chapter 2

Unconventional Gas Plays in South Australia

A petroleum play is an area in which oil and/or gas accumulations exist and/or may exist. The basic independent geologic factors that must operate together a petroleum play to exist can be generalized as: source rocks with a capacity to generate hydrocarbons; rock reservoirs from which petroleum can be produced, and circumstances that enable petroleum to be trapped and accumulate in the subsurface.

Chapter two provides descriptions of the geologic attributes and potential extent of unconventional gas plays in the Cooper, Arckaringa, Otway, Gambier, Pedirka, Simpson, Warburton and Officer basins.

The regulation of projects within plays is addressed in Chapter 5

2.1 Cooper Basin

The Cooper Basin is a Permo-Carboniferous to Triassic intracratonic basin located approximately 800 km north-northeast of Adelaide in South Australia. It lies unconformably over early Palaeozoic sediments of the Warburton Basin and is overlain disconformably by the central Eromanga Basin. In the northern Patchawarra Trough, the Cooper Basin is locally overlain by the Late Triassic Cuddapan Formation. Total area exceeds 130 000 km^2, of which ~35 000 km^2 are in NE South Australia (Figure 2.1).

Three major troughs (Patchawarra, Nappamerri and Tenappera) are separated by structural ridges (Gidgealpa–Merrimelia–Innamincka (GMI) and Murteree) associated with the reactivation of NW-directed thrust faults in the underlying Warburton Basin (Figures 2.2 and 2.3) and contain up to 2500m of Permo-Carboniferous to Triassic sedimentary fill overlain by as much as 1300 m of Jurassic to Tertiary cover.

The Basin contains a number of non-marine depositional sequences within the Late Carboniferous to Late Permian Gidgealpa Group and Late Permian to Middle Triassic Nappamerri Group (Figure 2.4).

2.1.1 Shale Gas Play

The principal shale gas play currently being pursued by several companies in the Cooper Basin is the Roseneath - Epsilon - Murteree (REM) play comprising Early Permian Murteree and Roseneath shales divided by tight sands of the Epsilon Formation. The two shale units are thick, generally flat lying, and laterally extensive, comprising siltstones and siliceous (and sideritic in part) mudstones deposited in large and relatively deep freshwater lakes.

The Murteree Shale is widespread, reaching a maximum thickness of 86 m in the Nappamerri Trough (Figures 2.5 and 2.8) and thins to the north, reaching a maximum thickness of 35 m in the Patchawarra Trough (Figure 2.7). It is absent over crestal ridges. The Roseneath Shale reaches a maximum thickness of 105 m in the Tenappera Trough (Boucher, 2000) and is not present over most of the Patchawarra Trough (Figures 2.6 and 2.8).

Figure 2.1 *Cooper Basin – Location and regional infrastructure*

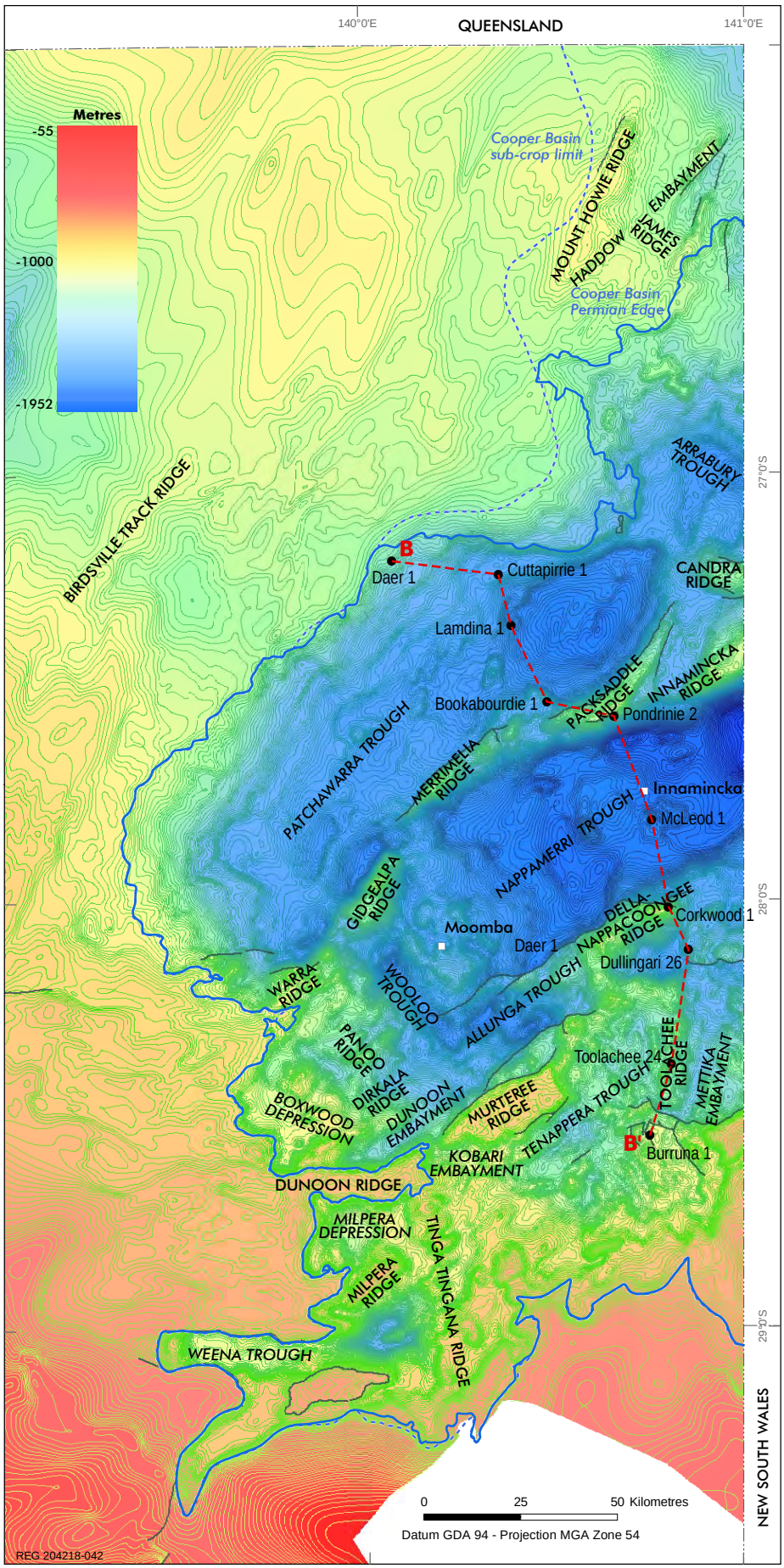


Figure 2.2 *Cooper Basin – Structural elements on Top Warburton (Z Horizon) showing line of section B-B' in Figure 2.3)*

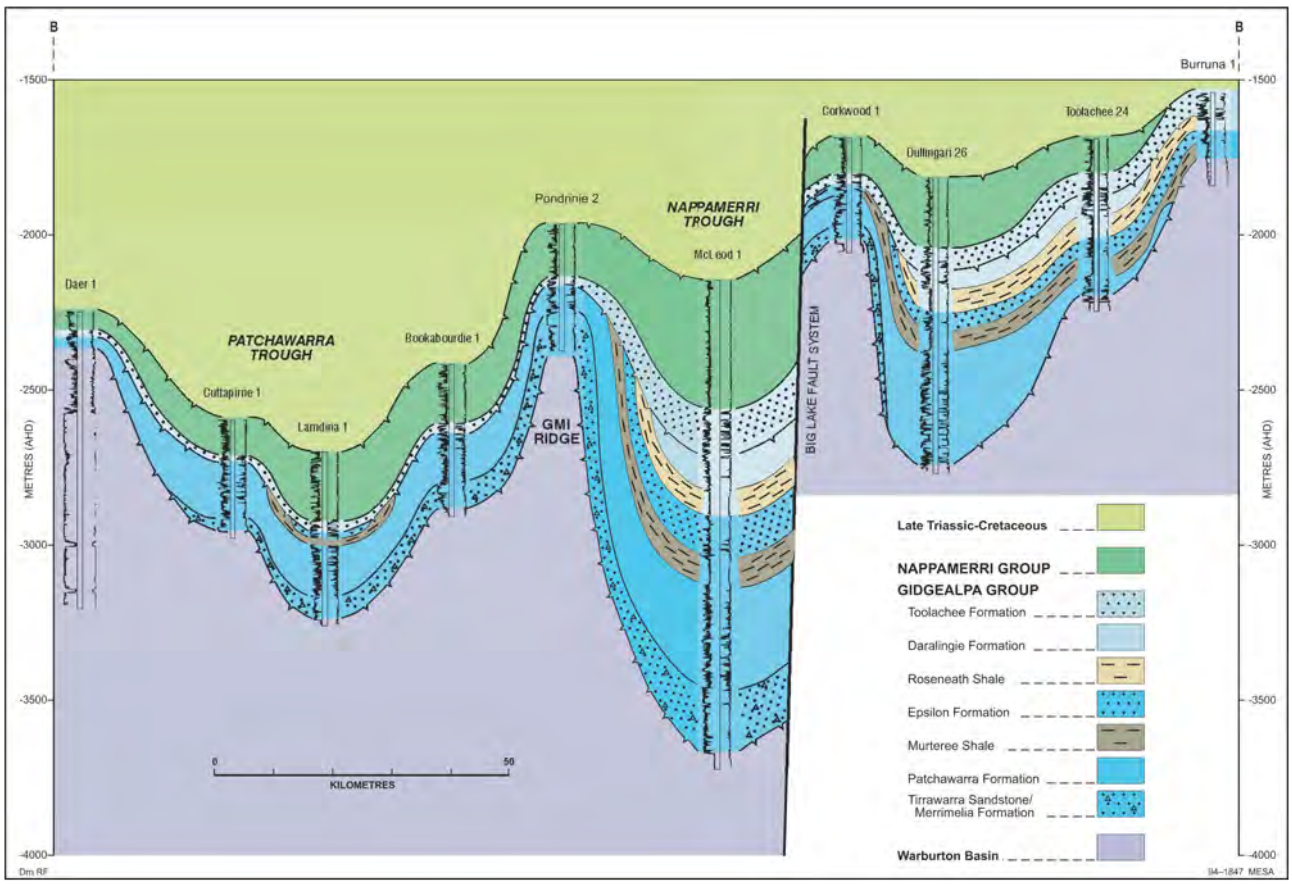


Figure 2.3 *Regional N-S log correlation across the Cooper Basin, South Australia, highlighting the shallower occurrence of the prospective Permian succession in the Tenappera Trough/Mettika Embayment compared with the Nappamerri Trough. Senex's planned Skipton-1 and Talaq-1 unconventional wells will test the Mettika Embayment. The relatively shallow depths mean lower temperatures are encountered, and there is no need for specialised casing or drilling materials. See Figure 2.2 for location of section.*

Figure 2.11 shows the Cooper Basin shale gas play fairways defined by the Murteree Shale exceeding 30m thickness, with a minimum maturity (as optically measured with vitrinite reflectance (Ro) at the base of the Murteree Shale of 0.95% (top of the wet gas window).

Total organic carbon (TOC) values average 3.9% in the Roseneath Shale and 2.4% in the Murteree Shale. HI vs. Tmax plots confirm a predominantly Type III kerogen for both shales (Figures 2.9 and 2.10).

Although the Roseneath and Murteree Shales are present over much of the Cooper Basin, organic maturity is variable (Figure 2.11). In the Patchawarra Trough, where only the Murteree Shale is present, maturity sufficient for wet gas generation (0.95<Ro<1.7) is only present in the deepest part of the trough. A significant portion of the Roseneath-Epsilon-Murteree (REM) section in the Nappamerri Trough lies within the dry gas window (Ro>1.7). This higher maturity is due to an elevated geothermal gradient resulting from high heat producing granites at depths around 4,000 m (Meixner, 2009). The REM section in the south western margin of the Nappamerri Trough, northern Tenappera Trough and Mettika Embayment is mature for wet gas generation.

Seismic data in the core Nappamerri Trough area is of variable quality, with good 2D seismic grid coverage over conventional structures (Burley, McLeod, Bulyeroo), grading to reasonable to poor coverage elsewhere. Seismic coverage over the Moomba high on the south-western margin of the Nappamerri Trough is very good and this area was selected in 2010 as the starting point of a fault and fracture systems study for application to unconventional gas plays in the Basin. Seismic attribute analysis of the

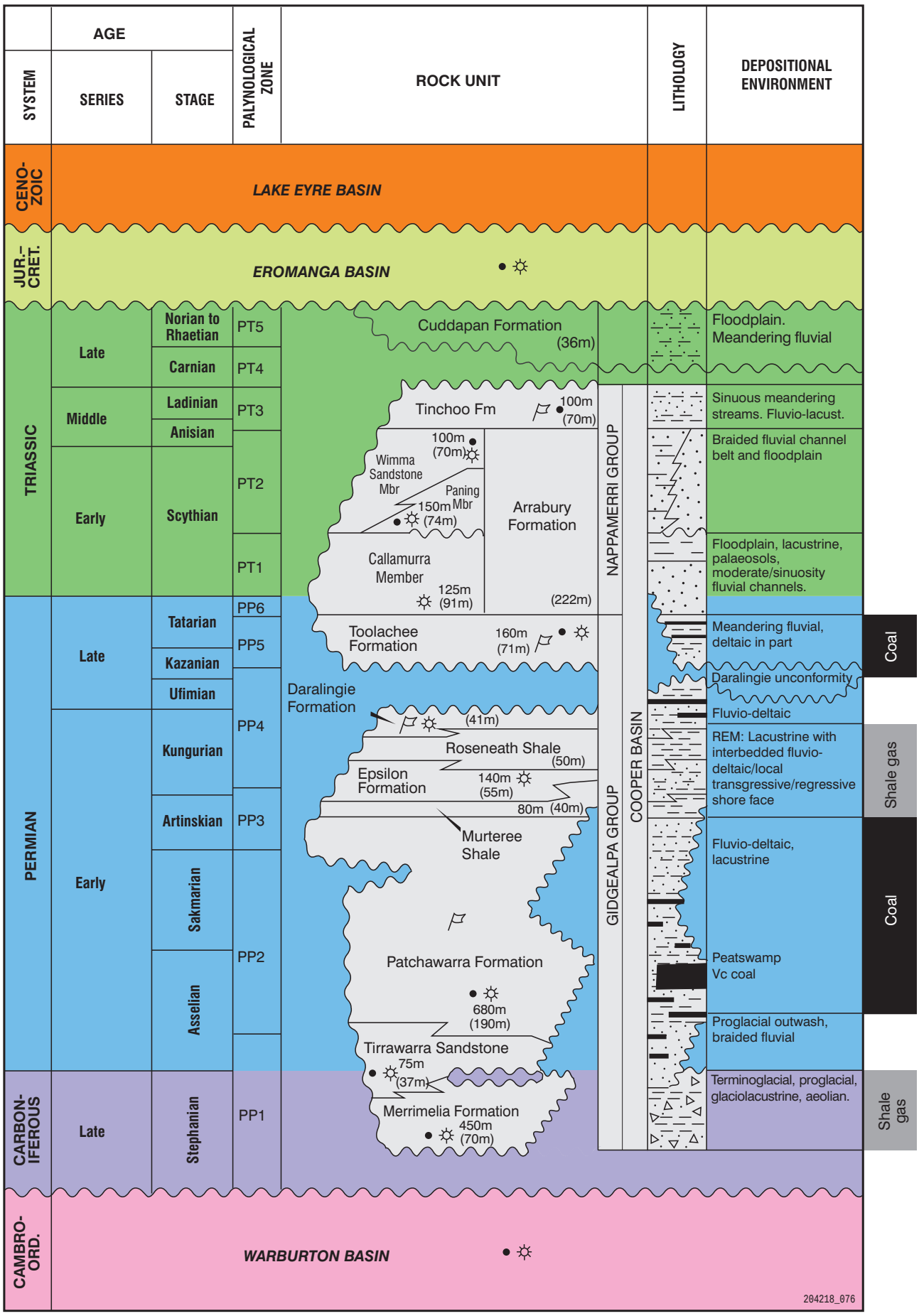


Figure 2.4 *Cooper Basin – Stratigraphy*

Moomba-Big Lake 3D seismic cube (Backé and King, 2010) identified both orthogonal patterns oriented N-S and E-W and curved lineaments that may assist in orientating future horizontal wells and fracture stimulations (Figure 2.12).

These natural fracture systems may have been naturally enhanced by the mineralogy of the clays in these lacustrine shales. Beach Energy has publicly discussed the mineral composition of the shales which are high in silica and illite with moderate siderite and absence of swelling clays which collectively are conducive to brittleness and ideal for fracture stimulation.

Gas content information is still largely unavailable as data are held confidential for two years after rig release in the case of a well or sampling event in the case of cores and cuttings. Open file information suggests lower porosity than US shales and highlights requirement for thicker and overpressured shale sections to commercialise the resource.

Shale gas reservoirs contain gas stored as both free gas and gas adsorbed to surfaces of solid organic matter. Gas adsorption capacity is a function of a number of parameters, including organic carbon content, and kerogen type.

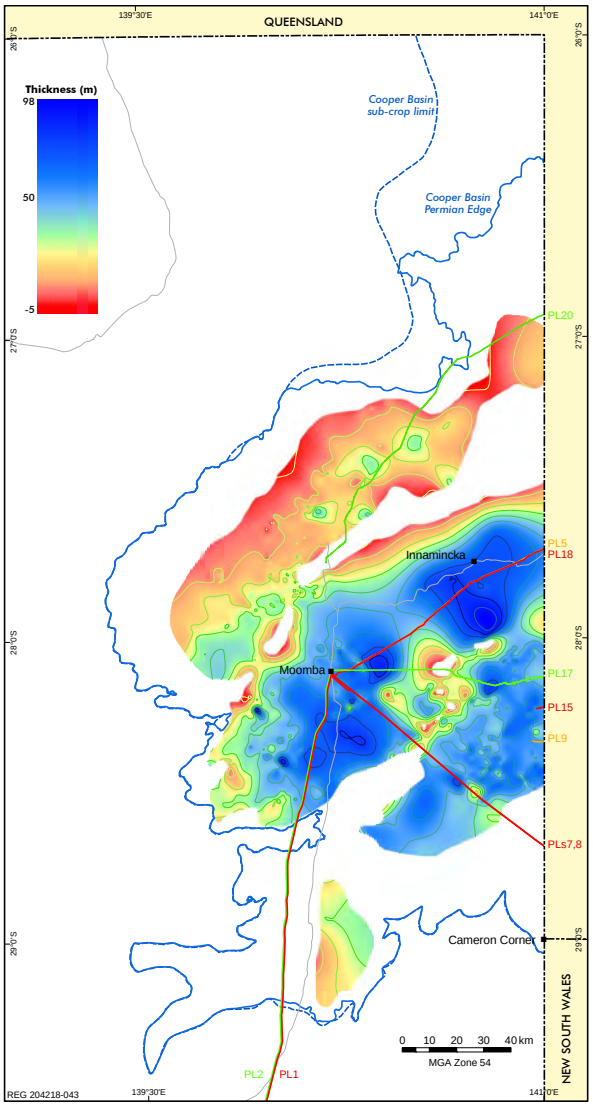


Figure 2.5 *Murteree Shale isopach*

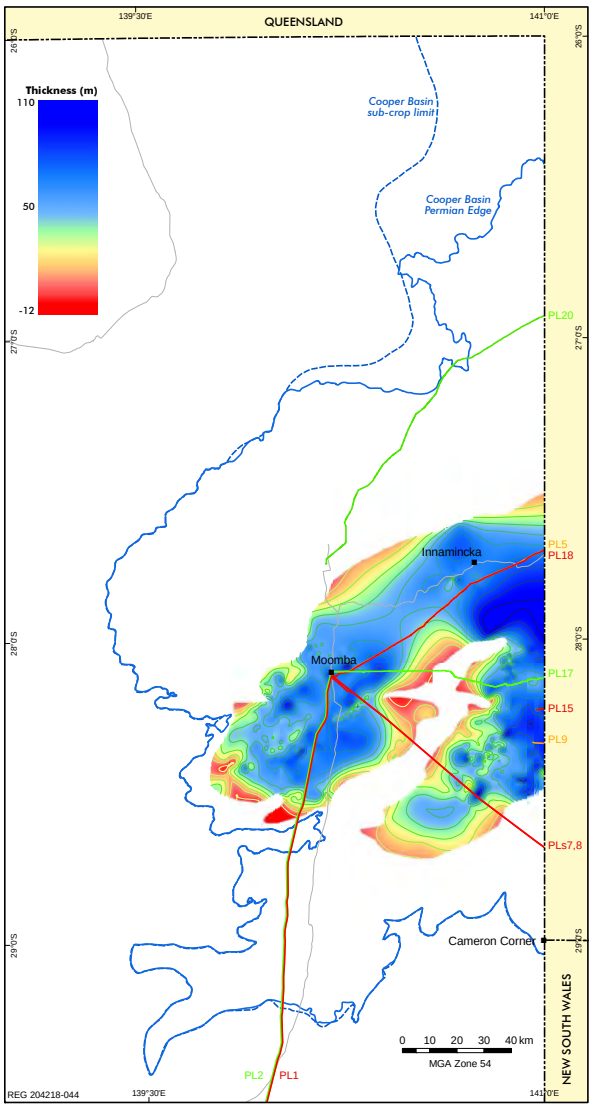


Figure 2.6 *Roseneath Shale isopach*

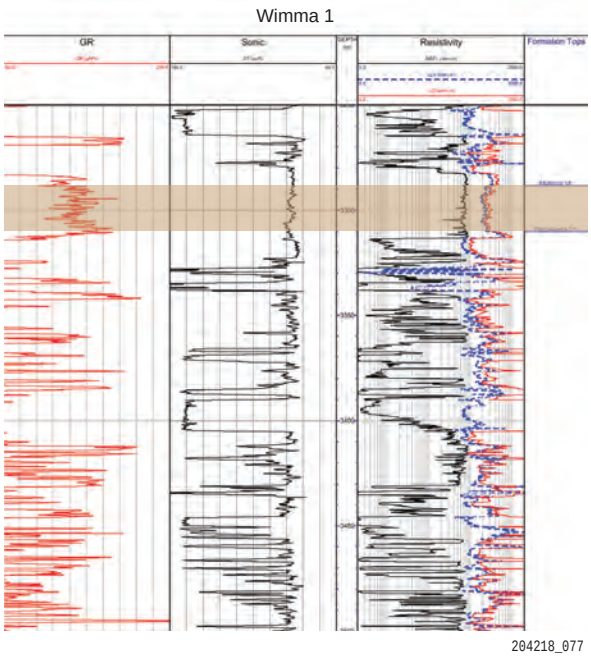


Figure 2.7 *Murteree Shale, Wimma 1, Patchawarra Trough*

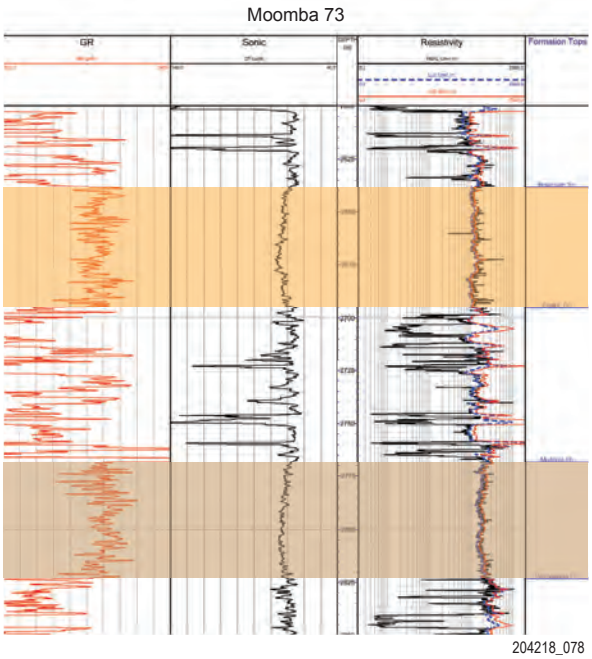


Figure 2.8 *Roseneath and Murteree shales, Moomba 73, Nappamerri Trough*

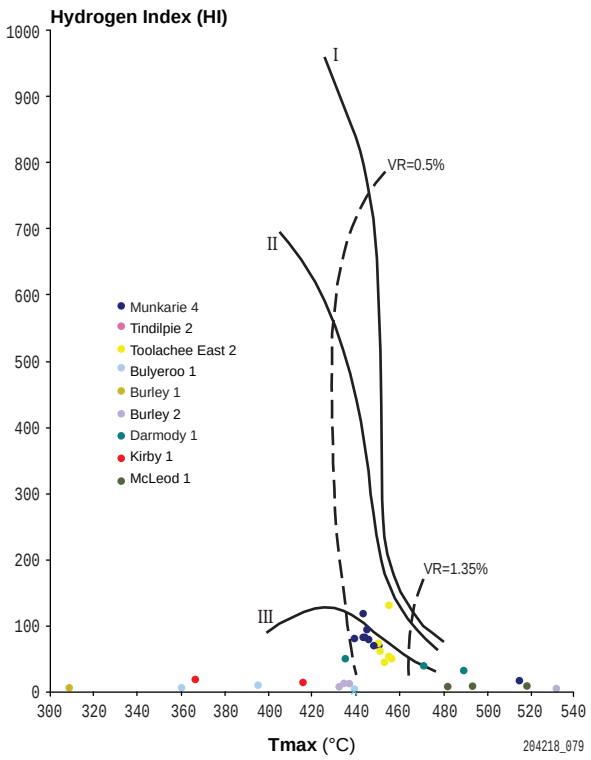


Figure 2.9 *Van Krevelen plot - Roseneath Shale*

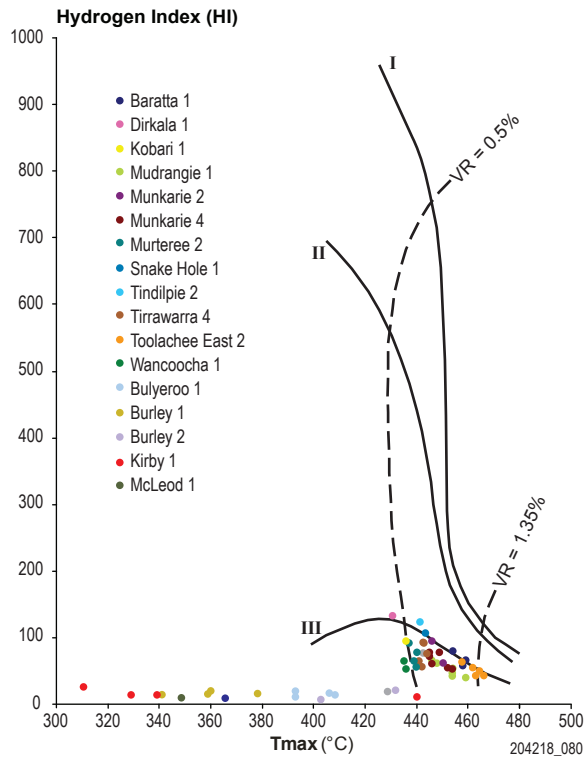


Figure 2.10 *Van Krevelen plot - Murteree Shale*

Hydrocarbon generation creates significant microporosity as nanopores within Type II kerogen (Loucks et al, 2012), increasing the surface area available for gas adsorption. As the Roseneath and Murteree shales are dominated by Type III kerogen, maturation is unlikely to result in increased adsorbed gas storage capacity characteristic of Type II source rocks. However being siltstones, these units may have considerable free gas storage capacity in mineral matrix pores and fractures.

Gas production from the Roseneath and Murteree shales has been observed in the overpressured Nappamerri Trough wells (Holdfast-1, Encounter-1 and Moomba 191) and further appraisal is planned.

2.1.2 Tight Gas Play

The presence of a basin centred gas accumulation (BCGA) in the Nappamerri Trough has been suspected for many years and the circumstantial evidence was presented by Hillis et al. (2001). Resistivity of the Permian succession exceeds 20Ωm over large intervals (Figure 2.13), tests have recovered gas with no water, and gas is located within overpressured compartments indicative of hydraulic isolation (Figure 2.14). The Santos operated Cooper Basin Joint Venture is actively reviewing tight gas associated with conventional trapping mechanisms in Permian strata throughout the basin. The JV is investigating well spacing, pad drilling, multi-stage fracture stimulation and microseismic monitoring to improve commerciality of the resource and increase recovery factors. Others can be expected to follow this lead.

The Permian succession in the Nappamerri Trough easily exceeds 1000m in the deeper parts, comprising very thermally mature, gas-prone source rocks with interbedded sands, ideal for the creation of a basin-centred gas accumulation. Excluding the Murteree and Roseneath shales, the succession comprises up to 45% carbonaceous and silty shales and thin coals deposited in flood plain, lacustrine and coal swamp environments. Thick siltstones of the Nappamerri Group may have been a regional top seal for the pervasive gas accumulation, and the Roseneath and Murteree shales will also have assisted gas containment. Generation and expulsion of hydrocarbons from the Cooper Basin source rocks occurred in the mid Cretaceous (Deighton et al., 2003), but overpressure has been retained in the Nappamerri Trough (Figure. 2.14).

The Early Permian succession in the Patchawarra Trough also has the necessary elements for basin centre gas accumulations (BCGA) e.g. gas-prone coal beds, sufficient maturity for thermal gas generation, low porosity and permeability reservoirs interbedded with the source rocks and gas shows (Law, 2002). At Wimma 1, in the deepest, most mature part of the Patchawarra Trough, overpressured gas sandstones with poor reservoir properties were encountered in the Early Permian succession.

