



## **LMDH1 Interpretive Summary**

### **Mallabah Dolostone Interval**

*As a part of:*

Northern Territory Geological Survey - Australia  
McArthur Basin Integrated Petroleum Geochemistry, 2016

*Submitted to:*

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Study Project No. AB-74329

June 29, 2016

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## PETROLEUM GEOCHEMISTRY

### INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Mallabah Dolostone in the LMDH1 well located in the Birrindudu Basin, Northern Territories, Australia. Five (5) 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
LMDH1	Mallabah Dolostone	<b>Estimated Original</b> →		Good (1.91% TOC)	Oil-prone Type I/II	Moderate
		<b>Measured Currently</b> →	Oil	Peak Oil Window	Gas-prone Type III	

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

Five (5) samples from the Mallabah Dolostone Formation were analyzed for LECO TOC content and programmed pyrolysis (Fig. 1). TOC contents ranged from 0.65 to 2.34 wt.% and averaged 1.51 wt.% (good). Four (4) of these samples have TOC content above the minimum requirement of 1 wt.% for *effective* petroleum source rocks, while only one (1) sample has TOC content above the minimum requirement of 2 wt.% for *economic* petroleum source rocks. Highest TOC content was found near the top of the designated Mallabah Dolostone interval (125.95 m depth) (Fig. 1), although TOC is also elevated in the lowermost sample as well and the middle section appears to have lower organic richness based upon the relatively sparse sampling available (Fig. 1).

The S1 values of the Mallabah Dolostone source rock samples average 0.21 mg HC/g rock (5 bbl oil/acre-ft) and the S2 values average 3.26 mg HC/g rock (71 bbl oil/acre-ft). The S1 and S2 values imply poor in-situ hydrocarbon saturation and fair remaining generative potential (Fig. 1). The normalized oil contents (NOC) in the Mallabah Dolostone samples,  $(S1/TOC) \times 100$ , average 14 (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. 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).

