Trøndelag platform, east of the Nordland Ridge. Just before the licencees were ready to relinquish the area, the Alve discovery was made in 1990. This proved the presence of hydrocarbons in the area. A simple fill spill model from Alve to a nearby horst structure was proposed, and exploration well 6608/10-2 was drilled in 1992. After eight years of discouraging exploration results in the Nordland I and II area, the Norne field was discovered (Gjerstad and Skagen, 1995, NPD, 2018). This large commercial oil and gas discovery opened up for further exploration in the area. Since then, several smaller discoveries in the Norne Area has been made. In the industy, a fill spill situation towards the north-east has been assumed (Hermanrud, pers.con).

The Marulk discovery was made on the Dønna Terrace in 1992. The primary target was in Jurassic sandstones, but instead the well opened up a new play with hydrocarbons in the Cretaceous Lysing and Lange sandstones. Later, The Snadd South, Snadd North and Snadd Outer discoveries confirmed the prospectivity of the cretaceous Lysing Formation on the Dønna Terrace.

Fugelli and Olsen (2007) conducted a study on the Lysing Formation deposits on the Dønna Terrace. The study proposes a detailed model for the geometry and the depositional style of the deposits. Several earlier articles mainly classifies the Lysing sandstones as slump deposits from local highs in the east (Hastings, 1987, Brekke et al., 1999, Vergara et al., 2001). Fugelli and Olsen propose a more complex depositional history with both transversely and longitudinal fed turbidite complexes. Three main turbidite complexes are described; the Snadd Turbidite Complex, the Hawkes Bay Turbidite complex and the South Turbidite

Complex. The Cretaceous deposit accumulations investigated in this thesis are all part of the Snadd Turbidite Complex. The Snadd Structure has an eastern up-dip pinch-out towards the Nordland Ridge, sealing the gas accumulation in a stratigraphic trap with a long continuous pinch out line. An in depth study of the Lysing deposits on the Marulk structure was done by Ormøy et al. (2011). The Marulk Turbidite System is defined and introduced as a part of the Snadd Turbidite Complex introduced by Fugelli and Olsen (2007).

While the reservoir geology and structural features that result in trapping of hydrocarbons in the greater Norne area has been described, information on the trapping mechanisms for individual structures has apparently not been published.

The aims of the study was to investigate the controls on hydrocarbon height in both the Dønna Terrace and the Norne area. This was done by conducting a detailed seismic interpretation of the areas of interest. The depths of the spill points and their position relative to the hydrocarbon-water contacts were identified, and fluid contacts that could not be explained by simple fill-spill mechanisms were further analyzed. The analyses of these structures included investigation of pore pressure data, seismic signatures in overburden rocks, clay smear along fault planes, and establishment of fill-spill-trapping scenarios for several structures in combination.

2. Geological setting

2.1 Tectono-stratigraphic evolution

The Norwegian Sea's tectonic history is mainly controlled by two structural trends: NE-SW, and NW-SE. The main tectonic phases were in Late Paleozoic, late Mid Jurassic – Early Cretaceous, and Late Cretaceous – Paleocene, but the area has been tectonically active from Carboniferous to Late Pliocene (Brekke, 2000). According to Brekke, the extensional tectonics in Carboniferous to Early Cretaceous were connected to continental rifting processes. In Late Cretaceous and Paleogene, relative movement along plate boundaries was the controlling mechanism for the tectonics.

2.1.1 Paleozoic

The Caledonian orogeny is the main event controlling the tectonic setting during most of the Paleozoic. The collision lasted until the Devonian. From the Early Devonian, the general tectonics changed from a compressional to an extensional regime (Larsen and Skarpnes, 1984). The main structuring of the internal parts of the Trøndelag Platform took place in the Carboniferous to Late Permian. The faults and basin axes constitutes the overall NE-SW structural grain. Major lineaments express the transverse NW-SE trend, which probably reflects the old Precambrian grain of the basement (Brekke, 2000).

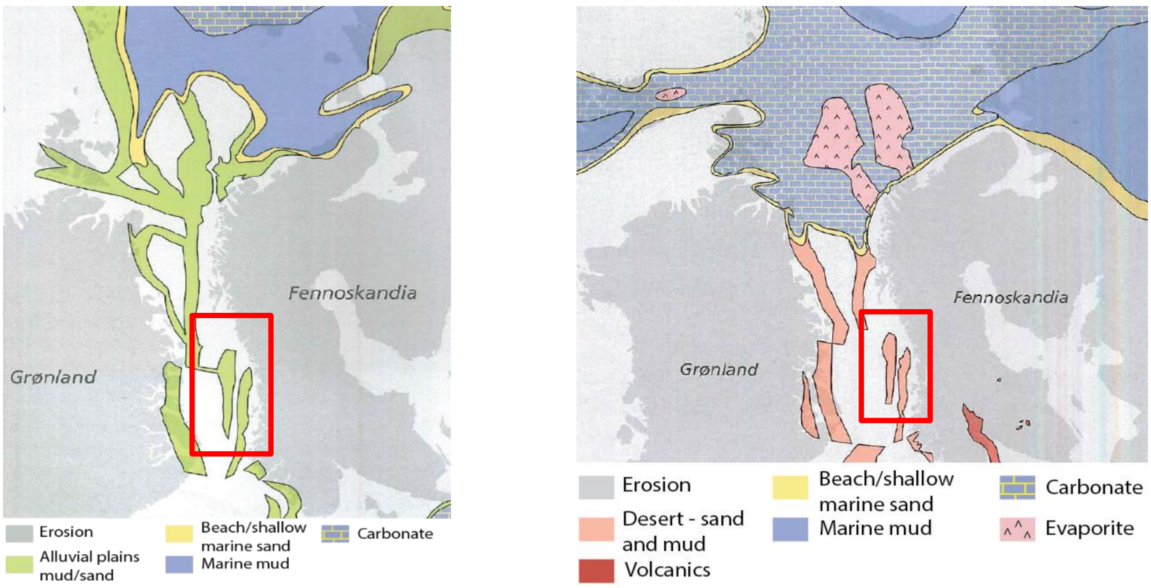

Figure 2.1: Paleogeography and depositional environment during the Mississipian (Left) and Early Permian (Right). Approximate location of the Norwegian Sea in red. Modified from Ramberg (2008).

In the Mississipian, the Early Carboniferous, the change in stress regime led to the formation of narrow rift basins with alluvial plain deposits sourced from the erosion of the Calidonides. Later in the Mid-Carboniferous the climate changed from humid to arid. The alluvial plains were replaced with arid desert deposits. These conditions continued into the Early Permian. In the Late Permian, as a result of transgression, a seaway was located where the Norwegian Sea is today (Ramberg et al., 2008).

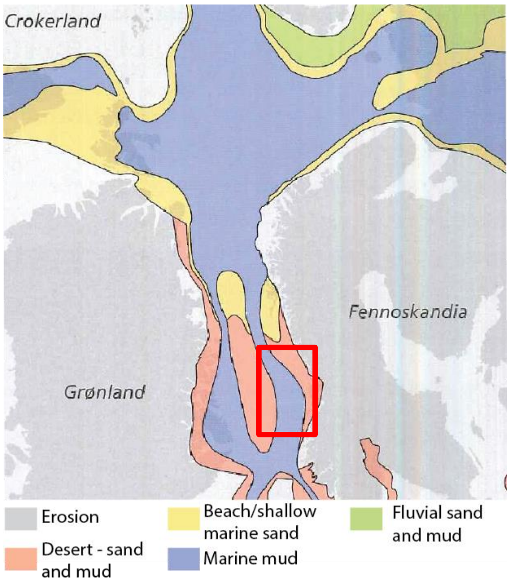

Figure 2.2: Paleogeography and depositional environment during Late Permian. Approximate location of the Norwegian Sea in red. Modified from Ramberg (2008).

2.1.2 Triassic

The formation of rift basins between Norway and Greenland as a result of crustal extension reflected the onset of the Pangea breakup. (Larsen and Skarpnes, 1984, Gowers and Lunde, 1984, Ramberg et al., 2008). During much of the Triassic, continued activity in major faults resulted in NE-SW trending basins. The Froan Basin is the best defined of these. Triassic and, in some locations, Upper Paleozoic sediments filled the basins (Brekke, 2000).

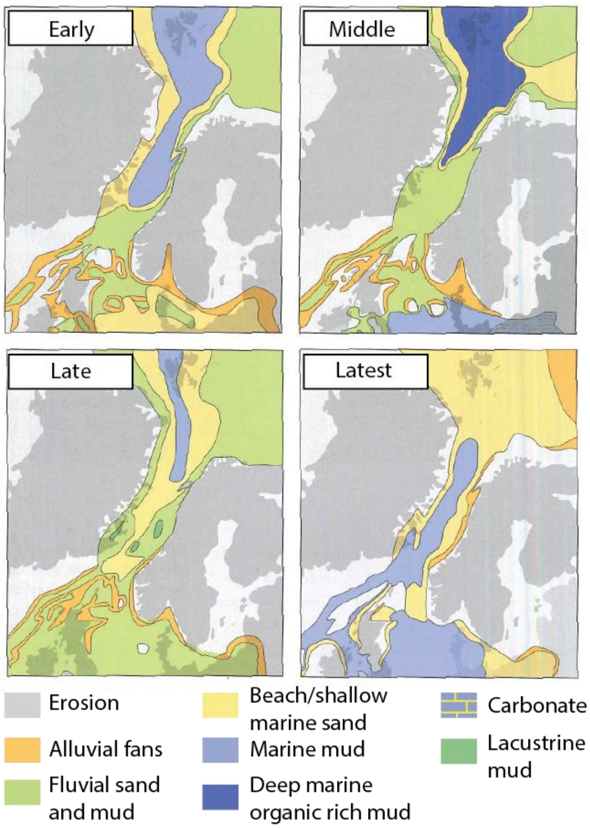

Figure 2.3: Paleogeography and depositional environment during Triassic. Modified from Ramberg (2008).

The rifting was followed by the deposition of thick continental Triassic successions, up to 2500 m in the Helgeland Basin (Grey and Red Beds). The Triassic also contains two major evaporate sequences. The deposits are a result of enhanced subsidence and deposition in a fluvial sabkha environment (Halland et al., 2011). Late Triassic was tectonically calm. Seawater flooded the alluvial plains following a transgression. Uplift in the mainland of Norway together with increasingly humid climate led to the start of the river transported Åre Formation deposits, which extend into Early Jurassic (Ramberg et al., 2008).

2.1.3 Jurassic

In the Early and Middle Jurassic, the Trøndelag Platform and the Dønna/Halten Terrace were included in a large subsiding basin. A deltaic to fluvial depostitional system was filling in the basin from several directions (Halland et al., 2011). Other than the subsiding of the basins, the Early and Middle Jurassic was tectonically relatively stable, but the period saw some basin flank uplift (Ramberg et al., 2008). The Nordland Ridge and the Frøya High were uplifted (Halland et al., 2011).

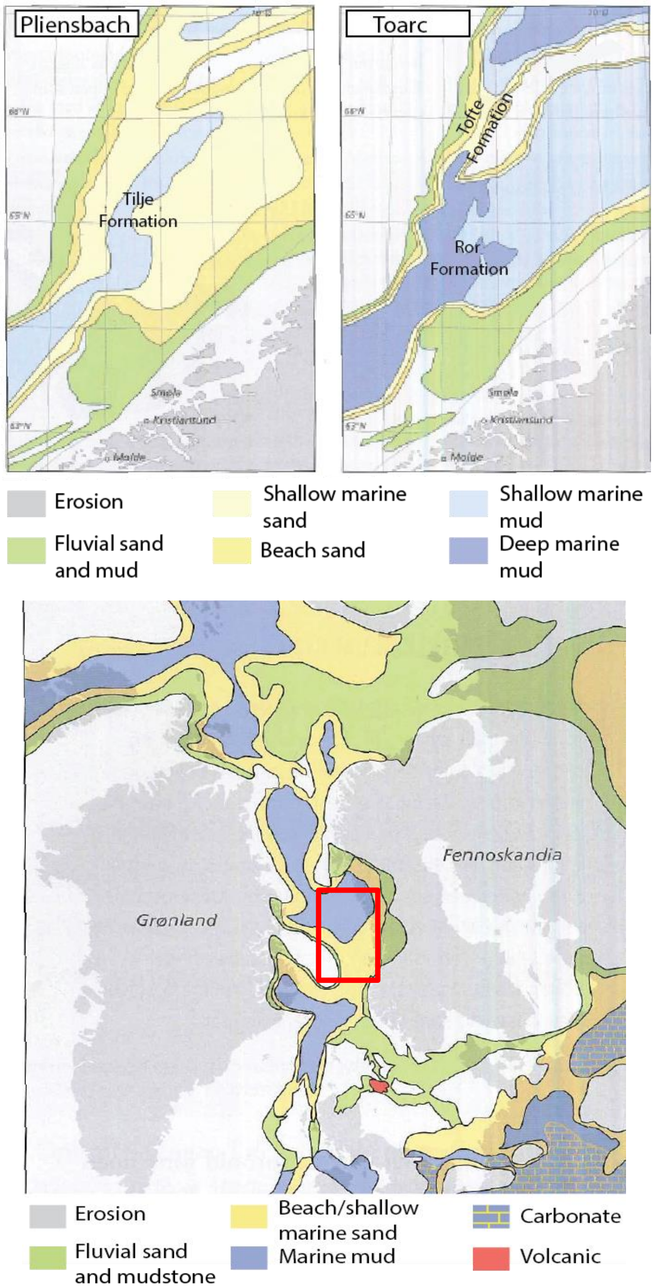

Figure 2.4: Paleogeography and depositional environment during Early (above) and Middle (below) Jurassic. The upper figure is zoomed in on the Norwegian Sea. Modified from Ramberg (2008).

The late Mid-Jurassic marks the start of a major extensional tectonic period culminating in the Early Cretaceous (Halland et al., 2011). During this period, the Trøndelag Platform was subject to minor faulting, partly by reactivation of older faults. The Dønna Terrace was subject to intense deformation through faulting (Brekke, 2000). Footwall blocks were exposed to subaerial conditions, forming islands that underwent heavy erosion. In parts of the Nordland Ridge, this led to the removal of Jurassic Sections, and locally parts of the Triassic rock sequence (Gowers and Lunde, 1984). In Late Jurassic, as a result of faulting, the terraces in the area were first formed as individual structural elements, expanding the Upper Jurassic succession along the Revfallet, Vingleia and Bremstein Fault Complexes (Brekke, 2000). Brekke points out that the terraces stayed close to the same elevation as the Trøndelag Platform relative to the western basins. The main subsidence of the terraces took place later in Cretaceous time.

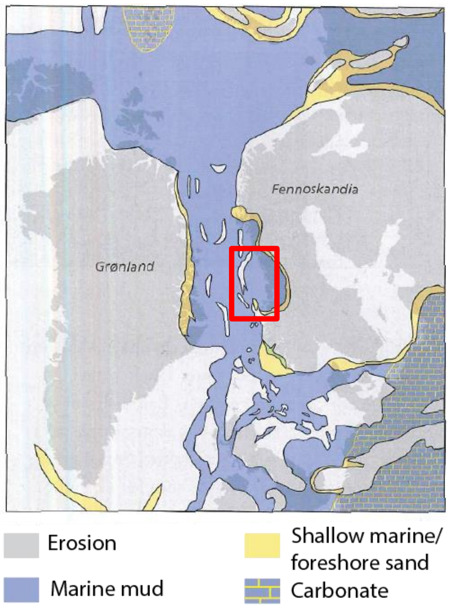

Figure 2.5: Paleogeography and depositional environment during Late Jurassic. Modified from Ramberg (2008).

Following the transgression in Late Jurassic, the sand deposits of Middle Jurassic was replaced with mud deposits. Some highs still experienced subaerial exposure. The high biological production resulting from high sea level, high temperatures and high atmospheric CO2 resulted in the formation of organic rich sediments (Ramberg et al., 2008).

2.1.4 Cretaceous

The Early Cretaceous saw the continuation of the extensional rift tectonics. There was uplift of the Nordland Ridge on the Trøndelag Platform edge. This can be identified by onlap of the Early Cretaceous basin fill of the Helgeland Basin (Brekke, 2000). Normal faulting continued on the flanks of the Nordland Ridge during the Early Cretaceous. According to Gowers and Lunde (1984), three major phases developed the area during the Early Cretaceous.

- The gradual subsidence of the Helgeland Basin in Berrasian - Valangian time, due to active faulting on the eastern flank of the Nordland Ridge.
- A flexure zone along the Rødøy High, as a result of subsidence, developed in Valangian - Barremian time. As a consequence, the high was exposed subaerially

- A regional transgression submerging most of the highs. This stopped the erosion in the Aptian – Albian time period.

In the Late Cretaceous, there was rapid subsidence in the areas west of the Nordland Ridge because of increased rifting (Halland et al., 2011). The faults on the eastern side of the Dønna and Halten Terraces, included in the Revfallet, Vingleia and Bremstein Fault Complexes, controlled the separation of the terraces from the platform. This took place in two phases, the last one in the Late Cretaceous (Brekke, 2000). According to Brekke, the last phase was part of the main Late Cretaceous tectonic episode in the Vøring basin. The southern part of the Nordland Ridge was uplifted during this phase, eroding and faulting the Late Jurassic peneplain in the area.

The sea level generally rose throughout the Cretaceous. In the Late Cretaceous the sea level was at its highest level recorded in the region (Ramberg et al., 2008).

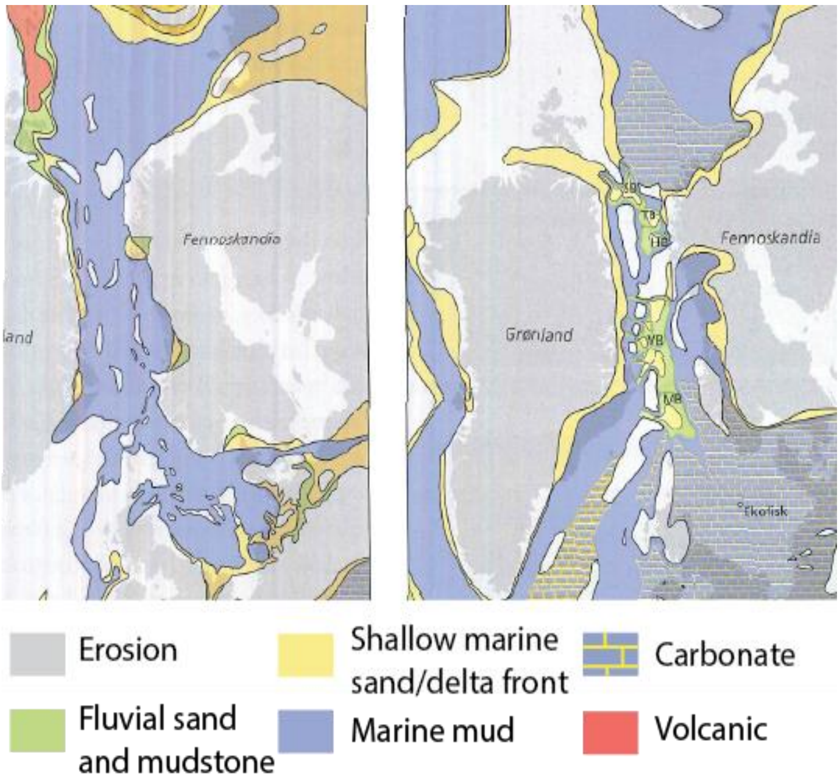

Figure 2.6: Paleogeography and depositional environment during Early(left) and Late(right) Cretaceous. Modified from Ramberg (2008).

2.1.5 Cenozoic

According to Brekke (2000), parts of the Nordland Ridge was further uplifted in several periods in the Paleogene. The consequence of this is that in those locations where the ridge has been subaerially exposed, Triassic to Jurassic sequences subcrop Paleocene to Pliocene strata.

In the Paleogene, earlier rift episodes culminated with the onset of sea floor spreading (Ramberg et al., 2008). Final lithospheric breakup of the Norwegian-Greenland continental plate took place near the Paleocene – Eocene transition, approximately 54-55 Ma (Faleide et al., 2008).

The western flank of the Nordland Ridge has acted as a hinge line between subsiding basins to the west, and the stable Trøndelag Platform in the east. Regional uplift on the continental shelf during occured as a consequence of isostatic rebound following the breakup of the continental plate (Eidvin et al., 2007).

2.2 Main structural elements

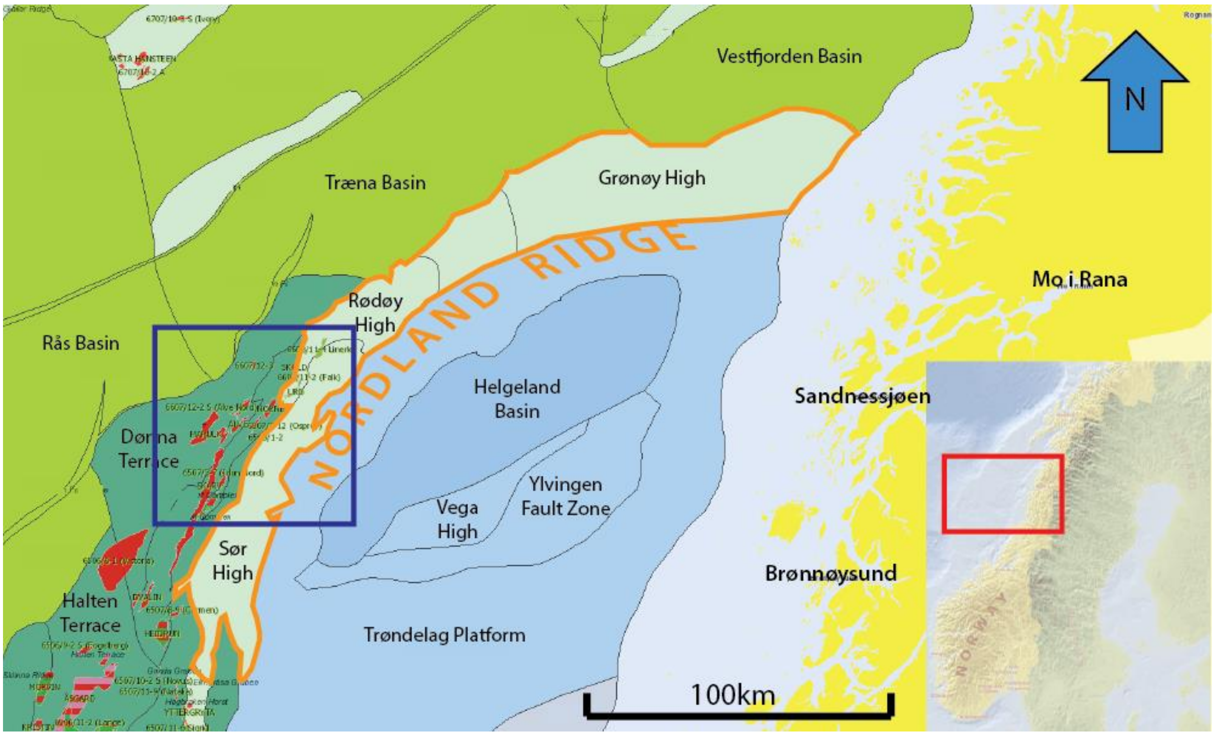

Figure 2.7: Map of the Nordland Ridge Area. Structural elements are annotated. The study area is enclosed in the blue square. Modified from NPD.

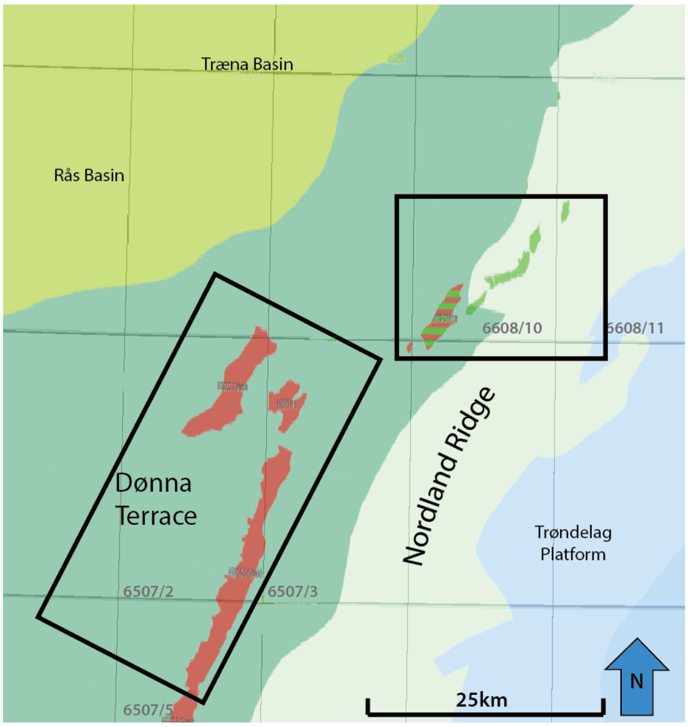

Figure 2.8: Location of the study area. The two specific areas discussed in the thesis are outlined. Modified from NPD's Factmaps

The structures studied in the thesis are located on the north-western part of the Nordland Ridge, on the Dønna Terrace, or in the transition between the two. Revfallet Fault delineates the Nordland Ridge against the Dønna Terrace.

The Nordland Ridge is an elongated structural high, arching along the north-western edge of the Trøndelag Platform. It is located between 65^o 15'N - 66^o 50'N and 7^o 30'E - 12^o 30'E in the Norwegian Sea. Its orientation changes from SSW-NNE in the south, to SW-NE in the north. It was first defined by Rønnevik et al. (1975) as the ridge separating the Vøring and Helgeland basins. The Nordland Ridge is regarded as a subelement of the Trøndelag Platform, which is one of the main structural elements in the Norwegian Sea (Blystad et al., 1995). The ridge is transected by deep faults, and can be divided into three large individual highs. These are the Sør High, Rødøy High, and the Grønøy High (Halland et al., 2011). A major hiatus, with rocks varying from Late Permian to Jurassic being truncated by the unconformity, is defining the Nordland Ridge. The overlying deposits vary from Early Cretaceous to Pliocene in age (Blystad et al., 1995). According to Blystad, the reason for the composite nature of the unconformity, is that it resulted from multiple events of erosion and deposition. The Nordland Ridge is also associated with large positive magnetic anomalies with maximum amplitudes west of the ridge crest (Rønnevik and Navrestad, 1977).

The Revfallet Fault Complex is the western fault boundary of the Nordland Ridge (Rønnevik and Navrestad, 1977, Gowers and Lunde, 1984). It is considered as a part of the Kristiansund-Bodø Fault Complex (Gabrielsen and Robinson, 1984). In the south, the Revfallet Fault Complex consist of NNE-SSW oriented normal faults dipping to the west, while north of 66^{o}N it is composed of a downflexed slope at the base of the Cretaceous, sloping into the Rås and Vestfjorden Basins. It nearly dies out in the south, as it gets close to the Sklinna Ridge. The largest fault shows more than 2000 m displacement (Blystad et al., 1995). The Revfallet Fault Complex seperates the Trøndelag Platform, including the Nordland Ridge, from the Dønna Terrace or further north; the Træna and Vestfjorden Basins.

The Dønna Terrace was first named by Aasheim et al. (1986), but it was only briefly mentioned in the paper. It was first described as the northern extension of the Halten terrace by Hastings and Spencer (1986). It is located approximately between 65^{o} 20’N - 66^{o} 30’N and 6^{o} 40’E - 8^{o} 30’E. It is situated adjacent to the Nordland Ridge. The terrace dies out NW of the Rødøy High in the north and widens towards the transition to the Halten Terrace in the south. Faults forming local horsts and grabens and rotated fault blocks are common, as the terrace is internally deformed (Blystad et al., 1995). According to Blystad, the Jurassic sequence is thick, overlain by thin Lower Cretaceous covered by Upper Cretaceous and Cenozoic deposits.

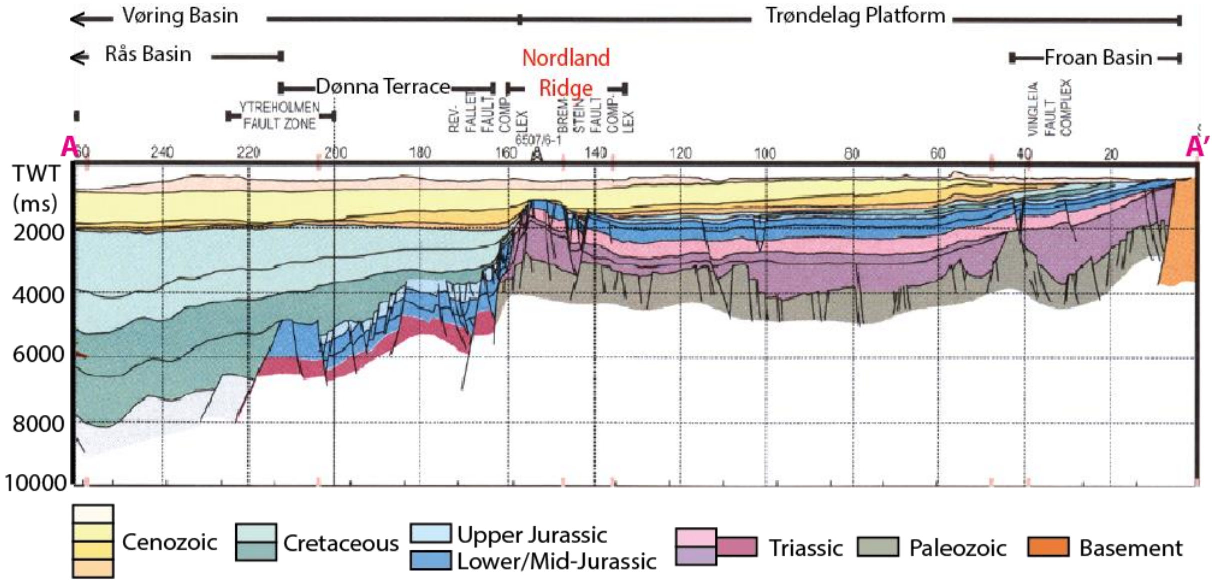

Figure 2.9: Cross section through the Trøndelag platform (including the Nordland Ridge), continuing out in the Vøring Basin (including the Dønna Terrace). Modified from Brekke (2000).

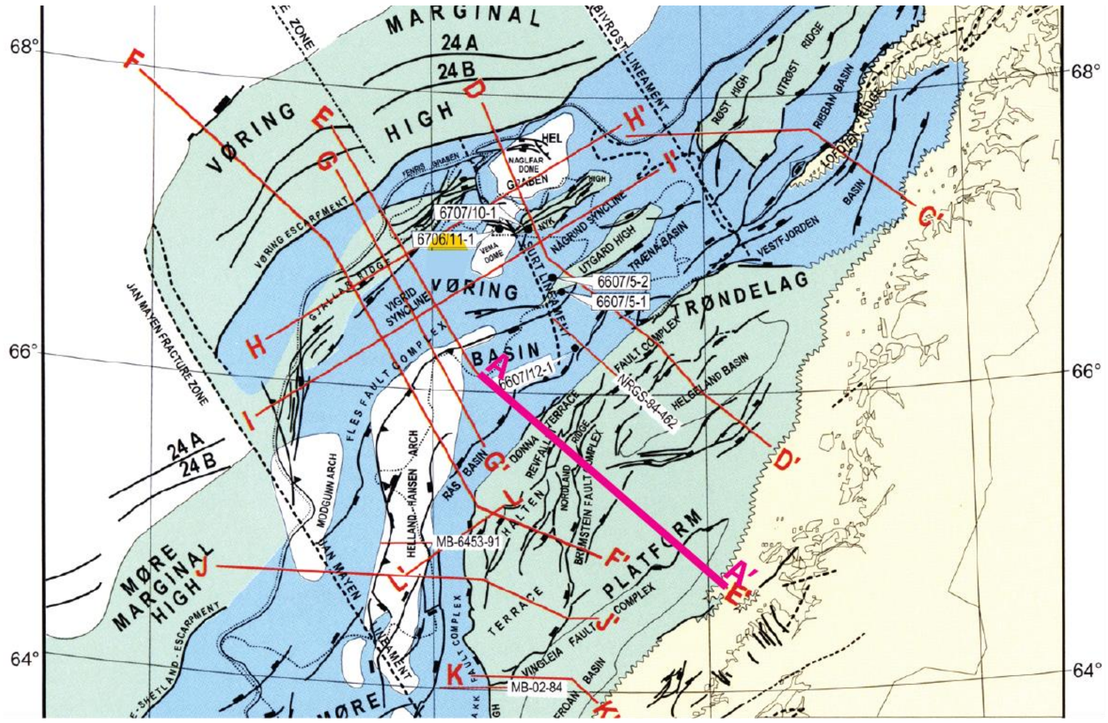

Figure 2.10: Location of the cross section A-A' from figure 2.3. A-A' is part of the E-E' line. Modified from (Brekke, 2000).

2.2 Geological formations

This subchapter presents a short description of the lithostratigraphic units (Groups and Formations) discussed later in the thesis. Information on the formations is provided by the NPD Factpages (NPD, 2018).

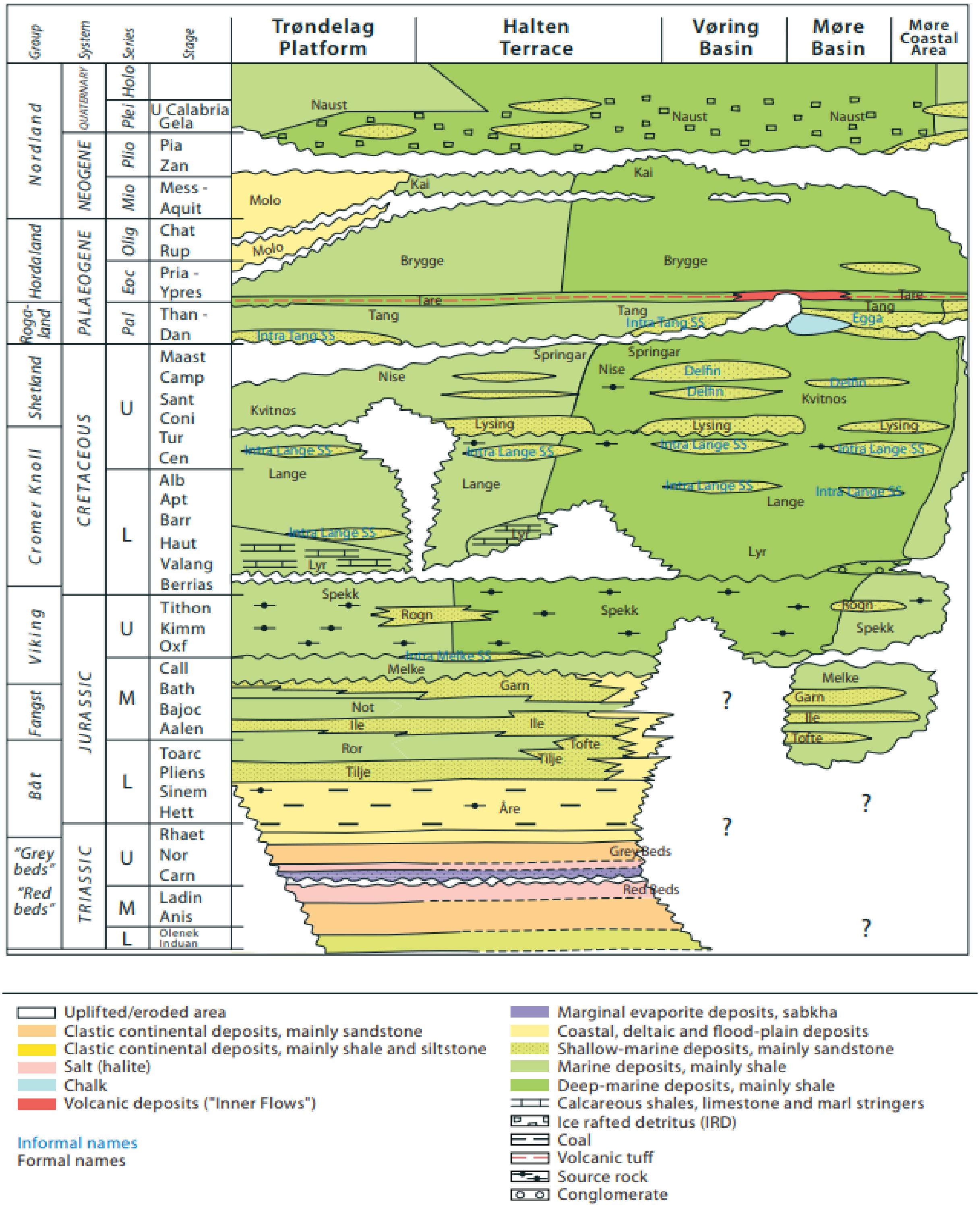

Figure 2.11: Lithostratigraphic chart over the Norwegian Sea. From NPD.

2.2.1 Triassic deposits

The Triassic Red Beds and Grey Beds have not been given a formal formation or group. Thicknesses of over 2500 m have been drilled.

Red Beds (informal):

Continental clastics of Triassic age. Red color. Deposited in more arid climate compared to the overlying “Grey Beds”.

Grey Beds (informal):

Continental clastics of Triassic age. Grey color. Deposited in more humid climate than the underlying “Red Beds”.

Lower Åre Formation:

The Lower Part of the Åre Formation is of Triassic age (Rhaetian). See subchapter 2.2.2 “Jurassic deposits” for description.

2.2.2 Jurassic deposits

Båt Group (Lower Jurassic)

Åre Formation:

Alternating sandstones and claystones interbedded with coals. Late Triassic (Rhaetian) to Early Jurassic coastal/delta plain deposits. The upper parts pass into marginal marine facies. Individual coals up to 8 m thick. More proximal lithofacies contain less sand and coarser sandstones. Generally between 300 and 500 m thick. The formation is truncated locally on highs like the Nordland Ridge.

Tilje Formation:

Sinemurian – Pliensbachian aged very fine to coarse grained sandstones, interbedded with shales and siltstones. The sands are commonly moderately sorted with a high clay content. Most shales are silty or sandy. The depositional environment is nearshore marine to intertidal. 98 m in the type well 6507/11-1, 91 m in the reference well 6609/10-1.

Tofte Formation:

Moderately to poorly sorted coarse grained sandstones with frequent large scale cross bedding. Pliensbachian to Toarcian in age. The sandstones wedge out in the east, interfingering with the Ror Formatiom. Deposited by eastwards prograding fan deltas, reflecting the uplift in the west. 65 m in the type well 6506/12-1, 40m in the reference well 6407/4-1.

Ror Formation:

Dominant grey to dark grey mudstones contain interbedded silty/sandy upwards coarsening sequences, commonly a few meters thick. More frequent in the top of the formation. Pliensbachian to Toarcian of age. Deposited in open shelf environments, mainly below wave base. 104 m in the type well 6407/2-1, 66 m to 160.5 m in the reference wells 6507/10-1, 6407/4-1, 6610/7-1. The formation is eroded over large areas on the Nordland Ridge.

Fangst Group (Middle Jurassic)

Ile Formation:

Fine to medium (occasionally coarse) sandstone with varying sorting. Interbedded with thinly laminated siltstones and shales. Thin carbonate-cemented stringers occur. Late Toarcian to Aalenian in age. The formation represents tidal-influenced delta or coastline settings. 64.5 m in the type well 6507/11-3 and 72m in the reference well 6407/1-3. General thickening to the west, thinning to the north-east.

Not Formation:

Claystones with micronodular pyrite, coarsening upwards into fine grained sandstones which are locally mica-rich and carbonate cemented. Of Aalenian to Bajocian age. Basal part reflects a transgression, leading to development of lagoons or sheltered bays. Upper part represents prograding deltaic or costal front deposits. 14.5m in the type well 6507/11-3, 37m in the reference well 6407/1-3. Locally eroded.

Garn Formation:

Medium to coarse grained sandstones. Moderately to well sorted. Mica rich and carbonate cemented zones are frequent. Bajocian to Bathonian age. May represent progradadations of braided delta lobes. Delta top and delta front facies are recognized. Entire unit may be eroded in structural highs. 104 m in the type well 6407/1-3, 45 m in the reference well 6507/11-3.

Viking Group (Middle – Upper Jurassic)

Melke Formation:

Dominantly claystone, with siltstone and limestone interbeds. Stringers of sandstone. The age is Bajocian to Oxfordian. The thickness is 116.5 m in the type well 6506/12-4, 44m in the reference well 6407/2-2. May attain thickness of several hundred meters in down-flank basins. Depositional environment is open marine. It is locally absent on structural highs.

Intra Melke Formation sandstones (informal):

Intra Melke sandstones have been encountered in several wells in block 6608/10, close to, or on the Rødøy High.

Spekk Formation:

Dark brown to dark grey shale. Very high organic content (type II kerogen). The age is Oxfordian to Ryazanian. Depositional environment is marine anoxic bottom water conditions. 65.5 m in the type well 6407/2-1, 14m in the reference well 6407/9-1. May be absent from the Nordland Ridge and other structural highs.

2.2.3 Cretaceous deposits

Cromer Knoll Group (Lower – early Upper Cretaceous)

Lyr Formation:

Marls with interbedded carbonates. 23.5 m in the type well 6506/12-1, 16 m in the reference well 6407/1-2. Valanginian to Lower Aptian Age. Open marine conditions. Absent on structural highs on the Nordland Ridge and the Trøndelag Platform.

Lange Formation:

Claystones with stringers of carbonates and sandstones. The age is Berrisian to Late Turonian. 622.5 m in the type well 6506/12-1, 685 m in the reference well 6506/12-4. Deposited in marine environment, possibly shallower on the Halten Terrace area and deeper in the basins to the west. Intra Lange Formation sandstones are common. The Intra Lange Formation sandstones are believed to have been sourced from the Nordland ridge (Hastings, 1987)

Lysing Formation:

Fine to medium, occasionally coarse, sandstones. Partly carbonate cemented and interbedded with shales. The age is Late Turonian to early Coniacian. 74 m in the type well 6507/7-1, 17.5 m in the reference well 6506/12-4. Interpretations vary from shallow to deep marine possible submarine fan deposits. The formation is absent on the Trøndelag Platform. The Lysing Formation is believed to have been sourced from the Nordland Ridge (Hastings, 1987).

Shetland Group

In the study area, the Shetland Group is generally represented by formations consisting of open marine claystone. Some sandstone and carbonate stringers are present. Only the formations present in the wells of the study areas are described.

Springar Formation

Greyish-green claystones. Some stringers of sandstone and carbonates are present. Regionally extensive and only absent on parts of the Nordland ridge. 169 m in the type well 6506/12-4. 167 m in the reference well 6506/12-1.

Nise Formation

Grey and greyish-green claystone with carbonate and sandstone stringers. Absent on parts of the Nordland Ridge. 220 m in the type well 6506/12-4, 212 m in the reference well 6506/12-1.

Kvitnos Formation

Grey and grey-green claystone with some carbonate and sandstone stringers. Missing on some parts of the Nordland Ridge. 532.5 m in the reference well 6506/12-4, 517 m in the reference well 6506/12-1.

Rogaland Group

In most of the Norwegian sector the Rogaland Group consists of argillaceous marine sediments. On Haltenbanken, the group consists of claystone with minor local siltstone. In the Norwegian Sea the sediments were deposited in a deep marine environment. The group is 684 m thick in well 10/1-1 A and 459 m well 21/10-1 (UK wells). It thins eastwards and is 345 m and 112 m thick in wells 31/2-6 and 2/7-1 (Norwegian wells).

3. Background theory

3.1 Generation and migration of hydrocarbons

3.1.1 Hydrocarbon generation

The generation of hydrocarbons occurs when sedimentary rocks with sufficient TOC (total organic carbon), typically organic rich shales, are buried and heated. Oil generation from kerogen occur at elevated temperatures in the sub-surface. The majority of oils are formed from kerogen at 100-150^{o}C. Most gas production from kerogen occurs between 150-220^{o}C, while oil to gas cracking occur between 150-190^{o}C (Quigley and Mackenzie, 1988)

The two main source rocks in the study area of the thesis are the organic rich Spekk Formation and the coals and shales of the Lower Åre Formation (Swiecicki et al., 1998, Karlsen et al., 1995, Rwechungura et al., 2010).

3.1.2 Primary migration

The process of mobilization and expulsion of hydrocarbons from a source rock, where the oil or gas migrates into a more permeable carrier bed where it can move freely, is defined as primary migration (Chapman, 1972). The initial porosity in mud, approximately 60%, decreases to 5-10% in mudstone after 2500 m subsidence. The mudstones are also of extremely low permeability. Porosity reduction resulting from the burial (first mechanical, and later also chemical compaction), and also the liberation of hydrocarbons from the maturing of kerogen leads to pressure buildup in the source rock. This can lead to the creation of micro fractures from where the hydrocarbons could escape into units of higher permeability (Barnard and Bastow, 1991).

3.1.3 Secondary migration

The migration of hydrocarbons through permeable carrier beds, starting after sufficient hydrocarbons has filled the pore space at the interface between the source rock and the permeable rock, is defined as secondary migration (Barnard and Bastow, 1991, Schowalter, 1979). The process is buoyancy-driven (hydrocarbons have lower density than water/brine), and the migration is believed to take place along restricted conduits. When the hydrocarbons have reached a saturation allowing for the buoyancy to overcome the capillary entry pressure in the pore throats in the carrier bed, the hydrocarbons are believed to migrate vertically upwards until they reach an impermeable layer. From there the hydrocarbons move up-dip, laterally along the top seal (Dembicki Jr and Anderson, 1989).

Faults often represent barriers for hydrocarbon migration. Juxtaposition between the carrier bed and impermeable shale across the fault, or a sealing fault prohibits across fault migration. In Jurassic reservoirs hydrocarbons commonly migrate up-dip following the strike of faults (Johnsen et al., 1995).

Juxtaposition of permeable units may allow for across fault migration. Migration of hydrocarbons vertically along the fault plane can occur when the fault plane itself acts as a fluid conduit. This allows for hydrocarbons in down faulted reservoirs to enter into up-faulted reservoirs.

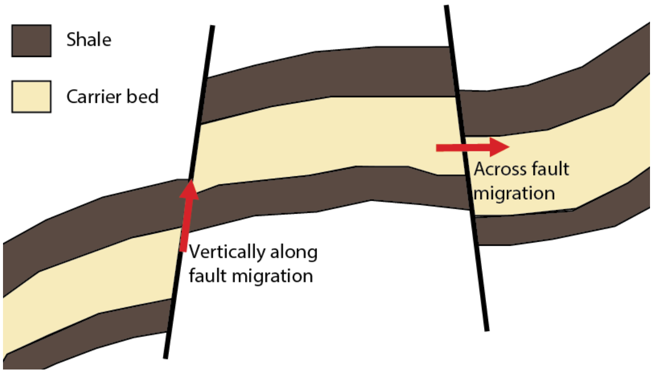

Figure 3.1: Hydrocarbon migration in and across faults.

3.2 Hydrocarbon accumulation

As the hydrocarbons reach a trap (structural or stratigraphic), the capillary entry pressure of the cap rock prevents further upwards migration, and the hydrocarbons start to accumulate (Bjørlykke, 2010).

3.2.1 Spill points

The accumulation of hydrocarbons can continue until the hydrocarbon-water contact reaches a depth where the hydrocarbons spills out of the closure. This depth is referred to as the spill point. Figure 3.2 shows the discrimination between a structural spill point and a fault spill point.

- The structural spill point refers to the shallowest point of the top of the reservoir along the hinge line of a syncline.
- A fault spill point is the shallowest point where the reservoir is juxtapositioned to a permeable unit.

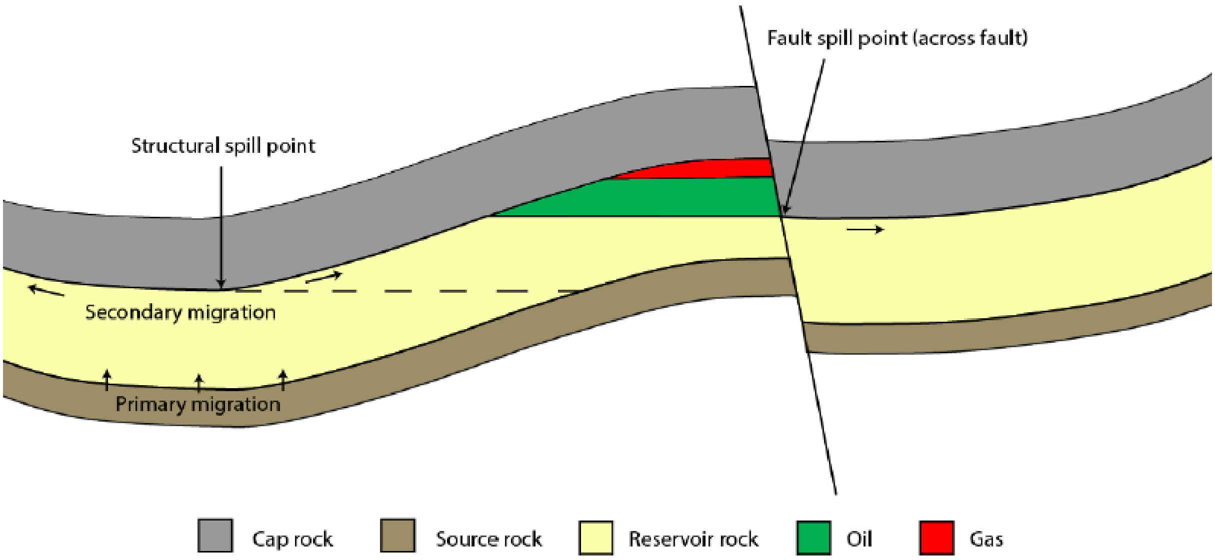

Figure 3.2: Structural and fault spill points. From Sollie (2015).

3.2.2 Filled structures

Filled structures are structures where hydrocarbons have accumulated down to the depth of the spill point. If the hydrocarbon-water contact is at the same depth as the spill point, the structure is interpreted as “filled to spill”.

