Amungee NW-1H – Velkerri B Shale Pool

Results of Evaluation of the Discovery and Preliminary Estimate of Petroleum in Place

Title holders	Origin Energy Resources Limited Sasol Petroleum Australia Ltd Falcon Oil & Gas Australia Ltd
Well	Amungee NW-1H
Permit	EP98(R1)
Notification of Discovery Submission	13 October, 2016
Initial Report of Discovery	13 October, 2016

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Contents

1 Executive Summary

This report, *Results of Evaluation of the Discovery and Preliminary Estimate of Petroleum in Place* (**Report**), is submitted as required under *Section 64* of the *Northern Territory Petroleum Act (2016)* (**Act**) and as per the *Reporting a Petroleum Discovery Guideline* (**Guideline**). The Report summarises the activity that has led to the discovery of a petroleum accumulation at Amungee NW-1H in EP98(R1), and meets the detailed reporting requirements of the Guideline.

The discovery of hydrocarbons (dry gas) in the Mesoproterozoic Velkerri Formation at Amungee NW-1H has been confirmed by the acquisition of geological data and the completion of an extended production test (EPT) following hydraulic fracture stimulation (HFS). The area of the pool produced from at Amungee NW-1H is only a small fraction of the total pool size, which covers an estimated P90-P50-P10 areal extent of 18,825–19,487–20,046 km^2. Origin's volumetric estimates, for the B Shale member of the middle Velkerri Formation, are summarized in Table 1.

	P90	P50	P10
OGIP (TCF)	434	601	841
OGIP Concentration (BCF/km^2)	22	31	43

Table 1. Summary of P90-P50-P10 volumetric estimates.

2 Summary of Amungee NW-1H History

2.1 Drilling

The Amungee NW-1H well is a horizontal well drilled from the intermediate hole section of the Amungee NW-1 vertical well. Both wells are located in EP98(R1) (**EP(98)**), close to the Carpentaria Highway (Figure 1), and were drilled by Origin Energy (**Origin**) in 2015. Amungee NW-1H kicked-off from the Amungee NW-1 well at 1932.5 m measured depth (MD) and reached a total depth of 3808 m measured depth (MD), and 2428 m true vertical depth (TVD). The Amungee NW-1H lateral section was landed and drilled through the 'B Shale' of the middle Velkerri.

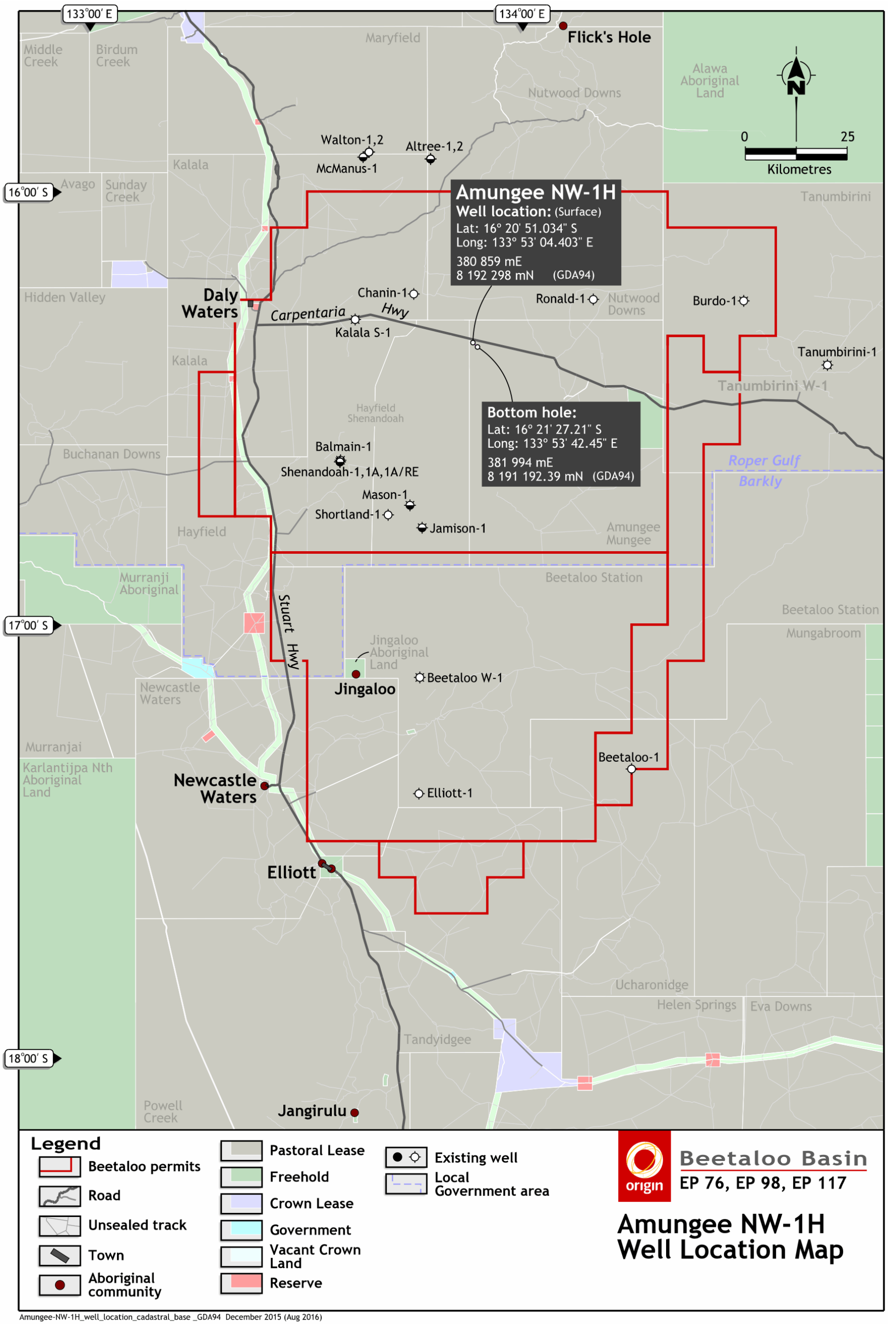

Figure 1. Location map for Amungee NW-1H in EP98.

2.2 Completion and Fracture Stimulation

Completions activities at Amungee NW-1H began in July 2016, preparing the wellbore for hydraulic stimulation operations. A Cement Bond Log (CBL) was conducted to confirm the cement integrity behind the 4.5" casing along with a 10,000 psi pressure test of the production casing to verify wellbore integrity.

An AbrasiJET perforation was performed on the toe stage, after the toe sleeve failed to shift open to gain access to the reservoir. A Diagnostic Fracture Injection Test (DFIT) was pumped on the first interval prior to the main stimulation treatments. In August 2016, a total of 11 stimulation stages were pumped, effectively placing 2.5 million lbs of proppant and 67,000 bbls of fluid (Figure 2). After the 7^{th} stimulation treatment interval, a casing deformation at 3111.6 mMDRT was discovered during the pump down operation. After some diagnostics with coiled tubing, it was decided to shift the remaining 5 frac stages along the wellbore to provide a greater standoff distance between the fracture initiation point and potential bedding planes. A 12^{th} stage was attempted on the well; however formation breakdown was not achieved and the frac treatment was terminated early without placing any proppant.

2.3 Flow-Back and Extended Production Test

The initial flowback of Amungee NW-1H commenced on 10 September 2017 up casing. The first hydrocarbons were detected after 321 bbls of load fluid were recovered. The first continuous gas breakthrough occurred on the 13 September. The well was flowed up casing until 29 September at which point it was shut-in to install tubing. The cumulative stimulation fluid recovered and gas produced to this point in time were 6,100 bbls and 5.6 MMscf respectively.

The well was completed with a tubing packer installed at 2400 mMDRT and 2 3/8" tubing. The well commenced the extended production test (EPT) after completion operations were finalized on 4 October (Figure 3). The initial production, as measured over the first 30 days was 1.11 MMscfd. The duration of the EPT was 57 days with a cumulative load fluid volume recovery and gas production volume of 6,207 bbls and 63 MMscf respectively. The average production rate over the EPT was 1.10 MMscfd and the final production rate of the EPT was 1.07 MMscfd. A summary of cumulative gas produced and load fluid recovered during the clean-up and EPT phase is provided in Table 2.

Phase	Cumulative Gas Produced (MMscf)	Cumulative Load Fluid Recovered (bbl)
Clean-up	5.6	6,100
EPT	63	6,207
Total	68.6	12,307

Table 2. Summary of the cumulative gas produced and load fluid recovered during the clean-up and EPT phase in Amungee NW-1H.

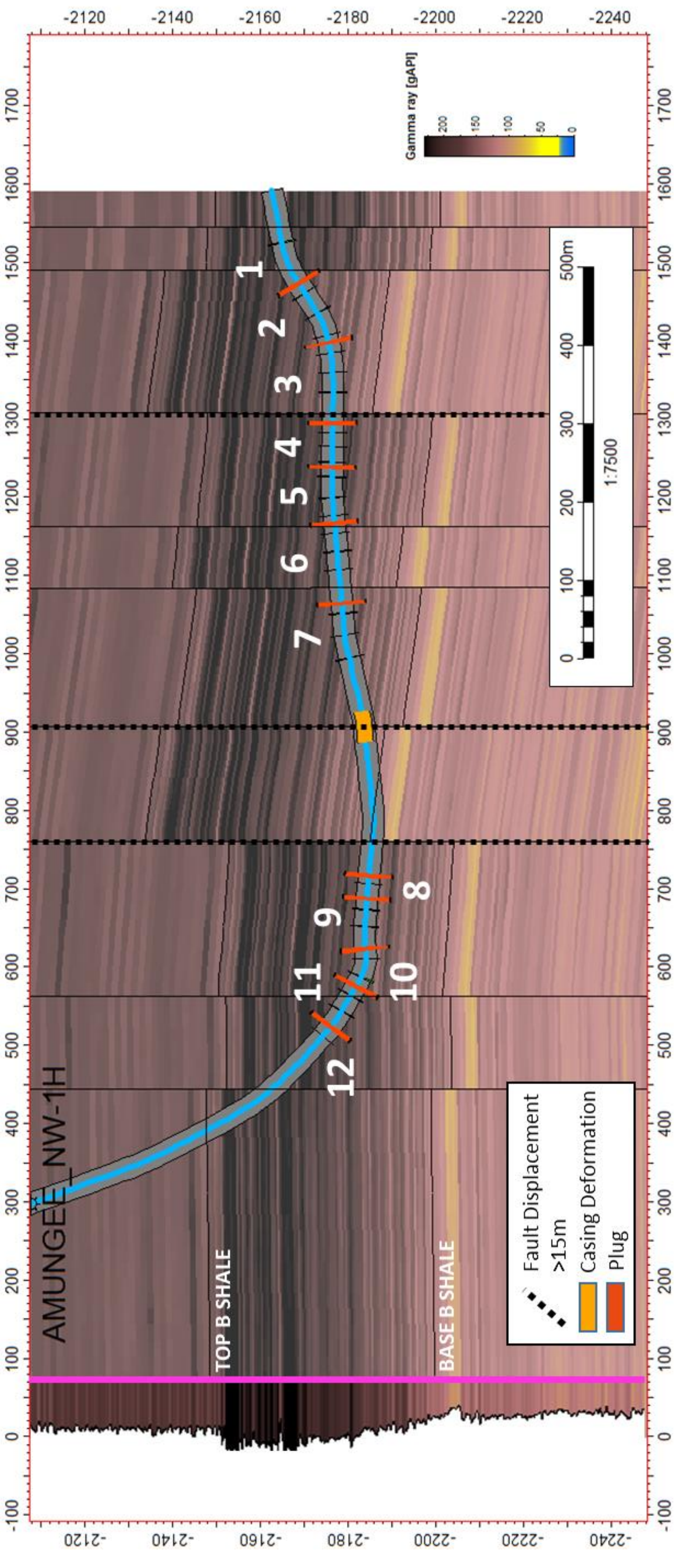

Figure 2. Location and distribution of fracture stimulation stages along Amungee NW-1H well cross-section. Background colour follows the gamma ray property values from the vertical well Amungee NW-1 as propagated across Origin's geosteering model over the B Shale interval.

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Figure 3. EPT data results for the Amungee NW-1H well.

Gas samples were collected off the manifold on the separator at regular intervals and sent to third party laboratories for detail gas compositional analysis. The gas chromatography results in Table 3 indicate a very dry gas composition as was expected based on the maturity modeling. The energy equivalent of the sample gas is 1.05 TJ per MMscf.

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Gas Constituent	Concentration (ppm)
C_1	
C_3+	
O_2 + Ar	
CO_2	
N_2	

Table 3. Amungee NW-1H gas chromatography results on samples collected during the EPT.

2.4 Discovery Notice and Initial Discovery Report

Origin reported the discovery of a petroleum accumulation as per the Guideline to the Northern Territory (NT) Department of Primary Industry and Resources (DPIR) on 7 October, 2016. The letter submitted on 7 October 2016 included both a "Notification of discovery" and "Initial report of discovery"; Table 4 reproduces the summary data provided as part of the Initial report of discovery.

Permit	EP98
Well	Amungee NW-1H
Data	Production test data supported by petrophysical log data and both conventional and sidewall core evaluation
Rate	Variable gas rates ranging from 0.8-1.2 MMscfd (note that the well is also flowing back fracture stimulation fluid volumes, ranging from 100-400 bbls per day)
Hydrocarbon properties (initial estimates)	C_1: ~95%, CO_2: 2-4%, C_2+: 1-3%
Physical properties of the pool (initial estimates)	Thickness: 30m; Porosity: 4-7.5%; Gas saturation: 50-75%; Permeability: 50-500 nD
Petroleum in place (initial estimate)	Evaluation underway

Table 4. Summary data from Origin's Initial report of discovery, submitted to the DPIR on 7 October 2016.

