Release Area S09-7, Western Otway Basin, South Australia

Location

Release Area S09-7 (**Figure 1**) is located 380 km southeast of Adelaide and 380 km west of Melbourne. The Release Area is bounded to the north by the South Australian Three-Mile Zone and to the south by the continental slope, roughly coinciding with the 1000 m bathymetric contour. Overall, water depths are less than 200 m. Heavy seasonal swells are a common feature in this part of the Great Southern Ocean. The area consists of 66 graticular blocks that cover approximately 3865 km^2.

Access to the Release Area is either via the port of Portland, Victoria or via the coastal town of Robe, South Australia. Southeastern South Australia is well serviced by a network of sealed roads and the onshore part has a long hydrocarbon exploration history. Whilst no offshore economic discoveries have been made in the South Australian portion of the Otway Basin, commercial discoveries have been made in the Victorian and Tasmanian portion of the Otway Basin including the Minerva, Casino, Henry, Thylacine and Geographe gas fields.

Release Area Geology

Local Tectonic Setting

Release Area S09-7 is located in the offshore Otway Basin and overlies the Voluta Trough on the northern margin of the offshore Morum Sub-basin (**Figure 1** and **Figure 2**).

Structural and stratigraphic evolution of the sub-basin

The Otway Basin and other basins of the southern Australian margin formed as a result of the latest Jurassic to Cretaceous rifting that culminated in the break-up of Australia and Antarctica in the Late Cretaceous. Significant tectonic periods are discussed below and summarised from Boult and Hibburt (2002).

Initiation of the Mesozoic Otway Basin began in the Late Jurassic as part of the breakup of Gondwana. Breakup started in Western Australia and propagated eastwards. The locus of propagation was focused by a series of east-trending structures which are collectively termed the Southern Australia Fracture Zone (Teasdale et al, 2002).

The Casterton Formation (**Figure 3**), comprising mainly carbonaceous shale with minor feldspathic sandstone, siltstone and basalt, was deposited during Tithonian to Berriasian times. It is best seen on the northern margins of the basin and is presumed to occur in the deepest parts of the troughs. The Casterton Formation is interpreted to have been deposited immediately prior to rifting in relatively deep lakes that were probably related to initial crustal fracturing.

Extrusion of volcanics within this formation occurred via early generated faults and fractures within the Paleozoic basement. Rapid escalation of rifting activity occurred in the Berriasian, with the development of numerous half graben along the length of the Otway Basin (Perincek and Cockshell, 1995). These graben are mostly filled with sediments of the Crayfish Subgroup, the deposition of which was strongly controlled by tectonic uplift and subsidence during this rifting stage. Up to 5800 m of fluvial and lacustrine clastics and carbonaceous mudstones were deposited over a period of 20 million years. Contemporaneous rift volcanism provided abundant volcanogenic debris (Gleadow and Duddy, 1981; Alexander, 1992; Little and Phillips, 1995).

Knowledge of basement structure and rift features is limited to shallower areas of the Otway Basin due to limited penetration by drilling and resolution of seismic. However, it is clear that rift tectonics were complex resulting in variable orientations of the many half graben as evidenced by the east-northeast trending Robe Trough to the southeast-trending Penola Trough. This early intensive rifting phase ceased during the Barremian and was followed by fault-related tilting, folding and uplift that resulted in extensive erosion of the Crayfish Subgroup.

Sediments of the Eumeralla Formation were deposited during a sag phase in the Aptian The formation is dominantly composed of fine-grained fluvial floodplain sediments but also includes minor coarse-grained fluvial channel sandstones as well as coal-seams. Onshore, Eumeralla Formation deposition was partly controlled by faulting, but the rapid facies changes and thickness variations observed in the underlying Crayfish Subgroup are not seen. Gleadow and Duddy (1981) commented that volcanogenic material is a common constituent of the Eumeralla Formation, and interpreted pulses of volcanism between 123 and 106 Ma using fission track dating. The extension direction of this phase is more widely accepted as being northeast-southwest. Norvick and Smith (2001) interpreted the provenance of the volcanogenic sediments to be from a volcanic arc off the east coast of Australia . Fault trends at top-Eumeralla Formation level show a strong sub-parallel trend in the orthogonal northwest-southeast direction.

It appears that the earlier rifting phase failed in the Barremian in most of the onshore areas. The overlying Eumeralla Formation blankets earlier troughs and basement highs thickening rapidly southwards of the Tartwaup Hinge Zone. Seismic and well data suggest that the sedimentary depocentre moved southwards during the Albian.

Late Albian uplift corresponds to continental breakup at 95 Ma. The onset of seafloor spreading as postulated by Veevers (1986) or cessation of subduction to the east of the continent, accompanied by an end to viscous corner convection in the underlying mantle, allowed rebound of the margin (Waschbusch et al, 1999). Offshore and closer to the basin depocentre, no angular unconformity is discernible on seismic data. It is possible that deposition across the Early to Late Cretaceous boundary may have been continuous.

Continental separation between the Australian and Antarctic plates began at the start of the Cenomanian. This marks a change from a Late Jurassic-Early Cretaceous intra-continental rift system to a Late Cretaceous-Paleogene oceanic rift. This extension and associated subsidence resulted in extensive deltaic, marginal marine and deepwater deposition, possibly within a restricted basin between the Tartwaup Hinge Zone and the Outer Margin High. Up to 5 seconds two way time (TWT) of Late Cretaceous Sherbrook Group sediments, overlain by up to 1500 m of Paleogene sediments, have been mapped offshore. Structuring was predominantly down-to-basin planar to listric syn-depositional faulting in contrast to previous rifting styles.

A bypass margin existed north of the Tartwaup Hinge Zone, with thin Sherbrook and Wangerrip groups being deposited. Most sediment was transported further south and deposited onto and beyond the continental margin. However, localised depocentres evolved over the Tithonian-Barremian troughs due to sediment compaction, leading to variations in Sherbrook Group thickness across the bypass margin.

In the northwestern offshore part of the South Australia Otway Basin, flexure between the stable platform and rapid subsidence during the deposition of the Sherbrook Group was concentrated across a single hinge zone. However, towards the southeast, flexure was split between the following three major hinge zones:

· The Tartwaup Hinge Zone, which was active from the Cenomanian to Campanian; this crosses the coast 30 km south of Beachport and is 20-25 km inland in the Mount Gambier region;

· The Coastal Hinge Zone also active from the Cenomanian to Campanian is well developed from Carpenter Rocks through to the Victorian border; and

· The Shelf Break Hinge Zone which was most active from the Turonian to the Campanian and largely coincides with the present day shelf break.

The Maastrichtian to early Paleocene unconformity (65 Ma) occurs throughout the Otway Basin and has been attributed to a eustatic low (Holdgate et al, 1986). South of the Tartwaup Hinge Zone this was also associated with a marked episode of northwest-trending normal faulting. Fault movement continued during progradational deposition of the Wangerrip Group (**Figure 3**).

A rapid increase in continental spreading rate occurred in the middle Eocene, around 44 Ma (Norvick and Smith, 2001) to 42 Ma (Yu, 1988), to reach half the current rate of ~11 mm/yr. Seafloor spreading penetrated the Otway Basin from the west and was accompanied by left lateral strike slip as Antarctica pulled away from Australia until final breakthrough of the oceanic crust occurred at the end of the Eocene.

Continuing thermal subsidence and starvation of clastic input led to deposition of predominantly marine carbonates. At least 670 m of Nirranda and Heytesbury group sediments occur in the southeastern offshore Otway Basin in South Australia (intersected in Breaksea Reef 1 ST3). The shelf edge prograded southwards throughout the Paleogene, and changes in sea level promoted the cutting and filling of deeply incised canyons.

Analysis of fault and anticline patterns throughout the Otway Basin by Perincek et al (1994), Perincek and Cockshell (1995) and St John (2001) indicate an east-west oriented dextral wrench system existed from the Miocene to present day. This has caused northeast-southwest anticlinal uplift in some areas, and significant inversion along many existing faults.

A stress regime with north-northwest - south-southeast S_{hmax} is indicated, for the present day, by borehole breakout analysis of Hillis et al (1995) and Jones et al (2000). Denham and Windsor (1991) supported this interpretation for both the Otway and Gippsland basins. The influence of this event on structures and fault planes is very important in hydrocarbon exploration with unfavourably oriented faults being prone to reactivation and leakage (Boult and Hibburt, 2002).

The cause of this change in stress regime has been related to collision on the northern and eastern margin of the Australian plate (Perincek et al, 1994). Continuity of this stress field to the present day is validated by the persistence of significant earthquake activity, particularly in the Beachport High area, the site of the most intense structural inversion mapped in the South Australian portion of the basin.

Stratigraphy

The basin fill of the Otway Basin is divided into five unconformity-bounded successions:

The Otway, Sherbrook, Wangerrip, Nirranda and Heytesbury groups (**Figure 3**). In South Australia, Cenozoic strata of the Wangerrip, Nirranda and Heytesbury groups are classified as belonging to the Gambier Embayment.

The **Otway Group** is a succession of continental and fluvio-lacustrine sediments up to 8000 m thick which accumulated in progressively widening and deepening graben and half-graben that formed during the first rifting event to affect the basin. Syn-rift lacustrine sediments and flow-basalts of the Casterton Formation are overlain by dominantly sub-lithic, fluviatile sediments of the Pretty Hill Formation. The overlying Laira Formation is characterised by lower energy fluvial and lacustrine sediments. The Katnook Sandstone represents a return to higher energy fluvial environments. Some hydrocarbon source potential for both oil and gas is recognised in these lacustrine sediments and coals.

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.

In the early Aptian, rifting became less active across most of the region and a broad thermal sag basin developed. The Eumeralla Formation filled the earlier half-graben and blanketed the intervening basement highs. A significant feature of the Eumeralla Formation is the presence of large amounts of volcaniclastic material derived from active volcanic complexes to the east. The Eumeralla Formation attains a maximum thickness of approximately 3000 m and was deposited in a variety of continental environments including fluvial flood plain, coal swamp and lacustrine settings. Coal measures within the formation have significant source potential for gas and some oil (Tupper et al, 1993). Most of the hydrocarbons discovered in the Otway Basin are derived from these source rocks.

