Contents

The North West Shelf of Australia - A Woodside Perspective*

By
I.M. Longley, C. Buessenschuett, L. Clydsdale, C.J. Cubitt, C.J., Davis, R.C., Johnson, M.K., Marshall, N, M., Murray, A.P., Somerville, R., Spry, T.B and Thompson, N.B.
Woodside Energy Ltd, 1 Adelaide Tce, Perth, WA 6000

*On line version of article of the same title by the same authors published in The Sedimentary Basins of Western Australia 3, M. Keep and S.J. Moss, eds., as Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth WA. Appreciation is expressed to the Petroleum Exploration Society of Australia for permission to present this article online.

Abstract

The North West Shelf of Australia is a world class gas province with minor oily sweet spots. It is a marginal rift with pre-rift Permo-Triassic intracratonic sediments, overlain by Jurassic to Cainozoic syn- and post-rift successions. These were deposited in response to rifting and seafloor spreading of at least three continental blocks in Oxfordian, Tithonian and Valanginian times. Rifting was initiated in the central Argo area in the Oxfordian. In Tithonian times, the rifting jumped to the north of Timor (where the spreading record has been subsequently subducted), then in the Valanginian it moved to the southern Cuvier area. This break-up history produced a complex spatial and temporal distribution of rift and post rift deposits, which strongly control the efficiency and liquid hydrocarbon potential of the margin's petroleum systems.

Since exploration drilling commenced in 1953, some 754 exploration wells have been drilled (at Dec 2001), discovering estimated reserves of 2.6 billion bbls of oil, 2.6 billion bbls of condensate and 152 Tcf of gas within 233 hydrocarbon fields. Most of the successful traps comprise sands within rift-related horsts and tilt blocks, or sands within overlying drape structures. Almost all (97%) of the margin's resources are reservoired beneath the (dominantly Cretaceous) regional seal. Other more complex traps have been rarely successful, in general the margin offers little encouragement for stratigraphic entrapment due to the sandy section beneath (and above) the regional seal.

The dominance of gas (84% by boe) is due to the quality, and often the high maturity, of the source rocks within all identified hydrocarbon systems. Rare oil-prone source rocks are present, but their effectiveness in producing economic oil fields relies on protection from gas flushing, and/or biodegradation or the selective loss or separation of the dominant gas charge via fault leakage or water washing. Effective oil source rocks are found locally within mainly Jurassic pre- and syn-rift deltaic, or syn-rift marine settings, within partially restricted depositional settings, whereas sediments deposited in open marine environments are typically lean and gas-prone.

The extensive coverage of 3D seismic acquired in the late 1990s over the 'oily' portions of the margin has not resulted in large exploration successes. This is due to the simple effective traps at base regional seal level being beneath the amplitude floor and had been

previously identified with 2D data. Small traps were identified by 3D in these areas, and these discoveries will be developed as infrastructure matures, and economic thresholds decrease.

Some 119 Tcf of gas reserves remain undeveloped, together with an estimated 1400 mmbbls of potential condensate reserves. The future of the North West Shelf hydrocarbon province largely lies in developing these resources and exploring for traps surrounding the future infrastructure. The province is still under-explored by global standards, especially outside of proven oily areas, where large potential volumes remain in untested deepwater Mesozoic basins, and inboard poorly explored Palaeozoic basins.

The North West Shelf of Australia provided the initial growth platform for Woodside, and Woodside will continue to be committed to further significant exploration in the province. With vast discovered, but undeveloped, gas reserves, Woodside is focussed on developing existing gas reserves, whilst continuing exploration for oil. However, the low probability of discovering a new oily sub-basin, simple trap geometries, gassy charge and the poor record of 3D seismic in proven oily areas, creates a challenge to compete for exploration funds for oil exploration on the North West Shelf when compared against global oil opportunities.

Introduction

The North West Shelf (Figure 1) is a geographic term applied to the offshore and marginal basins areas flanking the northwest coast of Australia (Purcell and Purcell, 1988a).

Woodside was first awarded a 268,580 km^2 exploration permit (PE213H) on the North West Shelf in 1963, and by 1965 had equity in a further nine blocks, with a total area of 367,000 km^2, which is equivalent to 0.53, 1.5 and 10.8 times the land area of Texas, UK and Holland respectively. Early exploration success within these and subsequent permit areas led ultimately (in 1984) to commercial development. By 2001, Woodside operated an onshore LNG plant with three processing LNG (liquified natural gas) trains (soon to be expanded to four and probably five), and other offshore operated facilities (two offshore platforms, two floating production and storage offtake vessels (FPSOs) and a mobile offshore production unit (MOPU). These facilities in 2001 cumulatively produced 131 cargoes of LNG (7.75 million tonnes of LNG and 803 tonnes of liquified petroleum gas (LPG)), an average of 536 terrajoules per day of domestic gas, 95,500 barrels of condensate per day and 254,000 barrels of oil per day. Also, at the end of 2001 Woodside was participating in 34 exploration licences (30 operated) along the North West Shelf, covering 101,000 km^2 and has equity in 19 production licences and/or retention leases (all Woodside operated) covering an area of 5116 km^2. Woodside's net reserves (reserves plus scope) from just the North West Shelf portion of its portfolio at the end of 2001 was 3.8 billion barrels of oil equivalent (17.8 trillion cubic feet (Tcf) of gas, 411 million barrels (mmbbls) of condensate and 445 million barrels of oil or 78% gas oil equivalent - using 6 billion cubic feet (bcf) of gas is equivalent to 1 mmbbls of oil).

In 1998, Woodside perceived that the potential for material growth of the company exclusively through further exploration within the North West Shelf (and Australia) was becoming increasingly difficult, due to its focus on exploring for large oil reserves in the dominantly gassy province. Consequently, an international oil exploration and growth strategy was developed. As new overseas provinces were evaluated, they were ranked against North West Shelf opportunities.

In April 2000, Woodside formed a North West Shelf evaluation team with the specific task of improving it's regional understanding. The work was completed by January 2001 and some of the results are presented in this technical overview.

The study confirmed that despite Woodside's ongoing commitment to oil exploration on the North West Shelf, this region alone was considered unlikely to satisfy its future oil volume targets. The rationale and logic behind this decision is the central theme of this paper.

{Figure Caption (1)}
1. North West Shelf location map.

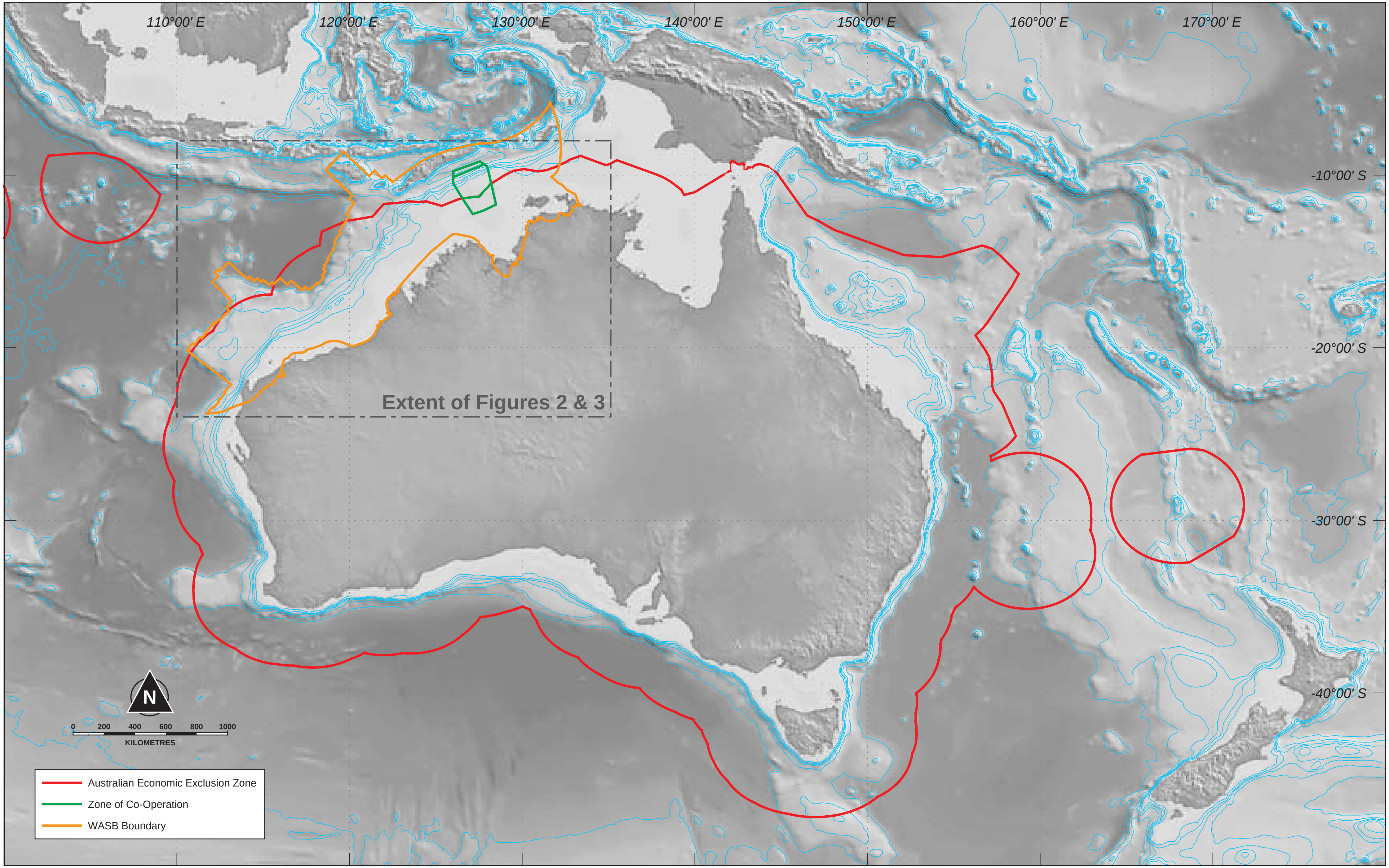

Figure 1. North West Shelf location map.

Geological Synopsis

The published geological evolution and petroleum geology of the North West Shelf is described in the proceedings of three Petroleum Exploration Society of Australia symposia edited by Purcell and Purcell (1988a, 1994, 1998). The following geological synopsis is based on these and other published works, integrated with the results of proprietary studies relating to Woodside's exploration activities over almost 40 years.

The limits of the North West Shelf as defined by this study are shown in Figures 2, 3, and 4, the underlying tectonic elements in Figure 5, and a set of schematic regional cross-sections in Figures 6a and 6b. The North West Shelf is comprised of four basins, namely the Northern Carnarvon, Offshore Canning (or Roebuck), Browse and Bonaparte basins, and one orogenic belt, herein termed the Timor-Banda Orogen. The four basins cumulatively comprise the "Westralian Superbasin" (Yeates et. al., 1987), abbreviated to WASB hereafter. The WASB is filled with a thick late Palaeozoic, Mesozoic, and Cainozoic sedimentary succession relating principally to the fragmentation of Gondwana. The Timor-Banda Orogen is the product of a Neogene collision between the distal edge of the WASB with the Banda Arc, and arc systems flanking the Southeast Asian Sundaland Craton (Figure 5) (Metcalfe, 1999; Keep et. al., 2002).

The WASB lies predominantly within Australian territorial waters, and the Timor-Banda Orogen lies exclusively within East Timorese and Indonesian waters (Figure 2). This overlap of political and geologic boundaries has historically tended to mask the common geology between the two regions, and confuse the outboard limit of the North West Shelf (*sensu* geological province as defined on Figure 2). In contrast, the inboard limit of the North West Shelf is generally well defined by the Proterozoic Australian craton. Flanking Palaeozoic basins on the edge of this craton (Figure 5) were the main provenance for Mesozoic WASB sedimentary sequences.

The outboard limit of the North West Shelf comprises oceanic crust in the south, and accreted volcanic arc and accretionary wedge material in the north (Figure 5). The lateral limits of the North West Shelf in the southwest and northeast are arbitrarily defined where post-Palaeozoic sediments thin onto platform areas.

The combination of sequence stratigraphic modelling within the constraints of a reliable and detailed biostratigraphic framework has had a considerable impact on the geological understanding of the North West Shelf within Woodside over the last decade. Of particular importance was the publication of the Helby et al. (1987) palynological zonation for the Australian Mesozoic, which provided a reliable and unified standard for correlating strata throughout the region. The currently used sequence stratigraphic model is an extension of that defined by Jablonski (1997) for the Dampier Sub-basin, and is based on the integration of electric log and biostratigraphic data from over 750 well sections which were calibrated against modern seismic data.

The major surfaces within this sequence stratigraphic model have been used to define a set of regional picks marking the boundaries of the Woodside play intervals shown as

Figure 7. The usage of the play intervals avoids the complications of trying to unify the different lithostratigraphic schemes currently being used in the individual basins and sub-basins. The intervals defined by the play intervals are essentially time-related packages of strata bounded by regionally distinct stratigraphic surfaces, and hence are similar to the timeslices applied by AGSO within the region (Bradshaw et al., 1988; AGSO North West Shelf Study Group, 1994). To assist readers familiar with traditional lithostratigraphic nomenclature, the most typical lithostratigraphic unit associated with each play interval is placed in parentheses after the Woodside play names (e.g. J20 (Legendre Formation)). The play names also have an age context, with TR=Triassic, J=Jurassic, K=Cretaceous, and T=Tertiary.

Significant tectonic events from within and beyond the study area are illustrated in Figure 7 (after Metcalfe, 1999; Norvick et al., 2001; Norvick and Smith, 2001; Muller et al., 2000; Keep et al., 2002; Hill and Raza, 1999) and the significant Jurassic and Early Cretaceous seismic events and intervening play intervals are summarised in Table 1.

The early Palaeozoic Cambro-Ordovician section is not described here, since this section is either deeply buried or absent, and has not materially contributed to the petroleum prospectivity of the study area. The early Palaeozoic is overlain in parts of the Bonaparte Basin with a thick salt deposit, which has later mobilised and formed salt-cored structures in some areas (see Figure 7 of Bradshaw et al., 1994, for palaeogeographic setting; Smith and Sutherland, 1991; Gunn et al., 1988a). The overlying Devonian to Permian section relates to the first two of three significant periods of Gondwanan terrain dispersion where continental fragments drifted northward and subsequently accreted to the Eurasian craton (Metcalfe, 1999). These sequences (PZ20-50 inclusive; Figure 7) form two synrift and sag cycles, filled with variable marine, deltaic and glacial deposits. It is not possible to image or map these Palaeozoic successions on seismic data over the entire study area, as they are overlain, particularly in basinal areas, by thick Mesozoic deposits. The Palaeozoic basin history, best described by Bradshaw et al. (1994), is pieced together from local areas of the WASB where Palaeozoic horizons can be imaged and mapped. Such regions include the Petrel Sub-basin of the Bonaparte Basin (Figure 2) (Mory, 1988; Colwell and Kennard, 1996), within shelfal areas where the onshore Palaeozoic Canning Basin extends offshore beneath the Offshore Canning Basin and in the inboard shelfal areas of the Northern Carnarvon Basin (e.g. Delfos and Dedman, 1988; and Bentley, 1988). Elsewhere there are occasional windows of information through the thick cover by virtue of deep seismic imaging (e.g. Browse Basin, Struckmeyer et al., 1998).

The second of the two main Palaeozoic rift phases occurred in the Late Carboniferous, and is the most important rifting event on the North West Shelf, as it gave rise to the WASB (AGSO NORTH WEST SHELF STUDY GROUP, 1994). It relates to the onset of the Sibamasu block separation (Metcalfe, 1999), and resulted in a thick (approx. 10 km), continuous fill of mainly Permian and Mesozoic sediments (Bradshaw et al. 1988), covering the entire NE-SW striking Westralian Basin area (Figure 4). This contrasts with the earlier successions which are interpreted to be less contiguous, and more influenced by the NW-trending early Palaeozoic structural grain (Figure 5) (Bradshaw et al., 1994). Late Carboniferous to Early Permian synrift fill comprises glacio-fluvial sediments which pass upwards into a thick sag section. The sag section itself comprises two units, marine Permian shelfal and shallow water carbonates and sands, overlain, after a major eustatic lowstand, by a thick succession of shelfal Triassic shales, which thicken and become more distal to the northwest (Nicoll and Foster, 1994) (Figure 7).

The third significant period of terrane dispersion from the Gondwanan margin occurred in the Late Triassic to Late Jurassic, associated with the Norian drift of the Lhasa block and the subsequent drift of the West Burma and Woyla blocks into the Late Jurassic (Metcalfe, 1999).

The Late Triassic Carnian to Norian succession was deposited following a regionally extensive period of significant tectonism, erosion and uplift along the edges of the craton, known as the "Fitzroy Movement" (Forman and Wales, 1981). Synchronous events (e.g. the Scott Reef-Buffon trend was created and the Bedout High further accentuated), are evident on seismic and well data in the offshore Bonaparte, Browse and Canning basins, suggesting a regional tectonic event. These were related either to breakup events from the Gondwanan margin or, more likely, to docking of continental blocks along the adjacent Irian/Papua New Guinea subduction margin. Regardless of the cause, the hinterland uplift and tectonic events associated with the Fitzroy Movement resulted in the influx of a thick sequence of (TR20) sediment in the Northern Carnarvon Basin, pouring out from the uplifted onshore Canning Basin region (Figure 8). These (predominantly) thick deltaic successions prograded some 500 km from the margin of the Onshore Canning basin, to the Exmouth Plateau, and into the marine embayment of the Wombat - Timor Trough (Nicoll and Foster, 1994).

The Lhasa block rifted from the northern Indian Margin during the Norian (Metcalfe, 1999). In the WASB this event is associated with a major flooding surface within the basal section of the Rhaetian, which is mapped as the TRR seismic event (Figures. 7 and 9).

Following the drift of the Lhasa block, extension along the Gondwanan margin continued, and the West Burma and Woyla Blocks subsequently drifted from the Australian margin of Gondwana. Metcalfe (1999) is not specific about the exact drift ages of the fragments and herein a more detailed model is proposed to explain the stratigraphic and structural observations from the WASB. This model is consistent with the work of Muller et al. (1998), and is based on preserved magnetic marine anomalies, which suggest that Oxfordian and Valanginian drift events respectively formed the Argo and Cuvier oceanic basins.

The interpreted age of block rotation in different areas, from latest Triassic to Early Cretaceous, is shown as Figure 5, while the age of the major rifting events (rift onset and cessation ages) along the margin is shown as Figures 7 and 9. The proposed model to explain these observations is shown as Figure 10, whereby the West Burma Block was comprised of three sub-blocks which rifted during the Sinemurian, Oxfordian and Tithonian, respectively. It is not considered crucial that the blocks fully rifted and drifted from the Gondwanan margin during these periods, since failed rift events may also have resulted in associated flooding events further inboard onto the craton.

In the proposed model, West Burma Block 1 (Figure 10) began to rift in the latest Hettangian as inferred from the dating of a major basinward shift of facies at the CTS5 seismic event, which marks the onset of a major phase of sand influx. This extension continued until break-up in the Sinemurian. The subsidence caused by the emplacement of oceanic crust, and the change to drift tectonism is expressed inboard as the major JP1 flooding event (seen over the North Carnarvon to Browse area – Figure 5). This flooding event becomes progressively less distinct in the Bonaparte Basin, as this northern area was beyond the limit of rift block rotation (Figure 5) and remained largely unaffected. The amount of accommodation space created by this event is shown by the thickness of the overlying J20 section (Figure 11a), which comprises a massive succession of deltaic prograding sediments (Figure 12) in the outboard Beagle area (Figure 2).

Rifting of the second West Burma Block from the margin (Figure 10) began in the Callovian (JC seismic event) and was complete by the Oxfordian (JO seismic event) (Figures 7 and 9). The palaeogeography of the synrift J30 Callovian section is shown on Figure 13, and highlights the dramatic change in palaeogeography from the underlying broad delta plain in the Bathonian (Figure 12), to deposition within narrow rift valleys. Again, because of the distance of the Bonaparte Basin from the main rift axis, and the area of block rotation (Figure 5), the section in this area remained largely unaffected by the southern rift event, with deposition continuing over a stable broad deltaic plain (Figure 12). Rift related valleys formed during this phase. Based on the log motifs and models presented by Ravnas and Steel (1998) for marine rift systems, these features were initially underfilled but were subsequently infilled by marine shale and sandstone, some of which appear to be shed from the craton during lowstand events.

In the Tithonian, it is interpreted that a third West Burma Block separated from the margin, from a position outboard of the Bonaparte Basin and that the oceanic crust and magnetic anomalies recording this event have been subducted (Figure 10). The only direct evidence for this model is the interpreted block rotation observed in the northern Bonaparte wells, and the associated significant unconformity near the base of the Tithonian (JT, top *D. swanense* Zone) observed in well sections (Pattillo and Nicholls, 1990) (note this reference labelled this event as the Intra-Kimmeridgian event within the *D. swanense* dinoflagellate zone of Helby et al. (1987), which is now interpreted to be near base Tithonian in age).

In the Vulcan, Sahul and Flamingo synclinal areas the onset of this rifting event is interpreted to be marked by the JK intra-Kimmeridgian seismic event, which records the relative deepening and reduction of clastic sediment supply into the already sediment-starved rift basin areas. The rift and associated flood is a precursor to a circum - Ashform Platform oceanic current (see Figure 14) which ended the relative restriction of the Vulcan Sub-basin failed rift arm (which existed prior to the Tithonian rift during J40 time). The basal condensed section which marks the rift onset, flood and change in circulation conditions is a marl unit in the Sahul Syncline (Gorter and Kirk, 1995).

Inboard rift shoulder areas were eroded during footwall uplift and subsequent relative lowstand periods and basinal sands were then deposited in the Barrow-Dampier, Vulcan and Nancar sub-basins.

The tectonic influence of the Tithonian rifting event on the southern portion of the margin was minimal, as these depocentres were located at some distance from the main active rift area (see Figure 15).

In the Berriasian, Greater India began to rift from Gondwana (Figures 7, 9 and 10), with the formation of a long narrow rift basin running down the length of the current Perth Basin. The onset of this rift caused a marine flooding event (K seismic event on Figures 7 and 9) which is observed over the whole margin. It is interpreted that the Perth Basin rift valley then disgorged a massive sedimentary load into the southern Northern Carnarvon Basin ("Barrow delta"; Figure 16). Uplift of hinterland areas inboard of the Browse Basin also produced local progradational deltaic deposits in the Browse area (Figure 16).

With the separation of Greater India in the Valanginian (Figures 7, 9 and 10), the entire WASB was subject to regional post-rift sag, and the various underlying sandy environments were drowned by a regional marine flooding (KV seismic event) (Figure 17). In the south, the remnants of the Barrow delta, now cut off from its Perth Basin hinterland, were reworked by transgression, and a small local delta prograded in the offshore Broome area.

The isopach between the Oxfordian and Valanginian seismic (see Figure 18) illustrates the combined thicknesses of the Barrow delta and underlying Oxfordian rift basins in the Barrow region, the Oxfordian rift basins in the Dampier Sub-basin, the Oxfordian and Tithonian rift sequences in the Vulcan Sub-basin, and the Tithonian rift basin in the Malita Graben area. What is particularly significant from this figure is the interpreted absence of other rift basins from the remainder of the margin, particularly within the offshore Browse and Canning Basin regions.

The thermal sag phase for the WASB following the separation of greater India in the Valanginian can be divided into three broad units;

- Early Cretaceous K20/K30 interval (KV - KA seismic events)
- Middle to Late Cretaceous K40/K50/K60 interval (KA -T seismic events)
- Tertiary T10/T30 interval (T-Water Bottom seismic events).

Isopachs for these intervals are shown as Figures 19, 20 and 21, respectively.

What is clear from these maps is that isopach thick intervals from the earliest sag unit (K20/K30) (Figure 19) do not overlie the rift basin areas highlighted on Figure 18, as would be expected in a simple rift-drift steershorn model. This is because many areas of the margin were starved of sediment throughout the K20/K30 period, and the basin was underfilled with sediment. This “bathymetric effect” can, and has, led to the misinterpretation of anomalous subsidence curves as explained by Kaiko and Tait (2001).

The early sag fill in the K20/K30 sequence was deposited as marine shales within a long (partially restricted) marine embayment. This deposition was punctuated by occasional regressive events, providing important reservoir facies on the inboard margin. The K20/K30 sequence is overlain by a regionally distinct marker (both seismically and lithologically) along the entire margin (Figures 7 and 9), which is termed the KA event. This event relates to the separation of Greater India from Antarctica and the establishment of open oceanic conditions (Figure10). KA marks the first flooding associated with the onset of a mature ocean phase (Bradshaw et al., 1988) and is recognised by a radiolarite-rich section which results from upwelling of deep oceanic water enriched in silica and more oxygenated oceanic circulation currents (Ellis, 1987).

The K40 section forms the uppermost portion of the regional Cretaceous seal over the WASB area (Figure 7). Locally, K50 and K60 units can be shaley, forming sealing strata. Commonly underlying units down into the uppermost Jurassic are also shaley, but K40 is the most extensive shale unit and forms the ultimate regional topseal.

During the Campanian, uplift of the hinterland (in response to rift events along the Australian southern margin), resulted in a phase of inversion in the Exmouth Plateau and Exmouth Sub-basin areas (Tindale et al., 1998; Bradshaw et al., 1998). This tectonic event marked the onset of transpressional structural growth of pre-existing rift related structures within the Barrow and Dampier sub-basins (e.g. Barrow Island). Further north in the Caswell Sub-basin, hinterland uplift resulted in a block rotation of the margin (tilt event on Figure 7), where sediments inboard of the tilt line were eroded and redeposited into deeper water environments (Blevin et al., 1998a). This regional tectonism is interpreted to be related to the far field plate movements, associated with the onset of Tasman Sea spreading (Figure 7) (Bradshaw et al., 1998). Further sand influxes into the Caswell and southern Vulcan areas occurred in the Maastrichtian, and following the base Tertiary onset of Coral Sea spreading (Figure 7), the North West Shelf had moved sufficiently far north for carbonate factories to be established in areas away from clastic input. Following a major plate re-organisation in the middle Eocene, Australia moved rapidly northwards, and carbonate deposition became dominant (Baillie et al., 1994). Reworking of carbonates from the factory tops led to massive carbonate progradation, infilling the underfilled accommodation space provided by the underlying rift basins.

In the Neogene, the WASB was affected by further regional tectonism, in response to two processes. The first was restricted to the Bonaparte Basin area, and was the direct product of the collision of the irregular edge of the Australian plate with the Java-Banda arc system (Keep et al., 2002) (Figure 5). The second effect, which is dominant in the North Carnarvon and Browse basin areas, relates to the change in the regional stress field associated with the formation of the Irian-PNG Fold Belt (Hillis et al., 1997). This latter process accentuated the transpressional structures formed in the Campanian, and is also used to explain the formation of synchronous inversion structures in southeastern Australia (Dickinson et al., 2001).

The timing of both Neogene events is shown on Figure 7. The New Guinea Fold Belt formed between about 12 Ma and 3 to 4 Ma (Hill and Raza, 1999) and the Sumba-Banda collision occurred between 8 Ma and 3 Ma (Keep et al., 2002). In New Guinea the end of the foldbelt phase was marked by a change from convergent to transpressional plate motion (Hill and Raza, 1999). In the Timor area the 3 Ma tectonic event records the cessation of Australian crust subduction into the Banda Arc, as it locally jammed the subduction system. Australia's northward movement was maintained, however, by the initiation of a north-facing subduction zone along the Wetar and Flores thrust system (McCaffrey, 1996; Genrich et al, 1996). The 3 Ma tectonic event is also evident on areas of the Sundaland craton adjacent to Sumba where massive structural inversion events occurred (Bransden and Matthews, 1992), and a synchronous change in plate motions also occurs in the Pacific at this time (Pockalny et al., 1997). The 3 Ma event is thus likely to be an event of regional significance.

The regional Neogene tectonism resulted in breach of some traps and release of hydrocarbons from existing hydrocarbon accumulations and the leakage to the seabed. It has been suggested by Hovland et al. (1994) that this seepage assisted in the formation of bioherms via the hydrocarbons providing nutrients for bacteria, which were, in turn, part of the food chain for organisms such as *Halimeda* codiacean algae. The association of leakage with surface biohermal mounds has also been noted by Bishop and O'Brien (1998) in the Nancar area and over the greater Timor Sea area by O'Brien et al. (2002). Since the 1970s it is has also been a suspected mechanism for the formation of the massive atoll over the Scott Reef field (Figure 3). However, whether all or just some of the Neogene to present-day reefs have been seeded from hydrocarbon leakage is not clear.

O'Brien and Woods (1995) and Cowley and O'Brien (2000) also describe interpreted seepage-related amplitude anomalies from within the shallow sedimentary section (called hydrocarbon related diagenetic zones, HRDZs) which are present over many of the margin's accumulations. These features are believed to be formed by the emplacement of carbonate cements within shallow Tertiary sand units via the oxidisation of migrating thermogengic hydrocarbons.

{Figure (2-21) and Table (1) Captions}

2. North West Shelf areal subdivisions, distribution of exploration wells and location of key wells.

3. Major hydrocarbon field locations and regional bathymetry map of the North West Shelf.

4. Regional JO seismic event (Oxfordian) depth structure map. Locations A-H show the locations of the schematic cross-sections illustrated in Figure 6a and 6b.

5. Simplified regional tectonic elements map (modified after AGSO, 1994), illustrating the extent and timing of major block rotations.

6. Simplified regional geological cross-sections. Section locations are shown on Figure 4. From south to north they are: a) A: Exmouth Sub-basin, B: Barrow Sub-basin, C: Dampier Sub-basin, D: Browse Basin; b) E: Vulcan Sub-basin, F: Londonderry High – Timor Trough, G: Sahul Platform – Malita Graben, H: Petrel Sub-basin.

7. Chronostratigraphic summary of the North West Shelf.

8. Simplified palaeogeographic map of the upper TR20 Triassic sequence (Norian).

9. Chronostratigraphic Post-Palaeozoic summary of selected North West Shelf sub-basins.

10. Simplified Pleinsbachian plate reconstruction and sequence of major block rifting/separation events affecting the North West Shelf.

11. Composite map of JP1-JO isopach map (J20 + J30 sequences) in the Northern Carnarvon Basin and offshore Canning Basin area and TR-JO (TR10+TR20+J10+J20+J30) isopach map in the Browse and Bonaparte basins area.

12. Simplified J20 sequence (Sinemurian - Callovian) palaeogeographic map.

13. Simplified J30 sequence (Callovian) palaeogeographic map.

14. Simplified lower J40 sequence (Oxfordian) palaeogeographic map.

15. Simplified lower J50 sequence (Early Tithonian) palaeogeographic map.

16. Simplified K10 sequence (Berriasian - Valanginian) palaeogeographic map.

17. Simplified K20 sequence (Valanginian-Barremian) palaeogeographic map.

18. JO (Oxfordian) to KV (Valanginian) isopach map incorporating the J40, J50 and K10 sequences).

19. KV (Valanginian) to KA (Aptian) isopach map.

20. KA (Aptian) to T (base Tertiary) isopach map.

21. T (base Tertiary) to water bottom isopach map.

Table
1. Summary of main North West Shelf megasequence boundaries.

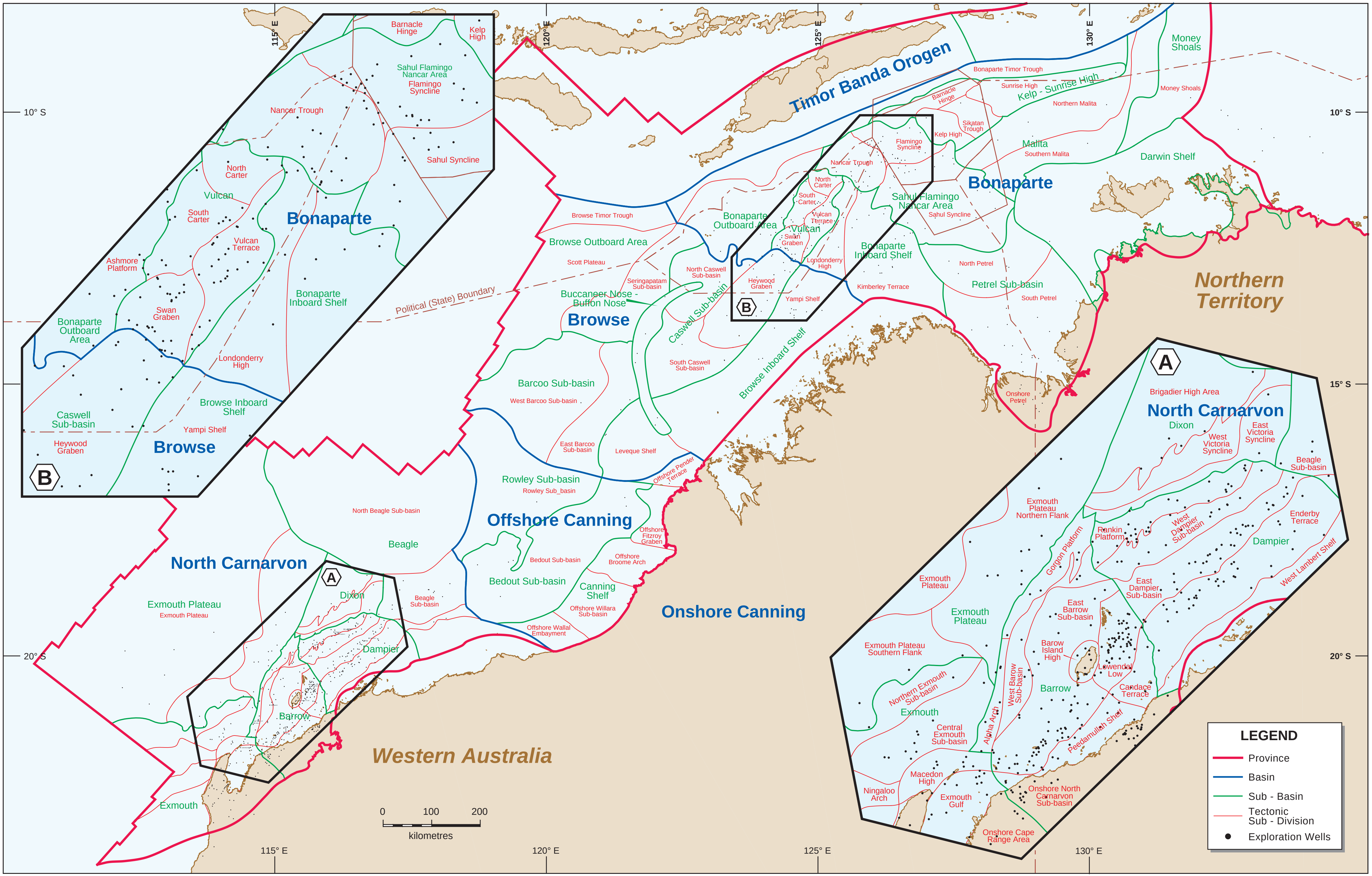

Figure 2. North West Shelf areal subdivisions, distribution of exploration wells and location of key wells.