3 Geological and Geophysical Interpretation

3.1 Regional Geology

The Palaeo- to Mesoproterozoic McArthur Basin is a poorly outcropping unit with subsurface coverage extending over a known area of 180,000 km^2 (Figure 4) in the northeastern Northern Territory (Bull 1998). The basin comprises, from oldest to youngest the Tawallah, McArthur, Nathan and Roper Groups and it is generally capped by the overlying Georgina, Wiso, Daly, Arafura and Carpentaria basins (Powell et al. 1987, Dunster and Ahmad 2010, and Ahmad and Scrimgeour 2013). Groups are separated by regional unconformities. The sequence is primarily an unmetamorphosed succession of sedimentary and minor volcanic rocks that accumulated within a multiphase intra-cratonic basin setting (Munson 2014). The sequence reaches maximum thickness of up to 15,000 m in the deepest parts of the basin (Munson 2014) and thins over major structural features and away from major depocenters. Despite covering a great portion of the NT, the total subsurface extent of the McArthur Basin remains poorly constrained. There has been considerable improvement in understanding sediment distribution within the Walker Fault Zone and Batten Fault Zone regions due to the relative abundance of outcrop and mining exploration in the area, however, regional understanding is still lacking.

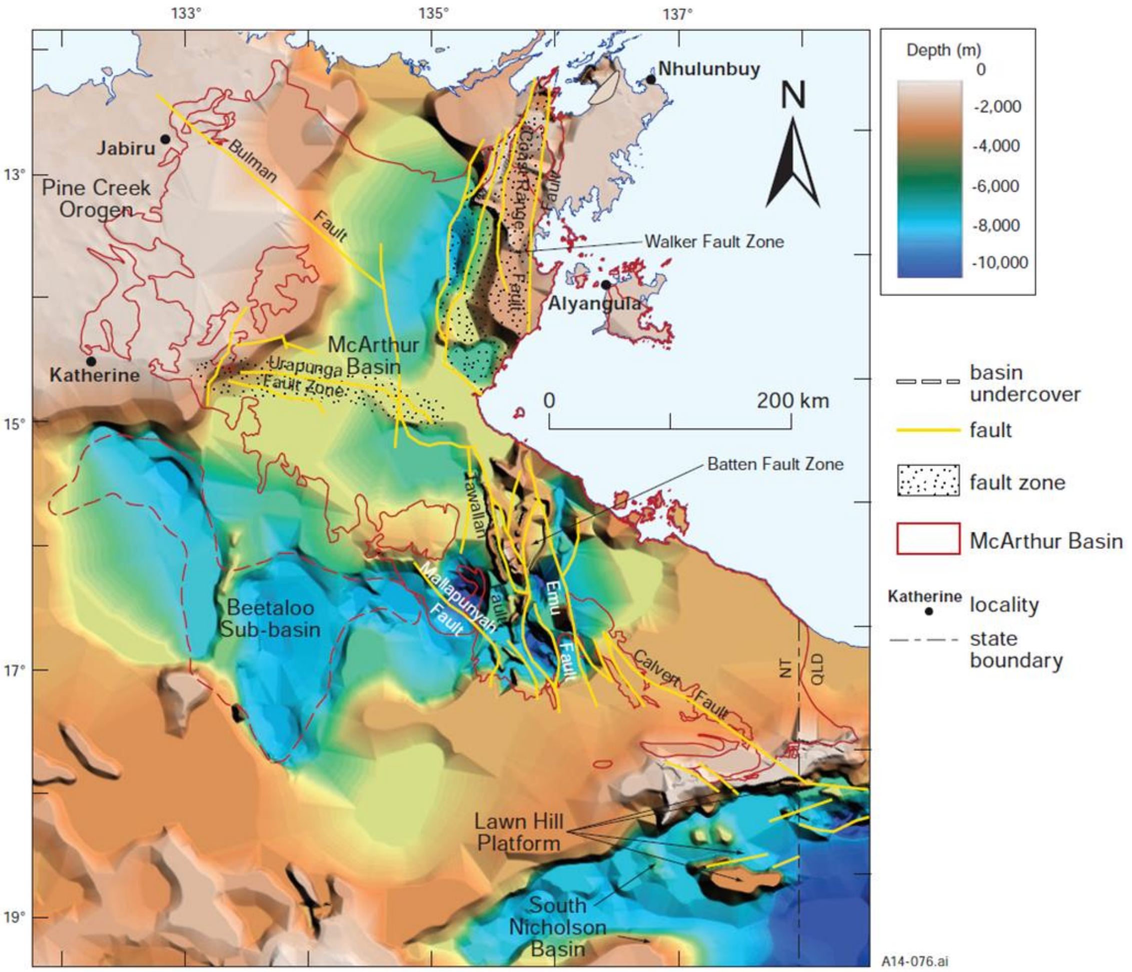

Figure 4. OZ SEEBASE™ depth-to-basement image (Pryer and Loutit 2005) showing interpreted location of the McArthur basin (red solid line) and other associated basins in the Northern Territory. The Beetaloo sub-basin is outline in red dashed line (after Munson 2014).

A remarkable aspect of the McArthur Basin is that it preserves some of the oldest, organic-rich source rock intervals in the world within the Barney Creek (1640 ± 3 Ma), Velkerri and Kyalla (1429 ± 31 Ma) formations. Environmental conditions during the Proterozoic, a restricted, shallow- to moderately deep marine environment (locally emergent) and high organic productivity, resulted in a prolific, long-lived, source sink system where high quality organic-rich sediments accumulated and were preserved over vast areas. Despite their antiquity, these source rocks have not been exposed to extreme alteration, rather remaining within depths and temperature ranges consistent with thermogenic generation of gas.

One of the largest structural depocenters within the McArthur Basin and current focus of considerable petroleum exploration activity is the Beetaloo Sub-Basin (**Beetaloo**). Located in the southern part of the Greater McArthur Basin, the Beetaloo is centered about 500 km southeast of Darwin extending over a known area >20,000 km^2 (Figure 4). The basin is primarily defined by gravity and magnetotelluric data (Cull, 1982), deep seismic sounding data (Collins, 1983), and exploratory drilling data (Ahmad et al. 2013) and structurally subdivided into three geographical areas and two major structural highs (Figure 5). The north-south trending, structurally complex Daly Waters Arch (west) and structurally benign Arnold Arch (east) divide the area in three major depocenters, referenced here as the Sever Sub-Basin, the Core area and the OT Downs Sub-Basin from west to east respectively. The northern boundary of the Beetaloo is largely defined by the regional Mallapunya Fault where seismic and well penetrations indicate that the strata shallow significantly to the north. Typically the Kyalla Formation is eroded outside of the Beetaloo area and the Velkerri Formation is often found at depths of <1000m or is also eroded. Despite the poorly constrained tectonic genesis, the Beetaloo is interpreted to result from multiple basin reconfigurations including periods of intra-cratonic sag (Plumb and Wellman 1987), crustal extension (i.e. Batten and Walker Fault zones) and foreland development (as suggested by a possible ancient arc or orogenic belt to the south) (Jackson et al 1990, and Jackson et al 1999). Seismic and well coverage across the Beetaloo confirm the core area was a major depocenter at the time of accumulation of the Roper Group retaining the thickest and most complete section known in the Northern Territory.

The Mesoproterozoic Roper Group comprises six, large-scale, upward-coarsening cyclic succession of mainly marine mudstone and sandstone units reaching thickness greater than 3,000 m and averages of 1,500 m away from major depocenters (Figure 6) (Abbott and Sweet 2000). The succession has yet to be fully penetrated in the deepest depocenters; however, individual formations can be traced over most of the McArthur Basin in seismic profiles and especially across the Beetaloo, where they show remarkable thickness consistency and lateral continuity (Munson 2014, Silverman et al 2007). The sequence is unconformably overlain by the Chambers River Formation which may be as young as Neoproterozoic (Lanigan et al. 1994), and successively overlain by the Bukalara Sandstone and volcanic rocks of the late early Cambrian Kalkarindji Large Igneous Province (Kalkarindji Province), and by Neoproterozoic–Palaeozoic Georgina Basin and Mesozoic Carpentaria Basin strata (Munson 2014). The Roper Group succession was deposited in a variety of shallow-marine, and nearshore to shelf environments (Powell et al 1987, Jackson et al 1988 and Abbott and Sweet 2000) with organic enrichment confined to the Velkerri and Kyalla formations. The sequence has been recognized as having excellent exploration potential (Falcon 2015).

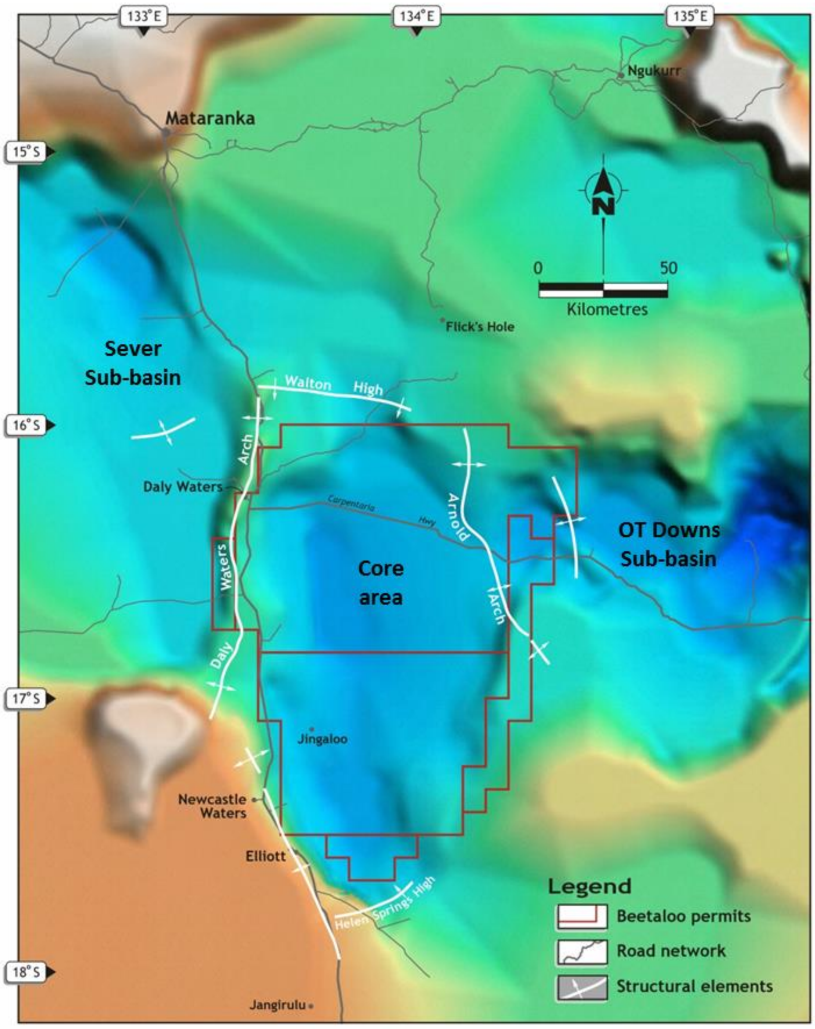

Figure 5. The Beetaloo is structurally subdivided into three geographical areas and two major structural highs. The north-south trending Daly Waters Arch (west) and Arnold Arch (east) divide the area in three major depocenters, the Sever Sub-Basin (west), the Core area (centre) and the OT Downs Sub-Basin (east). The Beetaloo is bounded to the north by the Walton High and south by the Helen Spring High. Background is OZ SEEBASE™ depth-to-basin image (Pryer and Loutit 2005).

The Velkerri Formation, primary unconventional target in the basin sits conformable on the Bessie Creek Sandstone, often showing a gradational contact with the Moroak Sandstone. North and west of the Beetaloo a ~1320 Ma dolerite sill known as the Derim Derim dolerite typically separates the Bessie Creek Sandstone and the Velkerri Formation reaching maximum thickness of 120 m before thinning and fingering to less than 10 m (average) within the Core area (Figure 6). The formation itself is informally sub-divided into a lower, middle and upper members based upon total organic content (TOC) and gamma ray response (Warren et al., 1998). Detailed sedimentological analysis describes the unit as marine facies displaying superimposed laminated black-grey, organic-rich (TOC ~4–8%) and grey-green, organic-lean (TOC <2%) mudstone and siltstone with minor fine glauconitic sandstone that transition up-section to cross-bedded sandstones of the Moroak Sandstone (Abbott et al. 2001, Jackson and Raiswell 1991, Warren et al. 1998).

High resolution X-ray diffraction (XRD) and Fourier transform infrared spectroscopy (FTIR) analysis of the interval reveals a dominant mineralogy comprising 60-80% quartz, 20-30% clays (illite,

Illite/mica, smectite, kaolinite, chlorite) with trace to 10% carbonate and other accessory minerals (feldspar, glauconite, and pyrite). Despite been relatively uniform throughout the section, systematic changes in mineralogy occur with depth. Petrographic evaluation including thin section and Ar-ion milled scanning electron microscopy (SEM) image analysis show facies are dominated by massive to laminated, typically undisturbed textures suggesting deposition beyond the effects of normal wave and tidal current activity (Jackson and Raiswell 1991). Exceptions occur towards the base and top of the formation where an increase in grain size and character of sedimentary structures suggest emplacement of relatively high energies and wave dominated activity (i.e Bessie Creek Sst and Moroak Sst.).