The unconformably overlying **Sherbrook Group** consists of a succession of sandstones and mudstones up to 5000 m thick that accumulated during the second rift phase in coastal plain, deltaic and restricted marine settings. The influence of the volcanic arc to the east had ceased, and sands deposited at this time are mineralogically mature and able to preserve porosity to greater depths than those of the underlying Otway Group. Deposition commenced in the Cenomanian to Turonian with thin barrier-lagoonal sandstone and mudstone of the Copa Formation in South Australia (**Figure 4**). This unit rests unconformably on the Eumeralla Formation and represents the first major marine incursion into the Otway Basin.

The Waarre Formation represents the first major, post-break-up, clastic influx into the basin and comprises an interbedded sequence of occasionally conglomeratic quartzose sandstone, mudstone, carbonaceous mudstone and coal. Sediments were deposited in a succession of deltaic to marine depositional environments. Coal-rich parts of the Waarre

Formation have significant regional source potential. Coastal barrier sandstones of the Flaxman Formation overlie the Waarre Formation. Sandstones of the Waarre and Flaxman formations are major exploration objectives in the Otway Basin as they have good reservoir character locally, and host hydrocarbon accumulations in the Port Campbell Embayment onshore and at Minerva, La Bella, Casino, Henry, Martha, Pecten, Thylacine and Geographe offshore.

These sandstones are overlain by thick, open-marine, prodeltaic, carbonaceous mudstones of the Belfast Mudstone (**Figure 4**) that were deposited during a period of rapid subsidence and high eustatic sea levels. The Belfast Mudstone forms a regional seal across most of the Otway Basin. The Paaratte Formation represents a deltaic depositional system that broadly prograded across facies of the Belfast Mudstone. Much of the Parratte Formation comprises lagoonal and proximal deltaic facies. Offshore in the deepwater areas, the Belfast Mudstone, Paaratte Formation and possibly Waarre Formation equivalents show seismic reflection character and geometries consistent with turbidite fan deposits. Here, stacked reservoir/seal couplets may form attractive exploration targets. Onshore, the Paaratte Formation passes laterally into the more proximal deltaic facies of the Timboon Sandstone (**Figure 4**). Sandstones within the Paaratte Formation and Timboon Sandstone have excellent reservoir characteristics.

The **Wangerrip Group** represents the beginning of passive margin sedimentation after cessation of rifting. The Wangerrip Group unconformably overlies rocks of the Sherbrook Group and consists of up to 700 m of sandstone and mudstone deposited in coastal plain, deltaic and inner shelf settings. A thin basal unit termed the Massacre Shale is described in Victoria (Partridge, 2001) and its depositional history probably spans the late Maastrichtian to early Paleocene. This unit has not been intersected in wells drilled in South Australia. The Massacre Shale may have some local potential as a seal for Sherbrook Group reservoirs. The Massacre Shale passes upwards into a ferruginous, shoaling-upward, deltaic succession of fine to very coarse-grained, argillaceous sandstone of the Pebble Point Formation. In onshore Victoria, multiple oil and gas shows occur within this formation and this unit is considered a potential fairway play (Mehin and Constantine, 1999). The Pebble Point Formation is in turn overlain by micaceous silty claystone and minor fine-grained sandstone of the Pember Mudstone, which exhibits good potential as a regional seal.

The Dilwyn Formation comprises sandstone and mudstone deposited in a range of marine, deltaic and coastal environments. Marine incursions resulted in complex inter-fingering of the Pember Mudstone with the Dilwyn Formation (**Figure 3**). Here, considerable potential for intra-formational seal development exists and the seismic character is very similar to the top-Latrobe Group beds of the same age that host the giant accumulations in the Gippsland Basin. The interbedded sandstones have excellent reservoir potential, and oil has been recovered from the formation onshore at Wilson 1 and significant oil shows were also noted in Fahley 1.

A major unconformity with significant incision separates prograding nearshore to offshore marine clastics and carbonates of the **Nirranda Group** from the underlying Wangerrip Group (**Figure 3**). The unconformity marks the beginning of rapid spreading in the Southern Ocean at about 44 Ma that led to rapid thermal subsidence and major marine transgression in the Otway Basin (Norvick and Smith, 2001). The basal Mepunga Formation of the Nirranda Group consists of interbedded sandstone and mudstone deposited in nearshore to offshore marine environments. Continued transgression resulted in an open marine depositional setting in which fine-grained, glauconitic facies of the Narrawaturk Marl were deposited. A major eustatic sea level fall during the Oligocene resulted in erosion on the shelf, and formation of low-stand turbidite fans on the continental slope (Lavin, 1998).

Fully marine conditions returned in the early Miocene with the deposition of calcareous mudstone, marls and sandy limestone of the Heytesbury Group. To date, the Nirrandara and Heytesbury groups have not generally been considered prospective petroleum exploration targets but their deposition was important for thermal maturation of underlying successions.

Exploration History

Release Area S09-7 has been the focus of exploration since 1961 and from that time has been almost constantly been a petroleum exploration permit. Only two wells have been drilled in the Release Area since that time (Argonaut A1 and Breaksea Reef 1 ST3)

During the period 1961 to 1966, Hematite Petroleum operated OEL 26 and conducted the first seismic survey in 1963.

From 1966 to 1971, OEL 26 was operated by Esso Australia and in 1968 the company drilled Argonaut A1 to a total depth (TD) of 3707 mKB to evaluate the hydrocarbon potential of the'A' culmination and deeper levels on the elongate, fault-closed Argonaut structure. No hydrocarbons were encountered.

From 1971 to 1977, Tyers Petroleum held EPP2 which covered a portion of Release Area S09-7.

During the period 1981 to 1987, Ultramar Australia Inc. (Ultramar) operated EPP 18 and in 1981, Shoreline Exploration recorded a marine hydrocarbon detection survey with a high resolution sparker seismic and side-scan sonar surveys in EPP 18. A'seepage' anomaly detected some 16 km south of Port MacDonnell was interpreted to be from an oil source because of the abundant propane content. Ultramar took ownership of EPP 18 over the southeastern end of the basin in 1981 and carried out marine seismic and geochemical surveys in 1981 and 1982.

Ultramar followed up its offshore surveys with the drilling of South Australia's deepest petroleum exploration well, Breaksea Reef 1 ST 3, in 1984. The well reached a TD of 4468 mKB after encountering several downhole mechanical problems. Gas shows in the Late Cretaceous Waarre Sandstone and a possible oil reservoir in intra-Belfast Mudstone sands were intriguing. The well was abandoned in May 1984.

Chevron Overseas Petroleum and Ultramar undertook seismic surveys in EPPs 18 and 22 (to the northwest of Release Area S09-7) in 1985. On the continental shelf and in deeper water (to the 5000 m isobath) 1555 line-km of seismic data were acquired by Chevron in EPP 22. The Bureau of Mineral Resources ((BMR) now Geoscience Australia (GA)) conducted a combination seismic and sea-floor dredge sampling survey in 1985 in EPPs 18 and 22. Grab, core and 4 rock and mud dredge samples were obtained, together with heat flow measurements, and 393 line-km of data were recorded. Head space gas analysis of samples gave highest hydrocarbon readings adjacent to near sea-bottom faults. Samples were taken in water depths from 50 to 5000 m. EPPs 18 and 22 were relinquished when farm-in partners could not be found to drill commitment wells.

Following a short hiatus, Cultus Petroleum (Victoria) Pty Ltd operated EPP 23 over the period 1987 to 1992 and during this period conducted 2 seismic surveys.

In August 1999, Release Area S98-01 was awarded to Tyers Investments as petroleum exploration permit EPP 27 and later Woodside Energy Limited acquired a 90% interest in the permit. The interests in the permit later were: Oilex NL 20%, Great Artesian Oil and

Gas 40%, Videocon Industries 20% and Gujarat State Petroleum Corp 20%. Work completed during the permit's primary term included the acquisition of 1444 line-km of 2D seismic data (Christine Marine Seismic Survey) and reprocessing of 2750 line-km of existing seismic data. In 2002, 342 km^2 of 3D seismic were acquired by Woodside Energy Limited over the northern portion of Release Area S09-7 as part of the greater Carpenter 3D seismic survey.

Well Control

Well control for Release Area S9-07 is provided by Argonaut A1 and Breaksea Reef 1 ST 3 wells, which are located within its borders (**Figure 1**). The nearest well outside Release Area S9-07 is Copa 1, located 7 km to the north in EPP 34. Additional relevant geological information is provided by a number of onshore wells.

Robe 1 (1915-16)

Robe 1 was drilled by SA Oil Wells in 1915-1916 to a TD of 1372 mKB. Minor gas shows were recorded and the well was plugged and abandoned.

Caroline 1 (1967)

Caroline 1, located 16 km southeast of the town of Mount Gambier on a prominent gravity high, was drilled by Alliance Oil Development Australia to test the petroleum potential of sands in the Wangerrip Group and to investigate possible reservoir-forming facies changes within the upper part of the Sherbrook Group. All target zones were found to be water-bearing and the Late Cretaceous sequence encountered was thinner than at Mount Salt 1.

