EVOLVING EXPLORATION METHODS IN THE HYDROCARBON PLAY WITHIN THE PATCHAWARRA FORMATION ON THE WESTERN FLANK, COOPER BASIN

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SUMMARY

The hydrocarbon play in the Patchawarra Formation lies within a Permian age, high latitude, fluvial sand and coal measure system that is up to 300m thick in the Cooper Basin of Central Australia. Fluvial channel belt sands, ranging from 1 to 20m thick, form a conventional reservoir. Seal and source play components are in the inter-bedded overbank, silts, clays and coal seams. The low seismic reflectivity sands combined with the numerous, high seismic reflectivity coals makes standard seismic interpretation difficult. These factors combined with the thin, irregular geometry of the reservoir, make exploring for hydrocarbon traps challenging.
The largest fields in the Western Flank, discovered to date, are considered to have a stratigraphic trap component that is combined with a structural influence. Each field has a single main pay zone located in a different clastic package compared to the other fields in the play.
An evolving exploration method is reviewed that uses the coals as local timelines with trap limits defined using structural and stratigraphic indications from the seismic. This method combined with ideas of source and trap has recently proved successful in extending the play.
Examples of some of the hydrocarbon traps and concepts are shown that may help with evolving ideas and future exploration methods in this basin and other basins with similar fluvial plays.

Key words: Fluvial, Permian, Trap, Exploration, Seismic

INTRODUCTION

The Patchawarra Trough, located in the western portion of the Cooper Basin, contains gas in sandstones of the Permian aged Patchawarra Formation. Historically, structural closures were targeted for exploration but with most significant structural closures already drilled, exploration efforts are focused on stratigraphic traps within the Patchawarra Formation. Within the Beach Energy operated acreage, 12 Patchawarra Formation gas fields have been discovered (January 2006 – February 2017). The wells in discovery order are Udacha-1, Middleton-1, Brownlow-1, Canunda-1, Admella-1, Haslam-1, Coolawang-1, Canunda-2, Ralgnal-1, Canunda-3, Crockery-1 and Mokami-1 (Figures 1 & 2). Structural relief on these gas traps is subtle with all the largest having produced volumes exceeding traditional 4-way dip closures. The reservoir is not directly resolvable on the 3D seismic and gas –water contacts are rarely intersected in the wells. A workflow involving various geophysical techniques integrated with geology and engineering, has been implemented to locate wells, define the likely trap limits and estimate Original Gas In-Place (OGIP) ranges. Beach reservoir engineers independently assess OGIP using pressure decline and production data and this is taken to be definitive. Historically, it was difficult to define the limits of traps containing fluvial channel belts with sufficient confidence to assign a range of OGIP. The techniques discussed here have now derived OGIP ranges more aligned with those from reservoir engineering.
The seismic stratigraphy and reflectivity issues of the Patchawarra Formation were outlined previously (Webb2015) and the workflow and interpretation method outlined here continues to expand on that work. The method uses newly available reprocessed data (bandwidth extended and higher frequency) combined with seismic package mapping, a new wavelet tracked horizon dataset and seismic stratigraphy image visualization techniques. Concepts on mapping geometry and some hydrocarbon play ideas will be reviewed. There is potential to apply the same workflow to other areas within the Patchawarra Trough, particularly those areas that have not benefited from recent 3D seismic acquisition and processing.

BACKGROUND CONCEPTS, METHOD AND RESULTS

Source, Migration, Seal and Structural elements of the Play

Understanding the elements of the Patchawarra stratigraphic play is essential for future exploration.

Source & Migration: The coals and carbonaceous shales within the Patchawarra Formation are the dominant source rock for the Cooper Basin oil and gas fields. While the play area is likely to be within the gas generation window, there is also the possibility for medium to long distance lateral migration through the Patchawarra Formation via connected channel belt sandstones.

Seal: Top, base and lateral seal for the sandstone reservoirs are provided by intra-formational shales and siltstones. Thin shales provide competent seals at the field scale, but also within channel belts where distinct sand bodies can become isolated; as observed in the Canunda channel belt (Figure 3).

Structure: On the Western Flank, it is possible to divide the Permian to Triassic age interval into at least two tectonostratigraphic sequences. The Base Jurassic Unconformity to Vs45 marker (Sequence I), and the Vs45 to Base Cooper Basin Unconformity (Sequence II). Sequence II is of most interest; it is complex with disrupted syn-sedimentary channelling and topographic scarps combined with zones of reactivated faults and propagation folds. This complexity offers a favourable combination of syn-sedimentary accommodation space, seal, source and trap interplay to create the trapped hydrocarbon pools in the Patchawarra stratigraphic play. The Patchawarra stratigraphic traps have, to date, been found in this unit. Sub-regional sections will illustrate the key elements.

