McManus 1 Interpretive Summary

Kyalla – Middle Velkerri 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 Kyalla, Upper and Middle Velkerri Formations in the McManus 1 well located in the Beetaloo Sub-Basin, Northern Territories, Australia. Four (4) 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 (Ro). In addition, client supplied published geochemical data for 179 samples were also incorporated into the interpretive evaluation. The complete results of these analyses are documented in this report along with an integrated geochemical interpretation that is summarized in the following table.

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Formation</th>
<th>Main Product</th>
<th>Thermal Maturity</th>
<th>Source Rock Richness</th>
<th>Organic Matter Type</th>
<th>Shale Oil Risk</th>
</tr>
</thead>
<tbody>
<tr>
<td>McManus 1</td>
<td>Kyalla</td>
<td>Estimated Original</td>
<td>Fair</td>
<td>Oil-prone Type II</td>
<td>High</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Minor Oil</td>
<td>Early Oil Window</td>
<td>Poor (0.40% TOC)</td>
<td>Mixed Type II/III</td>
<td></td>
<td></td>
</tr>
<tr>
<td>McManus 1</td>
<td>Upper Velkerri</td>
<td>Estimated Original</td>
<td>Very Good</td>
<td>Oil-prone Type II</td>
<td>Moderate</td>
<td></td>
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<tr>
<td>Measured Currently</td>
<td>Oil</td>
<td>Early Oil Window</td>
<td>Good (1.30% TOC)</td>
<td>Mixed Type II/III</td>
<td></td>
<td></td>
</tr>
<tr>
<td>McManus 1</td>
<td>Middle Velkerri</td>
<td>Estimated Original</td>
<td>Excellent</td>
<td>Oil-prone Type II</td>
<td>Low</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Oil</td>
<td>Peak Oil Window</td>
<td>Very Good (3.91% TOC)</td>
<td>Gas Prone Type III</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 1. Geochemical Summary

KYALLA FORMATION

No samples from the Kyalla Formation were analyzed for geochemical analysis by Weatherford Laboratories. The entire data set (17 samples) is composed of client supplied public data (Fig. 1). TOC contents ranged from 0.07 to 1.00 wt.% and averaged 0.40 wt.% (poor). Only one sample has a TOC content that just reaches the minimum requirement of 1 wt.% for effective petroleum source rocks, while none of the samples 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 Kyalla interval (590 m depth) (Fig. 1). Most of this interval has TOC content < 0.5 wt.% and is considered to have poor source potential (Fig. 1).

The S1 values of the Kyalla source rock samples average 0.15 mg HC/g rock (3 bbl oil/acre-ft) and S2 values average 2.20 mg HC/g rock (48 bbl oil/acre-ft). The S1 and S2 values imply poor in-situ hydrocarbon saturation and generative potential (Fig. 1). The normalized oil content (NOC) in the Kyalla samples, (S1/TOC) x 100, averages 19 (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. 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 at anywhere within the Kyalla Formation (Fig. 1).
Figure 1. Geochemical depth plots for the McManus 1 well.
Measured Hydrogen Index (HI) values in the Kyalla average 278 mg HC/g TOC, indicating mixed oil/gas-prone Type II/III kerogen quality in these source rocks at present day (Fig. 1). Original HI of these samples are estimated to average 450 mg HC/g rock, which indicate oil-prone Type II kerogen. Transformation Ratios (TR) based upon HI average only 50%, which is consistent with an early oil window thermal maturity. $T_{max}$ values in the Kyalla samples average 428°C. $T_{max}$ between 425 and 435°C typically indicate early oil window, while values < 425°C are considered immature with regard to the oil window (Type II kerogen). On the basis of these guidelines, the average Kyalla $T_{max}$ values in this well would be interpreted to be in the early oil window. Using the formula published by Jarvie et al. (2007) for Type II kerogen ($\text{Calculated } R_o = (0.0180)(T_{max}) – 7.16$), the average measured $T_{max}$ value of 428°C is equivalent to a Calc. %$R_o$ value of 0.54%. It is important to note that $T_{max}$ is only a crude measure of thermal maturation (Peters, 1986) and it can be compromised by a variety of pyrolysis artifacts and caveats.

