LMDH10 Interpretive Summary

Mallabah Dolostone 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)

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 Mallabah Dolostone in the LMDH10 well located in the Birrindudu Basin, Northern Territories, Australia. Eighteen (18) core chip samples from this well were analyzed by a variety of geochemical techniques, including total organic carbon (TOC, LECO®) and programmed pyrolysis (SRA). 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 Gas Risk
LMDH10	Mallabah Dolostone	***Estimated Original*** ⟶		*Very Good (3.23% TOC)*	*Oil-prone Type I/II*	**Moderate**
Measured Currently ⟶		Condensate Wet Gas	Wet Gas Window	Very Good (2.28% 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

MALLABAH DOLOSTONE

Eighteen (18) samples from the Mallabah Dolostone Formation were analyzed for LECO TOC content and programmed pyrolysis (Fig. 1). TOC contents ranged from 0.61 to 4.82 wt.% and averaged 2.28 wt.% (very good). Thirteen (13) of these samples have TOC content above the minimum requirement of 1 wt.% for *effective* petroleum source rocks, while ten (10) 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 Mallabah Dolostone interval (215.35 m depth) (Fig. 1) and the basal portion of the sampled interval appears to have generally higher TOC compared to the upper section (Fig. 1).

The S1 values of the Mallabah Dolostone source rock samples average 0.02 mg HC/g rock (0 bbl oil/acre-ft) and the S2 values average 0.02 mg HC/g rock (0 bbl oil/acre-ft). The S1 and S2 values imply non-existent in-situ hydrocarbon saturation and no remaining generative potential (Fig. 1). The normalized oil contents (NOC) in the Mallabah Dolostone samples, (S1/TOC) x 100, average 1 (Fig. 1). 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. 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 Mallabah Dolostone samples analyzed in this well (Fig. 1).

The measured Hydrogen Index (HI) values in the Mallabah Dolostone average 1 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 543 mg HC/g rock, which indicate oil-prone Type I/II kerogen. Transformation Ratios (TR) based upon HI are 100%, which suggest gas window thermal maturity. Programmed pyrolysis T_{max} values in these samples are generally quite low (< 435°C), with one sample having a very high value (573°C); all of these values are considered invalid for thermal maturity assessment. In the absence of reliable T_{max} data and no available organic petrology data thermal maturity

