# LMDH8 Interpretive Summary

# Mallabah Dolostone Interval

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# PETROLEUM GEOCHEMISTRY

## INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Mallabah Dolostone in the LMDH8 well located in the Birrindudu Basin, Northern Territories, Australia. Ten (10) 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 |
|---|---|---|---|---|---|---|
| **LMDH8** | Mallabah Dolostone | ***Estimated Original →*** | | *Excellent (7.09% TOC)* | *Oil-prone Type I/II* | **Moderate** |
| ***Measured Currently →*** | | Condensate Wet Gas | Wet Gas Window | Excellent (5.20% 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

Ten (10) samples from the Mallabah Dolostone Formation were analyzed for LECO TOC content and programmed pyrolysis (Fig. 1). TOC contents ranged from 0.48 to 11.30 wt.% and averaged 5.20 wt.% (excellent). Nine (9) of these samples have TOC content above the minimum requirement of 1 wt.% for *effective* petroleum source rocks, while six (6) 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 (185.07 m depth) (Fig. 1) and the upper portion of the sampled interval appears to have generally higher TOC compared to the basal 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 0 (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 566 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) and most samples are considered invalid for thermal maturity assessment. However, two samples in the Mallabah Dolostone do provide more elevated $T_{max}$ values that average 476°C. $T_{max}$ between 450 and 470°C typically indicate

