Release Areas V09-1, V09-2, V09-3 and V09-4, Central Otway Basin, Victoria

Location

The four 2009 Release Areas are located approximately 300 km west-southwest of Melbourne, the State Capital of Victoria with a population of over 3.5 million. The greater Melbourne region currently represents Australia's largest domestic gas market and is supported by major petroleum refineries. The City of Portland is the nearest centre (population 9900) along the western Victorian coast. Portland is famous for its deepwater port established for the large aluminium smelting operations. The port can be used for offshore operations and is serviced by an excellent network of road and rail links.

Release Area V09-1 extends from Victorian State waters (three-mile-zone) southwards from Portland across the shelf to the upper part of the continental slope (**Figure 1**). Water depths for the northern part of the block are less than 100 m with the remainder increasing to 500 m across the upper to middle continental slope. Release Area V09-1 comprises 46 (35 full and 11 partial) graticular blocks and covers an area of about 2,605 km^2.

Release Area V09-2 lies south of the town of Port Fairy beyond Victoria's Three-Mile Zone and northeastward of Release Area V09-1. Release Area V09-2 was part of the former exploration permit VIC/P44, which, following relinquishment in November 2006, is now partially being re-advertised. The area consists of 9 (6 full and 3 partial) graticular blocks that cover approximately 530 km^2. Water depths are typical for shallow shelf regions and range between 30 m and 100 m.

Release Area V09-3 lies 10 km east of the Henry and Casino gas fields and was also part of the former licence area VIC/P44. The area, consists of 3 full graticular blocks that cover an area of 200 km^2. Water depths range between 50 and 150 m.

Release Area V09-4 is the deepest water of the 4 Release Areas. Its southeastern boundary coincides with the Victorian and Tasmanian offshore boundary (**Figure 1**). Release Area V09-4 consists of 74 (66 full and 8 partial) graticular blocks, and covers an area of approximately 4710 km^2. Water depths increase to the southwest across the middle to lower continental slope, from around 500 m to over 2000 m along the southern boundary.

Release Area Geology

Local Tectonic Setting

Most of the major structural features of the offshore central Otway Basin were initially developed by Late Cretaceous rifting and transpressional folding, and later modified by Late Paleogene compression. Seismic mapping clearly shows the development of two main structural provinces in the area of interest.

Areas V09-1 V09-2 and V09-3 are mainly part of the Mussel Platform, while the deepwater area V09-4 is associated with the northwest trending Voluta Trough which is separated from the platform areas by a series of northwest striking faults that collectively comprise the Tartwaup and Mussel fault zones (**Figure 2**), in a regional context referred to as the Tartwaup-Mussel Fault Zone. The faults are laterally extensive with individual trends able to be traced over 30-80 km and propagate upwards to the Late Maastrichtian Unconformity where they are either truncated or show only relatively minor Paleogene reactivation.

Structural and stratigraphic evolution of the sub-basin

Structural growth occurred on the faults throughout the Late Cretaceous with the Sherbrook Group showing variable amounts of offset along the fault zones. Along the Tartwaup-Mussel Fault Zone, structural closure is associated with rollovers and tilted fault blocks with structures at the top Waarre Formation level. Within the Voluta Trough itself, tilted fault blocks dominate with a number of very large features mapped by previous explorers. Closures associated with these structures were targeted by wells such as Bridgewater Bay 1, Voluta 1, Discovery Bay 1 and Normanby 1, but are at significant depths (typically deeper than 3500 m), unlike the Mussel Platform prospects to the east. The Voluta Trough is predominantly a Late Cretaceous depocentre.

The Mussel and Crayfish platforms to the north see a dramatic thinning of the Late Cretaceous section over the respective Tartwaup and Mussel fault zones. A significant Paleogene structural feature is evident in the area of the Portland Trough. This is a major Paleogene depocentre with around 1000 m of Wangerrip Group sediments along its axis through the north of Release Area V09-1. The trough is not so much a graben but a relatively unfaulted syncline. The Wangerrip Group sediments in the trough can be seen onlapping the southern flank of a structural axis, the Bridgewater High, where the Paleogene section thins significantly. This structural high provides a focus for prospects and hydrocarbon charge through both Mesozoic and Cenozoic plays. The Bridgewater High appears to have been a significant structural feature during the early Paleogene and forms a southeast plunging anticline at the Late Maastrichtian Unconformity level.

Stratigraphy

The stratigraphy used in this chapter generally follows that established by Morton et al

(1994, 1995) with refinements from Perincek et al (1995), Geological Survey of Victoria (1995), Lavin (1997), Partridge (1997, 2001) and Geary and Reid (1998). The following descriptions are largely derived from Reid et al (2001) and Partridge (2001).

The Otway Group (**Figure 3**) represents the succession from early syn-rift graben fill to later sag phase deposition. It has been subdivided into five formations, each of which represents distinct facies associations in an overall fluvio-lacustrine palaeoenvironment.

The **Casterton Formation** comprises initial rift-fill sediments and volcanics of Late Jurassic to Early Cretaceous (Tithonian to Berriasian) age. Up to 500 m of section was deposited in isolated east-trending half-graben of limited lateral extent. The formation consists of interbedded carbonaceous mudstone with minor felspathic sandstone and siltstone, interlayered with basaltic flows and pyroclastics (Wopfner et al, 1971; Kenley, 1976). Low-energy lacustrine environments of deposition are inferred.

The Berriasian to Valanginian **Pretty Hill Formation** consists dominantly of sandstones (litharenite to feldspathic litharenite) with a varying but minor proportion of interbedded siltstone, mudstone and coal. The sandstones are medium to coarse-grained and conglomeratic in part, with porosities and permeabilities that are generally moderate to high where buried at relatively shallow depths. Diagenesis significantly reduces reservoir properties when more deeply buried. Fluviatile depositional environments are interpreted as ranging from high-energy braided stream to low-energy meandering stream. The formation was deposited in widening half-graben along the Otway Basin that developed in response to a rapid escalation of rift activity in the Berriasian (Perincek and Cockshell, 1995). Seismic data suggests that it is up to 5000 m thick in the Penola Trough in South Australia (Morton et al, 1995). Some sequences within the Pretty Hill Formation exhibit excellent source potential and the presence of oil shale has also been reported (Hill, 1995a, 1995b). However, like the Casterton Formation, the formation is buried too deeply to constitute either a viable source rock or a reservoir unit offshore.

The **Laira Formation** is predominantly a claystone-siltstone sequence with minor fine grained sandstone interbeds deposited in fluvial flood-plain to shallow lacustrine environments (Morton et al, 1995). The formation is best developed in the Penola Trough, South Australia where it is 888 m thick at Katnook 3. It can be mapped into Western Victoria as far as the Merino High, but may also be present in Eumeralla 1 (Morton et al, 1995).

The **Katnook Sandstone** consists of fine to medium-grained, cross-bedded sandstones, interbedded with micaceous siltstones (Morton et al, 1995). A fluvial depositional environment is interpreted with both high-energy braided and low-energy meandering streams interspersed with flood-plain deposition. The formation is the main gas reservoir unit in the Penola Trough (Katnook field) in South Australia. It is strongly diachronous with the Laira Formation and is difficult to correlate outside the Penola Trough due to erosion or facies change. The formation has not yet been identified in the Victorian part of the basin.

Change in lithological character and facies regime led to the informal subdivision of the **Crayfish Subgroup** (Kopsen and Sholefield, 1990). The dominantly fluvial sediments of the Pretty Hill Formation, the Laira Formation and the Katnook Sandstone, all of which are composed of quartz-rich sandstones with minor mudstones, have been combined in this subgroup (**Figure 3**). These sediments lack the volcaniclastic component of the thick and lithologically homogeneous Eumeralla Formation (see below) that overlies the Katnook Sandstone. The Crayfish Subgroup is mainly recognised in the Victorian part of the Otway Basin.

The **Eumeralla Formation** is characterised by abundant volcaniclastic detritus derived from active volcanic complexes located to the east (Constantine, 1992; Bryan et al, 1997). Fission track dating by Gleadow and Duddy (1981) tie the major pulse in volcanism to between 106 and 123 Ma. The formation comprises variable proportions of claystones, siltstones, sandstones and coal deposited in a variety of non-marine environments including coal swamp, fluvial flood plain and shallow to deep water lacustrine. Felton (1997a, 1997b) describes high to low-energy fluvial facies in outcrops along the Otway Ranges. The volcaniclastic nature of the sediments promotes diagenesis at relatively shallow depths of burial and reservoir quality sandstones are rare. However, in the onshore, the Windermere Sandstone Member and the Heathfield Sandstone Member are examples of localised quartzose sand bodies that were derived from uplifted fault blocks during deposition of the Eumeralla Formation (Duddy, 2003). These sand bodies are known to contain small oil accumulations in the Windermere 1 and gas accumulations in Katnook 1 wells.

The Sherbrook Group has been the prime exploration objective offshore, with most of the major gas discoveries onshore and offshore reservoired within the Waarre Formation. In recent years, the stratigraphy of the Sherbrook Group has been revised and the spatial and temporal relationships between the reservoir and sealing lithologies are now better understood. The description below follows that of Partridge (2001), who identified major discrepancies in the published data on the age of the formation and the extent of diachronism in the basin.

The Sherbrook Group (**Figure 4**) is separated from the underlying Otway Group by a regional, mid-Cretaceous unconformity (Otway Unconformity) represented by a time break of 6.5 Ma covering the latest Albian and all of the Cenomanian (Partridge, 1997). Deposition is inferred to have recommenced during a major rise in sea level induced by renewed rifting towards the end of the Cenomanian and the group comprises six formations.

The Turonian Waarre Formation comprises several sequences of marginal marine and partly nonmarine sandstones and mudstones, including minor coal. Buffin (1989) subdivided the formation into four units, which were, from oldest to youngest, Waarre A, B, C and D. Later work by Partridge (1999, 2001) recognised that Buffin's Waarre Formation Unit D actually comprised the Flaxman Formation. The lithologies of the remaining subdivisions of the Waarre Formation are as follows:

> Waarre A: Interbedded fine-grained lithic sandstones and carbonaceous mudstones.

> Waarre B: Carbonaceous siltstones and claystones.

> Waarre C: Fine to very coarse-grained quartz sandstones with thin interbedded mudstones and coals.

Waarre D, which is now recognised as the Flaxman Formation, has been characterised primarily based on the electric log character in onshore wells. Partridge's work (1997, 1999) and recent wells drilled by Santos Limited in the Port Campbell Embayment have provided additional palynological criteria that better constrain this intra-formational sub-division. In addition, offshore wells which have been drilled both within, and on the flanks of, the Shipwreck Trough, and which have Waarre Formation reservoirs as their primary target, have also provided additional constraints to help define the southerly extent of these units.

The Flaxman Formation is late Turonian in age and essentially represents a shallow to open marine sequence that consists mainly of sandy mudstones that commonly contain glauconite. On the Prawn Platform, in the vicinity of Release Areas V09-1, V09-2 and V09-3, the Flaxman Formation is distinctly sandier (Partridge, 1999) than in many other parts of the basin, reflecting a more marginal marine depositional environment. These marine sandstones contribute to total gas reservoir sections at both the Minerva and La Bella fields. However, reservoir development is poor in comparison to the underlying Waarre Formation. It has a very low net-to-gross reservoir sand ratio and does not constitute an exploration target by itself.

A localised break in sedimentation occurred prior to the deposition of the carbonaceous, pro-deltaic Belfast Mudstone. The depocentre had shifted to the south of the Tartwaup-Mussel Fault Zone, where the Belfast Mudstone can exceed 1500 m in thickness, especially in the Voluta Trough. On wireline logs the formation has a monotonous high gamma ray character with the sandstone occurring as distinctive, thin, upward coarsening interbeds. It is a major regional seal to the Waarre Formation and Flaxman sandstones below. The Belfast Mudstone is a strongly diachronous unit that ranges in age from Coniacian to late Maastrichtian, encompassing spore-pollen zones ranging from upper *P. mawsonii* (*Clavifera* n.sp. subzone) to upper *F. longus*.

A marine environment prevailed during deposition of the Campanian to Maastrichtian Paaratte Formation, which consists of offshore to marginal marine sandstones and shales. In the onshore and nearshore areas, the sediments of the overlying Timboon Sandstone have predominantly fluvial-deltaic characteristics.

The Nullawarre Greensand is a light greenish grey, fine to coarse grained sandstone composed of varying proportions of quartz and glauconite. The sandstone has been interpreted by the Geological Survey of Victoria (1995) as a shallow water marine unit that accumulated on the upper part of the shelf. A characteristic upward coarsening log profile represents upward shoaling and the transition from deeper to shallower water marine facies. Onshore the formation is widely distributed with an average thickness of 130 m; however, it does not appear to extend much beyond the present day coastline and is absent in wells offshore where it interfingers laterally with the Belfast Mudstone. Although its basal contact is generally described as sharp, it appears to be gradational in wireline logs from most wells, which is in better agreement with its lateral relationship with the Belfast Mudstone. A late Santonian age is interpreted for the unit based on its correlation with the *T. apoxyexinus* spore-pollen zone and the *I. cretaceum* microplankton zone.

