REPORT
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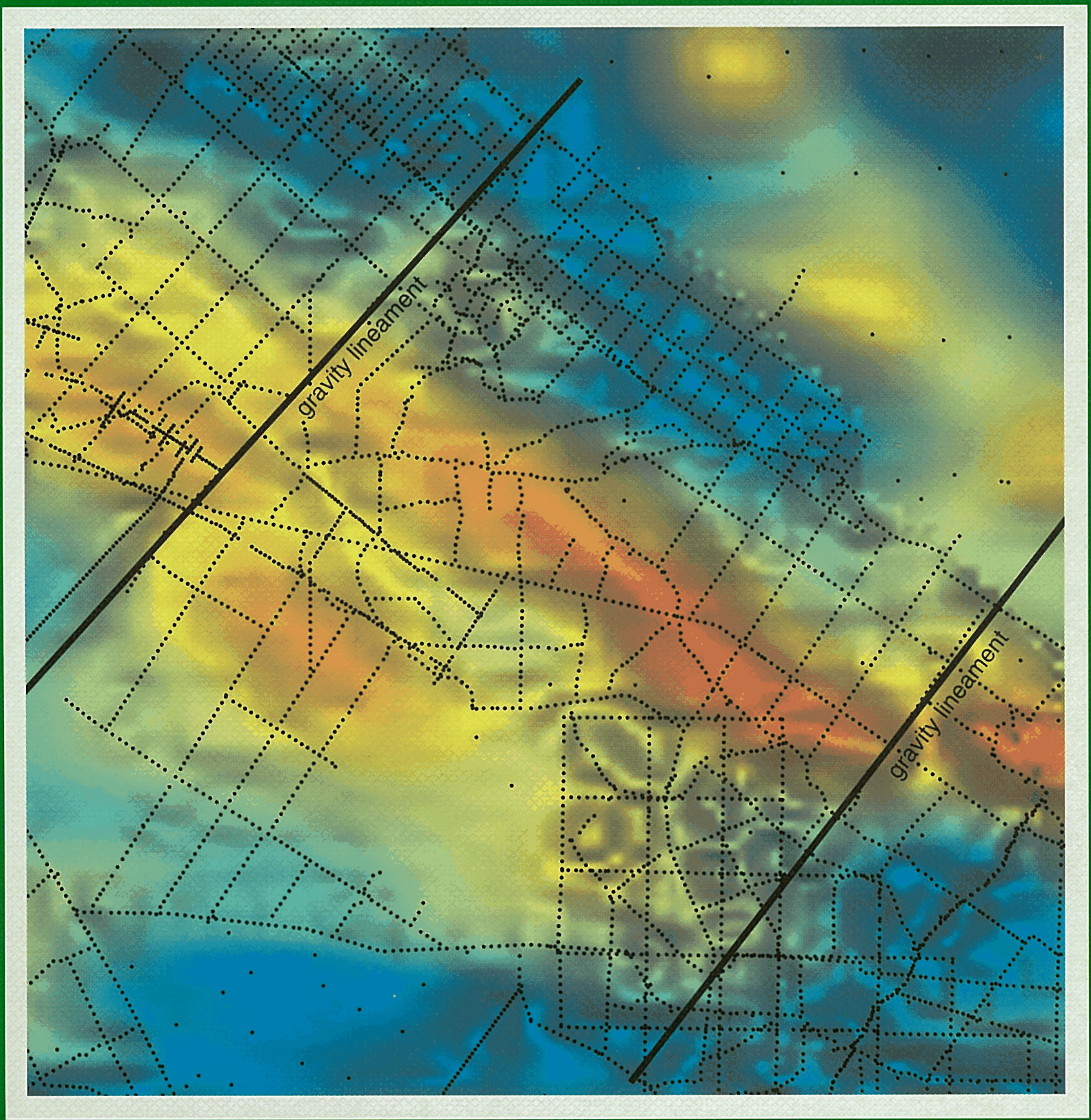
A REVIEW OF OIL OCCURRENCES WITHIN THE LENNARD SHELF CANNING BASIN WESTERN AUSTRALIA

by A. Crostella



GEOLOGICAL SURVEY WESTERN AUSTRALIA

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DEPARTMENT OF MINERALS AND ENERGY

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A REVIEW OF OIL OCCURRENCES WITHIN THE LENNARD SHELF, CANNING BASIN, WESTERN AUSTRALIA

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A. Crostella

Perth 1998

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Copy editor: D. P. Reddy

REFERENCE
The recommended reference for this publication is:
CROSTELLA, A., 1998, A review of oil occurrences within the Lennard Shelf, Canning Basin, Western Australia: Western Australia Geological Survey, Report 56, 40p.

National Library of Australia
Cataloguing-in-publication entry

Crostella, A. (Angelo), 1929–.
A review of oil occurrences within the Lennard Shelf, Canning Basin, Western Australia

Bibliography.
ISBN 0 7309 6578 3

1. Petroleum — Geology — Western Australia — Canning Basin.
2. Petroleum — Prospecting — Western Australia — Canning Basin
I. Geological Survey of Western Australia.
II. Title. (Series: Report (Geological Survey of Western Australia); 56).

553.28099415

ISSN 0508–4741

Cover photograph:
Image of the first vertical derivative of Bouguer gravity, Lennard Shelf. Dots indicate gravity stations.

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A review of oil occurrences within the Lennard Shelf, Canning Basin, Western Australia

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A. Crostella

Abstract

Oil exploration in the Lennard Shelf was initially guided by Devonian reef plays. Subsequently, seismically defined closures within Permo-Carboniferous clastic rocks became the most sought after targets, even though the reserves of the Blina oilfield within Devonian carbonates were greater than the combined reserves of the four fields with Permo-Carboniferous clastic reservoirs.

A study of the Lennard Shelf petroleum occurrences suggests that fractured carbonates offer the best opportunity for further, perhaps even more attractive, discoveries. Migration is most likely vertical, via northeasterly trending transfer faults connecting the Lennard Shelf to the deeper Fitzroy Trough, where the source rocks of the Gogo and Laurel Formations are mature. The good reservoir characteristics of the thick, brittle Nullara Limestone appear to be a result of extensive fracturing, with shear stresses present within the entire thickness of the formation.

Oil exploration wells should be located not only within closed structures, but also as close as possible to the main faults in order to test the Nullara Limestone. As the Lennard Shelf is characterized by vertical fractures and the primary permeability is virtually non-existent, the effective horizontal permeability in a direction orthogonal to the faulting is low; therefore, a crestal location is not necessarily critical.

The chances of finding more oilfields in the Lennard Shelf area are rated as good.

KEYWORDS: Devonian reef, Permo-Carboniferous clastic rocks, closed structures, petroleum, carbonates, petroleum migration, transfer faults, source rocks.

This report reviews oil occurrences within the Lennard Shelf in the Canning Basin (Figs 1 and 2) and evaluates the hydrocarbon potential of the Middle Devonian to Lower Triassic sequence of the region. Traps, sources, reservoirs, and seals of the five Lennard Shelf oilfields (Blina, Boundary, Lloyd, Sundown, and West Terrace) are analysed. In addition, results of drillstem tests (DSTs) or production tests on wells that recovered hydrocarbons are reviewed. Wells with oil or gas occurrences but no proven identified recoverable reserves are classified as ‘wells with hydrocarbon occurrences’ rather than fields. The production history of the discrete stratigraphic objectives in the region allows their performance and value to be assessed. Analyses of the structural setting of oil accumulations, the likely oil migration conduits, and the characteristics of reservoirs have led to a new model for petroleum exploration within the Lennard Shelf.

Many reviews of the area have been produced but they are mostly concerned with the entire Canning Basin. The following reviews, however, are of particular interest: Ellyard (1984) concentrated on the problems related to the migration of oil; Brown et al. (1984) focused on the geological evolution of the basin; Lehmann (1986) commented on the regional significance of the westernmost part of the Lennard Shelf; Goldstein (1989) produced a comprehensive summary of the petroleum geology of the Canning Basin; Dolan and Associates (1991) evaluated the offshore extension of the region; Jackson et al. (1992) and Jackson et al. (1993) reinterpreted both well and seismic data from the central part of the Lennard Shelf; Shaw et al. (1994) presented an updated tectonic picture of the Canning Basin; and Kennard et al. (1994a) discussed the Canning Basin depositional sequences.

A number of seismic sections and cross sections have been used to illustrate the interpretation. The source of the interpretation is acknowledged in the relevant caption; where no reference is mentioned, the interpretation is that of the author.

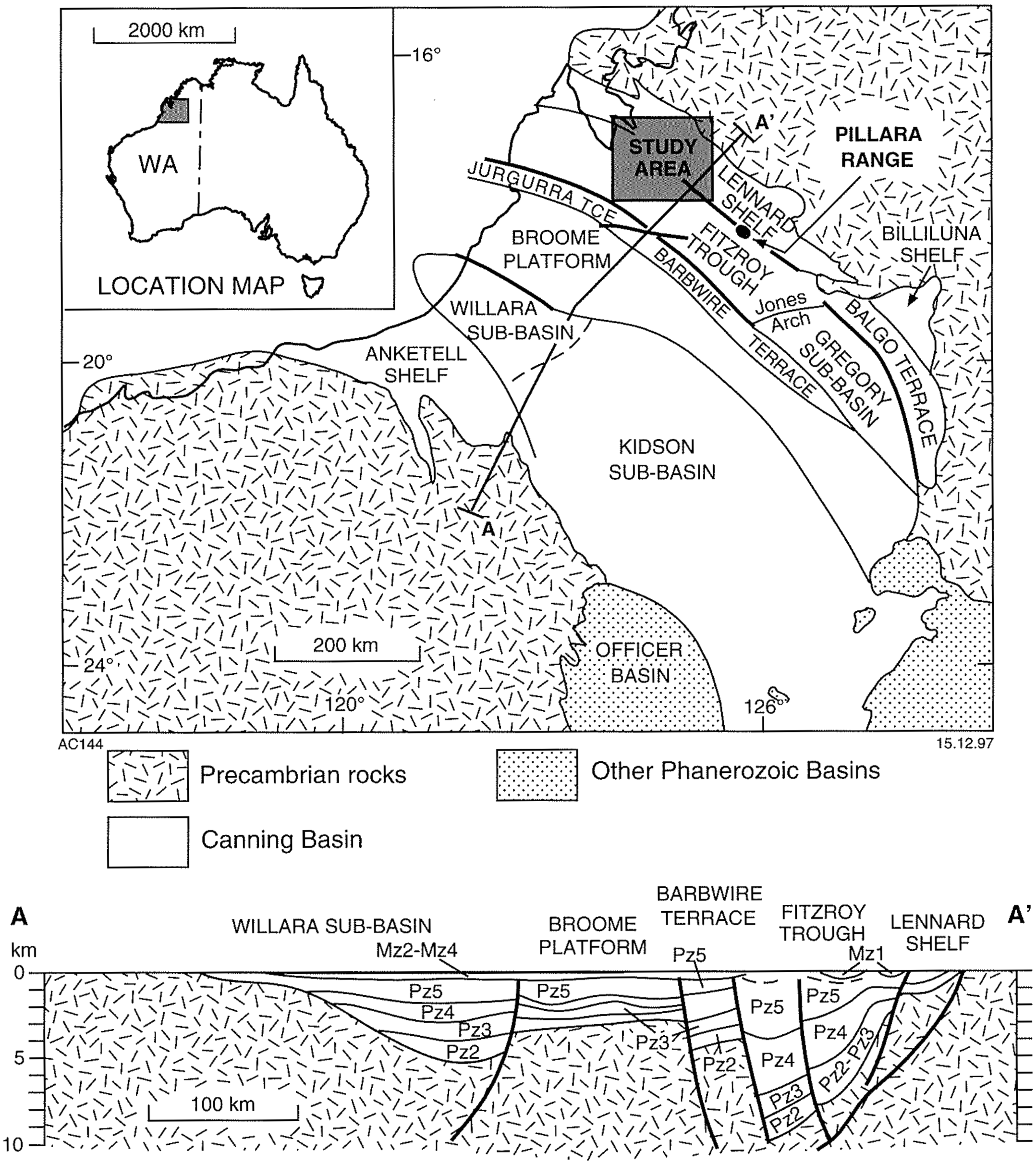


Figure 1. The Lennard Shelf within its regional context (modified from Middleton, 1990). Megasequences are: Pz2 = Ordovician; Pz3 = Silurian; Pz4 = Devonian – Early Carboniferous; Pz5 = Late Carboniferous – Permian; Mz1 = Triassic; Mz2–Mz4 = Early Jurassic – Cretaceous

Oil exploration drilling

The early stages of oil exploration in the Canning Basin have been described by Playford (1982). Prompted by oil shows reported in 1918 in a waterbore, the Freney Kimberley Oil Company was formed and explored the Fitzroy Valley area from 1922 to 1941 by drilling a series of wells. West Australian Petroleum (WAPET) commenced exploration in the area in the 1950s. In 1958 WAPET drilled the first well on the Lennard Shelf (Meda 1), which recovered a few gallons of oil from the Laurel Formation of the Fairfield Group. The follow-up well, Meda 2, failed to confirm the oil discovery. In the subsequent twenty years, little exploration took place and no commercial discoveries were made.

Oil exploration drilling resumed in the late 1970s, when a consortium led by Home Oil Australia drilled Blina 1 and, in DSTs, produced 6 m^3 of oil per day from the Yellow Drum Formation and 144 m^3 of oil per day from the Nullara Limestone. The Blina 1 oil well was followed by seven other Blina wells. Although of modest size, the discovery of the Blina oilfield spurred further activities in the Canning Basin, both within and outside the Lennard Shelf. These activities gradually declined because the first discovery was followed by only a few smaller oil accumulations within the Lennard Shelf, in the clastic rocks of the Anderson and Betty Formations. Sundown 3H, the last well to be drilled in the area, was a horizontal production well completed in 1995 in the Sundown oilfield.

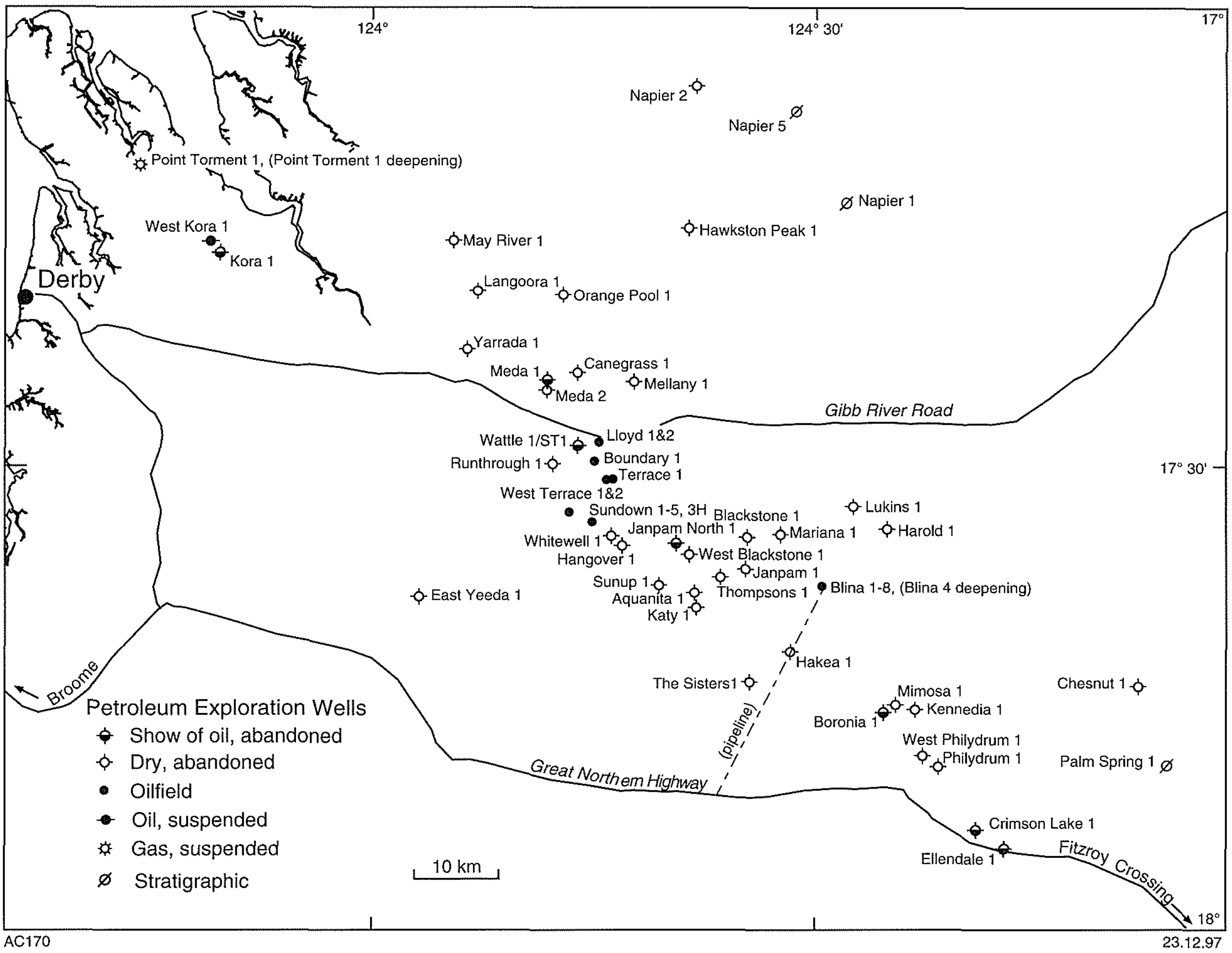


Figure 2. Western Lennard Shelf: well location map with major roads

Forty-three new-field wildcat holes have been drilled within the most productive western part of the Lennard Shelf (Fig. 2), resulting in the discovery of five small oilfields. Although the success ratio of 1 in 8.6 wells is good, the fields are quite small. In addition, 16 step-out and four stratigraphic wells have been drilled in the study area, resulting in a gross total of 63 wells (Table 1). Two wells, Blina 4 and Point Torment 1, were deepened several years after they were first drilled. In addition to the new-field discovery wells, eight wells recovered a measurable amount of oil, ranging from one litre in Ellendale 1 to about 3800 kL (24 000 barrels) in West Kora 1; a measurable amount of gas was tested in Point Torment 1.

Regional framework

The Lennard Shelf is the northernmost subdivision of the Canning Basin (Fig. 1), which is the largest onshore sedimentary basin in Western Australia. In the Lennard Shelf, basement is relatively shallow and the succession onlaps Precambrian rocks of the Kimberley Block to the north. To the south, the shelf is separated from the deep Fitzroy Trough by the Harvey Fault System and its western extension (Fig. 3). Up to 4000 m of strata are present on the Lennard Shelf, whereas the Fitzroy Trough is estimated to have a maximum depth of 15 000 m. The Lennard Shelf is up to 600 km long, and 60 to 110 km wide.

Initial subsidence and resulting marine transgression occurred in the Canning Basin during the Early Ordovician. During this time the Lennard Shelf was the northern part of a large intracratonic downwarp that included at least the Fitzroy Trough, Broome Platform, and Willara Sub-basin. Sedimentation during this Ordovician sag was initially dominated by carbonates, and was followed by evaporites as the environment of deposition gradually became more restricted. The Ordovician sedimentary rocks have a maximum thickness of about 1000 m. The sag phase of the basin continued into the Silurian – Early Devonian with the deposition of evaporites and redbeds in a restricted marine to continental setting. The pre-Givetian (Middle Devonian) geological history, which the Lennard Shelf shares with the main Canning Basin, is beyond the scope of this report. The regional structure of the central part of the Lennard Shelf, below the Givetian section, shows

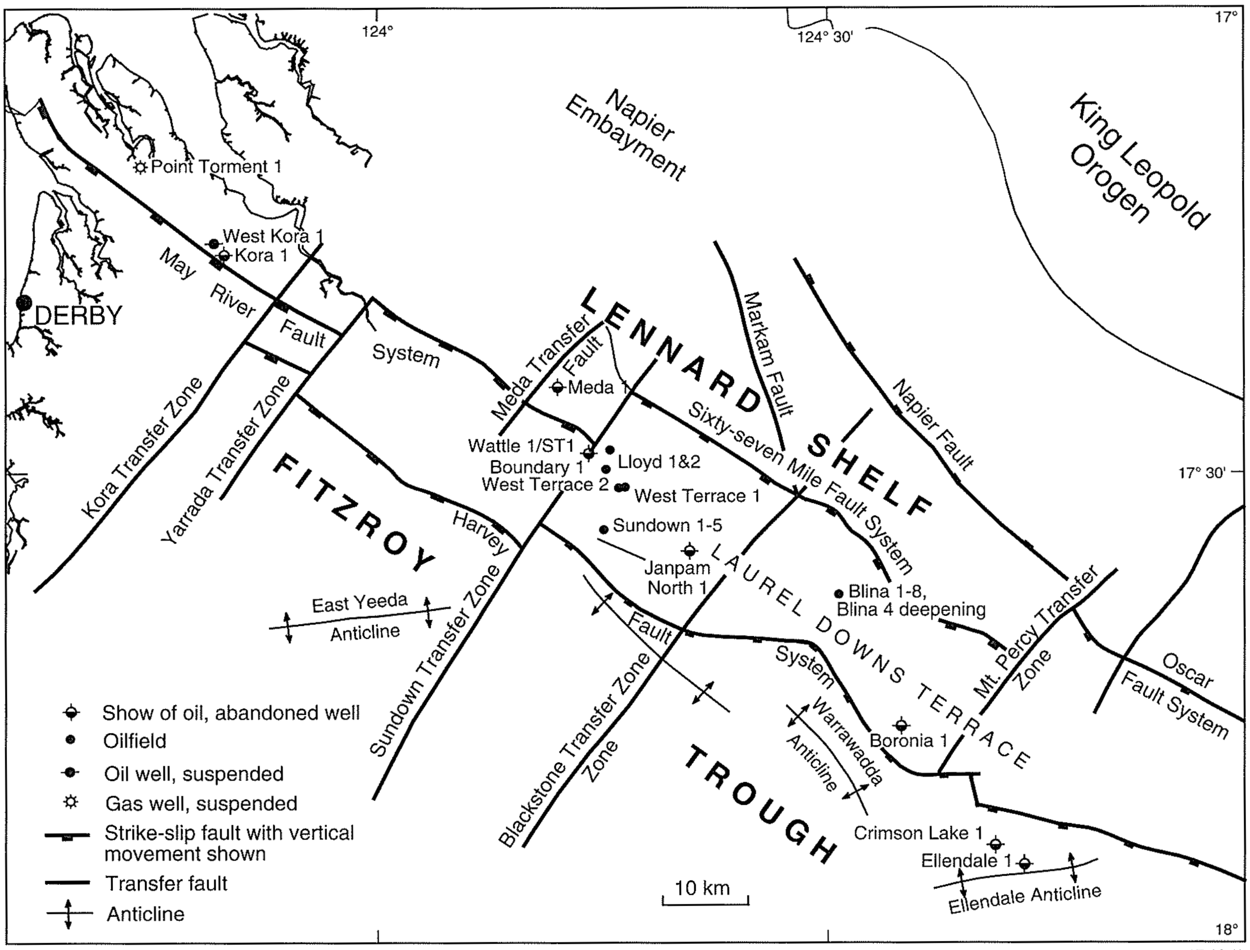


Figure 3. Tectonic lineaments of the western Lennard Shelf (after Shaw et al., 1994), and wells with shows

Table 1. Petroleum exploration wells drilled within the western Lennard Shelf

Type of well		*Well name*
Oilfield discovery wells		Blina 1, Boundary 1, Lloyd 1, Sundown 1, West Terrace 1
Wells with limited oil production		West Kora 1
Wildcats:	Gas wells	Point Torment 1
	Oil wells	Boronia 1, Crimson Lake 1, Ellendale 1, Janpam North 1, Kora 1, Meda 1, Wattle 1/ST1
	Dry wells	Aquanita 1, Booran 1, Canegrass 1, Chestnut 1, East Yeeda 1, Hakea 1, Hangover 1, Harold 1, Hawkston Peak 1, Janpam 1, Katy 1, Kennedia 1, Longoora 1, Lukins 1, Mariana 1, May River 1, Mellany 1, Metters 1, Nemile 1, Orange Pool 1, Philydrum 1, Runthrough 1, Sunup 1, The Sisters 1, Thompson 1, West Blackstone 1, West Philydrum 1, Whitewell 1, Yarrada 1
Step-out wells:	Successful	Blina 2, Blina 3, Blina 4, Blina 5, Blina 6, Sundown 1, Sundown 2, Sundown 4, Sundown 5, Sundown 3H, West Terrace 2
	Dry	Blina 7, Blina 8, Lloyd 2, Meda 2, Sundown 3
Stratigraphic wells		Napier 1, Napier 2, Napier 5, Palm Spring 1

