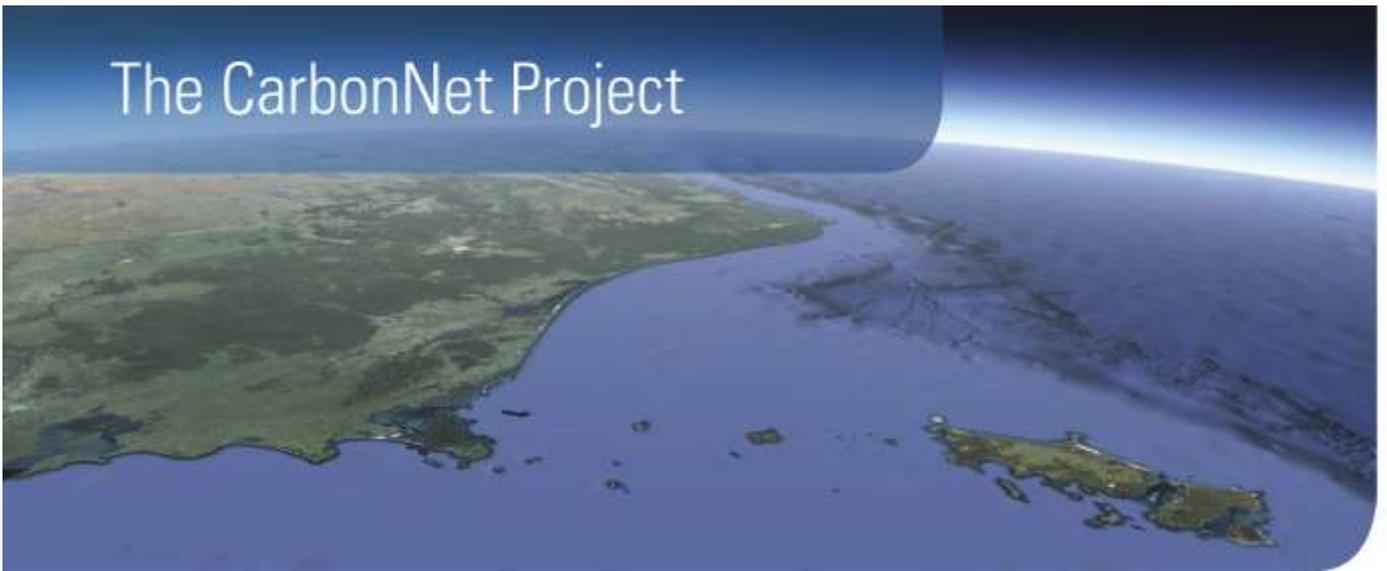


The CarbonNet Project



3D Mapping and correlation of Intraformational seals within the Latrobe Group in the nearshore Gippsland Basin



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Preface

3D Mapping and correlation of Intraformational seals within the Latrobe Group in the nearshore Gippsland Basin

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www.energyandresources.vic.gov.au/carbonnet

2500-character Abstract (2452)

During its assessment of the nearshore Gippsland Basin (within 25 km of the coastline), the CarbonNet project has identified laterally extensive seal units for upper Halibut reservoirs of the offshore Burong Formation. This interval corresponds to the T2 basal zone of the coal seams within the coal-bearing Traralgon Formation, which is widespread within the nearshore region of the Gippsland Basin (both onshore and offshore). These interbedded coals and shales of the Middle Eocene (Lower N. asperus Zone) are expected to provide an effective top seal for fluids injected into the Halibut reservoirs.

Previous hydrocarbon exploration shows that the T2 sequence is the intraformational topseal to several intra-Latrobe oil accumulations in the nearshore area, and that distinct pressure and salinity differences exist across this aquitard. Hence, the T2 represents a sub-regional seal, and is shown to be one of a set of backstepping subregional seals throughout the Bass Strait petroleum province.

A detailed correlation between nearshore and onshore wells has been carried out using existing well and 3D seismic data to define 3D geometry and continuity of the T2 units. Seismic attribute extracts are presented as maps of coal quality and facies demonstrating the aspect ratio and lateral extent of coal depocentres, as well as details of the fluvial inputs, channel geometries, and clastic depocentres.

Seal capacity of these intraformational seals is defined by the actual hydrocarbon columns and also by MICP data which suggest seal potential well in excess of the proven columns. The critical constraints on trap capacity appear to be fault-related, and depend on the time scale. For petroleum, where multi-million year trapping is required in order for oil to be still present today, very efficient trapping is required with essentially no fault permeation. For CO₂ storage over many thousands of years, slow seepage through faults and offset baffles may be acceptable, especially where it leads to additional solution into the active aquifer which is sweeping fluids from onshore to offshore.

Correlation of the T2 sequence and the definition of fairways where there is suitable seal potential is crucial to assess CO₂ storage potential over the next 50 years of Gippsland Basin activity.

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1. Introduction

In this study we approach the issue of intraformational seals in the Gippsland Basin from a variety of perspectives: these include the observations of actual trapped hydrocarbons with some gas columns in excess of 100m, measurements of seal capacity (MICP) from core samples, observations of pressure and salinity differences across key intraformational aquitards (seal units), and full 3D seismic geobody mapping and attribute extraction of seal-related lithologies. We use these observations to interpret the geometry of active seal units and their depositional context within the basin. We will show that a series of backstepping coal sequences are associated with intraformational petroleum traps and aquitards across at least 50 km of basin dip extent, and 20 million years of geologic time. The basal shales and seat earths underlying the freshwater facies of these coals will be shown to have distinctive properties that lead to effective sealing characteristics.

This study is based on depositional geometries and facies interpreted from the extensive open-file 3D seismic data that has been collected in the basin by the Esso-BHP Joint Venture and other operators. Individual and composite coal beds are mapped and fluvial cut-outs are identified. As a result, a detailed 3D basin model is developed which maps fluvial and swamp facies to predict reservoirs and seals at Intra-Latrobe levels, and the lateral connections of these facies to coeval paralic barrier bar systems further to the east at top Latrobe Group. A revised well and seismic correlation of the Traralgon T2 Member in the nearshore Gippsland Basin is presented, and the implications of this correlation discussed.

We then incorporate the results of detailed 1000-year dynamic simulations of injected CO₂ plume movement to model the trapping and migration processes of buoyant fluids. By incorporating an understanding of the active aquifer dynamics in the nearshore, and considering its impact on reservoir hydrocarbons, we establish that this aquifer has actively removed soluble hydrocarbon fractions and biodegraded oils over the past million years or so. We then calculate that the same aquifer dynamics and strong solubility will actively consume and sweep away any dissolved CO₂ over a timeframe of a few hundred thousand years and hence establish the effective timeframes for safe storage of CO₂ at intraformational level, and its ultimate fate as secondary rock-forming minerals.

Intraformational seals are important to study because they aid understanding of the facies of both reservoirs and seals. For CO₂ storage, intraformational seals offer multistorey storage potential in stacked reservoirs which can multiply the storage capacity of existing mapped structures at top Latrobe Group. Intra-Latrobe traps also offer the potential to decouple pressure and fluid effects between petroleum and CCS activities by using different subsections of the stratigraphy and further, the details of imperfect trap retention at intra-Latrobe level can actually assist with long-term dissolution trapping and mineralisation of CO₂ in the nearshore region of the Gippsland Basin.

2. Project background and basin setting

The CarbonNet Project, managed by the Victorian Department of Economic Development, Jobs, Transport and Resources, was established in 2009 by the Australian and Victorian governments as part of a suite of initiatives having potential to reduce CO₂ emissions. CarbonNet is one of two Australian Government CCS Flagship Program projects. The Project is administered by the State government but reports to both State and Commonwealth funders through a formal governance structure.

The project is currently in feasibility and commercial definition stage, and is investigating the potential for establishing a world class, large scale, multi user CCS network in the Gippsland Region of Victoria, Australia. The network will bring together multiple CO₂ capture projects in Victoria, transporting CO₂ via a shared pipeline and injecting it deep into an underground, offshore storage site. CarbonNet seeks to identify and demonstrate the capacity and integrity of CO₂ storage and design scalable infrastructure to underpin growth and deployment of a CCS network.

The project has identified the nearshore region of the Gippsland Basin, offshore and within approximately 25 km of the coast (Figure 1), as the most prospective area for “drill-ready” sites for secure long-term geologic storage of CO₂. To achieve this, the project is searching

for storage capacity for CO₂ in the range of 25 to 125 million tonnes (Mt). Several potential offshore underground storage reservoirs were evaluated through a site selection process, making use of extensive geologic and engineering data from the Gippsland Basin oil and gas fields (Hoffman & Carman, 2015).

The CarbonNet understanding of reservoir and seal distribution in the Gippsland Basin benefits from extensive prior technical work by Esso Australia (now ExxonMobil) and its co-venture partner, BHP Petroleum and the large open-file database of wells, seismic surveys, reports and diagrams available on the Victorian State government DEDJTR dbMap website <http://er-info.dpi.vic.gov.au/energy/scratch/> allow much of the basin to be understood. In recent years, extensive 3D surveys have become available and have been merged into “megavolumes” to enable more efficient basin-wide interpretation, review and comparison of areas (3D-GEO, 2011). CarbonNet has participated in much of this recent work and has distilled its basin understanding into a chronostratigraphy and depositional model presented in Hoffman et al. 2012. Overall storage site characterisation and the mechanisms of CO₂ trapping are presented in Hoffman et al., 2015.

3. Seals

The most important aspect (storage assurance) of any CO₂ injection site is its capacity to contain the CO₂ for geological periods of time to allow long-term processes of dissolution and mineralisation to occur, leading to effectively permanent storage as rock-forming minerals. To achieve vertical containment, sealing lithologies are required that are laterally extensive across the whole storage area, have no detectable voids, defects, or breaches, and offer adequate seal

capacity to retain the planned volume of injected CO₂ and restrain its buoyancy and injection pressure.

Proven Petroleum Seals

Fifty years of oil and gas exploration and production in the offshore Gippsland Basin has demonstrated a number of seal intervals. These include the world-class regional topseal of the Lakes Entrance Formation, and other less-understood intraformational seals within the Latrobe Group that trap a large number of additional oil

and gas pools (e.g. Malek and Mehin, 1998). The characteristics of the regional top seal of the Lakes Entrance Formation provide a benchmark of quality, thickness, and extent that is important to understanding the relevance of the Latrobe Group Intraformational seals and is therefore discussed first.

Lakes Entrance Formation

The Lakes Entrance Formation is an excellent seal lithology, proven to contain hydrocarbon gas columns in excess of 100m for several million years. The Lakes Entrance Formation has excellent seal capacity (median = 1962 psi or 186 m CO₂ from 63 samples) (Hoffman et al 2012). This seal is best developed in the upper third of the formation, which represents a condensed distal deepwater section of homogeneous lithology with low resistivity and sonic velocity. Borehole diameters are often oversized through this unit due to presence of reactive, dispersive, swelling, undercompacted clays. The true or effective regional seal is contained within this. It varies in thickness over the nearshore area from 110 to 40 m. For 90% of the area of interest it is between 60 and 80 m in thickness.

Although often viewed as a simple sheet deposit, it is in fact rather more complex and contains a number of sub-units which may have different mineralogy, lithology, and seal potential. The Lakes Entrance Formation was deposited in a basin-floor setting, with significant seabed topography from the growing structures that would become the present-day oil and gas fields (Hoffman et al., 2012). It is best interpreted as a toe-set facies of the Gippsland Limestone, highly time-transgressive, and slowly advances into the basin as the Gippsland Limestone shelf edge progrades forwards during Upper Oligocene and Miocene time. Submarine channels can be mapped throughout its thickness, and these evolve into and connect with the better-known submarine channels within the overlying Gippsland Limestone that progrades over the Lakes Entrance Formation.

Lakes Entrance Formation seal potential is interpreted to be best developed over the oil and gas fields, due to a higher component of hemipelagic fallout, rich in smectite mineralogy, and also due to bypass of the growing structures by mapped channels of clastic-rich

submarine flows that rework and transport material from shallower waters. This is just one example of how structural inheritance and facies control has led to a highly favourable outcome for this basin – the large structures with the thickest oil and gas columns tend to have the best topseals. It is important to understand this relationship between facies, structure, and petrophysics when planning CO₂ storage in this basin.

Some of these Lakes Entrance Formation channels can be mapped as potential local weak-spots or voids in the topseal, such as near the Beardie-1 well and in the Cuttlefish area (Hoffman et al., 2012). Nonetheless, away from these few areas where the defects are obvious and easily mappable, the Lakes Entrance Formation represents an excellent overall seal and can be demonstrated to have retained seal capacity during later tectonic reactivation of faults which bound the margins of structures and even extend across their crests, with significant throws. Providing that fault throw does not exceed seal thickness, the Lakes Entrance Formation is resistant to seal failure as attested by the billions of barrels of oil and many TCF of gas proven in the Bass Strait fields.

