LMDH9 Interpretive Summary

Amos Knob Interval

As a part of:
Northern Territory Geological Survey - Australia
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PETROLEUM GEOCHEMISTRY

INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Amos Knob Formation in the LMDH9 well located in the Birrindudu Basin, Northern Territories, Australia. Three (3) 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 Oil Risk***
LMDH9	Amos Knob	***Estimated Original →***		*Fair (0.64% TOC)*	*Mixed Type II/IV*	**High**
Measured Currently →		Oil	Peak Oil Window	Poor (0.47% TOC)	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

AMOS KNOB

Three (3) samples from the Amos Knob Formation were analyzed for LECO TOC content and programmed pyrolysis (Fig. 1). TOC contents ranged from 0.28 to 0.56 wt.% and averaged 0.47 wt.% (poor). None of these samples have TOC content above the minimum requirement of 1 wt.% for *effective* petroleum source rocks, nor do they have TOC content above the minimum requirement of 2 wt.% for *economic* petroleum source rocks. Highest TOC content was found in the upper portion of the designated Amos Knob interval (99-105 m depth) based upon the sparse sampling available (Fig. 1).

The S1 values of the Amos Knob source rock samples average 0.06 mg HC/g rock (1 bbl oil/acre-ft) and the S2 values average 0.32 mg HC/g rock (7 bbl oil/acre-ft). The S1 and S2 values imply poor in-situ hydrocarbon saturation and poor remaining generative potential (Fig. 1). The normalized oil contents (NOC) in the Amos Knob samples, (S1/TOC) x 100, average 11 (Fig. 1). NOC values of 20 to 50 are typical of low maturity source rocks, whereas values of 50 to 100 indicate possible oil staining or shows in thermally mature, tight petroleum source rocks. NOC > 100 are often associated with conventional oil reservoirs and indicate good prospectivity in unconventional shale oil plays. Very low NOC values < 20 are most likely related to post-mature source rocks that have likely generated and expelled most of their in-situ hydrocarbon saturation or source rocks with poor original hydrocarbon generation capacity. Jarvie (2012) has utilized a depth comparison of TOC versus programmed pyrolysis S1 yields as a potential indicator of producible hydrocarbon saturation in unconventional source rocks. When the S1 yields (reported as mg HC/g rock) exceed or "cross-over" the measured TOC content (reported as wt.%), this would be interpreted to represent zones with good potential for containing producible hydrocarbon saturation (or zones of possible contamination). In the present study, there is no S1 cross over TOC in any of the Amos Knob samples analyzed in this well (Fig. 1).

