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Shale Gas Volumetrics of Unconventional Resource Plays in the Canning Basin, Western Australia

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Abstract

Recent analyses of the potentially vast unconventional shale-gas resource in the Canning Basin, onshore Western Australia, estimate nearly 800 Tcf in the Goldwyer Formation alone. This and other Paleozoic marine shales share numerous characteristics with successful US shale-gas plays and commonly source conventional petroleum accumulations, although none has yet been produced directly. In order to further constrain volumetric estimates in the Canning Basin, we examined two formations that we identify as highly prospective, the Goldwyer and Laurel. Our assessment includes all data currently available for the basin and applies a combined volumetric modeling approach (USGS and PMRS). We compiled data regarding kerogen type, thermal maturity, hydrocarbon generation potential, rock mineralogy, and fluid analyses, in addition to data on porosity, permeability, and pressure and temperature variation, in every well that intersected these shales. Analysis showed maximum total organic content (*TOC*) of 6.4% (Goldwyer Formation), maximum vitrinite reflectance of nearly 2.0%, (Laurel Formation), and average Hydrogen Index of 0.13 gHC/gTOC (maximum of >1 in both formations). We then calculated total gas-in-place for the rock volumes corresponding to gas-prone sections of each shale (the Goldwyer III and Upper Laurel) by estimating total generation potential, original *TOC*, primary and secondary cracking of kerogen, and retained oil. Probabilistic analysis of the distribution of key parameters allowed estimation of total hydrocarbon in place, by applying a Monte Carlo simulation based on P90, P50, and P10. This resulted in the third independent estimate of Canning Basin shale-gas volumes and the first ever for the Goldwyer III and the Upper Laurel. Our work thus greatly improves confidence in estimates of the size of shale-gas accumulations in the basin, significantly increases the amount of data utilized in such estimations and provides the first reported volumes for previously unexamined shale layers.

Introduction

The Canning Basin of Western Australia is the largest sedimentary basin in Australia that is prospective for unconventional petroleum resources. It covers about 530 000 km^2, of which about 430 000 km^2 lie on the northwestern onshore portion of the state, an equivalent size to Texas, USA (**Fig. 1**, Petroleum Division & GSWA 2012). The basin is substantially under-explored, with only 307 wells drilled to date. Drilling is also very localized, mainly on the northwestern, coastward portion of the basin. Exploration in the past decade extended further into the basin, and scheduled work programs for the next few years will continue this trend, but such areas currently remain extremely frontier. The potentially highly prospective Kidson Sub-basin, for example, covers nearly 100 000 km^2 and contains eleven drilled wells (WAPIMS 2013).

The Canning Basin sedimentary fill is mainly Paleozoic; this and the youngest Cretaceous units all overly a Proterozoic basement (**Fig. 2**; D'Ercole et al. 2003). The basin is a northwesterly-trending intracratonic sag basin that lies between the Pilbara and Kimberley Cratons. It consists of two main depocentres separated by a mid-basinal arch; the northern depocentre contains the Fitzroy Trough and Gregory Sub-basin, while the southern includes the Kidson and Willara sub-basins **(Figs. 1 & 3).** Each depocentre is bounded by major fault systems, which separate them from the central arch and from their flanking terraces. Deposition in the basin included major episodes of evaporite formation and subsequent salt tectonism, a major succession of Devonian reef facies, and repeated episodes of continental to marine shelf deposition (D'Ercole et al. 2003).

Exploration in the Canning Basin traditionally centred on the Fitzroy Trough and Lennard Shelf, as well as parts of the Broome Platform and Barbwire Terrace, partly owing to a lack of infrastructure in more inaccessible parts of the basin (Petroleum Division & GSWA 2012). The Fitzroy Trough and Kidson and Gregory Sub-basins are potentially the most prospective areas of the Canning Basin, owing to their substantial accumulations of sediment and proven carbonate reservoirs. Despite past concerns about the potential of petroleum generation and migration, numerous shows and producing oil fields confirm the presence of four functional petroleum systems in the basin, the Ordovician, Devonian, Lower Carboniferous, and Carboniferous-Permian (D'Ercole et al. 2003).