The Paaratte Formation is an interbedded sandstone and mudstone sequence with each lithofacies present in approximately equal proportions. The section has been cored in several wells, including Voluta 1. The cores show black, laminated carbonaceous mudstone interbedded with bioturbated fine- to coarse-grained quartz sandstone. The sandstone beds generally display a pronounced coarsening upward, aggradational profile on wireline logs. The formation represents multiple progradations of delta lobes in delta front and lower delta plain environments. Facies distribution and dinoflagellate assemblages both reflect a shallowing upwards trend as depositional environments pass from offshore to nearshore marine to brackish lagoonal and eventually to fluvial delta plain facies that characterise the overlying Timboon Sandstone. Both upper and lower boundaries are gradational and are strongly diachronous. Offshore, the Paaratte Formation grades laterally into the Skull Creek Mudstone (Partridge, 2001), while onshore, the formation grades laterally into more proximal sandier deltaic facies of the Timboon Sandstone. The Paaratte Formation is a diachronous unit spanning most of the Campanian.

Palynological studies identified a thin shale unit that contains both latest Maastrichtian and basal Paleocene zones and established the existence in the Otway Basin of a widespread transgressive event equivalent to the Kate Shale in the Gippsland Basin (Partridge, 1999; Bernecker and Partridge, 2001). In most previous studies this unit has been included in the Pebble Point Formation (Geological Survey of Victoria, 1995), but is now considered to be a separate formation (Partridge, 2001), the Massacre Shale. To maintain continuity with established stratigraphic nomenclature, the Massacre Shale is included in the Wangerrip Group, even though there is evidence of a significant unconformity at the top of the formation or within the overlying Pebble Point Formation (Arditto, 1995).

The Wangerrip Group represents sedimentation under increasingly marine transgressive conditions. Rising sea levels in the latest Maastrichtian resulted in marine transgression over the eroded Maastrichtian Unconformity surface. The erosional products on this surface were reworked to form restricted shallow to marginal marine and nearshore deposits of the Pebble Point Formation. The formation has an overall coarsening-upwards profile with glauconitic, silty mudstone developed at its base, passing upwards into a sequence of fine to very coarse grained, occasionally gravelly, argillaceous sandstone that is burrowed and bioturbated (Tickell et al, 1992).

The Pember Mudstone is a major progradational sequence that developed across the shelf to the southwest, progressively onlapping the underlying Pebble Point Formation, or in its absence, the Maastrichtian Unconformity surface. The formation consists of micaceous, pyritic, silty claystone with minor fine grained sandstone. It contains carbonaceous material (including wood), glauconite, chert and abundant foraminifera and is conspicuously burrowed and bioturbated (Tickell et al, 1992). The formation was deposited mainly in a shallow marine, prodeltaic environment (Tickell et al, 1992), and is late Paleocene to early Eocene in age spanning the *L. balmei*, and *M. diversus* spore-pollen zones.

The Dilwyn Formation comprises dark brown, carbonaceous, sandy clay and silt, interbedded with coal beds, fine to medium-grained sand with minor coarse sand and gravel layers. The sandstones vary from being clean with little argillaceous matrix to being clay-rich with an abundant argillaceous matrix and are commonly burrowed. A range of marine, deltaic and coastal environments are interpreted including delta plain, coal swamp, lagoonal, estuarine, coastal marsh, shoreface, near-shore marine and delta-front. The Dilwyn Formation is early to middle Eocene in age and spans the Upper *L. balmei*, *M. diversus* and the Lower *N. asperus* spore-pollen zones.

A major middle Eocene marine lowstand is recognised in all basins along the southern Australian margin. The erosional surface, which in some parts of the Otway Basin exhibits considerable relief, is infilled and draped by sediments of the middle Eocene to early Oligocene Nirranda Group. The Nirranda Group comprises prograding nearshore to offshore marine clastics of the basal Mepunga Formation that give way to increasingly open marine carbonates and fine grained clastics that characterise the Narrawaturk Marl. Both formations are time equivalent to the proximal Demons Bluff and Eastern View formations recognised onshore in the northeastern part of the Otway Basin and Torquay Sub-basin (Abele et al, 1976; Blake, 1980).

Sediments belonging to the basal Mepunga Formation comprise sequences of interbedded sandstone, siltstone and mudstone deposited in nearshore to offshore marine, shelfal environments. The sandstones were deposited in coastal, beach and nearshore environments as barrier bars and back-barrier dunes (Yang, 1997)., Wireline log analysis of these sandstones in the Discovery Bay 1 well gives porosities of up to 40% thus demonstrating excellent reservoir targets.

In the Late Eocene, depositional environments in the Otway Basin became increasingly open marine resulting in a significant change in sediment supply from clastic to non-clastic and deposition of fine-grained clastics and carbonates of the Narrawaturk Marl. Lithologies include marls, marly limestones, limey marls and limestones with calcareous claystone interbeds. Thin glauconitic and dolomitic sandstones and siltstone are also sometimes present. Open marine conditions are interpreted with deposition in an offshore, middle shelf environment. Although the formation is still relatively uncompacted, it is generally regarded as providing a competent seal to the underlying Mepunga Formation.

Sedimentation of the Heytesbury Group signals the onset of climatic change that promoted the accumulation of temperate carbonates across the southern Australian margin. Deposition commenced with the widespread shallow marine calcarenite deposits of the Clifton Formation followed by the deposition of the deep water Gellibrand Marl Member. Later, the Port Campbell Limestone was deposited in intermediate water depths. The Heytesbury Group is unconformably overlain by the Pliocene to Recent Hanson Plain Sand sequence, which in turn is unconformably overlain by the Newer Volcanics. Sequences of a lowstand systems tract are interpreted to be present in the more basinal settings. Evidence on seismic exists for depositional sequences of the lowstand systems, such as slope and basin-floor fans with up-dip shelf slope incision.

Exploration History

Petroleum exploration in the offshore part of the Otway Basin commenced in 1959, with the first offshore permits, PEP 22, PEP 40 and PEP 49 awarded to the Frome-Broken Hill consortium. Extensive offshore aeromagnetic surveys were carried out in 1960 and 1961providing the first accurate indication of the basin's true extent in the offshore areas. This was followed by the first marine seismic survey offshore Warrnambool in 1961.

In 1966, Esso and Shell farmed into the offshore Otway Basin hoping to find an analogue to the Gippsland Basin, which by then had just experienced a raft of new and large gas and oil discoveries. Their efforts were, however, largely unrewarded. Pecten 1A, the first offshore well in the Otway Basin, was drilled on the Mussel Platform by Shell in 1967. The well flowed dry gas at 0.145 MMcfd from a test of a sandstone interval in the Late Cretaceous Waarre Formation.

Esso farmed into PEP 40 and PEP 49 and drilled 2 offshore wells, Nautilus 1 in 1968 and Mussel 1 in 1969. Both wells were plugged and abandoned with no significant shows encountered. Between 1970 and 1975, the offshore permits were re-issued, with PEP 22 becoming VIC/P10, PEP 40 becoming VIC/P6, and PEP 49 becoming VIC/P7. Shell and Interstate Oil Ltd. (IOL) jointly held VIC/P10, while Hematite Petroleum (a BHP subsidiary and a member of the original Frome-Broken Hill consortium) held permits VIC/P6 and VIC/P7. Seismic surveys were recorded in the offshore petroleum exploration permit areas by Hematite (between 1972 and 1976) and by Shell and IOL (between 1970 and 1975). By 1976, discouraged by the lack of commercial oil or gas discoveries, the major companies had begun to withdraw from the Otway Basin. Little exploration work was carried out between 1975 and 1980 and the petroleum exploration permits were relinquished progressively.

In 1980, 3 permits VIC/P14, VIC/P15 and VIC/P16 were awarded covering much of the shelfal portion of the basin. Phillips Petroleum drilled 2 wells in VIC/P14, Discovery Bay 1 in 1982 and Bridgewater Bay 1 in 1983; neither well encountered significant hydrocarbons shows. In 1982, Esso drilled Triton 1 ST1, located in the eastern offshore Otway Basin, again without encountering any significant hydrocarbons. Between 1986 and 1988, with the exception of VIC/P14, the permits were relinquished progressively and very little exploration was undertaken.

In 1990, BHP Petroleum (BHPP) farmed into VIC/P14, and in the same year, was awarded two new petroleum exploration permits, VIC/P30 and VIC/P31. These permits covered a large proportion of the Mussel and Prawn platforms in the eastern part of the basin. BHPP recorded in excess of 3500 line-km of regional and semi-regional marine seismic data, including the 3200 line-km OH91B seismic survey which covers part of the Mussel Platform. In 1993, BHPP made two gas discoveries on the Mussel Platform, Minerva 1 and La Bella 1, as well as two dry wells, Eric The Red 1 and Loch Ard 1 on the eastern flank of the Shipwreck Trough. After drilling an additional two wells that recorded only scattered gas shows, BHPP relinquished the permits in 1997, though retention permits were taken out over the Minerva and La Bella fields.

Since 1999, there has been a strong resurgence in exploration activity in the Victorian sector of the Otway Basin, with increased success rates driven largely by technological advances such as 3D seismic data. A major exploration program by the Woodside Joint Venture resulted in the discovery of the large Geographe and Thylacine gas fields in 2001. Geographe is located within Victorian waters and Thylacine is located in Tasmanian waters. Another commercial gas discovery, Casino 1, located about 20 km southwest of the Minerva field, on the western flank of the Shipwreck Trough, was drilled by Strike Oil in 2002. Discoveries were made in 2004 and 2005 by Santos Limited at Martha 1 and Henry 1 respectively and by the Woodside Energy-Origin Energy Joint Venture at Halladale DW1, and Halladale DW2 in 2005, both of which are near shore wells. The Casino gas development in VIC/P44, now operated by Santos Limited, is the company's main project to expand their southern gas assets and is designed to include the Henry gas field in future developments.

Overall, there has been an increase in both the exploration success rates and the size of fields discovered over the last few years within the Otway Basin. This is probably due to a combination of factors, which include dramatically improved trap definition (a result of 3D seismic acquisition), an improved understanding of seal integrity (especially fault seal integrity) and an overall improved understanding of the critical success factors in the region (O'Brien and Thomas, 2007).

Well Control

Well control for the 2009 Release Areas is provided by a number of gas discovery wells mainly in the Shipwreck Trough. However, numerous wells on the Mussel Platform and within the Voluta Trough, many of which were unsuccessful, also provide valuable information. In addition, onshore wells can be used to provide a good understanding of the overall stratigraphic framework in the Otway Basin, especially the Early Cretaceous section which has been penetrated by several exploration wells.

Flaxmans 1 (1961)

Flaxmans 1 was drilled by Frome Broken Hill Company P/L to evaluate the hydrocarbon prospectivity of the eastern Otway Basin. It targeted a northeast-southwest trending high westward of the Port Campbell structure. The well penetrated the complete Paleogene section before reaching a total depth of 3514 mKB in the Otway Group. Flaxmans 1 recorded numerous gas shows within the Otway Group sandstones and tested an unsustained gas flow of 0.25 MMcf/day including some condensate. The highly fractured nature of the Otway Group was interpreted as the main well failure, which, although promoting hydrocarbon migration, contributed to seal failure.

Pretty Hill 1 (1962)

Pretty Hill 1 was drilled by Frome-Broken Hill Company Pty Ltd to test Early Cretaceous sandstones of the Crayfish Subgroup in a tilted fault-block on the upthrown side of a large down-to-the-south fault. The well reached TD at 2478 mKB in ultrabasic volcanics of the

Late Jurassic Casterton Formation without recording any hydrocarbon indications.

Eumeralla 1 (1962)

Eumeralla 1 was drilled by Frome-Broken Hill Company Pty Ltd to test the Pretty Hill sandstones of the basal Crayfish Subgroup in the hanging wall of the Windermere Fault. The well reached a total depth of 3142 mRT within what was then considered basement rocks, but is now interpreted as the Laira Formation. The well failed to reach the Pretty Hill Formation and no hydrocarbon shows were encountered.

Pecten 1A (1967)

Pecten 1A was drilled by Shell Development (Australia) Pty Ltd on the Mussel Platform to evaluate the Waarre Formation, sealed by the Belfast Mudstone, in a seismically mapped anticlinal closure dissected by northwest-trending normal faults. The well spudded in 62.5 m of water and was drilled to a total depth of 2850 mRT. A gross gas column of 17.5 m was intersected in the Waarre Formation which flowed gas at 0.145 MMcfd on test. The flow was deemed uneconomic and the well was plugged and abandoned.

Voluta 1 (1967)

Voluta-1 was drilled by Shell Development (Australia) Pty Ltd on a large Paleogene anticlinal feature that is today named the Bridgewater High. The selected well location was based on 1966 vintage seismic data and despite the extensive seismic coverage, data quality below the upper Sherbrook Group is poor. In the vicinity of Voluta 1, data quality at the Paleogene level is also poor. The well was deepened to provide stratigraphic control of the pre-Paleogene section, but failed to record any hydrocarbon shows and was plugged and abandoned in the Flaxman Formation.

