Australian Government

Department of Resources, Energy and Tourism

Release Area NT09-1, Malita Graben, Bonaparte Basin, Northern Territory

Location

Release Area NT09-1 is located within the northeastern portion of the Bonaparte Basin 220 km northwest of Darwin and 40 km south of the Evans Shoal gas field (**Figure 1**). It is close to the Darwin operations base and the Wickham Point LNG plant that is supplied by the Bayu-Undan gas pipeline. Water depths range from 10 m to 170 m over the Release Area. The Release Area lies within the Malita Graben, a major depocentre of the northern Bonaparte Basin (**Figure 2**).

Release Area NT09-1 comprises 75 graticular blocks and covers an area of approximately 6305 km^2, with one well, Beluga 1, drilled within the area.

Release Area Geology

This summary of the regional geology and hydrocarbon potential of the northern Bonaparte Basin draws largely on studies by Mory (1988, 1991), Petroconsultants Australasia Pty Ltd (1990), West et al (1992), West and Miyazaki (1994), West and Passmore (1994), Longley et al (2002a, b), Cadman and Temple (2004), and various papers from the Timor Sea Symposium volume (Ellis et al, 2004).

Local Tectonic Setting

The Malita Graben (**Figure 2**, **Figure 3** and **Figure 4**) is a northeast-trending Mesozoic-Cenozoic depocentre that lies between the Sahul Platform to the north and the Petrel Sub-basin and Darwin Shelf to the south (Mory, 1991). It is a major depocentre bounded on both sides by large displacement normal faults that show some evidence of wrenching. The Malita Graben merges to the east into the Calder Graben where the faults change from northeast-trending to a north-northeast orientation. **Figure 3** is a structure map at the regional unconformity (near top Callovian) showing the extent of the Sahul Syncline, Malita Graben and Calder Graben (Woodside Energy Ltd, 2000). These depocentres are estimated to contain more than 10 km of post-Paleozoic sediment fill (Mory, 1988; West and Passmore, 1994). Release Area NT09-1 is located on the northeastern margin of the Malita Graben. The Calder Graben terminates at the Lynedoch Bank Fault System (**Figure 2** and **Figure 5**), which separates it from the Money Shoal Platform-the westernmost region of the Money Shoal Basin.

The Bathurst Terrace is a zone of shallow basement between the Malita Graben and the Darwin Shelf that consists of a series of narrow fault blocks where Paleozoic and Mesozoic sediments are progressively truncated (Forman et al, 1974; Northern Territory Geological Survey, 1990). The Darwin Shelf is an offshore extension of the Proterozoic Sturt Block (Mory, 1991). It has been subjected to several episodes of peneplanation, and is covered by a thin veneer of Mesozoic and Cenozoic sediments which thicken northwards into the Malita Graben (Northern Territory Geological Survey, 1990).

The Sahul Platform is one of the main tectonic elements in the region, being an area of elevated Paleozoic and Mesozoic sediments (<5000 m thick) that overlie relatively shallow basement (**Figure 2**). It is bounded by the Timor Trough to the north, the Flamingo Syncline to the west and the Malita Graben to the south. Late Miocene to Pliocene convergence of the Australian and Eurasian plates resulted in flexural down-warp of the Timor Trough and the generation of the Kelp and Troubadour (or Sunrise; Longley et al, 2002b) highs, which are separated by the Sikatan Syncline. This syncline is a northwest-trending localised depression with an areal extent of approximately 1500 km^2 that subsided during the late Miocene to Holocene over a pre-existing Paleozoic low.

The Troubadour Terrace is an area of relatively shallow basement that is arbitrarily separated from the Sahul Platform (**Figure 3** and **Figure 4**). The southern boundary of the Sahul Platform is marked by northeast-trending Mesozoic normal faults showing displacement down into the Malita and Calder graben creating a series of prominent blocks and terraces. The largest terrace in the area is the Heron Terrace, which is a perched, down-faulted block covering an extensive area adjacent to the Troubadour Terrace.

Structural and stratigraphic evolution

Regional structuring in the Timor Sea region resulted from episodic tectonic activity since the Precambrian, with sedimentary rocks dating from the Permian to Holocene being penetrated in the region (**Figure 6**). The first rifting in the northern Bonaparte Basin resulted from north-northwest-south-southeast oriented extension during the Pennsylvanian-Cisuralian (Late Carboniferous-Early Permian), which produced the incipient Malita Graben and its respective northeast-trending bounding faults (Shuster et al, 1998).

North-south transpression during the Late Triassic-Early Jurassic Fitzroy Movement resulted in reactivation of the previous extensional fault systems (O'Brien et al, 1993) and associated widespread uplift and erosion along the flanks of the depocentres. Associated changes in river drainage patterns led to a switch in sedimentation from fluviatile coastal plain deposits to continental'red-beds' (Malita Formation).

The area underwent northwest-southeast extension during the Middle-Late Jurassic to Early Cretaceous (Callovian-Berriasian) producing the dominant northeast-southwest structural grain. Although the Late Jurassic sediments are important source rocks elsewhere within the Bonaparte Basin, good quality source rocks have not been penetrated in the axis of the Malita Graben. A relatively thick syn-rift section is interpreted from seismic data to occur in the axis of this depocentre (**Figure 7**).

The Callovian unconformity is recognised throughout the northwest of Australia (Labutis et al, 1998; Pattillo and Nicholls, 1990; McLennan et al, 1990). However, in the northern Bonaparte Basin, the Callovian tectonic event was relatively mild. Nevertheless, the angular unconformity truncates the Plover Formation within tilted fault blocks (**Figure 4**, **Figure 5** and **Figure 6**), with that formation being preserved beneath the transgressive Elang Formation sandstones. Subsequent Kimmeridgian-Tithonian tectonism was a more important component in the tectonostratigraphic evolution of the region, and major block faulting and tilt reversal occurred at this time. Along with the formation of the Malita Graben, this tectonic episode resulted in the formation of structural closure at Chuditch, Evans Shoal and Lynedoch/Barossa (Longley et al, 2002b).

Extension in the late Tithonian-Berriasian formed thick sequences of syn-rift shales and coarse-grained clastics (upper Flamingo Group), the latter providing important reservoir targets.

The Early Cretaceous Valanginian unconformity relates to the onset of sea-floor spreading and the thermal collapse of the Northwest Australian continental margin to form a westerly tilted passive margin. Subsequent transgression resulted in the deposition of marine mudstones of the Echuca Shoals Formation and'Darwin Radiolarite', followed by prograding shelf and slope deposits of the upper Bathurst Island Group (Wangarlu

Formation). This section thickens locally into the Malita and Calder graben and thins markedly onto the Sahul Platform and Money Shoal Platform; the latter being controlled by the Lynedoch Bank Fault System. Eustatic falls in sea level during the Campanian and Maastrichtian resulted in the deposition of a marine siliciclastic sequence with deepening to the northwest. Sandstones of the Puffin Formation are widespread across the Malita Graben and Darwin Shelf (eg 158 m in Heron 1, 409 m in Evans Shoal 1).

Seismic mapping suggests that the Cretaceous structural history varies significantly from the Malita Graben to the Calder Graben, as reflected by major variations of the Aptian-Turonian and Turonian-Maastrichtian isochrons (**Figure 7** and **Figure 8**), suggesting an important structural boundary exists between these two graben.

The westerly tilt, established during the Cretaceous, was maintained throughout the Cenozoic, resulting in the thickening of Paleocene to Miocene sediments along the axis of the Malita Graben. The last phase of tectonism in the area resulted from the Miocene to Holocene collision of the Australia-India and Eurasia plates in the Banda Arc region (Keep et al, 1998, 2002; Shuster et al, 1998). It created the Timor Trough and is responsible for major faulting and reactivation throughout the northern Bonaparte Basin, including the creation of structural closure at Sunrise-Troubadour (Longley et al, 2002b). The resultant structural trends are explained by a combination of strike-slip faulting and flexure induced by oblique convergence and partial subduction of the Australia-India Plate under the Eurasia Plate. Fundamental to this model is that the basement highs (Money Shoal Platform and Sahul Platform) acted as rigid blocks and that the proposed shear (left lateral wrenching) preferentially reactivated the existing structural grain (Shuster et al, 1998). In the Calder and Malita graben this reflects high obliquity of the Banda Arc collision front with the Australia-India Plate motion. The resultant shear stress resulted in major Neogene strike-slip deformation on the Lynedoch Bank Fault System, and also along Mesozoic and older fault zones bounding the Malita Graben (Shuster et al, 1998).

High subsidence rates in the Malita Graben persisted until the Holocene. Total sediment thickness in the Malita and Calder depocentres is unknown, as only the terraces and platform areas have been drilled. However, these depocentres are estimated to contain more than 10000 m of post-Paleozoic sediment fill (Mory, 1988; West and Passmore, 1994).

Stratigraphy

The stratigraphy of the northern Bonaparte Basin has undergone many revisions since the publication of the offshore Bonaparte Basin definitions by Mory (1988), with subsequent formation names being either undefined, used only locally, or the same formation name being used for different stratigraphic units. This has led to a degree of confusion. The stratigraphic correlations between the Malita Graben, Calder Graben and Money Shoal Basin have been updated to the Geologic Time Scale 2004 after Gradstein et al (2004), as shown in **Figure 6**. The stratigraphic correlations are based largely on those by Mory (1988, 1991), using revised biostratigraphy and new well control, but modified to include commonly accepted company terminology; however, an accepted consensus has yet to be reached. The formation names in brackets in the following text are those that have been commonly used in wells within the region.

The oldest sedimentary unit penetrated on the Sahul Platform is the Permian Hyland Bay Subgroup, in which the gas is reservoired at Kelp Deep 1 (Shell Development (Australia) Limited, 1997). The top Permian horizon which marks the top of the Hyland Bay Subgroup is an important seismic event that can be mapped over the entire Bonaparte Basin. In Troubadour 1, a thin section of Lopingian (Late Permian) carbonates were found to overlie granitic basement (B. O. C. of Australia Ltd, 1974). The Hyland Bay Subgroup occurs within the Kinmore Group that comprises (in ascending order) the Fossil Head, Torrens, Pearce, Cape Hay, Dombey, Tern, Penguin and Mount Goodwin formations.

Triassic sediments were deposited during a period of tectonic quiescence related to the foundering of the passive margin associated with the Permo-Carboniferous cycle of rifting (Whittam et al, 1996). The nearest section relevant to Release Area NT09-1 occurs to the west in Troubadour 1 on the Sahul Platform, where Lopingian (Late Permian) to Early Triassic marine siltstones and shales of the Mount Goodwin Formation are conformably overlain by the Sahul Group. The time equivalent of the Sahul Group in the Petrel Sub-basin (and Malita Graben) are the Cape Londonderry Formation and Malita Formation (lower Troughton Group), the latter formation is overlain by the Early to Middle Jurassic Plover Formation (upper Troughton Group). The Troughton Group represents a regressive-transgressive phase of sedimentation and, together with the Sahul Group, forms the Triassic-Jurassic pre-rift sequence in the Bonaparte Basin (Mory, 1991). The Cape Londonderry Formation comprises shallow marine sandstones with lesser abundances of siltstones and claystones. Inversion and uplift in the Late Triassic resulted in the deposition of fluvial redbeds of the Malita Formation. The Cape Londonderry Formation and the Malita Formation are interpreted from seismic as being present within the Malita Graben but they have not been penetrated by any well.

The Early-Middle Jurassic (Hettangian-Callovian) Plover Formation is ubiquitous in the northern Bonaparte Basin, being deposited in the northeast-trending'sag' basin as a transgressive sequence of fluvio-deltaic to marginal marine sediments. The dominant lithology of this formation is sandstone, but significant siltstones and claystones also occur throughout. The sediments thicken markedly into the Malita and Calder graben and they may include good quality source rocks. Where penetrated in the Bonaparte Basin by the early Arco wells, the Plover Formation is referred to as Member C of the Petrel Formation. This term is also used in Shearwater 1 drilled in the Malita Graben.

To the southwest of Release Area NT09-1 in the Vulcan Sub-basin and Cartier Trough, Ambrose (2004a, b) established a four-fold subdivision (Units A to D, in ascending order) of the Plover Formation that is valid as far north as Thornton 1 on the southern margin of the Sahul Platform; there is a transition from this well to more marine facies to the northwest across the Sahul Platform. Coals and coaly shales are developed within the coastal plain-deltaic sediments of Unit C, as defined by Ambrose (2004a), and are important sources of gas within the Mesozoic depocentres of the Bonaparte Basin.

The most complete Plover section relevant to Release Area NT09-1 occurs in Troubadour

1 (300 m thick). Here a basal alluvial-fluvial floodplain section, about 150 m thick, largely comprises upward fining channel sandstone-overbank shale cycles, overlain by braided channel facies. These in turn are succeeded by marine claystones and siltstones overlain by shoreface sandstones. The latter are probably of Bathonian age, and may equate to well developed shoreface sandstones and distributary channel sandstones of the upper Plover Formation intersected in the Evans Shoal accumulation. Here the best quality Plover Formation reservoirs occur in an upper zone of shoreface sandstones (125 m thick at Evans Shoal 1), which comprise fine to coarse-grained pyritic sandstone deposited in several upward coarsening cycles.

The Plover Formation is unconformably overlain by the late Middle Jurassic to Early Cretaceous Flamingo Group, which comprises the Elang Formation, Frigate Shale and the Sandpiper Sandstone. The Flamingo Group includes all of the sedimentary succession above the Callovian breakup unconformity and below the Valanginian unconformity (Mory, 1988, 1991). Where penetrated in the Bonaparte Basin by the early Arco wells, the Frigate Shale and Sandpiper Sandstone are referred to as Members B and A, respectively, of the Petrel Formation. These terms are also used in Shearwater 1 in the Malita Graben. The Callovian to Oxfordian Elang Formation (Laminaria or informal'Jacaranda Formation' in Beluga 1; BHP Petroleum, 1992) is a thin (<50 m thick) transgressive sequence of shallow marine sandstones and claystones. The basal sand-rich, sheet-like section of the formation (*W. digitata* to *R. aemula* dinoflagellate zones) is ubiquitous. The Elang Formation is an important reservoir on the Troubadour High and in the Malita and Calder graben.

The Oxfordian-Tithonian Frigate Shale was deposited in a low-energy marine-shelf to slope environment. It comprises syn-rift deepwater shales with localised turbiditic siltstones and sandstones. The formation is relatively thin on the Sahul Platform (20-30 m thick) and thickens into the Petrel Sub-basin, Malita and Calder graben, and is present in the Money Shoal Basin. For example, in Heron 1 in the Malita Graben, the Frigate Shale is around 375 m thick, but it thins via onlap onto the Troubadour High.

The'Beluga Formation' intersected in Beluga 1 comprises Tithonian-aged bioturbated fine sandstones and coarse siltstones with carbonaceous laminae (BHP Petroleum, 1992; Anderson et al, 1993). These sandstones appear to have been eroded from the Sahul Platform to the north and represent distal shelf and slope fan deposits.

The Sandpiper Sandstone comprises coarse to fine grained sandstones and represents a progradational coastal plain succession (Messent et al, 1994; Robinson et al, 1994; Colwell and Kennard, 1996). The marine depositional environment of the Sandpiper Sandstone shallows into the Money Shoal Basin. The'Tuatara Formation' intersected in Beluga 1 comprises Berriasian-aged sandstones (BHP Petroleum, 1992) and hence is now placed within the upper Sandpiper Sandstone.

The intra-Valanginian unconformity separates the Flamingo Group from the overlying Bathurst Island Group that comprises the Echuca Shoals Formation,'Darwin Radiolarite', Wangarlu Formation and Puffin Formation. Within the Bonaparte Basin, the Bathurst Island Group is thickest in the Petrel Sub-basin, Malita Graben and Calder Graben. The basal glauconitic claystones of the Valanginian to Aptian Bathurst Island Group were originally defined as the Darwin Formation by Mory (1988, 1991). However, most subsequent workers have referred to this Valanginian to Aptian section as the Echuca Shoals Formation, and applied the term'Darwin Formation' to the overlying Aptian to Albian section of radiolarian-bearing calcareous claystones and calcilutites (referred to here as the'Darwin Radiolarite').

The mid-Valanginian to early Aptian Echuca Shoals Formation comprises a condensed section of glauconitic, marine claystones and siltstones. These sediments were deposited widely across the basin as a result of the foundering of the Australian margin following continental break up, sea-floor spreading and subsidence. The dark-grey to black claystones within this formation contain good quality, oil-prone kerogen that provides a potential liquid source within the northern Bonaparte Basin. The peak of the transgression is represented by a condensed sequence of radiolarian cherts, claystones and calcilutites (Whittam et al, 1996; the'Darwin Radiolarite'). The'Darwin Radiolarite' has very high sonic velocities and is a prominent seismic marker in the region that is often used as a'phantom' horizon to determine approximate structure at the'near top Plover' level.

The overlying Wangarlu Formation is a Cenomanian to mid-Campanian progradational sequence that was deposited in a marine shelf to slope environment. The basal section predominantly comprises massive, medium to dark-grey claystones with subordinate siltstones and minor sandstones. These lithologies grade into claystones, calcilutites and marls until the Santonian where sandstones are locally developed in the upper part of the formation. Fine grained carbonates equivalent to the upper Wangarlu Formation are referred to as the Vee Formation in some well completion reports (eg Lynedoch 2). The overlying Campanian to Maastrichtian sequence is a sandstone package with subordinate claystones, and herein is referred to as the Puffin Formation, with the name being derived from the Vulcan Sub-basin (Mory, 1988, 1991; de Boer, 2004). Calcareous claystones equivalent to the Puffin Formation are referred to as the Turnstone Formation in some well completion reports (eg Lynedoch 2). The Puffin Formation sandstones are 410 m thick in Evans Shoal 1 and 377 m in Beluga 1. Their reservoir quality makes them a potential exploration target in the Malita Graben.

The Paleocene to Holocene Woodbine Group comprises the Johnson, Hibernia, Prion, Oliver and Barracouta Shoal formations. The Johnson Formation (Paleocene) and Hibernia and Prion formations (Eocene) regionally consist of shallow water calcilutites (some dolomitised) with minor calcisiltites, calcarenites, cherts and marls. The Hibernia Formation regionally consists of shallow water calcarenites and calcilutites interbedded with marls and calcareous claystones but is absent over much of the Sahul Platform. The Eocene Grebe Sandstone Member is a shallow water sandstone unit within the Hibernia Formation that is present within the Calder Graben, as well as in the Vulcan Sub-basin where it is defined (Mory, 1988; 1991). The late Eocene Prion Formation regionally consists of shelfal carbonates.

Neogene subsidence in the Malita Graben resulted in deposition of a relatively thick Miocene carbonate sequence, the Oliver Formation. This carbonate unit is referred to as the'unnamed carbonate' by Apthorpe (1988) and Mory (1988, 1991). The formation terminates with an unconformity at the top of the Miocene section related to the collision of the Australian-Indian and Eurasian plates. The Pliocene-Holocene Barracouta Shoal

Formation (previously Barracouta Formation but herein renamed to distinguish it from the Barracouta Formation in the Gippsland Basin) unconformably overlies the Oliver Formation and consists of marine carbonates.

Exploration History

The first phase of exploration within the Arafura and Timor seas region occurred from the mid-1950s to the mid-1970s. Petroleum exploration commenced in the Northern Territory near Darwin in 1956 when a gravity survey was conducted on Bathurst Island by Santos Ltd, which resulted in the drilling of Bathurst Island 1 and 2 by Oil Development NL (1960, 1962). In 1958, The Bureau of Mineral Resources (BMR) conducted a gravity traverse from Cape Arnhem to Darwin. Integration of a seismic refraction survey with an aeromagnetic survey, flown over the Melville and Bathurst islands by Alliance Oil Development in 1963, indicated that northwestward thickening Cretaceous sediments were overlying a Precambrian magnetic basement.

