Broughton 1 Interpretive Summary

Mainoru – Dook Creek Interval

As a part of:
Northern Territory Geological Survey - Australia
McArthur Basin Integrated Petroleum Geochemistry, 2016

Submitted to:
Daniel Revie
Northern Territory Geological Survey
Department of Mines and Energy
38 Farrell Crescent
Winnellie, NT 0820 Australia

Prepared By:
Weatherford Laboratories
Study Project No. AB-74329

June 29, 2016

Weatherford Laboratories Disclaimer

LEGAL NOTICE: This report was prepared by Weatherford Laboratories as an account of work performed for the client and is intended for informational purposes only. Any use of this information in relation to any specific application should be based on an independent examination and verification of its applicability for such use by professionally qualified personnel. Neither Weatherford Laboratories, nor any persons or organizations acting on its behalf:

a. Makes any warranty or representation, expressed or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report; or

b. Assumes any liability with respect to the use of, or for damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

Report Contributors:

Tim Ruble (Petroleum Geochemistry)

Elizabeth Roberts (Compiler)

Brian Hankins & Jennifer Yee (Isologica Data Processing)

Elvira Barcelona (Organic Petrology)

Weatherford
LABORATORIES

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

PETROLEUM GEOCHEMISTRY

INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Mainoru and Dook Creek Formations in the Broughton 1 well located in the McArthur Basin, Northern Territories, Australia. Twenty-three (23) core chip samples from this well were analyzed by a variety of geochemical techniques, including total organic carbon (TOC, LECO®), programmed pyrolysis (SRA) and organic petrology with measured maceral reflectance (R_o). The complete results of these analyses are documented in this report along with an integrated geochemical interpretation that is summarized in the following table.

Well Name	*Formation*	*Main Product*	*Thermal Maturity*	*Source Rock Richness*	*Organic Matter Type*	*Shale Oil/Gas Risk*
Broughton 1	Mainoru	***Estimated Original*** ⟶		*Good (1.07% TOC)*	*Oil-prone Type II*	**High** *(Oil)*
Measured Currently ⟶		Oil Wet Gas	Late Oil Window	Poor (0.31% TOC)	Inert Type IV	
Broughton 1	Dook Creek	***Estimated Original*** ⟶		*Very Good (2.13% TOC)*	*Oil-prone Type II*	**High** *(Gas)*
Measured Currently ⟶		Gas	Dry Gas Window	Fair (0.75% TOC)	Inert Type IV	

Current TOC averages represent all data available; Original TOC averages are only high graded samples that have PPy data

Table 1. Geochemical Summary

MAINORU FORMATION

Fourteen (14) samples from the Mainoru Formation were analyzed for LECO TOC content and one (1) sample was analyzed for programmed pyrolysis (Fig. 1). TOC contents ranged from 0.19 to 0.79 wt.% and averaged 0.31 wt.% (poor). No samples have TOC content above the minimum requirement of 1 wt.% for *effective* petroleum source rocks, nor are there any samples which have TOC content above the minimum requirement of 2 wt.% for *economic* petroleum source rocks. Highest TOC content was found near the middle of the designated Mainoru interval (219.05 m depth) (Fig. 1), although the basal section of this formation below 288 m depth was not sampled.

The S1 value of the Mainoru source rock sample analyzed is 0.05 mg HC/g rock (1 bbl oil/acre-ft) and the S2 value is 0.14 mg HC/g rock (3 bbl oil/acre-ft). The S1 and S2 values imply poor in-situ hydrocarbon saturation and poor to poor remaining generative potential (Fig. 1). The normalized oil contents (NOC) in the Mainoru sample, (S1/TOC) x 100, is 6 (Fig. 1). NOC values of 20 to 50 are typical of low maturity source rocks, whereas values of 50 to 100 indicate possible oil staining or shows in thermally mature, tight petroleum source rocks. NOC > 100 are often associated with conventional oil reservoirs and indicate good prospectivity in unconventional shale oil plays. Very low NOC values < 20 are most likely related to post-mature source rocks that have likely generated and expelled most of their in-situ hydrocarbon saturation or source rocks with poor original hydrocarbon generation capacity. Jarvie (2012) has utilized a depth comparison of TOC versus programmed pyrolysis S1 yields as a potential indicator of producible hydrocarbon saturation in unconventional source rocks. When the S1 yields (reported as mg HC/g rock) exceed or “cross-over” the measured TOC content (reported as wt.%), this would be interpreted to represent zones with good potential for containing producible hydrocarbon saturation (or zones of possible contamination). In the present study, there is no S1 cross over TOC in any of the samples analyzed (Fig. 1).

