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Analysis of pore pressure measurements in exploration wells in the Norwegian North Sea

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Abstract

The aim of this thesis was to examine the pore pressure measurements in the Norwegian North Sea. To study the possibility of the overpressure being an indicator that can increase the probability of hydrocarbon discoveries in exploration wells**.** Studying this hypothesis, reasons for overpressure have been elaborated.

In this thesis, several wells from the northern part of the North Sea have been studied, mainly from the Tampen Area. The wells in this area are all exposed to an abnormal pore pressure. The reason for overpressure is further investigated in this paper. The overpressure has an impact on the production rate and influences the start-up time for injection or artificial lift. The effect of overpressure has been considered regarding production.

It was found that the water pressure below the oil zone varied between the fields; from normal pressure to high overpressure. It was further found that the water pressure level was field-specific. Normal water pressure in a few dry wells was interpreted as a probable result of leaking faults. We put forward the hypothesis that normal water pressure might be an indicator of leaking faults.

Acknowledgement

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Else Karin Neset

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Nomenclature

Abbreviation

A	Area, cross sectional area
A_b	Bit area [in^2]
APA	Awards in predefined areas
d	Bit size [inches]
d_e	d-exponent
D_{sea}	Depth of well from seabed
FMT	Formation multi-tester
FWL	Free water level
g	gravitational constant
GOC	Gas-oil ratio
GR	Gamma ray log
h_w	water depth
HMSE	Hydro mechanical specific energy
HPHT	High pressure, high temperature well
HSE	Health, safety and environement
k	Permeability
k_e	Effective permeability
k_r	Relative permeability
LOT	Leak off test
LWD	Logging while drilling
m	Cementation index
MD	Measured depth
MSL	Mean sea level depth reference point
MW1	Normal mud weight
MW2	Actual mud weight used
MWD	Measurement while drilling
N	Rotary speed [rpm]
n	Saturation exponent
NCS	Norwegian continental shelf
NORSOK	The Norwegian shelf's competitive position
NPD	Norwegian petroleum directorate
OBG	Overburden stress gradient [psi/ft]
OWC	Oil-water contact
P	Pressure
P_{ng}	Normal pore pressure gradient [psi/ft]
P_{pg}	Pore pressure gradient [psi/ft]
PSA	Petroleum safety authority
Q	Flow rate
R	Measured shale resisitivity
RFT	Repeated formation test
RKB	Drill floor depth reference point
R_n	Shale resisitivity in the normal pressure condition
R_o	Resisitivity value when Z=0
ROP	Rate of penetration [ft/hr]
R_t	Resistivity aqueous fluids
R_w	Resisitivity in water zone

s.g.	Specific gravity relative to water
S_w	Water saturation
T	Torque [lb-ft]
TVD	True vertical depth
V_b	Bulk volume
V_{pa}	Total void volume
WAG	Water alternating gas
WOB	Weight on bit [lbs]
ΔP_b	Bit pressure drop [psi]
Δt	Transit time in shale from well
Δt_n	Transit time in shale at normal pressure condition

Symbols

ρ	Density [g/cm^3]
φ	Porosity
μ	Viscosity [cp]

1.0 Introduction

The fields in Tampen area in the northern part of the North Sea have abnormal pore pressures. There are several mechanisms that cause overpressure, these are studied in this thesis. Pore pressures measurements in the exploration phase today are not well sampled, and in some cases, they are not real measurements, but estimates. This gives a considerable uncertainty in how the well is going to produce effectively. The hypothesis to be studied is, "Is it possible that the overpressure is an indicator that can increase the probability of discoveries?".

The pore pressure can be measured either directly or indirectly in the exploration phase. Direct pore pressure measurements can only be performed in permeable formations, and most of the rock above the reservoir is shale. Shale is almost impermeable; hence the pore pressure cannot be predicted by direct measurements but must be evaluated by indirect methods. Pore pressure is important to predict early in the exploration phase to determine whether the field must be produced by water/gas injection or artificial lift, or if it can be produced naturally.

1.1 Objectives

The main objective of this thesis is to examine the pore pressure measurements in exploration wells in the Norwegian North Sea, and to study the possibility of the overpressure being an indicator that can increase the probability of hydrocarbon discoveries in exploration wells. In this study reasons for overpressure in the areas also have been elaborated. This thesis is a review of previously studies that is emphasized when determine the factors which have caused overpressure in the different areas. Real pore pressure measurements, pressure patterns and regimes are investigated in order to see if the information can contribute to exploration issues, like if a fault is open or sealed. It is further investigated if overpressured fields containing dry wells, are affected by leakage.

If the pore pressure gradient lies between the lithostatic and hydrostatic gradient it is defined as overpressure. In Figure 1, the pressure gradient is illustrated. The method used to carry out this study include pore pressure measurement data from Diskos (The Norwegian Petroleum Directorate's database) which are plotted against depth to see if the fields are overpressured.

For this study the fields included are Gullfaks, Snorre, Vigdis, and Visund from the northern part of the North Sea, named Tampen/Tampen Spur. For comparison, Johan Sverdrup from the central North Sea, Heidrun from the Norwegian Sea and Goliat from the Barents Sea are also considered. A map of the location for these fields are shown in Figure 2.

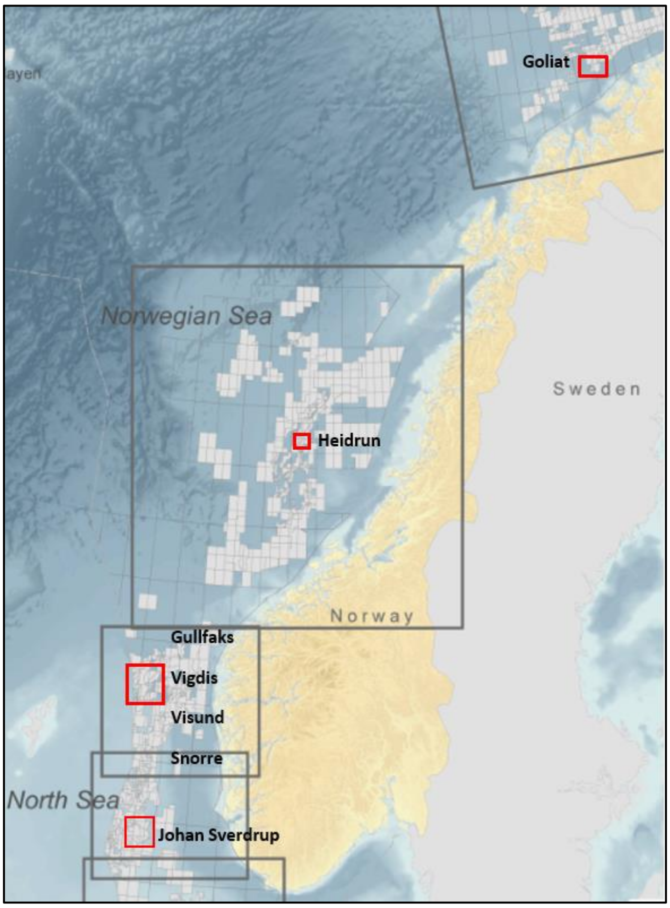


Figure 2 Location of the fields. Modified from Norwegian Petroleum, 2019, from https://www.norskpetroleum.no/en/developments-and-operations/activity-per-sea-area/

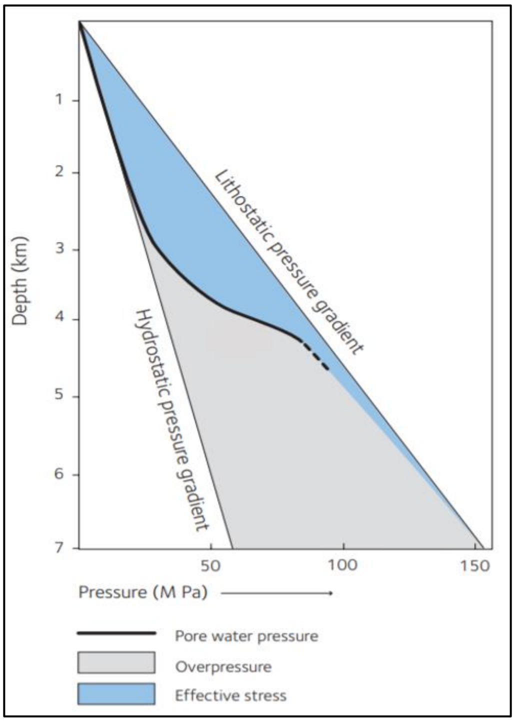


Figure 1 Depth plot of pressure regimes on the Norwegian continental shelf (NCS), from *"Distribution of hydrocarbons in sedimentary basins"* by Buller, Bjørkum, Nadeau & Walderhaug , 2005, Statoil Magazine.

1.2 Previous studies

Today there are several methods to measure pore pressure, but many of these have uncertainties in their measurements. Pore pressure prediction is important to ensure drilling safety, optimal production, reservoir modelling and proper well design. Oloruntobi and Butt, (2019; 2020), wrote two papers about two new methods to estimate the pore pressure from the drilling parameters; Mechanical Specific Energy (MSE) and Hydro Mechanical Specific Energy (HMSE), calculate pore pressure based on the concept of total energy needed to remove a volume of rock from surface measurements. They conclude with that these new methods can provide trustworthy measurements of the pore pressure. Today, downhole measurements are not measured often enough, but with these new methods it is possible at a low cost. Oloruntobi and Butt, (2019), claim that pore pressure prediction is very important to exploration drilling and production of oil and gas. They mention five different mechanisms which cause abnormal pore pressure: compaction disequilibrium (main reason), tectonic activities, clay diagenesis, aqua-thermal expansion and hydrocarbon generation. These mechanisms are further investigated in this study among others. Wensaas, Shaw, Gibbons, Aagard and Dybvik, (1994), did a study on these mechanisms in the Tampen area, more specifically at the Gullfaks field. From this study they suggested that compaction disequilibrium was not the main reason for overpressure at Gullfaks, but it could be caused by the high accumulation rate, and local leakage of gas from the reservoir.

Wiprut and Zoback, (2002), did a study on four oil and gas fields in the northern North Sea. They investigated the possibility for fault reactivation, leakage potential and hydrocarbon column heights from a geomechanically perspective. Further they discussed the relationship between overpressure and fault leakage in this area. The hypothesis discussed in their article was to investigate if faults that are reactivated in the current stress field are permeable, hence tend to leak, and if those that are not, might seal. To analyse the hypothesis, Wiprut and Zoback, (2002), investigated how the state of stress and pore pressure are acting on faults. They claimed that the three factors causing leakage and fault reactivation were:

- Locally high pore pressure,
- Optimal fault directions and
- Recent perturbation of stress.

These factors may have caused gas leakage and fault slippage in some fields, where in other fields the stress and pore pressure are not significant enough to generate faulting. In this thesis only the pore pressure is being studied.

Hermanrud and Nordgråd Bolås, (2002), carried out a study about leakage from overpressured hydrocarbon reservoirs at Haltenbanken and in the northern part of the North Sea. They found that cap rock leakage was the main reason for not finding hydrocarbons in the dry wells. Later when drilling deeper wells in this area, there were hydrocarbons present in some of the wells. They suggested that the probability for a leakage is higher in areas closer to the shelf edge, and that the risk of leakage is decreases with depth. They concluded with that leakage are a greater risk factor in Haltenbanken than in the North Sea.

2.0 Exploration phase

The main intention of exploration is to provide resource growth, and to discover and produce undiscovered resources. One of the most important aspects to keep the exploration activity going, is to award areas in licencing rounds. This includes areas both in mature and frontier areas, and not explored areas with little geological knowledge (Norwegian Ministry of Petroleum and Energy, 2011)

2.1 Licencing round

Before the exploration drilling can start, the companies need permission to explore the area and gain access to acres, which is given by licencing rounds. There are two different licencing rounds. The ordinary licencing rounds which includes frontier parts of the Shelf and the Awards in Predefined Areas (APA) which comprise mature parts of the Shelf. The ordinary licencing round are held every other year, and the APA is held every year (Norwegian Petroleum Directorate, 2019, https://www.npd.no/en/facts/production-licences/licensing-rounds). There is less knowledge about the frontier areas, compared to the APA and mature areas. These areas cover larger parts of the Barents Sea, smaller parts of the North Sea and deep-water areas in the Norwegian Sea. In these areas we have less knowledge about geology, structure and whether there are hydrocarbons present. It is therefore even more important with early estimates/indications of the pressure. These areas often have some technical challenges related to them, and also a lack of infrastructure. One benefit of an undiscovered area is that one might encounter larger discoveries since the areas have not been explored properly before (Norwegian Petroleum, 2019, https://www.norskpetroleum.no/en/exploration/exploration-policy/). All new companies that want to apply for a licence need to be prequalified before they can apply for the licensing rounds.

2.2 Prequalification

To be prequalified there are several factors a company needs to show that they can handle. The company applying to be prequalified need HSE competence (health, safety and environment), this is to strengthen the safety and to prevent major incidents occurring. The company also need to show that they can contribute to expand value creation, that they have an adequate management system and financial strength. They also need to specify that they have employees with the right competence to explore the area. This includes geology, reservoir technology, production and HSE (Petroleum Safety Authority Norway, 2019). The company need to send a production license application to the Ministry of Petroleum and Energy, and to NPD. This document includes geology, resource estimates, risk and probabilities and further plan for exploration among others of the block applied for. If we consider the risk & probability, it is possible to reduce this with early indications of the pressure.

2.3 APA

APA licencing started in 2003 and has since then been held every year. These areas contain information about geology, they are well planned and do not have that many technical challenges and are therefore called mature areas. Here it is more likely to encounter hydrocarbons, but maybe not as large discoveries that can be found in frontier areas. Even though large discoveries have been made here, like in 2010 the Johan Sverdrup field with its 406 million Sm^3 o.e oil and 10 million Sm^3 o.e gas was discovered in a mature area.

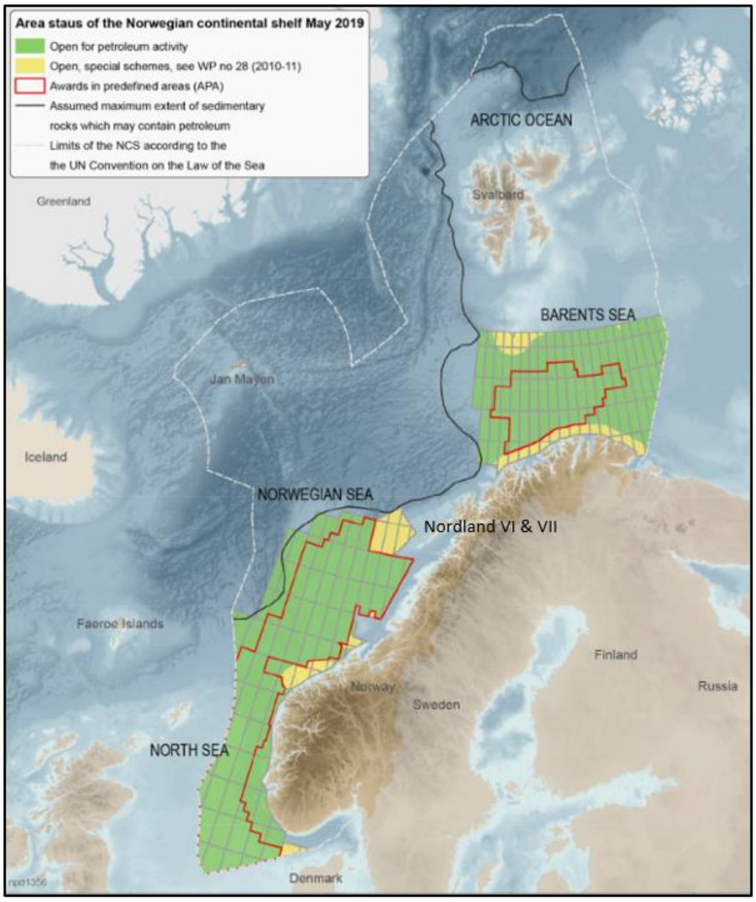


Figure 3 Licencing position for the Norwegian continental shelf , 2019, modified from Norwegian petroleum (https://www.norskpetroleum.no/en/exploration/exploration-policy/

Since the discoveries are usually smaller in these areas, the most profitable is to connect them to already existing infrastructure in production. This can also help already producing fields to produce for more years than what was originally planned (Norwegian Petroleum, 2019, https://www.norskpetroleum.no/en/exploration/exploration-policy /). As seen on Figure 3 from NPD, it shows the current status for areas on the Norwegian continental shelf (NCS). The red areas are awarded in APA, and the green areas has been opened for petroleum activity. The yellow area is open for exploration, but the companies must take certain precautions when exploring this area. In block Nordland VI and Nordland VII for instance, there is a large yellow area marked in Figure 3. Here there is a lot of fishing industry, shipping and tourism. In vulnerable areas like this, time limitations have been set for the companies to drill exploration wells and gather seismic data. The exploration phase for these areas is set to the period when the fishing activity is at its lowest (Norwegian ministry of petroleum and energy, 2011). The APA areas for 2019 are shown in Figure 4.

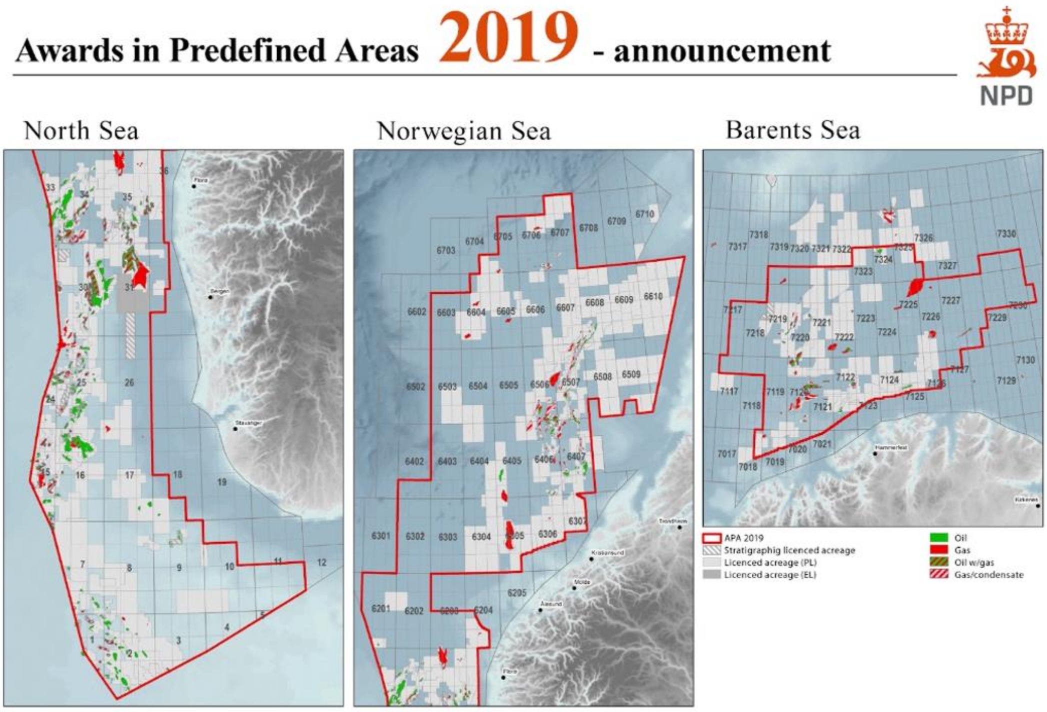


Figure 4 Announced acres in APA 2019, modified from Norwegian Petroleum, 2019, (https://www.norskpetroleum.no/en/exploration/licensing-position-for-the-norwegian-continental-shelf/)

2.4 Mapping of the area

Starting to drill an exploration well is a process that can take many years. The company works for several years with geological subsurface mapping of the area. Before an exploration well is drilled, seismic data must be collected and studied to see if there is any likelihood of hydrocarbon present. When mapping the area, it is important to understand the sub-surface, migration route for the hydrocarbons in the area, and where they could be trapped and possible accumulated. Seismic data is used to map the geological conditions in the area. The most common method now in modern time is 3D seismic surveys. 3D seismic surveys gives better quality images of the subsurface that provides insight into the petroleum system element and processes. The geologists interpret the images and decide if it is likely that there are hydrocarbons in the area. (Norwegian Petroleum, 2019, https://www.norskpetroleum.no/en/exploration/seismic-surveys/)

2.5 Uncertainty

During the exploration phase, the companies experience a lot of uncertainty. According to Ludvigsen, (2018), a company's biggest concern when starting to drill exploration wells is to encounter a dry hole, or not finding commercial amounts of hydrocarbons. On the NCS, the probability to find hydrocarbons are around 20-40 % (Ludvigsen, 2018). The geologists provide a geological model, where they estimate the probability of finding hydrocarbons in the area before the exploration drilling can begin. This high uncertainty to discover petroleum gives a remarkable potential for improvements, the pore pressure might be an indicator here that can help increase the probability of finding hydrocarbons.

2.6 Exploration wells

Exploration wells are divided into appraisal and wildcat wells, where the first stage is to drill a wildcat well (Ludvigsen, 2018). According to "the Norwegian shelf's competitive position" (NORSOK) D-010, "A wildcat well is a well drilled to explore a new, clearly defined geological unit, delimited by rock types by way of structural or stratigraphic boundaries" (NORSOK standard, 1997). If there is proven existing energy reserves at the field, appraisal wells are drilled to investigate the quality and size of the reservoir. An appraisal well is "A well drilled to establish the extent and the size of a petroleum deposit that has already been discovered by a wildcat well." (NORSOK standard, 1997). An appraisal well is important to learn about the reservoir properties of the field. When the decision is made to drill exploration wells, a drilling program is prepared. This program contains geological forecasts, like pore pressure and formation depth. It also contains information about which drilling parameters that are the most optimal for the conditions in the specific field (Ludvigsen, 2018). In this study, the data are mainly collected from appraisal wells, since these often contain more information about well properties.

2.7 Exploration activity on the NCS

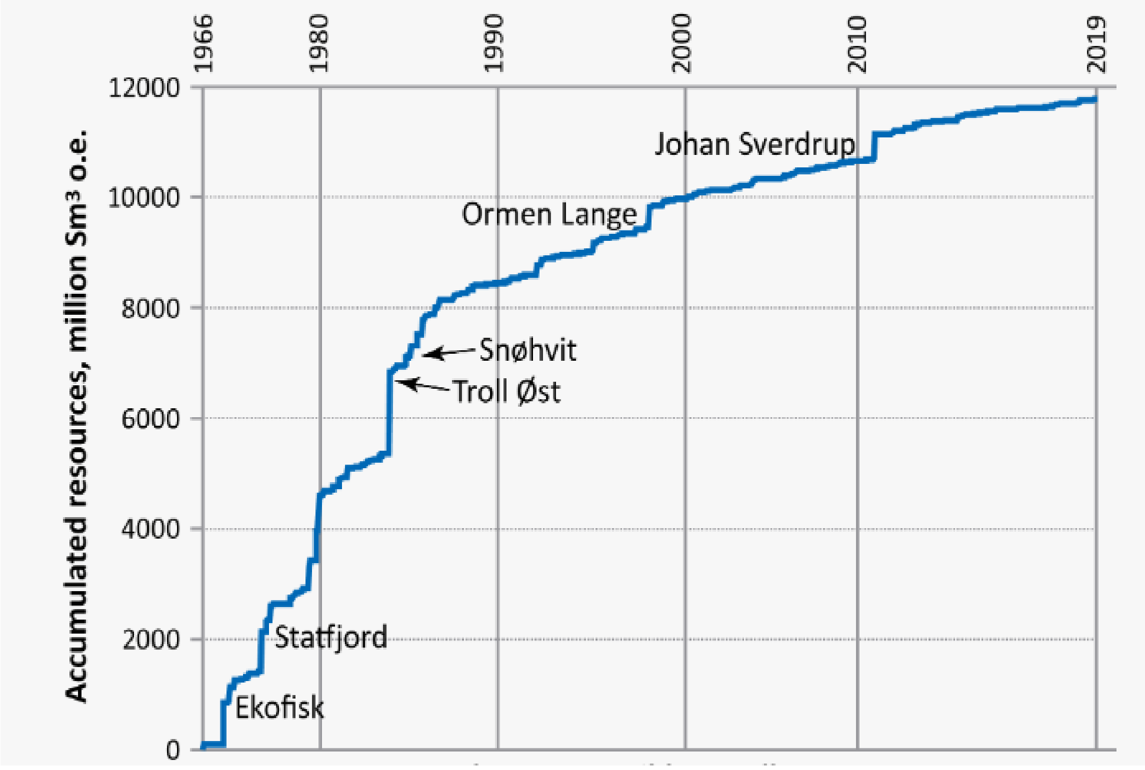


Figure 5 Accumulated resources on the Norwegian continental shelf, 1966-2018, from Norwegian Petroleum, 2019 https://www.norskpetroleum.no/en/exploration/

The NCS has an area of over two million square kilometres, and the first exploration well was drilled here in 1966. On the NCS around 1100 wildcat wells have been drilled, where more than 700 of them have been drilled in the North Sea (Norwegian Petroleum, 2019, https://www.norskpetroleum.no/en/exploration/exploration-activity/). As seen on Figure 5**,** the greatest discoveries were Statfjord and Troll, it was also a big growth in the discovery when Johan Sverdrup was found in 2010. From NPD`s resource report (2018), it is claimed that there has been reduced activity in exploration the last years, because of the drop in the oil price in 2014. This trend turned again in 2018 again, and the acres have been expanded by 5 blocks in the North Sea, 37 blocks in the Norwegian Sea and 48 blocks in the Barents Sea. The APA area is gradually becoming larger (Norwegian Petroleum, 2019, https://www.norskpetroleum.no/en/exploration/licensing-position-for-the-norwegian-continental-shelf/). In Norway today, there are around 65 fields producing in the North Sea, 18 fields in the Norwegian Sea and two in the Barents Sea (Norwegian Petroleum, 2019, https://www.norskpetroleum.no/en/developments-and-operations/activity-per-sea-area/).

In the years to come, Equinor is one of the companies that focus on more exploration. The executive vice president for exploration at Equinor, Tim Dodson claims that:

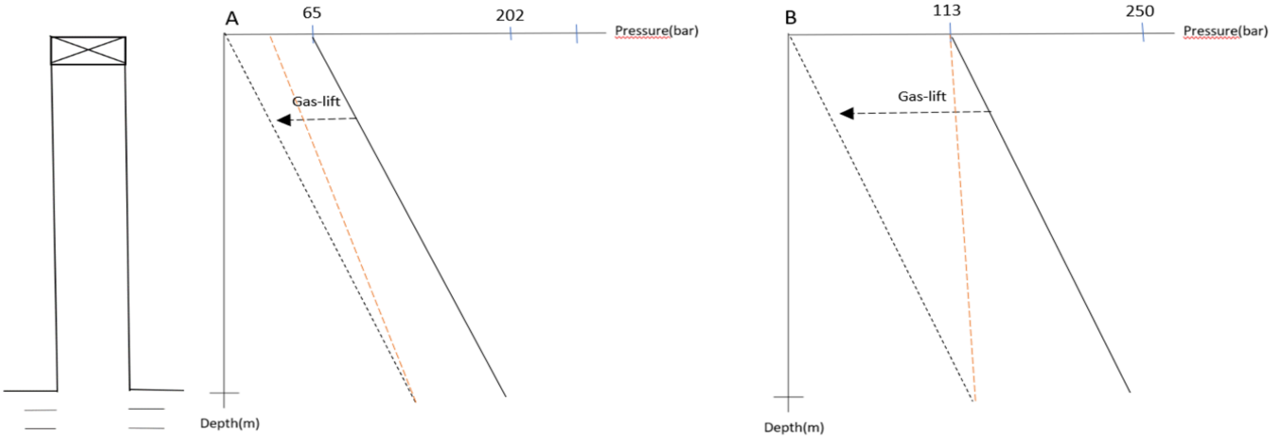
"Active exploration on the NCS is vital to succeed in renewing the shelf. We are making two important moves: We have developed a strategy for more gas exploration, and we will also test new ideas in some prospects every year. The likelihood of discovery in these wells will be lower than in other targets, but we see it as necessary to regularly test a few of what we call "game changing wells" in order to explore the NCS to its full potential".

This was stated in an article in August 2018 on Equinor`s news pages. Equinor plans to drill 20-30 exploration wells every year, in the years to come, and explore for more gas. This will as, Tim Dodson says, contribute to explore the NCS to it's fullest. By more gas exploration and exploration drilling close to already existing infrastructures the oil and gas industry can survive for many years to come (Equinor, 2018). In this study we will further look at the possibility for overpressured exploration wells being an indicator that can increase the probability of hydrocarbon discoveries on the NCS.