3.2.3 Underfilled structures

Underfilled structures contain hydrocarbon accumulations that does not fill the structure to its maximum capacity relative to its interpreted spill point. The hydrocarbon-water contact is situated at a shallower depth than the spill point. This can occur as either a consequence of leakage or limited hydrocarbon charge.

3.2.4 Overfilled structures

Overfilled structures contain hydrocarbon accumulation down to a deeper level than the interpreted spill point. The hydrocarbon water contact is located below the depth of the spill point. This points to the presence of a sealing mechanism, such as shale smear or cementation, preventing the hydrocarbons from migrating out of the trap at the spill point.

3.2.5 Fill spill models

If hydrocarbon charge continues after filling the trap to its spill point, the hydrocarbons can continue to migrate up-dip and accumulate in shallower traps before spilling further. The occurrence of several traps along an interpreted migration pathway leads to a fill spill model. Charge of both oil and gas to the system can lead to differential entrapment of oil and gas. Gussow (1954) introduced the most commonly accepted model for how oil and gas is distributed along a fill spill route.

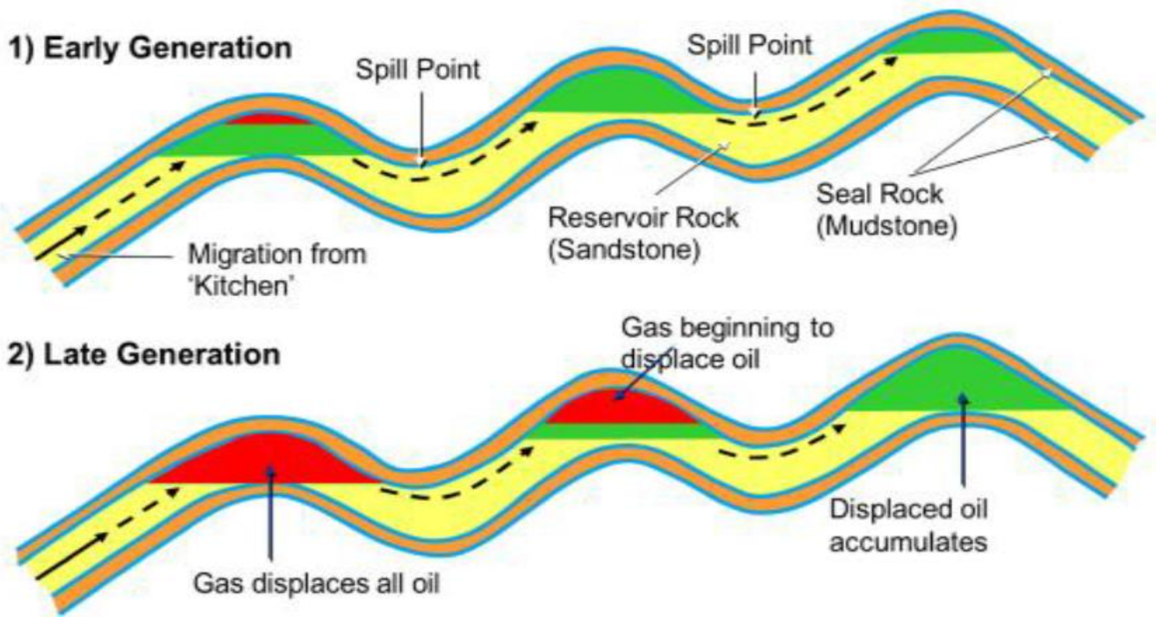

Figure 3.3: Conceptual presentation of the Gussow model. From Peacock (2014)

Because of the lower density of gas, it will accumulate above the oil, at the apex of the trap, leading to the spilling of oil when the accumulation reach the spill point of the trap. Only when the oil is completely flushed, the gas can spill out of the trap and migrate further up-dip. This leads to a phase distribution with gas in the deeper traps, oil in the shallower traps and a two-phase accumulation somewhere in the middle. We will refer to this as “the Gussow model”. The phase distribution will be the same regardless if the hydrocarbons are sourced from one continously subsiding source rock, yielding oil at an early stage and later gas, or if the oil and gas charge are simultaneous from different source rocks.

3.3 Fault sealing

The typical trap type in the Jurassic reservoirs in the study area is rotated fault blocks or horsts delineated by normal faults. Fault sealing can generally be divided into two categories (Welbon et al., 1997):

- Juxtaposition of the reservoir to shales or other impermeable rocks. This is referred to as juxtaposition seal (which strictly speaking is not fault sealing, as the properties of the fault is irrelevant if the reservoir is juxtapositioned to impermeable rocks).
- Membrane seal is the second category. This is caused by reduction of the pore throat radii due to smear of shale of impermeable layers along the fault, or through cementation or cataclasis in sandstones.

3.3.1 Juxtaposition seal

Juxtaposition seals have a high likelihood of being effective in keeping hydrocarbons from escaping through the fault surface (Farseth et al., 2007). They can therefore be considered as relatively low-risk faults. As there can be sub seismic features such as thin sandstone stringers, uncertainties cannot be disregarded.

3.3.1 Membrane seal

Diagenetic effects:

According to (Blatt, 1979), quartz cementation is the most important process resulting in porosity reduction in sandstone reservoirs. Investigations from the North Sea shows that sandstones from the Brent Group only contain small amounts of quartz cementation down to depths of 2.5 – 3km. The cementation becomes significant at burial depths above 3000 m (Bjørlykke et al., 1992). In reservoirs investigated by Fisher and Knipe (2001), diagenetic reactions such as quartz cementation do not occur at rapid rates below approximately 90°C. Quartz cementation in faults could lead to across fault sealing. In the case of cataclasis, one would need less cement in order to reduce the pore throat radii in the fault zone sufficiently for sealing the fault.

Shale smear

The process of smearing of impermeable units into the fault zone can increase the capillary entry pressure in a seemingly sand to sand juxtaposed fault. Lindsay et al. (1993) introduced a shale smear factor (SSF).

$$SSF = \frac{Fault\ throw}{Shale\ layer\ thickness} \tag{3.1}$$

A low SSF results in higher seal probability. They concluded that a SSF of 7 or higher gave a high risk for an incomplete shale smear. According to Færseth (2006), a SSF value lower than 4 is sufficient for resulting in an intact seal along a fault.

3.4 Trap integrity and leakage

3.4.1 Capillary leakage

Capillary leakage of hydrocarbons through a water wet seal can in theory occur if their buoyancy overcomes the capillary entry pressure. The capillary entry pressure is controlled by the radius of the largest pore throats in the cap rock (Berg, 1975).

$$Pc_e < (\rho_w - \rho_{hc})gh \tag{3.2}$$

$Pc_e = capillary\ entry\ pressure$
$\rho_w = density\ of\ water$
$\rho_{hc} = density\ of\ hydrocarbons$
$g = gravitational constant$
$h = height\ of\ hydrocarbon column$

3.4.2 Hydrofracturing

If the permeability in the cap rock is very low (meaning high capillary entry pressures if there were hydrocarbons), high overpressures, approaching the tensile strength of the rock, could result in hydrofracturing leading to hydrocarbon leakage (Watts, 1985, Borge, 2000).

3.4.3 Fault intersections

Fault intersections are locations where two or more faults converge and intersect. Vertical leakage of hydrocarbons at these intersections has been proposed (Gartrell et al., 2003, Gartrell et al., 2004). Hermanrud et al. (2014) conducted a study in the Hammerfest Basin, investigating 10 traps. All underfilled structures had a hydrocarbon-water at a level coinciding with fault intersections. Dry structures had fault intersections up-dip of the exploration wells.

3.4.4 Reactivation of faults

Leakage because of fault reactivation could lead to hydrocarbon leakage (Wiprut and Zoback, 2000). Favourably oriented faults will slip before the pore pressures can reach levels resulting in cap rock failure.

3.5 Pore pressure

Formation pressure or pore pressure is the fluid pressure within the pore space of a geological unit. It is also referred to as reservoir pressure. The pore pressure is often described relative to the hydrostatic pressure, which represent the theoretical pressure that would result from pressure communication to the sea surface. In other words it would reflect the weight of the water column to the surface (Osborne and Swarbrick, 1997). Formations following the hydrostatic pressure gradient are referred to as normally pressured formations.

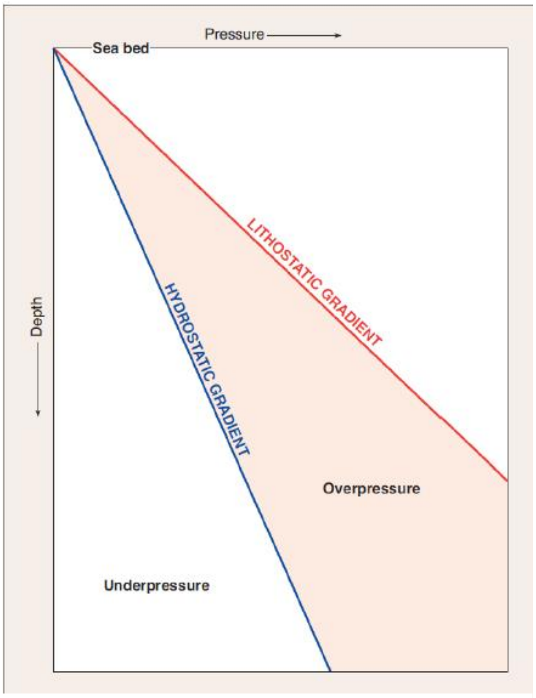

Figure 3.4: Idealized model showing the relation between hydrostatic/lithostatic pressure and overpressure/underpressure. From Moss et. al. (2003)

3.5.1 Overpressure

If the pore pressure is significantly higher than the hydrostatic pressure at the same depth, the formation is overpressured. Overpressure is defined as the difference between the pore pressure and the hydrostatic pressure at the same depth. Overpressures occur in formations with restricted communication with overburden formations, and no communication to the surface(Buhrig, 1989). The overpressure can result from several mechanisms (Buhrig, 1989, Osborne and Swarbrick, 1997):

- Rapid subsidence and following overburden loading. A system with an effective cap rock could trap fluids from escaping out of the system while mechanical compaction decrease the pore volume during subsidence. This rapidly results in overpressure buildup due to the incompressibility of formation water.
- Temperature increase leading to fluid expansion.
- Hydrocarbon generation, and cracking of oil to gas.
- Diagenesis/chemical compaction.

3.5.2 Underpressure

Underpressured formations are not as common. These are formations that have a pore pressure lower than the corresponding hydrostatic pressure. Similarly to overpressured units, they have no pressure communication to the surface, but instead of subsidence, the underpressured formations have been subject to uplift and overburden erosion (Osborne and Swarbrick, 1997).

3.6 Seismic amplitude variations

The interpretation of seismic data is the most commonly used method for geological mapping of the subsurface. Reflection seismic is based on the recording and processing of acoustic reflections that result from lithological boundaries (or contrast in pore fluid properties) representing a contrast in acoustic impedance. Acoustic impedance is defined as the product of the density and seismic velocity of a lithological unit (Badley, 1985, Herron and Latimer, 2011). The impedance contrast and the resulting seismic response varies laterally, due to local variation in lithology and pore fluid. For example gas replacing brine in the pore space will result in a change in the acoustic impedance of a reservoir. Such changes can often be observable in the seismic.

3.6.1 Tuning

The effect of interference will occur if two separate reflectors are situated sufficiently close to each other. For a thin layer, the reflections from the top and bottom of the layer will interfere constructively or destructively. This is called the tuning effect. Maximum constructive interference occur when the thickness of the bed is equal to ¼ of the wavelength, and the top and base reflectors have opposite polarity. This thickness is called the maximum tuning thickness(Brown et al., 1996).

3.6.2 Bright and dim zones

Seismic anomalies represented by local increase or decrease in the amplitude of reflectors are referred to as bright and dim zones/spots. A positive amplitude bright is associated with a local increase in acoustic impedance, while a negative amplitude bright is associated with a decrease. Strong negative amplitude anomalies are often associated with hydrocarbons, especially gas, replacing brine in the pore space. A hydrocarbon filled trap will often have a

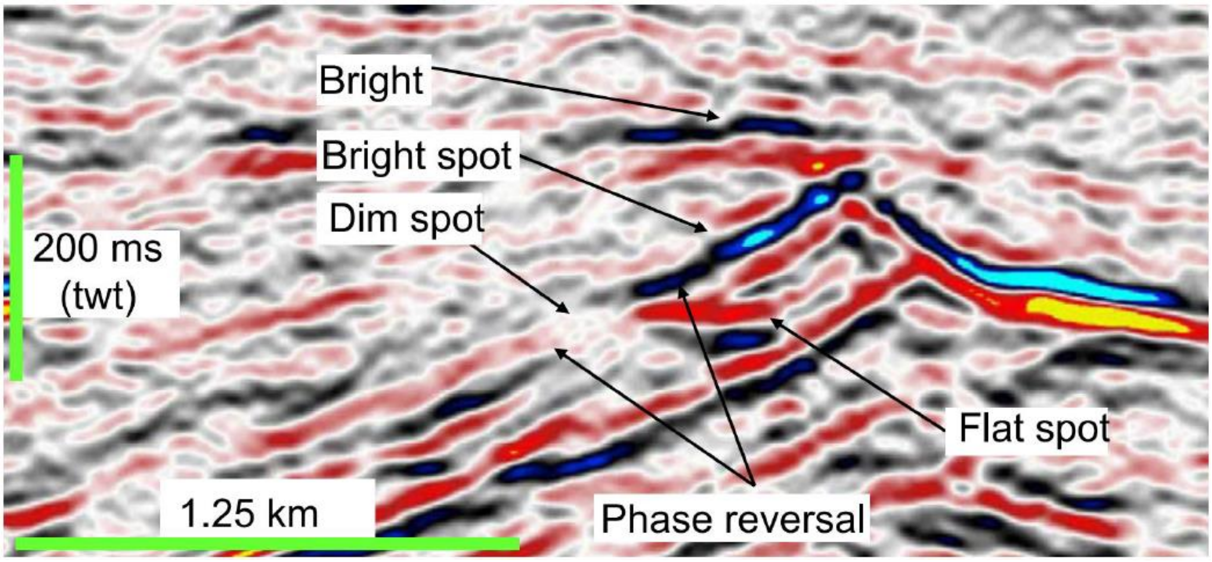

Figure 3.5: Seismic amplitude anomalies. From Løseth et al. (2009)

negative amplitude anomaly at the top reservoir reflector, while a peak represent the hydrocarbon water contact (often referred to as a flat spot) (Løseth et al., 2009). A dim zone is the result of hydrocarbons cancelling out the lithological impedance contrast, resulting in a weakening of the amplitude of the reflectors. Brights, dims, flatspots and also phase reversal are commonly referred to as DHI's (direct hydrocarbon indicators) (Allen and Peddy, 1993, Ligtenberg, 2005).

3.6.3 Seismic chimneys

Seismic chimneys are represented in seismic cross section as near vertical zones with distorted, low amplitude reflections resulting from hydrocarbons in the overburden above a trap (Ligtenberg, 2005). Seismic chimneys are interpreted as leakage indicators. A classification of chimney type based on underlying accumulations was proposed by Heggland et al. (2013). Gas chimneys normally are associated with brights at the flanks of the chimneys (Løseth et al., 2009).

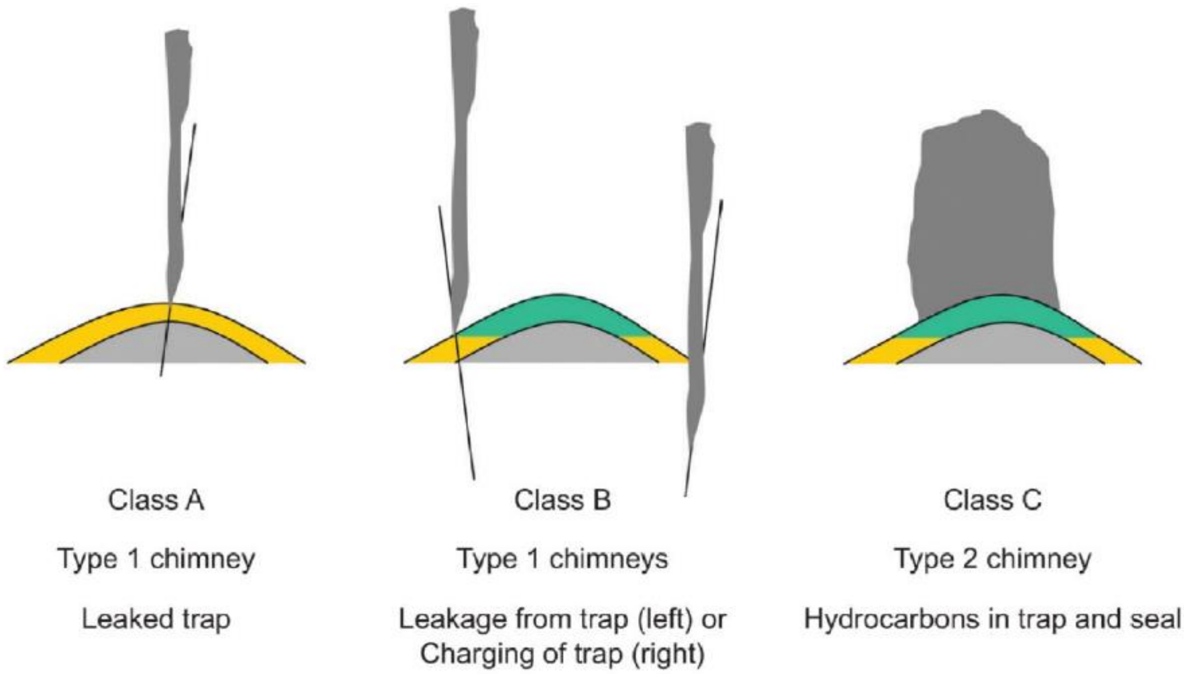

Figure 3.6: Chimney classification, and associated hydrocarbon accumulation. From (Heggland et al., 2013)

4. Data and workflow

Chapter 4 gives an overview of the workflow, data and tools that was used in this project.

4.1 Seismic dataset

The seismic dataset used for interpretation in the project consisted of three 3D-seismic cubes: MC3D-HVG2012, ST11M04 and ST0816Z13. The seismic was provided by Petroleum Geo Services ASA (PGS) and Equinor ASA (formerly Statoil ASA). Three separate Petrel E&P Software Platform (developed by Schlumberger) projects for each of the seismic cubes was provided by Equinor.

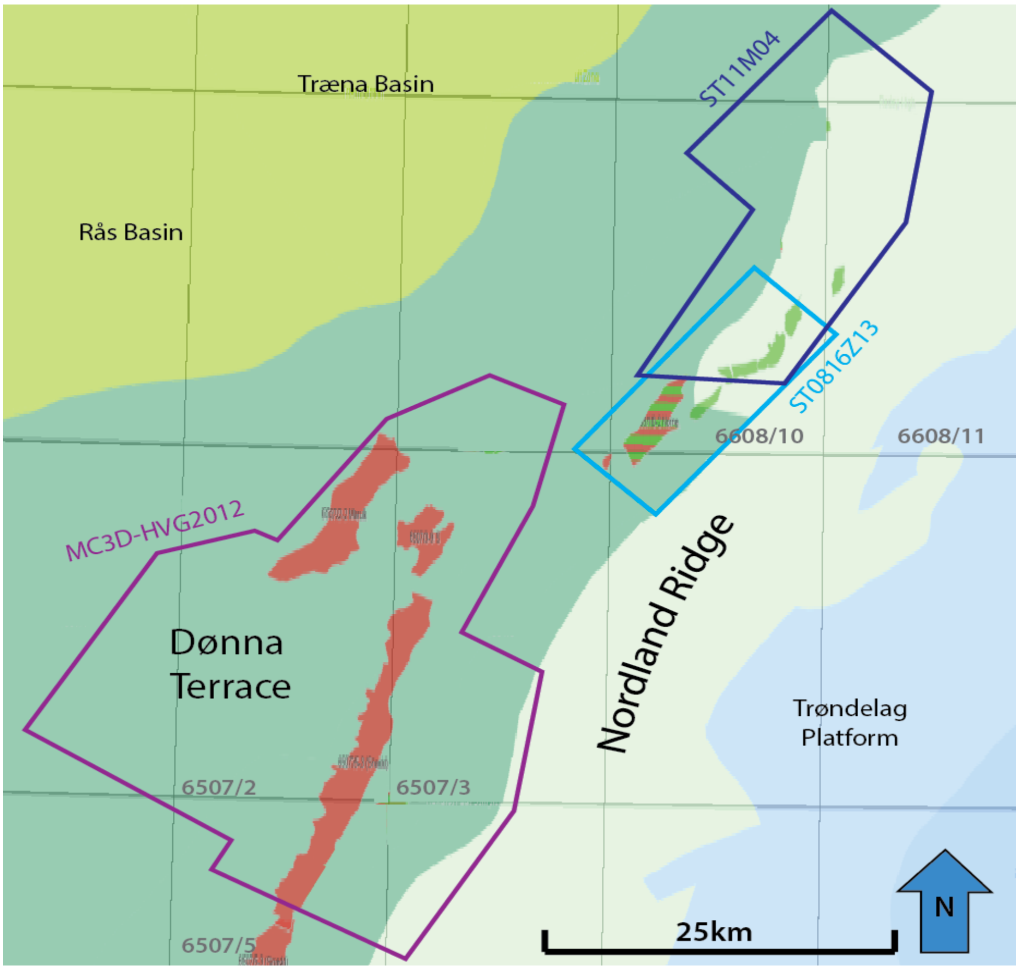

Figure 4.1: Map showing the coverage of the 3d-seismic cubes used for interpretation. The structures investigated in the project is added together with structural elements.

Survey	Phase	Inline rotation from North (deg)	Line spacing (m)	Resolution (m)	Quality
MC3D-HVG2012	Zero	-63	Inline: 12,5 Xline: 12,5	28 - 36	Moderate
ST11M04	Zero	41,8	Inline: 12,5 Xline: 12,5	18 - 26	Good
ST0816Z13	Zero	41,8	Inline: 12,5 Xline: 12,5	21-29	Good*

Table 4.1: Information on the 3D-seismic cubes

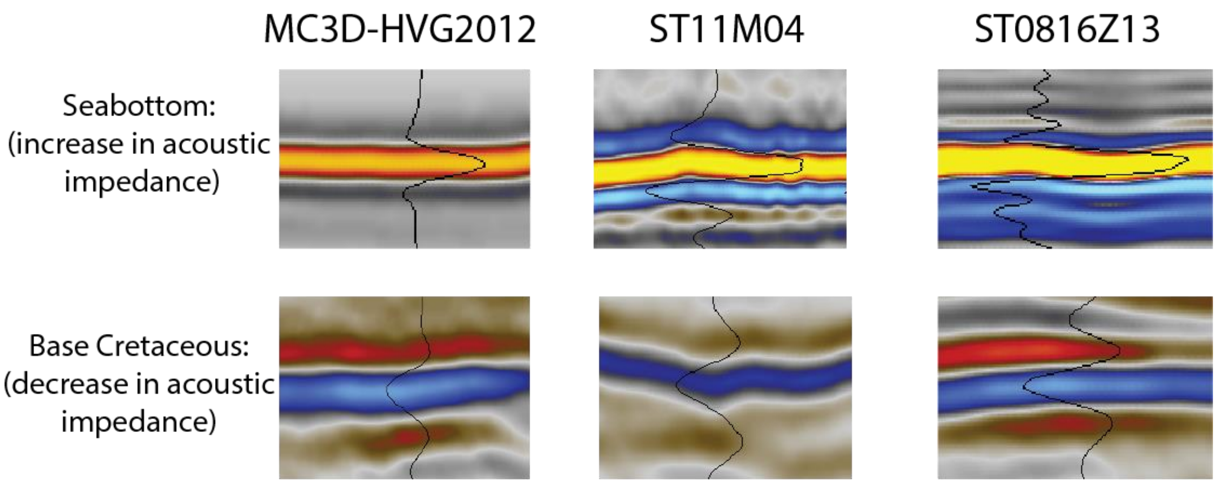

Figure 4.2: Shows the seismic presentation of increase and decrease in acoustic impedance in the different 3D-seismic cubes.

All the seismic surveys are time migrated to zero phase (wavelets are symmetrical about zero time). A downward increase in acoustic impedance is associated with a peak, and represented with a red reflection in the seismic. A downward decrease in acoustic impedance is represented by a blue through. All the seismic cubes are in the time domain, with a vertical axis representing TWT in ms.

The resolution of the seismic was varying between the three surveys. An approximation of the vertical resolution was made by using the wavelet toolbox in Petrel to estimate the dominant frequency range in the depths of interest in the different cubes. The velocities in the depth range of interest were calculated from the sonic log in representative wells. The resolutions are listed in table 4.1.

The following formulas were used for determining the vertical resolution of the seismic:

$$v = f\lambda \Leftrightarrow \lambda = \frac{v}{f} \quad (4.1) \qquad Res = \frac{\lambda}{4} \quad (4.2)$$

$$\begin{aligned} v &= velocity \\ f &= frequency \\ \lambda &= wavelength \\ Res &= vertical\ resolution \end{aligned}$$

To calculate the velocity from the sonic log (unit µs/ft), the following calculation was done:

$$v[m/s^2] = \frac{0.3048 * 10}{\Delta t[\frac{\mu s}{ft}]} \quad (4.3)$$

$$\begin{aligned} v &= velocity \\ \Delta t &= slowness(sonic\ log) \end{aligned}$$

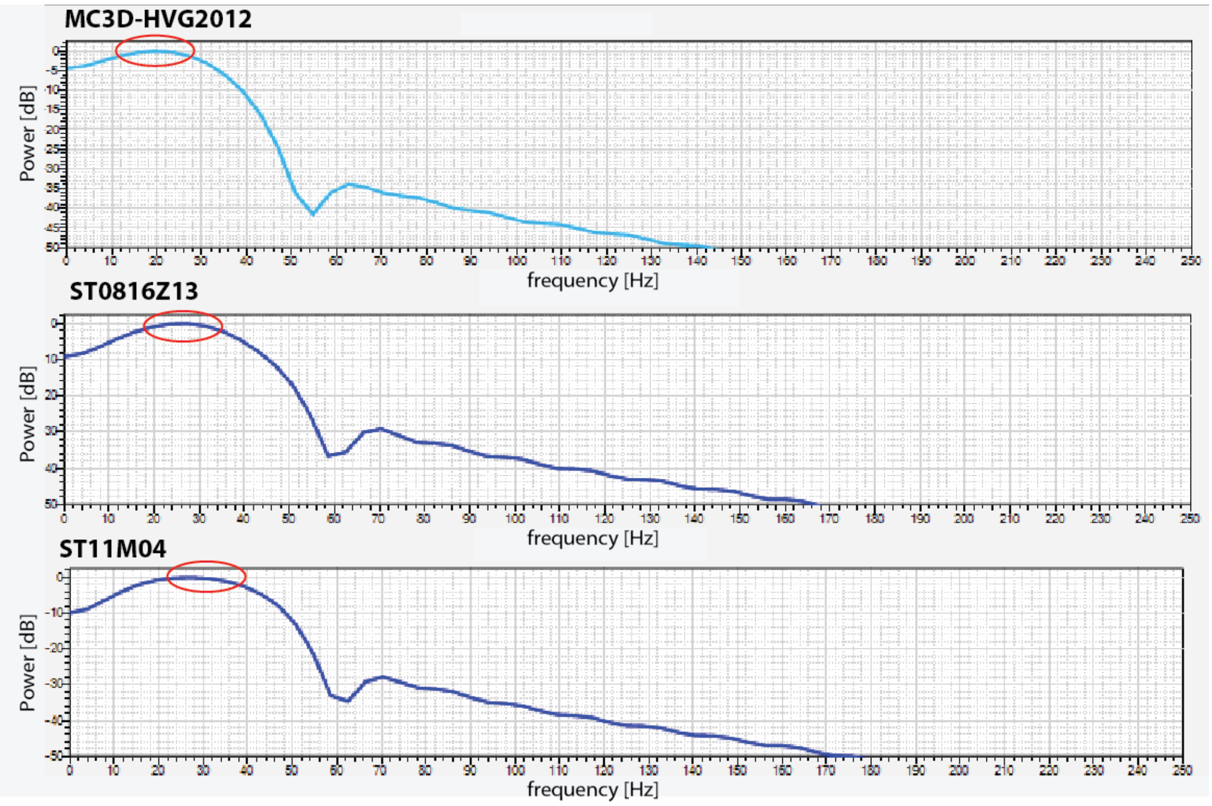

Figure 4.3: Power spectrums from the depth range of interest in the three different seismic cubes. Used to estimate vertical resolution. From Petrel's wavelet toolbox.

4.2 Well data

Equinor included well data in the provided Petrel projects. This included well location, trajectory, checkshots and in some cases digital conventional well logs (caliper, gamma ray, sonic, density etc.). All the wells used were exploration wells. Table 4.2 shows all the wells that were investigated and used in the thesis. Included is also the wells that were only used as guidance for the seismic interpretation.

Well	Structure
6507/2-1	Marulk
6507/2-2	Marulk
6507/2-3	Snadd North
6507/2-4	Marulk
6507/3-9 S	Snadd Outer
6507/5-6 S	Snadd North
6507/3-8	Gjøk
6608/10-2	Norne
6608/10-3	Norne
6608/10-4	Norne Main
6608/10-6	Svale
6608/10-7	Svale
6608/10-8	Stær
6608/10-8 A	Stær
6608/10-9	Lerke
6608/10-15	Svale North
6608/11-2	Falk
6608/11-8	Falk

Other wells –used for aid in seismic interpretation or to check formation depth
6507/3-1
6507/3-3
6507/3-4
6507/3-7
6507/5-1
6507/5-2
6507/5-3
6507/5-5
6607/12-2 S
6608/10-10
6608/10-12

Table 4.2: Wells used in the project.

4.2.1 Well-tops and checkshots

New well top folders were made for all wells in order to customize the Petrel project for the thesis. A few of the well-top folders provided by Equinor were corrupt, or missing some information so in order to conduct a quality control of the data to be used, all the welltops were manually imported. Depths of fluid contacts and important lithostratigraphic boundaries/formation tops were located in available well reports or from the information in the Norwegian Petroleum Directorate's online Factpages.

Checkshots for the wells was provided by Equinor. Multiple checkshots was available for most of the wells. Some of the wells were corrupt or formatted for a different coordinate referance system, so new versions were provided by Equinor. The best fitting checkshots and wells was identified by correlating clear seismic reflectors between neighbour wells. The seismic was also checked against well logs (density and sonic logs).

4.2.3 Pressure data

Pressure data was acquired from RFT (Repeat Formation Tester) measurements, and in a few cases MDT (Modular Formation Dynamics Tester), from available well reports. Some pressure data was downloaded from the online Diskos Data Browser.

4.3 Workflow and Methodology

4.3.1 Conditioning of the seismic dataset

The three 3D-seismic cubes and accompanying Petrel projects were merged into one project. The project containing the ST0816Z13 3D-seismic cube was referencing to a different coordinate system. It was formatted to the same reference system as the two other projects.

The cubes were differently processed. In order to avoid too much load on the computer, the cubes were converted from 32 to 8 bit. The amplitude range of the seismic was cropped and balanced, so that the strongest reflectors were still not clipping, and the weaker reflectors also was visible. Instead of just compressing the color the color scale, this operation also reduces the file size of the seismic cubes. Structural smoothing was also carefully applied before realizing the 3D-seismic cubes. This operation is used to increase the continuity of the seismic reflectors, and was used with care in order to not wash out structural boundaries such as faults.

Variance 3D cubes were realized from the original cubes. These cubes enhance edges or lateral contrasts by estimation the local variance in the signal.

4.3.2 Seismic interpretation

Petrel E&P 2015 was used to perform the seismic interpretation.

A detailed interpretation of the different top reservoir formations in the areas around the investigated structures was conducted. In the chapter describing Cretaceous reservoirs on the Dønna Terrace (chapter 5.1), the top reservoir was the top Cromer Knoll Group. The top Shetland Group was also interpreted. In the chapter 5.2 (Jurassic reservoirs), the top main reservoir varies between the structures because of lateral variation in deposition and erosion. In most structures, this was the upper sand in the Fangst Group (varying between the Garn Formation and some part of the Not Formation). In the Falk Structure, the Fangst Group was eroded and the top main reservoir is represented by the Åre Formation of the Båt Group. A separate, shallower reservoir level, the Intra Melke Formation was locally interpreted in the structures where it was present. In some structures, the Intra Melke Sandstones does not have a clear representation in the seismic, and assumed parallel reflectors were interpreted and shifted to the depth of the top Intra Melke Formation in well position. Other interpreted reflectors are the BCU (Base Cretaceous Unconformity), Intra Åre Coal marker (locally) and Seabottom. The BCU and the Intra Åre Coal Marker was used as guidance for the interpretation of the Jurassic Structures.

Both manual interpretation and different 2D and 3D-autotracking tools were used. The seeded 3D-tracking tool was only used where clear, coherent reflectors were present.

The interpretation was mainly done on inlines or crosslines. The choosing between inlines and crosslines was based on the orientation of structural features in the area (approximately perpendicular to general fault strike). In an area interpreted mainly on cross lines, a few inlines and random oriented composite lines was interpreted for quality control and as a guide for staying on the same reflector. In structurally complex areas, composite lines were used locally in order for the lines to be as perpendicular to fault strikes as possible. The line interval density varied from 2-50 lines depending on the structural complexity.

Large faults were manually interpreted in the Jurassic section (and in the Marulk structure of the Cretaceous chapter). Composite lines perpendicular to, and at a 45 degree angle to the fault plane was used in order to get the best possible interpretation of the geometry of the fault. Time slices from the Variance cubes and also the standard seismic cubes were very useful as guides for the geometry of the faults.

The interpretations of formation tops and faults was used to generate surface maps. These maps were used for visualization of the reservoir geometry, to interpret spill points, for structural analysis, and to extract seismic attributes along the formations of interest.

Uncertainties are connected to the seismic interpretation. The interpretations of the seismic data is subjective, and dependent on the interpreter’s experience, knowledge, etc. The same seismic dataset would most likely result in a different interpretation in the hands of other interpreters.

4.3.3 Seismic surface attributes

The surface attributes most used in the thesis are the Variance and the "interval average RMS amplitude". The Variance attribute looks for local variance in an interval in the seismic along the surface it is extracted from. It is used to enhance edges along the surfaces and is an effective tool when it comes to visualizing faults.

The RMS amplitude attribute takes the square root of the sum of the squared amplitudes in a specified vertical interval relative to the surface it is extracted from. It maps amplitude anomalies that may map to pore fluid changes or to geologic features that are isolated from the background features by amplitude response. This way it could highlight areas with hydrocarbons, or for example highlight the geometry of a sandy channel in contrast to a shaly background. If nothing else is specified, an interval of +/- 25ms was used for the RMS amplitude attribute.

4.3.4 Depth conversion of interpreted spill points

In order to acquire a depth in m TVDSS, the spill point's TWT (two way time) in the seismic were noted. This TWT was depth converted using the nearest well. Based on checkshots, the wells in Petrel can output a depth corresponding to a TWT input.

There are uncertainties associated with the process of converting from time to depth. In this project, this was observed when testing the same spill point TWT in different wells. An investigation of the uncertainties connected to the well based depth conversion was conducted by testing the same TWT in neighbor wells. 20 wells were tested, and an uncertainty of +/- 25 m was decided upon. If several wells are in similar distance from the interpreted spill point, an average of the TVDSS output by these wells were used as the depth for the spill point, but the uncertainty is kept at +/- 25 m.

4.3.5 Pressure investigation

Formation pressures from the RFT and MDT measurements were plotted. The reservoir pressure was compared to the hydrostatic pressure at the same depth. Overpressures were calculated in order to compare the pressure conditions in different structures. The overpressure is calculated by subtracting the hydrostatic pressure from the measured formation pressure.

The hydrostatic pressure gradient was calculated based on an assumption on an average brine density (from the surface to the depth of the pressure point) of 1025 kg/m^3 (typical density of sea water). A different brine density will affect the estimation of the overpressure. As an example of this, the changing of this from 1025 to 1050 kg/m^3, reduces the apparent overpressure in the Gjøk structure from approximately 7 bars to approximately zero.

The hydrostatic pressure represents the weight of the water column, assuming pressure communication to the surface:

$$P = \rho g z, [Pa] \quad \longleftrightarrow \quad P[bar] = \frac{\rho * g * (TVD)}{10^5} \tag{4.4}$$

ρ = average brine density in kg/m^3,
g = gravitational constant (9.81 m/s^2 is used),
TVD = true vertical depth below sea surface in m

4.3.5 Calculation of shale smear factor

An SSF was calculated on critical faults in the Norne fill-spill system. This was done using formula (3.1) shown in chapter 3.3.1. The throw of the fault was measured in the seismic. The shale layer thickness was determined by investigating logs and adding up all shale layers in the interval.

4.3.5 Visualization

All figures presented in the thesis has been made by utilizing Adobe Illustrator CS6. This includes all maps and seismic cross sections. MATLAB (matrix laboratory), developed by MathWorks was used for making most plots. Tables and some plots was made in Microsoft Excel.

5. Results

This chapter presents the results and observations from the seismic interpretation of the structures studied in this thesis. It will be divided into two main chapters, covering structures with Cretaceous reservoirs, situated on the Dønna Terrace, and Jurassic reservoirs located further north-east on the transition between the Dønna Terrace and Rødøy/Sør High of the Nordland Ridge.

5.1 Cretaceous reservoirs on the Dønna Terrace

The structures investigated in this chapter have accumulations mainly in the in the Cretaceous Lysing Formation. The area encompasses three Lysing gas/condensate discoveries: Marulk, Snadd North and Snadd Outer. The Snadd discovery was renamed "Ærfugl" in November 2017 and Aker BP's plan for development was approved in April 2018. For the purpose of discriminating between Snadd North and Snadd Outer, the old Nomenclature will be used. The Snadd South structure is not covered by the seismic surveys available for this thesis.

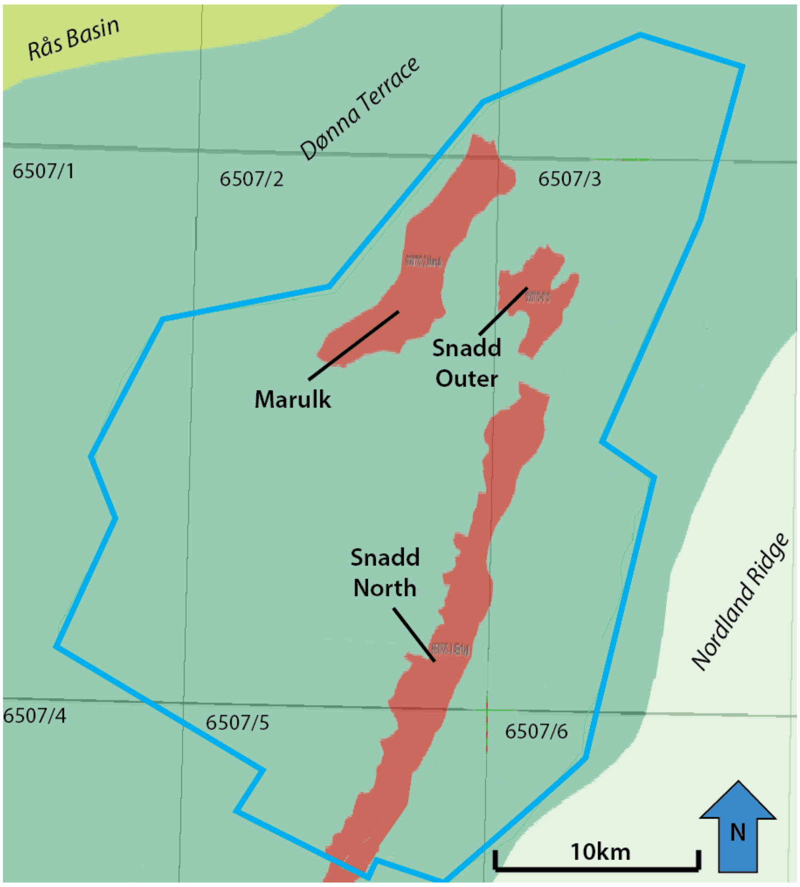

Figure 5.1: Study area and seismic coverage for the Cretaceous chapter including the discoveries of interest. Modified from NPD's Fact-maps.

5.1.1 Marulk

Marulk was discovered in 1992 but production wasn't started until 2012. The field is developed with a subsea template tied-back to the Norne field 25km to the north-east. It is located on the Dønna Terrace. It is an elongated structure with SW-NE trending faults defining its north-west border. The structure is upthrown, juxtapositioning the main reservoir, the Lysing Formation, to younger strata of the Shetland Group across the fault.

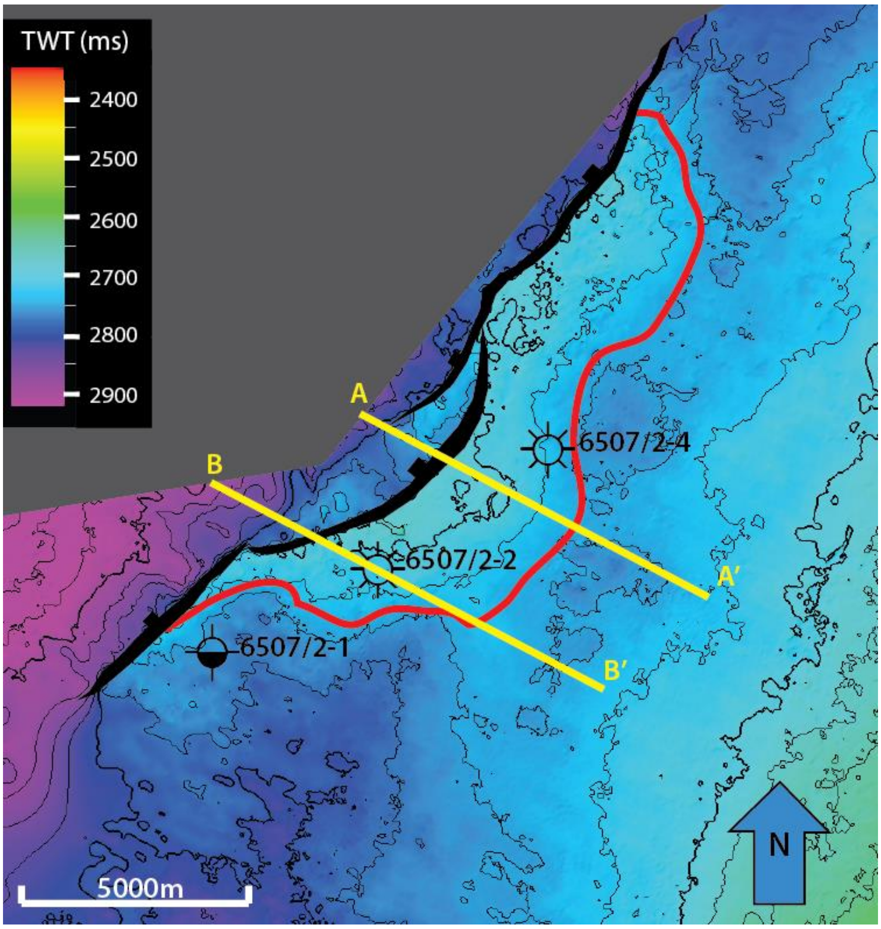

Figure 5.2: Interpreted top Cromer Knoll Group surface showing the structure and surrounding area. Approximate field outline based on depth contours and ODT/WUT.

The primary objective of the exploration wells 6507/2-1 and 6507/2-2 were actually in the Jurassic section; formations in the Fangst and Båt Group. The first well, 6507/2-1 (1986), was dry with shows in the primary objective Jurassic section, but also proved the presence of Cretaceous Lysing and intra Lange Formation sandstones of the Cromer Knoll Group. The Cretaceous sands were also dry with shows. As the first well left considerable potential volumes up-dip, well 6507/2-2 was spudded in October 1991. The primary objective was still the Jurassic reservoirs of Fangst and Båt Groups. The secondary objectives were the sandstones in the Lysing and Lange Formations. The Jurassic section was dry, but both intra Lange and Lysing sandstones were gas filled. Later, in 2008 well 6507/2-4 was drilled to apprise the discovery and prove the commerciality of the Lysing discovery. Intra Lange sandstones was the secondary objective. The Lysing formation sandstone was penetrated at 2832m MD and was gas filled down to its base, giving a GDT (gas down to) at 2852.5m MD.

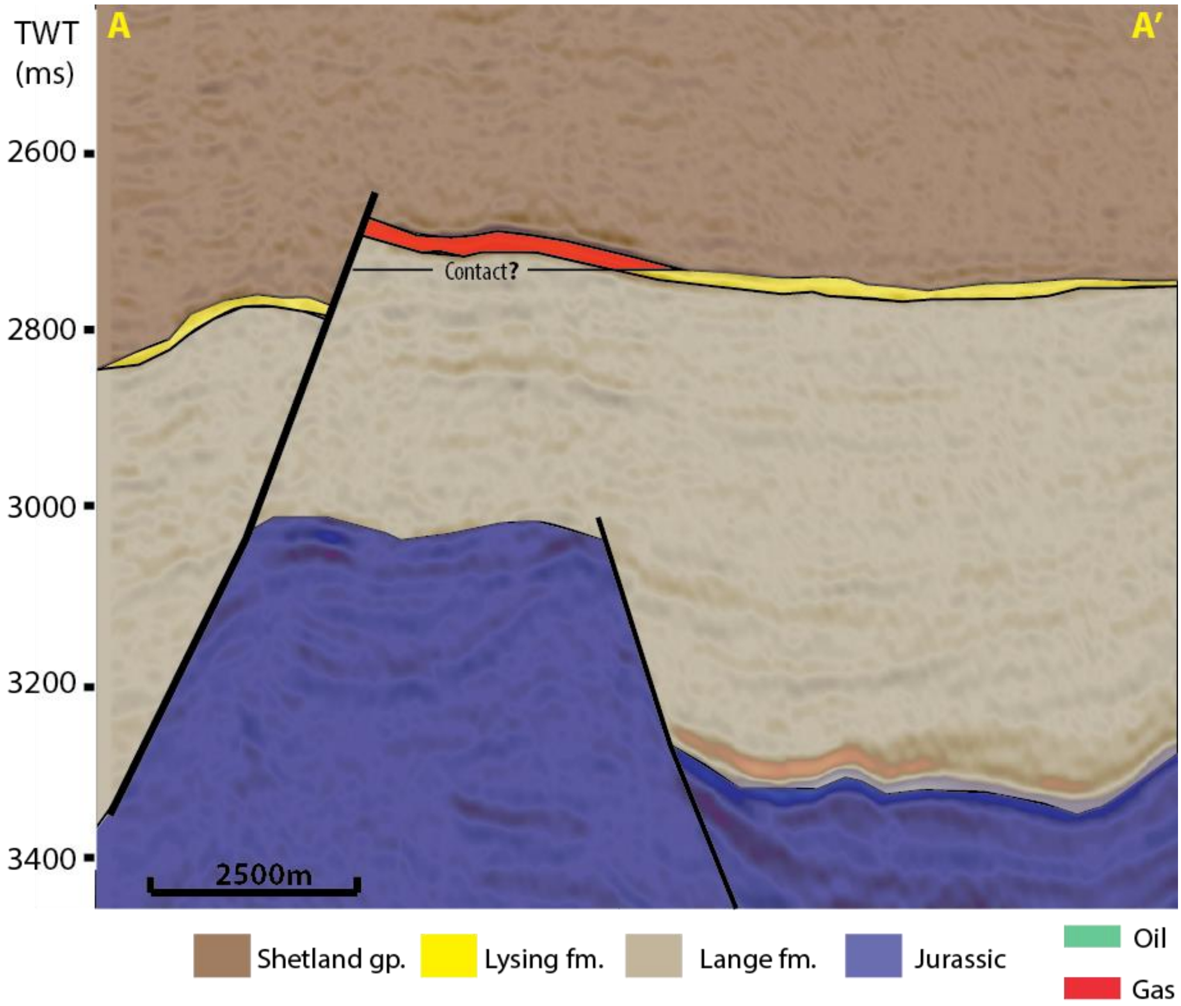

Figure 5.3: Interpreted cross section of Marulk structure. See figure 5.2 for location of the seismic line

The upper sandstone unit in the Lange formation was composed of sand layers interbedded with claystone. It was water wet. A deeper, 3 meters thick sand body at 3378.5m MD was oil filled.

Figure 5.3 shows a typical cross section of the structure, presenting the general geometry. The Lange Formation has a very homogenous appearance in the seismic, making it very difficult to pick the tops of the Intra Lange sands. The thickness of the oil filled Lange-sandstone layer from well 6507/2-4 is well below the vertical resolution of the seismic.

Well	Lysing top (m TVD)	Lysing base (m TVD)	Thickness (m)	Fluid type	Contact type	Contact depth (m TVD)
6507/2-1	2851	2856	5	Water, shows		
6507/2-2	2794,5	2808	13,5	Gas	GDT	2808
6507/2-4	2815	2834,5	19,5	Gas	GDT	2834,5

Table 5.1: Table containing information on the Lysing Formation from different wells on the Marulk structure. TVD = TVD MSL (True vertical depth from mean sea level)

The main focus of this subchapter is the gas accumulation in Lysing Formation. Table 5.1 summarizes data from the wells. The formation is thinnest in the most southern well, and thickest in the northern well. No gas-water contact was encountered. One well was dry with shows and in the other two, Lysing was gas filled down to its base.

