Hydrocarbon Potential of Eastern View Group Reservoir Rocks, Bass Basin, Australia

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CHAPTER 3

3. Porosity Trends and Regional Reservoir Quality in the Bass Basin

Past hydrocarbon exploration in the Bass Basin has proved the presence of mature source rocks in many parts of the basin which have generated and expelled liquid and gaseous hydrocarbons. Exploration had also identified lack of hydrocarbon charge into the Upper EVG, which may indicate hydrocarbons may have trapped in deeper reservoirs. Deeper reservoirs of interest are sand-dominated aggradational and retrogradational EVG sediments which contain many fine-grained sediments that may make migration of hydrocarbons more complicated. If hydrocarbons are trapped within the reservoirs of the Middle and/or Lower EVG, the reservoir quality of these successions has large implications for the basins prospectivity.

A regional porosity study, utilising well and log data (Appendix 2) has been undertaken to characterise the regional reservoir of the Middle EVG. A regional porosity study of the EVG was undertaken to better understand the occurrence of the reservoir and seal pairs, as well as depositional history of the basin. Determination of the regional reservoir qualities is also an important input for 2D and 3D basin models, particularly for hydrocarbon migration and accumulation modelling. The study was combined with optical observations from thin sections of the reservoir sands (Appendix 3) and other data to verify the causes of porosity trends observed within the Middle EVG succession.

The porosity trends and regional reservoir quality evaluation of the Bass Basin was published in the APPEA Journal, 2008 and is included in this thesis in its published format. The published article describes the data and methods used for porosity trends and regional reservoir investigation, including log-derived porosity determination and validation. It also discusses the findings and conclusions of the study as can be read below:

Arian, N., Tingate, P.R. & Hillis, R.R. (2008) Porosity trends and reservoir quality in the Bass Basin *APPEA Journal, v. 48, pp. 227-239*

NOTE:
This publication is included on pages 58-70 in the print copy of the thesis held in the University of Adelaide Library.

CHAPTER 4

4. 2D Generation, Expulsion, Migration and Accumulation Modelling

2D basin modelling allows simulation of the thermal maturity of source rocks, as well as fluid flow with three phases (water, liquid petroleum and gas). Darcy flow models are based on differential equation systems for the competing fluid phases (Hantschel& Kauerauf, 2009). It is also relatively easy to construct a 2D model, since it normally requires only depth converted 2D seismic line. Petroleum systems of the Bass Basin were modelled using Integrated Exploration Systems (IES)'s PetroMod10™. To analyse the basins petroleum systems, 2D PetroBuilder and 2D Simulator packages within PetroMod10™ were used to develop several 2D generation, expulsion, migration and accumulation models within several different locations across the basin.

The strength of 2D modelling is the ability of running quick simulations, which can provide a good prediction for hydrocarbon generation and expulsion across key traverses if good sections are chosen for modelling. However, its hydrocarbon migration and accumulation modelling are somewhat limited, 3D modelling is needed for full description.

The temperature profile of the Bass Basin (thermal data and their trend cross plot from 31 wells) used for 2D modells as well as 3D model (discussed later in this thesis) are attched (Appendix 4).

4.1. 2D Generation, Migration and Accumulation Modelling in the Central Bass Basin

It was important to model the deepest troughs of the basin, as the first pulses of expulsion would be expect to start within such regions. Hydrocarbon migration within deep troughs in the central part of the basin has the potential to indicate general migration patterns of the basin, as well as contributions to understand deeper reservoir/seal pairs in relation to hydrocarbon migration and possible entrapment. Two 2D models from the central Bass Basin were published in the PESA Eastern Australian Basins Symposium III. The publication outlines data, methods and calibration of the models; the results are also discussed in the publication. The published article is included in this thesis in its published format:

Arian, N., Tingate, P.R. & Hillis, R.R. (2008) Modelling petroleum generation, migration and accumulation in the central Bass Basin, Tasmania, Australia
PESA Eastern Australasian Basins Symposium III, Sydney, Australia, pp. 45-57

NOTE:
This publication is included on pages 73-85 in the print copy of the thesis held in the University of Adelaide Library.

4.2. 2D Generation, Migration and Accumulation Modelling across the Bass Basin

In addition, to the two published 2D models, several other 2D models were constructed to analyse different parts of the basin. 2D seismic lines that have the most calibration data in certain parts of the basin were carefully chosen for modelling. The 2D modelling pattern considered here can be useful for a quick understanding of general hydrocarbon migration pathways and accumulation within sediments of the basin. Locations of the modelled lines are shown in Figure (4.1).

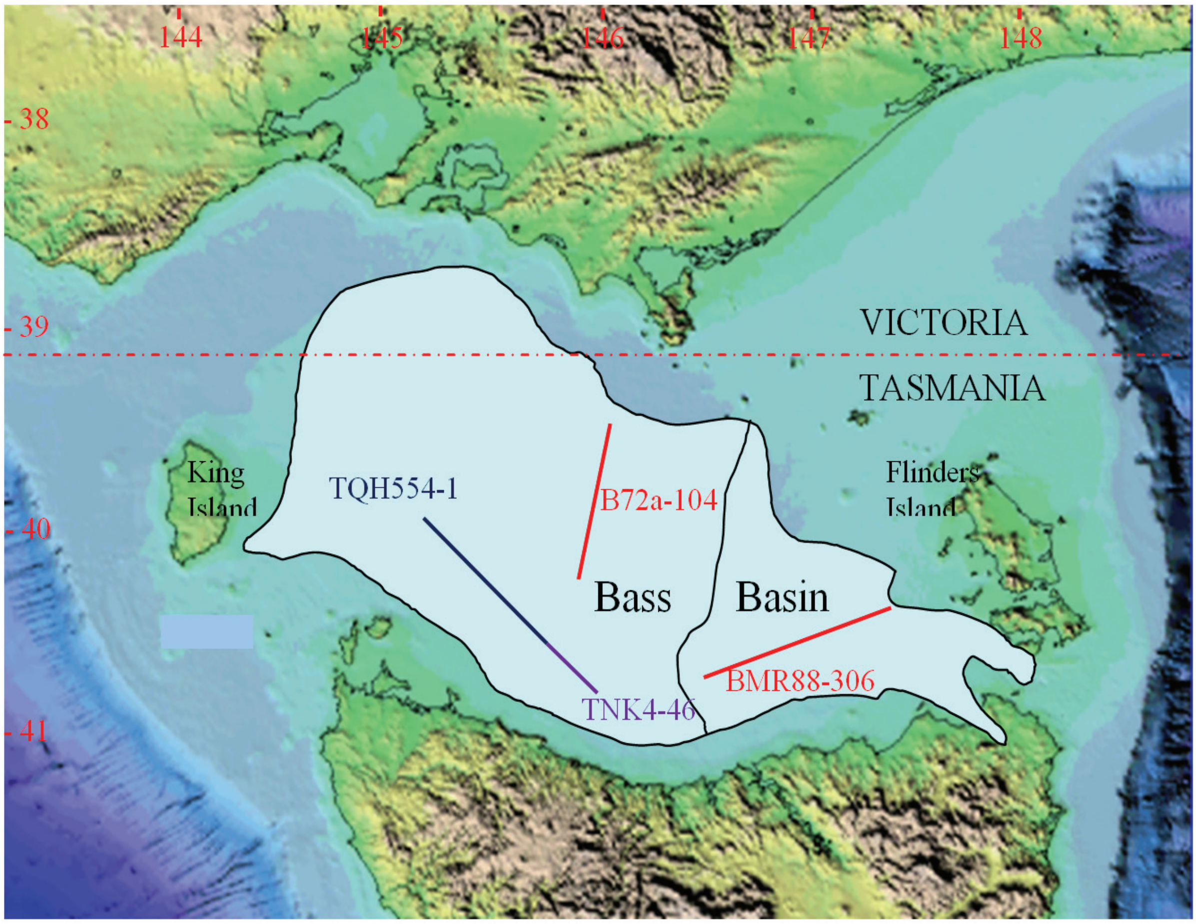

Figure 4.1: Map of the Bass Basin, showing the location of the 2D seismic lines used for modelling.

The model construction, simulation and calibration processes followed the methods described in the Part-1 of this chapter. Thus, only maturity, migration pathways and accumulations from these models are discussed in this part.

4.2.1. Hydrocarbon Generation and Expulsion

4.2.1.1 Line B70a-6a and B70a-6b, central Dondu Trough

This line intersects Bass-2, Yurongi-1 and Dondu-1 wells of Dondu Trough (Fig. 4.1). The isomaturity lines in Dondu Trough are similar to what have been seen in both the Yolla and Cormorant Troughs (Fig. 4.2). The source rocks of Upper EVG (with < 0.55 %Ro) - Aroo and Flinders aequences - are still not mature for oil expulsion at the present time. The Narimba sequence is lying within the main oil window and Tilana sequence within late oil window. While most of Furneaux sequence and Durroon Formation are within wet gas window (1.3-2.0 %Ro), however lower parts of Durroon Formation together with Otway Group have passed wet gas window and are within dry gas window (2.0-4.0 %Ro) at the present time.

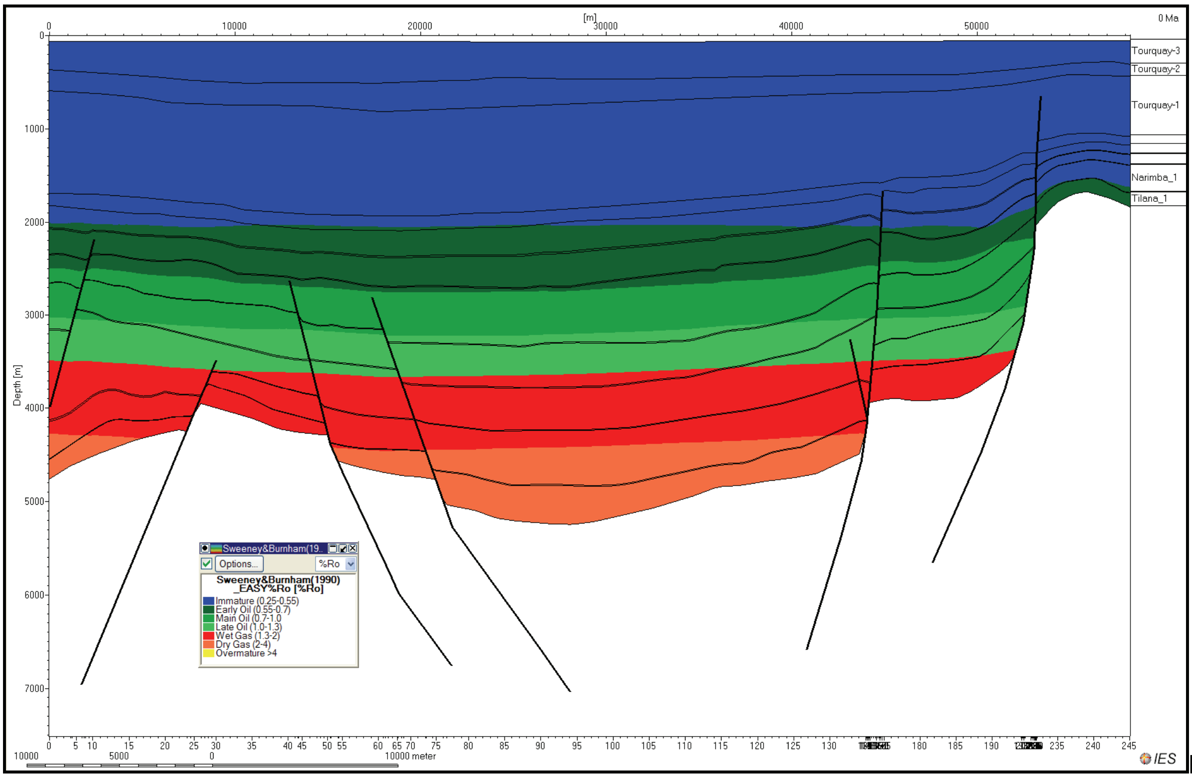

Figure 4.2: Maturity lines in the Dondu Trough at the present time (0Ma)

4.2.1.2 Line BMR88-306 of central Durroon Sub-basin.

This line passes through the Durroon-1 well, the sole well of the central Durroon Sub-basin, which is located in the central part of the Anderson Trough. 2D maturity modelling of this line shows that the source rocks of Upper EVG and Middle EVG in this area are not mature for oil generation even at the present time.

Source rocks of Lower EVG are partially entered main oil window were they are buried deep. Otway Group sediments are widely mature for oil expulsion, especially in the deeper areas of the Durroon Sub-basin (Fig. 4.3).

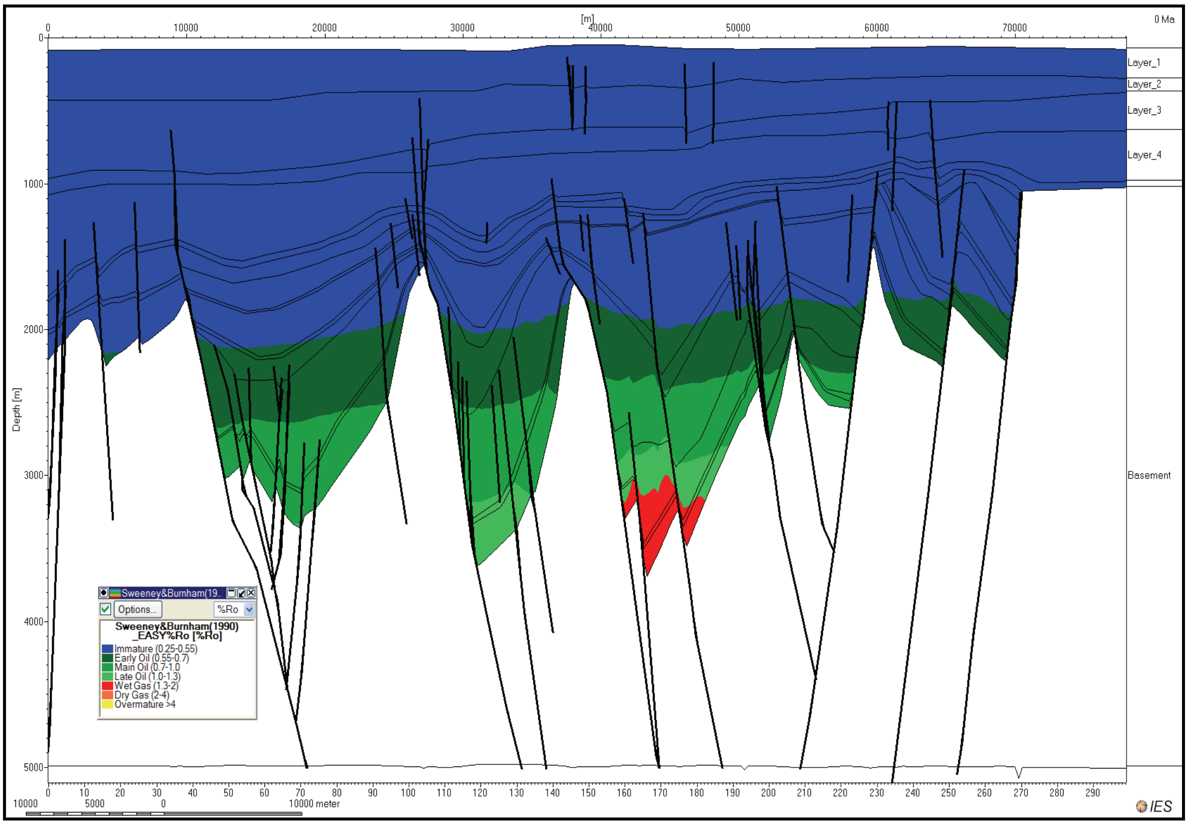

Figure 4. 3: Maturity lines in the Durroon Sub-basin at the present time (0Ma)

4.2.1.3 Western Cape Wickham Sub-basin

One continuous line has been constructed from TQH554-1 and TNK4- lines for the purpose of modelling, which in essence are extension of each other cross both the Yolla and Pelican troughs. It is important to assess the maturity in these two troughs of the Cape Wickham Sub-basin which have differences in heat-flow, as the Pelican Trough has a higher heat flow than the Yolla Trough.

The 2D modelling suggests the prominent source rocks of the Upper EVG, together with sediments of Narimba sequence (upper Middle EVG) in the Yolla Trough, have still not entered the main oil window (0.7-1.0 %Ro). In the Pelican Trough, most of

Upper EVG sediments are within the main oil window, and the Narimba sequence sediments are within the late oil window (1.0-1.3 %Ro) and deeper parts of the same sediments are just entering wet gas window (1.3-2 %Ro). Further details can be find in Fig. 4.4.

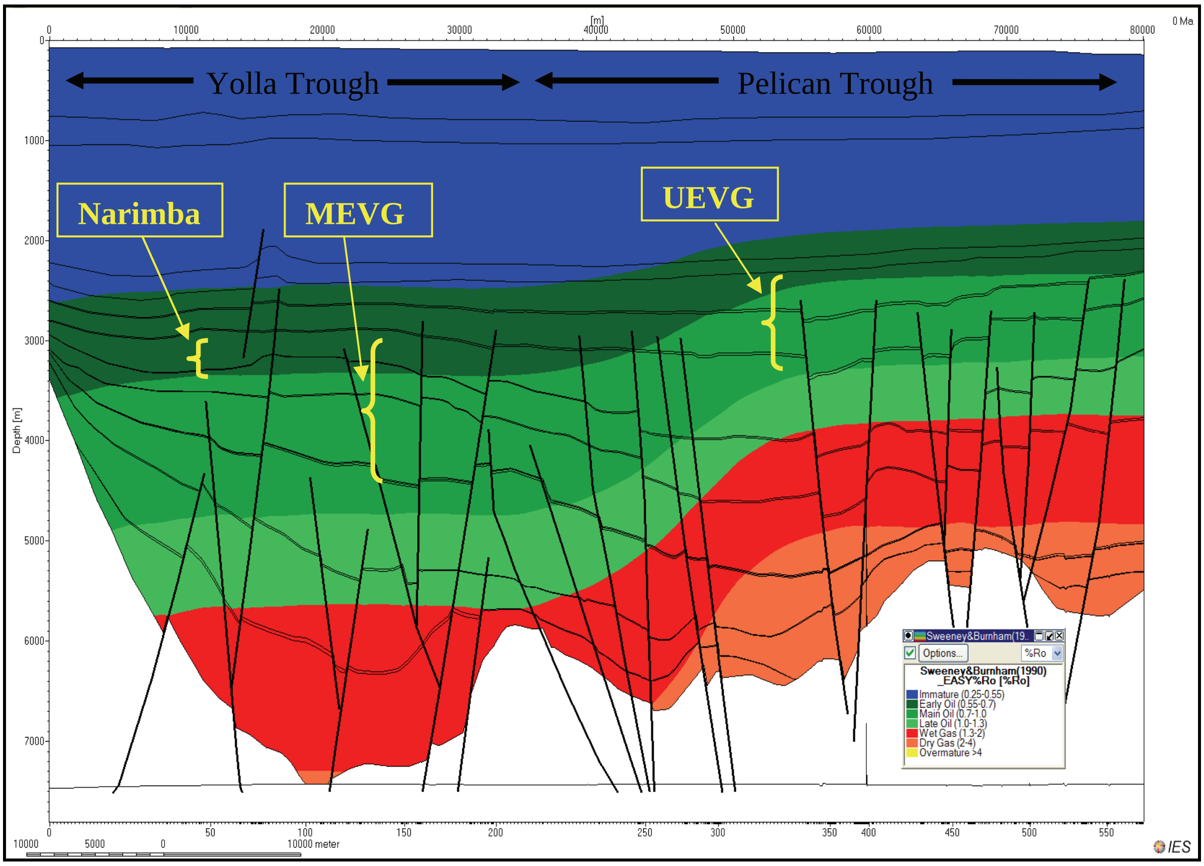

Figure 4.4: Maturity lines in the Yolla and Pelican Troughs at the present time (0Ma)

4.2.2. Hydrocarbon Migration and Accumulation

The older source rocks of the Bass Basin, which are buried deep in the central part of the different troughs in the basin, are providing the first pulses of hydrocarbon expulsion in the basin. However, sediments of the Crayfish, Otway and Durroon groups are not fully known, but are believed to provide some source rock, reservoir and sealing facies. The frequency and thickness of the coals (source rocks) increases upwards in the sediments of Middle and Upper EVG, which with their transgressive-regressive nature could provide a favourable stacking of reservoir and seal facies (Blevin, 2003). The existence of stacking of reservoir and sealing facies, together with fault planes has an enormous effect on hydrocarbon migration pathways.