The well was subsequently deepened to investigate the stratigraphy of the entire Sherbrook Group and the upper part of the Otway Group. Three drillstem tests (DSTs) were conducted in non-prognosed porous and permeable sandstone units within the basal Waarre Formation, with one resulting in a substantial flow of carbon dioxide (CO_2). DST No. 8, over the interval 2790-2799 mKB, flowed CO_2 at a maximum rate of 2.28 MMcfd (0.065 MMcmd) during the initial stage of the test, and flowed at a stabilised rate of 2.495 MMcfd (0.071 MMcmd) during an extended 15-hour second stage of the test. The gas consists predominantly of CO_2, with less than 1% hydrocarbons and only 0.5% nitrogen. Seven valid DST were run and 17 cores were cut. The well was completed as a CO_2 production well in 1967. A small purification plant was built and commercial CO_2 production commenced in 1968, the well has subsequently produced over 741250 tonnes of CO_2, making it the most valuable well in South Australia. The well also produces minor amounts of light oil from the Waarre Formation (sourced from the Eumeralla Formation) that is stripped by the CO_2.

Mount Salt 1 (1962)

Mount Salt 1 was drilled by Oil Development N.L. in the Gambier Embayment to evaluate a sedimentary sequence of Cretaceous age known to exist beneath Paleogene ('Tertiary') sediments. The well reached TD at 3061 mKB within the Belfast Mudstone. Although minor gas shows were recorded in the interval 2996-3001 mKB, a DST only produced salt water.

Crayfish A1 (1967)

Crayfish A1, drilled by Esso Exploration and Production Australia Inc. was designed as a stratigraphic test to evaluate the regional stratigraphy and interpreted seismic structure in an undrilled portion of the Otway Basin in offshore South Australia. The well was also designed to evaluate the lithology of the offshore section and test for the presence of hydrocarbons in the Crayfish prospect, an anticlinal closure at the top of what was regarded as an unconformity between the Casterton and Pretty Hill formations. The well penetrated a sedimentary section that was close to prognosis and TD was reached at 3200 mRT. No hydrocarbon shows were recorded. Well failure was attributed to the presence of a down-faulted block at the crest of the structure which appeared to have destroyed closure.

Argonaut A1 (1968)

Argonaut A1 was drilled by Esso Exploration and Production Australia Inc. to a depth of 3707 mKB to evaluate the hydrocarbon potential of the'A' culmination and deeper levels on the elongate, fault-closed Argonaut structure. The well also aimed to test the growth timing and trapping integrity of a closure typical of this part of the basin, which is characterised by numerous fault-closed structures of similar appearance. Moreover, the well was designed to test whether favourable reservoir sands and shale facies with source potential exist in the Late Cretaceous rocks offshore; and whether good seal conditions are developed at the base of the Paleogene.

No hydrocarbons were encountered. The Argonaut structure was demonstrated to be dry, due principally to the presence of unfavourable facies associations in both the Paleogene and Late Cretaceous rocks. However, the well proved the existence of good reservoir sands in the Late Cretaceous and good source potential in the Belfast Mudstone. There was a lack of seal at the base of the Paleogene, immediately overlying the best potential reservoir sequence. No hydrocarbon shows were encountered and no DSTs were run. Sixteen cores were cut.

Lake Eliza 1 (1969)

Lake Eliza 1 was drilled by Esso Exploration and Production Australia Inc. to test a large positive gravity anomaly that was subsequently detailed by seismic methods as a closed structural high with at least 240 m relief. It was drilled to evaluate the hydrocarbon potential of the Pretty Hill Formation, which overlies basement in a steep drape structure sealed by unconformably overlying Otway Group mudstones and greywackes. The Pretty

Hill Formation objective exhibited good porosity but very low permeability, although the sand characteristics were variable. The cored and tested intervals consist of silty sandstones. A DST run at the top of the cored zone flowed methane at a rate too small to measure. The well reached a total depth of 1473 mKB in steeply dipping meta-siltstones that may be related to the Kanmantoo Group. Three continuous cores were cut in the Pretty Hill Formation through to basement.

Breaksea Reef 1, ST 1, ST 2, ST 3 (1984)

Breaksea Reef 1 ST 3 was drilled offshore to a TD of 4468 mKB by Ultramar to test the petroleum potential of the Late Cretaceous succession south of the Voluta Trough. The primary objective was the Flaxman Formation with the Paaratte Formation sand sequence and any intra-Belfast Mudstone sands as secondary objectives. Although gas shows were observed while drilling through the sands of the lower Flaxman Formation, no electric log evaluation was possible because of technical difficulties.

Both secondary objectives were penetrated, but no hydrocarbon shows were encountered. Wireline logs revealed a resistivity anomaly over the interval 3664-3669 mKB although no fluorescence was observed whilst drilling. The anomaly could be related to a low-grade oil leg within intra-formational sands in the Belfast Mudstone. The well failed to penetrate the Eumeralla Formation due to mechanical problems.

Copa 1 (1990)

Copa 1 was drilled by Cultus Petroleum (Australia) NL to evaluate the hydrocarbon potential of the Cretaceous section to a TD of 3850 mKB. The well was located offshore to the southwest of the town of Beachport, on a seismically defined large, faulted northwest-oriented anticlinal structure.

Good quality reservoir rocks and seals were present in the Late Cretaceous section but no significant hydrocarbon shows were detected and no formation tests were run. No cores were cut and the well was plugged and abandoned.

Troas 1, ST 1 (1992)

Troas 1 was drilled by BHP Petroleum Pty Ltd to test the reservoir potential of the Early Cretaceous Crayfish Subgroup (Pretty Hill Sandstone). The well needed to be sidetracked and Troas 1 ST 1 penetrated the primary objective and reached a TD of 3506 mRT. Gas was recorded within fluvial sandstone reservoirs below 2350 mRT. Several open-hole and cased-hole RFTs recovered gas. The well was plugged and abandoned as an uneconomic gas discovery.

Rendelsham 1 (1994)

Rendelsham 1, located approximately 13 km west of the town of Millicent, was drilled by Sagasco Resources to test the hydrocarbon potential of the Otway Group within a large, faulted, four-way dip closure situated on the upthrown side of the Tartwaup Fault. The primary objective was the Crayfish Subgroup, which had only previously been intersected in the Biscuit Flat 1 well, where its sandstones lacked shows but were of reservoir quality.

The well was drilled to a TD of 2775 mKB without coring or testing. No significant hydrocarbon were encountered while drilling, but following the wireline logging program, DSTs were attempted on two sandstone units within the upper section of the Crayfish Subgroup. Each DST was a mechanical failure, but DST No.1 a retest of the lower sand over the interval2606.1-2638.0 mKB was mechanically successful, although the tool pressure charts showed the interval to be very tight and no flow was recorded. An attempted repeat test of the upper sand over the interval 2545-2580 mKB also failed.

The stratigraphic section was mostly as predicted, except the Crayfish Subgroup was intersected low to prognosis with upper Crayfish sediments (Katnook Sandstone and Laira Formation time equivalents) resting directly on basement. Consequently the possibly more prospective lower Crayfish Subgroup sediments could not be investigated at this location - they must onlap the Rendelsham structure downdip of the well. Overall, sand development was poor and only minor gas readings were recorded in generally tight sands. However, Crayfish Subgroup shales were shown to have excellent source rock quality, making a downdip test on the structure a continuing attractive proposition with potential reservoir quality sandstones capable of receiving charge from mature sediments in the adjoining depositional troughs.

Table 1: Key wells listing

Well	Operator	Year	Total Depth	Hydrocarbons
Argonaut A1	Esso Exploration and Production Australia Inc.	1968	3707 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	4437 mKB	no tests
Breaksea Reef 1 ST3	Ultramar Australia Inc	1984	4468 mKB	no tests
Caroline 1	Alliance Oil Dev Aust	1967	3371 mKB	Gas

Copa 1	Cultus Petroleum (Australia) NL	1990	3851 mKB	no tests
Crayfish A1	Esso Exploration and Production Australia Inc.	1967	3200 mRT	no shows
Lake Eliza 1	Esso Exploration and Production Australia Inc.	1969	1473 mKB	no shows
Mount Salt 1	Oil Development	1962	3061 mKB	minor gas
Rendelsham 1	SAGASCO Resources	1994	2775 mKB	no shows
Robe 1	SA Oil Wells Co	1916	1372 mKB	minor oil
Troas 1	BHP Petroleum Pty Ltd	1993	1430 mRT	no tests
Troas 1 ST1	BHP Petroleum Pty Ltd	1993	3506 mRT	Gas

Rig Release Year shown. Data accurate as at 31 March 2009

Seismic Coverage

Seismic coverage over Release Area S09-7 is excellent with 25 2D seismic surveys acquired over the period 1963 to 2008 for a total of 7181 line-km of data. In addition, 342 km^2 of 3D seismic were acquired by Woodside Energy Limited in 2002 over the northern portion of Release Area S09-7 as part of the greater Carpenter 3D survey. Most of the seismic data acquired over Release Area S09-7 are available in SEGY format and are open file.

Good quality data were also obtained from a regional deep seismic survey (AGSO 137) that was acquired by the Australian Geological Survey Organisation (AGSO, now Geoscience Australia (GA)), in 1999.

A full listing of the seismic is available in the **Western Otway Data Listing**.

Other data

In 1983, a 1600 line-km marine hydrocarbon detection survey conducted by Shoreline Exploration Co. located hydrocarbon'seepages' thought to be the source of the coastal bitumen. One large anomaly, located ~16 km south of the town of Port MacDonnell, was geographically coincident with'clouds of gas bubbles' observed on sonar records (Ducharme, 1983). Subsequent analysis of the gas indicated that peak propane is about half peak methane hinting towards an oil rather than a gas source. Low ethylene appears to rule out a biogenic source and iso-butane/n-butane ratios suggest a mature source of hydrocarbons.

These results contrast significantly to those obtained from a 1987 geochemical and geological sampling program conducted by the BMR aboard the research vessel M/V Rig Seismic (Heggie et al, 1988). These authors identified 9 locations that were found to contain thermogenic gases. Furthermore, all anomalies are located above major faults. The highest gas concentrations occur where faulting extends almost to the seafloor. However, all locations contained relatively'dry gas' with the driest anomalies occurring where maturation modelling predicts that Early Cretaceous source rocks are overmature. Gas wetness increases to the east in the vicinity of the Mussel Platform where Early Cretaceous source rocks lie within the oil window (Heggie et al, 1988). These authors concluded that from their limited data set, molecular composition of hydrocarbon gases from seafloor sediments reflects variations in the maturity of the deeply buried source rocks and suggested that the Early Cretaceous sequence appears to be the primary source of the anomalies. The conflicting results between these offshore surveys may simply be related to variations in depth of burial of the Early Cretaceous source rocks as opposed to variations in source quality or to origin from a different source interval (?Late Cretaceous).

