A systematic approach to unconventional play analysis: the oil and gas potential of the Kockatea Shale and Carynginia Formation, North Perth Basin, Western Australia

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ABSTRACT

Key formations throughout the North Perth Basin have been mapped from 3D and 2D seismic data to define depth grid inputs to a 3D basin model calibrated with temperature and maturity data from 45 wells, plus an additional 27 pseudo well models. The Permian Carynginia Formation and Early Triassic Hovea Member of the Kockatea Shale have been defined in this model as unconventional shale reservoir targets.

Basin-wide pyrolysis data have been used to construct kinetics curves for both the Carynginia Formation and Kockatea Shale, which define Type D/E and mixed B, and D/E kerogen types, respectively. When combined with thermal history inputs, these source rocks expel and retain significant volumes of hydrocarbons, of which the free hydrocarbons in the retained components reach 22 BCF/km² for the Carynginia Formation gas and 8 MMBBLS/km² and 21 BCF/km² for the Hovea Member liquids and gas, respectively. The defined kinetics relationships allow the estimation of kerogen-specific oil and gas windows, which have been applied across the study area to map unconventional play fairways for both formations, and to calculate the initial total organic carbon (TOC) and hydrogen index (HI) for each unit prior to significant maturation. This study employs a mass balance approach through basin modelling as a means of estimating likely retained hydrocarbon volumes in key unconventional reservoirs in the basin.

Sonic and density data from 28 wells in the basin have been used to calculate theoretical porosity to determine likely areas of overpressure. When combined with observed connection gas peaks and modelled maturity, there is a reasonable correlation suggesting that the basin exhibits modest overpressure of 2–6 MPa associated with the main gas window at 1.2 Ro% and this observation is applied to the play fairness mapping process.

Play fairways are further constrained through geomechanical and stress considerations from mechanical earth models (MEMs) built from log and image data for wells in the basin. These data define an overall strike-slip stress regime with S_Hmax consistently oriented east to west with the exception of local perturbations. Dynamic rock strength calculated from the same MEM process shows target zones in the Kockatea Shale and Carynginia Formation ranging from ~60–130 MPa unconfined compressive strength (UCS), calibrated against available static data. The net thickness of rock with a UCS >75 MPa is mapped and overlain on retained components reach 22 BCF/km² for the Carynginia Formation gas, shale oil, retained and free hydrocarbons, vitrinite reflectance, kerogen kinetics, play mapping, rock strength, stress, fracture, unconfined compressive strength (UCS).

INTRODUCTION

Unconventional play analysis and resource estimates for Australian basins tend to rely heavily on comparisons with US analogues even though many of these have very different geological characteristics, such as organic composition and geological setting. For this reason, the authors have tried to develop a methodology for more rigorous multi-disciplinary evaluation of unconventional targets that might be more suited to the Australian setting. This approach involves basin-wide mapping of the key geological parameters, combined with geochemical and geomechanical interpretation and modelling, to identify potential sweet spots for exploration and appraisal. The key components are basin-wide estimation of hydrocarbons-in-place, rock strength, in situ stress and reservoir pressure. The Perth Basin is highly suited to developing and implementing an unconventional play methodology for a number of reasons. It has:

1. extensive regional 2D seismic and some 3D data;
2. a substantial database from many historical wells, most of which have penetrated the most prospective Permo-Triassic interval;
3. proof of a working petroleum system from past conventional gas and oil discoveries;
4. encouraging test results from recent vertical wells drilled for unconventional targets; and,
5. a commercial incentive associated with access to existing infrastructure and attractive gas markets.

The methodology was specifically designed for the evaluation of the Carynginia Formation and the Kockatea Shale in the Perth Basin, but could easily be adapted for use for other rock types—such as tight gas sandstone—and for other basins.

Knowledge of unconventional play systems has increased dramatically in recent years. What was widely referred to in the industry as shale gas is now recognised as a hybrid system in which clay minerals are often a subsidiary component (e.g. Bustin and Bustin, 2011). The abundance and type of organic matter is clearly relevant to the generation of hydrocarbons but in some rocks also provides significant porosity and storage (Loucks et al, 2009). The presence of some fine-grained quartz or carbonate, as discrete interbeds of disseminate in the shale matrix, also contributes to storage capacity, but additionally demonstrated by substantial flows from wells such as Arrowsmith–2. This study outlines a new workflow for mapping unconventional resources and suggests that Australian rocks are unique in both depositional environment and mechanical properties such that unconventional assessment using US play cut-offs may be misleading.

KEYWORDS

North Perth Basin, Kockatea Shale, Carynginia Formation, shale gas, shale oil, retained and free hydrocarbons, vitrinite reflectance, kerogen kinetics, play mapping, rock strength, stress, fracture, unconfined compressive strength (UCS).
increases rock strength and hence the propensity for natural and induced fracturing (Sone and Zoback, 2013).

This study adopts a mass balance approach, which attempts to model and account for all hydrocarbons generated in the play system. This concept is summarised in Figure 1. The total oil and gas in place in any unconventional reservoir is referred to as the retained hydrocarbons and is the sum of the free and adsorbed components (Bustin et al, 2009). The generation of hydrocarbons in any organic-rich rock will result in oil and gas being held within the organic and matrix porosity but also adhered or sorbed to the surface of organic matter by Van der Waals forces. This is referred to as the sorption capacity of the rock. For shallow unconventional systems—such as CSG—a significant proportion of production is believed to emanate from the adsorbed gas volume. For deeper unconventional reservoirs such as shale or tight sands, however, production is thought to be dominated by the free hydrocarbon component that is retained in the organic and matrix porosity (Michael and He, 2011). Consequently, it is recommended that estimates of recoverable reserves or resources for the Perth unconventional reservoirs should exclude the adsorbed component of the retained hydrocarbons.

As generation proceeds, it is expected that the accessible organic and matrix porosity may be fully saturated after which excess hydrocarbons will be expelled from the source layer. Expulsion efficiency, however, is dependent on the characteristics of the organic matter (kerogen type, concentration and distribution) but also on multiple external factors such as thermal maturity, pressure and access to migration conduits. If expulsion is inefficient or impeded, then a significant volume of hydrocarbon saturation, both oil and gas, may reside within the available matrix and organic porosity of the source layer, and significant overpressure might be induced. If, however, expulsion is highly efficient, a large volume of free hydrocarbons will be expelled from the source layer and migrate to conventional and other unconventional traps, or escape from the system. In this case hydrocarbon saturations and overpressure in the source layer might be expected to be lower.

**REGIONAL GEOLOGY**

Regional geology is a basic requirement for unconventional play analysis and the quantification of prospective resources. The methodology described in this paper involves integrated assessment of hydrocarbons-in-place, rock strength, in situ stress and reservoir pressure, all of which require a full structural and stratigraphic understanding of the target basin. The Perth Basin has the advantage of a comprehensive suite of conventional well log data and extensive seismic coverage. The basin has also been intensively studied, given nearly 50 years of conventional exploration and production activity.

The North Perth Basin is defined as a north–south elongate basin located 140 km north of the city of Perth, onshore WA (Fig. 2). The basin is about 750 km long and up to 80 km wide, and has a complex geological history comprising multiple phases of rifting with intervening periods of subsidence, uplift and erosion. The prospective sedimentary section ranges from Permian to Early Cretaceous and overlies predominantly Precambrian granitic and metamorphic rocks. The Darling Fault defines the eastern margin of the basin and represents a major Archean terrain boundary (Dentith et al, 1993). To the west, the basin extends into the offshore Abrolhos Sub-basin and ultimately terminates at the continental margin.

The tectonic history of the basin has been described in detail by various authors (e.g. Dentith et al, 1993; Mory and Iasky, 1996; Song and Cawood, 1999; Norvick, 2004) and is summarised in Figure 3. Three major fault trends divide the basin into a series of fault-bounded elements (Fig. 2). From
west to east, the most significant features are the Beagle Ridge, which is a shallow horst that runs parallel to the coastline, the intermediate Cadda Terrace, and the deeply buried Dandaragan Trough where the total sedimentary section reaches up to 15 km. The unconventional plays are best developed across the Cadda Terrace and shallower parts of the Dandaragan Trough as the depth of burial is optimum for the preservation and commercial exploitation of the target horizons including the Carynginia Formation and Kockatea Shale that are the subject of this study.

The overall stratigraphy of the basin has been described by Mory and Jasky (1996) and is simplified in Figure 3. Early Permian deposition commenced with glacio-marine shale and sandstone of the Nangetty Formation and Holmwood Shale, followed by shoreface sandstone of the High Cliff and Kingia sandstones. The fluvio-deltaic Irwin River Coal Measures comprise a varied sequence of sandstone, siltstone, shale and coal. Marine sedimentation then returned with the deposition of shelf to distal deltaic mudstone and siltstone of the Carynginia Formation. The top of the Carynginia Formation is a significant unconformity that marks a period of regional tilting and erosion. This was followed by the deposition of coarse-grained shoreface units of the Wagina and Dongara Sandstones.