Mussel 1 (1969)

Mussel 1 was drilled by Esso Exploration and Production Inc to evaluate the Waarre Formation on a tilted fault block closure on the Mussel Platform. It spudded in 85 m of water and was drilled to a total depth of 2450 mRT. No hydrocarbons were encountered and the well was plugged and abandoned. The well appears to have been drilled within closure but significantly downdip from the mapped crest of the structure based on the current interpretation.

Nautilus A1 (1968)

Nautilus A1,drilled by Esso Exploration and Production Inc, was spudded in 100 m of water and was reached a total depth of 2011 mKB in the Belfast Mudstone (Sherbrook Group). The well targeted a Paleogene'clastic wedge' stratigraphic play on the northeastern flank of the Voluta Trough. However, the target section proved to be composed entirely of marl with no reservoir present. No significant hydrocarbon indications were encountered and the well was plugged and abandoned.

North Eumeralla 1 (1974)

North Eumeralla 1 was drilled by Shell Development (Australia) Pty Ltd and reached TD in Paleozoic meta-sedimentary basement at 2968 mDF. The well targeted a Pretty Hill Formation tilted fault-block on the upthrown side of a large down-to-the-north fault. No hydrocarbons were encountered.

Triton 1 (1982)

Triton 1 was drilled by Esso Exploration and Production Australia targeting the Waarre Formation within an interpreted fault-controlled closure. The well spudded in 100 m of water and was drilled to a total depth of 3545 mKB. The Waarre Formation exhibited poor reservoir development and was water wet. The well was plugged and abandoned. No closure was mapped over the structure (Geary and Reid, 1998). However, of significance to Paleogene prospectivity was the intersection of a thin sandstone at the base of the Paleogene section that produced a C_1 to C_6 mud gas peak, possibly indicative of oil.

Discovery Bay 1 (1982)

Discovery Bay 1, drilled by Phillips Australian Oil Company, was designed to test the Timboon Sandstone and underlying Paaratte Formation associated with a tilted fault block. The well spudded in 97 m of water and bottomed in the Paaratte Formation at a depth of 2776 mKB. Only minor hydrocarbon shows were encountered. Failure of the well is believed to be due to poor top sealing or lateral fault seal for both target intervals.

Lindon 1 (1983)

Lindon 1 was drilled by Beach Petroleum NL and reached TD in the Pretty Hill Formation at 3011 mKB. The well was designed to test the base Paleogene Pebble Point Formation and base Late Cretaceous Waarre Formation within a NW-SE striking horst block south of the Lake Condah High. A 3 m oil column was encountered in the Pebble Point Formation but no hydrocarbons were detected in the Waarre Formation. The well was eventually plugged and abandoned after two DSTs proved the Pebble Point Formation to be significantly tighter than expected.

Lindon 2 (1991)

Lindon 2 was drilled by Gas and Fuel Exploration NL and bottomed in Pebble Point Formation at 940 mKB. The well is located about 40 m to the south of Lindon 1 and was designed to retest the Pebble Point Formation oil column intersected in the latter using drilling mud parameters which would reduce the possibility of smectite swelling. As anticipated, oil stained cuttings were observed throughout the Pebble Point Formation. However, the two open-hole drill stem tests conducted both failed, so the well was later cased and perforated, and recovered a minor amount of oil during swabbing operations.

Bridgewater Bay 1 (1983)

Bridgewater Bay 1 was drilled by Phillips Australian Oil Company to test the Waarre Formation on a broad tilted-horst block on the Bridgewater High. The stratigraphically younger Paaratte Formation was a secondary objective. The well was drilled in 131 m of water and reached a total depth of 4200 mKB. The Waarre Formation (or Flaxman Formation as an alternative interpretation) was encountered some 1000 m deeper than prognosis and proved water wet. The well was plugged and abandoned. Later remapping suggests that the well is located significantly off-structure, on the downthrown-side of the fault block.

Normanby 1 (1986)

Normanby 1 was drilled by BP Petroleum Development Ltd to test the Waarre Formation in a large tilted fault block. The well was drilled in 49 m of water and reached TD in the Waarre Formation at 3306 mRT. Minor gas was recovered from sandstones during RFTs. Reservoir was interpreted to be tight and DSTs were not run. The well was plugged and abandoned. It is notable that visual porosity in several of the sidewall cores across the Waarre Formation sandstones was reported as fair to good, but borehole conditions were poor and the RFT tool failed in most attempts. Interpretation of reprocessed seismic data suggests the well was drilled significantly down-dip from the crest of the structure along strike. Potential exists for an up-dip accumulation. Lavin (1998) suggests that the well may have drilled at or near a gas-water-contact, with significant attic hydrocarbons remaining.

Windermere 1 (1987)

Windermere 1 was drilled by Minora Resources NL to test Pebble Point and Upper Eumeralla closures in the hanging wall of the Windermere fault. The well reached TD at 1852 mKB after recovering 41^{o} API oil in a secondary target interval, the Heathfield Sandstone Member of the Eumeralla Formation. Two DSTs recovered only 0.5 and 31.9 bbl of oil. The lack of permeability (though micro-porosity was good) appeared to be the primary reason for the poor recoveries.

Windermere 2 (1989)

Windermere 2 was drilled by Minora Resources NL in an up-dip location, to further evaluate the oil found in the Heathfield Sandstone Member in Windermere 1 and to test deeper objectives. Dry gas, which did not flow to surface on test (interval 1775.2-1802.3 mKB), was found in sandstones of the Heathfield Sandstone Member, and no significant oil shows were encountered. Permeability in these sands was again found to be low, though micro-porosity was fairly high. At deeper intervals, significant gas was observed in poor quality sands in the Lower Eumeralla sub-unit, particularly between 2900-3100 mKB. The gas was significantly wetter than that encountered within the shallower Heathfield Sandstone Member, which may suggest that it has been sourced from a different interval to that which sourced the shallower gas. In the deeper Windermere Sandstone Member, between 3187-3195 mKB, significant amounts of relatively wet gas ($C_1/C_2 = 4$) were encountered; DST 2A (3182.0-3198.0 mKB) recovered slightly gas-cut water, with a trace (<1%) of oil. The well reached a total depth of 3595 mKB in the Pretty Hill Formation. The Pretty Hill Formation sands are reported to have low porosities, with traces of minor wet gas.

La Bella 1 (1993)

La Bella 1was drilled by BHP Petroleum Pty Ltd, on the outer Mussel Platform to test closure mapped at the Waarre Formation level in a tilted-fault block. The well was drilled in 94 m of water and reached a TD of 2735mRT in the Waarre Formation. Hydrocarbons were encountered in sands of both the Flaxman (15 m gross column) and Waarre (65 m gross column) formations. RFT pressure data indicate that these are separate accumulation. No DSTs were run, but RFT samples showed that the gas is predominantly methane with a relatively high CO_2 content (12.5-13.3 mol%) and minor condensate. Gas-in-place is estimated by Luxton et al (1995) at 210 Bcf (5946 x 106 m^3). The well was plugged and abandoned as a sub-commercial gas discovery.

Minerva 1 (1993)

Minerva 1, drilled by BHP Petroleum Pty Ltd, was designed to test the hydrocarbon potential of the lower Waarre Formation within a northerly tilted-fault block located on the broader Minerva structure. Secondary targets included mapped anticlinal closures within the Sherbrook Group (Paaratte Formation, and the Belfast and Skull Creek mudstones) and the Wangerrip and Nirranda groups, which had only minor fault dependence. Claystones of the Belfast Mudstone were interpreted to provide both the vertical and cross-fault sealing to the gas-bearing reservoirs. Minor gas shows in the Skull Creek Mudstone and Flaxman Formation indicate that these units may represent valid targets elsewhere in the structure, where they may be thicker and of better quality. The main gas-bearing sand within the Waarre Formation was intersected in the interval from 1815-1948 mRT, where average porosities of 18% and average hydrocarbon saturations of 81% were measured (Locke, 1994a). Production testing resulted in gas flowing at a rate of 28.4 MMcfd, with a CGR of 2 stb/MMcf.

Minerva 2A (1993)

Minerva 2A was drilled by BHP Petroleum Pty Ltd in 1993, as an appraisal of the Minerva

1 discovery. The objective was to confirm the extension of the gas-bearing reservoir within the southern fault block of the Minerva structure. Secondary targets included gas-bearing sands in the Flaxman Formation and sand horizons within the Skull Creek Mudstone that had yielded gas shows in Minerva 1. The Skull Creek Mudstone had only minor gas shows. However, a gross gas-bearing interval of 20 m (10 m net) was penetrated within the Flaxman Formation. In the Waarre Formation, a total 98 m of net gas was interpreted over a 111 m interval, with an average porosity of 19% and average hydrocarbon saturation of 85% (Locke, 1994b). The gas and water gradients intersected in the Waarre Formation in the Minerva 2A reservoir were within 2% of the corresponding gradients measured in Minerva 1. Pressure data indicates that the wells either are, or were at some stage, in hydraulic communication.

Minerva 3 and Minerva 4 (2002)

Minerva 3 and Minerva 4 were both drilled by BHP Billiton as development wells to access'attic' gas in structures up-dip from Minerva 1 and Minerva 2A respectively (Ellis 2003a, 2003b). Both were completed successfully and gas production commenced in 2004.

Conan 1 (1995)

Conan 1 was drilled by BHP Petroleum Pty Ltd on the Mussel Platform flanking the western margin of the Shipwreck Trough. It was drilled to test closure mapped at the Waarre Formation level associated with a tilted-fault block. The well was drilled in 70 m of water to a TD of 1985 mRT. Good to excellent reservoir sands were encountered in the Waarre Formation but they proved to be water wet. A section of the lower Belfast Mudstone, Flaxman Formation and part of the upper Waarre Formation were absent, most likely through uplift and subsequent erosive truncation. The well was drilled within closure., A lack of cross-fault seal due to sand development in the Flaxman Formation or the Belfast Mudstone is thought to be the most plausible explanation for well failure.

Champion 1 (1995)

Champion 1 was drilled by BHP Petroleum Pty Ltd on the central, inboard part of the Mussel Platform, to test the Waarre Formation on a faulted structural high. The well was drilled in 53 m of water to a TD of 1882 mKB. A much thinner than expected (22 m) non-reservoir, lower Waarre Formation section was penetrated. The upper part of the Waarre Formation, and Flaxman Formation and lower Belfast Mudstone were absent, apparently through uplift and erosive truncation. The well was plugged and abandoned. The Belfast Mudstone provides adequate seal over the structure and well failure was attributed to lack of reservoir in the Waarre Formation and underlying Eumeralla Formation.

Langley 1 (1996)

Langley 1 was drilled by GFE Resource Ltd to test a bright amplitude anomaly on 3D seismic data that was associated with the Waarre Formation. It was the first well in the region that was drilled to target a prospect identified on 3D seismic. The well was a technical success in the sense that it discovered a 23 m gas column within the Waarre Formation (top-Waarre Formation Unit C), however, the reservoir contained one third dry hydrocarbon gas and two thirds CO_2. Because of this large proportion of carbon dioxide the well, was plugged and abandoned, as neither commodity was seen as commercially producible. Langley 1 reached TD at 2006 mKB within the Eumeralla Formation and recorded minor gas shows within intra-formational sandstones of that formation.

Thylacine 1 (2001)

Thylacine 1, drilled by Origin Energy Resources Ltd, targeted a composite horst structure on a north-northeast-trending ridge within the Shipwreck Trough. Thylacine 1 was drilled in 101 m of water and reached a TD of 2710 mRT in the Waarre Formation. The well intersected a 277.1 m gross (139.5 m net) gas column over the interval2049-2326 mRT in sands that spanned the Thylacine Member (of the Belfast Mudstone), a sequence of alternating fine to medium grained, well sorted sandstone, siltstone and minor claystone, and both the Flaxman and Waarre formations. The Thylacine field is the largest gas discovery yet made in the Otway Basin, according to Cliff et al (2004).

Geographe 1 (2001)

The Geographe prospect was identified on a southwest-plunging anticline which extends from the Otway Ranges. Geographe 1, also drilled by Origin Energy Resources Ltd in 85 m of water reached a TD of 2430 mRT in the Waarre Formation. The well intersected a 233 m gross (56.9 m net) gas column in the interval1817-2050 mRT in the Thylacine Member of the Belfast Mudstone, and the Flaxman Formation (Cliff et al, 2004). The Thylacine Member comprises the bulk of the reservoir interval in both the Thylacine and Geographe fields. The Waarre Formation preserved here has excellent reservoir qualities, with considerable lateral extent. The gas-water-contacts for Thylacine 1 and Geographe 1 are within the upper Waarre and Flaxman Formations respectively. The well was not tested, so a 7" liner was run and the well was plugged and suspended as a gas discovery.

