Cooper Basin Deep Coal – the New Unconventional Paradigm: Deepest Producing Coals in Australia

Camac, B.A.*
Santos Ltd
60 Flinders St, Adelaide 5000
Bronwyn.Camac@santos.com

Benson, J
Santos Ltd
60 Flinders St, Adelaide 5000
Jim.Benson@santos.com

Chan, V
Santos Ltd
60 Flinders St, Adelaide 5000
Vicki.Chan@santos.com

Goedecke, A
Santos Ltd
60 Flinders St, Adelaide 5000
Alison.Goedecke@santos.com

SUMMARY

Up to four years of gas production from Permian coals in the South Australian (SA) sector of the Cooper Basin illustrates their potential value as a sustainable unconventional gas resource. The success of this play is a result of many years of research, laboratory measurements and field trials designed to de-risk the play, following a well-defined road map. Since 2012, production variability has been tested in over 50 wells across the SA Cooper Basin. As an add-on frac stage in conventional gas development wells, coal targets regularly yield incremental reserve that provides an uplift in production and the opportunity to access a new tranche of gas. Production from the coal reservoirs is now accepted as "base business" for the Cooper Basin Joint Venture partners.

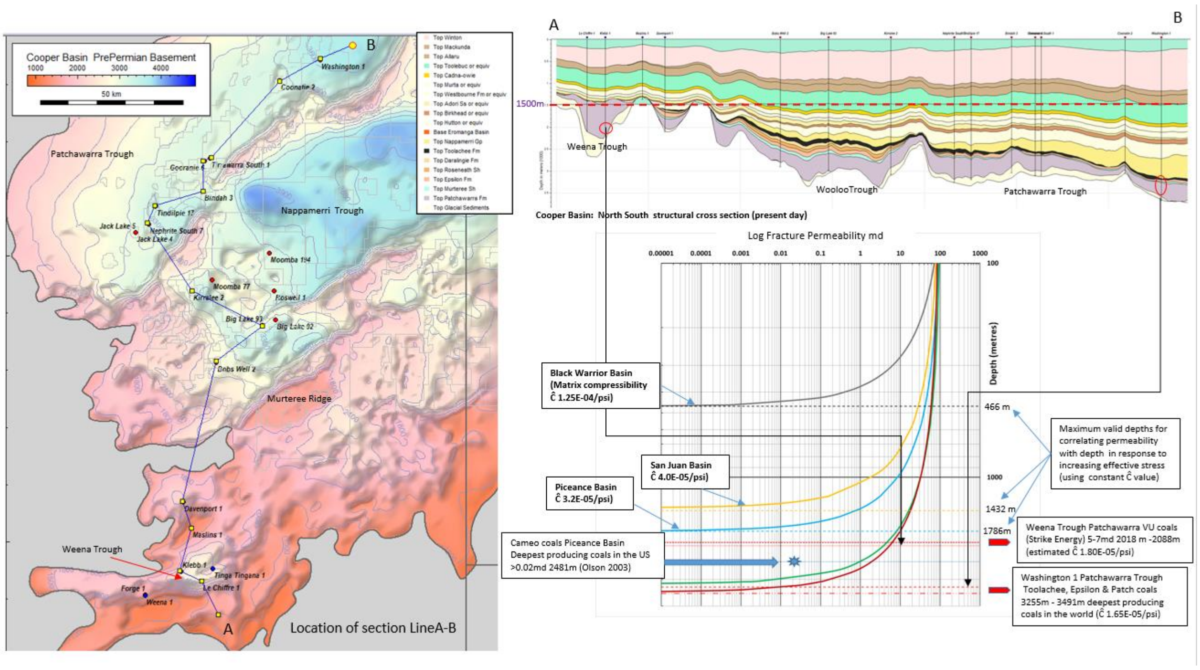
The key to progressing the play from its earliest inception as a candidate Source Rock Reservoir to a productive reservoir, lies in in a focussed approach to de-risking each economic barrier. These risk factors include frac containment, formation water production, gas composition, permeability, deliverability, completion design and cost. The next steps are to improve the economic viability of deep coal as a stand-alone development. In these first projects, planned for late 2017 - early 2018, both vertical and horizontal well-completions specifically targeting deep coal will be tested for commercial flow rates in an existing productive field