The Latest Permian is marked by a major marine flooding event with the commencement of the deposition of restricted marine mudstone and siltstone of the Kockatea Shale (K. saep-tatus palynological zone). The lower member of the Kockatea Shale, the Hovea Member, was further divided by Thomas and Barber (2004) into an upper organic rich interval, the Sapro-pelic Interval (L. pellucidus palynological zone), and a lower Interinitic Interval (P. microcorpus palynological zone), characterised by lower total organic carbon (TOC) and hydrogen index (HI) levels. The Permian-Triassic boundary separates these two intervals. The Kockatea Shale, and specifically the Hovea Member, is considered to be the source for most oil and gas accumulations in the Perth Basin (Boreham et al, 2001).

The remainder of the sedimentary sequence is primarily fluvio-deltaic but with occasional marine incursions. Deposition was terminated by a major phase of regional fault reactivation, tilting and erosion associated with the onset of Valanginian break-up (Hall et al, 2013). Break-up is, however, believed to have been highly segmented along Australia’s western margin and may have continued through to the Aptian northwest of the Wallaby Plateau (Hall et al, 2013). Volcanism in the Bunbury Trough to the south of the Perth Basin may have been associated with elevated regional heat flows at this time as evidenced by maturity profiles in the southern part of the basin. With the exception of some localised Mio-Pliocene inversion associated with Eurasian plate collision, the Perth Basin experienced a long period of tectonic quiescence during the Tertiary.

The Dongara/Wagina reservoir has been the main conventional exploration target in the basin and has produced the majority of oil and gas. Total cumulative production for the basin to date is 506 BCF of gas and 15 MMBRLS of oil and condensate (Department of Mines and Petroleum, 2014). The largest discovery to date has been the Dongara Gas Field, which has ultimate recoverable reserves of 450 BCF. The conventional exploration effort has provided valuable data to evaluate the potential for multiple unconventional reservoir objectives, some of which are under active exploration and appraisal. These include tight sandstone targets in the Dongara/Wagina Sandstones, Irwin River Coal Measures, Kingia Sandstone and the High Cliff Sandstone. The Carynginia Formation and Kockatea Shale provide the main shale objectives and are the subject of this paper.

The validity of these plays has been demonstrated by results of recent unconventional exploration activities. Stimulation and testing of Arrowsmith–2 in 2012 recovered gas from the High Cliff Sandstone, Irwin River Coal Measures and Carynginia Formation, and oil and gas from the Kockatea Shale. In 2010, Woodada Deep–1 tested gas from the Carynginia Formation, and Corybas–1 (2005) has produced gas from the Irwin River Coal Measures during an 18-month period. More recently in 2014, Drover–1 had encouraging wet gas shows in the Kockatea Formation, and oil and gas from the Kockatea Shale and Senecio–3 had high gas readings in all formations from the Dongara/Wagina Sandstones, Carynginia Formation, Irwin River Coal Measures, Kingia Sandstone and High Cliff Sandstone, although none have been tested at the time of writing. A summary of the unconventional reservoir targets and the tectonic development of the basin are presented in Figure 3.

**Figures 3.** Stratigraphic and hydrocarbon system summary of the Perth Basin, noting key structural events. Blue denotes marine rocks, green denotes fluvial rocks, grey denotes fluvio-glacial, and yellow denotes key sandstone units.
rameters such as net pay, porosity, saturation and permeability, given these are difficult to measure directly from rock samples or to derive from wireline log analysis. As a result, most unconventional play and resource estimates draw heavily on comparison with producing analogues. This has merit, but only if the analogue has similar geological and engineering characteristics. A summary of some existing approaches to unconventional play analysis and resource estimation are summarised in the next sections.

Geochemical screening

Assessments of shale gas and oil potential have historically been based on comparisons of mainly geological characteristics of successful US fields. This approach is dominated by geochemical characterisation (Jarvie et al, 2005), but increasingly geomechanical considerations, particularly rock strength and stress anisotropy, are being incorporated (Sone and Zoback, 2013).

Empirical approaches have concentrated on mapping sweet spots or fairways defined by traditional whole Rock-Eval pyrolysis of source rock samples (Jarvie, 2004; Jarvie et al, 2005) sometimes supplemented by visual maturity data. Some authors have defined minimum thresholds or target ranges for these parameters. For example, minimum values for the Carboniferous Barnett Shale in the Fort Worth Basin, Texas, were proposed as:

- TOC = 2.0%;
- transformation ratio (TR) = 80%;
- maximum temperature (Tmax) = 455°C;
- dry gas = 80%; and,
- vitrinite reflectance (VR) = 1.0% (Jarvie et al, 2005).

One difficulty with this approach is that many source rock samples are partially or fully mature and, hence, their present day Rock-Eval values do not necessarily reflect their original source potential. Another problem is that the Rock-Eval data cannot differentiate between the free and the adsorbed hydrocarbon components, although the S1 peak from whole-rock pyrolysis is sometimes empirically related to the possible presence of organic porosity.

Jarvie et al (2005) estimate that TOC values for the Barnett Shale are, on average, 36% lower than the original immature kerogen values. Consequently, any assessment of oil and gas potential from Rock-Eval data must account for thermal maturity including the specific time-temperature histories for each maceral or kerogen component (Dembicki, 2009). The relative generation of oil versus gas, and their rates of expulsion, are a function of maturity and organic matter type (Cook and Kanstler, 1982). The abundance and type of organic matter are strongly controlled by depositional environment but are also influenced by climate, palaeoecology and diagenesis. Broadly, reducing deep marine or lacustrine environments tend to be dominated by alginitic and liptinitic macerals (Type I and II kerogens), whereas more oxygenated terrigenous settings are rich in vitrinitic and inertinitic macerals (Type III and IV kerogens). Type I and II kerogens are more oil-prone with lower activation energies and, therefore, tend to generate and expel at lower temperatures compared to Type III and IV source rocks (Sweeney and Burnham, 1990). Basin or thermal modelling techniques are used in an attempt to quantify the retained and expelled hydrocarbons for each source rock based on a specific mix of kerogen types and thermal histories.

Estimation of hydrocarbons-in-place

A variety of methods are used to interpret rock quality and hydrocarbon content, but most tend to be qualitative rather than quantitative. Conventional wireline log interpretation is worthwhile but generally lacks sufficient resolution to quantify key parameters such as effective porosity or hydrocarbon saturation. Organic petrology of source rock samples is useful to confirm the maceral composition and particularly to assess the potential contribution from any large pores within the kerogen matrix, but most organic porosity will be too small to identify. Similarly, thin section X-ray diffraction (XRD) and scanning electron microscopy (SEM) will provide information on matrix mineralogy and texture, but quantifying nano-porosity beyond a single sample remains problematic. The general approaches to estimating conventional and unconventional original oil and gas in-place (OOGIP) are shown in Equations 1 and 2, where GRVnet is the net gross rock volume, θ is effective matrix porosity, Sh is hydrocarbon saturation and 1/Bg is the gas expansion factor. The distinct difference with unconventional systems is the need to also account for organic porosity (θo, Eq. 2). The sorption capacity of the target reservoir (So) is important for those unconventional plays, which rely on the extraction of sorbed hydrocarbons, such as CSG, but is immaterial for deep unconventional plays where free hydrocarbons dominate. Organic porosity is estimated as an empirical factor based on the assumption of the ratio of TOC reduction as a function of HI reduction during the thermal history of the source rock, expressed by the TR. Hence, the importance of the time-temperature history and kerogen kinetics of the source rock is essential in fully understanding the in situ unconventional resource.

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\text{OOGIP}(c) = \text{GRV}_{\text{net}} \times \theta_i \times S_h \times \left(\frac{1}{B_g}\right)
\]

\[
\text{OOGIP}(u) = \text{GRV}_{\text{net}} \times (\theta_i + \theta_o) \times S_h \times \rho k \times S_m \times \left(\frac{1}{B_g}\right)
\]

Hydrocarbon shows on drilling also provide a useful guide but unfortunately are strongly influenced by well bore conditions such as rate of penetration and mud weight. Similarly direct measurement of hydrocarbons from core samples is problematic due to the difficulty in estimating the volume of oil or gas lost in transit to the surface and the laboratory. Desorption testing can be used to extrapolate the volume of desorbed gas a rock can hold but as previously stated this may only be relevant for CSG reservoirs.

The constraints required to quantify an unconventional resource (Eq. 2) are difficult to determine and principally rely on the outcomes of tight rock analysis (TRA) conducted on core samples. TRA samples are crushed and retorted to better define the free, bound and structural water saturations of the source rock and provide a better assessment of the available pore-space (Handwerger et al, 2011). While this method provides information for kerogen and clay-rich rocks that cannot be obtained from conventional core analyses, core handling needs to be carefully monitored to avoid post-drill fracturing, which may bias the analysis (Handwerger et al, 2011). This study has constrained source rock reservoir criteria using TRA data where available.