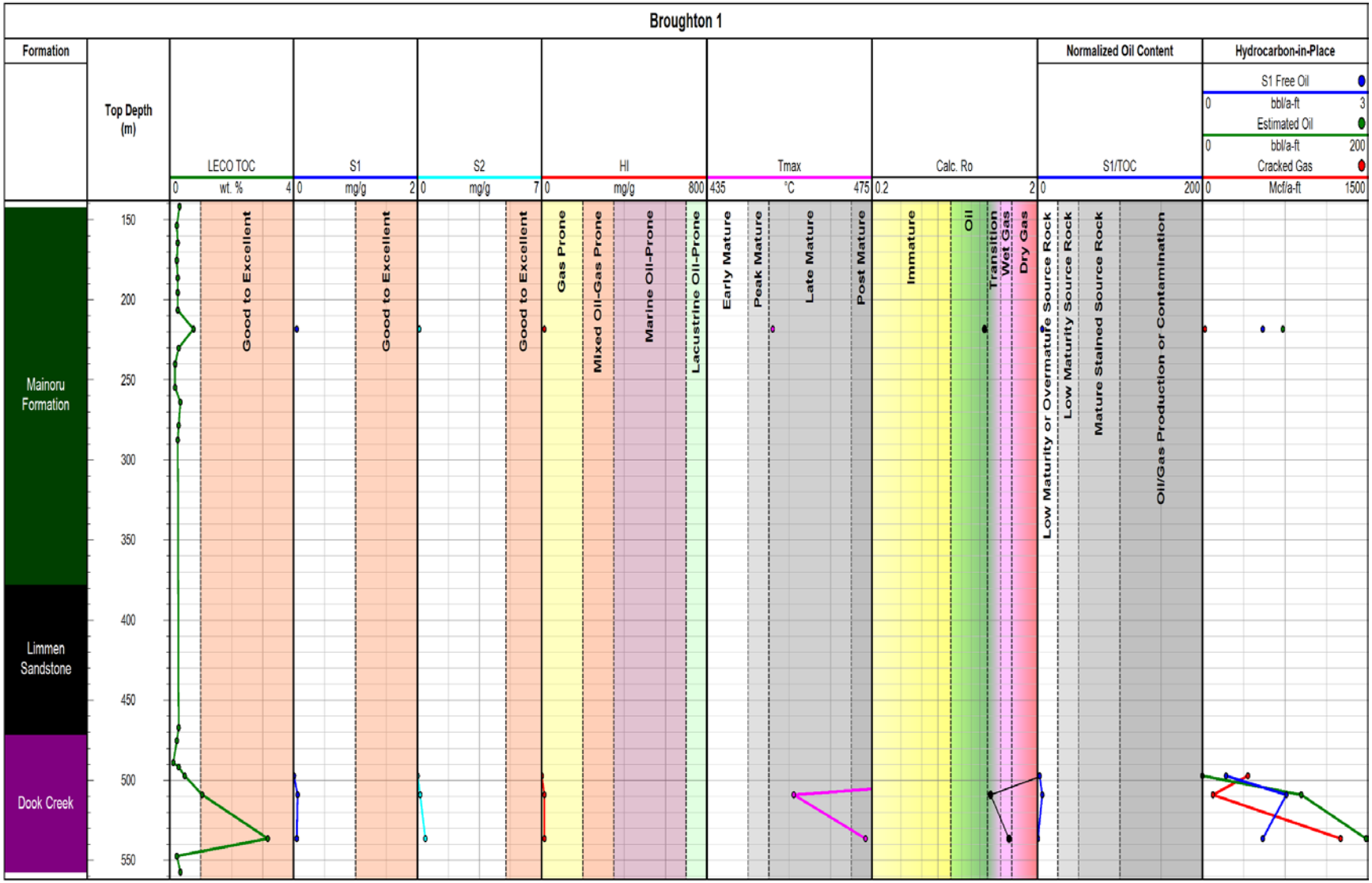

Figure 1. Geochemical depth plots for the Broughton 1 well. Note Tmax values plot off scale on depth plot beyond post-mature field.

Weatherford LABORATORIES

The measured Hydrogen Index (HI) value in the Mainoru is 18 mg HC/g TOC, indicating inert Type IV kerogen quality in these source rocks at present day. Original HI_o of this sample is estimated to average 450 mg HC/g rock, which indicates oil-prone Type II kerogen. Transformation Ratio (TR) based upon HI is 97%, which is more consistent with a dry gas window thermal maturity. The T_{max} value in the Mainoru sample is 451°C. T_{max} between 445 and 450°C typically indicate late oil window, while values between 450 and 470°C are considered in the condensate/wet gas window (Type II kerogen). On the basis of these guidelines, the Mainoru T_{max} values in this well would be interpreted to be in the early condensate/wet gas widow. Using the formula published by Jarvie et al. (2007) for Type II kerogen (Calculated $R_o = (0.0180)(T_{max}) – 7.16$), the measured T_{max} value of 451°C is equivalent to a Calc. $\%R_o$ value of 0.96%. It is important to note that T_{max} is only a crude measure of thermal maturation (Peters, 1986) and it can be compromised by a variety of pyrolysis artifacts and caveats.

The Production Index (PI) value in the Mainoru sample is 0.26. This elevated PI value is consistent with source rocks in the late oil window, which typically have PI values in the range of 0.25 to 0.35. Samples in the dry gas window tend to have very low PI values due to low S1 yields, but this is problematic since low S2 yields can cause this ratio to be erratic and inaccurate.

The thermal maturity of the Mainoru source rocks was also assessed by measured Kübler Index values from XRD, which are based upon illite crystallinity. These values can be used as maturity indicator when samples contain sufficient high quality clays (Abad, 2008). One sample from the Mainoru Formation (61% clays) have an average measured Kübler Index of 0.294, which is equivalent to a measured vitrinite reflectance of ~3% (mid stage metagenesis). This interpretation is inconsistent with the organic petrology data reported in this study and suggests the Kübler Index should be used with caution to evaluate thermal maturity in Mesoproterozoic aged source rocks.

DOOK CREEK FORMATION

Eight (8) samples from the Dook Creek Formation were analyzed for LECO TOC content and three (3) samples were analyzed for programmed pyrolysis (Fig. 1). The Dook Creek Formation in the Broughton 1 well exhibits fair generative potential for petroleum source rocks based on TOC content values (Fig. 1). TOC content ranges from 0.13 to 3.18 wt.% and averages 0.75 wt.% (fair). Two (2) samples have TOC content above the minimum requirement of 1 wt.% for *effective* petroleum source rocks, while one (1) sample has TOC content above the minimum requirement of 2 wt.% for *economic* petroleum source rocks. Maximum TOC content occurs in the lower portion of the sampled interval at a depth of 536.87 m (Fig. 1), although sampling frequency is rather sparse in this interval.

The S1 values in the Dook Creek average 0.05 mg HC/g rock (1 bbl oil/acre-ft), indicating poor in-situ hydrocarbon saturation (Fig. 1). NOC values in the Dook Creek interval are similar in comparison to the overlying strata and average 3. Oil cross over (NOC > 100) was not observed in this unit. The S2 values in this interval average just 0.22 mg HC/g rock (5 bbl oil/acre-ft), which indicates poor remaining generative potential.

