EVALUATING AUSTRALIAN UNCONVENTIONAL GAS—USE AND MISUSE OF NORTH AMERICAN ANALOGUES

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ABSTRACT

Evaluation of Australia's emerging unconventional gas sector (particularly shale gas, basin centered and tight gas) relies heavily on the use of North American analogues because of the lack of production history in Australian plays. While the use of analogues can be useful, no two shale or tight gas plays are identical so the use of analogues can also lead to significant pitfalls that need to be understood to be avoided. Production performance and recoverable hydrocarbons are strongly coupled to completion technology (far more than a conventional oil or gas project), and the successful implementation of technology requires an intimate knowledge of both reservoir petrophysics and geomechanics, not to mention a well-developed topside supply chain. This paper discusses the application of analogues to major Australian unconventional plays in the Cooper, Canning, and Perth basins, presents a case history from the Canning Basin, and provides guidance on the adjustments needed to ensure realistic predictions of recovery and well performance.

KEYWORDS

Australian shale gas, North American shale gas, shale analogues, fracture network, pad drilling, concurrent operations, integrated services, Cooper Basin, Perth Basin, Canning Basin, Montney shale, Laurel shale.

INTRODUCTION

The North American shale gas industry is a success story, and the search for prospective shale gas acreage is now a global activity. As a result, shale and similar unconventional gas development has attracted much attention in countries such as Germany, Hungary, Poland, China, India, and Australia (which has large sedimentary basins with enormous shale gas potential). Australian shales have the desirable properties that make an excellent shale prospect including high TOC (>2.5%) and thermal maturity (>1.5%) of kerogen (typically Type II) for marine shales, gas content, thick and potentially laterally continuous plays, fraccability, and other properties (the parameters listed here are not comprehensive, or mutually exclusive). Public literature suggests that the Barnett and Haynesville shales in the US are key analogues for Australian shales (McManus, 2012; Sharifzadeh, 2012).

Although shale gas exploration in Australia is still in its infancy, exploration activity has significantly increased in recent years. Beach Energy, which has substantial permits in the Cooper Basin, drilled Moonta–1, with a confirmed peak flow rate of 2 mmscf/d (56 10^3m^3/d). In 2012, Santos (2012) claimed Australia's first commercial shale well with Moomba–191 (also Cooper Basin), flowing at nearly 3 mmscf/d (85 10^3m^3/d). AWE is concentrated in the Perth Basin, with three wells cored. Drillsearch is another company pursuing shale gas exploration in Australia, with 15 licences and extensive exploration acreage in the Cooper Basin (Lingo, 2011). A number of other operators are actively exploring for unconventional gas plays including Cooper Energy, Norwest Energy, and Senex Energy. International operators include ConocoPhillips, which entered into a partnership with New Standard Energy to explore the shales of the Canning Basin, and Mitsubishi, which recently acquired a 50% stake in Buru Energy's unconventional assets in the Canning Basin.

According to public sources, Australia has nearly 400 Tcf (11.3 Tm^3) of recoverable shale gas, from about 26,000 Tcf OGIP (original gas in place) in four producing basins (Kuuskraa, 2011). These basins include the Perth, Canning, Cooper, and Maryborough basins, as shown in Figure 1. For the purpose of this study, the primary basins of interest are the Cooper, Perth, and Canning basins.

Figure 2 shows the first-order comparison that analysts might typically consider when evaluating analogues, as well as the modifiers and revisions required to ensure that a suitable geologic, engineering, and commercial model is generated. As will be demonstrated in this paper, first-order comparisons of Australian and North American shales rarely provide a true, or even suitable, analogue. The intention of the following text is to illustrate challenges or problems that occur when relying solely on a first-order comparison when selecting a North American analogue for an Australian shale. It is important to note that this paper is not intended to be a comprehensive comparison of North American shales, but an overview of the process, with recommendations. Finally, using an Australian case study, it will be shown that two shales appear analogous when making a cursory review, but detailed analysis in both geology and engineering is required to actually ensure that analogue conditions do exist.

The Cooper Basin has four troughs that contain Permian-aged shales (Fig. 3 shows a generalised stratigraphical column). These include the Nappamerri, Patchawarra, Arrabury, and Tenneppera troughs, with a lateral extent of 15,000 km^2 and a depth of about 3,000 m. Nelson (2012) considered the Nappamerri Trough the most prospective, based on thickness, organic content, mineralogy, maturity, and position in a basin-centred gas system containing low-permeability sands (Trembath et al, 2012). Most of the gas is trapped in the Epsilon Formation between two source rocks called the Roseneath and Murteree shales. These shales, with an OGIP estimate in the order of 40–80 Bcf/km^2 (1.1–2.3 Gm^3/km^2), are non-marine in nature, and are often viewed in combination as the REM formations (Baker and Bare, 2011). These shales are over-pressured with thermally mature, moderate to high organic content in the order of 2.5–5.0%, are relatively thick from 60–100 m, and

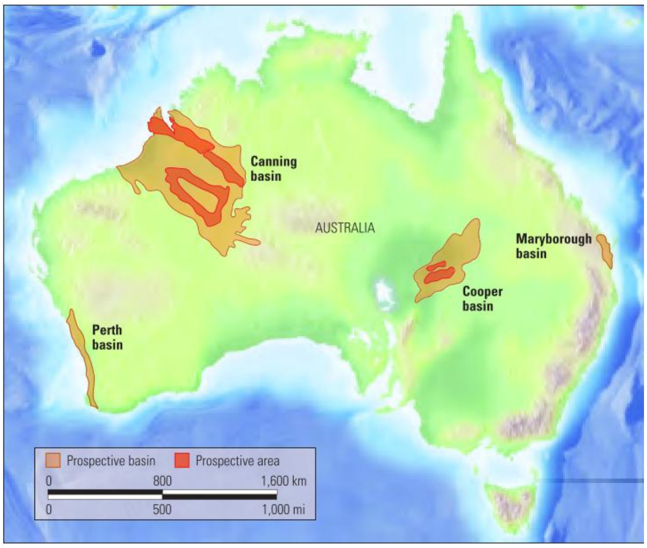

Figure 1. Australian gas basins (Boyer et al, 2011).

are considered to have silica content (a preliminary indicator of brittleness and, possibly, a fracturing candidate) comparable to many US shales (Baker and Bare, 2011). Although their lacustrine origin and Type III kerogen is not typically the target of shale gas, they have low clay content that aids fracture and could enhance productivity.

