Australian Government
Department of Resources, Energy and Tourism

Geological Information – Release Areas NT09-Special and W09-Special, Petrel Sub-basin, Bonaparte Basin

Location

Release Areas NT09-Special and W09-Special are located in the Joseph Bonaparte Gulf, about 400 km southwest of Darwin, in water depths ranging from 10 to 40 m (**Figure 1**). The Release Areas are about 35 km southeast of the Blacktip gas accumulation. Gas from Blacktip will be piped to Darwin via the onshore gas plant near Wadeye and the Bonaparte trans-territory pipeline. This pipeline connects to the existing pipeline transporting gas from the Amadeus Basin to Darwin. The Release Areas overlie an offshore portion of the southern Petrel Sub-basin, a distinct Paleozoic depocentre of the Bonaparte Basin (**Figure 2**).

Release Area NT09-Special comprises 44 graticular blocks, or parts thereof, and covers an area of approximately 2680 km^2. It contains the Barnett oil accumulation that was discovered by Barnett 2 (1989) and appraised by the Barnett 3 well. The exploration wells Kinmore 1 and Shakespeare 1 were drilled to the north of this Release Area, Kulshill 1, 2 and Sunbird 1 to the east, and Kingfisher 1 to the south.

Release Area W09-Special comprises 21 graticular blocks, or parts thereof, and covers an area of approximately 1220 km^2. It contains the Turtle oil accumulation that was discovered by Turtle 1 in 1984 and appraised by the Turtle 2 well. The Cape Ford 1 exploration well tested a stratigraphic play downdip of Turtle 2. Wells drilled just outside the Release Area include Cambridge 1, Lacrosse 1, Matilda 1, Sandbar 1, Weasel 1 and Windjana 1, which are located to the west, Lesueur 1 to the northwest, and Pelican Island 1 to the southwest. To the north-northwest, Retention Lease WA-33-L is held over the Blacktip gas accumulation.

Release Area Geology

The Petrel Sub-basin is located in northwestern Australia, with most of the sub-basin occurring offshore in the Joseph Bonaparte Gulf, where water depths are typically less than 100 m. The southernmost part of the sub-basin extends onshore in the area lying between the Ord and Victoria rivers (**Figure 2**). The Northern Territory/Western Australia boundary trends northwest along the axis of the sub-basin.

Local Tectonic Setting

The tectonic and stratigraphic development of the Petrel Sub-basin has been discussed in detail by Gunn (1988), Lee and Gunn (1988), Mory (1988, 1991), Gunn and Ly (1989), Petroconsultants Australasia Pty Ltd (1990), BRS (1994), McConachie et al (1996) and Colwell and Kennard (1996). It is most recently summarised by Kennard et al (2002) and Cadman and Temple (2004). Details of the onshore part of the sub-basin are discussed by Mory and Beere (1988).

The Petrel Sub-basin is an asymmetric, northwest-trending Paleozoic rift that contains a succession of thick Paleozoic and thinner Mesozoic sediments (**Figure 3** and **Figure 4**). The eastern and western faulted margins of the sub-basin converge onshore to form a southern termination. To the south and east of the Petrel Sub-basin, extensions of the Halls Creek-Fitzmaurice Mobile Zone separate this sub-basin from the Precambrian Victoria River Basin and Pine Creek Geosyncline. Extensive basement shelves are overlain by a thin cover of Phanerozoic sediments and are developed on the eastern, western and southern margins of the Petrel Sub-basin. To the east, the Kulshill Terrace and Moyle Platform extend to the north-northeast into the Darwin Shelf. In the southwest, the Berkley Platform extends eastward into the Cambridge and Turtle-Barnett highs, where it is flanked by the Lacrosse Terrace (**Figure 2**).

Strata within the Petrel Sub-basin dip regionally to the northwest with a northwest-plunging synclinal axis, resulting in exposure of Early Paleozoic sediments in the southern onshore area, and in the progressive subcropping of Late Paleozoic, Mesozoic and Cenozoic sediments offshore. The Late Paleozoic–Mesozoic section exceeds 15000 m in thickness in the central and northern Petrel Sub-basin.

Interpreted horizons for industry seismic lines through and nearby the 2009 Special Release Areas in the inboard Petrel Sub-basin are shown in **Figure 5**.

Structural and stratigraphic evolution

Late Givetian–Frasnian to Tournaisian upper-crustal extension produced a series of rift-related structures, particularly in the south and southwest of the basin (Gunn, 1988; O'Brien et al, 1993; Colwell and Kennard, 1996). These structures lie to the southwest of the axis of the main Visean basin 'sag' known as the Petrel Deep (**Figure 2**), indicating a possible partitioning between the mechanisms that controlled upper-crustal extension and the subsequent sag-dominated phase of the basin's tectonic evolution.

These rift-related extensional structures are bounded by major normal faults (and/or fault systems) and include planated basement platforms (eg, Berkley Platform and Moyle Platform), horst blocks (eg, Cambridge High and Barnett-Turtle High), rotated fault-blocks (eg, Lacrosse Terrace and Kulshill Terrace), and graben (eg, Cambridge Trough and Keep Inlet Sub-basin). Many of these features lie within, or are adjacent to, the 2009 Special Release Areas (**Figure 2**), and hence are considered in more detail later in this section.

The basin continued to receive sediment during the post-rift subsidence that occurred throughout the Carboniferous, Permian and Triassic. The Fitzroy Movement was a compressional event during the Late Triassic to Early Jurassic that is associated with salt mobilisation and resulted in the inversion of many earlier extensional faults. It is responsible for creating many traps within the sub-basin, including the anticlinal structures that host the Petrel and Tern gas accumulations. During this event, the onshore portion of the sub-basin was uplifted and eroded, resulting in the rapid thickening of the sediments from the south to the north.

Berkley Platform

The Berkley Platform is an area of planated shallow basement (tholeiitic dolerite was intersected in Berkley 1) that essentially forms an offshore extension of the Proterozoic Kimberley Basin. It dips to the northeast and is bounded on its northeastern margin by a major down-to-basin fault. Its landward extent approximates to the Kimberley coastline which, given its linear nature, may be fault controlled. The platform is overlain by about 2500 m of Pennsylvanian and younger sediments.

Moyle Platform

The Moyle Platform forms the eastern (largely onshore) flank of the Petrel Sub-basin where it consists of shallow crystalline basement, probably equivalent to those of the Pine Creek Geosyncline and Victoria River Basin. It is bounded on its eastern side by major faults of the Fitzmaurice Mobile Zone and on its western side by the Moyle Fault. It extends northward into the Darwin Shelf. The basement is overlain by ?Pennsylvanian–Cisuralian sediments, as intersected by the Moyle 1 well.

Cambridge High

The Cambridge High is an eastward-dipping, narrow basement horst-block that extends from the Berkley Platform in the west to the Turtle-Barnett High in the east. It is bounded by reactivated normal fault systems and flanked by major depocentres to both the south (Cambridge Trough) and north (Lacrosse Terrace and Petrel Deep). Initially, much of the syn-rift sediment in the southern Petrel Sub-basin appears to have been trapped south of the Cambridge High and adjacent Turtle-Barnett High. As the available accommodation space was filled, syn-rift sediments spread out as a series of alluvial fans across the highs and onto the developing Lacrosse Terrace to the north, and beyond. Movement on the faults bounding the Cambridge High during the late Tournaisian at the end of the syn-rift phase led to widespread erosion of syn-rift sediments across the high.

Turtle-Barnett High

The Turtle-Barnett High is a fault-bounded, approximately northwest-trending high-standing basement block, which juxtaposes the Cambridge High and Lacrosse Terrace. The position and trend of the high suggest that it may be related to reactivation of faults along the western edge of the Halls Creek Mobile Zone. Fault movements along its northwestern flank appear to post-date the formation of the main down-to-basin faults that form the northern margins of the Cambridge High and Lacrosse Terrace. However, during much of the Late Devonian–Early Mississippian (i.e. during syn-rift deposition) the Turtle-Barnett High was a high-standing feature that probably shed sediments into the adjacent developing depocentres of the Cambridge Trough and Keep Inlet Sub-basin. Like the adjacent Cambridge High, the feature was covered by sediments of the Bonaparte Formation and it was probably uplifted and eroded during the late Tournaisian at the end of the syn-rift phase.

Lacrosse Terrace

The Lacrosse Terrace is largely restricted to the area between the Turtle-Barnett High and the Lesueur 1 well, and comprises a rotated basement block that is overlain by syn-rift and younger sediments. The Lacrosse Terrace dies out as it merges into a series of deeper fault-blocks northwest of Lesueur 1.

Kulshill Terrace

The Kulshill Terrace has been variously applied to features in the southeast of the basin, but its usage herein is restricted to the onshore part of the basin to the west of the Moyle Fault. Two wells have been drilled in this area, Kulshill 1 and 2; both intersected thick Paleozoic sections.

Cambridge Trough

The Cambridge Trough is a graben that acted as a major Late Devonian–Mississippian depocentre lying to the south of the Cambridge High. Its geology is probably largely contiguous with that of the onshore Carlton Sub-basin, which lies to the south of a reactivated, east–west (wrench?) fault zone extending through the Pelican Island area. Sediments in the trough onlap the Berkley Platform to the west, and are bounded to the east by the Turtle-Barnett High. By the late Visean, the Cambridge Trough had filled and ceased to exist as a discrete structural entity.

Keep Inlet Sub-basin

The term Keep Inlet Sub-basin has been applied inconsistently over the years. It is used herein for the poorly developed depocentre lying east and southeast of the Turtle-Barnett High. It extends onshore in the south to the northeast of Keep River 1 and possibly to the east as part of the Kulshill Terrace.

Stratigraphy

The stratigraphy of the Petrel Sub-basin has been compiled from Beere and Mory (1986), Mory and Beere (1988), Mory (1991), Gorter (1998) and Gorter et al (1998). The stratigraphy shown in **Figure 3** has been updated to the Geologic Time Scale 2004 after Gradstein et al (2004), and revised to incorporate the most recent stratigraphic definitions by Gorter et al (2004, 2005, 2008 and 2009). Due to the complexity of the revised Petrel Sub-basin stratigraphy, **Figure 4** shows the relationships of the Devonian to Triassic subgroups and formations.

Sedimentation in the Petrel Sub-basin commenced in the Cambrian and continued into the Early Ordovician, with the deposition of shallow marine clastics and carbonates. This was followed, most probably in the Late Ordovician, by extensive evaporite deposits of unknown lateral continuity. These evaporites appear to be of similar age as those of the Carribuddy Group in the Canning Basin. A detailed account of salt diapirs and salt-related tectonics are given by Edgerley and Crist (1974), Woodside Australian Energy (2002a) and Leonard et al (2004).

Rifting was initiated in the Late Devonian and siliciclastic sediments and carbonates were deposited in terrestrial and shallow marine environments. In the southern onshore portion of the basin, the Frasnian sediments of the Cockatoo Group are dominated by coarse clastics and conglomerates, some of which may be non-marine (Mory and Beere, 1988). Northward, the coarse-grained Cockatoo Group facies are gradually replaced by siltstones and shales with interbedded sandstones and sandy limestones, known as the Bonaparte Formation (Mory and Beere, 1988).

In the Famennian, the clastics of the Cockatoo Group are replaced by the reefal carbonates of the Ningbing Group around the margins of the basin, while in the deeper central onshore and offshore portions of the basin, deposition of the Bonaparte Formation continued essentially unchanged (Mory and Beere, 1988).

By the Mississippian, rifting had produced a northwest-trending basin, in which marine, fluvio-deltaic and glacial sediments accumulated as a result of post-rift subsidence and salt withdrawal during the Carboniferous and Permian. These Permo-Carboniferous sediments represent the bulk of the basin-fill in the Petrel Sub-basin.

In the Tournaisian the reefal facies was replaced by mixed carbonates, and fine-grained clastics of the Langfield Group (Mory and Beere, 1988; Gorter, 2006a) on the basin margins, with deposition of the Bonaparte Formation continuing in the deeper portion of the basin. The type section for the Bonaparte Formation is defined between 2280 and 3210 mKB total depth (TD) in Bonaparte 1 (Beer and Mory, 1986; Mory, 1991) and comprises a sequence of shale, siltstone, sandstone and minor sandy limestone.

Towards the end of the Tournaisian, an unconformity separates the Langfield Group and offshore Bonaparte Formation from the overlying Weaber Group, represented at its base by the Milligans Formation.

The Mississippian Weaber Group, as developed in the southern part of the Petrel Sub-basin, is a complex package of clastic and carbonate sediments separated by several unconformities. The original definition of the Weaber Group as described by Mory and Beere (1988) and Mory (1991) has been revised by Gorter et al (2005), so that it now comprises the Milligans Formation (including the Waggon Creek facies), Yow Creek Formation, Utting Calcarenite, Kingfisher Shale/Burvill Formation, Tanmurra Formation, Sandbar Sandstone and Sunbird Formation.

The Tournaisian–Visean Milligans Formation was originally defined by Mory (1991) as consisting of fossiliferous shales and siltstones with the type section occurring over the depth range 44–155 m in Milligans No.1 Bore (Veevers and Roberts, 1968), Thick Milligans Formation is penetrated in the onshore wells Keep River 1 and Bonaparte 1 and 2, with the thickest offshore section occurring within Kingfisher 1 (Gorter et al, 2005). The 'Milligans Beds' is a term used to describe the shales overlying the Langfield Group in some of the earliest wells drilled in the Petrel Sub-basin, but may not correspond to the Milligans Formation as currently defined. The Milligans Formation extends throughout the Cambridge Trough, Keep Inlet Sub-basin and the onshore parts of the sub-basin. The age of this formation has been redefined and is regarded as being of latest Tournaisian–early Visean in age (Gorter et al, 2004, 2005). The basin margin equivalent of the Milligans Formation is known as the Waggon Creek facies that comprises predominately pebbly sandstones and conglomerates overlain by sandstones and shales, as intersected at Keep River 1 and Waggon Creek 1 (Beere, 1984; Gorter et al, 2005).