Key words: Cooper Basin, Deep Coal, Unconventional, Permian, Gas, fracture stimulation, geomechanics

INTRODUCTION

Conventional wisdom relating to the prospectivity of a deep coal gas resource in Australian Permian basins remains aligned with coal permeability experiments conducted in the United States by McKee et al 1986 with reference to the three most active Coal Bed Methane (CBM) operations at the time: the Late Carboniferous coals of the Black Warrior Basin (Alabama) and the Late Cretaceous coals of the San Juan and Piceance (NM Colorado) basins. The loss of fracture (cleat) permeability with depth was attributed to progressive increase in effective stress and defined a permeability floor or "the CBM window" for each basin. These depth range from 466m (1530ft) to 1786 m (5860ft), with the implication that cleat fracture aperture width was controlled by the "matrix" compressibility of the coal and maximum closure stress (Fig. 1). Subsequent work by McKee et al 1988, modified the stress-dependent permeability model and substituted both constant and variable pore compressibility as the primary formation parameter. Tonnsen & Miskimins (2010) adopted the same rationale and showed that for deep Cretaceous coals in the San Juan and Piceance basins, the modelled pore volume compressibility decreases with increase in effective stress thus making it harder to reduce the cleat aperture width. The production data from hydraulic fracture stimulation of deep Cretaceous Cameo coals from the White River Dome Field at a depth of 2480m in the Piceance Basin (Olson 2003), supports these conclusions. However, production from these deep coals is limited to low gas flow rates (0.15 mmscf/d) compromised by the presence of water as shown in production decline curves for the White River Dome Field.

By way of comparison, the fracture stimulation of water- free, deep Permian coals in the Cooper Basin has demonstrated economic flow rates of both dry and liquids-rich thermogenic gas, depending on the maturity of the interval, far in excess of those recorded from the Cameo coals of the Piceance Basin and extends the producible limit for deep coals by 1000 metres to depths exceeding 3000 metres (Fig. 1). The Cooper Basin offers multiple unconventional reservoirs associated with Shale Gas and Basin Centred Tight Gas targets in the Nappamerri Trough. Nevertheless, Permian Deep Coal, the most prolific source rock in the basin, provides the richest unconventional target, and is attracting significant attention by Santos and its JV partners.



Error! Not a valid bookmark self-reference.**: Comparison of permeability floor estimates for Cooper Basin deep coals with US CBM fields using the assumptions relating to "matrix" compressibility in McKee et al 1986**

GEOLOGY OF DEEP COAL PLAY

The Deep Coal Play in the Cooper Basin refers to retained gas and gas liquids in Late and Early Permian coals of the Toolachee, Epsilon and Patchawrra formations deeper than 2,500m. Unlike the shallow Late to Middle Jurassic biogenic coal seam gas (CSG or CBM) Walloon coals in the Surat Basin, the Deep Cooper Basin coals are thermogenic and contain no mobile water. Fracture stimulation of the coals liberates free gas held within the organic porosity and hierarchical fracture system within the coal seam, without the need for dewatering . In this way, they are similar to shale gas reservoirs (Fig. 2).