The offshore northern Bonaparte Basin was first explored on a regional basis using geophysical and potential field datasets in the mid-1960s to early 1970s, as summarised by Nicol (1970) and Balke et al (1973). Shell Development (Australia) Pty Ltd initiated a regional aeromagnetic survey over the Australian sector of the Arafura Sea in 1965. From 1966 to 1972, Shell Development (Australia) Pty Ltd and Australian Aquitaine Petroleum Pty Ltd conducted numerous seismic surveys over their permits in this region, culminating in the drilling of Money Shoal 1 (Shell Development (Australia) Pty Ltd, 1971). By 1972, a regional seismic grid of 10-20 km, and a semi-detailed grid of 3-10 km, had been compiled and indicated that a thick section of Mesozoic and older sediments existed in the offshore areas of the Arafura Sea. However, these early surveys gave little information below 1.5 secs and could not define prospects.

The first well to be drilled in the Malita Graben was Heron 1 in 1972 by Arco Australia Limited. This well encountered gas shows in Cretaceous to Late Jurassic sediments. This well was followed by Lynedoch 1 in 1973, in which gas indications were encountered in Cretaceous to Late Jurassic (Bathurst Island Group and Flamingo Group) sandstones, and a strong gas show recorded from an Early Cretaceous fractured limestone. Shearwater 1 was drilled in 1974 by Arco Australia Limited, 71 km west of Heron 1, but did not encounter any significant hydrocarbons.

In 1974 to 1975 the Troubadour and Sunrise gas-condensate accumulations were discovered by B. O. C. of Australia Limited in the Plover Formation. However, a dispute between Australia and Indonesia over sovereignty in 1975 halted further exploration until 1985 when the area was re-gazetted. It was not until the Timor Gap Treaty, establishing the Zone of Co-operation (ZOCA), was signed by the respective governments in 1991 that significant exploration continued within the region (Longley et al, 2002a; Seggie et al, 2000; 2003).

A second phase of exploration took place in the northern Bonaparte Basin in the mid-1980s to early 1990s, with the acquisition of more detailed seismic data over the Malita and Calder graben by Western Mining Corporation and BHP Petroleum Pty Ltd (BHP), an aeromagnetic survey by BHP, an airborne laser fluorescence survey (ALF) by BP Australia Pty Ltd, and the drilling of four wells. Jacaranda 1 (1984) and Darwinia 1A (1985) were drilled on the southeasternmost flank of the Malita Graben by Tricentrol Exploration Overseas Limited, and encountered minor gas indication. Evans Shoal 1 (BHP Petroleum Pty Ltd, 1989) encountered gas in the Plover Formation, proving gas charge from the graben. This discovery is now classed as a gas accumulation with P50 reserves of 8.3 Tcf gas (Department of Regional Development, Primary Industries, Fisheries and Resources [RDPIFR], 31 December 2007). Beluga 1 was drilled in 1991 (BHP Petroleum Pty Ltd, 1992) tested a structural/stratigraphic play on the southeastern margin of the East Malita Graben and encountered gas shows in tight Flamingo Group sandstones.

A third exploration phase in Australian waters was initiated in the late 1990s to 2000 by Shell Development (Australia) Limited, Woodside Energy Ltd and Woodside Offshore Petroleum Pty Ltd. Acquisition of new seismic and reprocessing of existing seismic data preceded the drilling of several wells by Shell Development (Australia) Limited in 1998 throughout the Malita and Calder graben. Evans Shoal 2 was a gas appraisal well, proving favourable deliverability from Plover Formation reservoirs with gas flows of 25 MMscf/d. Also within the Plover Formation, a proven gas zone was discovered at Chuditch 1, whereas Lynedoch 2 encountered a tight gas column. Wonarah 1, which targeted Late Cretaceous intra-Wangarlu Formation sandstones, did not encounter any significant hydrocarbons. During 1995 to 1998 Shell Development (Australia) Limited (1998a), Woodside Energy Ltd (1999) and Woodside Offshore Petroleum Pty Ltd (1995, 1998, 1999) appraised the Troubadour and Sunrise accumulations. Tyche 1 was the last well drilled by Woodside Energy Ltd and Shell Development (Australia) Pty Ltd (2000) in the region at this time. The well targeted a shallow stratigraphic play, but the well was plugged and abandoned without encountering significant hydrocarbon shows.

Drilling also occurred in Indonesian waters, with Abadi 1 being drilled in 2000 by Inpex Masela on the northeastern edge of the Sahul Platform. The well discovered a 73 m gas column within the Elang and Plover formations. A 3D seismic survey and two more wells (Abadi 2 and Abadi 3) in 2002 appraised the accumulation, which is reported to contain 5 Tcf gas with a 6-8% carbon dioxide content (Yui, 2003). A further four well appraisal drilling program is nearing completion (Energy Current, 12 July 2007).

The most recent exploration phase in Australian waters has occurred since 2005 and continues to the present day. ConocoPhillips Exploration Australia Pty Ltd (ConocoPhillips) drilled Caldita 1 in 2005, which resulted in a gas discovery with flow rates of 33 MMscf/d from reservoirs within the Plover Formation (Ottoman, 2005). This large gas field (initial recoverable reserves of 2.9 Tcf gas, RDPIFR, 31 December 2007) was further evaluated by the appraisal well Caldita 2 in 2007. ConocoPhillips also appraised the Lynedoch structure with the drilling of Barossa 1 ST1 in 2006. Gas flowed at 30.1 MMcf/d (with a CGR of 7 to 9 bbls/MMscf) from Barossa 1, which has greatly improved assessments of reservoir deliverability (Petroleum News, 29 November 2006); however, determining the areal extent of productive reservoir facies requires further appraisal drilling. Exploration in the vicinity of the Evans Shoal accumulation continued with the drilling of Evans Shoal South 1 in 2006 by Santos Offshore Pty Ltd.

The recent drilling programme by MEO Australia Ltd commenced in October 2007 with Heron 2 ST1, located 2.6 km south-southeast of Heron 1. The well flowed gas from the Elang Formation, but the Plover Formation was not tested due to drilling problems (Petroleum News, 21 January 2008; Geary, 2008). Blackwood 1 ST1 commenced drilling in February 2008 and encountered gas within the Flamingo and Plover formations

(Petroleum News, 17 March 2008; Geary, 2008).

This revival of exploration in the Bonaparte Basin is partly due to gas becoming an economically exploitable commodity and also the commissioning of the Wickham Point LNG plant near Darwin. This facility is fed by gas from the Bayu-Undan field in the Timor Sea and operated by ConocoPhillips Australia Exploration Pty Ltd and joint venture partner Santos Ltd. The plant has environmental approvals to produce up to 10 million tons per annum (MMtpa) LNG (ie three times its current capacity of 3.5 MMtpa). ConocoPhillips is targeting first production from a second train at the Darwin LNG facility by around 2014-15, with gas to be potentially sourced from either/or the Greater Sunrise and Caldita accumulations (Petroleum News, 18 July 2008). Options under consideration for the commercialisation of gas from the Woodside Petroleum-operated Greater Sunrise accumulation is via either liquefaction in Darwin or a floating LNG facility (Petroleum News, 31 July 2008).

MEO Australia Ltd has environmental approval for a proposed methanol plant on Tassie Shoal, located about 275 km north of Darwin. Tassie Shoal is an area of shallow water adjacent to the Evans Shoal gas field. In addition to the Tassie Shoal Methanol Project (TSMP), the company has approvals for a 3 MMtpa LNG plant to be co-located with the two methanol trains (Petroleum News, 17 March 2008). Updates of drilling activity, reserves and production can be found in'Oil and Gas Resources of Australia' (Geoscience Australia , 2005).

In summary, 15 wells have been drilled on the eastern part of the Sahul Platform, the Malita Graben and the Calder Graben: of these wells, 9 are hydrocarbon discoveries, giving a technical success of 60% and a 33% historical success rate for accumulations greater than 1 Tcf (5 discoveries). To date, over 20 Tcf of gas with several hundred million barrels of condensate reserves have been proven within this region. These statistics do not include the Abadi gas accumulation in Indonesian waters of the Calder Graben.

Well Control

One well, Beluga 1 (1991), has been drilled in Release Area NT09-1, and encountered minor gas shows. A significant number of hydrocarbon discoveries and appraisal wells have been drilled in permits near to Release Area NT09-1, including; Lynedoch 1, 2, Barossa 1 ST1, Chuditch 1, the Greater Sunrise wells, Evans Shoal 1, 2, Evans Shoal South 1, and Caldita 1 and 2. Exploration has continued in this area with the recent drilling of Heron 2 ST1 and Blackwood 1 ST1; both wells discovered gas. Further afield to the west, Chuditch 1 also discovered gas. Three other wells have been drilled in the region; Tyche 1 to the north, and Shearwater 1 and Wonarah 1 to the west. None of these wells encountered significant hydrocarbons.

NOTE: Formation names and terms shown in square brackets are updates of the information presented in the well completion reports.

Heron 1 (1972)

Heron 1, drilled by Arco Australia Limited (1972) 169 km northwest of Bathurst Island, was the first well drilled in the Malita Graben. The primary objective of the well was to investigate the hydrocarbon potential of Mesozoic and Permian sediments. It specifically targeted an Early Cretaceous reservoir in the Bathurst Island Formation [Bathurst Island Group] in a seismically-defined, low relief, faulted anticlinal structure identified at near top Jurassic level and base Cenozoic level.

The well penetrated a thick Cenozoic to Late Jurassic succession of sedimentary rocks and reached a total depth (TD) of 4209 mKB within the Petrel Formation [Flamingo Group]. Vertical closure for the structure is based on closure mapped at the Aptian unconformity (Shell Development (Australia) Limited, 1998a). The lower part of the well penetrated competent shales and minor sandstones. Due to slow penetration rates, lack of porosity (0.6-6.2%) and permeability (<0.1 mD) in the penetrated sandstones, and junk in the hole, drilling was terminated before reaching the programmed total depth of 4724 mKB. A high bottom hole temperature, approaching 204.5°C, was measured in Heron 1.

Gas indications were encountered from 1158 mKB in sediments of Late Cretaceous age to TD, with the most significant gas shows occurring within Early Cretaceous to Late Jurassic sediments from 2824 to 4209 mRKB [Darwin Radiolarite, basal Echuca Shoals Formation and Elang Formation]. However, due to technical problems and lack of quality reservoirs, none of the gas-bearing zones were tested. It has since been reported by MEO Australia that a 52 m gas-bearing column is interpreted to be present within the Darwin Formation ('Darwin Radiolarite': Petroleum News, 18 January 2007).

Lynedoch 1 ST1 (1973)

Lynedoch 1 was drilled by Shell Development (Australia) Pty Ltd (1973) about 350 km north-northwest of Darwin. It was the first well drilled in the Calder Graben, and the second well to be drilled in the northern Bonaparte Basin. The well targeted a seismically-defined, low-relief anticlinal structure mapped at the near base-Albian seismic horizon (labelled'P' in the well completion report, or base of the limestone unit within the Darwin Formation, and interpreted as the Aptian Disconformity by Shell Development (Australia) Limited (1998b)). There was no closure at either the Late Cretaceous or Cenozoic levels.

Lynedoch 1 was sidetracked when the drill pipe became stuck in tight Cretaceous shales and a fish was lost in the hole. The sidetracked well was logged. Lynedoch 1 ST1 penetrated a thick Cenozoic to Jurassic succession of sedimentary rocks and reached a TD of 3967 mRT within Valanginian (Oxfordian in WCR) sediments [Flamingo Group].

A thin (9.7 m) gas-bearing zone was encountered within a limestone unit (3674-3715 mRT) of the Bathurst Island Group ['Darwin Radiolarite'], but it was not tested. Methane to butane was reported in the gas kick at 3698 mRT. Porosities range from 8 to18% over a depth of 3689-3715 mRT, with low gas saturation occurring in the matrix and higher gas saturation occurring in the fractured zones. Log analysis indicates a further zone of possible gas saturation in water-bearing sandstones of the uppermost Jurassic section [upper Flamingo Group]. Due to the thinness of the Bathurst Island Group limestone reservoir and the presence of tight Jurassic sandstones in this well, the Mesozoic structures in this area were interpreted to be uneconomic for hydrocarbons.

Shearwater 1 (1974)

Shearwater 1 was drilled in 1974 by Arco Australia Limited (1975) 68 km west of Heron 1 to evaluate the hydrocarbon potential of Jurassic sandstones. The well was drilled on a large, faulted anticlinal feature at near base Cretaceous and near base Cenozoic levels on the northern margin of the Malita Graben. The structure is a northeast-trending horst that was formed in association with the subsidence of the Malita Graben in the Late Jurassic.

The well penetrated a thick Cenozoic to Jurassic succession of sedimentary rocks and reached a TD of 3177.54 mKB within the Petrel Member C-equivalent [Plover Formation]. The well was terminated prior to the programmed TD of 3657 mKB, as a result of the slow penetration rate, lack of porosity, absence of hydrocarbon indications and high water saturation. The only hydrocarbon shows reported were scattered traces of dead oil staining at 3124-3131 mKB within the Petrel Member C-equivalent [Plover Formation]. In addition to the lack of reservoir development, Shell Development (Australia) Limited (1998b) interpreted the well as an invalid structural test at the Intra-Valanginian unconformity.

Jacaranda 1 (1984)

Jacaranda 1 was drilled by Tricentrol Exploration Overseas Limited (1984) to test the Late Jurassic Petrel Formation [Flamingo Group] sandstones in a four-way dip closure on the northern downthrown side of the southern Malita Graben. The well was located to receive hydrocarbons migrating southwards from the depocentre.

The well intersected Late Jurassic sandstones of the Petrel Formation [Flamingo Group] and reached a TD of 3783 mRT in Jurassic sandstones [Plover Formation]. All these potential sandstones were tight, fine-grained and water-wet. Two water-wet sandstones of Late Cretaceous (Campanian and Santonian) age were encountered with good reservoir characteristics, but these are believed to be outside of mapped closure (Tricentrol Exploration Overseas Ltd, 1985).

Gas indications were encountered in argillaceous siltstones and sandstones throughout the Cretaceous and Late Jurassic section, with the most significant shows occurring in the Flamingo Group [Sandpiper Sandstone and Elang Formation], but no tests were undertaken. Fluorescence was observed throughout cuttings samples from 3550-3610 mRT [Elang Formation]. Fluorescence was also observed in a dark solid material that was distributed in pores and along bedding planes at 3575 mRT, and interpreted to be either kerogen or bitumen. A core cut at 3766-3766.13 mRT [Plover Formation] yielded a dark carbonaceous material (TOC=4.24%), but no extractable organic matter was recovered upon solvent extraction. No other hydrocarbon indications were noted to TD.

In summary, the objective reservoir sandstones show reduced porosity through diagenesis. The Jacaranda feature is interpreted to have formed primarily in the Cenozoic and has therefore post-dated major hydrocarbon expulsion from the Malita Graben (Botten and Wulff, 1990). Thus, the validity of the trap is in doubt.

Darwinia 1, 1A (1985)

Darwinia 1 was drilled by Tricentrol Exploration Overseas Limited (1985) in the southeastern part of the Malita Graben, 25 km west of Jacaranda 1. The well was designed to test two Late Cretaceous sandstones, both with a small four-way dip closure and a larger fault-dependent closure. A major fault, antithetic to the southern bounding fault zone of the Malita Graben, was interpreted as the main conduit for vertically migrating hydrocarbons. The Late Jurassic shales present in the central graben (intersected by Heron 1) are predicted to provide the top seal.

Darwinia 1 was drilled to 657 mKB and respudded as Darwinia 1A due to mechanical difficulties. Darwinia 1A reached TD at 2426 mKB in Cenomanian claystones of the Bathurst Island Group before being plugged and abandoned. Minor gas indications were encountered in Late Cretaceous sediments. Although the objective Late Cretaceous sandstones had excellent porosities and permeabilities they were all water wet. As the trap could possibly have been breached by late faulting, there is some doubt as to whether Darwinia 1A tested a valid structure.

Evans Shoal Gas Field

Evans Shoal 1 (1988), Evans Shoal 2 (1998).

Evans Shoal 1 is the discovery well for the Evans Shoal gas field, which is drilled on a terrace north of the Malita Graben (BHP Petroleum Pty Ltd, 1989). Evans Shoal 2 was the appraisal well drilled by Shell Development (Australia) Limited (1998b) to determine the gas-water contact, deliverability of the reservoir, and gas volume and composition. This well established the continuity of good quality, gas-bearing, upper Plover Formation reservoirs in the Evans Shoal structure, which has P50 reserves of 8.3 Tcf (RDPIFR, 31 December 2007).

Evans Shoal 1 (1988)

Evans Shoal 1 was drilled in 1988 on a terrace north of the Malita Graben (BHP Petroleum Pty Ltd, 1989). The well was sited on 2D seismic datasets of mixed vintage (1965 to 1988). It tested a large horst block with a low relief, drape-anticlinal structure mapped at top Middle Jurassic level and sealed by Late Jurassic-Early Cretaceous claystones. Basal Late Jurassic sandstones were a potential secondary target. The structure formed during the Late Jurassic-Early Cretaceous and had the potential of being filled with hydrocarbons migrating from the Malita Graben prior to porosity occlusion by quartz overgrowths, as seen in Heron 1 and Lynedoch 1. As no faults were interpreted to penetrate the Albian/Aptian disconformity on the structure, the risk of seal failure was greatly reduced.

The drilled section closely matched the predicted section, although the target horizon came in at 3543 mKB, some 110 m lower than predicted owing to thicker than anticipated Albian carbonates. The well reached a TD of 3712 mKB in Bathonian claystones of the Plover Formation.

Gas was recorded throughout the well, with gas concentrations increasing from the Bathurst Island Group claystones to TD. High gas readings in Albian carbonates ['Darwin Radiolarite'] suggest the presence of gas within fracture porosity. The most significant gas shows were recorded in low porosity sandstones of the Plover Formation and overlying Flamingo Group. However, the relatively high mud weight (SG 1.25) led to an overbalance of approximately 1000 psi at top reservoir level, which may have suppressed the gas readings in the Plover Formation. The presence of gas was confirmed on wireline logs, which indicated that at least a 167 m gross gas column (34 m of net gas pay; BHP Petroleum Pty Ltd, 1992) was present, without having penetrated the base of the column. Repeat Formation Tests (RFTs) recovered dry gas from 3554 m and 3678 mKB, but the third test at 3613.8 mKB failed. Traces of a fluorescent oil scum in some RFT samples are attributed to contamination.

Parameters obtained for the fine- to very fine-grained sandstones of the Plover Formation reservoir are; gross 169.5 m+ (base not drilled), net 33.7 m, net/gross=20%, average log porosity=8.3%, with a maximum of 12%, and average log water saturation (Sw)=12% to 23.7%. A short core cut at TD in a fine-grained section yielded measured porosities of 1.7-5.2% and permeabilities of 0.01-1.0 mD, with two plugs with vertical fractures recording 253 and 581 mD, respectively. In the reservoir, diagenetic destruction of the primary porosity by quartz overgrowths and minor pyrite and spar calcite has probably been enhanced by the high temperature in the well.

Production testing was not considered given the high temperature in the well (BHT=170°C at 3700 mRKB), indicating an absence of liquid hydrocarbons, and the low porosity of the reservoir. The high geothermal gradients are a regional phenomenon and preclude the likely generation or preservation of liquid hydrocarbons below approximately 2.5 km (assuming a maximum temperature of 130°C for which liquid hydrocarbons may be preserved).

Source rock analyses indicate that the Early Cretaceous (Aptian) to Late Jurassic claystones (3455-3542 m) are generally moderately rich in total organic carbon (TOC=0.81-2.29%) with both oil- and gas-prone kerogen. The Middle Jurassic section has a variable TOC content (0.3-3.6%), also containing both oil- and gas-prone kerogen. Maturation studies suggest that the gas could have been derived from either Jurassic or Early Cretaceous rocks in the vicinity of the well or further down-dip. The well was plugged and abandoned as a gas discovery.