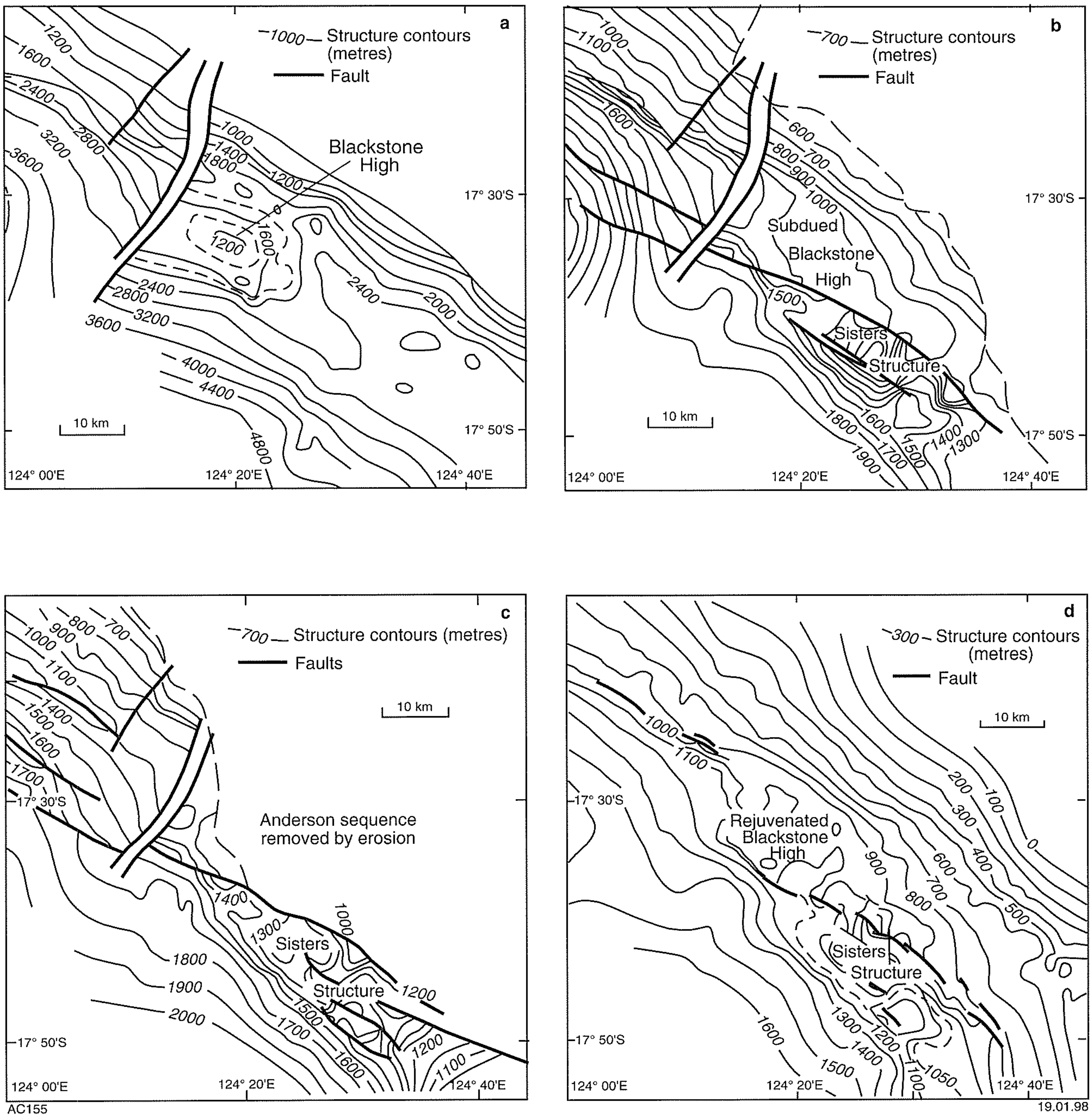


Figure 4. Structure contour maps of the central part of the Lennard Shelf (after Jackson et al., 1993): a) base undifferentiated Pillara–Napier equivalent (base Givetian); b) near-base Fairfield Group (base Carboniferous); c) base Anderson Formation (intra–Early Carboniferous event); d) base Grant Group (Late Carboniferous unconformity)

a central positive feature — the Blackstone High (Fig. 4a).

An extensional phase of rifting and subsidence began in the Givetian. At this time, pre-existing basement faults were reactivated and produced sites favourable for reef growth (Playford, 1982). In the late Givetian the evolution of the Lennard Shelf diverged from the rest of the Canning Basin, which was downthrown by a down-to-the-southwest normal-fault system. Figure 5 illustrates the generalized Middle Devonian (Givetian) to Middle Triassic (Anisian) stratigraphy of the Lennard Shelf. During the late Givetian, Frasnian, and Famennian, reefal carbonates grew on pre-existing structural highs while basinal sedimentary rocks were deposited in the lows. Two main reef cycles occurred: the first during the late Givetian – Frasnian (Pillara Limestone), and the second during the Famennian (Windjana and Nullara Limestones — commonly jointly referred to as Nullara Limestone in the subsurface). The carbonate platforms and basinal facies were essentially deposited horizontally. The marginal-slope deposits (e.g. Sadler and Bugle Gap Limestones) were deposited as steeply dipping talus, which interfinger basinward with the Gogo, Virgin Hills,

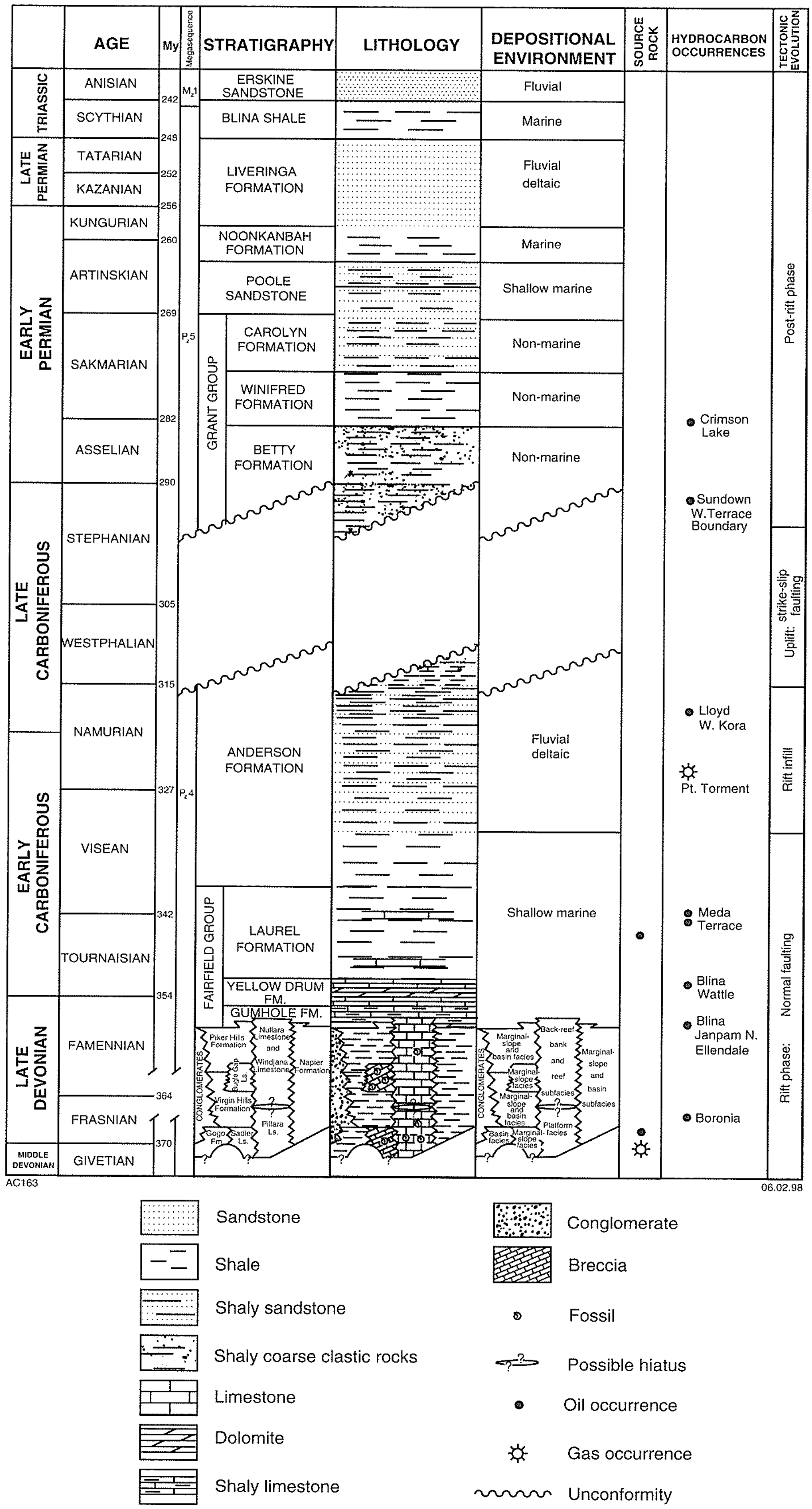


Figure 5. Middle Devonian (Givetian) to Middle Triassic (Anisian) stratigraphy of the Lennard Shelf (modified from Middleton (1990) and Playford (1982) for the Devonian, and Brown et al. (1984) for the basin evolution). Time-scale from Gradstein and Ogg (1996)

and Piker Hills Formations. The depositional relief between the platform and basinal facies ranges from a few tens to several hundreds of metres (Playford, 1982). Fluvial conglomerates interfinger with the reef complexes in several areas.

Near the end of the Famennian the reef complexes became extinct, probably because of an abrupt fall in sea level. During the ensuing transgression, shallow-marine sedimentary rocks (Fairfield Group) were laid down in the latest Famennian and Early Carboniferous — commencing with shale and carbonate of the Gumhole Formation, followed by carbonate of the Yellow Drum Formation, and then shale and carbonate of the Laurel Formation. The definition of the subsurface stratigraphy within the Fairfield Group and its equivalents is hampered by the non-systematic stratigraphic nomenclature applied by various workers and the extrapolation of definitions more valid for the Fitzroy Trough than the Lennard Shelf. A clastic marginal-marine to deltaic regressive episode followed with deposition of the Anderson Formation. This deltaic complex consists largely of sandstone with minor amounts of carbonate, representing a phase of rift infill.

Rifting during the late Givetian to Early Carboniferous created zones of weakness, as pre-existing normal faults became the loci of further normal movements. These west-northwesterly trending faults are the principal structural features of the area (Fig. 3) and indicate north-northeast extensional movement. A good example of the structural style of the Lennard Shelf was presented by Dörling et al. (1996) who analysed in detail the structural deformation of the Pillara Range. Seismic data (Fig. 6) confirm that throughout the shelf, Upper Devonian to Lower Carboniferous strata were affected by these movements. Figure 4b shows the dominant west-northwesterly trending faults at the base of the Carboniferous and Figure 7 shows a typical Lennard Shelf wrench structure of this age.

In the Lennard Shelf there is a clear correlation between basement structures and overlying sedimentary rocks. Devonian structural closures are superimposed on reefs developed on pre-existing highs; therefore, there is a close interrelation between structural and sedimentary features.

A time gap of several million years, an angular unconformity (as seen regionally on seismic sections between the top of the Anderson Formation and the Grant Group), and the local erosion of the entire Anderson Formation (Appendix 1) point to a major tectonic event on the Lennard Shelf at the end of the mid-Carboniferous. A project is currently underway within the Geological Survey of Western Australia to reassess the stratigraphy of the Grant Group. The unconformable boundary between the Anderson Formation and the Grant Group

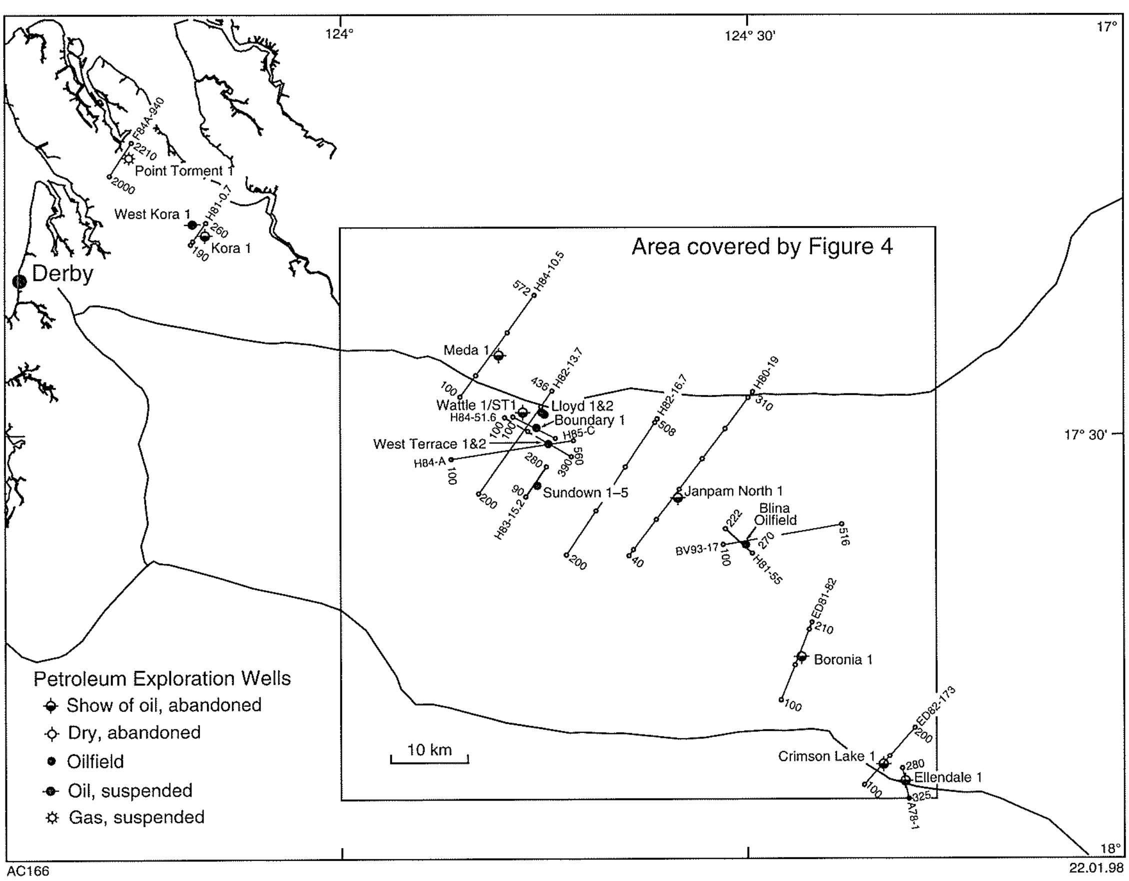


Figure 6. Location map, showing the area covered by the seismic maps and seismic lines presented in this report

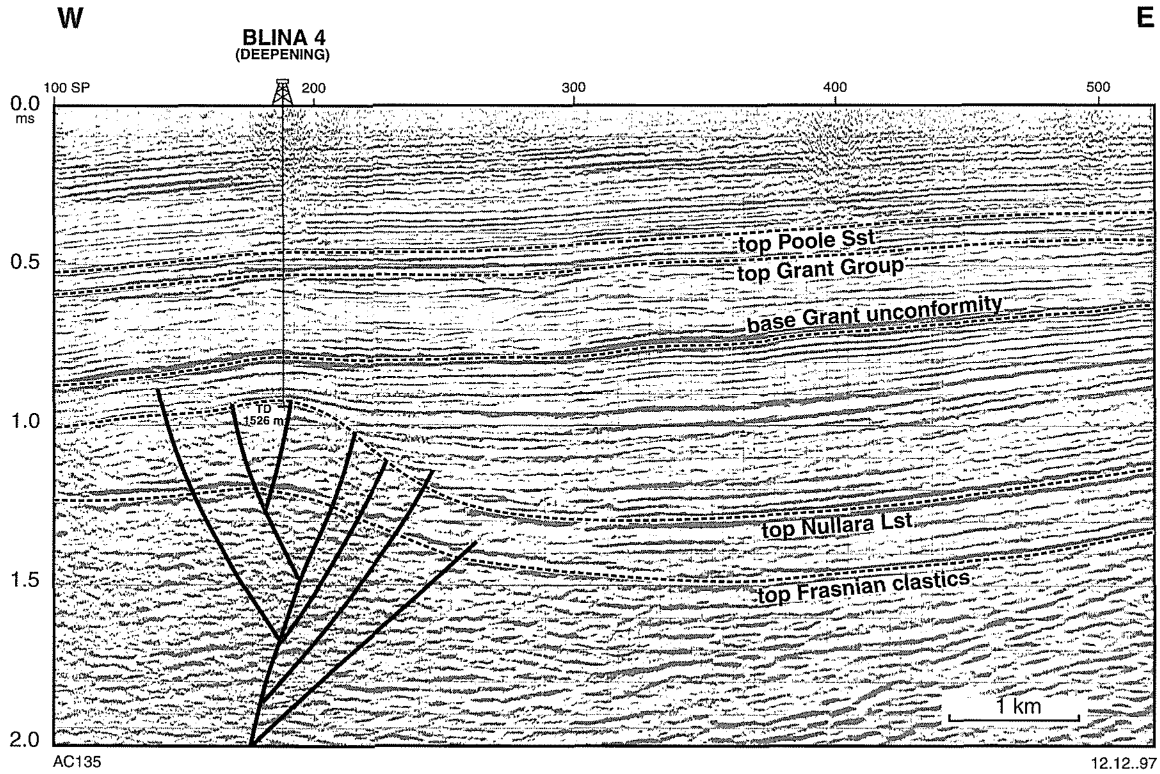


Figure 7. Seismic section BV93-17, showing a positive flower structure across the Blina oilfield (modified from Robinson and Roche, 1994a). The line of section is shown in Figures 6, 12, and 14

is marked by the appearance of glacigene sedimentary rocks at the base of the Grant Group. This approach avoids differentiating the cumbersome 'pre-Grant unit' (Kufpec Australia Pty Ltd, 1989) or a 'Lower Grant Sequence' (Jones and Young, 1993; Kennard et al., 1994a). The major mid–Late Carboniferous tectonic event was termed the 'Meda Transpressional Movement' by Shaw et al. (1994), and their observation that such a movement significantly differs in character from the thrust tectonics of the Alice Springs Orogeny is accepted here. Shaw et al. (1994), however, inserted a major unconformity within the Grant Group contrary to the principles of the code of stratigraphic nomenclature. The Meda Movement was followed by a major erosional event, interpreted from seismic (Fig. 4c) and well data (Appendix 1).

On the Lennard Shelf west-northwesterly trending faults are offset by orthogonal north-northeasterly trending lineaments (Fig. 3); it therefore seems plausible to refer these lineaments, which are considered to be transfer faults, to the Meda Movement. Alternatively, the transfer faults may have developed from pre-existing basement features that compartmentalized the shelf during the Givetian to mid-Carboniferous rifting. If so, the mid–Late Carboniferous tectonic event represents the climax of the rifting, and the en echelon strike-slip faults developed along the northwesterly trending normal rift faults. As these strike-slip faults are not strictly parallel, it is postulated that local compression through wrenching occurred at this time, with ensuing reverse faulting and the development of anticlines such as the Blina anticline (Fig. 7). The positive flower structure at Blina anastomoses from a deeper single fault and demonstrates the presence of local compressional features within the regional extensional regime. Other indications of compressional stresses are mentioned by Shaw et al. (1994) and Tompkins (1994). The north-northeasterly trending transfer faults show a sinistral sense of movement and are here correlated with the northerly trending faults of Vearncombe et al. (1995), who commented that faults striking at 130° in the Pillara Range (Fig. 1) show dextral displacements, albeit with a much smaller offset.

The regional transgression at the base of the Grant Group is related to partial melting of the extensive Carboniferous ice caps, and may be coeval with regional transgressions at the base of the Lyons Group in the Carnarvon Basin and the Nangetty Formation in the Perth Basin. The regional extent of the Late Carboniferous transgression over the Lennard Shelf and the presence of limited faulting affecting the post-Meda sedimentary rocks are shown in Figure 4d. The Upper Carboniferous to Lower Permian Grant Group is subdivided into the following three formations in ascending order: the non-marine Betty Formation, represented by coarse-grained clastic rocks with erratics of glacial origin; the mainly shaly Winifred Formation; and the sandy–shaly Carolyn Formation. Marine to fluvial, fine- to coarse-grained clastic rocks of the Poole Sandstone conformably overlie the Grant Group and are succeeded by shallow-marine

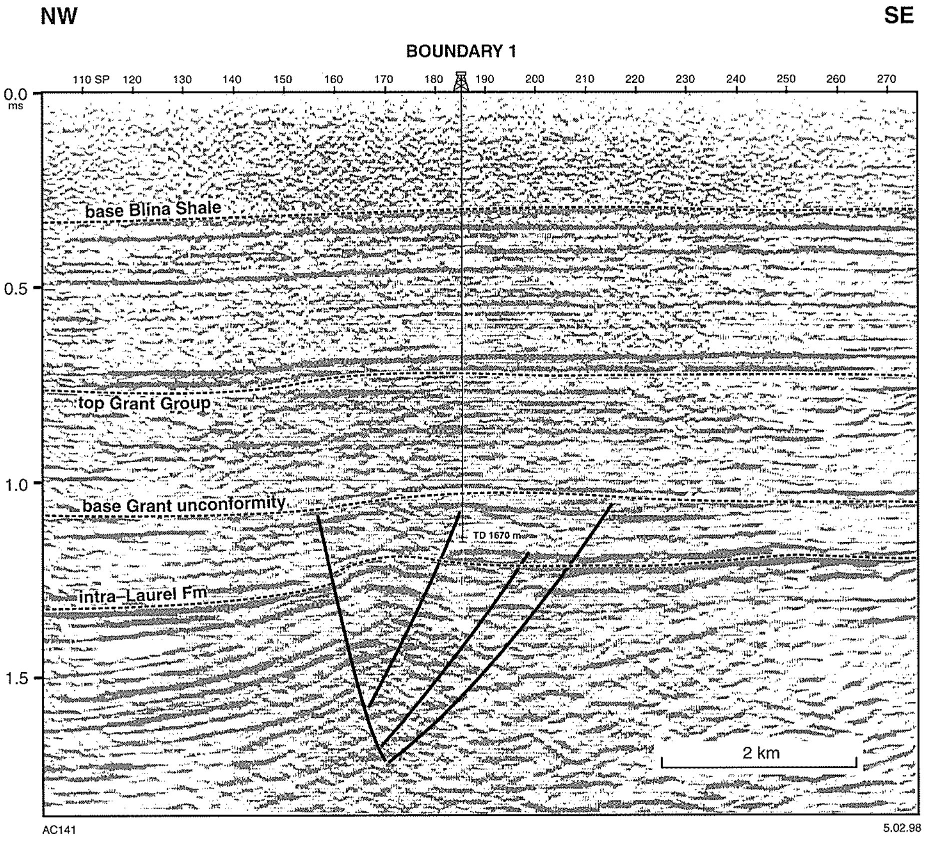


Figure 8. Seismic section H85-C, showing the structural attitude of the Boundary oilfield (modified from Jackson et al., 1993). The line of section is shown in Figures 6 and 15

clastic rocks of the Noonkanbah Formation and the fluviodeltaic Liveringa Formation. The Lower Triassic Blina Shale and Middle Triassic Erskine Sandstone are present over much of the region. Sedimentation on the Lennard Shelf ceased in the Middle Triassic.

Seismic section BV93-17 (Fig. 7) and the interpretation of section H85-C (Fig. 8) show that in the Blina and Boundary areas, no tectonic movements occurred within the post-Anderson sequence. In comparison, seismic section H83-15.2 (Fig. 9) indicates a post-Anderson compressional movement in the Sundown area. In the Fitzroy Trough, elongated anticlines controlled by reverse faulting formed from local compressional stresses during the Middle Jurassic breakup of Gondwana (Fig. 3). This was termed the 'Fitzroy Transpressional Movement' by Shaw et al. (1994). Middle Jurassic movements also occurred on parts of the Lennard Shelf in the vicinity of major faults. Figure 10 shows an example where a Middle Jurassic compressional anticline developed over a wrench-induced Devonian–Carboniferous flower structure, which was, in turn, propagated from an older fault.

