Shale Oil/Gas: A New Opportunity for New Zealand?

By

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ABSTRACT

Within New Zealand the East Coast Basin encompasses the primary shale oil and gas (unconventional) play areas in which both the Waipawa and Whangai formations are widespread. These formations are oil and gas prone and prevalent throughout a large area of the East Coast Basin. To characterise these two formations and evaluate their shale oil and gas potential, existing analytical results were supplemented by a set of new sample analyses of organic and inorganic geochemistry, and rock properties. Thus, some 242 samples from the Whangai Formation have organic geochemical analyses and 40 have inorganic geochemical analyses; for the Waipawa Formation there are 149 organic and 9 inorganic geochemical analyses. In addition, downhole logs from three exploration wells have been used to calculate the brittleness index of the Whangai Formation. All these data have been grouped by structural block and used to determine where the sweet spots are in each formation. Both basic and more robust statistical analysis (machine-learning) is applied to identify the best prospective area. The Rakauroa Member (Whangai Formation) and the Waipawa Formation have the best rock characteristics as unconventional reservoirs, based on quantity and quality. Maturation appears to be an issue for these formations, although there are some localised areas where the Whangai Formation has better maturity. The brittleness index is calculated only for the Rakauroa Member, given the lack of data available for other members of the Whangai Formation and the Waipawa Formation, and yielded promising results. The Motu block appears to be the best area in which to explore for unconventional oil and gas. The prospective resource volumes for the best case scenario for the Whangai (Rakauroa Member) and Waipawa formations combined in the Motu Block are 17% higher (713MMbbl) than the 2P (proved + probable) reserves of New Zealand for oil and condensate (588MMbbl) and 26% (2.1TCF) of the 2P (proved + probable) reserves of natural gas (7.8 TCF). Economic analysis shows feasibility to explore these unconventional reservoirs for both shale oil or shale gas with an oil price of US\$60 for both methodologies tested. However, the methodology applied using standard shale oil and gas assessments shows feasibility only for shale oil. Shale gas would not be economic, unless a higher oil prices, lower costs or a technology was developed to improve the recovery factor of these reservoirs. These results indicate a minimum economic field size of 4.5 km² for this area.

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Source: The search
Personal photograph collection surfing in Sumatra
Go confidently in the direction of your dreams.
Live the life you have imagined”
Henry David Thoreau
(1817 - 1862)

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1. INTRODUCTION

Natural oil and gas resources are most commonly divided into two categories: conventional and unconventional. Conventional oil and gas are typically found in reservoirs with permeabilities greater than 1 millidarcy (“mD”) and can be extracted via traditional techniques. A large proportion of the globally produced oil and gas to date is conventional, and is relatively easy and inexpensive to extract. In contrast, unconventional oil and gas are found in reservoirs with relatively low permeabilities (less than 1 mD) and therefore cannot be extracted via conventional methods (section 2.2).

There are several types of unconventional gas resources that are produced today. The three most common types are tight gas, coal bed methane (CBM) and shale gas. Given the low permeability of these reservoirs, in order to be produced commercially the gas must be developed via special techniques including fracture stimulation (“fracking”) and horizontal wells (Law and Curtis, 2002).

The first shale gas well in the U.S. commenced production in 1821 from a well near Fredonia, New York. Low levels of shale gas production occurred between this period and the turn of the century. However, only as recently as 2006 did the shale gas industry in the U.S. start to gain significant momentum and became financially viable.

Shale gas technology was largely pioneered in the U.S. The emergence of U.S. shale gas plays dramatically increased their proven reserves in the period of 2006-2011, thereby altering the domestic natural gas supply curve (U.S. EIA, 2012). In 2012, oil and gas exploration and production companies operating in the U.S. added 4.5 billion barrels of crude oil and lease condensate proved reserves, an increase of 15.4% from 2011, the largest annual increase since 1970. U.S. proven reserves of crude oil and lease condensate have now risen over four consecutive years. Proven reserves of oil also exceeded 33.4 billion barrels for the first time since 1976. However, proved reserves of U.S. wet natural gas decreased 7.5% (a loss of 26 trillion cubic feet) to 323 trillion cubic feet in 2012. The 2012 decline interrupted a 14-year trend of consecutive increases in natural gas proven reserves, rebounding a year later (Figure 1.1). U.S. proven reserves of natural gas declined in 2012 because of low natural gas prices. Total discoveries of oil and natural gas proven reserves both exceeded U.S. production in 2012, with the largest discoveries occurring onshore within the lower 48 states (Figure 1.2). With the increasing gas demand and proven concepts by Americans and Canadians, other

countries like China, Argentina, and the UK have started exploring unconventional shale gas resources (U.S. EIA, 2012).

The oil and gas industry in New Zealand, although with significant gas production since the early 1970s, is still in an incipient phase and could follow a similar steep growth trajectory. This research targets a niche opportunity that is already well developed in the U.S. and Canada. Unconventional exploration practices have only just commenced in the exploration and production (E&P) community in this country. In light of both model transferability and emergent worldwide demand, the potential of shale oil and gas economic volumes in the East Coast Basin (ECB) of New Zealand is worthy of deeper analysis.

The East Coast Basin has been the focus of hydrocarbon exploration for over one hundred years, due mainly to the encouragement given by numerous surface oil and gas seepages. Up until the early 1900s, exploration activity was confined to the drilling of shallow wells (< 500m) in the vicinity of natural oil seeps. The following period until 1941 saw a number of wells drilled to greater depths (up to 2000m) on structures identified by geological surface mapping. From 1957 geophysical prospecting techniques were applied to the area, and between 1960 and 1976 several wells were drilled, including one offshore well (Hawke Bay-1), on structures primarily defined by seismic (McQuillan, 1983). In the last 15 years, 14 wells were drilled by many different companies, mainly targeting Neogene limestones and sandstones, although a few wells targeted Upper Cretaceous sandstones. Since 2012, Tag Oil and New Zealand Energy Corporation (NZEC) have been looking for unconventional opportunities in two units thought to have shale oil and gas potential: the Whangai and Waipawa formations. Previous studies have been done on these two formations, evaluating their petroleum geochemistry. Fry (1982) has demonstrated the potential of Waipawa Formation as a source rock and Jackson (1982) for the Whangai and Waipawa formations. Moore (1987) defined the Waipawa Formation as having a very high generative potential and the Whangai Formation little potential. Both Hirner and Lyon (1989) and Rogers et al. (1999), Rogers et al. (2001), and Sykes et al. (2012) have characterised the oil and gas seeps along the East Coast Basin. Rogers classified these hydrocarbons as having two different families based on biomarker and stable carbon isotope analyses. Leckie et al. (1992) and Hollis and Manzano (2005) also characterised the Whangai and Waipawa formations as a potential source rock of the East Coast Basin. These are the main studies for prospecting these two units.

The East Coast Basin encompasses the primary play areas in which both the Whangai and Waipawa formations are widespread. These oil- and gas-rich formations are widespread

throughout a large area of the East Coast Basin, and are comparable in total organic carbon content and oil and gas maturity levels to such successful shale oil and gas plays as the Bakken Formation of North America's prolific Williston Basin and the Barnett Formation in East Texas. Furthermore, measured primary total porosities in both the Whangai and Waipawa formations are favourably in the 22-30% range, well above what is typically found in the Bakken or Barnett. Both the Waipawa and Whangai formations, where Waipawa has a higher source potential, have always been viewed as rich, high-quality source rock, however production was not considered viable until the success of the Barnett shale (Tag Oil, 2013).

Given the North American proof of concept, now is the time to increase both economic and technical scope by evaluating these shale rock formations, possibly justifying the development of this market in New Zealand. To do so, we must investigate the likely development of “sweet spots” based on existing and new analyses obtained as part of this study. There are 242 existing sample localities within the Whangai Formation that have been assessed by organic geochemistry and 40 that have been assessed by inorganic geochemistry, and there are 149 organic and 9 inorganic geochemistry assessment localities within the Waipawa Formation (GNS Science and new dataset). Three exploration wells already drilled in the East Coast Basin will also be analysed (Opoutama-1, Rere-1, and Hukarere-1). These are the only wells that reached these geological formations in subsurface and produced reliable data for analysis. In addition to these existing analyses, new rock samples will also be analysed for organic and inorganic geochemistry and rock properties as part of this study. Using these data, a statistical model is developed here in order to identify the sweet spots and predict the economic feasibility of undiscovered shale oil and gas deposits.

Distinct contrasts in the stratigraphy and structure in the East Coast Basin were recognised and utilised by Moore et al. (1986) and Moore (1988a) to propose structural subdivisions, which he called blocks. These subdivisions are grouped into the Western Sub-belt and the Eastern Sub-belt. Following the zonation of Moore (1988a) the North Island East Coast Basin can be broadly divided into seven distinct structural blocks (Figure 1.3). Five of these seven structural blocks (Tora, Coastal, Pongaroa, Motu and Allochthon) have already had measured sections logged through the target formations. The Woodville and Aorangi blocks are not being evaluated as a potential area because the exploration well results to the West of the Waewaepa-Oruawharo fault in Southern Hawke's Bay, where Pliocene or Upper Miocene strata overlie metasedimentary “basement” directly, showed the absence of any Upper Cretaceous to Oligocene formations. The goal of the present study is therefore to take the most complete measured sections, one per structural block (Figure 1.4), covering both upper and

lower units of the three main members of the Whangai Formation (Rakauroa, Porangahau and Upper Calcareous) together with the upper and lower units of the Waipawa Formation. Results are added to the GNS Science dataset to characterise the reservoir quality and its fracturability (organic and inorganic geochemistry, and geomechanical properties). From this combined data, a statistical model is developed (machine- learning) in order to identify the sweet spots and predict the economic feasibility of undiscovered shale oil and gas deposits. This new method is applied in the East Coast Basin as a case study.

Figure 1.1 The increase of oil and lease condensate proved reserve and the 2012 decline interrupted a 14-year trend of consecutive increases in natural gas proved reserves.

Figure 1.2 Map showing the 48 lower states of shale gas/oil occurrence.
(http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm)

Figure 1.3 Location and structural divisions of the East Coast Basin, New Zealand. Distribution of outcrops, basement and cover sequence shown, along with location of Cretaceous volcanic units. Modified after Moore (1988a), Crampton et al., (2003) and Adams et al., (2013).

Figure 1.4 Location of the eight measured sections distributed across the structural blocks (sub-division after Moore, 1988a & b), and the three exploration wells that will be used in addition to the existing data to identify the “sweet spots” in the basin.

1.1 Objectives of this thesis

Data used in this investigation includes: cores collected by this author from the outcrops of eight known measured sections along the East Coast basin and also extensive datasets from the public domain, which includes 2D seismic, exploration wells and rock sample analysis.

These data have been analysed with the overall goal of identifying and understanding where the sweet spots¹ of the Whangai and Waipawa geological formations occur.

The three main aims of this thesis are:

1. To characterize the Whangai and Waipawa geological formations vertically and horizontally in order to identify where the most likely hydrocarbons prospective sweet spots are in the basin;
2. To calculate more accurately the volumetric and economics relating to these unconventional targets; and
3. To determine the size and location of exploration blocks the government should release in future block offer bidding rounds in order to maximise exploration efficiency and returns to NZ.

1.2 The significance of this thesis

Given the lack of in-depth studies in New Zealand on shale oil and gas, the lack of economic feasibility understanding related to its exploration and the potential of finding a new energy matrix for this country, this project aims to identify the location of sweet spots in the East Coast Basin, by applying a multi-disciplinary approach. The five key questions this study intends to answer are:

1- Is there a Whangai/Waipawa sweet spot in the East Coast Basin?

When we talk about unconventional resources, we have to bear in mind that the exploration scale is different compared to conventional resources. Unlike a conventional trapping prospect, the source rock generally occurs in a wider area over the basin. The source rock that forms this new concept has to have basically two main characteristics; easy brittleness and good rock quality. It is also important to have the control of the macro and micro scale of the stress/strain field. When we identify where all these characteristics occur together, we have identified the sweet spots.

¹ Sweet spots in shale reservoirs may be defined by source-rock richness or thickness, by natural fractures, or by other factors, using geological data such as core analysis, well log data, or seismic data .
(<http://www.glossary.oilfield.slb.com/en/Terms.aspx?LookIn=term%20name&filter=sweet%20spot>).

2- Can these formations be produced?

Once the sweet spot is identified, we have to make sure that we can produce hydrocarbons from it. Using a known methodology of rock analysis, we can potentially forecast whether these rocks would or would not produce hydrocarbons.

3- What is the best analogue of Whangai and Waipawa formations worldwide?

New Zealand is in its infancy on this subject, therefore we have to identify worldwide, whether and where we could find an analogue. Using a methodology known as machine-learning we can establish if there is a good analogue for these two geological formations (Whangai and Waipawa).

4- How do we calculate the minimum economic volume to be exploited from the ground?

This is a key industry question. In order to answer that, we shall bring some worldwide analogue information to help us understand key parameters, such as: drainage areas, recovery factors, wells per pad and so on. Thus, with the area, thickness, rock characteristics and the analogue to provide the missing data of these unconventional rocks we should be able to calculate their volumetrics and feasibility.

5- What the size do the exploration blocks need to be, to be offered in the future Bid Rounds?

Calculating the volumetrics and economics, we should be able to come up with the size and location of exploration blocks that the government should release in future block offer bidding rounds.

The end result of this work is to assess the technical and economical potential of developing the shale oil and gas market in New Zealand, using the East Coast Basin as a case study. To do so, a sequence of analyses was taken as seen in the flowchart below (Figure 1.5):

Figure 1.5 The main steps done to achieve the goals of this study.

1.3 Thesis structure

Chapter 1 Introduces the thesis. **Chapter 2** presents a general review of the main concepts underlying conventional and unconventional exploration and discusses shale oil and gas in New Zealand. **Chapter 3** describes the geological settings of the East Coast Basin, focusing on the Whangai and Waipawa formations. **Chapter 4** describes the previous rock dataset, the new dataset collected for this thesis, and the methodology applied to the rock samples in order to achieve the main goals of this study. **Chapter 5** uses the East Coast Basin as a case study to test and compare results from a basic analysis and a new statistical method known as machine-learning, looking to establish where sweet spots will be identified. **Chapter 6** explains how volumetric assessment will take place in the sweet spot area and a feasibility study undertaken. **Chapter 7** discusses the economic factors affecting shale oil and gas production in the East Coast Basin. **Chapter 8** presents the conclusions achieved from this thesis and **Chapter 9** recommendations for future work.

1.4 Software used

Well analysis was performed using Kingdom Suite software. The analyses of the compressional and shear wave (V_p/V_s), were computed using Geoview-Hampson-Russell's software. The rock properties calculations were done using Model Builder from Baker Hughes and for the petrophysical analysis Teclog from Schlumberger. The sweet spots identification was performed using ArcGis software.

2. UNCONVENTIONAL (SHALE OIL AND GAS) RESERVOIRS

The purpose of this chapter is to discuss the history, shale properties, the main geological factors of shale rocks, the differences between conventional and unconventional reservoirs, and describe the main concepts of the production techniques in this type of reservoir.

2.1 HISTORY

The natural gas industry has its beginnings in the early 1820s, in Fredonia, New York, with the discovery and commercial development of gas from Devonian shales. Many shale gas fields were developed from Fredonia to Sandusky, Ohio, along the shoreline of Lake Erie (Figure 2.1). Data from these wells is limited, but were likely black shale formations were produced at Dunkirk, Rhinestreet, Middlesex, and to a degree the Marcellus (Harper, 2008). While gas flow rates were high to begin with, production was low and by today's standards hardly commercial at all. These were shallow wells supplying for domestic use and light industry. From the 1860s to the mid-1900s these were extensively developed. Thus, by the time of the famous Drake oil discovery in Titusville, Pennsylvania, in 1859, shale-gas development was already well begun in the Appalachian Basin.

The first major shale discovery in the Appalachian Basin was the Big Sandy Field in north-eastern Kentucky in 1921. Since then more than 21,000 wells have been drilled, mostly focused on the Upper Devonian Huron Shale, but also on the Cleveland, Rhinestreet, and Marcellus Shale intervals. Unlike some modern shale plays such as the Barnett, Fayetteville, and Haynesville shales which have higher pressure and lower density open fractures, this play is characterised by its underpressured profile and a well-established open natural fracture network. More than 2.5 tcf (Trillion Cubic Feet) have been produced from the Big Sandy Field (de Witt, 1986); furthermore, it remains one of the top 100 gas fields in the United States. The development of the Big Sandy Field continues using both vertical and horizontal drilling (Morris, 2008).

Figure 2.1 A map showing the historical trends of shale-gas production in the Appalachian Basin and the Marcellus Shale play trend (Zagorski, 2014).

George Mitchell, former head of Mitchell Energy and Development Corp., pioneered hydrocarbon production from shale formations. Mitchell developed unconventional drilling and completion technologies with the first successful application of horizontal drilling, micro-seismic imaging, and hydraulic fracturing applied to the Barnett Shale, enabling viable production. In 1998 Mitchell engineers used an innovative completion technique called “slick water fracturing” (or “light sand fracking”) that lowered fracture job costs from around \$250,000 to \$300,000 down to around \$100,000, making the unconventional resource commercially competitive. Commercial production rates climbed with the use of artificial fractures over existing open natural fractures. Mitchell’s unconventional development changed the future of the energy scenario in the United States, and may do similarly around the world. The success of the Barnett Shale in the 1990s began the U.S. shale gas revolution. Figure 2.2 shows the development trajectory since Mitchell showed that its fracking could produce reliable and economical oil and gas.

Production results were drastically improved with the exploration and production research in unconventional gas funded by the U.S. Department of Energy (DOE) and Gas Technology Institute (GTI), a consortium known as Gas Research Institute (GRI).

Figure 2.2 Brief history since Mitchell's innovation (modified from Stoneburner, 2013).

Since 2000, shale gas has become an increasingly important source of natural gas in the United States (Figure 2.3), with interest spreading around the world in the potential of shale gas. In 2000 shale gas provided only 1% of U.S. natural gas production; by 2010 it was over 20% (Figure 2.4), while the U.S. Government's Energy Information Administration predicts that by 2035, 49% of the United States' natural gas supply will come from shale gas (EIA, 2012). Some analysts expect that shale gas will greatly expand worldwide energy supply (Aguilera and Radetzki, 2013). China, for example, is estimated to have the world's largest shale gas resources (U.S. EIA, 2013), (Table 2.1).

Figure 2.3 The Shale gas contribution of the total natural gas production in USA (U.S. EIA, 2013).

Figure 2.4 United States natural gas production from 1990, and projected to 2035 (U.S. EIA, 2012).

Table 2.1 Top 10 countries with technically recoverable shale gas resources (U.S. EIA, 2012).

Rank	Country	Shale gas (trillion cubic feet)
1	China	1,115
2	Argentina	802
3	Algeria	707
4	U.S.	665
5	Canada	573
6	Mexico	545
7	Australia	437
8	South Africa	390
9	Russia	285
10	Brazil	245
World Total		7,299

Even though the shale oil and gas production and technology has been increasing from 2006 until 2014, following the expected learning curve, the collapse of the oil and gas prices in 2014 has slowed development, with the resulting decline curve characterising not only the unconventional market but the industry as a whole (Figure 2.5). In 2011, studies suggested that the high rates of decline of some shale gas wells were an indication that shale gas production may ultimately be much lower than is currently projected (Berman, 2011). Nevertheless, shale-gas discoveries are also opening up substantial new resources of tight oil ("shale oil") (Husain, 2013).

Figure 2.5 Schematic trajectory from the shale oil and gas boom and the oil price collapse.

2.1.1 Future

The International Energy Agency (IEA) has said that natural gas is poised to enter a golden age (IEA, 2012), if enough of the world's unconventional gas resources can be developed profitably and in an environmentally and socially acceptable manner.

Studies by the Department of Energy and Climate Change in the United Kingdom (2013) confirmed that life-cycle* greenhouse gas (GHG) emissions from shale gas are similar to those of conventional natural gas, and are much less and usually about half than those from coal; studies by Natural Resources Canada (2012) and a consortium formed by the U.S. National Renewable Energy Laboratory, with a number of universities (2012), conclude that life-cycle shale gas GHG emissions are much less than those of coal (Burnham et al., 2012). A contradictory view by Howarth and others of Cornell University concluded that shale gas GHG emissions were as high as those of coal, due to the escape of methane from shale-gas production to the atmosphere through venting and leaks over the lifespan of a well (Howarth et al., 2011). However, the Obama administration in the U.S. believed that increasing the shale gas development would help reduce greenhouse gas emissions as indicated in 2012 when U.S. carbon dioxide emissions dropped to a 20-year low (Carey, 2012). They believed that the world would benefit from shale gas replacing coal burning.

The IEA pointed that there is a chance that the greater availability of gas to drive down prices and lead to growth in demand of over 50% by 2035, would give gas a 25% share of the global energy market, and the second largest primary energy source after oil and ahead of coal. This would see annual production of unconventional gas – primarily shale gas – more than triple to 1.6 trillion cubic metres (60 trillion cubic feet) by 2035.

Increased unconventional shale gas production will secure energy supply in certain markets, but also bring complex challenges at global and local levels, regarding:

Climate change impacts as power generation moves to natural gas from other sources, and with methane emissions during production;

1. Concerns about the high volumes of water and “toxic” chemicals required for shale gas extraction, and associated risks of contamination, particularly to do with drinking water;
2. The effect of operations, including intense chemical use, emissions, waste and truck traffic, on the environment, biodiversity and ecosystems;

3. Social, cultural and economic consequences for local communities arising from operational factors (for example, landscape impacts, high volumes of truck traffic, and the influx of new workers), and the management of community expectations and concerns;
4. Operational challenges to companies arising from the scale and the cumulative impacts of multiple operators and contractors working in the one area; issues include coordination, and the anticipation and management of risks, including accidents and occupational health hazards;
5. The need for consistent and strong regulatory oversight of an industry with complex impacts, especially in territories with weak governance, corruption, and/or poor contractor management.

Most of these concerns and subjects will be discussed in this Thesis in the Chapter 7.

2.2 SHALE PLAY PROPERTIES

Shale is fine-grained sedimentary rock with a grain size less than 62 μm derived from clastic sources, including claystones, mudstones and siltstones, grouped together as “shale”. Clastic sedimentary rocks are composed of fragments (clasts) of pre-existing rocks that have been eroded, transported, deposited and lithified (hardened) into new rocks. Shales typically contain organic material which was deposited along with the rock fragments and is also typically fissile (Dow and O’Connor, 1982).

Shales contain soluble and insoluble organic matter (bitumen and kerogen respectively), the source material for hydrocarbon resources. The amount and maceral composition of kerogen determine petroleum potential and may differ vertically and laterally within a source rock. The three main maceral groups are liptinite (exinite), vitrinite, and inertinite (Stach et al., 1982).

Hydrocarbons are produced from the kerogen as the rock matures. Hydrocarbons may then migrate as liquid or gas, through fissures and fractures in the rock, eventually reaching the earth’s surface or else becoming trapped by impermeable strata. In a conventional reservoir, hydrocarbons accumulate in porous areas beneath these ‘traps’, frequently formed from carbonate or sandstone.

The diagram below shows how the gas-rich shale strata are typically the source rock for conventional oil and gas reservoirs (Figure 2.6).

Figure 2.6 Schematic geology of natural gas resources (U.S. EIA, 2012).

According to Jarvie 2012, shale oil and gas resources can be classified by their dominant organic and lithologic characteristics into three categories: (1) organic-rich mudstones with predominately no open fractures, if any (e.g. Barnett and Tuscaloosa shales); (2) organic-rich mudstones with open fractures (e.g. Monterey, Bakken and Bazhenov shales); and (3) hybrid systems with a combination of juxtaposed organic-rich and organic-lean intervals (e.g. Eagle Ford and Niobrara shales).

2.3 GEOLOGICAL FACTORS

2.3.1 Source rock quality

Total Organic Carbon (TOC) is the total amount of organic material (kerogen and bitumen) present in the rock, expressed as a percentage by weight. Generally, the higher the TOC, the better the potential for hydrocarbon generation. The rock's thermal maturity measures the degree to which organic matter in the rock has heated up over time, potentially converting to liquid and/or gaseous hydrocarbons, and measurable with vitrinite reflectance (R_o) and T_{max} . Vitrinite reflectance measures the percentage of light reflected off the vitrinite maceral at 500x magnification in oil immersion (Dow and O'Connor, 1982). The main advantage of vitrinite reflectance here is its sensitivity to temperature ranges that largely correspond to those of hydrocarbon generation (i.e. 60 to 120°C). With the right calibration, vitrinite reflectance indicates source rock maturity. Generally, the onset of oil generation ('top oil window') is correlated with a reflectance of 0.5-0.6% and the termination of oil generation ('bottom oil window') with a reflectance of 0.85-1.1%. Similarly, the gas window is typically associated with values of 1.0-1.3% and terminates at around 3.0%. However, generation windows vary with different kerogen types, (e.g. vitrinite is typically abundant in 'Type III'

source rocks). A conversion to 'Transformation Ratio' (TR) can be applied to create a kerogen-specific maturity parameter. The temperature recorded at the maximum of hydrocarbon generation during pyrolysis is called Tmax, and it is used in kerogen maturation rank evaluation. Other parameters for characterizing rock quality are S1 which is the amount of extractable organic material in the source rock, generally derived from kerogen breakdown; and S2 which is a measure of the insoluble kerogen content; Hydrogen Index, HI (S2/TOC), which characterises the type and origin of the kerogen; The Production Index (PI) is the ratio $S1/[S1 + S2]$, and is an evaluation of the transformation ratio of kerogen into oil (in the absence of migration) (Espitalié et al., 1977), see section 4.4.

2.3.2 Rock brittleness

A material is brittle if it breaks without significant deformation or strain when subjected to stress – this has implications for the development of tight oil and gas, since brittle rock can be hydraulically fractured to enhance rock connectivity (Rickman et al., 2008). It is quantified by the Brittleness Index (BI), the renormalization of the Poisson's ratio, and Young's modulus in some zone of interest. Rickman et al. (2008), suggested that the brittleness concept should combine Poisson's ratio, which they claimed reflects the rock's ability to fail, and Young's modulus, which represents the ability to maintain a fracture, once the rock fractures. With such rock properties analyses, based on rock velocities, for example, potential sweet spots in the formation of interest may be identified.

Given the special techniques required, extracting shale gas can be more expensive than extracting conventional gas. While the in-place gas resource can be very large because of the lateral extent and thickness of many shale formations, only a small portion of the world's shale gas is theoretically producible and even less likely to be commercially producible. The success of a shale play depends on whether, and how much, oil and gas can be recovered from the subsurface and at what cost. There is a worldwide supply chain and knowledge of shale exploration and production transferable by the main shale producers (U.S. and Canada).

In the production of hydrocarbon accumulations, the whole source rock, reservoir, seal, trap and generation-migration system, including timing, must be considered. But the concept must be modified for fractured shales, as organic shales are both source and reservoir rocks and, sometimes, seals. Whether biogenic or thermogenic, the origin of the gas must be considered in defining potentially producible hydrocarbons. Fracture and matrix permeability, enhanced by appropriate well stimulation treatments, are crucial if economical hydrocarbon

flow rates are to be achieved. Understanding the thermal history of the organic matter within the shales and analysing the rock mechanical response of the shale matrix and organic matter are critical in establishing hydrocarbon producibility. The poor quality of one factor (e.g. low adsorbed gas) may be compensated for by another factor (e.g. increased total organic matter, reservoir thickness); however, shale production cannot always be achieved even if combinations of geological and geochemical factors are optimal.

2.4 MAIN DIFFERENCES BETWEEN UNCONVENTIONAL AND CONVENTIONAL EXPLORATION

The main difference between shale oil or gas resource plays from conventional plays is that the shale acts as both the source and the reservoir in which the hydrocarbon is trapped. Due to the low permeability of this rock, the gas is trapped and prevented from migrating towards the surface. The gas is held in pore spaces and natural fractures, and can also be adsorbed onto organic/inorganic material, where early production is dominantly from open fractures (natural/induced), followed by free gas in microporosity, and then adsorbed gas. As drilling and completion technology is developed, such oil and gas can be exploited commercially as found in various basins in North America, Argentina, China, Ukraine, Australia and elsewhere.

Conventional and unconventional hydrocarbon accumulations differ significantly in respect of flow rate. Drilling into a conventional accumulation usually results in an immediate flow of some oil and gas. An unconventional accumulation, however, has to be stimulated to produce flow, since shale has very low permeability. The main contrasting methodologies are summarised in Table 2.2.

Table 2.2 Unconventional vs conventional methodologies (Stoneburner, 2013).

Unconventional	Conventional
<ul style="list-style-type: none"> • Project identification focuses "inside out"(core to basin); • Seismic control works "inside out"; • Stratigraphic support focuses on analysis of the entire basin; • Reservoir quality analysis is required over a very broad area of the basin; • Acts as a seal and trap reservoir. 	<ul style="list-style-type: none"> • Prospect identification focuses "outside in" (basin to core); • Seismic control works "outside in"; • Stratigraphic support eventually focuses on facies analysis local to the prospect; • Reservoir quality issues are relegated to the area of the prospect; • Combination of seal and trap, reservoir required.

Aside from permeability, the key properties of shale, when considering its oil and gas potential, are mainly the source rock quality, quantity and maturation: hydrogen index (HI) (quality), total organic carbon (TOC) S1, S2 and production index (PI) (quantity), thermal maturity (Tmax) and vitrinite reflectance (Ro), (maturation), and rock brittleness (rock properties). Quality, quantity and maturation are related to reservoir quality and rock properties to brittleness and stress/strain field (Figure 2.7). Also other significant geologic parameters controlling the productive capability of shale include thickness, porosity, pore pressure, depth, fluid characteristics, natural fracturing, structural complexity, lateral landing target and orientation, drainage area and ability to hydrofracture.

Figure 2.7 Schematic chart showing the three main subjects to be considered when evaluating an unconventional reservoir.

2.5 THE MAIN CONCEPTS OF THE PRODUCTION TECHNIQUES IN UNCONVENTIONAL RESERVOIRS

2.5.1 Key shale gas production techniques

As stated earlier, shales have very low permeability (on a nanodarcy scale, 10^{-6} mD). As a result, many wells are required to deplete the reservoir, in turn demanding special well design and well stimulation techniques in order to arrive at an economic rate of production. Horizontal drilling and fracture stimulation have both been crucial in the economic development of the shale gas industry.

2.5.1.1 Horizontal drilling

Horizontal drilling allows the wellbore to contact significantly larger volumes of hydrocarbon-bearing rock than in vertical wells. Increased contact brings increased production rates and recovery factors. As horizontal drilling and fracking technology has improved, the use of horizontal drilling has increased significantly. In the Barnett shale in the U.S., for example, the number of horizontal wells drilled in 2001-03 was 76; by 2007-08, this number had risen to 1,810. Over the same interval, the number of new vertical wells in the Barnett shale declined from 2,001 to just 131 (U.S. EIA, 2013).

2.5.1.2 Hydraulic Fracture Stimulation

Hydraulic fracture stimulation, “fracking”, creates fractures mechanically in the rock, allowing hydrocarbons trapped in subsurface formations to pass through those fractures, to the wellbore, and then on to the surface. Fracking can increase production rates and the volume of recoverable oil and gas. First pump pressure is transmitted via drilling fluid to fracture the rock, then water-bearing sand (“proppant”) is injected into the hydraulic fracture to keep it open, allowing the flow of oil and gas. Water and sand are the main components of hydraulic fracture fluid, but chemicals are often added in small concentrations to improve performance. Figure 2.8 explains schematically how hydraulic fracturing works.

Figure 2.8 Schematic of Typical Fracturing Process (EPA, 2016).

2.5.1.3 Pad drilling

Single drill pads are becoming increasingly common in shale development, since these allow a greater surface area to be developed. From one surface location multiple wells may be drilled, using different horizontal orientations and with different depths and intervals. Infrastructure costs and land use (including impact on the surface environment) are reduced, and hence operational efficiency increased (Springett, 2009).

2.5.1.4 Stacked wells

Where shale is sufficiently thick, or where multiple strata are layered one upon the other, it is possible to stack the drilling of horizontal wells. Drilling multi-laterals allows oil and gas to be produced from one vertical well, at different depths and using horizontal wells at each depth. Since surface facilities may be shared, costs may be lowered. And, like pad drilling, the reduced land use means a lower environmental impact.

Given the geometry of the East Coast Basin, it can be assumed that some thrust fault regions, along the basin, will allow this technique to be applied as the repetition of the Whangai and Waipawa formations would be expected (Springett, 2009).

2.5.1.5 Batch drilling

Batch drilling places a drill rig on rails or skids with hydraulic feet (Figure 2.9). Skids are easier to re-position over the target than rails, which tend to move slightly off target as they are moved from well to well. All the wells' surface sections are drilled in one batch, sliding from well to well. At the end of the line, the rig reverses and drills the intermediate and lateral sections.

Batch drilling has made the drilling process more efficient procedurally, in regard to trips in and out of the hole, run casings, changing out the drilling mud formula for each section, and tearing down and reassembling the rig. Rig crews may be retained, saving on re-training time. Batch drilling means there is no need for continuous changes in well size or parameters; all the wells are drilled using the same mud and tools for each section; and repetition makes for a more efficient crew. Although batch drilling is more expensive than multi-pad drilling, the time savings ultimately result in net savings (Springett, 2009).

Figure 2.9 Photo showing an example of a Batch drilling.
http://www.drillingcontractor.org/rig_concept_aims_to_revolutionize_batch_drilling-861

2.5.1.6 Multi-lateral drilling

Multi-lateral drilling, like stacked drilling, involves drilling two or more horizontal wells from the same vertical well bore. With multi-lateral drilling, the horizontal wells access different areas of the shale at the same depth, but in different directions. Figure 2.10 shows examples of pad and multi-lateral drilling:

Figure 2.10 Examples of pad drilling (Source: Tyndall Centre Report—Shale Gas: A Provisional Assessment of Climate Change and Environmental Impacts, January 2011) and multilateral wells (Source: Baker Hughes INTEQ).

2.5.2 Shale gas challenges and solutions

Shales have significantly different gas storage properties to conventional reservoirs. While the gas present in the matrix system of pores is similar to that in conventional reservoirs, shales also have gas bound to or adsorbed to the surface of organic materials in the shale. The contributions and combinations of free gas from matrix porosity, and from desorption of adsorbed gas, are crucial to the production profile of the well (Three Legs Resources, 2011).

The distribution and volume of gas within the shale is significantly determined by rock properties, initial reservoir pressure, and adsorption characteristics. During production, there are three main processes at play (Three Legs Resources, 2011):

1. Initial gas production, dominated by depletion of gas from the fracture network. Due to limited storage capacity, such production declines rapidly; once the initial decline rate stabilises, the depletion of gas stored in the matrix becomes the primary process involved in production;
2. The volume of gas held in the matrix is dependent on the shale reservoir properties, which can be hard to estimate;

- Secondary to this depletion process is desorption, where adsorbed gas is released from the rock with declining reservoir pressure. The rate of gas production via the desorption process depends on this pressure drop.

Pressure tends to evolve very slowly along the rock due to the low permeability. Tight well spacing may be required to lower the reservoir pressure and thereby cause significant gas desorption. Such overlapping production results in a production profile that declines sharply (typically by 60-80%) over the first year. Figure 2.11 illustrates how initial production rates for shale wells in four plays in the U.S. varied over time (Chesapeake, 2010).

Figure 2.11 An example of the decline curve from four different shale Formations in the U.S. (Chesapeake, 2010 Institutional Investor and Analyst Meeting).

Due to such properties, the ultimate recovery of the gas in place surrounding a particular shale gas well can be in the order of 28-40% (whereas the recovery per conventional well may be as high as 60-80%) (Chesapeake, 2010). Development of shale gas plays differs significantly from that of conventional resources. Each well in a conventional reservoir can drain oil or gas over a large area depending on reservoir properties. Only a few wells (usually vertical) are required to produce commercial volumes from a conventional field. With shale gas, a high number of tightly-spaced wells are needed to produce volumes sufficient to make plays feasible. For example, in the Barnett play in the U.S., the drilling density can exceed one horizontal well per 60 acres (0.25 km²).

2.6 BENEFITS OF TECHNOLOGY IMPROVEMENTS

2.6.1 Decline in drilling costs

Heavy reliance on horizontal drilling and hydraulic fracturing raises the costs and breakeven associated with the development of shale resources compared to conventional oil and gas. Costs have fallen over the past decade in North America, however, with improvements in the efficiency of large scale drilling programmes and the use of pad drilling and stacked or multilateral wells. For example, ENCANA reported significant improvements in drilling times and costs in the Eagle Ford shale in 2015 (Figure 2.12).

Figure 2.12 Improvements in drilling times and costs achieved by Encana in the Eagle Ford shale from 2014 to 2015. Drilling and Completion (D&C) Cost normalized to 7,200' lateral length (Hill, 2015).

2.6.2 Decline mitigation and increased recovery

Improved technology and greater experience with shale-specific plays has brought higher recovery factors and reduced decline rates. Assessing rock properties allows unique completion techniques for individual plays. Well performance depends on variables such as well orientation, fracking equipment and hence fracture size, density and fluid type (Three Legs Resources, 2011).

The initial production (“IP”) rate from a well may be correlated with fracking quality and well completion. IP rates in the U.S. have increased as the play matures; see, for example Figure 2.13, illustrating the development of the Haynesville Shale. Several techniques may improve IP rates, increasing the number of fracking stages and the number of perforations per fracking stage. With the development of fracking fluids, the quality of fracking is also improved. Micro-seismic data may also improve fracking efficiency (Three Legs Resources, 2011).

In North America, the combined benefits of improved technology and increased experience have resulted in the upward shift of well production curves in developed shales.

The rates of both the expected ultimate recovery per well and peak production per well have increased as plays have matured.

Figure 2.13 Development of the Haynesville Shale initial production from Q4-2008 to Q1-2010 (Chesapeake, 2010).

2.7 SHALE GAS BOOM

Vihma (2013) suggests that the impacts of the U.S. shale gas boom have manifested themselves in cheaper coal in areas such as Europe and Asia, with coal replaced by natural gas. The ‘coal renaissance’ in Europe could be avoided by either a carbon price or other regulation. Restoring the ability of the European Emissions Trading System to guide investments might be the best solution, and could be approached by setting an adequate emissions target for the post-2020 period. Globally, the rise of unconventional energy sources means that future energy markets will have a more competitive and fragmented nature, with many energy importing countries also able to utilise domestic resources, balancing imports with regional exporters and major players internationally. Such developments would probably signal a weakened Russia in respect of the European gas market, with consequent problems for Russian export revenues. Other states lag far behind the U.S. in shale gas technology, but will try to replicate the U.S. experiment, with Russia likely strive to prevent this eventuality in its neighbourhood.

The rise of shale gas in the U.S. has been swift. In 2010, with shale gas production rising, coal accounted for 42% of U.S. electricity production. Eighteen months later, coal had dropped by around 25%, to a par with natural gas. The dramatic drop was mainly due to the increased supply and cheap price of natural gas. In the U.S., natural gas had fallen from its peak of \$13 per million British thermal units (mBtu) in mid-2008 to \$2 mBtu four years later. Such low prices might also be attributed to valuable side products such as liquid carbons, as well as

the inelasticity of gas production post-initiation, and resulting oversupply. Mid- and long-term prices in the U.S. are also predicted to be around \$4-6/mBtu. Despite a modest price increase for gas, it has remained cheaper than coal in the U.S. In the wider economy, cheap gas is reinforcing the trend of ‘back-sourcing’ or ‘repatriation’ of industry in the U.S. From 2006 to 2011, the mining, oil and natural gas industries comprised the fastest growing sector, with an increase of jobs by nearly 60%, creating a total of 500,000 relatively high paid jobs. Petrochemical, fuel, fertilizer and steel companies were also among those that committed to or are considering large investments based on their ability to source cheap energy and feedstock. Dow Chemicals recently reported (The America Interest, 2012) that manufacturers have already announced \$90 billion worth of new investment in the U.S. to ‘take advantage of its cheap natural gas’. PricewaterhouseCoopers predicts that energy-intensive industries will create around seven hundred new jobs in the U.S. by 2023 (Pwc, 2014). However, from a global perspective, many questions remain about how efficiently unconventional gas resources can be developed outside North America.

The U.S. shale gas boom has been helped by an efficient gas market, flexible pricing and large indigenous unconventional resources. Shale gas recovery was easy to dismiss when the size of the resource could be doubted, and without the U.S. example in mind. Now shale gas recovery sets a powerful example. The U.S. experience suggests that the opinions of experts towards the potential of resources and feasible production has been unduly pessimistic, and often completely wrong (Salameh, 2011).

The global potential of unconventional energy sources may not be known before 2020. ‘Global potential’ here includes European, Argentinian and Chinese shale gas in particular. Where any of these succeed, even to a limited extent, lower fossil fuel prices will probably result. With increasing competition, major suppliers like Russia, Saudi Arabia and Venezuela will have their market power limited and their political clout curbed. Energy markets will become not only more competitive but more fragmented, though the exact scale and pace of change is hard to foresee, with many such uncertainties politically derived.

2.8 SHALE OIL AND GAS IN NEW ZEALAND

Shale oil and gas exploration in New Zealand started in 2006 when Tag Oil acquired four exploration permits and later New Zealand Energy Corp (NZEC) three permits, with a total area of 10310 km² along East Coast Basin. This area represented about 37% of the total area of the onshore basin. These companies drilled twelve wells (three explorations and nine stratigraphic wells) in order to fulfil their work programs, as well as geochemistry reports, 2D

seismic acquisition and reprocessing (Table 2.3). Tag Oil entered a farm-out agreement with Apache Corporation in 2011 that was intended to fund an ambitious drilling campaign. However, Tag appears to have struggled with prolonged consenting issues and difficult drilling conditions, while NZEC failed to find farm-in partners. Exploration by both companies was curtailed as oil prices plummeted in 2014. Also, between 2014 to 2015, three other companies had permits in the basin, Endeavour Energy (NZ) Ltd, Mosman Oil and Gas Ltd and Mont d'or Resources Ltd, totalling an area of 2737 km². Currently, only Mosman Oil and Gas Ltd has a permit (890 km²) in the study area. As Tag Oil and NZEC were more active in looking for unconventional reservoirs, the focus is on these companies.

Table 2.3 Shale oil and gas wells drilled by Tag Oil and NZEC and their workprograms in the Basin.

Company	Stratigraphic Wells	Exploration Wells	Geochemistry Studies	Reprocessed 2D Seismic (km)	New 2D Seismic (km)
TAG Oil	6	2	3	Not informed By the company	206
NZEC	3	1	1	250	185

There is an element of urgency in producing unconventional resources. The opportunity to benefit from shale revolution may not last as long as it would take some countries to develop their unconventional shale resources, due to growth in renewable energy. Those countries need to consider ways of putting development on a fast track to reduce the risk of losing the window of opportunity. Perhaps most countries do not have the advantage of ideal conditions that the U.S. exhibits, which have allowed them to enjoy the fruits of those conditions, but nevertheless they should use this momentum to their benefit. New Zealand is a case in point.

2.9 EXPLORATION, DEVELOPMENT AND PRODUCTION OVERVIEW

The oil and gas industry is divided by 4 different phases, as described below (<http://www.glossary.oilfield.slb.com/Terms/p/production.aspx>).

1. Exploration – The initial phase in petroleum operations that includes generation of a prospect or play or both, and drilling of an exploration well.
2. Appraisal and Development - The phase of petroleum operations that occurs after exploration has proven successful, and before full-scale production. The newly discovered oil or gas field is assessed during an appraisal phase, a plan to fully and efficiently exploit it is created, and additional wells are usually drilled.

3. Production - The phase that occurs after successful exploration and development and during which hydrocarbons are drained from an oil or gas field.
4. Abandonment - The proper plugging and abandoning of a well in compliance with all applicable regulations, and the cleaning up of the wellsite to the satisfaction of any governmental body having jurisdiction with respect thereto and to the reasonable satisfaction of the operator and landowner.

It is important to highlight that the most important and principal core business of any oil company is how much reserves the company has. We could, also expand this concept in a larger scale and assume that the countries have to have the same core business and increase their reserves. However, in order to create this maximum value, there is an evolution of concepts from a prospective resource to reserve (Figure 2.14). There are many business models and ways of creating value in the oil and gas industry, but the reserves create real value.

Figure 2.14 Global standard for reserves and resource determination is defined in the Petroleum Resources Management System (PRMS) <http://www.spe.org/industry/reserves.php>.

3. GEOLOGICAL SETTING

3.1 INTRODUCTION

The New Zealand subcontinent (“Zealandia”) is an irregularly-shaped mass of continental crust lying along the convergent margin between the Pacific and Australia lithospheric plates (Figure 3.1). This boundary contains three principal tectonic components.

1. In the northern area, the oceanic crust of the Pacific plate is subducting obliquely westwards beneath the continental crust of the Australia plate. The Hikurangi trough (Figure 3.1 and Figure 3.2), extending from the Tonga-Kermadec Trench in the north to Kaikoura in the south, marks where the thickened, oceanic Hikurangi Plateau of the Pacific plate dips down beneath the Australia plate (Wallace et al., 2004). To the north, the Hikurangi Plateau changes to a normal oceanic plate subducting at the Tonga-Kermadec Trench (the northern continuation of the Hikurangi trough);
2. In the northeast of the South Island, subduction gives way to a strike-slip dominated fault system, with the Marlborough Fault System and Alpine Fault accommodating most of the Australia-Pacific relative motion (e.g. Van Dissen and Yeats, 1991; Holt and Haines, 1995; Nicol and Van Dissen, 2002). The central sector of the plate boundary is represented by a transform system where the continental crust of the Pacific plate obliquely overthrusts the continental crust of the Australia plate. The dominant transform fault is the Alpine Fault, well known for its 480 km of Neogene-Quaternary dextral offset and the associated over thrusting that has given rise to the Southern Alps (Kamp, 1992);
3. Southwest of the South Island, the Macquarie Ridge and Puysegur Trench (Figure 3.1) mark a complex subduction zone. Along northern parts of this section of the plate boundary, the Pacific plate crust overrides the oceanic crust of the Australia plate.

Figure 3.1 The New Zealand subcontinent, showing the main bathymetric and tectonomorphic features (orange and green colours). Base image is the NIWA Undersea New Zealand map.

Figure 3.2 (facing page): Illustration of the tectonic setting of eastern North Island, New Zealand. Data used in this figure were derived from Beanland (1995), Field et al. (1997), Barnes and Nicol (2002), and Barnes et al. (2002) (modified from Bland, 2006).

The focus of this study is the East Coast Basin (ECB) located in the North Island, which started developing in Early to mid-Cretaceous time (110 Ma). It has an area of approximately 70,000 km² (Brooks and Remus, 1985) of which 28,000 km² is onshore and 42,000 km² offshore. The sedimentary succession in the basin is up to 10,000 m thick in places, and comprises mostly fine-grained marine sediments. It extends from East Cape in the north to Marlborough in the South Island, and is bounded to the west by axial ranges of Triassic to Early Cretaceous greywacke (basement) and to the east by the Pacific Ocean and the Hikurangi Trough.

The onshore East Coast region in the North Island comprises three geographic areas:

- Raukumara Peninsula;
- Hawke's Bay;
- Wairarapa.

Offshore areas (e.g. Raukumara and Pegasus Basin) and the Marlborough area in the South Island are not included at this study.

The East Coast Basin is currently situated on an active plate margin boundary with the oceanic Pacific Plate being subducted under the Indo-Australian Plate. A forearc basin is associated with the Hikurangi Trough which extends north at least as far as Fiji, and in the south the subduction zone merges with the main Alpine Fault system. The forearc basin is one of five tectono-geomorphic elements in the eastern North Island (North Island Shear Belt, Frontal Ridge, Forearc Basin, Accretionary Wedge, and Hikurangi Trough, Figure 3.2) and has formed in response to the evolution of the convergent Australia-Pacific plate boundary zone since the end of the Oligocene (Ballance, 1993a & b). Considerable tectonic activity has occurred and a complex thrust and fold belt has been generated containing much faulting, overthrusting and folding. During the Plio-Pleistocene, the marine forearc basin was differentially uplifted to form land. However, from Early Cretaceous to Paleogene two different main structural geological events have occurred:

1. From Permian to Early Cretaceous the Torlesse Terrane was accreted to what it is now East Coast Basin along a west dipping subduction zone (e.g. Bradshaw et.al., 1981; Howell, 1981; Spörli, 1987).
2. From mid-Cretaceous, regional convergence ceased or slowed down and was followed in some areas by crustal extension associated with the incipient rifting of New Zealand from Australia and Antarctica. Normal faulting has been recognised east of Raukumara Peninsula and dated as Cretaceous. Also, there is some evidence of continuing shortening on this Peninsula (Kenny, 1986; Mazengarb and Harris, 1994) and in southern Hawke's Bay (Crampton, 1989, 1997) until the early Mata Series time. Subsidence over this period could reflect a potential spreadout formation along the whole basin. Thus, the Whangai and Waipawa formations, the main goal of this study, dated as Cretaceous and Paleocene, respectively, should occur over the whole regional area.

Different models have been proposed for the palaeogeographic reconstruction of the East Coast Basin (Kamp, 1986; Field & Uruski et. al., 1997, and Hollis, 2012). This is important to determine the origin of potential sediment sources during the Late Cretaceous and Paleocene, when the Whangai and Waipawa formations were deposited.

It is important to highlight that the New Zealand geological community has developed its own set of biostratigraphic stages, partly because of the endemic fauna and flora and partly to avoid problems caused by diachronous bioevents (Figure 3.3).

3.2 BASEMENT

As the detrital and provenance composition of the Whangai and Waipawa formations affects their rock properties and hence their prospectivity, a brief outline of New Zealand's basement rocks is therefore provided here and a discussion of geochemistry in relation to provenance is proposed in section 4.5.3.2 of this thesis.

During prolonged, Permian to Cretaceous oblique convergence and subduction, accretionary terranes developed at this margin (Mortimer, 1994); these terranes are known as the Eastern Province (Bishop, Bradshaw & Landis, 1985). Between 112 and 85 Ma, accretion decreased and eventually stopped, and an extensional regime developed, covering these rocks by younger Cretaceous sedimentary successions (Laird & Bradshaw, 2004). In the west, these Cretaceous cover successions were mostly terrestrial–fluvial sedimentary rocks deposited on stabilized Paleozoic basement of the Western Province of New Zealand and also Eastern Province, e.g. Rakaia Terrane. However, younger terranes of the Eastern Province, e.g. Pahau and Waipapa terranes, were overlain by more marine sedimentary facies deposited in shallow and deep-water (Laird & Bradshaw, 2004).

The basement rocks of the East Coast region consist mainly of Triassic to Early Cretaceous indurated sandstone and mudstone (greywacke and argillite) in a variety of lithofacies associations (e.g. Speden, 1976a; Spörli, 1978; Kear, 1993; Mortimer, 1995). Basalt, chert and limestone are volumetrically minor but widespread lithologies, usually present in fault or mélangé zones. Bedding and fold axes are typically very steep, and broken formations and mélanges are not uncommon. The metamorphic grade ranges from zeolite to prehnite-pumpellyite facies. In most places basement is readily distinguished from cover on the basis of lithology, age, degree of induration (metamorphic grade) and/or structural style. Locally, however, these differences are less clear (e.g. Mazengarb & Harris, 1994). Regional deformation events affecting the Torlesse Terrane can be related to Early Jurassic collision of the Torlesse and Caples Terranes (Coombs et al., 1976; Mortimer, 1993) and Late Jurassic to Late Early Cretaceous subduction-accretion (e.g. Bradshaw, 1989). Basement rocks have variously been referred to as the Torlesse Supergroup (Suggate, 1961) or Torlesse Terrane (Coombs et al., 1976; Spörli, 1978). More recent regional subdivisions of Torlesse basement rocks into subterranes and mélangé zones have been made on the basis of fossil content, petrofacies and structural character (e.g. Bradshaw et al., 1981; MacKinnon, 1983; Silberling et al., 1988; Wilson et al., 1988; Mortimer, 1995; Begg & Mazengarb, 1996). From west to

east in the East Coast region, there are five principal basement units (Figure 3.4, mainly after Mortimer, 1995):

- (1) Rakaia Subterrane;
- (2) Waioeka Subterrane;
- (3) Pahau Subterrane;
- (4) Esk Head-Rimutaka Melange (mix of mainly Rakaia and Pahau subterrane rocks);
- (5) Whakatane Melange.

Figure 3.4 Tectonostratigraphic basement terranes of New Zealand, after Mortimer et al. (1999), adapted from Lee and Begg (2002). Basement rocks of the study area comprise the Torlesse composite terrane, and the Esk Head and Whakatane mélanges.

3.3 STRATIGRAPHY

The pre-Neogene sediments of the East Coast Basin represent mainly a fining-upwards succession from Cretaceous sandstone and mudstone to Paleocene–Eocene mudstone and muddy limestone (Field et al., 1997). Moore et al. (1986), using the divisions of Pettinga (1982), subdivided the Cretaceous–Paleogene stratigraphy of the East Coast Basin into four broad sedimentation phases. These were subsequently adopted by Field et al. (1997) in a stratigraphic review of the East Coast Basin:

1. Cretaceous rifting and drifting – deposition of predominantly clastic sandstone, mudstone, conglomerate and gravity flow deposits;
2. Late Cretaceous to Paleocene thermal subsidence phase – deposition of a fine grained, siliciclastic sequence that grades upwards to calcareous strata, forming a transition sequence. This phase includes the two formations targeted in this thesis (Whangai and Waipawa);
3. Further subsidence in the Eocene to Oligocene – deposition of a fine-grained, calcareous sequence, comprising smectitic mudstone, micritic limestone and glauconitic sandstone;
4. Earliest Miocene reactivated tectonism in response to the development of the modern plate boundary – deposition of calcareous turbidites, mass-flow deposits and massive mudstones and sandstones and emplacement of the East Coast Allochthon in the north of the region. New sub-basins were formed in this Neogene phase of tectonism.

Correlation of these sedimentary units has allowed the development of a structural and stratigraphic framework that enables the relationships between various lithostratigraphic components of the East Coast Basin to be determined. Distinct contrasts in the stratigraphy and structure were recognised and utilised by Moore et al. (1986) and Moore (1988a) to propose a structural division of the East Coast Basin. These divisions are grouped into the Western Sub-belt and the Eastern Sub-belt. Following the zonation of Moore (1988a) the North Island East Coast Basin can be broadly divided into seven distinct structural blocks (Figure 3.5). Mazengarb (1993) modified Moore's (1988a) scheme for the Raukumara Peninsula adding five structural domains within the Eastern and Western sub-belts. Domains 1,2 and 3 are located in Motu Block and 4 and 5 within East Coast Allochthon (Figure 3.6). The north eastern South Island aspect of the East Coast Basin can be divided into an additional five structural blocks (Crampton et al., 2003), which are delineated by the major transpressional fault structures of the Marlborough region (Figure 3.7). Based on the lithological correlation within the Late

Cretaceous succession of these five faulted blocks, the Western Sub-belt of the North Island can be used as an analogue for the north eastern South Island characterization (Crampton, 1997).

Figure 3.5 Location and structural divisions of the East Coast Basin, New Zealand. Distribution of basement and cover sequence shown, along with location of Cretaceous volcanic units. Modified after Moore (1988a & b), Crampton et al. (2003) and Adams et al. (2013).

Figure 3.6 Stratigraphic – Structural domains recognised post-basement. Unshaded areas represent Late Cretaceous and Cenozoic rocks. R.V – Rip Volcanics; M.F. – Moutohora Fault; A.F. – Arowhata Fault (after Marzengarb 1993).

Figure 3.7 Geological map showing the major transpressional fault structures of the Marlborough region. Map from Crampton et al. 2003, with geology from sources listed therein.

3.3.1 Sedimentary succession

The stratigraphic subdivision of the sedimentary succession shown below applies to the East Coast Basin as a whole, mainly as discussed by Field et.al. (1997) (Figure 3.8).

Figure 3.8 Broad-scale chronostratigraphic framework for the East Coast Basin (after Field et al., 1997). The blue dashed boxes highlight the two geological formations analysed in this study. The Waipawa Formation is shown as a solid line. The vertical scale is in Ma.

3.3.1.1 Cretaceous – Paleogene

A phase of intense tectonic and igneous activity took place in the Early Cretaceous (Aptian-Albian) throughout much of New Zealand, at the peak of the Rangitata Orogeny (Bradshaw et.al., 1981). The Torlesse composite terrane and other Eastern Province terranes are considered to have been juxtaposed at a convergent continental margin on the edge of the Gondwana supercontinent before the end of the Early Cretaceous (Bishop et al., 1985; Adams and Kelley, 1998).

Evidence from various sources suggests that, in the New Zealand region, climate in the Late Cretaceous was warmer at present. Turtle remains have been found in Piripauan-

Haumarian sediments at Te Hoe River, in Western Hawkes Bay (Wiffen, 1981). Also, there are records of *R. contusa* and *P. elegans* (foraminifera) from New Zealand in the uppermost Cretaceous at Flaxbourne River (Strong, 2000), maybe a local effect of late Haumarian warming (Olsson et al., 2001; Abramovich & Keller, 2002). There is no evidence for a late Cretaceous cooling episode in the Marlborough K/T sections. Indeed, the thin marl bed that underlies the K/T boundary at Flaxbourne River is thought to represent warmer oceanic conditions than underlying limestone beds (Hollis et al., 2003a).

Cretaceous cover rocks were deposited in two different but juxtaposed sub-regions, the Eastern and Western sub-belts. The Western sub-belt extends from present day Raukumara Peninsula to Marlborough whereas the Eastern sub-belt has only been recognised with certainty as far south as southern Wairarapa. The Western sub-belt, characterised by mudstone-dominated successions, is less deformed and contains more local unconformities than in the East (Moore, 1988a). On the other hand, the Eastern sub-belt is characterised by turbidites, complex deformation, and relatively continuous deposition. This sub-belt has not been recognised in Marlborough.

Western sub-belt – basement rocks are unconformably overlain by coarse-grained deposits of varying Early Cretaceous ages succeeded by Korangan to Piripauan sequences with a marked upward-fining trend. Most of the basal beds were deposited in local basins as olistostromes or by debris flow mechanisms, related to widespread tectonic activity at the western margin in mid- to late Motuan time. This means the thermal subsidence of the basin can be attributed to the thick mudstone-dominated units, maturation of the sediment source areas, and basin infilling in upper slope or outer shelf environments. Inner shelf and non-marine deposits in Marlborough identify the southwestern shoreline of the Western sub-belt (Field et al., 1997). Coarse-grained facies of Motuan age occur in the Western sub-belt rocks of Hawke's Bay, Wairarapa, and Marlborough, and in some areas of Raukumara Peninsula, and may be related to a brief intra-Motuan pulse of regional tectonic activity. Sandstone-dominated units of Piripauan-Haumurian age grade upward into siliceous mudstone-dominated facies of the Whangai Formation that were deposited over virtually the entire region, so that distinction between Eastern and Western sub-belts became less obvious towards the end of the Cretaceous.

Eastern sub-belt – Interbedded sandstone and mudstone, deposited on prograding submarine fans in a stable basin, and minor tectonism characterise the Eastern sub-belt. Deposition was probably at bathyal depths, although younger strata may have been deposited in shallower environments. By the late Cretaceous, there was a slow sedimentation rate of fine-

grained clastic sediments and limestone over much of what is now the East Coast Basin. This continued into the Paleocene and lasted in most areas until the late Oligocene. Even though there is some evidence of minor tectonism, which could be related to a more homogeneous depositional environment, the condensed sedimentary record and the nature of the facies suggest a passive margin setting throughout the Paleogene.

3.3.1.2 Neogene (Miocene to Pliocene)

The style of sedimentation in the basin changed dramatically in the earliest Miocene. Facies changes, basal unconformities and flysch depositions in the Waitakian and Otaian are inferred to mark the start of a new period of tectonism, involving large-scale faulting and the emplacement of allochthonous blocks (Mazengarb and Speden 2000).

By the late Paleogene to early Neogene, the East Coast Basin was covering around 10000 m of mudstone and flysch deposits. More than 500 m of sediment accumulated around the toe of the allochthons block, which may have been enhanced by foreland basin-style subsidence. The environment of deposition was mainly bathyal.

By the late early Neogene, most of the regional deposition was still bathyal mudstone and flysch. Based on paralic and shelf sedimentation around north Lake Waikaremoana, it is assumed that there was some erosion there in the early Altonian. This stage differed from the previous (Otaian) stage by having high sedimentation rates in the Raukumara Peninsula, a trend that continued into the late Miocene. A large depocentre developed in the present Raukumara Peninsula, away from which sediments thinned to the west, perhaps due to a lack of accommodation space near to the source, and to the east, where the depositional environments were probably more distal.

By the early middle Neogene, the depositional facies were mainly shelf sands in the west and bathyal mudstone in the east, and bathyal flysch as slope aprons. Tectonism continued with areas uplifting and subsiding.

Clifdenian strata are thickest on Raukumara Peninsula, being up to 1000 m thick in places but much less in Hawke's Bay and Wairarapa areas. In contrast, younger Lillburnian strata indicate onlap in the north. The exception is at Ruatahuna between two major strike-slip faults where an anomalous thickness was mapped at about 750 m. Probably these differences are related to the tectonism, sea level variation and sedimentation influxes (Mazengarb, 1993). Basement was probably exposed to the west and eroded during this stage, resulting in the Waiauian and younger sediments overlaying the Cretaceous basement. Also, this epoch is

marked by active tectonism, indicating major faulting, subsidence, and uplift followed by perhaps two eustatic falls (Mazengarb et al. 1991). These events are characterised by a mix of bathyal flysch and mudstone as well as paralic to neritic sandstone and limestone. The Late Miocene succession is characterised by variations in sediment thickness due to the influence of faulting.

The tectonic collision between the Australia and Pacific Plates continued throughout Plio-Pleistocene time and, combined with sediment influx and sea level changes, controlled sedimentation. The rate of tectonism was not necessarily higher than in the Early Miocene, but high rates of uplift and horizontal displacement suggest the Plio-Pleistocene was particularly active tectonically. Plate boundary compression also uplifted the coastal ranges through the Pliocene in the East Coast Basin (Field et al., 1997).

3.4 PRESENT DAY TECTONIC SETTING

3.4.1 Hikurangi Subduction Margin

The East Coast region is synonymous in a tectonic sense with the Hikurangi subduction margin, which is the southern end of the Tonga-Kermadec-Hikurangi subduction zone of the western Pacific. This subduction zone is a 3000 km-long plate boundary where the oceanic crust of the Pacific Plate is subducted beneath oceanic or continental crust of the Australian Plate (Wallace et al., 2004) (Figure 3.1). Here the Pacific Plate is subducting obliquely beneath the North Island. The margin comprises five main tectonic elements, from west to east (Figure 3.9):

- (1) The Taupo Volcanic Zone, an ensialic extensional marginal basin inferred to contain the present 'arc' of the system (see Cole, 1984);
- (2) Wanganui Basin;
- (3) Axial ranges;
- (4) Hikurangi forearc; and
- (5) The Hikurangi subduction interface (Walcott, 1978a; Cole & Lewis, 1981; Van der Lingen, 1982; Kamp, 1988; Collot et al., 1996).

The axial ranges (3), Hikurangi forearc (4) and Hikurangi subduction interface (5) are all within the East Coast region.

Figure 3.9 Tectonic elements of the Hikurangi subduction margin (after Beanland, 1995).

3.4.1.1 Axial Ranges

The forearc basin is limited to the west by a frontal ridge up to 1700 m high composed of Triassic to Early Cretaceous basement rocks assigned to the Torlesse composite terrane (Field et al. 1997). The frontal ridge is expressed geomorphologically stated as the North Island axial ranges and is separated from the forearc basin by major dextral oblique-slip faults. The Wellington and Wairarapa Faults bound the axial ranges in the southern portion of the North Island. The Wellington Fault bifurcates into the Ruahine and Mohaka faults. The Ruahine bifurcates into Waiohau and Whakatane faults near to Woodville (Figure 3.10). The Mohaka Fault continues as the Waimana Fault near to Te Haroto. The Ruahine and Mohaka faults normally juxtapose basement rocks of the frontal ridge against Mio-Pliocene rocks of the forearc basin. The frontal ridge has a strong NNE-SSW structural and topographic alignment, with faulting more prominent along the eastern margins of the ridge. According to Berryman (1988), the vertical displacement since the early Pleistocene along the bounding faults is possibly as much as 2000 m. The North Island Shear Belt acts to accommodate some of the modern plate motion through the North Island (Cashman et al. 1992; Beanland et al. 1998; Nicol and Van Dissen 2002; Wallace et al. 2004). Large areas of the axial ranges are

characterised by concordant summit height or smooth topography, which has been interpreted as representing a remnant erosion surface (Wellman 1948; Berryman 1988).

Figure 3.10 Map showing the major active dextral oblique-slip faults and minor faults in red along the East Coast Basin.

3.4.1.2 Hikurangi Forearc

The Hikurangi forearc *sensu stricto* extends from the arc to the Hikurangi deformation front, but south of the Taupo Volcanic Zone there is no active arc and the forearc region is usually described as the region between the present-day axial ranges and the deformation front (Figure 3.9). With the exception of the Hawke's Bay embayment, about half the width of the forearc is presently above sea level and is being actively uplifted. The forearc can be subdivided into three zones: the mainly onshore inner forearc; the mainly offshore imbricate frontal wedge; and a zone of frontal accretion (Lewis & Pettinga, 1993). A zone of rapid uplift along the east coast of the North Island, approximately along the boundary between the inner forearc and the imbricate frontal wedge, is commonly referred to as the highest accretionary ridge or outer arc high, forming the coastal ranges (Cole & Lewis, 1981; Pettinga, 1982; Berryman et al., 1989).

3.4.1.3 Hikurangi Subduction Interface

The Tonga-Kermadec-Hikurangi subduction zone is a 3000 km-long plate boundary where the Oceanic crust of the Pacific plate is subducted beneath the oceanic or continental

crust of the Australian plate (Wallace et al., 2004) (Figure 3.1). The Hikurangi trough (Figure 3.1) is the southern part of this subduction system, and continues southwest to the Marlborough region in the northeast of the South Island from where the plate boundary becomes a zone of oblique continent-continent collision. Displacement on the plate boundary is transferred to the dextral Alpine Fault via the Marlborough Fault Zone. The Hikurangi trough is a sediment-filled depression about 3000 m below sea level that marks the modern subduction boundary (deformation front) off the east coast of the North Island and northeastern South Island. It is approximately 4 km deep in the north and decreases to 1 km deep at its southwest end near Marlborough (Beanland, 1995). At Hawke's Bay the deformation front, as recorded by the location of the Hikurangi trough, is approximately 175 km offshore, and near Wellington lies 75 km offshore. The Hikurangi trough comprises two separate zones: 1) a northern, sediment-flooded, volcanic knoll-studded, SSW trending structural continuation of the Kermadec Trench; and 2) a southern, more east-west trending transform boundary between central New Zealand and the down warped continental crust of the Chatham Rise (Lewis, 1980). The presence of seamounts suggests that the subducted crust is oceanic rather than continental (Uruski and Wood, 1993). The Hikurangi trough southward becomes a zone of intracontinental transpression (Lewis, 1985) and the boundary between these two zones remains relatively poorly defined. The convergent trench slope is characterised by rapid frontal accretion of Pliocene-Holocene turbidites south of Hawke Bay and by tectonic erosion and seamount subduction to the northeast (Lewis and Pettinga, 1993; Collot et al., 1996). The Raukumara Peninsula is presently undergoing crustal extension, with listric faults and diapiric structures occurring in association with overpressurised shales (Walcott, 1987; Field et al., 1997; Mazengarb, 1998).