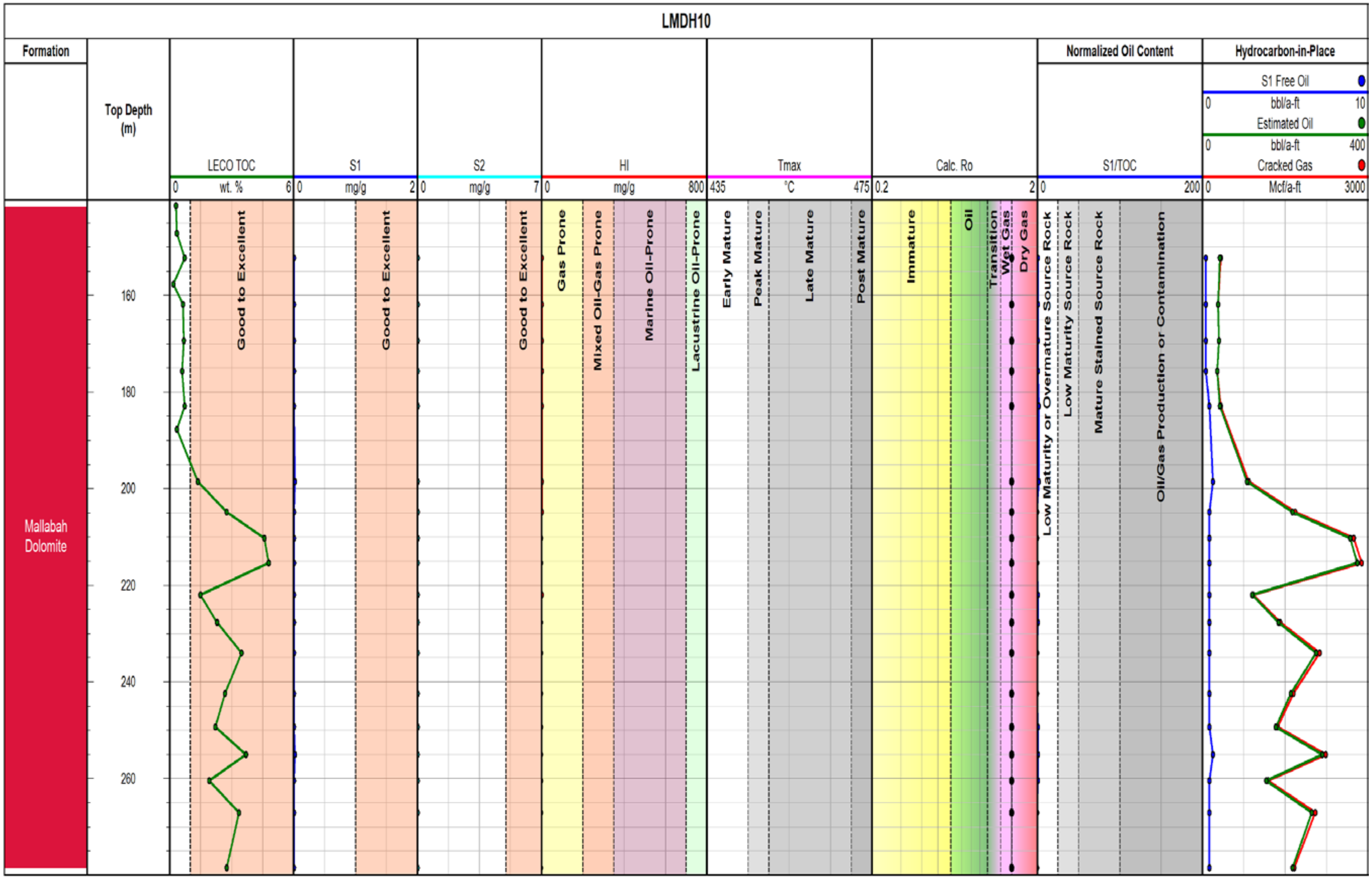

Figure 1. Geochemical depth plots for the LMDH10 well. Note Tmax values plot off scale on depth plot beyond post-mature field.

assessment was very constrained. Comparison with adjacent well data suggests a similarity in the maturity between the LMDH8 well and this well. Thus, the select T_{max} values that average 476°C were applied to the samples in the LMDH10 well. T_{max} between 450 and 470°C typically indicate condensate/wet gas window, while values > 470°C are considered post-mature with regard to the oil window (Type II kerogen). On the basis of these guidelines, the Mallabah Dolostone T_{max} values in this well would be interpreted to be post-mature and likely in the late condensate/wet gas to 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 476°C is equivalent to a Calc. %R_o value of 1.40%. 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 post-mature samples where S2 yields are very low.

The Production Index (PI) values in the Mallabah Dolostone samples average 0.49. This elevated PI value is considered unreliable for assessment purposes due to very low S1 and S2 yields which can cause this ration to be erratic and inaccurate.

The thermal maturity of the Mallabah Dolostone 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). Two samples from the Mallabah Dolostone (avg. 36% clays) have an average measured Kübler Index of 0.190, 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 Palaeoproterozoic aged source rocks.

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 Mallabah Dolostone 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 sedimentological information regarding this formation. Stromatolites are common throughout the succession, which was deposited in low- to medium-energy, shallow- to deep-marine conditions (Munson, 2014).