Hydrocarbon Potential

Petroleum Systems

Hydrocarbons sourced from basins along the southern margin of Australia have been assigned to the Austral Petroleum Supersystem by Bradshaw (1993) and Summons et al (1998). Within this supersystem, three petroleum systems related to the Otway Basin have been recognised (Edwards et al, 1999). Each system comprises geochemically distinct oil families and related source rock facies; the differences between the families are primarily related to differences in the depositional environments for the source rocks.

The three systems are:

> Austral I - Late Jurassic to earliest Cretaceous fluvio-lacustrine shales

> Austral 2 - Early Cretaceous fluvial and coaly facies

> Austral 3 - Late Cretaceous to earliest Paleogene fluvio-deltaic facies

Hydrocarbon Families

Padley et al (1995) assigned the oils, condensates and bitumens discovered in Crayfish Subgroup reservoirs in the Robe and Penola Troughs, and to a lesser extent the Chama Terrace, to three groups based on their source-dependent biomarker signatures. A fourth group not discussed by these authors but included below is associated with oils discovered predominantly in the eastern Otway Basin and sourced from the Eumeralla Formation:

> Group 1 - Katnook Field condensate, Sawpit 1 and Wynn 1 oils

> Group 2 - Troas 1 ST1 condensate

> Group 3 - Crayfish A1 and Zema 1 reservoir bitumens

> Group 4 - Caroline 1 oil-CO_2 (SA), Lindon 1, Port Campbell 4, and Windermere 1 and 2 oils.

Source affinity, maturity, oil-oil and oil-source correlations, are discussed below for each group.

On the basis of biomarker data, Padley et al (1995) concluded that Group 1 oils and condensates are sourced from algal-rich, bacterially degraded siliciclastic sediments deposited in either a suboxic fluvial or lacustrine environment. Whilst these oils and condensates have similar biomarker distributions, minor differences exist, suggesting generation from multiple source rocks or, alternatively, from laterally heterogeneous source facies.

Based on the limited available data, the freshwater lacustrine Casterton Formation sampled at Sawpit 1 is the most likely source of Group 1 oils. Slight variations between biomarker assemblages of the oils and their indicated source rock can be attributed to variations of the organic environment of the Casterton Formation. However, it is instructive to note that an extract from the Casterton Formation in Casterton 1 differs markedly from both the Sawpit 1 (Casterton Formation) extract and the Group 1 oils (Padley et al, 1995). The sterane biomarker signatures of the Group 1 oils and the Casterton Formation in Sawpit 1 (2501 mKB) are similar, although Price (1993) suggested that the Sawpit 1 oil has been sourced from a deep lacustrine environment of which the Casterton Formation in Sawpit 1 represents a marginal facies.

Condensates recovered from the Pretty Hill Formation in the Katnook field range in composition from light (51-53^{0}API gravity) paraffinic-naphthenic to heavier (48^{0}API gravity) aromatic-intermediate crudes with little evidence of water washing or biodegradation in the reservoir. They are non-waxy and are relatively immature as indicated by their low heptane and isoheptane values. The Katnook field gases are relatively dry with a high methane content (88-93%) and only negligible concentrations of nitrogen, carbon dioxide and helium (Parker, 1992; Boreham, 1999). Gas maturities increase with depth and gas appears to have probably originated from intra-Pretty Hill Formation shale (i.e. more or less in situ; MPI-derived R_{vcalc}=0.79-0.92%). Oils reservoired within the Crayfish Subgroup differ markedly from younger, Eumeralla Formation-sourced oils and condensates which were generated from bacterially reworked land-plant remains preserved in coaly facies (Padley et al, 1995). The maturity of Group 1 oils consistently falls within the conventional oil-condensate window R_{vcalc}=0.5-1.2%).

In contrast, condensate recovered from the Windermere Sandstone Member of the Eumeralla Formation in Katnook 1 is more paraffinic and less mature (R_{vcalc}=0.62%). The determination of the likely source for this condensate is equivocal. It may have been generated in situ rather than sourced from the Crayfish Subgroup. Furthermore, its biomarker assemblage is more similar to oils sourced from the Eumeralla Formation (i.e. Lindon 1, Port Campbell 4, Windermere 1 and 2) than oils from Group 1. However, the pristane/n-heptadecane and phytane/n-octadecane ratios indicate higher maturity (Watson and McKirdy, 1988). Moreover, comparison of the i-pentane/n-pentane ratio with headspace gas suggests that the oil may have originated from depths below 2500 m in Katnook 2 where maturities exceed R_{vo}= 0.9%. This would suggest that the condensate has migrated from a mature source kitchen basinward of Katnook 1, most probably from the lower Laira Formation or possibly intra-Pretty Hill Formation .

In Sawpit 1, migrated hydrocarbons have been identified in the Laira Formation (1526 mKB) by Price (1993). Based on aromatic maturity indicators, these hydrocarbons more closely match condensates from the Pretty Hill Formation of the Katnook field than the underlying sediment extracts (i.e. Casterton Formation and unnamed basal shale) in Sawpit 1. However, Price (1993) highlighted the difficulty in genetically characterising light hydrocarbons and was unable to conclusively prove this correlation.

Group 2 oils are represented by condensate reservoired in undifferentiated Crayfish Subgroup sediments at a depth of 2698 mKB in Troas 1 ST 1. Padley et al (1995) assigned a mixed landplant, algal and bacterial source affinity to this condensate, similar to Group 1 oils, but in this case the algae contributing to the parent kerogen included marine species. These authors have identified reliable markers for marine organic matter (C30 sterane (24-npropyl-cholestane) and C30 4-methylsteranes) that provide evidence for its marine source affinity. 30-Norhopanes, a class of biomarker commonly found in oils from marine carbonate source rocks, are abundant in the Troas 1 ST 1 condensate but are not detected in Group 1 oils. A calcareous marine mudstone deposited in a nearshore environment is the likely source rock of the Troas 1 ST 1 condensate (Padley et al, 1995). Possible source intervals are either carbonaceous shales of the Eumeralla Formation or the undifferentiated Crayfish Subgroup.

Evidence for marginal marine conditions during deposition of the Eumeralla Formation is provided by the occurrence of marine dinoflagellates in Lucindale 1 (564 mKB) and Troas 1 ST 1 (2340-2345 mKB). Elsewhere, the Eumeralla Formation is regarded as a fluvial-lacustrine succession. Padley et al (1995) suggested that the low proportion of dinoflagellates and limited species diversity indicate a near-shore depositional environment (i.e. back barrier lagoon, lower delta plain estuaries) with less than normal marine salinities. In Lucindale 1, this marine incursion is thought to have been short lived and possibly resulted from a spillover from the Murray Basin to the north. Biomarker assemblages of extracts in Troas 1 ST 1 indicate that marine algae contributed to the kerogen in the Eumeralla Formation at this location. Proximity of Troas 1 ST 1 to the Tartwaup Hinge Zone, which is coincident with a significant southward thickening of the Eumeralla Formation, may provide the reason for the development of marine conditions as the basin sagged prior to continental breakup (Padley et al, 1995).

Marine influences within sediments of the Crayfish Subgroup have been recognised in Robertson 1 (1747-1750 and 1710-1713 mKB) and in Troas 1 ST 1 (2569-3466 mKB). Extracts of the undifferentiated Crayfish Subgroup in Troas 1 ST 1 have a more marine geochemical signature when compared to the Eumeralla Formation in this well. Comparison of source-specific biomarkers of both these extracts and the condensate show that the Troas 1 ST 1 condensate originated from a marginal marine source similar to, but more mature than, that sampled at 2569 mKB (undifferentiated Crayfish Subgroup) in that well. However, Padley et al (1995) could not conclusively determine if the condensate was sourced from a more mature Eumeralla Formation south of the Tartwaup Hinge Zone or from the underlying Crayfish Subgroup.

Padley et al (1995) have assigned bitumens recovered from undifferentiated Crayfish Subgroup and Pretty Hill Formation in Crayfish A1 and Zema 1, respectively, to Group 3 oils. These authors noted that the biomarker assemblages of this group, especially the presence of gammacerane, would indicate derivation from hypersaline, microbial, organic matter deposited in a playa lake environment. Whilst this interpretation of the depositional environment is a departure from the commonly held view that Crayfish Subgroup sediments were deposited in a fluvio-lacustrine setting, it is not inconceivable that isolated graben lakes lacking external drainage may have formed in the developing rift basin and become hypersaline. The C27/C28/C29 sterane distribution for Group 3 oils indicates that they can be subdivided into two groups, the other being derived from lacustrine source rocks, rather than playa lakes.

A high thermal maturity (R_{vcalc} = 0.9-1.3%) derived from MPI-1 data for these reservoir bitumens may support the notion that they originated from basal Crayfish Subgroup shales or Casterton Formation.

Waxy crudes recovered from intra-Eumeralla Formation sandstones and Windermere Sandstone Member of the Eumeralla Formation in Windermere 1 and 2 respectively, Pebble Point Formation in Lindon 1 and Waarre Sandstone from Port Campbell 4, all drilled in Victoria, are believed to have been sourced from carbonaceous shales and coals of the lower Eumeralla Formation (McKirdy et al, 1994). The geological habitat of these oils was described by Kopsen and Scholefield (1990). Oil associated with CO_2 production from the Caroline plant is also thought to be sourced from the Eumeralla Formation with the CO_2 acting as a solvent to strip hydrocarbons. The oil in Caroline 1 comprises 50% aromatics and has a specific gravity of 17^0API (McKirdy, 1986). The maturity of this oil (R_{vcalc} = 0.71%) is in agreement with a Eumeralla Formation source (R_{vo}= 0.70%; 3200 mKB).