3.4.1.3.1 Imbricate Accretionary Wedge

In response to the oblique collision of the Australia and Pacific plates (Hikurangi subduction zone) along the edge of the New Zealand continental block (Walcott 1978a, 1984; Spörli 1980; Lewis et al. 1998; Barnes et al. 2002), the accretionary wedge in New Zealand has been developed during many phases of sediment off-scraping and deformation (Chanier and Ferriere, 1999). It is a thrust-fault controlled region up to 180 km wide, characterised by seaward-thinning imbricated sediments that form a wedge-shape sedimentary body frontal to the Australian plate and to the continental crust of New Zealand (Lewis and Pettinga, 1993).

The accretionary wedge involves three principal units:

1. Passive margin sediments;
2. Frontally accreted trench-fill;
3. Slope basin infill.

All these three units are being “reduced” into one unit by imbricate thrusting which elevates the seaward-verging, hanging wall anticlines. The widest portion of the accretionary wedge is in the Wairarapa-Hawkes Bay area, and the highest imbricate thrust ridge and slope basins are emergent on land (Cole and Lewis, 1981; Pettinga, 1982).

The accretionary wedge comprises pre-existing passive margin sediments overlying basement rocks that have been thrust-faulted and back-tilted during the past 25 million years (Pettinga, 1982). Neogene slope basins in the accretionary wedge are generally aligned parallel to the trench axis (Lewis, 1980; Berryman, 1988). Late Quaternary landscape features indicate that folding, faulting, and uplift of the accretionary wedge on land continues to the present day; these include uplifted and commonly tilted marine terraces, deeply incised and rejuvenating streams and rivers, and surface expression of active folds and faults (Pettinga, 2004). The offshore part of the accretionary prism contains many actively growing fault-controlled anticlines and active faults (Field et al., 1997; Barnes and Nicol, 2002; Barnes et al., 2002).

Follow below the three main tectonic settings that the studied area covers.

3.4.2 Active Faults

The principal zones of presently active faults and related folds in the East Coast region are the North Island Shear Belt, the Marlborough Fault System, and the Coastal Fault Zone (Figure 3.9). The North Island Shear Belt is usually viewed as the partitioned, translational component of oblique relative plate motion as described initially by Fitch (1972). The Marlborough Fault System comprises four principal faults in the northeast South Island that transfer the motion of the Hikurangi margin to the Alpine Fault. Trenchward of the North Island Shear Belt, there are a number of onshore compressional structures and many more in the offshore part of the margin. These accommodate a proportion of the plate-normal component of relative plate motion. North of Hawke’s Bay, compressional features in the outer forearc are rare, but normal faulting coupled with rapid uplift is identified (Cashman et al. 1992).

Presently active compressional structures in the eastern North Island are usually located east of the Wairarapa Fault and its along-strike correlatives, although reverse faulting was ubiquitous throughout the inner forearc as recently as 1 Ma (Kelsey et. al., 1995). To the north in Hawke's Bay, the compressional structures east of the Wairarapa Fault are not as prominent. This coincides with the Wairarapa Fault itself becoming compressional.

3.4.3 Gravity anomalies

The most prominent feature of both the Bouguer and isostatic gravity maps of the North Island is a large low near Whanganui which extends northeastward to Hawke's Bay and further north to the Raukumara Peninsula. This feature has been termed the Rangitikei-Waiapu anomaly (Robertson & Reilly, 1958) (Figure 3.11). Gravity anomalies describe the local variations of the gravity field around the model field. Thus, a location with a positive anomaly exhibits more gravity than predicted by the model, suggesting the presence of a sub-surface positive mass anomaly, while a negative anomaly exhibits a lower value than predicted, suggestive of a sub-surface mass deficit. Lateral variations in gravity anomalies are related to anomalous density distributions within the Earth. Gravity measures help the understanding of the internal structure of the planet (Linsser, 1967). Additional to that, derivatives of the gravity field have been used by geophysicists as they suppress low frequency components and enhance high frequency components, thus delineating shallow bodies due to the improvement of the resolution. In order to better understand the geological features at the time Whangai and Waipawa formations were deposited, the first and second derivative gravity anomaly maps should be used if available.

Figure 3.11 Bouguer (over land) gravity anomalies of the East Coast region. Contours are negative values in mgal. Note the Rangitikei-Waipu anomaly, blue dashed line (modified from Robertson & Reilly, 1958).

3.5 WHANGAI AND WAIPAWA FORMATIONS: OIL AND GAS SHALE POTENTIAL

To describe these two geological formations, it is important to define terminology. Mudstone refers to a terrigenous sediment with particles smaller than 0.0625 mm. Siltstone is usually used when the grain size has been more precisely determined. Shale is used for mudstone showing some lamination and/or fissility. Siliceous shale has been defined as a hard, fine-grained rock of shaly texture with an exceptional amount of silica (higher than 85%) (Bates & Jackson, 1980). As the Whangai and Waipawa formations do not show much lamination or fissility, we must classify both formations as mudstone rock and according to Jarvie's classification (2012) as a hybrid system with a combination of juxtaposed organic-rich and organic-lean intervals.

Following are descriptions of these two formations:

3.5.1 Whangai Formation:

Even if the Whangai Formation is not considered the most prominent source rock of the East Coast Basin due to its low TOC content and Hydrogen Index, in localised areas it shows good potential for an unconventional reservoir. However, when evaluating a source rock for unconventional plays, mineralogy is also an important variable because it is related to the rock brittleness. Although the organic matter is capable of generating, retaining, and storing hydrocarbons, oil and gas flow is limited if the individual microreservoir compartments cannot be connected via well stimulation.

The name Whangai Series was introduced by Quennell & Brown (1937) for Late Cretaceous sediments in Hawke's Bay that had earlier been mapped as part of the Mangatu Series. Finlay and Marwick (1948) gave the unit formation status, but it was Lillie (1953) who first defined the Whangai Formation. Since 1975 the unit has been consistently termed the Whangai Formation (e.g., Johnston, 1975; Suggate et al., 1978; Moore, 1988b). For more detail see Table 4.21 in section 4.5.3.1.

The basal transgressive sandstone facies of the Piripauan-early Haumurian age are disconformably overlain by the thick, regionally extensive, siliceous mudstone-dominated Whangai Formation of the Tinui Group (Lillie, 1953; Moore, 1988b; see Crampton et al., 2006, Figure 2). The formation consists typically of 300-500 m of non-calcareous and calcareous shale and mudstone of Haumurian-Teurian age; rarely the formation may be up to 600 m thick (Moore, 1988b). Three regionally extensive and two local members were differentiated by Moore:

Regional members:

1. Upper Calcareous Member
2. Porangahau Member
3. Rakauroa Member

Local members:

1. Te Uri Member
2. Kirks Breccia Member

It is a widespread formation which conformably or unconformably overlies older Cretaceous sedimentary rocks and is usually overlain conformably by the Waipawa Formation. Waipawa Black Shale is an old term used by Moore (1989a) and Leckie et.al. (1992). The formal term used nowadays is the Waipawa Formation.

As described above the Whangai Formation shows different lateral and vertical facies. Two main facies are distinguished: Western and Eastern facies (Figure 3.12), Moore (1988a).

- I. Western Facies – poorly-bedded, non-calcareous to slightly calcareous mudstone;
- II. Eastern Facies – mainly well-bedded, non-calcareous to highly calcareous mudstone.

Figure 3.12 Simplified diagram showing stratigraphic relationship of the Whangai Formation, and its various members and facies (modified from Moore, 1988a).

It is also important to highlight that within East Coast Allochthon, given the structural complexity and similar lithologies, it can be difficult to distinguish facies within the Whangai Formation. Thus, Moore (1988a) included “undifferentiated Eastern Facies” or “Undifferentiated Whangai” for this part of the Basin.

This thesis focused only on the three widespread members of the Whangai Formation (Upper Calcareous, Porangahau and Rakauroa), and the Waipawa Formation, because of their regional extents. The main organic and inorganic geochemical characteristics of these three facies of Whangai are given in Tables 3.1 to 3.3 and data coverages are shown in Figures 3.13, 3.14, and 3.15. Note that the analysis is based on all available data (GNS Science and new data).

Table 3.1 The three main facies of Whangai and their brief description (p.12–16 -Moore, 1988a).

Name	Main Type Sections	Description
Upper Calcareous	Tangaruhe Stream Te Rata Stream Te Weraroa Te Mai	Hard, usually very poorly bedded, light bluish-grey weathering, slightly to moderately calcareous (1-15% CaCO_3), bioturbated, laminated micaceous mudstone, glauconitic sandstone beds, and rare breccia. <i>Terebellina</i> tubes and fish scales are common. The average thickness 150–200 m.
Porangahau	Kaihika Ridge Old Hill Road Whangai Bluff Wairamaia Stream	Hard, well bedded, light grey to almost white weathering, grey to green-grey, slightly to highly calcareous (5-40% CaCO_3), mudstone with common glauconitic sandstones beds. Mudstones beds are moderately to highly bioturbated, Thin alternating light and darker grey mudstone layers are locally referred to as “Zebra Facies”. The average thickness is about 70 m.
Rakauroa	Upper Koranga Valley Rakauroa Stream Tangaruhe Stream Pukemuri Stream	Hard, usually very poorly bedded, rusty weathering, bioturbated, medium grey, non- calcareous, micaceous mudstone with thin glauconite sandstones beds. It can be sandy near the base. Fossils are rare, apart from fish scales and sparse foraminifera. The average thickness is about 200–300 m.

Table 3.2 Main organic geochemical characteristics of the three facies of the Whangai Formation, (Rogers, 1999 and GNS Science, 2016). Note that the Hydrogen Index of Porangahau Mbr. is 8 samples as one value was not reliable (700 mg HC/g) and for the Rakauaroa Mbr. 182 samples as two values were not reliable (613/818 mg HC/g).

	Quantity			Quality	Maturation
Whangai Fm. Member	TOC wt%	S1 mg HC/g	S2 mg HC/g	HI mg HC/g	T Max (°C)
Upp. Calc	0.08 - 2.0	0.01 - 0.35	0.2 - 4.42	39 - 377	374 - 450
Average	0.73 ₍₅₀₎	0.10 ₍₅₀₎	1.30 ₍₅₀₎	184 ₍₅₀₎	422 ₍₅₀₎
Porangahau	0.01 - 1.0	0.02 - 0.18	0.04 - 1.1	27 - 275	359 - 446
Average	0.35 ₍₀₉₎	0.08 ₍₀₉₎	0.37 ₍₀₉₎	130 ₍₀₈₎	410 ₍₀₉₎
Rakauaroa	0.2 - 1.77	0.02 - 5.12	0.08 - 10.14	26 - 350	333 - 440
Average	0.85 ₍₁₈₄₎	0.21 ₍₁₈₄₎	1.69 ₍₁₈₄₎	193 ₍₁₈₂₎	415 ₍₁₈₄₎

Table 3.3 Main inorganic geochemical characteristics of the three facies of the Whangai Formation, (Moore, 1988a, new data from this thesis and GNS Science, 2016).

Whangai Fm. Member	SiO ₂ _anhy* (%)	Al ₂ O ₃ _anhy (%)	CaO_anhy (%)	Al ₂ O ₃ _anhy+ K ₂ O_anhy+TiO ₂ _anhy (%)
Upp. Calc	70.08 - 82.30	5.86 - 11.00	0.22 - 7.75	7.15 - 13.50
Average	75.61 ₍₁₂₎	8.27 ₍₁₂₎	2.29 ₍₁₂₎	10.04 ₍₁₂₎
Porangahau	58.18 - 74.03	6.46 - 7.88	2.75 - 15.93	7.82 - 9.58
Average	67.14 ₍₀₃₎	7.38 ₍₀₃₎	8.47 ₍₀₃₎	8.99 ₍₀₃₎
Rakauaroa	68.59 - 84.78	5.97 - 12.09	0.04 - 4.98	7.15 - 14.72
Average	74.94 ₍₂₅₎	9.31 ₍₂₅₎	0.98 ₍₂₅₎	11.35 ₍₂₅₎

*Anhy – no water (removed)

Figure 3.13 Upper Calcareous Member sample locations along ECB and the seven tectonic blocks classified by Moore 1988a. (A) samples with organic geochemical analyses and (B) samples with inorganic geochemical analyses.

Figure 3.14 Porangahau Member sample locations along ECB and the seven tectonic blocks classified by Moore 1988a. (A) samples with organic geochemical analyses and (B) samples with inorganic geochemical analyses.

Figure 3.15 Rakauroa Member sample locations along ECB and the seven tectonic blocks classified by Moore 1988a. (A) samples with organic geochemical analyses and (B) samples with inorganic geochemical analyses.

3.5.2 Waipawa Formation:

The Waipawa Formation is considered the most prominent source rock of the East Coast Basin due to its high TOC content and Hydrogen Index. The formation is of particular interest because it is the best proven hydrocarbon source rock in the region. At Okau Stream, Wairarapa, 30 m of black shale contains oil-impregnated greensands (Francis, 1990b). North of Riversdale at Kororiki Stream, also in the Wairarapa, oil has been reported bleeding from freshly quarried Waipawa Formation (D.A. Leckie unpublished data). However, the geomechanical properties of this unit have not been evaluated fully.

Prior to 1957, black or chocolate-coloured mudstone (or shale) in different parts of the region was generally included in the Mangatu Group and/or the Whangai Formation (e.g., Lillie, 1953). Its stratigraphic position at the top of the Rakauroa (Whangai) was recognised by Finlay (1939), and he introduced the name Waipawa Black Shale in 1940 (Finlay, 1940 p.448). However, the formation was not described adequately until 1957 (Hornibrook & Harrington, 1957), and not defined formally until 1959 (Hornibrook, 1959).

In the eastern North Island, the Whangai Formation is conformably overlain by the Waipawa Formation (also called the Waipawa Black Shale; Moore 1989a; Leckie et al., 1992), a regional marker unit of very poorly bedded, dark brownish grey to brownish black, moderately soft to hard, non-calcareous, micaceous siltstone. In places, the Waipawa Formation includes glauconitic sandstone or greensand, and Whangai-like calcareous mudstone (Moore, 1989b).

The formation shows marked variation of thickness. The greatest known thickness is at Kerosene Bluff, Whakataki (Coastal Block), where an apparent thickness of 80 m is exposed, although some structural repetition is likely and the true thickness is probably 50-60 m. However, the well drilled by East Coast Energy Ventures in 2011 (Orui-1 and 1a, Coastal Block) showed the Waipawa thickness of 80 m. Based on Francis (2000), the average for Waipawa Formation is around 20-30 m.

The Waipawa Formation is mid- to late Teurian in age (Moore 1988b, 1989a), based on studies of calcareous nannoplankton (Edwards 1971 & unpublished data) and dinoflagellates (Wilson, 1988). The formation is highly bioturbated in places. Leckie et al. (1992) interpreted the Waipawa Formation as a condensed section deposited at the peak of the marine transgression that took place during the Late Cretaceous to Paleocene. The main

characteristics of Waipawa Formation are provided in Tables 3.4 to 3.6 and lateral extents of data coverage are depicted in Figure 3.16.

Table 3.4 The Waipawa Formation and its brief description (p.17-Moore, 1988a).

Name	Main Type Sections	Description
Waipawa	Te Weraroa Rakauroa Stream Taylor White Mangatarata Stream	Hard to moderately soft, usually very poorly bedded, dark brown-grey to brownish black, bioturbated, micaceous mudstone and fine sandstone with common glauconitic sandstone beds. Foraminiferas are sparse and Macrofossils are common. The average thickness is about 20 m.

Table 3.5 Main organic geochemical characteristics of the Waipawa Formation (Rogers, 1999 and GNS Science).

Formation	Quantity			Quality	Maturation
Waipawa	TOC wt%	S1 mg HC/g	S2 mg HC/g	HI mg HC/g	T Max (°C)
Range	0.38 - 12.3	0.02 - 3.0	0.2 - 45.9	22 - 550	386 - 436
Average	3.46 ₍₁₄₉₎	0.55 ₍₁₄₉₎	8.29 ₍₁₄₉₎	214 ₍₁₄₉₎	414 ₍₁₄₉₎

Table 3.6 Main inorganic geochemical characteristics of the Waipawa Formation (Moore, 1988a, new data “thesis” and GNS Science, 2016).

Formation	SiO ₂ _anhy (%)	Al ₂ O ₃ _anhy (%)	CaO_anhy (%)	Al ₂ O ₃ _anhy+ K ₂ O_anhy+TiO ₂ _anhy (%)
Waipawa	59.30-69.53	10.19-15.55	0.05-0.73	12.32-18.37
Average	64.05 ₍₉₎	12.00 ₍₉₎	0.34 ₍₉₎	14.55 ₍₉₎

Figure 3.16 Waipawa Formation sample locations along ECB and the seven tectonic blocks classified by Moore 1988a. (A) samples with organic geochemical analyses and (B) samples with inorganic geochemical analyses.

3.6 THE SOURCE ROCK POTENTIAL OF THE WHANGAI AND WAIPAWA FORMATIONS

Elgar (1997) reviewed the previous studies of petroleum geochemistry in the East Coast Basin, as follows. Gibbons (1980) also identified the Waipawa Formation as being the only potentially significant source in the Gisborne region and adjacent areas, but a very thin formation (c. 10m). Fry (1982) has demonstrated that the Waipawa Formation samples were characterised by dominated amorphous kerogen of marine algal origin and showed both oil and gas potential. Jackson (1982) used 30 samples in his studies but only three formations were considered to present moderate to good potential to generate hydrocarbons. These formations were Karekare, Whangai, and Waipawa, which were both oil and gas prone. The hydrocarbon signatures indicated two different sources: marine and a more terrigenous influence. Moore et al. (1987), examined 30 samples from uppermost Cretaceous to Paleocene, where Whangai was identified to present little source potential and Waipawa a very high generative potential. Both formations showed a mix of Types II (marine) and III (terrestrial) kerogen, although the Upper Calcareous Member of the Whangai Formation was found to contain more marine organic matter than Rakauora Member, which shows a higher proportion of terrestrial organic matter influence. According to Hirner and Lyon (1989) and Hirner and Robinson (1989), the oil from seeps along East Coast Basin showed a distinct family when compared to Taranaki and West Coast as they exhibited greater marine influence. However, it is important to highlight that none of the oils sampled has the Waipawa Formation as a source. Leckie et al. (1992), using results of 190 TOC and Rock-Eval analyses of Late Cretaceous and Paleogene along East Coast Basin, found that, except for the Upper Calcareous Member, the Whangai members showed low TOC and hydrogen index. Although, the Waipawa Formation does not exceed 50 m thick, it has shown TOC and hydrogen index up to 5.3% and 550 mg HC/g, respectively. Gas seeps are observed both onshore and offshore throughout the basin. Oil seeps and stains are less common, but are detected onshore. Two oil families are recognized based on biomarker and stable carbon isotope analyses of oil seeps and stain samples (Murray et al., 1994; Rogers et al., 1999). Family 1 oils are found in the Waitangi, Totangi, and Rotokautuku oil seeps and the Motu Valley, Isolation Creek, and Knights Stream oil stain locations and have been tentatively tied to the Whangai Formation (Murray et al., 1994; Rogers et al., 1999; Waples, 2001; Hollis et al., 2005). Family 2 oils are found exclusively in the Wairarapa region in the Okau Stream, Westcott, and Tunakore Stream locations. The Waipawa Black Shale is a proven source for Family 2 oils because the Okau Stream oil of Family 2 was sampled from sandstone enveloped by the Waipawa Black Shale (Rogers et al., 1999). This is further

confirmed by isotopic and biomarker source rock and oil analyses (Murray et al., 1994; Rogers et al., 1999). Mixtures of Family 1 and 2 oils are present in the Tiraumea and Kerosene Rock locations (Fig. 3.17) (Rogers et al., 1999).

Most of the Whangai and Waipawa formations samples are considered immature, mainly from the outcrop samples, except in very localised places, where the Whangai Formation shows a slightly maturity.

Figure 3.17 Hydrocarbon occurrence along East Coast Basin, New Zealand. Seep sites are based on locations from Hollis et al. (2005) and references therein. Well locations and well description are from the web-based Petroleum Basin Explorer (Scadden et al., 2013 and references therein). Miocene seep site locations are from Campbell et al. (2008) and Cretaceous seep site locations are from Kiel et al. (2013). Digital elevation map is from NIWA (2008).

3.7 OVERVIEW

These are the main geological contexts, which will serve as a framework to help analyse and understand the East Coast Basin petroleum system.

4. EAST COAST SHALE

4.1 INTRODUCTION

The purpose of this chapter is to show the scale and the previous and the new datasets used in this research, outlining three different analyses (organic and inorganic geochemistry, and rock properties) undertaken for this study. These are applied to characterize the Whangai and Waipawa formations as unconventional reservoirs.

Any type of sedimentary basin, whether explored or produced, can be classified under four main phases: exploration, appraisal, production and abandonment phases (Figure 4.1). The East Coast Basin is in its exploration phase, so the level of detail is appropriate to a basinwide scale. It is important to highlight that the most costly capital investment takes place in the appraisal phase. This is the phase where more detailed of the reservoir characteristics and required infrastructure are developed. For example, many shale basins in Canada and U.S. are in the production phase, whereas the Vaca Muerta (Argentina), Sichuan (China) and Bazhenov (Russia) are currently in the appraisal phase.

BUSINESS MODELLING

Figure 4.1 Schematic curve showing the four main phases of development of a petroliferous sedimentary basin and where the East Coast Basin is placed.

This study spans the area from Wairarapa Coast in the south to Raukumara Peninsula in the north. From the open file measured sections compiled by GNS, the most complete and representative measured sections of the Whangai and Waipawa formations were reviewed and one section per structural block was selected (Figure 4.2). All potential key measured sections of the East Coast CCP (Field et al., 1997) were reviewed, and from them, a database of the relevant qualitative (lithology) and quantitative information (grid co-ordinates, thickness, age) was constructed for each formation in each section. This allowed maps of sediment distribution, thickness and age to be produced. The East Coast CCP (Field et al., 1997) was used to determine key time intervals where sedimentary successions are exposed and accessible for study. Based on this, the following time intervals have been selected for this study: Piripauan (85 Ma), Haumurian (70 Ma), and Teurian (56 Ma). These intervals are readily identifiable and can be traced across the North and South Island extents of the East Coast Basin. In the case of the Teurian Stage, which is equivalent to the entire Paleocene, the analysis focuses on the extent of the Waipawa Formation, which is a comparatively thin (<5–70 m) but broadly distributed, isochronous unit that can be traced throughout the East Coast Basin (Moore, 1988b; Moore, 1989b; Field et al., 1997; Hollis et al., 2014). In the case of the Haumurian Stage, which is equivalent to the upper half of the Upper Cretaceous, the analysis focuses on the extent of the Whangai Formation and its members, which forms a comparatively thick (~400 m) but broadly distributed, isochronous unit that can be traced throughout the East Coast Basin (Moore, 1988a).

Due to the lack of organic and inorganic geochemistry and rock properties (geomechanical) analyses undertaken on the same rock sample in existing datasets for both Whangai and Waipawa formations, it was decided to collect a new dataset in which additional analyses could be performed. The organic geochemistry analysis gives the reservoir quality, the inorganic geochemistry analysis the reservoir quality, chemical weathering, climate fluctuations, composition, and provenance, and lastly, the geomechanical analysis gives the brittleness index (log interpretation from three exploration wells and outcrop samples). Types of analyses are summarised in Table 4.1.

Eight measured sections and three exploration wells were selected as a key dataset for characterizing the Whangai and Waipawa formations as unconventional reservoirs in the East Coast Basin (Figure 4.2). Twenty-three rock samples collected for this thesis are added to the GNS Science dataset to be used for machine-learning model analysis (Chapter 5) in order to identify the sweet spots in the basin.

Table 4.1 Variables used for Whangai and Waipawa characterization based on organic and inorganic geochemistry, and rock properties from outcrop samples as well as well log data interpretations from three exploration wells.

Formation	Organic Geochemistry	Uses of Inorganic Geochemistry	Rock Properties (Brittleness Index)	
			Exploration Wells	Outcrop Samples
Whangai	Quantity: TOC, S2 Quality: HI Maturation: Tmax, Ro	Brittleness Index: SiO ₂ , Al ₂ O ₃ , CaO Chemical Weathering, Climate Fluctuations, Composition, and Provenance: K ₂ O, TiO ₂ , MgO, Fe ₂ O ₃ , MnO, Na ₂ O, Al ₂ O ₃ and CaO	Log interpretation Well report	Vp/Vs (measure)
Waipawa	Quantity: TOC, S2 Quality: HI Maturation: Tmax, Ro	Brittleness Index: SiO ₂ , Al ₂ O ₃ , CaO Chemical Weathering, Climate Fluctuations, Composition, and Provenance: K ₂ O, TiO ₂ , MgO, Fe ₂ O ₃ , MnO, Na ₂ O, Al ₂ O ₃ and CaO	Log interpretation Well report	Vp/Vs (measure)

Figure 4.2 Location of the eight measured sections (black circles) distributed across the structural blocks sub-division of Moore (1988a & b) (coloured polygons) and the three exploration wells (red triangles) used in addition to the existing data to identify the “sweet spots” in the basin.

4.2 PREVIOUS DATA – PUBLIC DOMAIN

GNS Science made available, based on the purpose of this thesis, their entire set of various types of data relevant to the Whangai and Waipawa formations. Five different laboratories provided rock analyses: AGSO, Geotech, GNS, GSC, and LIG. No parametrization has been done to check for any discrepancies in the laboratory methodologies and, consequently, differences in their results. Only one data quality control was applied. The selection criterion was to use only the GNS datasets that have all the variables required for the purpose of this study (for example, only full Rock-Eval analyses were included; samples with only TOC measured were not). Based on that, 226 organic geochemistry and 24 inorganic geochemistry assessment localities within the Whangai Formation, and 142 existing sample localities within the Waipawa that had been assessed by organic geochemistry and two that had been assessed by inorganic geochemistry were selected (APPENDIX 1). In this respect, there are some differences in the numbers of localities compared to Hollis (2005), for example. See Table 4.2 to 4.5 to identify the numbers of localities from the GNS Science datasets of the Whangai and Waipawa formations subdivided by structural blocks. In addition, three exploration wells were selected for this study (Hukarere-1, Opoutama-1 and Rere-1, Figure 4.2). These are the only wells that reached these geological formations in the subsurface and produced reliable data for rock properties analysis.

Table 4.2 Numbers of samples per structural block, with organic and inorganic geochemical analyses of the Whangai Formation.

Structural Block	Organic geochemical analysis	Inorganic geochemical analysis
Tora	3	2
Pongaroa	93	8
Coastal	39	4
Motu	82	7
Allochthon	9	3
TOTAL	226	24

Table 4.3 Numbers of samples per structural block and member, with organic geochemical analyses of the Whangai Formation.

Structural Block	Rakauroa Member	Porangahau Member	Upper Calcareous Member
Tora	3	0	0
Pongaroa	82	0	11
Coastal	3	6	30
Motu	81	0	1
Allochthon	2	2	5
TOTAL	171	8	47

Table 4.4 Numbers of samples with inorganic geochemical analyses of the Whangai Formation.

Structural Block	Rakauroa Member	Porangahau Member	Upper Calcareous Member
Tora	2	0	0
Pongaroa	4	0	4
Coastal	1	2	1
Motu	6	0	1
Allochthon	0	0	3
TOTAL	13	2	9

Table 4.5 Numbers of samples per structural block, with organic and inorganic geochemical analyses of the Waipawa Formation.

Structural Block	Organic geochemical analysis	Inorganic geochemical analysis
Tora	0	0
Pongaroa	6	1
Coastal	71	0
Motu	20	0
Allochthon	45	1
TOTAL	142	2

4.3 NEW SAMPLES (THIS THESIS)

Tables 4.6 and 4.7 show the GNS dataset and the dataset collected for this thesis (new sample) relating to the same measured sections of the Whangai and Waipawa formations, respectively. The Measured sections are grouped into northern and southern parts of Hawke's Bay: **Southern Hawke's Bay** includes Mangatarata Valley, Taylor White, Angora Stream, Tangaruhe Stream and Pukemuri Stream, and **Northern Hawke's Bay** includes Rakauroa Stream, Te Weraroa, Waitahaia, Owheana and Waitahaia River (Figure 4.2). Figures 4.3 to 4.6 show the eight measured sections in detail selected as key sections, with the GNS and the new collection rock samples plotted (Whangai and Waipawa). Samples were taken systematically from the measured sections of different areas, selecting upper and lower parts of each rock formation and members (where present) and trying to fill the gaps from previous samples. Elemental analyses were performed on all samples. Based on these data, and with emphasis on an even distribution throughout the succession, samples were chosen for the SRA (Source Rock Analysis), XRF (X-Ray Fluorescence) and geomechanical analyses. SRA analysis took place at GNS (Lower Hutt), XRF at NIWA (in Wellington) and the geomechanical analyses at Auckland University (outcrop samples) and Baker Hughes of Brazil (well-logging).

Table 4.6 The total Whangai data set (from both GNS data and this thesis). “x” indicates presence and NA – not applicable.

	Block	Locality (measured section)	Rakauroa Mb.	Porangahau Mb.	Upper Calcareous Mb.	Samples (GNS)	Samples (Thesis)
Southern Hawke's Bay	Tora	Pukemuri Stream	x			2	4
	Coastal	Angora Stream	x	x	x	44	4
	Coastal	Taylor White				0	NA
	Pongaroa	Mangatarata Valley				1	NA
	Pongaroa	Tangaruhe Stream	x		x	12*	12*
Northern Hawke's Bay	Motu	Rakauroa Stream	x			3	3
	Motu	Waitahaia River/Owhena	x			1	3
	Allochthon	Te Weraroa Stream	x		x	5	2
Totals						77	16

*Samples used from GNS Science dataset, in order to represent Whangai in the Pongaroa Block.

Table 4.7 The total Waipawa data set (from both GNS data and this thesis). “x” indicates presence and NA – not applicable.

	Block	Locality (measured section)	Waipawa	Samples (GNS)	Samples (Thesis)
Southern Hawke's Bay	Tora	Pukemuri Stream	NA	0	NA
	Coastal	Angora Stream	x	35	NA
	Coastal	Taylor White	x	0	2
	Pongaroa	Mangatarata Valley	x	1	4
	Pongaroa	Tangaruhe Stream	NA	0	NA
Northern Hawke's Bay	Motu	Rakauroa Stream	x	3	0
	Motu	Waitahaia River	x	9	0
	Allochthon	Te Weraroa Stream	x	23	1
Totals				71	7

Figure 4.4 Key measured sections selected showing sample coverage for the Whangai Fm. per structural block from south to north: Rakauroa Stream (Motu Block), Te Weraroa Stream (Allochthon Block) and Owheha (Motu Block). Only the new samples are labelled here. See Appendix 2 for enlarged versions of measured sections.

● New Sample

Figure 4.5 Key measured sections selected showing sample coverage for the Waipawa Fm. per structural block: Taylor White (Coastal Block) Mangatarata Valley (Pongaroa Block). Only the new samples are labelled here. See Appendix 2 for enlarged versions of measured sections.

Figure 4.6 Key measured section selected showing sample coverage for the Waipawa Fm. at Te Weraroa Stream (Allochthon Block). Only the new samples are labelled here. See Appendix 2 for enlarged versions of measured sections.

The core plug samples obtained in this study were drilled from fresh outcrop faces, using a portable drill with a bit of 1.1/2 or 15/16-inch diameter. Samples were wrapped in a plastic bag and clearly identified. The ends of the cores were trimmed at the PORO (Physics of Rocks) laboratory of the Auckland University. The plug ends were milled and the powder was split into two containers for organic and inorganic geochemical analyses (sections 4.4 and 4.5, respectively). The remained core samples were used to calculate the brittleness index from the outcrops (section 4.6).

Core plug samples were not available for the three exploration wells, and geomechanical analysis was based on wireline log and well completion report data (section 4.7).

Below follows, the description of each methodology (organic and inorganic geochemistry, and rock properties) applied to outcrop samples and well logs, and their results and interpretations.

4.4 ORGANIC GEOCHEMISTRY

4.4.1 Introduction

Organic geochemistry provides the information needed to build up maps of quantity, quality and maturation of a source rock. These maps outline the stratigraphic and geographic extent of a kitchen of active source rock in a petroleum system (Demaison, 1984). Geochemical analyses are practical exploration tools for rapid and inexpensive evaluation of a large number of rock samples from outcrops and wells. Although, there are other types of geochemical analyses, such as organic petrography, vitrinite reflectance, gas chromatography, and liquid chromatography, the most effective screening method for a large number of rock samples from wells and outcrops combines Rock-Eval pyrolysis and TOC measurements. Given that, for this study only Rock-Eval pyrolysis, vitrinite reflectance and TOC are evaluated and are used as input data into the machine-learning model (Chapter 5).

4.4.2 Source Rock Properties and Terms

Sedimentary rocks generally consist of minerals and organic matter (OM), with their pore space occupied by oil, gas, bitumen and water. The OM is material derived from terrestrial and marine organisms (Tissot and Welte, 1984) and it is divided in two fractions: kerogen and

bitumen, where kerogen is insoluble and composed by particulate organic matter and bitumen is soluble and composed by molecular organic matter. The latter can be solid or semi-solid with a colloidal structure, or a highly viscous fluid. The degree of solubility depends of the type and strength of the solvent. Pyrobitumen is the solid hydrocarbon residue of hydrocarbon generation from bitumen and even through it is insoluble; it still shows capacity to generate hydrocarbons upon further heating. Char is the last residue of hydrocarbon generation and generally does not show any potential to generate hydrocarbons (Tissot and Welte, 1984). A schematic representation of the evolution of organic matter is shown in Figure 4.7.

Figure 4.7 Schematic representation of the evolution of organic matter from photosynthesis, through the oil/gas window, to post-methane generation. Solid outlines indicate solid material; short-dash outlines indicate fluids retained in the rock (gas dissolved in oil); long-dash outlines indicate expelled hydrocarbon and short-dashes indicate fluid retained in the rock. Φ – porosity hosted by various organic materials. The overall size of rectangles roughly indicates relative volume of each component (modified from Bohacs, et.al., 2013).

As described by Tyson (1995), kerogen represents about 95% or more of the total OM in sedimentary rocks. Figure 4.8, shows a schematic flowchart of organic richness controls. These two fractions generally use different techniques to be analysed. Kerogen uses microscopic and geochemical techniques and bitumen uses organic geochemical techniques, such as: solvent extraction, liquid chromatography (LC), and gas chromatography (GC).

Figure 4.8 The main factors of organic-richness interactions, (modified by Passey et.al., 2010).

Kerogen is defined by Spackman (1958) as an organic substance, or optically homogenous aggregates of organic substances, possessing distinctive physical and chemical properties, and occurring naturally in the sedimentary, metamorphic, and igneous materials of the earth. The amount and maceral composition of kerogen, determine petroleum potential and can differ vertically or laterally within a source rock. Using the three major elements (C, H and O) the kerogen composition can be subdivided into four types of kerogen first used by van Krevelen (1961) to characterize coals (Figure 4.9). This technique is time-consuming and expensive, making it unsuitable for onsite drilling operations or screening large sample populations. A quicker and less expensive method uses a modified van Krevelen diagram that utilizes Rock-Eval and TOC parameters. Tissot & Welte (1984) represented the main types of kerogen (Table 4.8) and their evolution paths based on Hydrogen Index (HI) and Oxygen Index (OI) (Figure 4.10) and their quality using the relationship between the Total Organic Carbon (TOC) and S₂ (Figure 4.11). Nevertheless, Jones (1987) demonstrated that the composition of the facies types is not only dependent on the original input material, but also on the availability of oxygen during and after deposition. He suggests that oxic environments convert hydrogen-rich OM into OM with lower H/C due to the OM degradation.

Figure 4.9 Plot of H:C vs. O:C atomic ratio used to evaluate the kerogen type, (Waples,1985).

Table 4.8 The main types of kerogen and its description, Tissot & Welte (1984).

Type of Kerogen	Basic Description
Type I	High initial H/C and low initial O/C atomic ratio; Lipidic material (algal/microbial activity); High potential of hydrocarbon generation.
Type II	High H/C and low O/C atomic ratio; Pollen grains, spores, cuticles and marine OM; Reducing environments; Medium to high sulphur content; High potential of hydrocarbon generation.
Type III	Low H/C and higher O/C than type I and II; Terrestrial higher plants; Oil potential is moderate, abundant gas in greater depths.
Type IV	High carbon content and is hydrogen poor; No potential hydrocarbon generation due its composition (aromatic components, oxidation -pre-depositional);

Figure 4.10 Modified Van Krevelan diagram, showing the types of the kerogen and their hydrocarbon potential generation, Tissot & Welte (1984).

Figure 4.11 Schematic Rock Eval plot showing the quality of the kerogen, Tissot & Welte (1984).

When the rock samples are submitted to a Source Rock Analyser (SRA), some terms have to be clarified. Table 4.9 and 4.10 to 4.12 show the main products derived from a pyrolysis system and its classification based on quantity, quality and maturation, respectively. With these results it is also possible to calculate the Total Organic Carbon (TOC).

Table 4.9 Description of the main products from pyrolysis (Mendonca Filho et al., 2012).

Products	Description
S1 – (mgHC/g of rock)	Free hydrocarbon in the rock: present at time of deposition or was generated from kerogen since deposition
S2– (mgHC/g of rock)	Source rock potential
S3– (mg CO ₂ /g of rock)	CO ₂ released from resistant components of the kerogen
HI– (S2/g TOC)	Hydrogen Index – quality of the organic matter
Tmax (°C)	Represents the maximum temperature of hydrocarbon generation during the pyrolysis
Production Index	Ratio S1/(S1+S2) – it is used when migration process did not occur
Total Organic Carbon (TOC %)	Mass weight percent of rock – provides only a semiquantitative scale of petroleum-generating potential. Indicates the quantity, but not the quality, of the organic matter.

Table 4.10 Geochemical parameters describing the petroleum potential (**quantity**) of an immature source rock (Peters et al. 2005).

Petroleum Potential	<u>Organic Matter</u>			Bitumen ^c		Hydrocarbons (ppm)
	TOC (wt. %)	Rock Eval Pyrolysis S1 ^a	S2 ^b	(wt. %)	(ppm)	
Poor	0-0.5	0-0.5	0-2.5	0-0.05	0-500	0-300
Fair	0.5-1	0.5-1	2.5-5	0.05-0.10	500-1000	300-600
Good	1-2	1-2	5-10	0.10-0.20	1000-2000	600-1200
Very Good	2-4	2-4	10-20	0.20-0.40	2000-4000	1200-2400
Excellent	>4	>4	>20	>0.40	>4000	>2400

^amg HC/g.dry rock distilled by pyrolysis.

^bmg HC/g dry rock cracked from kerogen by pyrolysis.

^cEvaporation of the solvent used to extract bitumen from a source rock or oil from a reservoir rock causes loss of the volatile hydrocarbons below about *n*-C₁₅. Thus, most extracts are described as C₁₅+ hydrocarbons.

Table 4.11 Geochemical parameters describing kerogen type (**quality**) and the character of expelled products ^a (Peters et al. 2005).

Kerogen Type	HI (mg HC/g TOC) ^a	Main Expelled Product at Peak Maturity
I	>300	Oil
II	200-300	Oil + condensate
III	150-200	Gas + condensate
IV	0-150	Gas

^a based on thermally immature source rock. Ranges are approximate.

Table 4.12 Vitrinite Reflectance and Tmax parameters describing level of **thermal maturation** (Peters et al. 2005).

Stage of Thermal Maturity for Oil	Maturation	
	Ro(%) Vitrinite Reflectance	Tmax(°C)
Immature	0.2-0.6	<435
Top Oil Window	0.6	435
Bottom Oil Window	1.35	470
Postmature	>1.35	>470

It is also important to recognise that the TOC for a given kerogen type will not be all converted into hydrocarbons; in other words, there is a generative organic carbon (GOC) and non-generative organic carbon (NGOC) percentage in the total value. The generative organic carbon is responsible for the generation of hydrocarbons and also accounts for the development of organic porosity. On the other hand, non-generative organic carbon does not generate any appreciable amount of hydrocarbon, but does account for storage by adsorption. If some hydrocarbon has been generated, it is important to distinguish two different TOC values: the original total organic carbon (TOC_o) and the present day total organic carbon (TOC_{pd}). Note that the fact that some hydrocarbon has been generated from the GOC, for example 50%, does not mean that TOC will be reduced by 50%. Only the GOC will be reduced by 50%. The NGOC will slightly increase due to hydrogen shortage in kerogen and bitumen. The distribution of TOC will vary by kerogen type. Thus, Type I has a higher percentage of GOC than II and III, consecutively.

What makes an OM become more or less generative is the maceral groups that form it. The three principal maceral groups in coal and sedimentary rocks are liptinite (hydrogen rich), vitrinite (oxygen rich), and inertinite (carbon rich), (Stach et al., 1982). Maceral composition (Table 4.13) is determined via petrographic (optical) analyses of pelletized samples or thin

sections. To fully characterize kerogen type and maceral composition, Rock-Eval pyrolysis and microscope analyses should be applied.

Table 4.13 Maceral Groups and type of kerogen, Merrill (1991) and Tyson (1987).

Maceral Group	Macerals	Organic Precursors	Kerogen Type
Liptinite	Alginite I	Fresh Water Algae	I
	Alginite II	Marine Algae	II
	Exinite	Spores (Sporinite), Pollen	II
	Cutinite	Leaf Cuticle	II
	Resinite	Resin, Tree Sap	II
Vitrinite	Vitrinite, Psuedovitrinite	Woody Tissue	III
Inertinite	Semifusinite, Fusinite, Sclerotinite, etc.	Reworked and/or Oxidized Material, Charcoal	IV

After understanding quality and quantity of the source rock, the final analysis is the thermal maturation, which it is achieved through burial of organic matter by sedimentation and subsequent basin subsidence and it is a key geochemical parameter to assess the likelihood of high-flow-rate shale oil/gas. Maturation of organic matter is considered to take place in three stages: diagenesis, catagenesis and metagenesis (Tissot and Welte, 1978) (Figure 4.12).

Figure 4.12 The three stages of maturation of organic matter (modified from Tissot and Welte, 1978).

Due to the physical/chemical complexity of organic maturation and levels of organic maturity, kerogen matures and generates hydrocarbons at different levels of thermal stress based on its chemical composition. Price and Barker (1985) noticed that hydrogen-rich kerogen matures at a slower rate than oxygen-rich kerogen, and equally, sulphur-rich kerogen can generate hydrocarbons at a very early stage of catagenesis compared with sulphur-poor kerogen (Rullkotter, 1993, Ventura et. al. 2013). For example, Jarvie and Lundell (2001) compared conversion rates, using kinetic data from many types of kerogen at 0.80% Ro at a constant heating rate of 3.3 °C/m.y. They found that a low sulfur type II kerogen such as the Barnett Shale would have 27% converted, a coaly type III kerogen 9% and a high-sulfur and oxygen Monterey Formation 65%. Thus, oil and gas windows vary depending on source rock type and thermal maturity. Given that, using only kerogen type analysis can under or over estimate different stages of hydrocarbon generation.

These are the main subjects that have to be understood in order to assess the potential of a source rock to generate hydrocarbons (quantity, quality and maturation).

4.4.4 Methodology

In this study, Source Rock Analysis (SRA) is used to estimate the petroleum potential of sedimentary rock samples by heating samples in an open pyrolysis system under non-isothermal conditions. The released hydrocarbons are monitored by a flame ionization detector (FID), forming the so-called peaks *S1* (thermovaporized free hydrocarbons) and *S2* (**quantity**) (pyrolysis products from cracking of organic matter) (Figure 4.13). The method is completed by combustion (oxidation) of the residual rock recovered after pyrolysis up to 600°C, under artificial air (N₂/O₂; 80/20). During pyrolysis and combustion, released CO and CO₂ are monitored online by means of an infra-red cell. This complementary data acquisition enables determination of the organic and mineral carbon content of samples, labelled TOC (**quantity**) and MinC, respectively (Espitalié et al., 1977).

Two other analytical parameters of value are the temperature *T*_{max} (**maturity**), recorded at the maximum of hydrocarbon generation during pyrolysis, and used in the kerogen maturation rank evaluation, and the Hydrogen Index ($HI = S2/TOC$) (**quality**), which is used for characterizing the type and origin of the kerogen. See Table 4.9 for the definition of the products from pyrolysis.

Figure 4.13 Schematic chart of a pyrogram. Modified from Roxanna (2011).

From the pyrogram results, criteria were defined in order to select reliable values for the geochemistry analyses.

So, based on the previous dataset (GNS Science) and the new data, vitrinite reflectance and T_{max} indicate that over most of eastern North Island the Whangai and Waipawa samples are immature ($R_o < 0.55\%$) and ($T_{max} < 435^\circ\text{C}$), except in the East Coast Allochthon, where reflectance values range from ~ 0.6 to 1.4% (section - 4.4.5.1). Given that, it has been assumed that variables such as Production Index (PI) and S1 are not very useful as they depend on a sample's maturity to be valuable, and therefore are not used as an input dataset for the machine-learning model and rock evaluation. Also, samples that have shown S2 peaks less than 0.2 mg/g rock (lean rocks), and consequently interfering with the HI and T_{max} result values, were not used. This mechanism is well described by various authors (Peters, 1986; Espitalié et al., 1980), who have shown that mineral matrix can reduce the S2 pyrolysis yield, resulting in a reduction of the hydrogen index and lower apparent source quality. In addition to that, when S2 peaks are small, it makes the T_{max} estimation harder. One good aspect from the formations being classified as immature is the fact that original values of TOC, S2, and hydrogen index have been preserved, as very little generation has occurred. This removes the need to estimate original values for these parameters. This concept is well documented by Rullkotter et al. (1988), who discussed loss of organic carbon during maturation.

In this study, 23 samples were collected and submitted for SRA analyses. The cores were milled and about 150 mg of powder used for the analysis. As this is a well-defined and known method (Espitalié et al., 1985), the SRA workflow is not detailed here, but summarised in Figure 4.14.

Figure 4.14 Schematic illustration of rock collection and SRA analyser.

4.4.5 Results and Interpretations

The results of the SRA analyses of the 23 rock samples (Whangai and Waipawa) for this study are presented in Tables 4.14 and 4.15, respectively. These tables are split by the results of quantity, quality and maturation by locality and structural block. See Figures 4.3 to 4.6 for the measured section locations and Table 4.6 and 4.7 for the number of samples per measured section.

The Rock-Eval diagrams by formation (Whangai and Waipawa) using the GNS science dataset as well as as new data generated here can be seen in Figures 4.15 to 4.20. Figures 4.15 and 4.16 shows the kerogen classification (quality), Figures 4.17 and 4.18 the quantity of both formations, and Figure 4.19 and 4.20 show the quality vs. maturation. Map gridding is performed on quantity (TOC and S2) and quality (hydrogen index) of the organic matter from the Whangai (Upper Calcareous and Rakauroa Members) and the Waipawa formations

(Figures 4.21 to 4.29, respectively). Note that some discrepancies of number of samples for S2 and consequently hydrogen index can be seen in Figure 4.22 and 4.23, as values less than (S2 <0.2 mg HC/g rock) were eliminated. The gridding (interpolation) method applied for these maps and also for the maturation maps, using the ArcGis suite, is the Inverse Distance Weighting (IDW). This is a type of deterministic method for multivariate interpolation with a known scattered data points (geo-referenced dataset-values). The measured values closest to the prediction location have more influence on the predicted value than those farther away. Furthermore, as many rock sample locations have more than one sample per geographical location, the mode is applied. Thus, some observed results plotted on the gridding maps do not match the categories displayed in the legends. Due to the lack of representativeness of rock samples, no map is generated for Porangahau Member. The raw data is provided in APPENDIX 1.

The maturation of these formations is covered in a section 4.4.5.1 after showing the results of quantity and quality of the study formations. Tmax results are used along with vitrinite reflectance measurements extracted from four different Petroleum Reports and a Master's dissertation (Eckersley,1999). Ideally, all these maturation results should be converted to an equivalent vitrinite reflectance range based on the equation given by Jarvie et al. (2001) in order to have a more reliable thermal maturity assessment. However, this is outside the scope of the present study.

Table 4.14 New results (this thesis) of Source Rock Analysis (SRA) from Whangai Formation samples, subdivided by locality, Formation and 3 Members.

Structural Block		Formation	Member	Measured Section	Sample	Quantity		Quality	Maturation
						TOC (wt. %)	S2 (mg HC/g)	HI (mg HC/g TOC)	Tmax (°C)
Southern Hawke's Bay	Tora	Whangai	Rakauroa	Pukemuri Stream	Upuk 01	0.89	1.48	166	430
	Tora	Whangai	Rakauroa	Pukemuri Stream	Lpuk 03	1.38	3.09	224	429
	Tora	Whangai	Rakauroa	Pukemuri Stream	Lpuk 04	1.32	1.68	128	435
	Tora	Whangai	Rakauroa	Pukemuri Stream	Lpuk 05	1.33	2.73	205	428
	Coastal	Whangai	Rakauroa	Angora Stream	AS 07	0.29	0.08	26	378
	Coastal	Whangai	Rakauroa	Angora Stream	AS 11	1	0.84	84	424
	Coastal	Whangai	Porangahau	Angora Stream	AS 13	1	0.76	76	425
	Coastal	Whangai	Upper Calcareous	Angora Stream	AS 18	1.01	0.94	93	427
Northern Hawke's Bay	Motu	Whangai	Rakauroa	Rakauroa Stream	RAK 01	0.76	1.04	138	430
	Motu	Whangai	Rakauroa	Rakauroa Stream	RAK 02	1.17	3.15	269	428
	Motu	Whangai	Rakauroa	Rakauroa Stream	RAK 03	1.04	2.56	247	427
	Motu	Whangai	Rakauroa	Waitahaia Owheua	OW01	0.62	0.75	121	438
	Motu	Whangai	Rakauroa	Waitahaia Owheua	OW02	0.48	0.34	71	434
	Motu	Whangai	Rakauroa	Waitahaia Owheua	OW03	0.41	0.24	58	435
	Allochthon	Whangai	Rakauroa	Te Weraroa Stream	TWR01	0.56	0.82	146	434
	Allochthon	Whangai	Upper Calcareous	Te Weraroa Stream	TWR02	0.76	1.7	223	434

Table 4.15 New results (this thesis) of Source Rock Analysis (SRA) from Waipawa Formation samples, subdivided by locality.

Structural Block		Formation	Member	Measured Section	Sample	Quantity		Quality	Maturation
						TOC (wt. %)	S2 (mg HC/g)	HI (mg HC/g TOC)	Tmax (°C)
Southern Hawke's Bay	Coastal	Waipawa	NA	Taylor White	TW02	3.57	11.2	312	411
	Coastal	Waipawa	NA	Taylor White	TW05	2.75	6.45	234	416
	Pongaroa	Waipawa	NA	Mangatarata Valley	MAN03	4.21	3.26	78	386
	Pongaroa	Waipawa	NA	Mangatarata Valley	MAN04	2.51	2.39	95	398
	Pongaroa	Waipawa	NA	Mangatarata Valley	MAN05	2.57	3.31	129	401
	Pongaroa	Waipawa	NA	Mangatarata Valley	MAN06	2.48	4.01	162	411
Northern Hawke's Bay	Allochthon	Waipawa	NA	Te Weraroa	TWR03	2.82	11.5	406	426

Figure 4.15 Classification of type of Kerogen of the three Members of Whangai Formation (GNS Science and new dataset), subdivided by structural block (**Quality**).

Figure 4.16 Classification of type of Kerogen of the Waipawa Formation (GNS Science and new dataset), subdivided by structural block (**Quality**).

Figure 4.17 Plot of organic richness (TOC) vs. generation potential (S2) of the three Members of Whangai Formation (GNS Science and new dataset) (**Quantity**).

Figure 4.18 Plot of organic richness (TOC) vs. generation potential (S2) of Waipawa Formation (GNS Science and new dataset) (**Quantity**).

Figure 4.19 Plot of kerogen quality (HI) vs. maturation (Tmax) of the three Members of Whangai Formation (GNS Science and new dataset). The shift in the Ranui-1 well could be related to a different laboratory used to run the samples or a lean section of the Rakaroa Member or both.

Figure 4.20 Plot of kerogen quality (HI) vs. maturation (Tmax) of the Waipawa Formation (GNS Science and new dataset).

WHANGAI - UPPER CALCAREOUS MEMBER

Figure 4.21 Map showing the Total Organic Carbon content of Upper Calcareous Mb. (Quantity).

Figure 4.22 Map showing the S2 of Upper Calcareous Mb. (Quantity).

Figure 4.23 Map showing the Hydrogen Index of Upper Calcareous Mb. (Quality).

WHANGAI - RAKAUROA MEMBER

Figure 4.24 Map showing the Total Organic Carbon content of Rakauroa Mb. (Quantity).

Figure 4.25 Map showing the S2 of Rakauroa Mb. (Quantity).

Figure 4.26 Map showing the Hydrogen Index of Rakauroa Mb. (Quality).

WAIPAWA FORMATION

Figure 4.27 Map showing the Total Organic Carbon content of the Waipawa Formation (**Quantity**).

Figure 4.28 Map showing the S2 of the Waipawa Formation (**Quantity**).

Figure 4.29 Map showing the Hydrogen Index of the Waipawa Formation (**Quality**).

4.4.5.1 Maturation of the Whangai and Waipawa formations

For evaluation of plays and prospects, it is convenient to overlay the predicted oil and gas windows with vitrinite reflectance and geochemical data. The exploration risk is lower if the interpretations agree and higher if they disagree. The occurrence of many oil and gas seeps along East Coast Basin indicates that the source rocks have reached enough maturity to generate and expel hydrocarbons in the basin. Based on Field & Uruski et. al. (1997), the isopach for Late Cretaceous and Paleocene sediments suggests that these rocks should have reached maturity over a wide area in the late Miocene. They also indicate that the highest maturity levels are related to the East Coast Allochthon. However, Eckersley's (1999) maturity studies utilizing outcrop samples have shown that potential source rocks in the Allochthon block area are immature to marginally mature. Thus, a compilation of all open file available data for this studied area has been utilized to summarise the maturation of the two main potential source rocks in the East Coast Basin, as well as the data generated for this thesis.

4.4.5.1.1 – Vitrinite Reflectance

Vitrinite-inertinite reflectance and fluorescence analysis (VIRF) were used to analyse the thermal maturity of the East Coast Basin outcrops and well rock samples in four open-file petroleum reports (summarised in Table 4.16) and a MSc dissertation by Eckersley (1999). It is important to define that the percentage unit of the vitrinite reflectance is the measured percentage of reflected light from a sample which is immersed in oil (%Ro = % reflectance in oil).

VIRF utilises paired fluorescence and reflectance measurements as a numerical basis for differentiating indigenous vitrinite of normal chemistry from perhydrous (maceral with high hydrogen content), caved, hydrothermally altered and reworked vitrinite. This greatly improves the precision of vitrinite reflectance as a maturity indicator. However, sometimes migrated/solid bitumen can occur covering pore spaces or fractures. These bitumens probably are solid residues of oil (Robert 1998) and be easily misinterpreted as vitrinite (Koch, 1997).

According to Newman (in ECEV 2012), interpretation of VIRF data for outcrop samples is challenging. Firstly, in contrast to a series of drill hole samples, an outcrop provides no contextual information. Also, weathering can alter the composition of organic matter, depressing fluorescence. Consequently, it is preferable to have both lithological and mineralogical evidence to assess the likely degree of weathering. Hydrothermal activity during

burial history can also depress fluorescence, and in some cases can arrest maturation of organic matter, causing both standard VR and VIRF Ro (normal) to underestimate maximum burial temperature. Mineralogy and microstructure must therefore be investigated for evidence of hydrothermal activity. This is difficult because sulphide oxidation and surface creep in outcrop can result in features that resemble the effects of hydrothermal alteration. Thus, reliability of using VR/VIRF depends on the experience of the interpreter and data from outcrop samples are typically assigned confidence ratings lower than for drill hole samples. Interpretation of VIRF charts for well samples is more straightforward than for outcrop samples, because weathering does not have to be considered. Also, when samples are cores it is not necessary to consider the possibility of caving contamination. However, one limitation of core samples is the very small stratigraphic interval represented, which can result in a restricted organic assemblage.

The following four petroleum reports and the master's dissertation of Eckersley (1999), demonstrate the thermal maturity of the East Coast Basin using VR/VIRF analyses:

1. Based on PR2582, Opoutama-1 well (Coastal Block), Ro (normal) in the cuttings from depths of 1399, 1754 and 1901m is 0.47%, 0.45% and 0.45%, respectively (Newman and Moore, 2000);
2. Based on PR4349, Ranui-1 well (Pongaroa Block), Ro (normal) in the cuttings from 920 m and 1134 m is 0.33% and 0.32% respectively (NZEC, 2011).
3. Based on PR4548, Ranui-2 well (Pongaroa Block), Ro (normal) in the cuttings from 1431m is 0.37%. Some large vitrinite fragments have reflectance greater than 0.50% but these could be related to a reworked vitrinite, or also could indicate material injected with hydrothermally fluidized sediments from greater depths or laterally from elsewhere in the basin (ECEV III, 2012).
4. Based on PR 4657 and 4658, Ro (normal) for the outcrops samples ranges from 0.43% to 0.67%, and exhibits some relationship with the assigned stratigraphic ages. VIRF analysis of Orui-1A (Coastal Block) and Te Mai-2 (Coastal Block) well cores, and stratigraphically equivalent Wairarapa outcrop samples, indicates uniformly low maturity for Whangai and Waipawa formations, with a tight distribution of Ro (normal) values between 0.33% to 0.37% (ECEV, 2012).

Table 4.16 Summary of the Vitrinite reflectance measurements from the four Petroleum Reports used to characterise the maturation of the Whangai and Waipawa formations.

Petroleum Report	Outcrop Samples (number)	Well Samples (number)	Outcrops	Well name	Ro(%)
2582		Cuttings samples Whangai	NA	Opoutama-1 Whangai Fm. Top 1402m – Base 2215m 1399m: 8 samples, inertinite dominant 1754m: 3 normal vitrinite, 3 reworked vitrinite and inertinite dominant 1901-1903m: Inertinite dominant	0.47 0.45 0.45
4349		2 composite cores Whangai	NA	Ranui-1 910 – 920m: Sparse normal vitrinite. Alginite is a common organic constituent but not abundant. Sporinite, cutinite and resinite are occasional features. 1125-1134m: Sparse normal vitrinite. Alginite is a common organic constituent but not abundant. Sporinite, cutinite and resinite are occasional features.	0.33 0.32
4548		1 cutting sample	NA	Ranui-2 1431.0m: vitrinite is more abundant than inertinite. Inertinite is relatively sparse.	0.37
4657 & 4658	4-Whangai 4-Waipawa	5 cores Waipawa	Whangai: (1) Langdale: very fine grained liptinite and significant alginite. Perhydrous and inertinite dominant and relatively sparse. (1) Awapuripuri: Vitrinite is relatively sparse. Inertinite is the dominant measurable organic. (1) Kahiku: Sparse alginite is present. Very weathering sample. (1) Te Mai: Vitrinite has a scattered distribution. Waipawa: (1) Awapuripuri: very abundant vitrinite. Alginite and sporinite are present and the rock matrix appears to be impregnated with amorphous yellow fluorescing kerogen. Inertinite too sparse. (1) Mangahoeke Quarry: vitrinite relatively sparse. Significant alginite and sporinite are present. (1) Triangle stn: normal vitrinite is absent. Alginite and sporinite are common but not abundant. Small amount of resinite are associated with vitrinite. (1) Te Mai: Vitrinite has a scattered distribution.	Orui-1: Mid Waipawa – 78.85 – 79.70m: Significant sporinite and alginite are present but not abundant. Normal vitrinite dominates. Lowest Waipawa – 115.65 – 115.75m: Alginite, sporinite and cutinite are all present in significant amounts but not abundant. Normal vitrinite dominates. Te Mai: Highest Waipawa – 124.70m: sporinite and alginite are present but not abundant. Mid Waipawa – 151.00 m: Alginite is present but not abundant, and sporinite is present in smaller amounts. Lowest Waipawa – 193.01-193.10m: perhydrous vitrinite.	Outcrops: 0.43% to 0.67% Wells: 0.33% to 0.37%

Eckersley (1999), has analysed several outcrops samples from the Whangai and Waipawa formations. She split her studies in Northern ECB and Southern ECB (Southern Hawke's Bay, Northern and Central Wairarapa):

Northern ECB only Waiotautu Stream, Whakariki Point, Te Puia, and Mahia Peninsula localities have samples collected: Waiotautu Stream (3 samples of Waipawa Formation), Whakariki Point (1 sample of Upper Calcareous Member – Whangai), Te Puia (2 samples of Waipawa Formation), and Mahia Peninsula (1 sample of Waipawa Formation).

Thus, the total samples collected for the VIRF analysis in Northern ECB are 6 samples of Waipawa Formation and 1 sample of Upper Calcareous Member – Whangai.

Southern ECB she collected samples from **Southern Hawke's Bay**: Waimarama (1 sample of Waipawa Formation), Otane Stream (2 samples of Rakauroa Member - Whangai), and Waipawa (2 samples of Waipawa Formation). **Northern Wararapa**: Tamumu Bridge (1 sample of Rakauroa Member - Whangai) Mangapuku Stream (1 sample of Rakauroa Member), and Angora Stream (2 samples of Rakauroa and 2 samples of Upper Calcareous Member – Whangai Formation, 2 samples of Waipawa Formation). **Central Wairarapa**: Owahanga (1 sample of Waipawa Formation), Waewae Stream (1 sample of Rakauroa and 2 samples of Porangahau Member – Whangai Formation), Akitio (1 sample of Waipawa Formation and 1 sample of Upper Calcareous Member-Whangai), Okau Stream (1 sample Waipawa Formation), and Castle Point (1 sample of Waipawa Formation and 1 sample of Upper Calcareous Member-Whangai).

Thus, the total samples collected for the VIRF analysis in Southern ECB are 7 samples of Rakauroa, 4 samples of Upper Calcareous and 2 samples of Porangahau Member (Whangai Fm.). On the other hand, for Waipawa Formation 9 samples were collected. The summary of the average Ro normal results from Eckersley (1999) can be seen in Table 4.17.

Table 4.17 Average of normal Ro% (Normal Vitrinite) collected along ECB, Eckersley (1999).

	Sample	Location	Formation	Ro Av (Normal Vitrinite)%
Northern Hawke's Bay	K21-1	Waiotautu St.	Waipawa Black Shale	0.34
	K21-3			-
	K21-4			-
	K21-5	Whakariki Point	Whangai Fm. Upper Calcareous Mb.	-
	K20-1	Te Puia	Waipawa Black Shale	0.39
	K20-5			0.38
	K24-7	Mahia Peninsula	Waipawa Black Shale	0.45
Southern Hawke's Bay	JD1-10	Waimarama	Waipawa Black Shale	0.31
	JD2-3	Otane St.	Whangai Fm. Rakauora Mb.	0.99
	JD2-4r			0.71
	JD1-14	Waipawa	Waipawa Black Shale	0.30
	JD1-16			-
Northern Wairarapa	JD1-12ri	Tamumu Bridge	Whangai Fm. Rakauora Mb.	-
	JD2-9r	Mangapuku St.	Whangai Fm. Rakauora Mb.	0.29
	AK2-9	Angora St.	Waipawa Black Shale	-
	AK2-12r			-
	AK2-10	Angora St.	Whangai Fm. Upper Calcareous Mb.	0.45
	AK2-11			-
	AK2-13i	Angora St.	Whangai Fm. Rakauora Mb.	-
Central Wairarapa	AK2-14i			-
	AK2-2	Owahanga	Waipawa Black Shale	-
	AK3-2	Waewae st.	Whangai Fm. Porangahau Mb.	0.75
	AK3-4			0.37
	AK3-3i	Waewae st.	Whangai Fm. Rakauora Mb.	-
	AK2-5r	Akitio	Waipawa Black Shale	-
	AK2-4r	Akitio	Whangai Fm. Upper Calcareous Mb.	0.42
	AK1-15	Okau St.	Waipawa Black Shale	0.30
	AK1-11	Castle Point	Waipawa Black Shale	0.35
	AK1-10	Castle Point	Whangai Fm. Upper Calcareous Mb.	0.35

r-reworked vitrinite, i-inertinite

A map with all the vitrinite reflectance values available for the Whangai and Waipawa formations can be seen in Figure 4.30 and 4.31, respectively. It is important to understand that some values can show some over/under estimation given the differences in the methods of determining vitrinite reflectance. Furthermore, the effects of pressure are under discussion in the coal scientific community: high fluid pressure retards chemical coalification reactions yielding gas, whereas tectonic strain causes an increase of vitrinite reflectance. According to Burgreen, et al. (2014) and the pore pressure calculations for three exploration wells in this report, the Whangai Formation is overpressured (section 4.7.2.2). Given that, this was probably subjected to high fluid pressures, which might cause a lowering of vitrinite reflectance. Another parameter to be considered is time, where rapid subsidence leads to a lower vitrinite reflectance for a given temperature. Overall, three parameters have to be considered when interpreting the maturity of these two formations: differentiating between migrated bitumen and vitrinite; high fluid pressures in the Whangai/Waipawa formations, and rapid subsidence and uplift. Considering these pitfalls, the maturity levels in the Cretaceous-Paleocene rocks may have been underestimated.

Figure 4.30 Vitrinite reflectance data for the Whangai Formation showing its maturity based on outcrop samples.

Figure 4.31 Vitrinite reflectance data for the Waipawa Formation showing its immaturity based on outcrop samples.

4.4.5.1.2 – Rock Eval - Tmax

Tmax values from outcrops and exploration wells are plotted to evaluate the geographic variations in the maturity of the Whangai and Waipawa formations using a different method to vitrinite reflectance. No differentiation of the members of Whangai was made for this analysis, as the idea is to evaluate the locations of the effective sources along the basin. Only areas that show more than three data points with Tmax > 435°C are considered potential kitchen areas. Figures 4.32 and 4.33 show the GNS Science and the new data results of Tmax for the Whangai and Waipawa formations, respectively. It is important to highlight that the effect of sulphur, which can decrease the generation temperature, is not considered in this study. This effect is mainly relevant in marine carbonates, where there is a widespread inclusion of sulphur into the kerogen, which can then decrease the activation energy and lead to early generation. In general terms, when organic matter diagenesis takes place in the marine environment, using sulphate as an electron acceptor, sulphides will be rapidly scavenged by iron which is nearly always plentiful in clay-rich environments. Carbonates form in environments with little clay and thus without abundant iron, so to get rid of sulphides, they are included within the kerogen, which leads to the development of Type-IIS source rocks, with different generation characteristics. However, the rocks analysed in this study are generally non-carbonate or low carbonate content, and sulphur-inclusion is not likely to be a significant factor. J. Bojesen (pers. comm., 2017), has found samples with S >5%, occasionally significantly higher than in the Whangai and Waipawa formations, without any significant sulfur-inclusion within the kerogen. As long as there is clay in the system, there will be iron, and any sulfide produced will be rapidly scavenged to form Fe-sulfides (see Jarvie and Lundell 2001 for a detailed explanation).

