Reservoir Characterisation of the East Coast and Pegasus Basins, Eastern New Zealand*

Angela G. Griffin¹, Kyle J. Bland¹, Brad D. Field¹, Gareth Crutchley², Richard Kellett², Dominic P. Strogen¹, and Mark J.F. Lawrence¹

Search and Discovery Article #10796 (2015)**
Posted November 30, 2015

*Adapted from poster presentation given at AAPG/SEG International Conference & Exhibition, Melbourne, Australia, September 13-16, 2015
**Datapages © 2015 Serial rights given by author. For all other rights contact author directly.

¹Petroleum Geoscience, GNS Science, Lower Hutt, New Zealand (a.griffin@gns.cri.nz)
²Marine Geoscience, GNS Science, Lower Hutt, New Zealand

Abstract

This integrated study focuses on the reservoir characteristics of the East Coast and Pegasus basins, located on- and offshore eastern North Island, New Zealand. The compilation of existing GNS Science knowledge and data includes paleogeographic maps, seismic interpretations, petrophysical analysis of both conventional wireline and FMI image logs in exploration wells, poroperm analysis and reservoir potential of likely Neogene and Cretaceous formations, found in both onshore and offshore parts of the basins. Integration of onshore/outcrop analogues with subsurface data sets (e.g. wireline logs, seismic interpretation) is undertaken, with the aim of building a model for predicting reservoir distribution and quality in the region. Over 300 known onshore oil and gas seeps occur in eastern North Island, New Zealand, indicating an active petroleum system. Although more than 40 wells have been drilled onshore, only three have been drilled offshore, all with significant gas shows. Reservoir units mainly comprise Neogene clastic rocks, such as deepwater slope (channel and overbank) and basin floor fans. Shelfal sands have been identified as possible reservoirs onshore however they are not thought to be extensive offshore. Fractured reservoir potential is present locally in the form of Miocene limestones. Recent GNS Science seismic interpretation studies indicate that Cretaceous aged units are present offshore, although more data are needed to better understand their reservoir potential, given that offshore wells have not yet encountered rocks of this age. In addition, a promising gas hydrate province exists offshore, where widespread bottom simulating reflections corresponding to a hydrate layer are observed in seismic data, and where methane seep sites indicate focused fluid flow that may have created concentrated gas hydrate deposits. However, the perceived lack of quality reservoir facies may be hindering the unlocking of the region’s petroleum potential.
1—EAST COAST REGION - THE NEW FRONTIER

Overview
The elements of a working petroleum (oil, gas, and gas hydrates) system are all present in the East Coast Basin and the region has good reservoir potential, although these reservoirs are also a key risk.

Several multi-national exploration companies have recently been awarded acreage in this region. The main reservoir types targeted by exploration companies in the past include:

- Cretaceous shelfal and deepwater sandstones
- Neogene shelfal and deepwater sandstones
- Neogene fractured limestones

This poster integrates data from studies of outcrops and well log analyses (image and conventional), petrography, seismic interpretation, poro-perm assessment, and fundamental field-based sedimentology. In particular, we focus on the reservoir potential of Neogene turbidite successions (posters 2 and 4) and fractured limestones (poster 3) in onshore East Coast as analogues for offshore East Coast and Pegasus basins.

This data contributes to a renewed effort to better understand the distribution and characterisation of potential reservoir units in these basins.

The data and their analysis are by no means complete, and it is hoped that with renewed interest in the East Coast and Pegasus basins, further research will better define their reservoir potential.

Geological Setting
East Coast Basin lies on the Australian plate, northwest of the Hikurangi Trough (Figures 1.1 and 1.2). The basin extends from the axial ranges of the North Island and southern South Island, east to the Hikurangi Trough.

Pegasus Basin lies entirely on the Pacific plate, east of Cook Strait and north of the east–west-oriented Chatham Rise (Figures 1.1 & 1.2).