A porosity trends study undertaken as a part of this project suggests existence of sealing facies with reasonable regional extent within sediments of the Middle and Upper EVG. These seals have variable thickness in different areas of the basin, but a previous sealing capacity analysis proved that these seals have excellent sealing capacity and ability to hold large columns of hydrocarbons (Daniel & Kaldi, 2003). If intraformational seals (thin with regional extent) are able to stop migration and trap hydrocarbons, then faults remain the only possible means for vertical hydrocarbon migration to upper reservoirs. Differences in fault permeability with adjusting formation permeability formulate the ability of faults to facilitate or oppose upward migration of hydrocarbons. Migration pathways, reservoir/seal pairs and entrapment structures are important elements affecting distribution of expelled hydrocarbon and their possible entrapment.

All 2D models suggest sufficient hydrocarbon expulsion in the Cape Wickham sub-basin. Previous workers recognised an inversion pulse during the Miocene which was oblique in direction (Cummings et al, 2004; Blevin et al., 2005). That is just during the filling process of the most reservoirs of the Lower and Middle EVG. The nature of the inversion suggests it has most likely reactivated a few suitably oriented faults to the direction of the far-filed oblique stresses. It is not possible to correctly model faults that are affected by the Miocene inversion and reactivated in a 2D model. Therefore, scenarios of reactivation have been equally applied to all the faults until acceptable predicted accumulations achieved. This issue best addressed in 3D migration modelling where the direction of the faults related to the paleo-stress directions can be investigated and expected faults affected by Miocene inversion can be determined. Overall, lack of hydrocarbon charge to many reservoir sands of the Upper EVG in several locations across the basin is due to little vertical migration may change current understanding of the basin’s hydrocarbon potential and provide a new insight into its hydrocarbon prospectivity.

4.2.2.1 Line TQH554-1 and TNK4-46 central Cape Wickham sub-basin

The 2D expulsion, migration and accumulation modelling of this line suggests early expulsion pulses in the Pelican Trough started as around 48Ma during the deposition of Aroo sequence. In contrast, expulsion in the Yolla Trough did not happened until during or after deposition of the Demons Bluff regional sealing unit, some of 11million years later. Both areas did not reach peak expulsion until Late Oligocene (until deposition of Flinders sequence had ended and deposition of Torquay sequence had started) around 28Ma. This observation outlines the importance of opening and sealing faults for the period of last 28 million years, which had the most effect on the distribution of hydrocarbon accumulations. The oblique inversion had affected suitably oriented faults only, with this situation during peak hydrocarbon expulsion being very important for the distribution of hydrocarbon accumulations. As discussed earlier it is not possible to determine fault directions in 2D modelling. therefore all the faults during this oblique reactivation were treated equally and remained open. The model showed that even if all the faults were open during the reactivation (as simulated), still predicts minimum hydrocarbon charge for the reservoirs of the Upper EVG (Fig. 4.5). This emphasizes limited vertical hydrocarbon migration in the Bass Basin.

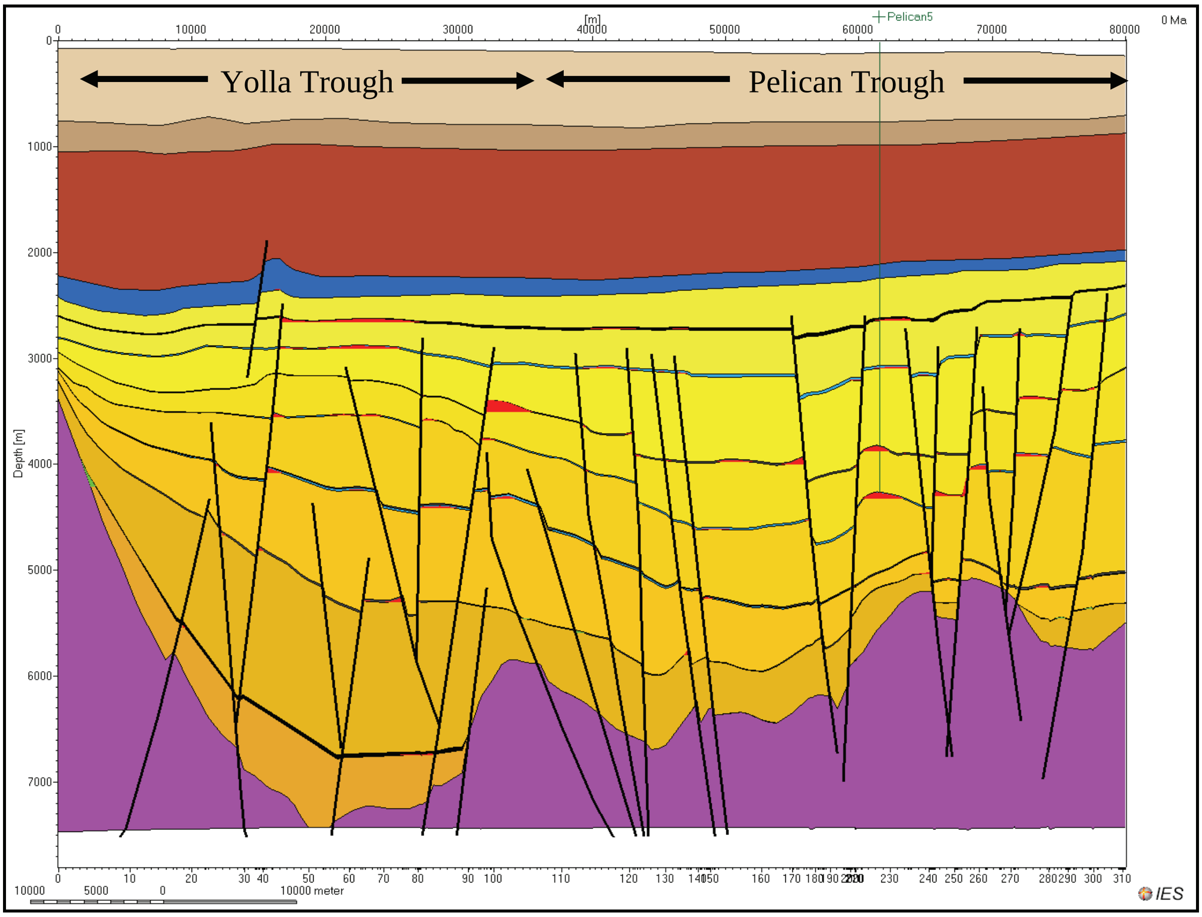

Figure 4.5: Predicted hydrocarbon accumulations across TQH554-1 and TNK4- lines within the Pelican and Yolla troughs.

4.2.2.2 Line B70a-6a and B70a-6b central Dondu Trough

This line has been chosen for 2D modelling because it runs through Bass-2, Yurongi-2 and Dondu-1 wells in the area, which could provide excellent calibration opportunity.

Unfortunately vitrinite reflectance data for Yurongi-1 and Bass-2 wells are not enough to establish a confident paleo-heat flow for this area, that is either because of limited readings or because samples have been taken over a very narrow range of depth. To overcome this problem several paleo-heat flow scenarios have been played on this model. The scenarios vary maturity level but did not predict much different accumulations than what have been predicted with calibrated paleo-heat flows (with limited calibration data).

The model predicts very few accumulations but unlike Yolla, Cormorant, and Pelican troughs, the reservoirs of Upper EVG now trap the accumulations (Fig. 4.6). That is due to presence of cleaner sands in this area and small N-S striking Eocene faults, which are suitably oriented to the direction of the Miocene reactivation, are largely controlled by older Cretaceous faults, near the eastern flanks of the basin. Some of these faults were interpreted to be part of the Cretaceous faults, which makes such Cretaceous faults appear to have propagated upwards into the Upper EVG sediments within the eastern margins of the basin.

4.2.2.1 Line BMR88-306 of central Durroon Sub-basin

Even though the source rocks have generated and expelled hydrocarbons in some parts of this area, the 2D model does not predict any accumulations. Instead the model illustrates that some generated hydrocarbons remained in the source rock at full saturation. The excess hydrocarbons expelled are volumetrically limited and although they migrated up words and partially saturate parts of some structures there is not enough to make accumulations (Fig. 4.7).

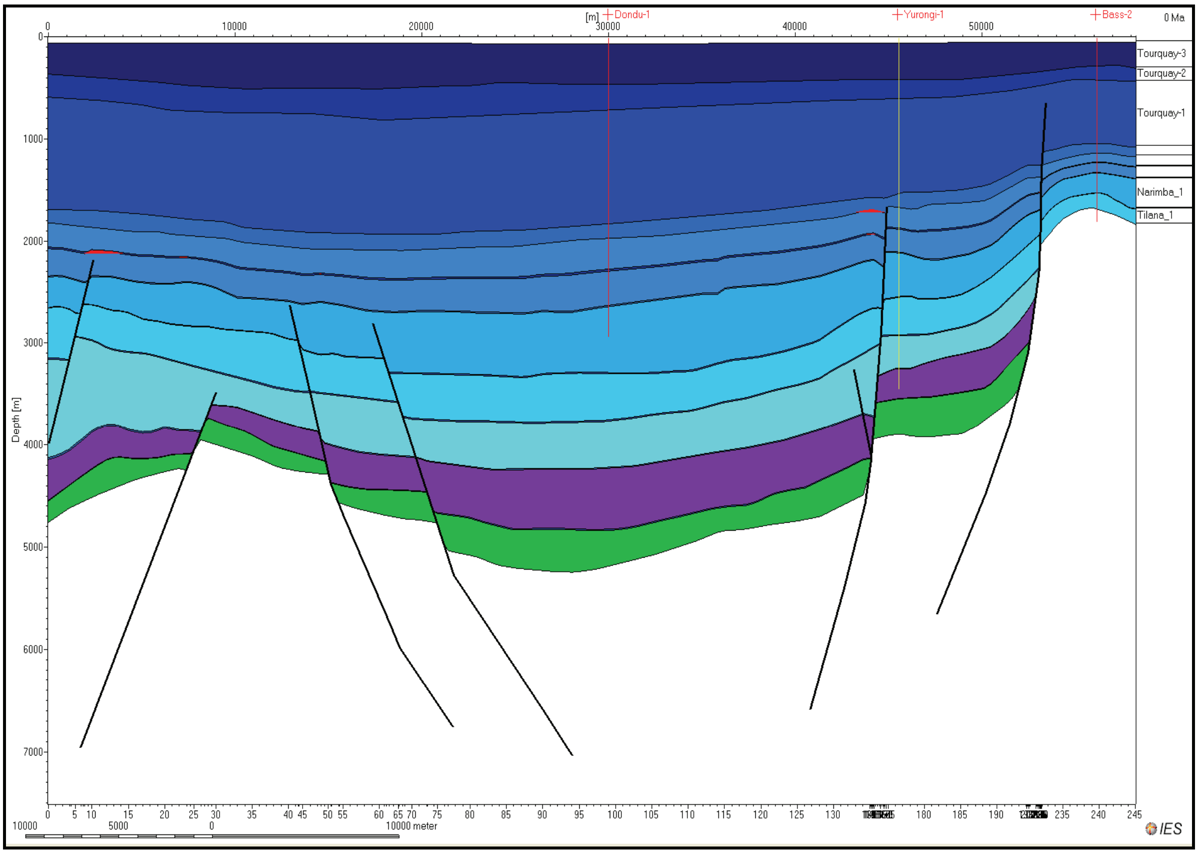

Figure 4.6: Predicted hydrocarbon accumulations across B70a-6a and B70a-6b lines within the central Dondu Trough

4.2.2.2 Line BMR88-306 of central Durroon Sub-basin

Even though the source rocks have generated and expelled hydrocarbons in some parts of this area, the 2D model does not predict any accumulations. Instead the model illustrates that some generated hydrocarbons remained in the source rock at full saturation. The excess hydrocarbons expelled are volumetrically limited and although they migrated up words and partially saturate parts of some structures there is not enough to make accumulations (Fig. 4.7).

4.2.3 General sense of the basin's petroleum systems

Different 2D basin models of the various parts of the basin illustrate generation and expulsion of hydrocarbons in both Cape Wickham and Durroon sub-basins. The expelled hydrocarbons migrate both vertically and horizontally making their paths through permeable layers and faults. The sediments of the EVG in the Bass Basin consist of fluvial-lacustrine clastic sediments which includes reasonable amounts of fine-grained sediments such as shale and claystone. The presence of fine-grained clastics had limited hydrocarbon migration pathways. Fine-grained sealing facies have effectively stopped vertical migration of hydrocarbons, but also may have affected permeability of the faults to act as barriers to migration. Expelled and migrated hydrocarbons have been trapped in the reservoirs of EVG, mostly close to their source and mainly in the reservoirs of Middle EVG. Some of these hydrocarbons has escaped entrapment in the lower sections of EVG and charged reservoirs of Upper EVG, but only in places where faults suitably oriented to the direction of the Miocene inversion reactivation.

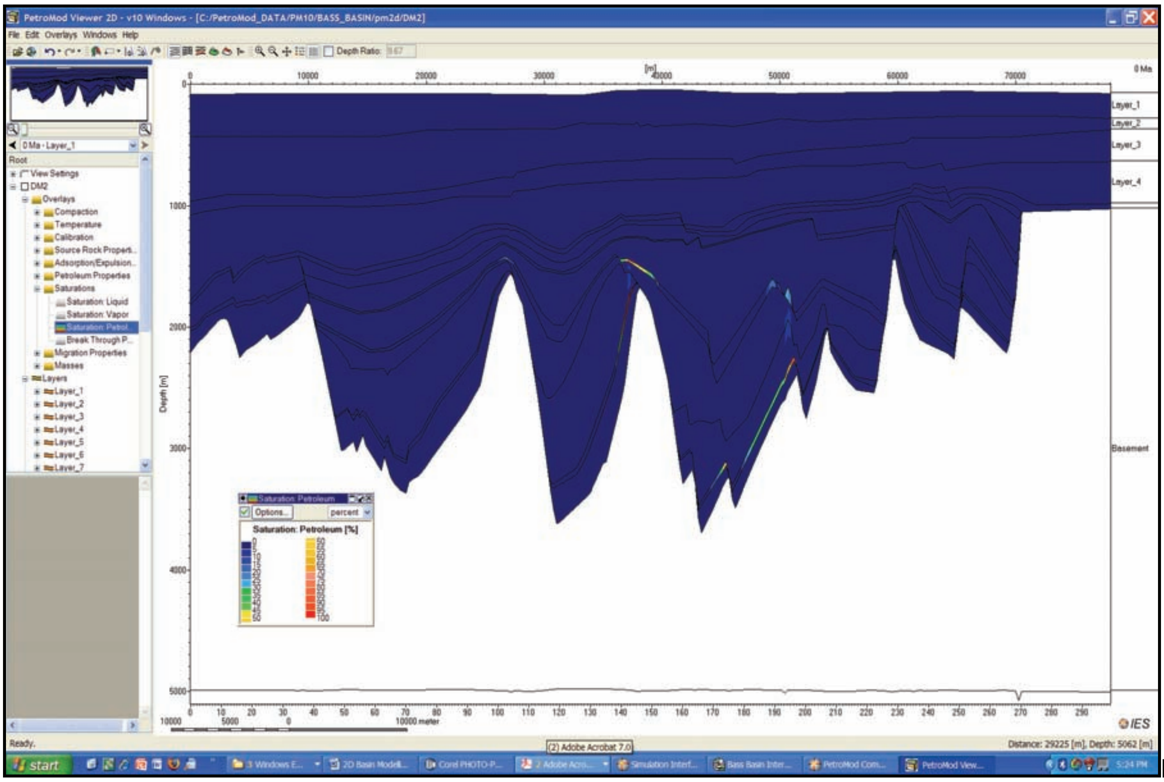

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Figure 4.7: Petroleum saturation in the Durroon sub-basin.

CHAPTER 5

5. 3D Petroleum Systems Modelling

The concept of basin modelling is to model all the geological, physical and chemical elements that have played a role during the development of sedimentary basins, which leads to a better understanding of the current petroleum systems.

Sedimentary basins contain a record of both its burial and possible exhumation history. The thermal history relies on this burial history and the physics of heat transport (Hermanrud, 1993; Poelchau et al., 1997; Armstrong, 2005). This together with the source rock kinetics constrains the maturity, the timing and type of hydrocarbons generated. Fluid expansion, fundamental structural changes and other physical and chemical elements can be employed to predict pressure build up and fluid movements within the modelled basin’s lithological layers. This makes basin simulation a dynamic modelling of geological processes in sedimentary basins over geological time periods. The analyses include but are not limited to, generation, expulsion, phase dissolution, migration pathways, trap formation, pressure distribution and hydrocarbon accumulations (Hantschel & Kauerauf 2008).

Hantschel and Kauerauf (2008) have simplified simulation steps of the main geological processes as shown in Figure (5.1).

The first modelling computer programs of 1D basin modelling were developed in 1980. The idea was to calculate and calibrate the temperature history through the evolution of a sedimentary basin. The development of basin modelling and its practices during the 1990s led to implementing new hydrocarbon migration and reservoir characterisation features which created the need to upgrade to full 3D modelling. Starting with 1998, most of heat and pore pressure calculations as well as three-phase Darcy flow modes were performed in 3D, but due to complexity and the huge computation efforts it was necessary for models to be simplified and restrictive resolutions which often led to unrealistic or oversimplified geometries (Hantschel &

Kauerauf, 2008). To overcome the complexity of three-phase Darcy flow models new alternatives such as Flowpath model, Hybrid (Flowpath + Darcy) models and invasion percolation models were developed (IES, 2007). In addition simulation of multicomponent resolved petroleum phases was introduced as well as fast thermodynamic PVT (Pressure Volume Temperature) analysis based on a flash calculation (composition of trapped hydrocarbons ‘flashed’ to surface conditions) for these components (Hantschel & Kauerauf, 2008). Flow model developments have made 3D basin modelling a very useful tool for exploration and research. However, the large computation times needed still make it necessary to keep 3D models relatively simple, especially if this exploration tool is used on a basin scale.

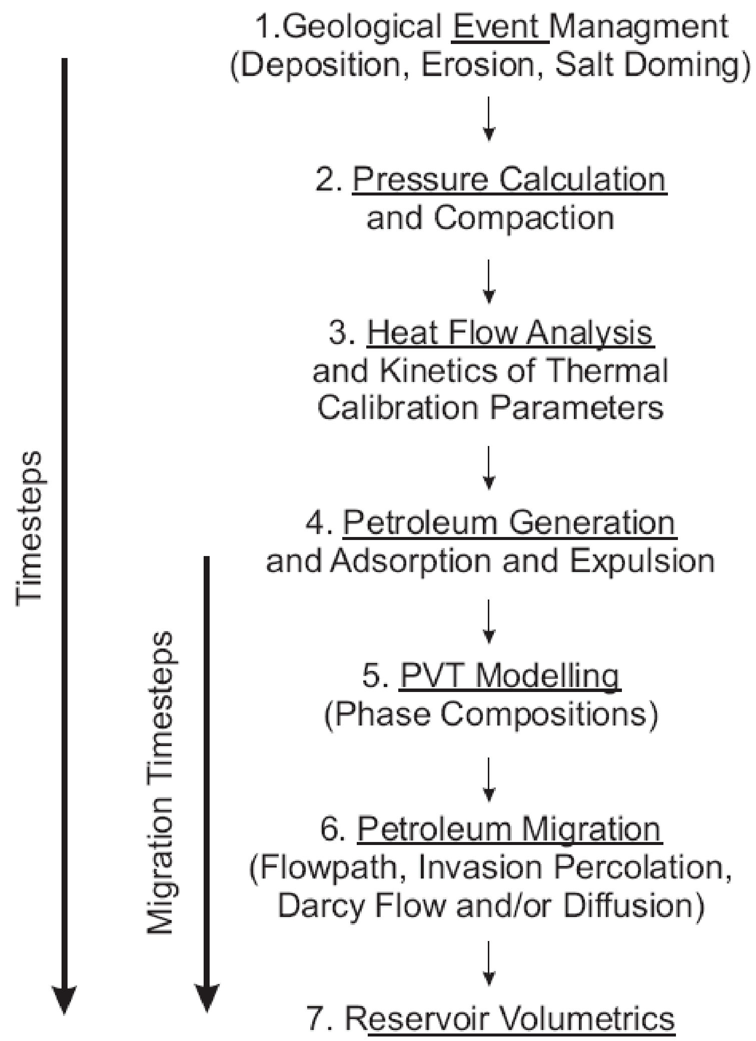

Figure 5.1: Main geological processes in basin modelling (From Hantschel & Kauerauf, 2008).