Figure 5.4 plots the pressures from each well in Lysing, and compares it to pressure measurements in the upper intra Lange Sandstone unit. It is reasonable to assume lateral

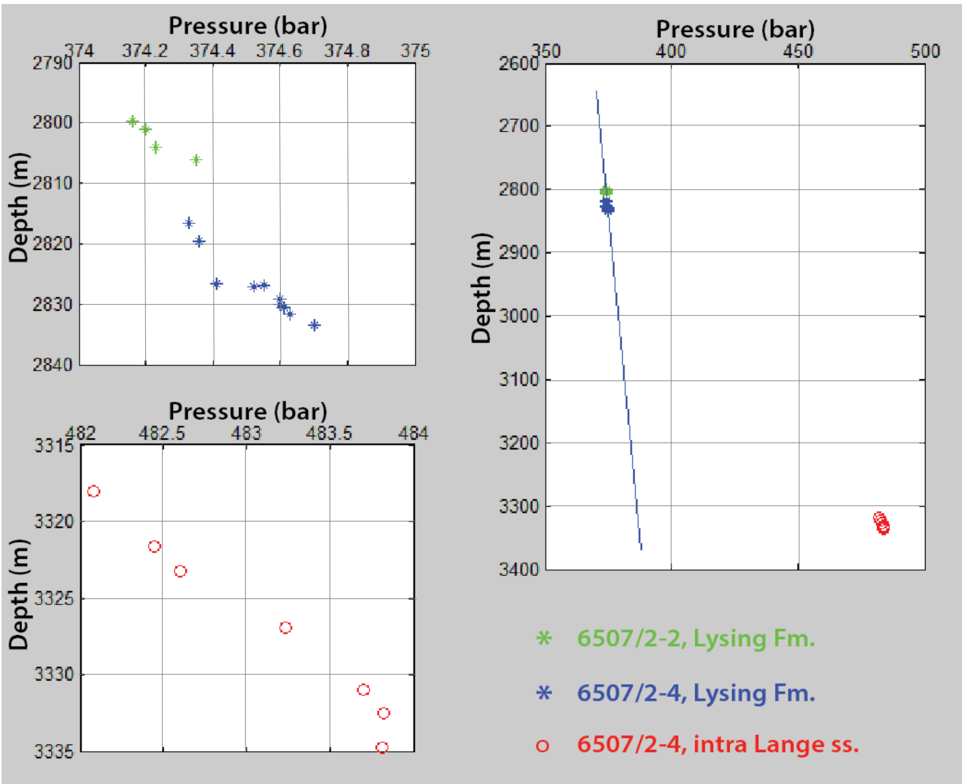

Figure 5.4: Formation pressure data from Lysing Formation and the upper intra Lange sandstone in wells 6507/2-2 and 6507/2-4. The pressures from well 6507/2-4 and 6507/2-5 falls on roughly the same gradient

pressure communication in Lysing formation. There is a pressure barrier between Lysing Formation and the upper Intra Lange Fm.

Lysing Formation is clearly visible in the seismic where it is present, and of sufficient thickness. It's usually represented by a sharp decrease in acoustic impedance, giving a clear blue through in the seismic. When Lysing is not present, the top of the Cromer Knoll Group corresponds to top Lange Formation. Top Cromer Knoll group is generally a red peak (increase in acoustic impedance) in locations where Lysing Formation's seismic signature is absent. As Lysing Formation gets thinner, the reflector changes its appearance.

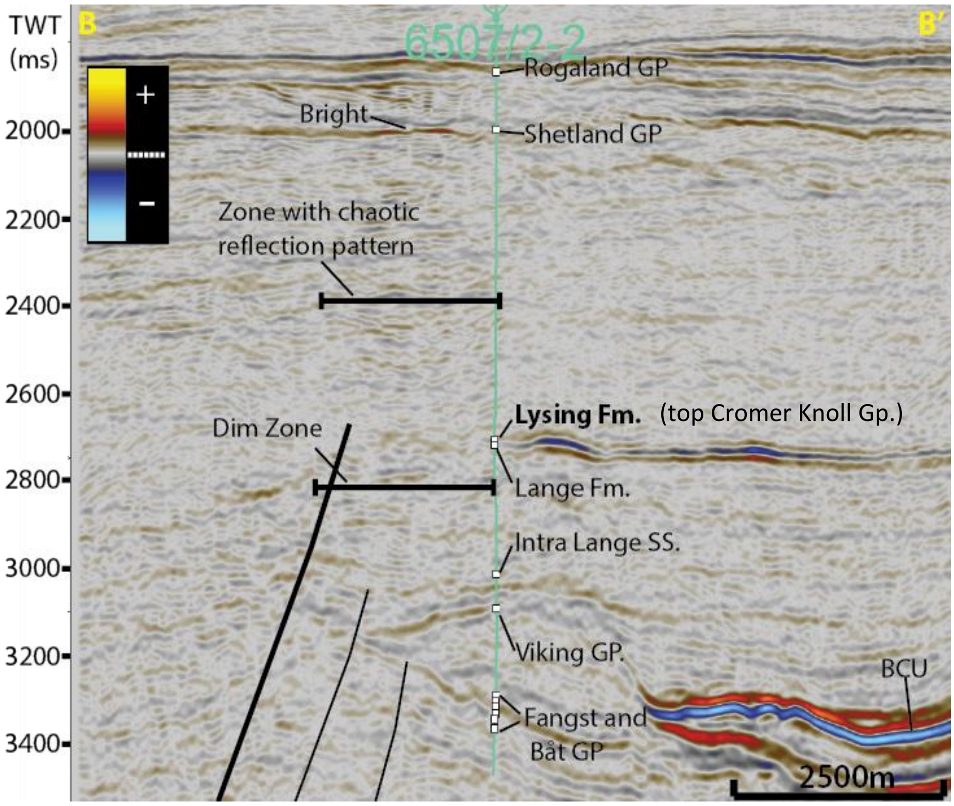

Figure 5.5: Seismic inline through well 6507/2-2. Including formation tops from Petrel, fault interpretations and general observations.

Figure 5.5 shows a seismic inline through the Marulk structure. The appearance of the top Cromer Knoll reflector is varying across the structure. Note the typical seismic signature of top Cromer Knoll Group when Lysing Formation is present to the right. The signature dims as you go left and approach the fault. Top Lange is very close to top Lysing in the well location. The thickness of Lysing Formation is 13,5m in the well.

In order to map the extent and amplitude of the Lysing deposits, an RMS interval average surface attribute was extracted at +/-20ms from the interpreted top Cromer Knoll Group.

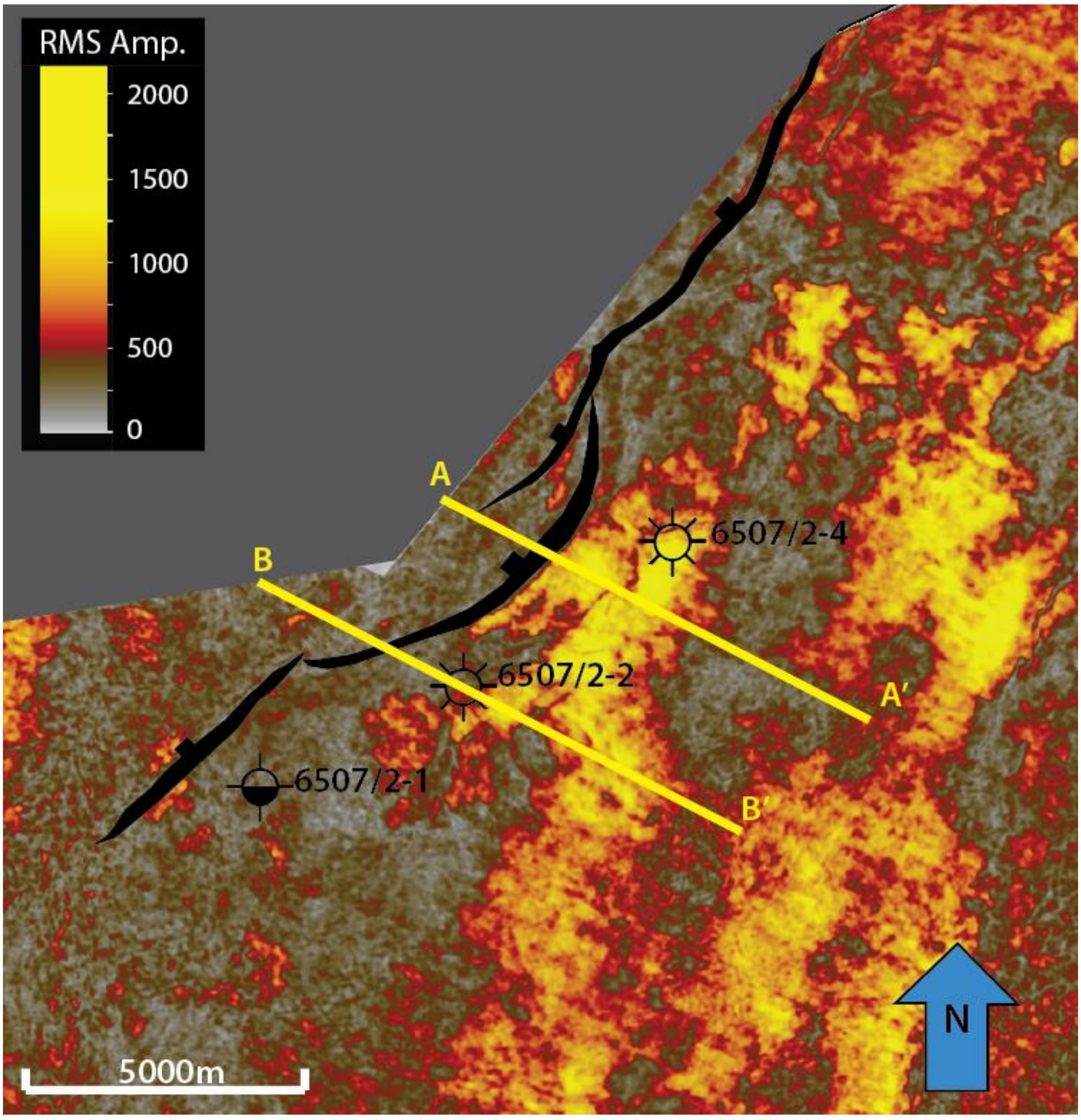

Figure 5.6: RMS amplitude extracted on top Cromer Knoll surface. High amplitudes are bright yellow.

Amplitudes are varying laterally in the Marulk area. The amplitudes in the proximity of well 6507/2-1, where Lysing Formation is only 5m thick, are dim. In the proximity of well 6507/2-4, where the formation is thicker, the amplitudes are bright. The weak amplitudes closer to the fault, seen in figure 5.5, is seen clearly on the RMS amplitude surface. The brightest areas of the amplitude map is usually where the sand is believed to contain gas, but there are bright areas outside the accumulations as well, so the map is better used for interpreted sand distribution than gas content.

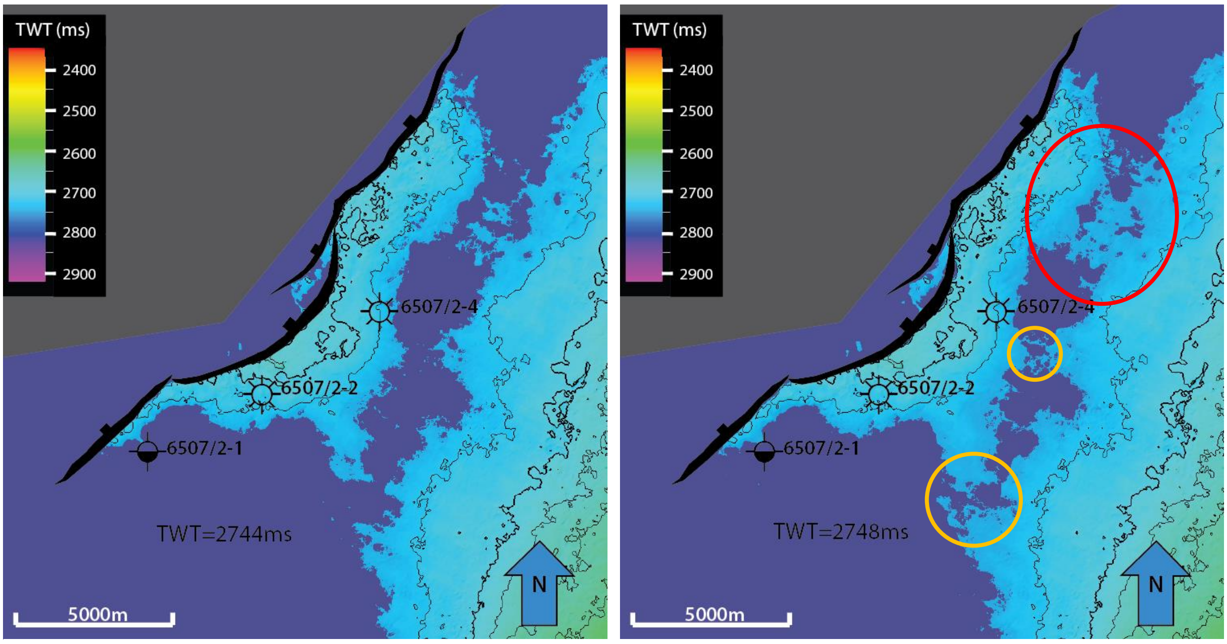

Figure 5.7: Spill point interpretation. Horizontal plane at TWT=2744ms (left) and at 2748ms (right). Most probable spillpoint in red, alternatives in orange.

As seen in figure 5.7, the location of an exact spill point is uncertain because of the flat topography. By lowering the horizontal plane with just 4ms (minimum step for the horizontal plane), the structure goes from not being filled to structural spill, to seemingly spilling at more than one location. The most likely spill point is located in the area encircled in red, but the uncertainties in the interpretation and depth-time correlation is greater than 4ms. Assuming the spillpoint is at 2748ms, using the checkshots for the two closest wells, 6507/2-4 and 6507/3-9 S, gives a depth of 2872 m TVDSS (+/-25 m)

5.1.2 Snadd North

Snadd North is an elongated SSW-NNE trending structure situated on the Dønna Terrace approximately 10km SSE of Marulk, closer to the Nordland Ridge. It is approximately 30km long with a width varying from 1-3 km. Gas is accumulated in Lysing Formation, in a stratigraphic type trap with an up-dip pinch-out line towards the Nordland Ridge in the east. If Lysing Formation did not pinch out, the hydrocarbons would just migrate further up towards the Nordland Ridge. The top seal is comprised of shales from the Shetland Group, while the base seal is comprised of shales from the Lange Formation. Figure 5.8 shows interpreted top Cromer Knoll surface (Top Lysing when present), interval average RMS amplitude map draped on the same surface. The Snadd North structure cannot be seen based on the topography, but the presence of Lysing Formation and the geometry of the pinch-out line is clear on the RMS amplitude map.

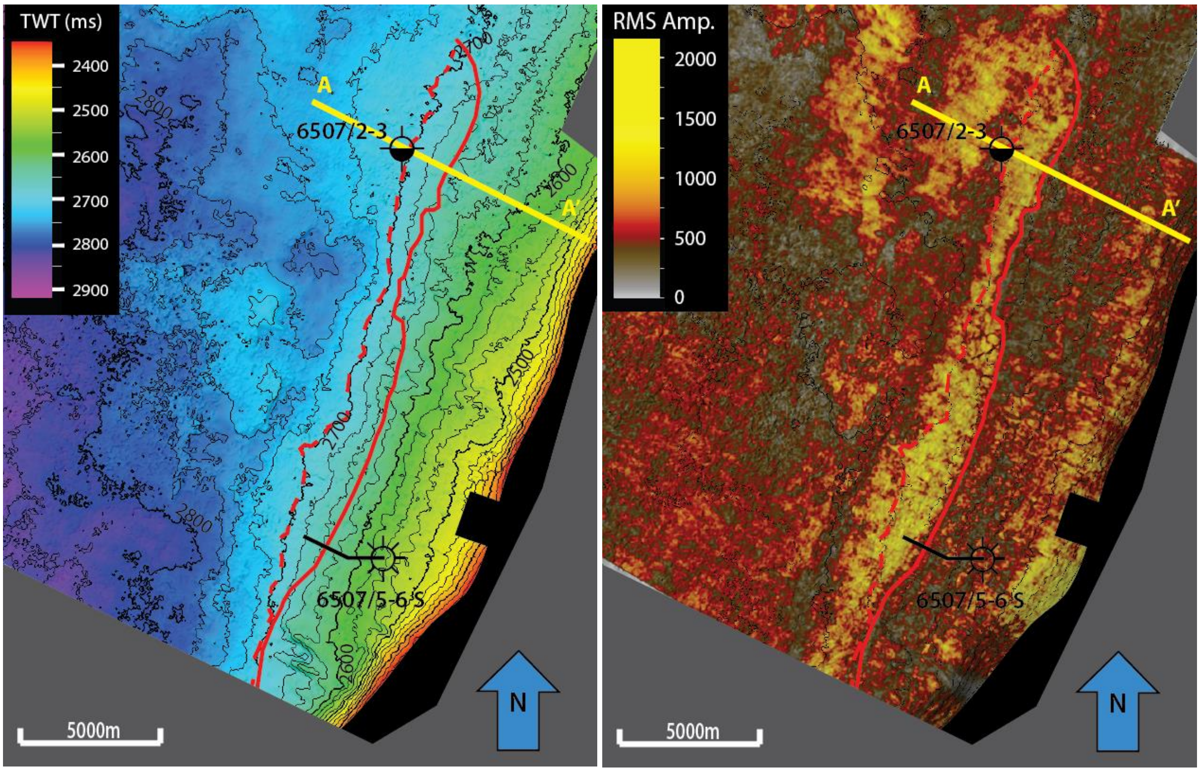

Figure 5.8: Top Cromer Knoll surface. Contour interval = 25ms. Seismic cross section A-A' is marked. Well locations. RMS amplitude surface attribute on the right. Dotted red line = approximate contact. Red line=pinch out.

The first well that was drilled in the Snadd North structure; well 6507/2-3, was spudded in March 1994. The objectives were to test the hydrocarbon potential of the Lysing Formation and the Intra Lange Formation. The primary target, the Lysing Formation was encountered from 2850m to 2891m MD. It was registered as a fairly massive water bearing sandstone sequence. The secondary target, the Intra Lange Formation sandstone was encountered at 3250.5 – 3281m MD. It consisted of a heterogeneous reservoir with very poor reservoir properties. It contained residual oil/oil shows.

In January 2010, well 6507/5-6 S was spudded. The Lysing Formation was encountered at 2767 m TVDSS and consisted of a 32m thick, good quality hydrocarbon-bearing sandstone. The reservoir was gas-bearing throughout the formation. No oil-shows were reported. The well was abandoned as a gas discovery.

Well	Lysing top (m TVDSS)	Lysing base (m TVDSS)	Thickness (m)	Fluid type	Contact type	"Contact" depth (m TVDSS)
6507/2-3	2827	2868	41	Water	WUT	2827
6507/5-6 S	2767	2799	32	Gas	GDT	2799

Table 5.2: Table containing information on the Lysing Formation from different wells on the Snadd North structure.

Pressure tests were done in well 6507/2-3. The formation is approximately 90 bars overpressured. There was good pressure communication throughout the formation.

MD (m)	TVD (m MSL)	Reservoir P (bar)	Hydrostatic P (bar)	Over-P (bar)
2852,5	2829,6	374,42	284,52	89,90
2856	2833,11	374,76	284,88	89,88
2859,5	2836,6	375,11	285,23	89,88
2862,6	2839,7	375,44	285,54	89,90
2871	2848,1	375,25	286,38	88,87
2878,2	2855,3	376,16	287,11	89,05
2881	2858,1	377,79	287,39	90,40

Table 5.3: Pressure data from well 6507/2-3. Hydrostatic pressure is calculated assuming a brine density of 1025kg/m^3.

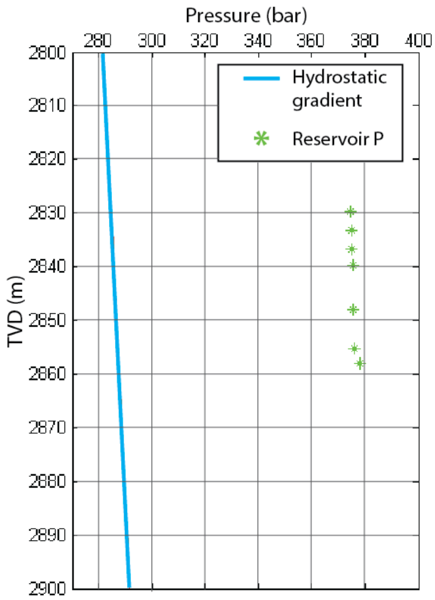

Figure 5.9: Pressure plot from Lysing Formation in well 6507/2-3

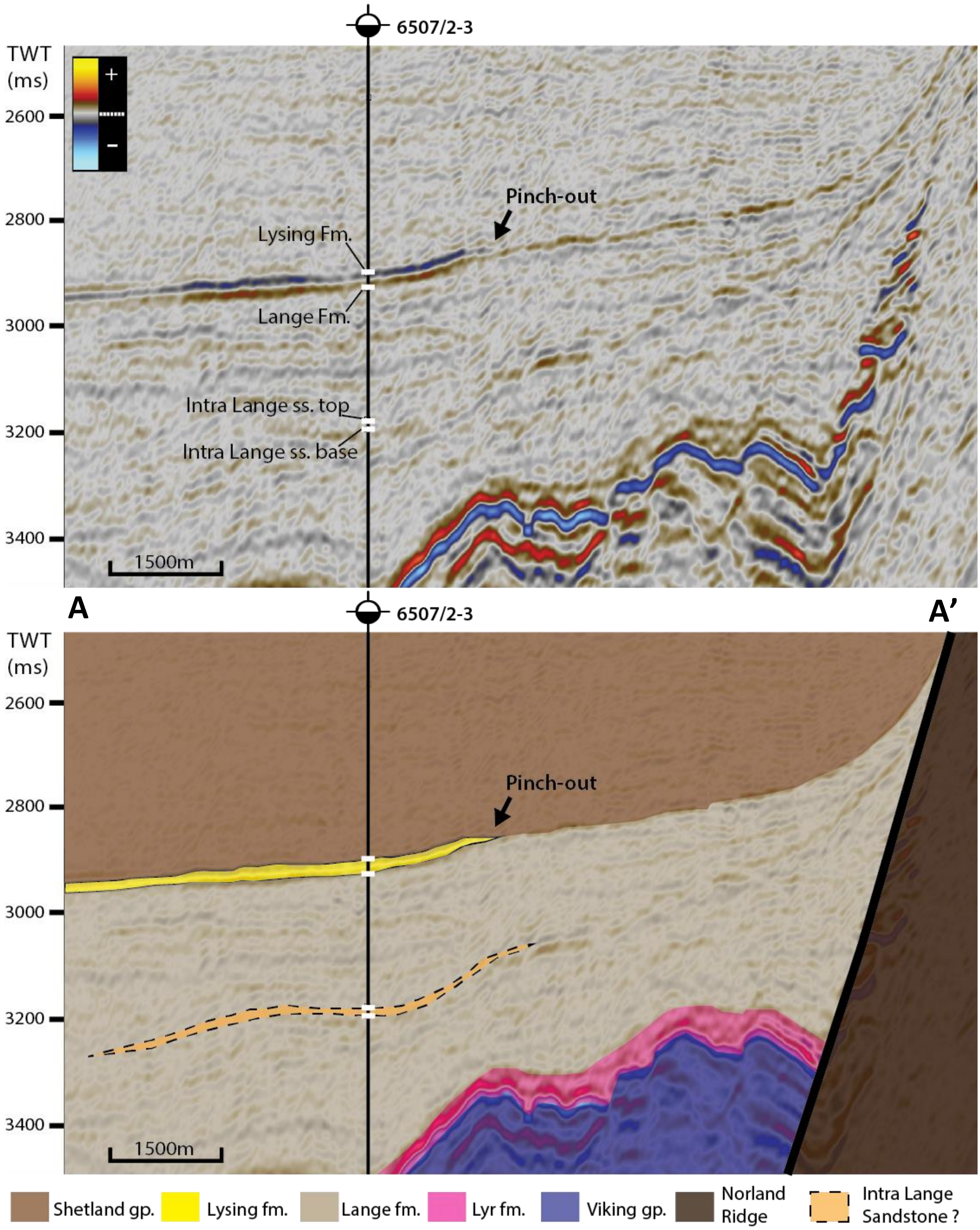

Figure 5.10 Seismic cross section A-A' (orientation is highlighted in fig. 5.8). Well tops from Petrel. Interpretations added in the lower figure.

Figure 5.10 shows seismic a cross section through well 6507/2-3. Top Cromer Knoll Group is represented by a blue trough (decrease in acoustic impedance) down-dip from the interpreted pinch-out of Lysing Formation. Up-dip of this pinch-out, Top Cromer Knoll is interpreted on a slightly dimmer red peak (increase in acoustic impedance) reflector. The dim red peak is typical of the top Cromer Knoll Group reflector when the upper formation is the Lange Formation. The top Lysing reflector has two bright sections divided by a small dimmer section approximately at the well location. This brightening and dimming can be seen on the RMS amplitude map in figure 5.8.

The Intra Lange sandstones are not observed in the seismic. This is often typical for these sands. The reason can be that they are frequently thin and heterogeneous. Another possibility is that they could have similar acoustic impedance as the background shale, resulting in a lower reflection coefficient and weaker seismic reflection.

5.1.3 Snadd Outer

The Snadd Outer structure is also situated on the Dønna Terrace, approximately 4km east of the Marulk field, and just north of Snadd North discovery. Both Marulk and Snadd are gas discoveries in the Lysing Formation.

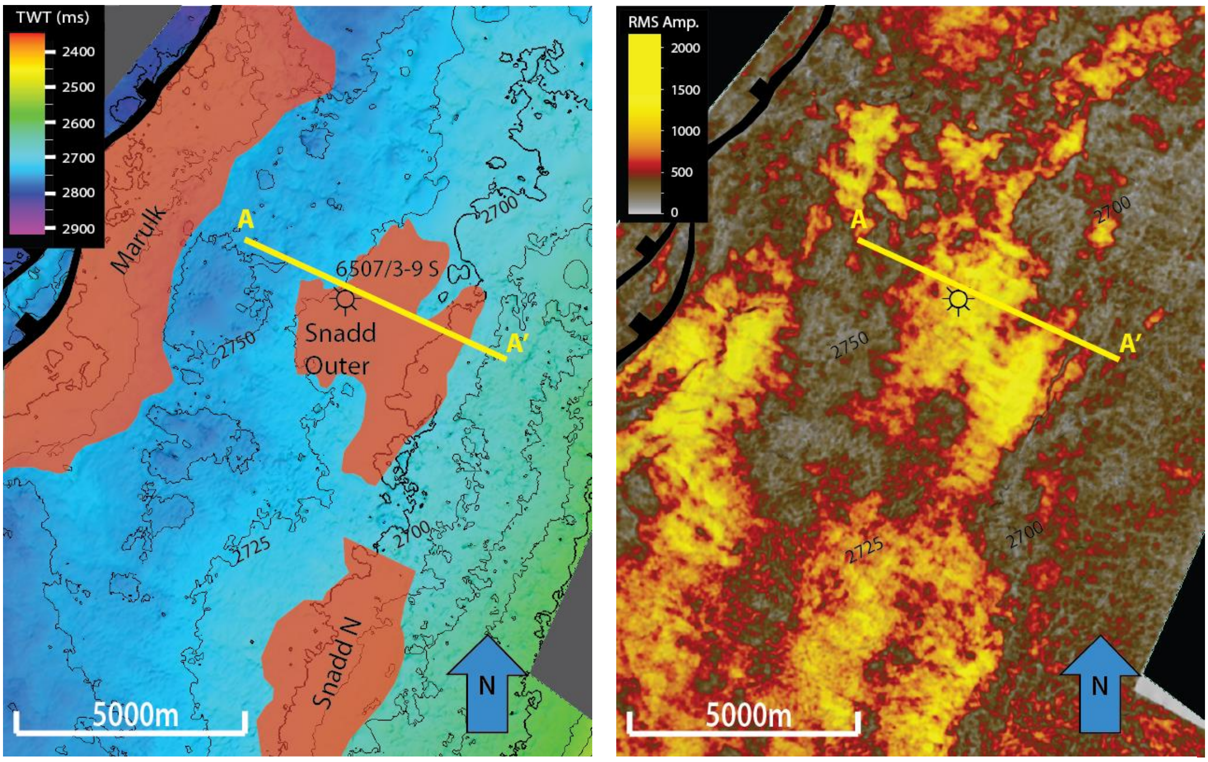

Figure 5.11: Top Cromer Knoll surface. Contour interval = 25ms. NPD field outlines shows the approximate location of the accumulations in the area. Location of seismic cross section (Cross section approximately intersects wellpath at depth, not at the wellhead). RMS amplitude map on the right.

Well 6507/3-9 S was spudded in June of 2012. The main objective was to prove gas accumulation in the Lysing Formation reservoir. Top of the Lysing Formation was encountered at 2849.3m MD (2808m TVDSS) with good reservoir properties. The well proved gas in the Lysing Formation. A gas water contact was interpreted at 2822.5m TVDSS from high quality pressure points. A high gas saturation was also seen in the sand below the contact.

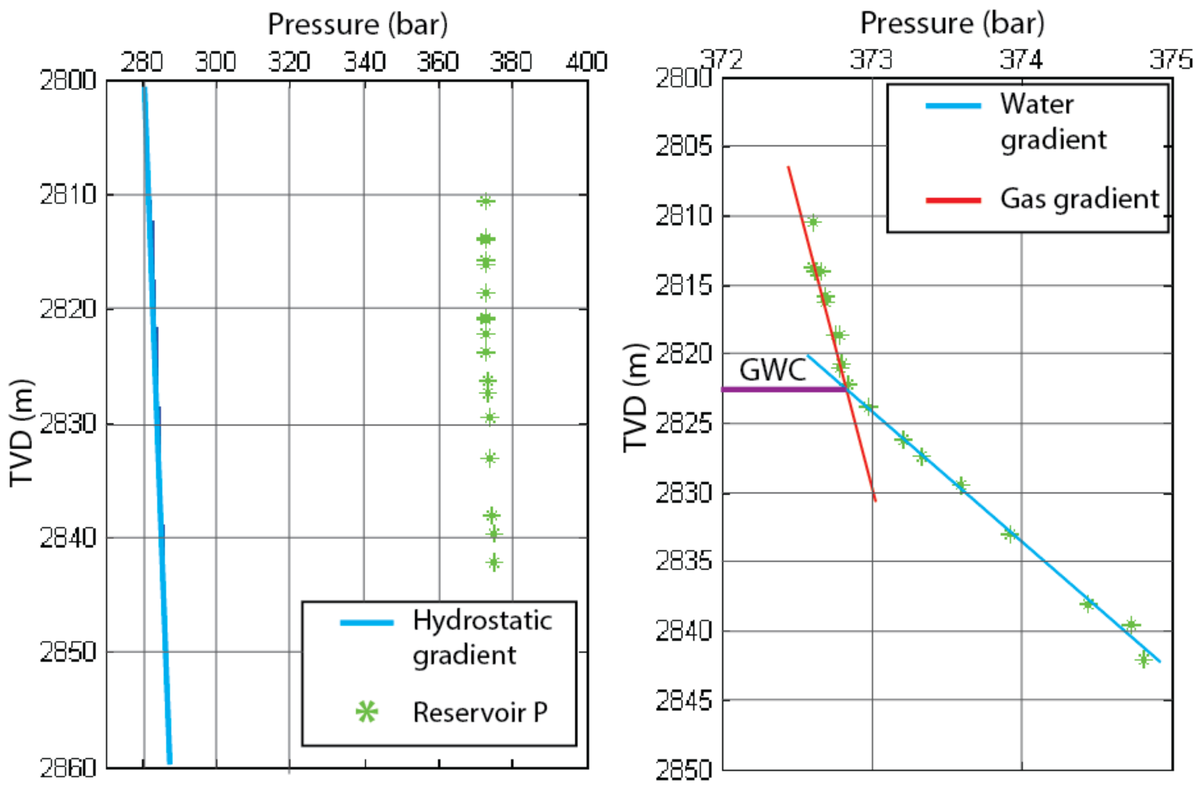

Figure 5.12: Pressure data plotted in Matlab. An average brine density of 1025kg/m^3 was assumed to calculate the hydrostatic gradient.

The pressure data shows that the Lysing Formation is approximately (just under) 90bar over-pressured. A brine density of 1025kg/m^3. The gas-water contact is easily approximated when plotting the pressure points. Good pressure communication is interpreted throughout the Lysing Formation. The overpressure of 90 bar is approximately the same as was found in the Lysing Formation of Snadd North.

Well	Lysing top (m TVD)	Lysing base (m TVD)	Thickness (m)	Fluid type	Contact type	Contact depth (m TVD)
6507/3-9 S	2808	2842,7	34,7	Gas	GWC	2822,5

Table 5.4: Table containing information on the Lysing Formation in Snadd Outer structure.
TVD = TVDSS (True vertical depth from mean sea level)

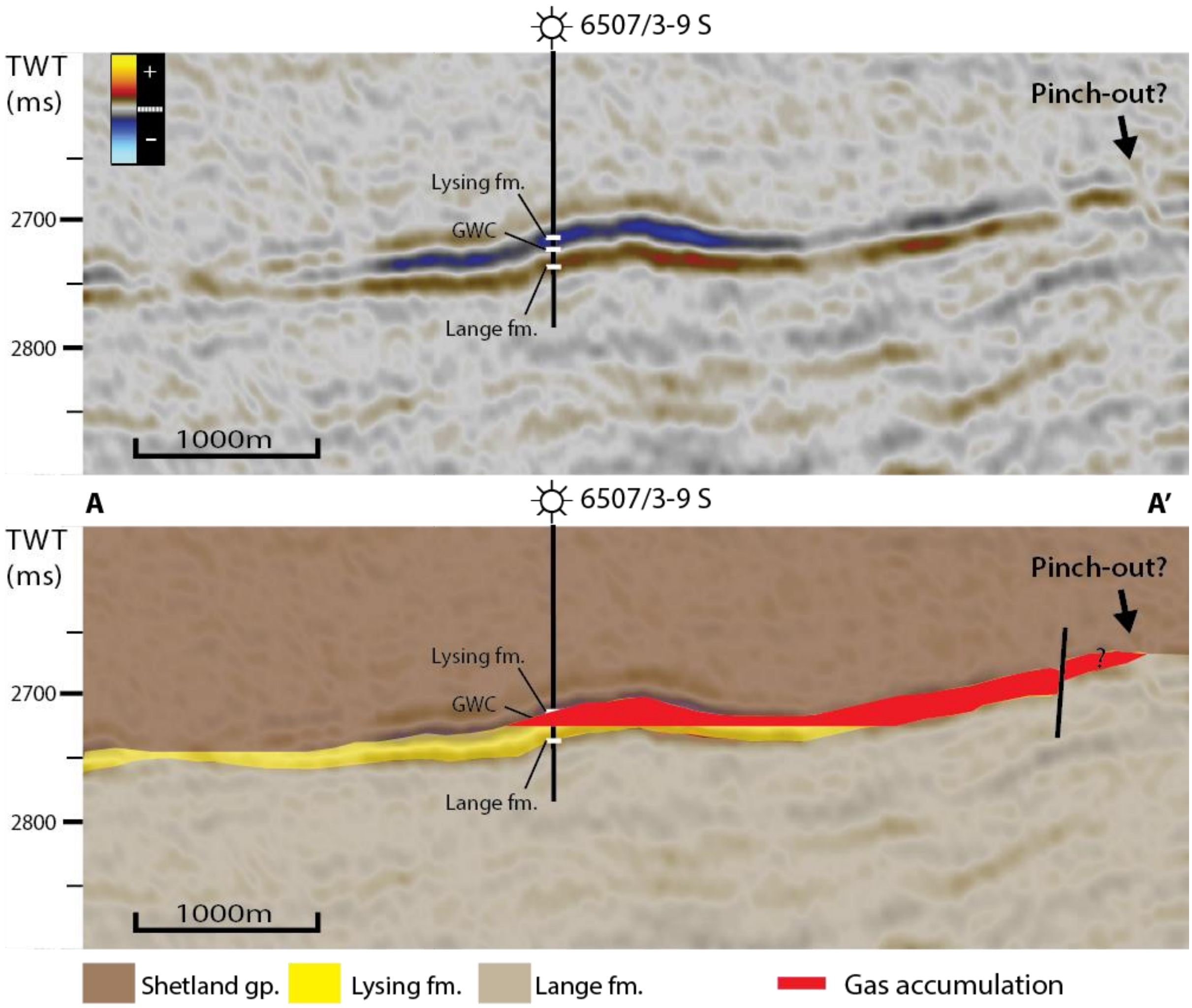

Figure 5.13: Seismic cross section of the Snadd Outer structure. Interpretations added on the lower figure. Well tops from Petrel. Vertical exaggeration = 7 in order to enhance the topography of reflectors.

Figure 5.13 shows the geometry of the Snadd Outer trapping mechanism. The gas accumulation is partly controlled by a 4-way closure, and partly by the stratigraphic pinch-out of the Lysing formation, the same mechanism trapping the gas in Snadd North. The Lange Formation acts as a base seal, while the top seal is comprised of Shetland Group shales. If not for the pinch-out, hydrocarbons could only accumulate in the structural 4-way closure-part of the structure. The 4-way closure is seen as a dome shape close to the well location in the seismic cross section. Small faults can be observed close to the pinch-out. They are not observed along the entire lateral extent of the pinch-out line in Snadd Outer, and is therefore not considered the main trapping mechanism. The stratigraphic pinch-out of the Lysing Formation is needed for the accumulation of hydrocarbons in the part outside the structural closure.

In the topography of the surface elevation map in figure 5.11, the Snadd Outer structure is not easily seen, even though the north-western part of the structure is a four-way closure. The reason for this is that the Top Cromer Knoll surface has a relatively flat topography. Figure 5.14 contains an enhanced and zoomed in version of the top Cromer knoll surface. Note the structural closure encircled in yellow. The gas-water contact is represented by the red line in the right figure. Because of the flat topography, the uncertainty in the geometry of this geometric representation of the GWC is high. This elevation map gives the best representation of the structure when used together with the RMS amplitude map. The interpreted spill point is at 2716 ms TWT. This corresponds to 2824 m TVDSS (+/- 25m) based on depth conversion using well 6507/3-9 S.

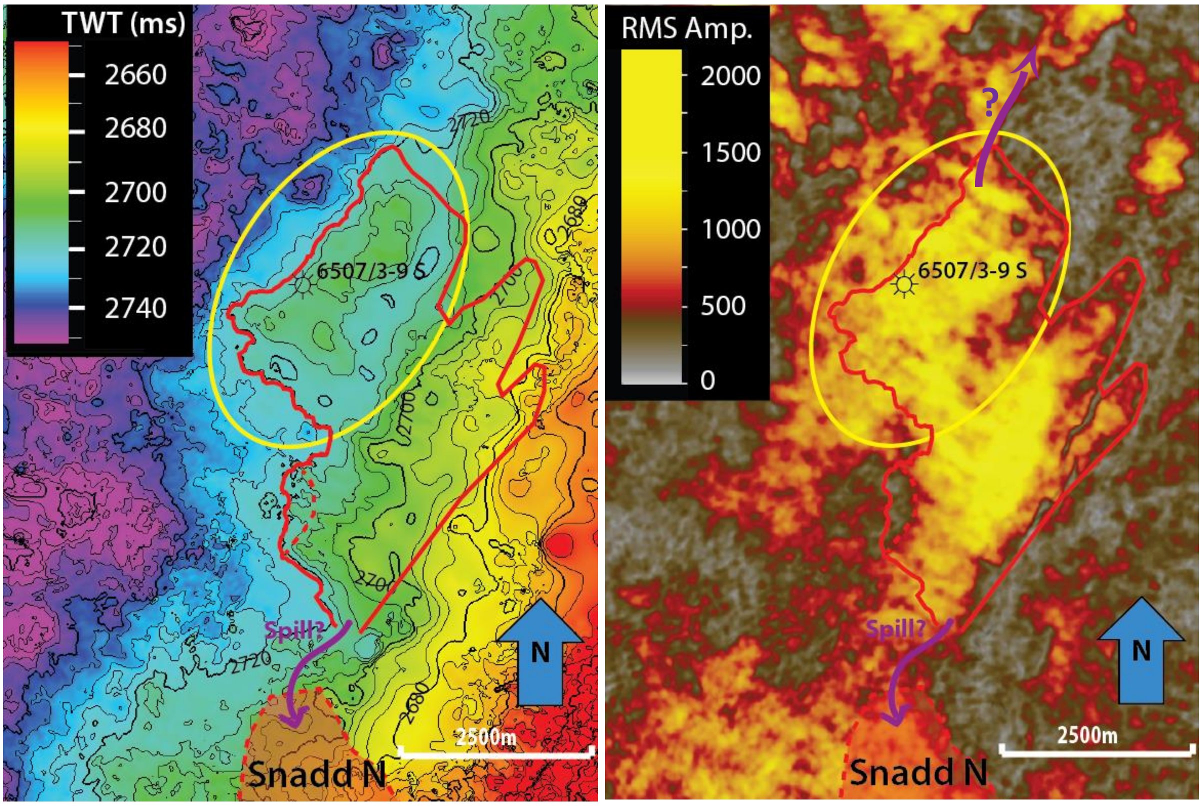

Figure 5.14: Colour-enhanced and zoomed in verison of the top Cromer Knoll surface. Contour interval = 5ms. The four-way closure encircled in yellow. Red line represent partly the GWC and partly the outline of the interpreted sand pinch-out. This gives the interpreted outline of the accumulation. Possible spill directions are annotated.

5.1.4 Possible spill route from Marulk to Snadd North.

The distribution of the Lysing Formation deposits in the area is best visualized in the RMS amplitude surface attribute map from the top Cromer Knoll surface.

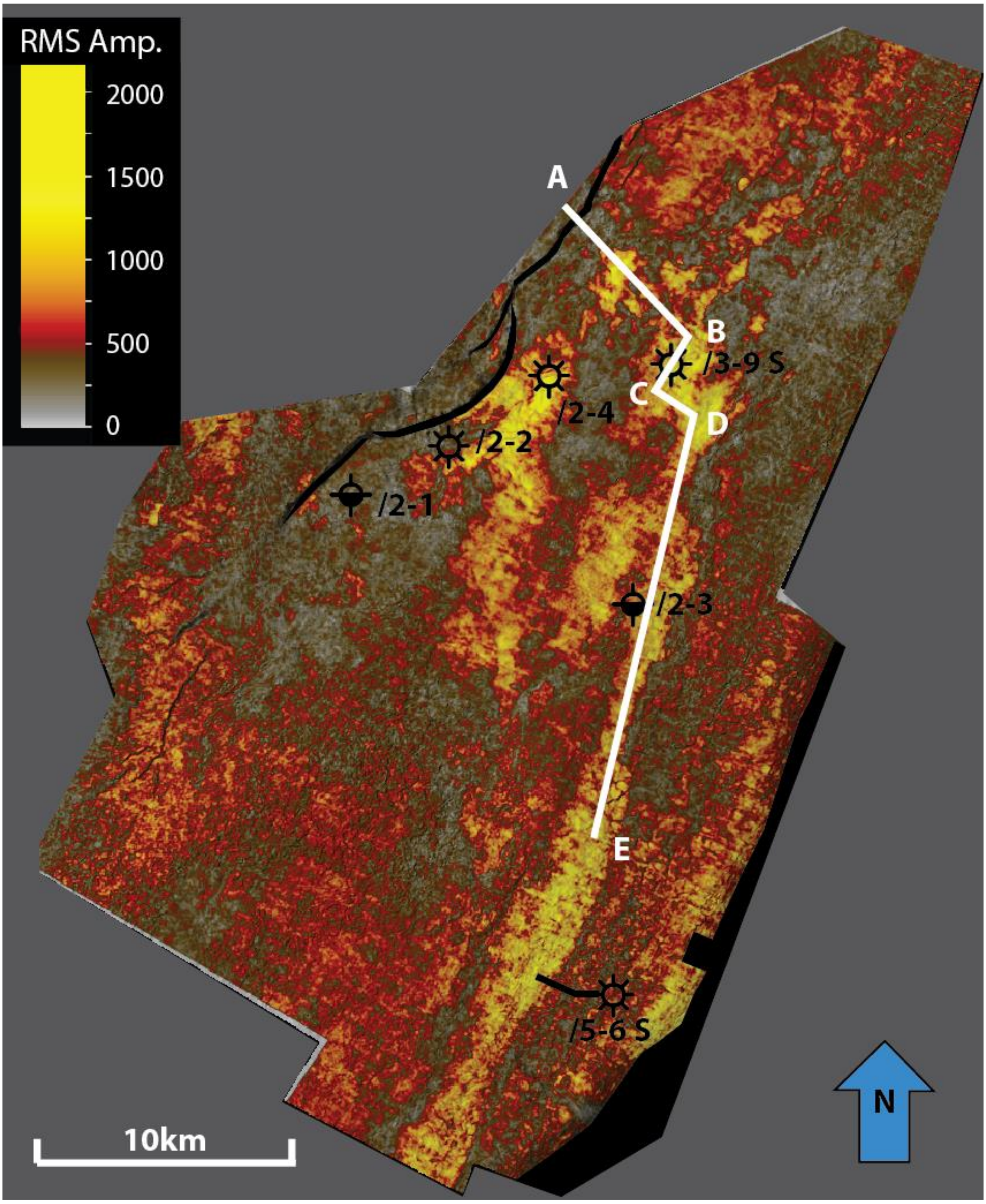

Figure 5.15: RMS amplitude on Top Cromer Knoll surface. Locations of wells marked. Composite line A-E trough proposed spill points is marked in white.

The seismic composite line A-E is presented in figure 5.16. The line is picked to show a proposed spill route between the three main structures based on the interpreted structural spill points. A high vertical exaggeration is needed to visualize the topography, and in order to fit the relatively long composite line in one figure.

The proposed spill route from Marulk through Snadd Outer and into Snadd North is based on

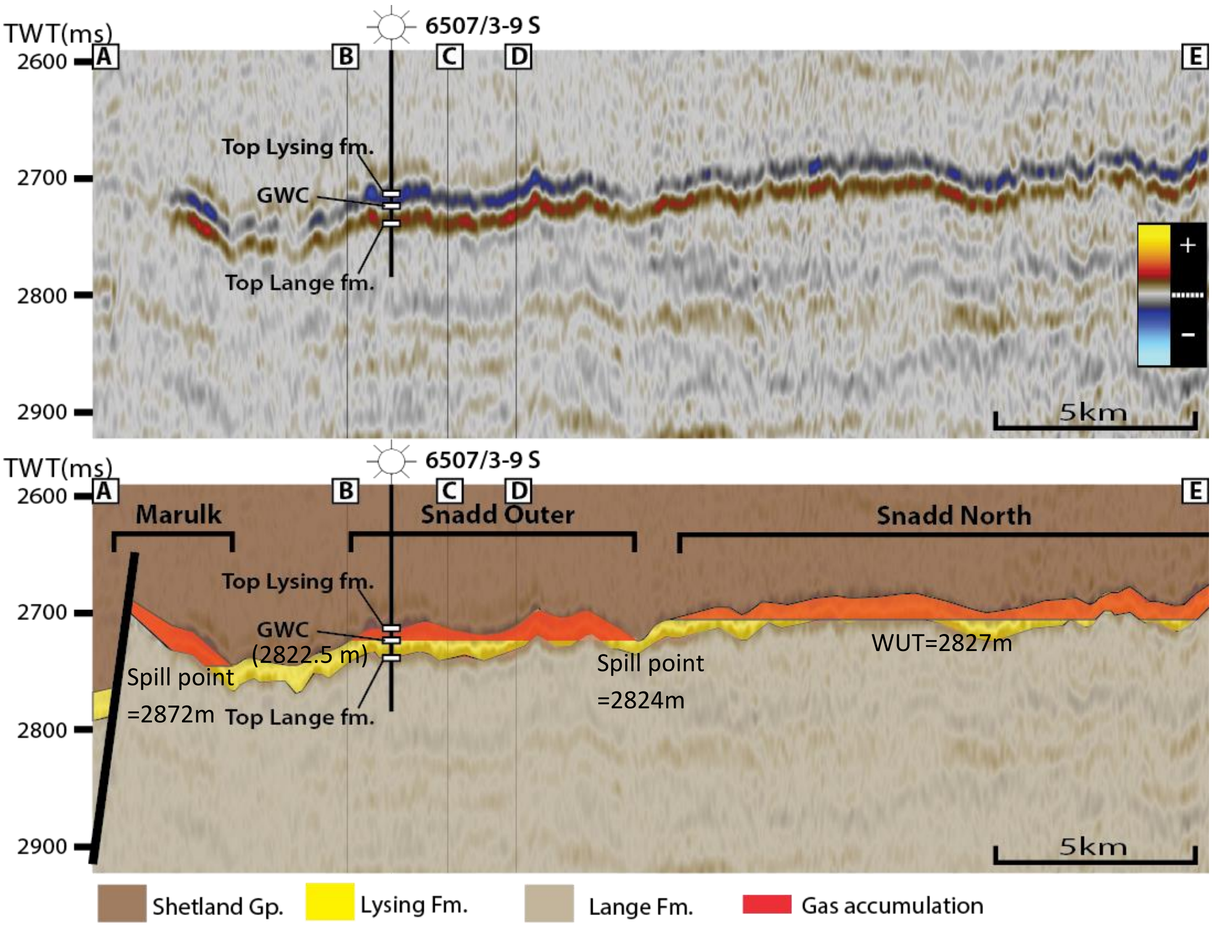

Figure 5.16: Seismic composite line A-E. Un-interpreted and interpreted. See figure 5.15 for location. Vertical exaggeration = 15.

the topography of the interpreted top Cromer Knoll Surface and the sand distribution interpreted from the RMS amplitude map. The spill point in Marulk is interpreted from the seismic at 2748 ms, giving a depth of 2872 m TVDSS (+/-25 m) based on the checkshots for the two closest wells. The Snadd Outer well 6507/3-9 S encountered a GWC at 2822.5 m. The interpreted spill point between Snadd Outer and Snadd North is at 2824 m (+/- 25 m). The GWC in Snadd North is unknown, but a WUT situation is registered at 2827 m TVDSS.