2.8 Production methods

Another parameter that is important to evaluate before expanding a new field, is the production. How the well is going to produce, and for how long before gas/water injection or artificial lift is introduced, is important to consider. There are related large costs to these methods for pressure and flow control in the wells. In this study, all the fields are produced by water/gas injection, gas lift or WAG. Some also with pressure depletion. Injection wells are drilled to inject either gas or water into the reservoir to maintain the reservoir pressure and force the hydrocarbons into the production well. Artificial lift on the other hand is used when the gas or water injection cannot maintain the hydrostatic pressure in the reservoir. The most common methods of artificial lift used on the NCS are Gas lift. Gas lift cause a decrease in the density and weight of the fluid in the tubing, so the differential pressure between the reservoir and the well increases, and the fluid starts to produce at an optimal flowrate (Devold, 2006). The wells in an overpressured area might be possible to produce for a longer time before these flow control methods are introduces. This will make the wells more profitable for the companies.

It is not only the reservoir pressure that affects the flow of the oil. The density and water pressure also play an important role. If the oil is light, it is possible to produce more before artificial lift is introduced. To show the advantage of having an overpressured reservoir, an example is provided.



Normal pressure = 0,098x1,03x2000 = 202 bar

Weight of oil = 0,098x0,7x2000 = 137 bar

Pressure under choke = 202 – 137 = 65 bar

Reservoir pressure = 0,098x1,28x2000 = 250 bar

Weight of oil = 0,098x0,7x2000 = 137 bar

Pressure under choke = 250 – 137 = 113 bar

In **Figure A** we assume a normally pressured reservoir. Here the water density is 1,03 s.g. which is considered as the normal pressure gradient in the North Sea. The reservoir pressure will than become 202 bar at 2000 m depth. If we assume the oil having a density of 0,7 s.g. the weight of the oil column will become 137 bar. From the normally pressured **Figure A** it is possible to produce the well for 65 bar before artificial lift must be introduces. In **Figure B** we assume a gradient in the reservoir of 1,28 s.g. The reservoir pressure than becomes 250 bar. If we assume the same weight of the oil column as in **A**, the pressure under the choke than becomes 113 bar. Here it is clear that the overpressured well are possible to produce for a longer time (48 bar more) before artificial lift must be introduced to make the well flow. The **Figures** also show the pressure gradient line when gas-lift are introduced.

3.0 Hydrocarbons in porous media

There are several mechanisms that affect how the hydrocarbons act in a porous media. Porosity, permeability and viscosity being the main mechanisms.

3.1 Permeability

Permeability is the rock's ability to transmit fluids and is important when determining the flow characteristics of hydrocarbons in a reservoir. It is the flow of the pore fluid through the porous rock, and it is often higher in horizontal direction than in vertical in sandstone (Zolotukhin and Ursin, 2000, p.63). The unit for permeability is Darcy. A rock has a permeability of 1D if 1 cm^3 fluid with viscosity of 1 cp can flow 1 cm/s through the cross section of 1 cm^2, with a pressure of 1 atm/cm along the flow direction (Zolotukhin and Ursin, 2000). The permeability can either be absolute, relative or effective. If there is a single fluid flowing through the medium, the permeability can be regarded as constant, hence *absolute permeability* (Zolotukhin and Ursin, 2000). *Relative* permeability is the ratio of effective permeability to absolute permeability.

$$k_r = \frac{k_e}{k} \tag{3.1}$$

Where:

k_r relative permeability
k_e effective permeability
k permeability

(Dandekar, 2006). At *effective* permeability, the medium is saturated with more than one fluid (oil, water, gas) in the system. The permeability can vary within a reservoir, and it depends on grain size, grain shape and cementation. It also depends on the connectivity of the flow path in the rock. If a formation has a permeability between 1-10 mD It is considered poor, if it has a permeability of 10-100 mD it is considered to be good, and if it has a permeability of 100-1000 mD it has excellent quality. Permeability is related to porosity, so they will affect each other. The permeability is often difficult to measure, so the correlation to porosity is often used (Zolotukhin and Ursin, 2000).

3.1.1 Flow potential

The permeability is common to measure through Darcy's law:

$$Q = -\frac{k}{\mu} A \frac{dP}{dL} \tag{3.2}$$

Where:

Q	volumetric flow rate through core plug [m^3/s]
k	permeability
µ	viscosity [cp]
A	cross sectional area [m^2]
$\frac{dP}{dL}$	pressure gradient [pa/m]

*The minus sign denotes a negative pressure gradient in the x-direction.

Darcy's law is used to calculate the flow of a fluid through a porous medium or reservoir (Zolotukhin and Ursin, 2000, p.64). The law depends on the viscosity of the specific fluid and the drop in pressure over a certain distance. Darcy's law is applicable only if the fluid is laminar, which means that the fluid flows smoothly in a parallel layer, with no currents or waves. If there is a turbulent flow rate, Darcy's law no longer is applicable because it causes a large pressured drop which is not linear with the flow rate. In laminar flow, this is insignificant (Zolotukhin and Ursin, 2000).

3.2 Porosity

Porosity is defined as the pore volume divided by the total volume and is expressed as a percentage. Dandekar, (2006), claims that the more porous the rock is, the more voids it contains, hence it contains more reservoir fluid. The porosity decreases with depth, but when there is overpressure in the reservoir, there is an increase in the porosity (Figure6). This is valid both for sandstone and shale (Dandekar, 2006). The formula for porosity is

$$\varphi = \frac{pore\ volume}{total\ or\ bulk\ volume} = \frac{V}{Vb} \tag{3.3}$$

We divide porosity into absolute and effective porosity. *Absolute* porosity is the ratio of the total void volume $V_{pa,}$ over the bulk volume V_b, regardless of the voids whether they are interconnected or not. *Effective* porosity on the other hand, is the ratio of the total volume of interconnected voids V_p over V_b (Zolotukhin and Ursin, 2000, p.64)

There are several factors that effective porosity is dependent on, some of them are (Dandekar, 2006, p.23):

- *Grain size* - If small particles are mixed with larger grains, the porosity is reduced.
- *Grain shape* - If the grains are irregular, the porosity is higher.
- *Sorting* - Good sorted sediments have higher porosity than poorly sorted sediments.
- *Clay content* - Increase the void space, and then makes an increase in porosity.
- *Compaction and cementation* - Tend to decrease the porosity.

Porosity of a reservoir rock vary from 5-40 %, with a range of 10-20 %. There are several ways of measuring the porosity, and the most common are by wireline log (sonic log, formation density and neutron porosity), core sampling and through cuttings (Dandekar, 2006).

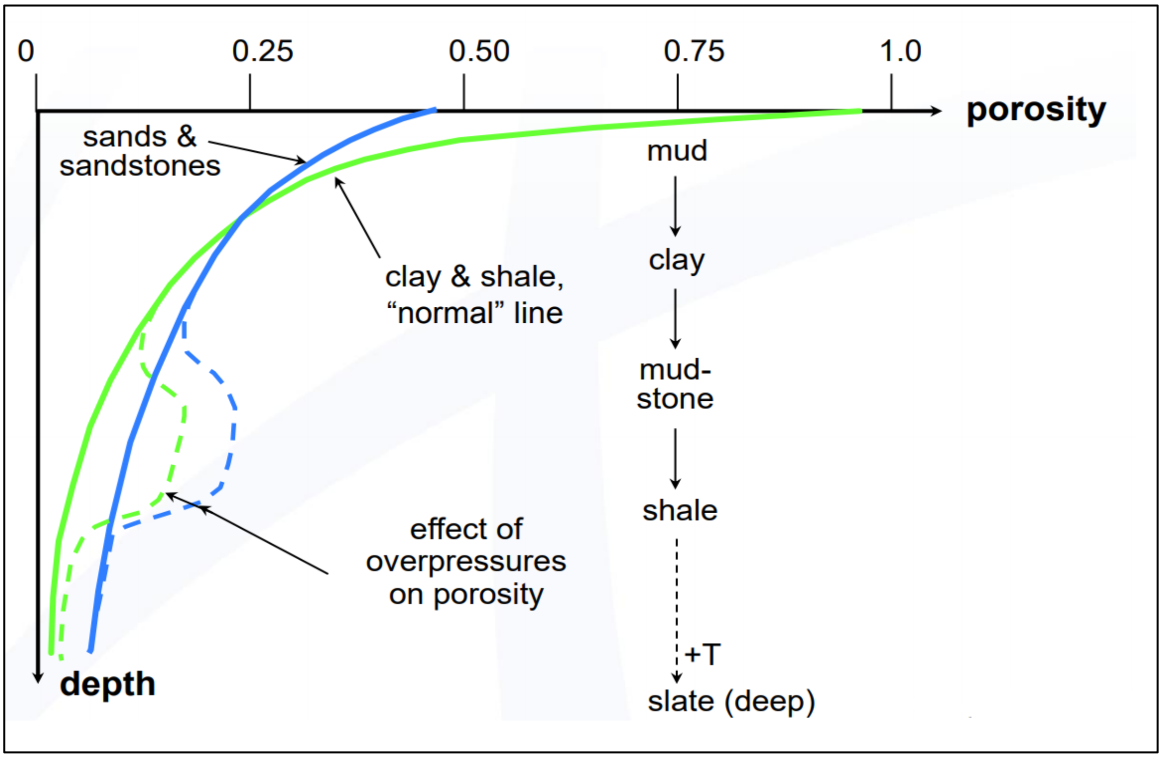


Figure 6 Porosity and Depth, from *"Pore Pressure, GMI Oilfield Geomechanics,"* by Baker Hughes geomechanics services, 2012, p. 19. Copyright 2012, Baker Hughes.

3.3 Viscosity

Viscosity can be defined as the fluid's resistance to flow. If the viscosity is high, there is high friction between the molecules in the fluid. The fluids with high viscosity, do not flow as easily as one with low viscosity. The viscosity of liquids varies with temperature, as it decreases when temperature increases and the viscosity of gases increase with higher temperature (Zolotukhin and Ursin, 2000, p.83). Viscosity also plays a role when deciding if a well or field is profitable to expand. If the oil has a high viscosity, and is difficult to produce, it is not certain that it could be profitable. The costs of heating the pipes, injection of chemicals or injection of gas/water might not be commercial. At the Mariner field located in the British sector of the northern part of the North Sea, there is problems with the production. The oil here is heavy and tough and requires a large amount of energy to produce. The Maureen formation has a viscosity of 67 cp while the Heimdal reservoir has a viscosity of 508 cp (Equinor, 2019). This heavy oil has no overpressure to flow into the production wells, so it must be produced with artificial lift or water/gas injection. To solve the production problem at Mariner, Equinor injects a lighter oil to improve the flow. The viscosity of the heavy oil is then reduced, there is then no need for heating of the oil during transport and storing.

To get a good flowrate in the reservoir we need the viscosity to be low, and the other parameters to be high. The desired viscosity in a well can be reached with the help of chemicals like CO^2 or temperature to make the oil thinner, and the pressure can be increased by for instance water/gas injection or artificial lift. Effective permeability can be reached by reservoir stimulation or hydraulic fracturing, and thickness is reached by drilling. By controlling these parameters, we can get better the flow, which again is more profitable.

4.0 Norwegian North Sea geology

The North Sea has its border between Norway, the British Isles and the European continent. The area of the North Sea is 575 000 km^2, and the deepest part of the sea is around 400 meters (SNL, 2019, https://snl.no/Nordsj%C3%B8en). The northern part of the North Sea covers the regions; East Shetland basin, Tampen Spur, North Viking and Sogn grabens and Horda platform (Knag, South and Spencer, 1995). The best sandstone reservoirs in the North Sea are found in the Triassic to Middle Jurassic age. In Table 1 reservoir formation names and their ages for the different fields chosen in this study are presented.

Field	**Formation**	**Age**
Gullfaks	Brent group Statfjord group Cook and lunde formation	*Middle jurassic* *Lower jurassic and upper Triassic*
Snorre	Lunde formation and Statfjord group	*Triassic and lower jurassic*
Vigdis	Brent group Statfjord group	*Middle Jurassic* *Upper Triassic and lower jurassic*
Visund	Lunde formation and statfjord group Brent Group	*UpperTriassic and lower Jurassic* *Middle Jurassic*
Johan Sverdrup	Draupne formation Statfjord group Vestland group	*Upper jurassic* *Upper triassic* *Middle, Upper Jurassic*
Heidrun	Åre, Tilje, Garn and Ile formation	*Lower, Middle Jurassic*
Goliat	Kobbe and Snadd formation Kapp Toscana gr	*Triassic* *Triassic-Jurassic*

Table 1 -Reservoir formation names and their ages of the wells in the North Sea, by Norwegian Petroleum, 2019 (https://www.norskpetroleum.no/en/facts/field/)

4.1 Triassic

The northern part of the North Sea is dominated by North-South faulting, which has resulted in well-defined and deep grabens (Figure 8) (Glennie & Underhill, 1998). Triassic was affected by a lot of rifting, with sediment deposits. In the Upper Triassic strata, carbonates and salt deposits are found in the southern part of the North Sea. Clastic sedimentation dominates the central and northern North Sea (Bjorlykke, 2015). The line between the Triassic and Jurassic age is marked by an extensive marine transgression (Halland et al., 2011), which is when the sea level rises relative to land, resulting in larger sea areas.

4.2 Jurassic

Middle Jurassic was affected by doming and erosion while Late Jurassic was dominated by rifting and erosion. Here several fault blocks were uplifted and eroded. During late Jurassic rifting, large tilted fault blocks were formed (Husmo et al., 2002). In Figure 7, an example from the northern part of the North Sea are shown. The dark green area in the Figure show the source rock, and the arrows show possible migration routes. As mentioned above, the area was affected by rifting, which have produced good conditions for the creation of source rock and traps on the uplifted fault blocks. During late Jurassic, and into Early Cretaceous there was a significant rifting phase in the North Sea. Extensive block faulting occurred in this period, which caused uplift and tilting which led to erosion on the topography and sediment supply. The most important source rock was deposited in the Draupne Formation (Halland et al., 2011). The deposition of this organic rich shale continued until Early Cretaceous (Bjorlykke, 2015). The rifting in this age resulted in rotated fault blocks and small fan deltas was formed along the rift. Fluvial and marine sandstone from lower Jurassic age are essential reservoir rocks in the Viking Graben in the northern part of the North Sea. Gullfaks, Vigdis, Visund and Snorre have traps which consist of rotated fault blocks formed during rifting in the Late Jurassic (Bjorlykke, 2015).

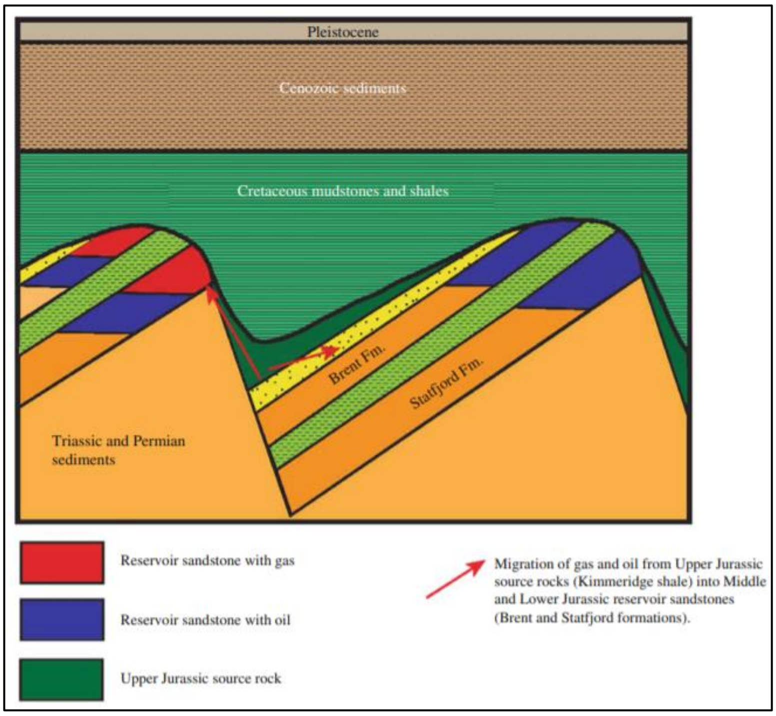


Figure 7 Illustration of migration from Upper Jurassic source rock to Middle and Lower Jurassic. From *"Introduction to Petroleum Geology"*, by Bjorlykke, 2010, *Petroleum Geoscience: From Sedimentary Environments to Rock Physics.*

In Figure 8, Jurassic age are marked as light and dark blue, and divided into Upper and Lower Jurassic. These two layers are parallel to each other, meaning they were deposited before the rifting took place (Husmo et al., 2002). The hangingwall has deposits of greater thickness than the footwall.

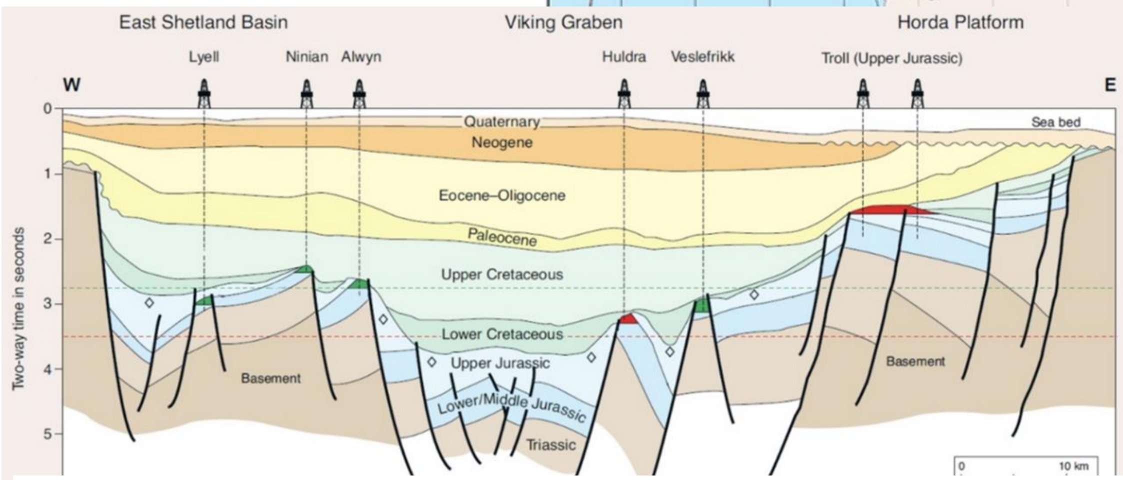


Figure 8 Cross section of the Viking graben in the North Sea, modified from "*Lower and Middle Jurassic",* by Husmo et al., *The Millenium Atlas: petroleum geology of the central and northern North Sea*, pp.129-155.

4.3 The Tampen area

The Tampen area is located in the northern part of the North Sea. In Figure 9 a cross section of the area are shown.-The fields that are in this area are Snorre, Sygna, Statfjord, Tordis, Gullfaks, Vigdis, Kvitebjørn, and Visund (SNL, 2019, https://snl.no/Tampenomr%C3%A5det2). The Tampen area consists of several series of fault blocks formed in the Late Jurassic to Early Cretaceous. This was due to uplift between Viking Graben and Møre Basin (Steen, Sverdrup and Hanssen, 1998).

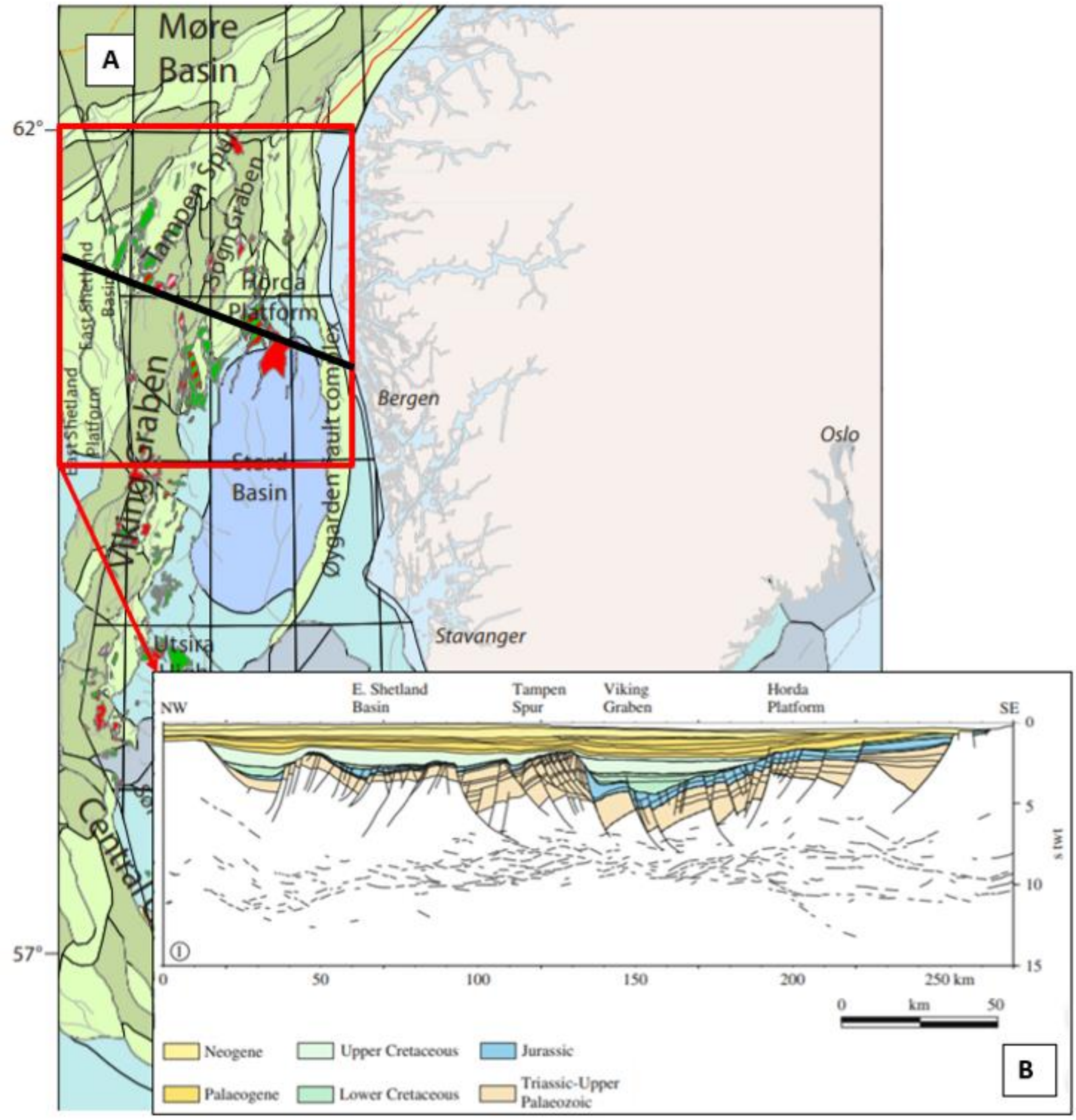


Figure 9 A) Map of the Norwegian part of the Norwegian North Sea. Modified from *"CO2 storage atlas: Norwegian North Sea"*, by Halland et al., 2011, p. 22, Copyright 2011, The Norwegian Petroleum Directorate **B)** Cross section of the northern part of the North Sea. From *"Geology of the Norwegian Continental Shelf. Petroleum Geoscience," by Bjorlykke, 2015, p. 609.*

The fields chosen in this study are shown in table 1.

- Snorre, Gullfaks, Vigdis and Visund are from the Tampen area.
- Johan Sverdrup from the central part of the North Sea.
- Heidrun is a field in the Norwegian Sea.
- Goliat is placed in the Barents Sea.

The Tampen area is the primary study area, but to get an overview of the whole NCS, one field from the Barents Sea, one from the Norwegian Sea and one from the central North Sea is chosen.

5.0 Pore pressure

Pore pressure is the pressure of the formation fluid in the pores of the reservoir rocks at any given depth (Zoback, 2007). When pore pressure is predicted, its either measured using well data at the wellbore or by seismic interpretation (Oloruntobi and Butt, 2019). Before drilling an exploration well, pore pressure prediction is important to ensure drilling safety. This to ensure that there is no unexpected overpressure in the well. It is used to determine how the well should be designed, and to predict the right mud program. It also plays a huge role for reservoir modelling, production forecast of the well, integrity and geo-mechanical analysis (Oloruntobi and Butt, 2019). The measurement of pore pressure depends on the lithology within the reservoir. If there is sandstone in the reservoir the pore pressure is determined from logging. If there is shale in the reservoir the pore pressure is not that simple to measure. Here it’s necessary to determine the pore pressure by indirect methods.

5.1 Normal pore pressure

If the pore pressure at any depth is equal to the hydrostatic head of water at the same depth, it is normal (Moss, Barson, Rakhit, Dennis and Swarbrick, 2003). The gradient for normal pore pressure varies with temperature, concentration of salt, pore fluid type and with depth (Oloruntobi and Butt, 2019). Normal pore pressure gradient in the North Sea are set to be 1,03. s.g, which is defined from salinity (Aadnoy, 2010). All pressure gradients above this, will be considered as overpressure in the North Sea. In for example the Gulf of Mexico, this gradient lies at 1,07 s.g. so the definition of overpressure here would be different.

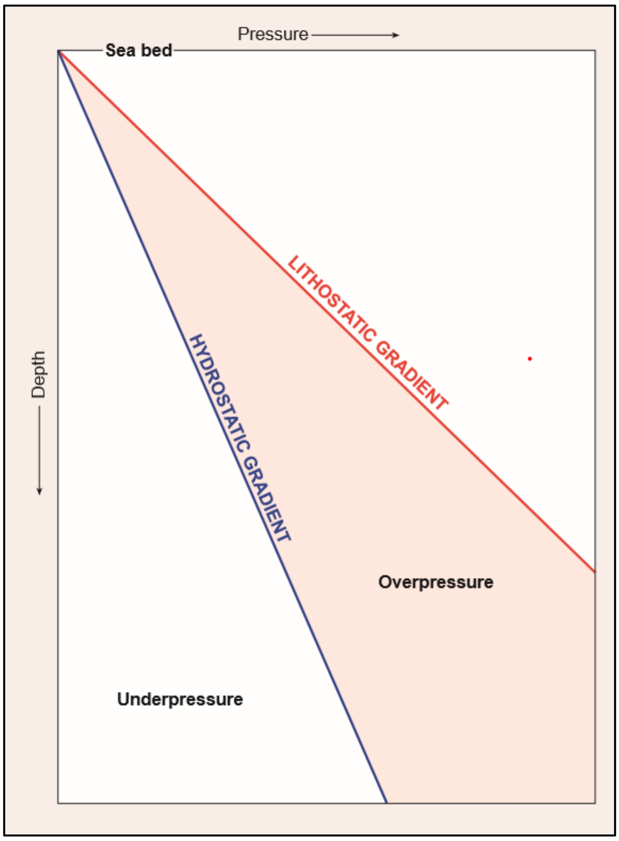


Figure 10 Pressure/depth plot. From *“Formation pore pressures and formation waters,”* by Moss et al., 2003, *The Millennium Atlas,* pp. 317-329.

The pore pressure can be found both above and below the hydrostatic gradient (abnormal pressure) (Figure 10). The lithostatic gradient is the pressure exerted by the overlying sediments weight. Overpressure can be observed between these two gradients (hydrostatic and lithostatic), and underpressure can be seen below the hydrostatic gradient. In the North Sea, the lithostatic gradient represents an approximate upper limit for pore pressures (Moss et al., 2003).

5.2 Subnormal pore pressure

When the pressure is subnormal it's below the hydrostatic pressure (underpressure). This may have occurred due to production and geological conditions. The geological reasons include tectonic activity or stratigraphic traps. Reservoir depletion is one factor that can affect the subnormal pore pressure related to production condition. If there has been erosion and uplift in the reservoir, it can result in subnormal pore pressure (Oloruntobi and Butt, 2019). If there is a underpressure in the reservoir, the production must eventually stop. It is not always that artificial lift methods work properly when the pore pressure is too low.

