Organic petrography and thermal maturity of the Permian Roseneath and Murteree shales in the Cooper Basin, Australia

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Abstract

The Permo-Triassic Cooper Basin is one of the largest intracratonic basins in Australia, covering approximately 130,000 km^2 in South Australia and Queensland. The basin is one of Australia's major onshore hydrocarbon province and most prospective region for both conventional and unconventional hydrocarbon exploration. Organic petrography and thermal maturity of two Permian lacustrine shale units in the Cooper Basin, the Murteree and Roseneath shales, were investigated on 21 wells with the objective of evaluating the gas generating potential of these units. Vitrinite reflectance values for the Murteree and Roseneath shales range between 1.17% and 2.00%. Macerals show systematic changes in properties relative to maturity rank. A range of maceral compositions, dominated by vitrinite group macerals, are present in both units, which vary between rich and very rich in organic content. Rock-Eval data suggest fair to very good kerogen quality (of kerogen types II, III, and IV ranging from immature to mature) and imply a mostly gas-prone generation potential in the shales.

Keywords: *Shale gas, Hydrocarbon prospectivity, Roseneath Shale, Murteree Shale, Permian, Cooper Basin.*

1 Introduction

The Cooper Basin is a mature petroleum province with oil/gas production since 1963. However, relative to its size and poor exploration coverage, large potentials remain for undiscovered stratigraphic and sub-unconformity traps as well as unconventional reservoirs and has demonstrated by renewed interest in the past five years. Pinch out plays along the margins of the Cooper Basin have been tested with commercial success (PIRSA, 2007) and more recently unconventional shale gas potential has been investigated by several exploration companies (PIRSA, 2012). The focus of this investigation are the Roseneath, and Murteree Shales that are typically considered to present the most advanced unconventional gas plays in Australia (PIRSA, 2012). Indeed, shale gas reservoirs in the basin are thought to be the main source for conventional gas and oil accumulations (CSIRO, 2012). However, proposed shale gas plays in both formations and other prospective units across the basin are still very poorly evaluated and have been only generally characterized as fine-grained, low permeability facies that vary widely in their reported reservoir characteristics (Wüst et al., 2014). Several shale gas reservoir wells in the basin are currently commercially developed by different operators making use of extensive midstream infrastructure already in place. One critical aspect of oil/gas exploration across the basin is understanding organic facies distribution, which is poorly known in this study, vitrinite reflectance (VR) was investigated on 65 samples from wells across the Cooper Basin (with target zones of both Roseneath and Murteree shales). Thirty-five of these samples were also analysed for H/C ratios of kerogen and pyrolysis T_{max} including spatial and stratigraphic variations in TOC. The primary goal of this study is to better understand the thermal maturity and impact of changes in H/C ratios on the hydrocarbon potential of organic matter in the Roseneath and Murteree shales across the Cooper Basin.

2 Geological setting of the Cooper Basin

The Cooper Basin is an intracratonic rift basin of Permian to Triassic age that extends from the northeastern corner of South Australia into southwestern Queensland. It covers an area of approximately 130,000 km^2, of which ~35,000 km^2 are in NE South Australia, where most exploration has focused. Three major troughs (Patchawarra, Nappamerri, and Tenappera) are separated by structural ridges (Gidgealpa, Merrimelia, Innaminka, GMI and Murteree) associated with the reactivation of NW-directed thrust faults in the underlying Neoproterozoic–Ordovician Warburton Basin (Wopfner,1985). In addition to the sedimentary deposits of the Warburton Basin, the base of the Cooper Basin is underlain in part by younger, intrusive granitoids (Klemme, 1980; Radke et al., 2012). Overlying and extending beyond the Cooper Basin are Jurassic-Cretaceous sequences of the Eromanga Basin.

The basal sedimentary unit in the Cooper Basin is the Merrimelia Formation, which is considered the economic basement for hydrocarbon exploration (Williams & Wild, 1984; Williams et al., 1985). The Merrimelia Formation is late Carboniferous to early Permian (Price et al., 1985; Price, 1996) and consists of conglomerates, sandstones and shales deposited in a glacial paleoenvironment (Williams & Wild, 1984) (Fig. 1). The overlying Tirrawarra Sandstone is characterized by thick, multi-story channel sandstones with distinctive quartzose compositions (Kapel, 1972; Gostin, 1973; Thorton, 1979). The Patchawarra Formation succeeds this unit and is considered to be the thickest unit in the Cooper Basin although it shows great lateral thickness variation (Gatehouse, 1972). It is thickest in the Nappamerri and Patchawarra troughs and thins by onlap onto the crests of intrabasinal ridges and at the basin margins (Battersby, 1977). The Patchawarra Formation represents an interbedded succession of minor channel lag conglomerates and massive, cross-bedded and laminated sandstones of fluvial origin, along with laminated siltstones, shales, and coals that formed in abandoned channels, shallow lakes and peat mires. The overlying Murteree, Epsilon, Roseneath and Daralingie formations record alternating lacustrine and lower delta plain environments, consisting mainly of interbedded fluvial-deltaic sandstones, shales, siltstones and coals (Kapel, 1972; Gostin, 1973;Thorton, 1979).

The Early Permian Murteree Shale (Price, 1996) is widespread across the Cooper Basin in both South Australia and Queensland and was defined by Gatehouse (1972) as the shale interval between the sandstone-dominated Patchawarra and Epsilon formations. It consists of black to dark gray brown argillaceous shales, siltstones and fine-grained sandstones, which become coarser grained towards the southern part of the basin. These organic-rich, carbonaceous siltstones with abundant pyrite and muscovite represent an important potential source rock in the Basin. The type section lies between 1922.9 – 1970.8 m in the Murteree 1 well (Latitude 28^0 23' 48.3''S, Longitude 1400 34' 15.3''E; (Gatehouse, 1972). It is relatively uniform in thickness, averaging ~50 m but has a maximum thickness of 86 m in the Nappameri Trough. It thins to the north, where a maximum thickness of 35 m is developed in the Patchawarra Trough. It is absent over the crests of structural ridges (Boucher, 2000). A relatively deep lacustrine depositional environment has been interpreted for the formation, in part based on the rarity of wave ripples and other evidence of storm reworking as would be expected for a shallow lake system (Gravestock et al., 1995).

The Roseneath Shale was defined by Gatehouse (1972) as the suite of shales and minor siltstones that conformably overlie the Epsilon Formation. The unit was originally included as one of three units in the Moomba Formation by Kapel (1972). Gatehouse (1972) raised it to formation status with a type section between 1956.8 – 2024.5 m in the Roseneath 1 well (latitude 28°10.10"S, longitude 141° 14’’E). The Roseneath Shale is composed of light to dark brown-grey or olive-grey siltstone, and shale with minor fine-grained pyrite and pale brown sandstone interbeds. It occurs across the central Cooper Basin, but has been eroded from the Dunoon and Murteree ridges and crestal areas of other structural highs during late Early Permian uplift. The Roseneath Shale is not as extensive as the Murteree Shale. It conformably overlies and intertongues with the Epsilon Formation and is overlain by and also intertongues with the Daralingie Formation. Where the Daralingie Formation has been removed by erosion, the Roseneath Shale is unconformably overlain by the Toolachee Formation. The unit thickens into the Nappamerri and Tenappera Troughs and reaches a maximum thickness of 105 m in the Strathmount 1 well (Boucher, 2000). It is considered to be Early Permian (Kungurian) in age (Price et al., 1996). A lacustrine environment of deposition, similar to that of the Murteree Shale, is inferred for the Roseneath Shale (Stuart, 1976; Thornton, 1979). Variations between massive to finely laminated intervals with minor cross-lamination and wave ripples, suggest storm reworking, and flame structures and slump folds indicate slope instability. The unit is inferred to have been deposited in a shallower lacustrine environment than the Murteree Shale (Stuart, 1976; Thornton, 1979).

3 Petroleum geology of the Cooper Basin

The Cooper Basin has produced conventional oil and gas for many decades from sandstone reservoirs, particularly in the Tirrawara Sandstone, which was identified as a significant hydrocarbon source in the early phase of exploration. Producing gas and oil fields in the basin are primarily related to broad arches and folds as both crestal and non-crestal hydrocarbon accumulations (Mott, 1952). Multiple oil and gas pools are stacked in coaxial Permian and Mesozoic structures, from as low as the Tirrawarra Sandstone to as high as the

Murta Formation (in the overlying Eromanga Basin succession) (PIRSA, 1998; DMITRE, 2012). Locally, Permian oil has also migrated downwards into the underlying Warburton Basin reservoirs on the basin margin and Permian gas has migrated into a fractured Ordovician reservoir fringing the Allungu Trough. Anticlinal and faulted anticlinal traps have been relied on as proven exploration targets, but potential remains high for discoveries in stratigraphic and sub-unconformity traps, especially where Permian strata are truncated by strata of the overlying Eromanga Basin succession. Economic oil and gas reservoirs are also found in the Nappamerri Group, which is paradoxically regarded as a regional seal to the Cooper Basin (Geoscience, 2000; DMITRE, 2012). The Early to Middle Triassic Nappamerri Group is the uppermost succession in the Cooper Basin, and consists of interbedded shales, siltstones and sandstones interpreted to represent fluvial depositional environments associated with arid climatic conditions (Papalia, 1969; Price, 1985; Youngs and Boothby, 1985).

Multi-zone, high-sinuosity, fluvial sandstones form poor to good quality reservoirs in the basin. The main gas reservoirs occur within the Patchawarra Formation (Gatehouse, 1972; Morton & Gatehouse, 1985). Shoreface and delta distributary sandstones of the Epsilon and Daralingie formations are also important oil reservoirs. Oil is produced principally from low-sinuosity fluvial sand bodies within the Tirrawarra Sandstone (Kapel, 1972; Williams et al., 1984). Towards the margin of the Cooper Basin, oil is also produced from the Patchawarra Formation and from fluvial channel sandstones in the Merrimelia Formation in the Malgoona field. Intraformational shale and coal form local seals in the major reservoir units. Beneath the Daralingie unconformity the Roseneath and Murteree shales form two important Early Permian regional seals (Gatehouse, 1972). The Roseneath Shale is the top seal of the Epsilon

Formation, and the Murteree Shale seals the Patchawarra Formation. A younger regional seal is provided by the Triassic Arrabury Formation.

4 Samples and methods

Sixty-five samples were selected from both cuttings and core material of the Roseneath and Murteree shales in various exploration wells, with sampling in the following areas: the Patchawarra Trough, Nappameri Trough, Allunga Trough and Tenappera Trough. Wells were also selected to range across the South Australian and Queensland portions of the Cooper Basin. All sampling was undertaken at Department of Manufacturing, Innovation, Trade, Resources and Energy (DIMITRE) South Australia and Department of Natural Resources and Mines, Queensland core library facilities.

Maceral analyses used reflected light and where necessary, reflected fluorescent light with a 10x ocular and 50x oil immersion objective. At least 500 points on each VR sample were counted using mechanical stage steps and a point counter. All counting included maceral, sub maceral and mineral matter. The results are expressed in volume percentage of each component (vol %) for V (Vitrinite), L (Liptinite), and I (Inertinte) (see ICCP, 1998; ICCP, 2001 and Taylor et al., 1998) for detailed procedures of maceral analysis). Random VR measurements were made by calibrating against two sets of reference standards (Gadolinium-Gallium-Granat 0. 91-59, R 546 nm, Oil=1.674%, and Glass, R 546, oil=0.576%) using monochromatic (546) non-polarized light in conjunction with a 10x ocular and 40x oil immersion objective. The reflectance measurements were carried out mostly on vitrinite, although other macerals were used when vitrinite was absent. Reflectance is mainly carried out on solid/ bitumen if available or fluorescing material like spore etc.

Organic matter in these samples occurs as a complex mixture. The identification of indigenous vitrinite populations is based upon petrographical observations and the distribution of reflectance data. The use of interpretive step to determine the indigenous vitrinite population can lead to different results when compared to whole rock analyses.

A source rock analyzer (SRA) was used to perform pyrolysis as described by Espitalie et al. (1977, 1986), Peter (1986), and Riedeger (1991). This method permits rapid evaluation of the organic matter type and the thermal maturity of the organic matter. The pyrolysis method is based on steady heating of rock samples so that hydrocarbon production is monitored as a function of temperature. Rock-Eval pyrolysis values are presented in Appendix-1, which includes measures at T_{max}, Production Index (PI), TOC (total organic carbon), HI (hydrogen index), OI (oxygen index) and S1 (the free hydrocarbons present in the sample before the analysis), S2 (the volume of the hydrocarbon that formed during thermal pyrolysis of the sample), S3 (the CO_2 yield during thermal breakdown of kerogen), S4 (the residual carbon content of the sample). All these values are indicative of the maturity level of the organic matter and a number of hydrocarbons already produced, or that could be produced from the rock samples. T_{max} represents the temperature at which the maximum amount of hydrocarbon is generated from kerogen by heating. The measure does not represent the actual burial temperature of the rock, but rather a relative estimate of thermal maturity. If the rock has not been significantly altered, it will produce free hydrocarbons when heated during pyrolysis.