Measured HI values in the Dook Creek samples average 12 mg HC/g TOC, which indicate inert Type IV kerogen quality in these source rocks at present day. Estimated original HI_o values in these samples average 450 mg HC/g TOC, which indicate oil-prone Type II kerogen quality. Transformation Ratios (TR) based upon HI average 98%, which suggest post-mature dry gas window thermal maturity.

The organic-matter in the Dook Creek interval in the Broughton 1 well is thermally post-mature and is interpreted to be in the dry gas window. Programmed pyrolysis T_{max} values in these samples are quite variable, ranging from 456 to 518°C and averaging 483°C. Due to the high variability and generally low S2 yields, these values should be used with caution to assess thermal maturity. T_{max} between 450 and 470°C typically indicate condensate/wet gas window, while values > 470°C are considered post mature and in the dry gas window (Type II kerogen). On the basis of these guidelines, the Dook Creek T_{max} values in this well would be interpreted to be in the early dry gas widow. Using the formula published by Jarvie et al. (2007) for Type II kerogen (Calculated $R_o = (0.0180)(T_{max}) – 7.16$), the measured T_{max} value

of 483°C is equivalent to a Calc. $\%R_o$ value of 1.52%. It is important to note that T_{max} is only a crude measure of thermal maturation (Peters, 1986) and it can be compromised by a variety of pyrolysis artifacts and caveats, especially in samples where S2 yields are very low.

Production Index (PI) values in these Dook Creek samples average 0.30. These elevated PI values more consistent with source rocks in the late condensate/wet gas window, which typically have PI values in the range of 0.25 to 0.35. Samples in the dry gas window tend to have very low PI values due to low S1 yields, but this is more problematic since low S2 yields can cause this ratio to be erratic and inaccurate.

Organic petrology was performed on one sample from the Dook Creek interval (536.87 m). The results from this analysis show a distribution that consists of macerals identified as either non-fluorescing Alginite or high reflectance solid bitumens (Fig. 2). The former population has relatively lower reflectance values that average 1.49% R_o and are considered the most representative indigenous kerogen population for thermal maturity assessment. The higher reflecting group of organic macerals is thought to possibly represent fine grained migrabitumen, although they could also represent preserved original cyanobacterial kerogen that has subsequently undergone thermal conversion to form a dispersed solid bitumen network within these Dook Creek source rocks. The mean measured reflectance value for these high reflecting solid bitumen organic macerals is 1.97% R_o. Published solid bitumen conversions were applied to these reflectance values. The conversion formula published by Landis and Castaño (1995) for bitumen in lenses/layers (Eq. R_o = (Bitumen R_o +0.41)/1.09) resulted in a 2.50% Eq. R_o, while the conversion formula published by Jacob (1985) equation (Eq. R_o = (Bitumen R_o $\times$ 0.618) + 0.4) for 'angular-like' pyrobitumen trapped in mineral pore spaces resulted in a 1.83% Eq. R_o. The Landis and Castaño (1995) conversion would appear to be much too high maturity for this interval. However, the Jacob (1985) conversion does appear to provide a possible correction back to a more suitable thermal maturity that is in general agreement with the average value from the population of non-fluorescing Alginite. Comparison with other samples examined in the current study suggest that the high reflectance solid bitumen reflectance readings can be corrected using the Jacob (1985) formula and often these “corrected” values compare favorably to “uncorrected” readings from the population of low reflectance solid bitumen within the same sample. Thus, the calculated 1.83% Eq. R_o value from solid bitumen and the measured 1.49% R_o values from non-fluorescing Alginite would both suggest the Dook Creek samples in this well are within the dry gas window.

