Geological controls on petroleum reservoir quality of the North Cape Formation, Taranaki Basin, New Zealand

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ABSTRACT

Taranaki basin is the petroleum production basin along the western side of New Zealand. The main production fields have been located along the marginal zone from Cenozoic reservoirs. However, Cretaceous sandstones within the North Cape Formation which deposited in sub-basin at the initial phase of basin formation might be potential reservoir in the deepwater area. In this study, well log data are used to investigate the potential reservoir of the North Cape Formation. The reservoir properties of the North Cape Formation exhibit that the porosity is between 10% and 27% and permeability is up to 700 mD. The porosity of sandstone in this formation is increased basinward. Barrier bar sandstone shows the highest porosity compared to channel and tidal flat sandstones. The North Cape Formation sandstone has potential to become a reservoir especially in the deepwater area. The main factors controlling reservoir properties are depositional environment and degree of compaction.

Keywords: North Cape Formation, Taranaki Basin, Reservoir quality

1. Introduction

Petroleum reservoirs usually represent suitable geometry, connectivity, heterogeneity, porosity, and permeability to form an effective reservoir for petroleum production (Bates and Jackson, 1980). Even though there are various properties affecting reservoir rocks, the most considering physical properties are porosity and permeability. While porosity which relates to all void space in rocks is a fundamental property, permeability or capacity of the formation to transmit fluids is the main factor for the success of exploring petroleum (Gluyas and Swarbrick, 2004). In addition, sedimentary basins may have different geological setting and tectonics history leading to a difference on petroleum reservoir quality.

The Taranaki Basin covers approximately 330,000 km^2, on- and offshore the west coast of North Island, New Zealand, and is the main petroleum producing basin in New Zealand (Figure 1). The basin developed in the Late Cretaceous with multiple phases of complex deformation (King and Thrasher, 1996). The main production fields have been located along the peninsula with Cenozoic reservoirs (King and Thrasher, 1996). However, these Cenozoic reservoirs are only restricted within a nearshore zone and could not prograde to an offshore zone which is a majority of the basin (King and Thrasher, 1996). Therefore, to explore the Taranaki deepwater area, new prospective reservoirs should be considered and one of the reasonable reservoirs is the North Cape Formation sandstones, deposited in Late Cretaceous throughout the basin (King and Thrasher, 1996; Stagpoole et al., 2001, Uraski, 2007).

Thus, the formation of interest in this study is the North Cape Formation, which is deposited in terrestrial to shallow marine environment. It is overlaid the source rock strata of the Rakopi Formation (Stogen et al., 2012; King and Thrasher, 1996). The outcrops and core data show that the North Cape Formation consists of various reservoir plays and the factors affecting reservoir properties are sandstone composition, a volume of clay minerals and degree of compaction (Higgs et al., 2010). Due to a small number of outcrops and sidewall cores, well log data should be included to interpret the reservoir properties of the North Cape Formation.

In this study, well log data are used to evaluate the reservoir quality of the North Cape Formation. A petrophysical analysis is used to analyze lithology, porosity, water saturation and permeability of the sedimentary formation in this study (Schlumberger, 1998; Asquith and Krygowski, 2004). The well log data are also used to describe the depositional environment of the North Cape Formation. Two major reservoir properties, porosity and permeability, of the sandstones in this formation are interpreted by using neutron and density log. The results of this study provide an evidence of geological controls on reservoir properties of sandstones in the North Cape Formation in deepwater area.

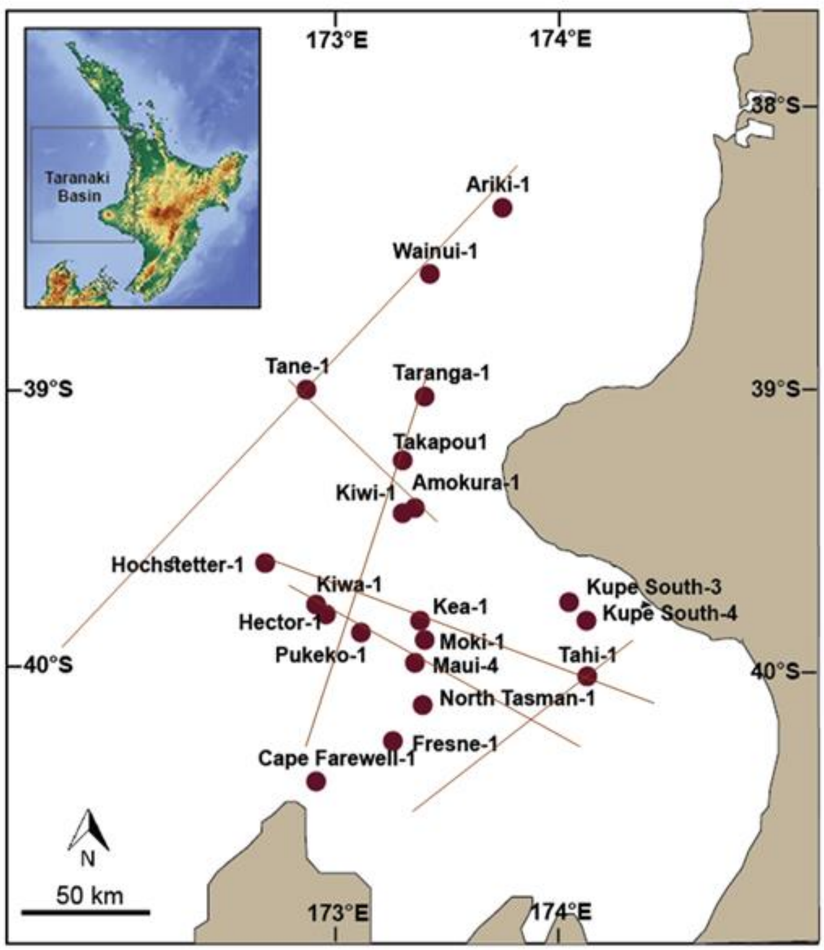

Figure 1. The study area, Taranaki basin, is located on the western side of North Island, New Zealand. Brown dots and lines show well and seismic locations used in the study, respectively.