Thick coals and organic rich shales in the Early Permian succession are capable of generating enormous hydrocarbon volumes. The total gas generative potential of the Cooper Basin source rocks has been estimated to be between 4,027 tcf to 8,055 tcf (Morton, 1998). Coal and carbonaceous shale of the Patchawarra Formation represent the principal source rocks of the Cooper Basin, both in source richness and quality, and overall thickness (Boreham and Hill 1998). Rock-Eval data (Figure 2.15) indicates that Patchawarra Formation source rocks contain a mix of both Type II and Type III kerogen[1]. Toolachee Formation coal and carbonaceous shale represent the second most important source rock unit of the Cooper Basin in terms of richness, quality and thickness. Rock-Eval data (Figure 2.16) indicate that Toolachee Formation source rocks also contain a mix of both Type II and Type III kerogen.

Average porosity and permeability maps for the Patchawarra Formation highlight the low porosities and permeabilities in the

1 For definitions of various types of kerogens – visit www.glossary.oilfield.slb.com/Display.cfm?Term=kerogen

deeper parts of the troughs (Figures 2.17, 2.18) conducive to the development of a BCGA (Heath, 1989). In the Nappamerri Trough and north-eastern Patchawarra Trough average porosities range <7% to 9% and average permeabilities range <0.1mD to 1mD. Gas wetness maps for the Patchawarra Formation (Figures 2.19, 2.20) highlight the dry nature of the gas in the deeper parts of the troughs, reflecting the high thermal maturity of the intra-formational source rocks in these areas traditionally viewed as hydrocarbon source "kitchens" (Heath, 1989).

Recent drilling in the Nappamerri Trough has targeted gas outside structural closure. Holdfast-1 and Encounter-1 have demonstrated gas production from overpressured tight sandstones in the Epsilon and Patchawarra Formations from structural lows within the Nappamerri Trough. Moomba 191 on the Moomba North structure has recently been fracture stimulated and flowed gas at 2.7 mmcf/d at systems pressures from shales in the REM section. Moomba 191 is Australia's first commercial shale gas well. There is regional

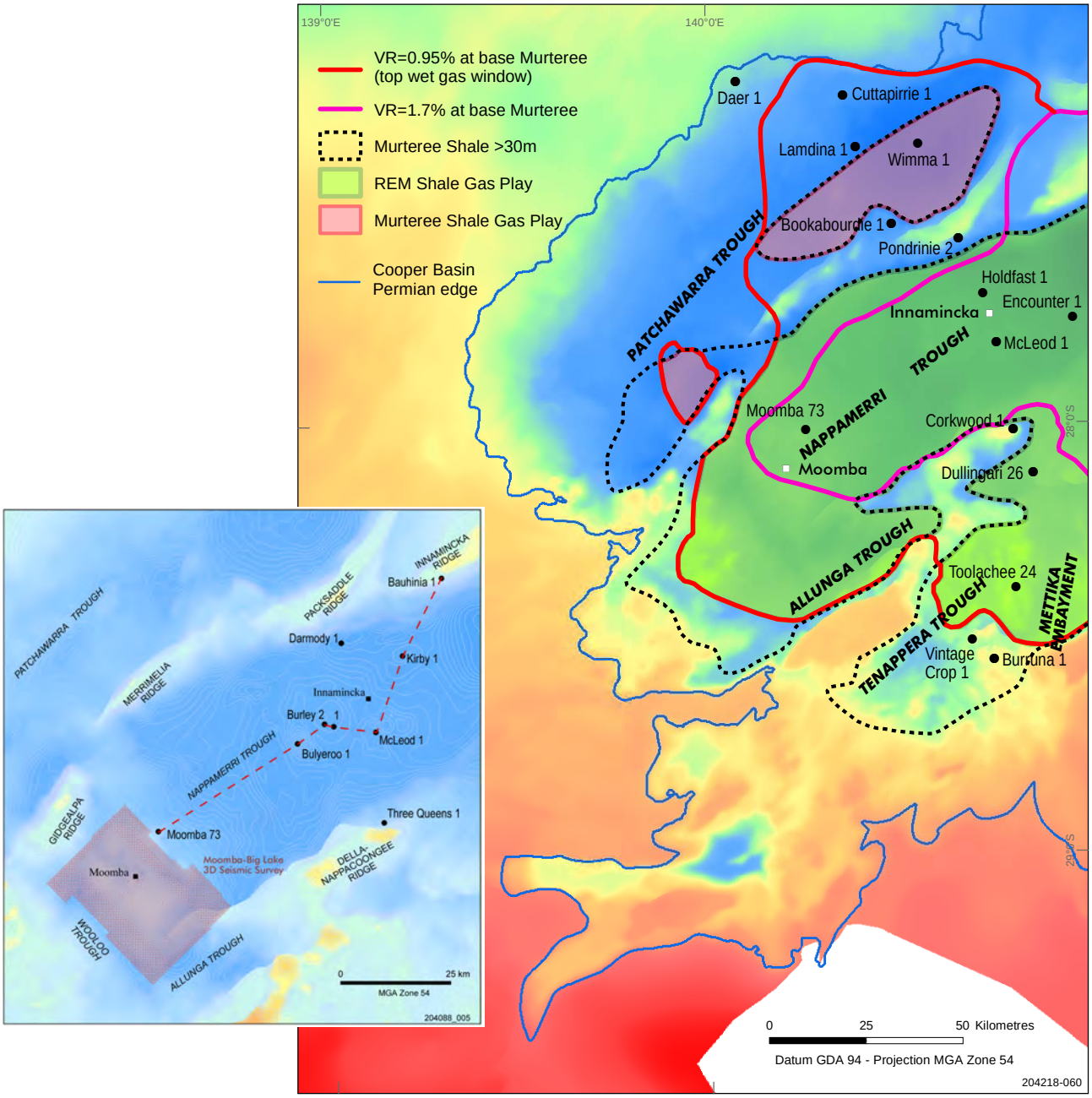


Figure 2.11 *Shale gas plays – Cooper Basin.*

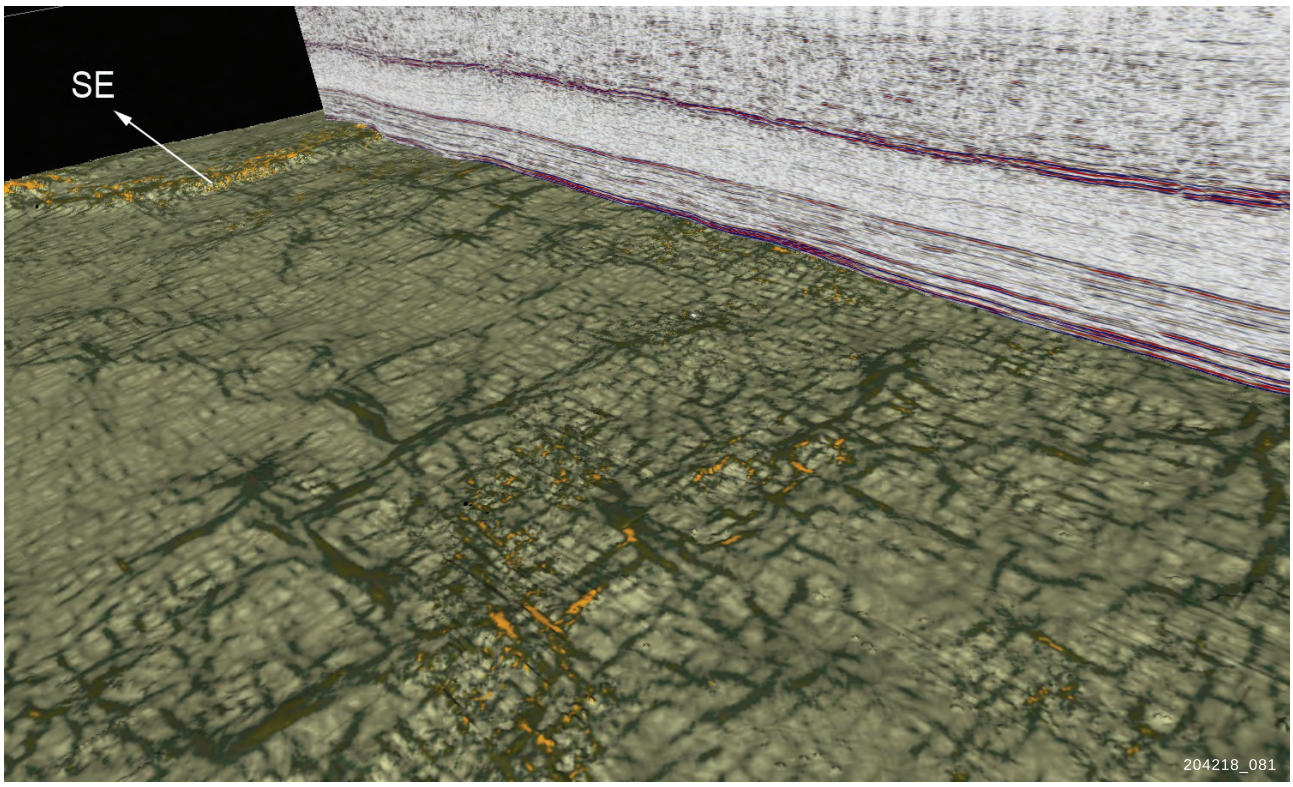


Figure 2.12 *Top Roseneath Shale pattern characterisation from Moomba-Big Lake 3D seismic cube (mapping and attribute analysis by Hani Abul Khair, supervisor Guillaume Backé). See Figure 2.11 for location of 3D survey.*

evidence to suggest the entire REM section is part of a BCGA (Figure 2.14).

Regional pressure gradient, average porosity, average permeability and gas saturation maps for the Patchawarra Formation sands and Epsilon Formation sands will assist in defining the areas of BCGA plays in the Cooper Basin. These maps will be prepared for a new edition of the Petroleum Geology of South Australia, Volume 4, Cooper Basin.

Table 2.1 Coal seam thickness for Patchawarra and Toolachee formations.

Coal Seam Thickness (m)	Patchawarra Formation	Toolachee Formation
Average	2.1	4.3
Maximum	22.3	21.9
Minimum	0.3	0.3
% seams >2 m	29.8	42.4

2.1.3 Deep Coal Seam Gas Play

The Gidgealpa Group is characterised by coal measures, especially in the Patchawarra, Epsilon and Toolachee formations. Thick, laterally extensive coal seams have been intersected in both the Patchawarra Formation and the Toolachee Formation (Figure 2.21).

The Patchawarra Formation was deposited in a coal-dominated fluvial/lacustrine depositional environment, with fluvial channel and point bar sandstones the principal conventional reservoirs, characterised by relatively low porosity and permeability (Strong et al., 2002). Individual coal seams occur throughout the formation and range in thickness from 0.3 m up to a maximum of 22.3 m (Table 2.1– excludes the results of recent drilling, in particular Davenport 1) with a combined thickness in excess of 60m in the Patchawarra Trough (Figure 2.21).

The VC50 chronostratigraphic (time-rock) unit corresponds to the thickest laterally extensive coal seam in the Patchawarra Formation, and to the Vc seismic horizon (Strong et al, 2002, Alexander et al, 1998). Examples of a thick VC50 coal seam, ranging 13 m to 23 m, are given in Table 2.3.

The base Patchawarra Formation maturity map shows that the Patchawarra Formation is sufficiently mature for the generation of gas from coal seams over much of the basin (Figure 2.22). High mud gas readings[2] are generally recorded when mature Patchawarra Formation coals are intersected in wells (Table 2.2).

The Patchawarra coal seams are deeper than 2000 m over most of the Cooper Basin. The floor for CSG production is generally considered to be 2000 m due to cleat closure and permeability reduction at these depths. However scanning electron microscopy of VC50 coal core samples from Bindah 3 has shown that the coals contain significant mesoporosity[3] (ACS Laboratories Report, 2011). The mesoporosity is a consequence of the high inertinite content of the coals (inertinite is derived from charred and biochemically altered plant cell wall material that generally remains intact during the carbonization process. The VC50 coal is thick and laterally continuous

2 Gas chromatography measurements on drilling fluids (drilling mud) pumped from the bit face to the surface enables the detection of rocks with relatively high gas saturations.

3 Micropores with diameters between 2 and 50 nanometers (10^{-9} metres)

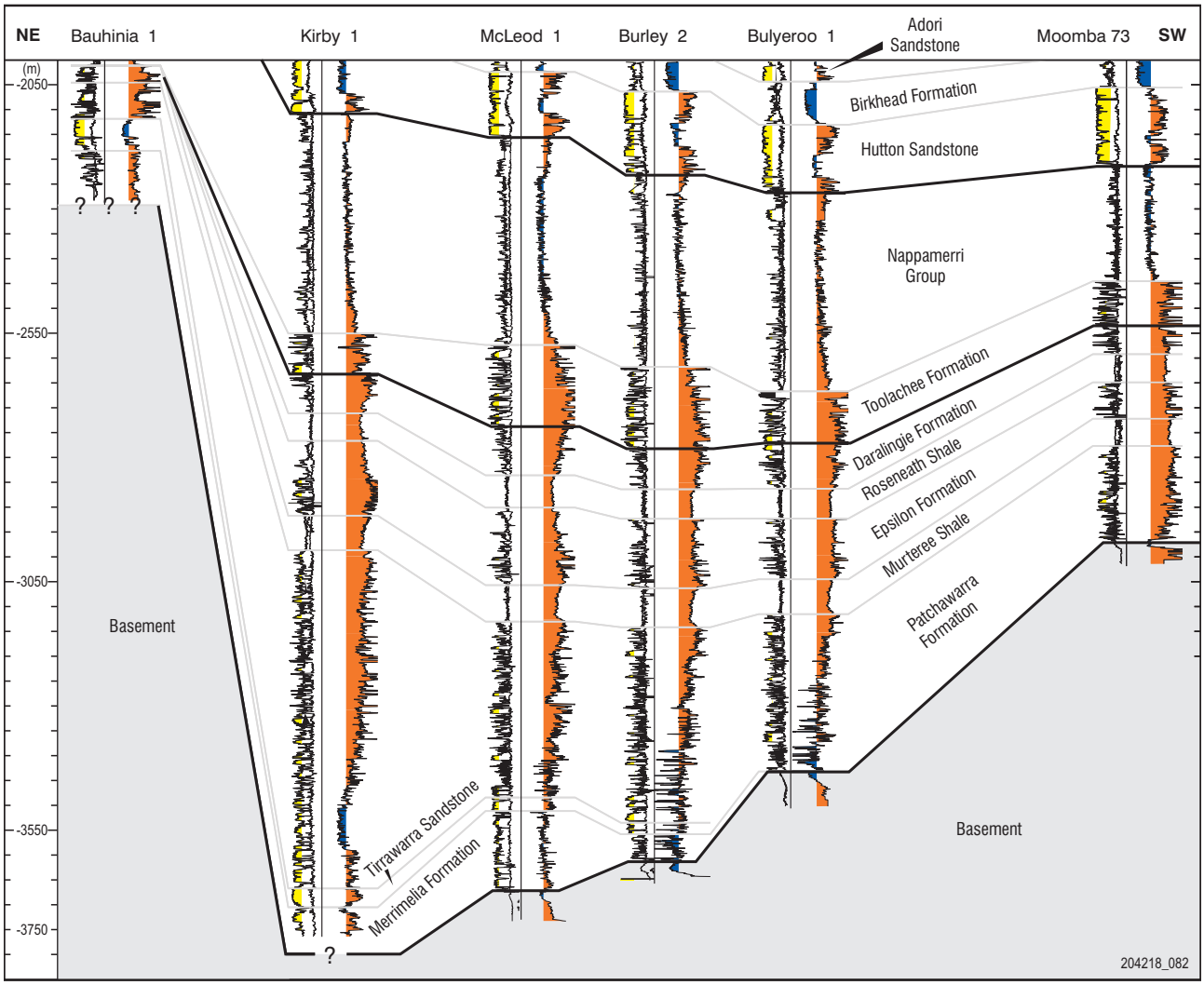


Figure 2.13 *Geological cross section, Nappamerri Trough showing elevated resisitivities (from Hillis et al, 2001). See inset on Figure 2.11 for line of section.*

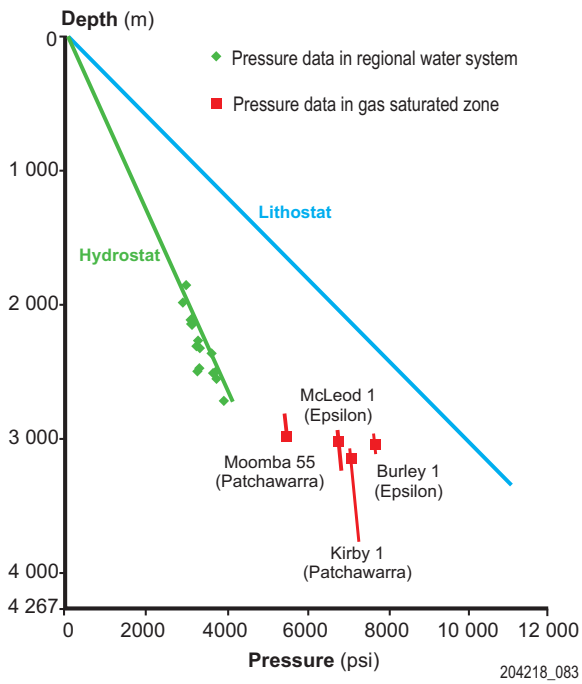


Figure 2.14 *Evidence for overpressured compartments in the Nappamerri Trough (from Hillis et al, 2001)*

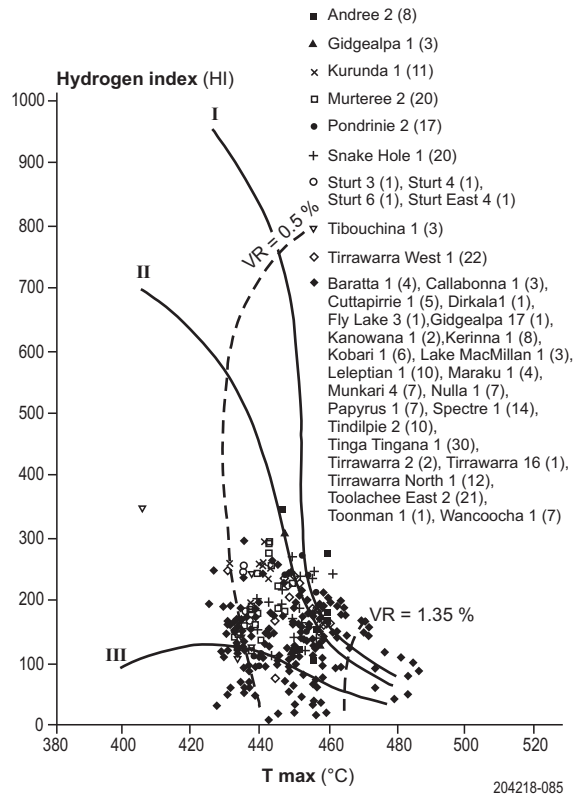


Figure 2.15 *Van Krevelen plot – Patchawarra Fm.*

in parts of the Basin and may be suited to gas extraction using horizontal drilling and hydraulic stimulation techniques. Targeting natural fracture systems is likely to enhance production rates and optimise drainage. The coals are expected to be gas saturated, so de-watering will not be necessary.

Assessment of the deep coal seam gas potential of the basin commenced with desorption analysis of a 4m Patchawarra coal seam cored in Dorodillo 2 gas appraisal well in1998. Further assessment of deep coal seam gas was suspended until 2007, when Santos flowed gas to surface at 100,000 scf/day from a fracture stimulated Patchawarra Formation coal in Moomba 77 gas development well (Figure 2.24). Since then additional deep coal seam gas assessment work, including coring the VC50 coal seam for analysis, has been carried out in several gas development wells. Gas desorption analysis of the VC50 coal seam cored in Bindah 3 returned excellent total raw gas results averaging 21.2 standard cubic centimetre per gram[4] (scc/g which

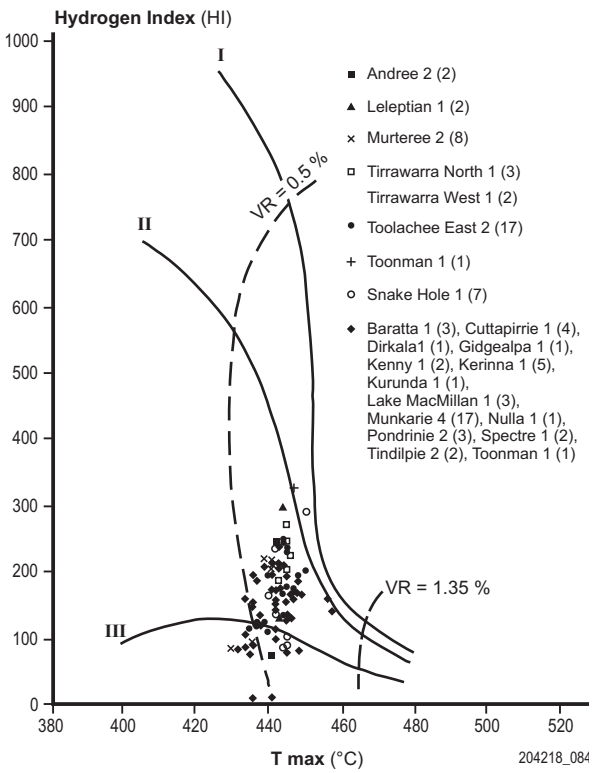


Figure 2.16 *Van Krevelen plot – Toolachee Fm*

4 1 scc/g is equivalent to 680 standard cubic feet per ton (scf/ton)

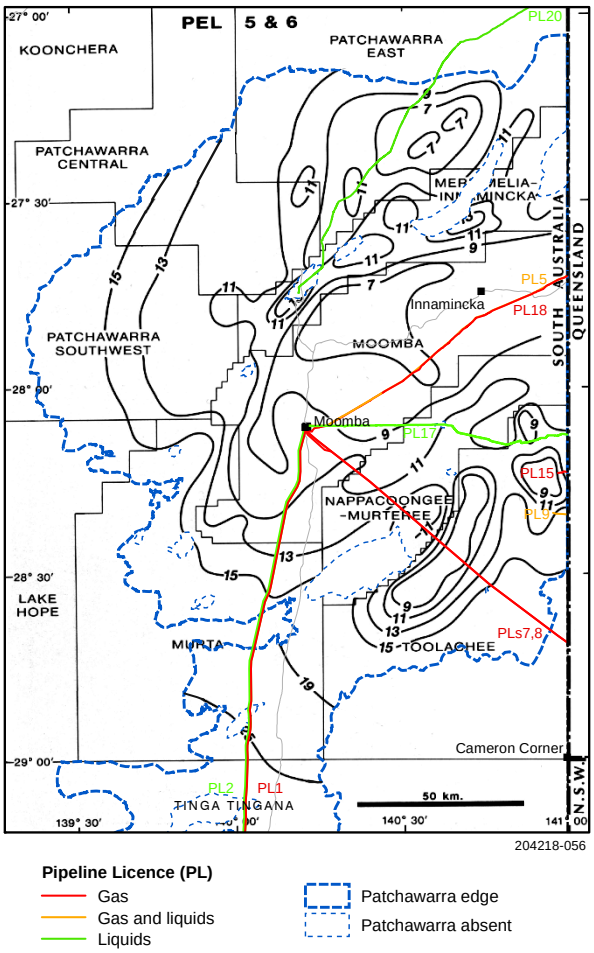


Figure 2.17 *Average Porosity, Patchawarra Formation (after Heath, 1989)*

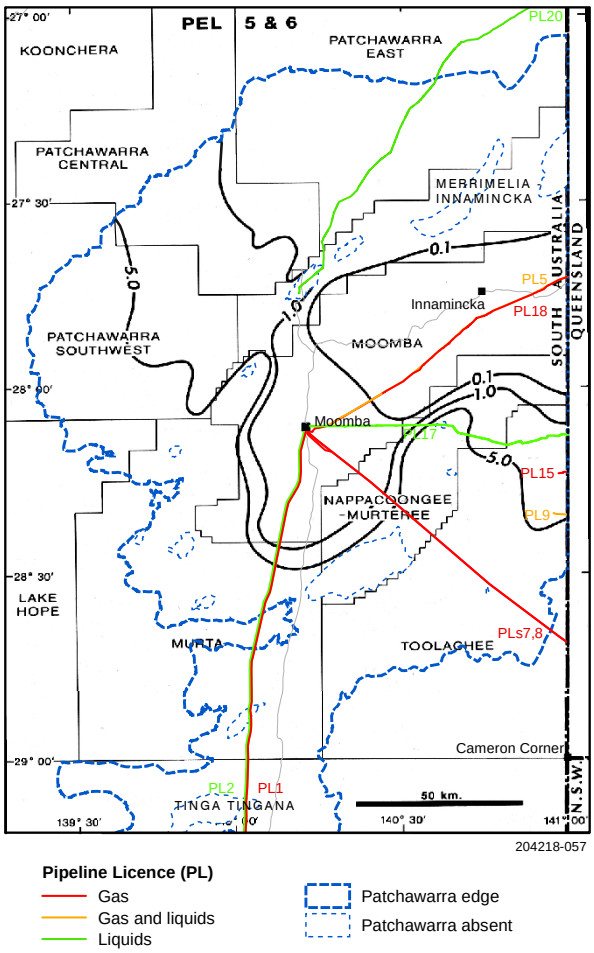


Figure 2.18 *Average Permeability, Patchawarra Formation (after Heath, 1989)*

is equivalent to 680 standard cubic feet per ton (scf/ton) over 10 metres (ACS Laboratories Report, 2011). Whilst the carbon dioxide (CO_2) content of the desorbed gas was high, CO_2 levels around the Basin are highly variable and lower CO_2 contents are expected in other parts of the Basin.

Recent drilling in the Milpera Trough has extended the area of known thick coal development in the Cooper Basin, and indications of thermal gas generation will require reworking of thermal maturity maps. Davenport 1 encountered over 110 m of net coal with elevated gas readings, including a 45 m thick Patchawarra coal, the thickest known coal in the Cooper Basin.

Table 2.2: VC50 Coal seam thickness and mud gas recorded whilst drilling

Well Name	VC50 Seam Thickness (m)	Total Gas (units)
Bindah 3	19	80 – 500
Meranji South 1	16	1000
Cowralli 1	18	1000 – 2000
Cowralli 10	16	2065 – 3550
Kanowana 2	18	600 – 900
Tindilpie 7	16	1000
Dorodillo 4	13	100 – 1000
Battunga 1	23	1835
Wimma 1	14	2800

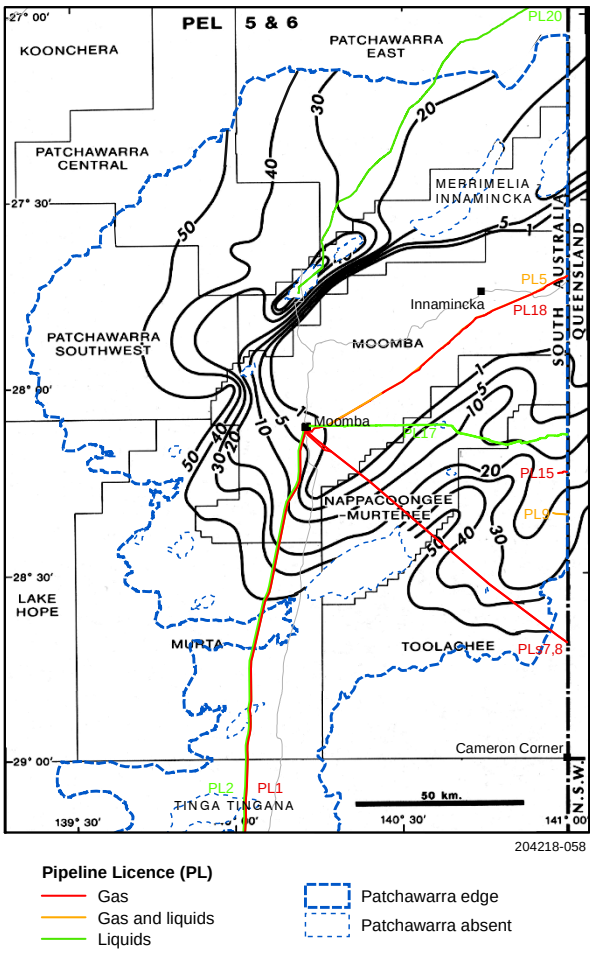


Figure 2.19 *Barrels of LPG/mmcf raw gas, Patchawarra Formation (after Heath, 1989)*

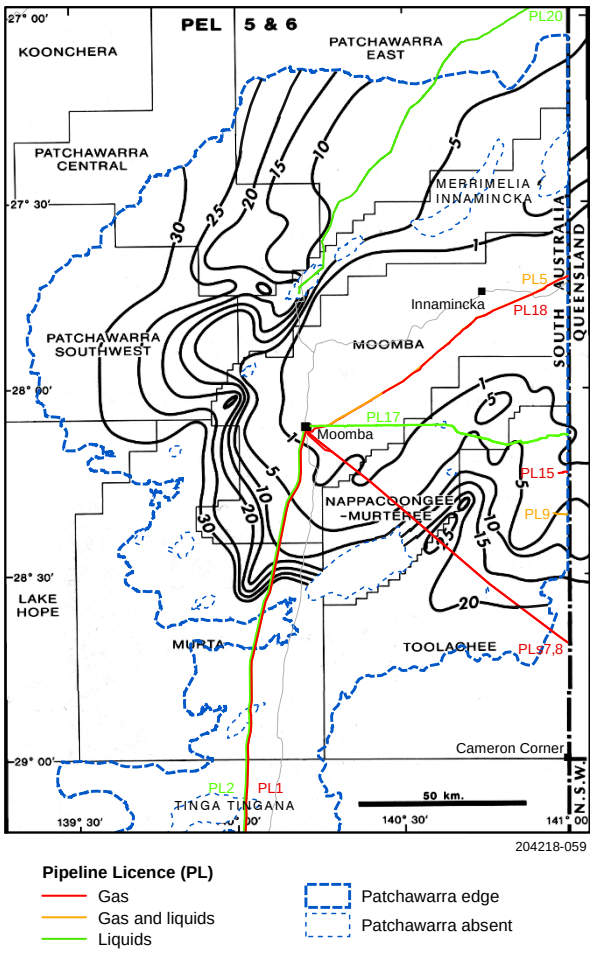


Figure 2.20 *Barrels of condensate/mmcf raw gas, Patchawarra Formation (after Heath, 1989)*

Thick, laterally extensive coal seams are also characteristic of the Toolachee Formation (Figure 2.21). The Toolachee coals are sufficiently mature for thermogenic gas generation in the Nappamerri and Arrabury troughs, and parts of the Patchawarra Trough (Figure 2.23), and high mud gas readings have been recorded whilst drilling through mature Toolachee coals (e.g. Paning 1).

