Overpressures in the Taranaki Basin: Distribution, causes, and implications for exploration

Mark Webster, Stephen O'Connor, Bitrus Pindar, and Richard Swarbrick

ABSTRACT

Analysis of subsurface pressure data from Taranaki Basin using direct (e.g., repeat formation tester) and indirect measurements (drilling parameters and wireline log data such as sonic and resistivity) indicates the presence of three pressure zones: a near-hydrostatic regime (zone A) that extends across the entire basin and to varying depths; an underlying overpressured regime (zone B), with pressures approximately 1100 psi (7.584 MPa) above hydrostatic, that extends throughout the Manaia graben and north along the eastern basin margin at depths of 1900 to 4100 m (6234–13,451 ft); and a third regime (zone C), with approximately 2100 psi (14.479 MPa) overpressure, that directly underlies zone A and zone B in different parts of the basin (although well penetrations are limited). The primary cause of overpressure is interpreted to be disequilibrium compaction preserved in upper Eocene and Oligocene marine shales. In parts of the basin, hydrocarbon generation (and in particular cracking to gas at high maturities) is interpreted to contribute to overpressures. The overpressures drain laterally and vertically into permeable units. Intervening transition zones (seals) comprise lithologic boundaries, diagenetic zones, and fault planes. Oligocene carbonates, although commonly thin, provide an effective barrier to vertical hydraulic communication over much of the basin. The Manaia graben is a partially closed system, with overpressures retained by a complex combination of a top shale seal overlying a regional sequence boundary, lithologic barriers within fault compartments, fault planes, and subcropping sequences; episodic fault breach enables vertical transfer of fluids from zone B to zone A in a dynamic fault valve process. To date, all oil reserves have been

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AUTHORS

Mark Webster ~ *Genesis Energy, P. O. Box 10568, The Terrace, Wellington, New Zealand; mawebster@paradise.net.nz*

Mark Webster is gas exploration manager at Genesis Energy. Since graduating from Victoria University in Wellington in 1982, he has worked for a variety of companies in exploration programs in New Zealand, Australia, Thailand, Philippines, Malaysia, and Canada, including roles as chief geologist at Petrocorp Exploration and exploration manager at Santos and TAG Oil. He is a member of the Petroleum Exploration Society of Australia and has been a member of AAPG since 1982.

Stephen O'Connor ~ *GeoPressure Technology Mountjoy Research Centre, Stockton Road, Durham DH1 3UZ, United Kingdom; s.a.oconnor@geopressure.co.uk*

Stephen O'Connor is technical manager at GeoPressure Technology (Ikon Science Group), supervising pressure projects around the world, including Europe, Black Sea, West Africa, and Trinidad. He specializes in producing pore and fracture pressure profiles using direct pressure measurements, petrophysical logs, and seismic velocity data for use in well planning, as well as both field and regional studies. He holds a B.S. degree in geological sciences from Leeds University and an M.S. degree from Reading University (Sedimentology).

Bitrus Pindar ~ *GeoPressure Technology Mountjoy Research Centre, Stockton Road, Durham DH1 3UZ, United Kingdom; bpindar@ikonscience.com*

Bitrus Pindar is currently a petroleum geoscientist at Geopressure Technology Limited. Before joining GeoPressure Technology, he served as a regional geologist at the Nigerian Geological Survey Agency, Abuja. He holds a B.S. degree in geology from the University of Maiduguri and an M.S. degree in petroleum geoscience from Imperial College London. He is a member of AAPG and Petroleum Exploration Society of Great Britain.

Richard Swarbrick ~ *GeoPressure Technology Mountjoy Research Centre, Stockton Road, Durham DH1 3UZ, United Kingdom; r.e.swarbrick@geopressure.co.uk*

Richard Swarbrick holds a Ph.D. in sedimentology/tectonics from Cambridge University and commenced his career in 1979 when he joined Mobil, with assignments in the United Kingdom and the United States. He joined Durham University in 1989 and was a principal investigator for a multidisciplinary research group funded by 17 oil and gas companies. During that period, he developed training courses in subsurface pressures and founded the company GeoPressure Technology. He is an honorary professor at Durham University and has been an AAPG member since 1982.

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found in zone A, a large proportion of gas-condensate reserves are within zone B, and no commercial reserves have been established within zone C. The spatial definition of these zones and the appropriate pressure regime is important for well design, drilling safety, determining hydrocarbon column heights and gas expansion factors, and for exploration migration analysis. Regional analysis of pressure regimes can identify subsurface barriers and seals. Faults, in particular, are key elements in fluid migration and the focusing of liquids at abrupt pressure transitions. The strength of fault planes and diagenetic zones is the likely control on dynamic fluid release. Zone C has been very lightly explored and may represent a potential for large dry-gas accumulations; the zone may be sealed by a diagenetic zone crosscutting lithologic boundaries (conventional mapping horizons).

INTRODUCTION

Overpressure has been documented in the Taranaki Basin from the earliest deep exploration wells (Shell BP Todd Oil Services Limited, 1959) and has subsequently been encountered over a wide area and a range of depths within the basin (Webster and Adams, 1996; Darby et al., 2000; Shell Todd Oil Services Limited, 2002; Lowry, 2006). Historically, the main interest in overpressure has been as a drilling hazard, typically associated with tight hole or well control incidents, such as the downhole blowout in McKee-13 (Brash, 1995), or as evidence of effective seal in exploration evaluations (Sphere Consulting Ltd., 2000). Overpressures, however, also provide important insights for understanding subsurface fluid flow (both lateral and vertical) and in the identification of hydraulic baffles or seals.

The Taranaki Basin has many of the attributes that are known to contribute to the development and redistribution of overpressures in sedimentary basins:

1. Periods of rapid subsidence and high sedimentation rates
2. Active tectonics, including several uplift episodes and extensive faulting
3. Prolific gas generation in low-permeability fluviodeltaic sequences
4. Horizontal stress associated with the basin's proximity to an active convergent plate margin

This study uses a combination of direct pressure measurements, such as repeat formation tester (RFT) data, to establish sand and reservoir pressures and porosity-based pressure prediction

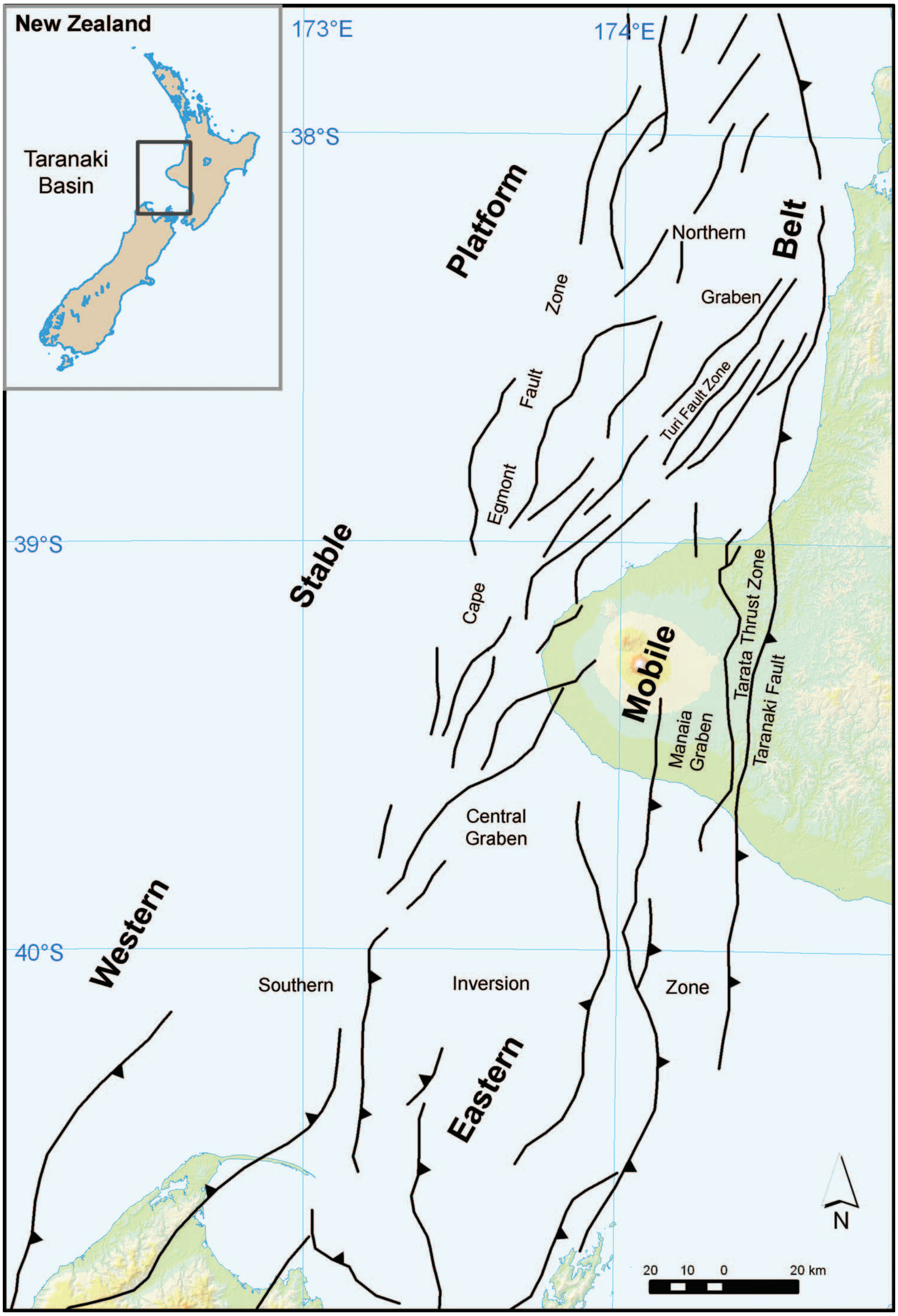


Figure 1. Taranaki Basin location map and structural elements.

techniques in shales to geospatially map the overpressure distribution in the Taranaki Basin. Only through integration of these techniques (as well as drilling parameters and responses) can a clear understanding of sand and shale pressure equilibria emerge. Once established, we examine the evidence for each of the potential causes of overpressure generation to establish the primary controls on distribution of overpressures and the resulting implications for exploration and production.

REGIONAL GEOLOGY

Taranaki Basin is an onshore and offshore Cretaceous–Tertiary basin located on the west coast of New

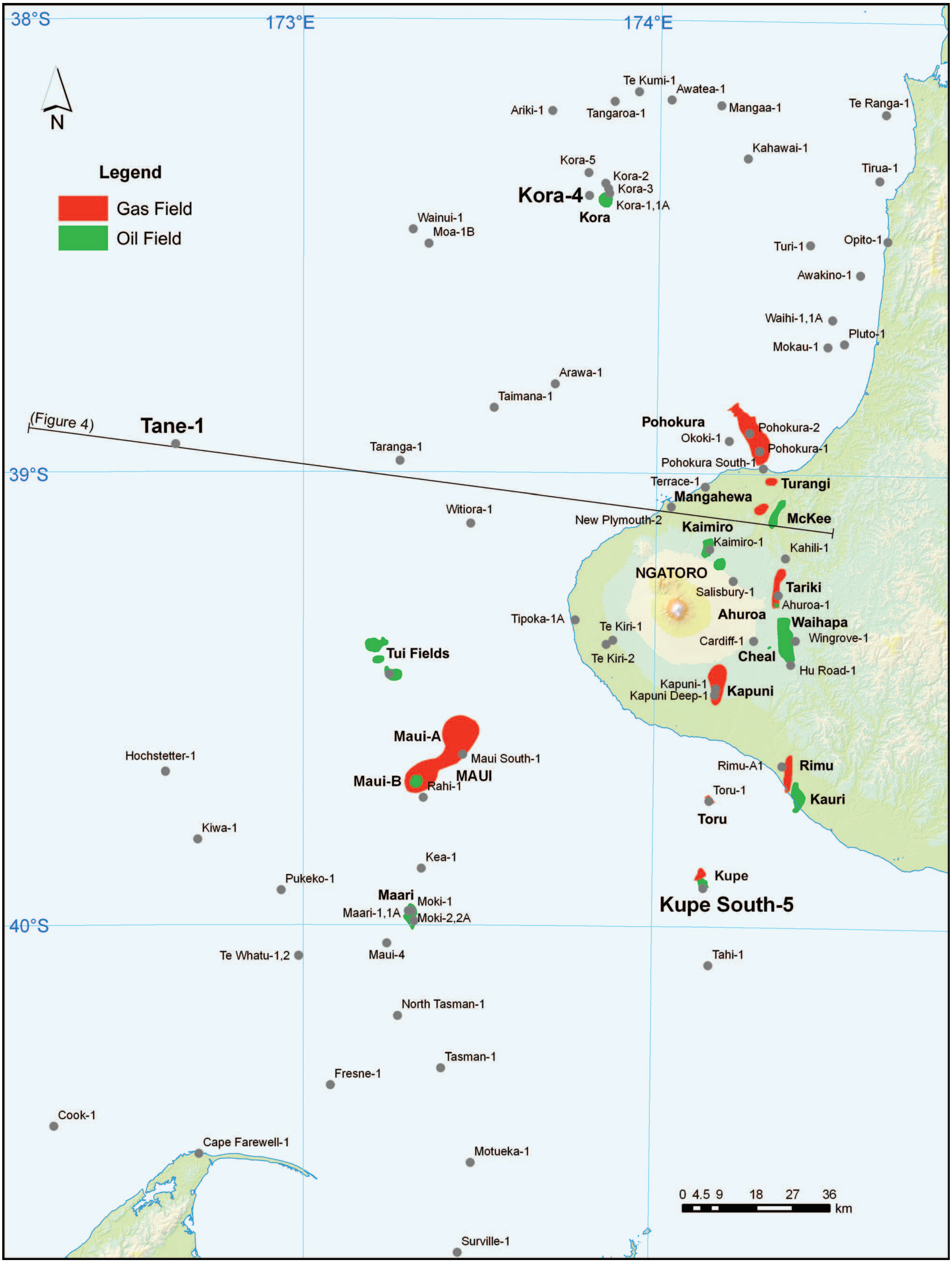


Figure 2. Taranaki Basin map showing fields, key wells, and location of section in Figure 4.

Zealand (Figure 1). The basin covers an area of approximately 100,000 km^2 and contains up to 9 km (5.6 mi) of sediment. Structurally, the basin can be divided into a stable and relatively undeformed block (the western platform) and an intensely deformed area termed the eastern mobile belt (comprising the southern inversion zone, Central graben, Manaia graben, and Northern graben of King and Thrasher, 1996). The eastern mobile belt contains a variety of compressional structural features, including reverse faults, inversion structures, and overthrusts, which formed during the Miocene. The basin contains total discovered reserves of approximately 1.8 billion bbl of oil equivalent in 33 pools (Figure 2) of which 70% (7.2 tcf) is gas. Most of the reserves are contained in Paleocene and Eocene fluvial and paralic reservoirs. The main trap styles are inversion anticlines, fault-dependent closures, and overthrusts. A total of approximately 220 true exploration wells have been drilled.