Propensity for natural or induced fractures

Reservoir enhancement through the use of hydraulic stimulation has been a standard tool in both conventional and unconventional resource development for many years (Hubbert and Willis, 1957). Unconventional explorers use knowledge of the prevailing stress regime and rock strength properties to increase reservoir productivity on stimulation, knowing that new fractures will propagate in the direction of the principle horizontal stress (S\text{hini}) and that competent or strong rocks will tend to sustain an open fracture network whereas incompetent rocks, often clay-rich, tend to deform plastically (Zoback, 2007).
Unconventional plays are, therefore, often high-graded based on assessments of stress, made from bore hole circumferential stress modelling and observations of break out (BO) and drilling induced tensile fracture (DITF) distributions from image logs (Brudy and Zoback, 1999; Zoback et al., 2003). Rock strength properties are determined by laboratory triaxial and uniaxial stress testing (static) to derive elastic properties such as Young’s Modulus (E) and Poisson’s Ratio (ν), which are used to calibrate dynamically determined elastic rock properties derived from density and sonic log data (Zoback et al., 2003).

More recently the role of natural fracture networks in providing valuable structural permeability to an unconventional play has become increasingly recognised (Gale et al., 2007; Zoback, 2007). Whether or not a fracture set is hydraulically conductive, however, depends on multiple factors including mineral precipitation and bridging as well as fracture orientation relative to the prevailing stress regime and stress magnitude (Barton et al., 1997). Fractures oriented ~30° from $S_{	ext{max}}$ have a greater probability of experiencing shear reactivation where effective normal stress is sufficiently large enough to drive rocks into failure (Zoback, 2007). Consequently, on a regional scale, displaying fracture rose distributions in reference to the direction of $S_{	ext{max}}$ may be a useful means of quantitatively assessing those areas with fracture sets optimally oriented for shear reactivation. A stimulation treatment program, which aims to capitalise on complex natural fracture arrays, may benefit where newly propagated fractures intersect the largest number of natural fracture sets, which are ideally oriented for shear reactivation. Likewise, the role of uplift and exhumation also needs to be considered as it is possible that significant uplift may lead to gas expansion in unconventional reservoirs and that the resultant pressure changes may yield higher gas saturations and improve production rates as well promoting the development of micro-fracture networks (Jarvie et al., 2005; Michael and He, 2011). Uplift and erosion has been estimated for the Perth Basin and it is described in the 3D basin model description of this paper.

It is noted that there is considerable debate in the industry with regards to the relative benefits of creating new fracture networks during stimulation treatments versus capitalising on existing natural complex fracture networks. Engineers may tend to avoid existing natural fractures due to a practical desire to mitigate the loss of stimulation fluids and pressure. This is likely to be true for large faults, which may thieve a considerable amount of stimulation energy, however, it is unlikely to be the case for complex networks of small natural fractures and other rock anisotropies (Zoback, 2007). Indeed, it is likely that the shear reactivation of natural fractures and long-term creep on bedding and cleavage planes provides a significant amount of the extended life performance of many shale gas wells in the US and that such natural features represent useful targets for enhanced structural permeability (Moos, 2012). Consequently, the role of seismic reflection and bore hole image data in structural modelling is an increasingly important consideration in unconventional resource definition.

Production analogues

Translating hydrocarbons-in-place to recoverable resource or reserve estimates is problematic for unconventional reservoirs as recovery factors are strongly influenced by the development concept and by project economics. Most unconventional developments require horizontal wells to achieve commercial flow rates but ultimate recovery will depend on the length of these wells, the effectiveness of their hydraulic stimulation, and the lateral and vertical spacing. Application of a single generic recovery factor is, therefore, rarely appropriate.

For a producing field, reserves estimates tend to be driven by the application of type production curves to each well in a defined development. The selection of these type curves is ideally based on extended production test data from horizontal appraisal wells in the same field or from offset production data on the same play trend. For projects that are still in the exploration phase, however, horizontal development well type curves will need to be extrapolated from static and test data from vertical exploration wells or from analogue fields with similar geological characteristics. Reservoir simulation is increasingly being used to model expected well and field performance but the uncertainty range will remain wide until significant production data are available. Any estimate of ultimate recovery should still be compared with hydrocarbon-in-place estimates to ensure the implied recovery efficiency is reasonable. Care should also be taken to ensure the full geological complexity of the play is represented, otherwise there is a significant risk of over-estimating future production, resources or reserves, and project economics.

AN ALTERNATIVE METHOD FOR UNCONVENTIONAL PLAY ANALYSIS

The alternative method described in this paper uses a mass balance approach for mapping the distribution of hydrocarbons-in-place and then structural and geomechanical analysis to define areas with enhanced potential for natural fracturing or propensity for induced fracturing. Reservoir pressure and overpressure are also considered to be important factors (Fig. 4).

**Figure 4.** Approach used for this study combining kinetic mass balance modelling with rock strength, stress and natural fracture distribution, and overpressure modelling to map unconventional sweet spots.

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**In-Place Resource Estimate**

**MASS BALANCE METHOD**

**3D Basin Modelling**

**In-situ stress regime, natural fracture and fault distribution**

**Image, sonic and density logs**

**Rock strength (MPa)**

**Static and Dynamic**

**Pressure and Overpressure modelling**

**Unconventional Sweet Spot**
The mass balance method includes many of the same inputs that are used in the empirical approach (such as Rock-Eval and VR data), but involves kinetic modelling to predict retained and expelled hydrocarbons based on the maceral composition of the source rock in a 3D model. This approach is relatively new with some of the earliest examples being its application to the Barnett Shale in the Fort Worth Basin (Michael and He, 2011; Romero-Saramiento et al, 2012). Some understanding of porosity and sorption capacity is desirable to constrain the prediction of the retained (free and sorbed) versus expelled components following generation. Similarly, empirically derived hydrocarbon saturation measurement is useful to validate the modelled efficiency and retention assumptions. To the authors’ knowledge the mass balance approach has not been previously applied to an Australian basin using 3D modelling. This is important, because few Australian unconventional plays match the rules of thumb parameters associated with successful US shale developments such as organic matter abundance, organic matter type, pressure, and sometimes stress regime.

A key to this method is defining the appropriate reaction kinetics, or activation energies, for the precise kerogen mix in the unconventional target. These activation energies can be measured from rock samples in the laboratory, but more generally basin modelling default values are used based on global published studies. 3D basin-wide modelling traditionally is used to generate maps for the expelled hydrocarbons that are used for the prediction of charge in conventional play analysis. The outputs, however, can also be used to calculate retained hydrocarbons including the free and sorbed components. As previously stated, for shale plays the authors believe the sorbed hydrocarbons do not make a significant contribution to ultimate production and, therefore, should be excluded from in-place and recoverable resource estimates.

A limitation on the mass balance approach is that it requires significant regional data to constrain the modelling. For those basins that have a history of conventional production—like the Perth Basin—this is not a problem, but for frontier basins this is a severe limitation. Given the data and interpretation requirements, building the initial model is very time consuming but once up and running provides a powerful tool for testing the various assumptions, and is readily updated as more data become available.

Once the free hydrocarbon distribution for the play has been modelled, other parameters can be overlain to identify areas with potential for enhanced deliverability. In this study this has involved structural and geomechanical interpretation to define areas with enhanced natural fracturing or propensity for induced fracturing. Other play refinements have been the application of a maximum depth threshold (nominally 4,000 m subsea) beyond which porosity and permeability might be expected to be impacted by compaction. Minimum maturity thresholds have also been applied in the belief that the onset of overpressure could enhance flow rates and ultimate recovery (Cander, 2012). Also, for the Kockatea Shale, comparison with oil-prone systems like the Eagle Ford shale, Texas Basin, indicates that the highest production rates may be expected from the condensate maturity window where gas drive assists flow (Cander, 2012).

So far, this methodology has been applied to the Kockatea Shale, the Hovea Member and the Carynginia Formation across the entire onshore North Perth Basin and will be progressively extended to the other unconventional targets. For brevity, however, only the free gas for the Carynginia Formation and the gas liquids/oil for the Hovea Member are described in detail in this paper. Modelling of the shale gas/oil resource of the Hovea Member is restricted to the upper portion of the unit, consistent with the Sapropelic Interval of Thomas and Barber (2004).

**Perth Basin 3D basin model**

Geochemical characteristics of key unconventional target reservoirs—the Carynginia Formation, the Kockatea Shale and the Hovea Member—were mapped throughout the Perth Basin and integrated within a 3D basin model using Trinity and Genesis software (He, 2014). Thermal, uplift and erosion considerations were imported into the 3D model through 72 individual 1D thermal history models, developed in Genesis, comprising corrected temperature, measured formational thermal conductivity and maturity data from 45 wells, plus an additional 27 pseudo well models. The 3D model covers an area of ~13,000 km² of the onshore Perth Basin and was populated with regional depth grids from 14 key horizons generated from seismic mapping plus a digital elevation model and fault files.

Modelling of corrected temperature and VR data show high elevated present-day heat flows, averaging 88 mW/m² throughout the basin, as well as evidence of elevated heat flows in the past, averaging 20% higher than present-day. This study has used the Horner temperature correction method of Hermanrud et al (1990), and has used formational rock thermal conductivities as measured for the Department of Mines and Petroleum using basin-wide core data by a divided-bar apparatus for key units in the Perth Basin (Hot Dry Rocks, 2008). This palaeo-heat flow event is most likely associated with Valanginian breakup, consistent with the absence of a post-Valanginian succession in the basin as well as some evidence of Mid-Cretaceous cooling from fission track data (Gibson et al, 1997). Wells in the central Dandaragan Trough do not preserve Cretaceous rocks younger than the B. enebbaensis spore-pollen zone (Backhouse, 1978), providing a Berriassian-to-base Valanginian age constraint to uplift, and erosion in the basin.