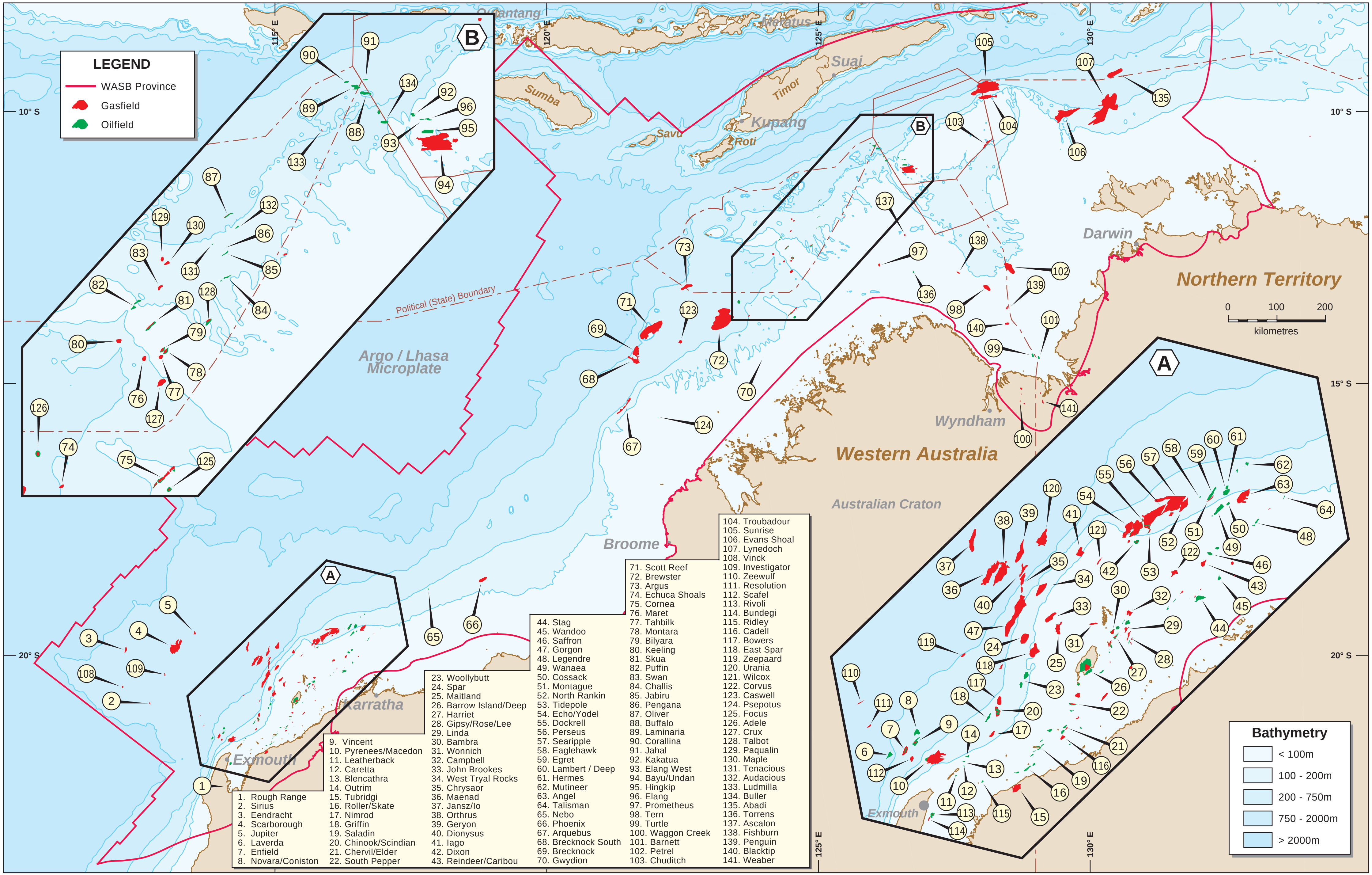

Figure 3. Major hydrocarbon field locations and regional bathymetry map of the North West Shelf.

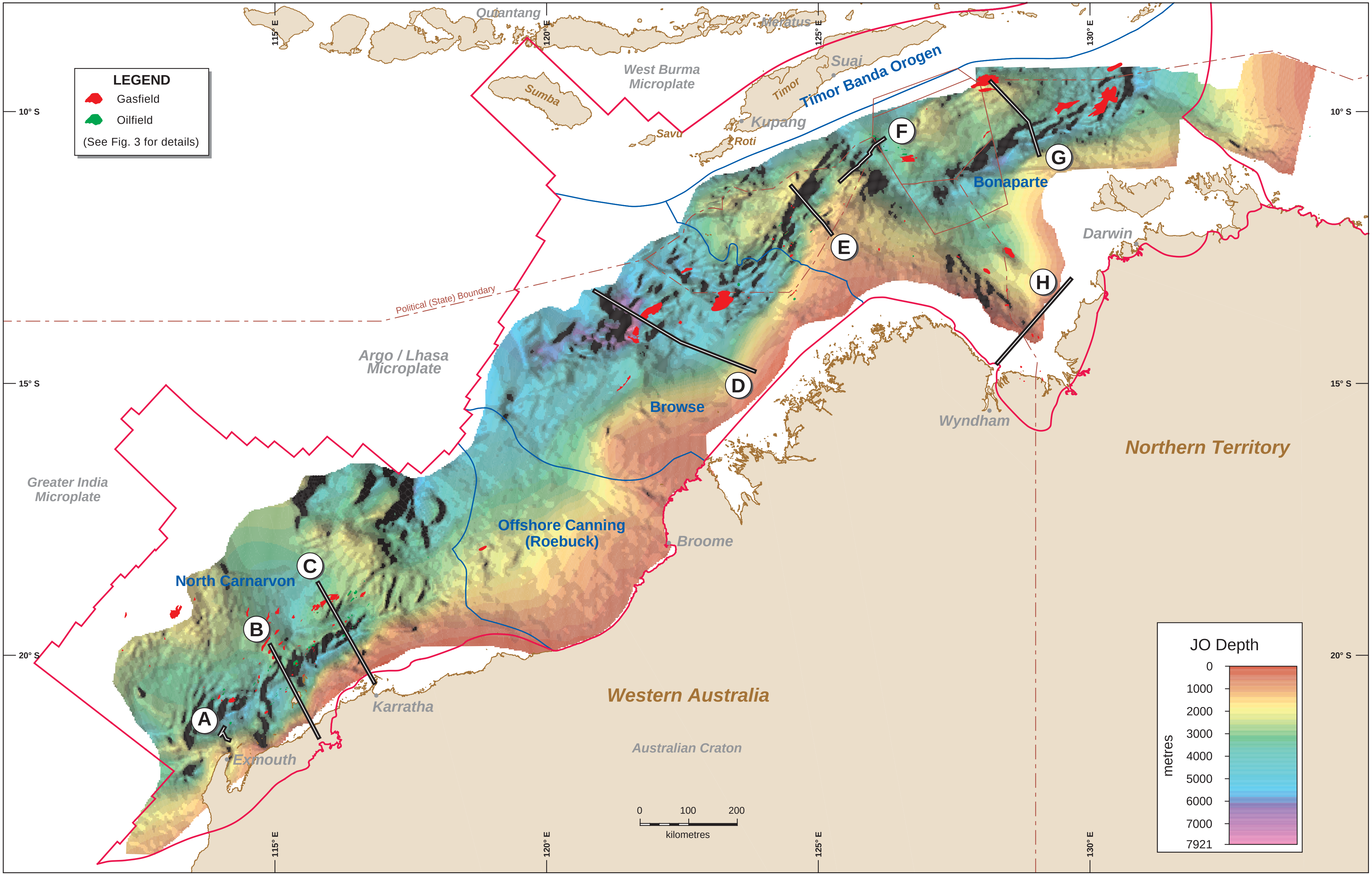

Figure 4. Regional JO seismic event (Oxfordian) depth structure map. Locations A-H show the locations of the schematic cross-sections illustrated in Figure 6a and 6b.

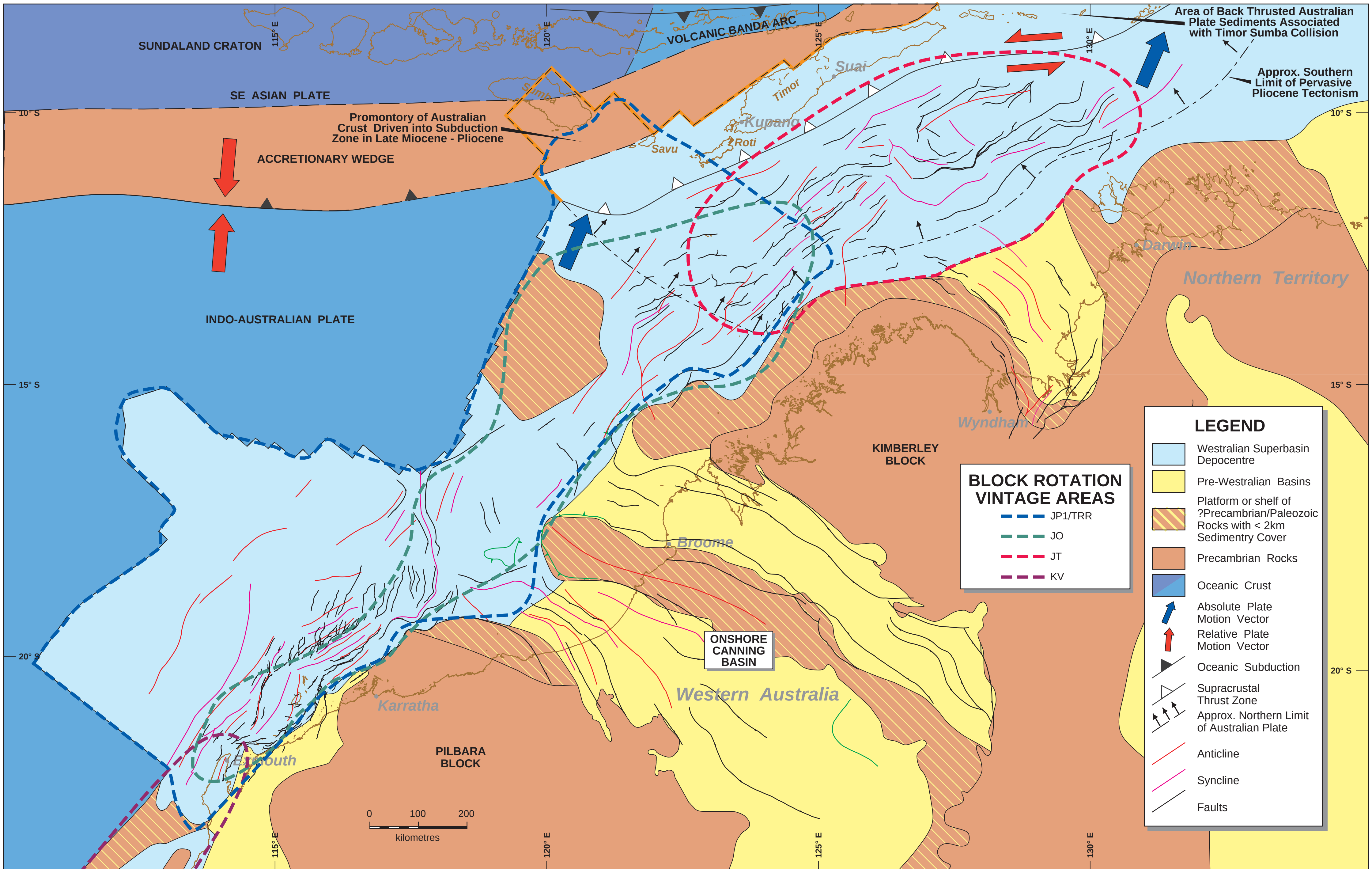

Figure 5. Simplified regional tectonic elements map (modified after AGSO, 1994), illustrating the extent and timing of major block rotations.

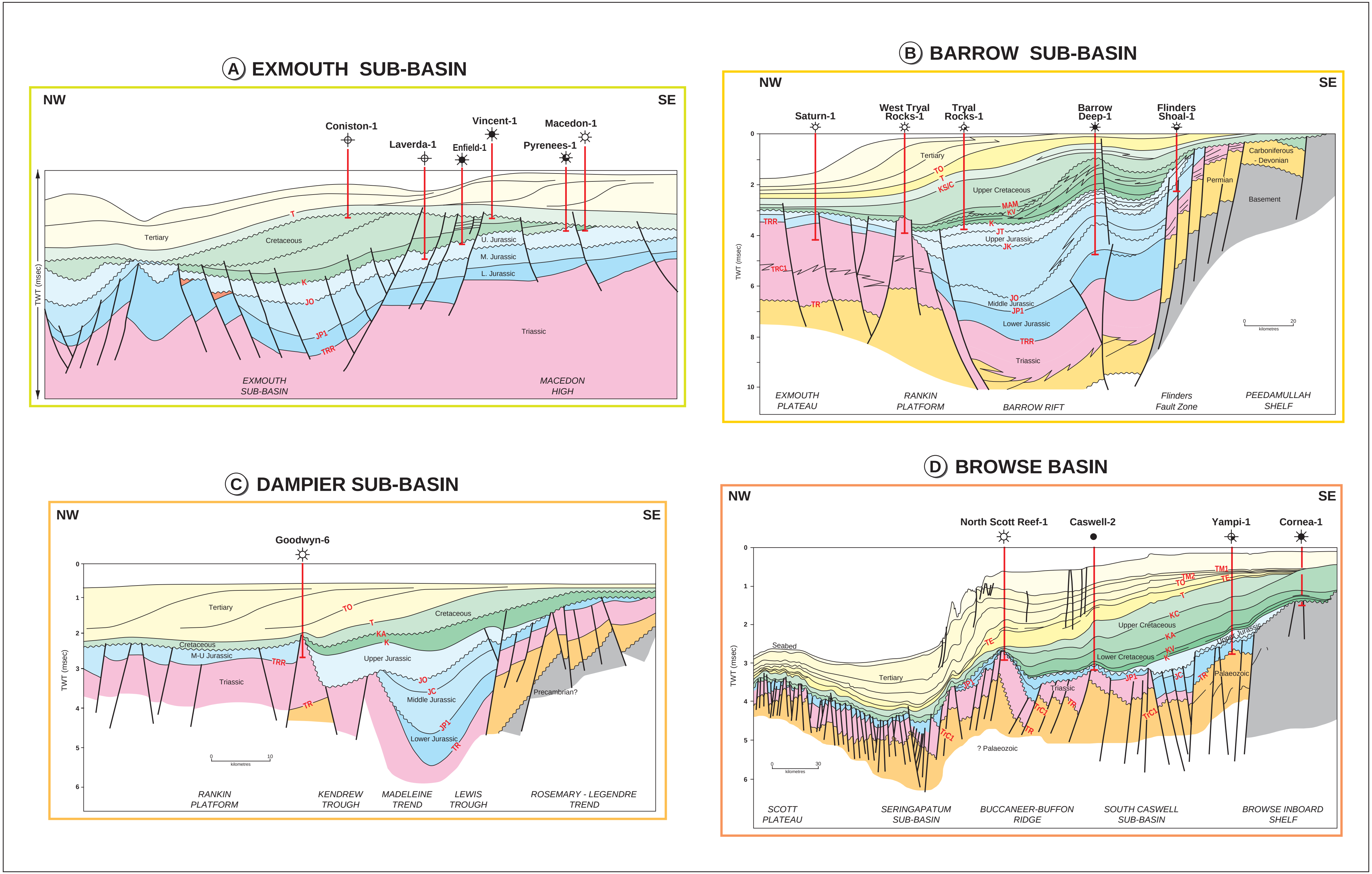

Figure 6a. Simplified regional geological cross-sections. Section locations are shown on Figure 4. From south to north they are: a) A: Exmouth Sub-basin, B: Barrow Sub-basin, C: Dampier Sub-basin, D: Browse Basin;

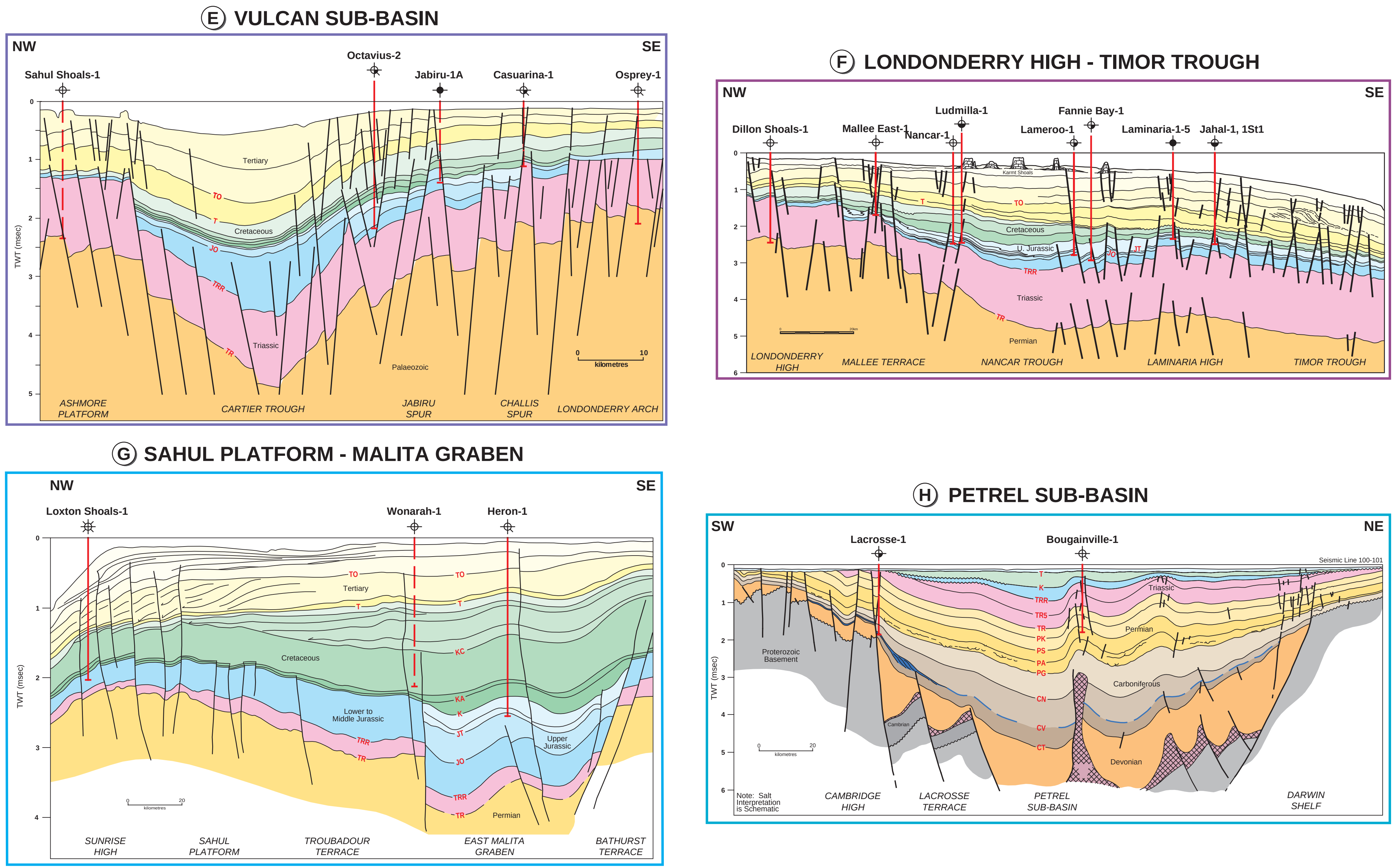

Figure 6b. Simplified regional geological cross-sections. Locations are shown on Figure 4, they are: E: Vulcan Sub-basin, F: Londonderry High –Timor Trough, G: Sahul Platform – Malita Graben, H: Petrel Sub-basin.

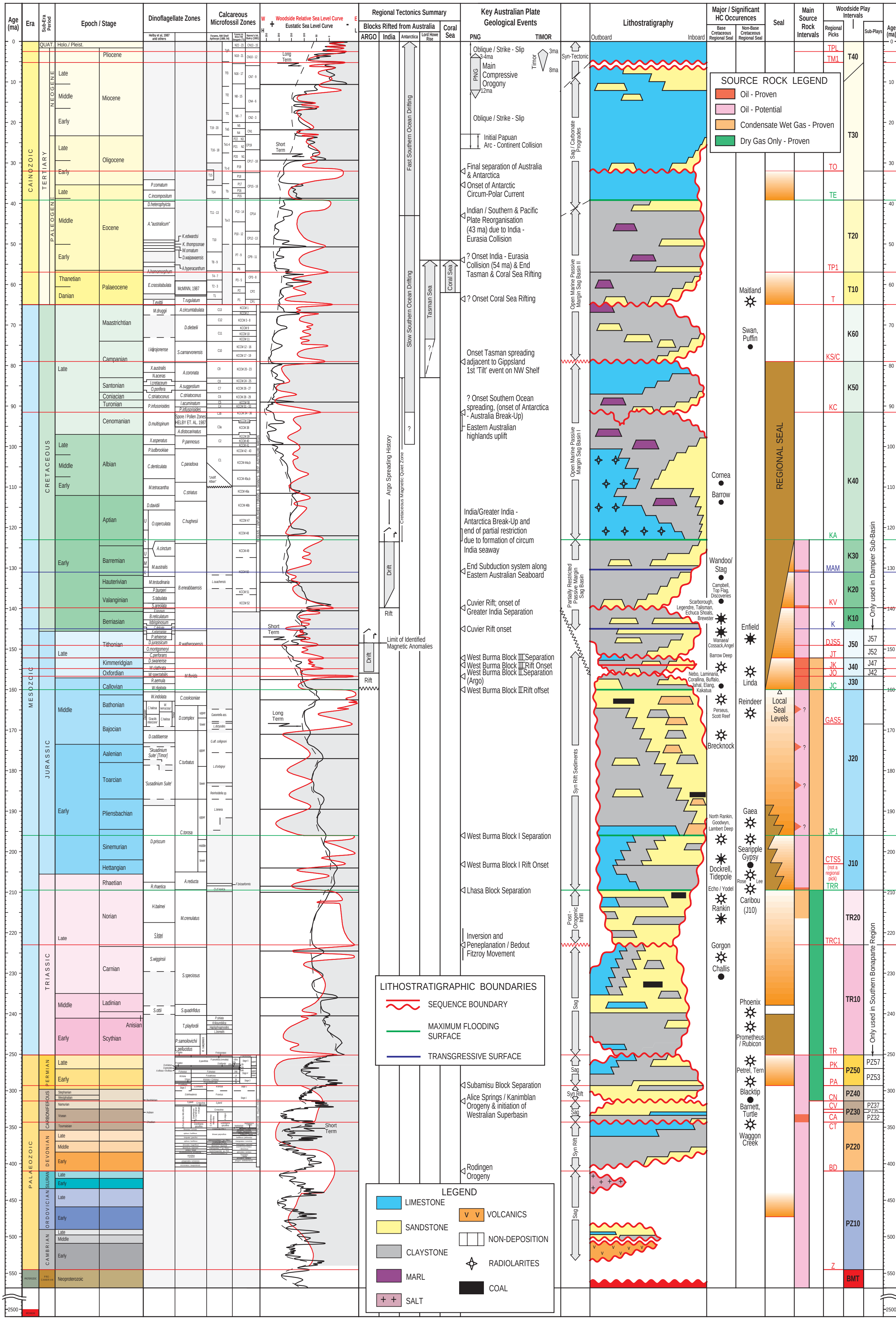

Figure 7. Chronostratigraphic summary of the North West Shelf.

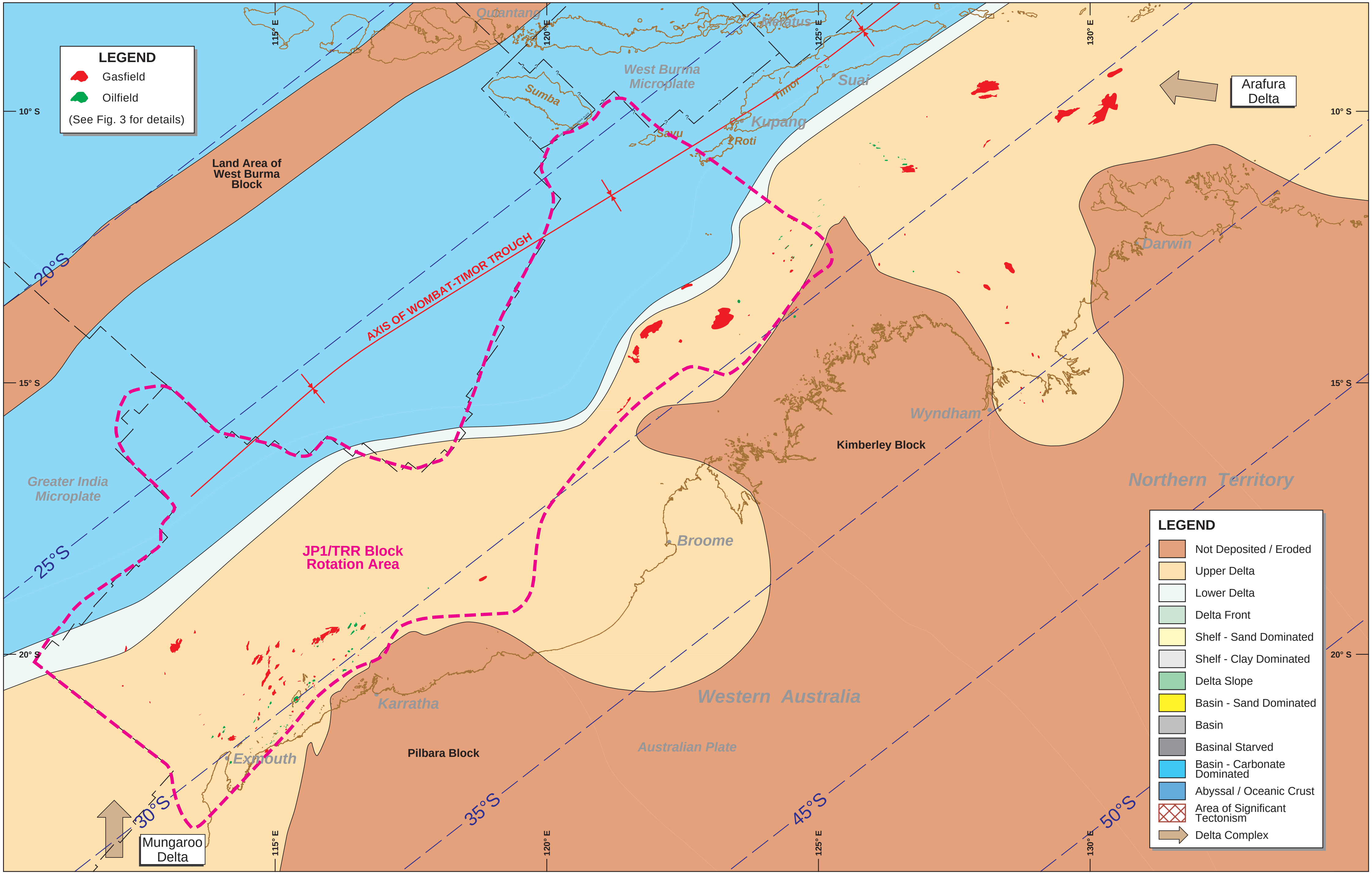

Figure 8. Simplified palaeogeographic map, upper TR20 Triassic sequence (Norian).

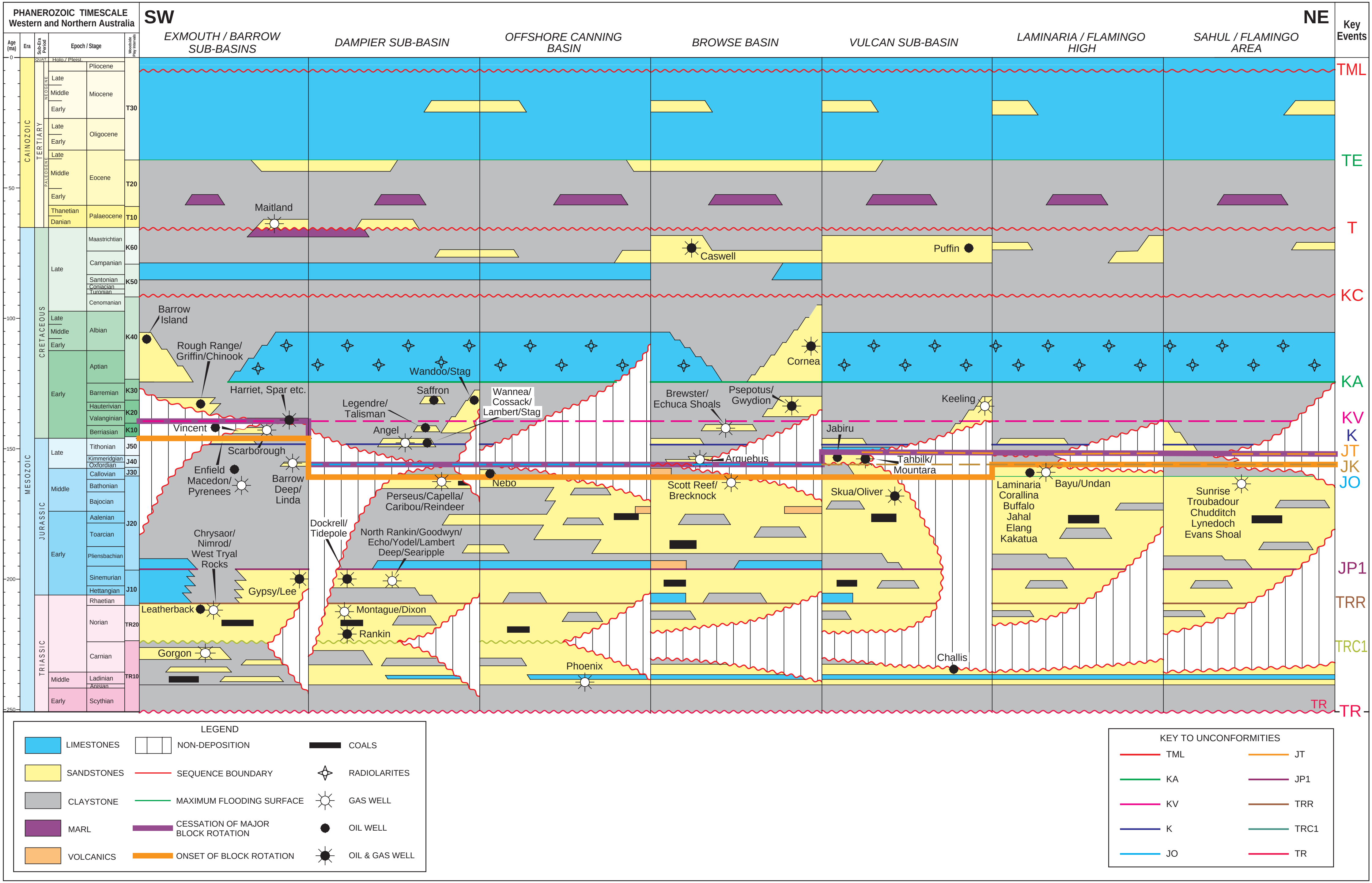

Figure 9. Chronostratigraphic Post-Palaeozoic summary of selected North West Shelf sub-basins.

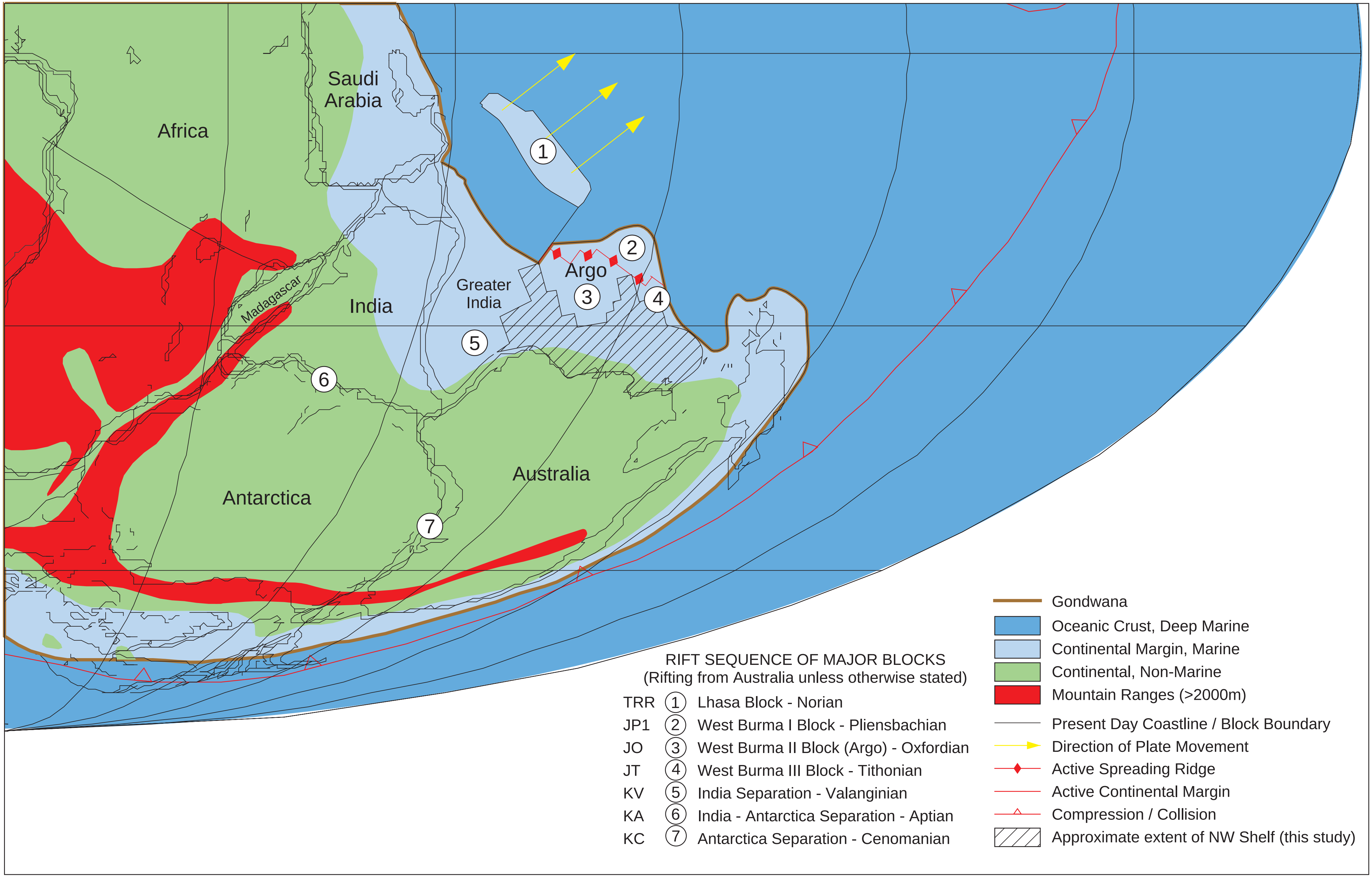

Figure 10. Simplified Pleinsbachian plate reconstruction and sequence of major block rifting/separation events affecting the North West Shelf.