Formation	%Type I 750 HI_o	%Type II 450 HI_o	%Type III 125 HI_o	%Type IV 50 HI_o	HI_o
Mallabah Dolostone	31	69	0	0	543

Table 2. Average Kerogen Estimations for LMDH10 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):

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

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 543 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 1.00 (Table 3), i.e., on average an estimated 100% 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):

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

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 estimated original TOC_o for the Mallabah Dolostone source rock samples in this well before petroleum generation average 3.23 wt.% (Table 3).

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

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

For the Mallabah Dolostone source rocks examined in the LMDH10 well, the average $S2_o$ values are 18.4 mg HC/g rock or approximately 402 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 Mallabah Dolostone samples analyzed in the current study, the generated cracked gas yields average 1356 Mcf/acre-ft along with 176 bbl/acre-ft of residual oil based upon an estimated 56% oil cracking (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
Mallabah Dolostone	2.28	1	0	543	1.00	3.23	402	0	176	1356

Table 3. Hydrocarbon Yields average data for LMDH10 well.

The Mallabah Dolostone source rock interval in the LMDH10 well is interpreted to be in the late condensate/wet gas window and hydrocarbon yield calculations suggest significant amounts of generation have occurred (predominantly cracked gas with significant residual oil/condensate). From an exploration risk perspective, this is 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 Mallabah Dolostone, original generation potential ($S2_o$) averages 402 bbl oil/acre-ft, this is above several of the other formations on the list of unconventional US Shale plays shown below, including the Utica Shale, Fayetteville Shale, Eagle Ford Shale and Haynesville Shale.

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
Mallabah Dolostone	543	1.00	3.23	18.38	0	402	0.56	0	176	1356

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

UNCONVENTIONAL OIL & GAS RISK ASSESSMENT

The Palaeoproterozoic Mallabah Dolostone Formation source rocks in the LMDH10 well have been evaluated for unconventional oil and gas potential. These source rock samples are presented in a modified geochemical risk assessment diagram (Fig. 2) based upon published results from the Barnett Shale in the Fort Worth Basin. The data illustrated in the star plot represents average values for two of the four of the diagnostic ratios (T_{max} data unreliable; measured R_o data unavailable). 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.