5.2 Jurassic reservoirs in the Norne Area

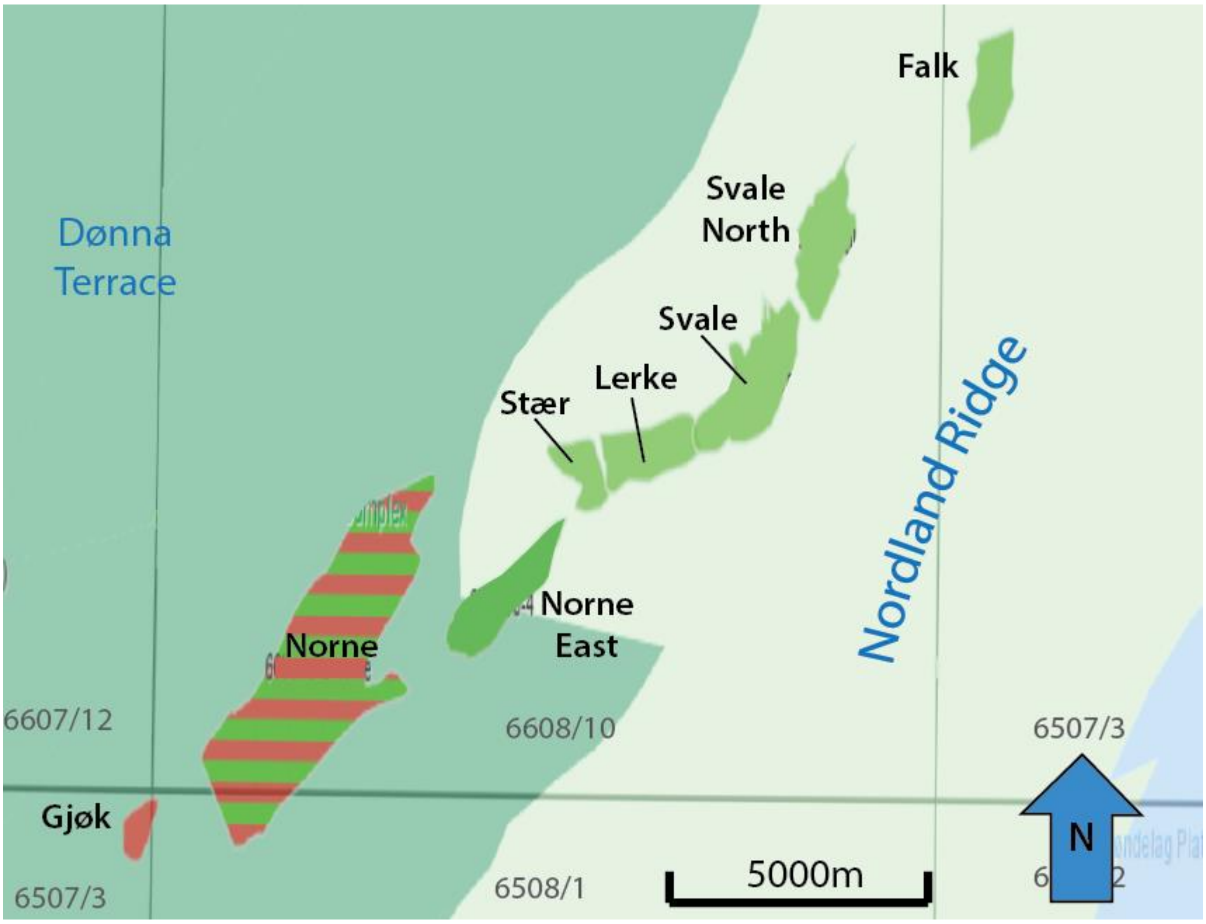

Figure 5.17: Location of the structures investigated in chapter 5.2. Modified from NPD

The structures investigated in this chapter are situated in the transtion between the Dønna Terrace and the Nordland Ridge. The structures are situated in, or close to, the Revfallet Fault Complex. All the accumulations are entirely or partly delineated by faults.

5.2.1 Gjøk

The Gjøk structure is located in the transition of the Dønna Terrace and the western flank of the Nordland Ridge. It lies just south-west of the Norne Field. The purpose of the well was to prove enough hydrocarbons in the Jurassic reservoirs to make a tie-back to the Norne field economically justifiable.

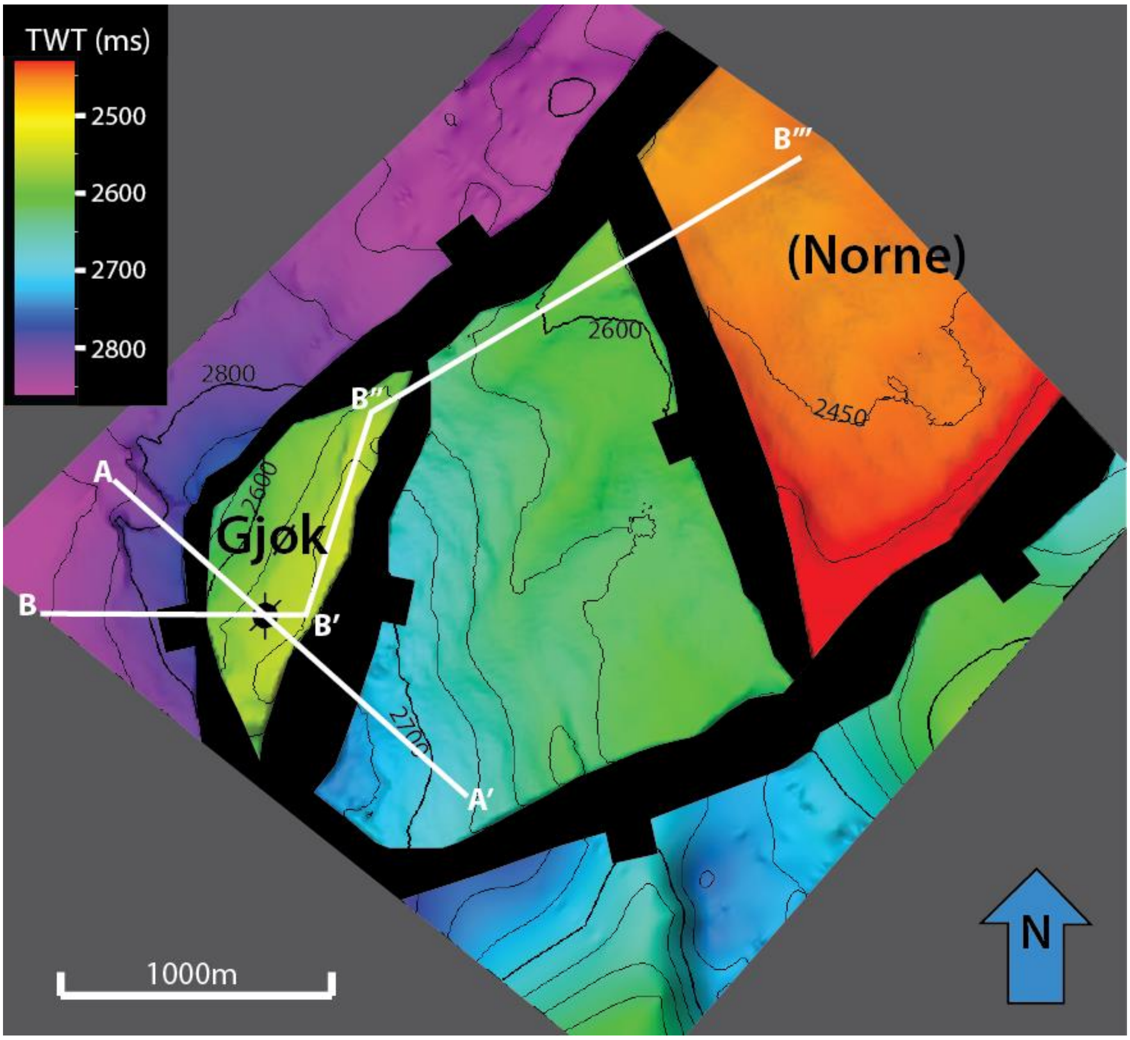

Figure 5.18: Top reservoir surface in the Gjøk area. Contour interval = 25ms. Seismic cross sections, both running through well 6507/3-8 is marked in white.

Gjøk is a small horst structure with a 4-way fault dependent closure. It lies on the same structural element as the Norne field. Figure 5.18 shows a map view of the structure. The general geometry of the structure is illustrated in figures 5.19 and 5.20.

Well 6507/3-8 was spudded in November 2009. It penetrated a 142 m thick gas column in Not, Ile and Tofte Formation. An oil leg of 9.5 m was proven in Tofte Formation. The sandstones showed good reservoir properties. A gas-oil contact was proven at 2835 m MD (2813 m TVD SS) and the oil-water contact at 2844 m MD (2822m TVD SS). No oil shows were recorded outside the hydrocarbon bearing zone. The shallowest reservoir; Not Formation is typically a shale in the other wells in the study. In the Gjøk structure, the formation has a good quality sandstone in the upper 24 meters of the formation. The lower 23 meters consist of claystone with sandstone stringers. The top reservoir fits well with a bright blue trough in the seismic, representing a decrease in acoustic impedance. The other formation tops included in the hydrocarbon filled reservoir do not have as clear seismic responses.

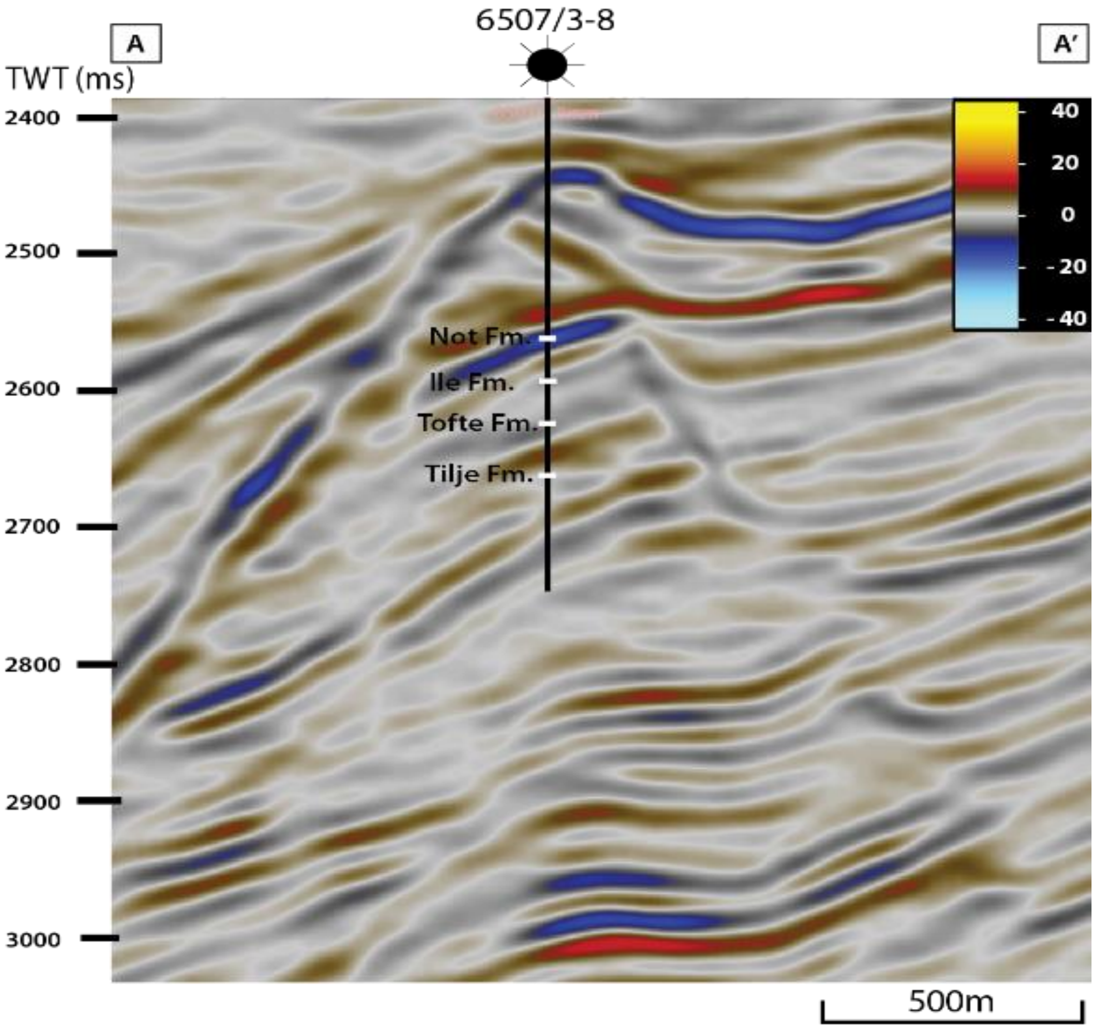

Figure 5.19: Seismic cross section A-A' across the Gjøk Structure (see figure 5.18 for location). Well tops from Petrel. Interpreted seismic can be seen in figure 5.20.

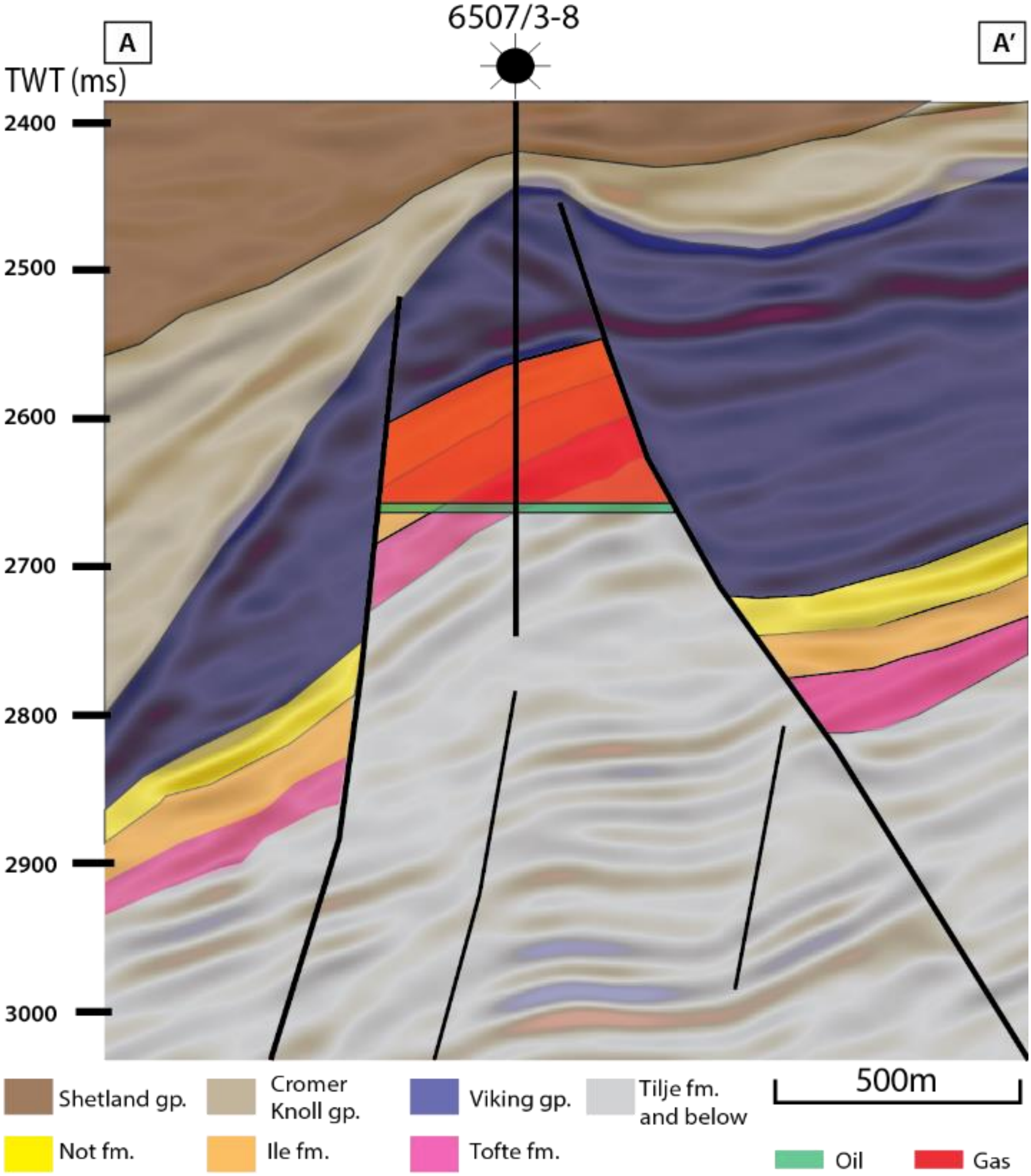

Figure 5.20: Interpreted seismic cross section A-A′ across the Gjøk Structure (see figure 5.18 for location). Showing the geometry of the structure.

Well	Top reservoir		HC-water contact		Spill point		Overpressure
	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	bar
6507/3-8	2564	2671	2659	2822	2651	2831	8

Table 5.6: Table containing a summary of important parameters from the Gjøk structure. TVD = TVDSS.

Pressure measurements were made in the reservoir zone (Not – Tilje). The reservoir pressure is close to hydrostatic pressure. An approximate overpressure of 7 bars is calculated. The Tilje formation (formation top just at the OWC in the well) has a slight overpressure increase with depth.

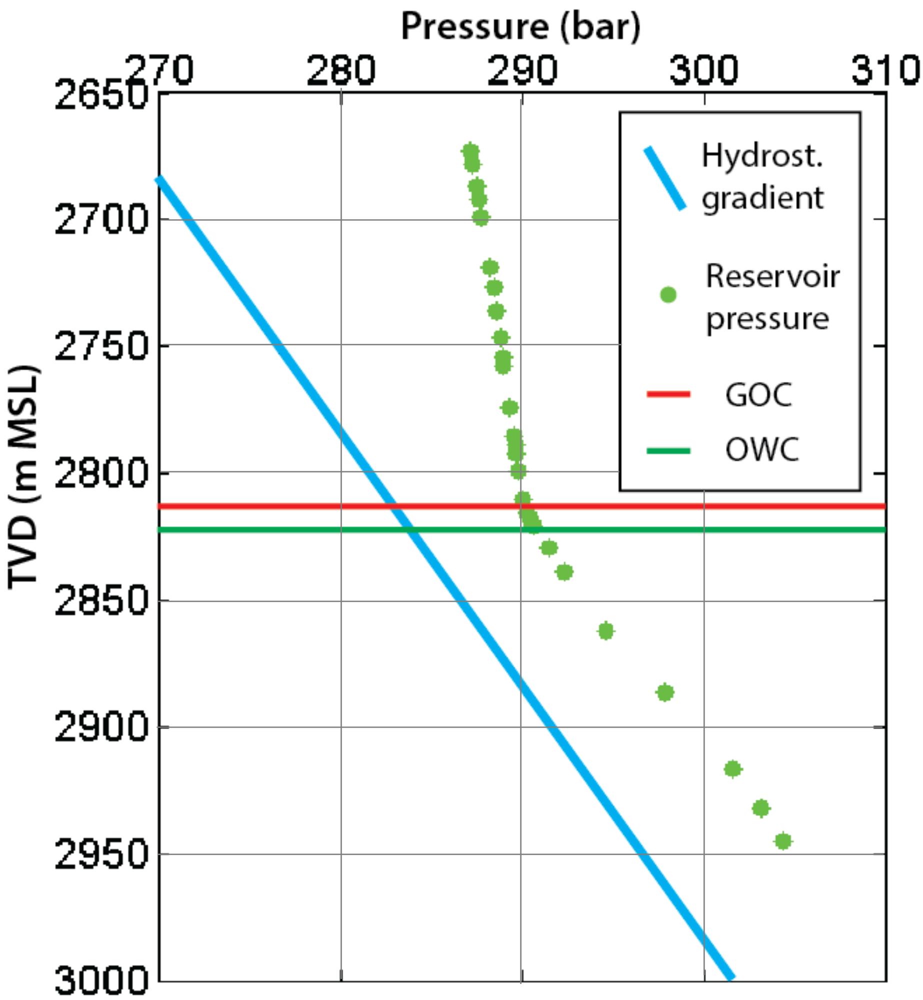

Figure 5.21: Pressure measurements in Gjøk.

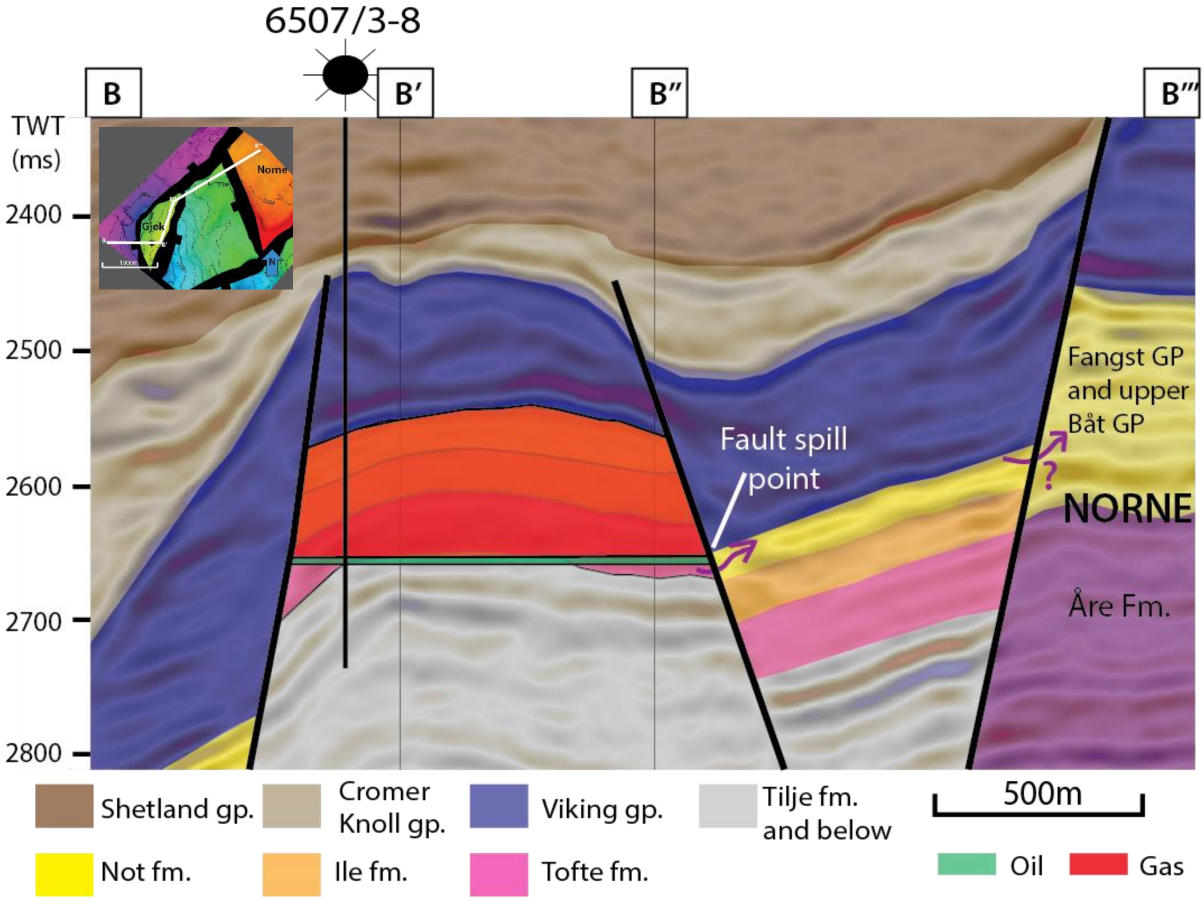

Figure 5.22: Seismic composite cross section B-B‴. See figure 5.18 for location. Shows interpreted spillpoint.

The OWC is at 2822 m TVDSS. The interpreted fault spill point in (or close to) the fault intersection in the north is at 2831 m TVDSS (+/-25 m). The spill point is 9m deeper than the OWC. This is within the uncertainties.

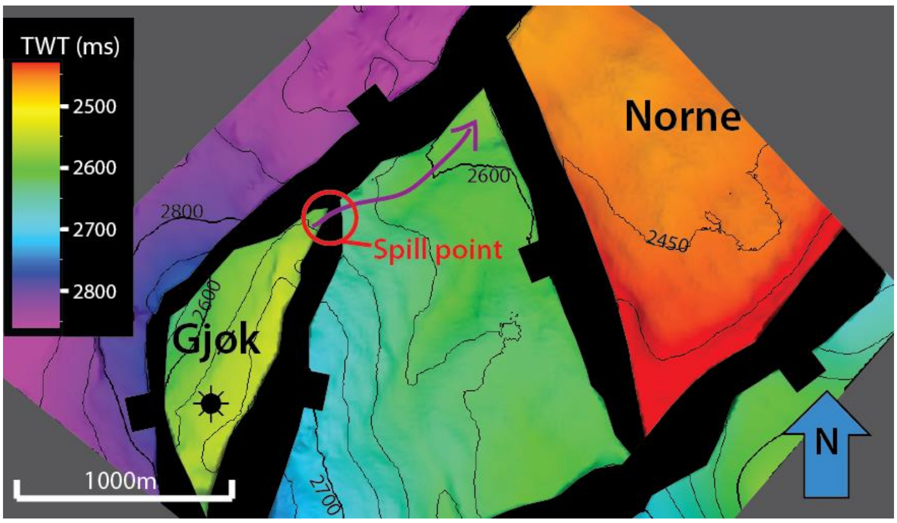

Figure 5.23: Showing location of the spill point in the Gjøk structure. Expected migration path towards Norne is added.

5.2.2 Norne and Norne East

The Norne field is located in the transition between the Dønna Terrace and the Nordland Ridge. The Norne field is comprised of two separate structures; the main Norne structure, which will hereafter be called just “Norne structure”, and the Norne East structure.

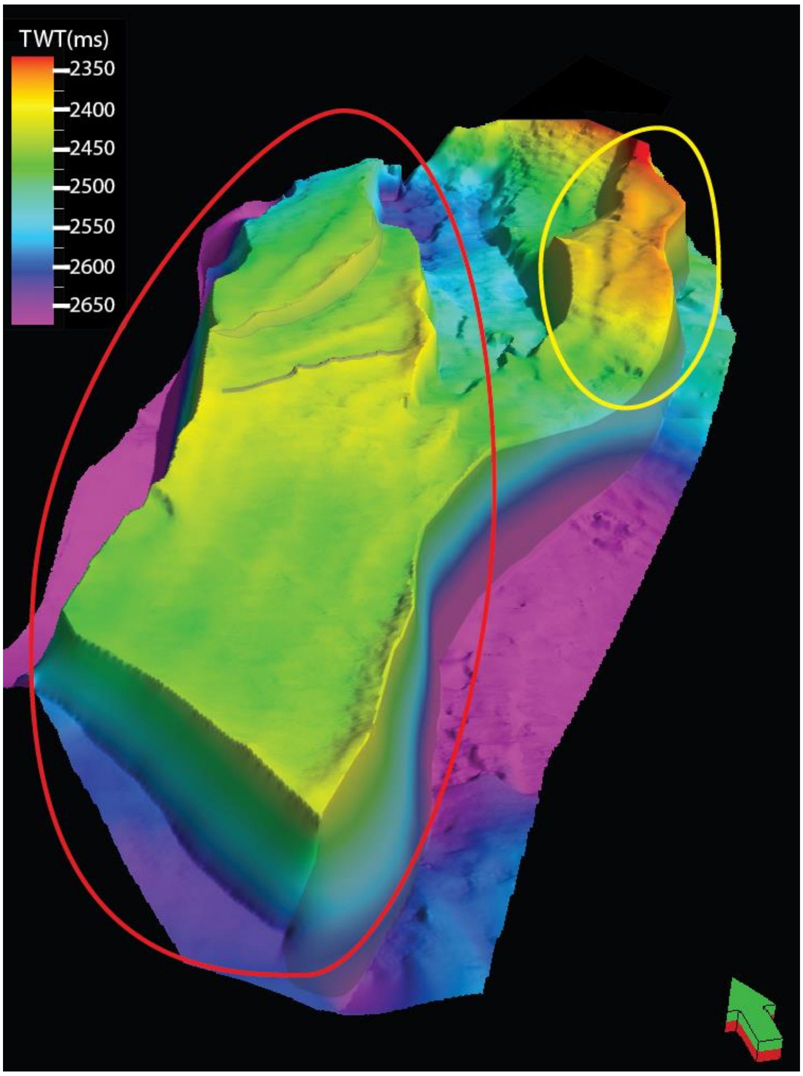

Figure 5.24: 3D representation of top reservoir interpretation in the Norne area. Norne encircled in red, Norne East encircled in Yellow. Vertical exaggeration = 3. Green arrow points north.

The structures are comprised of a large SW-NE oriented horst structure approximately 8.5km long and 1.5-3 km wide. Norne East is part of the same structural element, but the two structures are divided by a smaller graben. The Norne structure is itself divided into a north and south segment by a fault. There are similarly oriented small faults just south of the dividing fault, but these do not have the lateral extent sufficient to further divide the Norne structure into more segments.

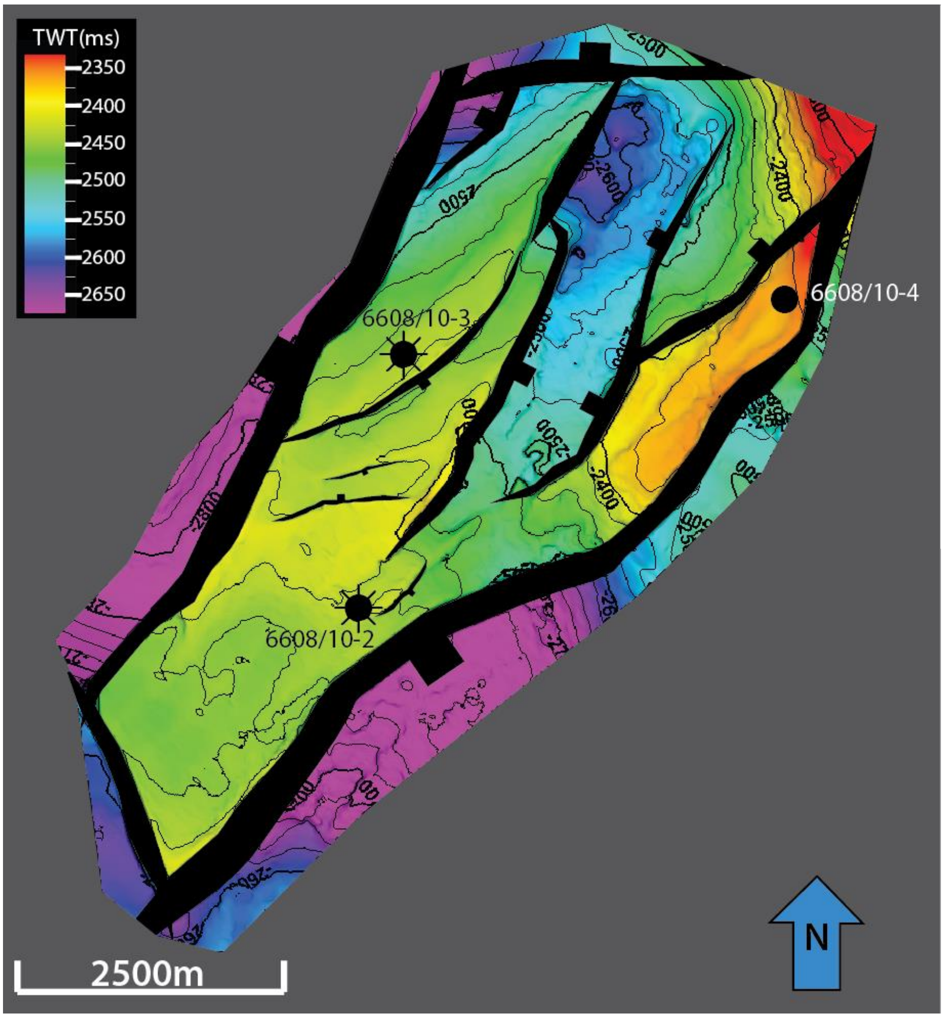

Figure 5.25: Top reservoir map in Norne area. Well positions are added. Contour increment = 25 ms.

Well 6608/10-2 was spudded on the Norne structure on the south segment in October 1991. The primary objective of the well was to test the hydrocarbon potential in sandstones of the Middle Jurassic Fangst Group. Oil and gas were encountered in the Fangst and Båt Groups. Based on interpretation of logs and FMT (Formartion Multi Tester) data, the gas-oil contact was encountered at 2605 m MD and the oil water contact at 2713.5 m MD. It was abandoned as a gas and oil discovery.

Well 6608/10-3 was spudded in January 1993. The main objective of the well was to apprise the Norne discovery in the Fangst and Båt Groups in the northern segment of the Norne structure (the northern fault block). The top of the Fangst Group, the Garn formation, was encountered at 2573.7 m MD. Oil and gas was encountered in the Fangst and Båt Groups. The GOC was encountered at 2598 m MD and the OWC at 2713 m MD.

Well 6608/10-4 was drilled on the Norne East structure in December 1993. The main objective was to prove hydrocarbon accumulation in the Middle Jurassic sandstones in the Fangst Group. The well was drilled to a total depth of 2800 m MD in the Lower Jurassic Åre Formation. The well encountered oil in the Garn Formation of the Fangst Group, and in Melke Formation sandstones, which opened a new play for the area. The Intra Melke Fm. accumulation was not in pressure communication with the Fangst Gp. accumulation. The Melke reservoir was of very poor quality and consisted of thin sandstone intervals interbedded with shales. DST 3 (Drill Stem Test 3) showed that the Intra Melke formation was tight with oil in place. No contact was documented in the Melke sandstones. The lower part of Melke Formation acts as a seal for the hydrocarbons in the Garn formation.

In the Fangst Group accumulation, it was difficult to establish a fluid contact from the logs.

- An ODT (Oil down to) Not Formation at 2559 m TVD MSL was registered.
- Water was found up to top Ile Formation, giving a WUT 2582.5 m TVD MSL.
- The shaley Not Formation is a possible pressure barrier but the pressure data is not good enough to conclude. It does not represent a pressure barrier in the reference wells (6608/10-2 & 3) in Norne.
- A common water zone with Norne is concluded.
- An OWC is observed in the cores at 2574 m TVDSS.
- The deepest trace of oil in the fluid samples is at 2571.3 m TVDSS.
- The geochemical evaluation suggested an OWC at approximately 2573 m TVDSS.
- The contact found in the cores will be used for the rest of this chapter.

Well	Top reservoir		Oil-water contact		Gas-oil contact		Spill point		Over-pressure
	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	(bar)
6608/10-2	2433	2554	2514	2690	2582	2581,7	2495	2657	≈ 6,5
6608/10-3	bad chks	2548,5	bad chks	2687,8**	bad chks	2572,8**	Bad chks	See /10-2	≈ 6,5
6608/10-4	2367	2544	2386	2574,5*	x	x	2380	2564	≈ 6,5

Table 5.7: * Based on OWC observed in cores. See description in text.
**Well path and checkshots in Petrel is flawed. Estimated from MD-TVDSS relationship. Uncertainty = +/- 1 m.
"Chks" = checkshots

Table 5.7 summarize information from the wells in the Norne structures.

Short lithological summary (reservoir section):

<u>Norne:</u>

- The Fangst Group is generally comprised of sandstones. Exception is the Not Formation which is comprised of shale/siltstone.
- The Båt Group is generally comprised of sandstones. Interbedded shales in lower part of Tilje and Åre.

<u>Norne East</u>

- The Fangst Group is generally comprised of sandstones. Exception is the Not Formation which is comprised of shale.
- The Båt Group is generally comprised of sandstones. Interbedded Shales in Åre Formation.

Pressures:

Figure 5.25 presents the pressure data from wells 6608/10-3 and /10-4. Detailed pressure measurements from 6507/10-2 was not available, but one DST (Drill Stem Test) gave a reservoir pressure of 27785 kPa (=277.85 bar) at DST interval 2691-2696 m TVDSS. Assuming a brine density of 1025 kg/m^3, an overpressure of approximately 7 bar was calculated. The overpressure in the water zones of the two wells with available FMT-data is approximately 7 bar. This fits well with the overpressure calculated from the DST from well 6608/10-2.

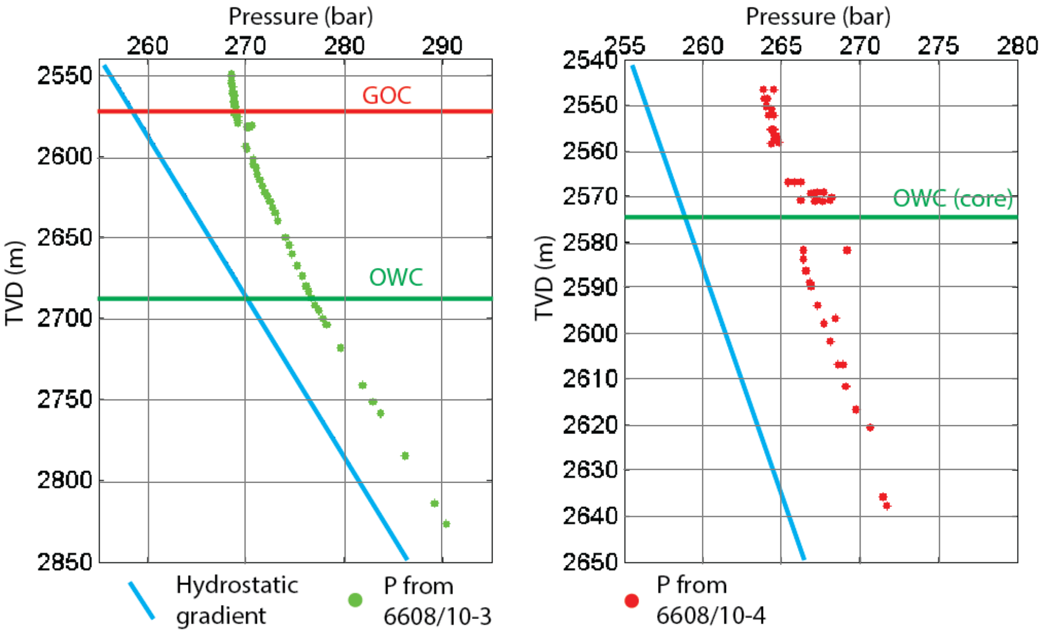

Figure 5.25: FMT pressure data from well 6608/10-3 and 6608/10-4. The water zones are similarly overpressured. The OWC in well 6608/10-4 is observed in the cores.

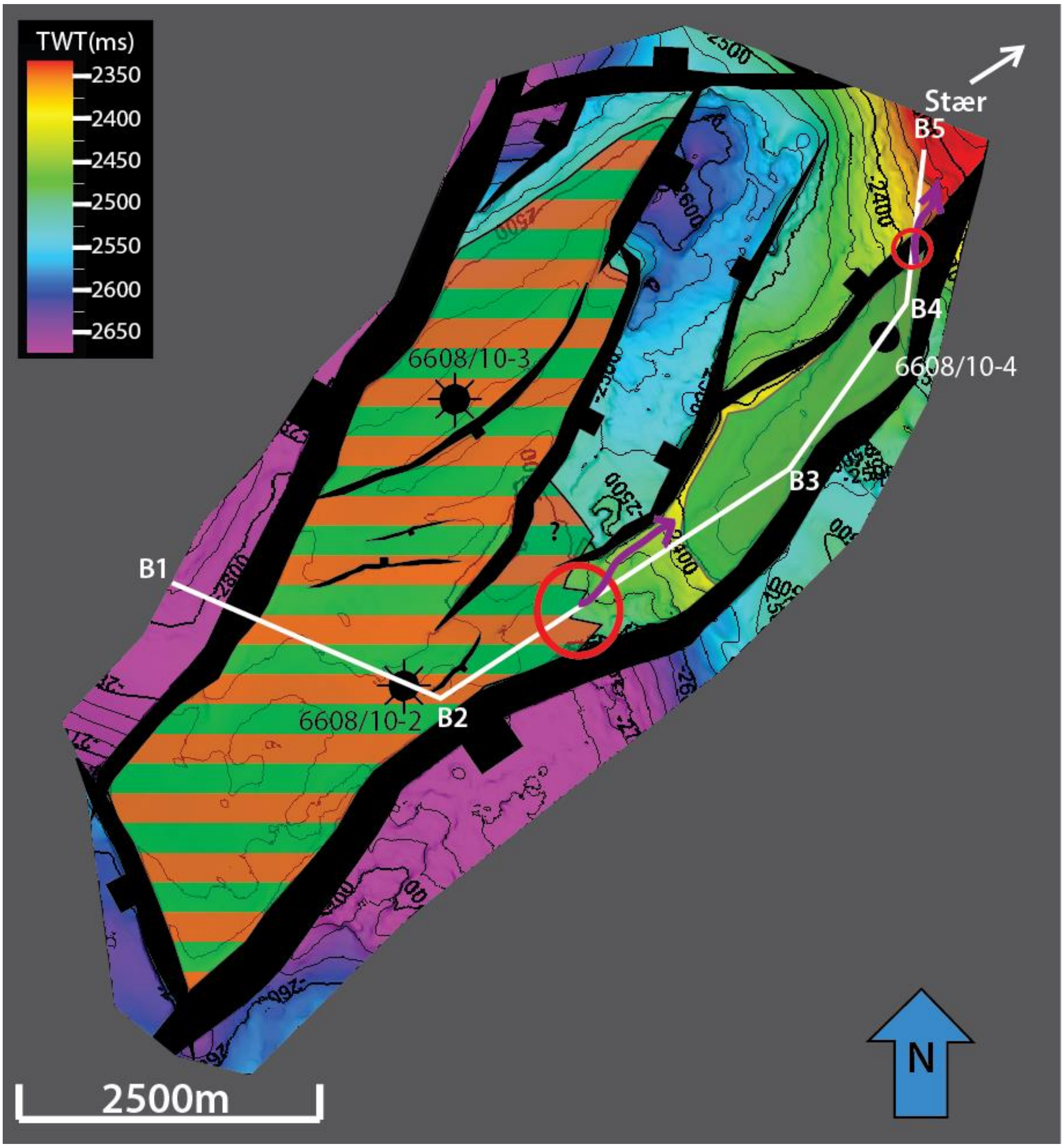

Figure 5.26: Hydrocarbon accumulation based on the OWCs. Interpreted spill points located in red circles. Seismic composite cross section B1-B5 represented by the white line.

A structural spill point is interpreted at TWT 2495 ms along the top Fangst Group. This corresponds to 2657 m TVDSS (+/-25 m) based on the depth conversion from the closest well 6608/10-2. A fault spill point is interpreted in the north of Norne East structure at 2587 m TVDSS (+/-25 m).

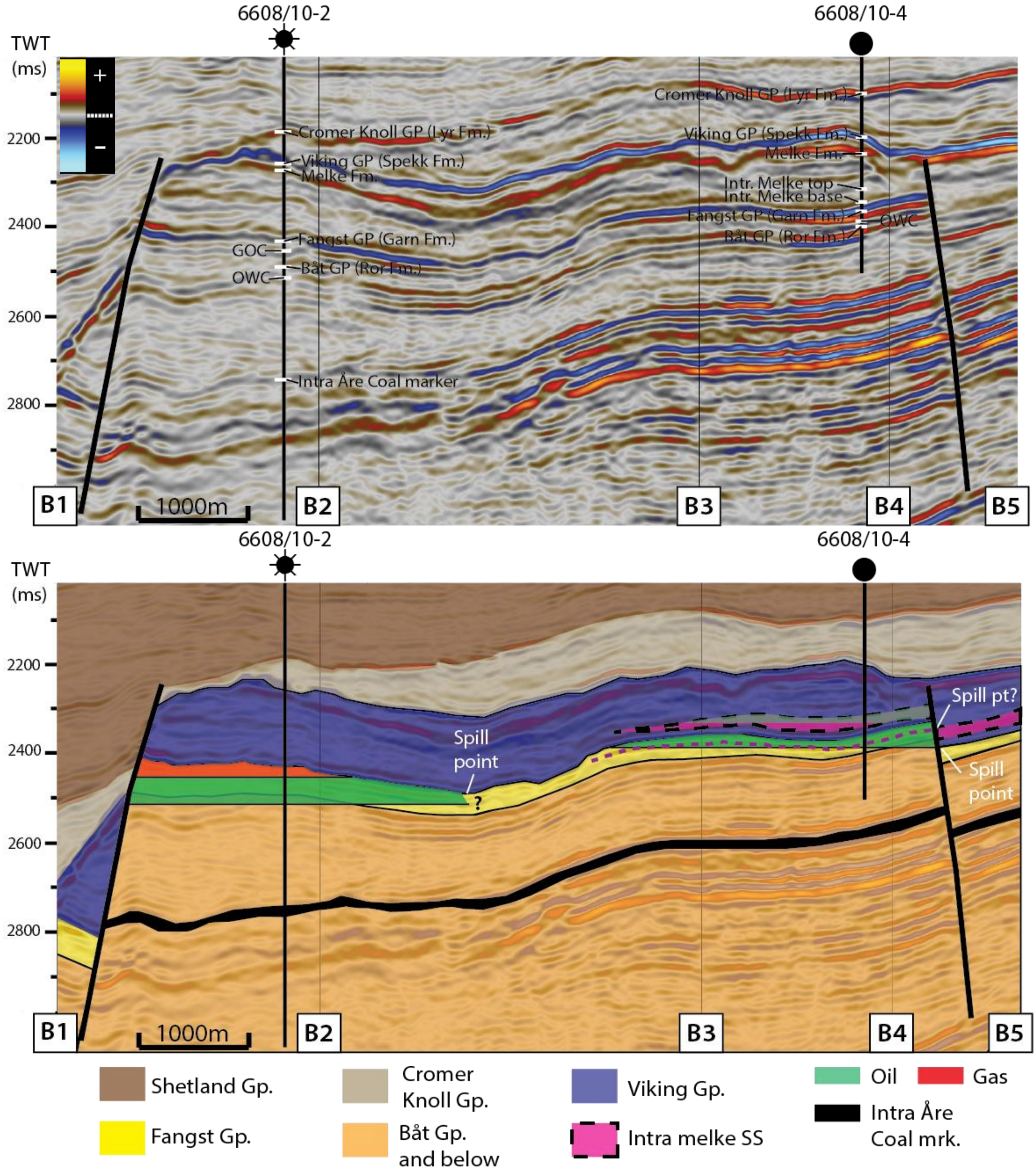

Figure 5.27: Seismic composite cross section B1-B5. See figure 5.26 for location. Well tops from Petrel. Interpretations added on lower figure. The purple dotted line in Norne East illustrates the Not formation (possible pressure barrier). The Not Formation is not a pressure barrier in Norne. The contact in the Intra Melke Formation is for artistic purpose. No contact was encountered in the Intra Melke sandstones.

Figure 5.27 shows the hydrocarbon accumulation and spill points in the Norne and Norne East structures. The formations in the Fangst Group and some of the Båt Group Formations are too thin to be interpreted. As they generally have reservoir characteristics, the tops of the Groups themselves is interpreted and presented. The Not Formation is represented by a purple dotted line in figure 5.27 as it represents a possible barrier for fluid flow. The dotted line is not extended into the main Norne structure, even though Not Formation is present, since there is proven pressure communication vertically across the formation in Norne.

The interpretation of the Intra Melke Formation is uncertain, as it does not have a clear seismic representation. It is not present in the Norne wells /10-2 and /10-3, so it has to pinch out somewhere between the /10-4 and /10-2 well. It is present in wells further north-east from the Norne East structure.

5.2.3 Stær and Lerke

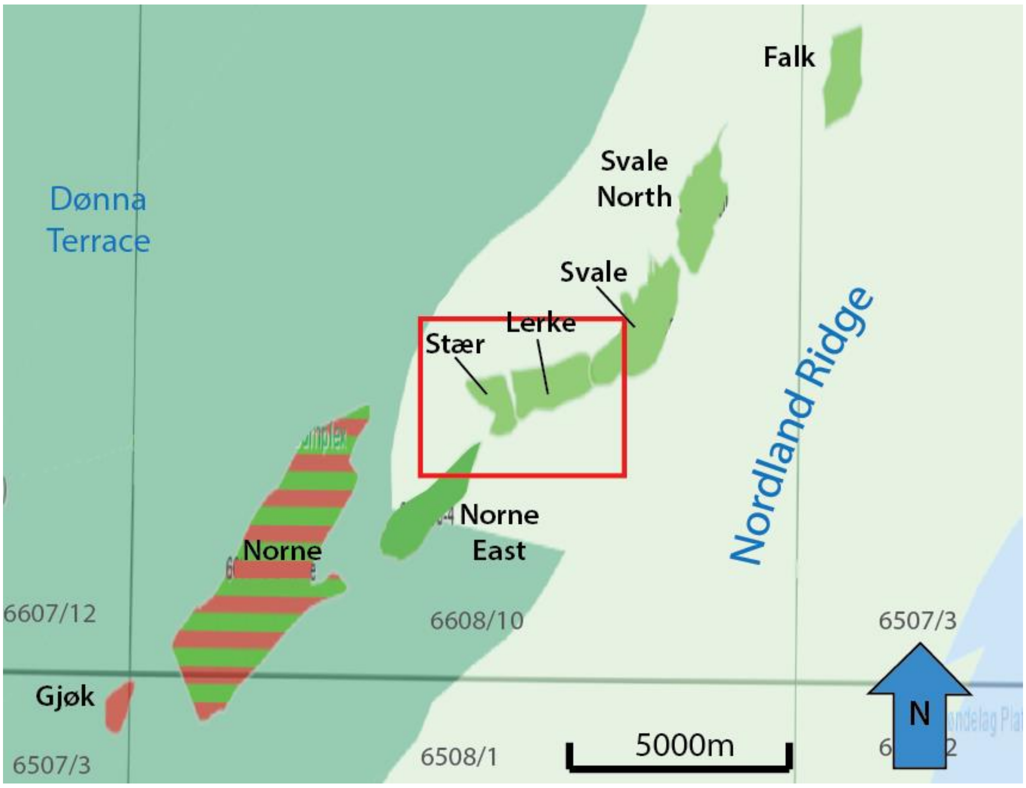

Figure 5.28: Location of the Stær and Lerke structures. Modified from NPD. The red rectangle shows the approximate location of the surface map presented in this chapter.