5.3 Overpressure

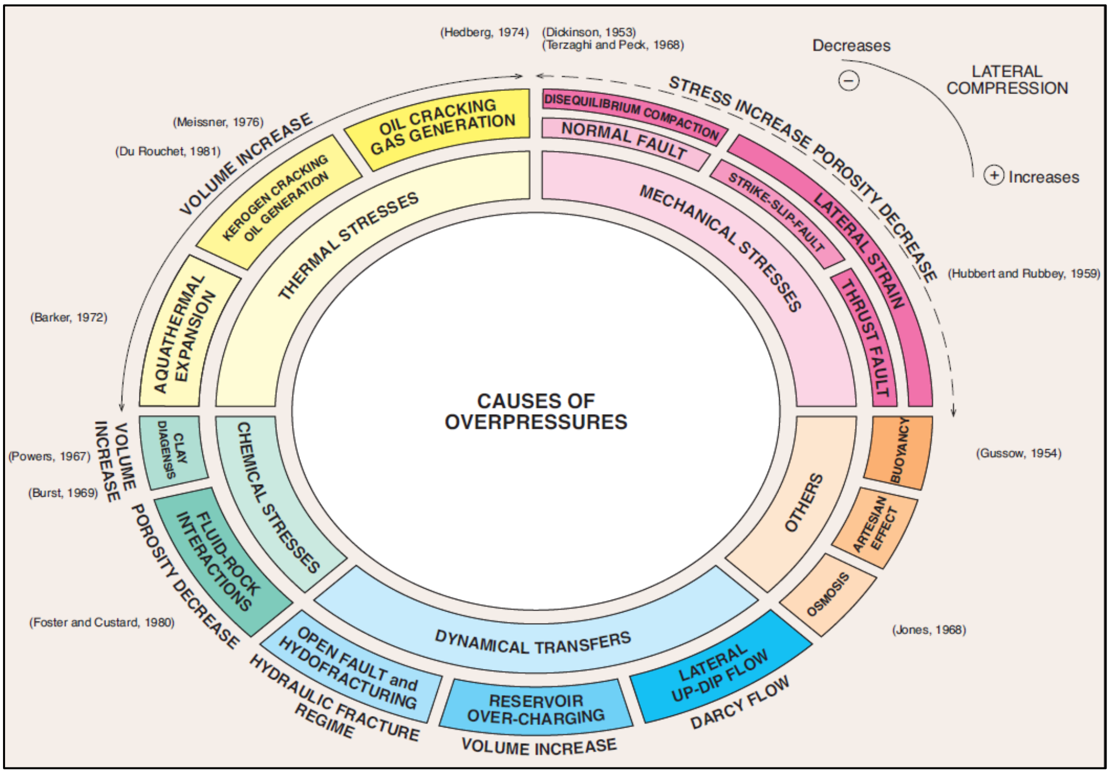


Figure 11 Overpressure generating factors. From "*Formation pore pressures and formation waters,*" by Moss et al., 2003, *The Millennium Atlas*, pp. 317-329.

Overpressure occurs typically in areas where there has been a fast burial of sediments, containing fluids, so that the pore fluid is not able to escape. The pore pressure will then increase, as overburden pressure also increase (Oloruntobi and Butt, 2019). Figure 11 shows the most common types of overpressure and reasons for them to occur. There are six main mechanisms that cause overpressure, which are further explained in this chapter.

- *Compaction disequilibrium/ undercompaction*
- *Buoyancy force*
- *Tectonic activities*
- *Clay diagenesis*
- *Aqua-thermal expansion*
- *Hydrocarbon generation*

5.3.1 Buoyancy

The buoyancy is the main driving force for petroleum migration, and one of the mechanisms causing overpressure. It occurs during the secondary migration stage and is resisted by the capillary force. The upward migration of oil, gas and water are driven by the buoyancy force (Schowalter, 1979). It is the density difference between the water and gas/oil phase. The bigger this difference is, the greater the buoyancy force will be for the hydrocarbon column. Water densities range from 1 to 1,2 s.g; oil densities are between 0,5 to 1 s.g; and gas densities are lower than 0,5 s.g. This results in oil-water buoyancy gradients ranging from 0 to 0,69 s.g. Gas-water buoyancy gradients in the subsurface range from about 0,46 to 1,15 s.g. (Schowalter, 1979).

The buoyancy is calculated using Archimedes law. This law says that buoyancy is the same as the volume of the fluid displaced.

Buoyant force acting on any submerged object = Weight of the displaced fluid.

$$F_A = \rho V g \tag{5.1}$$

Where

F_A buoyancy force [N]

ρ density of liquid [kg/m^3]

V volume of liquid moved [m^3]

g gravitational acceleration [m/s^2]

Buoyancy is a surface force, and it acts in the opposite direction as the gravitational force, which acts downwards. From this we know that it is only pressure acting on the vertical area that lead to buoyancy (Aadnoy & Kaarstad, 2006).

Buoyancy factor

$$\beta = \frac{Suspended\ weight\ in\ mud}{Weight\ in\ air} = 1 - \frac{\rho_{fluid}}{\rho_{pipe}} \tag{5.2}$$

5.3.2 Compaction disequilibrium

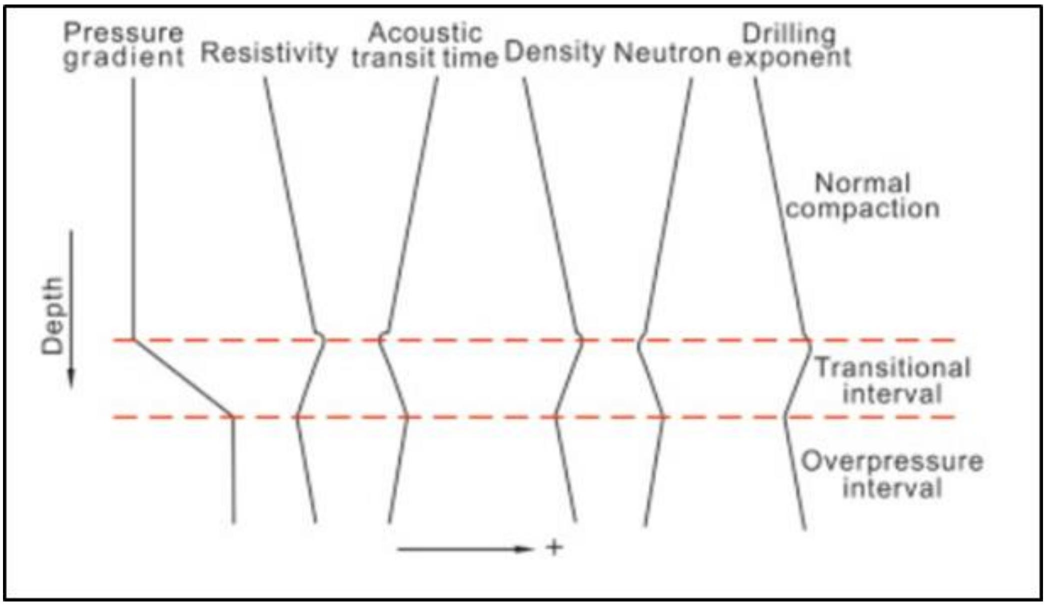


Figure 12 Logging response of overpressures caused by disequilibrium compaction, from *"Advances in the origin of overpressures in sedimentary basins"* Zhao, Li., Xu, 2018, Shaanxi Key Laboratory of Petroleum Accumulation Geology.

Compaction disequilibrium can occur where the formation has abnormal formation compaction, which gives abnormal pore pressure. This mechanism are often assumed to be the main reason for overpressure, but there are often limited data to support this assumption (Teige, 2008). Compaction leads to a decrease in porosity and volume of a sediment, and it occurs during quick sedimentation and burial of sediments. When the sedimentation happens rapidly, the permeability will also decrease (Chilingar, Serebryakov and Robertson, 2002). The sedimentation happens so fast that the fluid cannot diffuse through it. The fluid tries to penetrate these new layers of sediment, but if the sedimentation happens at a faster rate than the diffusion occurs, an overpressure builds up. The vertical stress is then increased. Since there is more weight added on top of the formation, because of the new sediments, the pores can eventually collapse. The fluid can then be trapped inside the deposited sediments, which cause compaction disequilibrium. It happens often in sand-rich to shale-rich environments (Mouchet & Mitchell, 1989). Figure 12 shows the logging response on some of the logs used to identify pore pressure, when there is overpressure due to compaction disequilibrium. This can be observed in the logs as decrease in resistivity, density and d-exponent, and an increase in the sonic and neutron logs.

Teige, Hermanrud, Wensaas and Bolås ,(1999), did a study in the North Sea and Haltenbanken to investigate if there was overpressure in the shales due to compaction disequilibrium. They investigated the hypothesis which says that overpressured shales had a higher porosity than normally pressured shale. In this study eleven units of shale were considered. Log data from around a 100 wells in the North Sea and Haltenbanken were studied. Teige et al., (1999), concluded with the fact that the porosity of the wells in the North Sea, nor the porosity from Haltenbanken varied much between the overpressured and normally pressured formation *(*Teige et al., 1999). Teige et al., (1999) claim that compaction equilibrium therefore seemed to be false in both Haltenbanken and the North Sea, since they do not have higher porosity in the overpressured shales. The different formations seemed to have been compacted separately during burial.

5.3.3 Tectonic activity

Tectonic activity influence fluid pressure distribution, due to rock deformation. Pressure may change due to changes in the formation and geometry. The sediments are also exposed to tectonic stress. Tectonic activity includes faulting, folding, sliding and movement of shale, sand and salt. The volume of pore pressure here is reduced by tectonic compression of the rock (Chilingar et al., 2002). The most common tectonic activity in the North Sea is faulting.

5.3.3.1 Faulting

Faulting is a fracture between two blocks in a given volume of rock where the blocks move relative to each other. A fault can displace a fluid-bearing layer vertically and create new paths for fluid migration or create barriers that isolate the fluids and preserve the original pressure from tectonic movements. In very folded formations, pore volume is reduced due to compression (Chilingar et al., 2002). The reservoir rocks are divided into sections, and the overpressure in the water zone is constant in each compartment. These sections are separated from each other by fractures, faults or seal. When one sections moves relative to another the fluid can migrate. This happens because the porosity

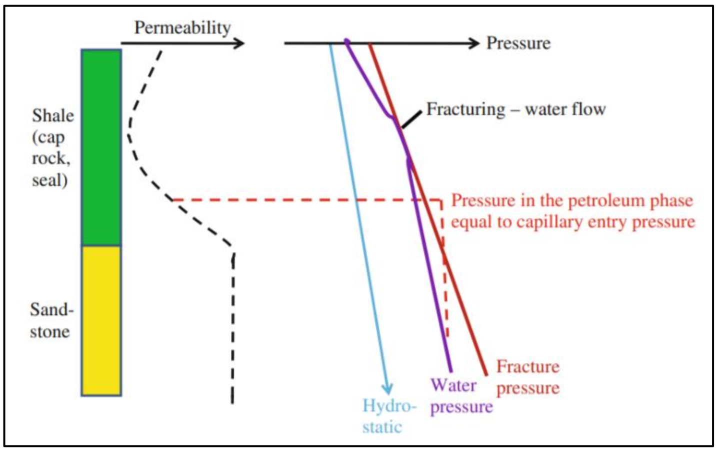


Figure 13 *Fracturing in seals. From "Petroleum migration", by Bjorlykke, 2010, Petroleum Geoscience: From Sedimentary Environments to Rock Physics, p. 357.*

in each section decreases during burial. The hydrocarbons also occupy a volume; hence the water is being replaced. As seen in Figure 13 the fracturing in seals occur with increasing pressure and when the permeability of water is low. The fracturing pressure can be regulated by the water-saturated shale, also when the pressure is high in the oil-zone *(Bjorlykke, 2015).*

5.3.3.2 Leakage

Leakage can occur in a trap through fractures from overpressure or tectonically activity, or it can leak through the seal matrix. Leakage through the matrix occurs if the capillary force cannot withstand the buoyancy force of the hydrocarbons (Bjorlykke, 2015). In the northern part of the North Sea, leakage between different seal rock in Jurassic reservoirs are the most common leakage (Hermanrud and Nordgråd Bolås, 2002). The leakage in the northern part of the North Sea are most likely a result of pressure builds up to the point where the cap rock has been fractured (Bjorlykke, 2015).

Wiprut and Zoback (2002) claim that for a leakage to occur, the pore pressure must be so high that it can reactivate the fault. They studied the hypothesis about the pore pressure and stress which affect the surface of the fault, decide if the fault is going to leak after sealing. When the fault has slipped and leak, it may seal again and creep. The fault can again slip and issue larger amounts of hydrocarbons, if the pore pressure increases to its critical level. Wiprut and Zoback, (2002), showed in their study that leakage along potentially active faults could influence various reservoirs in the northern part of the North Sea. Moss et al., (2003*)*, suggested that lateral fault leakage in the northern North Sea is an important factor on the overpressure magnitude, as the overpressure is less variable at a given depth.

5.3.3.3 Fault reactivation

During Middle Jurassic to Early Cretaceous reactivation of already existing faults occurred in the northern part of the North Sea. Over time, a fault can be reactivated over time, meaning that new pathways can be created that allow hydrocarbons to leak. This happens when changes in tectonic stress regimes occur. Another reason for fault reactivation can be when the pore pressure changes due to injection or production in and around an already existing fault. (Cerveny, Davies, Dudley, Fox, Kaufman, Knipe and Krantz, 2004/2005). Wiprut and Zoback, (2000), did a study on fault reactivation and fluid flow in the northern part of the North Sea, they claimed that there are three reasons for fault reactivation in the northern part of the North Sea:

- Fault reactivation caused by a recent increase in the compressional stress, due to postglacial rebound.
- Locally elevated pore pressure because of natural gas in the reservoir on the footwall.
- A fault orientation which is oriented for frictional slip in the stress field.

5.3.3.4 Glaciation/ glacial loading

Glaciations are characterised by high rates of erosion and low temperatures (Bjorlykke, 2015, p.104). Haltenbanken and the North Sea were exposed to several periods of glaciation and deglaciation during latest Cenozoic. Grollimund and Zoback (2003) calculated the stress changes resulting from glacial loading, to compare the possible fault reactivation to probable leakage in the past, in the northern part of the North Sea. The study looks at how the glaciation might have affected the formations. They suggested that fast subsidence and sedimentation due to glacial erosion influence the reservoir by maximizing the seal rock integrity. An increase in horizontal stress due to lithospheric bending from deglaciation can cause an increase in pore pressure. They concluded that the explored reservoirs might have been exposed to faulting and then leakage due to glaciation in the area, even though they were not able to prove it.

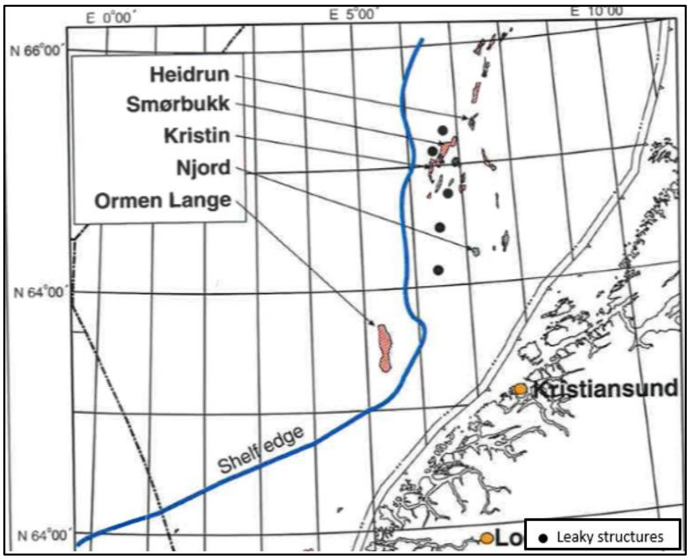


Figure 14 Shelf edge and leaky wells in the Haltenbanken area, modified from Hermanrud and Nordgård Bolås, 2002.

As seen in Figure 14, the blue line indicates the shelf edge, and the black marks indicates leaky wells. During glaciation in the Haltenbanken area, the ice was lying on the shelf edge. This resulted in increased vertical stress in the area (Hermanrud and Nordgård Bolås, 2002). Hermanrud and Nordgård Bolås (2002) concluded with that glacial flexuring might have resulted in leakage due to the formation of new fractures. Glaciation in the Barents is quite large, up to 3 km of erosion and uplift. This affects the quality of the reservoir, the migration and the maturity of the source rocks. Glacial erosion in the Barents Sea might have caused leakage out of the reservoir. In this area hydrocarbons might have escaped along faults which has been reactivated due to glaciation (Tasianas et al., 2016).

5.3.4 Clay diagenesis

Diagenesis is the changes a sediment undergoes after it is deposition. It includes the lithification process, where the sediment is converted into a rock, where the clay undergoes a mineralogical change under burial (Goldsmith et al., 2003). The smectite to illite reaction is a large contributor to pore pressure changes. This happens during diagenesis of clay-rich sediments or shales, because of increase in temperature. Diagenesis starts at 60-80 °C. The smectite has a large water absorption capacity, which causes the clay to start swelling when in contact with water. The transformation from smectite to illite occurs when the clay loses its ability to absorb water, due to replacement of Si^{4+} cations by Al^{3+} increase. Illite is formed by the electrical imbalance increase, and calcium (Ca) or potassium (K^{+}) ions become fixed in an interlayer position, illite is now formed. When smectite form to illite, the clay has lost its capacity to absorb water. Together with pore water, this can create an abnormal pore pressure (Mouchet and Mitchell, 1989). The smectite to illite transformation happens at 2,4-3,4 km depth in the North Sea (Lahann, 2002).

5.3.5 Aqua-thermal expansion

This mechanism causes fluid expansion. In a closed environment, the water expands due to thermal effects, and the pressure increses. The rise in pressure also depends on the density of water, and not only on the rise in temperature (Mouchet and Mitchell, 1989). According to Mouchet and Mitchell, (1989), aqua thermal expansion only has an effect if:

- The environment is completely isolated.
- The pore volume is constant.
- The increasing temperature takes place after the environment is isolated.

Overpressure is affected by any increase in the water volume. The increase of volume is in the order of 0,05% for a burial of 1 km where the temperature gradient is 25 °C /km. As a result, the minimum leakage will decrease the thermal effect. Aqua-thermal expansion also depends on time and permeability in the formation *(*Mouchet and Mitchell, 1989).

5.3.6 Hydrocarbon generation

Hydrocarbon generation cause an increase in pore volume, which gives overpressure. Organic material is formed into kerogen and the pore volume increases significantly when oil and gas are created from the kerogen (Chilingar et al., 2002). Kerogen is a waxy organic substance which is insoluble and is entrapped with a source rock. As the temperature rise, the kerogen molecules are formed into hydrocarbons by thermal cracking. This leaves the molecules with only hydrogen and carbon, as the oxygen and nitrogen are taken out (Zolotukhin and Ursin, 2000). The transformation of kerogen to fluid is an efficient mechanism for pore pressure increase, because the solids/fluid ratio changes. This might cause, petroleum to be expelled, since the source rock can hydrofracture. It is especially the generation of gas that cause overpressure due to hydrocarbon generation (Bjorlykke, 2015).

5.4 Indirect measurements of pore pressure

Shale and clay are two impermeable rocks where pore pressure needs to be measured indirectly. The gamma ray log and the sonic log are the main methods used to predict the pore pressure from shale. These are both logs that give an estimate of the pore pressure, but not a direct measurement (Udegbunam, Aadnoy and Fjelde,2013). Udegbunam et al., (2013), claim that pore pressure from direct measurement has an uncertainty of around 2 %, and for indirect measurement with logs it is around 30 %. As seen in Figure 15, the most reliable method when it comes to determination of the pore pressure is direct measurements like the wireline formation tester and formation interval tester. The least reliable ones are d-exponent and the equivalent depth method which are indirect measurements.

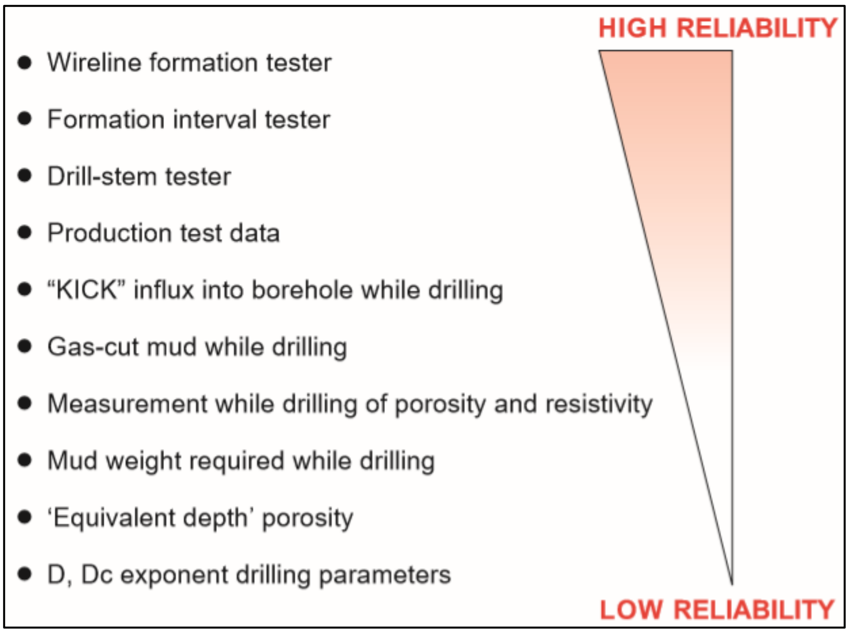


Figure 15 Methods to determine the pore pressure. From *"Formation pore pressures and formation waters,"* by Moss et al., 2003, The Millennium Atlas, pp. 317-329.

5.4.1 Resistivity log

Resistivity data can be used in shales to find the pore pressure. It relates the resistivity of a formation to the resistivity of a fluid saturating a formation, the porosity and the fractional degree of saturation. The values are expressed in ohm-m in the range of 0,2-2000 ohm-m. The resistivity log is a good indicator because hydrocarbons do not conduct electricity, but the formation water does. From the resistivity log one can then see a clear difference between the rocks filled with hydrocarbons, and those with only formation water (Schlumberger, n.d). The formulas used to calculate the resistivity are given below (Zhang and Yin, 2017):

$$R_o = R_w \varphi^{-m} \tag{5.3}$$

Archie's second law:

$$R_t = S_w^{-n} R_o \tag{5.4}$$

Where
m cementation index
n saturation exponent
R_w resistivity in water zone
R_t resistivity aqueous fluids
R_o resistivity in oil zone
S_w water saturation
φ porosity

To determine the pore pressure, the resistivity log can be used. The formula (5.5) for this calculation is shown below.

Eaton's method

$$P_{pg} = \text{OBG} - (\text{OBG} - P_{ng})\left(\frac{R}{R_n}\right)^n \tag{5.5}$$

Where
P_{pg} pore pressure gradient [psi/ft]
P_{ng} normal pore pressure gradient [psi/ft]
R measured shale resistivity
OBG overburden stress gradient [psi/ft]
R_n shale resistivity in the normal pressure condition
n exponent
R_o resistivity value when Z=0

Eaton's method is one of the main pore pressure prediction techniques. This model is especially convenient in overpressured zones, generated from compaction equilibrium (Oloruntobi and Butt, 2020). Eaton's method calculates the pore pressure based on the relation between the overburden gradient and the observed parameters from the resistivity log. The shale resistivity in normal compaction condition must be determined, if this method should be used, equation 5.6 is then implemented (Zhang and Yin, 2017).

$$R_n = R_o e^{bZ} \qquad (5.6)$$

5.4.2 Sonic log

Sonic is a log that measures the travel time of an elastic wave through the formation, and the main use is to derive the porosity of the formation, identify lithologies and fractures. An increase in pore pressure, with increasing porosity, can be indicated by an increase in sonic velocity log (DT). The overpressure can be observed when the sonic velocity greater than/surpasses the hydrostatic gradient (Figure 16). In Figure 16, the high values of gamma ray indicate shale (Moss et al., 2003). It is likely that there exists an overpressured zone if there is a break in the compaction trend with depth to an increase in transit time with no variation in lithology (Glover, n.d). Zhang and Yin (2017) presented equation 5.7 to calculate the pore pressure gradient.

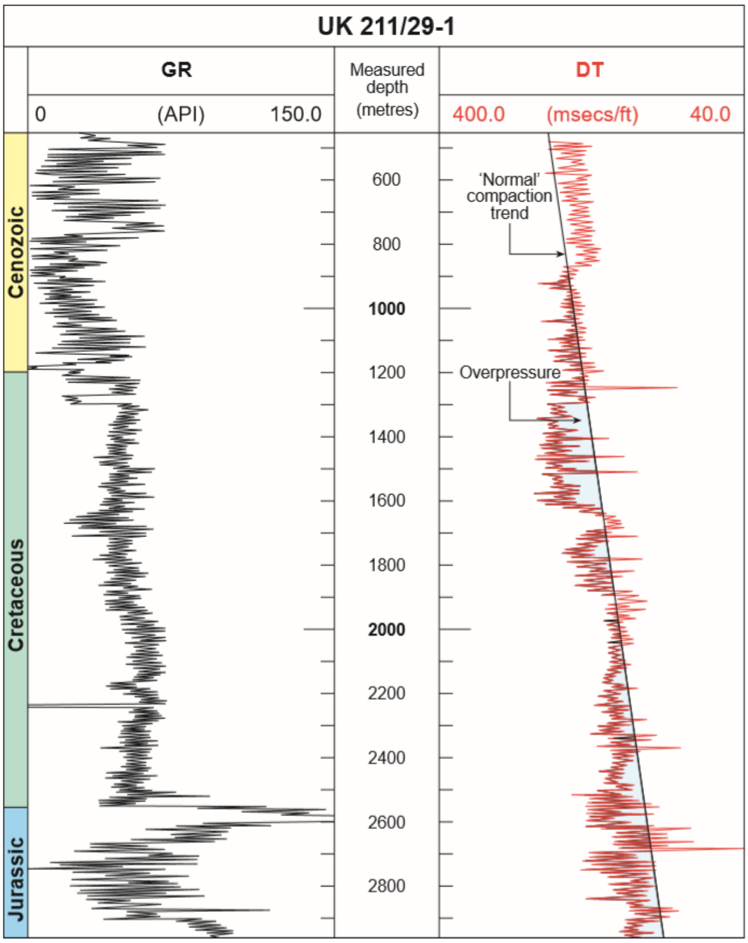


Figure 16 Gamma Ray-log and Sonic log showing overpressure. From *"Formation pore pressures and formation waters,"* by Moss et al., 2003, The Millennium Atlas, pp. 317-329.

$$P_{pg} = OBG - (OBG - P_{ng})(\frac{\Delta t_n}{\Delta t})^m \qquad (5.7)$$

Where

Δt transit time in shale from well

Δt_n transit time in shale at normal pressure condition

m exponent

OBG overburden pressure

P_{pg} pore pressure gradient

P_{ng} hydrostatic gradient

5.4.3 d-exponent

It is a real time pore pressure prediction method. Since it is not possible to always keep the weight of bit (WOB) and rotary speed (ROP) constant**,** the d-exponent is used (Chilingar et al., 2002).

(5.8) $$ROP = N \left(\frac{WOB}{D`h}\right)^{d}$$ $$d_e = \frac{\log\left(\frac{ROP}{N}\right)}{\log\left(\frac{WOB}{D`h}\right)}$$ (5.9)

Where

ROP rate of penetration [ft/h]

WOB weight on drill bit [lb]

N rotary speed [rpm]

D bit size [inches]

d_e d-exponent

If the d-exponent are plotted against the depth, it is shown that the d-exponent decreases with depth. In overpressured zones the calculated values of the d-exponent differ from the normal trend in many cases to lower values. Changes in the lithology and change in mud weight are two factors that will affect the values of the d-exponents. The drilling fluid density must be kept constant when using the normal d-exponent method. By then modification of the equation, and consider changes in mud weight, equation 5.10 are valid (Chilingar et al., 2002).

$$d_c = d \frac{MW_1}{MW_2} \quad (5.10)$$

Where

d_c corrected d-exponent

d original d-exponent

MW_1 normal mud weight

MW_2 actual mud weight used

How often the d-exponent is calculated depends on how fast the drilling operation is. For every 10 ft in increasing depth, it is the most common interval of calculating the exponent. This may differ when the drilling is fast, then it can be every 50-100 ft. If the formations are very compact, the sampling interval is every 5 ft. The advantages of the d-exponent method is that the measurements necessary for calculations are measured from the drill bit, and therefore the calculation of the d-exponent gives the pore pressure close to the bottom of the well (Chilingar et al., 2002).

5.5 Direct measurements of pore pressure

The best way to determine the pore pressure is by direct measurements. The most common methods used are wireline sampling, measurement while drilling (MWD), logging while drilling (LWD), repeated formation test (RFT), formation multi tester (FMT) and drill stem test data (DST) (Moss et al., 2003). To use these direct measurements methods, the formation needs to be permeable. Because when measuring the pore pressure with the tools mentioned above, fluid must flow to build up a pressure inside the tools. In shale it is not possible to measure the pore pressure directly since shale is almost impermeable. Below two new methods of estimating the pore pressure directly are presented, MSE and HMSE, and in this thesis only these are elaborated here. I have focused on these new methods since they give good measurements of the pore pressure (explained in upcoming subchapters), instead of the older methods.

5.5.1 Mechanical Specific Energy (MSE)

Pore pressure measured from drilling parameters is a recent discovery where mechanical specific energy (MSE) and hydro-mechanical specific energy (HMSE) are used. These parameters are calculated from measurements downhole (Oloruntobi and Butt, 2019). Oloruntobi and Butt (2020) suggest that MSE can be used for:

- Pore pressure prediction.
- Identifying problems related to the drilling phase.
- Drilling optimization.

