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NORTH WEST SHELF

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SUMMARY

INTRODUCTION

In this study, Robertson Research Australia and Robertson Research Singapore have carried out a study of the geology and petroleum geochemistry of the Northwest Shelf of Australia, encompassing the Northern Carnarvon, Canning, Browse and Bonaparte Basins. The broad objective of the study was to achieve a better understanding of the regional distribution of potential oil-prone source rocks and to highlight areas for future exploration.

The project has involved comprehensive geochemistry analyses on samples from 60 wells, and oil analyses from 13 wells, as well as re-analysis of several oil samples from a study carried out by the Robertson Research Group in 1979. The geological history for each of the basins was established from a study of all available wells, interpretation of regional seismic lines, and from a review of published reports on the area.

STRUCTURAL FRAMEWORK

Until the Middle Jurassic, Australia was an integral part of Eastern Gondwanaland. Rifting, as a precursor to the breakup of Gondwanaland, commenced in the early Mesozoic with resultant development of localised depocentres. The tectonic evolution of the Northwest Shelf broadly followed the pattern of development of divergent continental margins:-

a) subsidence, beginning with the infra-rift phase about 100 My before breakup and continuing from 50 My before breakup through to breakup time, in rift grabens and half grabens flanking the incipient continental boundary.

b) from breakup time subsidence becomes widespread, with bathyal sediments deposited at the continent-ocean boundary and a marine transgression extending shoreward.

The breakup unconformity, which is recognisable in all basins of the Northwest Shelf, is of Callovian age. Australia later began to move northward (95 Ma) and has been in collision with southeast Asia since the Late Miocene.

In this project, the study area has been divided into four main basins - Northern Carnarvon, Canning, Browse and Bonaparte. As the entire region has had a similar geological history, some basin boundaries are fairly arbitrary, e.g. the Vulcan Sub-basin has been included in the Browse Basin in this report, although there is some basis for incorporating it in the Bonaparte Basin.

The Northwest Shelf originated as an intra-cratonic basin, following the Alice Springs Orogeny in the Middle Carboniferous. This orogeny activated two main basement trends oriented NE-SW and NW-SE, which periodically affected the structural development of the region from that time.

Significant uplift, erosion and faulting occurred during the Late Triassic/Early Jurassic, which marked the transition from infra-rift to rift basins on the Northwest Shelf. The major depocentres of the Northwest Shelf began to develop during this rifting, e.g. Barrow-Dampier and Vulcan Sub-basins and Malita Graben.

Near the end of the Middle Jurassic, faulting, commonly involving rejuvenation of pre-existing faults was associated with the continental breakup which is marked by the main breakup unconformity of Callovian age. During the Callovian, major platforms were uplifted and subsidence of the depocentres occurred.

Following the Callovian breakup, rift development ceased and the region became a mature, continental margin sag in response to continuation of the continental separation. Major transgression then commenced but some high blocks remained emergent until Aptian-Albian times. A regional disconformity at the Aptian-Albian boundary is associated with northwestward tilting and subsidence. This disconformity marks a general change throughout the Northwest Shelf from argillaceous to carbonate deposition.

Reactivation of some major structures occurred in the Late Cretaceous, with development of features such as the Barrow Anticline and Dampier-Madeleine trends in the Northern Carnarvon Basin. A period of Middle Miocene folding, incorporating extensional wrenching and associated with the collision of the Australian and Asian continental plates, affected most of the Northwest Shelf. During this period, an important heat pulse occurred along the Northwest Shelf. Salt diapirism continued throughout the Tertiary in the Bonaparte Basin.

HISTORY OF SEDIMENTATION

The history of sedimentation on the Northwest Shelf reflects the progressive breakup of the Eastern Gondwanaland continental mass by rifting and seafloor spreading.

Carnarvon Basin

Little is known of the Permian in the Northern Carnarvon Basin because it has been penetrated by few wells. Triassic deposition commenced with a widespread transgression in the Scythian. A thick marine shale is overlain by 2000-3000m of fluvial sediments which reservoir most of the giant gas/condensate accumulations on the Rankin Platform. A change to a more marine environment occurred in the Late Triassic-Early Jurassic in response to the onset of continental separation. Sedimentation occurred in rift/listric fault basins formed as precursors to actual seafloor spreading. Rifting of the continents occurred in the Middle Jurassic and large scale horsts and grabens were formed. A very thick sequence of Middle-Late Jurassic shales accumulated in an aborted rift, while laterally equivalent shelfal and deepwater sandstones were also deposited.

Seafloor spreading to the south of the Exmouth Plateau occurred in the Neocomian. The uplift which occurred prior to this event provided the sediment source for the huge Barrow Group deltaic system, which prograded to the north. Coarse clastic sedimentation ceased when spreading commenced. Shales deposited in the subsequent transgression provide the most important regional seal in the basin. Overlying shales are more calcareous, reflecting the deepening open marine environment coincident with the Indian Ocean formation. Tertiary sedimentation consisted of deepwater clastics and marls followed by a thick sequence of prograding carbonates. A series of large anticlines formed during and after the Late Miocene, in response to right lateral shear forces.

Canning Basin

Little is known about the Palaeozoic sequence in the sparsely explored offshore Canning Basin. Deposition throughout the Triassic and Early-Middle Jurassic proceeded in a predominantly fluviatile environment with a number of short-lived marine incursions. After the Callovian breakup, the continental rift-fill environment was replaced by marine sedimentation. Water depths gradually increased from the Late Jurassic through to the Paleocene. Continued regression since the Middle Eocene has resulted in a prograding carbonate wedge covering the entire shelf.

Browse Basin

In the Late Carboniferous, a marine transgression extended through the Browse Basin which was followed by a westward regression in the Early Permian. In the Late Palaeozoic major tensional movement produced NE-SW trending horsts and grabens. Following a period of erosion and non-deposition, widespread sedimentation resumed in the Late Triassic with deposition of fluvio-deltaic and shallow marine sediments. Following a period of significant uplift in the Late Triassic/Early Jurassic, a rifting regime developed in which a thick sequence of Early-Middle Jurassic fluvio-deltaic sediments was deposited in the subsiding areas. Reactivation of fault blocks occurred in the Middle Jurassic, associated with continental breakup.

Following breakup, the basin was subjected to a major marine transgression from the NNW. Coarse clastic sediments were deposited along the southern and eastern margins contemporaneously with shallow marine sediments basinwards. This range of depositional environments persisted until the Late Cretaceous with high blocks such as the Ashmore Block being emergent for at least part of the time.

By the Late Cretaceous, a marginal sag regime had been created, and the whole region was tilted westward. Full marine circulation spread over the basin, with a change from clastic to carbonate sedimentation westward. The Late Tertiary was a period of basinwide carbonate sedimentation.

Bonaparte Basin

Sedimentation commenced in the Bonaparte Basin in the Cambrian, but offshore only the Late Carboniferous and younger section has been extensively drilled. Following the Middle Carboniferous Alice Springs Orogeny, a series of transgressions and regressions occurred from the Late Carboniferous to the Middle Triassic. These produced changes from continental to marine environments, with sequences of fine and coarse clastics and carbonates being deposited.

As the sea retreated north and northwestward in the Middle Triassic, a variety of environments resulted, ranging from shallow marine to a complex delta.

Major tensional tectonic activity which was initiated in the Late Triassic, reached its culmination in the Callovian, and is represented by the breakup unconformity. During this time several blocks were uplifted and eroded (e.g. Londonderry High) and grabens and troughs (Malita Graben) became depocentres for Late Jurassic to Recent sediments. A massive sequence of marine shales and siltstones filled the depocentres, while nearshore sands onlapped onto the relatively higher blocks. However, the highest uplifted blocks were starved of sediments until at least the Late Neocomian.

A Late Neocomian transgression followed with sediments ranging from fine grained, glauconitic sands to open marine shale and carbonates. Initiation of a regional northerly tilt in the Late Cretaceous resulted in the virtual cessation of sedimentation in the eastern and southern margins of the Bonaparte Basin. Carbonate deposition continued virtually uninterrupted in the northern part of the basin through to the Oligocene but marine sedimentation occurred over the whole basin in the Miocene.

PREVIOUS EXPLORATION AND DEVELOPMENT

The 1953 discovery at Rough Range in the onshore Carnarvon Basin stimulated exploration interest in the study area. The first exploration success was Barrow-1 in 1964, on Barrow Island, the operators being WAPET. By this time most of the Northwest Shelf was covered by a few large licences. The first important successes in true offshore wells were the North Rankin and Scott Reef gas discoveries in 1971.

A series of very large gas discoveries was made on the Rankin Platform in the Carnarvon Basin, while other gas discoveries were also made in the Browse and Bonaparte Basins. The Barrow Island oil field commenced production in 1967, with peak flow of 45,000 bbls/day in 1970. Anticipated recoverable reserves are 258 million bbls.

The North Rankin Field has been on production since mid-1984, with a current production rate of 260 MMCFPD and original gas-in-place of 11 TCF. Current plans call for the placement of a further two platforms to support LNG export to Japan, which is programmed to commence in 1989.

Between 1982 and the present, a number of small oil discoveries have been made in the Carnarvon and Browse Basins. Two of these are now on production, Harriet (9300 BOPD) in the Barrow Sub-basin and Jabiru (13,800 BOPD) in the Vulcan Sub-basin. It is likely that other fields, such as Challis and Saladin, will also be proved commercial in the near future.

GEOCHEMISTRY

The geochemistry objectives of this study were generally to determine if oil source rocks might be more widespread than envisaged in the 1979 study carried out by the Robertson Research Group. In the Northern Carnarvon Basin, the specific objectives were to determine the regional extent of known source rocks and to carry out oil-source correlations.

In the Browse Basin, the identification of oil-prone source rocks in the Vulcan Sub-basin was the primary objective, while an attempt was made to identify the possible extent of these source rocks elsewhere in the basin. For the Bonaparte Basin, good oil source rocks were sought and an explanation for the lack of oil discoveries was proposed.

Northern Carnarvon

The main oil source rocks occur in the Upper Dingo Claystone of Late Jurassic age. The kerogens are detrital and were derived from the delta plain and the landmass to the east. Within the central part of the basin exinites become abundant with a gradation to vitrinitic-rich and then to predominantly inertinite on the basin margins. Both the Middle and Lower Dingo Claystone contain good oil-prone source rocks but they are less extensive than the Upper Dingo source rocks.

The Dingo Claystone in the basinal areas is within the oil window and may have reached late maturity in the deeper parts of the basin.

The source potential of the Triassic sediments (Mungaroo Formation and Locker Shale) is more speculative because there are fewer data points. The Locker Shale may be a good source rock, particularly if its deep water facies is represented by black shale deposited under stagnant, anoxic conditions. Such source rocks would have become mature by the end of the Triassic and post-mature and gas-generating in the Late Jurassic. The Mungaroo Formation contains poor quality,but thick, gas source rocks but there is an area of good oil potential in the Barrow Sub-basin. The Mungaroo Formation is in the effective oil window in some of the Northern Carnarvon Basin depocentres. However, in the deeper parts of the basin, the Mungaroo Formation is in the post mature gas zone.

Fair to good oil source rocks occur in the Cretaceous Muderong Shale within the basin axis. However, this sequence is only in the oil window in the deepest parts of the basin.

Oil-source rock correlations have shown that there is a very close similarity between the oils and some of the source rocks analysed. However, it has not been possible to select a particular source rock for the oils and oil stains. Most of the oils contain one or more phases of biodegraded oil. On the western side of the basin, it has been concluded that the Locker Shale and basal Mungaroo Formation comprise the major source interval. However, the oil in Angel-1 may have been sourced from the Jurassic. The gas fields are also likely to have been sourced from the Middle to Late Triassic sequence. On the eastern side of the basin, the oil source is probably the Upper Dingo Claystone.

Canning Basin

No major source rocks have been identified in this basin from a limited data base. The Early and Middle Jurassic sequence has some oil source potential but maturity levels may be only early mature.

Browse Basin

The Middle and Late Jurassic sequence is the best source rock interval in the Browse Basin. The best potential is developed in the Vulcan Sub-basin but productive facies may extend into the central Browse Basin. Most of the areas with good source potential are in the oil window and have been middle mature since the Late Cretaceous-Early Tertiary in the depocentres. The Early Jurassic may also be a good source in the deeper parts of the Vulcan Sub-basin. Early to Middle Triassic sediments may have some source potential on the northwestern side of the Ashmore Block. If this formation does have significant source potential, it would have generated oil from the Miocene to Recent.

Oil-source rock correlations show that most, if not all, of the oils have been derived from mixed algal and land-plant derived kerogen. The oil from Puffin-3 appears to have been sourced from kerogen, which was deposited in an intertidal environment, but no source from this type of environment has been identified in this study.

Bonaparte Basin

In the southeastern part of this basin, the main source rock is the Early Permian Kulshill Formation. Delta front facies contain significant exinite in lagoonal coals and shales, and grade into inertinite/vitrinite-rich prodelta facies. The Kulshill Formation is middle to post mature in the southeastern Bonaparte Basin.

In the northwestern part of the basin, the main source rock is the Middle-Late Jurassic interval (Petrel Formation). Limited evidence indicates that this sequence could have good potential in the Malita Graben where it is fully mature. The Early Cretaceous (Flamingo Shale Member) also has some source potential in the northwestern part of the basin. The Middle Jurassic and younger source rocks have reached middle maturity from the Early Tertiary and later.

No oils were available for oil-source correlation but analysis of numerous oil stains indicates that terrestrial kerogens are the main component. However, on geological grounds, the Kulshill Formation is likely to have sourced the migrant oils found in the southeastern part of the basin. The Tern and Petrel gas fields have probably been sourced from the post mature Kulshill Formation.

The oil stains in the northwest part of the basin appear to have been derived from a Jurassic to Early Cretaceous source.

PROSPECTIVITY

Northern Carnarvon Basin

A major consideration in the prospectivity of this basin is the relative timing of hydrocarbon migration and trap formation. The Locker Shale and the Upper Dingo Claystone have been generating hydrocarbons since the Late Triassic-Early Cretaceous respectively. Large volumes of the hydrocarbons have not been trapped due to late trap formation.

Three main play types have been identified in the Northern Carnarvon Basin:

a) tilted fault blocks of pre-breakup main unconformity section

b) post-breakup unconformity anticlines, and

c) stratigraphic traps.

Tilted fault blocks are the main target on the western side of the basin, where they are sourced from the Victoria Syncline to the north. The play has not been as successful on the eastern side of the basin because of adverse regional dip and the lack of a regional top seal. Post-breakup unconformity anticlines have been produced by differential compaction over horsts and/or Tertiary structuring. These are the main productive traps on the eastern side of the basin, where the Upper Dingo Claystone is the main source rock. Structures formed prior to the Mid-Miocene are likely to be the most prospective, because oil generation probably reached its peak before this time.

Potential for stratigraphic traps exists within the Late Jurassic to Early Cretaceous section - turbidite and submarine fan sandstones, updip shale-out, onlap of basal Triassic sandstones on to pre-existing highs and channeling in the Locker Shale.

The Exmouth Plateau region appears to have had an unfavourable thermal history relative to structuring, with source rocks maturing in the Triassic, prior to substantial uplift in the Early-Middle Jurassic.

Lack of adequate seals may be a problem in the southern shelfal area and in the Beagle Sub-basin.

Canning Basin

Lack of identified source rocks is the major negative factor in this basin. However, by analogy with the other basins in this study, facies which may contain good source rocks could be present.

Browse Basin

Prospectivity varies between the northern, central and southern parts of the basin. In the northern part of the basin, the Middle and Late Jurassic source rocks began to generate oil in the depocentres from the Late Cretaceous to the Miocene. Structures formed by the Early Tertiary would therefore have been timely to trap most of the oil generated in the northern Browse Basin, e.g. drape over both horst blocks and palaeohighs associated with continental breakup, and rotated fault blocks.