The structural history, stratigraphy, and petroleum system elements of the Taranaki Basin have been comprehensively documented by previous authors (Palmer and Bulte, 1991; Palmer and Andrews, 1993; King and Thrasher, 1996; King and Funnell, 1997; Wood et al., 1998; Crown Minerals, 2000, 2004; Hill et al., 2004; Stagpoole et al., 2004). The basin history is summarized, and a stratigraphic column for the basin is included as Figure 3. A series of palinspastic reconstructions is included as Figure 4.

The Taranaki Basin was initiated as a series of isolated fault-bounded rift graben during the Late Cretaceous (ca. 85 Ma), associated with the opening of the Tasman Sea (Norvick et al., 2001). The synrift sequence comprises nonmarine and deltaic conglomerates, sands, silts, and coal measures of the Pakawau Group. These coal measures are the interpreted source for the discoveries in the west of the basin, including the Maui, Maari, and Tui fields (Killops et al., 1994; Funnell et al., 2004).

Following a marine transgression during the Late Cretaceous to early Paleocene, when rift valleys were progressively inundated and drowned, regional depositional systems were established as the basin developed into a postrift passive margin. A major delta system (Kapuni Group) was established, fed from the south and with a variably west-east– and southwest-northeast–trending coastal system (Matthews and Lewis, 2001). Prodelta shales (Turi Formation) were deposited to the north and northwest. Well-sorted sands within this coastal fairway (known as the F sands, D sands, C sands, McKee sands, and equivalents) are reservoirs for major fields (Maui, Pohokura, Tui, McKee). Thick coal measures were developed within preexisting graben areas in the east and are the source of the major onshore oil fields (Killops, 1996; Webster and Adams, 1996). Fluvial sediments of the Kapuni Group (Farewell, Kaimiro, and Mangahewa formations) are the reservoirs for the Kupe, Kapuni, Mangahewa, and Turangi gas condensate fields (K1A and K3E reservoir nomenclature used in this article refers to intra–Mangahewa Formation reservoirs in the vicinity of Kapuni field).

The onset of compressional tectonics during the late Eocene to early Oligocene, related to the development of the convergent plate margin, is reflected by a widespread sequence boundary in the eastern mobile belt. Paleocene and Eocene sediments were eroded from the south and transported into the basin to be redeposited as a series of bathyal basin floor fans (Tangaroa Formation) lying on a correlative conformity in the north of the basin (Gresko et al., 1994).

A foredeep developed during the Oligocene, although structuring did not intensify until the Miocene. A wedge of calcareous mudstones, marls, limestones, and submarine fans (comprising reworked Kapuni Group sediments from the east) were deposited in the foredeep, whereas on the western platform, this period is represented by a condensed section. The foredeep fans (Tariki Sandstone) are the reservoirs in the Tariki and Ahuroa gas condensate fields, and a fractured Oligocene limestone (Tikorangi Formation) is the reservoir in the Waihapa oil field.

Compression increased during the Miocene, and a series of transpressive inversion structures and overthrusts developed. A thick sequence of clastics (Wai-iti Group) was deposited, comprising bathyal mudstones (Manganui Formation), slope mudstones (Urenui Formation), and slope and basin floor fans (Mount Messenger and Moki formations). The thick Moki Formation turbidites are the reservoir in

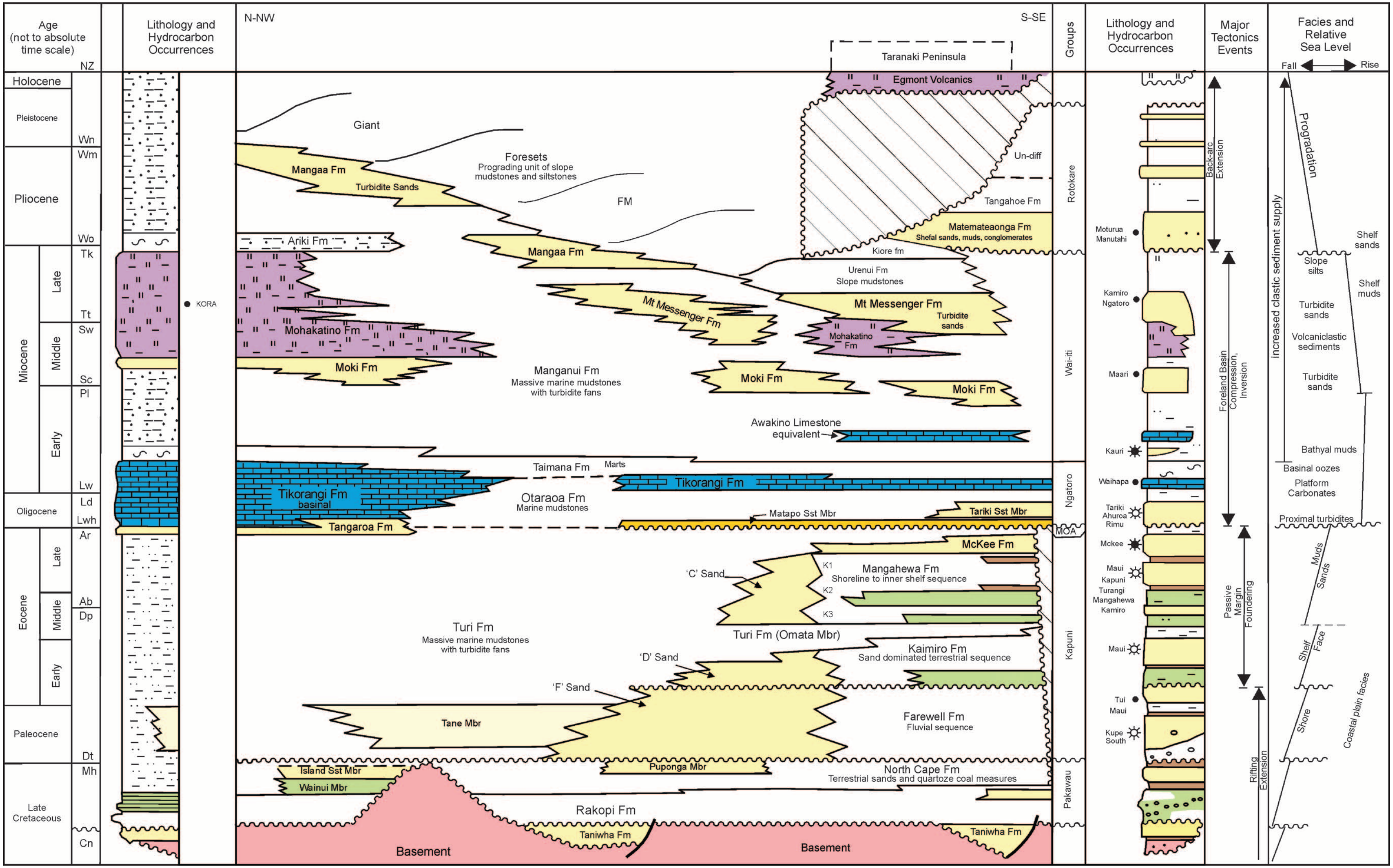


Figure 3. Taranaki Basin summary stratigraphic chart (modified from King and Thrasher,1996; reprinted with permission). New Zealand stage names: Cn = Ngaterian; Mh = Haumurian; Dt = Teurian; Dp = Porangan; Ab = Bortonian; Ar = Runangan; Lwh = Whaingaroan; Ld = Duntroonian; Lw = Waitakian; Pl = Altonian; Sc = Clifdenian; Sw = Waiauan; Tt = Tongaporutuan; Tk = Kapitean; Wo = Opoitian; Wm = Mangapanian; Wn = Nukumaruan.

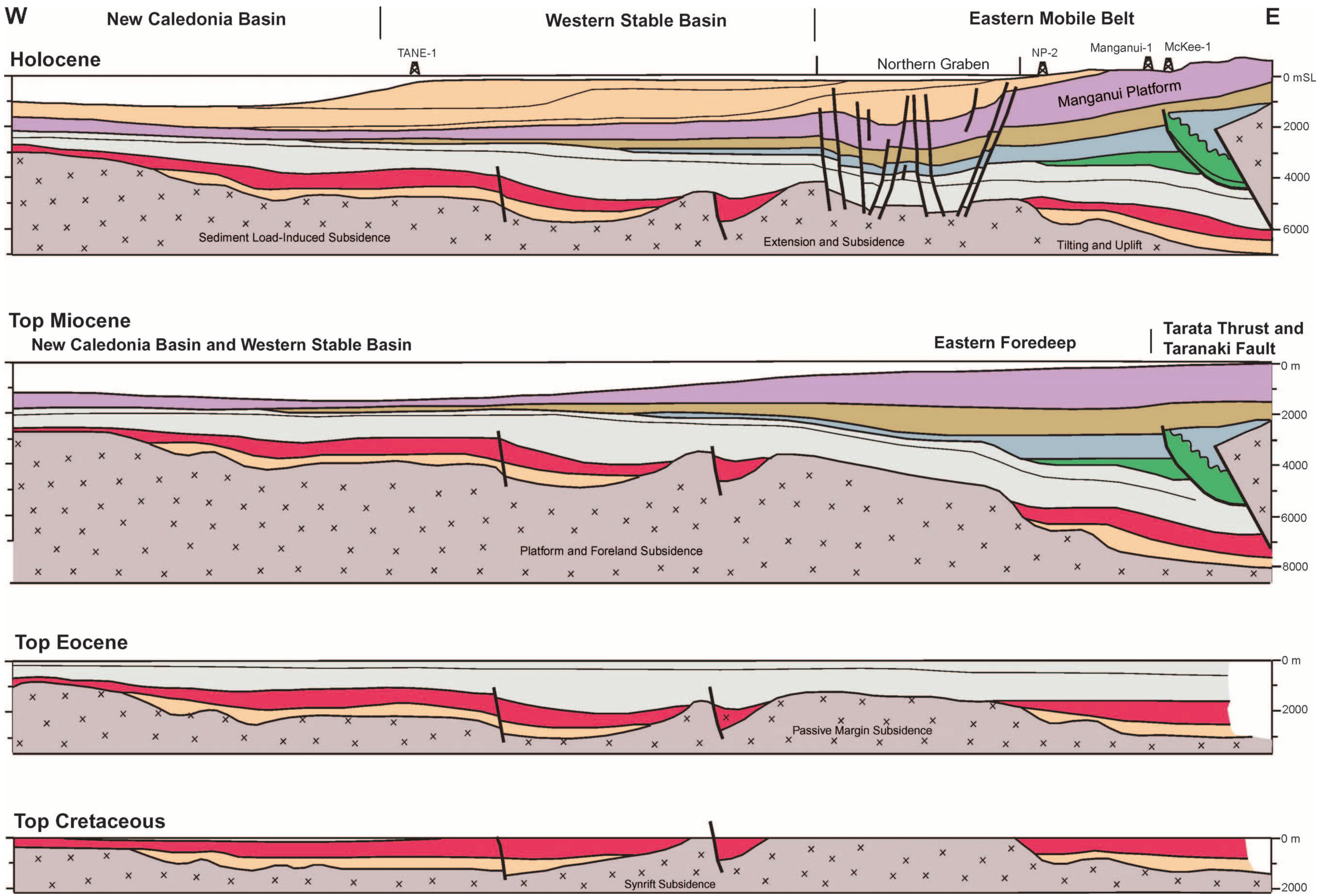


Figure 4. Regional palinspastic cross section across Taranaki Basin illustrating basin development (from King and Thrasher, 1996, used with permission; Hill et al., 2004). Location of section shown on Figure 2.

offshore Maari oil field, whereas the thinner channel levee and slope deposits of the Mount Messenger and Urenui formations are the reservoirs in the onshore Kaimiro, Ngatoro, and Cheal oil fields. In the northern graben, a series of andesite volcanoes developed, and volcaniclastic sediments (Mohakatino Formation) were deposited; these are the reservoir for the Kora oil discovery.

A second major uplift event occurred during the late Pliocene–Pleistocene, caused by wrench tectonics associated with back-arc extension. With accelerated uplift of the sediment source area along the Alpine fault in the South Island, a thick sequence of clastics was then deposited as a prograding wedge (Matemateaonga, Kiore, and Giant Foresets formations), as the shelf edge migrated to the northwest. The Giant Foresets Formation is up to 2000 m (6562 ft) thick on the western platform. Exhumation and volcanism occurred in the last 2 m.y. (Armstrong et al., 1998) with up to 1800 m (5906 ft) of erosion in onshore eastern Taranaki Basin and the development of the prominent (2518-m [8261-ft] elevation) andesite cone of Mount Taranaki.

DETERMINATION OF OVERPRESSURE

Direct Measurement

Pore pressures can be measured directly in permeable lithologies using wireline RFT (modular dynamic tester [MDT]) or drillstem test (DST) tools. The RFT and MDT data have been compiled from approximately 40 exploration and appraisal wells in the basin for this study; these have been complemented with DST data from 19 wells and original aquifer pressure measurements from key fields. A summary plot of water pressure measurements for Taranaki Basin, referenced to a freshwater hydrostatic gradient of 0.434 psi/ft (9.817 MPa/km), and a sea level datum, are included as Figure 5. Also displayed for reference is a lithostatic gradient of 1.0 psi/ft (22.621 MPa/km), which approximates the vertical (overburden) stress pressure gradient.

Wireline pressure measurements have been validated, using mud logs, petrophysical evaluations, and fluid gradients, to identify and remove the following, so that only valid aquifer pressures were used:

1. Hydrocarbon effects, that is, the effects of hydrocarbon buoyancy
2. Supercharging and seal failures
3. Depletion associated with nearby production from connected reservoirs (examples included Kahili-1 Tariki sands, Cardiff-1 McKee and K1A sands, Tui-1 D sands).

The DST data (Prasser et al., 1997; Adams, 1999) were similarly screened to exclude hydrocarbon zones or erroneous data. The DST database comprises pressures derived from tests with water flows, water recoveries, and in some cases, low-rate gas flows where petrophysical evaluation indicated high water saturations in the reservoir.

In the case of some older fields where RFT data were not acquired, aquifer pressures have been derived from early production data or inferred by extrapolating measured hydrocarbon gradients to a known oil-water contact or gas-water contact. In the absence of direct aquifer pressure measurements, these pressures are likely to be a little higher than at the free water level because of capillary effects.

The variations in depth and magnitude of overpressures recorded to date in the basin are illustrated in Figure 5, which shows the following:

- Pressures above the hydrostatic pressure (i.e., overpressure) are not simply depth dependant. Hydrostatic pressures have been measured down to 4117 m (13,507 ft) true vertical depth subsea (TVDSS) offshore (Pukeko-1) and 3997 m (13,114 ft) TVDSS onshore (Te Kiri-2), whereas significant magnitude of overpressure has been measured as shallow as 1934 m TVDSS onshore in the overthrust trend (ToeToe-2 in McKee field).
- Overpressures are not restricted to specific stratigraphic intervals. Cretaceous, Paleocene, and Eocene reservoirs on the western platform are normally pressured (Tane-1, Maui field, Pukeko-1, Tui-1), whereas equivalent intervals in the eastern mobile belt are typically (but not always) overpressured.

