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The role of the evaporitic Zechstein Group on geothermal energy. Insights from the Norwegian North Sea

by

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Abstract

Geothermal energy could potentially contribute to reduce CO_2 emissions at Norwegian Continental Shelf if it is used for electrification of platforms. The main focus for this thesis is to improve the understanding of the mechanisms affecting the geothermal gradient in the SW part of the Norwegian North Sea, and to propose a preliminary geothermal energy play concept in the study area. The study area is located in the Feda Graben, approximately 310 km south-west of Stavanger in the Central Graben. 3D seismic and well data will be utilized to study and propose a geothermal play, as well as the influence of the evaporitic Zechstein Group on the geothermal gradient.

For this study, the geothermal heat is divided into three different levels of temperatures: 90˚C, 120˚C and >150˚C. As the generation of electrical power requires quite high temperatures, the main focus will be temperatures equal or higher than 120˚C. Fluid can be used with direct use for temperatures between 90˚C to 120˚C, while temperatures larger than 150˚C is high enough for power generation. To define a geothermal play concept the following elements were considered: 1) the reservoir rock quality (both porosity and permeability); 2) the presence of fluids; 3) a heat source; 4) a seal and 5) a trap. In addition to this, mechanisms interpreted to affect the geothermal gradient are: the evaporitic Zechstein salt and a shallow Moho. Both having an important role leading to high geothermal temperatures in the study area.

Based on the temperatures (higher than 120 °C) the following groups and formations are suggested as potential reservoirs in the study area: the Hordaland Group, consisting of a sandstone layer at the base, the Shetland Group, consisting of chalk and the Haugesund Formation, consisting of sandstone. Some of the wells in the study are drilled on or close to the salt diapirs, where the groups are getting very thin. The lithologies consist of mostly sandstone, shale, and chalk, where shale is working as an impermeable cover, sealing the geothermal reservoir. The sandstone and chalk are good potential reservoirs, being able to contain fluids, heated by the interplay between a shallow Moho and shallow salt diapirs in the Norwegian North Sea. Further, a Binary Power plant would be best possible suggestion to extract the geothermal energy.

A model of the geothermal play concept has been proposed based on the elements required for a good geothermal reservoir. The traps identified consist of stratigraphic pinch-outs, and the potential reservoirs are displayed close to the salt diapir.

Content

1 Introduction

1.1 Definition of problem

The geothermal energy exploration will play an important role in the energy transition to reach a net-zero emission future. The interest for “clean” and renewable energy sources, is actively raising in Norway. The geothermal potential is estimated from a heat flow database, and it is confirmed that temperatures and heat flow in the subsurface, are not as low as assumed by previous studies (Pascal et al., 2010). With an average geothermal gradient in the North Sea of 34.6 ˚C/km, there has been locally identified higher gradients around 41 ˚C/km (Figure 1) (Kubala et al., 2003; Marín et al., 2022). Higher gradients also occur in shallower stratigraphic sections. For example, as on the crest of a salt diapirs in well 1/6-5 in the Feda Graben, SW Norwegian North Sea. Here, a geothermal gradient of 56˚C/km has been interpreted based on Bottom Hole Temperatures (BHT) (Nolan, 2021). Previous exploration activity in the North Sea has been focused on the assessment of the hydrocarbon potential in the Cretaceous chalk, and Paleocene sandstone, while the Upper Jurassic sandstone is quite underexplored. The geothermal exploration concept is practically unknown in the North Sea. Conductive material such as salt can locally affect the heat flow in an area (Daniilidis & Herber, 2017), and Nolan (2021) suggests that there could be a relationship between these high geothermal gradients in the southern west part of the Norwegian North Sea, and the presence of salt diapirs in the Zechstein Group. However, it is not clear if salt is the only mechanism that affects the geothermal gradient in the region or if the best geothermal targets are located at the tops or flanks of salt diapirs. Additionally, potential aquifers that can act as geothermal reservoirs (with temperatures higher than 120 °C) are unknown. The use of geothermal energy for both direct use and generation of electrical power, provides a promising option as a renewable energy source. Therefore, understanding the mechanisms affecting the geothermal gradient in the Central North Sea and an understanding of the potential reservoirs is necessary for further recovery of geothermal energy in this area. The study area is located on Norwegian continental shelf in the North Sea in the Central Graben. The well data and seismic used are located in the Feda Graben, approximately 310 km south-west from Stavanger (Figure 2). This area was selected due to its high geothermal gradients (Figure 1) (Marín et al., 2022).

1.2 Research questions

What is the role of the evaporitic Zechstein Group controlling the variation of geothermal gradient in the study area? Is it the only factor?

For areas with high enough geothermal gradient, which geothermal energy play concepts could be proposed?

1.3 Objectives

For this thesis, the main objectives are: 1) to improve the understanding of the mechanism affecting the geothermal gradient in the southern part of the North Sea, included the presence of salt in the Zechstein Group. 2) To propose a preliminary geothermal energy play concept within reservoirs with a temperature between or higher than 120°C and 150°C if these areas with high temperatures are identified.

To propose a geothermal energy play, the study of the heat distribution in the southwestern Norwegian North Sea will be important. To achieve the thesis objectives, available information on NPD (bottom hole temperatures), will be compared with the Zechstein Group and other groups and formations in the area. Structural and thickness maps of potential reservoirs will be built. An evaluation will be done for different elements such as the reservoir (including reservoir heat, type of fluids, porosity, and permeability), seal, and the heat source. This will be done by integrating seismic interpretation with petrophysics, and well reports available at NPD.

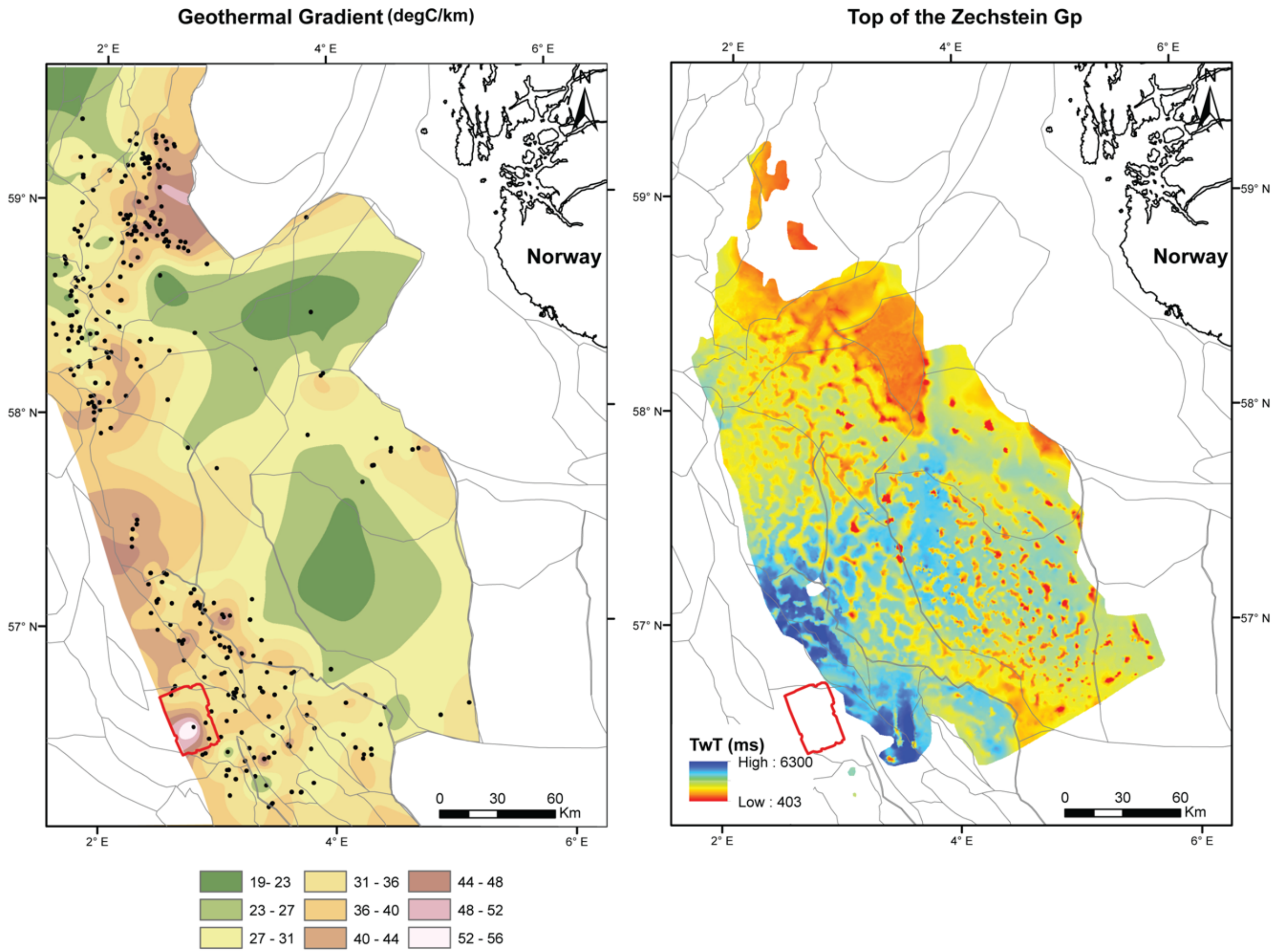

Figure 1: *Maps showing the geothermal gradient (˚C/km) and the top of the Zechstein Group (ms) for the southern Norwegian North Sea (Marín et al., 2022). Study area marked with a red polygon.*

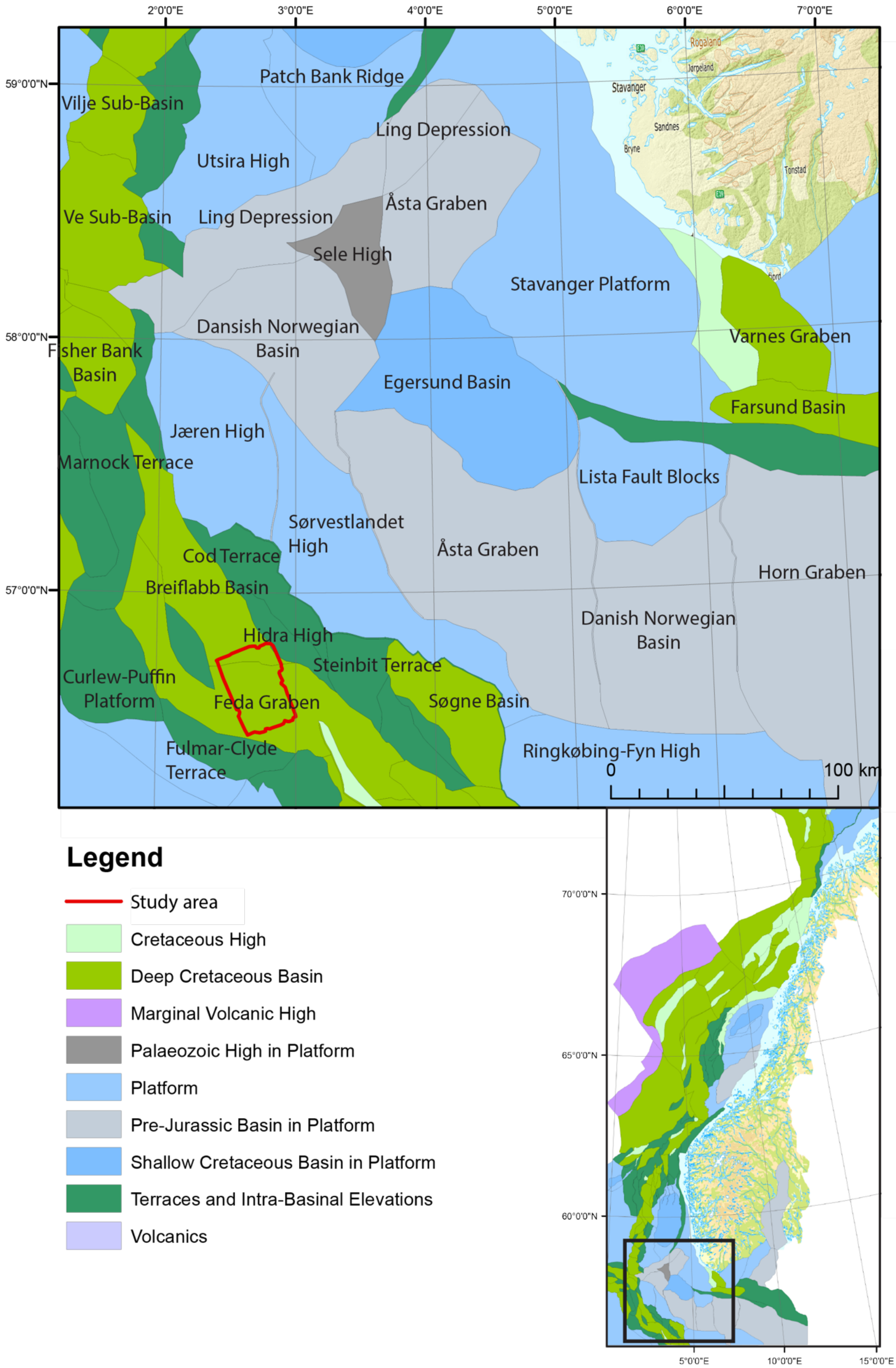

Figure 2: Location map of the Central North Sea and study area, including structural elements from the Norwegian sector (NPD, 2022; Skjørestad, 2022).

2. Geothermal energy

Renewable energy comprised about 12 % of the energy used worldwide in 2020 and will continue to increase to reach a future with net-zero emission. Geothermal energy, which constitute 2 % out of these 12 %, is heat which is continuously produced by the Earth and is both "baseload" and renewable (EIA, 2021). It can be used for both heating and generating electricity and is available below us all the time. Unlike solar and wind energy, geothermal is providing power 24 hours a day, all year long, and it will do so as long as the earth exists. The Earth can actually be used as a thermal bank (Boden & Ebscohost, 2017), and the geothermal potential with the stored geothermal energy of low-moderate enthalpy (<100 ˚C to 100 ˚C) has increased because of the concept of Enhanced or Engineered Geothermal Systems (EGS) (Moeck, 2014). The reason to the continuous geothermal heat is mainly radioactive decay within the Earth's core, as well as the heat from the Mantle. Temperatures can reach more than 5000˚C and will have a constant radiation out from the core, towards the crust, where rocks, fluids and other geological material will receive the heat energy. The Earth's temperature will therefore increase towards the core, and this change in temperature constitutes the geothermal gradient (Turgeon & Morse, 2012).