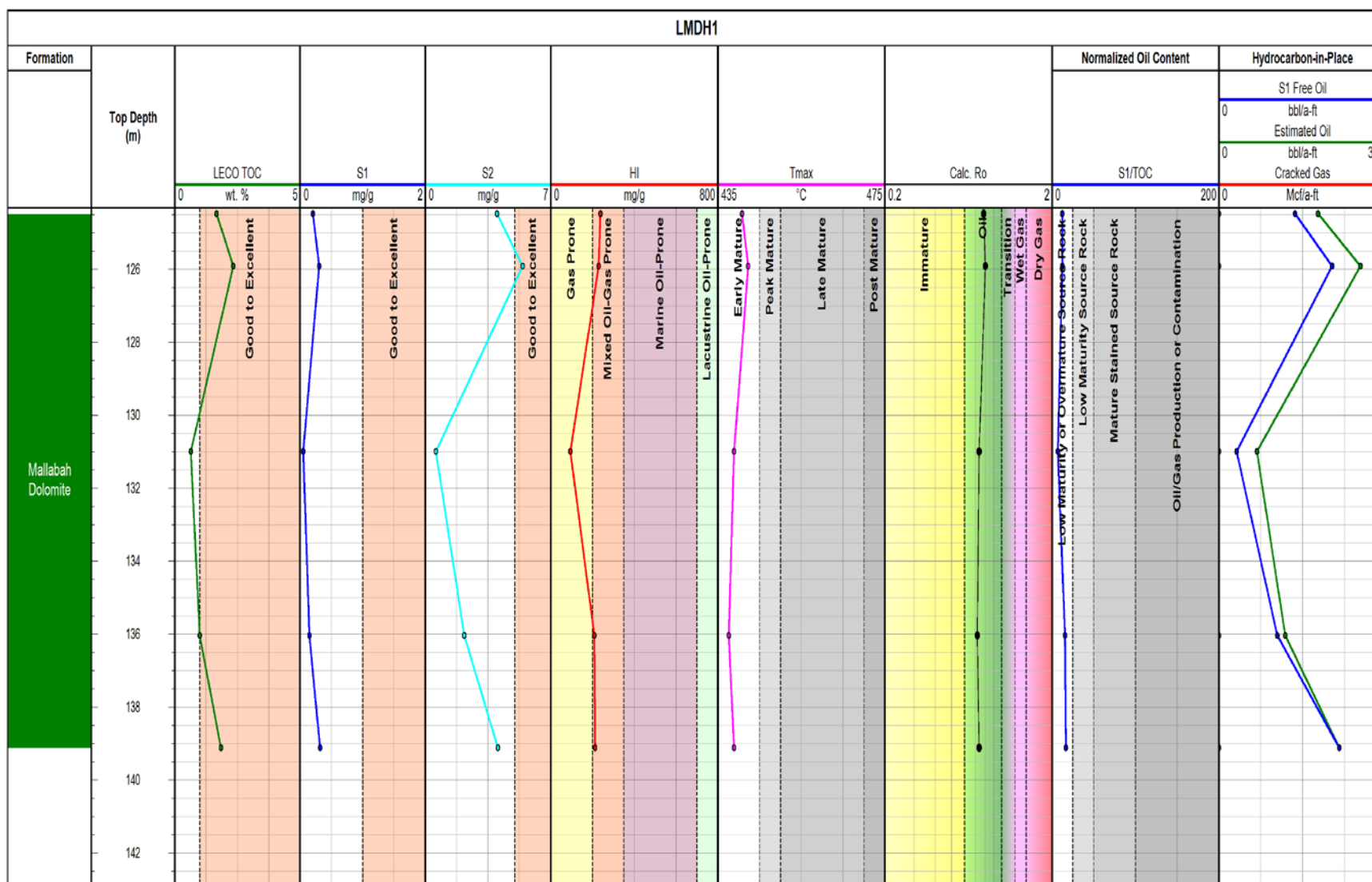


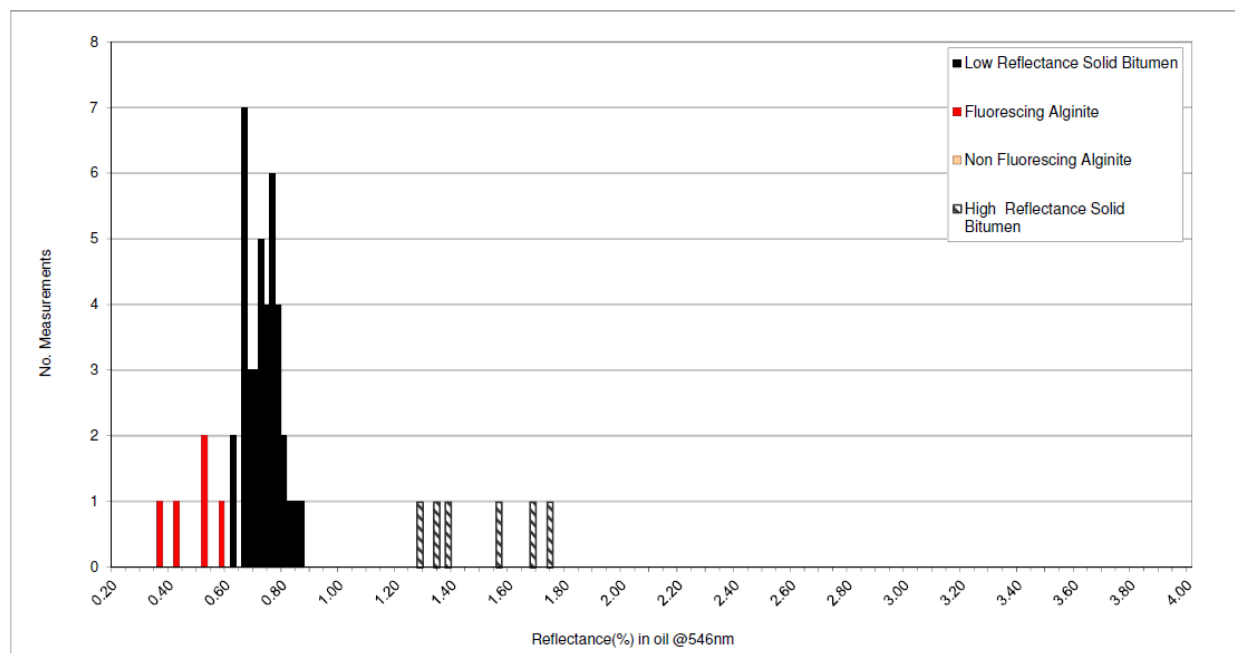
Figure 1. Geochemical depth plots for the LMDH1 well.