5 Results and interpretation

5.1 Maceral analysis of the Roseneath Shale

Inertodetrinite is widely distributed in the Roseneath Shale, as well as in the Murteree Shale, but vitrinite is the main maceral in both units, consisting of collotelinite and vitrodetrinite. Inertinite is the second most common maceral in terms of abundance, consisting of mainly inertodetrinite. Liptinite, in the form of liptodetrinite, is a minor component of both shales. Organic matter is mainly coaly in nature and derived from a variety of different sources including lipid-rich phytoplankton and terrigenous humic organic matter. Sample V-1423 of Roseneath Shale at depth 2127m to 2133m in the Munkarie-02 well contains telalginite, a structured organic matter (alginite) that is composed of large discrete colonial or unicellular algae in distinct laminae (Fig. 2c). Detrital resinite is common in many sections and is interpreted to occur in close proximity to deltaic facies. It may contain some internal domains showing that more than one phase is present (Fig. 2d). The occurrence of resinite as cell fillings indicates that at some point in the maturation process, the resinite was relatively fluid. The organic constituents luminesce when irradiated with blue light and UV excitation. Under white light, the resinite shows streaks of inorganic material. In white light, collotelinite that occupies the spaces between cell walls and present as groundmass (Fig. 2e).

In the Toolachee-25 well Roseneath Shale samples at depths of 2020 m to 2029 m show medium-grained vitrodetrinite fragments of varying shapes that are surrounded by non-vitrinitic material (Figs. 2f, 2g, and 2i). The vitrodetrinite consists of small particles of vitrinite, but the boundaries between particles becomes obscured with increasing depth. Inertodetrinite is also present and represented by small fragments derived by the physical degradation of the other types of inertinite, most probably fusinite and semifusinite.

In Moomba-46 well samples V-1415 (2464 to 2465m) and V-1417 (2463 to 2464m), organic matter is common and mostly medium sand sized grained. Vitrinite is the main maceral, consisting of vitrodetrinite. Inertinite is comprised of inertodetrinite. Liptinite occurs as thin alginite and liptodetrinite. Telinite shows non-gelified plant tissues with well-preserved cells (Fig. 2j). Under yellow fluorescence light, alginite is visible as irregular slender bands representing discrete laminae across domains with dispersed macerals (Figs. 2h, 2i). The samples exhibit high fluorescence, suggesting the organics have either a high hydrogen index or enhanced lipid content, whereas other samples exhibiting little or no fluorescence are interpreted as being hydrogen-poor or low in lipid content. Other domains (Figs. 2b, 2f and 2g) show vitrodetrinite, dominantly with small particles of vitrinite of other types. Vitrodetrinite is surrounded by siliciclastic material, but the boundaries between the particles can be obscure.

In Moomba-73 well samples V-1400 to V-1402 (2657 m to 2694 m) contain high percentages of vitrinite that are small and look oxidized and detrital in nature (Fig. 2k), deposited close to the source. The vitrinite consists of vitrodetrinite. Some inertinite consists of inertodetrinite, and liptinite is present in the form of liptodetrinite.

5.1.1 Maceral analysis of the Murteree Shale

Vitrinite is the main maceral, consisting of vitrodetrinite and inertinite is the second most abundant, consisting of inertodetrinite. Liptinite in the form of liptodetrinite is subordinate. Organic matter in the Murteree Shale is derived from a variety of sources such as lipid-rich phytoplankton and terrigenous humic organic matter. It is abundant and typically medium grained. Changes in optical properties reflect chemical changes in the macerals. Murteree Shale macerals from different wells in the Cooper Basin show variability.

In sample V-1374, from 2128m in the Epsilon well, organic matter is of medium sand size grained and consists of mainly fusinite and subordinate semi-fusinite, which mainly represent woody plant material. These are mostly derived relic tissues and cellular structures and are commonly well-preserved with yellow colour(Figs. 3n, 3o, and 3p) whereas white light shows unstructured collotelinite in the groundmass (Fig. 3m).

Sample V-1391 from Toolachee-East-2 well at a depth of 2203m to 2209 m is rich in the organic matter of medium grain size. Vitrinite is the primary maceral, consisting of collotelinite and vitrodetrinite. Graphite is a trace component in numerous samples (Fig. 3v). Collotelinite is dominant over vitrodetrinite in the ground mass. It is not optically uniform, in part due to strain anisotropy, and shows micro-domains with micrinite characteristics.

In the Moomba-145 well sample V-1410 at a depth of 2727 m to 2740 m, organic matter is common and mostly of medium-sand grain size. Vitrinite has been in part degraded to structureless collotelinite (Fig. 3s). Cellular structures, which are commonly well preserved, show the prominence of semifusite (Fig. 3q). This represents humic material that has been partially degraded by biochemical activity, most likely by fungal attack. Semifusinite is preserved with relict plant tissue structures. Epsilon well samples V-1373 and V1374 (from 2128 to 2139m) have abundant medium grained size organic matter, mainly as structure less vitrinite.

In Dirkala-02 well, sample V-1428 from 1896 to 1896.16m, the organics are composed mostly of an interconnected network of amorphous, light brown kerogen with minor to rare inertodetrinite and variable fluorescence. Inertodetrinite, as small fragments mainly derived from the physical degradation of other types of inertinite, is widely distributed. Some of the smaller fragments may have been of wind-born. Their definition becomes obscure with increasing rank. A major prominent feature of this sample is the abundance of micrinite with bituminite and a wide range of other liptinitic macerals which occur between vitrinite rich layers (Fig. 3w). Telinite shows non-gelified plant tissues with well-preserved cells containing organic matter, including vitrinite as discrete small fragments of varying shapes. Samples from a depth of 1893.42 to 1893.81 m V-1429 contain large, discrete relicts of colonial unicellular algae under the blue fluorescent light. For sample V-1429-(1894m) organic matter is abundant and medium grain size. Inertodetrinite is abundant as small fragments derived from the physical degradation of other types of inertinite. Liptinite occurs as alginite. Bituminite is also present (Fig. 3t), as prominent domains of even higher reflectance.

5.2 Vitrinite reflectance (VR)

Average random vitrinite reflectance (% R_0) measurements of Roseneath and Murteree shales from 20 different wells range from 0.68 to 2.2% R_0 (Appendix-1). Histograms summarizing the data show that through sections of both the Roseneath and Murteree Formations, % R_0 values generally increase with depth (Appendix-3) in supplementary data.

5.2.1 VR of the Roseneath Shale

Results for Roseneath Shale samples (Appendix-1) show that VR values generally increase with depth, but the relationship does not always apply. For Moomba1-45 well, VR increases from 2612.14 m to 2621.28 m reaching a value of 1.72% $R_{0.}$ Samples from Moomba-76 well are shallower and have lower VR values of 0.74% R_0 (2688m to 2697m), and 0.92% R_0 (2663.95m to 2673.10m), with still lower values for other samples. This variability most likely reflects sample quality and the accuracy of measurement. At depths between 2593.85 to 2606.04m in the Moomba North-01 well, average VR is 1.41% R_0 and this increases to 1.46% R_0

at depths between 2624.33 to 2627.38m. The overall trend is an exponential increase in maturity with depth.

For Moomba-73 well, VR is 0.98% to 1.89% R_0. The 49 readings do not show a direct relationship to depth, reaching a maximum value of 1.89% R_0 . In the Moomba- 133 well at 2816 to 2825m, VR ranges from 1.25% to 1.45%R_0 (19 readings) (Appendix-1, Table-3) supplement material. Moomba-46 samples are all from core samples and have excellent quality with a uniform organic matter composition.

VR from the Roseneath Shale wells is tabulated in Table-3 (Appendix-1). The shale shows a considerable scatter of values, but data are sufficient to identify that the samples correspond to maturity levels associated with early stages of oil generation; some characteristics are listed in Table-1, and plotted as a histogram in Appendix-2 in supplementary data. Observed changes in VR with depths between 2465m to 2467m (0.82% to 1.01% R_0) may be caused by one or all of the following: 1) Difficulties in recognizing true vitrinite particles; 2) VR was measured on vitrinized woody plant material; 3) Different maceral types may undergo different rates of thermal alteration under similar time-temperature conditions.

VR is a useful guide to maturity of the Roseneath Shale with respect to hydrocarbon generation. A sample from Ashby-01 well at 2068 to 2079m provided VR values between 1.83% and 1.88% $R_{0,}$ indicating that these samples are in the mature zone for hydrocarbon generation. Samples from Epsilon-01 and Epsilon-02 wells with VR values between (1.17% and 1.23% R_0) are also sufficiently mature for oil generation. Samples from Encounter-01 well averaging 1.79% $R_{0,}$ indicate that they are in the gas generation zone. Samples from Vintage Crop-01well at 2133m in Roseneath Shale average 1.80% R_0, suggesting a position in the wet to dry gas zone. Moomba-46 and Moomba-76 samples at depths of 2463 to 2688m indicate the early stage of oil generation (0.74% to 0.97% R_0). Finally, samples from the Moomba North -01 , Moomba 73 and Moomba-133 wells indicate the zone of late oil and early gas generation (1.68% to 1.88% R_0) (Fig. 4)

Sample No.	Formation	Depth m	Abundance	ORGANIC MATTER Composition					Maturity	
				Main types				Vitrinite reflectance	n	Well Name
				Vit%	Inet %	Lip %	Bit %	% R_0		
V-1398	Roseneath	2682.24–2694.43	abundant	≥ 50	<5	<5		0.98	14	Moomba-73
V-1417	Roseneath	2466.44–2463.24	abundant	≥ 50	<5	<5	<5	0.97	12	Moomba-46
V-1415	Roseneath	2464.19–2465.53	abundant	≥ 50	<5	<5	<5	0.85	23	Moomba-46
V-1373	Roseneath	2128.30-2130.25	abundant	≥ 50	<5	<5		1.17	18	Epsilon-02
V-1374	Murteree	2202.70–2206.18	abundant	≥ 50	<5	<5		1.17	13	Epsilon-02
V-1391	Murteree	2203.70–2209.80	abundant	≥ 50	<5	<5		0.91	28	Toolachee East-02
V-1402	Murteree	2791.97-2798.06	abundant	≥ 50	<5	<5		2.00	20	Moomba-73
V-1428	Murteree	1896–1896.16	common	≥ 50	<5	<5		1.07	19	Dirkala-02
V-1429	Murteree	1893.42–1893.81	abundant	≥ 50	<5	<5		1.01	19	Dirkala-02
V-1431	Murteree	1895.86–1905.00	common	≥ 50	<5	<5	<5	1.09	20	Dirkala-02

Table-1: Organic matter of Roseneath and Murteree shales of different wells, thermal maturity parameters based on vitrinite reflectance % R_0. Moomba-46, Moomba-73, Dirkala-02, Toolachee East-02 and Epsilon-02 wells were selected for the maceral analysis. Vit% is vitrinite, Inet% Inertinite, Lip% liptinite and Bit% bituminite.

5.2.2 VR of the Murteree Shale

Overall the Murteree Shale VR values are higher than those for Roseneath Shale reflecting its lower stratigraphic position and hence burial depth. Samples from the Moomba-145 well show a gradual, almost linear, increase from 1.50% to 1.92% R_0 across depths from 2740 to 2770 m. The VR of samples from Ashby-01 well is 1.83% to 1.88% R_0, at depths between 2068 to 2079m (Appendix-2) which corresponds to the maturity in the gas window.

In the Epsilon-1 and Epsilon-2 wells, samples in the 2128 to 2130m depth range have 1.23% to 1.30% R_0 values. For Big Lake-43, Toolachee-25, Toolachee-36, Toolachee-39, Toolachee-East-2 wells average VR ranges from 0.79% to 1.10% $R_{0,}$ indicating that these samples are within the oil window. Organic matter is mainly coaly in nature and of small particle size.

For Moomba-73 the VR is slightly elevated for samples from depths 26657 to 2679m, at 1.68% to 1.88% R_0. At depths between 2776m and 2798 m, VR values from 1.60% to 2.00% R_0 were obtained. The values indicate elevated maturity for hydrocarbon generation. In Moomba-133 well from 2776 to 2785m the average VR is 1.28% R_0.

The VR results in the Munkarie-02 and Baratta-south-01 wells at 1965 m to 2134 m are 0.82% to 0.94% R_0. For Baratta- south -01 the Murteree Shale at 2212 m to 2228 m has values of 0.94% to 1.07% R_0. Variation across this range is of little significance and indicates maturity for oil generation (Table-2).

Results from the Dirkala-02 well at 1895 to 1905m with 0.86 to 1.09% R_0 indicate early to mature stages of hydrocarbon generation, whereas analyses from depths of 1838 to 1905m give values of 0.84% to 1.07% R_0, indicating the onset of oil generation. For the Big Lake-70 well, at depths from 2417 to 2557m, average values are 0.84% to 0.97% R_0 indicating the onset of the hydrocarbon generation. Similar values are present in Toolachee-25, Toolachee East-02, Toolachee-36 and Toolachee-39 wells across Murteree Shale Formation at depths between 2179 to 2209m, indicating lower oil window maturity, whereas Toolachee-21 well samples at depths of 2176 to 2188m are at a mature stage of hydrocarbon generation with VR 0.83 % to 1.30% R_0.