Much current exploration in the Canning Basin centres on recent assessments of an exceptionally large unconventional shale-gas accumulation in the basin, estimated at 764 Tcf risked original gas-in-place (OGIP) for the Goldwyer Formation alone by the US Energy Information Agency (EIA 2011). The EIA estimate is best regarded as provisional, owing to the limited data used and the very generalized scope of the study. For example, they estimated shale-gas volumes in the Canning Basin for only the Goldwyer Formation, used only data from very limited acreage, and applied a recovery factor of 30% to obtain recoverable reserve figures, a factor that seems inappropriately optimistic, even by US standards (Barker 2012; McGlade et al. 2012). This estimate was recently modified in an updated 2013 study, to 748.7 Tcf of dry gas (risked OGIP) in the Goldwyer Formation, with an additional 395 Tcf of wet gas and 83.5 Tcf of associated gas (EIA 2013). However, the updated assessment excluded some areas of probable Goldwyer Formation gas-maturity (the entire Fitzroy Trough and Gregory Sub-basin) based on present-day burial depths that may be inaccurate (WAPIMS 2013). The only other published appraisal of gas resources in the Canning Basin, undertaken by the Australian Council of Learned Academies, estimated 409 Tcf of wet gas and 387 Tcf of dry gas in the Goldwyer Formation and 106 Tcf of wet gas and 63 Tcf of dry gas in the Laurel Formation (recoverable GIIP; Cook et al. 2013). The current investigation being undertaken by the DMP Resources Branch attempts an independent estimate of the entire shale-gas resource present in the Canning Basin, using all available data and all potential shale layers. This paper focuses on the two most prospective targets, the Goldwyer and Laurel Formations.

Statement of Theory and Definitions

This study examined ten potential shale-gas intervals, of which two were high-graded through classification and ranking (the Laurel and Goldwyer Formations). Each shale was classified according to *TOC* content (indicating source rock potential), Vitrinite Reflectance class (R_0, indicating maturity) or its equivalents in Ordovician or older material, Rock Potential (S_2, indicating remaining hydrocarbon generation potential from hydrogen cracking), shale thickness, porosity, clay content, and quartz / calcite content (indicating producibility), Capillary Suction Test (CST) Ratio, fracture intensity (measured visually from core, after Ding et al. 2010), and pressure data, which were measured as described below. Ranking parameters followed those of Netherland Sewell & Associates, Inc. (NSAI; Knights & Petrov 2010; **Table 1**). Each parameter was assigned a certain number of points for a corresponding range of values; each shale was then evaluated against these ranges, and values were totaled to give a cumulative score, which can range from 12 to 100 points. Maximum values were used for rankings, and the lowest value (2 points) was assigned when no data were available (e.g. CST ratio, fracture intensity, and pressure gradient for most shales).

The Middle Ordovician Goldwyer Formation is the oldest known geologic unit in the Canning Basin with unconventional shale-gas potential, as older rocks are primarily sandstones and limestones or non-sedimentary basement rock. The Goldwyer Formation consists of interbedded shales and siltstones with pyritic layers, which over- and underlie a middle carbonaceous member. The formation may be divided into a number of lithostratigraphic units, commonly a lower shale, middle limestone member and upper shale in basinal areas, with much greater carbonate content on the platforms and terraces (Fig. 2; Haines 2004). Deposition of the Goldwyer Formation occurred under unconstricted marine conditions, which ranged from subtidal and lagoonal to higher energy, shoal to intertidal to shelf conditions (Haines 2004). Along the Broome Arch, localized uplift in the latest Ordovician post-dated Goldwyer Formation deposition, resulting in karstification, dolomitization, and porosity development (D'Ercole et al. 2003). The formation thickens considerably in the Fitzroy Trough and Willara Sub-basin, and thins erosionally towards the basin edges. Depths and thicknesses of the Goldwyer Formation in the Kidson and even the Gregory Sub-basin remain conjectural, owing to a paucity of well data and the poor quality of limited seismic coverage.

The Fairfield Group, which overlies the Devonian reef complexes and extends from the Latest Devonian to the Middle Carboniferous, is a shallow marine carbonate and shale succession (Haines and Ghori 2010). It contains the second high-graded shale-gas target, the Laurel Formation, which has TOC values up to a maximum of 4.8%. The Laurel Formation is only present, however, in the northern depocentre, as it was never deposited south of the Fitzroy Trough, except as very thin section on the flanking, southern terraces (Fig. 3).