In the central Browse Basin, Middle and Late Jurassic source rocks may be present, based largely on extrapolation of palaeoenvironments from the northern Browse Basin. Reservoir quality of sands above and below the breakup unconformity has been affected by secondary dolomitisation. Trapping mechanisms would be provided by drape over pre-Callovian horsts.

The limited exploration in the southern Browse Basin has not established the widespread presence of good source rocks. However, some indications of Middle Jurassic source rocks have been found. Jurassic sandstones probably have the best reservoir potential. As is the case elsewhere in the Browse Basin, drape over pre-breakup horst blocks provides the major exploration targets.

Bonaparte Basin

Exploration results within this basin have been disappointing compared with the Browse and Carnarvon Basins, as no commercial oil discoveries have been made. The prospectivity of the basin is most simply considered by evaluating southeast and northwest segments separately. In the southeast part of the basin, the Early Permian is a good source but it is probably post mature in the northern part of the Petrel Sub-basin. Some oil trapped during generation has probably been lost by tilting during the Cretaceous. Reservoir quality in the southeastern Bonaparte is fairly poor, while the regional seal is also less effective in this area.

In the northwest of the basin, good, mature to late mature source rocks occur in the Malita Graben and in the Sahul Syncline. This sequence would have been in the oil window from the Early Cretaceous. Reservoir quality is poor in the depocentres but improves on the high blocks. Lack of exploration success may be related to unfavourable juxtaposition of source and reservoir sequences.

Shelfal to nearshore sands of Late Jurassic to Early Neocomian age are potential reservoirs. Potential traps include salt-induced anticlines and stratigraphic wedging of Middle Jurassic sands between the enclosing shales. In much of the northwest Bonaparte Basin, the seismic quality is such that it is difficult to interpret structures below the base Cretaceous.

1. INTRODUCTION

1.1 PURPOSE AND SCOPE OF STUDY

In 1972-74, Robertson Research International Ltd. (RRI), in association with BEICIP, completed a detailed regional geological and geophysical synthesis of the Northwest Shelf of Australia. This was followed in 1979 by a detailed RRI study of the petroleum geochemistry of the Northwest Shelf. In that study, geochemical analyses were undertaken on samples from 44 wells. The main conclusion was that the majority of the sections studied contained gas-prone source rocks.

After the 1979 study, a number of oil discoveries were made in the Northwest Shelf of Australia between 1982 and 1985, including Jabiru and Challis in the Vulcan Sub-basin, South Pepper in the Barrow Sub-basin, and Talisman and Harriet in the Dampier Sub-basin. These discoveries demonstrated that several areas on the Northwest Shelf had oil potential, rather than being gas/condensate provinces, as was widely believed.

In 1985, Robertson Research (Australia) Pty. Limited (RRA), in association with Robertson Research (Singapore) Pte. Ltd. (RRS) and RRI, therefore considered that a revised evaluation of the petroleum potential of the region was warranted because:

(a) the recent oil discoveries indicated that oil source rocks might be more widespread than was originally envisaged;
(b) the availability of many new well sections in the area of interest should have provided a better data base for assessing its oil potential;
(c) major relinquishments were due in much of the area in 1985 and 1986; it was anticipated that these would be offered to industry through 1985 and 1986. Enclosures 1-4 show the present distribution of permits and vacant acreage in the study area.

Following receipt of sufficient industry support, the project commenced in June 1985.

The broad objective of the study was to achieve a better understanding of the regional distribution of potential oil-prone source rocks. In the process, a number of specific objectives were achieved:

- to review, and where appropriate, to redefine the structural framework and tectonic history of the area;
- to establish the geological histories of the different basins;
- to reconstruct the palaeogeography and palaeofacies of significant intervals;
- to identify and characterise potential source rocks, and to determine their maturity profiles;
- to integrate kerogen facies with the palaeogeographic and structural studies in order to develop a predictive model of the distribution of source rock types;
- to attempt to relate known oil occurrences to possible source rocks;
- to derive maturation models of representative wells and hypothetical models for depocentres, in order to predict timing of petroleum generation and migration;
- to resolve specific correlation or facies problems indicated by the geological and geochemical interpretations by conducting limited biostratigraphical analyses.

1.2 DATA AND MATERIALS USED IN THE STUDY

For this project, well completion reports and representative wireline logs were obtained for all available wells. These reports were available from the Mines Departments of Western Australia and the Northern Territory and from the Bureau of Mineral Resources (BMR). Representative regional seismic sections were also acquired from the relevant State Mines Departments.

After a preliminary study of the well completion reports and of published data from the various basins on the Northwest Shelf, including the earlier Robertson Research report, about 40 wells were selected for sampling, to provide a representative coverage of the study area. Sample material used in this study was obtained from the Core and Cuttings Laboratory of the BMR in Canberra. When the results from these wells were available and had been interpreted, a further 20 wells were selected for sampling to provide additional data.

Permission was obtained from two operators (Woodside Offshore Petroleum and Hematite Petroleum Ltd.) to sample several wells which, at the time of sampling, were confidential. Ampol Exploration supplied samples from two onshore wells (Sandy Point-1 and Cape Range-2), while Offshore Oil supplied material from West Barrow-2. The co-operation of these companies is gratefully acknowledged. All wells sampled in this project are shown on Enclosure 5.

Oil samples were also obtained from a number of operators on the Northwest Shelf, and their contributions have been greatly appreciated:-

Bond Corporation:	Harriet, Lenita, Bambra
Woodside Offshore Petroleum: (Woodside)	North Scott Reef, Wilcox
Wesminco:	South Pepper, North Herald
West Australian Petroleum: (Wapet)	Saladin-1, Gorgon-1
Atlantic Richfield Co.: (Arco)	Puffin-2 and 3
Hematite Petroleum Ltd.: (BHP)	Jabiru
Ampol Exploration Ltd.: (Ampol)	Rough Range-1

In addition, several oil samples obtained for the 1979 RRI study were re-analysed.

Palynological slides from a number of wells were borrowed from the Mines Department of Western Australia for use in the study.

1.3 METHODOLOGY

1.3.1 Geology

Geological correlations across the various basins were made mainly by using gamma ray logs from the various well completion reports, with some subordinate use of electric logs. Lithological descriptions were also used extensively to support log correlations. Formation tops were determined for all available wells (Appendix A). Some log analysis to determine facies was undertaken, particularly in the Bonaparte and Browse Basins. This analysis assisted in predicting the distribution of source intervals in these basins. A geological history was compiled for each of the basins, using interpretations of the open file wells and published information.

1.3.2 Geophysics

The study area was divided into four map sheets using standard 1:1,000,000 grid boundary co-ordinates. These sheets correspond approximately to the Northern Carnarvon, offshore Canning, Browse and Bonaparte Basins. The sheets have an area of overlap so that adjacent maps can be spliced to form a composite map of the entire Northwest Shelf.

Regional seismic time structure contour maps were compiled from published and open file maps of various vintages and sources and, in some cases, were supplemented with original mapping. Regional seismic sections were constructed from open file data and were interpreted as a check of the original mapping.

Since the Northwest Shelf region contains sediments from Late Carboniferous to Recent age, and as hydrocarbons are reservoired at many different horizons, no one particular horizon can illustrate the overall geological framework of the region. Differing horizons were therefore selected for their geochemical and/or structural relevance and were spliced together to form a composite map. Individual map sheets contain the following horizon time structure contours.

Northern Carnarvon Sheet	- near base Triassic
	- near top Triassic
	- Middle Jurassic horizon
	- main breakup unconformity (Callovian)
	- intra-Neocomian unconformity
	- top Barrow Group (Neocomian)
Offshore Canning Sheet	- near top Triassic
	- main breakup unconformity (Callovian)
Browse Basin Sheet	- near top Permian
	- near top Triassic
	- base Cretaceous unconformity
Bonaparte Basin Sheet	- near top Permian

The time structure maps are discussed further in Chapter 4.

1.3.3 Petroleum Geochemistry

Source rock geochemistry was carried out on 60 wells (Encl. 5). Wells samples are located in the Northern Carnarvon, Browse and Bonaparte Basins. No well data have been placed on open file for the offshore Canning Basin since the 1979 study. However, analyses from Canning Basin wells in the 1979 study and other open file analyses have been reinterpreted in this project. The geochemical analyses results are plotted on petroleum geochemistry charts at 1:5000 scale in Volume 5, and the individual petroleum geochemistry well reports (with tabulated analytical data) are included in Volumes 2 and 3. Spore colour index (SCI) graphs, vitrinite reflectivity (VR) graphs, and representative chromatograms and gas chromatography-mass spectrometry (GC-MS) traces are also included in these volumes.

Analyses have been made of ditch cuttings samples and core samples. Specific lithologies were picked from many of the ditch cuttings for detailed analysis. Full use was made of wireline logs and other well data in the geochemical studies.

The main purpose of the geochemical analyses in the study was as follows:

- to identify and describe source rocks and maturity profiles in the study area;
- to study the distribution of kerogen facies;
- to study the productivity of source rock units in terms of volume of oil produced;
- to define the physical and chemical properties of the oils discovered in the area;
- to study the geological history in terms of basin subsidence and uplift, and variation in heat flow;
- to use time/temperature index (TTI) modelling to estimate maturity in the basin deeps.

Geochemical analyses and interpretations for the study followed routine procedures, details of which are included in Appendix B. Outlines of the interpretation of pyrolysis data, and the principles of interpretation for oil and source rock correlation are included in Chapter 8 of this volume. The types of geochemical analyses made are listed below:

(a) organic carbon screening;
(b) pyrolysis screening and 'Rock-Eval' pyrolysis analyses;
(c) source rock analysis including solvent extraction, extraction fractionation, gas chromatography and gas chromatography-mass spectrometry studies of extracts;
(d) spore colour index (SCI) determination;
(e) kerogen type and relative abundance (microscopic examination);
(f) vitrinite reflectance determination;
(g) oil to source rock correlation (including gas chromatography-mass spectrometry (GC/MS) of hydrocarbon fractions, and carbon isotope ratios of alkanes, aromatics and potential source rocks).

In this study, kerogen composition has been assessed both by interpretation of pyrolysis data, and by microscopic examination, with emphasis mainly on analysis of non-oxidised, unsieved preparations.

Crude oils, migrant oils (extracted from rock samples), and source rock extracts were analysed by column chromatography, gas chromatography, and gas chromatography-mass spectrometry, and for carbon isotope ratios. The results of these analyses have been used to classify oils, to draw conclusions about the type and maturity level of their source, and from these to suggest possible relationships between them and the various source rocks.

Exploratory wells are almost invariably drilled on or near the crests of structures which may have been high areas. Source rock sequences are often thin (having been stratigraphically condensed and/or eroded), or occur in different lithologies or facies, on the crests of structures. Moreover, source rocks on structural highs have usually been less deeply buried than coeval strata in surrounding, more basinal areas, and hence may be less mature. The geochemical findings in this report are based on data from the study wells interpreted with available structural information. In addition, in an attempt to overcome the problem of wells being drilled on structural highs, estimates of maturity of potential source rock horizons have been made in the basin deeps by using TTI modelling (Appendix C).

1.3.4 Biostratigraphy

In a number of wells, reinterpretation of the age of published palynological assemblages was made, because work subsequent to the initial interpretation has, in some cases, changed the age of the assemblage. In other wells, slides were borrowed from the Western Australia Department of Mines, palynological interpretations made, and ages assigned to the intervals studied (Appendix D).

1.4 PERSONNEL INVOLVED

RRA

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Mrs. M. Virdy	Report Compilation

<u>RRI</u>

Dr. B. Cooper	Geochemistry

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Dr. G. Blackburn	Seismic Interpretation

<u>Consultants</u>

Dr. R. Helby	Palynology
Dr. M. Apthorpe	Foraminifera

1.5 ARRANGEMENT AND PRESENTATION OF THE REPORT

Volume 1	General text and appendices
Volume 2	Petroleum geochemistry well reports and oil-source rock correlation data (Northern Carnarvon Basin)
Volume 3	Petroleum geochemistry well reports and oil-source rock correlation data (Browse and Bonaparte Basins)
Volume 4 (Atlas)	Geological maps and diagrams
Volume 5 (Atlas)	Well summary charts

1.6 ACKNOWLEDGEMENTS

The project team are very appreciative of the cooperation extended to them by numerous officers of the various Government departments from whom data were obtained for the study. Mr. J. White and Mr. A. Mond of Petroleum Division, BMR, Mr. J. Staunton of the Core and Cuttings Laboratory of the BMR, Mr. R. Elliott of the Western Australian Mines Department, Mrs. S. Hickey of the Northern Territory Department of Mines and Energy, and Mrs. Missons of the Australian Government Printing Office, Canberra, were particularly helpful.

The contributions of oil or cuttings samples from the following oil companies are also gratefully acknowledged, as the study would not have been nearly as comprehensive without this additional material, from West Australian Petroleum (WAPET), Wesminco, Woodside, Offshore Petroleum, Ampol Exploration Ltd., Hematite Petroleum, Arco and Bond Corporation.

Finally, the helpful comments and insights provided by technical staff of several subscribing companies are gratefully acknowledged.

2. BACKGROUND INFORMATION

2.1 INFRASTRUCTURE

The study area is located between latitudes 9°S and 23°S, and longitudes 113°E and 130°E, offshore Western Australia and Northern Territory (Encl. 5). The region is very sparsely settled, with some small towns along the coast, from Wyndham in the north to Exmouth in the south (Fig. 1). The largest of the towns is Port Hedland, with a population of 14,000. Most of the towns are ports for various industries, e.g. Dampier and Port Hedland for the nearby iron ore mines, Broome for pearling, and Wyndham and Derby for export of pastoral products. Withnell Bay, 10 km NE of Dampier, is the site for onshore gas treatment and liquifying facilities for the North Rankin field. LNG tankers, with a capacity of 125,000m^3 (approximately equivalent to a super tanker of 200,000 deadweight tonnes), will carry the gas to Japan when exports start in 1989. A natural gas pipeline, which supplies the domestic market, links Dampier to Perth. Iron ore carriers, with a capacity of up to 168,000 tonnes, load at Dampier and Port Hedland. Onslow is a base for offshore oil exploration.

The sealed North West Coastal Highway links Carnarvon and Port Hedland, and approximately follows the coastline (Fig. 1). It joins the Great Northern Highway at Port Hedland, follows the coast to Derby, and then passes inland through the small settlements of Fitzroy Crossing and Halls Creek. Near Kununurra, it joins the Victoria Highway en route to Darwin.

The larger coastal towns such as Broome, Derby and Port Hedland, are connected by daily air services to Darwin and Perth.