Production Index (PI) values in these Kyalla samples average 0.06. These low PI values are consistent with immature source, which typically have PI values < 0.10. Samples in the early oil window tend to have PI values in the range of ~0.10 to 0.15.

**UPPER VELKERRI FORMATION**

One sample (1) from the Upper Velkerri Formation was analyzed for LECO TOC content and programmed pyrolysis, with the remaining data set (22 samples) composed of client supplied public data (Fig. 1). The Upper Velkerri Formation in the McManus 1 well exhibits good generative potential for petroleum source rocks based on TOC content values (Fig. 1). TOC content ranges from 0.12 to 3.13 wt.% and averages 1.30 wt.% (good). Six (6) samples analyzed exceed the minimum value of 2.0 wt.% for economic petroleum source rocks (Lewan, 1987). High TOC samples occur near the base of the sampled interval below 1130 m, near the contact with the underlying Middle Velkerri Formation (Fig. 1).

The S1 values in the Upper Velkerri average 1.29 mg HC/g rock (28 bbl oil/acre-ft), indicating good in-situ hydrocarbon saturation (Fig. 1) and are consistent with a thermal maturity in the early oil window. These values should be considered a minimum for in-situ oil saturation since they do not account for potential loss of volatile components during sample collection and analysis. NOC values in the Upper Velkerri interval are much higher in comparison to the Kyalla Formation and average 72. Oil cross over (NOC > 100) was observed in only one sample from 1180 m depth (Fig. 1), which suggests possible producible hydrocarbons at this depth. The S2 values in the Upper Velkerri average 3.61 mg HC/g rock (79 bbl oil/acre-ft), indicating fair remaining hydrocarbon generation potential.

Measured HI values in these samples average 208 mg HC/g TOC, which indicate mostly mixed oil/gas-prone Type II/III kerogen quality in these source rocks at present day. Estimated original HI of these samples average 450 mg HC/g TOC, which indicate oil-prone Type II kerogen quality. Transformation Ratios (TR) based upon HI average 66%, which is consistent with an early oil window thermal maturity.

The organic-matter in the Upper Velkerri interval in the McManus 1 well is thermally mature and is interpreted to be in the early oil window. Programmed pyrolysis $T_{max}$ values average 434°C (Fig. 1). Using the formula published by Jarvie et al. (2007) for Type II kerogen ($\text{Calculated } R_o = (0.0180)(T_{max}) – 7.16$), the average measured $T_{max}$ value of 434°C is equivalent to a Calc. %$R_o$ value of 0.65%. It is important to note that $T_{max}$ is only a crude measure of thermal maturation (Peters, 1986) and it can be compromised by a variety of pyrolysis artifacts and caveats.

Production Index (PI) values in these Upper Velkerri samples average 0.26. These elevated PI values are consistent with source rocks in the early to mid-oil window. The PI values tend to increase toward the base of the Upper Velkerri interval and are generally elevated in the same zone where NOC values are also highest. This suggests possible producible in-situ oil saturation within this horizon.
Organic petrology was performed on one sample from the Upper Velkerri interval (1157.50–1157.54 m). The results from this analysis show a distribution that consists exclusively of macerals identified as low reflectance solid bitumens (Fig. 2). These organic macerals may represent preserved original cyanobacterial kerogen that has subsequently undergone thermal conversion to form a dispersed solid bitumen network within these Velkerri Formation source rocks. The mean measured reflectance value for these solid organic macerals is 0.83% R_o. 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 = (Bitumen R_o +0.41)/1.09) resulted in a 1.14% Eq. R_o, while the conversion formula published by Jacob (1985) equation (Eq. R_o = (Bitumen R_o × 0.618) + 0.4) for ‘angular-like’ pyrobitumen trapped in mineral pore spaces resulted in a 0.91% Eq. R_o. Neither of these conversions appears to be valid “corrections” for the measured reflectance readings when considered in the context of other geochemical data. Comparison with other samples examined in the current study suggest that the low reflectance solid bitumen reflectance readings are best utilized as stand-alone equivalent vitrinite reflectance values for the purposes of thermal maturity assessment. Thus, the measured is 0.83% R_o value would suggest samples within the mid-oil window and is only slightly higher than the interpreted early oil window thermal maturity determined using other geochemical indices.