The basins have a common Mesozoic–Paleogene history and similar Neogene stratigraphy, but differ structurally. Pegasus Basin is structurally simple, whereas a large part of East Coast Basin is structurally complex due to a Neogene oblique convergent margin overprint.

Petroleum Exploration
Petroleum exploration has been active on the East Coast of the North Island for over 100 years, primarily due to the presence of numerous oil and gas seeps (Figure 1.2), thick sandstones, and potential trap structures (Figure 1.3).

More than 40 wells have been drilled onshore (Figure 1.4), some of which have had significant shows. Three offshore wells in the East Coast Basin have shown more promise, with good gas shows and a sub-commercial discovery.

Seismic surveys have been shot in the Pegasus Basin, although no wells have been drilled. Little is known about the reservoir characteristics of Pegasus Basin, although insights are provided on potential reservoir quality by adjacent outcrop analogues.

A promising gas hydrate system has been interpreted from seismic surveys in the East Coast and Pegasus basins, along with potential gas pockets beneath the gas hydrate layer. Understanding reservoir quality within the gas hydrate layer is critical for assessing any producible resource.

Geological Risks
While there has been significant renewed interest in the East Coast and Pegasus basins, there are potential risks relating to petroleum prospectivity and exploration.

These include a lack, or limited extent of potential reservoirs and seals, scattered seismic distribution, and lack of wells drilled, especially offshore.

More work is needed in the basin to understand and hopefully eliminate some or all of these risks.
2—NORTHERN HAWKE’S BAY TURBIDITES
The Middle Miocene Tunanui Formation

Overview
The most widespread Neogene clastic reservoir lithology in the East Coast and Pegasus basins are deepwater sandstones (slope channel and overbank, and slope and basin floor fan deposits).

The Middle Miocene Tunanui Formation is an example of these deepwater sandstones that has been studied in both outcrop (Figure 2.2) and the subsurface. It has good clastic and predictable fracture reservoir potential and has been the focus of detailed poro-perm, borehole image analysis, outcrop, and fracture studies.

Flow testing of the Kauhaurua-5 well (Figure 2.1) yielded 50–145 Mcfd gas from the Tunanui Formation, and gas shows were recorded in Tuhara-1/1A.

The Tunanui Formation has good reservoir quality, such deepwater sandstone deposits are likely to be common in the subsurface, both onshore and offshore.

Figure 2.1 (right): Locations of wells that intersected the Tunanui Formation, and outcrops mentioned on this page.

Tunanui Formation
● Sandstone-dominated, deepwater deposit
● Comprises both thick and thin-beded mass flows (Figure 2.3)
● Metre-beded turbidite facies inferred to be mainly flow-stripped (Ta & Tb) turbidites (Figures 2.3 & 2.5)
● Facies with similar scales of bedding also interpreted in the subsurface (Figures 2.9 & 2.10)
● Fractures identified in outcrop and in subsurface (Figures 2.3, 2.10 & 2.11)
● Fractures in outcrop strike NNE, similar to those observed in Tuhara-1A FMI logs
● Good porosity (~13–30%) & moderate permeability (~20–90 mD) in outcrop sandstones (Figures 2.7 & 2.8)
● Good open pore-system based on high visible porosity values (Figure 2.6)
● Outcrop sandstones have undergone very little diagenesis, implying limited burial
● Likely to suffer compactional porosity loss from deep burial due to the lithic-rich nature of the sandstones (Figure 2.6)

Results from a fracture scanline survey (Figure 2.3) indicate that the most abundant fractures strike NE and dip steeply to moderately in two sets: set A1 dips NW and A2 dips ESE. Apertures range up to 2.9 mm. There does not appear to be a consistent, critical aperture above which fractures are open (Field et al., 2006, 2009).

Over half the aperture data from fractures picked and calculated from image logs from the Tunanui Formation in Tuhara-1A, plot within or close to the projected trend lines derived from outcrop measurements (Figure 2.4).