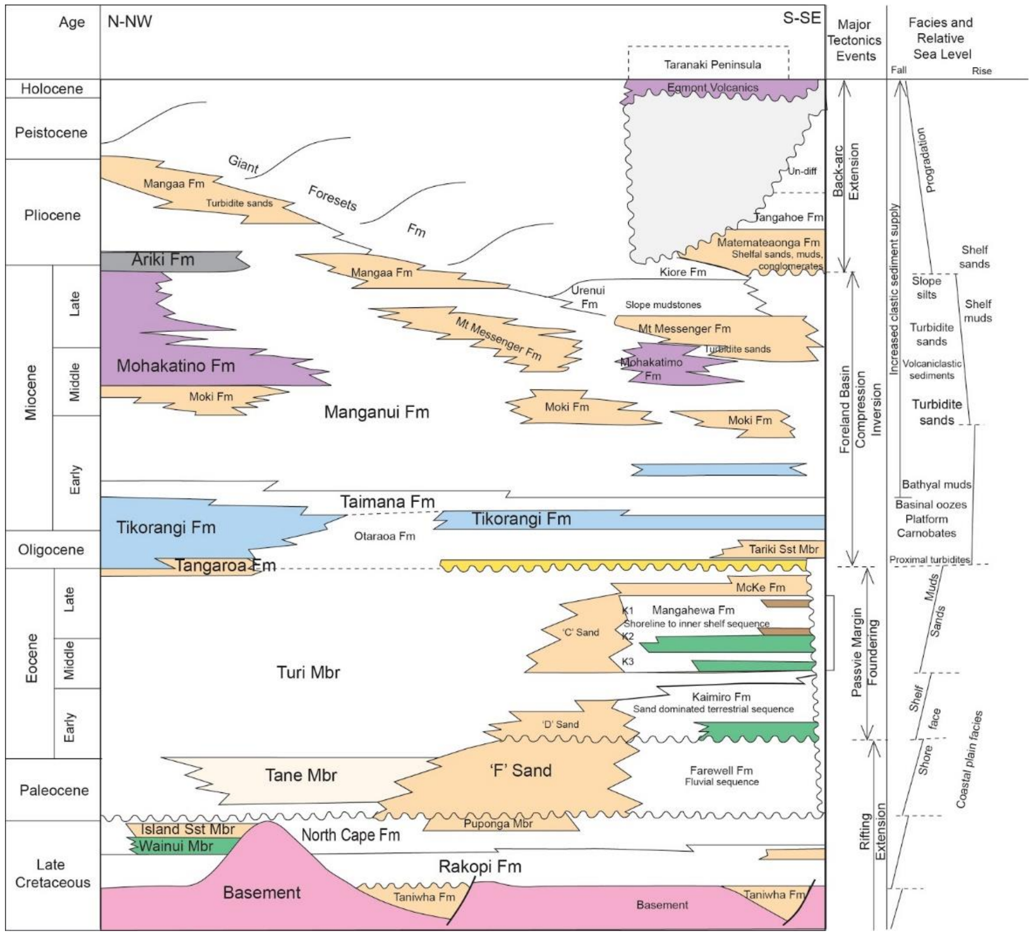

Figure 2. Synthetic stratigraphic column of the Upper Cretaceous to Quaternary of Taranaki Basin (modified from King and Thrasher, 1996).

2. Geological Setting

The Taranaki Basin is dominated by terrestrial, marginal marine and shallow marine sediments from the Cretaceous to Oligocene time (Figure 2). At the end of the Oligocene, the convergent tectonics of the Pacific and Australian plates caused a strong differential uplift, subsidence and deposition of deep water sediments in this region. In the Early to Late Miocene, part of the Taranaki Basin developed a complex fold-thrust belt in a back arc basin setting (King and Thrasher, 1992). During the Pliocene and Pleistocene, the proximal parts of the basin were tilted, uplifted and eroded, and the Southern Alps were rapidly uplifted, leading to rapid progradation of the Giant Foresets Formation that built up most of the modern continental shelf and slope (Hansen and Kamp, 2006).

The North Cape Formation was deposited from 72 to 70 Ma in a marine transgressive period before the basin was dominated by marine regression providing the terrestrial Kapuni group above the North Cape Formation. The thickness of this formation is up to 1500 m. (Thrasher, 1992). The North Cape Formation was dominated by shallow marine, shoreline and lower coastal plain depositional facies (Thrasher, 1992). The rocks consisted of light gray to brownish carbonaceous sandy siltstone and silty sandstone with minor conglomerate and coal of the Wainui Member (Roncaglia et al., 2013). The sediments present both fining upward and coarsening upward sequence, and gradually changed to mudstone in the Turi Formation (King and Thrasher, 1996). Seismically, the North Cape formation characterized by more chaotic seismic reflections (King and Thrasher, 1996).

3. Materials and Methods

This study focused on offshore exploration blocks in the Western Platform. Twenty wells, drilled deeply enough to analyst the North Cape Formation, are used to interpret physical properties of the formation (Figure 1). In this study, the major logs that are mainly used to do a petrophysical analysis are gamma-ray log, resistivity log, neutron porosity log and bulk density log. Manual facies analysis and well correlation are carried out on selected wells using Petrel software. Seismic data are used in this study for defining the sedimentary succession in the regional scale. However, only 2D seismic survey lines are used for key formation interpretation and correlation in this study.

Table 1. Summary of criteria used to interpret facies associations and specific facies (Higgs et al., 2012).

Level 1: Facies Association	*Log Character*	*Level 2: Facies*	*Log Character*
Coastal Plain	Often sandstone-prone with upward-fining to blocky log pattern and common high neutron and low-density spikes	Fluvial Channel	Sharp based, low API gamma log response, displaying a blocky to upward-fining log profile, and generally wide neutron-density separation
		Overbank	Generally moderate to high API gamma log response, with a common high neutron/low density spikes reflecting the presence of coals.
		Marsh/Floodplain	Serrate log profile showing the alternating high API gamma log response of mudstones and low API gamma, high neutron/low density spikes of coals.
Marginal Marine	Common serrate log character of interbedded sandstone and mudstone	Estuarine/ Distributary/ Tidal Channel	Sharp based, fairly low API gamma log response, displaying a blocky to upward-fining log profile. Neutron-density separation is wide to narrow, depending on abundance of mica/clay
		Beach/Back Barrier Bar/Tidal Sand Bar/Flood Delta	Upward-cleaning log profile, characterised by low to moderate API values and commonly narrow neutron-density separations.
		Tidal Sandflat/ Mudflat/ Embayment/ Lagoon	Variable log response, mostly characterised by high API gamma log response and a fairly serrated log profile.
Shallow Marine	Sandstone-dominated with coarsening-upward log profiles	Upper shoreface	Thick interval of low API gamma log response and wide neutron-density (sandstone) separation; generally forms the upper part of an upward-cleaning log profile.
		Middle Shoreface/	Thick aggradational packages of moderate API gamma log values that may form part of overall upward-cleaning

	Shoreline Mouth bar	log profile. Generally, very narrow neutron-density separations.
	Lower Shoreface	High API gamma log response forming bottom part of thick upward-cleaning (progradation) log profiles.

