Northern Australia contains extensive Proterozoic sedimentary basins that contain organic-rich rocks with the potential to host both major petroleum accumulations and basin-hosted mineral systems (Figures 1–5). These intracratonic basins comprise the greater McArthur Basin (McArthur and Birrindudu basins, and Tomkinson Province; Close 2014), the Isa Superbasin, and the South Nicholson Basin. The sedimentary successions within these basins are assumed to be of equivalent age and to have been deposited under similar climatic controls, resulting in correlative lithology, source facies and stratigraphic intervals.

The greater McArthur Basin contains Paleoproterozoic to Mesoproterozoic organic-rich mudrocks with the potential to generate conventional oil and gas deposits, and self-sourced continuous shale oil and shale gas targets (Munson 2014, Revie 2017a, b, Weatherford Laboratories 2017). Exploration has focused on the Beetaloo Sub-basin where organic-rich mudrocks of the Velkerri Formation contain up to 10 wt% total organic carbon (TOC) and have been assessed to contain 118 trillion cubic feet (Tcf) of gas-in-place (Munson 2014, Revie 2017a, Weatherford Laboratories 2017, Revie and Normington 2018). Other significant source rocks include the Kyalla Formation of the Roper Group, the Barney Creek, Yalco and Lynott formations of the McArthur Group, the Wollogorang, and perhaps the McDermott formations of the Tawallah Group, and the Vaughton Siltstone of the Balma.
Figure 2. Rock-Eval pyrolysis data for the Mesoproterozoic Urapungan Petroleum Supersystem in northern Australia. (a) $T_{\text{max}}$ (°C) versus HI (mg HC/g TOC). (b) TOC (wt%) versus HI (mg HC/g TOC). (c) OI (mg CO$_2$/g TOC) vs HI (mg HC/g TOC). (d) Production index versus $T_{\text{max}}$ (°C). Data points for the greater McArthur Basin sourced from Revie and Normington (2018); those for Isa Superbasin and South Nicholson Basin both collated from the literature in Jarrett et al (2018a) and 678 newly generated data points from Jarrett et al (2018b).
Figure 3. Rock-Eval pyrolysis data for the Paleoproterozoic McArthur Petroleum Supersystem and the Wollogorang Formation in northern Australia. (a) $T_{\text{max}}$ (°C) versus HI (mg HC/g TOC). (b) TOC (wt%) versus HI (mg HC/g TOC). (c) OI (mg CO$_2$/g TOC) vs HI (mg HC/g TOC). (d) Production index versus $T_{\text{max}}$ (°C). Data points for the greater McArthur Basin sourced from Revie and Normington (2018), those for Isa Superbasin and South Nicholson Basin both collated from the literature in Jarrett et al (2018a) and 678 newly generated data points from Jarrett et al (2018b).
Figure 4. Rock-Eval pyrolysis data ($T_{\text{max}}$ (°C) versus HI (mg HC/g TOC)) for Proterozoic units in northern Australia demonstrating the variability between (a) the Proterozoic McArthur Petroleum Supersystem, (b) the Urapungan Petroleum Supersystem, (c) data from the greater McArthur Basin sourced from Revie and Normington (2018), and (d) data from the South Nicholson Basin and Isa Superbasin both collated from the literature in Jarrett et al (2018a) and 678 newly generated data points from Jarrett et al (2018b).
Group in the northern McArthur Basin (Munson 2014, Frichot et al 2017). These source rocks are hosts to diverse play types; for example Côté et al (2018) described five petroleum plays in the Beetaloo Sub-basin: the Velkerri shale dry gas play, the Velkerri liquids-rich gas play, the Kyalla shale gas play, the Kyalla hybrid liquid-rich gas play, and the Hayfield sandstone oil/condensate play. This highlights the large shale and tight gas resource potential of the McArthur Basin for which the full extent is poorly understood and insufficiently quantified. More work is needed to characterise the source rocks, the petroleum generative potential, the fluid types and migration pathways, and the thermal and burial history in order to fully understand and quantify the hydrocarbon prospectivity of the basin.