Samples from the Munkaries-02 well are in the early oil generation zone, with values ranging from 0.68% to 0.94% R_0 at depths of 1965 to 2029 m. Baratta South-01 well samples show the onset of hydrocarbon generation zone with VR values of 0.94% to 1.20% R_0 at depths of 2157 to 2188m. Samples from depths of 2431 to 2599m from Big Lake-43 well are more mature than those from Big Lake-70 well at similar depths (2548 to 2551m), and have VR values of 1.01% to 1.10% R_0 and 0.84% to 0.97% R_0, respectively (Fig.5)

5.3 Rock-Eval Pyrolysis

Selected samples were analysed by Rock-Eval pyrolysis to evaluate maturity and identify kerogen types (II, III and IV) in both formations. Estimates of thermal maturity derived from cross-plots of hydrogen index (HI) versus T_{max} (Appendix-3) in supplementary data are particularly useful where the distribution of organic matter in vitrinite phytoclasts is lean. The T_{max} values from the Roseneath and Murteree shales range between 400 ^{0}C to 470 ^{0}C. For most samples, organic matter maturity based on T_{max} are in close agreement with those based on VR and estimates of maceral content correspond with those based on petrography.

In the HI - T_{max} diagram (Appendix-1) all samples indicate significant thermal maturity with respect to hydrocarbon generation. The Rock-Eval data shows that the Roseneath Shale is in the oil to wet gas zone and dominated by type II kerogen, with some mixtures of types III and IV. T_{max} for these samples is 440 ^{0}C to 450 ^{0}C (Fig.7).

Data for the Moomba-73 well shows the Roseneath Shale is typically gas prone and dominated by type III kerogen. In the Epsilon-01 and Epsilon-02 wells, T_{max} values range from 440^{0}C to 462^{0}C, indicating that the shale is in the wet to dry gas zones (Appendix-3) in supplementary material, and dominantly gas prone in the well intersections. For the Dirkala-2 well, pyrolysis reveals fairly variable generation potential for samples that are moderately to quite rich in organic matter. The data classify the organic matter as dominated by type III kerogen and shows that the Murteree Shale is typically wet to dry gas prone. T_{max} identified for the Roseneath Shale in Toolachee 21 well indicates type IV kerogen is dominant and thermally mature, with the Murteree Shale showing wet to dry gas thermal maturity (Fig. 8)

For the Encounter-01 well the Roseneath Shale presents a low Hydrogen Index and T_{max} ranging between 440^{0}C to 455^{0}C, representing the oil to wet gas zone. The Vintage Crop-01 well samples of the Murteree Shale have similar values (T_{max} at 440^{0}C to 455^{0}C) with some type III kerogen present but elevated type IV (Appendix-3) in supplement material. Roseneath Shale from this well lies within oil to wet gas zone, with T_{max} values between 440^{0}C to 450^{0}C and dominated by type IV maceral. In Moomba 46 and Ashby-01 wells, the Roseneath Shale with T_{max} values range from 430^{0}C to 455^{0}C and 445^{0}C to 465^{0}C, respectively, which implies oil to dry gas maturity.

6 Discussion

The results of quantitative optical analyses, VR and Rock Eval-pyrolysis presented in this study of the Roseneath and Murteree shales provide new information on their maceral content, kerogen types, and general potential for hydrocarbon generation. Hydrocarbons in the Cooper Basin are generally thought to have originated from the abundant dispersed organic matter (3 to 6% TOC weight) in fluvial and deltaic shales of the Toolachee and Patchawarra formations (Taylor et al., 1988). Here, data show that coal and dispersed organic matter in the shales are dominated by vitrinite and inertinite (Type III kerogen) with minor amounts of sporinite and cutinite, derived from a higher plant assemblage. Type III kerogen corresponds to terrestrial-derived organic matter, most likely from higher plants. This type of kerogen is therefore a source of gas rather than oil (Barker, 1974). The local concentration of liptinite and bacterially biograded organic matter, indicating significant oil generation potential, have been proposed as the source of oil found in Permian reservoirs across the basin (Kantsler et al., 1983). The organic characteristics of Cooper Basin source rocks have been previously discussed by Kantsler et al. (1983), Symyth (1983), Cook and Struck Meyer (1986) and Taylor et al. (1988).

6.1 Thermal maturity of the Cooper Basin

The Nappameri Trough is particularly large (~15,000km^2), deep (>3050m), thermally mature and over-pressured, suggesting that it is the most prospective oil/gas portion of the Cooper Basin (ICON Energy, 2011). The Permian uppermost unit boundary occurs at depths >2800 m in the center of this structure and over 3050 m in the Patchawarra Trough (Fig. 6). The thermal maturity of the Roseneath and Murteree shales intervals is high in the Nappameri Trough (Figs.4-5) and wells in this area are gas prone (3 to 4% R_0). These intervals for the Patchwarra Trough have lower thermal maturity (1% R_0), whereas in the Tennappera Trough they show R_0 values equivalent to medium maturity.

The Cooper Basin extends across the Queensland and South Australia border and is coincident with a prominent geothermal anomaly (Cull & Denham, 1979; Cull & Conley, 1983; Somerville et al., 1994). The region forms part of a broad area of anomalously high heat flow, which is attributed to Proterozoic basement enriched in radiogenic elements (Sass &

Lachenbruch, 1979; Mclaren et al., 2003). Thick sedimentary sequences in the Cooper and overlying Eromanga Basins provide a thermal blanketing effect resulting in temperatures as high as 270^{0}C at depths <5km (Holgate, 2005). There is evidence of rapid uplift, high heat flow and mobilization of granites in the upper crust of the Cooper Basin during the Early Permian (Battern and Grenfell, 1996) as a result of deep mantle process.

Thermal gradients in the Cooper Basin are generally high, averaging 1.41^{0}C/30 m (Icon Energy, 2011). Bottom hole temperatures at depths of 2750 m average about 166.66 ^{0}C. The Nappameri Trough experiences unusually high heat flow, with a thermal gradient of up to 1.90 ^{0}C/30m, due to its radiogenic basement. The Patchawarra Trough, which has a sedimentary/ metasedimentary basement, has a lower, but still elevated (1.12 ^{0}C/30m) thermal gradient. The OZ temperature map (Fig. 9) also highlights that relatively high bottom-hole temperature have been observed in patchy distributions in the Nappameri, Patchawarra, Allunga and Tennapera Troughs (Holgate, 2010). In these areas maturity modelling also suggests higher temperatures (~100 ^{0}C at 4km depth). Validation of the subsurface temperature estimates was attempted through direct comparison with measured bottom hole temperature recorded in the OZ temperature dataset (Holgate and Gerner, 2010).

Gravity lows are coincident with Nappameri and Tenappera troughs and extend beyond the trough boundaries. There is also evidence that density variations in the basement are contributing to the observed gravity field. There are also a number of prominent gravity lows which are not associated with any known basinal structures (Meixner et al., 2012). The negative gravity anomaly coinciding with Patchawarra Trough is much more pronounced than that of the Nappamerri Trough, even though sediment thicknesses are similar. This indicates that the density of the basement beneath the troughs is different.

Glikson et al. (2015) has suggested that the basement of the Cooper Basin was affected by a large-scale meteorite impact in the late Paleozoic. Thermal anomalies within the Cooper Basin, combined with the gravity anomaly pattern suggest granitoid plutons are present in the basement. Basement cores obtained for some wells confirm this hypothesis (Meixner et al., 2012). Thermal conductivity values have been assigned to the inferred granitoid bodies by Meixner et al., (2012) based on data for a range of granite samples within the Geoscience

Australia thermal conductivity database (Fig.11). This work indicates that thermal conductivities fall within the range of 2.79±.38 $Wm^{-1} K^{-1}$, whereas metasedimentary samples in the Geoscience Australia database all provide higher values (3.5± 0.89 $Wm^{-1} K^{-1}$), confirming that heat retention by granite bodies has occurred in certain areas (e.g. Nappameri Trough). The drill-hole intersection shows down-hole conductivity measurements (Fig.10).

6.2 Organic macerals

The maceral content of the Roseneath and Murteree shales is dominated by vitrinite with subordinate telinite, vitrodetrinite, and collotelinite. For vitrinite particles, vitrinite content is 50-55%, which is supported by fluorescence observation. Accordingly the organics have either a low hydrogen index and /or contain a high percentage of gas prone kerogen debris. Vitrinite is a major source of catagenic gas at high levels of maturation (Bostick,1979; Hunt, 1991; Taylor et al., 1998) but its role in hydrocarbon generation is uncertain. Several samples showed some liquid hydrocarbon. One significant observation from this study is the fact that vitrinite commonly generates some liquid hydrocarbons in these two units.

The second most abundant maceral in the Roseneath and Murteree shales is inertinite, which is dominantly comprised of inertodetrinite. This maceral type represents small fragments derived by the physical degradation of inertinite, which in turn is probably derived from fusinite, semifusinite, and less commonly, micrinite. The Roseneath and Murteree shales have abundant inertinite, typically between ~20 -40% (Figs. 12-13). The inertinite maceral group corresponds to type IV kerogen identified within the Roseneath and Murteree shales by Rock-Eval pyrolysis.

Liptinite, in the form of alginite, liptodetrinite, sporinite, cutinite, resinite and bituminite, is also present in Murteree and Roseneath shales. It generally represents an amorphous component intimately associated with the mineral matrix. Telalginite derives from alginite and is identified in both shales, but is restricted to isolated beds. It occurs in large bodies that commonly show botanical tissue structures and are predominantly yellow under intense fluorescence light (Figs. 2c-2h). Extant green algae of this association are planktonic, found in fresh water or brackish environments and are prolific producers of lipids rich in C25 – C34 paraffinic hydrocarbon (Maxwell et al., 1968; Largeau et al., 1980; Metzger et al., 1985a, 1985b; Mckirdy et al., 1986a). The bulk of these hydrocarbons are synthesized and stored in the outer cell wall where they impart buoyancy to the living algae. Resistant polymers have also been identified in the cell wall of these algae, and are potential precursors of highly oil-prone kerogen (Berkaloff, 1983; Largeau et., 1984). Resinite is common in the Roseneath Shale, and is rich in hydrogen and shows internal structures that suggest that more than one phase is present. The internal structure is similar to bitumen and appears to reflect degradation (Fig. 2d). The presence of resinite is an indicator of thermal immaturity.

Shales in the Cooper Basin are rich in organic matter and have hydrocarbon source potential. VR values increase in response to increasing maturation of organic matter with depth in both shales. Lower reflectance values, ranging from 0.1 to 0.7% R_0, were obtained for the Roseneath Shale; whereas the Murteree shale values range from 0.6 to 0.90% R_0. The data show a relationship of well intersections to the oil, wet gas and dry gas domains (Fig.14). Moreover differentiation of these domains broadly relates to sample depths. Maximum source rock maturity is usually at depths of approximately 2900 m, which returned the highest VR values for both shales

The Rosneath Shale is interpreted to be in the condensate/oil window (VR= 1-1.5% R_0) at depths of 1950 – 2700 m, whereas the Murteree Shale is interpreted to be in this window at depths of 2150 – 2800 m (Fig. 14). The dry gas window (VR > 1.5% R_0) is interpreted to be at depths of 2050- 2700m within the basin. Overall the Roseneath Shale is mainly interpreted be within the oil to wet gas-prone zone above 2700 m and the Murteree shale is mainly in the wet gas /dry gas-prone zone below 2700 m (Fig.14).

Rock-Eval results provide additional geochemical information on the hydrocarbon potential of the Murteree and Roseneath shales, and such data is particularly useful when considered in combination with the VR data. Oxygen Index (OI) values of both shales samples range from 10 to 200 mg CO_2/g TOC, indicating a terrestrial provenance for all organic matter in the two formation. Kerogen maturity, assessed by plotting HI versus T_{max}, is valuable for determining the potential hydrocarbon generation windows, which range between T_{max} values of 430^{0}C to 465^{0}C. T_{max} varies with the type of kerogen as well as the maturity of the samples.

Because the chemical nature of a particular kerogen is intimately related to observe T_{max}, different kerogen types may have influenced the maturation process.

In this study, the T_{max} data are summarized for kerogen types I, II, III Appendix-3, in supplementary data .T_{max} is a good maturation indicator for kerogen types II and III in Roseneath and Murteree shales. True type I source rocks tends to be primarily oil prone upon maturation and are relatively rare in both shales. T_{max} values for types I and II merge during the maturation process so that the type I can only be recognized at low maturation levels (below about 0.8% R_0). At all higher maturation stages, type I kerogen values become merged with type II (Appendix-3) in supplementary data. Type III kerogen comes predominantly from higher plant material in the Roseneath and Murteree shales. Type III tends to be more gas prone than type I and II is chemically analogous to the coal maceral, vitrinite. In fact kerogen maturity reflects T_{max} and (unlike VR) it is not sensitive to time. Temperature, therefore, controls kerogen breakdown and its relationship to oil and gas generation.