3D Basin modelling is a powerful tool for predicting the timing and location of petroleum generation, expulsion, migration and accumulation processes. It is equally valuable in new exploration areas where limited data are available, as well as in already explored areas where problems such as source-reservoir correlations, seal efficiencies and overpressure systems are investigated (IES, 2007). Though 3D basin modelling is a relatively new exploration tool, it has received a high level of acceptance among petroleum exploration companies and researchers.

The 3D Petroleum systems mode of the Bass Basin was constructed for this thesis using PetrMod^{TM}10 and was published in APPEA Journal, 2010. It has been included in this thesis in its published format. The modelling procedure, data input, simulation and calibrations, together with modelling results are discussed in the published paper as below:

Arian, N., Tingate, P.R., Hillis, R.R. & O'Brien, G.W. (2010) Petroleum systems of the Bass Basin: A 3D modelling perspective
APPEA Journal, v. 50, pp. 511-533

NOTE:
This publication is included on pages 98-120 in the print copy of the thesis held in the University of Adelaide Library.

CHAPTER 6

6. Implications for Petroleum Prospectivity

The series of basin analysis studies undertaken for this thesis have revealed several hydrocarbon implications for the Bass Basin. Individual studies contributed informative propositions and were used as input to develop a complete 3D generation, expulsion, migration and accumulation model of the Bass Basin.

A- Seismic and structural interpretation

Structural evaluation and architecture have significant implications for defining elements of petroleum systems. Seismic and structural interpretation of the Bass Basin undertaken in this study confirms some previous petroleum plays, but also suggests a new petroleum play in the basin. Detailed structural mapping and constructed 3D horizons from an extensive seismic grid of the Bass Basin illustrate a lateral shift in the Pelican Trough's locus of extension at the end of the Otway Rifting phase. This shift transferred the deep depocentre towards the northeast into the area previously known as the Tertiary Platform. The Tertiary Platform was recognised and described by Lennon et al. (1999) as containing Tertiary and younger sediments. However, the interpretation and identification of thick sediments of Cretaceous age suggest a new petroleum play. These Cretaceous sediments are ideally positioned to receive hydrocarbon charge from both the Pelican and Dondu troughs. The identification of the Central Basement High in the central Cape Wickham Sub-basin confirms the superlative location of the interpreted Cretaceous sediments to receive hydrocarbon charge. In addition to petroleum migration from the Pelican and Dondu troughs, hydrocarbons from the deeper Yolla Trough can also migrate towards the big structure.

Faults intersecting the regional sealing facies of the Demons Bluff Formation are mainly located near the margins of the Cape Wickham Sub-basin, which suggests that reservoir sands of the Upper EVG in the inner and central Cape Wickham Sub-basin have an increased chance of preserving hydrocarbon accumulations, if charged. In addition, NNE-SSW and N-S striking faults are intense in the northeastern part of the basin. These faults may have undergone strike-slip during the Miocene compression. Other faults traversing the regional seal in other parts of the basin were not reactivated by Miocene compressive stresses.

As compressive reactivation during the Early-Mid Miocene mainly affected the northeastern part of the basin around the Cormorant Trough, where there was a high chance of hydrocarbon loss within this area during reactivation. However, as a result of rotation in stress directions and waning compression, reactivation slowed during the Late Miocene and stopped by the end of the Miocene Epoch. Any filling process into previously breached reservoirs within the Cormorant Trough and surroundings may have resulted in entrapment and partial reservoir refill during last five million years. Discovered hydrocarbon accumulation in Cormorant-1 is interpreted to be the result of late stage partial reservoir refill.

B- Regional reservoir quality and sealing capacity

1- Middle EVG

The identification of quality reservoir sands in the deeper sections of the EVG, particularly within the Middle EVG, provides a new insight for future petroleum exploration in the Bass Basin. The recognition of four fining-upward sedimentary cycles that deposited fine-grained sediments (sealing facies) over coarse-grained sediments of good porosity (reservoirs) suggest the occurrence of reservoir/seal pairs within the Middle EVG succession. In addition, thick lacustrine shales (100m+) with a good regional extent occur within the Middle EVG succession, highlighting the importance of these reservoir/seal pairs close to the mature source rocks, especially in the northern part of the Cape Wickham Sub-basin where Koorkah Lake was located. MICP analysis suggests good sealing capacity for intraformational seals of the Middle EVG. Expelled hydrocarbons from mature source rocks within the Middle and Lower EVG may not have migrated very far before their possible entrapment by thick lacustrine shales and other intraformational seals to accumulate within reservoir sands of the Middle EVG.

2- Upper EVG

This study confirms good reservoir quality for sands of the Upper EVG under the regional sealing facies of the Demons Bluff Formation. The excellent sealing capacity for the regional top seal was also confirmed. This suggests a shallower play for the entrapment and housing of hydrocarbons which may have escaped entrapment in the deeper sections.

C- Generation, expulsion, migration and accumulation models

The 2D models have contributed improved insights into petroleum prospectivity in the Bass Basin, as they suggested that mature source rocks in the Bass Basin have generated and expelled an enormous volume of hydrocarbons into the system. This contrasts with the understanding of petroleum systems and plays which informed previous exploration when the lack of hydrocarbon charge into reservoirs of the Upper EVG was thought to be due to the limited volume of expelled hydrocarbons from terrestrial source rocks.

The 2D models also suggested a deeper petroleum play across the Bass Basin within quality reservoirs of the Middle EVG, where good structural traps and thick shales with good sealing capacity exist. This is an important finding in regard to petroleum prospectivity of the Bass Basin, as previous exploration targeted reservoir sands of the Upper EVG succession in many parts of the basin, with only limited success.

The 3D model also provided a new understanding of the petroleum systems and petroleum prospectivity of the Bass Basin. The 3D representation of the basin with complete sedimentation and decompaction, thermal history and pressure distribution has provided improved knowledge of the detailed stages of source rock maturation, expulsion, possible migration pathways and accumulation locations and has revealed several petroleum plays which may have prospectivity implications for the Bass Basin.

Deeper Early Cretaceous source rocks of the Otway Megasequence injected a reasonable volume of hydrocarbons into the system in the early stage of basin development. Hydrocarbons may have migrated towards the flanking margins and leaked out of the basin in many locations, but 3D petroleum systems modelling predicts hydrocarbon accumulations in the deeper parts of the Cape Wickham Sub-basin. The modelling also suggests that the majority of possible accumulations within the Durroon Sub-basin have an Early Cretaceous source.

Terrestrial source rocks of the Late Cretaceous to Palaeocene (T. Lillie to L. Balmei zone) are the source of the most hydrocarbon accumulations in the Bass Basin, including the discovered gaseous accumulations and the suggested accumulations within the reservoir sands of the Middle EVG.

The oil-prone source rocks of the Early Eocene (M. Diversus) may have supplied some oil charge to structures within the Upper EVG which are located within and around the Yolla and Cormorant troughs. Source rocks of this age are currently within the expulsion window only in the Yolla Trough. Discovered liquid hydrocarbons of Yolla-1 and Cormorant-1 are interpreted to have been sourced from rocks of Early Eocene age.

Generation and expulsion models suggest that source rocks within deeper depocentres of the Cape Wickham Sub-basin (e.g. Yolla and Pelican troughs) have generated and expelled most hydrocarbons in the Bass Basin. The Bark Trough is the only area within the Durroon Sub-basin to contain mature source rocks of Early Cretaceous age.

Migration model results support permeable faults in the northeastern region of the basin during Miocene inversion, which resulted in breaches within deeper accumulations, migration to upper reservoir sands, and in several cases leakage through the regional seal. N-S and NNE-SSW striking faults were subjected to strike-slip movement and/or compressive reactivation due to their orientation in relation to the direction of the compressive stresses during the Early to Late Miocene periods. Common NE-SW striking faults in the basin were not affected by the same compressive event and are predicted to be impermeable for hydrocarbon migration.

This suggests limited charge into reservoirs of the Upper EVG in most parts of the basin. As N-S and NNE-SSW striking faults are confined to the northeastern region, it is suggested that there were breaches in some deeper reservoirs and leakage through the regional seal during reactivation periods, despite the fact that the northeastern region is most likely to have received liquid hydrocarbon charge and the regional sealing facies of the Demons Bluff Formation reaches its maximum thickness in this area.

The 3D models support deep petroleum plays within the Bass Basin, especially within reservoirs of the Middle EVG. In general, several new and untested petroleum plays within reservoir sections of the Middle and Lower EVG were suggested by the 3D generation, expulsion, migration and accumulation models, which should impact favourably on the prospectivity of the Bass Basin.

CHAPTER 7

7. CO_2 Storage potential of the Bass Basin

The Bass Basin is one of the largest basins in Bass Strait, southeastern Australia. Its proximity to large CO_2 emissions in the Latrobe Valley and the presence of multiple reservoir and seal pairs makes it an attractive candidate for carbon dioxide storage. The Bass Basin also contains hydrocarbon resources, including commercial gas fields. A key requirement for the understanding the best locations within the basin for CO_2 sequestration is to better understand the distribution of existing and undiscovered petroleum within the basin so that resource conflict can be minimised. As a result, a basin scale assessment of the petroleum prospectivity has been undertaken and the best CO_2 storage play identified. Regional CO_2 storage associated with structural traps and saline aquifer storage in the Upper Eastern View Group has been assessed and accepted to be published in GHGT10.

Evaluation of the Bass Basin's suitability for hydrocarbon and CO_2 storage potential has been undertaken by analysing several key basin analysis elements. Hundreds of 2D seismic lines were interpreted, which resulted in mapping 11 stratigraphic horizons across the entire basin. The interpreted horizons were gridded and depth converted to facilitate construction of 3D hydrocarbon migration and accumulation modelling, as well as CO_2 injection migration and accumulation modelling. Key factors in the petroleum systems and CO_2 assessment of the basin were understanding the nature of the seals and the reservoirs.

An important factor in determining the petroleum potential and CO_2 storage capacity of the basin is understanding the top seal and fault seal behaviour of the basin. The regional seal, the Demon's Bluff Formation, has been investigated using the following criteria; seal capacity and integrity, thickness and geometry. Previously published work on the intraformational seals in the deeper parts of the basin was also examined to give a complete picture of the CO_2 retention ability for the basin's sealing facies. The Demons Bluff Formation has the ability to retain large column heights of petroleum and CO_2. The intraformational seals indicate similar retention capacity.

The reservoir characterisation study of the Eastern View Group combined core plug porosity and permeability, log derived porosity, optical and petrophysical study of reservoir samples, as well as other well data and reports. The analysis resulted in recognising excellent reservoir quality for sandstones of the Upper EVG. Similarly, sandstones of the Middle EVG were investigated and zones of fining upward cycles that deposited fine-grained sediments on top of coarse-grained sediments were recognised from porosity depth trends. Coarse-grained lithologies are interpreted to have resisted compaction better and preserved good reservoir properties, while fine-grained sediments at the top of each cycle have provided potential sealing lithologies for the good reservoirs underneath.

An important conclusion from the petroleum systems modelling is that the hydrocarbon inventory within the Upper Eastern View Group is likely to be limited and as a result it is a favourable stratigraphic level for CO_2 injection, migration and entrapment. To quantify storage elements, storage potential of the Upper EVG was modelled. Considering reservoir conditions and CO_2 behaviour under such conditions, a simulation of a large amount of carbon dioxide injected into the bottom of the reservoirs of the Upper EVG was undertaken. Their migration pathways upward and their accumulation in structural traps under the regional seal were modelled. In addition, an estimate of the saline aquifer trapping potential was calculated for the reservoir sands within the EVG.

Potential fault reactivation was investigated by fault risk evaluation under the present-day stress regime. Faults traversing the reservoir/regional seal boundaries, as well as faults intersecting the top of the regional seal were evaluated for future risk of reactivation. The analysis suggests some risk of reactivation associated with N-E striking faults, fortunately these faults are confined to the margins of the basin.

7.1. Geological Storage of Carbon Dioxide

Geological storage of carbon dioxide (CO_2) is the process that involves transporting captured CO_2 from its source (e.g. coal-fired power station, liquefied natural gas or mineral processing plant) and injecting it into the geological subsurface for long-term storage (Cook et al., 2000; Gibson-Poole et al., 2008). Structural traps in basins, which usually include a porous and permeable reservoir rock to permit injection and storage of the CO_2 and an overlying impermeable seal can make ideal storage sites (Van Der Meer, 1992; Bachu et al., 1994; Rochelle et al., 1999). When the injected CO_2 remains trapped in the reservoir the process is called geological storage. The stored CO_2 is at risk of leakage when suitable pathways out of the trap exist such as faults, or old petoleum wells.

Ultimately, injected CO_2 can become part of the reservoir rocks and fluid by reaction. As a result, some of the free CO_2 is changed to other substances and no longer has the potential to escape the reservoir. For instance, the CO_2 can react with the water in the reservoir to become bicarbonate. This type of reaction is considered permanent storage in the sense that the CO_2 is transformed into a substance that is part of the reservoir (PTRC, 2009). The reaction of CO_2 with the reservoir rocks and pore water allows the potential for saline aquifer trapping of CO_2. In this form of storage a limited subsurface migration path for CO_2 may be used rather than a specific trap, The CO_2 is injected into a basin and migrates until the free CO_2 is transformed by reaction with the reservoir rock and pore water.

7.2. Initial screening and ranking of the Bass Basin

Based on screening and ranking criteria for sedimentary basins developed by Bachu (2003) the factors such as tectonic setting, size and depth of the basin, intensity of faulting, hydrocarbon and geothermal regimes, as well as industry maturity of the Bass Basin have been evaluated. The Bass Basin is tectonically stable at the present day, which does not put CO_2 containment at risk. It‘s size of over 42000km^2 in area and over 9km depth provides an excellent storage size. The Bass Basin’s regional sealing facies (the Demons Bluff Formation) occurs at depths greater than 1km across most of the basin, which results in dense supercritical CO_2 and significantly augmented storage capacity. Though the faulting in the deep parts of the basin is reasonably extensive, the density of faults intersecting regional sealing facies and reservoir sands beneath it decrease fundamentally and are mainly confined to the northeastern part and margins of the basin. Despite the Bass Basin’s little discovered hydrocarbon resources, the Yolla gas project is situated in the central part of the Cape Wickham Sub-basin. Thus, the Bass Basin scores over 80% giving it a highest ranking of ‘1’ on Bachu’s scale for CO_2 storage and geosequestration ahead of all the Victorian basins (Table 7.1).

Criterion	Descriptor	Score
Tectonic stability	Mostly stable	3
Basin Size	Large (over 40,000Km^2)	3
Depth	Deep	3
Reservoir-Seal pairs	One regional seal and several good intraformational seals	3
Faulting intensity	Moderate within reservoir/top seal section	2
Geothermal regime	Moderate	2
Hydrocarbon Potential	Moderate	2
Top seal integrity	High	3
Knowledge level	Moderate-Low	2
Data availability	Moderate	2
Infrastructure	Moderate	2
Total Score		81%
Overall ranking		1

Table 7. 1: Screening and ranking criteria of the Bass Basin. The 81% overall suitability for CO_2 storage gives the Bass Basin ranking ‘1’ ahead of all the Victorian basins

7.3. Seal analysis

The Demons Bluff Formation is the regional seal which overlies thick channel sands of the Upper EVG succession. However, there is limited data about the seal capacity from this formation. As part of this study, further analyses were obtained and calculations of the CO_2 column heights were from mercury injection capillary pressure capacity determination of the Demons Bluff Formation can significantly improve our understanding of potential CO_2 storage capacity of the Bass Basin.

In addition to the lithology of the sealing facies, fault seal is recognised as a major factor that can control accumulation of hydrocarbons and have a significant influence on reservoir behaviour during petroleum production (Jones et al., 2000). Based on the mechanism of failure, the types of fault sealing can be categorised as juxtaposition seal, fault plane seal and fracture-related seals (brittle failure/ fault reactivation).

The juxtaposition seal and fault plane seals are primary fault sealing mechanisms within clastic sediments, which are known as membrane sealing. Juxtaposition sealing occurs due to differences in capillary pressure when fault displacements put impermeable layers such as shales next to the permeable reservoir sands. Fault fracture-related seal works when the threshold pressure does not surpass the geomechanical strength of the fault shale gouge. Once the threshold pressure surpasses shale gouge strength, the fault is considered to have been breached as a result of brittle failure (Jones et al., 2000).

In general, the top regional sealing facies of the Demons Bluff Formation occurs at depths greater than 800m which is favourable for carbon dioxide storage and sequestration (Fig. 7.1).

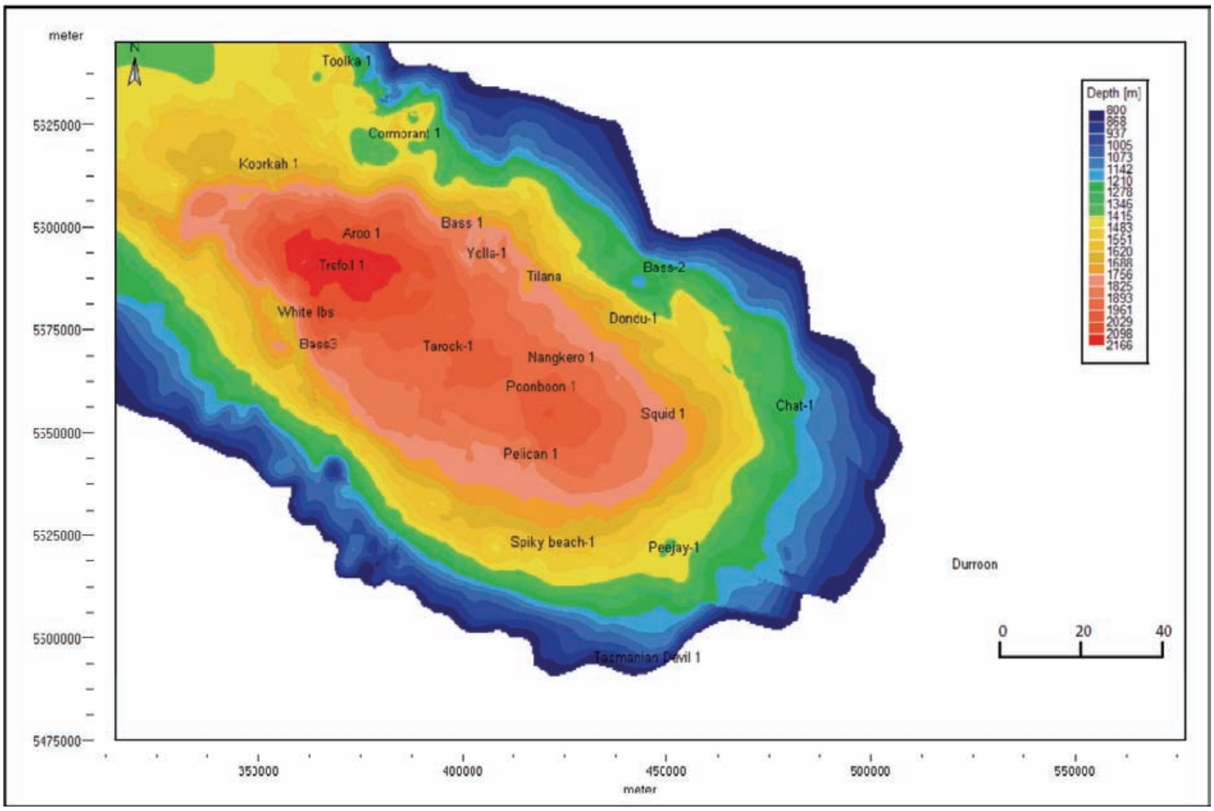

Figure 7.1: Depth map of the Bottom Demons Bluff Formation where occur at depths greater than 800m.