2.1.4 Eromanga Basin Shallow Coal Seam Gas Play

The principal shallow coal seam gas play in the Eromanga Basin (which disconformably overlies the Cooper Basin) is the Cenomanian to Turonian Winton Formation that comprises up to 1200 m of non-marine shale, siltstone with minor coal layers. Individual coal seams appear to be thin (~1 to 2 m) and not laterally extensive.

In late 2009, AGL Energy Ltd, in joint venture with Acer Energy Ltd, conducted a 3 core hole drilling program centred over the Innamincka Dome (Figure 2.11). Merninie 1, 2 and 3 wells were drilled to depths of 699 m, 518 m and 600 m respectively and core samples for desorption analysis taken, although final results are yet to be made available. However, ACER Energy in their quarterly statement in April 2010 indicated that preliminary results conclude that whilst coals appear sufficiently mature, coal thickness and gas content are below commercial thresholds within current commercial parameters. As such, the JV partners recognise that a standalone CSG development is unlikely to proceed.

Exploration for shallow Winton Formation coal seam gas has not commenced elsewhere in

(a) **(b)**

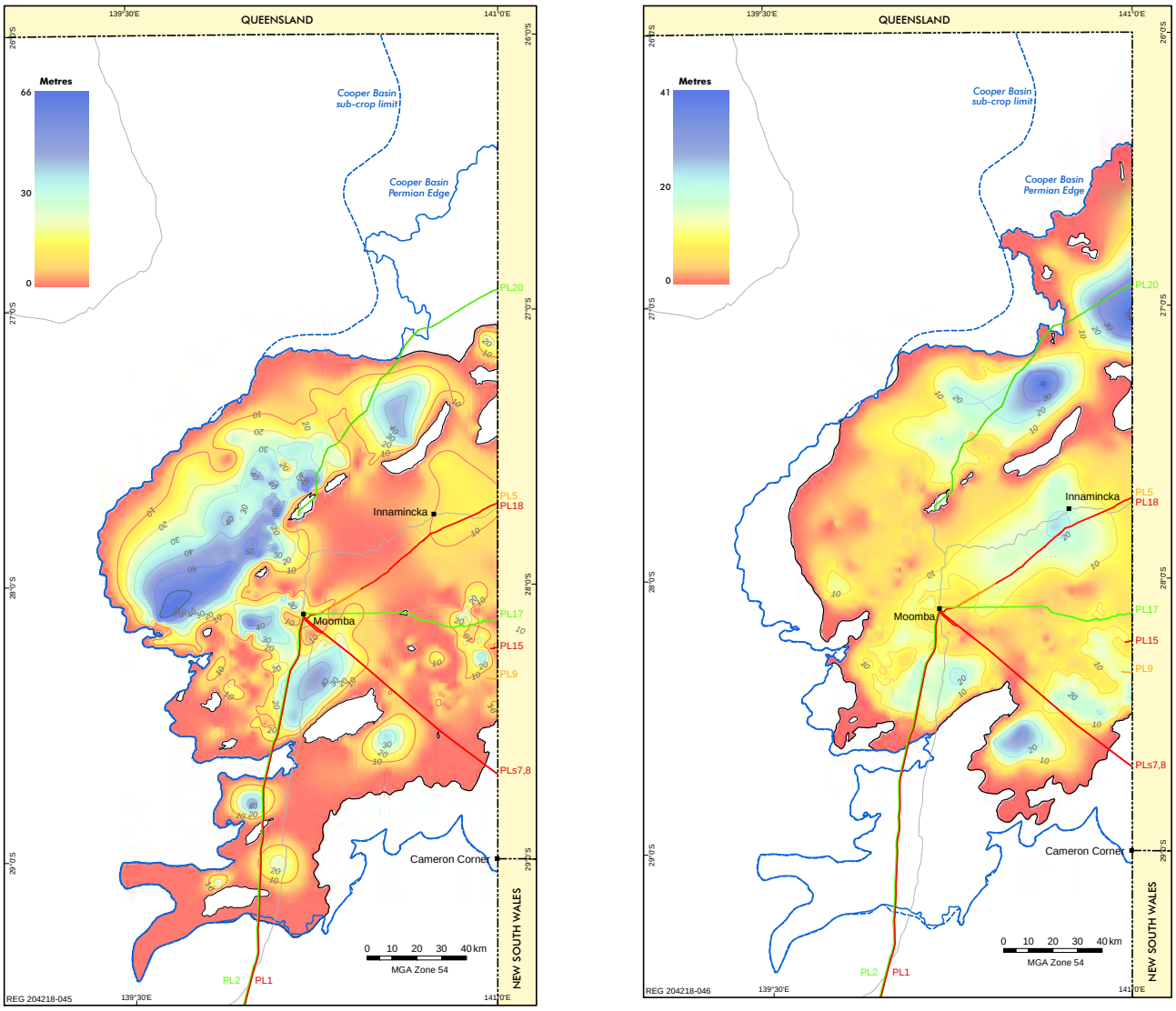


Figure 2.21 *Coal isopach maps* ***(a)*** *Patchawarra Fm;* ***(b)*** *Toolachee Fm*

the SA part of the basin, and its prospectivity is not yet well understood. Facies mapping within the Winton Formation across the basin may enable identification of more coal-prone areas and help focus exploration for this shallow play. In Queensland, coaly Birkhead Formation equivalent (e.g. Walloon Coal) occurs at shallow depths towards the eastern margin of the Eromanga Basin and forms another play. However, in SA finer grained and coaly Birkhead facies best developed in the Cooper depocentre, are laterally equivalent to sandy, braided fluvial Algebuckina Formation and do not occur at shallow depths on the basin margin.

2.2 Arckaringa Basin

The Arckaringa Basin is a Permo-Carboniferous intra-cratonic basin located approximately 750 km north-west of Adelaide (Figure 2.25).

The Basin comprises two main depocentres, the Boorthanna Trough in the east, and the southern Arckaringa troughs (including the West, Phillipson, Penrhyn and Wallira troughs) in the south, separated by shallow basement with a thin veneer of Permian sediments (Figure 2.26). The troughs contain up to 1300

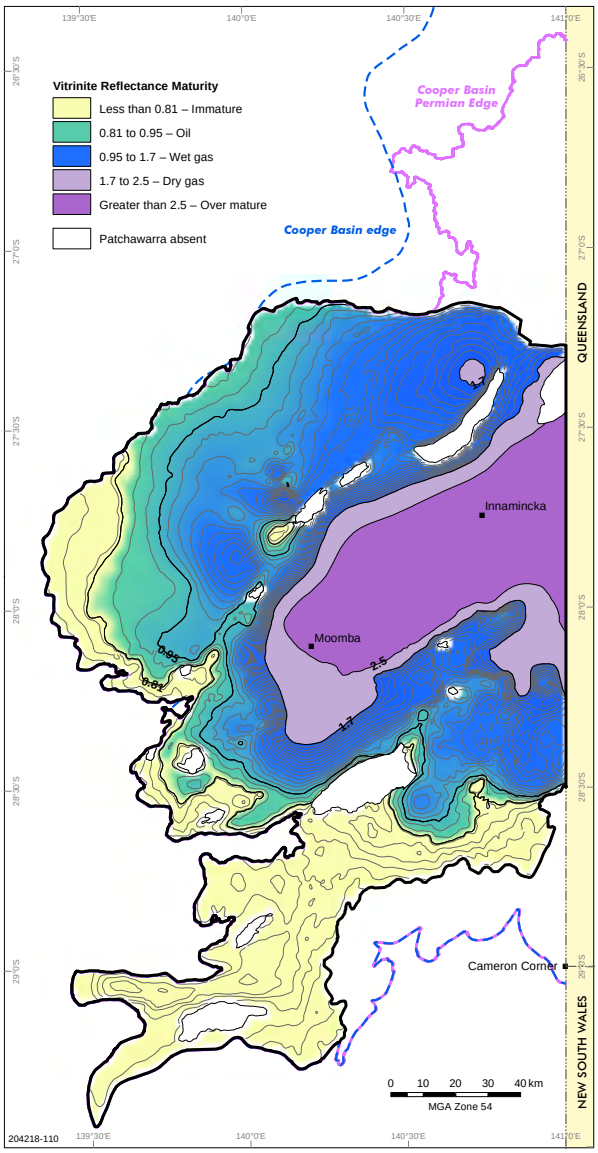


Figure 2.22 *Base Patchawarra Formation Maturity Map*

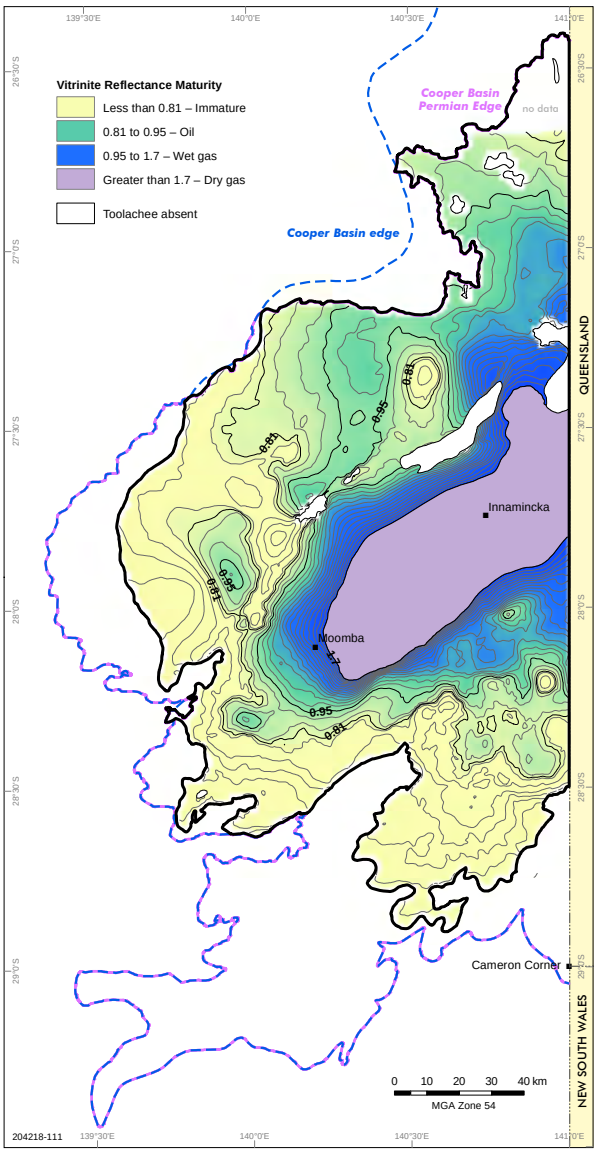


Figure 2.23 *Top Toolachee Formation Maturity Map*

m of Carboniferous-Early Permian sediments overlain by up to 300 m of Eromanga Basin sediments and generally less than 10 m of Tertiary cover. The Boorthanna Trough is broad, and underlain in part by Neoproterozoic and early Palaeozoic sediments of the Adelaide Rift complex. The southern Arckaringa troughs are narrow, and underlain by Archaean to Early Mesoproterozoic rocks of the Gawler Craton. Both depocentres show evidence of infill of basement topography.

The Permo-Carboniferous succession in the Arckaringa Basin has been divided into three formations (Figure 2.27) based on lithology and stratigraphic relationships (Hibburt, 1984). The Boorthanna Formation, possibly extending into the Late Carboniferous, comprises a glaciogene sequence with marine facies towards the top. Lithologies include diamictite (most probably paleo-glacial deposits), rhythmically bedded sandstone (probably representing deposition by turbidity currents) and laminated mudstone. The overlying Stuart Range Formation is generally homogeneous shale with minor siltstone and sandstone, deposited in quiet, restricted marine conditions but with occasional lacustrine intervals. This is in turn overlain by Mt Toondina Formation consisting of a lowermost deltaic sequence and an

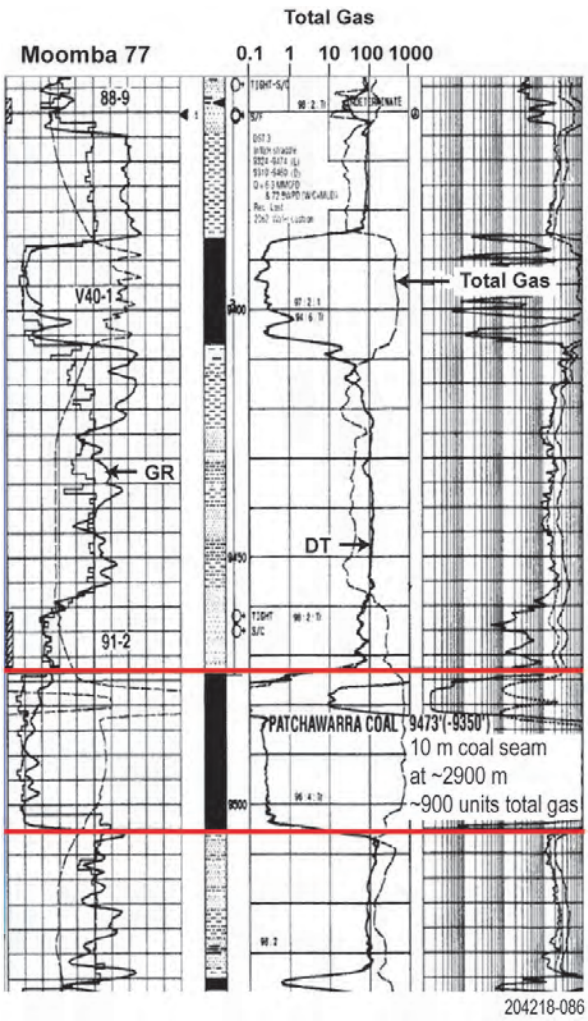


Figure 2.24 *Moomba 77 Patchawarra Coal Fracture stimulation coals at 9000ft flows 0.1 mmcf/d.*

uppermost fluvio-lacustrine succession with intermittent coal swamp development.

The history of the basin is summarised as follows (see Menpes et al, 2010):

1. Incision of deep glacial valleys (Figure 2.28)
2. Valleys fill with glacial and marine sediments of the Boorthanna and Stuart Range formations – some seismic evidence of sea-level fluctuations and minor contraction.
3. Progradation of the Mount Toondina delta system over the basin. Minor differential growth of this succession, as indicated by seismic and coal seam geometries, may be the result of ongoing minor contraction and differential compaction.
4. Contraction culminates with gentle folding of the succession, uplift and erosion. Vitrinite reflectance profiles from exploration wells suggest that the Permian has been subjected to pre-Jurassic uplift and erosion in the order of 0.5–1 km. Coal seam correlations demonstrate the subcrop relationship of the coal seams beneath the Eromanga Basin, indicating that folding and erosion occurred prior to deposition of the Eromanga Basin.

The absence of sediments younger than Sakmarian in age suggests the termination of deposition in the Arckaringa Basin and gentle folding of the succession may be related to the breaks in deposition identified in the Patchawarra Formation of the Cooper Basin (Gravestock and Jensen-Schmidt, 1998). Alternatively the final end to sediment accumulation event may be related to an uplift and erosion event recognised as the Daralingie unconformity between the Early and Late Permian in the Cooper Basin, or the end of the Hunter-Bowen Orogeny[5], which is essentially coincident with the unconformity at the top of the Cooper Basin succession.

To the end of 2011, 7 petroleum wells, 9 coal seam gas exploration wells, 14 stratigraphic wells and many mineral and coal exploration holes have been drilled in the Arckaringa Basin (Figure 2.25). Over 6000 line kilometres of 2D seismic data have also been acquired.

2.2.1 Arckaringa Basin Coal Deposits

Seven deposits of lignite A/sub-bituminous C rank coal (American Society for Testing and Materials classification) aggregating more than 20 Gigatonne (Gt[6]) of measured, indicated and inferred resource have

5 For definitions of orogeny – visit http://en.wikipedia.org/wiki/Orogeny. For a description of the Hunter-Bowen Orogeny – visit http://en.wikipedia.org/wiki/Hunter-Bowen_orogeny

6 One Gt equals 10^9 tonnes

been identified in the upper part of the Mt Toondina Formation (Figure 2.25). These are multi-seam deposits with individual seams ranging up to 10 m, with a cumulative thickness of up to 35 m (DMITRE Resources and Energy Group, 2012).

2.2.1.1 Arckaringa Coalfield:

The Arckaringa Coalfield comprises four deposits with a combined resource estimate of 10 billion tonnes of low grade, sub-bituminous coal (Figure 2.29). Heat value, moisture and ash contents of the coal are relatively uniform through the coalfield (DMITRE Resources and Energy Group, 2012):

- Low ash – 6% in-situ
- Low sodium in ash – 0.8 to 2.2%
- Heat value of 18 megajoules per kilogram (MJ/kg)
- Variable sulphur content

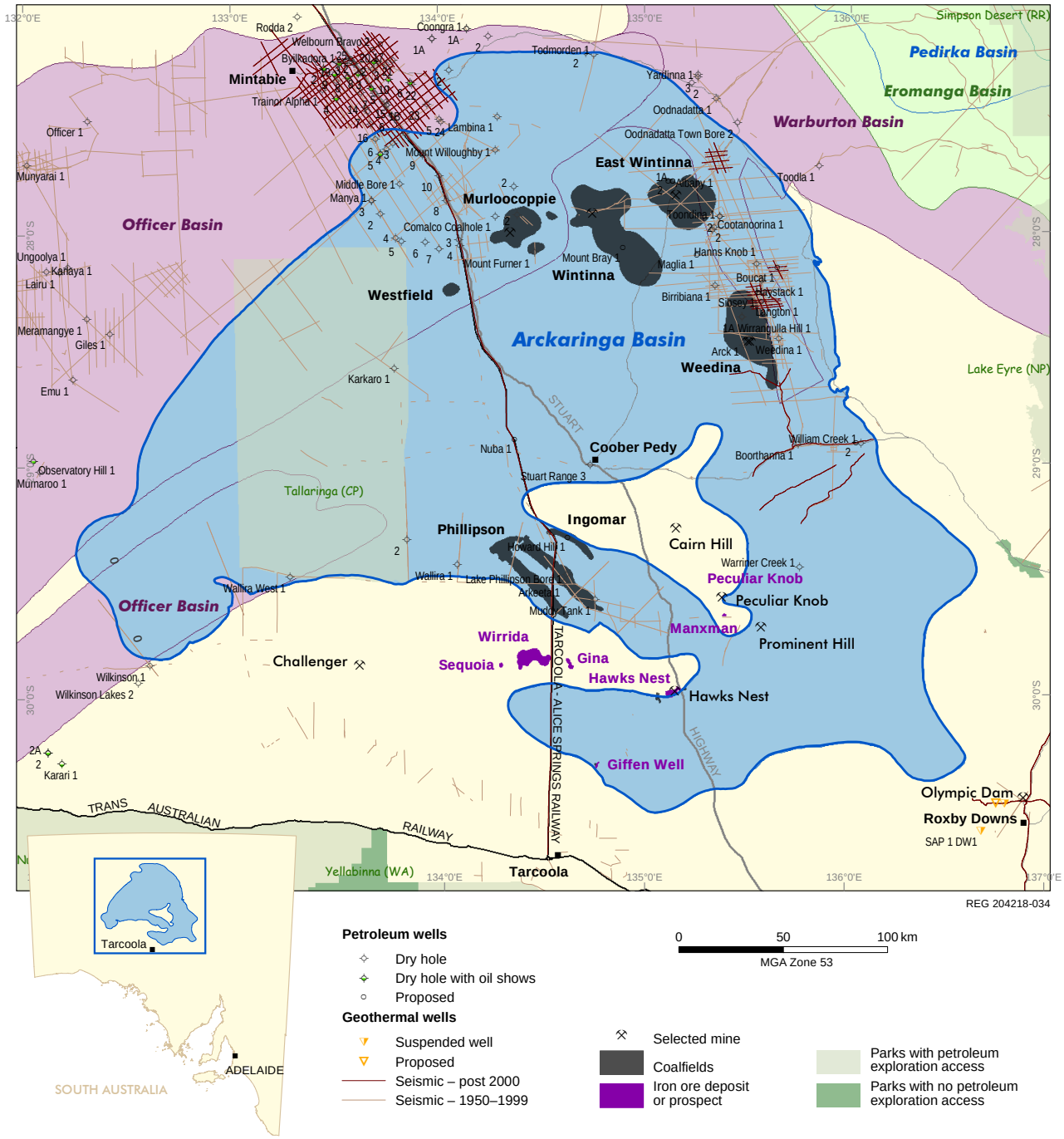


Figure 2.25 *Arckaringa Basin petroleum wells, seismic lines and coal deposits.*

The four deposits are summarised in Table 2.3

Weedina Deposit

The Weedina Deposit has an estimated coal resource of 7.2 billion tonnes (DMITRE Resources and Energy Group, 2012). The overburden contains the major aquifers of the Great Artesian Basin. The coal is suitable for conventional pulverised (coal) fuel power stations. The deposit is summarised in Table 2.4.

2.2.1.2 Lake Phillipson Coalfield

The Lake Phillipson Coalfield comprises two deposits associated with three glacial valleys scoured by the Permo-Carboniferous Gondwanan glaciation (Figure 2.30). The Phillipson Deposit has an estimated coal resource of 5 billion tonnes and has a comparable coal quality to other Arckaringa Basin coal deposits except for high sodium and chlorine levels (about 2%) (Figure 2.31). The Ingomar Deposit has an approximate inferred resource of 700 million tonnes with generally high levels of impurities such as sulphur, sodium and chlorine (Figure 2.32) (Caplygin and Shaw, 1996). The two deposits are summarised in Table 2.5.

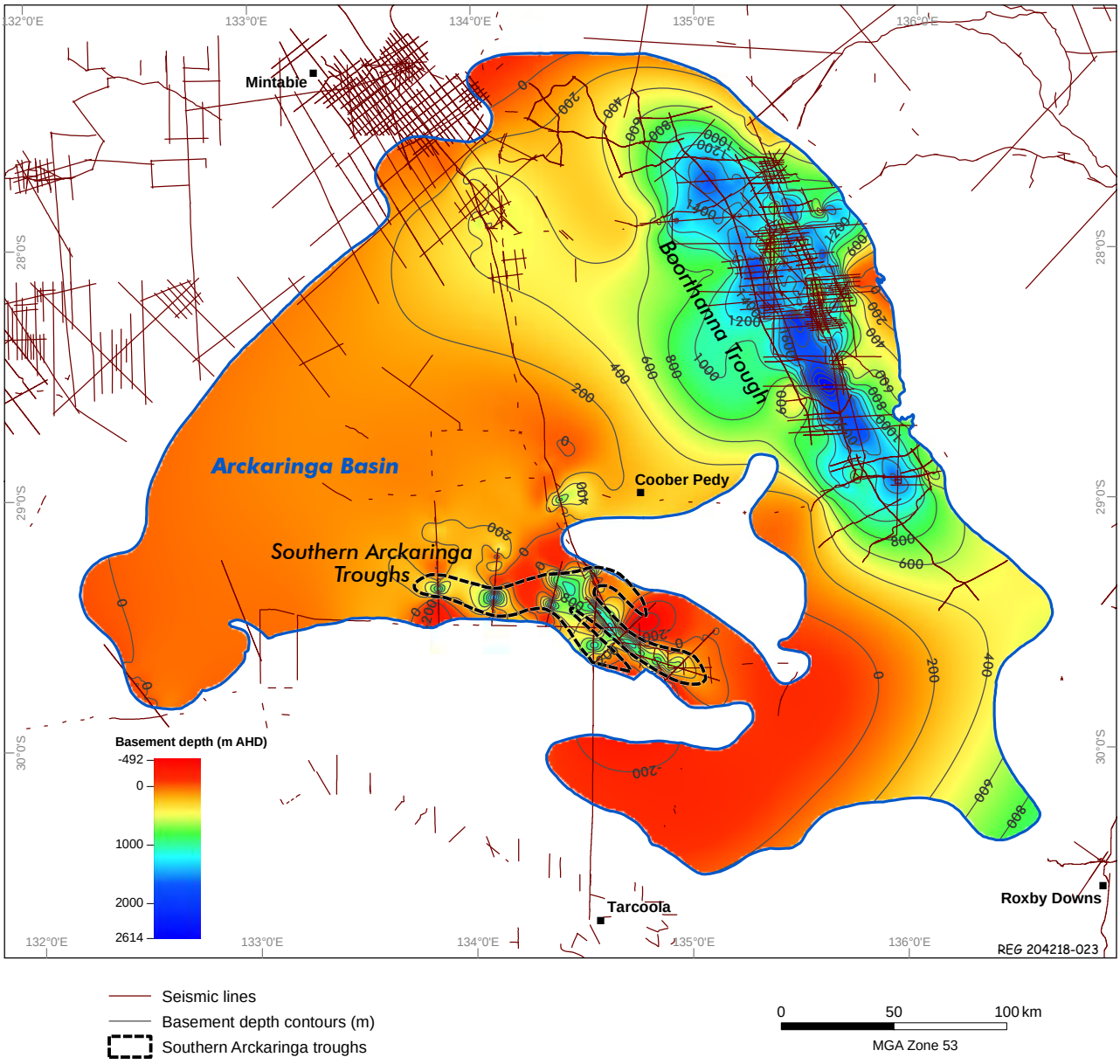


Figure 2.26 *Arckaringa Basin, Basement Depth Structure Map*

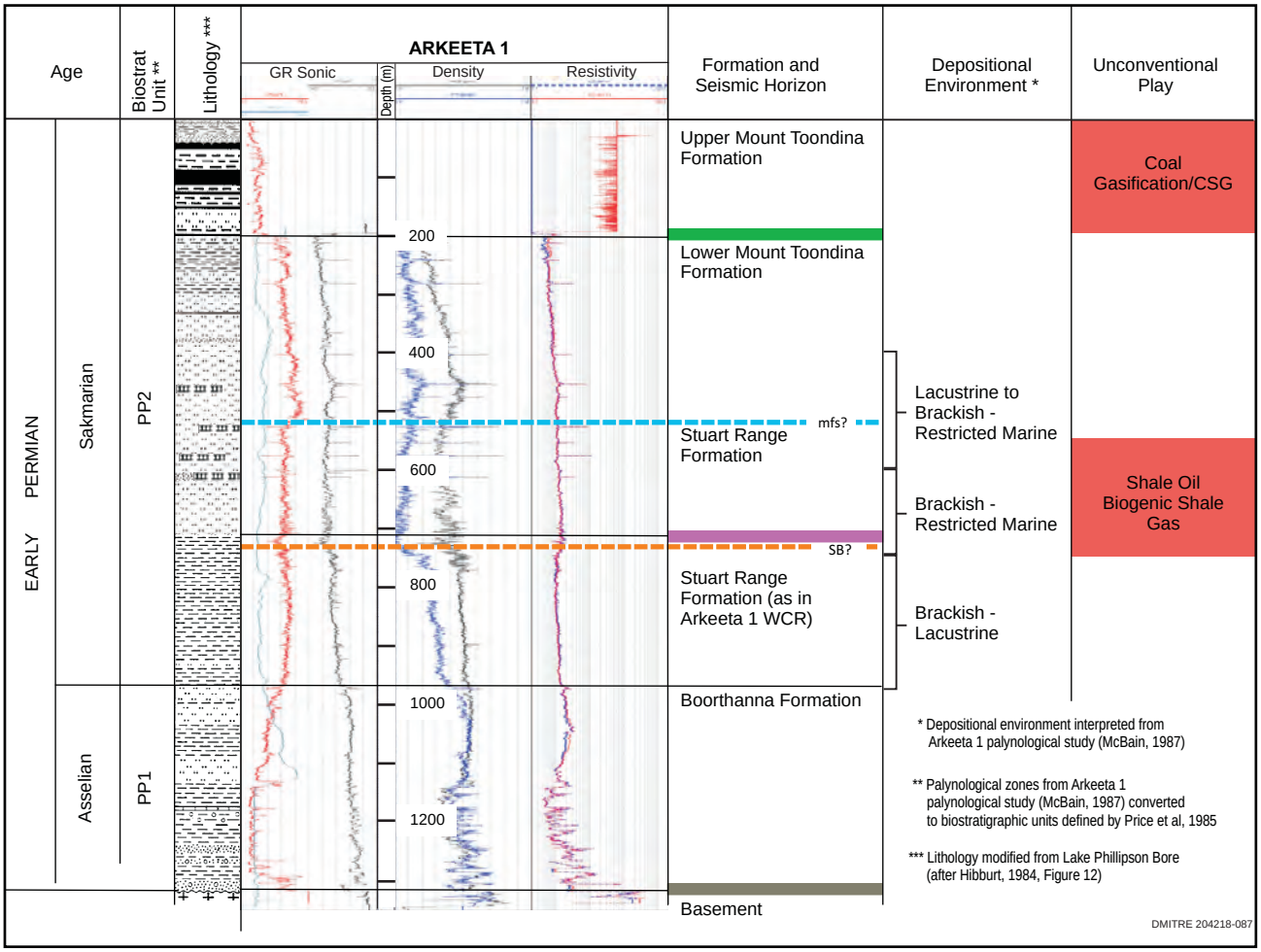


Figure 2.27 *Southern Arckaringa Basin stratigraphy, based on Arkeeta 1. SB = Sequence Boundary; mfs = maximum flooding surface.*

2.2.2 Coal Gasification Play

The coal deposits of the Arckaringa Basin are being explored for their coal gasification and coal seam gas potential.