The oils typically have low sulphur contents (Tupper et al, 1993) and have molecular signatures consistent with derivation from terrigenous organic matter. Extracts from the *C. hughesi* hydrocarbon source interval of the Eumeralla Formation confirm that land plants are the major contributors of organic matter. High pristane/phytane ratios are consistent with deposition in peat swamps (Tupper et al, 1993).

Source Rocks

The source potential of the Eumeralla Formation has been investigated by Struckmeyer and Felton (1990) and Tupper et al (1993). These authors identified a thick potential source sequence within the lower Eumeralla Formation characterised by thin bituminous coal seams up to 1 m thick which constitute ~30% of the total source interval.

TOC and Rock-Eval analyses have been summarised by McKirdy and Padley (1992) and Hill (1995). These data consistently demonstrate marked differences in kerogen type between the lower Eumeralla Formation source intervals and the siltstone and mudstone dominated upper Eumeralla Formation. In the Chama Terrace, coal is best developed in the *P. notensis* source interval (Tupper et al, 1993) where TOC values (mean = 31%) and potential yields (mean S1 + S2 = 85 kg hydrocarbons/tonne) indicate excellent source richness. In contrast, upper Eumeralla Formation source rocks have low to moderate organic richness (mean TOC = 1% and poor to fair genetic potential (mean S1 + S2 = 1.1 kg hydrocarbons/tonne).

Hydrogen indices for the *P. notensis* source interval are high (mean HI = 244 mg S2/g TOC), consistent with Type II-III kerogen and potentially capable of generating oil and gas. Source quality in the upper Eumeralla Formation deteriorates (mean HI = 59), indicating gas-prone Type IV kerogen. The most basinward well intersection of the Eumeralla Formation occurs at the southern margin of the Chama Terrace where the sedimentary package thickens and improves in source quality.

The Songliao Basin of Northeast China (Yang et al, 1985) has significant oil production in an almost identical setting to the Eumeralla Formation. Source rock quality changes from Type IV at the basin margin where the sediments are predominantly fluvial, grading to Type II-III and eventually Type I kerogen associated with lacustrine sediments at the basin centre. The difficulty with predicting source quality for the Eumeralla Formation is determining its depocentre.

The *P. notensis* source interval maceral assemblage is dominated by vitrinite with variable amounts of liptinite and subordinate inertinite. Exasudatinite infills fractures and open cell lumens in inertinite (Tupper et al, 1993). Solid bitumen and oil oozing from cracks in detrovitrinite occur in Chama 1A (2502-2505 mKB) and Crayfish A1 (1539-1542 m). The *C. striatus* hydrocarbon source interval comprises mostly siltstone with low to moderate amounts of DOM of mixed algal and plant origin. Vitrinite and liptinite predominate over inertinite.

The Belfast Mudstone is considered a potential source rock in offshore South Australia. TOC ranges from 2.40 to 3.0% (i.e. fair to very good) with an observed increase in source richness to the south in the vicinity of Breaksea Reef 1 ST3 (mean TOC = 1.5%). The genetic potential of the Belfast Mudstone ranges from poor to moderate, with the richest source rocks occurring in the vicinity of Breaksea Reef 1 ST3 (mean S1 + S2 = 2.63, range 0.30-5.92). This confirms the view that both source quality and richness improve to the south and that more favourable source rocks could occur in the deeper offshore areas.

Gravestock et al (1986) likened the Sherbrook Group to the Paleogene succession of the Niger Delta. In terms of source potential, however, there is limited similarity. Geochemical data indicate a Type IV (inertinitic) grading to at best Type III kerogen). The Belfast Mudstone is composed of terrigenous DOM rich in inertinite (I = 75-90%) and lean in vitrinite (V ≤20%). Moreover, the majority of inertinite is reworked (McKirdy et al, 1984). Exinite remains a minor component of DOM (E ≤5%). McKirdy et al (1984) highlighted an obvious discrepancy between the highly inertinitic character of the DOM within the Belfast Mudstone and the overall Type III kerogen composition in Breaksea Reef 1. A possible explanation may be provided by the widespread occurrence of trace oil and bitumen in the cuttings which would elevate the S2 peak on pyrolysis. In contrast, prodelta muds of the Niger Delta are commonly of Type III and to a lesser extent Type II kerogen. A key to the viability of the Belfast Mudstone as an oil source may be to delineate a more distal facies to the south and west of Breaksea Reef 1 ST3and beyond the present day shelf break.

HI values are highly variable and indicate that the Belfast Mudstone is predominantly gas prone (i.e. HI <100). In Breaksea Reef 1 ST3, HI values range between 17 and 181 mg S2/g TOC. Although considered to be predominantly gas prone, HI values frequently exceed 150, indicating some potential to generate liquids.

Sediments of the Crayfish Subgroup tend to be overmature for oil generation in the deeper portions of the Otway Basin, and mature for gas. On the flanks of troughs they tend to be early mature to mature for oil generation whilst on basement highs they are immature to marginally mature.

Basal coals of the Eumeralla Formation are probably the best source rocks of the Otway Group south of the Tartwaup Hinge Zone where they are mature for oil and early mature for gas.

In the Late Cretaceous succession, maturity for oil is generally low. The Belfast Mudstone, which represents the major Late Cretaceous source rock, does not attain peak generation for Type III organic material until depths greater than 4 km are reached. Of the wells drilled, only at the base of Breaksea Reef 1 ST3 are the sediments sufficiently mature for peak oil generation. An interpreted, thin, low-grade oil leg within sandy intervals of the Belfast Mudstone in Breaksea Reef 1 ST3 is most likely sourced from the Early Cretaceous Eumeralla Formation. Maturation assessment for speculative source rocks associated with the Waarre Sandstone has not been attempted.

Maturation was strongly influenced by the thickness of the Paleogene sediments. Increase of maturation levels during the Paleogene or Late Cretaceous of stratigraphically older source rocks is promoted when erosion and uplift at the top these formations is limited. The *C. hughesii* source interval near the base of the Eumeralla Formation exemplifies the case where uplift and erosion are significant prior to the deposition of the Sherbrook Group. In parts of Victoria, over 500-1000 m of Paleogene sediment is needed to further mature the *C. hughesii* source zone. In South Australia, where erosion at the top of the Eumeralla Formation is more subdued, a lesser thickness of Paleogene or Late Cretaceous sediment is needed to increase the maturity of the *C. hughesii* source zone.

Expulsion and Migration

Copa 1, Argonaut A1 and Breaksea Reef 1 ST3 are the only wells that reached the *C. hughesii* zone in the western Otway Basin and thermal and burial histories are based on modelling of Breaksea Reef 1 ST3 (**Figure 5**), the deepest well (TD 4468 mKB). Thermal modelling has not been attempted yet beyond the present day shelf edge.

The maturity of Eumeralla Formation sourced oils and condensates has been studied by McKirdy and Chivas (1992) and Tupper et al (1993). Their findings, coupled with recognition of bitumen, exsudatinite and live oil within the *P. notensis* source interval at a maturity of R_v = ~0.8%, suggest that oil expulsion has occurred over the range R_v = 0.7-1.2%. Tupper et al (1993) concluded that mid mature oil and/or wet gas generation from the lower Eumeralla Formation can be expected from 0.7 to 1.0% Rv, peak oil and wet gas generation from 1.0 to 1.3% R_v, and dry gas generation from 1.3% R_v onwards.

Only south of the Tartwaup Hinge Zone, where there is a substantial thickening of Sherbrook Group sediments (**Figure 5**), does the lower Eumeralla Formation source interval enter the zone of peak oil generation. Thermal modelling of Breaksea Reef 1 ST3indicates that the lower Eumeralla Formation entered the oil window (R_v = 0.7%) in the late Albian (~100 Ma), reaching peak maturity for oil at the close of the Sherbrook Group deposition, and has increased only marginally in maturity from the Paleogene to the present day. This highlights the importance of a thick Sherbrook Group as a mechanism for elevating and retaining heat.

Gas shows in Breaksea Reef 1 ST3yielded components up to C7 and extract gas chromatograms with significant n-alkane components up to C30, testifying to the liquids potential of the Belfast Mudstone. Significant overpressuring appears to be coincident with the highest HI values in Breaksea Reef 1 ST3, especially in the interval 3310-4362 mKB. $T_{max,}$ R_v-data and maturity modelling indicate that the top of the Belfast Mudstone is midmature for oil generation only offshore in the vicinity of Breaksea Reef 1 ST3and Argonaut A1, whilst Copa 1 is immature. The Belfast Mudstone at Breaksea Reef 1 ST3entered the base of the oil window at ~70 Ma and has remained in that window until the present day.

Beyond the Shelf Break Hinge Zone the Belfast Mudstone appears to rapidly thicken (**Figure 5**) and its maturation history there may be quite different from shelfal areas. In addition, deltaic systems are characterised by shifting depocentres as a result of rapid deposition and mass movement. As a consequence, sediments can have quite distinct thermal histories resulting from the isolation of discrete sand bodies encompassed by prodelta mudstones.

Severe overpressuring, common in productive deltas, can lead to enhanced temperature gradients, creating'hot spots' where the generative window is elevated closer to these isolated sands. For this reason, variations to the regional model of maturation trends can be expected for the Belfast Mudstone. Possible indications of migrated hydrocarbons are provided by high Rock-Eval production indices (PI) which exceed 0.2.

In Breaksea Reef 1, PI values of 0.67 to 0.72 (McKirdy et al, 1984) for samples taken from interval 3638-3677 mKB are coincident with an interpreted low-grade oil leg within intraformational sandy intervals in the Belfast Mudstone. A resistivity anomaly is evident over the interval 3664-3669 mKB although no fluorescence was observed during drilling. Two distinct oil types occur below 3275 mKB in Breaksea Reef 1 (McKirdy et al, 1984). Two types of bitumen were also recorded, one with moderate fluorescence and low reflectance (<0.2%), the other with dull fluorescence and high reflectance (0.4-0.6%).