Port Fairy 1 (2002)

Port Fairy 1 was drilled by Essential Petroleum Resources Limited in the onshore Otway Basin some 3.5 km north of the coastal town of Port Fairy. TD was reached at 1550 mRT. The prospect is a simple northeast-trending anticline with up to 100 m of four-way dip closure. Strong gas shows were recorded in the Pebble Point Formation, Timboon Sandstone and Eumeralla Formation, while oil was recovered for the first time from the Waarre Formation. The well was suspended as an oil discovery with minor gas.

Casino gas field (2002)

The Casino gas field was discovered by Santos Limited with the drilling of the Casino 1 well in 2002. The well was drilled in 70.5 m water and reached a TD of 2118 mRT in the Eumeralla Formation. Casino 1was drilled to test a high amplitude zone imaged on seismic within a tilted-fault block with three-way dip closure and updip fault closure. Gas was discovered in the Waarre Formation. Appraisal wells Casino 2 (2002) and Casino 3 (2003) intersected a younger reservoir within the Waarre Formation, increasing gas reserves sufficiently to justify economic development of the field.

Hill 1 (2003)

Hill 1 was drilled by Santos Limited in 213m of water and reached a TD of 2575 mRT in the Belfast Mudstone. The well tested a tilted-fault block closure at top Paaratte Formation level. Only minor gas shows and weak oil shows were recorded in the Paaratte Formation and the well was plugged and abandoned. Possible causes for the failure of Hill 1 are cross-fault seal leakage or limited hydrocarbon charge. However, the well did demonstrate the presence of good quality potential reservoir and top seal rocks.

Killarney EPRL 1 (2004)

Killarney EPRL 1 was drilled by Essential Petroleum Resources Limited in the onshore Otway Basin. TD was reached at 1650 mKB. The well was drilled to the east of Port Fairy 1, targeting hydrocarbons within the Waarre Formation. The well was a dry hole with only small gas traces intersected within the Flaxman and Waarre formations.

Callister 1 (2004)

Callister 1 was drilled by Santos Limited some 24 km southwest of the town of Portland. The well was drilled in 129 m of water and reached a TD of 3914mRT. The well targeted the unproven Belfast Mudstone-Paaratte Formation gas play and the proven Eumeralla-Waarre formations gas play in a faulted horst block. The well reached a depth of 3914 mRT and encountered gas shows in the Paaratte, Flaxman, Waarre and Eumeralla formations.

Amrit 1 (2004)

Amrit 1 was drilled by Santos Limited some 68 km south of the town of Portland. The well was drilled in 1425 m of water to a TD of 2979 mRT. It is the most outboard well drilled to date in the Otway Basin. Amrit 1 was drilled to test the oil potential of a Paaratte Formation fault-bound structural/stratigraphic closure. Minor gas shows were encountered in the Paaratte Formation.

Martha 1 (2004)

Martha 1 was drilled by Santos Limited some 18 km north of the Casino gas field. The well drilled in 55 m of water reached a TD of 1800 mRT. A 24.5m gas column was intersected in the Waarre Formation. Further details were unavailable at the time of writing.

Henry gas field (2005)

The Henry gas field was discovered in 2005 by Santos Limited with the drilling of Henry 1, ST1. The well located some 8.5 km northwest of the Casino gas field was drilled in 67.5m of water to a TD of 2100 mRT (Henry 1) and 2032 mRT (Henry 1 ST1). Gas was discovered in the Waarre Formation. In August 2008, Henry 2 was drilled as a development well. Further details were unavailable at the time of writing.

Halladale 1 DW 1/DW 2/DW 3 (2005)

Halladale 1 DW 1 was drilled by Origin Energy Resources Limited and was the first of a three-well program designed to target two prospects at the Late Cretaceous Waarre Formation within the coastal three-mile-zone. The well reached a TD of 1918 mRT and recorded a gross gas-bearing interval of 63 m in interbedded sandstones and mudstones of the Waarre Formation. Halladale 1 DW 2 was sidetracked from the original Halladale 1 DW 1 well and reached TD at 1941 mRT. This second well encountered a 21 m gas bearing interval in the Waarre Formation.

Halladale 1 DW 3 was sidetracked from Halladale 1 DW 2 and reached a TD of 1969 mRT.

Table 1: Key wells listing

Well	Operator	Year	Total Depth	Hydrocarbons
Amrit 1	Santos Limited	2004	2979 mRT	no public data
Argonaut A1	Esso Standard Oil (Australia) Ltd	1968	3707.3 mKB	minor gas
Breaksea Reef 1	Ultramar Australia Inc	1984	4260 mKB	minor oil
Breaksea Reef 1 ST1	Ultramar Australia Inc	1984	4386 mKB	minor gas
Breaksea Reef 1 ST2	Ultramar Australia Inc	1984	4436.8 mKB	no tests

Breaksea Reef 1 ST3	Ultramar Australia Inc	1984	4467.9 mKB	no tests
Bridgewater Bay 1	Phillips Australian Oil Company	1983	4200 mKB	no tests
Callister 1	Santos Limited	2004	3914 mRT	minor gas
Caroline 1	Oil Development Australia	1967	3371 mKB	Gas
Casino 1	Santos Limited	2002	2118 mRT	Gas
Casino 2	Santos Limited	2002	2112 mKB	Gas
Casino 3	Santos Limited	2003	2135 mRT	Gas
Champion 1	BHP Petroleum Pty Ltd	1995	1882 mRT	no tests
Conan 1	BHP Petroleum Pty Ltd	1995	1985 mRT	no tests
Copa 1	Cultus Petroleum (Australia) NL	1990	3850 mKB	no tests
Crayfish A1	Esso Exploration & Production Australia Inc.	1967	3199.5 mRT	no shows
Discovery Bay 1	Phillips Australian Oil Company	1982	2776 mKB	no tests
Eumeralla 1	Frome Broken Hill Co P/L	1963	3142 mRT	no shows
Flaxmans 1	Frome Broken Hill Co P/L	1961	3514 mKB	Gas
Geographe 1	Origin Energy Resources Ltd	2001	2430 mRT	Gas
Geographe North 1	Origin Energy Resources Ltd	2001	2156 mRT	minor gas

Halladale 1 DW1	Origin Energy Resources Ltd	2005	1918 mRT	Gas
Halladale 1 DW2	Origin Energy Resources Ltd	2005	194 mRT 1	Gas
Henry 1	Santos Limited	2005	2100 mRT	Gas
Henry 1 ST1	Santos Limited	2005	2032 mRT	Gas
Hill 1	Santos Limited	2005	2575 mKB	no tests
Killarney 1 (Essential)	Essential Petroleum Resources Ltd	2004	1640 mKB	no public data
La Bella 1	BHP Petroleum Pty Ltd	1993	2735 mRT	Gas
Lake Eliza 1	Esso Explor and Prod Aust Ltd	1969	1473 mKB	no shows
Langley 1	Gas and Fuel Exploration NL	1994	2006 mKB	Gas
Lindon 1	Beach Petroleum NL	1984	3011 mKB	minor oil
Lindon 2	Taipan Petroleum Pty Ltd	1991	970 mKB	no tests
Martha 1	Santos Limited	2004	1800 mRT	Gas
Mount Salt 1	Oil Development Australia	1962	3061 mKB	minor gas
Mussel 1	Esso Exploration and Production (Australia) Inc.	1969	2450 mRT	no tests
Nautilus A 1	Esso Exploration and Production (Australia) Inc.	1968	2011 mKB	no tests
Normanby 1	BP Petroleum Development Limited	1986	3306 mRT	minor gas

North Eumeralla 1	Shell Development (Australia) Pty Ltd	1974	2968 mDF	no tests
Pecten 1A	Shell Development (Australia) Pty Ltd	1967	2850 mDF	Gas
Port Fairy 1	Origin Energy Resources Ltd	2002	1550 mRT	Oil and minor gas
Pretty Hill 1	Frome Broken Hill Co P/L	1962	2478 mKB	no shows
Rendelsham 1	SAGASCO Resources	1994	2775 mKB	no shows
Robe 1	SA Oil Wells Co	1916	1372 mKB	minor oil
Thylacine 1	Origin Energy Resources Ltd	2001	2710 mRT	Gas
Triton 1	Esso Exploration and Prod. Australia	1982	2803 mKB	no tests
Triton 1 ST1	Esso Exploration and Prod. Australia	1982	3545 mKB	minor gas
Troas 1	BHP Petroleum Pty Ltd	1993	1430 mRT	no tests
Troas 1 ST1	BHP Petroleum Pty Ltd	1993	3506 mRT	Gas
Voluta 1	Shell Development (Australia) Pty Ltd	1967	3974 mDF	no tests
Windermere 1	Minora Resources	1987	1852 mKB	Oil and minor gas

Windermere 2	Minora Resources	1989	3595 mKB	minor oil

Rig Release Year shown. Shaded areas highlight those wells for which complete data sets are not yet available. Data accurate as at 31 March 2009

Seismic Coverage

Seismic coverage over the 3 inboard Release Areas (V09-1, V09-2 and V09-3) is good, comprising some recently acquired modern 2D seismic surveys, a 3D seismic survey by Santos Limited (2003) covering the Hill 1 and Amrit 1 area, as well as regional surveys that were acquired by the Australian Geological Survey Organisation (AGSO - now Geoscience Australia (GA)). However, compared to the Shipwreck Trough, the 2009 Release Areas are less well covered by seismic surveys. The outboard Release Area V09-4 is only sparsely covered, but includes the southern part of the 2003 Santos Limited 3D seismic survey.

A full listing of the seismic is available in the

Hydrocarbon Potential

Petroleum Systems

The 2009 Otway Basin Release Areas offshore Victoria are a mix of shallow water regions with a proven (Austral 2) petroleum system and a deeper water frontier province within which the petroleum system - Austral 3 - is unproven. O'Brien and Thomas (2007) have shown that the vast majority of the hydrocarbon inventory discovered within the Victorian Otway Basin has been generated by the Austral 2 petroleum system. The Austral 2 system consists of Early Cretaceous (Albian-Aptian) organic-rich source rocks which have generated hydrocarbons and charged the overlying basal Late Cretaceous Waarre siliciclastic reservoir unit. Commercial accumulations in the offshore and onshore basin are restricted to areas within approximately 3000 m of where the Austral 2 petroleum source rocks are actively generating and expelling hydrocarbons (**Figure 5**). This interval typically occurs at depths below the seafloor of between about 2500-4000 m. This observation has allowed the prospective areas of the Otway Basin - where the Austral 2 system is currently at peak hydrocarbon generation - to be mapped (**Figure 6**). It may be that the accumulations only occur close to the generating source rocks because the faults which bound the accumulations within the Otway Basin often leak - hence viable traps are located only in areas where the hydrocarbon charge rate exceeds the average leakage rate.

Hydrocarbon Families

Six Austral Petroleum System oil families (A1F1, A1F2, A1F3, A1F4, A2 and A3) were identified in the Otway Basin by Edwards et al (1999). However, a more recent integrated geochemical study by Boreham et al (2004) shows that the A1F1 oil family (e.g., bitumens from Crayfish A1), originally interpreted as being sourced from saline lacustrine source rocks, and the A3 oil family (e.g., Wilson 1), originally interpreted as being sourced from marine source rocks, are most likely drilling contaminants, rather than true oil families. Therefore, indigenous, uncontaminated oils in the Otway Basin are interpreted as belonging to four families (A1F2, A1F3, A1F4, and A2) within the Austral 1 and Austral 2 Petroleum Systems (Boreham et al, 2004).

It appears there are strong stratigraphic and geographic controls on oil families within the Otway Basin. Oils in the west and onshore (mainly South Australia) belong to Austral 1 families and were sourced from Late Jurassic - Early Cretaceous, syn-rift, dominantly fluvio-lacustrine organic facies. Oils in the east (mainly Victoria) belong to an Austral 2 family derived from Early Cretaceous, post-rift, coaly organic facies. Oils in the central part of the basin have a mixed source affinity, but are predominantly from Eumeralla Formation sources (Boreham et al, 2004).

Natural gases in the Otway Basin show clear geochemical differentiation between those from the western and eastern parts of the basin. The western gases (e.g., Jacaranda Ridge 1, Katnook 2, Ladbroke Grove 2, Redman 1 and Troas 1 ST1) belong to the Late Jurassic - Early Cretaceous, Crayfish Subgroup-sourced Austral 1 Petroleum System

(Boreham et al, 2004). The eastern gases (e.g., Thylacine 1, Geographe 1, La Bella 1, Minerva 3, Casino 1, Casino 2) belong to the Aptian-Albian, Eumeralla Formation-sourced Austral 2 Petroleum System (Boreham et al, 2004). Gases from the central Otway Basin (e.g., Port Fairy 1, Caroline 1) are the products of mixing from both sources within local depocentres.