There are two sub-plays recognised to date:

1. Medium rank bituminous coals that retain wet gas/condensate; and
2. High rank anthracitic coals with retained dry gas

Unlike the deep Cameo coals from the Piceance Basin, the deep Cooper Basin coals are "dry" with no water present in the natural fracture system. Both free gas and adsorbed gas are present within a gas saturated matrix. The presence of free gas in the fracture system implies that the coal is "oversaturated" with respect to its measured adsorbed gas storage capacity. Free gas production after flowback of the frac fluids occurs due to expansion of the free gas within the water-free fracture network.The abnormally low in-situ bulk densities measured from deep coals at depths below 2400m and free gas contents (calculated from partition of TRA gas filled porosity values into free and adsorbed phases) indicate that the matrix pore volume stores large volumes of free gas. Measurement of Katz & Thompson permeability calculated from the average in situ 5μ width of capillary fractures (partly occluded with diagenetic kaolinite) developed within the inertinite dominated matrix of MVB Cooper Basin Patchawrra coals shows that the fracture permeability varies between .011mD and 0.032mD at depths below 2790m (9153ft) and permits Darcy flow of free gas between free gas storage sites within the matrix (Fig. 3). Reservoir geometry is contiguous with flood basin coals that vary in area (50km2 – 150km2) and thickness (5m – 75m).

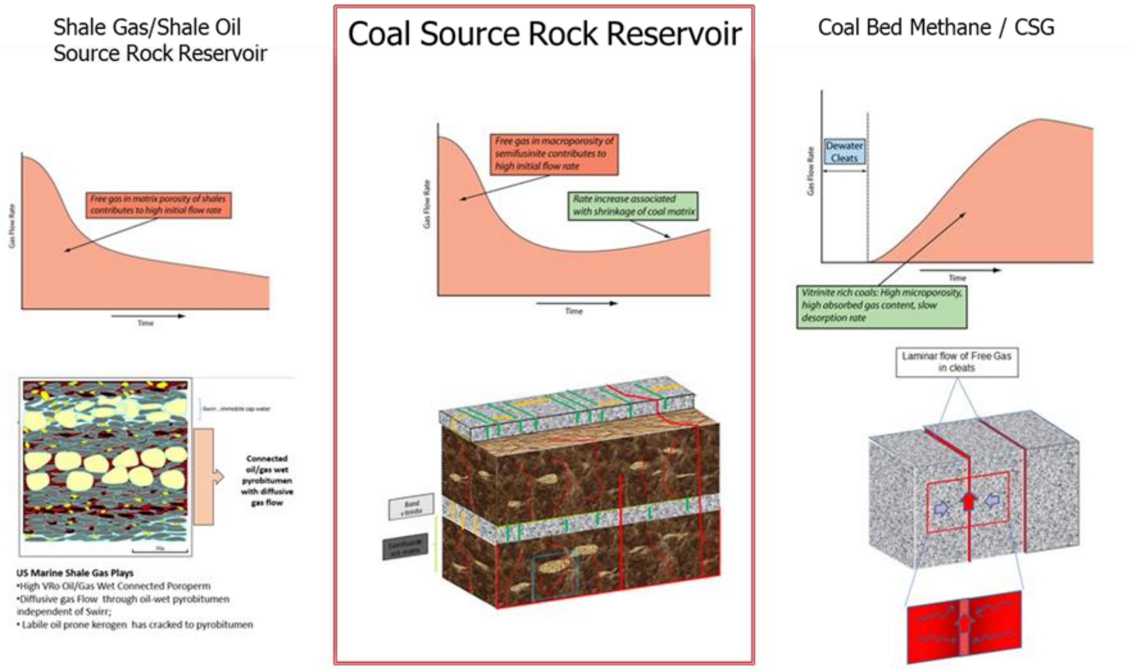


Figure 1: Diagrammatic illustration of the difference in flow rate behaviour with time between Shale-gas, Coal Bed Methane or CSG and the Permian Deep Coal reservoirs