The Arckaringa Coal-to-Liquids and Power Project, a Joint Venture between Altona Energy and partner CNOOC New Energy Investment Co., Ltd. (CNOOC-NEI), is well advanced. The Joint Venture is completing a bankable feasibility study for mining part of the Wintinna coal deposit (10Mtpa base case) supplying coal to a coal-to-liquids plant with an output of 10 MMbbls per annum liquid fuels (mainly ultra clean diesel) as well as a co-generation power plant delivering 560 MW per annum to the national power grid (Schrape, 2011). Elsewhere in the Arckaringa Basin, Linc Energy is assessing coal deposits for in-situ gasification and coal seam gas prospectivity.

2.2.3 Coal Seam Gas Play

The Arckaringa Basin coals are lignite A/ sub-bituminous C rank coals and are therefore not sufficiently mature to have generated significant thermogenic gas volumes. However the coal seams subcrop the Algebuckina Sandstone aquifer in part, meaning that microorganisms capable of producing methane in anaerobic conditions (methanogenic microorganisms) can be introduced to the coal seams at the aquifer subcrop, resulting in biogenic gas generation.

2.2.4 Shale Oil and Biogenic Shale Gas Plays

Sakmarian organic rich marine shales have been intersected in both the southern Arckaringa troughs and the Boorthanna Trough. In Arkeeta 1 (Phillipson Trough), all twelve samples from a 200 m interval

recorded TOC values >2% (up to 7.4%) and hydrogen index (HI[7]) values >400 (up to 654). The Tmax[8] vs. HI cross plot shows that these organic rich shales are Type II source rocks at the threshold of oil generation (Figure 2.33). In the Boorthanna Trough Linc Energy's 2011 Arck 1 stratigraphic well intersected around 70m of organic rich shale (Type I/II kerogen) with very high potential oil yields. Analyses indicate that the shales are at the onset of oil generation (Figure 2.34).

A detailed palynological study of cuttings and sidewall core samples from Arkeeta 1 (ECL Australia report, Appendix 6 in McBain, 1987) indicates a lacustrine to brackish-restricted marine environment during deposition of the organic rich shales. High organic carbon contents and hydrogen indices indicate anoxic bottom water conditions suitable for the preservation of organic matter. The presence of mixed lacustrine to brackish marine environments and anoxic bottom water conditions suggests a Baltic Sea analogy, where high fresh-water runoff into a restricted sea-way results in density stratification of the water column. High fresh-water runoff (including melt-water) into restricted seaways along the Arckaringa troughs is likely to have resulted in similar conditions. In the Boorthanna Trough an organic petrology study of the organic rich shales has shown that very abundant alginite is present in a significant number of samples, and the dominant alginate form is a small tasmanitid (Cook, 1981, Moore, 1982).

DMITRE's Energy Resources Division has recently undertaken preliminary work to identify sedimentary packages in the Arckaringa Basin in a sequence stratigraphic framework, focused on understanding the distribution of the organic rich marine shales. This will contribute to regional studies of aquifers of the Arckaringa Basin and overlying younger basins that will be part of South Australian Government environmental assessments to be undertaken pursuant

7 Determined from RockEval measurements and is a standard measure of source rock potential to generate petroleum. HI is the quotient of the second peak of gas evolved by heating a sample of rock (S2) and the TOC of the same rock e.g. the fraction (yield) of organic matter that may be converted to petroleum.

8 The temperature at which S2 is a maximum is Tmax in RockEval measurements

Table 2.3: Summary of Arckaringa Basin coal deposits

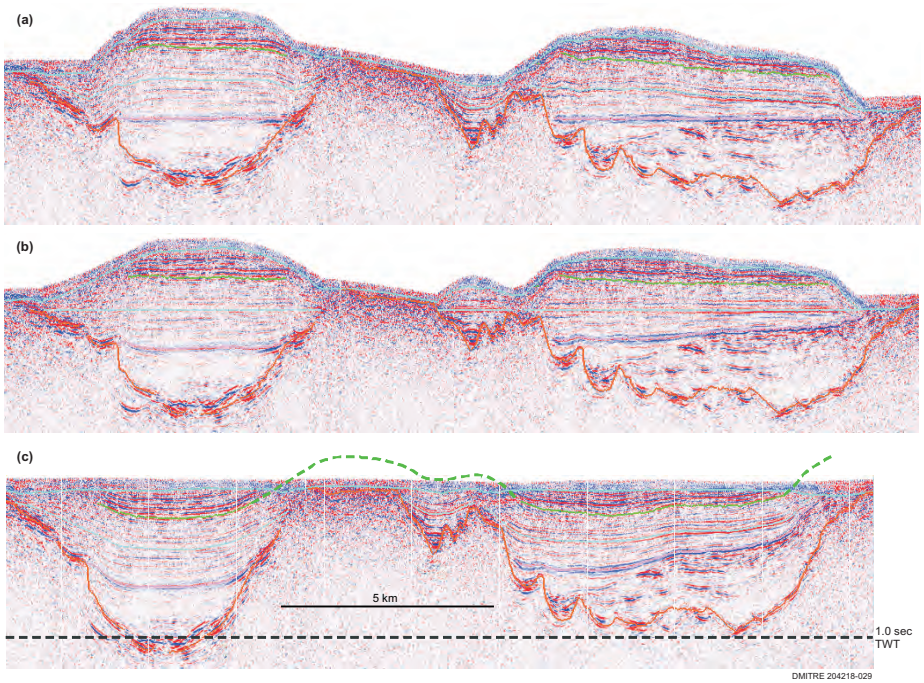
Deposit	No. of Persistent Seams	Cumulative Coal Thickness (m)	Top mineable coal (m)
Wintinna	8 -10	15-25	104-240
East Wintinna	6-7	Up to 20	220-300
Murloocoppie	8	Averages 20	140-230
Westfield	2	1-9	145-215

Table 2.4: Summary of Weedina Deposit

Deposit	No. of Persistent Seams	Cumulative Coal Thickness (m)	Top mineable coal (m)
Weedina	6 major seams (several minor seams)	35	130-150

Table 2.5: Summary of Lake Phillipson coalfield

Deposit	No. of Persistent Seams	Cumulative Coal Thickness (m)	Top mineable coal (m)
Phillipson	6 major seams	Up to 25	50-143
Ingomar	Up to 6 major seams	Up to 15	60-80



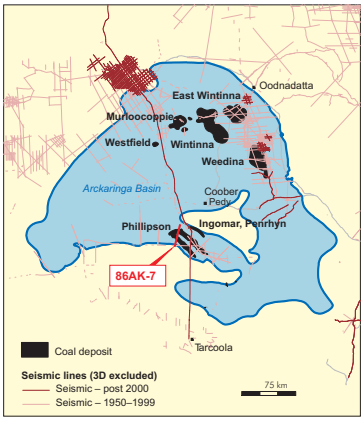


Figure 2.28 *Interpretation of seismic line 86AK-7 (migrated), showing the West Trough (left) and the Phillipson Trough (right). Top - section flattened on the Top Stuart Range horizon (pink). Middle - section flattened on the intra-Mount Toondina horizon (light blue – Note: this is not the MFS horizon). Bottom - Unflattened section. Seismic images from TrapTester.*

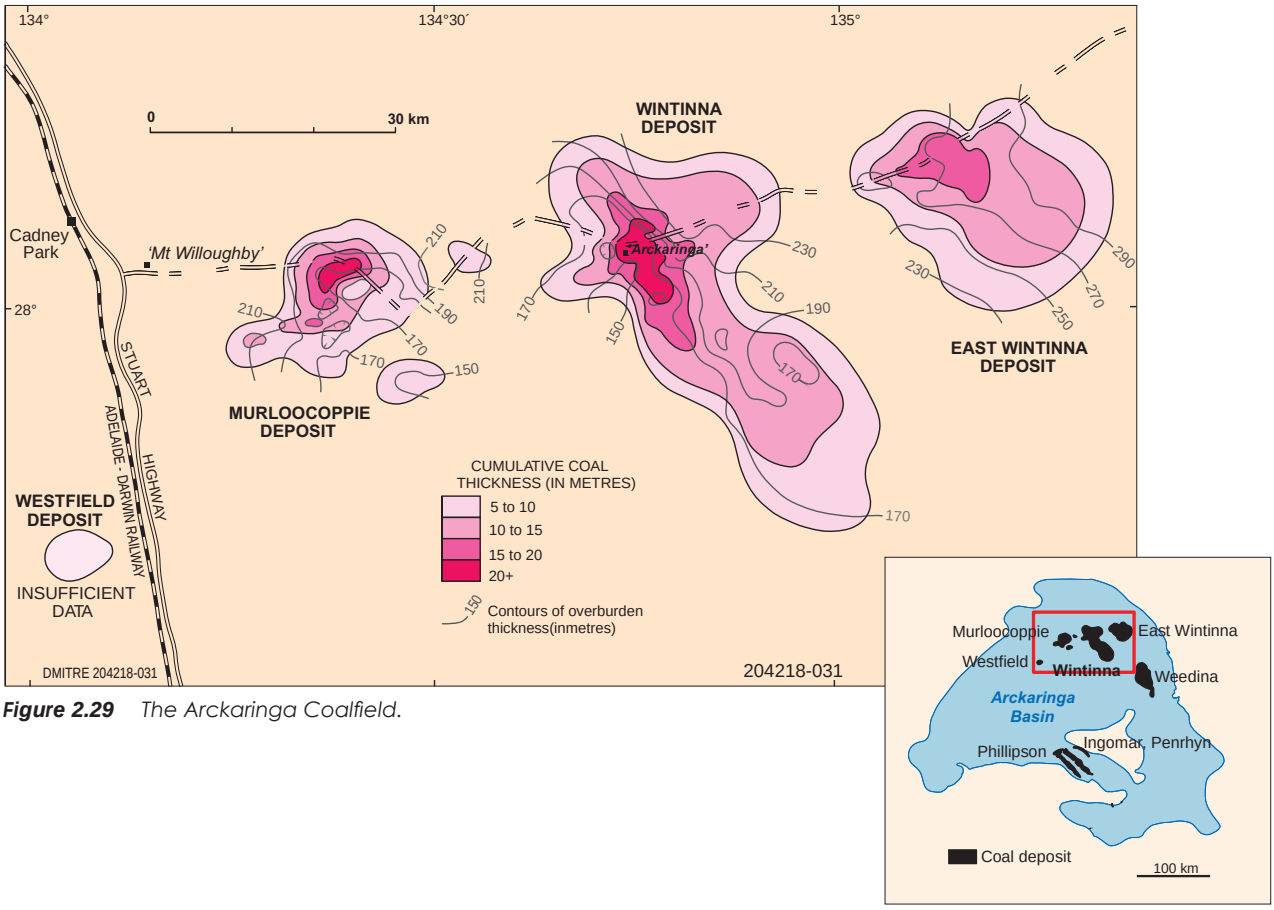


Figure 2.29 *The Arckaringa Coalfield.*

to the National Partnership Agreement for Coals Seam Gas and Large Coal Mines[9]. This will see the State Government act as the accredited one-stop-shop for State and Federal government environmental assessments pursuant to the Commonwealth *Environmental Protection, Biodiversity and Conservation Act 1999*. These water resource studies are expected to be referred to the Commonwealth Government's Independent Expert Scientific Committee to underpin informed regulation of, for example, proposed development of coal resources in the Arckaringa Basin.

A preliminary correlation of the Early Permian succession in the southern Arckaringa troughs and the Boorthanna Trough has been postulated; in particular the organic rich marine shales appear to have been deposited in a transgressive system that can be identified in both areas of the basin (Figure 2.35) (Menpes, 2012).

The organic rich shales will be an exciting shale oil target if sufficient maturity levels can be identified in the basin. Alternatively biogenically generated shale gas may be a possibility in parts of the basin.

9 For some details, see: www.pm.gov.au/press-office/south-australia-signs-coal-seam-gas-agreement

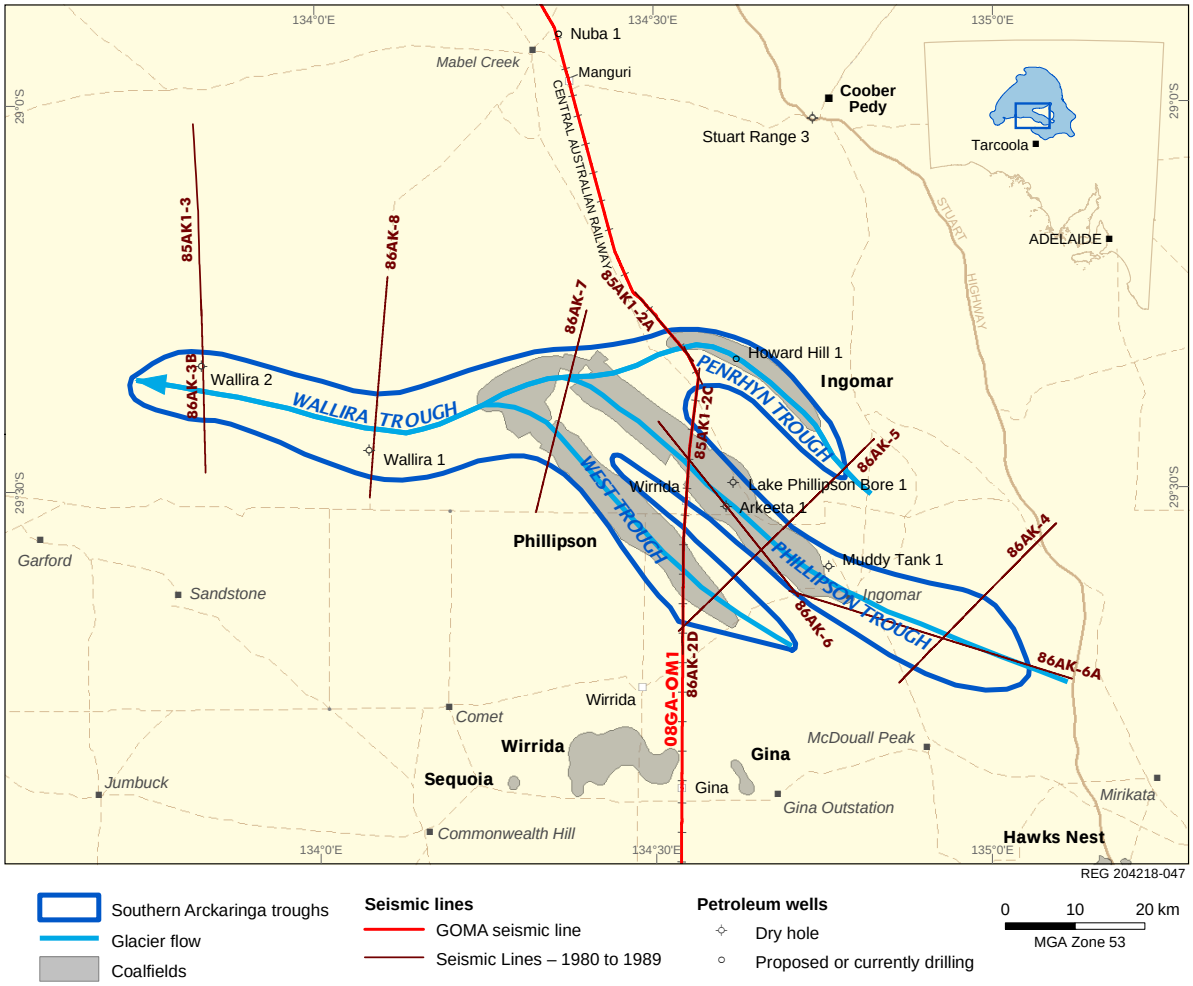


Figure 2.30 Southern Arckaringa Basin troughs showing inferred glacier flow direction.

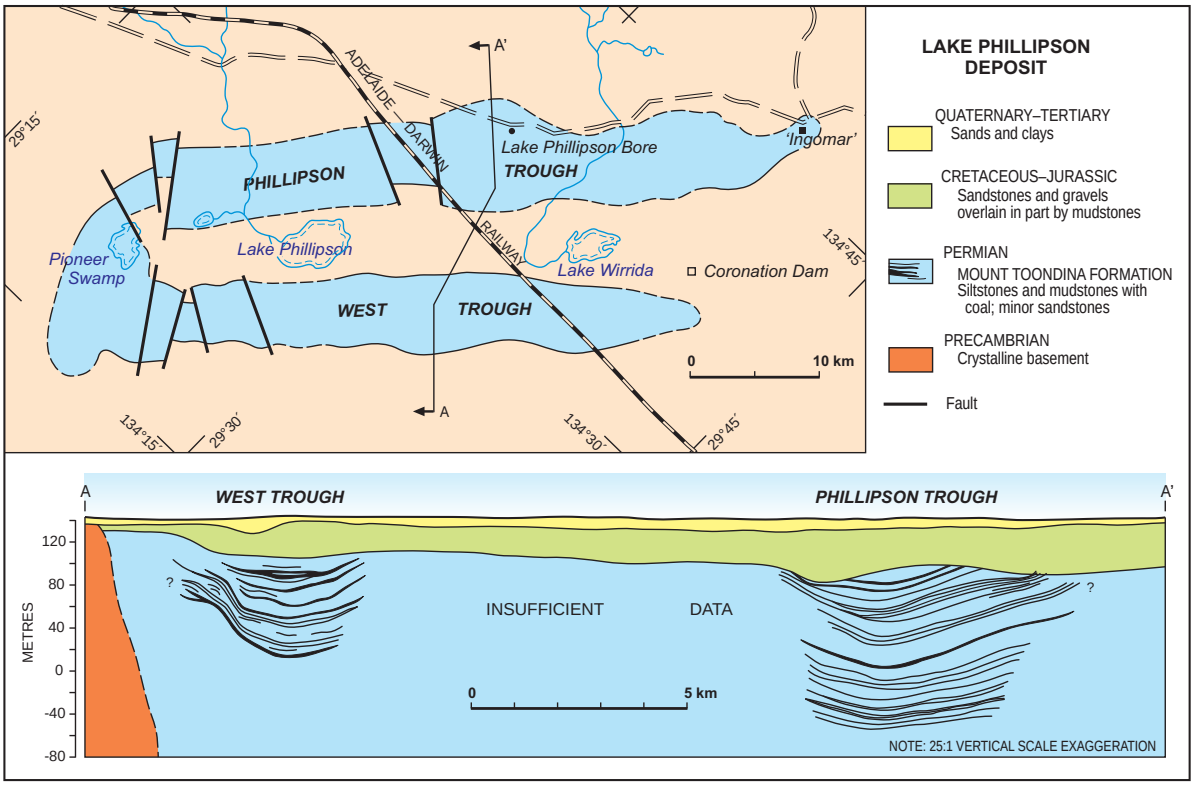


Figure 2.31 Lake Phillipson Coal Deposit, Phillipson and West troughs

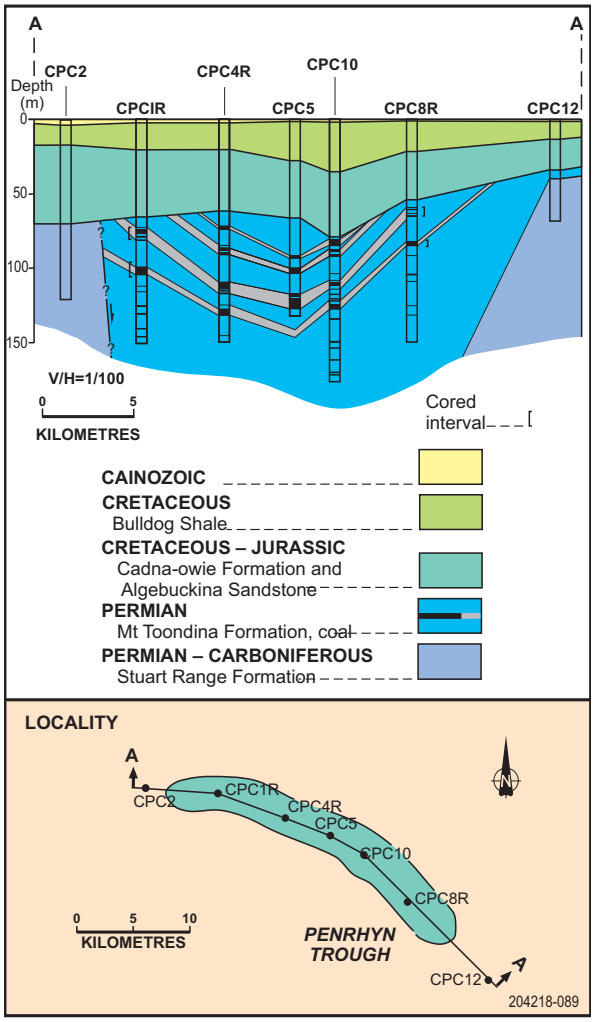


Figure 2.32 *Ingomar Coal Deposit, Penrhyn Trough*

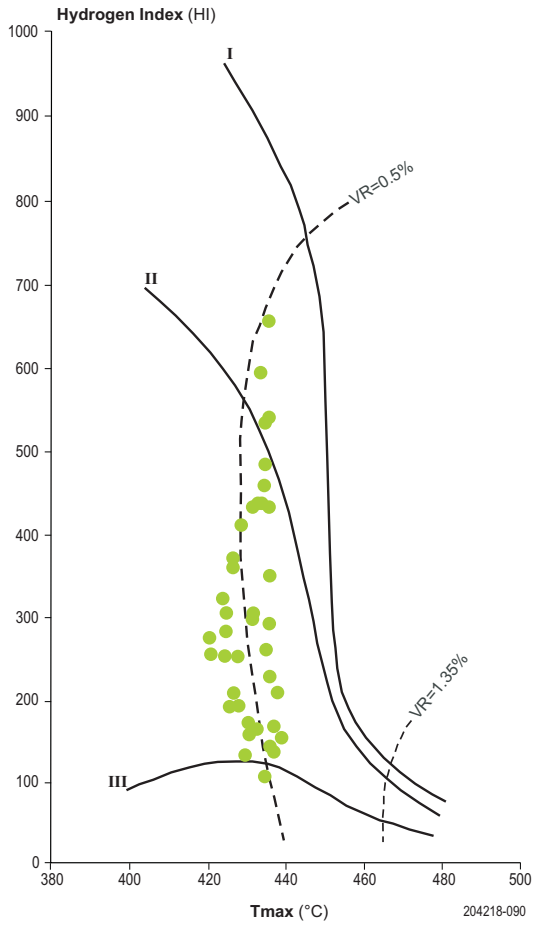


Figure 2.33 *Tmax vs. Hi cross plot for cuttings samples from Arkeeta 1, Phillipson Trough (from Appendix 5 in Arkeeta 1 Well Completion Report, McBain, 1987)*

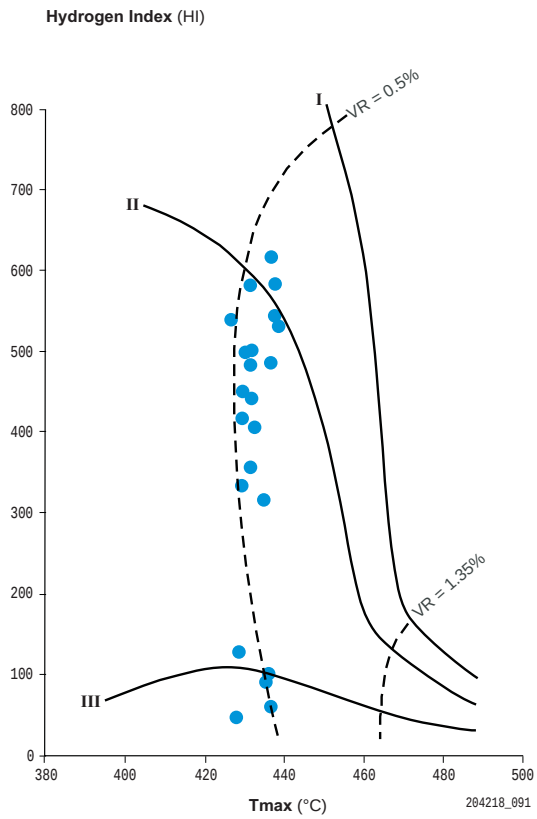


Figure 2.34 *Tmax vs. Hi cross plot for core samples from Arck 1, Boorthanna Trough (modified from Linc Energy ASX Announcement, 27 September 2011)*

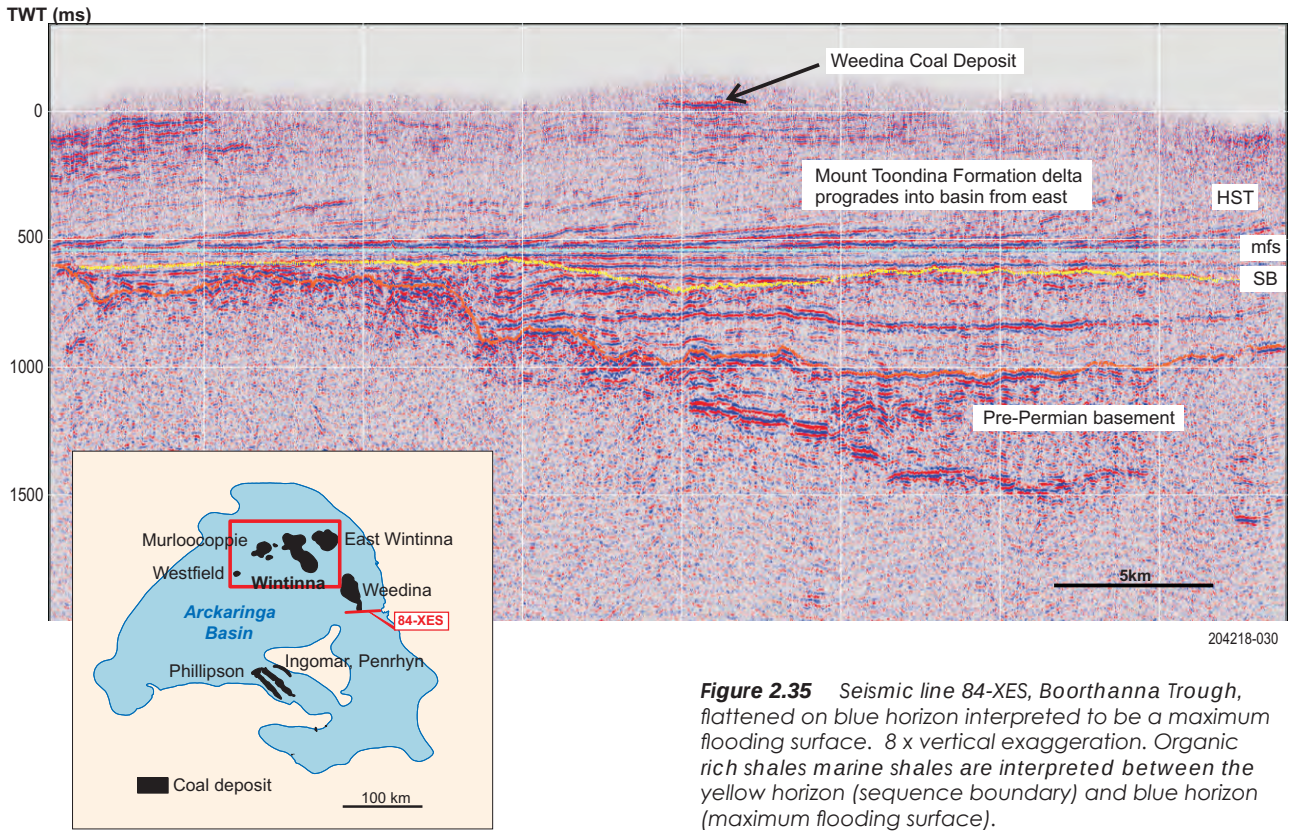


Figure 2.35 *Seismic line 84-XES, Boorthanna Trough, flattened on blue horizon interpreted to be a maximum flooding surface. 8 x vertical exaggeration. Organic rich shales marine shales are interpreted between the yellow horizon (sequence boundary) and blue horizon (maximum flooding surface).*

2.3 Otway Basin

The Otway Basin is a Jurassic to Cretaceous rift basin with a Tertiary cover (Gambier Basin) that occurs 300 km south-east of Adelaide (Figure 2.36). The basin extends into Victoria and the offshore in both states. The onshore area in South Australia covers 9650 km^2 with target depths for petroleum exploration anywhere between 1000 to 4000 m in the onshore portion of the basin.

Two major sedimentary sequences are targets for petroleum exploration in South Australia.

- The Berriasian to Hauterivian sequence (Crayfish Group, early rift) is known only from the northern area, where E–W and NW–SE trending half-grabens (Robe, Penola, St Clair and Tantanoola Troughs) contain fluvial to lacustrine sediments that are proven gas reservoirs (Figures 2.37, 2.38, 2.39).
- The Late Cretaceous sequence (Sherbrook Group) occurs as a deltaic to deep-water wedge south of the Tartwaup Hinge (Figures 2.37, 2.38, 2.39).

2.3.1 Shale gas play

The principal targets for shale gas in the onshore Otway Basin are thick basal shale sequences within the Upper and Lower Sawpit shales of the Otway Supergroup, and the underlying Casterton Formation which is separated from the Otway Supergroup by a regional unconformity (Figure 2.40). These non-marine shales all have good shale gas potential in the deeper portions of the basin and are discussed as follows.