**MIDDLE VELKERRI FORMATION**

Three (3) samples from the Middle Velkerri Formation were analyzed for LECO TOC content and programmed pyrolysis, with the remaining data set (122 samples) composed of client supplied public data (Fig. 1). TOC contents ranged from 0.21 to 10.85 wt.% and averaged 3.91 wt.% (very good). One hundred one (101) of these samples exceed the minimum requirement of 2 wt.% for economic petroleum source rocks. There are three distinct cycles of TOC within this interval with maxima occurring at depths of 1262, 1429 and 1531 m (Fig. 1). These three organic rich intervals have been previously recognized within the Middle Velkerri (Lanigan et al, 1994) and could be associated with the base of transgressive systems tracts (TST) in a series of platform/ramp parasequences (Bohacs et al., 2013). These stepwise changes in TOC and corresponding minimal change in Hydrogen Index values (HI) suggests that production was the major control on organic richness along with auto-dilution by pelagic carbonate (Bohacs et al., 2013).
The S1 values in the Middle Velkerri source rock samples average 2.10 mg HC/g rock (46 bbl oil/acre-ft) and S2 values are moderate with an average 5.04 mg HC/g rock (110 bbl oil/acre-ft). The S1 and S2 values imply generally good in-situ hydrocarbon saturation and fair remaining generative potential (Fig. 1). The normalized oil content (NOC) in the Middle Velkerri samples average 48 (Fig. 1) and there are multiple samples exhibiting oil “cross-over”, notably in the basal section of this source rock interval. This would be interpreted to represent zones with high potential for containing producible hydrocarbon saturation.

Measured Hydrogen Index (HI) values in the Middle Velkerri average 129 mg HC/g TOC, indicating gas-prone Type II kerogen quality in these source rocks at present day (Fig. 1). This is generally consistent with elemental analyses of select kerogen samples from the Upper Velkerri that have average H/C ratios of 0.65, which is typical for Type III to Type IV kerogen. These values have been reduced due to thermal maturity. Original HI₀ of these samples are estimated to average 450 mg HC/g rock, which indicate oil-prone Type II kerogen. Transformation Ratios (TR) based upon HI average 80%, which is consistent with a peak oil window thermal maturity. T_max values in the Middle Velkerri samples average 444°C. T_max between 425 and 435°C typically indicate early oil window, while values between 435 and 445°C indicate peak oil window (Type II kerogen). On the basis of these guidelines, the average Middle Velkerri 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 Rₒ = (0.0180)(T_max) – 7.16), the average measured T_max value of 444°C is equivalent to a Calc. %Rₒ value of 0.83%. 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. Additional support for this interpreted thermal maturity comes from aromatic biomarker ratios examined using core slice experiments (1215 m sample depth), which give a range of calculated reflectance values from 0.86 to 1.03% Rₒ (Flannery and George, 2014).

Production Index (PI) values in the Middle Velkerri samples average 0.32. These elevated PI values are consistent with source rocks in the peak oil window, which typically have PI values between ~0.25 and 0.40.

Organic petrology was performed on one sample from the Middle Velkerri interval (1206.20~1206.30 m). Analogous to the Upper Velkerri samples, the results from this analysis show a distribution that consists exclusively of macerals identified as low reflectance solid bitumens (Fig. 3). These organic macerals may represent preserved original cyanobacterial kerogen that has subsequently undergone thermal conversion to form a dispersed solid bitumen network within these Velkerri Formation source rocks. The mean measured reflectance value for these solid organic macerals is 0.90% Rₒ. 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. Rₒ = (Bitumen Rₒ +0.41)/1.09) resulted in a 1.20% Eq. Rₒ, while the conversion formula published by Jacob (1985) equation (Eq. Rₒ = (Bitumen Rₒ × 0.618) + 0.4) for ‘angular-like’ pyrobitumen trapped in mineral pore spaces resulted in a 0.96% Eq. Rₒ. Neither of these conversions appears to be valid “corrections” for the measured reflectance readings when considered in the context of other geochemical data. Comparison with other samples examined in the current study suggest that the low reflectance solid bitumen reflectance readings are best utilized as stand-alone equivalent vitrinite reflectance values for the purposes of thermal maturity assessment. Thus, the measured is 0.90% Rₒ value would suggest samples within the peak oil window and is consistent with the interpreted thermal maturity determined using other geochemical indices.
Figure 3. Organic petrology of the Middle Velkerri (1206.2 m) in the McManus 1 well. Mean maceral reflectance of low reflecting solid bitumen is 0.90% $R_o$.