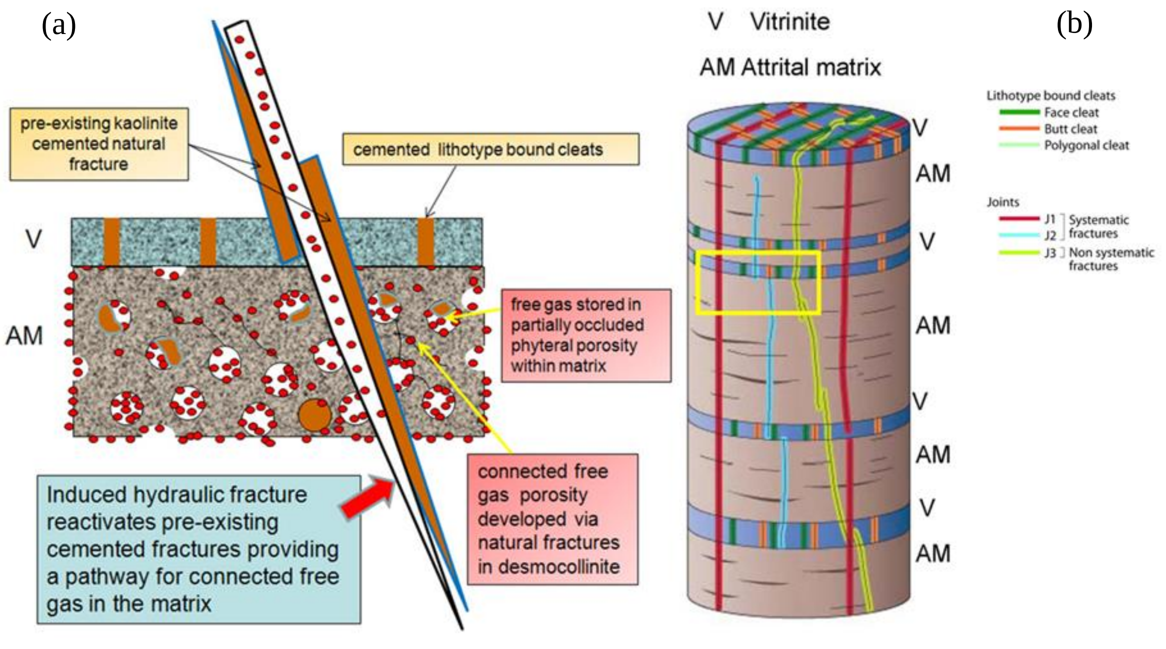


Figure 2: Conceptual diagram illustrating the development of connected free gas storage within the phyteral porosity, typical of inertinite rich Cooper Basin Permian coals and the development of a hierarchy of natural fractures (cemented capillary fractures, lithotype-bound cleats within thin band vitrinite, and master joints)

PLAY PROGRESSION - DE-RISKING

The key to progressing the play from its earliest inception to a productive reservoir, lies in a focused approach to de-risking each economic barrier. These risk factors include frac containment, formation water production, gas composition, permeability, deliverability, completion design and cost (Fig. 4).