To lead geothermal energy to the surface and then generate power, several different methods have been used generating power from either a vapor or liquid dominated reservoir. Vapor dominated systems require temperatures of at least 240 ˚C and are underlain long lived sources of heat, such as heat from magma. Boundaries of the system, at sides and at the top need a poor permeability to prevent the system from being flooded with water (Malcolm & Bixley, 2011). On the other hand, in a liquid dominated system, the fluid remains liquid, due to the increase in boiling temperature with the depth. The presence of dissolved gases like CO_2 can result in lowering the temperature of boiling. In a typical liquid dominated system, the fluid will start boiling, as extracted from the well, due to reduction in pressure (Boden & Ebscohost, 2017). Dry steam power plants were the first form of geothermal electrical power generation and were first used in 1913. This is the most energy efficient type and simplest of geothermal plants. Almost all the steam that ranges between 180 ˚C to 300 ˚C goes up the well and through a turbine and generator that generates electrical power (Boden & Ebscohost, 2017; Mulyana et al., 2016). Flash power plants constitute 63 % of all geothermal power produced by 2015 and is used for high enthalpy systems with temperatures typically >175˚C. These power plants have a separator which separates the steam and the water. About one third of the fluid in the well will be steam. Further, the water will be reinjected to the geothermal system. The power plants can also involve more than one flash, depending on the fluid's temperature. Binary geothermal powerplants are developed for moderate enthalpy systems, with temperature typically between 120 ˚C to 175 ˚C. Therefore, they have been more common around the world, since there are more easily accessible liquid-dominated sources than vapor dominated (Boden & Ebscohost, 2017; Dincer & Ishaq, 2021). In the binary powerplant the geothermal fluid heats a secondary fluid, which often is a hydrocarbon like isopentane. The isopentane has a lower boiling point than the water, leading to the production of a higher amount of steam. Further, the steam will go through a turbine which generates power. The water will be reinjected to the geothermal reservoir, which means that there will be no emission. Binary plants constitute 47 % of all the existing geothermal power plants. Compared to a flash power plant, this one generates a lot less power because of the smaller energy potential in the lower enthalpy (Boden & Ebscohost, 2017).

2.1 Classification

Geothermal energy can be used in different ways, depending on the different levels of temperature. Geothermal heat pump, direct use and power generation are examples on usage. Both geothermal heat pump and direct use can be used for residential, industrial, and commercial heating, while power plants are used for electrical power generation (Forge, 2022) (Table 1). Direct use requires temperatures between 50 ˚C to 100 ˚C and are mainly used for heating, but also cooling of buildings. Geothermal heat pumps can be utilized everywhere on the planet and are characterized as the lower end part of direct use. Temperatures used in geothermal heat pumps use to be the average temperature some few meters below the surface, often 10 ˚C to 15 ˚C. With this kind of usage, heat is deposited at summer and withdrawn in the winter, while for the electrical power generation, it is required higher temperatures and usually more than 100 ˚C. A classification scheme has been made by Boden (2019), explaining how to analyse a geothermal system. It includes crucial elements such as how the heat is transferred, what types of heat sources that are present, both geological and tectonic settings, enthalpy of the environment, type of fluid and use of geothermal systems. Heat is mainly transferred by conduction or convection. This means transfer of heat by contact or by motion of fluid. Conduction can be divided into three different system: sedimentary aquifers, geopressured reservoir and hot dry rock. Changes in density will affect fluids by the buoyancy forces, and will make hot material flow upwards, while cold material will sink. Conduction dominated geothermal plays has a low- to medium-enthalpy, with an average geothermal gradient, but can be localized at larger depths than convectional. Convection requires both good porosity and permeability for the fluid to transfer heat. The convective systems can be divided into two different heat sources, liquid- and vapor-dominated. Liquid dominated is the most common geothermal reservoir type, while most of the heat transferred to the surface occurs due to conduction (Boden & Ebscohost, 2017; Moeck, 2014).The average temperature increase per kilometre towards the core is 25 ˚C to 30 ˚C, but varies depending on the geological setting and thermal conductivity of rocks. This means that it is possible to find temperatures larger than 100 ˚C at a depth between 3 km to 5 km. Based on temperature we can classify the geothermal systems for their potential uses. The systems are ranked as either low, moderate, or high enthalpy, and the temperature intervals are respectively less than 100 ˚C, 100 ˚C to 175 ˚C, and more than 175 ˚C. Both low and moderate enthalpy can be used directly, but moderate can be used for power generation as well (Table 1). For high enthalpy systems, the fluid is used directly to power generation (Boden & Ebscohost, 2017).

Table 1: *Required mechanisms affecting the geothermal gradient and showing the usage and characteristics for each level of temperature (Forge, 2022; Guglielmetti, 2021; Nolan, 2021; Skjørestad, 2022)*

	Residential heating	**Industrial heating**	**Electrical power generation**
	Direct use		Power plants
Heat	90 ˚C	120 ˚C	≥150 ˚C
Enthalpy	Low (<~100 ˚C)	Moderate / High (~100 ˚C to >175 ˚C)	
System	Conduction		Convection
Reservoir rock	Sedimentary		Hot dry rock (HDR) (Sedimentary)
Fluid	Liquid (volatile fluid)		Steam or mixture
Permeability	Needs to be high enough for continuous flow of fluids		Require good permeability (0.001 md to 0.1 md)
Porosity	Needs to be high enough for fluid to be present (15 % to 20 %)		
Heat source	Radioactive decay in the core and heat from mantle		
Impermeable cover	Need to be sealed by an impermeable cover		

2.2 Elements of the geothermal system

Compared to a hydrocarbon system, with well-defined elements such as reservoir rock, source rock, trap rock etc. A geothermal system does not have any clear definition of what is required, except for the heat source. Such systems appear all over the world, in all kinds of environments. Drilling deep enough will theoretically lead to a geothermal system anywhere, and there are several suggested elements that are required to have a geothermal play (Moeck, 2014). These elements are a heat source, a reservoir rock, a fluid, a seal, and a trap (Forge, 2022; Guglielmetti, 2021). Geothermal resources, specifically the amount of heat is controlled by tectonic activity and the proximity to plate boundaries. Both convergent and divergent boundaries are characterized by active volcanoes often established above a magma reservoir. When the crust is stretched and extended, it will affect the temperature. Hot rocks will come closer to the surface and will then increase the heat flow and geothermal gradient. Weakening of the crust results in fractures and faults, which will provide a pathway for groundwater to flow downward. Groundwater will get heated when moving through hot rocks and will flow further upwards due to the buoyancy forces (Boden & Ebscohost, 2017). The geothermal reservoir needs a heat source, which appear all over the world because of the radioactive decay in the core, as well as heat flow from the mantle (Mussett & Khan, 2000). Further the reservoir rock, should have good porosity and permeability (Table 1). Fluid must flow through the rock, and then the porosity and permeability need to be high enough for fluid to be present and be able to have a continuous flow of fluids. In a typical good reservoir, permeability range between 0.001 md to 0.1 md (Yu & Sepehrnoori, 2018), while porosity ranges between 15 % to 20 % (Adaeze et al., 2018). An impermeable cover would also be necessary to keep the fluids within the geothermal play system (Table 1). This would have the same effect as a “caprock” for a hydrocarbon play system (Moeck, 2014). Fluid is used to extract heat from the reservoir. It is necessary that the fluid could flow towards the surface, which is why there is a need for a good porosity and permeability. This can be either liquid or vapor, or a mix of both (Nolan, 2021).

2.3 Salt conductivity and temperature

Salt is normally used as the description of rocks dominated by halite, even though the rock succession may contain other kinds of evaporitic rocks, like anhydrite or gypsum (Hudec & Jackson, 2007; Jackson et al., 2018). Halite, often characterized as rocksalt, is both weak and ductile under geological deformation (Rowan et al., 2019). The Zechstein Group is one of the largest salt giants in the world and have affected the development of the Middle Jurassic to

Late Cretaceous rift in the North Sea. However, the knowledge of the basin-scale variations in the North Sea on Norwegian sector are still quite unknown (Jackson et al., 2018). Hydrocarbon reservoirs are commonly identified within a salt basin. The presence of salt in a basin affects the petroleum system, contributing with the development of structural traps and salt tectonics influence the distribution of the reservoir. Salt also works as a seal to fluid migration. The salt is a good and effective conductor of heat, transferring heat to rocks above the salt bodies, and cooling the rocks below or beside salt structures (Hudec & Jackson, 2007). The thermal conductivity is up to four times higher than for non-evaporitic sediments, with a conductivity of 6 to 7 W/mK. (Daniilidis & Herber, 2017; Nolan, 2021). With such a high conductivity, the salt structures could be a dominant factor for hydrocarbon maturation within a basin and contribute to have geothermal targets in shallower reservoirs (Cedeno et al., 2019; Daniilidis & Herber, 2017; Grunnaleite & Mosbron, 2019)

3. Geological setting

3.1 Geothermal gradient North Sea

The geothermal energy potential in the North Sea has not been a priority during the production of hydrocarbons on Norwegian Continental Shelf (Lockett, 2012). Regional variations on the geothermal gradient in the Norwegian North Sea have been recognized before (Kubala et al., 2003), although there is not an agreement in the main factor controlling these variations. Well data showing temperatures from 1385 exploration wells on Norwegian Continental Shelf displays areas with high geothermal gradients, some places higher than 40 ˚C/km, especially in the southern Norwegian North Sea coinciding with the presence of salt diapirs (Figure 1) (Nolan, 2021). At least some of the wells in the Feda Graben are located on the top or around what is considered as shallow diapirs. Some of these salt bodies have a crest less than 2200 m, and Nolan (2021) suggests that there is a locally correspondence between shallow diapirs and high geothermal gradients in the North Sea. Well 1/6-5 is the most outstanding example, located in the Feda Graben. The well displayed abnormally high pressures and temperatures at a depth of 1854 m (4548 psi and BHT 104 ˚C) (NPD, 2022), and the geothermal gradient was estimated to 56 ˚C/km (Nolan, 2021). Higher temperatures localized in the Central Graben, are interpreted to be caused by a generally higher heat flow, as well as the presence of efficient caprocks that seal and create overpressure zones, affecting the geothermal gradient. Another essential element, is the shallower depth to the Moho (Kubala et al., 2003). The Moho is clearly uplifted, to a depth of 20 km within the Central-and Viking Graben. Compared to the rest of the North Sea, the Moho depth is about 10-15 km shallower in Central Graben (Figure 3)(Maystrenko et al., 2017).

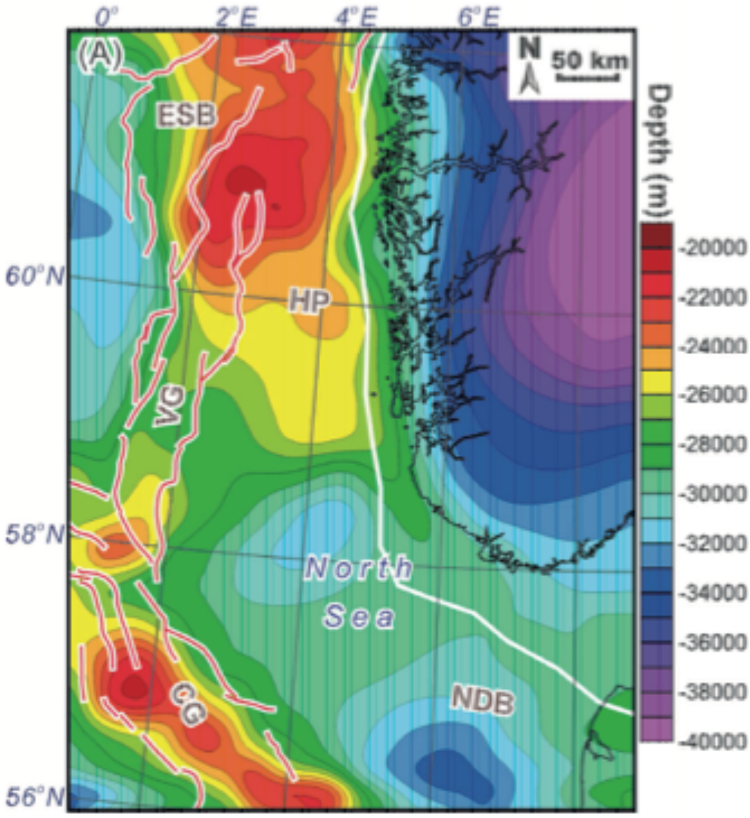

Figure 3: *Depth to Moho (Maystrenko et al., 2017).*

3.2 Tectonic setting

The Iapetus Ocean is a pre-existing ocean that was located west of today's Norway. It was at its widest from Cambrian until Ordovician, and from here, the plate movements changed. The North American continent with Greenland, moved towards Europe and Scandinavia. The collision of Baltica and Laurentia resulted in the Caledonian Mountain range formed in the closure of the Iapetus Ocean (Coward et al., 2003; Fossen, 2008). A multiphase extension involving numerous rift events and lithospheric stretching, is the mechanism responsible for the origin of the the northern North Sea Basin (Faleide et al., 2002; Odinsen et al., 2000).

After the closure of the Iapetus Ocean, the first major rifting phase led to a collapse of the Caledonian orogen, during the Devonian time (Peron-Pinvidic et al., 2020). Further in the late Permian to Early Triassic a major rift phase resulted in the formation of the North Sea Rift, which most likely was related to the Pangea breakup (Bell et al., 2014). The Zechstein Group covers much of the north-western Europe, and it is likely that the salt has influenced the rifting in the Middle Jurassic to Early Cretaceous. It was deposited during a sea level rise during late Permian, where repeated cycles and marine conditions resulted in deposition of a more than 1 km thick evaporitic layer (Jackson et al., 2018). The salt tectonics have further affected great hydrocarbon provinces with its special deformation style. The flow of salt have created structural traps, and works as a seal as well as conduct the thermal heat to rocks above the salt structures (Hudec & Jackson, 2007).

During the Triassic rifting north-westerly trending grabens were formed, with Triassic sediments thickening towards the east (Zanella & Coward, 2003). The second major period of rifting in the North Sea took place from the Middle Jurassic to Early Cretaceous. It is suggested from several authors that the rift phase initiated because of a collapse of thermal domes in the North Sea. An exerted regional tension was leading to the development of the North Sea rift system, consisting of Viking Graben, Moray Firth, and Central Graben (Bell et al., 2014; Evans, 2003; Zanella & Coward, 2003). Other authors have suggested that the subsequent fault activity could be related to a far-field stress regime (Bell et al., 2014). The Central Graben trends north-west to south-east, the same as the Viking Graben. Rifting in the Late Jurassic to Early Cretaceous also caused an uplift of rift flanks, in addition to tilting of Mesozoic strata away from flanks and towards the west and eastern edges of the basin. This generated partial erosion of Triassic and Permian sediments (Duffy et al., 2013; Evans, 2003; Zanella & Coward, 2003). The Late Jurassic and Early Cretaceous rifting, is the main responsible behind the structural frame of the Norwegian North Sea (NPD, 2022).

3.3 Stratigraphy

The sedimentary cover of the North Sea extends from Devonian to Cenozoic and covers the Precambrian and Lower Palaeozoic which has been deformed during the Caledonian Orogeny (Zanella et al., 2003). Below, the relevant units for this study will be described (i.e., potential reservoirs and the Zechstein Group).