The Visean Yow Creek Formation is a basinal shale that commonly contains ironstone, which is bounded by unconformities at the base and top (Gorter et al, 2005). The type section is between 980–1160 mKB in Bonaparte 1. The overlying Utting Calcarenite is named from the type section in Utting Gap and comprises fossiliferous sandy limestone and calcareous sandstone (Veevers and Roberts, 1968; Mory and Beere, 1988). This may be the low stand section of the Yow Creek Formation (Gorter et al, 2005). The abrupt lithological change from the Utting Calcarenite to the carbonaceous claystone of the Kingfisher Shale is taken to represent a rapid deepening event (Gorter et al, 2005). The type section for the Kingfisher Shale is between 1950–2091 mRT in Kingfisher 1. The Utting Calcarenite and Kingfisher Shale are lateral equivalents of the coarse clastic-dominated Burvill Formation developed near the basin margin.

The Visean Tanmurra Formation unconformably overlies the Kingfisher Shale and comprises a thick succession of calcareous and dolomitic sandstones and sandy carbonates deposited throughout the Carlton Sub-basin, Cambridge Trough and Keep Inlet Sub-basin. Carbonates of this age are known as the 'Medusa Beds' in Lacrosse 1 (Arco Limited, 1969). Gorter et al (2005) redefined the type section for the Tanmurra Formation from that of Mory (1991) to being between 220–497 mKB in Bonaparte 1. Shales within the sandstones contain high organic contents as intersected at NBF-1002, Keep River 1, and possibly within a poorly sampled section of Kingfisher 1.

The uppermost units of the Weaber Group are the Visean Sandbar Sandstone and overlying Visean–Serpukhovian Sunbird Formation (Gorter et al, 2005). The Sandbar Sandstone consists of mixed lithologies with the lower part dominantly carbonate and the middle and upper parts comprise carbonates and interbedded quartzose sandstones. The type section is between 1634–1695 mRT in Sandbar 1. The Sandbar Sandstone occurs within the Cambridge Trough, but it is not present on the Barnett-Turtle High and in Matilda 1. Seismic profiles show that the Sandbar Sandstone either pinches out or is truncated by the base of the Sunbird Formation. The Sunbird Formation is present widely throughout the southern Petrel Sub-basin and comprises massive limestone with minor quartzose sandstone, with the type section being between 2236.5–2598.5 mRT in Sunbird 1 (Gorter et al, 2005).

The Late Mississippian–Early Pennsylvanian Wadeye Group is represented on the basin margins by the Point Spring Sandstone, consisting of sandstones, pebbly sandstones and minor siltstones, and in the deeper parts of the basin by the finer grained clastics of the Arco and Aquitaine formations (Gorter et al, 2005). Note that the Wadeye Subgroup of Gorter et al (2008) has not been adopted herein. The base of the Wadeye Group is characterised by canyon incision as a result of a major fall in sea level.

The Wadeye Group is overlain unconformably by the Early Pennsylvanian–Cisuralian Kulshill Group. The Kulshill Group, as redefined by Gorter (2006b) and Gorter et al (2008) comprises the Kuriyippi, Treachery, Quoin, Ditji and Keyling formations. The Kulshill Group was deposited in an overall transgressive cycle, overprinted by the onset of glaciation in the Kuriyippi Formation (Mory, 1991). The Bashkirian–Asselian Kuriyippi Formation, and its western basin-margin equivalent Border Creek Formation and eastern onshore sub-basin equivalent the Keep Inlet Formation, are overlain by the regional Treachery Formation. The Kuriyippi Formation, as defined by Mory (1991), is a thick succession of upward fining cycles of sandstones, siltstones, shales and minor coals, overlain by glacial sandstones and conglomerates. The complex incised channel network at the top of the Kuriyippi Formation suggests that the area lay under an ice sheet at this time (Gorter et al, 2008). The capacity of this formation to entrap oil is demonstrated at Barnett and Turtle on the Turtle-Barnett High and gas at Blacktip. The type section is named after the Kuriyippi Hills and is defined in Lesueur 1 between 1784–2801 mKB, which is the thickest section penetrated in the Petrel Sub-basin (Mory, 1991).

The Sakmarian Treachery Formation extends throughout the southern Petrel Sub-basin where it unconformably overlies the Kuriyippi Formation (Gorter 2006b; Gorter et al, 2008). It comprises tillites, diamictites, carbonaceous shales, varved siltstones, sandstones and minor limestones and coals, and provides top seal to accumulations in the underlying Kuriyippi Formation. The type section is between 1094–1227 mRT in Kulshill 1 where it was named the Treachery Shale (Mory, 1991). However, Gorter et al (2008) renamed the unit the Treachery Formation, and includes the informally named Blacktip member, a reservoir at Blacktip 1. These authors also propose a reference section between 2827.3–3072.8 mRT in Blacktip North 1. In the Keep Inlet Sub-basin, the formation is over 300 m thick in Kingfisher 1, Sunbird 1 and Kulshill 1, with the formation thinning towards the basins margins.

The Sakmarian Quoin and Ditji formations as defined by Gorter et al (2008) were originally included within the overlying Keyling Formation of Mory (1991). The type section of the Quoin Formation is between 1145–1350 mKB in Barnett 1, with a reference section established in Blacktip 1 (Gorter et al, 2008). The Quoin Formation is a sharp-based blocky sandstone that fines upwards into thinner sandstones, siltstones and shales. These sediments were deposited in a fluvial environment after de-glaciation when melt water from the ice sheet carried vast quantities of sediments into the basin. The formation is thickest (˜750 m) in the vicinity of Kulshill 1 and 2. The overlying Ditji Formation is interpreted as a transgressive sequence deposited in response to the end of glaciation (Gorter et al, 2008). The type section of the Ditji Formation is between 1721–1795 mKB in Kinmore 1 with a reference section of 1079–1132 mKB in Barnett 1 where a characteristic ash bed is present (Gorter et al, 2008). The formation comprises hard calcareous sandstone grading into sandy limestone, with minor interbedded coals. The marine transgression was terminated by the prograding coarse-grained sediments of the Keyling Formation.

The Sakmarian Keyling Formation was originally defined as the type section between 254–1094 mRT in Kulshill 1 (Mory, 1991). Gorter et al (2008) redefined the formation and suggested a reference section within Blacktip 1 (2152.5–2601.5 mRT). The formation probably unconformably overlies the Ditji Formation, and is unconformably to conformably (in the north) overlain by the Fossil Head Formation. The formation comprises delta-plain and marginal marine sandstones, siltstones, shales and minor coals and limestones. The coals are intersected in the eastern Petrel Sub-basin and on the Darwin Shelf by Kinmore 1 and Flat Top 1, respectively. The coals and marginal marine shales have moderate to very good oil and gas potential. The Keyling Formation is present throughout the southeastern Petrel Sub-basin being 525 m thick at Polkadot 1 and 450 m thick at Blacktip 1. The Keyling Formation is about 300 m thick in Kulshill 1 and 2. It generally thins towards the southern basin margin, where it is truncated below the base of the Fossil Head Formation. The Keyling Formation was deposited in a marginal marine environment. The Keyling Formation is the primary reservoir below the Fossil Head Formation regional seal, and is a gas-bearing reservoir at Blacktip 1 (Leonard et al, 2004) and Tern 1 and contains oil at Turtle 1.

The Cisuralian to Middle Triassic Kinmore Group of Mory (1991) has been redefined by Gorter et al (1998) and Gorter et al (2009) so that it now comprises the Fossil Head Formation, Hyland Bay Subgroup and Mount Goodwin Subgroup (**Figure 3** and **Figure 4**). The Sakmarian–Roadian Fossil Head Formation comprises carbonaceous siltstones and mudstones with sandstones and minor limestones. The type section is between 2993–3569 mKB in Tern 1 (Mory, 1991). It occurs throughout the southern Petrel Sub-basin, south of Petrel 1 and was deposited under marine shelfal conditions. This transgressive sequence forms the regional seal in the Petrel Sub-basin.

The Hyland Bay Formation of Mory (1991) was revised to the Hyland Bay Subgroup by Gorter (1998), with the terminology used interchangeably in the well completion report extracts herein depending on the vintage of the report being quoted. The Hyland Bay Subgroup consists of pro-delta, deltaic and shoreface mudstones, siltstones and sandstones, as well as open shelf carbonates that are particularly thick (up to around 2300 m) in the central and outer parts of the Petrel Sub-basin. Gorter (1998) and Gorter et al (1998) divided the subgroup into five formations; Pearce, Cape Hay, Dombey, Tern and Penguin formations. However, the basal Torrens Member, as defined between 1208–1230 mRT in Torrens 1 (Gorter, 1998) has since been given formation status (**Figure 3** and **Figure 4**), and the Penguin Formation is now classed as the base of the Mount Goodwin Subgroup (Gorter et al, 2009). Robinson and McInerney (2004) published palaeogeographic reconstructions of the most important reservoir units within the Hyland Bay Subgroup. The Torrens Formation hosts gas at Penguin 1, Petrel 2 and Polkadot 1. The Pearce Formation is represented by a shelf and platform carbonates. The Cape Hay Formation (Gorter, 1988) is the equivalent to the Hay Member of Bhatia et al (1984). It is the reservoir unit for the gas accumulations at Ascalon 1A, Petrel, Tern 4 and oil shows at Turtle 2. It was deposited as part of a widespread, river-dominated delta system with restricted shoreface conditions (Robinson and McInerney, 2004). The Dombey Formation carbonates provide the top-seal to the Cape Hay Formation. The Tern Formation is the reservoir for the Tern gas accumulation and gas shows at Ascalon 1A. The formation is interpreted to represent shoreface and shoal environments (Robinson and McInerney, 2004). The Tern Formation comprises open-marine sediments and forms a broad, prograding shoreface system. The Hyland Bay Subgroup is conformably overlain by the thick transgressive claystones of the latest Permian–Early Triassic (Changhsingian–Olenekian) Penguin and Mairmull formations, which provides both vertical and lateral seal across the Petrel Sub-basin. Where the Penguin Formation is absent, the Mairmull Formation unconformably overlies the Hyland Bay Subgroup.

Collectively the Penguin, Mairmull, Ascalon and Fishburn formations comprise the Mount Goodwin Subgroup (Gorter et al, 2009). The type section for the Penguin Formation is between 2400–2449 mKB in Tern 3 (Gorter, 1998) and is believed to have been deposited in a lacustrine setting. Although the formation is predominantly claystones, it hosts gas at Fishburn 1. The Mairmull Formation consists of claystones and siltstones with the type section being between 2121–2320 mRT in Fishburn 1 (Gorter et al, 2009), where it was deposited in a shallow water marine environment. The Olenekian Ascalon Formation is a prominent, widespread sandstone and siltstone unit deposited throughout the southern Bonaparte Basin. The type section is between 4072.5–4105 mRT in Ascalon 1A (Gorter et al, 2009). The sandstones were deposited in a marginal marine setting and probably represent a lowstand package. Gas is reservoired within the Ascalon Formation at Blacktip 1 and gas shows occur at Ascalon 1A. The Olenekian–Anisian Fishburn Formation consists of claystones with minor siltstone and sandstone, probably deposited in a near-shore environment. The type section is between 1904.5–2084 mRT in Fishburn 1 (Gorter et al, 2009).

The Kinmore Group is unconformably overlain by the Troughton Group in the eastern Bonaparte Basin, and the partially time equivalent Sahul Group in the western Bonaparte Basin (Mory, 1991; Gorter et al, 2009). The Middle Triassic to Middle Jurassic Troughton Group comprises the Cape Londonderry, Malita and Plover formations (Mory, 1991). It is a thick clastic sequence of marginal-marine to marine sandstones, siltstones and dolomitic shales. The Sahul Group is also marine to marginal marine, but contains more carbonates and shales than the Troughton Group and is defined from well penetrations on the Ashmore Platform, Vulcan Sub-basin and Londonderry High.

The Anisian Osprey Formation is recognised in wells in the Vulcan Sub-basin and on the Ashmore Platform and Londonderry High. In the eastern Bonaparte Basin, the Osprey

Formation is equivalent to the basal part of the Cape Londonderry Formation (Mory, 1991). The formation has been mapped to extend within wells in the central Petrel Sub-basin as a package of interbedded sandstones and shales, with some minor carbonates underlying the sandstone-dominated Cape Londonderry Formation (Gorter et al, 2009).

The regressive Cape Londonderry Formation (Anisian–Norian) consists of sandstones and minor amounts of siltstones and shales, and was deposited during a relatively stable sag phase in a fluvial to braided stream environment. The type section is between 2471–2887 mKB in Petrel 1 (Helby, 1974; Mory, 1991). In the Middle Triassic, uplift and northeast–southwest rifting was initiated, which resulted in the widespread erosion of the Cape Londonderry Formation and parts of the Mount Goodwin Subgroup. Depositional environments changed from marine to terrestrial, culminating in red-bed deposition of the Late Triassic (Norian–Rhaetian) Malita Formation. The type section is between 2229–2471 mKB in Petrel 1 (Helby, 1974; Mory, 1991). Late Triassic compressional inversion related to the Fitzroy Movement involved extensive uplift and erosion along the southern margin, and created structural traps within the sub-basin.

The Early–Middle Jurassic Plover Formation ('Petrel C' of Arco Australia Limited (1971a) contains sandstones that may have excellent reservoir qualities, as well as shales with some source potential. These sediments were deposited as thick sequences in deltaic to near-shore environments within the central and northern Petrel Sub-basin.

The Middle Jurassic–Early Cretaceous Flamingo Group represents a time of minor extension and subsidence and herein comprises the Elang Formation, Lower Frigate Shale/Cleia Formation, Frigate Shale and Sandpiper Sandstone, as modified from Mory (1991), Pattillo and Nicholls (1990) and Whittam et al (1996). The Flamingo Group includes the packages of sediments referred to as 'Petrel A' and 'Petrel B' by Arco Australia Limited (1971a). The Callovian–Oxfordian Elang Formation is an excellent reservoir elsewhere in the Bonaparte Basin, whereas the basal marine shale, the Oxfordian–Tithonian Cleia Formation/Lower Frigate Shale and Frigate Shale, can form an excellent top seal and cross-fault seal to the Plover Formation. The overlying Berriasian–Valanginian Sandpiper Sandstone is an excellent reservoir unit, although no hydrocarbon shows have been recorded in this formation in the Petrel Sub-basin.