Uplift, erosion and thermal events have been built into the 1D Genesis well and pseudo-well models, which are then imported into Trinity to calibrate the 3D model and allow for a 3D resource calculation that also addresses these events. Of the 45 wells in the model, 35 wells have VR data, comprising a total of 357 sample points, and six other well models are populated with T°m maturity data, comprising an additional 91 sample points. These data have been used to model the burial, uplift and heating histories to constrain the 1D and 3D model. As noted by Thomas and Barber (2004), modelling can be influenced by the presence of perhydrous (suppressed) vitrinite, particularly in marine successions, and as no data are available for fluorescence alteration of multiple maceral (FAMM) analyses, modelling concentrated on obtaining a best fit against available data from terrigenous units where vitrinite is more likely to be orthohydrous. In addition to this, new targeted VR data were acquired for 15 existing wells and three new wells, substantially increasing the sampling density.

The resultant modelling suggests that the amount of Valanginian uplift and erosion is highly variable across the onshore North Perth Basin, with a median of 350 m of erosion at this time. Wells in the Dandaragan Trough exhibit negligible uplift and erosion, while wells closer to major faults in the north and west, such as the Mountain Bridge and Allanoooka faults, can exhibit 500–800 m of erosion in the Valanginian. Maturity data in these wells suggest that heat flow at this time was 100–115 mW/m². The exception to these observations is the southern part of the North Perth Basin where maturity data show consistently high heat flows in the past, with erosion rapidly increasing south of the Abrolhos Transfer Zone (Fig. 1). Wells in this area, such as Gairdner–1, were exposed to heat flows of 140–168 mW/m² and 1,000 m of erosion, with Jurien–1 having the greatest amount of modelled erosion, up to 2,400 m, heat flow dependent. It is likely that this southern area was exposed to regional heating associated with Valangin-
ian volcanism at the time of break-up. Vitrinite phytoclasts at the base of the Drover–1 well, where Ro is >2.2%, exhibit high birefractance and no evidence of mesophase structure, and the reflectance is, therefore, interpreted to represent regional heating, as opposed to contact metamorphism. The timing and magnitudes of thermal and uplift events modelled in this study are largely consistent with those modelled for the onshore Perth Basin by Thomas and Barber (2004) and are broadly consistent with those derived from tectonic subsidence modelling in the offshore Perth Basin (Pfahl, 2011).

Both 1D and 3D modelling suggests that all key source rocks in the basin generated and expelled the vast majority of hydrocarbons prior to Valanginian uplift and did not re-enter the generative window. The exception to this may be in areas that experienced only mild to negligible uplift, particularly towards the centre of the onshore basin, where some models suggest that a very small amount of late generation may have continued through the Tertiary to present-day. The Warradong–1 well is modelled to reach a maximum palaeo-heat flow of 97 mW/m² in the Valanginian, relaxing to a present-day heat flow of 88 mW/m² and comfortably fitting the measured VR data. The well model suggests that while the majority of hydrocarbon expulsion occurred in the Early Cretaceous, some minor expulsion may have continued through to the Tertiary (Fig. 5).

Identifying and mapping the Hovea Member

Both the upper Kockatea Shale and the Hovea Member represent viable unconventional targets in their own right, yet differentiating between the two units based on lithological log characteristics is difficult and there is a paucity of palynological data in the basin. In general, the upper Sapropelic Interval of the Hovea Member is characterised by higher TOC and HI levels due to increased anoxic conditions during deposition (Thomas and Barber, 2004). The 3D modelling process requires a depth grid of the target resource units, hence this study has used all available wells in the basin, for which sonic and resistivity data are available, to apply the Delta Log-R (DLR) method (Passey et al, 1990) to segregate the upper Kockatea Shale, the target upper Hovea Member (Sapropelic Interval) and the basal Interinitic interval using organic-richness log characteristics. The method was also used to produce both gross and net isopach maps of the same intervals such that net-to-gross considerations have been accounted for within the thickness assigned to the source-rock file in Trinity. DLR is a simple quicklook method, commonly used to identify organic rich rocks, using an empirical overlay of the resistivity and sonic log curves to highlight anomalously high organic-rich intervals. Sonic and resistivity curves are baselined across low-resistivity shales, aligning the sonic log to overlay the resistivity log at these points (Passey et al, 2010; Crain, 2014). At the baseline points, low-resistivity shales are assumed to be non-source rocks. In contrast, for intervals with resistivity and sonic log separation, this is an indication of source rock presence. Two primary factors effect the DLR separation in organic rich shales: the porosity curve reacts to the presence of low-density, low-velocity kerogen; and, the resistivity curve reacts to the formation fluid. A resistivity increase across mature source rock is due to generated hydrocarbons retained in place (Passey et al, 1990). There is an excellent correlation between the source rock identified in this method and elevated gas, where the source rock is mature.

An example of the DLR method is given in the well Hovea–3ST1 (Fig. 6), which shows the top of the Hovea Member source interval as immature (depths 1,950–1,995 mMD in Fig. 6) but approaching maturity at the base of the section (depths 1,965–1,983 mMD in Fig. 6). In the upper Kockatea Shale (depths 1,650–1,850 mMD) the DLR shows the character of an immature source rock. The mid-upper Kockatea Shale (depth 1,900 mMD) shows a non-source character due to its suppressed resistivity and higher relative density, and as such is chosen as the baseline point. The base of the Hovea Member (depths 1,985–2,000 mMD) has poorer source rock character reflected in its lower resistivity and gas response. Wells in deeper parts of the basin show thicker Hovea Member and Kockatea Shale units and more favourable maturity.

Actual TOC measurements are taken from core, cuttings and side wall cores of wells throughout the basin. These are used to confirm areas of source rock identified by crossover of the curves in the DLR method (Fig. 6), as well being used as an input into source rock generative potential as described in the basin modelling component of this study.

Present-day source rock characteristics

The 3D basin thermal model was combined with source rock files for the defined source intervals in the basin using average net thicknesses determined from the log analysis described
previously in this study. The mass balance approach depends on an understanding of the present-day source rock characteristics, which for the Perth Basin have been comprehensively described by Thomas and Barber (2004). Present-day geochemical and maturity data, largely obtained from Rock-Eval pyrolysis, have been collated to build kerogen kinetics files using associated Kinex software (Zetaware), for each source rock in the 3D model. The kerogen kinetics files control the rates and volumes of generation, expulsion and retention of each source rock in the 3D model, and provide a means by which the reaction kinetics can be used to back- interpolate initial values of HI and TOC for the given thermal history of the kerogen (Pepper and Corvi, 1995). This is a distinct difference between traditional empirical approaches, which make resource assumptions based on present-day metrics only.

Previously published geochemical data for various formations in the Perth Basin, including well completion reports and the WAPIMS Perth Basin well database available from the Department of Minerals and Petroleum, were compiled and added to for VR data through the sampling of additional wells as described previously. Data sources also included individual well compilations (Cook, 1978; 1979a; 1979b) as well as the same data used by Thomas and Barber (2004) and compiled by West (2003). Available data suggest that, on average, the Carynginia Formation is dominated by Type III kerogen with maturity driving present-day HI and TOC to average values of 47 mg/g/TOC and 2.4%, respectively. Local variations do occur, particularly in the southern Perth Basin, where marine influence in the Carynginia Formation increases. The Hovea Member is distinctly different from the upper Kockatea Shale with a basin-wide average HI of 475 mg/g/TOC (67 individual samples), however, this average is strongly biased by a single well, Hovea–3, drilled in a localised sweet spot for the Hovea Member source rock and for which pyrolysis samples constitute 55% of the available data for the unit (Fig. 7). Figure 7 shows average TOC and HI by well for both the Carynginia Formation and the Hovea Member, also incorporating the data of Gosjean et al (2013), with data from Hovea–3 also shown as individual sample points to illustrate the amount of variance in the data and the very high values exhibited by Hovea–3. These data suggest that there is a significant amount of lateral variation in the quality of the Hovea Member and that a HI of about 300 mg/g/TOC and an average TOC of 2.2% is more representative of the unit for modelling purposes (Table 1). Organic matter in the Hovea Member has a significant algal contribution, and as a consequence plots as Type II, with some Type I organic matter (Thomas and Barber, 2004). The upper Kockatea Formation is poorly sampled but exhibits a mixed Type III/Type II contribution with an average HI of 186 mg/g/TOC and an average TOC of 1.2%.

Present-day characteristics for most source rocks in the Perth Basin are summarised in a modified Van Krevelan diagram by well (Fig. 8). These data represent formational average HI values in available wells and demonstrate both the significant lateral variation in source rock quality across the basin and the influence of maturity. These source rock quality and maturity trends are consistent with those described for the same formations by Thomas and Barber (2004). Notably, the Type III dominance of the Permian succession in the North Perth Basin is similar to that of the Permian succession in the Cooper Basin (cf. Boreham and Hill, 1998). Although there are some Type II influences in the Patchawarra Formation associated with transgressions, the organic matter is dominantly humic (Smyth, 1985). Likewise, the Kockatea Shale, and in particular the Hovea Member, has HI and OI (oxygen index) characteristics that are similar to those of the Barnett Shale in Texas (cf. Jarvie et al, 2005).