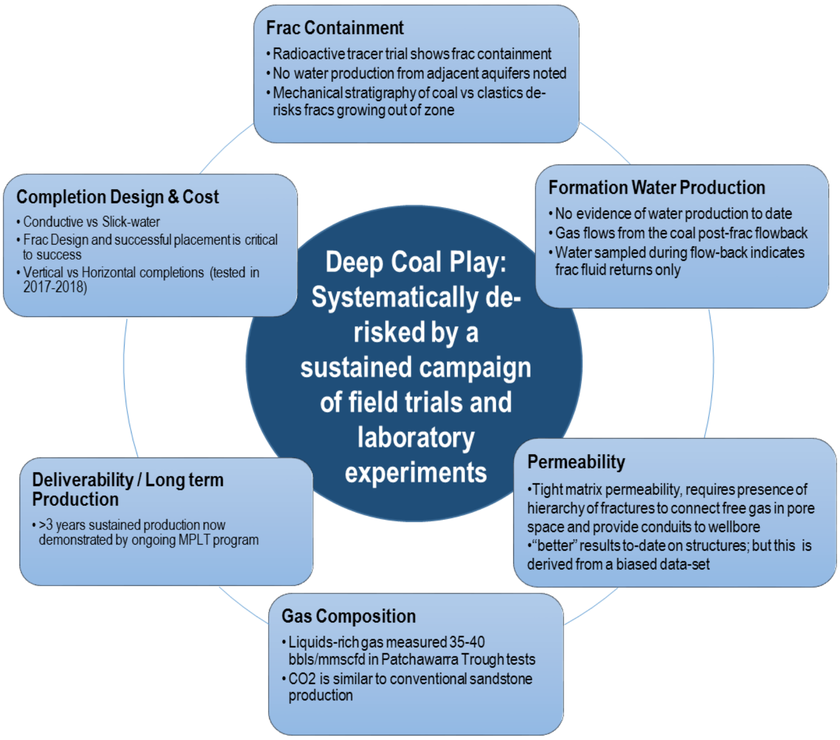


Figure 3: Diagrammatic representation of the addressed risk factors and results at each stage

The first deep coal was fracture stimulated in 2007 (Fig. 5). This project, in the Moomba Gasfield, Moomba-77, is of major significance as it provided the first evidence that coals at depths greater than 2500m could flow natural gas at a measurable rate. At that time, the "shale revolution" was kicking off in North America and it was thought that a slick-water shale-type frac design would be most effective when stimulating continuous reservoirs with very low permeability. Before the result from Moomba 77, the Cretaceous Cameo coals from the Piceance Basin held the record for gas production from deep coals in the White River Dome Field at 2481m (Olson 2003).

Over the next five years, four more field trials were conducted as single fracs within development projects. These trials were in Big Lake, Nephrite South and Tindilpie fields. All used a low proppant (<60 klbs), slick-water design and resulted in measurable gas to surface but not at economic rates.

In 2013, Roswell-1 was drilled to test the emerging shale gas play in Moomba Field (Fig.5). It was noted that this well intersected a reasonably thick (>5m) mid-Patchawarra coal (VC50 Coal). It was decided to fracture stimulate this coal as a single stage trial using a conductive design (cross-linked gel and higher proppant load) for the first time. This frac resulted in a step-change improvement in gas rate achieved to date (Fig. 4). Roswell-1 was followed by two more trials that year, the first targetting the dry-gas play and the other in a liquids-rich gas field. All fracs demonstrated economic gas flow rates >0.1 mmscfd from a single coal zone, with an associated flow of hydrocarbon liquids from a coal zone for the first time (Fig. 4).

Over the next two years, a further 21 coal fracs were placed as single stages, in gas development wells across the Cooper Basin, in what is referred to as the add-frac campaign. This program was a committed effort to add single zone fracture stimulations into the thickest coal seam in as many wells as possible, to appraise and test for long term production (Fig. 6). Larger job sizes were trialled at this time with a typical frac between 200 – 400 klbs per stage, depending on the thickness of the coal seam. An ongoing surveillance program of repeated production logging tests (MPLTs) has been intrinsic to understanding the longer term production behaviour of the coals over time (Fig. 4). To date, there are up to three MPLTs in the same well providing this important information. The average flow rate across the entire program was greater than 0.3 mmscf/d during this period, with a high side rate of 0.8 mmscf/d demonstrated. To date that particular coal zone has already produced 0.5 bcf, with a conservative forecast of 1.2 bcf as an ultimate recovery.

During 2015, the first correlation was recognised, namely economic rate vs 100% job placement as designed (Fig. 4). A further 16 coal fracs were added to the data set during 2015 (Fig. 6).

In August 2015, the first "coal-only" exploration well, Washington-1, was drilled and fractured stimulated in PEL570, SA Cooper Basin (Fig. 5). The well was located in the deepest part of the Patchawarra Trough and its primary objective was to test multiple Permian-aged coal seams seams.