Reservoir: The reservoir is comprised of sands within channel belts and splays. We use the term channel belt sands as a term to cover all potential reservoir sand facies. Such facies include as examples commonly used in literature; point bar sands, splay sands, channel floor sands, lateral and downstream accretionary sands. The connectivity of these channel belt sands is variable, with the larger accumulations associated with greater connectivity. It is not yet possible to resolve the sand bodies directly from the seismic data. As such we outline techniques in this paper that allow us to infer and interpret sand presence. In the best quality sands, porosities can range up to 20% with permeability in excess of 100 millidarcy.

Seismic data

The Beach Energy operated area of interest (Figure 1) is covered by the IRUS 3D seismic cube that was reprocessed in 2016 using post stack bandwidth extension. A seismic processing company, used a proprietary technique called Spectral Broadening by Local Attributes (SBLA™). The high frequency portion in addition to some low frequency data has been boosted (method outline in Smith et al 2008). Prior to the reprocessing, Pre-Stack Time Migrated (PSTM) data was used for interpretation. The PSTM data was a result of a merge completed in 2014 of four original 3D surveys; Irus (2012), Spinel (2007), Neritus (2006) and Raven-Moonanga (2002).

The bandwidth extended reprocessed data has enabled a more detailed interpretation with finer scale picking of seismic character and has generated more concepts of trapping geometries than could be done on the original lower frequency data. Unconformities, faults and syn-deposition scarp geometries are sharper and hence easier to interpret. Although the SBLA reprocessed data is pushing the limits of expected frequency content, the identification of geological patterns and features from interpreted events in map view gives confidence to the data (figures 3 & 5). Some example seismic lines illustrating the type of features being interpreted are shown in figures 4 and 6. Seismic data is considered to be near zero phase with the display convention being a black peak is a soft acoustic impedance.