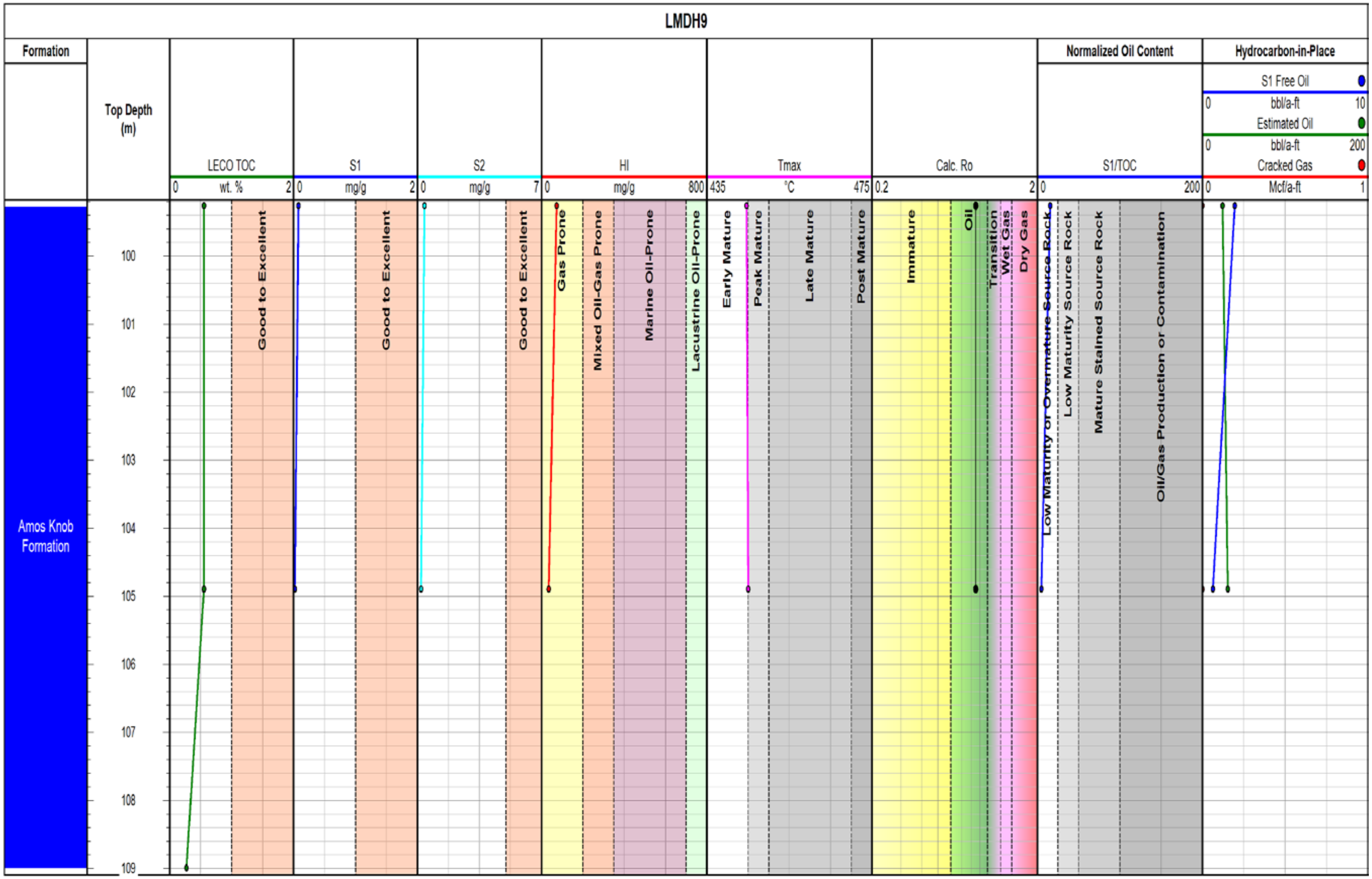

Figure 1. Geochemical depth plots for the LMDH9 well.

The measured Hydrogen Index (HI) values in the Amos Knob average 57 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 250 mg HC/g rock, which indicate mixed oil/gas-prone Type II/IV kerogen. Transformation Ratios (TR) based upon HI are 81%, which suggest a peak to late oil window thermal maturity. The T_{max} values in the Amos Knob samples average is 445°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 Amos Knob 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 445°C is equivalent to a Calc. $\%R_o$ value of 0.85%. 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 Amos Knob samples average 0.15. These moderate PI values are consistent with source rocks in the peak oil window, which typically have PI values in the range of 0.15 to 0.25.

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 Amos Knob 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**
Amos Knob	0	50	0	50	250

Table 2. Average Kerogen Estimations for LMDH9 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 250 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 0.81 (Table 3), i.e., on average an estimated 81% 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 Amos Knob source rock samples in this well before petroleum generation average 0.64 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 Amos Knob source rocks examined in the LMDH9 well, the average $S2_o$ values are 1.6 mg HC/g rock or approximately 35 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 Amos Knob samples analyzed in the current study, the estimated generated oil yields average 28 bbl/acre-ft (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
Amos Knob	0.56	57	7	250	0.81	0.64	35	1	28	0

Table 3. Hydrocarbon Yields average data for LMDH9 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 Amos Knob interval is 95%, which is more consistent with a source rock in the late oil to early wet gas/condensate window.

The Amos Knob source rock interval in the LMDH9 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 ($S2_o$) 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 Amos Knob, original generation potential ($S2_o$) averages only 35 bbl oil/acre-ft, this is far below all 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
Amos Knob	250	0.81	0.64	1.59	7	35	0.00	1	28	0

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

UNCONVENTIONAL OIL & GAS RISK ASSESSMENT

The Palaeoproterozoic Amos Knob Formation source rocks in the LMDH9 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.