**Initial source rock characteristics**

Available pyrolysis data for Kockatea Shale, Hovea Member and Carynginia Formation rocks have been used to modify kerogen kinetics curves, although this study only addresses the outcomes of the Carynginia Formation and Hovea Member source rocks, as discussed previously. Default kinetics files in Kinex software are based on those described by Pepper and Corvi (1995) and are tailored to fit specific input data (HI and VR data) by allowing the user to modify the activation energy (E) and frequency factor (A) to achieve a fit whereby the reaction curve best encompasses the input data (Fig. 9a). The temperature, uplift and pressure history built into the 3D model will interact with the source rock kinetics file to govern the amount of oil and gas generated for a given net thickness. The propor-

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**Figure 6.** Hovea–3ST1—an example of DLR application.

**Figure 7.** Present-day average TOC and HI values by well for key source rocks in the North Perth Basin. Individual sample results for Hovea–3 are shown in blue, while average values for all other wells are shown in green. Notably, the Carynginia Formation has significantly lower HI and TOC values, partly as a function of maturity.

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**Table 1.** Present-Day Geochemical Data for Key Source Rocks in the Perth Basin, Present-day TOC and HI.
Table 1. Input parameters for 3D basin model mapping.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Carynginia Fm.</th>
<th>Hovea Member</th>
<th>U. Kockatea Shale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thickness (m)</td>
<td>150–250</td>
<td>&lt;40–140+</td>
<td>500–800</td>
</tr>
<tr>
<td>Initial TOC (%)</td>
<td>2.7</td>
<td>3.5</td>
<td>2.0</td>
</tr>
<tr>
<td>Initial HI (%)</td>
<td>200</td>
<td>300</td>
<td>250</td>
</tr>
<tr>
<td>Hydrocarbon saturation (%)</td>
<td>20</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Organic porosity factor (1–10)</td>
<td>0.05</td>
<td>0.05</td>
<td>0.05</td>
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<tr>
<td>Rock matrix density (g/cc)</td>
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<td>2.6</td>
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<tr>
<td>Initial kerogen density (g/cc)</td>
<td>1.2</td>
<td>1.2</td>
<td>1.2</td>
</tr>
<tr>
<td>Initial oil sorption (%)</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
</tbody>
</table>

Other source rock characteristics

The mass balance approach requires an estimation of hydrocarbon saturation, porosity and density for each source rock file (Table 1). The model employs the approach of Pepper and Corvi (1995) involving retention of hydrocarbons in the allocated pore volume and by sorption to a specified saturation level, and then expulsion from the source rock beyond that point. In specifying these variables, the most useful source of data is derived from TRA as described by Hanwerger et al (2011). TRA data are presently only available for the Carynginia Formation at Woodada Deep–1 where the average gas saturation is 33%, although the distribution is log-normal with most analyses between 20–30% (Fig. 10). Rock density is about 2.6 g/cc and average effective porosity is about 4% (Fig. 10). As the samples are crushed during the TRA process the total porosity derived from the method is the sum of the matrix and organic porosity; consequently, a conservative estimate of organic porosity (<1%) has been assigned as part of the total porosity used in this study. It is, however, feasible that organic porosity may provide a greater contribution to overall porosity. Organic porosity is calculated as a function of both TOC and HI reduction with the kinetically modelled TR (The Beta Factor, 2013), with the assigned factor in Table 1 being a relative weighting of the outcome. Values for kerogen density and oil sorption, where oil sorption is the proportion of TOC capable of sorbing hydrocarbons, are based on global averages and these inputs tend to have little variability (Sandvik et al, 1992; Pepper and Corvi, 1995).

As TRA data for the Kockatea Formation are presently not available, this study has used the same values as derived from the Carynginia Formation TRA data, consistent with conventional log analysis, with the exception of an assumption of increased gas saturation associated with higher TOC and, hence, increased volume for sorption.

IN-PLACE RETAINED GAS AND LIQUIDS DISTRIBUTION

The outcomes of the 3D basin modelling process define a distribution of in-place gas and liquids for both the Carynginia Formation and upper Hovea Member (Sapropelic Interval), expressed as BCF/km² and MMBBLS/km², respectively. Free gas and liquids for both units have been calculated in the Trinity 3D model for net source rock thicknesses based on log-derived and seismic isopach mapping, with each thickness slab exported to Petrosys to make a summed composite resource map. The free gas and oil component of the retained hydrocarbons have been mapped as the sorbed component is not likely to contribute to the resource. The mapping of in situ hydrocarbons alone, however, does not account for other play criteria, which must also be considered in unconventional resource assessment, namely maturity windows for liquids versus gas, overpressure considerations, rock strength distribution, stress state and anisotropy, and natural fracture distribution.
Unconventional hydrocarbon play cut-offs need to be applied to the mapped distribution of the retained resource. In defining play cut-offs it has been accepted practice in Australia to use empirical cut-offs commonly applied in US shale gas assessments and, as discussed previously, the applicability of some US play cut-offs to the Australian context remains questionable. Resource cut-offs applied in this study are described below.

**Maturity and depth**

The calculation of Carynginia Formation and Hovea Member specific kerogen kinetics files has allowed the determination of oil, wet gas and dry gas windows for each formation (Fig. 9). This provides a means of using data specific to the target formations to define a maturity cut-off based on expulsion windows, rather than relying on assumed or default values. For the Hovea Member the onset of the oil expulsion, wet gas and dry gas windows is defined as 0.9, 1.1 and 1.4 Ro%, respectively. For the Carynginia Formation it is unlikely that significant liquid generation will occur, and the main gas window is defined at 1.2 Ro%. These windows have been applied to the retained (free) gas and liquids resource maps to truncate the distribution of a likely economic resource. Likewise, drilling depths greater than 4 km are unlikely to yield economic returns, hence the resource map is further truncated by this depth constraint from seismic mapping (Fig. 11a).

Estimated free gas in the Carynginia Formation reaches ~22 BCF/km², strongly influenced by maturity trends in the basin (Fig. 9). Estimated free liquids in the Hovea Member reaches ~8 MMBBS/km², most notably in the central basin near Redback-2 and Mungenooka-1. The Hovea Member also produces a significant amount of retained gas (up to ~21 BCF/km²), however, only the retained liquids case is shown here as an example of the process. Apart from maturity, this trend is strongly influenced by the thickness of the Hovea Member, which is greatest in the central basin (Fig. 11b). Importantly, while the Hovea Member comprises a large in situ resource in less mature parts of the basin (0.9–1.1 Ro%), by analogy with US shale gas fields, it is possible that this resource will not be economically extractable due to the probable absence of associated gas drive at this lower maturity. Consequently, the Hovea Member resource shown in Figure 11b could be further refined by only considering the condensate window, as defined by Hovea Member-specific kinetics, to be between 1.1 and 1.4 Ro% where gas drive may reasonably be expected.

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**Figure 9.** Basin-wide vitrinite reflectance and hydrogen index data for all Permian rocks in the Perth Basin (9a) and all Hovea Member-specific data (9b). Actual data are fitted to a modified Type D/E kinetics curve for all Permian rocks, including the Carynginia Formation (9a top) and a mixed B and D/E curve for Hovea Member rocks (9b top). The resultant expulsion curves for a 0–300°C heating history show the dominant expulsion of gas from Permian rocks (9a bottom) and a penecontemporaneous expulsion of oil and gas from the Hovea Member (9b bottom). The defined expulsion windows have been used in this study for unconventional resource distribution mapping.
Overpressure-assisted recovery

Elevated pore pressure, or overpressure, is a characteristic of US shale plays, which is regarded as advantageous as it allows higher concentrations of gases to be contained in the pore matrix, improves productivity, and it can assist in lifting liquids out with gas production (Cander, 2012). There are a host of mechanisms that cause overpressure including: disequilibrium compaction, tectonic compression, hydrocarbon column heights, aquathermal compaction, mineral diagenesis and hydrocarbon maturation (Zoback, 2007). With a few notable exceptions, such as in parts of the Cooper and Carnarvon basins, most reservoirs in Australia tend to be normally pressured and the relative absence of overpressure has been regarded as a poor omen for unconventional prospectivity. As, however, demonstrated by a number of wells in the Perth Basin—in particular Arrowsmith–2—substantial flow of gas and oil is possible under relatively modest pressure conditions.

A qualitative method of identifying areas of overpressure in shales is the use of compaction curves (Burrus, 1998) by plotting a theoretical porosity trend line against porosity calculated from a density or sonic log. In a normally pressured shale the theoretical porosity line should roughly follow the calculated porosity line since a shale compacts logarithmically with increasing overburden. Where the calculated porosity deviates from the theoretical porosity line, this indicates the top of the overpressure zone and transition zones. When the calculated porosity remains separated from the theoretical porosity line below the transition point, this highlights potential overpressure of an interval.

There are important limitations of the compaction curve technique. The first example is that intra-shale lithology variations and gas effects can influence the calculated porosity, giving a false positive of overpressure. Another example is that compaction curves assume a constant burial history and do not account for periods of uplift and erosion, and subsequent burial. Given some of the limitations of this technique, it is important to verify these qualitative overpressure observations by direct pressure measurements where possible.