The intra-Valanginian unconformity separates the Flamingo Group from the overlying Cretaceous Bathurst Island Group that comprises the Echuca Shoals Formation, Darwin Radiolarite and Wangarlu Formation. During this time, the Bonaparte Basin was submerged during a post-rift sag phase, and widespread, thick, shale-dominated marine sediments were deposited across the basin, with the thickest sections occurring in the Petrel Sub-basin, Malita Graben and Calder Graben. The basal glauconitic claystones of the Valanginian–Aptian Bathurst Island Group were originally defined as the Darwin Formation by Mory (1988, 1991). However, many subsequent workers have referred to this 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 herein as the 'Darwin Radiolarite').

The mid-Valanginian–early Aptian Echuca Shoals Formation comprises a condensed section of glauconitic, marine claystones and siltstones. These sediments were deposited widely across the Bonaparte 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 overlying Wangarlu Formation is an Albian to mid-Campanian progradational sequence that was deposited in a marine shelf to slope environment. The basal section predominantly comprises massive 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, in the Vulcan Sub-basin and northern Bonaparte Basin.

A regional erosional event occurred between the Late Cretaceous (Santonian) and Miocene leading to the accumulation of the Woodbine Group on a progradational shelf of the passive margin. The collision of the Australian Plate with the Banda Arc resulted in north–south compression and minor inversion of the generally east–west normal faults and possible strike-slip along older northeast–southwest-trending Triassic-aged faults.

Exploration History

In 1839, the crew of HMS Beagle found bitumen in water wells sunk on the banks of the Victoria River in the southern Petrel Sub-basin. This is one of the earliest oil shows documented in Australia. Initial petroleum exploration began in the early 1950s and resulted in seismic, aeromagnetic and gravity surveys being undertaken by the Bureau of Mineral Resources (BMR) in 1956. The first well to be drilled in the Bonaparte Basin was the onshore stratigraphic well Spirit Hill 1, which was spudded in 1959 by Westralian Oil Limited. It penetrated Carboniferous to Late Devonian sediments in which oil indications were recorded. This well was followed by the onshore gas discovery at Bonaparte 2 by Alliance Oil Development Australia in 1964 where gas flowed from reservoirs within the Mississippian Kingfisher Shale to Milligans Formation. Keep River 1, drilled by Australian Aquitaine Petroleum Pty Ltd in 1969, also flowed gas from the Milligans Formation. Other wells drilled by Australian Aquitaine Petroleum Pty Ltd in 1966 were Kulshill 1 and 2 which recorded oil shows, and Moyle 1, which was plugged and abandoned without encountering any hydrocarbons.

Some of the earliest offshore geological and geophysical surveys were undertaken by the Scripps Institute of Oceanography and the BMR, and included sea bottom echo profiling and sampling (van Andell and Veevers, 1967). Offshore exploration was conducted by several consortia, including the Arco Australia Ltd (Arco) led joint venture, which drilled the first offshore well, Lacrosse 1, in 1969. Arco then went on to drill Petrel 1, 1A, 2, Gull 1, Tern 1, Sandpiper 1, Pelican Island 1 and Penguin 1 throughout the early 1970s, resulting in the discovery of gas at Petrel, Tern and Penguin. Arco's later drilling of Curlew 1 (1975) and Frigate 1 (1978), were not able to maintain their earlier successes. Also during the 1970s, Australian Aquitaine Petroleum Pty Ltd (Australian Aquitaine) was actively drilling in the offshore Petrel Sub-basin; however, none of their wells (Newby 1, Flat Top 1, Bougainville 1 and Kinmore 1) resulted in discoveries.

Australian Aquitaine continued to drill exploration wells in both the onshore and offshore Petrel Sub-basin throughout the early 1980s, as well as appraising the Petrel and Tern accumulations. However, it was Western Mining Corporation Limited that discovered the small oil accumulation at Turtle (1984) in the southern, offshore part of the sub-basin. Petroleum-bearing reservoirs were found in numerous Carboniferous and Permian formations. The Barnett oil accumulation was discovered in 1989 with the drilling of Barnett 2 by Elf Aquitaine Exploration Australia Pty Ltd. Onshore, gas was discovered by Santos Ltd in the Garimala 1 well drilled in 1988.

In the early 1990s, appraisal of the offshore Petrel and Tern accumulations continued, as did the appraisal of the onshore Weaber gas accumulation, first discovered in 1982 by Australian Aquitaine. Of the eight offshore exploration wells drilled at this time, only Fishburn 1, drilled by BHP Petroleum Pty Ltd, was successful in making another gas discovery. Of the four wells drilled onshore in the 1990s, Waggon Creek 1 and Vienta 1 were gas discoveries made by Amity Oil NL.

Since the gas discovery at Blacktip 1 in 2001 by Woodside Energy Ltd, further success in this sub-basin has remained elusive, despite the drilling of Sandbar 1 (2001), Shakespeare 1 (2003), Weasel 1 (2003), Blacktip North 1 (2006), Marina 1 (2007) and

Sidestep 1 (2008). Frigate Deep 1 was drilled by Santos Ltd and reached a TD of 2520 m in August 2008. The well is reported as a 'new field gas discovery' (upstreamonline.com, 25 August 2008), but no further information is currently available. At the time of writing, Windjana 1 is being drilled 26.5 km west-southwest of Matilda 1.

The Eni Australia B.V. (Eni) owned Blacktip gas-condensate field is, to date, the only accumulation that is being commercialised in the Petrel Sub-basin and will deliver gas to Darwin for the Power and Water Corporation. Eni has recently drilled Blacktip 2 to appraise the accumulation's reserves and the drilling of development wells is imminent. The 287 km Bonaparte pipeline runs from Eni's gas processing facility near Wadeye to Ban Ban Springs (about 130 km southeast of Darwin) and will transport gas to the existing Amadeus Basin to Darwin pipeline (**www.abc.net.au/news/stories/2008/12/09/2441244.htm**). The Bonaparte gas pipeline will initially be capable of delivering up to 30 petajoules of gas per year to the Northern Territory gas market (**www.theterritory.com.au/resources/img/pdf/publications/territory_quarterly/TQ-2-2008.pdf**). In addition, the Penguin (and Polkadot 1, 2004) gas accumulation may become commercially viable when the Blacktip production hub is in place. Further work is continuing to develop the Petrel and Tern gas accumulations.

In summary, a total of 53 exploration wells have been drilled in the Petrel Sub-basin; of these wells, 14 are hydrocarbon discoveries, giving a technical success of 26% and a 6% historical success rate for accumulations greater than 0.5 Tcf (3 discoveries; Blacktip, Petrel and Tern). To date, over 2.4 Tcf of gas with 10.6 MMbbls of condensate reserves have been proven within this sub-basin. The Barnett and Turtle accumulations collectively contain 10.4 MMbbls recoverable biodegraded oil from a much larger in-place volume. A synopsis of the reservoir units containing hydrocarbon accumulations and shows in the Petrel Sub-basin is shown in Table 1.

Well Control

Release Area NT09-Special contains the Barnett oil accumulation and Release Area W09-Special contains the Turtle oil accumulation. Both Release Areas are located in close proximity to the Blacktip gas field and are also in the vicinity of the Tern and Petrel gas fields.

Several wells have been drilled north of Release Area NT09-Special; these include Kinmore 1 (1974) and Shakespeare 1 (2003). The wells Kulshill 1 (1966), Kulshill 2 (1966) and Sunbird 1 (1994) are located to the east, with Kingfisher 1 (1994) to the south.

Immediately to the west of Release Area W09-Special is the exploration well Matilda 1 (1985). Further to the west of this Release Area are the wells; Lesueur 1 (1980), Cambridge 1 (1984), Lacrosse 1 (1969), Sandbar 1 (2001), Weasel 1 (2003) and Windjana 1 (2009). Pelican Island 1 (1972) was drilled to the southwest.

NOTE: Formation names and terms shown in square brackets are updates of the information presented in the well completion reports and follow the terminology of Gorter et al (2005, 2008 and 2009).

Kulshill 1 (1966)

Kulshill 1 was drilled onshore by Australian Aquitaine Petroleum Pty Ltd (1966a), 15 km south of the township of Port Keats in the Northern Territory. The well was drilled to investigate the Paleozoic stratigraphy of the northeastern part of the onshore portion of the Petrel Sub-basin and the petroleum prospectivity of the Kulshill Structure, which was interpreted to be a faulted anticline.

The well reached a TD of 4394 mRT in sandstones of the Late Devonian Cockatoo Formation [Cockatoo Group], which had lower porosity than predicted. Oil shows were reported in cuttings of Permian to Carboniferous age during the drilling of the well. These shows progressively decreased with depth. Gas was associated with the oil shows in the Carboniferous sediments and increased in intensity with depth. The most significant oil shows occur within the Treachery and Kuriyippi formations. Six drill stem tests (DSTs) were conducted in the well, including two in the aforementioned formations; however, none yielded oil.

Kulshill 2 (1966)

Kulshill 2 was drilled onshore by Australian Aquitaine Petroleum Pty Ltd (1966b) 3 km south of Kulshill 1. The well was drilled on a central fault block, close to the culmination of the Kulshill Structure and in a higher structural position than Kulshill 1. The well was designed to test the reservoir quality of the Permian and Carboniferous sediments and investigate facies changes between the two wells.

The well reached a TD of 1961 mRT within the Milligans Beds [re-interpreted as the Arco Formation]. Traces of methane were detected throughout the drilling below 274 m, probably originating from the numerous coals. Oil and gas indications were encountered over a more restricted depth range than at Kulshill 1, with the most significant oil shows being observed in the Milligans Beds [Arco Formation]. These shows are described as a dark brown to black bitumen cement, and light brown to brown free oil that exhibited a strong dark greenish-yellow fluorescence. However, the oil shows are restricted to sandstones of poor porosity (3%) and no permeability.

Lacrosse 1 (1969)

Lacrosse 1, drilled by Arco Limited (1969) on the Lacrosse Terrace in the Petrel Sub-basin, was the first well to be drilled in the offshore Bonaparte Basin. The well, drilled in 32 m of water, was designed to evaluate the hydrocarbon potential of the Lacrosse Structure and identify the major seismic reflectors mapped over the Lacrosse Terrace. Although the well was drilled 'on-structure', it was considered a stratigraphic test. It targeted Permian and Carboniferous reservoirs in a dip-rollover feature on the up-thrown side of a bounding fault.

The well penetrated Permian and Carboniferous sediments and terminated at a TD of 3054 mKB within the Medusa Beds [re-interpreted as the Tanmurra Formation]. Two cores taken over the depth range 1742.5–1758.7 mKB [interpreted as the lower Treachery Formation to the upper Kuriyippi Formation] were partially saturated with residual dark-brown oil with an estimated API gravity of 15–20°. The reservoir units have porosities of up to 26% and permeabilities of up to 514 mD. However, DST 1 (1717–1759 mKB) failed to recover hydrocarbons, probably because of the poor lateral permeability exhibited by the lenticular reservoir sandstones.

Petrel Gas Field

Petrel 1 (1969), Petrel 1A (1970), Petrel 2 (1971), Petrel 3 (1982), Petrel 4 (1988), Petrel 5 (1994) and Petrel 6 (1996).

The Petrel gas field lies 270 km west of Darwin and is situated within Retention Leases NT/RL1 and WA-6-R held by Santos Limited. The field is reported to contain initial recoverable resources of 970 Bcf gas and 5.9 MMbbls condensate (RDPIFR, 31 December, 2007).

Petrel 1, drilled by Arco Australia Limited in 100 m of water, was the second well to be drilled in the Petrel Sub-basin. It was drilled to evaluate the hydrocarbon potential of a large anticline and discovered the Petrel gas accumulation, although the hole was lost due to a blow-out of Permian gas (Arco Ltd - Australian Aquitaine Petroleum Pty Ltd, 1969). The relief well, Petrel 1A, extinguished the blow-out approximately one year later and the Petrel 1 well was sealed off in January 1971. Since then, a total of five wells have been drilled on the Petrel Anticline. The accumulation is hosted within the Cape Hay Formation of the Hyland Bay Subgroup between 3500–4000 mKB. Gas is also reservoired within the Pearce and Torrens formations of the Hyland Bay Subgroup in Petrel 2. Porosities of up to 20% or more were recorded in the Cape Hay Formation in Petrel 1; however, permeabilities are low. The gas at Petrel is moderately dry, with a condensate-to-gas-ratio (CGR) of between 0.5–9 bbls/MMscf (2.8–50.5 m^3/MMm^3).

Tern Gas Field

Tern 1 (1971), Tern 2 (1982), Tern 3 (1982), Tern 4 (1994) and Tern 5 (1998).

The Tern gas field is situated 300 km west of Darwin and approximately 50 km to the southwest of the Petrel gas accumulation. It is situated within Retention Lease WA-27-R, which is held by Santos Limited. The field is reported to contain initial recoverable resources of 468 Bcf gas and 5.7 MMbbls condensate (DMP, December, 2007).

The Tern gas accumulation was discovered by Arco Australia Limited (1971b) and four wells have been drilled subsequently, to appraise the northwest-trending salt-related, faulted anticline. Tern 3 tested a separate culmination on the southern extension of the Tern structure. At Tern, the main reservoir is the Tern Formation of the Hyland Bay Subgroup. In addition, gas is also reservoired within the Dombey Formation at Tern 2 and

3, and within the Cape Hay Formation at Tern 4. Porosities in excess of 20% have been identified at depths of about 2600 m.

Pelican Island 1 (1972)

Pelican Island 1 was drilled by Arco Australia Limited (1972) on Pelican Island in the southern part of the Petrel Sub-basin. The well was drilled to evaluate the hydrocarbon potential of Carboniferous sediments on a large, faulted anticline.

The well penetrated a thick sequence of Carboniferous sediments, with the lower Bonaparte Beds [Milligans Formation] being the oldest dated section in the well. After penetrating 183 m of salt, the well was terminated at a TD of 1981 mKB within a salt diapir of presumed Late Devonian age.

Residual oil was recorded at shallow depths in tight sandstones of Carboniferous age [Arco Formation], and gas shows were encountered in the underlying Tanmurra Formation and Bonaparte Beds. These gas shows have been re-interpreted to occur within the Yow Creek and Milligans formations. Log and sidewall core analyses indicated that these hydrocarbon zones were either too tight or too thin to warrant formation testing.

Kinmore 1 (1974)

Kinmore 1 was drilled by Australian Aquitaine Petroleum Pty. Ltd. (1974) on the southeastern flank of a domal feature of diapiric origin on the northwest-plunging Bougainville-Kinmore anticlinal ridge, 37 km southeast of Bougainville 1. The major objective in the well was the Kulshill Formation.

