BREATHING NEW LIFE INTO POSTMORTEM ANALYSIS: THE TESTING AND FORMALIZATION OF A METHODOLOGY FOR THE IDENTIFICATION OF KEY FAILURE MODES IN DRY HOLES

by

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The petroleum exploration industry relies on various subsurface data and interpretations to minimize risk and uncertainties and maximize gains. Dry holes provide a wealth of useful subsurface information. However, far too often a company drills a dry hole and either does not conduct a postdrill analysis (postmortem), or incorrectly determines the failure mode. The purpose of this study is to formalize and test the applicability of a postdrill methodology (a decision tree) that helps identify the main failure mode for dry segments tested by conventional wells. Use of this decision tree allows the interpreter to evaluate and identify specific failure modes such as reservoir presence, reservoir deliverability, structure, seal, source maturity, and migration. The decision tree was tested on three exploration wells drilled in the Taranaki Basin, offshore New Zealand. Each segment’s key failure mode was identified based on the comprehensive, integrated evaluation of both pre- and postdrill reports, seismic data, well logs, geochemical analysis of gases and source rocks, and other materials freely available through the New Zealand government. Each individual segment’s unique failure mode has been carefully identified and compared to the failure mode(s) presented by the original operator of the well. It is my hope that this decision tree, or its customized versions, will become the best practice in postdrill analysis across the exploration industry. However, the acceptance and utility of the decision tree is tied largely to its applicability and ease of use. With that being said, the methodology described has met all of the objectives of this study’s evaluation, but should continue to be tested on other exploration wells from a variety of sedimentary basins.
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CHAPTER 1
INTRODUCTION

1.1 Study Objectives

The goal of this study is to test a methodology developed in collaboration with Dr. Alexei Milkov that aims to determine the key failure mode for a dry segment in a conventional well. The methodology that is to be tested throughout this study is a decision tree (Figure 1-1), the use of which reduces complicated questions to answers of either “Yes” or “No”. A segment is defined as a subsurface feature representing a potential petroleum pool and is the smallest assessment unit (Milkov, 2015). A prospect is then composed of one or more segments.

Recent work by Milkov and Navidi (2019) shows that roughly 50% of conventional exploration wells drilled around the world between 2008 and 2017 failed to find movable petroleum fluids. However, even though dry holes seem to be commonplace in petroleum exploration, only 60% of larger exploration companies’ assurance teams conduct systematic post-well reviews (Citron et al., 2017). While there are certain to be internal (and likely proprietary) methods and practices used at various companies around the world, the goal of this study is to formalize and test the applicability of a standardized and systematic approach to postmortem analysis that aims to become a best practice throughout the petroleum exploration industry.

As will be shown in this study, the decision-tree (Figure 1-1) should be used independently on each failed segment within a well. This is because wells may target several segments, and it is possible that individual segments might fail for different
reasons. In addition to different segments having different failure modes, it is also possible that a single segment could have multiple failure modes. It is certainly important to note when a segment has multiple failure modes; however, the goal of this study is to provide a method to assist with the identification of the single key failure mode for a given segment.

1.2 Previous Work

Even today, when information flows so freely, there remains very little published literature specifically related to dry hole postmortem analysis. It is my belief that the lack of published work on this topic is directly related to the large advantages gained through careful, systematic analysis and comparison of predrill targets with postdrill results.

Recently there has been literature that aggregates findings on failure modes for the industry as a whole (Laver et al., 2012), individual companies (ExxonMobil, Rudolph and Goulding, 2017), and specific exploration areas (Tari and Simmons, 2018; Mathieu, 2015, 2018). However, the information presented within these works tends to generalize their findings. For example, Rudolph and Goulding (2017) write in their paper analyzing data from the United States and Canada, that approximately half of the wildcat geologic failures (101 out of 195) were due to trap and seal elements, and the remainder were roughly even split between petroleum systems and reservoir elements. Examples such as the one above are the norm when it comes to literature on postmortem analysis. Even in the more detailed studies, such as Mathieu’s (2015, 2018) analysis of the UK North Sea in which he analyzed over 100 failed segments from 98 wells, there are still no detailed methodologies presented on how the writer arrived at his / her conclusions.
Far too often writers, interpreters, and companies, rely on their expert judgement in order to identify a segment’s key failure mode. While an interpreter’s expertise should certainly not be disregarded, the establishment of a systematic approach to postmortem analysis will lead to consistent and easily repeatable interpretations. If companies adopted the methodology put forth in this study (or future customized versions of this method), there would be far fewer misidentifications of key failure modes for segments, and implementing the results of the analysis to future projects (updating models, maps, etc.) would prove to be much simpler.

1.3 Area of Investigation

The area of investigation (AOI) for this study is the Taranaki region located off the west coast of the North Island of New Zealand (Figure 1-2). Within the Taranaki regions, wells were selected from the Taranaki Basin and the Deepwater Taranaki Basin. This area is of particular interest to this study due to the fact that all oil and gas exploration data in New Zealand becomes freely available 5 years after the rig release date through New Zealand Petroleum & Minerals’ (NZP&M) Online Exploration Database (2019). However, it is not uncommon for companies to submit well-related data to the New Zealand government before the 5-year confidentiality period expires.
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CHAPTER 2
GEOLOGIC BACKGROUND OF THE TARANAKI BASIN

2.1 Geologic Overview

The Taranaki Basin is located along the west coast of the North Island of New Zealand (Figure 2-1), and covers an area of roughly 100,000 km$^2$, most of which is offshore (Strogen et al., 2017). The Taranaki Basin sits within Zealandia, a large block of continental crust that separated from Gondwana roughly 100 Ma, during Gondwana’s Cretaceous fragmentation (Strogen et al., 2017). The basin is partly within the Neogene New Zealand plate boundary zone, which is characterized by variably deformed sedimentary fill (Strogen et al., 2017). The evolution of the southwest Pacific region, and more specifically the Taranaki Basin, can be divided into five broad tectonic phases. The first phase extends from the Triassic to the early Cretaceous (>100 Ma) and is characterized by the southwest-dipping subduction of the Pacific-Phoenix plate along the eastern margin of Gondwana. The second phase covers the latest Early Cretaceous to the early Late Cretaceous (100-85 Ma) and is characterized by widespread intracontinental rifting and extension. The third phase covers the end of the initial rifting phase and the transition to passive margin conditions, as well as seafloor spreading in the Tasman Sea between 85 and 50 Ma. The fourth and fifth phases are associated with the Cenozoic initiation and evolution of the Tonga-Kermadec-Hikurangi subduction zone (Bache et al., 2014).
Figure 2-1: Location of New Zealand's petroleum basins (MBIE, 2014).
The boundaries of the Taranaki basin are defined by the Taranaki Fault in the east, the merging of the basin with the New Caledonian Basin in the northwest (King & Thrasher, 1996), and in the south the merging of the Taranaki Basin with the smaller sub-basins of New Zealand’s South Island (Salazar et al., 2016). There are two main tectonic sub-regions within the Taranaki Basin, divided by the Cape Egmont Fault Zone: the tectonically active Eastern Mobile Belt, and much tectonically calmer and structurally less complex Western Stable Platform (Figures 2-2 and 2-3) (Salazar et al., 2016; King & Thrasher, 1996).

Figure 2-2: Schematic cross-section of the Taranaki Basin (Muir et al., 2000).

The Eastern Mobile Belt is a broad area of interconnected depocenters and structural sub-provinces that are the product of Neogene tectonic overprinting of previous morphology (King & Thrasher, 1997). The Eastern Mobile Belt can be subdivided into two distinct structural sectors: the northern sector, which is currently undergoing extension and includes the Central and Northern Grabens as well as the Mohakatino Volcanic Center, a buried Miocene andesitic volcanic arc (Salazar et al., 2016); and the southern sector, which includes the Tarata Thrust Zone and Southern
Inversion Zone, both of which are areas of former compression, with some of the more southern areas of the Southern Inversion Zone still undergoing compression (King & Thrasher, 1996). The Western Stable Platform is untouched by the Neogene tectonic events that deformed the Eastern Mobile Belt. The structural style in this area consists of Cretaceous-Paleocene age rift-associated half-grabens overlain by ‘layer-cake’ and progradational basin-fill of Eocene-Recent age (King & Thrasher, 1996).

Figure 2-3: Producing fields, faults, and sediment thickness within the Taranaki Basin, as well as the Cape Egmont Fault Zone (outlined in red), which separates the Western Stable Platform and the Eastern Mobile Belt (Modified from Strogen et al., 2012).
2.2 Stratigraphic Overview

The Taranaki Basin basement is heterogeneous, reflecting the amalgamation of the Paleozoic Gondwana craton with Mesozoic accretionary terranes and plutons (Kroeger et al., 2013). Similar to the two tectonic sub-regions of the Taranaki Basin, the basement-terrane suite can also be divided into a Western and Eastern Province (Kroeger et al., 2013). The Western Province is primarily made up of Paleozoic metasediments and granites derived from the Gondwana craton, intruded by Cretaceous granitoids at the boundary with the Eastern Province (Kroeger et al., 2013). This boundary has been classically interpreted as a broad suture zone termed the Median Tectonic Zone (MTZ) (Bradshaw, 1989; Coombs et al., 1976); however, the MTZ has more recently been identified as a remnant of a magmatic arc related to an active Gondwanan continental margin of Jurassic to Cretaceous age (Kroeger et al., 2013; Mortimer, 1999; Wandres and Bradshaw, 2005). The MTZ predominantly consists of calc-alkaline granodioritic and dioritic plutonic rocks of the unroofed volcanic arc with minor remains of rhyolitic and basaltic volcanism (Kroeger et al., 2013). The Eastern Province consists of arc volcanic and volcano-sedimentary rocks and accretionary complexes of Permian and Mesozoic age (Kroeger et al., 2013).

Unconformably overlying the basement are volcanic rocks and a succession of Late Cretaceous syn-rift sediments, primarily deposited in localized fault-controlled rift-associated grabens (Kroeger et al., 2013). King & Thrasher (1996) characterized the Cretaceous to Cenozoic sedimentary record in the Taranaki Basin as a major depositional cycle consisting of a transgressional phase beginning in the Late Cretaceous and ending in the Early Miocene, and an ongoing regressive phase. King &
Figure 2-4: Generalized Cretaceous-Cenozoic stratigraphic framework of the Taranaki Basin (Bierbrauer et al., 2008).
Thrasher (1996) further subdivided the Cretaceous-Cenozoic succession into four seismic-stratigraphic units: 1) the Pakawau Group, a Late Cretaceous syn-rift sequence; 2) the Paleocene-Eocene late syn-rift and post-rift transgressive sequence of the Kapuni and Moa Groups; 3) the Oligocene-Miocene foredeep and distal sediment starved shelf and slope sequence of the Ngatoro Group, and the Miocene regressive sequence of the Wai-iti Group; and 4) the Plio-Pleistocene regressive sequence of the Rotokare Group (Figure 2-4).

2.2.1 Late Cretaceous Pakawau Group

The Pakawau Group includes all Late Cretaceous sedimentary rocks in the Taranaki Basin, and is a 500-4200 m thick Late Cretaceous syn-rift sequence present in isolated and interconnected depocenters as well as downthrown sub-basins (King & Thrasher. 1996). The Pakawau Group is divided into the Rakopi Formation, which primarily consists of coal measures, and the North Cape Formation, dominated by shallow-marine lithofacies (Figure 2-4) (King & Thrasher, 1996). The contact between the Rakopi and North Cape Formations marks the oldest regional marine transgression definable in the Taranaki Basin (King & Thrasher, 1996).

The Rakopi Formation, which can reach up to 3000 m in thickness, but is generally less than 1000 m, primarily consists of terrestrial coal measures, predominantly sandstone, cyclically interbedded with carbonaceous siltstone and mudstone, thin coal seams, and rare conglomerate (King & Thrasher, 1996). The North Cape Formation is also generally less than 1000 m thick, but thickens up to 1800 m in the Moa and Manaia sub-basins (Thrasher et al., 1995). The North Cape Formation consists predominantly of shallow-marine siltstones, coastal sandstones and silty sandstones, with coal
measures and conglomerates also appearing at particular locations within the Taranaki Basin (King & Thrasher, 1996). The coal measures within the North Cape Formation are less prevalent than those within the Rakopi Formation.

2.2.2 Paleocene-Eocene Kapuni and Moa Groups

The Paleocene-Eocene succession is divided by King & Thrasher (1996) into the terrestrial to marginal marine Kapuni Group and the marine Moa Group, which together represent a late syn-rift and post-rift transgressive sequence. The two groups are separated from the Pakawau Group by a regional unconformity (King & Thrasher, 1996). The Kapuni Group is comprised of the terrestrial to marginal marine strata of the Farewell, Kaimiro, Mangahewa, and McKee Formations (Figure 2-4) (King & Thrasher, 1996). Outside of the southwestern and southeastern regions of the Taranaki Basin where the coarsest (often Paleocene aged) rocks of the Kapuni Group are located, the Group can otherwise be characterized by a relative absence of high-energy, non-marine depositional environments (King & Thrasher, 1996). As Kapuni Group sedimentation began to decrease throughout the Eocene, Moa Group marine sedimentation increased (King & Thrasher, 1996). The Moa Group, the product of a major regional transgression during the Paleocene and Eocene, is entirely marine and is made up of the Turi and Tangaroa Formations (Figure 2-4) (King & Thrasher, 1996).