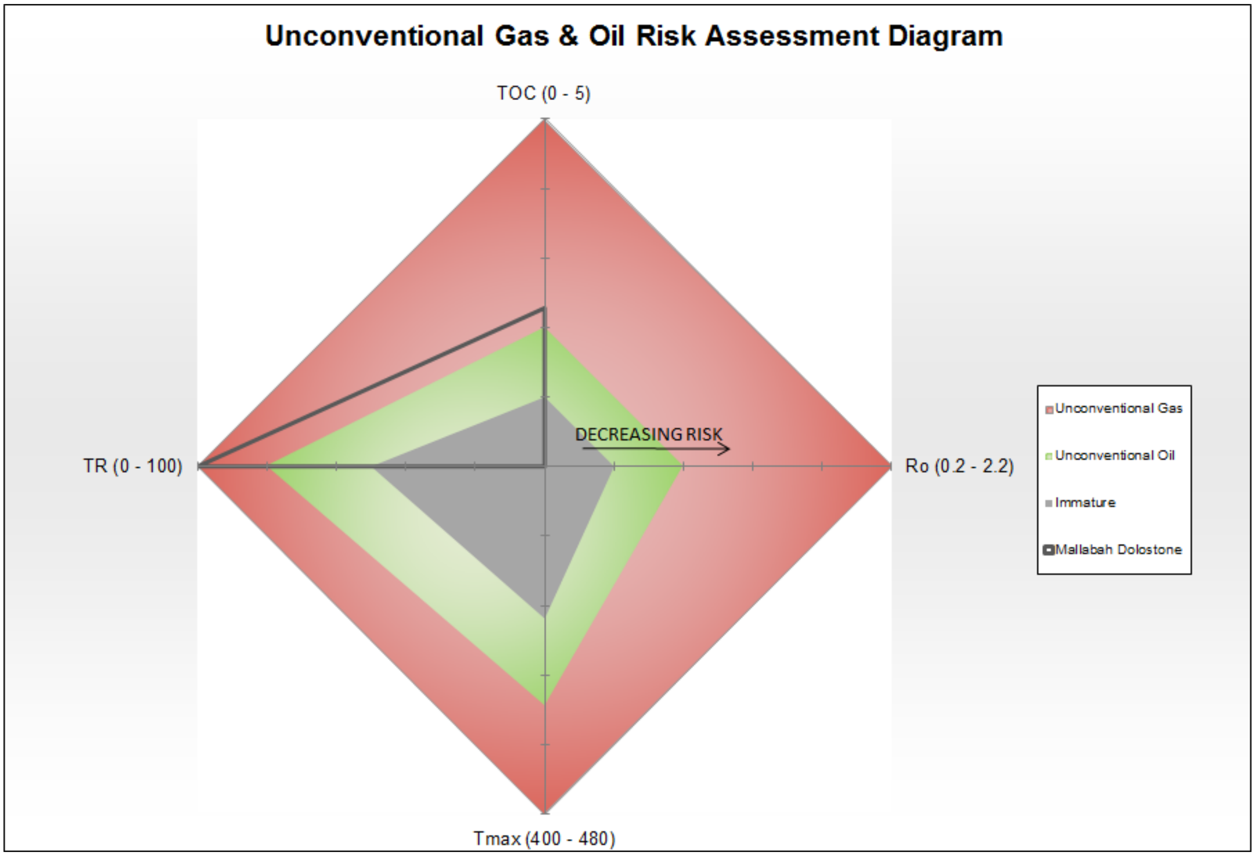

Figure 2. Geochemical Risk Assessment diagram for Palaeoproterozoic Mallabah Dolostone source rocks in the LMDH10 well.

The Mallabah Dolostone source rock interval in the LMDH10 well is interpreted to represent a moderate geochemical risk for in-situ shale gas production. The average measured TOC content of 2.28 wt.% is just above the generally accepted minimum value of 1% TOC to be considered an *effective* source rock for hydrocarbon generation/expulsion (Fig. 2). It is also above 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 I/II marine algal kerogen. Thermal maturity parameters from select programmed pyrolysis data tentatively place the Mallabah Dolostone source interval in late condensate/wet gas window. The average Tmax value of 476°C used for maturity assessment is based on two select data points from an adjacent well (LMDH8). While this value is somewhat speculative, it is the only maturity data available and is well above recommended minimum value of 435°C for shale oil and also above the minimum of 455°C for shale gas (Fig. 2). This amount of conversion would likely be sufficient to generate/expel significant amounts of hydrocarbons from this organic rich, oil prone source facies. Transformation Ratios (TR), the least constrained risk parameter, average 100% and are well above the recommended minimum of 50% for shale oil and the 80% threshold for shale gas systems (Fig. 2).

In the Mallabah Dolostone source interval, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is non-existent (avg. 0 bbl oil/acre-ft), which is a potential concern regarding risk assessment for unconventional gas given that maturity estimates would place this interval within the wet gas/condensate window and we would expect to find some residual hydrocarbons present (Fig. 3). Hydrocarbon yield calculations on the as-received sample shows estimates of average generated oil from the Mallabah Dolostone at 176 bbl oil/acre-ft. and oil cracking is estimated to have been 56%, resulting in a cracked gas yield of 1356 Mcf/acre-ft (Fig. 3). 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. Also, 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.3). Both the oil and gas generated yields for the Barnett Shale are somewhat higher compared to the Mallabah Dolostone in this well and this is due primarily to differences in organic richness (Barnett Shale oil example has average of 4.70 wt. % TOC).

