BMR Urapunga 5 Interpretive Summary

Mainoru/Wooden Duck Interval

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

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June 29, 2016

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INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Mainoru Formation (Wooden Duck Member) in the BMR Urapunga 5 well located in the McArthur Basin, Northern Territories, Australia. Twenty-five (25) 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 Risk*
BMR Urapunga 5	Mainoru Wooden Duck	**Estimated Original ⟶**		Fair (0.82% TOC)	Oil-prone Type II	High
Measured Currently ⟶		Minor Oil	Late Oil Window	Poor (0.32% 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

JALBOI FORMATION

Four samples (4) from the Jalboi Formation were analyzed for LECO TOC content only (Fig. 1). TOC contents ranged from 0.18 to 0.39 wt.% and averaged 0.27 wt.% (poor). Due to low organic richness, these samples are considered non-source rocks and no further geochemical evaluations were conducted in this study.

MAINORU FORMATION

Five samples (5) from the designated Mainoru Formation were analyzed for LECO TOC content only (Fig. 1). TOC contents ranged from 0.17 to 0.22 wt.% and averaged 0.20 wt.% (poor). Due to low organic richness, these samples are considered non-source rocks and no further geochemical evaluations were conducted in this study.

MAINORU FORMATION - WOODEN DUCK MEMBER

Sixteen samples (16) from the Mainoru Formation (Wooden Duck Member) were analyzed for LECO TOC content and programmed pyrolysis (Fig. 1). TOC contents ranged from 0.09 to 0.94 wt.% and averaged 0.32 wt.% (poor). None of these samples have TOC contents above the minimum requirement of 1 wt.% for *effective* petroleum source rocks and they are also below the minimum requirement of 2 wt.% for *economic* petroleum source rocks. TOC content is more elevated in the basal section of this interval and maximizes at a depth of 559.71 m (Fig. 1).

The S1 values of the Mainoru/Wooden Duck source rock samples average 0.07 mg HC/g rock (2 bbl oil/acre-ft) and S2 values average 0.13 mg HC/g rock (3 bbl oil/acre-ft). The S1 and S2 values imply poor in-situ hydrocarbon saturation and poor remaining generative potential (Fig. 1). The S1 values should be considered a minimum for in-situ oil saturation since they do not account for potential loss of volatile components during sample collection and analysis. The normalized oil content (NOC) in the Mainoru/Wooden Duck samples, (S1/TOC) x 100, averages 12 (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