Intraformational seals of the Middle EVG have been proven to be capable of holding hydrocarbon accumulations in the deeper parts of the basin (e.g. White Ibis-1). Thick shales of wide-spread nature were deposited across the basin, associated with the Lower and Upper Koorkah lake facies from the latest Maastrichtian to late Early Eocene. The reservoir/seal pairs are likely to add to the basin's overall storage capacity. A good contribution to basins storage capacity is expected from theses sealing facies of the Middle EVG. Analysis of their seal capacity has been integrated into this study to assess potential deeper storage capacity.

7.3.1. Seal Thickness and Geometry

a) The Demons Bluff Formation

The top and bottom of the Demon Bluff Formation were interpreted from 2D seismic and gridded to a 3D surface as outlined earlier, then calibrated with formation tops from well completion reports and from Geoscience Australia (GA). Regional thickness, distribution and geometry of the sealing facies were calculated from the constructed 3D surfaces.

The regional sealing facies of the Demons Bluff Formation were deposited in bay and shallow marine environments during a regional transgressive event during late Middle Eocene (Blevin, 2003). The Demons Bluff is usually between 100 to 250m thick over much of the Cape Wickham Sub-basin. It reaches its greatest thickness of 395m in the Cormorant Trough at the northern part of the Cape Wickham Sub-basin and generally decreases from the north to southeast of the basin. It gradually thins towards the southeast in the Durroon Sub-basin to less than 100m until it reaches its depositional limit in the southern and southeastern part of the Durroon Sub-basin. Overall, the top seal preserves a good thickness over most of the basin (Fig. 7.2).

The base Demons Bluff Formation is deepest at the deep Yolla Trough in the central part of the Cape Wickham Sub-basin, where it occurs at approximately 2100m. In parts of the Durroon Sub-basin and towards the margins of the Bass Basin, where the Demons Bluff Formation is at its thinnest, the base occurs between 500-100m.

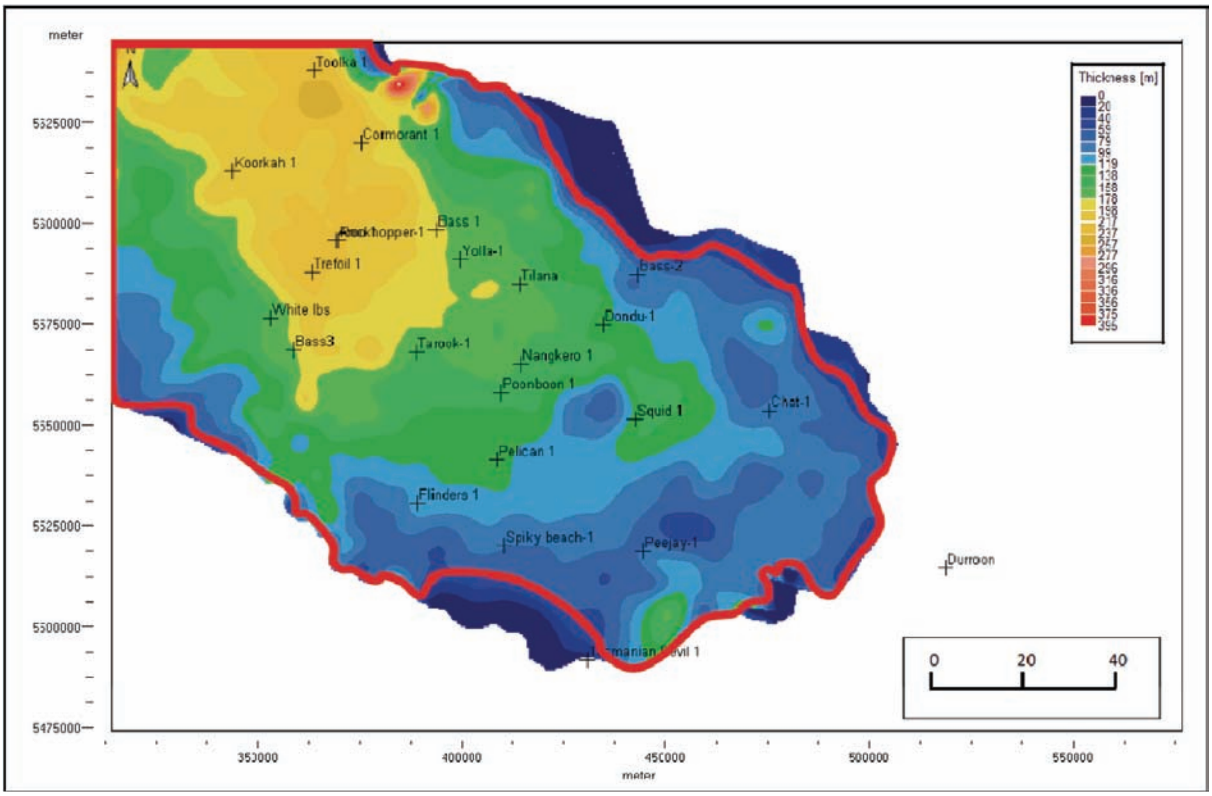

Figure 7.2: Thickness map of regional sealing facies of the Demons Bluff Formation. The red line outlines the occurrence of greater than 50m thick seal.

In the northern margin of the basin, the regional seal might have subjected to inversion during Late Oligocene to Miocene. Failure due to breach of regional seal is interpreted to have occurred for some wells in the basin (e.g. Barramundi-1, King-1: Trigg et al., 2003). Therefore, understanding the potential risk of reactivation associated with the present-day stress regime in the Bass Basin and particularly the already reactivated area (Cormorant Trough) is important for long-term CO_2 storage in the basin. Fault risk evaluation in the Bass Basin is considered later in this report.

b) Intraformational seals of the Middle EVG

The Middle EVG contains three different sedimentary sequences, which contain several intraformational seals that may vary in thickness and distribution. A biostratigraphic study by Partridge (2002), suggests occurrence of lagoonal, freshwater and brackish lacustrine environment across the Bass Basin from latest Maastrichtian to late early Eocene. The Lower Koorkah lake cycle (base Upper F. longus to base Upper L. balmei zones) which best developed in regions where fault-controlled subsidence rates were moderate to high correlates with the Tilana sequence. The Upper Koorkah Lake (Upper L. balmei to base Upper M. diversus zones) which developed in regions of low subsidence rate correlates with the Narimba sequence (Blevin, 2003). In addition, the freshwater shales developed during Maastrichtian times (Lower F. longus to base Upper F. longus) correlate with Furneaux sequence. The transgressive-regressive nature of the Furneaux sequence is interpreted to provide good stacking of seal/reservoir facies (Blevin et al., 2005). All these shales of the Middle EVG are expected to be reasonably thick and pervasive across most parts of the basin.

A recent porosity trend and regional reservoir quality study suggests mainly coarse-grained clastics of the EVG contain several lacustrine, flood plain and delta plain shales and coals with high potential sealing capacities (Chapter 3). The regional reservoir quality study has recognised four zones of fining upward cycles within sediments of the Middle EVG from porosity trends, each cycle ended with deposition of fine clastics on top of coarse clastics. The upper fine-grained clastics have low porosity and could possibly act as good seals. These zones suggest occurrence of reservoir/seal pairs within Middle EVG sediments where excellent structural and sedimentary traps exist. As zones of fine-grained sediments were recognised from wireline logs are pervasive across most of the basin, they also suggest that the upper fine-grained sediments (intraformational sealing facies) are reasonably thick and have good regional extent. Previous hydrocarbon explorations in the basin confirmed the occurrence of thick freshwater shales within the Middle EVG succession, while some wells drilled in the basin (e.g. Aroo-1, Konkon-1, Koorkah-1 and Tilana-1) have intersected thick (100+m) freshwater lacustrine shales overlying fluvial channel sandstones (Blevin et al., 2005).

7.3.2. Mercury Injection Capillary Pressure (MICP) Analysis

The upward migration of hydrocarbons is opposed by the capillary resistance of the seal, which represents the pressure needed for petroleum to enter and displace existing fluids from a rock with similar pore throat size (Kaldi et al., 1999). Whenever the capillary pressure of a lithology is greater than the buoyancy force of the petroleum, the lithology acts as a seal and the upward migration of hydrocarbons will come to an end (Watts, 1987). Mercury injection capillary pressure (MICP) analysis is a technique to calculate the sealing capacity for rocks from a pressure cell, which involves forcing a non-wetting fluid (mercury) into pore system of a dried core sample. The mercury displaces the wetting phase (air) that initially saturated the pores within the rock sample. The exerted pressure must exceed surface forces that oppose the entrance of the mercury into the pore space and thereby displace the air (Purcell, 1949). The smaller the pore throats, the greater the pressure required for the mercury to enter the rock (Daniel et al., 2003).

As a part of this study, the sealing capacity of 15 lithology samples of the Demons Bluff Formation and one sample from the UEVG from six different locations across the Bass Basin were collected. ACS Laboratories Pty Ltd in Brisbane examined the samples and maximum column heights for CO_2, gas and oil were derived from the threshold entry pressure into the samples using standard ACS methodologies. The CO_2 maximum column heights were recalculated (Appendix 5) after the method outlined by Daniel (2005). Exploration companies normally do not collect conventional cores within the seal section, therefore the number of samples were limited. From all the wells drilled in the basin, parts of the Demons Bluff Formation were cored only in five wells. As different sections of the regional seal were cored, collected samples were chosen from the lowest possible part of the cored sections. Further samples from same sections then chosen upwards.

In addition, the sealing capacity of 15 lithology samples from eight wells in the Bass Basin were previously examined by Daniel and Kaldi (2003) and their retention capacity for maximum oil and gas columns determined. In this study samples were taken from potential sealing facies within collected reservoir core samples in the basin; samples were described to represent various deposition environments.

Depending on determined bio-zones from the samples, at least 10 of these samples were from the Middle EVG. However, CO_2 retention capacities were not calculated, but the results were compared with calculated maximum oil column heights of samples from the Demons Bluff Formation and the comparison used as an indication of CO_2 retention capacity of intraformational seals.

a) The Demons Bluff Formation

A recent MICP analysis on 15 samples of the Demons Bluff Formation undertaken by ACS Laboratories for this study suggests an excellent sealing capacity for the tested samples. The analysis suggests a maximum capacity of 2342m of oil column and up to 753m of CO_2 column for an analysed sample from Cormorant-1. However, recalculated CO_2 retention column heights (Table 7.2) using the method outlined by Daniel (2005), resulted in predicting an overall higher retention capacity for $CO_{2,}$ with maximum sealing capacity of 1971m CO_2 column height for a Pelican-1 sample (Fig. 7.3). While the Cormorant-1 sample which has been interpreted to have a maximum column height of 753m CO_2, the recalculation suggested it could support a CO_2 column up to 1546m high.

The only Bass-3 sample included in the MICP analysis was sampled within sediments of the Upper EVG below the Demons Bluff Formation. Apart from the Bass-3 sample, a Cormorant-1 sample from a depth of 1158.8 could retain only 10m of oil, 6m of gas and 3m of CO_2, while a sample of similar description from a of depth 1163.7m shows a retention capacity of 2342m of oil column, 1457m of gas and 753m of CO_2 according to the standard methods followed by ACS laboratories. Visual observation of the samples suggests variation in withholding capacities between these two samples could be due to clay dehydration in the shallower sample, as extensive fracturing was observed in the sample and is believed to be caused by clay dehydration during the long period (tens of years) of storage.

Three samples from the lower part of the Demons Bluff Formation intersected in Toolka-1 location showed excellent retention capacity, while another sample selected from a higher section showed poor retention capacity. In the absence of the sample descriptions, it is suggested that the variation was influenced by upward facies change in this area. All other analysed samples across the basin and throughout the regional seal gave an excellent sealing capacity for CO_2, oil and gas.

A crossplot between sealing capacity of the Demons Bluff Formation and depth of the examined samples illustrates no relationship between sealing capacity and burial depth of the Demons Bluff Formation regional sealing facies (Fig. 7.4). This suggests its high retention capacity is not related to the degree of sedimentary compaction, but associated with the nature of lithological facies of the regional seal.

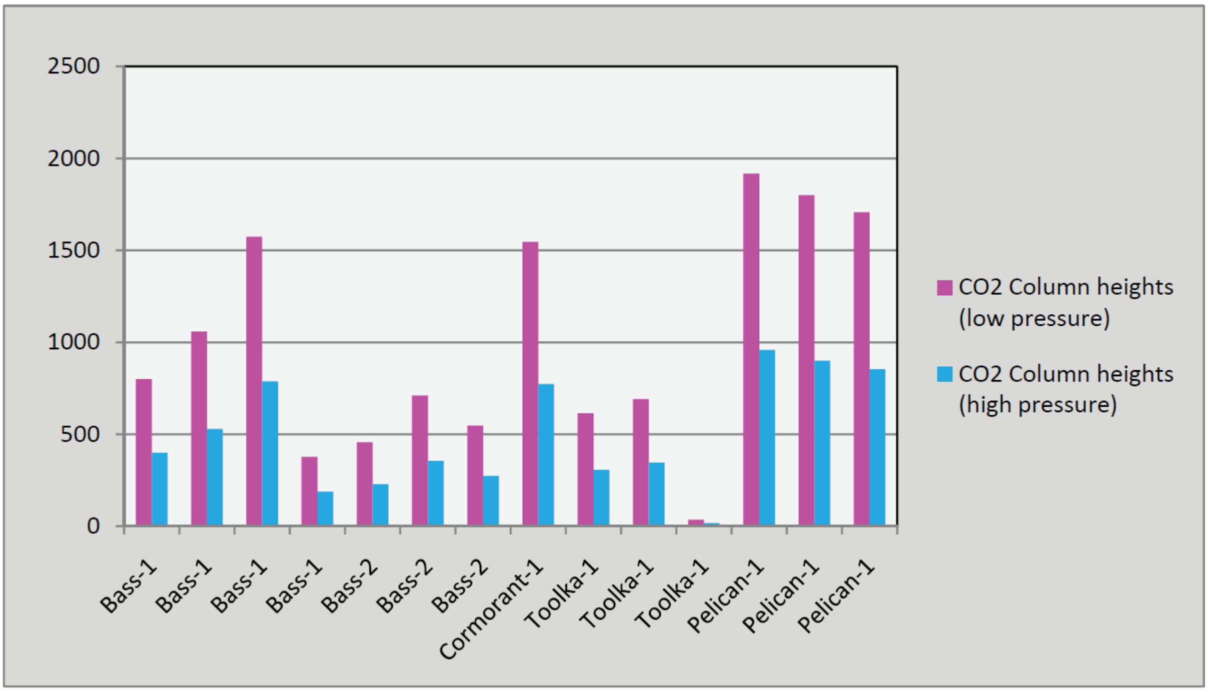

Figure 7.3 : Calculated maximum CO_2 column heights can be supported by samples from regional sealing facies of the Demons Bluff Formation, the Bass Basin.

WELL	SAMPLE DEPTH (FT)	SAMPLE DEPTH (M)	TEMP (C°)	SALINITY (mg/l)	FORMATION	SAMPLE PRESSURE (Mpa)	THRESHOLD PRESSURE (psi)	INTERFACIAL TENSION (dynes/cm)	BRINE DENSITY (g/cm3)	DENSITY CO_2 (g/cm3)	COLUMN HEIGHT (ft)	COLUMN HEIGHT (m)
Bass 1	5895	1796.8	66.25	30000	Demons Bluff Fm	17.61	6083.52	26.61	1.02	0.63	2624.94	800.08
Bass 1	5899	1798	66.31	30000	Demons Bluff Fm	17.62	8047.00	26.61	1.02	0.63	3473.59	1058.75
Bass 1	5880	1792.2	65.98	30000	Demons Bluff Fm	17.56	11947.67	26.60	1.02	0.63	5166.92	1574.88
Bass 1	5883	1793.3	66.05	30000	Demons Bluff Fm	17.57	2867.11	26.61	1.02	0.63	1238.15	377.39
Bass 2	3822	1164.9	40.96	30000	Demons Bluff Fm	11.42	3238.12	25.09	1.03	0.69	1496.30	456.07
Bass 2	3811	1161.5	40.78	30000	Demons Bluff Fm	11.38	5031.85	25.07	1.03	0.69	2331.89	710.76
Bass 2	3802	1158.8	40.64	30000	Demons Bluff Fm	11.36	3866.04	25.05	1.03	0.69	1792.92	546.48
Bass 3	5338	1627	68.52	30000	Upper EVG	15.94	19.65	27.04	1.02	0.56	5.89	1.80
Cormorant 1	3818	1163.7	50.89	30000	Demons Bluff Fm	11.40	15240.60	26.44	1.02	0.52	5074.81	1546.80
Cormorant 1	3802	1158.8	50.67	30000	Demons Bluff Fm	11.36	74.60	26.43	1.02	0.52	23.52	7.17
Toolka 1	5119	1560	57.61	30000	Demons Bluff Fm	15.29	4681.21	26.33	1.02	0.64	2015.40	614.29
Toolka 1	5113	1558	57.53	30000	Demons Bluff Fm	15.27	5267.29	26.32	1.02	0.64	2267.66	691.18
Toolka 1	5100	1554	57.36	30000	Demons Bluff Fm	15.23	273.00	26.31	1.02	0.64	116.07	35.38
Pelican 1	5625	1714.5	59.88	30000	Demons Bluff Fm	16.80	13703.01	26.33	1.02	0.66	6291.28	1917.58
Pelican 1	5613	1710.8	59.75	30000	Demons Bluff Fm	16.77	12873.41	26.32	1.02	0.66	5908.04	1800.77
Pelican 1	5620	1713	59.82	30000	Demons Bluff Fm	16.79	12196.69	26.33	1.02	0.66	5599.51	1706.73

Table 7. 2: Supportable CO_2 column heights for samples from the Demons Bluff Formation, calculated using methods outlined by Daniel (2005).

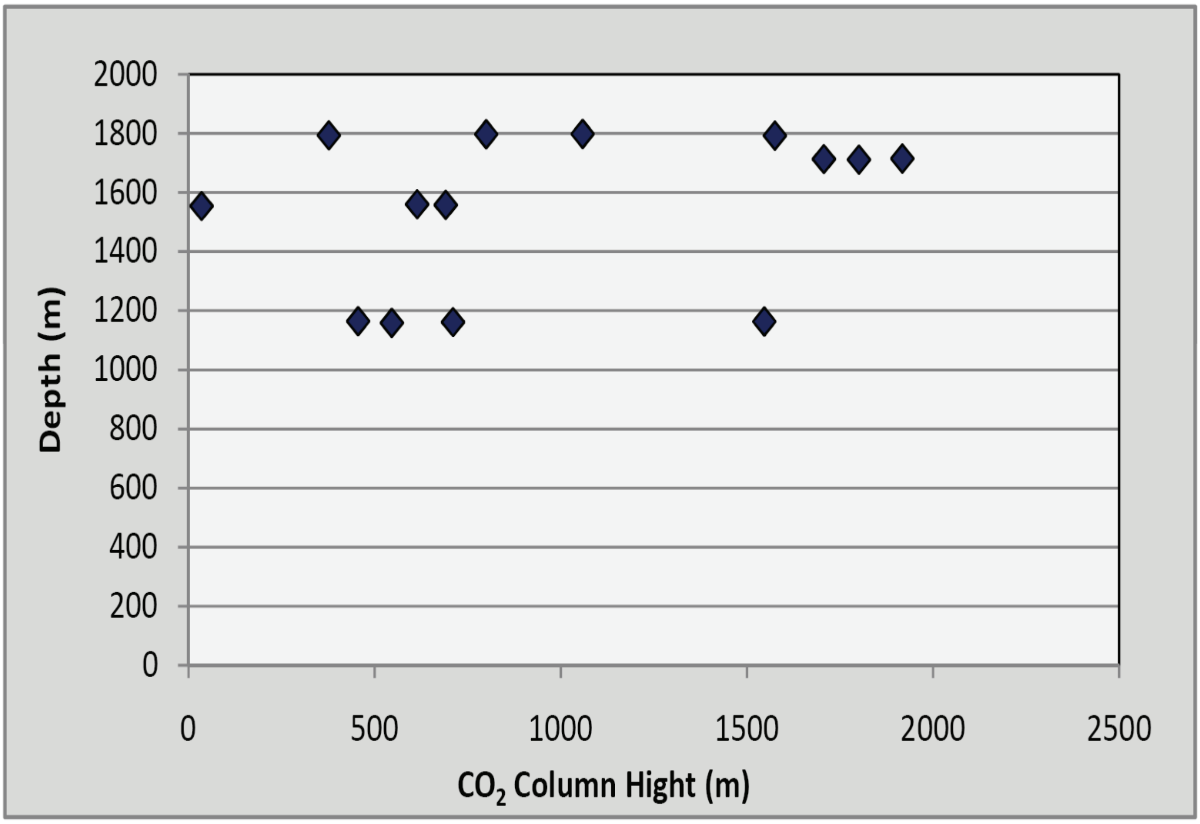

Figure 7.4: **Crossplot chart between depth of burial and sealing capacity of the Demons Bluff**

b) Intraformational seals of the Middle EVG

MICP analysis was carried out by Daniel et al. (2003) on intraformational seal samples from the Middle EVG. The analysis was undertaken to evaluate the sealing capacity of intraformational seals within the EVG for oil and gas. Regardless of the wide range variety in retention capacities, the analysis suggests an excellent retention capacity for the Middle EVG intraformational seals. The MICP analysis did not evaluate the sealing capacity for CO_2 retention; there is currently no simple correlation available to derive CO_2 column height from calculated oil or gas column heights. However, the excellent capacities of the intraformational seal relation to oil and gas (about 1400m of oil column and 567m of gas column) suggest a good retention capacity for CO_2 (Fig. 7.5).