The Exploring for the Future (EFTF) program is a four-year (2016–2020) $100.5 million initiative by the Australian Government conducted in partnership with state and Northern Territory government agencies, other key government, research and industry partners and universities.

Petroleum supersystems

A petroleum supersystem is a continental-scale framework linking basins of similar age, structural history, depositional environment and hydrocarbon potential. It may include a family of similar source rocks rather than one single source-reservoir-seal pair (Bradshaw et al 1994). Seven petroleum supersystems are recognised across Australia (Bradshaw et al 1994) of which two are identified in the EFTF project area: the McArthur and Urapungan supersystems. A regional

![Figure 5](image-url). Spatial variations in total organic carbon (TOC wt\%) of (a) Kyalla Formation (b) Velkerri Formation and (c) Barney Creek Formation.
chronostratigraphic and lithostratigraphic correlation between Paleoproterozoic and Mesoproterozoic basins across northern Australia has been proposed (eg Ahmad and Scrimgeour 2013, and references therein), supported with recent data for this interpretation (Hoffman 2015). We use the petroleum supersystem concept to investigate the links between families of potential source rocks in roughly time equivalent and structurally similar settings of the McArthur Basin, Birrindudu Basin, South Nicholson Basin, and Isa Superbasin (Figure 1).

Source rock geochemistry

A compilation of existing source rock geochemistry was used to define areas with the potential to host an active petroleum system and to target future areas for study as part of the EFTP program. The source rock geochemistry and maturity of all known source rock units and associated data has been reviewed from the greater McArthur Basin (Revie 2017b, Revie and Normington 2018) and compiled for the South Nicholson Basin and Isa Superbasin (Jarrett et al 2018a). These results, plotted in Figures 1–4, determined that although the Roper Group contains a significant amount of datapoints and has been thoroughly reviewed and interpreted (Revie, 2017b), higher-resolution pre-competitive source rock geochemical studies are required over multiple wells that intersect the greater McArthur and South Nicholson basins, and the Isa Superbasin. Such data density is required to better understand source rock properties used in the evaluation of resource potential in northern Australia. The large standard deviations in source rock quality (wt% TOC) within formations and supersequences plus the limited amount of Rock-Eval pyrolysis data highlight the importance of capturing uncertainty surrounding source rock properties in petroleum systems analysis and resource assessment studies (eg Jarrett et al 2018a).

Previously collected pyrolysis results from the greater McArthur Basin (Revie and Normington 2018, Revie 2017b) and preliminary results from this study are presented together in Figures 2 and 3. Figure 2 shows the Mesoproterozoic Urapungan Petroleum Supersystem and Figure 3 combines the data for the Paleoproterozoic McArthur Petroleum Supersystem and the Wollogorang Formation. Figure 4 is a comparison of T_max (°C) versus hydrogen index (HI; mg HC/g TOC) for Proterozoic units in northern Australia based on petroleum supersystems (Figure 4a–b) and by region (greater McArthur Basin versus South Nicholson Basin and Isa Superbasin); the results demonstrate that although both the Urapungan and McArthur petroleum supersystems contain excellent source potential, the sampling density is highest in the greater McArthur Basin, emphasising the need for more data elsewhere in the region.

Using the classification of Peters and Casa (1994), 10 source rock units in northern Australia exhibit excellent organic richness (TOC >4 wt%). These include the Kyalla and Velkerri formations (Figure 2; Table 1) of the Mesoproterozoic Urapungan Petroleum Supersystem, as reported by Revie (2017b); and the Barney Creek Formation, Riversleigh Siltstone, Mount Les Siltstone, Lawn Hill Formation, Termite Range Formation, and Wollogorang Formation of the Paleoproterozoic McArthur Petroleum Supersystem (Figure 4). In addition, the Mesoproterozoic Mullera Formation has good organic richness reaching a maximum TOC of 2.45 wt%, and the Constance Sandstone, Battle Creek and Timber Creek formations have fair source rock potential (TOC between 0.5 and 2 wt%; Figures 2–4; Table 1).