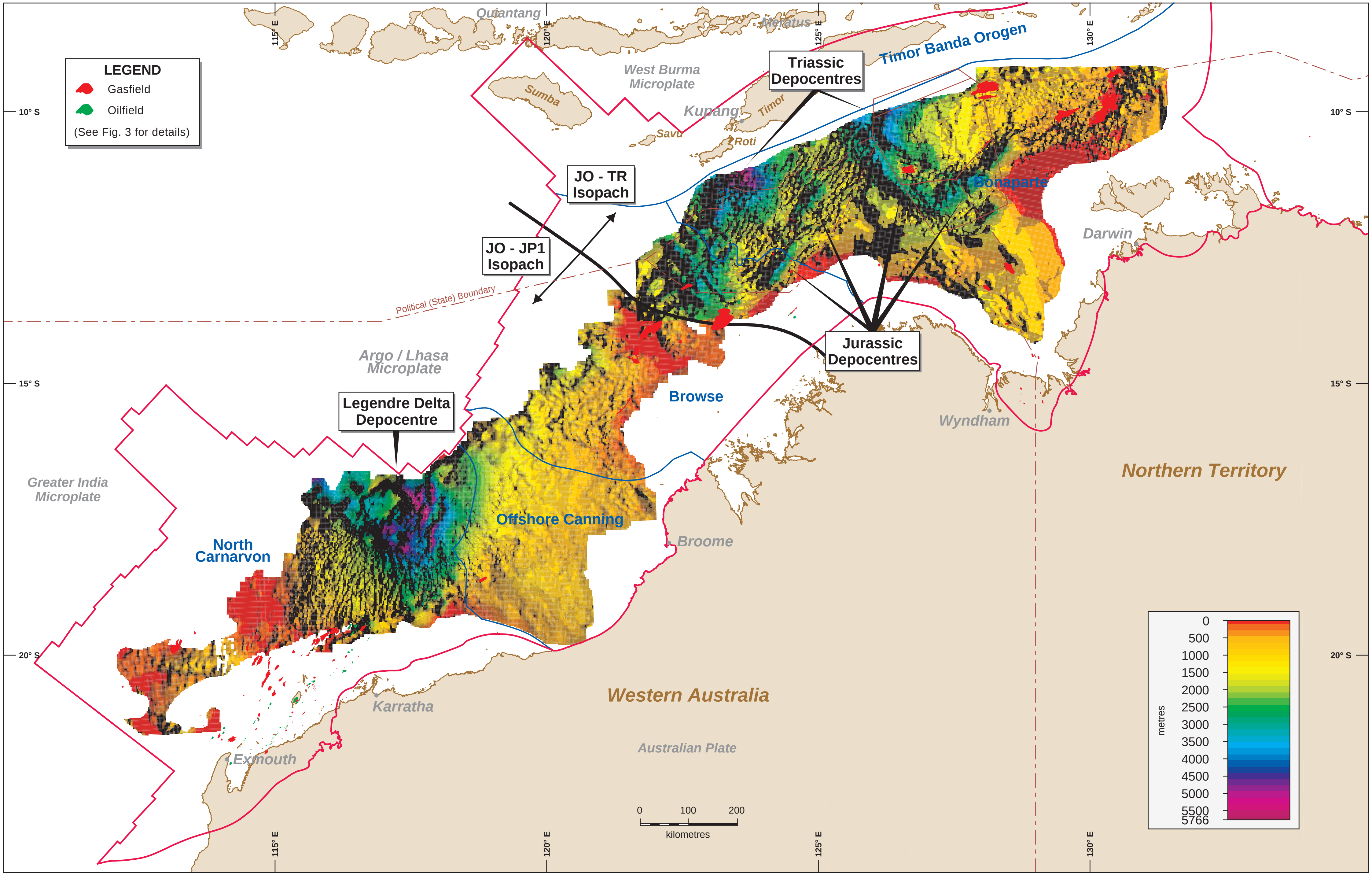

Figure 11. Composite isopach map, JP1-JO isopach map (J20 + J30 sequences) (south) and TR-JO (TR10+TR20+J10+J20+J30) isopach map (north).

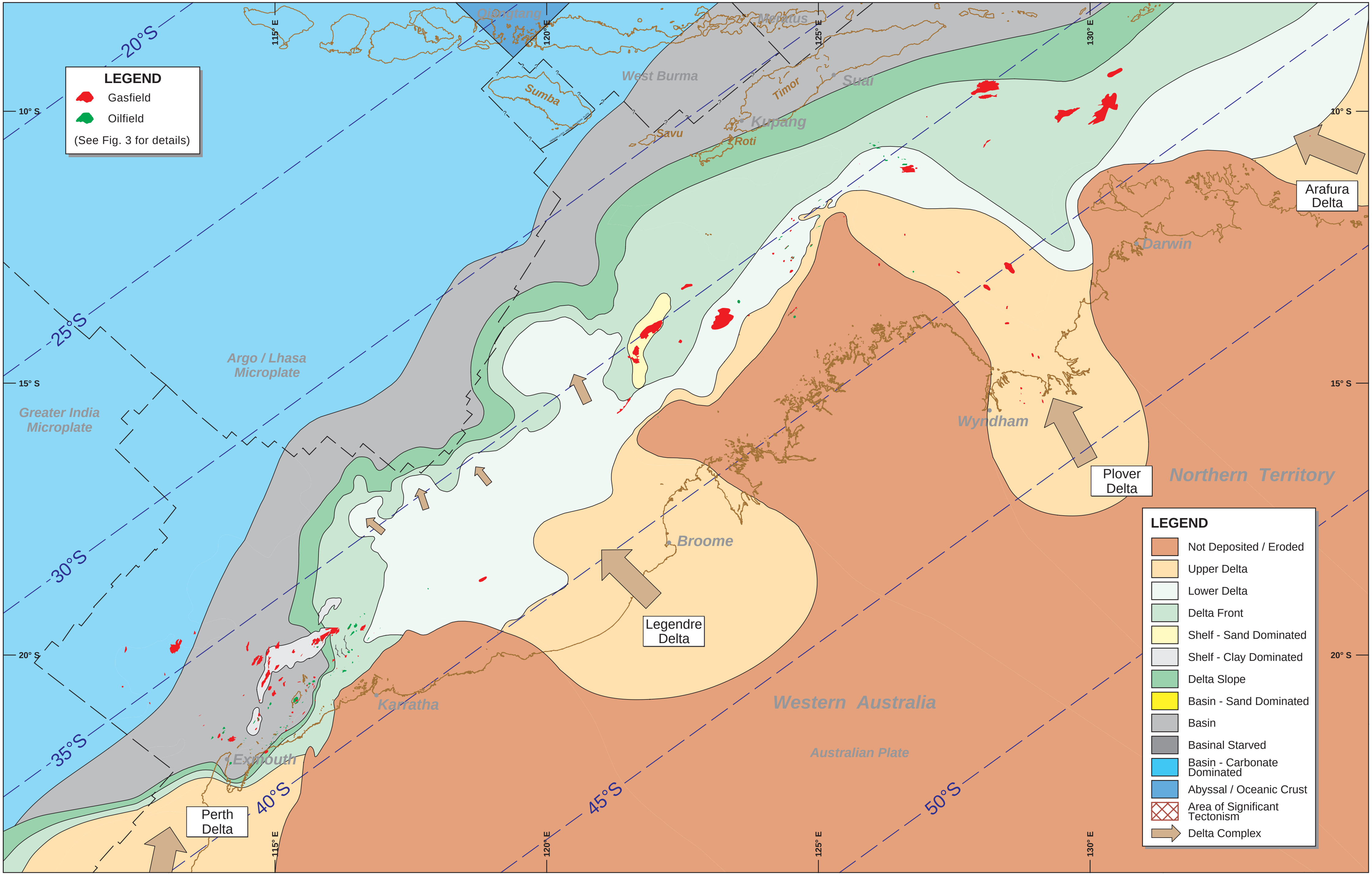

Figure 12. Simplified J20 sequence (Sinemurian - Callovian) palaeogeographic map.

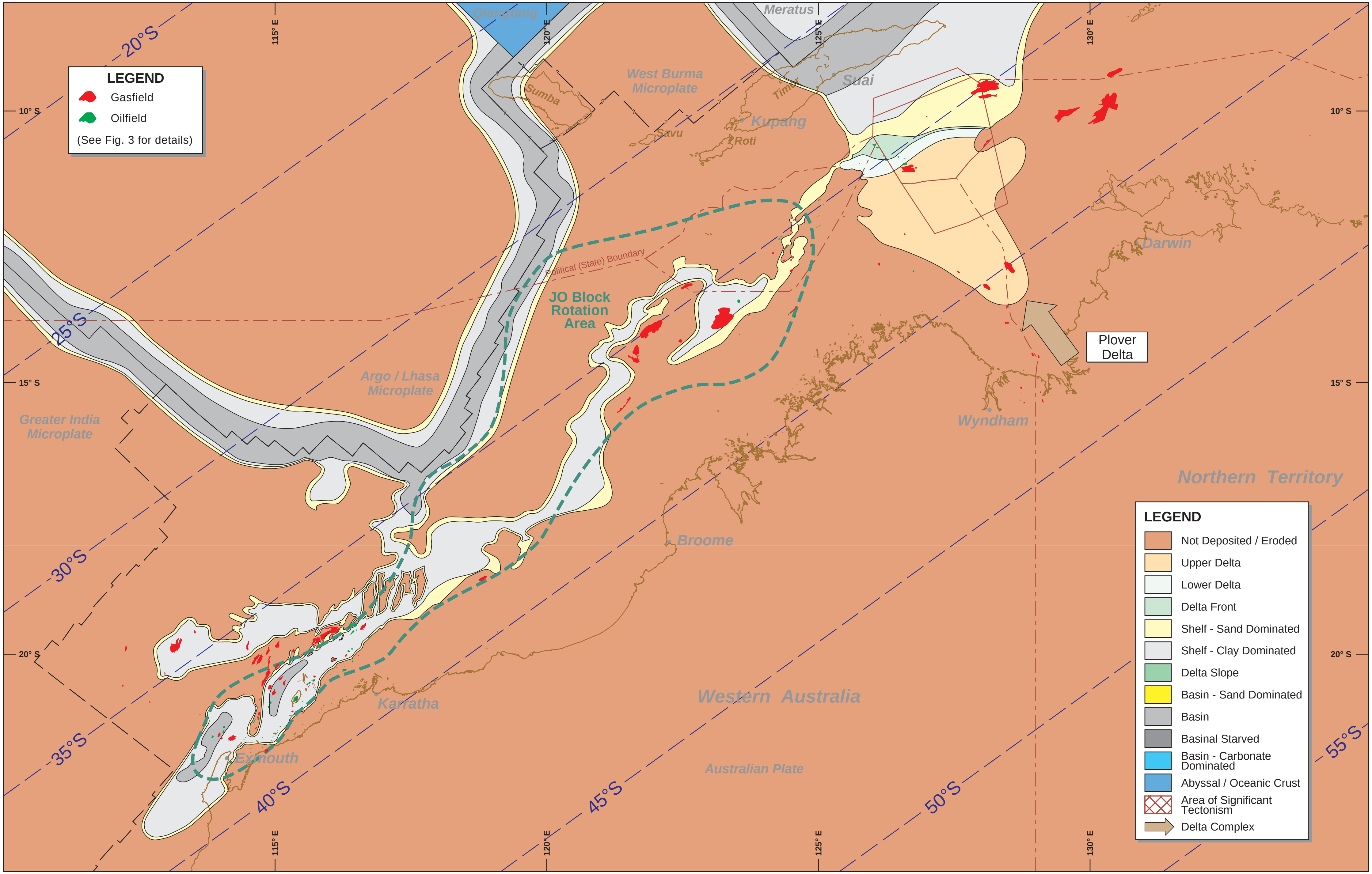

Figure 13. Simplified J30 sequence (Callovian) palaeogeographic map.

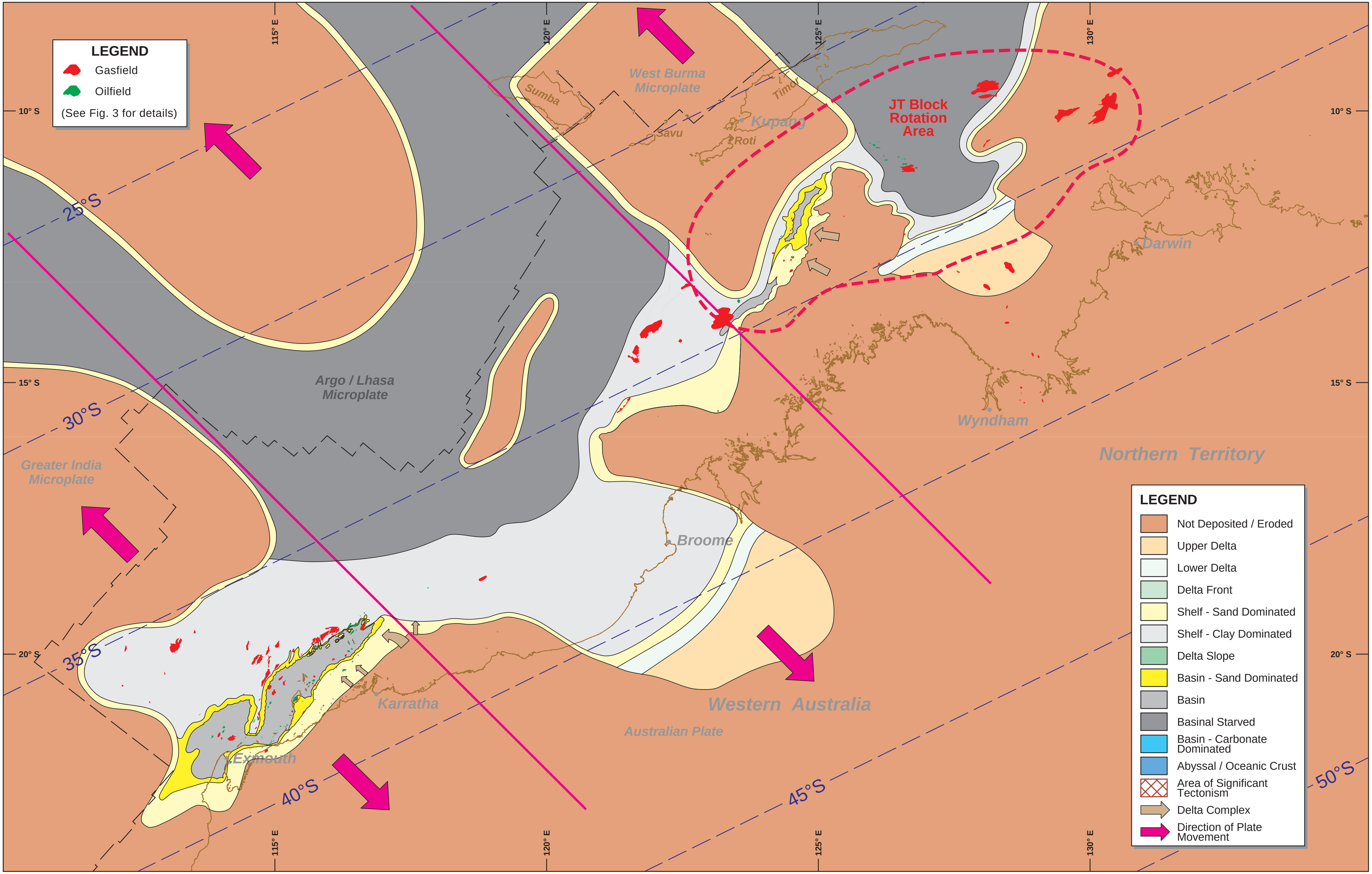

Figure 14. Simplified lower J40 sequence (Oxfordian) palaeogeographic map.

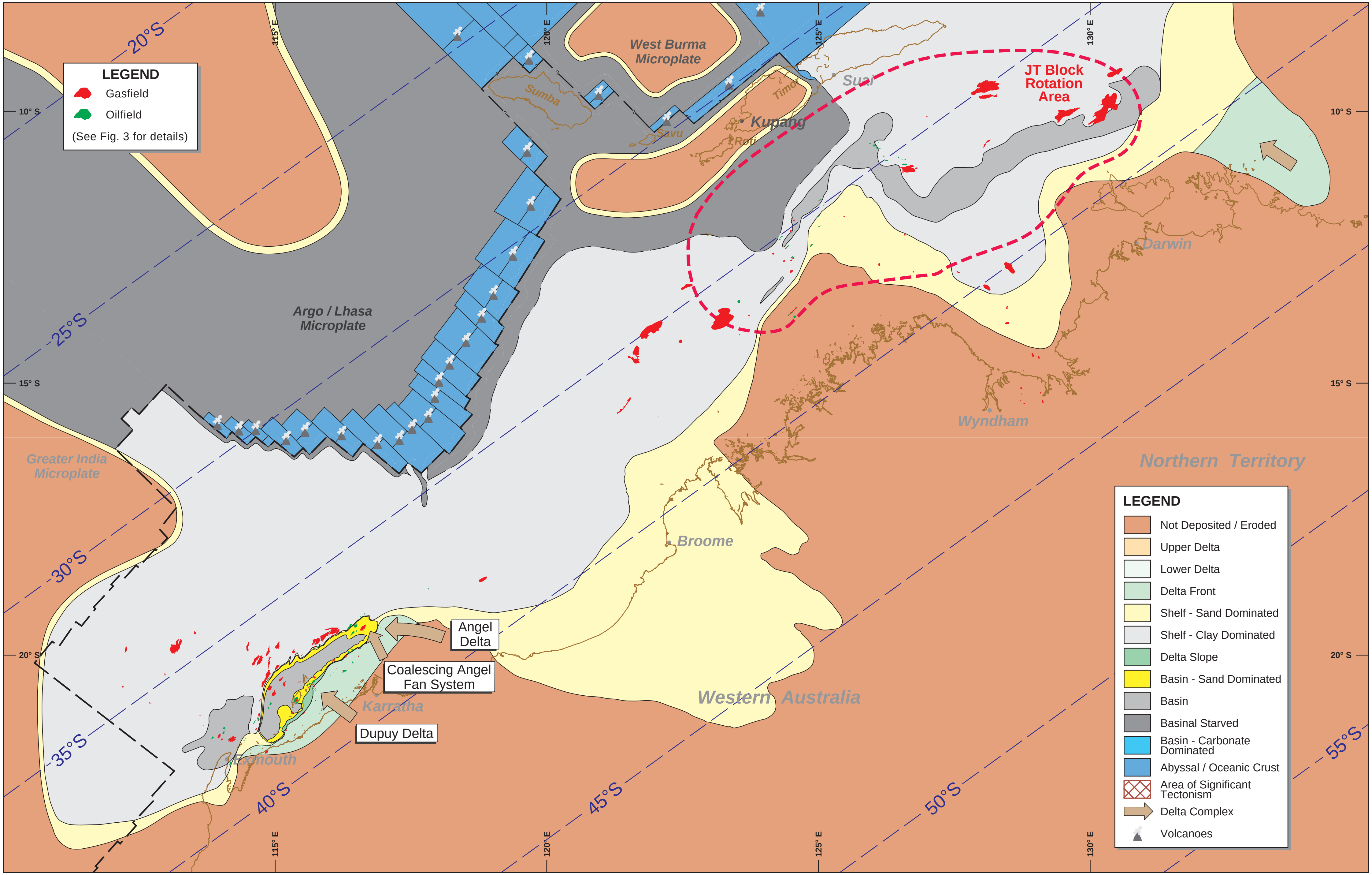

Figure 15. Simplified lower J50 sequence (Early Tithonian) palaeogeographic map.

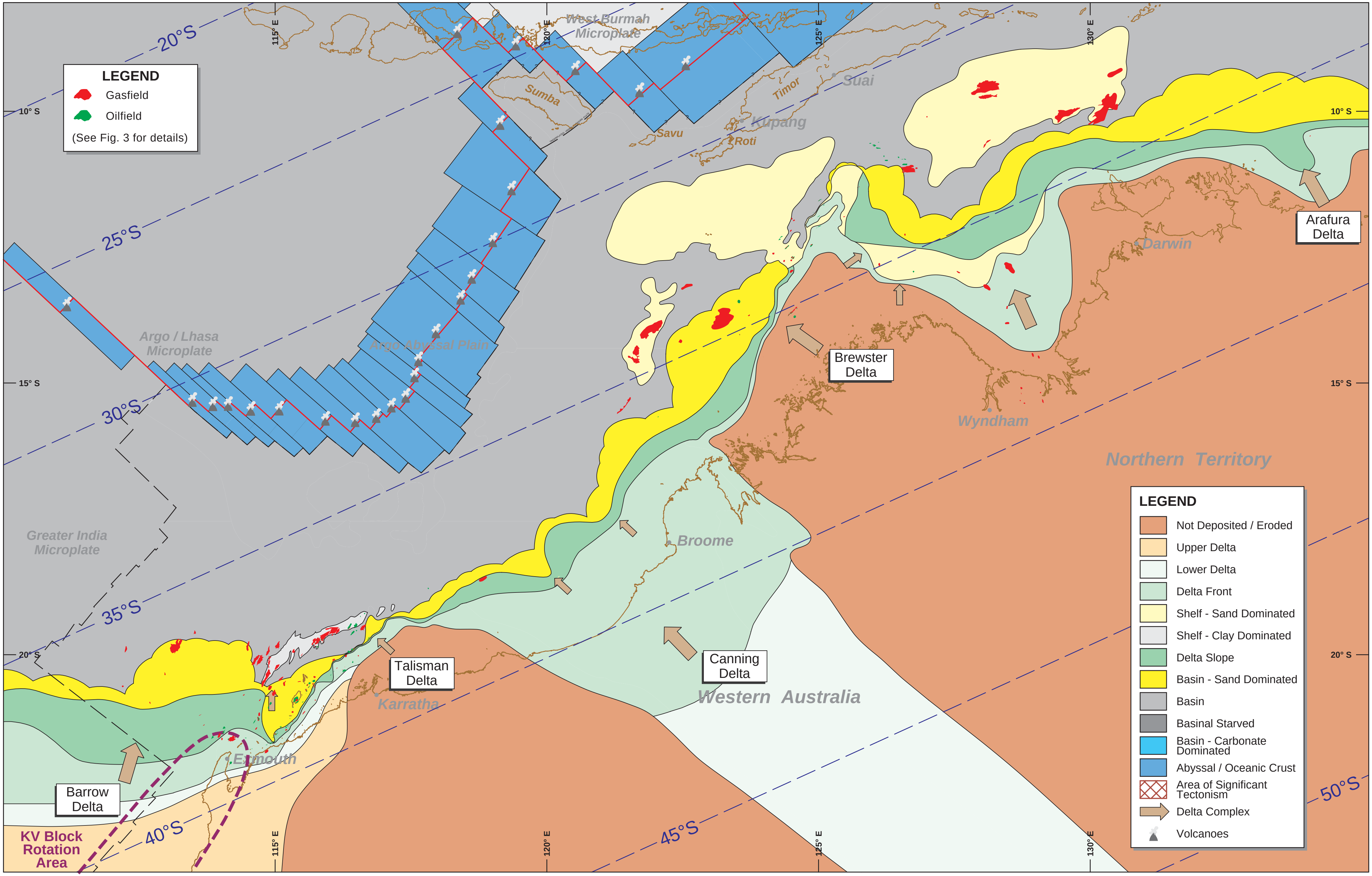

Figure 16. Simplified K10 sequence (Berriasian - Valanginian) palaeogeographic map.

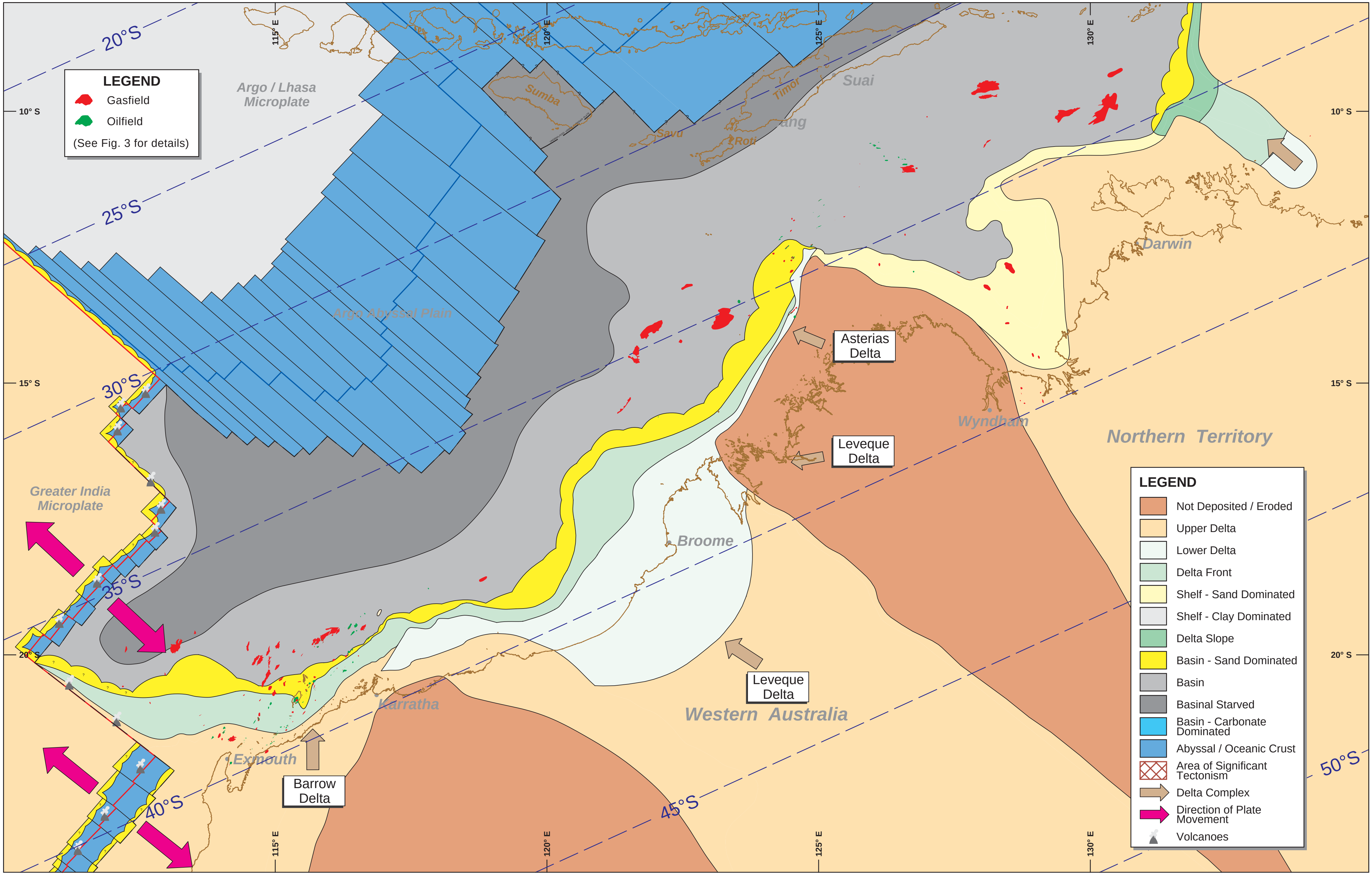

Figure 17. Simplified K20 sequence (Valanginian-Barremian) palaeogeographic map.

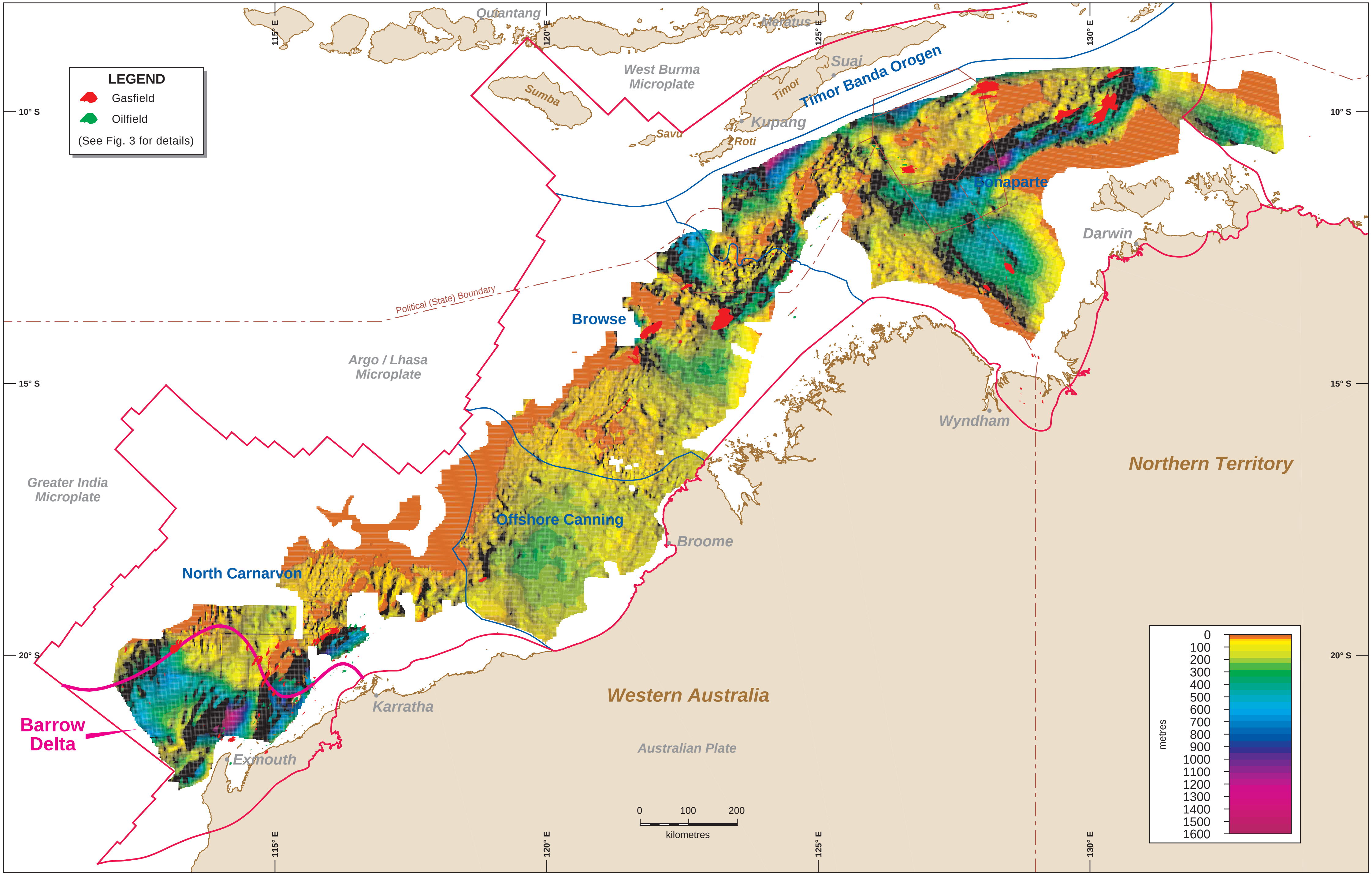

Figure 18. JO (Oxfordian) to KV (Valanginian) isopach map (J40, J50 and K10 sequences).

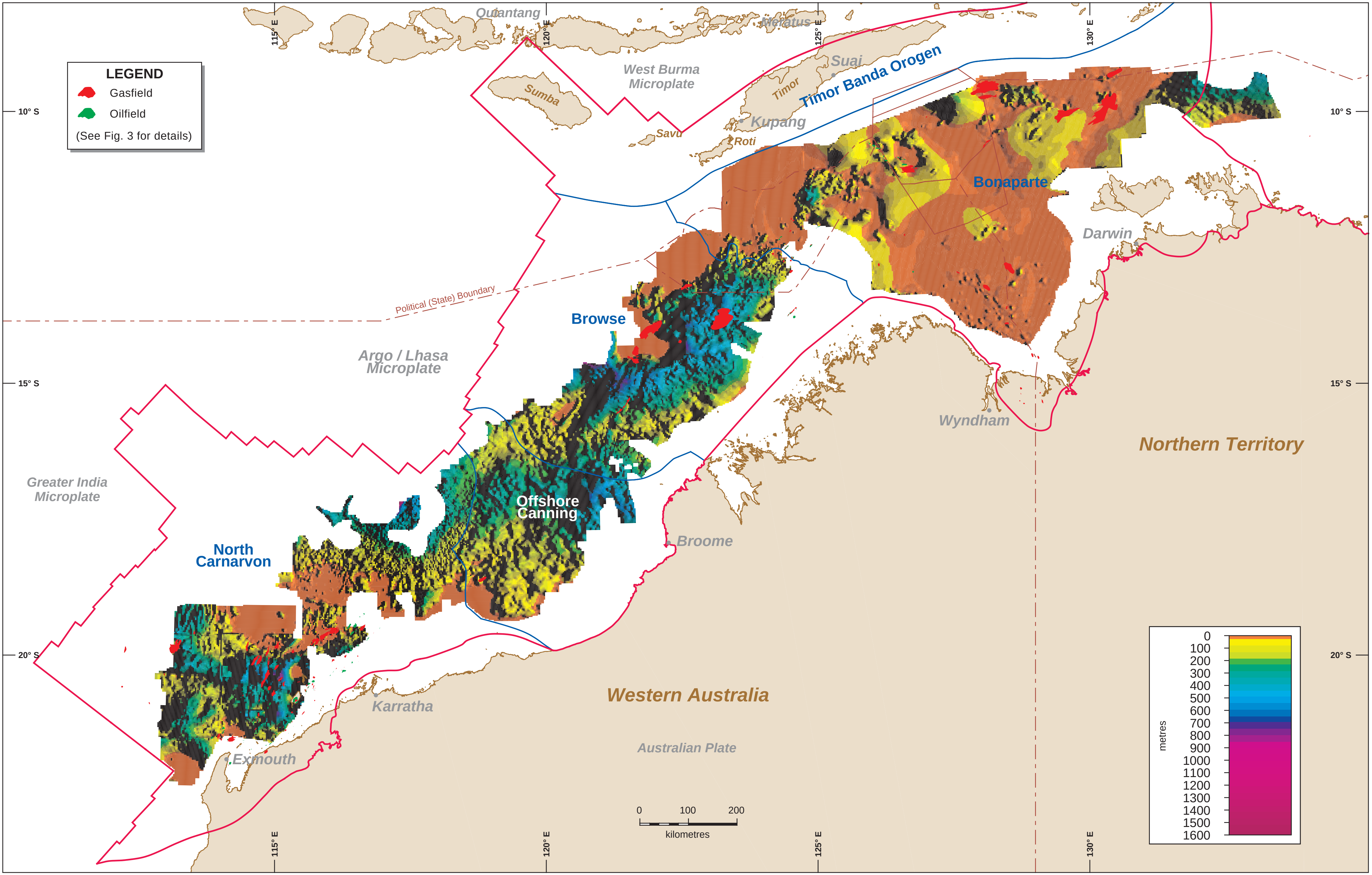

Figure 19. KV (Valanginian) to KA (Aptian) isopach map.