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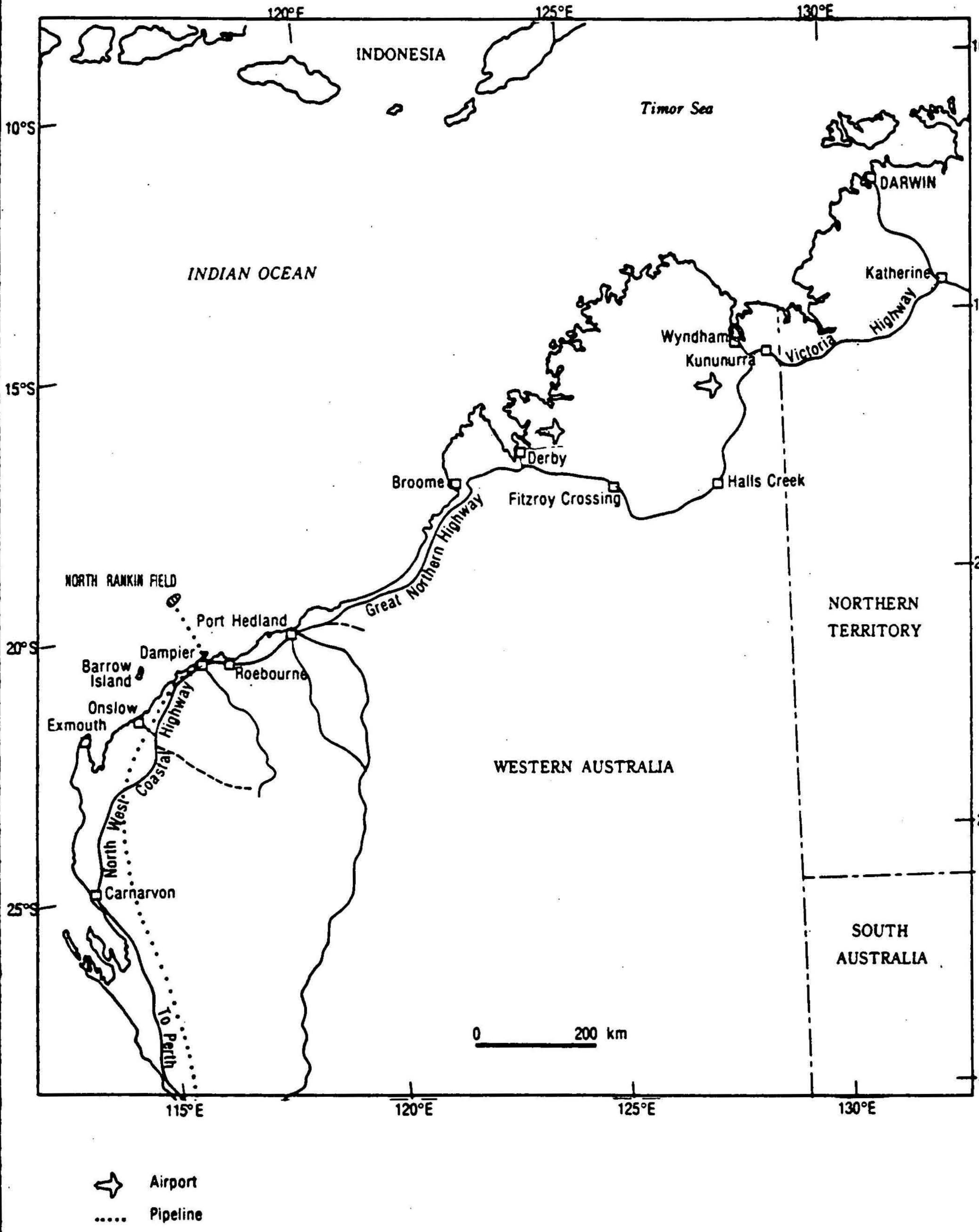

Location map, Northwest Shelf

Figure 1

2.2 CLIMATE

The climate is subtropical to tropical, and the area experiences a monsoonal wet season from approximately December-April. The annual rainfall varies from 300-600mm along the coastal strip. Cyclones are relatively common, and their path often approximately follows the coastline from north to south. However, it has been the practice over recent years to drill through the wet season offshore, with limited shutdowns only when cyclones are in the proximity of the drilling rigs. Temperatures range from maxima of about 40°C in summer, to about 25°C in winter.

2.3 PETROLEUM REGULATIONS

Offshore petroleum exploration and exploitation is administered under the Petroleum (Submerged Lands) Act, 1982. This act gave effect to revised administrative arrangements agreed between the Commonwealth and the States, which have produced a common code for all offshore exploration in Australian waters. An excellent summary of the legislation was presented by Mr. J.C. Starkey, then secretary of the Department of National Development and Energy, at the 1983 Australian Petroleum Exploration Conference (APEA). Much of this section is based on his paper.

The act established Joint Authorities for each area beyond the three mile (4.8 km) territorial limit, adjacent to the States and the Northern Territory. The Joint Authorities consist of the Commonwealth Minister for National Development and Energy, and the relevant State or Northern Territory Minister. Day to day matters arising in the administration of the legislation are the responsibility of the State and Northern Territory Ministers as Designated Authorities. The States and the Northern Territory exclusively regulate petroleum activities within their three mile territorial sea.

Offshore exploration permits are granted for a period of six years, and can be renewed a maximum of three times, each renewal being for a period of five years. On each renewal, 50% of the permit area is to be relinquished. Permit areas are from 16-400 graticular blocks, each block being 5 minutes of latitude by 5 minutes of longitude.

Invitations to apply for permits are issued periodically, generally with an interval of 3-5 months from issue of the gazettal notice to closing date. Until recently, the criteria for granting of the permit were the quality and quantity of the minimum work programme, the applicants' past performance in other exploration areas in Australia and elsewhere, and the technical and financial strengths of applications (Starkey, 1983). In December 1985, a modified work programme bidding system was introduced. Under this system, applicants are required to nominate a guaranteed minimum 'dry hole' exploration programme for the first three years of the permit term, and a 'secondary' programme for the remaining three years of the permit term. Each component of the guaranteed 'dry hole' programme must be completed in the designated year, or earlier. This system was applied to 6 areas in the Northern Carnarvon and Bonaparte Basins in December, 1985.

In November 1985, a cash bonus bidding system was introduced for areas categorised by the Joint Authorities as highly prospective for finding petroleum. To date, this system has been applied only to five blocks in the adjacent area of Ashmore and Cartier Islands, near the Jabiru field in the Browse Basin. Permits awarded for these blocks, or blocks awarded under similar terms, will be for one 6-year term and will not be renewable. However, the permit will continue in force if an application for a production licence has been lodged before the end of the 6-year term (Reid, 1986).

If petroleum is discovered in an exploration permit, an application can be made for a production licence. A production licence can vary in size from 1-9 blocks, and is granted for a period of 21 years, with a first renewal for a further 21 years, and subsequent renewals of up to 21 years.

2.4 PRICING, LEVIES, ROYALTIES AND TAXES

2.4.1 Crude Oil and Gas Liquids Pricing

2.4.1.1 Crude Oil

The pricing of indigenous crude oil production in Australia is subject to Federal Government regulation which currently sets an Import Parity Price (IPP) from time to time. The IPP is set for each area of crude oil production. The US$ Base Price is calculated as the weighted average of the official and spot prices of Saudi Arabian Light Marker Crude in January 1986, multiplied by the ratio of the current to the January spot prices for a basket of four Middle East crudes.

This price is adjusted to reflect freight charges, insurance and loss and quality differentials and is then converted to A$. The freight component is based on official tanker rates to the refinery port nearest to the Australian producing field; the IPP is therefore the price obtained at the nearest refinery port.

2.4.1.2 Condensate

The price for condensate supplies is determined by negotiation between individual refiners and producers, and is not directly controlled by Government regulation.

2.4.1.3 LPG

The price of naturally occurring and refinery-produced LPG is regulated by the Federal Government (except for the price of LPG sold as feedstock to the petrochemical industry which is freely negotiated). The price is generally to be set half-yearly.

Pricing policy has recently been reviewed. In future the price will be determined as A$20 a tonne above the average export parity price of Bass Strait (Gippsland Basin) propane for the six month period ending on the last day of the previous August for the 1st November 1986, and subsequent 1st October adjustments, and on the last day of the previous February for the 1st April adjustments. These arrangements will apply until 30th September 1988 when they will be reviewed.

A price of A$214.18 per tonne will apply from 1st November 1986 to 31st March 1987. The rate of excise for this period will be A$14.43 per kilolitre.

2.4.2 Government Charges, General

Australian Federal and State Governments currently impose four kinds of tax on oil and gas production onshore and offshore Australia. These are:-

(a) Levies on some crude oil and LPG production (Federal)
(b) Royalties on all hydrocarbon production (State)
(c) Resource Rent Tax (Federal)
(d) Resource Rent Royalty
(e) Corporation tax on all activities (Federal)

Levies, where applied, are applied to gross crude oil and LPG production. State Royalties are applied to the wellhead value of all hydrocarbon production, the methodology for calculating wellhead value varying from State to State. Resource Rent Tax (RRT) is applied to offshore developments in Permits other than those from which Production Licences have been granted prior to 1st July, 1984. RRT is applied in lieu of State Royalties and Crude Oil Levies. Corporation Tax is applied to profits from all oil and gas developments with Levies, Royalties and RRT being allowed as direct deductions in the tax calculation.

2.4.3 Crude Oil Levies

Oil produced from fields discovered before 18th September, 1975, is classified as "Old" oil and is subject to one of two Federal Government levy systems - i.e. either the "Old Levy" or the "Intermediate Levy". The Old Levy applies to most old oil, whereas the Intermediate Levy applies currently to certain Bass Strait (Gippsland Basin) developments.

All other oil produced in Australia is subject either to Resource Rent Tax (RRT), Resource Rent Royalty (RRR) or a levy system different from the one outlined above, referred to as the "New Levy".

The levies tabulated below are those effective as of July 1986. Excise has been removed for onshore producers for the remainder of the 1986/87 financial year, subject to review by the government and dependent on the level of the import parity price.

Annual Oil Production in thousand kilolitres	Equivalent Daily Production in thousand barrels per day	Levy as a percentage of the Import Parity Price for Bass Strait Crude Oil		
		Old Levy	Intermediate Levy	New Levy
0 to 50	0 to 0.862	0%	0%	0%
50 to 100	0.862 to 1.724	5%	0%	0%
100 to 200	1.724 to 3.448	15%	0%	0%
200 to 300	3.448 to 5.173	20%	0%	0%
300 to 400	5.173 to 6.897	40%	15%	0%
400 to 500	6.897 to 8.621	70%	30%	0%
500 to 600	8.621 to 10.345	80%	50%	10%
600 to 700	10.345 to 12.068	80%	55%	20%
700 to 800	12.068 to 13.792	80%	55%	30%
over 800	over 13.792	80%	55%	35%

2.4.4 LPG Levies

Federal Government LPG Levies are applied only to naturally occurring LPG produced from fields in production prior to 17th August, 1977. Naturally occurring LPG from fields brought into production on or after 17th August, 1977, is free of Levy.

The LPG Levy is related to the current LPG price determined generally at six monthly intervals by the Government.

The LPG Levy applying from 1st November, 1986 to 31st March, 1987, is A$14.43 per kilolitre (A$2.27 per barrel, which is approximately equivalent to A$27 per tonne).

2.4.5 Royalties

In offshore areas outside the Three Mile Territorial Sea, Royalty arrangements are subject to Commonwealth jurisdiction. Currently the rate applying to North West Shelf fields is 12.5 percent, whilst Bass Strait Royalties are 10 to 12.5 percent. The States control the arrangements onshore and within the Territorial Seas. Rates generally vary from 10 to 12.5 percent.

The detailed method of assessing Royalties varies from State to State in Australia. Except for the recently introduced Resource Rent Royalty in Western Australia, which currently applies only to the Barrow Island field, the methodology of assessment is similar for all States.

In general, Royalty is calculated as a percentage of wellhead value of all hydrocarbons produced from the field. Wellhead value is effectively sales revenue from hydrocarbon production less the costs of treatment and transportation from the wellhead to point of sale.

The deductions which may be claimed against Royalty are a matter for negotiation with the Commonwealth or State authorities. As a general guide, however, the assumptions below may be made for the purposes of broad economic analysis:

Item	Allowances
(a) Capital Costs (treatment and transportation only)	- Depreciated over 10 years or field life whichever is smaller. - Interest on capital not allowed - Head Office costs normally not allowed
(b) Operating Costs (treatment and transportation only)	- Crude Oil and LPG Levies not necessarily allowed. - Lifting costs now allowed. Workovers not allowed. - Overhead costs not normally allowed.

2.4.6 Resource Rent Tax

With effect from 1st July 1984, certain projects in Australia can be subject to Resource Rent Tax (RRT). This tax applies to projects for which no production licence had been obtained as at July 1984 and which are not located in the permit areas from which existing licences were drawn. Where it applies, RRT is payable on a project basis in place of Royalties and Federal Government Crude Oil Levies. It is profit related and applied at a rate of 40 percent to those projects earning a pre-tax rate of return greater than the long term Bond rate plus 12 percentage points. It is payable before Corporation Tax, and is deductible in full against Corporation Tax.

An example of the mechanics of the RRT calculation is given in the following tabulation (all figures in A$MM). Deductions allowed against this tax are restricted to a limited geographical area.

Year	Op. Profit[1]	Capex Allowed[2]	Net Recpts[3]	Indexed Net Recpts[4]	Indexed Early Exp[5]	Net Taxable Income	Res. Rent Tax[6]
1	0.0				10.0	-10.0	0.0
2	0.0	10.0	-10.0	-10.0	11.0	-21.0	0.0
3	0.0	10.0	-10.0	-23.0	12.1	-35.1	0.0
4	0.0	10.0	-10.0	-39.9	13.3	-53.2	0.0
5	0.0	10.0	-10.0	-61.9	14.6	-76.5	0.0
6	0.0	20.0	-20.0	-100.4	16.1	-116.5	0.0
7	0.0	75.0	-75.0	-205.6	17.7	-223.3	0.0
8	0.0	150.0	-150.0	-417.2	19.5	-436.7	0.0
9	300.0	0.0	300.0	-242.4	21.4	-263.8	0.0
10	330.0	0.0	330.0	14.9	23.6	-8.7	0.0
11	360.0	0.0	360.0	379.3	25.9	353.4	141.4
12	300.0	0.0	300.0	300.0	0.0	300.0	120.0
13	290.0	0.0	290.0	290.0	0.0	290.0	116.0
14	280.0	0.0	280.0	280.0	0.0	280.0	112.0

In this example, the meaning of the column headings and the way in which the calculations are made are as follows:

(1) Operating Profit is defined here as gross revenue from sales of hydrocarbons less operating costs of the project. For RRT purposes, the assessment of gross revenue is on the basis of the price at the point at which the products first become marketable.

(2) Allowable Capex consists of capital and exploration costs which can be offset against RRT. This will not necessarily be the same as the total capital expenditure on the project. It also does not include early allowable exploration expenditure (see (5) below).

(3) Net Receipts consist of Operating Profit less allowable Capex.

(4) Indexed Net Receipts are Net Receipts compounded at the appropriate RRT Threshold Rate (Bond rate plus 12 percentage points) applying in each year. In this case, this rate is assumed to be 30 percent throughout. The compounding process stops in the year following the year in which Indexed Net Receipts less Indexed Early Expenditure (i.e. Net Taxable Income) becomes positive.

(5) Indexed Early Expenditures are those exploration costs incurred more than 5 years before the first Production Licence in the Permit is granted. These costs (assumed to be A$10MM incurred in year 1) are not compounded at the Threshold Rate. They are instead compounded at the GDP deflator applying in each year. This is assumed to be 10 percent in the example given.

(6) Resource Rent Tax is payable on positive Taxable Income at the rate applicable. In this report the rate of RRT assumed is 40 percent. RRT is shown as payable in the year of assessment.

2.4.7 Resource Rent Royalty

The Resource Rent Royalty (RRR) currently applies only to the Barrow Island Field. It is proposed that it will replace Crude Oil Levies and State Royalties for some onshore developments. It is the onshore equivalent of the Resource Rent Tax, which applies to certain offshore developments.

The mechanics of application of RRR are similar to that of RRT, though the threshold rate and tax rate may be different.

2.4.8 Corporation Tax

Corporation Tax in Australia is currently assessed as 46 percent of taxable income. This will increase to 49 percent from July 1, 1987. Taxable income from oil and gas production is typically calculated as follows:

(1) Gross Revenue from all hydrocarbon sales

less

(2) Crude Oil and LPG Levies
(3) State, Commonwealth and Overriding Royalties
(4) Resource Rent Tax
(5) Operating Costs
(6) Exploration Costs
(7) Interest on Borrowed Capital
(8) Depreciation on Capital Expenditure

equals

(9) Taxable Income

Tax is payable in the financial year following liability. Taxable income losses can be carried forward indefinitely (there is no 7-year limit on loss carry forward as would apply in some other industries in Australia). There are no carry-back provisions.

For tax purposes, exploration costs (wildcat and appraisal drilling, seismic etc.) are written off immediately.

Depreciation on capital investment is on a straight line (prime cost) basis over 10 years or field life, whichever is smaller. In certain instances, companies can elect to depreciate at 20 percent (i.e. over 5 years) or 30 percent (i.e. over approximately 3 years).

In assessing overall corporate liability to tax, tax losses in one operation may be set off against taxable income in another operation anywhere in Australia.

