

Petroleum generation and migration models for the East Coast Basin

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Abstract

The level of petroleum exploration activity in the East Coast Basin, situated on the frontal arc of the Hikurangi subduction zone, has increased following the Kauhauroa-1 discovery in 1998. However, the additional information derived from the increased drilling activity has tended to confirm the complexity of, and difficulties associated with, exploration in the East Coast Basin. In this paper, we present a model aimed at providing insight into some of the key factors that control the distribution of oil and gas accumulations and seeps within the offshore Wairarapa region of the East Coast Basin.

Numerical models describe the maturation, expulsion and migration of hydrocarbons from various Late Cretaceous and Paleocene source rocks. The subsidence, deposition and erosion history of the basin is simulated using a GIS-based multi-1D model that provides quantitative estimates of hydrocarbon classes produced from each kitchen. High-resolution 2D models are used to illustrate migration of hydrocarbons from kitchen to trap. Sub-surface pressures are shown to be critical in the development of migration channels, causing a redistribution of generated hydrocarbons. The models provide insights into the East Coast petroleum system, confirm the hydrological importance of the Eocene / Paleocene seals, and the likely requirement for deep Cretaceous source rocks to account for the high gas saturation encountered in the Titihaoa-1 well. Models suggest that high gas saturation exist within Miocene sandstones in structural closures and oil remains trapped within, and beneath, thick Eocene seals.

The application of these techniques demonstrates the importance of understanding the complex structural development, impact of over-pressuring, timing of maturation and types of migration pathway in assessing exploration risk within the East Coast Basin.

Introduction

In recent years the East Coast Basin has been one of New Zealand's more active petroleum exploration theatres (Figure 1). The basin is, however, geologically complex, having experienced a large degree of Neogene deformation and associated uplift and subsidence. Due to the degree of deformation, and general paucity of data, the generation, migration and entrapment of hydrocarbons in the East Coast Basin is not well understood. This paper uses numerical modelling to examine the maturation and charge history of the offshore Wairarapa region, as an analogue for exploration in other parts of the East Coast Basin. This area is ideally suited to this approach due to the reasonable coverage of seismic data and available data from one of only two offshore wells in the basin.

In the offshore Wairarapa region, Amoco shot over 1400 km of 2D seismic data on a close-spaced grid in 1990. Amoco then drilled the Titihaoa-1 well in 1994, targeting the Early Miocene Takiritini and Oligocene Akitio sandstones. The

well did not reach its objectives since the Late Miocene section was much thicker than predicted and the well was terminated in the Middle Miocene at a depth of 2740 m. The well encountered significant gas shows (and kicks) over several hundred metres in Middle Miocene thin-bedded, inferred levee-overbank turbidite sands. No significant liquid hydrocarbons were recorded in the well (Biros et al. 1995).

Maturity modelling by Uruski & Funnell (1995) in the offshore Wairarapa suggested that hydrocarbons may have been generated from the Paleocene Waipawa Formation in two phases: firstly prior to initiation of subduction and during the late Oligocene and, later starting some time in the Late Miocene dependent on the depth of burial. Later, modelling in Field et al. (1997), for the Titihaoa-1 site, indicated that only deepest marine Cretaceous source rocks generated oil in the Oligocene with a rapid increase in generation rates due to rapid subsidence since the Middle Miocene. Late Neogene thrusting was modelled to trigger significant generation from Paleogene source rocks since 12 Ma in the

deeper parts of the offshore Wairarapa due to thickening of formations. Areas where the Waipawa Formation is inferred to lie in a mature kitchen area were also mapped in Field et al. (1997).

Following the drilling of the Titihaoa-1 well, Uruski (1995) re-interpreted seismic data in the offshore central Wairarapa region. This paper presents the results of numerical models based on Uruski's mapping and investigates some of the key factors that control the distribution of oil and gas accumulations (and seeps) within this Wairarapa region.