6.3 Comparison with the North American Shale gas

Unconventional shale gas plays in the North America have resulted in unprecedented growth in domestic energy supply in the USA. The best known and most productive shale gas producing systems are in the Fort Worth, East Texas and in the Appalachian basins. It is instructive to compare the petrology of the Cooper Basin shales with these systems, including the Mississippian Barnett Shale in the Fort Worth Basin, the Devonian Marcellus Shale in the Appalachian Basin, and the Cretaceous Eagle Ford Shale in East Texas. Their characteristics provide benchmark comparisons for evaluating the Roseneath/Murteree shales in terms of hydrocarbon potential. These examples are from different age strata to that found in the Cooper Basin, thus the different organic content between basins may lead to comparison issues..

Barnett Shale macerals are composed largely of amorphous kerogen (91-93%) with minor, sporadic algal Tasmanite (telealginite) (Hill, 2007). Vitrinite maceral shows that 3-5% is derived from lignin. Inertinite charcoal ranges from 1-5%, and liptinite (1%) is derived from pollen and spores. VR values for the Barnett Shale are 0.7 to 1.9% R_0 with T_{max} ≥465^0

(Montgomery et al., 2005). Total organic carbon (TOC) ranges from 1-10%. The kerogen is classified as type II with a minor proportion of type III; which together produce hydrogen index (HI) values of 350 to 475 (Pollastro et al., 2003 and Jarvie et al., 2007). Peters and Cassa (1994) classified the prospectivity of Barnett Shale as good (TOC 2-4%) to excellent (TOC>4%), with an original hydrogen index of 350 to 475 milligrams. The core areas produce dry gas; maturity is related to burial depth and high heat flow over deep seated faults.

The Marcellus Shale TOC ranges from 1 to 10%, and the kerogen is dominantly typed II and minor type III. % R_0 ranges from 1.2 to 3.5 with Tmax≥470^0 in the dry gas zone. The dominant organic component is algal maceral (Lash, 2008, Hill et al., 2004 and Nyahay et al., 2007). The Marcellus Shale is characterised by a mixture of terrestrial humic type III kerogen (Zielinski and Mclver, 1982) (Hill et al., 2004 and Nyahay et al., 2007). Based on Rock-Eval, Hydrogen Index (HI) is 250 to 400 and Oxygen Index (OI) is less than 50. The kerogen is type II with a mixture of type III. The Eagle Ford shale consists of organic rich mud rock with TOC 2 to 12 % and thermal maturity 0.45 to 1.4%R_0 (Cardneaux, 2012).

By contrast, organic matter in Roseneath and Murteree shales is composed of Type II/III and IV kerogen within the lacustrine macerals (i.e. inertinite>liptinite> vitrinite). Organic matter is abundant and of fine to medium-sand grain size. Vitrinite is the main maceral and consists of mostly vitrodetrinite. Inertinite, the second most common maceral, consists of inertodetrinite and semi-fusinite. Liptinite occurs as thin horizons with alginite and liptodetrinite. Bituminite is also present in both shales. VR values range between 0.79 to 1.79% R_0, higher for coal material at 1.83 to 1.88% R_0, for the Roseneath Shale. Values for the Murteree Shale are 0.83 to 2.00 % R_0. There is very little variation in maceral composition between the American shale gas basins and that of the Cooper Basin shales.

Shale	Basin	Age	Basin type	TOC	R_0	T_{max}	Kerogen type
Barnett	Fort Worth	Mississippian	Foreland	1-10%	1.60-3.5%	≥470 ^{0}C	Type II with minor admixture of type III
Marcellus Shale	Appalachian	Devonian	Foreland	2-6%	1.2-1.9%	≥465 ^{0}C	Type II with mixture of type III
Eagle Ford	East Texas	Late	Passive	2-12%	0.45-	435-475^{0}C	Type II with mixture

		Cretaceous	margin		1.4%		of type III
Roseneath	Cooper	Permo-Triassic	Intracratonic	2.89-30.74%	0.79-1.88%	>600 ^{0}C	Type II ,III and IV
Murteree	Cooper	Permo-Triassic	Intracratonic	2-6%	0.83-2.00%	>600 ^{0}C	Type II ,III and IV

Table 2: Generalized characteristics of productive American shales gas (Bruner & Smosna, 2011) and Cooper's shales(Roseneath/Murteree).

The organic content of the American shales ranges from 2 - 12% TOC and is broadly comparable with the Cooper Basin, which is between 2 and 15% TOC. Perhaps one major difference is that the American shale gas units lack kerogen type IV, which is prominent in Roseneath and Murteree shales. By comparison with Cooper Basin shales, thermal maturity as measured by the vitrinite reflective index is higher in two of the American shales the Barnett and Marcellus shales).

Conclusion

Cuttings and core samples from the Permian Roseneath and Murteree shales of the Cooper Basin show variable organic contents (TOC ranging between 2% and 30%), in the lacustrine siltstones and shales across the basin. The organic matter is dominated by fine to medium sand-sized carbonaceous and coaly particles. Vitrinite is the main maceral present in formations, dominated by detrital particles primarily of vitrodetrinite. Inertinite is the second most abundant maceral dominated by inertodetrinite that represents small fragments derived by the physical degradation of inertinite with fusinite and semi-fusinite indicating kerogen type IV. Although a significant amount of the organic matter in the basin appears oxidized, these results and associated fluorescence data indicate that gas prone organic material dominates both the Roseneath and Murteree formations and that in most portions of the basin, the formations are dominantly within the gas-generating zone. However, the presence of liptinite macerals, especially resinite, and associated fluorescence values showing high hydrogen values also indicates a component of immature oil prone source rocks containing type II kerogen in the study interval.

Vitrinite reflectance results for the Roseneath and Murteree shales indicate potential for significant hydrocarbon generation, and the Rock-Eval Pyrolysis data indicate that type II, III, and IV kerogens are all present, with fair to the excellent generative potential for oil and gas.

The most prospective portion of the Murteree and Roseneath shales in the Cooper Basin, in terms of thermal maturity, appears to be in the Nappamerri Trough and to a lesser extent, the Patchawarra Trough. The combination of techniques applied here provides a holistic approach for evaluating gas shale potential in the Cooper Basin; suggesting the significant potential for shale gas exploitation from the Roseneath and Murteree shales.

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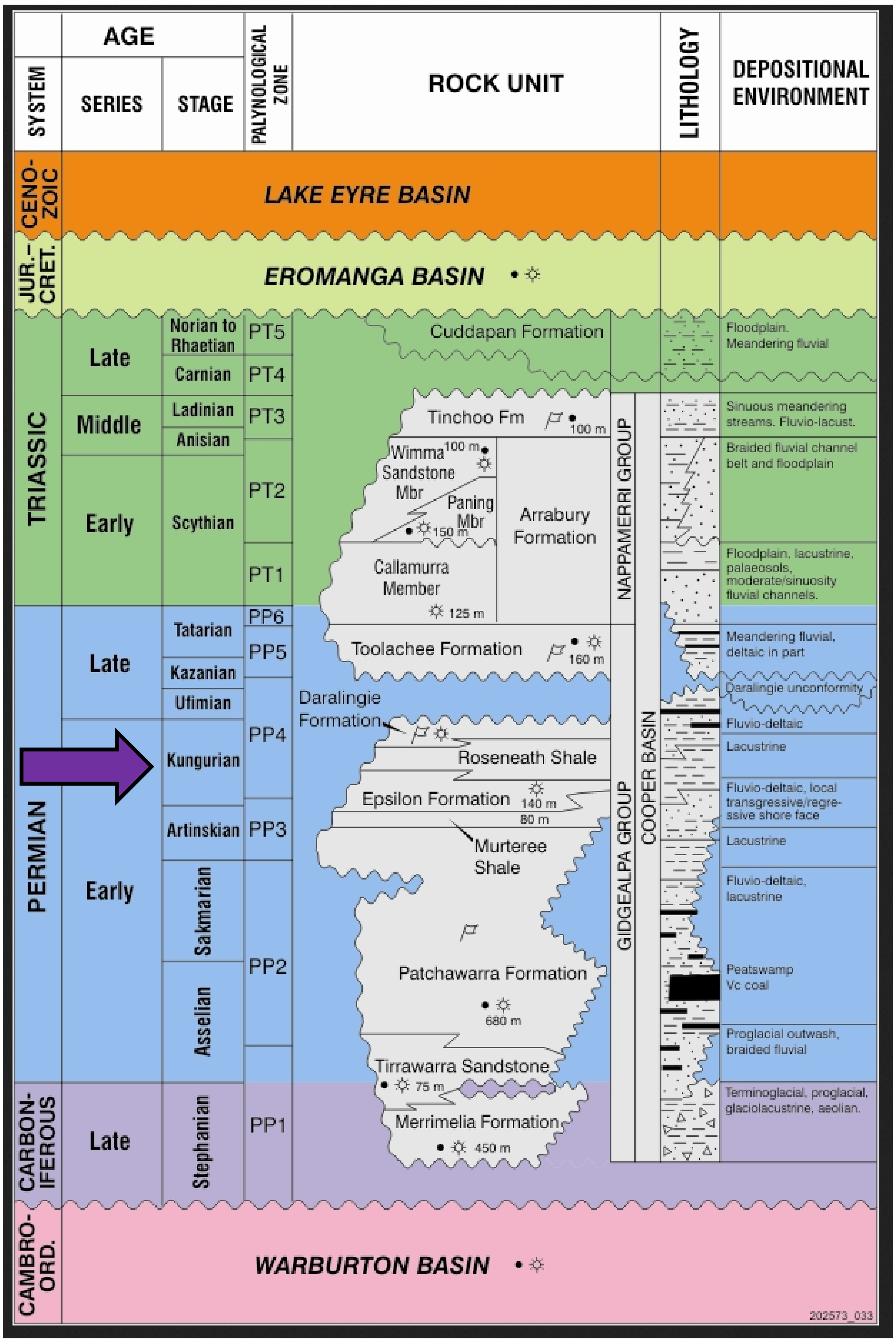

Figure 1: Stratigraphy of the Cooper Basin (PIRSA, 2007). Arrow shows the study interval that includes the Roseneath and Murteree shales. PIRSA 200171_2 and 200171_004.