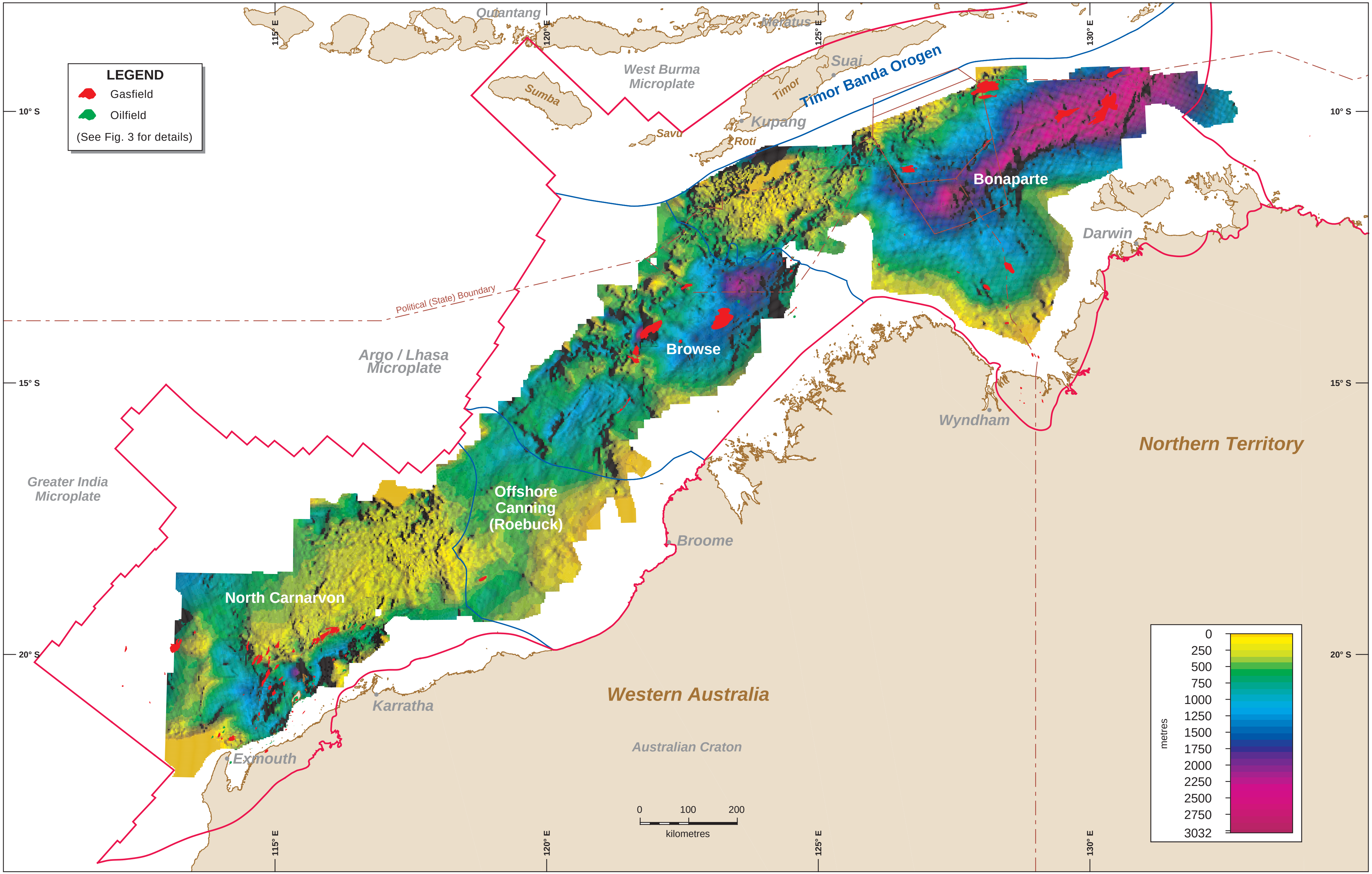

Figure 20. KA (Aptian) to T (base Tertiary) isopach map.

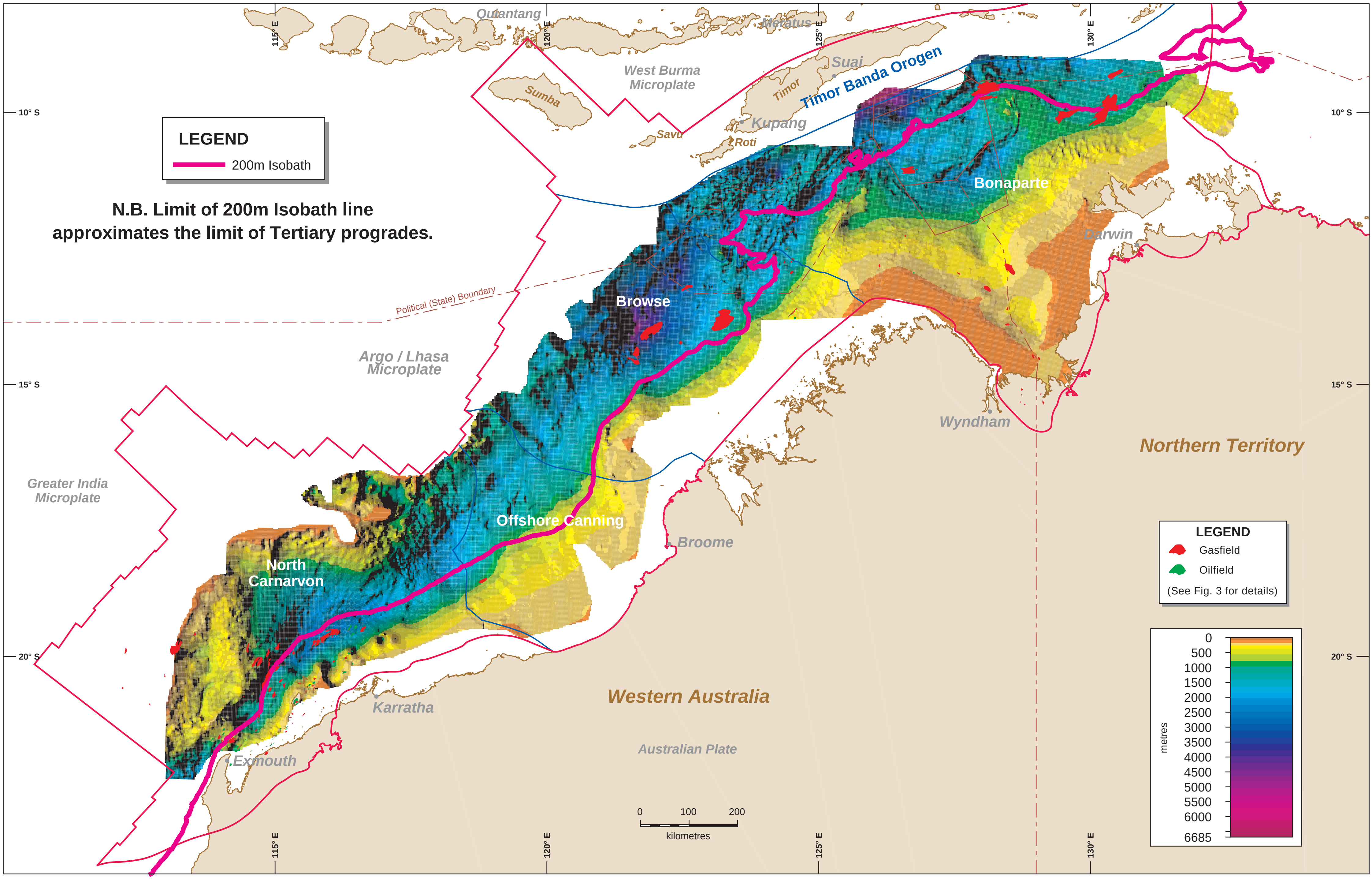

Figure 21. T (base Tertiary) to water bottom isopach map.

Approx. Absolute Age (Ma)	Play Interval	Regional Pick	Dinoflagellate Zone	Spore - Pollen Zones	Epoch	Stage	Event
2	Top T40	TPL			Late Neogene	Pliocene	
5	T40	TM1			Late Neogene	Pliocene	
32	T30	TO			Late Palaeogene	Early Oligocene	Final Separation of Aust. & Antarctica
39	Top T20/ Base T30	TE	*Base C. incompositum*		Middle Palaeogene	Late Eocene	
57	Top T10/ Base T20	TP1	*Intra A. homomorphum*		Early Palaeogene	Thanetian	
65	Top K60/ Base T10	T	*Base T. evittii*		Early Palaeogene	Danian/Maastrichtian Boundary	Onset of Coral Sea Rifting
79	Top K50/ Base K60	KS/C	*Base I. korojonense*		Late Cretaceous	Campanian	
91	Top K40/ Base K50	KC	*Base P.infusorioides/D.multispinum*		Late Cretaceous	Cenomanian	
123	Top K30/ Base K40	KA	*Base O. operculata*		Early Cretaceous	Aptian	Australia/ Antarctica Break-up
131	Top K20/ Base K30	MAM	*Base M. australis*		Early Cretaceous	Barremian	
140	Top K10/ Base K20	KV	*Base S. areolata*		Early Cretaceous	Valanginian	Australia/ India Break-up
145	Top J50/ Base K10	K	*Base C. delicata*		Early Cretaceous	Berriasian	Australia/ India Rift Onset
149	Top J52/ Base J57	DJS5	*Base D.jurassicum/O.montgomeryi*		Late Jurassic	Tithonian	
152	Top J40/J47/BaseJ50/J52	JT	*Base C. perforans/ D. swanense*		Late Jurassic	Kimmeridgian	West Burma Block III Separation
155	Top J42/ Base J47	JK	*Intra W. clathrata*		Late Jurassic	Oxfordian	West Burma Block III Rift Onset
157	Top J30/ Base J40/ J42	JO	*Base W. spectabilis*		Late Jurassic	Oxfordian	West Burma Block II Separation
160	Top J20/ Base J30	JC	*Base W. digitata*		Middle Jurassic	Callovian	West Burma Block II Rift Onset
196	Top J10/ Base J20	JP1	*Intra D. priscum*		Early Jurassic	Sinemurian	West Burma Block I Separation
209	Top TR20/ Base J10	TRR	*Base R. rhaetica*		Late Triassic	Rhaetian	West Burma Block I Rift Onset
223	Top TR10/ Base TR20	TRC1	*Base S. listeri*		Late Triassic	Norian	Lhasa Block Separation
250	Top PZ50/ Base TR10	TR		*Top P. microcorpus*	Permo-Triassic Boundary	Scythian	Regional Transpression Tectonism
292	Top PZ40/ Base PZ50	PA		*Top M. tentula*	Early Permian	Sakmarian	
313	Top PZ30/ Base PZ40	CN		*Top S. ybertii*	Carboniferous	Namurian	Alice Springs Orogeny
343	Top PZ20/ Base PZ30	CT		*Top Grandispora spiculifera*	Carboniferous	Tournasian	
410	Top PZ10/ Base PZ20	BD			Silurian-Devonian Boundary		Rodingen Orogeny
545	Top BMT/ Base PZ10	Z			Pre Cambrian-Cambrian Boundary		

Table 1. Summary of main North West Shelf megasequence boundaries.

Exploration History

The exploration history of the North West Shelf is described by Purcell and Purcell (1994), and the history of Australia's exploration industry (including a history of the North West Shelf), by Wilkinson (1991). Systematic exploration for hydrocarbons began in the early 1950s with field mapping of onshore and island areas. Onshore seismic followed, and the first exploration well was drilled at Rough Range 1 in 1953 (Fig. 2). Offshore exploration resulted in, with major oil and gas discoveries in the early 1960s, with significant discoveries being made through to the present day. A year-by-year summary of this exploration record is displayed as Figure 22, which shows the amount of 2D and 3D seismic acquired, the number of exploration wells drilled, success rates (for both zero and 20 million barrel oil equivalent cut-offs), total volumes discovered and average field sizes. The cumulative discovery history ("creaming") curves are shown by phase (oil, condensate and gas) as Figure 23, and by sub-basin area as Figure 24, and the detail of the oil discovery volumes is shown as Figure 25. In all cases the cumulative volumes are plotted against exploration well counts rather than time, so that the annual variation in drilled exploration wells does not distort the curve shape. Discovered volumes and basic success rates are detailed schematically by area as pie charts on Figure 26, which also shows the current coverage of 3D seismic data and Woodside's historical and current acreage holdings.

The data on Figures 23 to 25 are from Woodside's proprietary database, which classifies all wells into exploration or non-exploration types. Many "exploration" wells that discovered extensions to known pools are reclassified in the Woodside database as appraisal wells. Similarly, "appraisal" wells that discovered new pools are classified as exploration wells. Thus, the total exploration well counts shown on Figure 22 (and on all other figures and tables in this paper) will not necessarily match other published well count data. The distribution of wells classified as genuine exploration wells is shown on Figure 2.

Woodside's database also contains estimates of recoverable oil, condensate and gas volumes for all fields (conversion of gas to oil equivalent is based on 6 billion cubic feet of gas is equal to 1 million barrels of oil). Reserve estimates vary widely in quality from published certified and audited volumes, and estimates from annual reports, to those based on hearsay, where no documentation of field volumes exists in the public domain. It is not possible, therefore, to compile a database of in-place or hydrocarbon pore volume estimates, which would make a better basis for data comparison and tabulation. In addition, where multiple estimates are available, the estimate which corresponds to the "scope volume" has been used in plots and tables herein; i.e. the volume based on a theoretical recovery volume, unshackled by development economics. In essence, our database is imperfect, but we believe the conclusions and trends derived from the data are still valid.

Discovery history plots on Figures 23 to 25 do not include any measure of "reserves growth", i.e. a measure of how the reserve estimate has changed through time. On these plots, the best estimate of the scope recoverable volume for the entire field is allocated to the spud date of the "discovery well". When a well first penetrates a hydrocarbon pool this well is deemed to be the “discovery well”, even though the significance of the discovery may not become clear for many years, and a later well may actually be credited with the “discovery”. Examples of this include North Rankin 4, which first penetrated the Perseus gas accumulation in 1972, whereas Perseus 1 was not drilled until 1996 (Taylor et al., 1998). In our database, therefore, the current scope Perseus reserve estimates are attributed to the North Rankin 4 well, and Perseus 1 is classified as an appraisal well. Similarly Hilda 1 drilled in 1974 is the discovery well for the Griffin/Ramilles Field (i.e. not Griffin 1, drilled in 1989), the discovery well for the Woollybutt Field was West Barrow 1 in 1982 (not Woollybutt 1, drilled in 1997), and Brewster 1 drilled in 1980 is the discovery well for the Gorgonichthys/Titanichthys/Dinichthys discovery made in 1999/2000.

The relative volume of discovered oil, condensate and gas reserves, as shown on Figures 23 and 26, highlights the gas-prone nature of the North West Shelf, in that by billion oil equivalent (boe), the margin is 92% gas or condensate, with only 8% of the estimated reserves being oil. Discovery data and volumes by sub-basin are shown on Figure 26, and it is evident that only 33 Tcf or 22% of gas reserves have been developed, and some 119 Tcf of gas remains undeveloped. This is in contrast to oil reserves, of which 67% have currently been developed.

The various trends illustrated on Figures 22 to 26 show that exploration on the North West Shelf has gone through four phases:-

- The “Early Years” (1953-1970), with limited offshore drilling, where the only significant discoveries were Barrow Island (Barrow 1, 1964) and Legendre (Legendre 1, 1968).
- The 1971-1980 “Big gassy fish in a barrel” era when most of the large gas fields were discovered on open grids of poor quality 2D seismic data (North Rankin, Goodwyn, Scott Reef in 1971, Gorgon and Brewster in 1980).
- The 1981-1996 “2D seismic oil” era, when following the inability to develop the discovered gas reserves, and an increase in oil prices, most of the exploration effort was targeted at discovering oil via the use of more dense 2D seismic datasets (i.e. South Pepper in 1982, North Herald, Chervil, Jabiru, Harriet in 1983, Saladin in 1985, Wanaea in 1988, Cossack in 1989, Roller in 1990, Wandoo in 1991, Stag in 1993 and Laminaria in 1994).
- The 1997-2001 “3D seismic oil” era, where large multi-client seismic surveys were acquired over the proven oil-prone portions of the margin, and mop-up of the remaining oil potential was the primary exploration focus.

There has been a general increase in drilling activity, from 1-5 wells per year in the early years, to an average of around 40 wells per year in the 3D era. This exploration effort discovered approximately two-thirds of all the discovered hydrocarbons during the “Big Gas” phase of exploration, when most of the primary large structures were drilled. Since then, approximately 100 mmbbls of oil reserves and 400 to 700 bcf of gas reserves have been discovered annually, even though the average oil field size has steadily decreased through time. The total annual oil volumes have been maintained through increased numbers of exploration wells, and not via an exploration bonanza based on new 3D seismic- based plays. The reason for this rests with the inherent geology of the WASB margin.

The main trap styles on the North West Shelf are simple drape anticlines (over underlying horsts), and horst/tilted fault block structures at the level of the base regional seal (Longley et al., 2002). Throughout the evolution of the margin, the main clastic sediment provenance was from the southeastern cratonic flank, so the stratigraphic level of top porosity beneath the regional seal (Figure 7) generally becomes progressively younger towards the cratonic edge (Figure 27). Regional Valanginian uplift in the south of the Exmouth Sub-basin, beneath the KV seismic event, has reversed this trend in part, and in other areas, isolated sands at shallower levels locally complicate the detail of the top porosity surface. Some 97% of all hydrocarbons discovered to date occur at this base regional seal level, even though numerous wells along the margin have tested traps at deeper levels, i.e., the concentration of hydrocarbons beneath the base regional seal is not a product of selective sampling – many wells have unsuccessfully tested deeper structures. Failure at many of these deeper levels is due to a lack of effective sealing units (topseal and flank seal for fault bounded traps). Rare effective sealing strata at other levels are present (Figure 7), however, to date, these traps contain an estimated 3.1% of the regions reserves being split into 2.2% within Palaeozoic units within the Petrel Sub-basin and 0.9% beneath Jurassic intra-formational seals (eg Lambert 2 gas discovery, Kingsley et al., 1998). Furthermore, only three significant hydrocarbon accumulations totalling some 0.2% of the margin's estimated reserves have been discovered above the regional seal (Maitland, Swan and Puffin; Figures. 3 and 7). All of these shallow occurrences are associated with obvious fault conduits, but in general, the regional seal is highly effective.

The distribution of the region's estimated reserves by phase and reservoir level is shown on Figure 28. Most of the oil is reservoired in the Late Jurassic and Early Cretaceous section, and most of the gas is reservoired within Middle Jurassic to Triassic sandstones.

The main trap styles present along most of the North West Shelf are easily identified by good quality 2D seismic data. The advent of good-quality 2D seismic, and using local well control to define the level of top porosity, meant that most of the secondary simple traps on the WASB were identified and drilled during the “2D seismic oil” exploration phase. This left relatively little potential to be mopped up by subsequent 3D seismic exploration programs. Even in areas with no well control, common vertical stacking of target horizons meant that detailed knowledge of the stratigraphic level of the base regional seal porosity level was usually not required.

The primary impact of 3D on the North West Shelf has been:

- The better definition (decreased range) of discovered resource volumetric estimates, prior to field development (e.g. Perseus, Taylor et al., (1998); Legendre, Willetts et al. (1999));
- The discovery of smaller nearfield traps, not readily apparent on 2D datasets;

- To provide a consistent volume of seismic velocity data enabling the confident depth conversion of subtle traps (e.g. East Spar, Craig et al. (1997) and Woollybutt, Hearty and Battrick (2002);
- To identify potentially complex structural and stratigraphic traps, based on amplitude and AVO (amplitude versus offset) analysis (e.g. Linda, Apache (2002); Enfield, Bussel et al. (2001).
- To gain a better understanding of the geological evolution of the margin from the better imaging of deeper seismic events.

The depth conversion impact of 3D on discovered volumes has been modest to date, since there generally has to be an inflection or structural nose on existing two-way time or velocity data, which the depth conversion process accentuates into a robust depth closure. These features, although significant, are by their very nature uncommon and, because of their subtle relief, they are very unlikely to contain large hydrocarbon volumes (e.g. greater than 100 mmbbls of recoverable reserves).

The amplitude and AVO impact of 3D data on exploration is proven through numerous small discoveries, such as the amplitude supported onlap trap intersected by Linda 1 in the Barrow Sub-basin (Apache, 2002), and the larger Enfield lowside fault block oil and gas field trap in the Exmouth Sub-basin (Bussel et al., 2001). These successes attest to the impact of 3D on new exploration plays, however, in comparison with the number of prospects drilled, and the volume of 3D acquired, the results in terms of significant oil discoveries are very poor. This is because most of the areas with proven oil prospectivity are relatively deeply buried beneath the regional seal, where it is difficult to differentiate hydrocarbon pore fill from porosity and other anomalous effects. In addition, it is difficult to identify and calibrate oil (as opposed to gas) from offset data (AVO), since this generally requires a high-quality 3D dataset and a relatively shallow (sub-seabed) simple target, such as that which exists in a typical Enfield area. Commonly the focus on amplitude supported prospects results in gas discoveries, or more commonly, the seismic quality is so degraded by seabed, shallow carbonates, reefal anomalies and/or complex structures that it is impossible to even properly image the target horizons. This poor imaging leaves open the possibility for significant oil volumes remaining in stratigraphic traps.

{Figure Captions (22-28)}

22. Historical summary (1953-2001) of exploration along the North West Shelf showing by year (A) West Texas Intermediate and US Wellhead prices by US$ in money of the day, (B) Proprietary and speculative 2D seismic activity by line kilometers, (C) Proprietary and speculative 3D seismic activity by square kilometers, (D) Exploration well drilling frequency divided into dry wells, wells with discovered volumes less than 20mmboe and those with discovered volumes greater than 20mmboe, (E) Success rates for exploration drilling by both discoveries les than and greater than 20mmboe, (F) Total oil condensate and gas volumes (by boe) discovered per year, (G) Detailed display of total oil volumes found per year, (H) Average discovery size per successful exploration well by oil, condensate and gas (as boe) volumes, and (I) Average oil discovery volumes found per exploration well.

23. North West Shelf hydrocarbon discovery history curve by phase (mean success volume [MSV] for gas, condensate and oil) against exploration well count.

24. North West Shelf hydrocarbon discovery history curve by geographic area against exploration well count.

25. North West Shelf oil discovery history curve by geographic area against exploration well count.

26. Historical (from 1965 to 2001) Woodside permit coverage, current limits of 3D seismic data and summary of estimated oil, condensate and gas reserves for the entire North West Shelf and its principal sub-basin areas.

27. North West Shelf simplified map illustrating top porosity beneath the regional seal.

28. Distribution of oil, condensate and gas reserves (mean success volumes – MSV) by stratigraphic level.

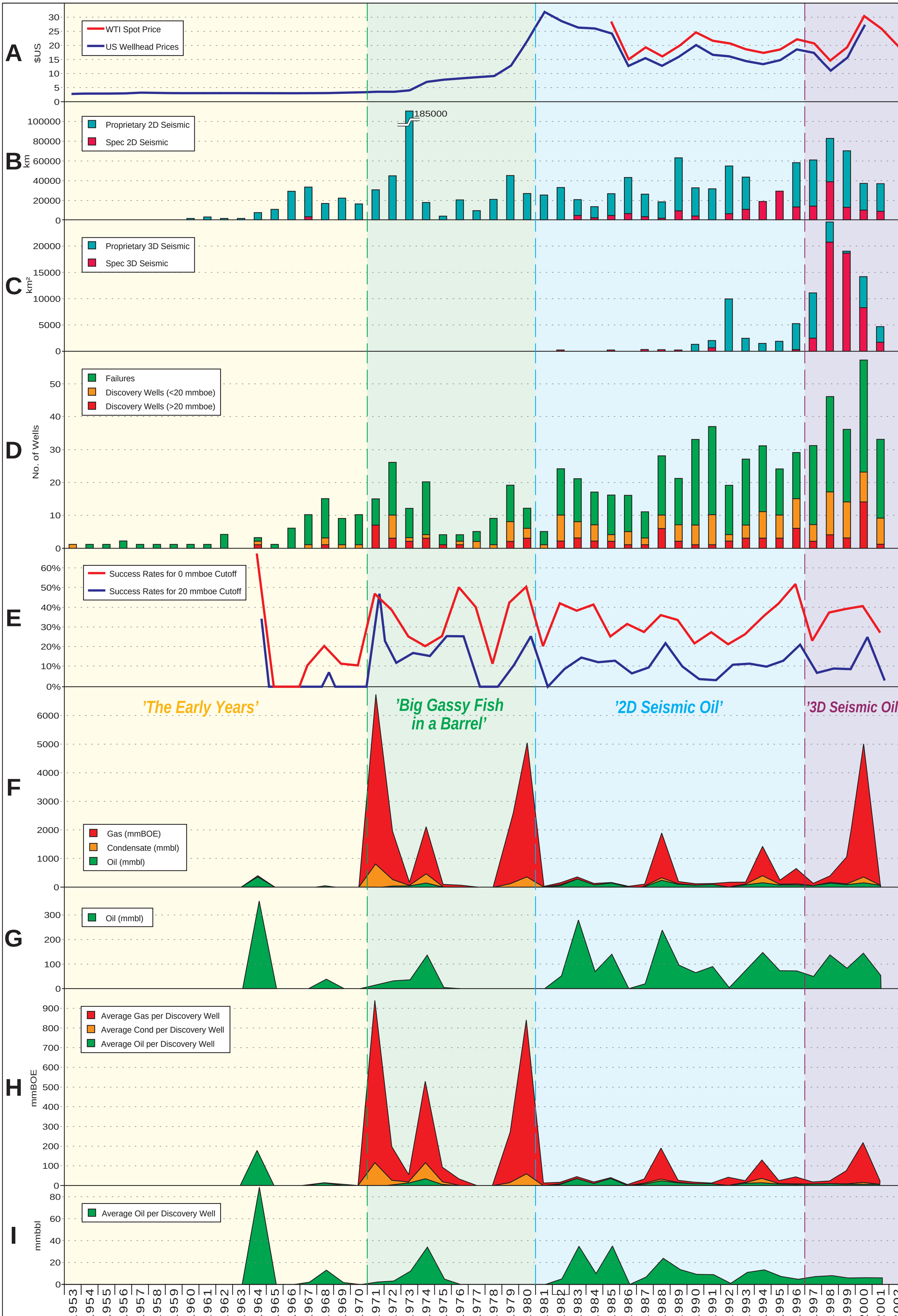

Figure 22. Historical summary (1953-2001) of exploration along the North West Shelf.

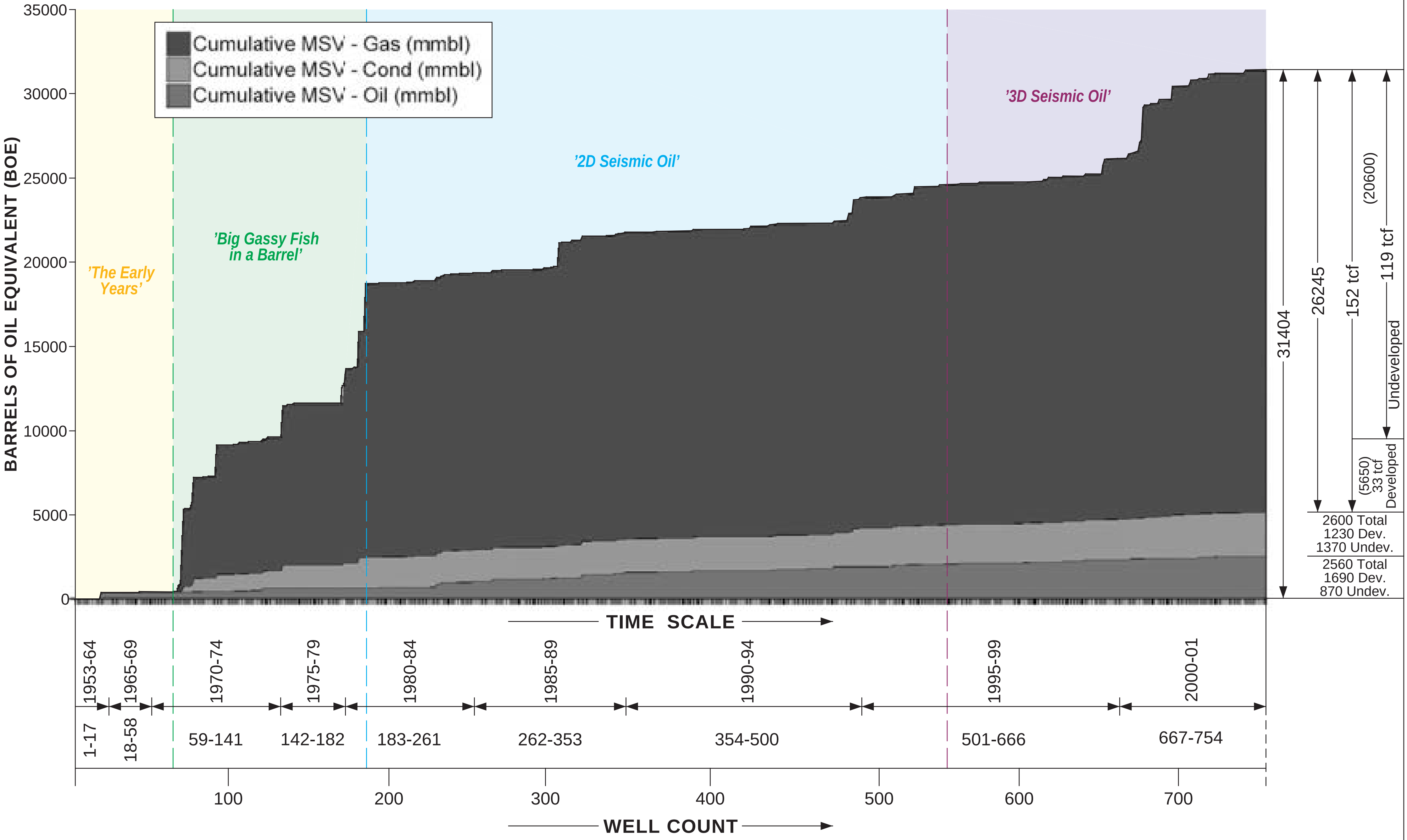

Figure 23. North West Shelf discovery history curve by phase (mean success volume [MSV] for gas, condensate and oil) against exploration well count.

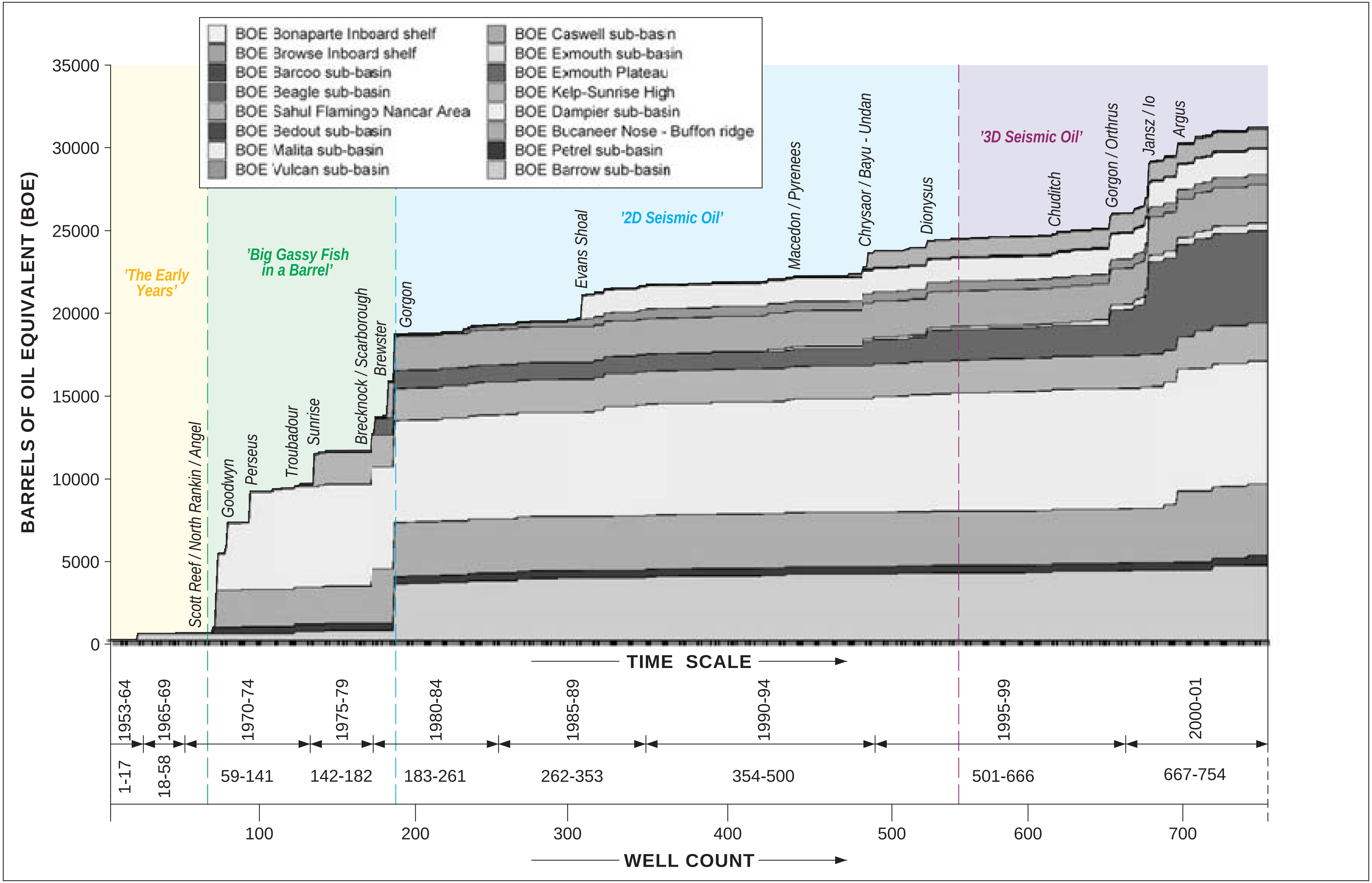

Figure 24. North West Shelf discovery history curve by geographic area against exploration well count.