3.3.1 Upper Permian

The later Permian time (Figure 4) is mostly known for the deposition of the evaporitic Zechstein Group which includes evaporites (e.g. halite, anhydrite, k-salts), carbonates and clastic rocks, seen as one of the worlds saline giants (Jackson et al., 2018; Marín et al., 2022). It is covering large parts of the Norwegian North Sea and north-west Europe. Structures, source rocks, reservoir rocks and seal rocks could all be present in the Zechstein Group (Jackson & Stewart, 2017). The group has a variable thickness partly because of post depositional halokinesis. Because of changes in sea level the group was deposited in forming the Zechstein cycles (Glennie et al., 2003; Glennie, 1998; NPD, 2022). Permian rocks could be covered by Upper Cretaceous and Paleocene strata because of an erosional event during the Late Jurassic (NPD, 2022).

3.3.2 Upper Jurassic

Two major basinal processes operated in the late Jurassic. Rift-related faulting and a relative sea level rise. The result was the deposition of shallow marine sand (Figure 4), and that the earlier thermal domes got drowned (Fraser et al., 2002). The Upper Jurassic, more precisely Callovian to Early Kimmeridgian, consist mainly of carbonaceous claystone and shale with interbeds of sandstone and siltstone. Interbedded sandstone units are identified in the Haugesund Formation. The shales were deposited in a deep marine environment (Figure 4) with low energy, while the sand has been deposited from the adjacent shelf, where sporadic turbidite influxes have occurred (NPD, 2022). Nearly all of them are arkose or subarkose. Since they are identified as interbeds within a formation, they are named Sandstone Unit I and II. Sandstone Unit I is fine to medium-grained, subangular to subrounded, subspherical to spherical and well sorted with excellent visible porosity about 21,5 %. Sandstone Unit II is very fine-grained, well sorted, subrounded and moderately cemented with silica and a visible porosity about 16.1 % (Fraser et al., 2002). The Upper Jurassic Haugesund Formation is part of the Tyne Group (NPD, 2022).

3.3.3 Cretaceous

The Cretaceous succession in the Norwegian North Sea is separated into a lower and upper group. The Lower Cretaceous corresponds to the Cromer Knoll Group, mainly consisting of deep marine deposited shale (Figure 4). The early Cretaceous was characterized by a competing effect of accommodation space, rifting, changes in global sea level, post-rift thermal collapse, and halokinesis (Copestake et al., 2003). During the Late Cretaceous one of the largest transgressions in the history of the Earth happened, as a result the chalk dominated Shetland Group was deposited (NPD, 2022). During the Late Cretaceous, local fault-controlled subsidence, inversion and halokinesis influenced the chalk deposition in the North Sea (Surlyk et al., 2003). The chalk identified in the study area, has a porosity between 17,5 % to 26 % (NPD, 2022).

3.3.4 Eocene

The Eocene in the Norwegian North Sea were exposed for earth movements, as well as inversion and compression from the Alpine Mountain belt caused an uplift of the basin margins. The result of this uplift was the deposition of several submarine fans (Jones et al., 2003; NPD, 2022). Further, the clime was characterized by an extreme global heat, with a rapid decreasing change (Schmidt & Shindell, 2003). The Eocene consist mainly of deep marine shale, with interbeds of shallow marine sandstone, and some volcanic tuff (Figure 4) (NPD, 2022).

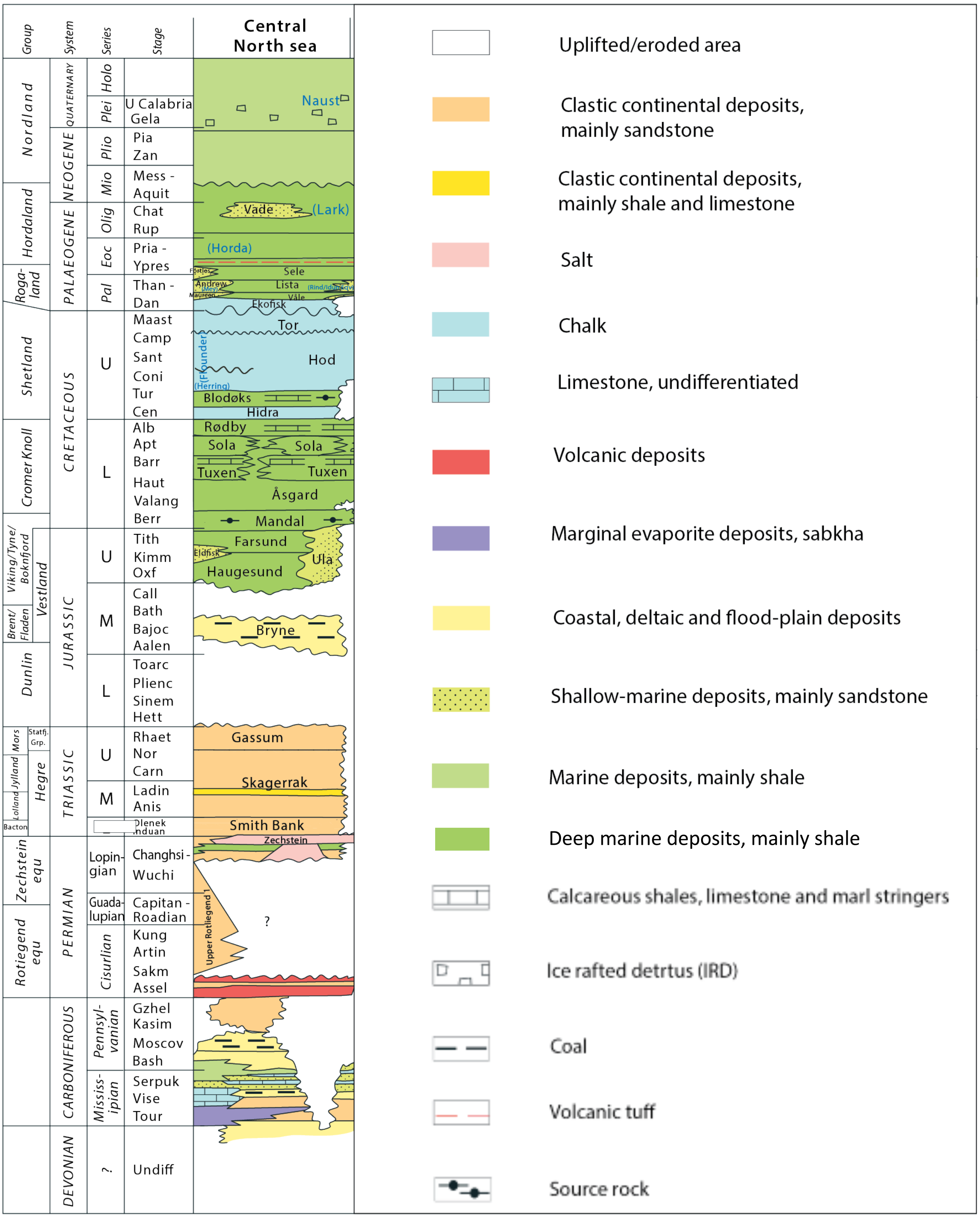

Figure 4: *Adapted lithostratigraphic chart of the Central North Sea, modified after (NPD, 2014; Skjørestad et al., 2021).*

4. Data and methods

4.1 Data

The dataset used for this study contains a seismic 3D survey (CN193) (Table 2), and five wells located in the Central Graben in the Norwegian North Sea (Figure 5). The vertical resolution of the seismic decreases with depth and is measured in meters per seismic reflector. It is calculated by dividing average interval velocity, with the dominant frequency eq. (1). This results in the wavelength, which is divided by four, giving the vertical resolution eq. (2) (Kaerey et al., 2002). This was done for the Intra Hordaland sand, the Shetland Group, and the Haugesund Formation, along well 1/6-7, to get the best possible approximate value. Gamma ray and density values was available for all the wells, while neutron porosity only was available for well 1/6-2, 1/6-3, and 1/6-5. Well tops and original well reports were also available for all wells at NPD (NPD, 2022).

$$\frac{v}{f} = \lambda \tag{1}$$

$$VR = \lambda * \frac{1}{4} \tag{2}$$

Table 2: *Vertical resolution in seismic cube CN193 for the Intra Hordaland sand, Shetland Gp and Haugesund Fm.*

$CN193$	$Formation\ /Group$	$Depth\ (TWT)$	v	f	λ	VR
	Intra Hordaland sand	-2935 ms	2355 m/s	27,5 Hz	85,6 m	21,4 m
	Shetland Gp	-3257 ms	4123 m/s	26 Hz	158,6 m	39,7 m
	Haugesund Fm	-4028 ms	4004 m/s	22,5 Hz	178 m	44,5 m

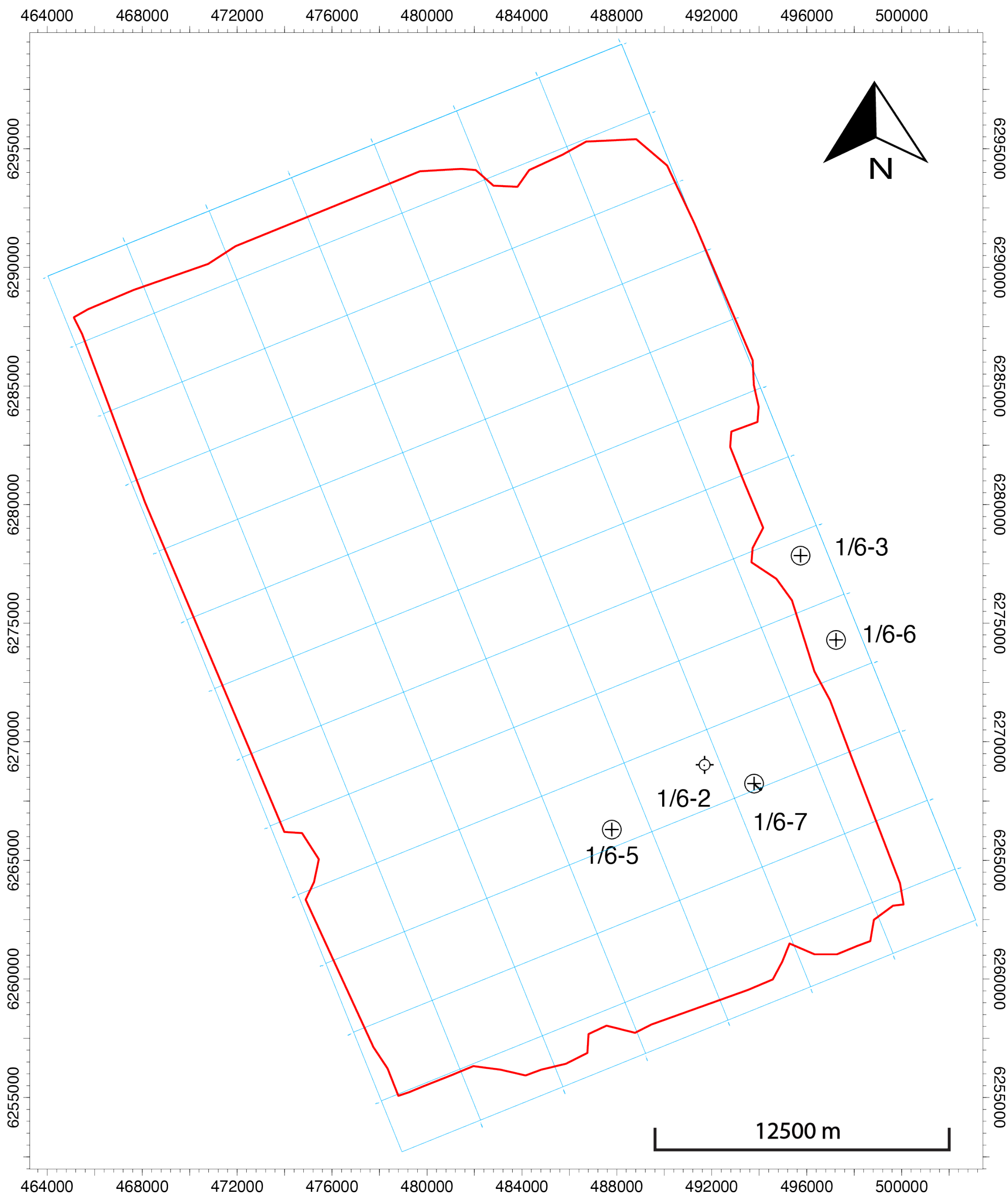

Figure 5: *Map showing seismic volume vs polygon. See the regional location of the study in Figure 2.*

4.2 Methods

Since the seismic is measured in two-way-time (TWT) while the well is measured in depth (m) a seismic well tie was used to correlate the well tops with the correct seismic reflectors (Figure 6). All the three well tops used in the study (Hordaland Group, Shetland Group and Haugesund Formation) were used to create the well tie, using Top Rogaland Group as control point.

Firstly, the sonic log and the calibrated velocity log were used as input to create a calibrated sonic log. Knee points were used to fit the original data, and to remove wavelet uncertainty. The output was further used to as input to a synthetic seismogram. This was done for each well to be used for a synthetic.