Source Rocks

Source rocks of the Early to mid-Cretaceous Austral 2 petroleum system charged the producing gas fields and other undeveloped discoveries in the Victorian part of the Otway Basin. These include the onshore fields in the Port Campbell Embayment and all offshore gas fields in the greater Shipwreck Trough area. Source intervals comprise coals and carbonaceous shales in the Aptian-Albian Eumeralla Formation contained within two coal measure sequences. The older occurs at the base of the Eumeralla Formation corresponding to the *P. notensis* spore-pollen zone and the younger lies in the middle of the formation and corresponds to the *C. striatus* spore-pollen zone. Although geochemical analyses suggest the source rocks have significant potential for liquids generation, well results to date suggest that they have produced mainly gas with only small quantities of condensate and oil.

Both the *P. notensis* and *C. striatus* coal measure sequences consist of thin coal beds interbedded with carbonaceous mudstone rich in disseminated organic matter (DOM). Coal beds range up to 3 m in thickness and constitute up to 30 % of the total interval (Struckmeyer and Felton, 1990; Tupper et al, 1993). Mudstone outside these two coal measure sequences is generally found to be organically lean.

The Eumeralla Formation coals consist largely of duroclarite (BHP Petroleum, 1992) consisting dominantly of vitrinite with subordinate but still significant liptinite (commonly up to 15 %) and inertinite. Minor clarite is dominantly composed of vitrinite with subordinate liptinite and rare inertinite. The DOM rich interbedded claystone in the coal measures contain vitrinite and liptinite in almost equal proportions, with minor inertinite (BHP Petroleum, 1992). Hydrogen Index (HI) values for both the coal and mudstone samples are often high and regularly exceed 100. TOC averages 50 %while the interbedded carbonaceous mudstone averages 4.5 %. HI values average 210 for the mudstone samples and 240 for the coal. Some individual values are in excess of 300. The high HIs together with the presence of Type I to III kerogens suggest that both the coal and carbonaceous mudstone source rocks are capable of generating both oil and gas although gas is likely to be the major product.

Late Cretaceous source rocks (Austral 3 Petroleum System) in the Otway Basin include the Waarre Formation, Flaxman Formation and Belfast Mudstone. These have not been shown to have generated any significant hydrocarbon accumulations. This lack of success does not necessarily mean that mature, generative and oil-prone Austral 3 source rocks are not developed in the Otway Basin. Most of the wells drilled in the Otway Basin have been located on platform areas or onshore where the Sherbrook Group has not reached sufficient maturity for significant hydrocarbon generation. Few wells have been drilled in areas with thick, mature section (eg. the Voluta Trough). In addition, where wells have been drilled in these basinal areas, hydrocarbon samples originating from possible Upper Cretaceous source rocks were not geochemically analysed.

However, recent work by GeoScience Victoria (O'Brien et al, in prep.) suggests that Austral 3 source rocks are capable of generating hydrocarbons. The details of that study will be published in 2009 but first results are encouraging. The majority of the key wells in the eastern part of the basin were analysed and revealed a very significant organic enrichment in the Turonian sequences throughout much of the eastern Otway Basin. This enrichment appears to be best developed along the outer margin of the basin, near the Tartwaup-Mussel Fault Zone and is less prominent - but still present - in more marginward locations. The new study supports a concept in which the basal parts of the Austral 3 petroleum system became increasingly rich in organic matter basinward, as the system became more fully marine in the Late Cretaceous. In these locations, organic enrichment was facilitated by the developed and well known Global Anoxic Event during the early part of the Austral 3 system. The new study has also revealed the development of source rocks systems much later in the Late Cretaceous; the best example of this appears to be at Normanby 1, where good source rock intervals are developed in the Late Cretaceous Paaratte Formation.

Expulsion and Migration

Results from PetroMod 2D-modelling (Reid et al, 2001) suggest that the Eumeralla Formation underwent two distinct stages of hydrocarbon generation - the first in the mid to Late Cretaceous and the second in the Paleogene. This interpretation is also consistent with conclusions reached from earlier 1D-modelling undertaken by Mehin (1999) and Mehin and Link (1997)

In the first stage, generation from the *P. notensis*, and in some areas, the younger *C. striatus* coal measures, was facilitated by an elevated palaeothermal gradient that peaked in the mid-Cretaceous. Over a significant part of the Voluta Trough, including the area south of the Bridgewater High (beneath the present day continental slope), Eumeralla Formation source rocks became overmature. They attained a high enough maturation to have generated and lost the majority of their hydrocarbons by the start of the Paleogene. In shelfal areas of the Voluta Trough that were not so deeply buried by Upper Cretaceous sediments (i.e. beneath the present day Portland Trough), the middle part of the Eumeralla Formation (containing the *C. striatus* coal measures) are interpreted to have remained in the gas and oil windows. Hydrocarbon accumulations formed by this initial phase were likely destroyed by subsequent tectonism and not preserved. A decline in the thermal gradient through the latter part of the Late Cretaceous, limited hydrocarbon generation from the Eumeralla Formation source rock. Substantial generation did not recommence until the Paleogene (post 65.5 Ma) when increased burial depths caused by passive margin subsidence and sediment loading overcame the early maturation effects. The modelling suggests that most of the hydrocarbons from the Eumeralla Formation sourcing accumulations in the Otway Basin originated during this Paleogene period. Duddy (1997) also draws a strong link between hydrocarbon generation from the Eumeralla Formation, the degree of Paleogene burial and hydrocarbon accumulation.

PetroMod 2D basin modelling was also undertaken for the regional maturity trends for Waarre Formation source rocks in the Voluta Trough (Reid et al, 2001). Modelled maturities for the Waarre Formation provide good approximations of maturity levels for the Flaxman Formation and the lower part of the Belfast Mudstone. The Waarre Formation is presently at maturity levels that equate with oil generation to overmaturity in much of the Voluta Trough, the Portland Trough and Bridgewater High. On the Bridgewater High, the Waarre Formation would be generating significant quantities of oil if adequate oil prone source rocks are present. In deeper parts of the Voluta Trough and Portland Trough where the Waarre Formation is more deeply buried, higher maturation results in present day gas generation. Although maturities sufficient for generation were reached in some areas (particularly west of the Bridgewater High) prior to the Paleogene, significant generation and expulsion from the Waarre Formation did not occur until later in the Paleogene as a consequence of passive margin subsidence and burial by Paleogene sediments. Within the Voluta Trough, structural architecture is one of horst and graben development (**Figure 7**). Burial depths of potential Sherbrook Group source rocks, including the Waarre Formation, are therefore highly variable. Each graben area can be considered an individual kitchen area with its own, unique thermal history.

Multiple charge histories in the natural gas reservoirs are evident from the widespread influx of overmature, dry gas to an initially in-place wet gas, particularly in the western Otway Basin. Both gas charges have the potential to displace and/or alter the composition of any reservoired oil. In the east, however, most natural gases (e.g., Geographe 1, Thylacine 1, La Bella 1, Lavers 1) are interpreted as the result of a single gas charge (Boreham et al, 2004).

Otway Basin natural gases show a strong geochemical association with their respective oils, suggesting that both are generated from the same source. Also, the gases and oils and their effective source rocks have a strong stratigraphic and geographic relationship, indicating mainly short- to medium-range migration distances from source to trap (Boreham et al, 2004).

Reservoirs

In the 2009 Victorian Release Areas, the main reservoir interval is provided by sandstones within the Waarre and Flaxman formations. These host the majority of the hydrocarbon accumulations discovered in the Victorian part of the Otway Basin, both onshore and offshore. The traps are associated with tilted-fault blocks developed within the Sherbrook Group and require cross-fault seal to be effective. While the sandstones of the Waarre and Flaxman formations sandstones often exhibit excellent reservoir properties, reservoir development is strongly facies-dependent. Where deeply buried (>3000 m), diagenetic overprints significantly reduce their potential as viable reservoir targets, particularly for oil (Geary and Reid, 1998). This suggests areas such as the Bridgewater High may be shallow enough to preserve suitable reservoir qualities. The upper part of the Waarre Formation is texturally more mature, whilst it becomes more lithic in the lower sequence. This depth cut-off for the Waarre Formation reservoirs may therefore be considered conservative. In Bridgewater Bay 1, the upper part of the Waarre Formation exhibits a more marine influence than in wells on the Mussel Platform. In Triton

1 ST 1, a more distal pro-delta facies was encountered, so poorer reservoir potential is expected. Along trend at Normanby 1, a delta plain depositional setting may be developed promoting slightly better reservoir conditions.

The stratigraphically younger Paaratte Formation contains several coarsening-upward sequences of dominantly quartzose sandstones that display excellent reservoir characteristics. Although a hydrocarbon accumulation is yet to be encountered in these sandstones they have been the primary target of only one offshore well (Discovery Bay 1) and its potential remains largely unassessed.

The Pebble Point Formation was not considered an exploration target until the recording of a live oil show in the unit at Curdie 1 in 1982 onshore in the Port Campbell Embayment. Since then, small quantities of oil have also been recovered from Lindon 1 and Fahley 1, while residual oil was encountered in the formation at Wilson 1 (Reid et al, 2001). However, poor reservoir development (high porosities - up to 25% - but low permeabilities) in these wells due to the presence of chamositic clay in the matrix prevented significant oil flows on test. Play validity depends on the presence of better reservoir development elsewhere in the basin.

Seals

The most widely distributed sealing facies is the Belfast Mudstone which provides an excellent regional top seal to any hydrocarbon accumulation within the Waarre and Flaxman formations. However, depending on the local facies regime, the Flaxman Formation has demonstrated intra-formational sealing potential and is certainly mud-rich in several offshore wells.

Intra-formational seals are also expected within the Paaratte Formation which comprises alternating mudstones and sandstones. Potential sealing units within the Wangerrip Group include the basal Massacre Shale, Pember Mudstone, basal mudstone units of the Dilwyn Formation, and mudstones in the Mepunga Formation are all associated with Eocene channelling.

Apart from the distribution of sealing lithologies, the structural juxtaposition of lithologies and sedimentary facies is a crucial ingredient for seal integrity. This is in particular relevant for the Late Cretaceous part of the basin fill which was subjected to intense syn-depositional tectonism that led to the development of numerous tilted-horst and graben structures.

Play Types

Given that the highest exploration success rate in the central Otway Basin to date is related to the Austral 2 petroleum system, the Waarre/Flaxman formations play represents the most viable exploration target in the 3 shallower water Release Areas. As demonstrated by O'Brien and Thomas (2007), the Eumeralla Formation at the top of the Otway Group currently occurs at peak maturity in the Shipwreck Trough and in areas inboard of the Tartwaup-Mussel Fault Zone (**Figure 2**). All of the offshore hydrocarbon fields are located either in, or within 2500-3000 m of this zone of peak generation. The larger gas fields in the offshore, such as Geographe, Thylacine and La Bella, are situated directly within the zone of peak generation. Casino 1 is located on the edge of the generative kitchen and Henry 1 appears to be the commercial field located the furthest away (perhaps 2500 m) from peak-mature Eumeralla Formation.

In the deep-water Release Area V09-4, the Eumeralla Formation lies below the peak maturity window and therefore any reservoirs here would require charge from a stratigraphically younger and therefore shallower source interval. The Tartwaup-Mussel Fault Zone delineates the boundary between the effectiveness of the Austral 2 and Austral 3 petroleum systems (O'Brien, in prep). It is proposed that the Turonian section is likely to be mature in areas southward of this fault zone and that therefore the Austral 3 petroleum system is operational in this outer region and is capable of charging reservoirs either within the Waarre-Flaxman formations section or, depending on structural configuration, reservoir units within the Paaratte Formation, depending on the offshore extent of coarse to medium-grained facies of that formation. Sealing units would be provided by intra-formational mudstones, resulting in possible stacked reservoir-seal sequences, by the Belfast Mudstone or possibly the Skull Creek Mudstone.

If access to the Austral 3 petroleum system is assumed, a top-Paaratte Formation/Timboon Sandstone play could be considered. Paaratte Formation and Timboon Sandstone reservoirs at the top of the Sherbrook Group depend upon the development of seal above the Maastrichtian Unconformity within the overlying Paleogene passive margin sequence. Potential sealing units within the Wangerrip Group include the basal Massacre Shale, Pember Mudstone, basal mudstone units of the Dilwyn Formation, and mudstones in the Mepunga Formation associated with Eocene channelling. However, this play remains untested with the exception of Normanby 1, located further west on the Bridgewater High.

Critical Risks

Throughout the exploration history of the offshore Otway Basin, poor fault-seal integrity has often been cited as the main reason for well failure. However, as recent geochemical studies (O'Brien, in prep) indicate, it is the distribution of the present day, peak generation window for the respective petroleum systems which is the primary determinant of prospectivity within at least the Victorian part of Otway Basin, if not within the entire hydrocarbon province.

The three Release Areas on the shallow shelf (V09-1, V09-2 and V09-3) are known to have access to the prolific Austral 2 petroleum system, but the main discoveries made to date seem to be concentrated around the Shipwreck Trough area. Maturity modelling suggests that the shelfal part inboard of the Tartwaup-Mussel Fault Zone lies well within the area of mature Eumeralla source rocks and it will be a matter of carefully mapping appropriate structures on modern seismic, ideally in 3D-format. In these inboard areas, it is also very important to understand lateral facies changes that range from fully terrestrial lower coastal plain to open shelf depositional environments. Risk here is associated with recognising the extent of good quality reservoir facies that are kept intact either by fault-seal mechanism or by the presence of intra-formational and regional sealing lithologies. In the palaeo-nearshore zone such facies changes occur rapidly and reservoir compartmentalisation is a common feature.