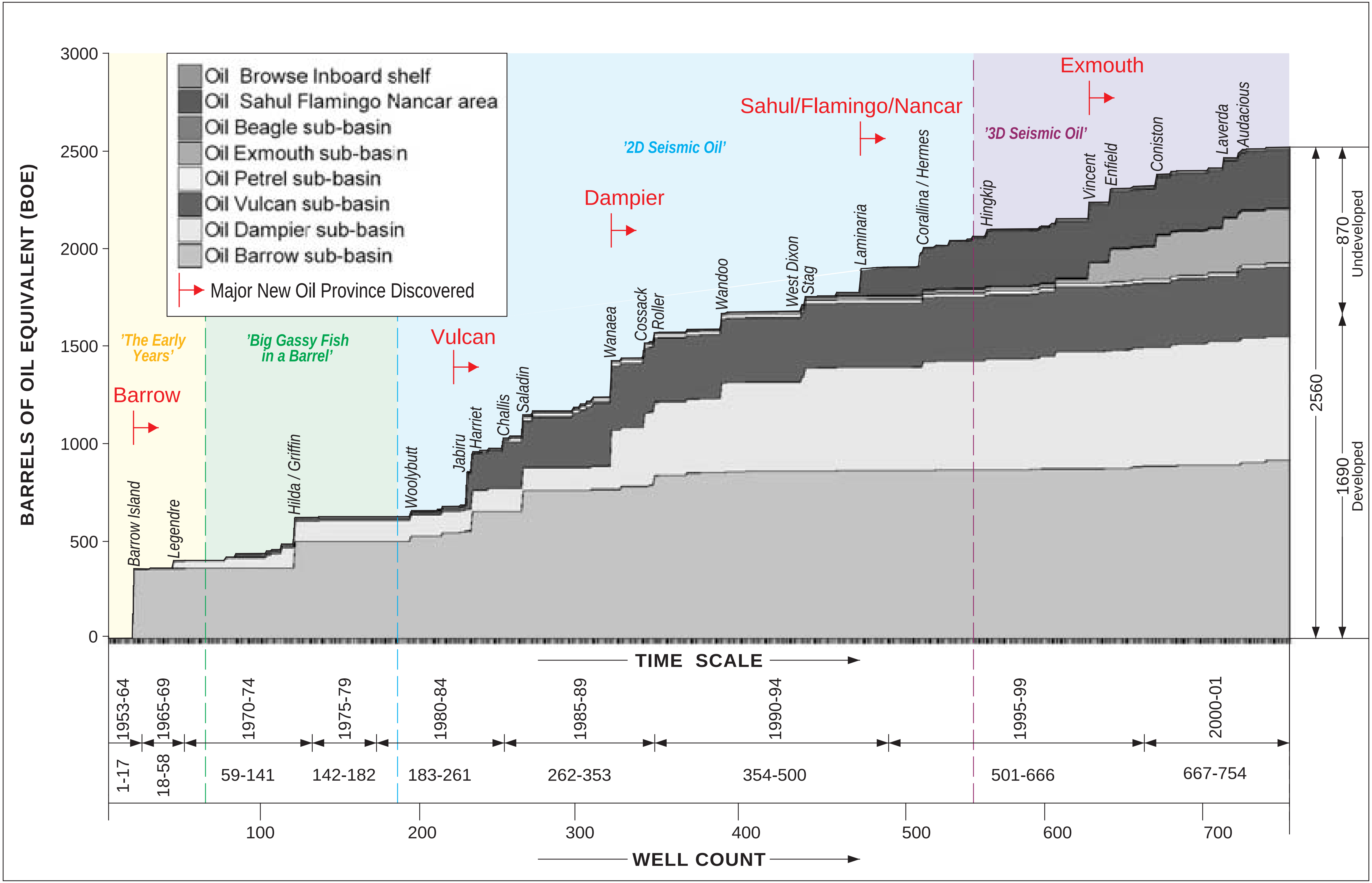

Figure 25. North West Shelf oil discovery history curve by geographic area against exploration well count.

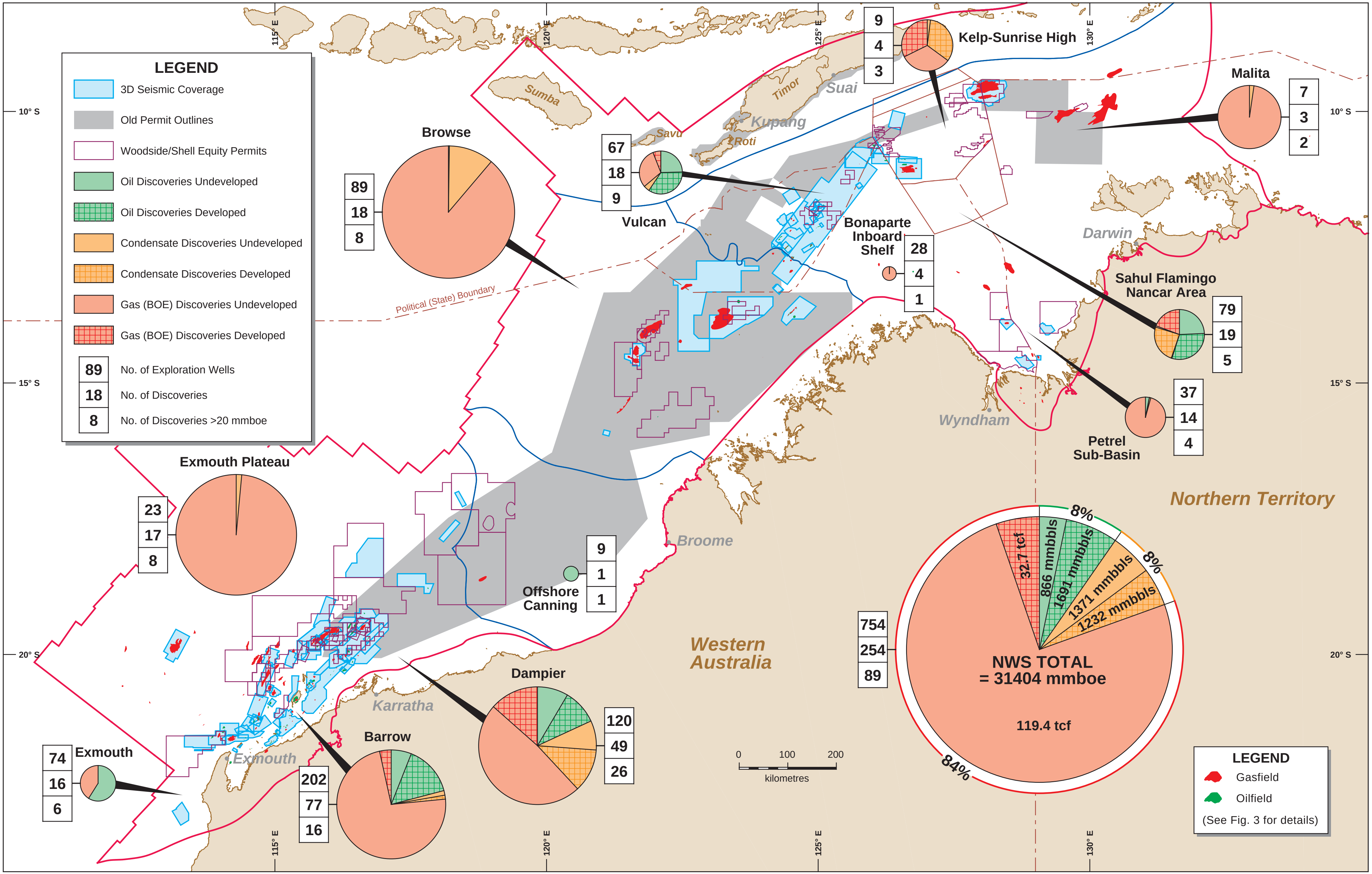

Figure 26. Historical (from 1965 to 2001) Woodside permit coverage, 3D seismic coverage and estimated reserves for North West Shelf and sub-basins.

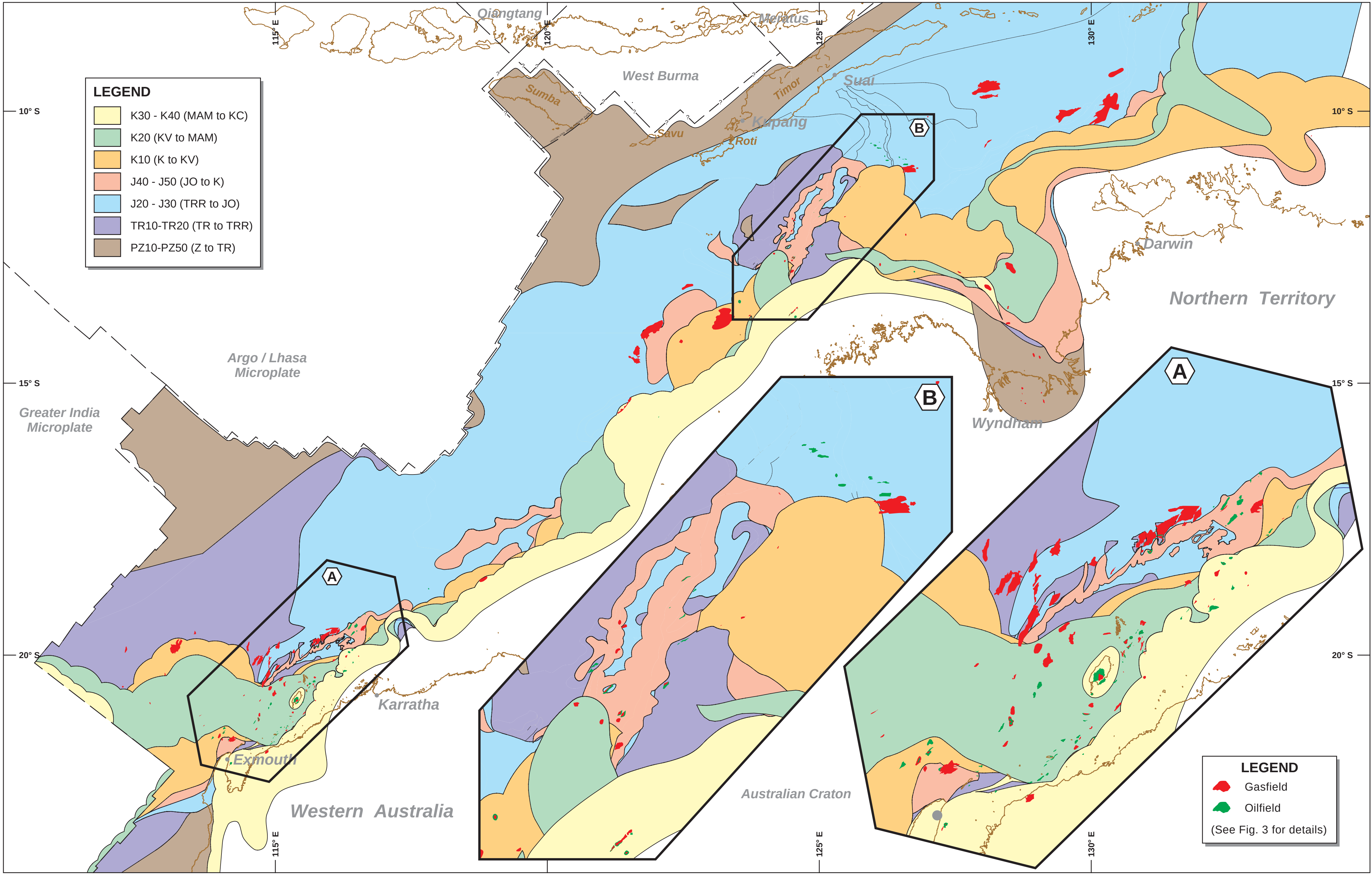

Figure 27. North West Shelf simplified map illustrating top porosity beneath the regional seal.

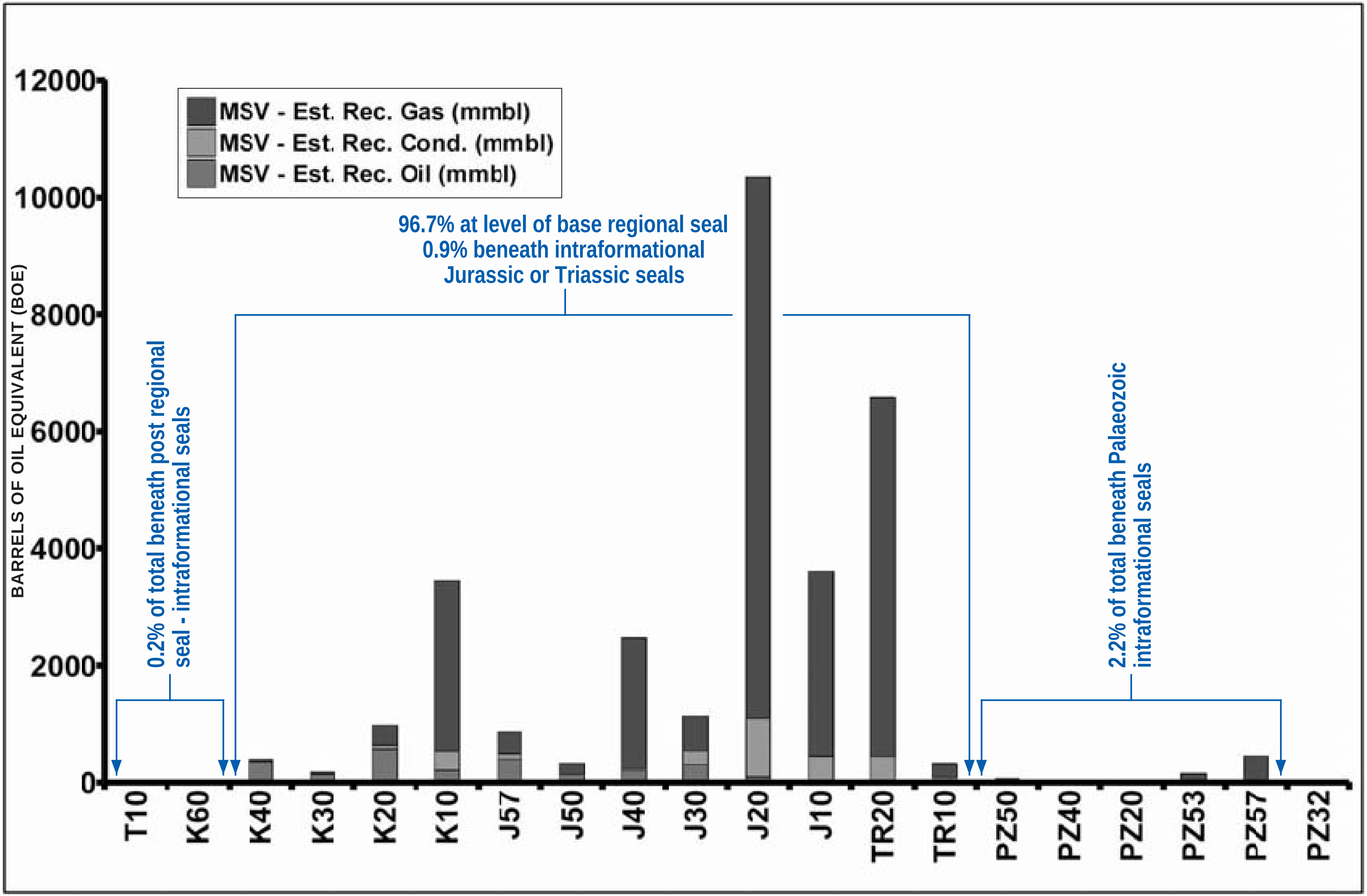

Figure 28. Distribution of oil, condensate and gas reserves (mean success volumes - MSV) by stratigraphic level.

Regional Petroleum Systems

The concept of a simple source-reservoir couplet "petroleum system" as defined by Magoon and Dow (1994) is not readily applicable to the North West Shelf since:

- There is no world class source rock present. Demaison and Huizinga (1994) and Spry (1993) both rate the major sub-basins along the margin as having a moderate "source potential index" as defined by Demaison and Huizinga (1994).

- Source rocks are generally of poor quality, and commonly occur at multiple stratigraphic levels. Products generated from different levels are usually geochemically similar, and co-mingle during migration (or in the reservoir), making the parent source units difficult to identify using conventional oil-source correlation methods;
- Many of the actual source units are difficult to identify, since some are undrilled, some contain source material dispersed over thick stratigraphic intervals, and others are developed within ephemeral facies which are rarely drilled and difficult to understand.

Notwithstanding the above, the petroleum systems operating on the North West Shelf have been defined by Bradshaw et al. (1994) and Edwards et al. (1997) and the work presented here builds on this foundation. Figure 29 presents a simplified distribution map of the effective petroleum systems and the migration style after Demaison and Huizinga (1994). These charge areas are schematic only and their limits are poorly constrained. Individual areas are described in more detail below, but the figure clearly demonstrates that many parts of the margin do not contain an effective charge system. In some areas this may be due to an insufficient sample population, but in other areas we believe this lack of effective charge is due to absence of an effective source rock, rather than issues such as seal, timing, maturity etc. The corollary to this, is that background organic material does not provide a ubiquitous effective charge (not even dry gas), and the fact that an area may be adjacent to kilometres of mature, shaley sediments, does not necessarily mitigate the charge risk.

Neogene reactivation of the North West Shelf has historically focussed attention on trap breach as a major reason for many exploration well failures (O'Brien et al., 2002). Although undoubtedly a major risk in some areas (e.g. the Londonderry Terrace – Figure 2 and Brincat et al., 2001) this focus has tended to mask the importance of the underlying source risk. Trap risk is the primary suspect in many failed trap analyses because of the obsessive focus of exploration companies on seismic prospect mapping. There is always plenty of seismic data to purchase, analyse, reprocess and discuss, and a plausible mechanism for structural failure can generally be supplied. Conveniently, the structural failure hypothesis always preserves the supposed prospectivity of the area, and focus quickly moves to the adjacent prospect. In contrast, the presence of an effective source system is significantly more difficult to evaluate and understand. Prediction of maturity and migration issues can usually be evaluated by well control, seismic mapping, thermal and burial history modelling, but the key element which is always difficult to quantify is source quality and effectiveness. The intrinsically intangible nature of the source effectiveness risk element, and the blighting of entire areas once the absence of an effective source is established, has tended to popularise the trap breach myth. The conclusion of absence of source assumes enough wells have been drilled and evaluated to make this damning assessment.

In an attempt to better understand the source rock systems, Woodside has compiled, quality controlled and evaluated a comprehensive set of source rock data, based on core, sidewall core and cuttings samples from the North West Shelf, consisting of almost 30,000 records. The Woodside database was supplemented from a fusion of Geoscience Australias ORGCHEM database and a Mesozoic Source Rocks database (Dolan and Associates et al., 2000). Histograms of Total Organic Carbon (TOC) and Hydrogen Index (HI) are displayed as Figures 30 and 31 respectively. Although somewhat simplistic, these demonstrate that whereas most sediments contain sufficiently high TOC to be considered as source rocks, the proportion of liquids-prone samples is very small, and that most sediments are probably only capable of generating gas. This is consistent with the dominance of gas over oil (92% of reserves are gas or condensate by boe – see Figure 26) within existing discoveries.

Identifying oil-prone source intervals from this data set is a key issue. Scott (1992) in his discussion of North West Shelf petroleum systems, noted the difficulty of characterising marginal source rocks with mixed marine-terrestrial kerogens, and suggested that Rock-Eval data underestimates their oil potential. He proposed the use of pyrolysis-gas chromatography (Py-GC) to complement source rock screening, by evaluating the distribution of gas and oil products in pyrolysates. We concur with Scott (1992) in finding no correlation between Rock-Eval Hydrogen Index and the Pyrolysis-GC derived parameter gas-oil generation index (GOGI; Figure 32). There is also no support for the GOGI versus HI correlation published by Pepper and Corvi (1995). This lack of correlation persists, regardless of how the data are filtered. Mineral matrix effects related to low TOC are not considered a root cause. This has important implications for the way Rock-Eval data are used in identifying and modelling source rock behaviour in marginal source rock provinces, as it implies that Hydrogen Index may not be sufficiently indicative of source quality.

With this caveat in mind, and in the absence of any more rigorous method of evaluating source potential, we attempted to map out the relative liquids potential of different source sequences, using a statistical comparison of source rock quality at each stratigraphic level. The details of this analysis remains confidential, but the simplified results are shown as Figure 33, showing source quality in different areas divided into a simple four (4) class relative scheme namely gas-prone, minor, fair and good liquid potential. No attempt was made to correct for sediment maturity, and it must be pointed out that even the “good” source rock successions would probably only be classified as fair by global standards.

When integrated with other geological and exploration data, the source rock screening data reveal that;

- Oil-prone source rocks occur at multiple levels in the Dampier, Vulcan and Sahul-Flamingo-Nancar areas (Figure 2), consistent with the occurrence of oil fields in these regions:

- Source rocks are not identified in the Barrow and Exmouth sub-basins (Figure 2), yet these areas contain numerous oil accumulations. This is interpreted to be due to a combination of under-sampling, and burial of J40 marine source beds beneath the thick K10 Barrow delta (Figure 18);
- The Beagle and Browse basins contain no identified liquids-prone source rock sequences, consistent with the very small volumes of oil discovered to date in these regions;
- The TR20-TR10 (Triassic) section appears to have little or no oil potential across the margin, though distal marine facies are not yet well sampled;
- There is some oil potential within the delta top sediments within the J10/J20/J30 sections particularly in the Dampier, Vulcan and Sahul-Flamingo-Nancar areas;
- Significant oil-prone source rocks are developed within the J40 section in the marine rift basins particularly within the Dampier and Vulcan regions;
- There is significant oil-prone potential within the condensed K10-K40 shale intervals in the Vulcan and Sahul-Flamingo-Nancar areas (Figure 19).

The observations above are consistent with the reservoir distribution of oil and gas, which, assuming upward migration of hydrocarbons, indicates that the primary oil source rock is at J30 or younger levels, and that major gas source rocks must be within TR20 or younger sediments (Figure 33).

The burial, maturation and migration of hydrocarbons from identified source rock successions is commonly evaluated using computer-based models, which are well beyond the scope of this regional synopsis. At a higher level, there are some general observations that can be made about the maturity and migration process along the margin. The present day maturity of the main Early Cretaceous-Triassic source rock units (Figure 33) is approximated by the present-day regional JO (Oxfordian) maturity map (Figure 34). The primary driver is the Tertiary prograding wedge (Figure 21), which attains thicknesses of up to 4 kms in some basinal areas. Late burial means that most kitchen areas are currently at maximum burial depths, and that there is no structuration-migration timing problem for most trap types; the only exception being some very late traps formed (not reactivated) by late Neogene tectonism. The areas which have not experienced this late burial, and rely on earlier burial phases for charge, include the outboard deepwater areas and inboard Palaeozoic areas such as the Petrel Sub-basin.

Portions of the WASB which are currently mature for gas are the central basinal areas within the Barrow-Dampier, Caswell and Malita Sub-basins (Figures 2 and 34). Burial history in these areas has resulted in the main source units (Figure 33) passing through the oil window in the Late Cretaceous in response to thick Cretaceous sedimentation (Figures 19 and 20). Subsequent Tertiary burial has pushed basinal source units into the gas window, and those on the flank (if present) into the oil window (Figure 34). The most complex area for maturation is the Exmouth sub-basin, where relatively thin Tertiary cover (Figure 21) overlies a thin Late Cretaceous and thick Early Cretaceous (K10; Barrow delta) section resulting in a complex multi-phase charge story (Tindale et al., 1998).

Figures 18 to 21 highlight the progressive outboard (northwesterly) migration of depocentres from the Oxfordian (Figures 18 to 21) to the present day. The primary reason why most deepwater portions of the margin are generally gas-prone is because they lack Late Jurassic synrift source rocks and that the migration of depocentres outboard has also tended to focus charge from the Late Jurassic depocentres in an inboard (southeasterly) direction.

It may be stated that all of the major oil and gas discoveries along the North West Shelf access source kitchen areas currently at maximum depths of burial due to Tertiary progradation. Local migration can be complex, particularly beneath the key diachronous base regional seal (Figure 27). Relatively unstructured basinal areas with thick Cretaceous shale development (Barrow/Dampier, Caswell and Malita sub-basins) are areas of laterally-drained high-impedence migration (sensu Demaison and Huizinga, 1994) at the base regional seal level. Consequently, lateral migration dominates, and oil generated during Cretaceous burial is flushed by gas, unless protected by an underlying shale aquaclude (e.g. at the base of the J20 section, Lambert 2 oil and gas discovery, Kingsley et al., 1998). Such a gas flushing versus overpressured (and thus effective) seal relationship was noted for the Barrow-Exmouth area by Zaunbrecher (1994).

All basinal areas are flanked by shelfal and platform areas, where Cretaceous sealing units become thinner and/or faulting becomes more pervasive. In these areas, a lower-impedence fault-related vertically-drained migration character dominates. In these lower impedance areas, particularly those affected by pervasive Neogene tectonism, such as the Vulcan Sub-basin, migration routes between source and trap are short, risk of fault breach is significantly higher, and risk of gas-flushing is significantly lower than in basinal high impedance areas. Some portions of the North West Shelf (e.g. the central Barrow Sub-basin and parts of the Vulcan Sub-basin) display both high and low impedance character respectively for oil and gas, thus enriching some traps with oil. This makes phase prediction problematical, as the phenomenon appears to be local, and gas pools (with flushed oil), and oil pools (with leaked gas) can occur adjacent to each other. Leakage explains the common occurrence of gas within the K40 radiolarite section, which is visible as bright amplitudes over some fields in the Barrow sub-basin, and the common development of HRDZ seismic anomalies along the margin (Cowley and O'Brien, 2000).

Apart from gas-flushing and the selective leakage of gas up faults, there are two processes which affect in situ reservoired hydrocarbons, and the resultant hydrocarbon phase. These are:-

- Degradation of a light oil into heavy oil and dry gas via biodegradation (e.g. Vincent - Enfield area, Figure 3) as evidenced by the association of a dry gas cap with a biodegraded oil.
- Water-washing, acting upon a mixed oil and gas charge to produce a light oil, as proposed by Newell (1999) for the Laminaria area.

The former will only occur at low temperatures (below 70 to 80^{o}C), and biodegradation risk can readily be assessed. Water washing resulting in enhancement of oil charge is poorly understood, however, it may be unrecognised elsewhere along the margin, or may be limited to the Laminaria area, and related to the establishment of an aquifer system by the recent (3 Ma) formation of the Timor Trough. The presence of a tilted gas-water contact in the Sunrise Field (Seggie et al., 2000) attests to the presence of this local aquifer system, and we favour a local phenomenon.

In summary, it appears that a gassy charge can be enriched in liquids via selective dynamic gas leakage and/or water washing, and an oily charge can be destroyed by gas flushing and/or biodegradation. The factors which affect the presence and phase of reservoired hydrocarbons along the North West Shelf are therefore complex, and go significantly beyond the traditional depth, pressure, temperature, source quality, maturity, migration and trap risk factors typically considered by explorationists.

Four source rock models have been identified; the first two illustrated in Figure 35 are favoured for the development of effective liquids-prone source rocks within the North West Shelf. Model A (Figure 35A) comprises marine shale deposited under suboxic to anoxic conditions, within an underfilled rift basin (Scott, 1994) and is the “traditional” depositional model used to explain the liquids along the margin. In this model it is proposed that organic matter was concentrated in thin source rock intervals during periods of sediment starvation and restricted circulation, possibly during periods of maximum flood, resulting in enhanced preservation potential. This model best describes the J40 (Kimmeridgian) source rocks observed in the centre of the Dampier sub-basin, and presumed to extend southwestwards along the axis of the Barrow and Exmouth sub-basins (Figure 14), and also the J40 (Oxfordian) source rocks observed in the Paqualin Graben (Vulcan Sub-basin) to the northeast.

The second model (Figure 35B) of oil-prone source rock development is seen in the underlying J20/J30 clastic section and is poorly understood. The observations concerning this source system are:

- Certain wells show enriched source rock intervals occurring within delta top coals or in proximal marine shales whereas in wells immediately along strike these sequences do not show the same enrichment. That is, source rock development is laterally discontinuous.
- Though the source potential is spacially erratic, where identified it tends to be repeated within stacked parasequences suggesting the enrichment mechanism is repeated in the same location and thus is probably structurally controlled
- Both the marine shale and delta-top coals are within strongly interbedded sequences associated within facies either side of the delta front suggesting the source rocks were deposited within a deltafront area where frequent, widespread marine floods occurred.

The “delta front enrichment” source rock models are shown in Figure 35. The models proposed both rely on “ponding” due to subsidence over an underlying low (sedimentary thick area) near the delta front. In the delta top case frequent marine incursions have been shown to considerably increase the oil source potential of coals (Sykes, 2001) and thick coal developments have been linked to highstand deposits as described for the Tertiary coals of Australia by Holdgate and Clarke (2000). Clearly structural embayments and/or structural depressions in areas behind coastal barrier systems would be favoured environments in this model. The underlying structural control on these depressions thus explains why the enrichment is both localised and repeated in stacked sequences. A similar model is also proposed in the shallow offshore bar environment beyond the coast where ponding occurs behind an offshore bar system and the shallow marine anoxia is maybe caused by the establishment of a freshwater wedge from hinterland run-off (Figure 35C). High resolution palaeogeographic maps highlighting ancient river systems is then a key for source rock prediction in these models.

A fourth unproven model for liquids could be hydrocarbons sourced from deep water marls rather than marine shales with a significant higher plant input as found in the inboard failed rifts (Bradshaw, 2001; Summons et al., 1998). There is some geochemical evidence to suggest that the oils sourced from Mesozoic carbonate facies seen in Seram, Buton, Buru and Timor may also extend to the outer Bonaparte and Browse basins (Edwards et al., 2001) and to the Carnarvon Basin (George et al., 1998). This petroleum system is developed out beyond the typical Late Jurassic Westralian system (Bradshaw et al., 1994) of the North West Shelf.

The starting point for Woodside's regional interpretation of fluid geochemistry was the "Oils of Western Australia" study by AGSO/Geomark (1996). This systematic review of 160+ oils and condensates emphasised the primary tectonic control on source rock depositional environment. Subsequent publications by the same group have extended the classification scheme (e.g. Summons et al., 1998). For this review we incorporated more recent published material into the AGSO/Geomark framework, and commissioned new analyses of aromatic hydrocarbons and compound specific isotopes for all fluids in the Woodside collection.

The new analyses help to identify differences due to maturity and secondary alteration from those fundamentally related to source. Until recently, very little published geochemical data was available for gases. Recent reports (AGSO/Geotech 2000; Boreham et al. 2001; Crostella and Boreham, 2000; Pallaser, 2000) have greatly improved matters but there is still a paucity of carbon isotope data for individual gas components. Such data are essential to gas typing and maturity estimation and in particular, to recognising mixtures of thermogenic and biogenic gas.

{Figure Captions (29-35)}

29. Simplified petroleum systems map of the North West Shelf.

30. Histogram and cumulative probability distribution summary of observed Total Organic Carbon (TOC) measurements from Rock-Eval data from the North West Shelf.

31. Histogram and cumulative probability distribution summary of observed Hydrogen Index (HI) measurements from Rock-Eval data from the North West Shelf.

32. Comparison between Hydrogen Index (HI) measurements from Rock-Eval data and Pyrolysis-gas Chromatography measurements for source rock samples from the North West Shelf.

33. Summary of observed Rock-Eval source rock screening results with interpreted effective oil and gas source rock units by area and stratigraphic age for the North West Shelf.

34. Regional interpreted current day maturity at the JO (Oxfordian) surface over the North West Shelf.

35. Summary of source rock depositional models for the North West Shelf. (A) Underfilled marine rift basin (after Scott, 1994); (B) Prograding delta model: (C) Shallow offshore ponding model: (D) Delta plain ponding model.

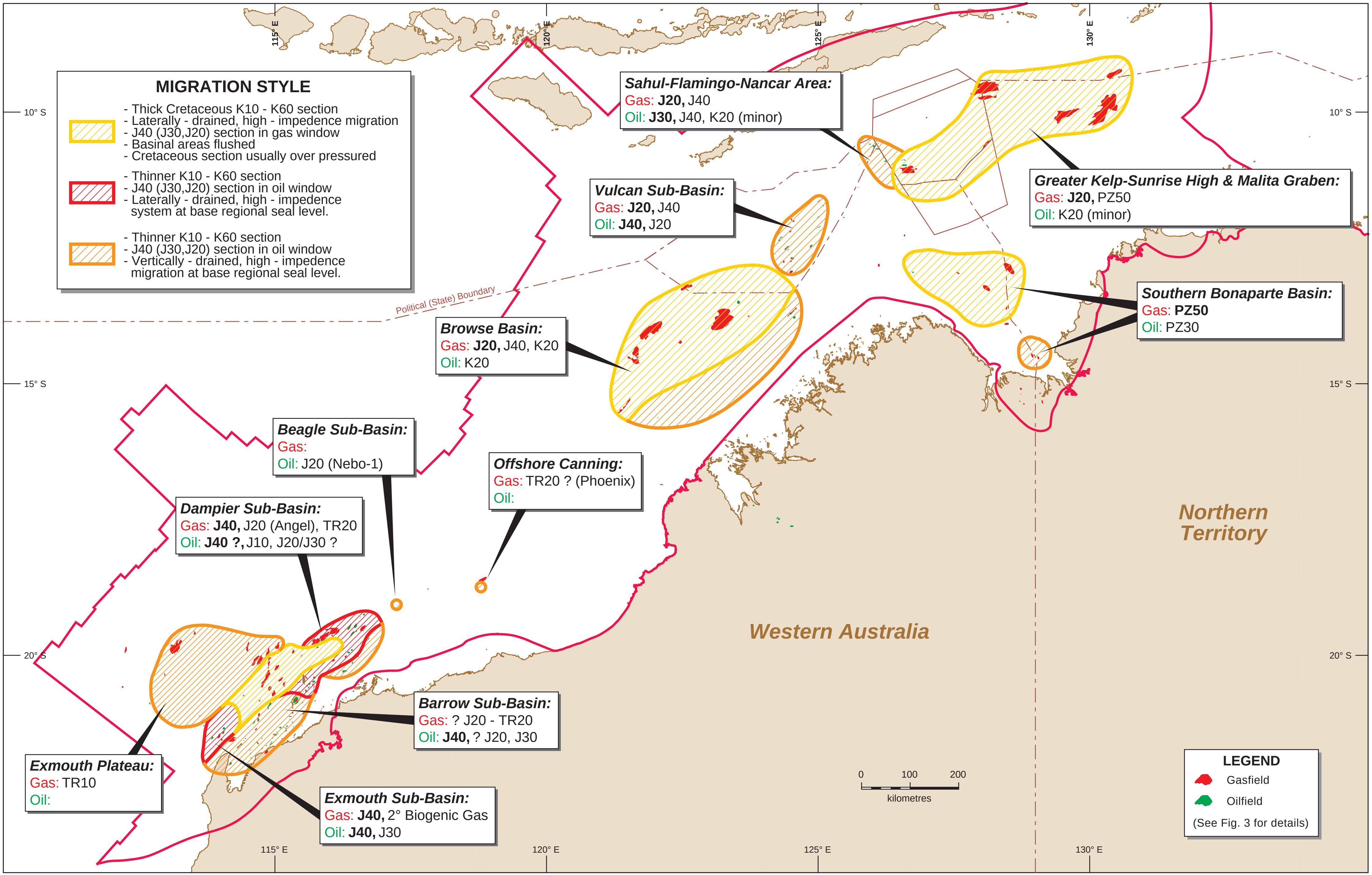

Figure 29. Simplified petroleum systems map of the North West Shelf.