The measured Hydrogen Index (HI) values in the Mallabah Dolostone average 199 mg HC/g TOC, indicating gas-prone Type III kerogen quality in these source rocks at present day. Original  $HI_o$  of these samples are estimated to average 556 mg HC/g rock, which indicate oil-prone Type I/II kerogen. Transformation Ratios (TR) based upon HI are 77%, which suggest a peak oil window thermal maturity. The  $T_{max}$  values in the Mallabah Dolostone samples average is 440°C.  $T_{max}$  between 435 and 445°C typically indicate peak oil window, while samples in the late oil window usually have values between 445 and 450°C (Type II kerogen). On the basis of these guidelines, the average Mallabah Dolostone  $T_{max}$  values in this well would be interpreted to be in the peak 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 measured  $T_{max}$  value of 440°C is equivalent to a Calc. % $R_o$  value of 0.76%. 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) values in the Mallabah Dolostone samples average 0.06. These low PI values would normally indicate immature source rocks, which typically have PI values < 0.1. Alternatively, the low PI values in these Mallabah Dolostone samples are a consequence of low S1 yields and could suggest significant expulsion/migration of hydrocarbons out of these potential source rocks.

Organic petrology was performed on one sample from the Mallabah Dolostone interval (125.95-126.0 m). The results from this analysis show a distribution that consists of macerals identified as either fluorescing alginite, low reflectance solid bitumen or high reflectance solid bitumens (Fig. 2). The fluorescing alginite population has a mean reflectance of 0.47%  $R_o$  and exhibit dull orange to light brown fluorescence colors suggesting peak oil window thermal maturity (~0.72 to 1.00%  $R_o$ ). The low reflectance solid bitumen population has reflectance values that average 0.72%  $R_o$  and are considered the most representative indigenous kerogen population for thermal maturity assessment. The high reflecting solid bitumen population has reflectance values that average 1.49%  $R_o$ . The solid bitumens are 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 Mallabah Dolostone source rocks. 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.  $R_o = (\text{Bitumen } R_o + 0.41)/1.09$ ) was applied to the low reflectance bitumen population and resulted in a 1.04% Eq.  $R_o$ . The conversion formula published by Jacob (1985) equation (Eq.  $R_o = (\text{Bitumen } R_o \times 0.618) + 0.4$ ) for 'angular-like' pyrobitumen trapped in mineral pore spaces was applied to the high reflecting population and resulted in a 1.32% Eq.  $R_o$ . The Landis and Castaño (1995) conversion suggest a late oil window thermal maturity, which is slightly higher than predicted by  $T_{max}$ . The Jacob (1985) conversion suggests an even higher thermal maturity that is within the early condensate/wet gas window. 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. In this well that does not appear to be valid since the calculated 1.32% Eq.  $R_o$  value and the measured 0.72%  $R_o$  values would suggest the Mallabah Dolostone samples in this well are within the early wet gas/condensate and peak oil windows respectively.

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). A single sample (139.13 m) from the Mallabah Dolostone (avg. 37% clays) has a measured Kübler Index of 0.228, 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.



**Figure 2. Organic petrology of the Mallabah Dolostone (125.95 m) in the LMDH1 well. Mean maceral reflectance of low reflecting solid bitumen is 0.72%  $R_o$ . The high reflecting solid bitumen has mean reflectance of 1.49%  $R_o$ , which equates to calculated Eq.  $R_o$  of 1.22%  $R_o$  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 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. For the LMDH1 well, a sample from 125.95 m depth was examined and the measured kerogen maceral distributions show 44% Type I and 56% Type II kerogen (dominantly lamalginite with subordinate amounts of lens/layer AOM and inert AOM). 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 <sub>o</sub>	%Type II 450 HI <sub>o</sub>	%Type III 125 HI <sub>o</sub>	%Type IV 50 HI <sub>o</sub>	HI <sub>o</sub>
Mallabah Dolostone	35	65	0	0	556

**Table 2. Average Kerogen Estimations for LMDH1 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):

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

HI<sub>pd</sub> and PI<sub>pd</sub> are the measured HI and PI values for the various source rock samples in this well. The average HI<sub>pd</sub> and PI<sub>pd</sub> for the formations evaluated in the current study are shown in Table 3. HI<sub>o</sub> and PI<sub>o</sub> 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<sub>o</sub> values of 588 mg HC/g TOC (Table 2). We assume a PI<sub>o</sub> of 0.02 (see Peters et al., 2005). Using these values in equation 2, the extent of fractional conversion of HI<sub>o</sub> to petroleum is 0.77 (Table 3), i.e., on average an estimated 77% of the petroleum generation process has been completed.