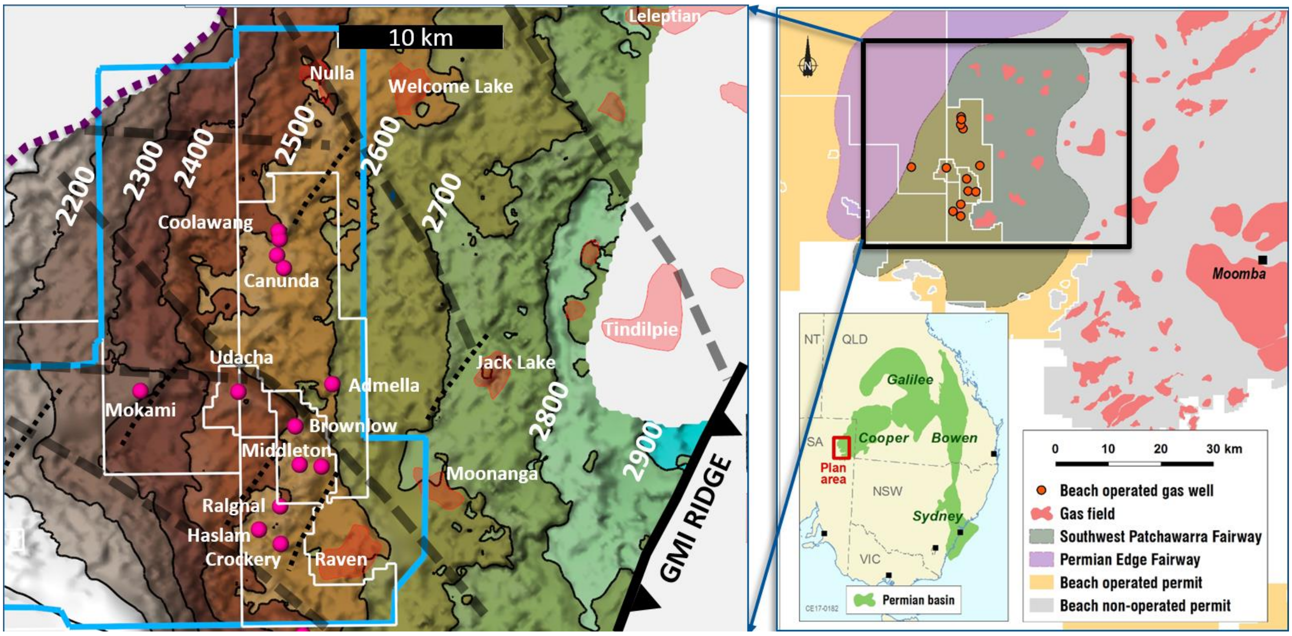

Figure 1: The map on the left is an Intra-Patchawarra (Vs45 seismic sequence coal marker) depth structure map in metres from interpretation of relevant 3D seismic on the western flank of the Patchawarra Trough. The thick grey dashed lines trending Northwest to West are considered to be expressions of associated major transpression faults. There are also associated subtle Northeast trending fault expressions (dotted) some of which are shown here. All these are thought to have been reactivated at different times throughout the Permian and influenced Permian channel belts. The colour bands in contour intervals of 100m show the overall structural dip to the Southeast and East. The purple dotted line in the Northwest marks the truncation of the Vs45 sequence coal marker below the Base Jurassic unconformity. The Beach Energy operated gas discoveries are red dots and other gas field outlines are shown as pale red polygons (Source: state government - DSD). The IRUS 3D seismic survey is outlined as the blue polygon (area of interest). The right map shows the location of the area reviewed within the main Permian gas plays.

Seismic Interpretation and picking

A specialist contractor was commissioned to compute pre-interpretation horizons of the entire IRUS 3D reprocessed seismic volume. The method uses a proprietary wavelet shape tracking algorithm to automatically generate picks and horizons on all trackable wavelets greater than 200m^2 in areal extent (Reference Ford et al (2015). The additional horizons generated from this processing are unbiased by interpreter input, and are useful as additional control on our main seismic sequence picks. The 3D realisation of the many surfaces and attributes generated provided additional interpretation of depositional patterns and seismic character changes, particularly when integrating and merging data within and between other sequences.

The ability to correlate coals between wells varies depending on scale and distances. At a seismic scale resolution, the coals correlate over a prospect/discovery area. Coals that tend to be thicker (e.g. Vs50) correlate over a larger sub-regional area on the seismic scale. The coals are low acoustic impedance in comparison to the adjacent clastic packages, and so are tied to the main 'soft' seismic events. The seismic hard events (high acoustic impedance) are taken to be more representative, at a seismic scale, of the clastic dominated intervals (sands, silts and shales), albeit not directly to any particular facies.

The evolving workflow used for exploration and definition of Patchawarra stratigraphic traps is built around the following steps:

- Interpretation of the major coal horizons using bandwidth extended, higher frequency 3D seismic data.
- Pre-interpretation processed auto-track picks that are then merged with interpreters' event mapping.
- Package mapping (seismic character/attributes).
- Time thickness (isochron) maps.
- The various data types are integrated with available well control to define trap geometries
- Finally, integration of depositional models, structural influence, migration concepts, and reservoir engineering data create drillable prospects.