The well was drilled in 29 m of water and reached a TD of 3250 mKB within massive salt of a diapiric core, with sandstones of the Kulshill Formation [re-interpreted as the Kuriyippi Formation, Kulshill Group] being the oldest penetrated sediments. Minor oil and gas indications were recorded from the basal unit of the Kulshill Formation Sandstone Member [Kuriyippi Formation], but are interpreted to be water-saturated. An untested structure exists on the northern flank of the Kinmore diapir.

Lesueur 1 (1980)

Lesueur 1 was drilled in 57.5 m water depth by Australian Aquitaine Petroleum Pty Ltd (1980) on the western margin of the Petrel Sub-basin, at the northernmost extent of the Lacrosse Terrace, 53 km southwest of Penguin 1. The well was positioned near the crest of a large anticlinal closure associated with the main basin-margin fault, ideally located to trap hydrocarbons migrating up-dip from the Petrel Deep. The primary reservoirs targeted were the Kulshill and Tanmurra formations.

The well intersected sediments ranging in age from Triassic to Carboniferous, and terminated within the Bonaparte Beds [re-interpreted as the Kingfisher Shale] at 3589 mKB. The quality of the sandstone reservoirs within the Kulshill Formation [Kuriyippi, Aquitaine and Arco formations] is good, but they are water-bearing. The limestones and calcareous sandstones of the Tanmurra Formation are gas-bearing, but are too tight to flow gas at economical rates. Although the Bonaparte Beds [Kingfisher Shale] had oil shows, they have very low permeabilities. Source rock analyses of sediments from the Tanmurra Formation and Bonaparte Beds [Kingfisher Shale] indicate poor hydrocarbon potential.

Cambridge 1 (1984)

Cambridge 1 was drilled by Western Mining Corporation Limited (1985a) on the Cambridge High, some 16 km west-northwest of Lacrosse 1. Sandstones of the Kulshill Formation were the primary objective, while the Tanmurra Formation limestones and Bonaparte Beds clastics were secondary objectives. The Fossil Head Formation is the regional seal. The faulted anticlinal trap relies on fault-seal of Kulshill Formation reservoirs against the Fossil Head Formation.

The well was originally scheduled to drill to 2450 mRT, but all horizons were intersected high to prognosis. Igneous intrusives were encountered below the Bonaparte Beds [re-interpreted as the Bonaparte Formation] at 2213.5 mRT and drilling was terminated at a TD of 2228 mRT. Gas indications were recorded while drilling and a maximum of 2000 ppm methane and traces of ethane were recorded in the Hay Member of the Hyland Bay Formation to base-Kulshill Formation [Hyland Bay Subgroup to Border Creek Formation]. The heavier homologues of propane and butane were limited to a thin unit between 1950–1990 mRT within the Bonaparte Beds [Milligans Formation]. However, gas was seldom associated with oil shows. Oil indications were recorded in the Hyland Bay Formation, Fossil Head Formation and Kulshill Formation [Hyland Bay Subgroup to Border Creek Formation]. The most significant oil shows occur within the Fossil Head Formation and these were tested by two open-hole drill stem tests (DST 1 and 1A; 555–557.5 mRT), but no hydrocarbons were recovered. Analyses of oil from three sidewall cores at 147 m, 413.5 m and 575 m [Hyland Bay Subgroup, Fossil Head Formation and Keyling Formation, respectively], indicate that the oil is a mixture of unaltered and biodegraded oil, similar to those analysed at Turtle 1. The lack of hydrocarbons may result from the lack of integrity or continuity of the fault-seal.

Turtle Oil Accumulation

Turtle 1 (1984) and Turtle 2 (1989).

The Turtle oil accumulation was discovered on the Turtle-Barnett High in 1984 by the Turtle 1 well. The discovery is located approximately 305 km southeast of Darwin. The initial recoverable oil resources are 7.7 MMbbls for the Turtle accumulation (DMP, December 2007).

The reservoirs are located in a large domal drape closure. There are four separate oil columns within the Permian and Carboniferous section, as well as numerous oil shows.

Oil columns are present within the Keyling and Treachery formations in Turtle 2. The deepest oil column occurs within the Tanmurra Formation and uppermost Milligans Formation [re-interpreted as the Kingfisher Shale]. In Turtle 1, oil columns occur within the Treachery and Ditji formations. In the two Turtle wells, oil shows occur from the Tern Formation to the Kingfisher Shale. Medium to light (33–36°API) oil was recovered (but did not flow) from the Treachery Formation during two DST's carried out in Turtle 1, and from the Tanmurra Formation and upper Milligans Formation [Kingfisher Shale] during two DSTs carried out in Turtle 2. Oil was also recovered by wireline formation tests carried out in Turtle 1 and 2 (Durrant et al, 1990).

Turtle 1 (1984)

Turtle 1 was drilled in 24 m of water by Western Mining Corporation Limited (1984) 15 km northwest of the Barnett oil field. The well was designed to evaluate the hydrocarbon potential of all Permian and Carboniferous reservoirs on the Turtle Structure – a domal drape closure at all levels over a tilted pre-Tanmurra Formation horst block. The primary objectives were sandstones in the Kulshill Formation and carbonates in the Tanmurra Formation. Secondary objectives were sandstones in the Hyland Bay Formation, Fossil Head Formation and pre-Tanmurra Formation sediments.

The well reached a TD of 2700 mRT within interbedded sandstones, shales, limestones and siltstones of the Bonaparte Beds [basal Milligans Formation]. The Carboniferous to Permian section was similar to that predicted but most formations were encountered high to prediction. Excellent reservoir rocks were encountered within the Hyland Bay Formation [Hyland Bay Subgroup] and uppermost Fossil Head Formation [Torrens Formation]. The Kulshill Formation [Keyling Formation, Ditji Formation, Treachery Formation and Kuriyippi Formation] contained the most extensive reservoirs in which numerous oil shows were recorded. The lower parts of the Kulshill Formation [Wadeye Group], the Tanmurra Formation and Bonaparte Beds [Kingfisher Shale and Milligans Formation] were very tight and appear to have only fracture porosity. Gas shows emanating from probable fractures occur in the basal Kulshill [Wadeye Group] and Tanmurra formations and the Bonaparte Beds [Kingfisher Shale and Milligans Formation].

Six conventional cores were taken to evaluate hydrocarbon shows – five in the Kulshill Formation [Kulshill Group] and one at the Tanmurra Formation/Bonaparte Beds [Kingfisher Shale] boundary.

A series of FITs were carried out to define pressure gradients and sample formation fluids. Eight cased-hole DSTs were carried out to evaluate the hydrocarbon potential of a number of zones of interest in the Kulshill Formation identified during drilling and wireline logging. Medium to light oil was recovered in the RFTs and while reversing out during two DSTs undertaken in the Treachery Formation. DST 4 (1622–1624 mRT) reversed out 26 bbls 32.5°API gravity oil, and DST 5 (1618.85–1621 mRT) reversed out 32.7 bbls of 32.7°API gravity oil. DST 5 also flowed oil and gas to the surface, but at a rate too small to measure.

Despite excellent reservoir characteristics, the tested zones had a very poor production performance, which has been attributed to a combination of viscous oil and low gas factors.

Post drill analysis suggests that the Turtle 1 well was a valid test drilled at or near the crests of the closures. The well was plugged and abandoned as a new field oil discovery.

Turtle 2 (1989)

Turtle 2 was drilled in 24.6 m of water by Western Mining Corporation Limited (1990), 3.25 km south of Turtle 1. The well tested the up-dip potential of the oil shows encountered in Turtle 1 in a faulted anticline. The well was located over crestal culminations in the Kinmore and Kulshill groups, but was off-structure in relationship to the underlying Weaber Group. The primary objectives were sandstones of the upper Kuriyippi Formation, with secondary objectives in the Keyling Formation, Treachery Shale, Point Springs Sandstone and lower Kuriyippi Formation.

Turtle 2 was originally scheduled to a TD of 2440 mRT in the Tanmurra Formation, but was deepened during drilling to test a pinchout play of the Milligans Formation against the tilted horst of the Turtle High. The well reached a TD of 2760 mRT within the Bonaparte Formation [re-interpreted to be within the basal Milligans Formation]. Drilling problems encountered at Turtle 2 are attributable to an extensive network of fractures developed in the Carboniferous oil-bearing reservoirs.

Oil shows were encountered throughout the Permian and Carboniferous sediments [from the Cape Hay Formation to the Milligans Formation]. Hydrocarbon shows in the top Keyling and Treachery formations do not appear to be constrained within structural closure, suggesting that there is a stratigraphic component to the trap. The oil shows in the Tanmurra Formation and Milligans Formation [Kingfisher Shale and Milligans Formation] are constrained within a stratigraphic pinchout onto the Turtle High. Four DST's were carried out in the well:

- DST 1/1A: 2632–2721 mRT recovered 22 bbls of 34.5°API gravity oil (but did not flow) from the Milligans Formation [Kingfisher Shale and Milligans Formation].
- DST 2: 2571–2607 mRT recovered 30 bbls of 36°API oil (but did not flow) from the lower Tanmurra Formation.
- DST 3: 2420–2447 mRT in the basal Point Spring Sandstone [Arco Formation]/top Tanmurra Formation failed to recover any significant reservoir fluids.
- DST 4A–C: 1614.5–1807 mRT in the upper Kuriyippi Formation [Treachery Formation–Kuriyippi Formation] failed to recover any significant reservoir fluids.

The oils recovered from DST1/1A and 2 are believed to have been recovered from a badly damaged fracture system.

In addition to the DSTs, two cased-hole RFTs were conducted at 1645 mRT in the

Kuriyippi Formation [Treachery Formation] and at 927.1 m in the upper Keyling Formation, with the latter test recovering four gallons (18.2 litres) of heavy, viscous oil (14.3°API gravity). The oil column within the Keyling Formation is interpreted to be between 13 m gross (RFT pressure) and 17.7 m gross (core shows). The interpreted oil column at 1439–1444 mKB within the Treachery Formation was not tested.

The hydrocarbon shows in Turtle 2 were grouped into two types. The Kulshill Group oil shows were a mixture of a severely biodegraded, heavy black oil and a degraded light brown oil. The Weaber Group hydrocarbon shows comprised non-degraded, black oil with associated gas.

Lithological comparisons between Turtle 1 and 2 showed that the Kulshill Group sediments are sandier in Turtle 2, with higher sand/shale ratios in both the Treachery and upper Kuriyippi formations. Porosity and permeability measurements from core plugs are reported from four conventional cores cut in silty sandstone reservoirs:

- Core 1: 922–940 mRT in the top Keyling Formation exhibited good to excellent reservoir characteristics with porosities and permeabilities ranging from 12.2 to 30.9% and 22–3053 mD, respectively.
- Core 2: 1443.2–1439.5 mRT in the top Treachery Formation exhibited fair to good reservoir characteristics with porosities and permeabilities ranging from 7.8 to 25.8% and 0.19 to 915 mD, respectively.
- Core 3: 1614.27–1597.5 mRT in the top Kuriyippi Formation exhibited a range in both porosity (3.6–25.2%) and permeability (<0.01–116 mD), being a poor to fair reservoir.
- Core 4: 2495.15–2483 mRT in the Tanmurra Formation the limestones exhibited poor to no reservoir potential, with a thin sandstone having a maximum porosity of 11.8%.

The sandstones of the Tanmurra and Milligans formations exhibit poor reservoir characteristics due to the presence of a kaolinite–calcite cement and authigenic clays. However, these units show extensive fracturing, with log evaluation indicated porosities of >10% in the clastic sections.

Barnett Oil Accumulation

Barnett 1 (1985), Barnett 2 (1989) and Barnett 3 (1990).

The Barnett oil accumulation was discovered on the Turtle-Barnett High by Barnett 2 in 1989, following the initial oil discovery at Turtle 1. The discovery is located 300 km southeast of Darwin and the initial recoverable oil resources are 2.7 MMbbls for the accumulation (RDPIFR, 31 December 2007).

The reservoirs are located in a large domal drape closure. Oil is reservoired within Permian and Carboniferous section, including sandstones of the Keyling Formation, Quoin Formation, Kuriyippi Formation and Wadeye Group. Oil also occurs within the

Weaber Group in Barnett 2.

Barnett 1 (1985)

Barnett 1 was drilled in 36 m of water by Australian Aquitaine Petroleum Pty Ltd (1985), 14 km northwest of Turtle 1. The well tested a northwest-trending broad anticline that terminates on the eastern flank with a series of north-trending faults. The structure is controlled by the Barnett-Turtle High, which is onlapped by upper Milligans Formation sandstones and draped by the Tanmurra Formation. The primary objective was to test a Kulshill Formation oil play following the drilling of Turtle 1. A secondary objective was the [Keyling Formation] sands beneath the Fossil Head Formation. Tertiary objectives were a sandy limestone play in the Tanmurra Formation and a Milligans Formation unconformity sandstone play.

The well reached a TD of 2350 mKB within the Milligans Formation [Utting Calcarenite] with all formation tops encountered close to prediction. Drilling confirmed the existence of a valid structure; however, the well did not encounter a significant hydrocarbon accumulation.

Good reservoirs (13–28% porosity) with oil shows were encountered in sandstones of the Kulshill Formation [Keyling Formation, Quoin Formation and Kuriyippi Formation, Kulshill Group]. Core 1, taken at 833–852 mKB [Keyling Formation], had consistent porosities of 20–30% and permeabilities >500 mD. Core 2 taken at 1311–1317 mKB [Quoin Formation] had porosities of 20–22% and permeabilities of 300–600 mD. Cores 3 and 4 were taken in finer grained sandstones at 1538–1561.5 mKB [Kuriyippi Formation] and had porosities of 10–18% and average permeabilities of 1 mD. The Tanmurra and Milligans formations did not contain any potential reservoirs.

Log analysis of the Kulshill Formation indicated 20% oil saturation, with the oil shows confined to tight reservoirs. The associated formation waters are fresh and of meteoric origin. Numerous RFTs and DSTs were conducted; however, the only oil recovery was in RFT No. 10 (Run 11) at 2033 mKB in Unit 'A' of the Kulshill Formation [Arco Formation] when 300 cc of 24° API gravity oil was recovered. The oil shows are interpreted to consist of a biodegraded residual oil and a second crude oil with a predominantly marine source character, although a terrestrial component was also identified. The lack of an accumulation at Barnett 1 is attributed to either reservoir flushing, breaching of the closure by faulting, lack of migrated hydrocarbons or a combination of all three factors.