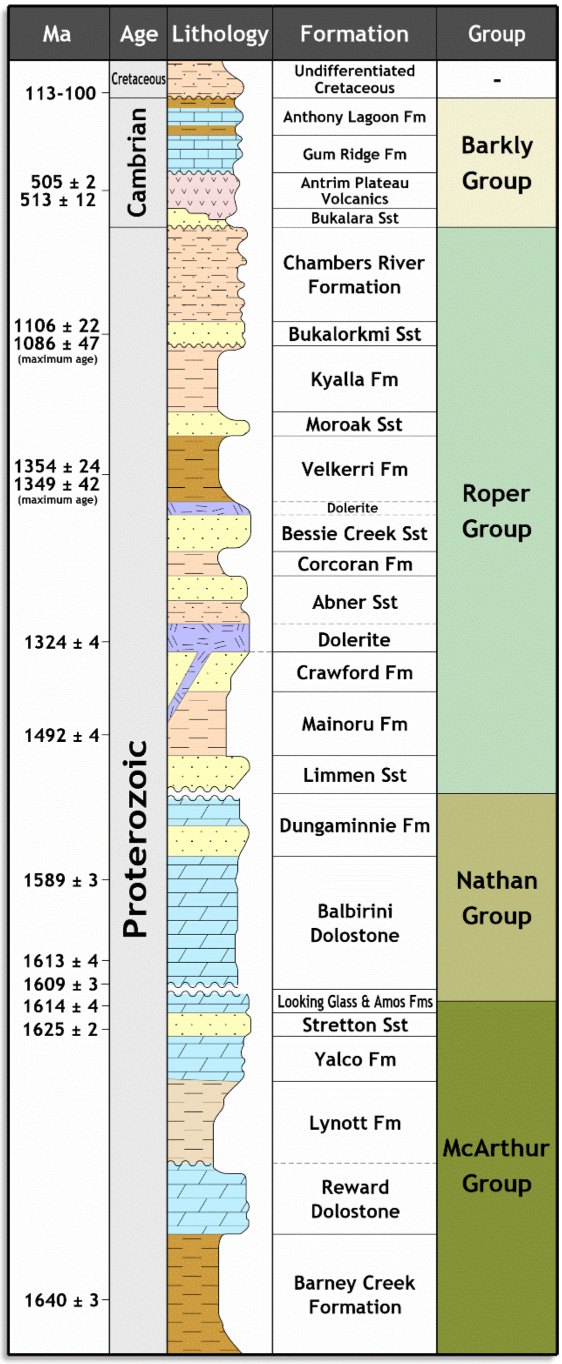

Figure 6. Stratigraphic column showing distribution of the McArthur, Nathan, Roper and Barkly groups and overlaying units.

The unconventional potential of the Velkerri Formation is greatest in the organic-rich mudstones of its middle member – informally subdivided by Origin, and other regional operators as A, B, and C Shale (from oldest to youngest). These organic-rich mudstones are typically separated by organic-lean siltstones. Organic matter is of marine origin derived from bacteria and filamentous organisms such as blue green algae (Cyanobacteria) with main organic matter types being alginite, bituminite and bitumen. Overall, total organic content ranges from <1% to ~10% and HI between ~5 and ~800 mgHC/gTOC. Variations are related to organic matter composition, the extent of maturation and hydrocarbons generated (Faiz et al, 2016). Mineralogical and geochemical evidence including an increase in authigenic pyrite (%) and trace element and rare earth element concentrations (i.e. Mo, V, U, Ce) suggest higher than average organic content is likely the result of periods of increased primary productivity (triggered by increase continent weathering and thus nutrient availability) coupled with preservation under euxinic bottom water conditions (Cox et al. 2016). Basin modelling and thermal maturity assessment suggest the middle Velkerri is generally mature for gas generation becoming increasingly over-mature towards the deepest parts of the basin (Faiz et al, 2016). Increasing maturity and secondary hydrocarbon cracking developed micron-size, secondary organic-hosted porosity within bitumen consistent with successful unconventional plays worldwide (Faiz et al, 2016).

Petrophysical evaluation show upwards of 7% total and 4% gas-filled porosity in the middle Velkerri Formation with total gas saturations within the range of 50 to 70%. Natural gas is stored in three ways: 1) the mineral matrix within the pore spaces of the shale; 2) adsorbed on mineral grains and organic material; and, 3) in natural fractures. Permeability is very low, typically within the 10-100's nanodarcy range requiring hydraulic fracture stimulation treatments to improve gas flow to the wellbore. Positive geochemical properties inferred from sonic and density logs (i.e. dynamic measurements) and laboratory tests on core samples (i.e. static measurements) indicate all organic-rich shale intervals are relatively 'brittle' and conducive to effective fracture stimulation.

The middle Velkerri forms a continuous accumulation across the basin owing to the depositional style and relatively unstructured basin configuration at the time of deposition. The formation reaches maximum thickness in the center of the basin (not fully penetrated; upwards of 420 m), thinning towards the north and ultimately eroded (not deposited?) to the north, west and east as inferred from seismic profiles and well coverage (Figure 7). Regional intra-formational thickness variations occur and are particularly evident in the A and C shales. The B Shale is the most consistent and well-develop shale interval in the basin with well penetrations intersecting a stratigraphic section of similar thickness and petrophysical characteristics for hundreds of kilometers across the Sever, Core and OT downs sub-basins (Figure 8).

The positive combination of reservoir quality, thickness continuity and geomechanical properties observed in exploration wells drilled by Origin in 2015 in EP98 high-grades the organic-rich B Shale as the most prospective middle Velkerri Source Rock Reservoir (SRR) target in the permit. Drilling of the Beetaloo W-1 well in 2016 confirmed the extent and prospectivity of B Shale in EP117 where no direct offsets to the formation exists.

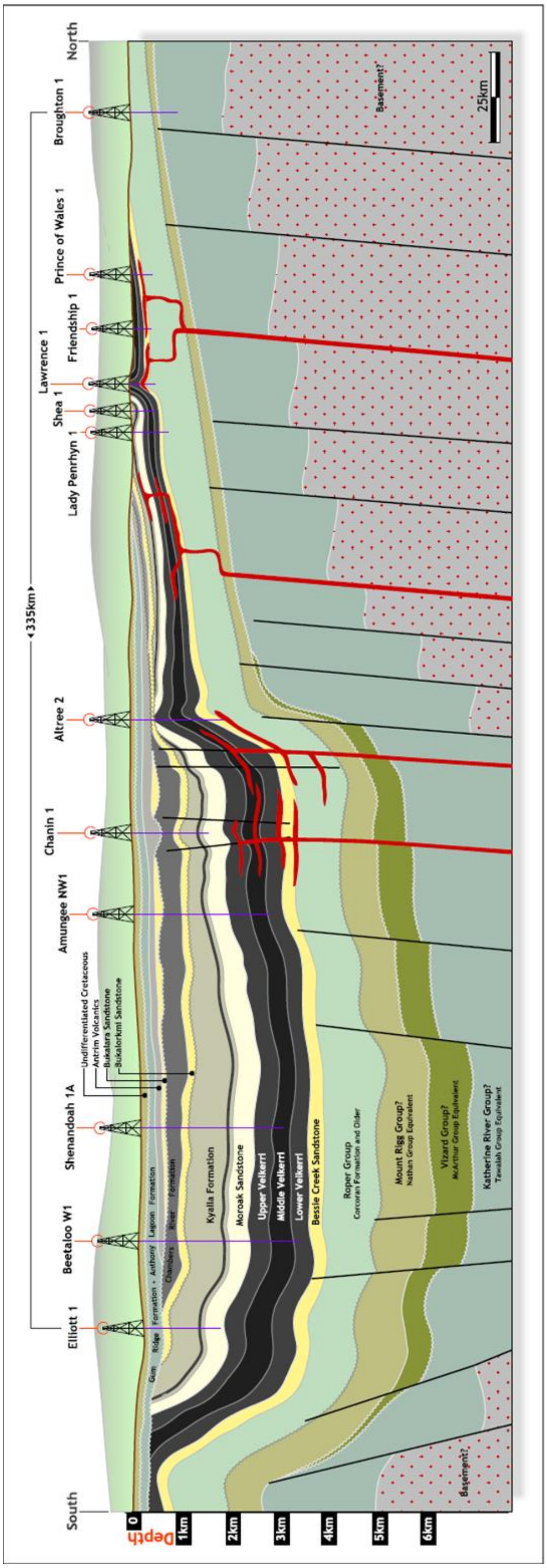

Figure 7. Extent and thickness continuity of the middle Velkerri across the Beetaloo

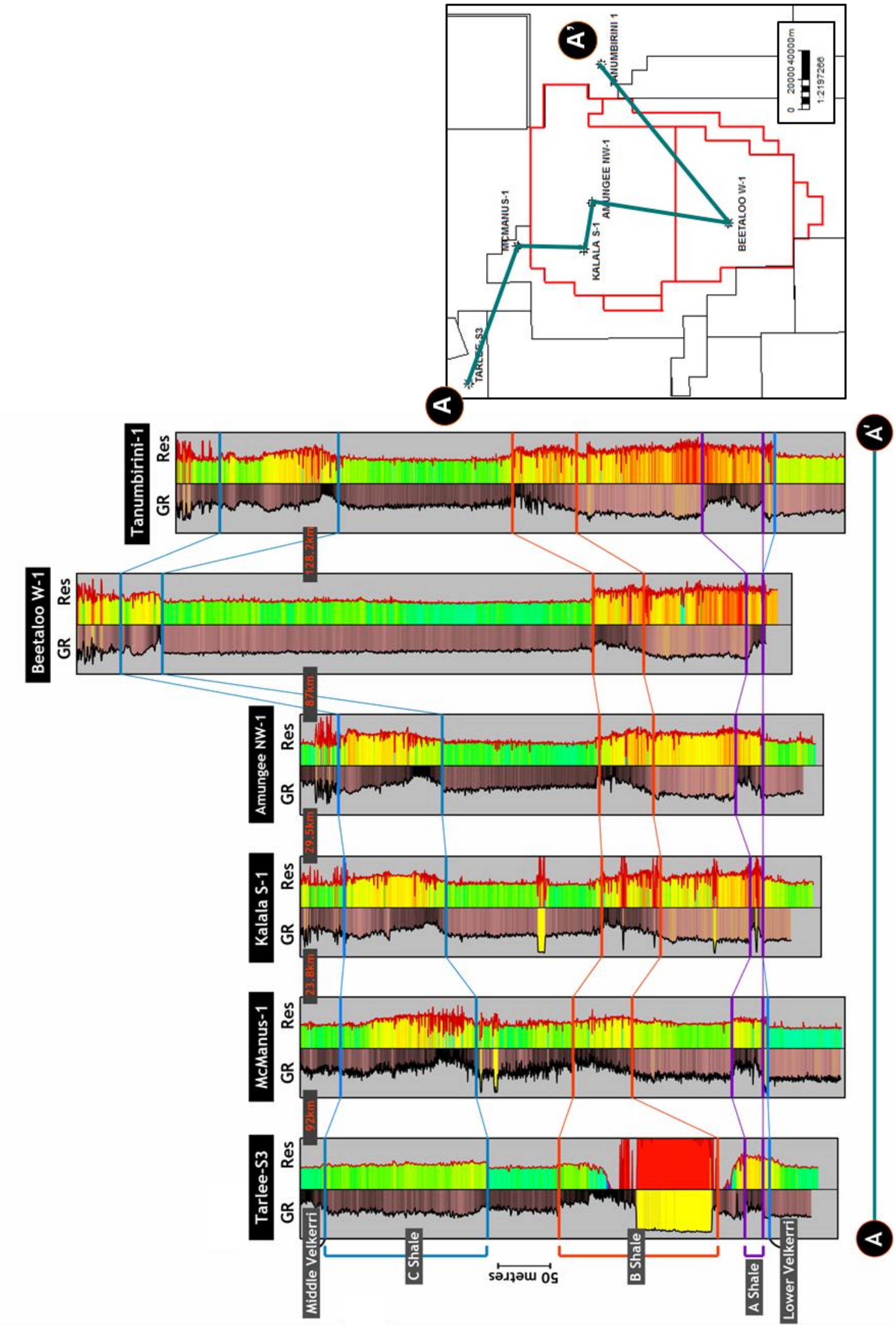

Figure 8. Regional intra-formational thickness variations occurs primarily in the middle Velkerri A and C shales. The B Shale is the most consistent and well-develop shale interval across the Sever, Core and OT downs sub-basins.

3.2 Exploration History

The McArthur and Roper groups have been the focus of sporadic exploration interest for a number of decades since activity commenced in 1980's encouraged by a gas blowout in a Kennecott minerals drillhole into the McArthur Group sediments in 1979. Despite consistent oil and gas shows in exploration wells, existing data is still sparse with only 28 petroleum wells drilled in the basin today.

Initial exploration was limited to conventional leads that recognised the presence of multiple proven petroleum systems. A total of 22 wells were drilled in the broader McArthur region between 1980's and 1990's with mix results. Since the mid- to late-2000's a change in exploration mindset has seen a shift primarily to the exploration of unconventional oil and gas resources focused on SRR or shale gas plays. One of the play targets of particular interest is the Mesoproterozoic Velkerri Formation of the Beetaloo. A total of 11 wells have been drilled into the formation showing promising gas and oil shows. A summary of historic well penetrations is provided in Table 5 and displayed in Figure 9.

Well name	Company	Year	Comment
Altree-2	Pacific Oil and Gas	1988	Stratigraphic test. Oil and Gas shows within middle Velkerri. Altree-2 terminated in a Dolerite sill within the Corcoran Fm.
Walton-2	Pacific Oil and Gas	1989	Anticline test. Oil and Gas shows within middle Velkerri. Walton-2 terminated within the Bessie Creek Sst.
McManus-1	Pacific Oil and Gas	1989	Syncline test for fracture play. Oil and Gas shows within middle Velkerri. McManus-1 terminated within lower Velkerri.
Sever-1	Pacific Oil and Gas	1990	Stratigraphic test. Minor gas shows within middle Velkerri. No oil shows. Dolerite intrusion within middle Velkerri appears to have destroyed source potential and/or liquids potential. Sever-1 terminated within the Corcoran Fm.
Jamison-1	Pacific Oil and Gas	1990	Stratigraphic test targeting 2-way closure mapped in 2D seismic line. DST over Bukalorkmi Sst recovered 1.5-2m light oil (34.6 API). Jamison-1 terminated within the upper Moroak Sst.
Elliott-1	Pacific Oil and Gas	1991	Stratigraphic test targeting apparent broad anticline in southern Beetaloo Basin. DST Moroak Sst recovered 5200L of saline formation water. DST Kyalla Sst, 15ml of oil. Elliott-1 terminated within lower Moroak Sst.
Mason-1	Pacific Oil and Gas	1991	Structural test at Bukalorkmi Sst level. No hydrocarbons recovered. Minor hydrocarbons shows. Mason-1 terminated within upper Kyalla Fm.
Balmain-1	Pacific Oil and Gas	1992	Test of a lateral resistivity anomaly from CTEM survey in 1991. DST over Chambers River Sst recovered 4.5L of oil and 24.5L of oil and water cut rat hole mud. Balmain-1 terminated in the upper Kyalla Fm.
Shortland-1	Pacific Oil and Gas	1992	Structural test of interpreted closure from 2D seismic lines.