Within the Belfast Mudstone there are several overpressured intervals overlain by normally pressured shales, giving rise to fracturing by thermal expansion of pore fluids and hydrocarbon generation. Beyond the shelf break, expulsion rates should be more efficient due to higher levels of maturity and lower porosity values.

Reservoirs

Reservoir facies are mainly represented by the Waarre and Flaxman formations, but the younger Paaratte Formation, drilled by many wells in South Australia, is known to have good quality reservoir intervals.

Because of a lack of deep drilling, the Waarre and Flaxman formations are known from only a few wells, but together their reservoir facies are highly likely to occur in all areas south of the Tartwaup Hinge Zone. The Flaxman Formation, with reservoir facies representing prograding delta lobes of *C. triplex* age, may however be of limited extent.

Further south of Breaksea Reef 1 ST3, there is considerable risk that these formations are too deep to be economic targets. Clean intra-Belfast Mudstone sand-dominated intervals are present in Breaksea Reef 1 ST3, and these can be correlated with the toe of the Argonaut Member Delta and should be mappable on good quality seismic.

Limited core data from these reservoir intervals (13 core plugs) reveal that core porosities range between 10 and 15%. Log analysis on Caroline 1 indicates a range of average porosities of 10.8-14.8%, with a maximum of 24% in the Waarre Formation. No detailed studies have been carried out on the characteristics of these reservoirs in South Australia, but the simple quartz-dominated mineralogy suggests mostly primary porosity. The very high concentration of CO_2 in the Caroline field may have resulted in growth of authigenic kaolinite, which may have occluded some primary porosity, as found in the Pretty Hill Formation of the Ladbroke Grove field (Little and Phillips, 1995). Elsewhere, the Waarre Formation reservoirs, where they contain hydrocarbons, may therefore be of much better quality than that found in Caroline 1.

Overpressure encountered offshore may help preserve porosity at greater depths than that predicted from normally pressured onshore data. Net to gross ratios (assuming 10% as a cut-off between productive and non-productive reservoirs) are high in the Waarre Formation (91% in Caroline 1), but lower in the Flaxman Formation (28-75%) due to facies differences. The net to gross ratio is effectively zero for the intra-Belfast Mudstone sandstones, and is probably related to diagenetic overprints in the deep-seated reservoir (3640 mKB in Caroline 1). These sandstones would probably be more porous at shallower depth.

The available core data indicate that permeabilities are low (<1 mD). However, flow tests carried out in Caroline 1 indicate good permeability. Further east in Victoria, where there has been considerably more drilling into these formations, the Waarre Formation is a major reservoir in a number of commercial gasfields. Discoveries in Victoria include a small oil flow from the onshore Mylor 1 well and the major offshore commercial gas discoveries at Minerva, Thylacine and Geographe fields, which have tested at flow rates up to 27.9 MMcfd (0.789 MMcmd) .

With respect to the Paaratte Formation, although considerable core porosity data exists, it is of vintage origin (BMR). Core porosities are generally high and range up to 38%. No detailed studies have been carried out on the characteristics of these reservoirs, but the framework mineralogy is quartz dominated with only minor labile (feldspar) grains.

Dolomite cement is common, and quartz overgrowths are rare but increase with depth. Secondary porosity is developed from leaching of dolomite cement and alteration of labile grains. The high measured core porosities may reflect a secondary origin. No log analysis has been carried out but net to gross ratios are presumed to be quite high. Measured core permeabilities are high, averaging several hundred millidarcies, but range up to 20000 mD. As no discoveries have yet been made in these formations, no DSTs have been conducted in this formation.

Seals

Intraformational shales within the Flaxman Formation may act as regional seals, but there is some risk that these may not be extensive or impermeable enough. However, the Belfast Mudstone facies (**Figure 3**) is a reliable regional seal for the Waarre Sandstone, Flaxman Formation and intra-Belfast Mudstone reservoirs. Risk increases onshore where the thickness of the Belfast Mudstone and its equivalents becomes less than fault throw, thus allowing juxtaposition of permeable sands.

Intra-Paaratte Formation shales may act as seals of limited lateral extent onshore, but offshore, may be viable. The early Paleogene Pember Mudstone or Pebble Point Formation may act as regional seals and are the only seals for condensed Sherbrook Group targets north of the Tartwaup Hinge Zone.

Play Types

A diverse range of play types has been identified in the offshore Otway Basin, and include:

> Turonian - Santonian (intra-Belfast Mudstone) slope fans.

> Waarre / Flaxman formation sandstones (intra-formational and regional Belfast Mudstone seals).

> Intra-Paaratte Formation sandstones (intra-formational seals).

Rapid deepening and steepening of the shelf to the southwest of the Tartwaup Hinge Zone, combined with sea-level rise, created a deep-water depositional environment over much of the Otway Basin. Post break-up uplift in the hinterland provided large volumes of clastic material that bypassed the relatively stable platform of the Tartwaup Hinge Zone to the northeast. Lower delta plain and marginal marine conditions suitable for the formation of oil-prone source rocks within the Waarre and Flaxman formations are most likely to be found in rapidly subsiding troughs, such as those located southwest of the Tartwaup Hinge Zone.

In such settings, slope-fan deposits overlying a thick, coal measure sequence (Waarre Formation) have been identified on dip seismic lines that cross the Release Areas and also on strike seismic lines. Frequent, high-amplitude anomalies that terminate at faults are evident on the dip seismic lines. These indicate possible juxtaposition of cross-fault seals against hydrocarbon-saturated reservoir sands. Occasionally, roll-over into faults and Direct Hydrocarbon Indicators (DHIs - flat spots) are also evident on seismic data. As in Breaksea Reef 1 ST3, these sands are probably over-pressured and retain porosity with depth.

Sandstones within the Waarre and Flaxman formations host the majority of the large hydrocarbon accumulations discovered in the Otway Basin. These traps are associated with tilted fault-blocks developed within the Sherbrook Group and require cross-fault seal to be effective. The Belfast Mudstone provides an excellent regional top seal while the

Flaxman Formation has demonstrated intra-formational sealing potential at Caroline 1. While the Waarre and Flaxman formation sandstones often exhibit excellent reservoir properties, reservoir development is strongly facies-dependant. Where buried deeply (>3000 m), diagenetic porosity occlusion may also reduce their potential as viable exploration targets, particularly for oil (Geary and Reid, 1998).

Tilted, intra-Paaratte (Sherbrook Group) fault blocks rely on both intra-formational and cross-fault seal for trap integrity. Trap seal is the main exploration risk associated with this play in proximal locations. In more distal areas, where the unit inter-fingers with the Belfast Mudstone, the risk of seal failure is reduced. Rollovers associated with anticlines developed on the hanging-wall of listric faults may provide independent four-way dip closures. The often coarsening-upwards, quartz sandstones display excellent reservoir characteristics. Although this play has yet to be validated by a hydrocarbon discovery, only one offshore well (Discovery Bay 1) has targeted this play. Downthrown fault blocks, with juxtaposition of Paaratte Formation reservoirs against shaly, Paaratte Formation sequences or Belfast Mudstone shales may also constitute valid traps. The potential for fault seal is expected to increase in a basinward direction.

Critical Risks

Given that only two wells have been drilled in the Release Area, direct petroleum geological control is rather limited. However, from a more regional perspective and considering that known petroleum systems operate in the region, exploration risk can be limited.

The main risk is clearly associated with the depth of Early Cretaceous source rock intervals within the Otway Group, which are today located below levels of hydrocarbon generation in areas beyond the shelf break. The mature source rocks of the Otway Group are likely to have generated hydrocarbons around 90 Ma, before major tectonism affected the Early Cretaceous section in the offshore.

Very high levels of CO_2 occur within the gas produced from some onshore Otway Basin wells. The Waarre Formation reservoirs are CO_2 -rich at Caroline 1 and Boggy Creek 1. At Ladbroke Grove 1 and Troas 1 ST1, CO_2-rich gas occurs in the Pretty Hill Formation while Kalangadoo 1 hosts CO_2 within fractured basement. At Caroline 1 and Boggy Creek 1, the purity of the CO_2 is remarkably high (~98%) and the gas is currently being produced commercially (Foster and Hodgson, 1995; Lovibond et al, 1995). Isotopic analyses of the CO_2 and associated gases suggests a magmatic origin (Chivas et al, 1987), derived from the Quaternary volcanic complexes of south-eastern South Australia and western Victoria (Chatfield, 1992). The maar-type volcanic centres at Mt Gambier, Mt Schank and Mt Burr Ranges appear to be the source of the CO_2 encountered in the wells drilled in the Mt Gambier Embayment and Penola Trough.