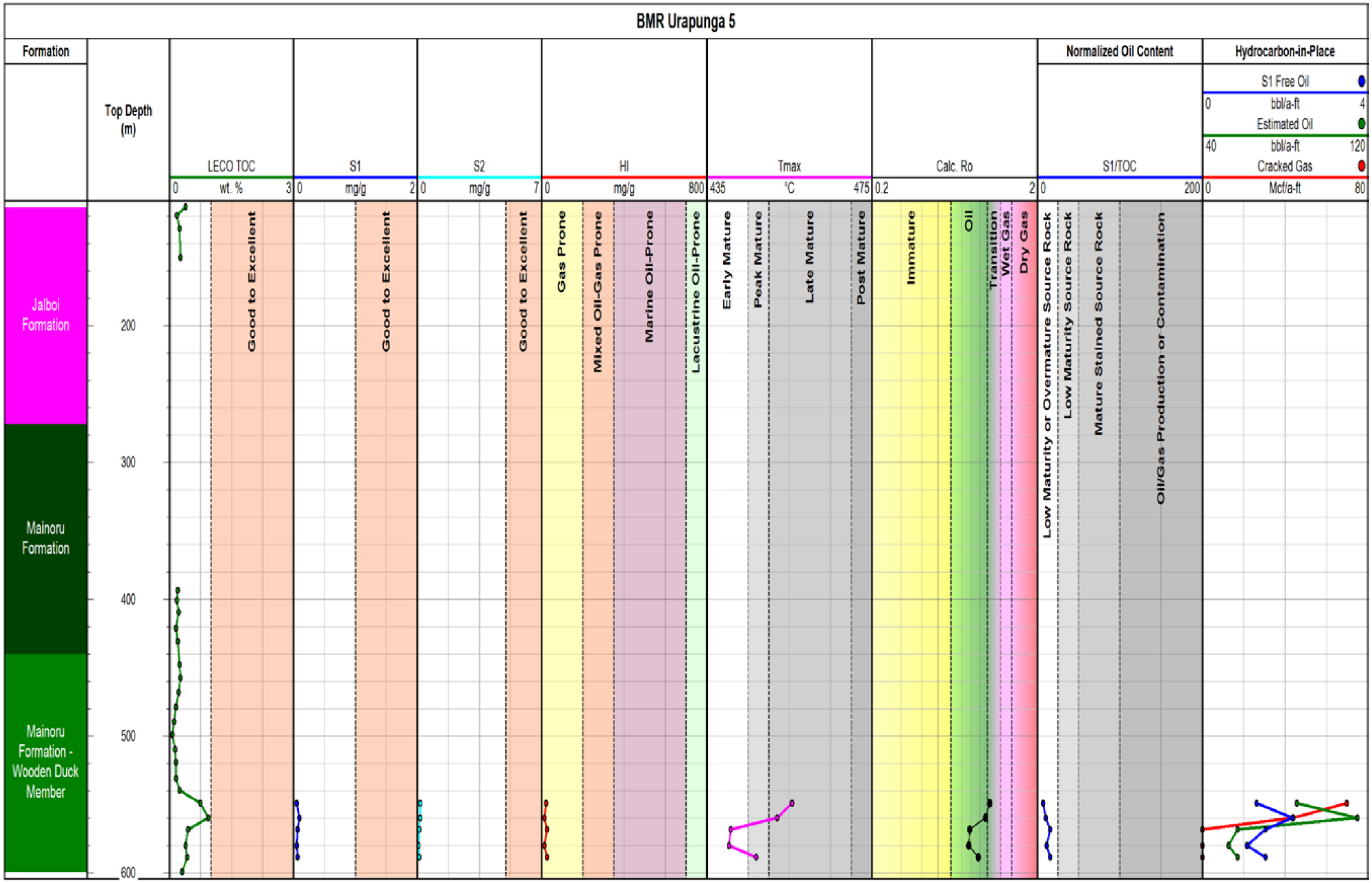

Figure 1. Geochemical depth plots for the BMR Urapunga 5 well.

are most likely related to post-mature source rocks that have 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 in the BMR Urapunga 5 well (Fig. 1).

Measured Hydrogen Index (HI) values in the Mainoru/Wooden Duck average only 22 mg HC/g TOC, indicating inert Type IV kerogen quality in these source rocks at present day. Original HI_o of these samples are estimated to average 450 mg HC/g rock, which indicate oil-prone Type II kerogen. Transformation Ratios (TR) based upon HI average 97%, which is consistent with a gas window thermal maturity. T_{max} values in the Mainoru/Wooden Duck samples average 447°C. T_{max} between 435 and 445°C typically indicate peak oil window, while values between 445 and 450°C typically indicate late oil window (Type II kerogen). On the basis of these guidelines, the average Mainoru/Wooden Duck T_{max} values in this well would be interpreted to be in the late oil window. Using the formula published by Jarvie et al. (2007) for Type II kerogen (Calculated $R_o = (0.0180)(T_{max}) – 7.16$), the average measured T_{max} value of 447°C is equivalent to a Calc. %R_o value of 0.89%. 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.

Production Index (PI) values in these Mainoru/Wooden Duck samples average 0.36. These elevated PI values are consistent with source rocks in the late oil window, which typically have PI values between ~0.25 to 0.35. However, PI values in these samples should be interpreted cautiously due to very low S1 and S2 values.

The thermal maturity of the Mainoru/Wooden Duck source was also evaluated 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). Three samples from the Mainoru/Wooden Duck interval (avg. 56% clays) have an average measured Kübler Index of 0.217, which is equivalent to a measured vitrinite reflectance of > 4% (late stage metagenesis). This interpretation is inconsistent with other geochemical maturity ratios evaluated in this study and suggests the Kübler Index should be used with caution to evaluate thermal maturity in Mesoproterozoic aged source rocks.

Organic petrology was performed on one sample from the Mainoru/Wooden Duck interval (559.71 m) in the BMR Urapunga 5 well (Fig. 2). The results from this analysis show a distribution that consist of macerals identified as either low reflecting solid bitumen or high reflectance solid bitumen. The low reflecting solid bitumen population has a reflectance value of 1.23% R_o on the basis of a single measurement (Fig. 2). While the low reflecting solid bitumen readings are generally considered the most representative indigenous kerogen population for thermal maturity assessment in this study, the single value measured in this sample appears to be providing an anomalously high maturity. This 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 source rocks. The maturity assessment from this maceral group would be consistent with the condensate/wet gas window, which is also supported by the absence of algal fluorescence colors in this same sample.