3.1 Depositional environment interpretation

Gamma ray log is utilized for depositional environment interpretation because it responses rock types and proportion of sand and clay contents (Kessler and Sachs, 1995). Commonly, gamma ray log is classified into five patterns (Cant, 1992). Cylindrical shape, distinguishing with the sharp top and bottom boundary, represents sediment deposits in aeolian, beach, fluvial channel, and submarine canyon environments. Funnel shape, characterized by upward decreasing of gamma ray response or coarsening upward sequence, can be interpreted as regressive barrier bar, prograding submarine fans, prograding deltas, and crevasse splays. Bell shape, characterized by fining upward sequence, indicates transgressive sand or shoreline shelf system. Symmetric shape, showing a gradually coarsening upward sequence in the bottom and a fining upward sequence in the top, represents progradation and retrogradation of clastic sediments and might be seen in shallow marine environment which is dominated by sea level change. Lastly, irregular shape, showing the fluctuation of gamma ray, represents laminated beds of various rock types in sedimentary successions. It might be described as a fluvial floodplain, storm-dominated shelf, tidal flat, and distal deep-marine slope. In this study, three facies associations and nine specific facies are identified by using criteria in Table 1.

4. Results

4.1 Well log correlations

Sediments deposited in different environments usually exhibit in various rocks and properties, showing in different log patterns. Therefore, well log characteristics can be used to classify sedimentary formations leading to regional stratigraphic interpretation of the study area. The sedimentary strata can be divided into 5 units based on well log characteristics as presented in Table 2 in order to correlate with key sedimentary formations in the study area as presented in Figure 3.

Unit A has a high gamma ray value and could be interpreted that the lithology of this formation has a high shale proportion. High resistivity values could be interpreted that this formation may be filled by hydrocarbon or the lithology of this formation is very tight resulting that brine water could not be filled in this formation. Neutron and density logs indicate low density and high neutron porosity. These properties indicate that this formation is probably a carbonaceous shale which could be a source rock of the basin. Comparing with King and Tresher (1996), this formation could be correlated to the Rakopi Formation.

Unit B, gamma ray has a serrated log pattern with low values indicating that sediments deposited in this formation have more sand contents compared with surrounded strata. Average resistivity of this formation is lower than those of unit A. It might be interpreted that rocks in this layer are looser than unit A. There are some peaks of resistivity in the formation which may related to the existence of hydrocarbon. Moreover, neutron and density logs come closer and crossover in some depth. From all these log characters, this succession might be dominated with sandstone and could be correlated to the North Cape Formation.

Unit C has a high gamma ray value and could be interpreted that it has high clay mineral contents. The low resistivity might relate to high water proportion in the formation. Density and neutron logs are significantly separated. All these log characteristics could be interpreted that the lithology dominated in this formation is probably shale and can be correlated to the Tui Formation.

Unit D is the key formation for marker picking in this study area. This unit exhibits very low gamma ray and high resistivity values. It is identified as carbonate beds in the Tikoranki Formation which is deposited throughout the basin. Thus, it is suitable to be a key formation for regional correlation.

In Unit E, gamma ray log exhibit serrated pattern with overall high values indicating high clay mineral contents. Neutron and density logs are separated even though it is not apparently like in the Unit C. It could be analyzed that this unit is related to shale in the Manganui Formation.

Table 2. Log characteristics of rock units in deep water Taranaki basin from this study.

Unit	*Gamma Ray*	*Resistivity*	*Neutron-Density*	*Correlation*
A	High	Very high	Shift to the left side	Rakopi Formation
B	Low	Fluctuated	Come closer and crossover	North Cape Formation
C	High	Steady low	Significantly separate	Turi Formation
D	Low	Steady high	Shift to the right side	Tikoranki Formation
E	High	fluctuated	Separate	Manganui Formation

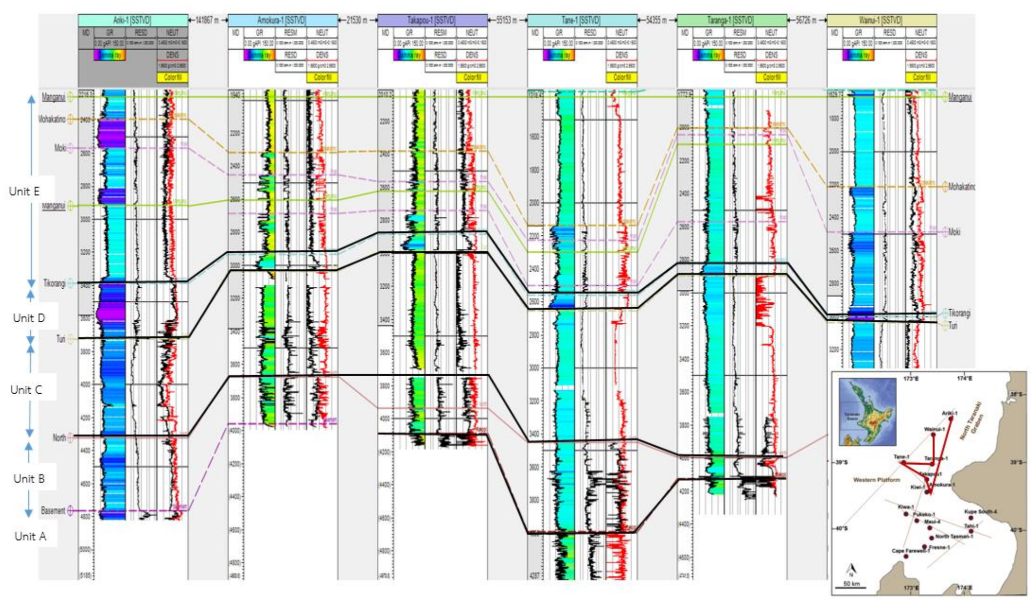

Figure 3. Well correlation of six wells in this study shows a regional correlation and key formations.

4.2 Depositional Environment

This study emphasizes depositional environment and reservoir properties of the North Cape Formation. From the patterns of gamma ray, resistivity, neutron and density responses, it could be interpreted that shale and sandstone are dominated in the North Cape formation. Carbonaceous shale and calcareous sandstone are found as minor proportions in this formation. Based on lithology of these rocks (sandstone, shale, carbonaceous shale and calcareous sandstone), this formation represents shallow marine environment which comprises coastal plain and marginal marine. The example of the common sedimentary facies and depositional environment of the formation within coastal plain and marginal marine found from well log data are shown in Figure 4. Regional correlations of the North Cape Formation are shown in Figures 5 and 6 representing a variation in depositional environments

4.3 Porosity analysis

Due to the complex lithology of the North Cape Formation, neutron-density cross plot method is used to identify porosity of sandstone in this formation. In each well, neutron and density data are plotted with gamma ray log. It could be classified that dark blue scatters with low gamma ray values are limestone having low porosity. Whereas, sandstone is represented in blue color with medium gamma ray values having about 20 percent of porosity. Shale is characterized by high gamma ray value with low bulk density. The results of cross plot of each well from the North Cape Formation are shown in Figure 7. From Table 3, the porosity of sandstone in the North Cape Formation is approximately 10-27 percent. Amokura-1 and Tane-1 wells have highest porosity ranging from 15 to 27 percent, while the wells that have lowest porosity are Taranga-1, Ariki-1 and Fresnel-1 ranging from 10 to 17 percent.