Despite episodic deposition of thick shales within the Middle EVG associated with Lake Koorkah, the thickness variation of these intraformational seals is not greater than the Demons Bluff Formation regional seal. Nevertheless, the predicted oil and gas retention capacities shown by intraformational seals of the Middle EVG are not much lower than the sealing capacity of the regional sealing facies of the Demons Bluff Formation (Fig. 7.6). This indicates a similar retention capacity of the Middle EVG intraformational seals to the Demons Bluff Formation with regards to CO_2 columns.

Past hydrocarbon exploration in the Bass Basin has revealed that many hydrocarbon accumulations in the basin are currently trapped under the intraformational seals of the Middle EVG, which confirms their good sealing capacity. Based on the available capacity data and the presence of hydrocarbon columns the capacity of the Middle EVG intraformational seals for CO_2 retention can be accepted as good to excellent.

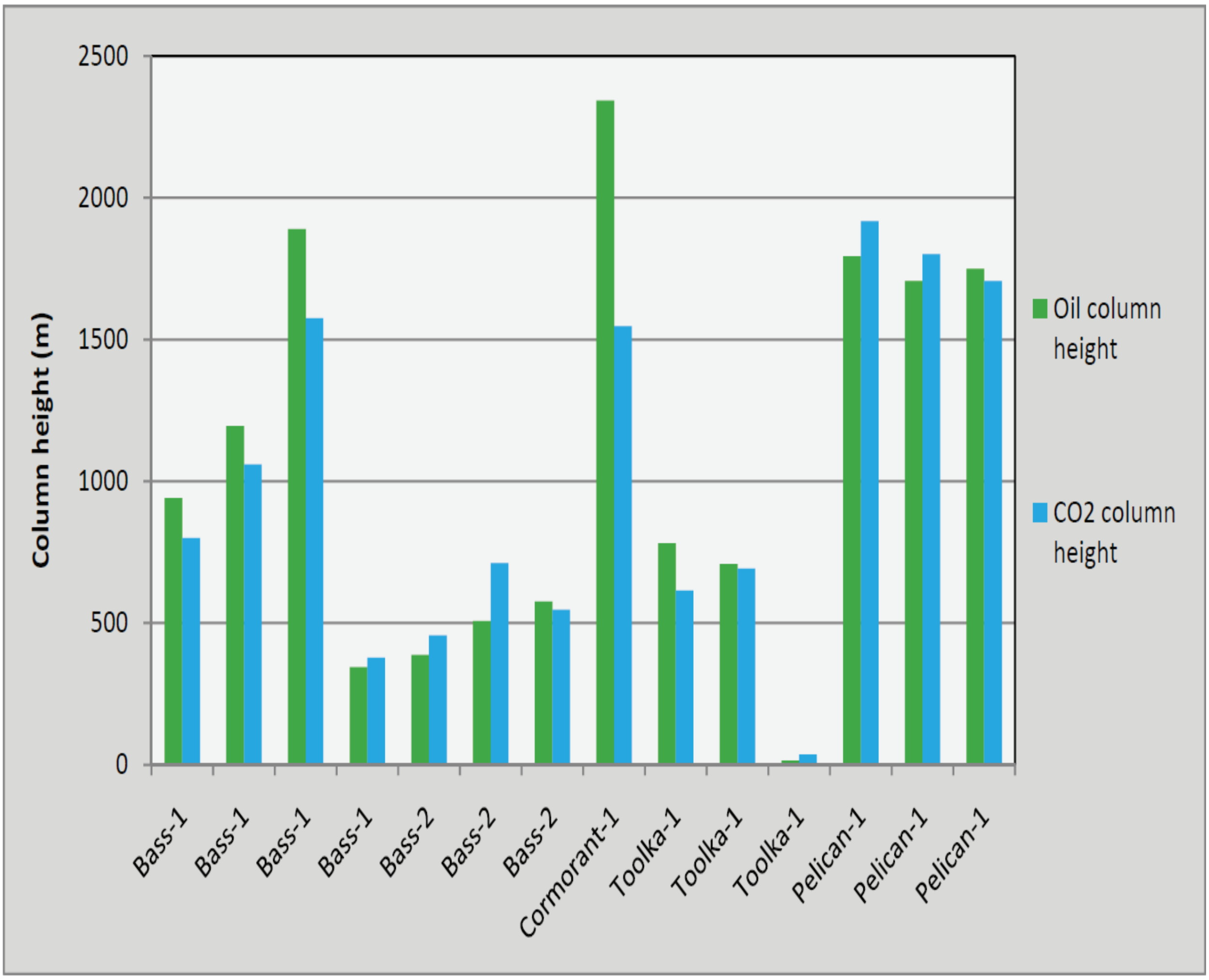

Figure 7.5: Similarity between retention capacities of the Demons Bluff Formation for both oil and CO_2.

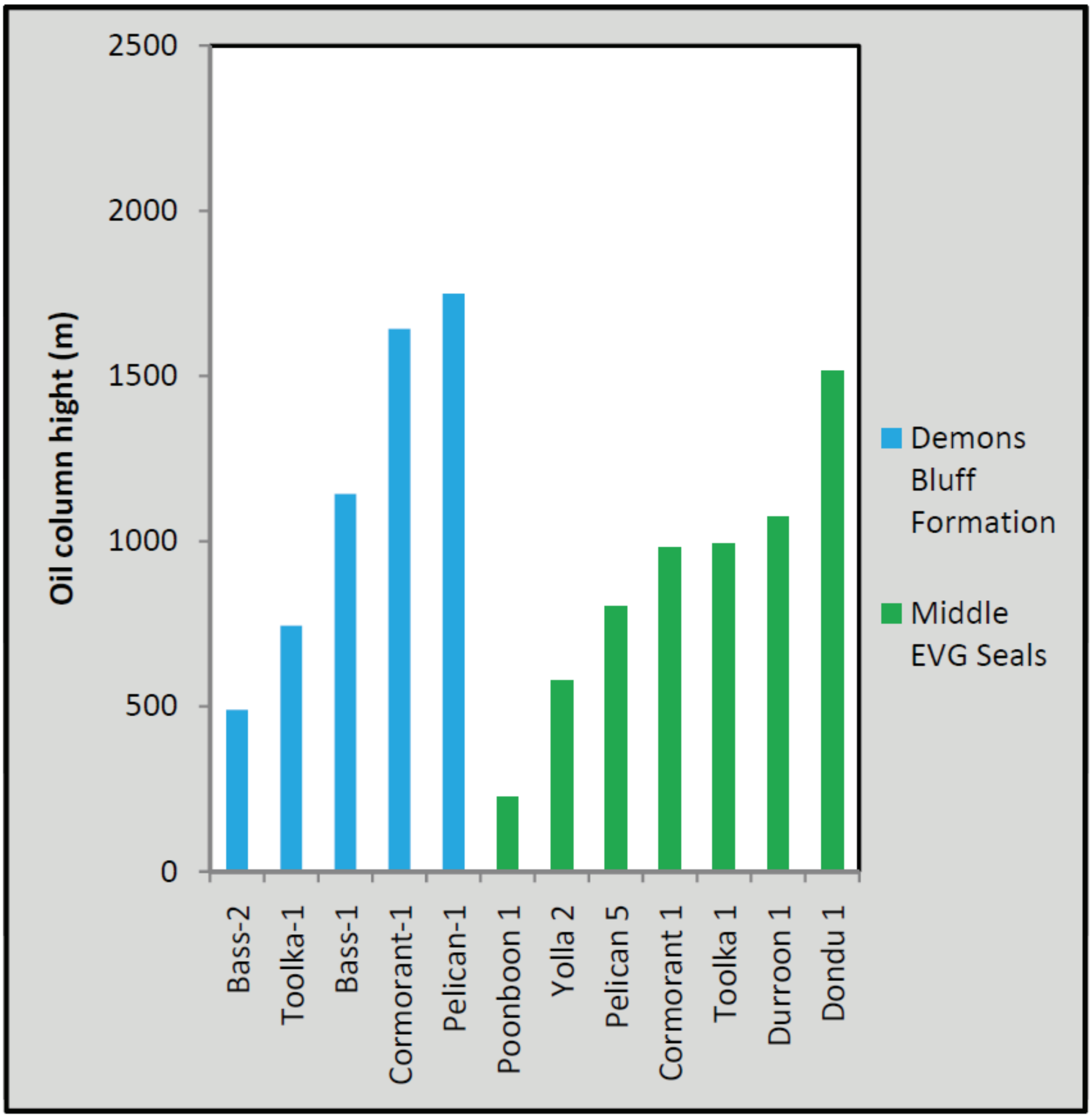

Figure 7.6: Retention capacity of the intraformational seal of the EVG compared to retention capacity of the regional sealing facies of the Demons Bluff Formation in terms of oil column heights.

7.4. Fault Risk Evaluation under the Present-day Stress Regime.

To have confidence that the injected carbon dioxide is stored within a sedimentary basin for a long period, it is important to examine factors that may contribute to any future CO_2 leakage from their storage formations, which may risk contaminating the groundwater and/or atmosphere. Hence, fault risk evaluation is an important aspect of CO_2 storage.

Depending on the present-day stress environment and structural geometry of an existing fault, the fault may undergo reactivation. An active fault can become highly permeable during deformation and provide a suitable conduit for fluid flow, which may facilitate trapped reservoir fluids to escape. The regional sealing facies of the Demons Bluff Formation is not intersected by many faults in most parts of the central part of the basin, but it is important to evaluate any risk of future reactivation. In particular, regions of previous fault reactivation in the northeastern region around the Cormorant Trough need to be investigated. Fault risk evaluation in the Bass Basin was undertaken by JRS Petroleum Research in Adelaide. Potential risk of fault reactivation were estimated from Mildren et al., (2002)'s FAST technique, which estimates the pressure change (ΔP) required to initiate brittle failure of a fault. CO_2 injection into the subsurface leads to increased pressure; changes in the pore pressure can enhance the process of reactivation.

7.5. Regional reservoir quality

Reservoir rocks of the Bass Basin primarily consist of fluvial and lacustrine sandstones of the EVG. In general, unlike reservoirs of the Latrobe Grope in the adjacent Gippsland Basin, reservoirs of the EVG are fluvial channels sands and lacustrine delta sands that lack marine influence. Facies analyses indicate the highest reservoir facies are coarse-grained fluvial channel sandstones, with secondary ranking facies of coarse-grained lacustrine shoreface and foreshore sandstones (Lemon, 2003).

This study used regional porosity trends to predict regional reservoir quality in the basin, which were combined with optical and petrophysical study of the reservoir samples (Chapter 3). Porosities were derived from sonic log using methods described in Chapter 3 and tested against possible factors that may have affected porosity trends, such as mechanical and chemical compaction, overpressure, and grainsize. Gamma ray and sonic cut-offs were used to recognise sand bodies of the EVG and porosity used as a measure of their reservoir quality. Reservoirs of the Upper and Middle EVG were investigated. To date, insufficient data were available to study reservoirs of the Lower EVG or deeper parts in the basin. However, such deeper reservoir sands are likely to have been buried too deep to expect good reservoir quality in most parts of the basin.

7.5.1. Sands of the Upper EVG

The Boonah sand marks a fall in base-level, associated with the demise of Lake Toolka and the establishment of fluvial systems, it is pervasive across the basin and is the highest reservoir within the basin succession (Blevin, 2003). It consists of stacked sandy facies of variable thickness (Lang, 2003). A reservoir diagenesis study by Lemon (2003) suggests the best conditions for reservoir development and preservation occurred in sediments of the Upper EVG, just under the regional sealing facies of the Demons Bluff Formation. The lower section of the Upper EVG is the Aroo sequence, which is consisted of fluvial to fluvio-deltaic, shallow lacustrine and lagoonal sediments. The dominant fluvial sands show good reservoir characteristics (Blevin et al., 2005). The Upper EVG pervasive across the basin and has a good thickness, especially over the area where buried deeper than 800m (Fig. 7.7).

Previous hydrocarbon exploration in the basin confirmed good reservoir characteristics of reservoir sands of the Upper EVG (e.g Nangkero-1, Poonboon-1, Yurongi-1 and Tarook-1). Ineffective migration pathways were blamed for not charging the good reservoir sands (porosities of 20-30% and permeabilities of 0.7mD to 1D) penetrated in King-1 (Blevin, 2003). Available core analyses of the Upper EVG sands show good to excellent reservoir properties. Porosities range between 13 and 32%, with an average of 26% porosity while permeabilities vary greatly between 1-1430mD with an average 198mD permeability.

In addition, sonic log-derived porosities show reservoir sands of the Upper EVG have high porosity (Fig. 7.8). Plotting core porosity against permeability for the Upper EVG samples shows a general permeability increase with increase in porosity (Fig. 7.9). This suggests the Upper EVG sands that show high log-derived porosity will also have good permeability characteristics.

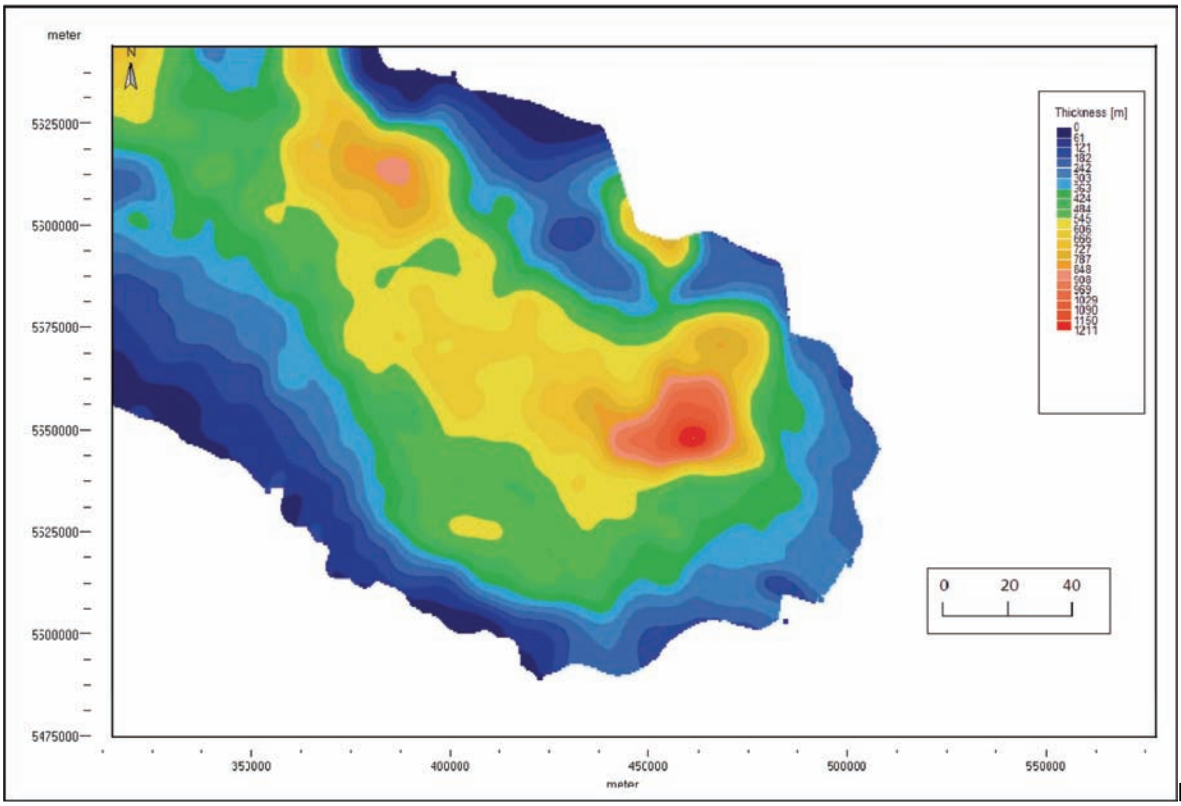

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Figure 7.7: Thickness map of the Upper EVG where occurs at depths greater than 800m.

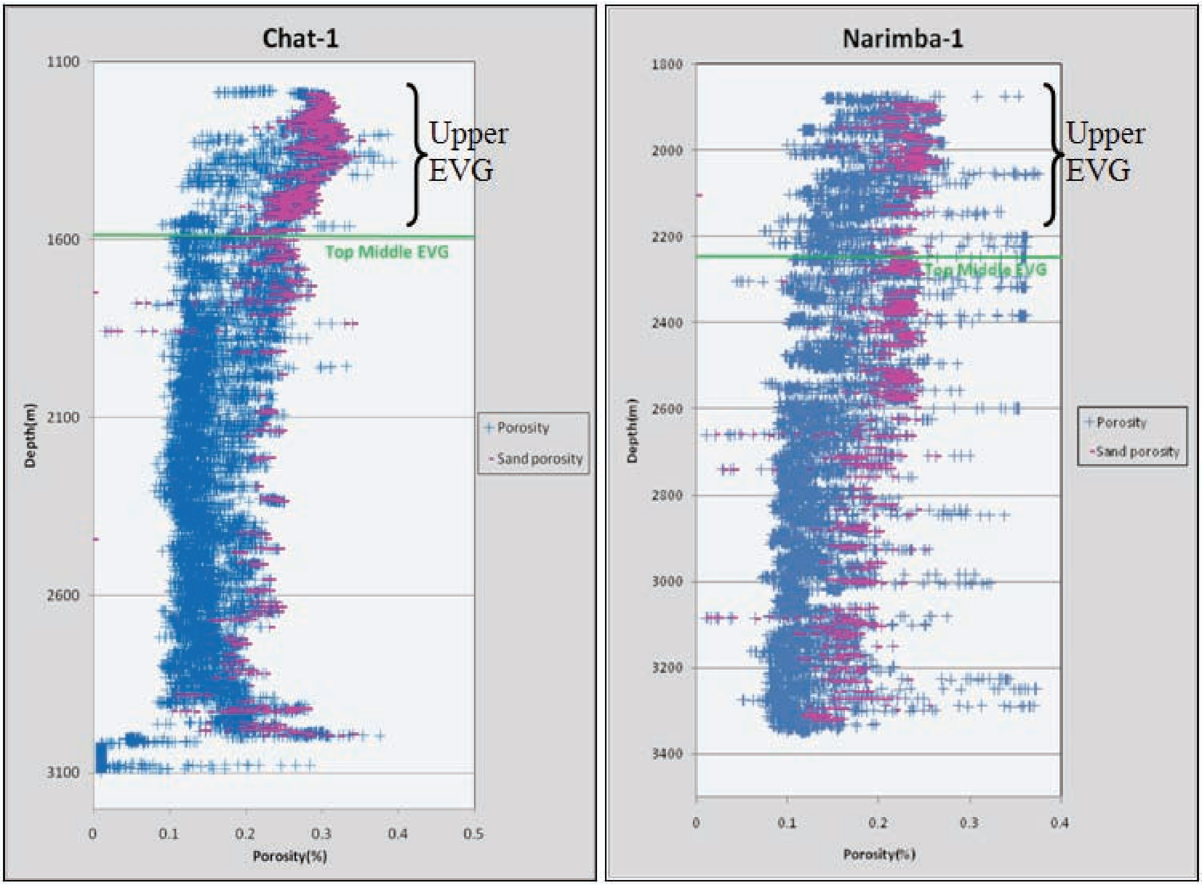

Figure 7.8: Examples of log-derived porosities for the EVG sands which show good porosity for the Upper EVG.