With a recoverable estimate of 60 Tcf (1.7 Tm^3), the smaller Perth Basin is another attractive shale gas basin (Baker and Bare, 2011; Kuick Research, 2012). The Dandaragan Trough has prospective marine shales of Triassic and Permian ages in the Kockatea and Carynginia shales, respectively. The shales have a TOC in the range of 1–4%, an average log porosity of 3–6%, and a pressure gradient slightly greater than normal. The OGIP is approximately 42 Bcf/km^2 (1.2 Gm^3/km^2). The Perth Basin is only 200–300 km away from the gas market in Perth, and is well connected with two pipelines (Kuick Research, 2012). Figure 4 shows a generalised stratigraphical column for the Perth Basin shales.

The Canning Basin has deep Ordovician to Carboniferoius aged marine shales, and is estimated to have about 300 Tcf (8.5 Tm^3) recoverable gas (Baker and Bare, 2011; Kuick Re-

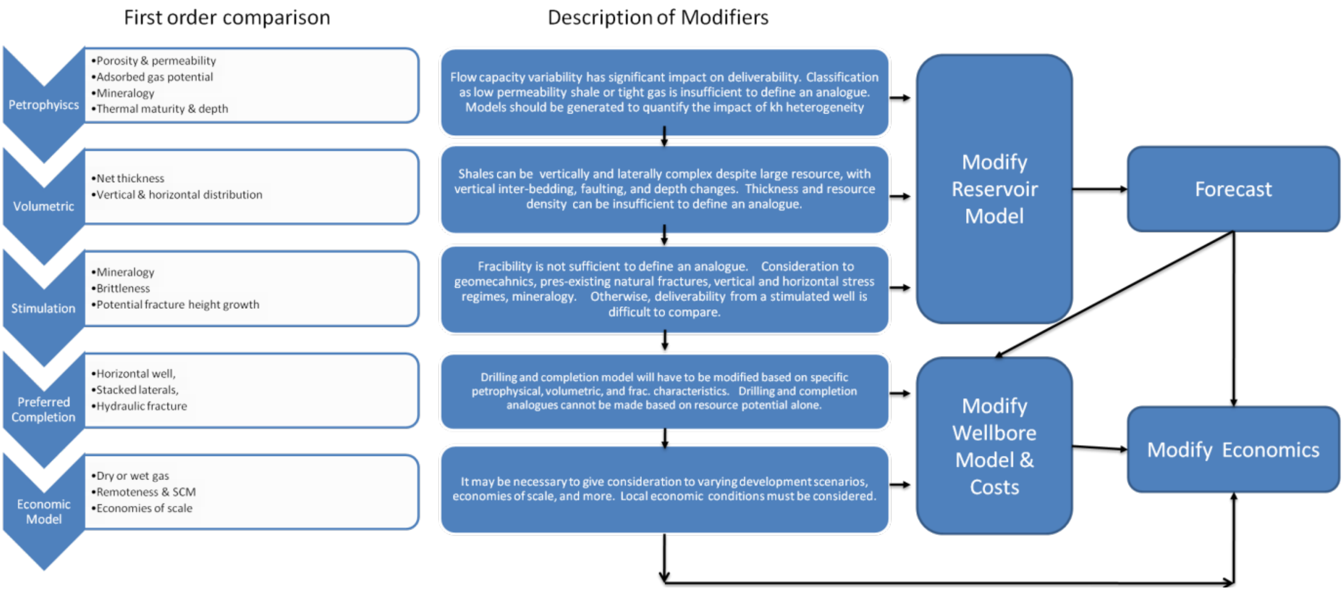

Figure 2. Suggested workflow for shale gas evolution.

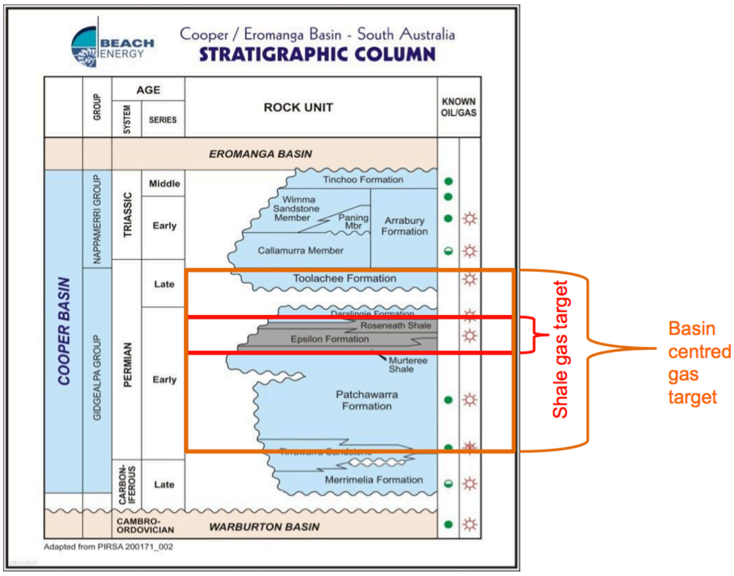

Figure 3. Geological setting of the Napparmerri Trough (Nelson, 2012).

search, 2012). Prospective shale gas has been identified in the Fitzroy Trough where the Goldwyer and Laurel formations are expected to contain producible shale gas. The Goldwyer Formation is nearly 400 m thick.

USE AND MISUSE OF ANALOGUES

Petrophysics and volumetrics

Australian shales are regularly compared with the major North American shales, leading to generalisations about deliverability, costs and development plans. North American shale development is often described as a mere manufacturing process, which can be easily implemented in petroleum producing provinces elsewhere; however, such manufacturing occurs in the context of a highly variable subsurface environment. In practice, despite laterally continuous and thick resources, significant variability still exists in shale production profiles and development plans due to uncertainty in the geological parameters.

Barnett shale, which is often used as an analogue in Australia and abroad, exhibits considerable variability in initial production (IP) ranging from 0.02–2 mmscf/d in 2009 (0.56–56 10^3m^3/d); an estimated 25% of the Barnett wells are potentially unprofitable under certain circumstances (Schaal, 2011). Figure 5 shows a comparison of the initial gas rate by year, completion type, and development tier, illustrating the production variability that has occurred in one of North America's most studied shale plays (recent data not obtained). Barnett shale has been found to be very heterogeneous, with both faulting and karsting regularly encountered, and permeability ranging from 100–400 nD (Coulter et al, 2004). Overall, the 30-day IP from the Barnett, Fayetteville, Woodford, Haynesville, Marcellus, and Eagle Ford shales range from 2–6 mmscf/d (70–175 10^3m^3/d). For the same resource plays, Tella (2011) shows the average recovery per well for the Barnett, Fayettville, and Woodford/Marcellus shales is 2.4, 2.6 and 4.3 Bcf, respectively (0.07–0.12 Gm^3), while the average recovery for Haynesville and Eagle Ford wells is generally more than 5 Bcf (0.14 Gm^3). Similarly, the Canadian Montney shale, an analogue commonly used for Laurel shale of Australia's Canning Basin, also shows considerable production variability due to both geologic complexity and completion method. Figure 6 shows the initial 30-day production rate (IP 30) based on 521 wells. With permeability ranging from 300 to >1,000 nD, and a subsurface pressure gradient ranging from 10–18 kPa/m, Okuszko and Hayes (2012) estimate that Montney production rates range from 0.01–10 mmscf/d (0.28 –282 10^3m^3/d) with a varying degree of associated liquids from 2–100 bbl/mmscf. As a result, a common but flawed practice in North America is to fracture laterals in equal increments, often ignoring vertical and lateral heterogeneity, resulting in waste of fracturing capital (micro-seismic monitoring has shown that significant portions of the reservoir may remain uncontacted due to unexpected fracture growth). In Australia, both the Maryborough and Perth basins are structurally complex if not faulted. Key findings of a recent Government of South Australia study (2011) showed two main directions of faulting in the REM shales of the Cooper Basin.