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

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

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<sub>R</sub> 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<sub>HI</sub> × C<sub>R</sub>. The kerogen mix for each individual sample was used in this calculation.

Using equation 3, the estimated original TOC<sub>o</sub> for the Mallabah Dolostone source rock samples in this well before petroleum generation average 1.91 wt.% (Table 3).

The original generation potential S2<sub>o</sub> can be calculated using the following equation:

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

For the Mallabah Dolostone source rocks examined in the LMDH1 well, the average S2<sub>o</sub> values are 10.9 mg HC/g rock or approximately 239 bbl/acre-ft (multiply S2<sub>o</sub> 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<sub>o</sub> 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 estimated generated oil yields average 168 bbl/acre-ft (Table 3).

Formation	TOC <sub>pd</sub>	HI <sub>pd</sub>	S2 <sub>pd</sub> bbl/a-ft	HI <sub>o</sub>	TR	TOC <sub>o</sub>	S2 <sub>o</sub> bbl/a-ft	S1 Free Oil bbl/a-ft	Est. Oil bbl/a-ft	Cracked Gas Mcf/a-ft
Mallabah Dolostone	1.51	199	71	556	0.77	1.91	239	5	168	0

**Table 3. Hydrocarbon Yields average data for LMDH1 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 Mallabah Dolostone interval is 97%, which is more consistent with a source rock in the late oil to early wet gas/condensate window.

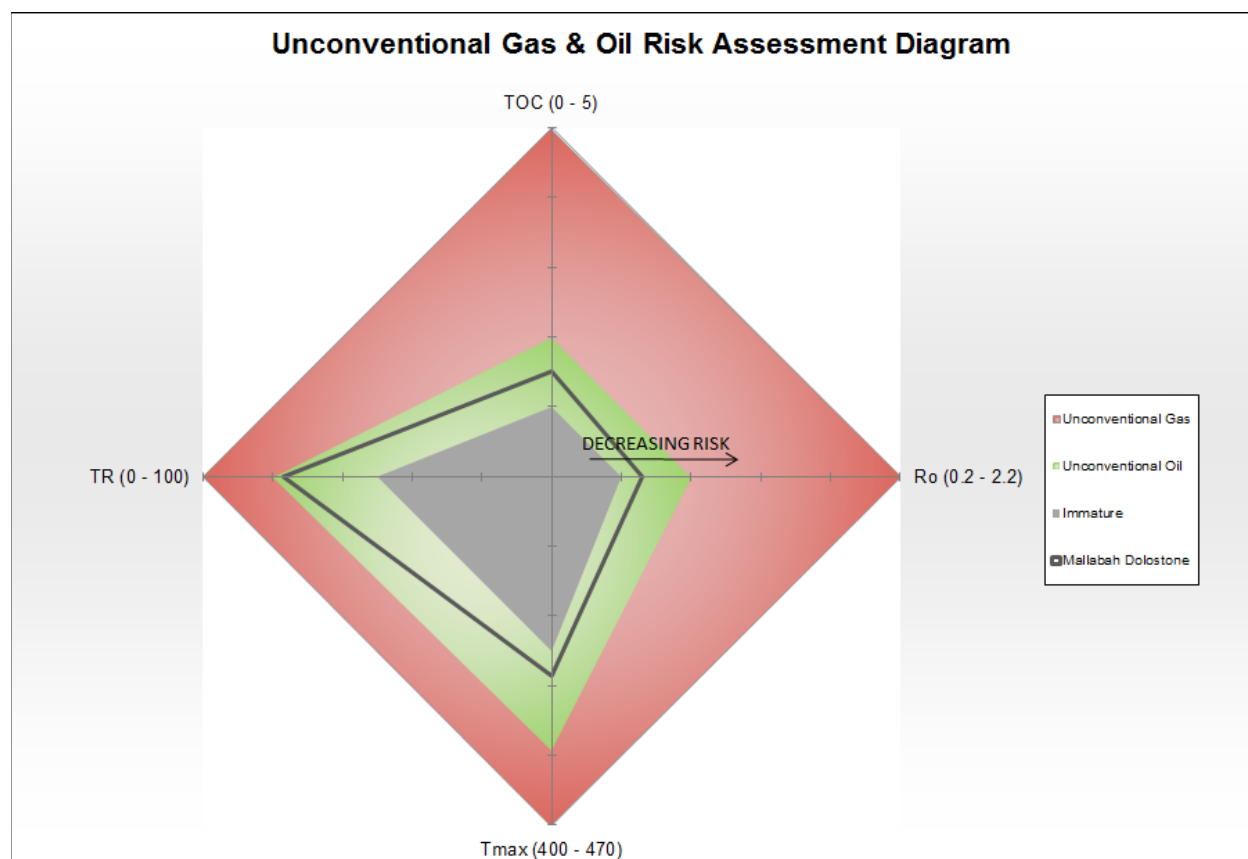
The Mallabah Dolostone source rock interval in the LMDH1 well is interpreted to be in the peak oil window and hydrocarbon yield calculations suggest significant amounts of generation have occurred (predominantly oil with some associated gas). From an exploration risk perspective, this is generally favorable. 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<sub>o</sub>) 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<sub>o</sub>) averages 239 bbl oil/acre-ft, this is below all of the other formations on the list of unconventional US Shale plays shown below.