Fair marine source rocks were encountered in the upper Kulshill Formation. The top of the oil window was placed approximately at 2200 mKB (Ro = 0.7%) within the upper Milligans Formation [Kingfisher Shale].

Barnett 2 (1989)

Barnett 2 was drilled in 24 m of water by Elf Aquitaine Exploration Australia Pty Ltd 1 km south-southwest of Barnett 1 and 11.8 km west-northwest of Turtle 2. Santos Limited purchased the permit in December 1989 and submitted the well completion report (Santos Limited, 1990). Barnett 2 tested an anticline mapped within the upper Milligans Formation on the Barnett Structure up-dip of Barnett 1. Barnett 2 is classed as an exploration well since its primary objective, the 'Barnett Member' of the upper Milligans Formation, was not penetrated in Barnett 1, although good oil shows were recorded from this formation in Turtle 2. The secondary objective for the well was the Kulshill Group up-dip of Barnett 1. Another objective was a tilted fault block in the lower Milligans Formation.

Barnett 2 was drilled to a TD of 2818 mKB within the Bonaparte Formation. As a result of significant oil and gas shows within the Permian and Carboniferous sediments, four DSTs were conducted, as follows;

- DST 1: 2393–2419.5 mKB flowed gas at a rate of 0.09 MMscfd (2550 m^3/d) and recovered 7L of 44.4°API gravity oil from the Milligans Formation [Yow Creek Formation].
- DST 2: 1929–1935 mKB flowed formation water at a rate of 1073 bbl/d from the Kuriyippi Formation [Aquitaine Formation].
- DST 3: 1491–1497 mKB flowed 38.6°API gravity oil to the surface on jet pump at a rate of 752 bbl/d (120 m^3/d) from the Kuriyippi Formation.
- DST 4: 1491–1506.5 mKB flowed 38.6°API gravity oil to the surface on jet pump at a rate of 921 bbl/d (921 m^3/d) from the Kuriyippi Formation.

The extrapolated bottom hole temperature at 2818.8 mKB was calculated to be 102°C, with an extrapolated geothermal gradient of 2.61°C/100 m. The well was cased and suspended as a possible future oil producer.

Barnett 3 (1990)

Barnett 3 was drilled by Santos (NT) Pty Ltd in 1990 some 0.3 km southwest of the Barnett 2 well. The primary objectives were sandstones (14.9 and 15.0 sands) in the top of the Kuriyippi Formation that flowed oil in Barnett 2. Secondary objectives were sandstones within the Keyling Formation and Treachery Shale; these objectives were not within closure in Barnett 1 (Santos - Petroz - Gas and Fuel Expl - Lenoco - Southern Cross - Cultus - Gulf Resources, 1990).

The well reached a TD of 1700 mKB within the Kuriyippi Formation. No resistivity anomalies were recognised and a comprehensive Sequential Formation Test (SFT) program indicated a water gradient for all reservoir zones. The primary reservoir sandstones of the top Kuriyippi Formation were intersected 16 m low to prognosis and were of poor quality. Residual brown oil, that exhibited fluorescence under UV light, was observed in cuttings throughout the Keyling Formation. Oil indications were recorded while drilling fossiliferous zones within shales of the Fossil Head Formation.

Matilda 1 (1985)

Matilda 1 was drilled by Western Mining Corporation Limited (1985b) 21 km west-northwest of Turtle 1. The well targeted sandstones of the Kulshill Formation in the basinward flank of a salt-induced structure. Secondary objectives were limestones of the Tanmurra Formation and sandstones of the Bonaparte Beds.

The well was originally scheduled to drill to a depth of 2350 mRT, but drilling ceased at a TD of 2313 mRT after the Bonaparte Beds were penetrated higher than expected. The well has been re-interpreted to terminate within the Utting Calcarenite. Minor gas indications were recorded in the Fossil Head Formation to mid-Kulshill Formation [Keyling Formation], with minor wet gases detected in the Bonaparte Beds [Utting Calcarenite]. Minor oil indications identified from cuttings that fluoresced with a dull yellow colour and exhibited a very slow cut and crush cut were reported in the Fossil Head to mid-Kulshill Formation [Keyling Formation] sediments. Reservoir quality was poor (average porosity 15%). All RFTs were unsuccessful due to either tight formations or packer failure. No DSTs were conducted and no cores were cut due to the paucity of hydrocarbon shows.

The Matilda structure relied on fault-seal of the salt piercement structure. The lack of hydrocarbons may be due to inadequate fault-seal of the Kulshill Formation against the salt intrusion. Multiple structural and stratigraphic closures within Permian–Late Devonian sediments along the flank of the Matilda salt diapir have not been tested.

Kingfisher 1 (1994)

Kingfisher 1 was drilled by Teikoku Oil (Bonaparte Gulf) Co., Ltd. (1994a) 28 km south-southeast of the Barnett oil accumulation. The well was drilled near the top of a salt induced drape structure at the top of the Milligans Formation. It tested sandstone reservoirs of the Kuriyippi and upper Milligans formations as primary objectives, and the underlying lower Milligans and Bonaparte formations as the secondary objectives.

The well, drilled in 26 m of water, reached a TD of 3257 mRT within the Bonaparte Formation [Ningbing Group-equivalent]. The stratigraphic sequence penetrated was as predicted; however, the top Bonaparte Formation was 692 m high to prognosis, and the Kuriyippi Formation 244 m high to prognosis. The objective Kuriyippi Formation and Point Springs Sandstone [Wadeye Group] have a fair reservoir quality, whilst the Milligans Formation [Weaber Group] has poor reservoir quality.

Only minor hydrocarbon shows were encountered during drilling. Gas peaks within the Bonaparte Formation [Ningbing Group-equivalent] from below 2612.5 mRT were less than 1.5% and dry with the composition usually greater than 95% methane. Wireline log analysis showed there were no significant hydrocarbons in the well and an RFT at 1900.5 mRT within the Milligans Formation [Tanmurra Formation] recovered mud filtrate.

Sunbird 1 (1994)

Sunbird 1 was drilled by Teikoku Oil (Bonaparte Gulf) Co., Ltd. (1994b) 40 km east-southeast of the Barnett oil accumulation. The well was drilled near the top of a fault-related drape structure at the top of the Milligans Formation and was designed to test Carboniferous sandstones, with the Kuriyippi and upper Milligans formations as the primary objectives and the Point Spring Sandstone as the secondary objective.

The well, drilled in 43 m of water, reached a TD of 3324 mRT within the Milligans Formation [Bonaparte Formation]. The Kuriyippi Formation and Point Spring Sandstone [Wadeye Group] potential reservoirs have fair porosity and permeability, and fair sand to shale ratios. However, the Milligans Formation potential reservoirs have poor porosity and permeability, and poor sand to shale ratios.

Only minor hydrocarbon shows were encountered during drilling. Wireline log analysis showed that there were no significant hydrocarbons in the well and RFT pressure plots gave normal pressure water gradients within the Kuriyippi Formation and Point Spring Sandstone [Wadeye Group]. An RFT sample at 2091.2 mRT within the Point Spring Sandstone [Aquitaine Formation] recovered mud filtrate. The well was plugged and abandoned without testing, as a dry hole.

Cape Ford 1 (1997)

Cape Ford 1 was drilled in 28 m of water, 4 km south of Turtle 1, on the southwestern flank of the northwest-plunging Turtle High by Cultus Petroleum NL (1998) in the Joseph Bonaparte Gulf. The well tested a stratigraphic pinchout play downdip of Turtle 2, which was drilled 1 km to the north-northeast. The primary objective was the Tanmurra Formation, with the secondary objectives being sandstones within the Treachery Shale, top Kuriyippi Formation, basal Point Springs Sandstone and Milligans Formation. The well was located to intersect a seismic anomaly identified from amplitude-versus-offset (AVO) and acoustic impedance inversion studies. The seismic anomaly was interpreted to represent a thick, high porosity sandstone (TN2 Sand Unit) within the Tanmurra Formation. The trap configuration was a stratigraphic pinchout of proposed fan-delta reservoir units against the Turtle High. The sands developed in response to erosion of the Turtle High during the Early Carboniferous.

The well was plugged and abandoned 144 m into the Bonaparte Formation at a TD of 3022 mRT. Oil shows were encountered within the Treachery Shale [Treachery Formation], Kuriyippi Formation, Point Spring Sandstone [Wadeye Group], and in the Weaber Group [Sunbird, Tanmurra, Yow Creek and Milligans formations]. Evaluation of wireline logs assessed a total of 62.1 m of potential log pay below the Treachery Shale [Treachery Formation], none of which was considered net oil pay. Structural interpretation indicates that the hydrocarbon occurrences are not controlled by structural closure, implying a stratigraphic trap.

The top of the reservoir section within the Tanmurra Formation was encountered at 2615 mRT. This reservoir section is 65 m thick and comprises two sandstones separated by a

5 m thick claystone. The reservoir had lower porosity than predicted, with the topmost clean sandstone having 12% porosity for 4.6 m of logged pay. The reservoir section contained hydrocarbons, with dead oil and a maximum of 50% hydrocarbon fluorescence being observed in cuttings. A strong gas peak (54 units), comprising methane to butane, was recorded.

Two oil-stained, fine-grained intraformational sandstones were penetrated within the Milligans Formation [Yow Creek Formation] at 2770–2792 mRT and Milligans Formation 2819–2840 mRT. Despite being thicker and cleaner than the sandstones penetrated at Turtle 2, they had lower average porosity (˜11%) and were not fractured.

Pervasive, late stage diagenetic carbonate (calcite or dolomite and ankerite) cementation of the sandstones from the Milligans Formation to the Point Spring Sandstone [Wadeye Group] has resulted in the loss of porosity and permeability. Early calcite cementation of some sandstones within the Milligans Formation would have caused them to be impervious to dolomitic alteration, and hence they may never have been potential reservoirs. No production testing was conducted due to the tight reservoir sandstones and absence of fracture porosity.

Blacktip Gas Field

Blacktip 1 (2001) and Blacktip 2 (2009).

The Blacktip gas accumulation was discovered by the drilling of Blacktip 1 in 2001. The accumulation is situated approximately 300 km southwest of Darwin. The initial recoverable gas resources are 957.2 Bcf (DMP, December 2007).

Blacktip 1 (2001)

Blacktip 1 was drilled in 2001 by Woodside Energy Ltd in 55 m of water on a four-way-dip closure on the Lacrosse Terrace. The well was drilled to evaluate the hydrocarbon potential of the Blacktip Structure, a Late Triassic compression-induced, fault-independent anticline with amplitude/AVO support at intra-Mount Goodwin Formation and base Keyling Formation (Woodside Australian Energy, 2002a; Leonard et al, 2004).

The well reached a TD of 3181 mRT within the Treachery Formation. The deeper Kuriyippi Formation target was not reached. The results of the well proved that the AVO effects were related to gas bearing units within the Mount Goodwin Formation [Mount Goodwin Subgroup], Keyling Formation and the Treachery Formation. Additional gas-bearing units were not clearly visible on the seismic possibly due to a combination of reservoir quality and thickness, and depth of burial of the sandstones.

The section penetrated was close to prediction and eight major gas-bearing sandstones were encountered. The primary gas reservoir sandstones occur within the Keyling Formation and are sealed by the Fossil Head Formation, which also contains gas.

Additional gas-saturated zones are located within the Mount Goodwin Formation [Ascalon Formation, Mount Goodwin Subgroup] which contains a 20 m gross gas unit, and two gas columns occur within the Treachery Formation (Leonard et al, 2004; Gorter et al, 2008).

Within the Keyling Formation, a cumulative gross gas column of 339 m was identified, with three reservoir sandstones being tested. The flows were constrained by surface equipment and tubing.

- DST 1: 2767–2785 mRT flowed gas at a rate of 34.4 MMscfd (974,000 m^3/d) through a 1" choke.
- DST 2: 2570–2588 mRT flowed gas at a rate of 27 MMscfd (764,500 m^3/d) through a 1" choke.
- DST 3: 2169–2187 mRT flowed gas at a rate of 28 MMscfd (792,000 m^3/d) through a 1" choke.

The sustained high flow rates (89 MMscfd; Leonard et al, 2004), recorded on testing the three combined gas-saturated zones in the Keyling Formation, indicate the presence of good quality reservoirs in the Blacktip Structure. The porosity of the Keyling Formation is between 15 to 28% and the permeability is up to 800 mD (Leonard et al, 2004). The gas at Blacktip is dry, with a CGR of 5 bbl/MMscf (28 m^3/MMm^3). The gas is low in carbon dioxide (<1%).

Gas and fluid composition analysis indicates a similar hydrocarbon composition to the Petrel and Tern gas fields to the north. Blacktip 1 has confirmed that the Keyling Formation over this part of the Petrel Sub-basin has excellent reservoir qualities. It has also demonstrated that potential reservoir/seal pairs occur in the underlying Treachery Shale [Treachery Formation] (Woodside Energy Ltd, 2002a). The well was plugged and abandoned as a gas discovery.

Blacktip 2 (2009)

Blacktip 2 is an appraisal well drilled on the Blacktip structure by Eni Australia B.V. in 2009. Data from this well is still confidential and further information is unavailable at this time.

Sandbar 1 (2001)

Sandbar 1 was drilled in 2001 by Woodside Energy Ltd in the western portion of the Cambridge Trough and targeted a dip closure in a basin-floor fan sandstone of the Milligans Formation (Waggon Creek Member) and in the underlying sandstones of the Bonaparte Formation. The structure was formed during the Carboniferous by the combined effects of block faulting and possibly salt withdrawal in the underlying Silurian–Devonian section (Woodside Australian Energy, 2002b).

The well, drilled in 17 m of water, reached its objectives and terminated at a TD of 2950 mRT within the Bonaparte Formation; however, only minor gas indications and fluorescence were recorded. Lithological descriptions suggested that no sandstones of reservoir quality were encountered within the sediments from the Tanmurra Formation to the Bonaparte Formation. Although there is no closure within the Kuriyippi Formation, Point Spring Sandstone [Wadeye Group] and Tanmurra Formation, petrophysical evaluation of these reservoir sandstones indicated that they are water-wet.