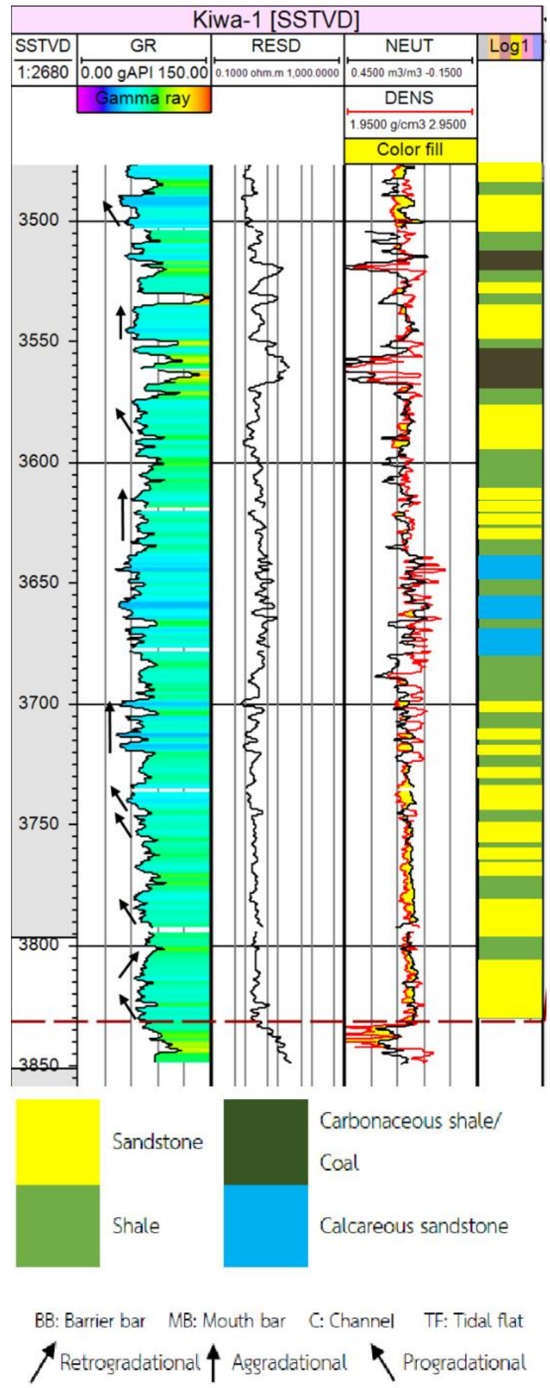

Figure 4. The example of lithology and depositional environment interpretation from North Kiwi-1 well.

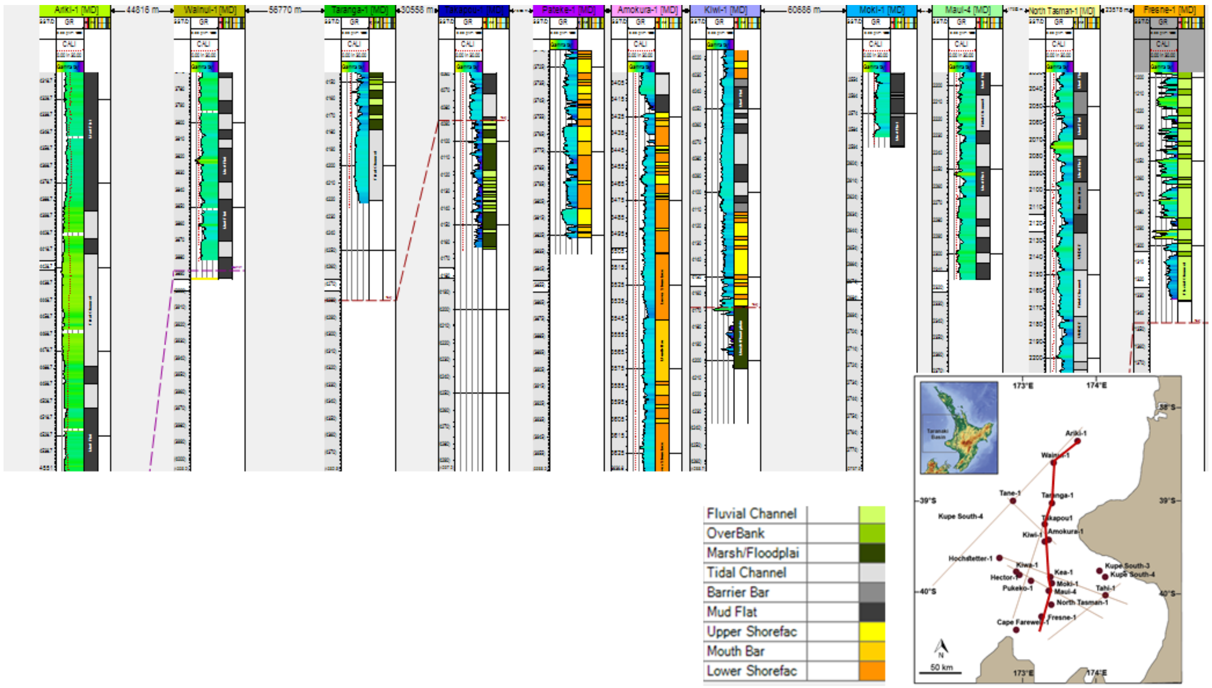

Figure 5. N-S well correlation represents depositional environment of the North Cape Formation.