Spatial variations in source rock potential in the McArthur Basin are evident in Figure 5. The Velkerri Formation shows a comparatively widespread distribution of very good to excellent source rock potential where data exists. There is a slight decline in organic richness towards the south of the Beetaloo Sub-basin (Figure 5). Although this trend is only controlled by one data point, it is likely to be related to observations of sandier facies towards the south of the basin (Munson 2016 and references therein). Revie (2017b) mapped thermal maturity within the Beetaloo Sub-basin demonstrating that the deepest and thickest intersections of the Velkerri Formation in the central region are mature to overmature, and that the Kyalla Formation is early to late mature across the entire region. Mapping the spatial variations is a significant component in play fairway analysis and risk mapping, and future work is needed to produce similar maps over the greater McArthur Basin and other Proterozoic basins in northern Australia.

The hydrogen index (HI) can determine the expelled petroleum product at the time of peak maturity (eg Peters and Casa 1994). Present day HIs demonstrate that the range of oil-prone, oil-and gas-prone, and gas-prone kerogens in the greater McArthur Basin are potential sources for the large range of petroleum shows present in the Proterozoic sections (Munson 2014, Revie 2017b, Cox et al 2019). Based on present-day hydrogen indices, the Urapungan Petroleum Supersystem contains oil-prone kerogen (HI >600 mg HC/g TOC) in the Kyalla and Velkerri formations and gas-prone kerogen (HI 50 to 200 mg HC/g TOC) within the Mullera Formation, Constance Sandstone, and Wondooan Hill Formation. The McArthur Petroleum Supersystem contains oil-prone kerogen in the Barney Creek, Battle Creek and Timber Creek formations and in the Riversleigh Siltstone. The Doomadgee Formation and Walford Dolostone (termed Walford Dolomite in Queensland) contain oil- and gas-prone kerogen (HI 200 to 300 mg HI/g TOC). Gas-prone kerogen characterises the Lawn Hill and Termite Range formations and the Mount Les Siltstone. Additionally, the Wollogorang Formation contains gas-prone kerogen.

The present day HI is affected by thermal maturity, which needs to be taken into account for extrapolation to initial/original HI (HIo). Hence HIo, for mature to overmature potential source rocks in the greater McArthur Basin and Isa Superbasin (Jarrett et al 2018a, b) requires an understanding of depositional environments and organic facies. However, additional data are required from immature samples of all units to have a better understanding of expelled petroleum products.

The generative hydrocarbon potential of potential source rocks can be further quantified using kerogen kinetics. Both the newly acquired and previously published kinetic results (Revie and Normington 2018) are combined in Figures 6 and 7 to show the bulk petroleum potential of the greater
McArthur Basin. Hydrocarbon generation of all the greater McArthur Basin samples are characterised by a typically narrow activation energy distribution (Ea), although a slightly broader Ea distribution exists in one sample from the Velkerri Formation (Figure 6d). The main activation energies are 51–54 kcal/mol in the Kyalla Formation, 53 kcal/mol in the Velkerri Formation, and 52–55 kcal/mol in the Barney Creek Formation (Figure 6). Application of the kinetic models was performed on samples using the ZetaWare–Kinex software. This involved a discrete Ea distribution and a single frequency factor (A sec^-1) to a geologic heating rate of 3°C/Ma (close to midway between the range of 1°C/Ma to 10°C/Ma in most sedimentary basins).

**Figure 6** shows the comparison of predicted transformation ratio (TR) against Pepper and Corvi’s (1995) five standard kerogen types. The Pepper and Corvi kerogen types are preferred in this study over the traditional Tissot and Welte (1984) ‘Type I – IV’ kerogen classifications that classified kerogen into groups using a combination of geochemistry and petrology. Proterozoic source rocks predate Vitrinite, and there are issues with our understanding of petrology and reflectance in pre-Vitrinite source rocks (eg. Palu et al. 2018).