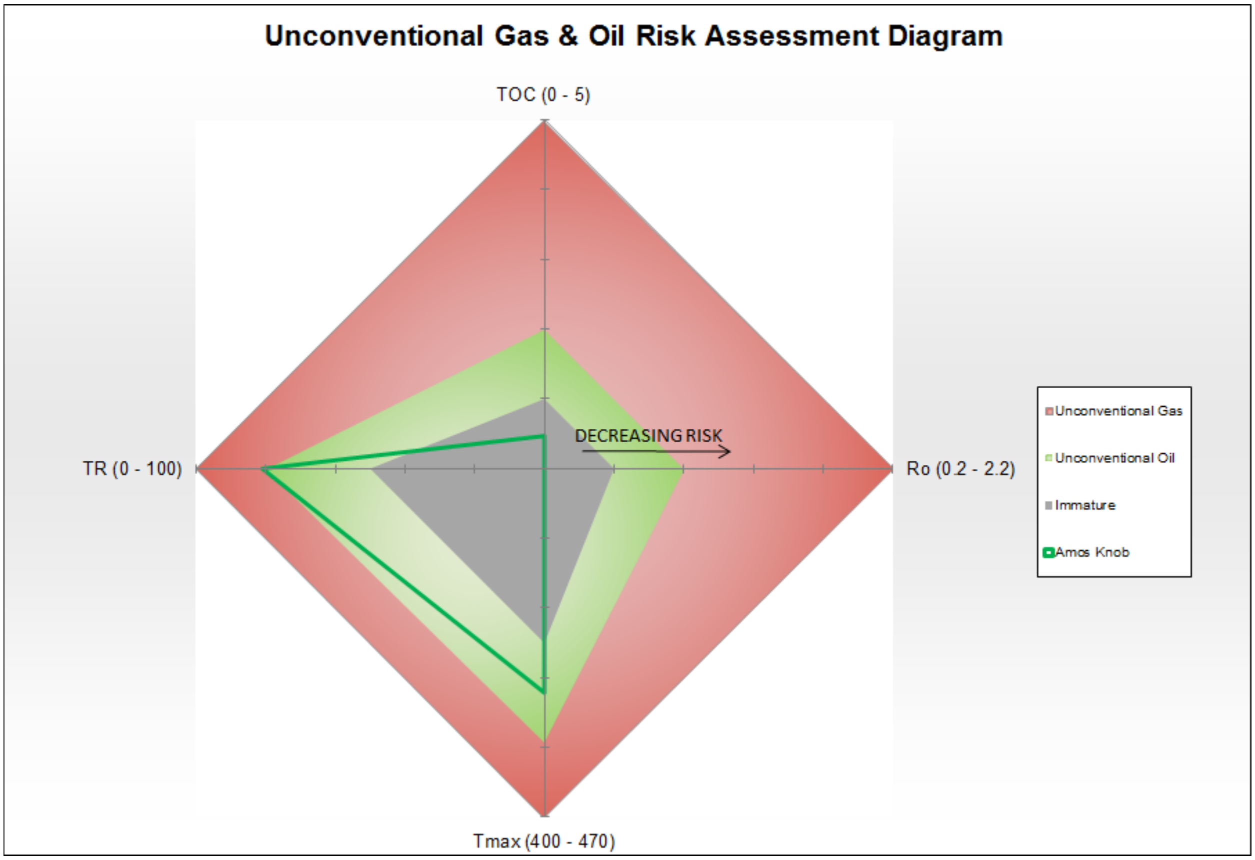

Figure 2. Geochemical Risk Assessment diagram for Palaeoproterozoic Amos Knob source rocks in the LMDH9 well.

The Amos Knob source rock interval in the LMDH9 well is interpreted to represent a high geochemical risk for in-situ shale oil production. The average measured TOC content of 0.47 wt.% is below the generally accepted minimum value of 1% TOC to be considered an *effective* source rock for hydrocarbon generation/expulsion (Fig. 2). It is also far below the minimum requirements of 2 wt.% for *economic* petroleum source rocks, which is also the minimum threshold for prospective shale gas. Original organic matter type is interpreted to be mixed oil/gas-prone Type II/IV kerogen. Thermal maturity parameters from programmed pyrolysis place the Amos Knob source interval in peak oil window. The average Tmax value of 445°C is above recommended minimum value of 435°C for shale oil and well below the minimum of 455°C for shale gas (Fig. 2). This amount of conversion would likely be sufficient to generate/expel minor amounts of hydrocarbons from this organic poor source facies. Transformation Ratios (TR), the least constrained risk parameter, average 81% and fall above the recommended minimum of 50% for shale oil and just above the 80% threshold for shale gas systems (Fig. 2).