2.2.3 Oligocene-Early Miocene Ngatoro Group and Miocene Wai-iti Group

The third unit, as defined by King & Thrasher (1996), is made up of the Oligocene-Miocene foredeep and distal sediment starved shelf and slope sequence of the Ngatoro Group, and the Miocene regressive sequence of the Wai-iti Group. The Ngatoro Group is commonly separated from the older Kapuni and Moa Groups by a major
unconformity, with the lack of latest Eocene to Early Oligocene sediment representing non-deposition at the culmination of passive margin development (King & Thrasher, 1996). The Ngatoro Group is divided into the Otaraoa, Tikorangi, and Taimana Formations (Figure 2-4), all of which contain rocks that are generally high in calcium carbonate content (King & Thrasher, 1996). The Miocene Wai-iti Group is a regressive, marine, clastic dominate succession that evolved in response to the southward migration of the modern subduction-transform margin (King and Thrasher, 1996; Bierbrauer et al., 2008). The Wai-iti Group contains the shelf, slope, and basin floor mudstones of the Manganui Formation, the turbidite sequences of the Moki and Mount Messenger Formations, the slope siltstones of the Urenui Formation, deep-water volcaniclastics of the Mohakatino Formation, and the basin floor marls of the Ariki Formation (Figure 2-4) (King & Thrasher, 1996). The stratigraphy of the Wai-iti Group is in response to the initiation of subduction uplift along the eastern margin of the Taranaki Basin and renewed sediment supply into developing grabens and nearby basin areas (Bierbrauer et al., 2008).

2.2.4 Plio-Pleistocene Rotokare Group

The Plio-Pleistocene regressive sequence of the Rotokare Group is divided into the Matemateaonga, Tangahoe, Mangaa, and Giant Foresets Formations (Figure 2-4) (King & Thrasher, 1996). Shelf facies dominate the south and southeastern areas of the Taranaki Basin, and include both the coarse-grained Matemateaonga Formation and the finer-grained Tangahoe Formation, whereas these shelf facies are incorporated into the Giant Foresets Formation on the Western Stable Platform (King & Thrasher, 1996).
The submarine fans of the Mangaa Formation were developed within the actively subsiding North Graben (King & Thrasher, 1996).

The nature of the boundary between the Plio-Pleistocene Rotokare Group and the Miocene Wai-iti Group is highly variable across the Taranaki Basin (King & Thrasher, 1996). In the south, shelf or marginal marine facies of the Rotokare Group are separated from the older shelf and slope mudstone of the Wai-iti Group by a pronounced angular unconformity formed by differential uplift and erosion (King & Thrasher, 1996). In the central parts of the basin where clastic sedimentation was long-lived, the Rotokare Group and the Wai-iti Group are contiguous and conformable (King & Thrasher, 1996). In the Northern Graben however, latest Miocene strata are notably absent across volcanic edifices due to these edifices being areas of positive relief along the ocean floor at that time, as can be seen by the Mohakatino Formation (King & Thrasher, 1996). In the northeastern regions of the Taranaki Basin, the Rotokare and Wai-iti Groups are separated by the lithological contact between a condensed section within the basin floor carbonates of the Ariki Formation and the overlying terrigenous clastic deposits (King & Thrasher, 1996). The boundary between the Rotokare and Wai-iti Groups in the northeast is readily identified by the lithological boundary related to the cessation of the volcanism that was prevalent in the area until the end of the Miocene (King & Thrasher, 1996).

2.3 Structural Overview

From the Devonian to the mid-Cretaceous, Zealandia was located along the active eastern margin of Gondwana, and was a site of subduction and terrane accretion (Kroeger et al., 2013). Prior to the break-up and separation of Zealandia from eastern
Gondwana, an early phase of crustal extension, coined the 'Zealandia rifting-phase' by Strogen et al (2017), developed subparallel rift basins oriented primarily WNW-NNW (Strogen et al., 2017). These rift-basins are well documented throughout not only the Taranaki Basin, but also in the surrounding Challenger Plateau and Reinga Basin and suggest that widespread extension occurred throughout Zealandia throughout this time (105-83 Ma) (Strogen et al., 2017). This Zealandia rift-phase occurred immediately prior to the formation of the Tasman Sea (roughly 83 Ma) and the subsequent Zealandia-Gondwana separation that followed (Kroeger et al., 2013). The Zealandia rift phase extension direction and rift basins formed approximately parallel to the Tasman Sea spreading centers (Strogen et al., 2017).

The previously widespread Zealandia rift phase ceased with the onset of seafloor spreading in the Tasman Sea (c. 83 Ma) as extension was taken up in the active oceanic spreading centers (Strogen et al., 2017). The deposition of the Taranaki Delta sequence (c. 83-80 Ma), a prograding unit up to 2.5 km in thickness, in the Deepwater Taranaki Basin and the lack of coeval sedimentary rocks throughout the rest of the Taranaki Basin suggest localized uplift and erosion that coincided with the onset of seafloor spreading in the Tasman Sea (Strogen et al., 2017). Strogen et al. (2017) suggest that these events could have formed in association with thermally induced uplift driven by the separation of Gondwana.

Crustal extension renewed around roughly 80 Ma, and with it widespread sedimentation (Strogen et al., 2017). Grabens and half-grabens associated with this phase of extension are primarily oriented N-NE, roughly orthogonal to the previous trend of the Zealandia rift phase (Figure 2-5) (Strogen et al., 2017). This 'West Coast-
Figure 2-5: Tectonic reconstructions for the Zealandia-Australia-Antarctica region, with Australia fixed. (a) 120 Ma prior to Zealandia rifting at the end of long-lived subduction on the eastern margin of Gondwana, with the related arc indicated. The approximate future positions of sedimentary basins are also shown. (b) 90 Ma showing widespread Zealandia rifting. (c) 82 Ma showing initial seafloor spreading in the Tasman Sea and Southern Ocean with uplift of parts of central Zealandia (d) 70 Ma showing continuing seafloor spreading and spatially limited West Coast–Taranaki rifting in parts of central Zealandia. Basin abbreviations in (a): AB, Aotea; BB, Bass basins; BT, Bounty Trough; CB, Canterbury; CFB, Capel–Faust; CH, Challenger; CP, Campbell; CR, Chatham Rise; DWT, Deepwater Taranaki; ECB, East Coast; FB, Fairway; GB, Gippsland; GSB, Great South; M, Marlborough; MB, Monwai; NCB, New Caledonia; OB, Otway; RB, Raukumara; RNB, Reinga–Northland; RSB, Ross Sea; TB, Taranaki; WC, West Coast; WSB, Western Southland (Strogen et al., 2017).
Taranaki rift-phase’, as named by Strogen et al (2017), formed a relatively narrow belt roughly 500 km long through central Zealandia, making it much more restricted than the Zealandia rift phase (Strogen et al., 2017). The West Coast - Taranaki rift-phase was coeval with the active seafloor spreading in the Tasman Sea, and there are two main models that take the role of the Tasman Sea into account when trying to account for the West Coast-Taranaki rift (Strogen et al., 2017). The first is the ‘failed rift arm’ model in which the West Coast-Taranaki rift system extends northward from a triple junction southwest of New Zealand (Laird, 1981). The second model is the ‘sinistral transform model’ in which lateral motion along the rift system would accommodate differential spreading rates (Strogen et al., 2017). Reilly et al., 2015) determined that faults within the Taranaki Basin were predominantly dip-slip and accommodated extension. Passive margin conditions arose following the cessation of the West Coast-Taranaki rift phase (c. 55 Ma) and a decrease in the spreading rate of the Tasman Sea (c. 56 Ma, with complete termination c. 52 Ma) (Strogen et al., 2017; Kroeger et al., 2013). Deposition occurred in fluvial to shallow marine environments across the basin under these passive margin, post-rift conditions (Kroeger et al., 2013).

The modern plate boundary through New Zealand began to develop around 45 Ma, as is apparent through the onset of seafloor spreading in the Emerald Basin southwest of the South Island as well as subduction at the Norfolk Ridge north of New Zealand (Kroeger et al., 2013). In addition to continued plate convergence, the Pacific plate’s pole of counterclockwise rotation began to move southward relative to the Australian plate, causing New Zealand to transition from a traditionally extensional setting to a more contractional tectonic setting (Kroeger et al., 2013). The end of
passive margin development in western New Zealand is marked by the previously
mentioned widespread unconformity that separates the Oligocene-Early Miocene
Ngatoro Group from the Paleocene-Eocene Kapuni and Moa Groups, and is followed by
the transpressional development of reverse fault-bounded structures and sub-basins
(Kroeger et al., 2013). Reverse faulting and shortening would dominate the Taranaki
Basin between roughly 40 and 12 Ma as the relative motion of the Pacific and Australian
plates was convergent (Giba et al, 2010). Reverse faulting in the Taranaki Basin was
primarily focused along the Taranaki Fault system, a major back thrust in the basin
(Giba et al, 2010). This crustal-scale fault system, with displacements of up to 15 km,
thrusts basement upward to the west and forms the eastern boundary of the Taranaki
Basin (King & Thrasher, 1996; Giba et al, 2010).

The structural changes in the Taranaki Basin throughout the Neogene, both
shortening and extension, can be related to subduction along the Hikurangi Trough east
of the North Island (Figure 2-6) (Kroeger et al., 2013; Giba et al, 2010). Prior to roughly
12 Ma, the Hikurangi Trough was responsible for and produced mainly shortening (Giba
et al, 2010). It is only in the last 12 Ma that subduction at the Hikurangi Trough has
caused both extension and shortening, and even though the two are occurring
simultaneously, they occur at different locations within the Taranaki Basin. Shortening is
primarily restricted to the more southern areas of the basin, with extension confined to
the north (Giba et al, 2010). In addition, Miocene and younger extension was
accompanied by volcanism that began around 16 Ma (Giba et al., 2010). These volcanic
centers are primarily submarine stratovolcanoes, buried and preserved by middle
Miocene-Recent sediment (Giba et al., 2010). The stratovolcanoes low-medium
potassium andesitic composition and general NNE trending alignment (as seen in Figure 2-7), running parallel to the late Miocene subduction margin, suggest that the magmas originated from the subducting Pacific Plate beneath the Taranaki Basin (Giba et al., 2010).

Plio-Pleistocene plate boundary deformation continues to affect the eastern Taranaki Basin, causing significant areas of extension and crustal downwarp to form in the Northern / Central Grabens and Toru Trough / South Manganui Basin, respectively (King & Thrasher, 1996). The location of these areas behind the active magmatic arc makes the Taranaki Basin an active volcanic back-arc basin (Giba et al., 2010; King & Thrasher, 1996). There continues to be an easily delineated separation between zones of contraction and extension, with contraction primarily confined to the Southern Inversion Zone (King & Thrasher, 1996). The Western Stable Platform remains in relative quiescence (King & Thrasher, 1996). The Plio-Pleistocene period was characterized by extremely high sedimentation rates, especially in the east, as sediments filled the tectonically controlled depocenters and caused the shelf / slope sedimentary wedge to prograde northwest across the Western Stable Platform, causing the platform to subside under the heavy load of the sediment (King & Thrasher, 1996).

2.4 Petroleum Exploration and Development

The first petroleum well in the Taranaki Basin was the Alpha well drilled in 1865 in the future Moturoa Field (Figure 2-3), in the town of New Plymouth along the southwestern coastline of New Zealand’s North Island (Figure 2-8) (King & Thrasher, 1996; MBIE, 2014). The people that had settled in the area noticed an oily residue on the beach and manually dug a well to a depth of 5 meters before they were overcome
Figure 2-6: Map of faults and volcanoes of the Taranaki Basin. Normal faults active in early Pliocene are shown in black. Mio-Pliocene reverse faults are indicated by lines with black triangles. Outlines of submarine volcanoes of mid Miocene-Recent age are shown in gray. Three volcanoes of the Taranaki peninsula are subaerial. Regional seismic interpretation is tied to exploration wells shown in red. Inset shows plate boundary setting and location of main map, with relative plate motion vectors derived from Beavan et al. [2002]. Section X-X' across the plate-margin illustrates subduction of the Pacific Plate beneath the Australian Plate and the present back-arc setting of the Taranaki Basin. TFS, Turi Fault System; CEF, Cape Egmont Fault; CVR, Central Volcanic Region (Giba et al, 2010).
Figure 2-7: Sequence of maps showing the Tertiary structural evolution of the Taranaki Basin. Each map displays active volcanoes (shown in gray), active faults (black lines) for the time period indicated. Maps highlight the general southward migration of active reverse faults, volcanoes, and normal faults (Giba et al, 2010).
with the smell of gas (Gregg and Walrond, 2006). Not long afterward, the original ‘tripod’
was replaced with a derrick and a well was drilled to a depth of 55 meters, and
produced at a rate of 2 barrels of oil per day (BOPD) for a short amount of time (King &
Thrasher, 1996).

Figure 2-8: The Alpha well’s original ‘tripod’, 1865. Alpha was the first well drilled in
the Taranaki Basin (Gregg and Walrond, 2006).

Although this well, and subsequent wells in the area only showed small amounts
of oil and gas, and were largely uneconomic, they did lay the groundwork for further
hydrocarbon exploration in the Taranaki Basin. By the early 1900’s the Moturoa Field
had seen 14 companies drill 20 wells, while only 12 total wells had been drilled
elsewhere in the Taranaki Basin (King & Thrasher, 1996). In 1906, a newly completed
well produced initial flow rates in excess of 10 BOPD, and New Zealand’s first “oil
boom” was underway (King & Thrasher, 1996).

Despite the newfound excitement for petroleum in New Zealand, results up until
1955 were largely disappointing. Between 1914 and 1955, 12 wells were drilled in the
Moturoa Field and the surrounding New Plymouth area, as well as 12 additional wells
elsewhere in the Taranaki Basin (King & Thrasher, 1996). Even though wells during this
time had been drilled to depths of over 3300 m, not a single well had yet penetrated the
Kapuni Group, which currently contains the majority of hydrocarbon-bearing sandstone
reservoirs and coaly source rocks in the Taranaki Basin (Bierbrauer et al., 2008; King &
Thrasher, 1996).