Table 2. Reserves and production to 30 June 1996 of the Blina, Boundary, Lloyd, Sundown, and West Terrace oilfields

Oilfields	*Original reserves (kL)*	*Production to 30.6.96 (kL)*	*Original reserves (barrels)*	*Production to 30.6.96 (barrels)*
Blina	277 935	265 935	1 748 211	1 672 681
Boundary	19 057	14 057	119 868	88 416
Lloyd	27 448	23 448	172 648	147 483
Sundown	74 620	55 620	469 360	349 839
West Terrace	30 148	26 148	189 631	164 466
Total	**429 226**		**2 699 718**	

Oilfields

Both liquid and gaseous hydrocarbons have been discovered within the Lennard Shelf, although only oil has been produced to date. The five oilfields discovered are within the western part of the shelf (Fig. 2), and have been brought into sustained production. The fields originally contained almost 2.7 million (M) barrels (about 429 000 kL) of recoverable oil (Table 2). The discovery wells were drilled by different companies, but following several changes of ownership the operations are currently integrated under Capital Energy, a non-registered participant. The production project is known as the North Canning Basin Project; all oilfields are under review and further drilling, such as an additional vertical appraisal at Boundary and a horizontal well at Blina, may be

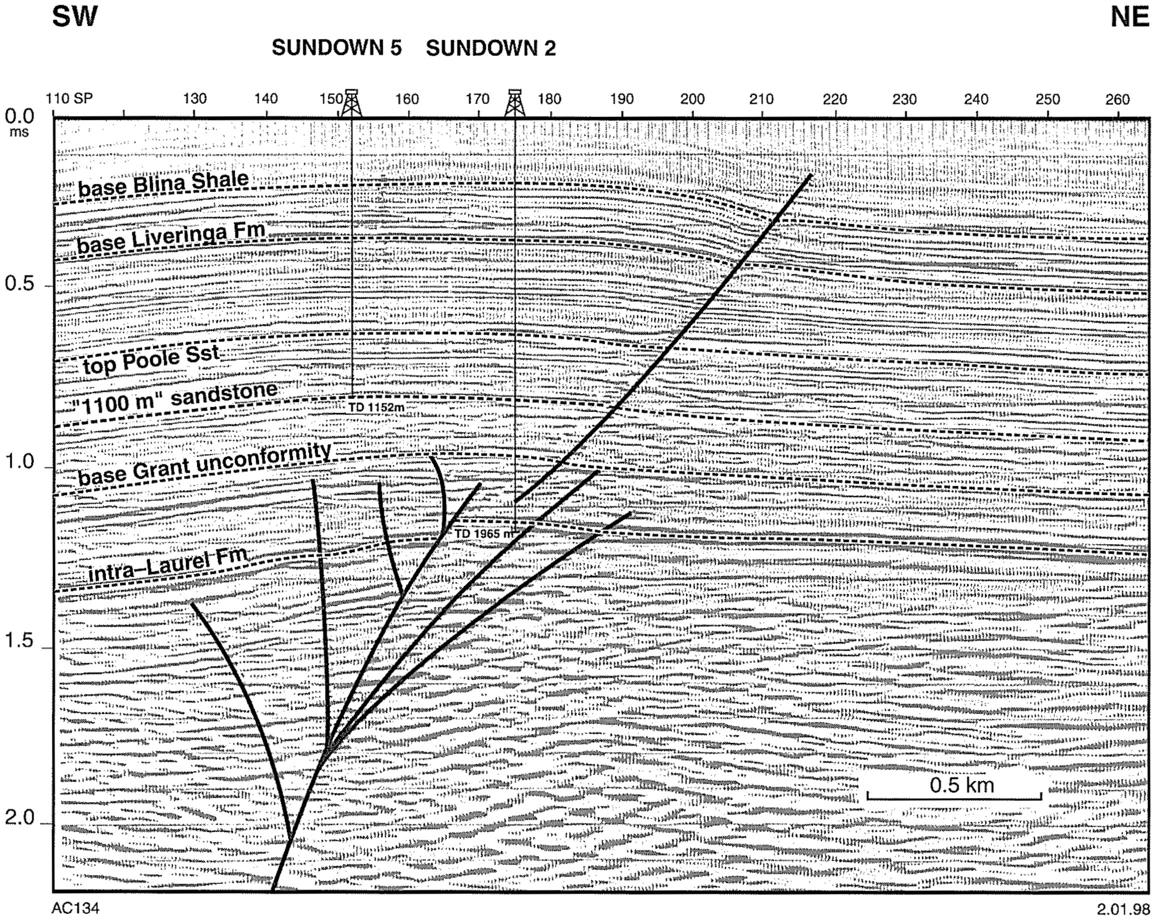
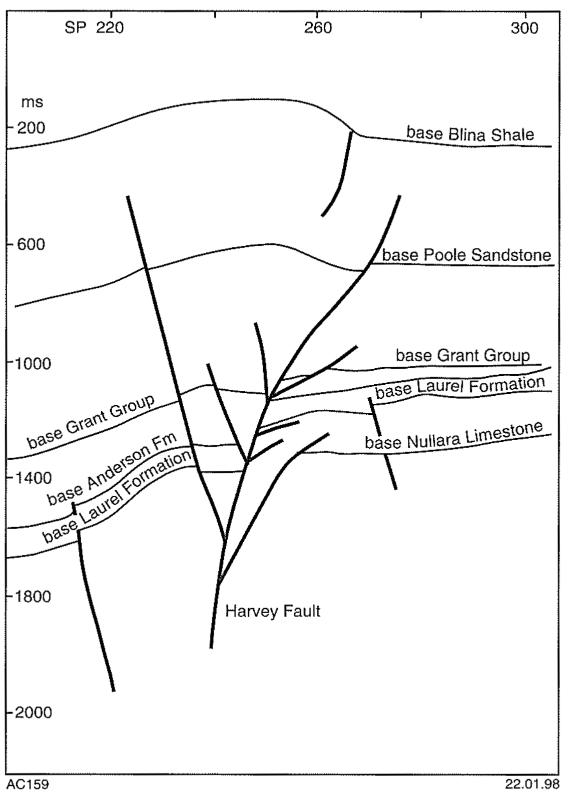


Figure 9. Seismic section H83-15.2, showing the structural attitude of the Sundown area (modified from Robinson and Roche, 1994b). The line of section is shown in Figures 6 and 19



undertaken (Department of Minerals and Energy, 1996). This tentative plan aims to maintain at least the minimum rate of production required to make the project profitable.

The analysis of drilling results uses open-file unpublished well completion reports held in the S-series at the Department of Minerals and Energy (DME). Details of the wells, including their S-series number, are summarized in Appendix 2, and formation tops are given in Appendix 1. For analysis of production from each oilfield, information has also been obtained from the relevant monthly production reports.

Blina oilfield

Location

The Blina oilfield is about 100 km east-southeast of Derby and 24 km north of the Great Northern Highway (Fig. 2). The discovery well was drilled in 1981 by Home Oil Company.

Figure 10. (left) Interpretation of seismic section H82-16.7, showing the structural development of the Harvey Fault zone (modified from Jackson et al., 1993). The line of section is shown in Figure 6

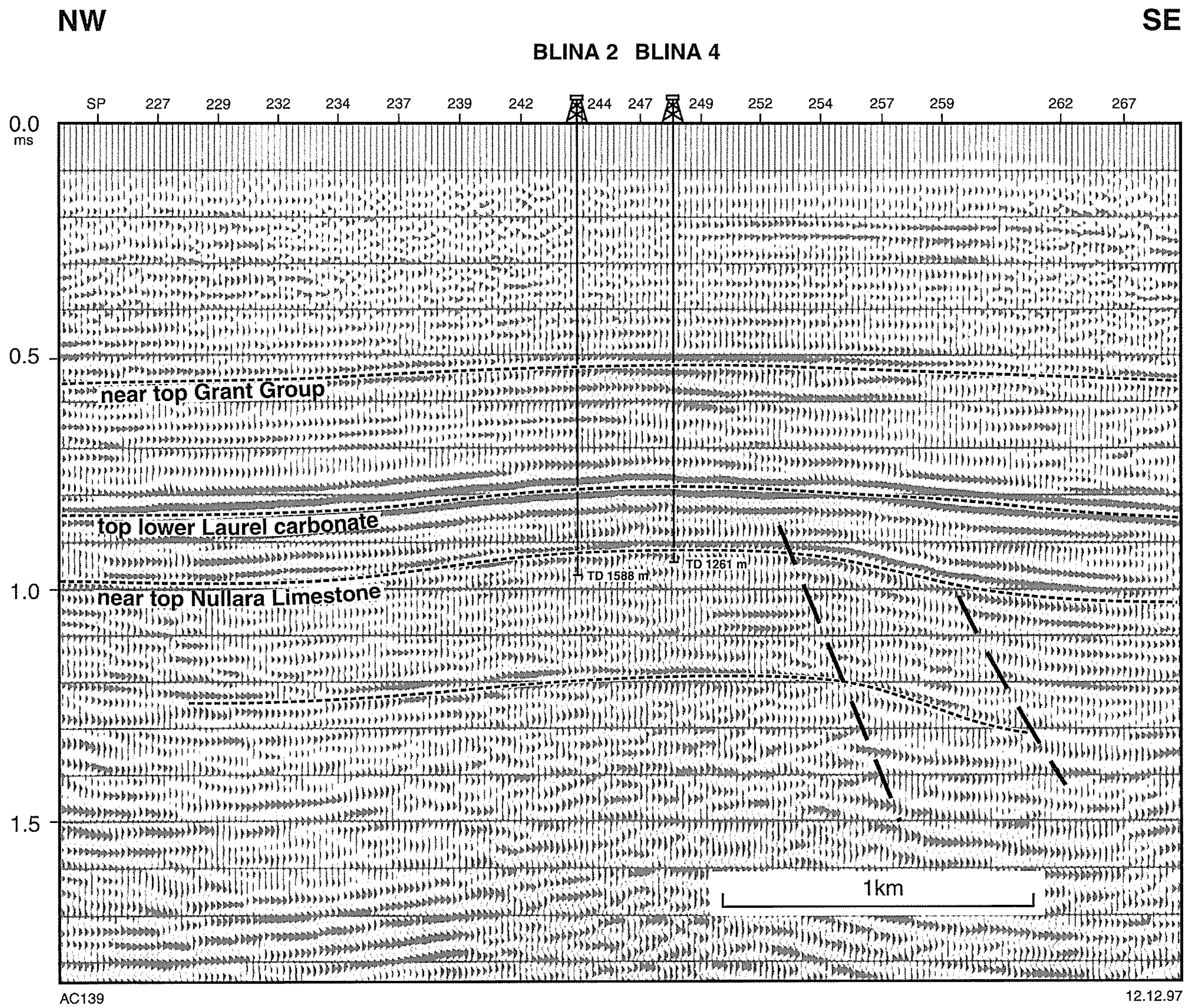


Figure 11. Seismic section H81-55, showing the structural attitude along strike of the Blina oilfield. The line of section is shown in Figures 6 and 12

Trap

Blina 1 was planned to test a seismically defined reef structure. Drilling results and subsequent seismic data indicate that the structure is a fault-controlled anticlinal flower structure of Late Devonian to mid-Carboniferous age (Figs 7, 11, and 12) superimposed on a Devonian reef. The main difference between the original seismic interpretation (Moors et al., 1984) and the most recent one (Fig. 12) is the definition of faults; the crestal zone of the feature is virtually the same in both interpretations.

Wells drilled

Eight wells have been drilled in the field, two of which lacked reservoirs and were dry. Information on the oilfield has been summarized from well completion reports (Townsend, 1981; Townsend and Kooyman, 1982a,b; Willmott et al., 1983; Mah, 1985a,b; Denn and Johnson, 1988; Knauer, 1990a; Robinson and Roche, 1994a). As at 31 December 1995, five wells were in production and one was depleted.

Reservoirs

Two reservoir zones are present within the Blina oilfield: the shallower within the Yellow Drum Formation, and the deeper at the top of Nullara Limestone. The Yellow Drum Formation produces from a dolomitic interval that is 10 m thick on average (with a porosity of 24%) out of a 110 m-thick total section (Moors, 1986). The horizontal permeability of this reservoir is very good, reaching a maximum of more than 2000 millidarcies (md), but vertical permeability is restricted to the porous interval where it reaches a maximum of 297 md. The Nullara Limestone produces from a highly fractured carbonate interval with a porosity of 1.1 to 4.2% and a maximum permeability of 1190 md. Where primary vugs are interconnected by

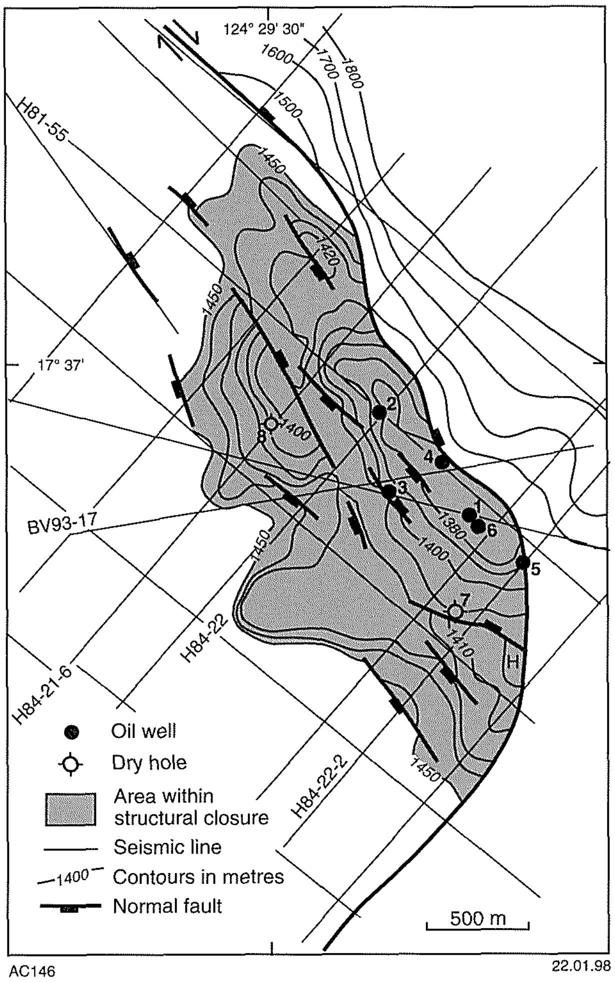


Figure 12. Blina oilfield: depth-structure map of top Nullara Limestone, showing seismic control (modified from Robinson and Roche, 1994a). The numbers refer to the Blina wells

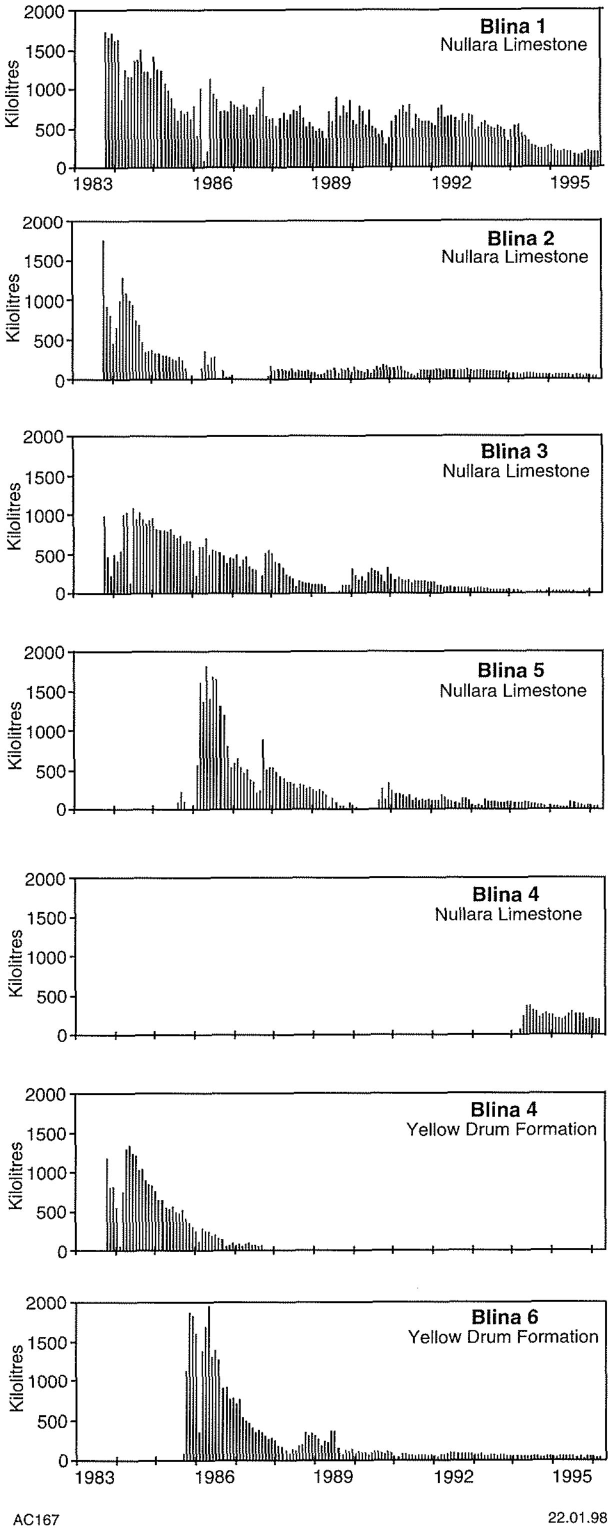


Figure 13. Blina oilfield: monthly production from October 1983 to March 1996 from the Nullara Limestone and the Yellow Drum Formation

secondary fractures, the permeability is very high. Production has also been stimulated by acidization.

Reserves and production

Original total recoverable reserves have been estimated by the operating company to be 277 935 kL (Table 2). The production for March 1996 was 529 kL.

The original oil–water contact for the Nullara Limestone pool was never clearly established and different depths have been suggested in each well from weak indications. Initial high water-saturation was found in Blina 3 below 1428 m sub-sea.

The oil is paraffinic, low in sulfur, and without any associated gas. The gravity of the Yellow Drum oil is 36.7°API (American Petroleum Institute) and of the Nullara oil is 37.7°API, as measured from the Blina 1 DST 2 and DST 3 respectively. Figure 13 shows the monthly production from the Nullara Limestone and Yellow Drum Formation from commencement in October 1983 to early 1996. Preliminary processing is carried out on-site where water disposal ponds have been made. The oil is stored in three field tanks from which it is pumped 28 km to the Great Northern Highway (Fig. 2), then trucked to Broome, and finally transported by ship to the BP Perth refinery.

Source

Alexander et al. (1985) considered that the Blina oil was sourced from Devonian or Ordovician rocks, or both. At present it is commonly accepted that the Givetian–Frasnian Gogo Formation is the source of both the Nullara and Yellow Drum oils (Cadman et al., 1993). The shales of the Gogo Formation contain marine algae deposited in an anoxic environment. The hydrogen-rich kerogen formed in such an environment would produce large quantities of oil and gas, but no oil or source-rock characterization is available for the formation.

Discussion

The histograms of monthly production from the Nullara Limestone (Fig. 13) show that production commenced in Blina 1 at a rate of about 1500 kL/month, decreased after three years to 300–500 kL/month, and then stabilized after eleven years of production at about 200 kL/month. Blina 1 was drilled about 100 m from a major fault. Blina 2, drilled 250 m from the same fault, commenced production at a lower rate than Blina 1 and this decreased rapidly to modest amounts, averaging only 50 kL/month in the last few years. Production from Blina 3, which is further away from the main strike-slip fault zone but close to a minor fault, was more than 500 kL/month for the first three years but then decreased abruptly until it was suspended early in 1996. Blina 5, substantially downdip within the structure but close to a number of faults, initially produced at a rate comparable to Blina 1 but production decreased very rapidly to about 50 kL/month. Blina 4, located close to a main fault and about 300 m from Blina 1, was planned as a Yellow Drum producer and deepened in 1994 to become a Nullara producer. Blina 4 has produced at a rate similar to Blina 1. The lack of initial high peaks in the flow rate from Blina 4, and the decrease in production from Blina 1 when Blina 4 commenced production from the Nullara Limestone, suggest that production from one well interferes with the other.

The histograms showing the production history of the two Yellow Drum producers (Fig. 13) are characterized by high peaks of production for the first two years, followed by a rapid decrease to about 50 kL/month.

In the first three months of 1996, Blina 1 and Blina 4 contributed more than two-thirds of the total production from the Blina oilfield.

The structural setting of the Blina oilfield is consistent with the regional setting of the Lennard Shelf, in which two trends of faults — one oriented west-northwest and the other north-northeast — are present (Fig. 3). The structural interpretation shown in Figure 14, in which two discrete fault sets are shown, is considered a better interpretation of the field than that shown by Robinson and Roche (1994a) in Figure 12, because a wrench-induced subvertical fault (Fig. 7) is unlikely to bend at 90°. Furthermore, normal faults, can be convex but not concave. Linear subparallel en echelon faults interpreted from seismic data have combined strike-slip and (minor amounts of) dip-slip movements, consistent with the fault geometries in basement-induced wrench faulting (Naylor et al., 1986). An early stage of strike-slip development is envisaged with incipient shear zones. The sense of displacement shown in Figure 14 conforms with the outcrop analysis of Vearncombe et al. (1995).

A comparison of histograms illustrating production from the Nullara Limestone in individual wells (Fig. 13) with the structural setting (Fig. 14) suggests that production from the Nullara Limestone is critically dependent on the proximity of the main strike-slip faults. These faults caused fracturing of the rigid reservoir and hence increased its vertical permeability. The complete lack of reservoir potential in Blina 7 and Blina 8, both of which are considerably higher than the most likely oil–water contact but remote from the fault system, confirms this relationship. In contrast, the production history of the Yellow Drum Formation (Fig. 13) indicates that the high horizontal primary porosity yields a fairly high initial flow rate that lasts for only a short period, probably because of poor vertical permeability.

Further production potential may exist in the Nullara Limestone in the area north of Blina 2, where a well

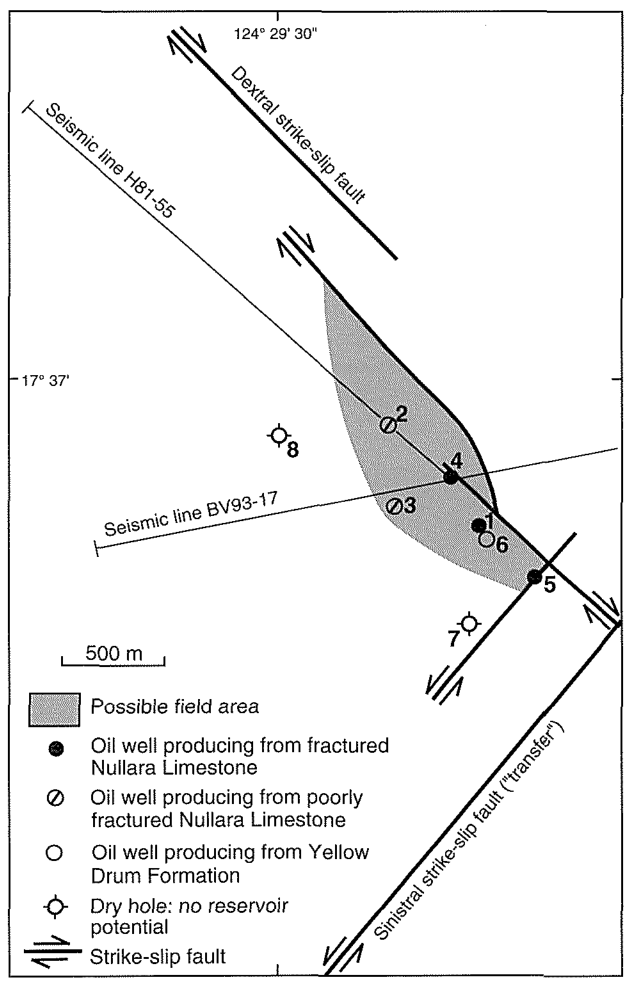


Figure 14. Blina field area: proposed structural setting. Numbers refer to Blina wells

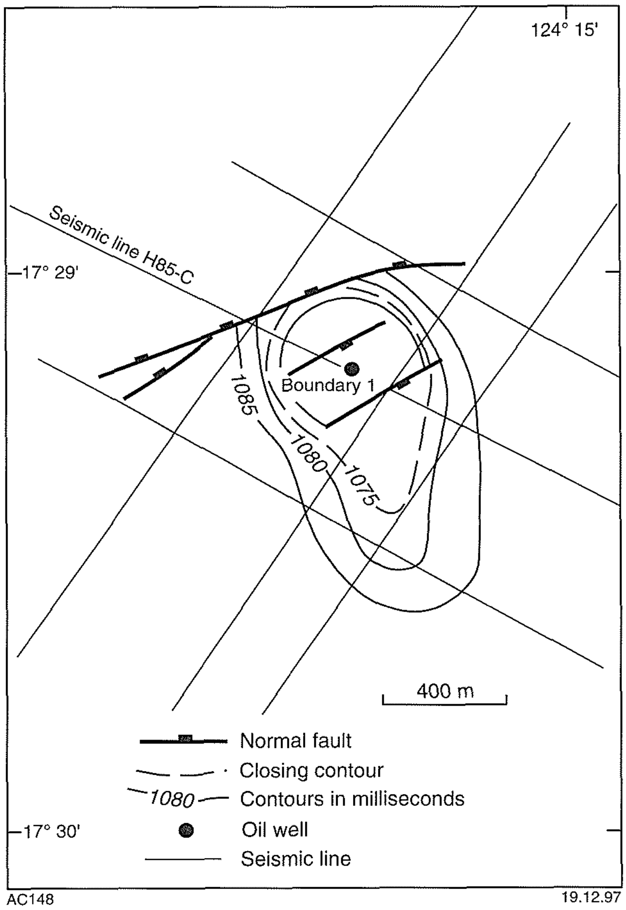


Figure 15. Structural configuration of the Boundary oilfield, showing seismic control (modified from Petroleum Securities Energy Ltd, 1990)

location should be chosen very close to the main strike-slip fault.