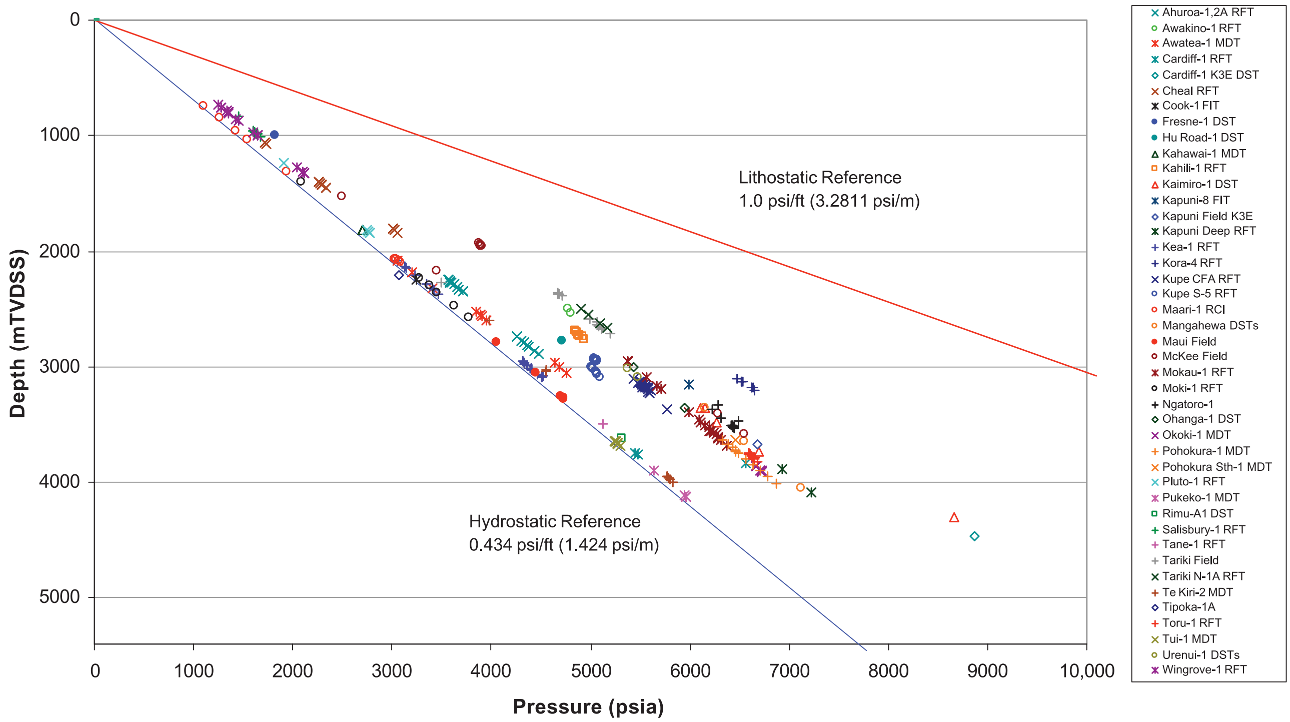


Figure 5. Summary pressure-depth plot, Taranaki Basin. Depth scale is meters true vertical depth subsea (mTVDSS). DST = drillstem test; MDT = modular dynamic tester; RFT = repeat formation tester.

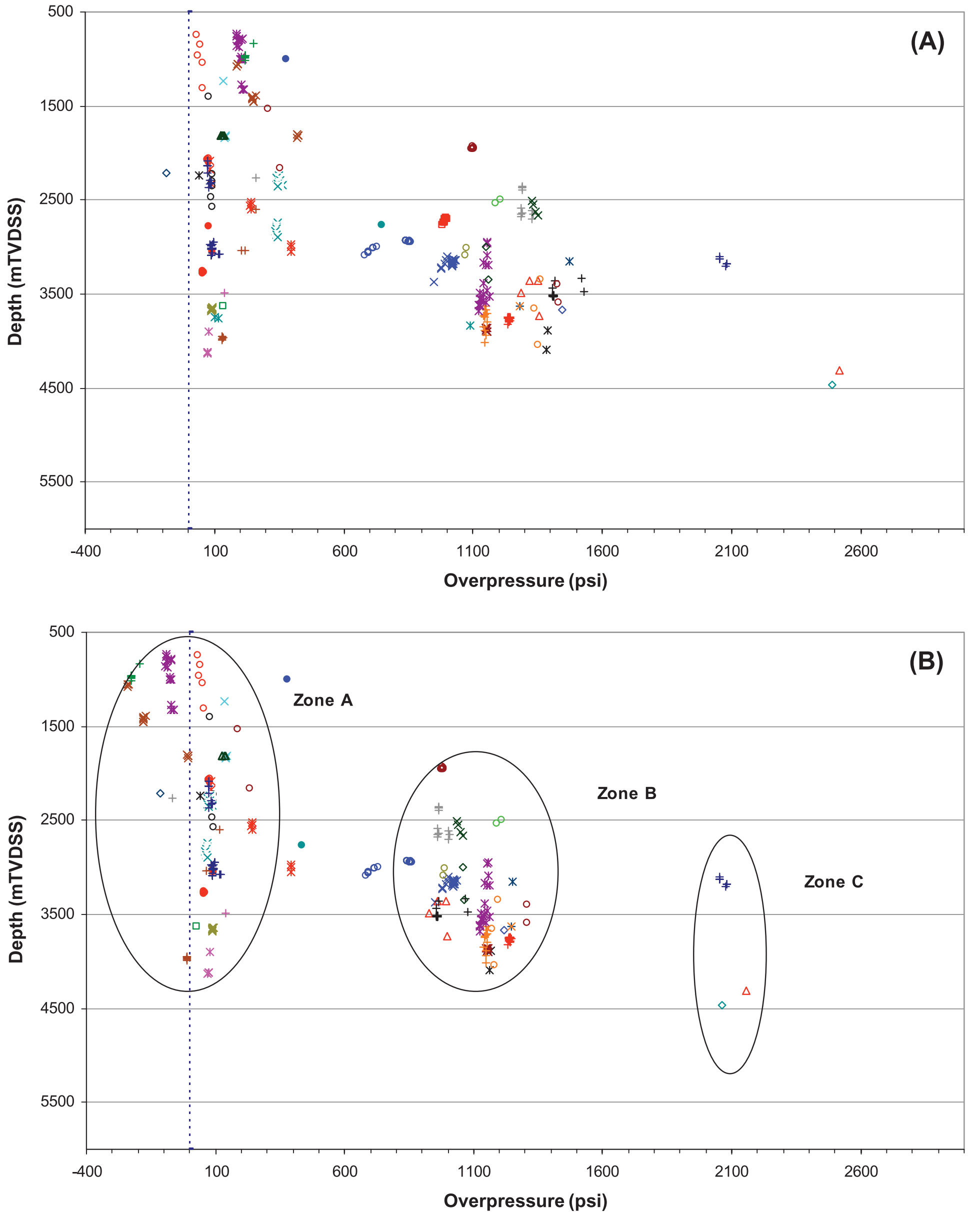
- Although most of the overpressures are between 400 psi (2.758 MPa) and 1600 psi (11.032 MPa) above a hydrostatic gradient, notable exceptions exist at Kora, Cardiff, and Kaimiro-1, where significantly higher overpressures (of up to 2500 psi or 17.237 MPa above hydrostatic) have been measured.
- Pressure gradients are parallel to hydrostatic.

Overpressures (and underpressures), calculated relative to a freshwater hydrostatic gradient (0.434 psi/ft [9.817 MPa/km]), and a sea level datum are shown as Figure 6A. Pressures from onshore wells were then corrected for water table depths (using water well data provided by the Taranaki Regional Council) and the calculated overpressures are shown in Figure 6B. All offshore wells are in less than 160 m (525 ft) water depth, so no corrections have been made for deep water.

The plot of overpressures (Figure 6B) shows the following:

- Pressures fall into three distinct populations: a cluster around a hydrostatic gradient (i.e., zero overpressure), a second group clustered around 1100 psi (7.584 MPa) overpressure, and a third group clustered around 2100 psi (14.479 MPa) overpressure.
- These distinct populations are interpreted to reflect discrete pressure zones or compartments (Webster and Adams, 1996), separated by transition zones (seals or baffles) and are here termed zones A, B, and C.
- Points falling between zone B and zone A can be explained by production-related depletion (Cardiff K1A, Kahili-1) or pressure loss through stratigraphic baffles (Kupe South-5), indicating lateral drainage. Awatea-1 is a notable exception and is interpreted to reflect disequilibrium compaction in rapidly deposited Pliocene fan deposits (Murray and de Bock, 1996).
- Shallow onshore reservoirs in Wingrove-1, Salisbury-1, and Cheal wells seem to be underpressured once water table elevation corrections have been applied. These data must, however, be treated with caution given the ground-level elevation (200–300 m [656–984 ft]) relative to reservoir depth (900–1500 m [2953–4921 ft]

Figure 6. (A) Summary overpressure plot, Taranaki Basin; (B) overpressure plot corrected for onshore elevations, Taranaki Basin. Well symbols as used in Figure 5. mTVDSS = meters true vertical depth subsea.



below ground level) and the uncertainty in water table elevation assumptions because of incomplete data and seasonal variations.

Mud Weights

In the absence of direct pressure measurements (which can only be taken in permeable horizons and therefore give indication of sand and reservoir pressures only) in fine-grained lithologies, anomalous pore pressures are more difficult to detect and then quantify. Mud weights are, however, commonly used as a proxy for pore-fluid pressures, using the assumption that mud weights are kept in balance or at slightly greater pressures than pore-fluid pressure. Mud weights can be used as a proxy for pore pressures in permeable intervals where no kicks or losses are encountered, because the mud weights in this scenario provide at least a guide to maximum pore pressures. Mud weight cannot, however, be used as a reliable direct guide to pore pressure in fine-grained lithologies because the low permeabilities mean that these intervals can commonly

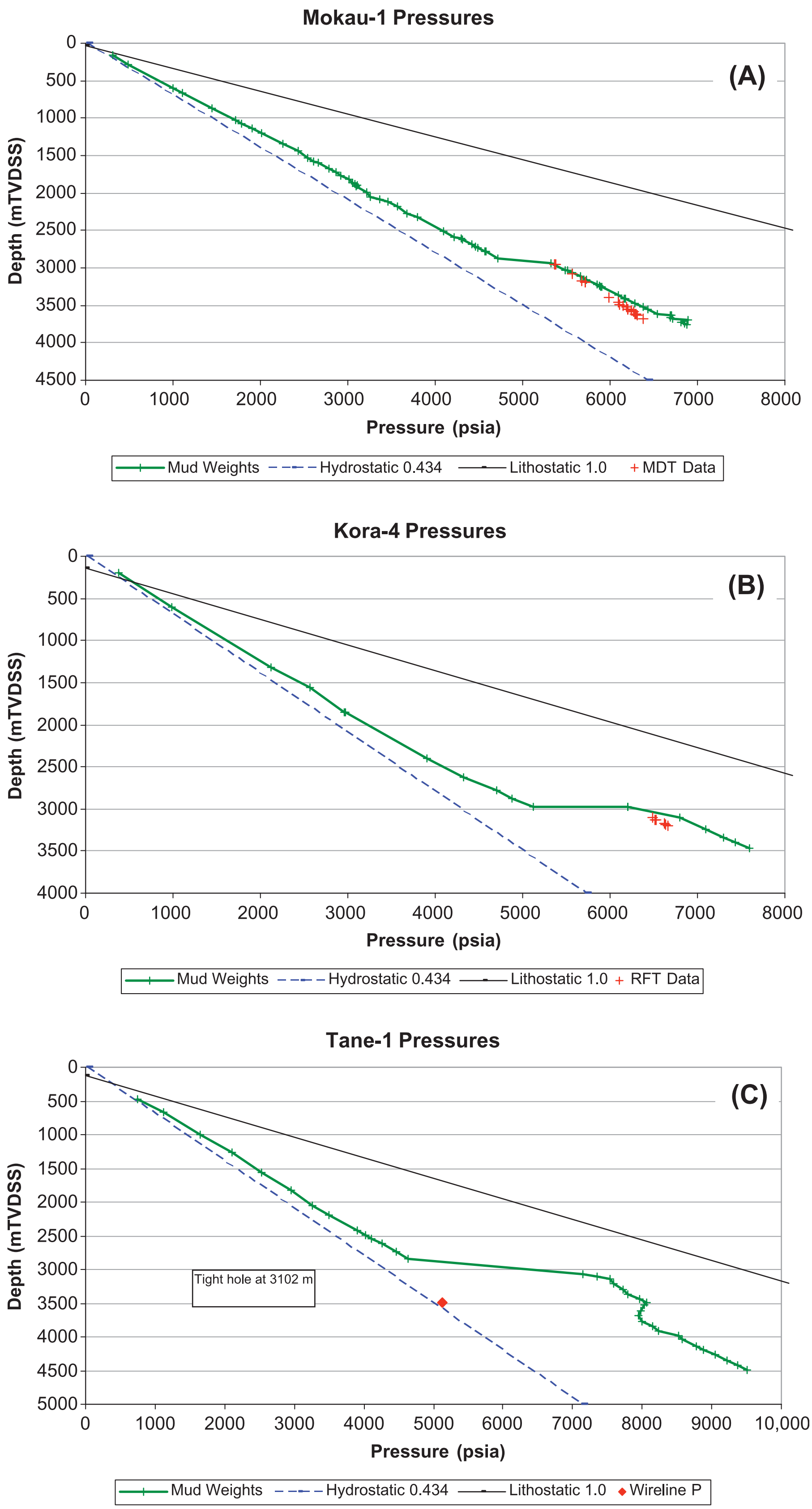


Figure 7. Examples of mud weights and measured pressures in (A) Mokau-1, (B) Kora-4, (C) Tane-1. MDT = modular dynamic tester; mTVDSS = meters true vertical depth subsea; RFT = repeat formation tester.

be drilled underbalanced (and, of course, overbalanced), which may go undetected. Drilling responses such as the *d* exponent, increasing connection gas, and cavings can be used as indirect measurements of overpressuring. An increase in connection gases, for instance, suggests that the pore pressure in the formation is exceeding the mud weight, allowing the formation to de-gas.

Mud-weight data from approximately 50 wells in the Taranaki Basin, approximately 35 of which have complementary pressure data (either RFT or DST), have been analyzed to identify the onset of overpressuring. In some cases, a good agreement is observed between mud weights and measured pore pressures (e.g., Mokau-1, Kora-4, Figure 7A, B), whereas in others, an apparent discrepancy exists between the pressures indicated by mud weight and the pressures measured in sands (e.g., Tane-1; Figure 7C). In some cases, very high mud weights have been used in response to drilling difficulties, occasionally exceeding the fracture gradient and resulting in lost circulation (e.g., Tipoka-1A). In addition, in anticipation of overpressures, some wells have been drilled highly overbalanced as a precautionary measure (e.g., Terrace-1) without confirming whether abnormal pore pressures are actually present, and no interpretation can be made of the pressure regime from drilling data in wells such as these.