This indicates a broad consistency between the structural datasets, from both outcrop and subsurface. As such, further structural properties and distributions noted from outcrop studies might be applicable to this formation in the subsurface in other prospects.

Figure 2.5: Metre-scale sandstone bedding in a thick-beded package from the Tunanui Formation, from an outcrop at Black’s Beach, near Maria Peninsula.
Figure 2.6: Photograph of a Tunanui Formation sandstone (blue ephy showing porosity). This sample forms part of a detailed reservoir quality study on the Tunanui Formation from outcrops near Opotutu (Striegen et al., 2010).
Figure 2.7: MIP data for a thin-beded Tunanui Formation sample. This sample has well-connected porosity with a simple pore throat size distribution, and a low throat/porosity pressure (10 psi)., suggesting it has good reservoir potential (Striegen et al., 2010).

Figure 11: Contoured stereonet of the faults and fractures identified in the Tunanui Formation, Tuhara-1A well. FMI borehole image. Dominant fracture dip direction is NW. Dip magnitudes are typically high. Initial interpretations suggest the thin-grained units are more fractured than the sandstones.
Figure 12: In-situ stress bi-directional rose diagram, Tunanui Formation, Tuhara-1A well. The diagram shows borehole breakouts and drilling-induced tensile fracture orientations in the well. Fractures parallel to the SHmax direction are more likely to be open.
3—NEOGENE FRACTURED LIMESTONES
The Kauhauora and Kiakia limestones, & correlates

Overview
Bioclastic limestones of Early, Middle, and Late Miocene age crop out across the East Coast region. Deposition of these limestones largely relates to significant basin-wide phases of uplift.

Two such limestones have been encountered in the subsurface in the Wairau area (Figures 3.1 & 3.3).

The late Early Miocene Kauhauora and earliest Late Miocene Kiakia limestones are almost purely fractured reservoirs. The Kauhauora field (discovered in 1998) produced gas on test from the Kauhauora Limestone, although it was deemed sub-commercial.

Kauhauora Limestone
• Only recognised in the subsurface, not in outcrop
• Outcrop analogues = Moonlight, Kouetumarau, & Takitiri formations (Figures 3.7 & 3.8)
• Mid to outer shelf depositional environment
• Strongly-cemented, bryozoan-rich grainstone
• Intersected by at least 6 exploration wells
• Up to 130 m thick (Figure 3.4)
• No visible matrix porosity
• An almost purely fractured reservoir
• Fractures identified in subsurface using borehole image logs and core (Figures 3.5 & 3.6)
• Porosity ~10.5% and permeability <0.1 mD (sidewall core analysis, Kauhauora-4B well)
• Stabilised flow rates of up to 11.5 MMcf/day methane in Kauhauora-1

Kiakia Limestone
• Strongly cemented, bryozoan-rich shelly grainstone
• Similar lithofacies and depositional setting to the Kauhauora Limestone
• Only known in the subsurface, intersected by 4 exploration wells
• Between ~3–30 metres thick in the subsurface
• Overlain by a massive mudstone with seal potential
• No visible porosity
• Unusually high natural gamma signal in Kauhauora-5, possibly indicating uranium oxide on fracture planes
• Flowed small amounts of gas and water in Kiakia-1/1A; gas shows in Kauhauora-4/4A
• Outcrop analogues are widespread in the East Coast, e.g. Waipuna Limestone, basal Te Haroto and Waitea formations, Kupa’s Sail

Figure 3.1 (right): Location map showing wells intersecting the Kauhauora and/or Kiakia limestones, and outcrop localities mentioned on this page.

Figure 3.2 (above): Waipuna Limestone Member (Waipuna Formation), an unconformity-based coarse-grained shell-rich wadi-fill facies (imbrication, cropping out in the Waimea River valley). The limestones is a correlate of the early Late Miocene Kiakia Limestones. Because the Kiakia Limestone is only known in the subsurface, outcrop correlative features are important for understanding the unit’s depositional settings.