Boundary oilfield

Location

The Boundary oilfield is about 70 km east of Derby and 40 km north of the Great Northern Highway (Fig. 2). Boundary 1 is the only well within the field and was drilled by Petroleum Securities Energy Ltd (1990), about 2.2 km south-southwest of the Lloyd oilfield and 2.7 km southeast of the West Terrace oilfield. The following information, apart from the production data, is derived from the well completion report (Knauer, 1990b).

Trap

Following the discovery of the Lloyd oilfield, Boundary 1 was planned to test several sandstone bodies within a poorly controlled closure in the upper Anderson Formation (Fig. 15). Oil was discovered in the Grant Group, which unconformably overlies the Lower Carboniferous Anderson Formation. Knauer (1990b), however, stated that the structural setting of the Grant Group corresponds to that of the underlying Anderson Formation, with only a slight offset. In this field the minor rollover at the base of the Grant Formation gradually disappears up the section (Fig. 8). After DST 4 produced water, the Anderson Formation sandstones were considered to be breached. The Anderson Formation rollover is superimposed on a minor flower structure defined at Laurel Formation level.

Reservoir

The productive interval lies within a unit of the Grant Group informally defined by the operating company as 'Unit C'. This unit is correlated with the Upper Carboniferous Betty Formation (Fig. 5). The oil-bearing sandstone (1277–1281 m) has a porosity of 20%. A fairly steady production rate (Fig. 16) is noticeable.

Reserves (original recoverable) and production

Original oil reserves were estimated at 19 057 kL (Table 2). Production commenced in December 1990, reached a peak of 592 kL/month in May 1991, and

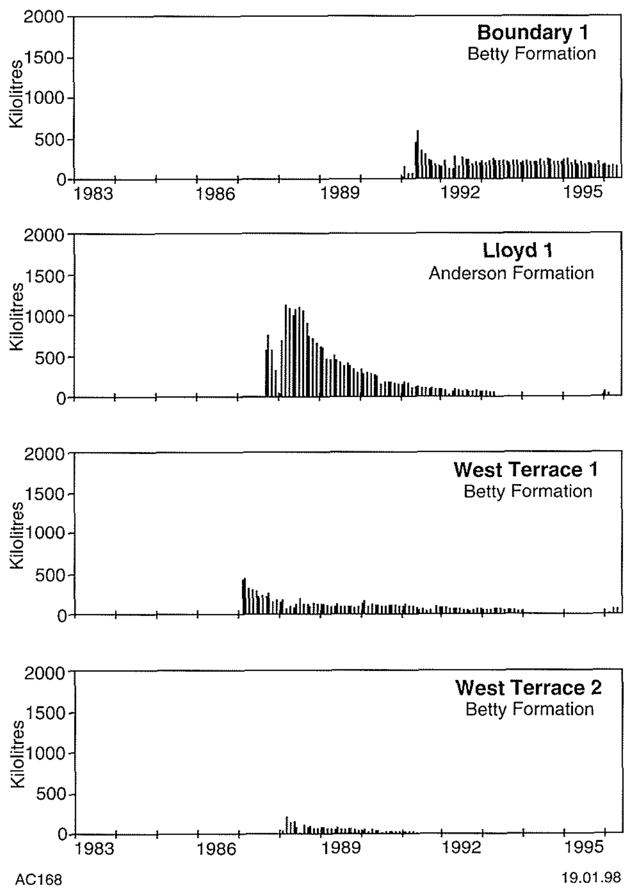


Figure 16. Boundary, Lloyd, and West Terrace oilfields: monthly production from inception to March 1996

stabilized after a few months at about 200 kL/month. In March 1996, 153 kL was produced (Fig. 16). The oil produced is trucked to central facilities at the Blina oilfield installation.

The paraffinic–naphthenic crude oil recovered from DST 2 has a gravity of 32.77°API, a pour point of 29°C, and has been water-washed.

Source

The source of the Boundary oil is probably shales of the Laurel Formation (Cadman et al., 1993) that contain predominantly algal–bacterial kerogen. The Boundary oil has probably been generated from a source of moderate maturity with an estimated equivalent vitrinite reflectance (Ro) of about 0.9%, although geochemical analyses are not conclusive and a mixed source cannot be excluded.

Lloyd oilfield

Location

The Lloyd oilfield is about 70 km east of Derby and 40 km south of the Great Northern Highway (Fig. 2). The discovery well, Lloyd 1, was drilled by Home Energy Company in 1987 close to the West Terrace oilfield.

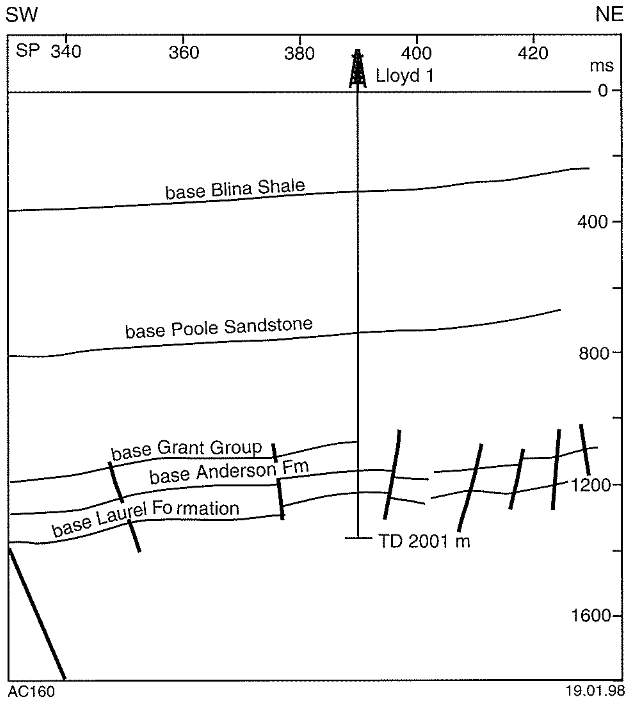


Figure 17. Interpretation of seismic section H82-13.7, showing the structural attitude of the Lloyd oilfield (modified from Jackson et al., 1993). The line of section is shown in Figure 6

Trap

Lloyd 1 was located to test a mapped four-way dip closure in the Yellow Drum Formation but the primary objective — a dolomite — was not encountered, and the entire formation was tight. Secondary sandstone objectives in the overlying gently folded Anderson Formation and Grant Group (Fig. 17) were more productive. In Lloyd 2, located 375 m southeast of Lloyd 1, the sandstone equivalent of the reservoir in the first well was finer grained and impermeable, and a DST over the interval recovered only half a barrel (80 L) of oil. These data and the amoeba-like configuration of the Lloyd structure in plan view (Fig. 18) suggest that the Lloyd oil accumulation is controlled, at least partially, by permeability barriers.

Wells drilled

Two wells have been drilled in the field, but only the first has produced oil. Information on the wells is provided by Denn and Johnson (1987c) and Denn (1988).

Reservoir

In Lloyd 1 a number of hydrocarbon shows ranging from minor to significant were encountered within the Grant Group, Anderson Formation, and Laurel Formation, but only one oil-bearing sandstone was penetrated in the Anderson Formation. Residual oil was also found as thin, tight streaks within porous sandstone of the Grant Group (929–935 m). The massive oil-bearing sandstone (1512–1528 m) is sealed by intraformational shales and was cored with 100% recovery. Petrophysical analyses of the core indicate that this reservoir has an average porosity of 18.7% and a permeability of 163 md. Production testing of the interval 1512.4–1522.8 m resulted in a flow rate of 62 kL/day (392 barrels of oil per day — bopd) through an 18/64" choke.

Reserves (original recoverable) and production

Original oil reserves were estimated to be 27 448 kL (Table 2). Production from the Lloyd oilfield commenced in August 1987 and the monthly production to March 1996 is shown in Figure 16. The flow rate peaked in February 1988 at 1129 kL/month, and then decreased rapidly to a few hundred kilolitres per month. Production was suspended in March 1993 when the monthly flow rate fell to 54 kL, and resumed at the end of 1995 following workover activities. In June 1996, Lloyd oilfield produced at rates of 1.5 kL/day (i.e. 9.4 bopd; Department of Minerals and Energy, 1996). The oil produced is trucked to central facilities at Blina.

The oil is a mature, saturated, light crude oil (40.4°API).

Source

A mixed marine–lacustrine source rock is envisaged for the Lloyd oil, which is probably from the Laurel Formation (Cadman et al., 1993).

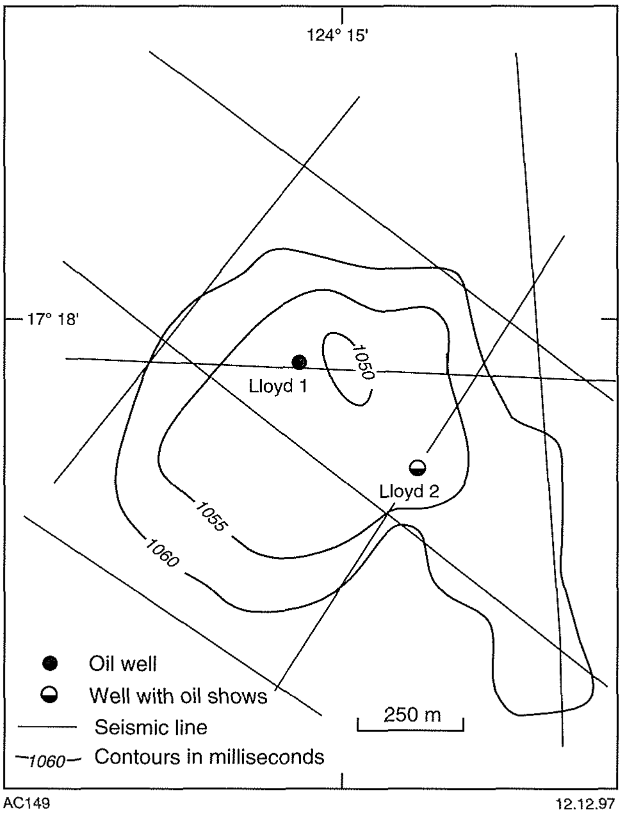


Figure 18. Structural configuration, in time, of the Lloyd oilfield on base reservoir sand, Anderson Formation, showing seismic control (modified from Denn, 1988)

Sundown oilfield

Location

The Sundown oilfield is about 32 km north of the Great Northern Highway and 73 km east-southeast of Derby (Fig. 2). The discovery well was drilled in 1982 by Home Energy Company.

Trap

Sundown 1 was drilled to test a seismically defined Famennian reef play, with the main objective being the Nullara Limestone. A compressional anticline of Mesozoic age over the reef was interpreted to be independent from the pre-existing depositional feature. A Famennian fringing reef was interpreted to extend from the Blina oilfield to Aquanita 1, and on to Sundown 1 and Yarrada 1. Another primary objective was the overlying carbonate of the Lower Carboniferous Yellow Drum Formation. Among the secondary objectives were sandstones of the Upper Carboniferous – Lower Permian Grant Group. The carbonates were found to be tight, but oil was recovered from sandstones of the Grant Group.

Further seismic control and drilling results of Sundown 1 to 5 indicate that the Sundown oilfield is at the crest of a gentle closure (Fig. 19). Seismic section H83-15.2 (Fig. 9) shows that at depth, the Sundown area is characterized by a positive flower structure typical of the regional late Givetian to Early Carboniferous rifting episode. Superimposed over this rift structure and probably controlled by its main fault, is an anticline bounded by a minor reverse fault that developed in the Middle Jurassic. Production results, however, indicate that the reservoir sandstones are of variable quality; therefore, the trap may be controlled by depositional factors. Since the Middle Jurassic anticline probably post-dated the migration of hydrocarbons, permeability barriers would be the likely trapping mechanism.

Wells

Six wells have been drilled in the oilfield, five of which are productive. Sundown 3 was plugged and abandoned because it did not encounter commercial quantities of oil (Table 3). Sundown 2 produced only intermittently from 1983 to 1985 after which it was suspended, apparently because of cement or mechanical problems. Sundown 3 was re-entered in 1995 to drill the horizontal Sundown 3H (Santos Ltd, 1995). The well was planned

Table 3. Sundown oilfield vertical wells

Wells	*Net pay*	*1995 bopd*	*Cumulative production (k bbls, 1995)*	*Notes*
Sundown 1	12.5	12	108.2	on-line from 1984
Sundown 2	8.5	–	18.0	shut-in in 1985
Sundown 3	–	–	–	plugged and abandoned (outside closure)
Sundown 4	11	13	120.8	on-line from 1985
Sundown 5	9	44	49.2	on-line from 1993
Total		**69**	**296.2**	**production for Sundown 3H excluded**

bopd: barrels of oil per day
k bbls: thousand barrels

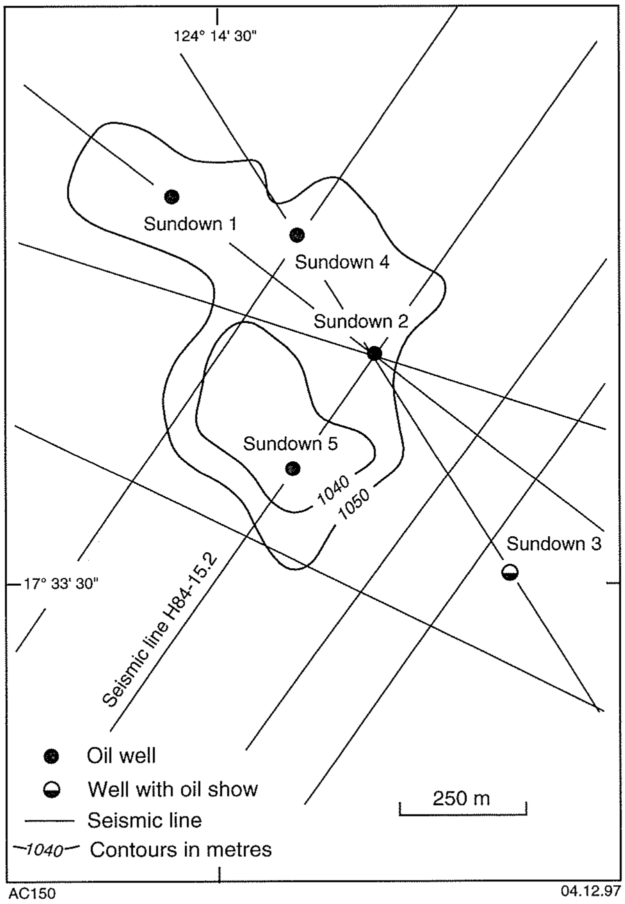


Figure 19. Structural configuration of the Sundown oilfield, near top Grant Group, showing seismic control (modified from Robinson and Roche, 1994b)

to pass horizontally through the central undrained portion of the main reservoir, with the hope of increasing the daily output of oil by as much as ten times, thus extending the life of the integrated operations of the five Lennard Shelf fields by several years. In 1995 total oil production from these fields declined to about 38 kL/day (240 bopd), and the operation was barely profitable. Information on the wells is from Mah (1983a,b; 1986), Denn (1985b), and Robinson and Roche (1994b).

Reservoir

The main reservoir of the Sundown oilfield is a massive, blocky fluvial-channel sandstone within the Betty Formation (Grant Group), named the '1100 m Sandstone' by the operating company. This reservoir is fine to medium grained with a few coarser layers, and has a variable porosity averaging 22.5% and reaching up to 24.5% (Robinson and Roche, 1994b). Permeabilities of as much as 2380 md have been measured, but mostly range from 200 to 900 md. In Sundown 4 the '1100 m Sandstone' produced under test 21.7 kL (136.5 barrels) of oil in 16.5 hours. Additional minor production may be possible from other sandstone units in both the Grant Group and the Anderson Formation.

Robinson and Roche (1994b) considered that in the Sundown area the presence of oil accumulations in the Grant Group is dependent upon the continuity of the relevant intraformational seal.

Reserves (original recoverable)

Total original recoverable reserves were estimated at 74 620 kL (Table 2). In March 1996, 867.8 kL (5458 barrels) of oil were produced, including output from Sundown 3H.

The oil is light (38–40°API) with a low sulfur content. Figure 20 shows the monthly production from the '1100 m Sandstone' commencing in October 1983. The early production rate of more than 500 kL/month per well, which peaked at 1500 kL/month in May 1986 from Sundown 4, was sustained for only a few months and declined rapidly to stabilize at around 100 kL/month after

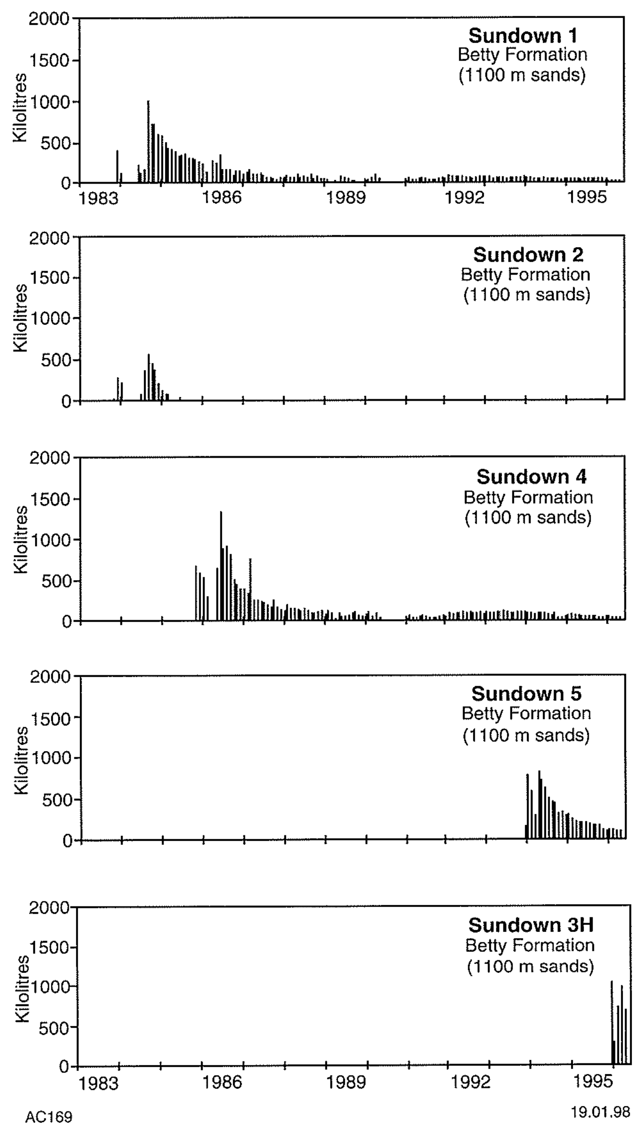


Figure 20. Sundown oilfield: monthly production from inception to March 1996

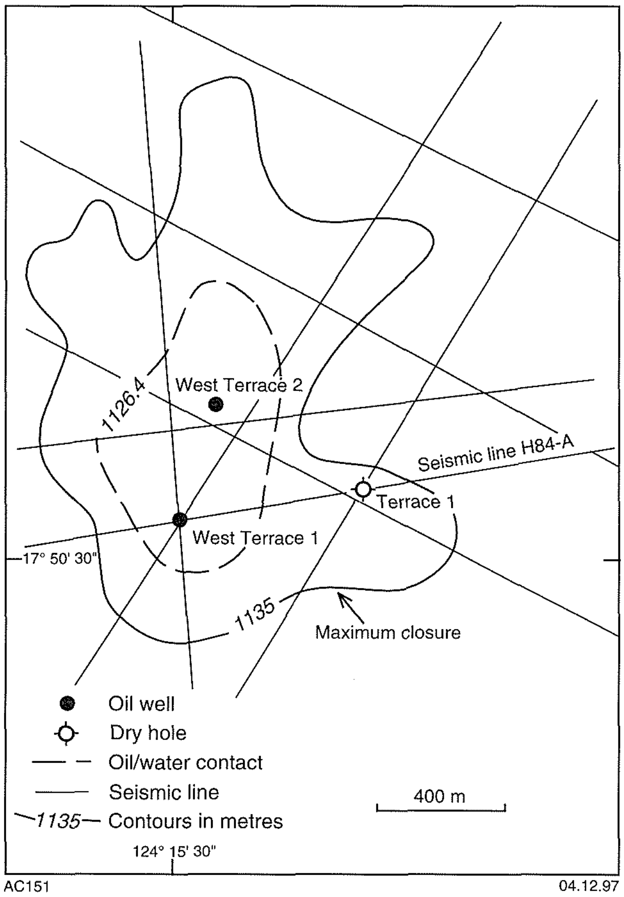


Figure 21. Structural configuration of the West Terrace oilfield on top reservoir sand, Betty Formation, showing seismic control (modified from Denn and Johnson, 1987b)

a few years. This decline has continued and production in most wells has diminished to a barely economic level. The initial production from Sundown 3H was 6754 kL/day (i.e. 1074 bopd; Fig. 20). The oil produced is trucked to central facilities at Blina.

Source

Mah (1983a) stated that the source of the Sundown oil is considered to be very mature and saturate rich, producing algal crude oil similar to that envisaged for Meda 1 from shallow-marine – lagoonal shales of the Laurel Formation. Robinson and Roche (1994b) suggested that the oil migrated via faults from deeper basinal areas such as the Fitzroy Trough, as oil accumulations are in close proximity to possible fault conduits. This suggestion is consistent with the Laurel Formation being within the oil window only below 1580 m in the Sundown area.

West Terrace oilfield

Location

The West Terrace oilfield is 74 km east-southeast of Derby and 38 km north of the Great Northern Highway (Fig. 2). A structural play in the area was first tested by Terrace 1 drilled by Home Energy Company in 1984, but the well encountered only residual oil at the top of the Grant Group and oil in uneconomic quantities from poor reservoirs in carbonates and sandstones of the Laurel Formation. The discovery well, West Terrace 1, was drilled by Home Energy Company in 1985.

Trap

The original objective of West Terrace 1 was a postulated stratigraphic trap related to a channel feature within the Grant Group. The well was located on the western flank of a major, dominantly northerly trending channel. The objective was water bearing, indicating that the channel feature was not a valid trap.

As mapped, the West Terrace oilfield lies in a simple unfaulted structure with four-way dip closure (Fig. 21). However, the subhorizontal attitude of the strata over the area (Fig. 22), the thickening of the intraformational sealing shale towards Terrace 1, the localized oil accumulation, and the environment of deposition of the oil-bearing Betty Formation (defined by the operating company as Lower Grant Formation) point to a stratigraphic entrapment.

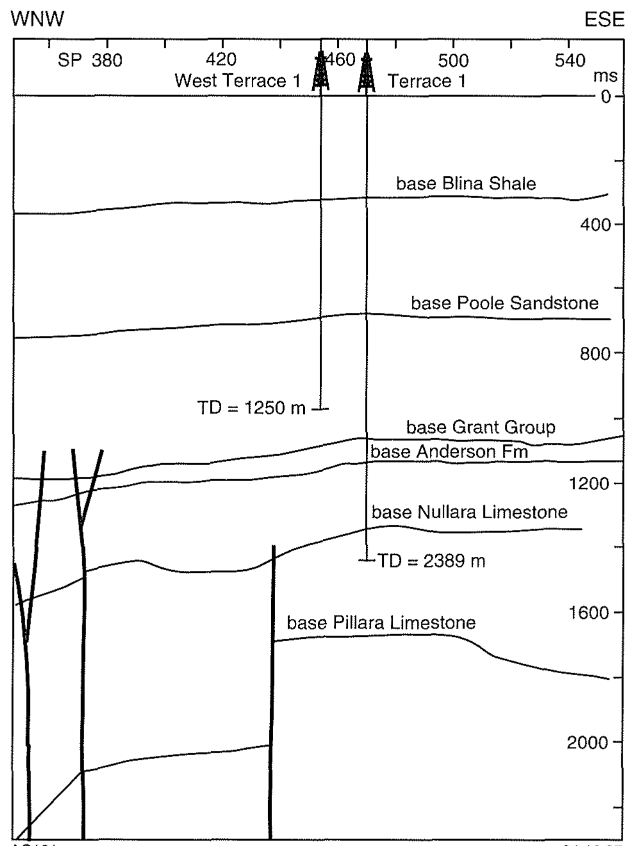


Figure 22. Interpretation of seismic section H84-A, showing the structural attitude of the West Terrace oilfield (modified from Jackson et al., 1993). The line of section is shown in Figures 6 and 21

Wells

Three wells have been drilled within the West Terrace area: Terrace 1 tested about 48 L (0.3 barrels) of 38°API oil from 1837 to 1868 m within the lower part of the Laurel Formation; and West Terrace 1 and 2 produced oil for a short time. Information on the wells is from Mah (1984), Denn (1985a), and Denn and Johnson (1987a).