Wireline Methods

Wireline logs provide a third technique to identify overpressuring and also provide a means to identify the likely cause(s). Methods for predicting pore pressures exploit the deviation of shale properties (e.g., sonic velocities, density, and resistivity data) relative to those values typical of a normally compacting sequence at the depth of interest. Overpressures generated by disequilibrium compaction (undercompaction) are associated with anomalously high sediment porosities (Hubbert and Rubey, 1959). The method exploits the relationship between compaction state and stress. In rapidly subsiding basins with low-permeability sediments (shales), fluid is unable to escape and overpressure progressively develops as a part of the total vertical stress is transferred to the fluids. Porosity is a direct measurement of compaction and enhanced porosity for depth of burial by undercompaction can be used to assess pressure in these shales. Porosity is being used as a proxy for vertical effective stress such that pore pressure can be estimated from the equation (below) of Terzaghi (1943) if the vertical stress is known.

$$S_v = \sigma' + P_p$$

Rearranged to give the pore pressure:

$$P_p = S_v - \sigma'$$

where P_p = pore pressure (psi); S_v = overburden pressure or vertical stress (psi); σ' = vertical effective stress (psi).

Velocity is one of the responses to pressure that is measured routinely both in wells and in seismic data (as interval velocities). Seismic velocity analysis has been previously applied successfully in the Taranaki Basin to predict overpressures (Humphris and Ravens, 2000). A selection of wells from different geologic provinces within the basin was used for petrophysical evaluation of overpressures in shales; these wells were selected on the basis of having a combination of high-quality wireline suites, direct pressure data, and mud-weight data. Ancillary data, such as temperature, stratigraphic information, composite logs, and drilling reports were also analyzed to reconcile with any shale pressure profiles produced.

The sonic log can be used to detect porosity variation in the subsurface, although the tool can be susceptible to textural changes in the rocks (Hermanrud et al., 1998; Tingay et al., 2009). The density log is a "bulk" log and thus can be a more reliable indicator of actual porosity but is commonly run only over limited depth intervals. In this study, sonic data have been used to detect anomalous porosity and predict shale fluid pressures as the data are available in all wells and provide the greatest depth coverage. Resistivity data were also available in certain wells, although depth coverage was less extensive than for the sonic log.

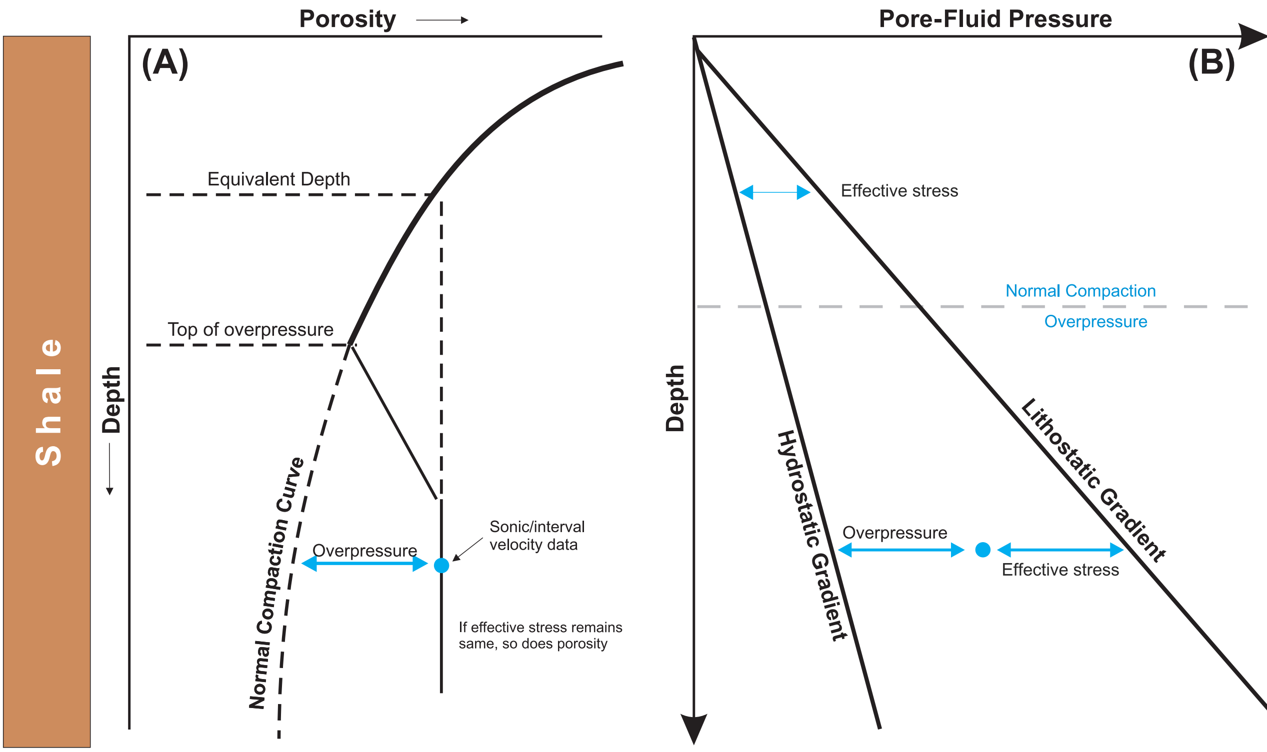


Figure 8. Disequilibrium profiles showing normal and anomalous compaction curves diverging below top of overpressure, below which, porosity loss is inhibited and subsequently ceases (A). Effective stress remains constant in the situation where porosity loss is completely inhibited, typically producing pore-pressure profiles that are parallel to the lithostatic gradient in shales (B). Overpressure also increases with increasing depth.

To quantify the magnitude of pressure from velocity (or other attributes responding to shale porosity), a commonly used approach is the equivalent depth method. The equivalent depth method assumes that porosity relates directly to vertical effective stress. Using this method, for any value of velocity that does not plot on the normal compaction trend (NCT), the pressure can be estimated by projecting the value vertically onto the NCT (in the normally pressured section) on a velocity versus depth plot (Figure 8). The data point is now at its "equivalent depth," where the vertical effective stress (vertical stress minus pore pressure) can be estimated because the rock is considered to be normally pressured, that is, at this depth, the pore pressure is known. Other data types such as density and resistivity were available as well as sonic data for use in this way; however, in the case of density data, the limited depth intervals of data counted against its use. The reliance on the accurate definition of the shallow normally pressured interval using this method meant that resistivity data could not be used because these data are commonly suspect in the shallow section because of lack of temperature correction.

The above pore-pressure technique is valid for shale sequences. Sands do not lend themselves to a similar analysis. However, the combination of direct pressure measurement in sands and pressure prediction in associated shales can indicate whether the sand and shale pressures are in equilibrium. Reservoir pressures are frequently higher or lower than the pressure prediction from the associated shales because of high hydraulic conductivity of reservoir sandstones (and carbonates). Care, therefore, must be exercised in calibration of shale pressure estimates by comparison with reservoir pressures.

This method to estimate pressure from shales assumes that overpressure is generated via undercompaction (disequilibrium compaction), that the rocks are presently at their maximum effective stress, and that the basin is extensional (i.e., maximum stress is vertical). Harrold et al. (1999) highlighted the potential importance of examining the mean stress instead of simply the vertical, and indeed, the eastern mobile belt contains compressional structures (King and Thrasher, 1996). However, use of the vertical stress is widely accepted particularly because of our generally poor constraint on the measurement of horizontal stress magnitudes.

When overpressure occurs from other mechanisms, particularly fluid expansion such as from gas generation, or where recent uplift exists, this method will underestimate the magnitude of the overpressure (Swarbrick, 2002). To identify, if possible, these mechanisms of overpressure generation (in addition to those derived from vertical loading), we have also used velocity/density crossplots that identify such mechanisms as gas generation, where a rapid decrease in grain contact stresses occurs, resulting in velocity reduction for minimal density change (Bowers, 1994) and load transfer (the transformation of framework-supporting grains to porosity and liquid), creating a reduction in velocity and density (Lahann, 2002). For reference, this approach is detailed in Chopra and Huffman (2006).

Several wells in different parts of the basin have been analyzed using wireline data, and results are included here for three key wells: Kora-4, Kupe South-5, and Tane-1 (Figures 9–12; well locations shown in Figure 2).

As previously mentioned, to produce pore-pressure profiles using the equivalent depth method, we need to establish (1) vertical stress (here integrated density data are used instead of the commonly used 1.0 psi/ft) and (2) an NCT or curves based on sonic data (BHC or DT). Because the Taranaki Basin has several distinct structural provinces with contrasting burial, uplift, inversion, and erosion patterns (western platform, Northern graben, Manaia graben, and onshore), different models for vertical stress and compaction were used for each of the key wells or areas.

Data from each of the key wells were integrated with relevant data from other wells in the same structural province to define both the vertical stress and compaction profile. Tane-1, Taranga-1, and Witoria-1 were used for the western platform; Kora-4, Mokau-1, Waihi-1, and Turi-1 for the Northern graben; and Kapuni-Deep, Te Kiri-1, Kaimiro-1, and Kupe South-5 for the Manaia graben and onshore.

Overburden profiles were similar for all wells in the western platform and Northern graben regions. The shallowest subsurface density measurement was extrapolated to the sea bed (mud line) and indicates an initial density of 1.8 to 1.9 g/cc (Figure 9; Tane-1). Density magnitudes increase with increasing depth of burial until approximately 2000 m (6562 ft), below which the density data remain constant at approximately 2.5 g/cc. In the Manaia graben and onshore regions, density data have a magnitude of 2.1 g/cc at the mud line and increase with depth throughout their profiles. Not all wells have complete density coverage, that is, Tane-1 has density data from 500 to 4500 m (1640–14,764 ft) TVDSS, whereas Kupe-South 5 only has density coverage between 2650 and 3100 m (8694–10,171 ft) TVDSS. In these cases, where only a section of a well is logged with density data, data from other wells in the same region have been used to produce a single robust overburden model.

Compaction models were derived in the same manner, that is, using sonic data for a series of wells in a region to produce a model for compaction for the key wells in that region. These models were then applied to produce pressure profiles for the Kora-4, Kupe South-5, and Tane-1 wells. Mud line magnitudes were 180 to 185 μs/ft for the western platform and Northern graben regions, and 140 μs/ft for the Manaia graben and onshore regions (except Kupe-South-5, 180 μs/ft). Anomalously high density and low sonic values at the mud line in the Manaia graben and onshore may reflect uplift in this region (1 km [0.6 mi]) (King and Thrasher, 1996).

Tane-1 was drilled in 123 m (404 ft) water depth on the western platform (Figure 2) in 1976 by Shell BP Todd Oil Services Limited. The objective of the well was to evaluate the reservoir properties and hydrocarbon potential of the Paleocene to Eocene Kapuni Group and the Upper Cretaceous Pakawau Group. Only minor quantities of background gas were recorded. The pressure-depth plot for Tane-1 (Figure 9) shows significant overpressure in the Eocene Turi Formation shales directly underlying the Oligocene carbonate. The

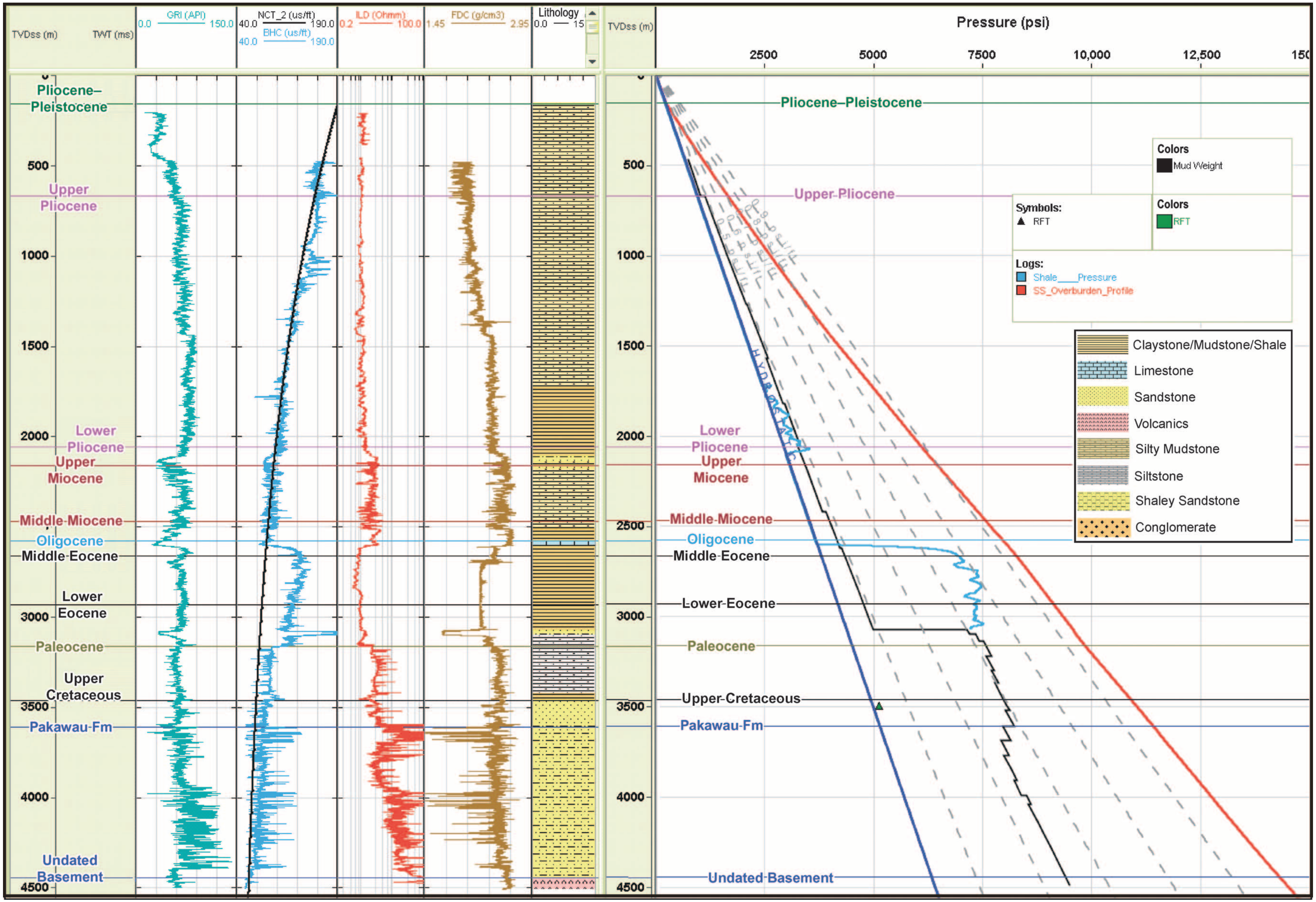


Figure 9. Tane-1 pore-pressure prediction from wireline data. The pressure-depth plot shows the suite of wireline measurements (GR, sonic (interval transit time [ITT]), resistivity, and density, where available), a summary lithologic column, pressure measurements (triangles), the mud-weight profile (black), normal compaction trend (NCT), and an interpreted shale-based pressure profile (blue).