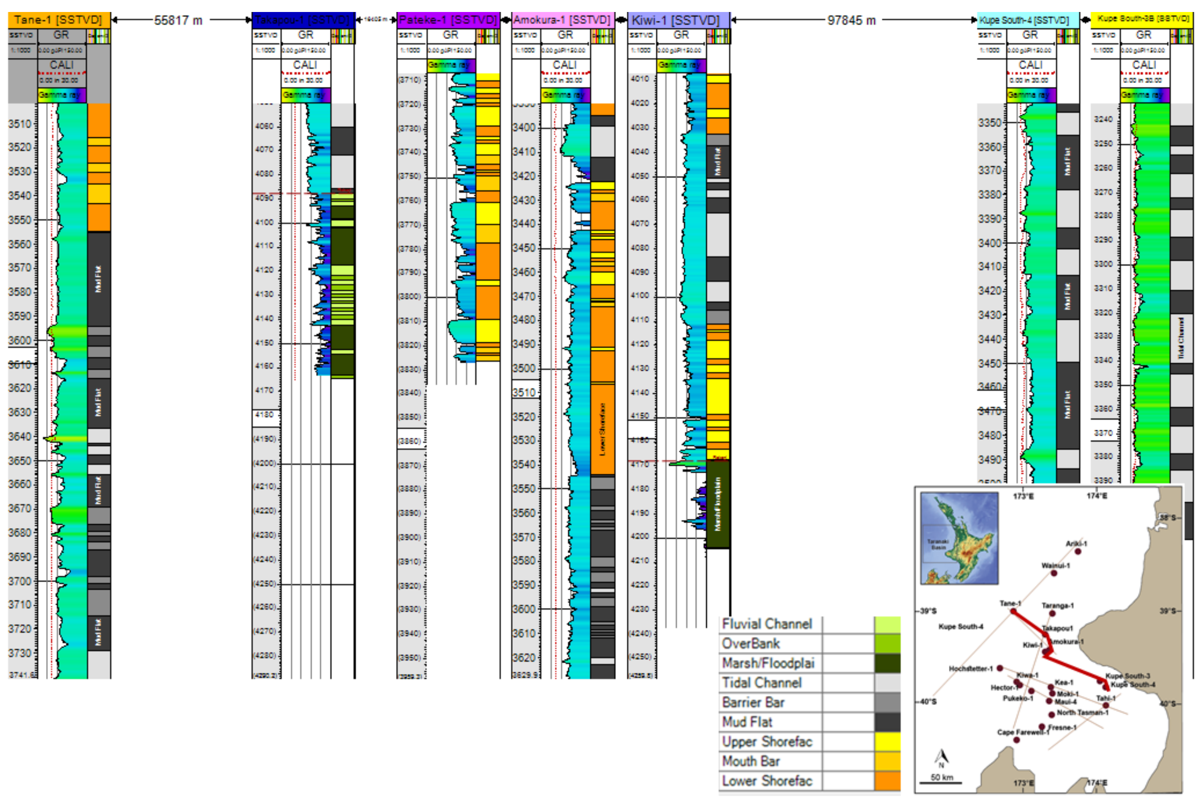

Figure 6. W-E well correlation represents depositional environment of the North Cape Formation

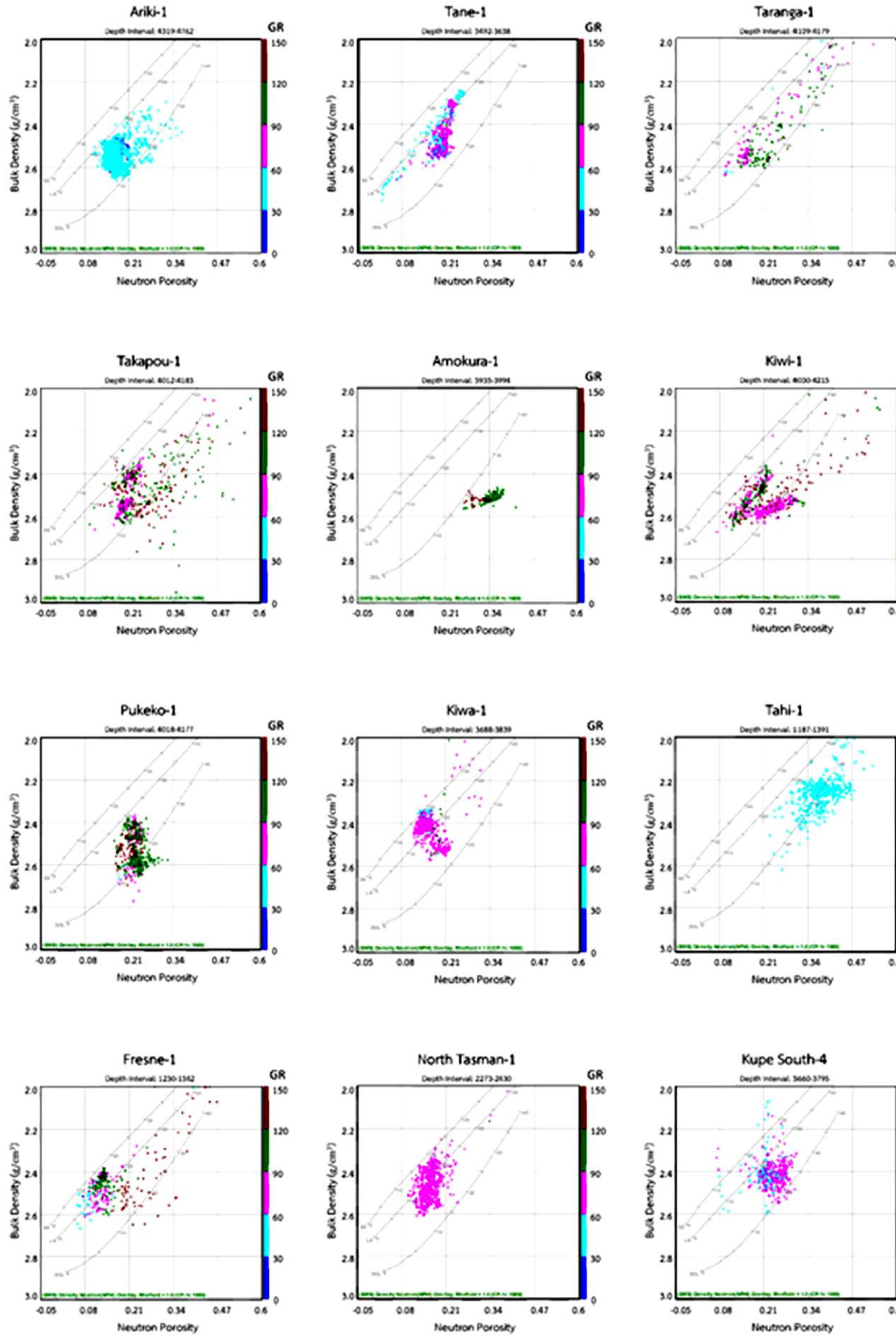
Ariki-1
Tane-1
Taranga-1
Takapou-1
Amokura-1
Kiwi-1
Pukeko-1
Kiwa-1
Tahi-1
Fresne-1
North Tasman-1
Kupe South-4
GR
150
120
90
60
30
0
Bulk Density (g/cm³)
2.0
2.2
2.4
2.6
2.8
3.0
Neutron Porosity
-0.05
0.08
0.21
0.34
0.47
0.6

Figure 7. Neutron-Density crossplot of wells used in this study. The scattering points come from depth interval of the North Cape Formation. The graphs are used to estimate porosity of sandstone in the formation by comparing with standard lines. Color refer to r