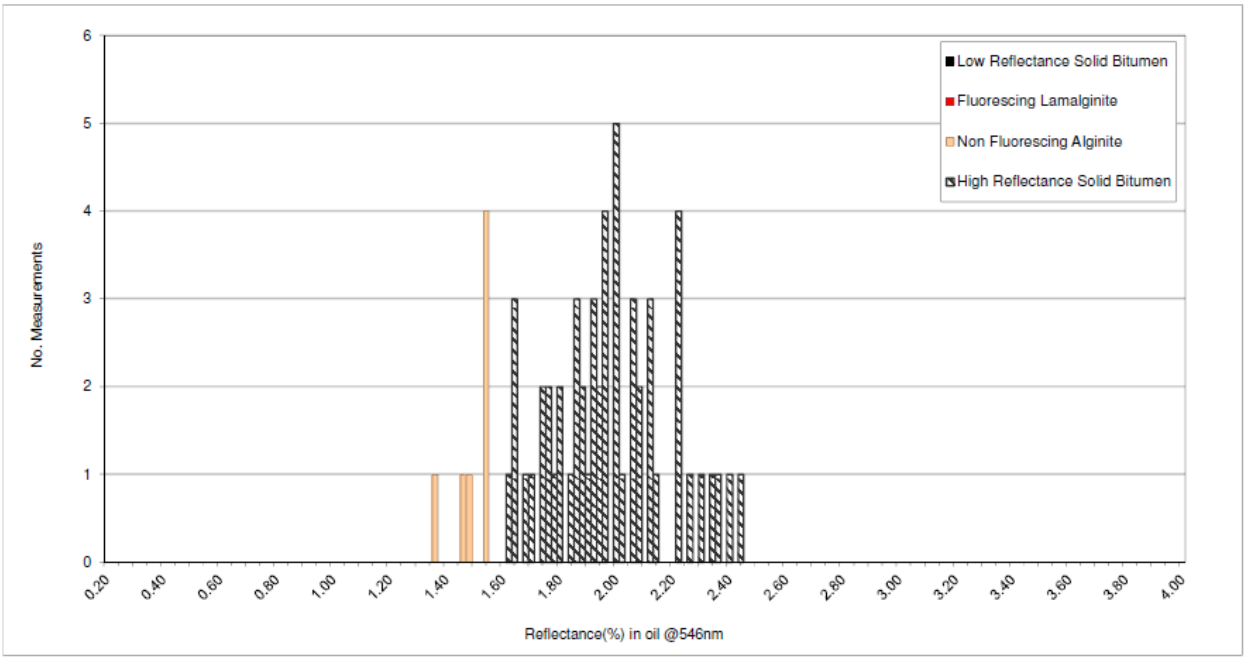

Figure 2. Organic petrology of the Dook Creek Formation (536.87 m) in the Broughton 1 well. Mean maceral reflectance of non-fluorescing Alginite is 1.49% R_o. The high reflecting solid bitumen has mean reflectance of 1.97% R_o, which equates to calculated Eq. R_o of 1.83% R_o using the conversion of Jacob (1985).

ORIGINAL GENERATIVE POTENTIAL AND HYDROCARBON YIELD CALCULATIONS

Petroleum generative capacity depends on the original quantity of organic matter (TOC_o) and the original type of organic matter (HI_o) (Peters et al., 2005, p. 97). The petroleum generation process has likely decreased the remaining generative potential as measured by TOC_{pd} and HI_{pd} in the Mainoru and Dook Creek source rocks examined in this study. We can estimate the extent of the petroleum generation process, the volume of expelled oil and the expulsion efficiency by making some reasonable assumptions based on the core geochemical data and published regional information (Jarvie et al., 2007; Peters et al., 2005).

HI_o values can be computed from visual kerogen assessments and assigned kerogen-type HI_o average values using the following equation (Jarvie et al., 2007):

$$HI_o = \left(\frac{\%\text{Type I}}{100} \times 750\right) + \left(\frac{\%\text{Type II}}{100} \times 450\right) + \left(\frac{\%\text{ Type III}}{100} \times 125\right) + \left(\frac{\%\text{Type IV}}{100} \times 50\right) \quad (1)$$

This equation requires the input of maceral percentages from visual kerogen assessment of a source rock. For the present study, only limited kerogen data were available. Where available, these kerogen data sets were used. In the absence of other measured kerogen data original kerogen type were interpreted in the context of measured present day TOC, HI and OI values to arrive at an appropriate kerogen mix for each sample examined in this investigation. All samples were modeled using appropriate kerogen mix to maintain an appropriate transformation ratio consistent with the interpreted thermal maturity. The average maceral percentage in the various formations evaluated in the current study are shown in Table 2, along with the resultant average original HI_o values calculated using equation (1) above. The kerogen estimations used in this study are generally in agreement with other published values that suggest Type II to a mixed Type I/II kerogen assemblage (Law et al., 2010; Crick et al., 1988; Taylor et al., 1994).

Formation	%Type I 750 HI_o	%Type II 450 HI_o	%Type III 125 HI_o	%Type IV 50 HI_o	HI_o
Mainoru	0	100	0	0	450
Dook Creek	0	100	0	0	450

Table 2. Average Kerogen Estimations for Broughton 1 well.

The extent of the petroleum-generation process, or transformation ratio (TR) which is also called fractional conversion, is calculated as follows (Jarvie et al., 2007, p. 497):

$$TR_{HI} = 1 - \frac{HI_{pd}\left[1200 - HI_o\left(1 - PI_o\right)\right]}{HI_o\left[1200 - HI_{pd}\left(1 - PI_{pd}\right)\right]} \quad (2)$$

HI_{pd} and PI_{pd} are the measured HI and PI values for the various source rock samples in this well. The average HI_{pd} and PI_{pd} for the formations evaluated in the current study are shown in Table 3. HI_o and PI_o are the original HI and PI values for immature organic matter in the rocks. For this calculation using the assumptions described previously results in an average HI_o values of 450 mg HC/g TOC (Table 2). We assume a PI_o of 0.02 (see Peters et al., 2005). Using these values in equation 2, the extent of fractional conversion of HI_o to petroleum is 0.97 to 0.98 (Table 3), i.e., on average an estimated 97 to 98% of the petroleum generation process has been completed.

The original TOC_o in the source rocks before burial and thermal maturation is constrained by mass balance considerations as follows (corrected from Jarvie et al., 2007):

$$TOC_o = \frac{HI_{pd}\left(\frac{TOC_{pd}}{1+k}\right)(83.33)}{\left[HI_o\left(1 - TR_{HI}\right)\left(83.33 - \left(\frac{TOC_{pd}}{1+k}\right)\right)\right] + \left[HI_{pd}\left(\frac{TOC_{pd}}{1+k}\right)\right]} \quad (3)$$

In this equation k is a correction factor based on residual organic carbon being enriched in carbon over original values at high maturity (Jarvie et al., 2007, p. 497). For Type II kerogen the increase in residual carbon C_R at high maturity is assigned a value of 15% (whereas for Type I, it is 50%, and for Type III, it is 0%) and the correction factor k is then $TR_{HI} \times C_R$. The kerogen mix for each individual sample was used in this calculation.

Using equation 3, the average estimated original TOC_o for the source rock samples in this well before petroleum generation varies from 1.07 to 2.13 wt.% (Table 3).

The original generation potential $S2_o$ can be calculated using the following equation:

$$S2_o = \left(\frac{HI_o \times TOC_o}{100}\right) \quad (4)$$

For the Mainoru and Dook Creek source rocks examined in the Broughton 1 well, the average $S2_o$ values vary from 4.8 to 9.6 mg HC/g rock or approximately 106 to 210 bbl/acre-ft (multiply $S2_o$ by 21.89 to calculate barrels/acre-ft, Jarvie and Tobey, 1999) (Table 3).