Overall, mineralogy data would suggest the Cooper, Canning and Perth basin shales are favourable for fraccing due to a lower clay content and high silica content. The depositional environment and lithologies, however, differ from many of the North American commercial analogies.

The major shale gas objectives for the Perth Basin are in the Irwin River Coal Measures (IRCM), and Carynginia and Kockatea formations. The IRCM contains alternating over-mature sandstone, siltstone, carbonaceous shales and coals deposited in a series of alluvial deltas prograding into a cold-temperate marine embayment.

The Carynginia Formation is a marine unit deposited over a wide area of the northern Perth Basin, much of it under condi-

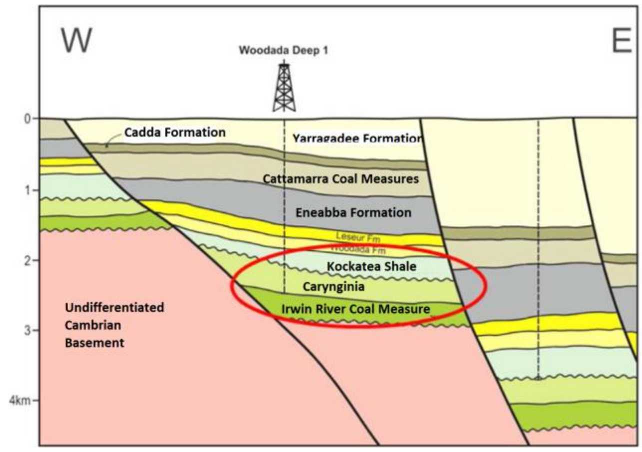

Figure 4. Perth Basin shale sequences (Clement, 2012).

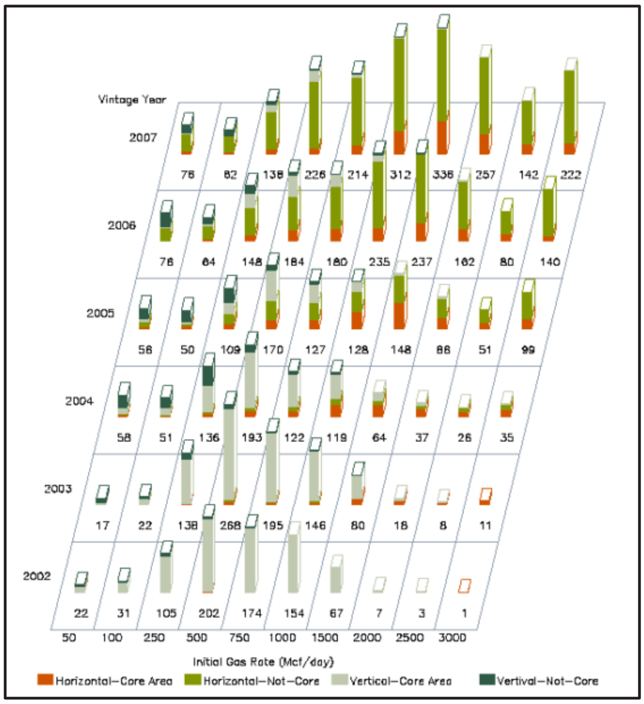

Figure 5. Barnett shale production variability (Schaal, 2011).

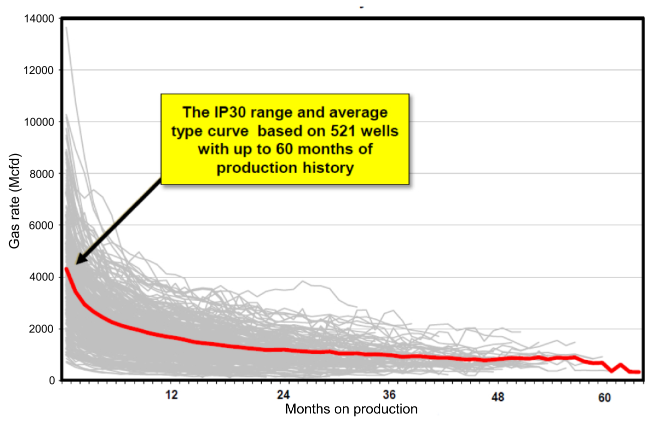

Figure 6. Montney shale production variability (Advantage Oil & Gas, 2011).

tions of restricted circulation. In outcrop it is largely silty with minor shale. Basinwards, however, it becomes dominantly shale with occasional thick beds of sandstone. Limestones are common towards the base of the unit. The basal Caryngninia Formation comprises marine shales with TOCs up to 11% and is largely in the over-mature to gas generative maturity range.

The Kockatea marine shale has TOCs over 2% and has thicknesses in excess of 1,000 m. The Kerogen type for this unit is predominatly Type II, so it has significant potential for liquids. An overprint, however, is the Perth Basin is structurally complex and lateral continuity may be an issue in places.

The Cooper shales gas target is contained in the Permian Roseneath, Espilon and Murteree units (REM). The Murteree and Roseneath shales are lacustrine with intervening fluviodeltaic sediments that were deposited during a phase of continued subsidence. This package results in an over-mature basin centered gas (BCG) accumulation. In the Canning Basin, the focus for shale gas lies in the Goldwyer Formation in the southern troughs and in the Anderson, Laurel (Fairfield Group), Gogo and Goldwyer formations in the northern troughs. The Laurel Formation contains very thick (more than 1,000 m) sequences of marginal marine to deeper water sediments—a combination of shales siltstones, carbonates, and fine grained sandstones—resulting in the potential for a hybrid lithology unconventional basin centred gas play. The resulting lithology is highly variable in clay mineralogy, porosity and TOC. The fracture design for these above-mentioned units will differ substantially from many North American commercial shales.