The mean measured reflectance value for the high reflecting solid bitumen population of organic macerals averages 1.66% R_o. Published solid bitumen conversions were applied to both populations of solid bitumen 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 1.50% Eq. R_o when applied to the low reflecting solid bitumens. 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 1.42% Eq. R_o when applied to the high reflecting solid bitumens. Neither of these conversions results in Eq. R_o values that are consistent with other geochemical maturity data since they would suggest early dry gas maturity. 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. This does not appear to be the case in readings from the Mainoru/Wooden Duck in the BRM Urapunga 5 well.

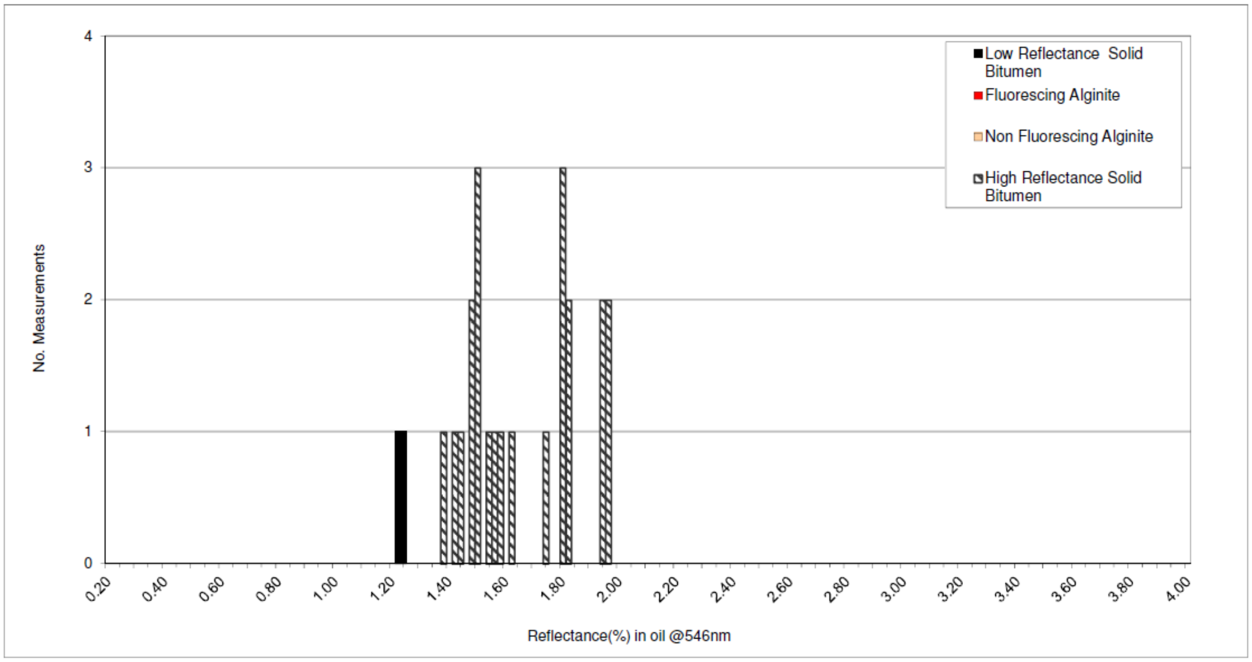

Figure 2. Organic petrology of the Mainoru/Wooden Duck (559.71 m) in the BMR Urapunga 5 well. Mean maceral reflectance of low reflecting solid bitumen is 1.23% R_o. The high reflecting solid bitumen has mean reflectance of 1.66% R_o, which equates to calculated Eq. R_o of 1.42% R_o using the conversion 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/Wooden Duck source rock samples 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. For the BMR Urapunga 5 well, the measured kerogen maceral distributions show 100% Type II kerogen (dominantly inert AOM with minor lens/layer AOM). 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/Wooden Duck	0	100	0	0	450

Table 2. Average Kerogen Estimations for BMR Urapunga 5 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):

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

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 value 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 (Table 3), i.e., on average an estimated 97% 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):

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

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 is 0.82 wt.% (Table 3).