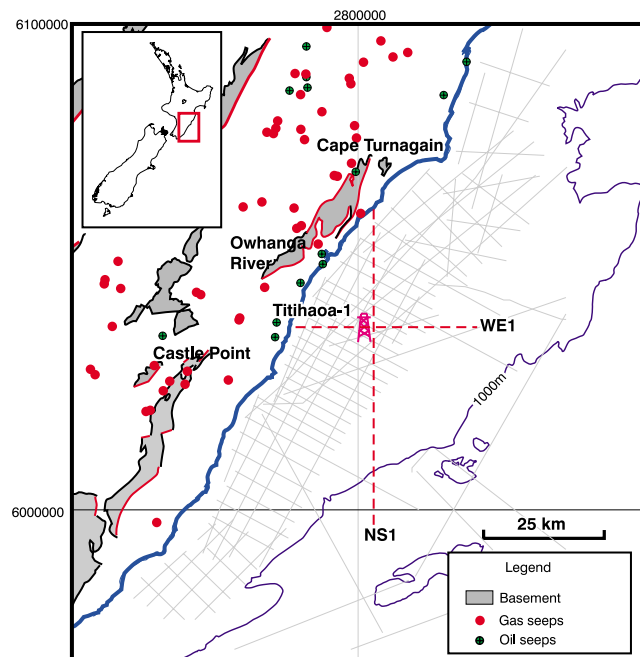


Figure 1. Location diagram showing onshore seeps and basement outcrop (Field et al. 1997), with seismic lines used for interpretation, Titihaoa-1 well location and 2D cross-sections identified.

Geology

The geology of the East Coast basin is described comprehensively in Field et al. (1997). Source rocks are thought to be Cretaceous-Paleocene and widespread. They have not been drilled offshore though the gas discovery in Titihaoa-1 supports the inferred continuance of source rocks offshore. Features more specific to the petroleum systems of offshore Wairarapa include broad anticlinal closures trending NE and up to 500 m wide by 1-3 km long (generally associated with Middle Miocene thrusting) and Late Neogene maturation and expulsion. There are several proven and potential reservoir units. Titihaoa-1 encountered high gas pressures in a thick Middle Miocene thin-bedded (?) levee-overbank turbidite succession, and other Miocene deep water channel-levee and fan units are probably present, as well as, perhaps, Eocene quartzose fan deposits (related to nearby outcrops at Cooks Tooth). Fractured, close-to-source reservoir potential in Late Cretaceous-Paleocene siliceous mudstone should be present; fractured Miocene limestone is possible though less likely. Sediments overlying the inferred source rocks total 4-7 km and potential Miocene reservoirs are at depths of 1.0-3.5 km in present water depths of up to 250 m.

Modelling approach

A multi-1D petroleum modelling approach presented by Wood et al. (1998) was used to predict sediment maturity and delineate areas of oil and gas generation in the region of interest. Migration pathways were then assessed using 2D fluid flow models to review important regional migration controls and their influence on petroleum accumulations along key transects.

The multi-1D software consists of an interactive 1-D finite element basin simulator (Armstrong et al. 1996) linked with a Geographic Information System (GIS). The model was applied to each 1 km² cell in a basin grid to determine a maturity (transformation ratio) profile throughout the sedimentary sequence, predict volumes of petroleum generated, and to re-construct the basin configuration and sediment fill through time.

Models of petroleum generation were undertaken using industry-standard IES PetroMod TM software. This is a two-dimensional, finite-element, basin simulator that uses interpreted seismic reflection data, lithology and hydrocarbon kinetics to predict maturity and three-phase flow (water, oil and gas) through time.

Structural and thermal input data

The input data consists of grids, or maps, of formation thickness and age, lithologic and geochemical properties of sediments, and heat flow. Interpreted seismic data (Uruski 1995) were digitised at shotpoint locations (every 1-2 km), and depth converted using a spatially varying two-way-traveltime/depth function derived from stacking velocities. The depth lines were then gridded in GMT, on a 1 km² grid, using the continuous curvature surface gridding algorithm (Smith & Wessel 1990). These structure grids were used to develop seven formation isopach grids (Pleistocene; Late and Early Pliocene; Late, Middle and Early Miocene; and Paleogene) and a bathymetric grid. The data was reviewed to remove small introduced errors due to "edge effects", and spurious data points in areas of poor seismic control. While several unconformities exist at various stratigraphic levels, the most significant in the region of interest are in the early Pleistocene. In this report these unconformities are combined as an eroded thickness grid by contouring missing section estimates from seismic sections.

The subduction and tectonic framework is an important factor in the models, although this model is limited to the upper plate with an average depth of 13 km. Heat flow into the base of the model is controlled by the subducted lower plate. Pre-Cenozoic strata in the model are represented by 3 km of Cretaceous sediments overlying 4.5 km of young Torlesse (Pahau) crust and 0.5 km of accreted sedimentary material overlying the slab interface. Thermal properties based on an average lithology for each formation, and paleo-water depths are treated as constant for each age period across the basin. The basal heat flow, defined at the plate interface, was derived after developing 1D models for well sites in the surrounding area (Field et al. 1997). Initial heat flow is fixed at 45 mW/m², a typical mantle heat flow beneath continental crust, and

is reduced at 25 Ma, the approximate time of the start of subduction, to a value of 29 mW/m². Secondary “heating” is also provided by heat productivity from sediments and crust (within the upper plate) contributing 17 mW/m² to a mean surface heat flow of about 45 mW/m², in agreement with well data.