Reservoir

The reservoir of the West Terrace oilfield is a fluvial sandstone interval within the Betty Formation of the Grant Group. A maximum porosity of 20% has been calculated for the oil-bearing sandstones. West Terrace 1 tested low-sulfur, saturated paraffinic oil of 32.8°API, at a rate of 109 kL/day (686 bopd) from the reservoir section.

Reserves (original recoverable) and production

The original oil reserves were estimated to be 30 148 kL (Table 2). Figure 16 shows the monthly production from West Terrace 1 from February 1987 to the end of 1993 when production became uneconomic. Following workover activities, limited production resumed early in 1996 and in June 1996 the West Terrace oilfield produced at rates of 1.6 kL/day (i.e. 10.1 bopd; Department of Minerals and Energy, 1996). The crude oil is trucked to central facilities at Blina.

West Terrace 2 produced only a modest amount of oil from January 1988 to mid-1991 (Fig. 16).

Source

The source rocks for the West Terrace oil are believed to be shales of the Famennian Laurel Formation (Cadman et al., 1993), which have excellent source-rock characteristics. In Terrace 1, samples from the Laurel Formation have a maximum T_{max} value (an organic maturity indicator generated by Rock-Eval pyrolysis) of 436°C, suggesting that the oil-generative window was reached. Vitrinite reflectance values from the Poole Sandstone down to the Frasnian (823–2351 m), however, range from 0.59 to 0.67%, indicating an immature or marginally mature sequence.

Other hydrocarbon occurrences

Within the Lennard Shelf, measurable but uneconomic amounts of oil have been discovered in Meda 1, Ellendale 1, Boronia 1, Kora 1, West Kora 1, Janpam North 1, Crimson Lake 1, and Wattle 1/ST1. Experimental production, totalling about 3800 kL (24 000 barrels) of oil, was obtained from West Kora 1 from 1989 to 1991. In addition, Point Torment 1 tested 4.3 million cubic feet per day (Mcf/d; about 121 000 m^3/d) of gas.

The following sections discuss the results of the wells, including possible reasons for the absence of economically significant hydrocarbons. The unpublished well completion reports referred to within the text are held in the S-series files at DME (Appendix 2).

Meda 1 and Meda 2

Location

Meda 1 was the first WAPET well to be drilled on the Lennard Shelf. It was completed in 1958 about 60 km east of Derby (Fig. 2) and was followed by Meda 2 in 1959 about 1200 m to the south. Data on the wells are provided by Pudovskis (1959a,b; 1962).

Stratigraphy

Meda 1 was spudded in alluvium overlying the Lower Triassic Blina Shale and continued down through the regional Permian, Carboniferous, and Devonian stratigraphic sequence to a basal conglomerate of probable Devonian age. The well terminated at 2685 m in Precambrian schist. The presence of cuttings of granite in the Betty Formation — 'Lower Fluvioglacial member' of Pudovskis, (1959a; 1962) — is here considered to indicate glacial erratics rather than 'pebbles' (Pudovskis, 1959, cuttings log). The Grant Group lithostratigraphy for the well (Fig. 23) is consistent with that of Middleton (1990). Meda 2 was terminated at 2325 m within the Nullara Formation.

Structure

Meda 1 was located on an elongate positive gravity anomaly, assumed to represent a basement high on which a Devonian reef may have developed. This interpretation was supported by seismic data. Meda 2 was located in what was thought to be a better palaeogeographic position, within a southern reef development, whereas Meda 1 was drilled shoreward (north) of the reef margin.

Figure 24 suggests that a basement-controlled wrench movement created the flower-like structure with a small closure up to an intra-Carboniferous level, whereas younger sedimentary rocks show a monoclinal structure.

Reservoirs

The reservoir in Meda 1 is a 2.5 m-thick, weakly permeable, fine-grained calcareous and dolomitic sandstone in the upper part of the Laurel Formation. Indications of oil within sandstones of the Laurel Formation are more numerous in Meda 2 than in Meda 1, but the potential reservoirs are thinner and less porous. The results of Meda 2 indicate that the oil-bearing sandstones in Meda 1 are lenticular and elongate along strike but limited in the direction of dip. Meda 1 encountered gas in a carbonate with low porosity and permeability. Sporadic vuggy porosity indicates that connections between vugs are poor.

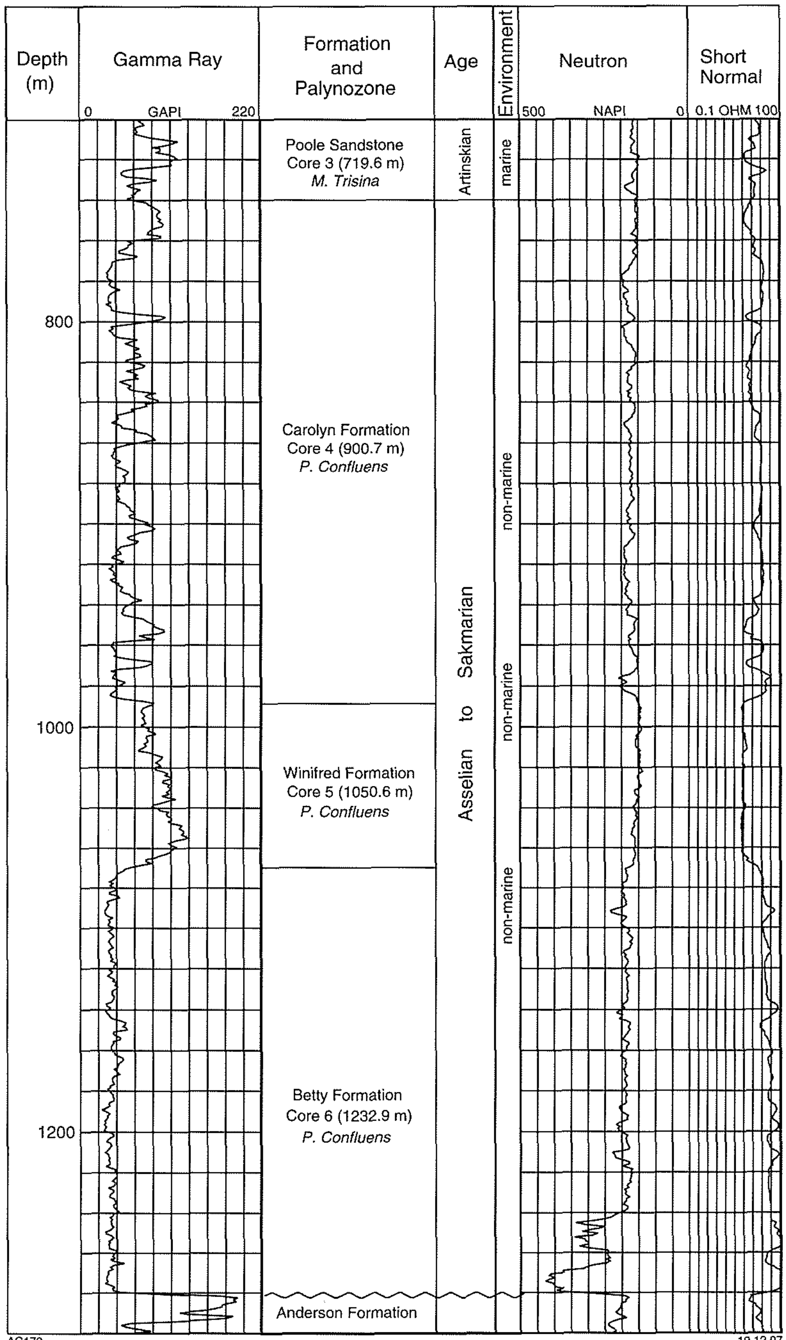


Figure 23. Meda 1 well log, showing the Grant Group and upper Anderson Formation

Hydrocarbons

In Meda 1 an estimated 3 gallons (about 11 L) of 38° API paraffinic crude oil was recovered from DST 9 (1558.5–1565.5 m). The oil is low in asphaltenes and sulfur content. An additional 4.5 gallons (about 17 L) of oil was recovered by skimming from the tanks during DST 9b, which lasted 30 hours.

Gas, predominantly methane, was tested in Meda 1 through perforated casing by DST 8 (1601–1619.5 m) in an amount too small to measure. Testing in the open hole by DST 2 (2029.5–2042 m) resulted in the flow of an estimated 100 thousand cubic feet per day (mcf/d; about 2800 m^3/d), decreasing to about 30 mcf/d (about 840 m^3/d) after two and a half hours. Testing through perforated casing by DST 7 (four intervals between 2011 and 2042 m) produced an unquantified moderate flow. The other DSTs carried out in Meda 1 were either dry or recovered saltwater. Modest shows of oil and gas were also detected during the drilling of Meda 2 in the Fairfield, Nullara, and Pillara units.

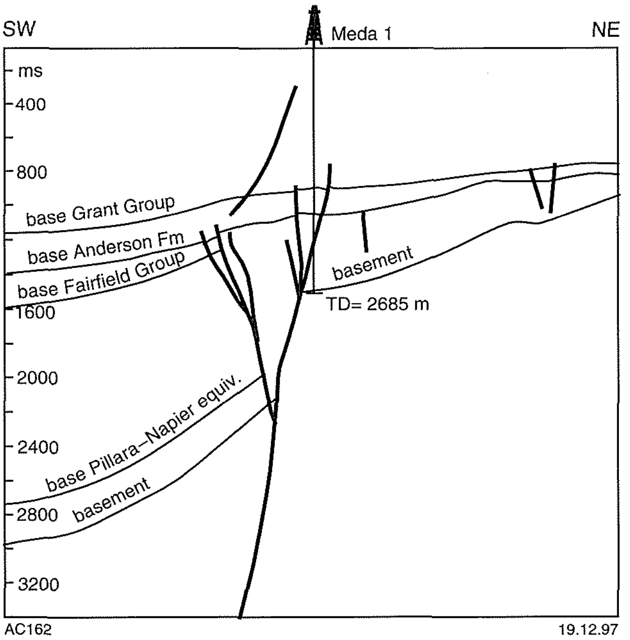


Figure 24. Interpretation of seismic section H84-10.5, showing the setting of the Meda structure (modified from Jackson et al., 1993). The line of section is shown in Figure 6

Source

Alexander et al. (1985) showed that the Meda oil had a high concentration of saturated hydrocarbons (91%) similar to the Blina oil, and they suggested an input from marine plant material. Alexander et al. (1985) also indicated that although the source type was broadly similar for all the oils examined (including Meda 1 and Blina 1), it was possible to distinguish between them provided sufficiently detailed analyses were carried out. They suggested that the Meda 1 oil was sourced from Carboniferous sedimentary rocks, which implies that the oil originated from the Laurel Formation. A Devonian source (?Gogo Formation) is likely for the gas.

Reason for failure

Although the presence of a valid trap was not fully demonstrated, the reason for the lack of hydrocarbons in the Fairfield, Nullara, and Pillara units is probably the poor development of potential reservoirs. The Upper Carboniferous, on the other hand, clearly lacks an effective trap (Fig. 24).

Ellendale 1

Location

Ellendale 1 is 5 km south of the Harvey Fault System, which defines the southern limit of the Lennard Shelf and therefore formally lies within the Fitzroy Trough (Fig. 3). The well is 135 km east-southeast of Derby, near the Great Northern Highway (Fig. 2), and was drilled in 1979 by Amax Petroleum. Basic information is derived from the well completion report (Amax Petroleum Pty Ltd, 1980).

Stratigraphy

Ellendale 1 was spudded into the Permian Liveringa Formation and terminated at 3190 m in the Famennian Napier Formation. The basin-wide unconformity at the base of the Grant Group was reached at 1425 m. In this report, formation tops below the Anderson Formation have been tentatively redefined, using the lithological descriptions and scanty datings provided by Amax Petroleum Pty Ltd (1980, table 2).

Structure

The well was planned as a new-field wildcat, primarily to test interpreted reefoidal carbonate build-ups within the Fairfield Group.

The well results suggest that Ellendale 1 tested the collapsed crestal part of a positive flower structure in the Fairfield Group and Nullara Limestone (Fig. 25). This structure formed from strike-slip faulting during the Meda Movement. A small amount of reversal at higher levels is probably related to Middle Jurassic tectonism. On seismic line A78-1 the crest of the structure at all levels appears to be 12 shotpoints east of Ellendale 1 (Fig. 25).

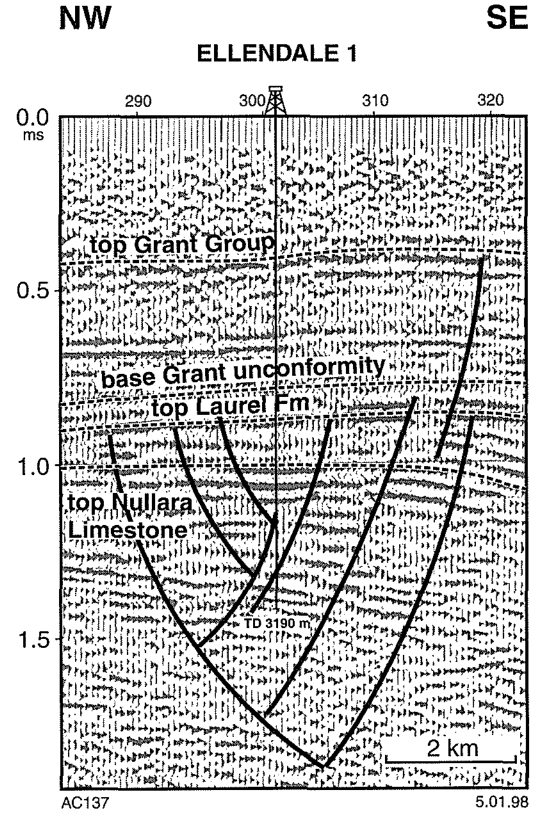


Figure 25. Seismic section A78-1, showing the setting of the Ellendale structure. The line of section is shown in Figure 6

Reservoirs

A minor gas flow was obtained from thin stringers of sandstone (1665–1701 m) in the Laurel Formation (Fairfield Group) by DST 3. The test results indicate that the low-porosity sandstones have very low permeabilities. In addition, a gas flow (100 mcf/d, about 2800 m^3/d) and some oil was obtained from fractured limestones of the Nullara Limestone by DST 2 (2155–2173 m).

Hydrocarbons

Minor hydrocarbon shows were present throughout the Anderson Formation. Strong shows of both oil and gas were obtained from clastic rocks in the Laurel Formation, from which DST 3 (1701–1694 m and 1665–1649 m) yielded a small volume of gas. The best indications of hydrocarbons were provided by the Nullara Limestone, from which DST 2 (2155–2173 m) produced a brief flow of gas and one litre of oily water. The oil is naphthenic, with a gravity of 35°API. The gas was composed of nitrogen (16%), methane (72%), ethane (5%), propane (5%), and higher hydrocarbons.

Source

Within the section drilled by Ellendale 1, the Laurel Formation has the best source-rock potential. The presence of oil within the Nullara Limestone (underlying the Laurel Formation) may support the statement that the Ellendale 1 oil was generated by a deeper source, such as shales in the Gogo Formation (Cadman et al., 1993), but this is not proven. Migration conceivably occurred via regional transfer faults from the deeper parts of the Fitzroy Trough.

Reasons for failure

Ellendale 1 encountered hydrocarbons (DST 2 and DST 3), potential reservoirs (sandstones of the Laurel Formation and fractured limestones of the Nullara Limestone), and seals (shales of the Fairfield Group). The presence of only a limited amount of hydrocarbons in the well may have resulted from the poor permeability of potential reservoirs, or poor migration paths from the kitchen areas. Alternatively, the reason that Ellendale 1 failed to find a sizeable hydrocarbon accumulation may be that the elevation of the Nullara Limestone in the well is about 50 m lower than the structurally highest part of the unit on seismic line A78-1 (Fig. 25), and possibly even lower than this with respect to the maximum elevation of the structure.

Boronia 1

Location

Boronia 1 was drilled in 1982 by International Energy Development Corporation of Australia within the southern part of the Lennard Shelf, about 110 km southeast of Derby and 9 km north of the Great Northern Highway (Fig. 2). Information on the well is from Ellyard (1983).

Stratigraphy

Boronia 1 was spudded in the Blina Shale and then penetrated the usual regional stratigraphic succession down to the Pillara Limestone, in which the well terminated at 3391 m (Appendix 1). This well shows that the Anderson Formation has been completely removed by Late Carboniferous erosion in this area.

Structure

Boronia 1 was planned to test two superimposed seismic anomalies thought to be the expression of Upper Devonian pinnacle reefs. The Boronia feature is interpreted here as wrench induced with rollover closure in the Pillara Limestone, and complex structuring at higher levels characterized by crestal collapse (Fig. 26). The absence of Anderson Formation in the well and onlap at the base of the Grant Group (Fig. 26, southwestern part) suggest that the structure was a positive feature in the Late Carboniferous.

Reservoirs

A small amount of oil was recovered from thin sandstones in the upper part of the Pillara Limestone. Drillstem test results indicate very low permeability for the sandstones.

Hydrocarbons

Boronia 1 did not encounter any shows of hydrocarbon above the Nullara Limestone. Fluorescence was noted in tight sandstones at the top of the unit here referred to as the Napier Formation and designated as 'Luluigui Shelf equivalents' by Ellyard (1983), but two DSTs in perforated $9^5/_8$ inch casing failed to recover any hydrocarbons, even after acid stimulation.

The best indication of hydrocarbons was in DST 1, which yielded several litres of 35°API oil. This test was run in the open hole in the interval 2799.5–2817.5 m within sandstones of the Pillara Limestone.

Source

The low sulfur content of the oil recovered by DST 1 suggests that it was probably sourced from a mature marine clastic unit, perhaps the Gogo Formation. Little, if any, contribution from land plants is indicated by the composition of the oil.

Reasons for failure

The Boronia structure was also unsuccessfully tested by Mimosa 1 (Fig. 26), in which the Pillara Formation contained low-permeability sandstones and from which no hydrocarbons were recovered. Therefore, the lack of an economic accumulation of hydrocarbons in this structure is most probably due to the absence of effective reservoirs.

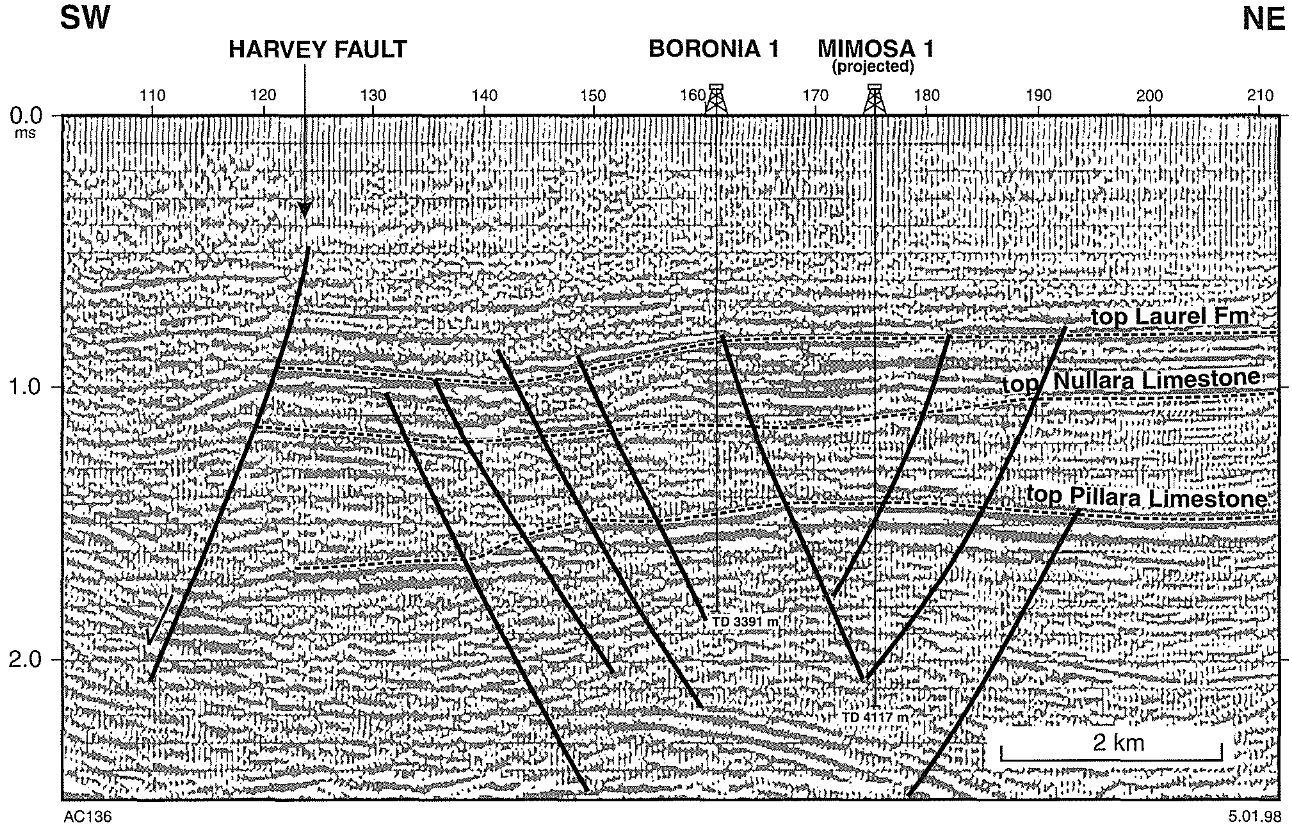


Figure 26. Seismic section ED81-82, showing the setting of the Boronia structure. The line of section is shown in Figure 6

Kora 1 and West Kora 1

Location

Kora 1 and West Kora 1 were drilled in 1982 and 1984 respectively by Esso Exploration, about 20 km east-northeast of Derby and 12 km north of the Great Northern Highway (Fig. 2), in the westernmost onshore part of the Lennard Shelf. Information on the wells is derived mainly from the well completion reports (Reeckman, 1983; Sloan and Neumann, 1984).

History of exploration

Kora 1 was programmed to test three objectives within a fault-controlled anticline: sandstones in the Permian–Carboniferous Grant Group and the Carboniferous Anderson Formation; sandstones and carbonates in the Lower Carboniferous Fairfield Group; and reefal limestones in the Upper Devonian Nullara Limestone. No production was obtained from Kora 1, although oil was recovered from the Betty Formation of the Grant Group (Table 4).

The results of Kora 1 focused the interest of Esso Exploration towards Carboniferous clastic sedimentary rocks. At this level Kora 1 was interpreted to be on the edge of a structural closure, where it would have intersected the objective sandstones in transition zones near the oil–water contacts of a series of stacked reservoirs. West Kora 1 was programmed to be a structurally better located follow-up to Kora 1, with post-Devonian sandstones representing the primary targets. A West Kora 1 production test recovered about 32 kL of oil (203 barrels; Table 5). No immediate action followed because the well productivity was considered too low.

Stratigraphy

Kora 1 penetrated a Middle Triassic (Erskine Sandstone) to Upper Devonian (Napier Formation) stratigraphic section, and reached a total depth of 3101 m (Appendix 1). In this report the sequence in the well is considered to be basically continuous, apart from the time gap represented by the basin-wide Grant Group – Anderson Formation unconformity. The units tentatively referred to here as the Yellow Drum and Gumhole Formations (Appendix 1) were previously not differentiated in this well, and were placed within the Laurel Formation (Reeckman, 1983). West Kora 1 penetrated a similar sequence down to 2606 m (Appendix 1) where the well terminated within the Nullara Limestone.

Structure

The Kora – West Kora structure initially formed when late Givetian to Early Carboniferous regional rifting opened up the basin in a northeast–southwest direction.

Table 4. Kora 1 drillstem tests

DST no.	Well status	Depth (m)	Formation	Recovery	Comments
1	open hole	1667–1689	Grant Group (Betty Fm)	–	tool plugged
2	open hole	1754–1800	Grant Group (Betty Fm)	–	test failed
3	open hole	1760–1800	Grant Group (Betty Fm)	77.3 bbls formation water, 2–3 gallons 41.9–44.8° API paraffinic oil	–
4	open hole	2086–2107	Anderson Fm	–	tight
5	open hole	2905.7–2914.9	Nullara Limestone	30–50 bbls of high salinity formation water	local vuggy porosity
6	cased	1674–1681	Grant Group (Betty Fm)	water, mud filtrate, trace oil	–
7	cased	1608–1611.8	Grant Group (Betty Fm)	water, mud filtrate, brine	?formation damage

Fm: formation
bbls: barrels

During that rifting Nullara Limestone was deposited over a pre-existing high, controlled by normal faults. Middle Jurassic wrench movements modified the structure to a fault-controlled, gentle, northwesterly trending anticline (Figs 27 and 28). The main northeasterly trending fault zone of the general Kora – West Kora area has been termed the Kora transfer zone (Shaw et al., 1994; fig. 4).