Latrobe Group Intraformational Seals

Although the majority by volume of oil and gas is trapped at top Latrobe level by the Lakes Entrance Formation (data from Malek and Mehin 1988), the number of hydrocarbon pools is dominated by intraformational pools – in other words, there is a large number of relatively small intraformational pools under and between the giant oil and gas fields (see Malek and Mehin 1988 Figure 4 for numerous examples of intraformational seals below the regional Lakes Entrance Formation seal). Although relatively thin columns and small areas are generally trapped, some of the intraformational pools are of significant size. The Turrum and West Tuna fields each consist of a stack of intraformational pools with multiple contacts and significant aggregate reserves. ExxonMobil media releases quote Turrum as holding 1 Tcf of gas and 110 mmbbl liquids, while West Tuna has produced 85 mmbbl oil up to 2011 – the last available production data. The Whiting-1 well has at least six stacked pays, two of which are gas columns of 100m and 120m, so

the intraformational seals have substantial proven retention capacity (up to 175 psi, or >200m supercritical CO₂ column). These large and small intraformational pools represent the long-term future of oil and gas production in the Gippsland Basin and they are a target for future exploration.

These intraformational seals are poorly described in the existing literature and it is the intention of this paper to collect together descriptions of them, analyse their facies and depositional setting, place them in a coherent sequence stratigraphic context, measure their seal potential, and set out the circumstances within which they can form viable CO₂ traps to enable future exploration to be targeted at this play type in a series of fairways across the basin.

In CO₂ storage terms, these intraformational traps represent an opportunity to store larger volumes of CO₂, at a wider range of sites, in a larger number of trap concepts than offered at top Latrobe alone. In particular, they offer an opportunity to achieve CO₂ storage while avoiding use of the pore space currently being exploited for oil and gas production. By separating the stratigraphy of storage from that of production, a number of potential interactions are minimised, or removed completely. These include pressure interaction, direct fluid contact, and physical infrastructure. Reduction of interaction is always a desirable goal when different resources seek to use the same basin in different ways.

Seal –Capacity – CO₂ column from MICP data

The seal potential of samples across the Gippsland Basin has been measured by a number of authors (Goldie-Divko et al. 2009a, b, 2010). Hoffman et al. 2012 reported on a compilation of this existing data, and a new dataset consisting largely of intraformational seals for a total of 138 samples from 70 wells. Figure 2 and Table 1 illustrate the compilation of CO₂ seal potential (as determined by MICP measurements, and reported as equivalent column of supercritical CO₂ at nominal density 0.4g/cc), grouped by stratigraphic interval. Note that since the previous publication, a careful review of chronostratigraphy has assigned a

number of samples from the Seahorse-1 and other nearshore wells to the lower Cobia (Traralgon Formation), rather than upper Cobia. Seal potential is characterised by a nominal CO₂ column that could be retained by that sample in a perfect trap. Samples were taken from existing cores, stored at GSV’s Werribee core store (now merged with the NOPTA National Core Facility in WA). Most of these cores have been stored in open core trays, although some retain their original wrapping and have never been inspected in the (up to) 50 years of storage. Indeed, one core suite had never been slabbed and was in its original wellsite packaging. The open storage has led to some deterioration, including friable sands disaggregating and, of relevance to this study, shales delaminating. Nonetheless, adequate shale samples were collected from many of the targeted intervals.

Table 1: MICP measurements from 138 samples in the Gippsland Basin

Interval	N	Median	Mean	Sigma/mean
		Metres CO ₂ column		
Gippsland Limestone	9	41.0	43.2	0.91
Lakes Entrance Formation	63	186.0	233.7	1.02
Greensands	9	180.5	269.5	1.03
Upper Cobia	9	124.0	134.4	0.80
Lower Cobia	27	143.1	330.0	1.11
Halibut	17	183.6	286.1	0.96
Golden Beach Fm.	4	156.4	366.1	1.17
All samples	138	170.0	260.4	1.06

It will be noted that the few samples of Gippsland Limestone shale interbeds demonstrated poor seal capacity (median 41.0 m CO₂ from 9 samples), but few seal units were targeted by existing core collection. CarbonNet analysis suggests that a more marly unit known as the Wuk Wuk Marl may have better seal potential, but no core is available at the present time.

The Lakes Entrance Formation, as expected, demonstrates excellent seal potential (median of 186.0 m and a mean of 233.7 m CO₂ column from 63 samples. Greensands collected in the transition zone between Latrobe Group clastics and the overlying Lakes Entrance Formation are statistically indistinguishable in seal quality.

Upper Cobia shales are of slightly poorer, but by no means inadequate quality (median of 124.0 m and a mean of 134.4 m CO₂ from 9 samples. Samples from the lower Cobia, however, offer remarkable seal potential – arguably as good as or better than the Lakes Entrance Formation. These 17 samples have a median of 183.6m and a mean of 330.0 m CO₂ column. The Lower Cobia samples are clearly more variable – they have a higher standard deviation, and Figure 2 shows that a number of samples showed very poor seal quality while others proved excellent. In contrast, the Lakes Entrance Formation shows less scatter. One would therefore conclude that the Lower Cobia samples are either less well preserved, or are intrinsically more variable in nature than the Lakes Entrance Formation.

Halibut and Golden Beach Subgroup seals are also good in quality but will not be discussed further in this review, other than to note that additional deep trapping potential exists at these levels, if reliable geophysical mapping can be extended to these depths.

It should be noted that, unlike the Lakes Entrance Formation, these intraformational seals are often hand-picked from thin units at metre-scale, rather than a thick whole-core scale where serial samples can be taken.

Number of seals and seal fairways

Initial review of the distribution of intraformational hydrocarbon seals from open file well completion reports and well proposals in the DEDJTR dbMap online database reveals a complex pattern with some discoveries having only a single hydrocarbon accumulation at top Latrobe Group and hence interpreted to have no or few intraformational seals, and others having many stacked pays, and hence several proven intraformational seals. A map of the number and nature of seals is presented in Figure 3. At

least eight stacked pay intervals with independent contacts or pressure gradients are recognised in the Emperor-Sweetlips complex and up to 16 in Archer-Anemone. Interestingly, both these sites are close to the depositional margins of the Latrobe Group, but one is in the north and one in the south of the basin. An interpretation of the overall number of seals is shown in Figure 4, which offers a more coherent view of the situation. A clear seal fairway exists on the northern flank of the basin, with peak development in the Snapper-Marlin (Turrum)-Emperor area. Note that all the fields discussed earlier as demonstrating commercially significant columns and pool sizes lie in this northern fairway (Whiting, Turrum, West Tuna).

A less well defined fairway may also exist on the southern margin through Omeo-Bream-Anemone trend. A difficulty of mapping seals from proven hydrocarbon pools is that if migration is insufficient in an area, then pools cannot occur, even if seals are effective. There is some question about petroleum migration on the southern flank of the basin, but overall the interpretation is that intraformational seals are patchy or inconsistent on the southern margin, and well-developed on the northern margin. It is possible to interpret the distribution of seals to be bimodal, with a relative low or total absence of seals along the centreline of the basin from Tarwhine to Blackback. We will return to this observation later when discussing facies belts in the Latrobe Group.

Further insight into the stratigraphic distribution of seals comes from Figure 5, a flattened seismic section across the core of the northern seal fairway (yellow line in Figure 4). The section is flattened on a prominent Middle Eocene coal event of *N. asperus* age in the nearshore zone and an equivalent datum in the deeper offshore once the coal has subcropped to the top Latrobe disconformity. The location of observed hydrocarbon traps is highlighted by yellow circles. A clear progression is indicated with proven hydrocarbon traps clustered some 300-800m below top Latrobe Group, over an age ranging from upper Cretaceous (at the Turrum gas field) to mid-Eocene (at the Mulloway oil field). This is no coincidence, but is a clear indication that a particular depositional environment and

sedimentary facies is predisposed to seal development and the trapping of hydrocarbons.

It is more relevant to understand the palaeogeography of these proven seal locations. In spatial terms, they are located approximately 20-30 km landwards of the contemporaneous barrier bar shoreline system, and are clearly located below the centre or landward side of a visible coal sequence (strong seismic events on Figure 5). These coal belts have a mapped width of 15-30 km and progressively backstep as the barrier bar system that traps their deposits in swampy low-lying environments itself backsteps with the top Latrobe retrogradation.

An example of 3D seismic mapping of one of these coal belts is the upper Halibut aged coal informally identified by CarbonNet as “B1” that is prominent in the Barracouta field between 1246 m and 1263 m RKB in well Barracouta-1 (see, for example, the correlation diagram of Rahmanian and Mudge, 1988, reproduced here as Figure 6). This coal is chosen as an example because it lies wholly within the area of 3D data, is relatively shallow and undeformed, and is easily mapped. The map of Figure 7 is a seismic amplitude of the peak corresponding to this ~15-20m coal, which is thick enough to be fully resolved with existing seismic data. A distinct depocentre is mapped with some local stronger and weaker zones, but defining an overall elongate region trending approximately 040 degrees. The region of coal accumulation is at least 15-18 km wide in the dip direction and 40 km in the strike direction but, interestingly, the northern end is truncated by an irregular fretted edge with finger-like indentations.

These fingers are interpreted as low angle slump structures with horseshoe-shaped heads. Each slump feature is 500m to 1 km wide and 2-4 km long. Careful attention to the figure demonstrates that coal amplitude is particularly high in some finger-like features of identical scale, suggesting a polyphase history of slumping and then re-accumulation of coal in a swampy depression filling the previous slump scar.

The area into which the material has slumped is interpreted as the feeder zone for the Marlin Canyon.

Maps on a variety of other surfaces around the Canyon demonstrate a continuing history of slumping into this unstable area.

The B1 coal is less-well developed south of Barracouta. Although there is change of seismic survey baseline from the Esso Northern Fields (G01A) to the Apache Sue (GAP04B) and others, this is interpreted as a systematic change of depositional facies and thickness. A key tectonic lineament lies south of the Snook-Mulloway-West Barracouta trend and appears to represent a primary down-to-the-north fault controlling sediment facies and thickness.

A variety of other coals have also been mapped on 3D seismic. They demonstrate similar aspect ratios, orientations, and scales, and similarly respond to the Mulloway lineament, although many are smaller and thinner than the main “B1” coal.

T2 as a key example of a seal

The Traralgon Formation was originally recognised from onshore coal geology but has been extended into the offshore area where it is recognised as far offshore as the Barracouta gas field (Holdgate, 2000). In the offshore, the petroleum nomenclature and the GeoScience Australia Australian Stratigraphic Units Database classify this sequence as the Burong Formation (Bernecker and Partridge 2001, for example, identify the Traralgon Seam as a *member* of the Burong Formation). A major seal identified as a petroleum intraformational trap and mapped as a candidate for CO₂ storage in the nearshore Gippsland Basin is the T2 member of the Traralgon Formation. Where good palynology data exists, the T2 sequence is of Lower N. asperus age, and overlying T1 and T0 units of Middle- and Upper N. asperus age, respectively.

The T2 marker is the datum for Figure 5. In the nearshore area, north of the Mulloway lineament, T2 is a 50-75m thick coal/shale unit that can be mapped across the entire area and correlated up to 20 km in the offshore//onshore direction and 50km laterally along the coast. T2 can also be correlated south of the Mulloway lineament, albeit at reduced thickness and seismic response. More than 50 offshore wells and onshore boreholes have been used in this correlation.

Within the nearshore region a number of wells are proven to trap hydrocarbons below the T2 coal-shale interval (Figure 8) These include Mulloway, Whiptail West, and Whiptail, which show two subtly different, but adjacent coals to be the trapping horizon. Esso Australia refer to these reservoirs as N1.0 and N1.1 but the nomenclature is not uniform across the nearshore and is at best a local scheme for indexing sands, relative to top Latrobe. Esso has released some local correlations across field areas such as Barracouta (Rahmanian and Mudge, 1988), but has not published extensively on this theme, other than the landmark Rahmanian et al 1990 paper on Gippsland sequence stratigraphy.