Table 3. Porosity of sandstone in the North Cape Formation

Well Name	*Porosity (%)*	*Well Name*	*Porosity (%)*
Amokura-1	18-20	North Tasman-1	11-20
Ariki-1	10-17	Pukeko-1	13-22
Fresnel-1	10-17	Takapou-1	12-20
Kiwa-1	14-20	Tahi-1	15-20
Kiwi-1	13-21	Tane-1	15-27
Kupe South-4	18-23	Taranga-1	12-18

4.4 Permeability analysis

Generally, actual permeability mainly comes from direct measurement of rock or cores samples. Indirect permeability measurement uses the relationship equation between porosity and permeability as a poroperm crossplot. In this study, permeability data come from well completion report of Cook-1, Pukeko-1, Tahi-1, and Tane-1 wells. The crossplot shows a high degree of sampling distribution, thus the relationship of the poroperm crossplot can be divided into two groups with different trend lines. The group of sandstone with low permeability has a poroperm trend line with this following equation:

$$\text{Permeability} = 0.008e^{0.3193\,(\text{porosity})} \quad \ldots\ldots\text{Eq. 4-1}$$

Whereas, the group of sandstone with high permeability has a poroperm trend line with this following equation:

$$\text{Permeability} = 0.3728e^{07138(\text{porosity})} \quad \ldots\ldots\text{Eq. 4-2}$$

These equations were used for permeability calculation by input porosity from neutron-density crossplot as presented in Table 4.

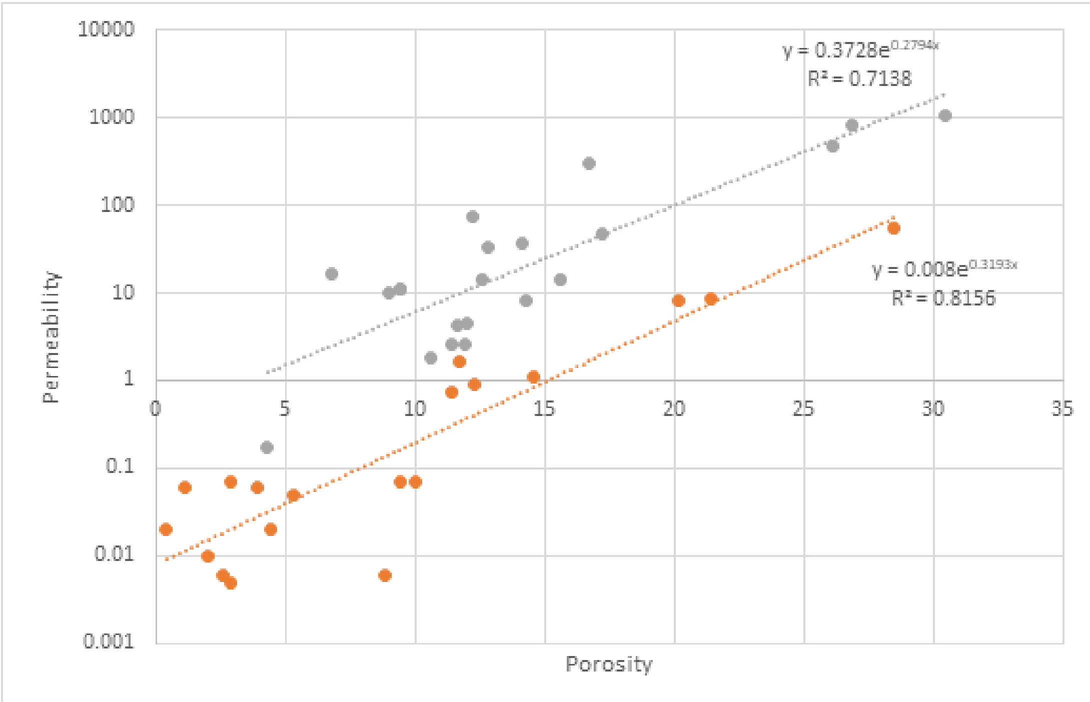

Figure 8. Porosity-permeability crossplot from Cook-1, Pukeko-1, Tahi-1, and Tane-1 wells showing relationship the relationship equation between these two properties.

Table 4. Permeability calculated from porosity by equation 4-1

Well Name	*Porosity (%)*	*Permeability (Eq. 4-1)*	*Permeability (Eq. 4-2)*	*Well Name*	*Porosity (%)*	*Permeability (Eq. 4-1)*	*Permeability (Eq. 4-2)*
Amokura-1	18-20	56.94-532.56	56.94-532.56	North Tasman-1	11-20	0.27-4.75	8.06-99.61
Ariki-1	10-17	6.09-43.08	6.09-43.08	Pukeko-1	13-22	0.51-8.99	14.09-174.18
Fresnel-1	10-17	6.09-43.08	6.09-43.08	Takapou-1	12-20	0.37-12.37	10.66-230.32
Kiwa-1	14-20	18.63-99.61	18.63-99.61	Tahi-1	15-20	4.75-12.37	99.61-230.32
Kiwi-1	13-21	14.09-131.72	14.09-131.72	Tane-1	15-27	0.96-44.38	24.61-704.22
Kupe South-4	18-23	56.97-230.32	56.97-230.32	Taranga-1	12-18	0.37-2.51	10.66-56.97

4.5 Seismic interpretation

Eight 2D seismic lines are used to interpret structure and depositional characteristics of the successions. The chaotic seismic reflections at the bottom of the seismic section are interpreted to be basement rocks. Above the basement rocks, the Rakopi Formation is characterised by high amplitude and discontinuous reflections. This formation is overlaid by the North Cape Formation and Tane member characterized by low to moderate amplitude reflections. The Turi Formation exhibits low amplitude and continuous reflections. The limestones of the

Tikoranki and Ariki Formations have high amplitude and discontinuous reflections. The Giant Foresets Formation is very vivid with a clinoform package due to progradation of sediments from the continent to an offshore area. All of these formations are overlaid by recent sediments which are represented as parallel and continuous reflections.