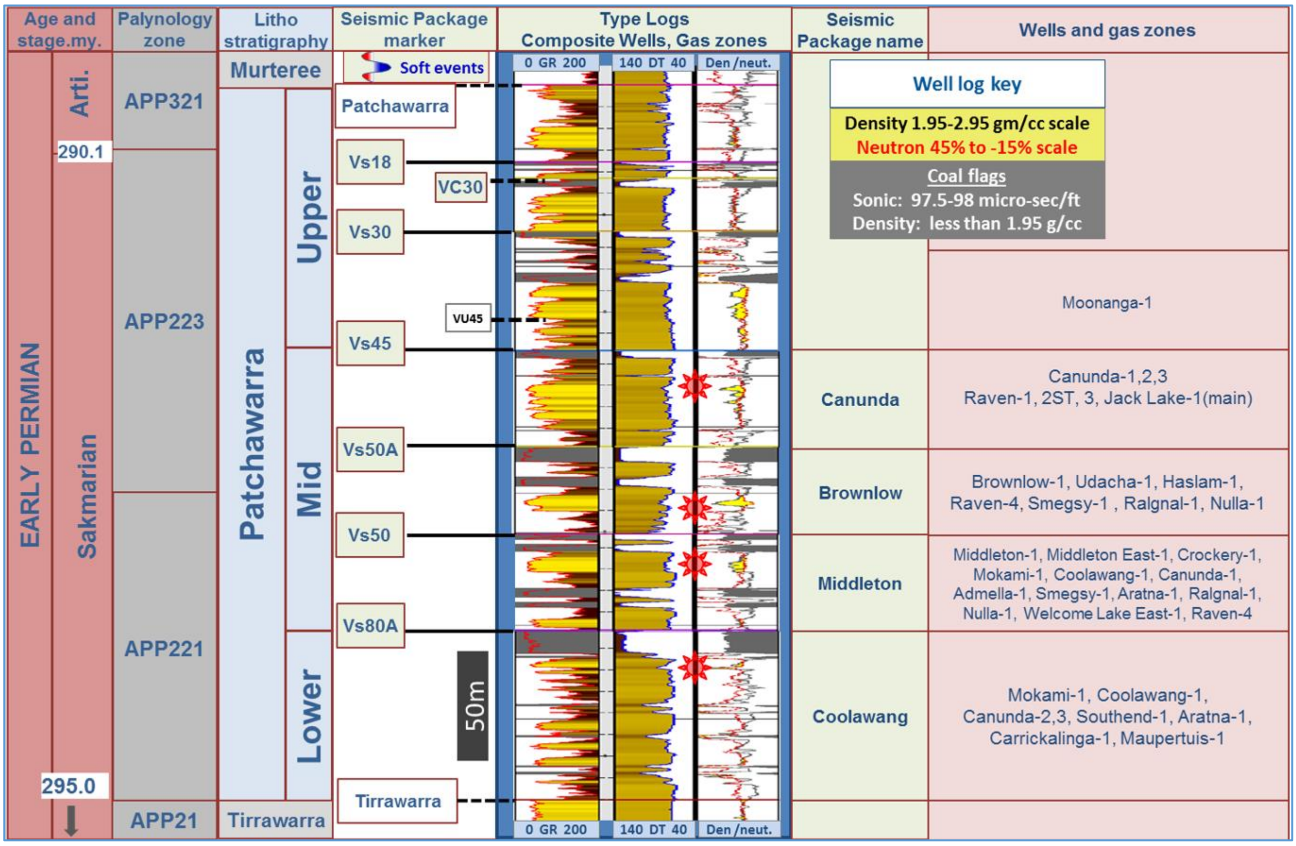

Figure 2: **The panel shows the seismic stratigraphy labels used for the Patchawarra Formation. The markers indicated as seismic package markers are interpreted sub-regionally and often characterised by a coal of varying thickness. The name of the seismic package is derived from the first exploration well that discovered gas within that particular interval. Nomenclature is informal and specific to Beach Energy workflows.**

Gas Traps and Channel Sands

Several examples will be shown illustrating the aspects that have been found useful to define features and well locations.

Canunda-3: The Canunda-3 gas accumulation was discovered in 2016. Pre-drill, the well was considered to be an up-dip appraisal of the gas pool intersected by both Canunda-1 & Canunda-2 (Figure 3). The prospect was identified on both the original PSTM volume and the reprocessed bandwidth extended IRUS 3D seismic data. The channel sands in the Canunda seismic package were the primary target of the well. The channel belt identified on the seismic had a high probability of a containing a sand body; this was based on interpretation of package geometry suggesting the presence of a compaction mound (Figure 4). The isochron map (Figure 3) supports the interpretation of a channel belt system in the Canunda area. The well intersected a channel belt sand as predicted. However, pressure data indicated the discovered gas volume to be an additional resource in a separate liquid rich gas pool within the Canunda channel belt package. The result highlights the capacity for intra-formational shales to act as seals even within the channel belts.