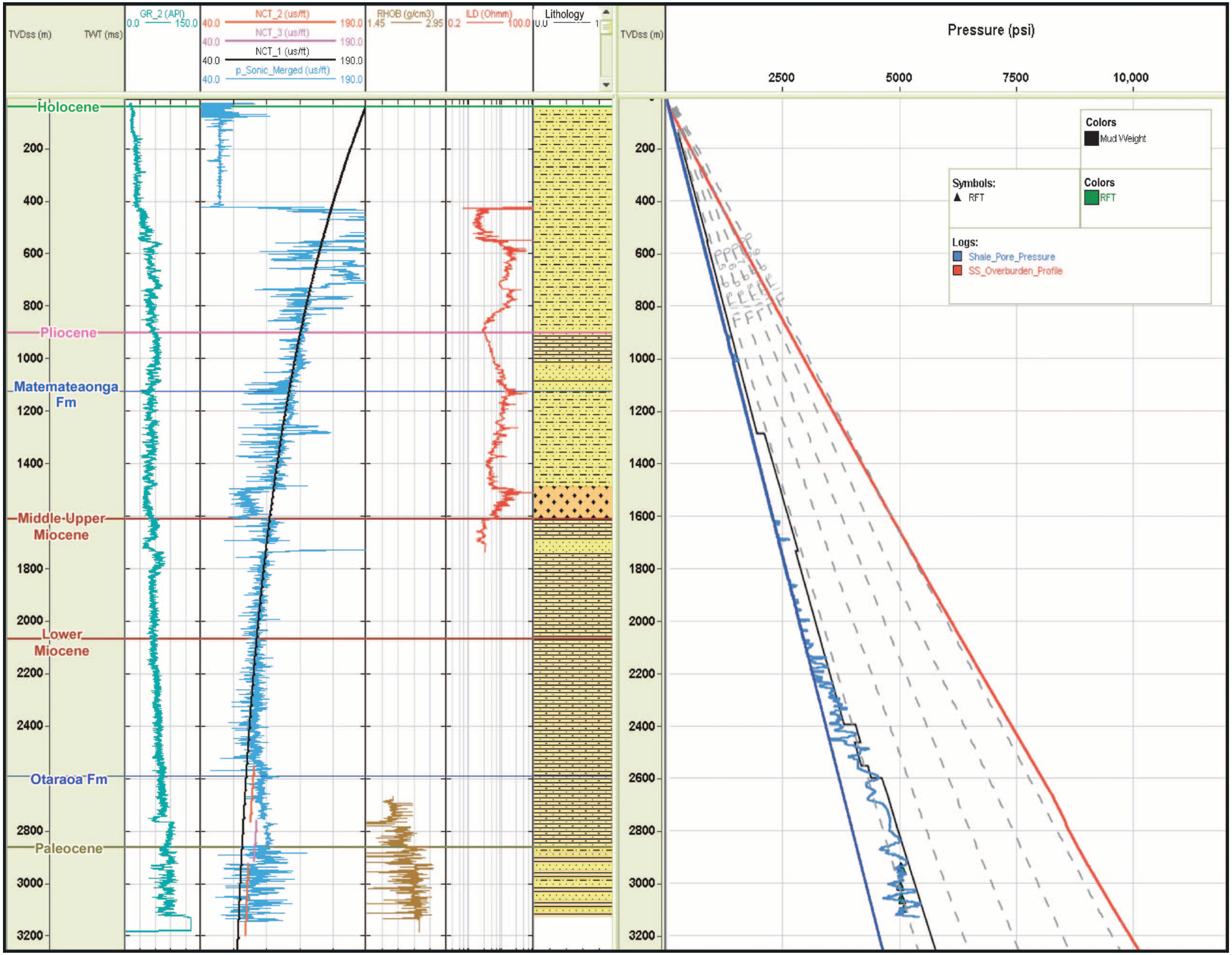


Figure 10. Kupe South-5 pore-pressure prediction from wireline data.

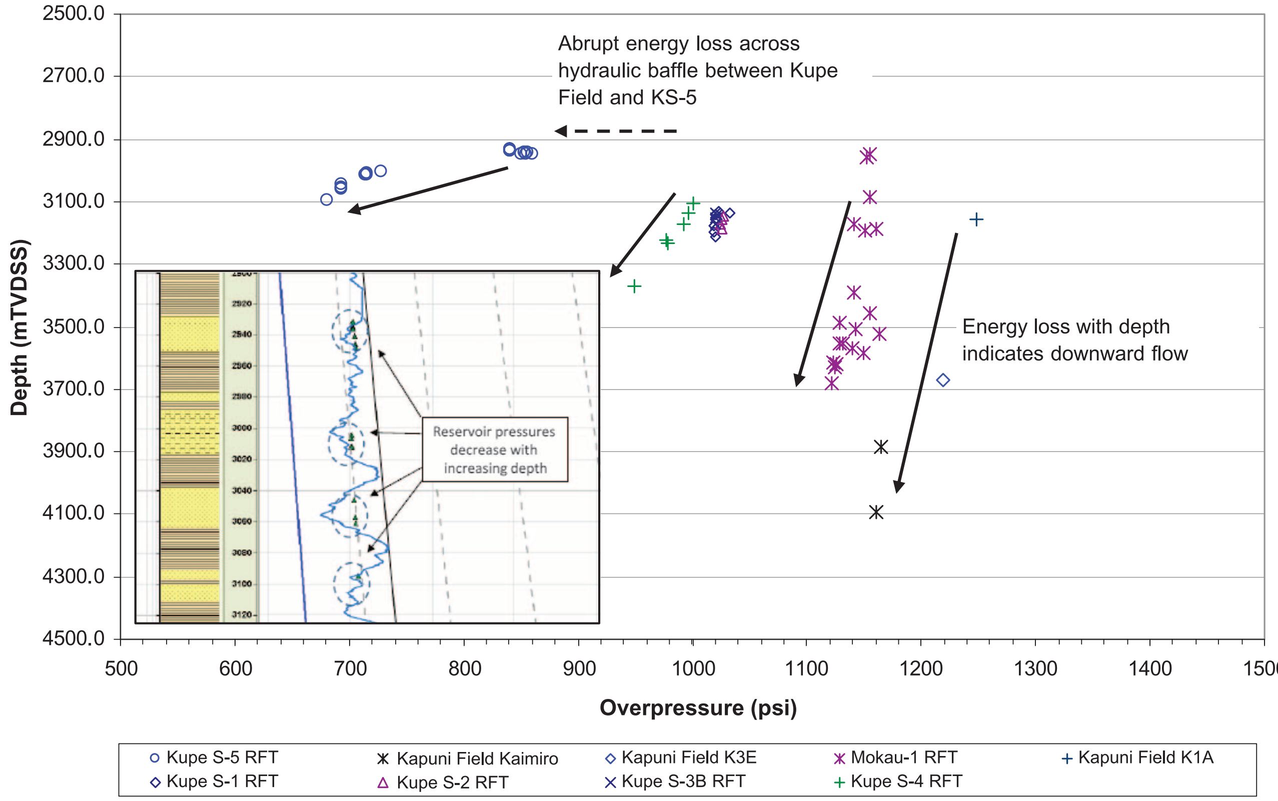


Figure 11. Manaia graben overpressures showing lateral and vertical drainage. Insert shows detail of Kupe South-5. Overpressures in reservoir shales are lower than the expected trend, indicating lateral drainage into sands. Note that the insert covers the depth interval 2910 to 3120 m (9547–10,236 ft) true vertical depth (TVD). RFT = repeat formation tester.

change to slow velocity indicated on the sonic log in this interval is also reflected on the resistivity and density logs (although the density log has not been corrected for borehole rugosity). Above these Eocene shales, minor overpressure is suggested building up in the upper Pliocene shales, where sonic, resistivity, and density all show a deviation from a normally compacting sequence.

The intervals 1669 to 2369 m (5476–7772 ft) TVDSS and 2599 to 3169 m (8527–10,397 ft) TVDSS were interpreted to be overpressured, as indicated by seismic velocity data, logs (sonic magnitudes were consistently greater than seismic velocities at the same depth, attributed to cycle skipping, at least in part) and also *d* exponent data (Shell BP Todd Oil Services Limited, 1976). Severe undercompaction was observed directly underneath the Oligocene unit. Borehole instability was experienced, approaching the Cretaceous Island Sandstone Member as permeabilities increased, causing rapid mud-weight increase between 3079 and 3094 m (10,102–10,151 ft) TVDSS to 13.5 to 13.9 ppg (pounds per gallon), allowing the 9-5/8-in. casing to be set. Mud weight at 2859 m (9380 ft) TVDSS had been 9.4 ppg. Converting these mud weights indicates an increase in overpressure from 563 psi (3.88 MPa) to 2762 psi (19.04 MPa) in this interval, very close to the magnitudes predicted for these Eocene shales. An RFT pressure measurement at 3523 m (11,558 ft) BRT (Figure 9), however, confirms that the underlying Cretaceous Island Sandstone Member is normally pressured, indicating a significant pressure reversal between the Eocene Turi Formation shales and the Cretaceous Island Sandstone.

Kupe South-5, in the Manaia graben (Figure 2), was drilled in 1990 in 40-m (131-ft) water depth to test the hydrocarbon potential of the Paleocene fluvial sands of the Farewell Formation. The well was drilled to 3200 m (10,499 ft) BRT and was plugged and suspended as an oil discovery. The pressure-depth plot for Kupe South-5 (Figure 10)

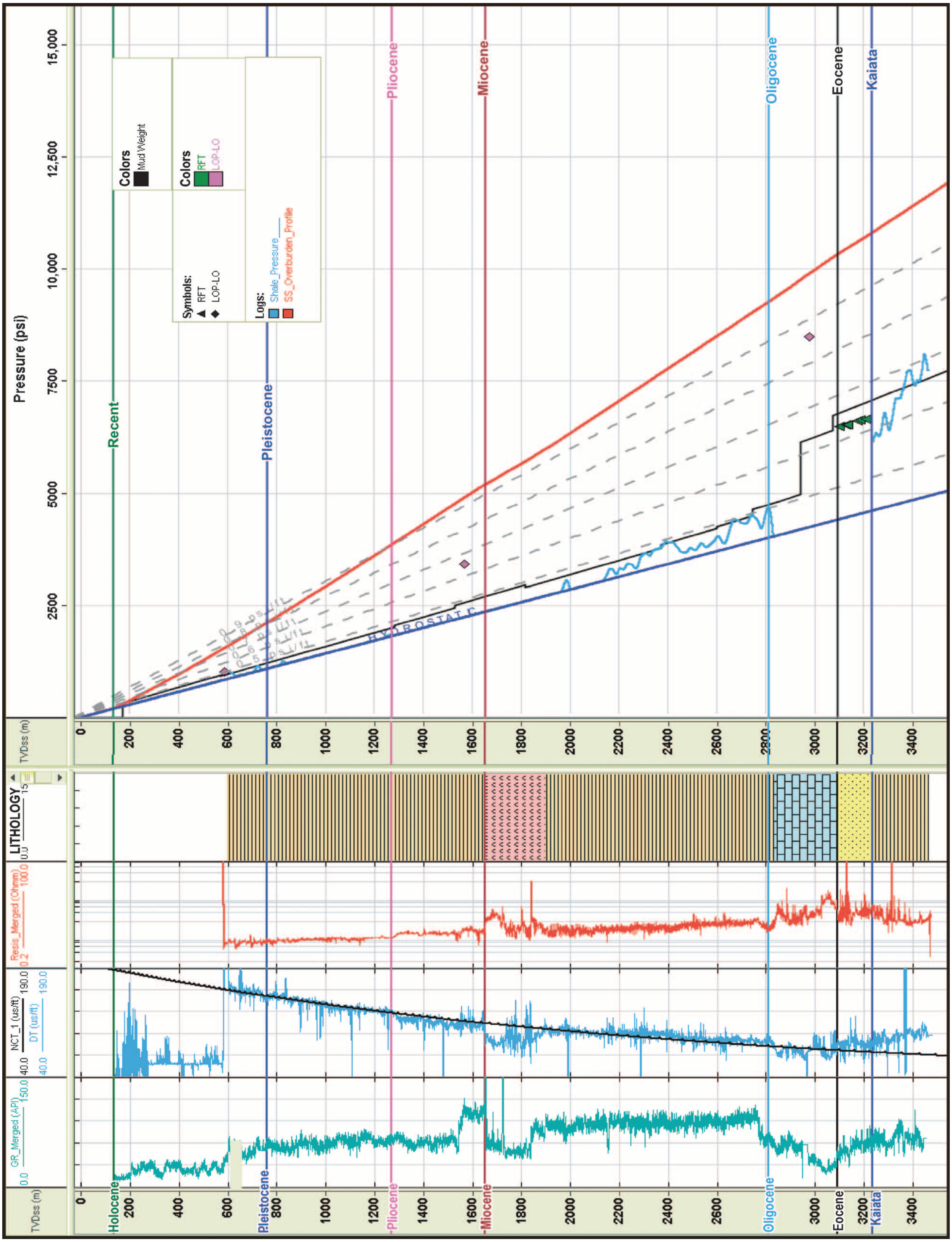


Figure 12. Kora-4 pore-pressure prediction from wireline data.