In the Dolphin field, some 20 km southwest of Mulloway, an equivalent zone of estuarine/swampy facies acts as a base seal to the proven oil column. At West Seahorse-3 and Wardie-1 (both drilled 2004), the T2 is a proven pressure seal, with differential drawdown of the virgin aquifer pressure – which we assume to be due to far-field pressure effects of production at major oil and gas fields in the basin, as reported by Varma and Michael., 2012. At Galloway-1 (2006), it is both a pressure seal and salinity barrier (Figure 9). At Golden Beach West-1 (1967), it is a salinity barrier. These wells collectively prove the existence of a pressure, salinity, and fluid seal at T2 over an area of over 1000 sq. km, for over 50 years. Pressure differences prove a barrier exists on a human timescale due to pressure drawdown, while salinity differences suggest that million-year differences exist in the flow paths and sweep efficiency of the meteoric water influx to the basin. Coal as a petroleum seal is an unusual occurrence worldwide, since coals are generally cleated and contain fissures and the equivalent of fracture porosity. The coals in the Gippsland Basin, however, are relatively low-rank and do not show obvious cleating, but rare sub-vertical fractures are noted in cores from ~1400m ss in the Seahorse area, and onshore well drilling in the Wombat field returns blocks of coals (Tim O'Brien, pers. comm.). Our own visual observation of the Wombat coals shows that they are more platy than blocky in form, but are beginning to cleat.

One likely possibility is that the seat earths of the coals are the key sealing lithology. These basal units can be identified on well logs and in cored sections (e.g. borehole Wulla Wullock-7) as unusually dense clays, for their burial depth. Although they contain some rootlet features, they do not seem to have significant vertical permeability. They are compact, widespread, and typically 5-10m thick in onshore wells. However, they are relatively thin to act as seals for hydrocarbons and other fluids and it is possible that they act as a basal “skin” for the coals, which provide the majority of the mechanical strength of the seal. The observation of over 100 intraformational oil and gas pools throughout the basin (over the set of all transgressive seat-earths, not just T2), many with columns of tens of metres demonstrates widespread seal potential for this trap concept, and the occasional development of 100m+ gas columns show that in appropriate circumstances, significant pressures can be maintained by these seals.

Facies (Coal) Mapping

Proving a seal for either petroleum or CO₂ purposes requires more than a demonstration of its regional quality and extent. Local mapping must also be undertaken to demonstrate that there are no visible seal defects such as channels or other facies changes, and that any faults that occur are not large enough to negate the seal potential. These are essential steps to take in prospect definition for both petroleum and CCS purposes.

Fortunately, due to the distinctive velocity and density of coals, they are easily mapped on high-resolution 3D and 2D seismic and any defects and variations in thickness are easily visualised. If the sealing lithology is closely identified with the coal, then it likely that an unbroken coal corresponds to an unbroken seal. There are issues that nearby coals will acoustically interfere with each other on seismic data, due to the relatively broad seismic wavelet compared to the detailed stratigraphic variation, and some of the seismic responses must be understood to be composites of several nearby events. Nonetheless, overall coal quality can be mapped for a series of seismically-defined sub-units.

Over part of the 3D-mapped area of T2 occurrence, it is essentially the last major sequence of the Latrobe Group. In the area identified by Holdgate et al., 2000 (his Figure 10c) as the Seahorse backwater, coaly intervals are superseded by a thin veneer (thickness in metres) of estuarine deposits, and then a rapid transition through greensand to Lakes Entrance Formation takes place as a significant transgressive backstep occurs. On this surface, individual finger-delta sands can be mapped, advancing from the coast as part of the depositional system. These finger deltas were probably protected from wave action within the lagoonal area of the Seahorse backwater, in an identical fashion to the modern-day Mitchell River in the onshore Gippsland Lakes which has built a ~ 10 km finger delta down the west side of Jones Bay, from the town of Bairnsdale towards Paynesville, and then eastwards across Lake King.

Fluvial inputs and throughputs

A seismic map of amplitudes at two levels (Figure 10) reveals clastic finger/birdsfoot deltas (orange) overlying T2 coals and estuarine units (blue). At any one time, fluvial inputs can be mapped by their disturbance of the characteristic seismic facies of both coals (Figure 10) and barrier bar units (Figure 11). These fluvial inputs are persistently focussed along tectonically controlled lineaments such as the Malloway trend. Analysis of the pattern of deposition shows several main areas of persistent fluvial input (Figure 11). Although these are represented on a map (after 3D-GEO, 2011) of top Latrobe amplitude (and hence facies) they persist at depth through the Latrobe Group, so far as it can be reliably mapped from coal units and their distinctive amplitude.

Three main clastic trends are recognised in the area mapped in Figure 11. In the south, there is a system that extends from the nearshore, south of Amberjack-1 and heads S 20° E, passing south of Bream and through Kingfish. After this, the trace is indistinct and it may merge with the next-described system. This fluvial system has no modern onshore equivalent, although two dry valleys on the east flank of the Baragwanath Anticline may be consistent with the last incarnation of

this fluvial axis, before the rising Baragwanath Anticline entirely cut-off the river systems.

The second fluvial system is interpreted to be the palaeo-course of the modern Latrobe River, prior to its deviation northwards by the Baragwanath Anticline. This palaeo-river passes under the modern-day Holey Plains, where distinctive coarse clastics in the basal Latrobe Group are named the Honeysuckle Hill Gravels. Holdgate et al. 2003 map Pliocene-Pleistocene coastal barrier bars and rivers crossing the Baragwanath Anticline from magnetic interpretation. This suggests the current topographic expression of the anticline today is a fairly recent phenomenon, maybe as young as a few hundred thousand years. Before this the Latrobe River headed south-southeast along the proposed pathway.

This fluvial axis passes along mapped thins in the Holdgate et al. T2 coal isopach and emerges in the nearshore as clearly mappable fluvial facies in the first of the 3D surveys in the Snook and Flying Fish area. This fluvial axis continues south of Malloway and Barracouta, passes north of Veilfin and then passes through Fortescue, Halibut and Blackback fields. Note that the majority of the present-day large oil and gas fields are inversion features that were former depocentres, and often acted as fluvial axes – hence the fields have a nett:gross ratio that is higher than the basin average – a fortunate outcome for their commercial development.

It is interpreted that the strong fluvial input along the Palaeo-Latrobe trend is responsible for the void in intraformational seals observed in the Central Deep (Figure 4). Again, the large structures where giant oil and gas fields are developed tend to have few (zero to three) intraformational seals (Figure 4), while the smaller pop-up structures that are not systematically located on these axes tend to have many more intraformational seals (five to 16). This is another outcome of structural inheritance and facies control in this basin.

The third fluvial axis runs more east-west and is aligned with the Rosedale fault system. We name it the Palaeo-Thompson River, although we have no firm evidence of

a direct connection to an ancestral Thompson River valley in the hinterland. This trend passes north of the Seahorse trend, south of Emperor, crosses the modern-day tectonic rhombochasm at the head of the Marlin Canyon and is inferred to extend at least as far as Longtom before it arrives at the head of the Tuna-Flounder slump and channel system (an earlier equivalent of the Marlin Canyon, filled-in by the abundant sediment supply).

Onshore-offshore correlation

It is fundamentally difficult to make detailed correlations within the Latrobe Group due to the lack of distinctive marker beds or internal unconformities or sequence boundaries. The succession is a highly-repetitious sequence of almost identical parasequences that steadily transgress shorewards. There is very limited age dating available with marine species absent or undiagnostic, and ages derived from relatively low-resolution palynology zonation. Many wells do not have reliable palynology determinations and so lithological correlation must be used to infill the available determinations.

Each well or borehole, at first sight, represents a very similar facies succession with Lakes Entrance claystones overlying a greensand at the top of a variously-sandy Latrobe group which has strong coal development at or near its top, decreasing downwards into a lower coastal plain setting. Each of these facies is time-transgressive and non-unique. It is therefore possible, despite good care and skill, to miscorrelate the coals and sands of the Latrobe Group and underestimate the degree of backstepping which has occurred. The lack of good seismic data onshore exacerbates this problem since even low-resolution control is lacking in some areas.

Using the insights of this study into actual seismic geometries visualised on 3D data offshore, and extending this through recently-reprocessed vintage 2D onshore data that has been optimised for resolution of upper Latrobe coals, an integrated re-correlation is made of the previous work of Holdgate et al. (2000, 2003). Holdgate et al. assembled a large number (thousands) of onshore coal boreholes and produced an integrated understanding of the onshore coal sequences which stands as the most in-depth study of

Latrobe Group coals to date, in the onshore area. However, by also incorporating the new observations from extensive offshore 3D data, there is the opportunity to update this landmark work. Our provisional correlation is presented as Figure 12.

The controlling principles used to build this correlation are that the top Latrobe disconformity should progressively ascend and backstep landwards at a similar average rate as observed in the offshore 3D data area (but the rate may fluctuate with time due to eustatic sea level changes, and variations in the rate of sediment supply or tectonic subsidence/uplift), and that all facies zones should backstep at similar rates. Section thinning would generally be at the base of the section, at the top Strzelecki unconformity and that zones of disruption to otherwise thick coals (e.g. the intercalated sands within Holdgate et al.'s T2b sequence at Wulla Wullock-4, -7, and Glencoe South-4 – Holdgate et al. 2000, Figure 3) are evidence of the shorewards limit of one coal depositional belt and a backstep into a younger depositional belt that is not time-equivalent.

Figure 9 identifies two major barrier-bar stillstands (yellow) – one extending from ~3 km inland of Dulungalong-1 to 4 km oceanwards of Golden Beach-1A, a dip extent of approximately 10 km. This unit is homologous with the Dutson Sand member (Holdgate et al., 2000, Figure 9), was previously identified by Blake, 1986, and is of Upper N. *asperus* palynological age. The sand-rich facies contains rare thin coals intercalated with barrier-bar sands. Occasional coarse sand grains scattered through some of these coals are interpreted as wind-blown debris from an adjacent dune system, superposed on the barrier bar, but removed by marine erosion when the barrier bar was transgressed.

The eastern limit of this sand belt can be mapped on 3D seismic data as a distinct amplitude feature at top Latrobe Group, and is also a geometric feature at the top Latrobe disconformity with a series of relatively steep steps of ~50m thickness, for a total height of ~250 m. The second barrier-bar system extends from 4 km oceanwards of Coolongoolun-101 to the Woundellah-11 location, a dip extent of 6 km. These barrier-bars are not imaged on 3D seismic data but

from well correlations appear to represent a total vertical relief of ~100m. This more inshore belt of sands is also identified by Holdgate as the Dutson Sand member, but will require a new name, given that it is physically and chronologically distinct from the barrier bars around the Dutson Downs-1 well. As a working nomenclature, we suggest the name “Woundellah sand member”, based on a well-developed section in the Woundellah-12 and Holey Plains-185 boreholes.

Stratigraphically beneath the Barrier bar sands is a zone of bioturbated thinly-bedded estuarine sands and clays (orange). In palaeogeographic terms, these represent a coastal lagoon system, analogous to the modern-day Gippsland Lakes, stretching 8-15 km inland from the coastal dune belt that would have been perched on the coastal barrier-bar. The basal part (more inland) of these estuarine systems is more coal-rich, however the best coal development is in the fresh-water systems (white) beneath and inland of the lagoons. Composite coal sequences up to 60m thick, with thin clay interbeds, are best developed in what would have been low-lying swampy areas, interpreted, after Holdgate, to be raised bogs in the onshore lower coastal plain.

In the previous section, we demonstrated that fluvial systems can be mapped passing between and around the raised bogs and interrupting coal development. These fluvial systems are expressed as coal-poor and sand-rich features that are elongate and tend generally S 20° E. These can be correlated through geologic time and tend to stack vertically to produce sand-rich belts that cut through the Latrobe Group and can be mapped as consistent inherited features, following structural lineations (Figure 11).

In the well correlation of Figure 12, the T2 basal seal is identified as a bold red correlation line. Stratigraphically, it lies at the base of one of these thick composite raised bog style freshwater coals. This type of location is likely the site of an extended duration of leaching of the subsoil and seat earth of the coal by organic acids and anoxic fluids derived from the long-standing coal swamp (with multiple cycles of coal development stacking at the same location). The chemical and physical changes associated with this leaching may well be responsible for the development

of the good sealing capacity of the distinctive dense basal shales to these major coal seams. This depositional setting explains the observation from Figure 5 that intraformational seals are developed on the landward half of major coal units. The seismic-mapped coals cannot distinguish between estuarine and freshwater deposition, but the palaeogeographic context does discriminate in terms of seal effectiveness. The coal swamps interbedded with or deposited in an estuarine setting do not develop effective seals, but the freshwater, raised bog style coals do develop proven seals in the basal shales and seat earths.

We hypothesise here that there are indications in some of the maps and correlations of Holdgate et al. 2000 that a more complex backstepping geometry of the coal units is compatible with the input data, required by the observed geometries, and not contradicted by the limited palynology age dating available. For example, in the offshore, the best-developed coal is the B1, which has a mapped dip extent of 20 km. Holdgate et al. correlate some T2 units over 60-80 km in dip extent. Our correlation breaks the Traralgon sequence into several distinct backstepping sub-units, and revises the internal correlation between proposed T2, T1, T0, and younger units.