Knowing the measured remaining generation potential S2 from programmed pyrolysis and using the calculated original generation potential $S2_o$ enables a determination of the amounts of hydrocarbons generated. A VR_o algorithm can then be applied to estimate fractional oil cracking thereby converting yields to estimated oil and cracked gas (reported as Mcf/acre-ft or thousand cubic feet/acre-ft).

$$\text{Original } (S2_o) - \text{Remaining } (S2) = \text{Generated HCs} \quad (5)$$

Using this methodology for the Mainoru samples analyzed in the current study, the generated oil yields average 98 bbl/acre-ft along with 30 Mcf/acre-ft of secondary cracked gas. For the Dook Creek samples analyzed in the current study, the generated cracked gas yields average 591 Mcf/acre-ft along with 106 bbl/acre-ft of residual oil (Table 3).

Formation	TOC_{pd}	HI_{pd}	$S2_{pd}$ bbl/a-ft	HI_o	TR	TOC_o	$S2_o$ bbl/a-ft	S1 Free Oil bbl/a-ft	Est. Oil bbl/a-ft	Cracked Gas Mcf/a-ft
Mainoru	0.76	18	3	450	0.97	1.07	106	1	98	30
Dook Creek	1.58	12	5	450	0.98	2.13	210	1	106	591

Table 3. Hydrocarbon Yields average data for Broughton 1 well.

For shale oil systems, the amount of hydrocarbons (oil + gas) expelled from the rocks can be estimated as the difference between the amount of residual oil measured via programmed pyrolysis (S1) and the amount of estimated generated hydrocarbon yields determined above (equation 5). The expulsion efficiency (ExEf) can then be calculated as a direct proportion of the measured retained oil saturations and the average generated hydrocarbon yields. Thus, the resulting expulsion efficiency for the Mainoru interval is 99% and for the Dook Creek it is ~100%, which may be a consequence of increased thermal maturity resulting in more volatile in-situ oil compositions and higher gas/oil ratios, both of which would tend to enhance expulsion. The high expulsion efficiency is a potentially significant risk factor for in-situ shale oil prospectivity.

The Mainoru and Dook Creek source rock intervals in the Broughton 1 well are interpreted to be in the late oil to dry gas windows and hydrocarbon yield calculations suggest moderate amounts of generation have occurred (predominantly oil in the Mainoru and dry gas in the Dook Creek intervals) in the select samples analyzed. From an exploration risk perspective, this is generally favorable. However, it is useful to relate these hydrocarbon yields to other productive unconventional US Shale plays (Table 4). In doing so, the potential critical value is not necessarily the generated oil and gas yields, but also the original ($S2_o$) generation potential of the source rocks. These values related to the ultimate volumes of hydrocarbon that could be generated at depth in the basin. For the Mainoru original generation potential ($S2_o$) averages 106 bbl oil/acre-ft, this is below all of the other formations on the list of unconventional US Shale plays shown below. For the Dook Creek, original generation potential is higher and averages 210 bbl oil/acre-ft, but this value still does not compare favorably with other unconventional US Shale plays. It is also important to note that the select samples from these two formations chosen for evaluation do not appear to represent the majority of the potential source rock interval, which in general has much lower organic richness and would have much reduced hydrocarbon generation potential.

Sample Database Averages TOC >1%	HI° mg/g TOC	TR	TOC° wt%	S2° mg/g Rock	Remaining Potential bbl/a-ft	Original Potential bbl/a-ft	Oil Cracked %	S1 Free Oil bbl/a-ft	Estimated Oil bbl/a-ft	Cracked Gas Mcf/a-ft
Barnett Shale Ft. Worth Basin	435	0.84	5.38	23.40	94	513	0.40	33	251	1005
Barnett Shale Delaware Basin	435	0.91	5.25	22.84	52	500	0.80	32	90	2149
Woodford Shale Delaware Basin	480	0.89	6.41	30.79	139	674	0.89	46	60	2854
Haynesville Shale E. Texas Basin	400	0.98	3.93	15.73	7	344	1.00	3	0	2022
Fayetteville Shale Arkoma Basin	435	0.95	3.34	14.53	15	318	1.00	10	0	1820
Woodford Shale Arkoma Basin	520	0.87	5.15	26.80	12	587	0.70	87	170	2431
Eagle Ford Shale Gulf Coast Basin	520	0.85	3.19	16.61	61	364	0.47	22	161	848
Marcellus Shale Appalachian Basin	600	0.97	6.44	38.66	34	847	1.00	24	0	4875
Utica Shale Appalachian Basin	450	0.98	2.74	12.32	6	270	1.00	12	0	1585
Barnett Shale Oil	450	0.47	5.47	24.64	326	540	0.00	79	213	0
Barnett Shale Gas	450	0.96	5.58	25.13	23	550	0.87	7	68	2751
Mainoru	450	0.97	1.07	4.82	3	106	0.05	1	98	30
Dook Creek	450	0.98	2.13	9.57	5	210	0.55	1	106	591

Table 4. Geochemical Properties and Generation Potential for US Shale plays and current study.

UNCONVENTIONAL OIL & GAS RISK ASSESSMENT

The Mesoproterozoic Mainoru and Palaeoproterozoic Dook Creek Formation source rocks in the Broughton 1 well have been evaluated for unconventional oil and gas potential. These source rock samples are presented in a modified geochemical risk assessment diagram (Fig. 3) based upon published results from the Barnett Shale in the Fort Worth Basin. The data illustrated in the star plot represents average values for all four diagnostic ratios where available. Also shown are the recommended areas for unconventional oil (in green) and gas (in red). Data that lies above the minimum threshold and within the shaded areas indicates samples with low geochemical risk for either thermogenic oil or gas production. Data that lie below the minimum threshold and fall in the immature region (in gray) indicate a high risk for commercial shale oil or gas production. Transformation ratios (TR) were calculated based upon HI_o estimates using measured and interpreted fractional composition of kerogen macerals.