Well data were mainly compiled from Well Completion Reports (WCR's, see WAPIMS), with additional information taken from industry studies (Jackson et al. 1994; SRK 1998) and Geological Survey of Western Australia (GSWA) publications (especially Ghori 2011; Ghori & Haines 2006). Shale characteristics were summarized and compared with average values from productive US plays **(Table 2).** Certain data known from US shale-gas plays, such as production characteristics, reserves, etc., are not available for shales in Australia, which are yet to be produced for shale gas. In general, prospective Canning Basin shales compare fairly well with known US plays. The basin is significantly larger than any US play except the Marcellus Shale, and both the Goldwyer and Laurel Formations cover much larger areas than most US plays. Both shales are approximately four times thicker than the US average, with equivalent depths, pressures, porosities, and mineralogies. Organic content and maturation are the two problematic characteristics for Canning Basin shales, with lower average TOC and R_o values than in the US. Maximum values for both measurements, however, are as high as averages in US plays, and some measurements of R_o from both formations do lie within the gas maturity window.

Gross thickness of fine-grained intervals was calculated for each shale unit using data from WCR's, published well data, mud logs, and well logs for every well drilled to date in the basin. Net shale-gas interval thickness was calculated by picking shale intervals with corresponding high TOC values (>1%), resulting in a very conservative measurement of the amount of a shale that could be source rock. This method is inadequate in that available TOC measurements rarely span the entire thickness of each formation. A value of 1% TOC cut-off, rather than the commonly standard 2%, was chosen to reflect potential best-practice in underexplored basins. Successful shale-gas plays require high *original* TOC values, not high present-day TOC, because much of the original organic content may already be converted to hydrocarbon (Cheng 2012; Zdanaviciute & Lazauskiene 2009). This means that a value of 2% may exclude potentially productive plays, a drawback reflected in recent USGS practices (Kirschbaum et al. 2012).

Data on the distribution of shales throughout the Canning Basin is available in reasonable detail for the Fitzroy Trough, Lennard Shelf, Barbwire Terrace, Broome Platform, and Willara Sub-basin, but remains sparse elsewhere. Mapping some shale layers is possible using the few available well penetrations and poor available seismic data, but estimation of areal extents will necessarily remain preliminary pending better well control and future acquisition of three-dimensional (3D) seismic data. Maps were produced for the two most prospective shales, the Goldwyer Formation (from 59 well penetrations; **Fig. 4**) and Laurel Formation (from 79 well penetrations; **Fig. 5**).

Geochemical data was taken mainly from Ghori & Haines (2006) and Ghori (2011), supplemented with recent unpublished GSWA data and a complete search of all available geochemical datasets in WAPIMS. Data compiled for analysis included measurements used for the original shale classification and ranking, as well as additional RockEval data [T_{max}, S_1, S_3, S_1+S_2, Production Index (*PI*), Hydrogen Index (*HI*), and Oxygen Index (*OI*)]. Where possible, porosities were calculated from well logs. Mineralogy (percent non-clay) was taken from X-ray diffraction (XRD) reports, which exist for only six wells in the Laurel Formation and five wells in the Goldwyer. When XRD was not available, WCR descriptions of cores, sidewall cores, and occasionally cuttings were used to estimate average percentage porosity. In some cases, TOC measurements were validated because such measurements are lacking in most sections of most wells and are notoriously unreliable in the Canning Basin owing to contamination during drilling etc. (Ghori, pers. comm.). As an alternative means of estimating the organic content, the total weight fraction of TOC was calculated using Eqs. 1-3, based on petrophysical data and considering the type of drilling mud used (Jacobi et al. 2009). This resulted in comparable estimates of percentage of TOC in both shales.