One direct method to estimate pore pressure in shales is through the use of connection gases. During drilling operations the force of the pumped mud down the pipe and around the annulus increases the mudweight pressure slightly above the pressure caused by the weight of the mud alone. During a connection, mud pumps are turned off, so that only the actual force of the mud in the annulus is holding back the formation. If at this point there is a gain in the mudpits; that is, a connection gas, then the formation pressure is roughly equivalent to the mudweight at that depth, such that formation pressure at the depth of connection can be estimated, as shown in Equation 3. If at the depth of a connection gas, the calculated mudweight pressure exceeds the calculated hydrostatic pressure, then the shale is overpressured. This study has reviewed porosity and theoretical porosity for all wells with suitable sonic and density logs in the basin to estimate likely points of overpressure deflection. Connection gas records were then compared with overpressure deflection points as a means of verification of the model.

\[
\text{Pressure} = \frac{(\text{mudweight} \times 0.052 \times \text{TVD})}{145} \tag{3}
\]

In Equation 3, pressure is in MPA, mudweight is in pounds per gallon (PPG) and true vertical depth (TVD) is in feet. At Redback–2, in the central deep of the study area, the Kockatea Shale shows a deflection of the calculated porosity from the theoretical porosity compaction curve, identifying the likely top of the overpressure zone at around 3,450 mSS (Point A, Fig. 12). Beneath this depth the calculated porosity maintains a roughly vertical gradient (i.e. approximately constant pressure) while the theoretical porosity continues to decline. The separation between the curves indicates a sustained overpressure beneath this point. Comparing this to the observed connection gases, the onset of connection gases in the mud logs appears at 3,580 mSS (Point B, Fig. 12) and continues to occur until the base of the Kockatea shale. This depth marks the start of hard overpressure. From these connection gas points, the formation pressure is calculated and confirmed to exceed the hydrostatic pressure.
Figure 11. Examples of modelled resource distribution for summed isopach slabs for retained free gas in the Carynginia Formation (11a) and retained free liquids in the upper Hovea Member, or Sapropelic Interval, (11b) as an output of the 3D thermal history modelling. Both maps show key modelled vitrinite reflectance contours based on maturity and temperature data from 45 wells, and are truncated by the 4 km depth contour.
the start of hard overpressure at this depth and below. To assist in defining shale target sweet spots.

For wells that showed a strong correlation between modelled overpressure deflection and connection gas occurrence, the modelled maturity for this depth was also calculated using calibrated 1D Genesis maturity models. It was noted that there is no consistent correlation between observed overpressure and depth, however, there is a good correlation between the maturity of the source rock and the start of hard overpressure observed from connection gases (Fig. 13). The highest frequency of connection gases are encountered (and continue beneath this depth), confirming the start of hard overpressure at this depth and below.

The level of overpressure determined from these combined methods for all wells ranges from 2–6 MPa (290–870 psi), which, while not excessive by US standards, suggests that shales in the Perth Basin do experience modest levels of overpressure.

The importance of the in situ stress state, both laterally and vertically, to the viability of unconventional hydrocarbon development has been known for some time. Initial studies on the role of stress in unconventional systems concentrated on the understanding of how Andersonian stress (Anderson, 1951) impacts the propagation of new fractures during stimulation treatments (e.g. Hubbert and Willis, 1957). There is now, however, increasing interest in how the stress state also interacts with existing natural fracture networks during stimulation as a means of providing structural permeability (e.g. Gale et al, 2007). Variations in the stress state, and the interaction of the stress state with rock strength, are key components of the unconventional play system, which must be overlain on the mapped resource distribution to further constrain the likely economic fairway.

The stress state of the onshore Perth Basin has been comprehensively studied and, despite the paucity of available well data, it is well established that the principle horizontal stress (S\text{Hmax}) throughout the basin is consistently oriented in an east-west direction with a strong strike-slip component (Beynolds and Hillis, 2000; King et al, 2008; Bailey et al, 2012). Horizontal stress magnitudes are, however, variable in parts of the basin with transitional strike-slip/reverse regimes described by King et al (2008). The consistency of S\text{Hmax} direction in the basin is largely the influence of the far-field stress regime established during the Mio-Pliocene collision of the Australasian and Eurasian plates (World Stress Map, 2014). This is an important observation as the calculation of individual well stress conditions can, therefore, include considerations for tectonic stress, as described in the Eaton method (Eaton, 1969) and shown in its simplified form in Equation 4. The equation can also be rewritten for the minimum horizontal stress tensor (S\text{min}) and expresses the horizontal components of stress as a function of effective vertical stress (S\text{v}) minus pore pressure (P\text{p}), a Biot constant (\alpha), and Poissons Ratio (\nu). A tectonic strain component (S\text{min-rect}) is also added, which reflects the ratio of longitudinal and axial strain from elastic rock properties (E) and \nu. The resultant S\text{Hmax} and S\text{min} log curves then need to be calibrated against physical well pressure data (leak off test [LOT]/formation integrity test [FIT]) and image log stress observations.

\[
S_{H_{\text{max}}} = (S_v - \alpha \times P_p) \times \left(\frac{\nu}{1-\nu}\right) + S_{H_{\text{max-rect}}} \quad (4)
\]

In situ stress state and stress anisotropy

The role of stress in unconventional systems (Anderson, 1951) imparts a critical influence on the propagation of new fractures during stimulation treatments (e.g. Hubbert and Willis, 1957). The stress state also interacts with existing natural fracture networks during stimulation as a means of providing structural permeability (e.g. Gale et al, 2007). Variations in the stress state and the interaction of the stress state with rock strength, are key components of the unconventional play system, which must be overlain on the mapped resource distribution to further constrain the likely economic fairway.

For the purpose of play fairway mapping, the 1.2 Ro% contour was, therefore, used as an additional top of overpressure proxy to assist in defining shale target sweet spots.

The level of overpressure determined from these combined methods for all wells ranges from 2–6 MPa (290–870 psi), which, while not excessive by US standards, suggests that shales in the Perth Basin do experience modest levels of overpressure.

For wells that showed a strong correlation between modelled overpressure deflection and connection gas occurrence, the modelled maturity for this depth was also calculated using calibrated 1D Genesis maturity models. It was noted that there is no consistent correlation between observed overpressure and depth, however, there is a good correlation between the maturity of the source rock and the start of hard overpressure observed from connection gases (Fig. 13). The highest frequency of connection gases are encountered (and continue beneath this depth), confirming the start of hard overpressure at this depth and below.

The importance of the in situ stress state, both laterally and vertically, to the viability of unconventional hydrocarbon development has been known for some time. Initial studies on the role of stress in unconventional systems concentrated on the understanding of how Andersonian stress (Anderson, 1951) imparts a critical influence on the propagation of new fractures during stimulation treatments (e.g. Hubbert and Willis, 1957). There is now, however, increasing interest in how the stress state also interacts with existing natural fracture networks during stimulation as a means of providing structural permeability (e.g. Gale et al, 2007). Variations in the stress state, and the interaction of the stress state with rock strength, are key components of the unconventional play system, which must be overlain on the mapped resource distribution to further constrain the likely economic fairway.

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\[
S_{H_{\text{max}}} = (S_v - \alpha \times P_p) \times \left(\frac{\nu}{1-\nu}\right) + S_{H_{\text{max-rect}}} \quad (4)
\]

This study has assessed 28 wells in the North Perth Basin, of which nine have dipole sonic and 19 have monopole sonic data, to estimate the likely stress state and build individual well mechanical earth models (MEMs). Figure 14 shows the location of the northern-most wells assessed in this study. The methodology used follows that of Zoback et al (2003) and Zoback (2007) in the use of sonic and density logs for the determination of vertical stress (S\text{v}) and the use of LOT, FIT and other
As with the studies by King et al (2008) and Bailey et al (2012), this study found that $S_{\text{max}}$ is consistently oriented east–west throughout the basin, although local variances occur near large faults. This observation suggests that some faults locally perturb the stress field with $S_{\text{max}}$ parallel to the local fault plane. Stress magnitudes vary both laterally and with depth, but overall the stress state in the basin is dominantly strike-slip ($S_{\text{max}} > S_{\text{min}}$), consistent with the interpretation of Bailey et al (2012). Notably some wells, such as Corybas–1 and Aplim–1, exhibit a transitional stress state and may be regarded as normal/strike-slip ($S_{\text{max}} - S_{\text{min}} < S_{\text{max}}$). These transitional wells occur near major fault intersections and may reflect complex stress interactions in those areas (Fig. 14). The stress state distribution shown in Figure 14 is colour-coded with green representing strike-slip and blue normal stress. This is the same colour palette used by Zoback (2007) for gradational stress distribution in southeastern US, where in situ stress grades from thrust in northeastern US (New York) to normal/strike-slip in the southwest (Texas). Hence, for much of the area covered by producing shale gas systems in eastern US, the stress state is largely identical to that of the Perth Basin (strike-slip).