At the time of publication of Holdgate et al. 2000, the T0 was not distinguished from T1 - hence the combined T0-T1 isopach. The subsequent recognition of T0 came about later from analysis of spore-pollen in Traralgon coal at Loy Yang, based on the high-resolution methodology and chronostratigraphy developed by Partridge, 1999. This analysis placed T0 into the early Oligocene Upper N. asperus zone, and high-resolution palynology applications to other coals along the Latrobe syncline suggested that onshore coals north of the Rosedale Fault were mostly of this age.

Where good palynology determinations are available, T1 and T2 ages exist offshore, but these coals have not previously been recognised north of the Rosedale fault. There is a consensus that the Upper N. asperus zone occurs in all T0 coals, and also throughout the Dutson Sand Member, making these units readily distinguishable from T1 coals that always have a Middle

N. asperus zone age, and T2 coals that always have a Lower N. asperus zone age.

From our new work, we now recognise T2 coals north of the Rosedale fault – at least in the offshore where a very precise 3D seismic correlation has been developed. The onshore seismic quality is inadequate to confirm how far onshore these coals extend and few wells and limited poor-quality seismic data exist in the relevant near-coastal area to reliably test the stratigraphy. We also find that T2 equivalents occur in offshore wells south of the Mulloway lineament (Wasabi-1, Amberjack-1, and Dolphin field) and even south of the Darriman fault system (Perch field, Palmer-1, and Tommyruff-1, although this latter well is outside of the area of 3D seismic control, but is covered by a good modern 2D seismic grid – survey GDPI10). The lack of good T2 coals in Tarwhine and Blenny is due to a combination of a persistent major fluvial input mapped in this area (Figure 11) and to the T2 coastline stepping west, to the south of the Mulloway lineament. This lateral step is seen in the barrier bar facies (Figure 11) as well as in the coal/swamp facies some 5-10 km shorewards (Figure 13).

We suggest that there may be unrecognised complexity to the Traralgon coal sequence with a need for additional sub-unit nomenclature. Most importantly, the new nomenclature should be flexible enough to allow intercalation of additional sub-units, as they are recognised and mapped out, and for revisions of the detailed correlations between sub-units in one borehole/area versus another. This revision of the correlation and the nomenclature should be approached on a holistic basis using all available data – seismic, well, biostratigraphy, etc. The present correlation is only a suggestion, and not proposed as definitive. In the nearshore zone, we interpret four parasequence sets within the Traralgon Formation (Figure 12). Each parasequence is transgressive, with steady shorewards movement of the facies belts, including the coal depocentres, but the parasequences are interrupted by disconformities where the facies step oceanwards. These are interpreted to be the terrestrial disconformities that correlate with marine lowstands - possibly early Oligocene glacial cycles.

In some cases, the lithological units recognised by Holdgate can be correlated with facies mapped in this study. For example, the Dutson Sand Member of Holdgate 2000 is interpreted in this study as barrier-bar sequences trending E 20° N. This barrier system was first reported by Blake 1986 from 2D seismic interpretation and now reliably mapped on offshore 3D data and tied to the Wasabi-1 well and continuing to Tommyruff-1 on 2D data, however there is also a contribution from sand-rich fluvial inputs trending S 20° E which gives rise to local thicks in the barrier system, and a relative lack of coaly facies. These fluvial units occur at Dulungalong-2 and Dutson Downs-1, but do not directly correlate with those mapped at Burong-1 and Lake Reeve-1, since they are separated by the Golden Beach raised bog and are interpreted to represent distinct fluvial systems (the Palaeo-Thompson and Palaeo-Latrobe Rivers of Figure 11, with possibly different detailed histories.

Some of the interpretations in this paper include assumptions about rates of subsidence and transgression in the nearshore area, where there is limited data, and some discrepancy between fully onshore and fully offshore interpretations. The nearshore zone appears to represent a transition spatially between the onshore and offshore geology, and temporally between the Eo-Oligocene deposition and the Oligo-Miocene. The unifying framework adopted in this paper allows a coherent well and seismic correlation across the entire nearshore region – both onshore and offshore.

In this paper we do not address the later Oligo-Miocene coals, which represent a dramatic backstep of the barrier bar systems that then constructed a thick aggradational to gently progradational build-up of stacked barriers between Rosedale and Sale (the Balook Sand). The Balook itself shows no backstepping, rather the Balook was periodically overtopped and sand incursions can extend 40km inland into the Morwell swamps.

Figure 13 illustrates our current understanding of T2 seal development. Within the available 3D seismic data, the seismic event corresponding to T2B is mapped in amplitude (blue-white colours). This map is merged

with T2 isopach maps from 2D data on the southern margin and the T2 isopach map of Holdgate et al. in the nearshore region, edited to remove the depocentre around the Stradbroke 64 borehole (i.e. the present-day Baragwanath anticline), and to include coals formerly assigned to the T1 and T0 north of the Rosedale fault, and in the onshore area. The resulting isopach is more complex than the earlier work of Holdgate, because we now recognise a number of cross-cutting fluvial systems which degrade T2 coal

4. Discussion: Basin understanding

It is important to understand the history and dynamics of the basin in which CO₂ storage is planned. We have described above how structural inheritance and facies control has a strong influence on seal (and reservoir) development at multiple stratigraphic level, throughout the Palaeogene period. Events and geometries from the past already influence existing properties of the basin and these properties will also predict likely future processes (such as areas of secure and less secure seals) that may affect storage security over medium to long timescales (thousands to millions of years). Oil exploration is based on this tenet, and the industry is experienced in modelling the past history of basins to predict where and when oil and gas maturity may have occurred. If maturity and expulsion occurred in the past, but is no longer active at the present day, then petroleum explorers must understand this and seek traps that are robust for long-term storage and secure against tectonic disturbance and other factors that can degrade or remove stored hydrocarbons over geological time. These considerations are substantially similar to the requirement for evaluating potential CO₂ storage sites for long term containment.

Calibration to ground truth by petroleum migration modelling

In the Gippsland Basin, peak hydrocarbon expulsion occurred a few million years ago, prior to the uplift events that exposed the Latrobe aquifer to meteoric water influx (Michael 2015). The influx of meteoric water coincides with an offshore weak uplift, or cessation or slowing of subsidence, and a significant

quality. Nonetheless, there is a more systematic distribution of T2 coals in depocentres: a) along the Rosedale fault and extending offshore to an undrilled area north of Seahorse, b) (the most significant depocentre) on an alignment from Lake Coleman through Golden Beach gas field to the west end of West Barracouta gas field, c) Southwest of Snook and Flying Fish in an area untested by offshore drilling, and d) southwest of the Perch oilfield.

cooling event as meteoric influx actively flushed the prior saline formation water. Since the cooling event, the Gippsland Basin is no longer at peak maturity and only residual hydrocarbons are mobile at the present day.

Models of petroleum expulsion up to the time of peak maturity can account for the major distribution of oils and gases in the basin, with a reasonable basin-wide thermal and burial model, and some local adjustments of kerogen types in various sub-basins (Moore 1988). However the meteoric influx to the basin has led to a significant pattern of alteration of in-situ hydrocarbons with substantial water washing and biodegradation affecting the nearshore parts of the basin (Hoffman and Preston, 2014).

Water washing and biodegradation

Due to the meteoric influx water to the basin (Michael 2015) on a timescale of the order of 1 million years, substantial alteration of the original in-place hydrocarbons has occurred (Hoffman and Preston, 2014). Entire hydrocarbon accumulations have been removed (e.g. the original top-Latrobe pools at Malloway and Whiptail), reduced to residual asphalts (Amberjack) or biodegraded and stripped of their soluble components (deeper pools at Whiptail and Malloway, top-Latrobe oil at Perch and Dolphin). Storage of highly-soluble CO₂ in the same region of the nearshore Gippsland Basin is almost inevitably going to result in similar water-washing and total dissolution of

the CO₂, within a foreseeable geological timescale of a million years or less.

Two subsidiary questions do need to be answered: 1) Why is there still a natural CO₂ content in some of the Gippsland gas fields? And 2) Is there a danger that acidized solutions containing dissolved CO₂ will impinge on existing oil and gas facilities within a foreseeable timescale?

As regards natural CO₂, there is clear gradient of declining CO₂ content of gas discoveries shorewards – towards and within the meteoric water “wedge”, with the lowest detectable CO₂ in Barracouta and no CO₂ at all in Golden Beach. Longer and more intense exposure to meteoric water is associated with a lower resulting CO₂ content, and the highest CO₂ content is associated with non-meteoric saline formation water in deeper pools such as Kipper. Therefore the first order explanation of CO₂ survival relates to exposure duration and intensity of flushing by the meteoric water, with proximity to shore increasing both parameters.

To an extent, the admixture with hydrocarbon gas will also protect the associated CO₂ from dissolution, and the geometry of a large accumulation is such that the ratio of volume of trapped gas to its contact area with the underlying aquifer – the gas-water contact increases as the trapped volume increases. Therefore, total removal of the CO₂ requires a nearshore setting for ease of access to meteoric water, low volumes of admixed non-soluble gases, and small pool size – all exemplified by the Golden Beach accumulation, for example.

As regards impact on nearby facilities, the rate of aquifer flow can be measured from basin-wide reservoir models (Varma and Michael, 2012) or from radiocarbon ages of meteoric water (Hofmann and Cartwright 2013). Both measurements agree at a flux of the order of 1m per year from onshore to offshore. Given this flux, a time of 10,000 years is required for a dissolved plume to traverse the typical ~10 km distance from a CO₂ injection site to a nearby oil or gas facility. Within this timescale, it is almost certain that mineralising reactions will have already immobilised the vast majority of the dissolved CO₂ and the resulting

formation water will only be very weakly acidic, if at all. If not, the petroleum facility will be long-abandoned with secure well completions, and may be the site of an independent structural storage site for CO₂ anyway in a scenario where carbon storage is extensively conducted to mitigate Australian emissions.

Seal Facies and perturbations

On a local prospect basis, detailed seal mapping is required to demonstrate continuity of seals across the local structure in order to calculate seal risk and demonstrate lack of any obvious facies changes, changes, and major fault offsets. Local petroleum studies would examine charge sufficiency and seal integrity while local CO₂ studies would focus more on seal continuity and fault seepage.

Seal perturbations can also result from legacy wells already drilled in the storage area as part of prior petroleum exploration and development. The CarbonNet Project has assessed this issue in detail in the nearshore area and concluded that the risks are low (Goebel et al., 2015).

Example of fault limitation and timescales

Observation of proven intraformational petroleum pools and studies of the evolution of injected CO₂ plumes in dynamic reservoir models both agree about the controlling factors on retaining accumulations over geological time. In the case of petroleum pools, faults can be demonstrated to form a lateral boundary to the accumulation, and hence present a probable path for upwards permeation of trapped fluids. Not all faults represent significant leak pathways – several of the proven petroleum pools have additional faults within the area of the pool.

In dynamic modelling studies, permeation is observed to occur up some fault pathways due to juxtaposition of sands, but the rate of permeation is relatively low. Some faults offer orders of magnitude less permeation than others, but all faults represent a clear risk to long-term storage of buoyant fluids. The challenge is to quantify that risk, and the rate of permeation, and to evaluate whether a viable trap still exists. In petroleum terms, this equates to an economic assessment of expected volume vs drill risk. In CO₂ storage, this

requires an analysis of permeation rate and the fate of permeating CO₂.

The ultimate goal of CO₂ injection is to achieve long-term retention of the CO₂ by augmented natural geological processes of mineralising reactions. The first step towards this is dissolution. One obvious question to ask is then – “is the rate of permeation faster or slower than the rate of dissolution into the formation water”. We can answer this question in two ways: 1) by modelling the permeation and dissolution rates in an aquifer of appropriate mobility and salinity as that in the studied basin, and 2) by looking at the fate of permeated hydrocarbons, which have orders of magnitude lower solubility than CO₂, but establish an absolute minimum.

1) Modelling

Reservoir simulations of CO₂ storage beneath faulted T2 seals show that slow permeation does occur into the T2 sequence, due to offsets of thin seals and baffles, and juxtaposition of porous zones. The rate of permeation is scenario-specific and reduces with time as dead-end pathways are entered and become saturated. Nonetheless, over 1000 years of storage, only 0.3% of 125 Mt stored CO₂ enters the T2 interval by a series of “ladder” offsets of permeable zones on faults, and no CO₂ escapes the top of the T2 sequence. CarbonNet has run hundreds of models exploring variations of horizontal and vertical permeability and different stratigraphy of the seal intervals over a shorter 300 year timeframe and in none of these sensitivity cases does CO₂ ever rise above T2. Regardless, by extrapolation of the 1000-year results, it is possible that if the rate of permeation continues undiminished, that a flux of ~500 tonnes per annum of CO₂ could ultimately emerge into the dynamic aquifer above T2.