Total Grain Density: $$\rho_{gr} = \frac{(\rho_b - \rho_{fluid}\varphi)}{(1-\varphi)} \quad (1)$$

Total Volume Fraction: $$V_{TOC} = \frac{\rho_m - \rho_{gr}}{\rho_m - \rho_{TOC}} \quad (2)$$

Total Weight Fraction: $$m_{TOC} = \left(\frac{\rho_{TOC}}{\rho_{gr}}\right)(V_{TOC}) = \left(\frac{\rho_{TOC}}{\rho_{gr}}\right)\left(\frac{\rho_m - \rho_{gr}}{\rho_m - \rho_{TOC}}\right) \quad (3)$$

Volumetrics. After shale ranking, formation mapping, and petrophysical analysis, the most prospective stratigraphic section of the high-graded shale-gas units were chosen for volumetric calculations. To obtain gross rock volumes, prospectivity maps were produced by combining areal extent, shale thickness, and zone of gas maturity **(Figs. 6 and 7).** Gas generation from hydrocarbons in shale source rocks strongly depends on the quality (original *HI*) and quantity (original *TOC*) of the organic matter present in thermally immature source rocks (Peters et al. 2005). The two main processes that result in the formation of thermogenic gas within shales are primary and secondary cracking (Jarvie et al. 2005). Primary cracking involves the decomposition of kerogen or bitumen into oil and gas, while the further decomposition of oil into gas comprises secondary cracking. Rock volume and calculated estimates of original *TOC* and original *HI* (obtained as described below) allowed estimation of the total Gas-Initial In-Place (GIIP, which is identical to OGIP as calculated by the EIA) in each section. This combined calculated estimates of expelled oil and gas, assuming an expulsion factor, with those for the retained capacity of oil and gas, or the amount of retained hydrocarbon that may be trapped in organic matter through adsorption.

To quantify the generative capacity of the source rocks in the basin, we used the source rock method (Cheng et al. 2012) for calculating the mass of generated hydrocarbons from only five parameters: source rock volume (determined above), HI_o (determined below), and weight percent of TOC, formation density, and HI_{pd} (all measured directly). Although volumetric estimates derived using the source rock (or RockEval) method are often wrong by an order of magnitude, this method is the only one available for use in frontier / under-explored areas such as the Canning Basin (Barker 2012). Following the source rock method, kerogen type (Types I-IV) is used as an indicator of the original *HI* expressed in a rock (HI_o) and thus allows its estimation (Eq. 4). If a kerogen sample is not completely decomposed, estimation of original *HI* must be adjusted using the transformation ratio (TR, Eq. 5), based on the Claypool equations below (Peters et al. 2006). With 100% conversion, the TR is equal to 1. Original TOC is calculated using present-day *TOC* and *HI* (Eq. 6). Finally, the amount of retained oil converted to the gas phase during secondary cracking is estimated using a correction factor (K) for residual hydrogen (Eq. 7).

Original Hydrogen Index: $$HI_o = 750\left(\frac{\%Type\ I}{100}\right) + 450\left(\frac{\%Type\ II}{100}\right) + 125\left(\frac{\%Type\ III}{100}\right) + 50\left(\frac{\%Type\ IV}{100}\right) \qquad (4)$$

Transformation Ratio: $$TR_{HI} = 1 - \frac{HI_{pd}[1200 - HI_o(1 - PI_o)]}{HI_o[1200 - HI_{pd}(1 - PI_{pd}]} \qquad (5)$$

Total Organic Carbon: $$TOC_o = \frac{HI_{\mathrm{pd}}\left(\frac{TOC_{\mathrm{pd}}}{1+k}\right)}{\left[HI_o(1 - TR_{\mathrm{HI}})(83.33 - \frac{TOC_{\mathrm{pd}}}{1+k})\right] - \left[HI_{\mathrm{pd}}(\frac{TOC_{\mathrm{pd}}}{1+k})\right]} \qquad (6)$$

Correction Factor: $$k = TR_{HI}C_R \qquad (7)$$

We next used Jarvie's method to quantify source rock potential in a deterministic analysis (**Figs. 8 and 9**; Jarvie et al. 2007). First, primary oil and gas potential was estimated for each source rock, then the total hydrocarbon generation was estimated for the given source rock thickness. Analogues in the US Barnett Shale and unpublished DMP research in the Canning Basin suggested an expulsion factor of 60%, as opposed to the 80% used previously (EIA 2011). The Barnett Shale was used as an analogue here owing to overall similarities with the Goldwyer Formation (e.g. an R_o average of 1.25%, lower TOC than the average US play, and similar lithology), and because it is currently the best known and most studied and produced shale-gas source in the US (EIA 2012). As there was insufficient hydrogen in the Laurel and Goldwyer Formations oil to convert it entirely to gas, a correction factor of 47% was applied.