			Incorrect interval velocity analysis resulted in the well being drilled off closure. Hydrocarbon shows were limited to weak, dull pale yellow fluorescence within the Chambers River and Bukalorkmi Sst. Shortland-1 terminated within the upper Kyalla Fm.
Chanin-1	Pacific Oil and Gas	1993	Structural test of a 4-way dip closure mapped in 2D seismic lines. Hydrocarbon shows was limited to minor mud gas while drilling and sparse florescence within the Bukalorkmi Sst. Chanin-1 terminated in the upper Moroak Sst.
Ronald-1	Pacific Oil and Gas	1993	Structural test of a 4-way dip closure mapped in 2D seismic lines. Limited gas flow was encountered within the Cambrian aged Antrim Plateau Volcanics. Minor dull yellow/green pin point fluorescence and elevated total gas to 2995ppm was observed in the base Bukalorkmi Sst. DST over top of Moroak Sst resulted in the recovery of 3108L of saline formation water and minor solution gas. Ronald-1 terminated within the upper Moroak Sst.
Burdo-1	Pacific Oil and Gas	1993	Crestal test of a possible fractured play within a prominent wrench structure. Structure mapped along a single 2D line. Increased gas shows in the lower Bukalorkmi Sst along with increased water indicate sandstone is water wet with minor solution gas. Tight gas zone was inferred from petrophysical logs within the upper Moroak Sst (1143-1151m). Burdo-1 terminated within the upper to middle Moroak Sst.
Shenandoah-1	Sweetpea	2007	Target conventional reservoirs south of Balmain-1. Fluorescence was observed in the Chambers River Sst and the upper Kyalla Fm. Shenandoah-1 was suspended within the lower Kyalla Fm.
Shenandoah-1A	Falcon Oil & Gas	2009	Re-enter and deepening of Shenandoah-1 Good wet gas shows within the lower Kyalla Fm and dry gas shows within the middle Velkerri. Fluorescence was not observed. Shenandoah-1A was terminated within the middle Velkerri.
Tarlee-S3	Pangaea	2014	Well was drilled outside structural/stratigraphic closure testing shale gas potential in the Velkerri Fm. Located in the Sever Sub-basin Oil shows and fluorescence observed in the Bukalara Sst, Kyalla Fm and Moroak Sst. Good mud gas shows within the Kyalla Fm. A 65 m (approx.) dolerite interval was intersected within the middle Velkerri Tarlee-S3 was terminated within the lower Velkerri.
Tanumbirini-1	Santos	2014	Well was drilled outside structural/stratigraphic closure testing shale gas potential in the Velkerri Fm. Located in the OT Downs Sub-basin Trace fluorescence observed in the Bukalara Sst and Chambers River Fm. Good wet gas shows within the lower Kyalla Fm and dry gas shows within the middle Velkerri. Tanumbirini-1 was terminated within the Bessie Creek Sst.

Kalala S-1	Origin	2015	Well was drilled outside structural/stratigraphic closure testing shale gas potential in the Velkerri Fm. Well location was selected based on thermal maturity modelling. Good wet gas shows within the lower Kyalla Fm and dry gas shows in the middle Velkerri. Kalala S-1 was terminated in the lower Velkerri.
Amungee NW-1	Origin	2015	Well was drilled outside structural/stratigraphic closure testing shale gas potential in the Velkerri Fm. Well location was selected based on thermal maturity modelling. Good wet gas shows within the lower Kyalla Fm and dry gas shows in the middle Velkerri. Amungee NW-1 was terminated in the lower Velkerri.
Amungee NW-1H	Origin	2015	Horizontal well drilled from the intermediate hole section of the Amungee NW-1 vertical well. The lateral section was landed and drilled through the 'B Shale' of the middle Velkerri. Good dry gas shows across approx. 1000m of horizontal drilled section Amungee NW-1H was terminated in the B Shale at a depth of at 3808 mMDRT
Beetaloo W-1	Origin	2016	Well was drilled outside structural/stratigraphic closure testing shale gas potential in the Velkerri Fm in the southern Beetaloo. Well location selected based on thermal maturity modelling. Good wet gas shows within the lower Kyalla Fm and dry gas shows in the middle Velkerri. Beetaloo W-1 was terminated in the lower Velkerri.

Table 5. Historic well penetrations in the Beetaloo Basin since the 1980's.

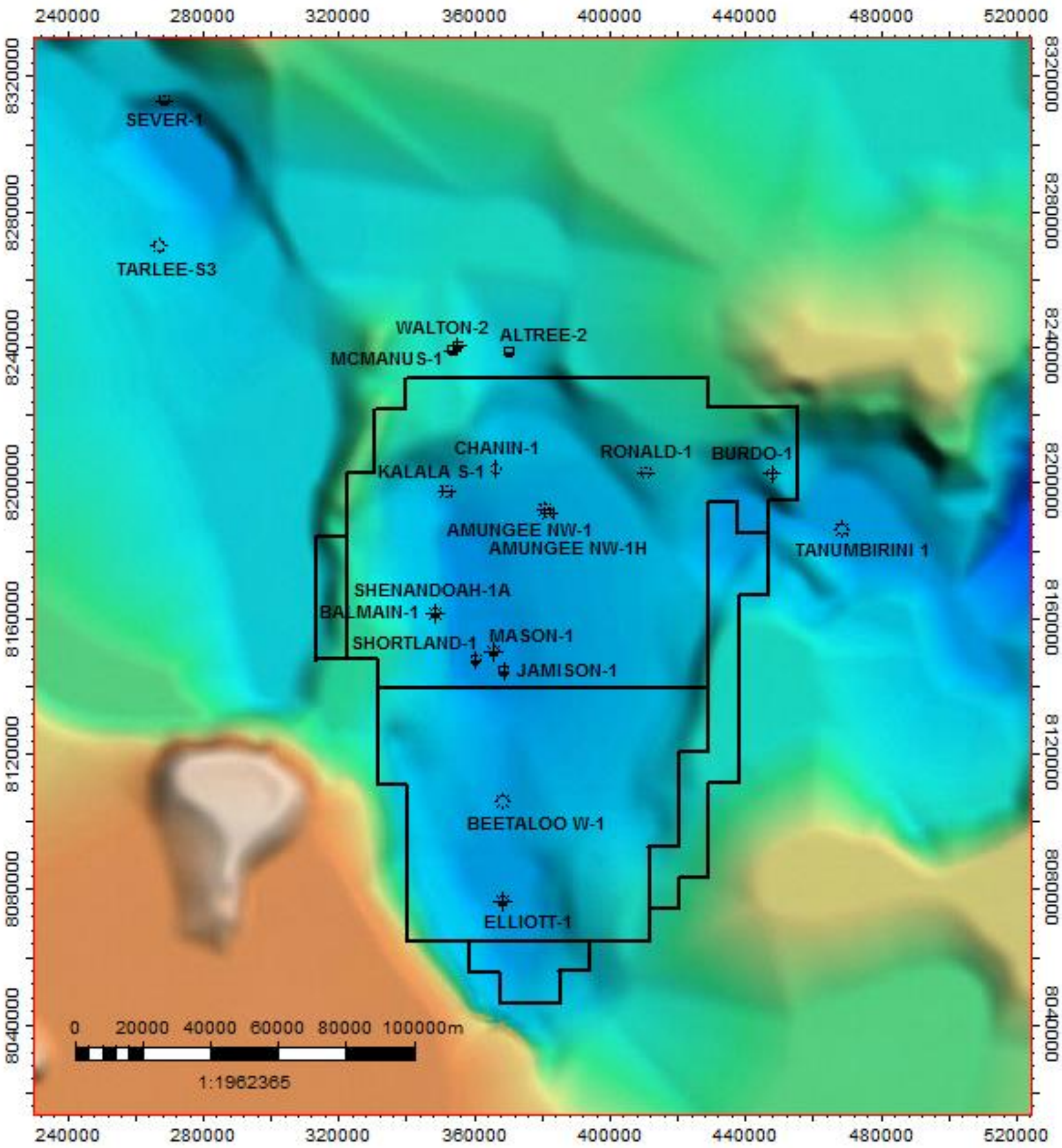

Figure 9. Summary of historic of well penetrations in the Beetaloo Basin since the 1980's. Background is OZ SEEBASE^{TM} depth-to-basin image (Pryer and Loutit 2005).

3.3 Seismic Interpretation

3.3.1 Summary of data

Interpretation of two-way time (TWT) reflection seismic data has been carried out over the Beetaloo to provide confidence in the continuity of sub-surface geology as well as allowed for the generation of depth maps for well prognosis, maturity modelling and Original Gas In Place (OGIP) estimation. Approximately 9500 km of 2D seismic data have been acquired over the basin between 1989 and 2013 in various acquisition campaigns carried out by a number of companies. These data delineate the aerial extent of the prospective Roper Group middle Velkerri target. Seismic data quality is heavily impacted by near surface geology which include thick basalts and karstic limestone sections.

Well to seismic ties are achieved via well check-shot surveys and synthetic seismograms generated from well log data. Well to seismic ties are the basis of interpreting and correlating geological horizons across the basin. TWT interpretation is converted to depth using a regional time-depth trend calculated from available well velocity information.

3.3.2 Seismic Data Quality

Seismic data quality in the Beetaloo Basin varies from very good around Elliot-1 to very poor around Jamison-1 (Figure 10). Quality is strongly affected by the presence of the basalt flows of the Antrim Plateau Volcanics, and karstic nature of the Gum Ridge Formation. The strong acoustic impedance contrast at the top and base of the basalt reduces the transmission of energy below the basalt with the majority of energy reflected back to surface. High frequencies are more heavily affected by absorption and scattering within the basalt which results in relatively low frequency and noisy reflection data from below the Antrim Plateau Volcanics. The majority of EP76, EP98 and EP117 are covered by the Antrim Plateau Volcanics at the near surface reaching up to 440 m thick (i.e. Chanin-1) in the north of the basin. The karstic Gum Ridge Formation ranges from 40 – 295 m thick providing a number of challenges with seismic energy scattering, static corrections and noise.

The effect of the Antrim Plateau Volcanics on seismic data quality is clearly illustrated on the South-North seismic section displayed in Figure 10. Within the southern Beetaloo (i.e. Elliott-1) the seismic character is generally well-defined with conformable reflector geometries and good imaging quality at depth. Seismic character typically decreases towards the center of the basin (i.e. Jamison-1) displaying poor signal to noise ratio and low frequency content owing to the presence of the Antrim Plateau Volcanics.

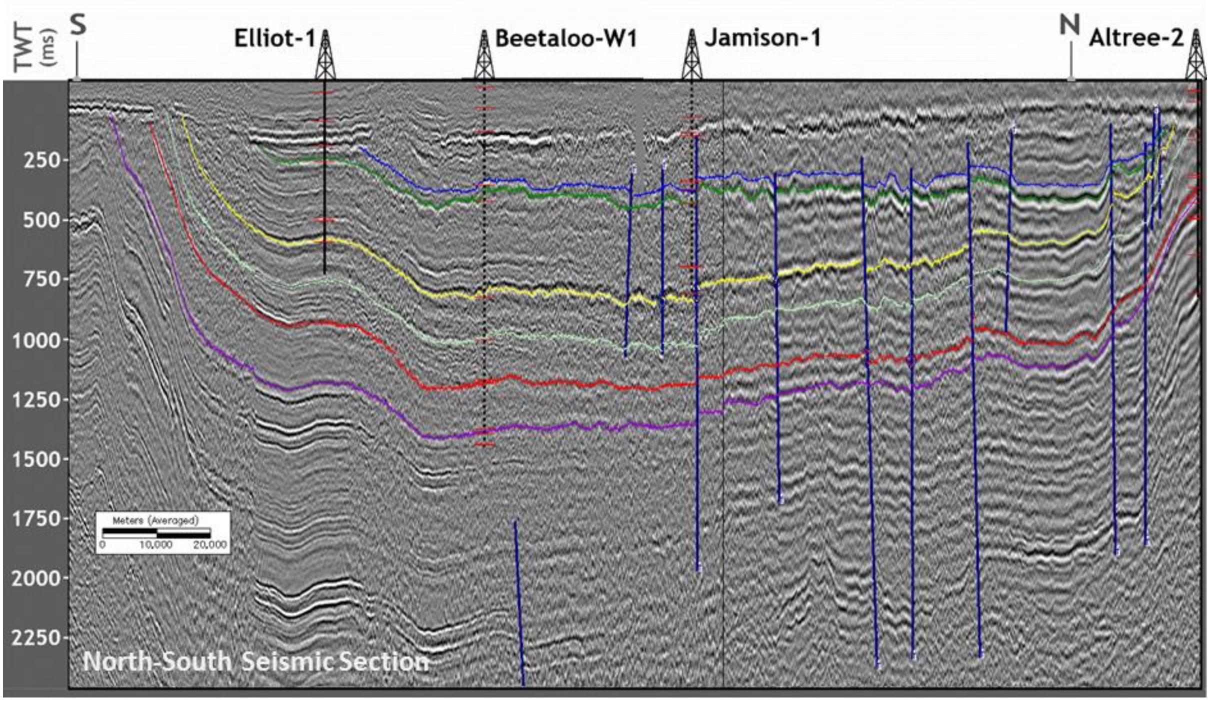

Figure 10. South-North seismic section intersecting Elliot-1, Beetaloo W-1, Jamison-1 and Altree-2. Data quality notably degrades from Elliot-1 to Jamison-1 due to near surface lithological effects. Reflector markers are as follow: Blue - Top Bukalorkmi Sst, Green – Top Kyalla Formation, Yellow – Top Moroak Formation, Teal – Top upper Velkerri, Red – Top middle Velkerri, and Purple – Top B Shale.