Figure 4.32 Tmax values showing the maturity of the Whangai Formation. Dashed lines outline the potential kitchens.

Figure 4.33 Tmax values showing the maturity of the Waipawa Formation.

Rock Eval plots show that the organic matter in the Whangai Formation (Figure 4.15) can be classified as **Type II** organic matter which, based on Tissot & Welte (1984) means high H/C and low O/C atomic ratios, pollen grains, spores, cuticles and marine organic matter, reducing environments, medium to high sulphur content, and high potential for hydrocarbon generation. Type II organic matter is related to maceral groups of liptinite: alginite II (marine algae), cutinite (leaf cuticle), resinite (resin and tree sap) and exinite (spores and pollen) (Merrill, 1991 and Tyson, 1987). Newman (in ECEV 2012) found that alginite is a common but not abundant organic constituent of the Whangai Formation. Sporinite, cutinite and resinite are occasionally present, and normal vitrinite is sparse.

The quantity, quality and maturation characteristics of the members of the Whangai Formation are described below and shown in Table 3.2.

In the Rakauora Member the TOC ranges between 0.2 - ~1.7% (poor to good generative potential), with hydrogen index between 26 – 818 (mg HC/g TOC), indicating potential for generating gas and oil. Given that only two samples among the whole dataset show hydrogen index higher than 350 (mg HC/g TOC), these two samples are excluded for this analysis, and thus the maximum retained hydrogen index value is 350 (mg HC/g TOC). 1D geochemical modelling by Pepper and Corvi (1995b) suggests that an HI of 200 is the minimum required for oil expulsion. Most of the maturation analyses (Tmax and vitrinite reflectance) indicate the rocks are immature, except in some specific localities such as the Motu and Allochthon blocks, and southern Hawke's Bay.

In the Upper Calcareous Member, the TOC is between 0.08-2% (poor to good generative potential) and most of the rock samples fall in the “poor” category except in the Coastal block where most of the samples have “good potential”. The hydrogen index varies between 39- ~350 (mg HC/g TOC) which indicates potential for generating gas and oil. Very few rock samples from this member have had their thermal maturity analysed. The results are not very encouraging, as most of the samples are classified as immature.

The lack of a representative rock samples from the Porangahau Member, makes the interpretation of this member a little unreliable but based on the results obtained so far, the TOC varies from 0.01-1% (poor to fair generative potential). The hydrogen index 27- ~275 (mg HC/g TOC), indicating a more gas and oil/condensate prone rock and this member is mostly immature based on Tmax and VR, except in the Coastal Block (central Wairarapa).

Based on the maps (Figures 4.21 to 4.26) and (Figures 4.30 and 4.32 the Rakauora Member in the Pongaroa Block shows the best area for quality, quantity and maturation in

terms of unconventional reservoir prospectivity (sweet spot). This is based on this simple evaluation of the whole dataset, with no statistical interpretation. In Chapter 5 the data are reassessed using a basic, and then a more robust statistical analysis, to provide comparative assessments.

Rock Eval plots (Figure 4.16), show the Waipawa Formation contains Types I, II and, in minor proportion III, organic matter. **Type I** is characterised by high initial H/C and low initial O/C atomic ratios; lipidic material (algal/microbial activity) and high potential of hydrocarbon generation. **Type II** is characterised by high H/C and low O/C atomic ratios; pollen grains, spores, cuticles and marine organic matter; reducing environments; medium to high sulphur content; high potential of hydrocarbon generation. **Type III** is characterised by low H/C and higher O/C than type I and II; terrestrial higher plants; oil potential is moderate, abundant gas in greater depths. Types I, II and III are related to the maceral group of liptinite (I and II) and vitrinite (III), where type I organic matter liptinite is related to alginite I (fresh water algae); type II organic matter alginite II (marine algae), exinite (spores and pollen), cutinite (leaf cuticle) and resinite (resin and tree sap) and Type III Vitrinite and pseudovitrinite (woody tissue) (Tissot & Welte, 1984). Newman (in ECEV 2012) found that Waipawa samples contain common but not abundant alginite and sporinite. Vitrinite is very abundant, perhaps related to Type III kerogen. Small amounts of resinite are associated with vitrinite. The mixed Type-II and Type-III kerogen in the Waipawa Formation indicate a mixed marine algal-terrestrial plant organic matter source.

Evaluating the Waipawa Formation in terms of quantity, quality and maturation, this formation shows a higher TOC content, varying from 0.4 - > 4% (poor to excellent generative potential), and also a higher hydrogen index variation, between 22 - > 400 (mg HC/g TOC) (Table 3.5), when compared to the Whangai Formation. These results are related to the potential to generate gas and oil. The higher Hydrogen Index results compared to the Whangai Formation indicates an increase in organic matter richness. The Waipawa Formation is immature in all outcrops samples and Orui-1 well (Figures 4.31 and 4.33)

Based on the maps (Figure 4.27 to 4.29) and (Figures 4.31 and 4.33) the Waipawa Formation in the Motu and Allochthon Blocks are the best areas for quality, quantity and maturation in terms of unconventional reservoir prospectivity (sweet spot). In Chapter 5, the data are reassessed using a basic and a more robust statistical analysis, to provide a comparative assessment.

According to Petersen and Rosenberg, (2000) the petroleum generative potential of humic kerogen (normally related to Type III kerogen) should show an overall decrease with increasing rank or maturity. All Rock-Eval parameters are dependent on both the rank and type of organic matter. Coals generally show more complex relationships than marine and lacustrine kerogen as its maturation has unique maturation characteristics due to its higher plant derived kerogen. Skyes and Snowdon (2002) have demonstrated improvements in kerogen type assessment of coaly source rocks using Rock-Eval parameters from ditch-cuttings, outcrops samples and cores from petroleum wells in Taranaki and other New Zealand sedimentary basins, as well as various coal exploration drillholes, and working mines and outcrop samples from Late Cretaceous–Cenozoic rocks. Based on their results the New Zealand coal band is well defined on crossplots of HI vs. Rank (Sr) and Tmax and display clear rank-related trends. They also showed an HI increase with an increase in maturation. This is an unexpected result given that the hydrocarbon generation should decrease in HI, not increase. Durand and Paratte, (1983) attributed this increase in HI to decarboxylation, effectively causing an enrichment in hydrogen relative to carbon. Skyes and Snowdon (2002) also pointed out a misinterpretation in the classification of many New Zealand immature coals as gas-prone, based solely on their H_i s of < 200 , thus underestimating the oil potential of New Zealand basins.

Based on GNS Science and new datasets, Figures 4.19 and 4.20 show basically two different trends regarding to HI and Tmax. These trends show an HI increase with increasing Tmax. Perhaps this trend behaviour could be related to two different source rocks both showing coaly characteristics. A more rigorous study has to be undertaken on the Whangai and Waipawa formations in order to cover these issues.

Overall, based on the geochemical analyses, the quantity of the Whangai Formation varies from poor to good with the majority classified as fair in generative potential. The quality shows a more oil and gas prone than gas-prone character, and the thermal maturity is immature to slightly mature. On the other hand, the quantity of the Waipawa Formation varies from poor to excellent, with the majority classified as very good in generative potential. Its quality shows not only oil and gas-prone but also either more oil- or more gas-prone characteristics, depending on location along the East Coast Basin. In terms of the maturity, the Waipawa Formation is considered immature. However, it is important to stress that most of the thermal maturity analyses use outcrop samples that are relate to uplifted areas. Perhaps in other locations, such as the depocenters of Neogene sub-basins, syncline areas, and beneath the Allochthon Block, the Whangai and Waipawa formations could be in the oil and gas window.

4.5 INORGANIC GEOCHEMISTRY - MAJOR ELEMENTS

4.5.1 Introduction

Although inorganic geochemistry and even better mineralogical analysis are generally not included in conventional source rock assessments, they are important factors in shale oil and gas production due to their importance in determining rock brittleness and fracture stimulation. Without understanding the importance of rock mineralogy, mechanical properties, stress fields, and stimulation processes, horizontal drilling and fracking alone would not have resulted in rapid development of the global shale oil and gas resource. Organic matter is an important factor, capable of generating, retaining, and storing huge amounts of hydrocarbons, but oil and gas flow also depends on the microreservoir connectivity when production wells are being stimulated. Given that, brittleness is an important component in shale oil and gas plays and it is directly related to the mineralogy of the rock that is being stimulated (Jarvie et al., 2007; Wang and Gale, 2009).

Both Whangai and Waipawa formations have a very high silica content, and some zones show high carbonate and low to medium aluminium contents. These formations show some variability, so it would be expected that some zones are more easily fractured during stimulation than others. Analyses were undertaken to characterize both the Whangai and Waipawa formations in order to define their composition, depositional environment (Pearce et al., 2005), degree of weathering, original source composition (provenance) and brittleness index (from outcrop samples). These analyses help the reservoir facies characterization and consequently, the sweet spot identification. Although homogeneous on the macro scale, shale rocks show substantial variations in their geochemistry on a small scale, and their inorganic geochemistry has been used to identify paleo-redox conditions (Jenkyns, 2010). In addition, the oil industry has made use of inorganic whole-rock geochemical data to define stratigraphic correlations (Wright et al., 2010a). The chemostratigraphic technique relies on recognizing changes in element concentration through a section and using those to develop a stratigraphic characterization that is based on changes in geological features, such as paleoclimate (Pearce et al., 2005) and provenance (Wright et al., 2010a). As the stratigraphic control of each rock sample used in this report is not well defined, total rock samples are combined per structural block to make the comparison between these blocks regarding depositional environmental, provenance and brittleness index. Even though a range of elemental data are obtained using X-Ray fluorescence (XRF), this study considers only nine elements: SiO₂, Al₂O₃, CaO, K₂O, TiO₂, Na₂O, MgO, Fe₂O₃, and MnO. SiO₂, Al₂O₃, CaO are used to calculate the Brittleness Index (Jarvie et al., 2007; Wang and Gale, 2009), and K₂O, TiO₂, Al₂O₃, Na₂O, MgO, Fe₂O₃,

and MnO are used to identify areas in the basin where the terrigenous input was higher (Pearce et al., 2005) and the relationship between degree of weathering and original source composition (Nesbitt and Young, 1982; Cox et al., 1995; Potter et al., 2005).

4.5.2 Methodology of Composition, Chemical Weathering, Climate Fluctuation, Terrestrial Input, and Provenance Assessment

All the methodologies applied in this section are based on major elements obtained from X-ray fluorescence (XRF).

Typically, bulk-rock geochemistry requires the application of wavelength-dispersive or energy-dispersive X-ray fluorescence (WD-XRF and ED-XRF, respectively) or inductively coupled plasma mass-spectrometry (ICPMS) based methods that require extensive preparation. The basic principle is that the unit emits X-rays that excite atoms in the sample. This causes the excitement and ejection of electrons from the inner valence shell of the atom. Outer shell electrons fill the void left by the exiting electron, emitting electromagnetic radiation in the process. The wavelength of the energy emitted is predominantly characteristic of the element, and the energy intensity is proportional to the concentration of the element in the sample (Gazley & Fisher, 2014).

The aim of applying (XRF) analysis to the Whangai and Waipawa formations is to define SiO₂, CaO and Al₂O₃ content, as these are important elements in rock quality characterization (brittleness) and consequently “sweet spot” identification. In addition, SiO₂, CaO, TiO₂, K₂O, Al₂O, Na₂O, MnO, Fe₂O₃ and MgO are analysed in order to estimate the composition, terrestrial input, chemical weathering, climate fluctuation, and provenance of samples. These nine major elements are reported as oxide percent by weight. Of these nine elements SiO₂, CaO and Al₂O₃ are the only elements used as inputs to the machine-learning model, described in chapter 5.

The percentage of each element was recalculated to 100%. Loss on Ignition (L.O.I.) was distributed among the major elements (Table 4.18 to 4.20), a procedure that follows studies on the rock types worldwide (Pettijohn, 1957, Peter et al., 1984, Clarke, 1924, and Ronov and Migdisov, 1971) and the Torlesse from the basement of New Zealand (Roser and Korsch, 1999). The original data can be seen in APPENDIX 1.

Table 4.18 New results (this thesis) of X-ray Fluorescence from Whangai Fm. samples sorted by locality, formation, member, and measured section.

Structural Block		Formation	Member	Measured Section	Sample Name	SiO ₂	Al ₂ O ₃	CaO	TiO ₂	K ₂ O	MnO	Fe ₂ O ₃	MgO	Na ₂ O
Southern Hawke's Bay	Tora	Whangai	Rakauroa	Pukemuri Stream	Upuk 01	84.04	6.45	3.35	0.34	1.39	0.00	2.61	0.79	0.97
	Tora	Whangai	Rakauroa	Pukemuri Stream	Lpuk 03	80.00	11.32	0.13	0.58	2.11	0.00	3.99	0.87	0.95
	Tora	Whangai	Rakauroa	Pukemuri Stream	Lpuk 04	78.40	11.77	0.25	0.64	2.18	0.01	4.76	0.78	1.16
	Tora	Whangai	Rakauroa	Pukemuri Stream	Lpuk 05	80.09	11.14	0.13	0.58	2.10	0.00	3.90	0.87	1.13
	Coastal	Whangai	Rakauroa	Angora Stream	AS 07	75.50	10.69	4.983	0.51	1.93	0.01	3.35	1.15	1.27
	Coastal	Whangai	Porangahau	Angora Stream	AS 11	81.69	8.7	3.03	0.44	1.43	0.00	3.10	0.98	0.56
	Coastal	Whangai	Upper Calcareous	Angora Stream	AS 13	80.86	9.60	1.95	0.48	1.59	0.00	3.46	1.03	0.99
	Coastal	Whangai	Upper Calcareous	Angora Stream	AS 18	79.36	6.60	8.72	0.35	1.11	0.00	2.45	0.84	0.44
Northern Hawke's Bay	Motu	Whangai	Rakauroa	Rakauroa Stream	RAK 01	79.50	11.64	0.56	0.54	1.84	-0.01	4.03	1.36	0.51
	Motu	Whangai	Rakauroa	Rakauroa Stream	RAK 02	80.01	12.25	0.35	0.59	1.78	-0.01	3.76	1.22	0.00
	Motu	Whangai	Rakauroa	Rakauroa Stream	RAK 03	80.21	12.58	0.11	0.58	1.68	-0.01	3.54	1.16	0.12
	Motu	Whangai	Rakauroa	Waitahaia Owheana	OW01	79.17	11.45	0.46	0.56	2.03	0.01	3.94	1.31	1.04
	Motu	Whangai	Rakauroa	Waitahaia Owheana	OW02	80.55	9.67	0.30	0.58	1.79	0.00	3.70	1.24	2.11
	Motu	Whangai	Rakauroa	Waitahaia Owheana	OW03	81.56	9.47	0.34	0.51	1.78	0.00	3.52	1.15	1.64
	Allochthon	Whangai	Rakauroa	Te Weraroa Stream	TWR01	82.72	8.86	1.95	0.44	1.43	0.01	3.06	1.00	0.50
	Allochthon	Whangai	Upper Calcareous	Te Weraroa Stream	TWR02	86.125	7.33	1.99	0.36	1.12	-0.01	2.21	0.87	0.00

Table 4.19 Results of X-ray Fluorescence from Whangai Fm. samples sorted by locality, formation, member, and measured section *.

Structural Block		Formation	Member	Measured Section	Sample Name	SiO ₂	Al ₂ O ₃	CaO	TiO ₂	K ₂ O	MnO	Fe ₂ O ₃	MgO	Na ₂ O
Southern Hawke's Bay	Pongaroa	Whangai	Rakauroa	Tangaruhe Stream	43942	83.30	9.18	0.35	0.41	1.56	0.00	2.63	0.98	1.52
	Pongaroa	Whangai	Rakauroa	Tangaruhe Stream	43943	89.44	6.37	0.05	0.30	1.28	0.00	1.23	0.56	0.73
	Pongaroa	Whangai	Rakauroa	Tangaruhe Stream	43944	85.92	7.49	0.78	0.35	1.01	0.01	2.54	0.87	0.96
	Pongaroa	Whangai	Rakauroa	Tangaruhe Stream	44594	88.82	6.36	0.07	0.34	1.10	0.05	1.80	0.52	0.83
	Pongaroa	Whangai	Upper Calcareous	Tangaruhe Stream	43945	87.28	6.84	0.52	0.31	1.17	0.00	2.03	0.80	1.01
	Pongaroa	Whangai	Upper Calcareous	Tangaruhe Stream	43946	84.52	7.52	2.09	0.34	1.26	0.00	2.05	0.91	1.23
	Pongaroa	Whangai	Upper Calcareous	Tangaruhe Stream	43947	81.55	9.64	1.62	0.43	1.60	0.00	2.74	1.31	1.03
	Pongaroa	Whangai	Upper Calcareous	Tangaruhe Stream	43948	83.34	7.35	2.98	0.33	1.20	0.00	2.39	1.17	1.17

* These data come from GNS Science dataset.

Table 4.20 New results (this thesis) of X-ray Fluorescence from Waipawa Fm. samples sorted by locality, formation, member, and measured section

Structural Block		Formation	Member	Measured Section	Sample Name	SiO ₂	Al ₂ O ₃	CaO	TiO ₂	K ₂ O	MnO	Fe ₂ O ₃	MgO	Na ₂ O
Southern Hawke's Bay	Coastal	Waipawa	NA	Taylor White	TW02	75.64	14.45	0.48	0.71	2.12	0.00	4.85	1.12	0.58
	Coastal	Waipawa	NA	Taylor White	TW05	79.75	11.80	0.74	0.58	1.75	0.00	3.86	0.83	0.64
	Pongaroa	Waipawa	NA	Mangatarata Valley	MAN03	77.76	13.76	0.42	1.08	2.43	0.00	3.19	0.86	0.48
	Pongaroa	Waipawa	NA	Mangatarata Valley	MAN04	79.59	12.39	0.41	0.95	2.30	-0.01	2.82	0.74	0.78
	Pongaroa	Waipawa	NA	Mangatarata Valley	MAN05	72.07	16.32	0.54	1.10	2.87	0.00	4.99	1.26	0.82
	Pongaroa	Waipawa	NA	Mangatarata Valley	MAN06	78.40	12.15	0.87	0.82	2.14	0.00	4.19	1.05	0.34
Northern Hawke's Bay	Allochthon	Waipawa	NA	Te Weraroa	TWR03	72.94	17.81	0.07	0.83	2.41	0.00	4.51	0.91	0.49

4.5.3 Results and Discussions

4.5.3.1 Composition

The Whangai Formation was first classified by Lillie (1953) and its classification has been reviewed by different authors since then (Table 4.21). The composition of each member of Whangai Formation is described below following (Moore (1988a), the most recent characterization after Kingma (1978). Based on Moore (1988a), a new classification method for the Whangai and Waipawa formations is applied in this study.

Table 4.21 Lithological classification of Whangai Formation according to previous workers (modified from Moore, 1988a).

Stage	Lillie (1953)	Wellman (1955)	Kingma (1959)	Kingma (1962)	Kingma (1964)	Kingma (1965)	Kingma (1967)	Kingma (1971)	Kingma (1974)	Kingma & Speden (1978)
TEURIAN	argillite	shale	non-calc. argillite	calcareous muddy siltstone	tuffaceous mudstone	tuffaceous, calcareous, silty mudstone and muddy siltstone	siliceous mudstone (quartz tuff)	calcareous muddy siltstone	siliceous siltstone (or calcareous chert)	?
HAUMURIAN				argillite	water-laid rhyolitic tuffs (tuffites)	water deposited muddy feldspathic quartz-tuffs	siliceous tuff (tuffite)	argillite	chert	siliceous rock (argillite?) and muddy siltstone
PIRIPAUAN					?					

Whangai Fm.:

1. Rakauroa Member: Grain size varies from very fine to coarse silt but it is generally fine to medium silt. The siltstones are moderately to poorly sorted and consist of angular to subangular quartz, plagioclase (albite-oligoclase) and muscovite in clay rich, siliceous matrix. Minor constituents include glauconite, biotite, opaques, polycrystalline quartz, and rare zircon, as well as foraminifera and recrystallized radiolarians. Calcite cement is rare. Based on the Folk et al. (1970) classification, Rakauroa siltstones are sublithlutites or feldspathic lithlutites.
2. Porangahau Member: The main difference of the Porangahau Member is the high concentration of calcite cement compared to the other Whangai Members. Calcareous foraminifera are common.

3. Upper Calcareous Member: It is very similar to Rakauora Member. Grain size ranges from fine to medium silt, with the main detrital constituents being quartz, plagioclase, mica, and clays. Glauconite appears slightly more common than in the Rakauora siltstones. As in Porangahau Member, calcareous foraminifera are common, but agglutinated foraminifera and recrystallized radiolarians are sparse. Patches of calcite cement are present in some samples. There is little difference between western and eastern facies.

The occurrence of clays and mica is summarized in the Table 4.22, based on Moore (1988a).

Table 4.22 Description of the mica and clay occurrence along ECB, Moore (1988a).

Clay and Mica	Description
Mica	The proportion decreases from west to east, it is considered to be largely detrital, high concentrations occur close to major areas of sediment input.
Chlorite	It shows a similar distribution pattern to mica, suggesting they have a common source, or represents an alteration product of primary mica (Selley, 1976). It is absent in many eastern sections and its abundance probably reflects distance from the paleo-shoreline (Parhan, 1966), rather than any diagenetic effect.
Smectite	It is the dominant clay but it does not show a distinctive distribution pattern. This could be from alteration of air-fall volcanic ash (Kingma, 1959), or reflect effective distribution of detrital clay by currents (Griffin, 1962). Also from a neof ormation (chemical sedimentation), as proposed in the Wanstead Fm. (Fergusson, 1985).
Illite	No obvious distribution pattern, and since there is little indication of any relationship to induration or organic maturity, it is probably largely detrital in origin. Fergusson, 1985 has a similar conclusion for Wanstead Fm. If it is detrital, then the lack of any obvious relationship to inferred points of sediment input, as indicated from the mica occurrence, is puzzling. Given that, illite could be the alteration of glauconite (Blatt et al., 1980). This could explain why illite is less abundant in the glauconite-rich Tahora sandstone than overlying Rakauora mudstone (Isaac, 1977), although it may simply be a function of grain size.
Kaolinite	Because of the difficulty in detecting kaolinite in the presence of chlorite, its distribution pattern is influenced by the chlorite content. Shows minor amounts compared to the other clays.

Waipawa Fm.:

Only two Waipawa samples have been analyzed for inorganic geochemistry, and their descriptions may not be representative. Moore (1988a) examined only one sample, a glauconitic fine sandstone from Okau Stream (P45826), which contained angular to subrounded quartz and minor plagioclase, common (10-15%) glauconite, and rare orthoclase. Rock fragments included chert and possible plutonic and metamorphic types.

A classification scheme for the Whangai and Waipawa formations based on bulk mineralogy was adapted from Gamero-Diaz et. al. (2012) for this study. This classification, known as sCore, is based on clay, carbonate and QMF (Quartz-Mica-Feldspar) proportions for organic mudstone. It is based on a combination of core and log based mineralogical relationships. The sCore diagram defines 16 classes of mudstones. However, the main classes are: siliceous, carbonate-rich and argillaceous mudstone. Sub-classes are based on relative amounts of these three mineral groups. This type of classification allows geoscientists to examine empirical relationships between mineralogy and factors that control the reservoir quality and, consequently, identify sweet spots for well completion. Productive mudstones tend to be dominated by non-clay minerals, mainly silicates and carbonates, and therefore place in the lower part of the classification diagram, away from the clay point. Given the lack of XRD analysis and based on the XRF results, it was assumed that Al_2O_3 concentrations are related to the amount of clay (Ratcliffe et al., 2013). Correlation of Al_2O_3 concentrations to clay content has been demonstrated for the Haynesville Shale (Figure 4.34), with CaO concentration related to the amount of calcite, and SiO_2 determined for the QMF diagram as quartz. An adapted classification of both formations is shown on Figures 4.35 to 4.38. Rakauora and Upper Calcareous members of Whangai Formation have similar characteristics whereas the Porangahau Member shows more carbonate enrichment. On the other hand, even though the Waipawa Formation is classified as a silica dominated lithotype, the same as the Rakauora and Upper Calcareous members, it tends to vary towards clay-rich siliceous mudstone (Figure 4.38).

Figure 4.34 Comparison of selected mineralogical data and total organic carbon (TOC) data with selected geochemical variables in the Haynesville Shale (Ratliffe et al., 2013). First track shows the correlation of the total clay content to Al_2O_3 . Depths in feet.

Figure 4.35 sCore classification scheme for Rakauroa Member (Whangai Formation.) based on bulk mineralogy (Gamero-Díaz et. al., 2012).

Figure 4.36 sCore classification scheme for Porangahau Member (Whangai Formation) based on bulk mineralogy (Gamero-Díaz et. al., 2012).

Figure 4.37 sCore classification scheme for Upper Calcareous Member (Whangai Formation) based on bulk mineralogy (Gamero-Díaz et. al., 2012).

Figure 4.38 sCore classification scheme for Waipawa Formation based on bulk mineralogy (Gamero-Diaz et. al., 2012).

The inorganic geochemistry results are plotted to show the variability of mineral composition within the Whangai and Waipawa formations (Figures 4.39 to 4.41).

Figure 4.39 Rakauora Member (Whangai Formation): Relationship between SiO₂, Al₂O₃, CaO and the sum of TiO₂, K₂O and Al₂O₃.

Figure 4.40 Porangahau and Upper Calcareous Members (Whangai Formation): Relationship between SiO₂, Al₂O₃, CaO and the sum of TiO₂, K₂O and Al₂O₃.

Figure 4.41 Waipawa Formation: Relationship between SiO₂, Al₂O₃, CaO and the sum of TiO₂, K₂O and Al₂O₃.

4.5.3.2 Chemical weathering, climate fluctuation and provenance

The tectonic history of a sedimentary basin controls how the provenance as well as weathering affect sedimentary fill. Moreover, understanding differences in provenance might help explain why two mudstones with similar diagenetic paths have different final compositions. Major element geochemistry analysis is an important tool for characterizing both aspects. Furthermore, chemical weathering can influence the major-element geochemistry of sedimentary rocks, particularly in regard to alteration of feldspars and volcanic glass (Nesbitt and Young, 1982; Taylor and McLennan, 1985).

Clay minerals are mainly formed by chemical weathering, and thus are the main constituents of the fine-grained sedimentary rocks, also known as mudrocks. This group of rock includes mudstones, claystones, and shales. Indeed, clay minerals make up about 40% of the minerals in sedimentary rocks. Five types of chemical reactions can occur in clay minerals:

1. hydrolysis (H^+ or OH^- replaces an ion in the mineral);
2. leaching (ions are removed by dissolution into water);
3. dehydration (removal of H_2O or OH^- ion from a mineral);
4. oxidation (Since free oxygen (O_2) is more common near the Earth's surface, it may react with minerals to change the oxidation state of an ion), and
5. complete dissolution (all of the mineral is completely dissolved by the water).

Based on their structures and chemical compositions, the clay minerals can be divided into three classes: kandites (e.g. kaolinite), smectites (e.g. pyrophyllite), and illites (e.g. chlorite). All classes have Al in their structure. Kaolinite is basically characterized by aluminium and silica, smectite (expanding clays) by aluminium, calcium, sodium, iron, manganese and silica and illite by aluminium, potassium and silica (Keller, 1955).

The degree of chemical weathering of a source area can be expressed using the chemical index of alteration (CIA; Nesbitt and Young, 1982), which is calculated using mole proportions as:

$$CIA = [Al_2O_3 / (Al_2O_3 + CaO^* + K_2O + Na_2O)] \times 100 \quad (Eq.4.1)$$

CaO* values are calculated using the method of McLennan (1993), where CaO is corrected for apatite using P_2O_5 .

The standard parameters derived from major element analysis are the CIA (Chemical

Index of Alteration) and ICV (Index of Compositional Variability). Cross-plots of these indices can be useful to determine the relationship between the degree of source-area weathering and the original detrital mineralogy (Cox et al., 1995; Potter et al., 2005). In general, CIA values are typically less than 40-50 for unweathered igneous and metamorphic rocks, 70 to 75 for shales, and 100 for pure aluminosilicate weathering products (i.e., kaolinite; Taylor and McLennan, 1985; McLennan et al., 1993).

A better discrimination of parent rock types would include Fe and Mg. Thus, the ICV can be used to discriminate source rock types based on major-element geochemistry of mudstones, where:

$$ICV = (CaO + K_2O + Na_2O + Fe_2O_3(T) + MgO + MnO + TiO_2) / Al_2O_3 \quad (Eq.4.2)$$

In this equation, CaO includes all sources of Ca including detrital carbonate. A high ICV value indicates compositionally immature source rocks rich in non-clay silicate minerals whereas low values represent compositionally mature source rocks. As the rocks become exhumed and exposed to weathering, ICV values decrease due to the alteration of feldspars to Al-bearing clays. Thus, variability in ICV values may be due to variations in source-rock composition or to differences in weathering (Cox et al., 1995; Potter et al., 2005).

Major element oxide compositions of 40 samples of the Whangai Formation and nine samples of the Waipawa Formation were determined by XRF (Tables 4.18 to 4.20 (thesis dataset) and APPENDIX 1 (public domain)). Cross-plots of ICV versus CIA can be seen in Figures 4.42 to 4.45. The higher ICV value is likely due to elevated CaO from associated carbonates (Lamaskin et al., 2008).

ICV values >1 indicate negligible recycling or weathering. Also, $K_2O/Al_2O_3 < 0.4$ indicates minimum K-feldspar content (Banerjee and Banerjee, 2010).

Also, according to Akul'shina (1976) the empirical relationship for the Al/Ti ratio and climate can be elaborated as follows: $Al_2O_3/TiO_2 < 20$ for humid, 20–30 for semi-humid and semi-arid, and > 30 for arid climate. Given that, the Al_2O_3/TiO_2 ratio is calculated and presented in the present work as a reference for estimating paleoenvironmental conditions.

The results of chemical index compositional variability, chemical index of alteration, and the ratio of Al_2O_3/TiO_2 are shown in the Tables 4.23 to 4.26.

Table 4.23 Chemical index of alteration and index of compositional variability calculated for all Rakauroa Mbr samples.

Formation/Member	Collection_Number	Block	ICV	CIA	Al ₂ O ₃ /TiO ₂
Rakauroa	UPuk-01 469	Tora_Block	1.47	53.04	19.13
Rakauroa	LPuk-03 468	Tora_Block	0.76	78.03	19.59
Rakauroa	LPuk-04 467	Tora_Block	0.83	76.65	18.44
Rakauroa	LPuk-05 470	Tora_Block	0.78	76.78	19.18
Rakauroa	44598	Tora_Block	0.71	77.25	21.59
Rakauroa	44599	Tora_Block	0.78	73.81	22.91
Rakauroa	44602	Motu_Block	0.86	73.71	24.06
Rakauroa	44603	Motu_Block	0.76	80.98	21.88
Rakauroa	44604	Motu_Block	0.81	74.62	24.04
Rakauroa	44607	Motu_Block	0.80	75.41	21.30
Rakauroa	44612	Motu_Block	0.85	75.51	23.16
Rakauroa	OW 01	Motu_Block	0.82	76.47	20.31
Rakauroa	OW 02	Motu_Block	1.01	69.71	16.46
Rakauroa	OW 03	Motu_Block	0.94	71.60	18.68
Rakauroa	RAK 01	Motu_Block	0.76	80.00	21.47
Rakauroa	RAK 02	Motu_Block	0.63	85.15	20.91
Rakauroa	RAK 03	Motu_Block	0.57	86.81	21.81
Rakauroa	TEWR 01	Allochton_Block	0.95	69.56	19.96
Rakauroa	43942	Pongaroa_Block	0.81	72.83	22.21
Rakauroa	43943	Pongaroa_Block	0.65	75.50	21.46
Rakauroa	43944	Pongaroa_Block	0.87	73.13	21.27
Rakauroa	44594	Pongaroa_Block	0.74	76.07	18.97
Rakauroa	44600	Coastal_Block	0.72	77.84	22.51
Rakauroa	44605	Coastal_Block	0.81	75.81	21.57
Rakauroa	AS-07 471	Coastal_Block	1.28	55.16	21.12

Table 4.24 Chemical index of alteration and index of compositional variability calculated for all Porangahau Mbr samples.

Formation/Member	Collection_Number	Block	ICV	CIA	Al ₂ O ₃ /TiO ₂
Porangahau	35250	Coastal	3.23	26.97	23.59
Porangahau	35251	Coastal	1.84	44.83	19.43
Porangahau	AS-11 473	Coastal	1.10	63.40	19.82

Table 4.25 Chemical index of alteration and index of compositional variability calculated for all Upper Calcareous Mbr samples.

Formation/Member	Collection_Number	Block	ICV	CIA	Al ₂ O ₃ /TiO ₂
Upper Calcareous	AS-13 474	Coastal	0.99	67.97	19.91
Upper Calcareous	AS-18 472	Coastal	2.11	39.12	19.12
Upper Calcareous	44601	Motu	1.25	57.23	22.23
Upper Calcareous	44606	Motu	0.89	68.02	21.96
Upper Calcareous	44609	Motu	1.28	55.08	21.81
Upper Calcareous	43945	Pongaroa	0.85	71.70	22.06
Upper Calcareous	43946	Pongaroa	1.05	62.15	22.12
Upper Calcareous	43947	Pongaroa	0.91	69.40	22.42
Upper Calcareous	43948	Pongaroa	1.26	57.87	22.27
Upper Calcareous	44610	Allochthon	1.25	57.90	22.47
Upper Calcareous	44611	Allochthon	1.09	62.97	22.26
Upper Calcareous	TEWR 02	Allochthon	0.89	70.20	20.43

Table 4.26 Chemical index of alteration and index of compositional variability calculated for all Waipawa Fm. samples.

Formation/Member	Collection_Number	Block	ICV	CIA	Al ₂ O ₃ /TiO ₂
Waipawa	MAN-03 478	Pongaroa	0.61	80.53	12.73
Waipawa	MAN-04 477	Pongaroa	0.64	78.05	13.05
Waipawa	MAN-05 479	Pongaroa	0.71	79.41	14.81
Waipawa	MAN-06 480	Pongaroa	0.77	78.39	14.83
Waipawa	45737	Pongaroa	0.59	80.83	23.38
Waipawa	TW-02 476	Coastal	0.68	81.97	20.29
Waipawa	TW-05 475	Coastal	0.71	78.98	20.49
Waipawa	45736	Allochthon	0.60	85.42	21.82
Waipawa	TEWR 03	Allochthon	0.52	85.74	21.54

(A)

(B)

Figure 4.42 (A) Plot of CIA vs. index of chemical variability (ICV), after Potter et al. (2005), of the Rakauroa Mbr of the Whangai Fm. showing relationship of degree of source-area weathering and original detrital mineralogy and (B) the fluctuations in climate conditions. As Al and Ti are immobile elements but diverges due to their migration and pH expose, the variation in their ratio is a good indicator for climate changes.

(A)

(B)

Figure 4.43 (A) Plot of CIA vs. index of chemical variability (ICV), after Potter et al. (2005), of the Porangahau Mbr of the Whangai Fm. showing relationship of degree of source-area weathering and original detrital mineralogy and (B) Al_2O_3/TiO_2 as a proxy for fluctuations in climate conditions.

(A)

(B)

Figure 4.44 (A) Plot of CIA vs. index of chemical variability (ICV), after Potter et al. (2005), of the Upper Calcareous Mbr of the Whangai Fm. showing relationship of degree of source-area weathering and original detrital mineralogy and (B) Al_2O_3/TiO_2 as a proxy for fluctuations in climate conditions.

(A)

(B)

Figure 4.45 (A) Plot of CIA vs. index of chemical variability (ICV), after Potter et al. (2005), of the Waipawa Fm. showing relationship of degree of source-area weathering and original detrital mineralogy and (B) Al_2O_3/TiO_2 as a proxy for fluctuations in climate conditions.

Also, in order to characterise the Whangai and Waipawa formations in terms of their inorganic geochemistry and compare them with other rock types, a series of cross-plots of SiO₂, K₂O, TiO₂, Fe₂O₃ in relation to Al₂O₃ were prepared (Figures 4.46 to 4.49). The data are subdivided by structural block and compared with:

1. Monterey Formation from California. selected due to its high silica content (Pettijohn, 1957 and Moore, 1988a);
2. North American shale composite (NASC) (Peter et al., 1984);
3. Average shale (Clarke, 1924);
4. Averages of USA and Russian Paleozoic, Mesozoic and Cenozoic shales (Ronov and Migdisov, 1971), and
5. Torlesse Terrane (MacKinnon, 1983 and Roser and Korsch, 1999).

MacKinnon (1983) and Roser and Korsch (1999) examined the major and trace element chemistry of Torlesse samples from New Zealand, and demonstrated that geochemical indices closely follow the modal variations and add valuable support to petrographic techniques. Studies of the whole-rock geochemistry of sedimentary successions have shown that chemical data can also be applied to studies of provenance, tectonic setting and terrane relationships (Winchester & Max, 1996). Therefore, cross-plots using a Torlesse Terrane rock geochemical composite (Roser and Korsh, 1999) is also plotted with other shales described above to compare the Whangai and Waipawa formations to their provenance composition signature. Figure 4.53 shows the distribution of Torlesse subterrane and faunally defined zones 1-5 (petrofacies - PF, 1-5) (MacKinnon, 1983).

A Total Organic Carbon (TOC) and Al₂O₃ content are plotted in Figures 4.50 to 4.52 in order to test if higher clay content could increase the TOC percentage through organic-matter sorption phenomena, as demonstrated by Keil et al. (1994) and Mayer (1994a & b).

Note that given the small number of rock samples of the Porangahau Member, due to its limited basin wide occurrence and availability of organic and inorganic geochemistry analyses from the same rock samples, a plot of TOC vs Al₂O₃ content for this unit was not warranted.

Figure 4.46 Plot of Al₂O₃ versus SiO₂, K₂O, TiO₂ and Fe₂O₃ content of the Rakauroa Member, subdivided by structural block and compared to Torlesse petrofacies and various US and Russian shales as listed above.

Figure 4.47 Plot of Al₂O₃ versus SiO₂, K₂O, TiO₂ and Fe₂O₃ content of the Porangahau Member, subdivided by structural block and compared to Torlesse petrofacies and various US and Russian shales as listed above.

Figure 4.48 Plot of Al₂O₃ versus SiO₂, K₂O, TiO₂ and Fe₂O₃ content of the Upper Calcareous Member, subdivided by structural block and compared to Torlesse petrofacies and various US and Russian shales as listed above.

Figure 4.49 Plot of Al₂O₃ versus SiO₂, K₂O, TiO₂ and Fe₂O₃ content of the Waipawa Formation, subdivided by structural block and compared to Torlesse petrofacies and various US and Russian shales as listed above.

Figure 4.50 Plot of Rakauroa Member showing the alumina content versus Total Organic Carbon (TOC) by structural block (blue arrows – increase in TOC with increase in alumina).

Figure 4.51 Plot of Upper Calcareous Member showing the alumina content versus Total Organic Carbon (TOC) by structural block.

Figure 4.52 Plot of Waipawa Formation showing the alumina content versus Total Organic Carbon (TOC) by structural block (blue arrows – increase in TOC with increase in alumina).

Figure 4.53 Map of central and southern New Zealand showing distribution of Torlesse subterrane and faunally defined zones 1–5 (equated by MacKinnon, 1983 to petrofacies 1–5) (Roser and Korsch, 1999). Petrofacies 3, 4 and 5 occur in the North Island.

Chemical index of alteration values of the Waipawa Formation range from 78 to 85 and those from the Whangai Formation (Rakauroa, Upper Calcareous and Porangahau members), from 53 to 86, 39 to 71 and 26 to 63, respectively. These suggest that the source rocks of the Waipawa Formation were subjected to weathering conditions stronger than Whangai Formation. However, among the three members of the Whangai Formation the Rakauroa Member was subjected to stronger weathering conditions in comparison to the Upper Calcareous and Porangahau members. Furthermore, ICV values of the Waipawa Formation range from 0.52 to 0.77 and the Whangai Formation, 0.57 to 1.47 (Rakauroa Member), 0.85 to 2.11 (Upper Calcareous Member) and 1.10 to 3.23 (Porangahau Member). Comparatively, these suggest that the Waipawa Formation has a more chemically mature mineralogy compared to all members of the Whangai Formation. Again, among the three members of the Whangai, the Rakauroa Member shows a more chemically mature composition than that of the Upper Calcareous Member which is also more mature than the Porangahau Member. These results imply that, although the Waipawa Formation data indicate stronger weathering, they also indicate the rocks were closer to the provenance area. The same rationale applies for the Rakauroa Member in comparison to the Upper Calcareous and Porangahau members. Using the ratio of $\text{Al}_2\text{O}_3/\text{TiO}_2$, the Whangai and Waipawa formations fluctuate from humid to semi-humid and semi-arid climate. However, the Waipawa Formation and the Rakauroa Member appear to present more variability in the climate than the other members of the Whangai Formation, showing intervals of relatively intense chemical weathering. These intervals could be related to changes in sedimentation rate and the peaks in TOC enrichment in the Waipawa Formation as described by Hollis et al. (2014). In addition, Schiøler et al. (2010) and Hollis et al. (2014) suggested a eustatic sea level regression at this time which also could be related to the sedimentation rate increase through the Waipawa Formation resulting in a terrigenous input being pushed towards to deeper depositional environment. On the other hand, Fuerst (2012) supports a transgressive model for the Waipawa Formation. Enhanced organic matter preservation can be attributed to decreased availability of oxygen, as well as rapid burial (Katz, 2005).

Few studies have identified the provenance for the Early Cretaceous to Oligocene rocks (Adams et al., 2013). The Waipapa Terrane, as a block over half the North Island, has no Cretaceous cover (apart from a little inside the Northland Allochthon). Nevertheless, the adjacent Buller-Takaka foreland and Torlesse Composite Terrane have very extensive Cretaceous and younger cover sequences. The Waipapa (and Murihiku) Terrane (Figure 3.4), as a block, was stabilized about 140 Ma ago and remained a terrestrial lowland for almost 100 million years – so a deep weathering, desert-style regolith could have developed. This must

surely be the provenance area for the Whangai (C. Adams pers. comm. 2017). The Waioeka Terrane in the East Cape and (allochthonous) scattered blocks along the North Island East Coast have detrital zircon signatures for the New Zealand Western Province, as they are very old and presumably deeply exhumed rocks. It seems unusual that the easternmost terrane in the North Island has sediment origins in the westernmost terranes of the South Island (C. Adams pers. comm. 2017).

Based on the series of SiO_2 , K_2O , TiO_2 , Fe_2O_3 in relation to Al_2O_3 , the Waipawa Formation shows the most compositional similarity to the Torlesse, suggesting it was closer to this provenance area or received sediment directly from this source. Compared to Waipawa Formation, Whangai Formation is more distal from the provenance area. Among the three members, Rakauroa Member is the geographically closest member to the Torlesse followed by Upper Calcareous and Porangahau members (Figures 4.46 – 4.49). It is also important to stress that, among the structural blocks, Tora Block and Motu Block seem to have had more influence from the Torlesse Group signature (Eastern Province) compared to the Pongaroa Block. Perhaps at the time of deposition, the Pongaroa Block had more influence from other sources, like the Western Province. Another possibility for the Pongaroa Block, based on the gravimetric map (Bouguer) (Robertson & Reilly, 1958, Figure 3.11), is that the lack of compositional similarity with the Torlesse Group could be related to proximity to the depocentre of the basin and therefore reflects being less influenced by the provenance characteristics. This could be tested in future studies combining petrographic work.

Based on Pearce et al., 2005, terrigenous input can be associated with the *sum* of Al_2O_3 , K_2O and TiO_2 . These three elements are therefore interpreted to be an indicator of total terrestrial sediment as they suggest the amount of terrigenous input into the basin. From Figures 4.39 to 4.41, it can be seen that the Rakauroa Member in the Motu and Tora blocks shows the highest totals indicating that these two blocks had more terrigenous input at the time of the deposition. This member also has more terrigenous input relative to the Porangahau and Upper Calcareous members. On the other hand, when the Waipawa Formation is compared to Rakauroa Member in the same structural blocks, the totals from Waipawa are higher, indicating that the terrigenous input was generally higher for this formation. Either a transgression or a regression model could account for the increased in terrestrial organic matter into the Waipawa Formation.

Another element used to characterize the proximity to provenance area is K_2O . This element is associated with clay-grade terrestrial detritus (Pearce et al., 2005); it is also present in K-feldspar and glauconite. Ideally, the ratio $\text{Rb}/\text{K}_2\text{O}$ should be used in order to distinguish

the amount of feldspar present, as the ratio in feldspar is lower than in clay minerals (Ratcliffe et al., 2007; Ellwood et al., 2008). Only K₂O is used as we lack trace element data. Comparing Figures 4.46 to 4.49, we conclude that the percentage of K₂O in the Rakauroa Member is slightly higher than in the Porangahau and Upper Calcareous members, and higher in the Waipawa Formation than in the Rakauroa Member. This suggests that the Waipawa Formation and Rakauroa Member rocks have more influence from the provenance area and are derived from the Torlesse Super group (Eastern Province). The lack of representativeness of rock samples decreases the reliability of testing this hypothesis but Figure 4.50 shows an increase in TOC with an increase in clay content. Given the fact that, for example, Motu and Tora Blocks shows more terrestrial input and probably more clay content, the higher amount of TOC could be related to this.

Comparing the structural blocks along East Coast Basin, the Tora and Motu blocks seem to be the closest blocks to the provenance area and a shallower depositional environment, based on the CIA/ICV plots, terrestrial input and the Torlesse signature. These results support evidence from the literature even using different methodologies, as discussed below.

Whangai Formation:

The following are quotes from other literature:

Tora Block:

Laird's study in 2003 notes:

The common presence of well-developed hummocky crossstratification, at least in the uppermost part of the succession, suggests that deposition of this portion was above storm wave base (i.e., mid-shelf depths or shallower; Harms et al., 1975). The presence of slump horizons and of debris flows, perhaps channelled, suggests a slope to the floor of the depositional basin. The fine grain size is typical of the Whangai Formation elsewhere on the east coast of New Zealand, and is inferred to record marine transgression resulting from thermal subsidence of the New Zealand landmass accompanying its separation from Gondwana at c. 85 Ma (Crampton et al., 1999). (p.282)

Motu Block:

Speden quoted in Stevens & Speden's study in 1978:

In the upper Waitahaia River valley of Raukumara Peninsula, allochthonous Early Cretaceous - Early Miocene sediments are faulted against autochthonous Early Cretaceous - Early Paleocene sediments. No complete sequence of Whangai Formation is exposed, although, ~200 m is present in the Waitahaia River with the top faulted. This autochthonous environment of deposition for Whangai Formation (Rakauroa Member) was a stable shelf environment, possibly behind offshore barriers. (p.298)

Allochthon Block:

Weston's et al. study in 1988 note:

Conducted a biomarker correlation study of the three main seep oils in the northern East Coast Basin (Waitangi, Totangi and Rotokautuku), and inferred a neritic depositional environment with a significant input of terrigenous organic matter. The oils were presumed to have been derived from Cretaceous shales, although biomarker correlation with the rock bitumens was not possible.

Coastal Block:

Neef noted in 1997:

The environment of deposition for the Whangai Formation was bathyal (p.337).

Leckie's study in 1995 notes:

Foraminifera in the Rakauroa Member indicates deposition in outer shelf to upper bathyal or deeper water depths and Porangahau Member sandstones represent deposition from turbidity currents, possibly on the basin plain. Also near the base of this member is where the first calcareous benthics come in. The percent of calcareous taxa increases steadily through Porangahau Member and the lower Upper Calcareous Member, and based on the taxa *Vulvulina buningi*, *Nuttallides florealis*, *Bolivinoidea* sp., etc..., the deposition indicates bathyal water depths (Morkhoven et al., 1986). In the Upper Calcareous Member the foraminiferal assemblage indicates outer shelf to upper bathyal conditions, except in particular layers where conditions deteriorated further, likely becoming more dysaerobic, with a significant increase in agglutinated taxa and decrease in diversity. (p.11 and 12)

Elgar's study in 1997 notes:

The organic matter in the Whangai Formation comprises predominantly structured terrestrial kerogen with variable contributions of structured aqueous and semi-opaque kerogen. Structured aqueous kerogen is more abundant in the Upper Calcareous Member than the Rakauroa Member and indicates a greater marine influence. In addition, this formation shows a moderate sulphur content and occasionally high relative abundances of 28,30-bisnorhopane, indicating deposition under conditions of reduced oxygen. (p.130)

Pongaroa Block:

Moore's study in 1988a notes:

Dramatic changes in thickness are seen in the Whangai Formation compared to Waipawa Formation. Whangai Formation is 550m at Tangaruhe Stream (Pongaroa Block), 160-200m at Porangahau, and only 50m between Mangakuri and Waimarama in Coastal Block. (p.14 and 15)

As no unconformity is recorded in these areas this difference in thickness could be related to the depocenter of the basin at the time of deposition of Whangai Formation,

consistent with Pongaroa block reflecting a deeper depositional environment among the studied structural blocks.

Waipawa Formation:

Coastal Block:

Leckie's study in 1995 notes:

A 64 mm long bivalve *Conchocoele* n.sp. (Thyasiridae) collected from near the base of the unit. The relationship to Lucinidae and the occurrence of only this one species suggests a deep infaunal burrower in black, mostly anoxic mud (cf. *Lucinoma*, etc.). The one living species today is a North Pacific deep-water form, in fairly cool water (A. Beu, pers. comm., 1986). (p.13)

Elgar's study in 1997 notes:

Demonstrated that the Waipawa Formation has terrestrially structured organic matter and also characterised the Waipawa Formation as a high sulphur content rock and, based on the 28,30-bisnorhopane. From this evidence, he inferred that this formation indicates dysoxic and periodically anoxic depositional conditions. (p.130)

Clowes et al.' conference presentation in 2016 shown:

The Roncaglia & Kuijpers (2006) triplot diagram, which counts the terrestrial palynomorphs in with the phytoclasts, shows that the Waipawa Formation has a very high terrestrial input, was deposited in a deep-water environment (bathyal; probably mid-bathyal) and is not a homogeneous unit.

Coastal and Pongaroa Blocks:

Schiøler et al.' study in 2010 note:

The Waipawa Formation is a regressive unit due to the increasing up section non-marine proxies. They suggested that a fall in sea level caused a base level drop and erosion provided the terrestrial material. (p.355)

Beggs's study in 2010a,b notes:

That large parts of the New Zealand continent were uplifted and eroded, related to the cessation of sea-floor spreading (Waipounamu Erosion Surface – from Cretaceous to the Oligocene). This may have provided the mechanism to uplift and erode swamps, giving the high terrestrial input, and causing the maximum regression suggested by Schiøler et al., (2010).

Fuerst's study in 2012 notes:

A transgressive model where rising sea level flooded low-lying swamps and peats. Rapid erosion and redeposition diluted the biological CaO and SiO₂ contents at Angora Quarry. The erosion of peat swamps during transgression may have limited deposition of sediments in the shallow water with shallow water, indicators washed into deeper waters. (p.107 and 108)

Hollis et al.'s conference presentation in 2014 shown:

Inferred upper bathyal (Mead Stream) to inner shelf (Great South Basin – Tartan Formation, Waipawa equivalent) depths with mass erosion and deposition of terrigenous sediments with abundant plant matter, rich in nutrients, which in some settings promoted high marine productivity and the development of dysoxic conditions.

4.6 BRITTLE INDEX (BI) USING OUTCROP SAMPLES

4.6.1 Introduction

The most common mistake in finding the optimum stimulation treatment in shale plays is to treat them all equally. There is no doubt that some parameters can be assumed mainly in new frontier shale development. Like any other type of reservoir (conventional and unconventional) each reservoir is unique and the stimulation and completion style for an emerging shale play starts in the laboratory.

Given that, twenty-one rock samples were taken from eight different measured sections along the East Coast Basin, in order to measure the brittleness index using the method of Mavko et al. (2009). Table 4.27 shows the source data available for the wells and outcrops subdivided by formation, member and structural block. Eighteen of the twenty-one samples from the Whangai and Waipawa formations yielded reliable shear velocity data, but three samples did not and were discarded (Table 4.28 and 4.29, respectively). Given these samples were cored from outcrops, they are expected to show different results from deep observations collected using geophysical logs under *in situ* stress, due to near-surface weathering and stress relief. In addition to these factors, anisotropy, pore pressure, alteration zone, bedding planes and joints zones, samples dimensions, also influence the P-velocity measured under *in situ* stress and without confining stresses (Dearman et al., 1987). For these reasons, velocity measurements made under *in situ* conditions and from outcrops in shallower zones are expected to vary. On the other hand, due to some intrinsic properties of the rocks that are not affected by confining and tectonic stresses and still acting even in shallower zones (pore fluid composition [salinity], mineralogical composition, total density, shape and grain size, total and effective porosity, anisotropy) it is expected that a constant value (K) represents the relationship between compressional velocity/shear velocity under shallow/near surface (V_{psh} and V_{ssh}) and *in situ* stress (V_{pis} and V_{sis}), according to the equation below:

$$K = \frac{V_{p(sh)}/V_{s(sh)}}{V_{p(is)}/V_{s(is)}} = \frac{K_{sh}}{K_{is}} \quad (\text{Eq.4.3})$$

This consideration is used in this research and K is evaluated in subsurface using geophysical logs, and a comparison with the ratio of V_{psh} and V_{ssh} is done. The K measurements from the laboratory without *in situ* stress (K_{sh}) was obtained, with mean value equal to 1.74. This value is closely to the Gasmann (1951) equation (Eq. 4.4), where K equals

to 1.73, indicating that the proposed equation from the literature could be used to estimate shear velocity using geophysical compressional log in subsurface due to absence of dipolar logs in any of the offset wells, also see section 4.7.2.1:

$$V_s = V_p / \sqrt[3]{\quad} \quad (\text{Eq.4.4})$$

Therefore, it was decided that these results (shear velocity and k) would be used for comparison only to the results obtained from the exploration well (Rere-1). This analysis aim to compare the results between outcrops (lab analysis), with well-log interpretation derived from the exploration well, and check if the outcrop's samples could be used as analogues to predict the BI in subsurface (qualitatively) section 4.7.4. Based on the lack of outcrop samples the only structural block where a comparison could be undertaken with a more robust dataset is Motu Block (Rakauroa Mb. - Whangai Fm.), because it has more than 3 cores taken from the same locality and also an exploration well drilled (Rere-1 well) (Table 4.27). The results of the BI of Rere-1 well can be seen in Table 4.32. The comparisons applied are: ratio between the compressional and shear wave velocities (V_p and V_s , respectively), Poisson's Ratio and Young's Modulus as well as the brittleness index, as described by Mavko et al. (2009).

Table 4.27 Number of samples per formation and member per structural block.

Formation	Member	Well					Outcrop				
		Structural Blocks					Structural Blocks				
		Motu	Allochton	Coastal	Pongaroa	Tora	Motu	Allochton	Coastal	Pongaroa	Tora
Waipawa								1	2	4	
Whangai	UC							1	1		
	Rak	Rere-1 (well logs)		Opoutama-1 (well logs)	Hukarere-1 (well logs)		6	1	2		2
	Poran								1		

4.6.2 Methodology

A conventional method was applied to measure the two different velocities from the outcrops samples, compressional wave (Vp) and Shear wave (Vs). These velocities measurements were undertaken on cored outcrop samples using two contacting transducers coupled to both ends of the core. The rock density was determined from core dimension and weighed measurements.

* σ = normal stress ((Pa) N/m², psi) and e = strain

Rickman et al. (2008), suggested that the brittleness concept should combine Poisson's ratio, which they claimed reflects the rock's ability to fail, and Young's modulus, which represents the ability to maintain a fracture, once the rock fractures. Therefore, brittle shales should have low Poisson's ratio and high Young's modulus. These two parameters are calculated from Vp and Vs waves, using the formulas below Mavko et al. (2009):

$$E = \frac{\rho V^2 s(3V^2 p - 4V^2 s)}{Vp^2 - Vs^2} \quad (\text{Eq.4.5})$$

$$\nu = V^2 p - \frac{2V^2 s}{2(V^2 p - 2V^2 s)} \quad (\text{Eq.4.6})$$

$$E_{brittle} = \frac{E - E_{min}}{E_{max} - E_{min}} \quad (\text{Eq.4.7})$$

$$\nu_{brittle} = \frac{\nu - \nu_{max}}{\nu_{min} - \nu_{max}} \quad (\text{Eq.4.8})$$

$$BI = \left[\frac{100(E_v - E_{vmin})}{(E_{vmax} - E_{vmin})} + \frac{100(\nu_v - \nu_{vmax})}{(\nu_{vmin} - \nu_{vmax})} \right] / 2 \quad (\text{Eq.4.9})$$

Where: E_v is the average E, E_{min} and E_{max} are minimum and maximum Young's modulus respectively, ν is the average Poisson' Ratio, ν_{v_min} is the minimum value and ν_{v_max} is the maximum Poisson's ratio.

Based on these calculations BI can be estimated.

4.6.2 Results and Interpretations

Table 4.28 Vp and Vs measurements of rock samples (cores) from outcrops of the Whangai Fm. Note that only the cores from Motu Block are used.

	Structural Block	Diameter	Measurements (Length-Cm)	Average (Length-Cm)	Diameter (cm)	Average Volume (m³)	Formation	weight (Kg)	VP (ms)	VS(ms)	Bedding	Vp (m/s)	Vs (m/s)	Density kg/m³	Vp/Vs
Upper Pukemuri															
UPuk01	Tora	15/16			2.38		Top Whangai								
Lower Pukemuri															
LPuk02	Tora	15/16	1.142;1.240;1.294 ;1.174;1.168;1.17 0;1.220;1.208;1.2 08;1.182	1.20	2.38	0.00000535	Base Whangai	0.0132	3	hard to read	Normal	4002.00	#VALUE!	2469	#VALUE!
Angora Stream															
AS07	Coastal	15/16	5.092;5.090;5.006 ;5.014;5.060;5.03 6;5.018;5.004;5.09 2;5.098	5.05	2.38	0.00002249	Whangai	0.0533	15.4	26.8		3279.87	1884.70	2369	1.74
AS11	Coastal	15/16	2.970;3.020;3.014 ;3.068;3.038;3.00 4;2.970;2.968;2.9 50;2.954	2.99	2.38	0.00001334	Whangai	0.0316	10.8	19.8	parallel	2773.70	1512.93	2369	1.83
AS13	Coastal	15/16	1.742;1.756;1.754 ;1.752;1.862;1.85 8;1.750;1.744;1.7 72;1.750	1.77	2.38	0.00000790	Whangai	0.0185	6.4	13.2	normal	2771.88	1343.94	2342	2.06
AS18	Coastal	15/16	1.612;1.664;1.722 ;1.750;1.768;1.79 0;1.788;1.414;1.4 44;1.254	1.62	2.38	0.00000722	Whangai	0.0170	6.4	13.2	normal	2532.19	1227.73	2355	2.06
Rakauroa Stream															
Rak 01	Motu		2.68;2.69;2.67	2.68	2.38	0.00001193	Whangai	0.0299	8.72	12	normal	3073.39	2233.33	2491	1.38
Rak 02	Motu		6.52;6.58;6.54	6.55	2.38	0.00002914	Whangai	0.03475	22	32.8	normal	2975.76	1995.93	2316	1.49
Rak 03	Motu		3.53;3.53;3.55	3.54	2.38	0.00001577	Whangai	0.06627	11.6	18.2	normal	3054.60	1946.89	2325	1.57
Waitahaia Stream Owhena															
OW01	Motu		1.58;1.54;1.57	1.56	2.38	0.00000696	Whangai	0.01516	4.4	8.6	normal	3553.03	1817.83	2332	1.95
OW02	Motu		2.57;2.62;2.60	2.60	2.38	0.00001156	Whangai	0.00858	7.6	12.5	normal	3416.67	2077.33	2451	1.64
OW03	Motu		1.41;1.38;1.38	1.39	2.38	0.00000619	Whangai	0.0167	4	7.1	normal	3475.00	1957.75	2226	1.78
Te Weraroa Stream															
Twr 01	Allochthon		2.38;2.36;2.38	2.37	2.38	0.00001056	Whangai	0.02553	7.6	13.4	normal	3122.81	1771.14	2220	1.76
Twr 02	Allochthon		2.54;2.51;2.59	2.55	2.38	0.00001134	Whangai UC??	0.02758	8.6	14.9	normal	2961.24	1709.17	2206	1.73

Table 4.29 Vp and Vs measurements of rock samples (cores) from outcrops of the Waipawa Fm.

Measured Section	Structural Blocks	Diameter	Measurements (Length-Cm)	Average (Length-Cm)	Diameter (cm)	Average Volume (m³)	Formation	weight (Kg)	VP (ms)	VS(ms)	Bedding	Vp (m/s)	Vs (m/s)	Density kg/m³	Vp/Vs
Mangatarata															
Man03	Pongaroa	1 1/2	2.142;2.138;2.138;2.138;2.124;2.112;2.116;2.114;2.124	2.12	3.81	0.00002427	Waipawa	0.0414	10.8	16.8	Normal	1970.74	1266.90	1706	1.56
Man04	Pongaroa	1 1/2	3.200;3.292;3.242;3.262;3.258;3.246;3.228;3.214;3.214;3.148	3.23	3.81	0.00003683	Waipawa	0.0661	17.4	27.4	Normal	1856.55	1178.98	1795	1.57
Man05	Pongaroa	1 1/2	1.900;1.930;1.934;1.878;1.824;1.806;1.884;1.810;1.818;1.808	1.85	3.81	0.00002120	Waipawa	0.0396	8.6	17.4	Normal	2161.86	1068.51	1868	2.02
Man06	Pongaroa	1 1/2	2.634;2.634;2.554;2.536;2.536;2.550;2.620;2.604;2.554;2.534	2.57	3.81	0.00002936	Waipawa	0.0530	11.6	fractured	Parallel	2220.34	#VALUE!	1805	#VALUE!
Taylor White															
Tw02	Costal	1 1/2	3.132;3.136;3.142;3.164;3.200;3.184;3.172;3.172;3.164;3.138	3.16	3.81	0.00003603	Base Waipawa	0.0592	12.6	18.2		2508.25	1736.48	1643	1.44
Tw05	Costal	1 1/2	3.992;3.968;3.962;3.972;3.994;3.924;4.032;3.958;3.956;3.992	3.97	3.81	0.00004532	Top Waipawa	0.0942	14.6	hard to read	angle	2722.60	#VALUE!	2079	
Te Weraroa Stream															
Twr03	Allochthon		5.02;5.04;5.06	5.04	2.38	0.00002243	Waipawa	0.05475	16	26	Normal	3150.00	1938.46	2329	1.63

4.6.3 Results and Conclusions

Rakauroa Member (Whangai Fm.) in Motu Block is the only formation evaluated here as there are both cores (6) and well data available. The brittleness index using Mavko et al. (2009) is 0.60 (Table 4.30). This method was used to estimate BI using elastic parameters in anisotropic material, once coring process took samples perpendicular to the bedding planes. This process guarantee that vertical velocity was slow when comparing velocity measured horizontally, respecting the considerations described by Mavko et al. (2009). Furthermore, the result of the BI from Rere-1 well, also using Mavko et al. (2009) is in between 0.280 to 0.534 (P10 and P90, respectively) with the mean of 0.422, see section 4.7.4. These results indicate that unloading process did not greatly affect the estimated brittleness index using elastic parameters, indicate that the unloading process in the study area was not severe. The same comparison was performed within the velocities in deep conditions (Rere-1 well). The results show that the mean values of V_{sin} is equal to 1,706.3m/s, the median is 1,866.5m/s, maximum value of V_{sin} is about 2,436.2m/s and the minimum of V_{sin} is about 561.04m/s (APPENDIX 3).

Table 4.30 Step by step to calculate BI from core sample measurements using Mavko et al. (2009) from 6 outcrops samples in Motu Block.

INPUT	WHANGAI Fm. (RAKAUROA Mb.) MOTU BLOCK			
Vp	MIN	2,975	m/s	from lab sample testing
	AV	3,258	m/s	from lab sample testing
	MAX	3,553	m/s	from lab sample testing
k= Vp/Vs	MAX	1.95		from lab sample testing
	AV	1.63		from lab sample testing
	MIN	1.38		from lab sample testing
density	AVERAGE	2,357	kg/m3	from lab sample testing
SHEAR MODULUS (G) =	MIN	5.48	GPa	from Vs and density
	AV	9.41	GPa	from Vs and density
	MAX	15.62	GPa	from Vs and density
YOUNGS MODULUS (E) =	MIN	14.50	GPa	from Vs and Vp Equat. 4.3
	AV	22.56	GPa	from Vs and Vp
	MAX	29.59	GPa	from Vs and Vp
		22.57	Gpa	
POISSON RATIO (V) =	MIN	0.05		from Vs and Vp Equat. 4.4
	AV	0.20		from Vs and Vp
	MAX	0.32		from Vs and Vp
E_{BRITTLE} =		0.53	normalised	from E (av,min,max) Equat. 4.5
V_{BRITTLE} =		0.67	normalised	from v (av,min,max) Equat. 4.6
Brittleness Index (BI) =		0.60		from Ebrittle and vbrittle Equat. 4.7

4.7 GEOMECHANICAL MODELLING

4.7.1 Introduction

Brittleness Index is the most widely used parameter for the quantification of rock brittleness. According to Holt et al. (2011), if the rock has a large region of elastic behaviour but only a small region of ductile behaviour the rock is considered brittle. In contrast, if the material under stress has a small region of elastic behaviour and a large region of ductile behaviour, absorbing much energy before failure, it is considered ductile. Several studies in the literature have been used to show that brittleness index can be applied to define the best interval or intervals to perform reservoir stimulation in unconventional reservoirs and tight formations (Hucka and Das, 1974; Mavko et al., 2009; Rickman et al., 2008; Wang and Gale, 2009; Jarvie et al., 2007).

Several characteristics of the reservoir rocks are important for identifying whether the rock is brittle and easily to be stimulated by hydraulic fracturing: pore pressure, rock strength, mineralogy, elastic parameters, natural fracture characteristics, stress state, porosity, permeability and TOC content. These properties are estimated using geomechanics and petrophysics.

According to Darby and Funnell (2001), the presence and magnitude of overpressure is variable along the East Coast Basin, depending both on local stratigraphy and structure. Therefore, the East Coast Basin is an ideal system to explore how the interplay of stratigraphy and structure impacts the development of overpressure. The development of overpressure can have a large influence on rock strength and structural basin development, (Foroozan, et al., 2012). Burgreen, et al. (2014) have demonstrated that the Whangai Formation is a prospective source rock, and, based on their modeling results, has likely experienced natural hydraulic fracturing also during early Miocene due to the build up of overpressure. This is supported by Field, et al. (2004), who recorded the fractured nature of this formation in outcrops. In contrast, the Waipawa Formation is more likely to have undergone ductile deformation due to its more clay-rich lithology.