Of greater significance is the down-hole variation in stress seen in a number of wells in the basin, demonstrating the influence of lithology on stress anisotropy at both a large and small scale. In the case of the Drover–1 MEM, the uphole section through the Kockatea Shale is in a transition state (strike-slip/reverse) while the bottom-hole section, beneath the Kockatea Shale, is dominantly strike-slip (Fig. 15). As most LOT and FIT data in the Perth Basin tend to be shallow, the depth variance in stress-state as seen at Drover–1 may have biased earlier stress interpretations in the basin towards a greater compressional influence. At a smaller scale the $S_{\text{min}}$ log demonstrates significant contrast (high stress) particularly in the bottom-hole as a result of mechanical stratigraphy at the bedding-scale (Fig. 15). High stress can be beneficial in assisting to constrain the vertical extent of a propagating fracture (Zoback, 2007).

**Figure 14.** Stress state across the northern part of the study area as a subset of an analysis of 28 wells in the basin where green equals strike-slip and blue equals normal/strike-slip, based on the colour code of Zoback (2007). Note the dominant east–west trend of $S_{\text{max}}$ derived from DITFs and the orthogonal trend of breakouts. Stress perturbations from these trends can be seen around major faults, such as at Arrowsmith–2 and Scenecio–1.

**Figure 15.** Drover–1 MEM stress plot. Across the Kockatea Shale $S_{\text{max}} > S_{\text{min}} = S_{\text{max}}$ suggesting a transitional strike-slip/reverse setting. Beneath the Kockatea Shale $S_{\text{max}} > S_{\text{min}} > S_{\text{max}}$ suggesting a strike-slip setting. $P_{\text{ho}}$ equals hydrostatic pressure, and $S_{\text{max}}$ and $S_{\text{min}}$ calculated from Eaton equations, are the orange and green lines, respectively. The red line denotes a linear $S_{\text{min}}$ trend from LOT data only and the blue line represents maximum possible $S_{\text{min}}$ assuming a critically stressed state. Note the fluctuations in stress in the deeper section, which are due to the varying rock properties of the Carynginia Formation and Irwin River Coal Measures.
In summary, available log and pressure data in the Perth Basin suggest that the in situ stress state is broadly consistent with that of central-southeastern US (strike-slip) through the shale gas play fairway in that region. In the Perth Basin, new fractures generated from reservoir stimulation treatments are likely to propagate east–west, in the direction of $S_{\text{min}}$, and in the vertical plane. Local variations and the influence of mechanical stratigraphy, however, need to be understood to better target stimulation programs.

Natural fracture distribution and orientation

Electrical image logs, such as the Formation MicroImager (FMI) log, are a key element to understanding both the in situ stress state as well as mapping the vertical extent and type of natural fracture networks. Image logs from 16 wells were imported and processed in Interactive Petrophysics (IP) software applying tool geometry to stitch pad data into a normalised, azimuth-corrected image. As fractures were identified they were categorised into DITF, breakout, fault, conductive, non-conductive and partial fractures. A total of 3,327 features were picked from image logs, of which 1,386 features were classified as natural fractures. Sinusoids were overlain on fractures such that dip angle and azimuth could be exported for stereonet plotting. An example of the image log through Senecio–1 shows the distribution of BOs, DITFs and interpreted conductive and non-conductive fractures (Fig. 16). It is noted that the assumption of open and closed fractures based on optical and electrical qualities can be misleading, consequently this study only differentiates fractures as conductive or not, and then overlaid the rose distribution of these subsets by formation on structure and stress maps (Fig. 17).

As shown in the subset example of fracture roses in Figure 17, some fracture orientations share common directions with major faults suggesting a relationship between some faults and fractures. In general, while fracture orientations vary from well to well, there appears to be a set of conjugate conductive fractures broadly oriented northeast and northwest and, at some locations, these sets appear optimally oriented to $S_{\text{min}}$ (~30°). If hydraulically active, these fractures sets may prove to be viable targets to enhance reservoir permeability during stimulation treatments.

Rock strength characteristics

The ability of a rock to sustain an open fracture network for production from an unconventional reservoir is dependent on the elastic properties of that rock relative to the in situ stress regime (Zoback, 2007). These elastic properties are a function of multiple factors including anisotropies within the rock and the clay, carbonate and quartz composition of the rock (Sone and Zoback, 2013). Regardless of these factors, the ultimate metrics for rock strength, reflective of compositional variation, are practically determined from dynamic log characteristics, namely Young’s Modulus (E) and Poisson’s Ratio ($\nu$). These metrics are calibrated against static rock measurements where available. This study has used the methodology described in Zoback et al (2003) and Zoback (2007) to calculate and calibrate dynamic rock strength characteristics for the Perth Basin using available log data as part of the MEM process.

Wells with available shear and compressional sonic data (di-pole) were used to calculate dynamic Shear Modulus, Young’s Modulus and Poisson’s Ratio as log tracks that were then calibrated against static laboratory data for available core samples. Uniaxial strength data are available for core samples from the Carynginia Formation, Irwin River Coal Measures and High Cliff Sandstone, as published by Rasouli and Sutherland (2013) for Arrowsmith–2 as well as for the same formations from well completion report data for Corybas–1, Redback–2 and Woodada Deep–1. As physical measurements of rock strength properties are limited in the Perth Basin, these four wells were used as reference points to calibrate log calculations of dynamic rock strength. Static data were compared against the dynamic response through the Wang transform (Wang, 2000).

Dynamic Young’s Modulus and Poisson’s Ratio were then used to calculate unconfined compressive strength (UCS), the most commonly used and practical log representation of down-hole rock strength (Zoback, 2007). Dynamic UCS was, likewise, calibrated against static UCS for the same four reference wells where laboratory data were available. In convert-
ing dynamic Young’s Modulus and Poisson’s Ratio to UCS, a number of methods were trialled including the use of basin-specific transforms calibrated against $V_{shale}$ lithology estimates determined from gamma logs. Three published equations were found to have a good fit for the observed Perth Basin data and these comprise: a relationship derived from fine-grained sandstones from the Bowen Basin (McNally, 1987); a relationship for limestones between 10 and 300 MPa UCS (Zoback, 2007); and, a relationship for strong compacted shales (Zoback, 2007). An example of each of these calculated curves is shown for Arrowsmith-2 (Fig. 18). While, in most cases, there is very little difference between each calculated UCS curve, the study has used the shale relationship (red) for UCS estimation as this best represents the target stimulation lithology.

For monopole wells in the Perth Basin, the same process was followed as for dipole wells, except that a sonic shear log was estimated from the compressional sonic using the Castagna transform (Castagna et al, 1993). The four dipole reference wells were again used to test that applicability of the Castagna transform, which was found to be a very good estimate of the shear sonic response for all units, with the exception of the Kockatea Shale; hence, a modified Castagna transform was applied to the Kockatea Shale in all wells.

The significance of rock strength in the Perth Basin

Young’s Modulus ($E$) and Poisson’s Ratio ($v$) are often considered as standard metrics in assessing the suitability of rocks to act as unconventional reservoirs with values for dynamic $E$ between 30 and 80 GPa and Poisson’s Ratio <0.25, documented for lower clay content shale plays in the US and seen as desirable (Sone and Zoback, 2013). The Arrowsmith-2 MEM shows that dynamic $E$ varies from ~20 GPa in the Kockatea Shale to ~50 GPa in the Carynginia Formation and Irwin River Coal Measures (Fig. 18), lower than those values described in some US shale plays. Throughout the Perth Basin modelled $E$ and Poisson’s Ratio vary significantly from location to location, however, a general view that Australian rock elastic values are not representative of stiff rocks prevails. This needs to be viewed in the context of both the in situ stress regime and mechanical stratigraphy. In strike-slip regimes, such as the Perth Basin, the ratio of transverse strain to axial strain is of less significance than in a normal stress regime, hence the use of Poisson’s Ratio as a reliable pay metric may likely be diminished. Indeed, MEMs constructed as part of this study demonstrated the relatively benign influence of Poisson’s Ratio on rock strength calculation.

<table>
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<tr>
<th>Fm. Tops</th>
<th>GR (API)</th>
<th>Young’s Modulus</th>
<th>UCS</th>
<th>Horizontal Stress</th>
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<tr>
<td></td>
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<td>$E_{dynamic}$ (GPa)</td>
<td>$E_{static}$ (GPa)</td>
<td>$E_{measured}$ (GPa)</td>
</tr>
<tr>
<td>Hovea Mbr.</td>
<td>250</td>
<td>150</td>
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<td>150</td>
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<td>Waginia</td>
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<td>Carynginia</td>
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<td>IRM</td>
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<td>High Cliff</td>
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**Figure 18.** Arrowsmith-2 MEM showing calculated (dynamic) rock strength characteristics from dipole sonic data across the Hovea Member to the High Cliff Sandstone interval. Three relationships for calculated UCS are shown, which correlate well with two physical measurements of UCS as shown by black squares. Likewise, calculated horizontal stresses agree well with initial shut-in pressure (ISIP) data from five pressure tests shown by black squares. Gas flow contributions from production testing are shown, noting the high contributions from stages one and three where dynamic UCS ranges from ~90–130 MPa. A minimum rock strength cut-off of 75 MPa is shown by the grey shading and discussed in text. Oil flow from the Hovea Member (17 BOPD) is likely to have come from the base of stage five where UCS is transitional from low to high strength.
Despite lower dynamic E values for some formations in the Perth Basin, particularly the Hovea Member of the Kockatea Shale, the calculated UCS remains relatively good with calibrated dynamic UCS at Arrowsmith–2 ranging from ~60–130 MPa (Fig. 18). Arrowsmith–2 was hydraulically stimulated in five stages with gas flow contributions shown on the right-hand side of Figure 18. The stimulation was preceded with a capillary suction time (CST) test due to the high clay content of rocks determined from XRD analysis (50–65% total clay) so as to assess the compatibility of stimulation fluid with mineralogy and ensure an effective treatment. Six rock samples were submitted for CST testing, three each from the Carynginia Formation and the Irwin River Coal Measures. The CST test measures the time for fluid to be extracted from a slurry made up of crushed formation rock mixed in with the nominated fluid to be used in fracture stimulation. Rock samples containing reactive or expandable dispersed clays form colloids that resist fluid extraction, giving longer CST times. Five proposed treatment fluids were examined for compatibility: 3% KCl, 1% KCl, 5% NaCl, 3% NaCl and fresh water (distilled). The results indicated that all samples displayed high sensitivity when using only fresh water. Use of even minor quantities of KCl or NaCl reduced reactivity to moderate to low levels, with 3% KCl being the most effective.