Rock volumes taken from our prospectivity maps were combined with the hydrocarbon generation volumes to estimate GIIP, using a combination of methodologies proposed by the US Geological Survey (USGS) and Advanced Resources Institute (ARI), as detailed below (Dubiel et al. 2011; INTEK 2011). ARI, the contractor for the EIA evaluation, split their study area into two portions, termed the ‘active’ and ‘undeveloped’ parts (INTEK 2011; McGlade et al. 2012). Utilising numerous technical, commercial, and industrial reports, ARI estimated the Ultimately Recoverable Resources per well (URR/well), given existing well spacing within both the active and undeveloped parts. The main disadvantage of this method is the assumption that the ‘active’ part is the acreage leased by a shale-gas producer; ARI thus used only parameters from a single leaseholder and its acreage for their Canning Basin estimation. This drawback is particularly disadvantageous in the Canning Basin because shale-gas formations greatly exceed current leaseholder acreage.

Following the updated USGS method (Dubiel et al. 2011), we considered the entire Canning Basin to be the investigated area and divided our investigation area into wells per unit area. We then split the shale play into individual areas, and estimated the areal extent of each portion, the drainage area of wells within those areas, and the mean URR/well of each area. In this updated method, we also estimated a ‘success ratio’ separately for the “sweet spots” and “non-sweet spots”. A drawback to the USGS method is that sweet spots and estimation of productivity for undeveloped areas such as the Canning Basin are currently very difficult to delineate. We estimated the drainage area and thickness of shale-gas units from our limited well data, then extended these to surrounding graticular blocks. Based on this procedure, we classified the Goldwyer Formation into six sectors (Fig. 6) with differing source rock thickness (Bellis 1987), maturity, and area; we likewise subdivided the Laurel Formation into four sectors, although in this case we used an equivalent area for each sector (Fig. 7). Given the lack of 3D seismic data in the Canning Basin, sweet spots are difficult to recognise, so we took the average of the parameters for each section, based on the source rock thickness in each well. Using the calculations for TOC_o, TOC converted to hydrocarbon and unconvertible hydrocarbon as described above, we then estimated the expelled hydrocarbon (possibly migrated), the hydrocarbon retained as gas, and the liquid volume per cubic kilometre. The sum of these factors resulted in total retained gas in each formation (Fig. 9; Jarvie et al. 2007).

We then derived a probabilistic estimate of un-risked GIIP using the full range of reservoir and geochemical data, as a comparison to the deterministic estimate detailed above. This incorporated the minimum, mean, and maximum of each parameter and its type of distribution (normal, log normal, triangular, type of skewness), applied to each sector. A Monte Carlo Simulation program assessed the distribution of parameters in each sector and estimated the GIIP separately for each depth section based on un-risked P90, P50, and P10 estimates. We then summed values for all sectors to give a total probabilistic estimate of shale gas in Tcf.

Presentation of Data and Results

Shales. The Goldwyer Formation lies at an average depth of 1330 m, with a depth range of 284 m (Solanum 1) to 2533 m (Wilson Cliffs 1). The formation thickness averages 353 m, with the thinnest section at Musca 1 (29 m) and the thickest at Willara 1 (742 m). Average TOC in the Goldwyer Formation is 0.61%, with a maximum of 6.4%, while average R_o is 1.02, with a maximum of 1.57. The Goldwyer Formation can be informally divided into three members: the basal Goldwyer III, the middle Goldwyer II, and the uppermost Goldwyer I. Goldwyer I and III are shale-rich layers distributed in the south of the Fitzroy Trough, while the Goldwyer II is a highly dolomitized section seen in many of the wells southwest of the Fitzroy Trough. We selected the Goldwyer III, which is a black, carbonaceous shale ranging from about 38 m (Thangoo 1) to 366 m (Matches Springs 1, Fig. 6) in thickness, for volumetric estimation owing to its better petrophysical characteristics and its probability as the primary gas source in the formation.