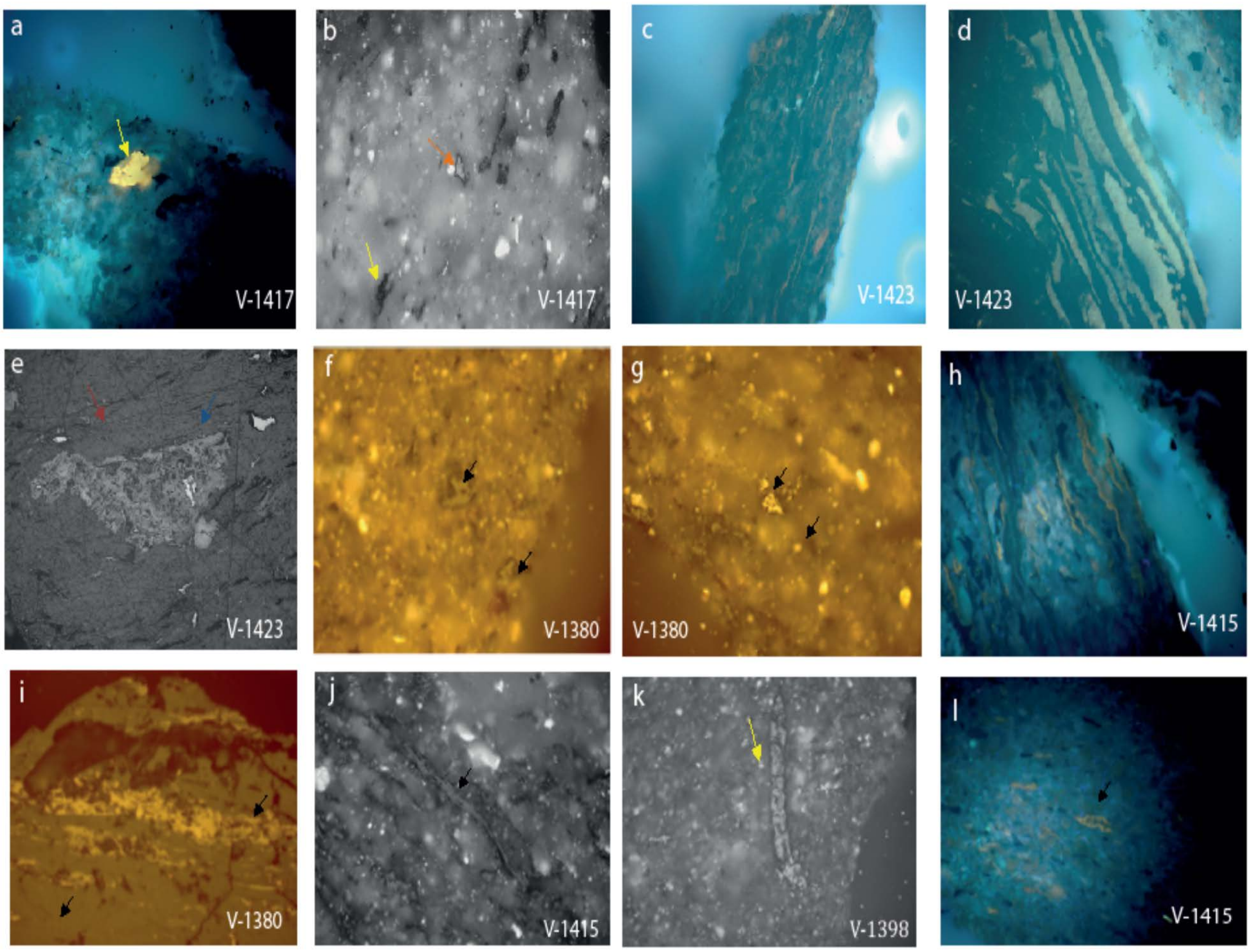

Figure 2 : a) Photomicrograph of polished sections,(oil immersion 50 X) showing coal maceral alginite occurs as larger bodies, it is commonly shows the botanical structure and typically gives more intense fluorence light than most other maceral and types (V-1417 Roseneath Shale (well Moomba-46).**b**) Inertinite derived from plant material strongly altered and degraded under oxidizing conditions. **c**)Alginite which is occurring colonial and thick walled unicellular larger bodies well Munkerie-02 **d**)Resinite rich in hydrogen and shows the internal structure like to be bitumen and occurring in this mode appears to be concentrated as a result of degradation. **e**) Collotellinite (red arrow) as a ground mass with fusinite (blue arrow). **f**) Vitrodetrinite at depth 2020m. **g**) Inertodetrinite at depth of 2020 to 2029m. **h**) Yellow alginite slender lines across the organic matter with flocculent groundmass are visible in fluorescence. **i**)Lower arrow shows collotellinite and upper lower shows fusinite **j**)Telinite thin longitudinal strip with organic matter **k**)Telinite maceral show s non-gelified plant tissues with well-preserved cell in well Moomba-73.**l**)Yellow alginite lumpy granular flocculent groundmass are visible in fluorescence light.

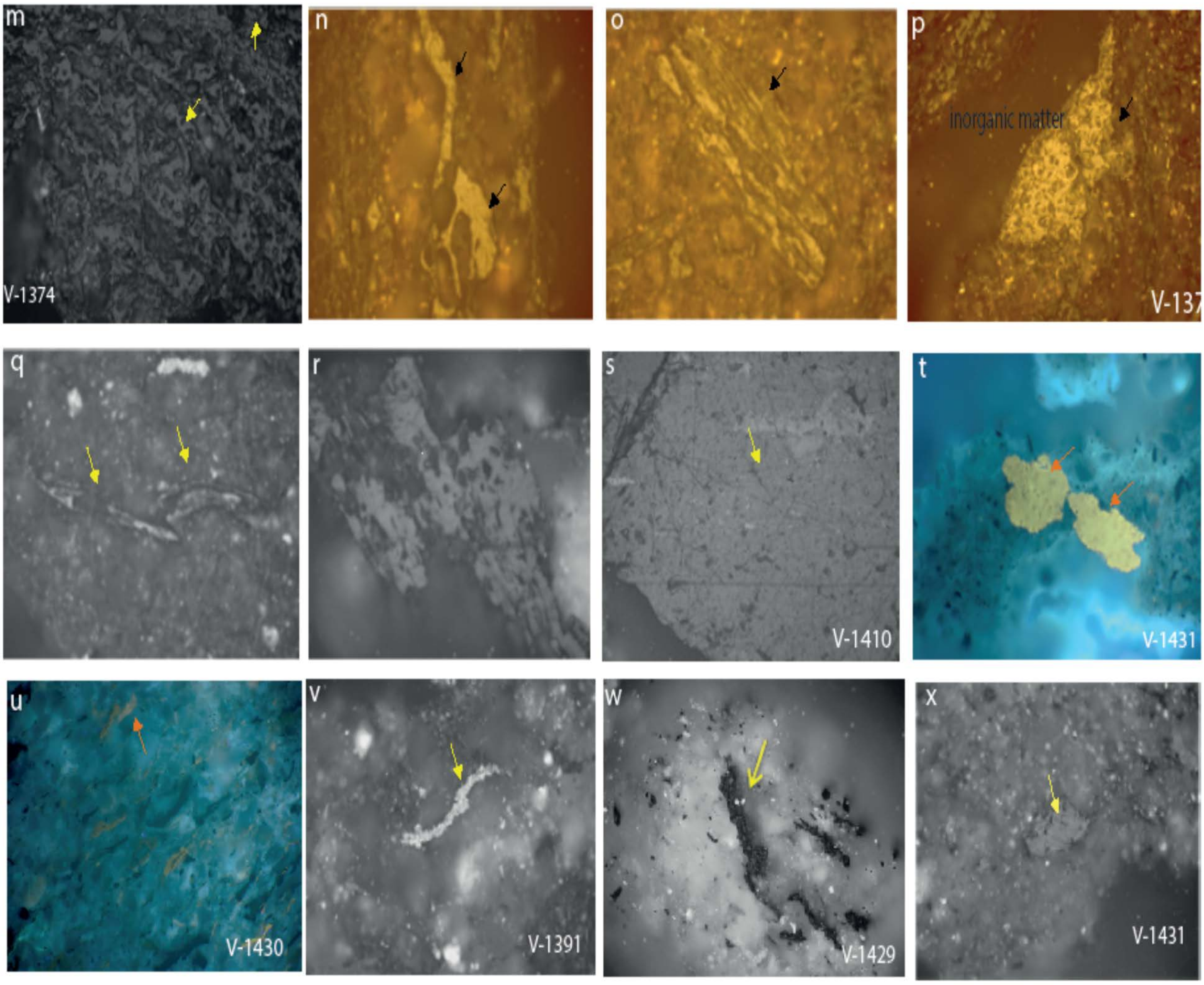

Figure 3: m) Photomicrograph set polished sections, (oil immersion 50 X) of coal maceral in the Murteree Shale in white light with sample V-1374 at depth 2128 m arrow is showing collotellinite. **n)** At depth 2128 m arrow is showing semi-fusinite. **o)** Arrow is showing fusinite. **p)** Fusinite which chiefly represents material resulting from wood. **q)** Arrows show the semi-fusinite has been partially oxidized by biochemical activity. **r)** Yellow arrow shows the collotellinite as groundmass with inorganic material. **s)** Collotellinite -rich and unstructured debris in plane light well Moomba-145.**t)** Coal maceral in fluorence light shows yellowish color of Bitumen that is group of liptinite maceral and those of vitrinite. The major distinguishing features are abundance of micrinite within bitumen, and it is typically interbedded with vitrinite layers. **u)** Yellow color of alginite in Dirkala 2**.** **v)** At depth 2203 m arrow is showing Graphite**.** **w**) Coal maceral in white light shows bituminite (orange arrow). A major distinguishing feature is the abundance of micrinite with bituminite and another association with a wide range of other liptinitic macerals which is interbedded with vitrinitic rich layers. **x)** Coal maceral in white light shows introdetrinite Dirkala-02.

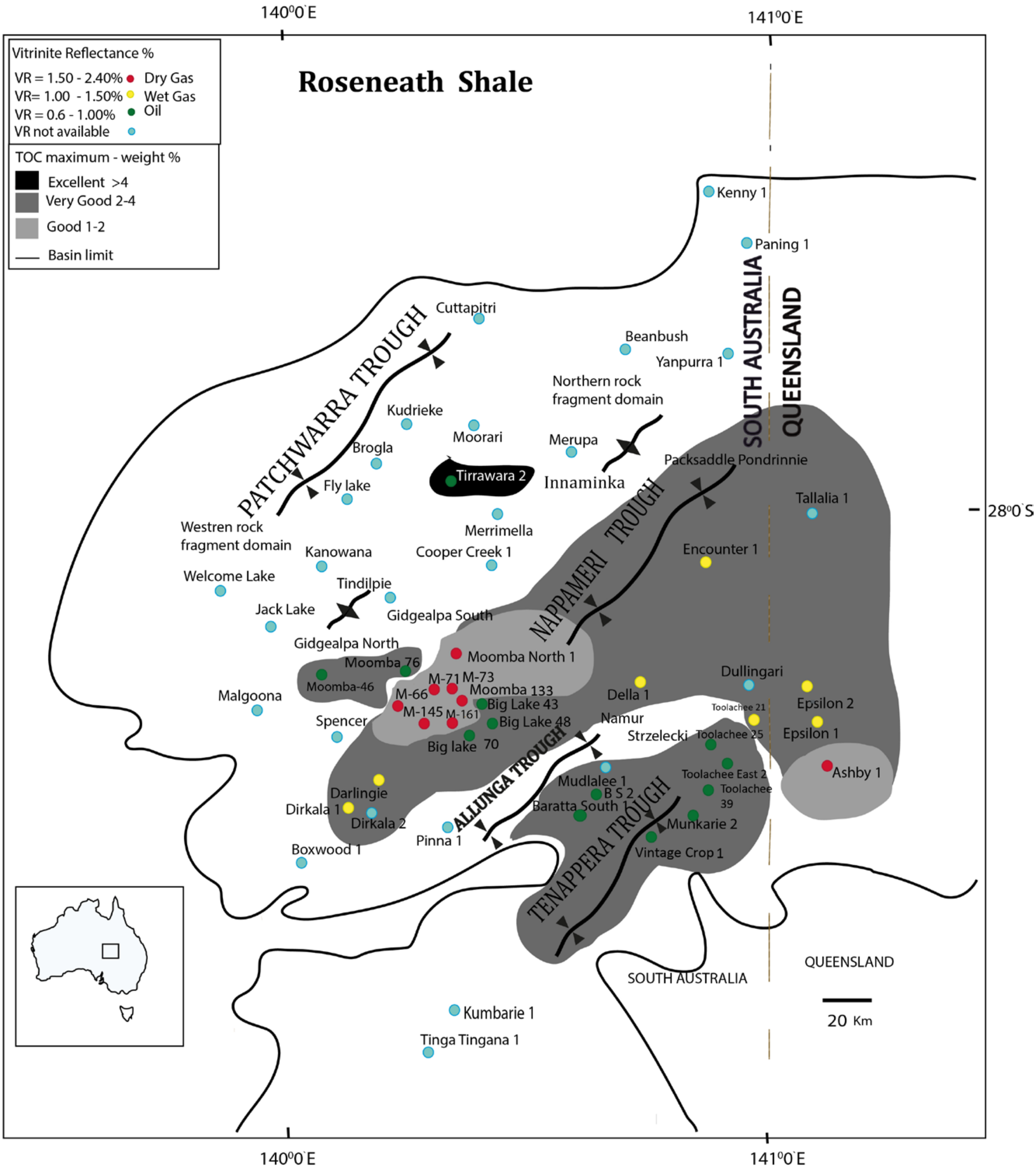

Figure 4: Distribution of core samples for the Roseneath Shale in the Cooper Basin showing generalized TOC and vitrinite reflectance characteristics, which indicate hydrocarbon potential.

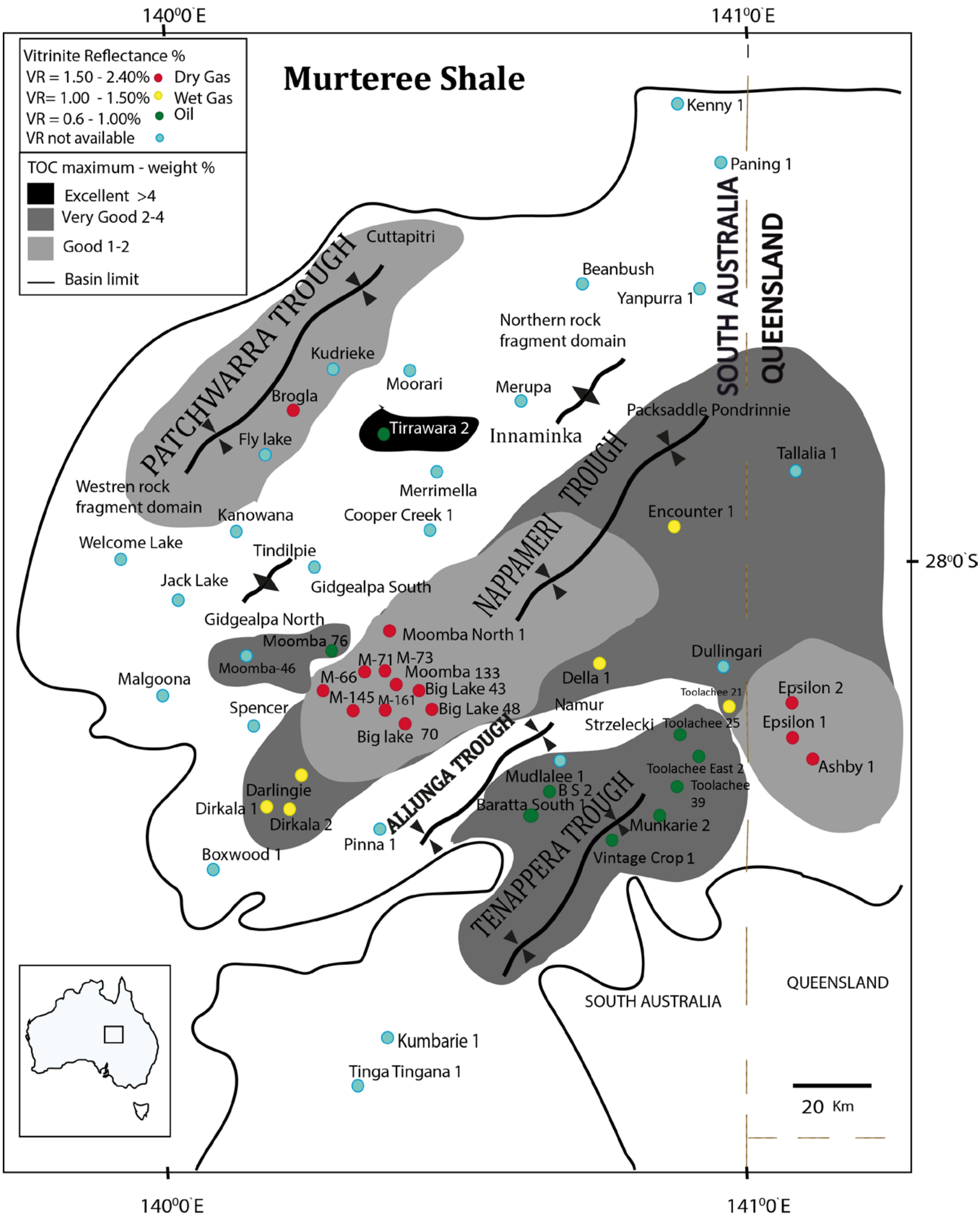

Figure 5: Distribution of core samples for the Murteree Shale in the Cooper Basin showing generalized TOC and vitrinite reflectance characteristics.