Further, the next step was to create a synthetic seismogram for the wells. Calculated wavelet, pre-defined wavelet, gamma ray, interval velocity and AI (acoustic impedance) were all used to correlate well tops to correct reflectors in the seismic. A bulk shift (15 ms) was used to adjust the synthetic and align points, which results in a new time depth ratio (TDR). The dominant frequency in the depth of interest was 25 Hz, and therefore the wavelet that was used in the calculation was Ricker Wavelet with 25 Hz. The seismic resolution was varying for the different formations/groups. For the Shetland Group

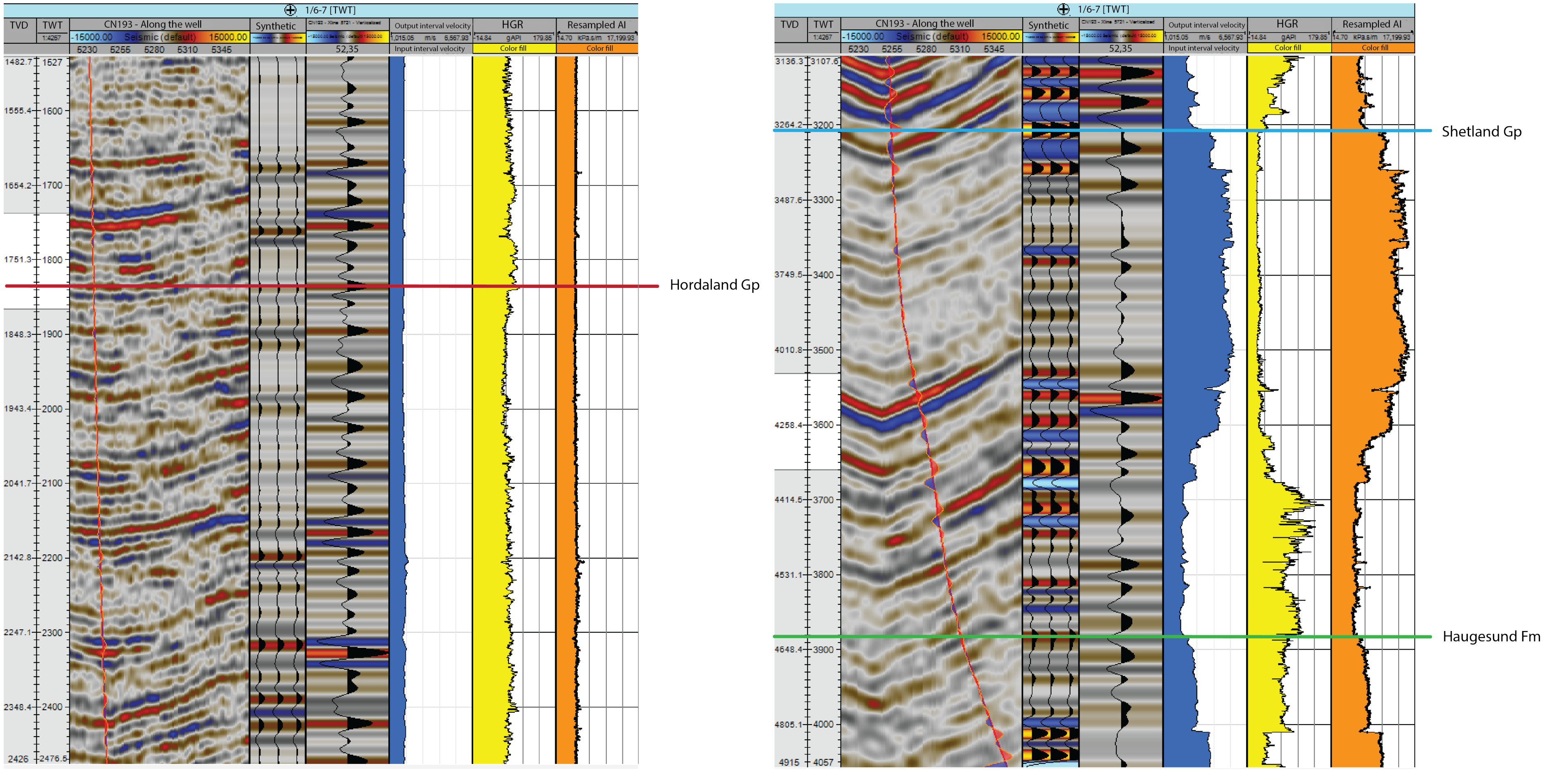

Figure 6: *Synthetic well tie from well 1/6-7 with interval velocity, gamma ray and acoustic impedance. Top Hordaland Gp, Top Shetland Gp and the Top Haugesund Fm were used together with Top Rogaland Group to correlate the synthetic with the seismic.*

5. Results

5.1 Study area temperatures (BHT), definition of the reservoirs and salt diapirs.

Temperatures in the study area defined as bottom hole temperatures (BHT) (Table 3) varies between 98.3 ˚C to a maximum of 190 ˚C for these 5 wells. 1/6-5 which is located on top of a shallow salt diapir has a BHT of 98.3 ˚C and a total depth of 1854 m. For well 1/6-2 the NPD front page says that the BHT is 70 ˚C, while the report says that there is a temperature in the chalk is approximately 121 ˚C. Due to the large deviation in the temperature, I choose to not use well 1/6-2 further. Well 1/6-7 which located close to the salt body has a BHT of 182 ˚C at a total depth of 4925 m. Further, well 1/6-3 and 1/6-6 has a bottom hole temperature of 140 ˚C and 190 ˚C at the total depth of 3343 m and 5562 m, respectively. The geothermal gradients range between 34 ˚C/km to 56 ˚C/km, where well 1/6-5 has the highest values (Table 4). Well 1/6-6 and 1/6-7 has 34 ˚C/km and 37 ˚C/km, and 1/6-3 has 42 ˚C/km.

The two-way-time to the top of the Zechstein Group, are displaying the location of the salt diapirs in the study area (Figure 7a). There is one circular formed diapir located in the northwest, while there is an elongated diapir in the west, about in the middle of the map. Further south, the shallowest of the diapirs are located, together with well 1/6-5. This one is oval shaped in the east west direction and seems to have a connection with the salt diapir in the southeaster part of the map, which has the same form. The salt structures have different elevations, where the shallowest diapir in the southern part of the map reaches 1183 ms two-way-time, and the one in the northwest has approximately 1400 ms two-way-time. The other salt diapirs reaches about 2300 ms two-way-time. The geothermal gradient gets its highest point south of the centre of the map, between 52 ˚C/km to 56 ˚C/km (Figure 7b). The geothermal gradient decreases slowly in the southwest direction, and quickly towards the north and east. Around the salt body in the northwest, there is also an area where the geothermal gradient reaches about 40 ˚C/km to 44 ˚C/km. Together the maps indicate a relationship between salt diapirs and higher geothermal gradients. The shallower the diapir is, the higher values the geothermal gradient reach. This counts for the hole map, except in the southwest, where the elevation of the Zechstein Group is approximately 5888 ms two-way-time, and the geothermal gradient still has values as high as 48 ˚C/km to 52 ˚C/km.

What is defined as potential reservoirs are areas with high enough temperatures and geothermal gradients, that also has a composition that fits the requirements of a good geothermal reservoir. The shallowest potential reservoir is the Hordaland Group (intra Hordaland sandstone). Mainly consisting of shale, there is also identified a sandstone layer approximately between 150 m to 200 m, at the base of the group. With such high geothermal gradients identified in the study area, temperatures around 120 ˚C potentially can be found in this sandstone layer. The next potential reservoir is the Shetland Group, mainly consisting of Cretaceous chalk. Well 1/6-2 and 1/6-3 have not been drilled deep enough to penetrate the group, but the thickness is about 1008 m in well 1/6-6 and 1341 m in well 1/6-7, reaching a depth of more than 4000 m. Temperatures at these depths can potentially be 150 ˚C with high enough geothermal gradient. The last potential reservoir is identified in the Tyne Group, more precisely in the Haugesund Formation. This formation consists of both shale and sandstone, where the sandstone package is deposited at the base. The depth is now between 4800 m and 5428 m for the two wells that is deep enough in this study, and with the high geothermal gradients, a possible temperature at this depth can more than 150 ˚C.

The geothermal gradient is presented for well 1/6-3, 1/6-5, 1/6-6, and 1/6-7 (Table 4) and has been calculated using 5 as the temperature of the sea bottom, the vertical depth (TVT), the water depth, the bottom hole temperature (BHT) and the Kelly Bush (KB) eq. (3). This data together with BHT from NPD (2022), was further used to do an interpretation of the isotherms. A suggestion is presented together with a formation or group that is believed to have this temperature, as well as the porosity and lithology (Table 5).

$$\frac{(BHT) - 5^{\circ}C}{TVT - Water\ Depth - KB} \cdot 1000 \tag{3}$$

Table 3: *Wells and their depth, BHT, ages and formations encountered (NPD, 2022).*

Well	Completed	TD (m)	BHT (˚C)	Oldest penetrated age	Oldest Fm/Gp penetrated
1/6-2	1973	3383	70	Late Cretaceous	Shetland Gp
1/6-3	1974	3343	140	Late Cretaceous	Shetland Gp
1/6-5	1990	1854	98.3	Late Permian	Zechstein GP
1/6-6	1993	5565	190	Triassic	Smith Bank FM
1/6-7	1992	4995	182	Late Jurassic	Haugesund FM

Table 4: *Wells with the calculated geothermal gradients for each well (Marín et al., 2022; NPD, 2022).*

Wb Name	Water Depth	FinVert Depth	KB	BHT	GeoT Gradient
1/6-3	69	3343	34	140	42
1/6-5	70	1854	25	104	56
1/6-6	70	5562	25	190	34
1/6-7	68	4925	22	182	37

Table 5: *The 5 wells in the study area showing available data for depth of different temperature intervals, formation, lithology and porosity..*

Well	Fm/Gp 120˚C	Fm/Gp 150˚C	Fm/Gp >150˚C
1/6-2*	Shetland Gp Depth: 3024 m Lithology: Chalk Porosity: 26%	Formation not penetrated.	Formation not penetrated.
1/6-3	Hordaland GP Depth: 2415 m Lithology: Shale/sandstone	Formation not penetrated.	Formation not penetrated.
1/6-5	Formation not penetrated.	Formation not penetrated.	Formation not penetrated.
1/6-6	Shetland Gp Depth: 3508 m Lithology: Chalk No report available	Shetland Gp Depth: 4392 m Lithology: Chalk No report available	Haugesund FM Depth: 5536 m Lithology: Shale and Sandstone Porosity: 16,1– 21,5 %
1/6-7	Shetland Gp Depth: 3278 m Lithology: Chalk Porosity: 17,5 %	Shetland Gp Depth: 4035 m Lithology: Chalk Porosity: 17,5 %	Haugesund FM Depth: 4908 m Lithology: Shale and Sandstone (unit I and II) Porosity: 21,5 % and 16,1 %

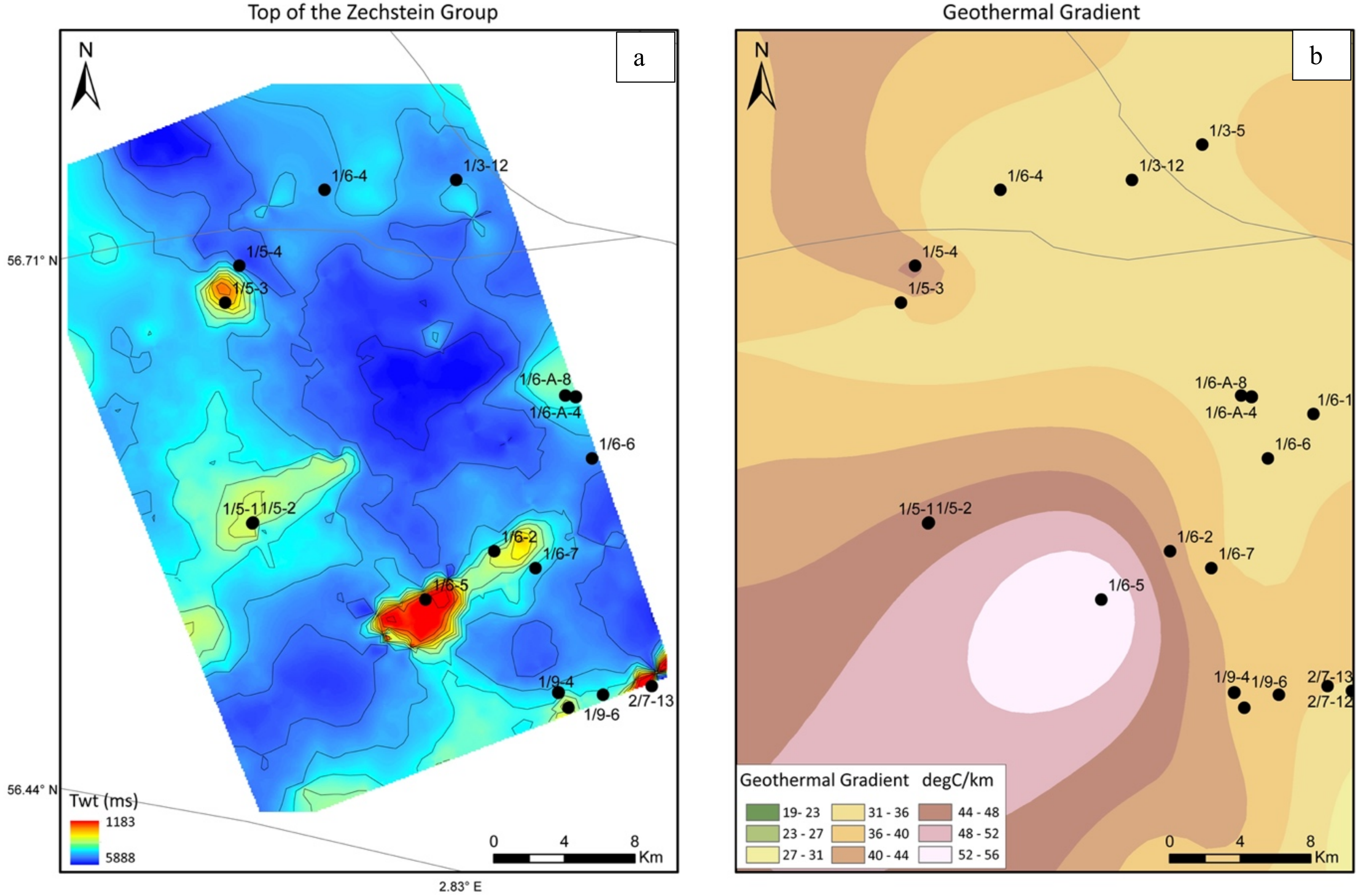

Figure 7 a and b: *Maps showing top of Zechstein Group and geothermal gradients in the study area.*

5.2 Potential formations and groups

5.2.1 Haugesund FM

5.2.1.1 Description from log observations

The only wells available that encounter the Haugesund Formation in the study area are well 1/6-6 and 1/6-7 located southeast in the study area. Vertically the formations differ in both depth and thickness, where the formation in 1/6-6 is located between 5429 m to 5275 m, while it is shallower in well 1/6-7 between 4900 m to 4601 m (Figure 8). The thickness is 154 m and 299 m, respectively. Gamma ray values are heterogeneous, where there the base has lower GR values than the top of the formation, counting for both wells. The GR character indicate that the lower part of the Haugesund Formation is coarser grained than the upper part. Two sandstone units were interpreted in well 1/6-7, unit I and II. The thickness is 98 m and 38 m, respectively, and these units are separated by a thin layer of finer grained rock. Unit II exhibit a fining upwards trend in the gamma ray values, while unit I has a slight increase in GR upwards, until the centre of the unit. One sandstone unit was interpreted in well 1/6-6, with a thickness of 61 m. The GR displays a fining upwards trend but have some higher spikes at the top of the sandstone package, indicating some thin layers of shale or clay. No neutron porosity is available for these wells, but well reports confirm 21,5 % and 16,1 % porosity (Table 5). Well reports also says that there were indications of hydrocarbon, but the drill stem test (DST) only produced water for both well 1/6-6 and 1/6-7 (NPD, 2022). Based on the geothermal gradient, the temperature that reaches up to 190 ˚C at this depth, the sandstone with its good porosity, as well as the presence water within the sandstone, the Haugesund Formation (marked green) could be a possible geothermal reservoir with the overlaying shale working as a seal.

5.2.1.2 Description from seismic structure

The structural map indicates that the top Haugesund Formation is quite uneven, with deeper parts about -5000 ms two-way-time in the southwest, northeast and a smaller area in the east (Figure 9). The map also shows a general decrease in depth towards the northwest with -3400 ms two-way-time at the structural high. A shallow area was additionally observed in the middle of the map, in the area where wells 1/6-2, 1/6-6 and 1/6-7 have been drilled. The top of the Haugesund Formation, and younger units, the interpreted faults, and a salt diapir are illustrated in Figure 10a and b. This interpretation also shows that the Tyne Group, with the Haugesund Formation, displays thickness variation and growth strata laterally (Figure 10b). At the right side of the salt diapir, the Tyne Group is thicker in the syncline than in the anticline, creating a minibasins adjacent to the salt body. The amplitude in the group also changes laterally, with higher amplitudes on the left side of the diapir, and with a decreasing amplitude laterally towards the east (Figure 10a). It is also the only group affected by normal faults. Included are also the interpreted isotherms, based on the BHT from NPD (2022), 90 ˚C, 120 ˚C, 150 ˚C and 180 ˚C, following the structure of the groups except for a general decreasing curve within the salt diapir. They are localized in the middle of the Hordaland Group, middle of the Rogaland Group, lower part of the Shetland Group and within the Haugesund Formation, respectively.