REGIONAL GEOLOGY

REGIONAL GEOLOGY

3. TECTONICS

3.1 PRESENT GLOBAL SETTING

Australia, today, is situated on the eastern part of the Indo-Australian Plate (Fig. 2).

The Australian continent is flanked on all sides but the north by oceanic lithosphere (Fig. 2). These oceanic basins can be dated from sea-floor spreading anomalies, calibrated by deep sea drilling results. The age of the oceanic lithosphere around the Australian continent varies from Late Jurassic in the north-west, through Early Cretaceous in the west, Late Cretaceous in the south and southeast, to Paleocene in the northeast.

3.2 TECTONIC EVOLUTION OF AUSTRALIA

Until the Middle Jurassic (prior to 160 Ma)[1], Australia was an integral part of Eastern Gondwanaland (Fig. 3). Palaeozoic sediments in the northwest of Australia were laid down in relatively stable intracratonic basins. Rifting, as a precursor of the breakup of Gondwanaland, commenced in the early Mesozoic. This resulted in the development of localised depocentres in which fluviatile to marginal marine sediments were laid down.

The earliest sea-floor spreading event, in the Argo Abyssal Plain, off the (present-day) NW margin of Australia, commenced in the late Middle Jurassic (Fig. 4). The oldest recognised sea floor spreading anomaly is M25 (160 Ma). This episode continued through until about 100 Ma (mid-Cretaceous). Sediments began to prograde offshore, across the Northwest Shelf, in an increasingly marine environment.

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1. Wherever possible, absolute, stratigraphic and palaeontological ages have been reconciled according to the Geological Time Scale of Harland et al. (1982).

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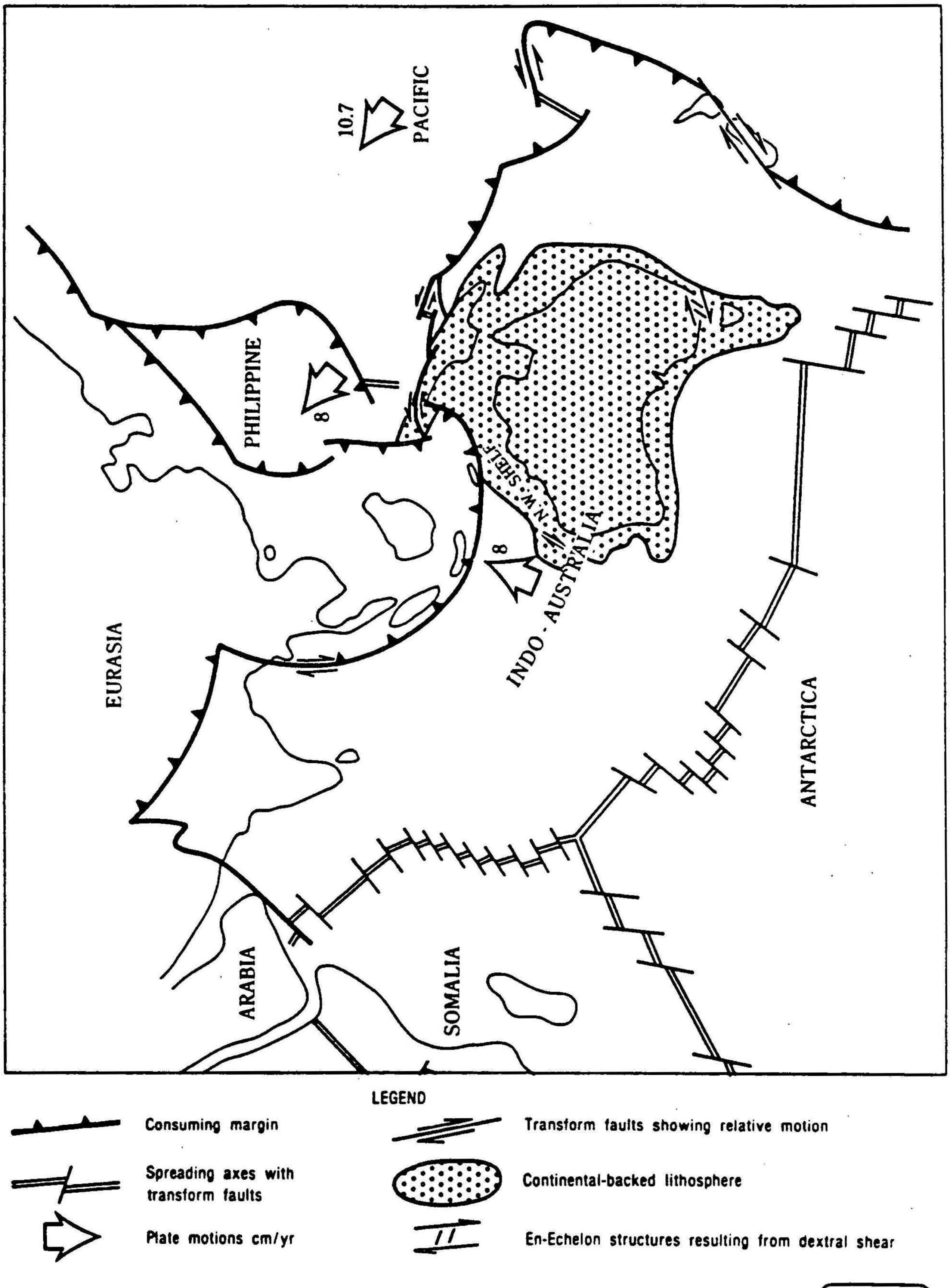

Present-day plate tectonic setting of Australia

Figure 2

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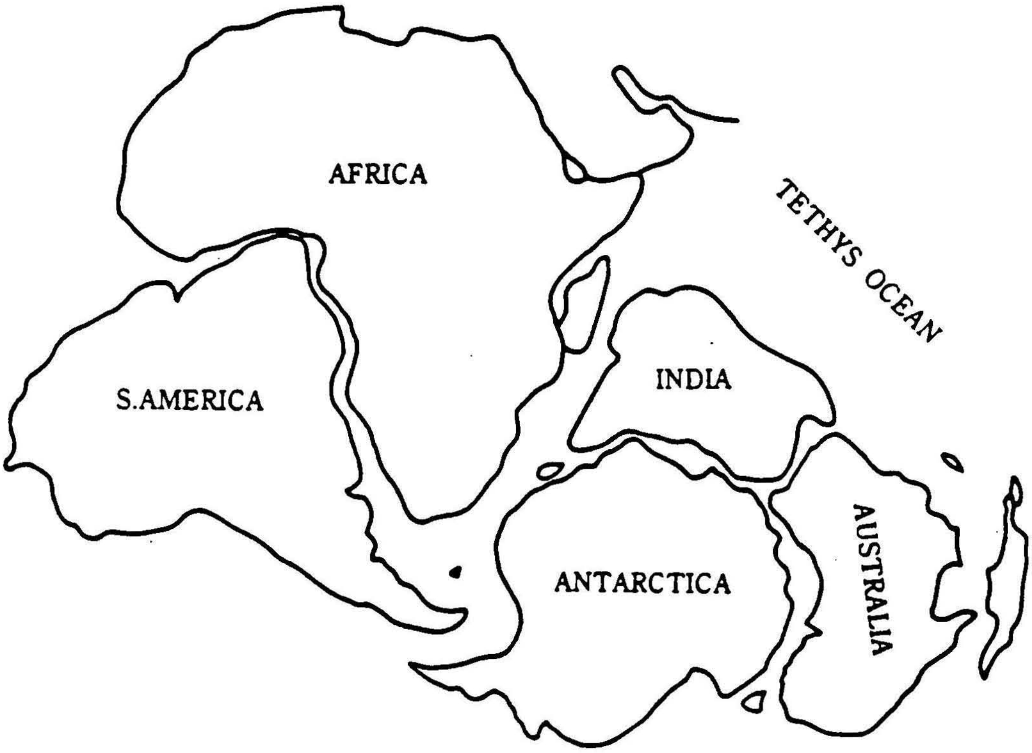

(Modified from Veevers et al. 1980)

Gondwanaland reconstruction (>160 Ma)

Figure 3

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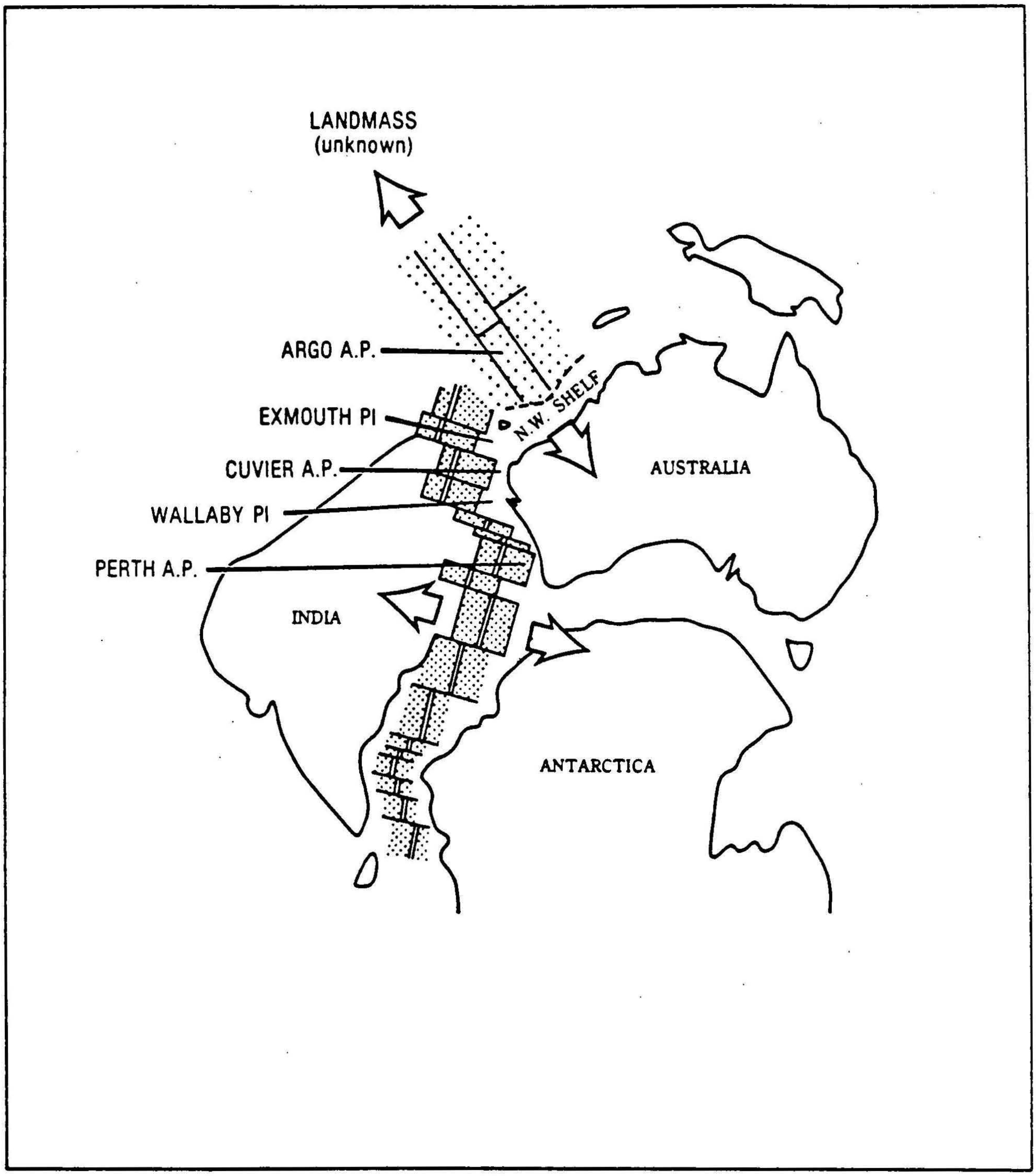

LEGEND

	Oceanic seafloor created by spreading initiated at 165 Ma (Middle Jurassic)		Relative motions of continental blocks
	Oceanic seafloor created by spreading between India and Australia/Antarctica since 130 Ma (Early Cretaceous)	A.P.	Abyssal Plain
	Spreading centre with transform fault offsets	PI	Plateau

Breakup along western coast of Australia (app. 120Ma)

Figure 4

During the Neocomian, sea-floor spreading commenced further south, between greater India and Australia/Antarctica (Fig. 4). The oldest sea floor spreading anomaly is M10 (132 Ma) in the Cuvier Abyssal Plain.

The outline of the present continental margin of northwest and west Australia was defined by these spreading events. The plateau margins represent transform fault offsets of the sea-floor spreading centres that formed the deep oceanic basins.

Later spreading events in the south and east did not directly affect the morphology of the northwest of Australia. However, changes in oceanic circulation, currents and palaeolatitude did exert a significant influence on the nature of the sediments and biota recorded on the Northwest Shelf.

During Tertiary times, Australia has moved northwards from Antarctica, and collided with southeast Asia. This has influenced the structural development of the Northwest Shelf. Left lateral shear between the Indo-Australian and Pacific Plates in the New Guinea region (Fig. 2) has resulted in anticlockwise rotation of Australia and the imposition of dextral (right-lateral) shear on the Northwest Shelf (Fig. 5).

3.3 TECTONICS OF THE NORTHWEST SHELF

The evolutionary scheme followed in this study is based largely on the work on Australia's continental margins by Falvey and co-workers (Falvey, 1974; Falvey & Mutter, 1981; Falvey & Middleton, 1981), and the Australia-wide synthesis of Veevers (1984).

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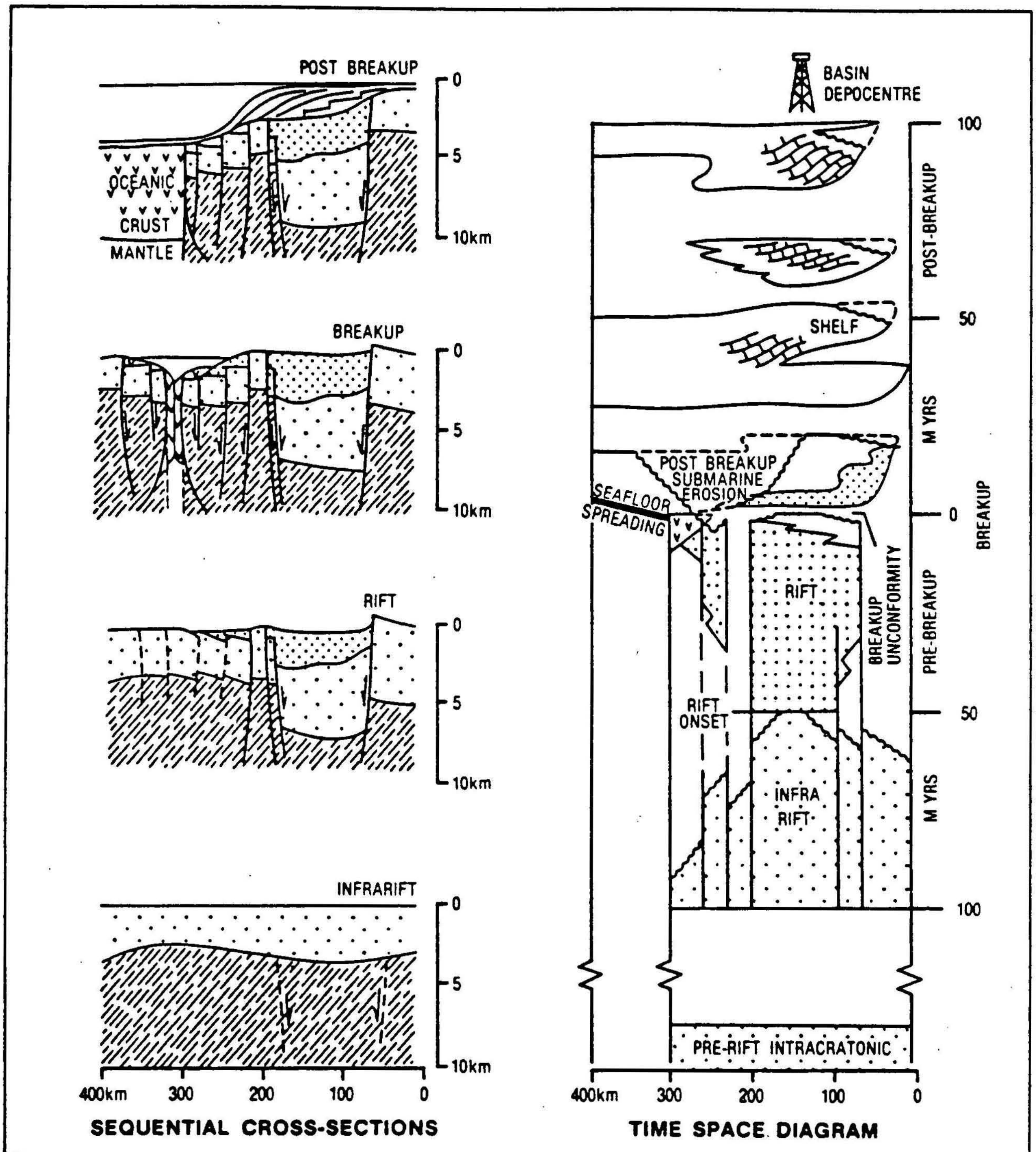

(Modified from Falvey & Middleton, 1981)

Generalized development of a rifted continental margin

Figure 5

According to Falvey & Middleton (1981), the evolution of the divergent continental margins has three main stages (Fig. 5) :

1) Subsidence begins with the infra-rift phase (usually about 100 My before breakup) preceded by some erosion of basement or pre-rift sediments. The infra-rift basin grows along the incipient continent-ocean boundary. It does not appear to be fault controlled and contains mostly non-marine and non-volcanic sediments (Fig. 5). In the Northwest Shelf area, these sediments are of Late Palaeozoic to Early Mesozoic age (mainly Permian and Triassic).