The Mainoru source rock interval in the Broughton 1 well is interpreted to represent a high geochemical risk for in-situ shale oil production. The average measured TOC content of 0.31 wt.% is below the generally accepted minimum value of 1% TOC to be considered an *effective* source rock for hydrocarbon generation/expulsion (Fig. 3). It is also far below the minimum requirements of 2 wt.% for *economic* petroleum source rocks, which is also the minimum threshold for prospective shale gas. Original organic matter type is interpreted to be predominantly oil-prone Type II marine algal kerogen. Thermal maturity parameters from programmed pyrolysis place the Mainoru source interval in late oil to early condensate/wet gas window. The average Tmax value of 451°C is well above recommended minimum value of 435°C for shale oil and slightly below the minimum of 455°C for shale gas (Fig. 3). This amount of conversion would likely be sufficient to generate/expel minor amounts of hydrocarbons from this organic lean, oil prone source facies. Transformation Ratios (TR), the least constrained risk parameter, average 97% and fall well above the recommended minimum of 50% for shale oil and are also above the 80% threshold for shale gas systems (Fig. 3). On the basis of all of these measured geochemical risk parameters (Fig. 3), the Mainoru source interval would be considered a high risk for shale oil and shale gas due primarily to insufficient organic richness throughout the majority of this sampled interval (Fig. 1).

The underlying Dook Creek interval examined in this study is also considered to represent high geochemical risk for in-situ shale gas production. The Dook Creek has an average TOC value of 0.75 wt.%, which is well below the recommended minimum threshold of 2 wt.% TOC for shale gas. Only one sample analyzed from this interval exceeds this minimum threshold, although sampling frequency is rather sparse (Fig. 1). Thermal maturity indicators suggest dry gas window maturity. On the risk assessment diagram, the Transformation Ratio of 98% is well above the recommended minimum of 80% for shale gas (Fig. 3). Measured maceral reflectance values in the Dook Creek Formation give a mean for non-fluorescing Alginite of 1.49% R_o, which is also above the recommended minimum of 1.0% R_o for

shale gas (Fig. 3). The average Tmax value of 483°C is also well above recommended minimum value of of 455°C for shale gas (Fig. 3).

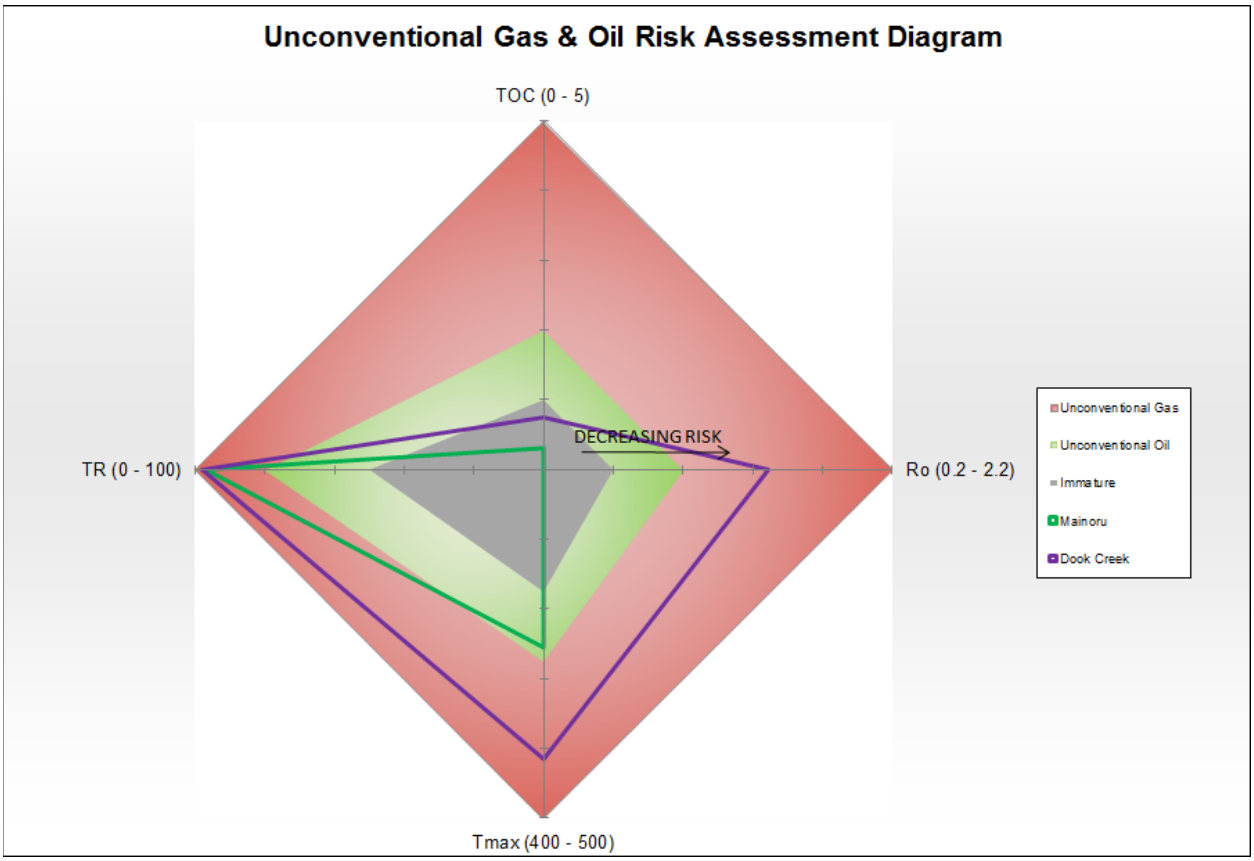

Figure 3. Geochemical Risk Assessment diagram for Mesoproterozoic Mainoru and Palaeoproterozoic Dook Creek Formation source rocks in the Broughton 1 well.