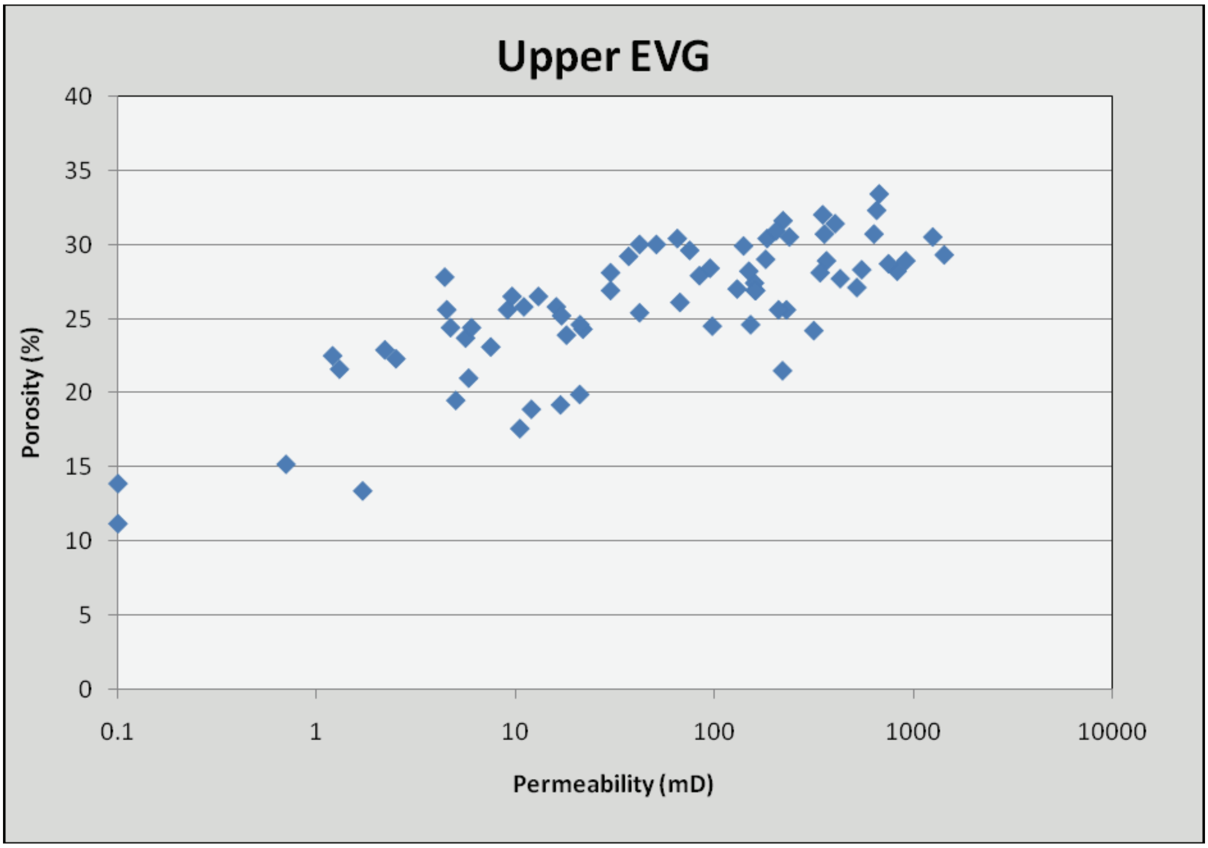

Figure 7.9: Crossplot between core porosity and permeability of the Upper EVG sands.

7.5.2. Sands of the Middle EVG

The deeper sediments of the Middle EVG have been described by previous workers as containing good reservoir sands within each of the Narimba, Tilana and Furneaux sequences (Cubitt, 1992; Lemon, 2003).

The sand-bearing zones of the Middle EVG recognised by the regional porosity trends study (Chapter 3) are interpreted to have good reservoir quality. The coarse-grained clastics within the lower section of each zone are interpreted to have resisted compaction and preserved better porosity and possibly better permeability, as a cross plot between porosity and grainsize showed a positive relationship (Fig. 7.10). This suggests good permeability for sections with high porosity within lower sections of each cycle. However, in general, some of these sands show low porosity in the Pelican Trough region, consistent with the findings by the previous hydrocarbon exploration, which showed sands of this region have lower permeability than other regions of the Bass Basin.

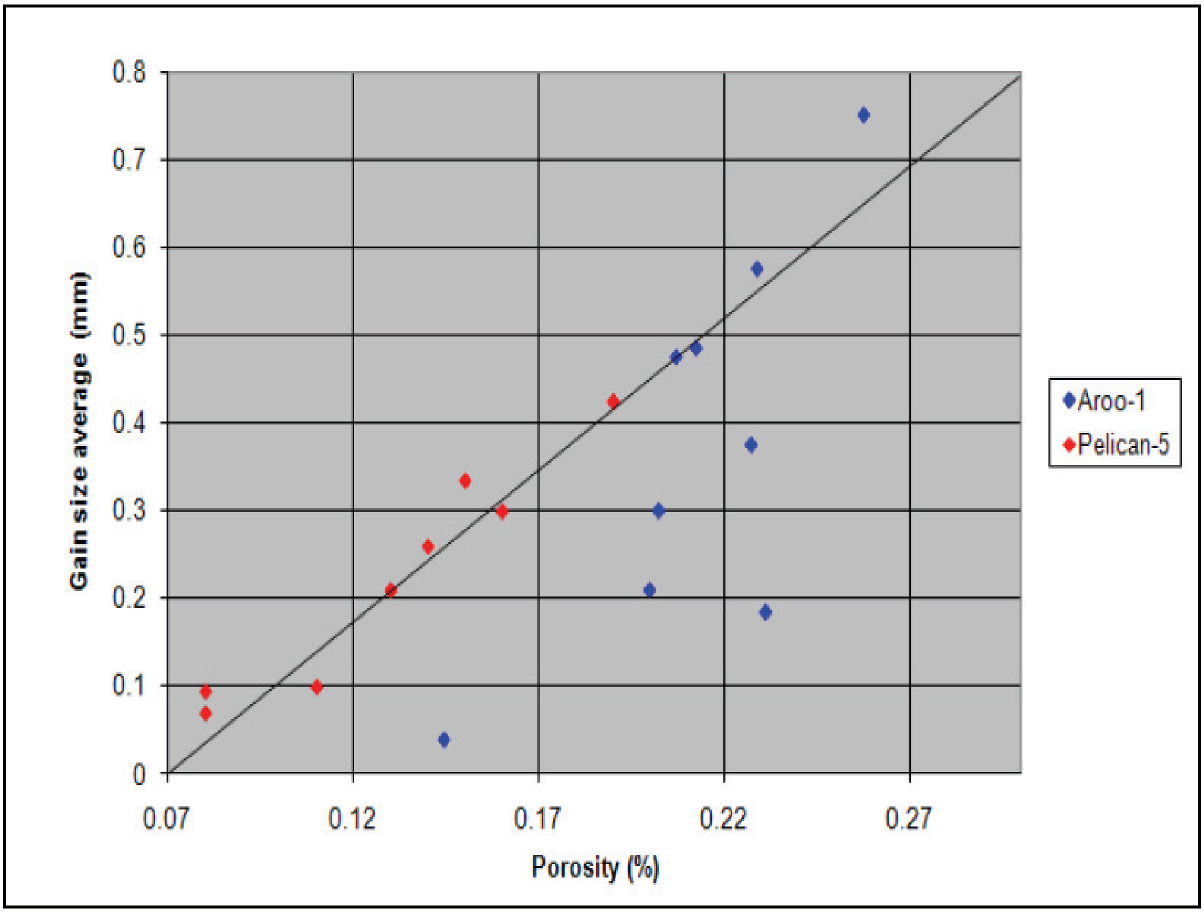

Figure 7.10: Porosity-grainsize cross plot showing positive relationship regardless of the depth of burial. It also indicates porosity and facies differences between wells in the Pelican Trough and other regions.

7.6. Potential CO_2 storage in saline aquifers of the Upper EVG

CO_2 can be injected into into large unconfined aquifers for storage without targeting a specific large structure or stratigraphic trap. Here injected CO_2 will rise in a plume due to buoyancy. The upward migrating of the immiscible fluid (CO_2) will be controlled by intra-reservoir permeability. Occurrence of low permeable lithologies such as intraformational seals will result in transferring the upward migration to horizontal migration. Thus, larger areas of the subsurface reservoirs below the cap rock can be utilised as a CO_2 trap. If the amount of the injected CO_2 is great enough to leak through intraformational seals, it eventually will be collected and trapped under the cap rock (regional top seal)

Combination of three main processes is responsible for trapping CO_2 in the reservoir rock, which under appropriate reservoir conditions can produce long-term subsurface storage (Chadwick et al., 2002):

- immobilisation in traps (structural/-stratigraphic),
- dissolution in the saline waters,
- and geochemical reaction, which results in formation of minerals in the pore space.

Deep saline aquifers have the largest storage potential among all subsurface storage options (Bentham and Kirby 2005). Storage capacity of the saline aquifers of the Upper EVG in the Bass Basin has been calculated using methods approved by Department of Energy of the United States (DOE).

$$\mathbf{GCO_2 = A\, h_g\, \phi_{tot}\, \rho E}$$

Where:

***GCO_2* is** *mass estimate of saline-formation CO_2 storage capacity,*

***A** is geographical area that defines the basin or region being assessed for CO_2 storage-capacity calculation,*

h_g** is gross thickness of saline formations for which CO_2 storage is assessed within the basin or region defined by **A,

***ϕ_{tot}* is** *average porosity of entire saline formation over thickness **hg,**.*

ρ is *density of CO_2 evaluated at pressure and temperature that represents storage conditions,*

***E** is CO_2 storage efficiency factor that reflects a fraction of the total pore volume that is filled by CO_2*

The equation includes an estimated CO_2 Storage Efficiency (E), which is the multiplicative combination of volumetric parameters that reflect the portion of a basin's or region's total pore volume that CO_2 is expected to actually contact. The components of the CO_2 storage efficiency factor for saline aquifers reflect different physical barriers that inhibit CO_2 from occupying 100 percent of the pore volume of a given reservoir section. The CO_2 storage efficiency factor also reflects the volumetric difference between bulk volume, total pore volume, and effective pore volume (DOE, 2006). Based on the results of the six Monte Carlo simulation runs for various lithologies and geological depositional systems, the DOE has estimated the storage efficiency can range between 0.01 and 0.04 of the total rock volume for each of P85 and P15, respectively.

Earlier in this report, the reservoir quality and charcterisations of the Upper EVG sands have been discussed. The effective reservoir area where buried greater than 800m and its thickness were shown in (Fig. 7.7).

Density of the injected CO_2 into reservoirs of the Upper EVG was calculated from regional temperature and pressure gradients (Fig. 7.11). Regional estimated CO_2 density versus depth for the Bass Basin was generated from regional temperature and pressure gradients (Fig. 7.12). An average reservoir temperature of 55.5 ^oC and average pressure of 10.6Mpa have been estimated. At the estimated average temperature and pressure gradients, the CO_2 density is calculated to be 410kg/m^3.

The CO_2 storage capacity of the saline aquifers of the Upper EVG can be calculated as below:

$\mathbf{GCO_2 = A\ h_g\ \phi_{tot}\ \rho E}$

= (200000*105000)*375*(26%)*410 *0.1%

= 21,000,000,000.00 *375*0.26*410 *0.01

= 8,394,750,000,000.00

= **8.39475GT** for the case of P85.

and for the case of P15 is

= (200000*105000)*375*(26%)*410 *0.4%

= 21,000,000,000.00 *375*0.26*410 *0.04

= 33,579,000,000,000.00

= **33.579GT**

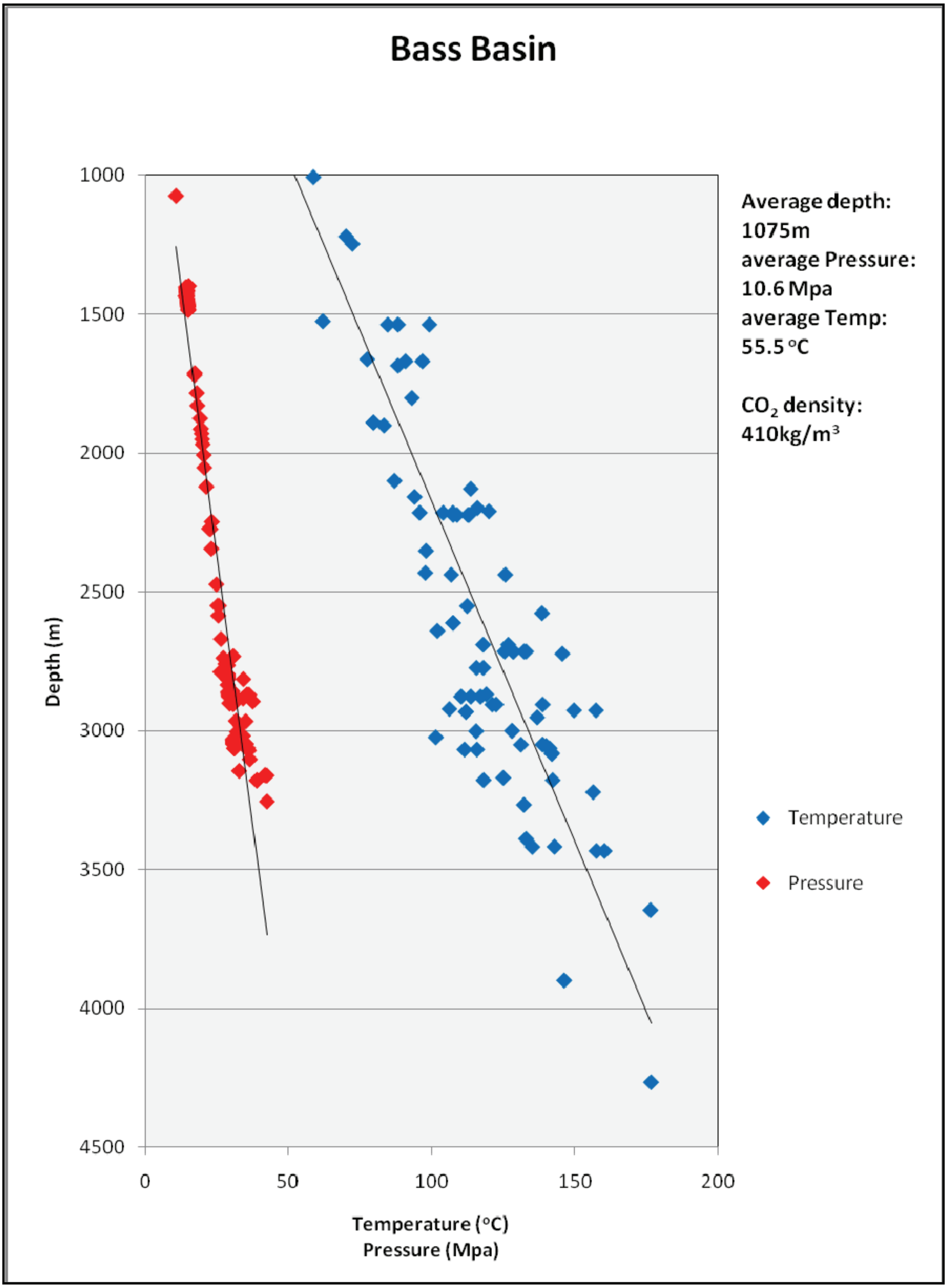

Figure 7.11: Regional temperature and pressure profiles of the Bass Basin.

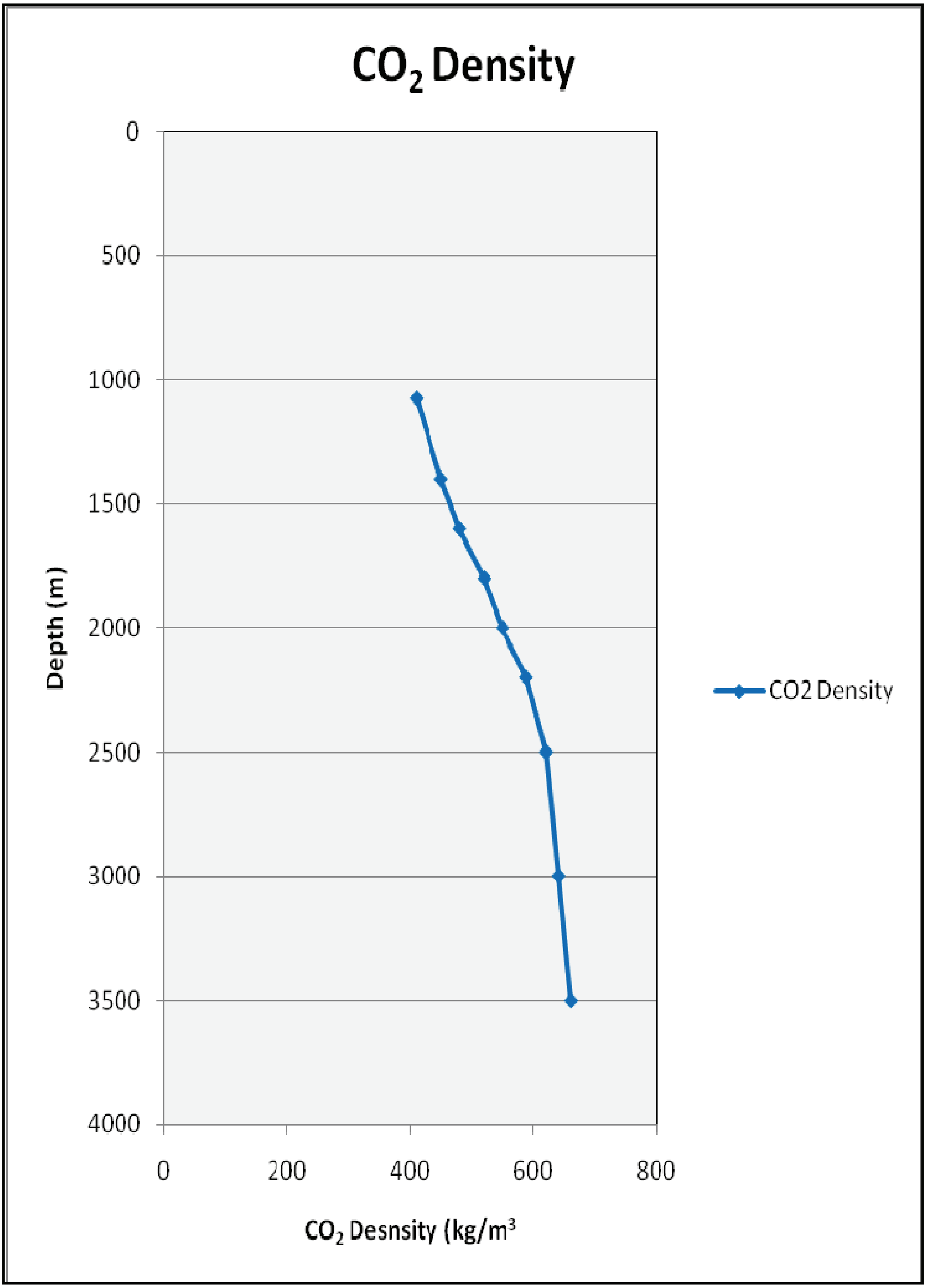

Figure 7.12: Regional estimated CO_2 density versus depth for the Bass Basin reservoir conditions.

7.7. Modelling Possible CO_2 Migration and Entrapment

The distribution, thickness and MICP analysis of the Demons Bluff Formation in the Bass Basin confirms its excellent top seal capacity. However, the capacity of the regional seal may reduce significantly in the Durroon Sub-basin due to thinning. Fault assessment also suggests an increase in risk of some fault reactivation in the northeastern part of the basin.