Evans Shoal 2 (1998)

Evans Shoal 2 reached a TD of 3940 mDF in the Plover Formation and the well was plugged and abandoned as a successful gas appraisal well. The well confirmed the presence of a 229 m gross gas column in Jurassic sandstones of the Plover Formation (>360 m thick), sealed by Cleia Formation [Frigate Shale] claystones. Gas indications were recorded throughout the Bathurst Island Group to TD. The reservoir quality of the Plover Formation was slightly better than predicted with some high quality zones with porosities ranging up to 15-20%, with net/gross ratios of 60-70%. This is different to the reservoir properties encountered in Evans Shoal 1 where the best quality reservoir occurred in the upper section. Reservoir performance measurements in DST 1 (3633-3715 mDF) established a maximum stable flow rate of 25.5 MMscf/d at 2080 psi on a 52/64" choke. DST 1A, undertaken over the depth range 3580-3609.5 mDF, flowed gas at a rate of 5.5 MMscf/d. The measured CGR was low (3.6 bbls/MMscf gas) and a high non-combustible gas content (27% CO_2, 0.5% N_2 and 34 ppm H_2S) was reported for the natural gas. The condensate density was 52.4°API.

Beluga 1 (1991)

Beluga 1 was drilled in 1991 some 150 km southeast of Evans Shoal 1 on the Bathurst Terrace that flanks the southern Malita Graben (BHP Petroleum Pty Ltd, 1992). The well was drilled to evaluate a structural/stratigraphic play comprising a Late Jurassic sand-dominated fan (referred to as the Beluga Sequence), sealed by the transgressive marine claystones of the Flamingo Group. The closure is modified to the southeast by down-to-the-basin normal faulting. The results from this well are discussed in detail by Anderson et al (1993), but they do not use the same informal stratigraphic nomenclature ('Jacaranda','Beluga' and'Tuatara' formations) presented in the well completion report.

The well reached a TD of 3100 mKB in the Plover Formation and encountered gas indications in the Bathurst Island Group, and gas shows within the Flamingo Group and Plover Formation. The most significant gas shows and hydrocarbon fluorescence was encountered in tight Flamingo Group argillaceous sandstones within the Beluga Sequence [Sandpiper Sandstone]. The Beluga Sequence comprises distal shelf and slope fan sands. Log analysis indicates that potential reservoir sands were encountered in the upper section of the Flamingo Group over the interval 2520-2543 mKB (11-16% porosity; informal'Tuatara Formation'). These sandstones are interpreted to have been deposited as channel fill in a shallow marine setting. The lower Flamingo Group sequence (informal'Beluga Formation'), the primary reservoir objective in the Beluga closure, was deposited in a distal shelf or upper slope environment, away from the clastic source. Abundant detrital clays, silica and minor carbonate cements and physical compaction account for the low porosity (average 10%) and very low permeability (<1 mD) of this sequence. Dip analysis suggests that the dominant direction of sediment transport was to the south such that the majority of the Flamingo Group sediments were derived from the Sahul Platform to the north and transported across a broad continental shelf. This sequence does not represent a viable reservoir objective in this distal setting due to the high amount of detrital argillaceous material, but may be satisfactory in more proximal facies to the north. Furthermore, quartz sandstones of the fluvial to shallow marine Plover Formation were also found to be tight due to silica cement and quartz overgrowths (average porosity 6%).

Tithonian outer shelf to upper continental slope fan sediments derived from the north ('Beluga Formation') were deposited on uplifted and eroded shallow marine deltaic sediments of late Callovian-Oxfordian age ('Jacaranda Formation'). Transgressive marine claystones subsequently onlapped the Tithonian sequence to create the potential stratigraphic closure. During the late Tithonian to Berriasian a series of progradational/aggradational cycles progressively filled a broad shallow basin. Towards the end of the Berriasian the onset of basin inversion is indicated by a change in sediment transport direction (derived from the south/southeast) and normal faults parallel to the graben margin which show increasing displacement stepping to the north. The combination of depositional setting and structural inversion rotated the Beluga feature down to the northwest and produced the potential for a closed feature. Base seal, which was considered a significant pre-drill risk, was provided by the base of the coarsening-upward'Beluga Formation'.

Source potential of the Late Jurassic to Early Cretaceous claystones was found to be relatively poor, showing an affinity for the generation of gas to light oil. The Middle Jurassic Plover Formation is considered to be early mature, based on a vitrinite reflectance measurement of 0.6%.

The apparent sediment source direction for the Late Jurassic sequences and present structural geometry indicates that significant basin inversion occurred during the latest Jurassic to Early Cretaceous. The majority of the Flamingo Group sediments have been derived from the north, probably from the Sahul Platform. Poor reservoir quality of the lower Flamingo Group sandstones reduces the prospectivity for similar play types in this area, but improved reservoir potential is predicted to the north along the northern margin of the Malita Graben.

Chuditch 1 (1998)

Chuditch 1 was drilled in 1998 by Shell Development (PSC 9) Pty Ltd on the southern margin of the Sahul Platform, some 14 km southwest of Shearwater 1. It tested a mapped structural closure at the Plover Formation level. The play relies on Miocene-Pliocene timing for oil generation, migration and entrapment (Shell Development (PSC 9) Limited, 1999).

The well reached a TD of 3035 mDF in the Plover Formation and encountered a 25 m gas column with a free water level (FWL) at 2945 mDF. P50 gas reserves are estimated to be 0.7 Tcf gas (TSDA, 2007). Condensate volumes were initially estimated at 15bbls/MMscf gas; however, after correcting for the oil-based mud used, the liquid content decreased markedly to 0.7 bbls/MMscf gas. Hydrocarbon indications were difficult to determine due to the use of synthetic based drilling mud and all shows must be considered questionable. Fluorescence was encountered in cores and cuttings from 2919 to 2979 mDF. No drill stem tests were conducted. Formation pressure tests and samples were taken using MDT. In total, 30 pressure readings were attempted and six samples were collected.

Lynedoch 2 (1998)

Lynedoch 2 was drilled 8.5 km southwest of Lynedoch 1 in 1998 by Shell Development (Australia) Limited (1999a). The primary objective was to test the Middle Jurassic Plover Formation, with the Early Cretaceous Darwin Formation ['Darwin Radiolarite'] as the secondary objective. The claystones and marls of the Wangarlu and Vee formations (Bathurst Island Group) provide vertical and lateral seals.

The well reached a TD of 4225 mDF within the Plover Formation. Although gas was encountered, after completion of final logging, the well was plugged and abandoned as a dry hole.

The succession penetrated at Lynedoch 2 was as expected from Lynedoch 1, with the exception of the presence of the Elang Formation and the absence of the Cleia Formation [Frigate Shale]. The well encountered 123 m of potential Plover Formation reservoir; however, the quality of the sandstones was slightly poorer than predicted, with porosities ranging from 2.4 to 8.7% and a net/gross of 50% (with a 5% porosity cut off). Hence it is not considered a viable reservoir and no production testing was carried out.

The total gas ranged from negligible to 0.9% in the Turnstone [Puffin Formation] and Vee formations [upper Wangarlu Formation] and contained only methane. In the underlying Wangarlu Formation, the total gas ranged from 0.025 to 0.3% of methane and ethane. Throughout the Darwin Formation ['Darwin Radiolarite'] the total gas increased from 0.04% to a peak of 7.26% at 3802 mDF with methane to pentane recorded. In the Echuca Shoals Formation, the total gas ranges from 0.3 to 64.5% at 3859 mDF, and contains methane to pentane. The Elang and Plover formations had total gas measurements ranging from 0.2 to 2.0% and contained methane to pentane. Gas wetness ratios (C_2-C_4 /C_1-C_5) from the lower Darwin Formation ['Darwin Radiolarite'] to the Plover Formation were high (7-50%). Trace weak, dull orange fluorescence was observed between 4163-4173 mDF and 4212-4215 mDF.

Wonarah 1 (1998)

Wonarah 1 was drilled in 1998 by Shell Development (Australia) Pty Ltd, 74 km west of Evans Shoals 1. The primary objective was the Late Cretaceous intra-Wangarlu Formation sandstones within a stratigraphic trap identified by an AVO anomaly. The Paleocene Johnson Formation was the secondary objective (Shell Development (Australia) Limited, 1999b).

The well penetrated a Cenozoic to Cretaceous section, reaching a TD of 2800 mDF in claystones of the Wangarlu Formation. No significant hydrocarbons were encountered and the well was plugged and abandoned as a dry hole. All formation tops came within the tolerance levels set in the well prognosis. However, Wangarlu Formation sandstone reservoirs were not intersected in the well. Hence, the Wangarlu play is not a viable target in this area. No testing was undertaken since fluorescence shows were not observed from cuttings or sidewall cores and total gas values were negligible (peaking at 0.1%). The AVO anomaly appears to be an artefact of seismic processing.

Tyche 1 (2000)

Tyche 1 was drilled by Woodside Energy Ltd on behalf of Shell Development (Australia) Pty Ltd (2000) and is located 53 km northwest of Lynedoch 1 and 5 km south of the Australia/Indonesia boundary. The objective of the well was to test the hydrocarbon prospectivity of a Cenozoic stratigraphic amplitude anomaly, interpreted to be associated with potential reservoir sands in a stratigraphic pinchout of the Oligocene Cartier Formation [Oliver Formation]. Due to the potential size of the accumulation and perceived overpressuring, the well was located within the lower 40 m of mapped closure. Lateral and top seal was to be provided by Miocene and Oligocene calcarenites and calcilutites, and base seal from the Hibernia Formation carbonates.

The well reached the planned TD of 1475 mRT in calcarenites of the Hibernia Formation without encountering significant indications of hydrocarbons and was plugged and abandoned as a dry hole. Total gas values ranged from 0-0.021% with only minor methane recorded over the depth range 1160 mRT to 1475 mRT. No hydrocarbon fluorescence was described in the well. The absence of hydrocarbons is not seen as a lack of charge to the trap but it is more likely that the sands have not retained evidence of migrating hydrocarbons due to their highly unconsolidated nature.

Caldita 1 (2005)

Caldita 1 was drilled in 2005 by ConocoPhillips Exploration Australia Pty Ltd, some 35 km south-southwest of Lynedoch 1. The well targeted Elang and Plover sandstones within a large faulted anticline (ConocoPhillips Australia Exploration Pty Ltd, 2006). Caldita 1 is reported as a gas discovery, having a'significant' gas column (Petroleum News, 25 October 2005) that on test flowed at a rate of up to 33 MMscf/d (DST 2, 3765.5-3775.4 mRT). The accumulation has P50 reserves of 2.9 Tcf of gas (RDPIFR, 31 December 2007).

It reached a TD of 4037 mRT within the Plover Formation, with a calculated extrapolated static bottom hole temperature of 166.39°C, with a temperature gradient of 3.8°C per 100 m (seabed temperature was 12.1°C, as measured by a remotely operated vehicle (ROV) (ConocoPhillips Australia Exploration Pty Ltd, 2006). The interpretation report for this well is currently confidential and no further information is available.

Barossa 1 ST1 (2006)

Barossa 1 ST1 was drilled in 2006 by ConocoPhillips Exploration Australia Pty Ltd in petroleum exploration permit NT/P69 to test the Lynedoch prospect. The Lynedoch 1 and 2 wells are located 6.5 km and 19.5 km to the east-northeast respectively. The prospect is a large faulted structure on the eastern margin of the Sahul Platform (ConocoPhillips Australia Exploration Pty Ltd, 2007a). The structure has P50 reserves of 2.7 Tcf of gas (RDPIFR, 31 December 2007). The gas contains high levels of carbon dioxide (16%) and has a low liquid content.

Barossa 1 reached a TD of 3435 mRT before being sidetracked as Barossa 1 ST1 to a TD of 4310 mRT because of overpressuring (ConocoPhillips Australia Exploration Pty Ltd, 2007a). The calculated extrapolated static bottom hole temperature is reported as 163°C, with a temperature gradient of 3.73°C per 100 m (seabed temperature was 12.1°C, as measured by ROV).

Two drill stem tests were conducted over the Elang and Plover formations (ConocoPhillips Australia Exploration Pty Ltd, 2007a). The first test, of a lower-quality reservoir between 4000 to 4148 mRT, flowed gas at a rate of approximately 0.8 MMcf/d through a one-inch choke. The second test, of a higher-quality reservoir over 3946 to 3982 mRT, flowed gas at a rate of approximately 30.1 MMcf/d through a 56/64" choke, with a condensate rate of 7 to 9 bbls/MMscf gas (measured at the rig site). The gas flow rate test was constrained by limitations of the surface equipment (Petroleum News, 29 November 2006). The interpretation report for this well is currently confidential and no further information is available.

Evans Shoal South 1 (2006)

Evans Shoal South 1 was drilled by Santos Ltd (Pitman, 2006) in Permit NT/P48, 17 km southeast of Evans Shoal 1 in about 100 m water depth. The well tested a large three way dip closure against a major fault that separates the Sahul Platform from the Malita Graben. The structure relies on top and cross fault seal by the Flamingo Formation [Frigate Shale] claystones. The primary reservoir objectives were the Elang and Plover formations and the secondary reservoir objective were sandstones within the Flamingo Group. A gas charge was predicted from the Plover Formation, with additional source potential from the Frigate Shale and Flamingo Formation [Flamingo Group] (Pitman, 2006). P50 gas reserves of 0.074 Tcf are reported for the structure (RDPIFR, 31 December 2007).

The well reached a TD of 4097 mRT and encountered gas. The Flamingo Group and Elang Formation reservoirs were not tested. The Plover Formation was not penetrated due to poor hole conditions, and the well was plugged and abandoned before the target depth of 4225 mRT was reached (Petroleum News, 24 July 2006). A maximum well temperature of 175.5°C was recorded from a FMT test carried out over 47.5 hours over the depth range 4067.15-4034.3 mRT (Pitman, 2006). The interpretation report for this well is currently confidential and no further information is available.

Caldita 2 (2007)

Caldita 2 was drilled in 2007 by ConocoPhillips Australia Exploration Pty Ltd in Permit NT/P61 as an appraisal well of the Caldita accumulation after the acquisition of a 3D seismic survey. Caldita 2 is located 6 km west-northwest of Caldita 1, and the primary objectives were the Elang and Plover formation reservoirs as intersected in the discovery well (ConocoPhillips Exploration Australia Pty Ltd, 2007b).

The well was drilled in a water depth of 136.5 m and reached a TD of 3972 mRT (ConocoPhillips Australia Exploration Pty Ltd, 2007b). It confirmed the presence of gas in the western part of the Caldita structure (Petroleum News, 9 February 2007), and is reported as a'modest-sized' gas column (NT DPIFM, 2007). No testing was carried out on this well. The interpretation report for this well is currently confidential and no further information is available.

Heron 2 ST1 (2007)

Heron 2 ST1 was drilled by MEO Australia Ltd in Permit NT/P68 as an appraisal of the Heron 1 well. The primary target was the fractured carbonates of the Darwin Formation within the mapped Epenarra Prospect, and secondary targets were the Elang and Plover formations (Petroleum News, 21 January 2008).

Heron 2 reached a TD of 4182 mRT before being sidetracked due to mechanical difficulties (Geary, 2008). Heron 2 ST1 reached a TD of 3967 mRT (shallower than the main well). Heron 2 is reported as a gas discovery within the Elang and Plover formations (Geary, 2008). The gas saturated Darwin Formation was perforated and treated with two acid wash procedures, but the well failed to flow gas to the surface (Petroleum News, 21 January 2008). Despite the Elang Formation sandstones being of poor quality, gas flowed to the surface on production testing at a maximum rate exceeding 6 MMscf/d (Petroleum News, 21 January 2008; Geary, 2008). The well intersected 202 m of Plover Formation with 164 m gross sandstone thickness (Petroleum News, 31 December 2007). The gas-water contact is predicted to be around 80 m below TD (Geary, 2008). Due to blockages within the well immediately above the formation, the Plover Formation sands did not contribute gas during the production test (Petroleum News, 21 January 2008). A cyclone in the Bonaparte Gulf resulted in the well being shut-in after testing. This well is currently confidential and no further information is available.

Blackwood 1 ST1 (2008)

Blackwood 1 ST1 was drilled by MEO Australia Limited in Permit NTP/68, 10.6 km southwest of Wonarah 1 on the Sahul Platform. MEO Australia Limited has reported that the Greater Blackwood structure contains 2.5 Tcf gas (Petroleum News, 17 March 2008; Geary, 2008). The well reached a TD of 3286 mRT and encountered 13 m of gross Flamingo Formation gas-bearing sands and 49 m of gross Plover Formation gas-bearing sands down to a preliminary gas-water contact at 3188 m subsea (Geary, 2008; Petroleum News, 17 March 2008). Borehole damage prevented a modular formation dynamic testing of the Flamingo Formation. A carbon dioxide content of 25-30% has been reported in the dry gas from this well (Petroleum News, 12 and 17 March 2008). This well is currently confidential and no further information is available.

Greater Sunrise Field

Troubadour 1 (1974), Sunrise 1 (1974), Bard 1 (1988), Loxton Shoals 1 (1995), Sunset 1 (1997), Sunset West 1 (1998), Sunrise 2 (1998), Sunrise 3 (2008).

The giant Greater Sunrise wet gas field is located some 430 km northwest of Darwin and 175 km northwest of Release Area NT09-1. Troubadour 1, drilled in 1974, was the discovery well for the accumulation, and was the first well to be drilled on the crest of the Sahul Shelf. This well was followed by the drilling of Sunrise 1 in the same year. These accumulations remained unappraised for a decade when in 1995-1999 acquisition of 2D seismic and an extensive drilling programme of five wells commenced (Seggie et al, 2000; Longley et al, 2002a). The Troubadour structure was appraised by Bard 1 in 1998, and the Sunrise accumulation by the wells Loxton Shoals 1 (1995), Sunset 1 (1997), Sunset West 1 (1998), Sunrise 2 (1998) and Sunrise 3 (2008). The accumulation has reserves of 5.44 Tcf gas and 243 MMbbls liquids (RDPIFR, 31 December 2007) with low carbon dioxide levels (4-5 mol%), reservoired within the Plover Formation. The Sunrise and Troubadour fields comprise a complex of large, east-west elongated fault blocks. The Middle Jurassic (Bathonian-Callovian) sandstone reservoir is 80 m thick and is entrapped in a fault-bounded structural closure that has 180 m relief and covers an area of 75 by 50 km (Seggie et al, 2003). Subtle geochemical differences in the composition of the gases and condensates suggest either some degree of compartmentalisation of the reservoir (although not substantiated by Ainsworth, 2005, 2006) or a lack of compositional equilibrium of the fluids, since they are modelled to have been emplaced in the structure in the last 1 my or less (Seggie et al, 2003). Currently, the three largest partners in Greater Sunrise are Woodside Offshore Petroleum Pty Ltd, ConocoPhillips Australia Exploration Pty Ltd and Shell Development (Australia) Limited, and their plan for its development is under discussion.

Troubadour 1 (1974)

Troubadour 1 was drilled by B. O. C. of Australia Limited (1974). The well tested the hydrocarbon potential of a large, faulted anticlinal feature in which closure at several horizons was controlled by faulting and drape over a topographically high feature on the crest of the Sahul Platform.