The Stær and Lerke structures are situated in block 6608/10, on the western edge of the Nordland Ridge approximately 4 km from Norne. The structures are situated on a WSW-ENE oriented horst, subdivided by a normal fault dipping towards Lerke.

The Stær structure is the structure closest to the Norne field, situated just north of the Norne East structure. In the Norne-subchapter, a spill route is introduced from Norne East and into the Stær fault block. The Stær structure is affected by smaller faults, increasing the complexity of the structure. The structure is upthrusted relative to the Lerke Structure.

The Lerke structure is a horst relative to the fault blocks north and south of it, but it is the hanging block of the normal faults dividing it from Stær in the west and Svale in the east.

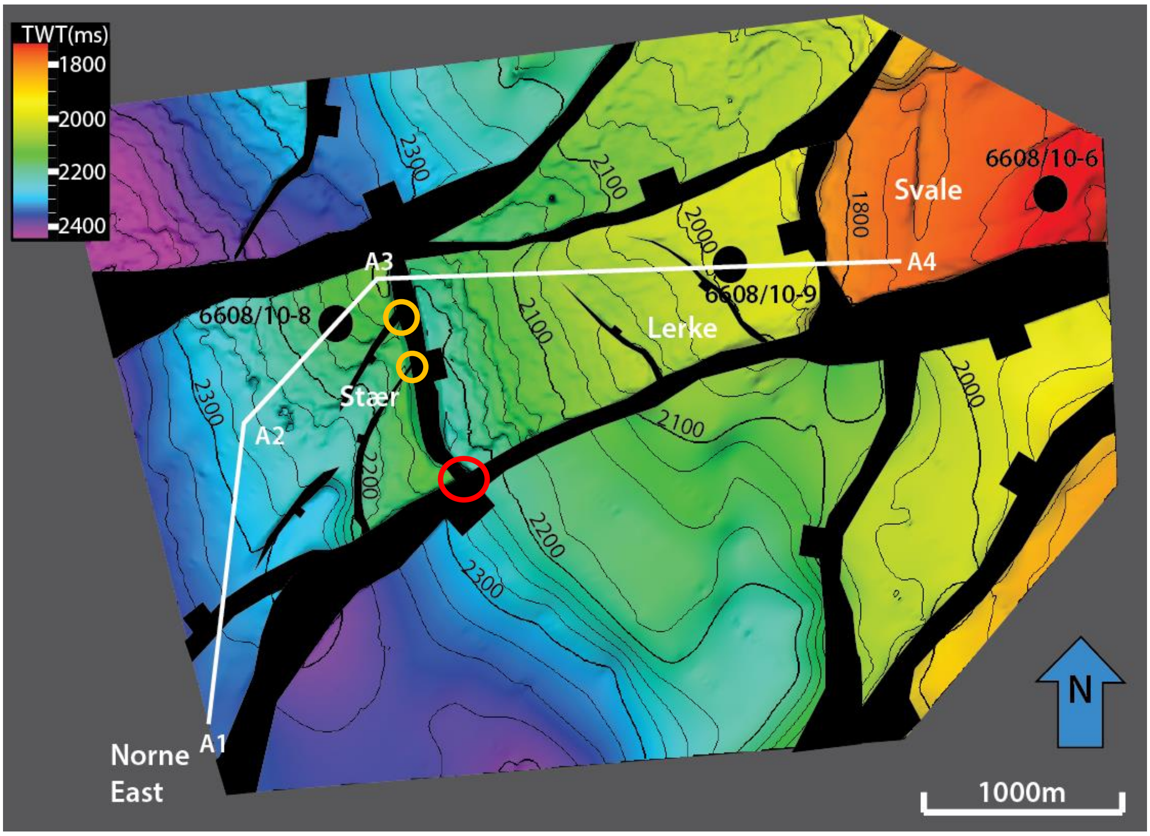

Figure 5.29: Top Reservoir interpretation in the Stær-Lerke Area. Contour increment = 25ms Well locations and location of seismic composite cross section A1-A4 are added. Fault intersections interpreted as possible spill points are encircled.

Well 6608/10-8 was spudded on the Stær structure in late December 2001. The primary objective was to prove hydrocarbons in sandstones of the Middle to Early Jurassic Fangst and Båt Groups. Testing the hydrocarbon potential of possible sandstones in the Late Jurassic Melke formation was the secondary objective. Five of the penetrated formations had reservoir qualities, and were oil bearing: The Intra Melke Sandstone of the Viking Group, the lower part of Not Formation and the Ile Formation of the Fangst Group, and the Tilje and Åre Formation of the Båt Group. An OWC was encountered at 2458.1m TVDSS in Åre Fm. The composition of the oil in the Not and Åre Formation was very similar to the Norne Oil.

An appraisal well, 6608/10-8 A, was kicked off from the first well and drilled down-dip in a SE direction. It confirmed the oil-water contact in Tilje Formation. The OWC was approximately 5-10m deeper in the appraisal well.

Well 6608/10-9 was spudded in early 2003 in on the Lerke structure. The primary objective was to prove hydrocarbons in the Early Jurassic Båt Group. The secondary objective was to prove hydrocarbons in the Intra Melke Formation. The Not, Tilje and Åre formation were water filled. The Intra Melke Formation consisted of three oil-bearing sandstones. An ODT (oil down to) situation was registered in the Intra Melke Formation. The composition of the oil in the Melke sandstones was very similar to the Norne-oil. Weak shows were observed in the Not and Tilje formations down to no shows at 2323m MD (2300 m TVDSS) in the Åre Formation.

Formation	MD (m)	TVDSS (m)	Thickness (m)
Melke	2224	2198,5	69,5
Intra Melke SS	2293,5	2268	47,5
Melke	2341	2315,5	7
Not	2348	2322,5	20,5
Not SS	2368	2343	20,5
Ile	2389	2363,5	2
Tilje	2391	2365,5	11,5
Åre	2402	2377	>249

Table 5.8:
Lithostratigraphic table from well 6608/10-8 in the Stær structure. "SS"= Sandstone ("Not SS" = Not Sandstone)

Formation	MD (m)	TVDSS (m)	Thickness (m)
Melke	2055	2032	78
Intra Melke SS	2133	2110	48
Melke	2181	2158	7
Not	2188	2165	16
Not SS	2204	2181	18
Tilje	2222	2199	6
Åre	2228	2205	>172

Table 5.9:
Lithostratigraphic table from well 6608/10-9 in the Lerke structure. "SS"= Sandstone ("Not SS" = Not Sandstone)

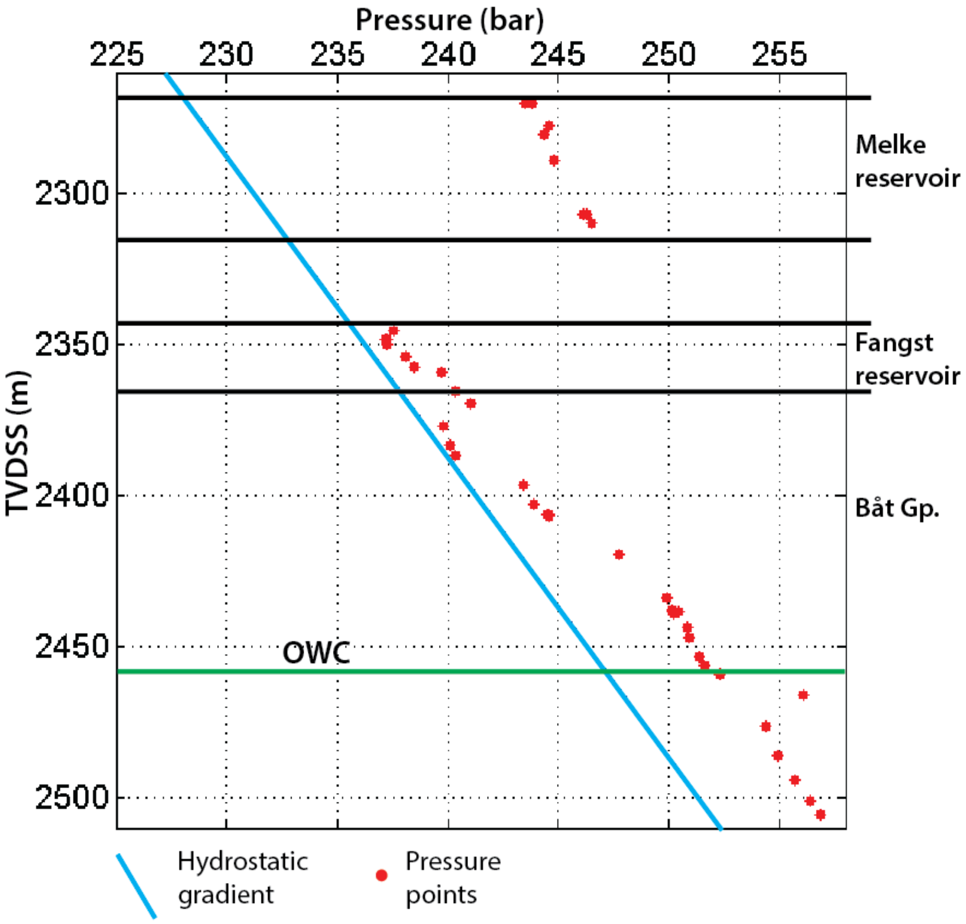

Figure 5.30: Pressure measurements from well 6608/10-8 in the Stær structure. The reservoir zones are marked and annotated. Brine density of 1025kg/m^3 is used for the hydrostatic pressure.

Figure 5.30 plots the pressure data from well 6608/10-8 in the Stær structure. The pressure conditions in the well were affected by depletion from production in the Norne Field. The degree of pressure depletion varied between the different sandstone layers in the reservoir. This made the acquiring of fluid gradient from the pressure data difficult. Generally, the Not formation has the biggest reduction in pressure and there is a gradual decrease in depletion down to the total depth (TD) of the well. The Sandstones from the Melke Formation was not affected by depletion.

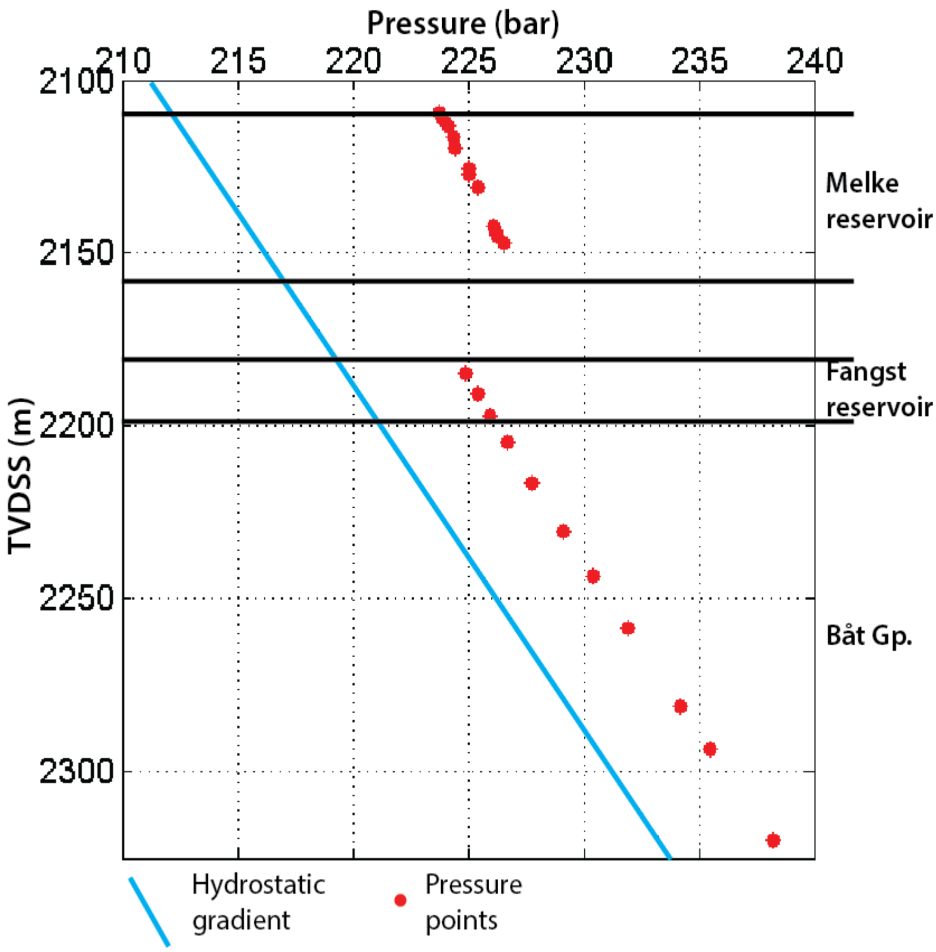

Figure 5.31: Pressure measurements from well 6608/10-9 in the Lerke structure. The reservoir zones are marked and annotated. Brine density of 1025kg/m^3 is used for the hydrostatic pressure

Figure 5.31 plots the pressure data from well 6608/10-9 in the Lerke structure. The tested water zone of the Middle and Early Jurassic has an overpressure of 4,8-5,2 bar.

Well	Top reservoir		HC-water contact		Spill point		Overpressure
	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	(bar)
6608/10-8	2191	2363,5	2269	2458,1	2240	2416,5	Depleted

Table 5.10: Information about Fangst/Båt reservoir in the Stær structure. TVD =TVDSS

Well	Top reservoir		HC-water contact		Spill point		Overpressure
	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	bar
6608/10-9	2045	2181	no fill	no fill	2028	2156	5

Table 5.11: Information about Fangst/Båt reservoir in the Lerke structure. TVD =TVDSS

The Stær structure has a fault-spill point at 2416.5 m TVDSS (+/-25 m), where the Båt Group of the Stær fault block is juxtapositioned to the Fangst Group reservoir. The OWC in Stær is 41.6 m deeper (2458.1 m TVDSS (+/-25 m)) in well position than the spill point. The structure has a shallower possible spill point where the Båt Group is juxtapositioned to the Intra Melke sandstones at 2328 m TVDSS (+/-25 m).

A fault-spill point is interpreted at 2156 m TVDSS (+/-25 m), where the Fangst Group is juxtapositioned to the Åre Formation of the Svale structure to the east. The accumulation is completely dependent on sealing of the fault between the Lerke and Svale structures.

The Intra Melke sandstones in the Stær structure is juxtapositioned to impermeable shales in younger strata of the Melke Formation and possibly the Cretaceous Cromer Knoll Group (Lyr Formation).

The Intra Melke sandstones in the Lerke Structure are juxtapositioned to the Åre Formation of Svale. The possible fault-spill point is at 2084 m TVDSS (+/-25 m).

Figure 5.32 presents the seismic composite cross section A1-A4 with interpretations.

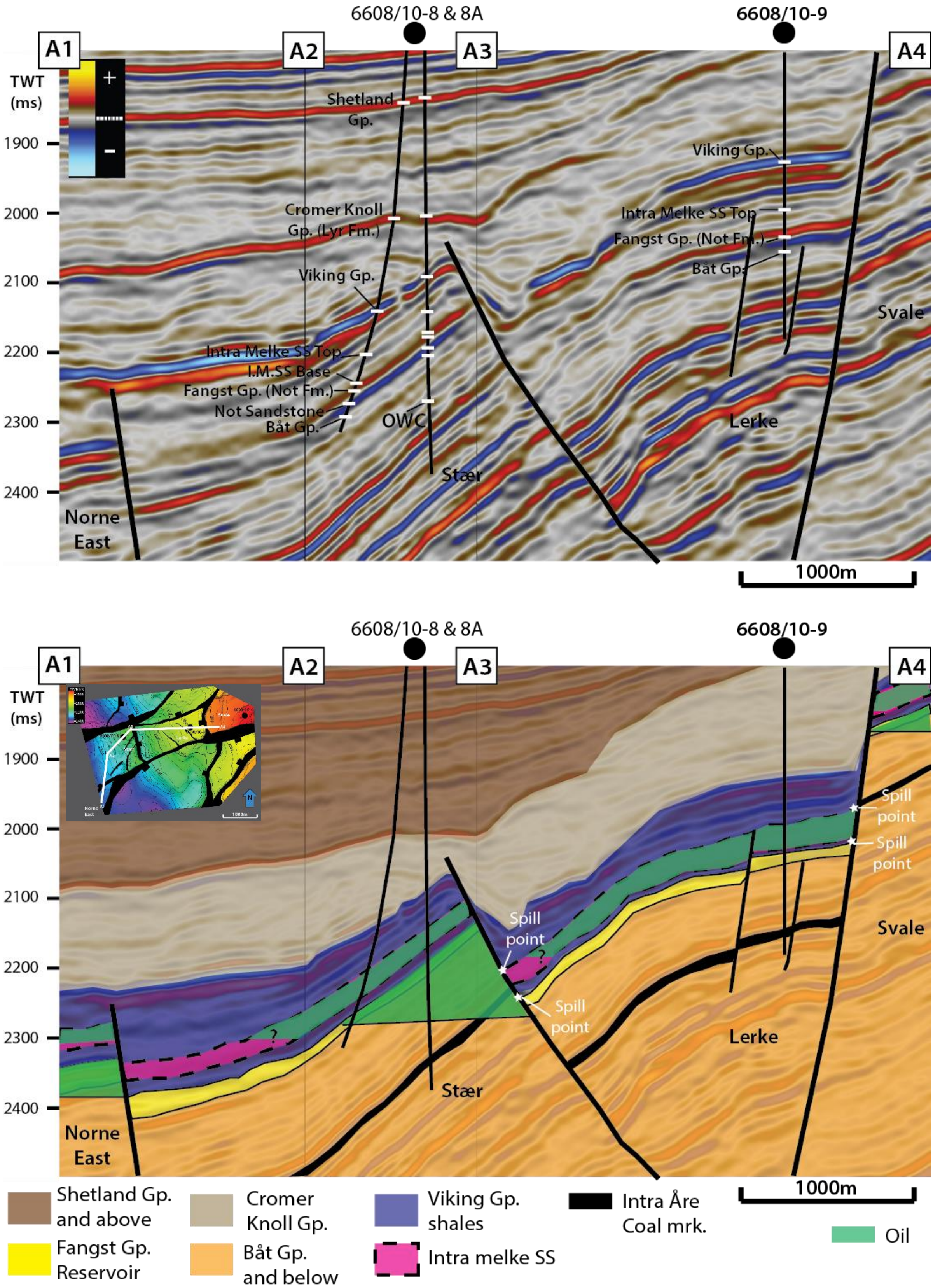

Figure 5.32: Seismic composite cross section A1-A4. See figure 5.29 for location. Well tops from Petrel. Interpretations are added on lower figure. Contacts in the Intra Melke SS are unknown.

5.2.4 Svale and Svale North

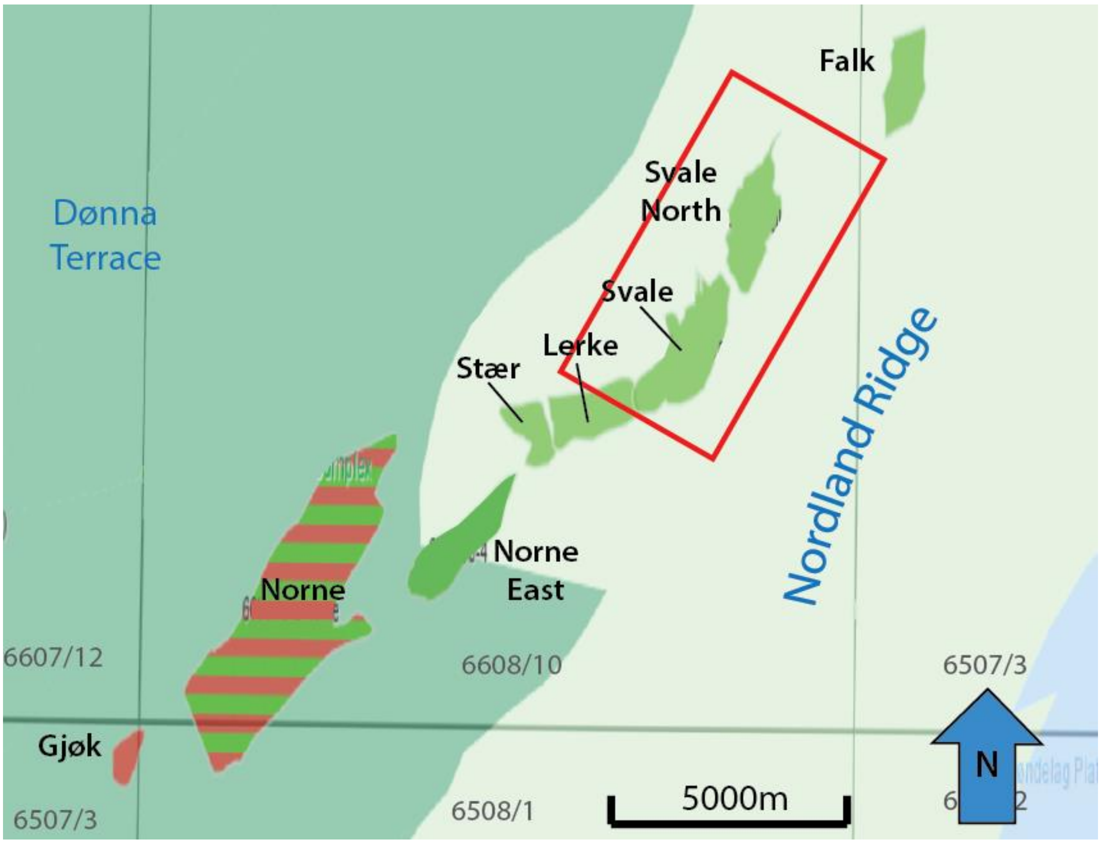

Figure 5.33: Location of the Svale and Svale North structures. Modified from NPD.

The Svale structure is located on the up-thrown fault block adjacent to the Lerke structure. The structure is fault bounded on three sides, but is open to the north. It is situated on the Western edge of the Nordland Ridge. The area is structurally complex with a high number of faults of varying size and offset. The Svale North structure is located on an adjacent fault block to the north. It is down-faulted relative to the adjacent fault block in the east.

Figure 5.34 illustrates the structural setting of the area through a variance surface attribute from the interpretation of the top reservoir (Not and Åre Formation). The location of the structures is presented in figure 5.35.

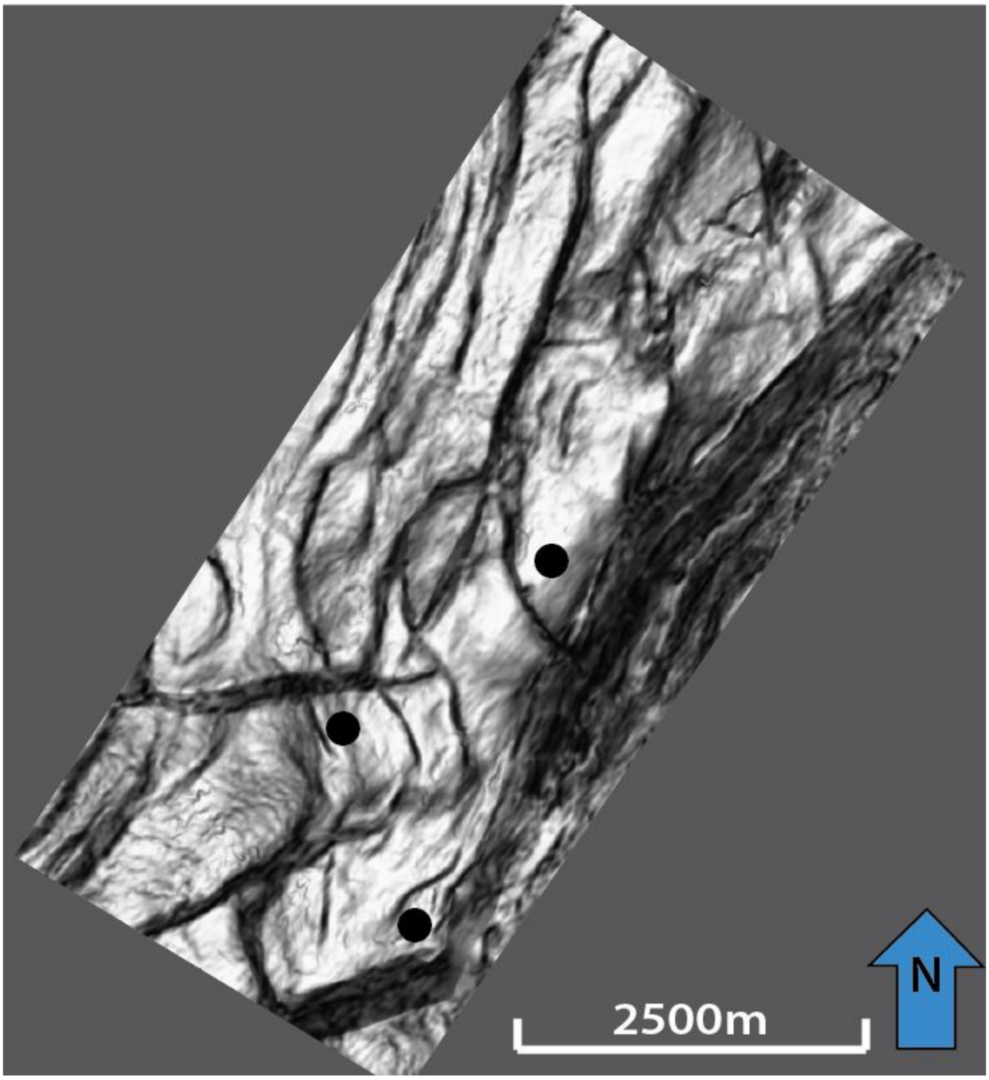

Figure 5.34:

Variance map from top reservoir surface. Enhances edges along surface. Well locations is added.

From south to north:
6608/10-6
6608/10-7
6608/10-15

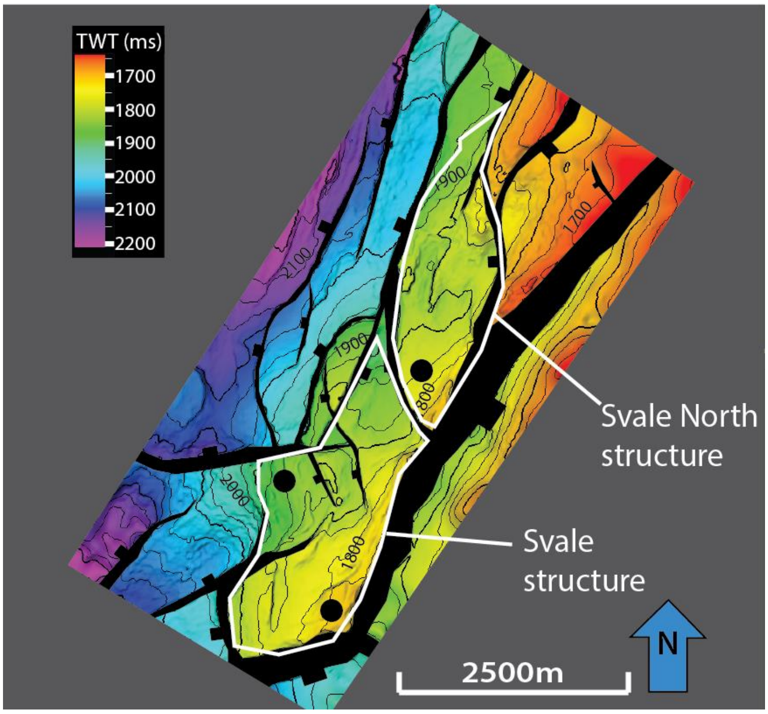

Figure 5.35:
Top reservoir surface showing the location of the structures described in this subchapter.

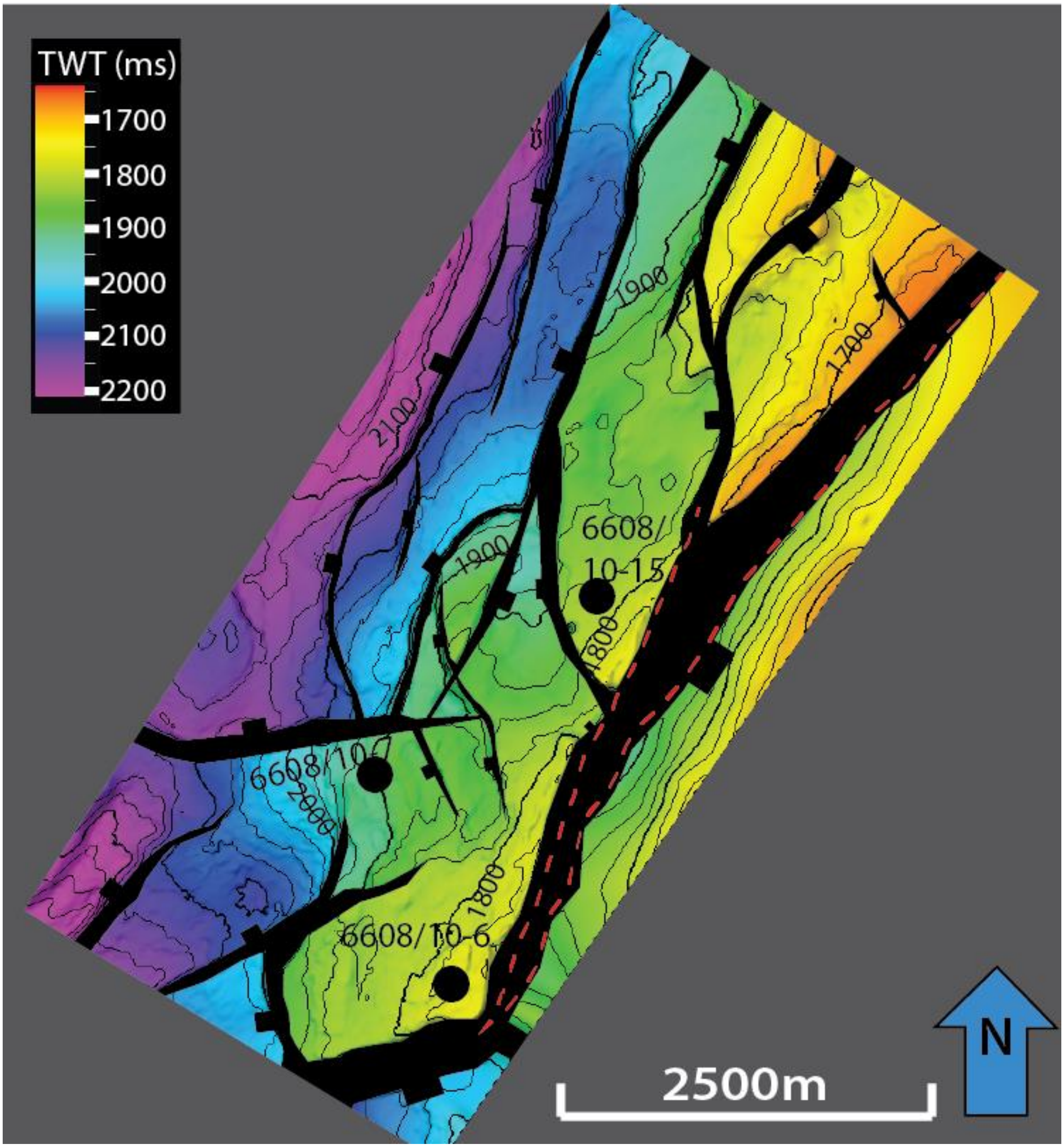

Figure 5.36: Top reservoir surface (Åre + Not reservoir). Contour increment = 25ms. Red dotted line represents underlying horst structures cut by the fault plane.

An important structural feature that is not seen in map view is one or several SSE – NNW oriented horsts hidden under the main fault that is defining the eastern border of the investigated structures. Svale and Svale North is generally down faulted relative to this horst complex. The horsts are cut by the large SSE – NNW oriented normal fault dipping to the south east. The horsts are illustrated in the map by a red dotted line. The horsts will be presented in several seismic cross sections.

Well 6608/10-6 was spudded on Ferbruary 29, 2000 in the southeastern part of block 6608/10, on the Svale structure. The main objective of the well was to prove hydrocarbons in Middle and Lower Jurassic sandstones of the Fangst and Båt Group. The Garn, Ile and Tofte Formations were not present in the well. The Intra Melke Sandstone and the Åre Formation was considered as good reservoir zones. A sandy Not Formation was present, but the reservoir quality was poor. Both reservoir zones were oil bearing. The oil water contact for the Åre/Not reservoir was encountered at 1994 m MD (1958 m TVDSS). An ODT situation was registered in the Intra Melke Sandstone.

Well 6608/10-7 was spudded 1.5 km NNW of well 6608/10-6 on March 30th 2001. The objective was to apprise the Svale-discovery from well 6608/10-6. Two reservoir zones was penetrated, reflecting a similar stratigraphy as in the discovery-well. The sandstone in the Melke Formation was oil filled down to its base. Below the sandstone, the Melke Formation consist of clay stone. In the claystone, shows got weaker with depth. Some weak shows were also seen in core chips from the Not Formation. The Åre Formation was water filled.

Later, in August 2013, well 6608/10-15 was drilled on the Svale North structure. It was spudded 3 km NNE of the first Svale well. The primary objective was to prove hydrocarbons in Åre Formation. The Intra Melke Sandstones was the secondary objective. Top of the reservoir is a sandstone in Lower Not Formation. The Intra Melke Formation was oil filled with an OWC estimated between 1890 and 1896 m MD (1865-1871 m TVDSS). A contact was interpreted at 1867.5 m TVDSS based on logs. Oil was also encountered in the Åre reservoir. With a WUT (water up to) 1975.5m MD and ODT 1967.5 m MD. A cemented shaly layer that may be a pressure barrier was present between the oil sample and the water sample. In case of a base seal, the contact could also be deeper than the WUT. Because of pressure depletion from production in the Svale field, scattered pressure data made the firm determination of a contact impossible. The amount of depletion is different above and below the shale layer.

Formation	MD (m)	TVDSS (m)	Thickness (m)
Melke	1794	1758	20
Intra Melke SS	1814	1778	36
Melke	1850	1814	9
Not	1859	1823	14
Åre	1873	1837	>242

6608/10-6 – Svale

Formation	MD (m)	TVDSS (m)	Thickness (m)
Melke	1902	1870,5	45,5
Intra Melke SS	1947,5	1916	38,5
Melke	1987	1954,5	21
Not	2007	1975,5	11
Åre	2018	1986,5	>301

6608/10-7 – Svale

Formation	MD (m)	TVDSS (m)	Thickness (m)
Melke	1830	1805	30
Intra Melke SS	1860	1835	37
Melke	1897	1872	8
Not	1905	1880	19
Not SS	1924	1899	10
Åre	1934	1909	>96

6608/10-15

Svale North

Table 5.11: Lithostrathic information from wells 6608/10-6 6608/10-7 and 6608/10-15

Table 5.11 presents a lithostratigraphic summary from the exploratioration wells on the two structures. Two reservoir sections are present in all the wells. The Intra Melke Sandstones, and the Åre/Not reservoir. The Not Formation, which is the only Formation from the Fangst Group that is present in the wells, is included in the reservoir. The Not Formation is generally thin and often of poor reservoir quality. In well 6608/10-15 of Svale North, the lower 10 meters of the Not Formation consist of reservoir quality sandstone.

Table 5.12 summarizes essential information from the Åre/Not reservoir

Svale

Well	Top reservoir		HC-water contact		Spill point		Overpressure
	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	bar
6608/10-6	1760	1823	1863	1958	1848	1940*	≈ 4
6608/10-7	1888	1975,5	dry	dry	1848	1922*	≈ 4

Svale North

Well	Top reservoir		HC-water contact		Spill point		Overpressure
	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	TWT(ms)	TVD(m)	bar
6608/10-15	1828	1989,8	1863	1946,5**	1890	1980	Depleted

Table 5.12: Tables presenting data from the Åre/Not reservoir. Spill points are structural spill points.
*: The difference between the wells illustrates the uncertainties connected to depth conversion from different wells.
**: Based on the mean between a WUT and ODT in the well. Uncertainty +/- 4 m

Several seismic cross sections were chosen to show the geometry of the structures, to present the horst that is hidden in map view, and to present interpreted spill points. Figure 5.37 shows the location and geometry of these seismic cross sections.

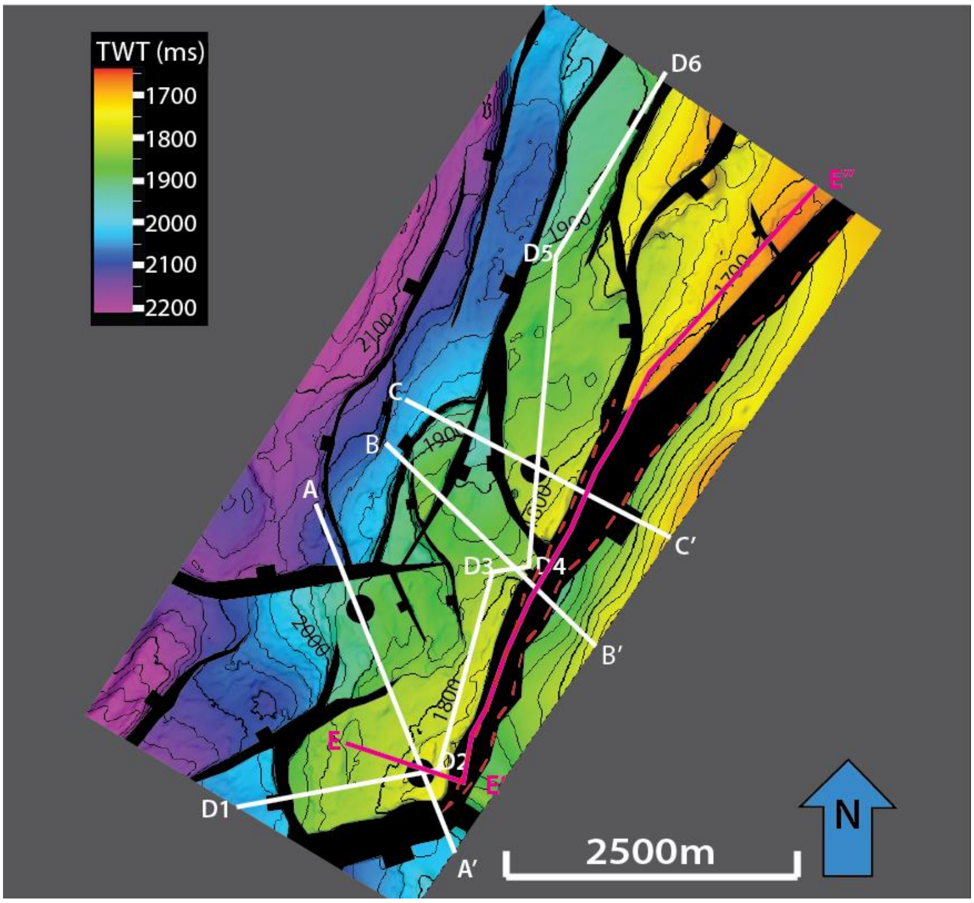

Figure 5.37: Seismic composite cross sections A-A', B-B', C-C', D1-D6 and E-E'''

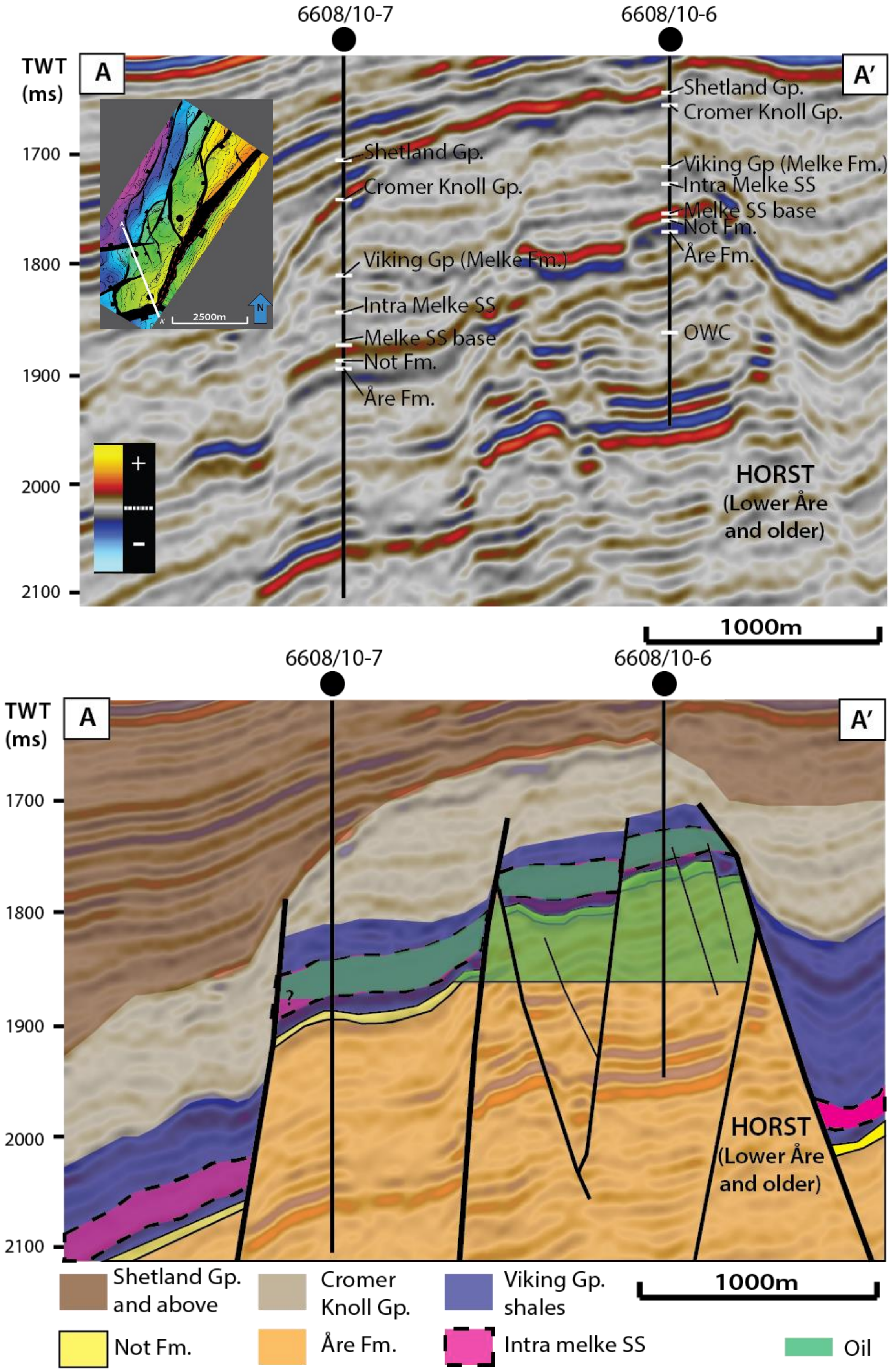

Figure 5.38: Seismic cross section A-A' of the Svale structure, through wells 6608/10-6 and 6608/10-7. Welltops from Petrel. With/without interpretation. See figure 5.41 for location.

The horst annotated in figure 5.38 is part of the same horst complex running along the eastern/southeastern boundary of the Svale and Svale North structures. It extends all the way north until it is no longer hidden by the normal fault in the top reservoir map.

The horst(s) become more prominent as you move to the north. This can be seen in figure 5.39:

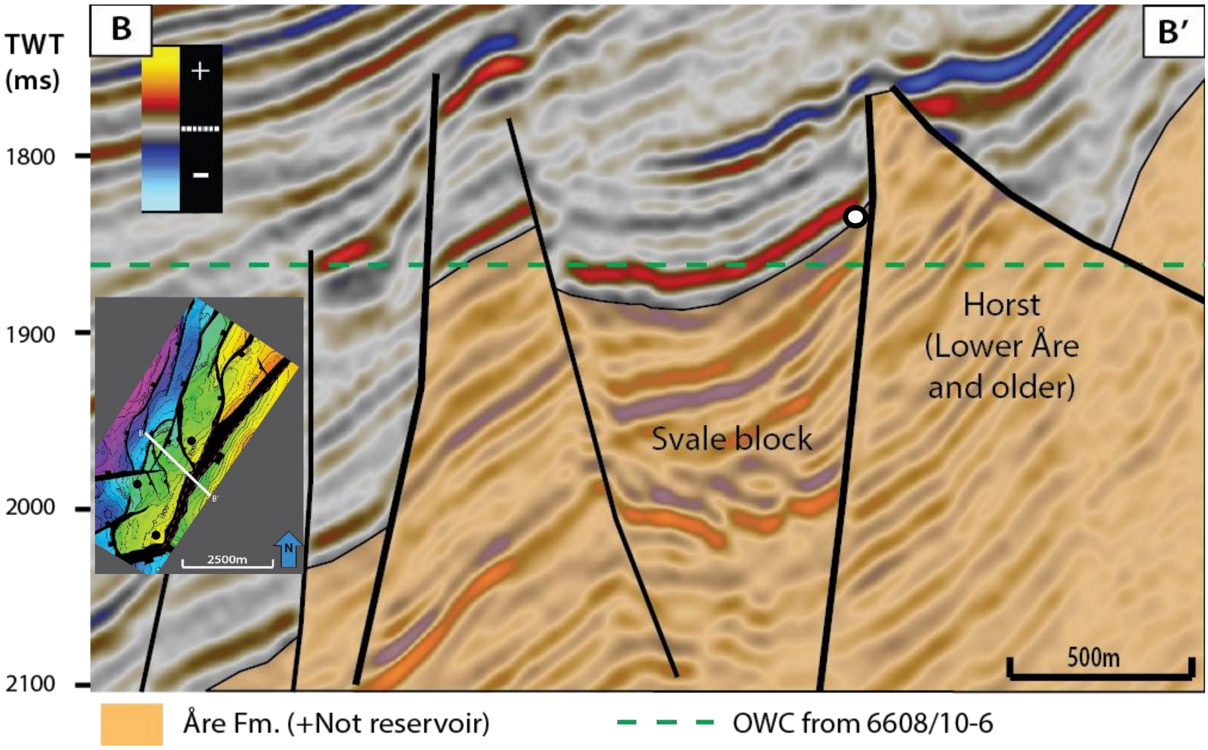

Figure 5.39: Seismic cross section B-B’. See figure 5.41 for location. Structural spill point marked (not a fault spill point).

Crossline B-B’ runs close to the interpreted structural spill point of the Svale structure. The location is where the top reservoir in the Svale block meets the horst. The interpreted spill direction is perpendicularly into the plane B-B’. Note that the spill point is shallower than the OWC from 6608/10-6.

The seismic cross section B-B’, shows the horst being more prominent than in crossline A-A’. Crossline C-C’, in figure 5.40, runs through the Svale North structure, including the discovery well. The horst is still a prominent structural feature, though still covered by the normal fault plane in map view.

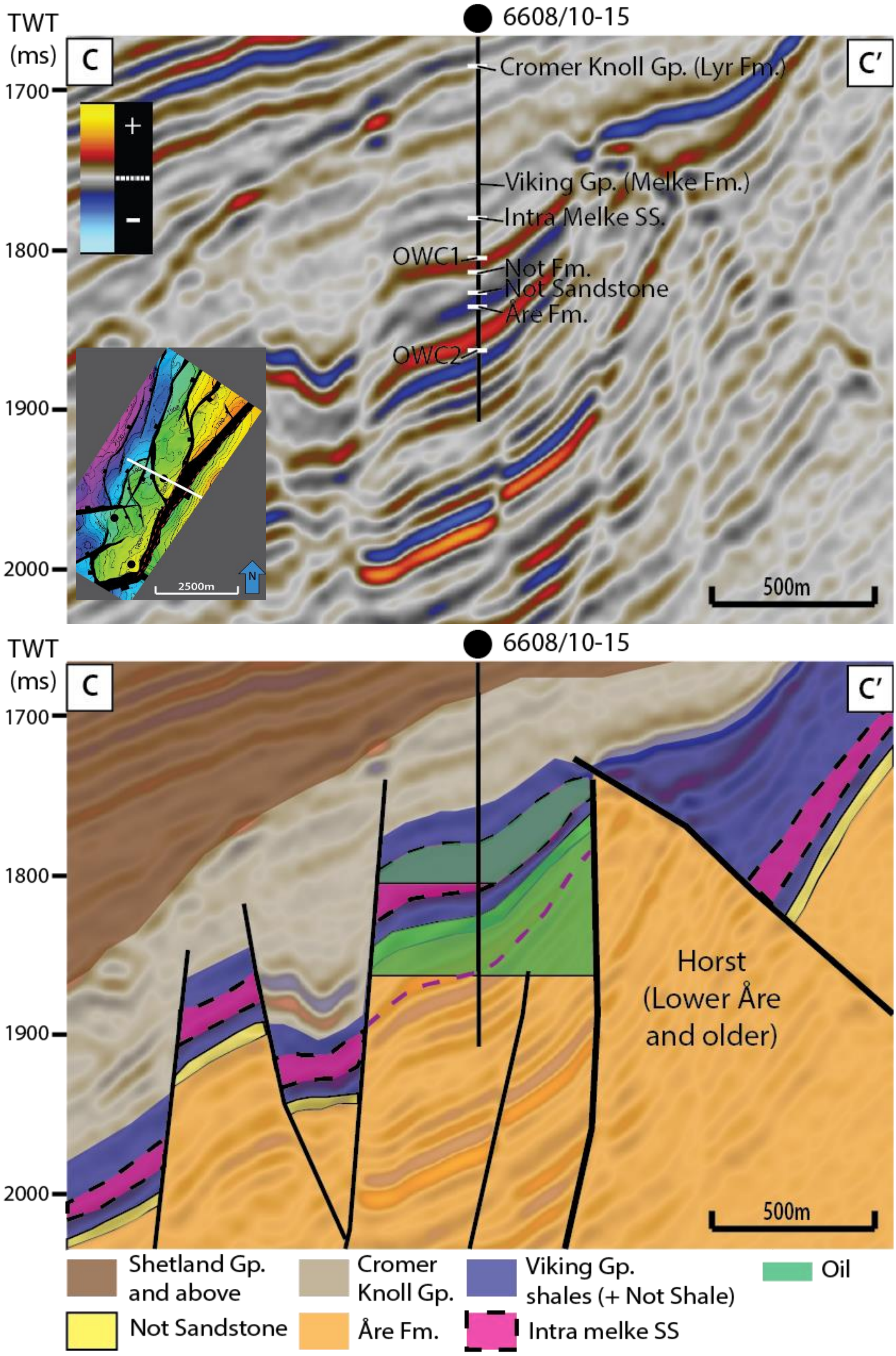

Figure 5.40: Seismic cross section C-C'. Well tops from Petrel. Dotted purple line represent a possible base seal.