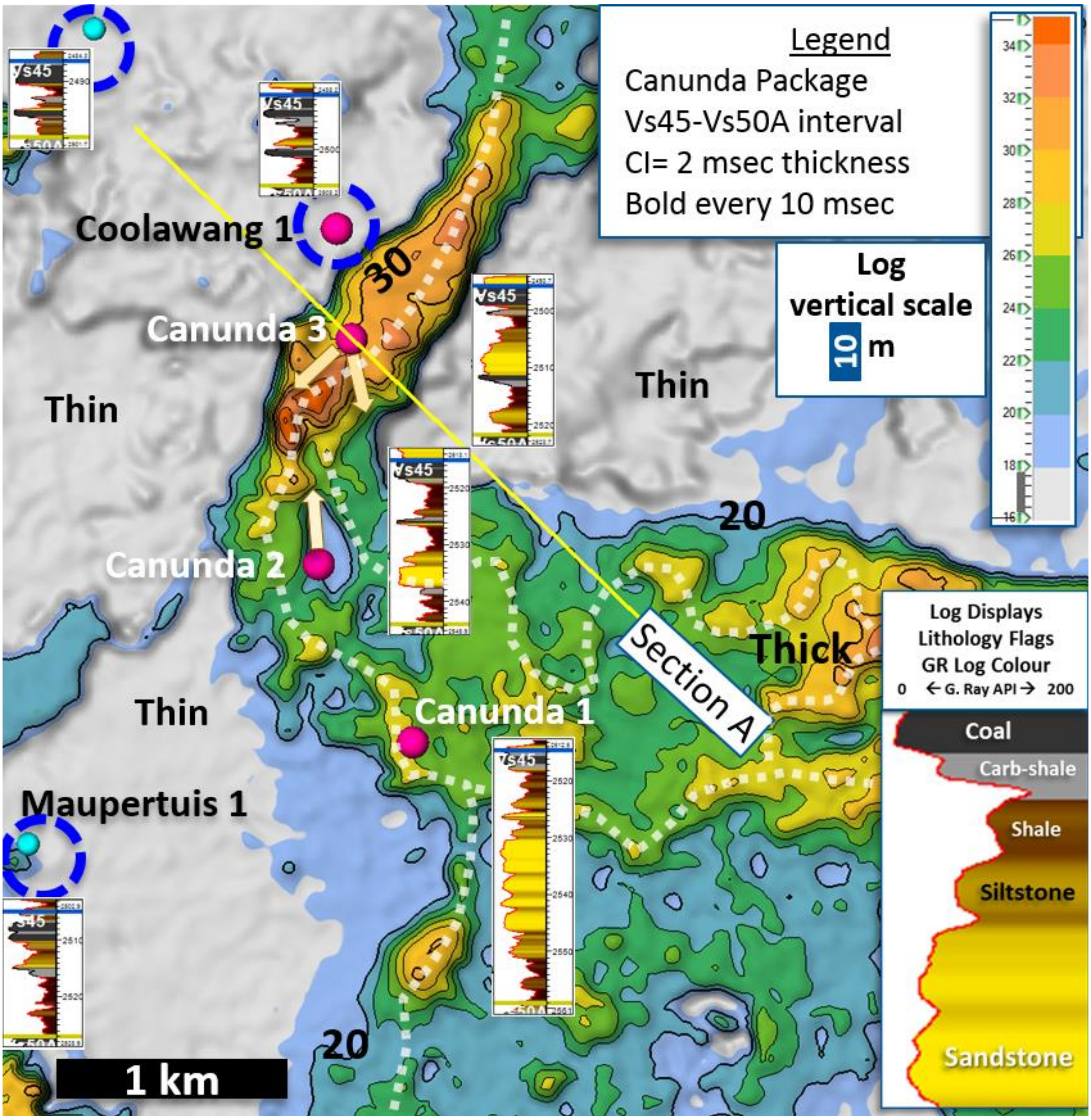

Figure 3: Canunda Package time thickness (Isochron) map with section position indicted by yellow line. Beach Energy operated gas wells shown as red dots. Pressure data show that Canunda-2 & 3 are separate hydrocarbon pools. Wells with no Canunda Package net sand are marked by dashed blue circles. Data available from 2 wells indicate contrasting current flow directions (pale yellow arrows North and South/Southwest); this is not surprising given the fluvial environment. The top surface form and isochron geometry can be interpreted to be a combination of differential compaction over clastic bodies, depositional scarps, syn-sedimentary faulting and channelling. The geometry is reminiscent of channel belt models as shown in reference Donselaar and Overeem (2009) and as modified in Webb (2015). Well gamma ray signatures are shown with lithology coded. Dashed white lines are interpreted as some of the sand prone axes in the channel belt.