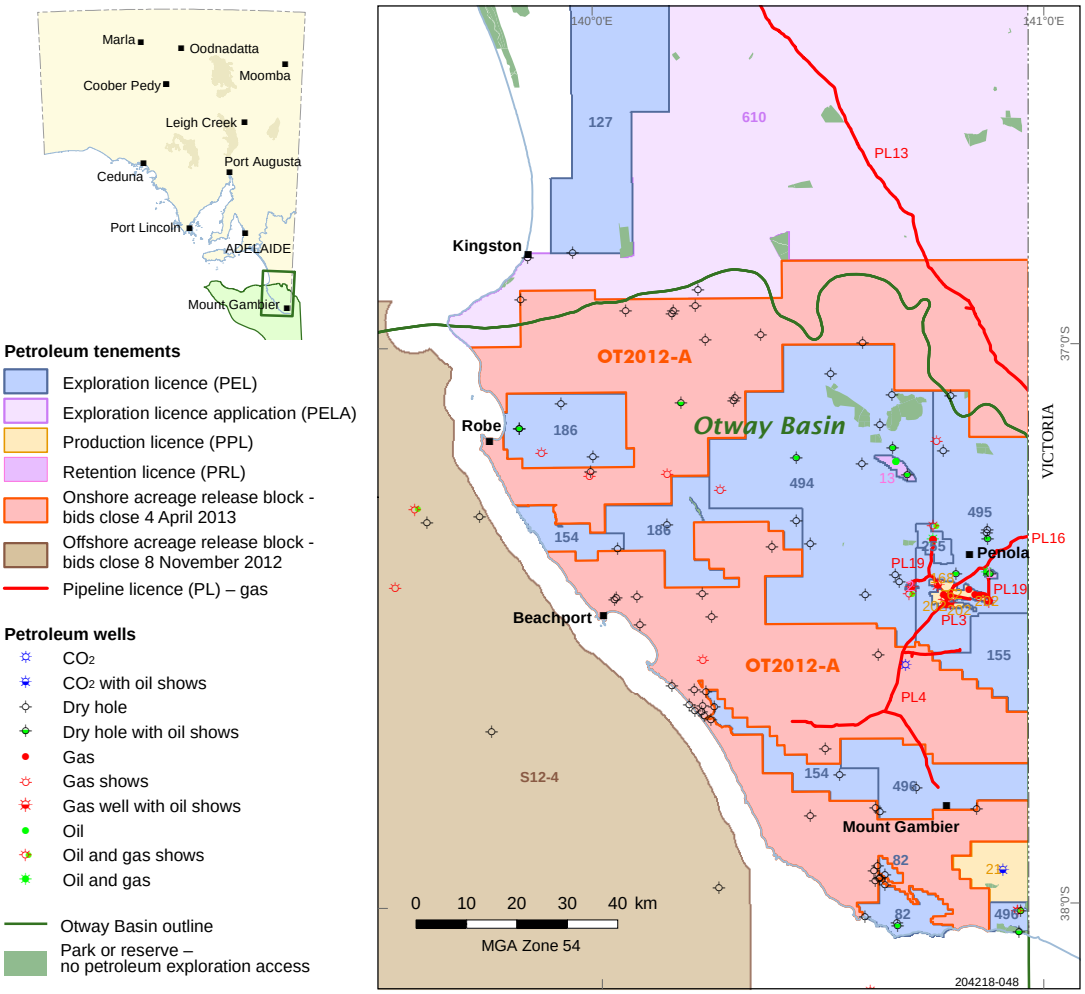


Figure 2.36 Otway Basin, South Australia. Infrastructure and tenements.

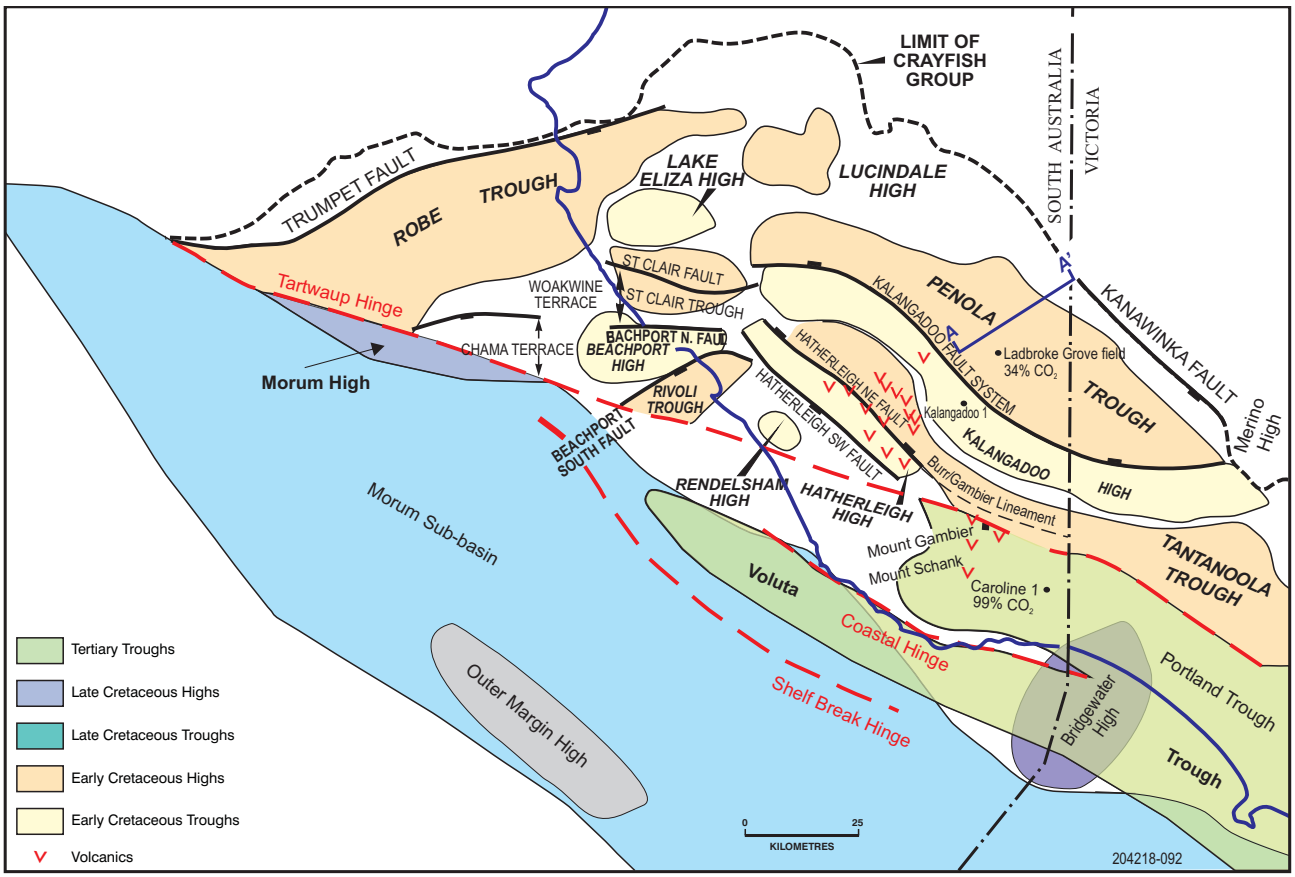


Figure 2.37 *Structural elements and wells.*

Casterton Formation

The Casterton Formation represents the richest source rock of the Otway Supergroup that is thought to be the source of commercial gas accumulations now in production in the Penola Trough region. It comprises pre-rift to early syn-rift interbedded shales, siltstones and sandstones and volcanic lithologies that have only been sparsely intersected. The formation reaches a maximum known thickness of 230 m in Casterton 1 well (Victorian Type Section) and 43 m in Sawpit 1 (SA reference section; Figure 2.41) although it is thought to be up to 500 m in the Robe Trough at depths greater than 4000 m based on seismic interpretation (Morton and Drexel, 1995). To date, the formation has been mostly intersected on the northern flanks where it is marginally mature for oil (as evidenced by oil shows in several wells) but not viable as a shale gas play.

TOC values range from 0.6 to 9%, averaging 1.9% (39 samples; 6 wells). The Tmax vs. HI cross plot shows that these organic rich shales are Type II (algal rich oil prone kerogen) to Type III (Gas prone) at the threshold of the oil window (Figure 2.42). However, in the deeper portions of the Penola, Robe and Saint Clair troughs they are expected to be gas prone with liquids potential (Figure 2.45).

Maturity modelling indicates that the Casterton Formation lies within the gas window at depths in excess of 3800 m in the Penola Trough and Robe Trough (Figure 2.45) but may be locally shallower in the Robe Trough where seismic is poor.

Somerton Energy is exploring the northern margin of the Otway Basin in Victoria and estimates the Casterton Formation Victorian PEP 171 could contain more than 25 trillion cubic feet of gas and significant oil volumes (see Section 4.1.6).

Upper and Lower Sawpit shales

The Upper and Lower Sawpit shales represent lacustrine deposits at the base of the Crayfish

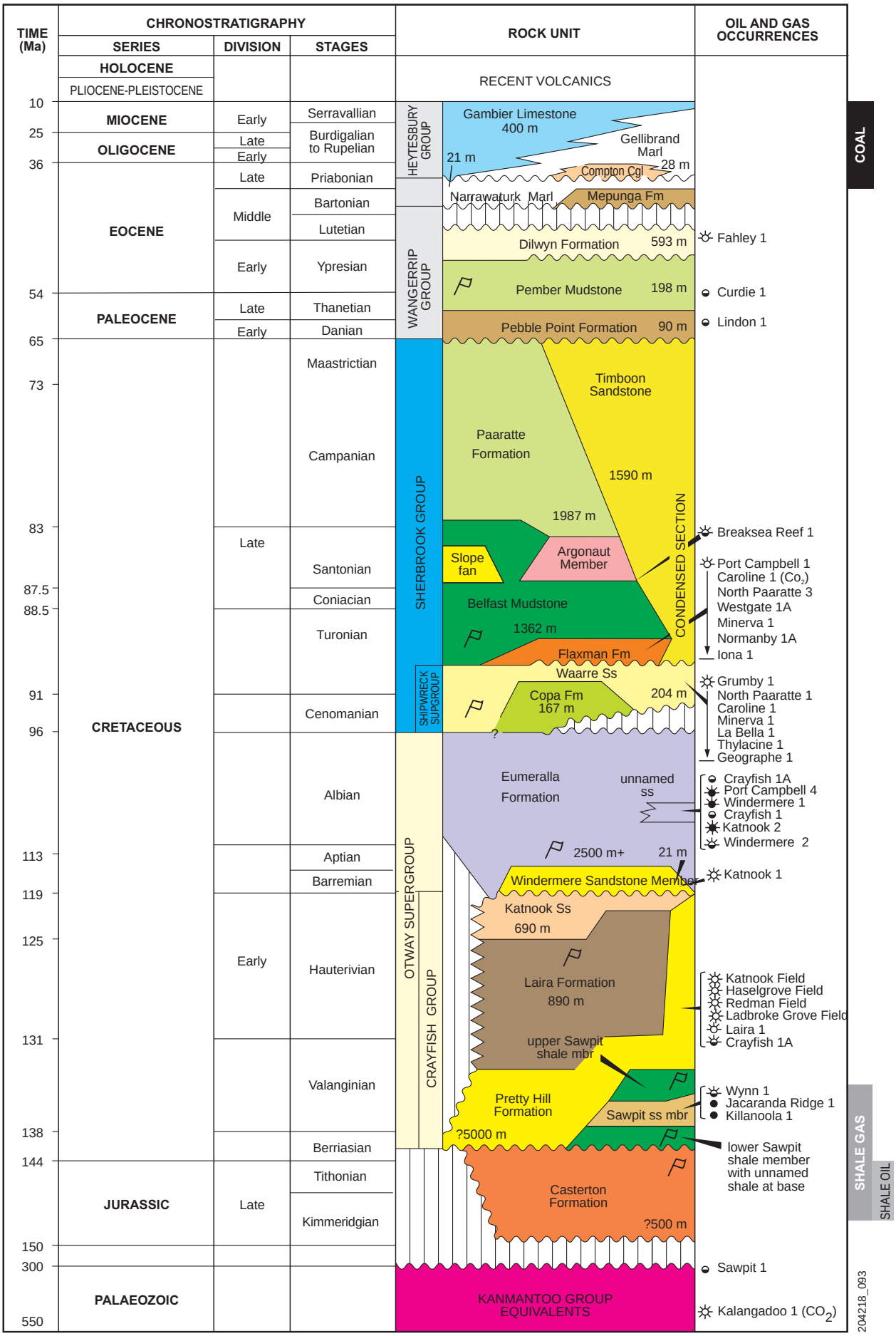


Figure 2.38 *Stratigraphic column, Otway Basin*

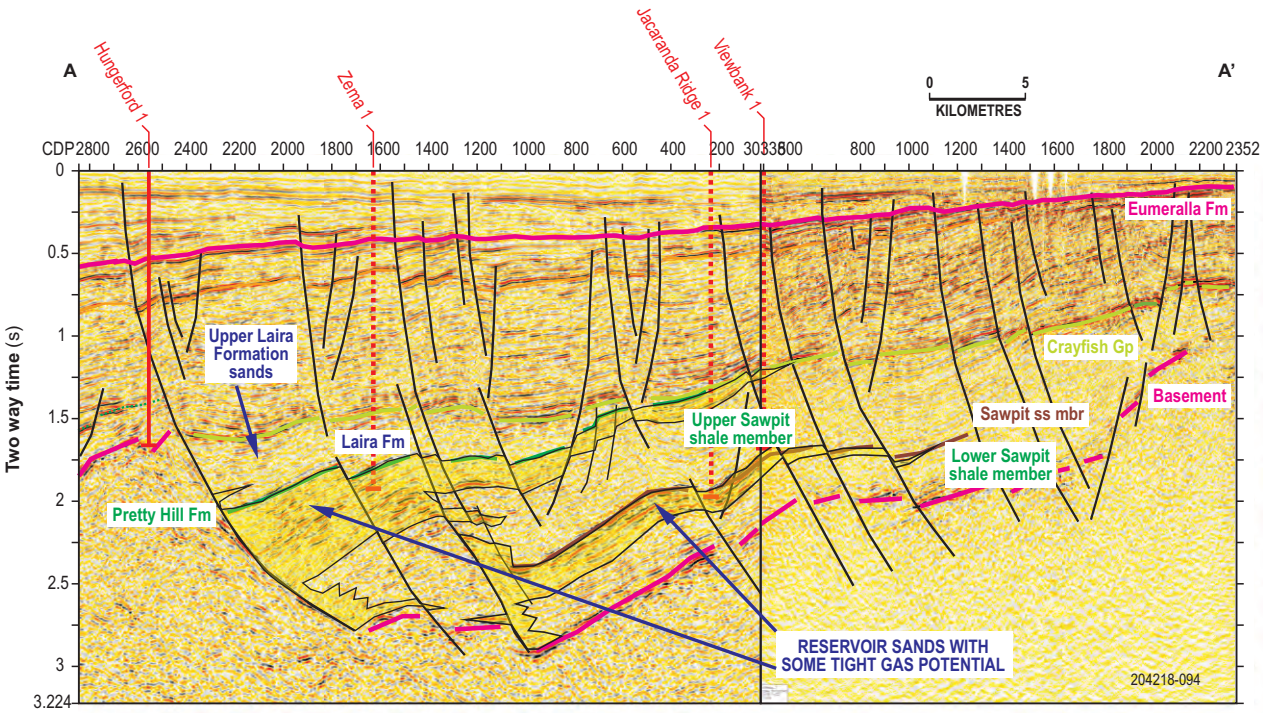


Figure 2.39 Composite seismic section, Penola Trough, Northern Otway Basin.

Group and can reach thicknesses up 900 m and 250 m thick respectively (Figures 2.38, 2.39 and 2.40). The shales are better developed on the northern flank of the Penola Trough (Figures 2.39 and 2.44), away from the axial drainage in the central part of the trough which is dominated by stacked fluvial channel fill of Pretty Hill Sandstone or Sawpit Sandstone (Boult and Hibburt, 2002).

Rock Eval analyses of samples from the Upper and Lower Sawpit Shales indicate that the shale is dominated by Type III gas prone kerogen with some Type II algal rich kerogen present (Figure 2.43). TOC values range 0.37 to 2.61% and average 1.12% (10 wells, 87 samples).

Maturity modelling in the Katnook area of the Penola Trough indicates that peak gas generation from the Casterton Formation and Upper and Lower Sawpit Shales occurred in the Maastrichtian at ~73 Ma and has remained in the gas window to present day at depths below ~3800 m (Figure 2.45).

Complex faulting resulting from rift tectonics could be advantageous for unconventional gas through enhancement of natural fracture networks that would improve connection with, and drainage of, the rock matrix.

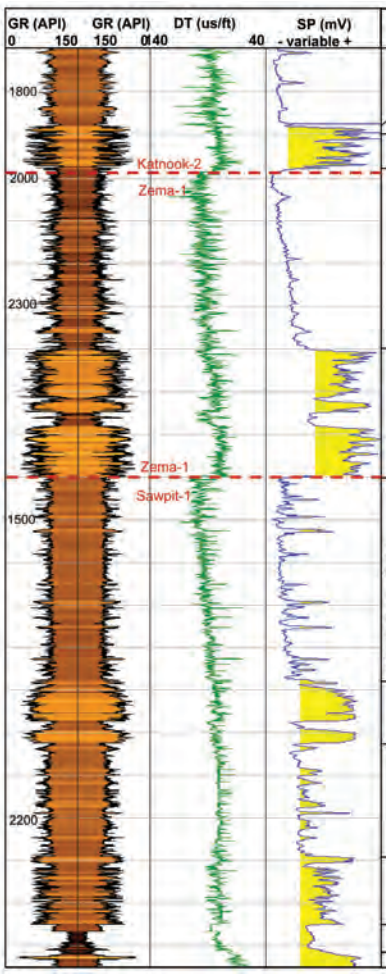
The prospective shale units have yet to be fully penetrated in the centre of the Penola Trough so an understanding of gas saturation and likelihood of water drive is yet to be established.

Access to infrastructure is another key factor in addressing the economic viability of both the Casterton and Sawpit Shale gas plays.

2.3.2 Shale Oil Play

Casterton Formation

As discussed in section 2.3.1, the Casterton Formation is most likely to be prospective for shale oil. The Tmax vs. HI cross plot shows that these organic rich shales are Type II (algal rich oil prone kerogen) to Type III (gas prone) at the threshold of the oil window (Figure 2.42).



Lithostratigraphy		Geothermal Significance	Distribution	Thickness	Porosity Qualifier	Permeability Qualifier	Depositional Environments
	Eumeralla Fm	regional thermal insulating layer	whole basin	max. 2500 m, typically >1500 m	very low	very low	shallow fluvial-lacustrine, local deep lacustrine at base
	Windermere Ss	Aquifer – thin, sheet-like	regional	max 160 m, typically 5 – 20 m	high	high	low-sinuosity fluvial
	Katnook Ss	Aquifer – lenticular	local	77 – 683 m	moderate - high	high	base = high-sinuosity fluvial top = low-sinuosity fluvial
	Laira Fm	Aquitard – thick, top seal (also comprises sandstone interbeds that may have aquifer potential)	regional	132 – 888 m, typically > 400 m	generally low, except for intra-Laira sandstones which are moderate	very low to impermeable	fluvial floodplain to shallow lacustrine; local coals and palaeosols
	Pretty Hill Sandstone	Aquifer – thick, sandy	regional	up to 875 m, typically > 200 m	• channel sands = high • bar sands = moderate • floodplain fines = low	• channel sands = m-h • bar sands = low • floodplain fines = v low	high-energy, low-sinuosity channel and bar sandstones grading into interbedded floodplain deposits
Pretty Hill Formation	upper Sawpit Shale	Aquitard– thick, shaly	regional	50-900 m	generally low	generally low	shallow lacustrine, overbank and floodplain
	Sawpit Sandstone	Aquifer–thick, sandy, semi-regional	semi-regional	typically 100-200 m	similar to Pretty Hill Sandstone	similar to Pretty Hill Sandstone	low- to high-sinuosity fluvial, overall fining upward
	lower Sawpit Shale	Aquitard– thick, regional	regional	typically 100 – 250 m	variable, generally low	variable, generally low	fluvial channel, lacustrine , swamp
	McEachern Sandstone	Aquifer?–thick, sandy, local to semi-regional	semi-regional	variable, up to 250 m	moderate to high	moderate to high	stacked braided fluvial channels. Coarse grained proximal alluvial facies
	Casterton Fm	Aquitard– base seal	regional	60 – 500m ?	low	very low	volcanic, deep lacustrine
	Basement						

Figure 2.40 *Crayfish Group of Stratigraphy.*

This diagram provides a stratigraphic summary of key units of interest in this study. The left most panel is a dual GR display with lithology colourfill–**orange** represents sandstone and **brown** represents mud rocks. Logs are a composite from 3 wells in the Penola Trough and show depths in metres from each of the three well intervals. The blue log represents the Spontaneous Potential log with a variable sand cutoff that has been coloured **yellow** to highlight the main sandstones. Unit distribution and thickness is based on regional seismic and well analysis along with data from Boultet al. (2002), Camac& Boult(2008) and various well completion reports. Porosity and permeability trends have been generalised from well completion report data and core analyses.

Maturity modelling suggest that the northern flank of the Otway Basin represents the most prospective area for shale oil play (Figure 2.45) where the Casterton Formation lies in the oil window at depths between 2300 m to ~3050 m (early mature for oil; Ro 0.7 to 1.0%) and ~3050 m to 3800 m (later mature for oil; Ro 1.0 to 1.3%) in the Robe, Penola, Rivoli and St. Clair troughs.

2.3.3 Tight gas play

Potential also exists for tight gas in the basal sands of the Pretty Hill Formation, particularly in the deeper portions of the Penola and Robe Troughs.

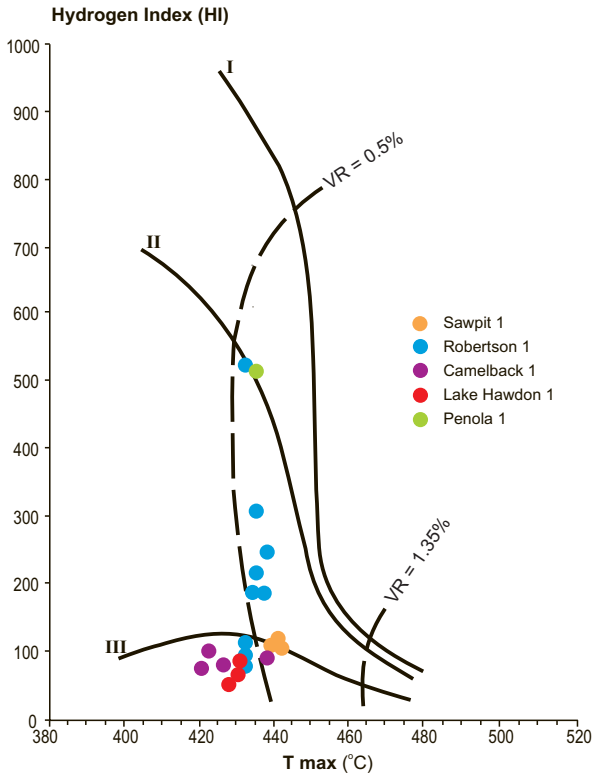


Figure 2.42 *Van Krevelen plot – Casterton Formation.*

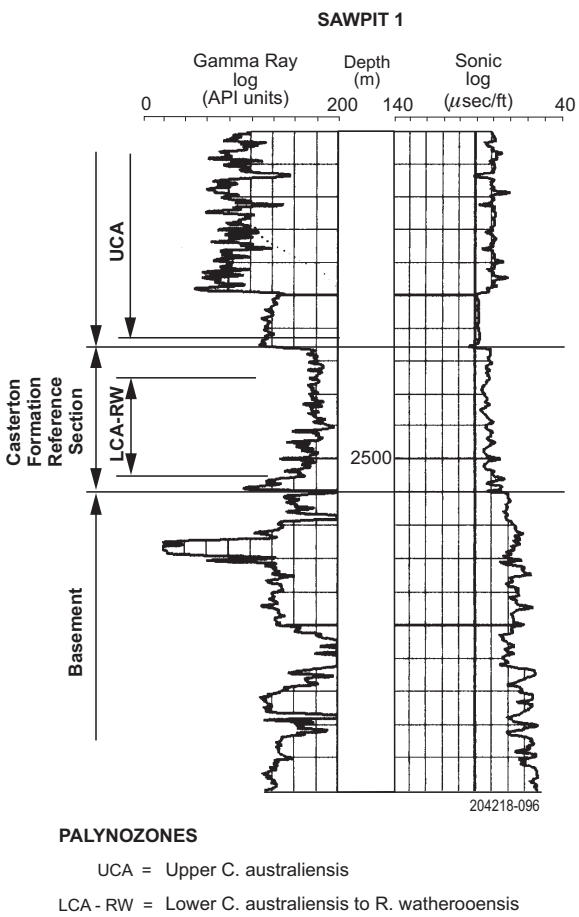


Figure 2.41 *Casterton Formation, SA reference section.*

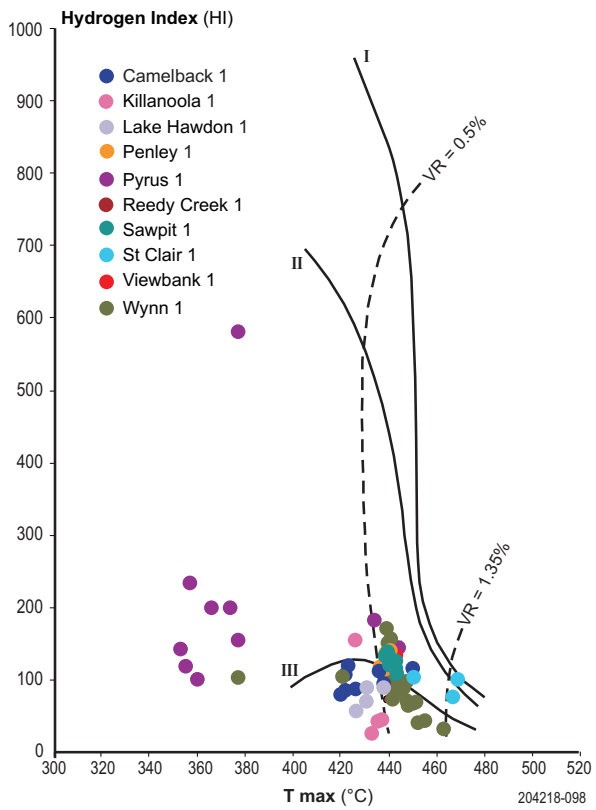


Figure 2.43 *Van Krevelen plot – Upper and Lower Sawpit Shales.*

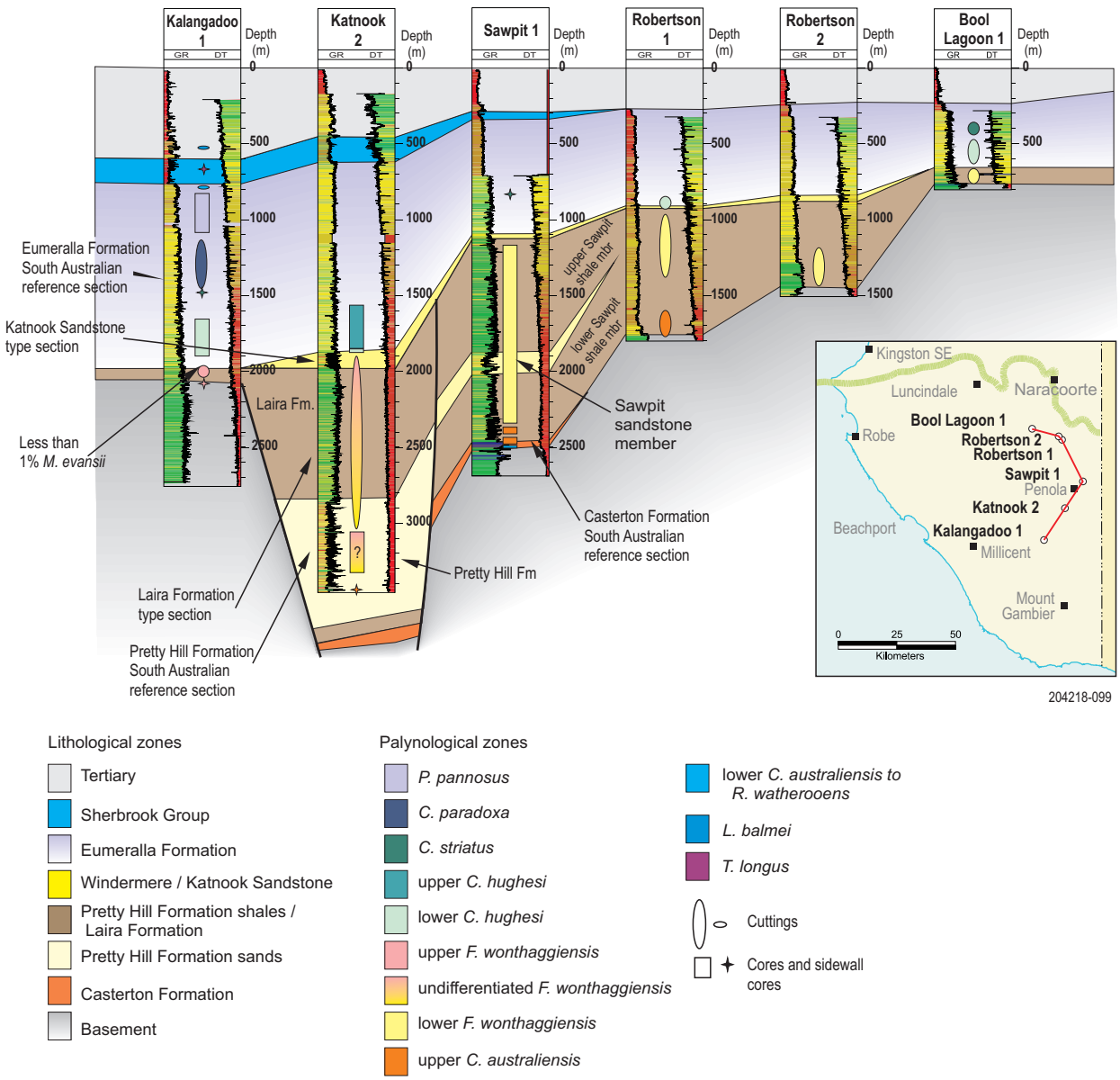


Figure 2.44 *Schematic cross section through Penola Trough.*

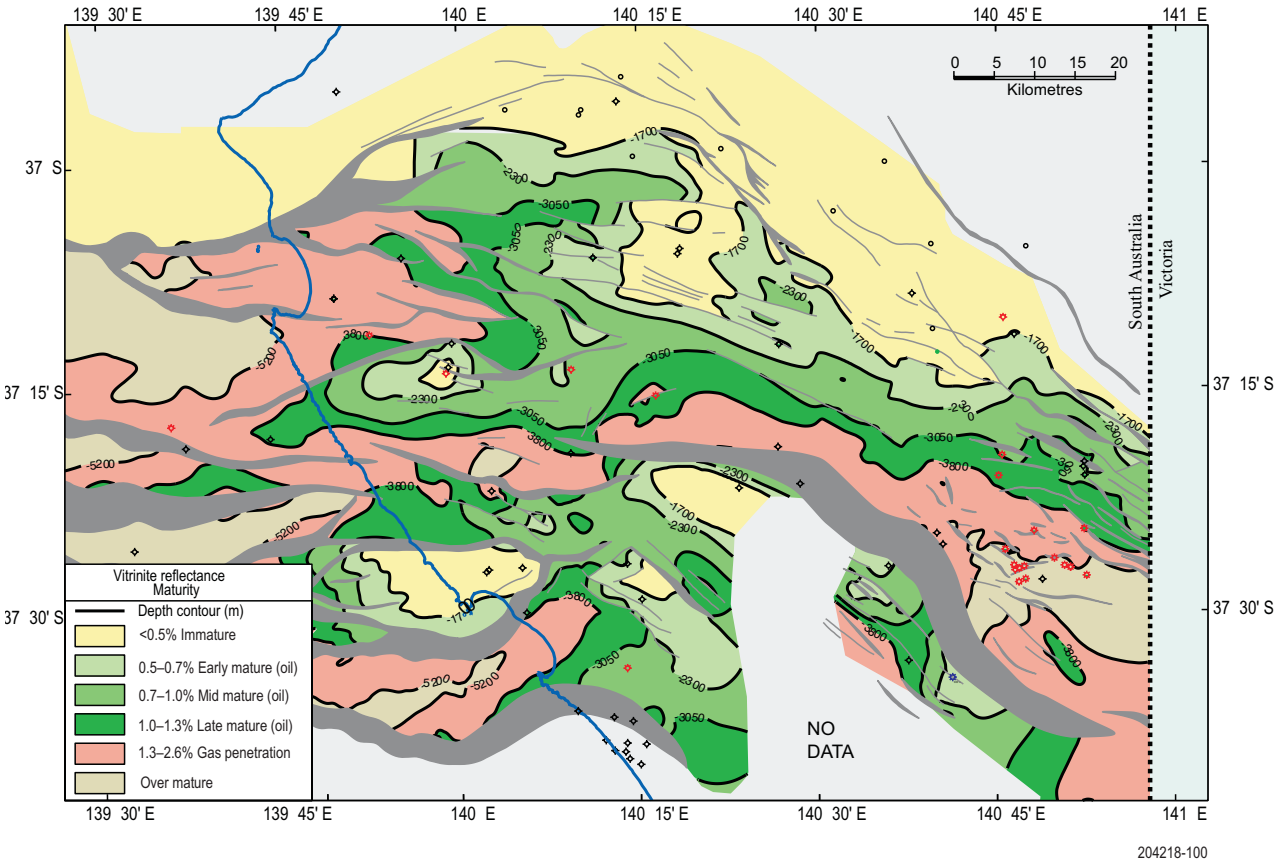


Figure 2.45 *Maturity map, base Casterton Formation.*

2.4 Gambier Basin

The Gambier Basin unconformably overlies the Mesozoic Otway Basin and comprises up to 1000 m of paralic to marine Tertiary sediments. Its northern boundary with the Tertiary Murray Basin is diffuse and is generally taken along the basement high of the Padthaway Ridge (Figure 2.46).