Tracers were mixed with the treatment fluids and each stage was assigned a different tracer that was monitored after pumping using a gamma ray log to assess those perforations, which were successful in creating fracture networks. It was found that all stages were successful in generating fractures, but for the Carynginia Formation, the most successful perforations occurred within the middle-to-lower Carynginia Formation where dynamic UCS is relatively high and remains consistently above 75 MPa.

To further understand the relative strength of Perth Basin rocks, in terms of UCS, a number of MEMs were constructed for Eagle Ford Shale wells in the Sugarloaf Field, US, in which AWE is a joint venture partner. Dipole sonic and density data for the Forshage Howell–2A well at Sugarloaf were used in the same MEM workflow as for Perth Basin wells with rock strength characteristics calibrated against laboratory measurement of UCS from the nearby Luna–1 well. The Forshage Howell–2A well was subject to 15 stimulation stages where the calibrated dynamic UCS was calculated to be between ~75–135 MPa. Likewise, the five stimulation stages at Arrowsmith–2 achieved significant flow from rocks where calculated UCS ranges from ~60–130 MPa, despite relatively high clay concentrations (Fig. 18). The calculated UCS for the Hovea Member at Arrowsmith–2 is generally low, and it is possible that oil flowed from the basal portion of stage five where UCS begins to increase (Fig. 18). Notably, production logging at Arrowsmith–2 showed that the most significant gas flow contributions were from the highest UCS intervals in the Irwin River Coal Measures, High Cliff Sandstone and Carynginia Formation (Fig. 18).

Consequently, this study used a baseline of 75 MPa UCS as a possible minimum rock strength for the purpose of play-fairway mapping. The 28 Perth Basin wells with available sonic and density data were modelled for dynamic UCS and the net thickness of rock with UCS >75 MPa was applied as an overlay to the play-fairway map (Fig. 19).

DEFINING SWEET SPOTS—COMBINING IN-PLACE RESOURCE MAPPING WITH ROCK MECHANICS

The unconventional system components for the Carynginia Formation and the Hovea Member in the North Perth Basin have been defined through an integrated 3D basin modelling approach to estimate retained hydrocarbons-in-place and an assessment of rock strength and stress characteristics using available dynamic and static data. These considerations are overlain in Figures 19a and 19b such that the following resource cut-offs and variables have now been applied:

- in-place retained gas and liquids for mapped isopach volumes;
- resource within kinetically defined maturity windows with a likely condensate window for gas drive between 1.1 and 1.4 Ro% for the Hovea Member;
- resource where drilling depth is <1,000 m;
- resource where overpressure may be present at >1.2 Ro%; resource where dynamically modelled UCS rock strength net thickness is >75 MPa; and,
- resource in reference to prevailing stress regime and natural fracture and fault orientation.

The Carynginia Formation unconventional play fairway, as defined by the above criteria, shows a significant area of resource largely influenced by the net thickness of rock with a strength >75 MPa UCS, which remains relatively constant (100–200 m) throughout most of the study area (Fig. 19a). Some areas in the Redback Terrace and east of Woodada may have increased potential owing to greater retained gas. The area east of Woodada lacks well control; however, available FMI data suggest that there are fewer natural fractures in the Woodada wells compared to those on the Redback Terrace. While both areas have east–west oriented Smin directions, the Redback wells exhibit multiple populations of conductive and non-conductive natural fractures, some of which are suitably oriented for shear reactivation.

While the Hovea Member has a significant distribution of in-place liquids, only a portion of this in the central and southern study area may be economically extractable using gas drive where the condensate window commences at 1.1 Ro% (Fig. 19b). This resource area is further truncated by rock strength considerations as the Hovea Member resource >75 MPa UCS is less than 10 m thick in the southern part of the study area and may be too thin for a targeted horizontal drilling campaign. This approach is also a good demonstration of refining play fairways through geomechanical overlays. Previous studies on the Perth Basin have highlighted the source potential of the Hovea Member based on geochemical characteristics only (e.g. Thomas and Barber, 2004; Grosjean et al, 2011). Although the Hovea Member is geographically widespread, the overlay of rock mechanics attributes could restrict the extractable resource area to the Redback-Warradong region (Fig. 19b).

DISCUSSION AND CONCLUSIONS

The combination of 3D basin modelling using a mass balance approach to estimate in-place resources, combined with rock mechanics and stress considerations, provides a unique method of defining unconventional play fairways and high-grading areas of prospectivity. Importantly, the process undertaken in this study highlights a large in-place unconventional resource for the Carynginia Formation and the Hovea Member of the Kockatea Shale, and that the workflow undertaken has high-graded areas of potential economic extractability through an integrated approach. The Perth Basin does not generally exceed the cut-offs used in US shale gas plays; there is sufficient empirical evidence from stimulation programs to show that significant flows are achievable. With regards to these resources it can be concluded that:

- Despite relatively low present-day TOC values for the Carynginia Formation and Kockatea Shale, 3D basin modelling demonstrates that significant volumes of gas are expelled and retained. Areas east of Woodada and in the Redback
Figure 19. Carynginia Formation (19a) and the upper Hovea Member—Sapropelic interval (19b) final unconventional hydrocarbon play fairway maps showing in-place modelled retained free hydrocarbons from a 3D basin model incorporating 14 seismically mapped depth grids, geochemical constraints and thermal models for 72 wells and pseudo wells. Overlain are regional faults, key modelled maturity cut-offs widows, drilling depth limitation (4,000 m), modelled net thickness of reservoir rock with UCS >75 MPa, and a possible overpressure window at 1.2 Ro%.
Terrace are high-graded as areas with the highest unconventional prospectivity.

- Modelled kerogen kinetics suggest that the Caryaeginia Formation will be gas prone with main gas expulsion commencing at 1.2 Ro% and the Hovea Member will expel liquids at 0.9 Ro%, but the condensate widow between 1.1 and 1.4 Ro% provides the best opportunity for economic recovery through gas drive.

- Calculated theoretical porosity for wells in the Perth Basin with sonic and density log data show some evidence of possible overpressure. Where these observations are correlated with observed connection gas occurrences and maturity data there is evidence to suggest that modest overpressures between 2 and 6 MPa exist in parts of the basin associated with the main gas window at ~1.2 Ro%.

- The stress state of the Perth Basin was found to be largely strike-slip. Of 28 wells for which log and pressure data exist to build MEMs, the vast majority show strike-slip conditions, transitional to normal/strike-slip for some wells. The stress state varies down-hole as a function of mechanical stratigraphy and this is an important consideration with regards to capitalising zones of high stress to guide stimulation treatments.

- Image log data for 16 wells in the basin have been used in the MEM process and define a principal horizontal stress trajectory oriented east-west as a function of far-field stresses. Local variations do occur where local faults perturb the stress field.

- Natural fracture mapping from image log data show multiple sets of conductive and non-conductive fractures. Northeast and northwest-oriented conductive fracture networks may provide structural permeability for any stimulation treatment to assist in recoverability.

- Dynamic rock properties for the Caryaeginia Formation, the Kockatea Shale and the Hovea Member have been calibrated against static values and suggest that while rock stiffness is not as high as that observed in US shale gas plays, there are zones of sufficient rock strength in all target formations to sustain an open fracture network. This is evidenced through gas and oil flows obtained from stimulations treatments at Arrowsmith–2 where rocks have calculated UCS between ~60 and 130 MPa.

- The net thickness of Caryaeginia Formation rocks with UCS >75 MPa remains relatively thick and constant throughout the basin. In contrast, the thickest section of the Hovea Member of the Kockatea Shale, with UCS >75 MPa, occurs in the Redback area, which therefore represents the best target zone for this play.

ACKNOWLEDGMENTS

The Management and Board of AWE Ltd are thanked for encouraging and authorising the publication of this study. Dr Zhiyong He of Zetaware provided excellent support, as usual, and Helen Zammitt and Ben Gussey assisted with drafting images. The manuscript benefited from the reviews of Dr David Lowry and Dr Lisa Hall.

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