The most critical exploration risk for Release Area V09-4 is the presence of mature Turonian source rocks which would be a marine equivalent to the marginal marine to terrestrial Waarre Formation. The extent of Paleogene and Neogene overburden in the far offshore also impacts severely on the maturity levels of the Late Cretaceous section. However, if it can be demonstrated that access to a mature Austral 3 petroleum system exists, this deep water Release Area may indeed be more prospective than the lack of exploration success, to date, indicates.

Figures

References

ABELE, C., KENLEY, P.R., HOLDGATE, G. AND RIPPER, D., 1976-Otway Basin (Tertiary). In: Douglas, J.G. and Ferguson, J.A. (eds), Geology of Victoria, Geological Society of Australia Special Publication 5, pp. 198-229.

ARDITTO, P.A., 1995-The eastern Otway Basin Wangerrip Group revisited using an integrated sequence stratigraphic methodology. The APEA Journal 35(1), 372-384.

BERNECKER, T. AND PARTRIDGE, A.D., 2001-Emperor and Golden Beach Subgroups: The onset of Late Cretaceous Sedimentation in the Gippsland Basin, SE Australia. In: Hill, K.C. and Bernecker, T. (eds), Eastern Australasian Basins Symposium, A Refocused Energy Perspective for the Future, Petroleum Exploration Society of Australia, Special Publication, 391-402.

BHP PETROLEUM, 1992-Farm-out proposal, VIC/P30 and VIC/P31, Otway Basin, unpublished.

BLAKE, W.J.R., 1980-Geology and hydrology of the early Tertiary sediments of the Otway Basin. MSc thesis, La Trobe University, Melbourne, unpublished.

BOREHAM, C.J., HOPE, J.M., JACKSON, P., DAVENPORT, R., EARL, K.L., EDWARDS, D.S., LOGAN, G.A. AND KRASSAY, A.A., 2004-Gas-oil-source correlations in the Otway Basin, southern Australia . In: Boult, P.J., Johns, D.R. and Lang, S.C. (eds), Eastern Australasian Basins Symposium II, Petroleum Exploration Society of Australia, Special Publication, 603-627.

BRYAN, S.E., CONSTANTINE, A.E., STEPHENS, C.J., EWART, A., SCHÖN, R.W. AND PARIANOS, J., 1997-Early Cretaceous volcano-sedimentary successions along the eastern Australian continental margin: Implications for the break-up of eastern Gondwana. Earth and Planetary Science Letters, 153, 85-102.

BUFFIN, A.J., 1989-Waarre Sandstone development within the Port Campbell Embayment. The APEA Journal, 29(1), 299-311.

CLIFF, D.C.B., TYE, S.C. AND TAYLOR, R., 2004-The Thylacine and Geographe gas discoveries, offshore eastern Otway Basin. The APPEA Journal 44(1), 441-462.

CONSTANTINE, A.E., 1992-Fluvial architecture and sedimentology of the Late Jurassic-Early Cretaceous Strzelecki and Otway Groups. Geological Society of Australia Abstracts, 32, 145pp.

DUDDY, I.R., 1997-Focussing exploration in the Otway Basin: understanding timing of source rock maturation. The APPEA Journal, 37(1), 178-191.

DUDDY, I.R., 2003-Mesozoic. In: Birch, W.D. (ed), Geology of Victoria, 239-286, Geological Society of Australia Special Publication 23, Geological Society of Australia (Victoria Division).

EDWARDS, D.S., STRUCKMEYER, H.I.M., BRADSHAW, M.T. AND SKINNER, J.E., 1999-Geochemical characteristics of Australia's Southern Margin petroleum systems. The APPEA Journal, 39(1), 297-321.

ELLIS, C., 2003a-Minerva-3 Well Completion Report, Interpretive Volume. BHP Billiton Petroleum report, February 2004, unpublished.

ELLIS, C., 2003b-Minerva-4 Well Completion Report, Interpretive Volume. BHP Billiton Petroleum report, February 2004, unpublished.

FELTON, E.A., 1997a-A non-marine Lower Cretaceous rift-related epiclastic volcanic unit in southern Australia : the Eumeralla Formation in the Otway Basin. Part I: Lithostratigraphy and depositional environments. Australian Geological Survey Organisation Journal of Australian Geology and Geophysics 16(5), pp. 717-730.

FELTON, E.A., 1997b-A non-marine Lower Cretaceous rift-related epiclastic volcanic unit in southern Australia : the Eumeralla Formation in the Otway Basin. Part II: Fluvial systems. Australian Geological Survey Organisation Journal of Australian Geology and Geophysics 16(5), pp. 731-757.

GEARY, G.C. AND REID, I.S.A., 1998-Geology and prospectivity of the offshore eastern Otway Basin, Victoria - for the 1998 Acreage Release. Victorian Initiative for Minerals and Petroleum Report 55, Department of Natural Resources and Environment.

GEOLOGICAL SURVEY OF VICTORIA, 1995-The stratigraphy, structure, geophysics and hydrocarbon potential of the Eastern Otway Basin. Geological Survey of Victoria, Report 103, 241 pp.

GLEADOW, A.J.W. AND DUDDY, I.R., 1981-Early Cretaceous volcanism and the early breakup of southeastern Australia : Evidence from fission track dating of volcaniclastic sediments. In Creswell, M.M. and Vella, P. (eds), "Gondwana V", Balkema, Rotterdam, pp. 295-300.

HILL, A.J.,-1995a. Burial and thermal history modelling and source rock distribution of the Otway Basin, South Australia. South Australia. Department of Mines and Energy. Report Book, 95/9.

HILL, A.J., 1995b-Source rock distribution and maturity modelling. In: Morton, J.G.G. and Drexel, J.F. (eds), 1995 Petroleum Geology of South Australia. Volume 1: Otway Basin. Mines and Energy, South Australia. Report 95/12, pp. 103-126.

KENLEY, P.R. 1976-Lower Cretaceous: Otway Basin, western part. In: Douglas, J.G. and Ferguson, J.A. (eds), Geology of Victoria. Geological Society of Australia . Special Publication 5, pp. 213-216.

LAVIN, C.J., 1997-The Maastrichtian breakup of the Otway Basin margin - a model developed by integrating seismic interpretation, sequence stratigraphy and thermochronological studies. Exploration Geophysics, 28, 252-259.

LAVIN, C.J., 1998-Geology and prospectivity of the western Victorian Voluta Trough, Otway Basin, for the 1998 Acreage Release. Victorian Initiative for Minerals and Petroleum Report 57, Department of Natural Resources and Environment.

LOCKE, A., 1994a-Minerva-1 Well Completion Report, Interpretative Volume. BHP Petroleum report, April 1994, unpublished.

LOCKE, A., 1994b-Minerva-2A Interpretative Well Completion Report. BHP Petroleum report, April 2004, unpublished.

LUXTON, C.W., HORAN, S.T., PICKAVANCE, D.L. AND DURHAM, M.S., 1995-The La Bella and Minerva gas discoveries, offshore Otway Basin. The APEA Journal, 35(1), 405-417.

MEHIN, K., 1999-Petroleum exploration in the Victorian Otway Basin, based on establishing the trends in generation potential of Cretaceous source rocks. Unpublished thesis for Doctor of Philosophy, Royal Melbourne Institute of Technology University.

MEHIN, K. AND LINK, A.G., 1997-Kitchens, kettles and cups of hydrocarbons, Victorian Otway Basin. The APPEA Journal, 37(1), 285-300.

MOORE, D.H., 2002-Basement-basin relationships in the Otway Basin, Victoria, Australia Victorian Initiative for Minerals and Petroleum Report 78, Department of Natural Resources and Environment.

MORTON, J.G.G., ALEXANDER, E.M., HILL, A.J. AND WHITE, M.R., 1995-Lithostratigraphy and environments of deposition. In: Morton, J.G.G. and Drexel, J.F., (eds.), 1995 Petroleum Geology of South Australia. Volume 1: Otway Basin. Mines and Energy, South Australia. Report 95/12, pp. 47-101.

MORTON, J.G.G, HILL, A.J., PARKER, G., AND TABASSI, A., 1994-Towards a unified stratigraphy for the Otway Basin. In: Finlayson, D.M. (compiler), NGMA/Petroleum Exploration Society of Australia Otway Basin Symposium, Melbourne, 20 April 1994: extended abstracts. Australian Geological Survey Organisation Record 1994/14, pp. 7-12.

O'BRIEN, G. W., AND THOMAS, J. H.,-2007. A technical assessment of the Yet-to-Find hydrocarbon resource inventory, offshore and onshore Otway Basin, Victoria, Australia . Victorian Initiative for Minerals and Petroleum Report 90, Department of Primary Industries.

O'BRIEN G.W., BOREHAM, C.J., THOMAS, H.J AND TINGATE, P, In: Prep-Understanding the critical success factors determining prospectivity, Otway Basin, Victoria. The APPEA Journal, 49.

PARTRIDGE, A.D., 1997-New Upper Cretaceous Palynology of the Sherbrook Group, Otway Basin. Petroleum Exploration Society of Australia News, Victorian Supplement April/May 1997.

PARTRIDGE, A.D., 1999-Late Cretaceous to Tertiary geological evolution of the Gippsland Basin, Victoria, PhD Thesis, La Trobe University. Bundoora, Victoria, 439p, unpublished.

PARTRIDGE, A.D., 2001-Revised stratigraphy of the Sherbrook Group, Otway Basin. In: Hill, K.C. and Bernecker, T. (eds), Eastern Australian Basins Symposium, A Refocussed Energy Perspective for the Future, Petroleum Exploration Society of Australia, Special Publication, 455-464.

PERINCEK, D. AND COCKSHELL, C.D., 1995-The Otway Basin: Early Cretaceous rifting to Neogene inversion. The APEA Journal, 35(1), 451-466.

PERINCEK, D., SIMONS, B.A. AND GUNATILLAKE, K., 1995-Seismic interpretation of the onshore Western Otway Basin. Victorian Initiative for Minerals and Petroleum Report 17. Department of Agriculture, Energy and Minerals.

REID, I.A.S, GEARY, G.C. AND CONSTANTINE, A., 2001-Hydrocarbon Prospectivity of Areas V01-1 to V01-3, offshore Otway Basin, Victoria, Australia : 2001 Acreage Release. Victorian Initiative for Minerals and Petroleum Report 68. Department of Natural Resources and Environment.

STRUCKMEYER, H.I.M. AND FELTON, E.A., 1990-The use of organic facies for refining palaeoenvironmental interpretations: A case study from the Otway Basin, Australia. Australian Journal of Earth Sciences 37, 351-365.

TICKELL, S.J., EDWARDS, J. AND ABELE, C., 1992-Port Campbell Embayment. 1:100,000 map geological report. Geological Survey of Victoria Report 95.

TUPPER, N.P., PADLEY, D., LOVIBOND, R., DUCKETT, A.K. AND McKIRDY, D.M., 1993-A key test of Otway Basin Potential: The Eumeralla-Sourced Play on the Chama Terrace. The APEA Journal, 33(1), 77-93.

WOPFNER, H., KENLEY, P.R. AND THORNTON, R.C.N., 1971-Hydrocarbon occurrences and potential of the Otway Basin. In: Douglas, J.G. and Ferguson, J.A. (eds), 1971. The Otway Basin of Southern Australia. Geological Survey of South Australia and Victoria Special Bulletin, pp. 385-435.

YANG, J.S., 1997-VIC/P35 Otway Basin Victoria - Nirranda and Wangerrip Groups Depositional Study. Unpublished Cultus Timor Sea Ltd report.