The Laurel Formation is the demonstrated source for a number of discoveries on the Lennard Shelf and shows elsewhere in the basin (GSWA 2006; Haines & Ghori 2010). It averages 1593 m in depth and 553 m in thickness, with ranges of 4 m to 2883 m in depth and 6 m to 1554 m in thickness. Average TOC in the Laurel Formation is 0.67%, with a maximum of 4.84%, while average R_o is 0.83, with a maximum of 1.95. The formation may also be sub-divided into a number of informal members: in descending order, the upper shale, upper carbonate, lower shale, and lower carbonate. We chose the Lower Laurel Shale for volumetric calculations because it is probably the most productive layer, based on its higher maturity as well as numerous gas shows. It is quite thick in places, reaching more than 700 m around the Valhalla accumulation (Fig. 7).

Shale Rankings. Rankings for the Canning Basin shales ranged from 38 to 68 points **(Table 3).** By comparison, ranking by the junior author of three shale-gas formations in the Perth Basin, WA using the same methodology resulted in scores of 54, 56, and 58. In general, low scores in the Canning Basin resulted from low generation potentials and low thermal maturities, as well as a lack of data (particularly for fracture intensity, CST ratios, and pressure gradients), not from lack of organic content. Although TOC percentages are lower in most Canning Basin shales than in the US, they remain high enough to produce gas and to achieve medium to high rankings according to NSAI parameters.

Geochemistry.

Thermal Maturity. T_{max} values were plotted against depth **(Fig. 10)** to evaluate hydrocarbon maturity, using the following ranges: less than 435°C (immature for hydrocarbons), 435°C to 465°C (oil maturity), greater than 465°C (gas maturity / overmature). One hundred wells with temperature data provided 1228 values, although certain formations contain very few measurements. The spread in this data was very wide, ranging from 181 to 548°C, but much narrower when only samples with TOC values greater than 1% are included. Nearly all data fell between 400 and 450°C (averaging 430°C), indicating that most wells and shales are in the oil window. In the Goldwyer Formation, values again averaged 435°C, in the early-maturity oil window, while the spread in temperature range was much greater in the Laurel Formation, with many temperatures indicating presence in the gas window (Fig. 10). Lower values for the Goldwyer Formation probably reflect the presence of oil-prone source rocks in the Goldwyer I, as other data suggests that there is in fact gas-prone rock in the formation (e.g. *HI* versus *OI* plots, see below).

R_0 values were compiled for 40 wells, resulting in 268 data points, and plotted against depth **(Fig. 11).** R_0 ranged from 0.25 to 1.57% and averaged 1.02% (oil maturity) in the Goldwyer Formation. It appears that R_o and hence maturity increase with depth in most wells; although the amount of data is sparse, oil-mature R_o appears at about 1300 m in the Goldwyer Formation and 1500 m in the Laurel Formation **(Fig. 12).**

TOC / Production Potential. Data on TOC were available for 107 wells, totalling 2689 measurements. Nearly 1000 measurements exist in the Goldwyer Formation and nearly 300 in the Laurel Formation. A cut-off of 1% TOC was again applied, and data indicated that all shales have sufficient potential to at least generate petroleum (Kale 2009). Values for production potential can be measured by plotting TOC values against S_1+S_2 (Generational Potential, or the quantity of kerogen already converted to hydrocarbon). Plotting values for the Canning Basin demonstrated some samples with excellent production potential and many in the “good” to “very good” range **(Fig. 13).** By far the largest amount of data points within the “very good” area of the plot are from the Goldwyer Formation, although this is probably an artefact of there being much more available data for this interval than for others in the basin.

Kerogen Typing. *HI* is a measure of hydrogen remaining in a source shale, while *OI* demonstrates the amount of oxygen present in the kerogen. Both measures are calculated from RockEval measurements, and plotting one against the other can show the source rock character (i.e. gas- versus oil-prone, and its kerogen type; **Fig. 14**). There are 383 data points with both *HI* and *OI* in the Canning Basin; 112 of these lie in the Goldwyer Formation and 31 lie in the Laurel Formation. *HI*'s range from 5 to 1174, and *OI*'s from 4 to 1313. Most rocks appear to be Type III kerogen, and range from oil-and-gas prone to inert. The Goldwyer Formation mainly contains Type II and III kerogen and is oil-and-gas prone, although much data also falls in the oil- and gas-prone ranges. Average *HI* in the Goldwyer Formation is 176 and average *OI* is 138. Most data points in the Laurel Formation are Type IV and immature, but those that are actually mature for hydrocarbons generally lie in the Type III and gas-prone ranges, with an average *HI* of 87 and an average *OI* of 102.