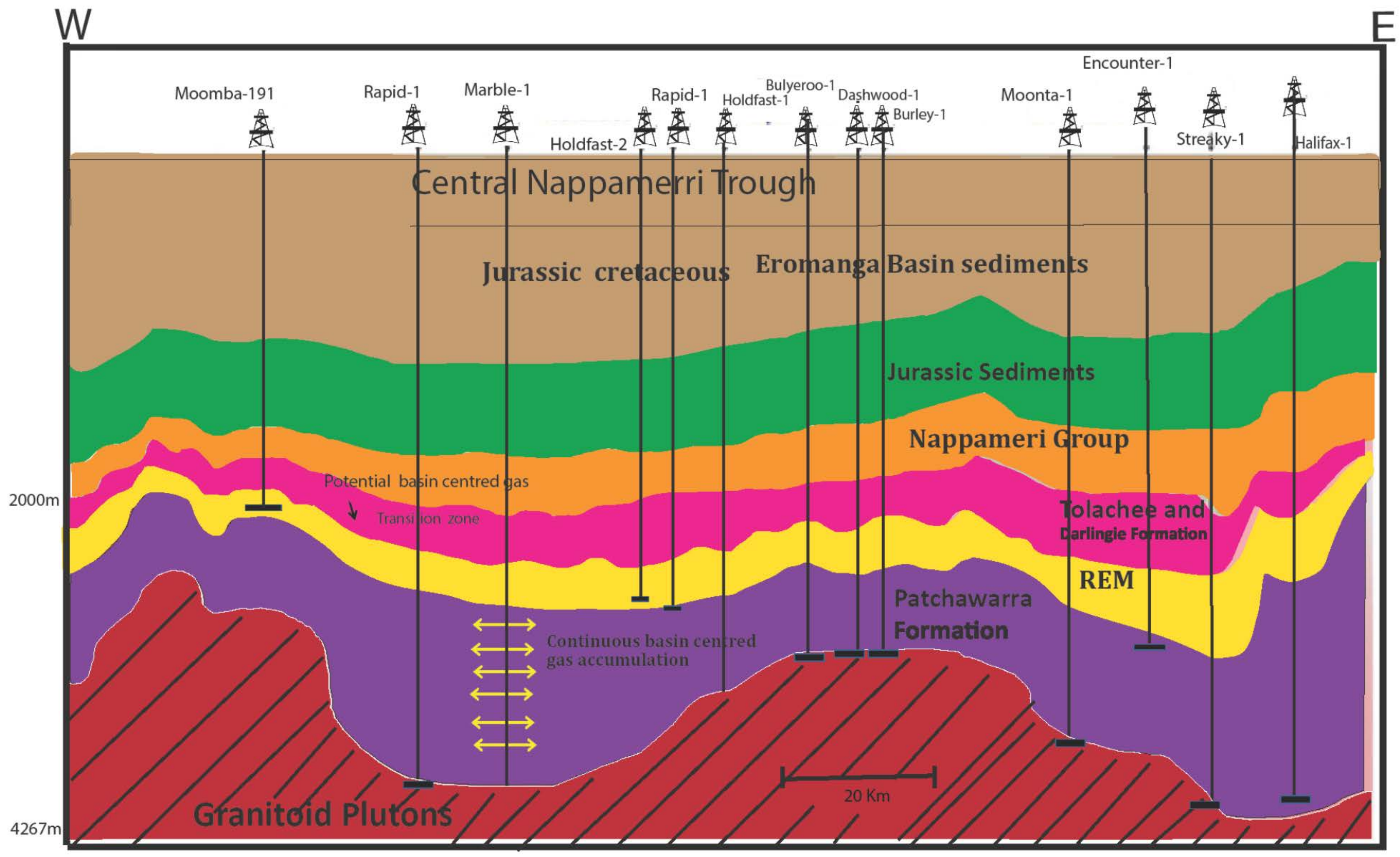

Figure 6: Schematic section showing the central Nappameri Trough, REM (Roseneath, Epsilon, and Murteree) shales in the Cooper Basin. Basement is Warburton Basin succession intruded by granitoid plutons modified from Beach Energy.

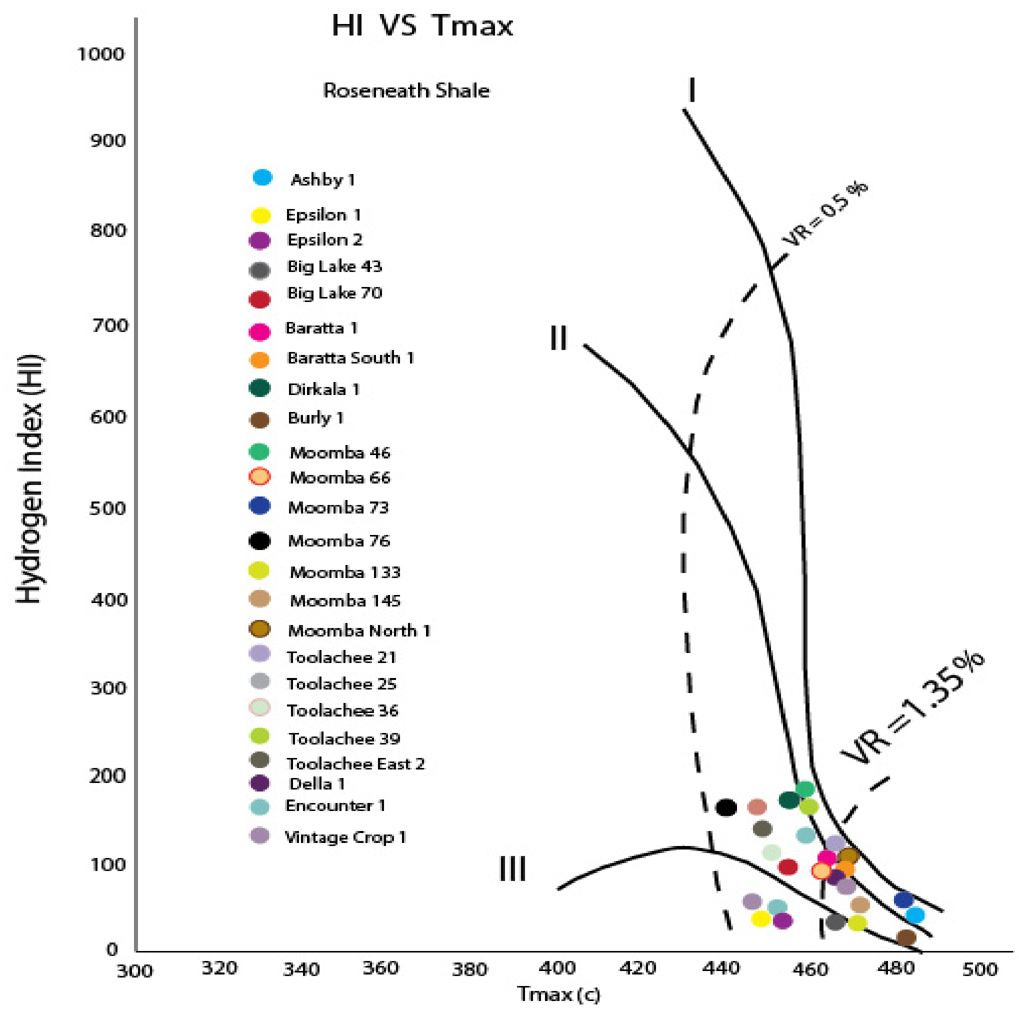

Figure 7: Roseneath Shale T_{max} Vs HI cross plot. Data in large part lie in Kerogen II with a mixture of types III.

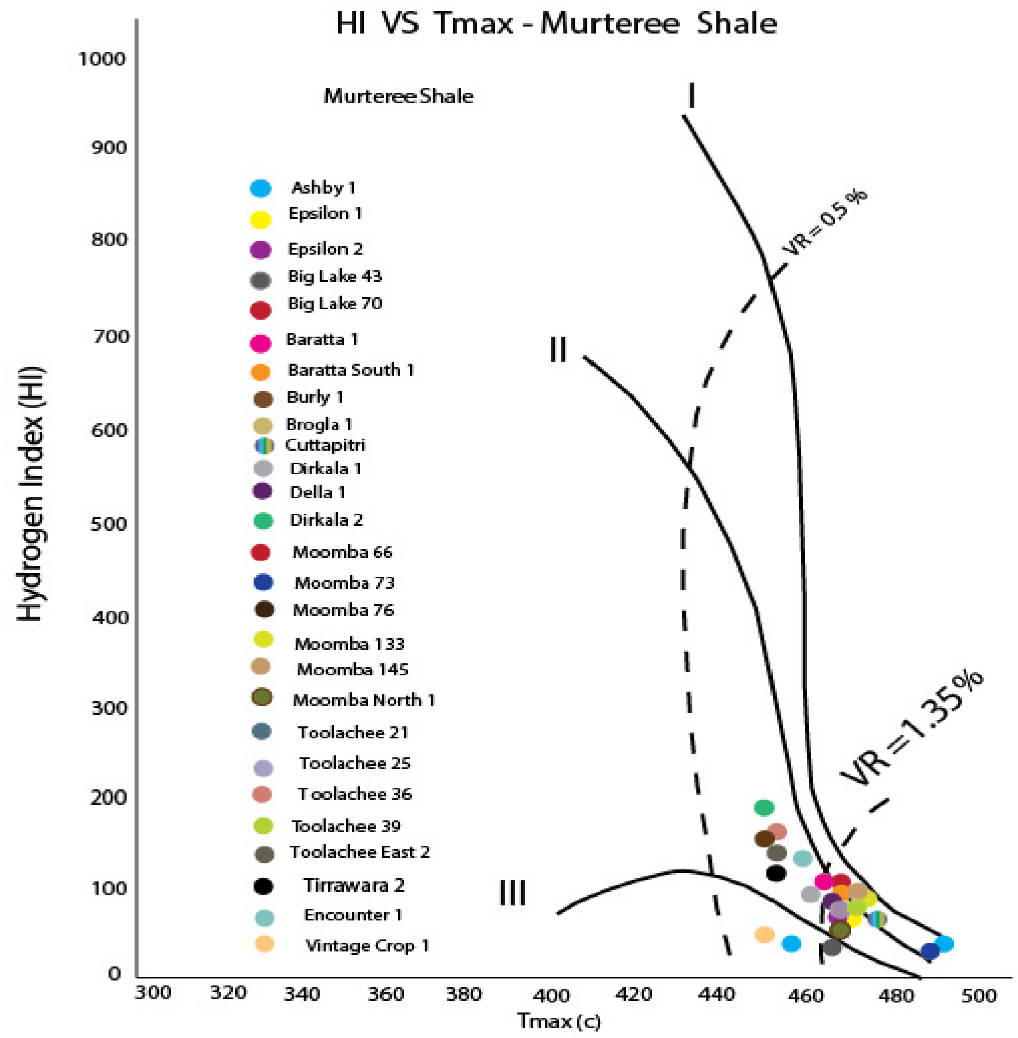

Figure 8: Murteree Shale Tmax Vs HI cross plot T_{max} shows kerogen III.