Sample Database Averages TOC >1%	HI <sup>o</sup> mg/g TOC	TR	TOC <sup>o</sup> wt%	S2 <sup>o</sup> 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	556	0.77	1.91	10.92	71	239	0.00	5	168	0

**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 LMDH1 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 of the 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.



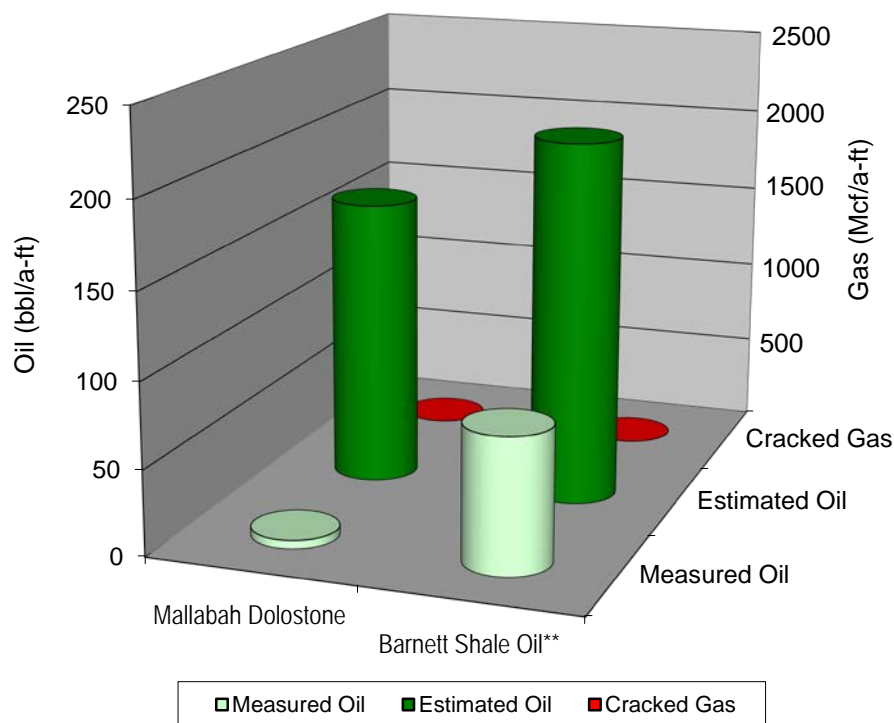
**Figure 3. Geochemical Risk Assessment diagram for Palaeoproterozoic Mallabah Dolostone source rocks in the LMDH1 well.**