In 1955, three companies, Shell, BP, and Todd (SBPT), formed a consortium and
ushered in a new era of exploration (King & Thrasher, 1996). In 1959, with the
advances made in seismic-data acquisition and processing throughout the previous
decade, SBPT discovered the onshore Kapuni Field southeast of the Moturoa Field
(Figure 2-3) (King & Thrasher, 1996). The Kapuni Field’s discovery well, Kapuni-1,
found, and would later produce gas-condensate in the Late Eocene Kapuni Group
(Figure 2-4) (Abbott, 1990). Kapuni-1 was the first well in the Taranaki Basin drilled
based on seismic reflection mapping (King & Thrasher, 1996). The Kapuni Field was
developed throughout the 1960’s and production began in 1970 (King & Thrasher,
1996). As of January 1, 2013 the Kapuni Field has produced over 1.8 Tcf of gas and 68
Mmbbl of condensate (MBIE, 2014). SBPT’s success in the Kapuni Field would mark
the beginning of New Zealand’s natural gas industry. In 1969, aided by the advent of
offshore seismic-surveying in the 1960’s, SBPT discovered the Taranaki Basin’s, and
New Zealand’s, largest hydrocarbon field to date – the Maui Field (Figure 2-3) (King & Thrasher, 1996; MBIE, 2014). Maui-1, the discovery well for the Maui Field, would prove the presence of not only gas and condensate, as was seen in the Kapuni Field, but also of some 10 m of net oil (MBIE, 2014). The Maui Field came online in 1979 and as of January 1, 2013 has produced nearly 3.6 Tcf of gas and 185 Mmbbl of oil / condensate (MBIE, 2014).

In 1978, the New Zealand government formed the Crown-owned Petroleum Corporation of New Zealand (Exploration) Limited, otherwise known as Petrocorp, and shortly thereafter took control of and focused the bulk of Petrocorp’s resources on an exploration license spanning a large portion of the Taranaki Peninsula (King & Thrasher, 1996). In 1979 Petrocorp drilled the McKee-1 well near the northwestern onshore limits of the Tarata Thrust Zone (Figures 2-2 and 2-3), but hydrocarbon flow from the overthrust Kapuni Formation reservoir targets was not sustained (King & Thrasher, 1996). Moving higher on the structure, Petrocorp drilled the McKee-2 well that tested light oil (43° API) at a rate of 1000 BOPD, marking the first major commercial oil discovery in not only the Taranaki Basin, but all of New Zealand (King & Thrasher, 1996). The McKee Field (Figure 2-3) is New Zealand’s largest onshore oilfield and as of January 1, 2013 has produced over 160 Bcf of gas and nearly 50 Mmbbl of oil (MBIE, 2014). Given the successes of SBPT and Petrocorp, the acquisition of additional 2D seismic surveys increased heavily in the 1980’s and still continues today (NZP&M, 2019). In addition to 2D surveys, 3D seismic acquisition in New Zealand began in 1987, with at least 35 surveys having been collected offshore as of the end of 2017 (Figure 2-9) (NZP&M, 2019).
Figure 2-9: Map showing location of 2D and 3D seismic surveys shot in the Taranaki Basin as of 2010 (Milner et al., 2010).
2.5 Petroleum System

Based on geochemical typing, the vast majority of the Taranaki Basin’s oil and gas accumulations are sourced from the Late Cretaceous Pakawau Group and Paleogene Kapuni Group coal measures and coaly mudstones, with TOC and Hydrogen Index (HI) values typically ranging from 2-75% and 200-400 mg HC/g TOC, respectively (King & Thrasher, 1996; MBIE, 2014). Modelling of these source rocks on the shelf as well as onshore regions of the Taranaki Basin suggests that over 1,500 billion barrels of oil and 2,400 tcf of gas have been expelled (MBIE, 2014). As of 2019, no similar models for areas beyond the shelf edge have been published. Rapid burial in the Neogene has brought these coals and coaly mudstones to depths where they are presently mature and expelling primarily gas, as well as minor quantities of oil, such as in the onshore McKee Field (Figure 2-3) (MBIE, 2014). In addition, the Late Paleocene organic-rich marine shales of the Waipawa Formation (Figure 2-4) have been geochemically typed as the source rock for the oil discovered in the Kora Field (Figure 2-3), and are currently one of only two proven non-coaly source rock in the Taranaki Basin, the other being the Taranaki Delta shales found in the Romney-1 well (MBIE, 2014; Sykes et al., 2013). Modeling completed by King & Thrasher (1996) suggests that the Waipawa Formation began generating and expelling petroleum fluids in the Late Miocene. According to thermal modeling completed by Stagpoole & Funnell (2001), source-rock maturation and expulsion are also partially controlled by the Middle-Late Miocene volcanism associated with the Mohakatino Volcanic Center (Figure 2-10); the results of the models indicating that Late Cretaceous section at certain depths and distances from the magmatism would become fully mature.
Figure 2-10: Map of the northern Taranaki Basin and adjacent area showing the Mohakatino Volcanic Center (light shading) comprising Miocene arc volcanoes. Older volcanic centers (no shading) are Northland andesitic volcanoes; younger volcanic centers (dark shading) are andesitic and basaltic volcanic cones. Faults active in the Neogene are also shown (Stagpoole & Funnell, 2001).

Commercial quantities of petroleum fluids have been encountered at every stratigraphic level in the Taranaki Basin except the Cretaceous (Figure 2-11), with the majority of petroleum reserves discovered in the Paleocene-Eocene Kapuni Group (Hart, 2001). Paleogene reservoirs most commonly trap gas-condensate, whereas Neogene reservoirs primarily trap oil, and stacked reservoirs are common in the Maui,
Kapuni, and Rimu / Kauri Fields (Figure 2-3) (MBIE, 2014). Of the producing formations, the Farewell, Kaimiro, and Moki Formations have been the most productive in the basin (MBIE, 2014). At year end 2017, six fields – the Kupe, Maari, Maui, McKee / Mangahewa, Pohokura, and Tui – constitute nearly 90% of all oil production in the Taranaki Basin, with four fields – the Kupe, Maui, McKee / Mangahewa, and Pohokura – responsible for roughly 90% of the gas production (Table 2-1) (MBIE, 2018).

Table 2-1:  Percentage of annual oil and gas production by field (MBIE, 2018).

<table>
<thead>
<tr>
<th>FIELD</th>
<th>PERCENTAGE OF TOTAL OIL PRODUCTION</th>
<th>PERCENTAGE OF TOTAL GAS PRODUCTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maari</td>
<td>28.5</td>
<td>0.0</td>
</tr>
<tr>
<td>Pohokura</td>
<td>23.6</td>
<td>38.2</td>
</tr>
<tr>
<td>Kupe</td>
<td>10.3</td>
<td>13.4</td>
</tr>
<tr>
<td>Maui</td>
<td>10.0</td>
<td>17.5</td>
</tr>
<tr>
<td>McKee / Mangahewa</td>
<td>8.4</td>
<td>18.4</td>
</tr>
<tr>
<td>Tui</td>
<td>7.9</td>
<td>0.0</td>
</tr>
<tr>
<td>Rimu</td>
<td>4.3</td>
<td>0.2</td>
</tr>
<tr>
<td>Turangi</td>
<td>2.6</td>
<td>5.7</td>
</tr>
<tr>
<td>Kapuni</td>
<td>2.4</td>
<td>4.1</td>
</tr>
<tr>
<td>Ngatoro</td>
<td>1.2</td>
<td>0.5</td>
</tr>
<tr>
<td>Kohwai</td>
<td>0.9</td>
<td>1.7</td>
</tr>
</tbody>
</table>

Widespread Late Cretaceous to Neogene mudstones deposited during the region’s passive-margin transgressive phase as well as the regressive convergent margin phase provide top seals or intraformational seals to nearly all hydrocarbon-bearing clastic reservoirs in the Taranaki Basin (Figure 2-11) (King & Thrasher, 1996; MBIE, 2014). The Oligocene-Early Miocene limestones also form effective sealing rocks due to their inherently low porosity and permeability (Figure 2-11) (King & Thrasher, 1996). Neogene-aged reservoirs being more prone to contain oil can potentially be
related to poor sealing quality, as mudstones at relatively shallow depths might not be sufficiently compacted to act as seal to more mobile gas (King & Thrasher, 1996).

Figure 2-11: The petroleum system of the Taranaki Basin (MBIE, 2014).

The Taranaki Basin is home to a wide variety of play types, but structural traps constitute the primary trapping mechanism for most discoveries in the basin (Grahame, 2015). The Late-Cretaceous West Coast-Taranaki rifting phase followed by Miocene contraction produced a large portion of the structures currently trapping petroleum fluids (MBIE, 2014). While the majority of wells drilled to date have targeted four-way dip closures, wells have also been drilled on thrust features, inversion structures,
extensional structures, volcanic edifices, half-graben fill, submarine fans, and diagenetic traps (MBIE, 2014). The largest discoveries in the Taranaki Basin – the Kapuni, Maui, Mangahewa, Kupe, Maari, and Pohokura Fields – have all been classified as inversion structures (Hart, 2001; MBIE, 2014). Uplift and inversion of sub-basins within the eastern and southern areas of the Taranaki was caused by Miocene crustal shortening reactivating and reversing movement along many extensional faults (MBIE, 2014). Due to the early successes at these fields, most of the obvious inversion structures in the basin have been targeted and drilled in the past five decades (MBIE, 2014).
CHAPTER 3
DATASETS

Conventional petroleum wells in this study were selected based on the availability of specific data required for proper analysis via the decision tree (Figure 1-1). The data required include, but are not limited to: well logs (sufficient to determine lithology, porosity, permeability, etc.); high quality seismic-data (with adequate coverage to interpret and determine the presence of the predrill predicted structure); gas data – either from traditional gas logs or IsoTubes (to determine the presence of shows and / or a thermogenic front); and geochemical measurements (in order to determine source-rock presence and maturity). Once a particular well was determined to have all of the data necessary to test it against the decision tree, data were then requested and obtained from New Zealand’s Online Exploration Database (NZP&M, 2019).

3.1 Romney-1

The initial well selected for this study was the Romney-1 exploration well drilled in the Deepwater Taranaki Basin (Figure 1-2) between November of 2013 and February of 2014 by Anadarko New Zealand Taranaki Company, a subsidiary of Anadarko Petroleum Corporation.

The predrill expectations for Romney-1, as well as the targeted segments, predrill structure maps (for both of the well’s targeted segments – the Late-Cretaceous North Cape and Rakopi Formations), and postdrill reported depths of formation tops and other
important stratigraphic horizons were all acquired from the well’s technical completion report (Rad, 2015).

Over 175 samples collected through various techniques at a variety of depths were submitted by Anadarko to Intertek Geochem for geochemical analyses. Intertek Geochem completed a robust geochemical program to evaluate Romney-1 samples on the basis of thermal maturity, source, and depositional environment. Samples that were analyzed included: 32 MSCT (mechanical sidewall coring tool) samples; 76 IsoJar samples; 66 IsoTube samples; and a series of mud samples from various depths throughout the well (Phillips, 2014).

In addition, rotary sidewall-core samples were sent by Anadarko to Core Laboratories for thin section petrography, X-ray diffraction (XRD), and scanning electron microscopy (SEM) analysis. The rotary sidewall core samples used by Core Laboratories were obtained over depths spanning roughly 1,000 meters. Fifty-two thin sections were prepared, 29 samples underwent SEM analysis, and 24 samples were examined via XRD analysis (Core Laboratories Inc., 2014).

The Romney 3D seismic survey (Figure 3-1), shot in 2011, was used in order to reinterpret specific horizons and create postdrill structure maps. The seismic survey covers an area of roughly 2,000 km² (Rusconi, 2017). In addition to blanket seismic coverage across the area of interest, subsurface well-log data from Romney-1 were also abundant. Both the seismic and well log data were interpreted and examined using Schlumberger’s Petrel software.
Figure 3-1: Map of wells, 3D and 2D seismic surveys used to conduct this study, and their location relative to New Zealand’s North Island.
3.2 Whio-1

The second well selected was the Whio-1 exploration well, drilled in the southern Taranaki Basin (Figure 1-2). Whio-1 was drilled by OMV New Zealand Limited between July 23, 2014 and August 31, 2014. OMV New Zealand Limited is a subsidiary of OMV Exploration & Production based in Vienna, Austria.

Information regarding Whio-1’s predrill primary targeted segments (the Middle Miocene M2A sandstone and the Middle Eocene Mangahewa Formation), pre- and postdrill structure maps, as well as the actual depths at which various important horizons were encountered while drilling was all gathered from the well’s technical completion report (Wyman & Smith, 2015).

Forty-one rotary sidewall-cores were sent by OMV to the Institute of Geological and Nuclear Sciences Limited (GNS Science) for a complete petrographic study. Of those 41 samples, 22 were specific to reservoir evaluation, and the other 19 were for seal evaluation. Analyses on reservoir samples included: thin section petrography on all 22 samples; x-ray diffraction (XRD) on a representative subset of five samples; scanning electron microscopy (SEM) on the same subset of five samples; and mercury injection capillary pressure (MICP) analysis on a single reservoir sample. Seal sample analyses included: thin section petrography on all 19 samples; XRD on six samples; SEM on four samples; and MICP analysis on 19 seal samples (Higgs et al., 2015). In addition, 44 core samples were also sent to Core Laboratories for porosity, permeability, and grain density measurement (Brown, 2014).

The Maari 3D seismic survey (Figure 3-1), shot in 2012 and covering an area of roughly 250 km$^2$, was used for all of OMV’s pre- and postdrill seismic interpretations
associated with the Whio-1 well, as well as all subsequent interpretations created for, and associated with this study (Knox, 2012). Both the seismic and well log data were interpreted and examined as part of this study using Schlumberger’s Petrel software.