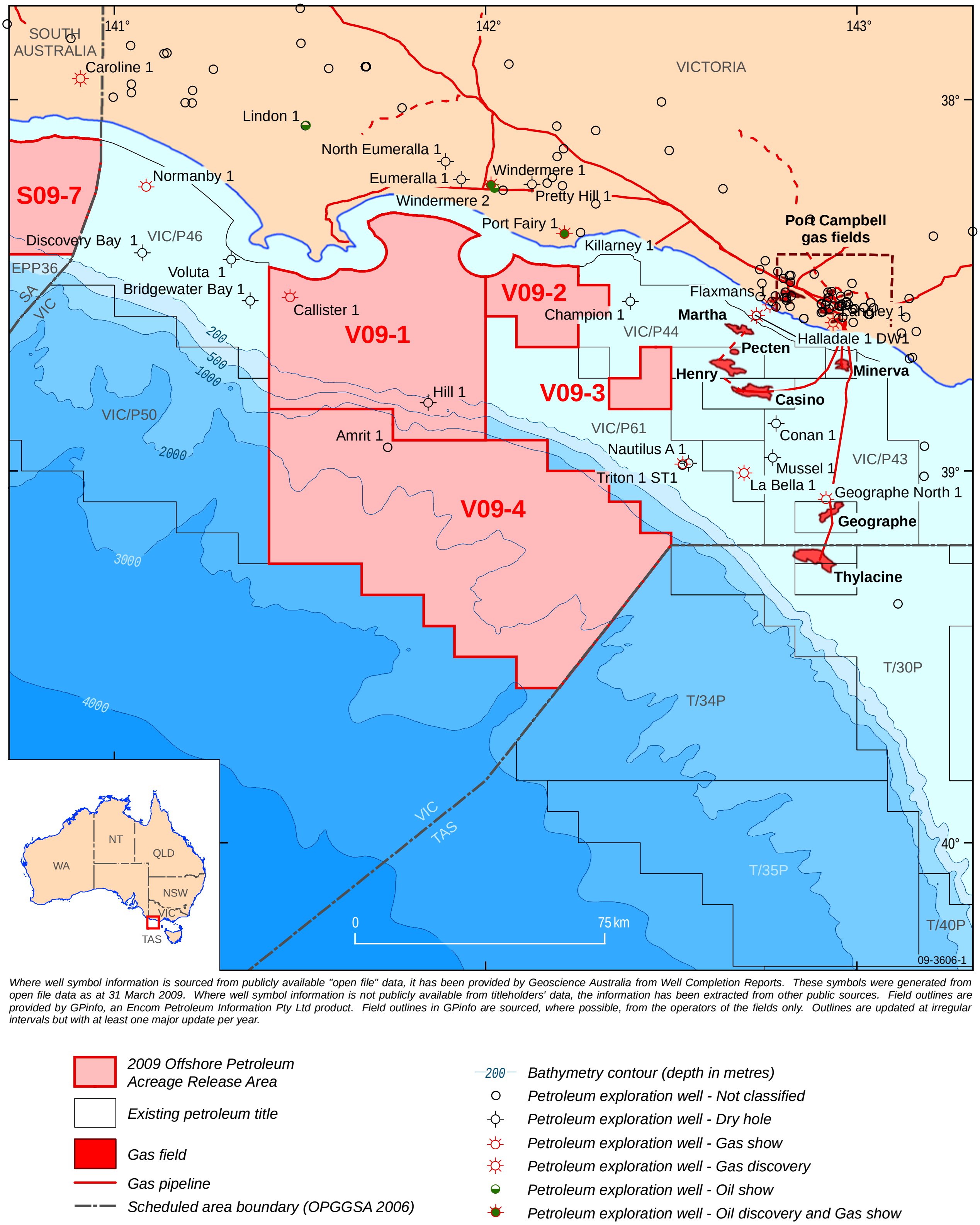


Figure 1. Location map of Release Areas V09-1, V09-2, V09-3 and V09-4.

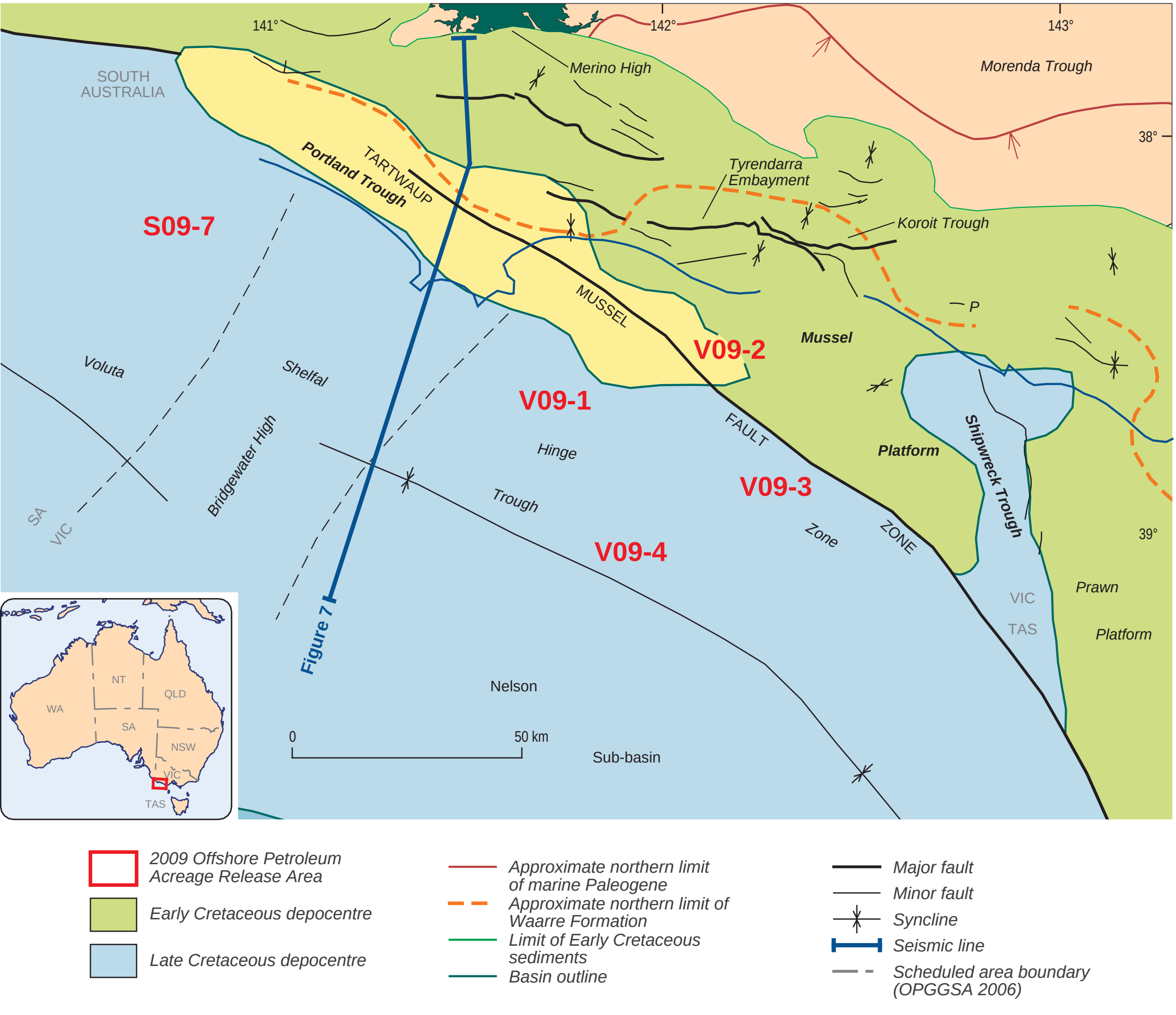


Figure 2. Tectonic elements map for central Otway Basin, showing location of seismic section (Figure 7).

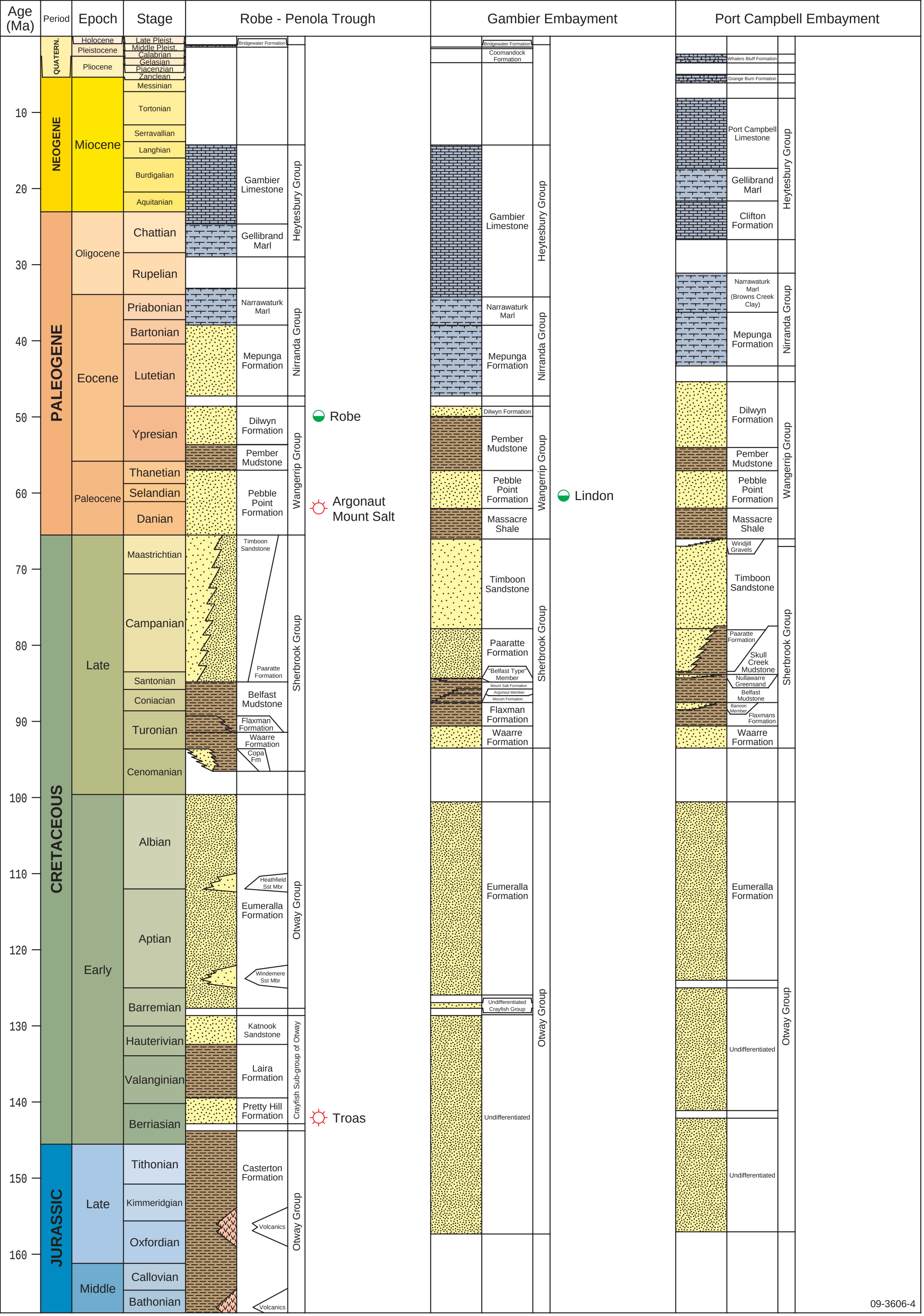


Figure 3. Stratigraphic chart for Otway Basin (Jurassic-Quaternary).

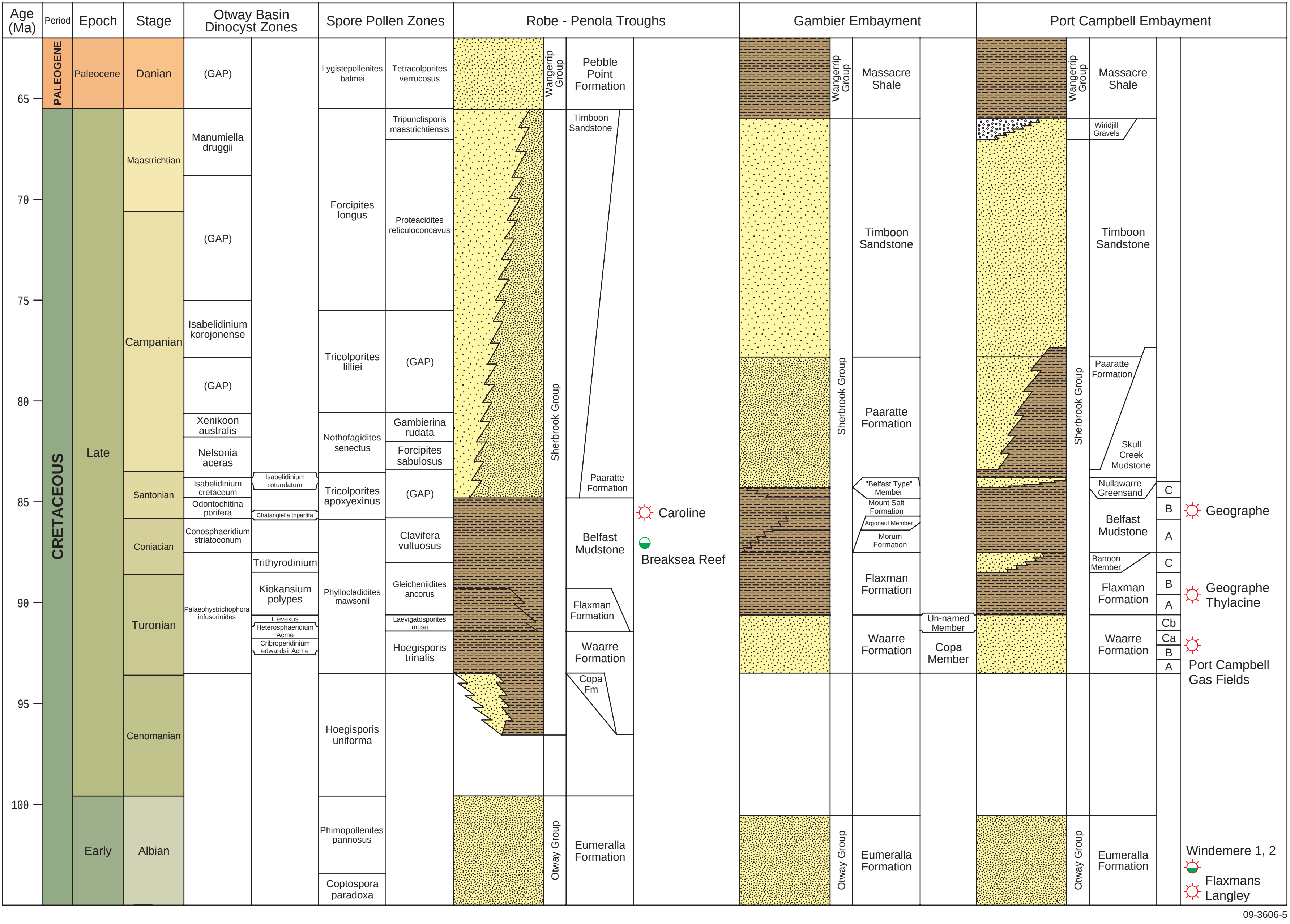


Figure 4. Stratigraphic chart for Otway Basin (Aptian-Danian).