**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 Velkerri source rock samples examined in this study. We can estimate the extent of the petroleum generation process, the volume of expelled oil and the expulsion efficiency by making some reasonable assumptions based on the core geochemical data and published regional information (Jarvie et al., 2007; Peters et al., 2005).

HI$_o$ values can be computed from visual kerogen assessments and assigned kerogen-type HI$_o$ average values using the following equation (Jarvie et al., 2007):

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

(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 values that suggest Type II to a mixed Type I/II kerogen assemblage (Law et al., 2010; Crick et al., 1988; Taylor et al., 1994).
Table 2. Average Kerogen Estimations for McManus 1 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):

\[ TR = 1 - \frac{HI_{pd}[1200 - HI_o(1 - PI_o)]}{HI_o[1200 - HI_{pd}(1 - PI_{pd})]} \]  

\[ (2) \]

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 450 mg HC/g TOC (Table 2). We assume a PI_o of 0.02 (see Peters et al., 2005). Using these values in equation 2, the extent of fractional conversion of HI_o to petroleum varies from 0.50 to 0.80 (Table 3), i.e., on average an estimated 50 to 80% 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):

\[ TOC_o = \frac{HI_{pd} \left( \frac{TOC_{pd}}{1+k} \right) (83.33)}{HI_o \left(1 - TR \right) (83.33) - \left( \frac{TOC_{pd}}{1+k} \right) + \left[ \frac{HI_o \left( \frac{TOC_{pd}}{1+k} \right)}{1+k} \right]} \]  

\[ (3) \]

In this equation k is a correction factor based on residual organic carbon being enriched in carbon over original values at high maturity (Jarvie et al., 2007, p. 497). For Type II kerogen the increase in residual carbon C_R at high maturity is assigned a value of 15% (whereas for Type I, it is 50%, and for Type III, it is 0%) and the correction factor k is then TR_{HI} \times C_R. The kerogen mix for each individual sample was used in this calculation.

Using equation 3, the average estimated original TOC_o for the source rock samples in this well before petroleum generation varies from 0.88 to 5.52 wt.% (Table 3).

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

\[ S2_o = \left( \frac{HI_o \times TOC_o}{100} \right) \]  

\[ (4) \]

For the Velkerri source rocks examined in the McManus 1 well, the average S2_o values vary from 4.0 to 24.9 mg HC/g rock or approximately 87 to 544 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).
Using this methodology for the Upper Velkerri samples analyzed in the current study, the generated oil yields average 141 bbl/acre-ft. The generated oil yield from overlying Kyalla was lower with an average value of only 39 bbl/acre-ft. The average generated oil yield from the Middle Velkerri averaged 417 bbl/acre-ft along with 102 Mcf/acre-ft of secondary cracked gas (Table 3) in this relatively higher thermal maturity zone.

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 Velkerri intervals varies from 92% in the Kyalla, 80% in the Upper Velkerri and 89 in the Lower Velkerri. The trend in the Velkerri samples is likely to be a consequence of increased thermal maturity resulting in more volatile in-situ oil compositions and higher gas/oil ratios, both of which would tend to enhance expulsion in the deeper source rock intervals. The higher expulsion efficiency of the overlying Kyalla interval is likely due to these units having adjacent porous reservoir lithologies in which expelled oil could more easily migrate.