Given that, a geomechanical and a petrophysical model has been constructed with the intention of quantifying and qualifying the petrophysical and rock mechanical properties. Data for the models are compiled from petroleum well logs, mudlogging reports, chromatography, laboratory X-ray, acoustic measurements, and fluorescence descriptions, which provided data for the mineralogy, total organic carbon (TOC), overburden model, pore pressure, elastic

parameters, and rock strength properties estimation. Using these parameters, a rock brittleness index can be calculated. Four different methods were tested and they are described below. In this way, the best structural block and the best zones in the Waipawa-Whangai formations for hydraulic fracturing stimulation can be identified.

Within the East Coast Basin, only the Opoutama-1, Rere-1 and Hukarere-1 exploration wells intersected the Whangai and/or Waipawa formations. These three exploration wells have been used to characterise the Brittleness Index of the Rakauroa Member, which is the only member of the Whangai Formation that was reached in the wells (the two other members, Porangahau and Upper Calcareous, were not identified). The Waipawa Formation may have been present in the Rere-1 well (Ward and Leask, 2014 and Ventura et. al., 2013) but as the original log interpretation does not identify this formation, it was decided not to characterize it here as Waipawa Formation. The formation is also not reliably identified in Opoutama-1, and is replaced by the laterally-correlative Te Uri Member of the Whangai Formation in Hukarere-1.

The data units have been maintained according to the worldwide oil and gas industry standards. See glossary for the conversion factors.

4.7.2 Building the Geomechanical Model

The geomechanical analyses can be used to anticipate and diagnose non-productive time (NPT) and wellbore failures ahead of the bit and to avoid inefficient hydraulic fracturing stimulation. Furthermore, the safe operating envelopes created at and ahead of the bit can be used to provide critical information necessary to optimize the casing and drilling fluid programs and reduce the probability of unscheduled events in unconventional reservoirs.

4.7.2.1 Data Available - Wells

Below are descriptions of the drilling activities in each of the offset wells used here:

Opoutama-1 well was spud on 28 February 1967 and drilled to a total depth of 3657.6 m MD in 170 days. It targeted Cretaceous sandstone formations on the Morere Anticline complex. In total 17 cores were cut; Where, 4 cores were cut over the interval 0-6,000ft (0 - 1828.8 m), and 13 cores over the interval 6,000-12,000 ft (1828.8 - 3657.6 m). Although good gas shows with higher hydrocarbons were recorded, a single drillstem test did not flow hydrocarbons. No potential reservoirs were encountered either in the Tertiary or Upper Cretaceous sediments down to 12,000 ft (3657.6 m). The thick Miocene to Upper Cretaceous

sedimentary succession includes 900 m of Miocene strata, a 200 m thick fault or melange zone, c.200 m of Wanstead Formation, c. 450 m of Whangai Formation, and c. 1800 m of Tikiore Formation (Mazengarb & Speden, 2000). The suggestion that Waipawa Formation may occur at the Wanstead-Whangai contact has not been confirmed.

There is an absence of drilling reports with detailed observations of torque and drag, total gas, cuttings, direct pressure measurements (field measurements), laboratory measurements and cavings analysis, etc., which are critical to calibrate the geomechanical model. Were they available, they could be coupled with wireline or LWD logging data to create a more comprehensive analysis for drilling and completion strategy (Zimmermann & Faber, 1967).

Rere-1 well was spud on 28 August 1985 and drilled to a total depth of 4351.5 m MD in 213 days. The expected Cretaceous sandstone reservoirs were not encountered. The lack of reservoir sandstone in the drilled section, the increased depth of burial and its adverse effect on reservoir quality, together with the slow drilling progress, led to the decision to plug and abandon the well approximately 500 m shallower than the predicted level of the target reservoir. The well was plugged and abandoned as a dry hole on 4th of April 1986. No hydrocarbon shows of significance were encountered during drilling. Background gas gradually increased with depth and sandstone and siltstone occasionally gave increased gas readings. Fluorescence was only occasionally detected; one 40 m-thick sandstone at 3900 m did not show increase in gas readings or fluorescence (de Bock et. al., 1986).

Hukarere-1 was spud on 11 October 2001 and drilled to a total depth of 3230.3 m MD in 56 days, to test the hydrocarbon potential of the Pania Anticline. A Pliocene – Miocene succession unconformably overlies a near-complete Paleogene succession, which includes the Weber Formation (Oligocene) at 1954 to 2127.5 m, the Wanstead Formation (Eocene – Paleocene) at 2127.5 to 2764 m. Two members of the Whangai Formation are present: the Paleocene Te Uri Member (2763.9-2810.2 m) and the Upper Cretaceous Rakauroa Member (2810.2-3086.7 m). An unusual facies of intensively calcite-veined mudstone at 2810.2-2902.3 m was interpreted as a fault zone. The Glenburn Formation was encountered at 3086.7 m and encountered gas up to 23%. Test 1 was carried out through 11.5 m of perforated intervals between 3179.3-3102 m. The well flowed water. Test 2 was carried out through perforations at (3155.2 - 3158.9 m). There was no significant pressure build-up, and 22 bbl water were swabbed to the surface. The identification of Glenburn Formation at the base of this succession is problematic as the formation is restricted to the eastern sub-belt but the well was drilled some 10 km west of the sub-belt boundary. Moreover, the Te Uri Member is not known in the eastern sub-belt (Moore, 1988b). The absence of the Upper Calcareous and Porangahau Members

further suggests that upper Cretaceous-Paleocene sediments in this well are more similar to the relatively shallow water western sub-belt sequence than to deeper water eastern sub-belt rocks. The most similar record is in Rere-1, where ~300 m of shelfal Haumurian strata, correlated with the Rakauora Member, are overlain by ~100 m of Te Uri Member. For this reason, the entire Haumurian interval in Hukarere-1 was correlated with the Rakauora Member of the Whangai Formation, and it was suggested that the well was drilled on a paleo-high. Drilling through the Rere ST Fm the hole was packed off around the Bottom Hole Assemblage (BHA) while the drill bit pull out of hole (POOH). A side track was required to be performed to continue to drill the well. Around 1.8% was detected as background gas in the Wheao Formation and in the top of Weber Formation. Low concentrations of C₂, C₃ and C₄, with high amount of C₁ were detected. In the Whangai Formation, no drilling problems were detected. The siltstone reservoir (Glenburn) below the Whangai Formation also did not present any drilling problem (Westech Energy New Zealand Ltd., 2001).

The geomechanical model presented here was built and verified based on the actual experience of these three previous wells. Few drilling problems and mud weight description are reported in some intervals of the offset wells without enough details to identify drilling problems (i.e., tight holes, pack off, stuck pipes, washouts) that could affect the quality of the logs. The drilling events potentially associated with the lower bound of the mud window (i.e., pore pressure and collapse pressure) such as stuck pipe, kicks, tight hole and hole enlargements are also used to calibrate and verify the model.

The main drilling problems were reported in the Opoutama-1 well to support density logs corrections (between 280-1725 m) due to hole washout and in Hukarere-1, that reported pack off and fishing while pull out of hole at 401 m. Fluoresce and chromatography logs indicated that in the Whangai Formation shows around 120 units alone 50-70 gas units of background gas in Rere-1 and in Opoutama-1 well 7.0% alone where 0.8% background gas with C₁=6%, C₂=0.2% and C_n with traces. In the Rere-1 well Whangai was drilled with 13.8 pounds per gallon (ppg) and Opoutama-1 well the same formation was drilled with MW=15.9 ppg. Pressure-while drilling data, direct pressure measurements and leak-off tests were not available in all offset wells. Tight holes or lost circulation events were not reported in all mudlogging reports. Occurrence of background gas, caliper enlargement, washout, and high mud weight in the Whangai Formation are both indication of mechanically weak formation and/or high pore pressure.

The wireline data available for each well can be seen in Table 4.31. Figures 4.54 to 4.56 show the lithology and the log curves used: acoustic velocity log (v_p , v_s), density, pseudo density from the acoustic velocity (Gardner et al., 1974), resistivity, caliper and gamma ray. From the left: The lithology column is based on the mudlogging report, the acoustic velocity log (v_p , v_s), used to derive the rock strength, elastic parameters and pore pressure; the density log, used to constrain the overburden; the resistivity log, used to derive the pore pressure; the caliper log, used to check the condition of the wellbore and the hole stability, the sonic logs for Static Youngs Modulus; and the Gamma ray log, used to discriminate clays from others lithology for pore pressure prediction, elastic parameters, rock strength, and brittleness index of Opoutama-1, Rere-1, and Hukarere-1 wells, respectively.

As there was no shear wave velocity information from the wells, the shear velocity (v_s) log (second column – Figures 4.54 to 4.56) was estimated using Gassmann equation $v_s = v_p / \sqrt{3.0}$, where v_p is in units of us/ft and v_s is in units of us/ft (Gassmann, 1951). The porosity (%) from v_p was estimated using the Wylie correlation ($n = (DTCO - DTMatrix) / (185 - DTMatrix)$), where DTCO and DTMatrix in us/ft.

Table 4.31 The three exploration wells used in the geomechanical model showing its log curves availability.

Curves	OPOUTAMA-1	RERE-1	HUKARERE-1
SP*	X	X	
Resistivity (short)	X	X	X
Resistivity (Mid)	X	X	X
Resistivity (Deep)	X	X	X
Induction		X	X
Conductivity			
Caliper	X	X	X
GR	X	X	X
Density	X		X
Total Gas	X	X	X
Mud Weight	X	X	X
Sonic	X		X
CheckShot	X	X	X
Nphi			

* Spontaneous potential (SP)

Figure 4.54 Data available to build the geomechanical model for the Opoutama-1 Well – Whangai Fm. (Rakaurua Member).

Figure 4.55 Data available to build the geomechanical model for the Rere-1 Well – Whangai Fm. (Rakaurua Member).

Figure 4.56 Data available to build the geomechanical model for the Hukarere-1 Well – Whangai Fm. (Rakauroa Member).

4.7.2.2 Overburden and Pore Pressure

Figures 4.57 to 4.59 presents the vertical stress (S_v) or overburden and pore pressure analysis for the Whangai Formation and for other formations encountered in Opoutama-1, Rere-1 and Hukarere-1 wells, respectively. Vertical stress was calculated by integrating density logs (solid blue line – first and second column), from 860mMD to 424mMD in the Rere-1 well using the Gardner equation, covering the Wheao, Weber, Wanstead, Whangai and Karekare formations. Density logs were available in the Opoutama-1 and Hukarere-1 wells. In these wells, the overburden was calculated directly using the density logs from each well. It is very important to get at least one density log as shallow as practical, but in the studied wells the data do not cover depths from the surface until 859mMD in the **Rere-1 well (velocity)**, from surface to 284.16m in the **Opoutama-1 well (density or velocity)** and from surface until 428.98 mMD in **Hukarere-1 well (density or velocity)**. For this reason, a power law relationship was created then fitted to the surface to fill in the missing data. In the **Opoutama-1 well** logs covered the Tunanui, Waingaromia, Wheao, Weber, Wanstead, Whangai and Tikiore formations. Data from **Rere-1 well** cover all formations with gamma ray log and the Wheao, Weber, Wanstead, Whangai and Karakare formations with others logs, and in the **Hukarere-1 well** the logs covered the Mahanga, Mangatoto, Haupori, Waitere, Weber, Wanstead, Whangai and Glenburn formations. Also, in this study, claystone/mudstone are the most dominant lithologies and their mechanical and petrophysical properties critical for the hydraulic fracturing design in the Whangai Formation. Therefore, all the statistical analyses considered only these lithologies. Siltstone is the second most common lithology in this formation, with small interlayer intervals. Although the statistical results did not consider this small portion of siltstone, this will be presented in the APPENDIX 3.

A statistical study has been performed to define the probabilistic distribution of overburden, pore pressure and brittleness properties of the Whangai Formation. A Monte Carlo probabilistic type evaluation was adopted, which allows resampling of data from the actual distributions of the described properties to estimate uncertainties. P_{90} means 90% of the estimates exceed the P_{90} estimate and P_{10} means 10% of the estimates exceed the P_{10} . Monte Carlo simulation, or probability simulation, is a technique used to understand the impact of risk and uncertainty in different types of forecasting models. Based on this approach, the solid red line in Figures 4.57 to 4.59 corresponds to the vertical stress (overburden). The statistics are indicating that in the Whangai Formation in **Opoutama-1** the median overburden is 18.47 lb/gal, the maximum is 18.53 lb/gal, P_{10} is equal to 18.34 lb/gal and P_{90} is equal to 18.49 lb/gal. In **Rere-1** the median overburden is 19.30 lb/gal, the maximum is 19.36 lb/gal, P_{10} is equal to 19.22 lb/gal and P_{90} is

equal to 19.35 lb/gal. Finally, in **Hukarere-1**, the measurements are indicating that in the Whangai Formation the median overburden is 18.43 lb/gal, the maximum is 18.48 lb/gal, P_{10} is equal to 18.34 lb/gal and P_{90} is equal to 18.47 lb/gal.

Pore pressure at a specific depth represents the average scalar value acting within an interconnected pore space. The value of pore pressure is equivalent to a hydraulic potential measured with respect to the Earth's surface (actually the free water level). In a confined pore volume with sufficiently low permeability (or a dynamic system), pore pressures can exceed or be less than hydrostatic values. Conceptually, the upper boundary for pore pressure is the overburden stress. Because of the extremely low tensile strength of rocks, pore pressure will always be less than the least principal stress, and may sometimes be limited by leakage along faults (Bowers, 1994).

Stress (e.g. compression leading to pore volume reduction) are related to burial effects (under compaction due to vertical loading stress) and tectonic stress (lateral compressive stress due stress regimen changes, unusual high pore pressure rocks, fault zones and seal nature). These are the major overpressure-generating mechanism that could be associated in in active tectonic areas (Bowers, 1995). This is considered the most probable pore pressure mechanism in the studied area. A possible secondary pore pressure mechanism can be related to fluid volume increase that cracks oil to gas (kerogen cracking). Under-compaction occurs when sediment dewatering is inhibited during burial. This happens if new sediments are deposited before fluid has had a chance to drain, i.e. rapid burial: as seals and barriers to fluid flow form. During under compaction pore fluids are trapped, porosity is retained, and further compaction is slowed or prevented. As burial continues, pore fluids support part of the weight of the overlying sediments and the fluid becomes overpressured.

Overpressuring due to lateral stress is reported along major fault zones, both within the fault and in the adjacent porous wall-rock (Byerlee, 1993). Episodic release of overpressured fluids is associated with earthquakes and fault rupture (Byerlee, 1993).

Kerogen cracking refers to changes of the petroleum phase masses and volumes, which result from the generated chemical components and the PVT controlled dissolution into the two petroleum phases. The modifications of the phase densities contribute to the generation of formation overpressure in the study area. The pore pressure (P_p) gradient profile, the solid blue line (sixth column) in Figures 4.57 to 4.59, was modelled using the acoustic slowness, density, resistivity and interval velocity data and constrained using the mud weight. The density normal compaction trendline (NCT) model (second column from left), the velocity NCT model (third column from left) and the resistivity NCT model (fourth column from left) are present in

Figures 4.57 to 4.59. All three logging datatypes (sonic DT, density and resistivity) exhibit similar trend behaviour when entering the top of Whangai Formation and deviate away from the normal compaction trend, which implies that the formation might be overpressured (max interpreted Pp ~ 13 ppg). Pore pressure shows reversal back to hydrostatic pressure below the Whangai Formation, at the top of Tikiore, Karekare and Glenburn formations in the Opoutama-1, Rere-1 and Hukarere-1 wells, respectively.

For this study the equivalent depth method was used to estimate pore pressure from density.

$$d_{eq1A} = GG_A - \frac{ZB}{ZA}(GG_B - d_{eq1B}) \quad (\text{Eq. 4.10})$$

Where: d_{eq1A} = equilibrium density at A, d_{eq1B} = equilibrium density at B, ZB = equivalent depth, ZA = depth of under compacted clay, GG_A = overburden gradient at A, GG_B = overburden gradient at B.

The equivalent depth method basically assumes that for every under-compacted overpressured shale (A) there will be an equivalent compacted point on the NCT (B). Since the effective stress is known at depth ZB (overburden – normal pore pressure) then for under-compaction the effective stress should be the same at point ZA . Since effective stress is constant the overpressure is simply due to the additional overburden at depth ZA . Note this method has no fudge factors and can only predict pore pressures generated by under compaction in shales (Mouchet and Mitchell, 1989).

The Eaton Method was used to estimate pore pressure using velocity and resistivity logs. This method was the first to introduce a fudge factor, the Eaton exponent (Eaton, 1975). This enables the user to alter the trend line, but if that does not match the expected results, the exponent can also be altered. Most trend-line pore pressure methods after this are variations with their own locally calibrated fudge factors. The Eaton method is generally sufficient for pore pressure calculation and negates the need to use other methods. Eaton established exponents for the Gulf of Mexico (GOM) shelf as 1.2 (Eq.4.11) for resistivity and 3.0 for sonic (Eq.4.12). These values may need altering for other basins and generally need adjusting down to account for overpressure mechanisms other than under-compaction.

$$P = S - \left(S - P_{hyd} \right) \left(\frac{R_{sh_{log}}}{R_{sh_n}} \right)^{1.2} \quad (\text{Eq. 4.11})$$

$$P = S - \left(S - P_{\text{hyd}} \right) \left(\frac{\Delta T_n}{\Delta T_{\text{log}}} \right)^{3.0} \quad (\text{Eq. 4.12})$$

The results of overburden and pore pressure analysis are presented in Figures 4.57 to 4.59 for Opoutama-1, Rere-1 and Hukarere-1 wells, respectively. The statistics indicate that in the Whangai Formation:

- Median pore pressure is 12.82 lb/gal
- Maximum pore pressure is 13.00 lb/gal,
- P_{10} is 11.80 lb/gal
- P_{90} is 12.98 lb/gal

In the Opoutama-1 and Hukarere-1 wells, the pore pressure gradient starts to ramp up in the middle of the Wanstead Formation, and maintains a high level throughout the Whangai Formation, dropping abruptly to a normal trend in the underlying Cretaceous formation (Figures 4.57 and 4.59). In Rere-1, the pore pressure gradient ramps up over a short interval at the top of the Whangai Formation, and then drops to a normal gradient over an equally short interval at the base of the formation (Figure 4.58). In the other formations the pore pressure is hydrostatic (8.6 ppg). Hydrostatic pressure is defined as the part of pore pressure which does not contribute to the water flow.

Figure 4.57 Overburden and pore pressure prediction – Opoutama-1 well.

Figure 4.58 Overburden and pore pressure prediction – Rere-1 well.

Figure 4.59 Overburden and pore pressure prediction – Hukarere-1 well.

4.7.2.3 Dynamic Poisson's Ratio, Shear's Modulus, Dynamic and Static Young's Modulus, UCS, and Internal Frictional Coefficient

4.7.2.3.1 Elastic Parameters and Rock Strength

Studies performed in different types of rocks (sandstones, shales, carbonates, marbles, etc...) shows general correlations between elastic parameters, rock mechanical properties, rock indices and petrographic characteristics, with the objective of replacing and / or complementing the rock mechanical laboratory tests measurements. Laboratory campaigns represent extra costs for field development, so, in general, petrophysical correlations are applied to obtain mechanical properties. The use of acoustic logs (shear and compressive waves) and porosity are the most widely used technique in industry to derive mechanical properties. Elastic parameters and rock strength have been used in this research in order to estimate brittleness index. Log analysis as a nondestructive method is able to provide a continuous estimation of such properties and also keep the rock characteristics in situ (e.g. moisture contents).

Elasticity is the property of matter that causes it to resist deformation in volume or shape. Hooke's law describes the behavior of elastic materials and states that for small deformations, the resulting strain is proportional to the applied stress. Elastic parameters are the connection between stress and strain and such connection is called the constitutive relation of a particular material.

The elastic properties were determined using existing equations in the literature (Zoback, 2007). They determined the following properties: Dynamic Poisson's Ratio (ν_d), Shear's Modulus (G), and Dynamic Young's modulus (E_d). Dynamic Poisson's Ratio and Dynamic Young's Modulus used the same correlation for all types of lithologies. Elastic parameters were calculated in all formations and lithologies (underlying, overlying and also in the Whangai Formation) in order to understand the vertical distribution of Young's Modulus and Poisson's Ratio. The values above and below were calculated to verify their vertical distribution and it is critical to understand for future studies how the hydraulic fractures will propagate (if they occur) outside the reservoir.

Dynamic Poisson's Ratio (ν_d) was calculated from the equation:

$$\nu_d = (V_p^2 - 2V_s^2) / [2(V_p^2 - V_s^2)] \quad (\text{Eq. 4.13})$$

Where V_p is compressional velocity and V_s is the shear velocity

Where V_p and V_s are in km/s.

Shear modulus (G, MPa) and Dynamic Young's modulus (E_d , MPa) were determined using (Zoback, 2007):

$$G = (V_s)^2 \rho \quad (\text{Eq. 4.14})$$

$$E_d = 2 G (1 + \nu) \quad (\text{Eq. 4.15})$$

Rock strength is a second group of mechanical properties used to estimate brittleness index and several techniques can be used to estimate and/or determine rock strength. Numerous relationships have been proposed that relate rock strength to parameters that are measurable with geophysical well logs. In this study, such properties were calculated in all formations and lithologies (underlying, overlying and also in the Whangai Formation) in order to understand the vertical distribution of rock strength. Most proposed formulae to determine rock strength from geophysical logs use P-wave velocity, Young's modulus, or porosity (Zoback 2007). Studies performed in different types of rocks show the general correlations between rock mechanical properties and petrographic characteristics, with the objective of developing an alternative method when core samples were unavailable or limited in certain formations for laboratory testing. Laboratory tests are an accurate method to determine rock strength, but they are usually destructive, expensive (coring and testing), and result in a set of discrete data. In addition, direct measurement of rock strength is generally not available or is restricted for certain formations, and geophysical empirical relationships from log data are commonly used for geomechanical purposes. In this study, samples and geomechanical tests, from wells, of the Whangai Formation were not available.

For the rock strength the following correlations were used to calculate Unconfined Compressive Strength (UCS) and Internal Frictional Coefficient (IFC). UCS was computed using equations published by wellcheck manual (2007) for marls, Vp Cube (Zoback, 2007) for claystone, shale and mudstone, and McNally (1987) for sandstone and siltstone. Zoback (2007) summarizes in his geomechanical book all correlations used in this research.

$$\text{Marls: Qatif-NPHI: } 23018 * \exp(-4.79 * \text{NPHI}) \quad (\text{Eq. 4.16})$$

where NPHI is adimensional

$$\text{Vp Cube: } 72.5 * V_p^3 \quad (\text{Eq. 4.17})$$

where Vp in km/s

$$\text{Mc Nally Equation: } 185165 * \exp(-0.037 * \text{DTCO}) \quad (\text{Eq. 4.18})$$

where: DTCO in us/ft

Total porosity is calculated from transit time logs using the Wyllie equation given below (Wyllie et al., 1956), see Figures 4.60 to 4.62. The Wyllie equation represents consolidated and compacted formations (Equation 4.19 and 4.20). In poorly consolidated or unconsolidated rocks, a correction factor is necessary. The presence of shale or clay within the sand matrix will increase Δt by an amount proportional to the bulk-volume fraction of the clay. An empirical equation is used for calculating porosity in sandstones in which adjacent shale values (Δt_{sh}) exceed 100 $\mu\text{sec/ft}$. In this project, the claystone/shale is considered compacted, so Compressibility (C_p) is considered as 1. The shale compaction coefficient (C) generally ranges from 1.0 to 1.3, depending on the regional geology.

$$\phi = \frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \times \frac{1}{C_p}, \quad (\text{Eq. 4.19})$$

Where,

Δt = acoustic transit time ($\mu\text{sec/ft}$);

Δt_f = acoustic transit time of interstitial fluids ($\mu\text{sec/ft}$);

Δt_{ma} = acoustic transit time of the rock matrix ($\mu\text{sec/ft}$).

Where, the compaction correction factor C_p is

$$C_p = \frac{\Delta t_{sh}(C)}{100}, \quad (\text{Eq. 4.20})$$

Where,

Δt_{sh} = specific acoustic transit time in adjacent shales ($\mu\text{sec/ft}$);

100 = acoustic transit time in compacted shales ($\mu\text{sec/ft}$).

Due to the high values of total porosity estimated using this methodology, these values were just used to support estimated of the geomechanical properties of Static Young's Modulus and UCS.

Figure 4.60 Example of calculating porosity from acoustic transit time (Opoutama-1 well).

Figure 4.61 Example of calculating porosity from acoustic transit time (Rere-1 well).

Figure 4.62 Example of calculating porosity from acoustic transit time (Hukarere-1 well).

To calculate the Internal Friction Coefficient, the Lal VP, (Lal, 1999) correlation was used for all types of lithologies:

$$\text{Lal VP: } \tan(\arcsin((V_p - 1)/(V_p + 1))) \quad (\text{Eq. 4.21})$$

where V_p is in Km/s

Static Young Modulus (E_{sta}) was calculated using the same correlation:

$$E_{sta} = E_{dyn} * (0.8 - PHI) \quad (\text{Eq. 4.22})$$

Static Poisson's Ratio was calculated considering equal to dynamic Poisson's Ratio:

$$V_{sta} = V_{dyn} \quad (\text{Eq. 4.23})$$

The results of UCS, Static Young's Modulus, Poisson's Ratio and Internal Frictional Coefficient are presented in Figure 4.63 to 4.65 for Opoutama-1, Rere-1 and Hukarere-1 wells, respectively.

Figure 4.63 UCS, Static Young's Modulus, Static Poisson's Ratio and Internal Frictional Coefficient – Opoutama-1 well.

Figure 4.64 UCS, Static Young's Modulus, Static Poisson's Ratio and Internal Frictional Coefficient – Rere-1 well.

Figure 4.65 UCS, Static Young's Modulus, Static Poisson's Ratio and Internal Frictional Coefficient – Hukarere-1 well.

The statistics indicate that at the Whangai Formation in the **Opoutama-1 well** the median UCS in the Whangai Formation is 1,600 psi, the maximum is 3,508 psi, P_{10} is equal to 1,096 psi and P_{90} is 2,468 psi. For the **Rere-1 well** the median UCS in the Whangai Formation is 2,451 psi, the maximum is 6087 psi (Claystone/mudstone), 10278 psi (Siltstone) P_{10} is equal to 1,134 psi, and P_{90} is 2,800 psi. In the **Hukarere-1 well** the median UCS is 2,961 psi the maximum is 5,987 psi, P_{10} is equal to 2,514 psi and P_{90} is 3,771 psi. The enlargement of the diameter of the borehole is responsible for high values of rock properties, once the transit time is increasing in such enlarged intervals. An example of this is presented in Figure 4.59, (Hukarere-1 well), indicating that between 2095-2142m and between 2368-2378.0mMD, transit time increases significantly.

The Static Young's Modulus (YM) has a median value in the **Opoutama-1 well** of 1,714,252 psi in the Whangai Formation. The maximum value is 3,088,031 psi, with P_{10} equal to 1,290,529 psi and P_{90} equal to 2,344,620 psi. In the **Rere-1 well** the median value of YM is 1,917,347 psi in the Whangai Formation. The maximum value is 3,418,040 psi, with P_{10} equal to 688,740 psi and P_{90} equal to 2,192,085 psi. In the **Hukarere-1 well** the mean value of YM is 2,109,094 psi in the Whangai Formation, the maximum value is 3,571,008 psi, with P_{10} equal to 1,646,155 psi and P_{90} equal to 2,525,655 psi.

All values of Poisson's Ratio in the **Opoutama-1** are constant and equal to 0.265, due to the absence of shear velocity log measurements in the Whangai Formation. The median value of Poisson's Ratio in the **Rere-1 well** is 0.345 and its maximum value is equal to 0.42. P_{10} is

equal to 0.319 and 0.409 for P_{90} . In the **Hukarere-1 well** the median value of Poisson's Ratio is 0.250 and its maximum value is equal to 0.388. P_{10} is equal to 0.25 and 0.399 for P_{90} . As Poisson's ratio is estimated considering compressional velocity, shear velocity and density, this geomechanical property is severely affected by the data available for analysis and should be regarded as provisional.

The Internal Friction Coefficient (IFC) in the claystone/mudstone of the Whangai Formation in **Opoutama-1** has a median value equal to 0.539 and maximum value equal to 0.693. The Statistics are also indicating that P_{10} is equal to 0.470 and 0.613 for P_{90} . In **Rere-1** the IFC in the Whangai Formation has a median value equal to 0.538 and maximum value equal to 0.784. The Statistics are also indicating that P_{10} is equal to 0.470 and 0.613 for P_{90} . The IFC in the Whangai Formation in **Hukarere-1** has a median value equal to 0.587 and maximum value equal to 0.733. The statistics are also indicating that P_{10} is equal to 0.556 and 0.630 for P_{90} .

4.7.3 Building the Petrophysical Model and Total Organic Carbon (TOC) Estimation

As mentioned before, the available well logs information includes gamma ray, resistivity, neutron, density and acoustic velocity. These logs are used to generate the petrophysical model of the Whangai Formation in the three wells. The gamma ray log is used to determine the clay volume. The mineralogy is determined using the different responses of the different logs. A deterministic approach which, uses a single value for each parameter, is applied to describe the mineral distribution of the rock. Total and effective porosities are calculated from the density-neutron combination.

Three offset wells with conventional log data, mudlog data and TOC laboratory tests have been analysed to evaluate the mineralogical compositional and to calculate the TOC content profile. Based on this, we have integrated studies of cuttings analysis (TOC and Rock-Eval pyrolysis) and well logs (gamma ray, neutron, density, sonic, and resistivity) for the mineralogical characterization. The petrophysical model for Opoutama-1, Rere-1 and Hukarere-1 is shown in Figures 4.66, 4.67 and 4.68, respectively.

Figure 4.66 Petrophysical model of the Opoutama-1 well.

Figure 4.67 Petrophysical model of the Rere-1 well.

Figure 4.68 Petrophysical model of the Hukarere-1 well.

Once the petrophysical model has been defined for the three wells, the total organic content (TOC) is calculated using the Passey $\Delta\log R$ technique, see Passey et al. (1990) for a more detailed explanation. This procedure uses a combination between resistivity and compressional transit time but also includes the maturity of the rock. The DTbase, Rbase, and interval used are: Opoutama-1 (DTC = 81 us/ft, Rt = 3 ohmm, and Interval = 1450 – 1800m), Rere-1 (DTC = 95 us/ft, Rt = 1.5 ohmm, and Interval = 2000-2370 m) and Hukarere -1 (DTC = 93 us/ft, Rt = 1.51 ohmm, and Interval = 2810-3050m). Even though all shales contain some measurable organic carbon, the Passey method uses as reference an interval that is considered as zero TOC. Passey et al's (1990) equation for TOC prediction is used to compare with the cutting analysis and create a TOC log profile, and petrophysics analysis for the mineralogical characterization.

The results of calculating the TOC for the three wells are shown in Figures 4.69, 4.70 and 4.71. Conventional curves are shown in the first four tracks. Petrophysical evaluation is in the fifth track. In the sixth track is a comparison between resistivity and acoustic response, which is the basis of the Passey methodology. The last track shows the calculated TOC compared with the TOC measured in rock samples using pyrolysis rock eval analysis, where available (red points) (Figures 4.70 and 4.71).

Figure 4.69 TOC calculation results using Passey methodology in the Opoutama-1 well.

Figure 4.70 TOC calculation results using Passey methology in the Rere-1 well.

Figure 4.71 TOC calculation results using Passey methology in the Hukarere-1 well.

4.7.4 Brittleness Index from well data

Measurements of applied force and displacement are required to quantify shale properties. According to Holt et al. (2011), brittleness is a common term used to describe how rocks fail and their brittle regime is characterized by a stress drop when the rock is deformed after failure. They affirm that most rocks deform in a brittle manner at low confining stresses, and become ductile above a certain stress level. They also concluded that there are no unique definitions of a brittleness parameter, as pointed out already more than 41 years ago by Hucka and Das (1974).

Two critical properties that affect wellbore stability and hydraulic fracturing are Young's modulus (E) and Poisson's ratio (ν). In short, Young's modulus describes the relationship between stress and strain ($E = \sigma/\epsilon$) while Poisson's ratio characterizes how much an object that is shortening extends perpendicular to the direction of shortening (or how much it shortens perpendicular to the direction of extension if we extend the object). Young's modulus is the stiffness and Poisson's ratio is the compressibility (Rees, 2012).

Brittleness is a key parameter for hydraulic fracture initiation and propagation in low permeability rock, typical in oil and gas shales (Holt et al., 2011). There are several definitions and methods for the brittleness Index (BI), so it is important to highlight that petrophysical analysis is able to develop parameters using more complex lithologies than geomechanical parameters. In the petrophysical simulations of a single zone, complex lithologies and TOC can be modelled, all at the same time. On the other hand, stresses, rock strength, and pore pressure effects are not covered using complex lithologies. However, using geomechanical analysis only one lithology can be simulated per interval, so combining different approaches gives us a broad analysis of the studied geological formations. That is why in this study we have used four different methods: Method-1 and Method-2 used geomechanical properties, and Method-3 and Method-4 used mineralogy (petrophysical properties). These methods were selected because brittleness is a function of rock strength and elastic parameters and such properties strongly depend on mineralogy, pore structure, grain size and shape, cement and organic content (TOC). Comparing these four methods we can evaluate if the results reveal the same trends, not just vertically but also laterally between structural blocks, to indicate the best reservoir intervals and locations. The statistical analyses applied in the BI results in the three exploration wells based on each method can be seen in APPENDIX 3. The BI results of the total zone in comparison to the optimum zone are demonstrated it.

Method-1

Rickman et al. (2008) suggested that the brittleness concept should combine Poisson's ratio, which they claim reflects the rock's ability to fail, and Young's modulus, which represents its ability to maintain a fracture. They suggest an empirically based brittleness index, derived from sonic log data, which increases with increasing Young's modulus and decreases with decreasing Poisson's ratio as shown in equation 4.24 below. Elastic Parameters for isotropic rockmass are derived from Mavko et al. (2009):

$$BI = \left[\frac{100(E_v - E_{vmin})}{(E_{vmax} - E_{vmin})} + \frac{100(v_v - v_{vmax})}{(v_{vmin} - v_{vmax})} \right] / 2 \quad (\text{Eq. 4.24})$$

Where: E_v is the average E , E_{min} and E_{max} are minimum and maximum Young's modulus respectively, v is the average Poisson's Ratio, v_{min} and v_{max} are the minimum and maximum Poisson's ratio, respectively.

Method-2

Hucka and Das (1974) determined a Brittleness Index from the internal friction coefficient (IFC) as:

$$BI_I = \sin(\phi) \quad (\text{Eq. 4.25})$$

Method-3

Jarvie et al. (2007), proposed a Brittleness Index (BI) based on the mineral composition of the rock, dividing the most brittle minerals by the sum of the constituent minerals in the rock sample. Their equation estimates BI using quartz in the numerator, and the sum of quartz, clay and calcite in the denominator.

$$BI_{Jarvie} = \frac{Qz}{Qz + Ca + Cly} \quad (\text{Eq. 4.26})$$

Where Qz is the quartz content, Ca is the calcite content and Cly is the clay content by fraction in the rock.

Method-4

Wang and Gale (2009), in contrast to Jarvie et al. (2007), proposed a BI based on mineral composition of the rocks that includes dolomite content as a contributor to brittleness and dolomite and TOC in the sum of constituent minerals of the rocks in the denominator (Perez, 2014).

$$BI_{Wang \& \text{ Gale}} = \frac{Qz + Dol}{Qz + Dol + Ca + Cly + TOC} \quad (\text{Eq. 4.27})$$

Where Qz is the quartz content, Dol is the dolomite content, Ca is the calcite content, Cly is the clay content, and TOC is the total organic carbon content, by fraction in the rock.

The flowchart of the methodology of the brittleness index calculation using (eq. 4.24 and 4.25) Mavko et al. (2009), and Hucka and Das (1974), and (eq. 4.26 and 4.27) Jarvie, et al. (2007) and Wang and Gale (2009) applied to the three exploration wells is set out below in Figures 4.72 and 4.73.

Figure 4.72 Flowchart showing the step by step of methods 1 and 2 Mavko et al. (2009), and Hucka and Das (1974), respectively.

Figure 4.73 Flowchart showing the step by step of methods 3 and 4 Jarvie et al. (2007) and Wang and Gale (2009), respectively.

The four different methods used to estimate BI for the Whangai Formation are compared in Figures 4.74 to 4.76. There is a consistency between the four different methodologies, which shows that the best intervals for reservoir stimulation are: 1497.00 to 1750.00 m MD for Opoutama-1, 2224.00 to 2365.00 m MD for Rere-1, and 2796.00 to 2920.00 m MD for Hukarere-1, with Table 4.32 representing the statistics for BI calculation using each method for the best intervals. These intervals also accounted for a high amount of TOC, high pore pressure and good elastic parameters (high Young's modulus and low Poisson's ratio). These results are derived from the combination of all four BI empirical equations. The results do not match perfectly due to the complexity and differences in the nature of all parameters used, which comprise mechanical properties (stress, elastic behavior, failure properties), formation pressure and rock properties as well as pore fluid type (oil, gas and TOC). In conclusion, these ranges give an approximation of the best intervals with high BI, using different approaches (keeping in mind this is an incomplete and imperfect datasets analysis).

Figure 4.74 BI comparison and best interval (1497-1750 m MD) for Hydraulic Fracturing Stimulation – Opoutama-1 well.

Figure 4.75 BI comparison and best interval (2224-2365 m MD) for Hydraulic Fracturing Stimulation – Rere-1 well.

Figure 4.76 BI comparison and best interval (2796-2920 m MD) for Hydraulic Fracturing Stimulation – Hukarere-1 well.

The best intervals to perform hydraulic fracturing correspond to the intervals with highest BI, considering all BI methods.

Table 4.32 Comparison of the four different methodologies of estimating BI in the best estimation zone and its percentage comparing to BI in all Whangai Formation for shale/claystone/mudstone mineralogy in different structural blocks. Green colour – highest BI; Red colour – lowest BI.

Method	Well	Best Interval mMD	BI Median optimum zone	BI (%)	BI P ₁₀ Optimum zone	BI(%)	BI P ₉₀ Optimum Zone	BI(%)	Structural Block
Internal Frictional Method-1	Opoutama-1	1497-1750 (253)	0.611	7.192	0.512	4.489	0.658	-0.303	Coastal
	Rere-1	2224-2365 (141)	0.558	1.454	0.506	42.937	0.597	2.931	Motu
	Hukarere-1	2796-2920 (124)	0.687	9.047	0.609	3.220	0.724	4.927	Pongaroa
Elastic Parameters Method-2	Opoutama-1	1497-1750 (253)	0.494	6.695	0.297	4.946	0.630	0.318	Coastal
	Rere-1	2224-2365 (141)	0.422	8.483	0.280	305.797	0.534	10.103	Motu
	Hukarere-1	2796-2920 (124)	0.384	40.145	0.247	14.351	0.494	1.022	Pongaroa
Jarvie Method-3	Opoutama-1	1497-1750 (253)	0.366	139.215	0.201	103.030	0.428	20.903	Coastal
	Rere-1	2224-2365 (141)	0.177	18.791	0.119	124.528	0.215	6.435	Motu
	Hukarere-1	2796-2920 (124)	0.359	73.429	0.254	92.424	0.413	6.718	Pongaroa
Wang Method-4	Opoutama-1	1497-1750 (253)	0.178	157.971	0.086	115.000	0.215	26.470	Coastal
	Rere-1	2224-2365 (141)	0.077	13.235	0.051	264.285	0.105	0.961	Motu
	Hukarere-1	2796-2920 (124)	0.163	87.356	0.104	79.310	0.196	12.643	Pongaroa

4.8 BI RESULTS AND CONCLUSIONS

For the wells studied here, there is an absence of daily drilling reports with detailed observations of torque and drag, total gas, cuttings, direct pressure measurements (field measurements), laboratory measurements and cavings analysis etc., which are critical to calibrate the petrophysical and geomechanical models. Were they available, they could be coupled with wireline or LWD logging data to create a more comprehensive analysis for drilling and completion strategy.

The Brittleness Index estimations indicate that the best interval for reservoir stimulation in the three petroleum wells is in the middle of the Whangai Formation between 1497 m MD and 1750 mMD in **Opoutama-1**, between 2224 m MD and 2365 m MD in **Rere-1**, and between 2796 mMD and 2920 mMD in **Hukarere-1**. Table 4.33 summarizes these results. All the different estimations of BI are higher for the Opoutama-1 well (Coastal Block), except for the method 1 (Internal Friction), making this well and structural block the best area for well stimulation, followed by Hukarere-1 (Pongaroa Block) and Rere-1 (Motu Block). All analyses indicate the same behavior in terms of brittleness.

These conclusions are derived from the higher Young's Modulus, Lower Value of Poisson's Ratio, High Pore Pressure, High Internal Friction Coefficient, Higher content of siltstone, lower content of mudstone and good quantity of TOC in certain intervals. The BI methodologies using geomechanical parameters give higher values than the methods using mineralogy and TOC, with very low discrepancy of P_{10} and P_{90} .

Table 4.33 Intervals best suited to hydraulic fracturing operations in each well.

Well name	Intervals (metres)	Thickness (metres)	Ranking of recommendations for stimulation
Opoutama-1	1497-1750	253	1 st
Rere-1	2224-2365	141	3 rd
Hukarere-1	2796-2920	124	2 nd

It is very important, after the BI sweet spots have been identified, to address outstanding geological issues (Zagorski et al., 2012), such as:

1. Structural complexity – faults can be good or bad for fracking activities;
2. Associated water production from deeper zones
3. Wellbore stability and lateral landing issues;
4. Fracturing and faulting issues
5. Thermal maturity risks
6. Pressure gradient
7. Lateral extent

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5. BASIC STATISTICS AND MACHINE-LEARNING ECB CASE STUDY

5.1 INTRODUCTION -TYPES OF STATISTICAL ANALYSES

A simple univariate statistical analysis is applied to the rock samples data relating shale-oil and gas prospectivity for the Whangai and Waipawa formations. This analysis is conducted to identify which structural block formation has the best rock characteristics: reservoir quality, quantity, and maturation. Geomechanics is the fourth important rock characteristic discussed in this report, but given the lack of available rock sample measurements, this property will not be considered in this analysis. These traditional summary statistics on discrete rock properties will then be compared to successively more complex statistical summaries of estimates based on multivariate relations and machine-learning. Thus, the approach of the dataset is split into three steps: first grid interpolation is applied to the dataset, for which no statistical analysis is applied, as shown in Figures 4.21 to 4.31; second a basic statistical model is used (univariate statistics); third, the model is refined using a machine-learning approach (section 5.5). A comparative assessment of these three methods is then made, in which sweet spot areas are identified.

5.2 UNIVARIATE STATISTICS

(The basic concepts described in this section were extracted from Mann (1995))

Univariate Statistics is concerned with the collection, organization, description (presentation), analysis and interpretation of experimental data; its main objective is the study of a population.

‘Statistic(s)’ carries two distinct applications:

1. in the singular, ‘statistic’ indicates a body of techniques or a technical methodology developed for the collection, classification, presentation, analysis and interpretation of quantitative data and the use of such data for decision-making.
2. in the plural, ‘statistics’ indicates any consistent collection of numerical data gathered for the purpose of providing information about any activity. For example, demographic statistics refers to numerical data on births, deaths, marriages, etc.

Univariate Statistics can be conducted in two ways:

1. by investigating all elements of the population, or
2. by sampling (selecting some elements of the population).

5.2.1 Division of statistics

1. Descriptive Statistics: is concerned with collecting, organizing, classifying, presenting, interpreting and analyzing data referring to the phenomenon through graphs and tables, besides calculating measures to describe the phenomena of interest.
2. Inductive Statistics (Amostrat or Inferential): starts from a sample, establishes hypotheses, draws conclusions about the population of origin and formulates predictions based on the theory of probabilities. Inductive statistics take care of data analysis and interpretation. The generalization process of the inductive method is associated with a margin of uncertainty. This is because the conclusion to be reached for the set of all individuals analyzed for certain common characteristics is based on a portion of the total observations.

5.2.2 Population

Population is the set, finite or infinite, of individuals or objects that present in common certain defined characteristics, whose behavior it is important to analyze.

5.2.3 Sampling

Sampling is the collection of information from the population, called a sample (the size of the sample is represented by the letter "n"), by means of appropriate methods of selection of these units.

5.2.4 Sample

A sample is a part (a finite subset) representative of a selected population according to suitable methods. The objective is to make inferences and to draw conclusions about populations based on the results of the sample. For this, it is necessary to ensure that the sample is representative. That is, the sample must contain the same basic characteristics of the population, with respect to the phenomenon that we wish to research. For this study, not following Mann (1995), who suggests a minimum of 30 samples, at least 10 samples were

required to be considered for basic statistical analysis, as this was considered minimum size to give a reliable confidence interval.

5.2.5 Descriptive statistics

Descriptive Statistics both summarizes and presents data.

5.2.6 Measures of central tendency

There are three common measures:

1. Mode. The mode of a data set is the value that occurs with the most frequency;
2. Median. The median is the central tendency of an ordered distribution. Data are ordered from smallest to largest. For an odd number of data values in the distribution, the median is the middle value of the data; for an even number of data values in the distribution, the median is the sum of the middle two values divided by two.
3. Arithmetic mean or average. The mean is the sum of all the entries divided by the number of the entries.

5.2.7 Variance and Standard Deviation

The variance is the mean squared deviation from the average and the standard deviation is the positive square root of the variance.

5.3 RESULTS AND DISCUSSION

Univariate statistical data and results subdivided by reservoir quality (in terms of quantity, quality and maturation) per structural block are given in Tables 5.1 to 5.6.

Average, median, standard deviation, minimum, and maximum are evaluated in order to identify which unit presents the best reservoir quality in each structural block in the basin and the distribution of the dataset. The median is used to define the sweet spot as the dataset does not show a normal distribution (when the median and the average values differ, it understood the distribution is not Gaussian). Using averages, the results could be misinterpreted.

Currently only the Rakauroa Member is identified in Tora Block, so no comparisons with other members can be done in this block (Table 5.5).

Table 5.1 Basic statistical results of the Whangai Formation in the Coastal Block. Green fill shows the best results based on median. Number of analyses are given in brackets.

	QUANTITY				QUALITY	MATURATION	Porangahau Mbr. Coastal Block
Statistics	S1 ₍₈₎	S2 ₍₈₎	TOC ₍₈₎	S1_S2 ₍₈₎	HI _{(7)*}	Tmax ₍₈₎	
Average	0.08	0.37	0.33	0.45	127	403.75	
Median	0.06	0.25	0.25	0.40	122	408.50	
St Dev	0.06	0.36	0.35	0.37	39.21	22.02	
Min	0.02	0.04	0.01	0.06	84	359	
Max	0.18	0.90	1.00	1.00	200	425	
	QUANTITY				QUALITY	MATURATION	Rakaroa Mbr. Coastal Block
Statistics	S1 ₍₄₎	S2 ₍₄₎	TOC ₍₄₎	S1_S2 ₍₄₎	HI ₍₄₎	Tmax ₍₄₎	
Average	0.07	0.52	0.55	0.70	78.50	394.25	
Median	0.07	0.27	0.60	0.55	60.50	397.00	
St Dev	0.03	0.68	0.46	0.64	62.34	26.81	
Min	0.03	0.03	0.04	0.11	26	365	
Max	0.10	1.50	0.98	1.60	167	418	
	QUANTITY				QUALITY	MATURATION	Upper Calcareous Mbr. Coastal Block
Statistics	S1 ₍₃₀₎	S2 ₍₃₂₎	TOC ₍₃₂₎	S1_S2 ₍₃₂₎	HI ₍₃₂₎	Tmax ₍₃₂₎	
Average	0.10	1.60	0.95	1.64	173.56	423.47	
Median	0.08	1.24	0.98	1.37	158.50	424.00	
St Dev	0.06	1.10	0.46	1.18	77.38	4.83	
Min	0.04	0.30	0.31	0.34	39	408	
Max	0.26	4.42	2.01	4.52	377	430	

Table 5.2 Basic statistical results of the Whangai Formation in the Pongaroa Block. Green fill shows the best results based on median. Number of analyses are given in brackets.

	QUANTITY				QUALITY	MATURATION	Rakaroa Mbr. Pongaroa Block
Statistics	S1 ₍₈₂₎	S2 ₍₈₂₎	TOC ₍₈₂₎	S1_S2 ₍₈₂₎	HI ₍₈₂₎	Tmax ₍₈₂₎	
Average	0.40	1.89	0.84	1.68	215.83	398.83	
Median	0.10	1.60	0.78	1.49	207.00	414.00	
St Dev	1.14	1.46	0.29	2.48	102.09	33.52	
Min	0.02	0.2	0.37	0.2	36	333	
Max	6.14	10.14	1.68	15.17	818	441	
	QUANTITY				QUALITY	MATURATION	Upper Calcareous Mbr. Pongaroa Block
Statistics	S1 ₍₀₉₎	S2 ₍₁₁₎	TOC ₍₁₁₎	S1_S2 ₍₁₁₎	HI ₍₁₁₎	Tmax ₍₁₀₎	
Average	0.08	0.43	0.28	0.49	138.91	416	
Median	0.07	0.34	0.27	0.41	144.00	415	
St Dev	0.05	0.31	0.12	0.32	48.21	3.43	
Min	0.01	0.04	0.08	0.05	50	412	
Max	0.19	1.22	0.54	1.23	226	421	

Table 5.3 Basic statistical results of the Whangai Formation in the Allochthon Block. Green fill shows the best results based on median. Number of analyses are given in brackets.

	QUANTITY				QUALITY	MATURATION	Porangahau Mbr. Allochthon Block
Statistics	S1 ₍₂₎	S2 ₍₂₎	TOC ₍₂₎	S1_S2 ₍₂₎	HI ₍₂₎	Tmax ₍₂₎	
Average	0.07	0.65	0.58	0.72	151.00	438.50	
Median	0.07	0.65	0.58	0.72	151.00	438.50	
St Dev	0.05	0.64	0.25	0.69	175.36	10.61	
Min	0.03	0.2	0.4	0.23	27	431	
Max	0.1	1.1	0.75	1.2	275	446	
	QUANTITY				QUALITY	MATURATION	Rakauroa Mbr. Allochthon Block
Statistics	S1 ₍₃₎	S2 ₍₃₎	TOC ₍₃₎	S1_S2 ₍₃₎	HI ₍₃₎	Tmax ₍₃₎	
Average	0.10	0.74	0.56	0.57	190.33	428.53	
Median	0.10	0.70	0.56	0.80	146.00	428.00	
St Dev	0.03	0.07	0.37	0.42	142.76	4.82	
Min	0.07	0.7	0.2	0.09	75	424	
Max	0.13	0.82	0.93	0.83	350	433	
	QUANTITY				QUALITY	MATURATION	Upper Calcareous Mbr. Allochthon Block
Statistics	S1 ₍₆₎	S2 ₍₆₎	TOC ₍₆₎	S1_S2 ₍₆₎	HI ₍₆₎	Tmax ₍₆₎	
Average	0.19	1.28	0.45	1.47	295.17	431.25	
Median	0.15	1.43	0.43	1.67	312.50	432.50	
St Dev	0.12	0.52	0.20	0.60	60.60	2.64	
Min	0.07	0.61	0.2	0.68	218	427	
Max	0.35	1.83	0.76	2.18	355	433	

Table 5.4 Basic statistical results of the Whangai Formation in the Motu Block. Green fill shows the best results based on median. Number of analyses are given in brackets.

	QUANTITY				QUALITY	MATURATION	Rakauroa Mbr. Motu Block
Statistics	S1 ₍₈₁₎	S2 ₍₈₇₎	TOC ₍₈₇₎	S1_S2 ₍₈₇₎	HI ₍₈₇₎	Tmax ₍₈₇₎	
Average	0.23	1.66	0.89	1.79	180.46	430.47	
Median	0.23	1.75	0.94	1.90	187.00	433.00	
St Dev	0.14	0.85	0.25	1.03	62.67	6.58	
Min	0.05	0.24	0.2	0.28	56	413	
Max	0.80	4.51	1.77	5.19	336	440	
	QUANTITY				QUALITY	MATURATION	Upper Calcareous Mbr. Motu Block
Statistics	S1 ₍₂₎	S2 ₍₂₎	TOC ₍₂₎	S1_S2 ₍₂₎	HI ₍₂₎	Tmax ₍₂₎	
Average	0.18	0.74	0.39	0.92	185.00	440.45	
Median	0.18	0.74	0.39	0.92	185.00	440.45	
St Dev	0.18	0.93	0.01	1.11	233.35	13.51	
Min	0.05	0.08	0.38	0.13	20	431	
Max	0.3	1.4	0.4	1.7	350	450	

Table 5.5 Basic statistical results of the Rakauroa Mbr. (Whangai Formation) in the Tora Block. No comparison is done. Number of analyses are given in brackets.

	QUANTITY				QUALITY	MATURATION	Rakauroa Mbr. Tora Block
Statistics	S1 ₍₇₎	S2 ₍₇₎	TOC ₍₇₎	S1_S2 ₍₇₎	HI ₍₇₎	Tmax ₍₇₎	
Average	0.14	1.92	1.11	2.06	180.00	430.29	
Median	0.13	1.68	1.32	1.75	166.00	429.00	
St Dev	0.12	0.95	0.47	1.02	48.22	5.41	
Min	0.00	0.50	0.20	0.50	122.00	422.00	
Max	0.37	3.09	1.64	3.25	250.00	439.00	

Table 5.6 Basic statistical results of the Waipawa Formation per structural block. Green fill shows the best results based on median. Number of analyses are given in brackets.

	QUANTITY				QUALITY	MATURATION	Waipawa Fm. Coastal Block
Rock_Eval1	S1 ₍₅₉₎	S2 ₍₅₉₎	TOC ₍₅₉₎	S1_S2 ₍₅₉₎	HI ₍₅₉₎	Tmax ₍₅₉₎	
Average	0.35	7.26	3.66	7.61	175.56	411.37	
Median	0.23	5.37	3.55	5.60	159.00	411.00	
St Dev	0.31	6.55	1.48	6.80	98.44	7.01	
Min	0.05	0.2	0.38	0.25	22	395	
Max	1.7	35.9	8.24	37.6	513	436	
	QUANTITY				QUALITY	MATURATION	Waipawa Fm. Allochthon Block
Rock_Eval1	S1 ₍₄₆₎	S2 ₍₄₆₎	TOC ₍₄₆₎	S1_S2 ₍₄₆₎	HI ₍₄₆₎	Tmax ₍₄₆₎	
Average	0.89	10.25	3.41	11.14	280.22	418.69	
Median	0.73	9.06	3.41	9.69	247.00	418.50	
St Dev	0.82	6.46	1.30	7.09	134.61	6.75	
Min	0.1	0.76	0.8	0.9	91	404	
Max	3	26.7	8.4	27.8	550	431	
	QUANTITY				QUALITY	MATURATION	Waipawa Fm. Motu Block
Rock_Eval1	S1 ₍₁₇₎	S2 ₍₂₀₎	TOC ₍₂₀₎	S1_S2 ₍₂₀₎	HI ₍₂₀₎	Tmax ₍₂₀₎	
Average	0.91	11.15	3.43	11.93	265.10	417.70	
Median	0.54	9.56	3.24	10.45	265.00	419.00	
St Dev	0.82	11.34	2.86	12.11	124.37	4.94	
Min	0.1	0.44	0.6	0.48	69	411	
Max	3	45.9	12	48.9	479	430	
	QUANTITY				QUALITY	MATURATION	Waipawa Fm. Pongaroa Block
Rock_Eval1	S1 ₍₁₀₎	S2 ₍₁₀₎	TOC ₍₁₀₎	S1_S2 ₍₁₀₎	HI ₍₁₀₎	Tmax ₍₁₀₎	
Average	0.36	3.77	3.16	4.13	112.10	400.20	
Median	0.30	3.66	3.13	3.8	124.50	400.50	
St Dev	0.26	2.07	1.03	2.24	44.85	6.53	
Min	0.09	0.4	1.3	0.55	31	386	
Max	0.79	7	4.34	7.6	167	408	

5.3.1 Discussion of the Whangai Formation by structural block:

Coastal Block: The Upper Calcareous Member shows the best rock characteristics regarding unconventional reservoir quality (Table 5.1). However, while the level of maturation is not high enough to prove that this member has achieved the oil window, the thermal gradient in this region is still uncertain. Newman and Moore (2000) show the maturation trend for the Opoutama-1 well (Coastal Block) is different from the original VR analyses conducted by Phillips Petroleum New Zealand Ltd (1976) and Jackson (1982). The original VR analyses overestimate maturity above 2400m depth, possibly due to readings from inertinite that morphologically resembles the vitrinite, and underestimates maturity below 3000m depth, possibly due to readings from suppressed vitrinite (Newman and Moore, 2000). These issues need to be resolved in order to improve shale oil and gas assessment for this structural block in the East Coast Basin.

Pongaroa Block: The Rakauroa Member shows the best rock characteristics (Table 5.2). The maturation is low but the thermal gradient is uncertain. Based on Newman and Moore (2000, 2002), and Newman (2013), vitrinite-inertinite reflectance and fluorescence from four wells (Hawke Bay-1, Hukarere-1, Opoutama-1 and Tawatawa-1) showed two distinct thermal curves, identified using a plot of maximum burial depth versus vitrinite reflectance. One curve is related to an early, higher thermal regime inferred to have existed from late Cretaceous to mid to late Miocene times, followed by a lower thermal regime from the late Miocene to Pliocene. In the Hukarere-1 well the results from vitrinite reflectance indicate Late Cretaceous rocks reached higher thermal maturation, entering the top of the oil window ($R_o\%$ normal 0.5 – 0.65) (Burgreen, 2014).

Allochthon Block: The Upper Calcareous Member shows the best rock characteristics (Table 5.3), although maturation is not very high. No wells in the Allochthon Block have reached Whangai Formation.

Motu Block: The Rakauroa Member shows the best rock characteristics (Table 5.4). Maturation analysis shows that this region is slightly mature. Based on Ventura et. al., 2013, Rere-1 well (Motu Block), the Whangai Formation is thermally immature, though the Karekare Formation has likely entered the oil window. Rere-1 well was drilled to test the potential occurrence of hydrocarbons in Cretaceous and younger sands in a fault-bounded anticline. Maturation might be higher in adjacent synclines or where the Neogene successions are thicker, such as under the allochthon. There is not much information about the Authochthon/Allochthon

block's thermal regime. Due to the tectonic regime in this region it would be expected that below the Allochthon Block is a higher thermal regime due to greater burial.

Tora Block: The Rakauroa Member shows good rock characteristics (Table 5.5).

Generally low numbers of rock samples available per structural block mean the comparisons are not very robust. However, based on the dataset available and using the threshold values of TOC (wt%) from the U.S. shale formations (1%), only the Rakauroa Member in the Motu, Tora, and Pongaroa Blocks and the Upper Calcareous Member in the Coastal Block, show rock characteristics that would warrant a deeper analysis. The other areas do not appear to be as promising.

5.3.2 Identifying the best rock characteristics among the Whangai Formation

The Rakauroa Member shows the best rock characteristics for unconventional reservoir potential in the Whangai Formation (Table 5.7). Furthermore, this is the only rock formation where geomechanical analyses were able to be undertaken in the subsurface. These analyses indicate that this formation could be stimulated via hydraulic fracking for a minimum interval of 141m in the Motu Block (section 4.7).

Table 5.7 Basic statistical results of the total Whangai Formation split by member. Green fill shows the best results based on the median. Number of analyses are given in brackets.

	QUANTITY				QUALITY	MATURATION	Upper Calcareous Mbr.
Statistics	S1 ₍₅₀₎	S2 ₍₅₀₎	TOC ₍₅₀₎	S1_S2 ₍₅₀₎	HI ₍₅₀₎	Tmax ₍₅₀₎	
Average	0.10	1.30	0.73	1.33	184.06	422.77	
	0.08	1.17	0.58	1.23	161.00	423.50	
St Dev	0.08	1.02	0.48	1.09	85.09	9.94	
Min	0.01	0.2	0.08		39	374	
Max	0.35	4.42	2.0		377	450	

	QUANTITY				QUALITY	MATURATION	Porangahau Mbr.
Statistics	S1 ₍₀₉₎	S2 ₍₀₉₎	TOC ₍₀₉₎	S1_S2 ₍₀₉₎	HI ₍₀₈₎	Tmax ₍₀₉₎	
Average	0.08	0.37	0.35	0.36	130	409.89	
	0.05	0.20	0.39	0.22	122.00	414.00	
St Dev	0.06	0.38	0.35	0.37	202.85	25.93	
Min	0.02	0.04	0.01		27	359	
Max	0.18	1.1	1.0		275	446	

	QUANTITY				QUALITY	MATURATION	Rakauroa Mbr.
Statistics	S1 ₍₁₈₄₎	S2 ₍₁₈₄₎	TOC ₍₁₈₄₎	S1_S2 ₍₁₈₄₎	HI ₍₁₈₄₎	Tmax ₍₁₈₄₎	
Average	0.21	1.71	0.86	1.81	192.78	414.91	
Median	0.13	1.60	0.82	1.49	199.50	423.00	
St Dev	0.53	1.15	0.29	1.74	84.76	28.27	
Min	0.02	0.08	0.2		26	333	
Max	5.12	10.14	1.77		613	440	

5.3.3 Discussion of the Waipawa Formation by structural block:

The best rock characteristics for unconventional reservoir quality for the Waipawa Formation are in the Motu Block (Table 5.6). The maturation of the Waipawa Formation, based on outcrop samples and the shallow stratigraphic wells, is low: Orui-1 and 1a (130 and 117m total depth, respectively) and Te Mai-2 (193.10 m total depth). The Waipawa Formation may be present in the Rere-1 well (Ward and Leask, 2014 and Ventura et. al., 2013), but as the original log interpretation does not identify this formation, it was decided not to characterize it in this report. The formation is also not reliably identified in Opoutama-1, and is replaced by the laterally-correlative Te Uri Member of the Whangai Formation in Hukarere-1. Given that, no maturity information from deep subsurface and geomechanical analyses are available for the Waipawa Formation. Nevertheless, identification of Waipawa-sourced oils in the Raukumara and Wairarapa regions indicates that the formation might have reached maturity at depth (Sykes et al., 2012). The geomechanical analysis undertaken in Orui-1a was to

distinguish natural fractures and its orientation, not brittleness index. Drilling a well penetrating beneath the allochthon with the goal of testing the maturation and rock properties of the Waipawa Formation of the underlying autochthonous could yield key information on this rich rock formation.

5.4 SUMMARY OF BASIC STATISTICAL ANALYSIS

Based on the basic statistical analysis discussed above, the Rakauroa Member in the Motu Block, and the Waipawa Formation, also in Motu Block, present the best rock characteristics (quality, quantity and maturation) as unconventional reservoirs. Only the Rakauroa Member has a calculated brittleness index. The Rere-1 well in the Motu Block shows that a 141m interval could be fracked and this thickness is considered attractive when compared to the shale formations in the U.S. (Table 5.8). No geomechanical analysis is undertaken for the Waipawa Formation using borehole well logs. It is therefore uncertain whether this formation could be stimulated via hydraulic fracking.

Because of the low number and geographic spread of samples in some structural blocks in comparison to others, these results most likely over- or underestimate the median values. A further approach was therefore tried (machine-learning) incorporating the relationships of all the variables selected to define the sweet spot areas. A description of machine-learning follows, including methodology, results and discussion.

5.5 INTRODUCTION MACHINE-LEARNING

This section looks to develop a machine-learning workflow that can be used to establish two important aspects. First, it seeks to find an analogue shale for the Whangai and Waipawa formations from the input dataset; second, to quantify the economic feasibility, based on the estimate ultimate recovery (EUR) of producing unconventional oil and gas from two rock formations, Whangai and Waipawa, in the East Coast Basin. Based on the proved economic studies of producing shales in the United States, 13 different shale formations were selected as input data to the machine-learning algorithm. Their rock characteristics are important analogues to test whether the Whangai and Waipawa formations show some similarities, which would justify the exploration of these formations in New Zealand.

To date no studies have been conducted to model the economic feasibility of producing undiscovered shale-gas resources from the East Coast basin due to the sparseness of data and the nonlinear, spatial, and temporal relationships among their attributes (variables). Traditional approaches depend on a complete (no missing values) dataset, whereas machine-learning

techniques (Kanevski and Maignan, 2004) offer a different approach and help address at least a few problems associated with:

1. Nonlinear systems;
2. Irregular, sparse and noisy data;
3. Unrelated information from numerous and assorted type variables;
4. Quick and easy to update.

Machine-learning techniques differ from traditional integration techniques in that they target nonlinear associations found in the variable data. Machine-learning techniques represent a generalized artificial intelligent-computing group that includes supervised and unsupervised methods. The successful implementation of the machine-learning depends on accurately identifying the weights (related to the minimum Euclidean distance – distance between two points in a Euclidean space) and output layer of the network prior to its arrangement. (Szidarovszky et al. 1984). By contrast, the unsupervised self-organizing map (SOM) technique does not require selecting hidden layers or knowledge of the output layer (Kohonen 2001). The SOM technique creates a network where similarities among data patterns are mapped into similar weights of the neighbouring neurons. Its competitive and stochastic learning algorithm characterizes this technique. In addition to that, the vector basis of a SOM provides a mechanism for relation, classification, estimation and prediction of variables (Wang, 2003). Some applications of the SOM-based estimation include streamflow hydrographs (Kaltch and Berndtsson, 2007), prediction of the economic feasibility of mining undiscovered porphyry copper deposits (Friedel 2012), and spatial physical and chemical hydrogeologic variables (Friedel and Iwashita 2013).

A hybrid-modelling approach, combining multiple modelling techniques, has begun to be employed in earth science recently (M. Friedel pers. Comm. 2017). In this approach, machine-learning provides data for subsequent use in traditional numerical or empirical modeling, collectively known as a computationally-intelligent workflow. To improve upon current empirical modelling approaches, this technique hypothesizes that the economic feasibility can be predicted as a function of data variables from field variables associated with reservoir quality (geomechanics, quality, quantity, and maturity) and geological conditions.

5.5.1 Methodology

The processing workflow used to determine the relationship among the variables selected for the self-organizing map (SOM), involves one workflow with three sequential machine-learning model steps. These steps represent a computational processing sequence involving data fusion, and estimation (Figure 5.1). These processing elements are described briefly below.

Figure 5.1 Machine-learning workflow used to identify the sweet spots along East Coast Basin.

5.5.1.2 Data Fusion

The simultaneous fusion of U.S. and NZ data is undertaken using the unsupervised self-organizing map (SOM) technique (Kohonen 2001, Kohonen 2013). The SOM consider a grouping of related samples in a multi-dimensional space and uses a competitive learning algorithm as a way of preserving the topology of spread data in a smaller dimensional space (Figure 5.2). The SOM is a set of nodes, connected to one another through a rectangular topology. The rectangular topology of the SOM is also presented in Figure 5.2, where each blue dot represents a node. The connections between the inputs and the nodes have weights, so a set of weights corresponds to each node.