Reservoir characterisation of the Upper EVG suggests presence of good reservoir sands directly under the regional seal. Modelled hydrocarbon migration, palaeo and current accumulations suggest these reservoirs are mostly suitable for CO_2 storage. Thus, understanding potential CO_2 migration pathways and trap locations within the Upper EVG is important.

In order to understand migration pathways within EVG sediments and possible entrapment under the Demons Bluff regional seal, simulation was undertaken using PetroCharge Express within PetroMod software package. Depth converted regional surfaces of the top Demons Bluff Formation, top Upper EVG and top Narimba sequence were used to construct the models. The Demons Bluff Formation was assigned a typical shale lithology with excellent sealing properties. The seal capacity determined by the software was in accordance with the known thickness, capillary pressure and fault property. The Upper EVG was assigned a typical sandstone lithology with 26% porosity and selected to be a carrier bed for migration purposes. In order to determine general migration pathways in the basin regardless of fault behaviour, a large amount of CO_2 was areally injected into the bottom of the carrier beds. A density of 600kg/m^3 was assumed for the carbon dioxide injected into the base of the Upper EVG at depths of >800m (Fig. 7.13).

NOTE:
This figure is included on page 152 of the print copy of the thesis held in the University of Adelaide Library.

Figure 7.13: Density change of carbon dioxide with depth. The density and volume of CO_2 change with depth (increase in pressure and temperature) to become a supercritical fluid below depths of 800m.The blue numbers and balloons show the volume of CO_2 at each depth compared to a volume of 100 at the surface (from CO2CRC).

The migration of the injected CO_2 was mapped by simulating buoyancy forces. The model suggests that the regional migration pathways in the Bass Basin are radial from central parts of the basin to the flanking basin margins (Fig. 7.14). In addition, local drainage areas within the Upper EVG associated with CO_2 injection and migration were calculated (Fig. 7.15). The drainage map can be used for planning storage stages for modelling and determining the best CO_2 injection point within a chosen drainage area.

The structural trapping capacity under the regional sealing facies were calculated by creating modells for CO_2 migration within the Upper EVG and its accmulation under the Demons Bluff Formation (Appendix 6).

An estimate of the maximum structural trapping under the Demons Bluff Formation has been tested with all faults set to be barriers to migration, and then areal CO_2 injection to the base of the carrier beds. The models demonstrate that reservoir sands of the Upper EVG under the regional seal can trap significant volumes of CO_2 (Fig. 7.16). The model predicts the total pore volume in all closures directly beneath the regional seal exceeds 15,000,000,000 cubic meters. The largest 15 closures contain over 74% of total calculated pore volume; with largest single closure in the basin has a pore volume of 2,600,000,000 cubic meters (Table 7.3).

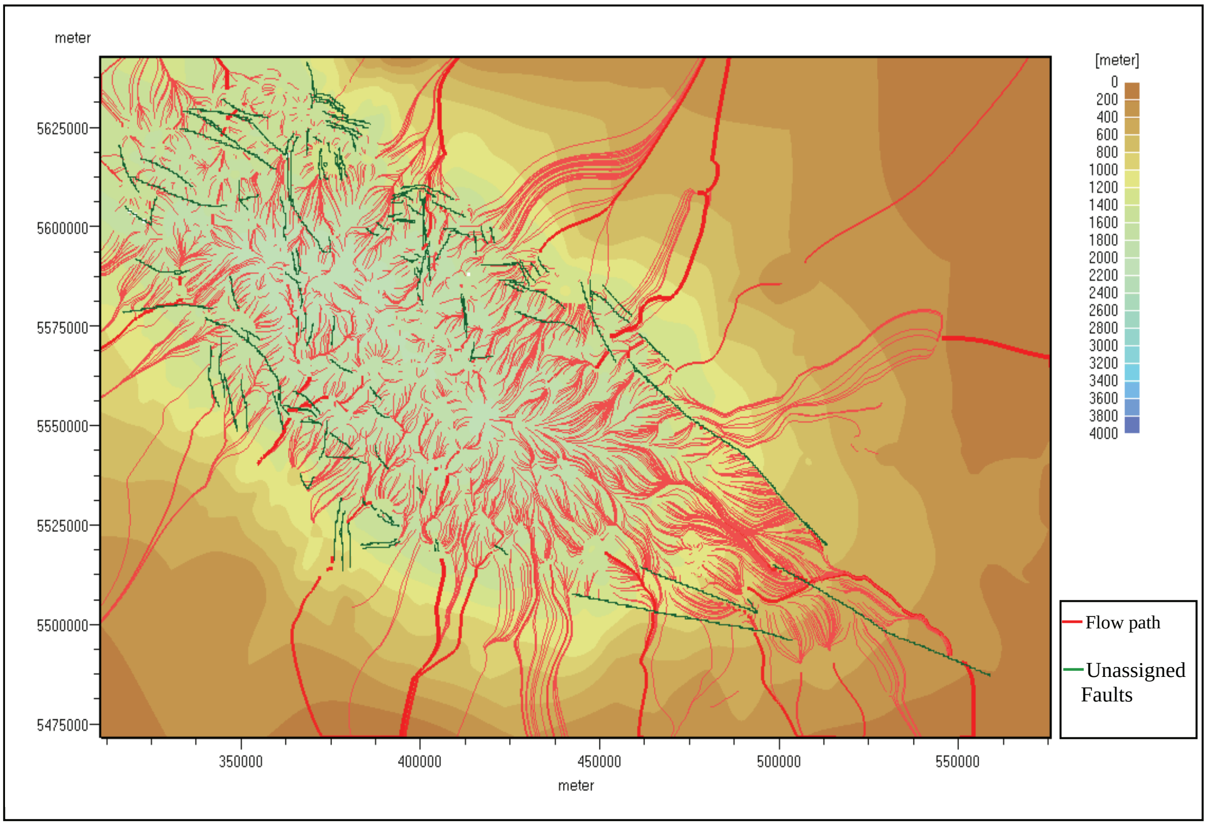

Figure 7.14: General migration pathways in the Upper Eastern View Group.

It is obvious that several closures are fault-dependent. If some or all of the faults facilitate CO_2 migration, then some of those closures would not have associated traps. To determine a more realistic total closure volume, the fault reactivation report has been used to determine which faults within the model may reactivate and leak. All the faults are marked as high risk of reactivation have been set to open and the rest set to be closed for CO_2 migration. Where faults are set to open fault-dependent closures cannot trap CO_2, thus, only relatively secure closures are calculated. Another areal injection of CO_2 has been injected to the bottom of the carrier beds of the Upper EVG to accumulate in secure closures that do not risk breaching from possible fault reactivation (Fig. 7.17). This model suggests secure closures within reservoirs of the Upper EVG under the regional seal have over 8,000,000,000 cubic meter of total pore space available for entrapment and the 15 largest possible accumulations contain over 76% of the calculated pore volume, with the largest single closure pore volume of over 1,100,000,000 cubic meters (Table 7.4).

In an attempt to understand total pore volume for non-fault dependent closures directly under the regional seal, another migration and accumulation model was developed setting all faults open for CO_2 migration. The injected CO_2 in this model could escape through each fault and accumulate in non-fault dependant traps only (Fig. 7.18). This exercise suggests a total pore volume of over 2,000,000,000 cubic meters; the largest 15 closures contain over 84% of the calculated pore volume, with the largest single closure having a pore volume of 750,000,000 cubic meters (Table 7.5).

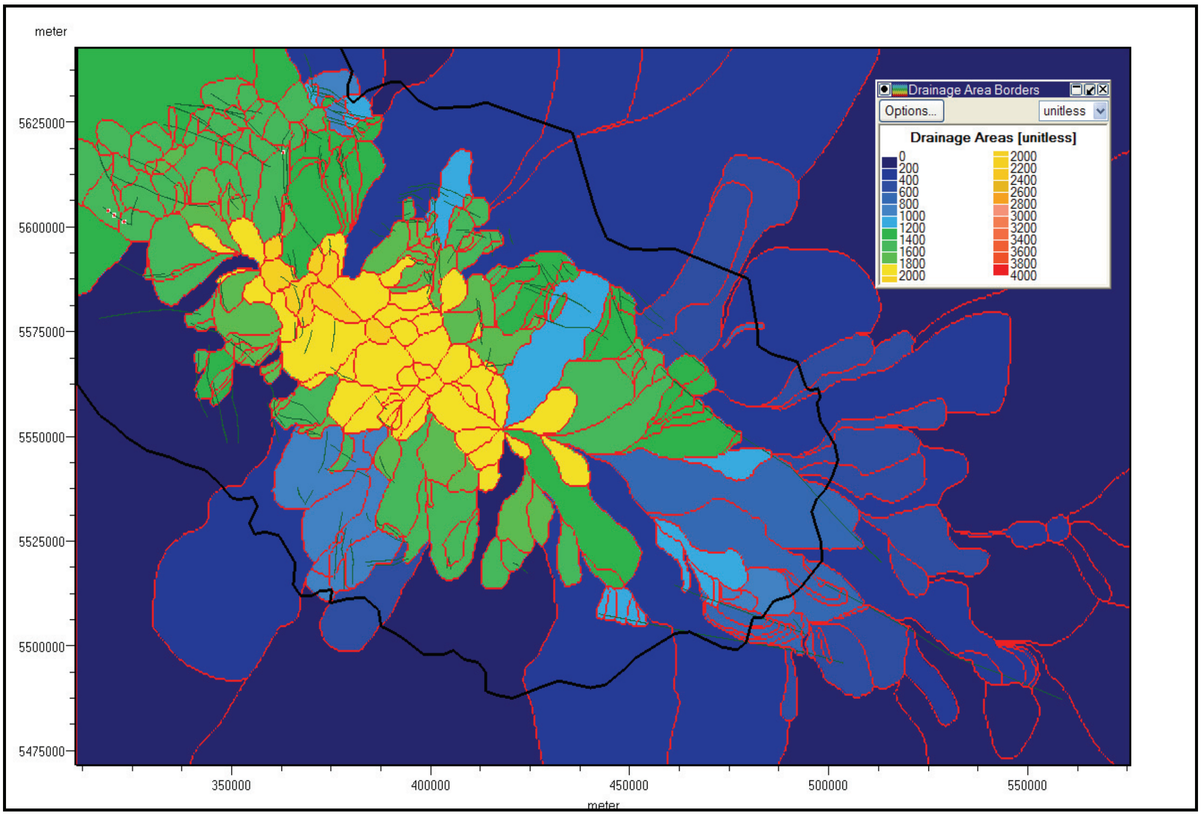

Figure 7.15: Drainage maps for CO_2 injection within the Upper EVG succession regardless of faults. Borders of each drainage area are defined with red lines, colour codes are degree of drainage probability from the centre of the basin, the black line outlines where reservoir/seal pairs deeper than 800m exist.

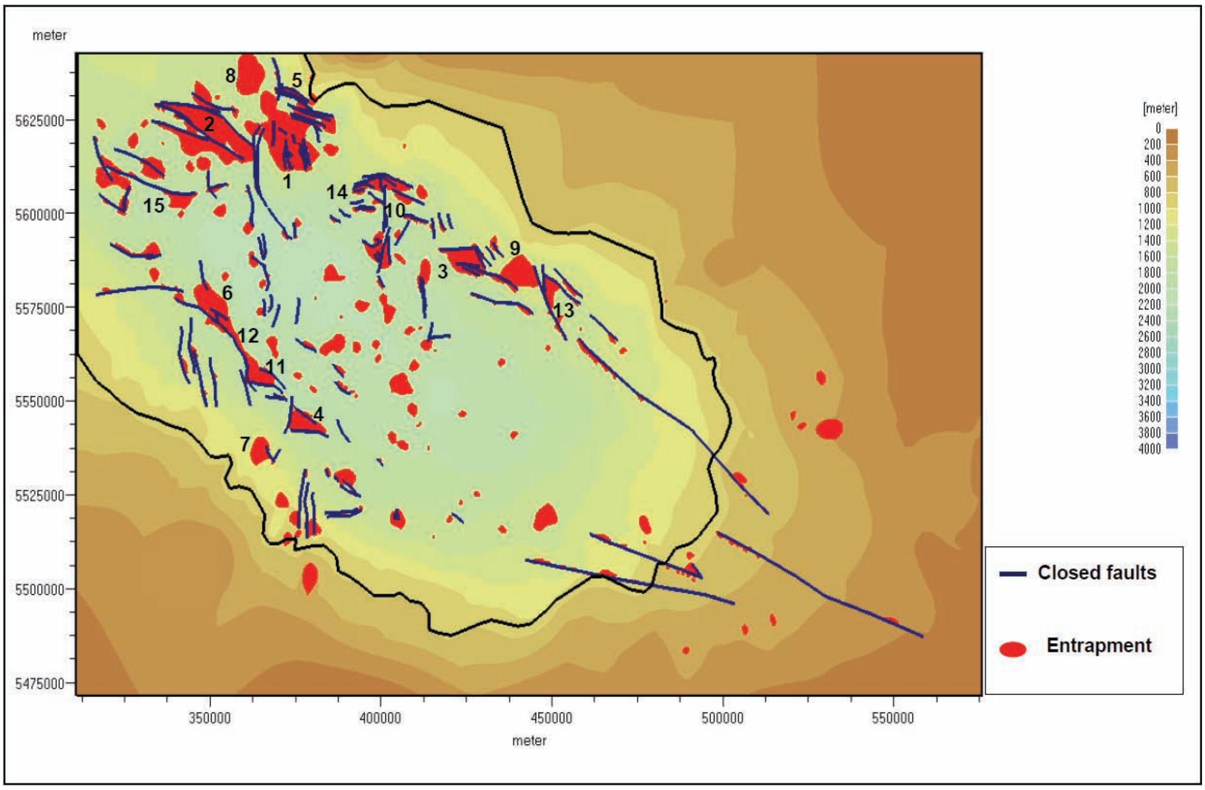

Figure 7.16: Highest possible CO_2 entrapment under the regional seal, in case of no leakage from faults, which are modelled closed for migration and shown in dark blue. The black line outlines where reservoir/seal pairs deeper than 800m exist in the basin.

Drainage Area (No.)	Closure Pore Volume [Million m^3]	Area (km^2)	CO2 Contact Area (km^2)	CO2 Filling [Billion cubic feet]	CO2 Filling saturation (%)	CO2 Column height (m)	Highest Point Depth (m)	Spill Point Depth (m)	Spill into (No.)
1	2611.96	408.49	179.81	92.23	100	281.5	1189.25	1470.75	395
2	2263.92	377.24	205.23	79.94	100	154.49	1445.57	1600.06	326
3	1159.43	112.75	47.46	40.94	100	231.02	1350.09	1581.11	186
4	772.67	65.5	38.42	27.28	100	228.82	1553.97	1782.79	82
5	658.25	14.25	19.84	23.24	100	495.26	985.63	1480.89	393
6	618.08	190	54.28	21.82	100	101.67	1607.52	1709.19	184
7	550.37	187.75	27.46	19.43	100	192.87	861.46	1054.33	17
8	548.06	114.75	63.98	19.35	100	103.34	1388.58	1491.92	393
9	539.69	173.25	58.84	19.06	100	82.41	1187.36	1269.77	209
10	397.62	44	18.38	14.04	100	187.81	1298.48	1486.29	295
11	392.62	61.5	36.81	13.86	100	157.66	1614.92	1772.58	381
12	372.36	63	20.55	13.15	100	140.48	1614.16	1754.64	384
13	330.77	24.5	21.88	11.68	100	200.94	1299.64	1500.58	182
14	245.9	12.5	11.85	8.68	100	174.75	1352.2	1526.95	280
15	208.58	72.75	22.81	7.31	99.23	117.17	1705.52	1822.95	389

Table 7.3: Fifteen largest available closures within reservoir sands of the Upper EVG directly under the regional seal, in the case of all fault-dependent and non fault-dependent closures were simulated. Depth of each closure, CO_2 filling and column heights also predicted. Structure number 1(Cormorant 1, King 1), number 8 (Toolka 1), number 6 (White Ibis 1), number 9 (Bass 2) and number 12 (Bass 3) are already drilled.

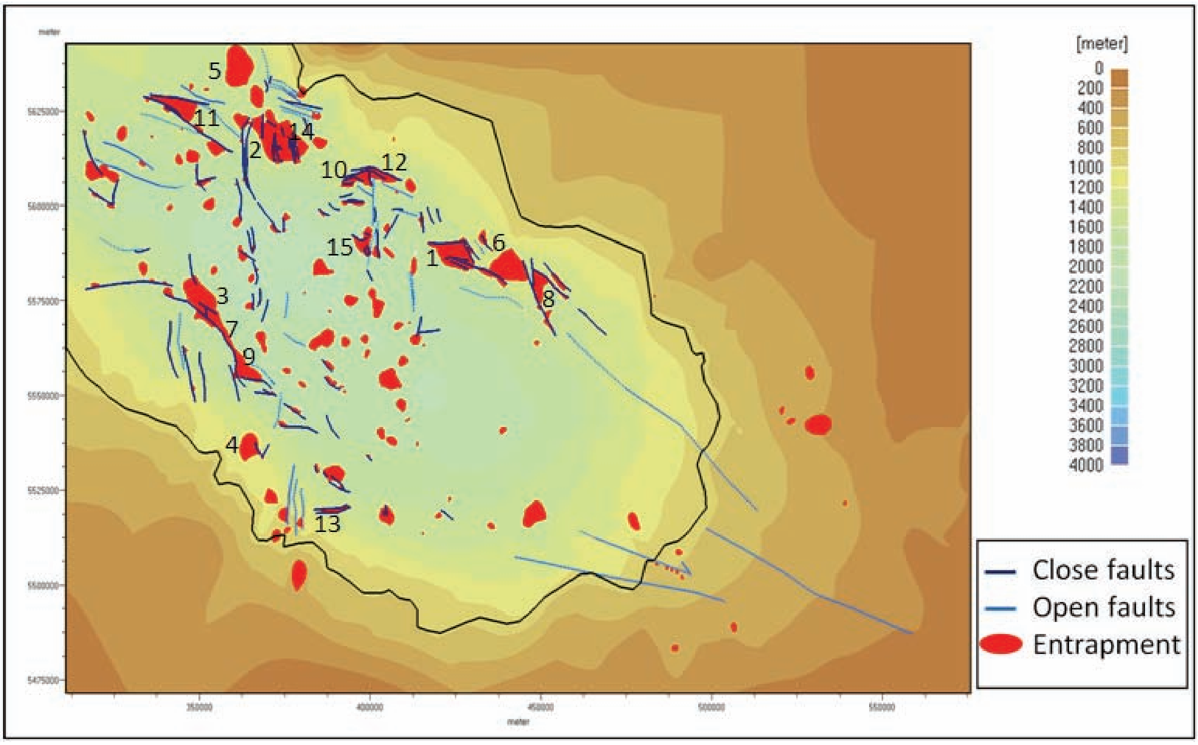

Figure 7.17: Possible CO_2 entrapment under regional seal, if all the faults that are at risk of reactivation are avoided. The faults not at risk of reactivation are shown in dark blue, the ones that have a moderate or greater risk of reactivation are modelled open for migration and are shown in light blue. The black line outlines where reservoir/seal pairs deeper than 800m exist in the basin.

Drainage Area (No.)	Closure Pore Volume [Million m^3]	Area (km^2)	CO2 Contact Area (km^2)	CO2 Filling [Billion cubic feet]	CO2 Filling saturation (%)	CO2 Column height (m)	Highest Point Depth (m)	Spill Point Depth (m)	Spill into (No.)
1	1159.43	112.75	47.45	40.94	100	231.02	1350.09	1581.11	157
2	1096.15	269.5	76.46	38.7	100	108.25	1328.71	1436.96	290
3	618.08	190	54.28	21.82	100	101.67	1607.52	1709.19	156
4	550.37	181.25	27.46	19.43	100	192.87	861.46	1054.33	15
5	548.06	114.75	63.98	19.35	100	103.34	1388.58	1491.92	304
6	539.69	166.75	58.84	19.06	100	82.41	1187.36	1269.77	179
7	372.36	63	20.55	13.15	100	140.48	1614.16	1754.64	331
8	330.77	24.5	21.89	11.68	100	200.94	1299.64	1500.58	153
9	264.34	58	29.78	9.33	100	143.17	1614.92	1758.09	96
10	246.05	11.75	11.84	8.69	100	174.75	1352.2	1526.95	247
11	216.39	45.5	44.32	7.64	100	91.37	1445.57	1536.94	222
12	146.15	11.25	7.98	5.16	100	149.29	1298.48	1447.77	252
13	116.04	5.4	5.40	4.10	100	163.00	1264.18	0	0
14	107.34	43.5	13.4	3.79	100	102.27	1329.16	1431.43	236
15	103.71	74.25	12.52	3.66	100	111.61	1724.74	1836.35	212

Table 7.4: Fifteen largest available closures within the Upper EVG directly under the regional seal in the case of low risk fault-dependent and non fault-dependent closures were modelled. Depth of each closure, CO_2 filling and column heights also predicted. Structure number 2 (Cormorant 1, King 1), number 3 (White Ibis 1), number 6 (Bass 2), number 7 (Bass 3) and number 15 (Yolla-1) are already drilled.