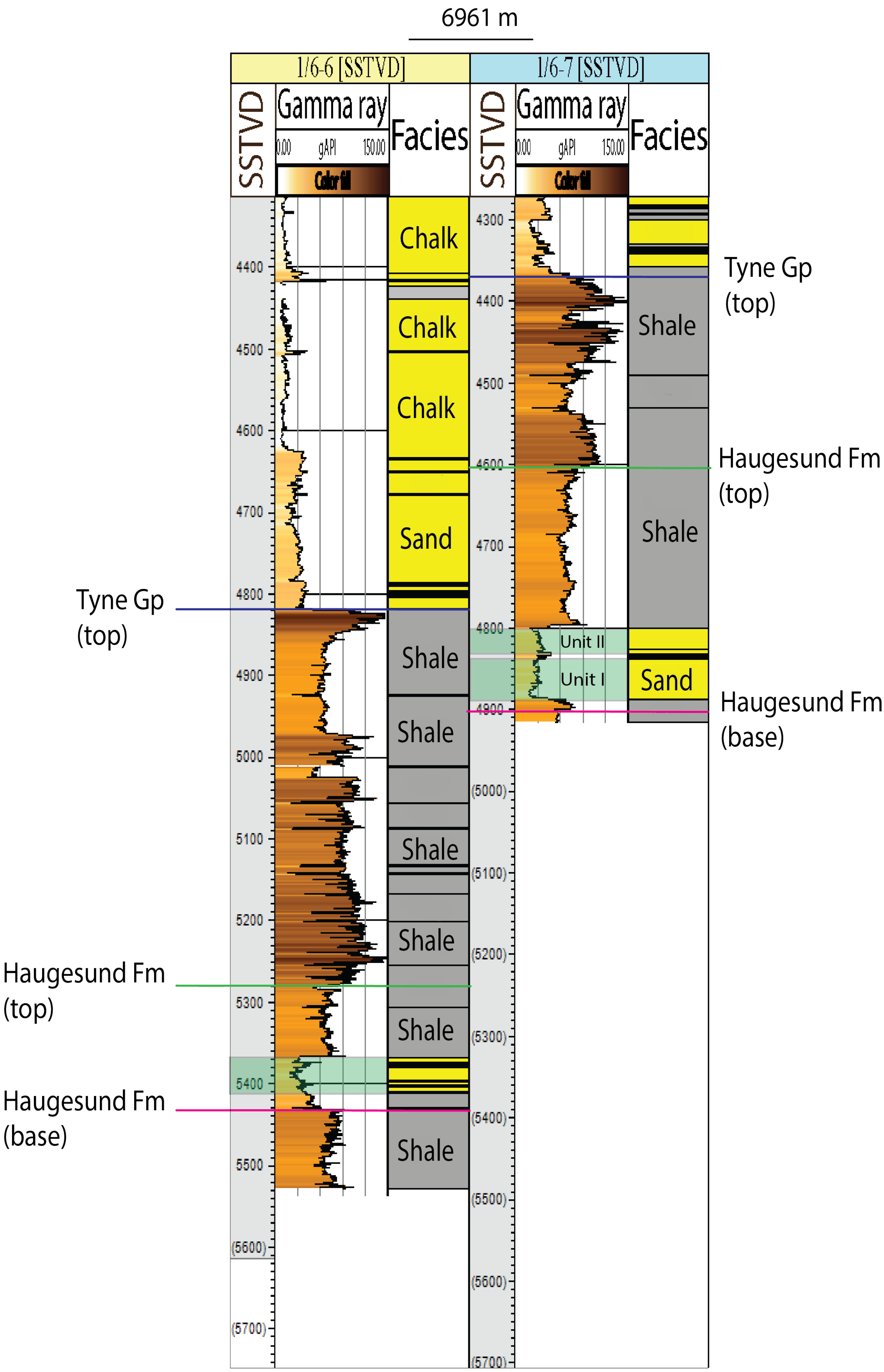

Figure 8: Log from well 1/6-6 and 1/6-7 in the Tyne Group and Haugesund Formation succession.

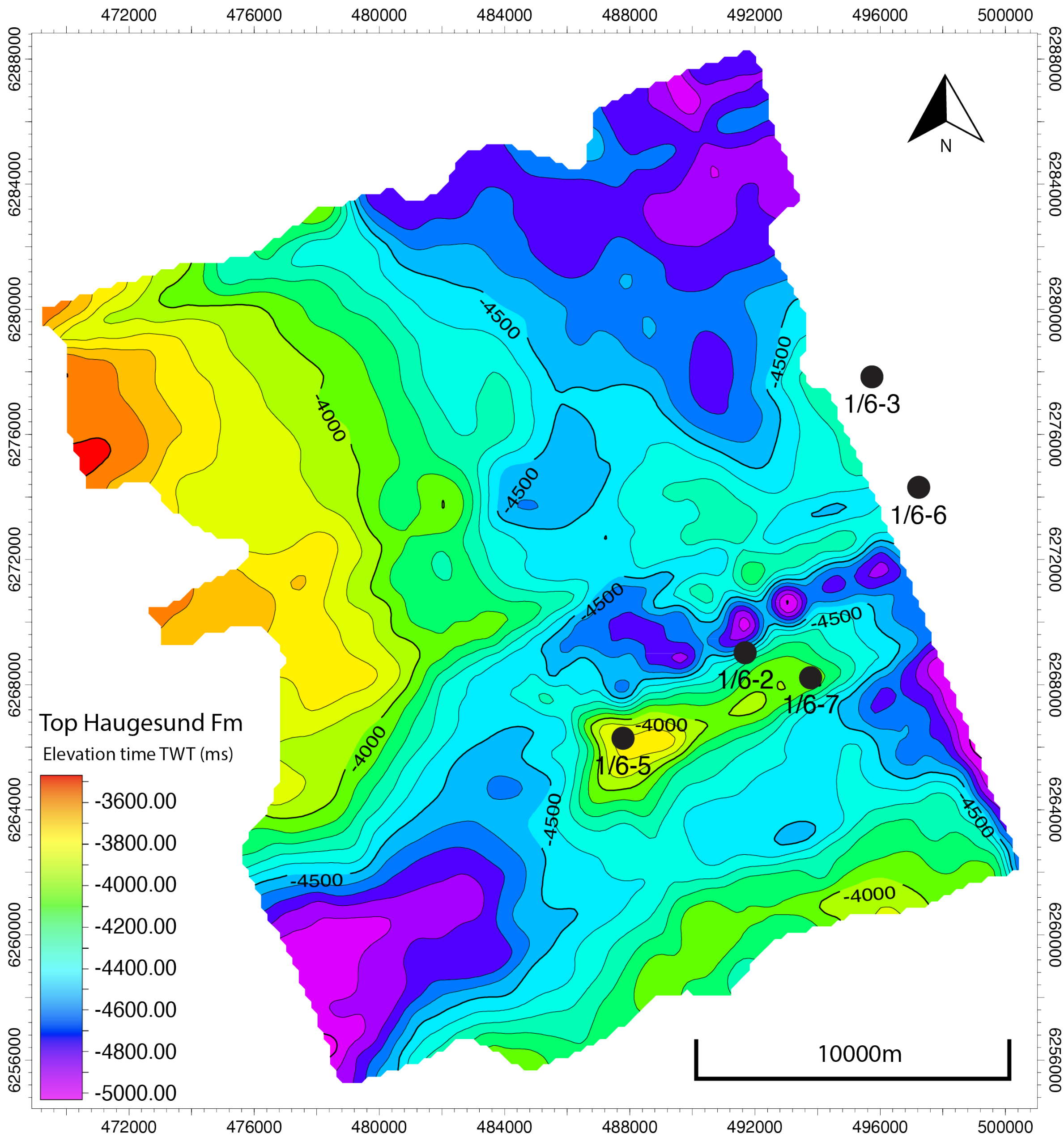

Figure 9: Structural map of the Haugesund Formation.

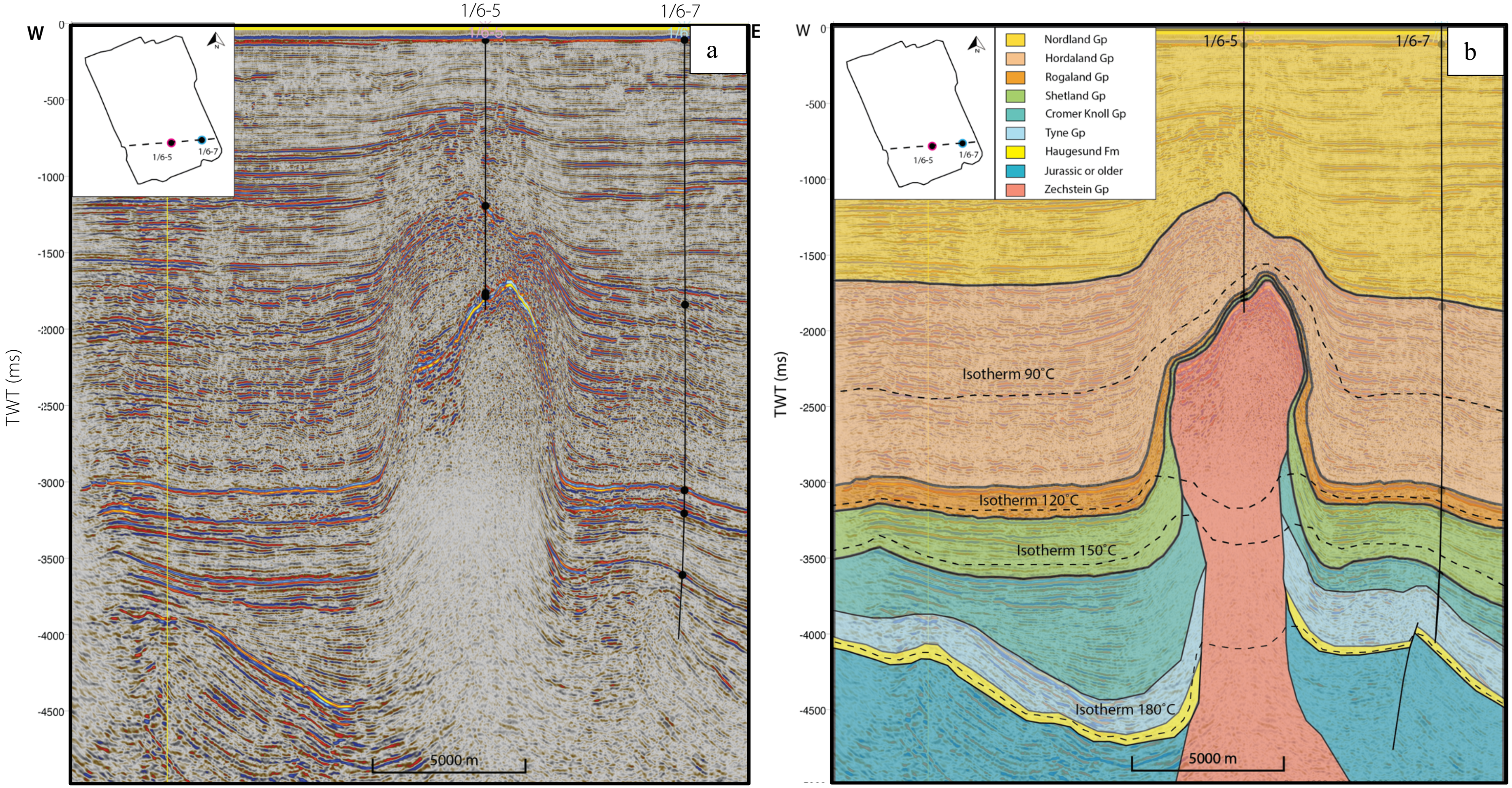

Figure 10 a and b: *Example of a salt diapir and a fault in the southern area. A: Seismic section without interpretation. B: Seismic section with interpretation.*

5.2.2 Shetland GP

5.2.2.1 Description from log observations

All five selected wells penetrate the Shetland Group, but because of deformation caused by the salt diapirs the depth of the Shetland Group varies considerably. In well 1/6-5, the Shetland Group is entered at 1693 m (Figure 11). Both well 1/6-2 and 1/6-3 are not drilled into any formation below the Shetland Group, but the base of the well is located at 3350 m and 3300 m, and the top at 2990 m and 3080 m. The thickness is approximately 360 m and 220 m. In well 1/6-6 and 1/6-7 the base of the Shetland Group is located at 4630 m and 4270 m, and the top at 3285 m and 3250 m. The thickness is approximately 1345 m and 1020 m. On the other hand, the gamma ray is homogeneous for well 1/6-2 and 1/6-3, with lower values than 30 API, indicating chalk. Well 1/6-6 and 1/6-7 is more heterogeneous, where facies variations in the chalk can be seen as thin layers of shale. This is also confirmed from the core photo, that shows some lamination, indicating that the chalk is not completely homogeneous (Figure 12). This is clearly seen between 3308 m and 3309 m, as a darker area below number 55. Well log 1/6-6 seems to have lower gamma ray values compared to the other wells, indicating sand above the Shetland Group. The implication of this is a possible laterally change in seal quality. A possible geothermal reservoir is the Shetland Group, marked green, with an overlaying Rogaland Group working as a seal, mainly consisting of shale. The porosity varies between 17,5 % to 26 % (Table 5), and the permeability for the North Sea chalk is naturally very low because of the small grain size (Kallesten, 2020). The presence of fluids was described in the well report, explaining that the Shetland Group contained both oil and gas in well 1/6-3, while it was water bearing in well 1/6-2 (NPD, 2022).

5.2.2.2 Description from seismic structure

The structural maps of both top and base Shetland Group show a general increasing depth towards the north (Figure 13a and b). The Top Shetland Group also indicates an increasing depth in the southern part of the map. Similar for both is the presence of salt diapirs, showing the highs around well 1/6-5, 1/6-2, and 1/6-7, southeast in the maps. The depth of the Shetland Group Top is about –2700 ms two-way-time in the centre of the salt structures, while it is –3400 ms two-way-time in the deepest parts in the north of the map. This also applies to the Base Shetland Group map, with depths about –2900 ms two-way-time at the shallowest parts and –4100 ms two-way-time at the deepest areas. A shallower area is also identified northwest in both maps. The thickness reaches its lowest values on top of the salt diapirs, approximately 180 ms two-way-time for those two in the south and southeast, while it is about 360 ms two-way-time for the one in the northwest (Figure 13c). Along the west boundary, there is also observed a shallower area, with values about 270 ms two-way-time. The depocenters are observed in the north with 720 ms two-way-time, and in the synclines formed adjacent to the diapirs. It is a decreasing thickness towards the southwest.