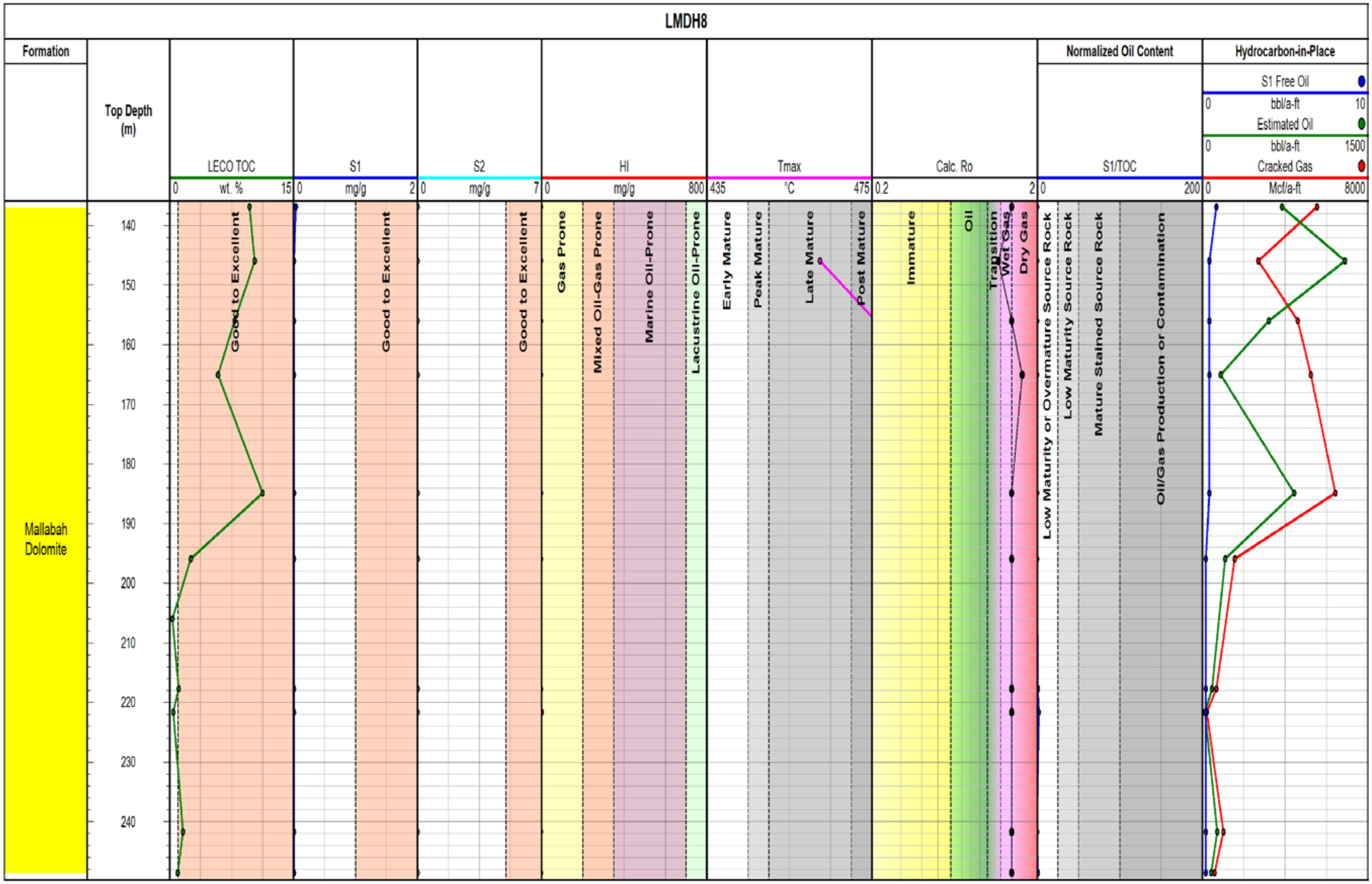


**Figure 1. Geochemical depth plots for the LMDH8 well. Note Tmax values plot off scale on depth plot beyond post-mature field.**

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 0.52. 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). Three samples from the Mallabah Dolostone (avg. 60% clays) have an average measured Kübler Index of 0.134, 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. However, this ratio is relatively low compared to other wells in this study that have intersected the Mallabah Dolostone, supporting a much higher relative thermal maturity in the LMDH8 well.

## 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):

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

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 | 39 | 61 | 0 | 0 | 566 |

**Table 2. Average Kerogen Estimations for LMDH8 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 566 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 7.09 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 LMDH8 well, the average $S2_o$ values are 41.0 mg HC/g rock or approximately 898 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 2881 Mcf/acre-ft along with 417 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 | 5.20 | 1 | 0 | 566 | 1.00 | 7.09 | 898 | 0 | 417 | 2881 |

**Table 3. Hydrocarbon Yields average data for LMDH8 well.**

The Mallabah Dolostone source rock interval in the LMDH8 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 898 bbl oil/acre-ft, this is above all of the other formations on the list of unconventional US Shale plays shown below.

| 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 | 566 | 1.00 | 7.09 | 40.99 | 0 | 898 | 0.56 | 0 | 417 | 2881 |

**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 LMDH8 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 three of the four of the diagnostic ratios (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.