In North America, quartz ranges from as low as 5% in Eagle Ford up to 80% in the Muskwa shale of the Horn River Basin, while Barnett has a quartz content of 40–60% (Hall, 2010). The wide range of silica (as well as clay) is a partial explanation of the wide variety of fracture stimulation methods implemented in North America. These stimulations include traditional slickwater, hybrid fracture treatments (water pad with friction reducers and breakers followed by crosslinked sand-laden stages), and energised stimulations (use of C_3H_8, CO_2, and N_2).

Geochemical analysis of Montney and other North American shales shows a wide variety of kerogen, ranging from Type III gas prone to Type II (oil prone), resulting in dry- and wet-gas shale projects; therefore, having significantly different economics (Hall, 2010). Liquids potential is relatively untested in Australia, and individual shales will also likely exhibit variability. Recent public-domain data suggests that liquid contents may be present near the western portion (flanks) of Cooper Basin shale, similar to Eagle Ford shale in the US (Lingo, 2011). Similarly, the Goldwyer Formation of the Canning Basin also has potential for liquids, as it comprises a continuous marine shale at varying depths and with different maturity windows, and the Laurel Formation has had reported significant wet gas potential.

Examples of the liquids-rich shale plays in North America are the Marcellus, Utica, and Eagle Ford have the greatest potential, with condensate ratios sometimes greater than 100 bbl/mmscf or 0.56 $m^3/10^3m^3$. Eagle Ford, which has some of the highest percentages of liquids, has ultimately been defined as three zones, including an oil, a condensate, and a dry-gas zone (with portions that are uneconomic). Figure 7 shows the generalised location and productivity condensate producers in Eagle Ford. Similarly, the Canadian Montney shale also exhibits a wide range of condensate ratios from 2–100 bbl/mmscf (0.11–0.56 $m^3/10^3m^3$), as shown in Figure 8, reducing the break-even price at nearly \$2/mscf (\$1.9/GJ) in some situations (Adams, 2012; MIT, 2011; Davidson and Mortensen, 2009).

In addition to mineralogy, shale thickness, and liquids content, there are other fluid factors that need to be considered when choosing a North American shale analog. Cooper Basin shales tend to have elevated levels of CO_2, with the Epsilon

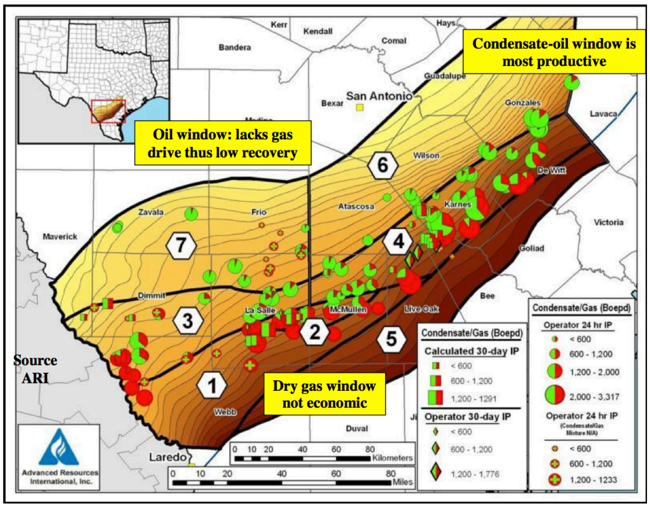

Figure 7. Eagle Ford shale (Urness, 2011).

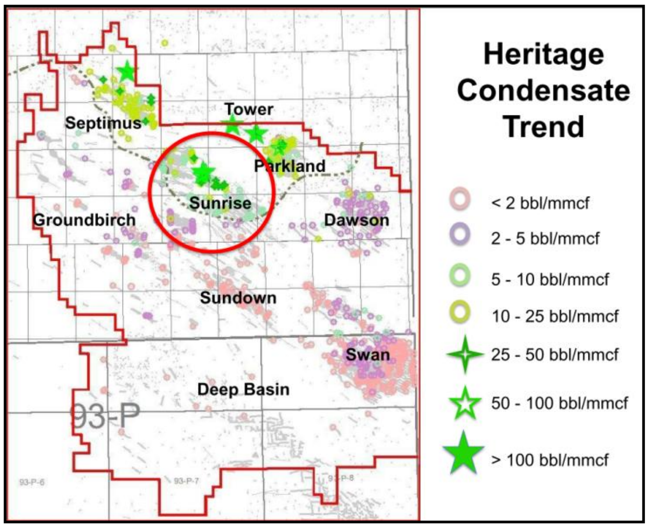

Figure 8. Montney liquids production by target area (Oskusko and Hayes, 2012).

Formation having up to 24 mol% CO_2 and the Patchawarra Formation up to 40% mol% CO_2 (Kuick Research, 2012), implying that more capital may potentially be needed to be spent cleaning (stripping) off the CO_2. Most Canadian shales have low CO_2 (1–5%), excluding the Horn River Basin (10–12%), where operators are pursuing a number of methods to offset the cost of inerts, including small-scale enhanced oil recovery, carbon sequestration, and recycling to produce methanol (Blue Energy Fuel, 2012). CO_2 removal solutions for Horn River are, however, difficult as the amount of impurities vary by both shale package and depth (Blue Energy Fuel, 2012).

Preferred completion

In Australia, Baker and Bare (2011) indicated that to achieve an internal rate of return (IRR) of 10%, a hypothetical well costing \$10 million AUD needs to deliver 3–4 Bcf (0.09–0.11 Gm^3) of gas at gas prices of \$5.5–7.0/GJ. As a result, even if a suitable geological analogue is obtained from the North American shale library, economic considerations are quite different in Australia and will impact both the technology and timing of projects. Presently, Australian shale gas completion costs can be two to three times greater than US shales (mostly due to a lack of infrastructure in basins other than the Cooper Basin, tight skilled labour and contractor expertise, and a lack of drilling technology and expertise).

The lack of infrastructure and facilities is a key factor in the dearth or delay of commercial production of Australian shale gas due to its early stages of development and remote location (Kuick Research, 2012). In the Canning Basin and parts of the Cooper Basin that are in the early stages of evaluation, due to the remote location, sparse road infrastructure and wet season periods operations can be very expensive, and supply chains can be intermittent during wet seasons. For comparison, there are more than 1,100 land rigs operating in North America, and more than 3,000 wells were drilled onshore in the US alone, while 155 wells were drilled in Australia (excluding CBM). The drilling and fracture stimulation experience, therefore, is far less than that observed in North America, which impacts cost and efficacy. Although these limitations are expected to improve as commercialisation proceeds, it does highlight the issues in getting projects off the ground. Shale gas plays are also manpower and supply intensive; for example, Canadian slickwater treatments use about 2,100–3,600 m^3 of water per stage of fracture treatment (Johnson and Johnson, 2012). In Australia, water sources and proppant (propping agent) sources are considered more scarce when compared to the US.