Shakespeare 1 (2003)

Shakespeare 1 was drilled in 2003 by Woodside Energy Ltd on a Late Triassic compression-induced, faulted anticlinal structure some 280 km west-southwest of Darwin and 60 km north-northeast of the Turtle oil accumulation. The primary objective was to evaluate the hydrocarbon potential of Early Permian fluvio-deltaic sandstones of the Keyling Formation. Secondary objectives were sandstones of the Kuriyippi Formation and Treachery Shale. Claystones of the Fossil Head Formation were interpreted to form a top seal and hydrocarbon charge was modelled to have been sourced from the Keyling and Kuriyippi formations within the Petrel Sub-basin to the northwest (Woodside Australian Energy, 2003a).

The well, drilled in 28 m of water, reached a TD of 2182 mRT within interbedded sandstones and claystones of the Keyling Formation. All formation tops came in as predicted except the Keyling Formation, which was encountered at 1986 mRT, some 53 m deep to prognosis. Although the Keyling Formation comprised good quality sandstones (average log porosity 18%) all potential reservoirs are evaluated as water-bearing. Indications of minor amounts of residual oil from a 50 m section in the Keyling Formation is inferred from log analysis and weak fluorescence observed in the cuttings.

Due to the lack of hydrocarbons at the primary objective level, the option to deepen the well was not exercised. Shakespeare 1 is interpreted to have tested a valid structural closure with good quality reservoir development at the objective level. Lack of lateral fault seal is interpreted as the reason for failure (Woodside Australian Energy, 2003a). The well was plugged and abandoned as a dry hole with hydrocarbon indications.

Weasel 1 (2003)

Weasel 1 was drilled in 2003 by Woodside Energy Ltd 325 km west-southwest of Darwin and just to the north of the Cambridge 1 and Lacrosse 1 wells on the Lacrosse Terrace. The well was drilled to evaluate the hydrocarbon potential of the fluvio-deltaic sandstones of the Keyling Formation in a four-way dip closure in the hanging wall of a northwest-trending basin margin fault. Secondary objectives were fluvial clastics of the Kuriyippi Formation sealed by intra-formational claystones (Woodside Australian Energy, 2003b).

The well, drilled in 38 m of water, reached a TD of 1776 mRT within sandstones of the Kuriyippi Formation. All formation tops came in close to prognosis. Good quality sandstones were encountered within the Keyling, Kuriyippi and Treachery formations, with average porosities of 23%, 15% and 18%, respectively. All potential reservoirs were evaluated as water-bearing, although weak hydrocarbon indications were reported from cuttings in the Keyling Formation.

Weasel 1 is interpreted to have tested a valid structural closure with good quality reservoir development at the objective levels. Geochemical analyses of the residual oil within the Keyling Formation indicated the presence of a severely biodegraded oil. The reason for failure at Weasel 1 is interpreted to be trap integrity (Woodside Energy Ltd, 2003b). The well was plugged and abandoned as a dry hole with minor hydrocarbon indications.

Blacktip North 1 (2006)

Blacktip North 1 was drilled northwest of Blacktip 1 in November–December 2006 by Eni Australia B.V. The well reached a TD of 3120 mRT and was plugged and abandoned. Data from this well is still confidential and further information is unavailable at this time.

Table 1: Key wells listing

Well	Operator	Year	Total Depth	Hydrocarbons
Barnett 1	Australian Aquitaine Petroleum Pty Limited	1985	2350 mKB	Oil shows
Barnett 2	Elf Aquitaine Exploration Australia Pty Ltd	1989	2818 KB	Oil recovered
Barnett 3	SANTOS (NT) Pty Ltd	1990	1700 mKB	Oil shows
Blacktip 1	Woodside Energy Ltd	2001	3181 mRT	Proven gas zone
Blacktip 2	Eni Australia B.V.	2009	3356 mRT	No public data
Blacktip North 1	Eni Australia B.V.	2006	3120 mRT	No public data
Cambridge 1	Western Mining Corporation Limited	1984	2228 mRT	Oil shows

Cape Ford 1	Cultus Petroleum NL	1997	3022 mRT	Oil shows
Kingfisher 1	Teikoku Oil (Bonaparte Gulf) Co, Ltd	1994	3257 mRT	No tests
Kinmore 1	Australian Aquitaine Petroleum Pty Ltd	1974	3250 mKB	No tests
Kulshill 1	Australian Aquitaine Petroleum Pty Ltd	1966	4394 mRT	Oil shows
Kulshill 2	Australian Aquitaine Petroleum Pty Ltd	1966	1961 mRT	Oil shows
Lacrosse 1	Arco Limited	1969	3054 mKB	Oil shows
Lesueur 1	Australian Aquitaine Petroleum Pty Limited	1980	3589 mKB	Oil and gas shows
Matilda 1	Western Mining Corporation Limited	1985	2313 mRT	No tests
Pelican Island 1	Arco Australia Limited	1972	1981 mKB	Oil and gas shows
Sandbar 1	Woodside Energy Ltd	2001	2950 mRT	No tests
Shakespeare 1	Woodside Energy Ltd	2003	2182 mRT	No tests
Sunbird 1	Teikoku Oil (Bonaparte Gulf) Co. Ltd	1994	3324 mRT	No tests

Turtle 1	Western Mining Corporation Limited	1984	2700 mRT	Proven oil zone, gas shows
Turtle 2	Western Mining Corporation Limited	1989	2760 mRT	Oil recovered
Weasel 1	Woodside Petroleum Ltd	2003	1776 mRT	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

Release Areas NT09-Special and W09-Special are covered by numerous grids of primarily 2D seismic data, with data density generally increasing towards the Turtle and Barnett oil accumulations in the southern part of the Release Areas. Seismic coverage in the northern part of Release Area NT09-Special includes the Baal Bone (1999) and the B88 (1989) 2D siesmic surveys, which have line spacings of between 1 and 5 km. The northern part of Release Area W09-Special is primarily covered by the WA-279/280-P (King Shoals) 2D seismic survey, which was acquired in 1999 and has a line spacing of 1–2 km. The central and southern parts of the Release Areas are covered by relatively more detailed 2D grids (typically with line spacing of approximately 1 km), including the SPA 5SL/1992-93 and Neptune 1990 surveys in NT09-Special and the Suzanne 1984 survey in W09-Special. Two 3D seismic surveys are situated either within or partially within the Release Areas. The B90-2D/3D Barnett seismic survey, which was acquired in 1990, covers approximately 56 km^2 over the Barnett oil accumulation in the southern part of Release Area NT09-Special. The Thresher 2D and 3D seismic survey, acquired in 1989, is situated adjacent to, and partially over, the southern margin of Release Area W09-Special. The most recent seismic acquisition in the Release Areas was the SNT04 - NT/P67 2D seismic survey, in which 136 line km were acquired by Santos in NT09-Special in September 2004.

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).

At least two active petroleum systems have been identified and mapped in the offshore Petrel Sub-basin (Bradshaw et al, 1994; McConachie et al, 1996, Edwards et al, 1997; Kennard et al, 2000, 2002; Barrett et al, 2004; Earl, 2004; Gorter et al, 2004, 2005; Taylor, 2006):

> An oil and gas-prone early Carboniferous Milligans-Kuriyippi/Milligans(!) Petroleum System (Barrett et al, 2004) sourced from Mississippian marine mudstones within the southern Petrel Sub-basin. These mudstones were previously assigned to the Milligans Formation (Edwards et al, 1997; Kennard et al, 2000, 2002; Barrett et al, 2004), but have since been shown to belong to the underlying Langfield Group (Gorter et al, 2004, 2005; Taylor, 2006). This petroleum systems model requires that the extent of the Langfield Group and its effective source pod be mapped, and that a re-appraisal of potential source rocks in the southern Petrel Sub-basin are undertaken given the stratigraphic refinements that have occurred in recent years.

> A gas-prone Permian Hyland Bay/Keyling-Hyland Bay (.) Petroleum System (Barrett et al, 2004) in the central and northern Petrel Sub-basin sourced from pro-delta marine mudstones of the Hyland Bay Subgroup and/or shallow marine and coastal plain mudstones and coaly mudstones of the Keyling Formation. The Petrel, Tern, Penguin, Polkadot, Prometheus and Rubicon gas accumulations are most probably sourced from either the Hyland Bay Subgroup and/or Keyling Formation, whereas contributions from the Fossil Head Formation, Keyling Formation and/or older (Carboniferous) strata to the Fishburn and Blacktip gas accumulations are possible given the thickness of these sediments in the southern Petrel Sub-basin. However, the 2009 Special Acreage Release areas are at the southern limit of this petroleum system, with their prospectivity relying on the earliest Carboniferous oil and gas-prone petroleum system.

Hydrocarbon Families and Source Rocks

Hydrocarbon families and their postulated source rocks have been extensively documented within the Bonaparte Basin. Published papers and reports that detail the geochemistry of oils and source rocks from the Petrel Sub-basin include Kraus and Parker (1979), McKirdy (1987), Jefferies (1988), Edwards and Summons (1996), Edwards et al (1997, 2000), Earl (2004), Gorter et al (2004, 2005) and Edwards and Zumberge (2005).

Few geochemical analyses exist for Late Devonian source rocks in the Petrel Sub-basin, although numerous mineral exploration holes around the southern margin of the basin penetrate these sediments (Edwards and Summons, 1996). The only oil-prone source rocks sampled in the Petrel Sub-basin are from the Langfield Group in the mineral hole NBF-1002 (McKirdy, 1987; Edwards et al, 1997; Gorter et al, 2004). Where sampled from wells in the southern Petrel Sub-basin, the 'Milligans Formation' is at best gas-prone at current maturity levels (Edwards et al, 1997; Gorter et al, 2004), although further sampling and reallocation to the revised formations are required given the recent revisions to the Carboniferous stratigraphy.

Reservoirs

The most prospective reservoirs within the offshore southern Petrel Sub-basin, and for the 2009 Special Release Areas, are the Permian Keyling Formation and Treachery Formation, and the Carboniferous Kuriyippi Formation, Tanmurra Formation, Kingfisher Shale and Yow Creek Formation, as exemplified by the oil accumulations at Barnett and Turtle. The Kingfisher Shale also contains gas shows at Turtle 2. The reservoir quality of the Keyling Formation sandstone is excellent at Blacktip 1, Cambridge 1, Lacrosse 1 and Turtle 2. Reservoir quality of the Carboniferous sandstone reservoirs is typically poor due to the presence of a calcareous matrix and authigenic clays. However, porosity and permeability may be improved by extensive fracturing.

In the onshore Petrel Sub-basin, the Mississippian Milligans Formation and/or Bonaparte Formation/Langfield Group are important reservoirs for gas in Bonaparte 1, Garimala 1, Keep River 1, Ningbing 1, Vienta 1, Waggon Creek 1A and the Weaber gas accumulation, although gas is also hosted within the Devonian Ningbing Group in Vienta 1. In addition, the Kingfisher Shale, Utting Calcarenite and Waggon Creek facies of the Milligans Formation are important reservoirs for gas in Bonaparte 2.

Gas at Blacktip 1 is reservoired in sandstones of the Triassic Ascalon Formation (Mount Goodwin Subgroup), Permian Keyling, Quoin and Treachery formations, and the Carboniferous–Permian Kuriyippi Formation (Gorter et al, 2008). The Keyling Formation was the primary objective with five gas-bearing zones encountered, equating to a 339 m cumulative gross gas column that is sealed by the Fossil Head Formation (Woodside Australian Energy, 2002a; Leonard et al, 2004). The sustained, high flow rates recorded on test from the combined units within the Keyling Formation at Blacktip 1 substantially exceeded the rates achieved by any of the individual wells in the Petrel and Tern gas accumulations.

In the Petrel Deep, the Permian Cape Hay and Tern formations of the Hyland Bay Subgroup are the main reservoirs for the Petrel and Tern gas accumulations. Gas is also reservoired within the Torrens Formation (basal Hyland Bay Subgroup) at Penguin 1 and Polkadot 1. Although the Hyland Bay Subgroup was deposited across most of the southern Petrel Sub-basin, post-depositional erosion associated with the Fitzroy Movement has removed these sediments along the margins of the sub-basin, including the Berkley Platform (Lee and Gunn, 1988). Reservoir distribution and characterisation for this subgroup have been mapped in detail by Robinson and McInerney (2004). Gas at Fishburn 1 is reservoired within the latest Permian Penguin Formation.

Seals

The Permian Treachery and Fossil Head formations provide regional seals for the respective underlying Kuriyippi and Keyling formations in the southern Petrel Sub-basin. However, the Treachery Formation regional seal is partially fault-breached across the Turtle-Barnett High (Durrant et al, 1990; Colwell and Kennard, 1996). Intra-formational shaly members of the Langfield Group, Weaber Group, Treachery Formation, Keyling Formation and Mount Goodwin Subgroup may form effective local seals in a variety of trap geometries. In Turtle 2, a shelfal carbonate within the Tanmurra Formation, where not fractured, provides an excellent seal to sandstones reservoirs of the lower Tanmurra Formation. Salt diapirs are also likely to provide effective seals in a variety of settings.

In the central and outboard areas of the Petrel Sub-basin, the transgressive, thick marine shales of the Mount Goodwin Subgroup form the regional seal to the reservoirs of the Hyland Bay Subgroup. Also within the Hyland Bay Subgroup are the intraformational marine shales of the Cape Hay Formation, and the biomicritic limestones of the Dombey and Pearce formations (Colwell and Kennard, 1996; McConachie et al, 1996).

Play Types

Structural and stratigraphic traps that contain both sandstone and carbonate reservoirs have been identified at numerous stratigraphic levels in the southern Petrel Sub-basin, as shown in **Figure 6**.

The main play types within the early Carboniferous (Mississippian) petroleum system of the southern Petrel Sub-basin are drape and pinch-out plays within the Weaber Group across and against the Turtle-Barnett High, lowstand basin-floor fan sandstones within the Milligans Formation, and closures and truncations of the Langfield and older sections beneath the basal Weaber Group unconformity. Sandbar 1 targeted a basin-floor fan in the Milligans Formation, but did not encounter reservoir sands or hydrocarbons. Other play types include Tanmurra Formation reefal plays, which appear to have formed on salt-induced seafloor mounds. There are also Kulshill Group rollover anticlines on fault-blocks down-thrown against the Lacrosse Terrace.