In the Mainoru source interval, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is very low (1 bbl oil/acre-ft), which is a potentially significant concern regarding risk assessment for unconventional oil (Fig. 4). Hydrocarbon yield calculations on as-received samples show estimates of average generated oil from the Mainoru at 98 bbl oil/acre-ft. As a comparison, a representative example from the core area of Barnett Shale oil production in the Fort Worth Basin has an estimated generated oil yield of 213 bbl/a-ft with a measured in-situ oil saturation of 79 bbl/a-ft. These values are much higher in comparison to the Mainoru Formation due primarily to differences in organic richness (Barnett Shale oil example has average of 4.70 wt.% TOC). Thus, even the most prospective sample selected from the Mainoru Formation does not compare favorably to proven oil shale systems like the Barnett and the relatively low TOC found within the remainder of the Mainoru clearly support a high risk assessment.

In the Dook Creek source interval, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is very low (1 bbl oil/acre-ft), which is consistent with an interpreted dry gas thermal maturity. Hydrocarbon yield calculations on select as-received samples shows estimates of average generated oil from the Dook Creek at 106 bbl oil/acre-ft. and oil cracking is estimated to have been 55%, resulting in a cracked gas yield of 591 Mcf/acre-ft (Fig. 4). As a comparison, a representative example from the core area of Barnett Shale gas production in the Fort Worth Basin has an estimated cracked gas yield of 2751 Mcf/acre-ft, with 68 bbl/acre-ft of residual oil/condensate and a measured in-situ oil saturation of 7 bbl/a-ft. These values are higher compared to the Dook Creek and are primarily due to differences in organic richness (Barnett Shale gas example has average of 4.21 wt. % TOC).

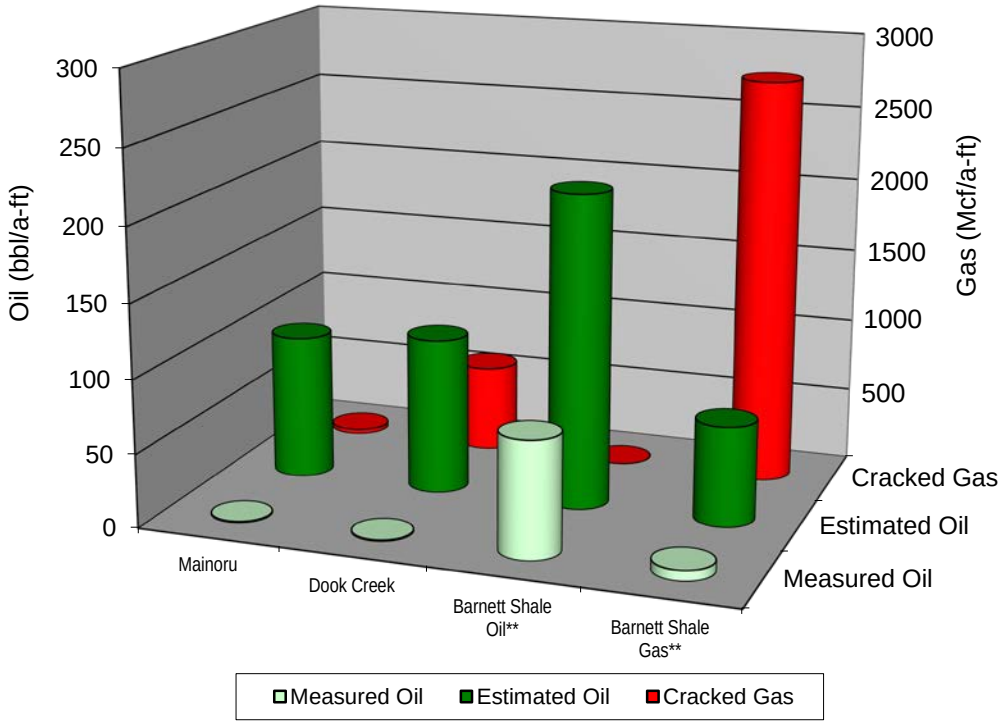

Figure 4. Hydrocarbon yield estimates for the Mesoproterozoic source rocks in the Broughton 1 well compared to Barnett Shale in the oil and gas window.

GEOCHEMICAL SUMMARY

The Mainoru Formation source interval in the Broughton 1 well is interpreted to represent high geochemical risk for unconventional shale oil development. Organic richness within this unit is generally lean (avg. 0.31 wt.% TOC) and is considered an poor source rock with dominantly oil-prone Type II kerogen. Thermal maturity parameters indicate that the source interval is in the late oil to early condensate/wet gas window, 0.96% Calc. R_o. The measured in-situ oil saturations determined by SRA analysis on the most prospective sample from this interval are very low (1 bbl oil/acre-ft). The narrow zone of elevated TOC within the Mainoru has likely generated moderate of oil (98 bbl/acre-ft), but it appears likely that most of this oil has been expelled from the source rock interval (likely into adjacent reservoir rocks).

The underlying Dook Creek Formation source rock interval evaluated in the Broughton 1 well is considered high risk for unconventional shale gas development. These horizons has organic richness values that average 0.75 wt.% TOC, which is well below the recommended minimum threshold of 2 wt.% for shale gas systems. Thermal maturity parameters are all above minimum thresholds and indicate early dry gas window. Select organic rich samples from this interval have likely generated a fair amount of secondary cracked gas (591 Mcf/acre-ft), but in comparison to proven shale gas systems like the Barnett Shale the generated gas volumes in the Dook Creek are significantly lower.

REFERENCES CITED

Abad, I., 2008, Physical meaning and applications of the illite Kübler index: measuring reaction progress in low-grade metamorphism, in F. Neito and J-M. Millan, eds., Diagenesis and low-temperature metamorphism: Theory, methods, and regional aspects: Seminarios de la Sociedad Española de Mineralogía, Unpaginated.

Crick I. H., Boreham, C. J., Cook, A. C. and Powell, T.G., 1988,Petroleum geology and geochemistry of Upper Proterozoic McArthur Basin, Northern Territory II: Assessment of source rock potential. American Association of Petroleum Geologists, Bulletin 72(12), 1495–1514.