The seismic interpretation reveals the larger thickness in the north, with a general decreasing thickness towards southeast (Figure 14), also seen in the interpretation (Figure 15). Additionally, the thickness of the Shetland Group is thinner on top of the salt bodies, as displayed in Figure 13c. The thickness also decreases in the crest and flanks of the salt diapir and is increasing in the salt minibasins. This thickness variation indicate that the Shetland Group was deposited during active salt tectonics. Some high amplitudes are also identified between the top and base of the Shetland Group, all the way northwest in the seismic. The isotherms are interpreted in Figure 15 as well and follows the same terms as in Figure 10b where the temperature decreases downwards within the salt. 90 ˚C, 120 ˚C and 150 ˚C are interpreted to be identified within the middle of the Hordaland Group, the middle of the Rogaland Group and at the lower part of the Shetland Group, respectively.

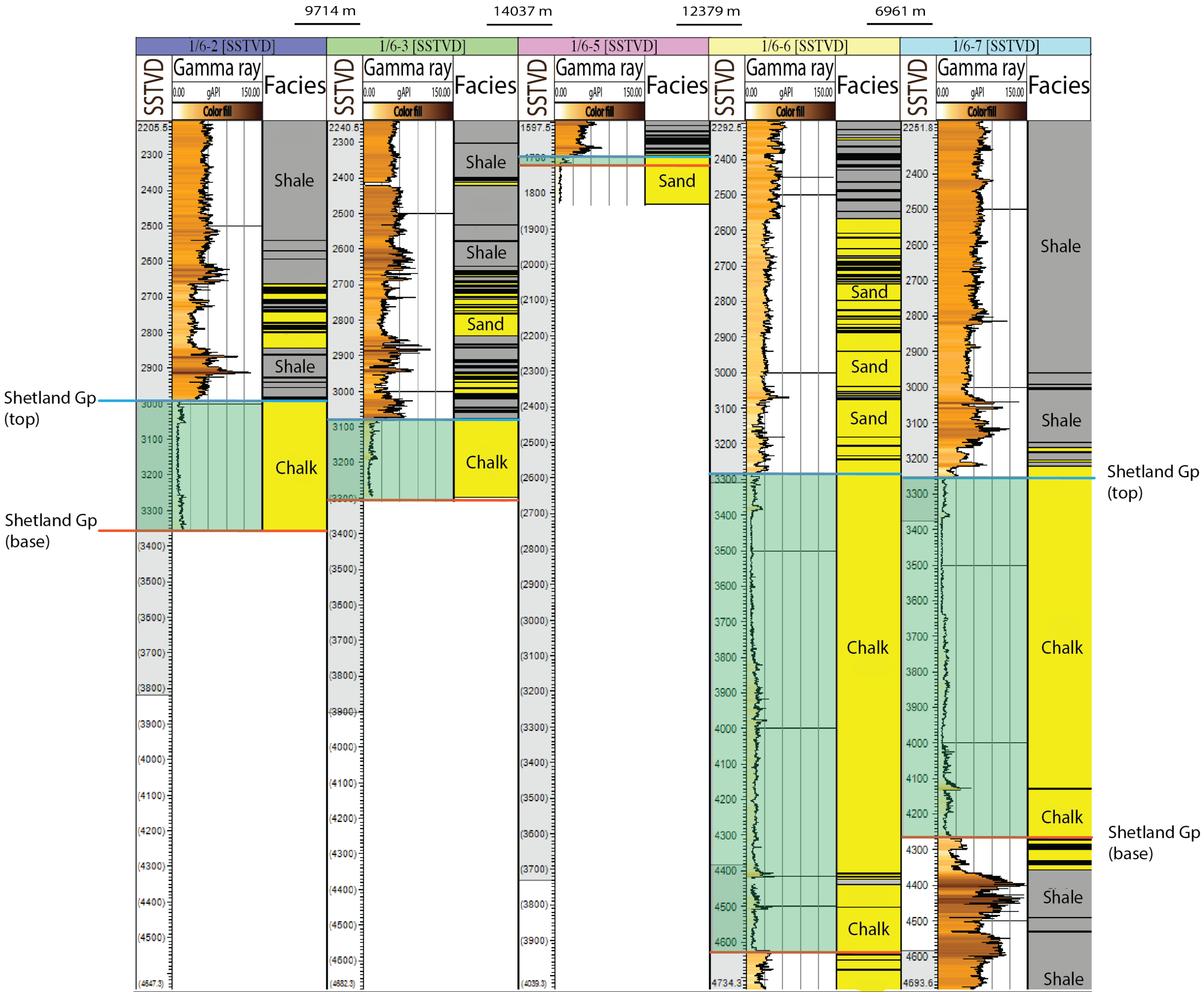

Figure 11: Logs for all five wells in the Shetland Group succession.

Figure 12: *Core photo from well 1/6-7 between 3307 m to 3311 m in the Shetland Group succession showing white/greyish chalk (NPD, 2022).*

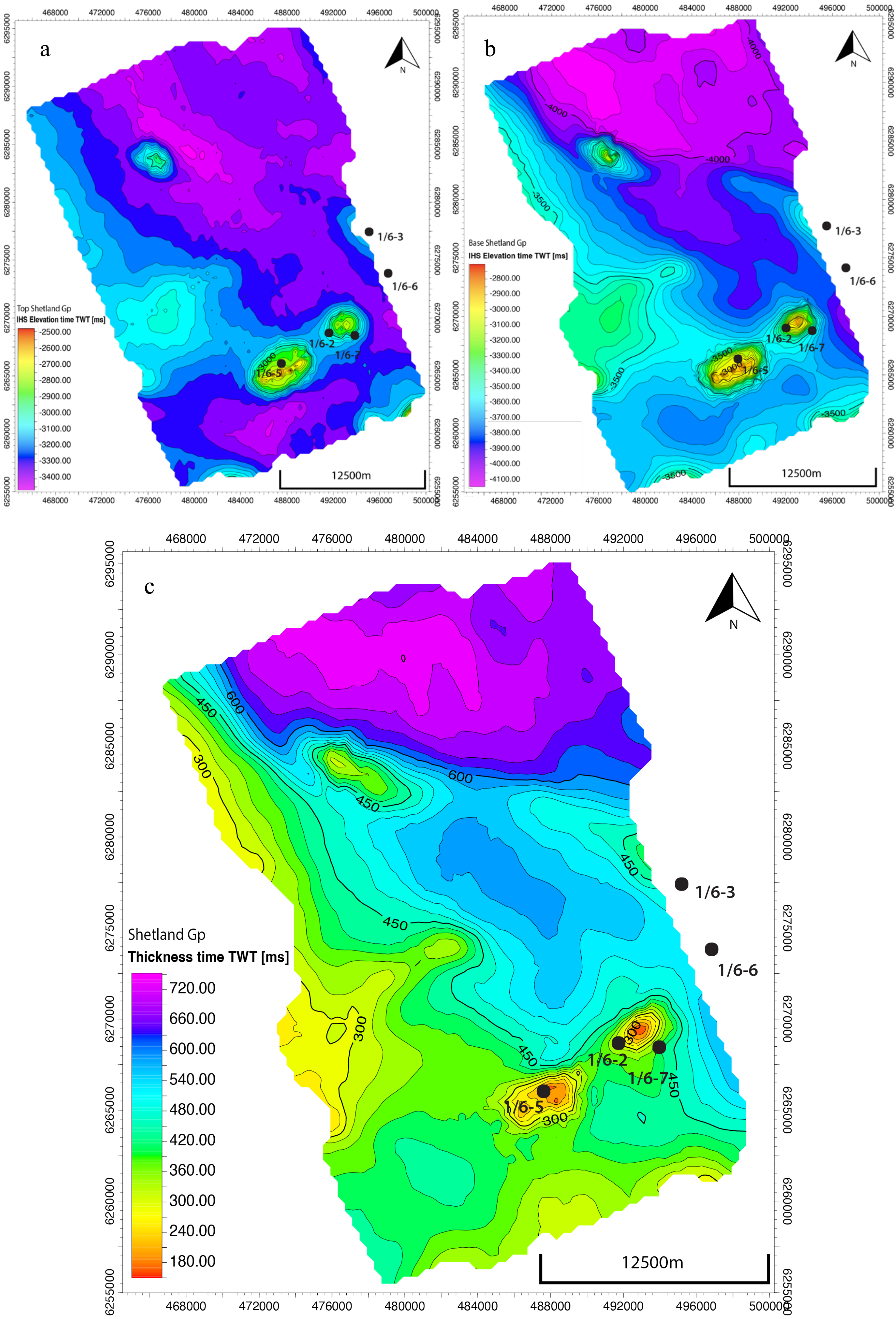

Figure 13 a, b, and c: A: Structural map of the Shetland Group top with location of the wells. B: Structural map of the Shetland Group base with location of the wells. C: Thickness map of the Shetland Group succession with location of the wells.

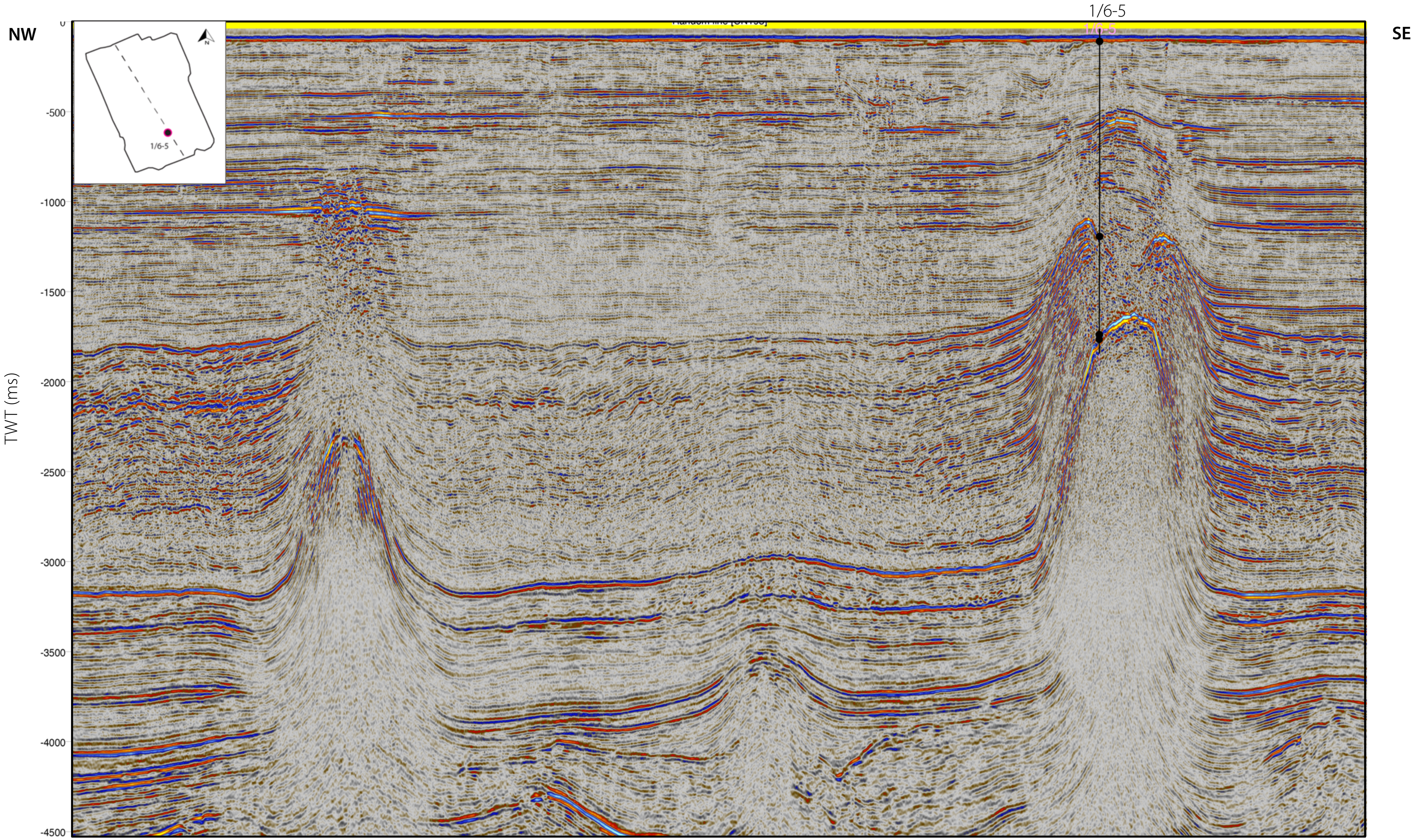

Figure 14: *Example of a salt diapir in the northwestern area and one together with well 1/6-5 in the southeastern area. Without seismic interpretation.*

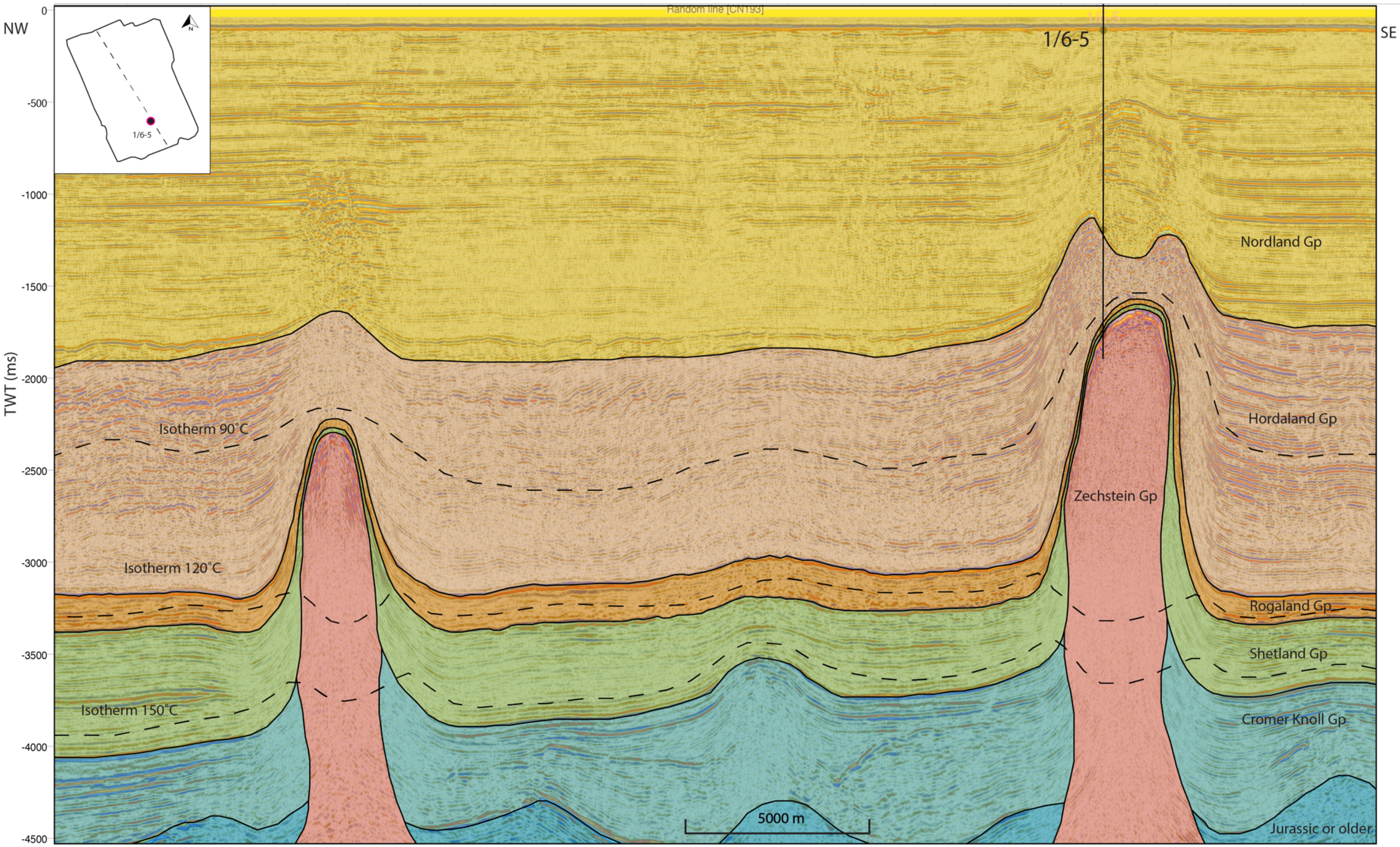

Figure 15: *Example of a salt diapir in the northwestern area and one together with well 1/6-5 in the southeastern area. With seismic interpretation.*