In Figure 7, TR = 0.1 indicates that the onset of hydrocarbon generation occurs between 120°C and 140°C and at maturities between 0.8% and 1.0% Rc; TR = 0.5 approximates peak hydrocarbon generation at relatively high temperatures between 140°C and 160°C. The bulk of primary gas generation is completed at TR = 0.9 and occurs between 150°C and 175°C from the residual refractory organic matter. The narrow range in Ea and steep generation gradient in the three McArthur Basin source rocks analysed can be effectively modelled using type C lacustrine organofacies similar to ‘type I’ kerogen (eg Pepper and Corvi 1995). Revie (2017b) demonstrated that Roper Group source rocks are a mixture of ‘Type I’ and ‘Type II’ source rocks and more work is likely required to model these different organic types. Additionally, there are also samples where the generation profile is more comparable with a type D/E fluviodeltaic organofacies of terrestrial type III kerogen. These interpretations of organofacies and kerogen type are incompatible with our understanding of the Proterozoic biosphere. Revie (2017b) suggested that Roper Group ‘type III’ to ‘type IV’ kerogen are the results of maturation from type II kerogen, this may explain some of the data. However there are many immature samples with low HI values, in addition to the kinetic results described above. These results largely reflect the limited range in standard kerogen types and thus require further investigation and refinements for early

**Table 1.** Rock-Eval pyrolysis statistics of potential source rocks of northern Australia. Data sourced from Revie and Normington (2018) and Jarrett et al. (2018a,b).
Figure 6. Bulk kinetic discrete activation energy distributions of source rocks. (a–b) the Kyalla Formation. (c–d) Velkerri Formation. (e–g) Barney Creek Formation in addition to the Mount Les Siltstone of the Isa Superbasin. (h) Activation energy distribution based on multiple heating rates (0.7; 2.0; 5.0; 15.0 K/min). Data generated in this study (d, e and f) and from Revie and Normington (2018) (a, b, c, g and h).
Palaeozoic and older (pre-land plants) organic matter (e.g., Shannon et al. 2018). Variations in the geochemistry of the preserved organic matter may be inherited from differences in the contributing biomass, degree of reworking, and the depositional environment; this results in different frequency factors (A) and HI (Hantschel and Kauerauf 2009). It is important to understand this variation for a petroleum systems model as different kinetics will result in the petroleum generation occurring at different times and temperatures. One sample from the Isa Superbasin, the Mount Les Siltstone from ND2 (Figure 1), has a broad Ea distribution, peak conversion temperature (TR = 0.5) at 165°C and primary conversion >200°C. This suggests very high thermal stability and a kerogen type between the fluviodeltaic organofacies D/E and F (Figure 7). The differences in bulk kinetics between the Mount Les Siltstone and the coeval Barney Creek Formation suggests that there are complexities in the initial petroleum supersystem framework defined by Bradshaw et al. (1994), and that predictions from one source rock might not be transferable to other coeval units. Future work is required to obtain a larger bulk kinetic dataset for northern Australian source rocks to determine how representative these results are at a regional scale.

Bulk kinetics focus on kerogen cracking and cannot distinguish between various petroleum products. We therefore recommend further experiments to better characterise the organic matter including: compositional and phase kinetics.

Figure 7. Transformation ratio (TR) curves calculated using bulk kinetics generated in this study in addition to data from Revie and Normington (2018). (a) TR plotted against maturity (calculated vitrinite reflectance equivalent, Rc%). (b) TR plotted against temperature (°C).
to predict evolving gas-to-oil ratios with maturation and to model fluid properties at surface conditions; Microscale sealed vessel (MSSV) pyrolysis for organofacies type distributions (eg Mahlstedt et al 2015); and spatial variability definition of bulk kinetics to determine heterogeneity of organic matter, which is useful in calibrating a petroleum systems model.

Fluid geochemistry

Identifying the source/s of migrated hydrocarbon fluids is important in defining the petroleum system and assisting in petroleum exploration (Magoon and Dow 1994). The source of the oil collected during a drill stem test from well Jamison 1 (Figure 1) in the McArthur Basin within the Jamison sandstone, for example, has not been geochemically typed to a source rock. Geochemically differentiating between the Kyalla and Velkerri formations has remained elusive due to the similarities between the typical biomarker (triterpane) assemblage prevalent in Mesoproterozoic systems and the relative homogeneity of isotopes over the so called ‘boring billion’ time period (eg Cawood and Hawkesworth 2014, Pawlowska et al 2013, Jarrett et al 2019).