The well penetrated 3315 m of sedimentary rocks of Miocene to presumed Late Permian age before intersecting 144 m of crystalline granitic basement. The well reached a TD of 3459 mRT. The interpreted gas-water contact is at 2273 mRT (2260 mSS) in the Plover Formation and is coincident with the mapped spill point for the Darwin Radiolarite (Shell Development Australia Limited, 1998a). Upon testing, gas flowed at a rate of 11 MMscf/d (0.03205 MMcm/d). Oil was observed bleeding from fractures and bedding planes in Core 1 (2203-2208.85 mRT), cut from Jurassic sandstones. In addition, the sandstones between 2206 and 2739 mRT also contained 10 to 20% of immovable oil. The porosity of these Jurassic sandstones varies greatly, with a maximum of 10% being recorded, but in many intervals it has been destroyed by silicification. The well was completed as a suspended gas discovery.

Sunrise 1 (1975)

Sunrise 1 was drilled by B. O. C. of Australia Limited (1975) in Permit NT/P12 on the northern edge of the Sahul Ridge targeting a large faulted anticline. It was the second well to be drilled in the northern Bonaparte Basin and is located 16 km north of Troubadour 1. Structuring on the Sahul Platform was created by renewed movement of the early Late Jurassic faults that occurred during the Neogene deformation period.

The well penetrated 2341 mRT of sedimentary section, ranging in age from Holocene to Early Jurassic. Wireline log interpretations indicated gas in two Cretaceous units over the depth ranges of 2142-2156 mRT and 2195-2206 mRT, with water saturations of 25% and 35%, respectively. The distribution of transgressive shell beds is an important factor in controlling vertical connectivity within the accumulation (Alsop and Ainsworth, 2006).

Four Formation Interval Tests (FITs) were run in the well to test for the presence of hydrocarbons and to establish the level of the gas-water contact. FITs 2 and 4 were run in the interpreted gas zone and recovered gas and condensate. The recovery of significant quantities of gas and condensate from the Jurassic Plover Formation in Sunrise 1 played an important role in defining the gas/condensate reserves of the Greater Sunrise accumulation.

Sunrise 2 (1998)

Sunrise 2 was drilled in 1998 by Woodside Offshore Petroleum Pty Ltd and is located some 11.5 km north-northwest of Sunrise 1. The well was drilled on a low relief east-northeast elongated satellite horst situated on the northern margin of the Sunrise accumulation. The primary objectives of the well were to appraise the quality, continuity and flow rate of the Plover Formation reservoir, reduce the uncertainty in structural elevation to top reservoir, determine the gas-water contact, and confirm the composition of the reservoir fluids (Woodside Offshore Petroleum Pty Ltd, 1999).

The well reached a TD of 2350 mRT in the Plover Formation. Hydrocarbons were encountered within the Laminaria Formation equivalent [Elang Formation] and the Plover Formation, with a 149 m gas column. The interbedded siltstone/sandstone sequence has a net to gross of 27.7%, with the sandstones being of moderate reservoir quality (average porosity is 18.3%). The top of the reservoir was encountered at 2101 mRT, 30 m shallower than prognosis, indicating a shallower northern flank of the horst. The gas-water contact is at 2250 mRT depth, 10 m shallower than at Sunset 1. Aquifer pressure suggests that the accumulation is either compartmentalised by faults or that the gas-water contact is tilted and sits above a dynamic aquifer; the latter is the preferred scenario of Seggie et al (2003). The Plover Formation reservoir is sealed by Early Cretaceous claystones [Echuca Shoals Formation].

Two successful Drill Stem tests (DSTs) were conducted. DST 1 (2161-2168 mRT) flowed gas at a maximum rate of 7.9 MMscf/d through a 36/64" choke with a condensate/gas ratio of 45 bbl/MMscf. DST 2A (2097-2142 mRT) flowed gas at a maximum rate of 30 MMscf/d gas through a 2" choke with a condensate/gas ratio of 52.1 bbl/MMscf. The well was plugged and abandoned as a successful appraisal well.

Sunset 1 (1997)

Sunset 1 was drilled in 1997 by Shell Development (Australia) Pty Ltd and is located some 20 km southwest of Sunrise 1. The primary objective was the fluvio-deltaic sandstones of the middle and upper Plover Formation, with the secondary objective being fracture porosity in the Darwin Radiolarite (Shell Development (Australia) Limited,1998a).

The well reached a TD of 2420 mDF with the expected succession being encountered. The Late Jurassic-Early Cretaceous Flamingo Group was absent and the Darwin Radiolarite was 31 m thick. Total gas readings increased from a background of 0.02% to 0.15% through the Darwin Radiolarite, Echuca Shoals and Elang formations, to a peak of 0.3% just above the Plover Formation. The gas composition in the reservoir was predominantly methane with traces of wet gas up to butane. The claystones of the Elang, Echuca Shoals and Wangarlu formations provide vertical and lateral seal for the Plover Formation reservoir. The well was plugged and abandoned as a gas discovery.

Sunset West 1 (1997)

Sunset West 1 was drilled in 1997 by Woodside Offshore Petroleum Pty Ltd, some 8.5 km west of Sunrise 1. The well was drilled to appraise the northwestern flank of the Sunrise gas accumulation which is contained within a broad, west-southwest-trending elongate, low relief, fault and dip-closure. The primary objectives of the well were to appraise the quality, continuity and productivity of the Plover Formation reservoir and reduce the uncertainty of the gas-water contact elevation (Woodside Offshore Petroleum Pty Ltd, 1999).

The well reached a TD of 2505 mRT in the Plover Formation sandstones, which were encountered at 2193.8 mRT, approximately 15 m shallower than expected. The sandstones were gas-bearing with the gas-water contact interpreted within a claystone at 2257 mRT (2235 mSS), some 5 m deeper than at Sunset 1.

Reservoir quality was better than expected. A gross hydrocarbon column of 63 m was penetrated, with net to gross of 27.1%, average log porosity of 12.3% and average gas saturation of 55%. The lower reservoir sand of the upper Plover Formation was water-saturated. Top seal for the Plover Formation is provided by the overlying siltstones and claystones of Late Jurassic to Early Cretaceous age.

Two DSTs were conducted: DST 1A (2189-2207 mRT) flowed gas at a maximum rate of 11 MMscf/d through an 1" choke with a condensate/gas ratio of 31.8 bbl/MMscf. DST 2 (2189-2231 mRT) flowed gas at a maximum rate of 19.3 MMscf/d gas through an 84/64" choke over a co-mingled test interval, straddling the Laminaria-equivalent and upper Plover formations. A condensate/gas ratio of 31.4 bbl/MMscf was reported for DST 2. The well was plugged and abandoned as a successful appraisal of the Sunrise/Troubadour gas accumulation.

Loxton Shoals 1 (1995)

Loxton Shoals 1 was drilled by Woodside Offshore Petroleum Pty Ltd (1995) some 12.5 km northeast of Sunrise 1. The well targeted a post-Miocene tilted fault block, where the Plover Formation reservoir is sealed both vertically and laterally by claystones of the Laminaria Formation equivalent. Thin condensed claystones of the Flamingo Group [Frigate Shale] and claystones of the Bathurst Island Group provide additional sealing capacity. The primary objective was to test the Plover Formation above the gas-water contact, and to test the presence or absence of an oil leg in the Loxton Fault Block. A high risk secondary objective was the Eocene Grebe Sandstone Member.

Loxton Shoals 1 terminated in the Plover Formation at a TD of 2330 mRT. The Plover Formation was intersected at 2089 m, and comprises interbedded sandstones and claystones with minor siltstones. The top reservoir sandstone was intersected at 2136 mRT and contains a 64 m gas column. Average porosity of the unit is 14.1%, with porosity in the hydrocarbon-bearing sandstone averaging 15.1%. A gas sample was taken at 2139.1 mRT, which had a condensate/gas ratio of 24.7 bbl/MMscf. Pressure data indicate that the Loxton Shoals accumulation is probably a separate accumulation to the Sunrise accumulation. The well was plugged and abandoned as a gas discovery.

Bard 1 (1998)

Bard 1 was drilled by Woodside Petroleum (Timor Sea 19) Pty Ltd (1998) some 11 km west-southwest of Troubadour 1 in a water depth of 100 m. The primary objective of the well was to confirm the presence of hydrocarbons at Bard 1, proving the extension of the Troubadour gas accumulation.

The well reached a TD of 2164 mRT; some 328 m short of the predicted total depth of 2492 mRT. Bard 1 was plugged and abandoned after drilling problems and the bottom hole assembly was lost in the hole. The primary objective was not achieved, but interpretation suggests that the well was slightly high to prognosis and would most likely have encountered gas in the reservoir section. Ditch gas, total gas and trip gas were recorded from 1464 to 2164 mRT. During attempts to control the gas peak at 2164 mRT a total gas of 18.5% was recorded. An oil scum was recovered from the top of the mud in the header box. A dull to bright whitish-yellow hydrocarbon fluorescence was observed in 40% of the clay ditch cuttings samples from 2155 to 2164 mRT with an associated brown oil stain.

Sunrise 3 (2008)

Sunrise 3 was drilled by Shell Development (Australia) Pty Ltd and reached a TD of 2444 mRT. This well is currently confidential and no further information is available.

Table 1: Key wells listing

Well	Operator	Year	Total Depth	Hydrocarbons

Bard 1	Woodside Petroleum (Timor Sea 19) Pty Ltd	1998	2164 mRT	minor oil and minor gas
Barossa 1	ConocoPhillips Australia Exploration Pty Ltd	2006	3435 mRT	no public data
Barossa 1 ST1	ConocoPhillips Australia Exploration Pty Ltd	2006	4310 mRT	Gas
Beluga 1	BHP Petroleum Pty Ltd	1991	3100 mKB	Minor gas
Blackwood 1 (MEO)	MEO Australia limited	2008		No public data
Blackwood 1 ST1	MEO Australia limited	2008	3286 mRT	Gas
Caldita 1	ConocoPhillips Exploration Australia Pty Ltd	2005	4037 mRT	Gas
Caldita 2	ConocoPhillips Australia Exploration Pty Ltd	2007	3973 mRT	No public data
Chuditch 1	Shell Development (PSC 9) Pty Ltd	1998	3035 mDF	Gas
Darwinia 1	Tricentrol Exploration Overseas Limited	1985	657 mKB	No tests

Darwinia 1A	Tricentrol Exploration Overseas Limited	1985	2426 mKB	No tests
Evans Shoal 1	BHP Petroleum Pty Ltd	1988	3712 mKB	Gas
Evans Shoal 2	Shell Development (Australia) Limited	1998	3940 mDF	Gas
Evans Shoal South 1	Santos Ltd	2006	4097 mRT	Minor gas
Heron 1	Arco Australia Ltd	1972	4209 mKB	Minor gas
Heron 2	MEO Australia limited	2008	4182 mRT	Gas
Heron 2 ST1	MEO Australia limited	2008	3967 mRT	No public data
Jacaranda 1	Tricentrol Exploration Overseas Limited	1984	3783 mRT	Minor gas
Loxton Shoals 1	Woodside Offshore Petroleum Pty Ltd	1995	2330 mRT	Gas
Lynedoch 1	Shell Development (Australia) Pty Ltd	1973	3714 mRT	No tests
Lynedoch 1 ST1	Shell Development (Australia) Pty Ltd	1973	3967 mRT	Minor gas

Lynedoch 2	Shell Development (Australia) Pty Ltd	1999	4225 mDF	Minor gas
Shearwater 1	Arco Australia Limited	1974	3177 mKB	No tests
Sunrise 1	B.O.C. of Australia Ltd	1975	2341 mRT	Gas
Sunrise 2	Woodside Offshore Petroleum Pty Ltd	1998	2350 mRT	Gas
Sunrise 3	Woodside Offshore Petroleum Pty Ltd	2008	2444 mRT	No public data
Sunset 1 (Shell)	Shell Development (PSC 19) Pty Ltd	1997	2420 mDF	Gas
Sunset West 1	Woodside Petroleum (Timor Sea 19) Pty Ltd	1998	2505 mRT	Gas
Troubadour 1	B.O.C. of Australia Ltd	1974	3459 mRT	Gas and minor oil
Tyche 1	Woodside Energy Ltd	2000	1475 mRT	No tests
Wonarah 1	Shell Development (Australia) Limited	1998	2800 mDF	No tests

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

The Release Area is largely covered by good quality 2D seismic data acquired by Shell from 1996 to 1998. These data provide approximate 2-5 km line spacings in the western portion of the Release Area and approximately 5-10 km line spacings in the eastern portion. Earlier surveys acquired by BHP Petroleum in 1988 to 1990, which defined the Beluga 1 and Caldita 1 prospects, provide additional coverage in the eastern and northeast portion. The Release Area is also traversed by several 2D regional deep lines acquired by Geoscience Australia (AGSO 116, 118).

A full listing of the seismic is available in the **Malita Graben Data Listing**.

Hydrocarbon Potential

Petroleum Systems

The petroleum systems of the northern Bonaparte Basin have been summarised by Barrett et al (2004), following the nomenclature proposed by Magoon and Dow (1994). They are also presented in montage format by Earl (2004).

As shown in **Figure 9** (after Barrett et al, 2004), the active petroleum system in the region of Release Area NT09-1 has been defined as the Jurassic Plover-Plover(.) Petroleum System. The active source pod within the Plover Formation is interpreted to extend throughout the Malita Graben and onto the marginal areas of the Sahul Platform (Heron Terrace). The discovery of gas in the Abadi accumulation, in Indonesian waters, implies that the Plover Formation is also an effective source rock within the Calder Graben. This petroleum system is mapped as extending north from the Malita Graben across the Sahul Platform, with the northern limit being defined politically by the seabed boundary with Indonesia. The Plover-Plover(.) Petroleum System has been modelled as gas-prone with moderate liquids, but with little or no oil potential.

Hydrocarbon Families

Recent geochemical studies indicate that the Greater Sunrise gas field was sourced locally from the Plover Formation in the Malita Graben and on the Troubadour Terrace (Longley et al, 2002b). The gases have CGRs ranging from 30 to 50 bbls/MMscf and condensate API gravities between 60 and 65° (Seggie et al, 2003). To the east, gas has been discovered in the Plover Formation at Barossa 1 ST1, Blackwood 1 ST1, Caldita 1, Evans Shoal 1 and 2, Evans Shoal South 1, Heron 2 and Lynedoch 1 and 2. Gas was also intersected in the Plover Formation by the Abadi 1, 2 and 3 wells drilled in Indonesian waters.

The carbon isotopic ($d^{13}C$) compositions of the liquids recovered from gases within the Malita and Calder graben are similar to those of the Greater Sunrise area, indicating derivation from the same source rock package (**Figure 10**; Edwards and Zumberge, 2005) that is assumed to occur within the Plover Formation. However, variations in the isotopic composition between gases, and between the gas and condensate range *n* -alkanes (AGSO and Geotech, 2002) imply that some of the accumulations comprise mixtures of gases derived from different source units of varying thermal maturity.

Figure 11 shows the distribution of carbon dioxide in the gas accumulations of the Bonaparte Basin. The gases tested at Evans Shoal 1 and 2 have a high carbon dioxide (CO_2) content (18 mol% at 3554 mKB and 24 mol% at 3633 mKB, respectively; **http://dbforms.ga.gov.au/www/npm.well.search**) resulting in the assessment of possible methanol production from this accumulation. Similarly high concentrations of carbon dioxide are recorded in Chuditch 1 (20 mol% at 2934 mKB) and Blackwood 1 ST1 (25-30 mol%, Petroleum News, 17 March 2008), with moderately high concentrations of carbon dioxide being reported for Barossa (16 mol%, Petroleum News, 29 November

2006), and significant, but lower, concentrations being published for Abadi (9 mol%, Yui, 2003). The Greater Sunrise accumulation contains significantly lower concentrations of carbon dioxide (4-5 mol%) and other non-combustible gases (**http://dbforms.ga.gov.au/www/npm.well.search**). These molecular differences between Sunrise and the Malita-Calder gas accumulations imply that they either have different source provinces or different charge histories; with the Sunrise gases perhaps being expelled and trapped earlier (V_{Ro} 1.3-1.5%) than those accumulations reservoired in more basinal settings.

From the similarity of the carbon isotopic data between most of the gas/condensates in the region, it is determined that the hydrocarbon component of the gases have the same source, whereas (and more speculatively) the carbon dioxide may have migrated into the deeper, more basinward Plover Formation reservoirs late in the basin's history from inorganic sources. **Figure 12** shows the $d^{13}C$ isotopic values for carbon dioxide from gases in the Bonaparte Basin. These carbon isotopic values for the Chuditch, Evans Shoal and Sunrise accumulation gases fall within the inorganic igneous and/or mantle-derived field, as defined by Smith and Pallasser (1996). However, it is interesting to note that some of the gases derived in drill stem tests from the acid-stimulated Permian carbonate reservoir at Kelp Deep 1 fall on trend with the Evans Shoal and Chuditch accumulation gases. Hence, it is suggested that the carbon dioxide could originate from either magmatic sources or from the mixing with gases derived from the thermal breakdown of carbonates. Both of these sources are possible given that recrystallised Late Permian carbonates of the Hyland Bay Subgroup are known to overlie granitic basement in Troubadour 1 and that high geothermal gradients are recorded regionally throughout the Malita Graben and Calder Graben.

Source Rocks

The most important hydrocarbon source rocks in the Malita Graben and Calder Graben occur in the Plover Formation, which is also the most important reservoir target. The source potential of this formation and its associated hydrocarbons has been discussed by Longley et al (2002b), Ambrose (2004a, b), Preston and Edwards (2000) and Edwards et al (2004, 2006). In the northern Bonaparte Basin, the oils reservoired in the Laminaria and Corallina accumulations are believed to be co-sourced from several organic-rich units of Jurassic age, with the Plover Formation providing a significant volume of hydrocarbons (Edwards et al, 2004, George et al, 2004). The claystones of the Elang Formation have also made some contribution to these oil accumulations, and they are recognised as the dominant source for the Bayu/Undan wet gas accumulation.

The organic-rich sediments of the Plover Formation are poor source rocks by world standards; however, the thickness of this formation, its regional extent and optimum thermal maturity makes it the most important source of gas in the Bonaparte Basin. The relevant Plover Formation source unit in the northern Bonaparte Basin and in the Vulcan Sub-basin is a coastal plain/deltaic unit largely defined by the *C. turbatus* spore-pollen zone (viz, Unit C as defined by Ambrose, 2004a). The northernmost well to intersect Unit C source rocks is Thornton 1 which was drilled in the Joint Petroleum Development Area (JPDA). The Plover Formation source rocks in the Greater Sunrise area may be slightly younger than the Unit C shales found to the west in the JPDA and Vulcan Sub-basin, but the inter-relationship is not well understood.

Across the Sahul Platform, the better quality potential source rocks within the Plover Formation contain Type II/III kerogen that is both oil- and gas-prone, whereas wet-gas-prone source rocks occur on the Troubadour Terrace. Elsewhere in the northern Bonaparte Basin the Plover Formation is mainly a source of dry gas. Unit C source rocks are speculated to occur in the deeper Plover Formation section in the Malita and Calder graben (Ambrose, 2004a).

Development of syn-rift Callovian-Oxfordian organic-rich shales of the Elang (Laminaria) Formation, which are proven source rocks elsewhere in the Bonaparte Basin, remains speculative in the Malita and Calder graben.

Organic-rich shales of Callovian-Kimmeridgian age in the Flamingo Group, and particularly in the Frigate Shale, are potential sources of hydrocarbons. The sandstone-dominated Elang Formation may also contain claystone units within the northern Bonaparte Basin. For example, in Sikatan 1 ST1, over 50 m of claystones were intersected in the *W. digitata* to *R. aemula* zone that show particularly good source characteristics with TOC contents of 1 to 4.6% (Boral Energy ZOCA91-08 Pty Ltd, 1995). Similar organic richness was encountered at Loxton Shoals 1. In the Malita Graben, the best source rock section occurs in Heron 1 which encountered 885 m of Flamingo Group (Frigate) shales. Total organic carbon (TOC) content ranges between 0.2 and 10% with an average value of 2.5%, but hydrogen indices (HI) indicate that the sequence is gas-prone.