3.3 Kanuka-1

The final well selected for this study was the Kanuka-1 exploration well, drilled on the Western Stable Platform of the Taranaki Basin (Figure 1-2). Kanuka-1 was drilled by Pogo New Zealand between October 23, 2007 and November 7, 2007.

The predrill expectations for Kanuka-1, as well as the targeted segments, predrill structure maps for Kanuka-1’s targeted horizon, and postdrill reported depths of formation tops and other important stratigraphic horizons were acquired from the well’s technical completion report (Bates & Heid, 2008).

Extracts of seven cuttings samples from a variety of depths were submitted by Pogo to Geomark Research for geochemical analyses. Geomark subsequently evaluated these samples by means of whole-extract gas chromatography - mass spectrometry (GC-MS) (Bates & Heid, 2008).

In addition, 23 rotary sidewall core samples were sent to Core Laboratories for thin section petrography, X-ray diffraction (XRD), and scanning electron microscopy (SEM) analysis. The rotary sidewall core samples used by Core Laboratories were obtained over depths spanning roughly 1,000 meters. Twenty-three thin sections were prepared, six samples underwent SEM analysis, and six samples were examined via XRD analysis (Bates & Heid, 2008).

The construction of postdrill structure maps and interpretation of specific horizons was completed using over 1000 km’s of 2D seismic data in conjunction with the
Parihaka 3D survey immediately to the southeast of the Kanuka Prospect (Figure 3-1). The Parihaka 3D seismic survey was shot in 2005, and covers an area of just over 1,500 km$^2$ (Cohen et al., 2006). In addition to 2D and 3D seismic coverage throughout the area of interest, subsurface well-log data from Kanuka-1 were also available for analysis. All of the seismic data were interpreted as part of this study using Schlumberger’s *Petrel* software.
CHAPTER 4
METHODOLOGY

In order to determine the key failure mode for a failed (dry) segment effectively and consistently, it is first necessary to establish technically robust and comprehensive, yet simple definitions as for what constitutes a segment, structural failure, reservoir deliverability failure, and so on. This study is not focused on economic successes and failures, but rather only on geologic (technical) successes and failures. For the purposes of this study a geologic success is defined as an instance where a conventional exploration well finds petroleum fluids that are able to flow freely and sustainably into a well from the penetrated subsurface segment(s) given the actions of a prudent operator (Milkov, 2015; Milkov & Samis, 2019). A dry conventional exploration well is one that fails to find movable petroleum fluids in any penetrated segment (herein referred to as “failed” or “dry”). On the other hand, a successful conventional exploration well is one where movable petroleum fluids are encountered in at least one segment, even though the well might still fail to find petroleum fluids in other failed segments. Postdrill analysis of a failed segment should always be compared or related to the predrill expectations or predictions for the well.

This study analyzes failed segments on the basis of seven risk factors: reservoir facies, reservoir deliverability, seal, structure, mature source rock(s), migration, and timing. This study, as well as Milkov & Samis (2019), determine success and failure for each individual risk factor based upon the methodology put forward by Sykes et al.’s (2011) study on ExxonMobil’s wells, with one stark difference – Sykes et al. (2011) does
not separate risk from volumes, whereas this study does. As previously mentioned, this study is only focused on geologically successful wells, i.e. a well that finds any freely and sustainably flowing petroleum fluids, regardless of the volume found. This greatly differs from Sykes et al.’s (2011), and thus ExxonMobil’s, approach as Sykes and ExxonMobil would determine the reservoir to be the failure mode even if the predicted reservoir were present yet it was unable to hold some predetermined minimum economic volume of petroleum. While the following definitions are meant to be comprehensive, yet simple, the figures presented are schematic and illustrate general concepts; they are in no way meant to illustrate every possible subsurface scenario, as each segment is unique (Milkov & Samis, 2019).

4.1 Structure Presence

Predrill descriptions of the predicted structural, or stratigraphic trap, include information regarding structural closure, geometry, container, etc. and presents a map of the structure. This study does not risk some minimum size of the structure, but rather the presence of a structure of any size. The first task is to determine whether the predicted structure is present (success) or absent (failure). Mapping the different structures in this study was done in Petrel using the various seismic data available for a given well. It is important to note that seismic interpretation is highly interpretive and often highly uncertain. This uncertainty can be due to any number of causes, but two of the most common are related to the ambiguity in picking horizons, and time-depth conversions (Rankey and Mitchell, 2003; Chellingsworth et al., 2015). Given the nature of these uncertainties, it is possible for a postdrill structure map to look similar to the predrill map (Figure 4-1A, B), or to differ significantly from the predrill map (Figure
4-1C,D). Even though the structure is present, a petroleum accumulation might be absent in the segment, or it could be present up dip from the well. The structure is determined to be absent (failed) in cases when analysis of well logs, well ties, and well-calibrated seismic conclude no structure is present (Figure 4-1E) (Milkov & Samis, 2019).

Figure 4-1: Cross-sectional schematics demonstrating the definition of success and failure for the presence of structure (closure, container). The postdrill structure may be similar to the predrill structure (A, B) or may have different amplitude (C) or shape and/or location (D). Even though the well is dry, the segment may contain no petroleum, represented in green (A, C) or may contain petroleum up dip from the well (B, D), in which case the segment may be re-evaluated and considered for re-drilling. The structure is absent if the new mapping using data from the drilled well definitively suggests so (E) (Milkov & Samis, 2019).
4.2 Reservoir Presence

The presence or absence of the predrill predicted reservoir facies can be established from many different tools and analytical techniques, including but not limited to: well logs, cuttings, sidewall cores, and conventional cores. This study determines the success or failure of reservoir presence based upon the presence of any reservoir facies that may contain any amount of movable petroleum. In practice, this means that reservoir presence could still be considered a success even if the discovered reservoir facies differs from the predrill prediction (e.g. carbonates as opposed to sandstones) (Figure 4-2). However, if the discovered reservoir facies does differ from the predicted facies, subsurface reservoir models should be updated with the newly acquired information.

![Diagram](image)

Figure 4-2: Examples of success (A) and failure (B) for the presence of reservoir facies (Milkov & Samis, 2019).

4.3 Reservoir Deliverability

Reservoir-deliverability success can be determined in cases where well logs and core data show that the segment’s reservoir facies contain porosity and permeability high enough to flow the predicted or likely petroleum fluid phase (Figure 4-3A). On the other hand, the segment lacks reservoir deliverability in cases where the porosity and
permeability are too low to flow petroleum fluids (e.g. tight cemented sandstones, Figure 4-3B), or if the fluids viscosity is too high, inhibiting the free sustainable flow of petroleum (e.g. heavily biodegraded oil. Figure 4-3C) (Milkov & Samis, 2019).

![Diagram of reservoir deliverability](image)

Figure 4-3: Examples of success (A) and failure (B,C) for reservoir deliverability (Milkov & Samis, 2019).

### 4.4 Top Seal Presence

The presence of top seal can be declared a success if well logs and core data suggest that a good effective top seal caps the reservoir in the drilled segment (Figure 4-4). Since most top seals leak (save for evaporites), it is necessary to evaluate not only the seals presence, but also its effectiveness, or sealing capacity. Even in cases where lithology inferred from well logs and core data suggest the presence of a top seal, special measurements (i.e. capillary-entry pressure) are often necessary to quantify the sealing capacity (effectiveness) of the seal. This step becomes critical if the seal contains thermogenic petroleum (e.g., as inferred from IsoTube gas data) and is apparently leaky. Nonetheless, for the purposes of this study, success and failure are established based upon the presence of a top seal capable of holding any column of petroleum, as opposed to only a column capable of holding some minimum predetermined size (Milkov & Samis, 2019).
Figure 4-4: Examples of success (A, B) and failure (C, D) for top seal. Green dots in C and D indicate the presence of petroleum shows and oil / gas anomalies suggested that petroleum migrated through the segment (Milkov & Samis, 2019).

4.5 Mature-Source Presence

Since exploration wells are typically not designed to test deeper lying source rocks, the presence of mature source rocks is often difficult to establish. In instances where the well does penetrate the source, interpretation of well logs, core data, and geochemical measurements (such as total organic carbon (TOC), hydrogen index (HI), temperature at which the maximum rate of petroleum generation occurs in a rock sample during pyrolysis analysis ($T_{\text{max}}$), and vitrinite reflectance ($R_o$)) allow for the declaration of the presence or absence of a mature source rock (Figure 4-5A, B). In the more likely scenario where the well does not penetrate the predicted source rock,
success can be declared if the well contains oil / gas shows or thermogenic gases (e.g. in mud-gas log and / or Iso Tubes) (Figure 4-5C). However, it is possible that even in the absence of oil / gas shows or thermogenic gases that migration might be the failure mode rather than the presence of a mature source, which will be elaborated upon in Section 4.6. In addition, information other than well logs, core data, and geochemical measurements can also be used to determine whether or not the predicted source rock is both present and mature, or if it is the failure mode for the segment. For instance, temperature measurements from the well might show that the area is significantly colder.
than predrill models assumed, meaning that the source rock(s) might be immature (Figure 4-5D) (Milkov & Samis, 2019).

### 4.6 Migration and Timing

The determination of success or failure for petroleum migration is often apparent through the analysis of oil / gas shows and / or gas observed in Iso Tubes, mud-gas logs, and other gas samples (Figure 4-6A, B). However, it is also possible that oil and / or gas shows are present in the reservoir yet the segment still fails. This is possible in circumstances where the structure formed after migration occurred through the area, herein referred to as failure due to timing (Figure 4-6C) (Milkov & Samis, 2019). Timing may be determined to be the failure mode through the process of elimination if all of the other elements (structure, reservoir presence and deliverability, top seal, mature source, migration, and lateral seal) are in place (Milkov & Samis, 2019). Structural restoration and basin modelling may be necessary to confirm timing as the failure mode.

### 4.7 Lateral-Seal Presence and Effectiveness

While declaring either success or failure for the presence of the top seal is relatively straightforward, lateral seals are much more difficult due to the fact that lateral seals are rarely penetrated intentionally by a well. However, if the lateral seal is penetrated by the well and the well logs and core data suggest that the segment’s targeted reservoir juxtaposes sealing lithology across the fault, then success may be established (Figure 4-7A). On the other hand, in the same scenario (where the well does penetrate the lateral seal) failure can be established if the well logs and core data show that the segment’s reservoir juxtaposes non-sealing lithology. This can be
established through the presence of oil or gas shows and / or thermogenic gases on both

Figure 4-6: Examples of success (A) and failure (B, C) for petroleum migration. Green dots in A and C indicate the presence of petroleum shows and gas anomalies suggesting that petroleum migrated through the segment. Green arrows in C indicate migration of petroleum within the reservoir. In the failure case described in B, all petroleum fluids generated by the mature source rock were lost during the migration (see, for example, Milkov, 2015). In the failure case described in C, the structure formed after petroleum migrated through the reservoir (Milkov & Samis, 2019).
Figure 4-7: Examples of success (A, D) and failure (B, C, E, F) for lateral seal in the fault-bounded segment (A, B, C) and for lateral / bottom seal in a stratigraphic trap (D, E, F). Green dots in B, C, E, and F indicate the presence of petroleum shows and gas anomalies suggesting that petroleum migrated through the segment. Pc stands for capillary entry pressure (Milkov & Samis, 2019).

Sides of the fault, suggesting cross-migration has occurred and thus that the lateral seal is either absent or ineffective (Figure 4-7B) (Milkov & Samis, 2019). It is far more likely, however, that an exploration well does not directly test the lateral seal. In such cases
where the lateral seal was not tested and the well also fails to find movable petroleum fluids, it is important to examine and determine the presence of all other elements (structure, reservoir presence and deliverability, top seal, mature source, and migration) carefully so that the lateral seal can be determined as the failure mode through the process of elimination (Milkov & Samis, 2019). Similar principles can be applied to the postdrill evaluation of lateral and bottom seals in stratigraphic traps (Figure 4-7C, D, E).
CHAPTER 5
RESULTS

5.1 Romney-1

Romney-1 was drilled between November 2013 and February 2014 in roughly 1500 m of water in order to test the exploration potential of the Deepwater Taranaki Basin off the west coast of the North Island of New Zealand (Figure 5-1). The primary targeted reservoir segment of the well was the Late-Cretaceous transgressive-marine to nearshore / shoreface sequences of the North Cape Formation within the Pakawau Group (Figure 5-2). A deeper secondary segment was also targeted – the Late-Cretaceous fluvio-deltaic and nearshore sand sequences of the Rakopi Formation within the Taranaki delta group (Figure 5-2) (Rad, 2015).

5.1.1 North Cape Segment

5.1.1.1 Predrill Evaluation

The North Cape segment in the Late Cretaceous transgressive marine to nearshore / shoreface sand sequences of the Pakawau Group (Figure 5-2) was the primary drilling objective of Romney-1. In the predrill evaluation by Anadarko (the operator), the North Cape segment was described as a complex closure with updip amplitude-supported stratigraphic pinch-outs associated with a facies change and lateral sealing by a basement-offsetting Oligocene-aged fault (Figure 5-3) (Rad, 2015).

Transgressive pro-delta shales located near the base of the Late Cretaceous Taranaki delta group were inferred as the main source rock for both the North Cape
Figure 5-1: Map of Areas of Investigation (AOI's) showing the location of the Deepwater Taranaki Basin and the Taranaki Basin, in addition to the wells used in this study.
Figure 5-2: Generalized Cretaceous-Cenozoic stratigraphic framework of the Taranaki Basin (Bierbrauer et al., 2008).
Figure 5-3: Predrill evaluation of the North Cape segment from the operator (Anadarko). (A) Predrill structure map. (B) Predrill structure map with amplitude overlay. The section views of Crossline 5300 (C) and Inline 1850 (D) showing predrill interpreted horizons, faults, and volcanics (purple) (Rad, 2015).
and Rakopi Formations. Despite numerous wells drilled in the Taranaki Basin, this predicted source interval had never been tested, and thus was listed by Anadarko as the key geological risk. Two secondary source intervals were also predicted. The first is the over-mature Late Jurassic to Early Cretaceous lacustrine shales interbedded with terrestrial coals underlying the Taranaki delta group, and the second is the widespread coal measures within the Late Cretaceous Rakopi Formation that are a proven source for many Taranaki Basin fields. However, Anadarko’s modeling suggests that the coals within the Rakopi Formation are immature and that 80-99% of in-place petroleum fluids would originate from the primary source (Rad, 2015).