There are additional seals and baffles in the T1 and T0 intervals, and the regional petroleum seal at top Latrobe Group, so CO₂ would never escape the confinement of the trap. However, it is important to establish whether the volume of meteoric water swept across the top of the T2 sequence could absorb the slow permeation of CO₂.

We can compare the ~500 tonnes per annum of slowly-permeating CO₂ to the flux of low-salinity water across the top of the T2 seal. Hofmann & Cartwright (2013) established the radiocarbon age of samples from within the Latrobe aquifer onshore and adopting these figures we find flow rates of 1-5 m per year through the nearshore storage sites. Over a crestal zone 1 km wide and 200m deep, 200 to 1000 kt of low-salinity water would sweep every year. This water has the capacity to dissolve up to 5% by weight CO₂ under ambient pressure, temperature, and salinity conditions (Duan and Sun, 2003). Hence the dissolution capacity of the aquifer is 20 to 100 times that required to “mop-up” any slowly permeating CO₂.

These preliminary calculations indicate that the meteoric water is easily able to dissolve all the permeating CO₂.

2) Hydrocarbon analogues

Studies of nearshore Gippsland Basin show that many of the small fields are water-wet at top Latrobe, with a deeper oil pool (blue ellipses in Figure 2). There are some exceptions, but in the zone of strongest meteoric water flushing, north of the Malloway lineament, six out of eight small oilfields are water wet above deeper oil (Malloway, Whiptail, West Whiptail, Wirrah, Whiting, West Whiting), and the Harlequin structure has residual oil only at depth and is water wet at top Latrobe. In this area of strong meteoric water influx, only Seahorse and West Seahorse differ, and for these accumulations there is direct geochemical evidence of a second phase of hydrocarbon charge, subsequent to water washing and volume depletion (Hoffman and Preston).

South of the Malloway lineament, oils do occur at top Latrobe, but not at deeper levels and the hypothesis of permeation cannot be tested other than to observe that hydrocarbon gas and light ends have been removed from all four oil accumulations in this zone (Tarwhine, Blenny, Dolphin, Perch).

The evidence suggests, therefore, that the dissolution rate of hydrocarbons in the strongly-flushed aquifer zone above T2 and below top Latrobe is sufficient to

entirely remove any permeating hydrocarbons, unless the charge is recent (i.e. within the last million years, based on Michael 2015 and the inferred timescale for meteoric water emplacement). For CO₂, we expect orders of magnitude faster dissolution, and hence a

5. Conclusion

In this study, we have reviewed the occurrence of intraformational seals in the Gippsland Basin, as proven by over 100 oil and gas pools, in over 25 hydrocarbon discoveries and producing fields. We demonstrate that the seals occur in distinctive depositional settings related to backstepping coal swamps. A major seal fairway is mapped in the northern part of the basin, between mapped fluvial fairways in major palaeo-river systems tending east-west. Shale samples from existing cores have demonstrated significant MICP seal potential, within these seal fairways, equivalent to samples from the Lakes Entrance Formation, the proven petroleum seal for the basin.

An improved onshore-offshore correlation has been developed that better accounts for the backstepping geometries observed on high resolution offshore 3D seismic and suggested by lower-resolution onshore seismic data that has been reprocessed to reveal additional detail of coal depositional geometries. Detailed 3D mapping of individual coal units shows good potential for detailed understanding of local and regional controls on depositional facies and sand fairways.

The exact nature of the intraformational seals remains somewhat enigmatic, with most well interpretations declaring the intervals to be “coal” or “coaly shale”. However, detailed onshore coal boreholes indicate that seat earths of the major coals are potentially important in the ensemble of mechanical seals (Holdgate, pers. comm.), along with the immature coal beds themselves. The seat earths are located in a facies belt of freshwater coals and minor sands and shales in a raised bog geometry between major fluvial systems. Repeated cycles of coal swamp development and peat accumulation will have allowed long-term exposure to humic acids and anoxic waters seeping down from the

lifetime of permeated CO₂ of 10,000 years or less. This is essentially permanent storage on a timescale that is geologically rapid, and meets the goal of CCS for permanent and safe storage.

coal swamps and altering the seat earths to distinctive dense lithologies.

One particular seal has been investigated in detail in the offshore area – the Traralgon T2 (a subdivision of the offshore Burong Formation)– which is a proven hydrocarbon seal in five offshore oil discoveries, and is a proven pressure and salinity barrier in the nearshore zone and is related to onshore aquitards. The T2 interval has been mapped out in the nearshore area and its potential to act as a hydrocarbon or CO₂ seal quantified.

The chief weakness of these intraformational seals is their vulnerability to slow seepage up fault planes. A study of the residence time of trapped fluids suggests that CO₂ storage would be safe over both short and long timescales, with only small amounts (500t/yr) slowly permeating into a well-flushed meteoric aquifer with abundant capacity to absorb that volume of CO₂. The ultimate fate of the injected CO₂ is dissolution into the meteoric water that is actively flushing the nearshore, and then permanent mineral sequestration within unproductive reservoir zones away from existing or future oil and gas activity.

Since the ultimate goal of CO₂ injection is to achieve long-term retention of the CO₂ by augmented natural geological processes of mineralising reactions, and dissolution is the first step towards this permanent capture, then the Gippsland Basin can be viewed as highly suitable for the long-term disposal of CO₂, since total dissolution appears to be the inevitable fate of the injected CO₂, even if significant volumes (gigatonnes) are considered.

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Abbreviations

BHP	Broken Hill Propriety
DEDJTR	Department of Economic Development, Jobs, Transport, and Resources State of Victoria
GHG	Greenhouse Gas
GSV	Geoscience Victoria
MICP	mercury injection capillary pressure
NOPTA	National Offshore Petroleum Titles Administrator
RKB	Depth measured relative to Kelly Bushing
ss	Depth measured sub-sea or relative to sea level
T2	Basal Traralgon Seam member of the Burong Formation

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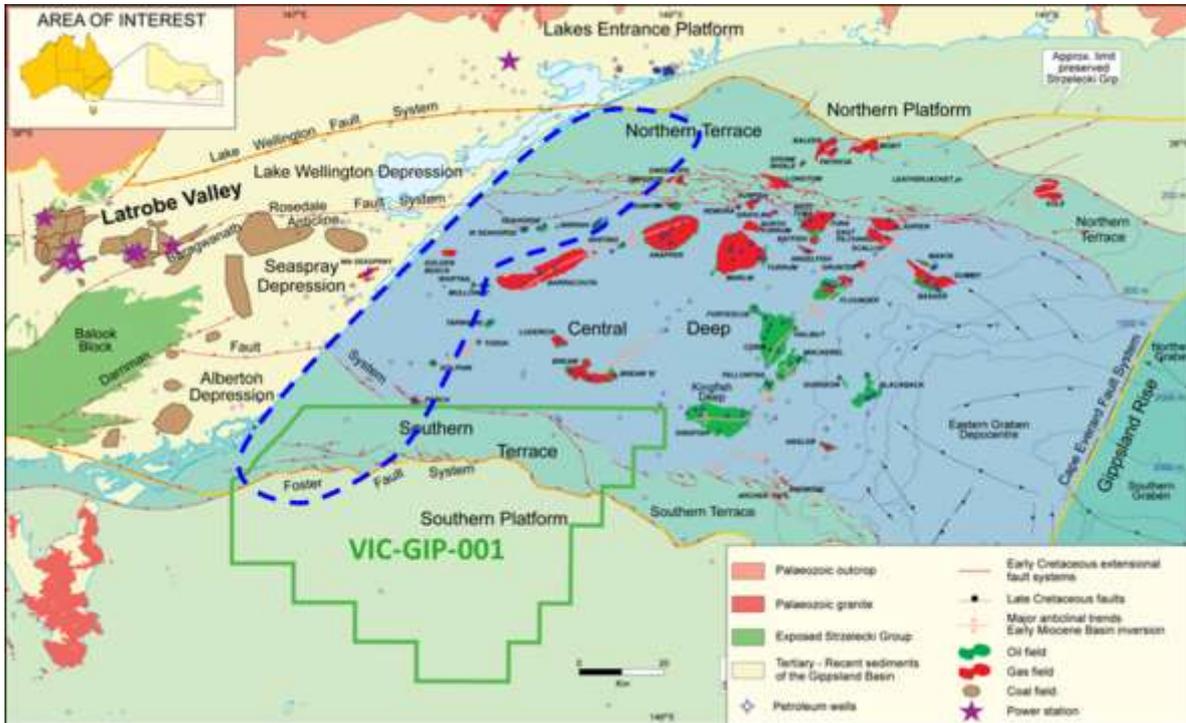
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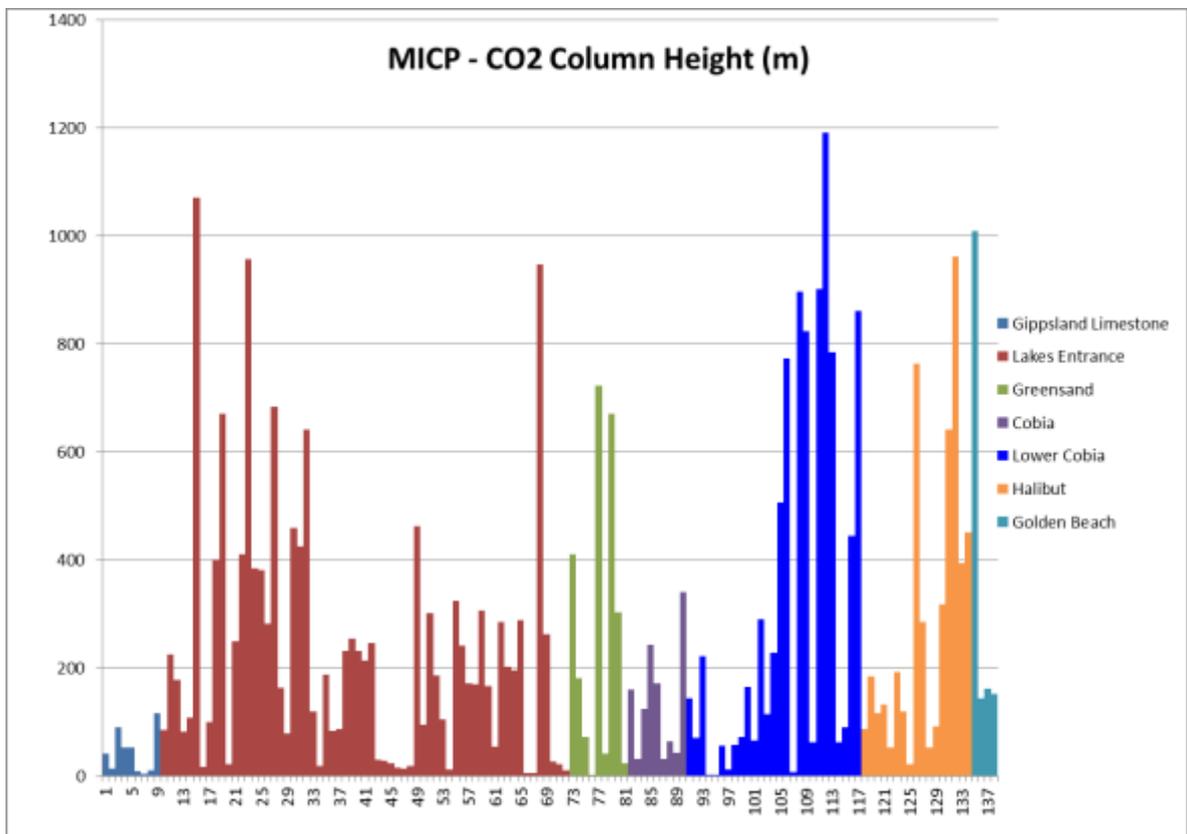
Figures