The basal unit of the Bathurst Island Group, the Valanginian-Aptian Echuca Shoals Formation has good source character, and could be a potential source of both liquid and gaseous hydrocarbons in the main depocentres (West and Passmore, 1994). The Wangarlu Formation shows fair TOC content ranging from 0.1 to 2.9% and is largely gas-prone (West and Passmore, 1994).

Expulsion and Migration

The highly faulted Greater Sunrise structure was formed in the Miocene or Pleistocene and was filled to spill at about 1 Ma or less (Seggie et al, 2000). The structuring at the Evans Shoal and Lynedoch structures appears to be much older (pre-Turonian) than that of the Sunrise complex, being associated with the formation of the Malita Graben and the juxtaposition of rift-related terraces and tilted fault blocks in the Tithonian.

Poor well control within the Malita Graben and the absence of recent published basin history models make it difficult to understand the timing of expulsion and migration of hydrocarbons throughout the region. Modelling by West and Miyazaki (1994) suggests that gas generation from the Plover Formation at Evans Shoal 1 (**Figure 13**), and from the surrounding faulted terraces, probably commenced in the mid-late Cenozoic. In the Malita Graben depocentre, gas generation from the Plover Formation commenced in the mid-Cretaceous. The deepest sections are currently thermally overmature.

Modelling by West and Miyazaki (1994) at Heron 1 in the Malita Graben indicates that the Flamingo Group and lowermost Bathurst Island Group were within the gas window in the Late Cretaceous to Paleogene (**Figure 14**). Similar results are reported by Shell Development (Australia) Limited (1999a). Oil-prone source rocks of the lower Bathurst Island Group are within the oil window or have passed through it since the Eocene; therefore opportunities for oil retention may exist in migration shadow zones on the faulted margins of the Malita and Calder graben. It may be significant that liquid petroleum-related fluorescence anomalies detected by airborne laser fluorosensor (ALF) occur south and east of the Calder Graben, hinting at the generation of liquid hydrocarbons in this depocentre (Martin and Cawley, 1991). However, high (Plover Formation) reservoir temperatures and pervasive gas flushing throughout this region are major risks for the preservation of liquid hydrocarbons.

Reservoirs

The primary reservoir targets within the region are the upper Plover Formation and Elang Formation, as exemplified by the Barossa, Blackwood, Caldita, Chuditch, Evans Shoal and Greater Sunrise accumulations. Increased diagenetic alteration of the Plover Formation sandstone reservoirs with depth has resulted in the downgrading of this play over the basinal areas of the Malita Graben. However, reservoir quality improves away from the main depocentres. Average porosities in the Greater Sunrise Plover Formation reservoirs range from 10.7% at Troubadour 1 to 15% at Loxton Shoals 1, with net to gross values ranging from 35 to 53% (Shell, 1998). A greater variation of porosity (5-25%) and permeability (0.1-10000 mD) have been measured for the Plover Formation in wells throughout the Malita and Calder graben.

Facies development and palaeogeography of the upper Plover Formation are shown in **Figure 15** (Barber et al, 2004). Depositional facies interpretation indicates the presence of marine shoreface sandstones in the upper Plover Formation, which form the primary reservoir zone. The lower Plover Formation section is mainly a fluvial-estuarine facies with different reservoir properties. Evans Shoal 2 encountered more than 360 m of Plover Formation sandstones containing high-permeability streaks (Lowe-Young et al, 2004). Pressure data indicates that the Evans Shoal structure is filled to spill, with a closure height of 300 m. Production tests over two zones in the Plover Formation in Evans Shoal 2 resulted in gas flows of 25.5 and 5.5 MMscf/d, with the larger flow mainly sourced from the upper shoreface zone. Natural fractures observed in core samples have probably enhanced reservoir performance.

The Flamingo Group is a secondary target reservoir in this region, with quartz clastics of the Sandpiper Sandstone offering good reservoir targets within combination structural/stratigraphic plays. Core-derived porosities range from 9% in the basin centre to 30% in basin margin locations (Botten and Wulff, 1990). These clastics were deposited on a marine shelf and in possible slope and basin-floor fan complexes (Anderson et al, 1993; Barber et al, 2004). **Figure 16**, based on the work of Barber et al (2004), portrays the palaeogeography of the Flamingo Group showing the areas of likely reservoir development.

The Bathurst Island Group contains high-quality reservoirs, including regionally developed Santonian (upper Wangarlu Formation) and Maastrichtian (Puffin Formation) sandstones. The thickness of the Maastrichtian sandstones ranges from 152 m in Darwinia 1A (Tricentrol Exploration Overseas Ltd, 1985) and 158 m in Heron 1 in the southern Malita Graben, to 410 m in Evans Shoal 1 in the central Malita Graben, and it reaches a maximum of 518 m in Lynedoch 1 in the Calder Graben. These sandstones are the equivalent of the oil-bearing Puffin Formation sandstones tested in the Vulcan Sub-basin further to the west. West and Passmore (1994) suggested that the Maastrichtian sandstones in Heron 1 and Evans Shoal 1 represented turbidite flows deposited as lowstand basin floor fans, tapping up-dip coastal plain and shelfal sands during a low sea level stand. On seismic lines, these sandstones appear as widespread, hummocky clinoform reflections with possible mounding and foresetting (West and Miyazaki, 1994). The porosity in these sandstones ranges from 10 to 33%, but the presence of seal and hydrocarbon charge remain to be proven.

Seals

In the northern Bonaparte Basin, the regional seal for Plover Formation and Flamingo Group reservoirs is the thick claystone unit of the lower Bathurst Island Group, the Echuca Shoals Formation. Claystones of the Flamingo Group (Frigate Shale and equivalent'Cleia' Formation) have increasing sealing capacity to the west, particularly across the Troubadour Terrace and Sahul Platform. Having said this, the Frigate Shale is the seal for the gas accumulations at Evans Shoal, Barossa and Caldita. Intra-formational claystones also occur within the Plover Formation and may form local seals.

Play Types

The known gas fields in the northeastern Bonaparte Basin are large, faulted anticlinal structures at the base of the Early Cretaceous regional seal (Longley et al, 2002b). Hence, tilted fault blocks, faulted anticlines and broad, low relief anticlinal drape over tilted fault blocks provide the main structural plays in this region, as exemplified by the Barossa, Blackwood, Caldita, Evans Shoal and Greater Sunrise accumulations, which are hosted within Plover Formation reservoirs. Tilted horst blocks are attractive targets on the faulted terraces adjacent to the Malita and Calder graben. These terraces include the Troubadour and Heron terraces to the northwest of the Malita Graben, as drilled by the Evans Shoal and Heron wells. A schematic play diagram for Heron 2 ST1 is shown in **Figure 17**.

The Bathurst Terrace is located to the south of the Malita and Calder graben (**Figure 2** and **Figure 3**) and provides structural play fairways in Release Area NT09-1. The possibility of hanging wall fault dependent traps on the down-thrown side of the bounding faults provides a secondary play type.

A regional carbonate unit of Aptian-Albian age in the Malita and Calder graben, the'Darwin Radiolarite', occurs within the Bathurst Island Group. Gas shows were reported from'fractured limestone' in Lynedoch 1 and Evans Shoal 1, and gas indications were reported in calcareous shales with thin limestone stringers in Heron 1 from the same section. The Darwin Formation ['Darwin Radiolarite'] was the primary target of Heron 2 ST1 (Petroleum News, 21 January 2008, Geary, 2008; Hart, 2008: **Figure 17**). The failure to flow gas from the fractured carbonate/radiolarite reservoir has downgraded exploration interest in this play.

Late Cretaceous sandstone plays have been considered within the Malita Graben since these sandstones are expected to be of better quality than the deeper Plover Formation sandstones. Darwinia 1A tested both Maastrichtian Puffin Formation and Santonian intra-Wangarlu Formation sandstones, which were found to be of excellent quality, but no hydrocarbons were found. However, this well may not have been a valid test of a fault-dependent closure. A Maastrichtian sandstone play was considered, but not tested, by Evans Shoal 1. However, poor source characteristic of the Late Cretaceous claystones, a lack of faults to feed hydrocarbon from the basal Cretaceous and Jurassic claystones, and the poor sealing capacity of the Cenozoic carbonates, was deemed to downgrade the potential of this play (BHP Petroleum Pty Ltd, 1989).

Jacaranda 1 did not test a Late Cretaceous play, but it penetrated good quality sandstones of Campanian and early Santonian age (upper Wangarlu Formation) and, although water-wet, gas indications were recorded in the latter sandstone despite being outside of mapped closure. Wonarah 1 was drilled to test intra-Wangarlu Formation sandstones within a stratigraphic trap; however, none were intersected.

A stratigraphic pinchout of the Oligocene Cartier Formation [Oliver Formation] was tested by Tyche 1, but no hydrocarbons were encountered in the unconsolidated sands.

Critical Risks

The key risk in the Malita Graben area is the quality of the Plover Formation reservoir sandstones. This unit is tight in basinal areas, but reservoir quality improves markedly away from the main depocentres. Excellent gas flow rates of 25, 30 and 33 MMscf/d have been recorded from the Plover Formation in the Evans Shoal 2, Barossa 1 and Caldita 1 exploration wells, respectively. Depth of burial has a significant impact on the degree of diagenesis, and reservoir quality is deemed most favourable where the depth of burial has been less than 3000 m, in which case, present day porosity is estimated to be between 15 and 30% (Petroconsultants Australasia Pty Ltd, 1990). Botten and Wulff (1990) speculated that the Plover Formation would also provide potential plays at depths greater than 3300 m, where early hydrocarbon emplacement has inhibited diagenesis. This is the case at Evans Shoal (near top reservoir approximately 3600 mSS) and Caldita 1 (near top reservoir approximately 4000 mSS). Significantly, it remains uncertain why the Plover Formation reservoir at Lynedoch 2 is tight, given that it occurs at approximately the same structural elevation as Caldita 1, which is about 20 km to the south. The Plover Formation reservoirs in Abadi 1 (3850 m) flowed gas at 25 MMscf/d suggesting regional development of viable reservoirs.

Another risk is that most gas accumulations in the Malita and Calder graben contain high concentrations of non-combustible gases including nitrogen (N_2), carbon dioxide (CO_2)

and hydrogen sulphide (H_2S). The low liquids content (<5 bbls/MMscf) coupled with the high carbon dioxide content are significant factors being considered in the development of the Evans Shoal accumulation.

High geothermal gradients are recorded throughout the Malita and Calder graben, precluding the likely generation or preservation of liquid hydrocarbons below approximately 2.5 km.

In summary, the Release Area offers excellent prospectivity for gas, with gas accumulations occurring immediately to the north and west. In the Malita-Calder area, condensate content in the gas ranges between 3 and 15 bbls/MMscf, and this may assist in offsetting the cost of removal of the high levels of carbon dioxide. Oil is a high risk target due to the high geothermal gradient, the absence of proven oil-prone source rocks in the Malita and Calder graben, and widespread gas flushing-given the discovery of the numerous dry to moderately wet-gas accumulations in the region.

Figures

Figure 9:	The Jurassic Plover-Plover(.) Petroleum System in the Malita Graben (after Barrett et al, 2004). Large well symbols indicate tests of this petroleum system.
Figure 10:	Carbon isotopic composition for C_{7+} *n*-alkanes of condensates recovered from gas accumulations in the northeastern Bonaparte Basin (after Edwards and Zumberge, 2005).
Figure 11:	Distribution of CO_2 (mole %) in Bonaparte Basin and Browse Basin gas accumulations.
Figure 12:	$\delta^{13}C$ isotopic values for CO_2 from Bonaparte Basin gas accumulations.
Figure 13:	Burial history model Evans Shoal 1 (after West and Miyazaki, 1994).
Figure 14:	Burial history model Heron 1 (after West and Miyazaki, 1994).
Figure 15:	Upper Plover Formation palaeogeography (after Barber et al, 2004).
Figure 16:	Flamingo Formation palaeogeography (after Barber et al, 2004).
Figure 17:	Schematic play diagram for Heron 2 ST1 and Blackwood 1 ST1 (after Geary, 2008; Hart, 2008).

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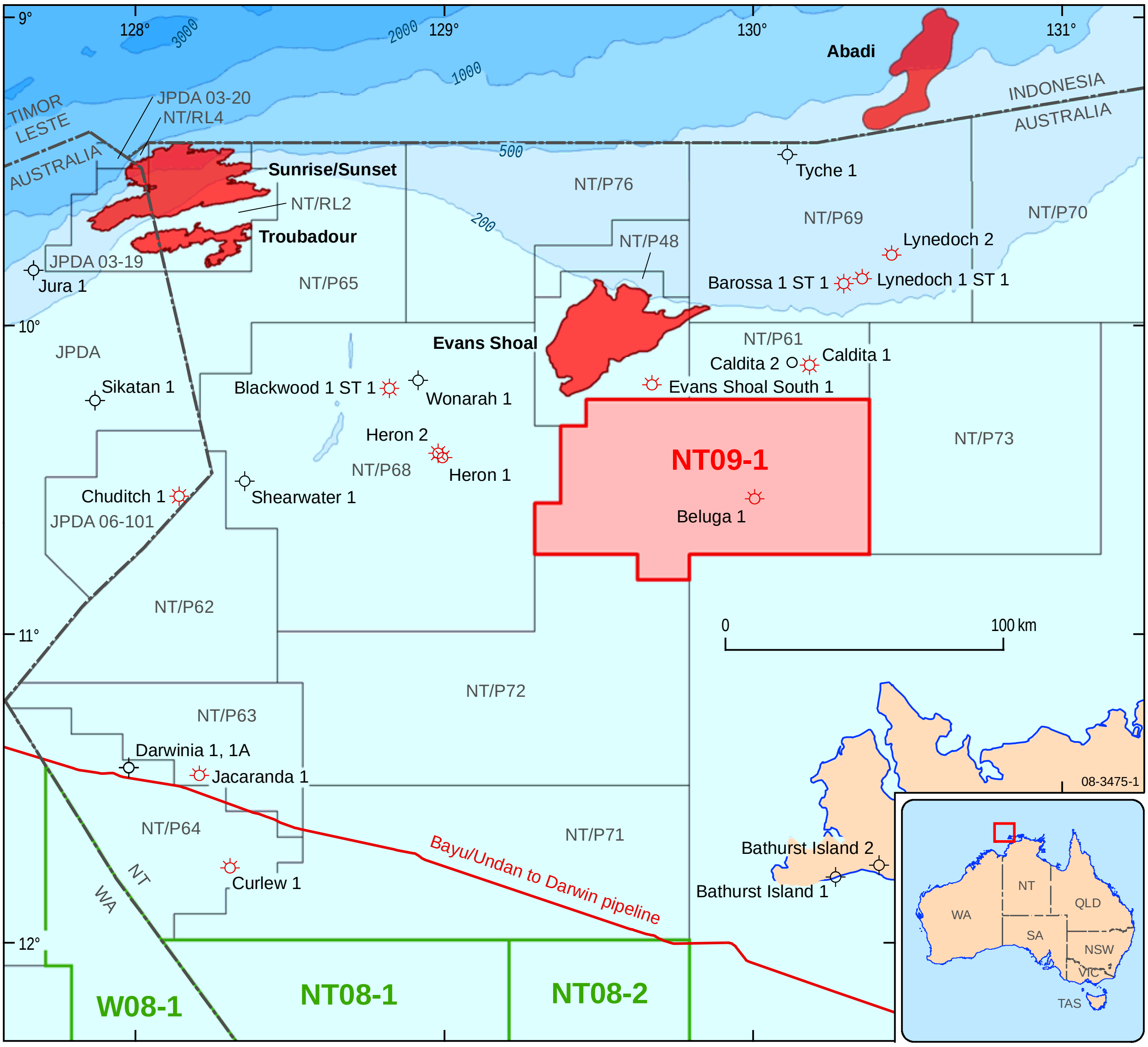


Where well symbol information is sourced from publicly available "open file" data, it has been provided by Geoscience Australia from Well Completion Reports. These symbols were generated from open file data as at 31 March 2009. Where well symbol information is not publicly available from titleholders' 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.

Field outline for Abadi is sourced from IHS Energy, 2006.

2009 Offshore Petroleum Acreage Release Area

2008 Offshore Petroleum Acreage Release Area

Existing petroleum title

Gas field

Gas pipeline

Scheduled area boundary (OPGGSA 2006)

200 *Bathymetry contour (depth in metres)*

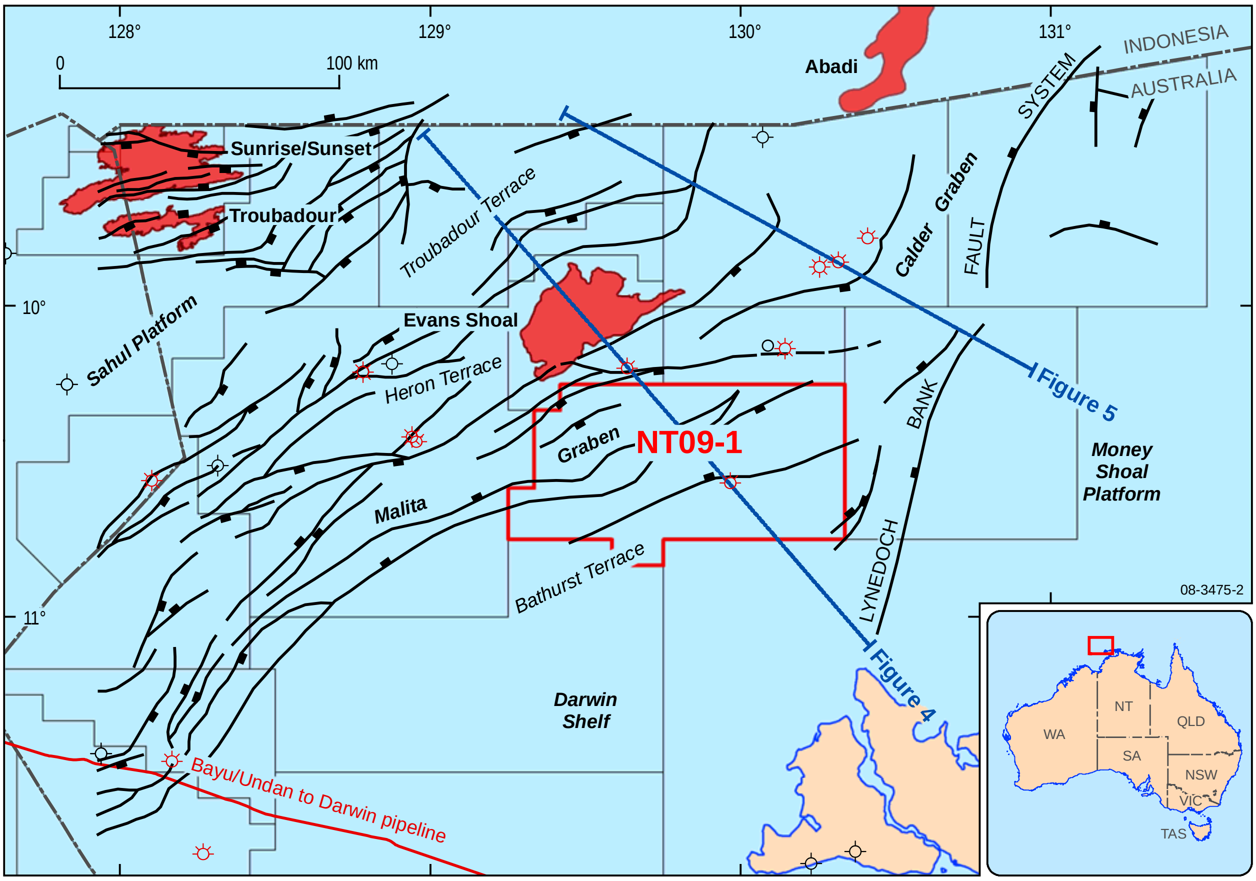
Petroleum exploration well - Not classified

Petroleum exploration well - Dry hole

Petroleum exploration well - Gas discovery

Petroleum exploration well - Gas show

Figure 1. Location map of Release Area NT09-1, Malita Graben, northeastern Bonaparte Basin.