When reviewing North American drilling, completion and operating costs, however, it is insufficient to simply scale North American shale gas costs by a factor generally observed in conventional oil and gas projects. In North America, significant experimentation and optimisation has been done in the logistical model, including potential pad drilling, concurrent operations, and vertical integration. For example, the thicker Canadian shales—such as the Horn River Basin and Montney Basin shales—are locally more than 300 m thick and are often developed using stacked horizontal wells from a single pad, offering significant reductions in time and cost (as well as the lowest possible environmental footprint), and may be a model for Australian shale development.

Using pad drilling, denoted as the resource play hub (RPH) model, Canadian major EnCana indicated significant drilling savings in their Horn River Basin projects (historically, a weather-constrained region with only a 100-day working window) through both an economies of scale model and the bundling of services (Dawson et al, 2012; EnCana 2012). The RPH model is a combination of aspects such as multiple wells from a single location coupled with concurrent operations and bundling services, achieving lower drilling and stimulation costs. EnCana also applied the RPH model to single-zone operations in their Louisiana Haynesville shale gas project, where drilling days were reduced from 80 to 40, for a potential saving of more than 50% on a per-well basis using pad drilling (Figs 9–11). Southwestern Energy, a natural gas producer in the US, is presently developing Fayetteville shale using vertical integration in logistical matters, with primary cost savings in drilling, fracture stimulation, and gathering facilities (Dawson et al, 2012). Southwestern Energy has managed finding and development (F&D) and other costs to less than $1/mscf ($0.9/GJ), as shown in Figure 12.

In Australia, in addition to a smaller environmental impact, pad drilling could perhaps provide cost savings of up to nearly 50%, substantially offsetting the higher cost regime as it provides a 40–50% decrease in drilling days after the first five or six wells are completed. Recently, Santos has reviewed the cost savings of multi-well pad drilling in the Cooper Basin, and is exploring the approach in the Greater Tindilpie and Cowralli areas (Cruickshank, 2012). Similar development scenarios have been expressed by Drillsearch (Lingo, 2011).

Given that the average breakeven price of Australian shale gas appears to be about $6–9/mscf ($5.7–8.3/GJ), North American natural gas liquids (NGLs) are often cited when making comparisons, since shale gas breakeven gas prices could be reduced to about $2–3.5/mscf ($1.9–3.5/GJ) with revenue from liquids sales. Figure 13, which shows the impact of liquids production on the breakeven gas price on a vintage Marcellus shale, indicates that a typical well could actually provide adequate return on investment, even if the natural gas were to realise no market value (MIT, 2011). Typical Marcellus wet-gas prices are about 70% above dry gas. Producers such as Range Resources and BHP Billiton report returns of more than 60% for wet shale gas projects, resulting in about 17% of US shale exploration driven by liquids search.

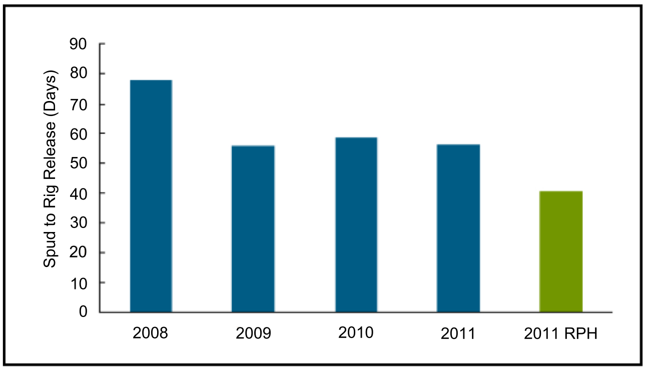

Figure 9. EnCana Haynesville drilling efficiency using the RPH model (Dawson et al, 2012).

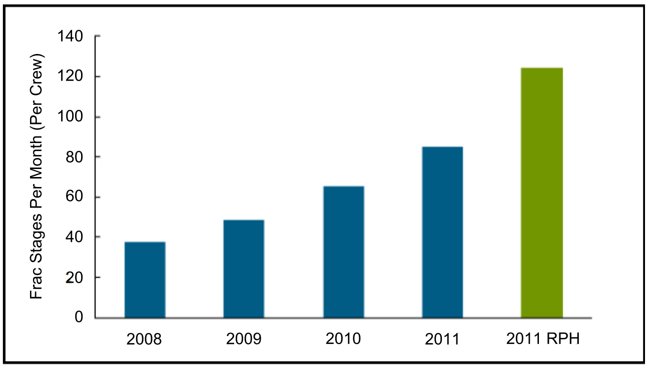

Figure 10. EnCana Haynesville fracturing efficiency using the RPH model (Dawson et al, 2012).

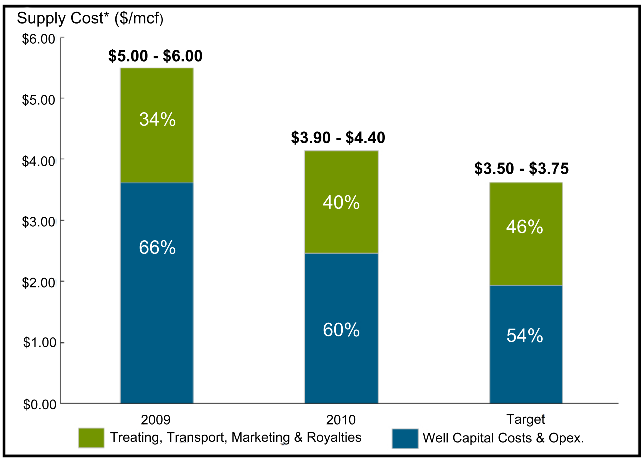

Figure 11. EnCana Haynesville supply/cost efficiency using the RPH model (Dawson et al, 2012).