Source rock distribution

The lack of data on source-rock thickness and quality in the area of interest makes mapping of the units for the purposes of generation modelling difficult. Potential source rocks for hydrocarbons are: the Waipawa Formation, which has sourced oil stains in outcrop and seeps in the south of the basin (Francis, 1998; Johnston et al. 1992, Leckie et al. 1992) the Whangai Formation, which is the postulated source of seeps in the north of the basin (Rogers et al. 1994, 2001), and possible Cretaceous terrestrial shales and coals (Field et al. 1997). The boundaries of the various members have not been identified in seismic sections in the area of interest, and so, at best, only the average thickness of each formation can be estimated. For this particular model, the Late Cretaceous-Paleocene Whangai Formation is assumed to be represented by the lower third of the Paleogene isopach and limited to a maximum thickness of 400 m. The overlying Waipawa Formation is represented by a constant 10 m-thickness isopach. The presence of a possible terrestrial Cretaceous source rock has been speculated on by a number of authors (Field et al. 1997) and has been included in the model by assigning the upper 1000 m of Cretaceous with limited oil-generative potential. Source rock geochemistry is based on data published by Field et al. (1997) and is presented in Table 1.

Hydrocarbon generation parameters

Volumetric calculations to determine the potential yield of oil and gas expelled from source rocks, or productivity, are calculated using:

$$Vol_{oil} = \frac{TOC}{100} [TR_{oil} \cdot HI_{oil} - S_r] \cdot r_{rock} \cdot vol_{source} / r_{oil}$$

$$Vol_{gas} = \frac{TOC}{100} [TR_{gas} \cdot HI_{gas}] \cdot r_{rock} \cdot vol_{source} / r_{gas}$$

Formation	Waipawa	Whangai	Cretaceous	
TOC	3.0	0.5	0.5	%
HI	300	250	245	mg/g
Sth	30	30	60	mg/g
GOGI	1	1	0.4	
Isopach	10	400	1000	mg/g
Volumetric fraction (HC)	0.024	0.0033	0.0028	m ³ /m ³
Mass of HC	18.9	2.6	2.2	kg/m ³
Oil expulsion	0.67	3.46	10.62	MM bbl/km ²
	82	11	13	bbl/acre-ft
Gas expulsion	4.32	24.45	34.09	BCF/km ²
	532	75	42	1000 cu ft/acre-ft

Table 1: Geochemical and total productivity data for Whangai and Waipawa formations, and upper section of Cretaceous sediments.

where TR is the transformation ratio determined from thermal modelling using kinetic parameters for oil or gas, S_r is the saturation threshold for oil expulsion, vol_{source} is the source rock volume, and ñ_{rock}, ñ_{oil}, and ñ_{gas} are the densities of source rock, oil and gas (kg/m³); using values of 800 and 0.86 kg/m³ for the densities of oil and gas.

The geochemical parameters, such as potential yield or Hydrogen Index (HI), TOC, saturation or expulsion threshold (Sth) and gas:oil index (GOGI), are not particularly well constrained due to a paucity of available data from wells and outcrop. Average values for HI and TOC from Field et al (1997) are used and equal quantities of generated oil and gas from shales are assumed where little GOGI data exists. A simple saturation-controlled expulsion threshold for oil is used, which can be assumed applicable whether the primary control is filling of pore space or the overcoming of adsorption capacity. This requires the generation of a certain amount of oil before any expulsion can occur. The use of a single saturation threshold may tend to over-estimate the amount of expelled oil during the early phases of oil generation. Gas, particularly methane, is expelled much more efficiently than oil, and an expulsion efficiency of 100% is assumed. Oil not expelled is typically subjected to secondary cracking processes, generating additional gas.

The geochemical parameters and total productivity estimates for oil and gas, assuming total conversion of available kerogen to oil and gas, are presented in Table 1. While the richness of the Waipawa Formation is significantly greater than that of the Whangai Formation and postulated Cretaceous source rocks, it is much thinner. Hence the productivity of the Waipawa Formation is generally at least 5 times lower than that of the Whangai Formation and Cretaceous source rocks.