The Kyalla and Upper Velkerri source rock intervals in the McManus 1 well are interpreted to be in the early oil window and hydrocarbon yield calculations suggest minor to moderate amounts of generation have occurred (predominantly oil with some presumed associated gas). The Middle Velkerri source interval in this well is interpreted to be in the peak oil window and has likely generated significant amounts of oil and some secondary cracked gas. 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 (S2o) 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 Middle Velkerri original generation potential (S2o) averages 544 bbl oil/acre-ft, which compares favorably to the list of unconventional US Shale plays shown below. For the Kyalla and Upper Velkerri, original generation potential is much lower from 87 to 220 bbl oil/acre-ft and these two units do not compare favorably with other unconventional US Shale plays.

<table>
<thead>
<tr>
<th>Formation</th>
<th>TOCpd</th>
<th>HIpd</th>
<th>S2pd bbl/a-ft</th>
<th>Hio</th>
<th>TR</th>
<th>TOCo</th>
<th>S2o bbl/a-ft</th>
<th>S1 Free Oil bbl/a-ft</th>
<th>Est. Oil bbl/a-ft</th>
<th>Cracked Gas Mcf/a-ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kyalla</td>
<td>0.77</td>
<td>278</td>
<td>70</td>
<td>450</td>
<td>0.50</td>
<td>0.88</td>
<td>87</td>
<td>3</td>
<td>39</td>
<td>0</td>
</tr>
<tr>
<td>Upper Velkerri</td>
<td>1.79</td>
<td>208</td>
<td>79</td>
<td>450</td>
<td>0.66</td>
<td>2.23</td>
<td>220</td>
<td>28</td>
<td>141</td>
<td>0</td>
</tr>
<tr>
<td>Middle Velkerri</td>
<td>4.34</td>
<td>129</td>
<td>110</td>
<td>450</td>
<td>0.80</td>
<td>5.52</td>
<td>544</td>
<td>46</td>
<td>417</td>
<td>102</td>
</tr>
</tbody>
</table>

Table 3. Hydrocarbon Yields average data for McManus 1 well.

Original (S2o) − Remaining (S2) = Generated HCs

(5)
A comparison was made between oil saturations based upon shale rock properties (SRP) analyses and those determined via programmed pyrolysis for a single sample from the Upper Velkerri Formation (1154.98 m depth). In this instance the measured SRP oil saturations are higher than those determined by SRA methods using the S1 yields. The saturation determined by SRP was 3.02 mg oil/g AR Rock (66 bbl oil/acre-ft), while that determined from S1 yields on a nearby sample is 1.41 mg oil/g AR Rock (31 bbl oil/acre-ft). This suggests that the S1 is significantly underestimating the total hydrocarbons extracted using Dean-Stark methods (toluene). The likely cause of this is undoubtedly related to the in-situ hydrocarbon saturation, which is considered to be relatively low thermal maturity (early oil window). Low maturity oils generally contain relatively high abundances of non-volatile polar and asphaltene components associated with the in-situ oil/bitumen saturation. Further evaluation of the extractable hydrocarbons by liquid chromatography and gas chromatography is warranted to fully evaluate the nature of these apparent discrepancies between SRP and S1 saturations.

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

<table>
<thead>
<tr>
<th>Sample</th>
<th>H²</th>
<th>TR</th>
<th>TOC²</th>
<th>S²</th>
<th>Remaining Potential Oil</th>
<th>Original Potential Oil</th>
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<th>S1 Free Oil</th>
<th>Estimated Oil</th>
<th>Cracked Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barnett Shale Ft. Worth Basin</td>
<td>435</td>
<td>0.84</td>
<td>5.38</td>
<td>23.40</td>
<td>94</td>
<td>513</td>
<td>0.40</td>
<td>33</td>
<td>251</td>
<td>1005</td>
</tr>
<tr>
<td>Barnett Shale Delaw are Basin</td>
<td>435</td>
<td>0.91</td>
<td>5.25</td>
<td>22.84</td>
<td>52</td>
<td>500</td>
<td>0.80</td>
<td>32</td>
<td>90</td>
<td>2149</td>
</tr>
<tr>
<td>Woodford Shale Delaw are Basin</td>
<td>480</td>
<td>0.89</td>
<td>6.41</td>
<td>30.79</td>
<td>139</td>
<td>674</td>
<td>0.89</td>
<td>46</td>
<td>60</td>
<td>2854</td>
</tr>
<tr>
<td>Haynesville Shale E. Texas Basin</td>
<td>400</td>
<td>0.98</td>
<td>3.93</td>
<td>15.73</td>
<td>7</td>
<td>344</td>
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Unconventional Oil & Gas Risk Assessment