By 2016, long term production from Permian coals, mainly from the Patchawarra Formation, had proved an estimated economic recovery such that coals greater than 5m thick were accepted by Cooper Development as an economic target for future program. This acceptance marked a turning point for the play and reserves were then booked for the first time as 2P developed and 2P undeveloped in an existing gas field. A further 13 coal fracs were added in 2016, with some newer technologies also trialled. Diversion technology was used to fracture stimulate two coal seams within the one stage. This technology is important when regarding cost reduction over multiple coal seams within a single well (Fig. 4). This technology trial was a success, with both coal seams achieving effective stimulation and both coal flowing at economic rates as proved by MPLT. Follow up MPLT after 9 months has demonstrated that these coals have sustained production.

In 2017, a further 11 frac stages have been placed in coals across the base development program, including the first coal frac to be successfully placed in a Queensland gas development well. At this time a Technical Interest Group was formed including all the major operators currently holding a material position in the liquids-rich gas Deep Coal play. A data sharing agreement was reached which allowed each operator to exchange current ideas and operational solutions in a workshop environment. The aim of this group is to learn fast and from each other, for minimal capital spent.

Plans are advanced to drill, frac, complete and connect two coal primary target wells over the next 12 months. The first of these is a short horizontal well placed in a thick VC50 coal targeting five frac stages; and the second is a vertical development well, targeting nine Permian coal seams and three conventional sands beneath the coal measures (Figs. 4 and 5).