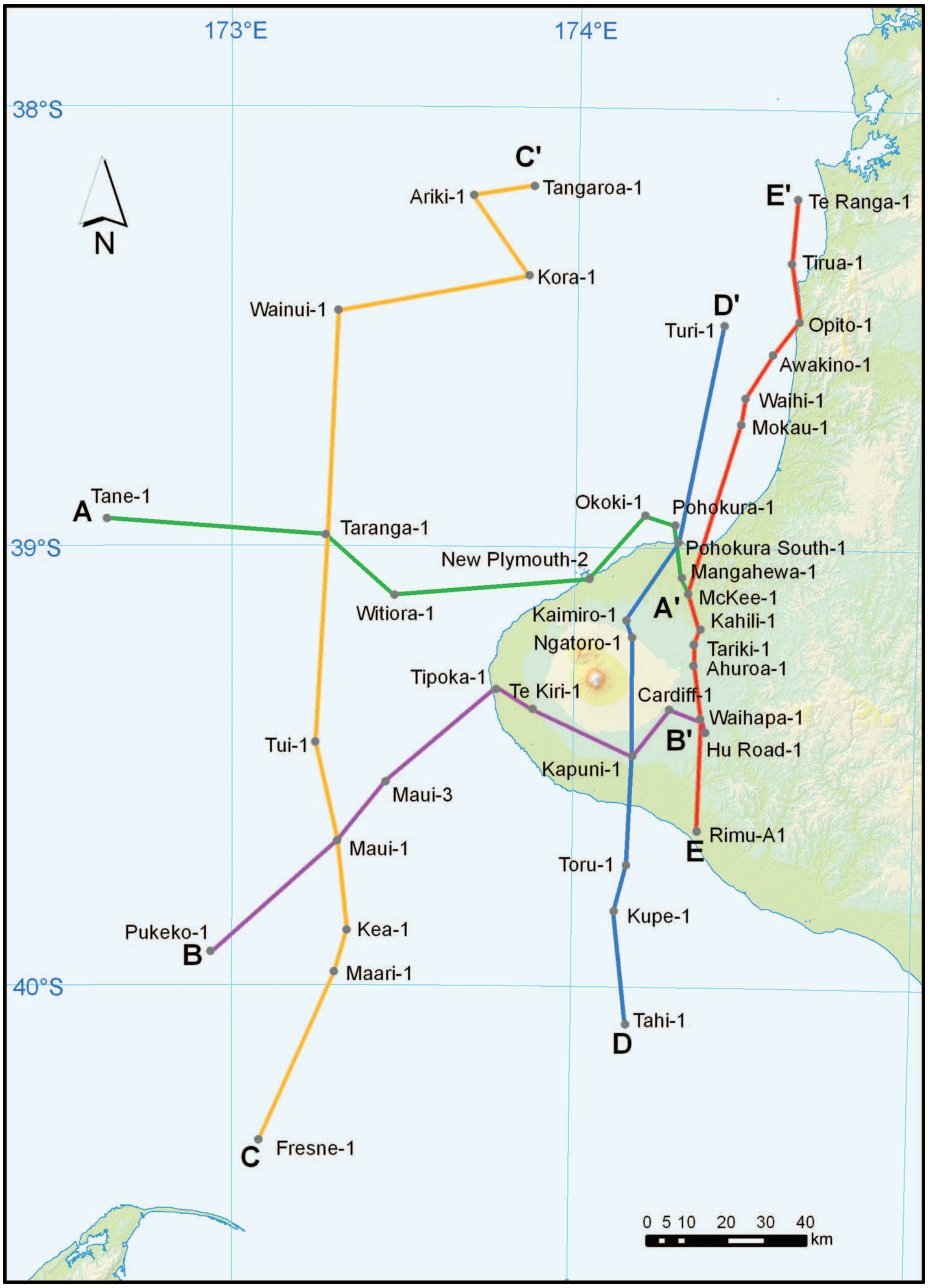


Figure 13. Location map of lines of sections (Figure 14), Taranaki Basin.

indicates overpressure building through the Oligocene Otaraoa Formation shales above the Paleocene boundary, and RFT data indicate that overpressures in the subcropping Paleocene and Cretaceous reservoirs are less than in the surrounding shales. In this case, a two-layer NCT has been used to reflect lithologic differences in shale type in the Otaraoa Formation. Smectite-rich mudstones are reported in the Oligocene Otaraoa Formation (Larmer, 1998). In contrast to other key wells, which have homogeneous shale packages, the Otaraoa Formation in Kupe South-5 displays a distinct change in gamma-ray values. This implied change in lithology may also explain the increasing density log over the same interval, that is, the density data are not actually increasing, implying normal compaction, but simply reflect a change in lithology in overpressured shales. Drilling data support the pressure interpretation, with a left shift in the *d* exponent from the normal trend between 2100 and 2190 m (6890–7185 ft)

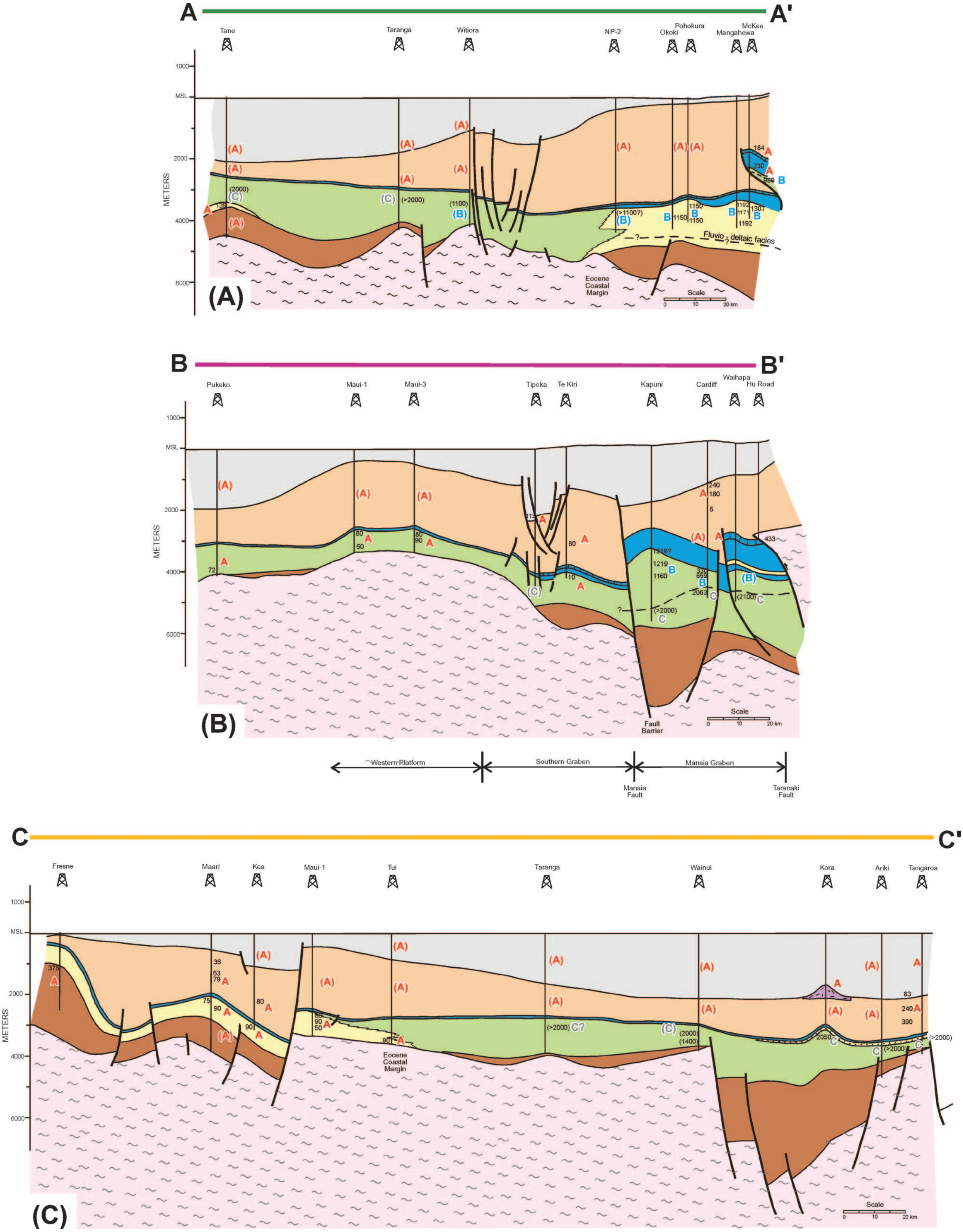


Figure 14. Geologic sections showing stratigraphic units with measured and inferred pressure regimes. Sections based on Thrasher et al., 1995.

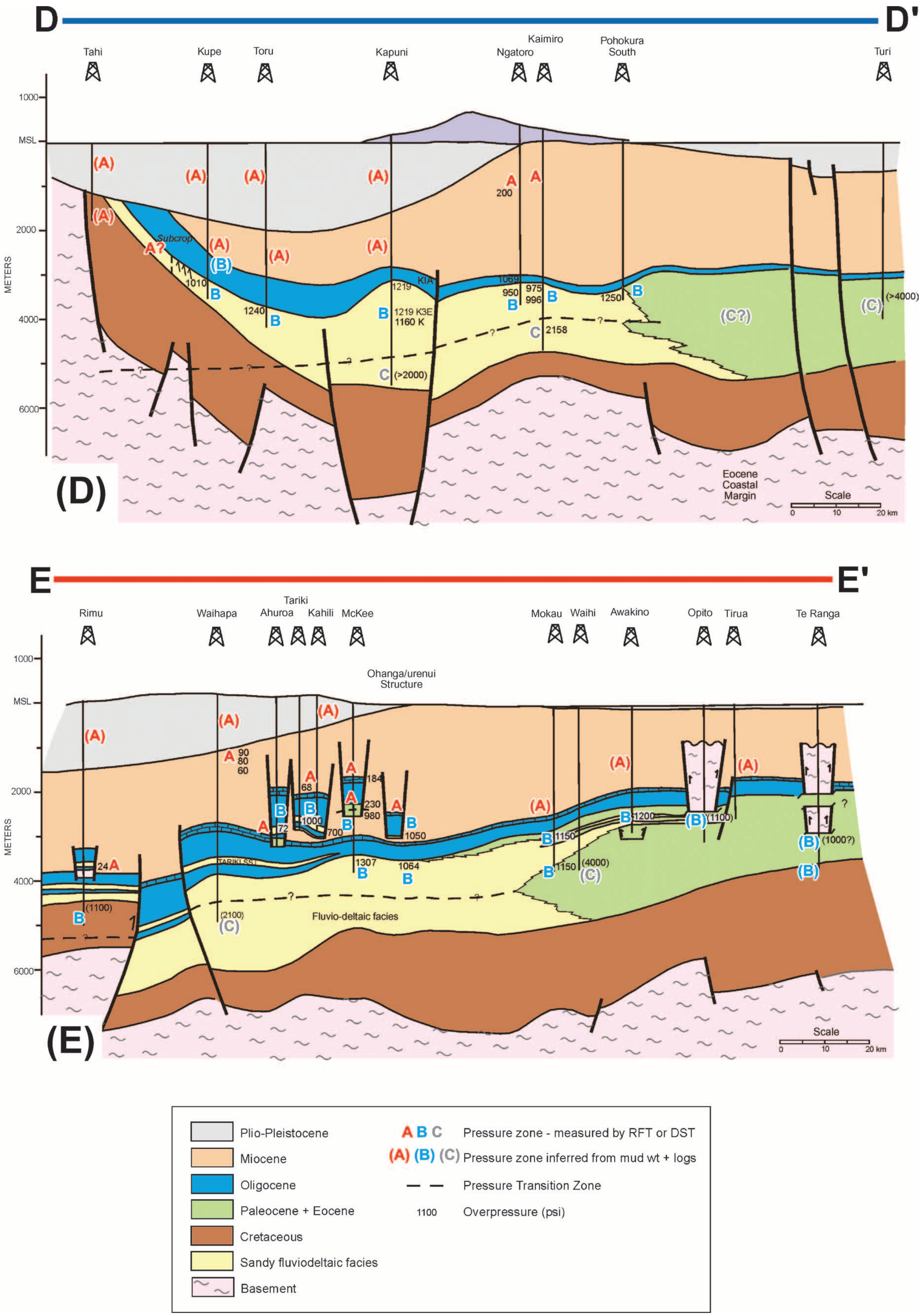


Figure 14. Continued.

BRT, suggestive of increasing pore pressures (Duff et al., 1991). Mud weight was steadily increased from 9.4 to 9.8 ppg (2424–2583 m [7953–8474 ft] BRT) then to 10.3 ppg (2630–2705 m [8629–8875 ft] BRT) to counter the increases in gas, at which point no further connection gas was noted (Duff et al., 1991). Increase in connection gas can indicate that pore pressure is exceeding the mud weight. The RFT data in the Otaraoa Formation showed decreasing magnitudes of overpressure, from 841 psi (5.80 MPa) to 715 psi (4.93 MPa) to 694 psi (4.78 MPa) and finally 681 psi (4.70 MPa), in separate reservoir sands. Shale pressures are therefore higher than reservoir or sand pressures. A similar profile is apparent in Ahuroa-1 on the Tarata thrust trend onshore, where the Oligocene Tariki Sandstone is at near-hydrostatic pressure, but shales of the Otaraoa Formation above and below are overpressured (Webster and Adams, 1996).

A plot of overpressures in the Manaia graben (Figure 11) illustrates the reduction in overpressures between the Kupe South field and Kupe South-5, 3.5 km (2.2 mi) to the south and at similar depths, interpreted to reflect a pressure baffle, where fluid pressure has been lost as a consequence of lateral drainage through interbedded sands of the Cretaceous Puponga Member. The insert in Figure 11 is a detail of the KupeSouth-5 well and shows that reservoir overpressures are less than intrareservoir shales and decrease with increasing depths, indicating downward hydraulic flow. Similar downward flow profiles are apparent in Kupe South-4, Mokau-1, and Kapuni field.

Kora-4 was an exploration and appraisal well drilled by ARCO Petroleum NZ in 1985, where the Miocene volcanics and Eocene Tangaroa sandstone objectives were water wet. The well was drilled in 135-m (443 ft) water depth to a total depth of 3470 m (11,385 ft) TVDSS and is located within the bounding fault system that separates the North Taranaki graben from the western platform (Figure 1). The pressure-depth plot for Kora-4 (Figure 12) interprets pressures close to hydrostatic then rising through the Miocene sequence (*d* exponent data suggest that overpressures start to build in the Miocene Mahoenui [now Manganui Formation] claystones; ARCO Petroleum, 1985). A sudden increase is apparent upon drilling through the Oligocene Te Kuiti Limestone (equivalent to the Ngatoro Group) and is confirmed by RFT data in the Eocene Tangaroa sands. The sands have confirmed water gradients and are offset by 28 psi (0.19 MPa), with the deeper sand having less overpressure (2054 psi [14.16 MPa]) than the shallower sand. The shales beneath these Eocene sands have approximately 400 psi (2.76 MPa) less overpressure than these sands (Figure 12). Nonshale lithologies such as the upper Miocene volcaniclastics and the Oligocene carbonates give spurious magnitudes of overpressure, and the interpretation has been removed.

DISTRIBUTION OF OVERPRESSURES

The measured and inferred under and overpressure data for the Taranaki Basin are displayed on a series of sections traversing the basin (Figures 13, 14) (based on Thrasher et al., 1995) to illustrate the spatial distribution of the overpressures. Using observations from the multiwell pressure-depth plots (Figures 5, 6) and correlation sections (Figure 14), the following observations can be made about the pressure zones.