The MSE consider WOB and torque to compute the energy required to drill a rock. The equation for this is:

$$\text{MSE}=\frac{WOB}{A_b}+\frac{120\pi NT}{A_b ROP} \tag{5.11}$$

Where

WOB weight on bit [lbs]
Ab bit area [in^2]
N rotary speed [rpm]
T torque on bit [lb-ft]
ROP rate of penetration [ft/hr]

The reason for using MSE to estimate pore pressure is that the pore pressure is a determining factor for the energy required to break down and remove a unit volume of rock with the drill bit (Oloruntobi and Butt, 2019).

5.5.2 Hydro Mechanical Specific Energy (HMSE)

In this method only drilling parameters from surface measurements are being used. It is a combination of torsional, axial and hydraulic energies required to destroy and remove a unit volume of rock. This technique can give an estimate of the pore pressure without measurements directly in the well at a low cost (Oloruntobi and Butt, 2019). Pore pressure measurements from the HMSE are compared to the pore pressure measurements taken from the formation. An increase in HMSE, both from downhole and surface measurements with equivalent rise in compressional sonic velocity, can indicate drilling into a harder formation than predicted. When the sonic velocity does not have an equivalent increase as the increase in HMSE, it can indicate problems with the drilling bit. When the downhole measurements from HMSE are not equivalent with the surface measurements from HMSE, it can signify problems in the wellbore (Oloruntobi and Butt, 2019). The HMSE method has an advantage that it can detecting different problems or complications in the well.

The main factor controlling the HMSE change is lithology, and if the HMSE has sudden changes in it's values, it can indicate lithology changes. Other factors like pore pressure, bit wear and type of bit, compaction and differential pressures affect the HMSE. The goal here is to minimize these effects, so that the lithology is the main mechanism affecting the drilling process. It might be of interest to analyze a small interval at the time when using this method. This is due to the result of rock compaction and bit dulling and to make sure that these factors mentioned above are within a safe range. All changes to HMSE in small intervals will then signify changes in the lithology or changes in differential pressures (Oloruntobi and Butt, 2020). The downhole measurements from the (downhole recordings) are important when estimating the HMSE, this gives the most accurate parameters. If the surface measurements of the drilling parameters are used instead it can cause errors. Errors occur especially in deviated wells due to friction between the wall of the borehole and the drill string. There will be an increase in HMSE if there is a reduction in ROP, this is caused by bit wear. A decrease in the HMSE, happen when drilling through the pressure transition zone, while pore pressure increase. This can help to identify formation and subsurface lithology (Oloruntobi and Butt, 2020).

$$\text{HMSE} = \frac{\text{Axial energy}}{\text{Rock volum drilled}} + \frac{\text{Torsional energy}}{\text{Rock volum drilled}} + \frac{\text{Hydraulic energy}}{\text{Rock volum drilled}}$$

$$\mathrm{HMSE} = \frac{\mathrm{WOB}}{A_b} + \frac{120\pi NT}{A_b \mathrm{ROP}} + \frac{1154\eta\Delta P_b Q}{A_b \mathrm{ROP}} \tag{5.12}$$

Where

WOB weight on bit [lbs]
Ab bit area [in^2]
N rotary speed [rpm]
T torque [lb-ft]
ROP rate of penetration [ft/hr]
ΔPb bit pressure drop [psi]
Q flow rate [gpm]
N hydraulic-energy reduction factor

The HMSE method is cost-saving, and it is good to use in wells where petrophysical information is missing. It can provide a trustworthy measurement of the pore pressure from the drilling parameters (Oloruntobi and Butt, 2020). Figure 17A shows the pore pressure estimates from HMSE, and the actual measurements from a wireline pressure sampling tool and drilling data from the desired depth of interest. Figure 17B shows the GR-depth and HMSE depth plot. There is a clear trend between the HMSE and GR, which indicates that HMSE can be used when identifying lithologies. Sudden changes in the HMSE, indicates lithology changes.

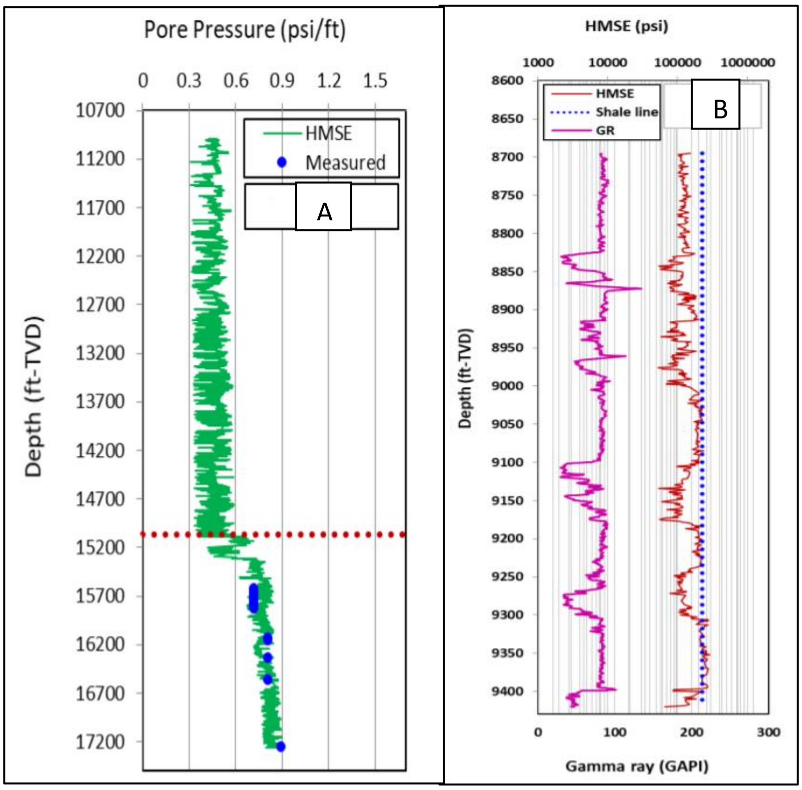


Figure 17 A) HMSE and pore pressure profile from an exploration well in the Niger Delta. From *"Energy-based formation pressure prediction,"* Oloruntobi and Butt, 2019, *Journal of Petroleum Science and Engineering,* Volume 173, 2019, pp. 955-964. **B)** Gamma ray and HMSE plot. From "Application *of specific energy for lithology identification,"* by Oloruntobi and Butt., 2020.

5.6 Problems when estimating incorrect pore pressure

If the pore pressure is not sampled well enough or investigated properly, well control incidents can occur. Problems like kick, damage of the formation, lost circulation, differential sticking and collapse are some of these (Oloruntobi and Butt, 2019). Therefore, the prediction of pore pressure is one of the most important factors for well design and planning.

The pore pressure needs to be lower than the pressure in the well during drilling, to avoid unwanted inflow and kick. A kick can happen when drilling into abnormally high pore pressure which was unpredicted. When a kick occurs, the pore fluid flow into the well from permeable layers, and in the presence of gas the well pressure increase. To minimize the risk of this happening, it is important to find overpressure zones before starting to drill. Then keep the mud weight adequately low so fluid loss is prevented. The best way of doing this is to compare the estimates of pore pressure from different calculations and observations, like drilling parameters, seismic data and logs (Oloruntobi and Butt, 2019).

6.0 Data and methodology

This thesis is based on data provided from NPD's database, Diskos. The study includes data from the northern part of the North Sea, more specific the Tampen Area, together with some external fields for comparison. This data was applied for interpretation done in Microsoft Excel. See appendix for the data from Diskos.

6.1 Data

In this study pore pressure measurements from 20 exploration wells have been evaluated in the Tampen area. These exploration wells are shown in Figure 18. The exploration wells used in the study are marked as black circles. As seen from Figure 18, these measurements cover most of the field areas. There are several exploration wells drilled in the fields, but these are not evaluated because of lacking data for pore pressure measurements among others. Pore pressure measurements were only available for four different fields in the Tampen area. Exploration data from the remaining fields in this area were absent. At Snorre, Vigdis and Visund there were not found any data from dry exploration wells either at Diskos or at NPD's factpages. The same applies to the dry wells in the Johan Sverdrup and Goliat fields. At Gullfaks, data from one dry well were found, and from Heidrun data from two dry wells were found.

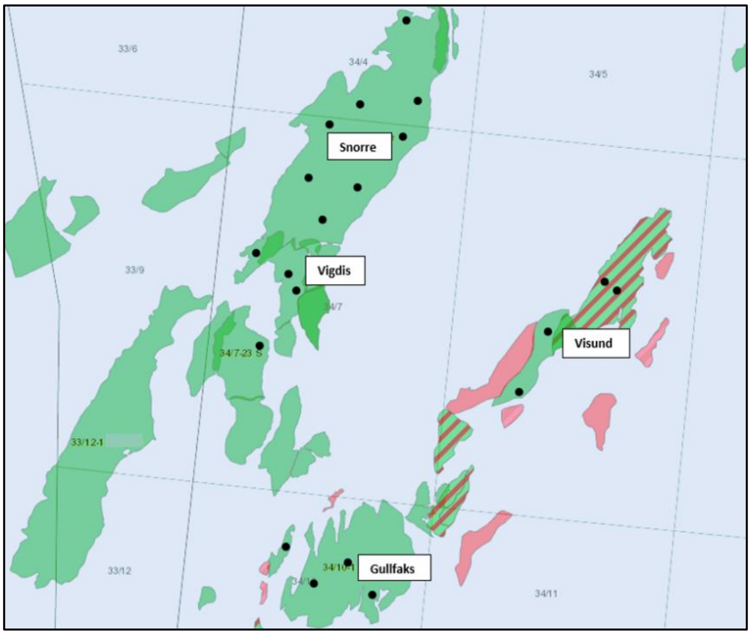


Figure 18 Exploration wells in the study, Tampen area. Modified from NPD.

Diskos is Norway's national data repository for petroleum data developed by NPD, and different oil companies on the NCS. The database contains relevant petroleum data, like well, seismic, and production data. The data from Diskos used in this study are primarily pore pressure data from exploration wells from repeated formation test (RFT) or by formation Multi-Tester (FMT).

6.1.2 FMT and RFT- test

The measured data of pore pressure provided from Diskos, are given either from the FMT-test or the RFT-test. FMT and RFT- tests are wireline formation testing tools. They can take several tests of fluids and pressure in the well without removal. The tests are also good indicators when determining the free water level (FWL), oil-water contact (OWC) and gas-oil contact (GOC). By the RFT-method, the tool is lowered down into the borehole. It is then jacked against the borehole wall (Figure 19). The RFT- tool is then sealed against the borehole wall and samples of fluid and pressure are collected. The reservoir fluids are identified by calculating and comparing pressure gradients (Glover, n.d).

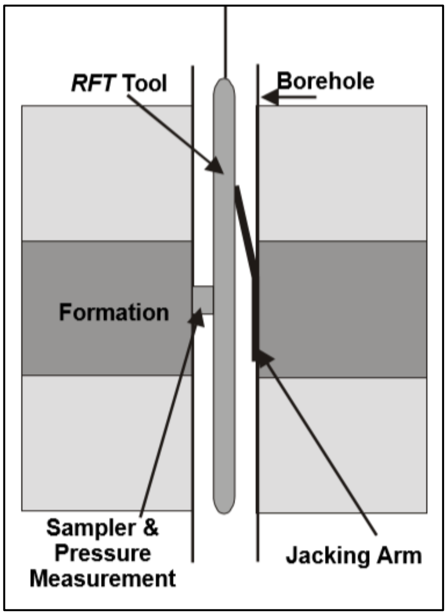


Figure 19 *RFT-tool. From "Petrophysics,"* by Glover, n.d, University of Aberdeen, UK, p. 74.

The FMT-test provides a detailed pressure profile of the well sampled. The tool is stationary, while it samples pressure at different depths in the well. The FMT-test also gives an indication of the permeability, and together with logs one can determine the OWC. This type of wireline test is fast and economical, and the purpose of this test is to check if the well has production potential (Atlas Wireline services, 1987).

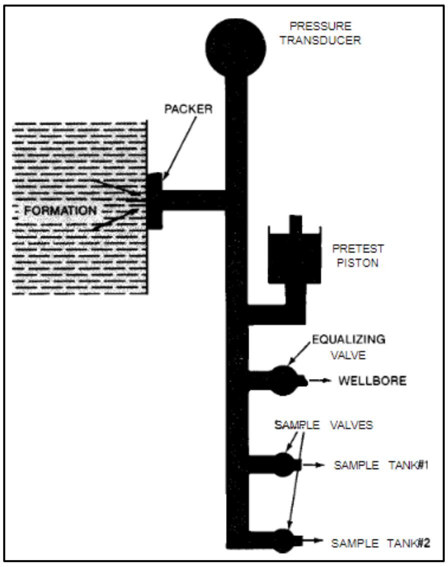


Figure 20 FMT-tool. From *" Formation multi-tester (FMT) principles, theory, and interpretation(,)"* by Atlas Wireline Services. 1987, Houston, Tex: Western Atlas International, p. 3.

The uncertainty connected to this data is that many of the measurements from the RFT and FMT-tests are old and may lack some information. It was not possible to obtain pore pressure data from all the wells in the Tampen area, but the wells with available data were used. As mentioned in chapter 5.4 wireline formation tester Figure 15 is the most reliable method to measure pore pressure, so these RFT and FMT measurements from the different fields interpreted seems to be trustworthy (Moss et al., 2003)

In table 2, the different fields studied are presented. This is to get an idea of the size of the fields, which area they are in, and if they contain oil, gas or both. Note that all the fields in the

Tampen area produce oil**.** The data in the table are collected from NPD's factpage. For comparison to the fields in the Tampen area, three other fields are used. Johan Sverdrup from the central North Sea, Heidrun from the Norwegian Sea and Goliat from the Barents Sea.

Field	Discovery year	Reserves oil mill Sm^3	Reserved gas mill Sm^3	Water depth (m)	Reservoir depth (m)	Area	Production
Gullfaks	1978	384	23	130-220	1700-2000	Tampen	Oil
Snorre	1979	310	6,6	300-350	2000-2700	Tampen	Oil
Vigdis	1986	72,9	1,7	280	2200-2600	Tampen	Oil
Visund	1986	40,9	59,1	335	2900-3000	Tampen	Oil
Johan Sverdup	2010	406,6	10,2	110-120	1900	Central North Sea	Oil
Heidrun	1985	196,6	46,3	350	2300	Norwegian Sea	Oil/gas
Goliat	2000	31,5	-	360-420	1100-1800	Barents Sea	Oil/gas

Table 2 Fields, by Norwegian Petroleum , 2019, *(https://www.norskpetroleum.no/en/facts/field/)*

6.2 Methodology

The data from Diskos are plotted into Excel. In this study pore pressure is plotted against depth for the different wells in each field. By the use of excel, plots to identify the abnormal pore pressure were created, and plots of the overpressure in the water zone. These plots were further interpreted and analysed during this study.

6.2.1 Well data

A total of seven wells were used in this study. The exploration wells have a vertical design, with a small inclination to avoid some geological structures. The depth values used here are True vertical depth (TVD). This is the vertical distance from a point in the wellbore to a certain point on the surface/rig. Measured depth (MD) is the total length of the well, including the total length of pipe to be used (Aadnoy, 2010). The depth of the well is then calculated into Mean sea level (MSL) from Rotary Kelly bushing (RKB) (Figure 21). To do so, the depth in RKB is subtracted with 25 meters, which is the most common height on the NCS from drillfloor to sealevel. The reason for doing this is to remove the effect of various drill floor elevations (Aadnoy, 2010). After plotting the pore pressure measurement from the different wells, a water gradient of 1,03 s.g. is added to the plots. This is as mentioned in chapter 5.1, the normal pore pressure gradient in the North Sea. Then the pressure gradient is parallel offset to line up with the plotted well data. From the plotted data the GOC, the GWC and the OWC is found depending on if it is an oil field or an oil/gas field. The difference between these boundaries-are.

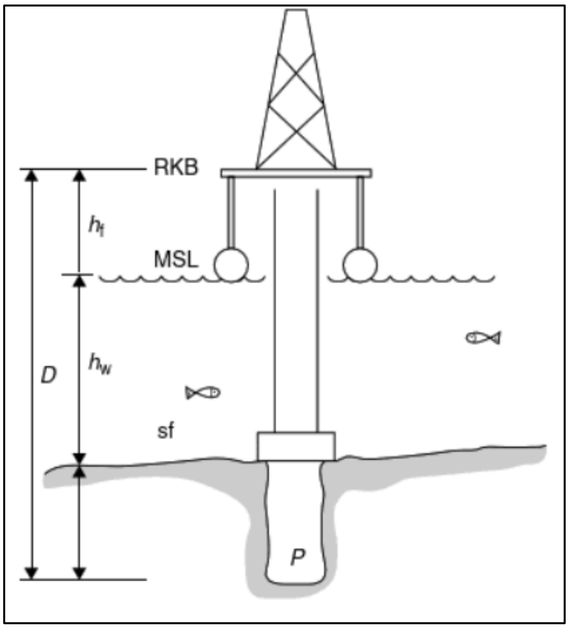


Figure 21 Definition of reference points. *From " Modern Well Design: second edition,"* by Aadnoy, 2010 , Taylor and Francis Group, London, UK

- OWC: The max evaluation (or minimal depth) where the water saturation is 100 %. There is contact between the oil and water in the reservoir.
- GWC: This is a contact that occur in a gas reservoir if there is good communication between the sands. Here there is no oil present.
- GOC: The contact where gas and oil are in contact.

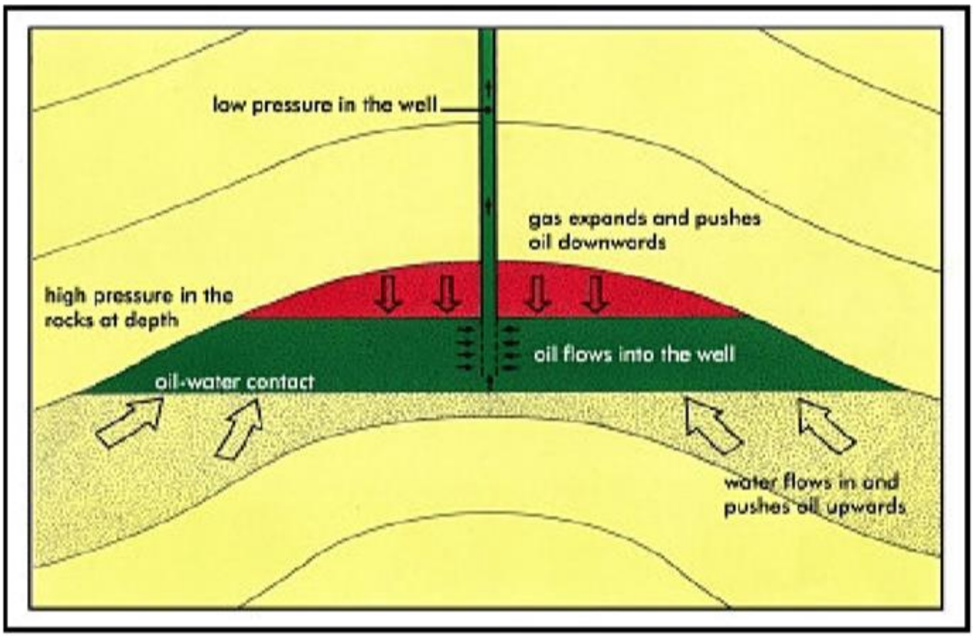


Figure 22 How hydrocarbons flow. From *"Oil and gas production handbook- an introduction to oil and gas production",* by Devold, 2006, ABB.

In Figure 22, a typical reservoir with OWC and GOC shown. The gravity separates the fluids into different phases (gas, oil or water). When drilling an exploration well, the main goal is to find the OWC in the well, and the most common method to find it is from the resistivity log and from the RFT data interpretation .The fields studied contain several wells and these wells have OWC at similar, but different depths , however in this interpretation the mean value of the OWC at the fields are chosen. To find out if there is overpressure in the water zone of the fields, the measurements from the OWC and down to the bottom of the well are plotted together. The reason for the OWC to vary between the wells in the same field can be that there are different isolated compartments between the faults or that hydrocarbons have migrated differently. The depth of the wells in the dataset provided are given in TVD (MSL).

7.0 Observations and interpretations of field data

In this chapter the analysis of the datasets is provided. This includes observations from the different fields followed by interpretation. In section 7.8 it is chosen to look closer at overpressure in the water zone, also when it is normalized to the seabed (chapter 7.9). Finally, the fields are compared, and differences/similarities are pointed out.

Depth TVD(MSL)	**ΔP_{Water}**	**Field**
2124-2763	9 bar	Heidrun
1772-2177	-	Johan Sverdrup
1061-1371	*9-11 bar	Goliat
1753-2338	118 bar	Gullfaks
2367-2935	118 bar	Vigdis
2393-3617	130 bar	Snorre
2815-3248,6	136 bar	Visund

Table 3 *Pressure differences in the fields.*

**9 bar for the gas well, and 11 bar for the oil/gas wells.*

From table 3, the pressure differences in the fields are shown. From the table it is clear that all of the four fields in the Tampen area have a pore pressure 100 bar over the normal. The reason for this overpressure in the fields, how it affects the production and how it influences the discovery of hydrocarbons will further be discussed.

7.1 Heidrun

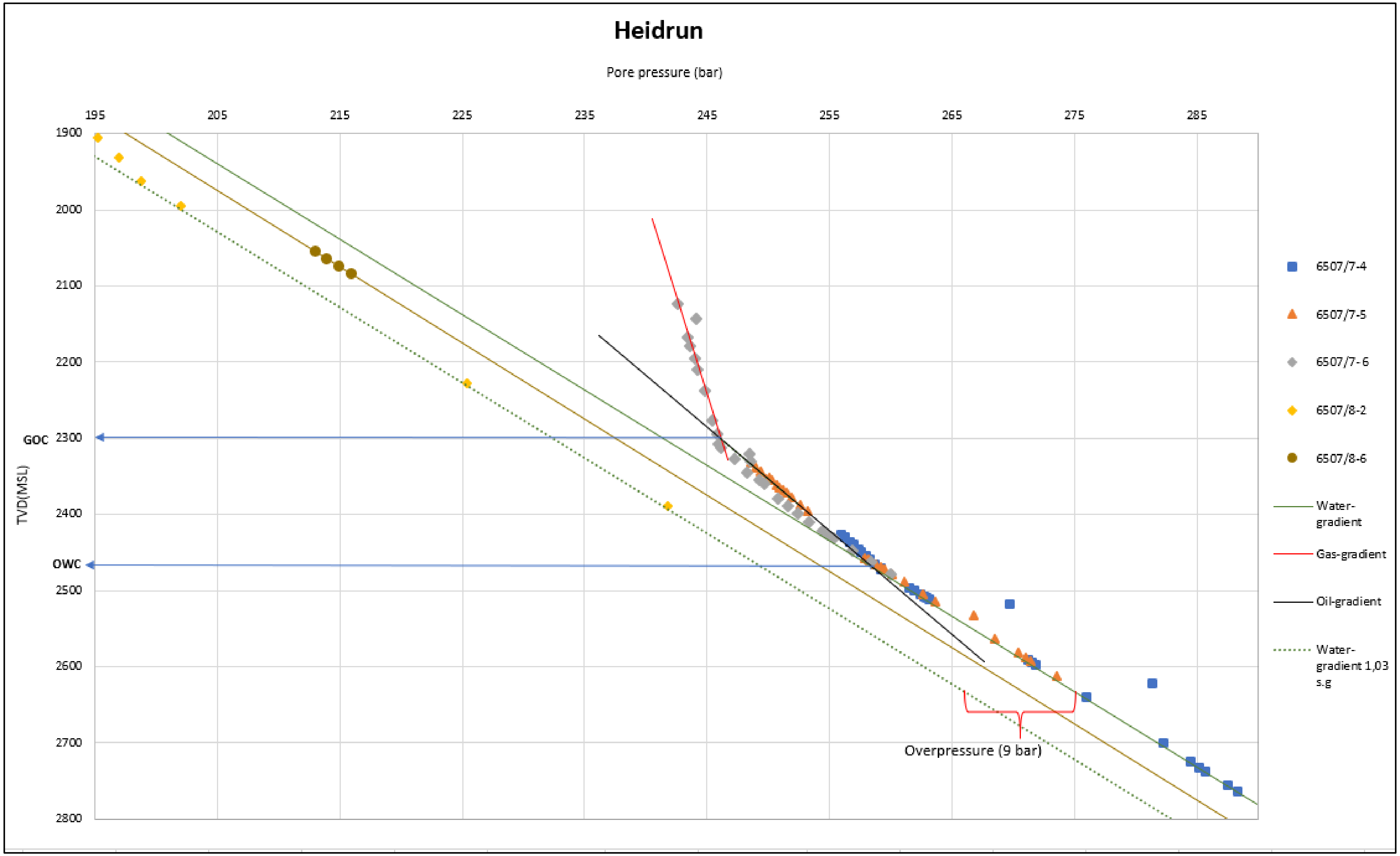


Figure 23 *Pore pressure vs depth at Heidrun.*

7.1.1 Observation

In Figure 23, three appraisal wells and two wildcat wells have been plotted. Heidrun is a field that contains both oil and gas, and in Figure 23 we can clearly see the oil, water and gas zone. Well 6507/7-6 clearly contains both oil and gas, as the pressure is almost constant from 2100-2300 m. The GOC is found at 2300 m and OWC at around 2460 m. Heidrun is the field from this study with the lowest overpressure of 9 bar (table 3). Well 6507/8-2 and Well 6507/8-6 are wildcat wells. They have both been found to be dry. As seen from the Figure, well 6507/8-2 has a pressure gradient of 1,03 s.g.

7.1.2 Interpretation

Hermanrud and Nordgråd Bolås, (2002), did a study on the possibility of leakage from overpressured hydrocarbon reservoirs at Haltenbanken and in the northern part of the North Sea. They concluded with that the lateral communication in the Haltenbanken area is poor, since the pore pressure vs depth is not completely parallel to the hydrostatic pressure line. The geology in the area was affected by tectonic activity in the Late Jurassic and rifting during Late Cretaceous. Hermanrud and Nordgård Bolås, (2002), assumed that the leakage in Haltenbanken is a result of fracturing and faulting, and not because of migration. They suggested that glacial flexuring resulted in leakage, due to creation of fractures from the top of the shallower structures. The risk of leakage in Haltenbanken decrease with depth in the overpressured zones. Teige et al., (2002), did a study where the goal was to identify seismic expressions of hydrocarbon leakage. This was done from a 2D dataset from the Haltenbanken area. From the study it was found that in the overpressured area where exploration wells were drilled, eight of the wells were dry. Meaning water filled in the Lower and Middle Jurassic reservoir. Six of these were connected to caprock leakage due to high pressure in the fluids of the area.

From this study it was observed that 2 of the wells at Heidrun were dry and they both had a pressure gradient closer to/ equal to 1,03 s.g. The rest of the wells had a higher pressure than the dry ones, and they contained hydrocarbons. The study from Teige et al., (2002), strengthen the hypothesis that normal water-pressure might be an indicator of a leaking fault. From this study it is suggested that the most likely reason for overpressure in the Haltenbanken area is due to tectonic activity. This due to the faulting and fracturing in Triassic and Jurassic, mainly faulting due to glaciation in the area. This might have caused leakage, which again can be the reason for normal pressure in the dry wells. This can be supported by the study from Hermanrud and Nordgård Bolås, (2002). Hermanrud and Nordgård Bolås, (2002), suggested faulting due to glaciation in the area, which seems to be likely due to their study where they calculated the Mohr-Coulomb fracture criteria. From their calculations it was found that the leakage took place during the last million year, when there was glaciations and deglaciations. Therefore, this is believed maybe be the reason for leakage in Haltenbanken. As mentioned by Hermanrud and Nordgråd Bolås, (2002), the risk of leakage decreased with depth. As seen in Figure 23, the dry wells are not drilled as deep as the ones with hydrocarbons present. According to Hermanrud and Nordgråd Bolås, (2002), the risk of leakage decreases with depth, which also might be an indication for leakage in these dry wells.