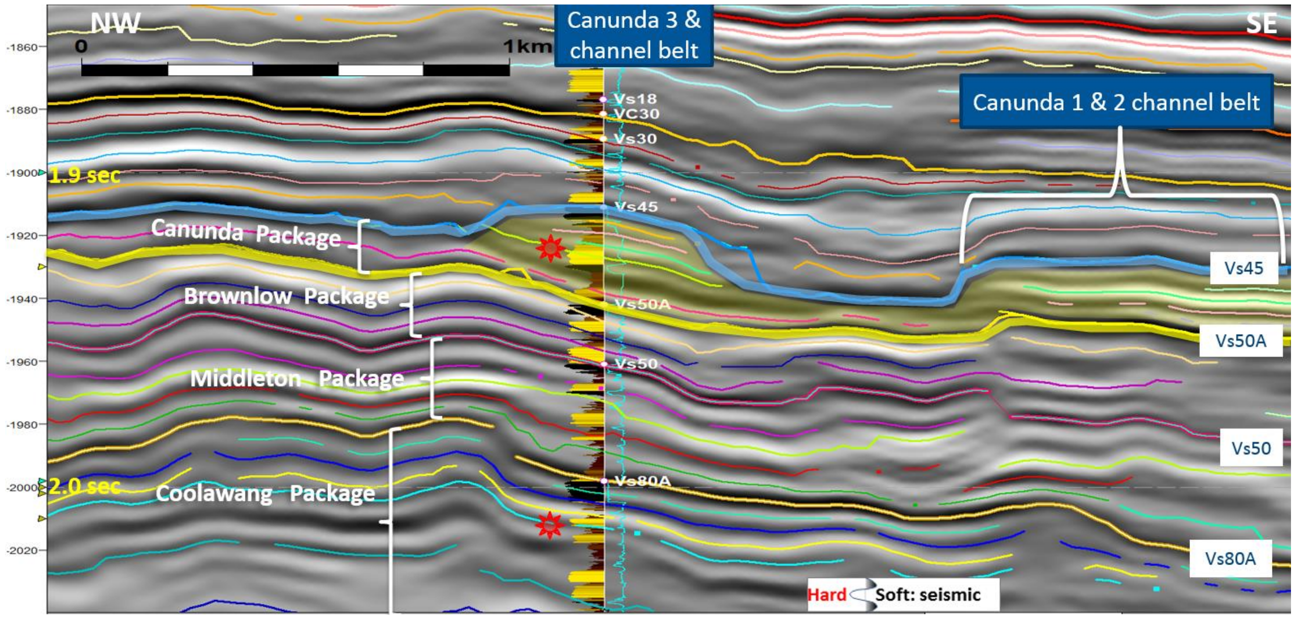

Figure 4: 3D seismic line (Section A) across the Canunda 3 gas well. Gas zones flagged by red stars and named seismic stratigraphic packages labelled and bracketed. The Canunda package channel belt contains a liquids rich gas sand at Canunda 3. The seismic sequence markers as bold labelled thick lines at Vs45 (blue) and Vs50A (yellow). The well path right trace is log acoustic impedance (pale blue) and a deflection to the left is low acoustic impedance and coincides with a black peak on the seismic. The seismic character is a convex top reflector (Vs45), concave to flat base reflector (Vs50A). Similar seismic characteristics are seen in other areas of the channel belt at Canunda 1 and 2 containing different channel sands. The thinner coloured lines are seismic picks generated using auto-tracking of the wavelet shape.

Brownlow-1: Brownlow-1 was drilled in 2008, on an early 3D seismic survey (Spinel 3D PSTM) and intersected a high quality thin gas sand in the Brownlow Package (Vs50A). Subsequent pressure analysis and production data suggest an elongate geometry of unknown orientation and a connected resource that forms 2nd largest accumulation (OGIP) in the Beach Energy operated area.

Udacha-1: (2006): The trap was identified on 2D seismic data as a small faulted 4-way dip closure. The well found a thin splay gas sand within the Brownlow package (Vs50A), but in a separate pressure regime and comprising slightly different fluid characteristics to Brownlow-1.

Ralgnal-1: Ralgnal-1 was drilled in 2015, and was identified on both the original PSTM and the reprocessed bandwidth extended IRUS 3D seismic data. The well discovered separate gas sands in each of the Brownlow (Vs50A) and Middleton (Vs50) packages. The well has been on production since mid-2016 and early pressure data from the Middleton package sand suggests that it is the 3rd largest accumulation (OGIP) in the Beach Energy operated area. The pressure analysis and mapping data indicate a complex stratigraphic trap that suggest an initial weak pressure connection to the Middleton-1 gas accumulation.

Crockery-1: Crockery-1 was drilled in 2017, and targeted a similar feature to that drilled by Ralgnal-1. The prospect was interpreted to be as part of the complex seismic zone seen extending towards Middleton East-1 and Middleton-1. One main pay zone of 7.2m net sand was intersected in the Middleton (Vs50) package. The well will be on production test in 2018. Pressure data from wireline pressure tests (MDT) is similar to that seen at Ralgnal-1 and suggests that there may be a poor connection to Middleton-1.

Middleton-1: Originally drilled on 2D seismic in 2006, Middleton-1 was located on a small faulted 4-way dip closure. One main pay zone of 7m net sand was intersected in the Middleton (Vs50) package. Subsequent pressure analysis and production data indicates an elongate reservoir geometry of unknown orientation and a connected resource that forms the largest accumulation in this Beach Energy operated area. Recent mapping using the described workflow has enabled a more refined description of the trap and estimated OGIP of the field (Figure 5). The trap is defined in the up dip (North and West) direction by breaks/changes in seismic character (Figure 6), and dip closed to the East. In 2016 Middleton East-1 were drilled on the PSTM 3D data and intersected a gas bearing sand (6.5m net sand thickness) in the Middleton Package. A gas-water contact was not drilled in this well or Middleton-1. The initial reservoir pressure matched that expected from pressure depletion consistent with the production from the Middleton-1 gas accumulation. However, subsequent pressure monitoring suggest the connection model is possibly via a complex low permeability zone. The lack of a direct linear connection is supported by the event seismic mapping (Figure 5).