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

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

For the Mainoru/Wooden Duck source rocks examined in the BMR Urapunga 5 well, the average $S2_o$ value is 3.7 g HC/g rock or approximately 80 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).

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

Using this methodology for the Mainoru/Wooden Duck samples analyzed in the current study, the generated oil yields average 74 bbl/acre-ft along with 23 Mcf/acre-ft of secondary cracked gas (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/Wooden Duck	0.60	22	3	450	0.97	0.82	80	2	74	23

Table 3. Hydrocarbon Yields average data for BMR Urapunga 5 well.

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/Wooden Duck interval in this well is estimated to be 98%.

The Mainoru/Wooden Duck source rock interval in the BMR Urapunga 5 well is interpreted to be in the late oil window and hydrocarbon yield calculations suggest minor amounts of generation have occurred (predominantly oil with some associated and secondary gas). From an exploration risk perspective, this is generally unfavorable. 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/Wooden Duck original generation potential ($S2_o$) averages only 80 bbl oil/acre-ft, which is much lower compared to any of the other formations on the list of unconventional US Shale plays shown below.

Sample Database Averages TOC >1%	HI^o mg/g TOC	TR	TOC^o wt%	$S2^o$ 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/Wooden Duck	450	0.97	0.82	3.67	3	80	0.04	2	74	23

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

UNCONVENTIONAL OIL & GAS RISK ASSESSMENT

The Mesoproterozoic Mainoru/Wooden Duck source rocks in the BMR Urapunga 5 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. 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.