7.2 Johan Sverdrup

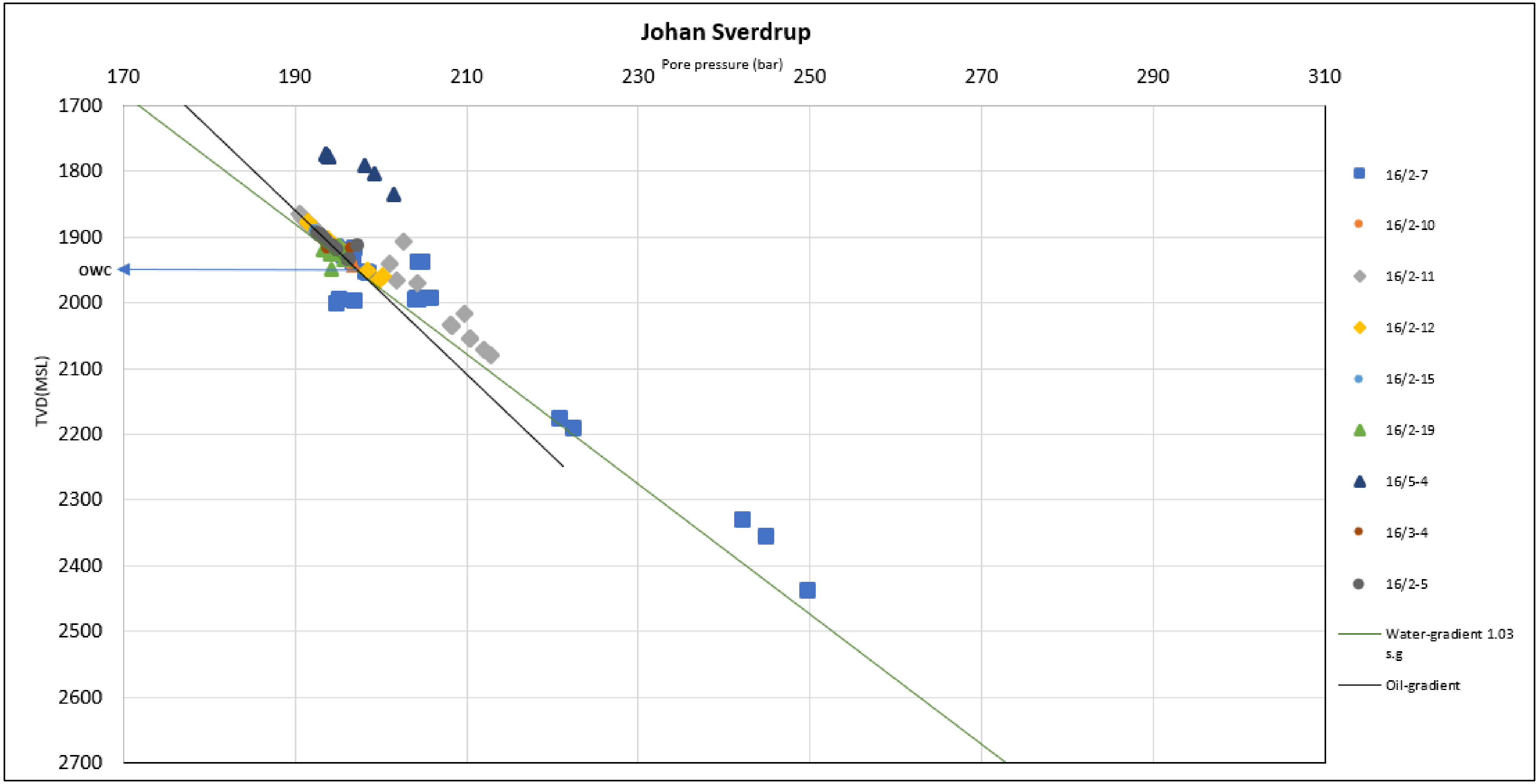


Figure 24 *Pore pressure vs depth at Johan Sverdrup.*

7.2.1 Observation

In Figure 24, data from nine appraisal wells have been plotted. Sverdrup is the field which has a pore pressure gradient closest to the seawater gradient of 1,03 s.g. Johan Sverdrup is an oil field, and has its OWC at around 1950 m. Here there were not found any data on the dry wells within the field.

8.2.2 Interpretation

The reason for choosing this field for comparison is to give an indication for how a normally pressured field produces, and since the field is not placed that far from the Tampen Area. It can for this reason be interesting to look at, to see if it follows the same trend as in the Tampen area. Johan Sverdrup has high permeability and good reservoir properties. As mentioned in chapter 3 we need low viscosity, and the other parameters (permeability and pressure gradient) to be high to get a good flowrate. This is valid from Darcy's law (formula 3.2).

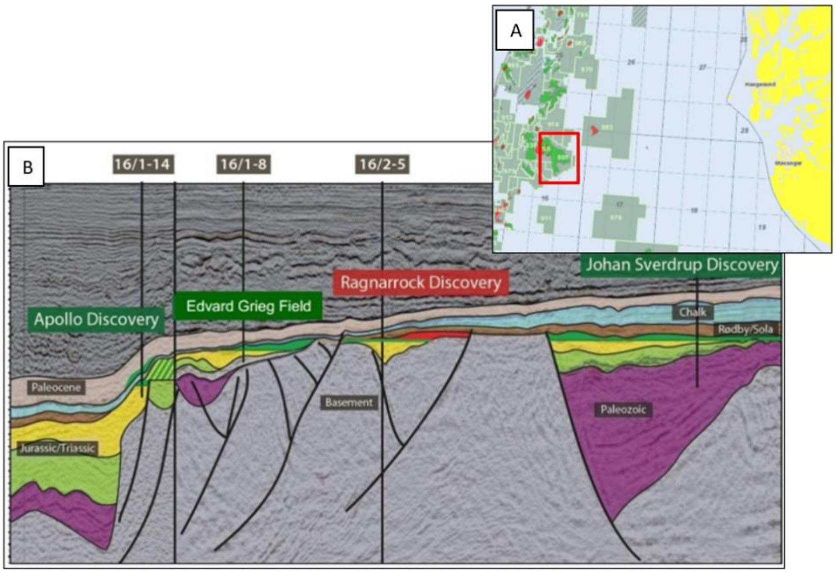


Figure 25 A) Map of location for Johan Sverdrup, modified from NPD**. B)** Cross section of Johan Sverdrup discovery, modified from Stoddard and Fjeldskaar, (2014). *Istiden bak fersk Johan Sverdrup- olje,* from https://www.geoforskning.no/nyheter/olje-og-gass/787-istidene-bak-fersk-johan-sverdrup-olje

In Figure 25 a cross section of the field are shown. In the area around Johan Sverdrup, several exploration wells have been drilled through the ages, and no discoveries had been found. The discovery of Johan Sverdrup is a result of new technology and better understanding of the area. Johan Sverdrup is the only field in this study from the central North Sea. It is difficult to say something about the overpressure in this area, since Johan Sverdrup is a normally pressured field. Since there are no other fields from this area studied here, it is hard to say if the fields are affected by an overpressure, or if the whole area are normally pressured.

7.3 Goliat

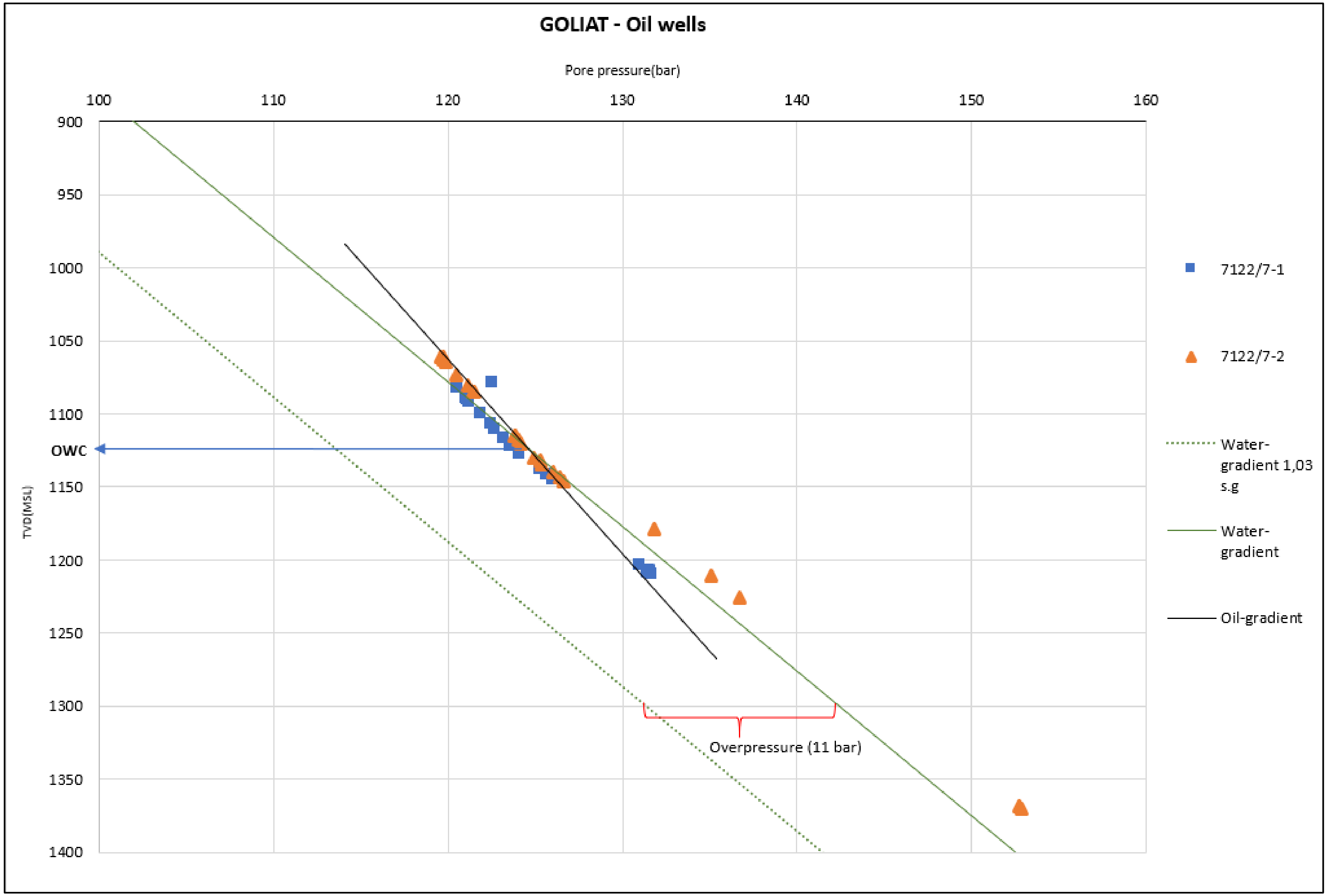


Figure 26 *Pore pressure vs depth at Goliat - oil wells.*

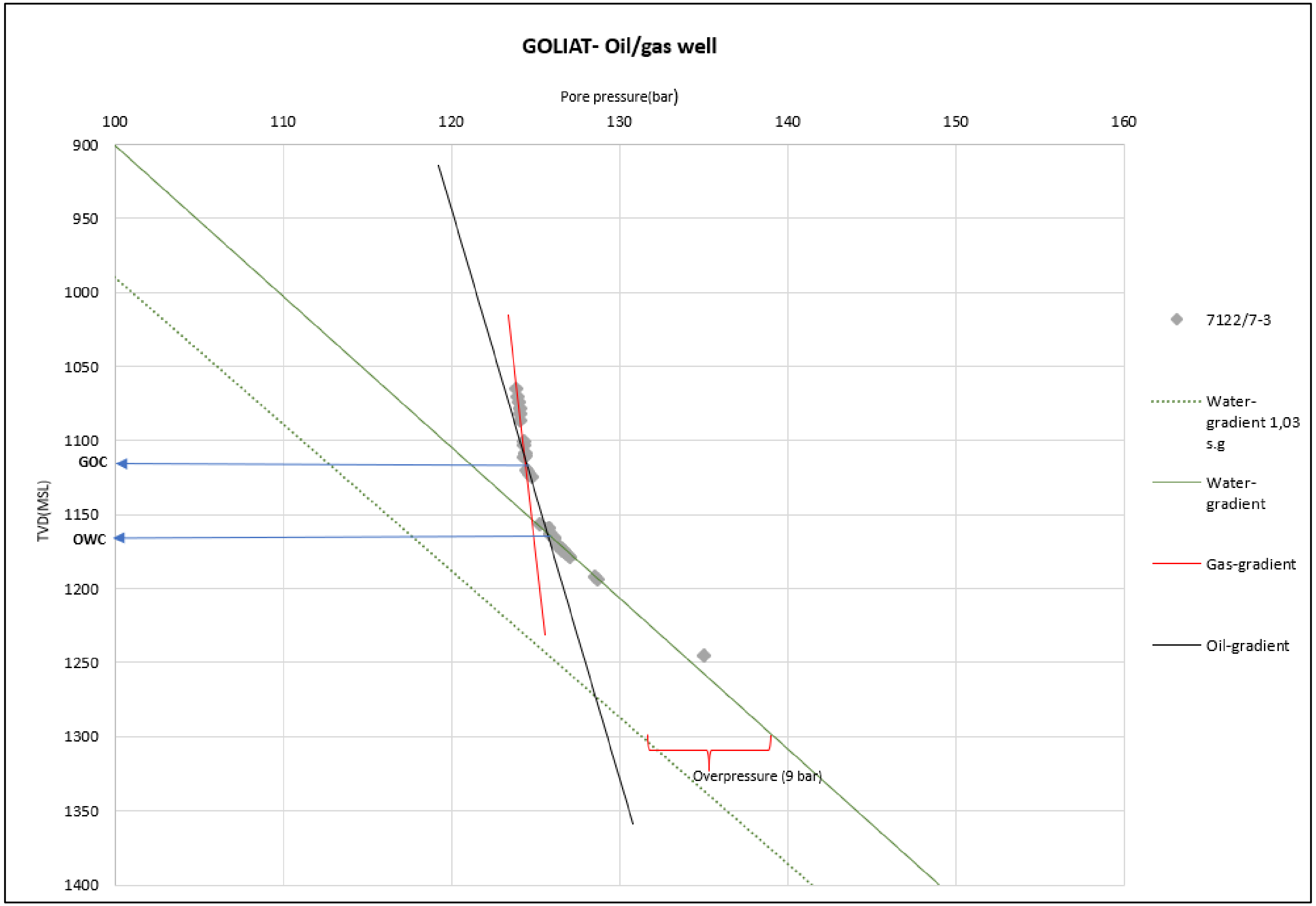


Figure 27 Pore pressure vs depth at Goliat -oil/gas well.

7.3.1 Observation

In Figure 26 and 27 the oil wells, and the gas well are plotted. Goliat is divided into two separate plots, because the oil wells have a different OWC than the oil/gas well. The two oil wells have an OWC at 1120 m. Here one can also here see that the pore pressure is almost constant from 1060-1120 m. The oil/gas wells has an GOC at 1120 m, and an OWC at 1160 m. Among the fields in the study, Goliat had the lowest pore pressure (120-155 bar), but not the lowest water gradient (1,105 s.g. in average). Unfortunately, there was not found any data from NPD on the dry wells in the area here.

8.3.2 Interpretation

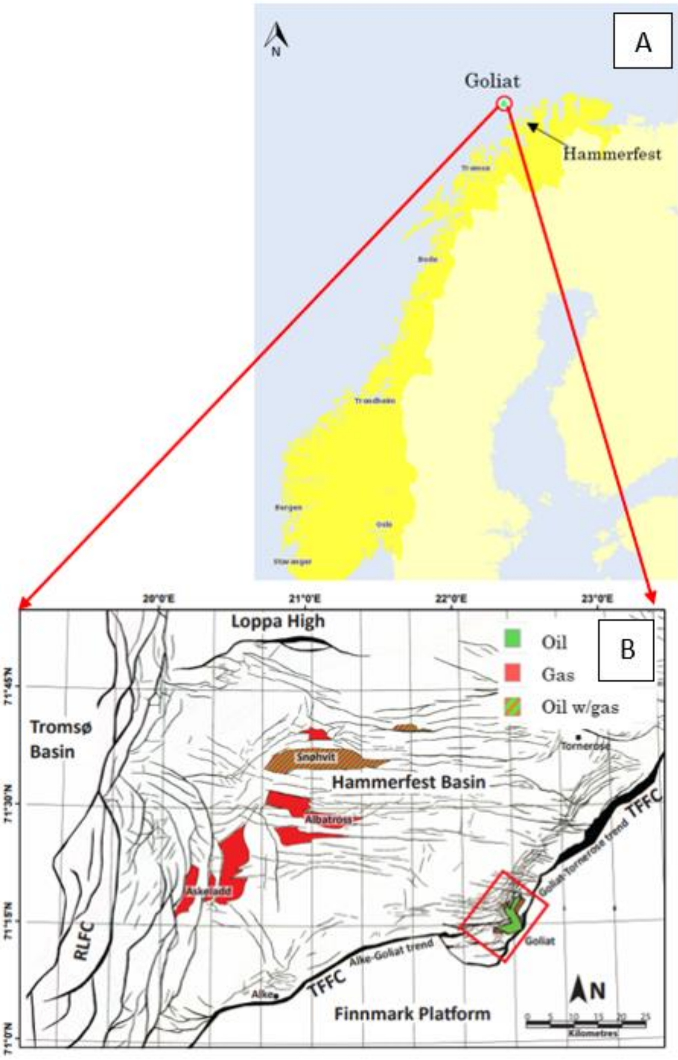


Figure 28 **A)** Map of the Goliat Field. From the Norwegian Petroleum Directorate (NPD). Factmap, 2019, retrieved from: (https://factmaps.npd.no/factmaps/3_0/B) **B)** map of the Goliat field in the Barents Sea. From *"A 3D structural analysis of the Goliat field, Barents Sea, Norway. Marine and Petroleum Geology," by Mulrooney,Leutscher and Braathen, 2017.*

Goliat has its main reservoir in the Kobbe and Snadd formation from Triassic age. And the Kapp Toscana group from Jurassic age (table 1). Both contain oil with an overlying gas cap. In Figure 28, a map of the field is shown, together with a structural map of the field. As seen from the Figure, Goliat is the only field in the area that produces only oil. Goliat has a lower overpressure than the other fields, and a thin gas cap, meaning that the gas do not contribute to pressure control. The field has the lowest pore pressure, and from this study it is also the shallowest field 1061-1371 m from table 4.

In the study from Riis, (2010), of the area between Goliat and Askeladden in the Jurassic reservoir, pore pressure was examined. In the east, the Jurassic aquifer is in contact with the base of Pleistocene, and the pore pressure is in equilibrium with the hydrostatic pressure at the seafloor. The water zone has a pressure which corresponds to the hydrostatic pressure, which belongs to the Jurassic aquifer. The pore water in this area has a high density, around 1,1 s.g. for the area. A lower pressure is obtained in shallow aquifers that are not in contact with the main Jurassic aquifer, and the pressure are lower than hydrostatic in some wells. Riis, (2010), claims that there seems to be a low pore pressure in the wells where no hydrocarbons have been found in the studied area, this due to processes in the aquifer.

From the study done by Riis, (2010), it was also discovered that the wells in the area where there were no hydrocarbons present, had a lower pore pressure than the wells where there were hydrocarbons present. This can be a result of leaking fault. The field is also the one with the lowest pore pressure, and the shallowest depth. As from the study in Haltenbanken by Hermanrud and Nordgråd Bolås, (2002), they claim that the risk of leakage decreases with depth in the overpressured zone. At Heidrun it was the same case, so this might indicate a leaking fault where the hydrocarbons have migrated from the trap which has resulted in a lower pore pressure in the dry wells. The reason for overpressure is therefore assumed to be the same as at Heidrun, tectonic activity, mainly faulting due to glaciation. According to Tasianas et al., (2016), glaciation in the Barents Sea are likely to have caused leakage from the reservoir here (chapter *5.3.3.4).*

7.4 Gullfaks

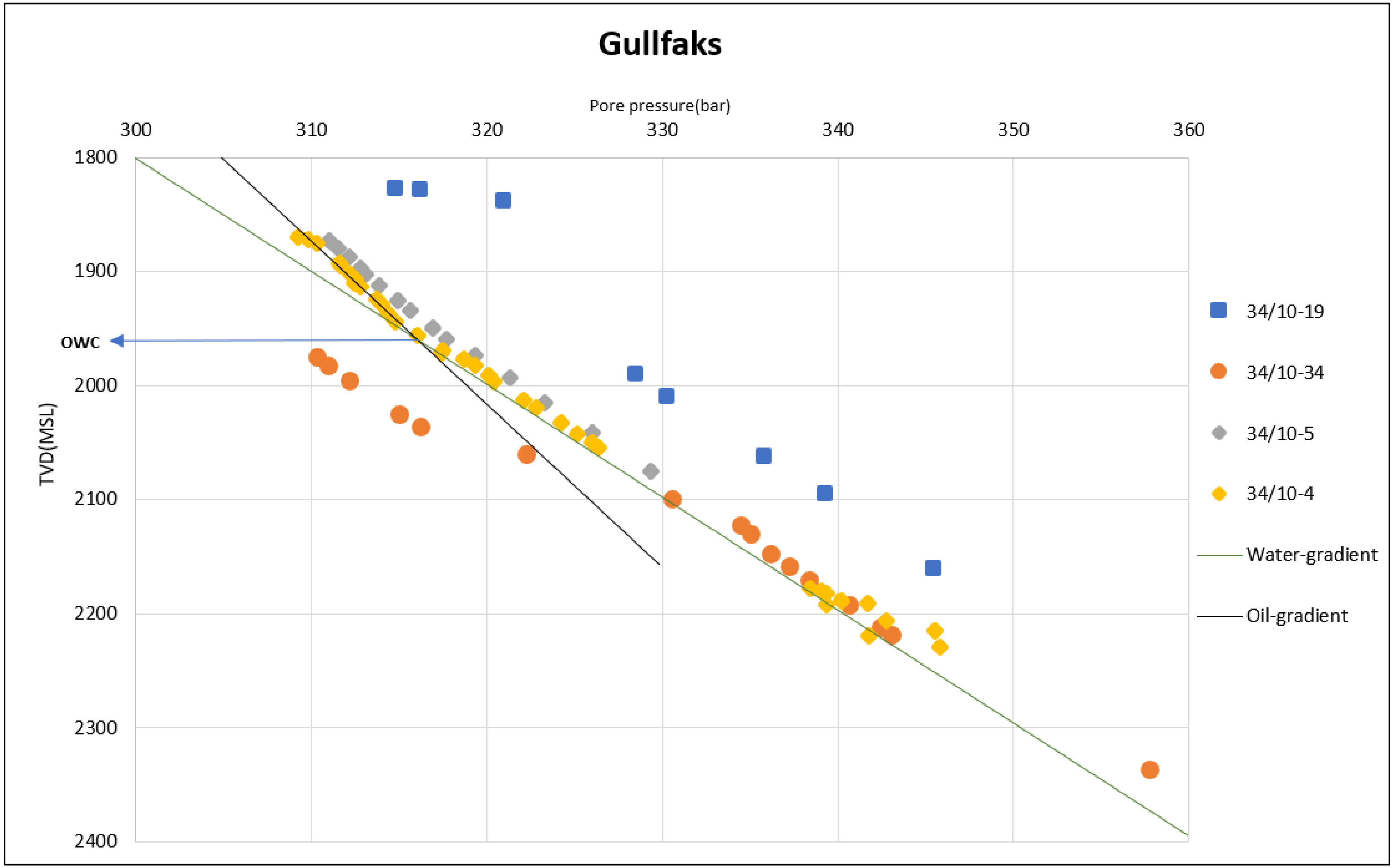


Figure 29 *Pore pressure vs depth at Gullfaks.*

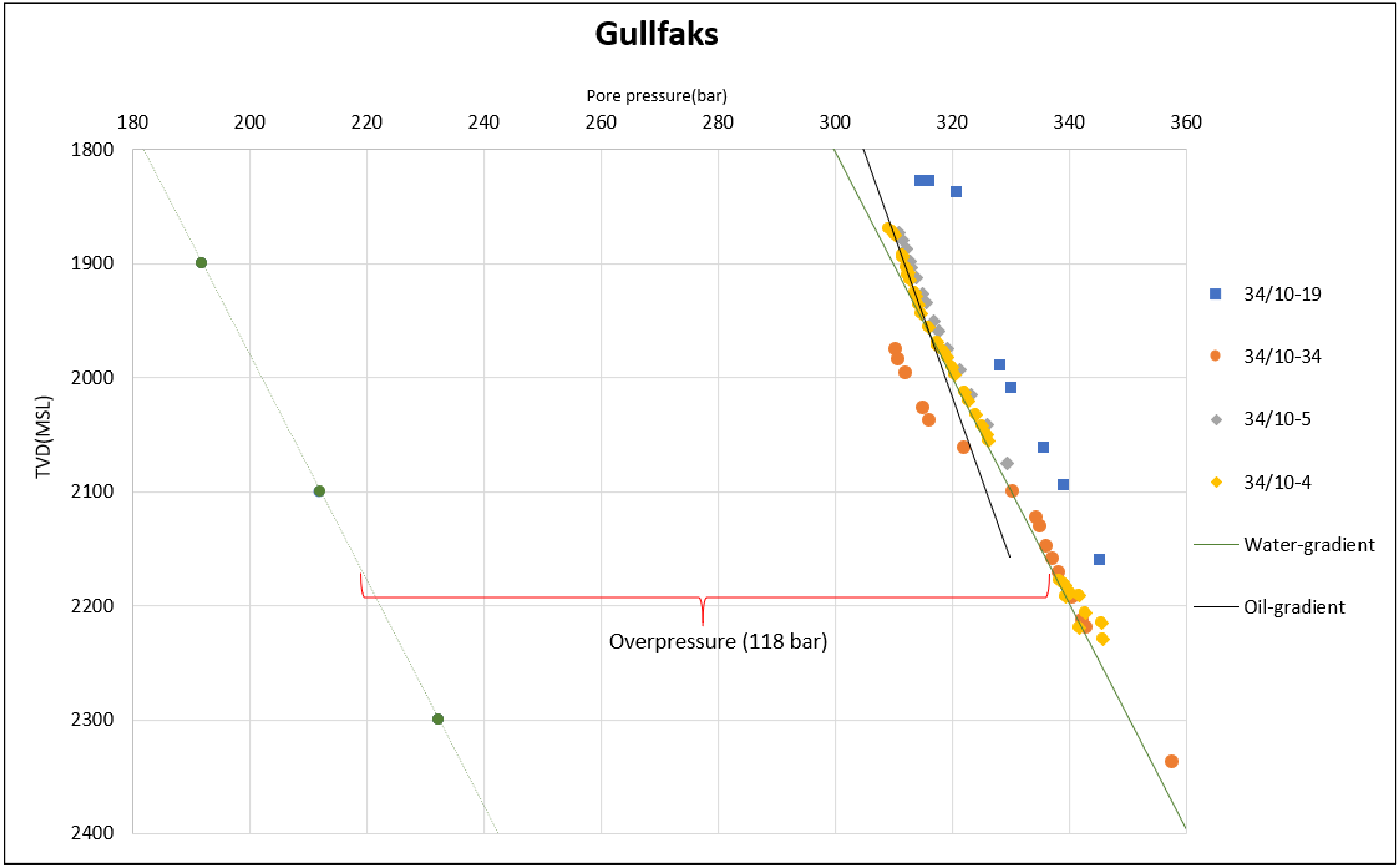


Figure 30 *Pore pressure vs depth at Gullfaks.*

7.4.1 Observation

Figure 29 and 30 shows that there is an OWC at around 1970 m. The pore pressure measurements in well 34/10-19 deviates from the rest. Well 34/10-19 is a dry well, and no hydrocarbons were found here. As seen in Figure 30 the overpressure is shown.

7.4.2 Interpretation

As seen in Figure 30 the well has a clear overpressure in the water zone (118 bar). The geology in Gullfaks are presented in table 1. Gullfaks has several dipping faults. From an interpreted cross section (Figure 31) done by Husmo et al., (2002), some of the interpreted faults at the field is shown. Gullfaks has a complex structure, which can be divided into three. East there is a horst area, west there is rotated fault blocks and between these there is a zone mainly with folds (Husmo et al., 2002).

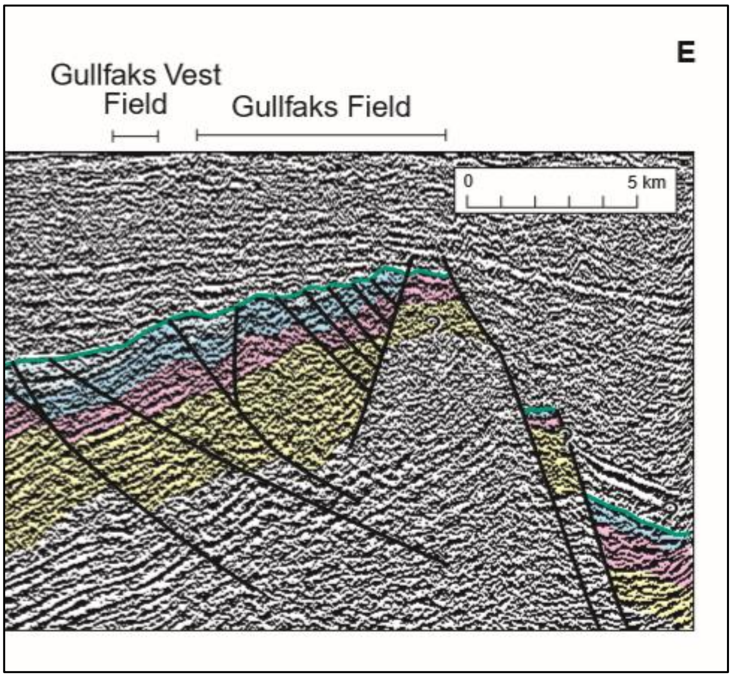


Figure 31 Seismic Section of the Gullfaks field, modified from *"Lower and Middle Jurassic. The Millennium Atlas: petroleum geology of the central and northern North Sea,"* by Husmo et al., 2002, The Geological Society of London, pp. 129-155.