Production data suggest that the accumulation is controlled by depositional factors.

Reservoirs

Reeckman (1983) reported a 1 m-thick oil zone at 1763 m depth from the Kora 1 logs, within a sandstone unit of the Betty Formation (Grant Group). The formation consists predominantly of sandstones with lesser amounts of interbedded siltstones and shales. The measured porosity of sandstone at 1680 m in Kora 1 is 14.5–16.1% with a permeability of 10–20 md. This porosity is a mixture of primary intergranular porosity and secondary porosity from the leaching of feldspars — permeability is significantly reduced by the presence of fine authigenic clays.

Oil was produced in West Kora 1 from the interval 1735–1751 m, within the lower part of the Anderson Formation, characterized by thinly interbedded sandstone and siltstone with numerous lateral facies changes. The environment of deposition is considered to be a low-energy coastal plain that was dissected by tidal channels and possibly some fluvial streams. The log-derived average porosity for the entire Anderson Formation in West Kora 1 is 12%. The porosity of the oil-bearing horizon is 13%. From the production test, the permeability of the same interval was calculated as 4–6 md. Production data from West Kora 1 indicate a drop in permeability below a depth of 43 m. This drop indicates either a change in the properties of the sandstone or a pinch-out.

The carbonates of the Nullara Limestone are tight, although poor localized porosity is indicated by a limited gas show in Kora 1.

Hydrocarbons

Kora 1: Oil bled from the top two metres of a core cut between 1680 m and 1689 m in sandstone of the Betty Formation (Grant Group). A sample taken during a repetitive formation test (RFT) recovered filtrate with a light-oil film from a depth of 1769 m. Shows of hydrocarbons were obtained throughout the Betty Formation, as well as from the Anderson and Laurel Formations. Table 4 illustrates the results of the seven tests carried out. The best results have been obtained

Table 5. West Kora 1 drillstem and production tests

DST no.	Well status	Depth (m)	Formation	Recovery	Comments
1	open hole	1741.0–1758.5	Anderson Fm 'upper unit'	6 barrels 49°API oil, 7 barrels filtrate	poor well productivity
1	cased hole	1987–1990	Anderson Fm 'middle unit'	water	poor well productivity
Production Test 1	cased hole	1735–1751	Anderson Fm 'upper unit'	203.1 barrels 48°API oil and 136.4 barrels of formation water	average flow rate: 30 stb/d oil with average water-cut of 40%

stb/d: stock tank barrel/day

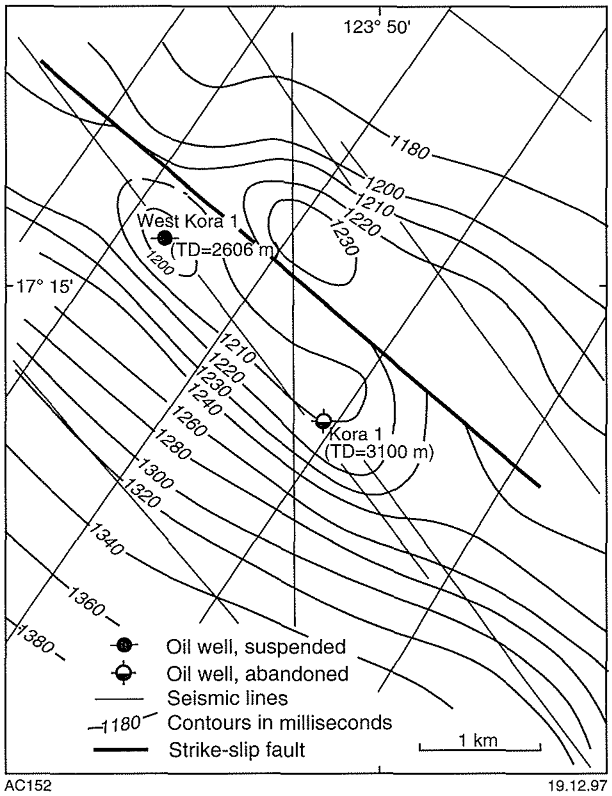


Figure 27. Structural setting of the Kora area: time-structure map of an intra–Anderson Formation level, (modified from Sloan and Neumann, 1984; and Lehmann, 1986). Seismic control shown

from DST 3 (1760–1800 m), which yielded about 10 L (2–3 gallons) of light oil from the Betty Formation.

High readings of mainly methane gas were detected in three zones of the Nullara Limestone.

West Kora 1: From the results of the production test (Table 5), 2 m of oil-bearing sandstone with low permeability is interpreted between 1735 m and 1751 m ('upper unit', Anderson Formation). Shows of hydrocarbons were obtained throughout the Anderson Formation and in three thin zones of the Laurel Formation in tight, highly water saturated sandstones. Following the production of oil from the 1735–1751 m interval, the well was suspended as a potential oil producer.

Limited production commenced in 1989 and the oil was gathered, separated, and stored at the well site before being transported to the Broome ship-loading facilities. Cumulative production from West Kora 1 to 30 June 1991, when production ceased, was about 3800 kL (24 000 barrels) of oil. West Kora 1 was re-entered in November 1992 for pump production testing and perforation of an additional interval. Production of up to 7.6 kL/d (48 bopd) was achieved with about 90% water-cut, without resolving whether the high water content originated from the pre-existing or the newly perforated interval. The well was shut-in pending remedial work. No estimate of oil reserves is available.

Source

A predominantly marine source is postulated for the light paraffinic Kora oil. As the oil shows extend up the sequence from the top of the Laurel Formation, shales and siltstones within that unit are the most likely source of the oil from the two wells. Lack of oil and modest indications of gas throughout the Devonian and Lower Carboniferous limestones, however, may be the result of lack of permeability, but exhaustive source-rock – oil correlations are needed to reach a definitive conclusion. At present, only a small number of chromatograms of cutting extracts from Carboniferous and Devonian sedimentary rocks of the entire Lennard Shelf are available, and these appear to be quite similar.

Reasons for the limited amount of hydrocarbons discovered

Carbonates

No hydrocarbon accumulation was found in the Nullara Limestone, probably because of the very localized porosity and the lack of permeability.

Clastic rocks

Oil was not found in the thick, extensive, and porous sandstone in the 'middle unit' of the Anderson Formation, or in the fluvial sandstone with very good reservoir potential in the overlying Grant Group. In West Kora 1, hydrocarbons are only preserved in the thin sandstone and siltstones, with numerous lateral facies changes. Migration is interpreted to occur via fault planes connecting both marine Devonian and Lower Carboniferous shales with the Permo-Carboniferous reservoirs. Therefore, the limited production is probably due to the limited effectiveness of the trap, which is in turn a result of the low sealing potential of both the Anderson Formation and the Grant Group.

Janpam North 1

Location

Janpam North 1 was drilled as a new-field wildcat hole in 1987 by Home Energy Company within the central part of the Lennard Shelf, about 80 km east-southeast of Derby and 30 km north of the Great Northern Highway (Fig. 2). Information on the well is from Denn and Johnson (1987b).

Stratigraphy

Janpam North 1 penetrated the typical Lennard Shelf succession from the Erskine Sandstone to the Napier Formation. The well terminated at 2202 m (Appendix 1) within the Napier Formation — defined by Denn and Johnson (1987b) as 'Frasnian clastics'. The Anderson Formation is not present and the Grant Group transgresses directly over the Laurel Formation.

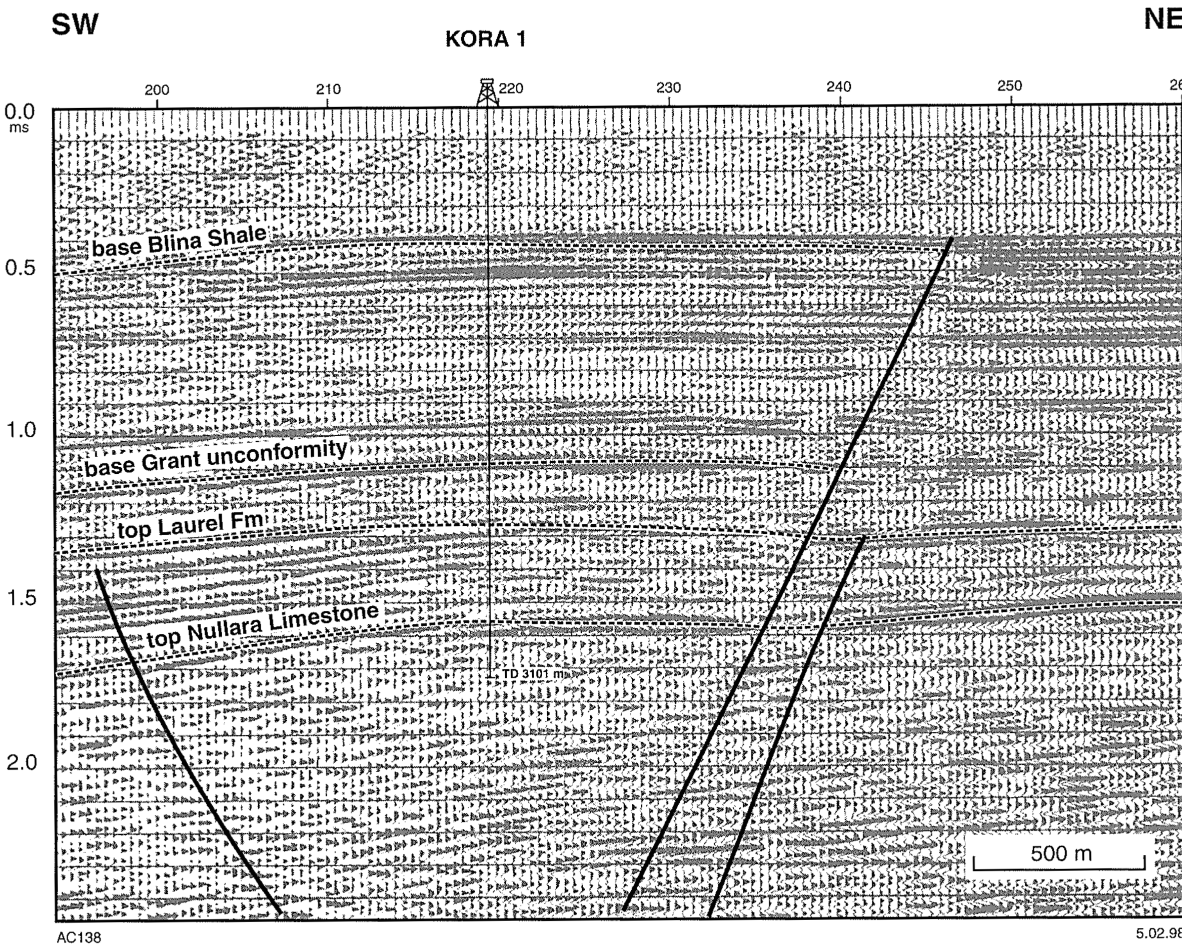


Figure 28. Seismic section H81-07, showing the setting of the Kora structure. The line of section is shown in Figures 6 and 27

Structure

Janpam North 1 was planned to test a seismically defined four-way dip closure, interpreted as a reefal feature. As is characteristic of rift-induced structures on the Lennard Shelf, the prospect shows Devonian and Carboniferous strata gradually becoming less faulted and folded upward, whereas only a simple monoclinal setting is present in the overlying Permian section (Fig. 29).

Reservoirs

Oil is contained within dolomites in the upper part of the Nullara Limestone. Core 1 (1662–1680 m) cut from this level shows very fine vuggy and fracture porosity. Permeabilities of 12–315 md have been measured over selected intervals, but these values are not valid for a comprehensive formation evaluation. Core 1 also contains a large amount of pyrite.

DSTs 3–5 across the upper part of the Napier Formation (selected intervals between 1852 and 2032 m) indicate that the tested sandstones are tight, with minimal porosity and virtually no permeability.

Hydrocarbons

Both oil and gas shows were encountered in limestones of the basal Gumhole Formation, dolomites of the Nullara Limestone, and clastic rocks of the Napier Formation. However, oil was only obtained from the Nullara Limestone; DST 1 (1644–1661 m) recovered 405 L (2.55 barrels) of 23°API oil, whereas only 80 L (0.5 barrels) of oil was recovered from DST 2 (1643.5–1680 m). Geochemical analyses indicate that the oil is a mature, saturate-rich, paraffinic type of crude oil.

Source

The oil was sourced from sedimentary rocks deposited in an anoxic marine environment. Such a source is consistent with the limited information available for the Gogo Formation.

Reasons for failure

In Janpam North 1 no effective reservoirs were encountered throughout the Carboniferous–Devonian interval. This

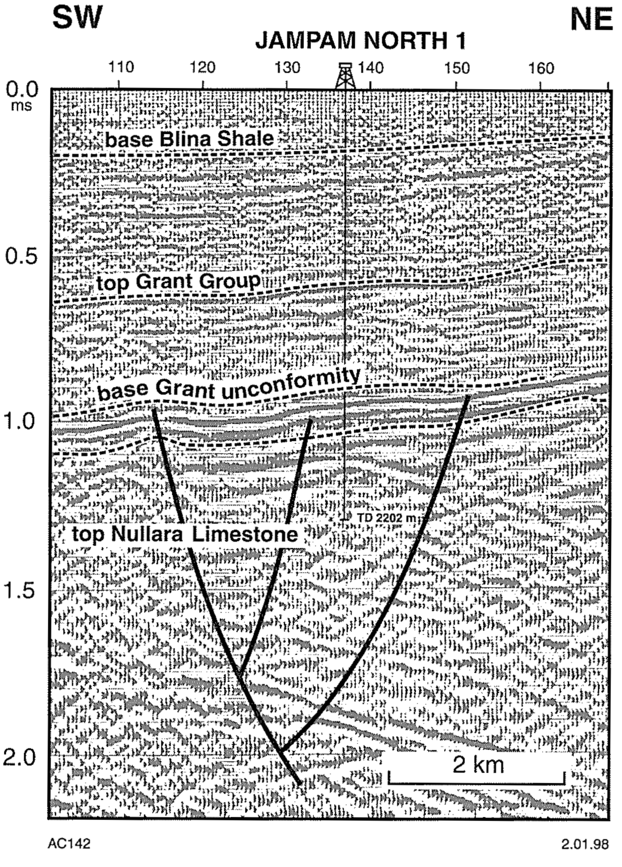


Figure 29. Seismic section H80-19, showing the attitude of the Janpam North structure. The line of section is shown in Figure 6

is considered to be the principal factor for the failure to discover a significant hydrocarbon accumulation at this location.

Crimson Lake 1

Location

Crimson Lake 1 was drilled in 1988 by Kufpec Australia in the southeastern corner of the study area close to the Lennard Shelf but just to the south of the Harvey Fault System, and therefore within the Fitzroy Trough (Fig. 3). The well is about 127 km southeast of Derby and 5 km northwest of Ellendale 1 near the Great Northern Highway (Fig. 2). Data are derived from the well completion report (Kufpec Australia Pty Ltd, 1989).

Stratigraphy

Crimson Lake 1 was spudded in the Lower Permian Liveringa Formation and penetrated the regional Lennard Shelf stratigraphic succession down to the lowermost member of the Laurel Formation, where the well terminated at 1980.9 m (Appendix 1). All four informal members proposed by Kufpec Australia Pty Ltd (1989) for the interbedded lithologies of the Laurel Formation are present in the well. Kufpec Australia Pty Ltd (1989) identified a 'Lower Grant Group Pre-glacial Unit' referred to here as the basal part of the Betty Formation.

Structure

Crimson Lake 1 was scheduled as a wildcat test of the Laurel Formation within a heavily faulted structure with four-way dip closure (Figs 30 and 31). Sandstones of the Grant Group and Anderson Formation were considered secondary objectives.

The structure is here interpreted as a young, probably mid-Jurassic, fault-controlled gentle anticline superimposed on a late Givetian to Late Carboniferous strike-slip induced flower structure. A crestal collapse is evident at the top Laurel Formation level (Fig. 31).

Reservoir

The well encountered reservoirs with very low permeability; both sandstones and carbonates proved to be tight. Pressure build-ups in DST 1 (Winifred Formation, Grant Group) indicate a permeability of less than one millidarcy, and that the reservoir was undamaged but tight. A very low energy depositional setting for the reservoirs is indicated by the petrographic reports, which also discuss the lack of significant porosity. DST 2 (1025–1036 m, Grant Group) and DST 3 (1587–1605 m, Laurel Formation) were ineffective probably because of low permeability.

Hydrocarbons

During drilling, occurrences of oil were observed from the Winifred Formation level to the end of the hole. In that unit DST 1 (1021–1048 m) recovered half a barrel of 37.9°API oil.

Selective formations testing (SFT) indicate a water gradient in both the Grant Group and the Anderson Formation. Trace amounts of free oil were collected from the shakers at a depth of about 1619 m (Laurel Formation, upper member).

Source

The pristane:phytane ratio of the whole-oil analysis (DST 1) suggests that the oil was generated from sedimentary rocks deposited in a mixed reducing environment. Such an environment is consistent with that of Laurel Formation shales, but as so little is known about the Gogo Formation it cannot be eliminated as a possible alternative.

Reasons for failure

Most of the potential reservoirs in Crimson Lake 1 were flushed by either fresh water (1100 mg/L) or formation water (17 000 mg/L). All potential reservoirs with

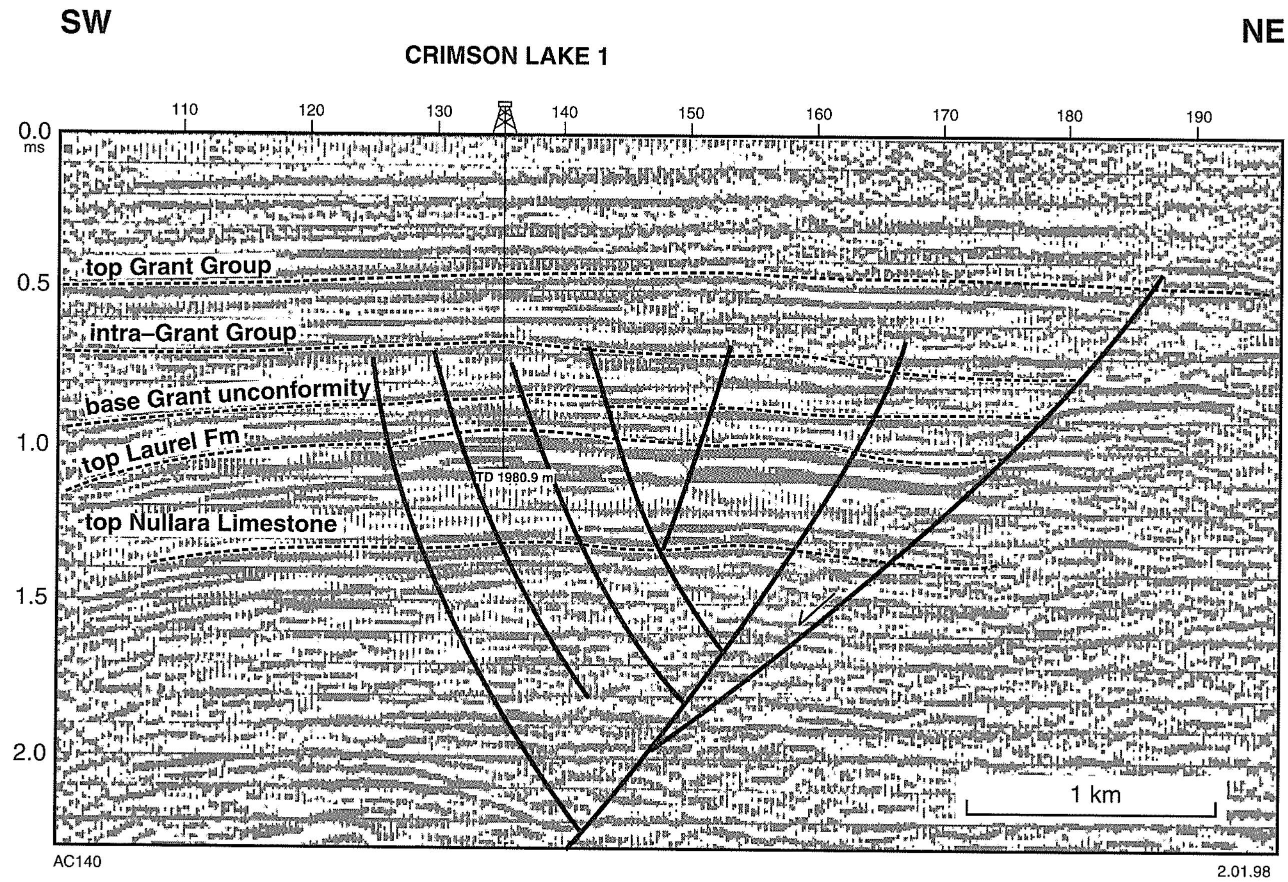


Figure 30. Seismic section ED82-173, showing the structural attitude of the Crimson Lake structure. The line of section is shown in Figures 6 and 31

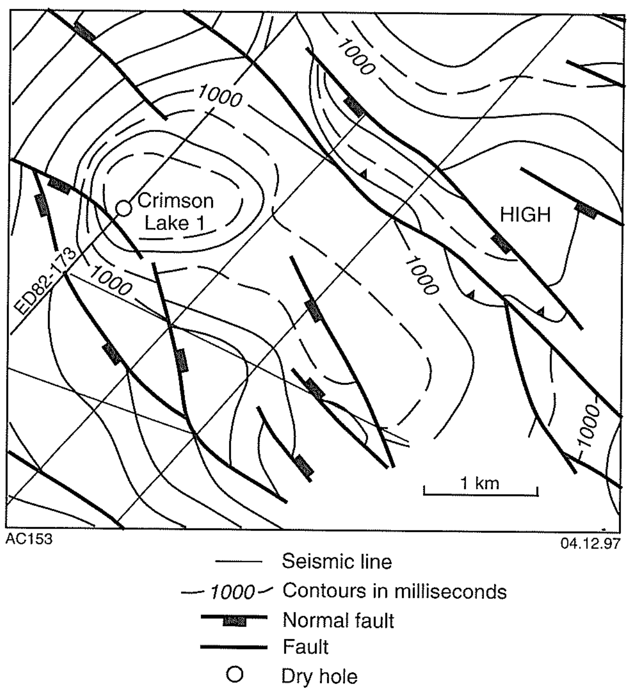


Figure 31. Crimson Lake time-structure map, near top upper Laurel Formation (modified from Kufpec Australia Pty Ltd, 1989)

hydrocarbon shows have little or no effective porosity and permeability. The lack of an economic accumulation of hydrocarbons, therefore, is related to the absence of sealed reservoirs.

Point Torment 1 and Point Torment 1 Deepening

Location and status

Point Torment 1 was drilled in 1992 by Anzoil within the westernmost part of the onshore Lennard Shelf, 20 km northeast of Derby and 13 km northwest of West Kora 1, which provided the nearest subsurface control (Fig. 2). Point Torment 1 was cased and suspended as a new gasfield discovery with production from the Anderson Formation. The well was then further deepened and tested in 1994 by Stirling Resources. Information on the well is derived from the well completion reports (Thornton, 1993; Nilsen and Knox, 1995).

Stratigraphy

Point Torment 1 was spudded into the Middle Triassic Erskine Sandstone and then penetrated the normal

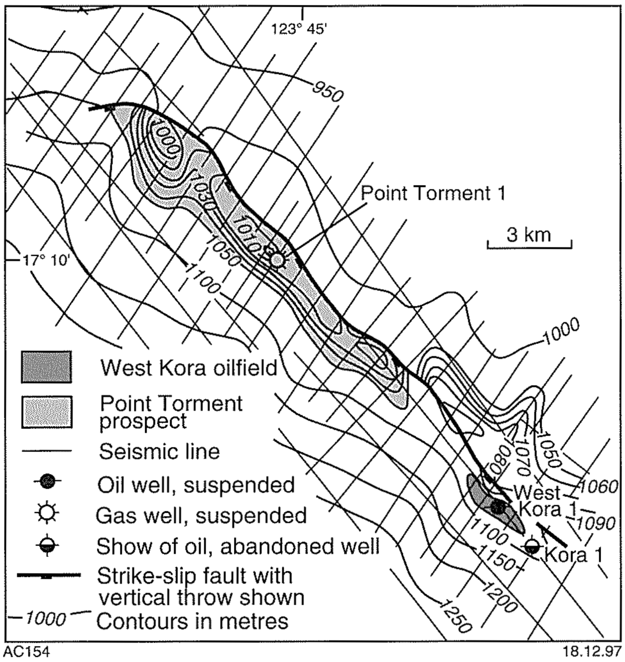


Figure 32. Structural configuration of the Point Torment, West Kora, and Kora areas (modified from Thornton, 1993). Seismic control shown

regional stratigraphic sequence to a depth of 2130 m where the well terminated in the Anderson Formation. Point Torment 1 Deepening well was extended into the Fairfield Group and Nullara Limestone reaching a total depth of 2603 m (Appendix 1). Only a small section has been eroded from the top of the Westphalian Anderson Formation, due to processes associated with the Meda Movement.