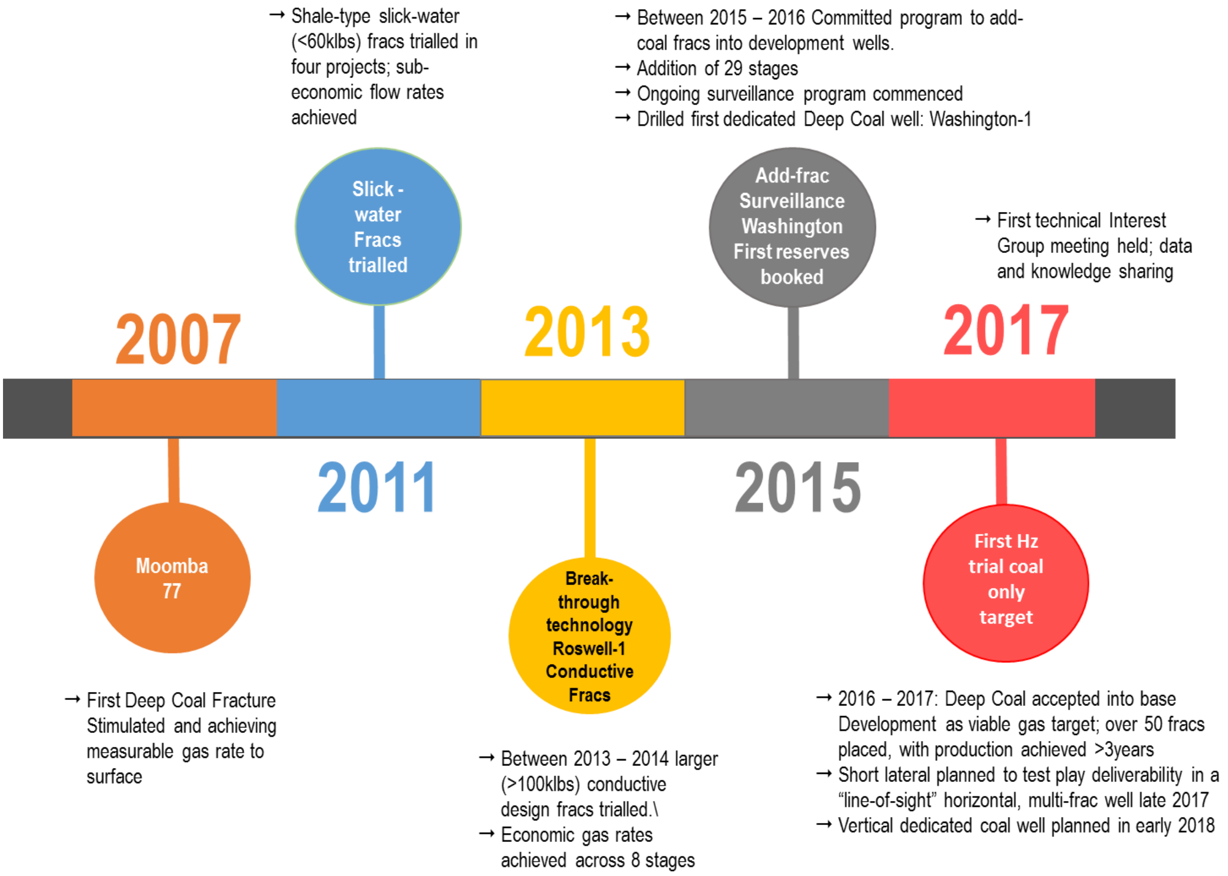


Figure 4: Timeline showing the progression of the Deep Coal Play in the Cooper Basin. Establishes 10 years on the learning curve. Focussed and persistent approach to de-risking each parameter before moving forward to the next stage

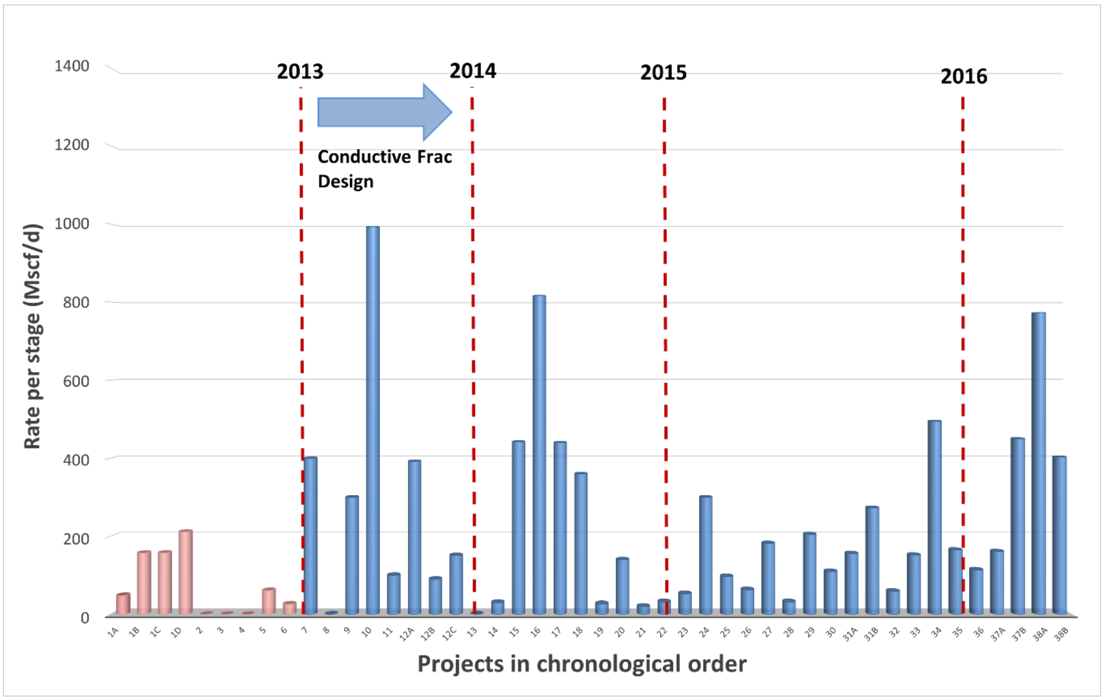


Figure 5: Plot of the single deep coal frac stages vs first measured rate in chronological order

CONCLUSIONS

To show value of what a new play can bring, requires an integrated team of dedicated geoscientists and engineers, working at all scales of the project. It is important that the internal structure and deliverability mechanism of the reservoir be understood just as well as its regional distribution and the technology applied in the field.