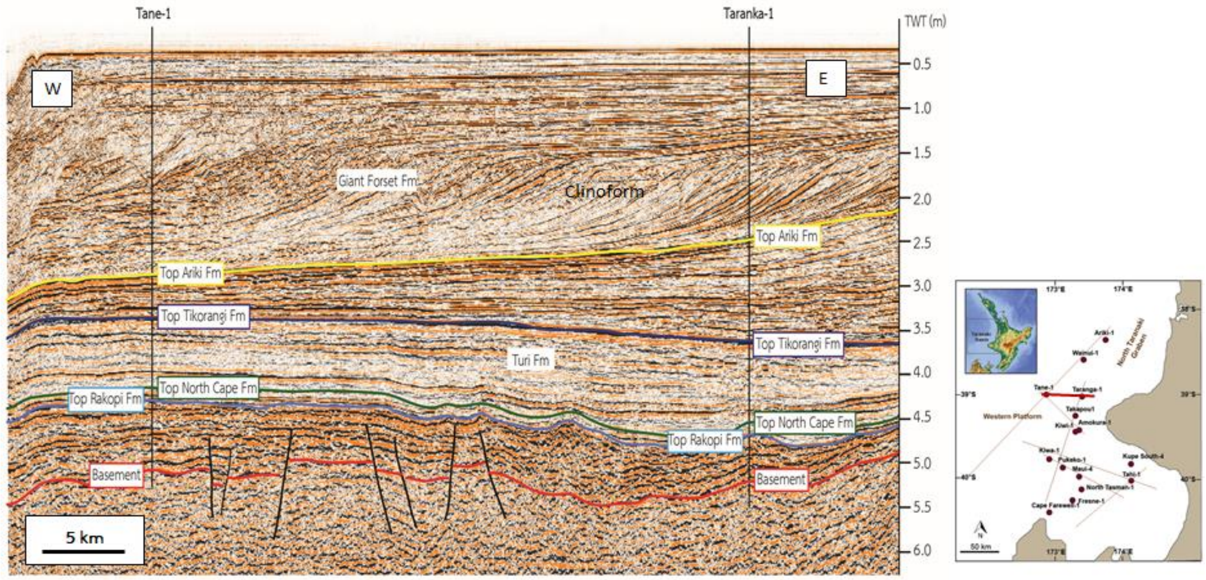

Figure 9. 2D seismic interpretation of line SUN with well top formations shows clinoform geometry of the Giant Foreset Formation.

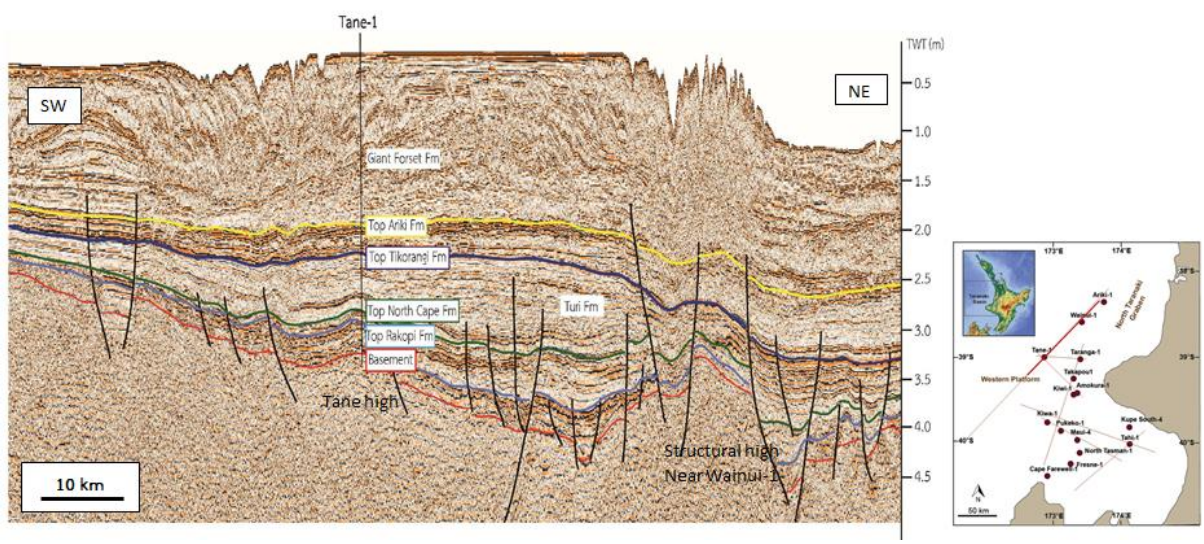

Figure 10. 2D seismic interpretation of line DTB01-32 with well top formations shows sedimentary successions parallel to the Taranaki Peninsula.

5. Discussions

5.1 Depositional Environment of North Cape Formation

From well log interpretation, the North Cape Formation succession consists of four main rock types: sandstone, calcareous sandstone, shale, and carbonaceous shale. Sandstone and shale are main rocks of the formation. Carbonaceous sandstone and Calcareous shale are possibly deposited in transitional zone. In addition, gamma ray log shape used for depositional environment interpretation shows that the most common log shape found in this formation is funnel shape. This log shape relates to a coarsening upward sequence indicating barrier bar sandstone. The presence of sandbars can be indicated a marginal zone. Moreover, the shale ratio of the formation is increased from the bottom to the top of the succession which could be explained that the formation deposits in marine transgressive period. This interpretation was supported by the presence of dinoflagella and marine algae fossils in sediments of the North Cape Formation (Wizevich et al., 1992). The sediment structure such as cross-bedding, mud-draped, bidirectional cross-lamination and bioturbation which indicated marginal environment are also presented in outcrops (Terwindt, 1988).