The Mesoproterozoic Kyalla and Velkerri Formation source rocks in the McManus 1 well have been evaluated for unconventional oil and gas potential. These source rock samples are presented in a modified geochemical risk assessment diagram (Fig. 4) based upon published results from the Barnett Shale in the Fort Worth Basin. The data illustrated in the star plot represents average values for all four diagnostic ratios. Also shown are the recommended areas for unconventional oil (in green) and gas (in red). Data that lies above the minimum threshold and within the shaded areas indicates samples with low geochemical risk for either thermogenic oil or gas production. Data that lie below the minimum threshold and fall in the immature region (in gray) indicate a high risk for commercial shale oil or gas production. Transformation ratios (TR) were calculated based upon Hl estimates using measured and interpreted fractional composition of kerogen macerals.
The Middle Velkerri source rock interval in the McManus 1 well is interpreted to represent a low geochemical risk for in-situ shale oil production. The average TOC content of 3.91 wt.% is above the generally accepted minimum value of 1% TOC to be considered an effective source rock for hydrocarbon generation/expulsion (Fig. 4). It is also above the minimum requirements of 2 wt.% for economic petroleum source rocks. Original organic matter type is interpreted to be predominantly oil-prone Type II marine algal kerogen. Thermal maturity parameters from programmed pyrolysis place the Middle Velkerri source interval in peak oil window. The average Tmax value of 444°C is above the recommended minimum value of 435°C for shale oil, but below the minimum of 455°C for shale gas (Fig. 4). 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 80% and fall above the recommended minimum of 50% for shale oil systems and at the threshold for shale gas (Fig. 4). Measured maceral reflectance values average 0.90% Ro, which is above the recommended minimum of 0.6% for shale oil (Fig. 4). Aromatic biomarker thermal maturity parameters reported for this interval (Flannery and George, 2014) in the McManus well provide an independent confirmation of peak oil thermal maturity conclusions from programmed pyrolysis and organic petrology. On the basis of all of these measured geochemical risk parameters, the Middle Velkerri source interval would be considered a low risk for shale oil and a moderate risk for shale gas since all of the thermal maturity risk parameters do fall just below recommended minimum thermogenic shale gas thresholds (Fig. 4).

The other formations examined in the current study are considered to represent low to moderate risk for in-situ shale oil/gas production. This is primarily related to organic richness and thermal maturity. The Kyalla samples have an average TOC of just 0.40 wt.% and thermal maturity indicators suggest early window maturity. On the risk assessment diagram, average Tmax value of 428°C is well below the
recommended minimum value of 435°C for shale oil and the Transformation Ratio of 50% is just at the minimum threshold (Fig. 4). For these reasons, the Kyalla interval is considered to be a high risk for commercial shale oil and shale gas development.

The Upper Velkerri samples are more prospective and have an average TOC of 1.30 wt. %, which is above the minimum threshold for shale oil (Fig. 4). Thermal maturity indicators suggest an early oil window maturity but higher than the overlying Kyalla. On the risk assessment diagram, average Tmax value of 434°C is just below the recommended minimum value of 435°C for shale oil and the Transformation Ratio of 66% is above at the minimum threshold (Fig. 4). Measured maceral reflectance values average 0.86% Ro, which is above the recommended minimum of 0.6% for shale oil (Fig. 4). Given its proximity to the underlying Upper Velkerri, it would be logical to conclude that any contribution to the overall resource potential from this horizon would simply be included within the evaluation of the Upper Velkerri, since fracture stimulation would likely connect both horizons, especially when considering the most prospective zone with elevated NOC values is the basal section of the Upper Velkerri.

In the Upper Velkerri source interval, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is good (avg. 28 bbl oil/acre-ft), suggesting moderate risk for shale oil development (Fig. 5). This is also supported by the high in-situ hydrocarbon saturations determined from SRP analysis (66 bbl oil/acre-ft), although this single sample may not be representative of the entire interval. Hydrocarbon yield calculations on as-received samples show estimates of average generated oil from the Upper Velkerri at 141 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. These values are higher in comparison to the Upper Velkerri and are likely due primarily differences organic richness and in thermal maturity (Barnett Shale oil example is at a peak oil widow maturity of 0.86% VRo).