Figure 3.3 (right): The Kauhauora Anticline (part of seven-line well-EC-23). The well was drilled on a fault-controlled antiformal structure. The fault transects the base of the Kauhauora Limestone. Seismic line from Kauhauora-5 well completion report (FRSA, 1999). Vertical and horizontal scale is 1:2,000.

Figure 3.4: Kauhauora Limestone wherein log signature, Kauhauora-4B well. Low gamma, high resistivity, high density and low neutron log values indicates limestone.

Figure 3.5: FMI resistivity borehole image from Kauhauora-5. The limestone has characteristically elevated resistivity (lighter colour on the statistically-normalised image) with abundant discontinuous, bed-limited conduit (dark) fractures. A fault contact is shown by the black arrows.

Figure 3.6 (above): Contoured element of the Kauhauora Limestone faults and fractures identified from the Kauhauora-5 FMI borehole image. Fracturing is common, and is dominated by bed-limited structures. Dominant fracture dip direction is east-west, with high dip magnitudes.

Figure 3.7 (left): Takitiri Formation (correlative of the Kauhauora-Limestone), Tinana area, Wairau river. Note the marine-thick sandstone and limestone beds (left).

Figure 3.8 (right): Moonlight Limestone, a Kauhauora Limestone correlative. A short-scanned survey (red tape in photo) through the unit suggests the main structure is a cut-and-fill [in terms of fracture and spacing], but statistical analysis indicates the data are close to random. The structural history could not be extrapolated with confidence (Field et al., 2006).

Figure 3.9 (above): Waipuna Limestone exposed in the Waimea River, near Papamoa, Hawke’s Bay. Inset: Erosional unconformity at base of the Waipuna Limestones. The limestones unconformably overstep basement (not visible in this image) here at Kupa’s Sail, Cape Palliser.

Figure 3.10 (left): Slipping-dip Late Miocene shelly shallow-marine breccia. The breccia unconformably overstep basement (not visible in this image) here at Kupa’s Sail, Cape Palliser.
4—WAIRARAPA TURBIDITES

The Whakataki Formation

Overview

The Early Miocene Whakataki Formation is a good example of a clastic deepwater turbidite reservoir in the East Coast region. The formation is an analogue for accretionary slope basin fill, which is present in the East Coast offshore Neogene. Outcrops at Wharepoouri’s Mark (Figure 4.3) provide an analogue for the gas-bearing thin beds in the offshore Tithorea-1 exploration well. Assessments of the formation’s fracture reservoir potential have been undertaken in outcrop and from borehole images.

As Tithorea-1 is the closest well to Pegasus Basin, it helps to provide an analogue for understanding the offshore levee-overbank and turbidite reservoir quality.

Whakataki Formation (onshore)

- Turbidite unit including channel and overbank deposits
- Alternating sandstone and mudstone beds (Figure 4.1)
- Similar to Gulf of Mexico and Taranaki Basin (Mount Messenger Formation) turbidites
- Good Bouma sequences in beds (Figure 4.2)
- Well developed climbing ripples in outcrop/high rate of sediment supply during deposition and waning flow, typical of overbank deposits
- Outcrops on the Wairarapa coast interpreted as thin-bed suprafan channel overbank facies
- Thin sandstone beds can be followed over 400–500 m in outcrop (Edbrooke and Browne, 1996)
- Beds are organised in vertical cycles, evident in gamma ray log and bed thickness plots (Figure 4.6)
- Bed and grain-scale variations in reservoir properties (outcrop)
- Faults and fractures seen in outcrop (Figures 4.4, 4.5)
- Porosities typically 10–20%
- Outcrop study permeabilities ~1–20 mD, up to 60 mD
- Nett-to-gross ~74% (Figure 4.6)