2) From as much as 50 My before breakup, through to breakup time, basin subsidence continues only in rift grabens and half grabens flanking the incipient continent boundary.

   Recently (McKenzie, 1978; Etheridge et al., 1985 a and b), shallow-dipping faults of great areal extent have been recognised in areas subjected to large-scale continental extensions (as might be expected prior to breakup). These subhorizontal faults are termed detachment faults (Fig. 6).

   Sediments are marginal to non-marine. Some vulcanism may be present close to the incipient continent-ocean boundary but it is absent from most major depocentres in the Australian region. Some uplift and erosion of infra-rift phase sediments is evident away from the major depocentres. On the Northwest Shelf, this rift stage commenced in the Early Jurassic, about 195 Ma, and perhaps earlier.

3) From breakup time, subsidence becomes widespread. Bathyal sediments are deposited at the continent-ocean boundary and onlap progressively younger oceanic crust. A marine transgression extends shoreward. Shelf and slope deposition is commonly interrupted by massive submarine erosion caused by changing current patterns in the progressively widening and deepening ocean basin (Deighton et al., 1976).

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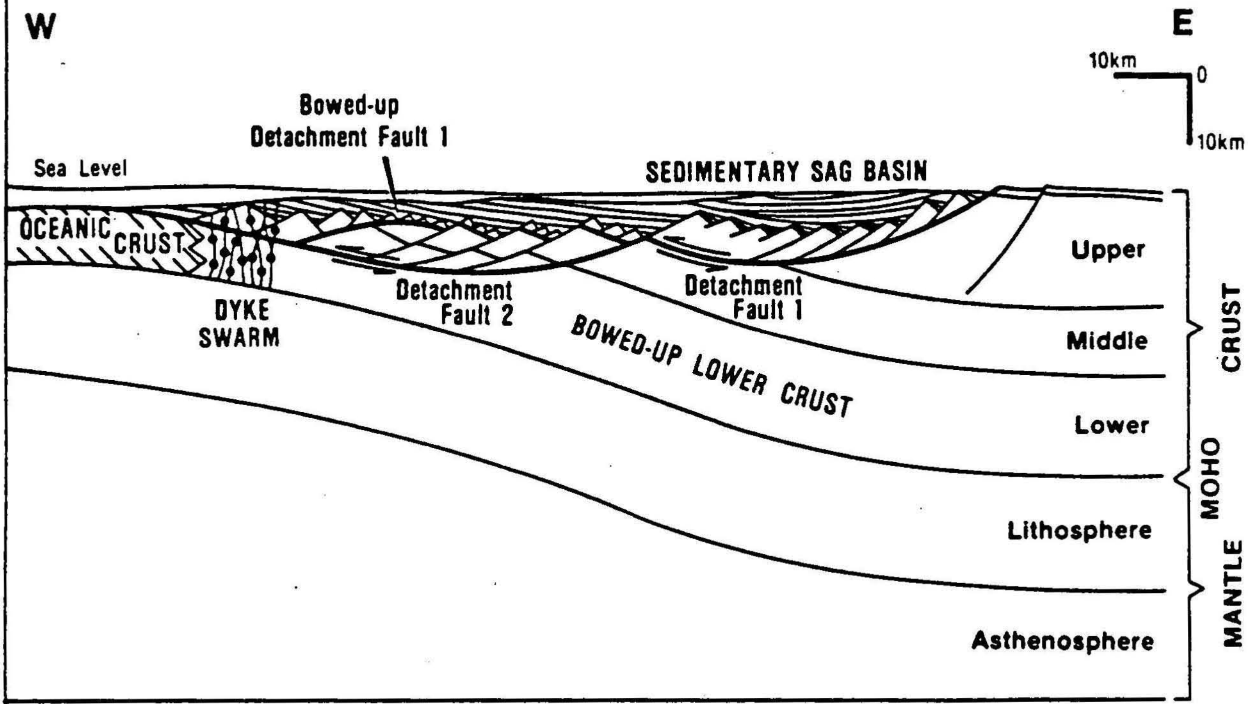


(Modified from Etheridge et al, 1985a)

Detachment Faulting - Passive Margin

Figure 6

The basins of the Northwest Shelf broadly follow this pattern. Although they formed initially as a series of intra-cratonic depressions within the Gondwanaland continent, their history relevant to petroleum potential is related to the divergent margin tectonics outlined above.

On the Northwest Shelf, the infra-rift phase commenced following a major orogenic event (Alice Springs Orogeny) in the mid-Carboniferous. This formed a series of depocentres, possibly related to structural weaknesses inherited from an earlier, Precambrian separation phase.

Following the retreat of the Carboniferous ice-sheet, large thicknesses of Permo-Triassic sediments were deposited in environments changing from glacial, to marginal marine and marine, to fluvio-deltaic and fluvial. The sedimentary section onlaps Precambrian basement in the east.

A major change to a more marine environment occurred in the Late Triassic-Early Jurassic (Fitzroy Movement) as rifting commenced. Sedimentation occurred in rift/listric fault basins (Fig. 6), formed as precursors to actual seafloor spreading.

Continental spreading of a landmass, which was then present off the northwest coast of Australia, to the north of the Exmouth Plateau is marked by the Callovian unconformity (Fig. 7). Previously fractured continental blocks were spread apart by the generation of new seafloor along an intervening spreading centre. Spreading to the south of the plateau commenced in the Vallanginian as India and Australia separated; the Cape Range Transform Fault (Fig. 7) now forms the southern margin of the Exmouth Plateau. Oceanic crust adjoins the western margin of the basin, and as this crust cooled during the Cretaceous and Early Tertiary, the Exmouth, Scott, Ashmore and Sahul Plateaux sank to upper bathyal water depths.

Regional Tectonic Framework
Northwest Shelf

(After AAPG, 1981)

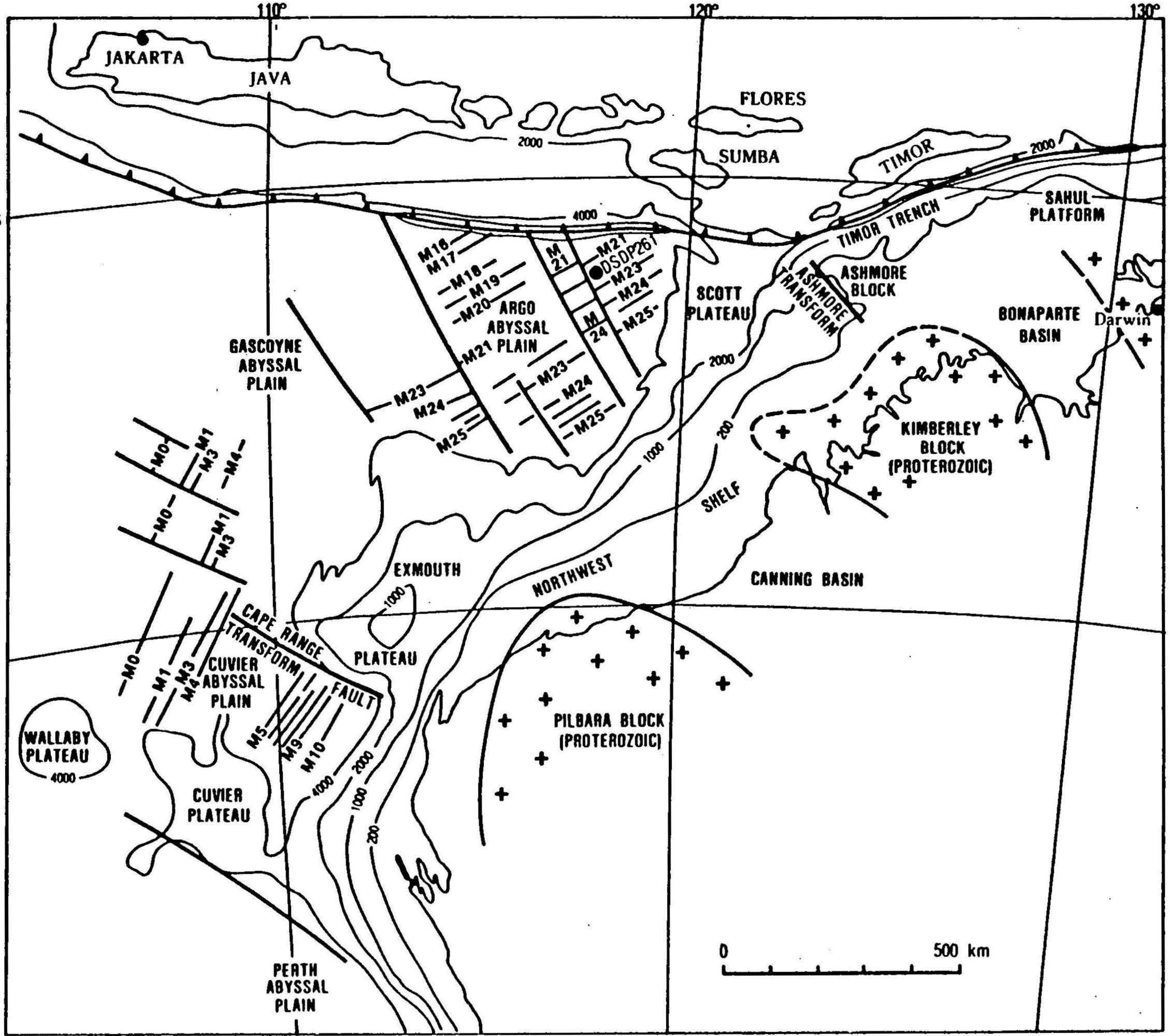


Figure 7

Robertson Research

33.

Australia later began to move northward, away from Antarctica (breakup 95 Ma), and has been in collision with southeast Asia since the Late Miocene. A series of major en-echelon folds, particularly in the Barrow-Dampier area, have developed as a result of the imposition of a regime of right lateral shear.

4. BASIN DEFINITIONS AND STRUCTURAL ELEMENTS

The Northwest Shelf study area has been divided into four main basin areas. From southwest to southeast they are: Northern Carnarvon, offshore Canning, Browse and Bonaparte. These are identified, together with the major structural elements in each, on Enclosures 6 and 7.

The whole Northwest Shelf region has had a similar geological and structural history; therefore, in some areas, precise basin boundaries are somewhat arbitrary. For instance, in this report, the Ashmore Block and Vulcan Graben/Cartier Troughs have been included within the Browse Basin, as the Browse/Bonaparte boundary is not marked by any major structural element.

Strictly speaking, the Northern Carnarvon Basin includes the Exmouth Plateau. However, no geochemical studies were conducted in the Exmouth Plateau for this report. The Northern Carnarvon Basin, as used in this report, generally refers only to the Rankin Platform, Exmouth, Barrow, Dampier and Beagle Sub-basins and the eastern shelf areas. Each basin and its relevant structural elements are further defined later in this chapter.

Regional seismic time structure maps have been compiled for the entire region to further define basin shape and morphology. They are outlined on four 1,000,000 map sheets which, in broad terms, correspond to the four main basin areas (Encl. 8 to 11).

- Northern Carnarvon Sheet (Encl. 8)

The dominant NNE-SSW break-up faulting for the breakup unconformity event is well illustrated along the Rankin Platform . The NE-SW trends are associated with the earlier rift onset event. The interplay of these two trends has created the hydrocarbon traps along the Rankin Platform. To the southeast, much of the Jurassic section has been eroded subsequent to the break-up and the top Triassic and base Triassic horizons were therefore mapped. The fault trends associated with rifting and break-up are still apparent at these levels. During the Neocomian, the Barrow Group prograding delta sands were deposited from the south and southwest, and form a major reservoir target. The delta sands did not prograde much further north than Gorgon-1 and Barrow Island.

. Offshore Canning Sheet (Encl. 9)

Except in the southwest, where the break-up unconformity has been mapped, the offshore Canning composite time map is datumed on the top Triassic. This horizon onlaps the Leveque Platform and Broome Arch.

. Browse Sheet

This composite map sheet (Encl. 10) consists of near-top Permian, top Triassic and Early Cretaceous unconformity time maps. The near top Permian has been mapped in the northeast and shows the dominant NE-SW fault trends that formed during the Callovian breakup. The top Permian event deepens to the west, especially within the Vulcan Sub-basin. The shallower Early Cretaceous unconformity event has been mapped in this area. On the Ashmore Block, Triassic sediments lie directly beneath this horizon while a series of Jurassic horsts and grabens exist within the Vulcan Sub-basin. Within the Browse depocentre, the Permian section is too deep for routine exploration drilling, and any potential source rocks would be over mature. The top Permian has been mapped on the shallower shelfal region to the east, while the top Triassic is shown within the Browse depocentre.

. Bonaparte Sheet.

This sheet (Encl. 11) comprises a near-top Permian time structure map and corresponds to the H_4 or upper limestone unit of the Hyland Bay Formation. This formation contains the reservoirs in the Tern and Petrel fields. Salt diapirs which pierce this horizon are shown. Overall structuring within the Petrel Sub-basin at the H_4 level is due to salt pillowing. The sub-basin thickens into the Malita Graben but rises to the north onto the Sahul Platform. The regional thickening to the northwest is due to post-breakup tilting of the basin.

4.1 NORTHERN CARNARVON BASIN

4.1.1 Basin Definition

The Exmouth, Barrow, Dampier and Beagle Sub-basins, Exmouth Plateau and eastern shelf areas all form part of the Northern Carnarvon Basin, which is a north-south oriented, elongate depression, approximately 1000 kms long. The basin contains sediments ranging from Ordovician-Silurian to Tertiary-Quaternary in age; its eastern margin is defined by sedimentary onlap onto the Precambrian Shield (Encl. 7).

This report is restricted to the offshore portion of the Northern Carnarvon Basin, where the section of interest ranges from Permian to Cretaceous.