Kinetic parameters used to describe the rate of reaction for conversion of kerogen to oil and gas are represented by marine type II kerogens (sub-type B organofacies by Pepper & Corvi 1995) and terrestrial type III kerogens (sub-type DE organofacies of type III kerogen by Pepper & Corvi 1995 for oil and IFP, 1995 for gas generation). The marine type II kinetic parameters, used to describe the Waipawa and Whangai organic rich formations, are consistent with data from an Angora Stream Waipawa Formation black shale sample. Terrestrial type III kinetics are included for Cretaceous sediments representing detrital plant debris found in the Glenburn Formation and the possible existence of Cretaceous terrestrial shales and coals.

Hydrocarbon migration approach

In this study transects were “cut” from the grids developed for the multi-1D model using the same modelled intervals and lithologies. For example, the Mid-Miocene sandstone reservoirs are generalised as a single unit (Layer 6 in Figure 2). Seal properties are based on

Formation	Pliocene	M-L Mio	E Mio	Paleogene
Volumes of expelled oil (B bbl)				
Waipawa Fm.	0.08	0.19	0.52	0.44
Whangai Fm.	0.40	0.98	3.24	2.77
Upper Cretaceous	0.55	2.23	10.43	9.54
Volumes of expelled gas (TCF)				
Waipawa Fm.	0.18	0.36	1.15	0.99
Whangai Fm.	0.94	2.09	7.56	6.91
Upper Cretaceous	0.76	3.05	12.36	12.07
Volumes of gas cracked from oil (TCF)				
Upper Cretaceous	0.67	3.58	13.13	13.31

Table 2: Volumes of oil and gas expelled from Waipawa and Whangai Formations and upper section of Cretaceous sediments, as modelled using parameters in Table 1. Calculated volumes based on using a 127kg / bbl of oil and 1kg / 41 scf of gas.

measured values (Darby et al. this volume), and compaction is stress related allowing overpressure to be modelled (although the model does not account for the development of flow associated with faults, fractures, and the effects of lateral stresses). Seal units in the Late Miocene (layer 5 in Figure 2) and Eocene / Oligocene (layer 8 in Figure 2) are modelled as fine-grained lithologies with high smectite contents. (i.e. seal properties include capillary entry pressures of 5 MPa, vertical permeabilities of 10^{-6} to 10^{-7} mD, horizontal permeabilities of 10^{-4} to 10^{-5} mD for 15 to 10% porosity equivalent to a burial depth of 3.0-4.5 km).

Results and discussion

Hydrocarbon kitchens

The results from the multi-1D generation model are presented in Table 2. Predicted volumes of oil and gas expelled from each formation are provided for various time periods in the basin history; Paleogene, Early Miocene, Middle to Late Miocene and the Plio-Pleistocene. The assumed thermal regime in this model generates significantly more hydrocarbons in the early-model history, prior to Middle Miocene, than the later period (since 16.5 Ma) in the primary kitchen areas. The reduction in generation rate is due to the modelled “cooling” of the basin caused by the initiation of subduction, and related to the thickening of the accretionary wedge sediments and emplacement of a relatively cold Pacific Plate. While the timing of this modelled “cooling” is somewhat uncertain, this is not expected to significantly affect the total volumes of expelled hydrocarbon. However, this cooling also correlates with the interpreted development of many of the mapped structures in the basin and, depending on vertical migration rates, hydrocarbons expelled prior to the Middle Miocene may have been lost from the system.

The total cumulative volumes of expelled hydrocarbons over the mapped area from each modelled source rock interval, to the present day, are mapped in Figure 3 for oil (MMbbl/km²) and Figure 4 for gas (BCF/km²). The volumes of expelled oil

and gas predicted from our modelling are large. However, typical values for generation – accumulation efficiencies are as low as 0.5% even in relatively efficient petroleum systems (Cornford 1994). Inefficiencies, or losses, will arise from a number of sources including; primary expulsion, losses along migration pathways, leakage up faults and through seals and through low production recovery factors caused by reservoir conditions. In addition, the expulsion threshold applied to the Cretaceous source rock is relatively optimistic and a primary migration, or expulsion, risk does exist for such low productivity source rocks. Any oil retained in the rock matrix, and modelled to be cracked to gas, effectively contributes to a two-fold increase in the gas volumes predicted as expelled at any one period in the basin history (see Table 2).