Zone A

Zone A is the most extensive compartment (Figure 14B, C), extending from buried basement on the eastern basin margin (Pluto-1) to Cretaceous reservoirs on the western platform (Tane-1) and southern inversion zone (Cook-1) and to depths of 4000 m (13,123 ft) TVDSS (Pukeko-1 and Te Kiri-2). All reservoir pressures in this zone lie within 300 psi (2.068 MPa) of hydrostatic (over and under). Some scatter of data is apparent in the onshore wells and may reflect hydrodynamic effects related to groundwater flow of meteoric waters (as proposed by Allis et al., 1997a), but data coverage is not sufficient to map flow magnitudes or directions. Some of the reservoirs at the upper end of the pressure range in this compartment (McKee field, Ahuroa field) likely were previously in zone B and have subsequently ruptured. Reservoir pressures

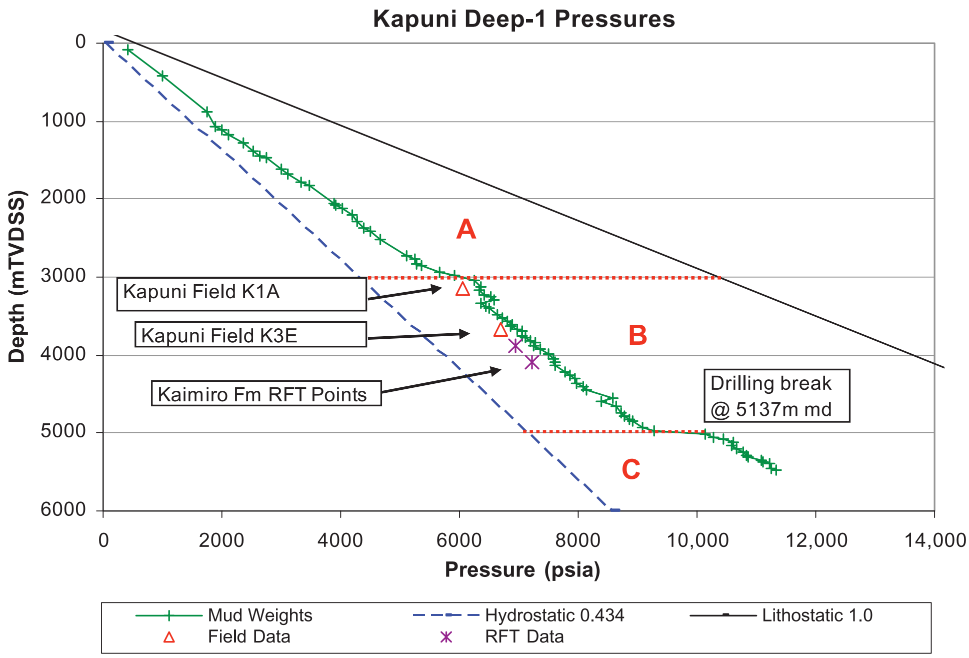


Figure 15. Kapuni Deep-1 pressure profile. mTVDSS = meters true vertical depth subsea.

measured in wells on the western platform (Tane-1, Maui field, Tui-1, Pukeko-1) are all within zone A, but laterally adjacent marine shales are overpressured (Figure 14C).

Zone B

Zone B includes most reservoirs between 2500 and 4300 m (8202–14,108 ft) in the Manaia graben and Northern graben (Figure 1) and includes all Kapuni Group gas discoveries in these structural provinces (Kapuni, Kaimiro Deep, Kupe, Toru, Pohokura). Pressures are 1100 ± 300 psi (7.584 ± 2.068 MPa) above hydrostatic. Zone B appears to be confined laterally by faults (e.g., Manaia and Taranaki faults; Figure 14B), by subcropping lithologies on the southern margin of the Manaia graben (Figure 14D), and by lateral facies changes associated with the Paleocene–Eocene coastal system (Figure 14A, D). The Eocene (sand-dominated) Mangahewa Formation is regionally overpressured in the Manaia graben (Figure 14D), with the transition zone within the overlying Otaraoa Formation. In the north of the eastern mobile belt, zone B extends as far as Opito-1, indicating connectivity with the Mangahewa Formation reservoirs to the south. It is difficult to establish what the pressure regime is at Te Ranga-1, as no pressure measurements were taken and the Cretaceous Taniwha Formation was drilled 1000 psi (6.895 MPa) overbalanced, hence could be in either zone A or zone B.

Along the overthrust trend (Figure 14E), fault compartments are overpressured in McKee field (Eocene Mangahewa Formation), Tariki field (Oligocene Tariki Sandstone), and Ohanga structure (Eocene Kapuni Group).

Zone C

Pressures in zone C have only been directly measured in Cardiff-1, Kaimiro-1, and Kora-4 (Figure 5). Wireline and drilling data indicate that the compartment has also been penetrated in Waihapa-1, Kapuni Deep-1 (Figure 15), and deeper wells in the North Taranaki graben (e.g., Tangaroa-1) and in the shaly Eocene facies on the western platform. Zone C underlies zone B in the Manaia graben but is apparently laterally equivalent to zone B and directly underlies zone A in the North Taranaki graben and on the western platform. Pressures are approximately 2100 psi (14.479 MPa) above hydrostatic. Kora-4 is a key calibration well, as wireline data indicate the Eocene sands and shales are in near-pressure equilibrium (consistent with the depositional setting of basin-floor fans enclosed by deep-marine shales). Note that whereas pressure depletion is apparent in the McKee and K1A reservoirs at Cardiff, because of production from the adjacent and updip Kapuni field, the K3E reservoir pressure at Cardiff (zone C) is significantly higher than the original K3E reservoir pressure at Kapuni (zone B). Also, RFT pressures within the Eocene Kaimiro Formation at Kapuni Deep indicate the same pressure regime as the K3E, indicating that the intervening Omata Member of the Turi Formation is not a seal (Figure 15). These data indicate the presence of a lateral hydraulic barrier between the K3E reservoirs in the Kapuni and Cardiff structures.

NATURE OF TRANSITION ZONES

Changes in overpressure with depth are indications of sediment baffles and are termed "pressure transition zones" (Swarbrick and Osborne, 1996, p. 111). In a vertical profile through a rock sequence, the first transition zone is located where overpressure begins and pressures exceed hydrostatic. In the Taranaki Basin, the top of overpressure is commonly associated with smectite-rich mudstones of the Oligocene Otaraoa Formation (Larmer, 1998) in the Manaia graben, or with the base of the Oligocene limestone in the North Taranaki graben and on the western platform (Sphere Consulting Ltd., 2000). In individual fault blocks along the Tarata thrust zone, the position of pressure transition zones varies stratigraphically from the intra-Mangahewa Formation (McKee field) to the intra-Otaraoa Formation (Tariki field). In McKee oil field, the discovery reservoir pressure in the Eocene McKee Formation was 230 psi (1.586 MPa) above hydrostatic. The underlying Mangahewa Formation sandstones are 980 psi (6.757 MPa) above hydrostatic. The intervening 30-m (98-ft)-thick interval of fine-grained lithologies (siltstones, mudstones, and coals) provides an effective hydraulic barrier within the overthrust. As a consequence of the steep (up to 60°) dips in the overthrust, overpressured Mangahewa Formation sands in the crest of the field are structurally higher than "normally" pressured younger reservoirs on the flank of the structure and as such may be prone to elevated crestal pressures via downdip pressure or lateral transfer (as discussed in Swarbrick et al., 2002).

At the southern margin of the Manaia graben, the lateral transition zone comprises an interbedded Upper Cretaceous sequence (Puponga Member) subcropping the Oligocene sequence boundary. The RFT data from the Kupe South wells (Figure 11) illustrate the lateral pressure differential created by these baffles. Similarly, mud-weight data from Taranga-1, Witiora-1, and Taimana-1 indicate a lens of overpressure in Eocene shales, and this is interpreted as the transition zone associated with the Eocene coastal trend, where pressures are able to dissipate via open reservoirs.

The transition zone between zones B and C in the Manaia graben is more difficult to define because of the very small number of well penetrations. One possibility is that the seal is stratigraphic and associated with the Eocene Omata Member, an extensive shale unit reflecting marine incursion. The difference in pressure between the K3E reservoir in the Kapuni and Cardiff fields (Figure 14B), however, suggests that this seal is not stratigraphic and may be structural (Voggenreiter, 1993) or diagenetic (related to temperature and cutting across structural and stratigraphic boundaries).

CAUSES AND MECHANISMS OF OVERPRESSURE

Overpressure in clastic sedimentary basins is created by two main groups of mechanisms (Swarbrick et al., 2002): (1) stress applied to a compressible rock (disequilibrium compaction, lateral compression); and (2) fluid expansion and/or increase in fluid volume (notably gas generation, where large volume changes occur, but also smectite dehydration). In addition, a growing recognition exists of the contribution to overpressure in shales from load transfer or framework weakening when smectite transforms to illite (Lahann, 2002). In this process, a volume change occurs at approximately 70°C, although typically 100°C, depending on age of sediments, and rock compressibility is affected, resulting in further matrix collapse. Kerogen transformation to liquid and gaseous hydrocarbons also allows the rock matrix framework to suffer matrix collapse, further adding to the fluid stress and increasing overpressures. Processes such as gas generation or load transfer increase the fluid pressures and reduce the grain-to-grain contact stresses (effective stresses); however, as compaction is mostly irreversible, porosity-based pore-pressure-prediction methods will not detect these increases in pressure as no associated porosity anomaly exists.

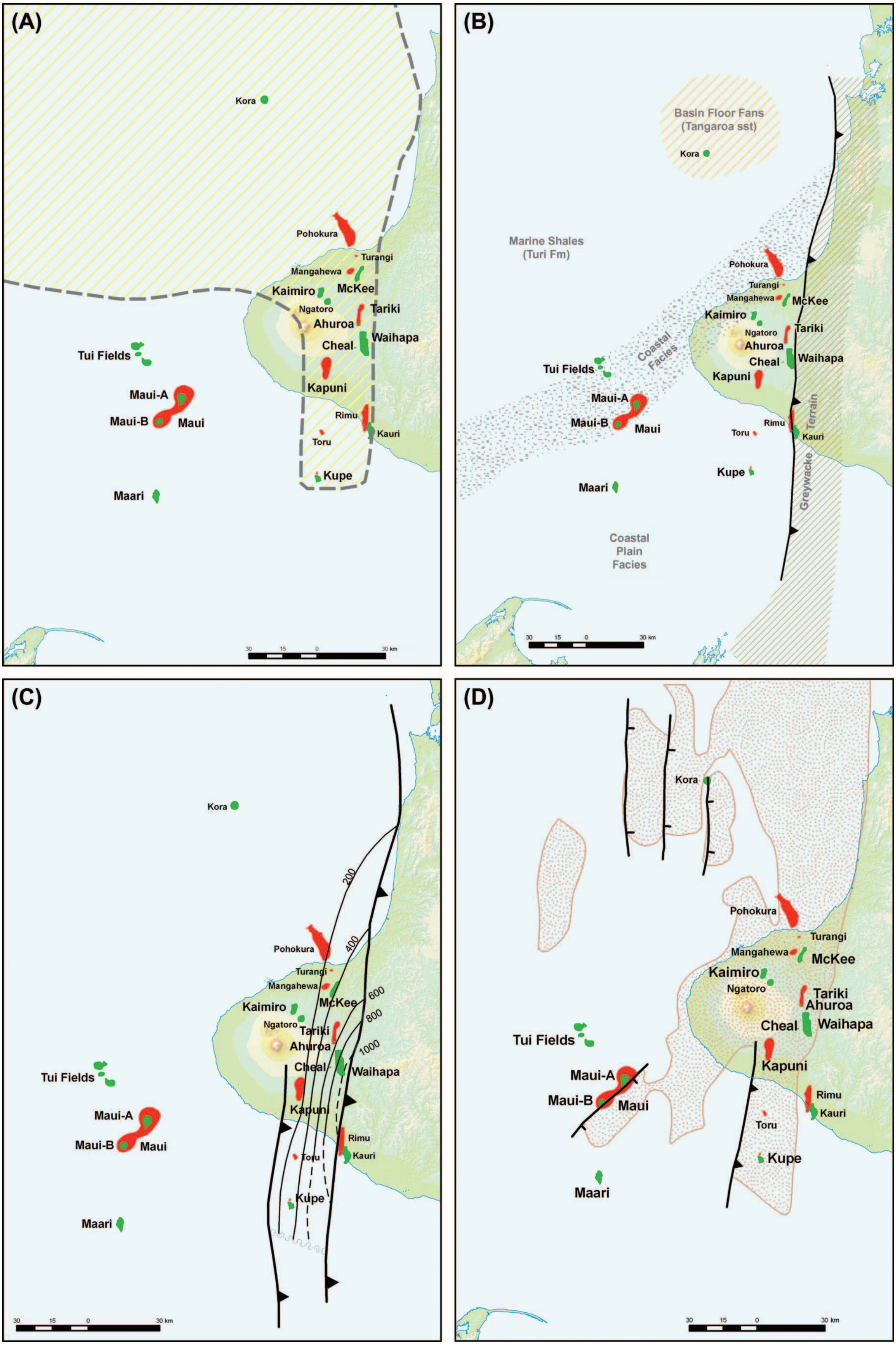
Pressures generated in shales, where porosity is low, temperatures are increasing, and clay mineral diagenesis and hydrocarbon generation are ongoing, are transmitted to any associated sands, particularly sands of restricted extent such as turbidites. Sands that are laterally extensive may allow the dissipation of these pressures if a leak or exit point is established via continuous reservoir or fault networks to shallower levels. Examples of reservoirs that have less pressure than the surrounding shales and are laterally draining pressures (and fluids) include the Paleocene fans of the central North Sea (Dennis et al., 1998, 2005), Egga Sandstone Formation, Ormen Lange field reservoir, mid-Norway, and Cauvery Basin, East India (O'Connor and Swarbrick, 2008).

Other processes that generate pressure in sands include hydrocarbon buoyancy, osmosis, and flushing with meteoric waters driven by hydraulic head. Meteoric flushing will increase the overpressures in permeable basinal rock units relative to the surrounding shales. Although not strictly a mechanism of overpressure generation, pressure can also be transferred within inclined reservoirs (lateral transfer) or via faults and fractures to other compartments (vertical transfer) (Yardley and Swarbrick, 2000; Tingay et al., 2009). Lateral transfer of pressure from deeper in the subsurface results in reservoir or sand pressures greater than the pressures in the surrounding shales (Gulf of Mexico) (Seldon and Flemings, 2005).

Overpressures in the Taranaki Basin have previously been attributed to a variety of causes, including rapid sedimentation and loading during the Miocene and Pliocene causing overpressures beneath a blanket of Eocene–Oligocene shales (Allis et al., 1997b; Stagpoole et al., 1998; McAlpine, 2000; Darby, 2002; Darby and Ellis, 2003), hydrocarbon generation and cracking to gas (Webster and Adams, 1996), uplift of originally hydrostatic reservoirs (Shell Todd Oil Services Limited, 2002), and a shallow radial hydrodynamic flow regime driven by topographic flow from Mount Taranaki (Allis et al., 1997a).

As previously mentioned, porosity-based shale prediction techniques will tend to underestimate fluid pressures caused by mechanisms other than compaction disequilibrium, so velocity/density crossplots were used to identify the presence of overpressure generated by other mechanisms. In the case of gas generation, density changes are minor, as the grain contact areas are unchanged. Velocity, however, is affected significantly as the fluid pressure increases and effective stress reduces at grain contacts, producing a slower rock (Bowers, 1994). An example of a typical resulting profile is also displayed in Chopra and Huffman (2006). Normal compaction and undercompaction/disequilibrium compaction display typical increasing velocity and density magnitudes. For load transfer, the transformation of framework-supporting grains to hydrocarbons (oil and/or gas) and porosity causes an increase in density and decrease in velocity as further compaction occurs. We analyzed sonic and density data from the western platform (Tane-1, Taranga-1, and Witoria-1), the North Taranaki graben (Kora-4, Mokau-1, Waihi-1, and Turi-1) and Kaimiro-1 from the Manaia graben and onshore regions. Only relationships of increasing density and velocity were observed and attributed therein to undercompaction (compaction disequilibrium).