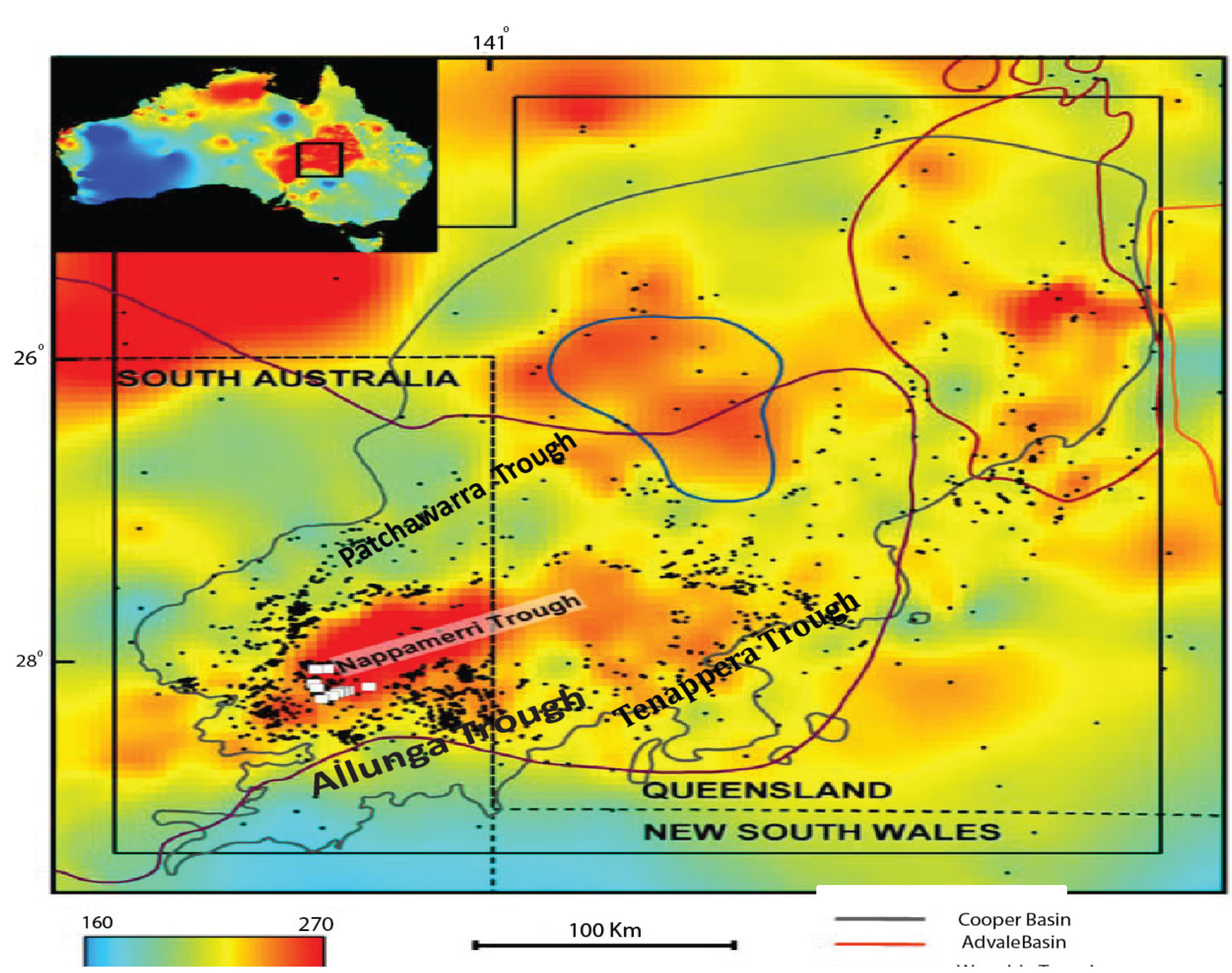

Figure 9: Well bottom temperature and 1780 boreholes temperature measurements in the Cooper Basin in relation to underlying basement (modified from OZ temp Gerner and Holgate, 2010).

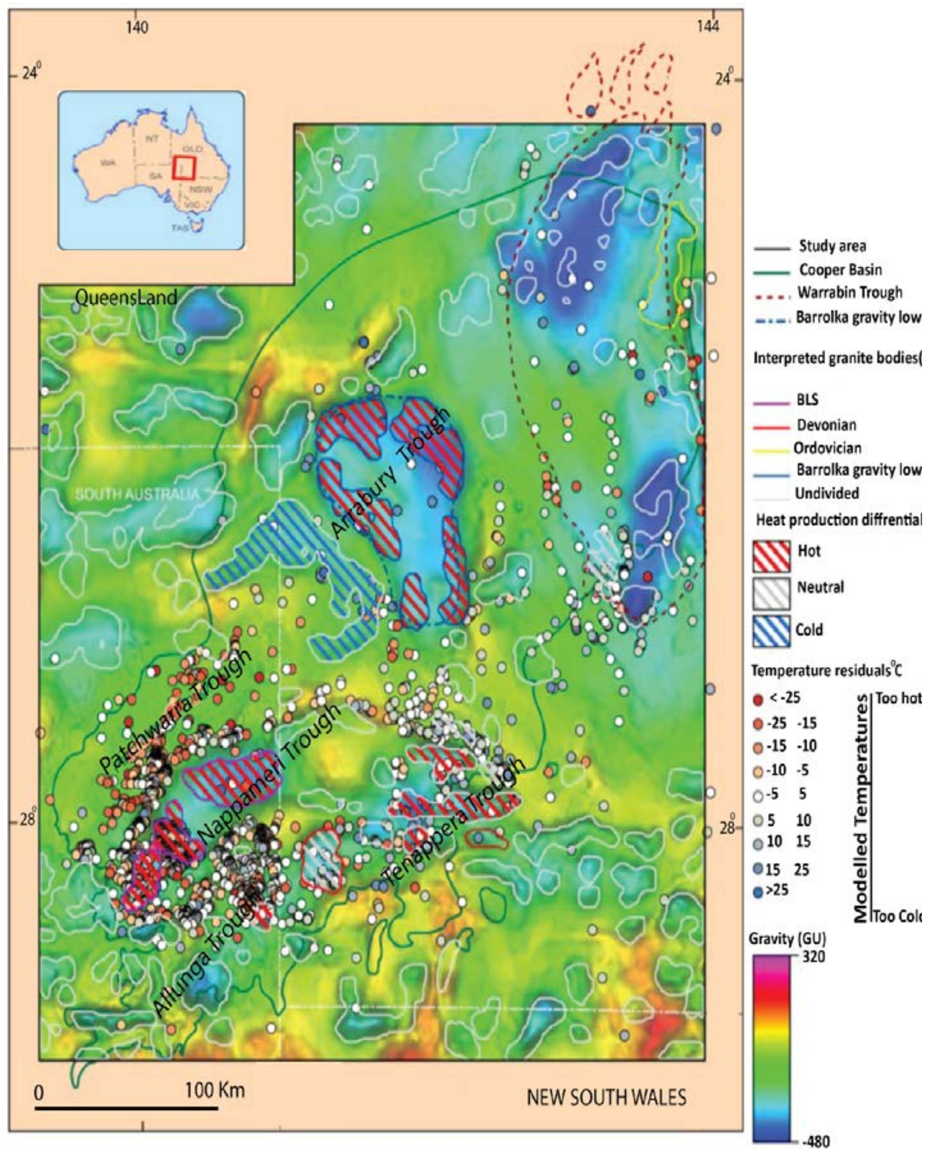

Figure 10: Thermal anomalies identified in the Cooper Basin (Geoscience Australia, 2010) showing a complex pattern of heat residue most likely due to emplacement of granitoid plutons across the Basin.

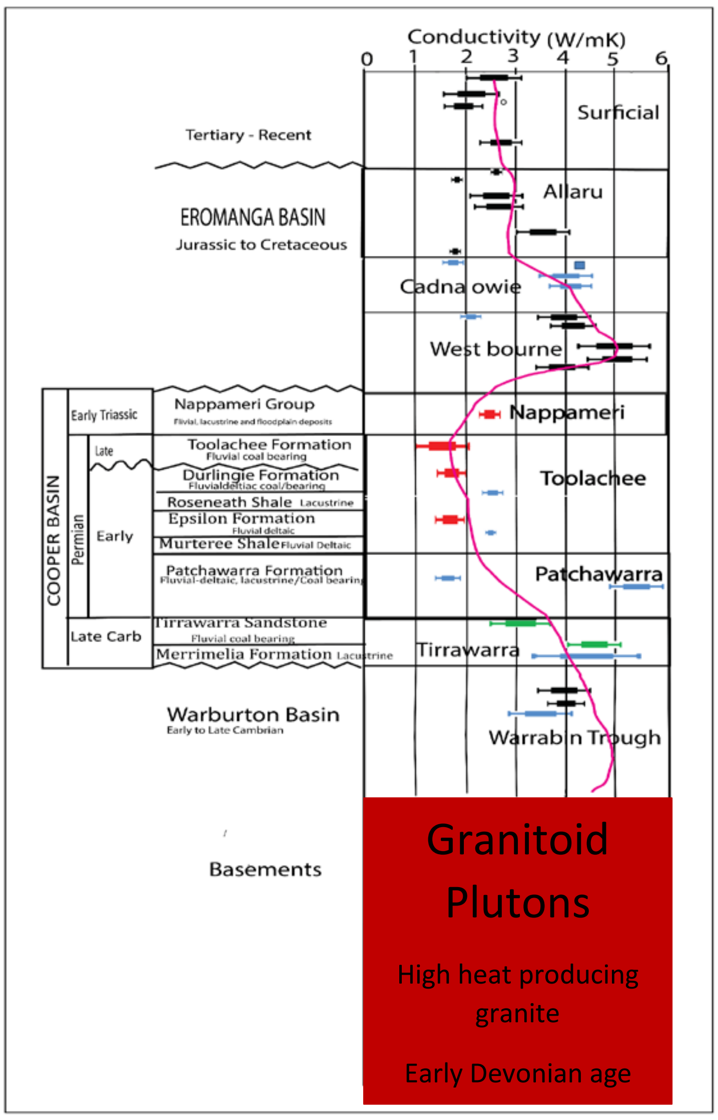

Figure 11: Cooper, Eromanga, and Warburton basin succession from drill hole intersection is showing down hole conductivity measurements (modified from NGMA, 2001 and Beardsmore, 2004).

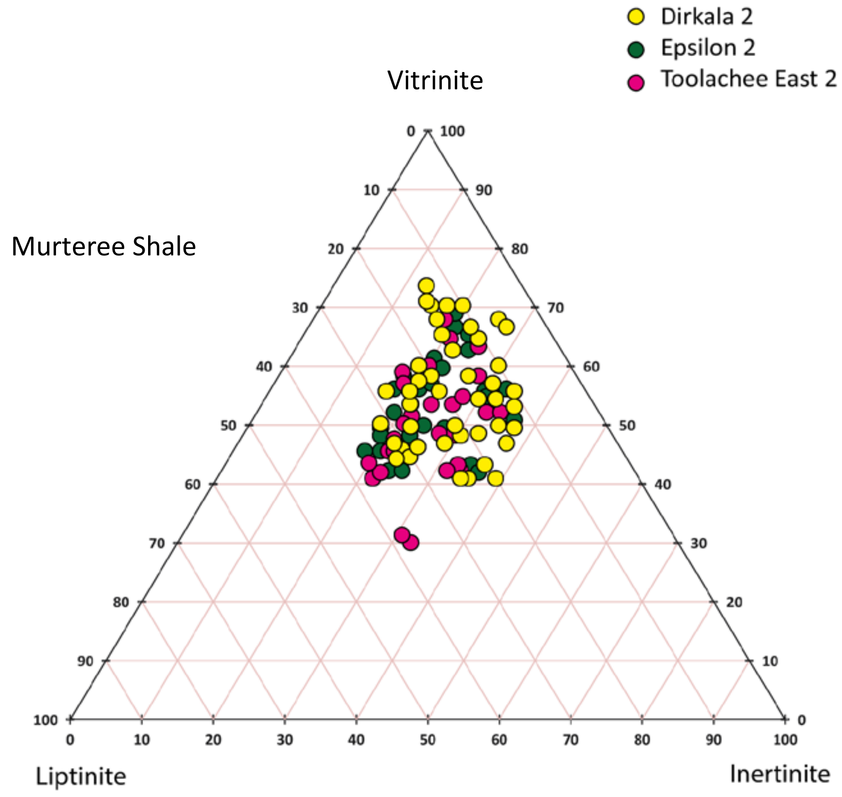

Figure 12: Vitrinite- Liptinite-Inertinite plot for the Permian Roseneath and Murteree shales base maceral study on five wells, Epsilon-02, Toolachee-02 and Dirkala-02 from Cooper Basin.