While the generated oil and gas yields of the Mallabah Dolostone are slightly lower compared to the Barnett, the in-situ oil saturation in the LMDH10 well is non-existent and this is the reason the Mallabah Dolostone is considered a moderate risk for commercial shale development. Further investigation is needed to assess the reasons why measured in-situ hydrocarbon saturation is so low within the Mallabah Dolostone interval. It is possible that thermal maturity is much higher (dry gas window) and organic petrology would help to constrain the maturity assessment. It is also likely that any in-situ hydrocarbon saturation (both oil and gas) has migrated out of this source facies as a consequence of uplift/erosion within the basin, since the depth of this sampled interval in the LMDH10 well is only ~152−279 m deep.

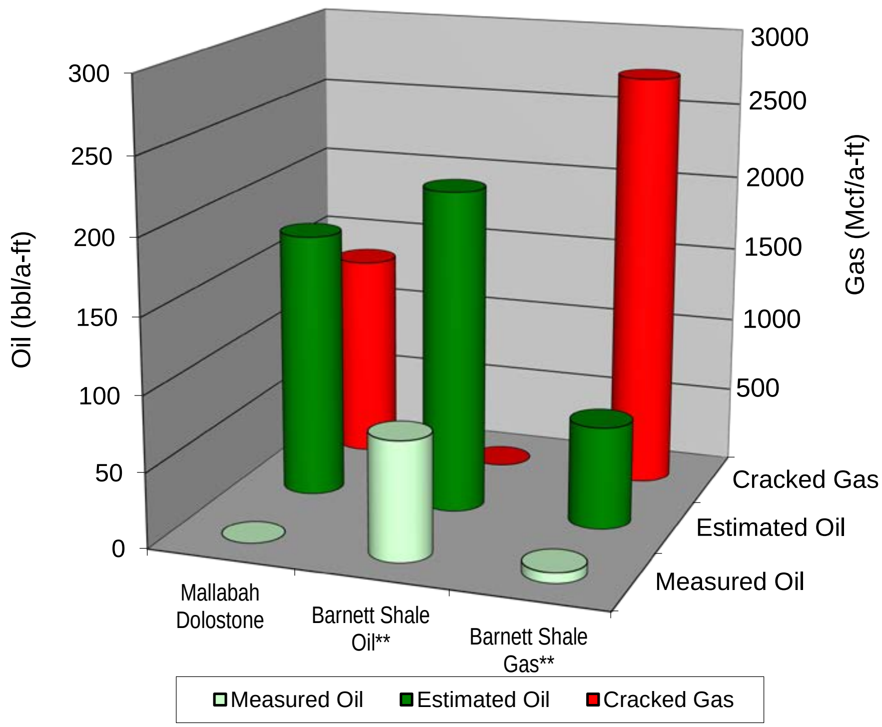

Figure 3. Hydrocarbon yield estimates for the Palaeoproterozoic source rocks in the LMDH10 well compared to Barnett Shale in the oil and gas window.

GEOCHEMICAL SUMMARY

The Mallabah Dolostone source interval in the LMDH10 well is interpreted to represent moderate geochemical risk for unconventional shale gas development. It clearly has elevated organic richness (avg. 2.28 wt.% TOC) and is considered an very good source rock with dominantly oil-prone Type I/II kerogen. Thermal maturity parameters are limited, but select T_{max} data from an adjacent well (LMDH8) may be reliable and these indicate that this source interval is in the late wet/gas condensate window, 1.40% Calc. R_o with a Transformation Ratio of 100%. Although all key risk ratios are above recommended minimum thresholds for shale gas systems, the measured in-situ oil saturations are non-existent (avg. 0 bbl oil/acre-ft) despite the fact that an estimated 176 bbl/acre-ft of residual uncracked oil is estimated from hydrocarbon yield calculations. This is in addition to the 1356 Mcf/acre-ft of secondary cracked gas. Thus, it appears likely that most of this generated oil/condensate and gas has been expelled from the source rock interval and this is the reason for a moderate risk assessment of the Mallabah Dolostone interval in this well. Further evaluation of thermal maturity via organic petrology would greatly assist this interpretation.

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.

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.

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.

Munson, T. J., 2014, Petroleum geology and potential of the onshore Northern Territory, 2014. Northern Territory Geological Survey, Report 22 03/2014.