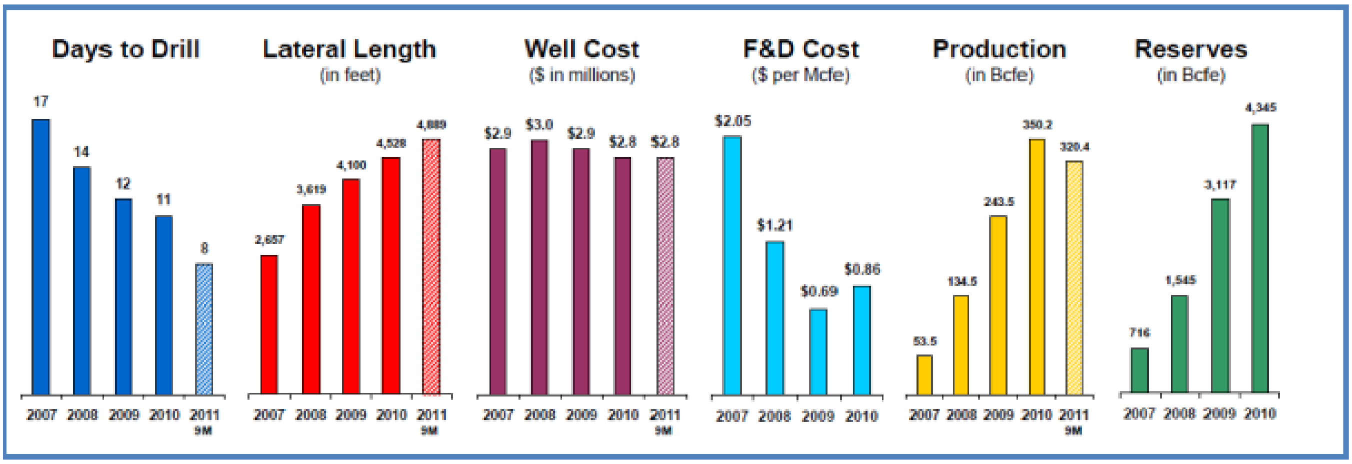

Figure 12. Improvements in operations from SWN investor presentation (Dawson et al, 2012).

Figure 13. Impacts of liquids for breakeven prices of US shale (MIT, 2011).

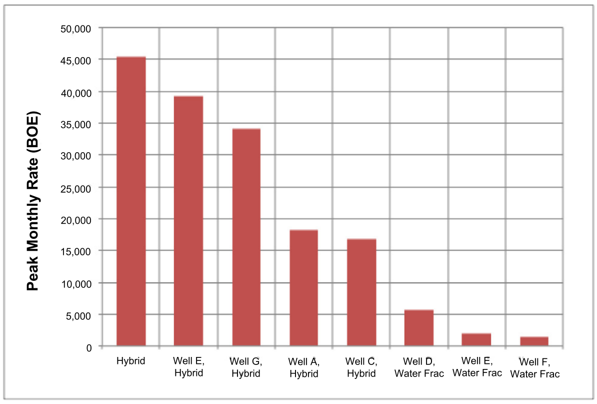

Figure 14. Performance of Eagle Ford shale wells (Ramurthey et al, 2011).

Stimulation

Similar to drilling and completion methods, fracturing has also been a trial and error process in North American shales. Although Barnett shale is often cited as a general analogue for fracturing processes, the fallacy is that the Barnett-style stimulation is applicable to all shales. Due to the success of the Barnett waterfrac (which has evolved during a 17-year period), it is a common assumption that the Barnett fracture processes would uniformly work in shales both inside and outside North America, or even in Australia. Barnett, however, is one of the hardest shales encountered (with low clay content), while the Haynesville and Eagle Ford shales, followed by Woodford, Bakken, and Marcellus, form the transition from brittle to ductile shale (Mckeon, 2011). In fact, Barnett is nearly five times as hard as Haynesville and other shales (excluding the Canadian Horn River Basin shales). In addition to brittleness (silica rich) conditions, factors such as pre-existing natural fissures, low differential horizontal stresses, and low clay content also contribute towards a greater chance to achieve a Barnett-style fracture distribution, as opposed to the classic bi-wing fracture. It is important to note that the Barnett waterfrac sometimes underperforms when compared to other fraccing methods; however, in select situations where hybrid fractures actually performed slightly better to slickwater fractures, many Barnett operators switched from cross-linked gel to slickwater (with reduced proppant), due to a 30% cost reduction.

In Eagle Ford, it was found from experimentation that hybrid fractures actually outperformed Barnett waterfracs, as shown in Figure 14 (Ramurthy et al, 2011). From 2009–10, Canadian operators almost doubled the number of fracture stages per well from 10 to 19 in the Horn River Basin, with an emphasis on slickwater fractures, while more emphasis was placed on energised fractures in both Montney and Montney North trends. Marcellus shale also has varying types of stimulation, with water fracture treatments commonly used in the deeper, higher pressure shales, while nitrogen foam treatments are commonly pumped in shallower shales with lower pressures for improved clean-up and/or flow-back. Operators still experiment between the effectiveness of water versus foam fracturing.

Explorers of hybrid shales such as the Laurel Formation of the Canning Basin may need to experiment for some optimum fracture spacing, reservoir mineralogy, and fracture design (slickwater, carbon dioxide, nitrogen, propane) as operators did in the Canadian Montney. Goldwyer shale of the Canning Basin can also have a mix of tight shale/silt, which may also suggest that some areas are more suited to Montney-style fractures, while other areas are perhaps suited to Barnett-style fractures.

In general, a handful of Australian fraccing jobs to date on specific wells have returned encouraging results; however, mineralogy alone is not a sufficient parameter for selecting fracturing analogues from North America. Stress regimes have to be understood, and faults may impose limitations on the extent of productive horizontal sections. North American analogies indicate the fracability of Australian shales, but not necessarily the process and quality of the induced fractures. Incidentally, although Perth, Cooper, and Canning basin shales are documented as having low clay content, the clay content of the Hovea Member of the Kockatea shale in the Hovea–3 well (Baker and Bare, 2011) actually ranged from 24–42%, which is substantially higher than many American shales. Figure 15 provides a comprehensive comparison between Australian and select North American shales with emphasis on fracturing process. For illustration, Figure 16 shows

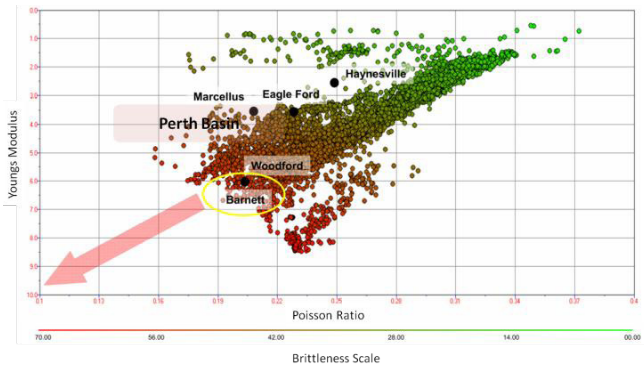

Figure 15. Cross-plot of Young's Modulus and Poisson's Ratio (Gray and Wall, 2012).

the unconventional gas continuum of various shales with well-known shales superimposed on possible, anticipated stimulation processes and results.