Well to seismic ties from either check-shot surveys or synthetic seismograms are the basis of interpreting seismic reflection events and correlating them with geological packages. In areas of good seismic data quality, high quality synthetic seismogram well to seismic ties are achieved using the well data alone. In areas of poor seismic data quality check-shot surveys are relied upon to provide well to seismic ties. Where check-shots are absent, synthetic seismograms are hung off of the regional reflectors of the Top Bukalorkmi Sandstone, Top Kyalla Formation and the Moroak Sandstone. Examples of synthetic seismograms from Tanumbirini-1 and Beetaloo W-1 are shown in Figure 11 and Figure 12 respectively.

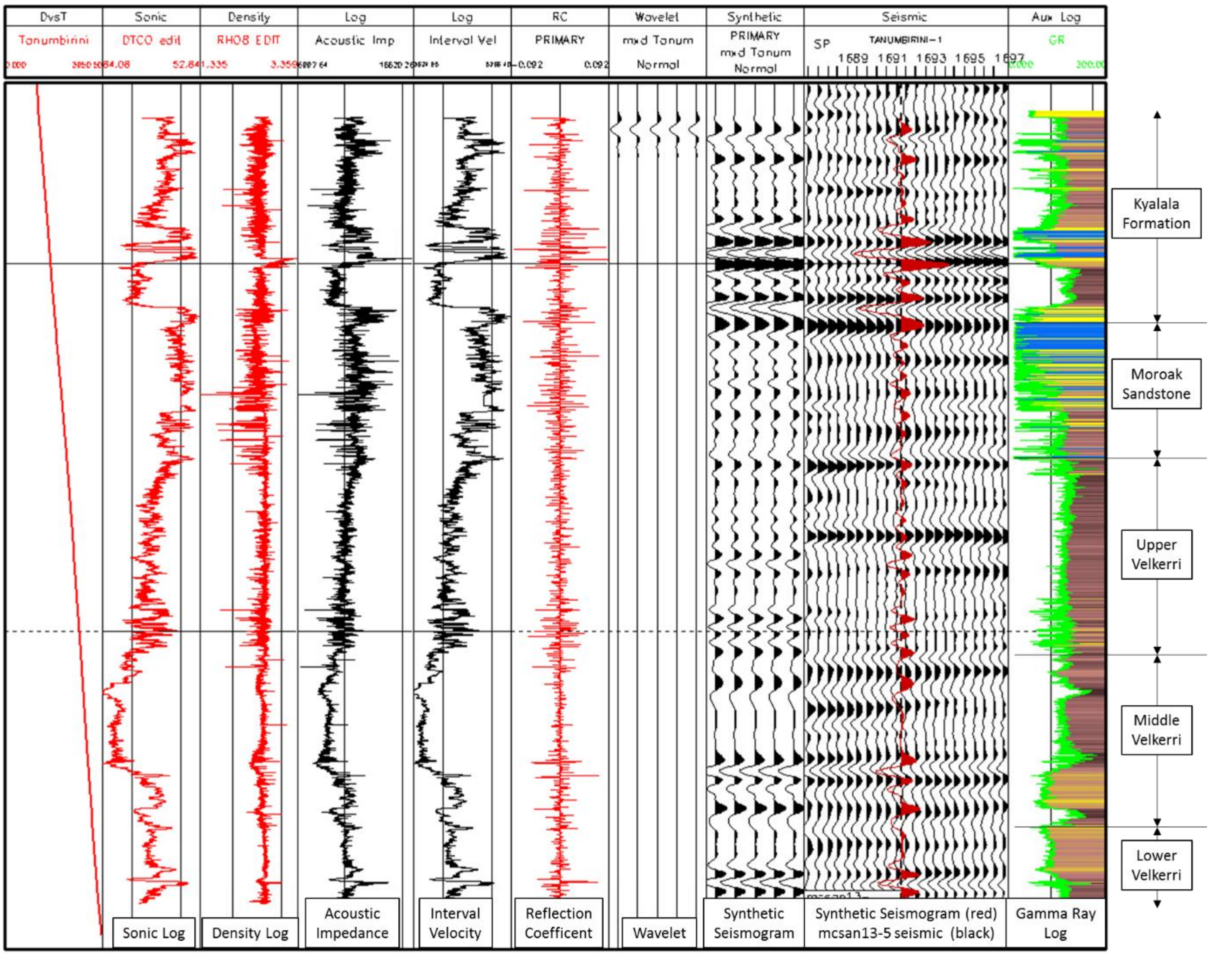

Figure 11. The Synthetic Seismogram and well to seismic tie for Tanumbirini-1 and seismic line mcsan13-5.

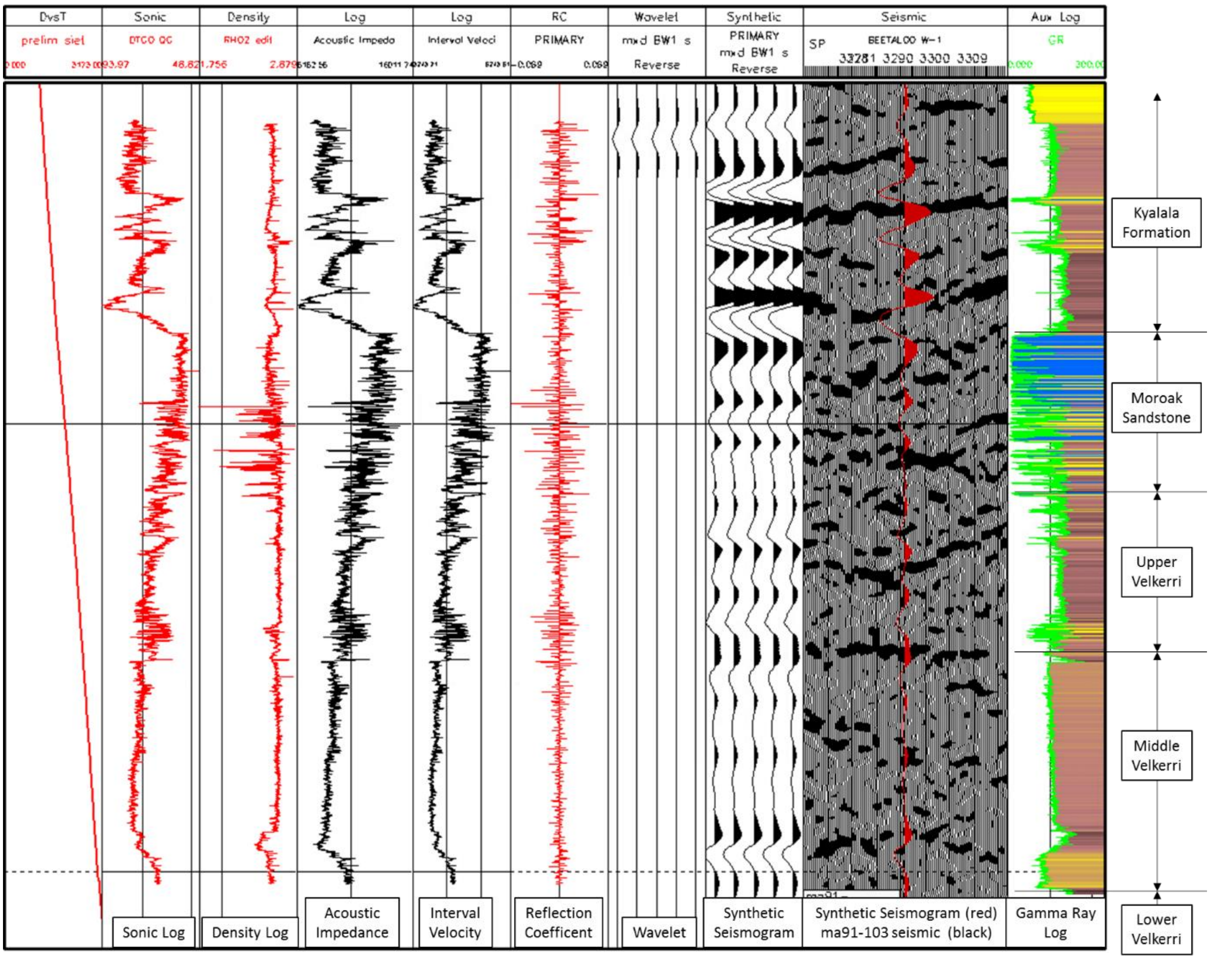

Figure 12. The Synthetic Seismogram and well to seismic tie for Beetaloo W-1 and seismic line ma91-103.

A total of 16 exploration wells are used as the primary calibration for the seismic interpretation across the basin. Interpretation of TWT reflection seismic data has been carried out with the picked horizons representing the main stratigraphic levels of the Roper Group sediments. Figure 10 shows the seismic character of the horizons. Due to the recent public release of seismic data acquired by Pangaea in 2013, the current Origin interpretation does not extend westward across the Daly Waters Arch to the Server Sub-Basin, although Origin does recognize that the Roper group stratigraphy extends across from the Core Area to the Server Sub-Basin.

TWT reflection seismic interpreted horizons are converted to depth using a regional time to depth relationship. TWT-Depth pairs from check-shot surveys and synthetic seismograms have been collated and plotted and a regional TWT-Depth function selected to approximate the regional velocity trend (Figure 13). The regional TWT-Depth function is used directly to convert TWT interpretation to depth via calculated average velocity. The calculated average velocity is calibrated to the available well control by the use of multiplicative scalars. There is considerable uncertainty in both TWT interpretation through areas of poor data quality and the estimation of velocities used for conversion from seismic time to depth due to the lack of well control over the basin; as such, exploration wells drilled by Origin in 2015 and 2016 have had an added depth uncertainty of ±150 to

200 m at the target level of the middle Velkerri B Shale. The seismic interpreted middle Velkerri Top B Shale Depth Map is shown in Figure 14.

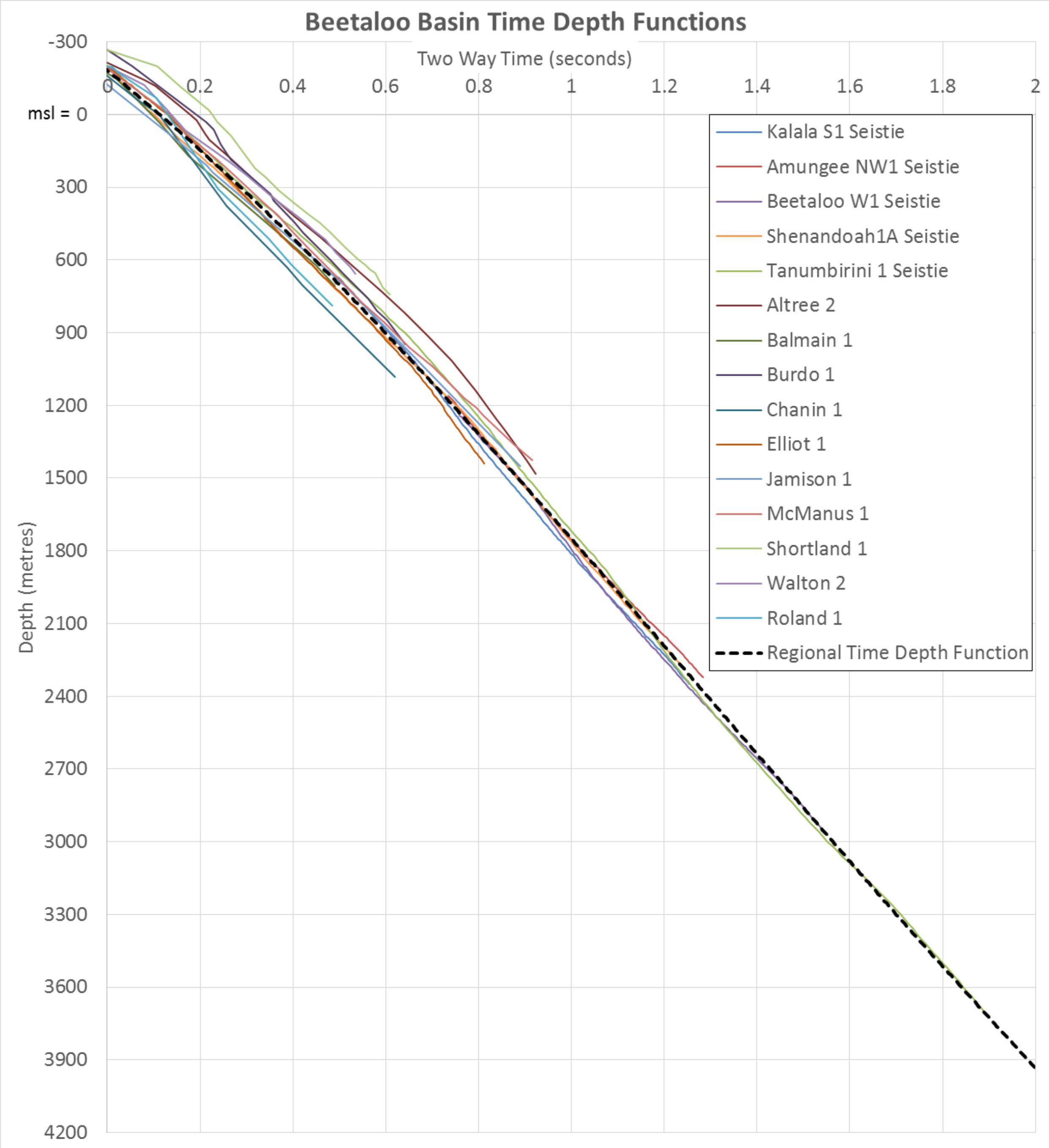

Figure 13. Relevant well time to depth relationships (check shot surveys and synthetic seismograms) for the Beetaloo Basin, and the regional time depth trend used for depth conversion.