The Exmouth, Barrow and Dampier Sub-basins are bounded to the east by the major, down-to-the-west Rough Range, Long Island, Flinders, Sholl Island and Rosemary Fault Systems (Encl. 7). The western limits of these sub-basins have been variously defined, but are taken here to be the major faults bounding the eastern edge of the

Rankin Platform. The positive Rankin Platform is part of the Exmouth Plateau megablock and is separated from the Exmouth Plateau mega-arch by the NNE-SSW trending, gently downwarped Kangaroo Trough (Encl. 6). The Rankin Platform plunges and becomes less well defined to the south. South of Gorgon-1, it has been named the Alpha Arch and its extension still further to the south is probably the Yardie East trend (Encl. 7). In this report, the western edge of the Carnarvon Basin is taken to be the Kangaroo Trough or Syncline.

The onshore extent of the Exmouth Sub-basin has been defined as the area of the present day Cape and Rough Ranges. The Barrow Sub-basin has been, in the past, arbitrarily defined as extending south to the zero edge of the Cretaceous Barrow Group. The boundary between the Cretaceous Barrow and Dampier Sub-basins is not distinguished by any marked change in basin style, but is mainly due to intercompany terminology. In broad terms, during initial exploration of the area, the Dampier Sub-basin was held by the Woodside consortium, while Wapet explored the Barrow Sub-basin. The boundary between the two sub-basins extends approximately from Wilcox-1 to midway between Arabella-1 and Enderby-1 (Encl. 7). The Dampier Sub-basin is separated from the Beagle Sub-basin by the northwesterly trending De Grey Nose (Encl. 7).

The Beagle Sub-basin has great similarities to the Exmouth, Barrow and Dampier Sub-basins but can be differentiated from them by lack of substantial subsidence in the Late Jurassic. The North Turtle Arch separates the Northern Carnarvon and Offshore Canning Basins.

4.1.2 Structural Elements

The main structural elements are depicted on Enclosure 7 and are described below, progressing westward from the eastern margin.

- The Pilbara, Cape Preston and Peedamullah Shelves form a region of relatively shallow basement east of the main Jurassic-Cretaceous depocentres. They are en-echelon extensions of the Ashburton, Gascoyone and Merlinleigh Sub-basins in the onshore Carnarvon Basin. All units thin onto and across the shelves by depositional thinning and onlap and/or erosion.

  Several terrace areas, such as the Enderby Terrace and the informally named "Candace Terrace" (Kopsen and McGann, 1985) exist on the shelf area. Tilted fault blocks are present on the terrace areas. Some pre-Triassic horsts are present (Kirk, 1985) but most half-graben growth occurred in the Early to Middle Jurassic. The listric faults rarely penetrate the main or breakup unconformity of Callovian age.

- The De Grey Nose separates the Beagle and Barrow-Dampier Sub-basins, and has been a positive feature at various times through the evolution of the basin.

- The Rough Range, Long Island, Flinders, Sholl Island and Rosemary Fault systems effectively form the eastern edge of the main rift sequence depocentres. These fault systems lie along hingelines which have been active since the Permian. The hingeline defines the shelf edge during Locker Shale deposition, and some of the faults show minor Early Triassic movement (Kirk, 1985). Early Jurassic to Cretaceous subsidence occurred west of the fault system, resulting in deposition of a very thick sequence in the main depocentres. Late Tertiary reactivation has produced down-to-the-west listric faulting and localized compressional wrenching.

- The Rosemary-Legendre Anticlinal Trend formed by rollover into the reactivated Rosemary Fault. It is thus Tertiary in age.

- The Barrow Island and Cape Range Anticlines, which have experienced a long history of growth, are probably everted sedimentary depocentres. The Barrow Anticline had considerable expression at the end of the Aptian (Campbell et al., 1984); further movement on it occurred during the Turonian and Middle Miocene. The Cape Range Anticline is mainly a Miocene feature but was probably also affected by earlier movements.

  Structures east of the Barrow Anticline, such as the Lowendal Syncline and the Flag-Bambra Anticline, may have had a similar history.

- The Lewis Trough, Barrow Depocentre and Cossigny Trough are the main present day synclinal areas. All are deep, narrow, pre-Callovian (pre-breakup unconformity) synclines. Considerable Late Jurassic to Cretaceous downwarping continued in the Lewis Trough and Barrow Depocentre, while the Cossigny Trough remained stable.

- The Dampier- Madeleine Trend forms the western edge of the Lewis Trough. The trend was positive during the Early-Middle Jurassic, as evidenced by marked thinning and onlap onto the high. Drape and compaction over this pre-existing high has resulted in structures developing in the Late Jurassic-Cretaceous section. The Spar-Tryal Rocks Trend has had a similar history.

- The Kendrew Terrace is a region of block-faulted, pre-Callovian sediments, separated from the Rankin Platform by a major down-to-the-east, Early-Middle Jurassic growth fault.

- The Rankin Platform, which extends from Gorgon-1 to north of Ronsard-1 is a major positive element, coincident with a bouguer gravity anomaly. Considerable uplift occurred on this trend during the Callovian breakup event. The platform, which comprises the eastern edge of the Exmouth Plateau, contains giant hydrocarbon fields in structures formed by Early-Middle Jurassic growth faults. It plunges to the south to form the Alpha Arch, and its extension still further to the south is probably the Yardie East Trend. The eastern edge of the Rankin Platform trends NE-SW, parallel to the main structural elements to the east, probably indicating control by older fracture patterns. Further to the north, in the outer Beagle Sub-basin, the extension of the Rankin Platform is characterised by north-south-trending horsts and grabens without such a strong overall NE-SW orientation.

- The Victoria and Kangaroo Synclines contain considerable thicknesses of Early to Middle Jurassic sediments. They are also Cretaceous-Tertiary depocentres, as a result of arching of the Exmouth Plateau.

- The Brigadier Trend is one of the many large Early-Middle Jurassic horst trends on the Exmouth Plateau.

4.2 OFFSHORE CANNING BASIN

4.2.1 <u>Basin Definition</u>

The offshore Canning Basin covers some 200,000 km^2 of the continental shelf and slope off the coast of Western Australia (Encl. 6). The coastline forms the eastern boundary with the 400,000 km^2 onshore Canning Basin. To the north, the boundary is ill-defined in the far offshore area. Close to the coast however, the Leveque Platform forms the divide between the Canning and Browse Basins. Similarly, in the south, the North Turtle Arch separates the Canning from the northern Carnarvon Basin (Beagle Sub-basin). The western boundary of the offshore Canning Basin is very poorly defined.

The basin contains a Mesozoic-Cainozoic sequence which ranges up to 6000m in thickness, and which overlies a little known Palaeozoic sequence.

4.2.2 Major Structural Elements

The offshore Canning Basin comprises two sub-basins which are bounded by areas of relatively shallow basement. In the area adjacent to the coast, from south to north, the various elements are (Encl. 6):

- The Wallal Platform is the offshore extension of the Anketell Shelf, and is an area of shallow basement.

- The Bedout Sub-basin is the offshore extension of the Samphire Depression/Willara Sub-basin, and contains an estimated post-Palaeozoic sequence up to 6000m thick.

- The Broome Arch, bounded both north and south by large fault systems in the onshore basin, plunges westwards in the offshore part, while still remaining an area of shallow basement.

- The Fitzroy Sub-basin also plunges westward from the onshore where over 2000m of Late Palaeozoic sediments are known to be present beneath a thin Mesozoic veneer. The Mesozoic sequence thickens rapidly westwards in the offshore basin.

- The Leveque Platform/Lennard Shelf forms a shallow basement area constituting the northern boundary of the offshore Canning Basin.

The Bedout High is a westerly downfaulted extension of the Broome Arch which provides a seaward boundary to the Bedout Sub-basin. A high associated with the Mermaid Fault provides the seaward boundary for the Fitzroy Sub-basin.

Westwards of the Bedout High lies the Rowley Sub-basin which contains over 6000m of Mesozoic and Tertiary sediments; in this report it is considered part of the Browse Basin.

4.3 BROWSE BASIN

4.3.1 Basin Definition

The Browse Basin is a large NE-SW trending, offshore sedimentary Permian to Cainozoic basin, underlying approximately 100,000 km^2 of the continental shelf and slope (Encl. 6). The Ashmore Block forms part of its northern margin. The Leveque Platform and the Buccaneer Nose together form part of the southern margin with the Rowley Sub-basin. The Kimberley Block, which marks the eastern limit of the Browse Basin, is onlapped by Permian and younger sediments. The basin is bounded to the west by the submarine Scott Plateau, which occupies about 80,000 km^2 of the continental slope. Water depths range from zero at the eastern margin, to more than 2000m seaward of Scott Reef.

The boundary between the Browse and Bonaparte Basins is arbitrary. The Londonderry Arch extends northwards to the Londonderry High and forms a divide between the SW-plunging Vulcan Graben and Vulcan Shoals Trough, and the NE-plunging Cartier Trough and Echo Syncline. However, this region is part of the same structural and geological regime. For the purpose of this study, the Cartier Trough and the Dillon Ridge have been included within the Browse Basin.

The Vulcan Sub-basin, encompassing the Vulcan Graben and Vulcan Shoals and Cartier Troughs, is composed of a series of NE-SW-trending horsts and grabens, which originated on the northwestern extension of the Londonderry High as the result of rifting systems. These rifting systems were initiated in Permo-Triassic time, and reached their maximum development with the tectonic activity in Middle/Late Jurassic time associated with continental breakup.

4.3.2 Structural Elements

From the stable Archean and Proterozoic Kimberley Block basinwards, the major structural elements comprise:

- Prudhoe Terrace and Yampi Shelf. These are regions of relatively shallow basement. The Prudhoe and Lacrosse Terraces (Bonaparte Basin) occur on the shelfal area, and coalesce to form the Londonderry High, which extends well into the basin. The Leveque Platform (Canning Basin) is the southern continuation of the Yampi Shelf and Prudhoe Terrace, and consists of shallow basement directly overlain by Late Jurassic and Cretaceous sediment.

- Londonderry High/Dillon Ridge. The Londonderry High is a northwest extension of the Precambrian Kimberley Block, and separates the Browse Basin from the Bonaparte Basin, as defined in this report. On the Londonderry High, shallow crystalline basement is covered by a thin veneer of Cretaceous and Tertiary sediments, which wedges out to the southeast. The high extends northeastwards onto the Dillon Ridge, where Permian to Early Jurassic sediments are onlapped by a thin, Late Jurassic and Early Cretaceous interval.

- Cartier Trough, Vulcan Graben and Vulcan Shoals Trough. The Vulcan Graben, Vulcan Shoals Trough and Cartier Trough are all integral parts of the Vulcan Sub-basin, which is separated from the Londonderry High and Ashmore Block by fault zones. Thick Jurassic sequences occur within the grabens. Block faulting has produced northeast-trending horst and graben topography, with drape in the overlying Late Cretaceous and Tertiary sediments.

- Central Browse Basin. The Central Browse Basin is bounded shorewards by the main basin margin faults, and extends westward to the edge of the Scott Plateau. The sub-parallel, NE-SW-oriented Mesozoic Central and Inner Basin Arch, Scott Reef, Buffon and Seringapatum Trends are the main structures in the region. The northern part of the central Browse Basin is separated from the Ashmore Block, Londonderry High and Prudhoe Terrace by major down-to-the-basin faults. Sedimentation is continuous with that in the Vulcan Sub-basin; however, the sediments thin to the northeast. Over 11,000m of sediment ranging in age from ?uppermost Carboniferous to Tertiary have accumulated in the basin.

- Scott Plateau. The Scott Plateau forms the western margin of the Browse Basin, and consists of relatively shallow Palaeozoic rocks, with minor Triassic/Jurassic troughs covered by Cretaceous-Cenozoic sediments. The plateau formed a pronounced high prior to the Middle Jurassic, but subsidence from the Early Cretaceous led to the development of dominantly open marine conditions.

- Ashmore Block. The Ashmore Block is an uplifted area of faulted Triassic/Permian sediments, overlain by Cretaceous and Tertiary deposits. A large hiatus occured in the Late Triassic due to erosion, which resulted from uplift at the end of the Triassic to Middle Jurassic. The platform has formed a stable block since the Early Jurassic.

4.4 BONAPARTE BASIN

4.4.1 Basin Definition

The Bonaparte Basin straddles the Northern Territory-Western Australia border, and extends offshore a considerable distance north and northwest on the continental shelf. The basin covers an area of approximately 486,000 km^2, and is known to contain sediments ranging in age from Devonian to Recent in the offshore, and Cambrian to Early Permian in the onshore part of the basin.

The sedimentary section thickens basinwards offshore, where more than 10,000m of sediments are believed to be deposited in the troughs and grabens. The Bonaparte Basin is separated from the Browse Basin to the west by the northern extension of the Kimberley Block, the Londonderry High (Encl. 6). To the east, the basin is limited by an arcuate fault system, which extends along the Darwin Shelf, the northern extension of the Proterozoic Sturt Block. The present southern boundary of the basin is largely erosional, and is approximately marked by the Phanerozoic zero edge. The northern limit of the Bonaparte Basin is marked by the present continental shelf margin immediately south of the Timor Trough.

4.4.2 Structural Elements

From the stable Archean and Proterozoic Kimberley and Sturt Blocks basinwards, the major structural elements comprise (Encl. 6):

- Plover Shelf

  The Plover Shelf is the easterly extension of the Kimberley Block and contains a thin cover of Cretaceous and Tertiary sediments.

- Van Diemen High

  The Sturt Block extends to the west to form the Van Diemen High. Thin Cretaceous/Tertiary sediments onlap onto this high.

- Van Cloon High/Dillon High/Echo Syncline

The Londonderry High extends northwards onto the Dillon High, where faulted Permian to Middle Jurassic sediments are onlapped by a thin Late Jurassic-Early Cretaceous sequence. The Van Cloon High developed in the Early-Late Jurassic as a passive arch, separating the largely fault-controlled Echo Syncline to the northwest, from the subsiding Petrel Sub-basin to the southeast.

- Lacrosse Terrace.

Major down-to-basement faulting along the Lacrosse Fault System has created a terrace of Early Palaeozoic-Early Carboniferous strata. The Lacrosse Fault System forms the southwestern edge of the Late Carboniferous-Recent depocentre.

- Darwin Shelf/Bathurst Terrace

A thin wedge of Permian to Recent sediment onlaps onto the Darwin Shelf and Bathurst Terrace.

- Petrel Sub-basin

The Petrel Sub-basin is bounded shorewards by major basin margin faults, and extends northwestwards into the Sahul Syncline. The sub-basin contains mainly Late Carboniferous to Triassic sediments; since the Jurassic, the depocentre of the Bonaparte Basin has moved northwestward. The Petrel Sub-basin tilts regionally to the northwest.

- Malita Graben

A thick Jurassic sequence occurs within the Malita Graben; it was initiated in the Late Triassic and culminated in the Callovian. Block faulting has produced a NE-trending horst and graben topography, with drape in the overlying Late Cretaceous and Tertiary sediments.

- **Sahul Platform**

The Sahul Platform is an uplifted area of faulted Triassic/Permian sediments, overlain by a Late Jurassic to Tertiary sequence. A large hiatus occurs in the Late Triassic due to erosion, which resulted from uplift from the end of the Triassic to Middle Jurassic. The platform has formed an essentially stable block since the Early Jurassic.

- **Sahul Syncline**

The Sahul Platform is separated from an equivalent platform to the west (Ashmore) by the Sahul Syncline. Permo/Triassic sediments thin onto both these platforms, while the Sahul Syncline contains a thick sequence and represents an extension of the Petrel Sub-basin. This outer region was uplifted during the Triassic to Middle Jurassic but foundered from the Middle Cretaceous, when westerly prograding carbonate shelf deposition became predominant.