Whakataki Formation offshore

- Seismic data suggest equivalent rocks can be up to 800 m thick (Figure 4.11)
- Similar facies of Middle Miocene age encountered by the Tithorea-1 exploration well
- Alternating thin-bedded sandstone and mudstone facies interpreted from borehole image (Figure 4.8)
- Log-derived nett-to-gross ~8–13%
- Sandstones in Tithorea-1 have reasonable reservoir potential with porosities ~13% and permeabilities of 20–200 mD (similar to that determined from outcrop)
- Faults & fractures interpreted from borehole image (Figures 4.8 & 4.9)
- Water-bearing sands (up to 100% water saturation)
- Gas encountered, but deemed non-commercial

Figure 4.1: Thin-bedded Whakataki Formation cropping out at Wharepoouri’s Mark. Figures circled for scale.

Figure 4.2: Bouma sequences, amalgamated sandstone, and sedimentary structures within the Whakataki Formation. Sandstone beds are dominated by Tp planar laminated beds with climbing ripples (Tp) and mudstone lobes (Td & Tt).

Figure 4.3: Whakataki Formation outcrops (hashed areas). Wharepoouri’s Mark outcrop location, Tithorea-1 and Tannaeh-1 exploration wells, and the composite seismic line in Figure 4.11 (solid red line) offshore southern Wairarapa. Dashed black line is approximate basin boundary.

Figure 4.4: (above) Faulting in the Whakataki Formation. Wharepoouri’s Mark. (Figure 4.5) (below) Small-scale faulting affecting thin beds.

Figure 4.6: (below) Seismic data. Whakataki Formation thin beds, showing vertical heterogeneity (right) and nett-to-gross values (Pfadt, 2003).

Figure 4.7: (right) Photomicrograph of Whakataki Formation, mounted in blue-gelatin and stained for planktonic foraminifera (P), planktonic ostracods (O) and anoxic clay-rich (CR) and degraded grains (DG) are shown. An overgrown hybrid dissolution zone (P') and a partially dissolved hyaloclast with porosity (P) are also indicated (Pollock et al., 2005).

Figure 4.8: (right) Extract from the 3D (red/orange) borehole image of the Whakataki Formation equivalent to Tithorea-1, showing a fault (pink line) within a series of thin beds. The offset is ~15 cm. Sandstones are dark (red/orange) in the image. Depths are in metres.

Figure 4.9: (below) Faulting seen in the 3D seismic data. Faults and fractures identified in the Whakataki Formation. Tannah-1 3D borehole image. Dominant fracture dip direction is SE. Most of the dip magnitudes are shallow, although high dip magnitudes values are also observed.

Figure 4.10: (below) Example of Whakataki Formation equivalent seismic log signature, Tithorea-1. The small scale log activity indicates the heterogeneous beds. UTI resistivity values “fracking together” indicate thin/thick hydrocarbons.

Figure 4.11: (left) Interpreted and uninterpreted (bottom left) composite seismic line through Tithorea-1, and outwards Pegasus Basin (location shown on Figure 4.3). The uninterpreted line shows the strong parallel reflections of the turbidites that make up the Whakataki Formation offshore. Small fault-bounded antiflakes are also evident in the seismic. These antiflakes grow and are either ended or thinly covered by sediments. Vertical exaggeration is approximately 5:1.
5—A NEW FRONTIER?
Tapping a potential gas hydrate resource

Overview
Seismic interpretations have identified attractive gas hydrate deposits in the southern East Coast and Pegasus basins (Figure 5.1), especially in regions where gas migration into the gas hydrate stability zone has occurred along permeable layers.

Gas hydrates (Figure 5.2) can form under specific pressure and temperature conditions in sediments immediately below the seabed in deep water (>650 m). The change in phase from solid hydrate to gas at the base of the hydrate stability field is marked by a sharp decrease in acoustic impedance (negative reflection polarity). This reflection mimics the seafloor and cuts across any dipping geological units, and is referred to as a bottom simulating reflection (BSR) (Figure 5.3).