Hydrocarbon biomarkers show general similarities in saturated fractions, such as a large unresolved complex mixture (UCM) and a relatively high proportion of monomethyl alkanes relative to regular n-alkanes and regular diastereomeres, but there are differences in both the saturated and aromatic isoprenoids between formations due to a shift in microbial assemblages and different water chemistries. Euxinic waters in the Barney Creek Formation contain 2,3,4- and 2,3,6-trimethyl aryl isoprenoids, which are biomarkers for the purple and green sulfur bacteria respectively (Brocks et al 2005, Jarrett et al 2018d); however, the largely ferruginous Roper Group does not contain these molecules (Jarrett et al 2018d, Jarrett et al 2019; Figures 8 and 9).

Stable carbon isotopic signatures (δ13C) of n-alkanes and the bulk saturated and aromatic hydrocarbon fractions were used to identify differences between source rocks, the produced oil, and oil stains in the McArthur Basin, as δ13C has proved useful for determining oil–oil and oil–source rock correlations (eg Murray et al 1994, Boreham and Ambrose 2007, Edwards et al 2013). Source rocks in the Velkerri Formation have n-alkane δ13C values ranging from -35.0‰ to -30.7‰ and those the Kyalla Formation range from -33.6‰ to -28.7‰, indicating a large overlap between the source rocks in the Roper Group (Figure 10). However, there is an isotopic differentiation between the Mesoproterozoic Roper Group and the Paleoproterozoic Barney Creek Formation, which has more isotopically enriched values between -24‰ and -29‰ (Figure 10). As the Barney Creek Formation dataset is limited to one well, further analyses are required to produce a statistically significant regional dataset.

The δ13C of n-alkanes of oil stains in the Velkerri Formation are in the range from -33.7‰ to -31.9‰ and sit within the most isotopically depleted source rock interval within this formation (Figure 9). This provides strong evidence for self-sourcing of the oil stains. Oil stains from

![Figure 8](image_url)  
Figure 8. Gas chromatograph-mass spectrometer (GC–MS) total ion chromatograms of characteristic source rock extracts in the (a) Velkerri, (b) Barney Creek, (c) Wollogorang formations of the McArthur Basin, and the (d) Doomadgee and (e) Mount Les Siltstone of the Isa Superbasin. All extracts contain a large UCM, high ratios of mid-chained and terminal branching mono methyl alkanes to n-alkanes. Only the Barney Creek and Wollogorang formations contain high concentrations of saturated isoprenoids including pristine and phytane.
the Kyalla Formation are in the range -31.5‰ to -28.45‰. These values are within the envelope of Kyalla Formation source rocks; however, low- to medium-chained \(n\)-alkanes (<\(n\)-C\(_{20}\)) also overlap into values of the most enriched Velkerri Formation (Figure 9). Carbon specific isotopes of \(n\)-alkanes in the Jamison 1 oil range from -31.5‰ to -30.2‰ and sit within the Velkerri Formation source rock envelope for values <\(n\)-C\(_{20}\) and within the Kyalla Formation for values >\(n\)-C\(_{20}\) (Figure 7). The \(n\)-alkane profile of the Jamison 1 oil appears to have a similar trend to the Kyalla Formation self-sourced oil stains and is therefore likely to have been sourced from the Kyalla Formation. The \(n\)-alkane envelope for the Barney Creek Formation is significantly more enriched in \(\delta^{13}C\) than those values seen for both source rocks and oils derived from the Roper Group (Figure 9).