The Mallabah Dolostone source rock interval in the LMDH1 well is interpreted to represent a moderate geochemical risk for in-situ shale oil production. The average measured TOC content of 1.51 wt.% is above the generally accepted minimum value of 1% TOC to be considered an *effective* source rock for hydrocarbon generation/expulsion (Fig. 3). However, it is 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 I/II marine algal kerogen based upon select measured visual kerogen analysis. Thermal maturity parameters from programmed pyrolysis place the Mallabah Dolostone source interval in peak oil window. The average Tmax value of 440°C is above recommended minimum value of 435°C for shale oil and well below the minimum of 455°C for shale gas (Fig. 3). 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 77% and fall above the recommended minimum of 50% for shale oil and just below the 80% threshold for shale gas systems (Fig. 3). Measured maceral reflectance values in the Mallabah Dolostone give a mean for low reflectance solid bitumen of 0.72%  $R_o$ , which is above the recommended minimum threshold of 0.5%  $R_o$  for shale oil and below the minimum of 1.0%  $R_o$  for shale gas (Fig. 3).

In the Mallabah Dolostone source interval, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is poor (avg. 5 bbl oil/acre-ft), which is a 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 Mallabah Dolostone at 168 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 (Fig.4). These values are higher compared to the Mallabah Dolostone and are primarily due to differences in organic richness (Barnett Shale oil example has average of 4.70 wt. % TOC). While the generated oil yield of the Mallabah Dolostone is slightly lower compared to the Barnett, the in-situ oil saturation is significantly lower and this is the reason the Mallabah Dolostone is considered a moderate risk for commercial shale oil 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 likely that any in-situ oil saturation has migrated out of this source facies (est. 97% expulsion) as a consequence of uplift/erosion within the basin, since the depth of this sampled interval in the LMDH1 well is only ~125–139 m deep.

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 Mallabah Dolostone source interval in this well is in the peak oil window and hydrocarbon saturation is likely to be fairly light and mobile. However, the presence of solid 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 Mallabah Dolostone 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 Palaeoproterozoic source rocks in the LMDH1 well compared to Barnett Shale in the oil window.**

### GEOCHEMICAL SUMMARY

The Mallabah Dolostone source interval in the LMDH1 well is interpreted to represent moderate geochemical risk for unconventional shale oil development. It clearly has elevated organic richness (avg. 1.51 wt.% TOC) and is considered a good source rock with dominantly oil-prone Type I/II kerogen. Thermal maturity parameters indicate that this source interval is in the peak oil window, 0.76% Calc.  $R_o$  and 0.72% measured  $R_o$  with a Transformation Ratio of 77%. Although all key risk ratios are above recommended minimum thresholds for shale oil systems, the measured in-situ oil saturations are low (avg. 5 bbl oil/acre-ft). The Mallabah Dolostone has likely generated moderate to high amounts of oil (168 bbl/acre-ft), but it appears likely that most of this oil has been expelled from the source rock interval. Risk criteria like the S1 versus TOC show no oil cross-over for any of the samples in this interval confirming the elevated risk assessment. Further evaluation of in-situ oil characteristics would be required to fully evaluate potential oil mobility and recovery risk.

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# Appendix I

*Hydrocarbon Yield Calculation*  
*Limbunya Group*  
*LMDH1*

McArthur Basin Integrated Petroleum Geochemistry, 2016  
Northern Territory Geological Survey - Australia



LMDH1

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
LMDH1	(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
LB14DJR013	125	1.67	240	0.21	4.00	<b>0.78</b>	0.05	0	0	56	44	583	0.73	2.09	12.19	88	267	0.00	5	179	0
LB14DJR014	126	2.34	234	0.31	5.47	<b>0.80</b>	0.05	<b>0</b>	<b>0</b>	<b>56</b>	<b>44</b>	583	0.74	2.93	17.09	120	374	0.00	7	255	0
LB14DJR015	131	0.65	94	0.05	0.61	<b>0.74</b>	0.08	0	0	100	0	450	0.86	0.84	3.77	13	83	0.00	1	69	0
LB14DJR016	136	1.02	213	0.16	2.17	<b>0.72</b>	0.07	0	0	56	44	583	0.77	1.31	7.63	48	167	0.00	4	119	0
LB14DJR017	139	1.87	217	0.33	4.05	<b>0.74</b>	0.08	0	0	56	44	583	0.77	2.38	13.90	89	304	0.00	7	216	0
Mallabah Dolostone (Avg)		1.51	199	0.21	3.26	0.76	0.06	0	0	65	35	556	0.77	1.91	10.92	71	239	0.00	5	168	0
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 balnce 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)