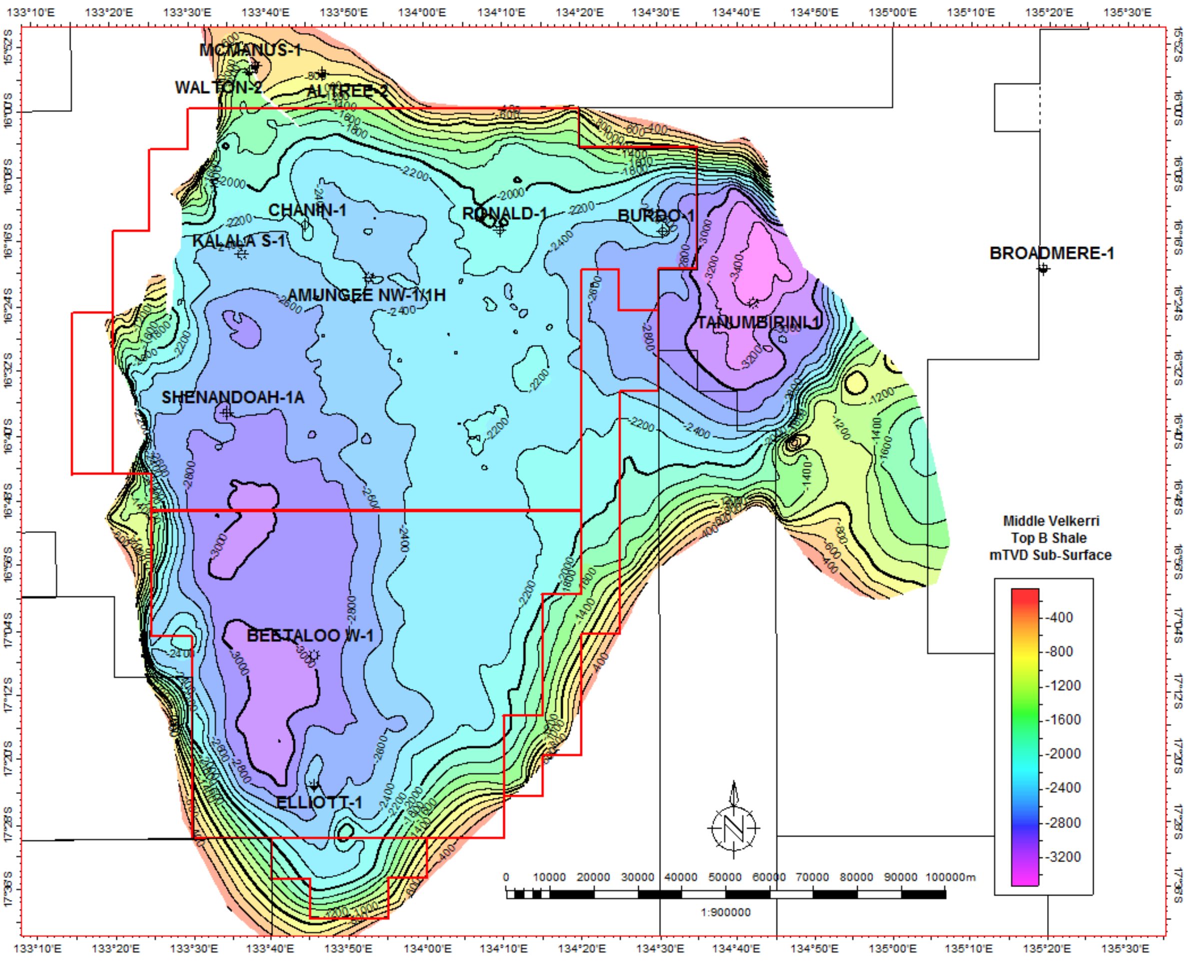

Figure 14. Middle Velkerri Top B Shale Depth Map converted from TWT reflection seismic interpretation.

3.4 Preliminary estimate of the location and areal extent of the petroleum pool

The Amungee NW-1H production test established the existence of a significant quantity of moveable natural gas hydrocarbons within the middle Velkerri B Shale. The hydrocarbon pool associated to this discovery is defined to be present in the dry gas window within the broader middle Velkerri B Shale play. The boundaries of the pool extend beyond the limits of conventional traps as confirmed by the EPT at Amungee NW-1H, which was intentionally drilled outside any stratigraphic or structural closure. In a stratigraphic sense, the pool sits within the middle Velkerri with seismic reflection data and regional well control confirming the extent and continuity across the basin. The pool is clearly identifiable as it shares very consistent thickness and petrophysical character.

Even though additional well penetrations are required to confirm the exact extent of the pool across the basin, Origin currently has sufficient data and understanding of the basin to develop a preliminary estimate of the pool's extent.

Origin have constrained the extent of the pool to only include the dry gas window within the middle Velkerri B Shale. The rationale behind this cut-off is that the Amungee NW-1H well test has demonstrated that dry gas is mobile within the B Shale. Additional drilling and testing will be required to demonstrate moveable hydrocarbons within the wet gas and/or oil windows.

Origin used a corrected Vitrinite reflectance equivalent (V_{re}) value of equal to or greater than 1.35% to delineate the dry gas window. Origin developed a robust V_{re} estimated from alginate and bitumen reflectance in addition to aromatic hydrocarbon maturity parameters derived from the Methylphenanthrene Index work undertaken to date. The resulting maturity model with depth has proven to be robust when compared to post-drill modeling and has been further calibrated to incorporate the recent data collected at Kalala S-1, Amungee NW-1, and Beetaloo W-1. The Beetaloo Depth vs. Maturity profiles for the regional wells is shown in Figure 15.

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Figure 15. Beetaloo Basin depth vs. maturity profiles for a total of 10 wells. The P90-P50-P10 depth estimates were calculated using a Vitrinite reflectance equivalent (V_{re}) cut-off of 1.35% to delineate the dry gas window.

The depth vs. maturity profile data was used to estimate the depth range at which the dry gas window is entered. Table 6 below summarizes this range.

P90	P50	P10
1370 m	1486 m	1610 m

Table 6. Estimated P90-P50-P10 depth range at a maturity cut-off consistent with the dry gas window.

Based on the depth to dry gas range shown above, the areal extent of the P90-P50-P10 depth contours is displayed in Figure 16 and summarized in Table 7. The narrow P90 to P10 range of the areal extent of the pool is a function of the Basin shape as seen in the basin area vs depth chart in Figure 17.

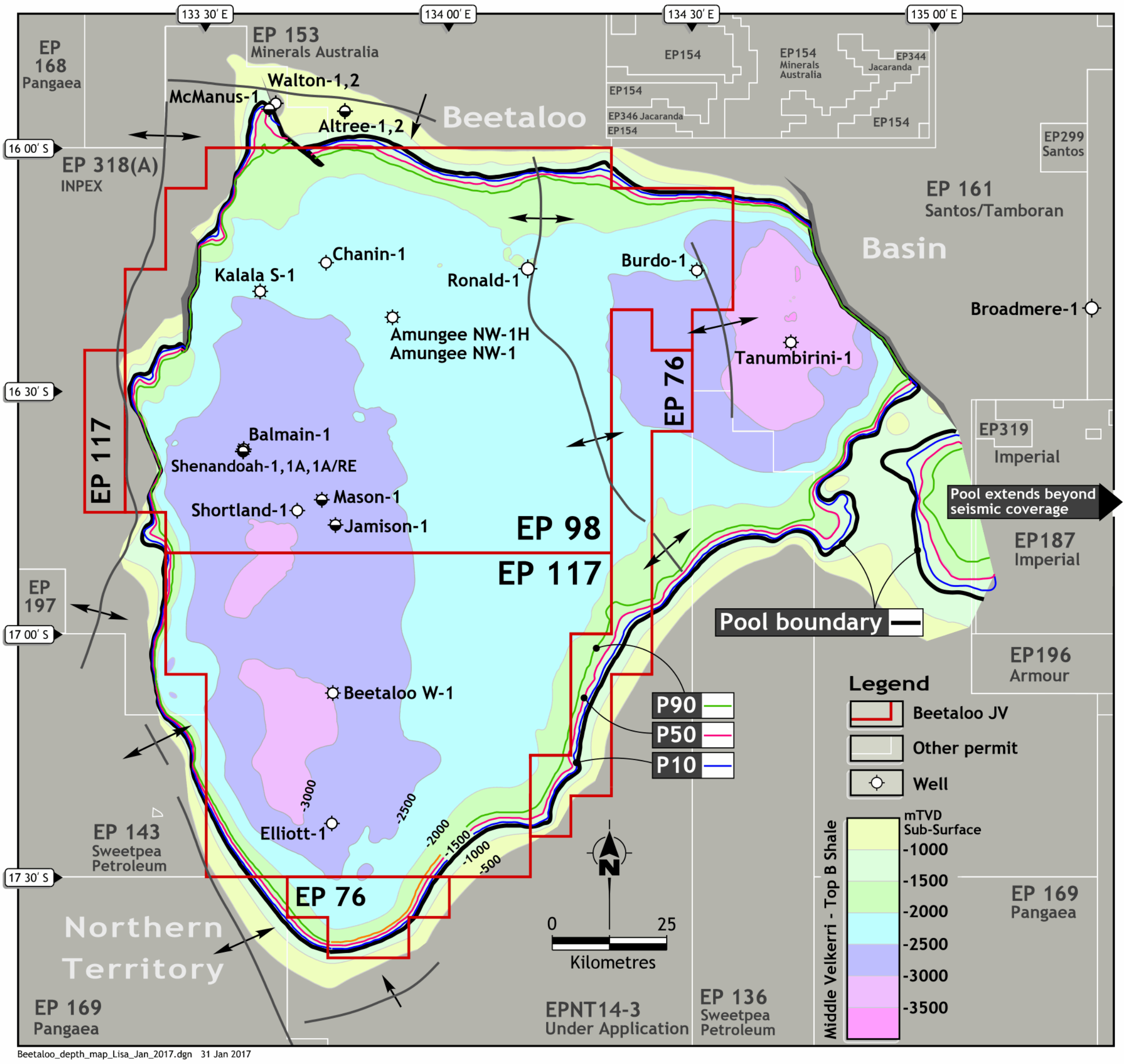

Figure 16. Middle Velkerri Top B Shale Depth Map displaying the pool boundary and areal extent of the P90-P50-P10 depth contours. Contour markers are as follow: Black – Pool boundary, Blue – P10, Purple – P50, and Green – P90.

	P90	P50	P10
Pool Area	18825 km^2	19487 km^2	20043 km^2
Pool Area Within Beetaloo JV Permits (EP76, 98, 117)	15810 km^2	16145 km^2	16400 km^2

Table 7. Estimated P90-P50-P10 depth range at a maturity cut-off consistent with the dry gas window.

The Pool extends past the Beetaloo JV exploration permits (EP76, EP98, and EP117) and is also present within the following permits: EP136, EP143, EP153, EP161, EP169, EP187, EP318(A), EPNT14-3. Figure 18 and 19 shows the extent of the P90-P50-P10 petroleum pool and estimated pool boundary against the NTGS interpreted extent of the Beetaloo Basin (after Munson 2014).

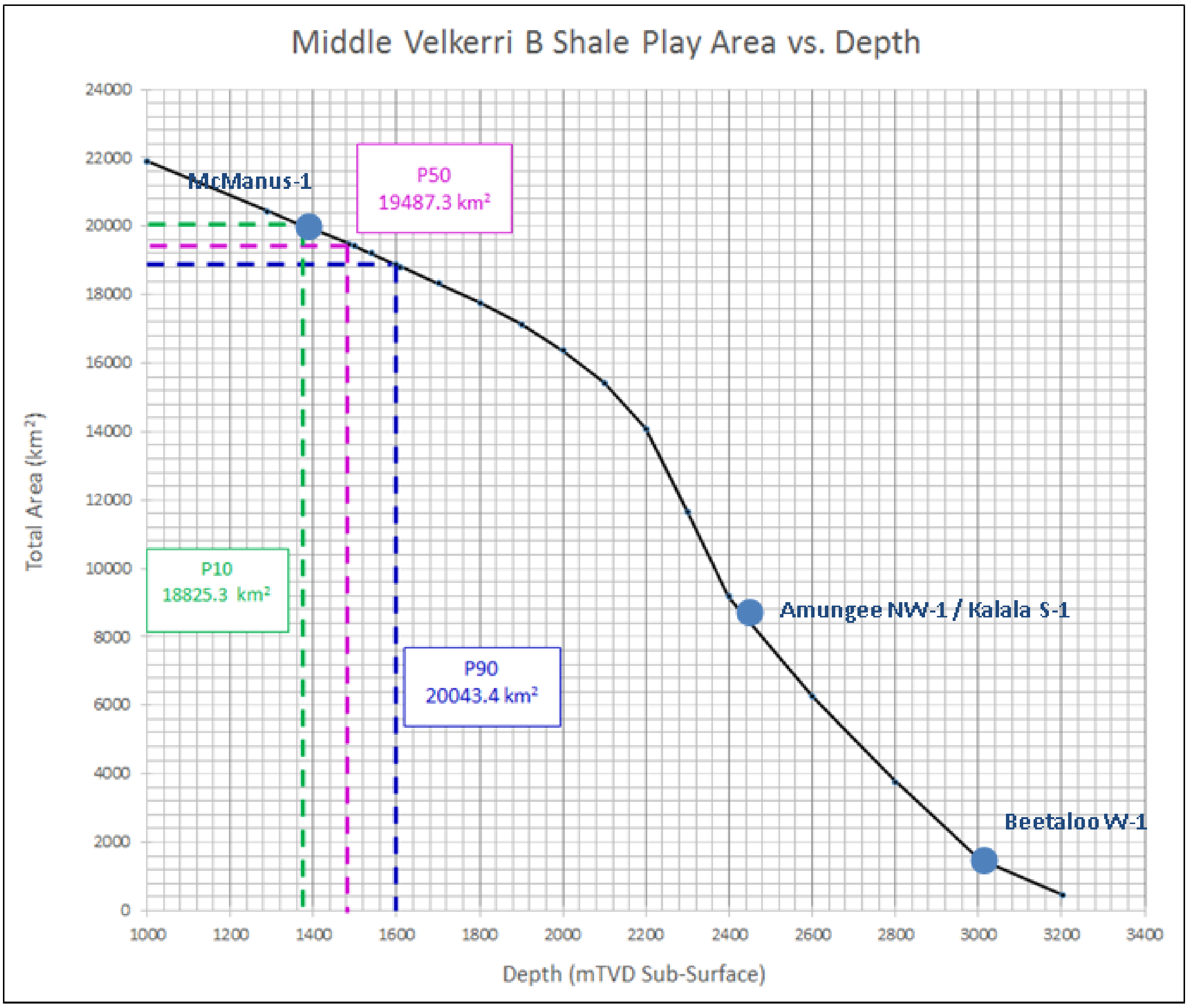

Figure 17. Beetaloo Basin area vs. depth based on the depth to dry gas range shown in Figure 15.