Prior to implementing the learning phase (training the network), the variables (input data) are normalized by their data variance and randomly assigned (presenting the input vectors to the map sequentially using a randomly sorted database) as an initial set of map weight vectors. The SOM learning algorithm:

1. Generates initial values including weights, radius, and learning parameter values;
2. Selects input vectors from the data set;
3. Identifies the winning node, which is the closest node to the input vector using the Euclidean distance metric;
4. Identifies the neighbourhood with the given radius using a Gaussian function;
5. Updates the weights for the winning node and all the nodes in the same neighbourhood;
6. Repeats steps 2 to 6 until the weight vectors reach a converged state.

Figure 5.2 Self-organizing map learning process. Sparse multi-dimensional data space converging to a smaller dimensional space.

After training of the SOM network, the relative quality is evaluated using the quantization and topographic error measures. See Kohonen (1984) for further explanation.

Component planes reflect the distribution of values as they relate to SOM nodes. Relations among component appears as similar colour patterns (high values are hot colours and low values are cool colours) among component plane variables. Strong positive correlations among pairs of variables will be reflective of the same colour patterns. By contrast, negative correlation between variables will appear as the same patterns but reversed colour distribution. Principal component analysis (PCA) is applied to median component plane values to identify redundancy of variables. Cross-component plots of variables are used to evaluate trends and for computing correlation coefficients.

5.5.1.3 Estimation

The estimates of variables can be taken directly from the best matching unit vectors (Fessant and Midenet 2002; Wang 2003). However, this approach often results in biased estimates (Dickson and Giblin 2007). For this reason, other studies have used a modified bootstrap (Breiman 1996), ensemble averaging (Rallo et al. 2002), or nearest neighbour (Malek et al. 2008) approaches. In this study the estimation is based on minimization of quantization and topographic error vectors. This approach is preferred over traditional split-sample validation because of the lack of available data. Ultimately, this approach provides a measure of model prediction error.

5.6 RESULTS AND DISCUSSION

5.6.1 Global analogue

The processing workflow used in this study relies on development and application of three SOM models (Figure 5.1). In the first model, a sparse data set from US shales comprises the global analogue set. The characteristics of these global shale deposits and producing operations vary from region to region. For this reason, a data set is compiled that includes information from 13 economic shale deposits producing gas and oil in the United States: Antrim, Bakken, Barnett, Bossier, Eagle Ford, Fayetteville, Haynesville, Lewis, Marcellus, Monterey, New Albany, Niobrara, and Woodford (Table 5.8). In general, the data set is sparsely populated with one dependent category describing the expected ultimate recovery (EUR), and 20 independent variables from categories describing character, economics, geomechanics, maturation, quality, and quantity. For example, *character* includes depth, m (DEPTH) and thickness, m (THICK); *economics* includes reserves, EUR, oil or gas prone (RES); well cost, \$ (WELLCOST); operational well cost, \$ (OPCOST), recovery, (RECOV); volume of drilling water per well, m3 (VDPW); and volume of fracking water per well, m3 (VFPW); *geomechanics* includes porosity, dimensionless (POR); permeability, mD (PERM); Poisson ratio, dimensionless (POIS); and Young's modulus, GPa (YOUNG); *maturation* includes maximum temperature, degree C (TMAX) and vitrinite reflectance, dimensionless (Ro); *mineralogy* includes clay content, % (Al2O3); carbonate content, % (CaO); and silica content, % (SiO2); *quality* includes hydrogen index, dimensionless (HI); *quantity* includes Free hydrocarbons, mg/g (S1); amount of hydrocarbons generated through thermal cracking, mg/g (S2); and total organic carbon, % (TOC).

Table 5.8 Thirteen shale formations and their characteristics. Variables used as input dataset for the analogue machine-learning model, (Jarvie, 2012, Law and Curtis, 2002, Rostam-Abadi, 1982, Ocubalidet, 2012, Akar, 2014, Johnston and Christensen, 1992, Merkel et al.,2015, Sheng, 2016, Dawson and Almon, 2010). Ps - present day value; original - the original value before the conversion of organic matter to petroleum.

Basin	Depth(m)	Thickness (m)	Net Thickness average (m)	TOC(%) (Range ps) (Avg.ps) (Avg original)	RO(%) (Avg)	SiO (%)	CaO(%)	Clay (%)	Area Basin (Km2)	Reserve (MMbbl)	Por (%)	Perm (MD)	Well EUR (MMcf)	Lifespan (years)	S1 mgHC/g	S2 mgHC/g original	T Max(°C)	HI original mg mgHC/g TOC	Poisson Ratio	Young Modulus (Gpa)	Well Cost (MMU\$S)	Well Spacing (Well/sq. mile) 2.6km2	In situ stress (Mpa)	Initial production rate (MMcf/day)	Anticipated recovery Factor(%)
ANTRIM	150-700	50	50	0.3-8 (N/a) (N/a)	0.4-0.6	20-41	2.38	42	31000	20 TCF	9	NA	116-1250	30	53	23	435	432	0.2-0.4	6-12	0.3-0.5	7	N/A	N/A	20-60
BAKKEN	950-3353	7-25	50	1-35 (10) (N/a)	0.3-1.2	45	45	10	520000	3650 oil, 1.75TCF,	5	0.04	1410	10-30	30(ppm)	200 (ppm)	420-450	298	N/A	N/A	5.5-8.5	1	N/A	N/A	N/A
BARNETT	1,980-2,590	60-300	90	3-12 (3.74) (5.92)	0.85- 2.1 (1.6)	45	25	5-40	130000	44 TCF	4-6	0.0001	1420	15-30	0.78 (gas window) 3.60(oil window) 0.53-1.26 (cuttings) 2.6-2.93 (immature)	1.27 (gas window) 14.09 (oil window) 0.86-6.59 (cuttings) 18.17-54.43 (immature)	490	434	0.22	30-40	2-3	8	35	2.5	25-50
LEWIS	1370	365-457		1.68-3.15 (N/a) (N/a)	0.6-2.0	N/A	N/A	18	38000	11.63tcf	3.5	0.2-215	1300	N/A	18	0.5	424-493	150-270	N/A	N/A	NA	3	N/A	N/A	5-15
NEW ALBANY	838	30-122		5-15 (N/a) (N/a)	0.5-1.0	52-74 63.25 mean	0.11-3.66 1.1 mean	10.6-16.16 13.27 mean	113000	11 TCF	1-25	N/A	1100	N/A	0.08-6.62	0.18-104.69	427-442	197-862	N/A	N/A	0.8-1.0	8	N/A	N/A	10-20
NIOBRARA	430-2,100	4-213		3-5 (N/a) (N/a)	0.46- 0.82	20-30	70-80	40-60	120000	1.2 TCF	25-50	0.01-0.5	N/A	N/A	0.25-1.0	1.13-5.67	430-448	164-317	0.18-0.27	6.1-9 mpsi	N/A	8	N/A	N/A	N/A
MARCELLUS	609-1828	Up to 290m, exploration where>15m	45	1-13 (4.01) (8.20)	0.6-3.0 (1.5)	47	6	47	202000	410TCF	5.5-8	0.00007	1150-3500	7.5	2.46	40.33	500	507	0.33	N/A	3-4	8	N/A	30	30
HAYNESVILLE	3000-4000	60-90	80	0.5-4 (3.01) (7.79)	2.2-3.0 (1.5)	32-35	20-22	36-39	23300	74tcf	8	0-0.005	3600-1500	N/A	0.1	55.51	525-545	722	0.2	18-20	7	8	15-25	10	25-30
FAYETTEVILLE	1220	15-107	40	2-10 (3.77) (5.74)	1.2-3.0 (2.5)	35	12	38	23300	32tcf	5	0.0001	2070	N/A	15	23.18	N/A	404	N/A	N/A	1.75-3	8	N/A	1-7	35-40
EAGLE FORD	2134	30-90	60	2-8.5 (2.76) (4.24)	0.45- 1.6 (1.2)	15-20	65	15-30	1600	20.81	9	0.001	5000	N/A	1-6	9-45 (17.42)	423-480	411	0.25	15-30	4-6.5	5	13-20	5-17	6
MONTEREY	3430	571		6.5	0.6	10-70	10-50	5-20	4538	15420 oil	11	N/A	0.5	N/A	N/A	N/A	N/A	N/A	0.125	50-80MPA	1.2-7	16	<20	N/A	N/A
BOSSIER	1220-3050	60-90	74	0.5-4.2 (1.64) (2.55)	1.1-2.4 1.55	43	21	40	N/A	N/A	7.5	0.00001	N/A	N/A	0.4	10.67	440	419	0.31	39	2	N/A	N/A	N/A	N/A
WOODFORD	1820-3960	30-275	48	3-12 (5.34) (9.33)	0.7-4.0 (1.5)	55	5	20	28500	N/A	5	0.000025	3800	N/A	4.05	46.93	445	503	0.335	22.5	4.5	N/A	N/A	N/A	N/A

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5.6.1.1 Training and estimation

Before training, the input variables are normalized by their data variance and randomly assigned to a set of map weight vectors. The SOM network is applied to training data with a map of 26 rows along its length and 14 columns along its width giving a total of 364 neurons. The data is trained in two phases: first, to a lower resolution, and then to a higher one. The lower resolution training uses 95 iterations using a Gaussian neighborhood with an initial and final radius of 30 units and five units; the second, higher resolution training involves 1900 iterations using a Gaussian neighbourhood with an initial and final radius of five units and one unit. These units represent the distance from the center of the Gaussian function towards the outer edge, where its value is zero. The initial and final learning rates of 0.5 and 0.05 decay linearly down to 10^{-5} , and the Gaussian neighborhood function decreases exponentially (decay rate of 10^{-3} iteration⁻¹) providing reasonable convergence for this study (Kohonen 2013). This is the threshold defined to be used in this model, following Kohonen (2013).

5.6.1.2 Performance evaluation

A component-planes plot of SOM variables is presented in Figure 5.2. These component planes visually portray relations among the multivariate dataset. The actual values plotted on the colour-bar reflect the interquartile range, that is, P25 to P75. Those component planes that are more related include: Those component planes with the same colour pattern are more highly related, e.g., EurAvg and StressAvg, or RoAvg and Tavg; whereas those with the same pattern but opposite colour distribution are negatively related, e.g. HIavg and PorAvg, and YoungAvg and StressAvg. In many cases, pairwise comparison of patterns reveals only partial similarity thereby revealing more complicated spatial relations among variables.

Figure 5.4 Graphic showing the positive correlation for EUR as a function of SiO₂. (A) Shale formation. (B) Shale oil and shale gas.

Figure 5.5 Graphic showing the positive correlation for EUR as a function of TOC. (A) Shale formation. (B) Shale oil and shale gas.

By contrast, a negative correlation ($\rho = -0.72$) exists for EUR as a function of Al₂O₃ (clay content) (Figure 5.6), and a negative correlation ($\rho = -0.94$) exists for SiO₂ and Al₂O₃ (Figure 5.7). The samples in these plots follow a colour wheel coded according to their spatial location. The ability to observe and quantify nonlinear monotonic trends among component planes demonstrates that it is possible to simultaneously integrate (fuse) sparse and disparate borehole measurements using the SOM technique.

Figure 5.6 Graphic showing the negative correlation for EUR as a function of Al₂O₃. (A) Shale formation. (B) Shale oil and shale gas.

Figure 5.7 Graphic showing the negative correlation for SiO₂ as a function of Al₂O₃.

EUR vs CaO shale gas and shale oil shows two trends; instead of a positive gas trend, the addition of shale oil in the plots makes the trend negative (suggestion to remove) as it is interfering with the interpretation of the variable correlations; similar false trends with EUR(Thickness), EUR(permeability) others such as EUR(HI) reduces strength in correlation. Given that the number of analogue shales was reduced to only shale gas not only to avoid the misinterpretation of the trends but also to reduce the number of required Monte Carlo trials. Figure 5.8 shows an example of how the shale oil affected the trend of shale gas (negative correlation).

Figure 5.8 EUR vs CaO plot showing the oil shales influence the positive trend. (A) Shale formation. (B) Shale oil and shale gas.

In general, the cross-validation results (based on a leave-one-out strategy and 30 Monte Carlo trials) indicate the SOM technique is an unbiased estimator. For example, the observed values of EUR plot within the minimum and maximum values indicating the model is unbiased (Figure 5.9). The differences in average to median values are not the same or symmetric about the limits, revealing a nonlinear process and underscoring the benefits of using the machine-learning approach. The fact that the observations and median values are not the same is reasonable given that the input also is uncertain. Cross-validation of the explanatory variables (not presented here) also finds the model to be an unbiased estimator. Lastly, despite the range of estimation uncertainty associated with the analogue unconventional shale-gas model, predictions of dependent variables from the East Coast basin should be reasonable if the median values are used for evaluating EUR.

	Shale	min	Obs	med	avg	max
1	Lew	1635	2000	1647	2039	3965
2	Fay	1301	1750	2223	2382	4301
3	Mar	2208	3846	3210	3667	5512
4	Eag	2321	5500	5190	4713	6169
5	Hay	2331	5800	5296	4808	6296
6	Wod	1812	2500	3309	3190	5309
7	Bos	1930	3000	2179	2764	5142

Figure 5.9 Observed EUR values (MMbcf) plot within minimum and maximum EUR values showing the model is unbiased.

5.7 LOCAL MAPPING (NEW ZEALAND DATA)

To identify and rank sample locations with respect to EUR (sweet spot), the sparse set of the East Coast Basin dependent variables are mapped to the U.S. analogue model.

5.7.1 Training and estimation

The fraction (0 to 1) of analogue shales associated with each of the NZ samples is estimated based on the multivariate relations in the underlying hypersurface.

Sites characterized as analogue shale are those that show higher similarity based on the interaction among all variables of the model. Thus, the analogue for the Rakauroa Member is Eagle Ford and the Waipawa Formation is Lewis and Eagle Ford, in order of higher similarity.

These estimates have median values that are very similar to input observation values:

1. e.g. for the Rakauroa Member where Eagle Ford shows the best match the comparisons are:

HI_eagle = 80; HI_rak = 193

Ro_eagle = 0.9; Ro_rak = 0.85

SiO+CaO_eagle = 82%; SiO+CaO_rak = 76%;

2. e.g. for the Waipawa Formation where Lewis and Eagle Ford shows the best match the comparisons are:

HI_lewis = 210; HI_waip = 214

TOC_lewis = 2.4; TOC_waip = 3.46

Clay_lewis = 18%; Clay_waip = 12%

5.7.2 Performance evaluation

To achieve this objective requires several tasks: (1) an analogue economic shale oil and gas deposit dataset must be assembled, (2) East Coast Basin samples must be mapped to their analogue counterparts, (3) the economic feasibility of producing unconventional gas from East Coast Basin shales, New Zealand, must be identified and ranked.

5.7.3 Estimated Ultimate Recovery (EUR) for the Whangai and Waipawa formations

The estimation function is used to predict the EUR_{gas} as a function of the global analogue variables. The median of the EURs is computed using the medians of 30 realizations at each location. Below are the results of EUR_{gas} for the Whangai and Waipawa formations. The EUR_{oil} is not estimated as the shale oil formations were excluded from the model as explained in the section 5.6.1.2.

1. Whangai Formation: 3690 MMcf (636136 Boe*);
2. Waipawa Formation: 3729 MMcf (642860 Boe);

* 5800 cf ≈ 1boe

5.7.4 Defining the sweet spots

First, rocks are ‘ranked’ using the Estimate Ultimate Recovery (EUR) to establish which rocks are most likely to yield high oil and gas volumes. Then, the ranked samples are split by formation (member) and locality. The lower the rock’s ranking the more likely it is to yield higher EUR. Thus, with the summation of the ranked samples, the lowest median number is considered the best formation (the sweet spot) by structural block. Below are the results of the machine-learning (Tables 5.9 to 5.13).

Table 5.9 Ranking of Whangai Formation members per structural block. Green fill shows the best result based on the sum of the rank in ascending order. Orange fill shows the U.S. analogue (best match).

Tora		PONGAROA BLOCK				MOTU BLOCK			
Whang	Rak	Whang	Rak	Whang	UCalc	Whang	Rak	Whang	UCalc
Σ9	1159	Σ64	13644	Σ15	2715	Σ93	18498	Σ3	771
Average	129	Average	213	Average	181	Average	199	Average	257
Median	130	Median	235	Median	193	Median	202	Median	253
St Dev	97	St Dev	108	St Dev	103	St Dev	122	St Dev	84
Min	3	Min	16	Min	5	Min	1	Min	156
Max	334	Max	394	Max	356	Max	395	Max	362
ANALOGUE	EG/FAY	ANALOGUE	EG/MAR	ANALOGU E	EG	ANALOGUE	EG	ANALOGUE	EG

COASTAL BLOCK				ALLOCHTHON BLOCK							
Whang	Por	Whang	Rak	Whang	UCalc	Whang	Por	Whang	Rak	Whang	UCalc
Σ9	1571	Σ5	1098	Σ33	7698	Σ2	94	Σ2	368	Σ9	1608
Average	175	Average	220	Average	233	Average	47	Average	184	Average	179
Median	178	Median	270	Median	233	Median	47	Median	184	Median	179
St Dev	114	St Dev	105	St Dev	112	St Dev	43	St Dev	4	St Dev	81
Min	9	Min	27	Min	2	Min	4	Min	180	Min	74
Max	375	Max	327	Max	392	Max	90	Max	188	Max	359
ANALOGU E	EG/BOS	ANALOGU E	EG/MAR	ANALOG UE	EG	ANALOGU E	EG	ANALOGU E	EG	ANALOG UE	BOS/MA R

Table 5.10 Rakauroa Member per structural block. Green fill shows the best result based on the sum of the rank in ascending order.

Tora	Whang
$\Sigma 9$	1159
Average	129
Median	130
St Dev	97
Min	3
Max	334

Pongaroa	Whang
$\Sigma 64$	13644
Average	213
Median	235
St Dev	108
Min	16
Max	394

Motu	Whang
$\Sigma 93$	18498
Average	199
Median	202
St Dev	122
Min	1
Max	395

Coastal	Whang
$\Sigma 5$	1098
Average	220
Median	270
St Dev	105
Min	27
Max	327

Allochthon	Whang
$\Sigma 5$	368
Average	184
Median	184
St Dev	4
Min	180
Max	188

Table 5.11 Upper Calcareous Member per structural block.

Pongaroa	Whang
$\Sigma 15$	2715
Average	181
Median	193
St Dev	103
Min	5
Max	356

Motu	Whang
$\Sigma 3$	771
Average	257
Median	253
St Dev	84
Min	156
Max	362

Coastal	Whang
$\Sigma 33$	147
Average	233
Median	247
St Dev	112
Min	2
Max	392

Allochthon	Whang
$\Sigma 9$	1608
Average	179
Median	179
St Dev	81
Min	74
Max	359

Table 5.12 Porangahau Member per structural block.

Coastal	Whang	Allochthon	Whang
$\Sigma 9$	1571	$\Sigma 2$	94
Average	175	Average	47
Median	178	Median	47
St Dev	114	St Dev	43
Min	9	Min	4
Max	375	Max	90

Table 5.13 Waipawa formation per structural block. Green fill shows the best result based on the sum of the rank in ascending order. Orange fill shows the U.S. analogue (best match).

WAIPAWA							
Allochthon	Waip	Coastal	Waip	Motu	Waip	Pongaroa	Waip
$\Sigma 47$	9209	$\Sigma 73$	14298	$\Sigma 20$	3449	$\Sigma 11$	2029
Average	196	Average	196	Average	172	Average	184
Median	186	Median	185	Median	155	Median	194
St Dev	110	St Dev	110	St Dev	133	St Dev	99
Min	8	Min	7	Min	21	Min	41
Max	389	Max	390	Max	372	Max	317
ANALOGUE	Lewis/EG/BO	ANALOGUE	Lewis/EG	ANALOGUE	Lewis/EG	ANALOGUE	EG

Based on the results of the machine-learning the best sweet spot for the Whangai Formation is Porangahau Member in the Allochthon Block and Motu Block for the Waipawa Formation. However, there are only two samples available for Porangahau member in this structural block, decreasing the reliability of the results. Given that, and based on number of rock samples available for each rock formation, the Rakauroa Member and Waipawa Formation, both in the Motu Block, are the best prospective areas for unconventional reservoirs. As mentioned, only the Rakauroa Member has its brittleness index calculated, so a geomechanical analysis should be assessed, offering a complete study to establish whether the Waipawa Formation could be considered a proper sweet spot. For the purposes of this study, however, the Waipawa Formation is considered a sweet spot.

The machine-learning estimates the Eagle Ford shale as the analogue for the Rakauroa Member, and the Lewis and Eagle Ford shales (in order of similarity) for the Waipawa Formation. Given the volumetric and economic evaluation, these two shale formations are the analogues for the missing data (recovery factors, volume factors, wells per pad, EUR etc.).

Overall, and assuming those formations with few rock samples are not included in the interpretation of the results, then not only the basic statistical model, but also the machine-learning model, point to the Rakauroa Member (Whangai Formation) and the Waipawa Formation in the Motu Block as the most prospective units for unconventional exploration. On the other hand, the grid interpolation dataset with no statistical treatment applied has pinpointed the Rakauroa Member in the Pongaroa Block and the Waipawa Formation in the Allochthon and Motu Blocks as the most prospective areas for unconventional exploration.

5.8 LIMITATIONS AND IMPROVEMENTS OF THE MODELING

This study presents a novel unconventional methodology for estimating expected ultimate recovery (EUR) in otherwise undiscovered East Coast Basin shale deposits. Given that these results are data driven, the quality of results will likely improve with the addition of information from other analogue sites. Further, the training phase can be improved by using a set of measurements generated from a correlated set of random global analogue variables. Such an approach would obviate the need to perform time consuming cross-validation while subsequently improving the EUR distribution tails for calculating accurate quantiles, e.g. P05, P10, ... P50, ... P90, P95. Introducing the geographic locations into the analysis would then provide an opportunity to produce regional quantile maps of EUR. Two different models should be created: one for immature rocks and one for mature rocks, thus avoiding miscomparison. Lastly, the range of estimation uncertainty can likely be reduced by

removing redundancy in attribute information. Additional time and machine-learning algorithms can be used to identify those attributes with optimal information quality.

6. SHALE OIL AND GAS RESOURCE ASSESSMENT (VOLUMETRICS)

6.1 INTRODUCTION

Volumetric estimates of petroleum resources and reserves are subject to substantial uncertainty because they rely upon the availability of data. Given that, the new frontier basins tend to show a very high risk and uncertainty. While reservoirs with high levels of liquid petroleum and gas present significant opportunities for the petroleum industry, they also bring significant challenges. Before the reserves can be defined, it is necessary to accurately estimate Stock Tank Oil and Gas Initially in Place (STOIIP & GIIP - the volume of oil and gas in a reservoir prior to production). In order to do that, ideally it is necessary to cover all these variables: the physics (including the balance between gravity and existing pore pressure), porosity distributions, capillary pressure curves, and thermodynamic data. However, given the lack of information available for the East Coast Basin, these variables are not considered in the model used in this thesis. Therefore, a basic volumetric calculation methodology using porosity, saturation, thickness, areal extent, and volume factors is applied. Furthermore, in this study we estimate the prospective resource using the notion of the generation potential of source rock, which is relatively well understood, as well as its retention capacity (or non-expulsion) which is less understood, using the best sweet spot area as a case study, identified in chapter 5. Various empirical and geochemical approaches from the basin to the laboratory scale are used to determine these volumes based on the GNS Science and this thesis' datasets, as well as the analogues to constrain the reservoir characteristics. There are basically two different approaches used in the assessment of shale oil and gas: probabilistic and deterministic analyses. The recent published guidelines for Application of the Petroleum Resources Management System (PRMS) (SPE/AAPG/WPC/SPEE/SEG, 2007) and Modernization of Oil and Gas Reporting by the U.S. Securities and Exchange Commission (SEC 2009) have both encouraged using probabilistic methodologies to estimate reserves and resources. However, the PRMS guidelines suggest that the probabilistic method can be computationally intensive, non-reproducible, and subjective. For these reasons, deterministic methods are still more common, even though they lack the ability to quantify the significant uncertainty within the resources estimation process. The deterministic method uses a single value for each parameter, based on a well control of the reservoir characteristics, and give a single value for the estimate of the resource or reserve.

Deterministic methods have some important advantages:

1. explain specific cases;
2. are direct, straightforward and efficient; and
3. give estimates that may be easily reproduced.

Because deterministic methods describe specific, physical cases, combinations of parameter values that are physically inconsistent can be observed and removed. Furthermore, because they are direct, efficient, and comprehensible, deterministic methods appeal to investors and shareholders. They are widely used to report for regulatory matters, reporting, for example, Proved and Probable Reserves. Given that, for this study, a deterministic analysis is applied in order to assess the low, best, and high case scenarios of the oil and gas volumes of the sweet spot area. It is important to highlight that only the recovery factor (Table 5.8) and the volume factor for the Whangai Formation are selected from the U.S. analogues for the studied formations. Other parameters are extracted from the GNS Science and this thesis datasets.

A prospective resource volumetric calculation is conducted in order to determine the potential of the East Coast Basin as a new frontier shale oil and gas basin. These results will be used as input data to evaluate the minimum economic field size and the economic feasibility of developing these resources, giving New Zealand an opportunity to follow the trajectory of Argentina and China as new entrants in shale oil and gas production.

It is important to mention that in the case of Argentina, where conventional gas prices are controlled by the government and kept at below market price, the increase of the attractiveness of its unconventional gas resources was only possible after the government allowed the international companies to exercise a differentiated price (<http://wikileaks.vicepresidencia.gob.bo/Argentina-s-Gas-Plus-Natural-Gas>). Due to the typical uncertainties associated with the geological knowledge in the exploration phase, policy makers should come up with price benefits to incentivize the market.

6.2 CONSIDERATIONS BEFORE THE SHALE OIL AND GAS ASSESSMENT

Three broad approaches are commonly used to estimate technically recoverable resources (TRR) of shale oil and gas, namely:

1. Literature review/adaptation of existing literature: uses third party estimation to adapt these to determine their own estimates;
2. Bottom-up analysis of geological parameters: appropriate for new frontier areas, relies on geological source rock dataset;
3. Extrapolation of production experience using Decline Curve Analysis (DCA): suitable for basins where production is relatively advanced.

A crossover between these approaches is common, with several reports employing and combining more than one approach. However, only a) and b) are used in this study. The following sub-sections outline the literature on depositional environment, porosity, adsorption of oil and gas and kerogen quality assessment.

6.2.1 Depositional Environment

The accumulation of organic matter (OM) rich rocks is a complex function of many interacting processes (Bohacs, 2005). In order to make successful predictions, an integration of many factors is required, such as: basin structural development, plate tectonic movements, paleo-environmental reconstruction and so on. Three main variables responsible for a significant enrichment of the organic matter are production, destruction and dilution (Figure 6.1). Ideally, the sweet spot is identified when production is maximized, destruction is minimized and dilution by clastic or biogenic material is optimized. These have to be in place in order for the accommodation rates to accumulate significant thickness to generate commercial hydrocarbon volumes (Passey et al., 2010).

Figure 6.1 The three main processes that control the enrichment of an organic rock (modified from Passey et al., 2010).

Even if conditions are generally favourable for organic matter accumulation, the characteristics and distributions of possible source rocks nonetheless vary vertically and laterally (Bohacs, 1993 and 1998). This variation is because of the three main physiographic settings in which organic enriched mudstone occurs: constructional shelf margin, platform/ramp, and continental slope/basin (Figure 6.2). These settings can be subdivided by two main depositional environmental areas (proximal and distal).

Constructional shelf margin settings are very sensitive to the sea level, sediment influx and accommodation space, which affects the type of organic matter changing systematically from terrigenous, low hydrogen content (proximal) to marine, high hydrogen content (distal).

Compared to the constructional shelf margin, the platform/ramp settings show slight or no organic facies variations towards the limit of fine-grained deposition (Bohacs, 1998; Guthrie and Bohacs, 2009). The thickness of the rocks is generally greater towards the depocenter of the basin and less towards the basin margins.

The physiography of continental slope/basin settings are related to the transition between continental to oceanic crust, hence an interaction with open-oceanic currents and processes characterize this environment (Vanney and Stanley, 1983). Mass gravity flows and organic pelagic and hemipelagic sedimentation are the dominant systems related to this feature. Relations among organic parameters and physical processes may differ considerably from those on continental shelves (Bohacs, 1990, 1993). In addition, the bathymetry and its effects on oceanic process and circulation

patterns dominates the distribution of fine-grained sediments and organic matter contained in this environment.

These physiographic settings are characterized by their relationship with the two main depositional environmental areas:

1. Proximal areas, characterized by high energy and oxygen levels due to shoreline progradation and water depth shallowing. These can result in a decrease in TOC because of increases in bioturbation, oxidation of the organic matter by storm currents and clastic sedimentation rates.
2. Distal areas, characterized by low energy and very low oxygen or anoxia levels. Given that, significant portions of silt and sand-size particles tend to be biogenic and the preservation of the organic matter is higher due to the lack of oxygen.

Figure 6.2 Physiographic settings of the occurrence of organically enriched mudstone. a) Constructional Shelf Margin, b) Platform/Ramp, and c) Continental Slope-Basin. Also shown are typical TOC and HI stacking patterns for each setting. Vertical scale is metres to tens of metres (Passey et al., 2010).

6.2.2 Porosity

A typical shale oil and gas rock volume is composed of a matrix made up of inorganic and organic matter, showing pore space between these components.

Porosity determination in shale oil and gas is complicated due to very small pore sizes. Although it is easy to differentiate intergranular porosity (between detrital grains) and secondary porosity within grains (intragranular porosity) in conventional siliciclastic reservoirs, once detrital clays are introduced, this differentiation is more complicated. Smectite clay that is common in mud

has interlayer water, but this clay tends to be minimized due to illitization in high maturity formations. Loucks et. al. (2009) and Ambrose et. al. (2010) identified the occurrence of porosity within organic matter. In some overmature organic-rich rocks, 50% of the volume of the original organic matter may consist of porosity. Thus, this type of porosity is very important in the volumetric assessment of unconventional reservoirs as the shales can be hydrocarbon wet and this is where the free gas resides.

It is important to highlight that kerogen is deposited at the same time as the inorganic rock minerals grains. The volume occupied by kerogen is much larger volume percent (vol%) than is indicated by the weight percent (wt%) measurement. This is caused by the difference in densities of the organic matter compared to the common rock-forming minerals (typically 1.1-1.4 g/cc and 2.6-2.8 g/cc, respectively). This is important to mention as most of the well logs report in volume percent quantities while a relatively small amount of TOC (in wt %) can result in a much larger porous volume % of the reservoir rock (Figure 6.3).

Another process coupling in shale porosity is diagenesis. A volumetrically important reaction is when the shale shows mixed layer clays, containing smectite and illite layers. The illitization is often accompanied by a volume change and is the source of significant dissolved silica that results in quartz cementation (Thyberg et al., 2010). This process can produce a large volume of water that can cause the development of overpressures (Rask et al., 1997). The volume change caused by illitization is not a constant transformation and varies from an increase of 4.1% to a decrease of 8.4% (Osborne and Swarbrick, 1999 and Swarbrick et al., 2001).

Figure 6.3 Schematic illustrating how the wt% TOC corresponds to vol% TOC, if much of the original volume is occupied by pores within the organic matter, then the 5% wt TOC impacts up to 20 vol% of the current rock (modified from Passey et al., 2010).

6.2.3 Adsorption of oil and gas

Gas is stored in shale rocks in two main ways: (1) adsorbed (chemical) and absorbed (physical) or even sorbed if we consider physicochemical and (2) as free gas, where it is stored in the pore spaces or in fractures created either by organic matter decomposition or diagenetic/tectonic processes (Pepper, 1992). The sorption capacity is impacted by the thermal maturity, kerogen type and organic richness, which is related to the hydrocarbon expulsion efficiency. Even expulsion efficiency is generally correlated to saturation levels.

The higher the pressure the higher the adsorbed gas. With uplift, temperature and pressure would be reduced, resulting in less adsorbed gas and easier release of gas.

With the integration of source rock volumetrics (total generation potential and thickness) and natural and induced fracture presence, gas flow rates can be estimated as shown schematically (Figure 6.4).

Figure 6.4 Diagram showing the increase in gas flow rates with increasing total organic carbon (TOC), thermal maturity, GOR, and brittleness (modified from Passey et al. 2010).

6.2.4 Kerogen quality assessment

According to Dahl et al. (2004), the original oil and gas potentials in source rock can be estimated using Rock Eval potential (S2) and total organic carbon (TOC). This is a simple method in which the average amounts of oil-prone, gas-prone and inert organic matter are computed in TOC units (Clayton and Ryder, 1984 and Langford and Blanc-Valleron, 1990). The methodology applied in Dahl et al. (2004) is based on a regression line from the plots of remaining hydrocarbon potentials (S2) versus total organic carbon (TOC). A transparent overlay is used to estimate the appropriate

kerogen mixture. As most of the rocks used in the sweet spot analysis in this study are considered immature to slightly mature, the overlay plot used has the transformation ratio (TR) equal to zero (Figure 6.5).

Figure 6.5 Selected overlays constructed for transformation ratios (TRs) (a) 0.0, (b) 0.3, and (c) 0.4. Note that only overlay (a) is being used as the rock dataset is considered immature to slightly mature Dahl et al., 2004.

The intersection on the TOC axis will give the amount of inert carbon (dead carbon) that does not participate in hydrocarbon formation. This overlay fits the maturity level in order to calculate the HI of the live fraction of the kerogen (the regression coefficient will represent average HI), which indicates the relative distribution of gas versus oil-prone kerogen (Conford et al. 1998). Depending on the characteristics, the rock matrix can cause erroneous results, mainly for lean samples. As mentioned before in section 3.4.4, this type of mistake is reduced by applying a quality control in order to select a dataset without these characteristics, by eliminating the lean samples ($S_2 < 0.2$ mg HC/g rock) from the dataset. Even though the effect of the rock matrix will not be addressed in this study, it is an important consideration in case a more detailed study is undertaken in future.

This method cannot replace gas chromatography and visual kerogen data for assessing oil and gas potentials, but it can estimate oil and gas potential when these analyses are not available. This method is applied in both Whangai and Waipawa formations in order to determine the percentage of the generative organic matter in the sweet spot area (Motu Block).

So, based on the methodology suggested for the kerogen assessment (Figure 6.6), the plot and the trend line using an overlay transformation ratio equal to zero can be seen (Figures 6.7 and 6.8) in the Whangai Formation (Rakauroa Member) and the Waipawa Formation, respectively.

Figure 6.6 Schematic flow chart to assess the oil and gas potential in source rocks horizons (modified from Dahl et al., 2004).

Figure 6.7 Assessment of the original oil and gas potentials in source rock of the Rakauroa Member (Whangai Formation) Dahl et al. (2004). Series 1 is the rock samples.

Figure 6.8 Assessment of the original oil and gas potentials in source rock of the Waipawa Formation Dahl et al. (2004). Series 1 is the rock samples.

Using the plot from Figure 6.7 the inert organic carbon for the Rakauroa Member is approximately 0.3 % TOC and the ratio between oil and gas prone is approximately 90% gas and 10 % oil prone. This member shows homogeneous characteristics given the little variation in its prone potential. On the other hand, for the Waipawa Formation, based on the plot of Figure 6.8, the inert

organic carbon is approximately 0.8% TOC and the ratio between oil and gas varies from 100% to 40 % gas prone, showing that some rock samples exhibited a 60% potential to generate oil. This demonstrates that the Waipawa Formation is not a homogeneous unit.

The generative TOC ($\text{TOC}_{\text{live}} = \text{TOC}_{\text{measured}} - \text{TOC}_{\text{inert}}$) is used to calculate the Langmuir volume (definition p.229) as shown in figure 6.10 in section 6.3.2.1.

6.3 METHODOLOGY

Based on Jarvie (2012), unconventional oil and gas are defined here as oil and gas generated by rock formations that are rich in organic matter, mature and trapped either within the source rock layers or in its immediate vicinity. This oil and gas have not experienced secondary migration and remain in these tight reservoirs and therefore are not limited by water-oil and gas contacts.

The methodology applied in this thesis is reproduced from U.S. EIA/ARI World Shale Gas and Shale Oil Resource Assessment, 2013 (EIA/ARI, 2013). This assessment should be viewed as an initial step toward future evaluations, which with more dataset gathering, will achieve a more accurate assessment.

This methodology follows six main stages:

1. Conducting preliminary reservoir characterization of the studied shale formations;
2. Identifying the sweet spots;
3. Establishing the areal extent;
4. Estimating the shale oil and gas in-place;
5. Risk factors;
6. Calculating the recoverable resource volumes.

After characterizing the reservoir quality, identifying the sweet spot, and its areal extent in the East Coast Basin, the recoverable volumes of the Whangai (Rakauroa Member) and Waipawa formations are calculated. In order to do that, it is assumed that these formations occur along the whole Motu block. The portion of this block which is not outcropping is considered to be in the oil or gas window depending on depth. So, based on the burial history, kinetics, and heat flow parameters for Rere-1 well as inferred in Field et. al. (1997) (Figure 6.9), the top and bottom of the oil window for Rakauroa Member are approximately 2000-4000m, respectively. Depths deeper than 4000m are considered to be in the gas window. Rere-1 well is also used to identify the thickness and because of the absence of a density log curve, Hukarere-1 well is used instead to calculate the effective porosity and water saturation of the optimum zone for Rakauroa Member in this area. As this well does not

show reliable information about the occurrence of the Waipawa Formation, the effective porosity and water saturation are considered the same as those for Rakaurua Member. Using these assumptions and proxies, and based on areal extent, thickness and geochemical and geomechanical parameters, the *in situ* oil and gas volume of these formations can be assessed. After this assessment, a risk factor is applied in the *in situ* volume. Finally, a recovery factor (RF) derived from the Eagle Ford and Lewis shales (U.S. analogues), Table 5.8 are applied into the risk volume for Rakaurua Member and Waipawa Formation, respectively, in order to estimate their recoverable volumes.

Figure 6.9 Burial history of Rere-1 (Motu Block) showing the oil and gas transformation rate and the temperature in subsurface. Red dash line represents the base of the Whangai Formation. Blue dashed line represents the middle of the Whangai Formation and the yellow dashed line the transition between Waipawa and Wanstead formations (modified from Field et. al., 1997).

The methodology applied to assess the oil, free gas and adsorbed gas used in this study follows.

6.3.1 Oil in place

As the Whangai and Waipawa formations have the potential to generate oil and gas, shale oil and gas in place assessments (OIP/GIP) for each unit will be estimated.

Two main aspects yield the calculation of oil in place for a given area: net organically-rich shale thickness and oil-filled porosity. In addition, pressure and temperature are important variables that influence the volume of gas in solution with the reservoir oil, defined by the formation factor (Bo).

Combining all these variables, an empirical formula was established using reservoir engineering equations and conversion factors to calculate the OIP per square mile (EIA/ARI, 2013).

$$\text{OIP} = \frac{7758 (A * h) * \emptyset * (So)}{Boi} \quad (\text{Eq. 6.1})$$

A = is area, in acres (with a conversion factor of 7,758 bbl per acre foot).

h = is net organically-rich shale thickness, in feet

$\emptyset$ = is porosity, a dimensionless fraction (these values are obtained from log or core information)

(So) = is the fraction of the porosity filled by oil

Boi = is the formation gas volume factor that is used to adjust the oil volume in the reservoirs, typically swollen with gas in solution, to oil volume in stock-tank barrels; reservoir pressure, temperature and thermal maturity (Ro%) values are used to estimate the Boi value.

6.3.2 Gas in place

6.3.2.1 Free gas

The calculation of free gas in-place for a given areal extent is determined, to a large extent, by four characteristics of the shale formation:

1. Pressure;
2. Temperature;
3. Gas-filled porosity, and
4. Net organically-rich shale thickness.

The calculation of free gas in place (GIP) uses the following standard reservoir engineering equation (EIA/ARI, 2013):

$$GIP = \frac{43,560 * Ah\emptyset (Sg)}{Bg} \quad (Eq. 6.2)$$

Where,

$$Bg = \frac{0.02829zT}{P} \quad (Eq. 6.3)$$

A = is area, in acres (with a conversion factor of 43,560 bbl square feet per acre and 640 acres per square mile);

h = is net organically-rich shale thickness, in feet;

$\emptyset$ = is porosity, a dimensionless fraction (these values are obtained from log or core information);

(Sg) = is the fraction of the porosity filled by gas;

P = Pressure in psi (from well test or analogue);

T = Temperature in degrees Rankin (from well test or regional temperature versus depth gradients; the factor 460 °F is added to the reservoir to provide the input value for the gas volume factor (Bg);

Bg = is the gas volume factor, in cubic feet per standard cubic feet and includes the gas deviation factor (z), a dimensionless fraction. The gas deviation factor (z) adjusts the ideal compressibility (PVT) factor to account for nonideal PVT behaviour of the gas.

6.3.2.1 Adsorbed gas

Shales may hold not only free gas but also adsorbed gas in the shale formation, specifically, on the surface of organics and clays. In shale reservoirs that display adsorption, it has traditionally been thought that the adsorbed gas resides in the matrix of the organic-rich portion of the rock, which does not contribute significantly to the porosity of the rock. However, according to Ambrose et al. (2010) this organic-rich portion of the shale, in fact, does contain the majority of the porosity, as well as the adsorbed gas. If this assumption is valid, it is possible that the adsorbed gas is occupying a portion of the measured porosity, thus decreasing the pore space available to free gas. The volume occupied by the adsorbed gas must therefore be subtracted from the measured pore volume when calculating the volume available for free gas storage. For this study, free gas and adsorbed gas are calculated separately for simplicity and then combined in order to calculate the total gas. This concept could be applied for future assessments.

In order to calculate the adsorbed gas a Langmuir isotherm is established for the prospective area of the basin using the available data of TOC and thermal maturity to establish the Langmuir volume (VL) and the Langmuir pressure (PL). Adsorbed gas in-place is then calculated using the formulas below (EIA/ARI, 2013):

$$GC = (VL * P) / (PL + P) \quad (\text{Eq. 6.4})$$

$$OGIPA = 43560 * A * h * \rho_b * (VL * P) / (PL + P) \quad (\text{Eq. 6.5})$$

Where P is original reservoir pressure (psia), ρ_b is bulk density of the rock (ton/ft³), A is the areal extent (acres), and h is net organic-rich shale (feet)).

In general, the Langmuir volume (VL) is a function of the organic richness and thermal maturity of the shale, as illustrated in Figure 6.10. The Langmuir pressure (PL) is a function of how readily the adsorbed gas on the organics in the shale matrix is released as a function of a finite decrease in pressure Figure 6.11.

Figure 6.10 Langmuir Volume vs. TOC for the Whangai and Waipawa formations (modified from Guérillot and Bruyelle, 2014).

Figure 6.11 Typical shale-adsorbed gas content, showing differences between lean, normal and rich shale in relation to adsorbed gas (Guérillot and Bruyelle, 2014).

6.4 CALCULATING THE VOLUMES: RESULTS AND DISCUSSION

Based on the results of the machine-learning, both the Whangai (Rakauroa Mb.) and Waipawa formations have shown the best rock characteristics for a shale oil and gas reservoir in the Motu Block. Other blocks could also be potential areas to be explored but, as the focus of this thesis is to point out the best area, the Motu block is the one to be considered.

Motu block has an approximate area of 13,314 Km² (onshore/offshore) where 3.112 Km² is offshore and 10,203 Km² is onshore. In order to calculate the shale gas volumes, it is assumed that Whangai and Waipawa formations are present in the whole block. The estimation of the potential area is done by subtracting the outcrops of both formations along the block. The total area for sub-surface Whangai and Waipawa, assuming the Waipawa formation overlays conformably the Whangai Formation, is 5,378 Km² (Figure 6.12).

Based on Rere-1 well, measured sections, and Francis (2000), along the Motu Block the average thickness for Rakauroa Member (Whangai Formation) is around 250m (Figure 6.13). However, only 141m can be stimulated (section 4.7). Therefore, only 141m are considered the net thickness for this unit. Although the Waipawa Formation is considered the best source rock in the region, it has a variable thickness distribution and generally is very thin (Figure 6.13). So based on a compilation of measured sections along the Motu Block and the isopach from Francis (2000), the average thickness used for the Waipawa Formation in the Motu Block is 10m. Table 6.1 shows the gross rock volumes for the Whangai and Waipawa formations.

Figure 6.12 Zoom of Motu Block showing the Whangai/Waipawa outcropping, rock samples and the red dashed line marking the boundary of the prospective area.

Figure 6.13 Isopach of the Whangai and Waipawa formations based on Francis 2000.

Table 6.1 Total source gross rock volumes used in this study for the Whangai (Rakauroa Mbr) and Waipawa formations.

Structural Block	Estimate Area Waipawa and Whangai fms. (Km ²)	Whangai Thickness (m)	Whangai GRV (Km ³)	Waipawa Thickness (m)	Waipawa GRV (Km ³)	Total Source GRV (Km ³)
Motu Block	5378	141	758	10	53	811

6.4.1 Reservoir conditions

The reservoir conditions and economic assumptions are extracted from an open file report prepared by Adams (2012) as well as this thesis results from Rere-1 well (Motu block).

The statistical results to calculate the pressure in the optimum zone can be seen in Figure 6.14 and the gas compressibility in Figure 6.15.

Figure 6.14 Statistics results of the pressure calculation in the optimum zone for the Rere-1 well

Figure 6.15 Input data to calculate the compressibility of the gas in the optimum zone for the Rere-1 well.

The Whangai Formation has been mapped at both the surface and subsurface in a number of exploration wells, as mentioned (Opoutama-1, Rere-1, and Hukarere-1). Although Ranui-1 and -2 also intersected the Whangai Formation in the sub-surface, the reservoir conditions are not used for this study, as they are too shallow. The Waipawa Formation is also mapped at surface and intersected sub-surface by the Orui-1A well. Given that the Waipawa Formation is very thin (10m) and the Orui-1A well the formation very shallow, all parameters of the reservoir conditions (mud weight and pressure) for Whangai Formation are also used for the Waipawa Formation. The reservoir conditions are summarized in Table 6.2.

Table 6.2 The reservoir conditions for the three exploration wells used in this study. However, only Rere-1 well is used, as it is located in the Motu Block (modified from Adams, 2012).

Exploration Well	Depth to Top Whangai Fm. (mMD)	Whangai Fm. Thickness	Mud gradient at Whangai Fm (ppg)	Pressure at 2000m TVD (psia)	Mean Pressure at optimum interval TVD (psia)
Opoutama-1 (1967)	1402	813	15.9	-	N/A
Rere-1 (1985)	1990	392	13.8	4100	4767.3
Hukarere-1 (2001)	2764	322	>14	4800	N/A
Normal Pressure	N/A	N/A	8.6	2840	

As shale zones have historically not been evaluated in detail, specific values related to the porosity, saturation and formation volume factor can be subject to a wide distribution. Shrinkage (formation volume factor) is set at a wide range, considering the possibility of overpressured reservoirs. Given that, the oil formation volume factor (B_o) of 1.358 is set for the Whangai using Eagle Ford as the analogue (Orangi et. al., 2011), and for the Waipawa Formation, Kora-1 well data is used, based on a reservoir fluid study (Deloitte, 2012). In this study, the 35-degree API gravity (American Petroleum Institute) Waipawa oil was calculated to have a formation volume factor of 1.293. The gas volume factor (B_g) for the Whangai and Waipawa formations is obtained applying equation 6.3. The Langmuir volume (V_L) and the Langmuir pressure (P_L) are derived from literature using a generic relation between Langmuir volume versus total organic carbon (Figure 6.10) and after defining the volume, the Langmuir pressure is determined (Figure 6.11). Thus, the Langmuir volume is 17 scf/ton and 54 scf/ton and the Langmuir pressure is 100 psia and 145 psia for the Whangai and Waipawa formations, respectively. Both gas content in (sm^3/kg) and pressure in (bar) were converted to appropriate units (scf/ton) and (psia), respectively, to fulfill the equation 6.4. For unit conversions, see glossary.

6.4.2 Rock properties

Permeabilities are not normally directly measured by wireline logs but can be inferred from porosity-permeability relationships. Although no permeability study is undertaken in this thesis, as the goal is not to build a reservoir model, it is important to note the average values of 0.001 mD and 0.2 mD from analogues Eagle Ford (Whangai analogue) and Lewis shale (Waipawa analogue) (Jarvie, 2012), respectively, in case reservoir modelling will be attempted using the parameters described in this thesis.

Hukarere-1 well is used to determine the low, best and high case effective porosities and water saturations as shown in Figure 6.16 and Table 6.3. The step-by-step estimation of these two variables follows the standard methodology applied in the oil and gas industry shown in Figure 6.17. The values for porosity and water saturation are kept the same for both oil and gas windows, so the expected porosity compaction tendency is not being considered at depths.

Figure 6.16 Red outline showing effective porosity and water saturation estimates for Hukarere-1 well.

Table 6.3 Parameters used to assess the oil and gas volumes for Whangai and Waipawa formations.

Hukarere-1 well	Low case	Best case	High case
Effective porosity (%)	1.5	8.0	18
Water saturation (%)	90	70	40
Rakauroa Mbr (Whangai Fm.)			
Bulk density of the rock (g/cm3)	2.34	2.34	2.34
Waipawa Fm.			
Bulk density of the rock (g/cm3)	2.30	2.30	2.30

Figure 6.17 Step by step estimation of the Vshale (shale volume), total and effective porosities and total water saturation in the zone of interest of Hukarere-1 well (Crain, 2017).

6.4.3 Risk factors estimated for unconventional exploration targets

Five criteria are considered in determining the overall geological risk:

1. Source rock – is there thermally mature hydrocarbon source rock present in adequate thickness, extent and organic richness?
2. Charge – is the source rock able to generate oil and gas?
3. Reservoir rock – does the reservoir have favourable parameters such as thickness, porosity and acceptable transmissibility?
4. Trap / Closure – does closure of the reservoir exist in terms of adequate areal extent and vertical relief?
5. Seal – are there effective sealing rocks present to guarantee that containment has occurred?

A factor ranging from zero to one is assigned to each criterion. The geological chance of success is the product of all factors. For the Whangai and Waipawa targets, the geological chances of success are shown in Table 6.4.

Table 6.4 Risk factors estimated for Whangai and Waipawa formations for low, best and high case.

Prospective Formations	Source rock	Charge	Reservoir rock	Trap/closure	Seal	Chance of success
Whangai Rakauroa Mbr	1.00	1.00	0.25 (low) 0.35 (best) 0.45 (high)	0.80	0.85	0.17 (low) 0.24 (best) 0.30 (high)
Waipawa	1.00	1.00	0.40 (low) 0.50 (best) 0.60 (high)	0.80	0.85	0.27 (low) 0.34 (best) 0.40 (high)

6.4.4 Low, best, and high case oil and total gas volume assessment

Tables 6.5 to 6.10 below show the recoverable volumes of oil, gas and adsorbed gas for the Rakauroa Member (Whangai Formation) and the Waipawa Formation. Units have been changed from the previous description of this chapter to fulfill the units required by the methodology used.

Table 6.5 Shale oil reservoir properties and resources of Whangai Formation (Rakauroa Member) in the Motu Block - East Coast Basin.

Basic Data	Basin/Gross Area		East Coast Basin (6.92E+6 Acres)		
	Shale Formation		Whangai (Rakauroa Member)		
	Geologic Age		Upper Cretaceous		
	Depositional Environment		Marine		
Physical Extent	Sweet Spot Area (Acres)		132942 Low case	664466 Best case	1.19E+6 High case
	Thickness (feet)	Organically rich	1050	1050	1050
		Net	462	462	462
	Depth (feet)	Interval	3280-6562	6528-7808	7874-8858
		Average	4921	7578	8366
Reservoir Properties	Reservoir Pressure		Highly Overpressured	Highly Overpressured	Highly Overpressured
	Median TOC (wt. %)		0.3	0.94	1.6
	Thermal Maturity (%Ro)		0.5	0.6	1.2
	Clay Content (%)		8	10	12
	Porosity (%)		1.5	8	18
	Water Saturation (%)		90	70	40
	Volume factor (bbl/stb)		1.358	1.358	1.358
Resource	Oil Phase		Oil	Oil	Oil
	OIP (MMbbl)		526	42100	339205
	Risked OIP (MM bbl)		89	10101	101761
	Risked Recoverable (MM bbl)		5.37	606	6105

Table 6.6 Shale gas reservoir properties and resources of Whangai Formation (Rakauroa Member) in the Motu Block - East Coast Basin.

Basic Data	Basin/Gross Area		East Coast Basin (6.92E+6 Acres)		
	Shale Formation		Whangai (Rakauroa Member)		
	Geologic Age		Upper Cretaceous		
	Depositional Environment		Marine		
Physical Extent	Sweet Spot Area (Acres)		132942 Low case	664466 Best case	1.19E+6 High case
	Thickness (feet)	Organically rich	1050	1050	1050
		Net	462	462	462
	Depth (feet)	Interval	11483-14764	14764-18045	18045-21325
		Average	13123	16404	19685
Reservoir Properties	Reservoir Pressure		Highly Overpressured	Highly Overpressured	Highly Overpressured
	Median TOC (wt. %)		0.3	0.94	1.6
	Thermal Maturity (%Ro)		1.2	1.4	1.7
	Clay Content (%)		8	10	12
	Porosity (%)		1.5	8	18
	Water Saturation (%)		90	70	40
	Volume factor (ft ³ /scf)		0.003	0.003	0.003
Resource	Gas Phase		Dry gas	Dry gas	Dry gas
	GIP concentration (TCF)		1.33	106	862
	Risked GIP (TCF)		0.22	25.70	259
	Risked Recoverable (TCF)		0.013	1.54	15.50
	Barrel of Oil Equivalent (MMBOE)*		2.24	265.48	2675

* A method of equating the energy produced by a hydrocarbon gas to a standard oil measurement. One barrel of oil has about the same heat producing capacity as 5,800 ft³ of gas at standard conditions. Abbreviated BOE.

Table 6.7 Shale adsorbed gas reservoir properties and resources of Whangai Formation (Rakauroa Member) in the Motu Block - East Coast Basin.

Basic Data	Basin/Gross Area		East Coast Basin (6.92E+6 Acres)		
	Shale Formation		Whangai (Rakauroa Member)		
	Geologic Age		Upper Cretaceous		
	Depositional Environment		Marine		
Physical Extent	Sweet Spot Area (Acres)		132942 Low case	664466 Best case	1.19E+6 High case
	Thickness (feet)	Organically rich	1050	1050	1050
		Net	462	462	462
	Depth (feet)	Interval	3500-4500	4500-5500	5500-6500
		Average	4000	5000	6000
Reservoir Properties	Reservoir Pressure		Highly Overpressured	Highly Overpressured	Highly Overpressured
	Median TOC (wt. %)		0.3	0.94	1.6
	Thermal Maturity (%Ro)		1.2	1.4	1.7
	Clay Content (%)		8	10	12
	Porosity (%)		1.5	8	18
	Water Saturation (%)		90	70	40
	Volume factor		N/A	N/A	N/A
	Langmuir volume (VL) (scf/ton)		17.65	17.65	17.65
	Langmuir pressure (PL) (psia)		72.5	72.5	72.5
	Reservoir Pressure (psia)		3627	4767	5216
Resource	Gas Phase		Adsorbed gas	Adsorbed gas	Adsorbed gas
	GIP adsorbed concentration (TCF)		3.04	15.2	27.3
	Risked GIP adsorbed (TCF)		0.516	3.65	8.18
	Risked Recoverable (TCF)		0.031	0.21	0.49
	Barrel of Oil Equivalent (MMBOE)*		5.34	36.20	84.47

* A method of equating the energy produced by a hydrocarbon gas to a standard oil measurement. One barrel of oil has about the same heat producing capacity as 5,800 ft³ of gas at standard conditions. Abbreviated BOE.

Table 6.8 Shale oil reservoir properties and resources of Waipawa Formation in the Motu Block - East Coast Basin.

Basic Data	Basin/Gross Area		East Coast Basin (6.92E+6 Acres)		
	Shale Formation		Waipawa Formation		
	Geologic Age		Paleocene		
	Depositional Environment		Marine		
Physical Extent	Sweet Spot Area (Acres)		132942 Low case	664466 Best case	1.19E+6 High case
	Thickness (feet)	Organically rich	65	65	65
		Net	32.8	32.8	32.8
	Depth (feet)	Interval	3280-6562	6528-7808	7874-8858
		Average	4921	7578	8366
Reservoir Properties	Reservoir Pressure		Highly Overpressured	Highly Overpressured	Highly Overpressured
	Median TOC (wt. %)		1	3.24	10.8
	Thermal Maturity (%Ro)		0.5	0.6	1.2
	Clay Content (%)		15	17	20
	Porosity (%)		1.5	8	18
	Water Saturation (%)		90	70	40
	Volume factor (bbl/stb)		1.293	1.293	1.293
Resource	Oil Phase		Oil	Oil	Oil
	OIP (MMbbl)		39	3140	25292
	Risky OIP (MM bbl)		10.59	1067	10117
	Risky Recoverable (MM bbl)		1.06	107	1011

Table 6.9 Shale gas reservoir properties and resources of Waipawa Formation in the Motu Block - East Coast Basin.

Basic Data	Basin/Gross Area		East Coast Basin (6.92E+6 Acres)		
	Shale Formation		Waipawa Formation		
	Geologic Age		Paleocene		
	Depositional Environment		Marine		
Physical Extent	Sweet Spot Area (Acres)		132942 Low case	664466 Best case	1.19E+6 High case
	Thickness (feet)	Organically rich	65	65	65
		Net	32.8	32.8	32.8
	Depth (feet)	Interval	11483-14764	14764-18045	18045-21325
		Average	13123	16404	19685
Reservoir Properties	Reservoir Pressure		Highly Overpressured	Highly Overpressured	Highly Overpressured
	Median TOC (wt. %)		1	3.24	10.8
	Thermal Maturity (%Ro)		1.2	1.4	1.7
	Clay Content (%)		15	17	20
	Porosity (%)		1.5	8	18
	Water Saturation (%)		90	70	40
	Volume factor (ft3/scf)		0.003	0.003	0.003
Resource	Gas Phase		Dry gas	Dry gas	Dry gas
	GIP concentration (TCF)		0.095	7.59	61.20
	Risked GIP (TCF)		0.025	2.58	24.48
	Risked Recoverable (TCF)		0.0025	0.25	2.44
	Barrel of Oil Equivalent (MMBOE)*		0.43	43.09	421

* A method of equating the energy produced by a hydrocarbon gas to a standard oil measurement. One barrel of oil has about the same heat producing capacity as 5,800 ft³ of gas at standard conditions. Abbreviated BOE.

Table 6.10 Shale adsorbed gas reservoir properties and resources of Waipawa Formation in the Motu Block - East Coast Basin.

Basic Data	Basin/Gross Area		East Coast Basin (6.92E+6 Acres)		
	Shale Formation		Waipawa Formation		
	Geologic Age		Paleocene		
	Depositional Environment		Marine		
Physical Extent	Sweet Spot Area (Acres)		132942 Low case	664466 Best case	1.19E+6 High case
	Thickness (feet)	Organically rich	20	20	20
		Net	10	10	10
	Depth (feet)	Interval	3500-4500	4500-5500	5500-6500
		Average	4000	5000	6000
Reservoir Properties	Reservoir Pressure		Highly Overpressured	Highly Overpressured	Highly Overpressured
	Median TOC (wt. %)		1	3.24	10.8
	Thermal Maturity (%Ro)		1.2	1.4	1.7
	Clay Content (%)		15	17	20
	Porosity (%)		1.5	8	18
	Water Saturation (%)		90	70	40
	Volume factor		N/A	N/A	N/A
	Langmuir volume (VL) (scf/ton)		52.97	52.97	52.97
	Langmuir pressure (PL) (psia)		145	145	145
	Reservoir Pressure (Psia)		3627	4767	5216
Resource	Gas Phase		Adsorbed gas	Adsorbed gas	Adsorbed gas
	GIP adsorbed concentration (TCF)		0.66	3.34	5.99
	Risked GIP adsorbed (TCF)		0.18	1.13	2.39
	Risked Recoverable (TCF)		0.01	0.11	0.24
	Barrel of Oil Equivalent (MMBOE)*		1.7	18.96	41.37

* A method of equating the energy produced by a hydrocarbon gas to a standard oil measurement. One barrel of oil has about the same heat producing capacity as 5,800 ft³ of gas at standard conditions. Abbreviated BOE.

The total prospective resources combining the Whangai and Waipawa formations for oil and total gas for the low, best and high cases are shown in Table 6.11.

Table 6.11 Total prospective resource of the Whangai and Waipawa formations in the Motu Block for the low, best and high cases. Best cases are highlighted in bold.

Formation	Recoverable oil (MMbbl)	Recoverable total gas (free + adsorbed gas) (MMboe)
Whangai (Rakauroa Mbr)	5.37 (low) 606 (best) 6105 (high)	7.58 (low) 301.68 (best) 2760 (high)
Waipawa	1.06 (low) 107 (best) 1011 (high)	2.13 (low) 62.02 (best) 462 (high)
TOTAL	6.46 (low) 713 (best) 7116 (high)	9.71 (low) 364 (best) 3222 (high)

Based on the total prospective resource, the volumes for the best case scenario for the Whangai (Rakauroa Member) and Waipawa formations combined in the Motu Block are 17% higher (713MMbbl) than the 2P (proved + probable) reserves for the whole of New Zealand for oil and condensate (588MMbbl) and 26% (2.1TCF) of the 2P (proved + probable) reserves of natural gas (7.8 TCF) (Energy in NZ, 2016).

Using the best case scenario, an economical model is tested (below), in order to define the minimum economic field size and the feasibility of developing the unconventional reservoirs from the two formations evaluated here.

6.5 ECONOMICS ANALYSIS – ESTABLISHING MINIMUM ECONOMIC FIELD SIZE

6.5.1 Introduction

Nowadays most decision-making - whether technical, economic, financial, administrative, or environmental - is no longer realized by simple intuition, imposition or even experience of a particular expert or group of experts. The decision maker, when faced with several alternatives of investments, has to choose one or a limited number of options. This is in spite of restrictions on the availability of resources, whether these resources are human, financial, or of any other nature.

The oil industry must continually refine its approach to risk assessment, because every stage of the industry's core business—from exploration, to production, to marketing—carries significant risk and uncertainty. As Simpson et. al (2000) point out, if the economics of field development are not properly worked out (especially given the variation of costs and oil prices), then even fields with attractive levels of recoverable resources may turn into development catastrophes. On the other hand, if risks are assessed accurately, then significant competitive advantages may be gained. Companies can now access a range of tools which properly assess appropriate risk, while doing so can give those companies a valuable edge in the market. Such tools (listed here from the relatively simple to the more complex) include: cash flow; discounted cash flow; internal rate of return (IRR) vs return on investment (ROI); risk, or chance of success estimation (described and used in this section); Monte Carlo analysis; and portfolio, options and preference theories. See Appendix 4 for the latter as they are not applied in this section but still important concepts to bear in mind.

The goal of this chapter is based on economical analysis to find whether a feasible exploration scenario could be developed in the East Coast Basin and to establish the minimum economic field size that the government should offer in future bid rounds.

6.5.2 Cash Flow

Figure 6.18 illustrates a typical schematic cash flow model used throughout the oil and gas industry, from exploration to abandonment. First, however, each step in the cash flow model must be defined:

1. “During the exploration phase expenses accrue related to prospecting and drilling exploration well(s);
2. During the appraisal phase, the quality of the reservoir is studied in order to find its economic feasibility;
3. During the development phase the reservoir is prepared for oil production. After this step, cash flow turns from expenses to revenues.
4. During the abandonment phase, as the life of the field runs out, the costs of shutting down production in keeping with environmental government agency requirements must be covered by investments.”

(Nepomuceno, 1997, translated from Portuguese by Rechden)

Figure 6.18 Schematic graphic of a basic cash flow of an oil and gas project.

6.5.3 Discounted Cash Flow, or Net Present Value (NPV)

Discounted cash flow (DCF) analysis is the most widely used method for valuing investments in the oil industry. Since timescales are measured in decades rather than years (i.e. the time value of money) the method is considered fundamental. The time value of money expresses the notion that money received in the future is worth less than the same amount received today, largely due to inflation (Rose, 1987).

The earlier exploration and development years incur most of the costs – i.e. cash outflows – while cash inflows – i.e. revenues – are spread over the production phase, throughout the working lifetime of the field. Whereas in conventional exploration, the highest risk occurs in the exploration phase and decreases through the development and production phases. In the case of unconventional resources, the highest risk is in the development phase.

Revenues received from hydrocarbons produced are worth less than the same sums paid earlier, as those revenues do not acquire interest in the intervening years.

DFC analysis determines the money value spent and received, and assuming a successful project. Net present value (NPV) assesses profitability, indicating whether an investment ought to proceed or not. NPV is the sum of discounted cash flow, representing the value of the present discounted cash flow over the lifetime of the project considering a certain discount rate.

- If the $NPV > 0$, the project should be considered;
- If the $NPV < 0$, the project should be rejected.

Consider the risk-free rate of return that banks offer for deposits. If calculations according to that rate yield a negative NPV, then putting the money in the bank offers a better return. A positive NPV means that the project offers a higher return than the bank, although the different levels of risk will also be taken into consideration by the potential investor. Alternatively, the cost of borrowing the money, from shareholders or the bank, could be used as the discount rate.

6.5.4 Payback Period Method

The Payback Period Method measures the time needed to recover the funds invested by dividing the cash outlay by the net cash generated after tax.

There are two different payback analyses:

1. Simple payback method in which no discount rate is applied, and
2. Discount payback method in which a discount rate is applied.

With no discount rate applied, the recovery time of the simple method is shorter than with the discount method. However, the simple method ignores investing the money in the bank, whereas the discount payback method does not, allowing proper evaluation of the project.

6.5.5 Internal Rate of Return (IRR) vs Return on Investment (ROI)

The internal rate of return (IRR) finds the interest rate that, when applied to discounting the project's cash flow, brings the NPVs of all cash flows to zero. There is no formula – instead it is a matter of trial and error. Return on investment (ROI) signifies the increase or decrease of an investment over time, expressed as a percentage. ROI is found by calculating the difference between the current (or expected) value and the original value, dividing this by the original value and then multiplying by 100. ROI may be improved by decreasing costs, increasing returns and accelerating returns. Even small variations in any of these may significantly alter the outcome. Although an apparently simple concept, ROI can be complicated by a range of different factors, hence a number of companies prefer to focus on financial metrics such as IRR and Payback periods, rather than offer ROI in quantitative terms (Eidleman, 1993).

6.5.6 Risk, or Chance of Success, Estimation

The analyses described so far are financial assessments – they do not factor risk or likely success. Investment risk must be calculated separately and then factored into economic analyses.

Opportunity analysis generally begins with a purely subjective estimation of success. The chance of success is binary; if the chance of something happening is X%, the chance of it not happening is 100% minus X%.

Most prospect evaluations fall into one of two categories: below-ground or above-ground.

Below-ground evaluation in exploration and production (E&P) involves working with geological evidence to confirm hydrocarbon presence, reservoir and trap presence, and other technical inputs. The development of unconventional reservoirs has seen engineering risks replace geological ones. It is important, for instance, to understand the optimum fracking stages per well, and when well-space would increase initial production and hence decrease payback. This is important when investing

in unconventional reservoirs, whose success rates are higher than conventional reservoirs, with less risky investment of time and money.