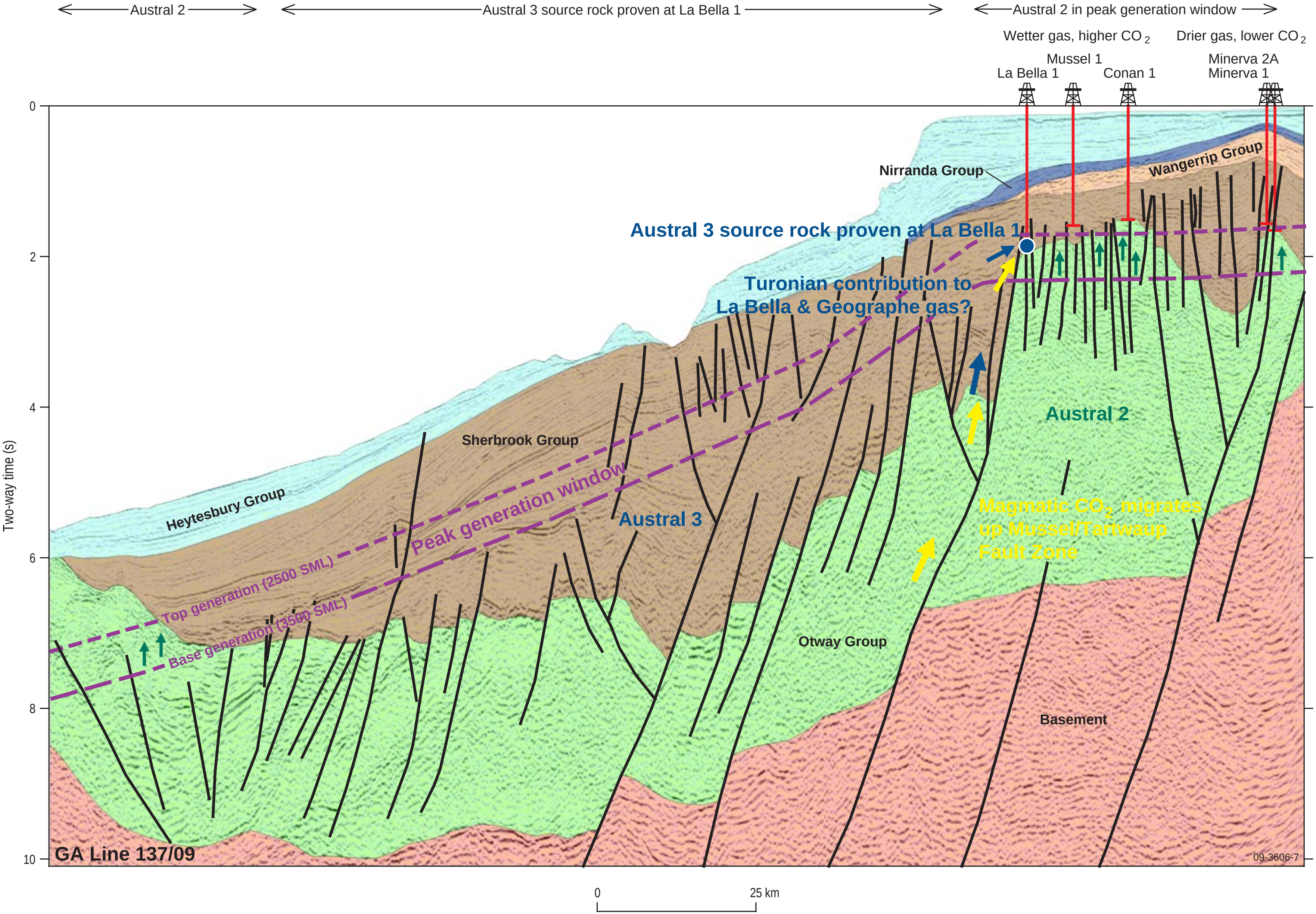
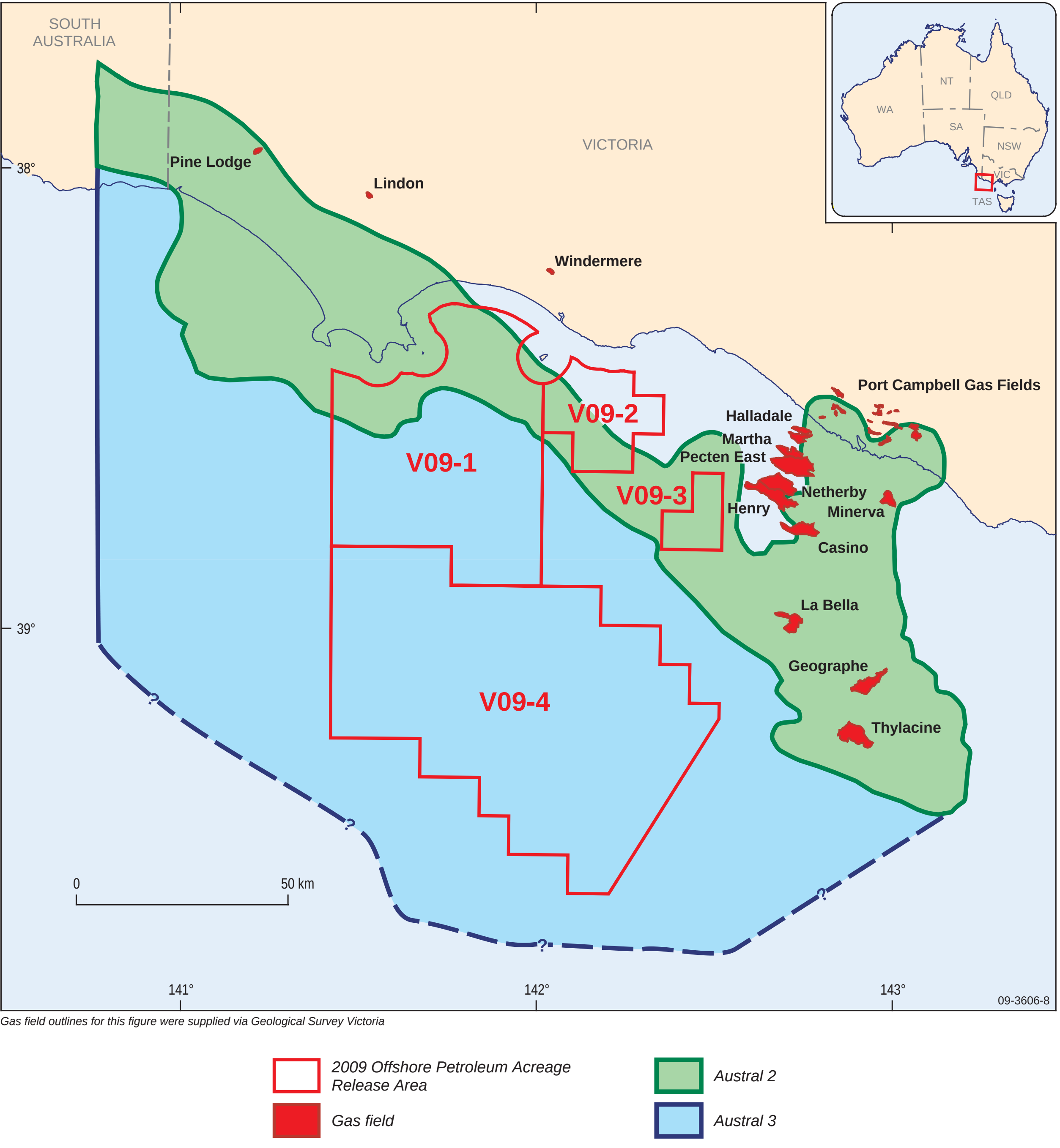


Figure 5. Hydrocarbon migration model for Austral 2 and Austral 3 petroleum systems (after O'Brien et al, in prep.).



Gas field outlines for this figure were supplied via Geological Survey Victoria

Figure 6. Generalised map showing maturity areas for Austral 2 and Austral 3 petroleum systems (after O'Brien et al, in prep.).

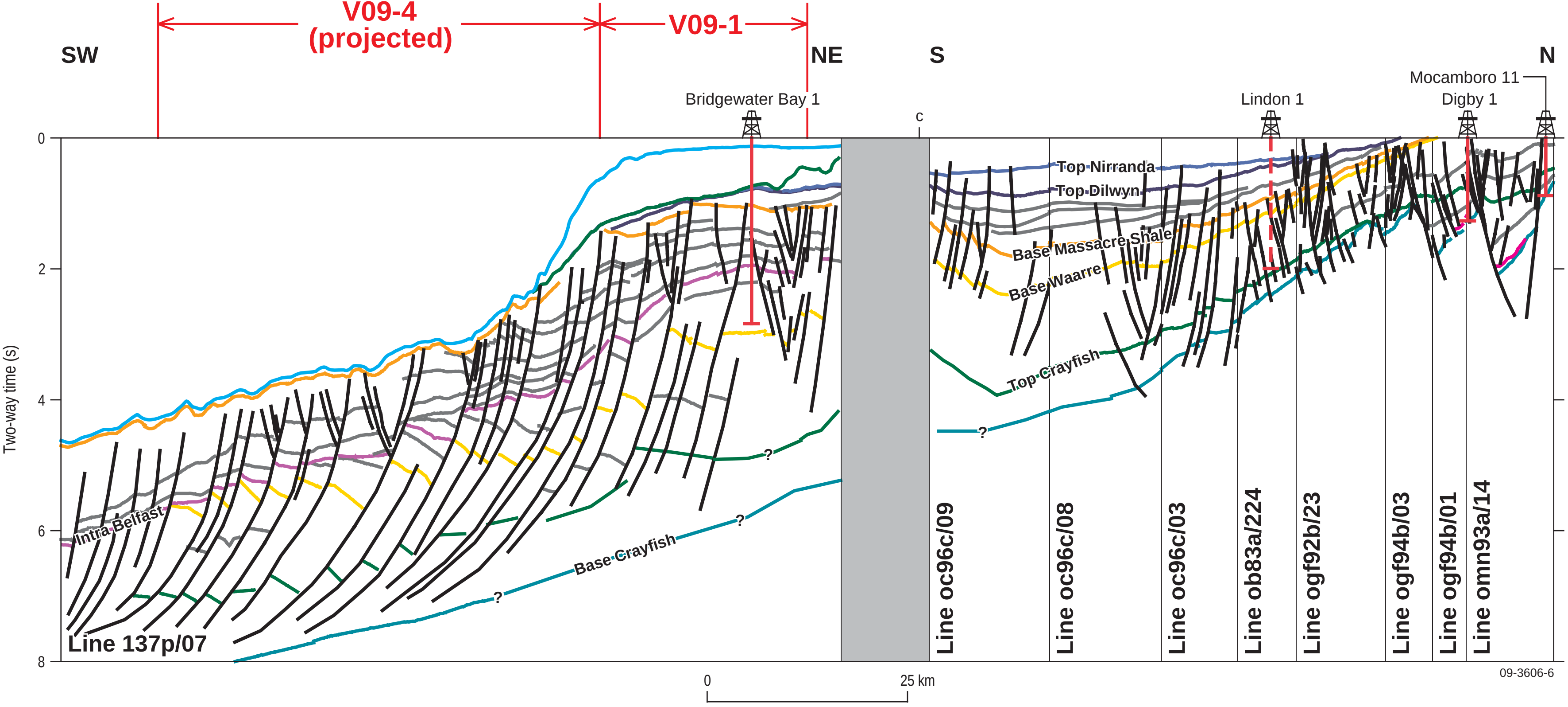


Figure 7. Simplified seismic section through Bridgewater Bay 1 highlighting downthrown interval of mature Turonian sediments.