The Fitzroy Movement is responsible for creating large-scale inversion anticlines (commonly associated with salt mobilisation), such as those drilled in the Petrel and Tern accumulations, as well as anticlines associated with faulting, for example those drilled by the Blacktip 1 (Leonard et al, 2004), Lacrosse 1 and Lesueur 1 wells.

Salt tectonics (flow, diapirism and withdrawal) has created numerous potential structural and stratigraphic petroleum traps. These features have either been identified or are thought to be present across most of the sub-basin (Edgerley and Crist, 1974; Durrant et al, 1990). Salt movement may have triggered petroleum migration and influenced migration pathways throughout the development of the Petrel Sub-basin.

Salt-related petroleum plays in the Petrel Sub-basin range from salt-core plays to salt-withdrawal basin plays. The timing of salt movements in the sub-basin varies widely, although many such salt-related traps may have formed too late with respect to hydrocarbon generation and migration. There is abundant evidence on seismic data for the presence of turbidites, basin-floor sandstones, slope-fan sandstones and coastal onlap of sandstone bodies within local depocentres over slowly migrating salt bodies (Lemon and Barnes, 1997; Miyazaki, 1997). These sandstones now constitute primary exploration objectives when found in favourable trap geometries.

Critical Risks

The key risks in the 2009 Special Release Areas are the identification of good quality reservoirs in suitable sized traps which have access to active oil and gas-prone source kitchens. Oil generation and migration has occurred within the Keep Inlet Sub-basin and Kulshill Terrace as indicated by the shows at Kulshill 1 and 2; however, the extent and adequacy of the oil charge and migration within the 2009 Special Release Areas is uncertain. Similarly, oil generation and migration has occurred within the Cambridge Trough and southern Petrel Deep, as confirmed by the oil shows at Cambridge 1, Cape Ford 1, Lacrosse 1, Lesueur 1 and Pelican Island 1. The Barnett and Turtle oil accumulations may have been sourced from either or both of these depocentres, given that there is evidence of multiple charges into these structures (Colwell and Kennard, 1996). Preservation of the oil following significant Triassic-uplift and erosion is another risk, as exemplified by the biodegradation of the Turtle and Barnett oils.

The northern parts of the 2009 Special Release Areas may be at the limit of the effective late Carboniferous–Permian gas-prone petroleum system to the north. Gas charge is confirmed at Blacktip immediately to the north, and the Fishburn, Tern, Petrel and Penguin accumulations in the central Petrel Sub-basin. The small number of suitable sized traps for economic gas accumulations provides an additional exploration risk.

Reservoir quality is variable within the 2009 Special Release Areas, with the preservation of porosity and permeability within Carboniferous reservoirs a significant risk. Sealing capacity also needs to be addressed given that oil shows occur throughout Carboniferous and Permian sediments in the wells of the southern Petrel Sub-basin. The Treachery Formation seal at Barnett and Turtle was partially breached by fault reactivation, and consequent fresh-water flushing and biodegradation of the shallow reservoirs (Colwell and Kennard, 1996).

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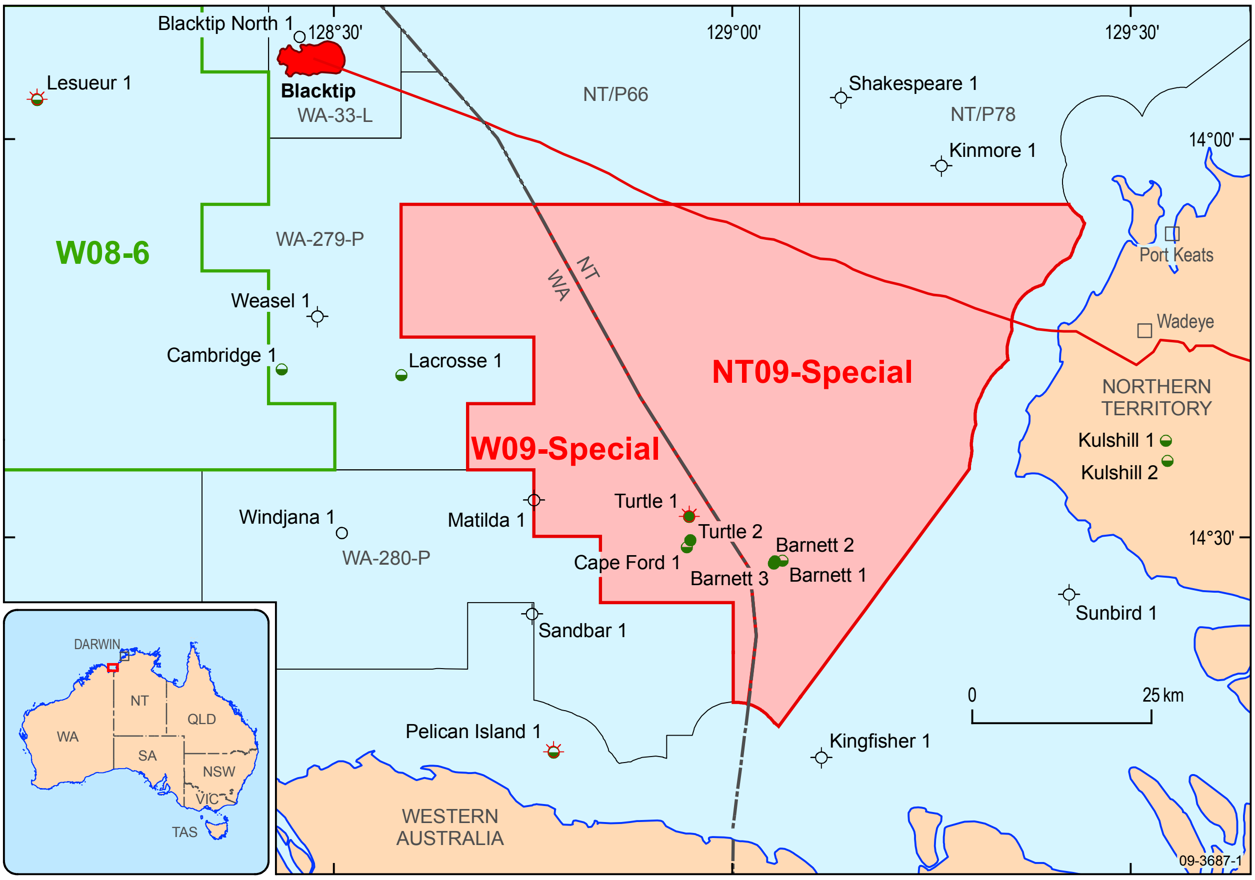
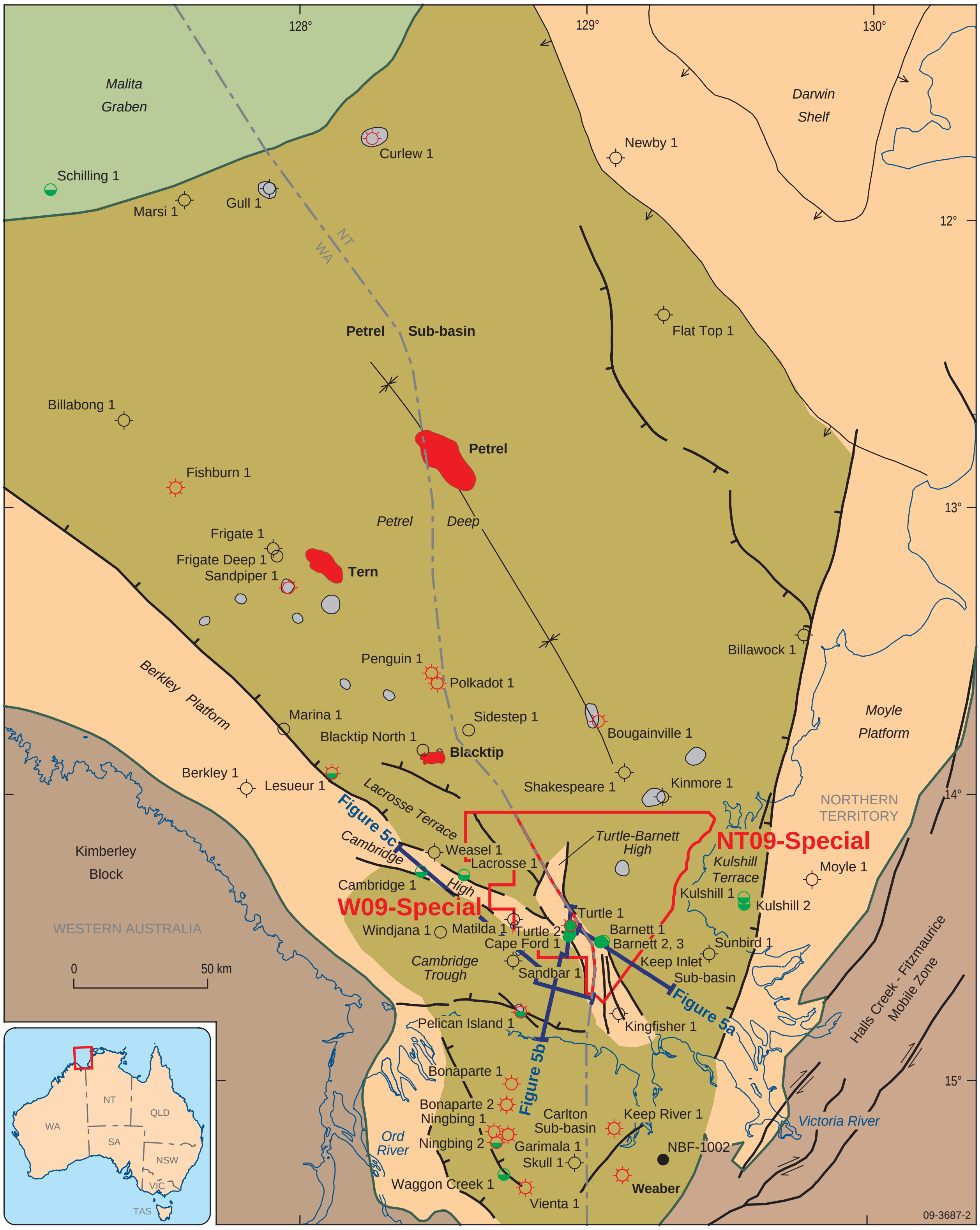


Where well symbol information is sourced from publicly available "open file" data, it has been provided by Geoscience Australia from Well Completion Reports. These symbols were generated from open file data as at 31 March 2009. Where well symbol information is not publicly available from titleholders'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

2009 Special Offshore Petroleum Acreage Release Area
2008 Offshore Petroleum Acreage Release Area
Existing petroluem title
Gas field
Gas pipeline
Scheduled area boundary (OPGGSA 2006)
Petroleum exploration well - Not classified
Petroleum exploration well - Dry hole
Petroleum exploration well - Oil show
Petroleum exploration well - Oil discovery
Petroleum exploration well - Oil and gas show
Petroleum exploration well - Oil discovery and gas show

Figure 1. Location map of Release Areas NT09-Special and W09-Special in the Petrel Sub-basin.



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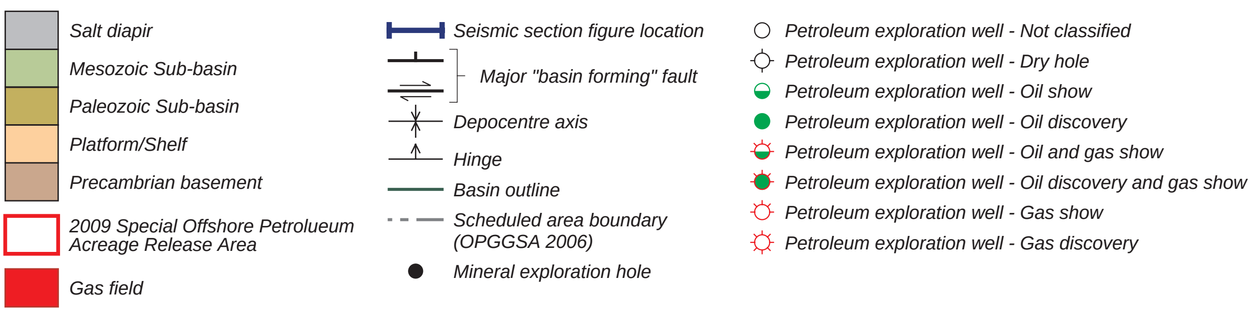

Figure 2. Regional structural elements of the Petrel Sub-basin showing the locations of seismic lines in Figure 5.