Above-ground evaluation can include consideration of politics, world economics and technological developments, the scope of influence of experts in governmental affairs, finance and technology.

Usually experts work collectively on prospect evaluations, considering known facts, past experience and possible scenarios. Notably, explorationists tend toward conservative estimates when evaluating the success or otherwise of “midrange” projects, those estimated to hold a 25% to 60% chance of success. These projects will meet with success about 35% to 75% of the time (Alexander et al., 1998). “High-risk” projects are those estimated to have a less than 20% chance of success. Historically, explorationists have been overly optimistic in these, with such projects finding oil less than 5% of the time.

In the present economic assessment, both below and above-ground risks are considered. However, more detail on the geological aspects are provided. Within these parameters, probabilities of occurrence are usually calculated by the Delphi method, involving experts from a range of disciplines (geologists, geophysicists, oil engineers, and so on) meeting to chart and discuss risks. Each individual among the group assigns a probability to each condition, and the “Consensual” probability for each condition found by taking the average point of all opinions (Pereira, 1992).

The probability of success (PS) is found via the following equation:

$$PS = Sr * E * R * S * M \quad (\text{modified from Pereira, 1992}), \quad (\text{Eq. 6.6})$$

Where,

PS = Success probability;

Sr = Source rock;

E = Trap (structural, stratigraphic or both)

R = Reservoir;

S = Seal;

M = Migration.

After identifying the risk of these variables being in place (see section 6.4.3), the Net Present Value (NPV) can be multiplied by the probability of success in order to estimate the Monetary Economic Value (EMV), when the oil and gas volume used is unrisks. However, in this study the risk volume is used. Thus, the NPV is equal to the EMV.

For the economic analysis of the Whangai (Rakauroa Member) and Waipawa formations in the Motu block, only concepts described thus far will be applied.

6.6. METHODOLOGY - HOW WILL THE ECONOMICAL CONCEPTS BE APPLIED IN THE EAST COAST BASIN?

After statistically identifying the sweet spot along the East Coast Basin (Chapter 5), and calculating its recoverable volume (Section 6.4.4), an economical analysis is assessed in order to establish the minimum economic field size block the government should offer for exploring unconventional reservoirs, as well as its feasibility in the East Coast Basin. To do so, only one development scenario model (best case) has been built and is used to assess the potential production of the Whangai and Waipawa formations and associated cashflows. This evaluation requires an integrated project model covering capital expenditure (CAPEX) and operational cost (OPEX), infrastructure availability, oil price, production forecast and the government-take (Bilderbeck and Beck, 2005). The minimum field size estimation is an interactive process that requires inputs from multidisciplinary fields to calculate a prospective resource size associated to zero NPV. There are many ways of assessing this model but the most commonly used one follows five steps:

1. Estimate the production profile and the number of producer and injector wells for the selected resource case;
2. Estimate the costs (CAPEX and OPEX);
3. Calculate the NPV;
4. Repeat steps 1,2, and 3 decreasing and increasing resources sizes, to make sure one NPV is negative;
5. Make the preliminary assessment of resource size that will yield NPV close to zero.

As the East Coast Basin has never produced oil and gas directly from the formations being evaluated here, some assumptions have to be made and these are described below.

Two methodologies are applied in this economical assessment:

1. The first methodology is based on the report from U.S. EIA/ARI World Shale Gas and Shale Oil Resource Assessment, 2013, as described in the Section 6.3.
2. The second methodology is based on the machine-learning EURgas forecast identified in Chapter 5. It is important to highlight that due to the shale oil interference in the statistical analysis as described previously, only the EURgas forecast was defined from the machine-learning results. The EUroil is extracted from the average EUroil from Eagle Ford. This

average is based on the latest oil and gas production data from 19014 horizontal wells in the Eagle Ford region producing since 2010 and through January 2017 (Peters, 2017). The total EURoil per well for Rakauroa Member is extracted from Eagle Ford (analogue for the Whangai Fm.). The total EURoil per well for Waipawa Formation should be Lewis Shale as it is the best match (analogue), but as Lewis shale was always commingled with the Dakota (DK), and Mesaverde (MV) formations, it was difficult to quantify the incremental production rates, reserves, and corresponding value of the Lewis (Dube et. al., 2000). Given that, Eagle Ford is also used as an analogue for the Waipawa Formation. The EURoil is 160000 M/bbl per well for both formations. The average of the total median EURgas predicted by the machine-learning model per well for the Whangai and Waipawa formations in the Motu Block is 3690 MMcf (636136 Boe) and 3729 MMcf (642860 Boe), respectively. This methodology uses the forecast of EURgas as a function internally consistent with the variables comprising the hypersurface (U.S. shales), as described in the machine-learning model. The median values of the EURgas from the Whangai and Waipawa formations are combined and used as input values into the model.

So, these EURgas and EURoil per well will be used as input data for production forecasting in the economic analysis. Thus, using the best case scenario, a production curve is built with all these variables in place to build up a cash-flow (revenues) model to estimate the minimum economic field size, break-even point and to test the feasibility with the oil price of US\$60 (equivalent of US\$10 per MMBtu or Gj). According to Coates et. al. (2013) the gas price scenarios for existing North Island gas market in New Zealand could vary from NZ\$4.5 (low case) to NZ\$12 (high case) per MMBtu.

Although only the best case scenario is assessed below, these are the three models scenarios that would represent the low, best, and high cases for sweet spot areas:

1. Low case covers an area of 538 km² (132942 acres – 10% of the total area) with 120 sites of 9 wells each (1 exploration, 2 appraisals, and 6 horizontal production wells (length 1000-2000m));
2. Best case covers an area of 2689 km² (664466 acres - 50% of the total area) with 597 sites of 9 wells each (1 exploration, 2 appraisals, and 6 horizontal production wells (length 1000-2000m)); and
3. High case covers an area of 4816 km² (1.19E+6 acres – 90% of the total area) with 1070 sites of 9 wells each (1 exploration, 2 appraisals, and 6 horizontal production wells (length 1000-2000m)).

However, only one site for the best-case scenario is calculated for this study, assuming that the results are contingent on their success. Each site has approximately 4.5 km² (1112 acres).

These methodologies are evaluated using net present value (NPV), return on investment (ROI) and a discount payback. Considering that the volumes used in the economic models are already risked by the geological chance of success (section 6.4.3) the Net Present Value (NPV) is equivalent to the Expected Monetary Value (EMV). This is the most commonly used decision analysis in the oil industry.

6.6.1 Estimating the exploration costs and oil and gas prices

A fictitious work program is created, as a case study, in order to assess economically the sweet spot in the Motu Block. This work program comprises: a seismic campaign and drilling exploration well costs (APPENDIX 5), while field development, production curve (APPENDIX 5), and abandonment costs are also determined. These costs are only estimated for the best case scenario for both the Whangai and Waipawa formations.

Given the East Coast Basin's hilly relief and high reservoir pressure it is assumed that a big rig is needed to drill a well in this location. Mauku-1 well (onshore north Taranaki) is the reference for the drilling costs of the vertical wells as it is a robust drilling rig used in New Zealand (Skinner et. al., 2013) and Ngapaeruru-1 well (onshore East Coast) for the drilling forecast (Smiley, 2014). For the horizontal wells the costs are derived from the costs of a horizontal well in the Vaca Muerta shale in Argentina, as this country is still developing this concept and therefore its high costs represent better the start costs for New Zealand (Bloomberg, 2017). For the seismic campaign a cost of NZ\$ 35,000 per km is applied. The CAPEX/OPEX data is derived from both public domain and private sources. For the oil and total gas (free gas and adsorbed gas) volumetric assessment, both the Whangai and Waipawa formations are combined. Seismic acquisition and OPEX are kept the same for both oil and gas, except the facilities and wells, where an additional 30% of their costs are applied because gas needs more complex facilities and deeper wells (< 4000m), as demonstrated in section 6.3. With this basic information, the best case economic scenario is evaluated.

6.7 RESULTS

Tables 6.12 to 6.19 follow, with the results of the two methodologies used to define the minimum economic field size and the feasibility using the oil price of US\$ 60. It is important to mention that only the oil price is in US\$ (using the average exchange rate of May/17 of NZ\$1.45), all the costs and revenues are in NZ\$. These tables show the results of the net present value (NPV), return on investment (ROI) and Payback, and determine the minimum economic field size is 4.5 km² per exploration block for exploring the Whangai and Waipawa formations in the Motu Block of the East Coast Basin. Note that zero NPV spreadsheets for this concept would not be valid as this is an economic attribute to calculate the breakeven of no gain no loss. The geological risk will be the same for the oil and gas scenarios as it is assumed that the geological aspects are effectively the same.

6.7.1 Oil assessment of the Whangai and Waipawa formations combined

Table 6.12 Economic evaluation for oil production from the Whangai and Waipawa formations, using EIA methodology with the best case oil price of US\$ 60. Dashed red lines outline the main economical factors.

Best Case: methodology oil 1 – EIA 60 dollars barrel

CASHFLOW - WHANGAI+WAIPAWA BEST CASE

INDEX /INDICATORS	Calc CUP	1	2	3	4	5
Production						
- Oil (bpd)		0.00	1,813.28	773.67	313.34	121.85
- Water (bpd)						
- Gas Production (mil m³/d)						
Destination of Gas (Thd m³/day)						
- Consumption						
- Loss					0.00	0.00
- Gas Sold		0.00	0.00	0.00	0.00	0.00
Prices						
- Oil (USD/bbl)		60.00	60.00	60.00	60.00	60.00
- Gas (USD/m³)		0.00	0.00	0.00	0.00	0.00
Exchange Rate (USD/NZD)		1.45	1.45	1.45	1.45	1.45
CASH FLOW (NZD)						
Revenue		0.00	57,580,776.00	24,567,797.76	9,949,958.09	3,869,428.15
- from Oil		0.00	57,580,776.00	24,567,797.76	9,949,958.09	3,869,428.15
- from Gas		0.00	0.00	0.00	0.00	0.00
Operational Costs		0.00	4,632,936.00	1,976,719.36	800,571.34	311,333.30
Operating Costs		0.00	4,632,936.00	1,976,719.36	800,571.34	311,333.30
Intervention						
Water treatment						
Oil transport						
Taxes		0.00	15,249,103.14	5,560,742.67	2,375,790.78	-388,670.03
Royalties		0.00	2,879,038.80	1,228,389.89	497,497.90	193,471.41
Others		0.00	0.00	0.00	0.00	0.00
Corporate income tax		0.00	12,370,064.34	4,332,352.78	1,878,292.88	-582,141.44
Investments		4,700,000.00	54,200,000.00	0.00	0.00	3,500,000.00
- Non-Depreciated (Abandonment)		0.00	0.00	0.00	0.00	3,500,000.00
- Depreciated (Wells, Tubes, Installation)		4,700,000.00	54,200,000.00	0.00	0.00	0.00
Residual Value		0.00	0.00	0.00	0.00	0.00
Economic Cash Flow		-4,700,000.00	-16,501,263.14	17,030,335.73	6,773,595.97	446,764.88
Accumulated Cash Flow		-4,700,000.00	-21,201,263.14	-4,170,927.41	2,602,668.56	3,049,433.44
Accumulated Cash Flow		-4,700,000.00	-21,201,263.14	-4,170,927.41	2,602,668.56	3,049,433.44

ECONOMIC INDICATORS

Net Present Value (NZD\$ Millions)	1,190,827.89
Return on Investment (% year)	9.2%
NPV/Invest. Acum (NZD\$/NZD\$)	0.02
Unit Profit (NZD\$/BOE)	1.19
NPV/Expenditure. Acum Updated (NZD\$/NZD\$)	0.01
Payback (Operation start)	3.00
Operational Unit Cost (NZD\$/BOE)	7.00
Investment Unit Cost (NZD\$/BOE)	57.93
Unit Cost Government Take (NZD\$/BOE)	20.84
Brent Breakeven (NZD\$/bbl)	58.80
Unit Cost Reserve (NZD\$/BOE)	1.08

MAIN ASSUMPTIONS

Data Base	1
Brent (US\$/bbl)	60.0
Oil Spread (NZD\$/bbl)	0.0
Vectors Concentration	Meio
Discount Rate (% a.a.)	5.00%
Royalty (%)	5%
Government Take (%)	28%
Retention fee (NZD\$/km²/year)	0.00
Block area (km²)	4.50
Unit Cost Treatment (NZD\$/m³)	0.00
Transportation (tanker) (NZD\$/m³)	0.00

Net Present Value (NPV) (NZD\$ millions) = Expected Monetary Value (EMV) 1,190,827.89

Table 6.13 Oil price breakeven for oil production from the Whangai and Waipawa formations using EIA methodology.

Best Case: methodology oil 1 – EIA ONPV

CASHFLOW - WHANGAI+WAIPAWA BEST CASE

INDEX /INDICATORS	Calc CUP	1	2	3	4	5
Production						
- Oil (bpd)		0.00	1,813.28	773.67	313.34	121.85
- Water (bpd)						
- Gas Production (mil m³/d)						
Destination of Gas (Thd m³/day)						
- Consumption						
- Loss					0.00	0.00
- Gas Sold		0.00	0.00	0.00	0.00	0.00
Prices						
- Oil (USD/bi)		58.77	58.77	58.77	58.77	58.77
- Gas (USD/m³)		0.00	0.00	0.00	0.00	0.00
Exchange Rate (USD/NZD)		1.45	1.45	1.45	1.45	1.45

CASH FLOW (NZD)

Revenue	0.00	56,396,773.46	24,062,623.34	9,745,362.45	3,789,863.18
- from Oil	0.00	56,396,773.46	24,062,623.34	9,745,362.45	3,789,863.18
- from Gas	0.00	0.00	0.00	0.00	0.00
Operational Costs	0.00	4,632,936.00	1,976,719.36	800,571.34	311,333.30
Operating Costs	0.00	4,632,936.00	1,976,719.36	800,571.34	311,333.30
Intervention					
Water treatment					
Oil transport					
Taxes	0.00	14,874,958.33	5,401,107.56	2,311,138.56	-413,812.56
Royalties	0.00	2,819,838.67	1,203,131.17	487,268.12	189,493.16
Others	0.00	0.00	0.00	0.00	0.00
Corporate income tax	0.00	12,055,119.66	4,197,976.39	1,823,870.44	-603,305.72
Investments	4,700,000.00	54,200,000.00	0.00	0.00	3,500,000.00
- Non-Depreciated (Abandonment)	0.00	0.00	0.00	0.00	3,500,000.00
- Depreciated (Wells, Tubes, Installation)	4,700,000.00	54,200,000.00	0.00	0.00	0.00
Residual Value	0.00	0.00	0.00	0.00	0.00
Economic Cash Flow	-4,700,000.00	-17,311,120.88	16,684,796.43	6,633,652.55	392,342.44
Accumulated Cash Flow	-4,700,000.00	-22,011,120.88	-5,326,324.45	1,307,328.10	1,699,670.54
Accumulated Cash Flow	-4,700,000.00	-22,011,120.88	-5,326,324.45	1,307,328.10	1,699,670.54

ECONOMIC INDICATORS

Net Present Value (NZD\$ Millions)	0.00
Return on Investment (% year)	5.0%
NPV/Invest. Acum (NZD\$/NZD\$)	0.00
Unit Profit (NZD\$/BOE)	0.00
NPV/Expenditure. Acum Updated (NZD\$/NZD\$)	0.00
Payback (Operation start)	3.00
Operational Unit Cost (NZD\$/BOE)	7.00
Investment Unit Cost (NZD\$/BOE)	57.93
Unit Cost Government Take (NZD\$/BOE)	20.28
Unit Cost Reserve (NZD\$/BOE)	0.00

MAIN ASSUMPTIONS

Data Base	-1
Brent (US\$/bbl)	58.4
Oil Spread (NZD\$/bbl)	0.0
Vectors Concentration	Meio
Discount Rate (% a.a.)	5.00%
Royalty (%)	5%
Government Take (%)	28%
Retention fee (NZD\$/km²/year)	0.00
Block area (km²)	4.50
Unit Cost Treatment (NZD\$/m³)	0.00
Transportation (tanker) (NZD\$/m³)	0.00

Table 6.14 Economic evaluation for oil production from the Whangai and Waipawa formations, using machine-learning methodology with the best case oil price of US\$ 60.

Best Case: methodology oil 2 – machine-learning 60 dolares

CASHFLOW - WHANGAI BEST CASE

INDEX / INDICATORS	1	2	3	4	5
Production					
- Oil (bpd)	0.00	2,104.11	897.75	363.59	141.40
- Water (bpd)					
- Gas Production (mil m³/d)					
Destination of Gas (Thd m³/day)					
- Consumption					
- Loss				0.00	0.00
- Gas Sold	0.00	0.00	0.00	0.00	0.00
Prices					
- Oil (USD/bbl)	60.00	60.00	60.00	60.00	60.00
- Gas (USD/m³)	0.00	0.00	0.00	0.00	0.00
Exchange Rate (USD/NZD)	1.45	1.45	1.45	1.45	1.45
CASH FLOW (NZD)					
Revenue	0.00	66,816,000.00	28,508,160.00	11,545,804.80	4,490,035.20
- from Oil	0.00	66,816,000.00	28,508,160.00	11,545,804.80	4,490,035.20
- from Gas	0.00	0.00	0.00	0.00	0.00
Operational Costs	0.00	5,376,000.00	2,293,760.00	928,972.80	361,267.20
Operating Costs	0.00	5,376,000.00	2,293,760.00	928,972.80	361,267.20
Intervention					
Water treatment					
Oil transport					
Taxes	0.00	17,959,376.00	6,717,125.76	2,844,125.93	-206,539.69
Royalties	0.00	3,340,800.00	1,425,408.00	577,290.24	224,501.76
Others	0.00	0.00	0.00	0.00	0.00
Corporate income tax	0.00	14,618,576.00	5,291,717.76	2,266,835.69	-431,041.45
Investments	4,700,000.00	54,200,000.00	0.00	0.00	3,500,000.00
- Non-Depreciated (Abandonment)	0.00	0.00	0.00	0.00	3,500,000.00
- Depreciated (Wells, Tubes, Installation)	4,700,000.00	54,200,000.00	0.00	0.00	0.00
Residual Value	0.00	0.00	0.00	0.00	0.00
Economic Cash Flow	-4,700,000.00	-10,719,376.00	19,497,274.24	7,772,706.07	835,307.69
Accumulated Cash Flow	-4,700,000.00	-15,419,376.00	4,077,898.24	11,850,604.31	12,685,912.00
Accumulated Cash Flow	-4,700,000.00	-15,419,376.00	4,077,898.24	11,850,604.31	12,685,912.00

ECONOMIC INDICATORS

Net Present Value (NZD\$ Millions)	9,692,608.01
Return on Investment (% year)	44.4%
NPV/Invest. Acum (NZD\$/NZD\$)	0.17
Unit Profit (NZD\$/BOE)	8.38
NPV/Expenditure. Acum Updated (NZD\$/NZD\$)	0.11
Payback (Operation start)	2.00
Operational Unit Cost (NZD\$/BOE)	7.00
Investment Unit Cost (NZD\$/BOE)	49.93
Unit Cost Government Take (NZD\$/BOE)	21.49
Brent Breakeven (NZD\$/bbl)	51.35
Unit Cost Reserve (NZD\$/BOE)	7.57

MAIN ASSUMPTIONS

Data Base	1
Brent (US\$/bbl)	60.0
Oil Spread (NZD\$/bbl)	0.0
Vectors Concentration	Meio
Discount Rate (% a.a.)	5.00%
Royalty (%)	5%
Government Take (%)	28%
Retention fee (NZD\$/km2/year)	0.00
Block area (km2)	4.50
Unit Cost Treatment (NZD\$/m3)	0.00
Transportation (tanker) (NZD\$/m3)	0.00

Net Present Value (NPV) (NZD\$ millions) = Expected Monetary Value (EMV)

9,692,608.01

Table 6.15 Oil price breakeven for oil production from the Whangai and Waipawa formations using machine-learning methodology.

Best Case: methodology oil 2 – machine-learning 0 NPV

CASHFLOW - WHANGAI BEST CASE

INDEX /INDICATORS	Calc CUP	1	2	3	4	5
Production						
- Oil (bpd)		0.00	2,104.11	897.75	363.59	141.40
- Water (bpd)						
- Gas Production (mil m³/d)						
Destination of Gas (Thd m³/day)						
- Consumption						
- Loss					0.00	0.00
- Gas Sold		0.00	0.00	0.00	0.00	0.00
Prices						
- Oil (USD/bi)		51.35	51.35	51.35	51.35	51.35
- Gas (USD/m³)		0.00	0.00	0.00	0.00	0.00
Exchange Rate (USD/NZD)		1.45	1.45	1.45	1.45	1.45
CASH FLOW (NZD)						
Revenue		0.00	57,178,946.09	24,396,350.33	9,880,521.88	3,842,425.18
- from Oil		0.00	57,178,946.09	24,396,350.33	9,880,521.88	3,842,425.18
- from Gas		0.00	0.00	0.00	0.00	0.00
Operational Costs		0.00	5,376,000.00	2,293,760.00	928,972.80	361,267.20
Operating Costs		0.00	5,376,000.00	2,293,760.00	928,972.80	361,267.20
Intervention						
Water treatment						
Oil transport						
Taxes		0.00	14,914,066.96	5,417,793.90	2,317,896.53	-411,184.46
Royalties		0.00	2,858,947.30	1,219,817.52	494,026.09	192,121.26
Others		0.00	0.00	0.00	0.00	0.00
Corporate income tax		0.00	12,055,119.66	4,197,976.39	1,823,870.44	-603,305.72
Investments		4,700,000.00	54,200,000.00	0.00	0.00	3,500,000.00
- Non-Depreciated (Abandonment)		0.00	0.00	0.00	0.00	3,500,000.00
- Depreciated (Wells, Tubes, Installation)		4,700,000.00	54,200,000.00	0.00	0.00	0.00
Residual Value		0.00	0.00	0.00	0.00	0.00
Economic Cash Flow		-4,700,000.00	-17,311,120.88	16,684,796.43	6,633,652.55	392,342.44
Accumulated Cash Flow		-4,700,000.00	-22,011,120.88	-5,326,324.45	1,307,328.10	1,699,670.54
Accumulated Cash Flow		-4,700,000.00	-22,011,120.88	-5,326,324.45	1,307,328.10	1,699,670.54

ECONOMIC INDICATORS	
Net Present Value (NZD\$ Millions)	0.00
Return on Investment (% year)	5.0%
NPV/Invest. Acum (NZD\$/NZD\$)	0.00
Unit Profit (NZD\$/BOE)	0.00
NPV/Expenditure. Acum Updated (NZD\$/NZD\$)	0.00
Payback (Operation start)	3.00
Operational Unit Cost (NZD\$/BOE)	7.00
Investment Unit Cost (NZD\$/BOE)	49.93
Unit Cost Government Take (NZD\$/BOE)	17.53
Unit Cost Reserve (NZD\$/BOE)	0.00
MAIN ASSUMPTIONS	
Data Base	1
Brent (NZD\$/bbl)	51.35
Oil Spread (US\$/bbl)	0.0
Vectors Concentration	Meio
Discount Rate (% a.a.)	5.00%
Royalty (%)	5%
Government Take (%)	28%
Retention fee (NZD\$/km2/year)	0.00
Block area (km2)	4.50
Unit Cost Treatment (NZD\$/m3)	0.00
Transportation (tanker) (NZD\$/m3)	0.00

6.7.2 Total gas assessment of the Whangai and Waipawa formations combined

Table 6.16 Economic evaluation for total gas production from the Whangai and Waipawa formations, using EIA methodology with the best case oil equivalent price of US\$ 60 (BOE) (US\$ 10/MMbtu).

Best Case: methodology gas 1 – EIA 60 dolares

CASH FLOW - WHANGAI + WAIPAWA GAS - BEST CASE

INDEX / INDICATORS	Calc CUP	1	2	3	4	5
Production						
- Oil (bpd)		0.00	925.02	394.67	159.84	62.16
- Water (bpd)						
- Gas Production (mil m³/d)						
Destination of Gas (Thd m³/day)						
- Consumption						
- Loss					0.00	0.00
- Gas Sold		0.00	0.00	0.00	0.00	0.00
Prices						
- Oil (USD/bbl)		60.00	60.00	60.00	60.00	60.00
- Gas (USD/m³)		0.00	0.00	0.00	0.00	0.00
Exchange Rate (USD/NZD)		1.45	1.45	1.45	1.45	1.45

CASH FLOW (NZD)

Revenue	0.00	29,373,984.00	12,532,899.84	5,075,824.44	1,973,931.72
- from Oil	0.00	29,373,984.00	12,532,899.84	5,075,824.44	1,973,931.72
- from Gas	0.00	0.00	0.00	0.00	0.00
Operational Costs	0.00	2,363,424.00	1,008,394.24	408,399.67	158,822.09
Operating Costs	0.00	2,363,424.00	1,008,394.24	408,399.67	158,822.09
Intervention					
Water treatment					
Oil transport					
Taxes	0.00	6,482,340.22	1,539,965.96	784,042.21	-1,106,274.16
Royalties	0.00	1,468,699.20	626,644.99	253,791.22	98,696.59
Others	0.00	0.00	0.00	0.00	0.00
Corporate income tax	0.00	5,013,641.02	913,320.97	530,250.99	-1,204,970.75
Investments	5,900,000.00	70,460,000.00	0.00	0.00	3,500,000.00
- Non-Depreciated (Abandonment)	0.00	0.00	0.00	0.00	3,500,000.00
- Depreciated (Wells, Tubes, Installation)	5,900,000.00	70,460,000.00	0.00	0.00	0.00
Residual Value	0.00	0.00	0.00	0.00	0.00
Economic Cash Flow	-5,900,000.00	-49,931,780.22	9,984,539.64	3,883,382.55	-578,616.21
Accumulated Cash Flow	-5,900,000.00	-55,831,780.22	-45,847,240.59	-41,963,858.03	-42,542,474.24
Accumulated Cash Flow	-5,900,000.00	-55,831,780.22	-45,847,240.59	-41,963,858.03	-42,542,474.24

ECONOMIC INDICATORS

Net Present Value (NZD\$ Millions)	-39,542,115.95
Return on Investment (% year)	#NUM!
NPV/Invest. Acum (NZD\$/NZD\$)	-0.53
Unit Profit (NZD\$/BOE)	-77.73
NPV/Expenditure. Acum Updated (NZD\$/NZD\$)	-0.47
Payback (Operation start)	-
Operational Unit Cost (NZD\$/BOE)	7.00
Investment Unit Cost (NZD\$/BOE)	145.57
Unit Cost Government Take (NZD\$/BOE)	14.08
Brent Breakeven (NZD\$/bbl)	140.00
Unit Cost Reserve (NZD\$/BOE)	-70.27

MAIN ASSUMPTIONS

Data Base	1
Brent (US\$/bbl)	60.0
Oil Spread (NZD\$/bbl)	0.0
Vectors Concentration	Meio
Discount Rate (% a.a.)	5.00%
Royalty (%)	5%
Government Take (%)	28%
Retention fee (NZD\$/km²/year)	0.00
Block area (km²)	4.50
Unit Cost Treatment (NZD\$/m³)	0.00
Transportation (tanker) (NZD\$/m³)	0.00

Net Present Value (NPV) (NZD\$ millions) = Expected Monetary Value (EMV) -39,542,115.95

Table 6.17 Total gas price breakeven (BOE) for gas production from the Whangai and Waipawa formations using EIA methodology.

Best Case: methodology gas 1 – EIA 0 NPV

CASH FLOW - WHANGAI + WAIPAWA GAS - BEST CASE

INDEX / INDICATORS	Calc CUP	1	2	3	4	5
Production						
- Oil (bpd)		0.00	925.02	394.67	159.84	62.16
- Water (bpd)						
- Gas Production (mil m³/d)						
Destination of Gas (Thd m³/day)						
- Consumption						
- Loss					0.00	0.00
- Gas Sold		0.00	0.00	0.00	0.00	0.00
Prices						
- Oil (USD/bbl)		140.31	140.31	140.31	140.31	140.31
- Gas (USD/m³)		0.00	0.00	0.00	0.00	0.00
Exchange Rate (USD/NZD)		1.45	1.45	1.45	1.45	1.45

CASH FLOW (NZD)

Revenue	0.00	68,689,460.58	29,307,503.18	11,869,538.79	4,615,931.75
- from Oil	0.00	68,689,460.58	29,307,503.18	11,869,538.79	4,615,931.75
- from Gas	0.00	0.00	0.00	0.00	0.00
Operational Costs	0.00	2,363,424.00	1,008,394.24	408,399.67	158,822.09
Operating Costs	0.00	2,363,424.00	1,008,394.24	408,399.67	158,822.09
Intervention					
Water treatment					
Oil transport					
Taxes	0.00	18,906,030.82	6,840,740.62	2,930,855.95	-271,402.15
Royalties	0.00	3,434,473.03	1,465,375.16	593,476.94	230,796.59
Others	0.00	0.00	0.00	0.00	0.00
Corporate income tax	0.00	15,471,557.79	5,375,365.46	2,337,379.01	-502,198.74
Investments	5,900,000.00	70,460,000.00	0.00	0.00	3,500,000.00
- Non-Depreciated (Abandonment)	0.00	0.00	0.00	0.00	3,500,000.00
- Depreciated (Wells, Tubes, Installation)	5,900,000.00	70,460,000.00	0.00	0.00	0.00
Residual Value	0.00	0.00	0.00	0.00	0.00
Economic Cash Flow	-5,900,000.00	-23,039,994.25	21,458,368.32	8,530,283.17	1,228,511.81
Accumulated Cash Flow	-5,900,000.00	-28,939,994.25	-7,481,625.92	1,048,657.25	2,277,169.06
Accumulated Cash Flow	-5,900,000.00	-28,939,994.25	-7,481,625.92	1,048,657.25	2,277,169.06

ECONOMIC INDICATORS

Net Present Value (NZD\$ Millions)	-0.00
Return on Investment (% year)	5.0%
NPV/Invest. Acum (NZD\$/NZD\$)	-0.00
Unit Profit (NZD\$/BOE)	-0.00
NPV/Expenditure. Acum Updated (NZD\$/NZD\$)	-0.00
Payback (Operation start)	3.00
Operational Unit Cost (NZD\$/BOE)	7.00
Investment Unit Cost (NZD\$/BOE)	145.57
Unit Cost Government Take (NZD\$/BOE)	50.87
Unit Cost Reserve (NZD\$/BOE)	-0.00

MAIN ASSUMPTIONS

Data Base	1
Brent (US\$/bbl)	140.3
Oil Spread (NZD\$/bbl)	0.0
Vectors Concentration	Meio
Discount Rate (% a.a.)	5.00%
Royalty (%)	5%
Government Take (%)	28%
Retention fee (NZD\$/km2/year)	0.00
Block area (km2)	4.50
Unit Cost Treatment (NZD\$/m3)	0.00
Transportation (tanker) (NZD\$/m3)	0.00

Table 6.18 Economic evaluation for total gas production from the Whangai and Waipawa formations, using machine-learning methodology with the best case oil price of US\$ 60 (BOE) (US\$ 10/MMbtu).

Best Case: methodology gas 2 – machine-learning 60 dolares

CASH FLOW - WHANGAI + WAIPAWA GAS - BEST CASE

INDEX / INDICATORS	Calc CUP	1	2	3	4	5
Production						
- Oil (bpd)		0.00	8,409.84	3,588.20	1,453.22	565.14
- Water (bpd)						
- Gas Production (mil m³/d)						
Destination of Gas (Thd m³/day)						
- Consumption						
- Loss					0.00	0.00
- Gas Sold		0.00	0.00	0.00	0.00	0.00
Prices						
- Oil (USD/bbl)		60.00	60.00	60.00	60.00	60.00
- Gas (USD/m³)		0.00	0.00	0.00	0.00	0.00
Exchange Rate (USD/NZD)		1.45	1.45	1.45	1.45	1.45

CASH FLOW (NZD)

Revenue	0.00	267,054,364.80	113,943,195.65	46,146,994.24	17,946,053.31
- from Oil	0.00	267,054,364.80	113,943,195.65	46,146,994.24	17,946,053.31
- from Gas	0.00	0.00	0.00	0.00	0.00
Operational Costs	0.00	21,487,132.80	9,167,843.33	3,712,976.55	1,443,935.32
Operating Costs	0.00	21,487,132.80	9,167,843.33	3,712,976.55	1,443,935.32
Intervention					
Water treatment					
Oil transport					
Taxes	0.00	76,234,702.09	31,300,973.69	12,837,250.35	3,581,084.56
Royalties	0.00	13,352,718.24	5,697,159.78	2,307,349.71	897,302.67
Others	0.00	0.00	0.00	0.00	0.00
Corporate income tax	0.00	62,881,983.85	25,603,813.91	10,529,900.63	2,683,781.89
Investments	5,900,000.00	70,460,000.00	0.00	0.00	3,500,000.00
- Non-Depreciated (Abandonment)	0.00	0.00	0.00	0.00	3,500,000.00
- Depreciated (Wells, Tubes, Installation)	5,900,000.00	70,460,000.00	0.00	0.00	0.00
Residual Value	0.00	0.00	0.00	0.00	0.00
Economic Cash Flow	-5,900,000.00	98,872,529.91	73,474,378.63	29,596,767.34	9,421,033.43
Accumulated Cash Flow	-5,900,000.00	92,972,529.91	166,446,908.53	196,043,675.88	205,464,709.31
Accumulated Cash Flow	-5,900,000.00	92,972,529.91	166,446,908.53	196,043,675.88	205,464,709.31

ECONOMIC INDICATORS

Net Present Value (NZD\$ Millions)	179,262,142.35
Return on Investment (% year)	1648.7%
NPV/Invest. Acum (NZD\$/NZD\$)	2.42
Unit Profit (NZD\$/BOE)	38.76
NPV/Expenditure. Acum Updated (NZD\$/NZD\$)	0.82
Payback (Operation start)	1.00
Operational Unit Cost (NZD\$/BOE)	7.00
Investment Unit Cost (NZD\$/BOE)	16.01
Unit Cost Government Take (NZD\$/BOE)	24.27
Brent Breakeven (NZD\$/bbl)	19.96
Unit Cost Reserve (NZD\$/BOE)	35.04

MAIN ASSUMPTIONS

Data Base	1
Brent (US\$/bbl)	60.0
Oil Spread (NZD\$/bbl)	0.0
Vectors Concentration	Meio
Discount Rate (% a.a.)	5.00%
Royalty (%)	5%
Government Take (%)	28%
Retention fee (NZD\$/km2/year)	0.00
Block area (km2)	4.50
Unit Cost Treatment (NZD\$/m3)	0.00
Transportation (tanker) (NZD\$/m3)	0.00

Net Present Value (NPV) (NZD\$ millions) = Expected Monetary Value (EMV) 179,262,142.35

Table 6.19 Total gas price breakeven (BOE) for gas production from the Whangai and Waipawa formations using machine-learning methodology.

Best Case: methodology gas 2 – machine-learning 0 NPV

CASH FLOW - WHANGAI + WAIPAWA GAS - BEST CASE

INDEX / INDICATORS	1	2	3	4	5
Production					
- Oil (bpd)	0.00	8,409.84	3,588.20	1,453.22	565.14
- Water (bpd)					
- Gas Production (mil m³/d)					
Destination of Gas (Thd m³/day)					
- Consumption					
- Loss				0.00	0.00
- Gas Sold	0.00	0.00	0.00	0.00	0.00
Prices					
- Oil (USD/bbl)	19.96	19.96	19.96	19.96	19.96
- Gas (USD/m³)	0.00	0.00	0.00	0.00	0.00
Exchange Rate (USD/NZD)	1.45	1.45	1.45	1.45	1.45

CASH FLOW (NZD)

Revenue	0.00	88,819,680.37	37,896,396.96	15,348,040.77	5,968,682.52
- from Oil	0.00	88,819,680.37	37,896,396.96	15,348,040.77	5,968,682.52
- from Gas	0.00	0.00	0.00	0.00	0.00
Operational Costs	0.00	21,487,132.80	9,167,843.33	3,712,976.55	1,443,935.32
Operating Costs	0.00	21,487,132.80	9,167,843.33	3,712,976.55	1,443,935.32
Intervention					
Water treatment					
Oil transport					
Taxes	0.00	19,912,541.81	7,270,185.31	3,104,781.05	-203,764.61
Royalties	0.00	4,440,984.02	1,894,819.85	767,402.04	298,434.13
Others	0.00	0.00	0.00	0.00	0.00
Corporate income tax	0.00	15,471,557.79	5,375,365.46	2,337,379.01	-502,198.74
Investments	5,900,000.00	70,460,000.00	0.00	0.00	3,500,000.00
- Non-Depreciated (Abandonment)	0.00	0.00	0.00	0.00	3,500,000.00
- Depreciated (Wells, Tubes, Installation)	5,900,000.00	70,460,000.00	0.00	0.00	0.00
Residual Value	0.00	0.00	0.00	0.00	0.00
Economic Cash Flow	-5,900,000.00	-23,039,994.25	21,458,368.32	8,530,283.17	1,228,511.81
Accumulated Cash Flow	-5,900,000.00	-28,939,994.25	-7,481,625.92	1,048,657.25	2,277,169.06
Accumulated Cash Flow	-5,900,000.00	-28,939,994.25	-7,481,625.92	1,048,657.25	2,277,169.06

ECONOMIC INDICATORS

Net Present Value (NZD\$ Millions)	0.00
Return on Investment (% year)	5.0%
NPV/Invest. Acum (NZD\$/NZD\$)	0.00
Unit Profit (NZD\$/BOE)	0.00
NPV/Expenditure. Acum Updated (NZD\$/NZD\$)	0.00
Payback (Operation start)	3.00
Operational Unit Cost (NZD\$/BOE)	7.00
Investment Unit Cost (NZD\$/BOE)	16.01
Unit Cost Government Take (NZD\$/BOE)	5.92
Unit Cost Reserve (NZD\$/BOE)	0.00

MAIN ASSUMPTIONS

Data Base	1
Brent (US\$/bbl)	20.0
Oil Spread (NZD\$/bbl)	0.0
Vectors Concentration	Melo
Discount Rate (% a.a.)	5.00%
Royalty (%)	5%
Government Take (%)	28%
Retention fee (NZD\$/km²/year)	0.00
Block area (km²)	4.50
Unit Cost Treatment (NZD\$/m³)	0.00
Transportation (tanker) (NZD\$/m³)	0.00

Based on the results of the economic model using the assessment of the Energy Information Administration (EIA) methodology, oil production, from the Whangai and Waipawa formations combined, would be feasible with an oil price at US\$ 60. The net profitability would be NZ\$ 1,190,828, the return on investment 9.2%, and payback in three years after the operation starts. The breakeven of US\$ 58.77 for the oil price is determined for an area of 4.5 km². If the oil price drops to less than US\$ 58.77 there are no gains in this scenario. However, if the machine-learning assessment is applied, oil production would be feasible with an oil price at US\$ 60. The net profitability would be NZ\$ 9,692,608, the return on investment 44.4%, and payback in two years after the operation starts. The breakeven of US\$ 51.35 for the oil price is determined for an area of 4.5 km².

On the other hand, based on the results of the economic model using the assessment of the Energy Information Administration (EIA) methodology, total gas production, from the Whangai and Waipawa formations combined, would not be feasible with an oil price of US\$ 60. A financial loss of NZ\$ 39,542,117 would be suffered. The oil price should rise to US\$ 140.31 to zero the NPV (breakeven). However, if the machine-learning assessment is applied, total gas production, from the Whangai and Waipawa formations combined, would be feasible with an oil price at US\$ 60. The net profitability would be NZ\$ 179,262,142, the return on investment would be 1648% and payback in one year. The breakeven of US\$ 19.96 for the oil price is determined for an area of 4.5 km².

Beside the gas production using the EIA methodology, all the other scenarios have shown that it is feasible to explore for oil and gas in the Whangai and Waipawa formations. These results indicate that an exploration block with a minimum size of 4.5 km² would be economic for the East Coast Basin, assuming the premises described here and easy access to drill sites.

While geological and engineering factors help make a project feasible, non-geological factors also have to be evaluated. Given that, a discussion of the non-geological factors affecting shale gas production in the East Coast Basin is covered in Chapter 7. These variables can help to increase the successful rate of developing the unconventional industry as well as decrease the Capital Expenditure (CAPEX) and Operational Cost (OPEX) of potential projects that could take place in this area.

7. NON-GEOLOGICAL FACTORS

7.1 INTRODUCTION

This chapter presents the non-geological factors that could affect shale exploration in a positive or negative way in the East Coast Basin. It is important to describe even briefly the water supply, infrastructure and environmental issues we could face in this basin. The importance and understanding of the oil and gas market for New Zealand must also be considered. These subjects are not the focus of this thesis, but still important consideration in respect of shale oil and gas development needs. Some sections of this chapter provide only bullet-points, although the importance of these topics is acknowledged. No deeper analyses are carried out; as they fall outside the primary scope of this thesis.

7.2 WATER SUPPLY

7.2.1 Water Sourcing Issues for the Natural Gas Industry

Typically, hydraulic fracture operations use three to five million gallons (18927 m³) of water per well (ALL Consulting and GWPC, 2012), though exact volumes may vary significantly from well to well. But while drilling and stimulating shale oil and gas wells may demand high volumes of water, the total water resource used in shale oil and gas basin areas for non-fracture purposes is far larger. The Marcellus Shale in New York, Pennsylvania and West Virginia provides a good example. At peak drilling activity, estimates formulated by ALL Consulting (2012) put the maximum water usage in the Marcellus at 650 million barrels per year (assuming five million gallons of water per well, and at peak production in each state). This is less than 0.8 percent of the 85 billion barrels used per year in the area for all recreational, industrial, domestic, agricultural and other purposes (Arthur, 2010). Freshwater consumption for electricity in the Susquehanna River Basin on its own is nearly 150 million gallons (567811 m³) per day, while expected total demand for peak Marcellus Shale activity in the same region is only 8.4 million gallons (31797 m³) a day. Golf courses in the Marcellus Shale require between 100,000 and 1,000,000 gallons (378 and 3785 m³, respectively) of water per week. Similarly, municipalities, manufacturing and agriculture use far more water than the volumes required for shale gas development, which is small in comparison (Alliance for Water Efficiency, 2009). Of the total freshwater consumption in the U.S., total estimated water consumption for all completed shale wells in 2011 was 0.3 percent (Jenkins, 2013). The Professional Golf Association reports that it uses 0.5 percent of total freshwater consumption.

Per annum, Texas homeowners use 18 times the amount of water used by fracking when watering their lawns, while agriculture uses 243 times more water than fracking (Jenkins, 2013). According to Time magazine, thermoelectric generation (using heat to make steam, and including coal, natural gas and nuclear technologies), accounts for 40 percent of freshwater withdrawals in the U.S.

While fracking operators require water for drilling and hydraulic activities which take relatively short periods of time, these activities occur year-round. Municipal water supplies and industries (such as power generation) as well as recreation activities and aquatic life may be affected if water is withdrawn during periods of low stream flow. Operators may consider making withdrawals during periods of high stream flow and storing the water to use during times of low stream flow or drought. Similarly, regions may have abundant water supplies but wells might not be near large streams or lakes. To protect all given water sources, operators might consider making withdrawals from more than one nearby source, or even consider overland pipe supply from adequate sources of water further afield.

Evaluating water needs requires consideration of location of need, seasonal timing, location of available water, and water withdrawal regulation. Although shale gas withdrawals may be small on a regional level, withdrawals must be carefully managed to maintain the overall ecological wellbeing of the water source and consider other industrial and recreational uses. Operators should minimize transportation costs by acquiring permits to withdraw water as close as possible to development areas. Hence, groundwater and surface water sources closest to well sites are desirable. Operators should consider several water sources to meet their needs and minimize their impacts on the environment.

Regulations and permitting procedures are a major factor for consideration in planning water withdrawals. Shale gas operators must be highly aware of the specific permitting requirements for each location. Water withdrawal is regulated by a combination of state and interstate bodies, each reflecting the needs of individual states and groups, while hydrographic basin committees have strict requirements around the seasonality of permit table withdrawals for water bodies near development sites.

7.2.2 Hydraulic Fracturing: Staying Safe in Times of Water scarcity

This is a question commonly posed when we talk about water supply for fracking activities. Given that, a few points must be addressed when this subject arises:

In accordance with Lockard (2014), one of the criticisms imposed against hydraulic fracturing, particularly during recent periods of drought, is the amount of water used in the process. However, energy companies claim they are seeking ways to reduce water use during hydraulic fracturing, even as research shows more water is used in other activities. Some water solutions have been put in practice, listed below:

1. Hospital disinfectant, a chemical product designed to kill bacteria in hospitals, is gaining traction in the oil and gas industry as a solution for treating hydraulic fracturing water;
2. Fracking with CO₂ to replace water;
3. Produced water treatment, a technology originally developed to harvest algae for biofuels production, has proven effective in treating produced water from oil and gas wells;

Many large shale reservoirs are found in arid or semi-arid areas. And yet while many areas prone to drought have long been naturally so, there is a common perception that oil and gas companies compound drought by accessing water from shallow reservoirs supplying water for drinking and agricultural use. This is not completely accurate. In some parts of Texas, for example, water used for fracking is often taken from deeper wells whose water is not suitable for drinking or agriculture due to its high salinity.

More fracking water is now being recycled than at any time in the past, and conservation efforts have been stepped up. This is related to the learning curve. Figure 7.1, shows schematic water use:

Figure 7.1 Schematic water use for hydraulic fracturing.

Modified from (<http://www.dow.com/en-us/water-and-process-solutions/markets/oil-and-gas/sustainable-water-management>).

7.2.3 New Zealand East Coast Aquifers

When we talk about hydraulic fracking the first things that come to the public's mind are: "a lot of water use", "pollutes all aquifers", "waste of water". However, the first thing that comes to an exploration manager's mind is: "is there enough water available around the area I am exploring? Or do I have to import water from somewhere else?" In order to answer these questions, it is important to understand the water availability in the region that might be explored, in this case the East Coast Basin.

GNS Science, has reviewed information on known aquifers on the East Coast Basin of the North Island from East Cape to Wairarapa, as summarised in the following sections.

The locations of known aquifers and their sub-division by horizontal and vertical extent can be seen in Figure 7.2 White and Reeves (2002). It is important to highlight that the small aquifers have limited information while major aquifers have long been identified and their horizontal boundaries relatively well established. The vertical extent is related to three types of data: lithology, hydraulic properties (particularly hydraulic conductivity), and water quality (particularly salinity).

Figure 7.2 Aquifers, blue outlines, known along the North Island of New Zealand with small modifications (White and Reeves, 2002).

The East Coast has been subdivided into three known aquifer regions: Gisborne, Hawke's Bay and Manawatu-Wanganui (Table 7.1). The characteristics of each will be described briefly below.

Table 7.1 The main known aquifers along the East Coast Basin. The numbers are related to the aquifers location (Figure 7.2).

Region	Name		Number
Gisborne			
	Waipaoa Valley		
		Te Hapara sand	48
		Shallow fluvial	49
		Waipaoa gravel	50
		Makauri gravel	51
		Matokitoki gravel	52
	Waiapu and Tolaga Bay flats		53
Hawke's Bay			
	Northern Coastal		
		Wairoa Valley	58
		Nukaha Coastal	59
		Nukaha limestone	60
		Mahia sand	61
		Mahia alluvium	62
		Mahia	63
	Esk Valley		64
	Heretaunga Plains		65
	Poukawa Basin		66
	Papanui Stream Valley		67
	Ruataniwha Plains		68
Manawatu-Wanganui (Horizons)			
	Taraua		74

7.2.3.1 Gisborne Region

This region has 17 individual aquifer areas, the horizontal extent can be seen in Figure 7.3. It can be noticed that most of the wells are located in the largest area of the aquifer. This is related mainly to Waipaoa Valley. The vertical extent of the Waipaoa Valley aquifer, the depth, is best indicated by a compilation of lithology data in well logs, data on screened intervals, total depths of wells and data on groundwater quality. There is lots of information available for this aquifer but not as much for the smaller ones. What is known regarding the lithology of the Waipaoa Valley can be extrapolated from the circumstances of the smaller aquifers. The Gisborne region aquifers are composed of relatively shallow sedimentary basins in-filled with Quaternary-age terrestrial and marine sediments, including sands and gravels

which form the most productive portions of the aquifers (White, et.al. 2012). This region would be the potential water supply for the Motu block.

Figure 7.3 Gisborne region known aquifers and wells (White, et al. 2012). Outline of the Motu Block and the potential water supply aquifers.

Table 7.2 shows the summary of total wells drilled as well as depths of the main known aquifers along Gisborne Region. (BGL - below ground water).

Table 7.2 Well depth statistics for Gisborne region.

Region/ Aquifer	Number	Statistic (m BGL)				Count	Total	%
		Min	Median	Mean	Max			
Waiapu, Uawa, and Waiomoko	5,8 and 10	1.2	6	9	34	67	238	28
Waipaoa Valley	11-17	0.5	11	22	207	1,141	3,818	30
Exploratory or test wells	-	100	154	177	300	12	12	100
Unzoned	-	1.5	11	19	100	90	359	25

7.2.3.2 Hawke's Bay Region

This region has eight individual aquifer areas, five along the coast and three inland. The locations of the wells and the aquifers are shown in Figure 7.4.

Figure 7.4 Hawke's Bay Region known aquifers and wells (Gordon, et.al., 2012).

The vertical extent of northern coastal aquifers in the Hawke's Bay region is limited. Based on the well data, these aquifers seem relatively shallow with median depths in the 9-31m range BGL. They reach their maximum depth around 36-100 m BGL (Table 7.3).

Table 7.3 Summary of total wells drilled as well as the depths of the main known aquifers. (BGL – below ground water).

Region/ Aquifer	Number	Screen depth (m BGL)				Count	Total	%
		Min	Median	Mean	Max			
Mahia	18	3	9	22	91	105	123	85
Nuhaka	19	8	16	25	62	15	19	79
Wairoa Valley	20	3	26	30	90	28	29	97
Esk Valley	21	2	9	9	36	176	194	91
Heretaunga Plains (Unconfined)	22	5	19	21	79	592	652	91
Heretaunga Plains (Confined)	22	2	36	37	251	3069	3651	84
Poukawa Basin	23	7	61	68	272	76	85	89
Otane	24	3	31	34	100	64	74	86
Ruataniwha Plains	25	1	39	47	342	536	584	92
Exploratory	-	937	1704	1717	2316	14	14	100
Unzoned	-	1	20	32	272	1845	2053	90

7.2.3.2.1 Northern Coastal Aquifers

Few exploratory oil and gas wells have been drilled around this region. The results of these wells show low permeability materials, with shallow aquifers suitable for small water supplies only in some. Cameron (1997) presents some results for pump tests run in one well each in the Mahia and Wairoa aquifer areas, respectively.

The Mahia test was located in the shallow sand and alluvium underlain by mudstone and/or sandstone and the result was a transmissivity of 792 m²/day. Saturated aquifers thickness was not stated, but could be as much as 13m. In this case, hydraulic conductivity would be 61m/d. On the other hand, for the Wairoa Valley aquifer, the pump test in shallow confined gravels indicated a transmissivity of 370 m²/day and storativity of 3.5 x 10⁻³. Saturated aquifer thickness was not stated but it could be around 12m. In this case, hydraulic conductivity would be 31m/d.

These are the main aquifers along the East Coast Basin that could serve as a starting point for the water supply assessment. It is important to notice that the depths of these aquifers are relatively shallow compared to the average drilling targets of Whangai and Waipawa

formations, which are expected to be at least 1500 m below the ground, thus, decreasing the concern around aquifer contamination.

7.2.4 Rivers and Lakes

The management of catchments (rivers and streams, wetlands, freshwater, groundwater and coastline) in New Zealand are looked after by the Regional Council for an area. Given that, as it would take too much time to compile all the data, region by region, and this is not the scope of this thesis, Figure 7.5 shows the occurrence of the water availability via rivers and lakes along the studied area. For further information for the Gisborne region for example see: <http://www.gdc.govt.nz/water/>.

Based on the rivers, lakes and aquifers availability, water supply is not expect to be an issue for the East Coast Basin.

Figure 7.5 Map showing the occurrence of rivers and lakes along the North Island, dashed line marking the western limited of the studied area.

7.3 INFRASTRUCTURE

In order to decrease the CAPEX (capital expenditure) and OPEX (operational cost) it is important to have access to infrastructure. Because the focus of this thesis is the onshore East

Coast Basin, it is relevant to understand at least the main available oil /gas pipelines and roading (Figure 7.6).

New Zealand has a network of high pressure transmission pipelines and low pressure distribution pipelines. There are two open access pipeline systems:

1. The 308 km Maui pipeline (average diameter of 750mm)
2. The 2,220 km Vector pipeline system (mostly from 100 to 200 mm diameter).

Open access to the gas transmission pipeline started in the mid-1990s when the Natural Gas Corporation of New Zealand Limited (NGC), a gas wholesaler, now Vector, introduced an open access regime for its transmission system. Access to the Maui system was introduced in 2005 and is now operated by Firstgas. The benefit of natural gas pipelines is in large economies of scale, allowing the unit cost of transporting gas to decrease as volumes increase. This means that it is generally not feasible for the companies to provide alternative transmission pipeline services, although there is some local by-passing. Therefore, gas transmission pipelines tend to be natural monopolies. The East Coast Basin has access only to the Vector Pipeline System.

Also, the North Island has a widespread and well-maintained road system. If liquid hydrocarbons are discovered and produced onshore, they can be trucked or railed to any potential market/port in the country. Even though New Zealand is considered a frontier country for oil and gas exploration, except for the well-established Taranaki Basin, the level of basic infrastructure already in place should not considerably increase the Capital Expenditure (CAPEX) and the Operational Cost (OPEX) of any project to explore and produce hydrocarbons in the East Coast Basin.

Figure 7.6 Gas used by region and the two open access gas systems (Energy data file, gas registry, 2012), the main roads and cities, and the railway lines of the North Island of New Zealand.

7.4 ENVIRONMENTAL FACTORS

Environmental factors are a broad and controversial subject and are not the main focus of this thesis. However, the basic issues are described below.

7.4.1 The Environmentalist Onslaught – The myths and facts

While the U.S. Environmental Protection Agency (EPA) has reviewed hydraulic fracturing several times, and cleared the process in 2004, Congress required a new study be undertaken by the EPA in 2010. This study coincided with increasing media pressure, from Facebook to privately-funded documentaries such as *Gasland*, to stories running in the national media, such as the *NY Times*, all keen to run with popular anti-fracking sentiment. Claims included that drinking water aquifers risked contamination and that radioactivity could spread, while others questioned the need for fracking in the first place. Outside of the U.S., regulatory bodies have reacted with a range of actions. The U.K. government has endorsed fracking; the French have made it illegal; while Germany has limited fracking to depths less than 3000m. This is a ‘safety distance’ intended to guarantee against over-propagation and the mixing of fracking- and ground-water.

While shale gas activity has increased, its effects may not be as bad as claimed. Figure 7.7 shows a composite schematic of fracture treatments in the Marcellus Shale. Fracture treatments are plotted with a red line representing mid-depth, the point of origin of fractures. The shallowest and the deepest points are both plotted. The blue at the top plots the deepest groundwater. The fracture treatments are well-confined, at least a 4000 feet below groundwater, meaning there is little chance of upwardly spreading a fracture into it.

Figure 7.7 Fracture height and groundwater aquifers, mapped in the Marcellus shale region. (http://www.halliburton.com/public/pe/contents/Papers_and_Articles/web/A_through_P/AOGR%20Article-%20Data%20Prove%20Safety%20of%20Frac.pdf)

Shale gas developments are complex, requiring effective regulation. Ineffective or corrupt regulation not only puts local interest groups at risk, but represents a danger for oil and gas companies themselves. Given that these companies' activities attract negative publicity around environmental impacts, economic transparency, and human rights, a robust regulatory system is essential for companies wishing to conduct good business.

7.4.2 General Environmental Issues

These are the ten basic points discussed in this section:

1. New Development Areas/Urban;
2. Well Site Selection;
3. Traffic;
4. Wildlife;
5. Noise;
6. Seismicity;
7. Air Emissions;
8. Hydraulic Fracturing;
9. Water Sourcing /Management;
10. Sand Disposal.

7.4.2.1 New Development Areas/Urban

1. General feeling of distrust of “Big Oil”;
2. Fear and lack of knowledge creates trepidation among mineral and nonmineral owners;
3. Education of public takes time;
4. Lack of infrastructure;
5. Misinformation abounds;
6. Scrutiny and greater concern because of proximity to populace;
7. Local government ordinances:
 - a. Restrict operation times;
 - b. Reduced noise levels;
 - c. Lighting restrictions;
 - d. New setbacks;
 - e. Restrict truck traffic.

- Issues raised by fracking activity will vary from place to place and community to community, depending on how familiar local interest groups are with such activity, including the impacts, benefits and trade-offs. Less experienced communities may bring a range of new sensitivities to the activity as well.

- Leasing contracts may be highly contentious socially and legally. Tensions and litigation may follow, for example, where landowners have surface rights but no royalties from mineral ownership or extraction. Guaranteeing suitable compensation for owners might ease tension and improve public relations.

- The industry requires workers with specific skills. With new workers arriving to take up available jobs, local communities are affected in a number of ways. There is an economic benefit with new arrivals putting money into the local economy, but on the other hand, for example, house prices may climb. Environmental degradation, real or perceived, including increased risk to groundwater, may negatively affect property values (Gopalakrishnan, 2012). According to Gibbons et. al. (2016), residents within 3km of a shale gas well might expect a fall in house prices of 24%.

- Temporary workers can also increase pressure on local services, generating rising costs through greater demand for health services, social welfare, police and fire services, and schools (Guidance note for financiers, 2013).
- In more remote communities, new workers can not only disrupt but completely alter ways of life with lasting ramifications. Landscapes can be changed and the local character lost, in turn affecting local economies tied to tourism, conservation and the natural environment.
- In some U.S. regions, oil and gas facilities are prohibited within 300m of homes, schools, hospitals and other public buildings, as well as freshwater wells (Mall, 2009). The Natural Resources Defense Council (NRDC) has launched the Community Fracking Defense Project to help communities access legal protections and policy advice concerned with the implications of fracturing in their own communities.

7.4.2.2 Well Site Selection

1. Larger surface disturbance;
2. Increased activities at location;
3. Increased traffic;
4. Sediment and erosion increase;
5. Ground compaction leading to increased storm water.

7.4.2.3 Traffic

1. Road damage;
 2. Traffic restrictions imposed by ordinances;
 3. Road repair bonds \$50,000 to \$100,000 per mile;
 4. Road use agreements.
- The high volumes of water and chemicals required for hydraulic fracturing also have implications for transport, storage and truck traffic around a site.
 - It takes some 200 trucks to transport one million gallons (3,785 m³) of water, and hydraulic fracturing can take up to 8 million gallons (30,283 m³) per well. The wastewater must also then be removed. In addition, some 30-45 semi-trucks are needed to move and assemble a rig that can drill down 1000 feet/300m, alongside further trucks to carry sand, waste, other equipment and heavy machinery.

- Such effects associated with traffic – as well as increased congestion, noise, dust, and risk of accidents – can upset local communities and increase their costs in maintaining infrastructure. Even though companies may reduce their footprint and costs by drilling multiple wells from single pads, such activity brings more effects, such as emissions and truck traffic to and from sites (Guidance note for financiers, 2013).

7.4.2.4 Wildlife

1. Habitat Loss;
2. Habitat Fragmentation;
3. Disrupted wildlife patterns from increased traffic and noise;
4. Utility corridors invite unwanted off-road traffic.

7.4.2.5 Noise

5. Noise restrictions may be required by local ordinances or because of wildlife issues;
6. Sound blankets and barriers are often used to mitigate issues in sensitive areas.

7.4.2.6 Water Sourcing /Management

1. Options available to meet water needs for drilling and fracturing;
2. Surface Water;
3. Groundwater;
4. Municipal Water;
5. Industrial Water;
6. Recycled Produced Water;
7. Collected Water;
8. Private Water Purchases.

7.4.2.7 The gas-coal equation and implications for climate change

- Gas is widely seen as a ‘transition fuel’ to a lower carbon economy, because burning natural gas emits 40-50% less carbon dioxide per megawatt than burning coal (IGU, 2010). Shale gas is therefore seen in some quarters as having positive effects in terms of climate change since it represents a shift from coal-generated power.

- The U.S. and China are the world's largest emitters of greenhouse gases. A significant portion of their emissions come from coal. Thus, for both countries to develop their vast shale reserves may be seen as a positive step away from carbon-intensive coal industries (Boden et al., 2012).
- The International Energy Agency (IEA, 2012) argues that while climate change demands the development of renewable energy, careful policy is required to prevent investments in renewables producing a 'dash for gas'. In 2012 the IEA found that for global warming to be limited to 2°C requires that at least two-thirds of proven hydrocarbon reserves remain untouched until 2050 ("World Energy Outlook", 2012).

7.4.2.7.1 Fugitive methane

Although shale oil and gas holds many advantages of coal use, methane release presents a significant issue to address.

- In respect of global warming, based on the EPA's mid-range methane leakage rates, gas performs better than coal over 100 years, while over a 20 year timeframe the climate impacts of gas and coal are similar (EPA, 2017).
- The data on methane leakage rates from shale gas developments is currently limited.
- Although methane breaks down in the atmosphere far more quickly than CO₂, its warming effects are stronger over its lifetime. Some have found that methane leakage rates must be kept below 2% if substituting gas for coal is to be effective in mitigating the effects of climate change (Wigley, 2011).
- In 2007 the Intergovernmental Panel on Climate Change released its fourth Assessment Report. It suggested that methane has 72 times the global warming potential of CO₂ over a 20 year period; over 100 years, methane has 24 times the global warming potential of CO₂.
- Fortunately, low-cost technologies designed to catch methane throughout gas production and distribution are available, while current research is focused on addressing the data deficit in methane leakage rates in shale gas production.
- Meanwhile the Global Methane Initiative and UNEP's Climate & Clean Air Coalition on Short-lived Climate Pollutants continue to raise awareness, spread understanding, develop best practice and improve the ability to reduce methane emissions.

7.4.2.8 Concerns about water use, chemicals & contamination

- The migration of the large volumes of water and chemicals injected deep underground in the course of fracking is not completely predictable. Conventional (i.e. non-shale) wells with a single fracture require around 50,000 to 100,000 gallons (189 to 378 m³) of fluid; a horizontal shale well uses from one to eight million gallons (3785 to 30283 m³) of water and thousands more gallons of chemicals (Guidance note for financiers, 2013).
- Companies may try to handle these figures in real, contextual terms. For example, ExxonMobil says that it requires the equivalent of three to six Olympic swimming pools (or three to six times 2,500 cubic metres) of freshwater to drill and frack a standard horizontal well. And yet the numbers themselves are less important than the effects of the water stress itself. These impacts vary from country to country and even from community to community (Guidance note for financiers, 2013).
- The volumes of water (95%) and sand and chemicals (5%) have caused concerns over the risks of drinking water contamination. At shallow depths, the release of fracturing fluids (due, for example, to insufficient well-casing) could threaten drinking water supplies. Furthermore, though some fracking fluid is removed from the well upon completion, substantial amounts will remain underground.
- The removal of wastewater from shale gas wells by injection into underground wells at depth has been linked to increased seismic instability. On the other hand, storing wastewater in open pits has also concerned people.
- Recently the U.S. House of Representatives' Committee on Energy & Commerce reported that: "Between 2005 and 2009, oil and gas companies used hydraulic fracturing products containing 29 chemicals that are: (1) known or possible human carcinogens; (2) regulated under the Safe Drinking Water Act for their risks to human health, or (3) listed as hazardous air pollutants under the Clean Air Act. These 29 chemicals were components of more than 650 different products used in hydraulic fracturing." Chemicals recovered as wastewater, stored in tanks near well sites, and then disposed of, are also a cause for concern, given the risk of spills. Recently the EPA has begun to study the effects of fracking on drinking water (EPA, 2017).
- In the U.S., only those companies using diesel in hydraulic fracturing are subject to EPA regulation in respect of the underground injection of chemicals. This is due to a 2005 exemption under the Safe Drinking Water Act, and has proven highly contentious. Royal Dutch Shell,

however, estimates that 17 states (representing 96% of unconventional production) have sufficient regulation addressing the issue of chemical disclosure.

- Increasing methane levels in drinking water due to shale gas operations have also caused controversy in the U.S. (Hand, 2015). Osborn et. al. (2011) have found that increasing proximity to gas wells coincide with increasing average and maximum concentrations of methane in drinking water. Methane concentration levels in some wells have reached ‘explosion hazard’ levels. According to Kappel et. al. (2012), methane requires venting at concentrations above 28 milligrams per litre to safely avoid explosions.

- Overall trends suggest that lessons have been learned, with water and chemical volumes used in hydraulic fracturing generally falling, as some recent articles support:

1. ‘Defense Research Leads to Frac Ball Technology’ (Boman, 2013). TervAlloy frac balls are designed to frack the reservoir. The balls are magnesium alloys offering better value and performance than dissolvable metals used previously. TervAlloy balls react to wellbore fluid and downhole temperature then quickly dissolve into compounds that are nontoxic. They come off seat in only a few hours and completely dissolve over a period of days. The balls bring significant advantages, including faster and more efficient well-completion (and hence quicker revenues), and lower environmental impact including reduced water usage.
2. ‘Hospital Disinfectant Gaining Ground as Oil, Gas Water Treatment Solution’ (Boman, 2014). The oil and gas industry has become increasingly keen to use an anti-bacterial chemical designed for use in hospitals as a treatment for hydraulic fracturing water. Exelyte, like bleach, uses chlorine as an active ingredient, but is Ph-neutral and thus benign to humans. (Bleach on the other hand is highly alkaline and caustic.). Exelyte is nontoxic, undetectable after 90 days, and has been successfully tested on flowback water in the Piceance and Marcellus shale basins. Accordingly, the EPA has approved its use in hospital disinfection, food processing, veterinary practices, and the oil and gas industry. Given concerns over the oil and gas industry’s impact on water supply, an effective water treatment solution (one that kills bacteria but without leaving toxic after-effects) for the industry is highly desirable.

7.4.2.9 Workforce silica exposure

- Large quantities of silica sand are used during hydraulic fracturing, and its transport and movement can lead to the release of dust containing silica into the air. Workers can be exposed too if they breathe the dust, which can lead to a lung disease called silicosis.
- In the U.S., the Occupational Safety & Health Administration (OSHA) has released hazard alert (http://www.osha.gov/dts/hazardalerts/hydraulic_frac_hazard_alert.html), identifying the issues, associated standards and directives, and appropriate protection and mitigation.

7.4.2.10 Seismicity

- Some countries raise concerns over seismicity associated with hydraulic fracturing activity, or injecting wastewaters into deep disposal wells. Many tremors have been recorded within a radius of 1.6 km from horizontal wells, prompting the Ohio Department of Natural Resources to suggest a new state law prohibiting drilling below 2800m (Guidance note for financiers, 2013).
- A recent UK study ('Shale gas extraction in the UK: a review of hydraulic fracturing', Royal Society and Royal Academy of Engineering, 2012) notes increasing acceptance, among a range of interested groups, that the magnitude of seismicity induced by hydraulic fracturing would likely be no greater than magnitude 3 or 3M, i.e. felt by few people and resulting in negligible, if any, surface impacts.
- Seismicity and geological risks – similar to the challenges of water scarcity – vary by location and associated risks need to be evaluated on a case-by-case basis.