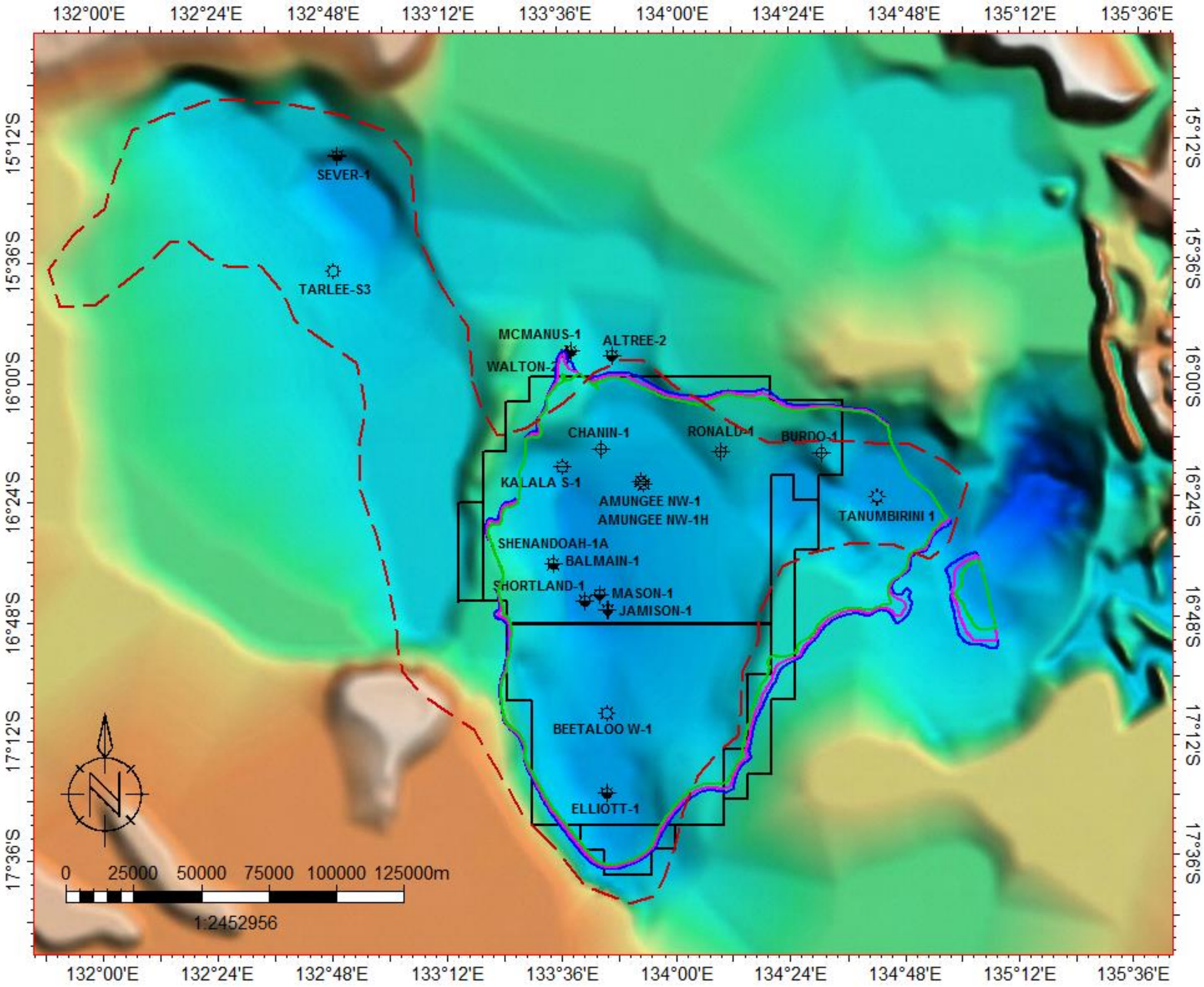

Figure 18. Areal extent of the P90-P50-P10 petroleum pool compared with the overall extent of the Beetaloo basin (after Munson 2014). Contour markers are as follow: Blue – P10, Purple – P50, and Green – P90. Background is the OZ SEEBASE™ depth-to-basement image (Pryer and Loutit 2005) showing the NTGS interpreted location of the Beetaloo Basin in red dashed line (after Munson 2014).

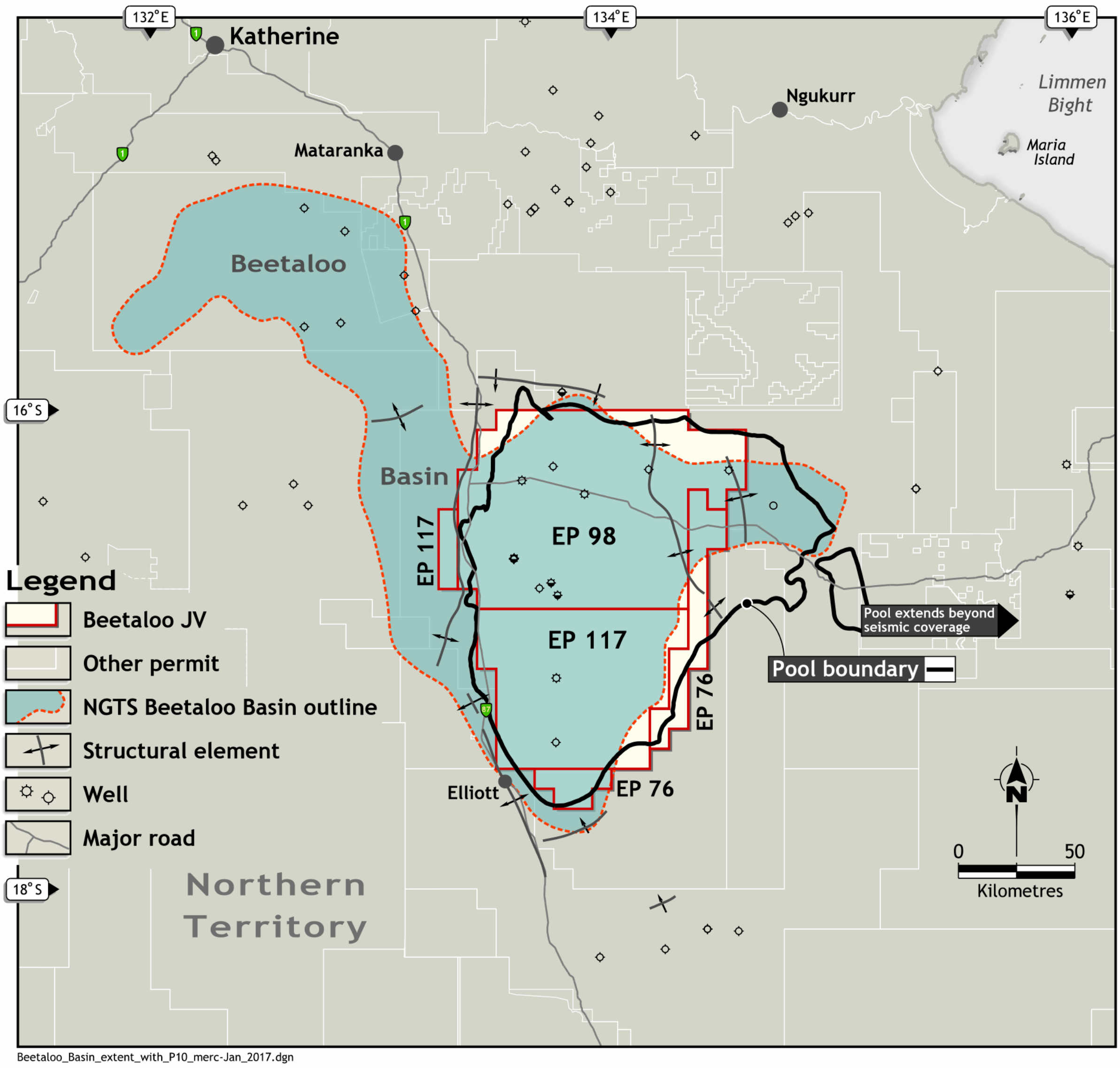

Figure 19. Areal extent of the petroleum pool compared with the NTGS interpreted extent of the Beetaloo (after Munson 2014).

3.5 Details of geological structure in which the petroleum is located

No structural or stratigraphic trap present.

The middle Velkerri Formation is defined as a Source Rock Reservoir (SRR, Type 3) after Schmoker (1995). SRR targets are continuous and spatially extensive accumulations where traditional structural or stratigraphic trapping mechanisms, seals and distinct gas-water contacts are absent. SRRs are tight with permeability generally within the nanodarcy (nD) range which inhibit buoyancy-driven fluid migration effectively retaining hydrocarbons in place (Bartberger et al. 2002).

3.6 Geological and Petrophysical Data Summary

Results from Amungee NW-1 and Amungee NW-1H support the presence, lateral continuity and good reservoir and completion quality of the middle Velkerri B Shale Play. A remarkably consistent petrophysical character and thickness continuity observed in well penetrations within and outside the Core Area (i.e. the Sever and OT Downs Sub-Basins) confirms the target is regionally consistent across the broader Beetaloo Basin.

Conventional and sidewall core evaluation indicate the middle Velkerri B Shale possess good reservoir properties (porosity, saturation), total organic content (oil to gas mature Type I-II oil prone source rocks) ranging from 1-10%, and a mineralogy make-up conducive to stimulation (relatively low clay, quartz-rich mudstone to siltstone lithologies) that compares favourably with successful SSR plays worldwide. Basin modelling and thermal maturity assessment based on alginite reflectance, associated bituminite and bitumen suggests the middle Velkerri is gas mature to over-mature.

Three prospective intervals were identified in the middle Velkerri; the A, B and C Shales (from oldest to youngest). All three zones were found to be gas bearing and have high quartz content. The average gas saturation for the three zones was 61 % which aligns with the total gas content derived from direct measurements of pressurised side wall cores recovered in the basin (i.e Kalala S-1). The B Shale showed the best reservoir quality overall, with higher porosity and quartz content. The gas saturations were also the highest in the B Shale, owing to a higher total organic content. A summary of average properties is provided in Table 8.

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Velkerri Formation Total										
Formation	Top	Base	Gross /Net	PHIT	PHIE	TOC	VCLAY	VOL QTZ	SWT	VOL UGAS
	mMDRT	mMDRT	m	%BV	%BV	wt%	%BV	%BV	%PV	%BV
C Shale	2196.6	2285.9	89.3							
B Shale	2418.3	2465.7	47.4							
B Shale (base)	2465.7	2536.9	71.2							
A Shale	2536.9	2559.45	22.6							
Velkerri Total	2196.6	2559.45	230.5							

Table 8. Summary statistics for gas bearing zones in the Velkerri Formation at Amungee NW-1. Total porosity (PHIT), effective porosity (PHIE), total organic content (TOC), clay volume (VCLAY), quartz volume (VOL_QTZ), total water saturation (SWT), total volume of free gas (VOL_UGAS). All properties are listed as a percentage of the total rock bulk volume (%BV), except for total water saturation, which is reported as a percentage of total pore volume (%PV).

4 Discovery Evaluation

4.1 Results of all assessments of the discovery

The results of the assessments of the discovery (pool size, OGIP, OGIP concentration, and technically recoverable resource) are presented in sections 3.4, 4.2, and 4.4.

4.2 Preliminary estimate of the quantity of petroleum in the petroleum pool

	P90	P50	P10
Pool OGIP (TCF)	434	601	841
Pool OGIP within Beetaloo JV Permits (EP76, 98, 117) (TCF)	360	496	692
OGIP Concentration (BCF/km^2)	22	31	43

Table 9. Summary of the preliminary estimate of the quantity of petroleum in the petroleum pool. Estimated P90-P50-P10 OGIP (TCF) for the pool and pool within the Beetaloo JV permits (EP76, EP98, and EP117) and OGIP Concentration (BCF/km^2) range.

4.3 Data used to estimate the quantity of petroleum in the petroleum pool

A summary of data used to estimate the quantity of gas in place in the hydrocarbon pool is presented below:

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Table 10. Summary of the data used to estimate the quantity of gas in place in the hydrocarbon pool.

4.4 Preliminary estimate of the recoverable petroleum in the petroleum pool

The Amungee NW-1H flow and build-up data provides insight as to the achievable recovery factor of a well within its stimulated rock volume (SRV) within the pool. Given the low system permeability of the pool the working assumption is that a well can only reasonably drain the gas in place within the SRV. Origin's rate transient analysis (RTA) work completed to date underpins the preliminary SRV recovery factor range of 30-50%. Origin have yet to collect sufficient build-up data to complete a pressure transient analysis (PTA) to confirm and/or to refine the RTA.

Even though a single well, such as Amungee NW-1H or an area within the pool may have a recovery factor as high as 30-50% it is unlikely that the aggregate recovery factor of the pool will be this high. Understanding of the factors that control deliverability and recovery factor as well as their spatial variation within the Pool are in there infancy. To conduct a robust quantitative assessment of the aggregated estimated recoverable resource of the pool that can handle these complexities will require a statistically significant number of wells testing the pool. As there is only a single production test within the pool Origin has decided upon a qualitative assessment approach instead to estimate the technically recoverable resource[1].

[1] *"Technically recoverable" resources are those that are producible using current technology without reference to the economic viability thereof.*

The factors that were considered in the qualitative assessment of technically recoverable hydrocarbon resource in the pool were the SRV recovery factor range, the subsurface utilization factor range, and surface utilization factor range.