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Field outline for Abadi is sourced from IHS Energy, 2006.

2009 Offshore Petroleum Acreage Release Area
Existing petroleum title
Gas field
Fault
Gas pipeline
Seismic line
Scheduled area boundary (OPGGSA 2006)
Petroleum exploration well - Not classified
Petroleum exploration well - Dry hole
Petroleum exploration well - Gas discovery
Petroleum exploration well - Gas show

Figure 2. Regional structural elements, northeastern Bonaparte Basin (after West and Passmore, 1994), showing locations of Figures 4 and 5.

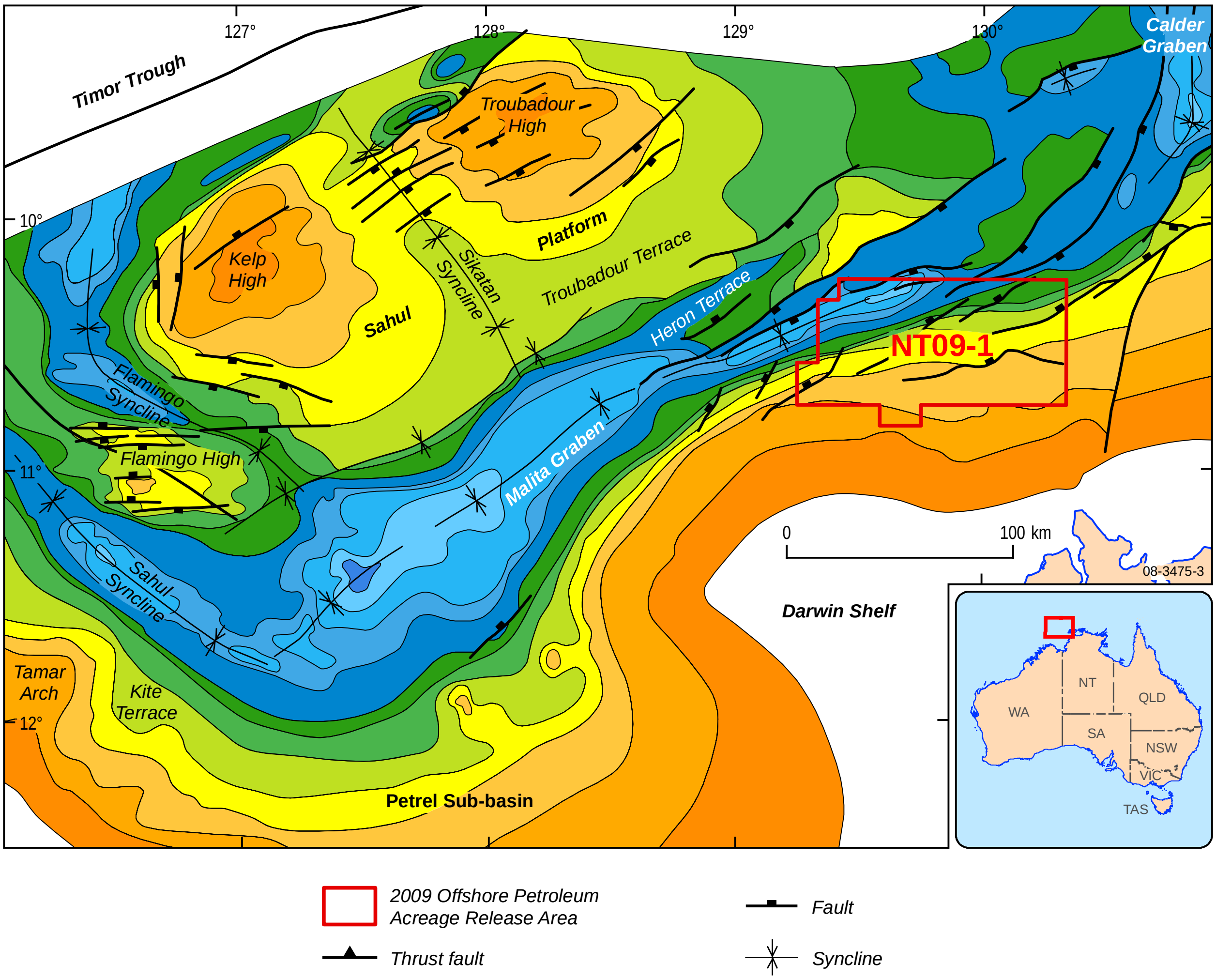


Figure 3. Structural elements map at main unconformity level (approx top Callovian TWT), northeastern Bonaparte Basin showing Plover Formation depocentres (Shell Development (Australia) Pty Ltd, 2000).

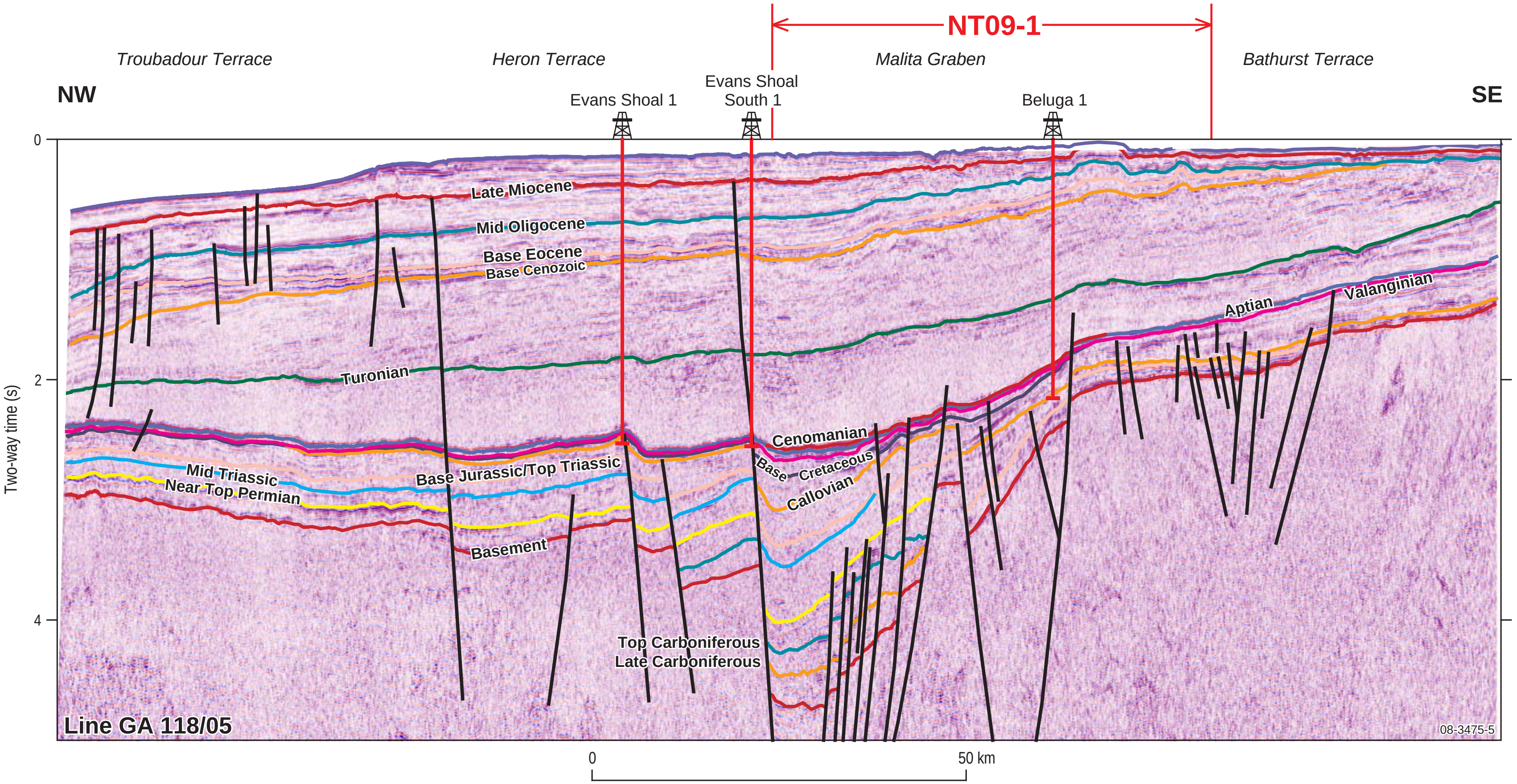


Figure 4. Geoscience Australia seismic line 118/05 through Evans Shoal 1, Evans Shoal South 1 and Beluga 1.

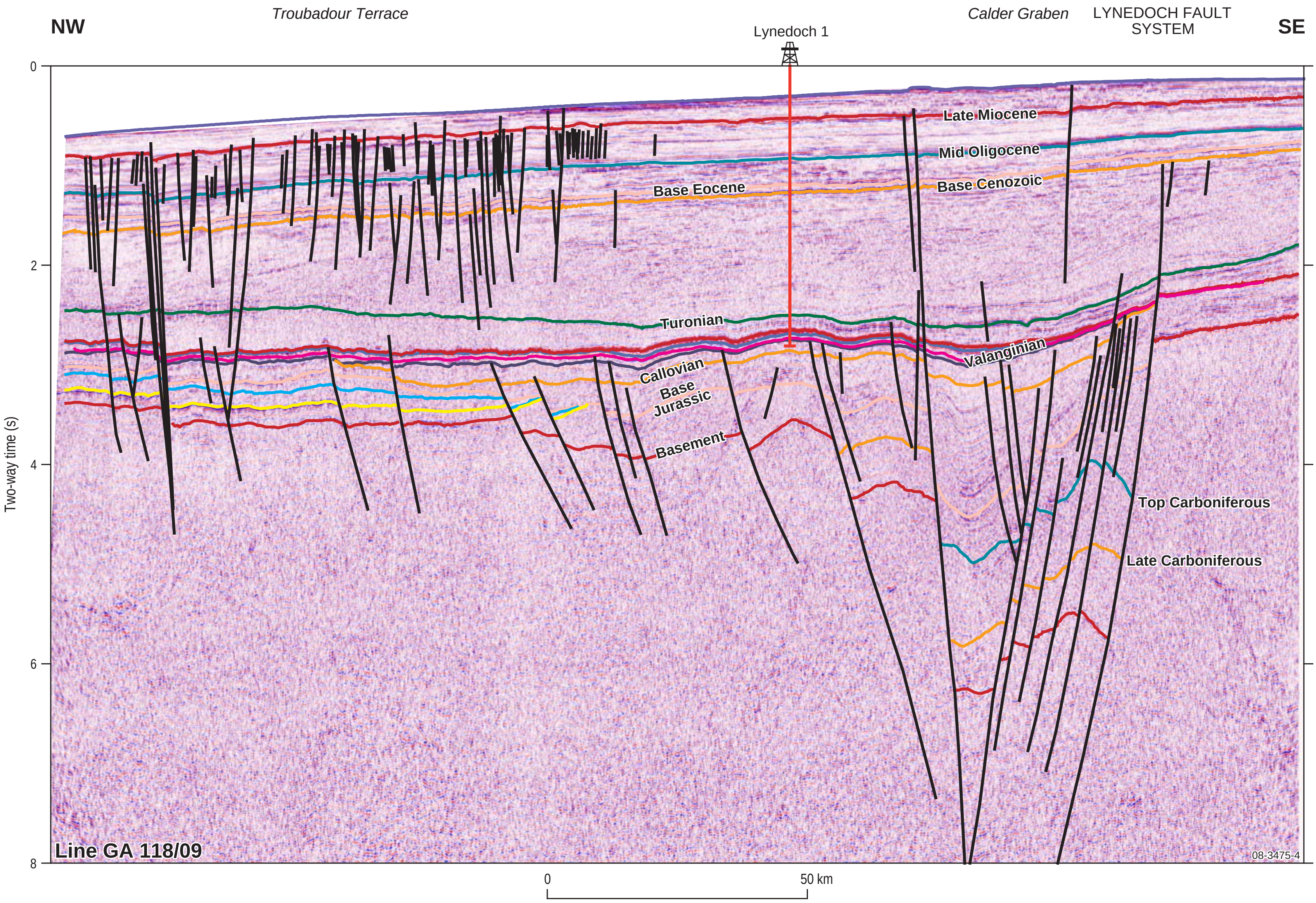


Figure 5. Geoscience Australia seismic line 118/09 through Lynedoch 1.

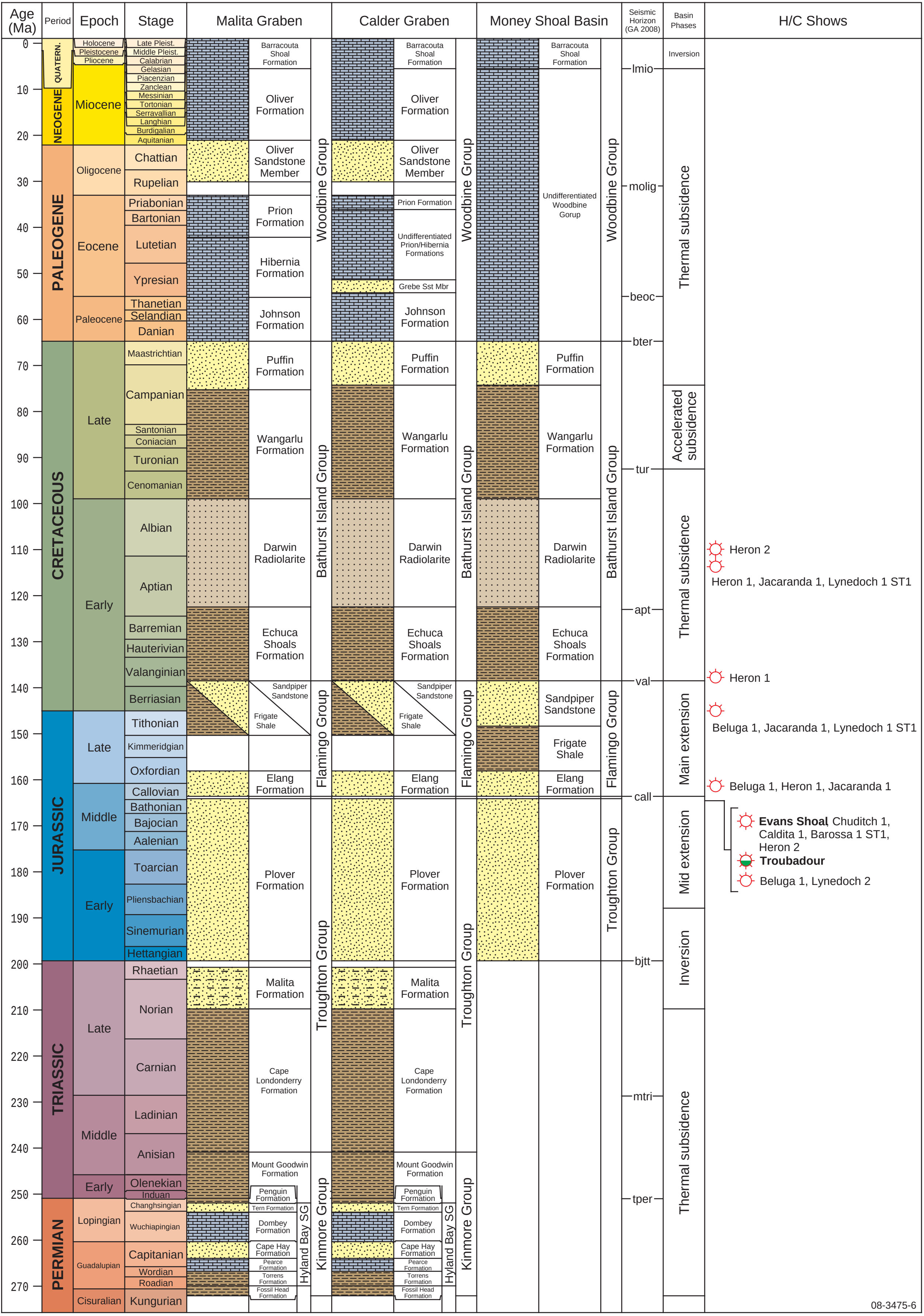


Figure 6. Stratigraphic correlations between the Malita Graben, Calder Graben and Money Shoal Basin, Northern Bonaparte Basin (using Geologic Time Scale: 2004, Gradstein et al, 2004).

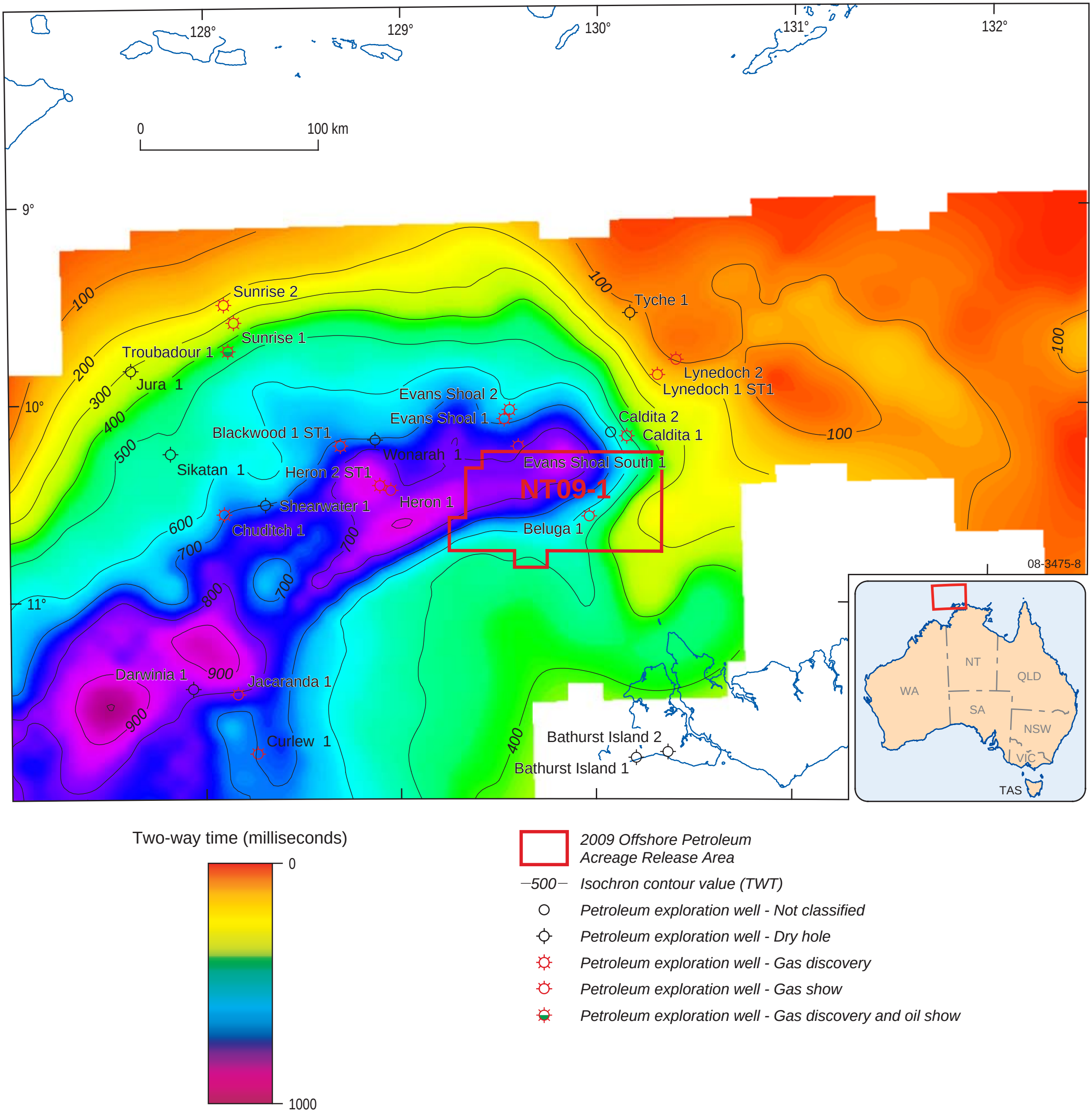


Figure 7. Isochon map (two-way-time) of the Aptian to Turonian (lower Wangarlu Formation). Contour interval is 100 milliseconds (Geoscience Australia, 2001).