In offshore areas, however, the risk for significant CO_2 is generally rated as low, although the occurrence of large proportions of thermogenic CO_2 cannot be discounted. However, some Paleogene intrusives were noted on seismic sections in the area of interest and may pose a risk, albeit predictable. Paleogene volcanics within the offshore sedimentary section and may account for the CO_2 at Troas 1 ST1. (O'Brien et al, 1994)

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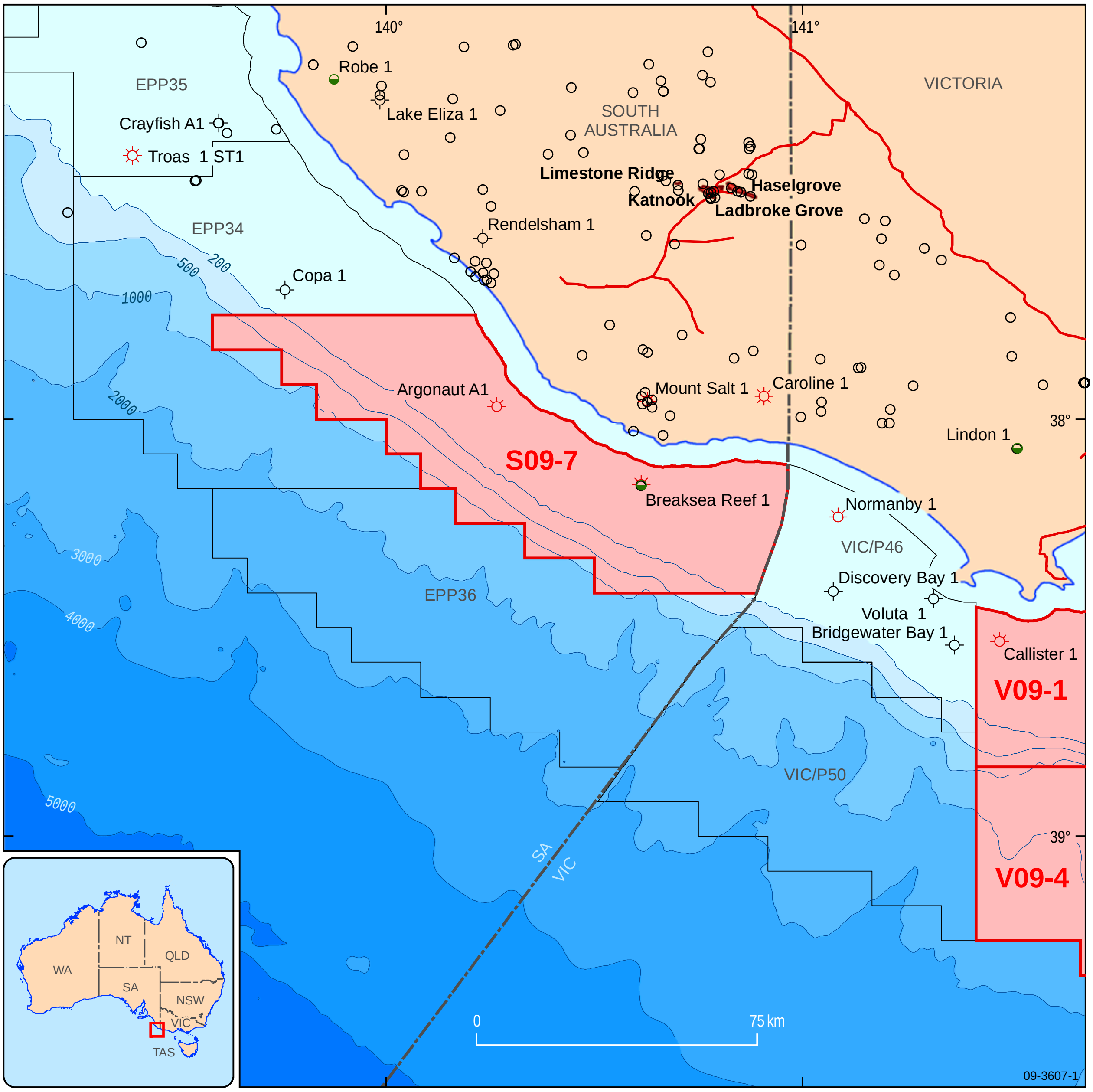

Where well symbol information is sourced from publicly available "open file" data, it has been provided by Geoscience Australia from Well Completion Reports. These symbols were generated from open file data as at 31 March 2009. Where well symbol information is not publicly available from titleholders' data, the information has been extracted from other public sources. Field outlines are provided by GPinfo, an Encom Petroleum Information Pty Ltd product. Field outlines in GPinfo are sourced, where possible, from the operators of the fields only. Outlines are updated at irregular intervals but with at least one major update per year.

2009 Offshore Petroleum Acreage Release Area
Existing petroleum title
Gas field
Gas pipeline
Scheduled area boundary (OPGGSA 2006)
200 *Bathymetry contour (depth in metres)*
Petroleum exploration well - Dry hole
Petroleum exploration well - Gas show
Petroleum exploration well - Gas discovery
Petroleum exploration well - Oil show
Petroleum exploration well - Oil and Gas show

Figure 1. Location map for Release Area S09-7.

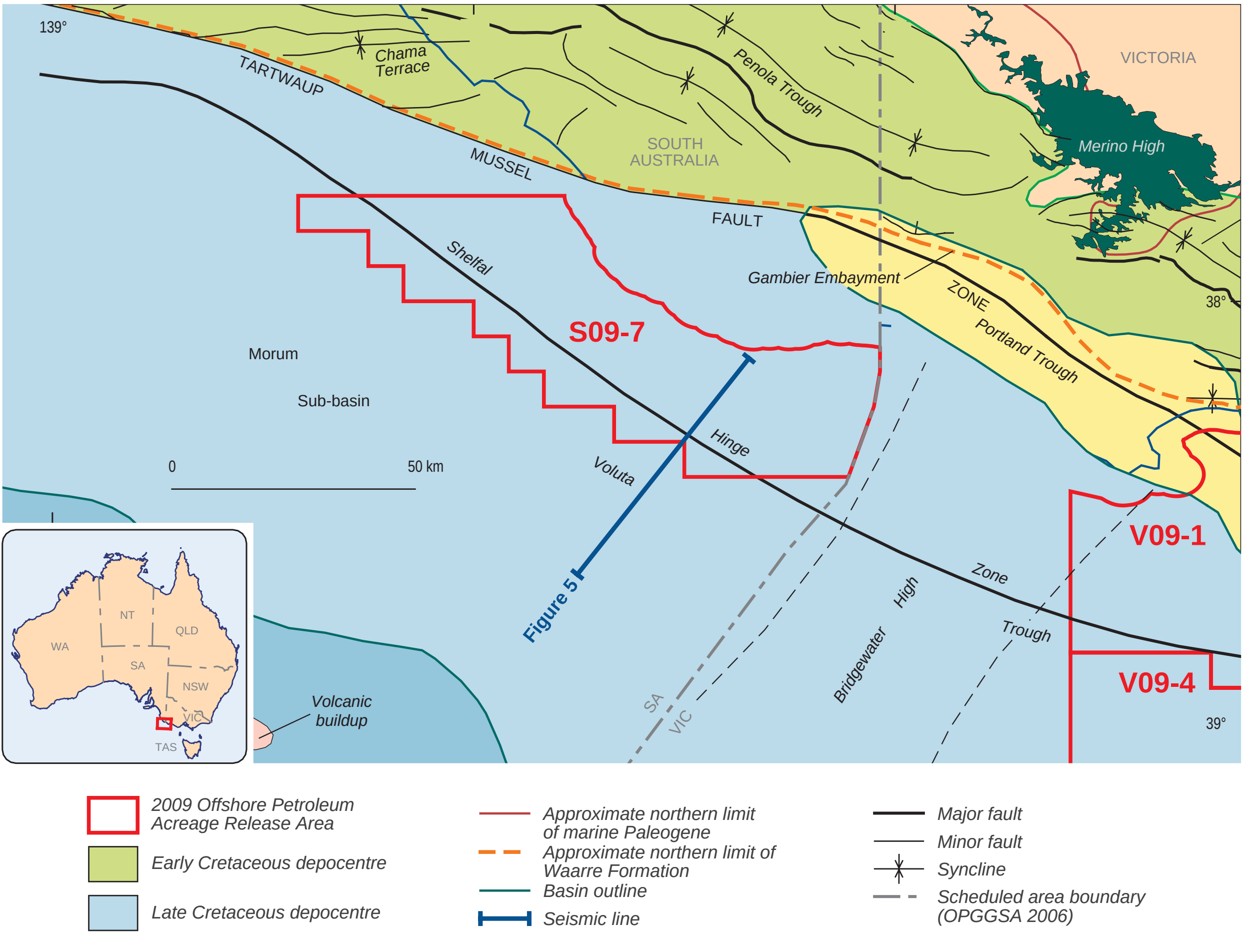

Figure 2. Tectonic elements map for western Otway Basin, showing location of seismic line omn137p-04 (Figure 5).