The North Cape segment was penetrated by the Romney-1 exploration well between 2013-2014. The North Cape segment is deemed to have failed because there were no indications of movable petroleum fluids (Rad, 2015).

5.1.1.2 Segment-Failure Analysis

The top of the North Cape sands was picked at 3,429 mMDRT (3,429 meters measured depth below the rotary table), 6 m above prognosis (Rad, 2015. (All depth values below, as well as in Tables and Figures, are reported as mMDRT). The drilling floor for the Romney-1 well was 25 m above sea level and water depth was 1546.6 m (Rad, 2015). Various well-logging tools and curves (gamma ray, caliper, and resistivity) (Figure 5-4) were used to aid in the identification of distinctive lithologies within the target interval. In addition to well logs, a detailed petrologic analysis of rotary sidewall cores (Table 5-1) was completed by Core Laboratories, Inc. (2014). These petrologic reports used in conjunction with the well logs confirmed the presence of a 294 m thick reservoir interval of primarily siltstone interbedded with sandstone. Of that 294 m
interval, roughly 61 m total are sandstone layers varying in thickness from 0.5 m to 7 m.

Figure 5-4 shows the gamma ray, caliper, resistivity, permeability, porosity, bulk density, and interpreted lithology throughout the North Cape segment.

Figure 5-4: Gamma ray (GR), caliper (HCAL), resistivity (AE10, AE30, AE90), permeability (KTM and KSDR), porosity (NPHI), and bulk density (RHOZ) curves, as well as interpreted lithology throughout the North Cape interval (modified from Rad, 2015).
Table 5-1: Petrographic summary for samples from Romney-1 exploration well (modified from Core Laboratories Inc., 2014).

<table>
<thead>
<tr>
<th>Depth (m)</th>
<th>Geological Age/ Local Formation Name</th>
<th>Lithology</th>
<th>Thin Section Textural Features</th>
<th>Pore size (%)</th>
<th>Permeability (md)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3418.98</td>
<td>Late Cretaceous</td>
<td>Sandy Shale</td>
<td>Faint, waxy, silt-poor laminae; faintly mottled; burrowed</td>
<td>26.2</td>
<td>0.030</td>
</tr>
<tr>
<td>3442.00</td>
<td></td>
<td>Argillaceous Sandstone</td>
<td>Thin, discontinuous detrital clay-rich laminae; mottled burrowed</td>
<td>14.6</td>
<td>0.163</td>
</tr>
<tr>
<td>3472.93</td>
<td></td>
<td>Sandy Shale</td>
<td>Faintly aligned, compacted plant fragments; burrowed</td>
<td>16.6</td>
<td>0.499</td>
</tr>
<tr>
<td>3476.02</td>
<td></td>
<td>Slightly Argillaceous Sandstone</td>
<td>Mottled</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>3480.04</td>
<td></td>
<td>Slightly Argillaceous Sandstone</td>
<td>Aligned, compacted ductile grains; titanium-rich minerals concentrated into thin, discontinuous laminae</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>3504.96</td>
<td></td>
<td>Slightly Argillaceous Sandstone</td>
<td>Wavy, non-parallel, detrital clay-rich laminae; mottled</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>3505.96</td>
<td></td>
<td>Sandstone</td>
<td>Mottled</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>3546.93</td>
<td></td>
<td>Argillaceous Sandstone</td>
<td>Faintly aligned ductile grains; mottled</td>
<td>24.4</td>
<td>18.2</td>
</tr>
<tr>
<td>3560.03</td>
<td></td>
<td>Kaolinite-cemented Sandstone</td>
<td>Aligned ductile grains; faintly mottled</td>
<td>37.2</td>
<td>7.4</td>
</tr>
<tr>
<td>3671.97</td>
<td></td>
<td>Argillaceous Sandstone</td>
<td>Microstylolites; mottled, burrowed; wavy, detrital clay-rich laminae; thick, size-sorted laminae</td>
<td>16.6</td>
<td>0.017</td>
</tr>
<tr>
<td>3686.93</td>
<td></td>
<td>Sandstone</td>
<td>Aligned, compacted plant fragments; organic-rich seams, and ductile grains; mottled</td>
<td>20</td>
<td>0.327</td>
</tr>
<tr>
<td>3729.93</td>
<td></td>
<td>Basalt</td>
<td>Phaneritic, porphyritic, fity, interstitial, amygdaulitic</td>
<td>12</td>
<td>0.004</td>
</tr>
<tr>
<td>3747.94</td>
<td></td>
<td>Basalt</td>
<td>Phaneritic, porphyritic, plagioporphitic, fity, interstitial, amygdaulitic</td>
<td>5.2</td>
<td>0.005</td>
</tr>
<tr>
<td>3758.93</td>
<td></td>
<td>Argillaceous Sandstone</td>
<td>Massive</td>
<td>21.3</td>
<td>0.135</td>
</tr>
<tr>
<td>3774.99</td>
<td></td>
<td>Siltitic Argillaceous Sandstone</td>
<td>Massive</td>
<td>12.5</td>
<td>0.057</td>
</tr>
<tr>
<td>3786.93</td>
<td></td>
<td>Calcrete-cemented Sandstone/Siltitic Argillaceous Sandstone</td>
<td>Massive</td>
<td>14.4</td>
<td>0.056</td>
</tr>
<tr>
<td>8800.98</td>
<td></td>
<td>Argillaceous Sandstone/Sandy Shale</td>
<td>Aligned, compacted ductile grains; burrowed/wavy, sub-parallel sand-poor laminae; thin, sub-parallel organic-rich laminae; calcrete-filled microfractures</td>
<td>15.1</td>
<td>0.024</td>
</tr>
<tr>
<td>8830.01</td>
<td></td>
<td>Kaolinite-cemented Sandstone</td>
<td>Massive</td>
<td>21.7</td>
<td>13.3</td>
</tr>
<tr>
<td>8825.02</td>
<td></td>
<td>Kaolinite-cemented Sandstone</td>
<td>Aligned, compacted plant fragments and ductile grains</td>
<td>24.8</td>
<td>12.3</td>
</tr>
<tr>
<td>8846.03</td>
<td></td>
<td>Kaolinite-cemented Sandstone</td>
<td>Faintly aligned ductile grains</td>
<td>21.1</td>
<td>12.0</td>
</tr>
<tr>
<td>8897.93</td>
<td></td>
<td>Kaolinite-cemented Sandstone</td>
<td>Aligned, compacted ductile grains</td>
<td>18.6</td>
<td>11.4</td>
</tr>
<tr>
<td>8925.00</td>
<td></td>
<td>Kaolinite-cemented Sandstone</td>
<td>Aligned, compacted plant fragments, and ductile grains</td>
<td>18.1</td>
<td>0.497</td>
</tr>
<tr>
<td>8955.00</td>
<td></td>
<td>Sandstone</td>
<td>Aligned, compacted plant fragments, and ductile grains</td>
<td>14.7</td>
<td>0.405</td>
</tr>
<tr>
<td>8999.03</td>
<td></td>
<td>Kaolinite-cemented Sandstone</td>
<td>Aligned, compacted plant fragments, and ductile grains</td>
<td>20.2</td>
<td>7.36</td>
</tr>
<tr>
<td>8935.97</td>
<td></td>
<td>Argillaceous Sandstone</td>
<td>Aligned, compacted plant fragments, organic-rich seams and detrital clay concentrated into wavy sub-parallel laminae; size-sorted laminae; microstylolites</td>
<td>17.6</td>
<td>115</td>
</tr>
<tr>
<td>9550.05</td>
<td></td>
<td>Sandstone</td>
<td>Aligned compacted plant fragments and ductile grains, some concentrated into sub-parallel laminae</td>
<td>18.6</td>
<td>0.692</td>
</tr>
</tbody>
</table>
After confirming the presence of the reservoir, the workflow then proceeds to the evaluation and identification of the existence, or lack thereof, of oil shows and/or thermogenic gases (Figure 1-1). Based on data from the conventional mudlogging gas system, the North Cape formation is characterized by low background gas mostly around 0.01%, and no gas shows/peaks. Although very poor and poor oil shows were reported from intervals 3469-3509 m, they were interpreted to be caused by oil-based mud additive as petrophysical evaluations and MDT (Modular Formation Dynamics Tester) pretests did not suggest the presence of any movable oil in this interval (Rad,
Table 5-2 presents the molecular and isotopic composition of gases from Romney-1 as measured in Iso Tubes and Iso Jars. The North Cape Formation, and gases within it, are represented by the values in Table 5-2 between the depths of 3440-3710 m. Although the ratio of \( C_1/(C_2+C_3) \) within the segment is relatively low (from 5 to 16) and may suggest thermogenic origin of the gas, the concentration of \( C_1-C_5 \) gases is very low. The concentration of \( C_1 \) is 22-120 ppm, and concentrations of individual \( C_2-C_5 \) gases do not exceed 6 ppm in Iso Tubes. Because of such low concentrations, no \( \delta^{13}C_1 \) measurements were made. The only gas sample above the North Cape segment with available \( \delta^{13}C_1 \) value is from depth 3226 m, about 200 m above the top of the reservoir and within the seal. This sample has \( C_1/(C_2+C_3) \) value of 77 and \( \delta^{13}C_1 \) value of -68.3‰, and has either a microbial or early mature in-situ thermogenic origin, or some combination of both (Milkov and Etope, 2018). The study of thin sections from sidewall-cores revealed high abundance of oil fluid-inclusions (orange / white-fluorescent in carbonate cement) in sandstones from 3501.96 m, 3505.98 m, and 3935 m, suggesting elevated oil saturation in these sandstones at some time (Fluid Inclusion Technologies, Inc., 2014). However, these fluid-inclusions data contradict the apparent lack of oil-related mature thermogenic gases in the pore space of sandstones in the North Cape Formation evidenced by mudlogging and Iso Tubes data. Despite the presence of the expected predrill reservoir facies, there is no firm evidence for thermogenic gases in the North Cape segment, requiring further analysis on the segment’s specific failure mode to move forward on the decision tree (Figure 1-1) to an investigation into structure.
Table 5-2: Mud-gas data for the Romney-1 well (modified from Phillips, 2014). Molecular composition data (in parts per million, or ppm) are for IsoTube samples (C₁ – methane, C₂ – ethane, C₃ – propane, iC₄ – iso-butane, nC₄ - n-butane, iC₅ – iso-pentane, nC₅ – n-pentane), and δ¹³-C₁ data are reported for both IsoTube and IsoJar samples. With IsoTubes, the gas samples are collected from the mudline during drilling and these gases represent gases in the pore space of the drilled rocks. With IsoJars, washed cuttings are collected into the jars, and gases from the headspace are analyzed (the gases are both from the pore space and desorbed).
The predicted predrill trap for the North Cape segment was a stratigraphic pinch out associated with a facies change and lateral trapping by a fault (Figure 5-3, Rad, 2015). Postdrill mapping conducted for this study, completed using the same 3D seismic data available to the operator and with the top North Cape Formation tied to the well, confirmed the presence of a low-relief fault-bounded structure (Figure 5-5). Romney-1 penetrated the top of the segment 6 m downdip from the crest of the structure. The predrill top seal for the North Cape segment was predicted to be claystones interbedded with siltstones and sandstones. Using both well-logs (Figure 5-6) and core data (Table 5-1), the presence of these sealing facies was confirmed, although the decision tree (Figure 1-1) does not require a test for top seal at this stage of key failure analysis.

Unlike many exploration wells, Romney-1 did penetrate the predicted primary source-rock interval, transgressive pro-delta shales located near the base of the Taranaki Delta group / Rakopi Formation. This interval from 4441 m to 4619 m (well total depth, TD) is dominated by interbedded sandstones and siltstones. The deepest penetrated section from 4586-4619 m is comprised of carbonaceous siltstones with relatively high gamma ray readings. Based on TOC, HI, T_max and Ro measurements (Figure 5-7), mature source-rocks are present in this interval at the well location. Macerals are apparently dominated by intertinite, while liptinite is sparse to rare, but that could be due to strong fluorescence of mineral matter masking some weak fluorescing liptinite (Phillips, 2014). The source rocks are mature (T_max 452-457°C, mean Ro 0.94-0.98%) and have
Figure 5-5: Postdrill structure map of the North Cape segment (A), Crossline 5300 (B) and Inline 1850 (C) as interpreted in this study.
Figure 5-6: Well logs showing the top of the North Cape segment and the overlying top seal (modified from Rad, 2015).
Figure 5-7: (A) Total organic carbons (TOC, wt.%), (B) hydrogen index (HI, mg HC/g TOC), (C) temperature at which the maximum rate of petroleum generation occurs in a rock sample during Rock-Eval pyrolysis analysis ($T_{\text{max}}$, °C) and (D) vitrinite reflectance ($R_o$, %) values measured on solvent-extracted samples from sidewall cores taken by mechanical sidewall coring tool (MSCT) in the Romney-1 well (data from Phillips, 2014).
measured values of TOC between 1.2-3.1 wt.% and HI between 138-184 mg HC/g TOC. The source rocks could have original (before maturation and expulsion) average values of TOC around 2.5-3.5 wt.% and HI around 300 mg HC/g TOC (estimated with online Source Rock Potential Calculator from ZetaWare, Inc., 2003). Based on this data and according to Peters (1986), the penetrated source rock has “fair” or “good” initial generative potential. Additional source potential exists in shallower section within the Rakopi Formation characterized by the presence of mature shale intervals (with original HI of roughly 350-400 mg HC/g TOC). There are also coal measures within the Rakopi Formation. However, these coals are most likely not sufficiently mature to expel significant petroleum fluids (Figure 5-7), due to the fact that coals require higher thermal stress than shales to expel oil and / or gas (Pepper and Corvi, 1995). The presence of thermogenic gas in the Rakopi Formation (Table 5-2, see below) confirms the presence of mature source rocks in the area of the Romney prospect.