A seismic composite cross section E-E'' was picked to run from Svale and into the horst structure, running along its strike towards the northeast. Figure 5.37 shows the location and geometry of the composite line. The top of the reservoir section is difficult to track because the horst is itself faulted, and with the main normal fault cutting the Åre Formation at different stratigraphic levels. This makes the top reservoir interpretation in figure 5.45 highly uncertain. Inside the Åre Formation there is a sequence with high impedance-contrast reflectors coinciding with a coal rich interval seen in the well. The base reflector of this interval, a high amplitude red peak, was tracked along the composite section with a high confidence, and gives a good picture of the general topography of the horsts.

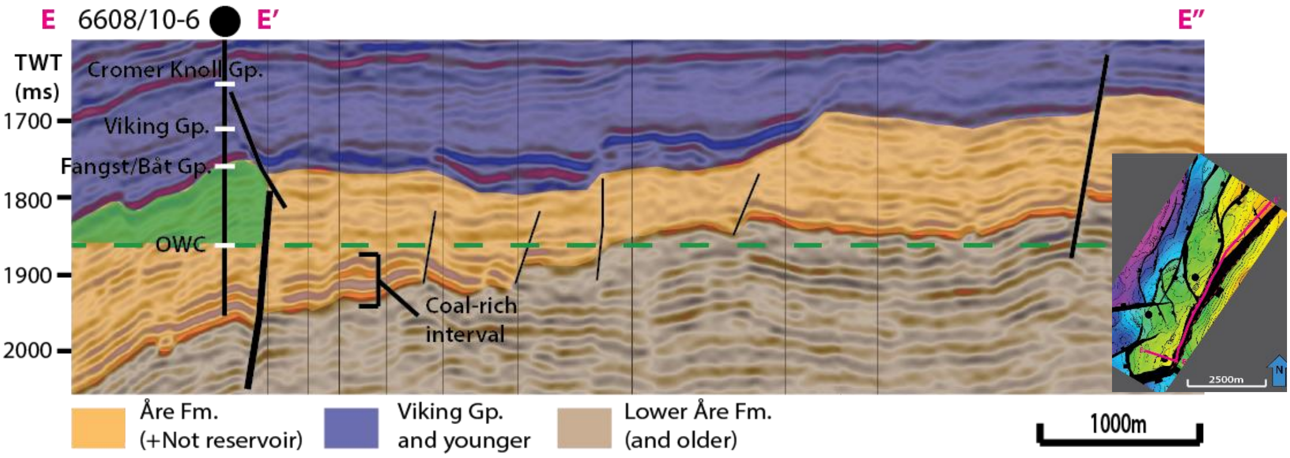

Figure 5.41: Seismic cross section E-E''.

Pressure measurments from all the wells were plotted together with a hydrostatic gradient calculated with an assumed brine density of 1025kg/m^3.

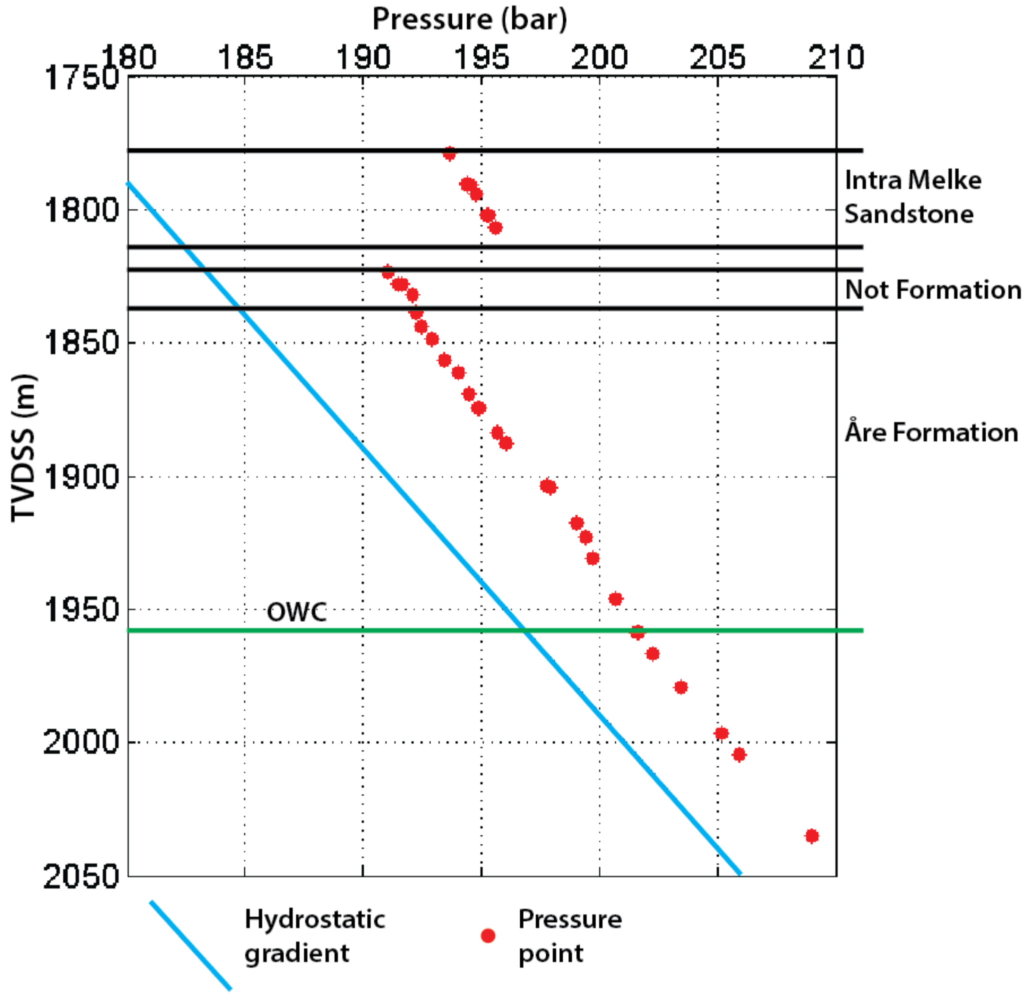

Figure 5.42: Pressure data from well 6608/10-6. Reservoir formations and oil water contact are marked. Assumed brine density = 1025 kg/m^3.

Pressure data from 6608/10-6 was collected in the Intra Melke Formation, the Not Formation and the Åre Formation. There is a pressure decrease between the Melke sandstones and the Åre/Not reservoir. The Åre Formation is approximately 4 bars overpressured in the water zone, based on an average brine density of 1025kg/m^3.

Pressure data from well 6608/10-7 was collected in the Intra Melke Formation and the Åre Formation. A pressure decrease was observed between the Melke Sandtones and There is an overpressure of approximately 4 bars in the top of Åre formation

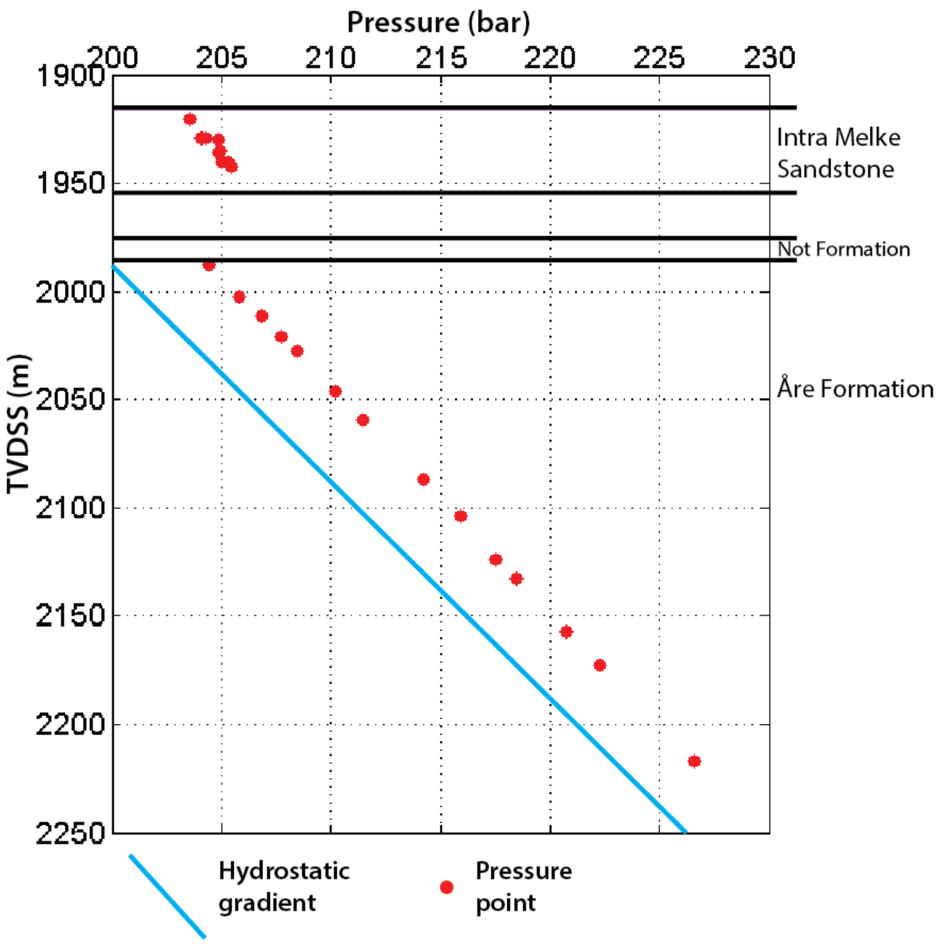

Figure 5.43: Pressure data from well 6608/10-7. Reservoir formations are marked. Assumed brine density = 1025 kg/m^3

Figures 5.42 and 5.43 sums up the pressure measurements done in the two wells on the Svale structure.

Pressure measurements were done in well 6608/10-15 on the Svale North structure. Valid pressure samples were acquired in the Intra Melke Formation, Not sandstone and the Åre Formation. A pressure decrease is observed across shales in the lower Melke Formation and Upper Not Formation. The Åre/Fangst reservoir is affected by pressure depletion from production in the Svale field. No gradients are established in this zone. The OWC in the Åre Formation is not based on the pressure data.

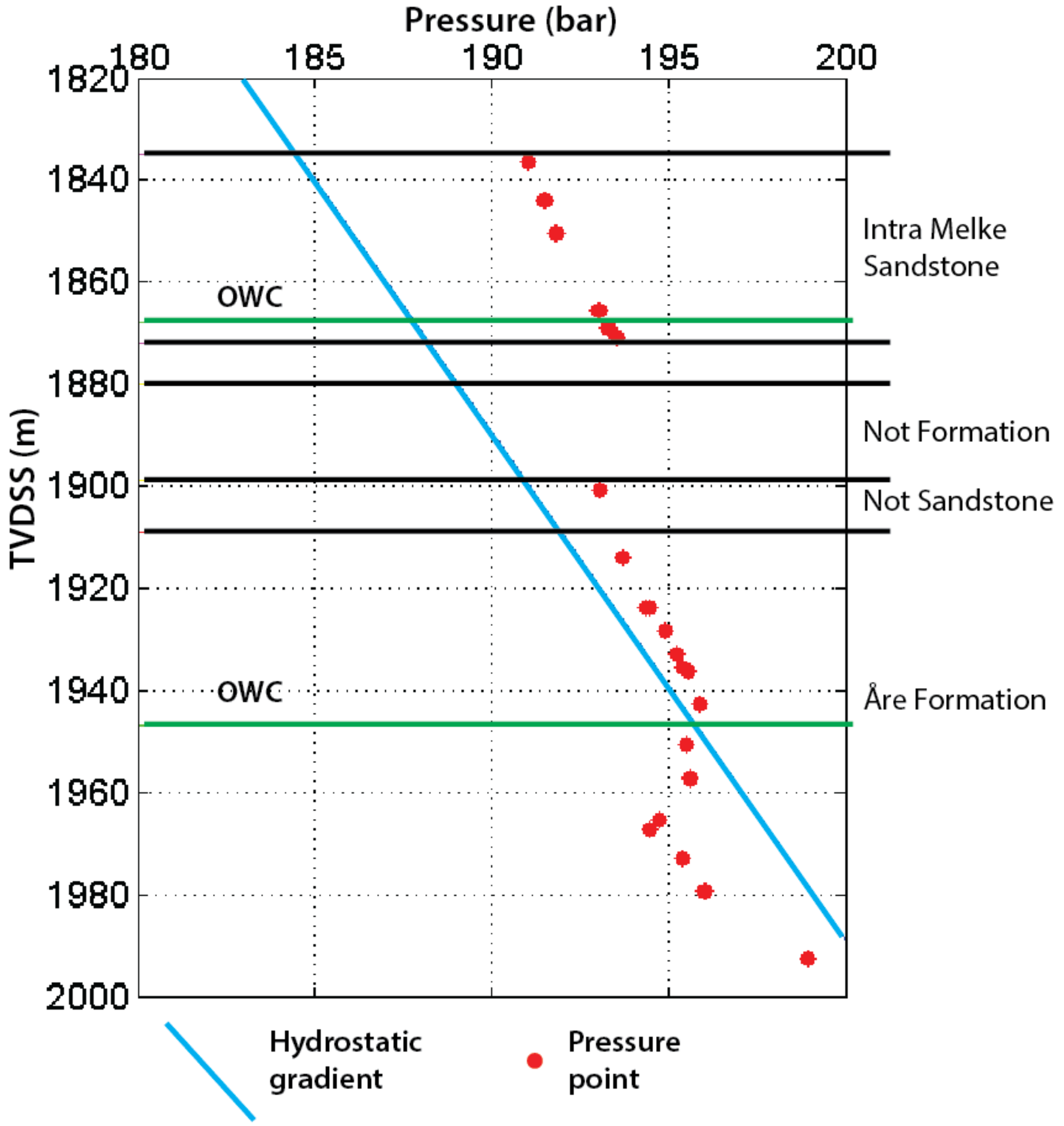

Figure 5.44: Pressure data from well 6608/10-15. Reservoir formations and oil-water contacts are marked. Assumed brine density = 1025 kg/m^3.

Seismic composite cross line D-D6 was picked to run through the wells and through interpreted structural spill points of the two structures. The depth of the structural spill point of the Åre/Not reservoir in Svale is at 1848 ms TWT, which corresponds to 1931 m (+/- 25 m). The structural spill point north of Svale North is at 1890 ms TWT, corresponding to 1980 m TVDSS (+/- 25 m). The Structural spill point in the Intra Melke Formation in Svale North is at 1885 m TVDSS (+/- 25m).

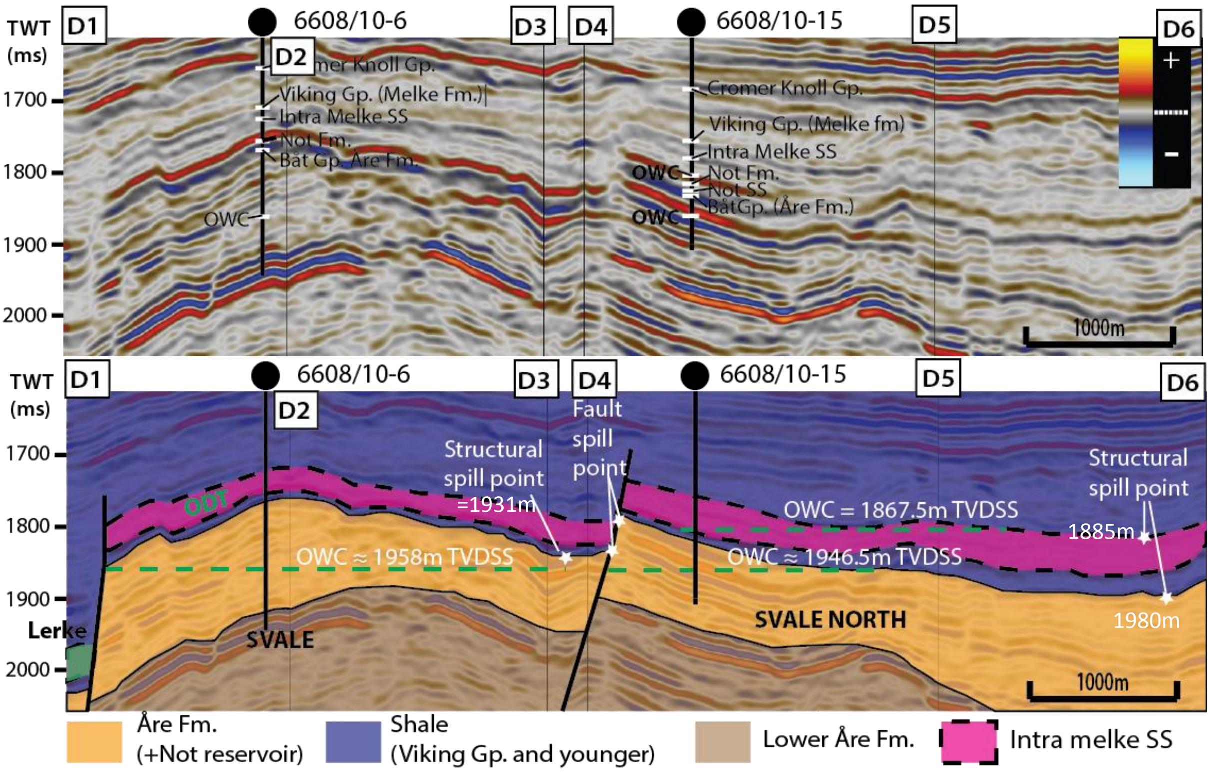

Figure 5.45: Composite cross section D-D6. With and without formations interpreted. Major faults are interpreted. Well tops from Petrel.

5.2.5 Falk

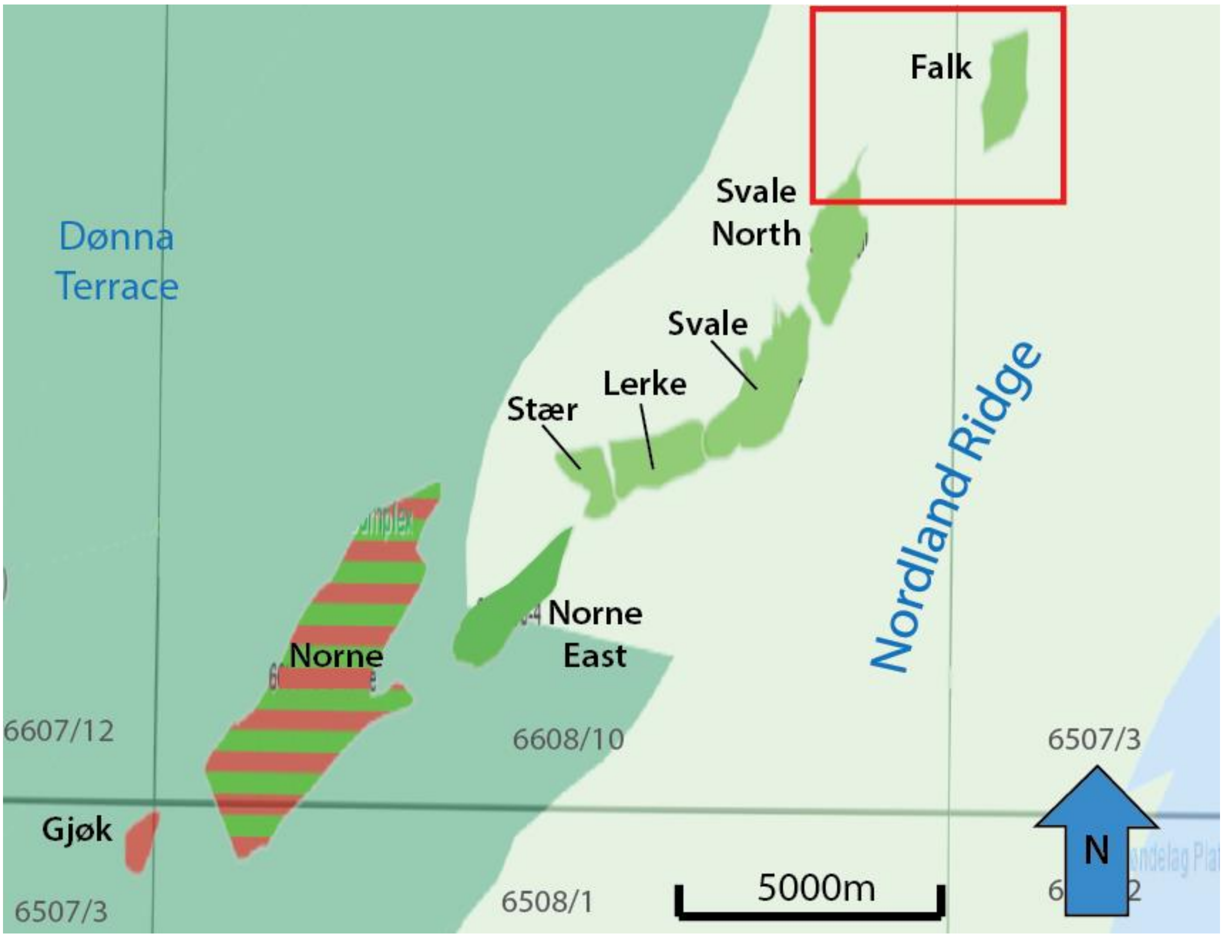

Figure 5.46: Location of the Falk Structure. Modified from NPD.

The Falk structure is situated on the north-western edge of the Nordland Ridge, on the Rødøy High. It is located approximately 4 km north-west of the Svale North Structure. The structure is a shallowly dipping fault block enclosed by faults on the N, E and S, but partly open in the west (north-west). The structure is down-faulted relative to the hanging block/horst in the east. The area is structurally complex, and the general fault geometry can be seen on a variance map extracted along the top Åre Formation interpretation.

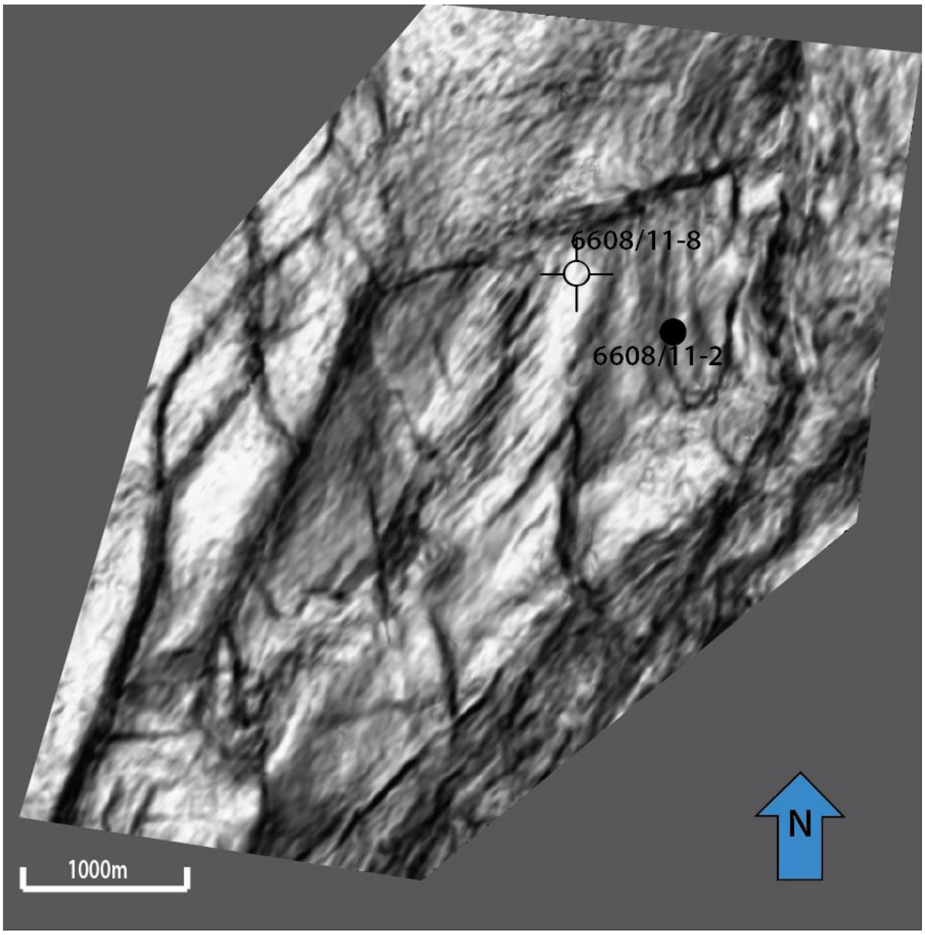

Figure 5.47:

Variance map from top Åre surface. Enhances edges along surface. Well locations are added.

Well 6608/11-2 was spudded on the Falk structure on October 28 2000. The objective of the well was to prove Hydrocarbons in sandstones of the Lower Jurassic Åre Formation and in the Upper Jurassic Melke Formation. The well was was drilled to a total depth of 2215 m MD in the Late Triassic Grey Beds. Several good reservoir zones were encountered in the Åre Formation and in the Grey Beds. A silty Intra Melke Formation was encountered. The Intra Melke Formation did not have the same reservoir quality as the other reservoir sequences. The reservoir sequence at the top of the Åre Formation proved to be oil bearing. The Melke Formation, the Lower Parts of Åre Formation and the Triassic reservoirs were all water-wet. No oil water contact was established, but an oil sample was taken at 1747 m MD and a water sample was taken at 1773 m MD. This establishes an ODT 1710.7 m TVDSS and a WUT 1736.7 m TVDSS. The oil was biodegraded. In the cores, there were good shows down to 1762 m MD.

13 years later, on the 3rd of June 2013, well 6608/11-8 was spudded down-flank on the Falk structure, 650 m WNW of the discovery well. The primary objective of the well was to apprise the upper-Åre hydrocarbons from the Falk discovery. The secondary targets were Intra Melke sandstones and lower Åre Formation sandstones. The well penetrated sandstones within the Melke and Åre formations as expected. A 9 m thick Ile Formation, consisting of sandstone, was also present. The Ile formation was not prognosed. All the Formations were water wet, and no shows were observed on cuttings from the well.

The lithostratigraphic information from the two wells on the Falk structure, is summarized in table 5.13.

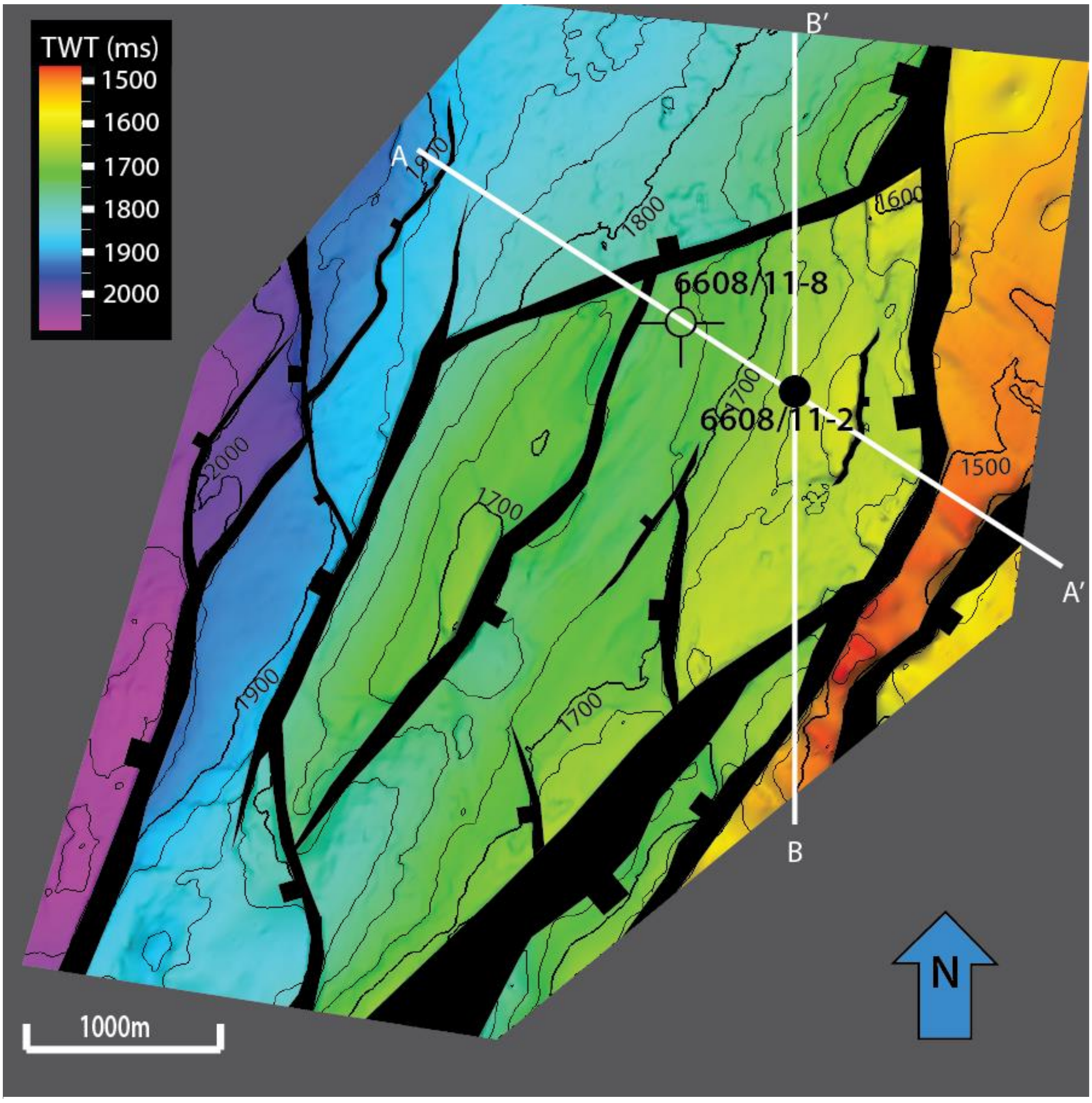

Figure 5.48: Top reservoir surface (Åre Formation). Contour increment = 25 ms. Locations of wells and seismic cross sections are added.

Table 5.13: Lithostratigraphy from well 6608/11-2 and /11-8. All formations from top Melke Formation and down to TD are included.

6608/10-2

Formation	MD (m)	TVDSS (m)	Thickness (m)
Melke	1613,5	1577,5	91,5
Not	1705	1669	31
Åre	1736	1700	328
Grey Beds	2064	2028	>151

6608/10-8

Formation	MD (m)	TVDSS (m)	Thickness (m)
Melke	1613,5	1588,5	116
Intra Melke SS	1729,5	1704,5	42,5
Melke	1772	1747	8
Not	1780	1755	34
Ile	1814	1789	9
Åre	1823	1798	>147

The Intra Melke Sandstones were present in the down-flank well 6608/11-8, but of poor quality. In well 6608/11-2 they were very poorly developed, and thus not included in the lithostratigraphy. The second well also encountered the Ile formation, which is not present in the discovery well. This formation has to pinch out between the two wells.

Pressure measurements are plotted for both wells on the structure. The plots are presented in figures 5.49 and 5.50

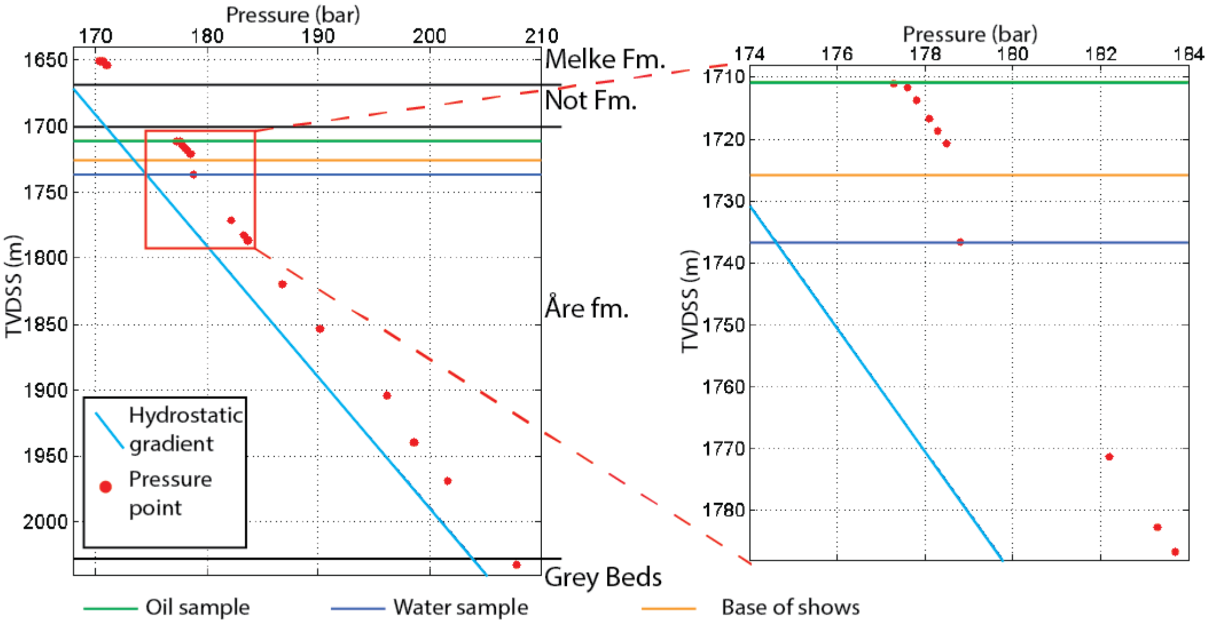

Figure 5.49: Pressure data from well 6608/11-2. Formations and important depths are marked. Assumed brine density = 1025 kg/m^3

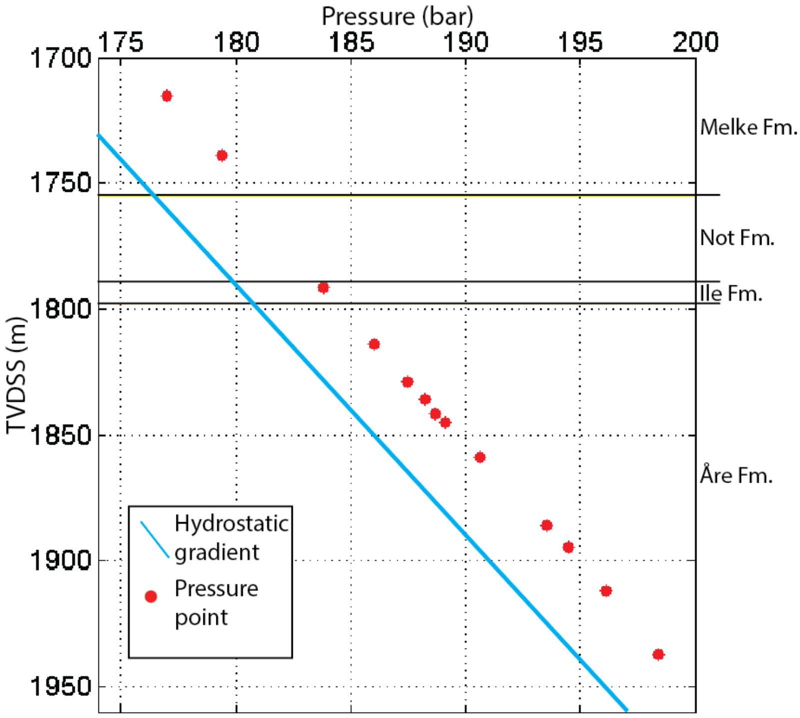

Figure 5.50:
Pressure data from well 6608/11-8. Reservoir formations are marked. Assumed brine density = 1025 kg/m^3

In well 6608/11-2, an oil gradient is present in the upper part of the Åre Formation. The deepest pressure point fitting this oil gradient is at 1757 m MD (1720.7 m TVDSS). The ODT defined by the fluid sample containing oil at 1710.7 m TVDSS can be redefined to the depth of the deepest pressure point on the oil gradient. At least when there are good shows down to 1725.7 m TVDSS (1762 m MD) in the cores. The ODT is therefore set at 1720.7 m TVDSS.A pressure decrease is observed between the lowest pressure point in the oil zone, and the upper water sample at 1736.7 m TVDSS. This introduces the possibility of a base seal. The water zone is approximately 4 bars overpressured, based on an assumed brine density of 1025 kg/m^3.

In well 6608/11-8, the water zone in the top of the reservoir is approximately 3.6 bars overpressured. The overpressure in the Åre Formation varies between 3.54 – 4.01 bars.

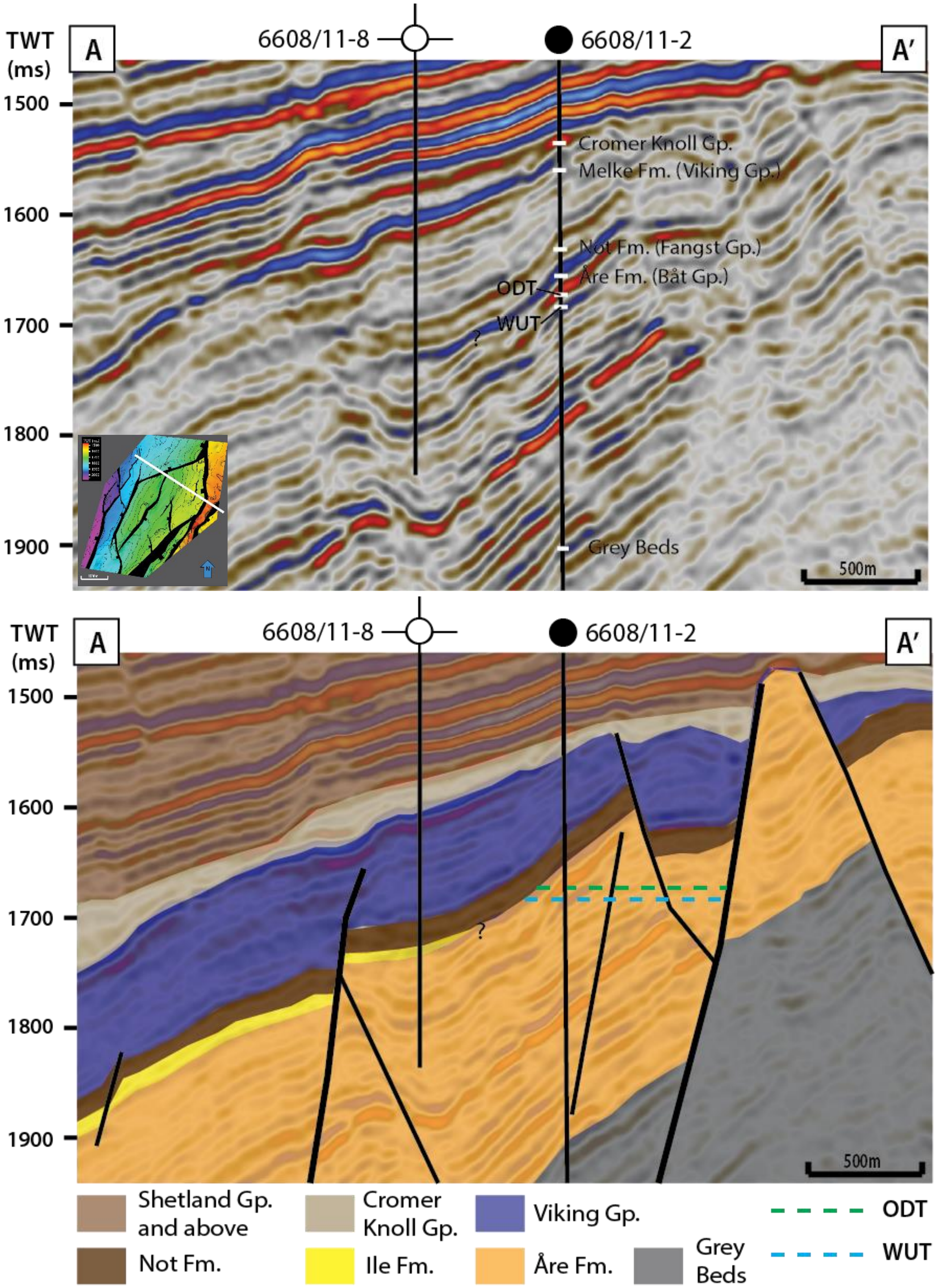

Figure 5.51: Seismic cross section A-A'. See figure 5.48 for location. With and without interpretation. Well tops from Petrel.

Figure 5.51 presents a seismic cross section through both the wells located on the Falk structure. Only well tops from well 6608/11-2 is used, as the /11-8 well's checkshots were not available. The interpretation in the /11-8 well location is based on the lithostratigraphic information, and using the checkshots from well /11-2 to get an idea of the relative thickness of the formations in the time domain. The interpretation of the Ile formation is uncertain, but the formation pinches out before reaching the up-dip well.

The layers in the Åre Formation is intersecting the Not Formation discordantly, making the top-reservoir/top Åre surface an angular inconformity. This is better illustrated in a south – north oriented cross section. The angular unconformity is well presented in the seismic cross section B-B' in figure 5.53.

A brightening of the top Åre reflector, a blue trough (decrease in acoustic impedance), can be seen in parts of the structure. One of the reflectors that are discordant to the top Åre reflector is frequently standing out as a bright red peak. This reflector is centered at the ODT in well position. An interval average RMS amplitude attribute was extracted on the top Åre interpretation, to highlight amplitude changes. Note the bright area and the amplitude shut off just south of the discovery well.

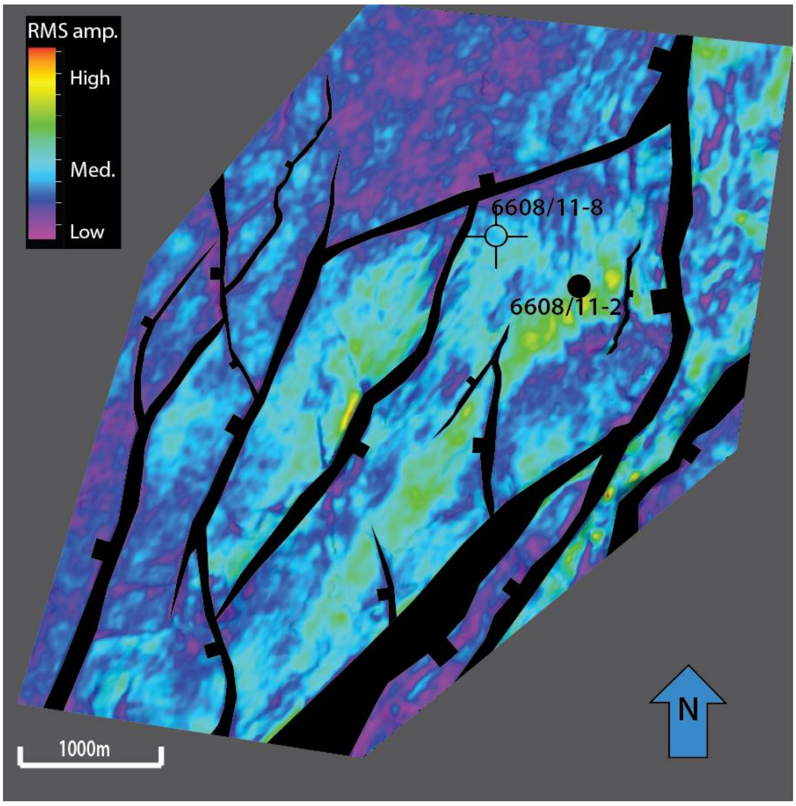

Figure 5.52: RMS amplitude map from the top Åre surface.

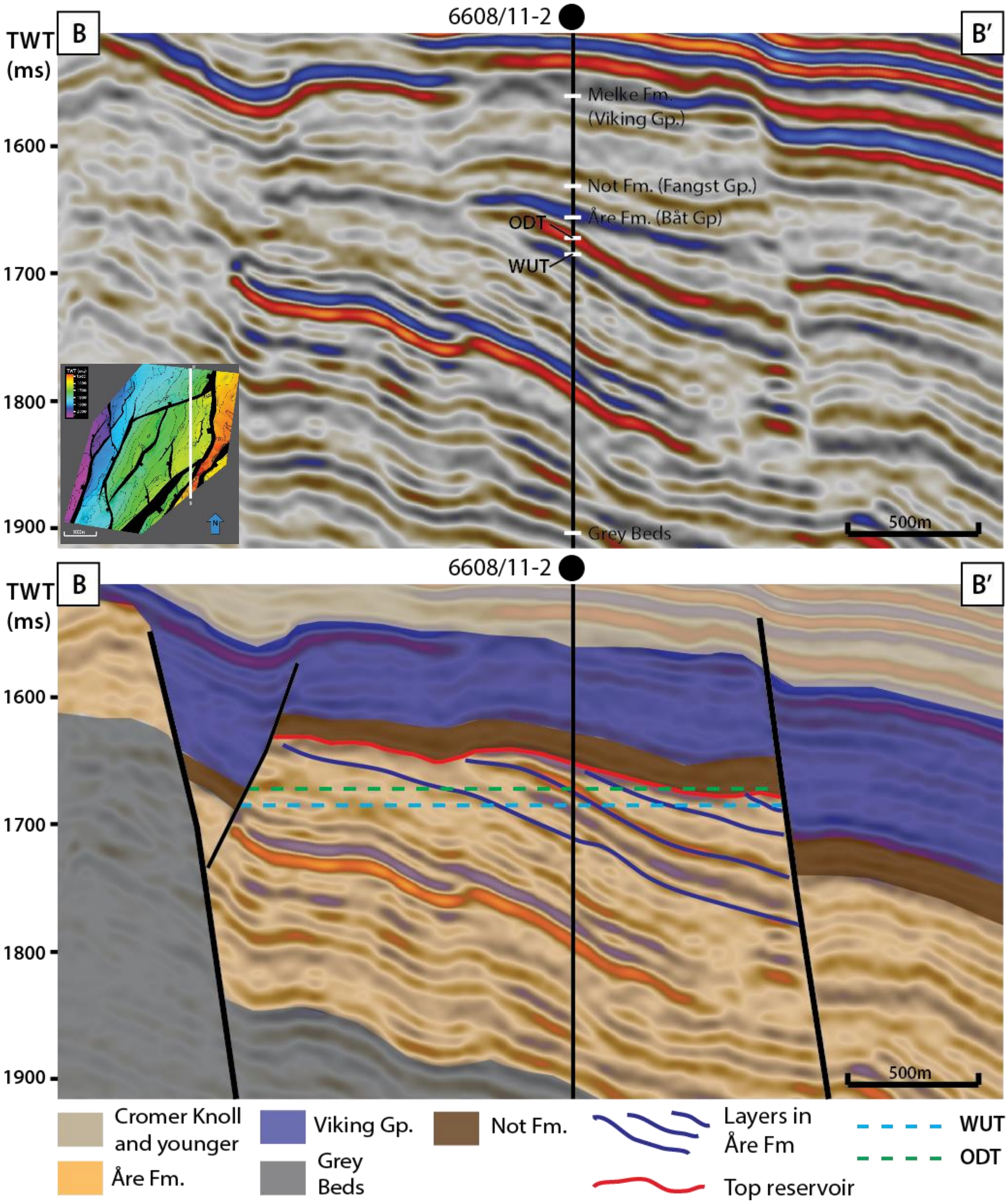

Figure 5.53: Seismic cross section B-B'. See figure 5.48 for location. With and without interpretation. Well tops from Petrel.

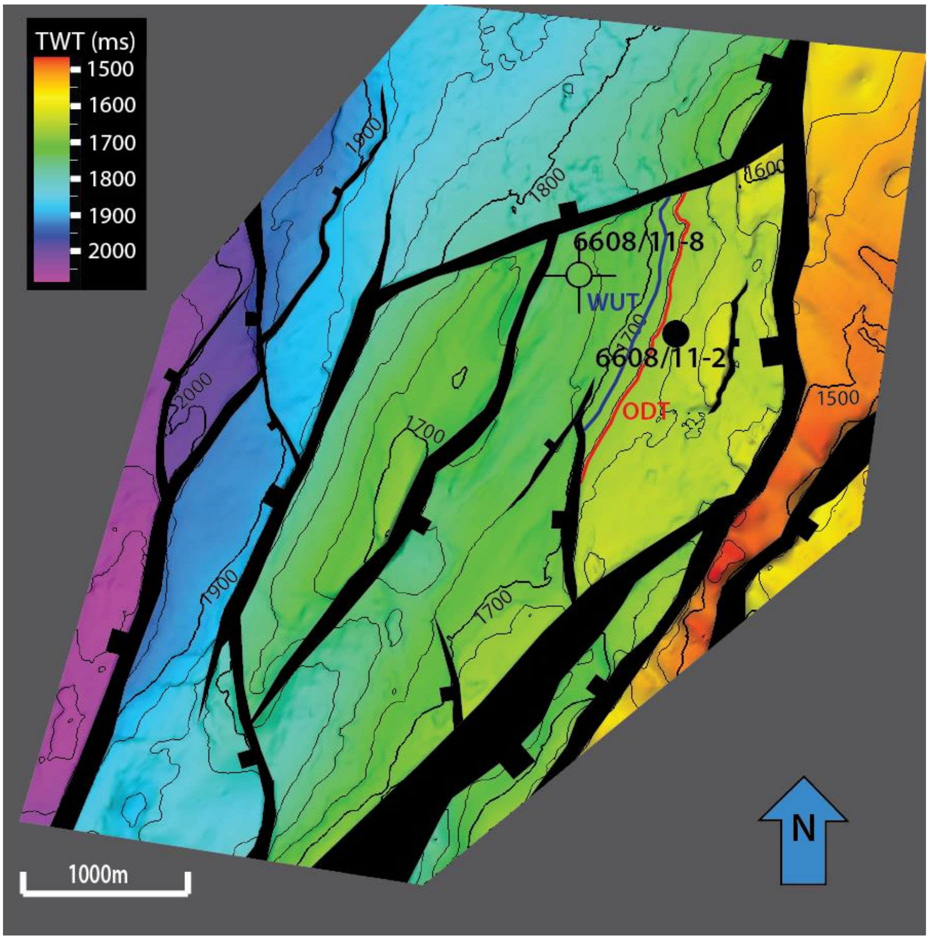

Figure 5.54:
Top reservoir surface with ODT and WUT marked on the map.