A comparison of stable carbon (\(\delta^{13}C\)) saturate and aromatic isotopic values has been shown to define major Palaeozoic oil families in Australia (Edwards and Summons 1996, Edwards et al 1997, Summons et al 2002). These general trends in bulk \(\delta^{13}C\) are depicted in Figure 11 for oils and oil shows in the Arafura Basin, Northern Territory (Moore et al 1996); Canning Basin, Western Australia (Edwards et al 1997, 2013); and in the Georgina Basin, Northern Territory and Queensland (Boreham and Ambrose 2005). These results show that, in general, Palaeozoic marine oils become isotopically depleted with age. Roper Group oils and oil stains are isotopically even more depleted than the Palaeozoic oils, and have some of the most depleted carbon isotopic signatures of any Australian crude oil. Oil stains within the Velkerri Formation are the most isotopically depleted with \(\delta^{13}C\) values between -35‰ and -31‰. Kyalla Formation oil stains are slightly more enriched, with values ranging from -32‰ to -29‰, similar to Cambrian and Ordovician oils. The Jamison 1 oil sits within the cluster of Kyalla Formation oil stains, thus providing further evidence for a Kyalla Formation source (Figure 11).

**Thermal and burial history**

Proterozoic sedimentary basins in northern Australia have a complex thermal history due to a multitude of factors.
including: faulting (Etheridge and Wall 1994), hydrothermal fluid flow (Glikson et al 2006, Golding et al 2006 and references therein), igneous intrusions (Abbott et al 2001), and uncertainties on the overburden deposition through time (eg Palu et al 2018). To date, the only published burial history models for the McArthur Basin are by Crick (1989), Silvermann et al (2005) and Hoffman (2016). Silvermann et al (2005) and Hoffman (2016) both modelled wells in the Beetaloa Sub-basin; Crick (1989) modelled two drillholes and one petroleum well in the Gidye Sub-basin. The models of Crick (1989) demonstrate oil-window maturity in both the Barney Creek Formation and the Velkerri Formation. Despite variability in the input parameters used in the Hoffman (2016) and Silvermann et al (2005) models, eg the heat flow applied and the amount and timing of burial, both come to a similar conclusion as that of Crick (1989). Although source rock deposition occurred during the Mesoproterozoic, primary and secondary migration may have been active much later.

The EFTF program is investigating the regional burial and thermal history of Proterozoic sedimentary basins in northern Australia. Recent petroleum systems modelling work on the Lawn Hill Platform indicates a major burial event during the middle Mesoproterozoic related to deposition of the South Nicholson Basin (Palu et al 2018). Further work will investigate the thermal and burial history of the greater McArthur Basin and the South Nicholson Basin with a focus on the newly imaged Barkly Sub-basin (see Carr et al 2019).

Conclusions

Geoscience Australia is undertaking a detailed geochemical and petroleum systems study of northern Australian basins to better understand the hydrocarbon prospectively of the region and thus reduce exploration risk. One technique is to use the petroleum systems approach to compare the McArthur Basin to the frontier South Nicholson Basin and Isa Superbasin. This study has focused on the source rock component of the Mesoproterozoic Urapungan and Paleoproterozoic McArthur petroleum supersystems.

Geochemical data has demonstrated that the Urapungan and McArthur petroleum supersystems host good to excellent source rocks with the potential to generate both oil and gas in the McArthur Basin, as well as in the South Nicholson Basin and Isa Superbasin. Most kerogens in greater McArthur Basin source rocks are characterised by narrow activation energy distributions with high thermal stability that require high (140–160°C) temperatures for peak generation. Inherent variabilities within the kerogen kinetics and petroleum generative potential may be due to differences in organofacies; this requires further investigation. Although there are many similarities between the biomarker signatures, the stable carbon isotopes of both bulk saturate and aromatic fractions and n-alkanes can differentiate between source rocks and their derived oils within the Proterozoic. Specifically, the Paleoproterozoic Barney Creek Formation is more enriched in δ13C than the Mesoproterozoic Roper Group. Importantly, the only oil to have flowed to surface in the McArthur Basin is from the Jamison 1 drill stem test, which has been geochemically typed to a source rock within the Kyalla Formation. The results of this study provide a platform to target future work in northern Australia.

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References


105