Wensaas et al., (1994), did a study about the causes of overpressuring in the Gullfaks area. They claimed that it was unlikely that the Gullfaks area has an overpressure due to hydrocarbon generation. This is due to low maturity in the Draupne formation. There are also small variations in the thermal gradient, especially in the southern wells. This indicates that it is not likely that aqua thermal- expansion is the cause for the overpressure. As mentioned in section 5.3.2, compaction disequilibrium happens during quick sedimentation and burial of sediments. In the Gullfaks area the sedimentation rate is not that high and there is few differences in the depositional facies and burial history. Therefore, Wensaas et al, (1994), suggested that compaction disequilibrium was not the main reason for overpressure at Gullfaks. This can be supported by the study to Teige, (2008), about the lack of relationship between overpressure and porosity where it was stated that the compaction disequilibrium is not the reason for overpressure. This since the porosity did not differ to much between the normally and overpressured formation. Wensaas et al, (1994), claimed that the main reason for overpressure in this field could be the high accumulation rate, and local leakage of gas from the Jurassic reservoir, and Teige (2008) claim that the reason for overpressure in the North Sea might be due to diagenetic processes that weren't affected by fluid pressure.

One important note here is that the dry well in the field, has a very high overpressure. This contradicts with our hypothesis about dry wells having a lower pore pressure than the wells containing hydrocarbons. The reason for this overpressure in the well might be that there never were hydrocarbons here, only overpressured water. This is not possible to prove, so this is an assumption.

7.5 Vigdis

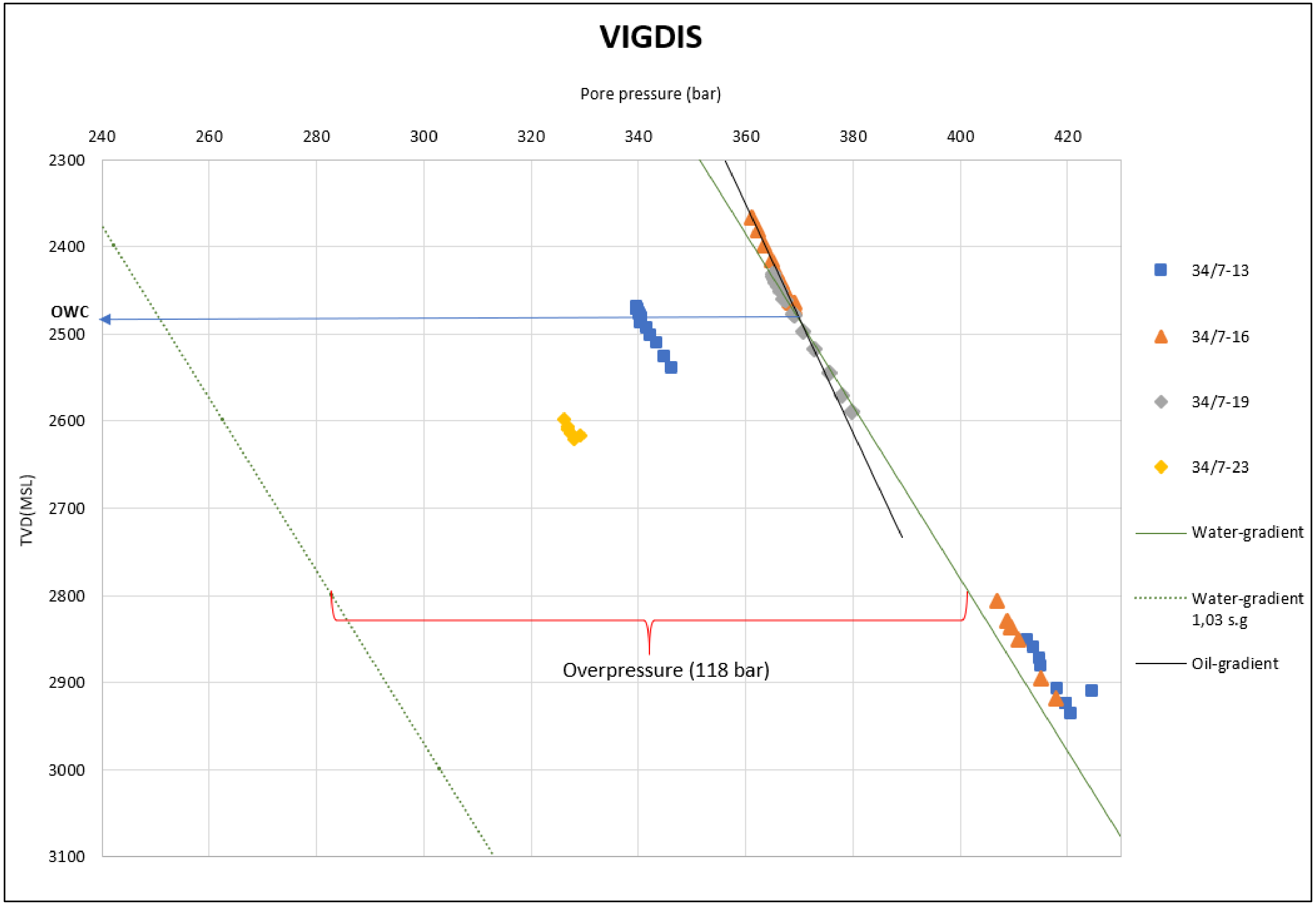


Figure 32 *Pore pressure vs depth at Vigdis.*

7.5.1 Observation

Figure 32 shows that Vigdis is the field with the largest spread between the pore pressure in the different wells. There is found an OWC at 2490 m for well 34/7-16.

7.5.2 Interpretation

The data from the different exploration wells at Vigdis has some spread. This might be because the wells are drilled in different sections (Figure 33). The OWC here is a bit uncertain, this might be due to the lack of communication between the reservoirs.

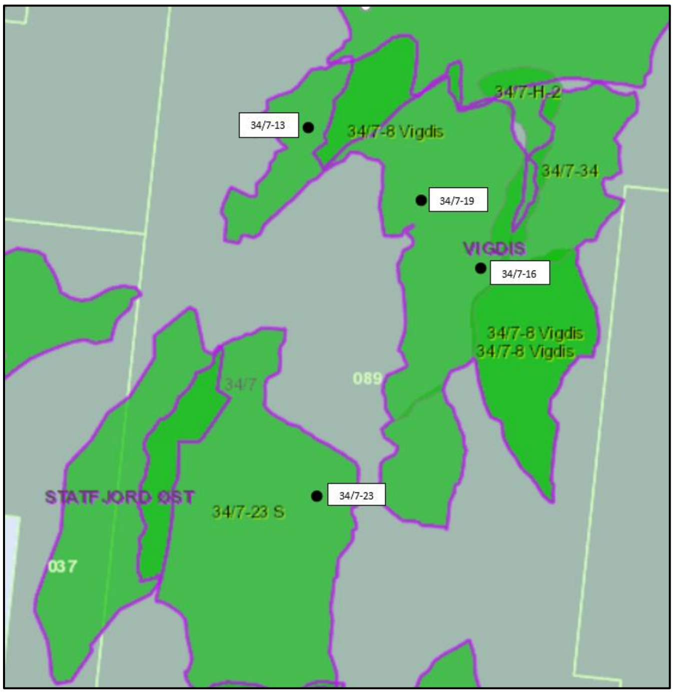


Figure 33 Exploration wells at Vigdis, modified from https://factmaps.npd.no/factmaps/3_0/

Vigdis is from the period where rifting, faulting and sedimentation depositions occurred in the area. This might be some of the reasons for overpressure in this area. There were not found any earlier studies on Vigdis, which considered the pressure regime here. The reason for overpressure here is assumed to be because of tectonic activity, and Vigdis is a good field to show the overpressure trend in the Tampen area.

7.6 Snorre

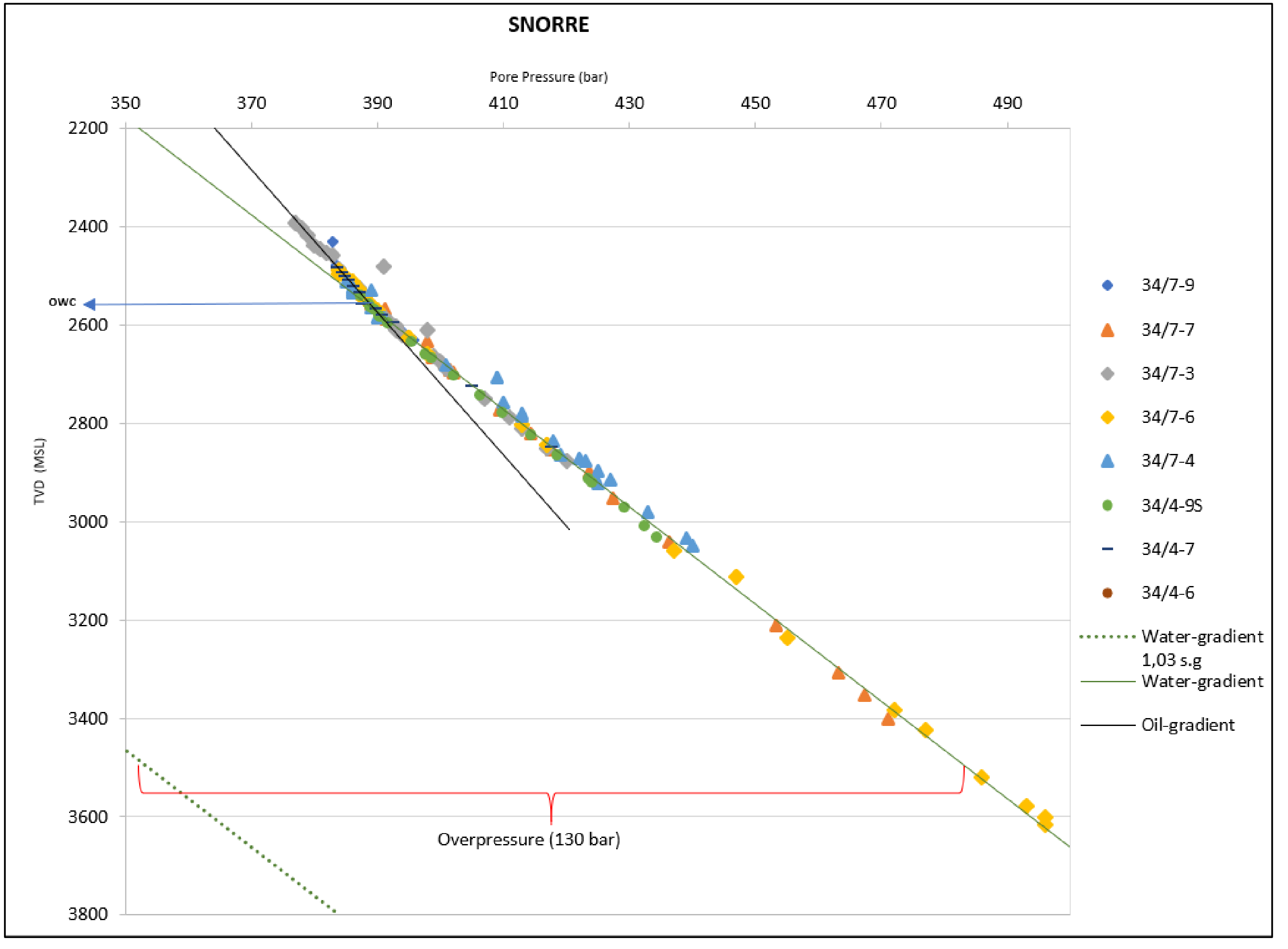


Figure 34 *Pore pressure vs depth at Snorre.*

7.6.1 Observation

In Figure 34 it is shown that Snorre has an OWC at 2580 m. The field also has good communication between the reservoirs. From table 4 its shown that Snorre has a high overpressure in the water zone, around 130 bar.

7.6.2 Interpretation

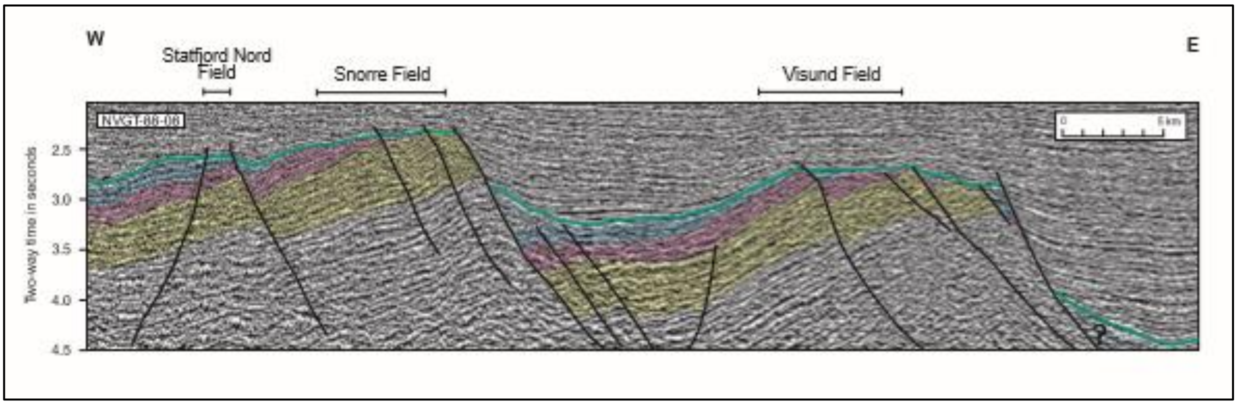


Figure 35 Seismic section of the Snorre and Visund field. From *"Lower and Middle Jurassic. The Millennium Atlas: petroleum geology of the central and northern North Sea," by Husmo et al., 2002, The Geological Society of London, pp. 129-155.*

The field has large fault blocks, and a varied structure with channels and internal flow barriers. Faulting occurred during different time periods within the reservoir (Norwegian Petroleum, 2019, https://www.norskpetroleum.no/en/facts/field/snorre/).The area consists of several rotated fault blocks. A seismic section is shown in Figure 35 of the field. During late Jurassic the area was uplifted and rotated (Goldsmith, Hudson and Van Veen, 2003). The reason for overpressure in the Snorre field might be due to tectonic activity. This due to the faulting, rifting, erosion and uplift during Triassic and Jurassic age in the area. Snorre is the field which lies closest to Vigdis, so it is assumed that the reason for overpressure in these two fields might be the same. There is some uncertainties around this, since there is not found previously studies in either of these field about overpressure or possible leakage.

7.7 Visund

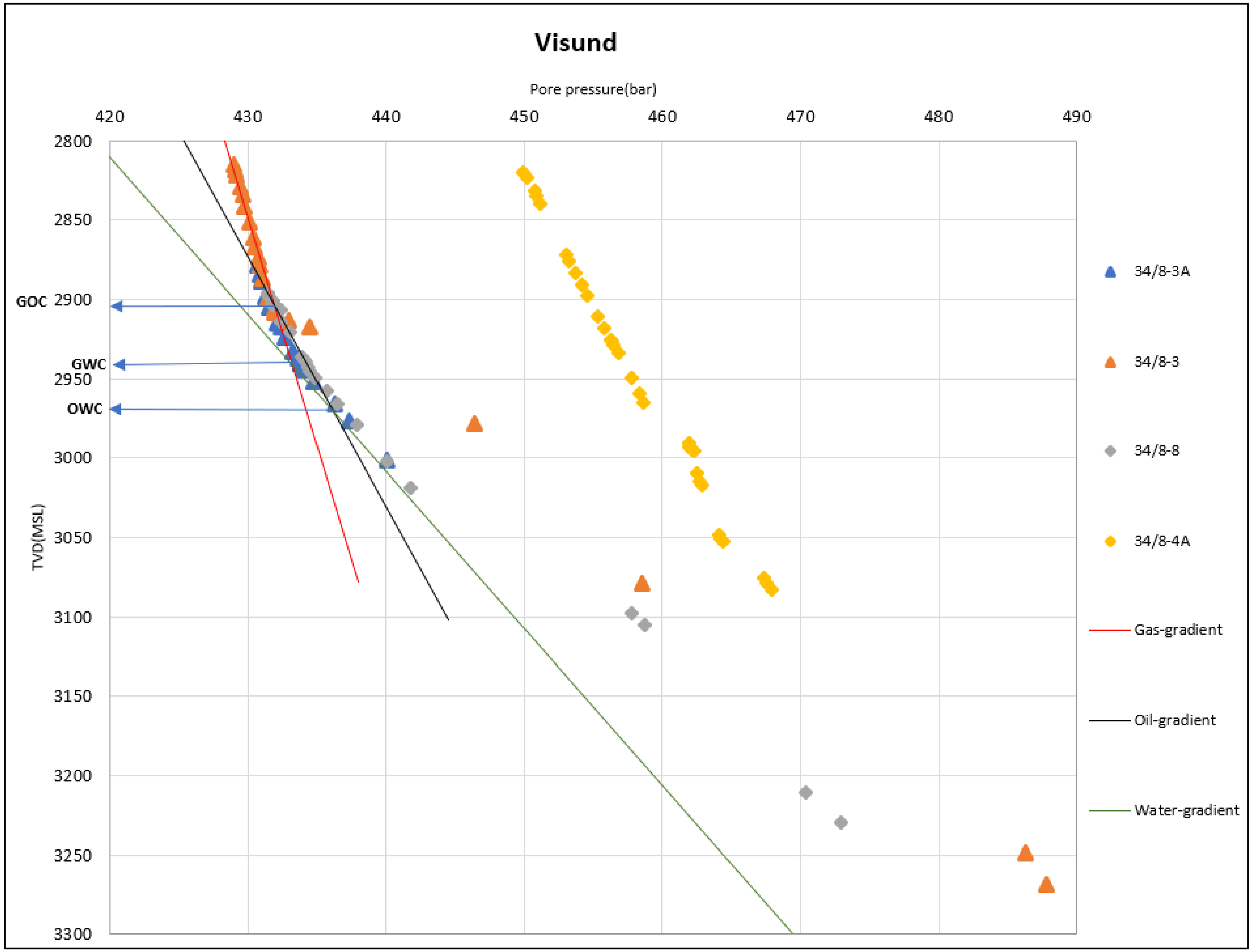


Figure 36 *Pore pressure vs depth at Visund.*

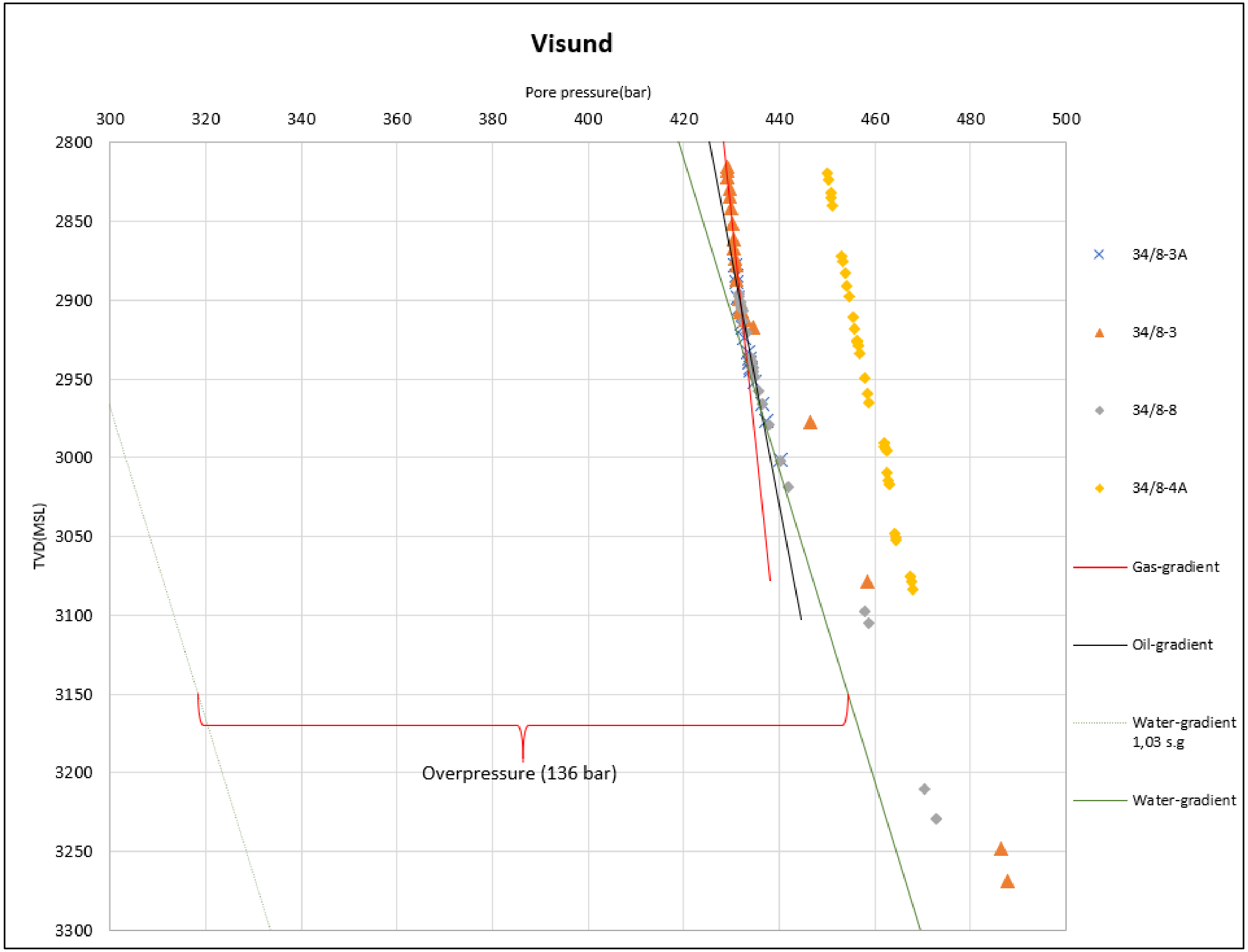


Figure 37 *Pore pressure vs depth at Visund.*

7.7.1 Observation

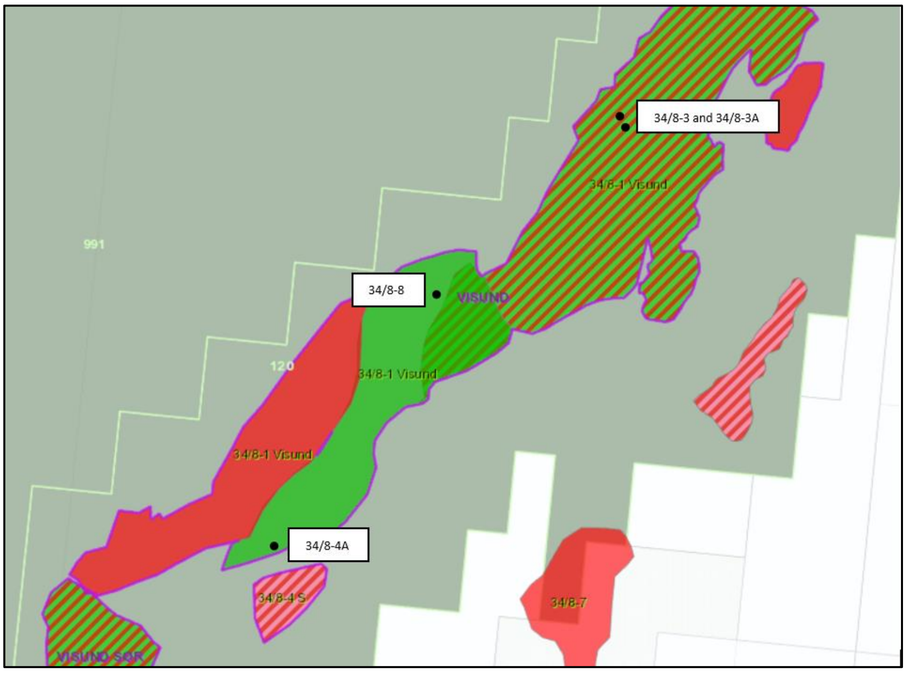


Figure 38 *E*xploration wells at Visund, from https://factmaps.npd.no/factmaps/3_0/?run=FieldByNPDID&NPDID=43745

In Figure 36 and 37 it is shown that three of the wells here has pore pressure measurements that deviates from the rest. In Figure 38 it is shown that well 34/8-4A lies a bit more south than the other wells. Visund has an GOC at 2910 m and an OWC at 2970 m. There also might be an GWC at 2940 m. As seen in Figure 37 and table 3 Visund has a high overpressure in the water zone at 136 bar.

7.7.2 Interpretation

Wiprut and Zoback, (2002*)*, did a study on the leakage potential of seismically mapped faults in in the Visund field. The pore pressure data were direct measured from the reservoir. As seen in Figure 39 A, they found it to have low seismic reflectivity along the southern part of the Brent reservoir, due to gas leakage. In Figure 39.B, the black dashed line shows the faults and gas leakage in the field. The black circles here are exploration wells. The A-central fault here separate some of the gas and oil compartments. Figure 39.C shows a cross section of well D. Well D was drilled through the A-central fault. Geochemical analyses of the gas from both sides of the fault, show that there is no flow of oil and gas across the A-central fault. The pore pressure in Visund are significantly over the hydrostatic pressure in the whole reservoir. Wiprut and Zoback (2002) claimed that the pore pressure in the footwall might have caused the A-central fault to leak and slip. And that the fault slip resulted in increased permeability that has affected the pore pressure. The overpressure in the water zone was very high, so Wiprut and Zoback, (2002), claimed that this might have prevented larger hydrocarbon columns to stay in the reservoir.

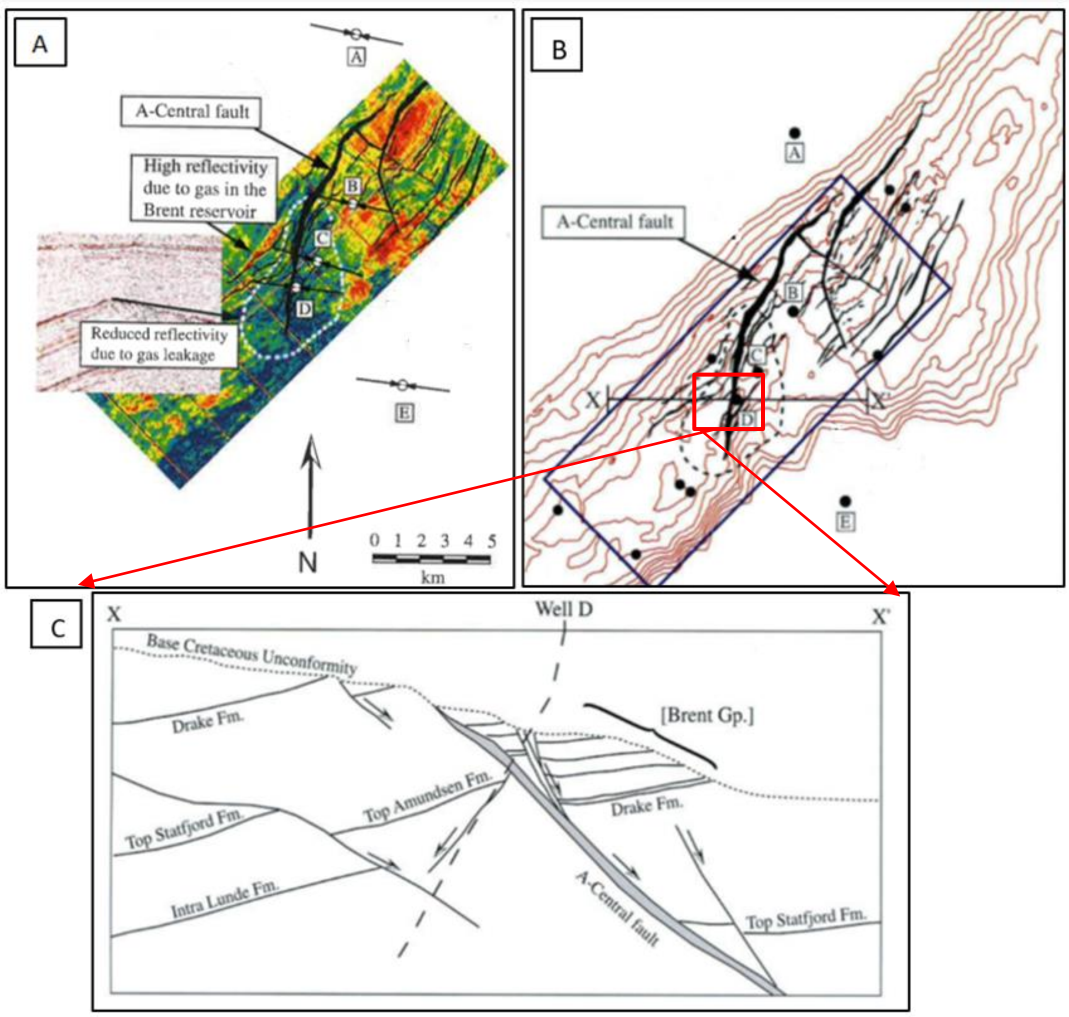


Figure 39 **A)** Contour map of the Brent reservoir at Visund. **B)** Map showing the A-central fault **C)** Cross section through the Visund field. From *"Fault reactivation, leakage potential, and hydrocarbon column heights in the northern North Sea,"* by Wiprut and Zoback, 2002, Norwegian Petroleum Society Special Publications, Elsevier, Volume 11, 2002, pp.203-219.