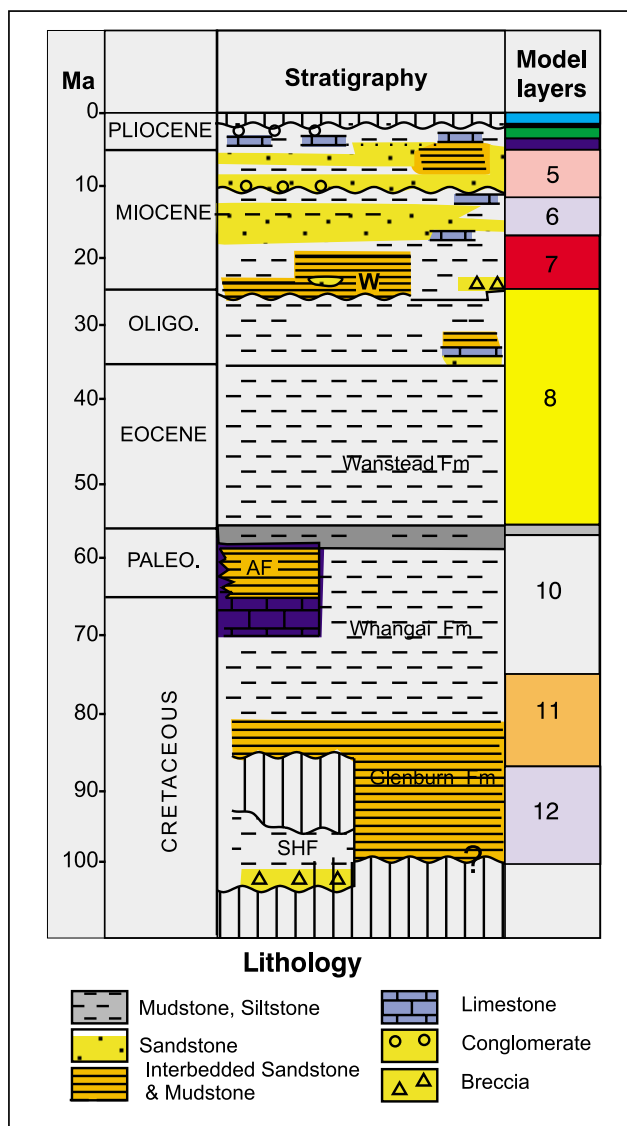


Figure 2. Stratigraphy of the onshore Wairarapa region with the stratigraphic intervals used in the model.

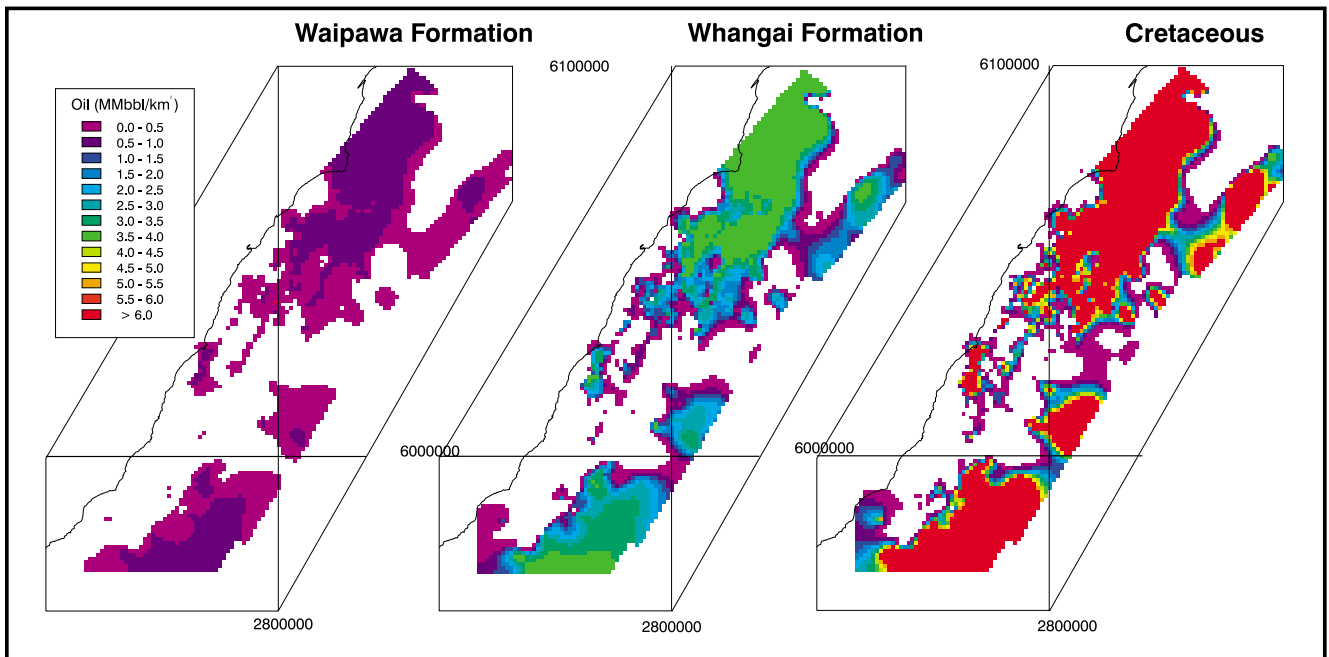


Figure 3. Predicted cumulative volumes of oil generated and expelled from the three modelled source rock intervals, up to the present day. Volumes are presented in MM bbl / km².