Figure 1: Basin Map



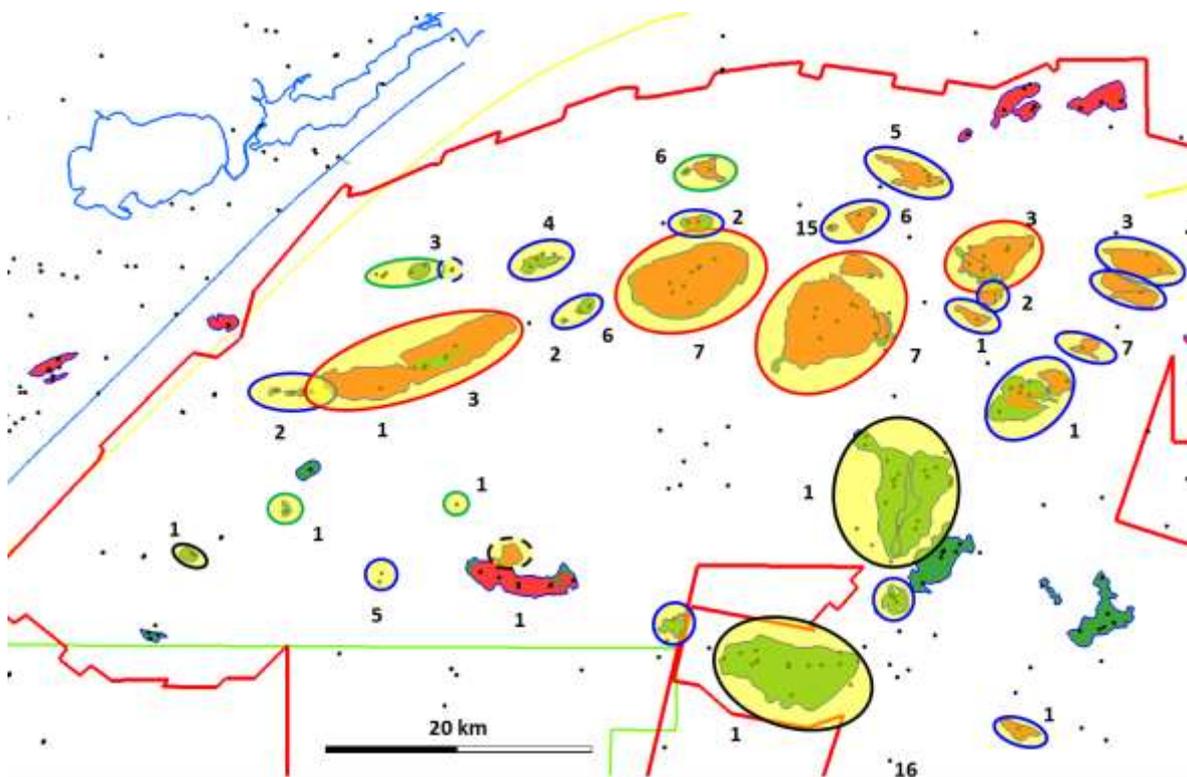
The CarbonNet area of interest (blue dashed line) covers the nearshore Gippsland Basin out to approx 25 km from the coastline, but avoiding major hydrocarbon accumulations. Basin architecture is a classic e-w rift basin with fill of fluvial clastics from the west and a shoreline backstepping over time from the eastern limit of the basin at ~80 Ma to behind the modern (intra-glacial) shoreline at ~25Ma, then advancing to the shelf edge at glacial lowstands. The northern and southern boundaries of the basin are fault-delimited and the rift section is thinned/partially eroded with poorer trapping potential.

Figure 2: MICP data sorted by geological formation for the Gippsland Basin.



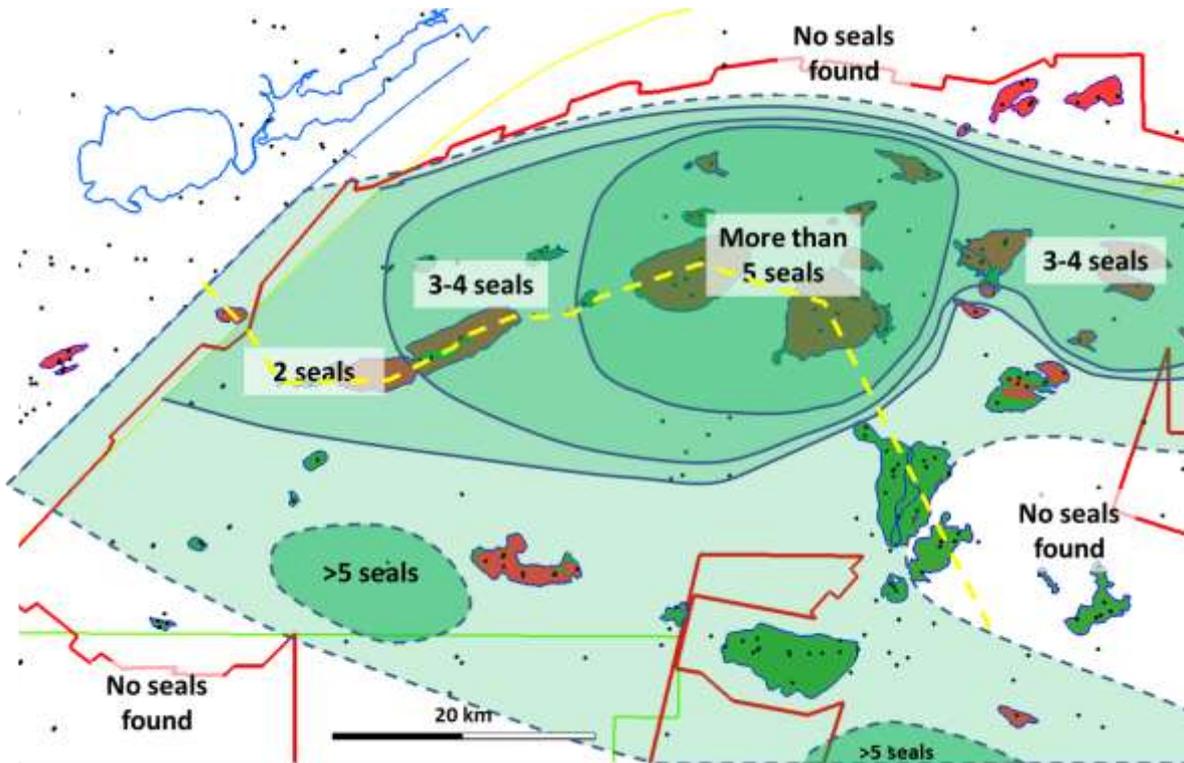
The cover sequence of Gippsland Limestone has poor seal capacity. The classic petroleum topseal of Lakes Entrance Fm. is an excellent seal, as is the underlying greensand. Upper Cobia Subgroup seals are poor, but many lower Cobia Subgroup (Traralgon Fm.) seals are again excellent and essentially equal to Lakes Entrance Fm. Some deeper Halibut and Golden Beach Subgroup seals also have merit.

Figure 3: Occurrence of intraformational seal fairways in the Gippsland Basin



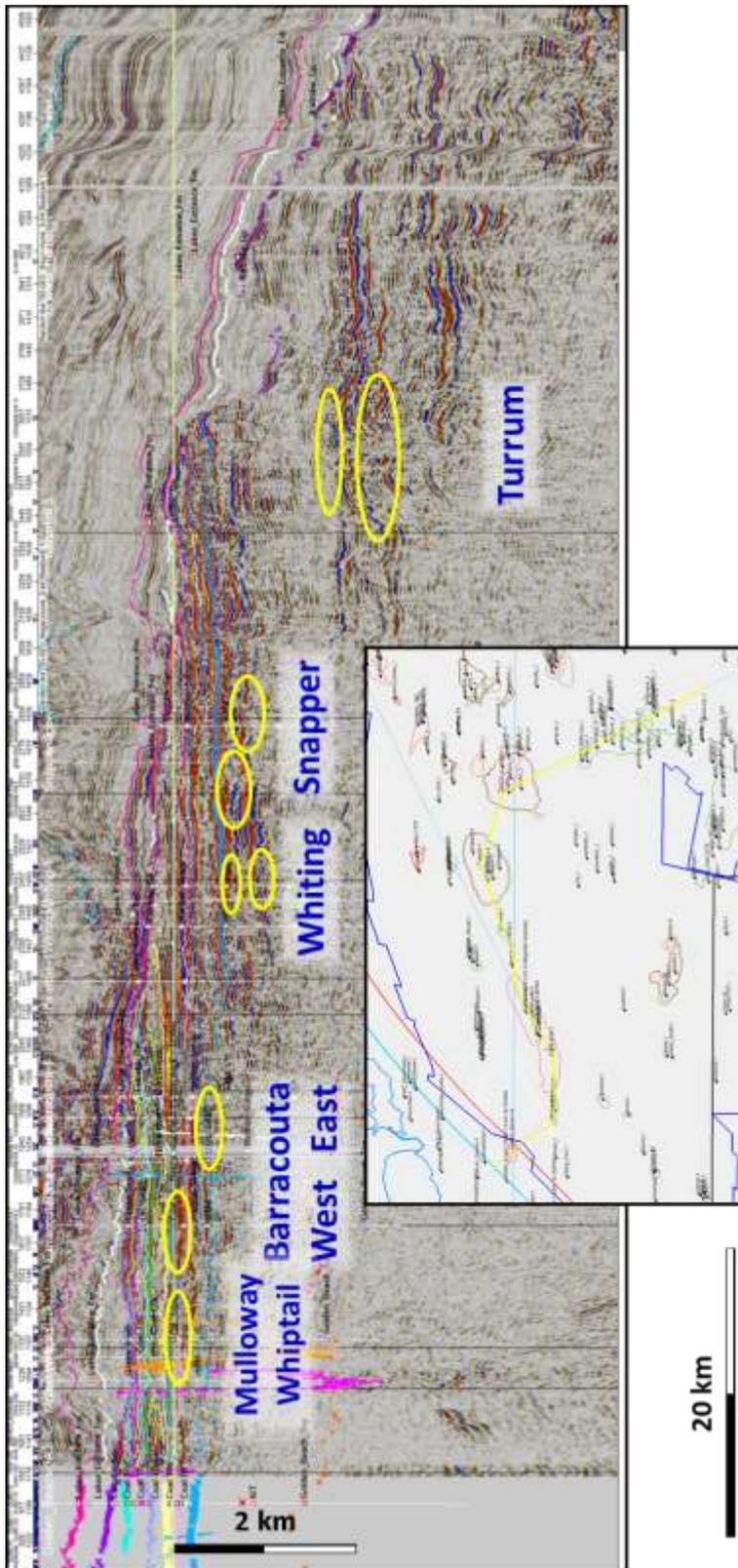
The number of intraformational seals proven by petroleum finds in the basin. Each distinct water contact or pressure gradient counts as one column. The pattern is difficult to interpret from this data alone. Coloured ellipses classify the types of intraformational seal: Red – A deeper pool lies below top Latrobe gas; Green – a deeper pool underlies top Latrobe oil; Blue – a deeper pool underlies water-wet top Latrobe; Black – a differential hydrocarbon water contact exists across a field (Dashed for Bream where a fieldwide oil-water contact exists, but gas-oil contact varies). Lakes Entrance Formation seals are proven over a wider area than intraformational seals – as evidenced by oil and gas pools without associated numbers of intraformational pools.

Figure 4: Map of intraformational seal fairways in the Gippsland Basin



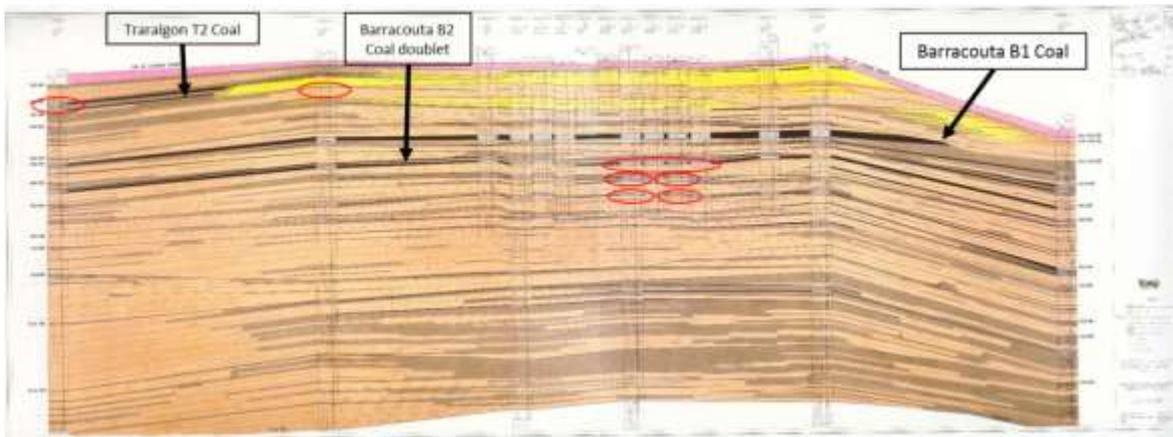
A contour map of the trend of Figure 3, showing the clear definition of an intraformational seal fairway in the northern half of the basin, a deficit of seals along the axis of the basin, and the suggestion of a second seal fairway on the southern margin. More seals may exist in areas near the edges of the basin, where petroleum migration and preservation is limited, but this diagram measures proven intraformational petroleum pools only. Lakes Entrance Formation seals are proven over a wider area than intraformational seals – as evidenced by oil and gas pools outside of the green contours.