2.4.1 Coal Gasification Play

The Late Palaeocene to Mid Eocene Dilwyn Formation comprises fluvial to restricted marine facies with well developed lignitic intervals that generally occur as a single seam up to 9 m at Kingston where a deposit 27 km long and up to 5 km wide was identified by Western Mining Corporation in 1979 with 985 million tonnes resource delineated. In the northern area of the Kingston Coal Deposit a total thickness of 12 m is attained where the main seam coalesces with an overlying, less well developed lignite. Overburden thickness ranges from 20 to 80 m.

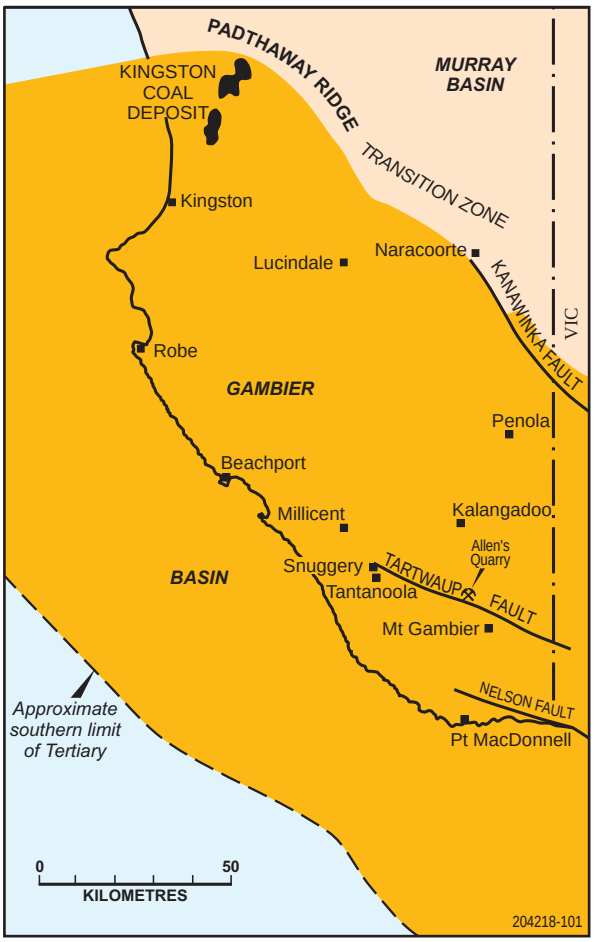


Figure 2.46 *Gambier Basin showing extent of Kingston Coal Deposit.*

Hybrid Energy Australia Pty. Ltd (a fully owned subsidiary of Strike Energy Ltd) has successfully gasified the lignite through testing by the University of Adelaide who were able to prove that a continuous operation is technically feasible. The company has identified a 578.3 million tonne coal resource of which 523.5 million tonnes has been measured.

2.5 Pedirka Basin

The Pedirka Basin covers an area of 150 000 km^2, approximately one fifth of which is in South Australia and the remainder in the Northern Territory (Figure 2.47).The Pedirka Basin overlies the SE Amadeus Basin and western Warburton Basin which were deformed during the Alice Spring Orogeny and possibly during Delamerian Orogenies. A final NW–SE compressional phase of the Alice Springs Orogeny in the Mid to Late Carboniferous initiated deposition in the Pedirka Basin and created thrust faults (e.g. Mt Hammersley). Permo-Carboniferous sediments were subsequently deposited in a tectonically quiescent crustal sag phase.

The Pedirka Basin in SA comprises a shallow western depocentre and a deeper eastern depocentre separated by the Dalhousie-McDills Ridge. This ridge comprises shallow folded and faulted Devonian and older rocks, with a thin cover of late Palaeozoic sediments preserved across the ridge, linking the two depocentres (Figure 2.48). The western depocentre contains up to 1000m of Carboniferous-Early Permian sediments generally at depths less than 1500 m whilst to the east, sediments are 300-400 m thick and at depths exceeding 2000 m (Figure 2.49). The Pedirka Basin is entirely overlain by up to 2500 m of Triassic to Late Cretaceous sediments of the Simpson and Eromanga basins.

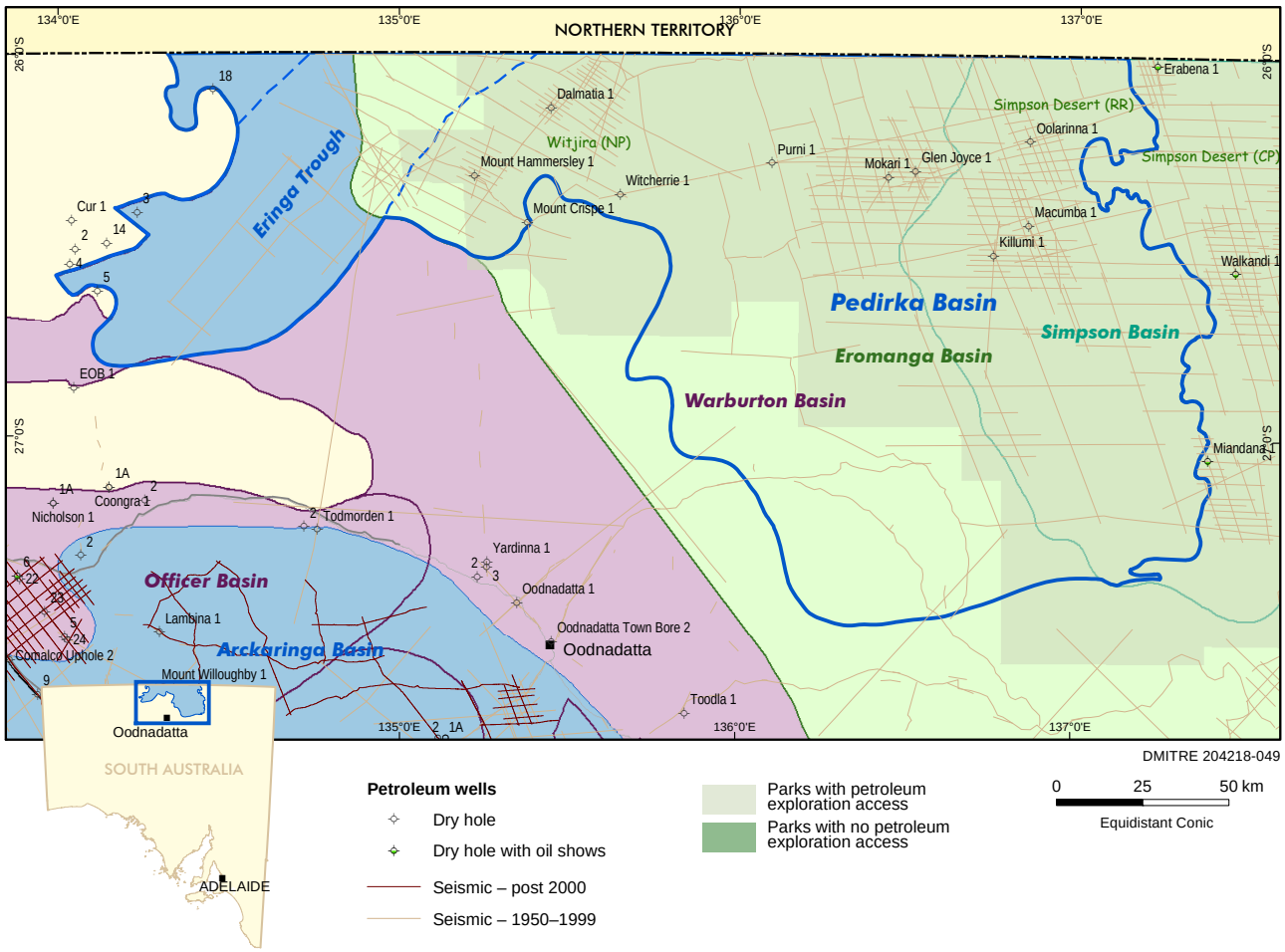


Figure 2.47 *Pedirka Basin, South Australia. Wells and seismic lines.*

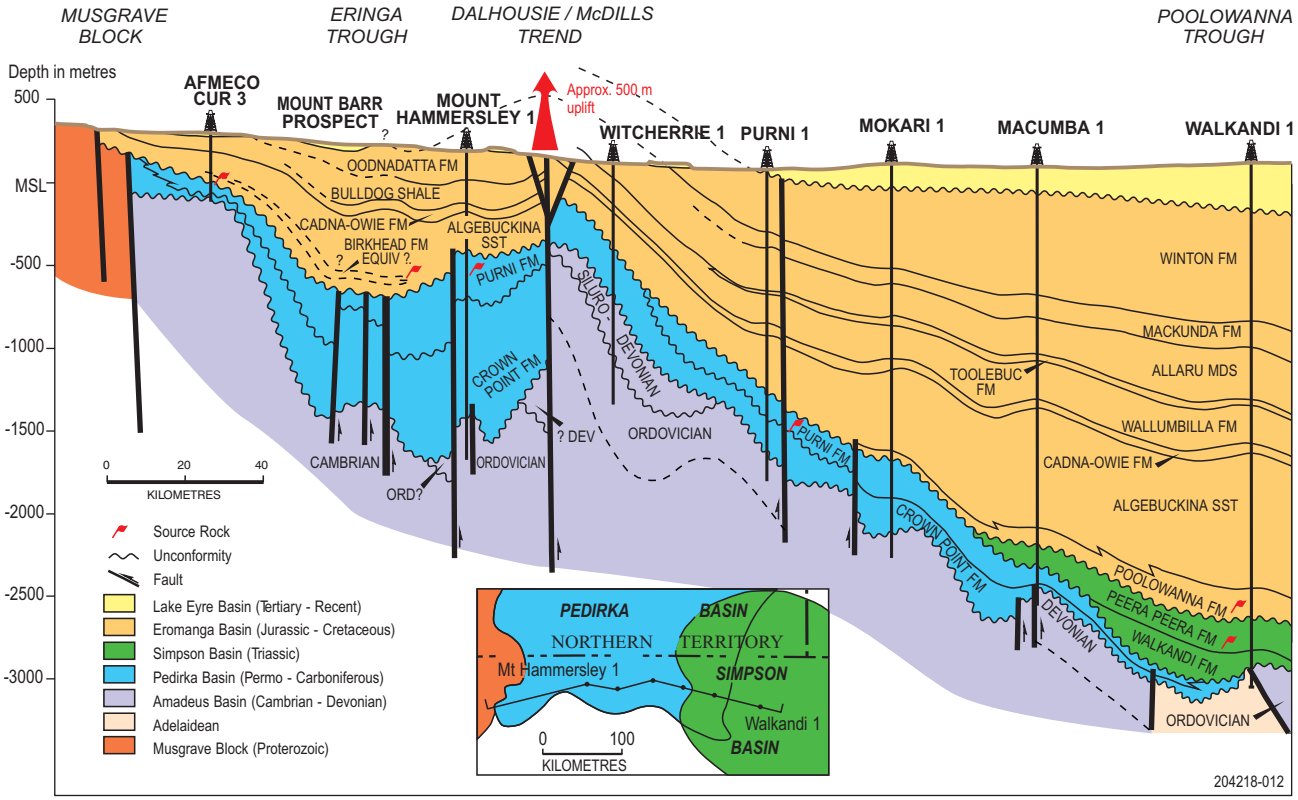


Figure 2.48 *Cross-section through the Pedirka Basin.*

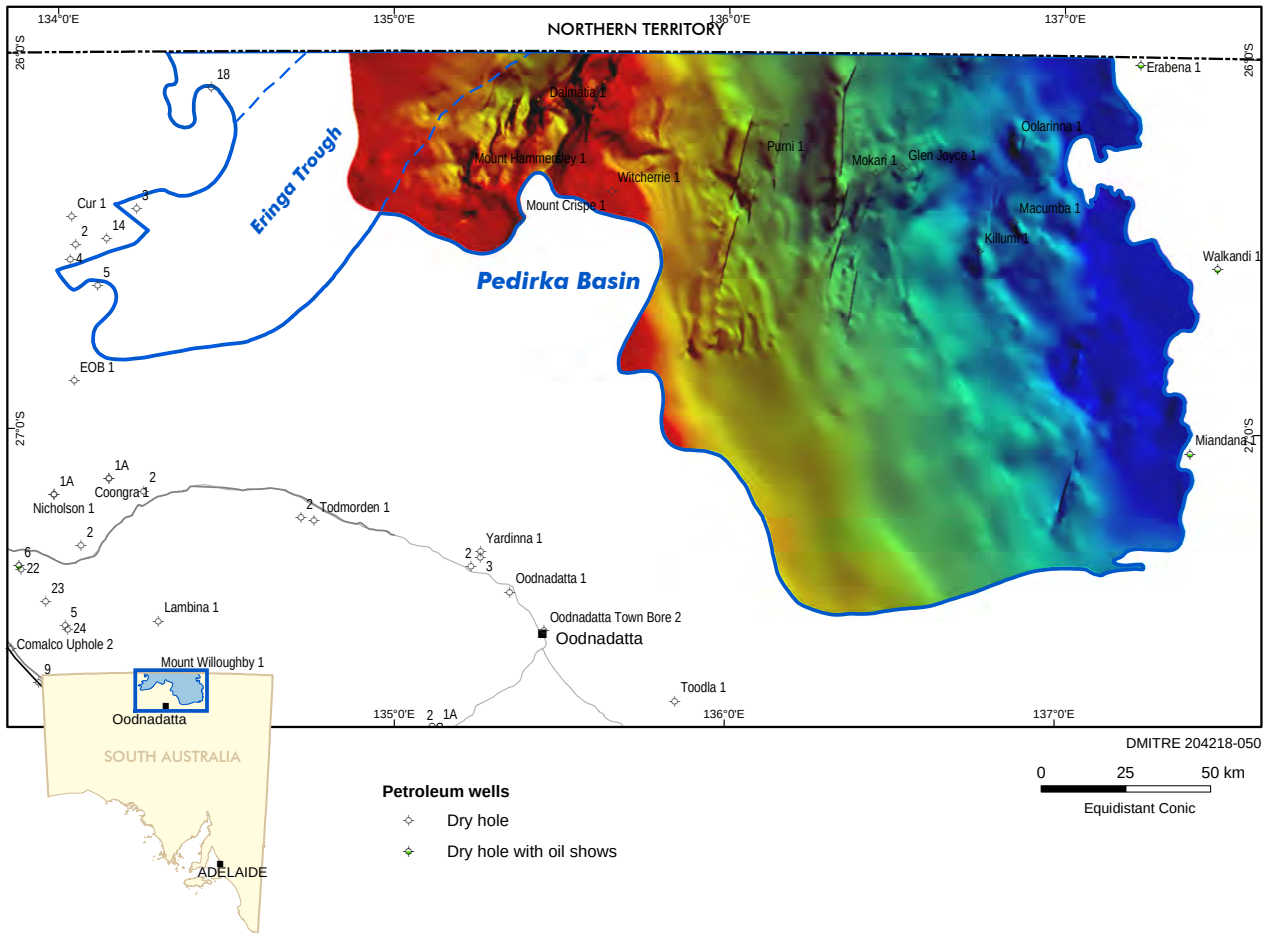


Figure 2.49 *Top Purni Formation depth structure map.*

The Permo-Carboniferous succession in the Pedirka Basin has been divided into two formations (Figure 2.50). The lowermost unit, the Crown Point Formation, consists of sandstone and extensive muddy to cobbly diamictite deposited in periglacial, interglacial, fluvioglacial and glaciolacustrine environments. The overlying Purni Formation is equivalent to the Patchawarra Formation of the Cooper Basin and was deposited in an extensive coal swamp and floodplain environment crossed by high-sinuosity fluvial channels.

To mid 2012, 10 petroleum wells have been drilled, and almost 6000 line kilometres of 2D seismic data have been acquired in the Pedirka Basin (Figure 2.47).

2.5.1 Coal Seam Gas Play

Coal seams are characteristic of the upper member of the Purni Formation. A thermogenic coal seam gas play fairway may be present in the deeper eastern depocentre, and sweet spots for biogenic coal seam gas may be present in parts of the western depocentre.

In the eastern depocentre, thermal maturity increases with increasing depth of burial beneath a thickening Eromanga Basin succession. Ro values range from 0.79 to 0.94% in Macumba and Oolarinna respectively at depths greater than 2200 m. Mud gas peaks corresponding to coal seams were recorded in Oolarinna 1, with 82 units total gas recorded over a 6 m coal seam with shale partings.

The Purni coals are immature for thermogenic gas generation in the western depocentre, with Ro measurements ranging from 0.45 to 0.47%. However the coal seams subcrop the Algebuckina Sandstone aquifer in part, meaning that methanogenic bacteria carried in meteoric waters can be

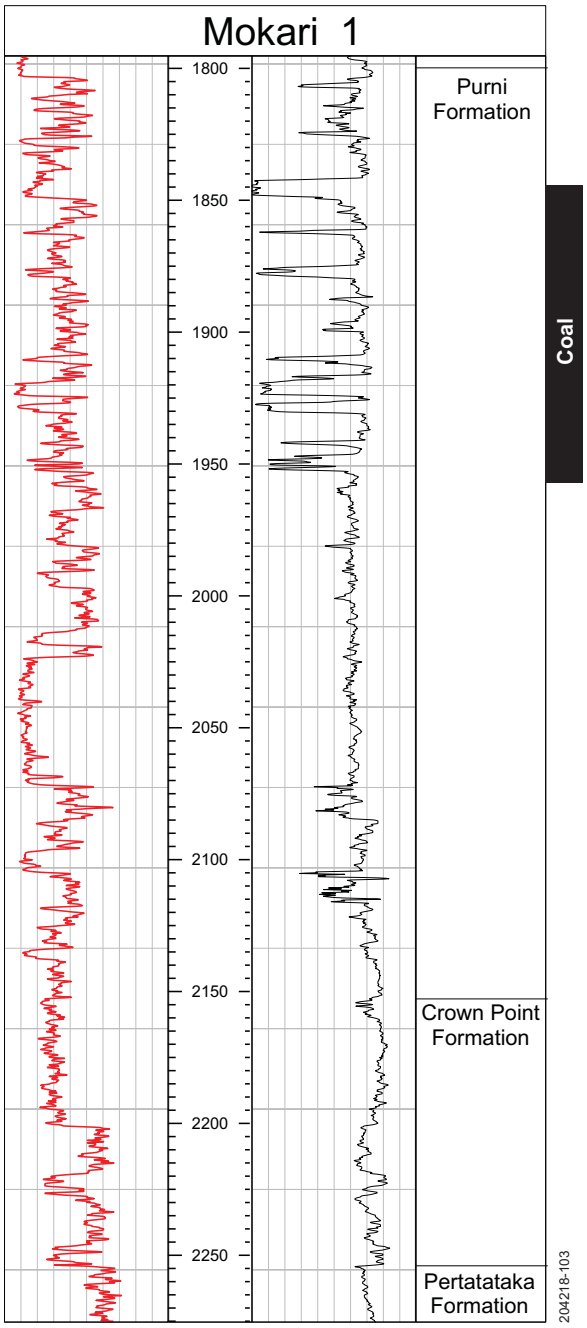


Figure 2.50 *Mokari 1 Permian stratigraphy (being updated).*

introduced to the coal seams, and biogenic gas generation is possible. Most significant production of shallow biogenic gas comes from depths of less than 600 m, although the depth of the biogenic floor may vary from basin to basin (Shurr and Ridgley, 2002).

2.5.2 Shale Gas Play

The absence of thick, laterally extensive shale and the overall low maturity of the succession downgrades the shale gas potential of this basin.

2.6 Simpson Basin

The Simpson Basin has an area of 100,000 km^2, approximately half of which is in South Australia and the remainder in the Northern Territory and Queensland. It is a circular, poorly defined depression with one major depocentre, the Poolowanna Trough (Figure 2.51). The basin unconformably overlies Pedirka Basin and western Warburton Basin and is overlain by the Eromanga Basin.

The Northern Territory Geological Survey has reviewed the Simpson Basin and are proposing to re-define the Triassic Section as part of the Pedirka Basin *(Munson, pers comm May 2012)*.

Simpson Basin stratigraphy has been divided into two formations. The Early to Middle Triassic Walkandi Formation consists of non-marine interbedded red-brown shale, green siltstone and fine grained sandstone, restricted to the Poolowanna Trough. The maximum thickness of the Walkandi Formation is 134 m in Poolowanna 2.

The overlying Late Triassic Peera Peera Formation consists of basal grey shale, siltstone, minor sandstone and coal, overlain by upwardly fining sandstone and an upper black carbonaceous shale. The Peera Peera Formation was deposited in a high-sinuosity fluvial environment with possible development of lakes on the floodplain. The maximum thickness of the Peera Peera Formation is 190 m in Walkandi 1 (Figure 2.52).

The Simpson basin is overlain by the non-marine fluvio-lacustrine Early Jurassic Poolowanna Formation, Mid Jurassic Algebuckina Sandstone and Early Cretaceous Cadna-owie Formation (Figure 2.53). The Cretaceous marine transgression resulted in a thick sequence of shales and shore-face sands with restricted marine conditions during deposition of the Toolebuc Formation. The marine succession is overlain by non-marine fluvial-coal swamp Winton Formation. The Eromanga Basin is unconformably overlain by fluvio-lacustrine sediments and silcretes of the Tertiary Lake Eyre Basin.

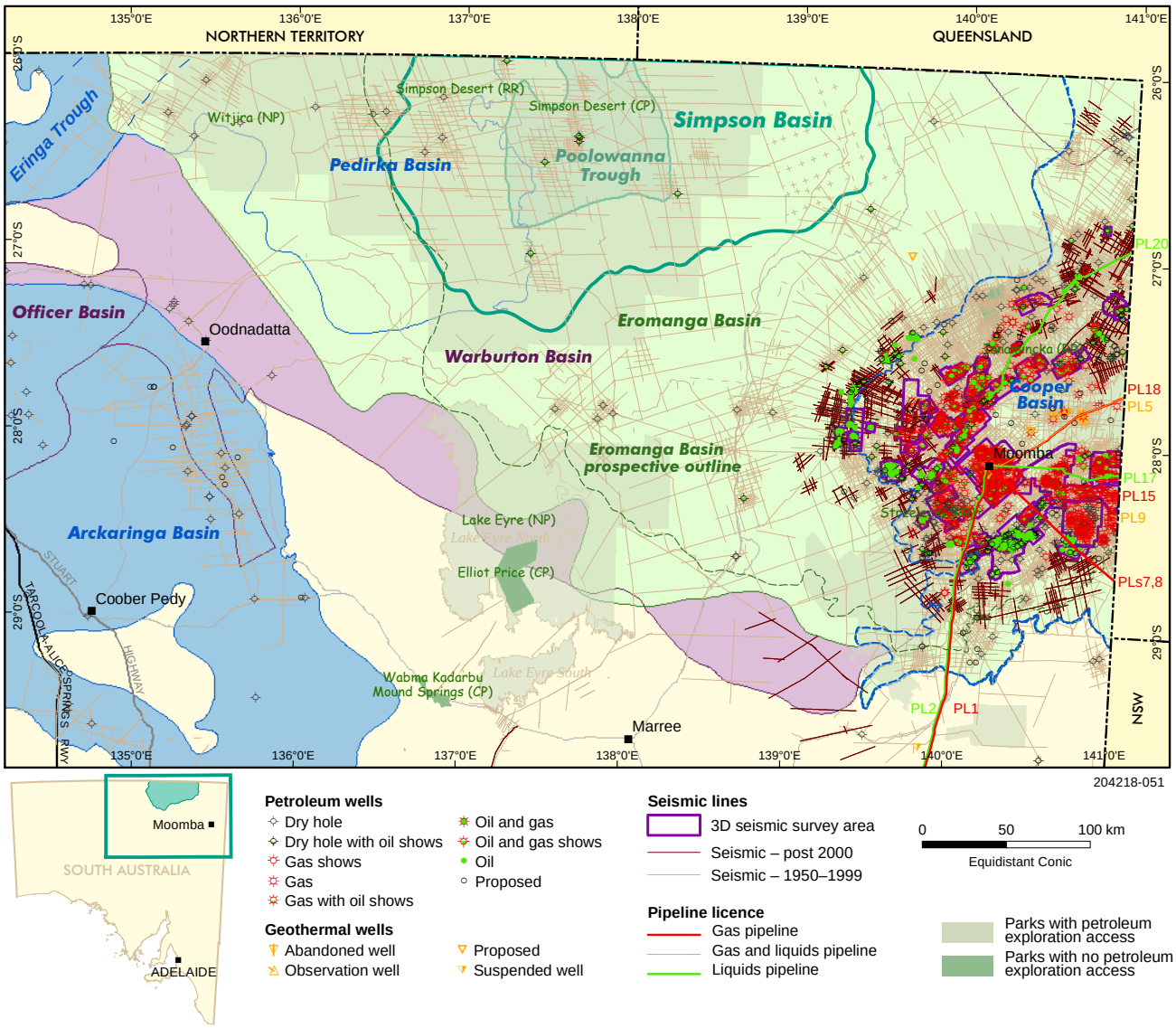


Figure 2.51 *Simpson Basin, South Australia. Wells and seismic lines.*

To mid 2012, 6 petroleum wells have been drilled, and approximately 7200 line kilometres of 2D seismic data have been acquired in the Simpson Basin (Figure 2.51).

2.6.1 Coal Seam Gas Play

The Poolowanna Trough (Figure 2.52) forms the major Triassic-Recent depocentre in the region, containing up to 2,500 m of non-marine sandstone, coal and siltstone and marine shales. Significant oil shows in Walkandi 1 and the oil recoveries in Poolowanna 1 indicate that hydrocarbon generation and migration has occurred in the deeper parts of the trough.