Geothermal gradients in the Taranaki Basin are approximately 2.9°C or 1.6°F/100 m, for example, Tane-1 (Shell BP Todd Oil Services Limited, 1976). Although smectite to illite transformation occurs at temperatures of greater than 70° C, significant regional overpressures are expected where shales are below the 100°C isotherm in a basin (R. Lahann, 2009, personal communication). In the Taranaki Basin, this would occur at a depth of 3 km (1.9 mi). Therefore, only shales buried below these depths are likely to be affected by secondary generation of overpressure via mechanisms such as load transfer. We analyzed, for instance, the Kaiata (Turi Formation) shales in Kora-4 using


(A)
Kora
Pohokura
Turangi
Mangahewa
Kaimiro
McKee
Ngatoro
Tariki
Ahuroa
Waihapa
Cheal
Tui Fields
Kapuni
Maui-A
Maui-B
Maui
Rimu
Kauri
Toru
Kupe
Maari
30 15 0 30 km
(B)
Basin Floor Fans
(Tangaroa sst)
Kora
Marine Shales
(Turi Fm)
Pohokura
Turangi
Mangahewa
McKee
Kaimiro
Ngatoro
Tariki
Ahuroa
Cheal
Waihapa
Coastal Facies
Tui Fields
Kapuni
Maui-A
Maui-B
Maui
Rimu
Toru
Kauri
Terrain
Greywacke
Kupe
Maari
Coastal
Plain
Facies
30 15 0 30 km
(C)
Kora
200
400
Pohokura
Turangi
Mangahewa
600
McKee
Kaimiro
800
Ngatoro
Tariki
Ahuroa
1000
Cheal
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Maui-B
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30 15 0 30 km

velocity/density relationships (and these shales are <3 km [<1.9 mi] current burial depth) but found no evidence for any other mechanism than compaction disequilibrium. It may be that deeper in the section, in wells such as Kaimiro-1 that penetrate greater than 4.5 km (2.8 mi), there would be evidence, although in this well and other deep wells such as Tane-1, the lithologies are commonly sandy.

The compiled pressure data from multiple sources presented in this study, including pressure estimation in shales using wireline data, are most consistent with disequilibrium compaction as a major cause of overpressure in the Taranaki Basin. Some areas within the Taranaki Basin have experienced sedimentation rates of up to 750 m/m.y. during the last 4 m.y. (King and Thrasher, 1996) associated with uplift along the Pacific Plate boundary. McAlpine (2000) and Darby (2002) modeled the development of overpressures and dynamic flow on the western platform as a consequence of rapid burial of Eocene and Oligocene shales beneath the prograding Giant Foresets Formation during the Pliocene–Pleistocene. Oligocene carbonates and smectite-rich clays are interpreted to restrict the capacity of underlying Eocene shales to de-water. Upper Eocene and Oligocene shales of the Turi and Otaraoa formations also contain significant smectite (Larmer, 1998) and, hence, are likely to retain water and mechanically deform, severely reducing permeability (Darby, 2002). The similarity in area of overpressured shales offshore and the Turi Formation (Figure 16A, B), and the Otaraoa Formation and overpressures in the Manaia graben (Figure 16A, C) suggests that disequilibrium compaction is the dominant overpressure mechanism in the Taranaki Basin. Pressure profiles through shale sequences support this interpretation, for example, Figures 10, 11. Overpressures have been retained either by the very low permeability of these shales or by overlying Oligocene carbonates, which provide a vertical hydraulic barrier. In the shallow thick turbidite successions in the North Taranaki graben, disequilibrium compaction is also the likely cause of overpressures measured in shallow Miocene–Pliocene sands (e.g., Awatea-1).

Given the large volume of gas generated from local source rocks, especially in the eastern mobile belt, a contribution to overpressure from gas expansion during hydrocarbon generation, and in particular the cracking of kerogen and oil to gas at high maturities, might be expected. The Eocene coal measures of the Mangahewa Formation attain significant thicknesses in the Manaia graben (195 m [640 ft] of coal and 380 m [1,247 ft] of carbonaceous shale in Waihapa-1). Well data and modeling confirm that these coal measure sequences are currently in the oil (vitrinite reflectance [R_o] >0.8%) through to dry gas windows throughout much of the eastern mobile belt south of Pohokura (Webster and Adams, 1996; Stagpoole et al., 2004), and the underlying Cretaceous coal measures attain maturities of 3.8% R_o in the deeper grabens (Armstrong et al., 1996). The areal coincidence of mature source (Figure 16D) and overpressure and onset of overpressures at around top oil window suggest hydrocarbon generation, and the cracking of hydrocarbon liquids to gas has also contributed to the development of overpressures but with a signature that is too subtle to identify in the pattern of direct pressure measurements and the wireline characteristics of the associated shales. If gas generation in the deepest parts of the basin, with subsequent vertical transfer, was the sole cause of overpressures, pressures in permeable sands would be higher than in associated shales, and this is not the case in the wells analyzed.

LATERAL AND VERTICAL DRAINAGE

Wireline log characteristics confirm that upper Eocene shales are overpressured over parts of the western platform and in the North Taranaki graben (e.g., Tane-1; Figure 9). In Kora-4, these overpressures have been retained in the Eocene Tangaroa Sandstone, and indeed, in this well, the

Figure 16. Areal distribution of overpressures (A) and possible mechanisms, (B) distribution of Eocene facies (modified from Matthews and Lewis, 2001), (C) isopach of Otaraoa Formation (modified from New Zealand Oil and Gas, 1988), (D) distribution of Cretaceous and/or Eocene gas kitchen areas (modified from King and Thrasher, 1996; Stagpoole et al., 2004).

reservoir pressures even exceed the shale pressures, suggesting that lateral transfer of pressures has occurred from downdip in these turbiditic sands. Cretaceous, Paleocene, and Eocene reservoirs on the western platform are at near-hydrostatic pressures, suggesting that the reservoirs and shales are not in equilibrium. This may indicate that pressures have been able to drain laterally and dissipate through the coarser grained Kapuni Group rocks to the south. In the Manaia graben, overpressures generated within the Otaraoa Formation by disequilibrium compaction seem to have been driven by the pressure differential into the underlying (and subcropping) Cretaceous to Eocene reservoirs (Figure 11). Near-hydrostatic pressures within Eocene (McKee field) and Oligocene (Ahuroa field) reservoirs in the Tarata thrust are likely to reflect lateral or vertical drainage of original overpressures. Examples of pressure retention and dissipation in basins affected by disequilibrium compaction, dependant on whether sands are enclosed in shales or connected to surface, are documented by O'Connor and Swarbrick (2008).

Kapuni Group rocks within the Manaia graben (zone B) appear to be in a transitional pressure regime between zone C (underlying and laterally equivalent) and zone A (hydrostatic). Zone B is sealed vertically by faulted (and overpressured) shales of the Otaraoa Formation and laterally by fault boundaries and stratigraphic baffles and may reflect partial breaching of zone C during Pliocene uplift. Overpressures in zones B and C in the Manaia graben could also be affected either by lateral drainage and partial retention of overpressures generated in Eocene shales north of the coastal trend or gas generation and cracking within the Kapuni and Pakawau Groups. The limited data set, however, precludes detailed mapping of lateral gradients.

VERTICAL TRANSFER

Shallow oil accumulations in the Taranaki Basin have long been recognized to overlie deeper structures and are connected to source intervals by faults. The distribution of hydrocarbons at various stratigraphic intervals along the Tarata thrust trend illustrates the capacity of faults to transmit fluids, likely through episodic failure, which enables migration of overpressured fluids to stratigraphically shallower reservoirs in a dynamic charge system (e.g., central North Sea, Holm, 1996, 1998; Brunei, Tingay et al., 2008), where these reservoirs are contained in a sealed fault compartment (such as at Tariki field) the overpressures are retained. Measured pore pressures do not approach the lithostatic gradient; hence, seal failure is likely to be caused by fault-plane leakage instead of hydraulic failure or fracturing of top seal, or to shear failure, which occurs at lower overpressures than tensile failure (Hillis, 1998). The upper limit of zone B overpressures (approximately 1300 psi or 8.96 MPa) is likely to define the strength of the "weak point" in the seal. Episodic charge and seal failure is reflected in the long residual columns in structures along the Tarata thrust trend (Ahuroa, Tariki, etc.).

IMPLICATIONS FOR EXPLORATION AND PRODUCTION

An understanding of subsurface fluid movement is a critical element of exploration (as emphasized in the Taranaki Basin by McAlpine and O'Connor, 1998), and an understanding of overpressure zones assists in both trap identification and migration mapping. A plot of the distribution of reserves within each pressure zone in the Taranaki Basin

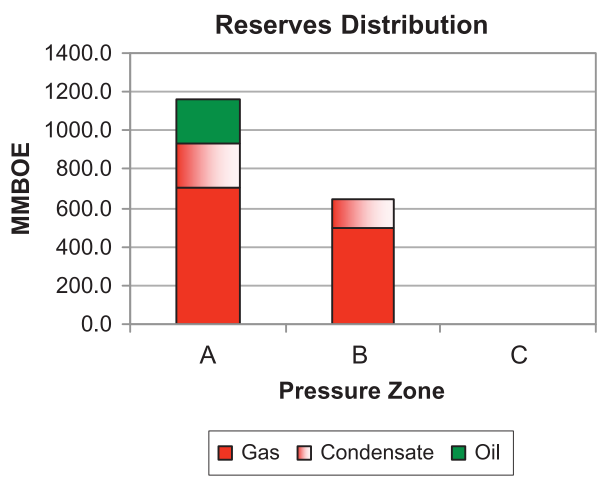

Figure 17. Reserves distribution in pressure zones, Taranaki Basin. MMBOE = million bbl of oil equivalent.

(Figure 17) shows that all commercial oil reserves are located within zone A, gas and condensate reserves are evenly distributed between zones A and B, and no commercial reserves to date have been proven in zone C. This is not surprising given the very small number of zone C penetrations. We know, however, that one of the major source units in the basin, the Cretaceous coal measures within the Pakawau Group, lies within zone C in the eastern mobile belt. Given that the transition zone between zones B and C is capable of holding an overpressure differential of 1000 psi (6.895 MPa) it should provide an effective seal to any gas accumulation. If the transition zone is not stratigraphic, however, as pressures from Kapuni and Cardiff indicate, it may not conform to structure, and different techniques (in particular, detailed seismic velocity analysis) will be required to identify traps. Reservoir deliverability will be a critical risk at these depths, although core and test data from Kaimiro-1, Kapuni Deep-1, and Waihapa-1A indicate the presence of natural fractures in zone C, which would greatly enhance productivity.

Detailed pressure mapping can also confirm the sealing capacity of different fault populations against which hydrocarbon accumulations can be trapped; the pressure data presented here illustrate the sealing capacity of the Manaia and Taranaki faults (Figure 14B) and high-grade plays associated with these trends.

The transition between zones B and A provides a rapid pressure drop for migrating fluids, which is likely to provide a focus for liquids (Webster and Adams, 1996); an example of this mechanism is Kupe South-5, where oil was discovered in association with a rapid pressure transition. The identification of this transition zone therefore remains a valid technique to high-grade oil prospects.

Higher than expected crestal pressures in reservoirs with significant downdip extent and reservoir tilt can be a major drilling problem. Understanding the relationship between inclination of sand body and pressure transfer is key to avoiding drilling surprises and also in risking of traps for hydraulic top-seal failure. In this scenario, elevated crestal pore pressures exceed the rock strength, causing top-seal failure and loss of hydrocarbons.

Another example of where sands and shales are out of equilibrium is the occurrence of lateral drainage of pressures, which has implications for the petroleum system. On a regional scale, hydrocarbon prospectivity can be inferred (if traps are identified) in the direction of fluid migration, driven by overpressure gradients in these draining reservoirs. Fields present in laterally draining systems have the potential to have tilted hydrocarbon-water contacts, impacting on reserves.

The Taranaki Basin is a geologically complex basin with a very limited data set, and a full picture of fluid movement and pressure distribution will only emerge as multiple techniques, and data sources are integrated to give a more complete understanding of the reservoir and shale pressures. Sonic logs have been used to predict the pressures in thick shale intervals (hundreds of meters), however, for new wells that are to be drilled in the basin, careful calibration with offset wells, particularly drilling data, as well as an understanding of rock properties for each stratigraphic interval, that is, clay lithotype (multiple models for compaction) is necessary. Once understood, the influence of overpressure (and its mechanisms of generation) can be an invaluable input to basin modeling as it becomes increasingly sophisticated and integrates all relevant factors—burial and uplift history, temperature history, rock properties, mineralogy, diagenetic processes, hydrocarbon charge, hydrodynamic flow, and fault properties.

Robust one-dimensional modeling at well locations, analyzing pressure regimes in sands and shales separately and then integrating in a regional geologic model, also has the potential to provide reliable calibration to estimate shale pressures based on velocity data interpretation. Reservoir pressures then have to be predicted based on sand-body geometries and structural tilt and lateral continuity, and tied to available RFT data. The success of these pore-pressure predictions based on seismically derived velocities, converted to interval velocities, depends on initial predictions made at the wells and subsequently tied to the velocity field. Well-based pressure prediction should always be the first stage of an exploration strategy to analyze pressures, in areas where data permit.

CONCLUSIONS

1. Mapping of pressure data derived from direct and indirect measurements indicates the presence of at least three pressure zones in the Taranaki Basin:
   a. Zone A (near hydrostatic or normally pressured) extends across the basin and is open to groundwater flow from both Mount Taranaki and the eastern margin, where Miocene–Pliocene units crop out in structurally elevated surface exposures.
   b. Zone B (1100 psi/7.584 MPa above hydrostatic) appears to be constrained laterally by fault planes (in particular, the Manaia and Taranaki faults) and stratigraphic boundaries (subcropping units in the south of the Manaia graben and lateral facies changes in the north).
   c. Zone C (2100 psi/14.479 MPa above hydrostatic) appears to underlie zone B in the Manaia graben, and underlie zone A in the North Taranaki graben and on parts of the western platform.
2. The pressure transition zone between zones A and B in the Manaia graben is commonly associated with the Oligocene Otaraoa Formation. The transition zone between zones A and C is commonly defined by the Oligocene carbonates. The transition zone between zones B and C may be stratigraphic or diagenetic; limited data suggest the seal may cut across lithologic boundaries.
3. The primary cause of overpressure is considered to be disequilibrium compaction in upper Eocene and Oligocene smectite-rich marine shales (Turi Formation and Otaraoa Formation). The overpressure in the Manaia graben may also be caused in part by either lateral drainage from Eocene shales to the north and/or hydrocarbon generation and/or cracking with vertical transfer. Zone B is an intermediate pressure compartment, with maximum overpressure constrained by seal capacity at fault planes.
4. Fluids are transferred vertically by episodic fault valve discharge within the eastern mobile belt. The major source units lie within zones B and C, but all oil discoveries occur within zone A.
5. Direct pressure measurements in reservoirs can be misleading where sands and shales are not in equilibrium because of fluid escape via lateral drainage or vertical transfer.
6. An understanding of the nature and distribution of the pressure compartments, intervening seals, and of fluid migration mechanisms within and between pressure zones will assist in the definition of new exploration plays and the placement of appraisal wells for field development.

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