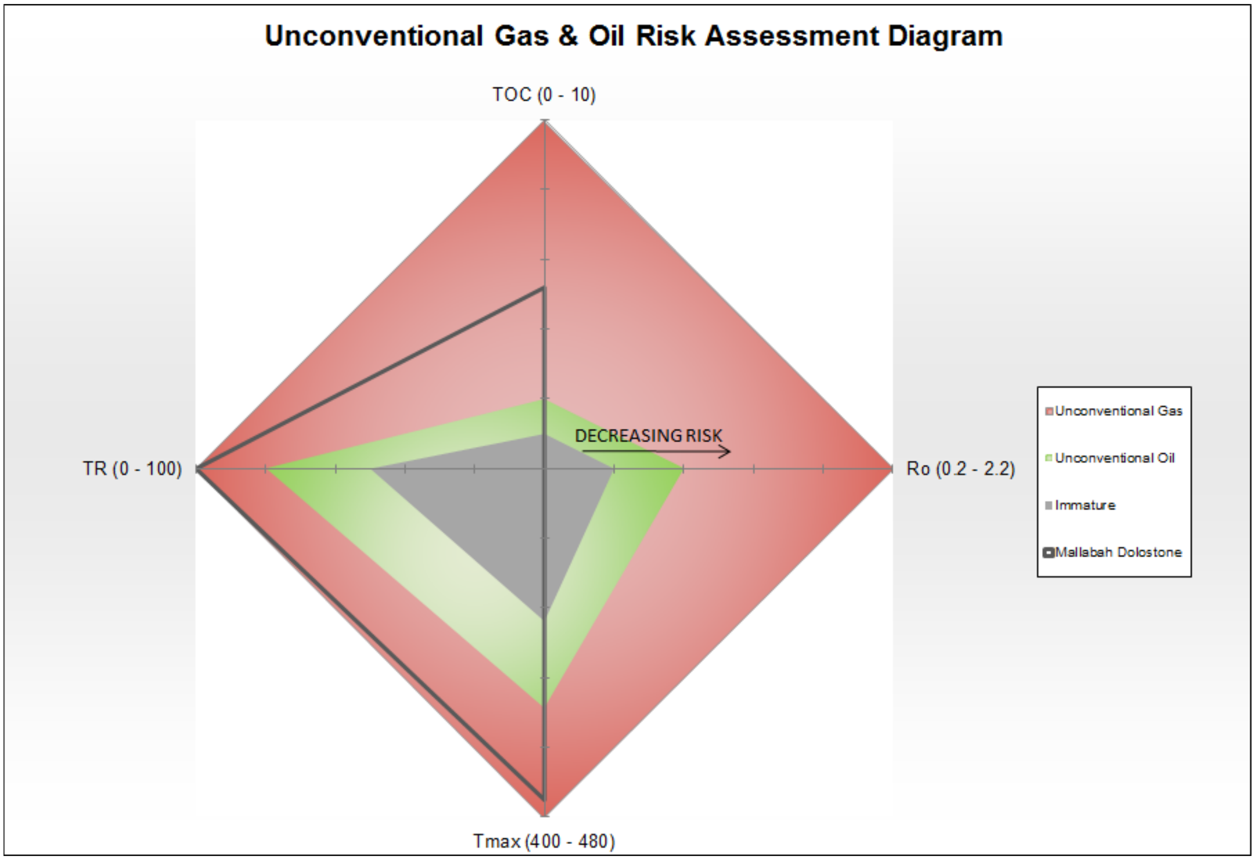


**Figure 2. Geochemical Risk Assessment diagram for Palaeoproterozoic Mallabah Dolostone source rocks in the LMDH8 well.**

The Mallabah Dolostone source rock interval in the LMDH8 well is interpreted to represent a moderate geochemical risk for in-situ shale gas production. The average measured TOC content of 5.20 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 well 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 based on two select data points 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 417 bbl oil/acre-ft. and oil cracking is estimated to have been 56%, resulting in a cracked gas yield of 2881 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 lower compared to the Mallabah Dolostone and are primarily due to differences in $HI_o$ and original generation potential, which are much higher in the Mallabah Dolostone.

While the generated oil and gas yields of the Mallabah Dolostone are much higher compared to the Barnett, the in-situ oil saturation 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 LMDH8 well is only ~137−249 m deep.

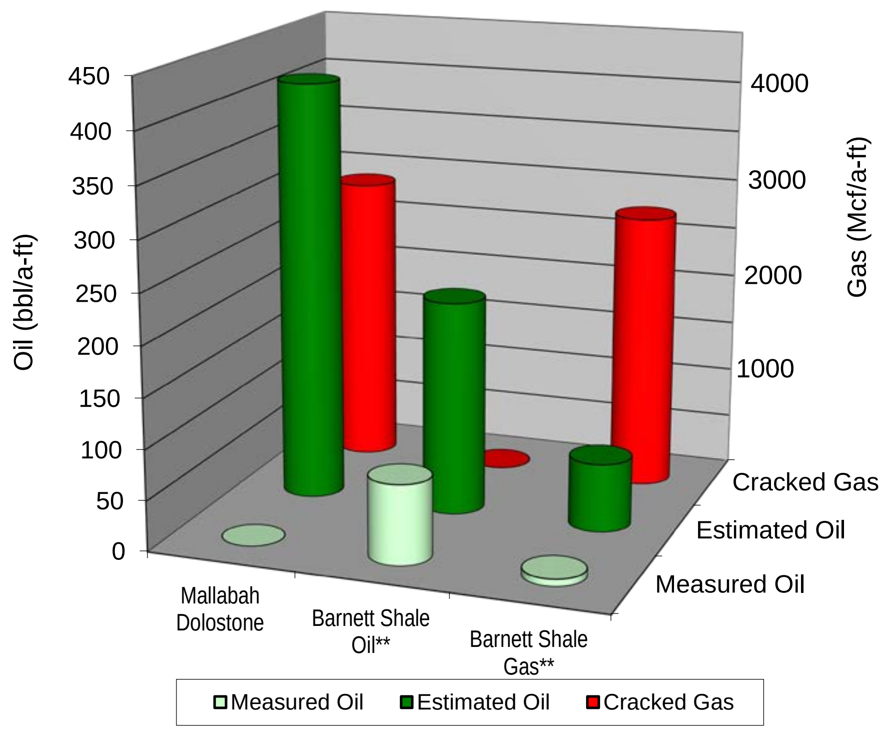


**Figure 3. Hydrocarbon yield estimates for the Palaeoproterozoic source rocks in the LMDH8 well compared to Barnett Shale in the oil and gas window.**