From this study it is interpreted to be leakage in the reservoir due to fault reactivation. To reactivate the fault, the pore pressure must be high. The reason for overpressure seems to be due to tectonic activities (faulting). From the study by Wiprut and Zoback, (2002), this might be an indication for the possibility of encountering a dry well where leakage have occurred in the reservoir. Unfortunately, we do not have any data from dry wells in the Visund field available.

7.8 Plot of all fields, only for water-gradient

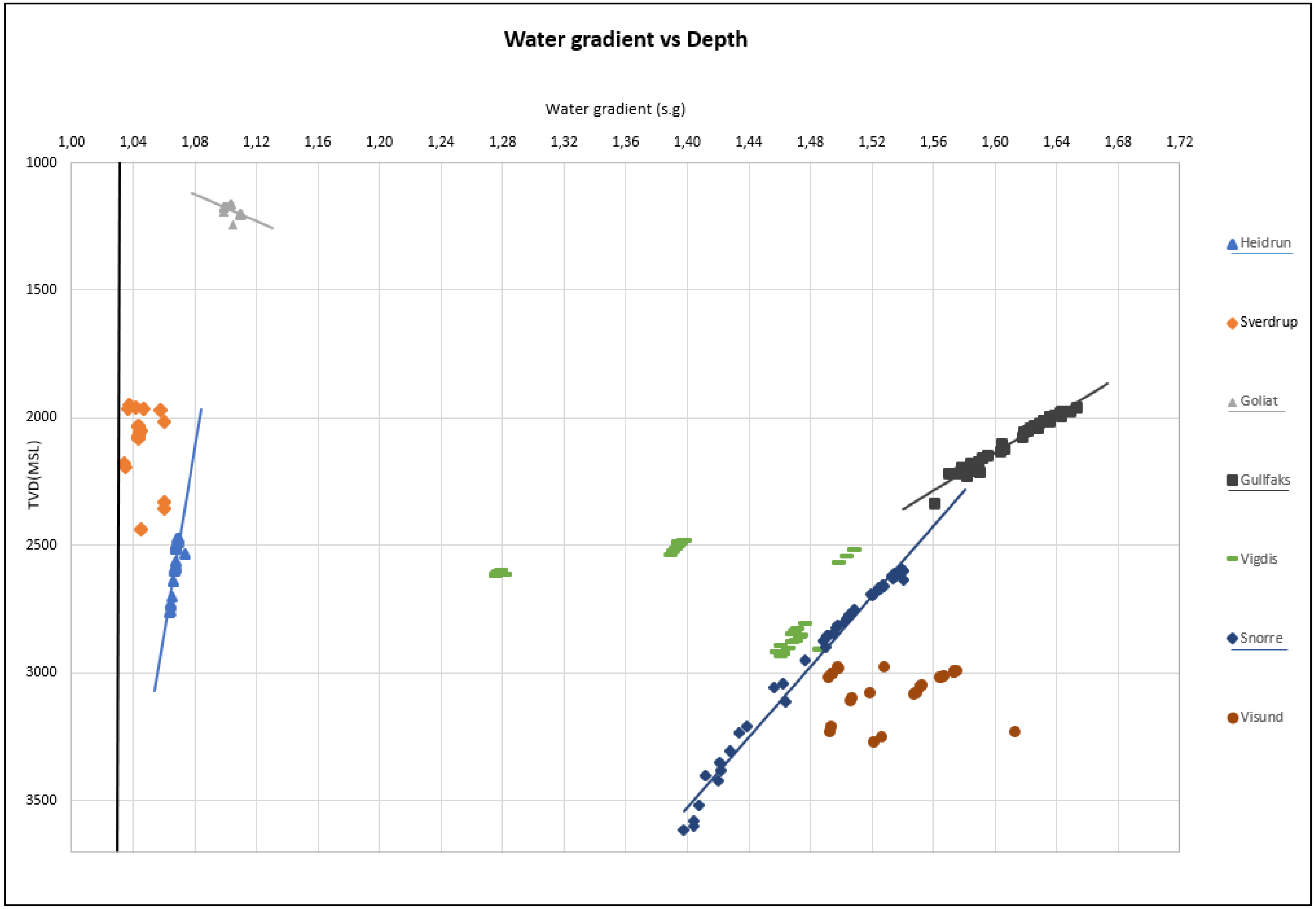


Figure 40 *Plotted water gradient vs Depth for all the fields.*

7.8.1 Observation

In Figure 40, the data from the water zone for each well are plotted. Here the data from OWC and down to the bottom of the well are used. In Figure 40 one can see that all the wells in the Tampen area which there are provided data for, has an abnormal pore pressure compared to the water gradient in the different fields. The water gradient is set to be 1,03 s.g (the black line). The field which has the pressure closest to the hydrostatic gradient is Johan Sverdrup and Heidrun. Gullfaks is the one that deviates the most from the normal trend.

7.8.2 Interpretation

In Figure 40, it is possible to assume that the wells in Heidrun and Goliat have been affected by fault leakage. From the Figure one can also state that the overpressure in the water zone varies a lot among the fields, and that it is field-specific. It is also possible to assume from the Figure that the deepest wells have the highest pressure gradient in the water zone.

7.9 Normalized to Seabed

7.9.1 Pressure vs. depth

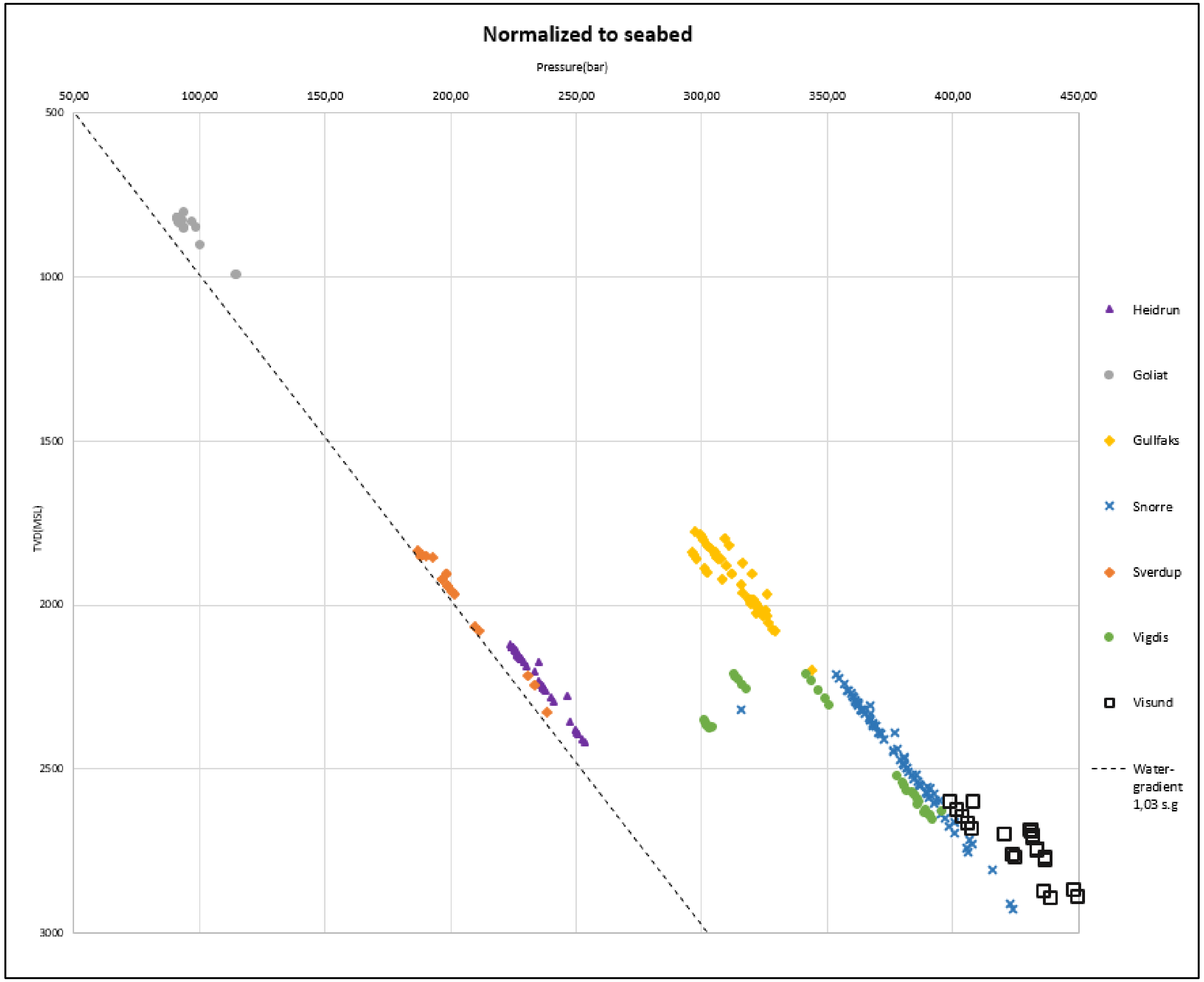


Figure 41 *Pore pressure in water zone, normalized to seabed.*

The seafloor is used as a reference level. Here the effect of water is removed by subtracting the water head from each pressure reading (Aadnoy, 2010). It is assumed that the normal pressure gradient is 1,03 s.g, which can be shown in Figure 41 as the black line. The North Sea has a water depth that do not vary too much between the fields, around 100-380 meters for the fields in this study. The formulas used for these calculations are shown below.

Pressure of seawater

$$P_{sea}=\rho g h_w \tag{7.1}$$

Depth from seabed

$$D_{sea}=D-h_w \tag{7.2}$$

Pressure under seabed

$$P=P_{pore}-P_{sea} \tag{7.3}$$

Where

P_{pore}	pore pressure [bar]
P_{sea}	pressure of seawater [bar]
P	pressure [bar]
D_{sea}	depth of well from seabed [TVD(MSL)]
D	bottom of well [TVD(MSL)]
h_w	water depth [m]
ρ_{water}	density of seawater (1,03) [s.g]
g	gravitational constant [m/s^2]

In Figure 41 it is shown that Goliat, Johan Sverdup and Heidrun are the fields that have a pressure gradient closest to the one for seawater (1,03 s.g), when taking the depth from seabed to the end of each well. Visund is the one deviating mostly from the rest of the fields. This field is also one of the deepest. The field has here an overpressure of 150-200 bar compared to the gradient of seawater (1,03 s.g.). The normalization is done to make the data more comparable. From this plot it is very clear that Goliat is not as deep as the rest of the field.

7.9.2 Water-gradient vs. depth

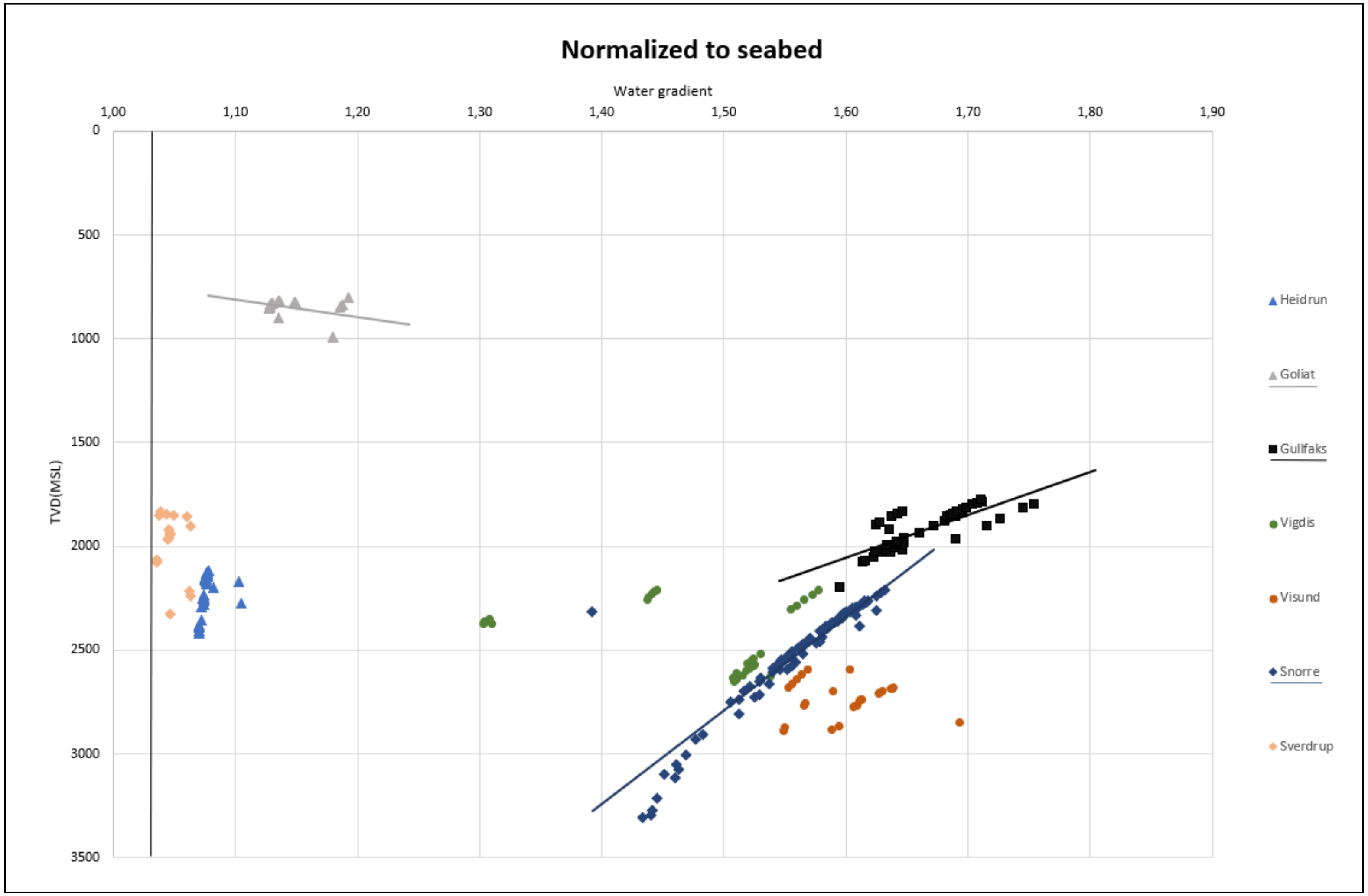


Figure 42 *Water-gradient, normalized to seabed*

In Figure 42 the pressure gradients from the different wells in the fields have been plotted against the depth from seabed. The pressure under seabed is divided by the gravity, times depth of well from seabed, as shown in the following formula (7.4)

$$\rho = \frac{P}{gDsea} \tag{7.4}$$

Where

ρ	density [s.g]
P	pressure under seabed [bar]
g	gravitational constant [m/s^2]
D_{sea}	depth of well from seabed [TVD(MSL)]

From this plot it is possible to see that Goliat, Johan Sverdrup and Heidrun are the fields with water-pressure gradients closest to the seawater gradient (1,03 s.g). Johan Sverdrup has the lowest water-pressure gradient at 1,045 s.g. Gullfaks is the field with highest water-pressure gradient, with the highest at 1,6 s.g. in average (table 4). Visund also here shows a high water-pressure gradient with the average of 1,53 s.g. (table 4).

7.10 Comparison of the fields

Field	$d_{overpressure}$ (s.g)	$d_{Average}$ (s.g)	Depth TVD(MSL)	HC
Heidrun	1,06-1,07	1,065	2471-2763	*Oil/gas*
Johan Sverdrup	1,03-1,06	1,045	1950-2438	*Oil*
Goliat	1,10-1,11	1,105	1163-1245	*Oil/gas*
Gullfaks	1,56-1,65	1,6	1959-2338	*Oil*
Vigdis	1,28-1,51	1,4	2481-2935	*Oil*
Snorre	1,4-1,54	1,47	2596-3617	*Oil*
Visund	1,49-1,57	1,53	2978-3269	*Oil/gas*

Table 4 *Average pressure gradient for the fields.*

7.10.1 Observation

The average pressure gradient for the different fields are shown in table 4. The field with the largest spread in the pressure gradients between the wells are as seen here Vigdis.

7.10.2 Interpretation

In Figure 43 the average overpressure for the different fields are plotted. Johan Sverdrup, Goliat and Heidrun have the lowest average measurements here. The four fields in the Tampen area, has an overpressure between 1,4-1,6 s.g. Here Gullfaks has the highest values. The largest spread in pressure gradient is in Vigdis. The reason for this might be due to due to the lack of communication between the reservoirs as mentioned in chapter 7.5. From this it is possible to say that the Tampen area has an abnormal pore pressure, and that the overpressure is area specific.

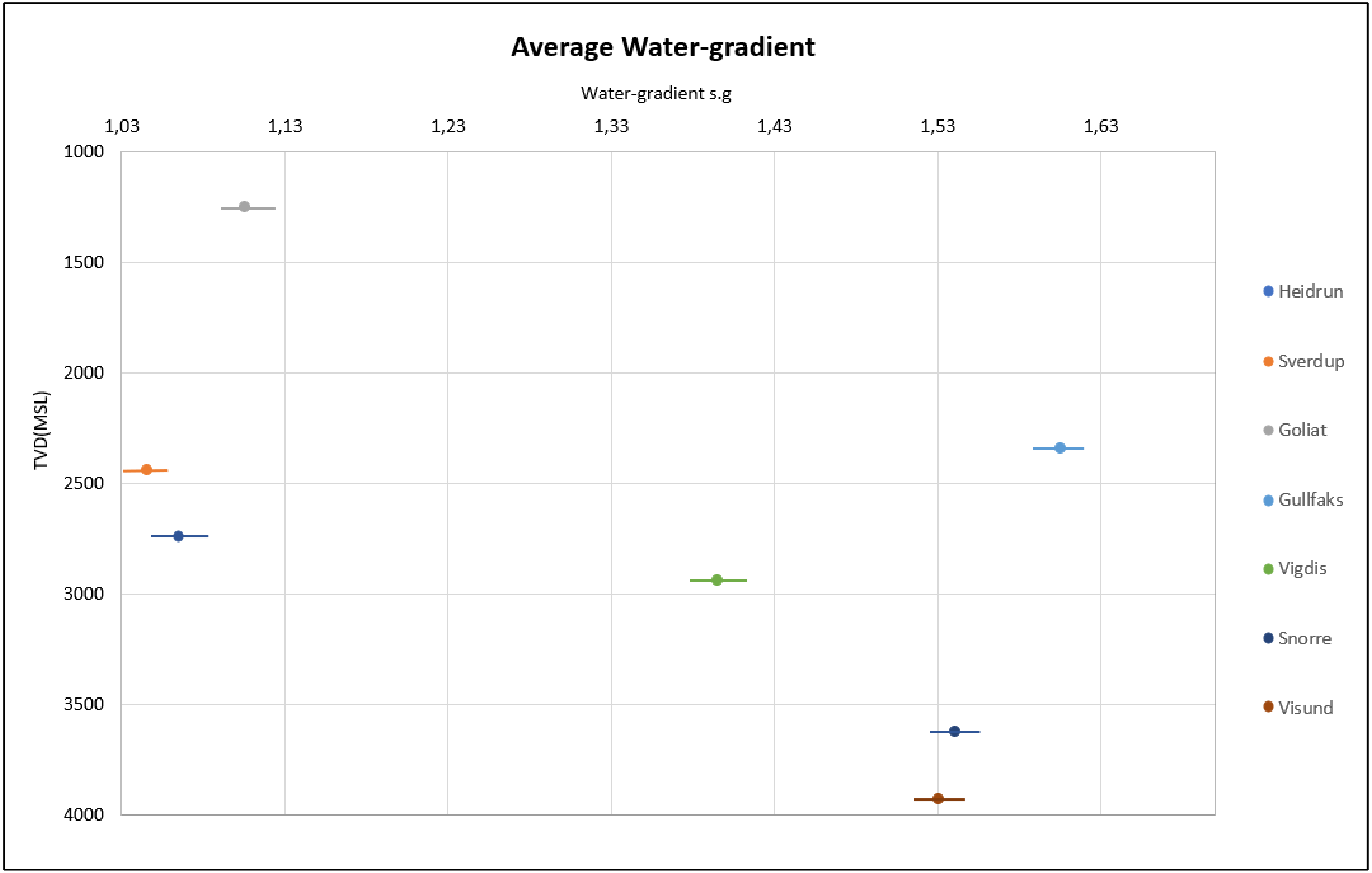


Figure 43 Average water-gradient vs depth.

8.0 Discussion

8.1 Reasons for overpressure

A review of previous studies is emphasized when determining the factors which have caused overpressure in the different regions. When evaluating the pore pressure, it is also important to perform a geological analysis. Because the pore pressure estimates are not always reliable.

As interpreted in chapter 7, there can be several different reasons for overpressure in the different fields studied. Compaction disequilibrium are often assumed to be the reason for overpressure, when the overpressured shale have a high porosity. In the North Sea and Haltenbanken, the porosity does not differ significantly between the normally pressured and overpressured formation, so compaction disequilibrium does not seem to be the reason for overpressure in these areas (Teige, 2008). According to the study from Teige, (2008), it is assumed that the reason for overpressure in the North Sea and Haltenbanken might be due to diagenetic processes.

When interpreting the fields in the Tampen area, it was observed a large overpressure (over 100 bar) for all the fields in this area. The reason for the overpressure here, might mainly be due to tectonic activities. All the fields have reservoirs of Jurassic and Triassic age in the studied areas. This was a period exposed to uplift, erosion, rifting and faulting in the North Sea, which might have caused an overpressure. Grollimund and Zoback, (2003), claims that an increase in horizontal stress due to lithospheric bending from deglaciation may have caused an increase in pore pressure. The Haltenbanken, the North Sea and the Barents Sea have been exposed to periods of glaciation and deglaciation, which might have affected the pore pressure in the areas studied.

There are several uncertainties related to the assumptions regarding the reasons for overpressure. Since there is no specific data that can claim that diagenetic processes, tectonic activity or glaciation/deglaciation are the main mechanisms causing an overpressure in the area. The overpressure might also be caused by several of these mechanisms in the same areas.

8.2 Reasons for normal water pressure in dry wells

At the Heidrun field two dry wells were found, both had a pressure gradient close to/equal to 1,03 s.g. The rest of the exploration wells at the field containing hydrocarbons, had an overpressure. Riis, (2010), did a study on Goliat (see chapter 7.3.2) where he suggested that the dry wells in the field had a normal water pressure. As seen from this study, Goliat has an overpressure (1,105 s.g.) in the wells where there are hydrocarbons present. It seems like both Heidrun and Goliat follow the same trend with normally pressured dry wells. Unfortunately, no available data were obtained from the dry wells at Goliat in this study, therefore the previous study from Riis, (2010), has been used.

The idea in this study was that maybe the pressure in the dry wells were normal due to possible leakage. Hermanrud and Nordgråd Bolås, (2002), claims that the reason for not finding hydrocarbons in dry wells in the northern part of the North Sea and Haltenbanken are due to cap rock leakage, with leakage mainly from reservoirs of Jurassic age. This seems like a reasonable explanation, because for a leakage to occur, the pore pressure must be so high that it can reactivate faults (Wiprut and Zoback, 2002). And as seen from this study, the fields in the northern part of the North Sea and Heidrun (Haltenbanken) has overpressure, where the pore pressure might have reactivated the faults causing a leakage. Wiprut and Zoback, (2002), claims that there is a relationship between the overpressure and fault leakage in the northern part of the North Sea. Pore pressure, stress and faulting may lead to leakage and migration in this area.

Another reason for a possible leakage in the northern part of the North Sea and Haltenbanken, are glacial flexuring. Hermanrud and Nordgråd Bolås (2002) concluded with that glacial flexuring might have resulted in leakage due to formation of new fractures. Hermanrud and Nordgråd Bolås, (2002), found that the risk for leakage is decreasing with depth, and that the risk is higher in Haltenbanken than in the North Sea.

The study to Teige, (2008), concluded with that when there is high overpressure in the formation, it is assumed to be Hydrocarbon leakage through the seal rock. Teige ,(2008), assume that the reason for this might be hydrofracturing or due to high water pressure which forces the hydrocarbons through membrane seals. Teige, (2008), claims that high overpressure is consistent with hydrocarbon preservation. That vertical water leakage can happen while the hydrocarbons are kept in the structure by capillary forces. On the background of this, it is possible to say that many of the overpressured fields in the study have a high overpressure and are leaking, but still contain a large amount of hydrocarbons.

In this study there were only found data from one dry well at Gullfaks. As seen in chapter 7.4, the field has data from a dry well. This dry well has a high overpressure. It was assumed that the reason for this might be that there never were hydrocarbons present in this well, only overpressured water. Since there is no more data from other dry wells in this field or others in the Tampen area, it is hard to make a statement for why this dry well are highly overpressured. No evidence of leakage was found in the northern part of the North Sea in this study, and therefore previous studies has been used. From these there seems like the northern part of the North Sea are suffering from leakage in the reservoirs, due to fault reactivation, cap rock leakage or glaciation, but the fields still contain large amounts of hydrocarbons.

8.3 Production point of view

Early detection of pore pressure is important to ensure the drilling safety and efficient production. The viscosity, permeability and porosity also play an important role when deciding if a field is profitable (chapter 3).

Field	Production methods
Gullfaks	*Water & gas injection* *WAG*
Snorre	*Water & gas injection* *WAG*
Vigdis	*Water & gas injection* *Pressure depletion in some wells*
Visund	*Water & gas injection* *Pressure depletion*
Johan Sverdrup	*Water & gas injection* *Gas lift*
Heidrun	*Water & gas injection*
Goliat	*Water & gas injection*

Figure 44 Production methods in the fields, modified from Norwegian Petroleum.

As seen in figure 40, Johan Sverdrup is the field which is closest to the water gradient of 1,03 s.g. Heidrun and Goliat also have lower pressure gradients compared to those in the Tampen area. From a production point of view, it means that these fields cannot produce for a long time before they need gas/water injection or artificial lift as pressure support. This is due to the reduction in pore pressure when producing. The fields Gullfaks, Snorre and Visund, which have a high overpressure in the water zone, might be capable to produce for a longer time, before injection and artificial lift is introduced.

Snorre and Visund are the two fields with the highest overpressure, at around 130 bar. According to NPD, (2019), Snorre suffers from poor reservoir communication, which is a challenge for pressure maintenance. This indicates that Snorre is a field that might not be able to produce from only the overpressure, but due to poor reservoir communication, need pressure support.

At Sverdrup there is no possibility to use the formation pressure to produce the well, since there is no overpressure in this field. There is immediate need for gas lift. The Sverdrup field is also planned to have full reinjection of the produced water in the reservoir for pressure support. There might also be used polymers to increase the viscosity of the injected water (Statoil, 2014). Sverdrup is a field that has high production rate, even though there is no overpressure in this specific field.

Goliat has a low overpressure and is therefore produced with water injection. To maintain the reservoir pressure and be able to produce hydrocarbons, artificial methods are needed. Produced gas is re-injected to provide pressure drive (NPD, 2019).

In this study it is believed that an overpressured field can produce for a longer time before injection or artificial lift is introduced. Especially in the highly overpressured fields; Visund, Vigdis, Snorre and Gullfaks. This can increase the profit for the field and might elongate the production time for the well. When drilling and producing in an overpressured reservoir, precautions must be taken, if not, problems like kick, damage of the formation, lost circulation, differential sticking and collapse may occur (see chapter 5.6). If the pore pressure is sampled in an early stage these risks will be diminished. It is important to compare the estimates of pore pressure from different calculations and observations, like drilling parameters, seismic data and logs (Oloruntobi and Butt, 2019).

8.4 Overpressure and hydrocarbon discoveries

As seen from this study the overpressured areas are likely to have an impact on the probability for future hydrocarbon discoveries. This tendency is especially seen in Heidrun and Goliat where the dry wells are normally pressured, while the wells containing hydrocarbons are overpressured. When than exploring new areas, it might be more likely to encounter hydrocarbons if there is an overpressure. A normally pressured reservoir might indicate a dry well. Therefore, it might be a larger probability for finding hydrocarbons in overpressured zones, but it seems to be dependent on the area. It is therefore necessary to study these areas closer to see if this is an overall trend. In the Tampen area, all the fields studied contain large amounts of hydrocarbons. For this specific area, it seems to be likely that the overpressure is an important factor which have generated the hydrocarbons. Johan Sverdrup is the only field from this study that has a pressure gradient close to/equal to 1,03 s.g. This is a field with high production rate and contains large amounts of hydrocarbons. It is therefore necessary to explore more in this area, to see if the other fields here follow the same trend with normal pore pressure.