7.4.2.10.1 Seismicity evaluation: An example in New Zealand

In some instances, overseas, hydraulic fracturing or deep well reinjection of wastewater have caused alarm in respect of increasing seismic instability. In New Zealand concern over hydraulic fracturing is widespread. Accordingly, GNS Science produced a report (through the GeoNet project) in 2012, 'Assessment of the Effects of Hydraulic Seismicity (Earthquakes) in Taranaki'. It concludes:

No evidence for either hydraulic fracturing or long-term deep injection activities in Taranaki between 2000 and mid-2011 having any observable effect on natural earthquakes of magnitude 2 or larger, the magnitude threshold of the earthquake catalogue. In terms of any seismic activity that might be associated

directly with hydraulic fracturing, an earthquake of about magnitude 2 would be a relatively large event. At a depth of 2-4 km such an earthquake is likely to produce (for those in the near vicinity) ground shaking similar to that caused by a nearby passing truck, but no more. A series of questions with yes and no answers will help assess if any seismic activity could be due to hydraulic fracturing operations. It will be difficult to distinguish earthquakes due to hydraulic fracturing or deep injection from natural seismic activity if natural earthquakes are common close to those sites. Given the location of hydraulic fracturing and deep injection operations there is no evidence of any effect on volcanic activity at Mt Taranaki. (GeoNet project, 2012).

It should be noted, however, that while Taranaki is in the backarc basin, the East Coast Basin is in the more active forearc region, where the upper plate is thinner and more stressed, and therefore prone to quakes. Given that, a hydraulic fracking activity could be responsible for triggering some earthquakes.

7.5 REGULATION AND ENVIRONMENTAL OVERSIGHTS IN NEW ZEALAND

This section is based on the report of the Parliamentary Commissioner for the Environment, 2012 and 2014.

As the proposal of this thesis is to evaluate the rock characteristics of the Whangai and Waipawa formations in order to evaluate their potential as an unconventional reservoir in the East Coast Basin, and not the processing to acquire an environmental license, this section will briefly discuss the process of onshore exploration in New Zealand, and the responsibilities of the agencies involved.

There are a number of different agencies involved in regulating the oil and gas industry. Each operates under different legislation and with a different purpose (Figure 7.8).

Figure 7.8 Agencies involved in regulating the oil and gas industry in New Zealand (modified from www.pce.parliament.nz). Ministry of Business Innovation and Employment (MBIE), Environmental Protection Authority (EPA), Ministry for Environment (MfE), and New Zealand councils.

The New Zealand Government is encouraging the oil and gas industry to expand. Most of the drilling activities in New Zealand take place in the Taranaki Basin, but exploratory drilling is starting elsewhere, like the offshore East Coast, Pegasus and Canterbury Basins.

A resource consent is not needed in Taranaki for drilling for oil and gas. However, outside Taranaki, drilling an oil and gas well generally does require a consent from the regional council.

Based on the Parliamentary Commissioner for the Environment there are four physical aspects that should be done well: choose the well site carefully, design and complete the well to prevent leaks, prevent spills and leaks on the surface, and store and dispose of waste with care.

In New Zealand there are four main laws that control different subjects related to the oil and gas industry. Figure 7.9 shows how these main laws are subdivided and the responsibilities involved.

Figure 7.9 The four main laws that control the onshore oil and gas extraction in New Zealand
(modified from www.pce.parliament.nz).

7.5.1 Obtaining permits to drill for oil and gas

All permits related to drilling an exploration well come under the Crown Minerals Act. Figure 7.10. shows the step which an oil company has to go through in order to get a license to drill.

Figure 7.10 Flow chart showing the steps from the bid round to commercial discovery (modified from www.pce.parliament.nz).

7.5.2 New Zealand regulations for hydraulic fracturing operations

Fracking was first used in New Zealand in 1991, in Taranaki. As technology has improved, the method has been used more frequently. Since 2001, fracking has been used in 28 conventional oil and gas wells, all in Taranaki, without any adverse effects on local water or land. Figure 7.11 shows where the fracking has occurred and the depth of the water aquifers related to the fracking zones. Up to now the East Coast Basin has never been subject to hydraulic fracturing activity. There have been two unsuccessful attempts to frack for coal seam gas in Ohai in Southland, as well as Solid Energy's coal seam gas pilot in the Waikato. It is important to address the process involved in case this activity takes place in the studied basin.

In New Zealand hydraulic fracturing operations are subject to existing laws and regulations. The Resource Management Act 1991 (RMA) covers the environmental effects of fracking. The RMA requires consent for all activities that have an impact on the land, that take or use water, and that involve discharges. Hence, unless permitted by a regional or district plan, hydraulic fracturing requires consent under the RMA.

Land use activities are governed by the RMA under District Council management. Whether consents are required is determined by rules in the District plan. Wells are subject to the Health and Safety in Employment (Petroleum Exploration and Extraction) Regulations 2013, overseen by the High Hazards Unit of WorkSafe NZ.

Figure 7.11 Map showing where hydraulic fracturing has been done and the difference intervals between the water aquifers and the reservoirs fractured (Taranaki Regional Council, 2012).

7.6 SOCIETY

7.6.1 Community engagement & support

During site selection, companies should recognise how their activities will affect communities and interest groups, and make an effort to address any concerns raised. This is especially important for companies operating in countries and jurisdictions with weak regulatory control where formal requirements for such engagement may be lacking.

Similarly, companies ought to establish for themselves means of engaging with local communities beyond those required by law, laying down satisfactory, third-party resolution frameworks in the event of conflict. As a part of this forward-planning, companies should avoid, for example, operating in areas with schools, hospitals, churches or recreational areas and locations of other local significance.

Companies ought to consider whether they have sound policies around seeking community support and reaching understanding with locals. For instance, the notion of ‘Free, Prior, and Informed Consent’ is especially important in respect of dealings with indigenous communities. Advance agreements may be found with communities, in order to reach agreement on a range of relevant issues such as noise pollution, road use, damage repair and maintenance, as well as monitoring environmental, social and health impacts. Again, these agreements may go beyond the requirements of the law.

Some practices and policies which responsible companies ought to consider include:

- An open-door approach to informing local communities of business practices and operations. This includes actively distributing policies and principles associated with shale gas development, conducting site tours, and regular contact meetings to hear and exchange views on issues and concerns.
- A hotline by which to receive complaints and a mechanism to deal with those complaints in a satisfactory and timely fashion.
- Independent third-party conflict resolution channels.
- Formal disclosures of records and results of complaint procedures, noting too trends and findings to do with conflict resolution.

7.7 MARKET

New Zealand has a limited increase potential of its energy matrix. The lack of exploration activity, shortage of prospects and leads, caused by the lack of standard regulatory bid round process, limits to developing new hydro plants, likelihood of hydro decreasing (i.e. Roxburgh), shortage of quality undeveloped wind sites and high cost of wind and solar energy and their unsustainability (i.e. short lifetimes due to wear and tear as compared to gas fired generation), are some topics that should be discussed to help us understand the market need in the short and long term for New Zealand.

Any type of project has to have a good technical, economical and society acceptance. This section describes briefly what the energy market looks like in New Zealand, given the importance of evaluating how an oil and gas discovery would affect the country. Some analyses follow to help this question.

7.7.1 Energy Overview

Produced by the Energy & Building Trends team of the Ministry of Business, Innovation & Employment (MBIE) a report containing an analysis of New Zealand's energy sector was published in 2015 referencing the calendar year of 2014.

This section shows an overview of New Zealand's key energy information, such as: primary energy supply, energy transformation, energy consumption, non-energy use, and energy sector performance.

7.7.1.1. Primary energy supply

Total primary energy supply (TPES) is the total amount of energy supplied for use in the country. It is calculated using the domestic production plus imports, less exports and energy used for international transport, as showed in Figure 7.12.

Figure 7.12 New Zealand's TPES by fuel since 1974 (Energy in New Zealand, 2015).

It is important to highlight that renewable energy achieved its record in 2014, providing 39.5% of New Zealand's TPES. Increased electricity generation from geothermal energy and reduced electricity generation from coal have caused the rapid increase in renewable energy's share of TPES. However, information on the direct use of renewable energy and use for distributed generation is more difficult to obtain, given that the input energy source is often used without being purchased and is therefore not well recorded.

7.7.1.2. Energy transformation

Energy transformation refers to the conversion of primary energy to more useful forms of energy. It is related to activities such as oil refining, electricity and other transformation as well as losses. By convention, energy recorded as an input to energy transformation is recorded as negative; energy output from energy transformation is recorded as positive (e.g. gas used for generating electricity is negative; the electricity generated from gas is positive) Figure 7.13 shows that Since 2009, total energy transformation has grown by an average of 4.9% per year.

Figure 7.13 It shows the total energy transformation by fuel from 1990 to 2014. This figure highlights the growth in renewables (Energy in New Zealand, 2015).

7.7.1.3. Energy Consumption

Consumer energy demand includes all energy used by final consumers. It does not include energy used for transformation, or non-energy use. Figures 7.14, 7.15 and 7.16 show consumer energy demand by fuel and sector and its share from 1990 to 2014.

Figure 7.14 Consumer energy demand by fuel (Modified from Energy in New Zealand, 2015).

Figure 7.15 Consumer energy share demand by fuel (Energy in New Zealand, 2015).

Figure 7.16 Consumer energy share demand by sector (Energy in New Zealand, 2015).

It is important to highlight the increased demand in 2014 from the industrial sector, whose demand increased 10%, and which saw gas demand increase by 23% (Figure 7.14). This gives us a good picture that the gas market has an important role for this sector's demand. Based on this high rise in demand, it is clear how important it is to keep the exploration of oil and gas activities happening in the country. An example is Taranaki New Zealand's energy province, responsible of the nation's oil and natural gas production, and 90 percent of the industry's nationwide employment, generating \$NZ 2.5 billion in GDP yearly for the country (Venture Taranaki, 2017).

7.7.1.4. Non-Energy Use

Non-energy use refers to use of fuels (oil and gas) to produce non-energy products. Non-energy use in New Zealand consists mostly of natural gas (conversion of natural gas to methanol or urea) with the remainder being oil (e.g. bitumen for roads) (Figure 7.17).

Figure 7.17 A time series of non-energy use by fuel since 1990 (Energy in New Zealand, 2015).

Although methanol can be combusted for energy purposes, the methanol produced in New Zealand is mainly exported for use as a chemical feedstock (e.g. to make plastic). Gas combusted during the production of petrochemicals such as methanol, urea and ammonia is included as industrial sector demand within total consumer energy. Only gas used as a feedstock (and therefore not combusted) in petrochemical production is classified as a non-energy use.

7.7.2 Energy Sector Performance

Energy sector performance indicators show how well New Zealand's energy sector is performing on a variety of aspects. These include energy intensity and energy self-sufficiency.

Energy intensity is a measure of the energy used (in MJ) per unit of gross domestic product (GDP)². It is influenced by the composition of industry within the economy, improvements in energy efficiency and changes in behaviour.

The energy intensity of the economy has improved annually by an average of 1.1% since 1990. This improvement was driven by the rapid growth of the commercial sector (Figure 7.18).

Figure 7.18 New Zealand GDP (Real 2009/2010 Prices ²) by sector in 1990 and 2014 (Energy in New Zealand, 2015).

² Statistics New Zealand has updated the base year for fixed price weights from 1995/96 to 2009/10, meaning values presented in this section are not directly comparable with those from previous editions.

7.7.2.1 Energy Self-Sufficiency

Based on Figure 7.19 oil is the only energy source that New Zealand needs to import, as it does not achieve 100% of the energy needs. It also shows that total energy self-sufficiency was 83% in 2014. The peak was 92% in 2010, which was related to a combination of historically high oil, gas and coal production. The minimum occurred in 2005 at 74%. In order to achieve its self-sufficiency New Zealand has to invest in the oil industry.

Figure 7.19 Time series of New Zealand's energy self-sufficiency (Energy in New Zealand, 2015).

7.7.3 Energy Balances

It is important to understand the energy balance to assess the need for, and the types of source energy. This section presents the annual energy supply and demand balance for New Zealand (Table 7.4). The energy balances focus on commercial energy. In order to better understand Table 7.4, it is also important to define the following topics: supply, energy transformation, liquid biofuel, losses and own use, non-energy use and demand.

1. Supply – The amount of energy available for use in New Zealand;
2. Energy Transformation – Includes generation of electricity, oil production and other transformation;
3. Liquid Biofuel – Production appears as renewable energy supply;
4. Losses and own use – Losses before and after transformation;
5. Non-energy use – Primary energy used for purposes other than combustion;
6. Demand – The amount of energy consumed by final users.

Table 7.4 Energy supply and demand balance, calendar 2014 (Energy in New Zealand, 2015).

Converted into PJ using Gross Calorific Values		COAL			OIL								NATURAL GAS	RENEWABLES							ELECTRICITY	WASTE HEAT	TOTAL	
		Bituminous & Sub- bituminous	Lignite	Total	Crudes/ Feedstocks/ Natural Gas Liquids	LPG	Petrol	Diesel	Fuel Oil	Aviation Fuel/ Kerosene	Others	Total	Total	Hydro	Geothermal	Solar	Wind	Liquid Biofuels	Biogas	Wood	Total	Total		Total
SUPPLY	Indigenous Production	98.22	4.83	103.06	83.46	10.19						93.65	204.03	87.61	200.14	0.42	7.95	0.14	3.20	58.28	357.75		0.85	759.34
	+ Imports	10.43	0.00	10.43	234.44	0.04	50.73	351.7	0.27	6.99	5.77	333.40												343.84
	- Exports	54.93	-	54.93	78.51	2.79	-	0.14	5.12	-	-	86.55												141.49
	- Stock Change	-3.08	0.03	-3.04	-0.37	-0.02	5.40	-0.18	5.07	0.69	-0.58	10.00	-0.37											6.59
	- International Transport						0.00	2.10	10.60	37.66	-	50.36												50.36
	TOTAL PRIMARY ENERGY	56.80	4.80	61.60	239.76	7.47	45.33	33.11	-20.51	-31.36	6.34	280.15	204.40	87.61	200.14	0.42	7.95	0.14	3.20	58.28	357.75		0.85	904.74
	ENERGY TRANSFORMATION	-34.39	-0.19	-34.57	-239.45	-0.01	61.31	85.92	28.21	44.48	5.28	-14.26	-65.44	-87.61	-188.48	-0.06	-7.95	-0.14	-2.87	-5.06	-292.17	141.31	-0.85	-265.97
	Electricity Generation	-13.22	-	-13.22				-0.01	-			-0.01	-42.05	-87.61	-187.11	-0.06	-7.95		-2.12		-284.85	147.24		-192.89
	Cogeneration	-7.58	-0.19	-7.77									-16.85		-1.37				-0.74	-5.06	-7.17	9.45	-0.85	-23.18
	Fuel Production				-239.21		61.21	85.71	27.93	44.55	12.93	-6.88	-					-0.14			-0.14			
Other Transformation	-11.81	-	-11.81																					-11.81
Losses and Own Use	-1.78	-	-1.78	-0.24	-0.01	0.11	0.22	0.27	-0.07	-7.65	-7.36	-6.54									-15.37			-31.06
Non-energy Use											-11.62	-11.62	-59.33											-70.95
CONSUMER ENERGY (calculated)		22.41	4.62	27.03	0.31	7.46	106.65	119.04	7.70	13.12	-	254.27	79.63		11.66	0.36	-	-	0.33	53.22	65.58	141.31	-	567.82
DEMAND	Agriculture, Forestry and Fishing	1.67	0.02	1.68		0.07	1.64	17.49	2.32	-		21.52	1.63		0.73						0.73	9.55		35.12
	Agriculture	1.66	0.02	1.68		0.07	1.51	13.06	-	-		14.64	1.63		0.73						0.73	8.65		27.33
	Forestry and Logging	0.00	-	0.00			0.01	2.86	-	-		2.87	0.00									0.75		3.62
	Fishing	0.00	-	0.00			0.12	1.57	2.32	-		4.01	-									0.15		4.17
	Industrial	19.63	4.30	23.93		3.04	0.15	14.59	0.95	-		18.73	68.02		8.38				0.05	45.88	54.32	52.90		217.89
	Mining	-	-	-			0.00	3.17	-	-		3.17	0.06									1.56		4.78
	Food Processing	11.93	4.28	16.21			-	-	-	-		-	15.83									8.38		40.42
	Textiles	0.07	-	0.07									0.56									0.38		1.00
	Wood, Pulp, Paper and Printing	0.64	0.01	0.65									5.12									9.44		15.22
	Chemicals	0.00	-	0.00									40.00									2.67		42.67
	Non-metallic Minerals	5.11	0.01	5.12									1.67									1.48		8.27
	Basic Metals	-	-	-			-	-	-	-	-	-	3.44									23.80		27.24
	Mechanical/Electrical Equipment	0.00	-	0.00									0.74									0.53		1.27
	Building and Construction	-	0.00	0.00			0.01	3.72	0.02	-		3.75	0.45									1.28		5.47
	Unallocated	1.87	-	1.87		3.04	0.14	7.70	0.93	-		11.81	0.16		8.38				0.05	45.88	54.32	3.38		71.53
	Commercial	0.99	0.14	1.13		1.19	0.27	4.46	0.00	-		5.91	8.71		2.25				0.28		2.53	33.53		51.82
	Transport	0.02	-	0.02		0.38	104.16	83.69	4.34	12.38		204.96	0.02						-		-	0.22		205.22
	Residential	0.21	0.16	0.37		2.86	-	0.10	-	-		2.96	6.56		0.30	0.36				7.34	8.00	44.86		62.74
	CONSUMER ENERGY (observed)		22.51	4.61	27.12	-	7.52	106.22	120.33	7.62	12.38	-	254.08	84.94	-	11.66	0.36	-		0.33	53.22	65.58	141.07	-
Statistical Differences		-0.10	0.00	-0.09	0.31	-0.06	0.43	-1.29	0.08	0.73	-	0.19	-5.31		-	-	-		-	-	-	0.24	-	-4.97

7.7.4 Electricity

Most of the electricity generation in New Zealand comes from hydro but gas and geothermal are the second source, playing an important role. Even if New Zealand is self-sufficient in gas, reserves are being depleted and not many considerable discoveries have been made in the last 8 years (Energystream, 2017). Finding gas could be an important aspect to keeping a steady source for electricity, mainly in years with a low water reservoir levels.

Figure 7.20. shows the time series of generation by fuel type and growth in geothermal generation, which has shown a steady growth since the beginning of 2000. If this is not maintained, gas remains an important source for electricity generation.

Figure 7.20 Annual electricity generation by Fuel Type (Energy in New Zealand, 2015).

The largest share of consumption comes from the industrial sector, representing 37%, followed closely by the residential and commercial sectors, 32.1% and 24.1%, respectively (Figure 7.21).

Figure 7.21 Electricity consumption by sector (Energy in New Zealand, 2015).

It can be seen that consumption has been growing steadily since 1975. There is no doubt that there is market for alternative sources for generating electricity.

7.7.5 Renewable

The share of renewable in the primary energy supply was 39.5% in 2014. This is the highest proportion since records began. New Zealand occupied the third highest renewable primary energy supply of the Organisation for Economic Co-operation and Development (OECD) after Norway and Iceland in 2014. Figure 7.22. shows the breakdown of renewable primary energy supply for 2014.

Figure 7.22 Renewable primary energy sector for 2014 (Energy in New Zealand, 2015).

Almost 80% of renewable energy is used to generate electricity. Figure 7.23 shows how renewable sources have fluctuated through the years.

Figure 7.23 Percentage of New Zealand electricity generation from renewable sources (Energy in New Zealand, 2015).

7.7.6 Oil and Gas

The oil and gas industry in New Zealand, although with significant gas production since the early 1970s, is still in an incipient phase. It is important to understand the structure of this industry in New Zealand, comprising production fields, players, refiners, wholesalers, distributors, retailers and consumers (Figures 7.24 and 7.25).

Figure 7.24 Oil industry summary 2014 (Energy in New Zealand, 2015).

Figure 7.25 Gas industry summary 2014 (Energy in New Zealand, 2015).

As shown in Figure 7.26 production has been fluctuating since 1970. We can see a big drop from 2007 through 2013 and a peak starting up to now. Most of the production has been exported in the last few years, so we could consider that there is a market for hydrocarbons internally and externally.

Figure 7.26 Annual crude, condensate, naphtha and natural gas liquids production by field (Energy in New Zealand, 2015).

As New Zealand has high quality light oil, economically speaking, it is worthwhile exporting this and import the heavier oils. Figure 7.27. shows the 12 countries from which New Zealand imports its oil.

Figure 7.27 Crude oil imports by country of origin (Energy in New Zealand, 2015).

In New Zealand, gas is produced entirely in the Taranaki basin and reticulated gas is only available in the North Island. Even if gas used for electricity has dropped, the non-energy use of gas has increased. This suggests that any gas discovery in New Zealand will find a market. New Zealand has a conventional gas industry structure (Figure 7.28), with an upstream and downstream sector containing high and low pressure transmission and distribution, respectively. If the country faces a big gas discovery, which would justify a Liquefied Natural

Gas plant (LNG), New Zealand could achieve an overseas market like the Asian countries. Figure 7.29 shows natural gas consumption by sector for 2014.

Figure 7.28 Gas industry structure (The New Zealand Gas Story, 2013).

Figure 7.29 Natural gas consumption by sector for 2014 (Energy in New Zealand, 2015).

Figure 7.30 shows the existing routes and possible new routes worldwide, showing that New Zealand is not even mentioned as a potential country for exporting LNG. The shale development could give the country an opportunity to grow as an exporter country, following the trajectory of the U.S., and decrease the amount of waste of fossil fuel burned in the oil imports from 12 different locations around the globe.

Figure 7.30 Future global LNG trade potential. (Citi Investment research and analysis)

8. CONCLUSIONS

1. The Rock-Eval plots show that the organic matter for the Whangai Formation can be classified as Type II with very little occurrence of Type III. The TOC in the Rakauroa Member varies from fair to good potential for gas and oil prone generation. The TOC in the Upper Calcareous Member varies from poor to good generative potential with most of the rock samples falling in the “poor” category, for gas- and oil-prone generation. Given the lack of representative rock samples for the Porangahau Member the results for this unit are very speculative; its TOC varies from poor to fair and indicates a more gas and oil/condensate-prone generation. The Waipawa Formation has organic matter of Type I, II and, in minor proportion, III. The TOC varies from good to excellent generative potential with gas- and oil-prone generation. Based on vitrinite occurrence the Waipawa Formation appears to have more terrestrial organic matter input among all the rocks analysed for this study. Even though most of the maturation results from these rock formations indicate that they are immature, there are some localised areas where the maturity of Whangai Formation is greater. Increased maturity is also expected in synclines, where the Neogene successions are relatively thick and also below the allochthon on Raukumara Peninsula.
2. The Rakauroa and Upper Calcareous members of the Whangai Formation plot as silica-dominated lithotypes, and the Porangahau Member plots as a carbonate-rich siliceous mudstone. The Waipawa Formation plots as silica-dominated with a tendency to clay-rich siliceous mudstone.
3. The Waipawa Formation and the Rakauroa Member in the Motu and Tora Blocks, based on inorganic geochemistry, show a relatively high terrestrial input and inferred provenance of the Eastern Province. On the other hand, the Pongaroa Block shows less similarity to the Eastern Province signature. This area could be related to the Western Province rock signature or could have been situated further away from both the Eastern and Western provenance areas and the principal axes of sediment transport. The Rakauroa Member in the Motu and Tora Blocks has a higher clay content and a higher TOC (both suggesting terrestrial input). This could

be related to organic matter sorption onto clays. The low HI values characteristic of the member suggest a shallower depositional environment for these areas.

4. Based on the chemical index of alteration and the index of compositional variability the Waipawa Formation and Rakauroa Member show stronger weathering influence and more chemically mature mineralogies compared to the Porangahau and Upper Calcareous members. The Motu and Tora Blocks appear to show more influence of these features. These two units also show more climate variability, showing intervals of relatively intense chemical weathering based on the ratio of $\text{Al}_2\text{O}_3/\text{TiO}_2$. These intervals could be related to changes in sedimentation rates and the peaks in TOC enrichment in the Waipawa Formation. Enhanced organic matter preservation can be attributed to decreased availability of oxygen, as well as rapid burial that preserved the organic matter.
5. Based on the first sweet spot assessment using only organic geochemistry with no statistical analysis applied to the Whangai Formation, the Rakauroa Member in the Pongaroa Block shows the best rock characteristics as an unconventional reservoir (quality, quantity and maturation), and the Waipawa Formation has its best potential in the Motu and Allochthon Blocks. These assessments do not take into account geomechanical or inorganic geochemical results.
6. The results of the analyses of brittleness index indicate that the Rakauroa Member could be stimulated via hydraulic fracking for an interval up to 250m. Although the Waipawa Formation shows very good source rock quality, it lacks a brittleness index evaluation, making it difficult to assess the potential of this unit as an unconventional reservoir.
7. Based on the basic statistical analysis using only organic geochemistry, both the Rakauroa Member and the Waipawa Formation in the Motu Block show the best rock characteristics of the units evaluated. Rakauroa Member has fair to good generative potential based on TOC, poor generative potential based on S_2 , and gas to condensate-prone characteristics based on hydrogen index. Tmax and vitrinite reflectance results show that the Motu block is mature (top – oil window) and an

interval of 141m of the Rakauroa Member can be stimulated via hydraulic fracking. The Waipawa Formation has very good generative potential based on TOC, good generative potential based on S₂, and oil to condensate prone characteristics based on hydrogen index. However, the maturity for the Waipawa Formation is low and no geomechanical analyses have been undertaken. Nevertheless, it is likely that, based on the greater thermal gradient in this region (Motu and Allochthon area), this formation could reach maturity in the subsurface.

8. Based on the machine-learning analysis, the third sweet spot assessment, using as many variables as possible, both the Rakauroa Member and the Waipawa Formation in the Motu Block show the best rock characteristics of the units evaluated. This evaluation determines the estimate ultimate recovery for both formations. Because shale oil was excluded from the model only the gas forecast could be determined. EURgas for Rakauroa Member is 3690 MMcf (636136 Boe) and for the Waipawa Formation is 3729 MMcf (642860 Boe);
9. The results of the economical model using the Energy Information Administration and the machine-learning methodologies both have shown that an economic feasibility would be achieved for both oil and gas discoveries if the oil price is US\$ 60 or higher. Except the gas discovery, using the EIA methodology would result in a financial loss.
10. The minimum economic field size for exploring unconventional in the East Coast basin has been determined as 4.5 km² if the oil price swings around US\$60 or higher.

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9. RECOMMENDATIONS

9.1 INTRODUCTION

Machine-learning is essential to more confidently assess the sweet spots along the East Coast Basin but more organic and inorganic geochemical analyses are needed for both formations in order to check the results of the statistical analysis presented here. There is a minimum of 30 samples requirement in order to have a more representative for any statistical model results (Mann, 1995). Ideally, these rock samples should be taken from the lower, middle and upper parts of each unit spread across each structural block. Tables 7.1 and 7.2 for the Whangai Formation and Tables 7.3 and 7.4 for the Waipawa Formation indicate the localities where more samples should be taken. Note that ticks denote 30 or more samples already extracted per block, “X” block denotes less than 30 samples, and NP denotes member not present or identified.

Table 9.1 Structural Blocks that need to have more organic geochemistry analyses available per member of the Whangai Formation.

Member	Tora Block	Pongaroa Block	Coastal Block	Motu Block	Allochthon Block
Rakauroa	X	✓	X	✓	X
Porangahau	NP	X	X	NP	X
Upper Calcareous	NP	X	✓	X	X

Table 9.2 Structural Blocks that need to have more inorganic geochemistry analyses available per member of the Whangai Formation.

Member	Tora Block	Pongaroa Block	Coastal Block	Motu Block	Allochthon Block
Rakauroa	X	X	X	X	X
Porangahau	NP	X	X	NP	X
Upper Calcareous	NP	X	X	X	X

Table 9.3 Structural Blocks that need to have more organic geochemistry analyses available for the Waipawa Formation.

Formation	Tora Block	Pongaroa Block	Coastal Block	Motu Block	Allochthon Block
Waipawa	NP	X	✓	✓	

Table 9.4 Structural Blocks that need to have more inorganic geochemistry analyses available for the Waipawa Formation.

Formation	Tora Block	Pongaroa Block	Coastal Block	Motu Block	Allochthon Block
Waipawa	NP	X	X	X	X

- Currently, based on the regional scale of this study and existing dataset, sweet spot identification is based on sparse rock samples from the Whangai and Waipawa formations per structural block. Better internal stratigraphic control of the units evaluated in this report would be vital to identifying the intervals with more potential as unconventional reservoirs (best intervals within the sweet spot). At least one key measured section per structural block should be assessed in more detail with closely-spaced analyses;
- Given the seismicity-prone of the East Coast Basin, a deeper analysis should be undertaken to acknowledge the effects of hydraulic fracking activities could generate;
- To further reduce uncertainty in the statistical model, it would be desirable to remove the redundant parameters. For example, hydrogen index could be retained and S2 and TOC could be removed from the model, or vice versa, because of direct relationships among TOC and S2 with hydrogen index.
- One-dimensional basin modelling, to predict the transformation ratio, generation peak, expulsion, and potential kitchens along the sweet spot areas, is essential to improve assessment of shale oil and gas potential; This modelling could combine the Allochthon and the underlying Autochthonous block as very little is known regards to the underlying Autochthonous block
- Additional inorganic geochemistry analyses to help with palinspastic reconstructions, redox environments and provenance, are desirable. Also, phytoclast studies to provide a better proximal-distal indicator would be useful. These data would help to achieve better reservoir facies characterization;
- Geomechanical analyses in the Upper Calcareous and Porangahau members (Whangai Formation), as well as the Waipawa Formation, would be beneficial;
- Shooting 2 dimensional seismic lines along the sweet spot area and tie lines crossing some existing exploration wells is fundamental in order to understand

the geological complexity of the area and define the lateral extent of the studied formations. These are important for planning hydraulic fracking;

- Extend the 2 dimensional seismic lines through the Allochthon/Autochthonous blocks in order to better understand the occurrence of the Whangai and Waipawa formations underneath the Allochthon block. It is expected that not only the thermal gradient is greater but also better reservoir facies.
- With more data available, either from the analogues or from the Whangai and Waipawa formations or both, the machine-learning model could be updated and consequently more reliable results would be obtained;
- According to Ambrose et. al., 2010, the current industry methodology is not taking into account the volume consumed by the sorbed phase. In their approach, this pore space has to be decreased from the free gas calculation, thus, avoiding an overestimation of total gas volumes. A new shale gas assessment has to be applied in order to avoid that;
- New Zealand needs to guarantee its energy matrix in the long-term. The country is still not self-sufficient in oil, while its oil and gas reserves are currently depleting due to steady production and the few new oil and gas discoveries in recent years. The last two discoveries were taken place in 2010 (Sidewinder) and 2011 (Copper Moki) with a total 2P reserve of 1.55MMboe. According to the Ministry of Business, Innovation and Employment (2016), New Zealand's 2030 production profile will be alarmingly smaller than the currently existing production profile. The forecast of the population growth is to triple by this time. Given that, New Zealand should be investing heavily in the oil and gas industry.

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GLOSSARY:

Term	Definition	Source of Definition
Abandon	To cease work on a well which is non-productive, to plug off the well with cement plugs and salvage all recoverable equipment. Also used in the context of field abandonment.	https://oilandgasuk.co.uk/glossary.cfm
Appraisal Well	A well drilled as part of an appraisal drilling programme which is carried out to determine the physical extent, reserves and likely production rate of a field.	https://oilandgasuk.co.uk/glossary.cfm
Associated Gas	Natural gas associated with oil accumulations, which may be dissolved in the oil at reservoir conditions or may form a cap of free gas above the oil.	https://oilandgasuk.co.uk/glossary.cfm
Barrel	A unit of volume measurement used for petroleum and its products (7.3 barrels = 1 ton; 6.29 barrels = 1 cubic metre).	https://oilandgasuk.co.uk/glossary.cfm
Barrel of oil equivalent (boe)	It is a term used to summarize the amount of energy that is equivalent to the amount of energy found in a barrel of crude oil.	http://www.investopedia.com/terms/b/barrelofoilequivalent.asp
bbl	One barrel of oil; 1 barrel = 35 Imperial gallons (approx.), or 159 litres (approx.); 7.5 barrels = 1 tonne (approx.); 6.29 barrels = 1 cubic metre.	https://oilandgasuk.co.uk/glossary.cfm
bcf	Billion cubic feet; 1 bcf = 0.83 million tonnes of oil equivalent.	https://oilandgasuk.co.uk/glossary.cfm
bcm	Billion cubic metres (1 cubic metre = 35.31 cubic feet).	https://oilandgasuk.co.uk/glossary.cfm
Block	acreage sub-division measuring approximately 10 x 20 kms, forming part of a quadrant.	https://oilandgasuk.co.uk/glossary.cfm
Brent	UK Brent Oil is sourced from the North Sea and its value is used to price two-thirds of the world's internationally-traded crude oil supplies.	http://www.onefinancialmarkets.com/market-library/uk-brent-oil
British thermal unit (BTU)	A measure of the heating value of a fuel.	https://oilandgasuk.co.uk/glossary.cfm
Capex	Capital expenditure.	https://oilandgasuk.co.uk/glossary.cfm

Casing	Metal pipe inserted into a wellbore and cemented in place to protect both subsurface formations (such as groundwater) and the wellbore. A surface casing is set first to protect groundwater. The production casing is the last one set. The production tubing (through which hydrocarbons flow to the surface) will be suspended inside the production casing.	https://oilandgasuk.co.uk/glossary.cfm
Commercial field	An oil and/or gas field judged to be capable of producing enough net income to make it worth developing.	https://oilandgasuk.co.uk/glossary.cfm
Drilling rig	A drilling unit that is not permanently fixed to the seabed, e.g. a drillship, a semi-submersible or a jack-up unit. Also means the derrick and its associated machinery.	https://oilandgasuk.co.uk/glossary.cfm
E&P	Abbreviation for exploration and production. The ‘upstream’ sector of the oil and gas industry.	https://oilandgasuk.co.uk/glossary.cfm
Enhanced oil recovery (EOR)	A process whereby oil is recovered other than by the natural pressure in a reservoir. Refers to a variety of processes to increase the amount of oil removed from a reservoir, typically by injecting a liquid (e.g., water, surfactant) or gas (e.g., nitrogen, carbon dioxide).	https://oilandgasuk.co.uk/glossary.cfm
Exploration well	Drilling carried out to determine whether hydrocarbons are present in a particular area or structure. Also known as a ‘wildcat well’.	https://oilandgasuk.co.uk/glossary.cfm
Farm in	When a company acquires an interest in a block by taking over all or part of the financial commitment for drilling an exploration well.	https://oilandgasuk.co.uk/glossary.cfm
Field	A geographical area under which an oil or gas reservoir lies.	https://oilandgasuk.co.uk/glossary.cfm
Fracturing	A method of breaking down a formation by pumping fluid at very high pressure. The objective is to increase production rates from a reservoir.	https://oilandgasuk.co.uk/glossary.cfm

Hydrocarbon	A compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate.	https://oilandgasuk.co.uk/glossary.cfm
Lease	A legal document conveying the right to drill for oil and gas, or the tract of land on which a lease has been obtained where the producing wells and production equipment are located.	https://oilandgasuk.co.uk/glossary.cfm
Mmboe	Million Barrels Oil Equivalent.	https://oilandgasuk.co.uk/glossary.cfm
Metric tonne	Equivalent to 1000 kilos, 2204.61 lbs; 7.5 barrels.	https://oilandgasuk.co.uk/glossary.cfm
mcf	Thousand cubic feet	https://oilandgasuk.co.uk/glossary.cfm
mmcf/d	Millions of cubic feet per day (of gas).	https://oilandgasuk.co.uk/glossary.cfm
Mud	A mixture of base substance and additives used to lubricate the drill bit and to counteract the natural pressure of the formation.	https://oilandgasuk.co.uk/glossary.cfm
Natural Gas	Gas, occurring naturally, and often found in association with crude petroleum.	https://oilandgasuk.co.uk/glossary.cfm
Natural gas liquids (NGLs)	The portions of gas from a reservoir that are liquified at the surface in separators, field facilities, or gas processing plants. NGL from gas processing plants is also called liquified petroleum gas (LPG).	https://oilandgasuk.co.uk/glossary.cfm
Non-associated gas	Natural gas produced from a reservoir that does not contain significant quantities of crude oil.	https://oilandgasuk.co.uk/glossary.cfm
Oil	A mixture of liquid hydrocarbons of different molecular weights.	https://oilandgasuk.co.uk/glossary.cfm
Oil field	A geographic area under which an oil reservoir lies.	https://oilandgasuk.co.uk/glossary.cfm
Oil in place	An estimated measure of the total amount of oil contained in a reservoir, and, as such, a higher figure than the estimated recoverable reserves of oil.	https://oilandgasuk.co.uk/glossary.cfm
Operator	The company that has legal authority to drill wells and undertake production of hydrocarbons. The operator is often part of a consortium and acts on behalf of this consortium.	https://oilandgasuk.co.uk/glossary.cfm
Opex	Operating expenditure.	https://oilandgasuk.co.uk/glossary.cfm

Payzone	Rock in which oil and gas are found in exploitable quantities.	https://oilandgasuk.co.uk/glossary.cfm
Permeability	The property of a formation which quantifies the flow of a fluid through the pore spaces and into the wellbore.	https://oilandgasuk.co.uk/glossary.cfm
Petroleum	A generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products.	https://oilandgasuk.co.uk/glossary.cfm
Porosity	A ratio between the volume of the pore space in reservoir rock and the total bulk volume of the rock. The pore space determines the amount of space available for storage of fluids.	https://oilandgasuk.co.uk/glossary.cfm
Possible reserves	Those reserves which at present cannot be regarded as 'probable' but are estimated to have a significant but less than 50% chance of being technically and economically producible.	https://oilandgasuk.co.uk/glossary.cfm
Primary recovery	Recovery of oil or gas from a reservoir purely by using the natural pressure in the reservoir to force the oil or gas out.	https://oilandgasuk.co.uk/glossary.cfm
Probable reserves	Those reserves which are not yet proven but which are estimated to have a better than 50% chance of being technically and economically producible.	https://oilandgasuk.co.uk/glossary.cfm
Proven field	An oil and/or gas field whose physical extent and estimated reserves have been determined.	https://oilandgasuk.co.uk/glossary.cfm
Proven reserves	Those reserves which on the available evidence are virtually certain to be technically and economically producible (i.e. having a better than 90% chance of being produced).	https://oilandgasuk.co.uk/glossary.cfm
Recoverable reserves	That proportion of the oil and/gas in a reservoir that can be removed using currently available techniques.	https://oilandgasuk.co.uk/glossary.cfm
Recovery factor	The ratio of recoverable oil and/or gas reserves to the estimated oil and/or gas in place in the reservoir.	https://oilandgasuk.co.uk/glossary.cfm
Reservoir	The underground formation where oil and gas has accumulated. It consists of a porous rock to hold the oil or gas, and a cap rock that prevents its escape.	https://oilandgasuk.co.uk/glossary.cfm

Royalty	A percentage interest in the value of production from a lease that is retained and paid to the mineral rights owner.	https://oilandgasuk.co.uk/glossary.cfm
Spud-in	The operation of drilling the first part of a new well.	https://oilandgasuk.co.uk/glossary.cfm
tcf	Trillion Cubic Feet (of gas).	https://oilandgasuk.co.uk/glossary.cfm
Well log	A record of geological formation penetrated during drilling, including technical details of the operation.	https://oilandgasuk.co.uk/glossary.cfm
Wildcat well	A well drilled in an area where no current oil or gas production exists.	https://oilandgasuk.co.uk/glossary.cfm
Workover	Operations on a producing well to restore or increase production. A workover may be performed to stimulate the well, remove sand or wax from the wellbore, to mechanically repair the well, or for other reasons.	https://oilandgasuk.co.uk/glossary.cfm
WTI	West Texas Intermediate, a type of crude oil commonly used as a price benchmark.	https://oilandgasuk.co.uk/glossary.cfm

Conversion Factors

Volume

Unit	multiplied by	Approximate Conversion Factor	equals	Unit
barrels of oil (bbl)	X	42	=	US gallons (gal)
barrels of oil (bbl)	X	0.136	=	tonnes of oil equivalent (toe)
barrels of oil (bbl)	X	0.1589873	=	cubic metres (m ³)
barrels of oil equivalent (boe)	X	5,658.53	=	Cubic feet (f ³) of natural gas
tonnes of oil equivalent (toe)	X	7.33 ^[1]	=	Barrels of oil equivalent
cubic feet (f ³)	X	0.02831685	=	cubic metres (m ³)
cubic feet (f ³) of natural gas	X	0.0001767	=	Barrels of oil equivalent (boe)
Cubic metres	X	6.2898106	=	barrel
[1] This conversion can range from 6.5 to 7.9 depending on the type of crude oil. This factor is intended to provide an approximation that can be used when the exact factor is unknown.				

Area

Unit	multiplied by	Approximate Conversion Factor	equals	Unit
Acres	X	0.40469	=	Hectares (ha)
Square miles (mi ²)	X	2.589988	=	Square kilometres (km ²)
Square feet (ft ²)	X	0.09290304	=	Square metres (m ²)
Square kilometres (km ²)	X	247.105381	=	Acres

Energy

Unit	multiplied by	Approximate Conversion Factor	equals	Unit
British Thermal Units (Btus)	X	1,055.05585262	=	joules (J)
kilowatt hours (kWh)	X	3.6	=	Megajoules (MJ)
tonnes of oil equivalent	X	10,000,000	=	kilocalories (kcal)
tonnes of oil equivalent	X	41.868	=	Gigajoules (GJ)
tonnes of oil equivalent	X	11,630	=	Kilowatt hours (kWh)
cubic feet (f3) of natural gas	X	1,025	=	British Thermal Units (Btus)

Permeability

Unit	multiplied by	Approximate Conversion Factor	equals	Unit
1 Darcy	X	0.986923×10^{-12}	=	Square metres
1 Darcy	X	0.986923×10^{-8}	=	Square centimetres
1 Darcy	X	1.06×10^{-11}	=	Square feet

Density

Unit	multiplied by	Approximate Conversion Factor	equals	Unit
1 g/cm ³	X	62.42797	=	lb/ft ³
1 g/cm ³	X	1000	=	kg/m ³
1 lb/ft ³	X	0.016018	=	g/cm ³

Pressure Gradient

Unit	multiplied by	Approximate Conversion Factor	equals	Unit
1 psi/ft	X	144	=	lb/ft ³
1 psi/ft	X	19.24	=	lb/gal
1 psi/ft	X	2.31	=	g/cm ³
1 psi/ft	X	2.31	=	SG
1 psi/ft	X	0.0225	=	Mpa/m
1lb/gal		119.826427		kg/m ³

Pressure

Unit	multiplied by	Approximate Conversion Factor	equals	Unit
1 atm	X	1.01325	=	bars
1 atm	X	14.695949	=	psi
1 atm	X	1.033227	=	kg-force/cm ²
1 bar	X	10 ⁶	=	dinas/cm ²
1 bar	X	10 ⁵	=	newtons/m ²
1 bar	X	0.1	=	Mpa
1 bar	X	14.50	=	pound/sq inch
1 kg-force/cm ²	X	9.80665 10 ⁵	=	dinas/cm ²
1 kg-force/cm ²	X	0.97784	=	atm
1 kg-force/cm ²	X	14.22	=	pounds/sq inch
1 psi	X	0.07307	=	kg/cm ²
1 psi	X	0.006895	=	Mpa
1 psi	X	0.06895	=	bar

1 Pa	X	1	=	n/m ²
1 Pa	X	1.4504 10 ⁻⁴	=	psi
1 Mpa	X	10 ⁶	=	Pa
1 Mpa	X	145.0378	=	psi
1 Mpa	X	10	=	bars
1kb	X	100	=	Mpa

Force

Unit	multiplied by	Approximate Conversion Factor	equals	Unit
1 newton	X	1	=	kg-m/s ²
1 dina	X	10 ⁻⁵	=	newtons
1 kg-force	X	9.80665	=	newtons
1 kg-force	X	9.80665 10 ⁵	=	dina

Velocity

Unit	multiplied by	Approximate Conversion Factor	equals	Unit
1 Usec/ft	X	3.278	=	usec/m

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APPENDICES

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APPENDIX 1 DATASET

Dataset used from the new samples and GNS Science. Set of samples are inorganic geochemistry from Rakauroa, Upper Calcareous and Porangahau members and the Waipawa Formation. Follow by organic geochemistry dataset from Rakauroa, Upper Calcareous and Porangahau members and the Waipawa Formation.

*New
Samples
Raw
data*

Ident	Time	UTM		Pos	SiO2	TiO2	Al2O3	Fe2O3	MnO	MgO	CaO	Na2O	K2O	P2O5	L.O.I.	Total	Formation (member)
UPuk-01	3/12/2015 18:40	1880750	5340000	3	77.82	0.31	5.97	2.41	0.00	0.73	3.10	0.90	1.29	0.06	6.66	92.59	Whangai (Rakauroa)
LPuk-03	3/12/2015 15:36	1880750	5340000	2	74.22	0.54	10.50	3.70	0.00	0.81	0.12	0.88	1.95	0.05	6.60	92.78	Whangai (Rakauroa)
LPuk-04	3/12/2015 14:33	1808000	5399500	1	72.91	0.59	10.94	4.42	0.01	0.73	0.23	1.08	2.02	0.06	6.90	92.99	Whangai (Rakauroa)
LPuk-05	3/12/2015 19:40	1808000	5399500	4	74.04	0.54	10.30	3.61	0.00	0.80	0.12	1.05	1.95	0.05	6.88	92.45	Whangai (Rakauroa)
MAN-04	4/12/2015 02:35	1912527	5567808	11	65.47	0.78	10.19	2.32	-0.00	0.61	0.34	0.64	1.89	0.03	17.22	82.26	Waipawa
MAN-03	4/12/2015 03:35	1912529	5567805	12	61.95	0.86	10.97	2.54	-0.00	0.68	0.34	0.38	1.93	0.03	19.58	79.67	Waipawa
MAN-05	3/12/2015 16:40	1912527	5567808	1	59.30	0.91	13.43	4.11	0.00	1.03	0.44	0.68	2.36	0.03	16.79	82.29	Waipawa
MAN-06	3/12/2015 17:40	1912529	5567805	2	65.78	0.69	10.19	3.51	0.00	0.88	0.73	0.28	1.80	0.04	15.28	83.90	Waipawa
AS-07	3/12/2015 20:40	1895100	5516700	5	68.59	0.46	9.71	3.04	0.01	1.05	4.98	1.16	1.75	0.09	9.08	90.84	Whangai (Rakauroa)
AS-18	3/12/2015 21:40	1895000	5516400	6	70.60	0.31	5.87	2.18	0.00	0.74	7.76	0.39	0.98	0.13	10.35	88.96	Whangai (Upper Ca)
AS-11	3/12/2015 22:41	1895100	5516500	7	74.03	0.40	7.88	2.81	0.00	0.89	2.75	0.51	1.30	0.05	8.47	90.62	Whangai (Porangahau)
AS-13	3/12/2015 23:35	1895000	5516500	8	72.95	0.44	8.66	3.12	-0.00	0.93	1.76	0.89	1.43	0.04	8.85	90.21	Whangai (Upper Ca)
TW-05	4/12/2015 00:35	1894380	5514980	9	69.53	0.50	10.29	3.36	0.00	0.72	0.65	0.56	1.53	0.04	12.11	87.18	Waipawa
TW-02	4/12/2015 01:35	1894380	5514980	10	65.05	0.61	12.43	4.17	0.00	0.96	0.41	0.50	1.82	0.04	13.13	86.00	Waipawa

Southern Hawke's Bay

*New
Samples
Raw data*

Ident	Time	UTM		Pos	SiO2	TiO2	Al2O3	Fe2O3	MnO	MgO	CaO	Na2O	K2O	P2O5	L.O.I.	Total	Formation (member)
OW 01	16/05/2016 16:47	2036212	5775106	1	72.84	0.52	10.54	3.62	0.01	1.20	0.43	0.95	1.86	0.03	7.29	92.00	Whangai (Rakauroa)
OW 02	16/05/2016 17:47	2036306	5775153	2	74.95	0.55	9.01	3.45	0.00	1.16	0.28	1.97	1.66	0.03	6.66	93.04	Whangai (Rakauroa)
OW 03	16/05/2016 18:47	2036397	5775246	3	75.74	0.47	8.80	3.27	-0.00	1.07	0.32	1.52	1.65	0.03	6.78	92.87	Whangai (Rakauroa)
RAK 01	16/05/2016 19:47	1995584	5738417	4	70.80	0.48	10.36	3.59	-0.01	1.21	0.50	0.46	1.64	0.03	9.87	89.06	Whangai (Rakauroa)
RAK 02	16/05/2016 20:47	1996048	5738419	5	71.10	0.52	10.89	3.35	-0.00	1.09	0.31	-0.00	1.58	0.03	10.30	88.86	Whangai (Rakauroa)
RAK 03	16/05/2016 21:47	1996077	5738481	6	71.26	0.51	11.18	3.14	-0.01	1.03	0.10	0.10	1.49	0.03	10.18	88.84	Whangai Rakauroa
TEWR 01	16/05/2016 22:48	2021716	5758170	7	74.64	0.40	8.00	2.76	0.01	0.90	1.76	0.45	1.29	0.03	8.96	90.23	Whangai (Rakauroa)
TEWR 02	16/05/2016 23:42	2021620	5757932	8	77.99	0.33	6.65	2.01	-0.01	0.78	1.80	-0.04	1.02	0.04	8.65	90.56	Whangai (Upper Ca)
TEWR 03	17/05/2016 00:42	2021628	5757824	9	63.67	0.72	15.55	3.94	-0.00	0.80	0.06	0.42	2.10	0.04	12.00	87.30	Waipawa

Northern Hawke's Bay

GNS Science Dataset

Raw data																
Ident	Time	UTM		SiO2	TiO2	Al2O3	Fe2O3	MnO	MgO	CaO	Na2O	K2O	P2O5	L.O.I.	Total	Formation (member)
43942	4/01/1981	2803010	6098470	78.56	0.39	8.66	2.48	0	0.92	0.33	1.43	1.47	0.07	5.41	99.74	Whangai (Rakauroa)
43943	4/01/1981	2803200	6098300	84.4	0.28	6.01	1.16	0	0.53	0.05	0.69	1.21	0.04	4.83	99.2	Whangai (Rakauroa)
43944	4/01/1981	2803330	6098390	80.56	0.33	7.02	2.38	0.01	0.82	0.73	0.9	0.95	0.06	6.35	100.11	Whangai (Rakauroa)
44594	1/01/1984	2801050	6098800	84.78	0.32	6.07	1.72	0.05	0.5	0.07	0.79	1.05	0.1	3.74	99.19	Whangai Rakauroa
44598	1/01/1981	2718040	5961200	72.91	0.56	12.09	3.48	0	1	0.21	1.32	2.03	0.06	6.37	100.03	Whangai (Rakauroa)
44599	1/01/1981	2717600	5961700	75.22	0.46	10.54	3.08	0.02	0.94	0.49	1.54	1.71	0.06	4.99	99.05	Whangai (Rakauroa)
44600	1/01/1981	2757040	6003460	77.37	0.39	8.78	2.57	0.01	0.84	0.04	0.99	1.47	0.03	7.41	99.89	Whangai (Rakauroa)
44602	1/01/1982	2895700	6295300	70.84	0.5	12.03	4.22	0.04	1.27	0.6	1.5	2.19	0.06	5.83	99.08	Whangai (Rakauroa)
44603	1/01/1982	2906000	6299800	70.7	0.5	10.94	3.79	0.01	1.45	0.52	0.49	1.56	0.05	9.94	99.95	Whangai (Rakauroa)
44604	1/01/1982	2920700	6324600	75.39	0.45	10.82	3.35	0.02	1.25	0.32	1.52	1.84	0.04	4.69	99.69	Whangai (Rakauroa)
44605	1/01/1982	2920950	6324650	74.95	0.51	11	3.55	0	1.34	0.22	1.3	1.99	0.05	4.63	99.54	Whangai (Rakauroa)
44607	1/01/1982	2930100	6328000	80.96	0.37	7.88	2.38	0	1.02	0.18	1.04	1.35	0.04	3.98	99.16	Whangai (Rakauroa)
44612	1/01/1982	2946170	6336360	74.23	0.45	10.42	3.63	0.01	1.41	0.46	1.01	1.91	0.02	5.78	99.33	Whangai (Rakauroa)

**Raw
data**

Ident	Time	UTM		SiO2	TiO2	Al2O3	Fe2O3	MnO	MgO	CaO	Na2O	K2O	P2O5	L.O.I.	Total	Formation (member)
43945	4/01/1981	2803550	6098300	82.3	0.29	6.45	1.91	0	0.75	0.49	0.95	1.1	0.05	5.53	99.91	Whangai (Upper Ca)
43946	4/01/1981	2803740	6098340	79.13	0.32	7.04	1.92	0	0.85	1.96	1.15	1.18	0.07	6.67	100.4	Whangai (Upper Ca)
43947	4/01/1981	2803830	6098430	75.9	0.4	8.97	2.55	0	1.22	1.51	0.96	1.49	0.07	7.12	100.23	Whangai (Upper Ca)
43948	4/01/1981	2803880	6098480	77.52	0.31	6.84	2.22	0	1.09	2.77	1.09	1.12	0.06	7.15	100.24	Whangai (Upper Ca)
44601	1/01/1981	2756730	6003580	72.22	0.35	7.78	2.52	0	1.04	3.83	0.75	1.23	0.06	9.64	99.42	Whangai (Upper Ca)
44606	1/01/1982	2924500	6323200	73.3	0.49	10.68	2.89	0	1.1	2.3	1.02	1.7	0.04	6.01	99.53	Whangai (Upper Ca)
44609	1/01/1982	2930450	6326400	71.84	0.39	8.58	2.58	0.01	1.04	4.67	0.87	1.45	0.04	7.72	99.19	Whangai (Upper Ca)
44610	1/01/1982	2931700	6319700	70.08	0.41	9.17	3.2	0.01	1.14	4.14	0.96	1.57	0.04	8.79	99.51	Whangai (Upper Ca)
44611	1/01/1982	2931500	6319300	77.26	0.32	7.19	2.25	0.01	1.05	2.5	0.57	1.15	0.05	6.94	99.29	Whangai (Upper Ca)

**Raw
data**

Ident	Time	UTM		SiO2	TiO2	Al2O3	Fe2O3	MnO	MgO	CaO	Na2O	K2O	P2O5	L.O.I.	Total	Formation (member)
44596	1/01/1984	2852350	6145000	58.21	0.27	6.46	1.73	0.05	1.33	15.94	0.47	1.09	0.06	14.38	99.94	Whangai (Porangahau)
44597	1/01/1984	2852350	6145000	68.81	0.40	7.77	2.53	0.04	1.79	6.69	1.54	1.34	0.07	9.06	100.58	Whangai (Porangahau)

**Raw
data**

Ident	Time	UTM	SiO2	TiO2	Al2O3	Fe2O3	MnO	MgO	CaO	Na2O	K2O	P2O5	L.O.I.	Total	Formation (member)	
45736	1/01/1984	2989300	6360800	63.25	0.53	11.64	3.5	0.04	0.95	0.05	0.3	1.63	0.17	17.81	99.84	Waipawa
45737	1/01/1984	2815370	6133950	62.5	0.57	13.32	2.78	0.04	1.25	0.07	1.36	1.73	0.13	16.44	100.15	Waipawa

New samples dataset

Structural Block		Formation	Member	Measure Section	Sample Name	Quantity			Quality		Maturation	
						TOC (wt. %)	S1 (mg HC/g)	S2 (mg HC/g)	HI (mg HC/gTOC)	OI (mgHC/gTOC)	Tmax (°C)	PI
Southern Hawke's Bay	Tora	Whangai	Rakauroa	Pukemuri Stream	Upuk 01	0.89	0.08	1.48	166	16	430	0.05
		Whangai	Rakauroa	Pukemuri Stream	Lpuk 03	1.38	0.16	3.09	224	7	429	0.05
		Whangai	Rakauroa	Pukemuri Stream	Lpuk 04	1.32	0.07	1.68	128	56	435	0.04
		Whangai	Rakauroa	Pukemuri Stream	Lpuk 05	1.33	0.13	2.73	205	8	428	0.05
	Coastal	Whangai	Rakauroa	Angora Stream	AS 07	0.29	0.05	0.08	26	61	378	0.39
		Whangai	Rakauroa	Angora Stream	AS 11	1	0.06	0.84	84	36	424	0.07
		Whangai	Porangahau	Angora Stream	AS 13	1	0.05	0.76	76	28	425	0.06
		Whangai	Upper Calcareous	Angora Stream	AS 18	1.01	0.08	0.94	93	35	427	0.08
Northern Hawke's Bay	Motu	Whangai	Rakauroa	Rakauroa Stream	RAK 01	0.76	0.08	1.04	138	10	430	0.07
		Whangai	Rakauroa	Rakauroa Stream	RAK 02	1.17	0.17	3.15	269	25	428	0.05
		Whangai	Rakauroa	Rakauroa Stream	RAK 03	1.04	0.13	2.56	247	23	427	0.05
	Motu	Whangai	Rakauroa	Waitahaia Owheana	OW01	0.62	0.05	0.75	121	12	438	0.06
		Whangai	Rakauroa	Waitahaia Owheana	OW02	0.48	0.05	0.34	71	30	434	0.12
		Whangai	Rakauroa	Waitahaia Owheana	OW03	0.41	0.04	0.24	58	14	435	0.15
	Allochton	Whangai	Rakauroa	Te Weraroa Stream	TWR01	0.56	0.07	0.82	146	14	434	0.08
		Whangai	Upper Calcareous	Te Weraroa Stream	TWR02	0.76	0.14	1.7	223	14	434	0.08

New samples dataset

Structural Block		Formation	Member	Measure Section	Sample Name	Quantity			Quality		Maturation	
						TOC (wt. %)	S1 (mg HC/g)	S2 (mg HC/g)	HI (mg HC/g TOC)	OI (mgHC/gTOC)	Tmax (°C)	PI
Southern Hawke's Bay	Coastal	Waipawa	NA	Taylor White	TW02	3.57	0.16	11.2	312	15	411	0.01
		Waipawa	NA	Taylor White	TW05	2.75	0.10	6.45	234	37	416	0.02
	Pongaroa	Waipawa	NA	Mangatarata Valley	MAN03	4.21	0.24	3.26	78	81	386	0.07
		Waipawa	NA	Mangatarata Valley	MAN04	2.51	0.12	2.39	95	82	398	0.05
		Waipawa	NA	Mangatarata Valley	MAN05	2.57	0.10	3.31	129	50	401	0.03
		Waipawa	NA	Mangatarata Valley	MAN06	2.48	0.09	4.01	162	46	411	0.02
Northern Hawke's Bay	Allochton	Waipawa	NA	Te Weraroa	TWR03	2.82	1.29	11.5	406	02	426	0.10

GNS dataset

Rakauroa mb.