5. STRUCTURAL HISTORY

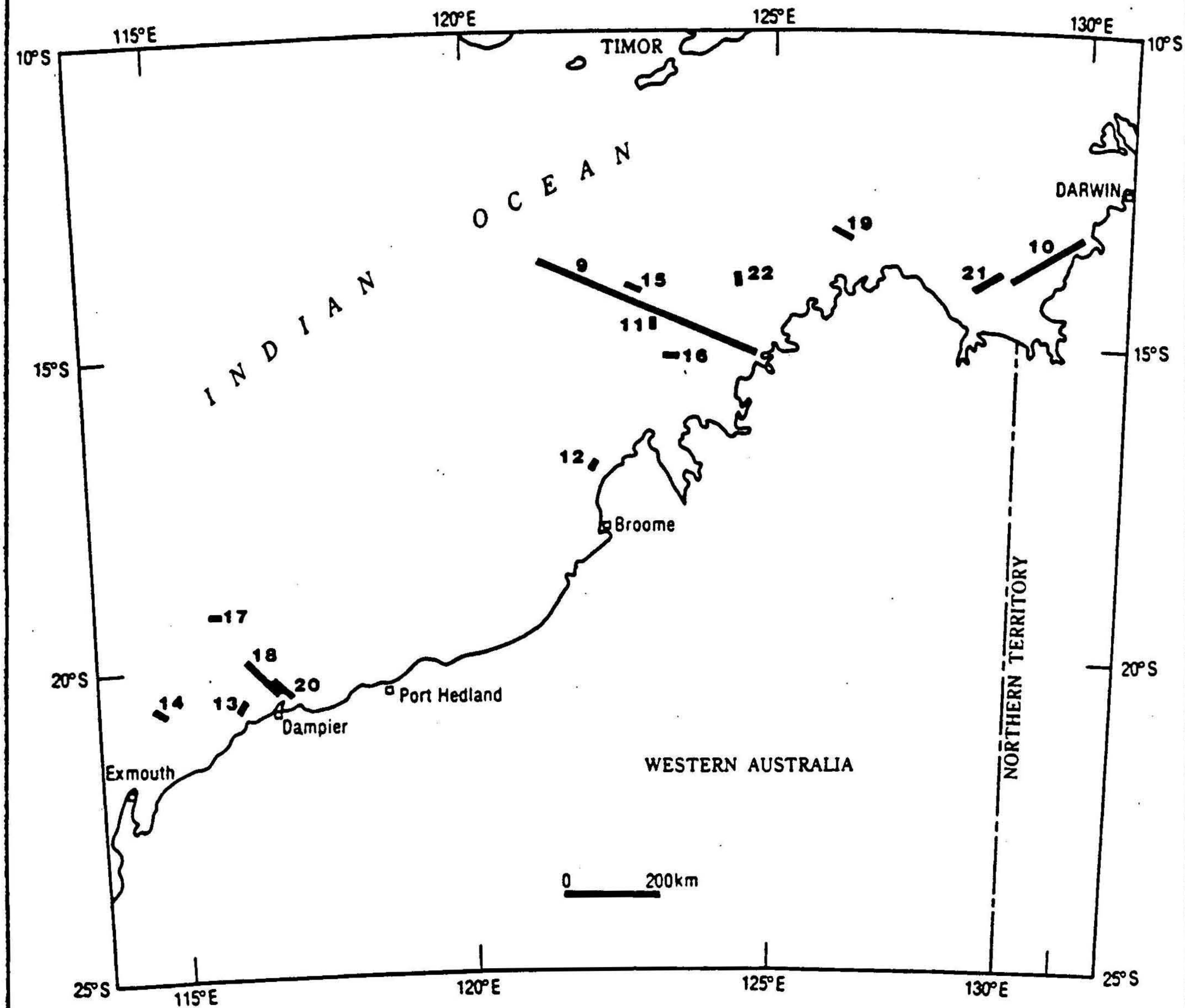
In this discussion, the structural history of the whole of the Northwest Shelf is considered. Figure 8 shows the location of the seismic sections used as illustrations in this section.

The Northwest Shelf originated as an intracratonic basin, following the Alice Springs Orogeny in the Middle Carboniferous. This orogeny activated two main, approximately orthogonal, basement trends oriented northeast and northwest. Activation of bounding faults along the Kimberley and Sturt Blocks and broad tectonic doming of the western landmass, which includes the present day Scott Plateau and Ashmore-Sahul Blocks, initiated the dominant northwest trend of the Bonaparte, and the northeast trend of the Browse Basin (Fig. 9 and Encl. 6). A seismic line, PI-17, across the northeast-trending Van Diemen High in the northeast Bonaparte Gulf shows typical initial down-to-basin faulting (Fig. 10). Similar faulting along the Prudhoe Terrace is shown on seismic line 79-029 (Fig. 11).

Continued reactivation of the bounding NW-SE trending faults of the Fitzroy Graben and the southern Leveque Platform, and possible uplift of the De Grey Nose, imparted to the Canning Basin a dominant NW-SE grain (Encl.6). Faulting along the Pilbara Block, and the doming of the present day Exmouth Plateau, imparted a dominant NE-SW trend to the Carnarvon Basin. During the Early Permian, basin development changed from a fault-controlled phase to a general 'sag' subsidence, with little contemporaneous faulting.

Mafic dykes, sills and cone sheets, which are restricted to the northwest edges of the Canning Basin and the northern onshore Carnarvon Basin, were intruded during the ?Late Permian (Reeckmann and Mebberson, 1984). Domal structuring related to dolerite intrusion of the Carboniferous sequence near Perindi-1 is shown on seismic line F79A-26 (Fig. 12).

Robertson Research

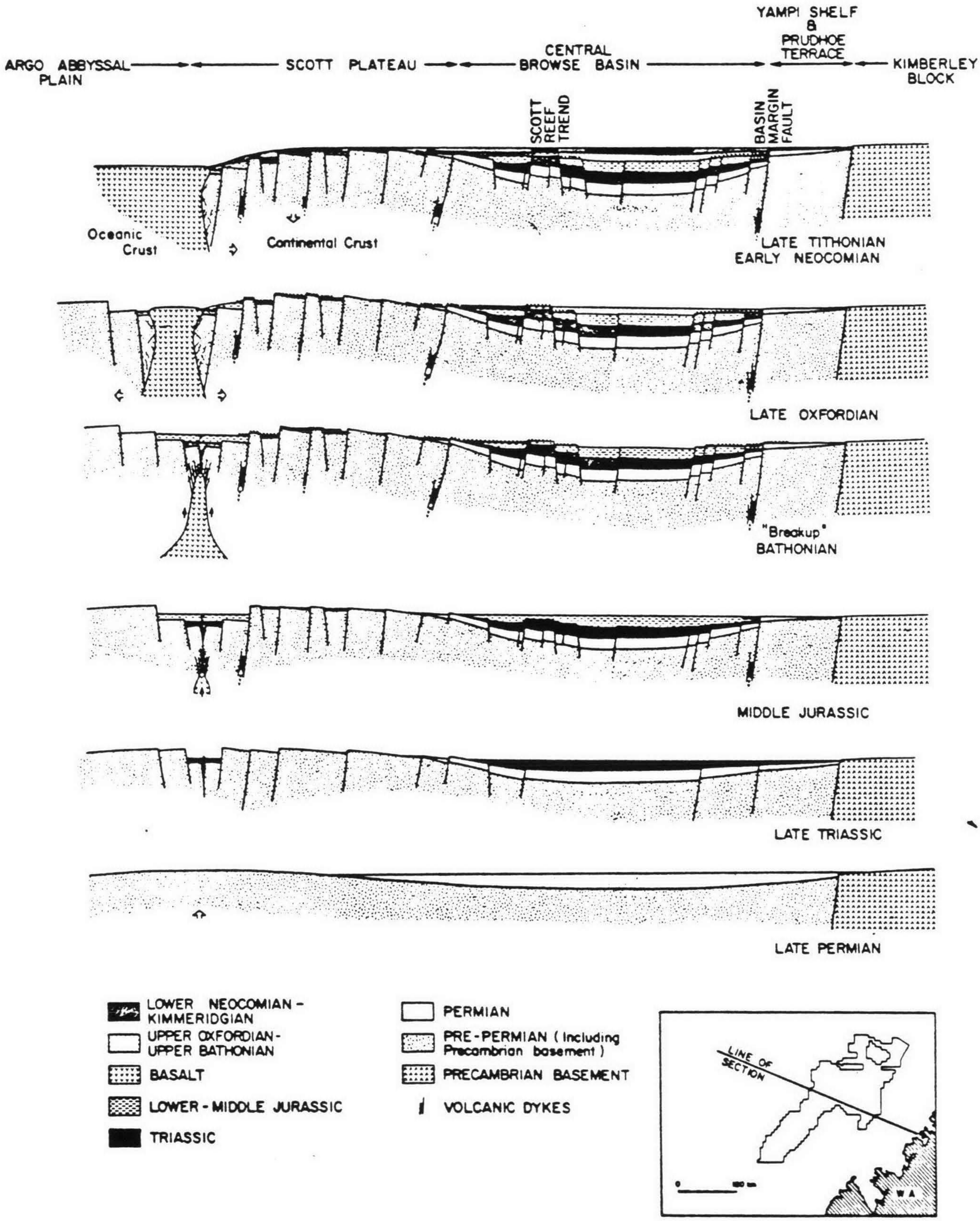


9 Locations of Figures 9-22

Location map of illustrative seismic sections
Northwest Shelf

Figure
8

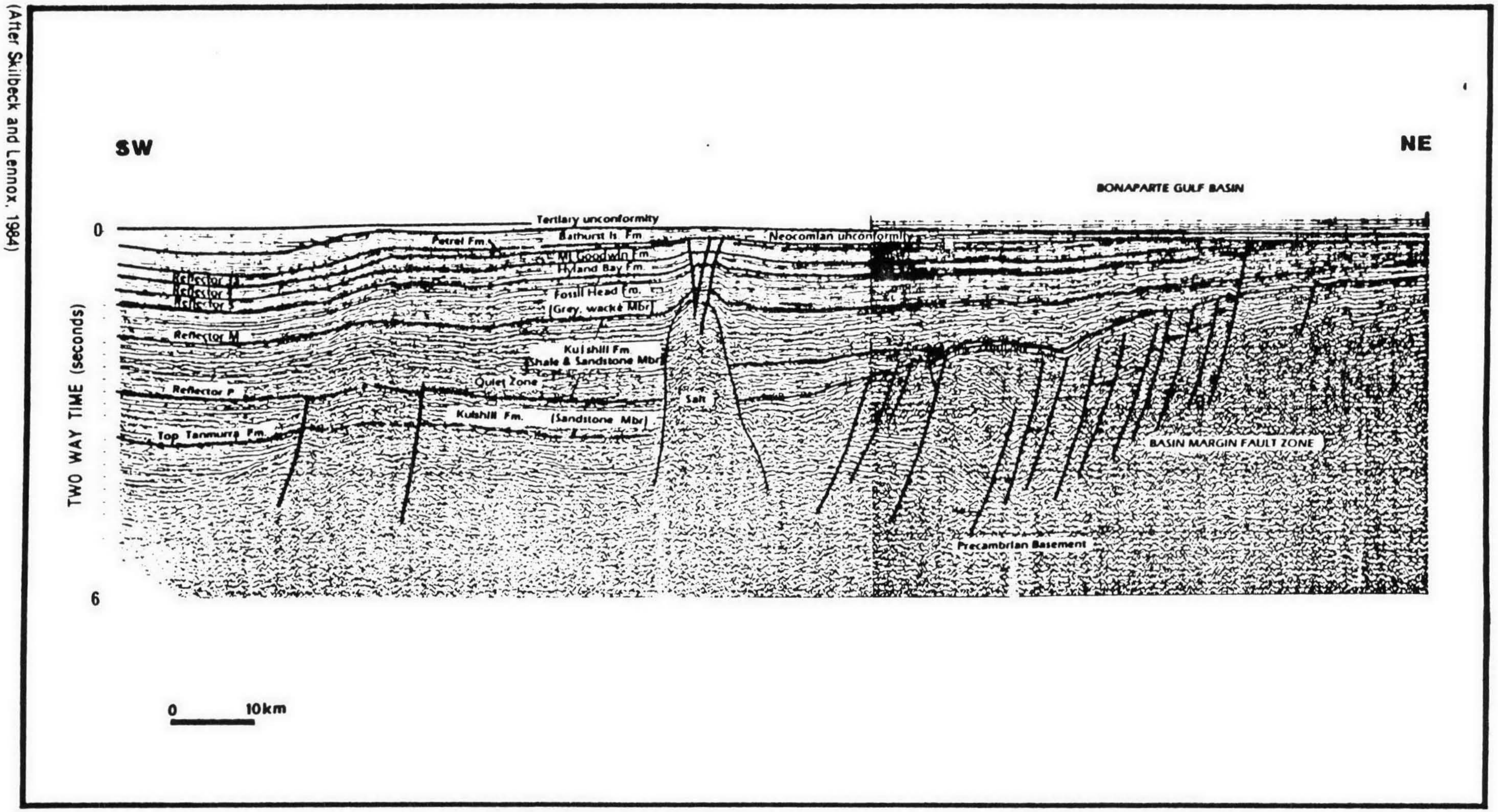
Robertson Research



(After Allen et al. 1978)