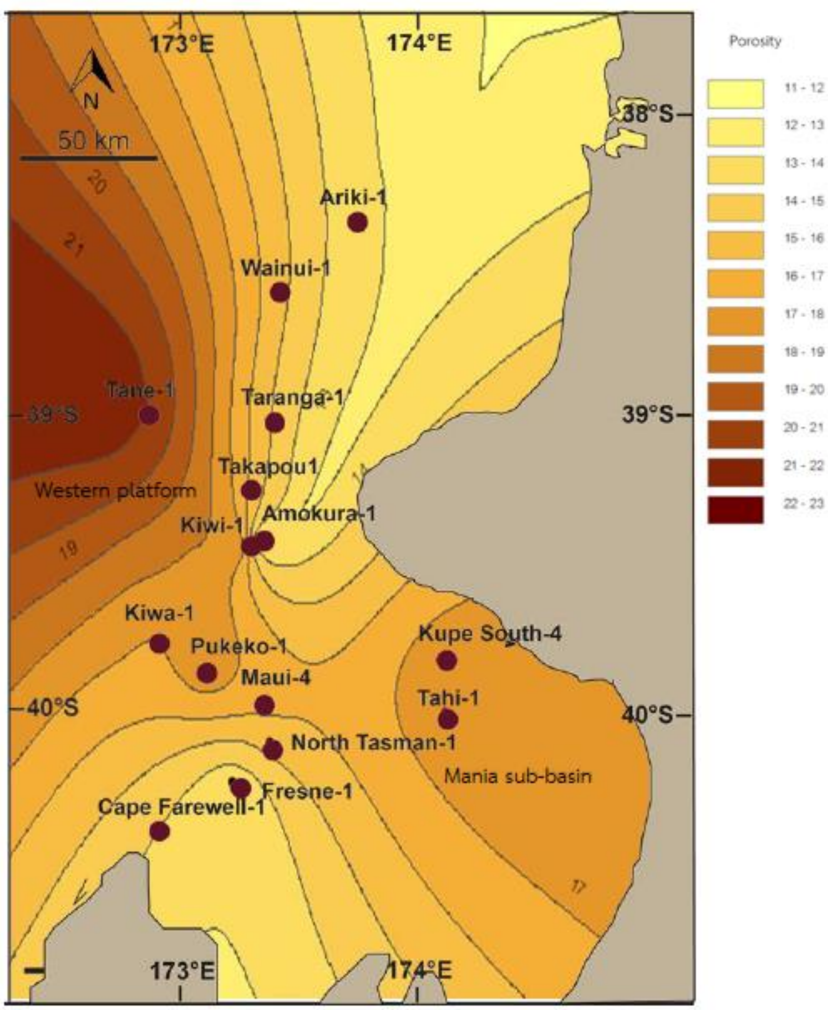

Figure 11. Porosity contour map of sandstone in the North Cape Formation.

5.2 Reservoir Properties

The reservoir properties of sandstone in the North Cape formation are calculated from the neutron-density cross plot and petrophysical analysis. The sandstone in this formation has a porosity between 10 and 27 percent. Porosity can be used to characterize the reservoir quality, thus sandstone in this formation is a fair to very good reservoir which means that this sandstone has potential to become a petroleum reservoir in the Taranaki basin. However, the porosity varies within different wells and can be divided into two zones. First zone includes Tahi-1 and Kupe-1 wells in Mania sub-basin having approximately porosity of 15-20 percent. The other high porosity zone includes Tane-1, Kiwa-1, Kiwi-1, and Pukeko-1 wells in the Western Platform having approximately porosity of 17-22 percent. From the porosity contour map (Figure 11), the porosity of sandstone in this formation increases basinward. Therefore, sandstone of the North Cape Formation within the deepwater area, which is a majority of the basin, might has high porosity and could be a good to very good reservoir for petroleum exploration.

From gamma ray log patterns, the North Cape Formation consists of barrier bar sandstone, channel sandstone and tidal flat sandstone. Sandstones form different depositional environments are plotted to observe the relationship between depositional environment and porosity (Figure 12). The graph shows that barrier bar sandstone has significantly high porosity compared to channel and tidal flat sandstones. The variation of porosity might be related to heterogeneity of sandstone in different depositional environments. Barrier bar sandstone deposits in high energy environment and usually provides clean sandstone or sand prone. Channel sandstone in the North Cape Formation might be deposited as a distributary or tidal dominated channel in the marginal zone. The channel sandstone having fair to good reservoir quality may be influenced by fine-grained sediments within low-energy tidal environment. Tidal dominated environment is characterized by a high degree of heterogeneity. Therefore, the porosity of barrier bar sandstone in the North Cape Formation is higher than the other environments.

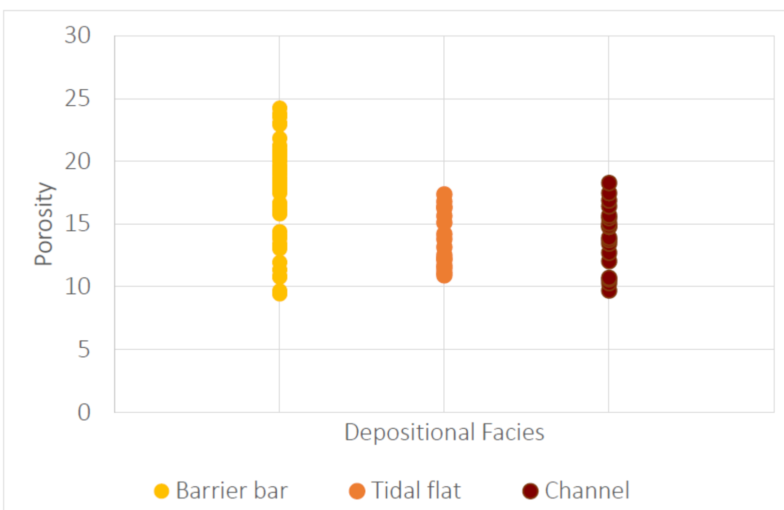

Figure 12. Relationship between depositional facies and pososity of sandstone in the North Cape Formation.

5.3 Overburden Sediment and Reservoir Properties

Overburden sediments affect the secondary porosity of the sandstone. Feldspar which composed of the rocks could be alternated to be clay minerals and fill in pore spaces decreasing in porosity (Morris and Shepperd, 1981). Moreover, overburden sediment weight can induce compaction of the underlying rocks resulted in lowering of the reservoir properties by reducing porosity in a formation. Another cause of reducing porosity in sandstone is clay minerals within formation. The reducing porosity is significant in kaolinite and chlorite, while illite-smectite is likely not appeared in this area. Kaolinitisation is often appeared in an early diagenesis phase. While chlorite is usually found in late diagenesis or early metamorphic rocks (Galán, 2006; Wilkinson et al., 2006). Wells located far from the Taranaki peninsular such as Wainui-1, Tane-1 and Taranga-1 show high percentage of kaolinite and little to no chlorite presented in the formation. Whereas, Kupe south-4, Pukeko, and Tahi-1 wells located near the present day marginal area show high percentage of chlorite. It could be concluded that the degree of compaction of sandstone in the North Cape Formation of wells located far from the marginal zone is lower than well located near the marginal zone.

Seismic data are used to interpret the deposition of the overburden sediments. Seismic data show a thick sedimentary package of clinoform geometry of the Giant Forsets Formation. Delta progradation of the Giant Forsets Formation is deposited from east to west of the basin. Seismically, the Giant Foreset Formation extension is approximately 200 km from the Taranaki peninsular. The rapid sediment loading and thick overburden delta could affect compaction and diagenesis of the North Cape Formation. Thus, the North Cape Formation sandstone away from the peninsula might has low degree of compaction and good reservoir properties.

6. Conclusions

The North Cape Formation consists of sandstone, calcareous sandstone, shale and carbonaceous shale. Sediments in this formation deposited in shallow marine environment during a marine transgressive period. The most common depositional environment of sandstone in the formation is barrier bar. Porosity analysis from neutron-density crossplot indicates that sandstone in the North Cape Formation has approximately 10-27 percent of porosity providing a fair to very good reservoir. Permeability of sandstone in this formation is up to 700 mD. The porosity contour map demonstrates that the porosity of sandstone in this formation is increased basinward. The factors controlling porosity of sandstone are believed to be depositional environment and degree of compaction. This study indicates that barrier bar sandstone has the highest porosity compared to channel and tidal flat sandstones. Seismic data show progradation of overburden sediments from the Taranaki peninsular leading to different compaction delta progradation.

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