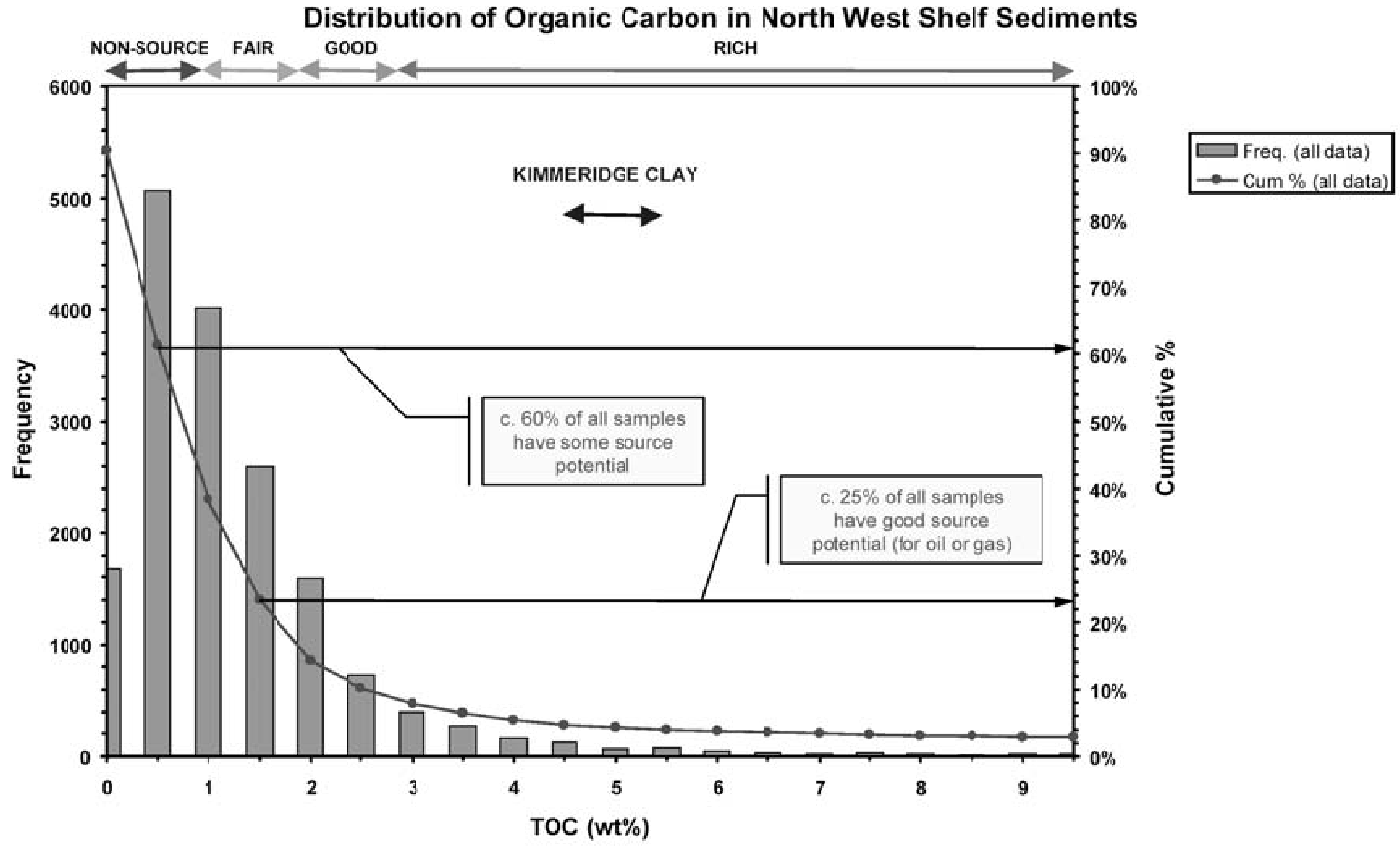

Figure 30. Histogram and cumulative probability distribution of Total Organic Carbon (TOC) (from Rock-Eval data), North West Shelf.

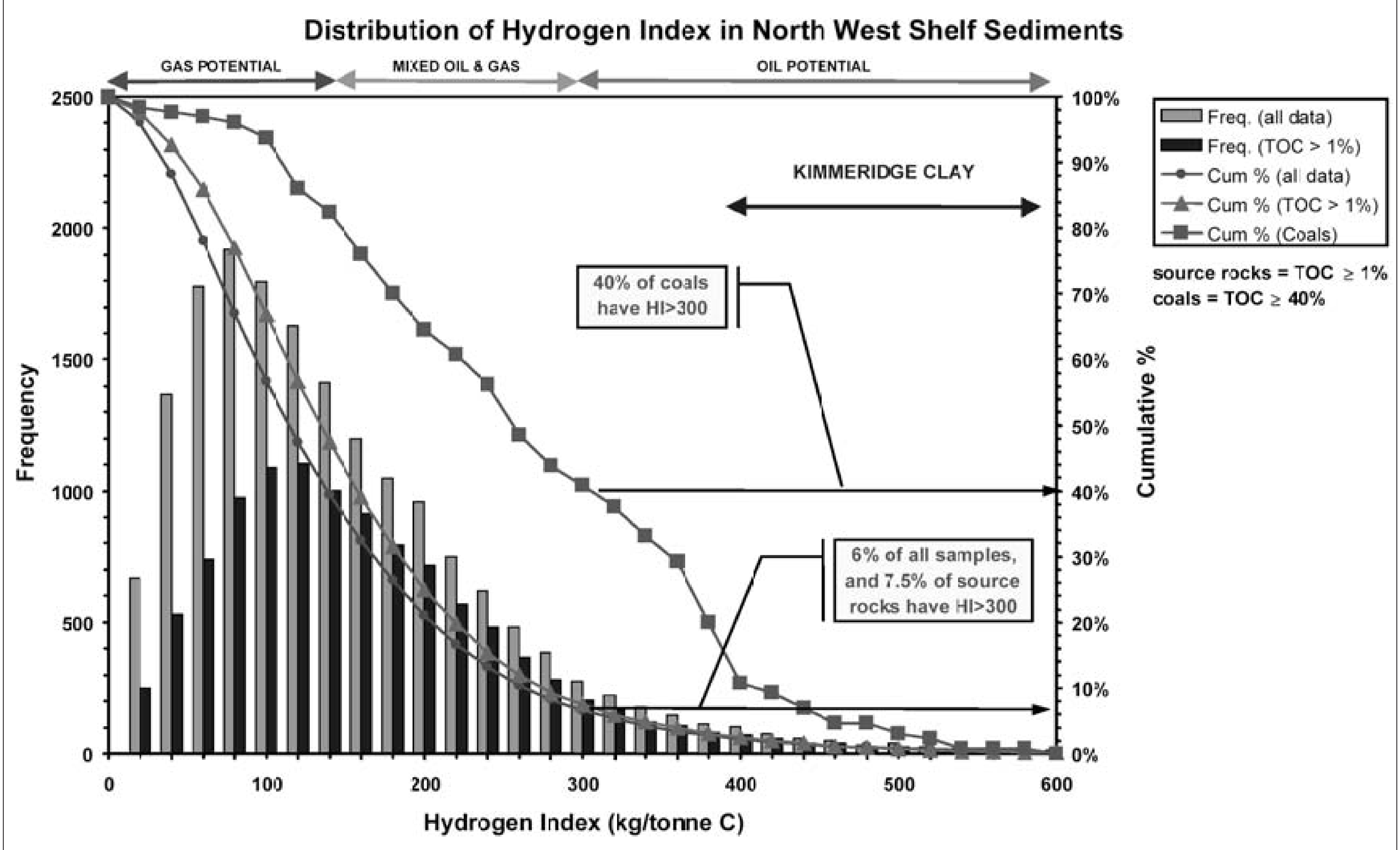

Figure 31. Histogram and cumulative probability distribution of Hydrogen Index (HI) (from Rock-Eval data), North West Shelf.

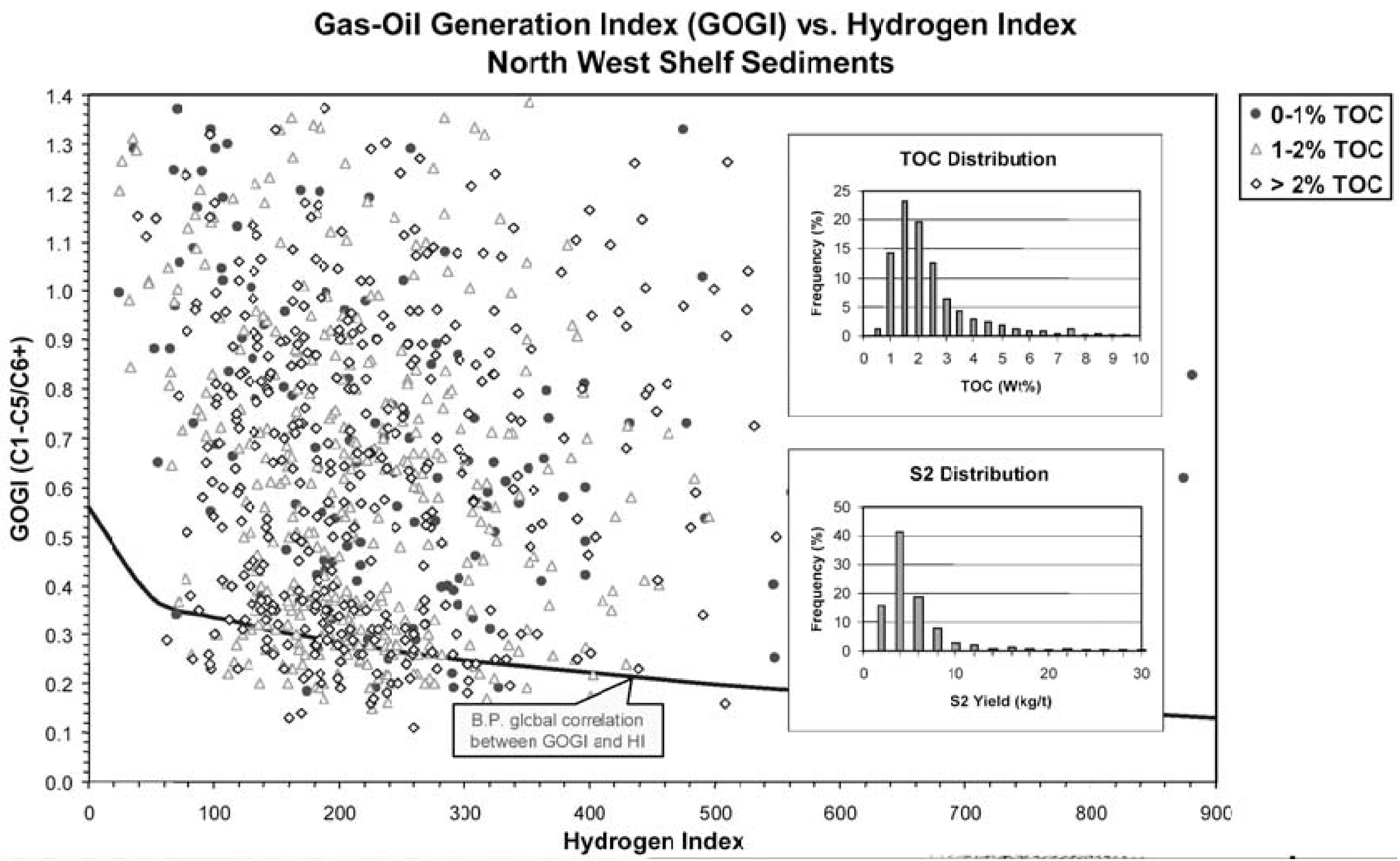

Figure 32. Hydrogen Index (HI) (from Rock-Eval data) versus Pyrolysis-gas Chromatography measurements, North West Shelf.

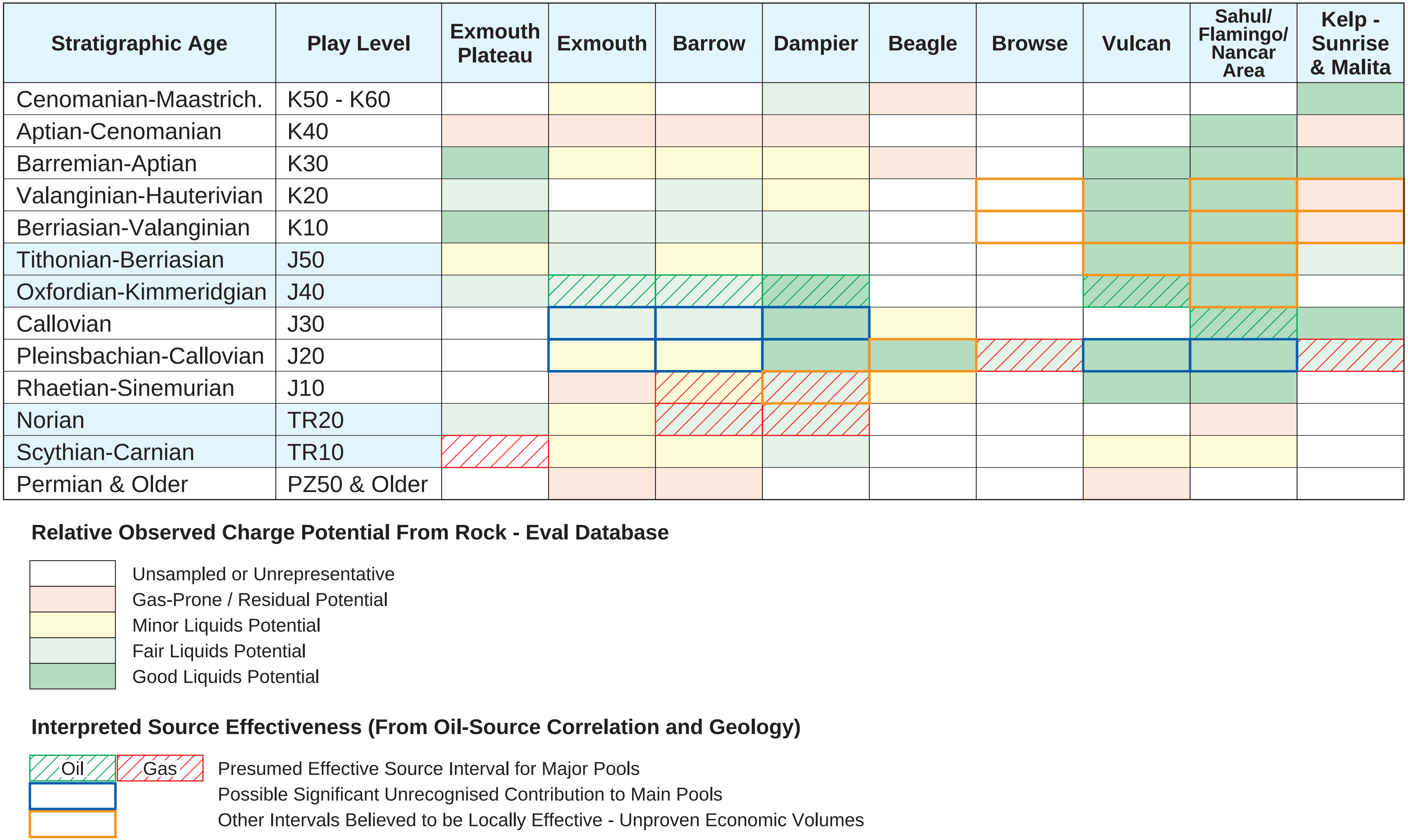

Figure 33. Summary of Rock-Eval screening results, with interpreted source rock unit, by area and age for the North West Shelf.

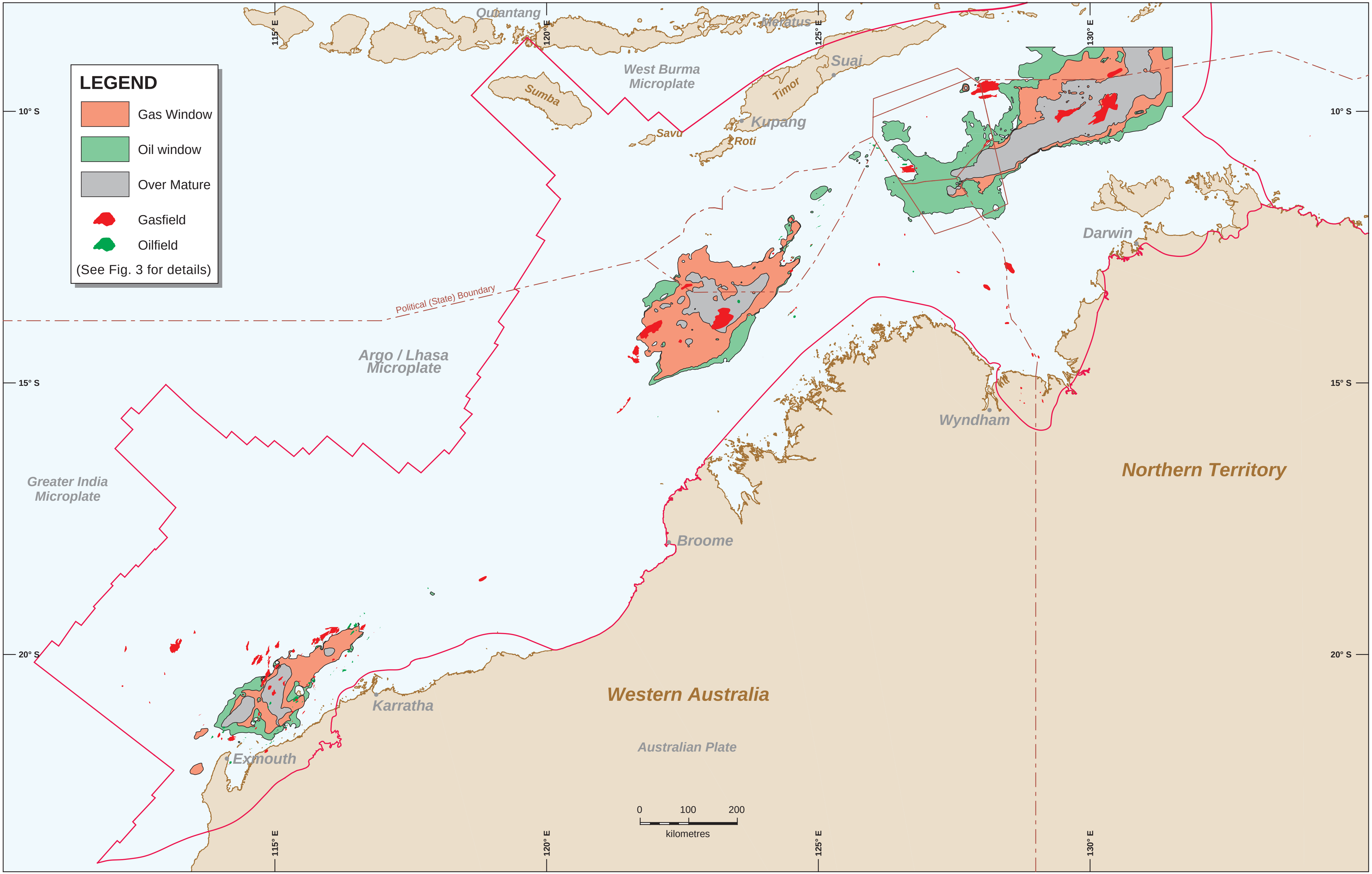

Figure 34. Regional interpreted current day maturity at the JO (Oxfordian) surface over the North West Shelf.

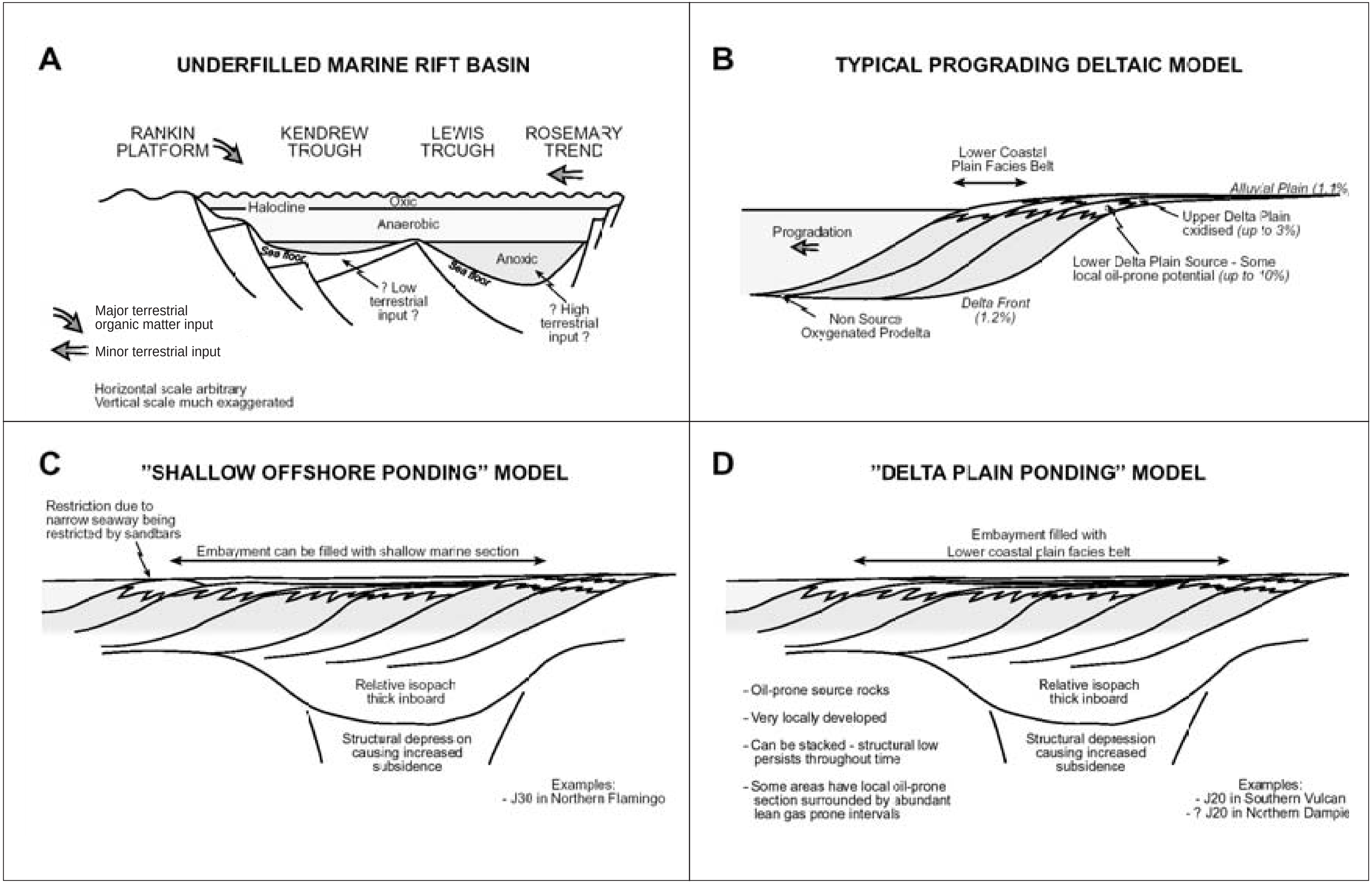

Figure 35. Summary of source rock depositional models for the North West Shelf. (A) after Scott (1994).

Petroleum Geology of the Main Productive Areas

The petroleum geology of the various sub-basins and areas along the North West Shelf is described below.

At the end of 2001 the North West Shelf contained some 233 field discoveries and 754 exploration wells indicating an historical technical success rate of 32% and a 12% historical success rate for fields greater than 20 mmboe. The margin is estimated to contain (scope) reserves of 152 Tcf of gas, 2603 mmbbls of condensate and 2557 mmbls of oil which equates to a 8%/8%/84% oil/condensate/gas volume split respectively by boe. Of these discovered estimated (scope) reserves at the end of 2001 some 866 mmbbls of oil, 371 mmbbls of condensate and some 119 Tcf of gas remains undeveloped.

Exmouth Plateau (Figures 2, 3, 20, 29)

The Exmouth Plateau at the end of 2001 contained 11 discoveries and 23 exploration wells with a historical technical success rate of 74% and a 35% historical success rate for fields greater than 20mmboe. The plateau is estimated to contain (scope) reserves of 32 Tcf of gas, 81 mmbbls of condensate and no oil which which equates to a 1%/99% condensate/gas volume split respectively by boe. None of these reserves have yet been developed.

The petroleum geology and early exploration history of the Exmouth Plateau is described by Barber (1988). The Exmouth Plateau contains a number of large Cretaceous (K10) dry gas accumulations including Scarborough, and Jansz/Io (reservoired in J40 fan sands - see Bussel et al., 2001) and a number of large Triassic (TR20) dry gas accumulations such as Orthrus and Maenad inboard (Figures 2 and 29) plus smaller gas pools intersected in Jupiter, Sirius and Eendracht (Figure 3). All these accumulations have the majority of their reserves reservoired at the base regional seal level. The sandiness of the stratigraphy beneath this level generally precludes significant intra-Triassic (TR20 and TR10) accumulations, and enables effective vertical migration to regional top porosity level. Evidence of trap breach is present on seismic data, explaining why some traps (e.g. Jupiter) are underfilled. TR20 and younger sequences are immature, and the dry gas is consequently interpreted to have been sourced from TR10 delta top sediments, as penetrated by Jupiter 1. Gas in the large Scarborough field (4 TCF) (Longley et al., 2002; Bradshaw et al., 1998) is both extremely dry (C_1/(C_1-C_4 = 0.998) and low in CO_2 (trace). This composition and the relatively shallow/cool reservoir suggest a biogenic origin, however, the methane isotope value of minus 42.3 (Crostella and Boreham, 2000) is more consistent with a thermogenic source. Furthermore, biodegraded gases at Sirius and Eendracht are at least partly thermogenic (James and Burns, 1984), and consistent with a Middle Triassic (TR10) coaly source. Assuming that the composition and carbon isotope values of Scarborough gas are both valid, it could be an end-stage anaerobic biodegradation product of an initially dry, thermogenic gas. In the absence of isotope data for the CO_2, an early thermal origin is also possible.

The Exmouth Plateau was strongly affected by Campanian structuring (Bradshaw et al., 1998) and the largest inversion structure is Scarborough, which is still at the bathymetric crest of the plateau (Figure 3). Significant Tertiary burial occurs inboard of this area (Figure 20), and TR10 in the (uninverted) synclinal area is interpreted to be at maximum depth of burial, and still supplying gas to reservoirs at the base regional seal level.

Dampier, Barrow and Exmouth sub-basins (Figures 7, 14, 33, 34)

The principal effective oil source rocks in the Dampier, Barrow and Exmouth sub-basins are J40 synrift anoxic marine shales (Figures 14 and 33) which are currently within the oil window on the basin margins and within the gas window in basinal areas (Figure 34). Other source rocks appear to be effective within both the J20 deltaic sequence and the basal J10 section (Figure 7), although the relative, albeit probably minor, contribution of liquids from these levels is poorly understood. The principal gas source rock levels are deltaic sediments within the J20 (Legendre), J10 (Brigadier) and TR20 (Mungaroo) sections, although as for the oil, the exact level of contribution from each of these units is still unclear.

Dampier Sub-basin (Figures 2, 6, 7)

The Dampier Sub-basin is described by Woodside (1988) and Jablonski (1997). At the end of 2001 it contained 49 field discoveries and 120 exploration wells, with a historical technical success rate of 41% and a 22% historical success rate for fields greater than 20 mmboe. The sub-basin is estimated to contain (scope) reserves of 34 Tcf of gas, 1037 mmbbls of condensate and 633 mmbls of oil which equates to a 8%/14%/78% oil/condensate/gas volume split respectively by boe. Of these discovered estimated (scope) reserves at the end of 2001 an estimated 440 mmbbls of oil, 418 mmbbls of condensate and some 15Tcf of gas remain undeveloped.

The Dampier Sub-basin can be divided broadly into two structured flanks, either side of the main Oxfordian depocentre (Figures 2 and 6). Fields along the western flank include the large rift-related horst block traps, such as the Goodwyn (Young, 1998), North Rankin (Vincent and Tilbury, 1988) and Echo-Yodel wet gas fields, the single, unique, Perseus lowside saddle trap (Taylor et al., 1998), and numerous other smaller horst and tilted fault block traps such as Eaglehawk (Vincent and Tilbury, 1988), and the Searipple field beneath Perseus (Taylor et al., 1998). Subcrop of different J10 and TR20 sands within many traps at the level of the base regional seal produce complex fields containing various hydrocarbon phases (oil only, oil and dry gas, and wet gas) and stacked pools with different fluid contacts (Longley,et.al., 2002). Indeed, some individual pools contain sands in pressure communication and sharing a common contact, which produce gas with markedly different condensate-gas-ratios (CGRs). The central basin area has hydrocarbons within J50 low relief oil-filled drape traps which overlie deeper rift-related gas-filled J10 horst traps. Wanaea and Cossack (di Toro, 1994), Lambert (Kingsley et al., 1998) and Mutineer and Egret (Vincent and Tilbury, 1988) typify these traps. The exception is the J50 Angel Field (Vincent and Tilbury, 1988) which contains wet gas. The eastern flank contains the lowside roll-over K10 Legendre field (Willetts et al., 1999), the faulted horst K10 Talisman field (Ellis, 1988), the J20 Reindeer faulted anticline gas field (Ballesteros, 1998) and the Wandoo oilfield (Delfos, 1994) and Stag (Crowley and Collins, 1996) K20 drape anticlines (note Stag is a combination drape and onlap trap see field map in Clare and Cowley, 2001), plus numerous smaller accumulations. All of these eastern flank fields are at the level of the base regional seal except for Reindeer, which is reservoired beneath a thick J20/J30 shale unit.

The accumulation of significant volumes of hydrocarbons at multiple stratigraphic levels along both flanks and within the main basinal area demonstrates the laterally drained high-impedance nature of the petroleum system within the central Dampier Sub-basin.

In the Dampier Sub-Basin the complex charge history is reflected in the recognition of five distinct fluid families (AGSO/Geomark, 1996). Oil accumulations such as Wanaea, Cossack, Legendre, Lambert and Mutineer are reasonably well typed to Upper Jurassic (J40) sediments in the Lewis and Kendrew troughs, as are the biodegraded oils at Wandoo and Stag (Summons et al.,1998). These fields are shielded from J20, J10 and TR20 gas charge by a thick J30 (Calypso Formation) shale, and a thick basal J20 shale (Athol Formation) (Figure 6). Angel Field gases are isotopically distinct from others in the province, consistent with breach of the J30 seal, allowing mixing of Middle and Late Jurassic systems. On the Rankin Platform, gas-condensates overlie either oil rims or biodegraded oil residues, and show variable CGRs. The oil rims invariably abut the main bounding fault and the wettest gases occur in reservoirs which do not physically contact the main basinal bounding fault. This suggests the fluids may be a mixture of vertically migrated upper Jurassic J40 oil, and drier gas from deeper units (?J40-TR20 Undiff) within the Kendrew Trough, with the wetter gas possibly being generated locally within the Rankin Platform area from J10-TR20 source intervals. This is the simplest explanation for the variable character of the fluids encountered on the Rankin Platform. In support of the vertical migration model, data from recent wells show evidence for formation of at least some of the gas-condensates via dysmigration of an initially waxy oil. Furthermore, condensates on the Rankin Platform bear more geochemical affinity to Jurassic source rocks (J40, J20) than they do to the Triassic (Mungaroo Formation TR 20) coals often assumed to be their source (Figure 2). Thus, the relative volumetric contribution from Jurassic and Triassic sediments remains unclear. Until resolved, such uncertainties call into question the use of the Rankin Platform as an analog for Triassic gas plays elsewhere in the WASB.

Most oils in the Dampier Sub-Basin are sourced from marine or marine-deltaic sediments such as those in the Late Jurassic of the Kendrew and Lewis Troughs (J40, Kimmeridgian and Oxfordian). The oils at Eaglehawk 1, Egret 1 and some of the North Rankin condensates, however, show evidence for a source containing a higher proportion of land-plant matter. In the case of Egret, the oil in question is a biodegraded phase which has been overprinted by a fresh charge of oil of the same type as Lambert, Wanaea, etc. (i.e., Late Jurassic, J40 origin). Identification of the source of the first charge at Egret and Eaglehawk awaits a detailed charge/migration model but it may be significant that a rich, marginal marine lagoonal source rock occurs in the Rhaetean portion of the J10 sequence (Figure 7) at Egret 1. As many condensate-rich gases occur in early Jurassic reservoirs, it is possible that this source also contributes to the liquids charge in other parts of the Rankin Platform, however, there are alternative explanations for the higher CGR gases. The simplest of these is retention of liquid components in the gas phase in the more highly pressured traps (as opposed to the formation of discrete oil-rims). Again, integration of the fluid property data with a high resolution charge/migration model is needed to resolve such issues.

The imprint of an early, biodegraded oil charge to the Rankin Platform is evident in the prevalence of 25-norhopanes in oils trapped in Triassic reservoirs. Although this feature has long been recognised (Volkman et al., 1983) the implications for fluid source correlation have not always been considered. Biomarker compounds traditionally used for fluid-source correlation are initially enriched in biodegraded oils and unless degradation has proceeded to the point where they are completely removed, they will mix with and alter the biomarker signature of any subsequently emplaced fluid. This is especially so if the second phase is a gas-condensate, as occurs at several places on the Rankin Platform (e.g. Dockrell and Rankin fields). Because of this, and the lack of gas-isotope data, the origin of some large gas accumulations in the Carnarvon Basin remains uncertain, with Triassic, Middle and Late Jurassic sediments all potentially contributing.