Sample_num	Formation	Member	Block	Date_of_Ro	UTM		TOC	S1	S2	HI	OI	Tmax	PI
U24/f540	Whangai	Rakauroa	Coastal Block	Jun. 1992	2805100	6078400	0.98	0.03	0.45	46	11	416	0.06
24-4	Whangai	Rakauroa	Coastal Block		2757000	6003500	0.9	0.1	1.5	167	89	418	0.06
60-38	Whangai	Rakauroa	Coastal Block		2852400	6145000	0.6	0.1	0.9	150	217	418	0.1
52-4	Whangai	Rakauroa	East Coast Allochthon		2970700	6357500	0.2	0.1	0.7	350	400	428	0.13
KR55	Whangai	Rakauroa	East Coast Allochthon		2960200	6381100	0.93	0.13	0.7	75	81	424	0.16
AN-1	Whangai	Rakauroa	Motu Block		2879000	6283000	0.8	0	1.4	175	75	431	0
42-6	Whangai	Rakauroa	Motu Block		2920900	6325700	0.6	0.1	0.5	83	0	434	0.17
10-7	Whangai	Rakauroa	Motu Block		2895700	6295300	0.4	0	0.6	150	100	440	0
X17/f309	Whangai	Rakauroa	Motu Block	Jun. 1992	2895690	6295210	0.73	0.07	1.34	184	8	436	0.05
X17/f310	Whangai	Rakauroa	Motu Block	Jun. 1992	2895670	6295220	0.61	0.08	0.65	107	25	439	0.11
X17/f311	Whangai	Rakauroa	Motu Block	Jun. 1992	2895660	6295250	0.65	0.16	0.83	128	12	428	0.16
X17/f312	Whangai	Rakauroa	Motu Block	Jun. 1992	2895650	6295270	0.57	0.15	0.87	153	32	432	0.15
X17/f313	Whangai	Rakauroa	Motu Block	Jun. 1992	2895640	6295300	0.54	0.12	0.85	157	33	438	0.12
X17/f314	Whangai	Rakauroa	Motu Block	Jun. 1992	2895620	6295340	0.54	0.11	0.68	126	39	436	0.14
KR28	Whangai	Rakauroa	Motu Block		2841700	6247150	0.9	0.04	0.51	57	0	417	0.07
KR29	Whangai	Rakauroa	Motu Block		2841650	6247200	0.83	0.08	1.19	144	0	426	0.06
KR30	Whangai	Rakauroa	Motu Block		2841650	6247200	0.92	0.07	0.51	56	0	414	0.12
9-11	Whangai	Rakauroa	Motu Block		2841600	6247200	0.7	0.1	1.8	257	43	422	0.05
V19/f251	Whangai	Rakauroa	Motu Block	Jun. 1992	2841750	6247170	0.7	0.05	0.96	137	26	423	0.05
V19/f252	Whangai	Rakauroa	Motu Block	Jun. 1992	2841730	6247180	0.77	0.09	1.17	152	26	419	0.07
V19/f253	Whangai	Rakauroa	Motu Block	Jun. 1992	2841710	6247210	0.81	0.11	1.3	160	31	425	0.08
V19/f254	Whangai	Rakauroa	Motu Block	Jun. 1992	2841690	6247240	0.71	0.06	0.99	139	27	425	0.06
X17/f315	Whangai	Rakauroa	Motu Block	Jun. 1992	2905960	6299860	0.44	0.11	1.1	250	30	427	0.09
X17/f316	Whangai	Rakauroa	Motu Block	Jun. 1992	2906050	6299930	0.72	0.32	2.42	336	24	427	0.12
KR9	Whangai	Rakauroa	Motu Block		2906100	6299900	0.96	0.17	1.06	111	0	425	0.14
KR113	Whangai	Rakauroa	Motu Block		2898400	6293600	0.81	0.14	1.21	148	0	422	0.1
KR121	Whangai	Rakauroa	Motu Block		2898400	6293500	0.87	0.1	0.97	111	0	423	0.09
V19/f238	Whangai	Rakauroa	Motu Block	Jun. 1992	2840530	6249160	0.59	0.03	0.39	66	27	418	0.07

V19/f239	Whangai	Rakauroa	Motu Block	Jun. 1992	2840520	6249150	0.52	0.06	0.66	127	23	422	0.08
V19/f240	Whangai	Rakauroa	Motu Block	Jun. 1992	2840520	6249140	0.7	0.11	1.4	200	24	426	0.07
V19/f241	Whangai	Rakauroa	Motu Block	Jun. 1992	2840510	6249130	0.48	0.07	0.85	177	27	430	0.08
44-6	Whangai	Rakauroa	Motu Block		2930100	6328000	0.6	0.6	1.8	300	117	434	0.25
KR31	Whangai	Rakauroa	Motu Block		2843800	6248400	1.07	0.06	0.66	61	1	416	0.08
KR32	Whangai	Rakauroa	Motu Block		2843800	6248400	0.93	0.05	0.59	63	0	413	0.08
V19/f231	Whangai	Rakauroa	Motu Block	Jun. 1992	2843700	6248300	0.79	0.11	1.17	148	35	417	0.09
V19/f232	Whangai	Rakauroa	Motu Block	Jun. 1992	2843750	6248350	0.6	0.07	0.95	158	38	419	0.07
12-Jun	Whangai	Rakauroa	Motu Block		2946200	6336400	0.2	0	0.4	200	0	436	0
Rere-1 2034m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.93	0.35	2.2	237	103	433	0.14
Rere-1 2040m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.96	0.28	2.12	221	120	436	0.12
Rere-1 2046m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.92	0.28	2.09	227	93	434	0.12
Rere-1 2049m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.94	0.27	1.92	204	95	435	0.12
Rere-1 2055m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.94	0.28	1.74	185	86	435	0.14
Rere-1 2061m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.94	0.23	1.58	168	86	434	0.13
Rere-1 2067m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.96	0.29	2.01	209	72	437	0.13
Rere-1 2076m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.88	0.22	1.61	183	68	435	0.12
Rere-1 2085m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.9	0.23	1.75	194	66	435	0.12
Rere-1 2091m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.83	0.32	2.01	242	112	432	0.14
Rere-1 2097m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.8	0.26	1.77	221	85	434	0.13
Rere-1 2100m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.82	0.29	1.8	220	88	434	0.14
Rere-1 2103m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.78	0.22	1.63	209	73	435	0.12
Rere-1 2112m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.09	0.24	2.04	187	81	437	0.11
Rere-1 2118m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.97	0.14	1.49	154	71	435	0.09

Rere-1 2121m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.08	0.2	2.05	190	84	437	0.09
Rere-1 2130m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.03	0.19	2.12	206	62	439	0.08
Rere-1 2139m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1	0.12	0.95	95	49	422	0.11
Rere-1 2154m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.17	0.79	3.49	298	136	432	0.18
Rere-1 2169m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.11	0.33	2.46	222	65	436	0.12
Rere-1 2181m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.08	0.3	2.42	224	63	436	0.11
Rere-1 2190m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.1	0.25	2.3	209	61	437	0.1
Rere-1 2199m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.1	0.21	1.15	105	100	433	0.15
Rere-1 2208m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.13	0.36	2.11	187	83	431	0.15
Rere-1 2220m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.07	0.38	2.14	200	153	434	0.15
Rere-1 2229m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.06	0.34	2.23	210	111	437	0.13
Rere-1 2241m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.14	0.28	1.94	170	128	435	0.13
Rere-1 2250m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.1	0.26	2.48	225	112	434	0.09
Rere-1 2259m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.31	0.39	2.14	163	121	436	0.15
Rere-1 2271m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.98	0.3	2.26	231	85	435	0.12
Rere-1 2280m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.01	0.4	2.51	249	128	433	0.14
Rere-1 2289m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.1	0.25	2.47	225	84	435	0.09
Rere-1 2301m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.46	0.49	3.78	259	75	433	0.11
Rere-1 2310m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.2	0.34	3.02	252	58	433	0.1
Rere-1 2319m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.25	0.33	3.32	266	53	428	0.09
Rere-1 2331m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.04	0.31	2.38	229	71	434	0.12

Rere-1 2343m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1	0.34	2.81	281	88	432	0.11
Rere-1 2355m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.94	0.28	1.69	180	66	431	0.14
Rere-1 2367m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.99	0.29	2.16	218	49	429	0.12
Rere-1 2379m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.13	0.26	2.19	194	63	434	0.11
Rere-1 2391m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.2	0.32	1.96	163	103	435	0.14
Rere-1 2403m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.05	0.2	0.88	84	111	429	0.19
Rere-1 2415m	Whangai	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.71	0.15	0.5	70	146	414	0.23
Rere-1 2028m	Whangai/Waipawa?	Rakauroa	Motu Block	Sept. 1994	2908100	6289687	1.77	0.68	4.51	255	47	422	0.13
Rere-1 2010m	Whangai/Waipawa?	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.01	0.39	2.11	209	135	430	0.16
Rere-1 2016m	Whangai/Waipawa?	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.01	0.39	2.1	208	128	430	0.16
Rere-1 2022m	Whangai/Waipawa?	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1.07	0.29	2.23	208	87	434	0.12
Rere-1 2025m	Whangai/Waipawa?	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	1	0.25	2.04	204	83	433	0.11
Rere-1 2028m	Whangai/Waipawa?	Rakauroa	Motu Block	Jun. 2012	2908100	6289687	0.99	0.31	2.23	225	78	435	0.12
TW-4	Whangai	Rakauroa	Pongaroa Block		2784740	6084020	0.68	0.08	1.68	247	24	416	0.05
TW-5	Whangai	Rakauroa	Pongaroa Block		2784090	6081340	0.63	0.04	1.33	211	43	419	0.03
TW-27	Whangai	Rakauroa	Pongaroa Block		2783530	6082720	0.9	0.05	2.03	226	22	411	0.02
TW-28	Whangai	Rakauroa	Pongaroa Block		2783540	6082750	1.04	0.1	3.18	306	23	417	0.03
TW-29	Whangai	Rakauroa	Pongaroa Block		2783520	6082790	0.84	0.03	1.49	177	39	420	0.02
TW-30	Whangai	Rakauroa	Pongaroa Block		2783520	6082820	0.86	0.04	1.38	160	33	416	0.03
TW-31	Whangai	Rakauroa	Pongaroa Block		2783500	6082830	0.81	0.04	1.99	246	31	425	0.02
KY-14	Whangai	Rakauroa	Pongaroa Block		2816350	6138560	1.43	0.18	2.84	199	10	427	0.06
KY-15	Whangai	Rakauroa	Pongaroa Block		2816320	6138600	1.67	0.21	3.66	219	11	433	0.05
KY-16	Whangai	Rakauroa	Pongaroa Block		2816370	6138700	1.37	0.23	2.99	218	28	431	0.07
KY-17	Whangai	Rakauroa	Pongaroa Block		2816370	6138700	1.31	0.12	2.28	174	14	429	0.05
2-4	Whangai	Rakauroa	Pongaroa Block		2816300	6138600	1.5	0.3	3.1	207	27	430	0.09

KY-20	Whangai	Rakauroa	Pongaroa Block		2786500	6090870	0.77	0.11	1.33	173	42	408	0.08
KY-22	Whangai	Rakauroa	Pongaroa Block		2786500	6090870	0.82	0.1	1.1	134	49	406	0.08
KY-24	Whangai	Rakauroa	Pongaroa Block		2786500	6090870	0.8	0.05	0.76	95	48	401	0.06
8-5	Whangai	Rakauroa	Pongaroa Block		2796300	6105800	1	0.1	1	100	70	405	0.09
U24/f581	Whangai	Rakauroa	Pongaroa Block	Jun. 1992	2802920	6098450	0.72	0.15	1.91	265	68	411	0.07
U24/f582	Whangai	Rakauroa	Pongaroa Block	Jun. 1992	2803170	6098450	0.48	0.2	0.68	142	58	407	0.23
U24/f583	Whangai	Rakauroa	Pongaroa Block	Jun. 1992	2803230	6098430	0.37	0.18	0.7	189	68	419	0.2
U24/f584	Whangai	Rakauroa	Pongaroa Block	Jun. 1992	2803200	6098290	0.43	0.07	0.76	177	44	422	0.08
U24/f585	Whangai	Rakauroa	Pongaroa Block	Jun. 1992	2803360	6098390	0.44	0.03	0.53	120	34	406	0.05
NE27	Whangai	Rakauroa	Pongaroa Block		2816300	6138600	1.52	0.28	3.32	218	28	431	0.08
TW-19	Whangai	Rakauroa	Pongaroa Block		2784010	6082450	0.72	0.04	1.49	207	25	418	0.03
TW-20	Whangai	Rakauroa	Pongaroa Block		2784000	6082450	0.67	0.04	1.49	222	18	414	0.03
TW-32	Whangai	Rakauroa	Pongaroa Block		2783480	6082800	0.85	0.05	2.16	254	22	417	0.02
TW-33	Whangai	Rakauroa	Pongaroa Block		2783480	6082750	1.63	0.06	4.51	277	15	421	0.01
TW-34	Whangai	Rakauroa	Pongaroa Block		2783478	6082750	1.68	0.06	4.31	257	23	420	0.01
TW-35	Whangai	Rakauroa	Pongaroa Block		2783450	6082760	0.85	0.04	1.51	178	76	422	0.03
TW-37	Whangai	Rakauroa	Pongaroa Block		2783100	6082770	0.81	0.05	2	247	36	422	0.02
TW-38	Whangai	Rakauroa	Pongaroa Block		2782920	6082820	0.81	0.06	2.09	258	30	421	0.03
TW-26	Whangai	Rakauroa	Pongaroa Block		2783580	6082740	0.79	0.04	1.6	203	27	416	0.02
TW-114	Whangai	Rakauroa	Pongaroa Block		2780100	6082750	0.93	0.07	1.42	153	44	412	0.05
TW-61	Whangai	Rakauroa	Pongaroa Block		2782180	6081480	0.81	0	1.51	186	33	420	0
TW-62	Whangai	Rakauroa	Pongaroa Block		2782120	6081610	0.81	0.03	1.45	179	35	414	0.02
TW-63	Whangai	Rakauroa	Pongaroa Block		2782010	6081650	0.7	0.03	1.8	257	44	419	0.02
TW-64	Whangai	Rakauroa	Pongaroa Block		2781930	6081680	0.7	0.04	1.37	196	41	416	0.03
TW-65	Whangai	Rakauroa	Pongaroa Block		2781850	6081740	0.59	0.03	1.08	183	42	415	0.03
TW-67	Whangai	Rakauroa	Pongaroa Block		2781730	6081810	0.65	0.04	0.59	91	40	405	0.06
TW-68	Whangai	Rakauroa	Pongaroa Block		2781660	6081830	0.71	0.06	0.81	114	41	404	0.07
TW-69	Whangai	Rakauroa	Pongaroa Block		2781540	6081850	0.71	0.07	0.84	118	51	407	0.08
TW-60	Whangai	Rakauroa	Pongaroa Block		2782230	6081450	0.74	0.05	1.6	216	24	418	0.03
TW-72	Whangai	Rakauroa	Pongaroa Block		2781340	6081970	0.51	0.02	0.23	45	43	401	0.08
TW-76	Whangai	Rakauroa	Pongaroa Block		2786300	6080290	0.56	0.03	1.64	293	32	414	0.02

TW-75	Whangai	Rakauroa	Pongaroa Block		2786200	6080290	0.66	0.05	1.44	218	27	417	0.03
TW-159	Whangai	Rakauroa	Pongaroa Block		2786870	6086240	0.83	0.09	1.66	200	42	406	0.05
TW-161	Whangai	Rakauroa	Pongaroa Block		2786970	6086320	0.78	0.09	1.05	135	46	409	0.08
TW-81	Whangai	Rakauroa	Pongaroa Block		2785630	6087210	0.76	0.05	1.41	186	46	416	0.03
TW-82	Whangai	Rakauroa	Pongaroa Block		2785380	6087270	0.63	0.05	1.1	175	48	412	0.04
TW-83	Whangai	Rakauroa	Pongaroa Block		2785380	6087270	0.63	0.04	1.25	198	46	418	0.03
TW-85	Whangai	Rakauroa	Pongaroa Block		2785320	6087370	0.69	0.06	1.39	201	42	415	0.04
TW-86	Whangai	Rakauroa	Pongaroa Block		2785270	6087430	0.67	0.08	0.75	112	52	405	0.1
TW-87	Whangai	Rakauroa	Pongaroa Block		2785270	6087430	0.85	0.12	1.15	135	46	402	0.09
TW-88	Whangai	Rakauroa	Pongaroa Block		2785270	6087430	0.91	0.09	0.94	103	56	404	0.09
TW-21	Whangai	Rakauroa?	Pongaroa Block		2784020	6082610	0.55	0	0.2	36	95	438	0
TW-42	Whangai	Rakauroa?	Pongaroa Block		2782310	6082990	0.73	0.05	1.39	190	51	422	0.03
Hukarere-1 (2917m)	Whangai	Rakauroa	Pongaroa Block		2847242	6185251	1.24	5.03	10.14	818	190	436	0.33
Hukarere-1 (3027m)	Whangai	Rakauroa	Pongaroa Block		2847242	6185251	1.37	5.12	8.4	613	199	433	0.38
7-6	Whangai	Rakauroa	Pongaroa Block		2803200	6098300	0.4	0.1	1.1	275	125	403	0.08
ToiFlat-1 TW-163	Whangai		Pongaroa Block		2790500	6089900	0.81	0.13	1.63	201	54	422	0.07
NE121	Whangai	Rakauroa	Pongaroa Block?		2783500	6055700	1.29	0.13	0.53	41	32	412	0.2
NE144	Whangai	Rakauroa	Tora Block		2719200	5962800	1.64	0.37	2.70	165	26	429	0.12
22-4	Whangai	Rakauroa	Tora Block		2717900	5961300	0.2	0	0.50	250	150	439	0
NE136	Whangai	Rakauroa	Tora Block		2713700	5957300	1.02	0.16	1.24	122	28	422	0.11
Ranui-1 (910m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.54	0.09	1.17	217	39	357.00	0.07
Ranui-1 (920m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.58	0.10	1.78	307	41	354.00	0.05
Ranui-1 (930m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.82	0.21	2.43	296	29	347.00	0.08
Ranui-1 (940m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.62	0.12	1.95	315	21	428.00	0.06
Ranui-1 (950m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.69	0.15	1.91	277	28	348.00	0.07
Ranui-1 (960m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.71	0.18	1.84	259	23	340.00	0.09

Ranui-1 (970m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.69	0.09	1.48	214	20	349.00	0.06
Ranui-1 (980m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.78	0.16	1.82	233	24	342.00	0.08
Ranui-1 (990m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.76	0.16	1.62	213	20	344.00	0.09
Ranui-1 (1000m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.63	0.13	1.48	235	51	341.00	0.08
Ranui-1 (1010m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.78	0.15	1.84	236	26	344.00	0.08
Ranui-1 (1020m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.72	0.16	1.60	222	29	342.00	0.09
Ranui-1 (1030m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.79	0.14	1.49	189	22	348.00	0.09
Ranui-1 (1040m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.67	0.13	1.52	227	27	345.00	0.08
Ranui-1 (1050m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.77	0.16	1.64	213	30	343.00	0.09
Ranui-1 (1060m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.67	0.15	1.80	269	45	345.00	0.08
Ranui-1 (1070m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.81	0.19	1.98	244	44	344.00	0.09
Ranui-1 (1080m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.85	0.15	1.74	205	44	349.00	0.08
Ranui-1 (1090m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.62	0.11	1.35	218	53	347.00	0.08
Ranui-1 (1100m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.83	0.15	1.94	234	45	348	0.07
Ranui-1 (1110m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.75	0.12	1.46	195	49	348	0.08
Ranui-1 (1120m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.83	0.16	1.77	213	42	347	0.08
Ranui-1 (1130m)	Whangai	Rakauroa	Pongaroa Block	06/10/2011	1845616	5463540	0.84	0.16	1.66	208	45	347	0.09

Upper Calcareous

Sample_num	Formation	Member	Block	Date_of_Ro	UTM		TOC	S1	S2	HI	OI	Tmax	PI
NE113	Whangai	Upper Calcareous	Coastal Block		2799800	6061900	1	0.24	1.13	113	50	422	0.18
5-10	Whangai	Upper Calcareous	Coastal Block		2805000	6078100	0.5	0	0.8	160	60	427	0
U24/f559	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805040	6078230	0.63	0.18	1.19	189	19	417	0.13
U24/f560	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805040	6078210	0.56	0.05	0.88	157	23	423	0.05
U24/f561	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805030	6078200	0.58	0.09	1.03	178	28	429	0.08
U24/f562	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805030	6078190	0.49	0.06	0.72	147	22	422	0.08
U24/f563	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805020	6078180	0.55	0.06	0.65	118	24	424	0.08
U24/f564	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805020	6078170	0.57	0.11	0.82	144	35	424	0.12
U24/f565	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805010	6078160	0.5	0.05	0.84	168	34	423	0.06
U24/f566	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805010	6078150	0.65	0.19	1.5	231	35	423	0.11
U24/f567	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805000	6078140	0.31	0.07	1.17	377	65	425	0.06
U24/f568	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805000	6078130	0.39	0.05	1.19	305	46	424	0.04
U24/f569	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805000	6078120	0.63	0.14	1.56	248	41	423	0.08
U24/f570	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805010	6078090	1.7	0.17	4.32	254	24	420	0.04
U24/f571	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805010	6078090	1.04	0.09	2.99	288	27	423	0.03
U24/f572	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805020	6078080	1.55	0.1	4.42	285	27	423	0.02
U24/f573	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2805020	6078060	1.52	0.16	4.31	284	23	421	0.04
DAL3-33	Whangai	Upper Calcareous	Coastal Block	Jan. 2010	2805010	6078090	1.7	0.06	1.37	81	36	410	0.04
MT3-03	Whangai	Upper Calcareous	Coastal Block	Oct. 2011	2804969	6078128	1.12	0.05	1.61	144	40	427	0.03
MT3-07	Whangai	Upper Calcareous	Coastal Block	Oct. 2011	2804969	6078128	0.77	0.04	0.3	39	56	420	0.12
MT3-09	Whangai	Upper Calcareous	Coastal Block	Oct. 2011	2804969	6078128	1.06	0.05	1.36	128	43	427	0.04
MT3-13	Whangai	Upper Calcareous	Coastal Block	Oct. 2011	2804969	6078128	1.01	0.05	1.17	116	44	426	0.04
MT3-16	Whangai	Upper Calcareous	Coastal Block	Oct. 2011	2804969	6078128	1.02	0.06	1.29	126	40	426	0.04
MT3-19	Whangai	Upper Calcareous	Coastal Block	Oct. 2011	2804969	6078128	1.23	0.05	1.49	121	36	428	0.03
MT3-28	Whangai	Upper Calcareous	Coastal Block	Oct. 2011	2804941	6078064	1.77	0.08	1.55	88	36	408	0.05
MT3-29	Whangai	Upper Calcareous	Coastal Block	Oct. 2011	2804941	6078064	2.01	0.09	3.25	162	37	426	0.03
DAL1001	Whangai	Upper Calcareous	Coastal Block	Jun. 1992	2769400	6011000	0.87	0.12	1.7	195	71	429	0.07
25-2D	Whangai	Upper Calcareous	Coastal Block		2779700	6048300	0.4	0	0.8	200	100	421	0
NE24	Whangai	Upper Calcareous	Coastal Block		2804900	6078100	1.3	0.26	2.64	203	72	430	0.09

NE46	Whangai	Upper Calcareous	Coastal Block		2778300	6033300	0.95	0.13	1.29	136	122	428	0.09
14-1	Whangai	Upper Calcareous	East Coast Allochthon		2931700	6319700	0.2	0.1	0.7	350	50	433	0.13
Y16/f798	Whangai	Upper Calcareous	East Coast Allochthon	Jun. 1992	2931700	6319500	0.28	0.07	0.61	218	36	432	0.1
Y16/f799	Whangai	Upper Calcareous	East Coast Allochthon	Jun. 1992	2931700	6319500	0.44	0.15	1.56	355	39	433	0.09
Y16/f800	Whangai	Upper Calcareous	East Coast Allochthon	Jun. 1992	2931700	6319400	0.41	0.33	1.29	315	39	427	0.2
Y16/f801	Whangai	Upper Calcareous	East Coast Allochthon	Jun. 1992	2931700	6319400	0.59	0.35	1.83	310	34	429	0.16
43-1	Whangai	Upper Calcareous	Motu Block		2924500	6323200	0.4	0.3	1.4	350	25	450	0.18
U24/f586	Whangai	Upper Calcareous	Pongaroa Block	Jun. 1992	2803400	6098350	0.27	0.04	0.39	144	48	414	0.09
U24/f587	Whangai	Upper Calcareous	Pongaroa Block	Jun. 1992	2803460	6098320	0.37	0.13	0.7	189	57	421	0.16
U24/f588	Whangai	Upper Calcareous	Pongaroa Block	Jun. 1992	2803530	6098300	0.32	0.11	0.49	153	63	413	0.18
U24/f589	Whangai	Upper Calcareous	Pongaroa Block	Jun. 1992	2803590	6098310	0.26	0.19	0.45	173	92	415	0.3
U24/f590	Whangai	Upper Calcareous	Pongaroa Block	Jun. 1992	2803670	6098300	0.17	0.07	0.2	118	88	413	0.26
U24/f591	Whangai	Upper Calcareous	Pongaroa Block	Jun. 1992	2803740	6098350	0.33	0.07	0.34	103	58	419	0.17
U24/f529	Whangai	Upper Calcareous	Pongaroa Block	Jun. 1992	2796720	6086320	0.27	0.02	0.34	126	81	421	0.06
U24/f530	Whangai	Upper Calcareous	Pongaroa Block	Jun. 1992	2796720	6086320	0.08	0.01	0.04	50	113	374	0.2
U24/f531	Whangai	Upper Calcareous	Pongaroa Block	Jun. 1992	2796720	6086320	0.25	0.06	0.24	96	40	412	0.2
61-1	Whangai	Upper Calcareous	Pongaroa Block		2843800	6156300	0.2	0	0.3	150	250	429	0
TW-77	Whangai	Upper Calcareous	Pongaroa Block		2786400	6080350	0.54	0.01	1.22	226	31	419	0.01

Porangahau mb.

Sample_num	Formation	Member	Block	Date_of_Ro	UTM		TOC	S1	S2	HI	OI	Tmax	PI
U24/f552	Whangai	Porangahau	Coastal Block	Jun. 1992	2805060	6078290	0.45	0.05	0.55	122	18	425	0.08
U24/f553	Whangai	Porangahau	Coastal Block	Jun. 1992	2805060	6078260	0.03	0.02	0.04	133	167	396	0.33
U24/f558	Whangai	Porangahau	Coastal Block	Jun. 1992	2805040	6078230	0.11	0.05	0.11	100	0	403	0.31
V22/f418	Whangai	Porangahau	Coastal Block	Jun. 1992	2842800	6131620	0.03	0.16	0.06	200	533	359	0.73
V22/f419	Whangai	Porangahau	Coastal Block	Jun. 1992	2842790	6131620	0.39	0.18	0.39	100	90	414	0.32
V22/f420	Whangai	Porangahau	Coastal Block	Jun. 1992	2842780	6131610	0.01	0.03	0.07	700	1600	391	0.3
KR134	Whangai	Porangahau	East Coast Allochthon		2936550	6216950	0.75	0.03	0.2	27	0	446	0.13
13-4	Whangai	Porangahau?	East Coast Allochthon		2970600	6370800	0.4	0.1	1.1	275	50	431	0.08

Waipawa Fm.

Sample_num	Formation	Block	Date_of_Ro	UTM		TOC	S1	S2	HI	OI	Tmax	PI
DAL1009	Waipawa	Coastal Block	Jun. 1992	2804500	6076700	2.95	0.14	4.48	152	31	418	0.03
NE23	Waipawa	Coastal Block		2805000	6078000	4.99	1.18	11.03	221	42	403	0.1
5-11	Waipawa	Coastal Block		2805000	6078000	4.5	0.7	16.1	358	42	414	0.04
DAL1004	Waipawa	Coastal Block	Jun. 1992	2805000	6078000	2.96	0.21	4.73	160	29	416	0.04
DAL3-39	Waipawa	Coastal Block	Jun. 1992	2805040	6078010	3.17	0.25	7.57	239	19	412	0.03
U24/f574	Waipawa	Coastal Block	Jun. 1992	2805020	6078040	4.35	0.58	14.73	339	14	408	0.04
U24/f575	Waipawa	Coastal Block	Jun. 1992	2805030	6078020	4.78	0.88	16.63	348	10	407	0.05
U24/f576	Waipawa	Coastal Block	Jun. 1992	2805040	6078010	3.15	0.39	8.5	270	10	412	0.04
U24/f577	Waipawa	Coastal Block	Jun. 1992	2805050	6078000	2.64	0.35	6.39	242	11	410	0.05
U24/f578	Waipawa	Coastal Block	Jun. 1992	2805050	6078010	5.75	0.82	16.59	289	1	411	0.05
U24/f579	Waipawa	Coastal Block	Jun. 1992	2805060	6078020	4.44	0.87	13.96	314	16	410	0.06
DAL3-37	Waipawa	Coastal Block	Jan. 2010	2805020	6078020	4.07	0.22	7.77	191	28	401	0.03
DAL3-39	Waipawa	Coastal Block	Jan. 2010	2805040	6078010	3.05	0.11	3.88	127	30	403	0.03
DAL3-41	Waipawa	Coastal Block	Jan. 2010	2805050	6078010	5.18	0.27	8.57	165	28	404	0.03
24-11	Waipawa	Coastal Block		2756600	6003700	1.8	0.1	3.3	183	61	429	0.03
KB-1	Waipawa	Coastal Block		2778300	6033300	6.58	0.28	14.7	223	29	408	0.02
NE44	Waipawa	Coastal Block		2778300	6033300	3.17	0.31	3.94	124	58	407	0.07
NE45	Waipawa	Coastal Block		2778300	6033300	4.24	0.51	5.36	126	65	413	0.09
MT3-100	Waipawa	Coastal Block	Oct. 2011	2804971	6078057	4.01	0.24	8.27	206	32	406	0.03
MT3-103	Waipawa	Coastal Block	Oct. 2011	2804971	6078057	3.99	0.2	8.3	208	28	401	0.02
MT3-113	Waipawa	Coastal Block	Oct. 2011	2804989	6078004	2.91	0.13	4.76	164	37	413	0.03
MT3-119	Waipawa	Coastal Block	Oct. 2011	2804989	6078004	4.64	0.3	12.18	263	27	401	0.02
MT3-127	Waipawa	Coastal Block	Oct. 2011	2804989	6078004	1.58	0.14	1.74	110	53	423	0.07
MT3-130	Waipawa	Coastal Block	Oct. 2011	2804989	6078004	8.24	1.05	29.03	352	22	395	0.03
MT3-136	Waipawa	Coastal Block	Oct. 2011	2804372	6076693	4.7	0.38	8.53	181	36	406	0.04
MT3-139	Waipawa	Coastal Block	Oct. 2011	2804372	6076693	3.66	0.38	4.31	118	59	411	0.08
MT3-140	Waipawa	Coastal Block	Oct. 2011	2804372	6076693	0.44	0.05	0.2	45	109	423	0.2
MT3-30	Waipawa	Coastal Block	Oct. 2011	2804941	6078064	2.38	0.1	3.21	135	30	412	0.03
MT3-31	Waipawa	Coastal Block	Oct. 2011	2804941	6078064	3.2	0.15	4.38	137	37	410	0.03

MT3-38	Waipawa	Coastal Block	Oct. 2011	2804941	6078064	1.25	0.07	0.64	51	91	423	0.1
MT3-42	Waipawa	Coastal Block	Oct. 2011	2804941	6078064	3.58	0.18	5.44	152	32	409	0.03
MT3-45	Waipawa	Coastal Block	Oct. 2011	2804941	6078064	2.09	0.23	0.94	45	115	418	0.2
MT3-50	Waipawa	Coastal Block	Oct. 2011	2804941	6078064	2.67	0.16	3.59	134	36	408	0.04
MT3-53	Waipawa	Coastal Block	Oct. 2011	2804941	6078064	3.48	0.23	5.37	154	33	408	0.04
MT3-56	Waipawa	Coastal Block	Oct. 2011	2804941	6078064	2.86	0.15	3.31	116	36	411	0.04
MT3-80	Waipawa	Coastal Block	Oct. 2011	2804971	6078057	3.24	0.14	5.67	175	32	413	0.02
MT3-86	Waipawa	Coastal Block	Oct. 2011	2804971	6078057	3.55	0.17	4.95	139	34	410	0.03
MT3-90	Waipawa	Coastal Block	Oct. 2011	2804971	6078057	3.73	0.18	6.66	179	34	411	0.03
MT3-94	Waipawa	Coastal Block	Oct. 2011	2804971	6078057	5.28	0.31	13.77	261	25	403	0.02
V22/f421	Waipawa	Coastal Block	Jun. 1992	2842770	6131600	0.38	0.3	0.51	134	118	408	0.37
NE43	Waipawa	Coastal Block		2773800	6033700	5.58	0.68	7.22	129	88	409	0.09
68-2	Waipawa	Coastal Block		2744000	5986400	7	1.7	35.9	513	31	406	0.05
NE131	Waipawa	Coastal Block		2781700	6036400	3.84	0.59	4.47	116	95	415	0.12
NE48	Waipawa	Coastal Block		2781700	6036400	3.27	0.52	3.82	117	119	418	0.12
NE26	Waipawa	Coastal Block		2840800	6118000	1.16	0.14	0.49	42	320	436	0.22
NE54	Waipawa	Coastal Block		2768900	6021700	5.58	0.73	8.9	159	76	417	0.08
DAL1002	Waipawa	Coastal Block	Jun. 1992	2769400	6011000	2.96	0.16	2.54	86	41	410	0.06
DAL1003	Waipawa	Coastal Block	Jun. 1992	2769400	6011000	4.66	0.26	2.12	45	30	404	0.11
DAL1005	Waipawa	Coastal Block	Jun. 1992	2769400	6011000	4.55	0.18	2.49	55	24	411	0.07
DAL1006	Waipawa	Coastal Block	Jun. 1992	2769400	6011000	4.43	0.16	2.74	62	25	411	0.06
DAL1010	Waipawa	Coastal Block	Jun. 1992	2769400	6011000	2.76	0.09	1.52	55	37	414	0.06
RQ4	Waipawa	Coastal Block	Oct. 2011	2769611	6011364	3.45	0.15	2.56	74	70	420	0.06
RQ5	Waipawa	Coastal Block	Oct. 2011	2769621	6011345	3.28	0.18	5.38	164	40	414	0.03
W3	Waipawa	Coastal Block		2773800	6033700	3.5	0.4	8.3	237	0	412	0.05
25-4	Waipawa	Coastal Block		2779600	6048600	4.6	0.6	14.2	309	43	407	0.04
NE63	Waipawa	Coastal Block		2764400	6018100	3.79	0.32	3.66	97	54	420	0.08
NE4	Waipawa	Coastal Block		2852400	6145100	1.35	0.16	0.3	22	72	411	0.35
PPR-9	Waipawa	East Coast Allochthon	Jun. 2012	2974611	6368092	2.48	0.08	2.97	120	117	425	0.03
KR93	Waipawa	East Coast Allochthon		2966610	6346030	1.97	0.2	3.49	178	0	410	0.05
KR46	Waipawa	East Coast Allochthon		2971000	6370400	3.54	0.67	11.89	336	19	406	0.05

493	Waipawa	East Coast Allochthon		2971100	6370500	3.5	0.4	9.3	266	51	417	0.04
PPR-17	Waipawa	East Coast Allochthon	Jun. 2012	2974671	6368097	4.48	0.25	10.87	243	24	404	0.02
PPR-5	Waipawa	East Coast Allochthon	Jun. 2012	2974550	6368078	1.24	0.06	1.55	125	71	421	0.04
KR20	Waipawa	East Coast Allochthon		2989200	6360800	5.81	0.86	17.11	294	46	407	0.05
W1	Waipawa	East Coast Allochthon		2930600	6315100	3.9	0.7	14.4	369	0	414	0.05
KR128	Waipawa	East Coast Allochthon		2930600	6315100	3.08	0.41	6.9	224	58	417	0.06
P78664	Waipawa	East Coast Allochthon	Jan. 2010	2975397	6335362	8.39	1.12	26.65	318	13	410	0.04
W2	Waipawa	East Coast Allochthon		2931700	6319800	4.4	2.5	20.2	459	0	421	0.11
14-3B	Waipawa	East Coast Allochthon		2931500	6319200	3.8	3	14.2	374	87	427	0.17
DAL1007	Waipawa	East Coast Allochthon	Jun. 1992	2931700	6319400	4.49	1.23	18.47	411	21	424	0.06
DAL1008	Waipawa	East Coast Allochthon	Jun. 1992	2931700	6319400	4.54	1.43	20.72	456	7	422	0.06
DAL2-17	Waipawa	East Coast Allochthon	Jun. 1992	2931700	6319400	3.42	2.11	17.49	511	13	428	0.11
Y16/f802	Waipawa	East Coast Allochthon	Jun. 1992	2931700	6319400	3.22	1.81	15.29	475	17	425	0.11
Y16/f803	Waipawa	East Coast Allochthon	Jun. 1992	2931700	6319400	2.76	2.15	13.6	493	13	428	0.14
Y16/f804	Waipawa	East Coast Allochthon	Jun. 1992	2931700	6319400	3.68	2.7	18.51	503	7	428	0.13
Y16/f805	Waipawa	East Coast Allochthon	Jun. 1992	2931700	6319400	5.26	2.29	24.91	474	5	425	0.08
Y16/f806	Waipawa	East Coast Allochthon	Jun. 1992	2931700	6319400	3.26	2.18	17.94	550	6	429	0.11
Y16/f808	Waipawa	East Coast Allochthon	Jun. 1992	2931700	6319400	2.73	1.86	13.76	504	7	425	0.12
Y16/f809	Waipawa	East Coast Allochthon	Jun. 1992	2931700	6319400	3.27	1.55	13	398	7	422	0.11
DAL21-3	Waipawa	East Coast Allochthon	Oct. 2011	2931700	6319400	0.82	0.14	0.76	93	26	421	0.16
DAL21-4	Waipawa	East Coast Allochthon	Oct. 2011	2931700	6319400	0.9	0.15	0.82	91	29	423	0.15
DAL21-5	Waipawa	East Coast Allochthon	Oct. 2011	2931700	6319400	3.59	1.02	8.09	225	14	419	0.11
DAL21-6	Waipawa	East Coast Allochthon	Oct. 2011	2931700	6319400	2.93	0.91	6.73	230	16	416	0.12
DAL21-6	Waipawa	East Coast Allochthon	Jan. 2010	2931700	6319400	3.03	0.76	7.29	241	7	416	0.09
DAL21-7	Waipawa	East Coast Allochthon	Oct. 2011	2931700	6319400	3.96	0.91	7.8	197	18	416	0.1
DAL21-8	Waipawa	East Coast Allochthon	Oct. 2011	2931700	6319400	4.79	0.68	14.05	293	17	420	0.05
DAL21-9	Waipawa	East Coast Allochthon	Oct. 2011	2931700	6319400	3.51	0.98	8.82	251	13	416	0.1
DAL21-9	Waipawa	East Coast Allochthon	Jan. 2010	2931700	6319400	3.45	0.83	9.97	289	6	415	0.08
DAL21-11	Waipawa	East Coast Allochthon	Oct. 2011	2931700	6319400	3.41	0.8	6.48	190	20	417	0.11
DAL21-12	Waipawa	East Coast Allochthon	Oct. 2011	2931700	6319400	3.41	0.9	5.52	162	22	416	0.14
KR54	Waipawa	East Coast Allochthon		2960300	6381000	2.89	0.36	4.15	144	33	412	0.08

54-1	Waipawa	East Coast Allochthon		2968700	6360300	4.8	0.5	12.1	252	42	413	0.04
PPR-10	Waipawa	East Coast Allochthon	Jun. 2012	2974620	6368093	3.23	0.12	6.42	199	72	420	0.02
PPR-11	Waipawa	East Coast Allochthon	Jun. 2012	2974634	6368094	3.9	0.12	6.58	169	63	416	0.02
PPR-12	Waipawa	East Coast Allochthon	Jun. 2012	2974644	6368095	2.95	0.14	7.69	261	41	414	0.02
PPR-13	Waipawa	East Coast Allochthon	Jun. 2012	2974651	6368096	4.12	0.2	9.48	230	26	407	0.02
PPR-14	Waipawa	East Coast Allochthon	Jun. 2012	2974655	6368096	3.24	0.11	3.51	108	101	418	0.03
PPR-15	Waipawa	East Coast Allochthon	Jun. 2012	2974660	6368096	3.59	0.15	7.46	208	43	410	0.02
PPR-16	Waipawa	East Coast Allochthon	Jun. 2012	2974668	6368097	2.98	0.12	7.09	238	42	414	0.02
PPR-6	Waipawa	East Coast Allochthon	Jun. 2012	2974556	6368079	1.58	0.08	1.48	94	110	431	0.05
PPR-7	Waipawa	East Coast Allochthon	Jun. 2012	2974562	6368081	2.23	0.1	2.91	130	113	427	0.03
PPR-8	Waipawa	East Coast Allochthon	Jun. 2012	2974567	6368082	1.5	0.07	1.62	108	123	422	0.04
DAL14-6	Waipawa	Marlborough	Jan. 2010	2575600	5916100	0.9	0.02	0.74	82	51	428	0.03
DAL14-8	Waipawa	Marlborough	Jan. 2010	2575600	5916100	2.94	0.04	4.94	168	22	414	0.01
IH256	Waipawa	Motu Block		2955500	6339800	12.3	3	45.9	373	18	411	0.06
X17/f317	Waipawa	Motu Block	Jun. 1992	2906090	6299880	0.74	0.11	1.66	224	45	430	0.06
X17/f318	Waipawa	Motu Block	Jun. 1992	2906090	6299880	3.59	1.93	17.18	479	21	421	0.1
KR7	Waipawa	Motu Block		2906100	6299900	4.62	0.93	18.11	392	4	411	0.05
V19/f244	Waipawa	Motu Block	Jun. 1992	2840490	6249100	0.56	0.04	0.61	109	16	420	0.06
V19/f245	Waipawa	Motu Block	Jun. 1992	2840470	6249090	0.64	0.04	0.44	69	16	421	0.08
V19/f246	Waipawa	Motu Block	Jun. 1992	2840460	6249080	2.83	0.22	6.33	224	18	420	0.03
V19/f247	Waipawa	Motu Block	Jun. 1992	2840450	6249070	2.62	0.12	4.94	189	15	421	0.02
41-2	Waipawa	Motu Block		2899800	6293000	8.1	2	28.2	348	23	412	0.07
V19/f234	Waipawa	Motu Block	Jun. 1992	2843750	6248350	1.08	0.16	1.78	165	34	420	0.08
V19/f235	Waipawa	Motu Block	Jun. 1992	2843800	6248400	1.02	0.02	0.71	70	24	421	0.03
V19/f236	Waipawa	Motu Block	Jun. 1992	2843800	6248400	5.37	0.39	14.98	279	18	411	0.03
KR13	Waipawa	Motu Block		2950600	6338100	4.31	1.09	15.52	360	0	416	0.07
KR14	Waipawa	Motu Block		2950600	6338100	4.32	0.68	11.94	277	3	418	0.05
KR15	Waipawa	Motu Block		2950600	6338100	3.78	1.08	11.09	293	4	411	0.09
KR16	Waipawa	Motu Block		2950600	6338100	3.17	0.7	8.03	253	1	414	0.08
KR17	Waipawa	Motu Block		2950600	6338100	1.28	0.16	1.5	117	0	422	0.1
Y16/f812	Waipawa	Motu Block	Jun. 1992	2950600	6338100	3.3	1.2	15.22	461	18	419	0.07

Y16/f813	Waipawa	Motu Block	Jun. 1992	2950600	6338100	0.72	0.23	1.53	213	32	419	0.13
Y16/f814	Waipawa	Motu Block	Jun. 1992	2950600	6338100	4.26	1.44	17.35	407	14	416	0.08
NE37	Waipawa	Pongaroa Block		2794100	6102400	2.42	0.35	1.47	61	84	405	0.19
NE33	Waipawa	Pongaroa Block		2799200	6109800	1.3	0.15	0.4	31	73	395	0.27
NE31	Waipawa	Pongaroa Block		2799100	6109600	3.69	0.79	4.8	130	65	398	0.14
KR1	Waipawa	Pongaroa Block		2815500	6134000	4.34	0.5	6.44	148	41	404	0.07
NE40	Waipawa	Pongaroa Block		2815400	6134000	3.89	0.67	4.65	120	85	407	0.13
57-1	Waipawa	Pongaroa Block		2799000	6111000	4.2	0.6	7	167	62	408	0.08
Orui-1A_MG11	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	3.55	0.2	7.48	211	24	418	0.03
Orui-1A_MG12	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	2.65	0.14	2.97	112	38	425	0.05
Orui-1A_MG13	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	3.26	0.16	5.84	179	29	424	0.03
Orui-1A_MG14	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	2.63	0.16	3.91	149	86	423	0.04
Orui-1A_MG15	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	3.34	0.23	4.61	138	77	420	0.05
Orui-1A_MG16	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	3.23	0.2	5.9	183	67	419	0.03
Orui-1A_MG2	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	3.59	0.22	6.3	175	29	414	0.03
Orui-1A_MG3	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	4.7	0.26	14.09	300	16	395	0.02
Orui-1A_MG4	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	3.15	0.21	7.94	252	14	409	0.03
Orui-1A_MG5	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	3.65	0.25	10.65	292	16	407	0.02
Orui-1A_MG6	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	2.3	0.14	3.64	158	20	415	0.04
Orui-1A_MG7	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	2.97	0.21	5.27	177	32	422	0.04
Orui-1A_MG8	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	2.76	0.19	3.72	135	13	422	0.05
Orui-1A_MG9	Waipawa	Coastal Block	Oct. 2011	2769442	6010955	3.08	0.25	6.53	212	16	419	0.04

Rock types worldwide and the Torlesse from the basement of New Zealand.

Al2O3	SiO2	TiO2	Fe2O3	MnO	MgO	CaO	Na2O	K2O	P2O5	L.O.I.	Total	Shale	REFERENCES
1.76	82.69	NA	1	0.01	1.08	2.93	0.5	2.61	0.21			Monterey_Fm	Bramlette,1946, p49
6	23.3	0.26	2.3	0.02	0.85	25.4	1.6	1.24	3.24	33.8	98.01	Monterey_Fm	KG-1 - Piper and Isaacs, 1995
6.5	28.2	0.34	2.4	0.02	1.2	14.5	1.5	1.08	4.36	38.4	98.5	Monterey_Fm	KG-2 - Piper and Isaacs, 1995
10	40.3	0.54	3.5	0.03	1.4	3.62	1.9	1.74	0.98	35.9	99.91	Monterey_Fm	KG-4 - Piper and Isaacs, 1995
6.7	57.7	0.34	2.4	0.02	1	7.86	1.9	1.14	0.7	22.2	101.96	Monterey_Fm	KG-5 - Piper and Isaacs, 1995
11.7	50.4	0.62	4.3	0.03	1.6	4.04	2.3	2.02	0.68	19	96.69	Monterey_Fm	KG-6 - Piper and Isaacs, 1995
8.9	67.8	0.48	2.7	0.02	1.1	1.06	2.1	1.76	0.28	13.9	100.1	Monterey_Fm	KG-7 - Piper and Isaacs, 1995
11.1	50.9	0.6	4.3	0.04	1.7	3.12	2.3	1.98	0.96	22.4	99.4	Monterey_Fm	KG-8 - Piper and Isaacs, 1995
5.7	39.8	0.28	2.3	0.02	1.8	20.7	1.3	1.28	0.36	25.9	99.44	Monterey_Fm	KG-10 - Piper and Isaacs, 1995
3.4	57.7	0.18	1.3	0.02	1	15	1	0.74	0.18	18.3	98.82	Monterey_Fm	KG-11 - Piper and Isaacs, 1995
14.83	70	0.56	4	0.07	1.45	2.3	4.01	2.64	0.11			PF1	Roser and Korsch, 1999 Avg-21
14.48	70.68	0.54	4.37	0.06	1.44	2.08	3.83	2.43	0.11			PF2	Roser and Korsch, 1999 Avg-12
14.5	71.45	0.51	3.66	0.06	1.37	1.71	4.02	2.61	0.12			PF3	Roser and Korsch, 1999 Avg-24
13.13	74.99	0.4	2.61	0.05	0.92	1.57	3.34	2.94	0.06			PF4	Roser and Korsch, 1999 Avg-19
13.29	73.91	0.5	3.46	0.06	1.1	1.56	3.64	2.41	0.09			PF5	Roser and Korsch, 1999 Avg-15
16.9	64.8	0.7	5.66	0.06	2.86	3.63	1.14	3.97	0.13	*	100	NASC - paper	Weighted averaged of micropobe analyses
17.02	64.21	0.72	6.71	0.5	2.7	3.44	1.44	3.58	0.19	*	100	Avg - Shale	(Clark, 1924)
17.79	59.75	0.98	5.59	-	4.02	6.1	0.72	4.82	0.12	*	100	Avg - North american Paleozoic shale	Ronov and Migdisov, 1971
16.89	56.78	0.92	6.56	0.08	4.56	8.91	0.77	4.38	0.13	*	100	Avg - Russian Paleozoic shale	Ronov and Migdisov, 1971
16.59	67.78	0.7	4.11	-	3.38	3.91	0.98	2.44	0.1	*	100	Avg - North American mesozoic/Cenozoic shale	Ronov and Migdisov, 1971
16.65	64.09	0.82	6.03	0.07	2.54	5.65	1.27	2.73	0.12	*	100	Avg - Russian mesozoic/Cenozoic shale	Ronov and Migdisov, 1971
16.67	66.9	0.78	5.87	0.06	2.59	0.53	1.5	4.97	0.14	*	100	Avg - Canadian Proterozoic (Aphebian) Shale	Cameron and Garrels, 1960

18.63	63.04	0.94	7.66	0.12	2.6	1.31	1.02	4.57	0.1	*	100	Avg - Russian Proterozoic shale	Ronov and Migdisov, 1971
18.11	62.13	0.78	7.33	0.1	3.57	2.22	2.68	2.92	0.17	*	100	Avg - Canadian Archean Shale	Cameron and Garrels, 1960
16.11	65.47	0.49	5.85	0.07	2.5	4.1	2.8	2.37	0.14	*	100	Avg - Archean shale	Ronov and Migdisov, 1971

*Weight percent oxides, recalculated to 100% on a volatile-free and reduced iron basis.

APPENDIX 2: THE MEASURED SECTIONS SAMPLED FOR THIS STUDY WITHIN EAST COAST BASIN.

KEY USED FOR MEASURED SECTIONS

Mudstone
Sandstone/Greensand
Siltstone
Shale
Well bedded
Horizontal stratification
Calcareous		GNS Sample
Moderately Hard		New Sample
Very hard	OR	Concretion
Bioturbation	OR	Glaucinite
Burrows		Foraminifera
Fish scales		Fossils
Slump structures		Sparse fossils
Fractured
Cherty		Nodular

Whangai Formation - Southern Hawke's Bay measured sections:

1. Tangaruhe Stream
2. Angora Stream
3. Pukemuri Stream

Tangaruhe Stream

Measured Section of Tangaruhe Stream, eastern Whangai Range					
Geologists: P.R. Moore; V. Bull					
Region: East Coast		U24	Date of measurement: 7 th /8th April 1981		
AGE	FORMATION	SCALE (m)	GRAPHIC LOG	ADDITIONAL GRAPHIC	DESCRIPTION
Teurian (Dt)	Whangai Formation (Te Uri Member)	670			Sandstone/Siltstone, 35m: bd g/c Sst/ lt gy calc Zst.
		660			
Haururian (Mt)	Whangai Formation (Upper Calcareous Member)	650			Mudstone, 70m: thin-bdd (nodular) lt gy/ dk gy sil Mst.
		640			
Haururian (Mt)	Whangai Formation (Upper Calcareous Member)	630			Mudstone, 140m: lt bl-gy weath hd sl calc Mst.
		620			
Haururian (Mt)	Whangai Formation (Upper Calcareous Member)	610			Mudstone, 140m: lt bl-gy weath hd sl calc Mst.
		600			
Haururian (Mt)	Whangai Formation (Upper Calcareous Member)	590			Mudstone, 140m: lt bl-gy weath hd sl calc Mst.
		580			
Haururian (Mt)	Whangai Formation (Upper Calcareous Member)	570			Mudstone, 140m: lt bl-gy weath hd sl calc Mst.
		560			
Haururian (Mt)	Whangai Formation (Upper Calcareous Member)	550			Mudstone, 140m: lt bl-gy weath hd sl calc Mst.
		540			
Haururian (Mt)	Whangai Formation (Upper Calcareous Member)	530			Mudstone, 140m: lt bl-gy weath hd sl calc Mst.
		520			
Haururian (Mt)	Whangai Formation (Upper Calcareous Member)	510			Mudstone, 140m: lt bl-gy weath hd sl calc Mst.
		500			
Haururian (Mt)	Whangai Formation (Upper Calcareous Member)	490			Mudstone, 140m: lt bl-gy weath hd sl calc Mst.
		480			
Haururian (Mt)	Whangai Formation (Upper Calcareous Member)	470			Mudstone, 140m: lt bl-gy weath hd sl calc Mst.
		460			
Haururian (Mt)	Whangai Formation (Upper Calcareous Member)	450			Mudstone, 140m: lt bl-gy weath hd sl calc Mst.
		440			

Measured Section of Tangaruhe Stream, eastern Whangai Range					
Geologists: P.R. Moore; V. Bull					
Region: East Coast U24 Date of measurement: 7 th /8th April 1981					
AGE	FORMATION	SCALE (m)	GRAPHIC LOG	ADDITIONAL GRAPHIC	DESCRIPTION
Haumuri (Mh) - Teurian (Ot)	Whangai Formation (Rakauroa Member)	430		2% CaCO ₃	poorly bd med gy hd Mst.
		420		T	
		410			
		400		T	
		390			
		380			
		370			
		360			
		350		(=)	
		340			
		330			
		320			
		310			
		300			
		290			
		280			
		270			
		260			
		250		⊕ (=)	
		240			
		230		T	
		220			
		210

Angora Stream

Pukemuri Stream

Upuk - 01

Lpuk - 03, 04 and 05

Whangai Formation - Northern Hawke's Bay measured sections:

1 – Waitahaia, Owhena

2 – Te Weraroa Stream

3 – Rakauroa Stream

Waitahaia, Owhehena

Measured Section of Waitahaia River (below old foot bridge) and lower Owheua Stream					
Geologists: P.R. Moore; I. Baillie					
Region: East Coast Y16 Date of measurement: 13 th March 1982					
AGE	FORMATION	SCALE (m)	GRAPHIC LOG	ADDITIONAL GRAPHIC	DESCRIPTION
Pripauan (Mp) - Lower Haumuran (LMh)	Owheua	60 50 40 30			med gy mic Zst with thin // lam graded g/c f Sst bds; Inoceramus frags. poorly bd gy bioturb sl g/c mic gritty v f Sst; scattered concr.
Pripauan (Mp) - Lower Haumuran (LMh)	Owheua	20 10 0			well-bd (cm-bd) alt // to ripple lam. carb Sst/gy s Zst; minor dk gy Mst. carb lam Sst beds - 1 m.
Arowhuanan (Ra)	Karekare	-10 -20 -30			Concr. Zone gy hd Mst with thin // lam f Sst beds.

Te Weraroa Stream

Measured Section of Te Weraroa Stream, Mangatu Forest					
Geologists: P.R. Moore; I. Baillie					
Region: East Coast Y16 Date of measurement: 9 th March 1982					
AGE	FORMATION	SCALE (m)	GRAPHIC LOG	ADDITIONAL GRAPHIC	DESCRIPTION
		390 380 370 360 350 340 330 320 310 300 290 280 270 260 250 240 230 220 210 200 190 180 170 160 150 140 130 120 110 100 90 80 70 60 50 40 30 20 10 0 -10 -20 -30 -40 -50		6% CaCO ₃ T H T F T 8% CaCO ₃ T ~	Not exposed, 100m. Mudstone, 50m: lt gy weath calc Mst. Not exposed, 90m. Mudstone, 110m: poorly bd lt gy weath med gy hd mic calc Mst. Mudstone, 50m: // lam rusty weath gy mod hd non-calc Mst. Not exposed.

Rakauroa Stream

Measured Section of Rakauroa Stream, ~6km south of Matawai					
Geologists: P.R. Moore					
Region: East Coast X17 Date of measurement: 3 rd March 1984					
AGE	FORMATION	SCALE (m)	GRAPHIC LOG	ADDITIONAL GRAPHIC	DESCRIPTION
Teurian (D) - Lower Wapawan (LDw)	Wardstead				<p>Mudstone, 110m:</p> <p>10-15% CaCO₃</p> <p>v poorly bd lt bl-gy weath hd calc Mst.</p> <p>lt bl-gy weath hd sl calc sl g/c Mst.</p> <p>lt bl-gy sl calc bioturb Mst.</p> <p>4% CaCO₃</p> <p>Shale, 1.2m: dk gy Sh.</p>

Measured Section of Rakauroa Stream, ~6km south of Matawai					
Geologists: P.R. Moore					
Region: East Coast X17 Date of measurement: 3 rd March 1984					
AGE	FORMATION	SCALE (m)	GRAPHIC LOG	ADDITIONAL GRAPHIC	DESCRIPTION
<div>Teauri (O1)</div> <div>Haunui (M1) - Teauri (O1)</div> <div>Teauri (O1)</div> <div>Teauri (O1)</div>	<div>Wardad</div> <div>Wapawa Blk. Sh.</div> <div>Wapawa (Rakauroa Mbr.)</div>	<div>130</div> <div>120</div> <div>110</div> <div>106</div> <div>100</div> <div>90</div> <div>80</div> <div>70</div> <div>60</div> <div>50</div> <div>40</div> <div>30</div> <div>20</div> <div>10</div>		<div> </div> <div> </div> <div> </div> <div> </div>	<div>lt bl-gy hd sl calc Mst.</div> <div>med gy mod hd non-calc mic Mst.</div> <div>Shale, 10m: dk gy-blk Sh.</div> <div>Mudstone, 100m: v poorly bd med gy hd mass mic non-calc Mst.</div>

- RAK - 01
- RAK - 02
- RAK - 03

Waipawa Formation - Southern Hawke's Bay measured sections:

1. Mangatarata Valley
2. Taylor White

Mangatarata Valley

1. Taylor White

Measured Section of Upper Angora Stream, road/quarry section					
Geologists: -					
Region: - Base: U24/0435-7670 Date of measurement: -					
AGE	FORMATION	SCALE (m)	GRAPHIC LOG	ADDITIONAL GRAPHIC	DESCRIPTION
TW - 02	Wanstead Formation	1615			dm bedded glauconitic sandstones and cm bedded soft dark grey mudstones
	Wanstead Formation	1614			35cm glauconitic sandstone 40 cm hard, light grey, bioturbated, highly calcareous mudstone dm bedded glauconitic sandstones and cm bedded soft dark grey mudstones
TW - 05	Wanstead Formation	1613			poorly exposed disrutes unit, 40cm sst blocks enclosed in softer, dark grey mudstone 20 cm, hard, slightly glauconitic fone sandstone and thinner softer, interbedded mudstones. 1-2 cm sl. gl. sst at base sulphurous, silty, micaceous, dark grey siltstone
	Wanstead Formation	1612			Dark brown (grey) micaceous non-calcareous, massive, organic-rich mudstone ? more "typical Whangai-UCM", light-medium blue-grey weathering, ?very slightly calcareous (low TOC middle Waipawa Formation unit) Dark brown (grey) micaceous non-calcareous, massive, organic-rich mudstone

Waipawa Formation - Northern Hawke's Bay measured sections:

1. Te Weraroa Stream

TWR - 03

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APPENDIX 3: STATISTICS OF THE VP AND VS OF THE WHANGAI FORMATION IN THE RERE-1 WELL AND FOUR EMPIRICAL EQUATIONS USED TO CALCULATE THE BRITTLINESS INDEX OF THE EXPLORATION WELLS: OPOUTAMA-1, RERE-1 AND HUKARERE-1.

Vp of the Rere-1

Claystone	
Mean	2,960.236 m/s
Median	3,237.575 m/s
Max	5,160.973 m/s
Min	959.641 m/s
Std. Dev	775.425 m/s
p10	2,438.874 m/s
p90	3,383.397 m/s
Samples	2,139

Vs of the Rere-1

Claystone	
Mean	1,706.383 m/s
Median	1,866.458 m/s
Max	2,436.141 m/s
Min	561.044 m/s
Std. Dev	443.93 m/s
p10	1,412.75 m/s
p90	1,952.336 m/s
Samples	1,090

Opoutama-1 well – BI Internal Friction total zone.

Opoutama-1 well – BI Internal Friction optimum zone.

Opoutama-1 Well - BI Elastic Parameters total zone.

Opoutama-1 Well - BI Elastic Parameters optimum zone.

Opoutama-1 Well - BI Jarvie total zone.

Opoutama-1 Well - BI Jarvie optimum zone.

Opoutama-1 well – BI Wang total zone

Opoutama-1 well – BI Wang optimum zone.

Rere-1 Well – BI Internal Friction total zone.

Rere-1 Well – BI Internal Friction optimum zone.

Rere-1 Well – BI Elastic Parameters total zone.

Rere-1 Well – BI Elastic Parameters optimum zone.

Rere-1 Well - BI Jarvie total zone.

Rere-1 Well - BI Jarvie optimum zone.

Rere-1 Well - BI Wang total zone.

Rere-1 Well - BI Wang optimum zone.

Hukarere-1 Well – BI Internal Friction total zone.

Hukarere-1 Well – BI Internal Friction optimum zone.

Hukarere-1 Well – BI Elastic Parameters total zone.

Hukarere-1 Well – BI Elastic Parameters optimum zone.

Hukarere-1 Well - BI Jarvie total zone.

Hukarere-1 Well – BI Jarvie optimum zone.

Hukarere-1 Well – BI Wang total zone.

Hukarere-1 Well – BI Wang optimum zone.

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APPENDIX 4. ECONOMICAL CONCEPTS

The below concepts are largely taken from:

- Lamb, 1999
- Nepomuceno, 1997
- Rose, 1987
- Simpson et.al., 2000

It is important to stress that the informations shown in this Apendix are related to conventional oil and gas, but it is still helpful and useful to transfer these concepts for the unconventional exploration.

Monte Carlo Simulation

A Monte Carlo simulation calculates the chances of different outcomes to those mentioned so far. The simulation allows for risk in quantitative analysis and decision-making. It can answer technical questions – for example, finding the range of recoverable prospective resources of hydrocarbons in a given exploration block – and economic ones, such as the probability that the prospect’s IRR will exceed the target of \$X million.

The recoverable prospective resources in a prospect would be simple to calculate if shales were homogenous, addressing a single value for each variable. In reality it is seldom possible to assign single values to each variable. Geoscientists and engineers must estimate areal extent with average values for properties like saturation and porosities since based on incomplete information. They can, however, plot a distribution curve that charts the probability that a particular value will occur for each input variable.

In a Monte Carlo simulation, each variable is sampled at random and the individual values multiplied together (this is called a “trial”). A single trial gives a result which provides a possible answer for recoverable reserves. Such random sampling of each input distribution is repeated many times, usually from 1000 to 100,000 depending on which kind of calculation is being carried out. Given the high number of trials, the simulation samples the most likely outcomes per distribution rather than the extremes, because more examples fall in that range. This, in turn, results in a new distribution curve, pointing to a range of possibilities for the size of recoverable prospect resources, and for the probability that a particular value will occur.

Ideally, individual distribution curves would factor many measurements. Generally, however, available data are limited. Geoscientists will often suggest a curve consistent with the limited data, and in accord with prior experience. Geologists, for example, will often make parallels between the porosity of the rocks examined and that of rocks previously exploited from a comparable area. As Figure 1 shows, distributions can vary widely. Individual distribution curves describe individual variables in the most appropriate way. For example, a triangular distribution to describe porosity would indicate that experts could confidently ascertain the most likely minimum and maximum porosities. Lognormal

distribution describing GRV would indicate that experts believed the range is greater on the high side rather than the low side.

Figure 1 The various shapes of distributions curves.

Options Theory

Timing is crucial to decision-making – that is, deciding ‘when’ to decide. Decisions made at different points in time can significantly affect the outcome, since input information can change over time, as perceived conditions themselves change. Figure 2 demonstrates how and why ‘decision trees’ are considered essential for many oil companies’ decision-making; decision trees illustrate the complex relationship between available choices, uncertainties, and estimate outcomes per decision. Trees help clarify not only choices, risks, and objectives, but also the potential monetary gains and crucial information needs which help influence accurate decision-making (Newendrop, 1996). Estimating the value of each potential outcome and settling on the likelihood of each outcome coming to pass allows the overall risk-value of the outcome of the decision to be calculated.

Just as decision trees help decision-makers to more accurately assess likely financial outcomes, options theory proceeds on the understanding that successful projects rely on accurate understanding of risks and opportunities attached to each choice made throughout the project. For instance, developers might have to ask themselves whether it is wiser to invest early on in a development project, or to delay investment till more secure and reliable information becomes available. DFC analysis (the common method of investment evaluation in the oil industry) tends to assume that once an investment is made, the project will go ahead without unforeseen hitches and complications, which is highly unrealistic. DFC tends to evaluate assuming successful outcomes. Hence, considering when it is wiser to abandon a failing project, or whether to increase the project’s scope in the face of unexpected demand, is not factored.

Unlike DFC, options theory accounts for flexibility inherent in development projects. It is thus

more sophisticated. Also, the theory of real options means that practical and useful parallels can be drawn between the worlds of, for example, financial stocks and bonds, and physical assets like factories and oil fields.

Figure 2 Decision tree showing the choices and the steps to be followed.

Decision trees help individuals consider uncertain conditions and make decisions. They clearly show what the alternative options are, consider the financial consequences of those alternatives, and help predict the chances of certain future outcomes. On the decision tree, decision points are shown as branching points, or nodes, with outcomes themselves shown as branches. One advantage of decision trees is that they can be as simple or as complicated as the project requires – they can have very few branches or very many (adapted from Newendorp, ref. 6:117).

Oil industry projects tend to be complicated with decision-making required through many stages, involving, for example, seismic surveys, drilling, building platforms, laying pipelines, as well as production and decommissioning phases. When making decisions, if there are multiple options available, then there are multiple opportunities that need to be considered. Thus, companies try to capitalize on the flexibility which goes with multiple options and opportunities. This type of analysis does not feature in this thesis, but it is important to note as it is one way by which interested groups look to make investment decisions.

Preference, or Utility, Theory

As the above shows, there are a lot of decision tools available to help in decision-making, but in the end decisions rest with individuals and groups. It is important to note how subjective and

psychological factors can thus influence decision-making. Given that assessing risk plays such a large part in the oil industry from an investment and development perspective, understanding particular individuals' and groups' attitude to risk is important.

In theory, curves could be drawn for any individual or company, with different curves describing different approaches to decision-making (Figure 3). The shape of the curve describes how the individual or company feels about loss (Nepomuceno, 1997). And yet the use of preference theory in decision-making is not widespread. Critics point to practical problems. Within the one company, some managers may be naturally risk-averse while others might be risk-takers. Although of limited practical use, however, preference theory still usefully shows individuals and companies what their preferred approach to decision-making is.

Figure 3 Feelings about loss and gains (modified from Nepomuceno, 1997).

While large companies often use portfolio theory, smaller companies often feel that they lack sufficient assets to have a 'portfolio' at all (Nepomuceno, 1997).

The Roles of Intuition and Bias

The procedures described so far do not tell the whole story. Analysis that is structured and quantitative plays a crucial part in decision-making, but, as mentioned, qualitative judgements involving an intuitive approach to decision-making are also highly significant. Figure 4 offers a model of the more complete decision-making picture, as formulated by the Aberdeen Researchers (Lamb, 1999).

Figure 4 Quantitative and qualitative analysis (Rose, 1987).

Looking at quantitative analysis alongside qualitative shows the importance of understanding different sides to decision-making. The blue half of the graphic shows how quantitative means (such as DFC and Monte Carlo analysis) approach decision-making and risk; the pink half shows how qualitative analysis approaches the same concepts. The white arrows over the meeting points of blue and pink indicate that tensions sometimes result when executives tend toward purely intuitive decisions which relegate the importance of considering hard numbers and figures. Research is now being conducted into what part the ‘softer’, more qualitative aspects of decision-making play in the whole process. Hence, research is moving towards considering the precise relationship between the two approaches as linked factors in decision-making.

The type of decision being considered is shown on the vertical analysis. Higher level decisions (for instance, whether to operate in a new basin, or even country, or whether to buy out another company) sit in the top half of the model, with more routine decisions at the operational level fall in the lower half. The horizontal axis implies ‘company culture’. For example, companies which depend more on quantitative analysis fit on the left-hand side of the model, whereas companies with more dependence on the qualitative slide to the right. It is interesting to note that partnerships can be complicated when companies working together fall on different points of the horizontal axis.

The business practice of those working in the oil and gas industry is well illustrated by this model of decision-making. And yet no correlation has been found between business success and companies’ position according to the model. In the E&P industry there is an understanding that estimates ought to be expressed within ranges of probabilities rather than as single ‘best-guess’ values. Having said that, strong evidence of significant bias exists in E&P project estimates. In particular:

1. Factoring uncertainty is underestimated because the predictive ranges of key parameters are too narrow (Capen, 1976).
2. Across the board, once discovered, fields generally hold only about 40% of the volumes of oil and gas predicted before exploratory drilling (Figure 5, 1997 Annual Report of Norwegian Petroleum).
3. Risk is widely underestimated, meaning high-risk projects fail about four times more than predicted (Citron, 1997).
4. The actual costs of wells regularly exceed forecasts by 20% to 100%.
5. The means by which ventures are measured and ranked are seldom compared with actual outcomes, meaning widely-used economic projections and yardsticks are in fact uncalibrated.

Figure 5 Predicated versus discoveries volumes (The 1997 Annual Report of the Norwegian Petroleum).

On the topic of recalibrating prospect forecasts, Norwegian North Sea operators show an interesting example. Often these operators show undue optimism when predicting the size of prospects in support of applications for concessions. The X-axis of Figure 5 above shows the size range of prospects reported over the last ten years by operators to the Norwegian Petroleum Directorate. The Y-axis balances this with the actual size found. Hence, the blue diagonal line shows the perfect calibration. The yellow diagonal line shows that predictions underestimated prospect size by a factor of ten, while the red diagonal line shows predictions overestimated by a factor of ten. Most predictions fall below the blue diagonal line, hence pointing out the extent of the bias on the part of operators. Making the same point, the sum of actual discovery sizes only achieves 38% of the total sum of predicted ones. Figure 5 only includes discovery data (adapted from ‘Discoveries on the Norwegian Continental Shelf’, produced in collaboration with the Norwegian Petroleum Directorate: Stavanger, Norway, 1997).

Reporting on worldwide projects, one major oil and gas company found the following

discrepancies between forecast and actual measures:

1. Capital expenditure overruns averaged 95%, with a maximum of 974%;
2. Operating expenditure overruns averaged 140%;
3. First-oil production started between one and three years later than predicted;
4. Average production rates achieved only 65% of those predicted (Smith, 1997).

A significant challenge for companies is, therefore, how to correct widespread predictive bias. Meeting the challenge is an organizational problem involving people, incentive systems, procedures, company culture and leadership.

The problem is not primarily technological though technology may help remove bias. The solution, however – and especially given the factors outlined above – must also involve qualitative factors such as preferred styles of decision-making. In particular, many companies might more accurately assess how, for instance, an intuitive style has helped them succeed, but also be more open to including probabilistic and systematic portfolio-management styles. A number of independent studies support this picture. Simpson et. al. (2000) argue that properly integrated, probabilistic, systematic, and centrally-coordinated management of exploration and production portfolios produces better performance than traditional methods. Many companies working in the systematic, probabilistic style are conscious of predictive bias, tracking their own predictive performance to date to improve future forecasts. Hence, achieving unbiased forecasts is a widely-prized objective. While the risk-analysis tools, procedures and concepts discussed here show huge potential to improve E&P, as always, the human factor must also be properly accounted for, acknowledged, and improved, for such potential to be realized.

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APPENDIX 5. DRILLING COST FOR A VERTICAL EXPLORATION WELL.

DOL = 1.30

DRILLING COSTS	AFE NZ\$	AFE US\$
DRILLING	4,000,532.86	3,077,332.97
Materials and Equipments	2,024,800.77	\$ 1,557,539.05
Well Head	NZ\$ 7,730.77	\$ 5,946.75
Casings and Accessories	NZ\$ 1,788,770.00	\$ 1,375,976.92
Bit	NZ\$ 52,615.38	\$ 40,473.37
Drilling Fluid Material	NZ\$ 92,307.69	\$ 71,005.92
Cement / Additives	NZ\$ 31,153.85	\$ 23,964.50
Diesel for Drill Rig	NZ\$ 51,507.69	\$ 39,621.30
Other Materials and Equipments	NZ\$ 715.38	\$ 550.30
Services	1,864,931.42	\$ 1,434,562.63
Drill Rig Rent - Mobilization	NZ\$ 192,307.69	\$ 147,928.99
Drill Rig Rent - Daily Taxes	NZ\$ 781,543.85	\$ 601,187.57
Drill Rig Rent - Other	NZ\$ 3,230.77	\$ 2,485.21
Well Logging	NZ\$ 39,230.77	\$ 30,177.51
Access and Prep of the Location	NZ\$ 53,076.92	\$ 40,828.40
Cementing	NZ\$ 21,350.58	\$ 16,423.52
Drilling Fluid Services	NZ\$ 59,731.15	\$ 45,947.04
Mud Logging	NZ\$ 51,375.00	\$ 39,519.23
Directional Drill	NZ\$ -	\$ -
Tools Rent	NZ\$ 5,548.71	\$ 4,268.24
Handling of Residues	NZ\$ 209,281.54	\$ 160,985.80
Run a Casing	NZ\$ -	\$ -
Other Services	NZ\$ 3,846.15	\$ 2,958.58
Drilling Supervision and Control - Externo	NZ\$ 76,153.85	\$ 58,579.88
Technical Support (HH External)	NZ\$ 53,254.44	\$ 40,964.95
Insurance	NZ\$ 15,000.00	\$ 11,538.46
Well Completion	NZ\$ 300,000.00	\$ 230,769.23
Other - Drilling	25,000.00	\$ 19,230.77
Support Base	NZ\$ 5,769.23	\$ 4,437.87
Landowner fee	NZ\$ -	\$ -
Other	NZ\$ 19,230.77	\$ 14,792.90
LOGISTIC SUPPORT	85,800.67	\$ 66,000.51
Transport	NZ\$ 26,961.54	\$ 20,739.64
Other Logistic Supports	NZ\$ 58,839.13	\$ 45,260.87