5.2.3 Hordaland GP

5.2.3.1 Description from log observations

The Hordaland Fm is the most homogeneous of the three selected intervals. Laterally, both depth and thickness are quite similar (Figure 16). The top of the group is located at a depth between 1722 m to 1811 m, except for well 1/6-5 where the top is located at 1114 m, and the thickness is 555 m. In well 1/6-2 and 1/6-3 the base of the Hordaland Group is located at 2858 m and 2872 m, where the thickness is approximately 1139 m and 1115 m, respectively. For well 1/6-6 and 1/6-7 the top of the Hordaland Group is located at 1810 m and 1770 m, and the thickness is approximately 1274 m and 1276 m. The facies vary, where the group mainly contain shale, but also has a sand rich layer at the base of the group. The GR shows variations in values, where there is a lot of spikes, indicating that the sandstone is interbedded with shale or claystone. Well 1/6-7 displays higher GR values indicating that there is no sign of sandstone in this well. The possible reservoir is the sandstone layer at the base of the Hordaland Group, marked green, sealed by the shale which constitute the rest of the Hordaland Group. With such high geothermal gradients that is present in the study area, temperatures about 120 ˚C, could be possible at the base of this group. The thickness of the interval with sandstone varies. In well 1/6-2 the thickness is 170 m, in 1/6-3 it is 150 m and in 1/6-6 it is 510 m thick.

5.2.3.2 Description from seismic structure

The structural maps for the intra Hordaland sand top indicate a maximum depth of approximately –3000 ms two-way-time for the top and southeast of the map (Figure 17a), while it is –3200 ms two-way-time in the same areas for the base of the intra Hordaland sand map (Figure 17b). Both figures displays that the interpreted sandstone layer is shallower around and on top of the salt diapirs. The diapirs located south and southeast in the map reaches elevation time about -2400 ms two-way-time and -2700 ms two-way-time, for the Top intra Hordaland sand. In the northwest the elevation time to the shallowest point of the top intra Hordaland sand is about -2580 ms two-way-time. For the base of the intra sand the elevation time is higher compared to the top, but it displays the same structures at the same locations. The elevation time for the salt in the south is -2550 ms two-way-time, and for the one in the southeast and the one in the northwest it is -2700 ms two-way-time. The maps are also indicating that there is an increasing depth towards the east. The thickness map displays small thickness variation (Figure 17c). The thickness is about 160 ms two-way-time all over the map, with decreasing thickness towards the centre of the salt diapirs. The thickness on top of the salt structures is about 80 ms two-way-time for the two located south in the map, while it is about 50 ms two-way-time for the one located in the northwest. Also, the thickness reaches its lowest values in the south-eastern part. The small variations in thickness can also be seen in the seismic, where their thickness is quite continuous in the Hordaland Group compared to for example the Shetland Group (Figure 18a and b).

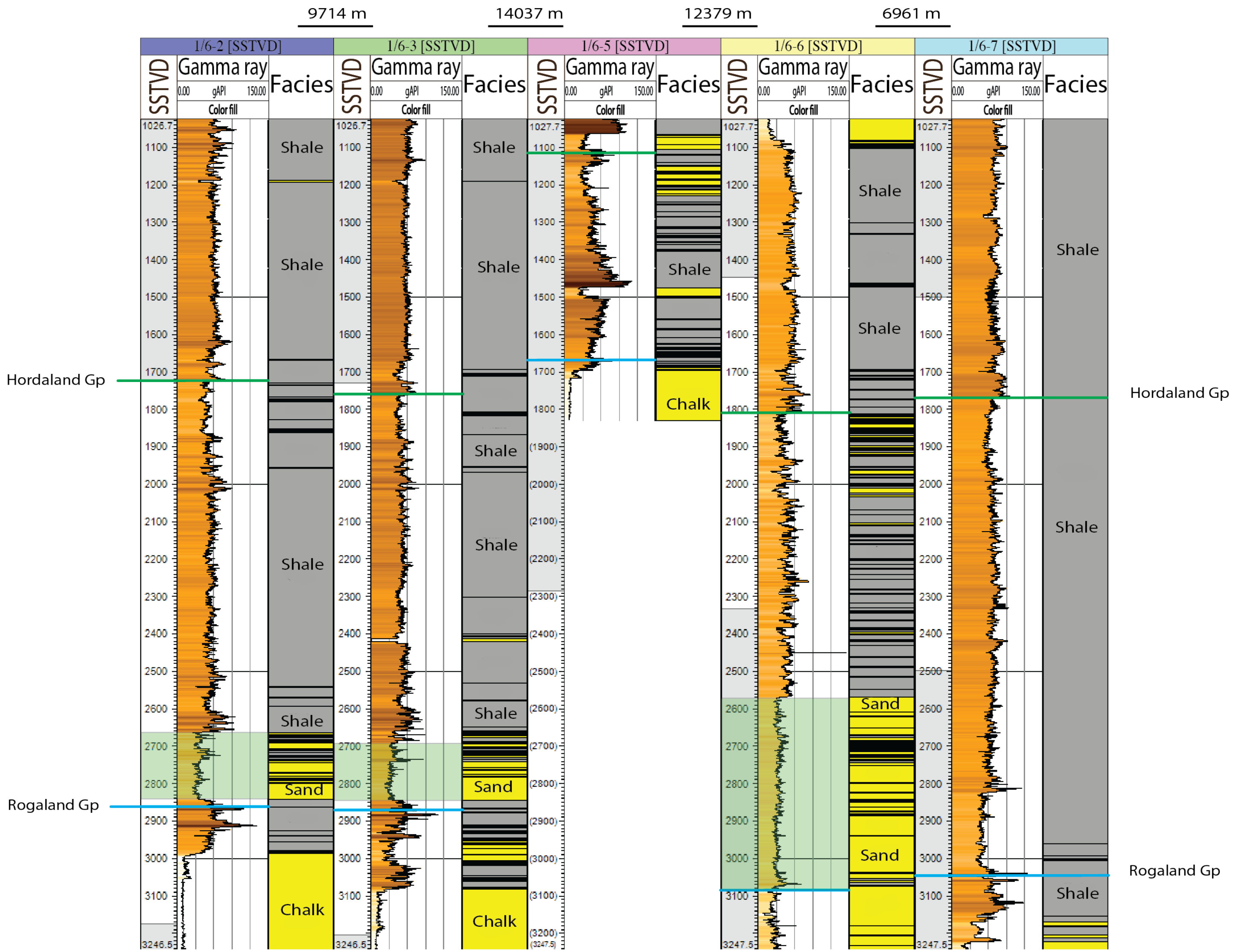

Figure 16: Logs for all five wells in the Hordaland Group succession.

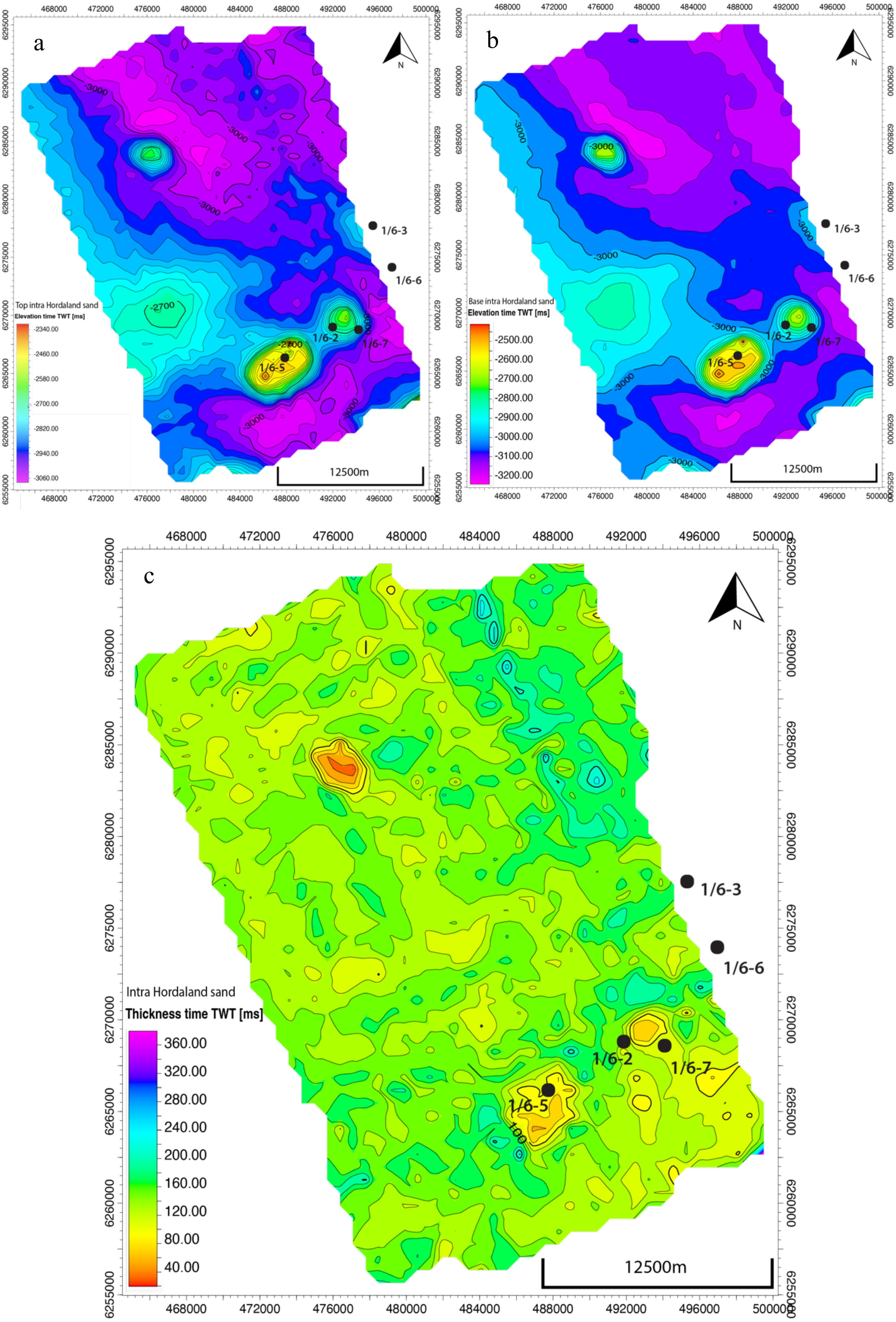

Figure 17 a, b, and c: A: Structural map of the Hordaland Group top with location of the wells. B: Structural map of the Hordaland Group base with location of the wells. C: Thickness map of the Hordaland Group succession with location of the wells.

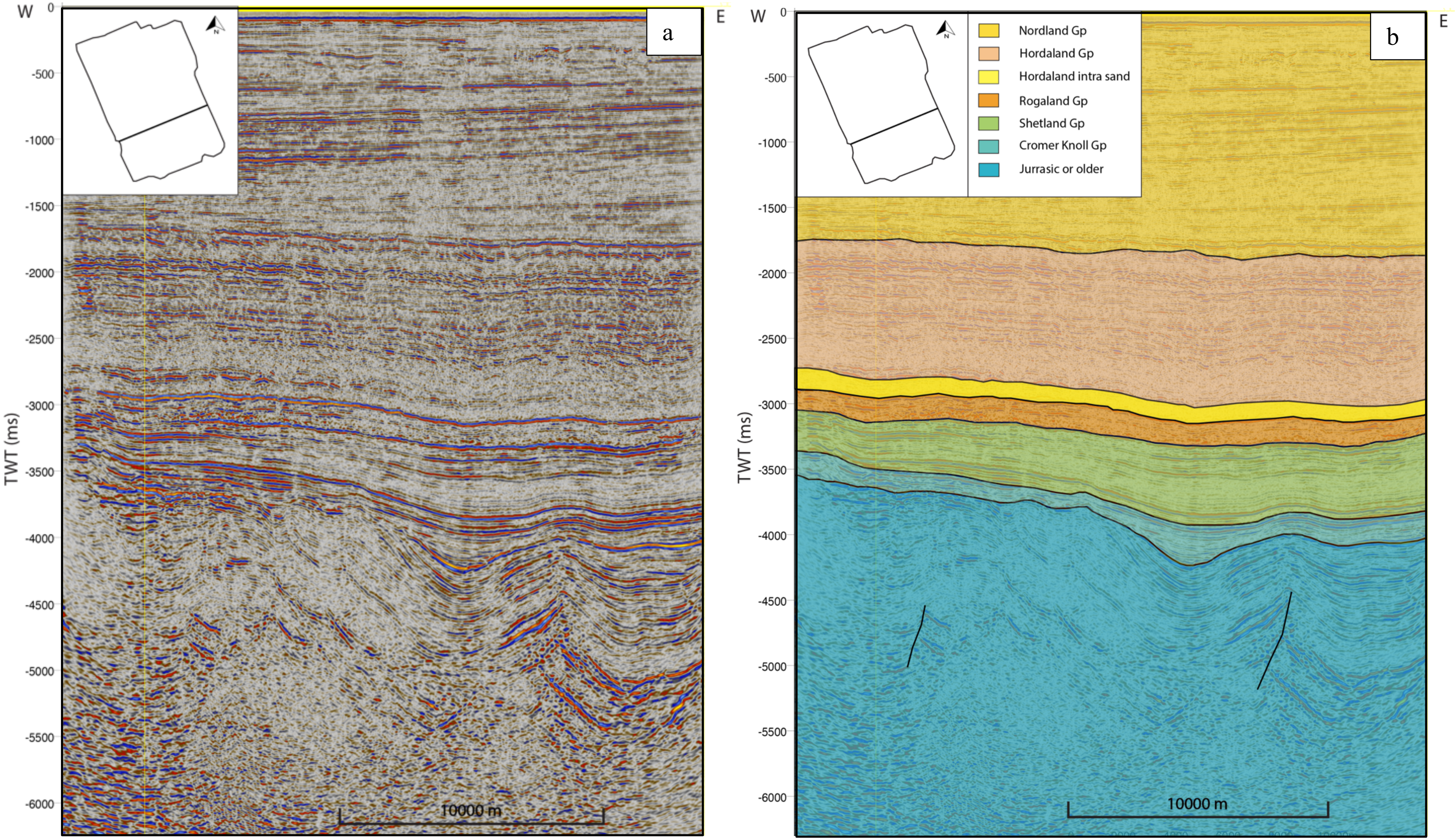

Figure 18 a and b: *Example of a homogeneous thickness in the Hordaland Group. A: Without seismic interpretation. B: With seismic interpretation.*