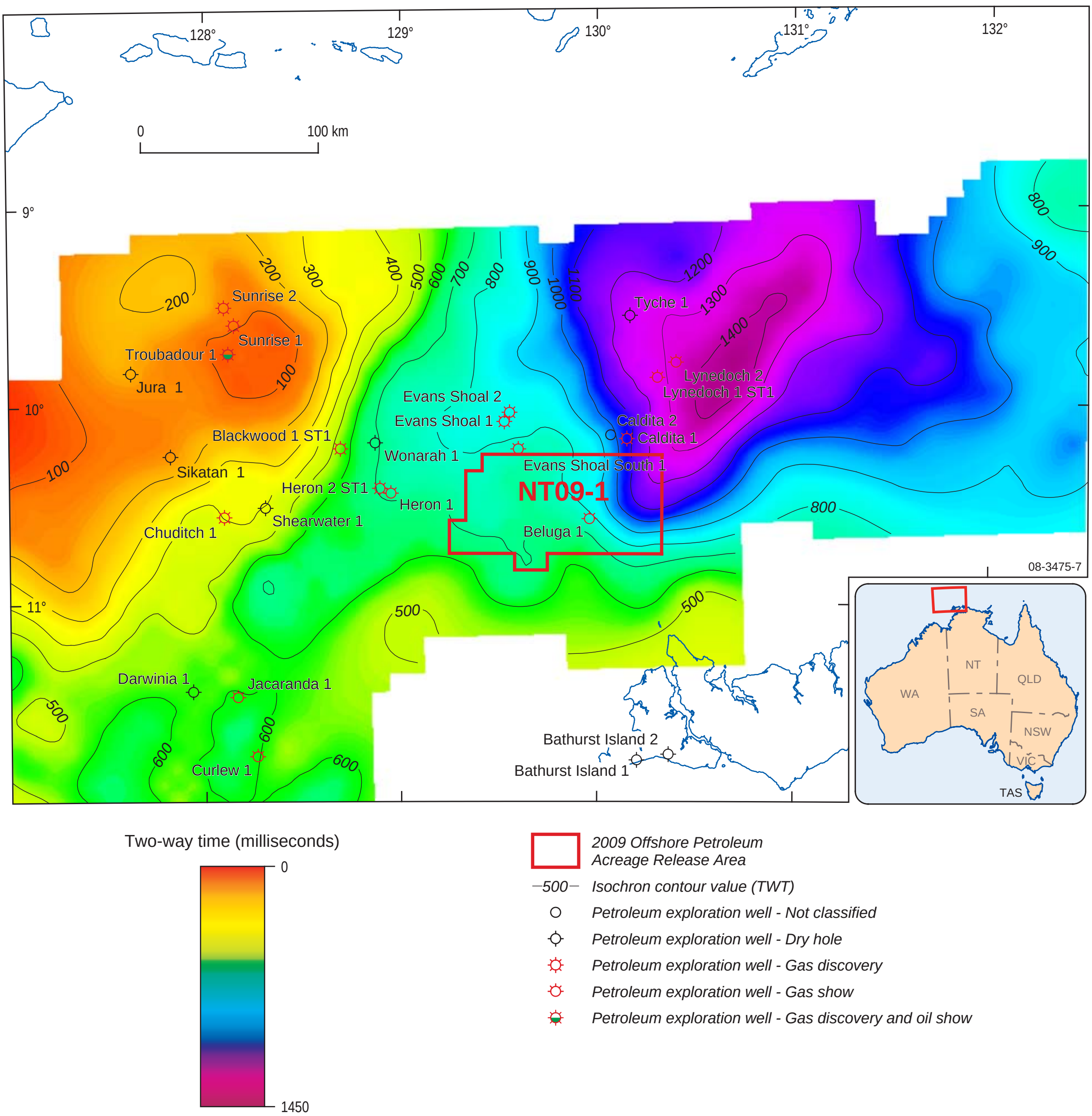
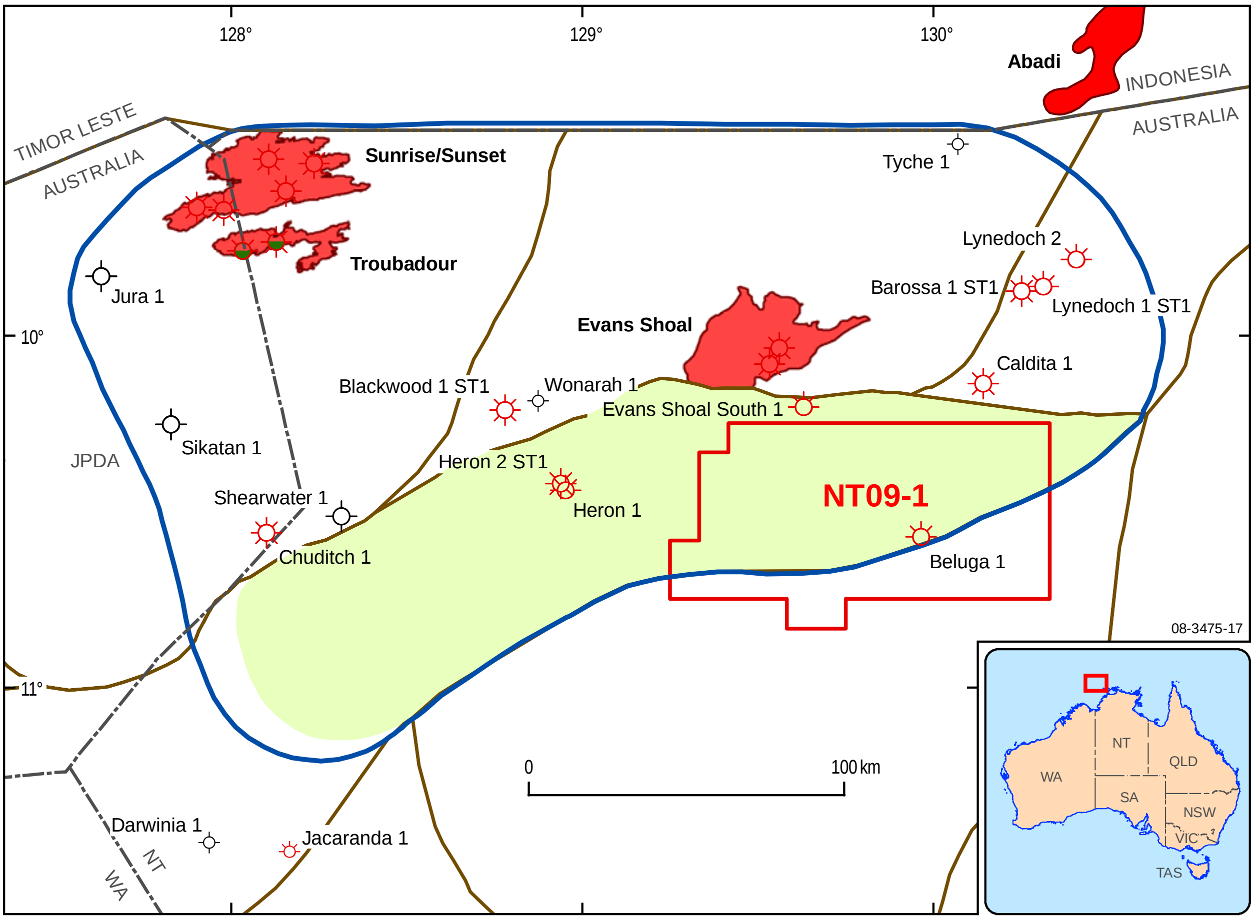


Figure 8. Isochron map (two-way-time) of the Turonian to Maastrichtian, (upper Wangarlu and Puffin formations). Contour interval is 100 milliseconds (Geoscience Australia, 2001).



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Field outline for Abadi is sourced from IHS Energy, 2006.

2009 Offshore Petroleum Acreage Release Area
Gas field
Inferred source pod
Limit of petroleum system
Structural element boundary
Scheduled area boundary (OPGGSA 2006)
Petroleum exploration well - Not classified
Petroleum exploration well - Dry hole
Petroleum exploration well - Gas discovery
Petroleum exploration well - Gas show
Petroleum exploration well - Gas discovery and oil show
Petroleum exploration well - Gas and oil show

Figure 9. The Jurassic Plover-Plover(.) Petroleum System in the Malita Graben, Bonaparte Basin (after Barrett et al, 2004). Large well symbols indicate tests of this petroleum system.

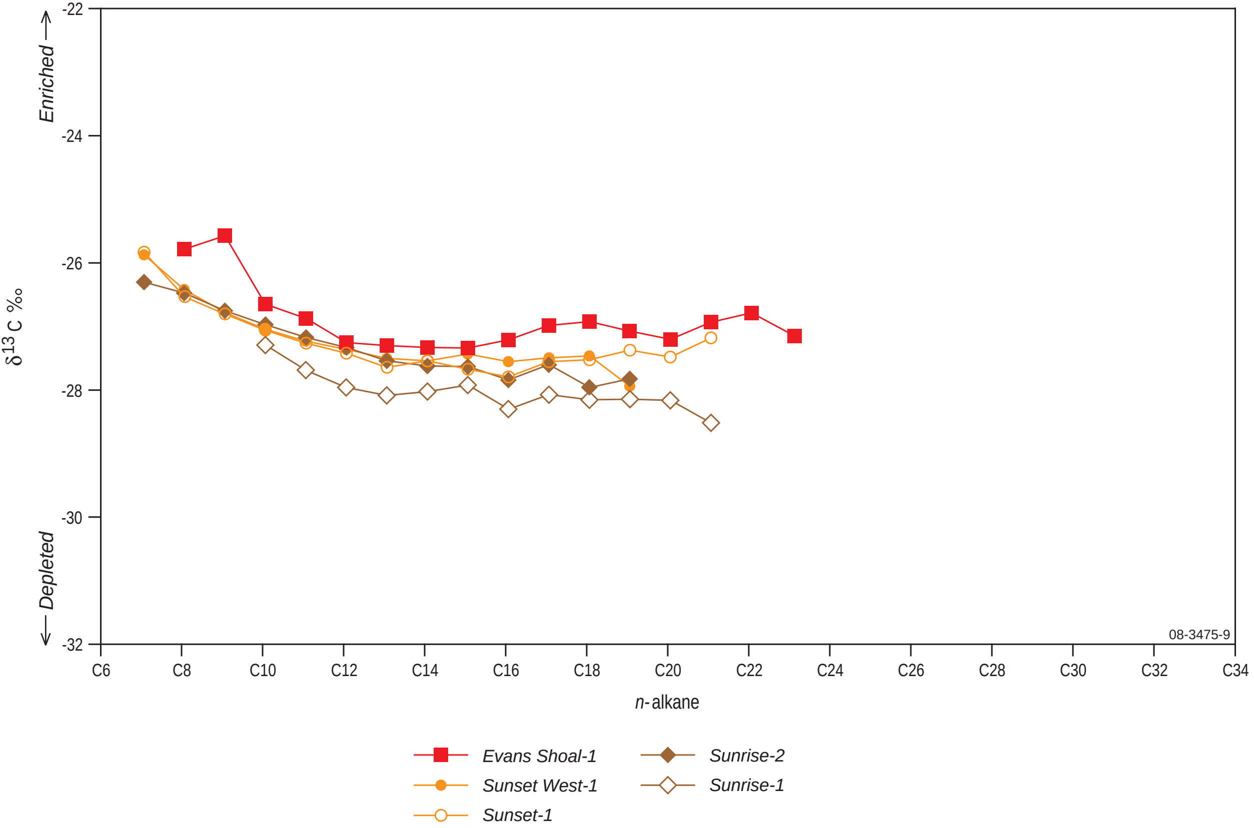
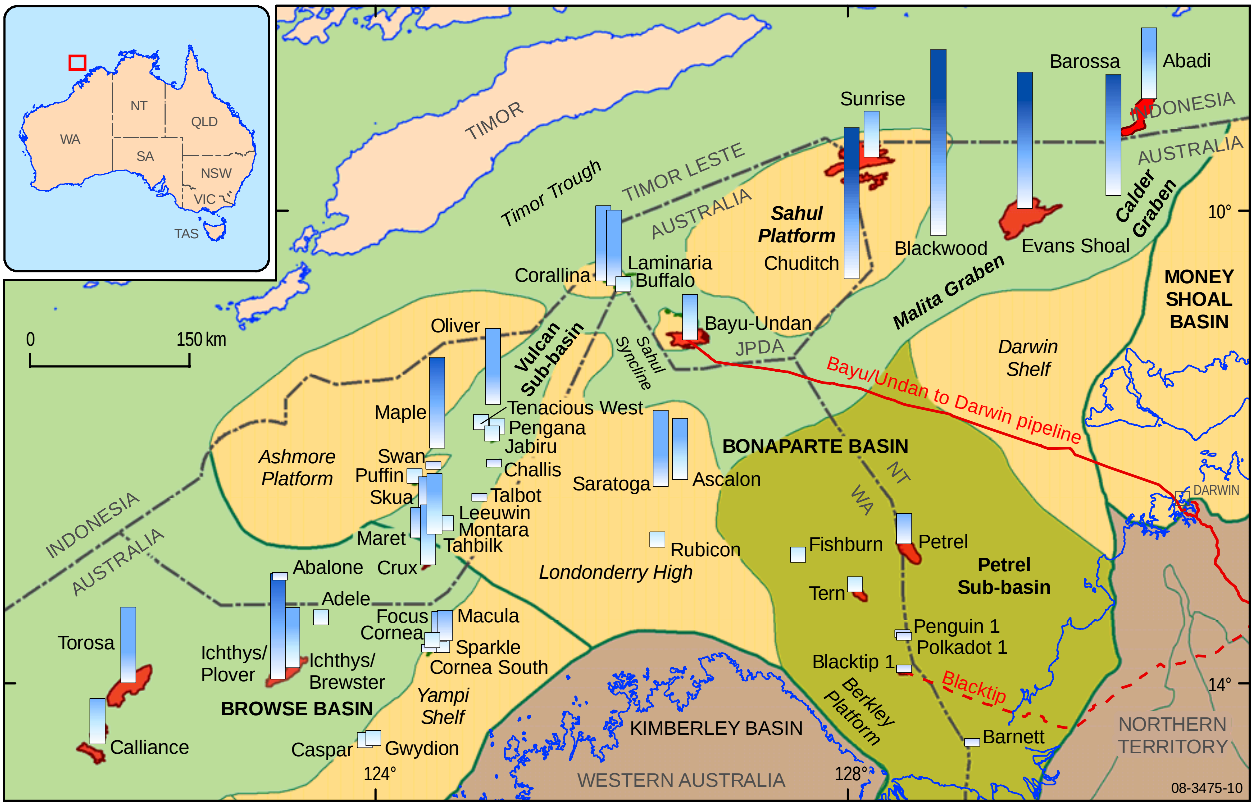


Figure 10. Carbon isotopic composition for C_{7+} *n*-alkanes of condensates recovered from gas accumulations in the northeastern Bonaparte Basin (after Edwards and Zumberge, 2005).



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.

Field outlines for Cornea, Ichthys and Abadi are sourced from IHS Energy, 2006.

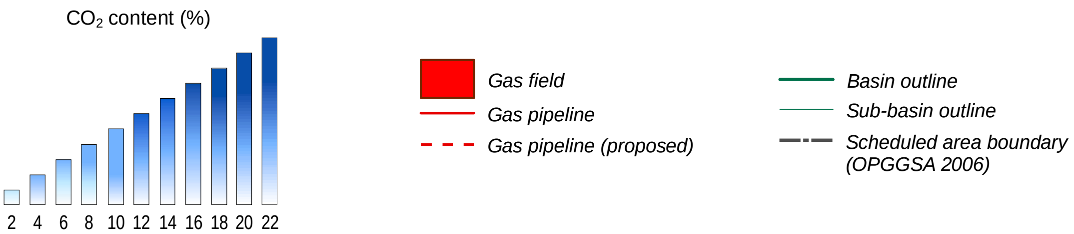


Figure 11. Distribution of CO_2 (mole %) in Bonaparte Basin and Browse Basin gas accumulations.

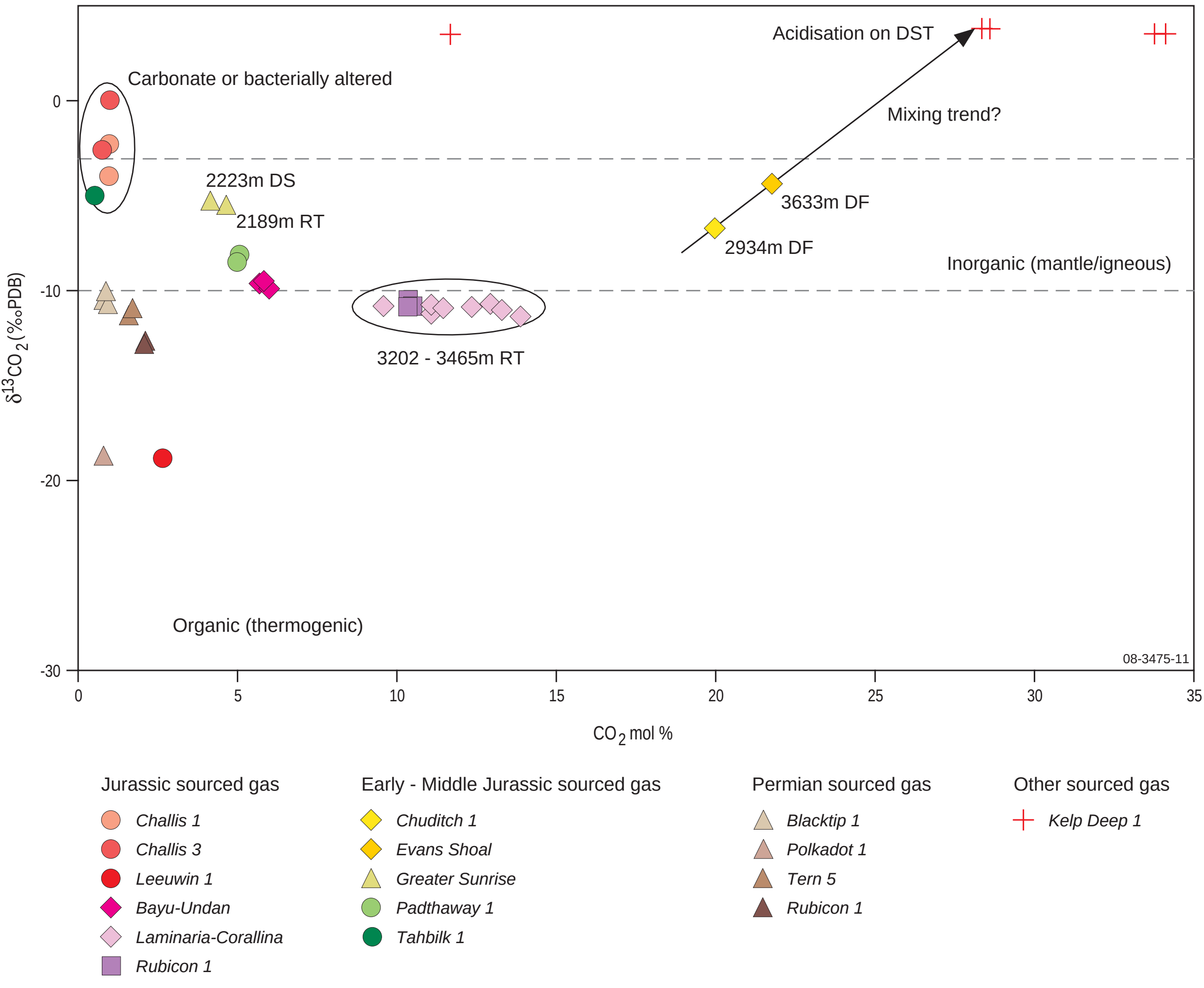


Figure 12. $\delta^{13}C$ isotopic values for CO_2 from Bonaparte Basin gas accumulations.