Barrow Sub-basin (Figures 2, 7, 11, 12, 16, 18, 27, 33)

The Barrow Sub-basin is described by Parry and Smith (1988) and Baillie and Jacobson (1997). The Barrow Sub-basin at the end of 2001 contained 77 field discoveries and 202 exploration wells with a historical technical success rate of 38% and a 8% historical success rate for fields greater than 20 mmboe. The sub-basin is estimated to contain (scope) reserves of 21 Tcf of gas, 113 mmbbls of condensate and 913 mmbls of oil which equates to a 20%/2%/78% oil/condensate/gas volume split respectively by boe. Of these discovered estimated (scope) reserves at the end of 2001 some 266 mmbbls of oil, 61 mmbbls of condensate and some 19.5 Tcf of gas remains undeveloped.

The Barrow Sub-basin, like the Dampier, can be divided into a western and eastern flank surrounding a central deep. The outboard northern end of the western flank (Figure 2), along the Gorgon platform, contains large dry TR10 and TR20 gas fields such as Gorgon, West Tryal Rocks (McClure et al., 1988), Chrysaor, Dionysus, Geryon (Sibley et al., 1999), and Iago. All of these contain gas within simple horst traps at the base regional seal level. As for the Rankin Platform traps to the north, these fields have intraformational Triassic seals subcropping the base regional seal resulting in numerous pools with different fluid contacts (Sibley et al., 1999). The southern end of the western flank (Alpha Arch) contains K20 oil accumulations such as Griffin and Scindian/Chinook (Tindale et al., 1998). The basinal area contains deeper K20 horst block traps such as Spar (McClure et al., 1988), but also the amplitude supported K20 East Spar anticlinal trap (Craig et al., 1997), the K20 Woollybutt oil field (Hearty and Battrick, 2002) and the K20 John Brookes gas field (Auld et al., 2002) and the recognition of the latter three structures are heavily dependent on depth conversion techniques. Also present in this basinal area is the Maitland amplitude-supported dry gas field (Sit et al., 1994), the only significant Tertiary (T10) discovery (Figure 7) along the North West Shelf. The eastern flank accumulations include the margin’s largest oilfield, Barrow Island (Ellis et al., 1999), which has a topographic (island) expression and multiple oil and gas zones within K40-J20 intervals, the tilted fault block and lowside traps of the South Pepper, Chervil and Saladin areas (McClure et al., 1988), which are tilted fault blocks at the level of the base regional seal located along a broad Campanian to Miocene inversion anticlinal trend. To the northeast of Barrow Island, beyond the progradational limit of the Barrow delta (Figure 16) are the Harriet area fields surrounding the Lowendal Syncline (Figure 2) which include the tilted fault block traps of Harriet (Howell, 1988), Bambra and Campbell (McClure et al., 1988), Gypsy-Rose-Lee (Apache, 2002), Wonnich (Ballesteros, 1998), and many other smaller accumulations which contain hydrocarbons mainly at the K20 base regional seal level within basinal fan sands deposited off the front of the Barrow delta and forming the local base regional seal level (Baillie and Jacobson, 1997). Also in this area are key deeper accumulations within J40 onlap traps (Linda) and complex J10-TR20 highside and lowside fault block traps (Gypsy-Rose-Lee).

The lack of observed source potential in Barrow and Exmouth sub-basins from the Woodside source screening work (Figure 33) is interpreted to be due to burial of the main J40 source sequence beneath thick K10 Barrow sequence of deltaic sediments (Figure 18), with the result that it is rarely drilled, and often overmature where penetrated.

Volkman et al. (1983) correlated some Barrow Sub-Basin oils to the Late Jurassic Dingo claystone (J50/J40). A more specific assignment was made on the basis of aromatic biomarkers by van Aarssen et al. (1996), who observed that most oils correlated best with *the W. spectabilis* biozone (J40 Oxfordian). While a Late Jurassic origin of most of the oils is likely, there is evidence for contribution from other source rocks at some locations. For example, a calcareous source component is suggested by biomarker profiles of North Herald and Chervil oils, and for an early oil phase seen in inclusions at South Pepper (Summons et al., 1998; George et al., 1998). Some condensates from the West Tryal Rocks area have an unusual isotope composition suggesting mixed origins (AGSO/Geomark, 1996) and an oil recovered from Callovian sands at Bambra 1 shows a close correlation with the encasing shales (J30 *R. aemula* age).

Gases of the Gorgon area, especially those in reservoirs associated with deep, high angle faults, are higher in CO_2 and much lower in liquids content than analogous fields of the Rankin Platform. This is in part due to the deeper burial of source units within the adjacent basinal area, but also due to flushing of earlier (wetter) gases via a spill chain passing from Gorgon (south to central to north) to Chrysaor, Dionysus and Geryon, with a late dry, CO_2 rich charge. It is possible that the J20 section may be responsible for much of the liquids content in the Dampier gas fields (as is the case at Angel) and since the J20 delta top sediments were limited to the Dampier area and did not extend into the Barrow rift (Figures 11 and 12) the initial charge into the flanking Gorgon area traps may have been relatively dry gas. In addition, the amount of erosion at the base regional seal level is greater in the Gorgon area and little or no delta top sediments within the J10 or J20 units remain to provide a wet gas charge as they may do in the Rankin Platform area. Condensates in the Gorgon Platform fields are highly aromatic, and both saturated and aromatic biomarkers show evidence of mixing (AGSO/Geomark, 1996; AGSO/Geotech, 2000; van Aarssen et al., 2000). It is therefore considered likely that the liquids and gas components of the Gorgon gases are decoupled with respect to source and maturity, and in fact the liquids may be the result of gas stripping of mature coal organic matter in the reservoir and/or along the migration pathway. Such considerations reduce the relevance of biomarker information in assigning a source for the gas. Furthermore, in the absence of information on kerogen isotopes it is not possible to deconvolute source and maturity influences on the gas isotope signature. As noted in the AGSO/Geotech study, however, uniformity in the isotope composition of wet gas components argues for a common source for most Carnarvon Basin gases, including those of the Gorgon complex. Since Jurassic sediments are downthrown to great depth by the faults forming the Gorgon fields, a Triassic source is not necessary to explain a dry gas charge here.

Gases in the Barrow Sub-Basin often appear to contain a component of biogenic methane (AGSO/Geotech, 2000). This is apparent from the isotope signature wherein methane is isotopically anomalously light, relative to ethane in the same accumulation. In cases where biogenic methane occurs with biodegraded oils it is probably of secondary biogenic origin, i.e. formed as a by-product of anaerobic degradation of oil and gas (Pallaser, 2000; Boreham et al., 2001). A strong association of ^{13}C depleted methane (product) with ^{13}C enriched CO_2 (substrate) lends weight to this theory. The methane may also be partly of early thermogenic origin, however, and derived from the Cretaceous seal rock (Muderong Shale).

The deep basinal areas of the Barrow Sub-basin adjacent to the Gorgon and Alpha arches (Figure 2) has a thick Cretaceous shale section with the base regional seal at the TR20 stratigraphic level (Figure 27) and this shale pile is overpressured due to disequilibrium compaction (Tingate et al., 2001). Southwards and eastwards from this shale depocenter the Cretaceous section becomes more interbedded with deltaic and fan sands of J20-K10 age and overpressure and gas flushing is less dominant and mixed oil and gas pools exist at the level of the base regional seal. A string of fields along the western flank of the basin has deeper gas at J30 and J20 levels with mixed oil and gas at the main K10-K20 base regional seal reservoir levels (Zaunbrecher, 1994). This suggests that deeper gas is accessing basinal Jurassic J40 gas mature source rocks and or gas is leaking through the aquiclude J40-J50 shale pile from deeper ?J10-Tr20 units. Regardless of the source of this mixed oil and gas at the base regional seal level selective dynamic leakage of the gas from this level results in close proximity of oil and gas pools and local selective enrichment of oil in some fields. In the south, medium range migration at the base regional seal level fills small pools along a spill chain all the way to the shallow onshore and biodegraded K20 Turbridgi gas field.

Exmouth Sub-basin (Figure 29)

The Exmouth Sub-basin is described by Tindale et al. (1998). At the end of 2001 the area contained 16 field discoveries and 74 exploration wells with a historical technical success rate of 22% and a 8% historical success rate for fields greater than 20 mmboe. The sub-basin is estimated to contain (scope) reserves of 1.2 Tcf of gas, 0 mmbbls of condensate and 278 mmbls of oil which equates to a 58%/42% oil/gas volume split respectively by boe. None of these discovered estimated (scope) reserves at the end of 2001 had been developed.

The Exmouth Sub-basin only has significant hydrocarbon accumulations on it's eastern flank, due to strong tilting down to the northwest. The main accumulations include the K10 Macedon/Pyrenees faulted anticline dry gas field (probably produced from biodegradation of oil and initially wet gas), numerous K10 tilted fault blocks such as Novara, Outtrim, Blencathra, Caretta, Vincent and Leatherback (Tindale et al., 1998), the J50 amplitude supported lowside fault block traps at Enfield and Laverda (Bussell et al., 2001) and the onshore minor oil accumulation at Rough Range (Ellis and Jonasson, 2002) (Figure 29).

All of the Vinceint, Enfield and Laverda fluids are heavily biodegraded (both oil and gas), and would be unproduceable were it not for (a) the excellent reservoir quality in the K20 and J50 and (b) the fact that the oils were light to begin with and therefore contained low concentrations of the polar and asphaltenic materials responsible for high viscosity in biodegraded oils. Oil-source correlation is hampered by the heavy bio-degradation, but a combination of analytical techniques has revealed that the primary Vincent charge resembled light marine oils of Late Jurassic (J40) origin from the central and western Barrow Sub-Basin (e.g. Griffin 1). The Laverda and Enfield J50 (Macedon) oils show slightly more terrigenous source character. In this respect they are intermediate between the main Barrow family, and the group of oils exemplified by Leatherback 1 (see below).

A group of oils with much stronger terrestrial affinity than those of the main Barrow-Dampier-Exmouth family are found in the eastern part of the Exmouth Sub-Basin (Figure 29). These include Leatherback, Blencathra, Outtrim and Rough Range. The oils show varying degrees of terrestrial influence in their biomarker profiles, and are all relatively waxy. The Rough Range crude is regarded as an end member, with no marine influence, and it appears to originate entirely from coals or lacustrine shales. Callovian (J30) sediments in Leatherback 1 show a reasonable correlation with the Leatherback oil. Although this oil is in a TR20 (Triassic) reservoir, the source rock is not likely to be of Triassic age as the oil contains abundant retene and other conifer biomarkers, more characteristic of the latest Middle and Late Jurassic (van Aarssen et al., 1996; van Aarssen et al., 2000). This family of oils is generally less mature than those in the central and northern Barrow Sub-basin, consistent with a source closer to the basin margin. Summons et al. (1998) have shown that oil from a core at Dill 1 also correlates with Leatherback 1 crude, making it the most northerly example of this fluid family. It is not clear if this oil is coming from a more proximal facies of the J40, J30 or J20 section.

Beagle Sub-Basin (

The geology and early exploration in the Beagle Sub-basin area is described by Blevin et al., 1994. The Beagle Sub-basin at the end of 2001 contained one field discovery (the Nebo Field; Osborne, 1994) and 17 exploration wells with a historical technical success rate of 6% and a 0% historical success rate for fields greater than 20 mmboe. The undeveloped Nebo field is estimated to contain up to 5mmbbls of recoverable oil.

The Nebo oil is a one of only two oils along the North West Shelf for which there appears to have been no contribution of marine algae to the source (Woodside, unpublished data). All other fluids are at least partly derived from marine algal kerogens. No specific oil-source correlation has been established for Nebo but modelling suggests that J20 fluvio-deltaic sediments are sufficiently mature in the adjacent graben to source this oil. The total lack of marine biomarkers and relatively high wax content (19%) argues against the source beds being marginal marine to paralic delta top environments, and the most likely origin is a discrete interval of fluvial or (more likely) lacustrine carbonaceous shale.

The Beagle Sub-basin has several wells on robust structural traps which were thought to have failed due primarily to trap breach (Blevin et al., 1994). Fair source rock sections are present within some wells within the J20 section and these can be modelled as being within the oil window at depth. Woodside interprets the lack of success in this inboard area as due to the absence of an effective source rock. The outboard area remains untested.

Offshore Canning Basin

The offshore Canning Basin is described by Horstman and Purcell (1988), Lipski (1994), Colwell and Stagg, (1994), and Smith et al. (1999). The basin is relatively underexplored but large long-lived structures at the base regional seal (particularly the Bedout structure) are devoid of hydrocarbons and it is strongly suspected that there may be no effective hydrocarbon charge within most parts of the basin.

The offshore Canning Basin at the end of 2001 contained one undeveloped discovery (Phoenix) and nine exploration wells with both a historical technical success rate and a historical success rate for fields greater than 20 mmboe of 11%. The Phoenix field is estimated to contain (scope) reserves of 500bcf of gas with no condensate or oil, however, the confidence level on this estimate based on the available data is very low. The Phoenix 1 gas is reservoired in fluviatile sediments of TR10 Triassic age, which also probably act as the source off-structure. This assignment cannot be confirmed by direct fluid-source correlation but is inferred on maturity grounds.

Browse Basin (Figures 2, 7, 8, 9, 12, 18, 29, 33, 34)

The petroleum geology of the Browse Basin is described by Maung et al. (1994), Struckmeyer et al. (1998) and Blevin et al.(1998a, b). The Browse Basin at the end of 2001 contained 19 field discoveries and 59 exploration wells with a historical technical success rate of 32% and a 14% historical success rate for fields greater than 20 mmboe. The basin is estimated to contain (scope) reserves of 35 Tcf of gas, 722 mmbbls of condensate and 15 mmbls of oil which equates to a 11%/89% condensate/gas volume split respectively by boe. None of these estimated reserves have been developed.

The Browse Basin resource base is dominated by the large J20 Scott Reef, Brecknock and Brecknock South horst block dry gas fields (Figures 2 and 7) (Longley et al; 2002 and Bint, 1988) that have been discovered outboard of the main Caswell Sub-basin source kitchen area (Figure 34). Inboard of this depocentre are the relatively small K30 Gwydion and K40 enigmatic Cornea basement drape fields (Spry and Ward, 1997; Ingram et al., 2000) which contain both gas and oil. In the north of the Caswell Sub-basin the large Brewster K10 drape structure contains wet gas (Figure 8) and in the south a single small gas pool is interpreted to have been intersected by the Arquebus 1 well within an inversion structure formed (not just re-activated) by Neogene tectonism. This has previously been interpreted by Haston and Farrelly (1993) to be a potential oil accumulation. A very small oil accumulation was also intersected at Caswell 2 (Figures 2 and 29) within the K60 section (Figures 7 and 9). All pools except the small Caswell 2 accumulation are reservoired in sands beneath the level of the base regional seal.

The Central Caswell Sub-basin is currently in the gas window at the J20 level and the basin is devoid of thick anoxic J40 marine shales except for locally in the north adjacent to the Brewster Field, where an extension of the J40 Vulcan rift basins system (the Heywood-Anderton graben) extends into the Northern Browse Basin area.

Good Late Jurassic oil-prone source rock successions have not been identified in the offshore Canning and Browse basins (Figure 33). This is because no major rifting occurred in the region during the Oxfordian and Tithonian rift events elsewhere on the margin (Figure 18) and consequently the restricted conditions that favoured development of marine source rocks were not developed. Source rocks are present within the J20 deltaic units (Figure 12), but these are generally gas-prone where penetrated (Figure 33).

The gas potential of the Early-Middle Jurassic is highlighted by the giant gas fields at Scott Reef, Brecknock and Brecknock South. These gases have low CGRs (around 20 bbls/MMscf), compared with fields in the Carnarvon Basin, and yet the liquid fraction boiling range extends to beyond C_{30}. Thus, in many respects they resemble an oil dissolved in gas (rather than a product of high maturity), and oil rims could develop if these fluids occurred in slightly shallower traps. No explicit fluid-source correlation has been established, but condensate biomarkers suggest a clastic source, containing mixed marine-terrestrial kerogen at moderate to high maturity. Kerogens of this type, and with variable quality, occur throughout the J20 deltaic section, which is interpreted to be the principal source (Figure 33).

Elsewhere in the Browse Basin, the pervasive Middle Jurassic gas charge is supplemented to varying extent by liquids derived from Late Jurassic and Early Cretaceous marine shales (J40 and K30 respectively). The Gwydion, Cornea and Caswell 2 oils are all interpreted to be the product of K10-K20 (Early Cretaceous) oil system diluted with J20 Jurassic (and perhaps older) gas (see Blevin et al., 1998a). The biomarker signature is dominated by the Early Cretaceous source, and these compounds are present in much higher concentrations in oils than in condensates. Nevertheless, a mixed origin is evident from the gas isotope data, Cornea 1 gas for example, being very similar in its isotope profile to Brecknock South and also only moderately biodegraded compared with the heavily biodegraded Cretaceous oil. The CGR of the Brewster gas is higher than those of Brecknock/Scott Reef, probably due to a contribution from Late

Jurassic shales, which are gas-mature within its drainage cell (though no information on the geochemistry of the Brewster fluid was available for this study), and penetrated at Heywood 1. The Caswell Sub-basin petroleum system at the base regional seal level is a laterally drained, high-impedence migration system and is interpreted to be largely gas flushed (Figure 29). The shallow oil at Caswell 2 from the K10-K20 section indicates a shallow oil play above the level of the regional seal may be locally viable in basinal areas where it is protected from gas flushing and/or biodegradation as has occurred in inboard areas.

Vulcan Sub-basin (Figures 2, 12, 33, 34)

The tectonostratigraphy of the Vulcan Sub-basin is described by Pattillo and Nicholls (1990) and the structural evolution of the area is summarised by Woods (1994).

The Vulcan Sub-basin at the end of 2001 contained 18 field discoveries and 67 exploration wells with a historical technical success rate of 27% and a 13% historical success rate for fields greater than 20 mmboe. The sub-basin is estimated to contain (scope) reserves of 1.3 Tcf of gas, 31 mmbbls of condensate and 357 mmbls of oil which equates to a 58%/5%/36% oil/condensate/gas volume split respectively by boe. Of these discovered estimated (scope) reserves at the end of 2001 some 170 mmbbls of oil, 31 mmbbls of condensate and some 1.2 Tcf of gas remains undeveloped.

The Vulcan Sub-basin contains numerous large J40 oil-only complex horst structures such as Jabiru, Challis and Skua (Nelson, 1990; Gorman, 1990; Osborne, 1990). Other accumulations include the Oliver oil and gas J40 tilted fault block and the small horst blocks such as Montara, Bilyara and J20 Maret accumulations in the south. The Puffin K60 anticlinal field (circa 10-20 mmbbls) is the only significant oil pool above the regional seal along the margin.

Source rocks in the Vulcan Sub-basin are stratigraphically extensive, with good liquids potential occurring throughout the J20-K30 Jurassic and Early Cretaceous section (Figure 33). Evaluation of our Rock-Eval database suggests peak liquids potential occurs in J10-J20 (Early-Middle Jurassic) deltaic successions (Figure 12) and within J40 (Kimmeridgian) marine anoxic shales. In the Swan Graben area (Figure 2), axial wells penetrate a discrete, oil-prone marine source interval towards the top of J40 (Kimmeridgian, *D. swanense* biozone), whereas further north, in the Paqualin Graben, sediments of this age are virtually absent, but a thick section of liquids-prone shales are present within the base of the J40 (Oxfordian *W. spectabalis* biozone). As for the Northern Carnarvon rift systems, these source rocks are interpreted to have been deposited within partially restricted, anoxic marine rift basins during the J40 Oxfordian-Kimmeridgian time.

The multiple source levels present in the Vulcan are reflected in the character of the fluids, many of which show mixed sourcing. Most oils can be correlated to marine shales of the J40 section but the oil rim at Oliver and oils at Montara, Maret and Bilyara originate and can be typed to the J20 delta top sediments (Early-Middle Jurassic)

(Edwards et.al., 2001 and pers.comm.). The latter oils are more waxy than the Late Jurassic family, reflecting the greater land plant contribution to the source. Oils at Puffin 1 and Pituri 1 may be mixtures of the the two families, and there are hints of a Middle Jurassic contribution to the Skua, Challis and Jabiru accumulations.

The Vulcan Sub-basin is 'oily' because the area contains oil quality marine and deltaic source rocks within the oil window and it is located in a regional saddle area protecting the main base regional seal units from gas flushing (Figure 34). The pervasive Neogene tectonism has generally enhanced the oil-prone nature of the area since it has limited the significance of lateral gas migration and gas flushing of oil and it has allowed selective gas leakage from some mixed oil and gas pools. Small gas pools (such as the dry gas Pengana close to Jabiru) are adjacent to major oil-accumulations attesting to the selective nature of this gas leakage.

Sahul, Flamingo and Nancar Area (Figures 3, 13, 33, 34)

The tectonostratigraphic evolution of the Sahul, Flamingo and Nancar area is described by Whittam et al. (1996) and the source geochemistry is described by Preston and Edwards (2000). A water washing model is described for the Laminaria area by Newell (1999). At the end of 2001, the area contained 19 field discoveries and 74 exploration wells with a historical technical success rate of 26% and a 7% historical success rate for fields greater than 20 mmboe. The area is estimated to contain (scope) reserves of 3.4 Tcf of gas, 233 mmbbls of condensate and 337 mmbls of oil which equates to a 29%/20%/51% oil/condensate/gas volume split respectively by boe. Of these discovered estimated (scope) reserves at the end of 2001 some 227 mmbbls of oil, 4 mmbbls of condensate and some 50 bcf of gas remains undeveloped (it should be noted that Bayu-Undan (Figure 3) is classified as developed for the purposes of this paper).

The Sahul-Flamingo-Nancar area contains numerous significant oil pools such as the J30 Laminaria and Corallina horst blocks (Smith et al., 1996) and the large Bayu-Undan J30 gas-condensate horst (Brooks et al., 1996). All of the major hydrocarbons are at the level of the base regional seal except for isolated small volumes recovered from K40 fractured radiolarite in some wells (Preston and Edwards, 2000).

In the Nancar Trough, Laminaria High and Flamingo High area, source rocks occur at all levels, from the J20 (Early-Middle Jurassic) deltaic section through to the K20-K30 sequence (Figure 33) (Preston and Edwards, 2000). A thin interval of the Echuca Shoals Formation, near the base of K20, displays high gamma response and excellent source potential based on Rock-Eval data that can be traced over a wide area of the Northern Bonaparte Basin. This unit is a condensed section relating to the phase of regional subsidence which followed the Greater India separation in the Valanginian. On the Laminaria High, the lower J40 marine shale section (Oxfordian, Frigate Formation) appears less important as an oil source than the underlying J30 deltaic succession (Callovian, Laminaria Formation), which, although composed largely of sandy reservoir lithologies, contain thin, but rich, oil-prone shales, deposited in a shallow marine setting. Similar source potential extends into the underlying J20 deltaic succession (Middle

Jurassic, Plover Formation). Organic matter type is largely terrestrial in the J20 (Plover) section, becoming increasingly marine throughout J30 (Laminaria), J40 (Frigate) and J50 (Flamingo) formations, and wholly marine in the K20 (Echuca Shoals) section.

High quality J30 (Callovian) marine shale oil-source rocks on the Laminaria High correlate well with the liquids component of the Laminaria, Corallina, Buffalo and Jahal oils, though the latter also displays a contribution from the Frigate Formation seal rock (J40). The oils are highly undersaturated, have very low biomarker maturity, and yet are very light and paraffinic with API gravities in the range 55 to 60°. This highly unusual character is thought to arise from the action of water-washing and leakage upon mixtures of a local oil and regional gas charge (Newell, 1999). The extent to which each of these factors determines the overall fluid composition is poorly understood. The sub-commercial oils in the K40 section are typed to the condensed section representing the K20-K30 section (Preston and Edwards, 2000).

The large Bayu-Undan gas field at the southern end of the Flamingo Syncline area has not been sourced from the Northern Flamingo Syncline because it has a hydrocarbon contact which is deeper than the spill chain of oils running out of the Flamingo Syncline area. It is either:-

- locally charged from the same J40-J30 source section as the oil fields to the north and has subsequently been protected from trap breaching and/or water washing
- or it is a mixture of locally sourced liquids with gas migrating out for the Malita Graben area to the south.

The Flamingo Syncline area is the model area for the “delta front ponding” source rock concept. The Laminaria structure is interpreted to be a pre-Tithonian extension of the palaeo-north Flamingo Syncline, which ran along along an axis joining the Laminaria, Bluff and Buller wells. This synclinal axis corresponds with isopach thicks in the J30 (Elang) section as described by Arditto (1996). Barr (2001) interprets the sands between the marine oil source rock shales in this area as offshore bar deposits and hence the north Flamingo Syncline area is believed to have been a locally barred, shallow marine embayment within which marine oil-quality source rocks were deposited (Figure 13).

Oils and core extracts from the very small volumes of oil in Ludmilla 1 and Fannie-Bay 1 from the Nancar Trough (de Ruig et al., 2000) contain unusual biomarkers (monomethylalkanes) which differentiate them clearly from other fluids in the region, and define a “Nancar” family (George et al., 2002). The source is presently unknown.

The Sahul-Flamingo-Nancar area is an ‘oily’ area since most of the source rocks lie within the oil window (Figure 34) in an area protected from gas-flushing. The local gas charge, which probably filled the earlier traps, was subsequently enriched in oil via water washing or dynamic fault leakage. The disparate distribution of oil volumes between the Nancar and Flamingo areas may be due to trap breach but it is more likely to be related to the deposition of effective J30 delta top source rocks in the latter area, but not the former.

Greater Kelp-Sunrise High and Malita Graben (Figure 34)

The petroleum geology in the Malita Graben and Sunrise High area is described by Mory (1988) and the area is adjacent to the study area described by Whittam et al. (1996). The combined Greater Kelp-Sunrise High and Malita Graben areas at the end of 2001 contained 7 field discoveries and 16 exploration wells with a historical technical success rate of 43% and a 31% historical success rate for fields greater than 20 mmboe. The sub-basin is estimated to contain (scope) reserves of 20.2 Tcf of gas, 379 mmbbls of condensate and 0 mmbls of oil which equates to a 10%/90% condensate/gas volume split respectively by boe. Of these discovered estimated (scope) reserves at the end of 2001 some 54 mmbbls of condensate and some 10.7 Tcf of gas remains undeveloped.

The giant Sunrise - Troubadour gas-condensate field (Seggie et al., 2000; Longley et al., 2002) and gas at Evans Shoals, Lynedoch and Chuditch are large faulted anticlinal structures at the base regional seal level. The former was formed by Neogene structuring (at about 3 Ma) and the latter fields are deeply-buried rift-related terrace and tilted fault blocks associated with the Tithonian formation of the Malita Graben. The gas in all fields originates in J20 fluvio-deltaic sediments (Middle Jurassic). The major kitchen area for this charge is the Malita Graben and Troubadour Terrace, to the southeast of the Sunrise High. The central basin area is currently gas-mature (Figure 34) and the thick regional seal has resulted in a laterally drained, high-impedence basin style where the base regional seal level appears to be flushed by gas. AGSO/Geomark (1996) suggested a calcareous element in the source of the Sunrise 1 and Troubador 1 condensates on the basis of biomarker work. The biomarker content of these fluids is however, extremely low, and recent work employing more sensitive methods, and including samples from the more recent Sunrise 2 and Sunset/Sunset West 1 wells does not support this interpretation.

Gas and condensate isotope data infer that both the Evans Shoals 1 and Chuditch 1 gases are mixtures. For Evans Shoals, anomalies in the isotope composition of isobutane and isopentane have been interpreted as evidence of biodegradation (AGSO/Geotech, 2000), which seems unlikely given that the reservoir is currently buried to over 3.5 km. The Chuditch gas-condensate shows a disconnect between the gas and liquid range isotopes, suggesting mixing of a dry gas charge from the Malita Graben, with liquids from a less mature kitchen. Very ^{13}C enriched methane in the Kelp Deep 1 gas implies that it was expelled from a Permian source (PZ 50) at relatively high maturity.

Petrel Sub-basin and Bonaparte Inboard Shelf Areas (Figure 26)

The Petrel Basin area is described by Colwell and Kennard (1996), McConchhie et al. (1996) and Edwards et al. (1997), and the Bonaparte Inboard Shelf area is described by Gorter et al. (1998). The Petrel Sub-basin and Bonaparte Inboard Shelf at the end of 2001 contained 18 field discoveries and 65 exploration wells with a historical technical success rate of 28% and a 8% historical success rate for fields greater than 20 mmboe. The sub-basin is estimated to contain (scope) reserves of 3.9 Tcf of gas, 7 mmbbls of condensate and 19 mmbls of oil which equates to a 3%/1%/96% oil/condensate/gas volume split respectively by boe. No fields in these areas have been developed.

The large gas fields in the area include older discoveries such as Petrel and Tern (Gunn, 1988b) and the more recent discoveries of Rubicon and Blacktip. All of these discoveries are faulted anticlines (some salt-cored) or tilted fault block traps at the regional base Triassic seal level, and contain dry gas within PZ50 (Permian) sands. The oil fields include the Turtle and Barnett PZ30 accumulations within faulted horst block structures.

The Turtle and Barnett oils correlate with a Carboniferous (PZ30) marine shale seen in onshore mineral exploration wells (Edwards et al., 1997) but not yet observed in offshore wells. By contrast, the Petrel and Tern gas accumulations are attributed to Permian fluvio-deltaic sediments, largely on the basis of their ^{13}C enriched isotope composition. There is some danger of interpreting every isotopically heavy fluid as Permian in origin as high maturity can also be responsible for enrichment in ^{13}C, however, similarities in the fluid signature to stains and inclusion oils at Torrens 1 to the west emphasise the widespread viability of the Permian source. The liquids potential of this system is yet to be proven, although palaeo-oil indications in Torrens and Osprey (Vulcan Sub-Basin) are encouraging (Kennard et al., 2000). The relative volumes of oil and gas in the Palaeozoic sections in the Petrel area are small in comparison with the dominantly Mesozoic sub-basins elsewhere along the margin (Figure 26).

Summary

There are large portions of the North West Shelf that do not contain effective hydrocarbon source rock sequences.

Within areas that do have effective source rock there are three broad types:

- Areas with thick Cretaceous sections with laterally-drained, high-impedance migration from gas-mature J20 deltaic source rock sequences, which have resulted in efficient gas flushing of basinal areas at the base regional seal level (Caswell and Malita sub-basins and western basinal areas of Barrow and –Dampier sub-basins). These areas have potential for overlying, vertically-drained, low-impedence style Cretaceous-sourced oil plays that are protected from the underlying gas by the regional seal.
-
- Areas with thin Cretaceous sections where J40 (and/or J20/J30 oil-prone source rocks are in the oil window and a laterally-drained, high-impedance migration style together with effective underlying aquicludes protects the base regional seal oil accumulations from gas-flushing (e.g. central/western Dampier Sub-basin and eastern Exmouth Sub-basin). These areas have potential for deeper sub-base regional seal gas accumulations both beneath the basinal oily areas and on the flanks of the basin.
-
- Areas with thin Cretaceous sections where J40 (and/or J20/J30 oil-prone source rocks are in the oil window and a vertically-drained, lower impedence, migration style results in a mixed oil and gas (from deeper units) charge to the base regional seal level. Selective enrichment of some pools in oil, due to dynamic leakage of gas and/or water washing, then occurred (Vulcan, Flamingo, eastern flank of Barrow-Dampier). The most likely

primary control on the effectiveness of this dynamic leakage is Neogene tectonism as almost all the significant oil accumulations have been reactivated by Neogene tectonism. Limited potential exists for major gas accumulations at levels deeper than the base regional seal.

Other generally gassy minor petroleum systems falling outside of the above petroleum system types do exist on the Exmouth Plateau and within the Petrel Sub-basin.

Remaining Potential (Figures 23, 25, 27, 35)

A comparison of the estimates of the remaining hydrocarbon potential for the major basins of the North West Shelf has been made by Powell (2001) and the preferred published P50 estimates after AGSO are 1330 mmbbls of oil and 28Tcf of gas. The United States Geological Survey (USGS) estimates for the remaining potential along the whole North West Shelf (USGS, 2000), namely 4721 mmbbls of oil, 5696 mmbbls of condensate and 107Tcf of gas (at the mean level), are not considered to be tenable realistic estimates, and in our opinion are wildly optimistic.

The additional 28Tcf of undiscovered gas reserves predicted by AGSO (Powell, 2001), together with considerable associated condensate is credible, given the large under-explored area, the 'gassy' nature of the margin and the focus to date on oil exploration. The discovery history (creaming) curve for gas is also still strongly growing (Figure 23) and supports this large estimate. Unfortunately, this estimate is largely academic, given that an estimated 119Tcf of discovered gas is not yet developed. Only gas which is adjacent to existing producing facilities and can compete for production ullage on a value basis will attract any exploration focus in the short-medium term.
The key question is what is the remaining oil potential along the margin. This can be divided into two parts; namely:
1. Are there any remaining unproven oil sub-basins still to be discovered along the margin? and
2. What is the remaining oil potential in the existing 'oily' sub-basins?

The question of finding an unproven sub-basin is clear. There are no obvious untested Late Jurassic rift basins with marine anoxic (J40) source intervals within the oil-window, so alternate oily source models are required. As discussed above, evidence for a significant deltaic (J30-J20) oil contribution exists in the Dampier, Beagle, Vulcan and Flamingo areas. The J20 section is believed to be the main source interval for the Browse and Malita/Sunrise gas fields and is clearly the prime interval likely to provide future oil charge elsewhere. The key future challenge is to apply a model which will decrease oil source presence risk within this interval (the delta front enrichment models, Figure 35, or any other valid model), since oil-quality source intervals appear to be only sporadically developed. Even if this strategy is successful, the generated oily product will have to be protected from trap breach and gas flushing and/or it will have to be enriched through dynamic gas leakage.

An alternate way of evaluating the new oil sub-basin possibility, is to look at historical trends. In general, the history of oil discovery on the North West Shelf, is that new productive oil sub-basin areas have progressively been discovered by wildcat exploration, throughout the region's history (Figure 25). Five provinces have been discovered since 1963 (Barrow, Dampier, Vulcan, North Flamingo and Exmouth). This equates to one every 8 years or about one in every 150 exploration wells. Recoverable volumes discovered in these oil areas have been progressively smaller. Exmouth was the last sub-basin area where discoveries were made (Vincent and Enfield in 1999) (Figure 25). Consequently, it may be many years and take many more dry wells, before another significant oil discovery. As the exploration maturity of the margin increases, it becomes increasingly improbable that a major oil province will remain undiscovered.