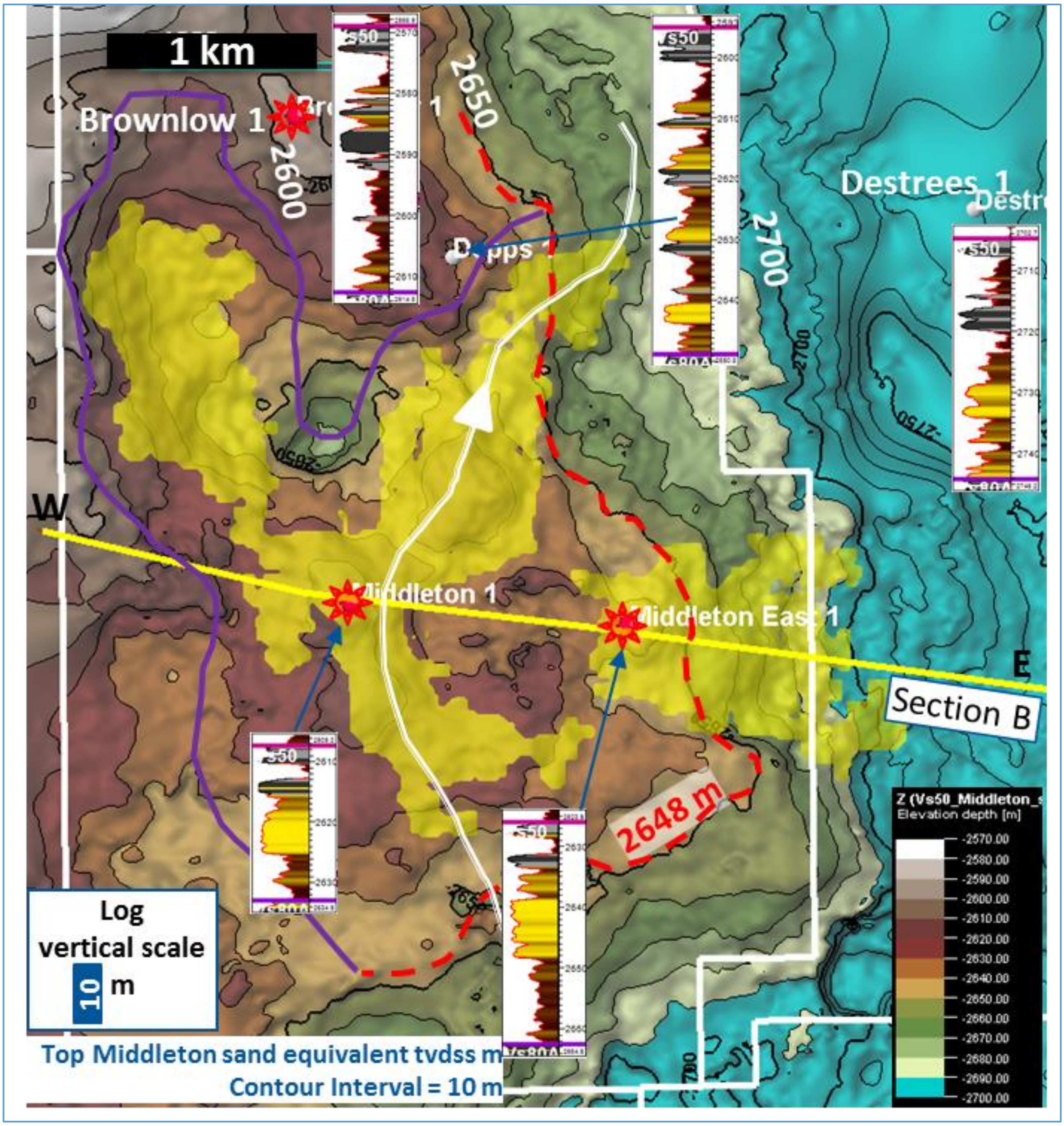

Figure 5: Middleton-1 Top sand depth structure map: The transparent yellow surface is the map view of the marker event (shown in Figure 6). This marker event is draped on the depth map. This event is interpreted to be the core of the Middleton Package channel belt. The purple polygon is the possible extent of the channel belt in the immediate area as defined by the interpreter. The interpretation is a channel belt trending North to South (white line), with the up-dip seal provided by the termination of the channel belt towards the West. Gas down-to (GDT at 2648 mSS) is marked by the dashed red line in the East. The area defined by the purple and red lines is approximately 7 km^2 and the resource volume derived from a slab model coincides with the range estimated from reservoir engineering.