The gas hydrate province in the offshore East Coast region covers an area greater than 50,000 km². BSRs are widespread and prominent in the Pegasus Basin, one of New Zealand’s premier gas hydrate provinces, and have been included in the 2015 Blocks Offer announced earlier this year.

Gas Hydrate Potential
- Widespread BSRs on the East Coast margin indicate an extensive gas hydrate province
- Sandy sediment reservoir types preferred for gas hydrate formation and production
- Thrust ridges on the slope are primary sites for hydrate exploration
- Faults provide conduits for gas migration into the hydrate stability zone
- Migration of free gas along the dipping beds into the hydrate stability zone can result in concentrated gas hydrate deposits
- Gas likely to be more "easily" produced in porous sediments
- Hydrate saturated zones can be mapped in seismic data
- Good indications for resource quality gas hydrates are high seismic velocities associated with strong reflections near the base of the hydrate layer
- Saturated zones are often underlain by broad regions of strong reflectivity that represent accumulations of free gas beneath the gas hydrate layer (Figure 5.4)
- Fluid contacts (gas-water) can often be mapped in the seismic data (Figure 5.5)
- Major unknown in gas hydrate potential is the quality of reservoir rocks for hydrate formation and production

Putting It All Together
- An active petroleum system exists in the East Coast and Pegasus basins
- Preliminary research has revealed useful data on these systems, but some aspects remain poorly understood
- A variety of reservoir rocks and play types have been identified from exploration efforts

Many other reservoir types exist, beyond those discussed in this poster, such as shelly limestones, canyon fill, slope channels, and shelly and shoreface sandstones. However, a robust understanding of the basins’ reservoir potential requires further research.

We continue to actively derisk the reservoir aspect of the petroleum system by applying multi-disciplinary techniques, from the microscopic to the seismic scale.

Figure 5.1: The area outlined in purple, defined by the 650 m isobath, delimits the areas of potential gas hydrate occurrence. The black lines show the distribution of PEG200 seismic lines that cross Pegasus Basin. Thin faint blue lines are depth contours (m bsl). Green stars highlight locations of seafloor gas seeps. Boxes labelled “1” and “2” show the locations of seismic data examples given in Figures 5.4 and 5.5.

Figure 5.2 (left): Gas hydrates are naturally occurring, crystalline, ice-like substances composed of gas molecules (methane, ethane, propane, etc) held in a cage-like ice structure. Source: http://www-pcm.lsa.umich.edu/glimpse/icesim/icesim.html

Figure 5.4: Seismic data from Line PEG200-05, showing the BSR (dashed blue line) cutting across the dipping beds on the flanks of a anticline. High-amplitude reflections dipping beneath the strong BSR are indicated (black arrow). The seismic line is the blue box labelled “1” in Figure 5.1.

Figure 5.7 (below): Illustrated seismic line PEG61-1TP1003, East Coast and Pegasus basins from Bland et al. (2014). The seismic line shows the relationship between the anomalous slope basins, turbidite deposits, and BSRs in the basins, some of which have been described in this poster.

Figure 5.5 (right): Seismic data from Line PEG200-05, showing a strong segment of a BSR (dashed blue line) beneath gently folded strike-slip (blue arrows). A strong, slightly down-dip reflection (red arrow) beneath the BSR has been interpreted as a flat spot marking a gas-water contact (i.e. the base of the gas, whereas the BSR marks the top of the gas) (Germain et al. 2012). The seismic line is the red box labelled “2” in Figure 5.1.

Figure 5.6: What lies beneath? Looking out towards Pegasus Basin. Image Limetstones correlate at Kupa’s Skil, Cape Palliser.
Acknowledgements
This work was undertaken as part of the Petroleum Basins Research Programme with direct Crown funding from the New Zealand Government (Ministry of Business, Innovation and Employment).

References