Cost reduction and efficiencies come hand in hand with the learning curve. The sponsoring company or joint venture must provide capital and be amenable to accepting sufficient risk to understand whether the new play can deliver an economic result. The variability across the area of interest must be tested sufficiently before a decision can be made as to whether to proceed to the next phase or not.

Collaboration with other operators with material interests in the play is also a recommended way forward. Data and knowledge sharing aids in the deeping of technical understanding for minimal cost.

The “extraordinary” idea that oil and gas could be produced from Deep Coal in the Cooper Basin was formed over 25 years ago. Reference was first made to the Permian Deep Coal potential of the Cooper Basin by Kuuskraa & Wyman (1993) following on from experimental completion of Elmworth Lower Cretaceous coals at 3000m by Canadian Hunter Exploration in the Deep Basin of Alberta (Wyman 1984).

In 2007 the concept was first tested in the Cooper Basin, by hydraulic fracture stimulation of the Patchawarra VC50 coals in Moomba 77 at 2865m, with gas flow to surface. Since that time, the play has been tested by single zone stimulations within development gas wells across the basin whilst developing technological capability. Sampling, >50 single coal fracs, some now on production for nearly four years, has been mainly limited to the liquids-rich coal play and has reached a point where the joint venture is encouraged enough to continue to the next phase of appraisal.

ACKNOWLEDGMENTS

The authors would like to acknowledge all the efforts of the various teams in the past in Santos, dedicating themselves to investigating new concepts and stepping outside the norm. Making mistakes, learning from them and always moving forward.

We would also like to thank our joint venture partners, Origin Energy and Delhi Petroleum for allowing the publication of this abstract.

REFERENCES

Kuuskraa, V.A. & Wyman, R.E. 1993 Deep coal seams: an overlooked Source for long term natural gas supplies. SPE Gas Technology Symposium Calgary Alberta June 1993. SPE paper 26196

McKee, C.R., Bumb, A.C., Way, S.C., Koenig, R.A., Reverand, J.M. & Brandenburg, C.F. 1986 Using Permeability-vs-Depth correlations to Assess the Potential for Producing Gas from Coal Seams. Quarterly Review of Methane from Coal Seams Technology 4 (1) July 1986 pp. 15-26

McKee, C.R., Bumb, A.C. & Koenig, R.A. 1988a Stress-Dependent Permeability and Porosity of Coal. In: (Fassett, J.E. Ed.) Geology and Coal –Bed Methane Resources of the Northern San Juan basin, Colorado and New Mexico. Guidebook series Rocky Mountain Association of Geologists.pp. 143- 153

McKee, C.R., Bumb, A.C. & Koenig, R.A. 1988b Stress- Dependent Permeability and Poroity of Coal and Other Geologic Formations SPE Formation Evaluation March 1988 pp.81-90

Olson, T.M. 2003 White River Dome Field: Gas production from Deep Coals and Sandstones of the Cretaceous Williams Fork Formation. In: (Peterson,K.M., Olson, T.M. & Anderson, D.S. Eds.,) Piceance Basin 2003 Guidebook series Rocky Mountain Association of Geologists. White River Dome Field: Gas production from deep Coals and Sandstones of the Cretaceous Williams Fork Formation.pp. 155 – 169

Tonnsen, R.R & Miskimins, J.L. 2010 Coalbed Methane Production Potential in Deep Environments, AAPG Search & Discovery Article # 80122

Wyman, R.E. 1984 Gas Resources in Elmworth Coal seams.In: Masters, J.A. Elmworth: Case study of a Deep Basin Gas Field. AAPG Memoir 38, pp. 173 – 187