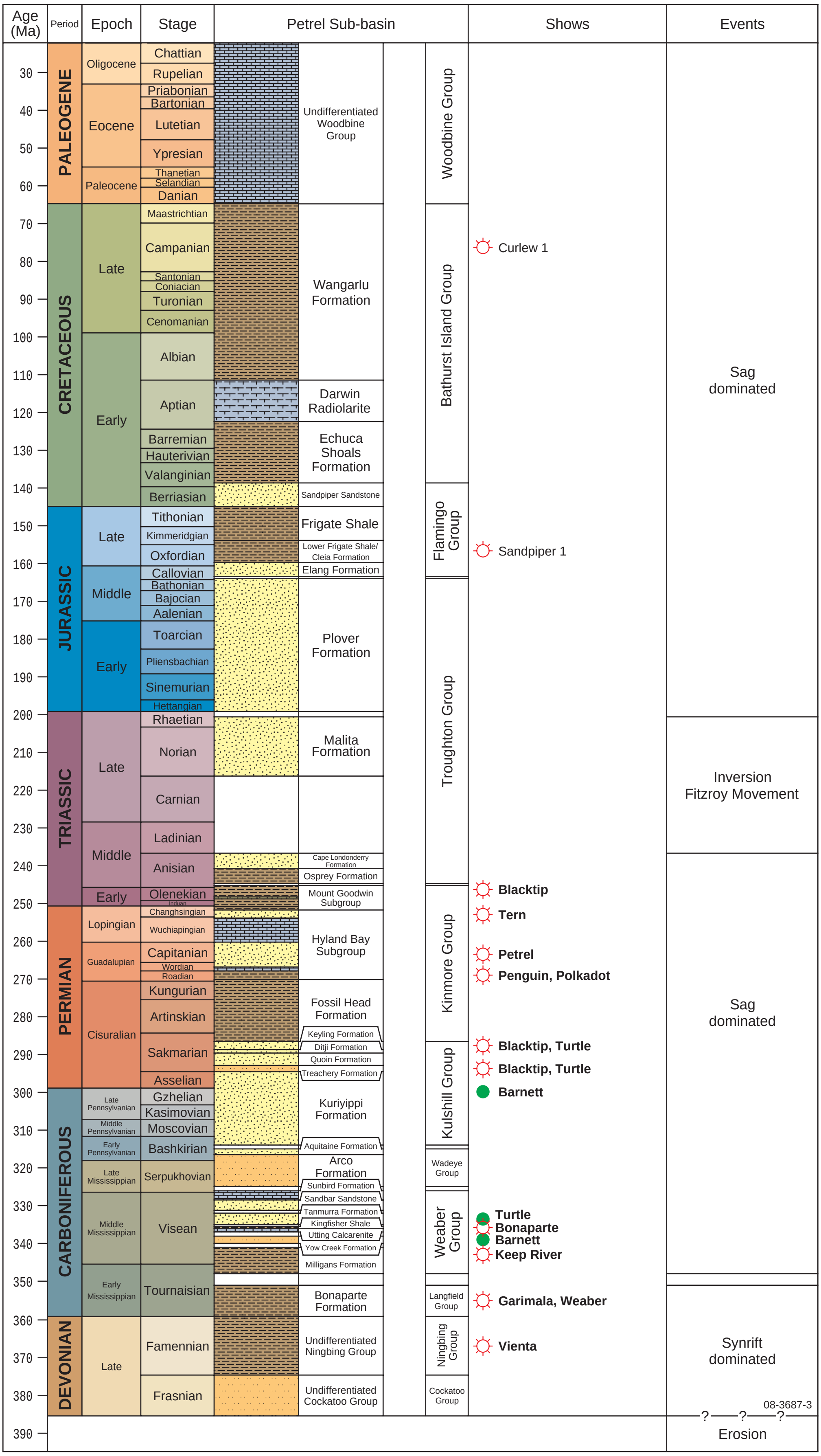

Figure 3. Stratigraphy of the Petrel Sub-basin, using Geologic Time Scale 2004 after Gradstein et al (2004) including the recent updates by Gorter et al (2004, 2005, 2008 and 2009). Names in bold are acccumulations.

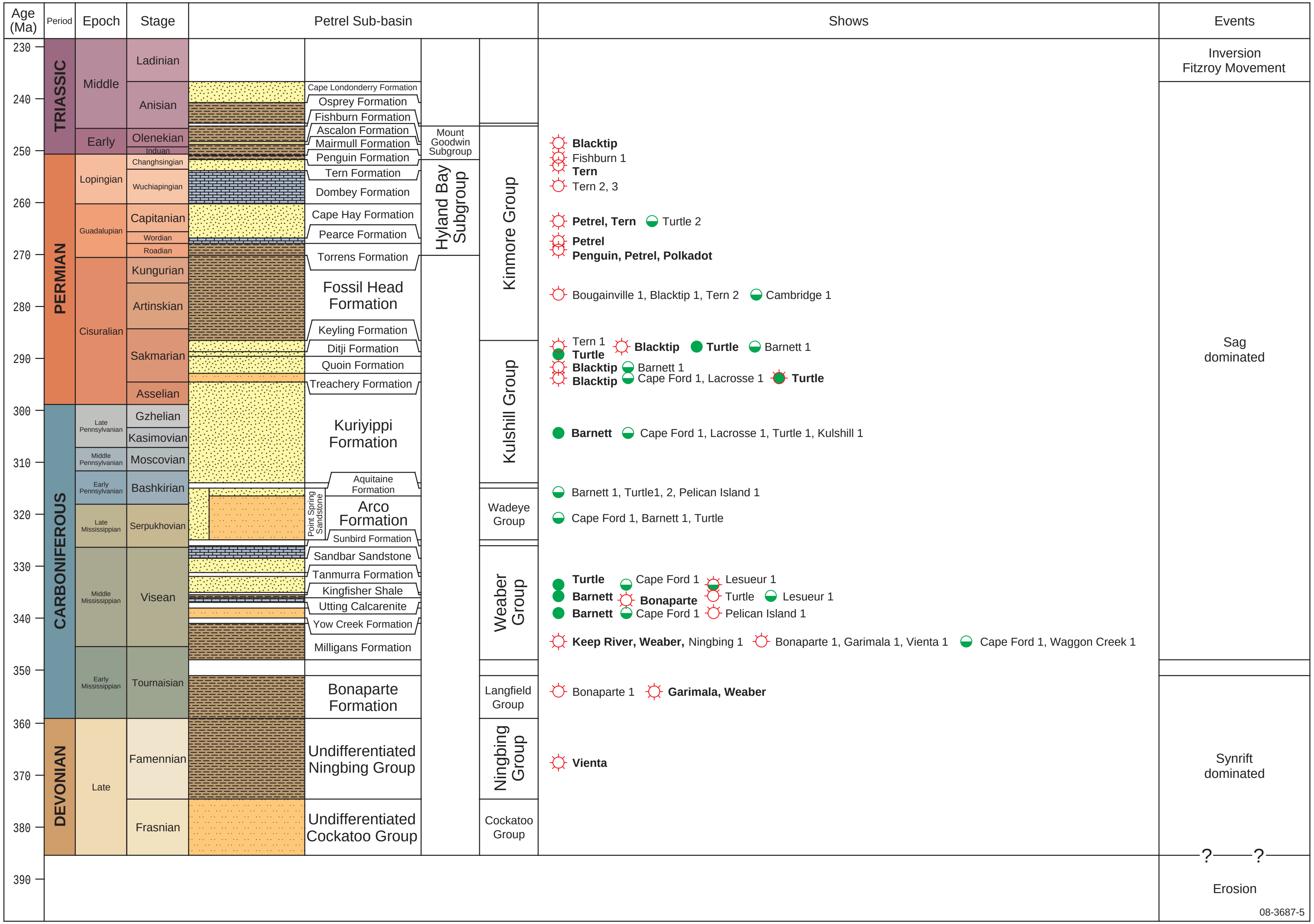

Figure 4. Detailed Devonian to Triassic stratigraphy of the Petrel Sub-basin, using Geologic Time Scale 2004 after Gradstein et al (2004) including the recent updates by Gorter et al (2004, 2005, 2008 and 2009). Names in bold are accumulations.

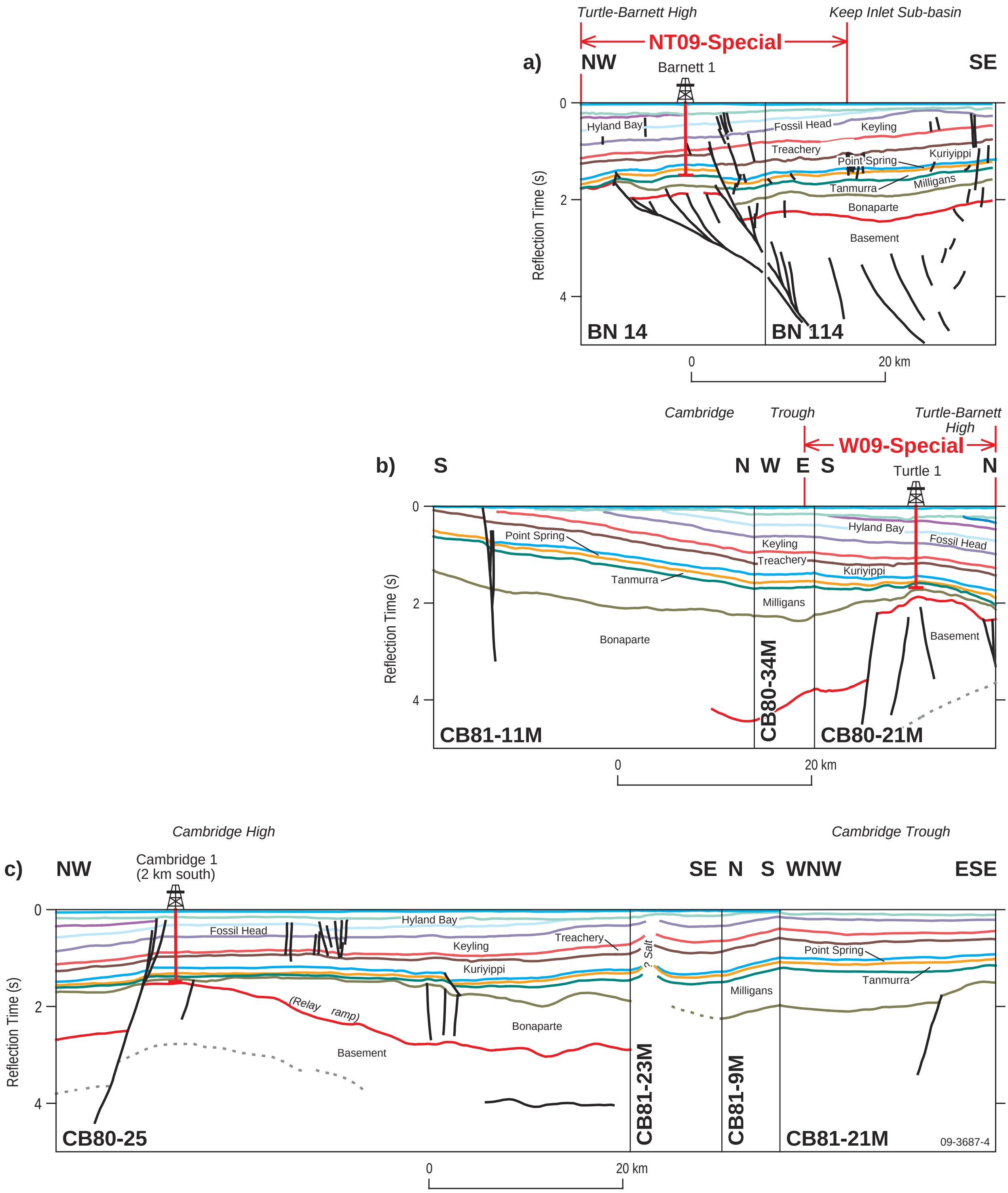

Figure 5. Line drawings of transects from selected company seismic lines through and near to Release Areas NT09-Special and W09-Special (enclosure 9, Colwell et al, 1996). Locations of lines are shown in Figure 2.

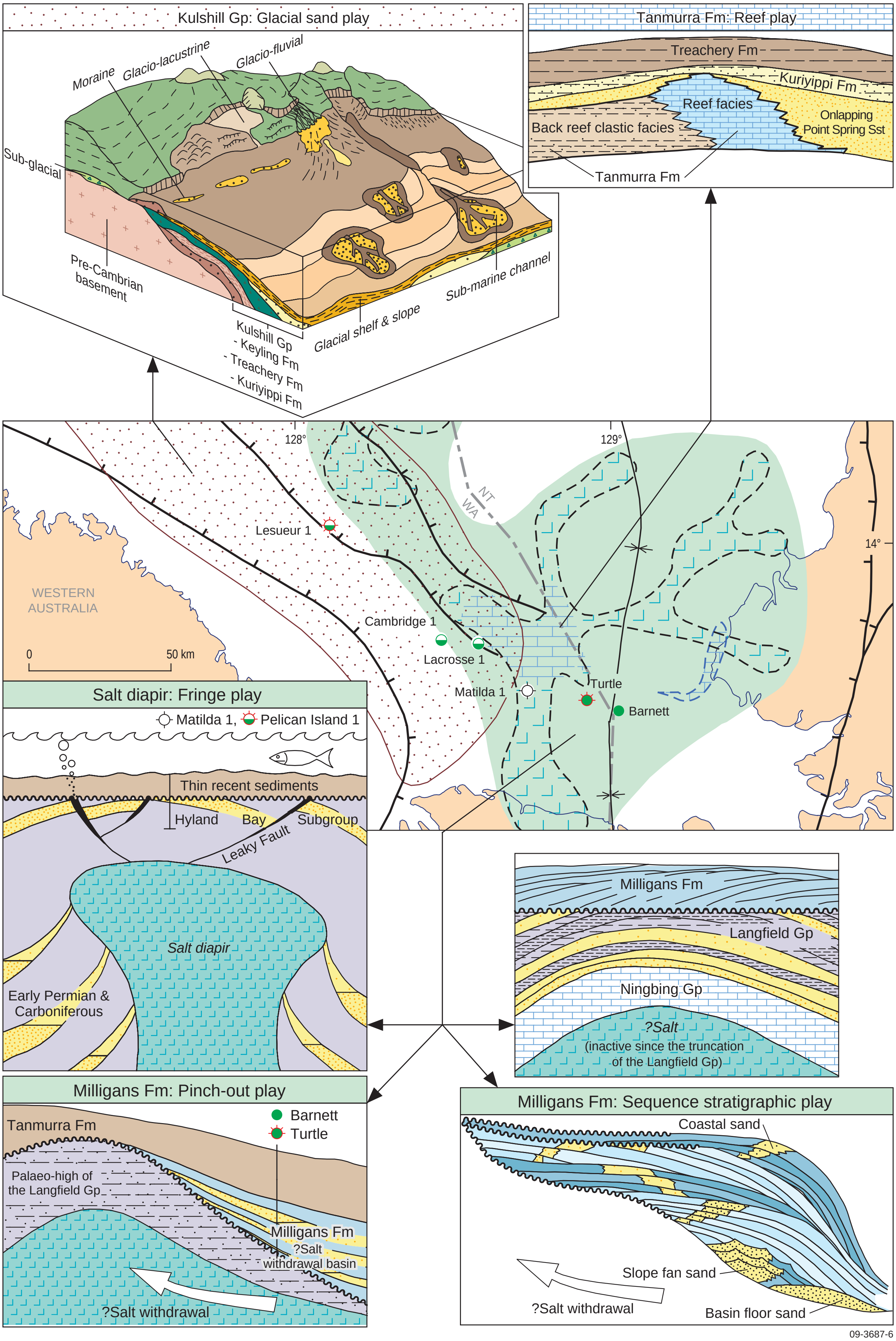

Figure 6. Play types in the southern Petrel Sub-basin (after Miyazaki, 1997).