Plotting *HI* against T_{max} may also indicate the maturity window of source rocks. In the Canning Basin, most samples appear as oil mature, which is potentially the largest problem when exploring for shale gas in the Canning Basin. The Goldwyer Formation, for example, is generally early mature (430 to 445°C), but also contains many immature samples **(Fig. 15).** Most Goldwyer Formation data is also Type II, although there is some spread in the data. The Laurel Formation, which has much less data available, clusters in the Type III and Type IV kerogen range, generally in the early maturity oil window. This data probably reflects the fact that parts of each formation (the Goldwyer I and the Upper Laurel shale) are probably oil-mature, as are shallower sections of each formation (e.g. areas on the Lennard Shelf).

Organic matter type may also be calculated as the amount of cracked hydrocarbon per CO_2 in the rock (S_2/S_3), a measurement that generally corroborates other RockEval data **(Figs. 16a and 16b).** S_2 and S_3 data are available from 27 wells in the Goldwyer Formation and from 25 wells in the Laurel Formation, and show 59% of Goldwyer Formation and 72% of Laurel Formation penetrations lying in the early gas window; most other data points fall within the oil and gas window, with only a few in the oil window. Finally, kerogen typing may be achieved by plotting TOC against Generational Potential and dividing the results into kerogen types I to IV **(Fig. 17).** This method corroborates most Canning Basin shales as being Type II or Type II/III, and the Goldwyer Formation as having the highest generational potential.

It appears that maturity in both the Goldwyer and Laurel Formations may be a concern for shale-gas exploration in the Canning Basin, as some RockEval data (*OI* and *HI*, S_2/S_3) supports interpretation of these shales as being in the gas window, but some data (mainly temperature data) supports interpretation as mainly in the oil window. The most logical interpretation may be that the shales are both oil- and early-gas-mature, but in different stratigraphic layers and in different locations within the basin.

Volumetrics Estimation. The Goldwyer III and the Lower Laurel were classified into six and four sectors respectively, based on thickness and maturity (Figs. 6 and 7). Original *TOC* and *HI* were determined analytically, and original *PI* was assumed to be 0.2 for all sectors. The total potential hydrocarbon generation, total oil and gas expelled, and total retained were determined for each sector (**Tables 4 and 5**; Jarvie et al. 2007). This resulted in a deterministic estimate of un-risked GIIP of 783.9 Tcf for the Goldwyer III and 193.6 Tcf for the Lower Laurel. Probabilistic methods resulted in a P10, P50, and P90 estimate for each shale, which are the sums of the probabilistic estimates for each sector **(Table 6).** For the Lower Laurel, a 40.2% higher estimate of GIIP resulted, with a P50 of 271.5 Tcf (ranging from 192.1 to 399.8 Tcf). Probabilistic estimation for the Goldwyer III, however, was only increased by 10.7%, to 867.4 Tcf for the P50 case (ranging from 736.2 to 1016.4 Tcf).

To facilitate comparison with previously published shale gas assessments, we also calculated risked GIIP with risk factors of both 50% (our preferred factor) and 30% (the factor used by the EIA; ACOLA does not appear to have calculated risked GIIP), as well as Risked Recoverable Resource, using a variety of recovery factors (30%, after EIA 2011; 20%, after EIA 2013; and 15%, our preferred recovery factor and the one used by ACOLA). We extrapolated each of these volumes for each of the three previous shale gas studies **(Table 7),** as there previously was no other way to properly compare these estimates. A wide variety of recovery rates are reported for shale gas plays and applied to volumetric assessments, and large uncertainties exist regarding which might possibly be appropriate in an area as underexplored as the Canning Basin (Barker 2012). Considering this, and the fact that only perhaps 10 to 20% of a shale gas play consists of ‘sweet spots’, we used a 15% recovery factor, lower than the EIA figures, which only account for recovery efficiency, not sweet spot availability. This resulted in risked GIIP values (50% risk factor) of 392 Tcf for the Goldwyer III and 96.8 Tcf for the Lower Laurel and risked recoverable volumes (15% recovery factor) of 35.3 Tcf for the Goldwyer III and 8.7 Tcf for the Lower Laurel.