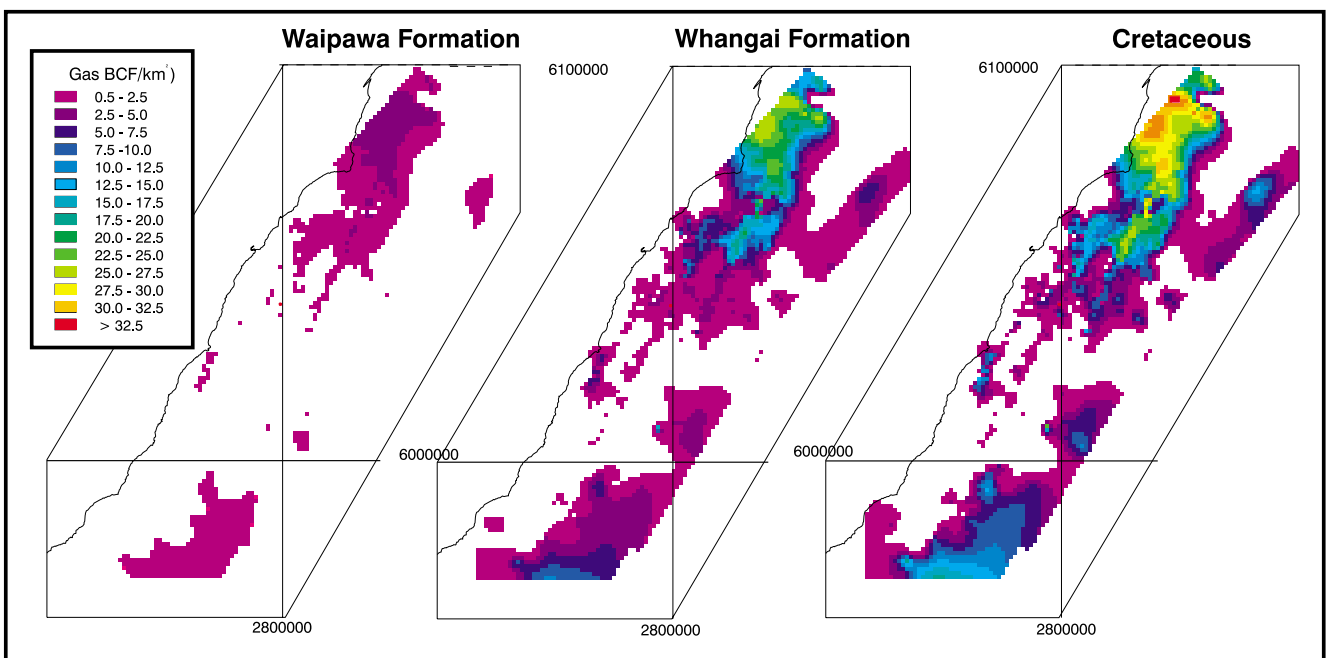


Figure 4. Predicted cumulative volumes of gas generated and expelled from the three modelled source rock intervals, up to the present day. Volumes are presented in BCF / km².

The predicted volumes of oil expelled from the postulated Cretaceous source rocks are high and may reflect optimistic source rock properties; notably thickness and productivity. However, the values given in Table 1 and 2 provide a means to re-assess volumes and quantify the relative importance of different source rocks. Kitchens are present in the north and south of the region, with all modelled source rocks over-mature for oil generation in the deepest sections of both kitchens. Gas generation is primarily in the more deeply buried northern kitchen, where all source rocks span the gas window with maturity based on depth of burial.