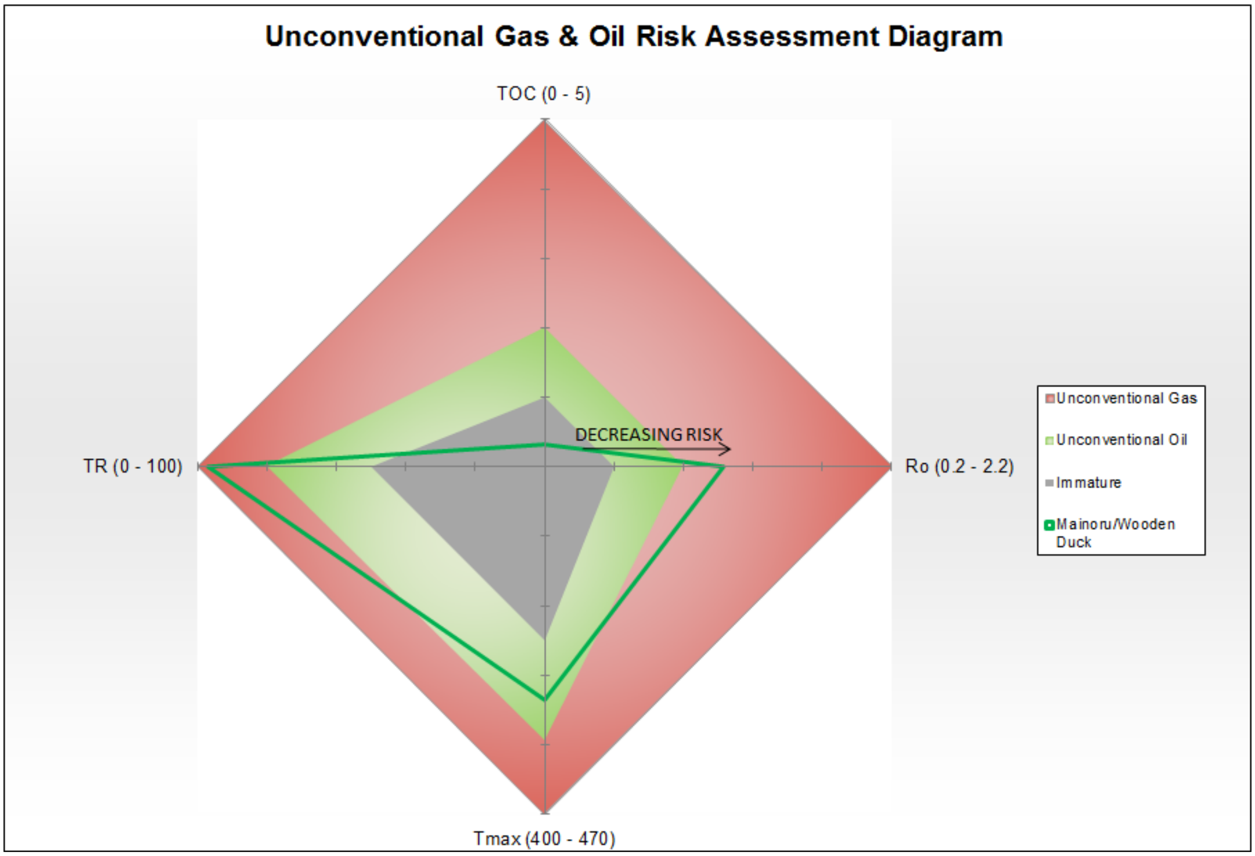

Figure 3. Geochemical Risk Assessment diagram for Mesoproterozoic Mainoru/Wooden Duck source rocks in the BMR Urapunga 5 well.

The Mainoru/Wooden Duck source rock interval in the BMR Urapunga 5 well is interpreted to represent a high geochemical risk for in-situ shale oil production. The average TOC content of 0.32 wt.% is far 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 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 based upon measured visual kerogen analysis. Thermal maturity parameters from programmed pyrolysis place the Mainoru/Wooden Duck source interval in late oil window. The average Tmax value of 447°C is above the recommended minimum value of 435°C for shale oil, but 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-poor, oil prone source facies. Transformation Ratios (TR), the least constrained risk parameter, average 97% and fall above the recommended minimum of 50% for shale oil systems and 80% for shale gas (Fig. 3). Measured maceral reflectance values in the Mainoru/Wooden Duck give a mean for low reflectance solid bitumen of 1.23% R_o, which is above the recommended minimum threshold of 0.5% R_o for shale oil and above the minimum of 1.0% R_o for shale gas (Fig. 3). On the basis of all of these measured geochemical risk parameters, the Mainoru/Wooden Duck source interval would be considered a high risk for shale oil and a high risk for shale gas since organic richness is well below the minimum thresholds (Fig. 3).

In the Mainoru/Wooden Duck source interval, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is very low (avg. 2 bbl oil/acre-ft), suggesting high risk for shale oil development (Fig. 4). Hydrocarbon yield calculations on as-received samples show estimates of average generated oil from the Mainoru/Wooden Duck at 74 bbl oil/acre-ft, along with 23 Mcf/acre-ft of secondary cracked gas (Fig. 3) based upon an estimated 4% oil cracking. 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 (Fig. 6). These values are much higher compared to the Mainoru/Wooden Duck and due to differences in organic richness (Barnett Shale oil sample has an avg. 4.70 wt.% TOC).

It is important to note that the quantity of oil generated from a potential source rock is only one geochemical factor to consider in regard to risk assessment. Equally important is the quality of the oil generated, since this factor can be a critical element in assessing the movability and ultimate recovery. The interpreted thermal maturity of the Mainoru/Wooden Duck source interval in this well is in the late oil window and hydrocarbon saturation is likely to be fairly light and mobile. However, the presence of heavy oil and/or bitumen could also indicate a source interval with restricted microporosity. Such microporosity is considered necessary for recovery of in-situ oil saturation and can be better assessed using scanning electron microscopy (SEM). Source rock extract fingerprints and bulk fractional compositional analyses from select Mainoru/Wooden Duck samples would also aid in the determination of the quality of the in-situ hydrocarbon saturation and provide a better assessment of their movability and ultimate recovery potential.