Jarvie, D. M., 2012, Shale resource systems for oil and gas: Part 2 – shale-oil resource systems, *in* Breyer, J.A., ed., Shale reservoirs—giant resources for the 21st century: AAPG Memoir 97, CD-ROM Material, p. 89-119.

Jarvie, D. M., Hill, R.J., Ruble, T.E., and Pollastro, R.M., 2007, Unconventional shale gas systems: the Mississippian Barnett Shale of north-central Texas as one model for thermogenic shale-gas assessment, American Association of Petroleum Geologists Bulletin, v. 91, p. 475-499.

Jarvie, D. M. and Tobey, M H., 1999, TOC, Rock-Eval, or SR Analyzer Interpretive Guidelines: Application Note 99-4: Weatherford Laboratories, 16 p.

Law, B. E., Ahlbrandt, T. and Hoyer, D., 2010, Source and reservoir rock attributes of Mesoproterozoic shale, Beetaloo Basin, Northern Territory, Australia. Search and Discovery Article #110130 (14 June 2010). Adapted from oral presentation at session: Genesis of shale gas – physicochemical and geochemical constraints affecting methane adsorption and desorption, at AAPG Annual Convention, New Orleans, Louisiana, April 11–14, 2010.
http://www.searchanddiscovery.com/documents/2010/110130law/ndx_law.pdf

Lewan, M. D.,1987, Petrographic study of primary petroleum migration in the Woodford Shale and related rock units, *in* B. Doligez, ed., Migration of hydrocarbons in sedimentary basins, 2nd Edition, IFP Exploration Research Conference, Carcans, France, June 15-19, 1987, p. 113-130.

Peters, K. E., 1986, Guidelines for evaluating petroleum source rocks using programmed pyrolysis, AAPG Bulletin, v 70, p. 318-329.

Peters, K. E., C. C. Walters, and M. Moldowan, 2005, The biomarker guide, 2nd Edition, Volumes 1 and 2, Cambridge University Press, 1155 p.

Taylor, D. P., Kontorovich, A. E., Larichev, A. I. and Glikson, M., 1994. Petroleum source rocks in the Roper Group of the McArthur Basin: Source characterisation and maturity determinations using physical and chemical methods. APEA Journal 34, 279 –296.

Appendix I

Hydrocarbon Yield Calculation
Shelf Group
Broughton 1

McArthur Basin Integrated Petroleum Geochemistry, 2016

Northern Territory Geological Survey - Australia

Weatherford®
LABORATORIES

Broughton 1

Hydrocarbon Yield Calculation

																S2 (meas)	S2 (orig)				
Sample	Top Depth	TOC*	HI*	S1*	S2*	Calc.Ro	PI*	%Type IV 50 HIº	% Type III 125 HIº	%Type II 450 HIº	%Type I 750 HIº	HIº	TR	TOCº	S2º	Remaining Potential	Original Potential	Oil Cracked	S1 Free Oil	Estimated Oil	Cracked Gas
Broughton 1	(m)	wt%	mg/g TOC	mg/g Rock	mg/g Rock	%						mg/g TOC		wt%	mg/g Rock	bbl/a-ft	bbl/a-ft	%	bbl/a-ft	bbl/a-ft	Mcf/a-ft
UR14DJR021	219	0.79	18	0.05	0.14	**0.96**	0.26	0	0	100	0	450	0.97	1.07	4.82	3	106	0.05	1	98	30
Mainoru (Avg)		**0.79**	**18**	**0.05**	**0.14**	**0.96**	**0.26**	**0**	**0**	**100**	**0**	**450**	**0.97**	**1.07**	**4.82**	**3**	**106**	**0.05**	**1**	**98**	**30**
UR14DJR001	498	0.51	4	0.02	0.02	**2.16**	0.50	0	0	100	0	450	0.99	0.70	3.15	0	69	1.00	0	0	412
UR14DJR002	510	1.05	16	0.07	0.17	**1.05**	0.29	0	0	100	0	450	0.98	1.43	6.41	4	140	0.12	2	120	102
UR14DJR003	537	3.18	15	0.05	0.48	**1.36**	0.09	0	0	100	0	450	0.98	4.25	19.15	11	419	0.51	1	199	1260
Dook Creek (Avg)		**1.58**	**12**	**0.05**	**0.22**	**1.52**	**0.30**	**0**	**0**	**100**	**0**	**450**	**0.98**	**2.13**	**9.57**	**5**	**210**	**0.55**	**1**	**106**	**591**
Barnett Shale Oil**		4.70	300	3.60	14.90	0.86	0.20	0	0	100	0	450	0.47	5.47	24.64	326	540	0.00	79	213	0
Barnett Shale**		4.21	26	0.33	1.07	1.66	0.24	0	0	100	0	450	0.96	5.58	25.13	23	550	0.87	7	68	2751

Notes: Calc.Ro values in **bold** are calculated from measured Tmax. Calc.Ro values in red font are intrepreted from other geochemical maturity data because Tmax was considered unreliable. All other Calc.Ro values are formation specific averages because Tmax was considered unreliable.

Kerogen Type in **bold** have visual kerogen data for estimates TR = Transformation Ratio (fractional conversion) (Original Potential - Remaining Potential) = (Estimated Oil + Cracked Gas)

Estimated Oil and Cracked Gas yield data assume complete conversion and no expulsion of hydrocarbon products and the proportion between each is based on empirical Ro calculated % cracking.

Yields do not represent recoverable products and are intended primarily for comparison purposes, yield calculations based on carbon mass balance are likely to be overestimations. **Estimated parameters for productive Barnett Shale in the Ft. Worth Basin

Hydrocarbon yield calculations and formulas are fully documented in the appendix section of Jarvie et al. (2007)

Weatherford LABORATORIES