Collectively, the REM sequence of the Cooper Basin also appears to have a brittle lithology and an orthogonal set of natural fractures, but with an anisotropic stress regime (Government of South Australia, 2011). Portions of the REM may, therefore, respond well to Barnett-style fractures, but with a completely unique and different fracture pattern. Similarly, the maximum and minimum stresses of the Perth Basin become increasingly anisotropic between depths of 1–3 km (which includes both Kockatea and Carynginia), indicating perhaps differing fracture programs with depth (King et al, 2011).

AUSTRALIAN CASE STUDY

In this research, a hybrid shale play considered typical of Australian conditions was selected. The example formation has a gross thickness of 800 m, which can be compared to thicker North American hybrid shales such as the Canadian Montney. Both Montney and the example are hybrid shales with various combinations of shale, silty shale, and shaley sand, with the example even containing carbonate sequences. Although it is common to use more well-known North American shales—namely the Barnett—to evaluate prospectivity, the example is more comparable to the Canadian Montney in terms of lithology, possible completion style, and potential fracturing process (Table 1). As will be demonstrated, however, any comparison between the example and Montney formations will require an iterative process to ensure a reliable example model is derived from Montney.

Using Montney as an analogue, IP was expected to be 6–40 mmscf/d, and recovery at 3.5–6 Bcf per well (0.1–0.17 Gm^3 per well) based on data by Hall (2010). The preferred completion model in Montney is, however, typically a horizontal well(s) with transverse fractures (to date, Montney is fractured with a variety of processes ranging from energised hybrids to slickwater). Since 2005, the average number of fracture stages in Montney has increased from 5 stages to 12 stages per lateral, while horizontal well length has increased from 1,200 m to 2,000 m (Johnson and Johnson, 2012). As a result, it becomes clear that in addition to variability in reservoir properties, changing technology and variability in the completion design also contributed to the uncertainty in public production profiles and type curves.

In Australia, the ability to implement the preferred Montney completion is a challenge due to the higher cost and higher geological risk involved with Australia's relatively less-explored shales plays. Consideration, therefore, must be given to varying completion design as well as the economies of scale. To this end, Montney production data

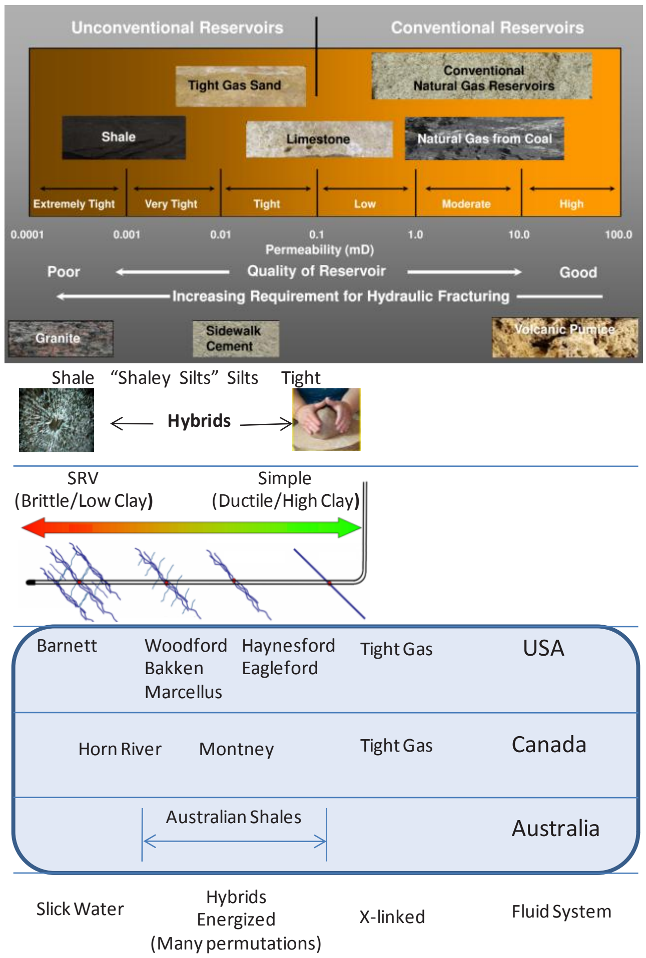

Figure 16. Unconventional rock continuum (modified from Canadian Society for Unconventional Resources, 2012).

Table 1. Tabulation of the example and Montney parameters. Sst refers to sandstone, Slst is siltstone, and Lst is limestone.

Metric	Montney	Example
Burial depth (m)	1,000–4,000	3,000
Thickness (m)	50–500	500 to >1,000
Gross lithology	Sst–Slst–Shale	Sst–Slst–Lst–Shale
Silica/carbonate %	20–60% (clay <30%)	>50% (low clay)
TOC %	1–7%	0.1–5% (avg. 3%)
Maturity (Ro equivalent)	Ro 0.8–2.5	Ro <1 to 3 (avg. 1.5%)
Gas filled porosity %	1–8%, 5.3% avg.	1–17% (avg. 5%)
In-situ permeability (mD)	6.5 × 10^{-8} to 1	0.0005–0.01 (model)
Natural fracturing	Variable	To be established
Pressure (psi/ft)	Normal to 0.70	Normal
Gas saturation %	64–80%	10–90% (assumed)
Adsorbed gas %	20–36%	To be evaluated
Gas in-place (bcf/km^2)	8–300	10–200
Play area GIP (Tcf)	80–700	100 to >500
Recovery factor	20–40%	To be established
Initial production (mmscf/d)	4–10	To be established
Reserves per well (Bcf)	2–8	To be established

was normalised to a per fracture basis (Fig. 17) to remove the impacts of varying lateral length. This normalisation process indicated an expected recovery per fracture of 0.3–0.8 Bcf/fracture (0.009–0.03 Gm^3), with the most likely value near 0.4 Bcf/fracture (0.01 Gm^3). Normalisation was believed to be a suitable approach given the assumption that recovery is generally dominated by the fracture, with little contribution from the unstimulated section of the horizontal wellbore.

Montney permeability is documented as ranging from 10–600 nD, with select sources suggesting 100 nD is the most likely value (Okuma et al, 2012). Although these permeability values are directionally low and considered representative of tight rock, predicted IPs obviously ranged by more than a factor of 10. Furthermore, consideration had to also be given to fracture height when generating forecasts, as the recoverable gas is often constrained to the practical drainage area of the fracture, both vertically and laterally.