Structures and charge

A west to east cross-section through the Titihaoa-1 well is presented in Figure 5. Excess pressure increases rapidly within and beneath the Eocene smectite-rich mudstones during the Miocene. Overpressures developed within and beneath the Eocene seal rocks, equivalent to 11-16 ppg mud, are critical in the development of migration channels and are important in the redistribution of expelled petroleum. For this model, these thick mudstone seals overlying the Paleocene to Cretaceous source rocks effectively trap all oil generated and expelled from source. During further burial in the Late Miocene the trapped oil is cracked to gas in the more deeply buried parts of the section. In this model, gas

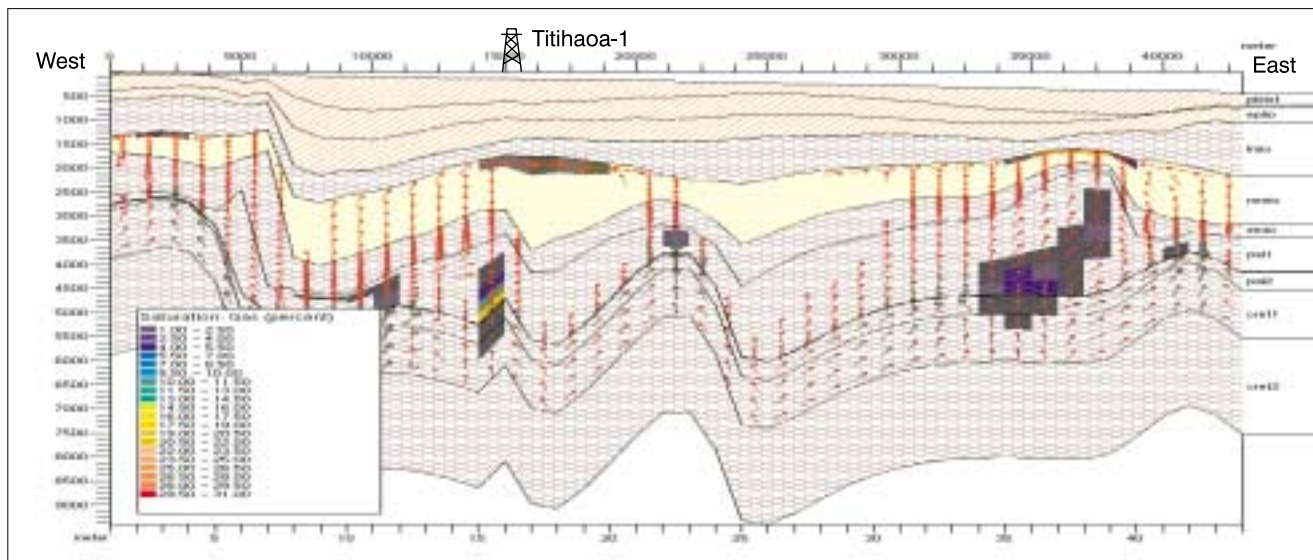


Figure 5. Cross-section WE1 showing levels of modelled gas saturation and migration directions of oil (green arrows) and gas (red arrows). Lithologies are siltstone (orange diagonal lines) for Plio-Pleistocene, sandstone for Middle Miocene (yellow), and shale or mudstone (brown dashed lines) for Paleogene, Cretaceous and Late and Early Miocene. See Figure 1 for location.