Early pore pressure measurements are assumed to have an impact on the probability for discoveries. Because normally pressured areas might indicate dry wells. It is therefore important to sample the pore pressure earlier, and to analyse the pore pressure more before mapping the area and making a reservoir model. To do so, the new methods discussed in chapter 5.5 (HMSE and MSE) might be used. These methods might give more precise measurements of the pore pressure at an early stage, and possibly lowering the costs (Oloruntobi and Butt, 2019).

9.0 Conclusion and future work

9.1 Conclusion

The reason for overpressure in the Tampen area might be caused by tectonic activities. Mainly due to fracturing and faulting, but glaciation and deglaciation might also have contributed to the increase in pore pressure in this area. This also seems to be the case for Heidrun in Haltenbanken. From the study by Teige, (2008), diagenetic processes may also be the reason for overpressure in the northern part of the North Sea. It is assumed that the overpressure in Goliat in the Barents Sea is mainly due to glaciation/deglaciation (Tasianas et al., 2016). As seen in this study, the northern part of the North Sea, especially the Tampen Area has a high overpressure. Heidrun and Goliat are fields where the wells have a lower overpressure in the water zone compared to those in the North Sea, while in Johan Sverdrup the reservoirs are normally pressured. The water pressure level seems to be field specific. Normal water pressure in the dry wells at Heidrun are interpreted to be a probable result of leaking faults. The reasons for leakage in the areas studied, might be fault reactivation, glaciation/deglaciation and cap rock leakage.

Early detection of pore pressure measurements in exploration wells are from this thesis shown to be necessary. The aim of this thesis was to examine the pore pressure measurements in exploration wells in the Norwegian North Sea. To study the possibility of the overpressure being an indicator that can increase the probability of hydrocarbon discoveries in exploration wells. From the fields studied, one can see a clear trend that the water pressure below the oil zone varies in the different fields, from normal pressure to high overpressure. By early detection of abnormal pore pressures, one can then increase the probability of finding hydrocarbons in overpressured zones. If a dry well with normally pressure is discovered in the overpressured zone, it might be an indication of previously present hydrocarbons that has been exposed to leakage. Meaning that the hydrocarbons could have accumulated in an area close to the dry well.

9.2 Future work

The following are considered for future work:

- Study more exploration wells in Haltenbanken, the Barents Sea and the central North Sea to investigate if other fields follow the pore pressure trend for Heidrun, Goliat and Johan Sverdrup.

- Find data from more dry wells in the areas studied, and check if these are normally pressured or if they are overpressured to see if there is a recurring trend on the whole NCS.
- Improve seismic data, sampling methods and interpretation methods for the exploration phase, to get more precise and trustworthy measurements of the pore pressure.
- Examine if the HMSE and MSE-method to measure pore pressures, are adequate methods to find overpressured areas.

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Appendix

Pore pressure measurements in the exploration wells

1.1 Heidrun

Well6507/8-2	Dry	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
1930	1905	195,24
1957	1932	196,96
1987	1962	198,74
2020	1995	202,04
2253	2228	225,36
2414	2389	241,75

Well6507/8-6	Dry	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
2080	2055	213
2090	2065	214
2100	2075	215
2110	2085	216

Well6507/7-6	Oil/gas		
DEPTH(RKB)	DEPTH(MSL)	FMT(Psi)	FMT(BAR)
2149	2124	3518	242,56
2169	2144	3540	244,07
2192	2167	3530,7	243,43
2204	2179	3533,7	243,64
2221	2196	3538,8	243,99
2235	2210	3542,5	244,25
2263	2238	3550,6	244,81
2302	2277	3560,2	245,47
2320	2295	3565,3	245,82
2332	2307	3567,5	245,97
2337	2312	3569,3	246,09
2346	2321	3604,2	248,50
2351,5	2326,5	3585,6	247,22
2356	2331	3604,7	248,54
2370,5	2345,5	3601	248,28
2380	2355	3615,4	249,27
2385	2360	3622	249,73
2405	2380	3638,1	250,84
2414,5	2389,5	3649,1	251,60
2424	2399	3660,3	252,37
2436	2411	3674,7	253,36
2447	2422	3689,7	254,40
2452	2427	3696,6	254,87
2457	2432	3703,8	255,37
2472	2447	3726,2	256,91
2487	2462	3746,9	258,34
2504	2479	3771,5	260,04

Well6507/7-5	Oil/gas		
DEPTH(RKB)	DEPTH(MSL)	FMT(Psi)	FMT(BAR)
2358	2333	3604,5	248,52
2363	2338	3611,4	249,00
2368	2343	3616,5	249,35
2378	2353	3622,9	249,79
2377	2352	3626,9	250,07
2380,5	2355,5	3630,3	250,30
2386	2361	3635,3	250,65
2389	2364	3638,4	250,86
2393	2368	3642,9	251,17
2397	2372	3647,4	251,48
2402,5	2377,5	3653,2	251,88
2413	2388	3664,5	252,66
2420	2395	3672,3	253,20
2482	2457	3740,4	257,89
2485	2460	3744,4	258,17
2485,5	2460,5	3745,7	258,26
2491	2466	3753,2	258,77
2494	2469	3759	259,17
2498	2473	3763,3	259,47
2504	2479	3772	260,07
2514	2489	3786,4	261,06
2529	2504	3808,5	262,59
2540	2515	3824,5	263,69
2557	2532	3868,9	266,75
2589	2564	3894,6	268,52
2607	2582	3921,7	270,39
2613	2588	3930,4	270,99
2618	2593	3937,5	271,48
2637	2612	3967,9	273,58

Well 6507/7-4	Oil/gas		
DEPTH(RKB)	DEPTH(MSL)	FMT(Psi)	FMT(BAR)
2451	2426	3712,2	255,95
2455	2430	3716,1	256,22
2461	2436	3722,7	256,67
2465	2440	3726,5	256,93
2471	2446	3732,1	257,32
2474,5	2449,5	3736	257,59
2479	2454	3740,9	257,93
2484	2459	3746,3	258,30
2490	2465	3752,6	258,73
2496	2471	3758,7	259,15
2498	2473	3759,9	259,24
2521	2496	3792,9	261,51
2525	2500	3798,9	261,92
2530	2505	3805,6	262,39
2533	2508	3810,4	262,72
2535	2510	3813,4	262,92
2537	2512	3816,3	263,12
2543	2518	3912,3	269,74
2616	2591	3933,6	271,21
2620	2595	3937,8	271,50
2623	2598	3942,4	271,82
2647	2622	4081	281,38
2665	2640	4003,2	276,01
2726	2701	4094	282,27
2750	2725	4126,3	284,50
2757	2732	4136,8	285,22
2762	2737	4144	285,72
2780	2755	4170,6	287,55
2788	2763	4182,2	288,35

1.2 Johan Sverdrup

Well16/2-7	Oil	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
1980,02	1955,02	198,55
1976,92	1951,92	198,24
1963,5	1938,5	196,91
1958,95	1933,95	196,46
1954,97	1929,97	196,05
1951,99	1926,99	195,76
1947,97	1922,97	195,36
1945,5	1920,5	195,15
1943,45	1918,45	194,98
1941,61	1916,61	194,83
1940,51	1915,51	194,75
2021,03	1996,03	204,41
2017,97	1992,97	204,21
2021,03	1996,03	204,172
2017,97	1992,97	205,9
2026,41	2001,41	194,96
2022,45	1997,45	197
1941,58	1916,58	196,98
1963,48	1938,48	204,49
1963,49	1938,49	204,89
2020,94	1995,94	204,49
2020,15	1995,15	195,22
1945,45	1920,45	195,22
2354,63	2329,63	242,2
2380,13	2355,13	244,93
2462,9	2437,9	249,86
2216,96	2191,96	222,5
2202,12	2177,12	220,9

Well 16/3-4	Oil	
Depth(RKB)	DEPTH(MSL)	FMT(bar)
1942,844	1917,844	196,4378
1942,81	1917,81	193,82
1939,44	1914,44	194,68

Well16/2-15	Oil	
Depth(RKB)	DEPTH(MSL)	FMT(bar)
1926,85	1901,85	193,516
1946,42	1921,42	195,099
1957,01	1932,01	196,14
1913,74	1888,74	192,357
1916,55	1891,55	192,532

Well16/2-10	Oil	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
1893,47	1868,47	190,86
1893,48	1868,48	190,93
1893,68	1868,68	190,857
1894,47	1869,47	190,917
1894,48	1869,48	190,99
1896,98	1871,98	191,116
1899,98	1874,98	191,174
1902,97	1877,97	191,353
1906,95	1881,95	191,592
1908,94	1883,94	191,827
1912,96	1887,96	192,069
1915,98	1890,98	192,385
1918,97	1893,97	192,627
1921,94	1896,94	192,864
1926,97	1901,97	193,098
1926,97	1901,97	193,335
1926,97	1901,97	193,531
1926,97	1901,97	193,572
1927,02	1902,02	193,58
1928,96	1903,96	193,501
1933,46	1908,46	193,657
1934,96	1909,96	194,047
1934,97	1909,97	194,143
1935,46	1910,46	194,138
1935,46	1910,46	194,176
1935,63	1910,63	194,182
1935,63	1910,63	194,181
1935,96	1910,96	194,187
1936,95	1911,95	194,215
1937,95	1912,95	194,37
1938,94	1913,94	194,45
1940,96	1915,96	194,62
1942,96	1917,96	194,78
1943,95	1918,95	194,85
1944,95	1919,95	194,93
1945,96	1920,96	195,021
1947,95	1922,95	195,098
1948,95	1923,95	195,176
1949,95	1924,95	195,25
1950,96	1925,96	195,332
1951,96	1926,96	195,4
1952,95	1927,95	195,49
1954,04	1929,04	195,57
1954,97	1929,97	195,66
1954,97	1929,97	195,722
1955,95	1930,95	195,814
1956,95	1931,95	195,8
1957,46	1932,46	195,8
1957,95	1932,95	195,878
1958,95	1933,95	195,922
1959,96	1934,96	195,972
1960,96	1935,96	196,074
1961,03	1936,03	196,17
1965,46	1940,46	196,27
1965,95	1940,95	196,361
1965,96	1940,96	196,7
1966,46	1941,46	196,816

Well16/2- 11	Oil	
Depth(RKB)	DEPTH(MSL)	FMT(bar)
1890,2	1865,2	190,49
1892,22	1867,22	190,661
1895,05	1870,05	190,887
1897,43	1872,43	191,075
1899,9	1874,9	191,271
1903,75	1878,75	191,57
1910,2	1885,2	192,085
1913,06	1888,06	192,313
1916,54	1891,54	192,591
1917,84	1892,84	192,69
1931,5	1906,5	202,718
1933,69	1908,69	193,97
1935,3	1910,3	194,088
1936,38	1911,38	194,169
1937,3	1912,3	194,253
1941,28	1916,28	194,577
1942,16	1917,16	194,641
1942,93	1917,93	194,706
1964,46	1939,46	201,101
1989,81	1964,81	201,815
1993,79	1968,79	204,303
2040,98	2015,98	209,73
2058,29	2033,29	208,075
2059,9	2034,9	208,237
2078,07	2053,07	210,394
2079,62	2054,62	210,458
2096,87	2071,87	212,049
2105,42	2080,42	212,869

Well 16/5-4	Oil	
Depth(RKB)	DEPTH(MSL)	FMT(bar)
1797,61	1772,61	193,535
1798,08	1773,08	193,569
1798,96	1773,96	193,643
1800,05	1775,05	193,729
1800,96	1775,96	193,804
1802,18	1777,18	193,905
1802,66	1777,66	193,935
1815,15	1790,15	198,14
1828,86	1803,86	199,226
1858,88	1833,88	201,497

Well16/2- 12	Oil	
Depth(RKB)	DEPTH(MSL)	FMT(bar)
1901,3	1876,3	191,534
1939,99	1914,99	194,961
1928,24	1903,24	193,697
1940,1	1915,1	194,858
1944,99	1919,99	195,386
1975,51	1950,51	198,45
1984,66	1959,66	200,215
1989,78	1964,78	199,784

Well16/2-19	Oil	
Depth(RKB)	DEPTH(MSL)	FMT(bar)
1937,39	1912,39	195,1
1937,59	1912,59	195,268
1939,3	1914,3	194,477
1940,57	1915,57	194,632
1942,48	1917,48	195,12
1944,7	1919,7	194,025
1944,98	1919,98	194,066
1945,01	1920,01	194,074
1945,01	1920,01	193,293
1947,39	1922,39	194,226
1948,38	1923,38	194,235
1948,87	1923,87	194,278
1948,91	1923,91	194,296
1949,37	1924,37	194,401
1950,13	1925,13	194,484
1950,17	1925,17	194,418
1950,2	1925,2	194,425
1950,2	1925,2	194,433
1950,32	1925,32	194,123
1950,42	1925,42	194,602
1951,09	1926,09	194,607
1951,1	1926,1	195,524
1957,89	1932,89	195,719
1974,38	1949,38	194,263

Well16/2- 5	Oil	
Depth(RKB)	DEPTH(MSL)	FMT(bar)
1918,09	1893,09	192,673
1919,99	1894,99	192,821
1921,9	1896,9	192,981
1923,79	1898,79	193,129
1925,67	1900,67	193,281
1927,64	1902,64	193,436
1929,53	1904,53	193,585
1930,94	1905,94	193,703
1937,44	1912,44	197,384
1937,73	1912,73	194,337
1920,04	1895,04	192,863
1920,04	1895,04	192,875
1943,54	1918,54	194,906
1943,54	1918,54	194,856
1959,33	1934,33	196,258
1959,37	1934,37	196,285
1959,37	1934,37	196,276

1.3 Goliat

Well7122/7-1	Oil
DEPTH(MSL)	FMT(bar)
1078,29	122,5
1081,8	120,47
1088,57	120,99
1089,76	121,08
1090,75	121,16
1099,26	121,83
1106,25	122,38
1109,76	122,65
1116,24	123,147
1121,26	123,527
1126,24	124,051
1137,55	125,249
1140,52	125,555
1144,51	125,983
1202,44	130,939
1207,12	131,421
1209,01	131,622

Well7122/7-2	Oil
DEPTH(MSL)	FMT(bar)
1060,9	119,6
1061	119,7
1062,9	119,7
1064,9	119,9
1073,3	120,5
1080,8	121,1
1084,8	121,4
1084,9	121,5
1114,8	123,8
1114,9	123,9
1117,8	124
1120,8	124,2
1130	124,9
1131,9	125,3
1134,3	125,4
1140,3	126
1143,8	126,4
1145,8	126,6
1179	131,8
1210,6	135,1
1225,7	136,7
1368,5	152,7
1370,5	152,9

Well7122/7-3	Oil/gas
DEPTH(MSL)	FMT(bar)
1065,1	123,88
1070,3	123,95
1074,1	123,98
1078,8	124,045
1082,2	124,059
1086,1	124,092
1100,5	124,274
1103,1	124,312
1108,2	124,4
1110,1	124,359
1111,3	124,3
1119,8	124,476
1121,4	124,547
1122,7	124,657
1124,6	124,801
1156,1	125,257
1159	125,83
1162,5	125,863
1163,7	125,9
1165,2	126,091
1166,3	126,124
1170,3	126,298
1171,2	126,4
1173,5	126,546
1174,2	126,605
1175,3	126,707
1177,6	126,937
1178,7	127,05
1192,1	128,511
1194	128,669
1245,3	134,98

1.4 Gullfaks

Well 34/10-19	DRY		
DEPTH(RKB)	DEPTH(MSL)	FMT(PSI)	FMT(BAR)
1852,8	1827,8	4565,3	314,76635
1853	1828	4586,3	316,21425
1863,2	1838,2	4655,3	320,97164
2015	1990	4764	328,46624
2035	2010	4790	330,25887
2087	2062	4870	335,77468
2120	2095	4921	339,29101
2185	2160	5010	345,42734

Well 34/10-4	Oil		
DEPTH(RKB)	DEPTH(MSL)	FMT(PSI)	FMT(BAR)
1932,5	1907,5	4533	312,53935
2254	2229	5016	345,84103
2240	2215	5012	345,56524
2231,5	2206,5	4971	342,73838
2244,5	2219,5	4957	341,77312
2216,5	2191,5	4956	341,70417
2217	2192	4922	339,35995
2213,5	2188,5	4934	340,18732
2207	2182	4922	339,35995
2205	2180	4918	339,08416
2202,5	2177,5	4909	338,46364
2080	2055	4733	326,32886
2075	2050	4728	325,98412
2067	2042	4716	325,15675
2058	2033	4702	324,19149
2045	2020	4682	322,81254
2037,5	2012,5	4672	322,12306
2022	1997	4647	320,39937
2016	1991	4643	320,12358
2007	1982	4631	319,29621
2002	1977	4622	318,67568
1994	1969	4605	317,50357
1895	1870	4485	309,22986
1897	1872	4493	309,78145
1900,5	1875,5	4501	310,33303
1918	1893	4519	311,57408
1920	1895	4520	311,64303
1928	1903	4528	312,19461
1935	1910	4532	312,4704
1939	1914	4537	312,81514
1950	1925	4550	313,71146
1953,5	1928,5	4554	313,98725
1961	1936	4559	314,33198
1969	1944	4566	314,81462
1981	1956	4584	316,05567
1997	1972	4604	317,43463

Well 34/10-34	Oil	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
2362,5	2337,5	357,8
2244	2219	343,1
2238	2213	342,5
2218,5	2193,5	340,7
2196	2171	338,4
2184,5	2159,5	337,3
2173	2148	336,2
2155,5	2130,5	335,1
2148,5	2123,5	334,5
2125	2100	330,6
2086,5	2061,5	322,3
2062,5	2037,5	316,3
2051,5	2026,5	315,1
2021,5	1996,5	312,2
2009	1984	311
2000,5	1975,5	310,4

Well 34/10-5	Oil		
DEPTH(RKB)	DEPTH(MSL)	FMT(PSI)	FMT(BAR)
1898	1873	4511	311,0225
1904,5	1879,5	4518	311,50513
1912,5	1887,5	4527	312,12566
1922,5	1897,5	4537	312,81514
1928	1903	4541	313,09093
1937	1912	4552	313,84935
1951	1926	4568	314,95251
1959	1934	4578	315,64199
1975	1950	4596	316,88305
1984	1959	4608	317,71042
1999	1974	4631	319,29621
2018,5	1993,5	4660	321,29569
2040	2015	4689	323,29517
2066	2041	4728	325,98412
2100,5	2075,5	4777	329,36256

1.5 Vigdis

34/7-19	Oil	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
2456,88	2431,88	365
2459,55	2434,55	365,17
2462,07	2437,07	365,33
2465,06	2440,06	365,56
2466,08	2441,08	365,65
2470,59	2445,59	365,97
2476	2451	366,47
2484,46	2459,46	367,07
2487,04	2462,04	367,33
2501,56	2476,56	368,74
2503,88	2478,88	368,96
2522,07	2497,07	370,76
2542,1	2517,1	372,74
2570,09	2545,09	375,49
2595,04	2570,04	377,94
2614,06	2589,06	379,81

34/7-16	Oil	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
2392	2367	361,2
2406	2381	362,3
2423	2398	363,5
2440	2415	364,8
2455	2430	365,9
2467	2442	366,7
2477	2452	367,5
2482	2457	368
2486	2461	368,2
2488	2463	368,3
2489,8	2464,8	369
2490	2465	368,7
2494,5	2469,5	369,1
2832	2807	406,8
2855	2830	408,8
2862	2837	409,4
2876	2851	410,8
2920	2895	415,1
2943	2918	417,7

34/7-23	Oil	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
2622,6	2597,6	326,2
2632	2607	326,8
2634,25	2609,25	326,9
2641,8	2616,8	329,2
2645,5	2620,5	328,1
2638,3	2613,3	327,3

34/7-13	Oil	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
2494	2469	339,6
2496	2471	339,7
2496,4	2471,4	339,6
2497	2472	339,9
2500,4	2475,4	340,1
2502,4	2477,4	340,2
2503,4	2478,4	340,3
2506,3	2481,3	340,4
2506,3	2481,3	340,6
2512	2487	340,4
2518	2493	341,6
2526	2501	342,3
2536	2511	343,3
2550,4	2525,4	344,7
2563,4	2538,4	346,2
2876,6	2851,6	412,5
2885	2860	413,6
2897	2872	414,7
2905,4	2880,4	415,1
2931,4	2906,4	418,1
2935	2910	424,5
2949	2924	419,6
2949	2924	419,6
2960	2935	420,7

1.6 Snorre

Well 34/7-9 Oil		
DEPTH RKB	DEPTH MSL	FMT (bar)
2456,4	2431,4	382,95
2503,1	2478,1	383,5
2512	2487	384,19
2533	2508	385,76
2552	2527	387,06
2582,5	2557,5	389,14
2585	2560	389,29
2591,3	2566,3	389,72
2623,5	2598,5	392,71
2637,5	2612,5	394,01
2656	2631	395,83
2698,5	2673,5	400,09

Well 34/4-6 Oil		
DEPTH RKB	DEPTH MSL	FMT(bar)
2577,5	2552,5	388,53
2579	2554	388,63
2580,5	2555,5	388,72
2581,5	2556,5	388,77
2585,5	2560,5	389,04
2593	2568	389,66
2594,5	2569,5	389,95
2599	2574	390,33
2602,5	2577,5	390,61
2609,5	2584,5	391,34
2622	2597	392,64
2660	2635	396,32
2688	2663	399,08
2699,5	2674,5	400,25
2717	2692	402,02
2747	2722	404,91

Well 34/7-7 Oil		
DEPTH RKB	DEPTH MSL	FMT(bar)
2562	2537	387,66
2567,5	2542,5	388
2582	2557	389,02
2591	2566	391,13
2587	2562	389,37
2613,5	2588,5	391,32
2643,5	2618,5	346,51
2658,5	2633,5	397,93
2692	2667	398,79
2715,5	2690,5	401,59
2721,5	2696,5	402,18
2797	2772	409,32
2846	2821	414,27
2879	2854	417,62
2923	2898	423,66
2976,5	2951,5	427,41
3066	3041	436,34
3236,5	3211,5	453,36
3331,5	3306,5	463,09
3378,5	3353,5	467,35
3426	3401	471,11

Well 34/4-9S Oil		
DEPTH RKB	DEPTH MSL	FMT(bar)
2564,55	2539,55	387,23
2583,04	2558,04	388,72
2586,03	2561,03	388,87
2592,52	2567,52	389,35
2604,53	2579,53	390,23
2607,52	2582,52	390,45
2620,02	2595,02	391,57
2658,63	2633,63	395,38
2682,64	2657,64	397,58
2691,57	2666,57	398,53
2725,55	2700,55	402,09
2767,03	2742,03	406,16
2803,06	2778,06	409,9
2847,56	2822,56	414,32
2889,57	2864,57	418,47
2936	2911	423,47
2945,07	2920,07	424,01
2996,02	2971,02	429,24
3034,04	3009,04	432,44
3055,54	3030,54	434,38

Well 34/7-3 Oil		
DEPTH RKB	DEPTH MSL	FMT(bar)
2418	2393	377
2428	2403	378
2442	2417	379
2462	2437	380
2470	2445	381
2477	2452	382
2482	2457	383
2511	2486	384
2547,9	2522,9	387
2504,9	2479,9	391
2606,9	2581,9	391
2620,9	2595,9	392
2626,9	2601,9	393
2634,9	2609,9	393
2644,9	2619,9	394
2634,9	2609,9	398
2687,4	2662,4	399
2697,9	2672,9	400
2714,9	2689,9	401
2775	2750	407
2812	2787	411
2836	2811	413
2876,4	2851,4	417
2901	2876	420

Well 34/4-7 Oil		
DEPTH RKB	DEPTH MSL	FMT(bar)
2509	2484	383,79
2518	2493	384,42
2526	2501	384,93
2533,5	2508,5	385,49
2547	2522	386,36
2560,4	2535,4	387,28
2581,1	2556,1	387,67
2592	2567	389,74
2604,5	2579,5	390,91
2620,5	2595,5	392,66
2748,5	2723,5	405,13
2874	2849	417,72

Well 34/7-4 Oil		
DEPTH RKB	DEPTH MSL	FMT(bar)
2537	2512	385
2548,5	2523,5	386
2554	2529	386
2558	2533	386
2590,5	2565,5	389
2610,5	2585,5	390
2610	2585	391
2705	2680	401
2555	2530	389
2731,1	2706,1	409
2783	2758	410
2806	2781	413
2811	2786	413
2860	2835	418
2897	2872	422
2902,5	2877,5	423
2921	2896	425
2940	2915	427
2947	2922	425
3005	2980	433
3058	3033	439
3073	3048	440
2890	2865	419

Well 34/7-6 Oil		
DEPTH RKB	DEPTH MSL	FMT (bar)
2520,8	2495,8	384
2512,5	2487,5	384
2528,3	2503,3	385
2536,8	2511,8	386
2551,4	2526,4	387
2561,4	2536,4	387
2571,4	2546,4	388
2585,4	2560,4	389
2595,4	2570,4	390
2649,4	2624,4	395
2682,4	2657,4	398
2828,5	2803,5	413
2868,5	2843,5	417
3084	3059	437
3138	3113	447
3261	3236	455
3408	3383	472
3449	3424	477
3545	3520	486
3604	3579	493
3626	3601	496
3642	3617	496

1.7 Visund

34/8-4A	Oil	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
2844,7	2819,7	449,9
2848,6	2823,6	450,17
2856,8	2831,8	450,8
2859,8	2834,8	450,85
2865	2840	451,17
2897	2872	453,05
2900,7	2875,7	453,26
2908,2	2883,2	453,76
2915,7	2890,7	454,15
2922,7	2897,7	454,57
2935,5	2910,5	455,35
2943	2918	455,8
2950,5	2925,5	456,24
2951,5	2926,5	456,34
2954	2929	456,49
2958,9	2933,9	456,8
2974,4	2949,4	457,74
2984	2959	458,32
2990,2	2965,2	458,67
3015,5	2990,5	461,92
3018,2	2993,2	461,99
3020,5	2995,5	462,35
3019,8	2994,8	462,1
3035	3010	462,51
3039,3	3014,3	462,74
3042	3017	462,9
3073,2	3048,2	464,16
3075,5	3050,5	464,24
3077,5	3052,5	464,45
3100,7	3075,7	467,38
3103,5	3078,5	467,56
3108,3	3083,3	467,87

34/8-8	Oil	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
2921,2	2896,2	431,5
2922,7	2897,7	431,5
2925,6	2900,6	431,8
2928,1	2903,1	431,7
2930,2	2905,2	432,1
2931,6	2906,6	432,4
2938,6	2913,6	432,4
2938,6	2913,6	432,4
2945,6	2920,6	433,1
2961,1	2936,1	433,9
2962,6	2937,6	434,1
2964,6	2939,6	434,2
2967,6	2942,6	434,4
2970,1	2945,1	434,5
2974,1	2949,1	434,9
2982,6	2957,6	435,7
2990,6	2965,6	436,5
3004,5	2979,5	437,9
3027	3002	440,1
3043,5	3018,5	441,8
3122,4	3097,4	457,8
3130,4	3105,4	458,7
3235,7	3210,7	470,4
3254,3	3229,3	472,9

34/8-3A	Oil/gas	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
2903,2	2878,2	430,7
2909,5	2884,5	430,9
2913,8	2888,8	431
2923,4	2898,4	431,3
2929,9	2904,9	431,6
2939,7	2914,7	432,1
2942,6	2917,6	432,4
2949	2924	432,7
2958	2933	433,3
2961,9	2936,9	433,6
2965	2940	433,8
2965	2940	433,8
2967,6	2942,6	434
2969,4	2944,4	434,1
2976,8	2951,8	434,8
2991	2966	436,3
3001,6	2976,6	437,3
3026,6	3001,6	440,1

34/8-3	Oil/gas	
DEPTH(RKB)	DEPTH(MSL)	FMT(BAR)
2840,1	2815,1	429
2843,1	2818,1	429,1
2847	2822	429,2
2854,4	2829,4	429,5
2859,4	2834,4	429,7
2866,8	2841,8	429,8
2876,6	2851,6	430,1
2886,5	2861,5	430,4
2891,9	2866,9	430,5
2898,8	2873,8	430,8
2903,3	2878,3	430,9
2912,1	2887,1	431,1
2924	2899	431,5
2930,9	2905,9	431,9
2932,8	2907,8	432
2932,9	2907,9	431,9
2937,8	2912,8	433
2942,7	2917,7	434,5
3002,9	2977,9	446,4
3103,5	3078,5	458,5
3253,3	3228,3	510,9
3273,6	3248,6	486,3
3293,7	3268,7	487,8