Figure 5: Backstepping intraformational seals and coal beds in the Latrobe Group



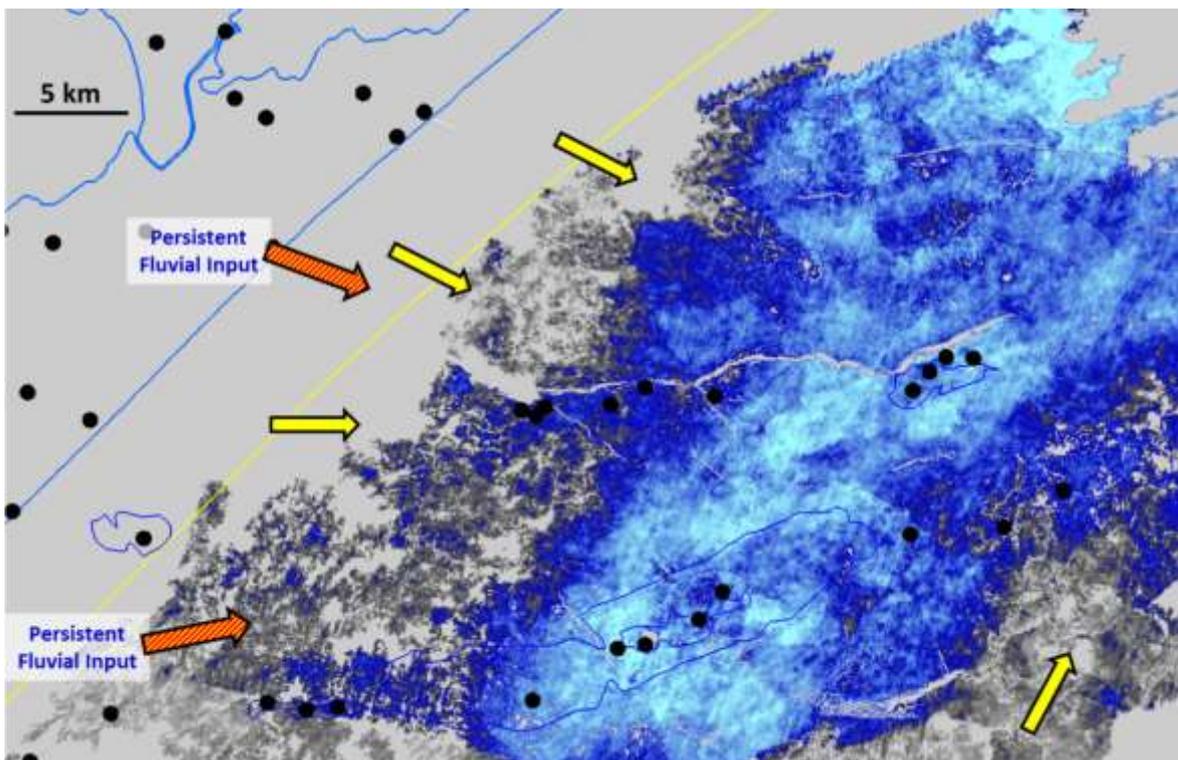
A flattened seismic section across the axis of the northern seal fairway showing backstepping intraformational seals (yellow ellipses) associated with the landward side of prominent coal reflectors.

Figure 6: Esso Australia Sequence Stratigraphic Correlation of Barracouta Field



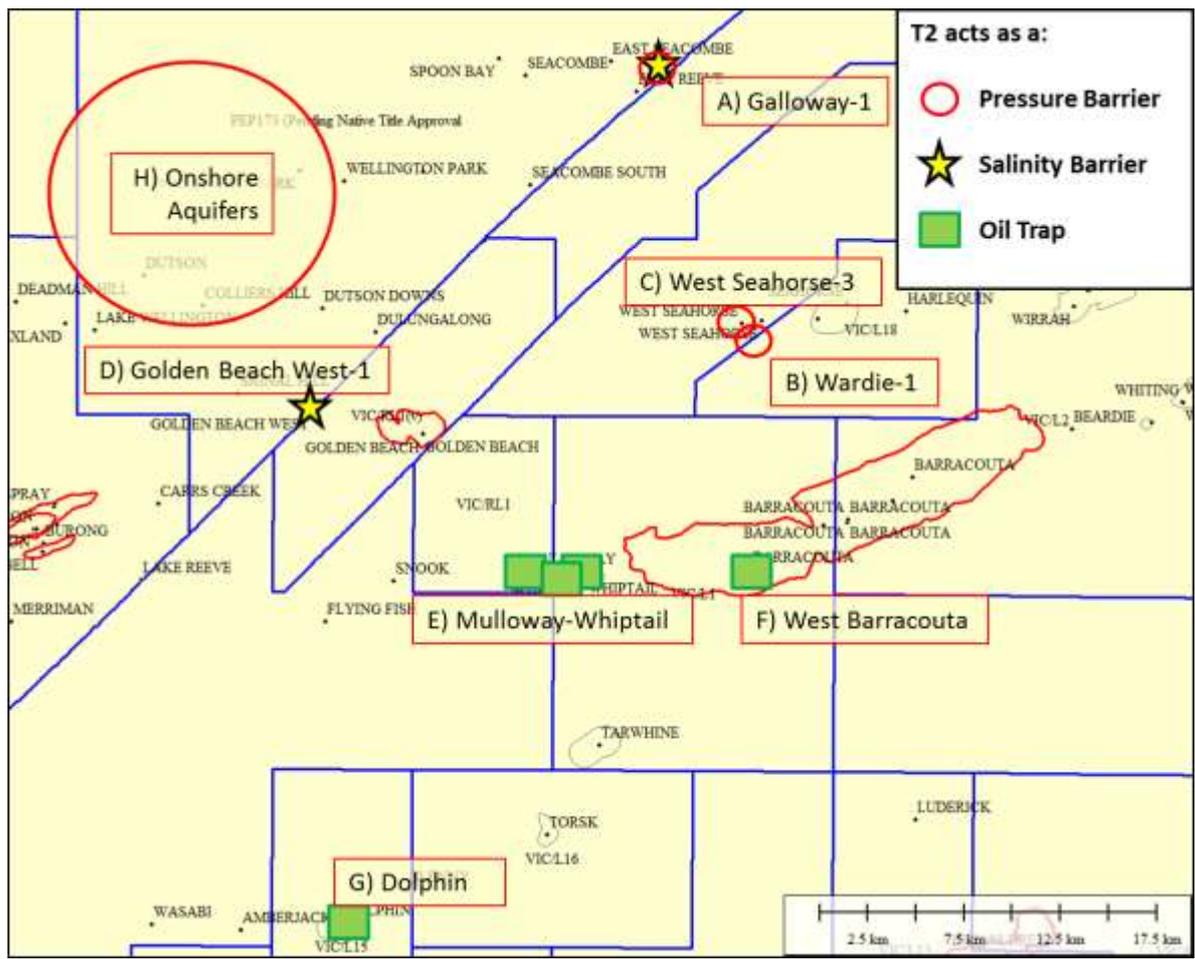
This well correlation section along the same alignment as Figure 5 shows backstepping intraformational seals (red ellipses) associated with the basal zone of prominent coals. (Section is not formally published, but is on Open File).

Figure 7: Seismic amplitude map of the prominent Barracouta “B1” coal.



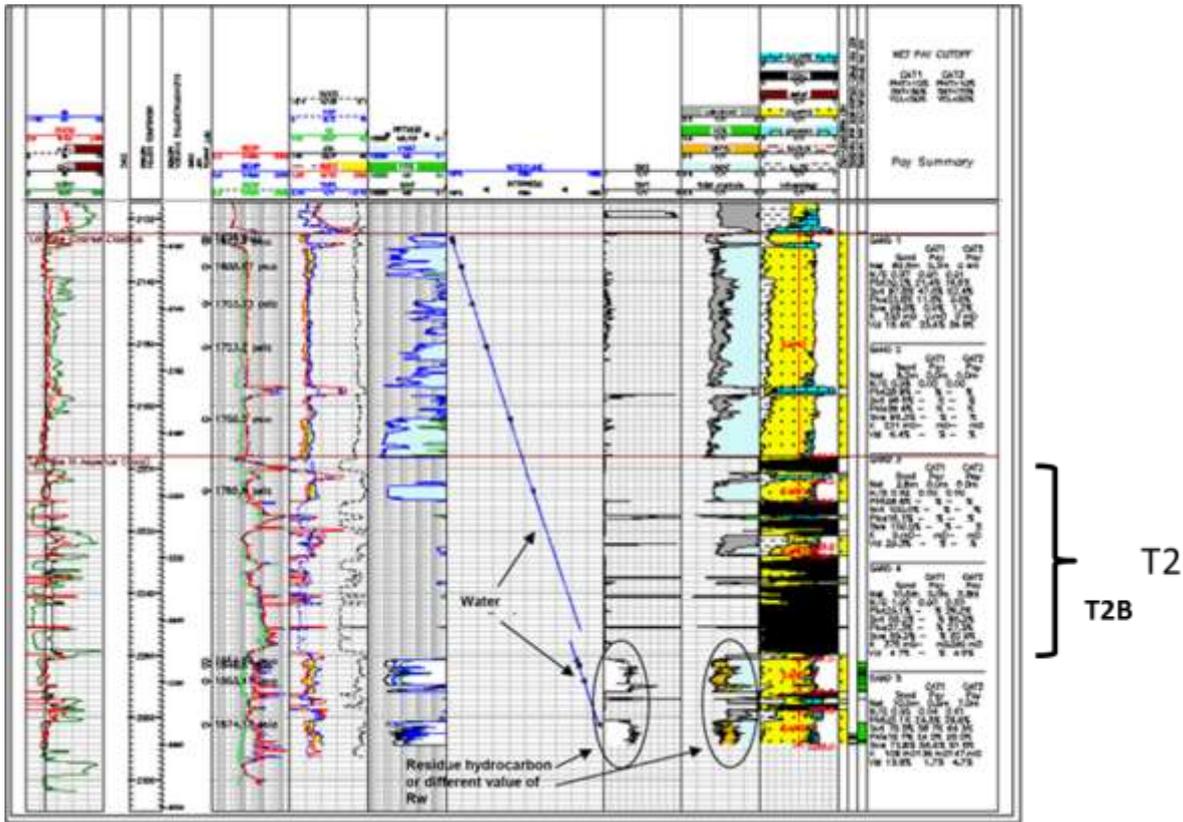
A clear depocentre is aligned NNE, with a set of sub units aligned more ENE, on the trend of modern pup-up structures (oil and gasfields, outlined in blue). Fluvial inputs can be mapped by degradation of the coal amplitude and the identification of channel forms and meander belts

Figure 8: Occurrences of proven seal across the Traralgon T2 member.



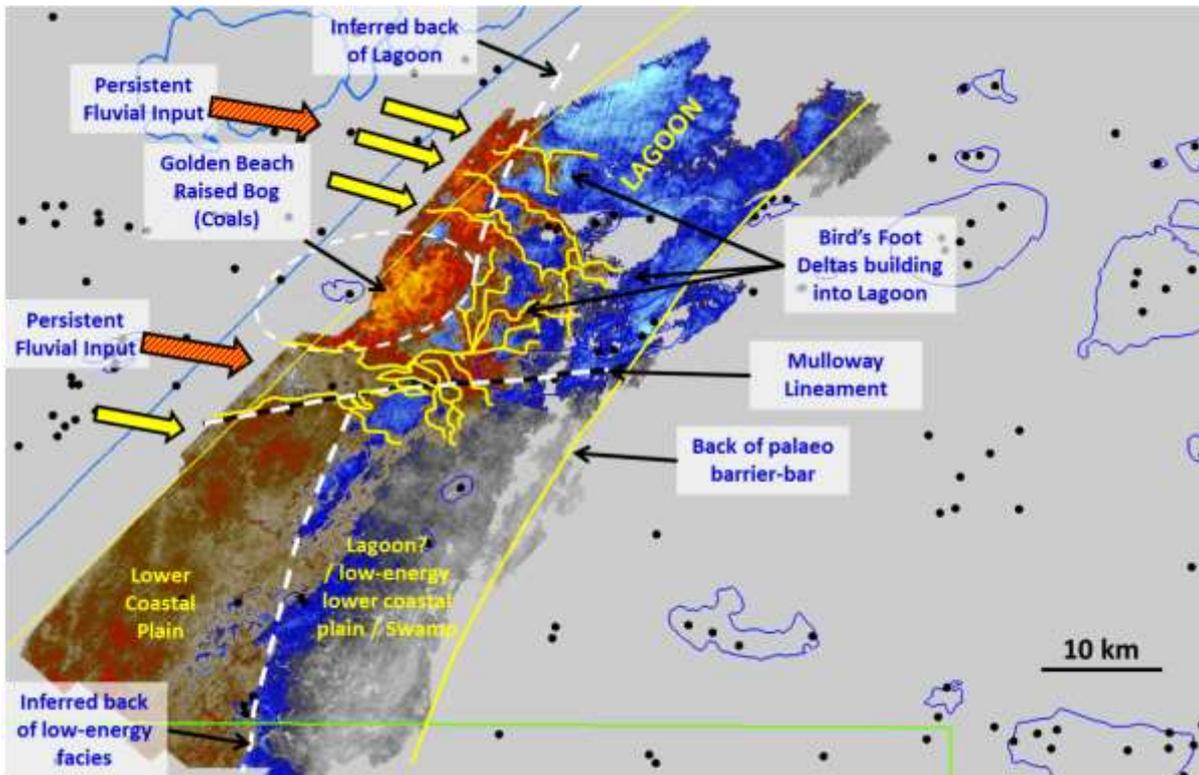
This unit variously acts as a pressure barrier (red circles), a salinity interface (yellow stars) or as a seal for a deeper oil ley (green square). At Dolphin field, the T2 acts as a base seal for an oil leg.