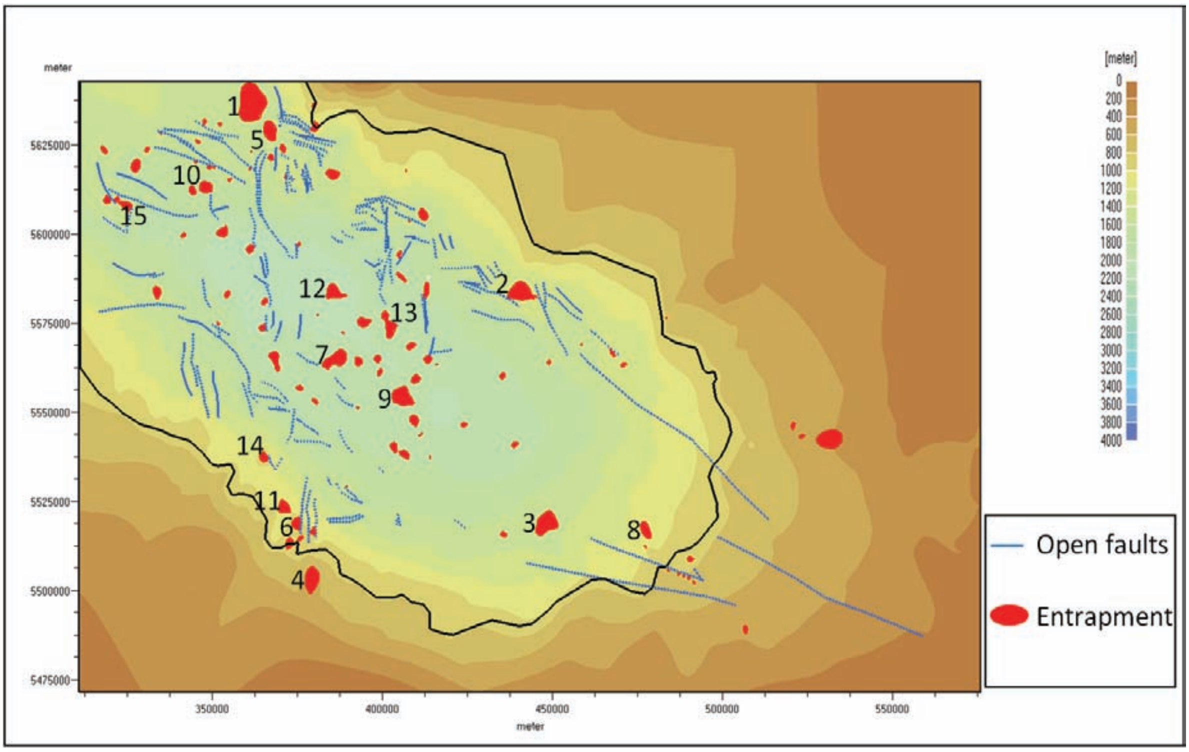

Figure 7.18: Non fault-dependent closures within the Upper EVG directly under the regional seal. Faults are modelled open for migration and are shown in light blue. The black line outlines where reservoir/seal pairs deeper than 800m exist in the basin.

Drainage Area (No.)	Closure Pore Volume [Million m^3]	Area (km^2)	CO2 Contact Area (km^2)	CO2 Filling [Billion cubic feet]	CO2 Filling saturation (%)	CO2 Column height (m)	Highest Point Depth (m)	Spill Point Depth (m)	Spill into (No.)
1	758.86	114.75	63.97	26.77	100	103.32	1388.58	1491.92	290
2	178.83	124.5	26.39	6.31	100	45.95	1187.36	1233.31	156
3	123.03	380.74	28.24	4.34	100	26.25	1403.15	1429.4	16
4	116.44	286.25	21.42	4.01	100	37.59	531.67	569.63	1
5	87.42	55.25	15.35	3.09	100	34.86	1423.88	1458.74	282
6	71.56	28	6.45	2.53	100	89.87	833.44	923.31	33
7	65.45	135	21.29	2.31	100	19.49	1897.05	1916.54	97
8	55.57	117.25	9.12	1.96	100	41.56	1042.47	1084.03	26
9	54.76	108	23.17	1.93	100	15.98	1922.66	1938.68	73
10	49.63	37	9.44	1.72	100	37.64	1568.98	1606.84	247
11	44.45	144.75	8.99	1.57	100	32.26	967.72	999.98	311
12	43.49	108.5	13.57	1.54	100	23.29	1997.67	2020.96	168
13	34.74	98.5	14.44	1.23	100	17.22	1914.95	1932.17	138
14	34.2	153	4.8	1.19	100	42.82	861.46	904.59	67
15	30.61	41	6.05	1.08	100	37.79	1468.1	1505.89	253

Table 7.5: Fifteen largest available non fault-dependent closures, within reservoir sands of the Upper EVG, directly under the regional seal. Depth of each closure, pore volume, CO_2 volume, CO_2 filling and column heights also tabulated. Structures already drilled are 1 (Toolka 1), 2 (Bass 2), & 7 (Tarook 1) and 9 (Poonboon 1).

CHAPTER 8

8- Conclusions

The main goal of this thesis was to predict hydrocarbon generation, migration and accumulation in the Bass Basin, Tasmania, Australia. Potential CO_2 geosequestration in the basin was also assessed. Several questions and secondary objectives were addressed to meet these goals. The result was a comprehensive study that presents new insights into the hydrocarbon prospectivity of the Bass Basin. It also provides inclusive evaluation of the potential of carbon dioxide storage and geosequestration in the basin. Results and conclusions for the objectives of this thesis are summarised below.

8.1. 2D Seismic and Structural Interpretation

2D stratigraphic and structural mapping presented new insights into the structural and depositional evolution of the Bass Basin and resulted in redefinition of the limits of the basin. The geological history of the Bass Basin was developed through the recognition of structural styles and through stratigraphic observations from seismic interpretation. The basin's structural and depositional evolution were integrated and employed to develop 2D and 3D basin models, including decompaction models and the creation of palaeo-models. The identification of the main depocentres in the basin was highly important for thermal maturity modelling and for understanding petroleum systems in the basin.

8.1.1. Structural and Depositional Evolution

The early extensional rifting phase was associated with the initial separation of Australia and Antarctica (Southern Ocean rifting). Early Cretaceous (possibly latest Late Jurassic) structures consist of deep half-grabens in the central Cape Wickham Sub-basin where the Tithonian/Berriasian - (?)-Barremian Crayfish Equivalent Megasequence is locally deposited. The extension rift phase propagated towards the south and the southeastern Bass Basin during the Barremian-Albian to form a deep half-graben which was initially connected to the Pelican Trough in the southern Cape

Wickham Sub-basin, but was separated by the end of the rifting period. A deep half-graben in the northeastern Durroon Sub-basin also formed, and is known as the Otway Megasequence which is deposited across the entire Bass Basin.
The second extensional rifting phase was related to the separation of the Lord Howe Rise complex from Australia and the Tasman Basin break-up (the Tasman rifting). This rifting period resulted in the deposition of the pervasive Durroon Megasequence. The deep depocentre in the southern Cape Wickham Sub-basin has gradually moved towards the east, to a location between the Bark and Dondu Troughs.

The third extensional rifting phase was associated with the prolonged separation of the Australian and Antarctic plates along the Tasman-Antarctic Shear Zone. The Bass Megasequence, which is also pervasive across the basin, was deposited as a result of this latest rifting phase.

The Aroo, Flinders and Torquay sequences were deposited as a result of three different post-rift subsidence phases.

8.1.2. Structural Styles

Regional Early Cretaceous faults of the Cape Wickham Sub-basin generally strike ENE-WSW and probably reflect the strong control of the Proterozoic basement terrane. On the other side of the Chat Accommodation Zone, in the Durroon Sub-basin, the Early Cretaceous faults are NNE-SSW in direction.
A Central Basement High (CBH) is evident in the central Bass Basin, which is oriented in a NW-SE direction. The CBH separates closely-spaced, shorter, fault-relay style and domino faults in the northwestern and western part, from pervasive faults across the southeastern Bass Basin.

The growth of Early Cretaceous faults largely stopped during the Early Eocene. Rotation in the direction of stresses created a new set of small N-S striking faults to accommodate the extension, particularly in the northeastern part of the basin.
The inversion of previously normal growth faults was associated with strike-slipping of compressive stresses during the Late Oligocene-Miocene, which largely affected

N-E striking faults and created anticlinal inversion structures in the northeastern Bass Basin.

8.2. Regional Reservoir Quality

8.2.1. The Middle EVG

The sand-bearing zones of the Middle EVG are thick and have excellent lateral continuity and regional extent. Good porosity is preserved within coarse-grained sandstones even at depths greater than 3000 m. There are four main sand-bearing zones in the Middle EVG with recognised porosity trends for each zone. These sand zones represent major depositional cycles with recognisable aggradational, retrogradational and progradational patterns. Coarser-grained sands have resisted compaction and cementation and have preserved better intergranular porosity and reservoir characteristics. Fining-upward cycles potentially provide capping seals for the clean reservoir sands, as fine-grained clastics are deposited on top of coarse-grained clastics.

Poor reservoir quality of the Narimba sequence within the Pelican Trough is due to lateral facies change and the terrestrial nature of the sediments. The sand-bearing zone of the Narimba sequence shows good reservoir characteristics in other parts of the basin.

8.2.2. The Upper EVG

Reservoir sands of the Upper EVC show good reservoir characterisation. The aggradational and retrogradational nature of the sediments has placed sand-bearing zones between and on top of the coaly facies. The top reservoir sands with their good reservoir quality can provide enormous pore volume and are buried under regional sealing facies of the Demons Bluff Formation.

8.3. Seal Integrity and Capacity

8.3.1. Regional Seal

The regional sealing facies of the Demons Bluff Formation has an excellent retention capacity. Its sealing capacity is supported by its tremendous thickness and regional extent across most of the basin. The regional seal is generally between 100-250 m thick and preserves its thickness over almost the entire Cape Wickham Sub-basin; however, it is normally thinner than 100 m over the Durroon Sub-basin and disappears in its southern parts.

Due to strike slip and fault reactivation in the northeastern part of the basin, the top seal has failed to secure some traps which may have charged in this area. Although the regional seal is thickest in the northeastern region, there is also the risk of seal leakage associated with fault reactivation.

8.3.2. Intraformational seals

The intraformational seals of the Middle EVG have a good retention capacity. This study suggests a reasonable thickness and regional extent for these seals, especially where palaeo-lakes occurred in the basin during the deposition of the Middle EVG succession.

8.4. Petroleum plays and prospectivity

New plays in the central, northwestern and southern parts of the basin, predicted by this study, provide new horizons into the hydrocarbon prospectivity of the Bass Basin and may result in a new era of hydrocarbon exploration. The more advanced understanding of temperature and pressure distribution within the basin, provided by this study, has answered many questions regarding source rock maturity, migration pathways and potential locations of hydrocarbon accumulations.

8.4.1. Generation and Expulsion

Source rocks of the Bass Basin have generated and expelled enough hydrocarbons for migration and accumulation in many parts of the basin. However, due to the terrestrial nature of the mature source rocks and the maturity of the deeper source rocks, dominantly gaseous hydrocarbons were expelled, with the exception of the Early Eocene source rocks that generated and expelled a reasonable amount of liquid hydrocarbon. While most oil-prone source rocks of the late Early-Middle Eocene (P. Asperopolus zone) are yet not mature for oil expulsion at the present time, modelling suggests hydrocarbon expulsion in the Bass Basin is not a risk for exploration.

Early Cretaceous source rocks of the Otway Megasequence in the Bass Basin started oil generation in the deepest troughs as early as the Turonian, around 89 Ma, with early expulsion pulses from the Campanian, about 78 Ma.
Maastrichtian source rocks of the Ferneaux sequence sedimets entered the oil generation window during the Early Eocene (~50 Ma), but did not get into the oil expulsion window until the Early Oligocene (~32 Ma).

Palaeocene source rocks of the Tilana sequence (L. Balmei) started oil generation during the late Middle Eocene (~37 Ma) and expelled oil by the Early Miocene (~21 Ma), while the better source rocks of the Early Eocene entered the oil generation window during the Late Oligocene (~27 Ma) and started expulsion only during the Pliocene (~4 Ma).

Oil-prone source rocks of the Narimba sequence (M. diversus) entered the oil generation window during the late Early Miocene and expelled during the Pliocene.

8.4.2. Migration pathways

The expelled hydrocarbons from mature source rocks of the Bass Basin have migrated towards upper reservoirs and the flanking margins of the basin. This study suggests radial migration pathways from the centre of the basin to the flanking margins, except where permeable faults have facilitated some vertical migration. The radial migration pattern might have been responsible for major hydrocarbon loss from the margins of the basin.

Vertical migration from the lower sediments of the basin through permeable fault planes, during deformation periods, has played a role in charging many reservoirs within the EVG succession, primarily the reservoirs of the Lower and Middle EVG. Intraformational seals limited vertical migration of hydrocarbons into the Upper EVG. An exception is in the northeastern basin, where faults oriented in the direction of Miocene compressive stresses have been inverted and have facilitated the escape of hydrocarbons through to the Upper EVG reservoirs.

Cretaceous faults striking NE-SW were not largely affected by the Miocene compressive event and have assisted in keeping hydrocarbons within reservoirs of the Middle EVG and deeper sediments. However, N-S striking Eocene faults were reactivated during the Miocene and caused breaching of several previously accumulated hydrocarbons within the northeastern region of the Bass Basin where the regional sealing facies has prime thickness.

The Bark Trough is the only trough within the Durroon Sub-basin that has similar maturity ranges as the Cape Wickham Sub-basin. The older source rocks have generated and expelled hydrocarbons, which may have been trapped by intraformational seals within the reservoirs of the Durroon Megasequence. Any migrations towards younger successions of the sub-basin and the flanking area were probably lost due to the lack of effective seals.

8.4.3. Accumulations

The 3D accumulation study suggests that there are many hydrocarbon accumulations trapped within reservoir sections of the Bass Basin, besides those known to-date. Reservoirs in the Narimba, Tilana and Ferneaux sequences have the highest probability of keeping these accumulations and are most suitable for production. Although deeper reservoirs of the Durroon and Otway megasequences may have trapped several hydrocarbon accumulations across the basin, these reservoirs are buried too deep within the deeper troughs of the Cape Wickham Sub-basin to be considered good candidates for hydrocarbon production. However, those parts of the Durroon and Cape Wickham sub-basins that are not too deeply buried are candidates for exploration, especially where accumulations within these reservoirs are located beneath other predicted accumulations within higher reservoir sections.

Several new and untested petroleum plays within the Bass Basin have been predicted by this thesis (as per Chapter 7), which may improve the petroleum prospectivity of the basin.

Reservoirs of the Upper EVG did not receive much hydrocarbon charge in many areas of the basin, except in the northeastern region, however some of these accumulations were breached during Miocene reactivation.

8.5. Fault Conductivity Prediction

The mechanism of rotation in palaeostresses within the 3D petroleum systems modelling has been tested by this study to observe its effect on fault permeability for periods after the first hydrocarbon expulsion within the modelled basin. 3D Migration model results suggest, most faults can turn to barriers for petroleum migration soon after deformation periods. Thereafter, rotation in palaeo-stress direction may have a great effect on fault conductivity for migration of hydrocarbons. Pre-existing faults or parts of them may facilitate petroleum migration during periods of suitable stress direction for reactivation despite non recognition of fault reactivation from seismic. These results may propose a framework for dealing with fault conductivity in future migration modelling studies.

8.6. Potential CO_2 Storage and Sequestrations

The Bass Basin has the potential to become a good storage site for CO_2 geosequestration. Good reservoirs of the Upper EVG, which lie beneath the regional sealing facies of the Demons Bluff Formation, are normally buried deeper than 800 m, and can provide excellent pore volume for CO_2 storage without much interference with the basin's petroleum systems, as they received little hydrocarbon charge.

The Bass Basin contains reservoir/seal pairs that can be potentially utilized for geological storage of CO_2. Upper EVG reservoirs have excellent porosity/permeability characteristics and well positioned beneath a high quality regional top seal, the Demons Bluff Formation. In addition, deeper sections of the Middle and Lower EVG also contain several prospective structures that could capture large volumes of CO_2.

Petroleum systems models predicted that the Upper EVG reservoirs under the regional seal have received only local hydrocarbon charge. This leaves excellent potential for CO_2 storage in the basin with limited effect on current and future petroleum exploration and production.

The Upper EVG reservoir sands in the Bass Basin show excellent reservoir quality (26% average porosity and 198mD average permeability). Supporting evidences of excellent retention capacity of the regional sealing facies of the Demons Bluff Formation, together with limited predicted hydrocarbon charge into these reservoirs, makes them much more attractive for CO_2 capture and storage. The Demons Bluff Formation has a wide distribution across the basin, is suitably thick and has very good top seal potential. It has an average CO_2 column hight of 988m, which makes it an excellent seal for CO_2 storage.

Reservoirs of the Middle and Lower EVG might provide additional storage sites as there are several reservoir/seal pairs, as well as excellent structures within these two successions. The intraformational seals may have good regional continuity but are likely to be thinner than the Demons Bluff Formation. MICP analysis, together with past hydrocarbon exploration support good sealing capacity for intraformational seals of the Middle EVG, as most discovered hydrocarbons in the basin are trapped within reservoirs of the Middle EVG. These reservoir/seal pairs are buried deeper under reservoirs of the Upper EVG, which adds positive value to suitability of the Bass Basin for CO_2 storage, because any possible leakages from stored CO_2 could migrate into the upper reservoirs. A negative aspect of using these reservoirs for CO_2 storage is that they have been assessed as having the greatest potential for economic hydrocarbon accumulations in the basin. Careful hydrocarbon accumulation prediction studies need to be undertaken as part of their assessment for CO_2 storage.

The Bass Basin contains several non fault-dependent closures in the central part of the basin that make very good candidates for CO_2 storage. Good reservoirs sands under the regional seal (with no hydrocarbon charge) occur in Tarook-1, Nangkero-1, Narimba-1 and Poonboon-1 in the central part of the basin. Toolka-1 is another example in the northern part of the basin.

The potential risk of fault reactivation under present-day stress is mostly confined to the margins of the basin, particularly the northeastern margin. Nevertheless, if storage sites contain faults that cut the regional seal, individual faults need to be properly evaluated for any potential risk, including pore pressure change due to CO_2 injection.

Overall, the Bass Basin has large potential for CO_2 storage and sequestration. Its storage capacity, stability and location suggest it can be an excellent candidate to provide a good storage site for the Victoria's CO_2 storage needs.

8.7. Recommendations for future work

Complete source rock maps across the basin including Total Organic Carbon percentage (%TOC) and Hydrogen Index (HI) can improve the 3D petroleum systems model to a great degree, especially where hydrocarbon expulsion volumetrics is an issue. Any future petroleum systems work should consider source rock maps as a necessity.

Prospective regions for hydrocarbons require detailed localised 3D petroleum systems modelling for better exploration. Detailed models may contain detailed maps of the reservoir facies, TOC and HI maps and sealing facies maps, this helps better constrain pressure and temperature distribution within the model.

Influence of volcanics on the regional seal, especially areas where dykes cut through the seal can be significant. Timing of volcanic activities is also important, particularly if these occurred after hydrocarbon entrapment in the region. Understanding volcanic influences may be important in determining the geological carbon storage potential of the basin.

Understanding present-day stress field orientation is vital for safe carbon dioxide storage in the basin. Future work needs to focus on reducing uncertainty in the orientation of the present-day stress field.

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