The remaining potential in existing proven 'oily' areas is perceived to be relatively low because:

- Four of the five 'oily' areas appear to show a mature ("creamed") discovery history curve character (Figure 25). Only the Exmouth Sub-basin still has a rapidly growing discovery trend.

- The vast majority of oil discovered to date has been within simple traps at the base regional seal level which were mappable on 2D seismic data (Figure 27).

- The testing of other trap types and deeper play levels has been largely unsuccessful because, beneath the regional seal, the section is generally sandy, leaky or gas-flushed and the post-regional seal level is generally uncharged or leaky.

- The majority of the base regional seal targets are beneath the amplitude floor or the quality of the current 3D seismic is so poor that direct hydrocarbon detection of oil is very difficult.

The key question, in proven oily areas of the North West Shelf, is can the 3D seismic data be improved to a quality that will directly image oil in the sub-surface? If the answer is no, then the oil future for the province is limited and the emphasis will remain on the discovered and undiscovered gas. Expansion of LNG facilities, floating LNG and gas-to-liquids technology, will become the key enablers in the North West Shelf's bright future.

In summary, the future potential for significant large gas discoveries along the North West Shelf is very high. However, the probability of discovering a previously unknown significant 'oily' sub-basin is perceived to be low, using current 3D seismic technology.

Conclusions

The North West Shelf is a gas province with minor oily sweet spots. These sweet spots are largely approaching exploration maturity. The perception is that current technology appears to be limited in its ability to define any remaining oil target of significance. Woodside and its partners on the North West Shelf are committed to ongoing oil exploration and will continue to apply and develop new technologies capable of unleashing the next suite of exploration successes. The probability discovering new 'oily areas' elsewhere along the margin, is perceived to be low. The potential for further significant gas discoveries is good, but with an estimated 119 Tcf of undeveloped gas reserves, there is only limited demand in the short term for exploration targeting gas adjacent to existing infrastructure.

Woodside has considerable existing discovered and undeveloped gas reserves on the North West Shelf. However, the commercialisation of these reserves will be market driven. Only oil discoveries, have the potential to generate early returns. This study has shown that (as suspected in 1998) the probability of discovering significant quantities of oil along the North West Shelf is believed to be fair at best and is high risk. Woodside will continue to pursue opportunities, however, it must balance its portfolio by targeting low risk and commercially attractive oil-prone areas, to deliver maximum shareholder value and growth.

Significant oil and gas discoveries will continue to be made along the North West Shelf in the future. Woodside will be a part of this continued exploration effort and will also allocate a proportion of its exploration effort overseas. Future technological breakthroughs may revitalise the region, as will surprise exploration results, which have regularly occurred throughout the region's history. The North West Shelf is a fascinating, complex hydrocarbon province. The future potential is unpredictable and new discoveries might be spectacular.

References

AGSO NORTH WEST SHELF STUDY GROUP, 1994, Deep Reflections on the North West Shelf: Changing Perceptions of Basin Formation, in PURCELL, P.G., and PURCELL, R.R., (Eds), 1994, *The Sedimentary Basins of Western Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 63-76.

AGSO/GEOMARK, 1996, The Oils of Western Australia – Petroleum Geochemistry and Correlation. *Australian Geological Survey Organisation and Geomark Research Inc.*, March 1996, unpublished.

AGSO/GEOTECH, 2000, Characterisation of Natural Gases from West Australian Basins, *Australian Geological Survey Organisation and Geotechnical Services*, Multiclient non-exclusive report, unpublished.

APACHE, 2002, Recent discoveries in the Barrow Sub-basin, in M. Keep and S.J. Moss (Eds), The Sedimentary Basins of Western Australia 3: Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth WA.

ARDITTO, P.A., 1996, A sequence stratigraphic study of the Callovian fluvio-deltaic to marine succession within the ZOCA region. APPEA Journal 36(1), 269-283.

AULD, K., THOMAS, B., GOODALL, J. ELLIOT, L., and BENSON, J., 2002, The Johns Brookes gas – the road to discovery, in M. Keep and S.J. Moss (Eds), The Sedimentary Basins of Western Australia 3: Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth WA.

BAILLIE, P.W., and JACOBSON, E.P., 1997, Prospectivity and exploration history of the Barrow sub-basin, Western Australia, *The APPEA Journal,* 37 (1), 117-135.

BAILLIE, P.W., POWELL, C.McA., LI, Z.X., and RYALL, A.M., 1994, The tectonic framework of Western Australia's Neoproterozoic to Recent Sedimentary Basins, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 45-62.

BALLESTEROS, M., 1998, Recent discoveries in the Barrow and Dampier sub-basins: Agincourt, Alkimos, Wonnich, Reindeer and Legendre fields, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1998, 541-551.

BARBER, P.M., 1988, The Exmouth Plateau deep water frontier: a case history. The North West Shelf, Australia. in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 173-187.

BARR, D.C., KENNARD, A.F., FOWLES, J., MARSHALL, N., and CUTTEN, V.L., 2001, Determining Reservoir Continuity in the Laminaria Formation by integrated geological study, *The APPEA Journal*, 41 (1), 415-428.

BAUER, J.A., HOOPER, E.C.D., and CROWLEY, J., 1994, The Leatherback Discovery, Carnarvon Basin, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 573-582.

BEACHER, G.J., McLERIE, M.K., and MILLER, N.W, 1994, Recent WAPET Discoveries near Thevenard Island, Southeast Barrow Sub-basin, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 639-642

BENTLEY, J. 1988 The Candace Terrace - a geological perspective. The North West Shelf, Australia. in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 157-171.

BINT, T, 1988, Gas fields of the Browse Basin, in PURCELL, P.G., and PURCELL,R.R. (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 413-417.

BISHOP, D.J., and O'BRIEN, G.W., 1998, A multi-disciplinary approach to definition and characterisation of carbonate shoals, shallow gas accumulations and related complex near-surface sedimentary structures in the Timor Sea, *The APPEA Journal*, 38 (1), 93-114

BOREHAM, C.J., HOPE, J.M., and HARTUNG-KAGI, B., 2001, Understanding source, distribution and preservation of Australian natural gas: A geochemical perspective, *The APPEA Journal*, 41 (1), 523-547.

BLEVIN, J.E.; Stephenson, A.E.; and West, B.G., 1994, Mesozoic structural development of the Beagle Sub-basin - implications for the petroleum potential of the northern Carnarvon Basin in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia :* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 479-496.

BLEVIN, J.E., STRUCKMEYER, H.I.M., CATHRO, D.L., TOTTERDELL, J.M., BOREHAM, G.J., ROMINE, K.K., LOUTIT, T.S., and SAYERS, J., 1998a, Tectonostratigraphic Framework and Petroleum systems of the Browse Basin, North West Shelf, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1998, 369-396.

BLEVIN, J.E., BOREHAM, G.J., SUMMONS, R.E., STRUCKMEYER, H.I.M., and LOUTIT, T.S., 1998,b, An effective Lower Cretaceous Petroleum System on the North West Shelf: Evidence from the Browse Basin, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1998, 397-420.

BRADSHAW, M.T., 2001, Australia and Eastern Indonesia at the cross-roads of Gondwana and Tethys - the implications for petroleum resources, SEAPEX Exploration Conference, Abstract, Singapore 4th-6th April, 2001.

BRADSHAW, J., SAYERS, J.; BRADSHAW, M.; KNEALE, R.; FORD, C., SPENCER, L., LISK, M., 1998, Palaeogeography and its impact on the petroleum systems of the North West Shelf, Australia in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1998, 95-121.

BRADSHAW, M.T., BRADSHAW, J., MURRAY, A.P., NEEDHAM, D.J., SPENCER, L., SUMMONS, R.E., WILMOT, J., and WINN, S, 1994, Petroleum systems in west Australian basins, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 93-118.

BRADSHAW, M.T., YEATES, A.N., BEYNON, R.M., BRAKEL, A.T., LANGFORD, R.P., TOTTERDELL, J.M., and YEUNG, M., 1988, Palaeogeographic evolution of the North West Shelf region in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 29-54.

BRANSDEN, P.J.E., and MATTHEWS, S.J., 1992, Structural and Stratigraphic Evolution of the East Java Sea, Indonesia, Proceedings of the Indonesian Petroleum Association Annual Convention, 21 (1), 417-453.

BRINCAT, M.P., O'BRIEN, G.W., LISK, M., DE RUIG, M., and GEORGE, S.C., 2001, Hydrocarbon charge history of the Northern Londonderry High: implications for trap integrity and future prospectivity. The APPEA Journal, 41 (1), 483-496.

BROOKS, D.M., GOODY, A.K., O'REILLY, J.B., and McCARTY, K.L., 1996, Bayu/Undan gas-condensate discovery: Western Timor gap zone of cooperation, area A, The APPEA Journal, 36 (1), 142-160.

BUSSELL, M.R., JABLONSKI, D., ENMAN, T., WILSON, M.J., and BINT, A.N., 2001, Deepwater Exploration: North Western Australia compared with Gulf of Mexico and Mauritania, *The APPEA Journal*, 41 (1), 289-319.

CASAGRANDE, D.J., 1987, Sulphur in peat and coal in SCOTT, A.C. (Ed.): Coal and Coal-bearing Strata: Recent Advance, Geological Society Special Publication 32, 87-105.

CLARE, A.P., and CROWLEY, A.J., 2001, Qualitative analysis of spectral gamma ray data as a tool for fieldwide and regional stratigraphic correlation, Enderby Terrace, Carnarvon Basin, Western Australia. *The APPEA Journal, 41 (1), 449-462.*

COWELL, J.B., and STAGG, H.M.J. 1994, Structure of the offshore Canning Basin: first impressions from a new regional deep-seismic data set in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 757-768.

COLWELL, J.B., AND KENNARD, J.M., 1996, AGSO Petrel Sub-basin Study 1995-96, Summary Report, *AGSO record* 1996/40.

COWLEY, R., AND O'BRIEN, G.W., 2000, Identification and interpretation of leaking hydrocarbons using seismic data: a comparative montage of examples from the major fields of Australia's north west shelf and Gippsland Basin, *The APPEA Journal*, 40 (1), 121-150.

CRAIG, A., SIT, H., SHERIDAN, P., AND MACLEAN, L., 1997, A geophysical appraisal of the East Spar gas/condensate field, *The APPEA Journal*, 37 (1), 12-30.

CROSTELLA, A., and BOREHAM, C.J., 2000, Origin, distribution and migration patterns of gas in the Northern Carnarvon Basin, *The Petroleum Exploration Society of Australia Journal*, 28, 7-20.

CROWLEY, J., and COLLINS, E.S., 1996, *The Stag Oilfield*, *The APPEA Journal*, 36 (1), 130-141.

DEMAISON, G., and HUIZINGA, B.J., 1994, Genetic Classification of petroleum systems Using three factors Charge, Migration, and Entrapment, in MORGAN, L.B., and DOW, W.G., (Eds), *The Petroleum System from source to trap*, American Association Petroleum Geologists Memoir, 60, 73-89

DELFOS, E. 1994, Wandoo oil field: a formation evaluation case history. in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia :* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 615-631.

DELFOS, E., and DEDMAN, R., 1988, The petroleum potential of the Peedamullah Shelf. in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 147-156.

DE RUIG, M.J., TRUPP, M., BISHOP, D.J., KUEK, D., and CASTILLO, D.A., 2000, Fault architecture and the mechanics of fault reactivation in the Nancar Trough/Laminaria area of the Timor Sea, *The APPEA Journal*, 40 (1), 174-193.

DICKINSON, J.A., WALLACE, M.W., HOLDGATE, G.R., DANIELS, J., GALLAGHER, S.J., and THOMAS, L., 2001, Neogene Tectonics in SE Australia: implications for petroleum systems, *The APPEA Journal*, 41 (1), 37-52.

DI TORO, G.A.E., 1994, The reservoir geology of the Wanaea and Cossack oil fields, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 557-572.

DOLAN and ASSOCIATES, GEOTECHNICAL SERVICES, PETROLEUM GEOLOGICAL ANALYSIS PTY LTD and WA CENTRE FOR PETROLEUM EXPLORATION, 2000, Mesozoic Source Rocks Database Bonaparte Basin, Browse Basin and Carnarvon Basin, Mesozoic Source Rocks of Western Australia, (unpublished).

EDWARDS, D.S., SUMMONS, R.E., KENNARD, J.M., NICOLL, R.S., BRADSHAW, J., BRADSHAW, M., FOSTER, C.B., O'BRIEN, G.W., and ZUMBERGE, J.F., 1997, Geochemical characteristics of Palaeozoic petroleum systems in northwestern Australia, *The APPEA Journal*, 37, 351-379.

EDWARDS, D.S., KENNARD, J.M., PRESTON, J.C., BOREHAM, C.J., SUMMONS, R.E., and ZUMBERGE, J.E., 2001, Geochemical evidence for numerous Mesozoic petroleum systems in the Bonaparte and Browse Basins, Northwestern Australia. Abstracts of the AAPG Annual Meeting, Denver, Colorado, June 3-6, 2001, *American Association of Petroleum Geologists Bulletin*, 85 (13).

EDWARDS, D.S., KENNARD, J.M., PRESTON, J.C., SUMMONS, R. E., BOREHAM, C.J., AND ZUMBERGE, J.E., 2002, Geochemical Characteristics of Hydrocarbon Families And Petroleum Systems in the Bonaparte Basin, Northwestern Australia, AGSO Research Newsletter.

ELLIS, G., 1987, Lower Cretaceous radiolarian biostratigraphy and depositional environment of the Windalia Radiolarite, Carnarvon Basin, Western Australia. Honours Thesis, University of Western Australia, unpublished.

ELLIS, G.K., 1988, Diagenesis of the Talisman 1 reservoir sequence, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 237-249.

ELLIS, G.K., and JONASSON, K., 2002, Rough Range Oilfield Carnarvon Basin, in M. Keep and S.J. Moss (Eds), The Sedimentary Basins of Western Australia 3: Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth WA.

ELLIS, G.K., PITCHFORD, A., and BRUCE, R.H., 1999, *Barrow Island oil field*, *The APPEA Journal,* 39 (1), 158-176.

FORMAN, D.J AND WALES, D.W., 1981, Geological evolution of the Canning Basin, Western Australia, *Bureau of Mineral Resources, Geology and Geophysics Bulletin,* 210, 91p.

GEORGE, S.C., LISK, M., SUMMONS, R.E., and QUEZADA, R.A., 1998, Constraining the oil charge history of the South Pepper oilfield from the analysis of oil-bearing fluid inclusions, *Organic Geochemistry,* 29, 631-648

GEORGE, S.C., VOLK, H., RUBLE, T.E., and BRINCAT, M.P., 2002, Evidence for a new oil family in the Nancar Trough area, Timor Sea, *The APPEA Journal,* 42 (1), 387-404.

GENRICH, J.F., BOCK, Y., McCAFFREY, R., CALAIS, E., STEVENS, C.W., and SUBARYA, C., 1996, Accretion of the southern Banda arc to the Australian plate margin determined by Global Positioning System measurements, *Tectonics*, 15, 288-295.

GORTER, J.D., and KIRK, A.S., 1995, The Kimmeridgian marl in the Timor Sea: Relevance to regional geological evolution and possible hydrocarbon plays, *The APPEA Journal,* 35 (1), 152-168.

GORTER, J.D., ZIOLKOWSKI, V., and BAYFORD, S.W., 1998, Evidence of Lower Triassic reservoirs with possible hydrocarbon charge in the southern Bonaparte Basin in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 229-235.

GORMAN, I. G. D. 1990, The role of reservoir simulation in the development of the Challis and Cassini fields, *The APPEA Journal*, 30 (1), 212-221.

GUNN, P.J., 1988a, Bonaparte Basin: evolution and stratigraphic framework, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 275-286.

GUNN, P.J., 1988b, Hydrocarbon discoveries in the Bonaparte Basin, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 419-424.

HASTON, R.B., and FARRELLY, J.J., 1993, Regional significance of the Arquebus-1 well, Browse Basin, North West Shelf, Australia. APEA Journal 33(1), 28-38.

HEARTY, D., and BATTRICK, M., 2002, The Woolybutt oilfield, an odyssey from prospect, through discovery to development, in M. Keep and S.J. Moss (Eds), The Sedimentary Basins of Western Australia 3: Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth WA.

HELBY, R., MORGAN, R., AND PARTRIDGE, A.D., 1987. A palynological zonation of the Australian Mesozoic, *Memoir of the Association of Australasian Palaeontologists,* 4, 1-94.

HILL, K.C., and RAZA, A., 1999, Arc-continent collision in Papua Guinea: Constraints from fission track thermochronology, *Tectonics*, 18, 950-966.

HILLIS, R.R, MILDREN, S.D., PIGRAM, C.J., and WILLOUGHBY, D.R., 1997, Rotation of horizontal stresses in the Australian North West Shelf continental shelf due to the collision of the Indo-Australian and Eurasian Plates, *Tectonics,* 16, 323-335.

HOLDGATE, G.R., AND CLARKE, J.D.A., 2000, A review of Tertiary brown coal deposits in Australia – their depositional factors and eustatic correlations, *American Association of Petroleum Geologists Bulletin*, 84, 1129-1151.

HORSTMAN, E.L., AND PURCELL, P.G., 1988, The offshore Canning Basin - a review, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 253-257.

HOVLAND, M., CROCKWER, P.F., and MARTIN, M., 1994, Faults-associated seabed mounds (carbonate knolls?) off western Ireland and north-west Australia, *Marine and Petroleum Geology*, 11, 232-246.

HOWELL, E.A., 1988, The Harriet Oilfield, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 391-401.

INGRAM, G.M., EATON, S., and REGTIEN, J.M.M., 2000, Cornea case study: lessons for the future, *The APPEA Journal*, 40 (1), 56-65.

JABLONSKI, D., 1997, Recent advances in the sequence stratigraphy of the Triassic to Lower Cretaceous succession in the northern Carnarvon Basin, Australia, *The APPEA Journal*, 37 (1), 429-454.

JAMES, A.T., and BURNS, B.J., 1984, Microbial alteration of subsurface natural gas accumulations. AAPG Bulletin 68(8), 957-960.

KAIKO, A.R., and TAIT, A.M., 2001, Post-rift tectonic subsidence and paleo-water depths in the Northern Carnarvon Basin, Western Australia, *The APPEA Journal,* 41 (1), 367-380.

KEEP, M., LONGLEY, I., and JONES, R., 2002, The Sumba enigma and its effect on Australia's northwest margin, in HILLIS, R.R., AND MULLER, R.D., (Eds), *The Evolution and Dynamics of the Australian Plate*, Joint Special Publication of GS Aust and Geol. Soc. America, in press.

KENNARD, J.M., JACKSON, M.J., ROMINE, K.K., SHAW, R.D., and SOUTHGATE, P.N., 1994, Depositional sequences and associated petroleum systems of the Canning basin, WA, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 657-676.

KENNARD, J., EDWARDS, D.S., BOREHAM, C.J., GORTER, J.D., KING, M.R., RUBLE, T.E., and LISK, M., 2000, Evidence for a Permian Petroleum System in the Timor Sea, Northwestern Australia, Abstract from the AAPG International Conference and Exhibition, October 15-18, 2000, Bali, Indonesia, *American Association of Petroleum Geologists Bulletin*, 84 (9), pp.1395-1518

KINGSLEY, D.R.; THOMPSON, M.J.; HARRIS, D.P., and FOWLES, J., 1998, Lambert 2 oil and gas discovery, Carnarvon Basin in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 515-526.

KINGSLEY, D.R., and TILBURY, L.A., 1999, Impact of 3D seismic on exploration and drilling success in the Dampier Sub-basin, WA, *The APPEA Journal* 39 (1), 87-103.

KINGSLEY, D.R., THOMPSON, M.J., HARRIS, D.P., and FOWLES, J., 1998, Lambert 2 Oil and Gas Discovery, Carnarvon Basin, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1998, 515-526.

LARTER, S., HOCKEY, A., APLIN, A., TELNAES, N., WILHELMS, A., HORSTAD, I., DI PRIMIO, R., and SYLTA, O., 1999, *When biodegradation preserves petroleum: North Sea oil rimmed gas accumulations (ORGA's).* In: SCHOELL, M., and CLAYPOOL, G.E., (Eds.), Proceedings of the American Association of Petroleum Geologists Hedberg Research Conference, June 6-10, 1999.

LIPSKI, P., 1994, Structural framework and depositional history of the Bedout and Rowley Sub-basins, In: PURCELL, P.G., and PURCELL, R.R., (Eds), 1994, *The Sedimentary Basins of Western Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994,769-777.

LONGLEY, I.M., BRADSHAW, M.T., and HEBBERGER, J., 2002, Australian Petroleum Provinces of the 21st Century, in DOWNEY, M.W., and MORGAN, W.A., (Eds), *Petroleum Provinces of the twenty-first century*, American Association of Petroleum Geologists Memoir, 74, 287-317.

MAGOON L.B., and DOW, W.G., 1994, The petroleum system – from source to trap, *American Association of Petroleum Geologists Bulletin*, 75 (3), 3-25.

MAUNG, T.U., CADMAN, S., and WEST, B., 1994, A review of the petroleum potential of the Browse Basin in PURCELL, P.G., and PURCELL, R.R., (Eds), 1994, *The Sedimentary Basins of Western Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 333-346.

McCLURE, I.M., SMOTH, D.N., WILLIAMS, A.F., CLEGG, L.J., and FORD, C.C., 1988, Oil and Gas Fields in the Barrow sub-basin, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 372-390.

McCAFFREY, R., 1996, Slip partitioning at convergent plate boundaries of SE Asia, in HALL, R., and BLUNDELL, D., (Eds*), Tectonic Evolution of Southeast Asia:* Geological Society Special Publication, 106, 3-18,

McCONACHIE, B.A., BRADSHAW, M.T., and BRADSHAW, J., 1996, Petroleum systems of the Petrel Sub-basin – an integrated approach to basin analysis and identification of hydrocarbon exploration opportunities, *The APPEA Journal*, 36 (1) , 248-268.

METCALFE, I., 1999, Gondwana dispersion and Asian accretion: An overview, in METCALFE, I., (Ed), *Gondwana Dispersion and Asian Accretion* – IGCP 321 Final Results Volume, A.A. Balkema, Rotterdam, 9-28.

MORY, A.J., 1988, Regional geology of the offshore Bonaparte Basin, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 287-309.

MULLER, R.D., MIHUT, D., and BALDWIN, S., 1998, A new kinematic model for the formation and evolution of the west and northwest Australian margin in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 55-72.

MULLER, D, GAINA, C., TIKKU, A., MIHUT, D., CANDE, S.C., and STOCK, J.M., 2000, Mesozoic/Cenozoic Tectonic Events around Australia, in, *The History and Dynamics of Global Plate Motions*, Geophysical Monograph 121, American Geophysical Union, 161-188.

NELSON, W. A., 1989, Jabiru field - horst, sub-horst or inverted graben? *The APPEA Journal*, 29 (1), 176-194

NELSON, W. A., 1990, Wrench interpretation of the Jabiru oil field, Australia. *American Association of Petroleum Geologists Bulletin* 74(5), 729.

NEWELL, N.A., 1999, Water washing in the Northern Bonaparte Basin, *The APPEA Journal*, 39 (1), 227-247.

NICOLL, R.S., and FOSTER, C.B., 1994, Late Triassic conodont and palynomorph biostratigraphy and conodont thermal maturation, North West Shelf, Australia. AGSO Journal of Australian Geology and Geophysics, 15(1), 101-118

NORVICK, M.S., and SMITH, M., A., 2001, Mapping the plate tectonic reconstruction of southern and south eastern Australia and implications for petroleum systems, *The APPEA Journal*, 41 (1), 15-36.

NORVICK, M.S., SMITH, M.A., and POWER, M.R., 2001, The Plate Tectonic Evolution of Eastern Australia Guided by the Stratigraphy of the Gippsland Basin, in HILL, K.C., and BERNECKER, T., (Eds) *Eastern Australian Basins, A Refocussed Energy Perspective for the Future*: Petroleum Exploration Society of Australia, Special Publication, 15-24.

O'BRIEN, G.W., AND WOODS, E.P., 1995, Hydrocarbon-related Diagenetic Zones (HRDZ's) in the Vulcan Sub-basin, Timor Sea: Recognition and Exploration Implications, *The APPEA Journal*, 35 (1), 200-251.

O'BRIEN, G.W., GLENN, K., LAWRENCE, G., WILLIAMS, A.K., WEBSTER, M., BURNS, S., and COWLEY, R., 2002, Influence of Hydrocarbon migration and seepage on benthic communities in the Timor sea, Australia, *The APPEA Journal*, 42 (1), 225-239.

OSBORNE, M., 1990, The exploration and appraisal history of the Skua field, AG/P2 - Timor Sea, *The APPEA Journal*, 30 (1), 197-211

OSBORNE, D.G., 1994, Nebo oil discovery, Beagle Sub-basin in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 653-654.

PALLASSER, R.J., 2000, Recognising biodegradation in gas/oil accumulations through the $d^{13}C$ compositions of gas components, *Organic Geochemistry*, 31, 1363-1373

PARRY, J.C., and SMITH, D.N., 1988, The Barrow-Exmouth Sub-basins, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 129-145.

PATTILLO, J., and NICHOLLS, P.J., 1990, A tectonostratigraphic framework for the Vulcan Graben, Timor Sea Region, *The APPEA Journal*, 30 (1), 27-51.

PEPPER, A.S and CORVI, P.J., 1995, Simple kinetic models of petroleum formation Part 1: Oil and gas generation from Kerogen, *Marine and Petroleum Geology*, 12, 291-319.

PETERS, K.E., 1986, Guidelines for evaluating petroleum source rocks using programmed pyrolysis, *American Association Petroleum Bulletin*, 70, 318-329

POCKALNY, R.A., FOX, P.J., FORNARI, D.J., MACDONALD, K.C., AND PERFIT, M.R., 1997. Tectonic reconstruction of the Clipperton and Siqueiros Fracture Zones: Evidence and consequences of plate motion change for the last 3 Myr, Journal of Geophysics Resolution Solid Earth, 102, 3167-3181.

POWELL, T.G., 2001, Understanding Australia's Petroleum Resources, Future production trends and the role of the frontiers, *The APPEA Journal*, 41 (1), 273-287.

PRESTON, J.C., and EDWARDS, D.S., 2000, The petroleum geochemistry of oils and source rocks from the Northern Bonaparte Basin, offshore Northern Australia, *The APPEA Journal*, 40 (1), 257 – 281.

PRYER, L.L., ROMINE, K.K., LOUTIT, T.S., and BARNES, R.G., 2002, Carnarvon basin architecture and structure defined by the integration of mineral and petroleum exploration tools and techniques, *The APPEA Journal*, 42 (1), 287-309.

PURCELL, P.G., and PURCELL, R.R, 1988a, The North West Shelf, Australia - An Introduction, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 3-15,

PURCELL, P.G., and PURCELL, R.R., (Eds), 1988b, *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society, Australia, Perth, 1988**.**

PURCELL, P.G., and PURCELL, R.R., (Eds), 1994, *The Sedimentary Basins of Western Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 1 - 15.

PURCELL, P.G., and PURCELL, R.R., (Eds), 1998, *The Sedimentary Basins of Western Australia 2*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1998, v.

RAVNAS, R., and STEEL, R.J., 1998, Architecture of marine Rift-Basin successions, *American Association of Petroleum Geologists Bulletin*, 82, 110-146.

SCOTT, J., 1992. Accurate recognition of source rock character in the Jurassic of the North West Shelf, Western Australia, *The APPEA Journal*, 32 (1), 289-299.

SCOTT, J., 1994, Source rocks of Western Australia, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 141-155.

SEGGIE, R.J., AINSWORTH, R.B., JOHNSON, D.A., KONINX, J.P.M., SPAARGAREN, B., AND STEPHENSON, P.M., 2000, Awakening of a sleeping giant: Sunrise-Trobadour gas-condensate field, *The APPEA Journal*, 40 (1), 417-435.

SIBLEY, D., HERKENHOFF, F., CRIDDLE, D., and McLERIE, M., 1999, Reducing resource uncertainty using seismic amplitude analysis on the southern Rankin Trend, northwest Australia, *The APPEA Journal*, 39 (1), 128-148.

SIT, K.H., HILLOCK, P.M., and MILLER, N.W.D., 1994, The Maitland gas discovery - a geophysical/petrophysical case history in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 597-613.

SMITH, G.C., TILBURY, L.A., CHATFIELD, A., SENYCIA, P., and THOMPSON, N.B., 1996, Laminaria: a new Timor Sea discovery, *The APPEA Journal*, 36 (1), 12-29.

SMITH, P.M., and SUTHERLAND, N.D., 1991, Discovery of salt in the Vulcan Graben, A geophysical and geological evaluation, *The APPEA Journal*, 31 (1), 229-243.

SMITH, S.A, TINGATE, P.R, GRIFFITHS, C.M AND HULL, J.N.F, 1999, The structural development and petroleum potential of the Roebuck Basin, *The APPEA Journal*, 39 (1), 364-385

SPRY, T.B., 1993, Source Potential Index (SPI) as a hydrocarbon prospectivity ranking factor in Australian basins, BSc (Hons), University of Adelaide, unpublished.

SPRY, T., and WARD, I., 1997, The Gwydion discovery: a new play fairway in the Browse Basin, *The APPEA Journal*, 37 (1), 87-104.

STRUCKMEYER, H.I.M., BAXTER, K., BLEVIN, J.E., and CATHRO, D.L. 1977, Palaeozoic rift basin evolution in the Browse Basin, Northwest Shelf, *PESA News*, June/July 1977, 50-51.

STRUCKMEYER, H.I.M.; BAXTER, K.; BLEVIN, J.E., and CATHRO, D.L., 1997, Palaeozoic rift basin evolution in the Browse Basin, Northwest Shelf. PESA News, April-May, 62-63.

STRUCKMEYER, H.I.M, BLEVIN, J.E., SAYERS, J., TOTTERELL, J.M., BAXTER, K., and CATHRO, D., 1998, Structural Evolution of the Browse basin, North West Shelf: New Concepts from deep seismic data, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1998, 345-367.

SUMMONS, R.E., BRADSHAW, M., CROWLEY, J., EDWARDS, D.S., GEORGE, S.C., and ZUMBERGE, J.E., 1998, Vagrant oils: geochemical signposts to unrecognised petroleum systems. in: PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2*. Proceedings of the Petroleum Exploration Society of Australia, Perth, 1998, 169-184.

SYKES, M.P., and DAS, U.C., 2001, Directional filtering for linear feature enhancement in geophysical maps. Geophysics, 65, 1758-1768.

TAYLOR, M.L., THOMPSON, N.B., and TAYLOR, N.C., 1998, The Perseus field, North West Shelf, Australia; a giant gas accumulation in a complex structural/stratigraphic trap, *The APPEA Journal*, 38 (1), 52-67.

TINDALE, K., NEWELL, N., KEALL, J., and SMITH, N., 1998, Structural evolution and charge history of the Exmouth Sub-basin, northern Carnarvon Basin, western Australia, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1998, 447-472.

TINGATE, P.R., KHAKSAR, A., VAN RUTH, P., DEWHURST, D., RAVEN, M., YOUNG, H., HILLIS, R., and DODDS, K., 2001. Geologic controls on overpressure in the northern Carnarvon basin, *The APPEA Journal*, 41 (1), 573-593.

US GEOLOGICAL SURVEY WORLD ENERGY ASSESSMENT TEAM, 2000, *US Geological Survey World Petroleum Assessment 2000*, USGS Digital data Series 60, 4 CD-ROMS.

VAN AARSSEN, B.G.K., ALEXANDER, R., and KAGI, R.I., 1996, The origin of Barrow Sub-Basin crude oils: A geochemical correlation using land-plant biomarkers, *The APPEA Journal*, 1996, 465-476.

VAN AARSSEN, B.G.K., ALEXANDER, R., and KAGI, R.I., 2000, Reconstructing the geological history of Australian crude oils using aromatic hydrocarbons, *The APPEA Journal*, 40, 283-292.

VOLKMAN, J.K., ALEXANDER, R., KAGI, R.I., NOBLE R.A., and WOODHOUSE, G.W., 1983, A geochemical reconstruction of oil generation in the Barrow Sub-Basin of Western Australia, *Geochemical. Cosmochim. Acta*, 47, 2091-2105.

VINCENT, P., and TILBURY, L., 1988, Gas and oil fields of the Rankin Trend and northern Barrow-Dampier Sub-basin, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The North West Shelf, Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1988, 341-369.

WHITTAM, D.B., NORVICK, M.S., and MCINTYRE, C.I., 1996, Mesozoic and Cainozoic tectonostratigraphy of western ZOCA and adjacent area, *The APPEA Journal*, 36 (1), 209-232.

WILKINSON, R., 1991, *Where God Never Trod*: David Ell Press Pty Ltd, Australia.

WILLETTS, J.M., MASON, D.J., GUERRERA, L., and RYLES, P., 1999, Legendre: maturation of a marginal offshore oil discovery to development project, *The APPEA Journal*, 39 (1), 523-531.

WOODS, E.P., 1994, A salt-related detachment model for the development of the Vulcan Sub-basin in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 260-274.

WOODSIDE 1988, Petroleum geology and hydrocarbon potential of the Barrow-Dampier Sub-basin and environs. Petroleum in Australia: the first century. Sydney: Australian Petroleum Exploration Association, 213-231.

YOUNG, A., 1998, Development of the Goodwyn Gas Field, north west shelf, Australia, in PURCELL, P.G., and PURCELL, R.R., (Eds), *The Sedimentary Basins of Western Australia 2:* Proceedings of the Petroleum Exploration Society of Australia, Perth, 1998, 535-540.

YEATES, A.N., BRADSHAW, M.T., DICKINS, J.M., BRAKEL, A.T., EXON, N.F., LANFORD, R.P., MULHOLLAND, S.M., TOTTERDELL, J.M., and YEUNG, M., 1987, The Westralian Superbasin, an Australian link with Tethys, in McKENZIE, K.G., (Ed), *Shallow Tethys 2*: International on Shallow Tethys 2, Wagga Wagga, 1987, 199-213.

ZAUNBRECHER, M.I., 1994. Oil and gas accumulations of the offshore Barrow and Exmouth Sub-Basins – Trends in hydrocarbon habitat in PURCELL, P.G., and PURCELL, R.R., (Eds), 1994, *The Sedimentary Basins of Western Australia*: Proceedings of the Petroleum Exploration Society of Australia, Perth, 1994, 449-458.

Acknowledgements

The authors acknowledge both the contribution from the many geoscientists who worked at Woodside over the last 40 years and the contribution that both Woodside's numerous joint venture partners and particularly Geoscience Australia (formerly AGSO) has made to the ideas and content of this paper. The authors also recognise the significant contribution former Woodside employee Dariusz Jablonski made to the study results.