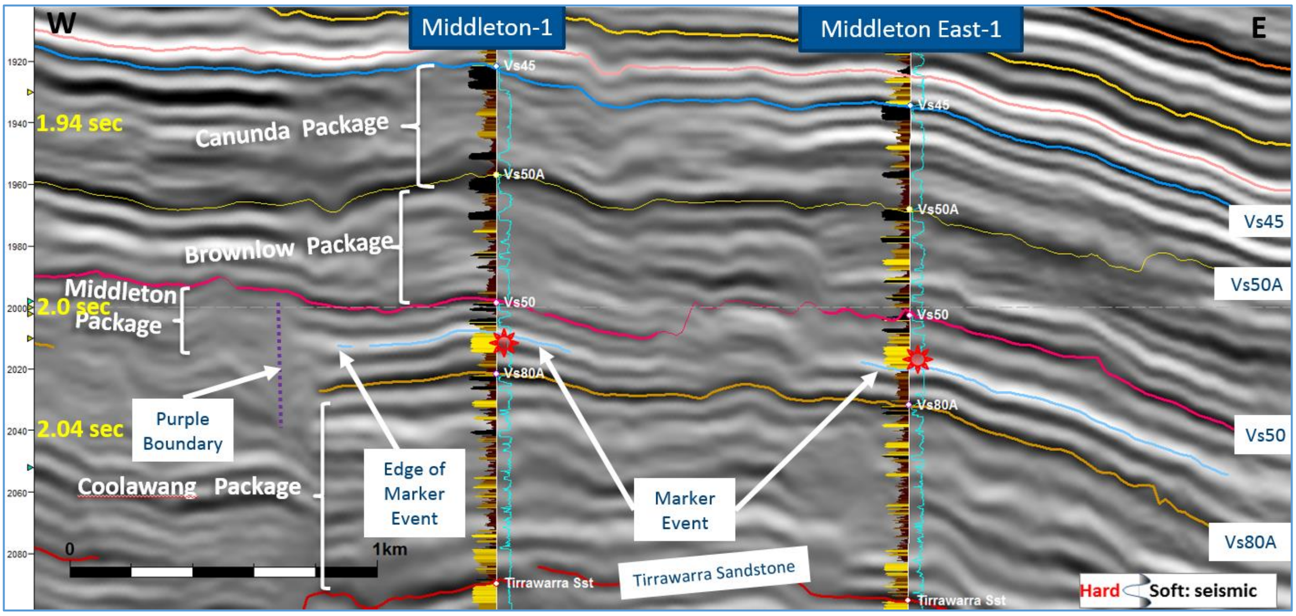

Figure 6: Middleton-1 Discovery: Seismic line (Section B) across Middleton-1 and Middleton East-1. Gas zones flagged by red stars and named seismic stratigraphic packages labelled and bracketed. The well log lithology code is, black for coal and yellow for sands. The 'Marker Event' is a computer generated auto-track horizon, created from a single seed point with minimal interpreter influence (bias). The event reflects what we interpret to be a channel belt. The purple line represents the interpreters' up dip boundary of the channel belt (Figure 5 in plan view). The appearance is more sheet like when compared to the Canunda-3 seismic character.

Mokami-1: Mokami-1 was drilled in 2017 on a low relief 4-way dip structure on the ridge up-dip from Carricakalinga-1 and Udacha-1 gas well. Three liquids rich gas sands were discovered in the Patchawarra Formation, and one gas sand in the Tirrawarra Sandstone. At this early stage, we interpret the Mokami-1 discovery to be structurally trapped.

CONCLUSIONS

The workflow discussed using seismic scale interpretation of sedimentary packages and interpreter controlled auto-track events allows for clearer definition of individual traps and their corresponding range of OGIP. It was not possible to estimate, with confidence, the full resource range on prospect specific features on the original data (PSTM) with standard interpretation methods. The evolving methods outlined together with the new (bandwidth extended) seismic data has improved the identification of traps and estimating the range of volumes pre and post-drill. We continue trialling these methods for all features and have had some early encouragement; undoubtedly there will be revisions to come.

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