Based on this study’s workflow (Figure 1-1) as well as the data and interpretations described above, migration is determined to be the failure mode for the North Cape segment. Although mature source rocks are present and thermogenic hydrocarbons occur in the deeper section below roughly 3820 m (Table 5-2), these hydrocarbons apparently did not migrate into the North Cape segment. This may be due to the presence of relatively impermeable volcanic rocks at the base of the North Cape section (Table 5-2 and Figure 5-5).
5.1.2 Rakopi Segment

5.1.2.1 Predrill Evaluation

The Rakopi segment in the Romney prospect was the secondary objective of the Romney-1 well. This segment is located within the play of Late Cretaceous fluvio-deltaics and the nearshore sand sequences of the Rakopi Formation (Figure 5-2) within the Taranaki delta group (Rad, 2015). It was modeled as a 3-way structure with a combination of volcanics and faults providing the updip lateral seal (Figure 5-8). Similar to the North Cape segment discussed previously, the primary source interval was inferred to be the transgressive pro-delta shales near the base of the Taranaki Delta sequence. Since that interval had not been drilled in New Zealand before, source presence and quality was determined as the key geological risk for the Rakopi segment (Rad, 2015). The Romney-1 well penetrated the segment, but found no movable petroleum fluids, so the segment failed (Rad, 2015).

5.1.2.2 Segment-Failure Analysis

The top of the Rakopi (Taranaki Delta) Formation was picked at 3784 m, 4 m lower relative to prognosis (Rad, 2015). Various well-logging tools and curves were used to aid in the identification of distinctive lithologies within the target interval (Figure 5-9). Interpretation of petrologic reports in conjunction with the well logs confirmed the presence of a 657 m thick interval of interbedded sandstones and siltstones with abundant coal seams typically ranging in thickness from 0.5 m to 1 m and up to 3 m at certain depths. Of that 657 m interval, roughly 298 m total are sandstones varying in thickness from 0.3 m to 80 m (Rad, 2015). Figure 5-9 shows the gamma ray, caliper, resistivity, permeability, porosity, bulk density, and interpreted lithology throughout the Rakopi segment.
Figure 5-8: Predrill evaluation of the Rakopi segment from the operator (Rad, 2015). (A) Predrill structure map. (B) Zoomed-in predrill structure map from the operator, showing the outline of Rakopi segment as blue polygon and the volcanics.
Figure 5-9: Gamma ray (GR), caliper (HCAL), resistivity (AE10, AE30, AE90), permeability (KTM and KSDR), porosity (NPHI), and bulk density (RHOZ) curves, as well as interpreted lithology throughout the Rakopi interval (modified from Rad, 2015).
Data from the conventional mudlogging gas system indicate a significant increase in background gas, the appearance of C_2-C_5 hydrocarbons, and gas peaks below 3818 m. This is coincident with the appearance of coal seams and carbonaceous claystones in the drilled section. Very poor to fair oil shows were reported in the interval 3896-3950 m, and were interpreted to be caused by an oil-based mud additive. No movable oil was found through petrophysical evaluations and MDT test at 3941.2 m (Rad, 2015). Gas samples from the Rakopi Formation have significantly (one order of magnitude) higher concentrations of C_1-C_5 gases than samples from the North Cape Formation previously discussed (Table 5-2, Phillips, 2014). The values of C_1/(C_2+C_3)<6 and δ^{13}-C_1 values around -42‰ to -45‰ in IsoTube samples are consistent with a thermogenic origin of the gas (Milkov and Etiope, 2018). The Rakopi Formation contains shales and coal measures with abundant liptinite macerals, present-day TOC values 1-70% and HI values 179-403 mg HC/g TOC. These samples have T_{max} values 426-444°C and R_o values 0.49-0.76% (Phillips, 2014), with the deeper shales being in the early maturity window (Figure 5-7). Therefore, some thermogenic gases observed in the Rakopi Formation could be generated within that formation. Additional charge of thermogenic gases is possible from the deeper source rocks penetrated near the bottom of the well (base of the Taranaki delta group) or deeper Jurassic-Cretaceous source rocks not yet proven in New Zealand.

Based on the petrologic analyses from Core Laboratories, Inc. (2014) (Table 5-1), as well as the various well-logs shown in Figure 5-9, the average porosity and permeability throughout the Rakopi Formation sandstones is 17% and 12.1 mD, respectively. The upper section of the formation, where the segment is located, has
sandstones with porosities exceeding 20% in some samples. These values are sufficient to ensure the flow of light-medium oil and gas, and allows for the elimination of reservoir deliverability as the failure mode for the Rakopi segment.

The Rakopi sandstone reservoir is sealed at the top by volcanic and volcaniclastic facies as confirmed by both well logs (Figure 5-10) and core data (Table 5-1). These sealing facies have permeability as low as 0.002 mD in basalts, although volcanoclastic argillaceous sandstones may be more permeable (up to 0.135 mD) (Core Laboratories, Inc., 2014). The sealing capacity of volcanics above the Rakopi Formation is corroborated by the fact that the North Cape section overlaying the volcanics does not contain thermogenic gases even though thermogenic gases are present below the volcanics (as evidenced by the IsoTube data, Table 5-2)

The postdrill mapping of the well-tied top Rakopi horizon and faults confirms the presence of a 3-way (fault-bounded) structural trap (Figure 5-11). The well penetrated the top of the segment 111 m downdip from the crest of the structure.

The predrill predicted lateral seal for the Rakopi segment was a combination of volcanics and faults for the upper sands within the Rakopi Formation, with the lower sands sealing against localized Cretaceous-aged faults (Figs. 5-5B, C and 5-8). Well logs through this section (Figure 5-10) as well as postdrill seismic interpretations (Figure 5-11) have confirmed the presence of both the volcanics and lateral faults. Romney-1 did not penetrate the lateral seal for the Rakopi segment.

The next item to investigate on the decision tree (Figure 1-1) is whether the structure formed prior to petroleum migration. Maturity data from the base Taranaki
Figure 5-10: Well logs showing the top of the Rakopi Formation and the overlying volcanics acting as a top seal (modified from Rad, 2015).
Figure 5-11: Postdrill structure map of the top Rakopi Formation as interpreted in this study.
Delta section near TD (maximum $T_{max}$ 457°C, maximum mean $R_o$ 0.98%) suggest that the source facies are in the middle-to-late oil window and are still actively expelling petroleum. Furthermore, the Rakopi Formation contains early mature shales that likely currently expel petroleum. By process of elimination, the establishment and verification of all other potential failure modes (Figure 1-1) leads to the conclusion that the Rakopi segment failed due to lack of effective lateral seal. However, because the well penetrated this secondary target roughly 111 m downdip from the crest of the structure, it is possible that a petroleum accumulation exists in the Rakopi segment updip from the well if the lateral seal is effective.

5.2 Whio-1

Whio-1 was drilled between July and late August 2014 in just under 100 m of water and in order to test the presence of petroleum fluids in Miocene to Eocene sandstones at the Whio Prospect south of the North Island of New Zealand in the Taranaki Basin (Figure 5-1). The primary targeted reservoir segment of the well was the Middle Miocene proximal slope fan M2A sandstone, an informal unit within the Wai-iti Group (Figure 5-2) (Roncaglia et al., 2013; Wyman & Smith, 2015). The M2A sandstone represents an extension of “Moki Formation” type facies, and is potentially a stratigraphic member of the Manganui Formation (Figure 5-2). A deeper secondary segment (herein referred to as the Mangahewa segment) was also targeted – the stacked reservoirs of the Upper Eocene inshore marine sandstone of the ’Maui Sand’, and the Middle Eocene lower coastal plain to marginal marine Mangahewa Formation within the Kapuni Group (Figure 5-2) (Wyman & Smith, 2015).
5.2.1 M2A Segment

5.2.1.1 Predrill Evaluation

The M2A segment in the play of Middle Miocene fan-system sand sequences of the Wai-iti Group (Figure 5-2) was the primary drilling objective of Whio-1. The four-way dip closure containing the M2A segment was described in the predrill evaluation by OMV (the operator) as forming during Late Miocene contractional tectonism associated with the Southern Inversion Zone (Wyman & Smith, 2015). Petroleum fluids are interpreted to be sourced from a proven Cretaceous source rock ‘kitchen’ in the Maui Sub-basin to the north, with expulsion active since the Miocene (Figure 5-12) (Wyman & Smith, 2015). Migration is postulated as occurring within Cretaceous-Eocene and Miocene sandstone reservoirs that have regional dips up the basement high of the Tasman Ridge (Figure 5-13) (Wyman & Smith, 2015). Petroleum fluids that migrated through this area have been trapped in a variety of plays including inversion anticlines, erosional subcrop traps at Late Eocene and Base Oligocene levels, as well as potentially in basement onlap traps (Figure 5-13) (Wyman & Smith, 2015). The Whio structure, a four way dip closure, is interpreted by the operator to have been charged primarily by spill from the Maari Field (Figures 5-12, 5-13, and 5-14) at Miocene and Eocene reservoir levels prior to the Pleistocene breach of the Maari trap (Wyman & Smith, 2015).

The M2A segment was penetrated by the Whio-1 exploration well between July and late August 2014 and found no indications of movable petroleum fluids, thus the segment failed.
Figure 5-12: Whio regional structure (Base Oligocene Two-way Time). Cross-section A-A’ shown in Figure 5-13 (Wyman & Smith, 2015). The white arrow shows the charge fairway and how charge was inferred to have originated in the Maui Sub-basin and charged and filled the Maari Field before subsequent spilling led to supposed charge in the Whio prospect (modified from Wyman & Smith, 2015).
Figure 5-13: Schematic geological cross-section along the Tasman Ridge displaying potential hydrocarbon traps between Maari (North) and Tasman (South). Inset map shows principal tectonic elements on basement depth, with cross section as white line (Wyman & Smith, 2015).
Figure 5-14: Operator (OMV) pre- and postdrill structural comparison at the top M2A sandstone level (Wyman & Smith, 2015).
5.2.1.2 Segment-Failure Analysis

The base of the M2A sandstone was picked at 1,464 mMDRT, 2 m shallow to prognosis (reasoning for listing base depth as opposed to top depth is described below) (Wyman & Smith, 2015). The drilling floor for the Whio-1 well was 25.9 m above sea level and water depth was 98.4 m (Wyman & Smith, 2015). Various well-logging tools and curves (gamma ray, caliper, and resistivity) (Figure 5-15) were used to aid in the identification of distinctive lithologies within the target interval. In addition to well logs, detailed petrologic analyses of rotary sidewall cores and MSCT samples were completed for OMV by GNS Science (Higgs et al., 2015) and Core Laboratories (Brown, 2014), respectively (Table 5-3). These petrologic reports, used in conjunction with well logs (Figure 5-15), confirmed the presence of a 5 m thick reservoir interval of an upward-fining layered-sandstone deposit. Definition of the top of M2A sandstone was difficult due to the nature of the upward-fining sands (Wyman & Smith, 2015), so OMV (operator) defined the M2A sandstone as the basal 5 m of clear reservoir-quality sand, as this base depth is a sharp surface clearly marked on gamma, resistivity, and density logs. However, it should be noted that the composite log shows poorer quality net sand up to 1456 m (Wyman & Smith, 2015). The 5 m thick M2A basal sandstone section from 1459-1464 m has a reported 100% net:gross with log porosities ranging from 24-28% (Wyman & Smith, 2015).

After confirming the presence of the reservoir, the workflow then proceeds to the evaluation and identification of the existence, or lack thereof, of oil shows and / or thermogenic gases (Figure 1-1). Based on data from the conventional mudlogging-gas system, the M2A sandstone is characterized by low background gas, mostly between
Figure 5-15: Gamma ray, resistivity, and porosity curves for M2A segment and depths surrounding (data from Wyman & Smith, 2015).
Table 5-3: Petrographic summary for samples from Whio-1 exploration well (modified from Brown, 2014; Higgs et al., 2015; Wyman & Smith, 2015).

<table>
<thead>
<tr>
<th>Depth (m)</th>
<th>Local Formation Name</th>
<th>Lithology</th>
<th>Porosity (%)</th>
<th>Permeability (md)</th>
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<td>Sandstone</td>
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0.1-0.13% and no gas shows / peaks. Although very weak oil shows were reported from intervals 1458-1464 m, they were interpreted to be caused by oil-based mud additive as petrophysical evaluations did not suggest the presence of any movable oil in this interval (Wyman & Smith, 2015). Table 5-4 presents the molecular and isotopic composition of gases from Whio-1 as measured in IsoTubes. However, due to the apparent IsoTube sampling interval, the M2A sandstone (1459-1464 m), and gases within it, are not represented in Table 5-4. However, looking at Table 5-4 there is a discernable trend of dry non-associated gas all through the shallower depths and up until the Moki Formation at 1550 m. Figure 5-16 serves to highlight gas dryness beginning in the Mount Messenger Formation and continuing to the Lower Manganui (Sykes, 2015). The study of thin sections from sidewall-cores also revealed no visible petroleum inclusions in sandstones from 1440 m, and 1465 m (Fluid Inclusion Technologies, Inc., 2014b). While these thin sections are still not directly within the M2A sandstone, they do provide more support for the lack of thermogenic gases in strata immediately surrounding the M2A sandstone. Despite the presence of the expected predrill reservoir facies, there is no firm evidence for thermogenic gases in the M2A segment, requiring further analysis on the segment’s specific failure mode to move forward on the decision tree (Figure 1-1) to an investigation into structure.