Conclusions

Of the ten Canning Basin shales examined for their potential as unconventional shale-gas resources, the Goldwyer and Laurel Formations were ranked the highest. Further examination of the two top-ranked shales resulted in the compilation of all available geochemical, lithological and volumetric data in the Canning Basin for these two intervals. The Goldwyer Formation was classified as being in the early maturity oil window, and containing most of the “excellent” and “very good” samples of production potential. It is generally composed of Type III kerogen, and oil-and-gas- or gas-prone in most of its extent. It appears that the Goldwyer III is gas-prone, while data showing the Goldwyer Formation as oil-prone probably comes from the Goldwyer I. Much less data was available for the Laurel Formation, but what does exist suggested that this formation is also composed of Type III kerogen and lies in the early mature oil window. Although data taken from both shales indicated the presence of oil-mature rock, and maturity may be a limiting factor for shale-gas exploration in shallower parts of the basin, we also concluded the presence of gas-maturity (oil overmaturity) in many samples, particularly those taken from the Goldwyer III and the Lower Laurel.

Our deterministic estimate of total original gas-in-place for the Goldwyer and the Laurel Formations is the most detailed published estimate to date. It expands upon the scope of the only previously published calculations of resource potential of the Canning Basin (Cook et al. 2013; EIA 2011 & 2013) by extending the analysis to multiple shales; estimating resource size in only the most prospective layers, rather than the entire formation; using all available data, rather than only that from leased areas or a single explorer; and using actual rock volumes, rather than an average thickness for each shale. The three previous estimates of Goldwyer shale gas in the Canning Basin appear to differ drastically, from 149.7 Tcf GIIP (EIA 2013) to 387 Tcf risked recoverable resource (ACOLA, Cook et al. 2013). However, this results only because ACOLA did not risk the volumes, and the EIA used a 5% higher recovery factor. Accounting for these differences results in nearly identical volumetric estimates of risked recoverable resource, at 116.1 Tcf (ACOLA) and 114.6 Tcf (EIA, Table 7), despite the fact that volumetric estimates in frontier basins are known to differ from reality by up to an order of magnitude (Barker 2012; McGlade et al. 2012). These assessments of course used nearly identical baseline data, but their remarkably similar conclusions probably also stem from the general lack of data in the Canning Basin. This comparison also highlights the fact that the only real difference between these estimates results from differing risk and recovery factors.

We still cannot compare our estimates with previous studies, however, because we estimated volumes in only the Goldwyer III and the Lower Laurel, while ACOLA and the EIA included both formations in their entirety. We can only conclude that our volumes are smaller than those estimated for the whole formations, as one would expect, and that our assessment is probably a more realistic estimate of the amount of shale gas present because it excludes the portions of the two formations that are probably not gas mature and that are not actually shale (e.g. the Laurel carbonates). Our best estimate of risked recoverable resource is 35.3 Tcf for the Goldwyer III and 8.7 Tcf for the Lower Laurel, but this is highly dependent on both future recovery efficiencies and on the high risk factors associated with frontier exploration in a basin containing very little infrastructure.

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Nomenclature

C_R = residual organic carbon (carbon remaining after pyrolysis), wt. %
HI = hydrogen index (remaining potential (S_2) divided by TOC x 100), mg HC/g TOC
k = correction factor for enriched residual organic carbon at high maturity
PI = production index [$S_1/(S_1 + S_2)$], values from 0.00 to 1.00
R_0 = vitrinite reflectance or its equivalent, values from 0.00 to ~3.00%
TOC = total organic carbon, wt. %
TR = transformation ratio
TR_{HI} = transformation ratio, calculated from HI
V_{TOC} = volume fraction of *TOC*
$\mathrm{m_{TOC}}$ = mass fraction of *TOC*
ρ_b = bulk density, g/cm^3
ρ_{fluid} = fluid density, g/cm^3
ρ_{gr} = grain density of rock, g/cm^3
ρ_m = matrix density, g/cm^3
ρ_{TOC} = *TOC* density, g/cm^3
φ = porosity, &

Subscripts used with terms:
$_{pd}$ = present day
$_o$ = original

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