The oxidised nature of the Walkandi Formation redbeds downgrades their source potential. However, the overlying Peera Peera Formation is rich in organic matter (TOC up to 5%) and should be oil mature in the Poolowanna Trough. Further exploration would be needed to determine if the coals are sufficiently mature to have generated significant gas volumes for a Coal Seam Gas play.

2.6.2 Shale Gas Play

The absence of thick, laterally extensive shale and the overall low maturity of the succession downgrades the shale gas potential of this basin. The Peera Peera Formation is not mature enough to have generated gas, but may have potential for shale oil.

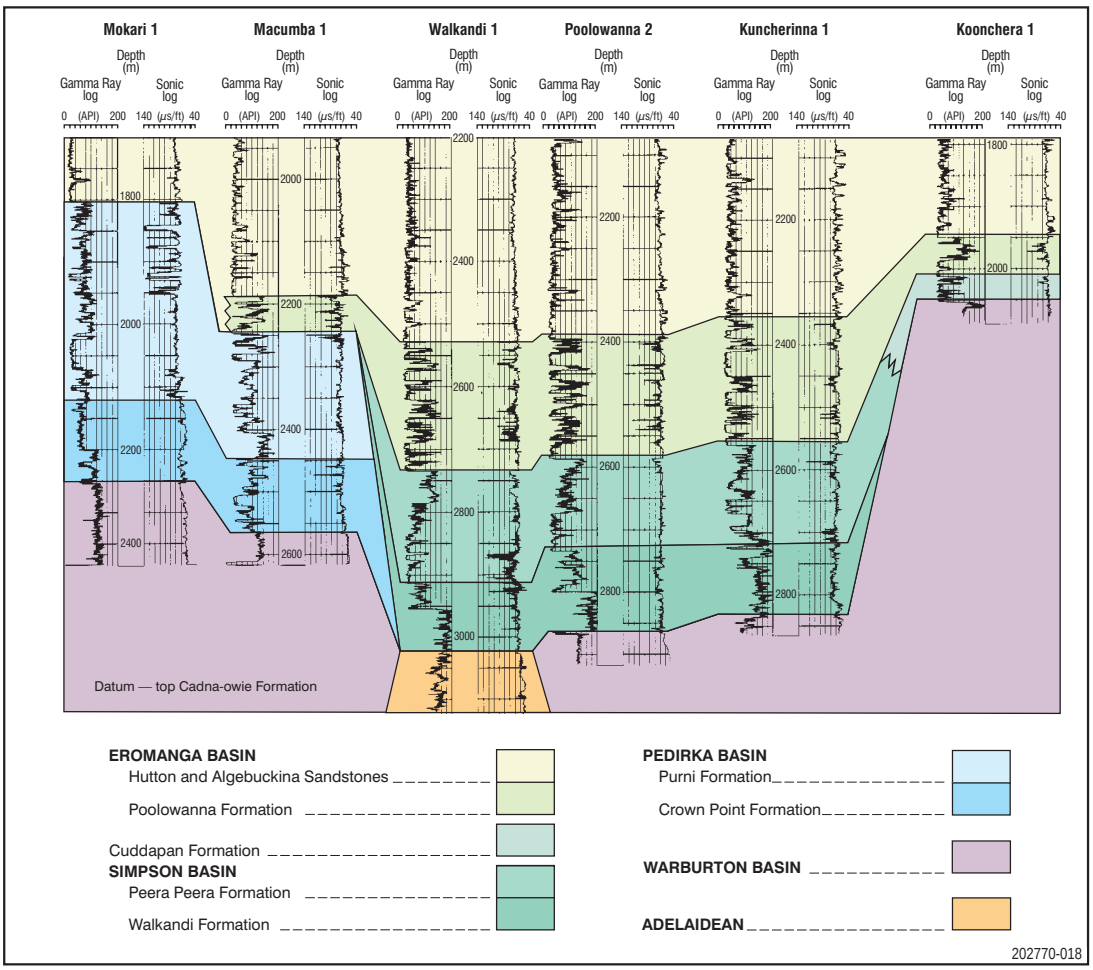


Figure 2.52 *Wireline log correlation from Mokari 1 to Koonchera 1.*

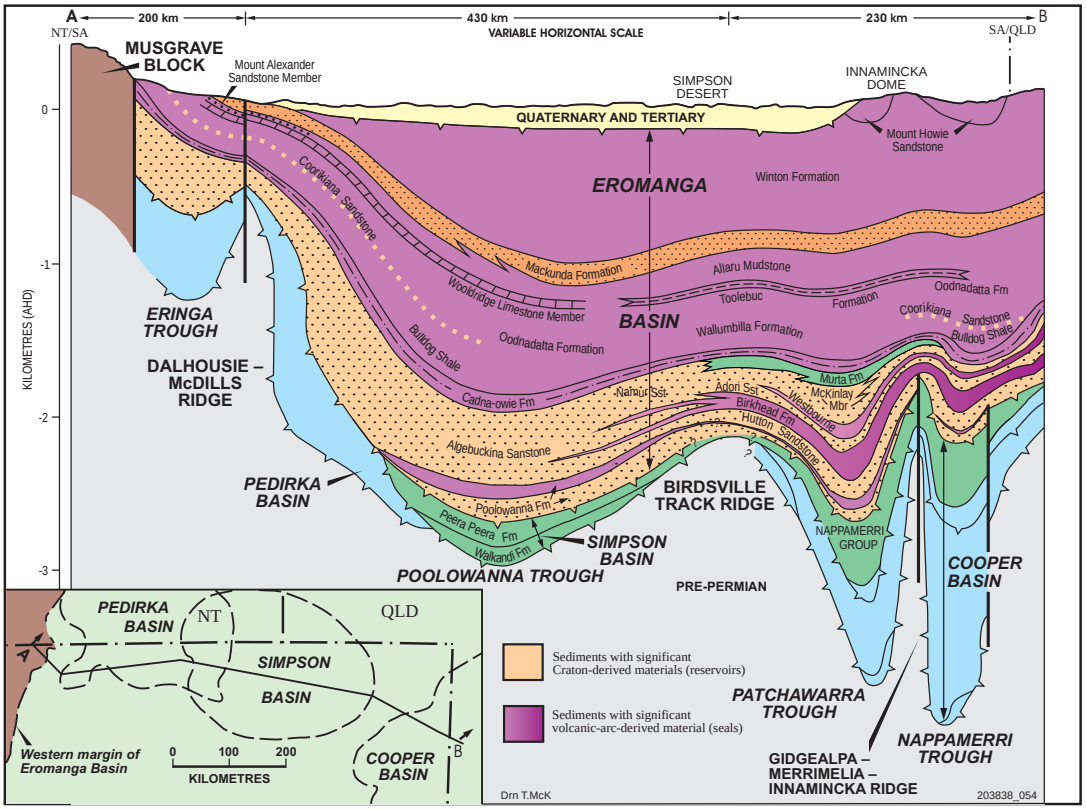


Figure 2.53 *Schematic cross-section across the Eromanga, Pedirka and Simpson basins.*

2.7 Warburton Basin

The Cambro-Ordovician Warburton Basin Figure 2.54) is a polyphase foreland and rift/sag basin that covers a vast subsurface area of ~45,000 km^2 north and north-east of the Gawler Craton (Figure 2.55) that is completely covered by Late Carboniferous and younger strata including the Cooper, Pedirka, Simpson and Eromanga basins (Figure 2.56).

The eastern Warburton Basin (Figures 2.54, 2.55) is essentially a fold belt deformed and uplifted during the Carboniferous Alice Springs Orogeny beneath the Cooper Basin. Structural dip varies from sub-horizontal beneath the Patchawarra Trough and GMI Ridge to vertical and locally overturned. Early to Middle Carboniferous Big Lake Suite granitic intrusives beneath the Nappamerri Trough were responsible for local contact metamorphism of Cambrian country rock.

A stratigraphic summary of the eastern Warburton Basin is shown in Figure 2.56. Four seismic sequence sets have been recognised in Figure 2.56:

- Sequence Є1 comprises Early Cambrian acid-intermediate volcanics and tuff of the Mooracoochie volcanics;
- Sequence Є2 is characterised by dolomite with vuggy and moldic porosity (Diamond Bog Dolomite), indicating a high-stand deposit altered by sub-aerial exposure;
- Sequence Є3 is characterised by a back-stepping style and several stacked cycles of catch-up and keep-up carbonate systems (lower Kalladeina Formation/Dullingari Group);

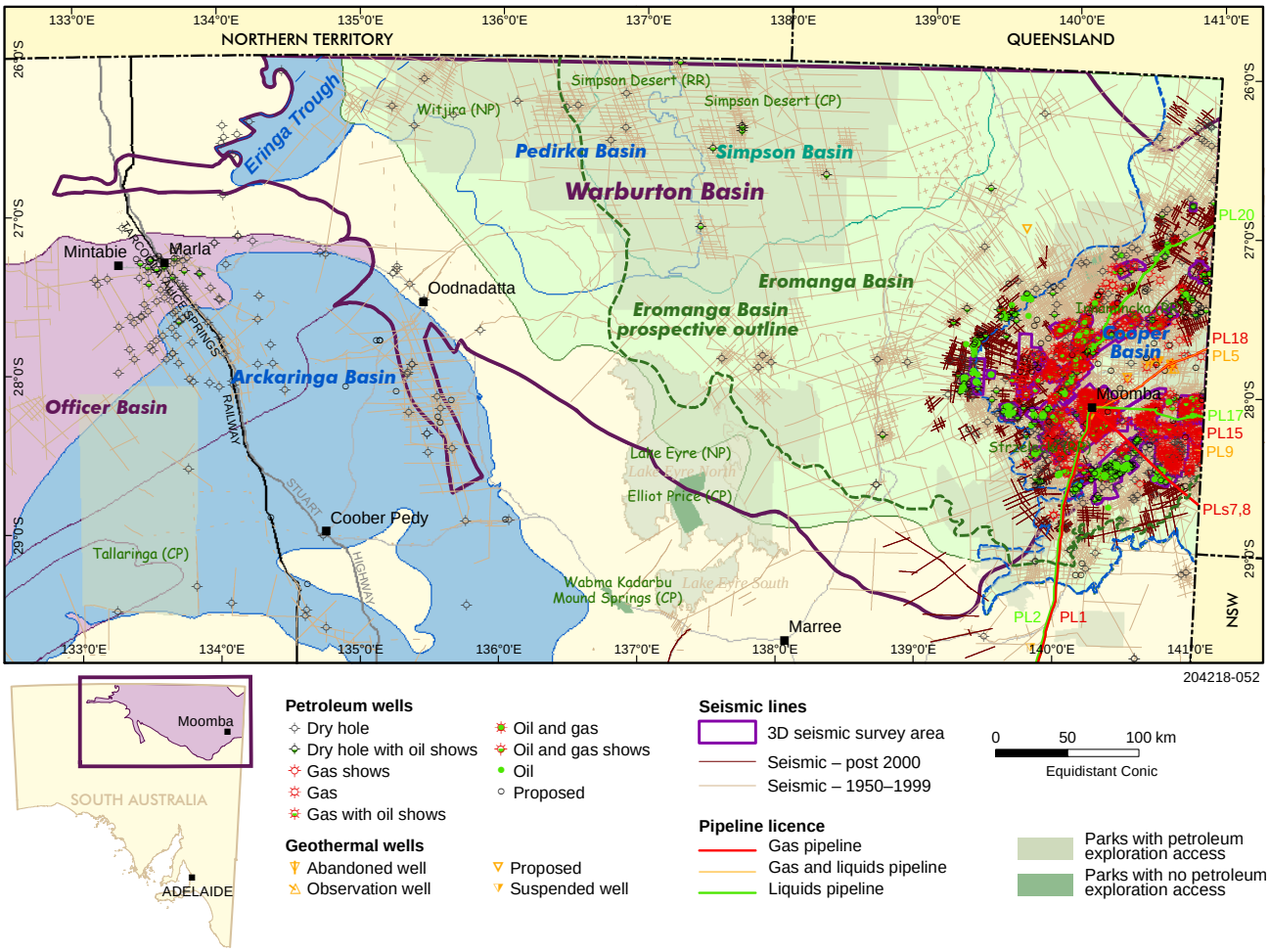


Figure 2.54 *Well and seismic line coverage, Warburton Basin.*

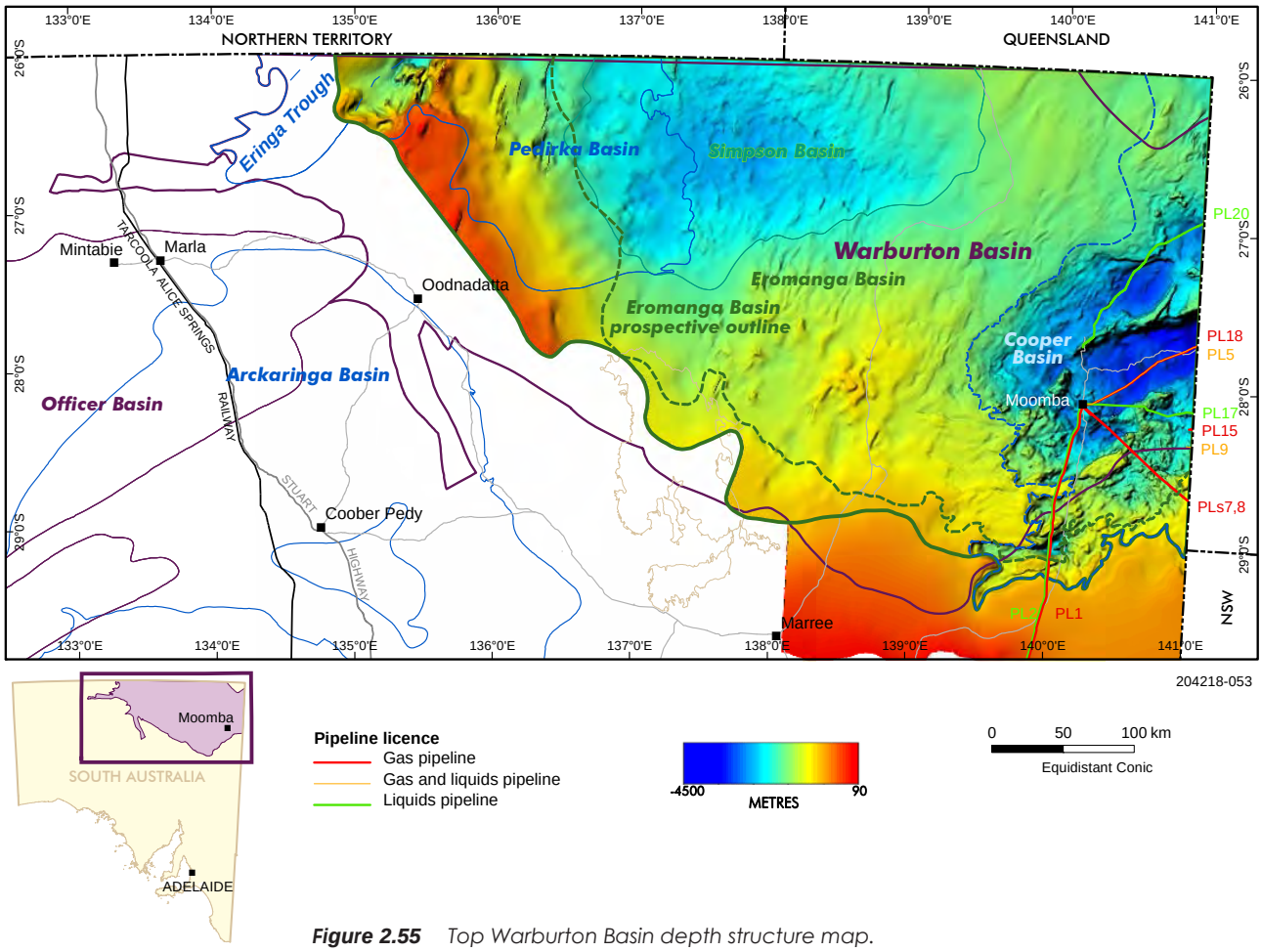


Figure 2.55 *Top Warburton Basin depth structure map.*

- Sequence Є4 was deposited after a major transgression following low relative sea level (Upper Kalladeina Formation/ Dullingari Group). The succeeding high-stand systems tract can be subdivided into three major parasequence sets: early high-stand aggradation, middle high-stand progradation and late high-stand regression.

The uppermost sequence (Innamincka Formation) is characterised by numerous stacked shoaling-upward parasequences, which may indicate a shallow stable shelf under influence of frequent sea-level fluctuations. An increase in siliciclastic content at the expense of carbonate suggests an approaching shoreline. Shoaling is recorded on the Coongie–Cuttapirrie shelf, and the Innamincka Formation continues this trend to shallow subtidal water depths as part of a deltaic complex with clastics probably derived from the Proterozoic Arunta Block to the north. The Pando Formation is an extensive marine shelf sand equivalent to the lower Innamincka Formation. The Narcoonowie Formation is a laterally equivalent lowstand fan (Figure 2.56).

Black shale of the Dullingari Group was deposited in deep water of the Tilparee Trough to the south during the Early Ordovician. This trough, bordered to the north by the Innamincka Shelf and to the south by the Gnalta Shelf, formed part of the Larapintine Sea which extended through the Warburton and Amadeus basins to the Canning Basin.

Source rock quality of samples principally from the Kalladeina Formation is poor to fair. With the exception of anomalously low maturity indices from Kalladeina 1, the succession below 3000 m is late-mature to post-mature for oil. Organic matter is mainly Type II kerogen derived from marine algal–bacterial precursors.

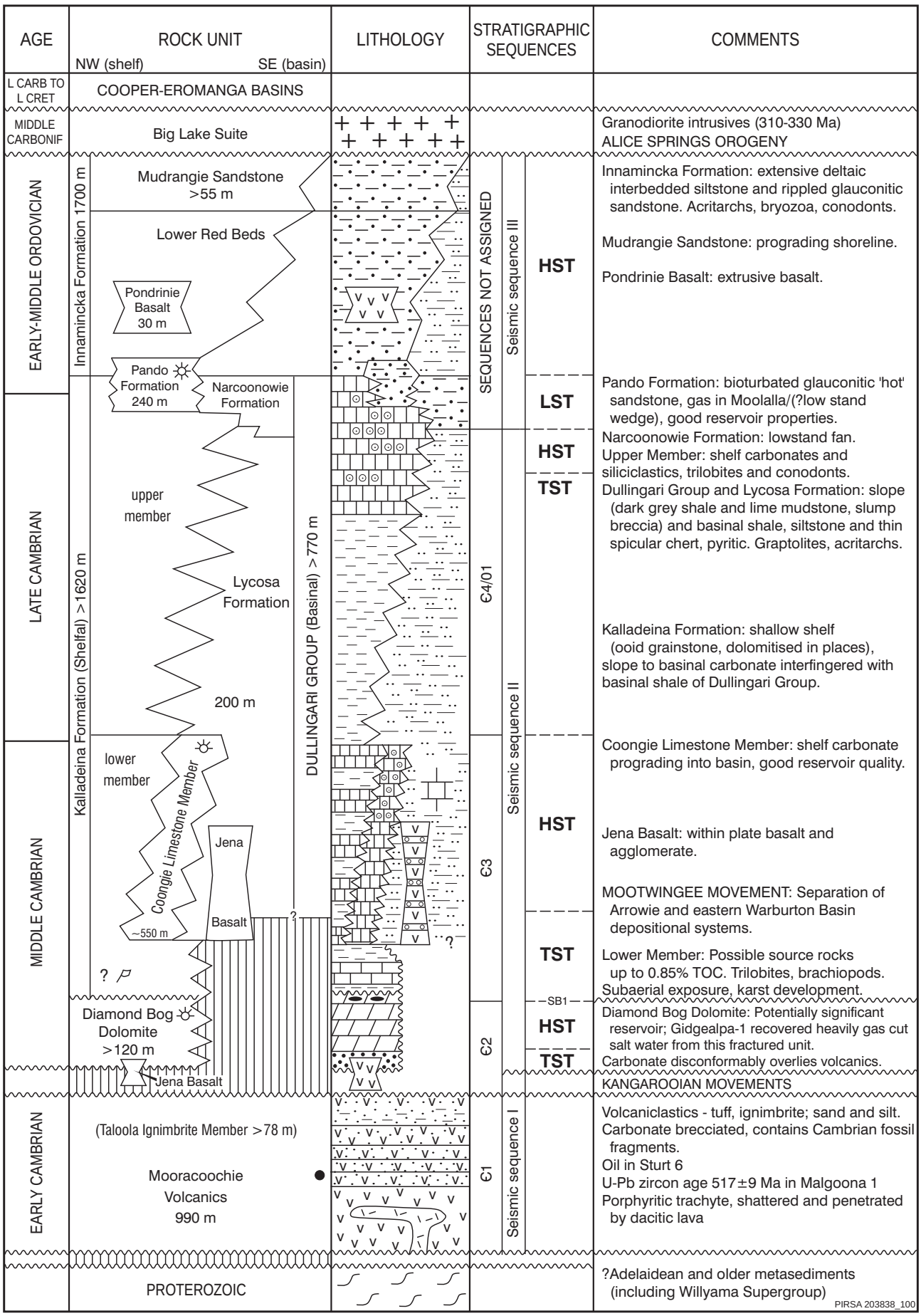


Figure 2.56 *Geological summary of the eastern Warburton Basin. HST = Highstand Systems Tract; LST = Lowstand Sytems Tract; TST = Transgressive Systems Tract; SB = Sequence Boundary.*

A TEISA–SPIRT project on oil migration in the Cooper and Eromanga basins has recognised pre-Permian inputs to oil pools on or adjacent to the Gidgealpa and Warra ridges, most notably at Gidgealpa, Meranji, Muteroo, Malgoona and Sturt, but also at Cowan and Mudlalee. The most likely source rocks are Cambrian carbonates in the underlying Warburton Basin.

2.7.1 Tight Gas Play

Recognition of a unique alteration profile around the unconformity between the Cooper and Warburton basins has generated a new play concept that could trap Permian sourced hydrocarbons as well as Warburton Basin sourced hydrocarbons. The nature of the alteration remains enigmatic and it is uncertain if it is a palaeosol or a result of hydrothermal alteration.

This weathered zone is up to 150 m thick comprising altered Warburton Basin strata and the granites in particular, immediately beneath the Cooper Basin unconformity (Boucher, 2001b) that can act as a seal for Warburton Basin reservoirs charged by downdip Permian source rocks and possibly indigenous hydrocarbons (Figures 2.57, 2.58, 2.59 and 2.60).

Fractures in brittle siltstones, such as those in the Dullingari Group in Lycosa 1, are capable of producing commercial oil and gas charged by downdip Permian source rocks (Figures 2.59, 2.61 & 2.62). Lycosa 1 tested a fractured shale, siltstone and sandstone sequence with multiple sets of carbonate-, quartz- and pyrite-filled fractures that produced up to 4.1 mmcfd over the interval 2633 to 2683 m from drill stem test (DST) 1 decreasing to 1.4 mmcfd with trace condensate after extended flow over the interval 2621 to 2697.5 m during DST 4 (Figure 2.62). The DST charts indicate possible formation damage and a dual porosity system.

Pando Formation sandstone ranges in porosity from 5 to 20% but relies on fractures for permeability. The unit is glauconitic and zircon-rich and consequently has a high gamma ray response. Moolalla 1 gas is reservoired in this formation which extends from Pando wells in the west to Moomba wells in the northeast.

Basal and middle Kalladeina Formation dolomites are shelf limestones exposed to meteoric diagenesis during marine lowstands. Although minor gas shows have been recorded, porosity prediction has proved difficult, the dolomites and associated karst breccias proving tight when drilled.

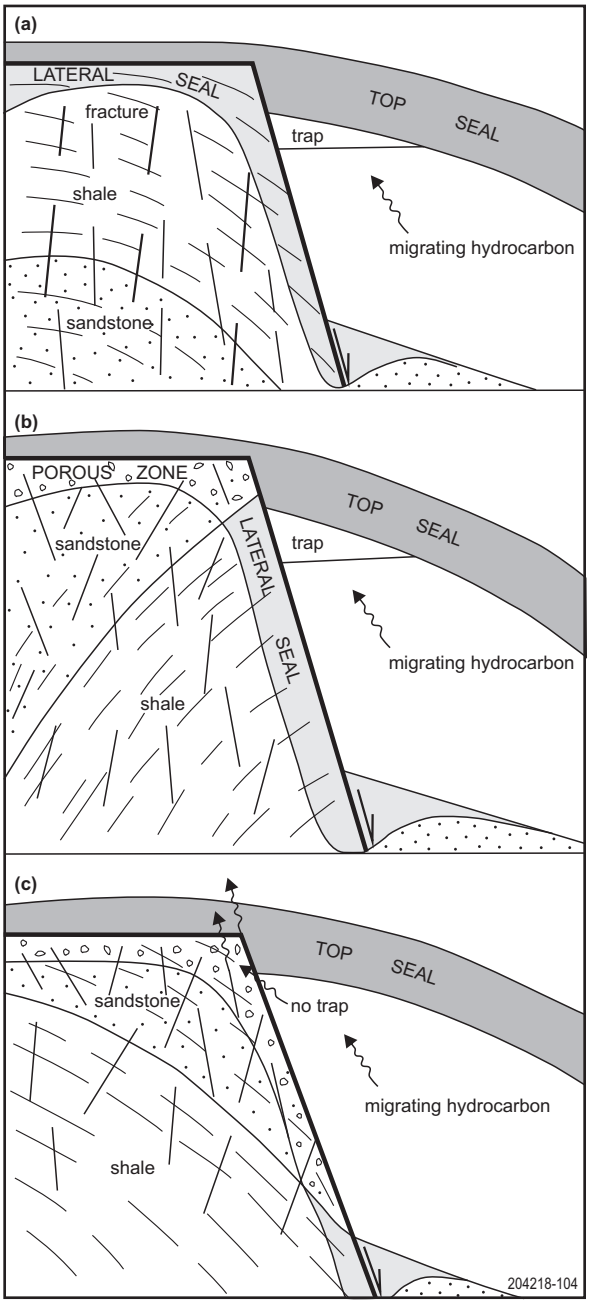


Figure 2.57 Potential seal configurations for altered zone basement and related plays (Boucher, 2001b).

Sturt 6 oil was produced from fractured and weathered tuff and ignimbrite of the Mooracoochie Volcanics. Porosity values reach 17% due to dissolution of feldspar and glass shards, fractures create the necessary permeability for flow.

2.7.2 Shale Gas Play

Black, pyritic shales of the Cambro-Ordovician Dullingari Group were deposited in deep water of the Larapintine Sea which extended through the Warburton and Amadeus basins to the Canning Basin (currently a focus for shale gas exploration in Western Australia).

Whether the Dullingari Group constitutes a valid shale gas play is yet to be proven. Of the meagre core recovered to date, from wells drilled on structural highs, the formation is consistently deformed and steeply dipping which is undesirable from a shale gas prospectivity perspective. In terms of source richness, TOC values from 4 wells (Dullingari 1, Pandieburra 1, Koochera 1 and Kuncherinna 1) average 0.24% (range 0.17 to 0.56%; 6 samples). These values are not encouraging and would suggest that gas recorded in Lycosa 1 and other wells with gas shows encountered in the Dullingari Group is migrated via natural fractures, rather than indigenous. The petroleum potential of this formation remains poorly understood and hampered by lack of data.