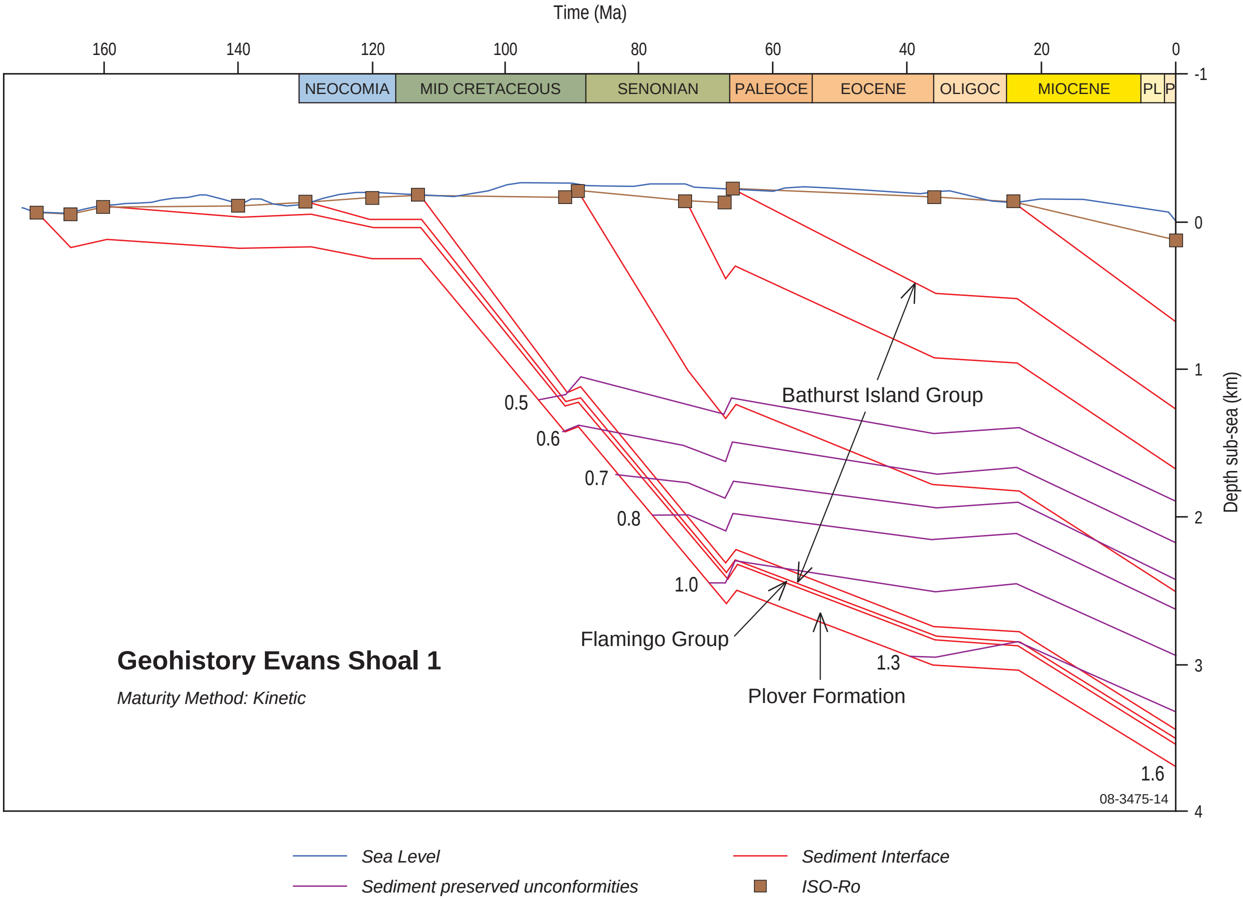


Figure 13. Burial history model Evans Shoal 1 (after West and Miyazaki, 1994).

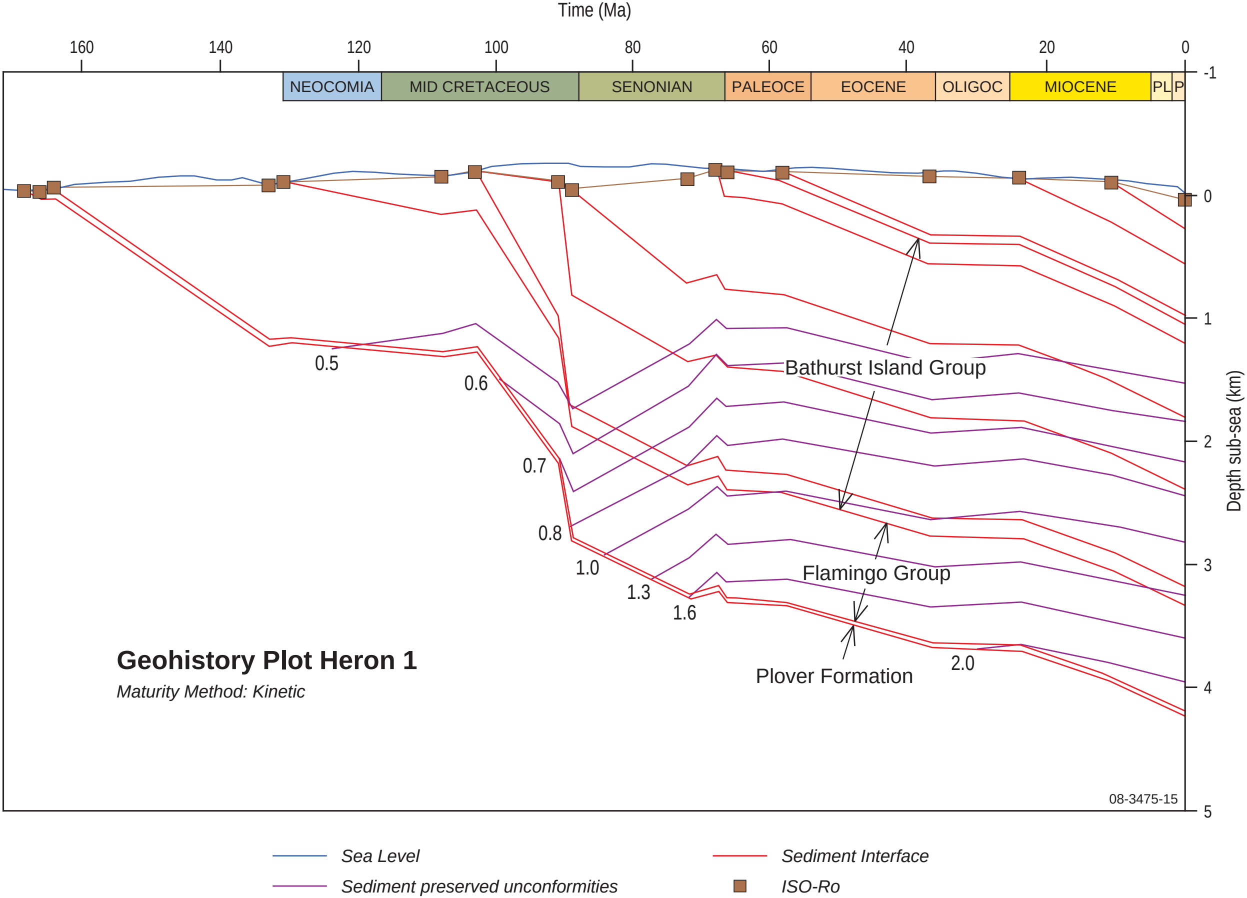


Figure 14. Burial history model Heron 1 (after West and Miyazaki, 1994).

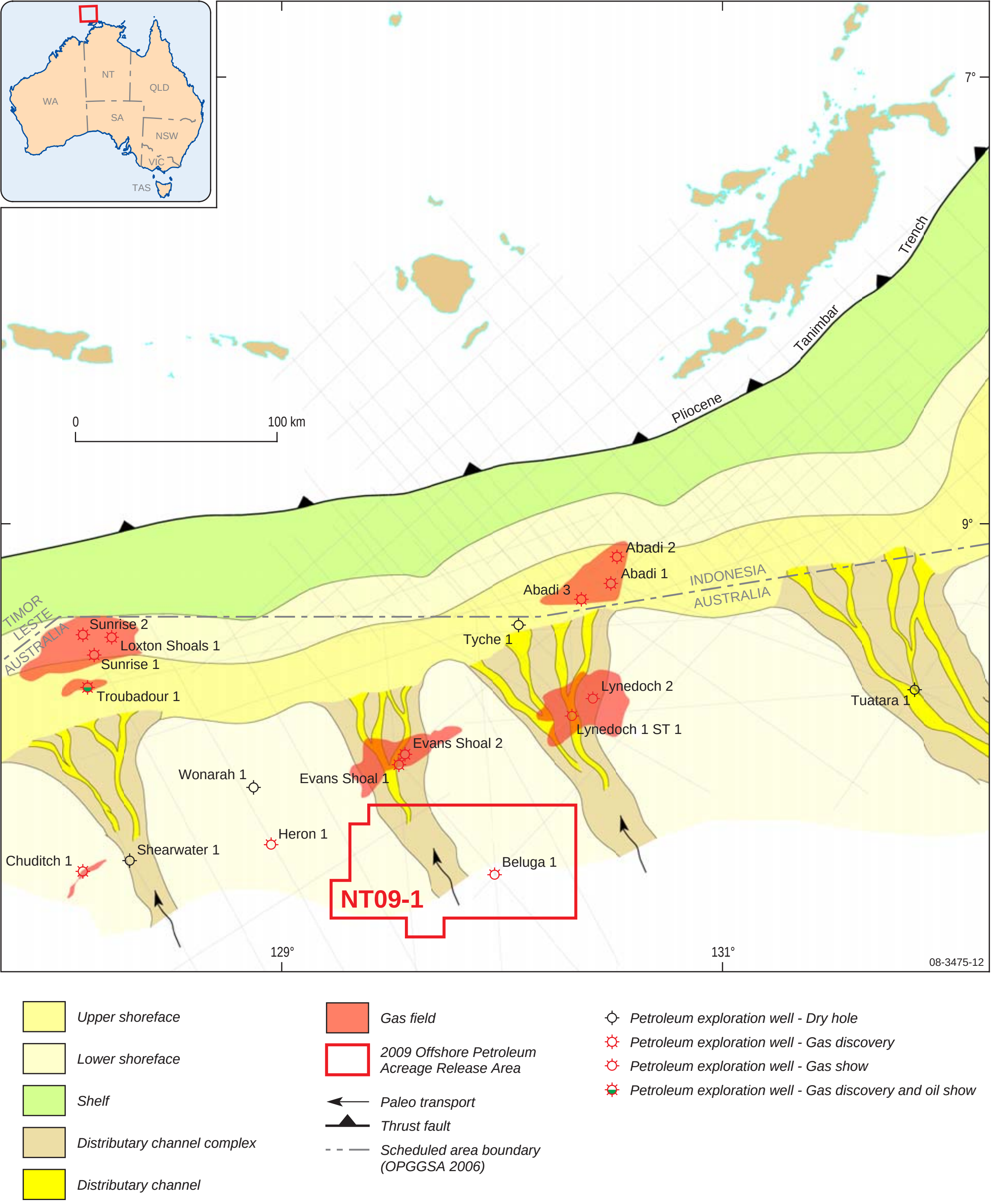


Figure 15. Upper Plover Formation palaeogeography (Barber et al, 2004).

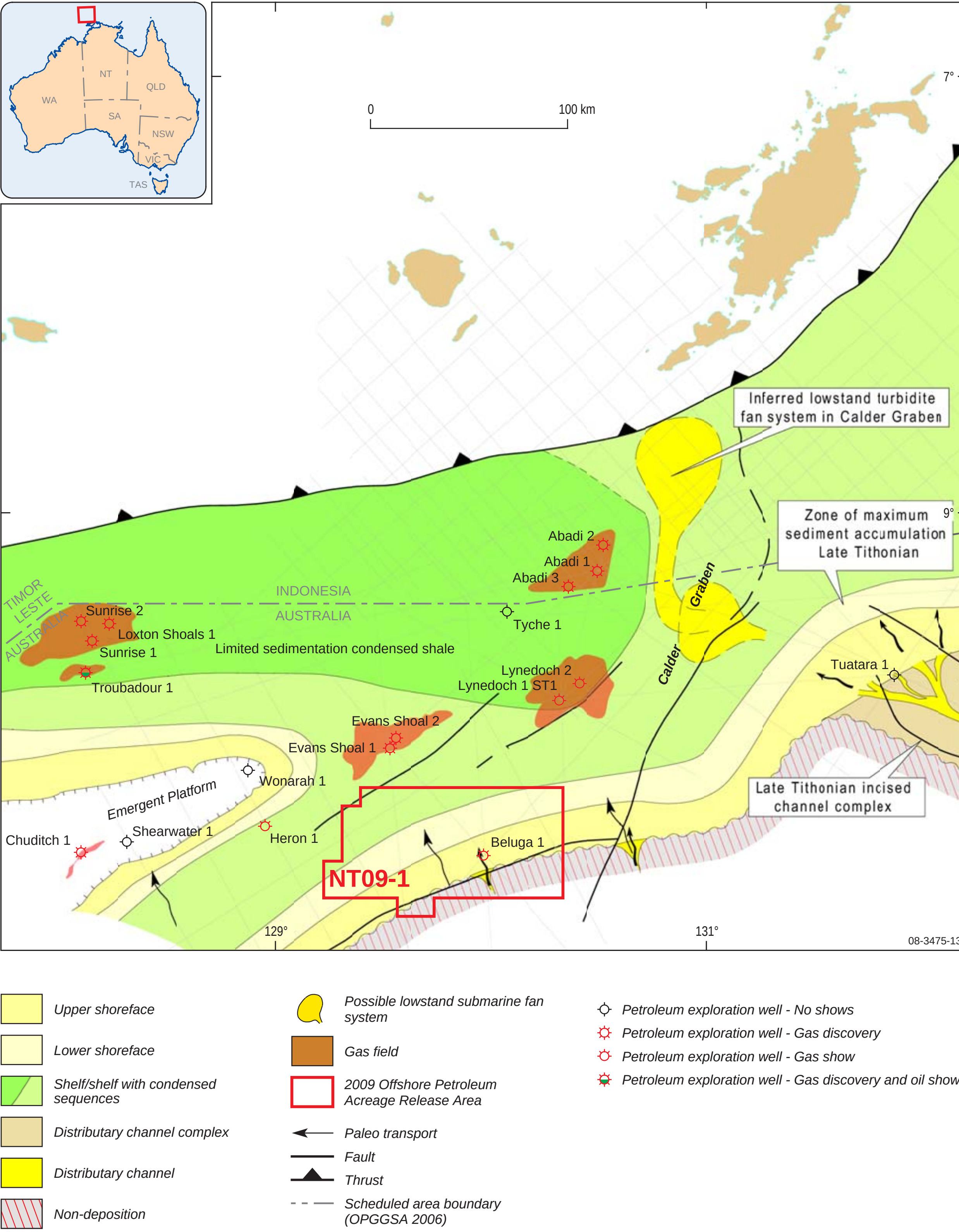


Figure 16. Flamingo Formation palaeogeography (Barber et al, 2004).

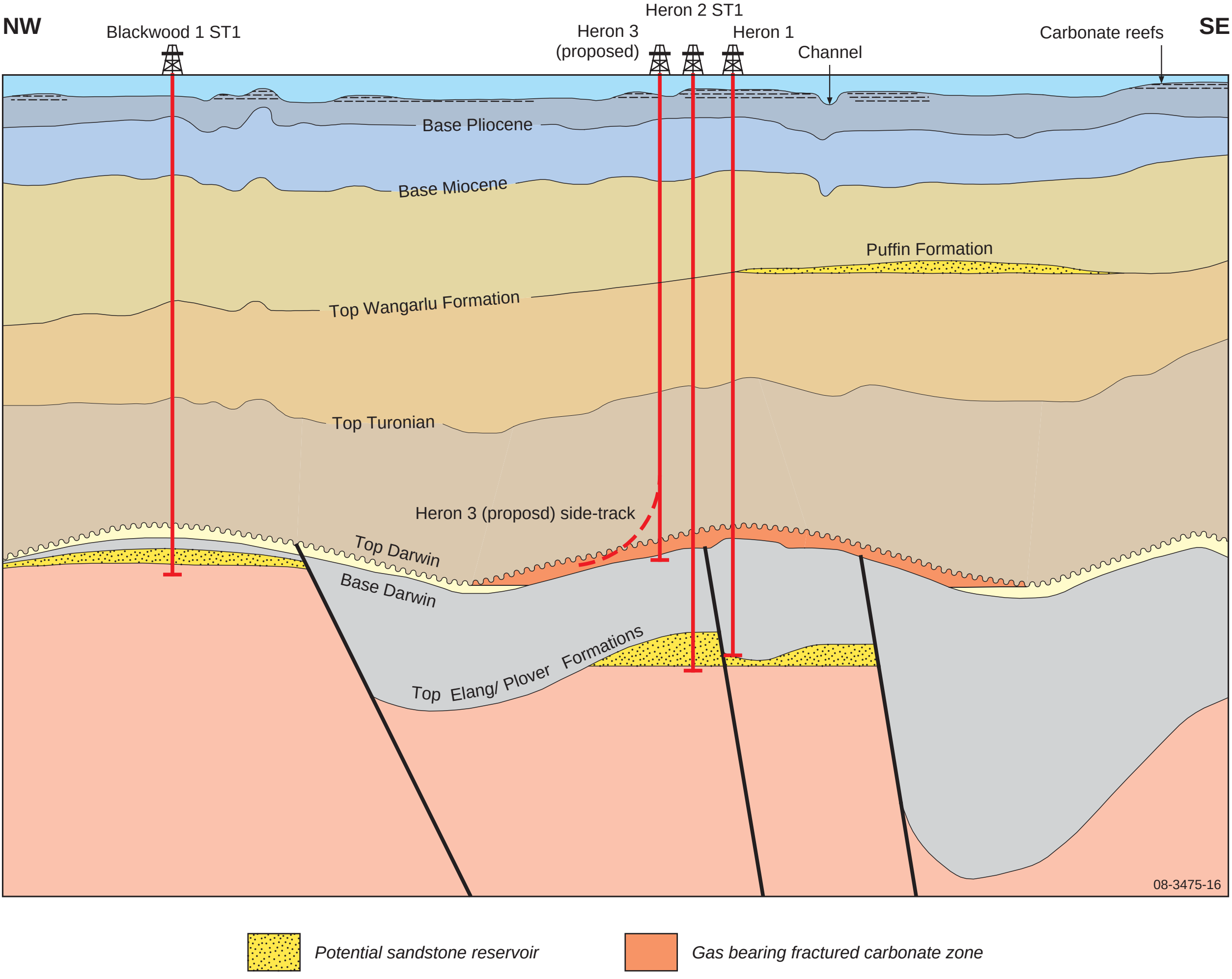


Figure 17. Schematic play diagram for Heron 2 ST1 and Blackwood 1 ST1 (after Geary, 2008; Hart, 2008).