Provided an OWC between the ODT and WUT, the outline of the oil accumulation will follow the faults surrounding the structure, and lie between the ODT and WUT annotated in figure 5.54.

If a base seal situation is assumed, the contact can be deeper than the WUT.

6. Discussion

6.1 Geological constraints on hydrocarbon columns in the Cretaceous deposits.

The main focus in the study area on the Dønna Terrace has been the structures with accumulations of hydrocarbons in the Lysing Formation. The Intra Lange Formation sandstones have not been investigated in the seismic cross section due to the lack of interpretable reflectors. In contrast, the Lysing Formation, or the Top of the Cromer Knoll Group (Lange Formation when Lysing is absent), has a relatively clear response. The seismic signature varies depending on thickness, reservoir fluid, overburden and the reservoir fluids. In the structures investigated in the thesis, with reservoirs consisting of turbidite complexes, the top of the Lysing sandstones are generally represented by decrease in acoustic impedance (a blue through in the provided seismic), when the formation is of sufficient thickness. (Fugelli and Olsen, 2007).

Looking at the distribution of the turbidite deposits is crucial when proposing a fill-spill model for the area. According to Fugelli and Olsen (2007), the Lysing Formation deposits in the study area are sourced mainly from the north. This can be seen on the conceptual model in figure 6.1.

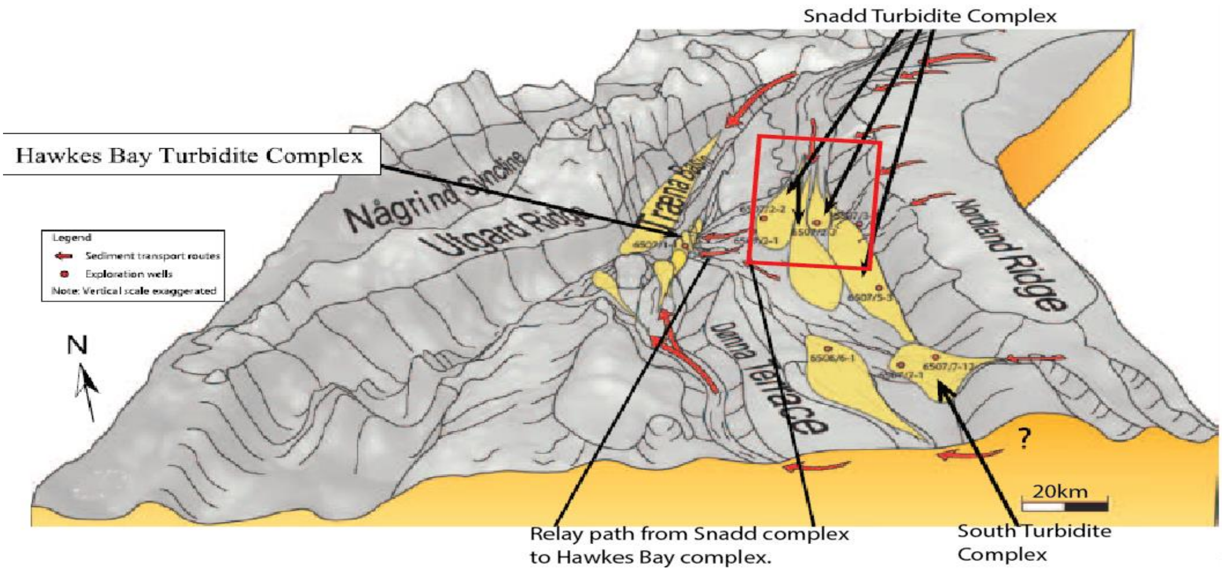

Figure 6.1: Depositional model for the Lysing Formation on the Dønna Terrace. Approximate location of the study area eclosed in the red square. Modified from Fugelli and Olsen (2007).

As can be expected, contribution from the Nordland Ridge, east of the Snadd structure, is also described in Fugelli and Olsen's model. All the investigated structures; Marulk, Snadd North and Snadd Outer are included in what Fugelli and Olsen defines as "Snadd Turbidite Complex".

The RMS-amplitude map from the interpreted top Cromer Knoll Group, earlier presented in figure 5.15, provides a basis for the interpretation of the sand deposit distribution.

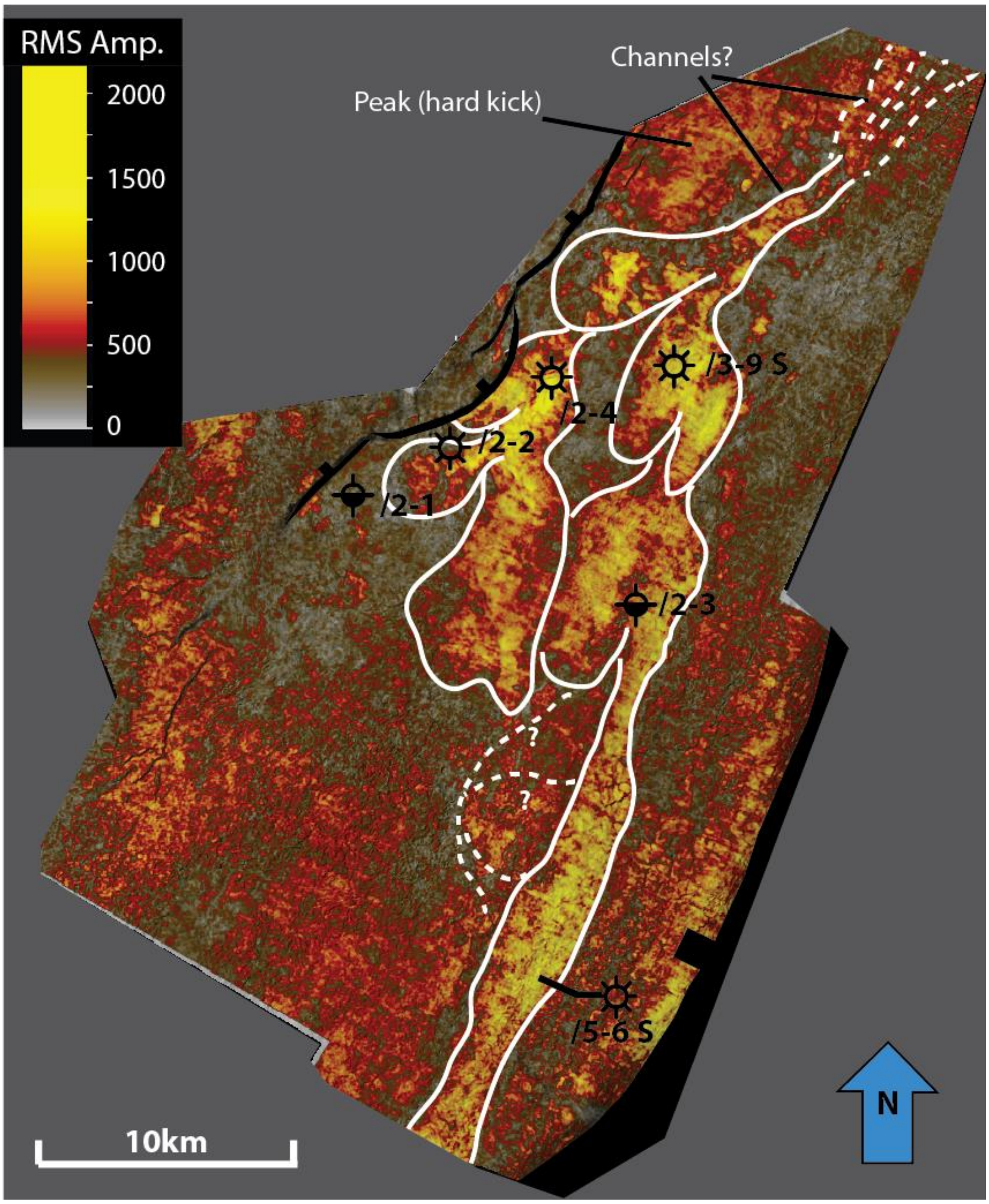

Figure 6.2: Interpreted version of figure 5.15. RMS amplitude surface attribute on top Cromer Knoll surface. Well locations are added. The "peak/hard kick" annotation in the north means that in this area, the top Cromer Knoll reflector is a peak rather than the through that usually represents the top Cromer Knoll Gp. When the Lysing formation is present. The RMS attribute squares the amplitude values, so it does not discriminate between positive and negative amplitudes.

Figure 6.2 shows an interpretation of the Lysing deposits. The deposits probably extends a bit further than the interpreted lobes. For example, there is Lysing Formation sandstone in well 6507/2-1, but the thickness is only 4 meters in this location. The most distal parts of the lobes are too thin to register a clear seismic response, and are therefore not visible in the RMS map. The channels in the north are not clear in seismic cross section. They are seen as brighter sections, but a seismic representation of channels cutting into the underlying deposits is not clearly seen. The geometry seen on the RMS map is the reason for the suggestion of channels, in addition, Fugelli and Olsen's model showing the turbidites coming from the north gives more substance to the interpretation. Even though specific locations of channels are not found, it is a probable assumption that some of the Lysing sands in the Snadd structures are sourced from the Ridge in the east. Fugelli and Olsen's conceptual model in figure 6.1 is also based on this assumption.

6.1.1 Marulk

The gas water contact was not encountered in any of the Marulk wells. Two alternatives for the accumulation in Marulk will be presented. Following the observations from the structure, presented in chapter 5.1.1, there are a set of observations to help reach a conclusion. A short repetition of these is given:

- Well data:
  - All three wells have Lysing formation sandstones in them. Two wells show a gas filled Lysing Formation, while the other is dry. With the assumption that the Lysing Formation exhibits pressure communication throughout the structure, the contact must be located between base Lysing in well 6507/2-4 and top Lysing in well 6507/2-1. This gives a GWC between 2834.5 and 2851 m TVDSS. There are uncertainties connected to the assumption of communication between the gas filled wells and the dry well.
- Seismic interpretation/observations:
  - The interpreted structural spill point is at 2872 m TVDSS +/-25 m.
  - Based on the topography of the top Cromer Knoll Gp. and the RMS amplitude map, a spill from Marulk to Snadd Outer is a reasonable scenario. The

composition of the gas is similar. The greatest uncertainties of this model is the assumption of communication between the Lysing sands in Marulk and the Lysing sands in Snadd Outer.

- Brights and other features in the overburden is observed in the seismic.

- Pressure data:
  - Pressure measurements from well 6507/2-2 and 6507/2-4 point to pressure communication between the wells. Data from 6507/2-1 was not available.
  - The Lysing and Intra Lange formation sandstones exhibit a large overpressure.
  - As the water zone was not encountered and tested in the Lysing Formation, an exact overpressure cannot be firmly determined.

Alternative 1: Fill spill from Marulk to Snadd Outer:

The pressure in the water zone of Snadd Outer is accurately documented in well 6507/3-9 S. We have no pressure measurements from the water zone in Marulk. To estimate this, a pressure gradient of 0.227 bar/m was calculated based on linear regression on the pressure points from the Marulk gas zone. If the Marulk gas spills at 2872 m TVDSS, it can be assumed that the pressure follows this gradient down to the gas-water contact at spill point depth. This estimates a pore pressure of 375.55 bar at the GWC/spill point, giving an overpressure of 86.7 bars if an average brine density of 1025 kg/m^3 is assumed for the hydrostatic gradient. The overpressure in the water zone in Snadd Outer is calculated to be 89.03 – 89.09 bar using the same brine density. The difference of approximately 2.7 bars shows that the structures are not in pressure communication. Together with the WUT at 2851 m TVDSS provided by well 6507/2-1 (assuming pressure communication with the gas filled reservoir), this information makes the spill model from Marulk to Snadd Outer a low probability scenario.

Alternative 2: Underfilled Marulk structure:

An underfilled Marulk structure is a possible scenario. The two main alternatives resulting in this situation are:

1) The hydrocarbon supply has not been sufficient to fill Marulk to its spill point.
2) The structure has been/is leaking.

The presence of other hydrocarbon filled structures in the area, along with the fact that there has been hydrocarbon migration into the structure, makes the first alternative improbable. Since Marulk has hydrocarbon accumulation, it is highly unlikely that the supply would be insufficient to fill the rest of the structure.

The seismic shows some features that may indicate the presence of gas in the overburden. A seismic cross section through well 6507/2-2 was previously presented in figure 5.6. Some brights can be seen and also dim zones. The dim zone is best seen the top Shetland Group reflector, or the peak approximately 50 ms under the Top Rogaland Group reflector. These reflectors are clearly dimmed. There seem to be slightly lower average amplitudes in the entire Shetland Group below the dim zone of top Shetland Gp. This could reflect a gas chimney in this zone. Gas chimneys are believed to represent cap rocks with irregularly distributed gas charged zones as a result of hydro fracturing or tectonic fracturing of the low-permeable rock.

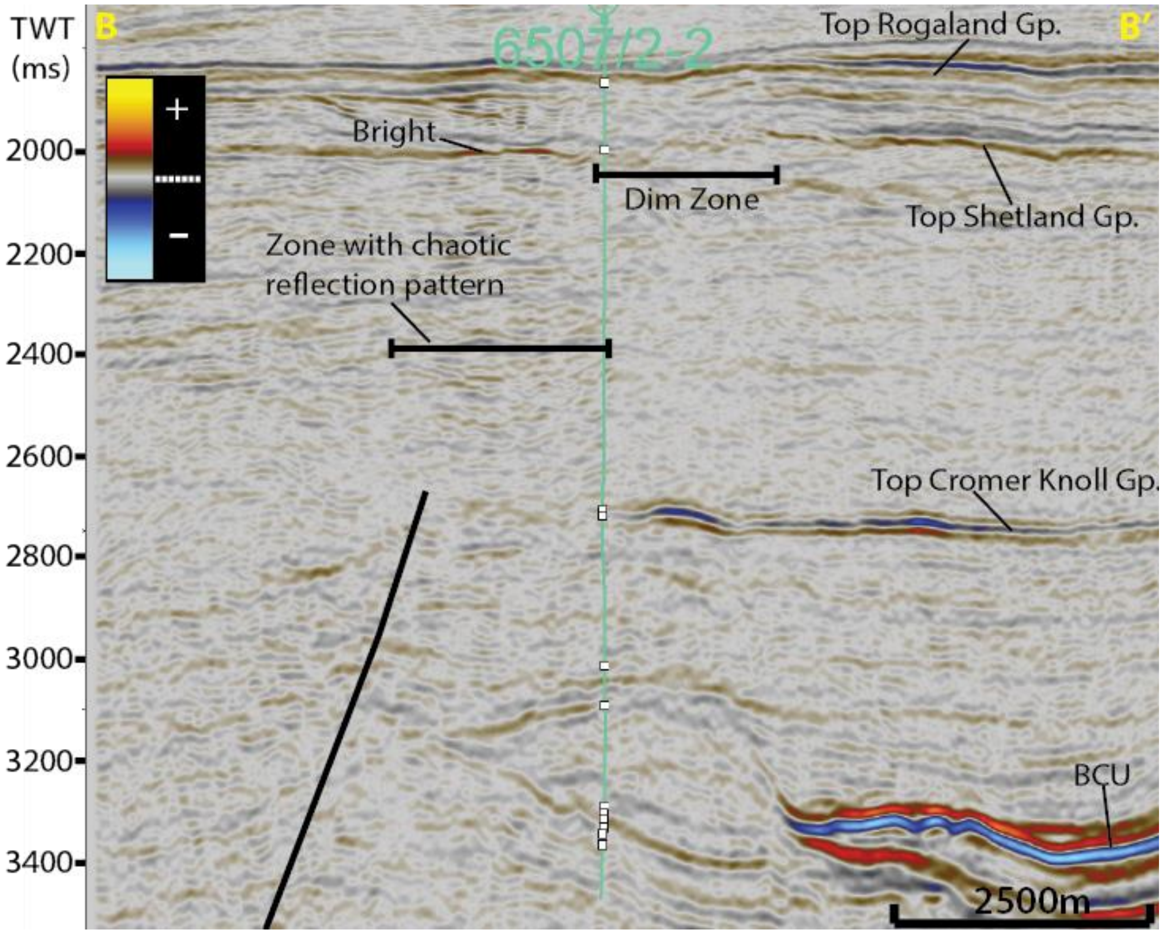

Figure 6.3: Modified version of figure 5.5.

To further investigate the possibility of leakage in the area, an interval average RMS amplitude surface attribute was extracted on the interpreted top Shetland Group surface. The same was done on the peak approximately 50 ms under the top Rogaland reflector.

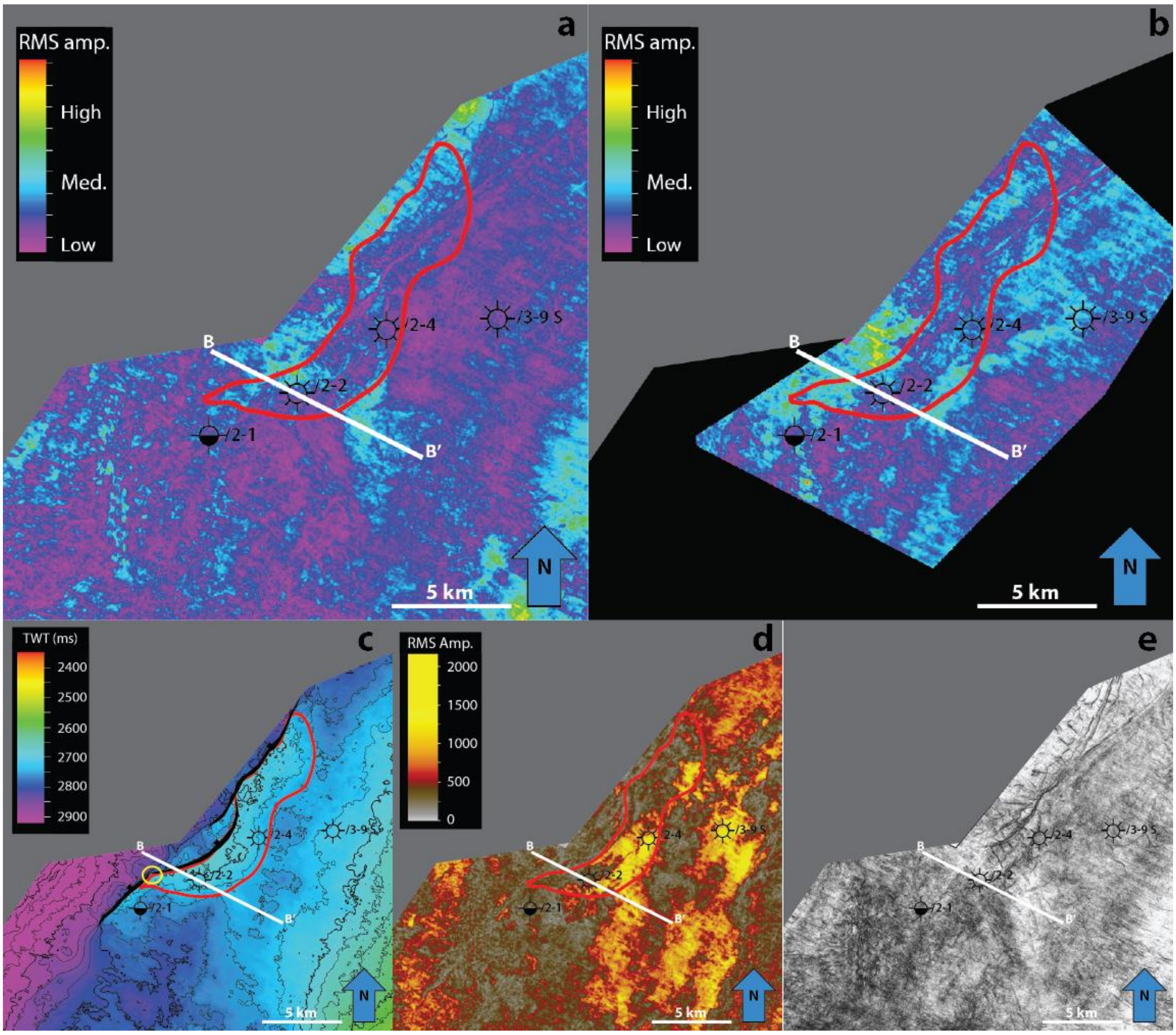

Figure 6.4: a: RMS amplitude +/-20 ms on top Shetland Gp. surface.
b: RMS amplitude +/-20 ms on surface interpreted on peak 50 ms below top Rogaland Gp.
c: Top Cromer Knoll Gp./Lysing Fm. RMS amplitude map.
d: Top Cromer Knoll Gp. Surface.
e: Variance attribute on top Shetland Gp. Surface.
The red line represents the approximate accumulation outline.
Fault intercection encirceled in yellow

No clear delineation of the approximate GWC is seen in the RMS amplitude maps. Dim amplitudes seem to follow a geometry similar to the geometry of the faults defining the Marulk structure's NW border. The variance map (6.4 e) on the Top Shetland reveals that the faults or associated fractures seem to extend all the way up through the Shetland group. Bright zones are seen, especially two zones north and east of well 6507/2-2. When considering possible leakage, it is tempting to propose that the dim amplitudes following the faults (and associated fractures) are a result of gas that has leaked up through these. However, if leakage has occurred through the fault, this does not explain the remaining gas in Marulk. A highly speculative model is that the hydrocarbons have leaked into the fault at a depth coinciding with the depth of the unproven GWC, and then been distributed laterally along the fault plane, resulting in the dims following the fault/fracture pattern seen in the variance map. For example the fault intersection/junction encirceled in yellow, which is close to the approximate GWC, and also relatively close to bright zones, could be such a point.

A strong argument for an underfilled Marulk structure, is the dry Lysing Formation in well 6507/2-1. The top and base (only 5 m thick) of the formation is shallower than any possible structural spill point. Unfortunately, pressure points were not available to confirm pressure communication with the other wells. Shows are registered in both the Lysing Formation and the deeper Intra Lange Formation. This points to a deeper fill at some earlier point in time. A leaking Marulk structure is the most likely scenario, which will come back to in chapter 6.1.4.

6.1.2 Snadd North

The GWC is not encountered in the Snadd N structure. The WUT at 2827 m TVDSS in well 6507/2-3 and the GDT at 2799 m TVDSS from well 6507/5-6 S estimates the contact between these two depths. The hydrocarbon accumulation is dependent on the pinch-out of the Lysing Formation to avoid leaking up-flank. The structure seems to spill either to the south or north. The spill point between Snadd North and Snadd Outer is interpreted as deeper than the WUT, so a spill from Snadd North and north into Snadd Outer is unlikely, but the uncertainties connected to depth conversion could allow this.

A possible scenario is that the structure spills south of the coverage of the seismic provided for this thesis. A strong argument against the southward spill is that according to NPD’s Fact Pages, the discovery well of Snadd South segment; 6507/5-3, encountered a GWC in the Lysing Formation. The top Lysing Formation came in at 2839 m TVDSS (contact depth is not available). This means that the top of the Lysing Formation in the location of the discovery well in the Snadd South structure is deeper than the WUT from well 6507/2-3 (2827 m TVDSS). With the dataset provided for the thesis not covering this structure, a conclusion on the depth of a southern spill point in Snadd North is not reached.

The Lysing Formation in well 6507/2-3 was reported as dry, but the log shows some responses that could be interpreted as being associated with hydrocarbons. A section of the composite log is presented in figure 6.5. Note the response in the neutron and density logs, as well as the deep resistivity. If the formation was flushed before sampling, the GWC could be deeper than the WUT from the well (top of the Lysing Formation). This is speculative, but if this is the case, it is more likely that the Snadd North structure could be filled to the structural spill point between Snadd North and Snadd Outer, and the gas could spill northwards.

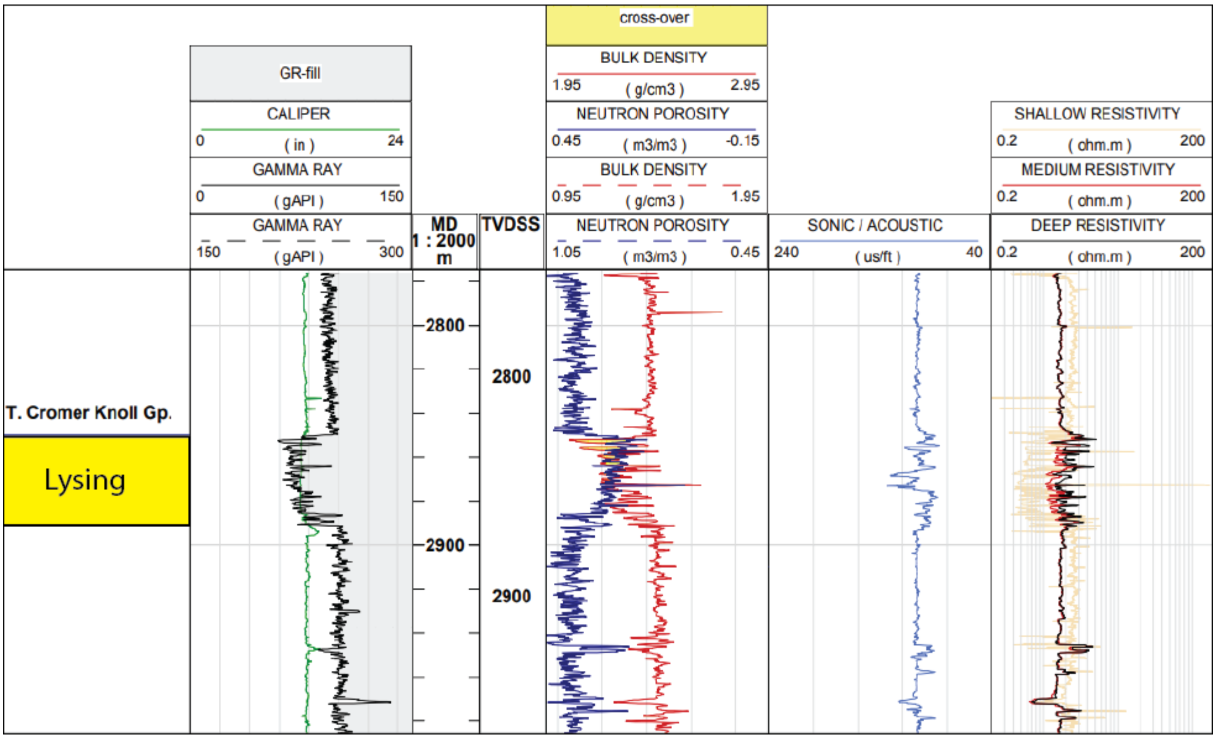

Figure 6.5: Composite log from well 6507/2-3. Modified from NPD.

A situation with an underfilled Snadd North cannot be excluded based on the available data. The most probable explanation for this situation would be that the structure had leaked. An overburden RMS amplitude map from the top Shetland Group was investigated, but no clear signs of leakage was identified over the Snadd North structure.

6.1.3 Snadd Outer

The Snadd Outer structure has a GWC at 2822.5 m TVDSS. The structural spill point interpreted between Snadd Outer and Snadd North is at 2824 m TVDSS. It is tempting to conclude that this spill point controls the hydrocarbon column in the formation, and that the gas spills southward into the Snadd North structure. See figure 5.16. The two structures are interpreted to be in pressure communication based on the similar overpressures.

Another alternative is that the formation spills northwards. Based on the topography of the interpreted surface and the RMS amplitude map from top Cromer Knoll Group, the latter seems less likely, but the uncertainties in the seismic interpretation and depth conversion from the well makes it a possible scenario. This spill situation is also annotated in figure 5.16.

The fact that the results from the well shows a high gas saturation also in the sands below the contact is an observation worth discussing. This points to the formation being filled to a deeper level at an earlier period of time. Because of this, the likelihood of the occurrence of leakage from the structure or from another structure with a common paleo-GWC with Snadd Outer is high. No clear signs of leakage is identified in the overburden over Snadd Outer in the seismic. Based on the observations in the following chapter, this might be the most probable model.

6.1.4 Investigation of pressures and leakage

All the Cretaceous sandstones from the Lysing Formation and Intra Lange Formation that has been investigated in the thesis shows a significant overpressure (approximately 90 bars). A lot of the structures show signs of leakage:

Lysing formation:

- Marulk is most likely underfilled, and overburden amplitude anomalies can be interpreted as leakage. Well 6507/2-1: "Strong shows"
- Snadd North: Inconclusive based on available data.
- Snadd Outer: Well 6507/3-9 S registers high gas saturation below the GWC

Intra Lange Sandstones:

- Marulk:
  - Well 6507/2-1: "Strong shows".
  - Well 6507/2-2: Gas filled
  - Well 6507/2-4: Two separate units, one oil filled and one water filled
- Snadd North: Residual oil was observed in well 6507/2-3
- Snadd Outer: Intra Lange was not drilled.

Residual hydrocarbon shows points to one of two things: 1) Hydrocarbon migration through carrier beds. 2) Remigration of trapped hydrocarbons (leakage) (Schowalter and Hess, 1982). As hydrocarbon migration is believed to occur along restricted conduits (Dembicki Jr and Anderson, 1989), striking the exact migration pathway is unlikely. The shows and residual hydrocarbons are most likely a sign of leakage.

Hermanrud and Nordgård Bolås (2002) studied leakage from overpressured reservoirs at Haltenbanken. They demonstrated that the high fluid pressures at Haltenbanken followed a well-defined gradient with depth. The publication argues that the maximum pore pressures in the area are controlled by leakage through fracturing. The stress state in the area at the time of leakage was such that rock failure occurred. The pore pressure gradient, hereinafter referred to as the "HB-gradient" (Hermanrud and Bolås gradient or Haltenbanken gradient), can be seen in figure 6.6.

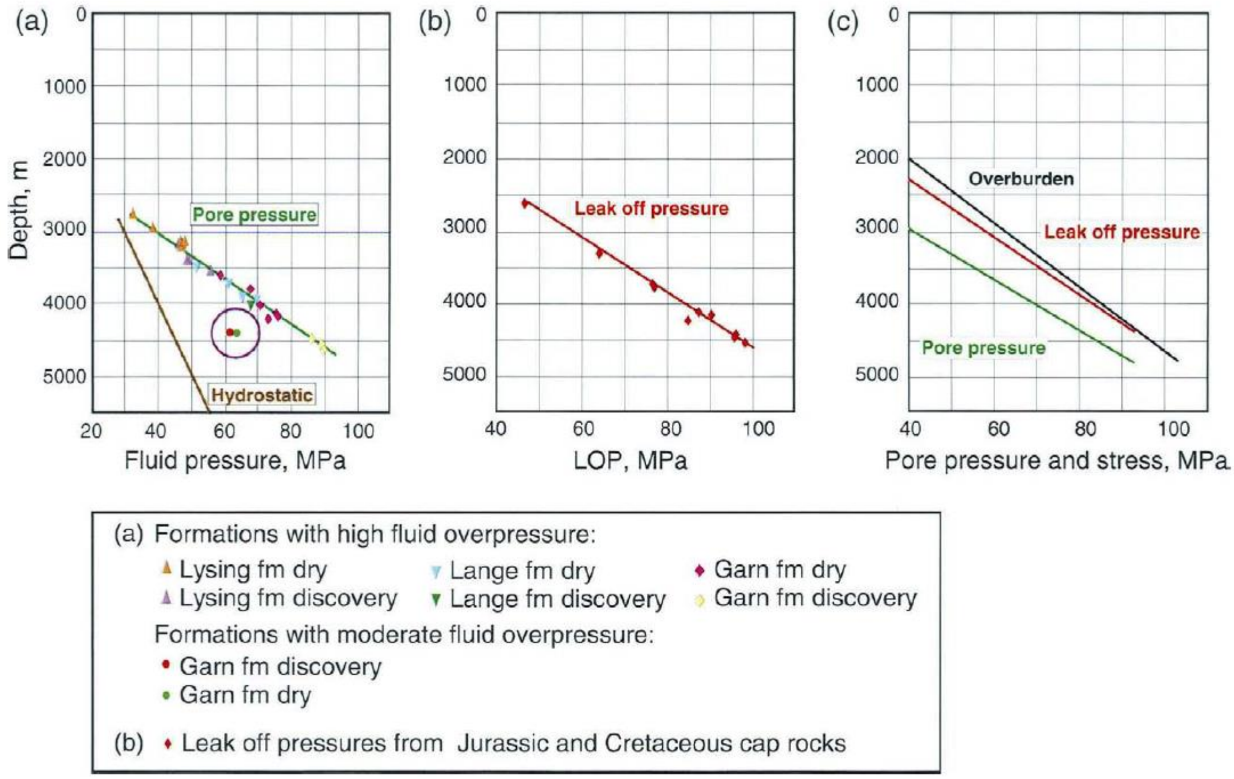

Figure 6.6: The pressure data from the Haltenbanken reservoirs. The HB-gradient in green. Figure from Hermanrud and Nordgård Bolås (2002)

Plotting of pressure data was done to investigate if some of the overpressured cretaceous reservoirs found in the study area of this thesis follow the same gradient with depth. One good pressure point (where it was available) from each reservoir section in each of the wells described in chapter 5.1 and 6.1 was chosen. This included 4 pressure points in the Lysing Formation from wells 6507/2-2 and /2-4 (Marulk), 6507/2-3 (Snadd North) and 6507/3-9 S (Snadd Outer). 4 pressure points from Intra Lange sandstones were used; from wells 6507/2-2, 6507/2-4 (two pressure points from two separate Intra Lange formations) and 6507/2-3. The HB-gradient was found to follow this equation when converted to bar:

$$P = 0.303z - 509, \qquad P=\text{pressure (bar)},\ z=\text{depth (m TVDSS)}$$

The HB-gradient was plotted together with the pressure points. The plot can be seen in figure 6.7

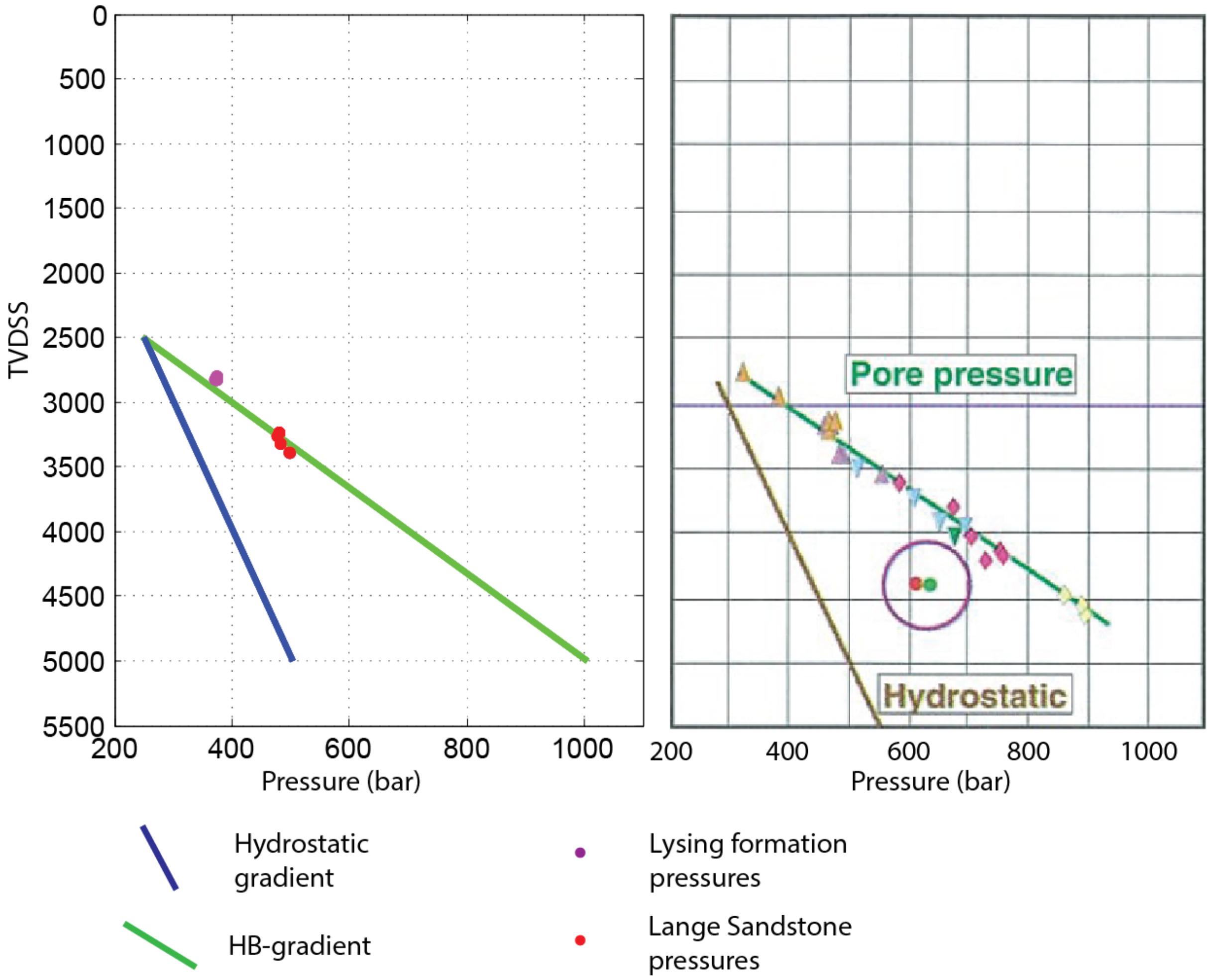

Figure 6.7: Left: Pressure points from the Cretaceous study area on the Dønna Terrace, together with the HB-gradient. Right: The pore pressures from the Haltenbanken study of Hermanrud and Nordgård Bolås (2002). (The pressures has been converted from MPa to bar). The four Lysing pressure points cluster together, appearing as a single point.

As shown in figure 6.7, all the pressure points from the study area falls on or close to the HB-gradient. The deviations from the trend are within the range of deviations seen in Hermanrud and Bolås' figure.

If we follow the logic from the original article, the consequence of this is that the overpressures in all the investigated reservoirs are controlled by a retained pressure from a leakage event where the pore pressures reached the failure pressure of the caprocks. All the structures have leaked, or were in pressure communication with a leaking structure. The pressures and the stress state at the time of leakage was such that rock failure occurred. This means that the work of Hermanrud and Bolås probably can be extended northwards to the Dønna Terrace.

Another important observation that follows if we assume that all the investigated pressure compartments has leaked is that the long stratigraphic pinch out of Snadd North is capable of withstanding significant pore pressures. The pinch out holds so well that the reservoir is able to reach rock failure pressure.

Sealing capacity and mechanism of the pinch-out line of Snadd North:

Snadd North has an approximately 25 km long pinch-out line that delineates the structure to the east. The pinch-out retains hydrocarbons from up-dip migration for a considerable lateral distance. The fact that the Lysing Formation is significantly overpressured (approximately 90 bars) demonstrates that the stratigraphic pinch-out is a very effective trapping mechanism. Based on the observations that

As discussed earlier, and proposed in Fugelli and Olsen's conceptual model in figure 6.1, it is probable that some contribution to the Lysing deposits may come from the Nordland Ridge in the east. If this is the case, the turbidite channels would represent a significant leakage risk. Different kinds of sand deposits are common in turbidite channels. Even though not all of them necessarily occur in every channel, most erosionally confined channels have some kind of basal lag from when the channel was cut. These almost always have some sand content (Mayall et al., 2006). To accumulate Hydrocarbons in the structure, a sealing mechanism for the channels is needed. Two main suggestions for a sealing mechanism for possible channels are:

- Up-flank erosion. If the channels are eroded somewhere up-dip of the main deposits, then the Shetland group, truncating the channel, will seal off the leakage risk together with the underlying Lange Formation (base seal).
- Sealing faults cutting the channel. If the proposed channels are intersected by up-flank faults that are vertically sealing and juxtapositioning the channel to impermeable rocks (or the fault is laterally sealing because of shale smear or cement), then the leakage risk is removed.

The latter alternative is highly probable. The Lysing Formation is of Late Cenomonian to Turonian in age (Dalland et al., 1988). As described in chapter 2.1.4, the last phase of the separation of the Trøndelag Platform (including the Nordland Ridge) from the Dønna Terrace took place in the Late Cretaceous. These large faults in the Revfallet Fault Complex could cut off possible channels.

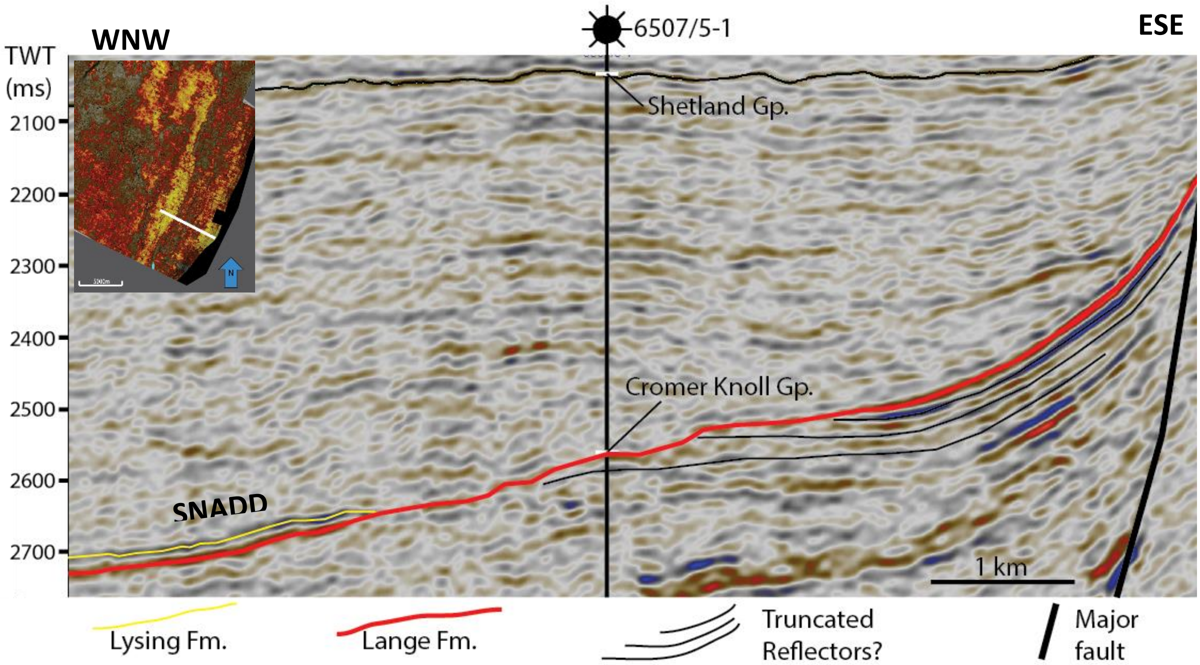

Figure 6.8: Seismic cross section demonstrating possible erosion up-dip from Snadd. Well tops from petrel are added. Formation tops are annotated.

Even though the proposed channels are not seen in the seismic data, the general top Cromer Knoll reflector could be investigated for signs of erosion up-dip from the main structure.

Signs that may point to erosion was located up-dip of the Snadd structure. Note the terminating reflectors that intersect the top Lange Formation. This is interpreted as a possible erosional truncation.

The observation of up-flank faults and erosion gives a satisfying explanation for why there can be hydrocarbon accumulation in the Snadd structure, even with the scenario where deposits come from the east (Nordland Ridge) through channels running up-dip.

6.2 Geological constraints on hydrocarbon columns in the Norne fill-spill route.

6.2.1 Gjøk

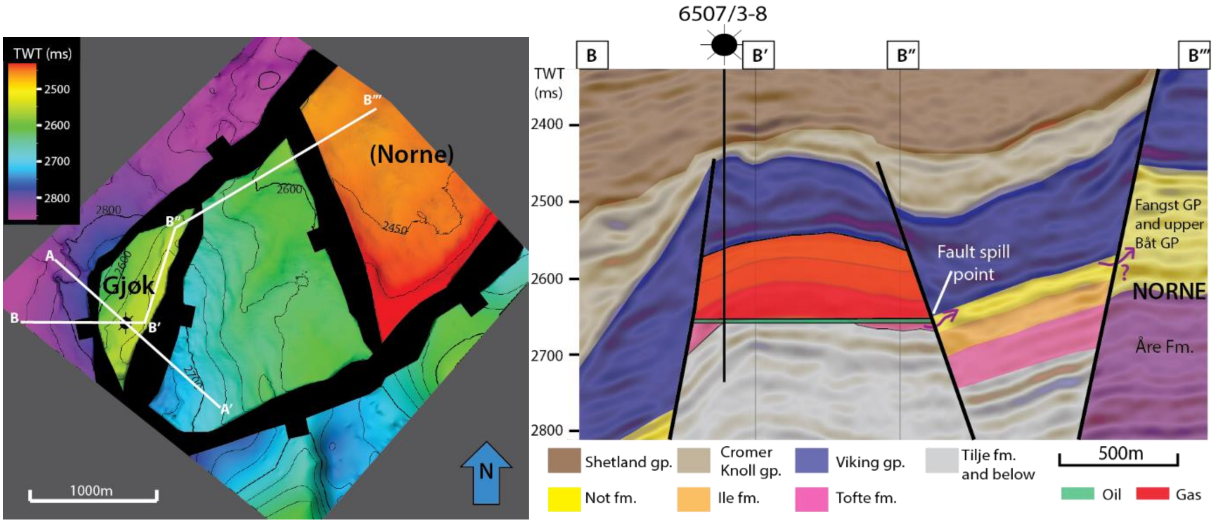

Figure 6.9: Gjøk structure. Modified from figure 5.18 and 5.22

The Gjøk structure is a horst structure with normal faults on all sides. Assuming a tight top seal and no sands in the sediments juxtapositioned to the hydrocarbon bearing reservoir, the hydrocarbon accumulation is only dependent on vertically sealing faults. The Melke formation acts as both top and side seal. There is no Intra Melke Formation sands in the Gjøk structure or in the nearby main structure of Norne, in contrast to the structures from Norne East and further north-east.

The difference between the depth of the OWC and the interpreted spill points is 9.5 m, which is within the uncertainties connected to well based depth conversion

The height of the hydrocarbon column is interpreted to be controlled by a fault spillpoint in or near the fault intersection in the north where the Tofte Formation is juxtapositioned to the Not sandstone. The structure is filled to its spill point.

The hydrocarbons can migrate up-dip towards the south-western fault defining the Norne structure, close to a fault intersection. The sandstones in the migration pathway is juxtapositioned to the upper part of the Båt Group in the Norne structure.

6.2.2 Norne

The Norne structure is a horst structure with faults bounding the structure on all sides, except a small open section in the east. The reservoir is within structural closure down to an interpreted spill point in the open section at 2657 m TVDSS. The Norne Oil is believed to spill out of the structure at this location and into the Norne East structure. The OWC in Norne is at 2690 m TVDSS. This is 33 m deeper than the interpreted spill point, which would mean that the Norne Structure is overfilled. 33 m is significant enough so that it needs to be discussed, as it is in the upper range of uncertainties connected to well-based depth conversion (+/-25 m).

If the structure in fact is overfilled, there need to be some kind of sealing mechanism allowing for a deeper spill than the interpreted structural spill point. When looking closely at the seismic composite cross section presented in figure 5.31, the spill point is between two small features that can be interpreted as normal faults. Another possible small fault is interpreted further towards Norne East. These observations, though small, point to some structural deformation in the area. Fault damage zones in porous sandstones are often associated with deformation bands (Knipe, 1992). Deformation bands or deformation band clusters can act as barriers to fluid flow. The ability to act as barriers/sealing ability varies along the bands. (Torabi and Fossen, 2009). The possibility of faults, or sub-seismic structural features connected to the faults, sealing the down to the depth of the OWC, could be an explanation if an overfilled scenario is assumed.

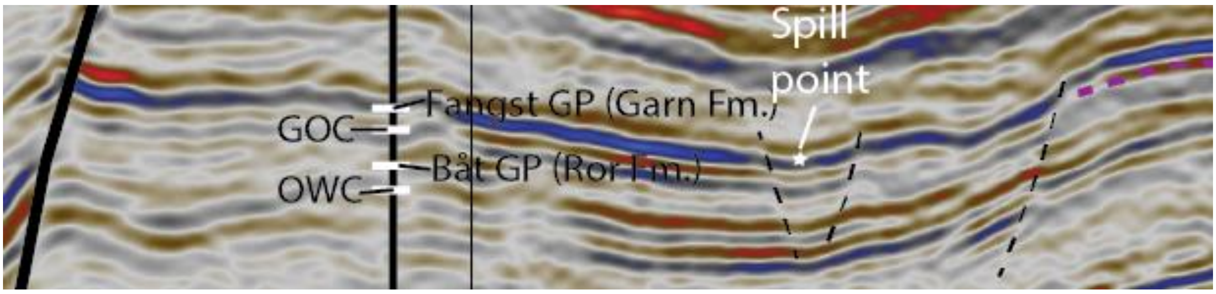

Figure 6.6: Zoomed in version of figure 5.27. Spill point and possible faults are marked.