6. Discussion

6.1 Role of salt on the geothermal gradient

Based on the geothermal gradients, observations of the Top Zechstein Group and the Moho in the study area, the Zechstein salt are considered to play an important role, controlling the variation of geothermal gradients in the Norwegian North Sea. The top of the Zechstein salt has a shallower depth in areas with higher geothermal gradients, indicating that the salt is affecting the temperature in the area (Figure 1). Where the salt is identified at a deeper depth, the geothermal gradient is significantly lower (Figure 7a and b). Again, indicating the necessity of the salt. The interpretation also displays a clear difference in temperature between shallow and deep diapirs, where the 90 ˚C isotherm will be localized at different elevations depending on the depth of the top of the salt (Figure 15). The heat within the salt will be higher in the top, heating the rocks above the salt (Hudec & Jackson, 2007). Since the isotherm is identified above the salt diapir, it is affected by the depth of the salt, which will affect the geothermal gradient. This could be why the geothermal gradient reach values between 52 ˚C/km and 56 ˚C/km for well 1/6-5 in the southernmost and shallowest salt diapir, and not more than 44 ˚C/km to 48 ˚C/km in the northwestern diapir (Figure 7a and b). With these observations, the shallow diapirs tend to amplify the geothermal gradient locally.

Observations from the depth of the Moho (Figure 3), indicates that there are other factors that affects the geothermal gradient in addition to the salt. Within the Central Graben there is both a shallow Moho, a shallow Zechstein Group, and high geothermal gradients. A shallow Moho will naturally lead to higher temperatures at shallower depths, indicating that the geothermal gradient could be affected by both a shallow Moho and the Zechstein Group. A relationship between the Moho depth and the high geothermal gradient is therefore suggested. In addition to this, the reservoirs will affect the heat when it comes to expanding the heat energy. Geothermal reservoirs adjacent to the salt diapir, could make the heat expand laterally and vertically along the salt, depending on the rock and its characteristics. The geothermal reservoir could possibly contribute to that the geothermal gradient is high in wells located further away from a salt diapir because the heat flow within formations will expand.

The interpretations of high geothermal gradients caused by an increased thermal conductivity by the salt are suggested in previous papers. Daniilidis & Herber (2017) suggests that high geothermal gradients within sedimentary basins, could be affected by the conductivity of salt, as well as the salt thickness and intrusion is important (Daniilidis & Herber, 2017). Further, Nolan (2021) suggests that areas with higher geothermal gradients, tends to be coincident with areas where fluid migration along a salt diapirs occurs (Nolan, 2021).

6.2 Elements of the geothermal system

To have a geothermal reservoir, the most important element would be the heat source. Radioactive decay and heat from the Mantle would both produce a lot of geothermal heat energy that will flow upwards and heat overlaying sediments. The heat will naturally increase with the depth, but the geothermal gradient depends on the environment, as described in previous chapter. Different temperatures are interpreted, giving an indication of the possible temperatures at the different depths (Figures 10b and 15). The isotherms 120 ˚C, 150 ˚C and more than 150 ˚C, are suggested from BHT data from the selected wells, giving an assumed elevation for the isotherms. Different wells with several kilometres distance between each other will naturally have different temperatures, depending on the environment. 120 ˚C are interpreted to be in the middle of the Rogaland Group. The 150 ˚C isotherm are suggested in the lower part of the Shetland Group, while it is expected more than 150 ˚C below this.

Further, the geothermal reservoirs are suggested adjacent to the salt diapir, in formations and groups containing sandstone or chalk, at a depth with high enough temperatures. The proposals are also covered by the overlying shale. Well logs in Figures 8, 11 and 16 are displaying facies based on the GR values. This indicates the possible energy play concepts that could be proposed. The sandstone layer at the base of the Hordaland Group, the chalk in the Shetland Group, and the sandstone at the base of the Haugesund Formation, are all potentially geothermal reservoirs, containing high enough porosity and permeability (Table 3). From the interpretation, the top of the salt diapir would not be a potential geothermal reservoir, considering that the thickness has been decreased and affected too much. Based well logs, permeability, porosity and temperature, the Jurassic Haugesund Formation would be the best geothermal reservoir. With temperatures up to 190 ˚C and such a good porosity and permeability that is identified within this formation, the possibilities for extraction are many, considering the utilization of the reservoir. The chalk would possibly be more difficult regarding the lower permeability that is present here (Kallesten, 2020). While the intra

Hordaland sand could be a good solution, but the temperatures would naturally be lower for this reservoir.

The need of fluids is necessary to extract the geothermal heat (Table 1). Based on the well reports from NPD, the presence of water in the Haugesund Formation supports the proposal that it could be a potentially good geothermal reservoir. Further, the Shetland Group contained both water, gas, and oil. In a case like this, the fluids could have been extracted and then substituted by reinjected water.

Salt movements, such as diapirs are interpreted to have caused deformation within the overlaying formations while rising upwards and creating anticlines. From growth strata in Figure 10b the footwall in the Tyne Group is thinner than the hanging wall, while the sandstone layer has the same thickness in both sides. Based on the thickness variations, the deposition of the Tyne Group was affected by salt tectonics and fault activity. The higher amplitudes in the depocenter (synclines) can indicate that the sandstone of the Haugesund Formation is preferentially located in these synclines formed adjacent to salt diapirs. Further, the decreasing thickness towards the top of the salt body, are interpreted to be caused by the deformation and halokinesis.

Furthermore, the evaporitic Zechstein Group is an impermeable rock and therefore acts as a seal. The salt will transfer heat to adjacent rocks, and fluids that receive the heat will therefore not migrate further into the salt. Instead, it will keep moving within the reservoir, and this is also where the trap is necessary. Since the overlaying sediments above both the intra Hordaland sand and the Shetland Group mainly consist of shale, this is estimated as good seals. The base of the Rogaland Group and the Zechstein salt structure will meet where the Shetland Group will disappear and “fade” towards the top of the salt diapir. This will create a trap consisting of a pinch-out, where two different seals are closing the geothermal reservoir. The same would happen for the intra Hordaland sand, and this is also the case interpreted for the Haugesund formation, which is not included in the Figure 19. Seals and traps will together refuse a further migration of fluid upwards, and will then create good possible geothermal reservoirs, given that there is high enough porosity and permeability. A proposed model of the elements in a geothermal reservoir is presented (Figure 19).

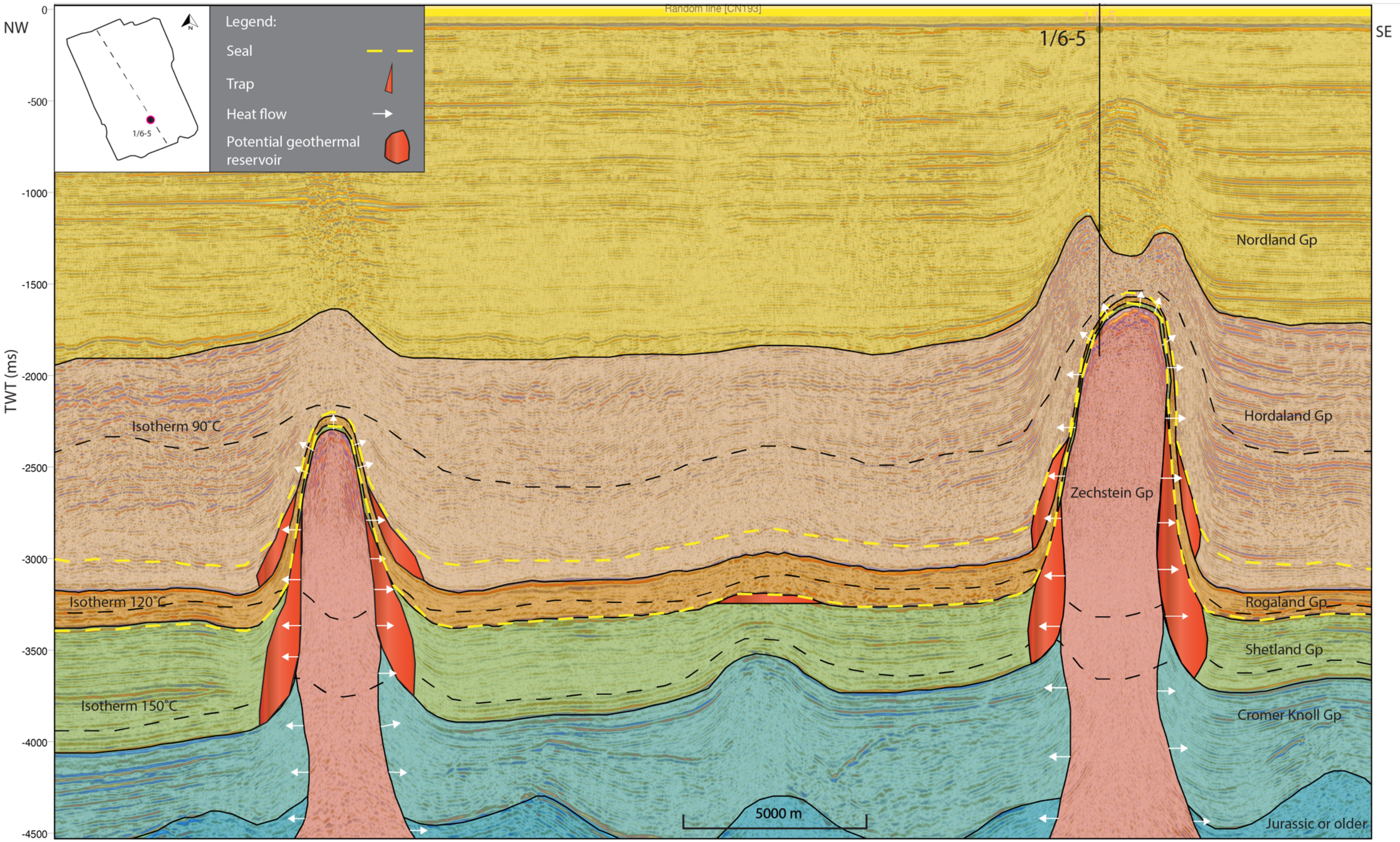

Figure 19: *Proposed model for the geothermal system in the study area.*

6.3 Challenges and opportunities

As described earlier, the geothermal heat has been used for several years, and can be used as long as the Earth exists. As a renewable energy source that can be used without any emission, which also is under constant production from the Earth's core, the geothermal energy has an enormous potential. Based on previous work there is a lot of opportunities, and according to Boden & Ebscohost (2017) there already exists several different methods to get to use it. Still there are challenges, especially regarding the use of geothermal energy in the Norwegian North Sea. Transporting geothermal heat from the central part of the North Sea towards Norway would be too long, and heat could be lost. It would be more efficient transporting heat to a power plant stationed on a platform. For the lowest temperatures, direct use could be an alternative, heating the platform. Based on all the new installation of equipment and new costs, it would probably be more economical if there also was a generation of electricity. The temperatures available in the study area reaches between 120 ˚C and about 190 ˚C, which means that the temperatures may be too low for a Flash power plant, that usually require high enthalpy systems. Instead, a Binary geothermal power plant could be a good possibility. Using moderate enthalpy between 120 ˚C to 175 ˚C. In addition to this, the high temperatures within the Haugesund Formation would have given a lot higher power output. This is also the case in the Ngatamariki plant in New Zealand, where the geothermal fluids reach about 193 ˚C (Boden & Ebscohost, 2017). Estimated costs over a life span would also be lower for a binary geothermal power plant, rather than a flash plant.

The geothermal energy is a promising and clean energy source, but there can be challenges using it in the Norwegian North Sea. Firstly, the interpretation about the geothermal gradients and top Zechstein Group in Figure 7a and b, displays that the location is restricted. Therefore, there tends to be a geological challenge, where there is a need for a salt diapir to reach the potentially highest temperatures. In addition to this, activities in the subsurface could potentially increase the risk of earthquakes and subsidence. Which could lead to damaged equipment etc.

Further, there could be challenges within the reservoirs. From the amplitude variations from the seismic (Figure 10a), a suggestion could be variations in facies, meaning that they are not laterally continuous. If the sandstone is not continuous, and contain shale or other impermeable layers, the fluid migration within the reservoir could be affected. Differences in porosity and permeability could also occur, affecting the reservoir in a positive or a negative way. The costs could also be a challenge, since the geothermal exploration in the Norwegian North Sea still is quite unknown, there must be a lot of exploration. As well as the equipment must be present, where a power plant most likely must be placed offshore.

7. Conclusion

- The Zechstein Group has an impact on the geothermal gradient in the Norwegian North Sea, where geothermal gradients are higher in areas with a shallow top Zechstein Group.

- There is an interplay between geothermal gradients, the Moho depth and shallow diapirs in the Norwegian North Sea.

- The salt diapirs are affecting the reservoirs. Considering that the salt is impermeable, it works as a seal as well as the halokinesis makes traps during the deformation.

- The intra Hordaland sand, the Shetland Group and the Sandstone Unit I and II within the Haugesund Formation are all good potential geothermal reservoirs, with positively high isotherms. The temperatures reach about 90 ˚C in the middle of the Hordaland Group, 120 ˚C in the Rogaland Group, and 150 ˚C within the Shetland Group. The highest values are found in the Tyne Group with approximately 180 ˚C. The lithology is both sandstone (intra Hordaland sand and Haugesund Formation) and chalk (Shetland Group), where especially the sandstone is estimated as good reservoirs. All of them are overlayed by shales, preventing the fluid from further migration.

- The composition of the Hordaland Group is quite similar regarding thickness within the study area, while the Shetland Group has a decreasing thickness towards the north. The Haugesund Formation has a lot of thickness variation, because of post rifting deposition.

- Considering the temperatures, a binary geothermal power plant could be the best proposed solution, utilizing the geothermal heat energy stored in the Central North Sea. Direct use could also be an option, for the lowest temperatures.

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