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.

Appendix I

Hydrocarbon Yield Calculation
Limbunya Group
LMDH10

McArthur Basin Integrated Petroleum Geochemistry, 2016

Northern Territory Geological Survey - Australia

Weatherford LABORATORIES

LMDH10

Hydrocarbon Yield Calculation

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°	S2 (meas) Remaining Potential	S2 (orig) Original Potential	Oil Cracked	S1 Free Oil	Estimated Oil	Cracked Gas
LMDH10	(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
LB14DJR042	152	0.74	3	0.01	0.02	1.40	0.33	0	0	100	0	450	1.00	1.01	4.56	0	100	0.56	0	44	335
LB14DJR044	162	0.66	3	0.01	0.02	1.40	0.33	0	0	100	0	450	1.00	0.90	4.06	0	89	0.56	0	39	298
LB14DJR045	170	0.69	3	0.01	0.02	1.40	0.33	0	0	100	0	450	1.00	0.95	4.27	0	94	0.56	0	41	314
LB14DJR046	176	0.61	3	0.01	0.02	1.40	0.33	0	0	100	0	450	1.00	0.83	3.75	0	82	0.56	0	36	275
LB14DJR047	183	0.75	4	0.02	0.03	1.40	0.40	0	0	100	0	450	0.99	1.03	4.61	1	101	0.56	0	44	338
LB14DJR049	199	1.37	2	0.03	0.03	1.40	0.50	0	0	57	43	579	1.00	1.98	11.44	1	250	0.56	1	109	842
LB14DJR050	205	2.77	1	0.02	0.03	1.40	0.40	0	0	57	43	579	1.00	3.95	22.86	1	501	0.56	0	219	1686
LB14DJR051	210	4.59	0	0.02	0.02	1.40	0.50	0	0	57	43	579	1.00	6.45	37.34	0	818	0.56	0	358	2756
LB14DJR052	215	4.82	0	0.02	0.02	1.40	0.50	0	0	57	43	579	1.00	6.76	39.14	0	857	0.56	0	375	2889
LB14DJR053	222	1.51	1	0.02	0.02	1.40	0.50	0	0	57	43	579	1.00	2.17	12.59	0	276	0.56	0	121	928
LB14DJR054	228	2.32	1	0.02	0.02	1.40	0.50	0	0	57	43	579	1.00	3.32	19.22	0	421	0.56	0	184	1418
LB14DJR055	234	3.52	1	0.02	0.02	1.40	0.50	0	0	57	43	579	1.00	4.99	28.88	0	633	0.56	0	277	2132
LB14DJR056	243	2.71	0	0.02	0.01	1.40	0.67	0	0	57	43	579	1.00	3.87	22.39	0	490	0.56	0	215	1652
LB14DJR057	250	2.25	0	0.02	0.01	1.40	0.67	0	0	57	43	579	1.00	3.22	18.65	0	409	0.56	0	179	1377
LB14DJR058	255	3.70	0	0.03	0.01	1.40	0.75	0	0	57	43	579	1.00	5.24	30.32	0	664	0.56	1	291	2238
LB14DJR059	261	1.94	1	0.02	0.01	1.40	0.67	0	0	57	43	579	1.00	2.78	16.13	0	353	0.56	0	155	1190
LB14DJR060	267	3.38	1	0.02	0.02	1.40	0.50	0	0	57	43	579	1.00	4.80	27.77	0	608	0.56	0	266	2049
LB14DJR061	279	2.76	1	0.02	0.02	1.40	0.50	0	0	57	43	579	1.00	3.94	22.79	0	499	0.56	0	218	1681
Mallabah Dolomite (Avg)		**2.28**	**1**	**0.02**	**0.02**	**1.40**	**0.49**	**0**	**0**	**69**	**31**	**543**	**1.00**	**3.23**	**18.38**	**0**	**402**	**0.56**	**0**	**176**	**1356**
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