Structure

Prior to drilling, it was proposed that the prospect was a stratigraphic or structural play on the downthrown side of the Pinnacle Fault. Three small structural culminations were mapped within a larger possible stratigraphic trap (Fig. 32). Point Torment 1 was planned in the context of the previously discovered West Kora 1 oil accumulation and, if it had been successful in discovering another oil-field, would have allowed a common gathering system, pipeline, and deep-water tanker loading buoy offshore from Point Torment, 20 km to the northeast. The Pinnacle Fault, which was interpreted to bound the northern margins of both the West Kora and the Point Torment features, has a smaller throw in the Point Torment area than in the West Kora area (Figs 28, 32, and 33). As a consequence, the Point Torment structure has markedly

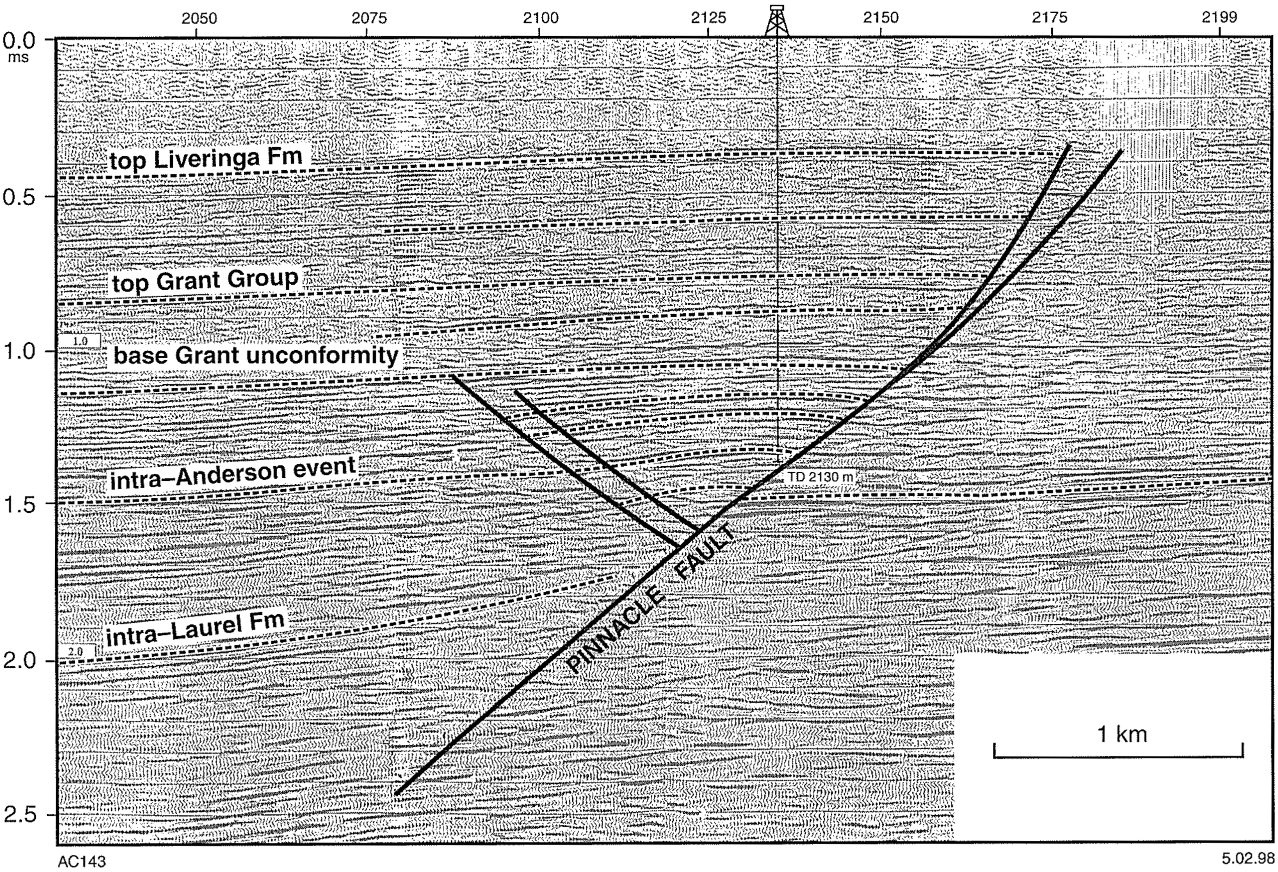


Figure 33. Seismic section F84A-940, showing the structural attitude of the Point Torment area. The line of section is shown in Figure 6

less vertical relief than the Kora – West Kora structure. An alternative interpretation is that Point Torment 1 tested a very gentle fault-bounded anticline of Middle Jurassic age and that a series of en echelon faults is present.

Reservoir

In Point Torment 1, gas is contained in minor, thin sandstone streaks within the otherwise tight Anderson Formation. The usually porous and permeable thick fluvial sandstones of this formation have been subjected to diagenesis, thereby depositing silica and kaolinite within pore spaces. Better reservoir quality is maintained by the thinner, less porous and permeable sandstones. Intervals with net pay are 2030–2034 m, 2052–2055.3 m, and 2092.2–2095 m. Within the pay zone the log-derived porosity is 9.6–12.9%, and the corresponding water saturation is 72–47%. Gas reservoirs in Point Torment 1 are within the lower unit of the Anderson Formation, informally defined by Thornton (1993) as unit 'C', whereas the oil-bearing sandstones of the Anderson Formation in West Kora 1 are within the upper unit (unit 'A').

Hydrocarbons

Poor oil shows were recorded in unit 'B' of the Anderson Formation, whereas gas shows were mainly recorded within unit 'C'. Within unit 'C' DST 1 (2085.8–2096.5 m) produced gas to surface after 3 minutes at a stabilized flow rate of about 121 000 m^3/d (about 4.3 Mcf/d) — the highest gas flow recorded within the basin. In addition, 6.2 barrels (about 1 kL) of condensate-cut mud and 1.2 L of condensate were recovered from the sample chamber. Strong indications of gas were also obtained from Point Torment 1 Deepening. In this well further DSTs were run and flows of gas, albeit smaller, were obtained in the Anderson Formation, Laurel Formation, and Nullara Limestone (Table 6).

Long-term production tests were carried out in Point Torment 1 during November and December 1994 (Fekete Australia Pty Ltd, 1995a,b). No sustained flow could be established from the intervals 2027.5–2034.5 m, 2042.5–2045 m, and 2050.5–2055.5 m. The average effective permeability of these intervals was calculated to be only 0.002 md. In the 937 hours that the tests were conducted over the 2090–2095 m interval, about 130 000 m^3/d (about 4.6 Mcf/d) of gas was produced. The final measured pressure after the build-up was about 4000 kPa (about 594 psi) less than the initial pressure. Because the pressure loss should be compared with the volume of gas produced, it is suggested that the effective gas reserves are very low. In the event that the pressure returns with time to the initial conditions, the drainage area would have an extremely low permeability (calculated at about 0.05 md), which would not deliver economic amounts of gas during the test. In addition to the gas, 5.7 kL (36 barrels) of oil were produced by the test.

Source

Both the Gogo and Laurel Formations contain shales that may have generated the hydrocarbons found in Point Torment 1.

Reasons for failure

Point Torment 1 and Point Torment 1 Deepening failed to discover an economic accumulation of hydrocarbons because of poor seals, related limited reservoir preservation throughout the Anderson Formation, and poor reservoir development within the Fairfield Group and the Nullara Limestone.

Wattle 1/ST1

Location

Wattle 1/ST1 was drilled by Bow Valley in 1994 about 62 km east-southeast of Derby (Fig. 2), with access to the

Table 6. Point Torment 1 Deepening drillstem tests

DST no.	*Well status*	*Depth (m)*	*Formation*	*Recovery*	*Comments*
1	open hole	2389.5–2470.5	Nullara Limestone	GTS: 134 mcf/d, trace oil	Test aborted during the final flow period
2	open hole	2260–2275	Laurel Formation	–	Misrun
3	open hole	2105–2184	Anderson Formation (unit 'C')	–	Misrun
4	cased hole	2391–2437	Nullara Limestone	–	Mechanical failure
4 - RR1	cased hole	2391–2437	Nullara Limestone	–	Misrun
4 - RR2	cased hole	2391–2437	Nullara Limestone	–	Misrun
4 - RR3	cased hole	2391–2437	Nullara Limestone	GTS: 81.9 mcf/d, trace oil	Tight reservoir
5	cased hole	2267.5–2280	Laurel Formation	GTS: 63.4 mcf/d	Tight reservoir
6	cased hole	2145.5–2163.5	Anderson Formation	GTS: too small to measure	Major gas pick obtained during drilling: very low porosity

GTS: gas to surface
mcf/d: thousand cubic feet/day
RR: re-run

well site via the Great Northern Highway (40 km to the south) and then along graded tracks and seismic lines. Wattle 1/ST1 was drilled to 1591 m at which depth the drilling assembly became stuck. After leaving a fish in the hole the well was sidetracked at 1151 m. Information on the well is from Bow Valley (Australia) Ltd (1995).

Stratigraphy

Wattle 1/ST1 was spudded in the Triassic Erskine Formation and then penetrated the normal regional stratigraphic sequence to the Upper Devonian Nullara Limestone, in which the well terminated at 3056 m (Appendix 1). The well intersected the regional Grant Group – Anderson Formation unconformity at 1590 m.

Trap

The primary objective of Wattle 1/ST1 was siliciclastic rocks, equivalent to the Nullara Limestone, in a large stratigraphic trap. Such sedimentary rocks are present in Puratte 1, about 115 km to the west (Huebner, 1980), and represent a hitherto unexplored stratigraphic play type. Seismic section H84-B (Fig. 34) illustrates the structural position of Wattle 1/ST1, which was drilled on the western flank of a flower structure related to the Sundown Transfer Zone.

Reservoir

The oil recovered from the well flowed from thin, tight carbonates of the Yellow Drum Formation. Some porosity was developed within these carbonates but no effective reservoir was intersected. The main stratigraphic objective (sandstones equivalent to the Nullara Limestone) was represented entirely by carbonates, without the reservoir-quality sandstones that had been anticipated.

Hydrocarbons

Excellent oil shows were present in Lower Carboniferous micritic calcarenites. About 300 L (2 barrels) of 35.1°API oil was recovered from the only DST run, over 2529–2550 m. In this test gas also reached the surface after 17 minutes but at rates too small to be measured.

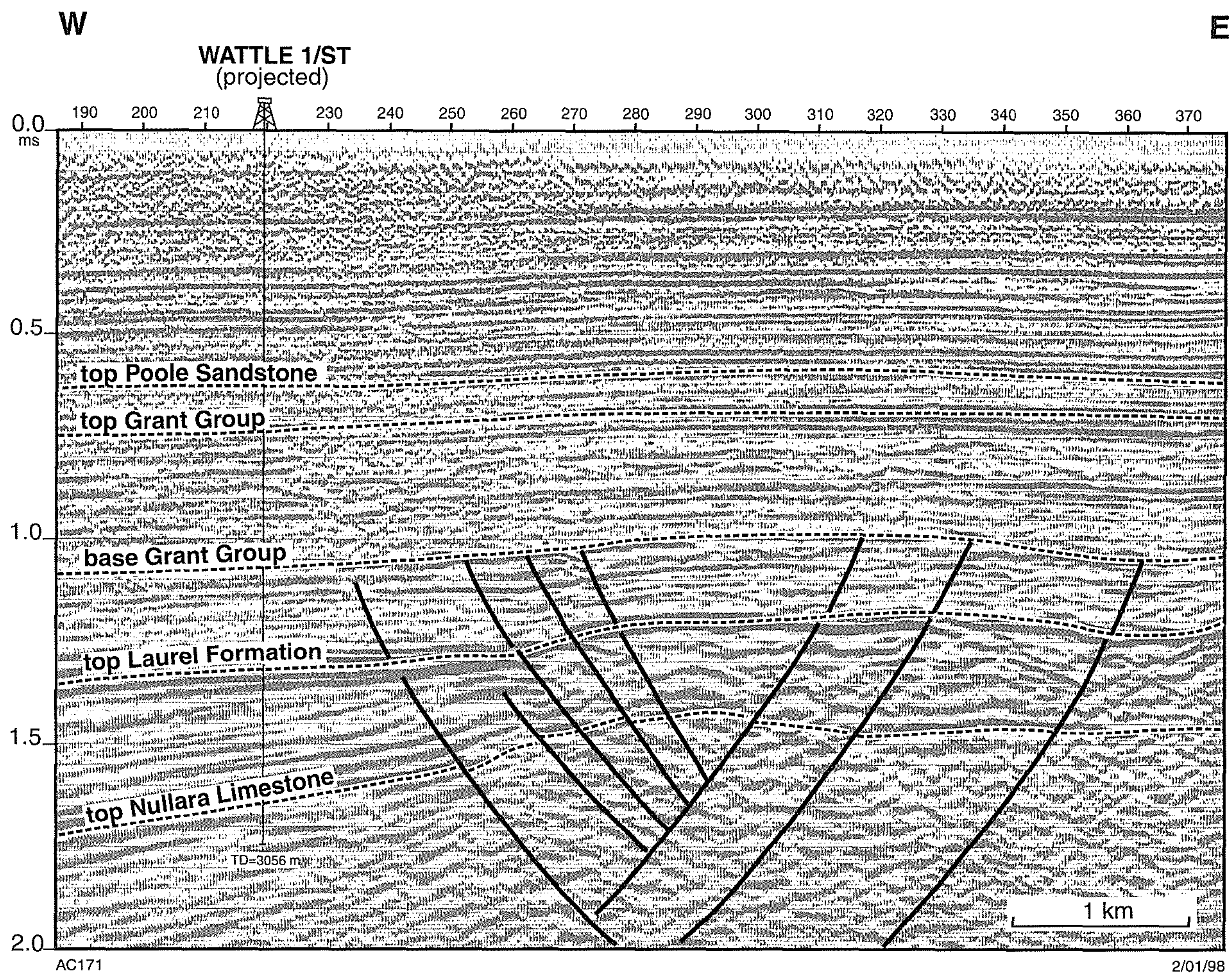


Figure 34. Migrated seismic section H84-B illustrating the structural position of Wattle 1/ST1. The line of section is shown in *Figure 6*

Source

The paraffin content of the recovered oil is 12.7% and the sulfur content is low (0.08%). The oil is mature and can be classified as paraffinic–naphthenic. A mixed marine–algal source is envisaged. The low pristane: phytane ratio (1.35) indicates that the source rocks were deposited in an anoxic depositional environment. The Middle to Upper Devonian interval below the shows is here suggested as the most probable source of the hydrocarbons encountered by Wattle 1/ST1.

Reasons for failure

Wattle 1/ST1 did not encounter the anticipated siliciclastic basinal facies equivalent to the Nullara Limestone, and the failure of the well to find hydrocarbons has to be related to the lack of potential reservoirs. Furthermore, no trap has been documented for Wattle 1/ST1; the limited amount of oil recovered may be related to a localized zone with some limited porosity.

Hydrocarbon habitat

The petroleum habitat of the Lennard Shelf is discussed by referring to the factors controlling the hydrocarbon accumulations discovered. Reservoirs, seals, traps, source rocks, and migration paths are analysed critically, and the hydrocarbon potential of the geological province is evaluated.

Reservoirs and seals

Within the Lennard Shelf, oil is found in both carbonate and clastic rocks.

In Blina — the biggest oilfield in the region (albeit of limited size) — oil is produced from fractures in the Nullara Limestone and, to a minor extent, dolomites in the Yellow Drum Formation. Some porosity is maintained in the dolomitic Yellow Drum Formation, whereas porosity in the Nullara Limestone depends almost entirely on fractures. In both formations the permeability is secondary and has resulted chiefly from shear stresses caused by wrenching, here believed to be similar in origin to the en echelon tensional gashes described by Vearncombe et al. (1995) in the area of the Cadjebut mine. In the context of the regional geology it is most likely that the development of the fractured reservoirs is related to the Meda Movement. Primary porosity and permeability, where present, must have been destroyed by diagenetic processes before hydrocarbons migrated in the area, as the early migration of hydrocarbons into reservoir rocks would have prevented secondary processes.

The thick, competent but brittle Nullara Limestone appears to have been subjected to more extensive fracturing than other units; shear stresses having been propagated throughout the entire formation. The thinner carbonates of the Yellow Drum Formation, on the contrary, were in some way protected from these stresses by the enclosing incompetent intervals. Production histories (Fig. 13) show that the Nullara Limestone has the best potential for sustained production. Therefore, potential reservoirs are more likely in thicker rigid competent units (Nelson, 1985). As is frequently the case with fractured reservoirs, porosity and permeability are areally very variable and a quantitative relationship may not be clear. In the Cadjebut area each fault is separated from the next by essentially undeformed carbonate rocks (Vearncombe et al., 1995). The neptunian dykes, as described by Playford (1984) and further discussed by Dörling et al. (1996), may represent surface expressions of deeper movements. Typically, rocks closer to faults are subjected to greater stresses and are therefore more heavily fractured, and larger faults have more intense fracturing. The shales of the Fairfield Group provide a good seal for both carbonate reservoirs.

Clastic rocks are common throughout the Givetian to Permian, but reservoirs of economic interest have only been encountered within the Carboniferous Anderson and Betty Formations. As discussed above for the carbonate reservoirs, well results suggest that the regional migration of hydrocarbons occurred only after diagenetic processes obliterated any porosity and permeability that may have been present in the Devonian and basal Carboniferous section. This may also account for the absence of pre–Anderson Formation oilfields in clastic rocks, as they are less competent than carbonates and therefore lack secondary porosity and permeability. In addition, post–Betty Formation potential reservoirs in the Lennard Shelf lack effective seals.

Carboniferous oil accumulations within both the Anderson and Betty Formations are present in thin and tight sandstones. In these units widespread porous, permeable, and thick sandstones are all water-wet. The critical factor for the presence of oil in the Carboniferous is probably the presence of a seal because upward migration appears to be widespread (Fig. 5). Thick, porous, and permeable sandstones require regionally extensive seals, which are not common in fluviatile systems. Thin sandstones may shale-out within short distances and, therefore, a less extensive intraformational shale can still provide an adequate trap. Tight sandstones may accumulate hydrocarbons via permeability barriers. For these reasons only small oilfields are expected to be present within the Anderson and Betty Formations. However, the Winifred Formation may provide a regional seal and mid-Jurassic anticlines, such as the West Kora structures, may deserve further examination.

A comprehensive set of porosity and permeability data has been assembled by Jackson et al. (1994).

Traps

The types of traps present within the Lennard Shelf are listed in Table 7. Structural traps such as the Blina oilfield (Fig. 11) may be provided by faulted anticlines that were a result of strike-slip movements during the Late Carboniferous Meda Movement.

Table 7. Types of traps within the Lennard Shelf

Oilfield	*Trap*	*Reservoir*
BLINA	Carboniferous faulted anticline (Figs 7, 11 and 13)	Nullara Limestone fractured limestone Yellow Drum Formation fractured carbonate
SUNDOWN	Middle Jurassic fault-controlled anticline (Figs 9 and 19) or permeability barriers	Betty Formation sandstone
WEST KORA	Pinch-out or permeability barrier within a gentle Middle Jurassic fault-controlled anticline (Figs 27, 28 and 32)	Anderson Formation sandstone
WEST TERRACE	Very minor fold (Figs 21 and 22). Probable stratigraphic entrapment	Betty Formation sandstone
BOUNDARY	Permo-Carboniferous gentle drape closure overlying Carboniferous flower structure (Figs 8 and 15)	Betty Formation sandstone
LLOYD	Carboniferous four-way dip closure (Figs 17 and 18). Permeability barriers	Anderson Formation sandstone

Locally, anticlines generated by mid-Jurassic strike-slip movements are also present. Sundown (Fig. 19) and Kora – West Kora (Fig. 28) are examples of such anticlines that are typically superimposed on Carboniferous structures and show rejuvenation of pre-existing faults. The Boundary and West Terrace oilfields appear to be controlled by very gentle four-way dip closures due to rejuvenation, drape, or differential compaction over older structures. The Lloyd oilfield reservoir is in a Carboniferous wrench-induced fold. For the accumulations contained in clastic rocks, a stratigraphic component contributes to, or is critical to, the trapping mechanism.

Source rocks and migration paths

Geochemical data point to the presence of two regional source-rock intervals, namely the Gogo and the Laurel Formations. In the majority of cases the oil can be related to the latter unit, but no exhaustive source-rock – oil characterization has been carried out and the quality of the oils produced are not significantly different. Many evaluations of source rocks in the literature are based on Total Organic Carbon (TOC) data. However, TOC data on their own are of little value due to the scattering of the data and elemental analyses and provide a very incomplete evaluation of source rocks. A comprehensive set of geochemical data has been assembled by Jackson et al. (1994). Whereas most regional reviews of the area offer only general discussions, Alexander et al. (1985) indicated that the organic material of the Gogo Formation, deposited in a reducing anoxic environment, is mainly of marine origin with little contribution from higher plants. The organic matter of the Laurel Formation, however, is characterized by greater input of terrestrial material with little marine contribution, consistent with a more oxygenated environment. The shales of the Laurel Formation in Blackstone 1 can be classified as excellent source rocks (Alexander et al., 1985).

Within the Lennard Shelf the Laurel Formation is largely immature or only marginally mature, whereas the Gogo Formation is considered to have reached maturity, albeit at different levels, over large tracts of the shelf (Ellyard, 1984). Migration was mainly via the northeasterly trending transfer faults connecting the deeper Fitzroy Trough, where both potential source-rock intervals reached maturity for hydrocarbon generation, to the shallower Lennard Shelf where generation has been limited. Lehmann's (1986) statement that oil (and mineral) accumulations in the area are related to transcurrent faults is supported here. The northeasterly trending faults are caused by the mid–Late Carboniferous Meda Movement, and since then there has been migration of oil over long distances into the available reservoirs; the oil being gradually sourced from progressively shallower generative areas. Tompkins (1994) concluded that the Cadjebut zinc–lead mineralization, hosted in the Givetian Pillara Limestone, formed during the mid-Carboniferous shelf-wide event, confirming the analogy between the regional migration paths for both oil and minerals. As discussed by Vearncombe et al. (1995), however, the precise date of Lennard Shelf Mississippi Valley-type mineralization (such as Cadjebut) is controversial; ages ranging from Early to Late Carboniferous are considered possible. In the Cadjebut area hydrocarbons are present as inclusions in sphalerite. Vertical migration along fault planes would also favour the presence of oil generated by different source rocks.

Figure 3 illustrates the main northeasterly trending transfer faults and northwesterly trending faults as delineated by Shaw et al. (1994). The image of the first vertical derivative of Bouguer gravity (Fig. 35) also shows lineaments that are interpreted as 'hard-linked' transfer faults within basement (O'Brien et al., 1996). The resolution of the gravity image is limited because the data have been acquired in a number of surveys with different station densities. By integrating the gravity data with the surface geology and seismic data, a more complete regional tectonic picture is achieved (Fig. 36). The Sundown Transfer Zone appears to correspond with a concentration of oil accumulations (Fig. 36). It is conceivable, however, that hydrocarbon fields are present along both the main transfer-fault zones and the interconnected orthogonal strike-slip faults. The tectonic framework described is consistent with the 'hard-linked' system described by O'Brien et al. (1996).

Time of hydrocarbon migration versus time of major structural development

Two tectonic events are critical to the post-Givetian structuring of the Lennard Shelf, namely the mid–Late Carboniferous Meda Movement and the Middle Jurassic Fitzroy Movement. Kennard et al. (1994b), in discussing their relevance to hydrocarbon accumulation in the Canning Basin, stated that the peak hydrocarbon generation from the shales of the Gogo Formation occurred in the Lennard Shelf at various times, including the Permian–Triassic. Consequently, migration of hydrocarbons from the Gogo source interval post-dates the formation of the mid–Late Carboniferous structures.

Oddly, Kennard et al. (1994b) also stated that peak generation from the stratigraphically younger, and thus shallower, Laurel Formation source rocks occurred in the Fitzroy Trough before the Meda Movement and that consequently, migration of hydrocarbons from the Laurel source interval pre-dated the formation of the mid–Late Carboniferous structures. However, throughout the Lennard Shelf the Laurel Formation shales are still immature (Ellyard, 1984). Therefore, there must be a region between the studied part of the Fitzroy Trough and the presently immature Lennard Shelf where the Laurel source interval matured after the Meda Movement. It is concluded that migration of hydrocarbons from the Laurel source rocks also post-dates the formation of the mid–Late Carboniferous structures.