In the Kyalla source interval measured in-situ oil saturation from S1 yields is generally poor (avg. 3 bbl oil/acre-ft) and estimated generated oil yields are also quite low (avg. 39 bbl oil/acre-ft) due to marginal organic richness (Fig. 5). As noted previously, this source rock is considered a high risk for shale oil development.

The Middle Velkerri has the highest measured in-situ oil saturation (46 bbl oil/acre-ft), which is a consequence of higher organic richness and elevated thermal maturity. Estimated generated oil is very high (417 bbl oil/acre-ft) along with some minor amounts of secondary cracked gas (102 Mcf/acre-ft). These values exceed those of samples from the core area of Barnett Shale oil production in the Fort Worth Basin (Fig. 5) and suggest a low risk for commercial shale oil development.

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 Kyalla and Upper Velkerri source intervals in this well is in the early oil window and hydrocarbon saturation is likely to be moderately heavy. The presence of heavy oil and/or bitumen could also indicate a source interval with restricted microporosity. Such microporosity is considered necessary for recovery of in-situ oil saturation and can be better assessed using scanning electron microscopy (SEM). In contrast, the interpreted thermal maturity of the Middle Velkerri is peak oil window and in-situ oil saturation is likely to be more mobile with a higher gas/oil ratio in comparison to the overlying units. Source rock extract fingerprints and bulk fractional compositional analyses from select Velkerri samples would 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 5. Hydrocarbon yield estimates for the Mesoproterozoic source rocks in the McManus 1 well compared to Barnett Shale in the oil window.

**GEOCHEMICAL SUMMARY**

The Middle Velkerri source interval in the McManus 1 well is interpreted to represent low geochemical risk for unconventional shale oil development. It clearly has elevated organic richness (avg. 3.91 wt.% TOC) and is considered an excellent source rock with dominantly oil-prone Type II kerogen. Thermal maturity parameters indicate that the source interval is in the peak oil window, 0.83% Calc. R<sub>o</sub>, 0.90% R<sub>o</sub> measured maceral reflectance and key risk ratios are at or above recommended minimum thresholds for shale oil systems. While the Middle Velkerri has likely generated significant amounts of oil (avg. 417 bbl oil/acre-ft), comparison to other systems such as the Barnett Shale show in-situ oil saturations are generally lower for the Middle Velkerri. Risk criteria like the S1 versus TOC show oil cross-over for several samples in this unit, notably in the basal section. Further evaluation of in-situ oil characteristics would be required to fully evaluate potential oil mobility and recovery risk.

The other source rock intervals evaluated in the McManus 1 well generally have higher risk in comparison to the Middle Velkerri. The Kyalla Formation has marginal organic richness (avg. 0.40 wt.% TOC) and is below the thermal maturity thresholds for shale oil. The Upper Velkerri (avg. 1.30 wt. % TOC) exceeds the minimum threshold for TOC and most thermal maturity parameters are above the threshold for shale oil. The estimated generated oil and in-situ hydrocarbon saturation is moderate in the Upper Velkerri, but SRP analysis suggest that the in-situ value may be somewhat higher, which would improve prospectivity. Thus, the basal portion of the Upper Velkerri could be considered a potential shale oil target especially when considered in the context of the development of the underlying Middle Velkerri source rock interval.
REFERENCES CITED


Jacob, H., 1985, Disperse solid bitumens as an indicator for migration and maturity in prospecting for oil and gas, Erdöl und Kohle-Erdgas-Petrochemie, v. 38, no. 8, p. 365.


Appendix I

*Hydrocarbon Yield Calculation*
*Beetaloo Sub-Basin Group*
*McManus 1*

Northern Territory Geological Survey - Australia
## Hydrocarbon Yield Calculation

### Morook Sandstone (Avg)

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Notes: Calc.Ro values in **bold** are calculated from measured Tmax. Calc.Ro values in red font are interpreted 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)