Although the example is similar to Montney, and is, therefore, a fracture candidate based on potential brittleness, both Montney and the example are not as brittle as Barnett shale (resulting in different fracture patterns). Furthermore, as discussed, Barnett also has micro-fractures and a relatively isotropic stress regime, which together contribute to the large, observed fracture networks. Montney is a combination of siltstone, tight sands, and shales resulting in fractures intermediate between classic bi-wing and Barnett-style fracture networks (the example also includes carbonates). If the stress regime in the example formation was unknown, it would create additional uncertainty regarding the stimulation result. As a result, the impact of non-shale reservoir problems must be considered, including multiphase effects (i.e., relative permeability) and general clean-up efficiency.

Generally speaking, evaluation of micro-seismic data integrated with reservoir flow testing demonstrates that the total effective fracture rarely exceeds 200 m; therefore, 200 m was considered as an optimistic scenario. Hence, total fracture height was eventually limited to 100 m, and fracture half-length was limited to approximately 100 m. Significant discussion focused on the achievable fracture characteristics, since a review of the example temperature and pressure regime indicated that a number of stimulation models were possible, ranging from foam, CO_2, N_2, x-linked gel, or assisted x-linked gel. Unknowns in multiphase effects (relative permeability), general fracture clean-up (gel breakdown), and proppant transport complicated the anticipated fracture success. Figure 18 shows the predicted example-type curves after iteration on reservoir flow parameters.

CONCLUSION

Overall, Australian shales are comparable to North American shales when considering general volumetric and petrophsyical parameters. The Australian shales have a substantial resource base, and exhibit volumetric and petrophysical parameters within the distribution observed in North America. Although not conclusively demonstrated, Australian shales appear amendable to the completion and fracture technology implemented in North America. Analogues can, however, be misleading if used inappropriately. Shale gas play risks encompass both technical and non-technical factors. For specific projects and work beyond scoping exercise, attention and detail must be given to the cross-section of reservoir and production characteristics in any particular shale.

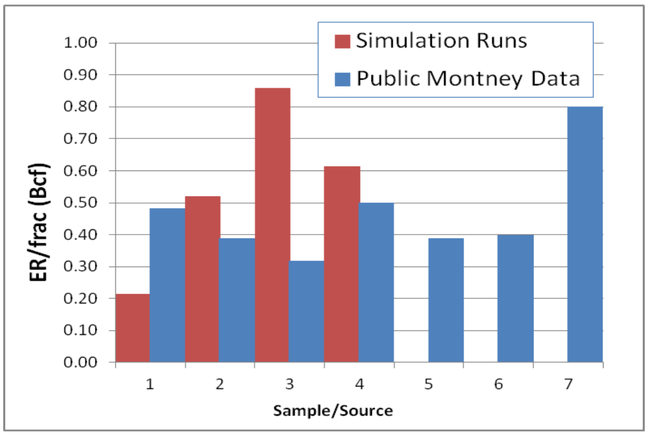

Figure 17. Expected recovery per fracture (Montney shale).

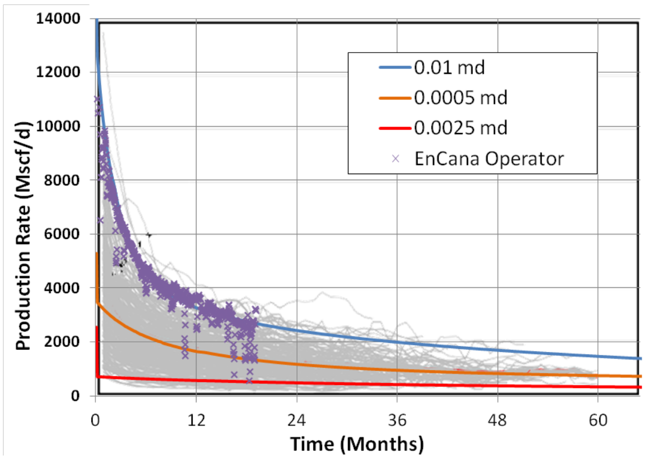

Figure 18. Laurel-type curves overlaid on Montney-type curves.

Consideration must be given to variances in reservoir properties such as varying permeability and porosity, thermal maturity (liquids potential, or lack thereof), pressure, and even temperature. Using average production profiles from a particular North American shale will likely be unsuitable as an analogy, as distribution of observed well production profiles will quite likely vary due to significant variability in reservoir properties and fluids (when normalised for the completion method).

Once a potential analogue is chosen, based on petrophysical and volumetric properties, critical evaluation of drilling, completion, and production costs must be undertaken with the logistical model. A significant portion of the North American shale success has been not only due to new completion and fraccing technology, but a change to the method of execution. In North America, drilling and completion costs vary significantly not only from one shale play to another, but sometimes in a shale of interest. Australian analogies will need to be modified for potential economies of scale, or acknowledge that a critical number of wells needs to be drilled and completed to justify the implementation of the concurrent operations and integrated services in development plans. In shale resource plays, analysts often ignore that fracturing process and completion style are development choices made by operators, and are not truly comparison parameters between two shales. After the preliminary comparison—the volumetric and petrophyiscal processes between two shales—approaches in completion and fracturing should be optimised. Furthermore, the stress regime, as well as the mineralogy (clay and silica content) of the main Australian shales, is still uncertain;

therefore, without experimentation in fracture design, it is difficult to choose a North American analogue since observed productivity is heavily influenced by the fracture process.

Ultimately, shale gas analogue selection should be more rigorous, and even iterative. Adjustments will need to be made to productivity models both in the exploration stage, and even during field development; a fit-for-purpose modelling outlook should be used. Identification of sweet spots, through mapping and history matching, is still crucial to the success of many shales as analogue well performance is often unrepeatable. Outside North America, all shale gas is generally frontier exploration (although some shale gas is still explored in North America). In short, a geological subset of a particular shale is probably the best recommendation when choosing shale analogues-based geology.

It took nearly a decade of drilling, completion, and fraccing refinement, from the initial development of initial North American shales to the recent shale gas boom. Improving technology often expands reservoir boundaries, and increases both initial rates and ultimate recovery (UR) quite substantially. When choosing an analogue, consideration must also be given to technology. In resource plays, variability still exists in horizontal length, lateral number, fracture stimulation rates, and/or perforation clusters.

It is important to recall that much of the technological success in North America was, in part, funded by the American tax incentives specifically aimed at research and development efforts into unconventional gas. Canadian provincial governments help ensure adequate road and pipeline infrastructure in the Montney and Horn River areas using various natural gas infrastructure programs. These programs provide credit to promote all-season road pipeline construction projects, upgrading of roads and bridges to support commercial vehicles, and the development of major roadworks to ensure year-round access to these basins (Ministry of Energy and Mines, 2011). Royalty holidays are also implemented to stimulate investments.

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