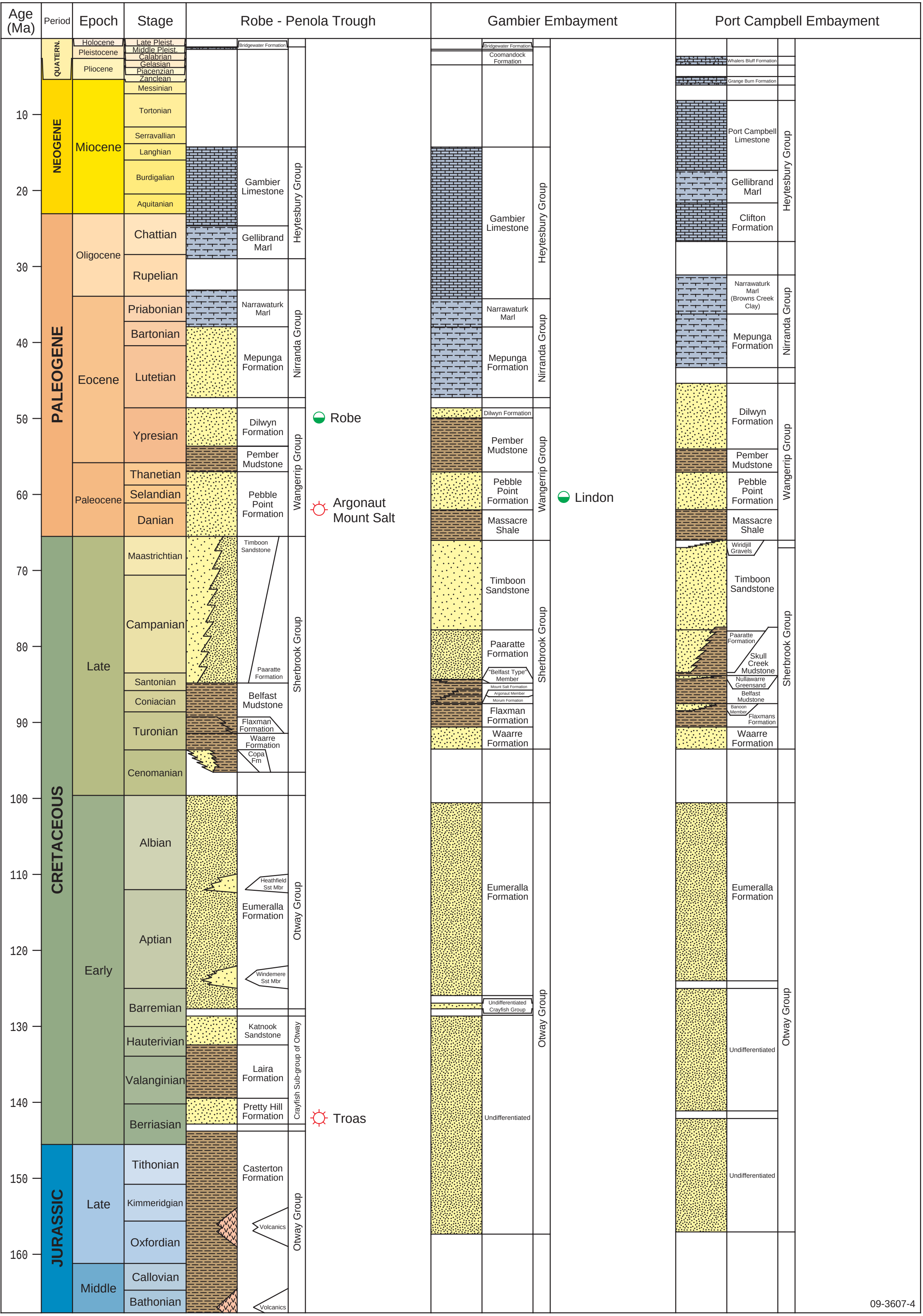

Figure 3. Stratigraphic chart for Otway Basin (Jurassic-Quaternary).

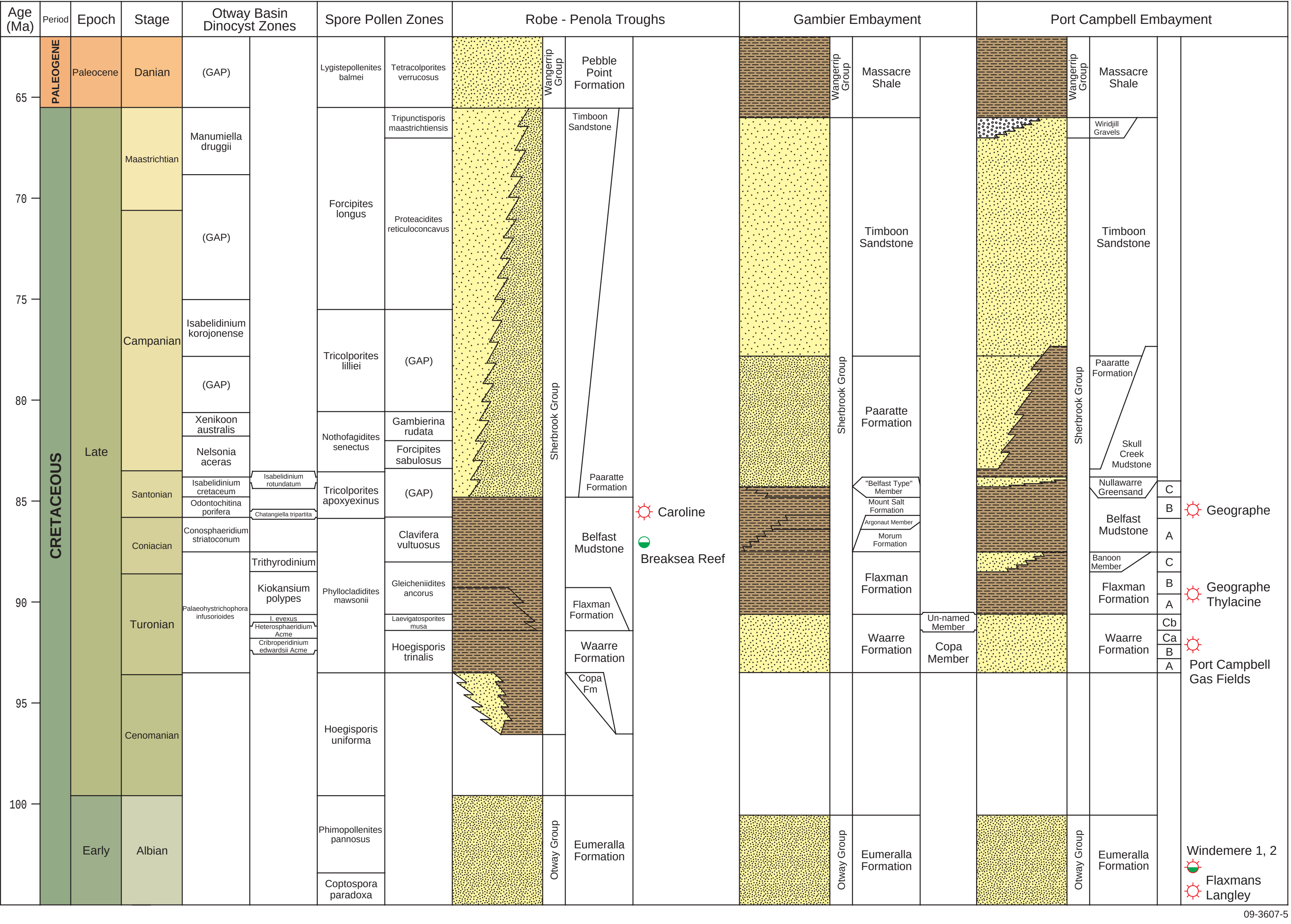

Figure 4. Stratigraphic chart for Otway Basin (Aptian-Danian).

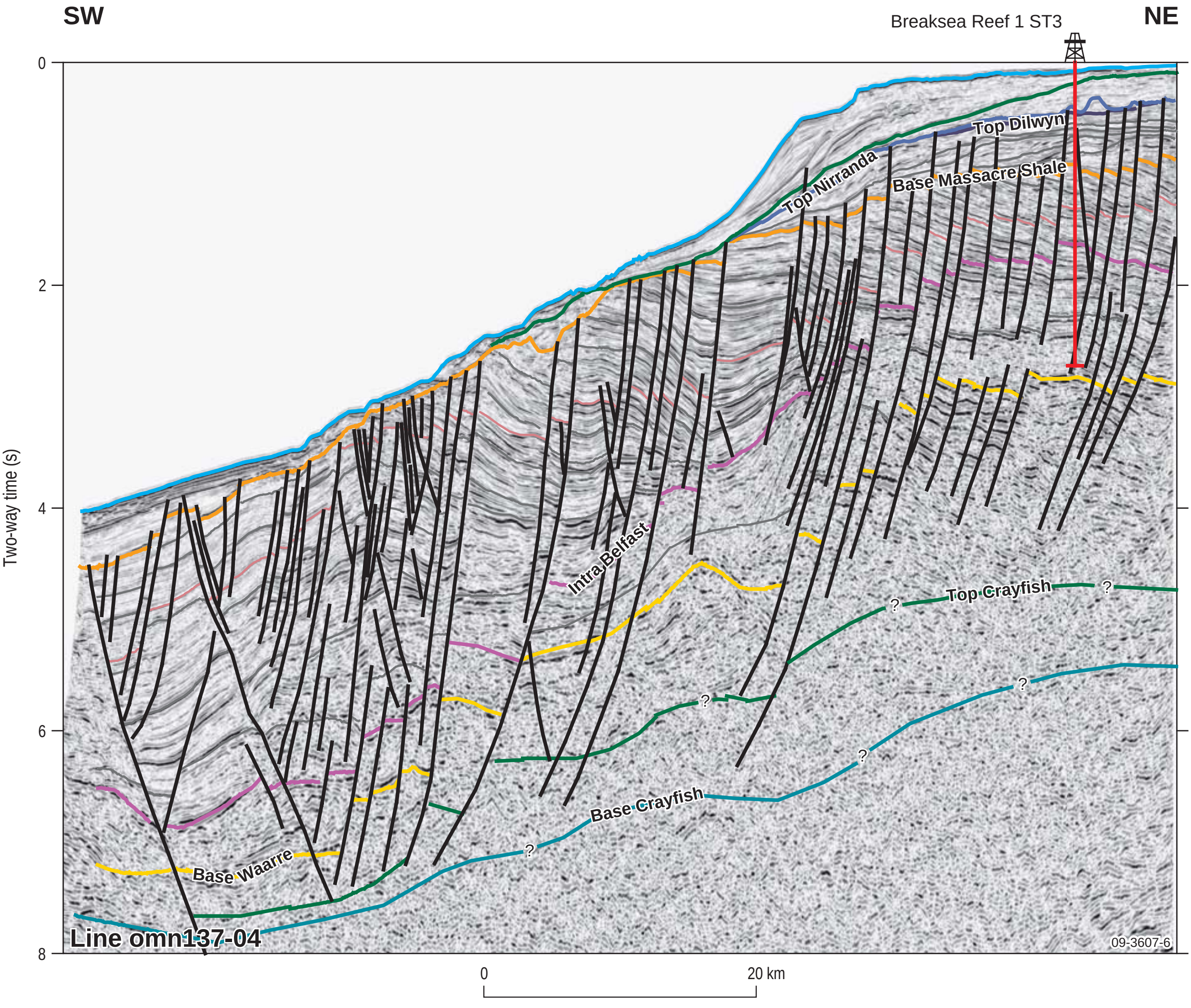

Figure 5. Seismic section through Breaksea Reef 1 ST3, showing structural styles and variations in sequence thickness. Refer to Figure 2 for location of seismic line.