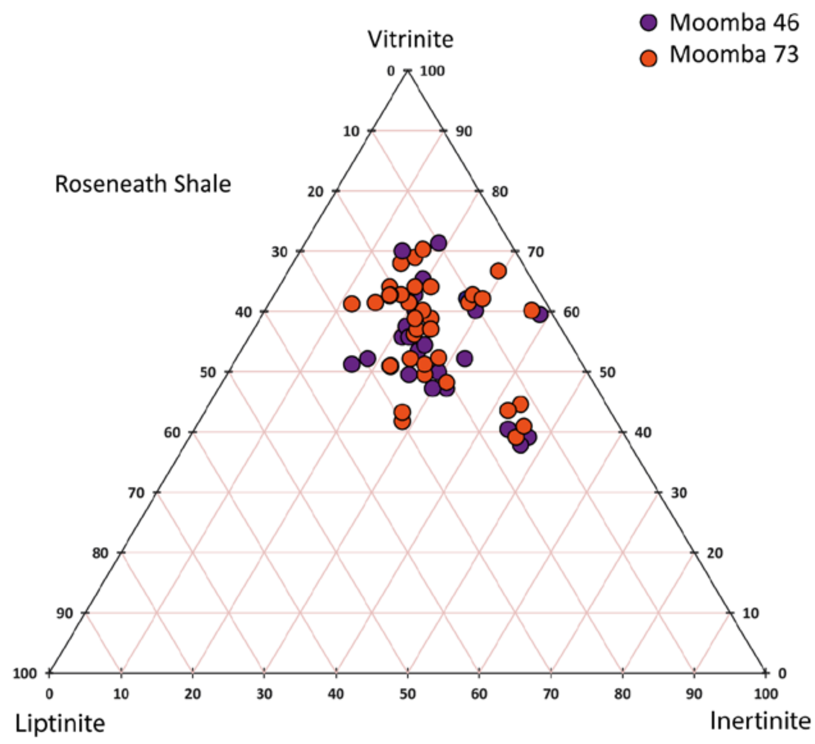

Figure 13: Vitrinite- Liptinite-Inertinite plot for the Permian Roseneath and Murteree shales base maceral study on five wells, Moomba-73, Moomba-46 from Cooper Basin.

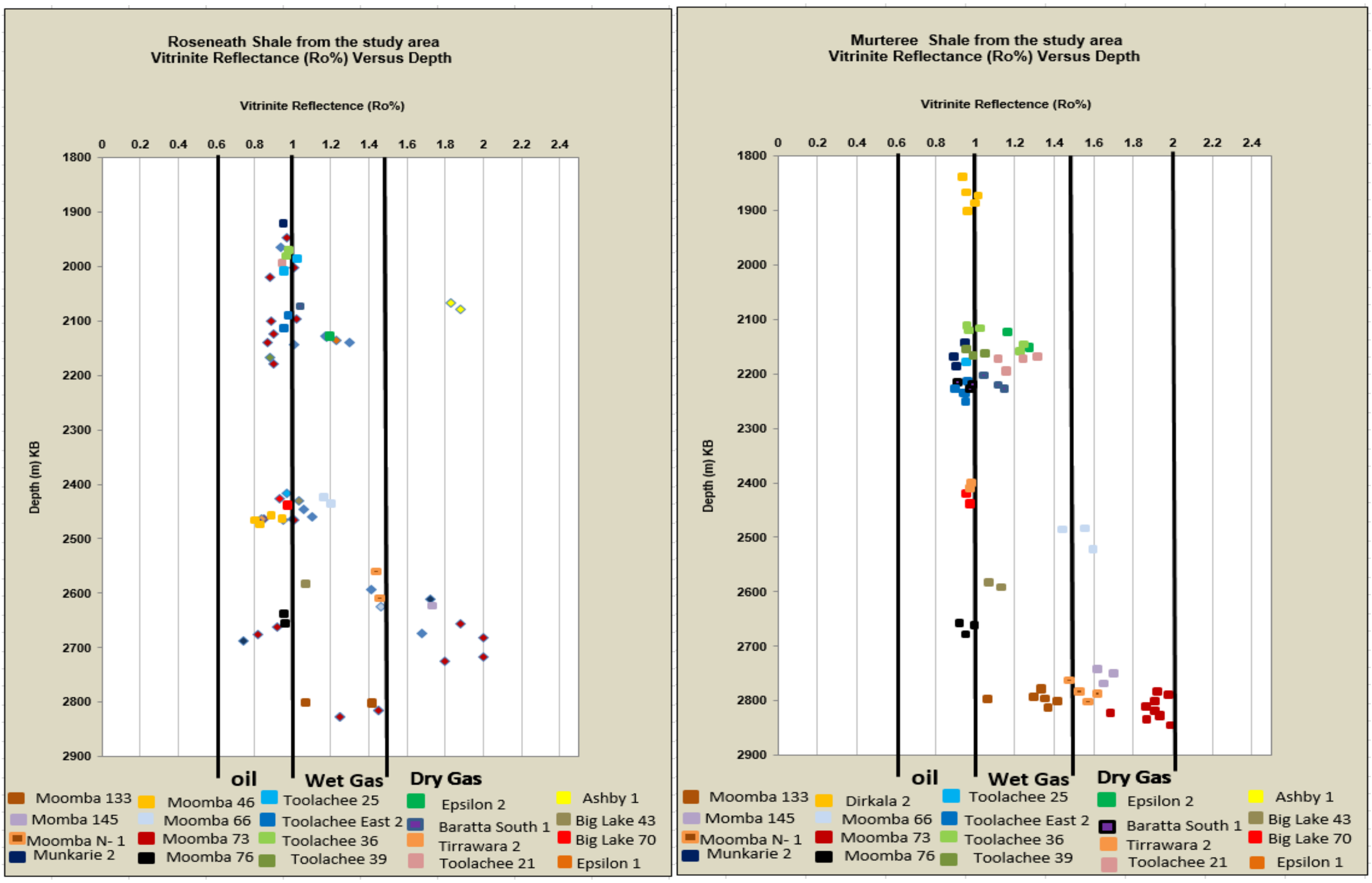

Figure 14: Vitrinite reflectance profile is showing the effect of change of in %R_0 with depth in Roseneath and Murteree shales of Cooper Basin. The data represents a wide geographic distribution of wells.

Supplementary Data

Appendex-1

Sr.No.	***Sample No***	***Formation***	***Well***	***Lab No***	***Depth(m)***	***Maturity***
1	V-1370	Roseneath	Ashby-01	Pr-13299	2068.07 m	1.83 %.
1	V-1371	Roseneath	Ashby-01	Pr-13300	2079 m	1.88 %.
2	V-1372	Roseneath	Epsilon-01	Pr-13301	2136m	1.23 %.
2	V-1373	Roseneath	Epsilon-02	Pr-13303	2128.38	1.17 %.
2	V-1374	Murteree	Epsilon-02	Pr-13303	2202.70–2206.18	1.30 %.
2	V-1375	Murteree	Epsilon-02	Pr-13304	2158.28	1.18 %.
3	V-1376	Roseneath	Big Lake-43	Pr-13305	2431.39 - 2625.24	1.01 %.
3	V-1377	Murteree	Big Lake-43	Pr-13306	2590.80 2599.94	1.03 %.
3	V-1378	Roseneath	Big Lake-43	Pr-13307	2447.54 2453.64	1.06 %.
3	V-1379	Roseneath	Big Lake-43	Pr-13308	2459.74 2465.83	1.10 %.
4	V-1380	Roseneath	Toolachee-25	Pr-13309	2020.82 2029.97	0.88 %.
4	V-1381	Roseneath	Toolachee-25	Pr-13310	2002.54 2011.68	1.01 %.
4	V-1382	Roseneath	Toolachee-25	Pr-13311	2029.97 2036.06	0.95 %.
4	V-1383	Roseneath	Toolachee-25	Pr-13312	2039.11 2060.45	0.79 %.
4	V-1384	Murteree	Toolachee-25	Pr-13313	2179.32 2194.56	0.90 %.
5	V-1387	Roseneath	Toolachee-39	Pr-13316	2167.13 2176.27	0.88 %.
5	V-1388	Murteree	Toolachee-39	Pr-13317	2191.51 2203.70	1.01 %.
6	V-1389	Roseneath	Toolachee-East-02	Pr-13318	2124.46 2133.60	0.90 %.
6	V-1390	Murteree	Toolachee-East-02	Pr-13319	2218.94 2228.09	0.83 %.
6	V-1391	Murteree	Toolachee-East-02	Pr-13320	2203.70 2209.80	0.91 %.
6	V-1392	Murteree	Toolachee-East-02	Pr-13321	2261.62 2273.81	0.92 %.
7	V-1393	Roseneath	Toolachee-36	Pr-13322	1947.67 1959.86	0.94 %.
8	V-1394	Murteree	Toolachee-21	Pr-13323	2176.27 2188.46	1.05 %.
8	V-1395	Murteree	Toolachee-21	Pr-13324	2157.98 2164.08	1.02 %.
8	V-1396	Murteree	Toolachee-21	Pr-13325	2164.08 2176.27	1.30 %.
9	V-	Murteree	Moomba-	Pr-	2813.30	1.89 %.

	1397		73	13326	2822.45	
9	V-1398	Roseneath	Moomba-73	Pr-13327	2682.24 2694.43	0.98%.
9	V-1399	Murteree	Moomba-73	Pr-13328	2782.82 2791.97	1.60 %.
9	V-1400	Roseneath	Moomba-73	Pr-13329	2657.86 2663.95	1.88 %.
9	V-1401	Roseneath	Moomba-73	Pr-13330	2673.10 2679.19	1.68 %.
9	V-1402	Murteree	Moomba-73	Pr-13331	2791.97 2798.06	2.00 %.
10	V-1403	Murteree	Moomba-133	Pr-13332	2776.73 2785.87	1.28 %.
10	V-1404	Roseneath	Moomba-133	Pr-13333	2828.54 2831.59	1.25 %.
10	V-1405	Roseneath	Moomba-133	Pr-13334	2816.35 2825.50	1.45 %.
11	V-1406	Roseneath	Moomba North- 01	Pr-13335	2593.85 2606.04	1.41 %.
11	V-1407	Roseneath	Moomba North- 01	Pr-13336	2624.33 2627.38	1.46 %.
12	V-1408	Roseneath	Moomba-145	Pr-13337	2612.14 2621.28	1.72 %.
12	V-1409	Murteree	Moomba-145	Pr-13338	2767.58 2770.63	1.52
12	V-1410	Murteree	Moomba-145	Pr-13339	2727.96 2740.15	1.50 %.
13	V-1411	Roseneath	Moomba-76	Pr-13340	2676.14 2685.29	0.82 %.
13	V-1412	Roseneath	Moomba-76	Pr-13341	2663.95 2673.10	0.92 %.
13	V-1413	Murteree	Moomba-76	Pr-13342	2788.92 2795.02	0.86 %.
13	V-1414	Roseneath	Moomba-76	Pr-13343	2688.34 2697.48	0.74 %.
14	V-1415	Roseneath	Moomba-46	Pr-13344	2464.19 2465.53	0.85%
14	V-1416	Roseneath	Moomba-46	Pr-13345	2464-2464.31	0.84 %.
14	V-1417	Roseneath	Moomba-46	Pr-13346	2464.9 - 2463.24	0.97%
14	V-1418	Roseneath	Moomba-46	Pr-13347	2466.44 – 2466.59	0.89 %
14	V-1419	Roseneath	Moomba-46	Pr-13348	2468.27 - 2468.58	0.82 %.

14	V-1422	Roseneath	Moomba-46	Pr-13349	2465.22 – 2465.53	0.94 %.
15	V-1423	Roseneath	Munkarie-02	Pr-13350	1965.96 1975.10	0.94 %.
15	V-1424	Murteree	Munkarie-02	Pr-13351	2127.50 2133.60	0.82 %.
15	V-1425	Murteree	Munkarie-02	Pr-13352	2017.78 2029.97	0.68 %.
16	V-1426	Murteree	Baratta South-01	Pr-13353	2212.85 2228.09	0.94 %.
16	V-1427	Roseneath	Baratta South-01	Pr-13354	2097.02 2103.12	1.02 %.
17	V-1428	Murteree	Dirkala-02	Pr-13355	1896- 1896.16	1.07 %.
17	V-1429	Murteree	Dirkala-02	Pr-13356	1893.42 1893.81	1.01 %
17	V-1430	Murteree	Dirkala-02	Pr-13357	1897.08 – 1897.38	1.01 %.
17	V-1431	Murteree	Dirkala-02	Pr-13358	1895.86 1905.00	1.09 %
17	V-1432	Murteree	Dirkala-02	Pr-13359	1837.94 1844.04	0.85 %.
18	V-1433	Roseneath	Big Lake-70	Pr-13360	2426.21 2432.30	0.93 %.
18	V-1434	Murteree	Big Lake-70	Pr-13361	2557.27 2560.32	0.97 %.
18	V-1435	Murteree	Big Lake-70	Pr-13362	2548.13 2551.18	0.84%.
18	V-1436	Roseneath	Big Lake-70	Pr-13363	2417.06 2423.16	0.97%.

Table- 3: Organic matter is abundant, fine to medium grain size. Organic matter is mainly coal in nature and oxidized in nature. Vitrinite is the main maceral consist of vitrodetrinite and collinite. Inertinite is the second maceral consists of inertodetrinite .Liptinite is the third maceral in the form liptodetrinite, alginite, bituminite are present. Kerogen types are III, IV, and II.