The SRV recovery factor range was developed using a tri-linear analytical model that was populated and constrained with the Amungee NW-1H RTA data, regional core and petrophysical data.

The subsurface utilization factor range was developed considering subsurface features that would prevent the successful application of horizontal drilling or HFS. Consideration was given to geohazards (e.g. dolerite sills), proximity to structural elements, and stress regime.

The surface utilization factor range took into consideration areas that are challenging to develop from a surface topography perspective or areas that sit on nature reserves and freehold land.

Factor	P90-P50-P10 (%)
SRV recovery factor range	15 – 30 - 45
Subsurface utilization factor range	42 – 69 - 89
Surface utilization factor range	78 - 90 - 97
Combined recovery/utilization factor	6 - 16 - 30

Table 11. Recovery and utilization factors considered in determining the technically recoverable resource.

The combined recovery/utilization factor range was applied stochastically to the OGIP range (See section 4.2). The P90-P50-P10 technically recoverable resource for the petroleum pool and pool within the Beetaloo JV permits is summarized in Table 12.

	P90	P50	P10
Pool technically recoverable resource (TCF)	37	103	197
Pool technically recoverable resource within Beetaloo JV Permits (EP76, 98, 117) (TCF)	30	85	163

Table 12. Summary of the preliminary P90-P50-P10 estimate of the technically recoverable resource in the petroleum pool and pool within the Beetaloo JV permits (EP76, EP98, and EP117).

4.5 Contingent Resources

The preliminary estimate of technically recoverable resources, reported in Section 4.4, is not a resource category defined by the Petroleum Resources Management System (PRMS). To comply with Australian Stock Exchange (ASX) Origin was required to prepare PRMS compliant resource estimates. The scope of Contingent Resources is different than the work required to comply with the requirements of the Discovery Report.

4.5.1 Contingent Resources Summary

- The Velkerri B-Shale discovery meets the Petroleum Resources Management System (PRMS) discovery status
- The **Project Maturity** of the Contingent Resources is classified as **Development Unclarified** and **Development On Hold,** as per PRMS definitions, due to technical and regulatory contingencies respectively
- The **Economic Status** of the Contingent Resources is **Undetermined** as per PRMS definitions
- The resource can be recovered by applying current technology
- Additional appraisal programs are to be drilled if the regulatory contingencies are removes in order to test the technical contingencies and to better assess the economic status of the Contingent Resources

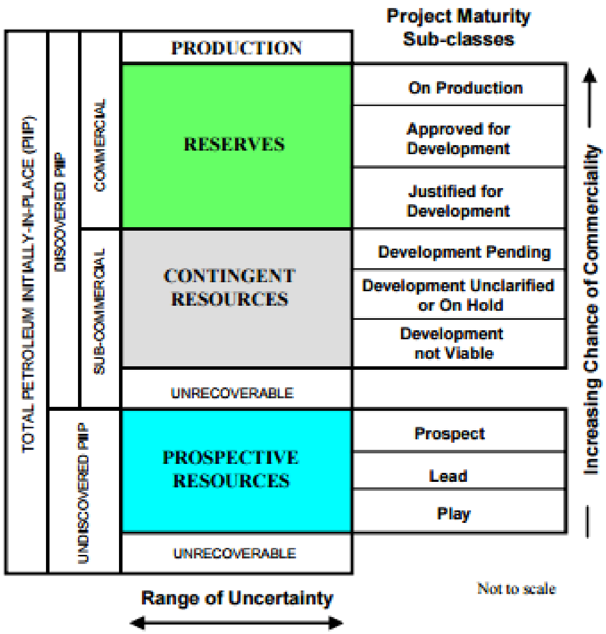

Table 13. PRMS Reserves and Resources classifications

4.5.2 Discovery Status

The data collected from the Velkerri B Shale Pool meets the determination of discovery threshold as per both the PRMS and the NT Petroleum Act. The discovery status of the Pool allows Origin to prepare Contingent Resource Estimates for the Pool in accordance to PRMS. The key points that support the discovery are:

- The successful well test at Amungee NW-1H which produced enough gas to surface to be of commercial interest.

- Core and log data from Amungee NW-1H, Beetaloo W-1, Kalala SW-1, Tanumbirini-1, McManus-1, Altree-2 and Walton-2 provide convincing evidence of a significant volume of moveable hydrocarbons
- The Marcellus and Barnett are the closest commercially-productive analogue with sufficient similarity to the Velkerri B Shale reservoir to conclude that it should be able to produce gas at comparable rates and recoveries

In addition the JV has successfully collected the majority of the data needed to fully characterize a shale gas reservoir as outlined in the Guidelines for Application of the PRMS (see Table 13). This further supports the decision that the discovered recoverable quantities are classified as Contingent Resources.

Table 14: Data Obtained to Characterise the Velkerri B Shale Gas Reservoir

Data	Usage	Acquired	Comments
TOC	Provides an indication of source-rock richness and sorption capacity.	Yes	Data from Amungee NW-1, Kalala S-1, Beetaloo W-1, Tanumbirini -1, McManus-1, Altree-2, Walton-2
Gas content	Includes the volumes of desorbed, lost, and residual gas obtained from the desorption of core. It is an indicator of the in-situ sorbed gas content.	Yes	Data from Kalala S-1
Sorption isotherm	A relationship, at constant temperature, describing the volume of gas that can be sorbed to a shale as a function of pressure.	Yes	Data from Amungee NW-1, Kalala S-1
Gas composition	Used to quantify the percentage of methane, carbon dioxide, nitrogen, ethane, etc. in the desorbed gas. Used to build composite sorption isotherms.	Yes	Data from Amungee NW-1, Amungee NW-1H, Kalala S-1, Beetaloo W-1
Rock-eval pyrolysis	Assesses the petroleum-generative potential and thermal maturity of organic matter in a shale sample.	Yes	Data from Amungee NW-1, Kalala S-1, Beetaloo W-1, McManus-1, Altree-2, Walton-2
Mineralogical analyses	Determines bulk and clay mineralogy using petrography, X-ray diffraction, scanning electron microscopy, and similar techniques.	Yes	Data from Amungee NW-1, Kalala S-1, Beetaloo W-1, McManus-1, Altree-2, Walton-2
Vitrinite reflectance	A value indicating the amount of incident light reflected by the vitrinite maceral. It is a fast and inexpensive means of determining thermal maturity.	Yes	Data from Amungee NW-1, Kalala S-1, Beetaloo W-1, McManus-1, Altree-2, Walton-2
Core description	Visually captures lithology, bedding, fracturing, grain size	Yes	Data from Amungee NW-1, Kalala S-1,

	variations, etc.		Beetaloo W-1, Tanumbirini -1, McManus-1, Altree-2, Walton-2
3D seismic	Used to determine interwell shale properties including lateral extent, thickness, faulting, and those areas with higher gas saturation and brittleness.	No	2D seismic coverage over the majority of the pool
Kerogen types	Used to assess whether rocKalala S are Type I (oil-prone), II (mixed), or III (coal).	Yes	Data from Amungee NW-1, Kalala S-1, Beetaloo W-1, McManus-1, Altree-2, Walton-2
Routine core analysis	Includes total porosity, fluid saturations, bulk density, and matrix permeability (via pressure pulse testing on crushed samples).	Yes	Data from Amungee NW-1, Kalala S-1, Beetaloo W-1, McManus-1, Altree-2, Walton-2
Conventional logs	SP, GR, resistivity, microlog, caliper, density, neutron, sonic, and temperature logs are run to provide thickness, porosity, matrix, and sorbed gas saturations.	Yes	Data from Amungee NW-1, Kalala S-1, Beetaloo W-1, Tanumbirini -1, McManus-1, Altree-2, Walton-2
Special logs	May include image logs (fractures), NMR logs (free water, bound water, gas saturation), pulsed neutron and geochemical tools (mineralogy), dipole sonic (geomechanical properties), spectral GR (clay types), etc.	Yes	Data from Amungee NW-1, Kalala S-1, Beetaloo W-1, Tanumbirini -1
Pressure transient tests	Pressure buildup or injection fall-off tests to determine static reservoir pressure, permeability, skin factor, and to detect fractured-reservoir behaviour.	Yes	Data from Amungee NW-1H, Kalala S-1
Geomechanical properties	Young's modulus and Poisson's ratio for determining shale brittleness, stress orientations and magnitudes to predict fracture growth.	Yes	Data from Amungee NW-1, Kalala S-1, Beetaloo W-1
Microseismic	Used to assess hydraulic fracture geometries and stimulated reservoir volumes.	No	
Fracture diagnostics	Treating pressures, closure stress, pumped volumes, flowback volumes, etc. to determine the quality of a fracture stimulation.	Yes	Data from Amungee NW-1, Amungee NW-1H, Kalala S-1
Gas, water rates	Captured daily (preferably) to assess individual well behaviour.	Yes	Data from Amungee NW-1H
Bottomhole pressures	Preferably recorded in closely-spaced increments early in well life; can also use surface pressures with wellbore-fluid	To be collected	Data from Amungee NW-1H

	gradients.		
Tracer surveys	Chemical or radioactive tracers to assess which fracture stages are contributing.	No	
Facilities	Variations in line pressure, etc., that affect producing well rates.	Yes	Data from Amungee NW-1H
Rate-transient analysis	Decline analysis tool that analyses production rates and pressures using various methods to assess EUR, GIP, drainage area, etc.	Yes	Data from Amungee NW-1H
Numerical modelling	Helpful in understanding reservoir mechanisms, predicting early well behaviour, and estimating EURs and recovery factors.	Yes	Data from Amungee NW-1H
Decline-curve analysis	Traditionally used to forecast well performance. More reliable later in well life (after a few years) due to uncertainties regarding b-factor values.	Yes	Data from Amungee NW-1H
Analogues	May be useful to estimate EURs and recovery factors if a strong correlation exists between key reservoir parameters of subject and analogue reservoir.	Yes	Key static reservoir parameters are analogous Marcellus and Barnett

4.5.3 Project Maturity

The **Project Maturity** of the Contingent Resources is classified as **Development Unclarified** and **Development On Hold,** as per PRMS definitions, due to technical and regulatory contingencies respectively. Key contingencies for commercialising the estimated resource include the lifting of the Northern Territory moratorium on hydraulic fracture stimulation, establishing longer-term deliverability, reducing well costs with scale of activity, establishing gas sales agreements and building infrastructure to connect the resource to market. Contingent on the moratorium on HFS being lifted, additional appraisal wells are planned (as per the Work Program) to be drilled, HFS, and tested to assess deliverability and move the project towards commercialisation.

4.5.4 Economic Status

The **Economic Status** of the Contingent Resources is classified as **Economic Status Undetermined** as per PRMS guidelines. The Contingent Resources will continue to be assessed as additional appraisal wells are drilled and tested in order to better evaluate the commercial potential of the play. After a sufficient number of wells have been drilled to demonstrate that the project is technically feasible and a development plan has been generated, economics can be run to determine whether the project should be placed in the marginal or submarginal Contingent Resources category as per the PRMS guidelines.

4.5.5 Assessment of Technology Required to Develop the Resources

The Velkerri B Shale Pool can be developed using existing technology. Both horizontal drilling and hydraulic fracture stimulation have been demonstrated to be commercially viable in analogous reservoirs.

4.5.6 Contingent Resource Estimates

Assessment of 2C Contingent Gas Resource Estimates for the Velkerri B Shale Pool within EP76, EP98, and EP117 as of 14 February 2017[1]		
Measured and Estimated Parameters	**Units**	**Best Estimate**
Area[2]	km^2	1,968
Original Gas In Place (OGIP)[3] (Gross)	TCF[6]	61.0
Contingent Resource[4] (Gross)	TCF	6.6
Contingent Resource[4] (Net)[5]	TCF	2.3

[1] Contingent Resource Estimates have been prepared on a statistical aggregation basis and in accordance with the Society of Petroleum Engineers Petroleum Resources Management System (SPE-PRMS). Contingent Resource Estimates are those quantities of gas (produced gas minus carbon dioxide and inert gasses) that are potentially recoverable from known accumulations but which are not yet considered commercially recoverable due to the need for additional delineation drilling, further validation of deliverability and original gas in place, and confirmation of prices and development costs.

[2] P50 area from the Contingent Resource area distribution

[3] OGIP presented is the product of the P50 Area by the P50 OGIP per km^2

[4] Estimated Gas Contingent Resource category of **2C**

[5] Net to Origin's 35% interest in EP76, EP98, and EP117

[6] TCF: trillion cubic feet

Table 15. 2C Contingent Resource Estimates

5 Plans for Further Evaluation

Origin plan to continue monitoring the pressure build-up at Amungee NW-1H. The PTA data will help to support and refine the RTA as well as to provide a robust assessment of the initial reservoir pressure of the pool.

No additional drilling, stimulation, or testing activities are planned within the next 12 months from the date of the report due to the introduction of a Moratorium on Hydraulic Fracturing of Unconventional Reservoirs Onshore by the Government of the Northern Territory on 14 September 2016.

If the current moratorium is altered or lifted to allow HFS activity Origin will be able to resume the work commitment obligations for Permit Years 3, 4, and 5. This currently requires one vertical well and one vertical well HFS in EP98 to complete Permit Year 3, and two horizontal HFS wells in each of Permit Years 4 and 5 (in EP117 and EP98 respectively); although it should be noted that Origin has submitted a variation request to the DPIR with respect to the remaining Permit Year 3 commitments. In the near term Origin plans to progress a production retention license application for Amungee NW-1H.

6 Conclusion

This report has provided preliminary estimates to the areal size, OGIP, and technically recoverable resources within the pool. The preliminary estimates provide insight into the potential size and materiality of the resource. The work to date has confirmed that the pool is a regionally extensive SRR play crossing multiple permits. The P50 OGIP and P50 technically recoverable resource are 601 TCF and 103 TCF respectively. Additional wells and well tests will be required to refine the pool size and better assess the recoverable resource range and, ultimately the commerciality of the play.

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