In the Amos Knob source interval, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is poor (avg. 1 bbl oil/acre-ft), which is a significant concern regarding risk assessment for unconventional oil (Fig. 3). Hydrocarbon yield calculations on as-received samples show estimates of average generated oil from the Amos Knob at 28 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.3). The generated oil yields and in-situ oil saturations in the Barnett are much higher than the Amos Knob due to differences in both TOC content and original HI_o. Despite low estimated generated oil yields in the Amos Knob, further investigation is needed to assess the reasons why measured in-situ hydrocarbon saturation is so low within this interval. It is likely that any in-situ oil saturation has migrated out of this source facies (est. 95% expulsion) as a consequence of uplift/erosion within the basin, since the depth of this sampled interval in the LMDH9 well is only ~100 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 Amos Knob 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 Amos Knob 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.

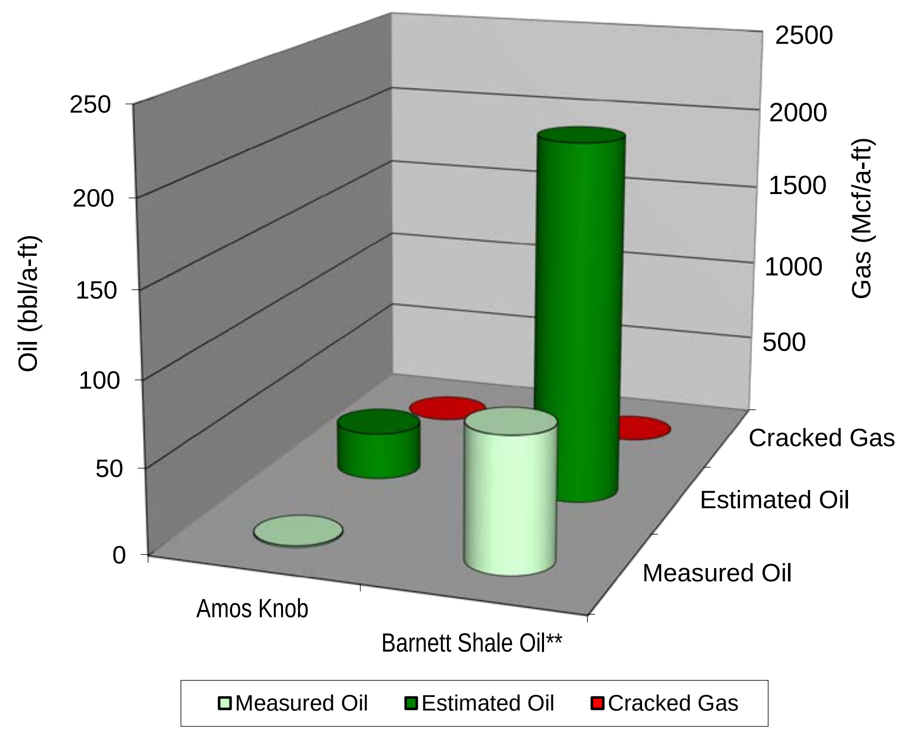

Figure 3. Hydrocarbon yield estimates for the Palaeoproterozoic source rocks in the LMDH9 well compared to Barnett Shale in the oil window.

GEOCHEMICAL SUMMARY

The Amos Knob source interval in the LMDH9 well is interpreted to represent high geochemical risk for unconventional shale oil development. It generally has low organic richness (avg. 0.47 wt.% TOC) and is considered an poor source rock with mixed oil/gas-prone Type II/IV kerogen. Thermal maturity parameters indicate that this source interval is in the peak oil window, 0.85% Calc. R_o with a Transformation Ratio of 81%. The Amos Knob Formation has likely generated minor amounts of oil (28 bbl/acre-ft), but it appears likely that most of this oil has been expelled from the source rock interval as measured in-situ oil saturations are very low (avg. 1 bbl oil/acre-ft). 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
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LMDH9

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LMDH9

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
LMDH9	(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
LB14DJR037	99	0.56	77	0.09	0.43	**0.85**	0.17	50	0	50	0	250	0.74	0.63	1.57	9	34	0.00	2	25	0
LB14DJR038	105	0.56	37	0.03	0.21	**0.85**	0.13	50	0	50	0	250	0.88	0.65	1.61	5	35	0.00	1	31	0
Amos Knob (Avg)		**0.56**	**57**	**0.06**	**0.32**	**0.85**	**0.15**	**50**	**0**	**50**	**0**	**250**	**0.81**	**0.64**	**1.59**	**7**	**35**	**0.00**	**1**	**28**	**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 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)

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