## GEOCHEMICAL SUMMARY

The Mallabah Dolostone source interval in the LMDH8 well is interpreted to represent moderate geochemical risk for unconventional shale gas development. It clearly has elevated organic richness (avg. 5.20 wt.% TOC) and is considered an excellent source rock with dominantly oil-prone Type I/II kerogen. Thermal maturity parameters are limited, but select $T_{max}$ data 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 417 bbl/acre-ft of residual uncracked oil is estimated from hydrocarbon yield calculations. This is in addition to the 2881 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.

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# Appendix I

*Hydrocarbon Yield Calculation*
*Limbunya Group*
*LMDH8*

McArthur Basin Integrated Petroleum Geochemistry, 2016

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**LMDH8**

## 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 |
| LMDH8 | (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 |
| LB14DJR001 | 137 | 9.67 | 0 | 0.04 | 0.03 | 1.40 | 0.57 | 0 | 0 | 57 | 43 | 579 | 1.00 | 13.06 | 75.61 | 1 | 1656 | 0.56 | 1 | 725 | 5582 |
| LB14DJR002 | 146 | 10.30 | 0 | 0.02 | 0.02 | **1.17** | 0.50 | 0 | 0 | 57 | 43 | 579 | 1.00 | 13.84 | 80.15 | 0 | 1755 | 0.26 | 0 | 1301 | 2721 |
| LB14DJR003 | 156 | 7.93 | 0 | 0.02 | 0.02 | 1.40 | 0.50 | 0 | 0 | 57 | 43 | 579 | 1.00 | 10.85 | 62.85 | 0 | 1376 | 0.56 | 0 | 603 | 4640 |
| LB14DJR004 | 165 | 5.92 | 0 | 0.02 | 0.01 | **1.63** | 0.67 | 0 | 0 | 57 | 43 | 579 | 1.00 | 8.23 | 47.66 | 0 | 1044 | 0.84 | 0 | 166 | 5266 |
| LB14DJR005 | 185 | 11.30 | 0 | 0.02 | 0.01 | 1.40 | 0.67 | 0 | 0 | 57 | 43 | 579 | 1.00 | 15.07 | 87.27 | 0 | 1911 | 0.56 | 0 | 837 | 6444 |
| LB14DJR006 | 196 | 2.60 | 1 | 0.01 | 0.02 | 1.40 | 0.33 | 0 | 0 | 57 | 43 | 579 | 1.00 | 3.71 | 21.49 | 0 | 471 | 0.56 | 0 | 206 | 1586 |
| LB14DJR008 | 218 | 1.11 | 1 | 0.01 | 0.01 | 1.40 | 0.50 | 0 | 0 | 57 | 43 | 579 | 1.00 | 1.60 | 9.29 | 0 | 203 | 0.56 | 0 | 89 | 685 |
| LB14DJR009 | 222 | 0.48 | 2 | 0.01 | 0.01 | 1.40 | 0.50 | 0 | 0 | 100 | 0 | 450 | 1.00 | 0.66 | 2.97 | 0 | 65 | 0.56 | 0 | 28 | 219 |
| LB14DJR010 | 242 | 1.70 | 1 | 0.01 | 0.01 | 1.40 | 0.50 | 0 | 0 | 57 | 43 | 579 | 1.00 | 2.45 | 14.16 | 0 | 310 | 0.56 | 0 | 136 | 1045 |
| LB14DJR011 | 249 | 1.01 | 1 | 0.01 | 0.01 | 1.40 | 0.50 | 0 | 0 | 57 | 43 | 579 | 1.00 | 1.46 | 8.46 | 0 | 185 | 0.56 | 0 | 81 | 624 |
| **Mallabah Dolomite (Avg)** | | **5.20** | **1** | **0.02** | **0.02** | **1.40** | **0.52** | **0** | **0** | **61** | **39** | **566** | **1.00** | **7.09** | **40.99** | **0** | **898** | **0.56** | **0** | **417** | **2881** |
| 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)