Assuming the opposite, a filled to structural spill scenario, a possible explanation for the seemingly deeper contact, are the hydrocarbons in the immediate overburden (in the reservoir) over the spill point depth in well position. Hydrocarbons and especially gas has an impact on the seismic velocities. These low velocity anomalies can cause underlying seismic to suffer time distortion in the form of “push down” (Armstrong et al., 2001). As the interpreted TWT for the spill point is depth converted using the well, which is calibrated for the seismic velocities at well location, it will output a shallower depth in meters than it would if there were no hydrocarbons over the point of interest. In the location of the spill point, there are no hydrocarbons in the overburden. Following this conclusion, the depth conversion from the well will underestimate the depth of the spill point.

The magnitude of the effect described above is uncertain, but it is probable that it can at least contribute to push the difference between the spill point and the contact into the range of uncertainties connected to well-based depth conversion.

Based on this, a fill to spill scenario is likely, but a situation with a deeper contact due to sealing fault related structures cannot be excluded. The oil is in both outcomes believed to spill into the Norne East structure. Norne and Norne East is in pressure communication in the water zone.

6.2.3 Norne East

The Norne East contact was not determined from the pressure points due to lack of good measurements in the oil zone. An OWC interpreted from the cores is defined at 2574.5 m TVDSS. A fault spill point is interpreted on the northern tip of the structure where the reservoir is juxtapositioned to Fangst Group sandstones of the Stær structure. The contact is located 9.5 m deeper than the spill point (2587m TVDSS), which is considered within the uncertainties of the depth conversion. The hydrocarbon column in the Fangst/Båt Group reservoir in Norne East is interpreted to be controlled by the fault spill point. See figures 5.26 and 5.27.

Based on the interpretation, the Fault dividing the Norne East structure from the Stær structure has to be sealing between the downthrown Intra Melke Formation and the Fangst Group of Norne East. If not, the oil would spill over to the Stær structure and leave only a minimal oil column in the apex of the Norne East structure. One alternative that would allow an open fault, and still accumulate the oil proven in Norne East, is a completely filled Intra Melke Formation in the Stær structure (filled down to at least base Intra Melke at the location where the Fangst group of Norne East is juxtapositioned to the Intra Melke Formation). Data from well 6608/10-8 (Stær structure) shows that the Fangst and Båt Group reservoirs suffer from pressure depletion as a result from production in the Norne field. The Intra Melke Formation is not affected. This observation makes the situation with Norne East spilling into the Intra Melke formation of the Stær structure highly unlikely.

The Not Formation is previously introduced as a possible pressure boundary (inconclusive due to the lack of good pressure measurements). An argument can be made for it not representing a pressure barrier, while it still may represent a fluid migration barrier in the Norne East structure. Norne East is in pressure communication with Norne (fluids are freely migrating into the Garn Formation in Norne East). Since there is pressure communication over the Not Formation in Norne, there must be pressure communication at least “around” the possibly sealing part of Not Formation in Norne East.

6.2.4 Stær

The OWC in the Åre Formation in Stær, at 2458 m TVDSS in well 6608/10-8, is 42 m deeper than the interpreted spill point where Stær is juxtapositioned to the Lerke Structure. This is not within the uncertainties of the well based depth conversion. Based on this, the structure is characterized as overfilled. The situation is shown in figure 5.32.

The south eastern corner of the Stær structure is where the fault dividing Stær from Lerke intersects the fault between Stær/Lerke and the downfaulted block to the south. In addition, two small faults that is part of the Stær structure intersects the fault dividing Stær from Lerke. At the location of these fault intersections (encircled in orange and red in figure 5.29), the top of the Fangst/Båt Group reservoir in the Lerke structure intersects the fault intersection at approximately the same depth as the OWC in well 6608/10-8. Based on these observations, it is tempting to suggest lateral spill over to the Lerke Structure at one of these fault intersections. Vertical spill/leakage at fault intersections has been well documented

(Hermanrud et al., 2014, Gartrell et al., 2003, Gartrell et al., 2004), showing that fluids can enter the fault at these locations. If we assume that fluids can enter the fault intersection from one side, it is not improbable that the same fluids could escape across to the other side. This is speculative, but based on the position of the OWC and the fault intersection, the model fits the observations.

The lower part of Åre formation has a higher frequency of interbedded shales, and also some coal beds. One alternative explanation is that the fault could be sealing due to sufficient shale smear down to spill point depth.

A shallower fault spill point is located where the Båt Group of the Stær structure is juxtapositioned to the Intra Melke Formation of the Lerke structure. To accumulate hydrocarbons deeper than this, which is the case in Stær, the fault needs to be sealing. Another model, assuming an open fault situation is discussed in the next chapter; 6.2.5.

No contact was encountered in the Intra Melke Formation of the Stær structure. A shared contact with the Fangst/Båt Group accumulation is not the case, as the two reservoirs are not in pressure communication. The controlling factor on the hydrocarbon accumulation in the Intra Melke Formation is, is unknown. The Intra Melke Formation is juxtapositioned to shales of the Cromer Knoll Group and the upper part of the Melke Formation in the Lerke Structure. Therefore, spill from the Intra Melke Formation into the Lerke structure is unlikely.

6.2.5 Lerke

There is no accumulation in the Fangst/Båt Group reservoir in the Lerke structure. The oil has most likely spilled from the Stær structure, migrated through the Lerke structure, and spilled into the upthrusted (relative to Lerke) Svale structure. See figures 5.29 and 5.32.

The Intra Melke Formation is filled to its base. Once again the OWC of the Intra Melke accumulation was not encountered. The Intra Melke Formation of the Lerke structure is juxtapositioned to the Åre Formation of the Svale structure. The accumulation in the Intra Melke Formation is completely dependent on a sealing fault.

As mentioned in the previous subchapter, an open fault situation between the Båt Group in Stær and the Intra Melke Formation is possible. Assuming an open fault, the Intra Melke Formation needs to be completely filled to allow the deep fill in the Stær structure. Assuming this model, the hydrocarbons would first fill the Intra Melke Formation of the Lerke structure, spilling over from Stær at the Båt Gp./Intra Melke- spill point. Only when the Intra Melke Formation is completely filled, the model would allow further accumulation in the Stær structure. The Stær structure continues to accumulate hydrocarbons until the OWC reaches the depth were spill across the fault into the Fangst/Båt Group reservoir occurs.

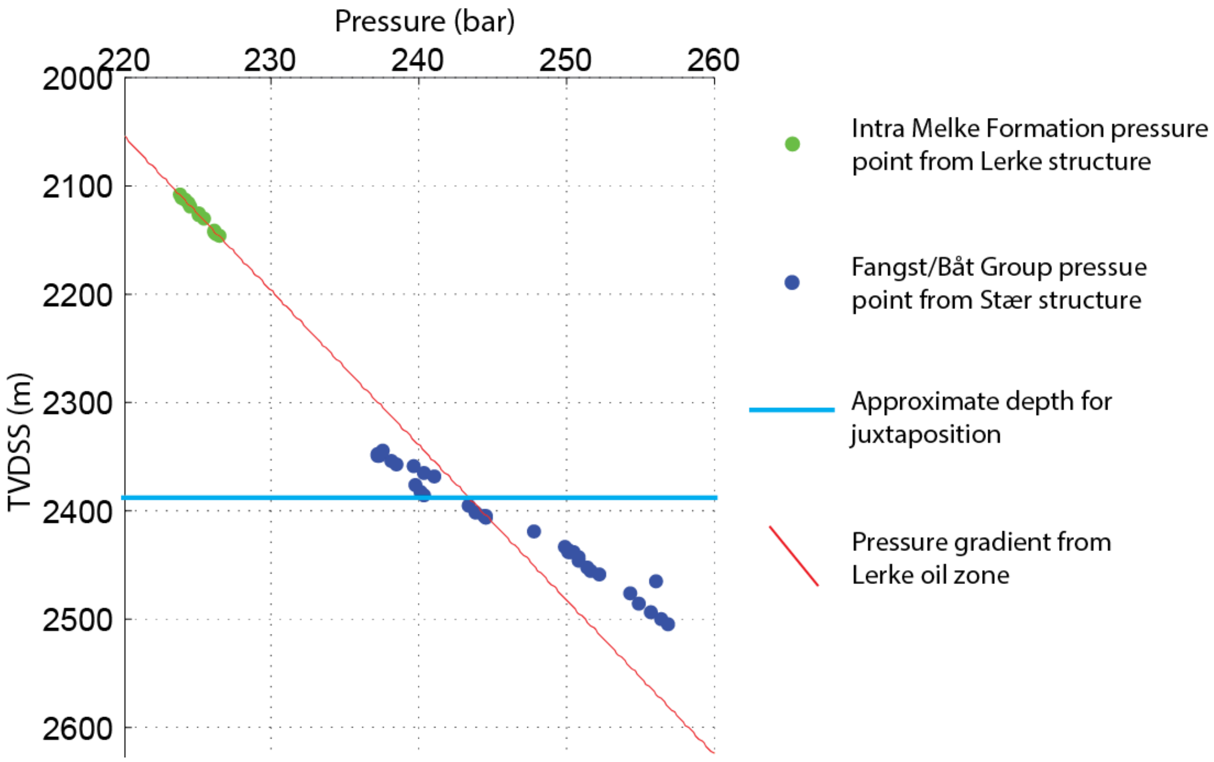

Figure 6.7: Pressure measurements from the Intra Melke Fm. in the Lerke structure plotted together with pressure measurements from the Fangst and Båt Groups in the Stær structure.

To check the plausibility of the suggested model, the pressures of the Lerke oil zone was plotted together with all pressure points from the Fangst and Båt Groups of the Stær structure (OWC is at 2458 m), as shown in figure 6.7. The approximate depth where the Intra Melke Formation of the Lerke structure is juxtapositioned to the Stær reservoir (in the location of the fault intersections) is marked. The gradient from the Intra Melke accumulation in Lerke intersects the pressure points of the Stær Formation at approximately the same depth as the Båt Group – Intra Melke juxtaposition. The amount of pressure depletion varies between different zones, and is also time and distance dependent. This increase the uncertainty in confirming the model using pressure data, but assuming pressure communication between the Båt Group in Stær and the Intra Melke Formation in Lerke, the amount of depletion in these two at the juxtaposition should be approximately the same. This means that the pressure gradient from the Intra Melke Formation should intersect the pressure measurements in the Stær structure at the approximate depth of the juxtaposition, which it does. These observations, together with the fact that the oil in Lerke is reported to be similar to the Norne-oil, makes the model proposing a completely filled Intra Melke Formation in the Lerke structure a probable explanation for the Stær-Lerke system. It also explains how the oil has accumulated in the Intra Melke Formation of Lerke.

6.2.6 Svale and Svale North

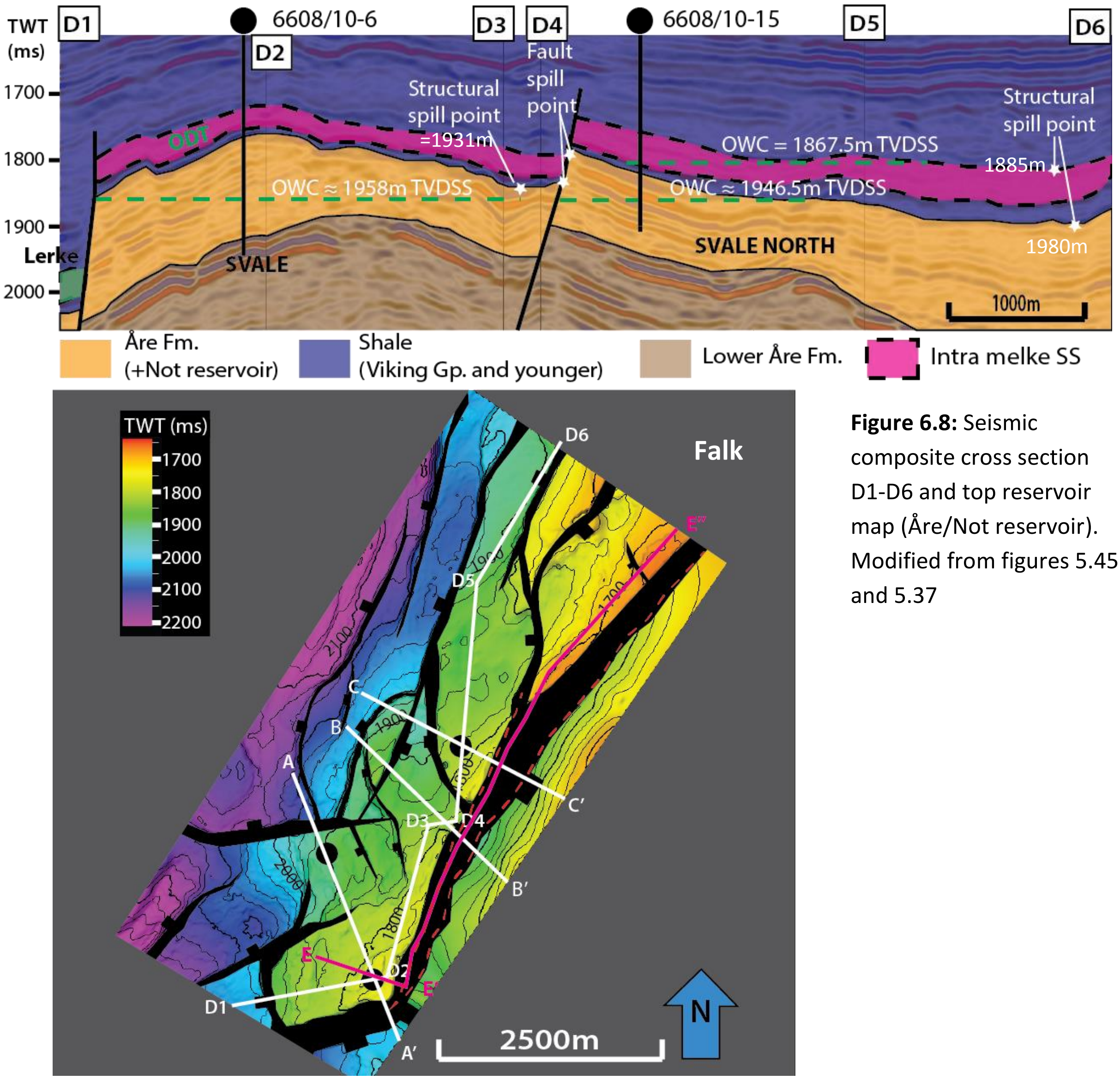

Figure 6.8: Seismic composite cross section D1-D6 and top reservoir map (Åre/Not reservoir). Modified from figures 5.45 and 5.37

The horst/horst complex described in chapter 5.2.4 (presented in figure 5.41 and all seismic cross sections except D1-D6), is up-thrown relative to the Svale and Svale North structures along the entire main fault. Both structures can be characterized as overfilled, as the reservoir zones are juxtapositioned to the Lower Åre Formation. They are both dependent on a sealing fault against the horst complex to accumulate the amount of hydrocarbons proven in the structure. Svale North is completely dependent on fault sealing, as the apex of Svale North is juxtapositioned to the Lower Åre Formation of the horst. If hydrocarbons leak into the horst complex, it is possible that they would migrate northwards along the horsts. A model could be suggested, where the contacts in Svale and Svale North are controlled by spill across the fault and into the horst at some permeable layer at the level of the OWCs. This would also allow for oil migration northwards along the horst complex, and into the Falk Structure. This model is speculative, and of low probability. It is assumed most likely that the fault between the Svale and Svale North structures and the horst complex is sealing all along the 3.5 km border to the structures.

The hydrocarbons in Svale is believed to migrate northwards and into the Svale North structure. The fact that the Åre/Not reservoir in Svale North is affected by pressure depletion, points to the two structures being in pressure communication. This leads to an assumption of an open fault between Svale and Svale North. The structural spill point between Svale and the fault, is interpreted at 1931 m TVDSS +/- 25 m. This is 27 m shallower than the OWC proven in well 6608/10-6 in Svale (1958 m TVDSS), which is just outside the estimated uncertainties connected to well based depth conversion. This means that the probability of the structure being overfilled relative to this spill point is relatively high, but a fill to structural spill situation cannot be excluded. The part of Åre Formation that the Åre/Not reservoir of the Svale structure is juxtapositioned to in the Svale/Svale North fault has a high shale percentage, so that a shale smear situation sealing the fault down to contact depth is a possible explanation.

As no contact was encountered (ODT situation in both Svale wells) in the Intra Melke Formation of the Svale structure a conclusion for the controlling factor on this accumulation was not reached.

In the Intra Melke Formation of Svale North, the OWC is at 1867.5 m TVDSS. This is 17.5 m shallower than the interpreted spill point (1885 m TVDSS +/- 25 m). This difference is within the uncertainties connected to the well based depth conversion. It is a probable scenario that the Intra Melke Formation is filled to this spill point. Following this model, the Intra Melke oil will migrate northwards, not entering the Falk structure.

The Åre/Not Formation in Svale North has a structural spill point in the same location as the Intra Melke Formation. This spill point is at 1980 m TVDSS +/- 25 m, 34m deeper than the estimated OWC in Svale North (1946.5 +/- 4 m). This is not within the uncertainties connected to the well based depth conversion. If a base seal is the case between the ODT and the WUT, then the Svale North contact can be deeper than the WUT, and would then allow for a fill to spill situation controlled by this northern spill point. The base seal would approximately follow the strong red peak reflector located where the OWC is marked in well position in figures 5.45 and 6.8. The strong positive amplitude on this reflector could be caused by the effect of the pore fluid going from oil to water, giving an increase in acoustic impedance. This situation would complicate the explanation for how the oil has migrated from Svale to Svale North (this migration direction is the most probable and is assumed in all the models). As there is no oil accumulation under the proposed base seal, the hydrocarbons spilling from Svale would need to somehow migrate vertically up along the fault, before spilling into the Åre and (Lower Not) reservoir of the Svale North structure. Then, Svale North could be filled to the structural spill point in the north. This would mean, since the spill point in the north of Svale North is deeper than the spill point in Svale, that a common contact between the structures could be the case, and that the OWC in Svale is actually controlled by the spill point in the north of Svale North. The interpreted spill point north of Svale North is 22 m deeper than the OWC in Svale. This is just within the uncertainties connected to the depth conversion of the spill point, so the spill point could be at the contact depth of the Svale accumulation. A tempting extension of this model is to propose spill from the Åre/Not reservoir into the Intra Melke Formation of the Svale structure. In well 6608/10-7, an ODT situation is registered, with the base of the Intra Melke sandstones at 1954 m TVDSS, 4 meters shallower than the contact in the Åre Formation of Svale. The model would then give a common contact depth in Svale, Svale North and the Intra Melke Formation of Svale. This extension of the model breaks down when analyzing the pressure data, which shows that the Intra Melke Sandstones are overpressured relative to the Åre/Not reservoir.

Assuming no base seal, the structural spill point in the north of Svale North is most likely not the controlling factor for the hydrocarbon column in Svale North. When looking closer at the geometry of the top Åre/Not reservoir surface, an additional, shallower spill point can be interpreted at 1846 ms TWT, corresponding to 1925 m +/- 25 m. This is 21.5 m shallower than the OWC in Svale North (1946.5 +/- 4m), and within the range of the uncertainties. Figure 6.9 shows a zoomed in version of the Svale North structure. An RMS amplitude surface attribute along the top reservoir surface is also presented. As can be seen in the figure, oil will first spill over to a height where two fault intersections are located. These could represent possible leakage points, either vertically, or laterally across the fault. The Åre/Not reservoir of Svale North is juxtapositioned to the Åre Formation in the location of the fault intersections. Lateral leakage in the southernmost fault intersection could represent an explanation for how oil has migrated into the Falk structure. The previously

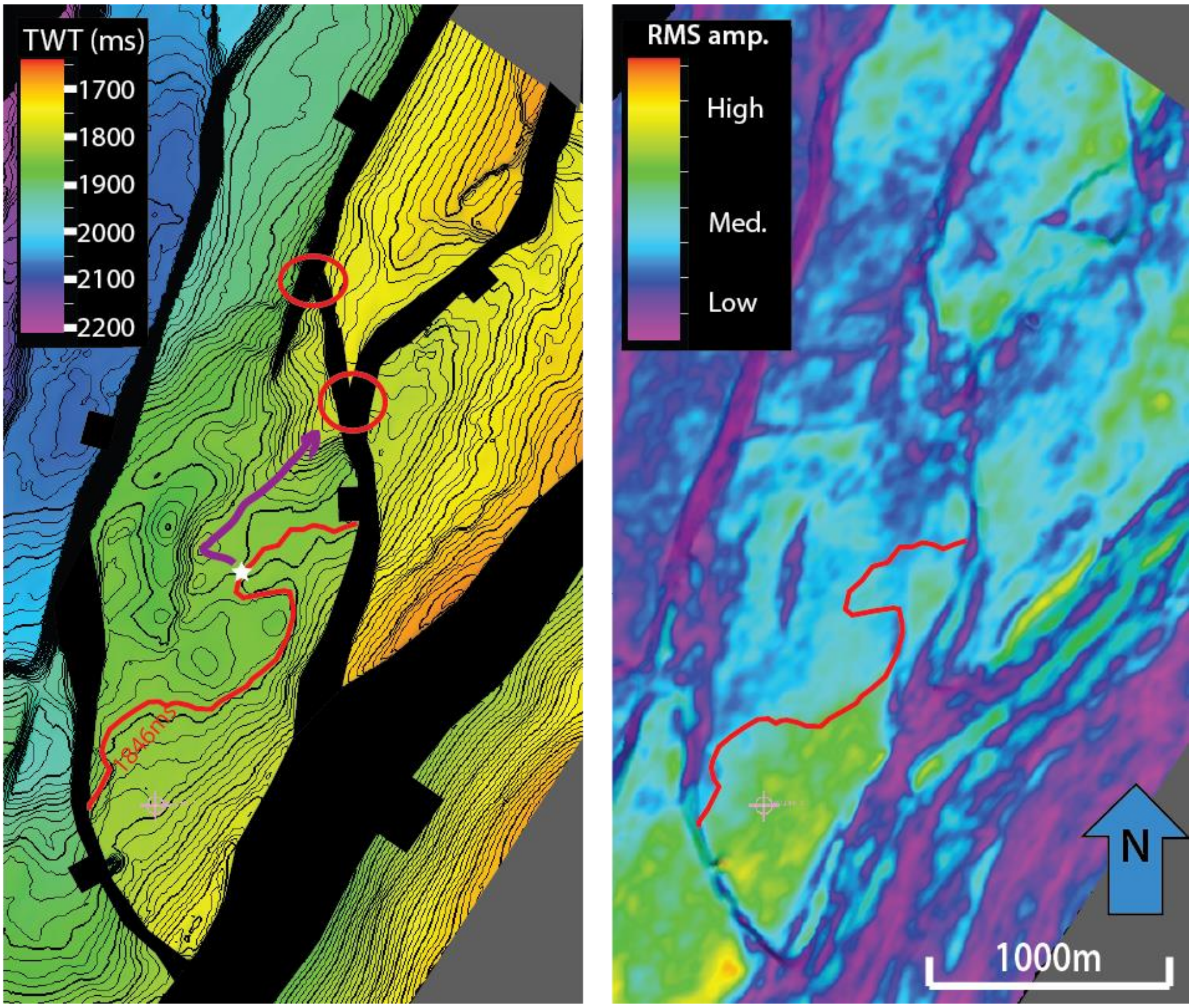

Figure 6.9: Zoomed in version of the top reservoir surface map presented in figure 5.32. On the right: RMS amplitude map extracted on top Not/Åre reservoir surface. Fault intersections, spill point, fault intersections and interpreted migration path are annoted.

described model, assuming a spill point north of Svale North, does not explain the oil charge in Falk. If we assume lateral spill in the northernmost fault intersection, the up-thrusted structure that the oil would spill into would need to be filled before the oil could spill further north-east and into Falk. As shown in RMS amplitude map, a positive amplitude anomaly approximately follows the contours defined by the spill point at 1846 ms TWT. This observation increases the confidence in this model. The fault section just south of the southern of the two fault intersections is assumed to be sealing, as lateral spill in the southern part of this fault (close to the main fault) would lead to a shallower contact. An open (for lateral spill) fault section between the two fault intersections would lead to approximately the same scenario as the situation with lateral spill through the fault intersections.

This model is concluded as the most likely scenario for the Svale North accumulation, coupled with the model where the fault between Svale and Svale North is sealing down to contact depth. The model with the base seal in Svale North, and common OWC with the Svale structure, is regarded as less likely, but cannot be excluded. The Intra Melke accumulation in Svale North is believed to be filled to the northern structural spill point, while no conclusion is made regarding the Intra Melke accumulation in Svale, due to the lack of an OWC.

6.2.7 Falk

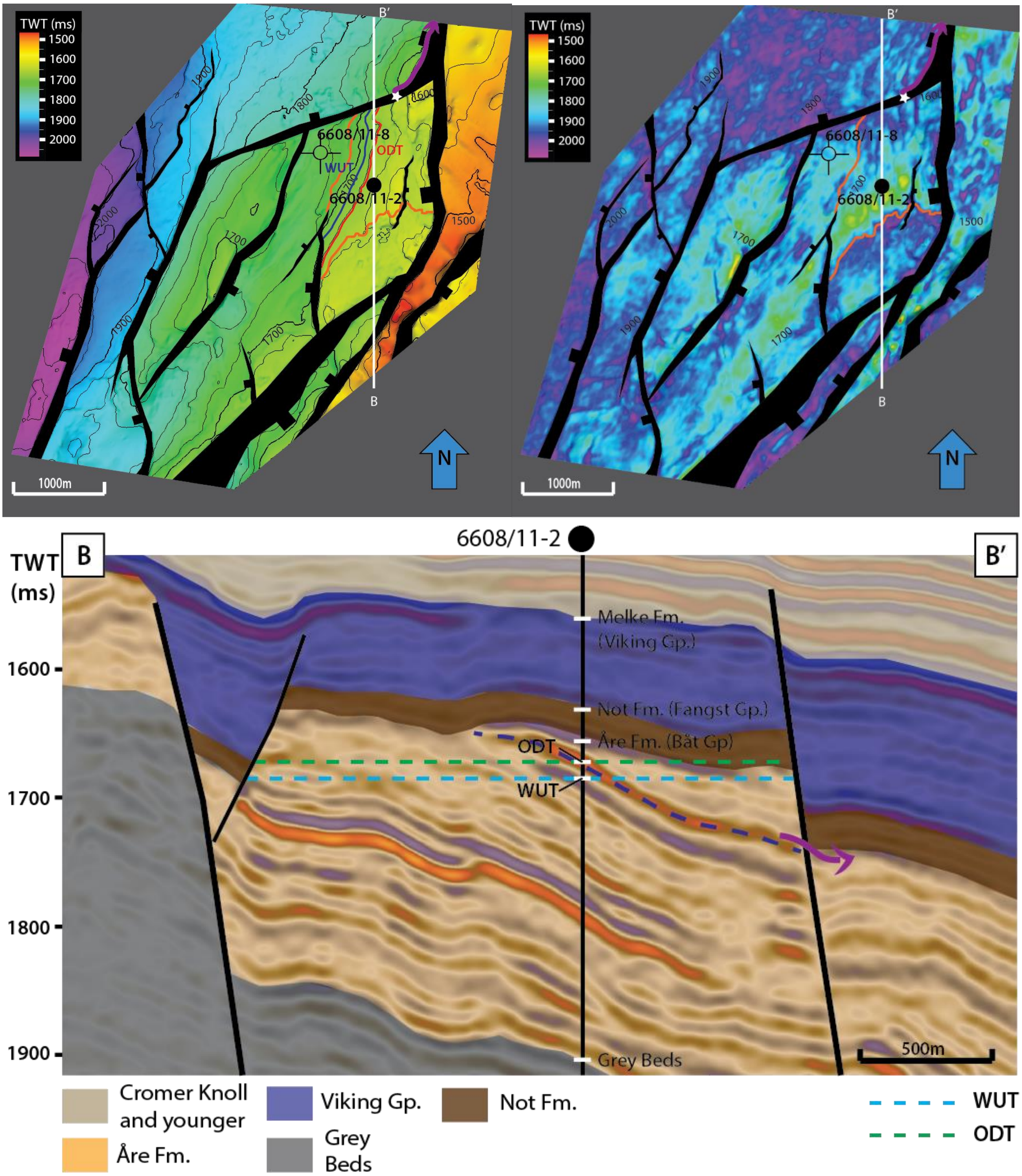

Figure 6.10: Top reservoir map, RMS amplitude map and crossline B-B'. Modified from figures 5.48, 5.53 and 5.54. Spill point is interpreted up-dip from B-B'; the mechanism is the same, but the Åre Formation of the hanging wall is higher relative to the footwall block, allowing Åre-Åre juxtaposition above the interpreted base seal (dark blue dotted line).

In order to accumulate oil in Falk, the Horst in the east must be sealing all along the structure. The fault in the east juxtapositions the Åre reservoir of Falk to sedimentary rocks of lower Åre Formation, and in some locations the Triassic Grey beds. The structure is considered as overfilled, as it is dependent on a sealing fault against the horst.

A possible fault spill point across the north-bounding fault of the Falk structure was interpreted at the shallowest point where the upper part of Åre formation in the northern, downfaulted block is juxtapositioned to the Åre Formation above the base seal in the Falk structure. The lateral location along the fault of this spill point depends on if we have a base seal situation or not. There is a pressure increase in the well between the ODT and the WUT, indicating a seal between the two measurements. The bright peak reflector approximately in the depth of the ODT in the position of well 6608/11-2, could represent the increase in acoustic impedance resulting from the pore fluid changing from oil to brine. In addition, the top reservoir reflector is a brighter trough above the areas where the assumed base seal reflector is bright. An RMS amplitude surface attribute was extracted on the top reservoir (Åre) interpretation (see upper left of figure 6.10). A brightening towards a sharp amplitude shutoff south of well 6608/11-2 can be seen in the RMS amplitude map. This is interpreted as a tuning effect, as the reservoir thickness approaches the vertical resolution (tuning thickness). The shutoff is interpreted to represent the approximate location where the discordant reservoir is truncated in the south. Allowing for a deeper fill than the WUT if the base seal case is assumed, the accumulation contour is represented by the orange lines in the map. This is based on interpreted spill point depth and the amplitude shutoff geometry. Assuming spill through the northern fault, a small accumulation could form in the corner defined by the north-bordering fault of the Falk structure, and the large fault continuing with a northbound strike. Based on the interpretation, there would only be a minimal accumulation before the oil would spill further north along the fault.

Assuming no base seal, a firmly determined fault spill point through the north fault, reflecting a contact between the ODT and WUT, is not defined, but the oil is interpreted to be able to spill at a shallower depth than if a base seal is present. Both this model, and the model assuming a base seal are based upon the assumption of an open fault in the north.

An alternative with a closed fault to the north, and the oil spilling into some permeable layer in the eastern horst, or the fault intersection in the north-eastern corner at the depth of the OWC cannot be excluded.

6.2.8 Fault sealing

A shale smear factor was calculated for 12 faults delineating different structures from Gjøk in the south-west, to Falk in the north-east in order to investigate the correlation between SSF and the sealing capabilities of the faults.

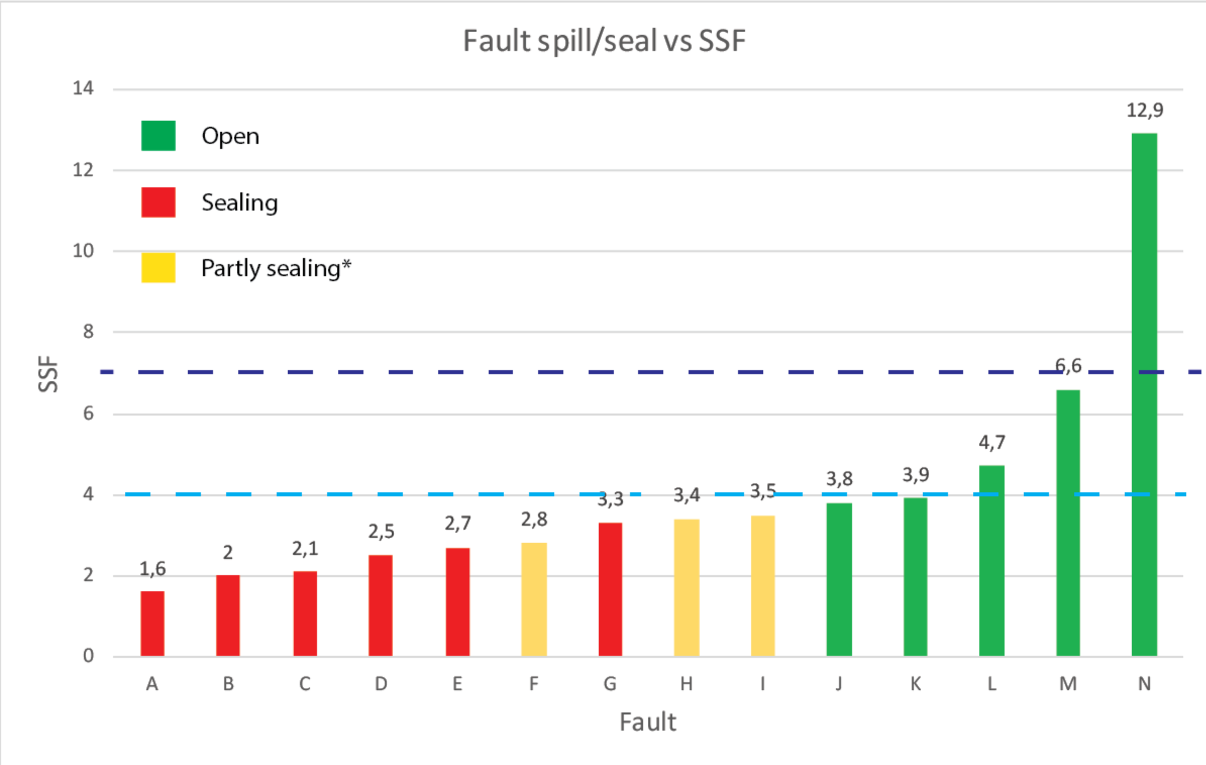

Figure 6.11: Shale smear factor (SSF) for important faults. Anonymous labelling of faults from A-M is due to some of the logs being confidential. Dotted lines represent limits suggested by Lindsay et al. (1993) in light blue (high risk of spill over SSF=7) and Færseth (2006) in dark blue (sufficient for seal under SSF=4).
*Faults interpreted as sealing down to a specific level, or suggested to spill laterally at fault intersections due to position of oil water contact.

Figure 5.59 shows the SSF of the investigated faults, with increasing SSF from left to right. A clear trend can be seen, where the faults that are interpreted as open at their spill point (in green) all have a higher SSF than the sealing faults (in red). The faults marked in yellow are faults that have been interpreted as partly sealing. The distinction between these and the sealing faults (red), was made because spill through the yellow faults deeper than the interpreted spill points is assumed to control the hydrocarbon water contact. The sealing faults (red) are faults that have to seal in order for accumulation down to the depth of the OWCs to be possible, and they are interpreted not to control the position of the oil water contacts.

Færseth (2006) claimed a number below 4 was sufficient for a sealing fault, while Lindsay et al. (1993) suggested that a number above 7 represented a high risk for an incomplete shale smear. These values are represented by the dotted lines in the plot. Two faults with an SSF below 4 are open, but the values are very close to 4 (3.8 and 3.9). Based on the observations in figure 6.11, a limit value for this area of between 3.5 and 3.8 is reasonable, as all faults with a SSF below this are sealing or partly sealing, and all with a SSF value above the limit are open. However uncertainties connected to the calculation of the SSF must be considered, and a more accurate and comprehensive study of SSF versus fault seal would be needed in order to determine a specific limit value.

Based on the observation of elevated SSF values for faults that are interpreted as open and consistently lower values in the sealing faults, it can be concluded that the most probable fault sealing mechanism in the area is shale smearing of the fault plane. Lien (2017) conducted a study in the Greater Oseberg area. Quartz cementation was claimed as the main mechanism for fault sealing. As can be seen in figure 6.12, no overfilled structures were encountered below a depth of 2800 m, except two faults that were associated with shale smear. All structures investigated in this project had hydrocarbon contacts between 2822 m TVDSS (OWC in Gjøk) and 1720.7 m TVDSS (ODT in Falk). This support the conclusion of shale smear, and not quarts cementation as the main mechanism for fault sealing in the investigated structures.

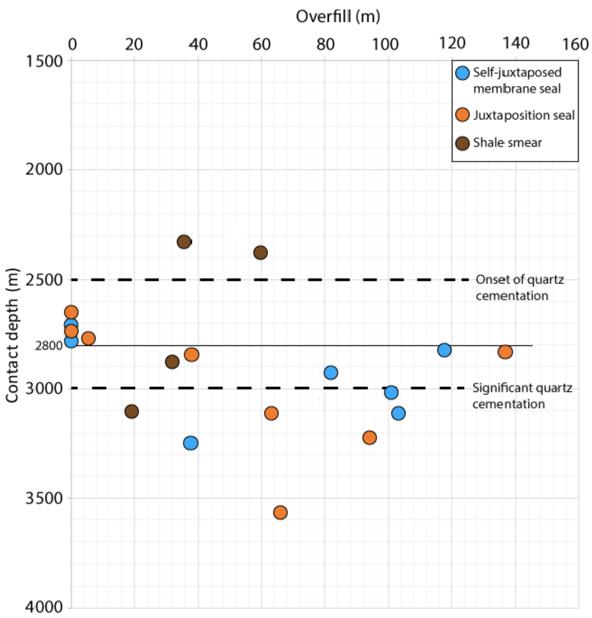

Figure 6.12: Hydrocarbon contact depth versus overfill plot. From Lien (2017).

6.2.9 Pressure communication in the Norne fill-spill system

Based on the interpretations of spill points and oil-water contacts, the proposed fill-spill migration route from Gjøk in the SW, to Falk in the NE seems to be the most likely model for all the individual structures. The plot in figure 6.13 shows that the pressures from each structure falls on roughly the same gradient with depth. Deviations due to pressure depletion occur, as can be seen in the pressure point from Svale North, which is affected by production from the Svale structure.

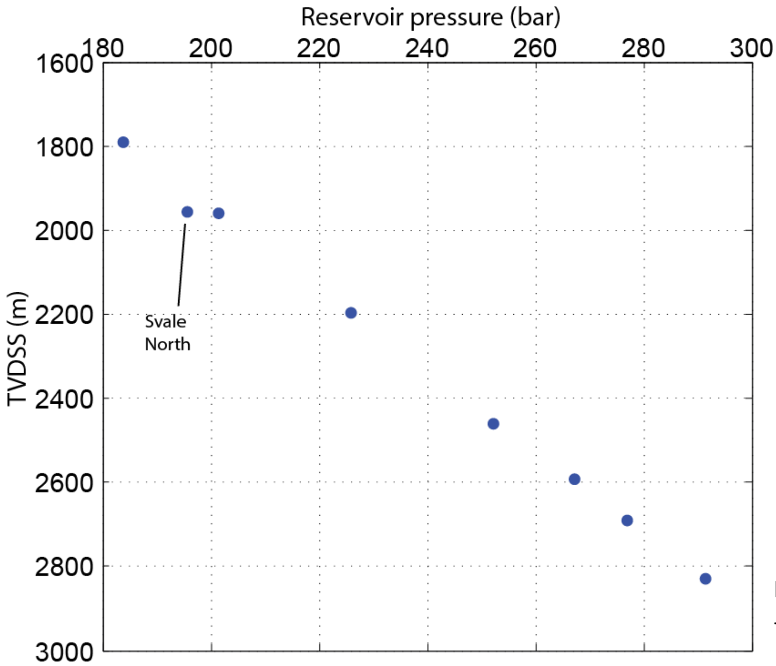

Figure 6.13: Pore pressures from each structure in the

The calculated overpressures vary somewhat between the structures. This is partly because some of the structures are affected by pressure depletion from nearby producing fields in the same fill-spill route. The observation of pressure depletion supports the assumption that there is pressure communication between structures.

The choice of brine density influences the calculated hydrostatic gradient. This density should represent the average brine density in the water with pressure communication from the reservoir to the surface, and is not necessarily the same as the reservoir brine density. A change from 1025 kg/m^3 to 1050 kg/m^3 gives a difference of 6.1 bar at 2500 m TVDSS. The brine density chosen when the individual structures were investigated, 1025 kg/m^3 (density of sea-water), results in a higher calculated overpressure in the deep structures than in the shallower structures. This means that if we assume pressure communication through the whole system, the value of 1025 kg/m^3 is a too low approximation for the average brine density. This is demonstrated in table 6.1 and figure 6.14, where the scatter of overpressures is plotted for three different brine densities. An average brine density at 1050 kg/m^3, results in very little scatter of the overpressures, except for structures that are affected by pressure depletion. This “best fit” brine density yields an overpressure for the system very close to zero.

Based on these observations it can be concluded that there is pressure communication from the Gjøk Structure to the Falk structure, and that the Norne fill-spill system is most likely normally pressured and open for fluid migration to the surface.

Well	Structure	TVDSS (m)	PoreP (bar)	HydroP1 (bar)	OverP1 (bar)
6507/3-8	Gjøk	2829,3	291,472	284,493	6,979
6608/10-3	Norne	2691,8	277,080	270,667	6,413
6608/10-4	Norne East	2593,9	267,320	260,823	6,497
6608/10-8	Stær	2459,3	252,300	247,289	5,011
6608/10-9	Lerke	2197,4	225,910	220,954	4,956
6608/10-6	Svale	1958,9	201,570	196,972	4,598
6608/10-15	Svale N	1957,5	195,626	196,830	-1,204
6608/10-8	Falk dry	1791,6	183,800	180,150	3,650

HydroP2 (bar)	OverP2 (bar)	HydroP3 (bar)	OverP3 (bar)
288,657	2,815	291,432	0,040
274,628	2,452	277,269	-0,189
264,640	2,680	267,185	0,135
250,908	1,392	253,320	-1,020
224,188	1,722	226,343	-0,433
199,855	1,715	201,776	-0,206
199,710	-4,084	201,630	-6,004
182,786	1,014	184,544	-0,744

Table 6.1: One depth point from each structure chosen in the water zone close to the OWC. Associated pore pressures, hydrostatic pressures and overpressures are also presented.
HydroP1: Average brine density = 1025 kg/m^3
HydroP2: Average brine density = 1040 kg/m^3
HydroP3: Average brine density = 1050 kg/m^3

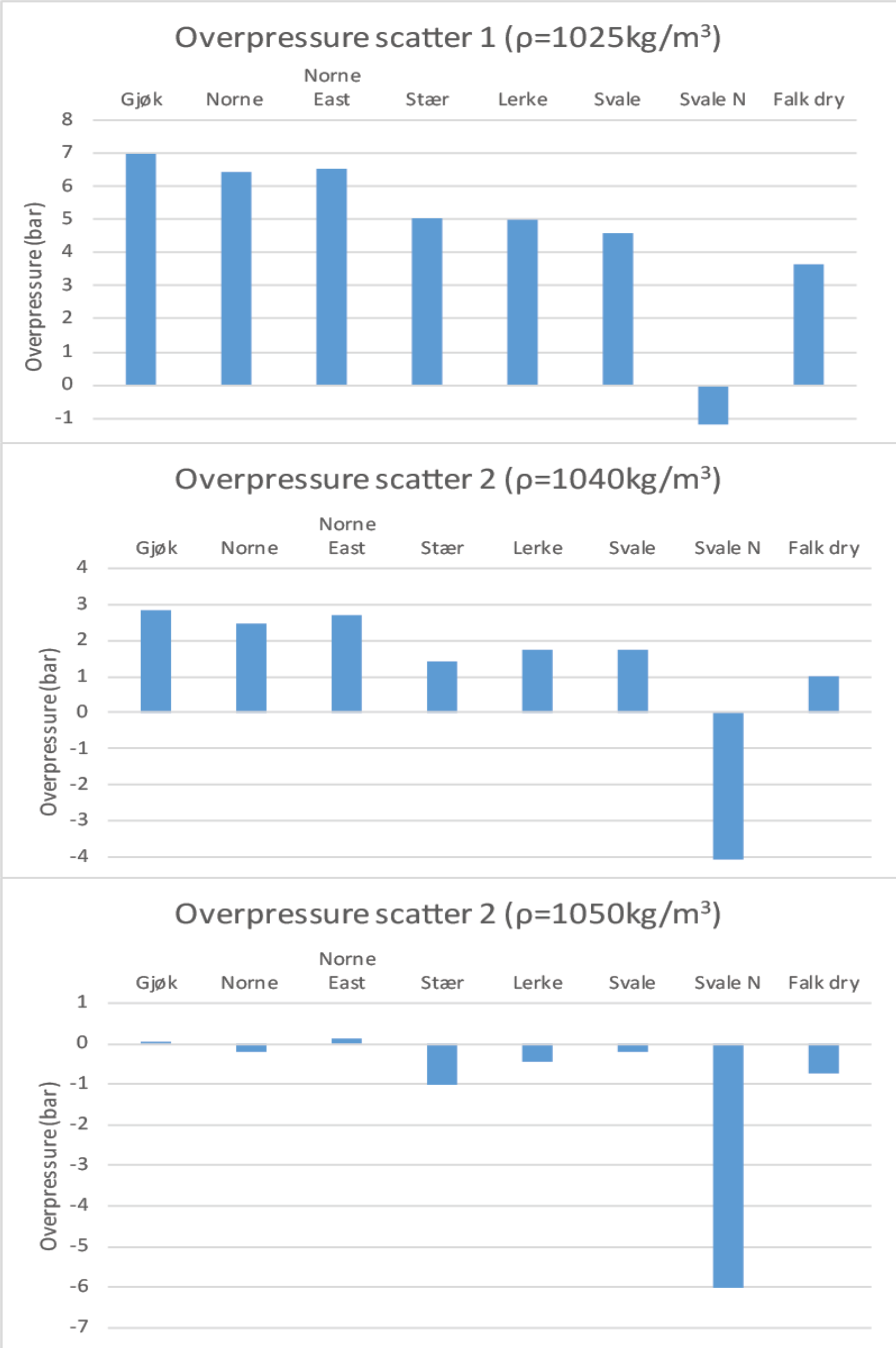

Figure 6.14: Overpressure scatter plots. Overpressure plotted for each structure, using different values for the average brine density.

7. Proposal for future work

- Investigations into why there are no reported gas caps up-dip from Norne in the Norne fill-spill route should be conducted. The commonly accepted Gussow-model for differential entrapment of oil and gas does not take into account the phase behavoiur of saturated oils and gases as they move through a succession of traps. All oils from two-phase accumulations will be saturated with solution gas. When these oils spill to a shallower depth, some gas will come out of solution resulting from the lower reservoir pressure. This will for most input GORs (gas oil ratios) result in a succession of two phase accumulations with smaller and smaller gas caps. This was demonstrated through the building of numerical models made to test the behavior of commonly accepted models for fluid migration during a summer internship in 2017 at Equinor (then Statoil).
- The consistency of elevated SSF values for open faults and low values for sealing faults, shows that a more comprehensive study to document the accuracy of SSF-based fault seal estimates could be valuable for exploration purposes.
- Further investigation of significantly overpressured structures on the Dønna Terrace both in Cretaceous and Jurassic reservoirs, and their compatability with the pressure versus depth gradient ("HB-gradient") that is present in overpressured structures in the Haltenbanken area. If the gradient fits (as it does for the overpressured structures investigated in this thesis), this could be valuable information for further exploration on the Dønna Terrace. It would also mean that the work of Hermanrud and Nordgård Bolås (2002) would be valid further north.
- The Intra Lange Formation sandstones is proven as a hydrocarbon reservoir on the Dønna Terrace. The problem with these sandstones is that they are very poorly observable in the seismic. If it is concluded that all of these sands have leaked (as the placement on the HB-gradient suggests), a study on whether overburden seismic signatures of leakage could be used as an explorational tool instead of traditional seismic interpretation would be interesting.

8. Conclusions

The aim of this study has been to investigate the geological constraints on hydrocarbon-water contacts in the greater Norne area of the Norwegian Sea. Detailed geological mapping of the structures, their fluid contacts and their associated structural or across-fault spill points. If the structures are overfilled or underfilled, one or more mechanisms have been suggested as the controlling factor on the hydrocarbon columns. The study has resulted in the following main conclusions:

- The Cretaceous structures on the Dønna Terrace are significantly overpressured and all structures follow a pore pressure versus depth gradient that is present in overpressured and leaky structures in the Haltenbanken area. The Marulk and Snadd Outer structures show some sign of leakage, and Marulk is underfilled relative to its structural spill points. This means that the structures has most likely leaked due to the fracturing of the caprock. This also applies to the Snadd North structure, which is sealed by an approximately 25 km long pinch out line towards the Nordland Ridge. This demonstrates that the stratigraphic pinch out line forms an excellent seal and is unlikely to be limiting the hydrocarbon column height.
- The proposed Norne fill-spill spill route, from the Gjøk structure in the SW to the Falk structure in the NE, is confirmed both by the investigation of spill points and hydrocarbon-water contacts, and by the investigation of pressure measurements. The system is normally pressured, with pressure communication to the surface. Some faults are sealing or partly sealing, resulting in some of the structures having a deeper oil water contact than their interpreted spill points. At some locations, fault sealing is needed for the hydrocarbons to follow the proposed and confirmed fill spill migration route.
- The investigation of shale smear factor versus fault sealing in the area shows that sealing faults have a SSF between 1.6 and 3.5 while open faults have a SSF between 3.8 and 12.9. Based on these observations, shale smear is the most likely sealing mechanism in the Norne fill-spill route.

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