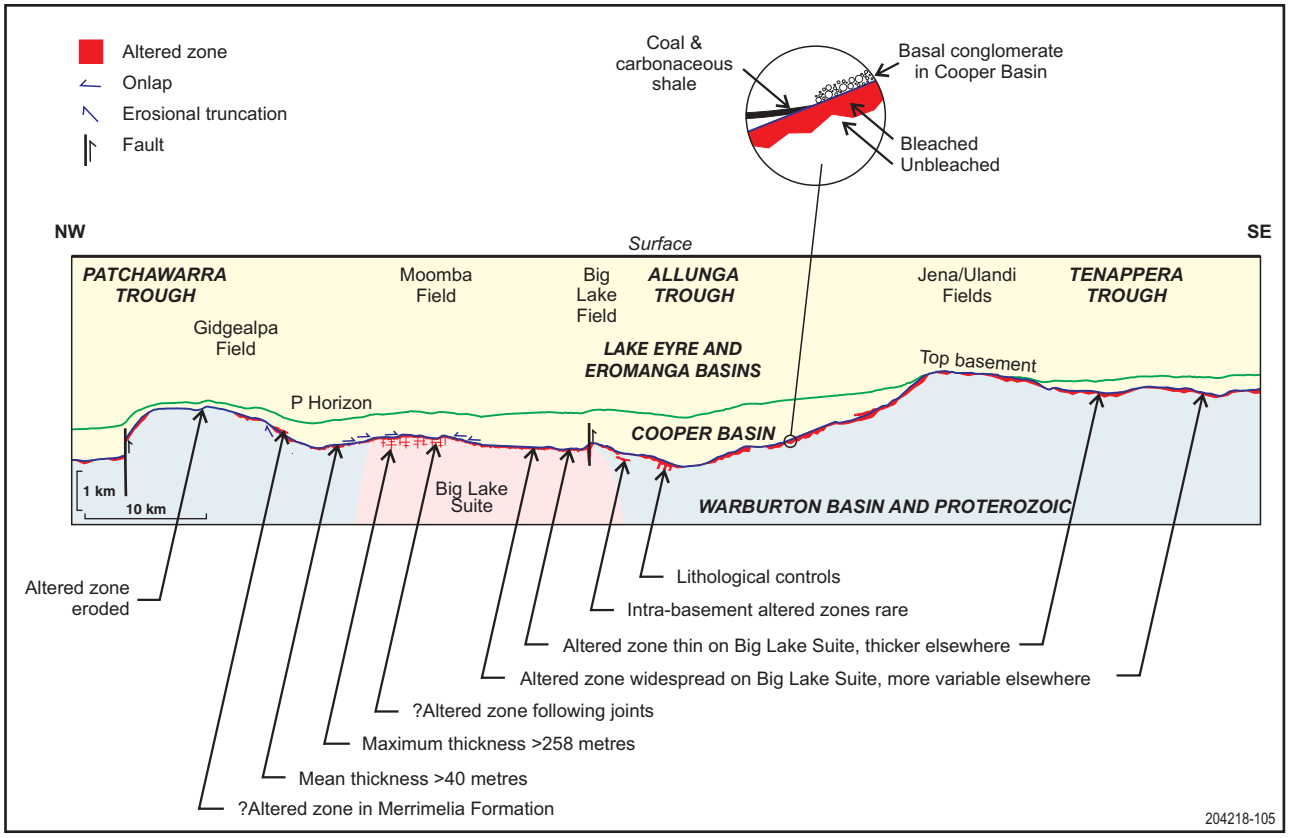


Figure 2.58 *Characteristics of altered zone, Warburton Basin (Boucher, 2001b).*

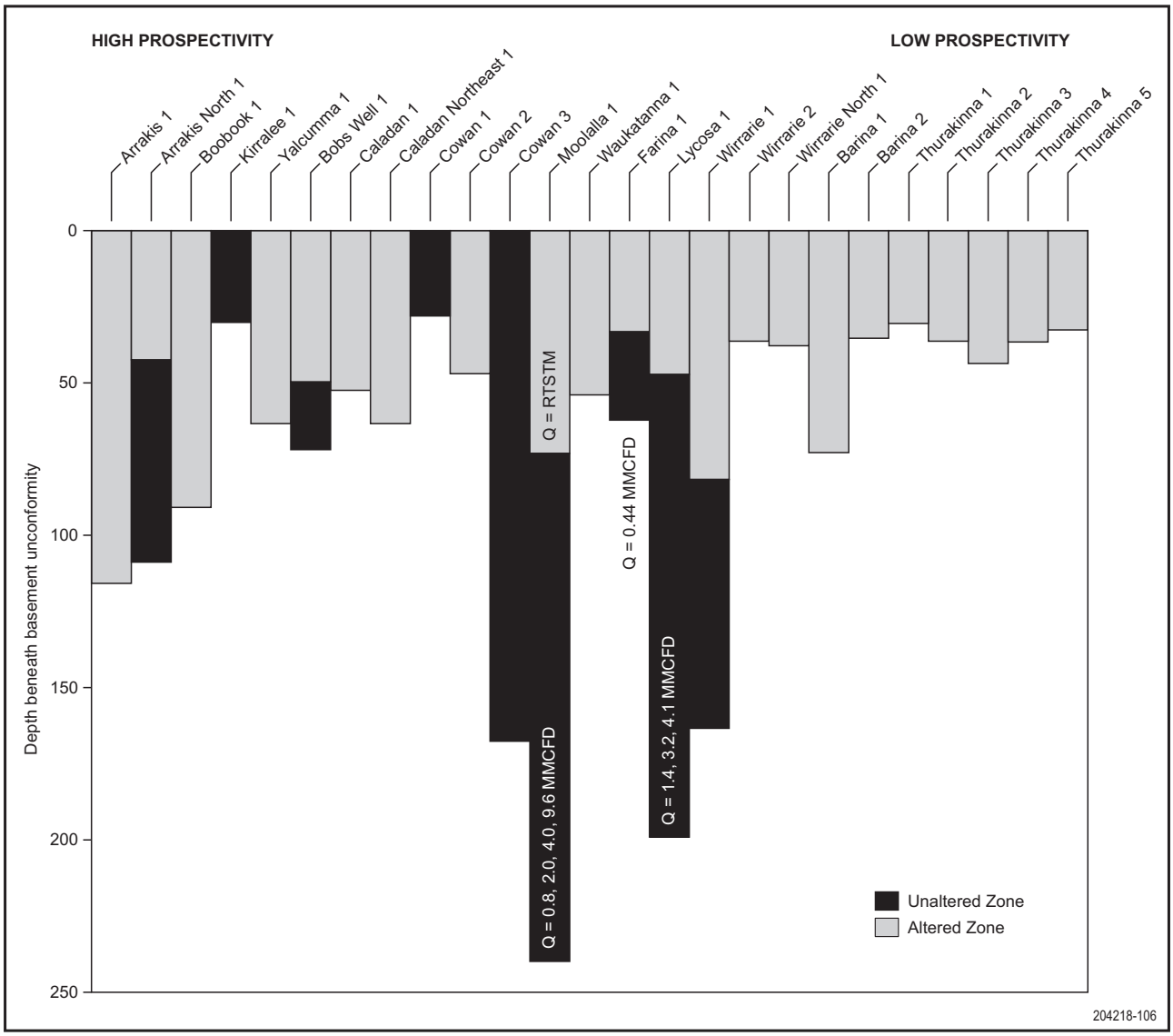


Figure 2.59 *Altered zone play for wells adjacent to Wooloo and Allunga Troughs. 3 of the 6 wells that penetrated the altered zone and into potential reservoir discovered gas (Boucher, 2001b).*

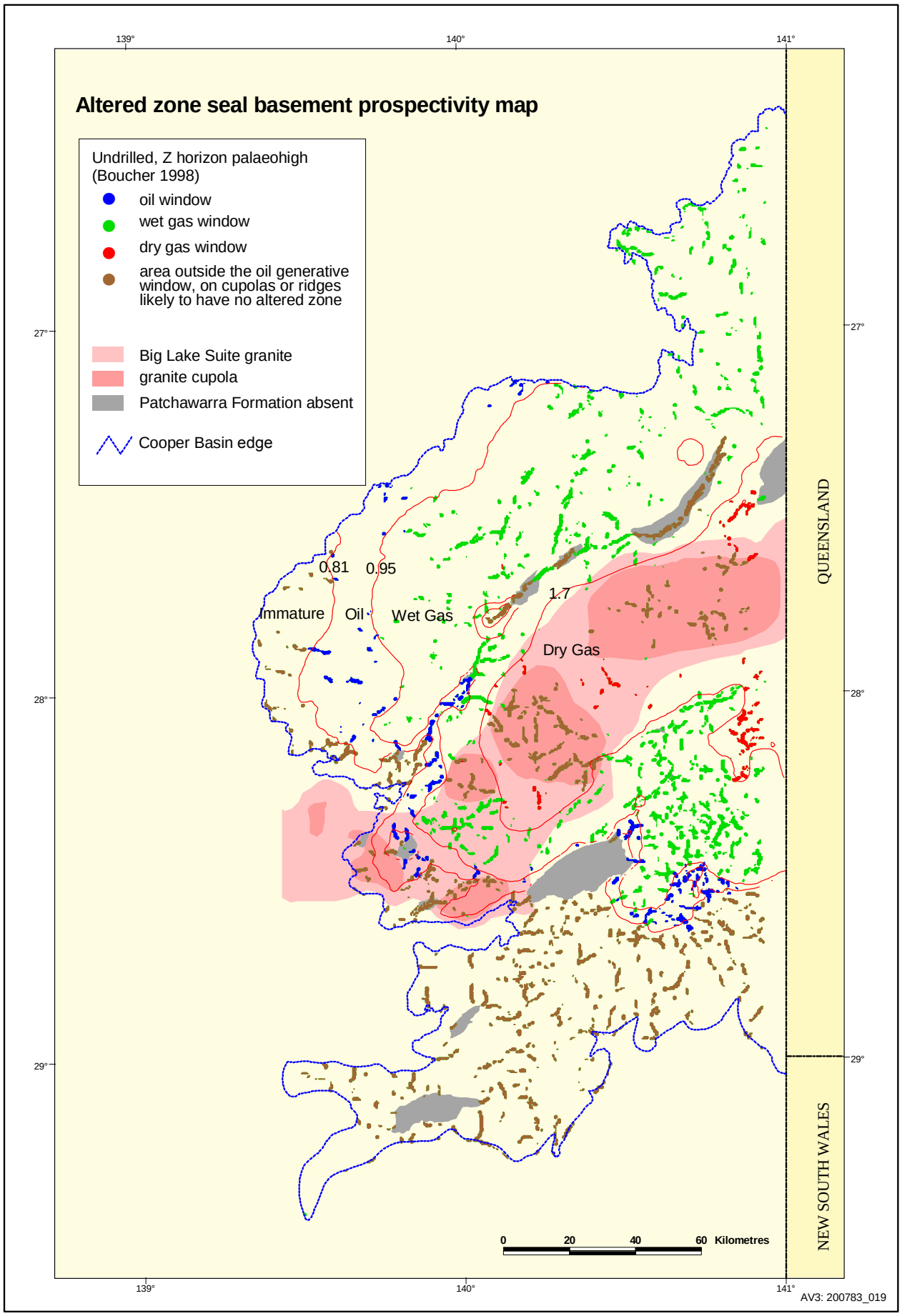


Figure 2.60 *Altered zone seal basement prospectivity map. Vitrinite reflectance data is for top Patchawarra Formation. (Boucher, 2001b).*

Figure 2.61 *Fractured Dullingari Group shales, siltstones and sandstones – Lycosa 1.*

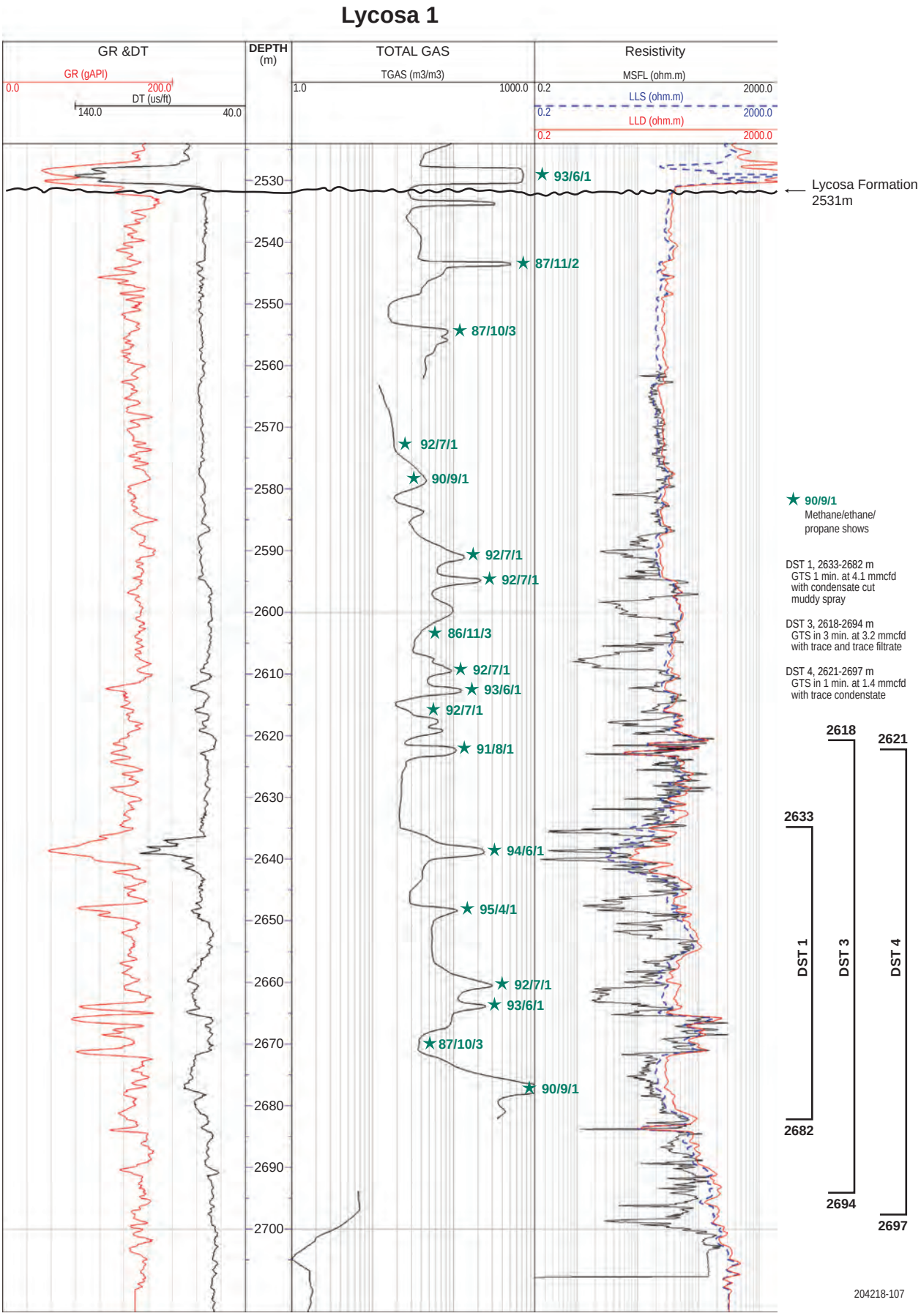


Figure 2.62 *Lycosa 1 composite log showing drill stem test flows over Dullingari Group metasediments.*

2.8 Officer Basin

The Officer Basin is an arcuate depression 500 km long extending from South Australia to Western Australia with six main depocentres containing flat to gently dipping Neoproterozoic and Palaeozoic sediments (Figure 2.63). About one third (176 000 km^2) of the basin occurs in South Australia. Officer Basin sediments crop out in a linear belt south of the Musgrave Block, marking the northern limit of the basin (Figure 2.64). Outcrop is sporadic elsewhere. To the south the basin is overlapped by up to 400 m of Cenozoic, Mesozoic and locally, Permian strata. The eastern margin is ill defined.

Stratigraphy of the eastern Officer Basin and a rock-relation diagram linking the Birksgate Sub-basin, Munyarai Trough and Murnaroo Platform are shown in Figures 2.65 and 2.66. The sediment packages of immediate interest are the Neoproterozoic (Willouran, Marinoan) and Cambro-Ordovician.

2.8.1 Tight Gas Play

Although no commercial discoveries have been made in the Officer Basin, hydrocarbon shows have been found in 4 formations (the majority in a playa carbonate in the Marla Overthrust Zone) including significant oil bleeds in the Observatory Hill Formation in Byilkaoora 1 stratigraphic well.

Principal source rocks are the Marinoan Dey Dey Mudstone and Narana Formation (Figure 2.65) that have TOC values to 1.47% (87 samples, mean 0.28%) and shallow marine carbonates of the Early Cambrian Ouldburra Formation that has TOC values from 0.4 to 1.87% although the richest source intervals are thin (~1 m). Up to nine recorded oil bleeds have been recorded from vugs and fractures in the Observatory Hill Formation with TOC values ranging from 0.5 to 1.4% in Byilkaoora 1.

The Munyarai and Manya Troughs and the Marla Overthrust Zone (Figures 2.64, 2.66) are prospective for conventional oil and gas and unconventional tight gas.

Burial history modelling (Gravestock and Hill, 1997) of the Manya Trough (based on Manya 6 well) suggests the entire sequence below ~175 m lies in the gas window with wet gas down to ~944 m. Significantly, source rocks of the Ouldburra Formation have remained in the wet gas window just after the Alice Springs Orogeny (~360 Ma) and have remained in the wet gas window to present day. It is expected that structures that were in place as a result of the Petermann and Delamerian Orogenies could be charged.

Burial history modelling of the Marla Overthrust Zone (Gravestock and Hill, 1997), based on Byilkaoora 1, suggests that the Dey Dey Mudstone – Karlaya Limestone source rock package entered the wet gas window at ~550 Ma during the Delamerian Orogeny and passed into the dry gas window between ~490 and 475 Ma. In this region, thick sandstone sequences of the Tarlina Sandstone and Murnaroo Formation and interbedded sandstone, siltstone and conglomerates of the Narana Formation represent viable tight gas targets.

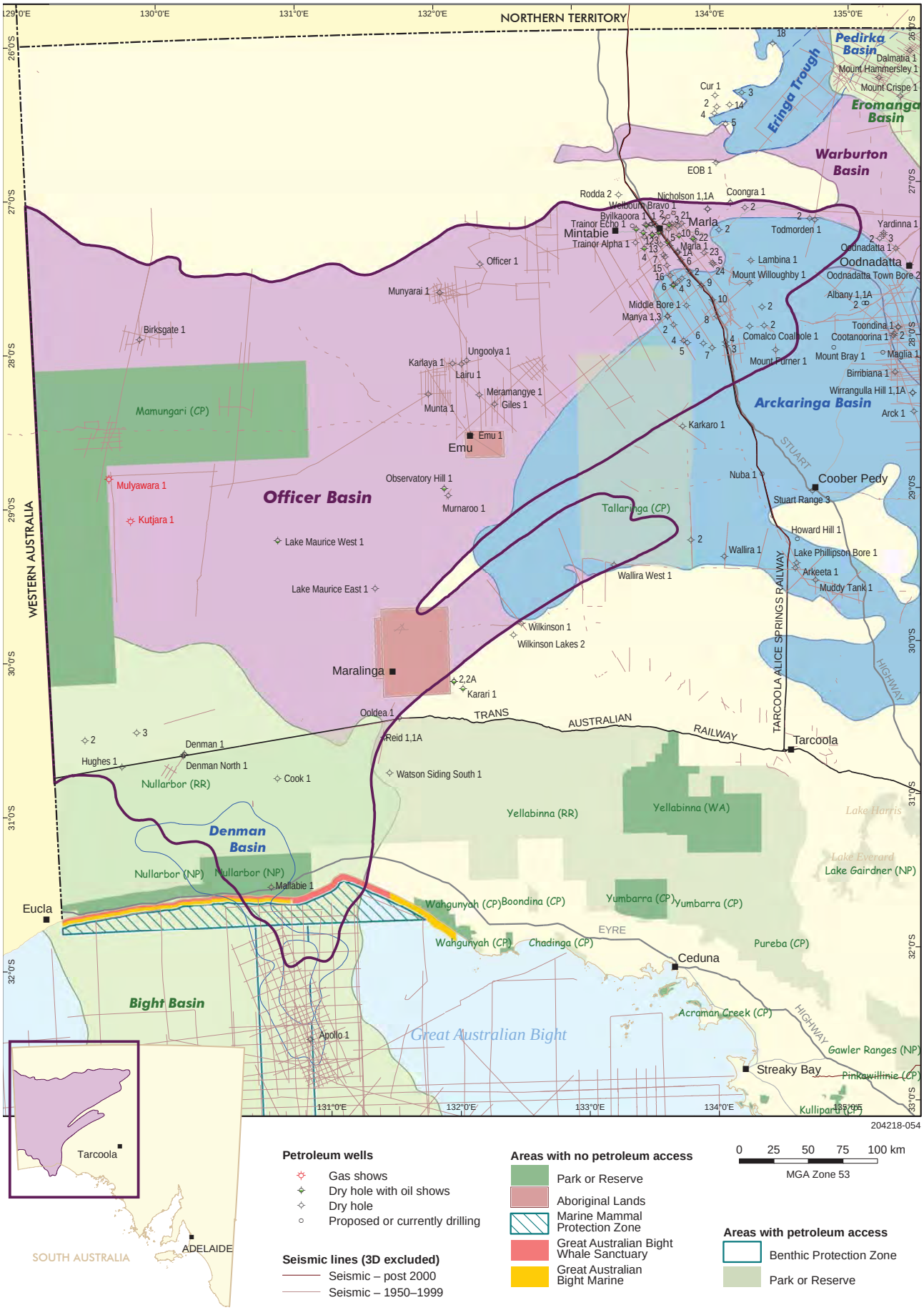


Figure 2.63 *Officer Basin, South Australia. Wells and seismic lines.*

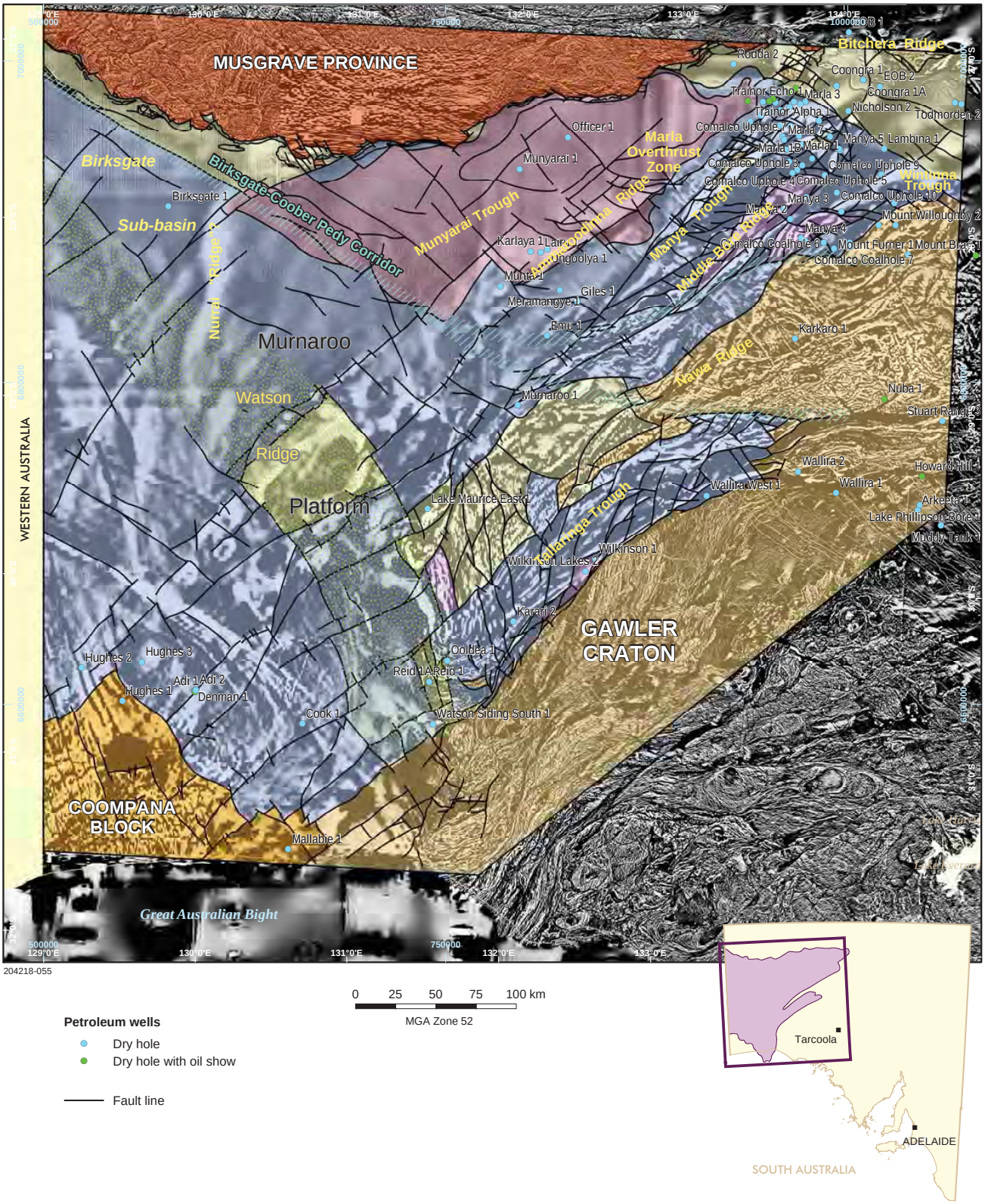


Figure 2.64 *Officer Basin structural elements map.*

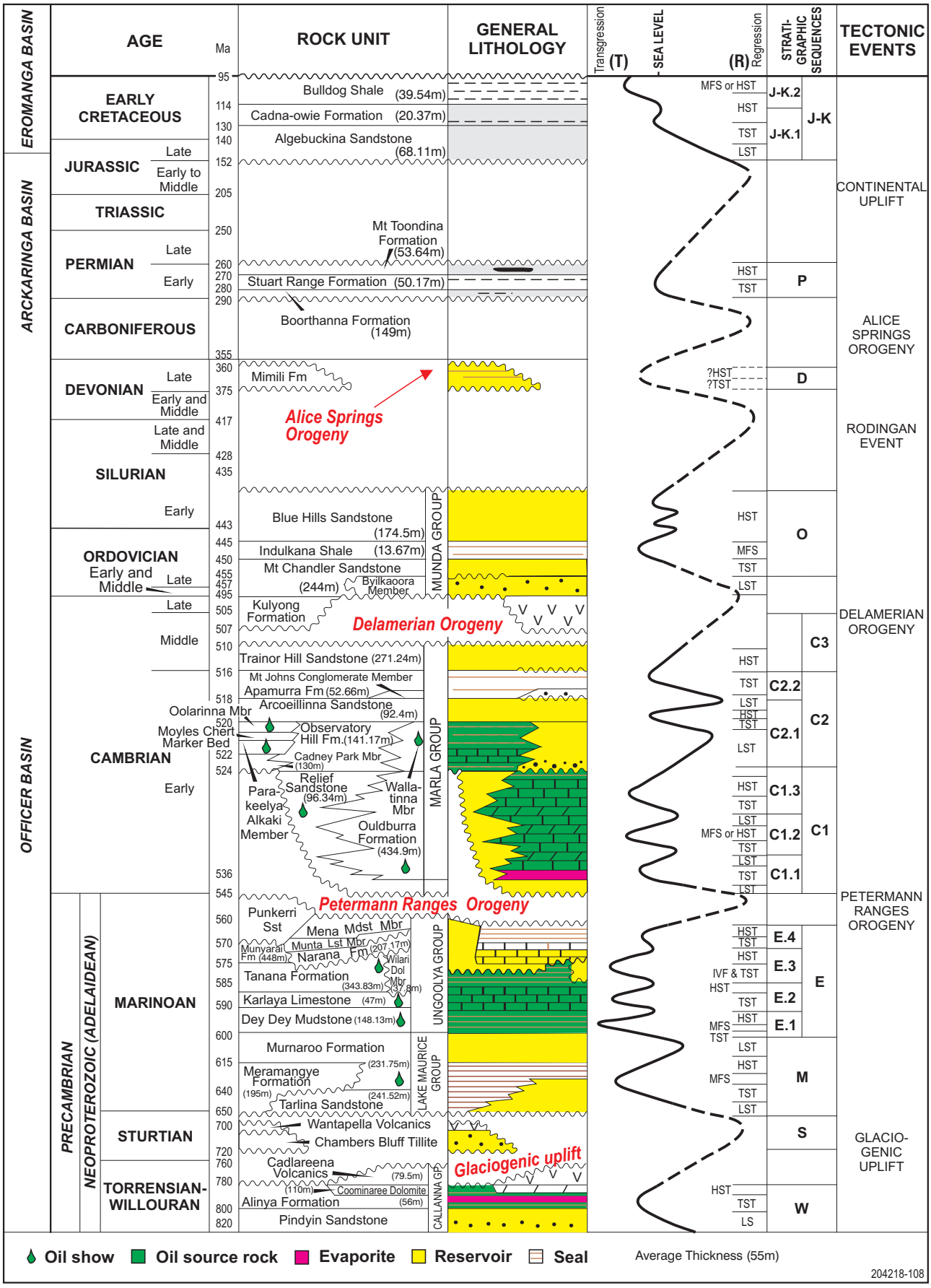


Figure 2.65 *Stratigraphic framework, eastern Officer Basin. Systems tract acronyms are as follow: HST = Highstand Systems Tract; LST = Lowstand Systems Tract; TST = Transgressive Systems Tract; MFS = Maximum Flooding Surface; IVF = Incised Valley Fill.*

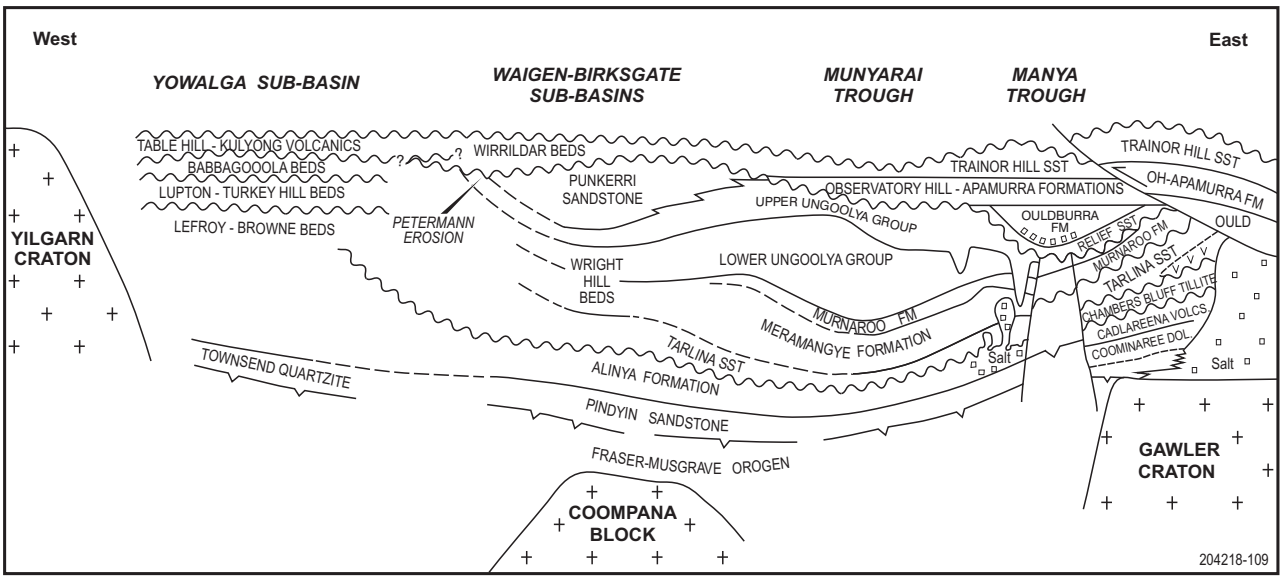


Figure 2.66 *Basin architecture.*