The predrill predicted structure for the M2A segment was a four-way dip closure (Figures 5-13 and 5-14) (Wyman & Smith, 2015). Postdrill mapping conducted for this study, completed using the same 3D seismic data available to the operator and with the top M2A sandstone tied to the well, confirmed the presence of this four-way dip closure (Figure 5-17). Whio-1 penetrated the top of the segment 6 m downdip from the crest of
the structure. The predicted seal for the M2A segment was the mudstone and siltstone dominated Upper Manganui Formation. Using well-logs (Figure 5-15) and core data (Table 5-3), the presence of these sealing facies was confirmed, although the decision tree (Figure 1-1) does not require a test for seal at this stage of key failure analysis.

Unlike Romney-1, Whio-1 did not penetrate the predicted source rock interval for the Whio prospect, inferred to be a proven Cretaceous source rock ‘kitchen’ in the Maui Sub-basin to the north. However, gas data from deeper sections of the well (Table 5-4) can be used to confirm the presence, or lack of mature source rocks in the area of the

![Diagram showing stratigraphic variation in Bernard-ratio values of gas dryness (C1/(C2+C3)) and the isotopic composition of methane (δ13C1 (‰)) for the IsoTube samples from Whio-1 (data from Patterson, 2015).]
Table 5-4: Mud-gas data for the Whio-1 well (modified from Patterson, 2015). Molecular and isotopic ($\delta^{13}$C1) composition data are for IsoTube samples (C1 – methane, C2 – ethane, C3 – propane, iC4 – iso-butane, nC4 - n-butane, iC5 – iso-pentane, nC5 – n-butane).

<table>
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<tr>
<th>Depth (mMD)</th>
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<th>C₁ (ppm)</th>
<th>C₂ (ppm)</th>
<th>C₃ (ppm)</th>
<th>iC₄ (ppm)</th>
<th>nC₄ (ppm)</th>
<th>iC₅ (ppm)</th>
<th>nC₅ (ppm)</th>
<th>C₁/(C₂+C₃)</th>
<th>δ¹³-C₁ (‰) Isotubes</th>
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<td>520.0</td>
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<td>0.00</td>
<td>34.4</td>
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</tr>
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<td>Kaimiro Fm</td>
<td>6820.0</td>
<td>510.00</td>
<td>87.00</td>
<td>28.00</td>
<td>9.00</td>
<td>6.00</td>
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<td>11.4</td>
<td>-36.30</td>
</tr>
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<td>2532.7</td>
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<td>0.00</td>
<td>11.3</td>
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<td>0.00</td>
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<td>2600.0</td>
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<td>119.00</td>
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<td>1.00</td>
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<td>0.00</td>
<td>10.5</td>
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<td>149.00</td>
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<td>10.00</td>
<td>8.00</td>
<td>4.00</td>
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<td>581.0</td>
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<td>4.00</td>
<td>3.00</td>
<td>1.00</td>
<td>11.0</td>
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<tr>
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<td></td>
<td>1590.0</td>
<td>121.00</td>
<td>83.00</td>
<td>37.00</td>
<td>33.00</td>
<td>13.00</td>
<td>9.00</td>
<td>7.8</td>
<td>-38.10</td>
</tr>
</tbody>
</table>
Figure 5-17: Postdrill structure map (in depth) of the M2A segment as interpreted in this study.

Whio prospect, given the Bernard-ratio values of wetness – $C_1/(C_2+C_3)$ – and isotopic composition of methane – $\delta^{13}\text{C}_1(\%o)$ – from IsoTubes. Values from Table 5-4 are plotted according to Milkov & Etiope’s (2018) revised genetic diagrams (Figure 5-18), and very clearly show the gases to be of thermogenic origin. The presence of thermogenic gas in the deeper Moki, Mangahewa, Kaimiro, and Farewell Formations (Figure 5-18 and Table 5-4) confirms the presence of mature source rocks in the area of the Romney prospect.
Following the decision tree (Figure 1-1) and the data and interpretations described above, migration is determined to be the failure mode for the M2A segment due to the presence of thermogenic gases in deeper sections, yet not in the M2A segment. Although mature source rocks are present and thermogenic hydrocarbons occur in the deeper section below roughly 1950 m (Table 5-4), these hydrocarbons apparently did not migrate into the M2A segment. This might be due to an effective bottom seal prohibiting vertical flow of petroleum fluids.

5.2.2 Mangahewa Segment

5.2.2.1 Predrill Evaluation

The Mangahewa segment in the Whio prospect was the secondary objective of the Whio-1 well. This segment is located within the play of the stacked reservoirs of the Upper Eocene inshore marine sandstone of the ‘Maui Sand’ and the Middle Eocene
lower-coastal-plain-to-marginal-marine Mangahewa Formation, both within the Kapuni Group (Figure 5-2) (Wyman & Smith, 2015). The Mangahewa segment was predicted to be within the same four-way dip closure containing the M2A segment (Figures 5-13 and 5-19), which was described in the predrill evaluation by OMV (the operator) as forming during Late Miocene contractional tectonism associated with the Southern Inversion Zone (Wyman & Smith, 2015). OMV predicted that the Mangahewa segment would also be charged from the same source as the M2A segment – the proven Cretaceous source rock ‘kitchen’ in the Maui Sub-basin to the north (Figures 5-12) (Wyman & Smith, 2015). The Whio-1 well penetrated the segment, but found no movable petroleum fluids, so the segment failed (Wyman & Smith, 2015).

5.2.2.2 Segment-Failure Analysis

The top of the Mangahewa segment was picked at 2363 m, 11 m shallow to prognosis (Wyman & Smith, 2015). Various well-logging tools and curves were used to aid in the identification of distinctive lithologies within the target interval (Figure 5-20). In addition to well logs, detailed petrologic analyses of rotary sidewall cores and MSCT samples were completed by GNS Science (Higgs et al., 2015) and Core Laboratories (Brown, 2014), respectively (Table 5-3). Interpretation of petrologic reports in conjunction with the well logs confirmed the presence of a 148 m thick interval (2361-2509 m, 17.5 m in the ‘Maui Sand’ and 130.5 m in the Mangahewa Formation) dominated by interbedded mudstones, siltstones, and sandstones, with a number of thin coals ranging in thickness from 0.5 m to 1 m. Within the 148 m Mangahewa segment, the upper ‘Maui Sand’ has 15% log porosity and 90% net: gross reservoir sand (nearly
Figure 5-19: Operator (OMV) pre- and postdrill structural comparison at the top Mangahewa segment level (modified from Wyman & Smith, 2015).
16 m net), whereas the Mangahewa Formation has 14% log porosity and 6% net:gross reservoir sand (roughly 8 m net) (Wyman & Smith, 2015).

Data from the conventional mudlogging-gas system indicate a slight increase in background gas when compared to the M2A segment (values range from 0.1-0.25% within Mangahewa segment), the appearance of C₂-C₅ hydrocarbons, and gas peaks below 2383.5 m (Wyman & Smith, 2015). This is coincident with the appearance of coals in the drilled section. Several trace oil shows were reported at various intervals.
throughout the Mangahewa segment (2378.5-2385 m, 2390-2410 m, 2415-2455 m, 2465-2480 m, 2480-2495 m), although these shows are said to have been compromised by the use of a mud system containing glycol that was recycled from a previous OMV well (Wyman & Smith, 2015). Gas samples throughout the Mangahewa segment have significantly higher concentrations of C\textsubscript{1}-C\textsubscript{5} gases than all samples further up section except the shallow Mt. Messenger and Otunui Formations (Table 5-4) (Patterson, 2015). C\textsubscript{1}/(C\textsubscript{2}+C\textsubscript{3}) values less than 60 and nearly all \(\delta^{13}\textsubscript{C}\textsubscript{1}\) values between -52\textperthousand{} and -59\textperthousand{} (one sample has a \(\delta^{13}\textsubscript{C}\textsubscript{1}\) value of -39\textperthousand{}) in IsoTube samples (Table 5-4) are consistent with a thermogenic origin of the gas (Figure 5-18) (Milkov and Etiope, 2018).

Based on the petrologic analysis data in Table 5-3, as well as the various well-logs shown in Figure 5-20, the average porosity and permeability of reservoir sandstones throughout the Mangahewa segment is 15\% and 607 mD, respectively. These values are sufficient to ensure the flow of most petroleum fluids, and allow for the elimination of reservoir deliverability as the failure mode for the Mangahewa segment.

The predicted seal for the Mangahewa segment was the Turi Formation mudstones, an important regional seal (Wyman & Smith, 2015). The presence of the Turi Formation mudstones was confirmed both by well logs (Figure 5-21) and core data (Table 5-3). All four samples taken from this sealing facies have low permeability (<0.01 md, Table 5-3). The two shallowest samples analyzed from the Turi Formation are glauconitic mudstones and have capillary entry pressures capable of holding petroleum fluid columns of hundreds of meters (Higgs et al., 2015). However, the third shallowest sample in the Turi Formation (2341 m) showed fluorescence and roughly 20\% of its
pore space filled with mercury before the main threshold pressure was reached (Higgs et al., 2015). In addition, the lowest sample from the Turi Formation – only 3 m above the 'Maui Sand' – had indications of petroleum fluids within the sample and a minor intrusion of mercury prior to reaching the main threshold pressure (Higgs et al., 2015).

Figure 5-21: Well logs showing the top 'Maui Sand' and the overlying Turi Formation seal (data from Wyman & Smith, 2015).

These two samples might suggest that the Turi Formation is an ineffective seal, and this potential ineffectiveness should be noted in the case of future exploration. However, it is unlikely that the Turi Formation is a completely ineffective seal, but instead just leaky (which aligns with the fact that nearly all seals leak). This conclusion is based on the fact the uppermost samples within the Turi Formation are effective seals capable of holding petroleum fluid columns of hundreds of meters, and that the shallower M2A segment lacks thermogenic petroleum (as evidenced by the IsoTube data, Table 5-4).
Nevertheless, success and failure, as defined in this study, is established on the presence of a top seal capable of holding any column of petroleum, as opposed to only a column capable of holding some minimum predetermined size (Milkov & Samis, 2019). So while the Turi Formation might be an inefficient seal, its presence and capability to hold a column of petroleum means that the study into the Mangahewa segment’s failure mode now moves to an investigation into structure.

The predrill predicted structure for the Mangahewa segment was a four-way dip closure (Figures 5-13 and 5-19) (Wyman & Smith, 2015). Postdrill mapping conducted for this study, completed using the same 3D seismic data available to the operator and with the top ‘Maui Sand’ and Mangahewa Formation tied to the well, confirmed the presence of this four-way dip closure (Figure 5-22). Whio-1 penetrated the top of the Mangahewa segment 24 m downdip from the crest of the structure.

Given that Whio-1 targeted and penetrated a four-way closure and the nature of these types of closures, there is no lateral seal within the segment, only a top seal. Following the logical progression of the decision tree (Figure 1-1), timing can be determined as the failure mode for the Mangahewa segment. Migration cannot be the failure mode for this segment because there is substantial evidence for the presence of thermogenic gases (Table 5-4). It is possible that migration occurred through the Mangahewa segment before the structure / trap was formed (Figure 4-6C) and that the presence of thermogenic gases simply shows the evidence of that migration.
Figure 5-22: Postdrill structure map (in depth) of the Mangahewa segment as interpreted in this study.

5.3 Kanuka-1

The Kanuka-1 exploration well was drilled between October and November 2007 in 136 m of water off the west coast of the North Island of New Zealand in the Taranaki Basin (Figure 5-1). Kanuka-1 was drilled in order to evaluate the hydrocarbon potential of the Late to Early Miocene sand sequences that were deposited in a basin-floor fan setting (Bates & Heid, 2008). These sand units have been variously called the Mt. Messenger sands, Mohakatino sands, and Moki sands. For the purposes of this study, these basin floor fan sand sequences will be referred to as the Mt. Messenger segment.
5.3.1 Mt. Messenger Segment

5.3.1.1 Predrill Evaluation

In the predrill evaluation by Pogo New Zealand (the operator), the Mt. Messenger segment was described as targeting basin-floor fan sequences on the Kanuka structural high, a large 27 km$^2$ N-NE to S-SW elongated structural closure with roughly 34 m of 4-way closure mapped against a down to the East-SE bounding fault (Figures 5-23 and 5-24) (Bates & Heid, 2008). Pogo predicted that there would be five basin-floor fans stacked upon one another, totaling over 200 m of potential reservoir-quality sand (Bates & Heid, 2008).

Based on regional basin modeling, Pogo predicted that several well-developed and mature source kitchens exist adjacent to, and virtually encircle the Kanuka prospect (Bates & Heid, 2008). The same modeling suggested that substantial oil and gas have been expelled from these source kitchens, and that hydrocarbon charge can be inferred from these kitchens into Kanuka’s Miocene structural closure (Bates & Heid, 2008).

The Mt. Messenger segment was penetrated by the Kanuka-1 exploration well between October and November 2007, and was dry (Bates & Heid, 2008).