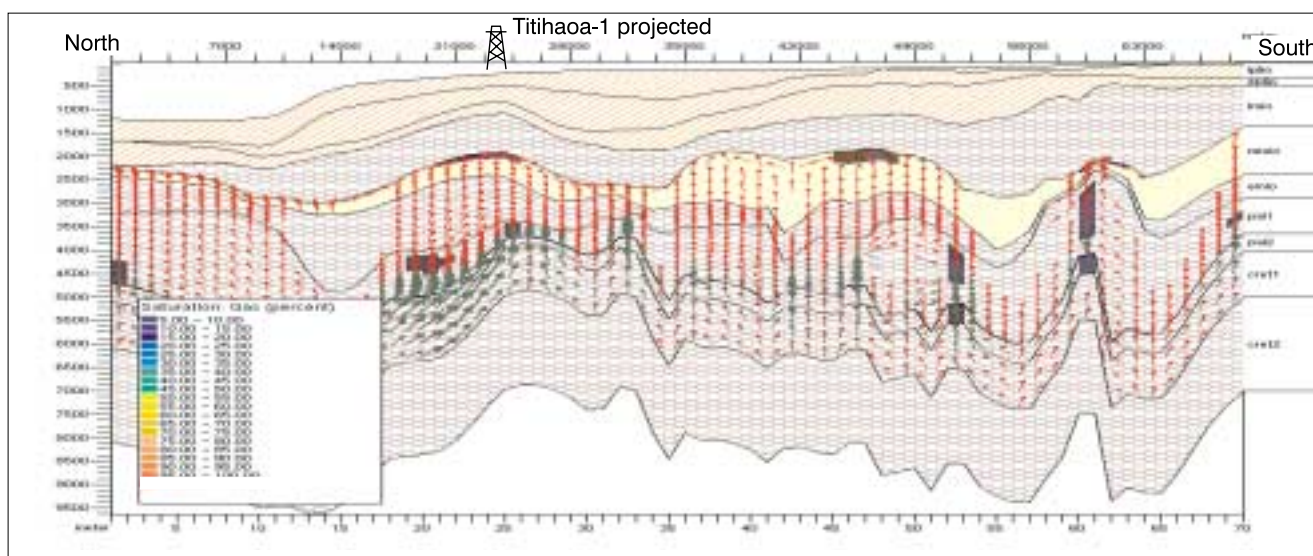


Figure 6. Cross-section NS1 showing levels of modelled gas saturation and migration directions of oil (green arrows) and gas (red arrows). Lithologies are as given in Figure 5. Note projected location of Titihaoa-1 well from location diagram in Figure 1.

migrates vertically through the Eocene mudstone seals although the rate of migration is critically dependent on adopted seal-rock properties. Any gas that is able to migrate through this seal prior to the development of the upper Late Miocene seals is modelled to be lost to the system. Since Late Miocene time, gas is then predicted to accumulate in the Middle Miocene reservoirs. Gas tends to migrate vertically and be focussed into the Miocene sands through sub-seal leak points, although some control may be expected through the development of fractures or fault-related damage zones (neither of which is included in the model).

Figure 6 presents the north-south oriented cross-section through the Titihaoa-1 well. As in Figure 5, any expelled oil is trapped within and beneath the Eocene thick mudstones and is cracked to gas with further burial. The development of thrust ridges in the north and south of the study area effectively compartmentalises the drainage areas, creating a focus for migration through overlying seals. In the case where

depocentres are inverted, as in the north, gas-saturated sands and shales are brought to relatively shallow depths. The high gas-saturation close to the surface within these anticlinal cores, in combination with possible fracturing, is likely to lead to seal breaching and surface gas seepage.

Deep sands in the Paleogene and Cretaceous sediments are modelled to reach high gas saturation and their presence significantly modifies the pattern and timing of migration. Any increase in permeability of Paleogene and Cretaceous sediments generally increases the degree of horizontal migration, tending to focus oil and gas along axes of structural highs. There is a commensurate reduction in vertical migration into Miocene sands.

In Figure 6 gas-saturation levels within the Middle Miocene sands at the Titihaoa-1 well location are predicted to be 30% using the three source rocks detailed above. Models run using only the Waipawa and Whangai formation source

rocks present a similar pattern to oil and gas distribution, although saturation levels are much smaller; gas saturation in the Titihaoa-1 well location Middle Miocene sands is 3%.

The migration modelling presented here is poorly constrained. However, the models provide insights into the East Coast petroleum system, confirm the hydrological importance of the Eocene / Paleocene seals, and the likely requirement for deep Cretaceous source rocks to account for the high gas saturation encountered in the Titihaoa-1 well. Models suggest that high gas saturation exist within Miocene sandstones in other structural closures.

Conclusions

The models presented provide some insight into important controls on generation and migration processes in the offshore Wairarapa region of the East Coast Basin. In conclusion modelling predicts that:

- Whangai and possible Cretaceous source rocks, which are modelled as relatively lean, possess a significant expulsion risk since oil saturation may not reach levels required for expulsion. Any oil retained in the matrix is likely to be subsequently cracked to gas following further burial.
- Large petroleum kitchens exist in the north and south of the study area, which have generated large quantities of oil and gas in the Paleogene and Early Miocene.
- Initiation of subduction causes a reduction in generation rates from all source rocks, a deepening of the oil and gas windows, and is primarily responsible for structural development of potential petroleum traps.
- The Eocene mudstones form seals that are important migration barriers with any expelled oil remaining trapped within and beneath these smectite-rich seals.
- The preferential migration of gas through seals, into overlying Miocene sands is controlled by sub-seal leak points based on existing structure.
- Sub-seal sands in Paleocene and Cretaceous sediments are a critical element of the model - effectively removing any migrating oil and gas from many pathways into Miocene sands and modifying the overall pattern and timing of migration.
- Thrust development causes the compartmentalisation of drainage areas and remigration of hydrocarbons with likely breaching of traps near the surface. Where seals are intact, oil is predicted to remain trapped at deeper level in the cores of the anticlines.

While we model large-scale losses - through residual saturation and losses to surface- there is clearly the potential for large gas accumulations in Miocene traps. However, more detailed input is required for modelling and subsequent evaluation of any prospect specific studies.

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