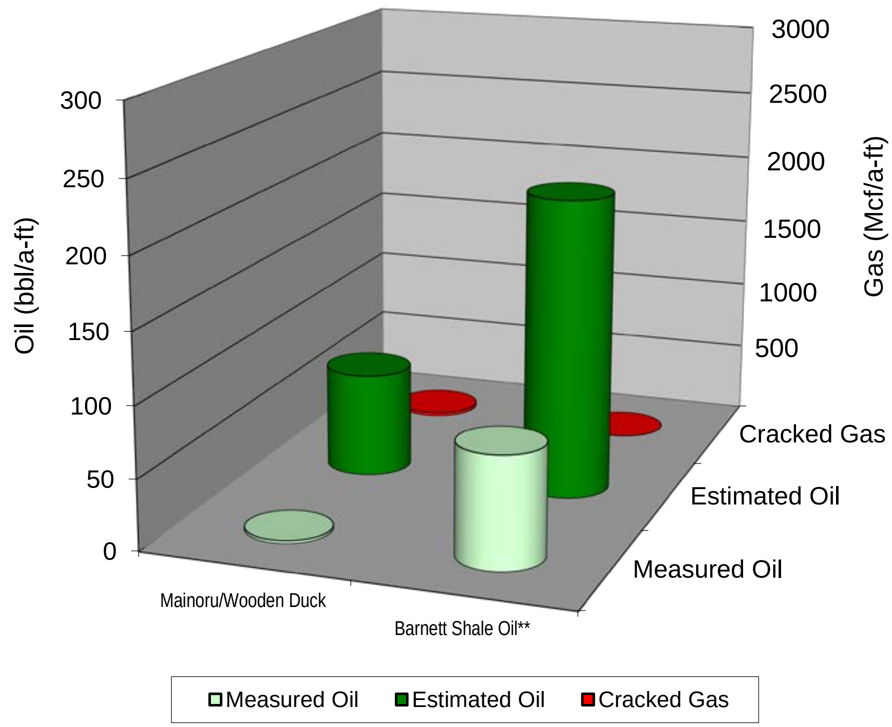

Figure 4. Hydrocarbon yield estimates for the Mesoproterozoic source rocks in the BMR Urapunga 5 well compared to Barnett Shale in the oil window.

GEOCHEMICAL SUMMARY

The Mainoru/Wooden Duck source interval in the BMR Urapunga 5 well is interpreted to represent high geochemical risk for unconventional shale oil development. Organic richness in this interval is generally low (avg. 0.32 wt.% TOC; maximum 0.94 wt.% TOC) and it is considered a poor source rock with dominantly oil-prone Type II kerogen. Thermal maturity parameters indicate that the source interval is in the late oil window, 0.89% Calc. R_o and 1.23% R_o from solid bitumen reflectance (one reading). All key thermal maturity risk ratios are above recommended minimum thresholds for shale oil systems. The Mainoru/Wooden Duck has likely generated minor amounts of oil and secondary cracked gas (avg. 74 bbl oil/acre-ft; 23 Mcf gas/acre-ft). However, in-situ oil saturation is very low (avg. 3 bbl oil/acre-ft) and risk criteria like the S1 versus TOC show no oil cross-over with the Mainoru/Wooden Duck interval, supporting a high risk assessment.

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Appendix I

Hydrocarbon Yield Calculation
Shelf Group
BMR Urapunga 5

McArthur Basin Integrated Petroleum Geochemistry, 2016

Northern Territory Geological Survey - Australia

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BMR Urapunga 5

Hydrocarbon Yield Calculation

																S2 (meas)	S2 (orig)				
Sample	**Top Depth**	**TOC***	**HI***	**S1***	**S2***	**Calc.Ro**	**PI***	**%Type IV 50 HI°**	**% Type III 125 HI°**	**%Type II 450 HI°**	**%Type I 750 HI°**	**HI°**	**TR**	**TOC°**	**S2°**	**Remaining Potential**	**Original Potential**	**Oil Cracked**	**S1 Free Oil**	**Estimated Oil**	**Cracked Gas**
BMR Urapunga 5	**(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**
UR14 DJR124	549	0.76	25	0.06	0.19	**1.04**	0.24	0	0	100	0	450	0.96	1.03	4.65	4	102	0.12	1	86	70
UR14 DJR125	560	0.94	16	0.10	0.15	**0.98**	0.40	**0**	**0**	**100**	**0**	450	0.98	1.28	5.74	3	126	0.06	2	115	44
UR14 DJR126	569	0.45	27	0.07	0.12	**0.78**	0.37	0	0	100	0	450	0.96	0.61	2.75	3	60	0.00	2	57	0
UR14 DJR127	580	0.40	17	0.05	0.07	**0.77**	0.42	0	0	100	0	450	0.98	0.55	2.48	2	54	0.00	1	53	0
UR14 DJR128	589	0.45	27	0.07	0.12	**0.89**	0.37	0	0	100	0	450	0.96	0.61	2.74	3	60	0.00	2	57	0
Mainoru/Wooden Duck (Avg)		**0.60**	**22**	**0.07**	**0.13**	**0.89**	**0.36**	**0**	**0**	**100**	**0**	**450**	**0.97**	**0.82**	**3.67**	**3**	**80**	**0.04**	**2**	**74**	**23**
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)