5.3.1.2 Segment-Failure Analysis

The top of the Mt. Messenger segment sandstones was picked at 2494 mMDRT, 8 m above prognosis (Bates & Heid, 2008). The drilling floor for the Kanuka-1 well was 23 m above sea level and water depth was 136 m (Bates & Heid, 2008). Various well-logging tools and curves (gamma ray, caliper, and resistivity) (Figure 5-25) were used to aid in the identification of distinctive lithologies within the target interval. In addition to well logs, a detailed petrologic analysis of rotary sidewall cores (Table 5-5) was completed by Core Laboratories Inc. (Bates & Heid, 2008). These petrologic reports,
Figure 5-23: Predrill structure map of the 2500 Horizon from the operator (Pogo New Zealand) (Bates & Heid, 2008). The 2500 Horizon is the same surface as the top of the Mt. Messenger segment in this study. Seismic lines A-A' and B-B' shown in Figure 5-24.
Figure 5-24: Seismic lines A-A’ and B-B’ referenced in Figure 5-23 (Bates & Heid, 2008).
Figure 5-25: Well logs through the Mt. Messenger segment (data from Bates & Heid, 2008)
Table 5-5: Petrographic summary for samples from Kanuka-1 exploration well (modified from Bates & Heid, 2008). Gold-shaded cells correspond to samples within the Mt. Messenger segment.

<table>
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<th>Depth (m)</th>
<th>Geologic Age / Local Formation Name</th>
<th>Lithology</th>
<th>Porosity (%)</th>
<th>Permeability (md)</th>
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<td>528.5</td>
</tr>
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<td></td>
<td>Sandstone</td>
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<td>Sandy and Silty Claystone</td>
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<td>0.2</td>
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<td>Sandstone</td>
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<td>Sandstone</td>
<td>19.8</td>
<td>37.3</td>
</tr>
</tbody>
</table>

used in conjunction with well logs, confirmed the presence of a 227 m-thick stacked reservoir interval of sandstone with thin interbeds of claystone. Of that 227 m interval, roughly 79 m are reservoir quality sandstone (Bates & Heid, 2008).

After confirming the presence of the reservoir, the workflow then proceeds to the evaluation and identification of the existence, or lack thereof, of oil shows and / or thermogenic gases (Figure 1-1). Based on data from the conventional mudlogging gas system, the Mt. Messenger segment is characterized by low background gas mostly at
or below 0.06% with no oil shows and two gas peaks (2515 m and 2553 m). Findings similar to the Mt. Messenger segment – very little to no oil shows, extremely low background gas, and minimal gas peaks – were consistent all throughout the Kanuka-1 well. Intervals that did record shows, however minor, were subsequently evaluated for Pogo by Geomark via solvent extraction of the cuttings (whole extract GC-MS). After completing the Gas Chromatography (GC) screening, Geomark was not able to identify any naturally occurring petroleum fluids in a single sample (Bates & Heid, 2008). Geomark did observe isolated GC peaks, but was able to relate the peaks to the polymer which was used as a mud additive. Despite the presence of the expected predrill reservoir facies, there is no evidence for thermogenic gases in the Mt. Messenger segment, requiring further analysis on the segment’s specific failure mode to move forward on the decision tree (Figure 1) to an investigation into structure.

The predicted predrill trap for the Mt. Messenger segment was a large 27 km² N-NE to S-SW elongated structural closure with roughly 34 m of 4-way closure mapped against a down to the E-SE bounding fault (Figures 5-23 and 5-24) (Bates & Heid, 2008). Postdrill mapping conducted for this study, completed using the same seismic data available to the operator and with postdrill formation tops tied to the well, confirmed the presence of the predicted elongated structural closure (Figures 5-26 and 5-27). Kanuka-1 penetrated the top of the segment 77 m downip from the crest of the structure.

Due to the lack of geochemical analysis on samples from the well – vitrinite reflectance measurements, TOC analysis, Rock-Eval pyrolysis, etc. – in addition to the absence of thermogenic gases throughout the Kanuka-1 well, the construction of a 1-
Dimension (1D) source-rock maturity model is necessary in order to evaluate the presence of a mature source-rock within the area of the Kanuka prospect. This model was built using ZetaWare’s Genesis software. The model’s subsurface thermal regime is constrained – thus calibrating the model – using bottomhole temperatures that have been corrected using the Horner correction method (ZetaWare, 2017). Extensive seismic interpretation is also necessary for not only the Kanuka prospect area, but also the predicted fetch area and the areas connecting the two. Seismic interpretation of the fetch area is necessary due to the fact that the source rock does not lie directly beneath the Kanuka-1 well, but rather it lies some distance away, and petroleum fluids have – potentially – migrated to the Kanuka prospect. Crustal thickness inputs – 24 km split evenly between upper and lower crust – for Genesis’ thermal-history controls were based on maps published by Woodward & Wood (2000). In addition, radiogenic heat contribution for the upper and lower crust was determined from a GNS Science report to be 1.84 µW/m³ and 0.57 µW/m³, respectively (Constable, 2011). The results of these calibrations are shown in Figure 5-28.

The results of Genesis 1D modeling suggest that the predicted Cretaceous source-rock, if present, is mature within the fetch area for the Kanuka-1 well. Modeled values for transformation ratios within the modeled Late-Cretaceous source-rock are in the range of 10-60+%, vitrinite reflectance (R₀) between roughly 0.9-1.0%, and temperatures between 130-150°C (Figure 5-29). Following the decision tree (Figure 1-1) and given the lack of shows and / or thermogenic gases, in conjunction with the presence and maturity of the predicted source rock, migration is determined to be the failure mode for Kanuka-1’s Mt. Messenger segment.
Figure 5-26: Postdrill structure map (in depth) of the Mt. Messenger segment as interpreted in this study.
Figure 5-27: Lines A-A' and B-B' as interpreted for this study. The predrill lines from Pogo are shown in Figure 5-24, with the location of A-A' and B-B' shown in Figure 5-23.
Figure 5-28: Bottom hole temperature calibration results for *Genesis* source-rock modeling.
Figure 5-29: *Genes*s source-rock model displaying transformation ratio (colormap) and vitrinite reflectance (%, contour)
The usefulness of this study is largely based on the applicability of the decision tree (Figure 1-1) tested within it, and even more so when the results from this study are compared to the published results of the three wells’ individual operators (Table 6-1).

Table 6-1: Summary of operators’ pre- and postdrill risks and failure modes, respectively, compared to the findings of this study

<table>
<thead>
<tr>
<th>Well</th>
<th>Operator</th>
<th>Segment</th>
<th>Operator’s Pre-Drill Failure Mode</th>
<th>Operator’s Postdrill Failure Mode</th>
<th>Failure Mode (from this study)</th>
</tr>
</thead>
<tbody>
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<td>Romney-1</td>
<td>Anadarko</td>
<td>North Cape</td>
<td>Ineffective top and/or lateral seal</td>
<td>Lack of Effective Lateral Seal</td>
<td>Migration</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Rakopi</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>White-1</td>
<td>QINIV</td>
<td>M2A</td>
<td>1. “Oil and gas migrated through Wills area”</td>
<td>Migration</td>
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</tr>
<tr>
<td></td>
<td></td>
<td>Maggabwana</td>
<td>2. “Oil (and gas) never migrated into the Wills prospect...”</td>
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<td></td>
</tr>
<tr>
<td>Kanuka-1</td>
<td>Pago NZ</td>
<td>Mt. Bassenger</td>
<td>“The conclusion is that hydrocarbon migration to the Kanuka structure may not have occurred...”</td>
<td>Migration</td>
<td></td>
</tr>
</tbody>
</table>

6.1 Romney-1

Anadarko, the operator on the Romney-1 exploration well, did not determine a failure mode for each individual dry segment within the well. Rather, they concluded that the failure mode for the well as a whole was an insufficient / ineffective top and / or lateral seal (S. Blanke, 2018, personal communication). Anadarko’s conclusions do align with this study’s findings for the Rakopi segment. The derivation of lateral seal as
the failure for the Rakopi segment is the logical conclusion based on the decision tree (Figure 1-1) since of the other elements (reservoir presence, reservoir deliverability, top seal, structure, and mature source) appear to be in place.

This study, however, does not agree with Anadarko’s conclusion that the North Cape segment failed due to an ineffective top and/or lateral seal. The predicted top seal is shown to be present (Figure 5-6), and if the segment were to have failed due to the lack of an effective top seal, there would still be firm evidence suggesting the presence of thermogenic gases within the segment, of which there is none (Table 5-2).

It is possible that Anadarko’s desired outcome was simply to determine a failure mode for the well as a whole, rather than the key failure mode for an individual failed segment. However, determination of the key failure mode for each failed segment is critical if the operator—or any other company—plans to use the findings from the postmortem analysis for future exploration. If a company does not conduct analysis on every failed segment in a well, they are potentially leaving out crucial pieces of information that might be the difference between the success or failure of future wells. For example, if Anadarko were to drill another well in the immediate area with only the notion that Romney-1 failed due to an insufficient/ineffective top and/or lateral seal, they might update their models and maps to try and identify an area/areas that have better defined/proven seals. If the seals in an area look promising, but Anadarko has not taken into account the relative impermeability of the volcanics that inhibit flow to reservoirs from deeper, proven source rocks, they are in essence choosing to increase future wells’ risk, and thus decrease the probability of success. Companies should aim to conduct failure analysis separately on every failed segment, and then use that
knowledge to update their modes and, in this case, remap the extent of the volcanics that are prohibiting migration.

6.2 Whio-1

Unlike Anadarko, OMV (the operator) did complete and publish a thorough postmortem analysis for the Whio-1 exploration well (Wyman & Smith, 2015). While OMV does suggest two potential failure modes, they do not specify if one of the failure modes pertains to a specific segment – with the other failure mode linked to the other segment – or if the failure modes are simply two different possibilities for the well as a whole. This vagueness is something that companies should look to avoid in order to increase consistency and thoroughness in future failed-segment analysis.

The first failure mode suggested by OMV is that oil and gas generated from Cretaceous source rocks in the Maui Sub-basin (Figure 5-12) migrated through the Whio area prior to the development of the Whio prospect trap. As determined in this study, OMV’s proposed failure mode aligns with the failure mode for the deeper Mangahewa segment.

The second failure mode proposed by OMV is that significant quantities of petroleum fluids never migrated into the Whio area before Late Miocene inversion, and in recent times has been prevented from migrating south (from the Maui sub basin kitchen to the north, Figure 5-12) due to opening of vertical migration pathways to the surface during Plio-Pleistocene extension. This failure mode aligns with this study’s findings that the M2A segment failed due to migration.
6.3 Kanuka-1

Whereas Anadarko and OMV were rather vague in the manner in which they presented their findings on specific failure modes, Pogo’s findings go beyond vagueness and border on confusing and contradicting. Pogo presents two sentences that are supposed to describe the failure mode, yet those two sentences seemingly suggest two different specific failure modes. The first sentence, “[the conclusion] is that hydrocarbon migration to the Kanuka structure may not have occurred” is relatively straightforward and is line with the findings of this study that the Mt. Messenger segment failed due to a lack of migration. However the next sentence, “This was possibly due to the presumed late structuring and / or the lack of effective conduits” suggests both timing (“late structuring”) and migration (“lack of effective conduits”) as a failure mode. Again, this study agrees with Pogo’s findings that the Mt. Messenger segment failed due to a lack of migration, however cannot agree with timing as the failure mode for the segment. If timing were in fact the failure mode for the segment, there would still be evidence of migration throughout the Kanuka structure. However, there is no firm evidence – either through shows or thermogenic gases – and actually quite a lot of evidence to the contrary.

6.4 Future Work

The major limiting factor throughout this study was the availability and quality of data. While companies most likely do not want to plan for segments and wells failing, the reality is that roughly 50% of conventional exploration wells drilled within the past decade have failed to find movable petroleum fluids (Milkov & Navidi, 2019). Operators have direct control over what data are acquired pre-, during, and post-drilling, and this
study highlights a need for operators to begin planning their data acquisition with failure in mind, rather than either assuming success or trying to save money. If operators were to acquire data with the knowledge that, on average, 50% of conventional wells fail (the variance of that number will change from company to company) the quality and quantity of data acquired would surely increase. With an increase in data quality and quantity, operators would then be able to complete more robust and systematic analysis on failed segments, the application of which, on prospective wells, would likely serve to reduce the probability of future failed segments.

In addition to data quality and quantity, another limiting factor of this study was its restriction to only the Taranaki Basin. Given that sedimentary basins differ greatly from one another, it is highly likely that scenarios will arise that the decision tree (Figure 1-1) would have to be customized in order to properly assess a failed segment and determine its key failure mode. For example, modifications to the decision tree would be necessary in the Gulf of Mexico where the continuity of salt (sealing welds versus non-sealing welds) is critical. It is the goal of this study that the decision tree (Figure 1-1) tested herein becomes a best practice in the industry, and while this study tests and proves the concepts that the decision tree is based on, the true future-value of the decision tree lies in basin-specific customized versions.
CHAPTER 7

CONCLUSIONS

The goal of this study was to formalize and test the applicability of a decision tree aimed at simplifying and standardizing postmortem analysis in the petroleum industry. Well logs, both pre- and postdrill technical reports, seismic data (both 2D and 3D), geochemical analysis of gases and source rocks, and 1D basin models were utilized in order to conduct a comprehensive, fully-integrated analysis of five individual failed segments across three exploration wells, and then compare those results with the failure modes suggested by the individual wells’ operator.

1. The main limiting factor on thorough analysis using the decision tree (Figure 1-1) is the availability and quality of data. While this study at times ran into issues acquiring sufficient high-quality data for proper analysis of all of the risked elements, well operators will have control over the data acquired on a well-to-well basis in addition to a more complete understanding of the predrill predictions and expectations.

2. One of the desired outcomes of this study is that the methodology tested herein, or its customized versions, will become the best practice in postdrill analysis across the exploration industry. The decision tree has met all of the objectives of this study and has served to prove the concepts upon which the methodology is built. This allows for companies, individuals, or future studies to build upon these concepts and begin to develop some of the ‘customized
versions’ that might prove more applicable in certain situations and environments given the disparity of individual sedimentary basins, plays, and prospects.
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