Conversely, migration from both the Gogo and Laurel source intervals appears to have occurred before the Middle Jurassic movement. Increased geothermal gradient related to the latter tectonism may have caused further hydrocarbon generation, but it cannot be proved.

Hydrocarbon potential

The distribution of oil accumulations over an area approaching 10 000 km^2 is a tantalizing incentive for oil explorers. Migration of oil over long distances has occurred. The hydrocarbon potential of the Lennard Shelf may be upgraded by the comparative analysis of critical factors, particularly structural factors, controlling the oil discoveries.

In the Lennard Shelf area the main objective has been fractured carbonates of the Nullara Limestone overlain by shale of the Fairfield Group. This carbonate play has been proven productive by the Blina oilfield, albeit in a limited way. In this report the Blina oilfield is not considered indicative of the hydrocarbon potential of the Lennard Shelf, especially if exploration philosophy can be focused on prospects that have close relationships not only with possible reef developments but also with the fault pattern — critical to both the presence of effective reservoirs in carbonate rocks and migration from mature source areas to shallower host rocks. Previous exploration strategies, in comparison, have focused on defining models for reef development or suitable structures with little concern for other critical factors such as migration pathways. In this context, potential reservoirs based on primary porosity and permeability are of little value, as fractures are the primary reservoir type. Structural elevation is less important than proximity to major faults that may provide both conduits for hydrocarbons and fractured reservoirs (if there is some structural closure at the base of the sealing horizon). Wildcat holes should also be drilled to at least reach and test the Nullara Limestone.

The sandstones of the Anderson and Grant Formations are secondary objectives but are still capable of yielding an economic oil accumulation. Unfortunately, it is difficult to suggest a new approach for this clastic play, as the presence of effective traps for the Anderson and Grant Formation sandstones is unpredictable, depending on thin lenticular seals or a permeability barrier. The potential of the Betty Formation sandstones sealed by the Winifred Formation shales in mid-Jurassic anticlines will be significantly upgraded if post–Fitzroy Movement hydrocarbon generation is demonstrated.

The remote location makes exploration on the Lennard Shelf less attractive, and the economics of transporting oil by truck is marginal. Furthermore, the small amount of oil available makes its shipment by sea from Broome to Perth too dependent on the availability of a suitable tanker. Further discoveries would lead to an upgrading of the infrastructure, increasing the profit per barrel of oil from the region.

Conclusions

The first phase of oil exploration in the Lennard Shelf was guided by interpreted reef developments and culminated in the discovery of the Blina oilfield in carbonate reservoirs. The second phase was dependent on seismically defined closures and led to the discovery of smaller oilfields in clastic sedimentary rock reservoirs. This case study of the onshore petroleum system of the Lennard Shelf allows the definition of a new model for future exploration activities in the region.

Oil accumulations are widespread both horizontally and vertically; thus the generation and migration of hydrocarbons is not in question. Fractured carbonates are expected to offer opportunities for more attractive discoveries than sandstones.

A third phase of exploration on the Lennard Shelf would be enhanced by the acquisition of a large, medium-resolution gravity survey over the Lennard Shelf. Basement faults, which appear to control the location of

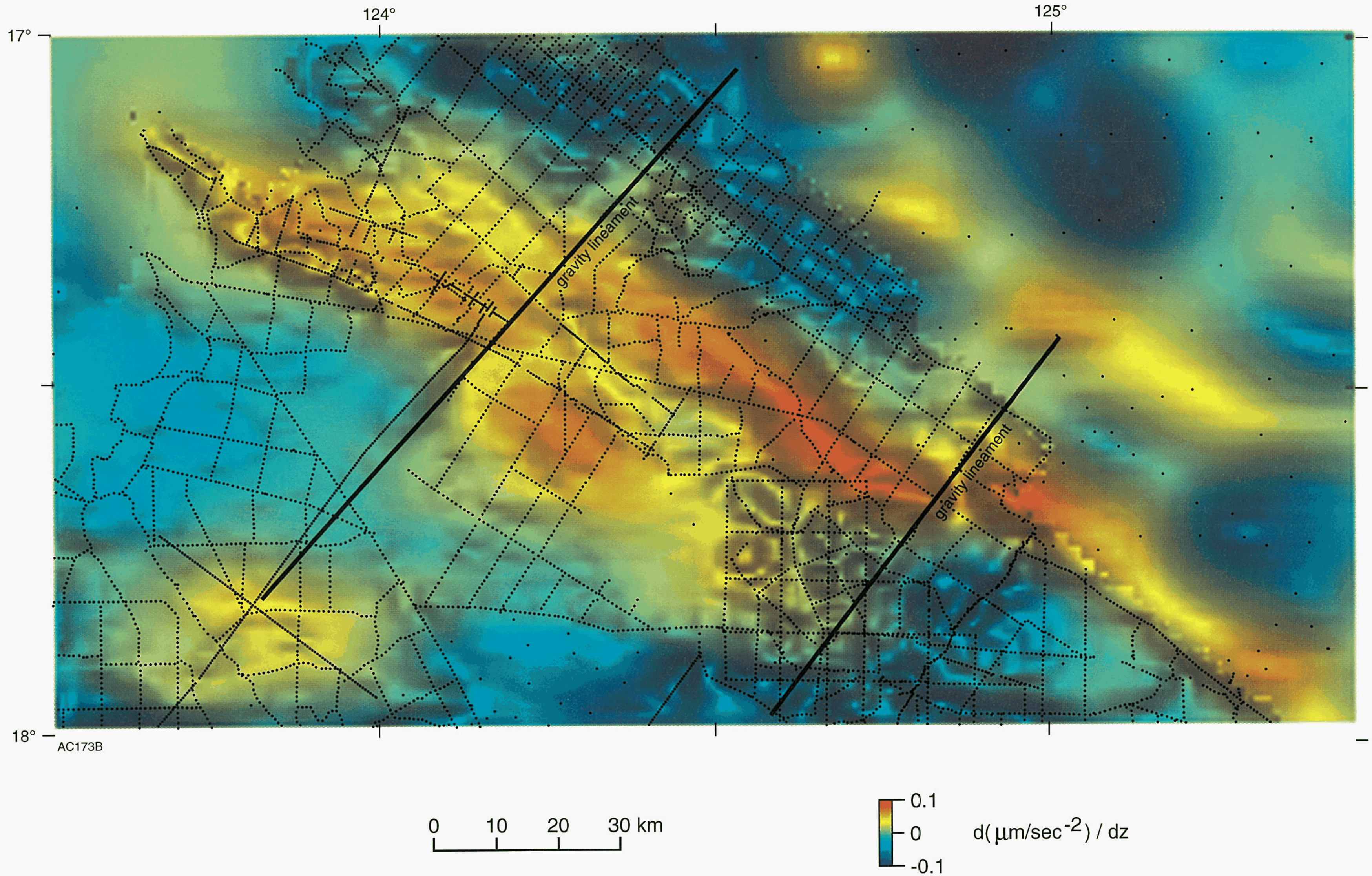


Figure 35. Image of the first vertical derivative of Bouguer gravity of the Lennard Shelf. The image has been produced by the GSWA, utilizing gravity surveys carried out by mining and oil companies. Dots indicate gravity stations

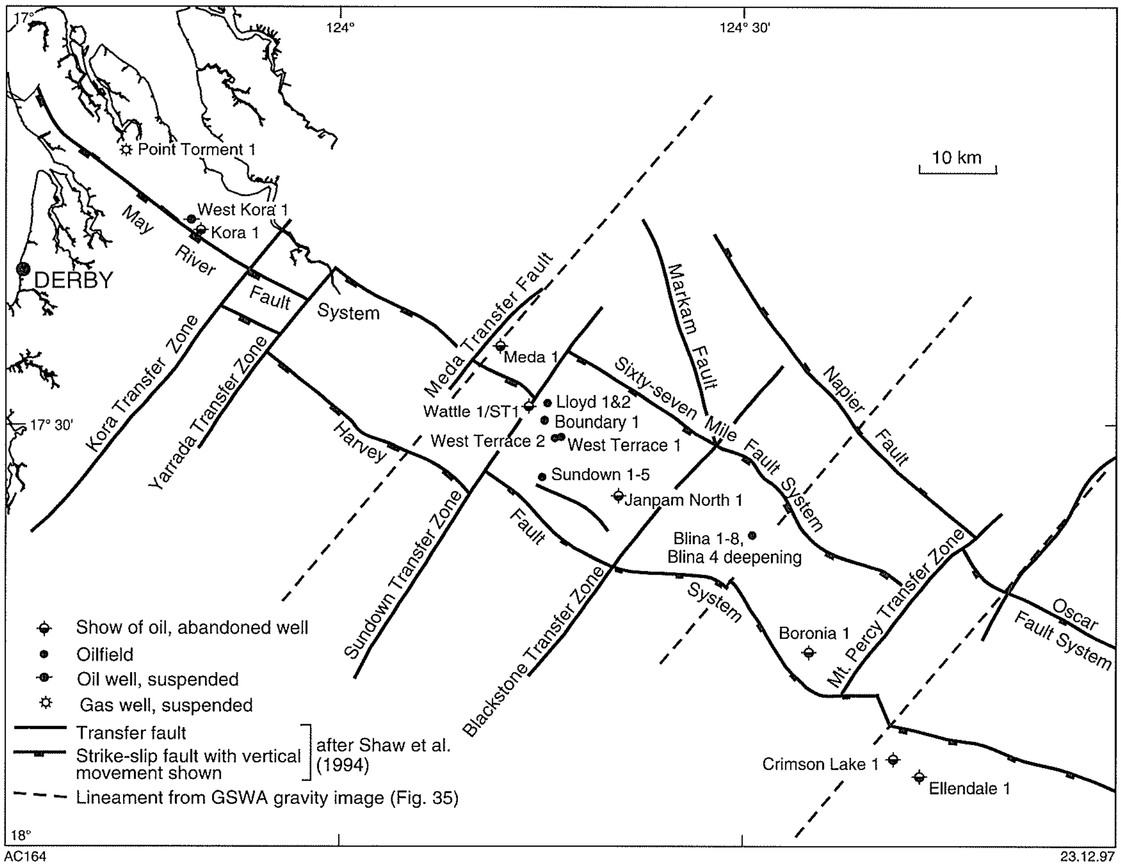


Figure 36. The Lennard Shelf hydrocarbon accumulations within their regional tectonic framework

rift, normal, strike-slip, and transfer faults could be mapped from such a gravity data set. Confirmation of the propagation of these faults through the sedimentary section and the selection of further drilling locations on major dilatational zones could be based on existing or new seismic data.

A more extensive study of the tectonic framework of the Lennard Shelf based upon the existing gravity, magnetic, and seismic datasets would be useful to mining and hydrocarbon exploration ventures, as the same migration pathways taken by hydrocarbons may also be followed by mineral-rich hydrothermal fluids forming Mississippi Valley-type deposits.

The location of exploration and step-out wells in carbonate rocks should take advantage of fracture analyses in order to optimize well productivity.

Oil exploration wells should be located not only within closed structures but also in close proximity to major faults so that the Nullara Limestone and other carbonates can be tested. As the Lennard Shelf contains mostly vertical fractures and primary permeability is virtually non-existent, the effective horizontal permeability is likely to be low; therefore, a crestal location is not necessarily critical. The chances of finding new oilfields in the Lennard Shelf are rated as good.

The model proposed here for future exploration within the Lennard Shelf is expected to apply to other geological provinces of the Canning Basin. In particular, hydrocarbon accumulations have already been discovered in the eastern extension of the Lennard Shelf and in the Barbwire Terrace, where geological characteristics are similar to those of the Lennard Shelf.

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Appendix 1

Formation tops of stratigraphic units in wells used for this report

Age		*Triassic*	*Permian*						*Carboniferous*		*Late Devonian*			*Middle Devonian*			
						Grant Group				*Fairfield Group*							
Well name	*Kelly bushing*	*Blina Shale*	*Liveringa Fm*	*Noonkanbah Fm*	*Poole Sandstone*	*Carolyn Fm*	*Winifred Fm*	*Betty Fm*	*Anderson Fm*	*Laurel Fm*	*Yellow Drum Fm*	*Gumhole Fm*	*Nullara Limestone Cycle*	*Pillara Limestone Cycle*	*Pre-Givetian units*	*Base-ment*	*Total depth*
Blackstone 1	65	9	319	511	751	830	930	998	–	1 486	1 579	1 697	1 812	1 914	2 220	NP	2 350
Blina 1	62	30	133	335	571	652	776	917	–	1 104	1 142	1 314	1 438	2 241	NP	NP	2 498
Blina 2	61	35	139	334	570	657	768	992	–	1 076	1 150	1 323	1 444	NP	NP	NP	1 588
Blina 3	61	21	140	338	577	663	746	971	–	1 088	1 152	1 329	1 454	NP	NP	NP	1 580
Blina 4 [(a)]	60	20	135	330	566	652	769	986	–	1 071	1 140	1 312	1 435	NP	NP	NP	1 526
Blina 5	62	17	132	326	586	685	777	867	–	1 124	1 171	1 278	1 460	NP	NP	NP	1 600
Blina 6	61	17	133	323	580	678	776	924	–	1 107	1 161	NP	NP	NP	NP	NP	1 260
Blina 7	62	5	145	349	599	680	770	856	–	1 125	1 183	1 250	1 469	NP	NP	NP	1 551
Blina 8	62	50	160	334	606	699	793	1 015	–	1 088	1 181	1 335	1 467	NP	NP	NP	1 550
Boronia 1	65	7	124	409	594	697	829	987	–	1 166	NI	NI	1 343	2 506	NP	NP	3 391
Boundary 1	46	106	370	536	845	946	1 041	1 225	1 554	NP	NP	NP	NP	NP	NP	NP	1 670
Crimson Lake 1	97	–	8	277	657	712	961	1 088	1 471	1 545	1 711	1 815	NP	NP	NP	NP	1 981
Ellendale 1	100	–	5	268	603	646	1 015	1 050	1 425	1 547	1 745	1 986	2 067	2 705	NP	NP	3 190
Janpam North 1	60	25	259	445	715	795	940	977	–	1 332	1 472	NI	1 649	1 858	NP	NP	2 202
Kora 1	14	40	502	652	998	1 098	1 195	1 355	1 918	2 283	2 498	NI	2 568	3 000	NP	NP	3 101
Lloyd 1	44	97	355	533	823	927	1 125	1 223	1 432	1 686	1 827	NP	NP	NP	NP	NP	2 001
Lloyd 2	43	90	355	545	822	922	1 118	1 216	1 440	NP	NP	NP	NP	NP	NP	NP	1 580
Meda 1	30	18	218	397	678	740	987	1 069	1 281	1 505	1 735	NI	2 019	2 130	NP	2 642	2 685
Meda 2	30	21	254	435	725	790	1 040	1 113	1 262	1 551	1 732	NI	2 019	NP	NP	NP	2 325
Point Torment 1 [(a)]	17	23	415	560	894	984	NI	NI	1 516	2 210	NI	NI	2 394	NP	NP	NP	2 603
Sundown 1	46	26	228	441	777	898	973	1 092	1 451	1 796	1 982	NP	NP	NP	NP	NP	2 736
Sundown 2	46	17	222	444	785	907	980	1 094	1 451	1 902	NP	NP	NP	NP	NP	NP	1 965
Sundown 3	44	32	214	438	779	904	995	1 096	NP	NP	NP	NP	NP	NP	NP	NP	1 220
Sundown 4	47	30	228	443	783	901	968	1 090	1 451	NP	NP	NP	NP	NP	NP	NP	1 800
Sundown 5	47	26	220	443	785	907	990	1 095	NP	NP	NP	NP	NP	NP	NP	NP	1 152
Sundown 3H (TVD)	45	–	–	–	–	908	995	1 094	NP	NP	NP	NP	NP	NP	NP	NP	1 645
Terrace 1	39	88	360	542	827	931	1 124	1 170	1 535	1 689	1 865	NI	2 060	2 218	NP	NP	2 389
Wattle 1/ST1	46	143	409	576	874	1 012	1 215	1 355	1 590	1 885	2 220	2 688	2 916	NP	NP	NP	3 056
West Kora 1	15	40	480	625	977	1 024	1 192	1 264	1 557	2 252	2 361	2 455	2 534	NP	NP	NP	2 606
West Terrace 1	36	103	362	541	834	937	1 041	1 154	NP	NP	NP	NP	NP	NP	NP	NP	1 250
West Terrace 2	36	85	357	535	825	931	1 043	1 157	NP	NP	NP	NP	NP	NP	NP	NP	1 200

(a): Including deepening
Fm: Formation
NI: Not identified
NP: Not penetrated
TVD: True vertical depth

Appendix 2

Details of wells drilled in the study area

Well name	*S number*	*Latitude*	*Longitude*	*Year*	*Operator*	*Gas show*	*Oil show*
Aquanita 1	2211	17°37'44.13"S	124°21'26.568"E	1982	Home Energy	Nil	Nil
Blina 1	1819	17°37'24.46"S	124°30'02.604"E	1981	Home Energy	Nil	Producer
Blina 2	1913	17°37'09.64"S	124°29'46.48"E	1981	Home Energy	Nil	Producer
Blina 3	1986	17°37'22.08"S	124°29'47.72"E	1981	Home Energy	Nil	Producer
Blina 4	2116V	17°37'18.03"S	124°29'56.69"E	1982	Home Energy	Nil	Producer
Blina 4 (Deepening)	2116V	17°37'18.03"S	124°29'56.69"E	1993	Minora Energy	Nil	Producer
Blina 5	2782	17°34'34.52"S	124°30'10.553"E	1985	Home Energy	Nil	Producer
Blina 6	2821	17°37'28.51"S	124°29'59.22"E	1987	Home Energy	Nil	Producer
Blina 7	3240	17°37'42.22"S	124°29'59.22"E	1987	Home Energy	Poor	Fair
Blina 8	20032	17°37'10.92"S	124°29'29.04"E	1990	Petroleum Securities	Nil	Nil
Booran 1	2215	17°20'08.36"S	123°39'48.84"E	1982	Esso	Nil	Nil
Boronia 1	2055	17°45'29.7"S	124°34'17.8"E	1982	International Energy	Nil	Excellent
Boundary 1	20034	17°29'14.19"S	124°14'38.09"E	1990	Petroleum Securities	Nil	Producer
Canegrass 1	20189	17°23'30.00"S	124°13'32"E	1993	Bow Valley	Fair	Nil
Chestnut 1	20225	17°43'46.34"S	124°51'20.96"E	1994	Bow Valley	Good	Poor
Crimson Lake 1	3346	17°53'05.232"S	124°40'35.556"E	1988	Kufpec	Nil	Good
East Yeeda 1	2774	17°37'59.21"S	124°02'49.96"E	1985	Bridge Oil	Nil	Poor
Ellendale 1	1551	17°54'18"S	124°42'15"E	1979	Amax Petroleum	Good	Fair
Hakea 1	2431	17°41'37.32"S	124°27'50.47"E	1983	International Energy	Nil	Nil
Hangover 1	2319	17°34'39.15"S	124°16'31.843"E	1983	Home Energy	Nil	Nil
Harold 1	3150	17°33'40.5"S	124°34'18.049"E	1987	Home Energy	Nil	Nil
Hawkstone Peak 1	47	17°14'24.03"S	124°24'31.373"E	1962	WAPET	Nil	Nil
Janpam 1	2229	17°36'08.29"S	124°24'51.85"E	1982	Home Energy	Fair	Nil
Janpam North 1	3186	17°34'06.853"S	124°24'59.973"E	1987	Home Energy	Nil	Good
Katy 1	2323	17°38'39.98"S	124°21'29.34"E	1983	Home Energy	Nil	Nil
Kennedia 1	2815	17°45'15.4"S	124°36'19.3"E	1985	International Energy	Poor	Poor
Kora 1	2190	17°15'38.41"S	123°49'42.52"E	1982	Esso	Nil	Excellent
Langoora 1	41	17°18'06"S	124°06'53"E	1962	WAPET	Nil	Nil
Lloyd 1	3144	17°28'03.226"S	124°14'56.441"E	1987	Home Energy	Nil	Producer
Lloyd 2	3246	17°28'11.27"S	124°15'06.35"E	1987	Home Energy	Nil	Good
Lukins 1	2901	17°32'14.64"S	124°32'04.319"E	1985	Home Energy	Nil	Nil
Mariana 1	2613	17°33'56.66"S	124°27'08.846"E	1984	Home Energy	Nil	Nil
May River 1	357	17°14'49.07"S	124°05'06.322"E	1967	WAPET	Nil	Nil
Meda 1	89	17°23'56.17"S	124°11'32.293"E	1958	WAPET	Poor	Good
Meda 2	177	17°24'35.05"S	124°11'28.43"E	1959	WAPET	Poor	Poor
Mellany 1	3154	17°24'06.577"S	124°17'17.79"E	1987	Home Energy	Nil	Nil
Metters 1	20257	17°56'41.48"S	124°44'31.412"E	1994	Wildcat	Nil	Nil
Napier 1	482	17°12'20"S	124°31'36"E	1969	Lennard Oil	Nil	Nil
Napier 2	504	17°04'55"S	124°21'20"E	1969	Lennard Oil	Nil	Nil
Napier 5	596	17°06'30"S	124°28'06"E	1970	Lennard Oil	Nil	Nil
Nemile 1	20205	17°51'37.11"S	124°33'25.317"E	1994	Wildcat	Poor	Poor
Orange Pool 1	1826	17°18'17.82"S	124°12'33.71"E	1981	Home Energy	Nil	Nil
Palm Spring 1	724	17°48'56"S	124°53'07.74"E	1972	WAPET	Nil	Nil
Philydrum 1	2697	17°48'59.55"S	124°37'56.27"E	1984	International Energy	Nil	Poor
Point Torment 1	20140V	17°09'57.81"S	123°44'14.882"E	1992	Anzoil	Producer	Good
Point Torment 1 1994 Deepening	20140V	17°09'57.81"S	123°44'14.882"E	1994	Stirling Resources	Producer	Good
Runthrough 1	3148	17°29'22.86"S	124°11'56.29"E	1987	Home Energy	Nil	Nil
Sundown 1	2233	17°33'10.03"S	124°14'30.849"E	1982	Home Energy	Nil	Producer
Sundown 2	2321	17°33'17.98"S	124°14'41.54"E	1983	Home Energy	Nil	Producer
Sundown 3	2687V	17°33'29.19"S	124°14'49.814"E	1984	Home Energy	Poor	Excellent
Sundown 3H	2687V	17°33'29.19"S	124°14'48.814"E	1995	Santos	Poor	Producer
Sundown 4	2838	17°33'11.94"S	124°14'37.489"E	1985	Home Energy	Nil	Producer
Sundown 5	20195	17°33'23.97"S	124°14'37.17"E	1993	Minora Energy	Fair	Producer
Sunup 1	2799	17°37'13.12"S	124°18'57.775"E	1985	Home Energy	Nil	Nil
The Sisters 1	42	17°43'31"S	124°25'09"E	1956	AFO	Nil	Nil
Thompsons 1	2227	17°36'41.46"S	124°23'10.346"E	1987	Home Energy	Poor	Poor
Wattle 1	20233	17°28'13.86"S	124°13'34.93"E	1994	Bow Valley	Fair	Excellent
West Blackstone 1	2801	17°34'31.67"S	124°20'12.254"E	1985	Home Energy	Nil	Poor
West Kora 1	2555	17°14'47.54"S	123°49'00.12"E	1984	Esso	Nil	Producer
West Philydrum 1	2757	17°48'20.5"S	124°36'53.02"E	1985	International Energy	Nil	Nil
West Terrace 1	2786	17°30'26.4"S	124°15'31.264"E	1985	Home Energy	Nil	Producer
West Terrace 2	2855	17°30'14.68"S	124°15'34.783"E	1987	Home Energy	Nil	Excellent
Whitewell 1	2575	17°34'01.88"S	124°15'40.012"E	1984	Home Energy	Nil	Poor
Yarrada 1	1828	17°21'59.53"S	124°06'09.03"E	1981	Home Energy	Nil	Nil

AFO: Associated Freney Oilfields NL
Amax Petroleum: Amax Petroleum (Australia) Inc
Anzoil: Anzoil NL
Bow Valley: Bow Valley (Australia) Ltd
Bridge Oil: Bridge Oil Ltd
Esso: Esso Exploration and Production Australia Inc
Home Energy: Home Energy Co Ltd
International Energy: International Energy Development Corporation of Aust Pty Ltd
Kufpec: Kufpec Australia Pty Ltd
Lennard Oil: Lennard Oil NL
Minora Energy: Minora Energy (Australasia) Pty Ltd
Petroleum Securities: Petroleum Securities Energy Limited
Santos: Santos Ltd
S number: Geological Survey of Western Australia S-series number
Stirling Resources: Stirling Resources NL
WAPET: West Australian Petroleum Pty Ltd
Wildcat: Wildcat Australia Pty Ltd