Figure 9: Pressure and salinity contrast across Traralgon T2 member at Galloway-1



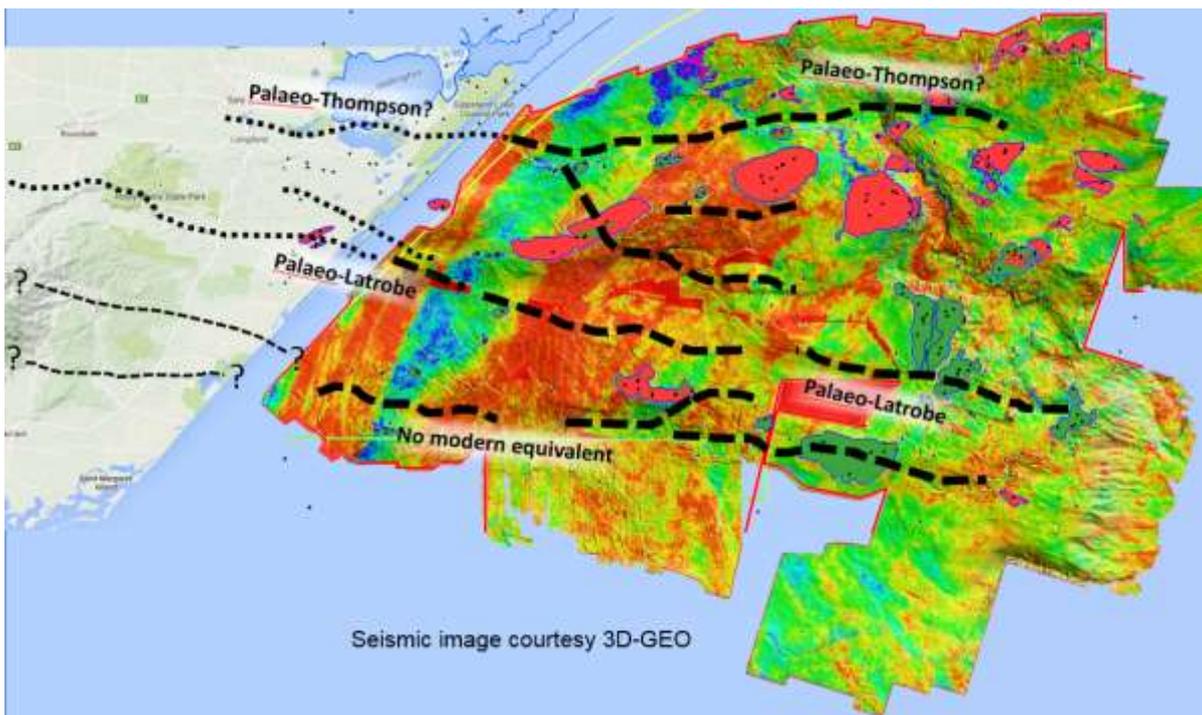
Extract from Galloway-1 WCR showing operators interpretation of the unit that CarbonNet correlates as T2B, acting as a pressure and salinity barrier.

Figure 10: Middle N. asperus palaeogeography (Traralgon T1/T2)



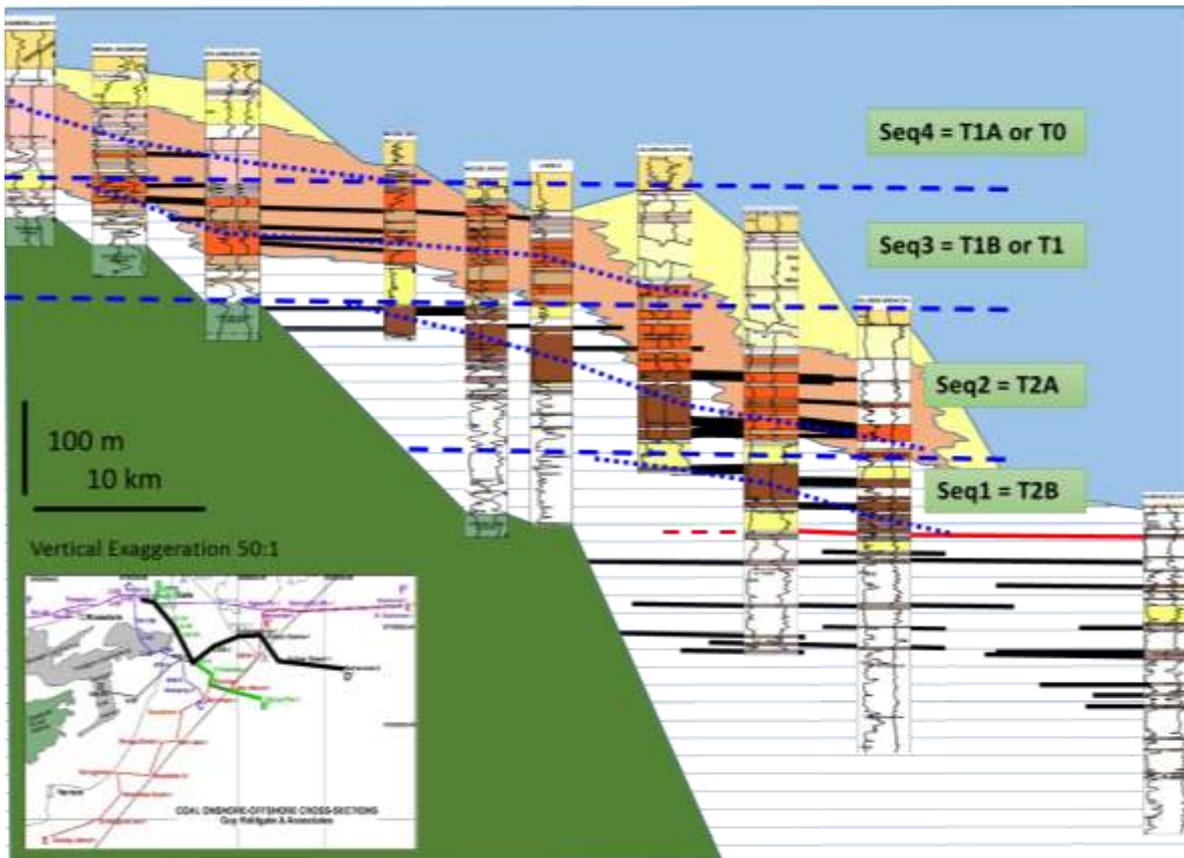
Palaeogeographic interpretation of finger- and birds-foot deltas building into the Seahorse Lagoon. Note raised bog coals in Golden Beach area (enhanced amplitude through tuning), and offset of barrier bar facies along Mulloway lineament.

Figure 11: Palaeo river systems of the Latrobe Group



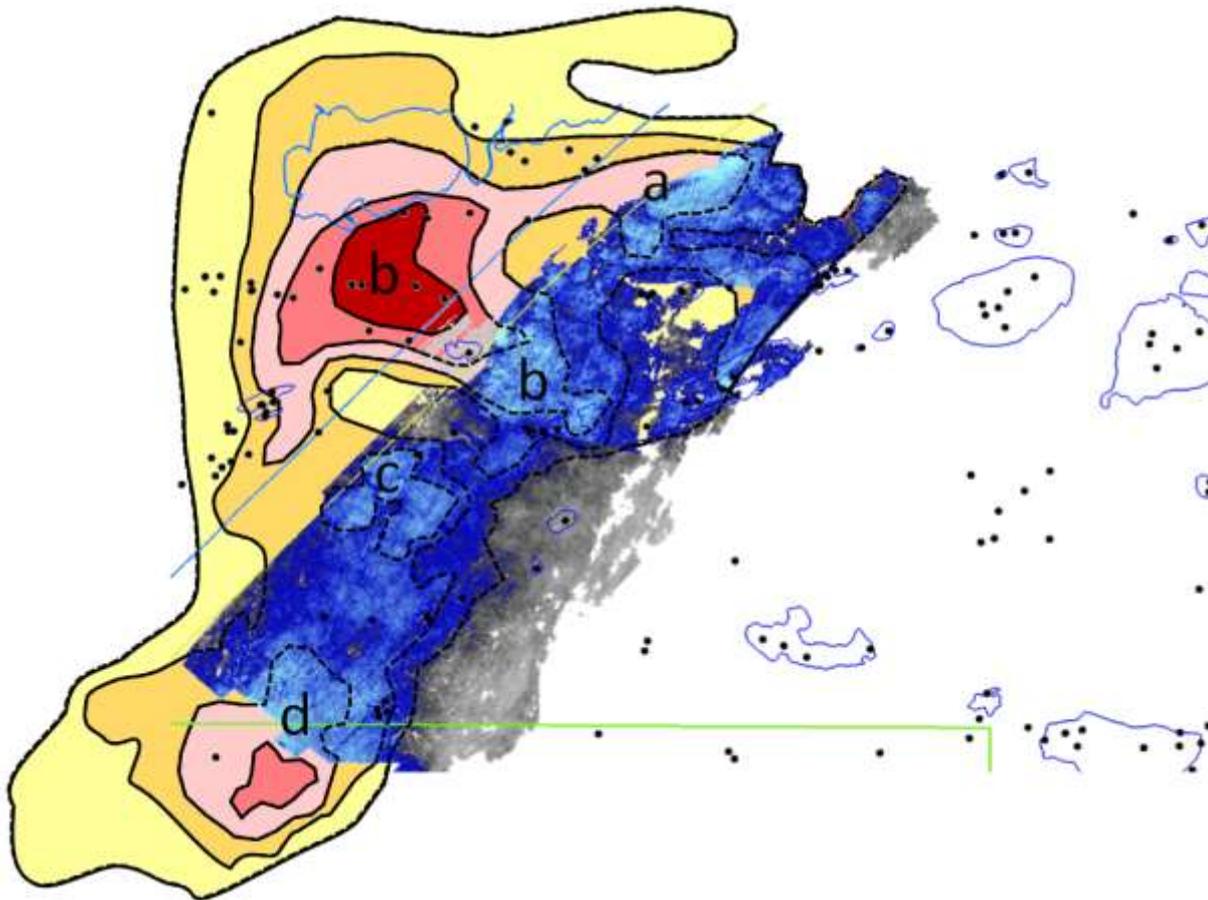
Interpreted persistent fluvial systems within the Latrobe Group. Coloured surface is seismic response (amplitude) at top Latrobe Group from which some of the evidence for channel location is drawn. Red corresponds to barrier-bar sands, green and blue to shale and coal. The Palaeo-Latrobe is the axial system in the basin. Two flanking systems feed along fault lineaments to the south and north. Other evidence comes from intra-Latrobe seismic response and well data (not shown).

Figure 12: Onshore-offshore correlation of the Traralgon coal sequences in the nearshore Gippsland Basin



A provisional correlation of the Traralgon coal sequences in the nearshore Gippsland Basin (+25 km from shoreline). Four parasequences are identified, each transgressive, commencing from a basal regression. T2B is the first of these sequences and the overlying ones may be assigned to T2A, T1B and T1A or alternatively to T2A, T1, and T0. Further work is required to confirm this correlation. Depositional environment is flagged as coloured backdrop (blue, marine; yellow, paralic; orange, estuarine, and white, fresh water). Strzelecki “basement” is indicated in green. Major correlation lines are included but for clarity of the background environment, not all coals are highlighted.

Figure 13: T2 member isopachs – CarbonNet key nearshore seal



A compilation of 3D seismic amplitude (blue colours), CarbonNet 2D isopachs on the southern margin, and borehole isopachs, modified after Holdgate et al. (2000). Four depocentres of the Traralgon T2 sequence are identified (a to d), between zones of fluvial throughput (not marked, but identifiable from isopach thins and amplitude drop-out).