Structural Evolution, Northwest Shelf

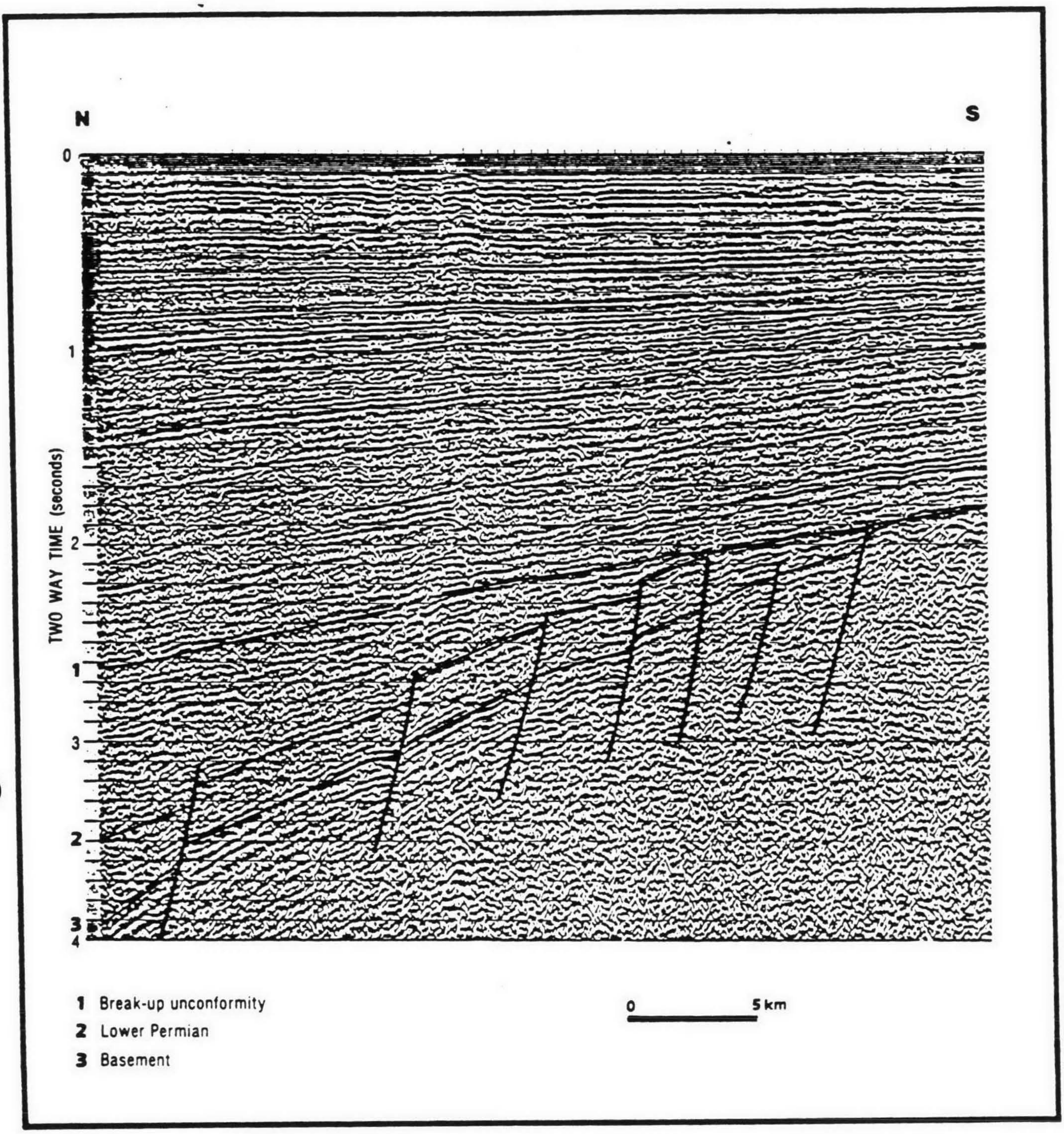
Figure 9



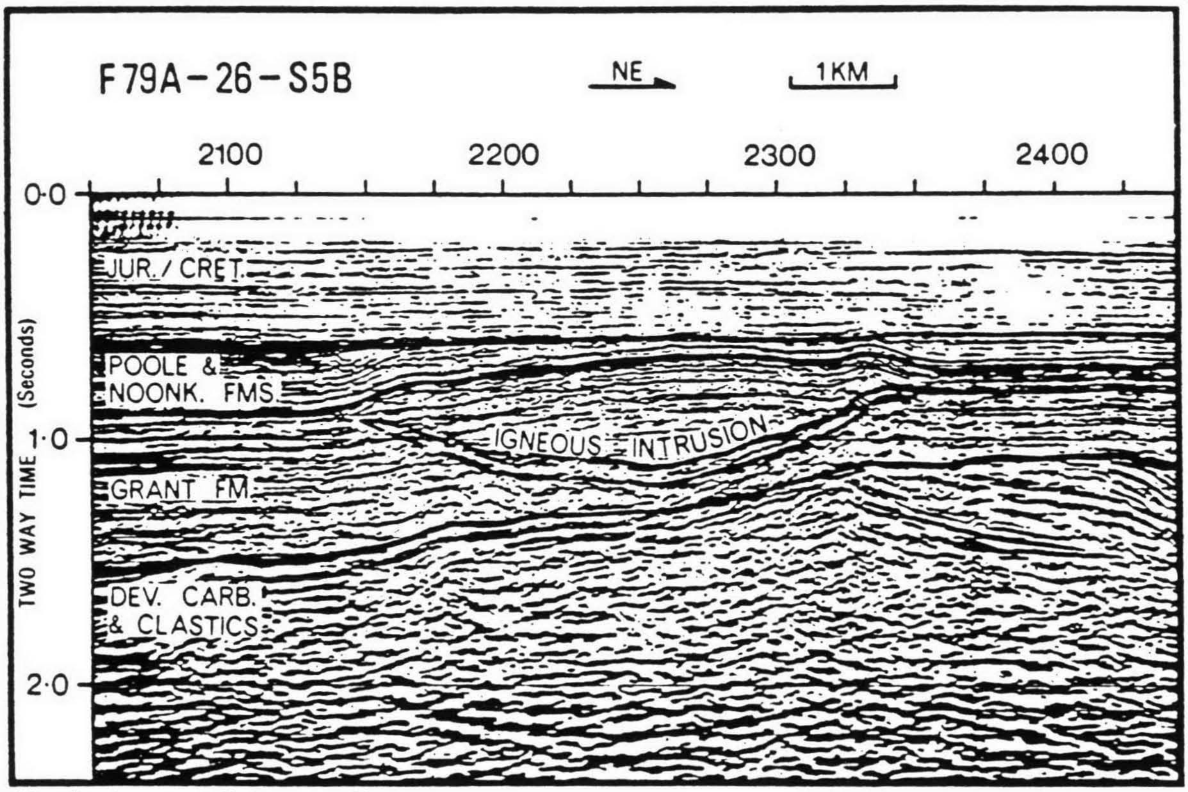
(After Skilbeck and Lennox, 1984)

Seismic Line PI-17, Bonaparte Basin

Figure 10



Seismic Line 79-029, Browse Basin **Figure 11**



(After Reeckman and Mebberson, 1984)

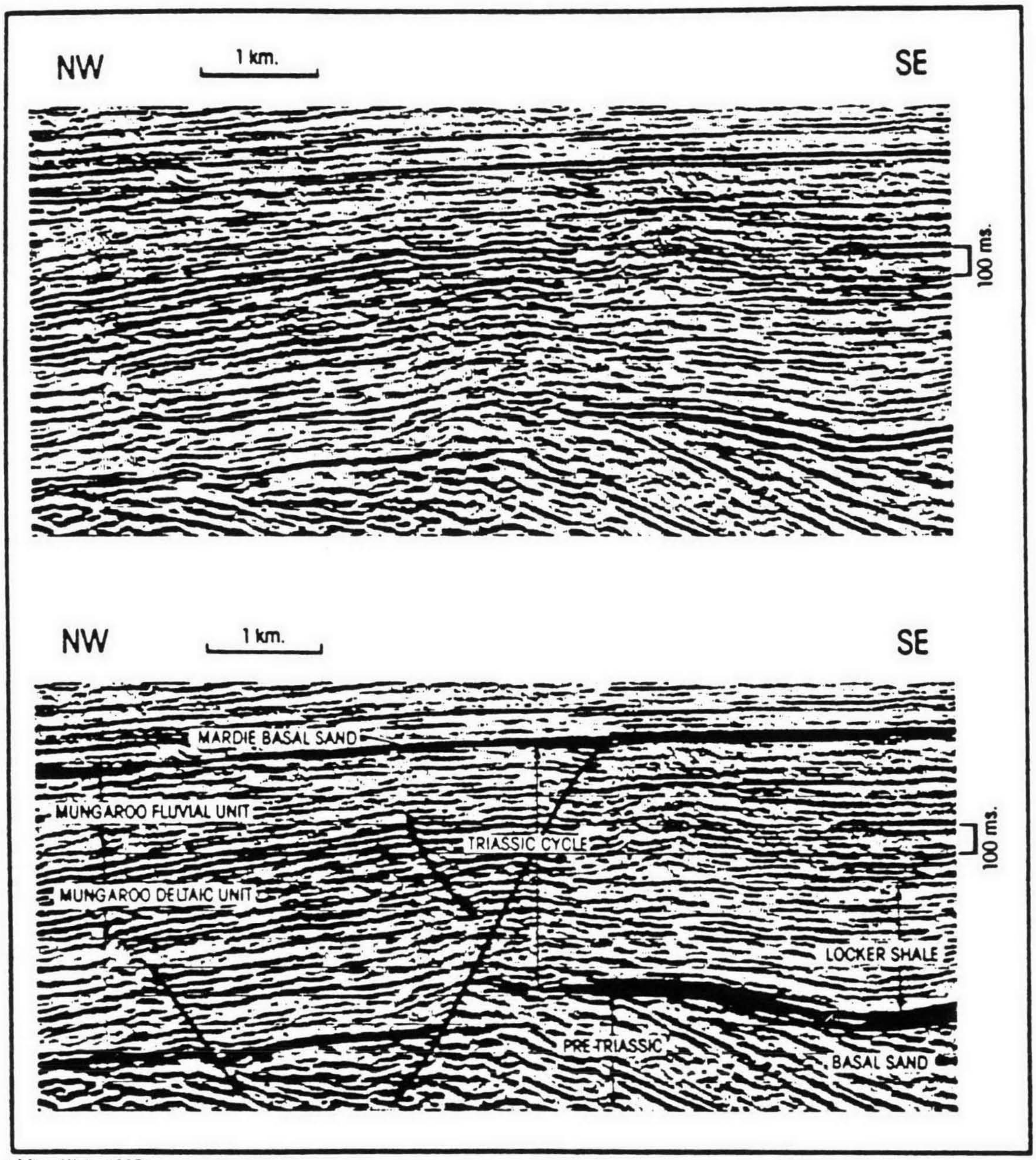
Seismic Line F79A-26, Offshore Canning Basin **Figure 12**

Basin margin tectonism in the Late Permian-Early Scythian is evidenced by a pronounced stratigraphic break, commonly with marked angularity, in wells on the eastern flank of the Browse and Carnarvon Basins (Fig. 13).

A tectonic episode in the early Late Triassic had little effect other than to elevate the basin margins, increase erosion and accelerate the regression of the Triassic seas.

Significant uplift, erosion and faulting occurred during the Late Triassic/Early Jurassic Fitzroy Movement. This marks the transition from infra-rift to rift basins on the Northwest Shelf. Listric faulting, essentially normal and downthrown to the northwest, increased across the onshore Canning Basin towards the present day coastal margin, where faulting parallel to the coastline became an important structural element. This resulted in widespread deltaic sedimentation in the offshore part of the Canning Basin. The Fitzroy Movement was responsible for the dextral wrenching which formed major en echelon anticlinal features in the Fitzroy Graben of the onshore Canning Basin. Offshore, these folds diminish and block faulting is predominant. The movement is characterised by a well defined unconformity on the offshore seismic data. To the south in the Carnarvon Basin, this unconformity is termed the Barrow-Dampier rift onset unconformity (Barber, 1982).

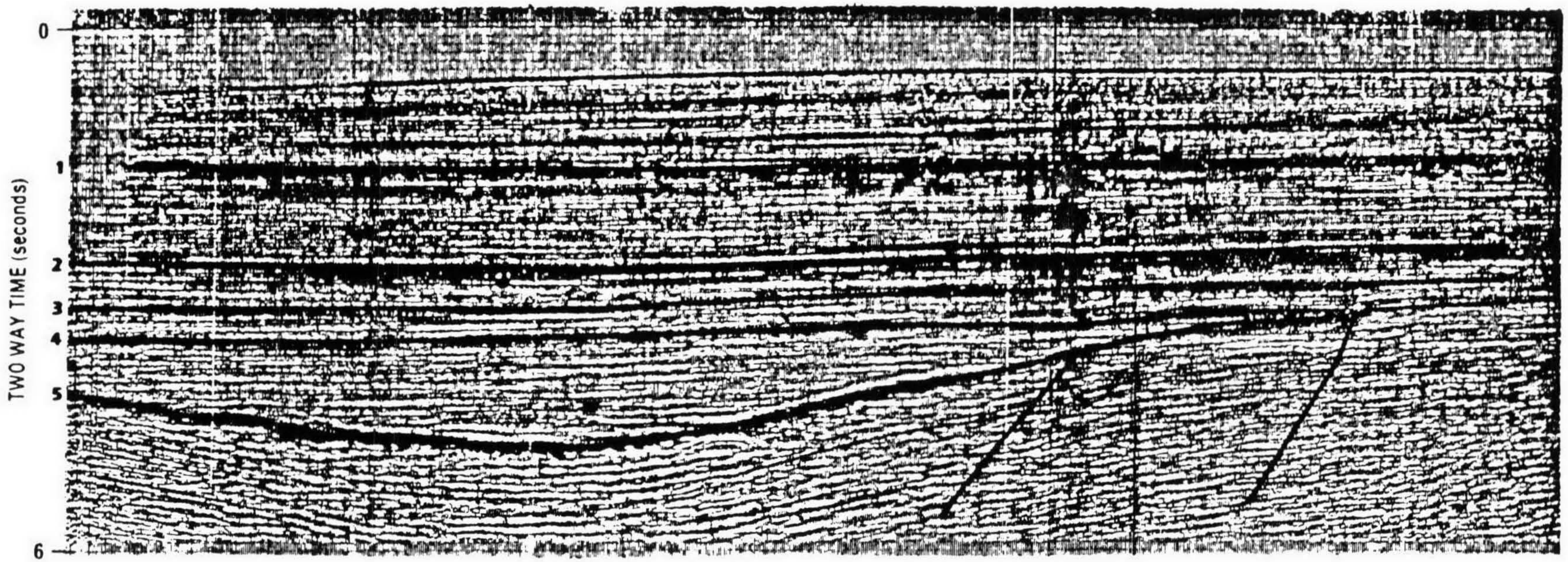
Rifting associated with dominant NNE-SSW to NE-SW normal fault trends initiated the Exmouth, Barrow, Dampier, Beagle Sub-basins and the Victoria and Kangaroo Synclines (Fig. 14) in the Carnarvon Basin. At the same time, the Rowley, Malita and Vulcan Sub-basins developed in the Bonaparte and Browse Basins. The Rob Roy Graben, which trends northwestwards across the Prudhoe Terrace, also formed at this time. Most of the features in the Browse Basin



(After Kirk, 1985)

Seismic Line near Arabella-1, Northern Carnarvon Basin

Figure 13



1 Top Toolonga Calcilutite
2 Top Windalia Radiolarite
3 Top Barrow Group
4 Break-up unconformity
5 Top Triassic

0 2km

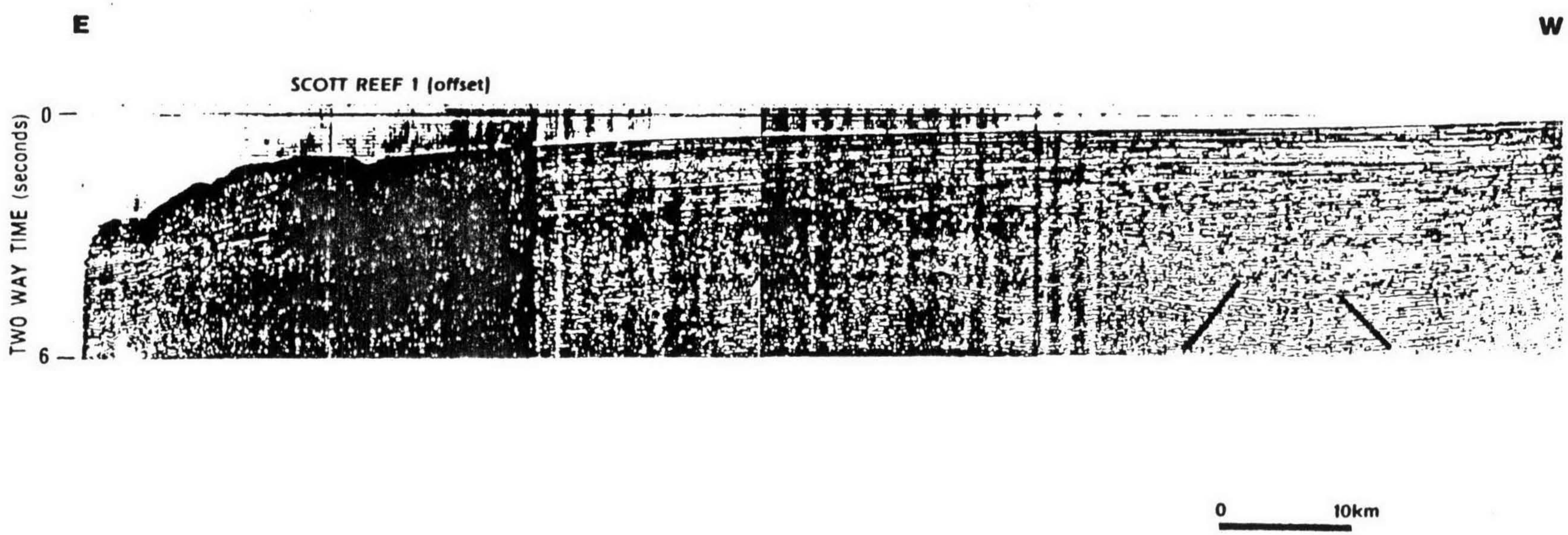
Seismic Line 72-20 Kangaroo Syncline, Northern Carnarvon Basin

Figure 14

probably originated no later than this event, although they subsequently underwent varying degrees of rejuvenation (Fig. 9). The Scott Reef Trend was initiated during this rifting (Fig. 15). Barber (1982) has dated the rift onset as top Pliensbachian on the Exmouth Plateau, and such dating is not inconsistent with the known information elsewhere along the Northwest Shelf.

Structural elements to the west of the Barrow-Dampier Rift, including the positive Rankin Trend, are part of the Exmouth Plateau megacrustal block. The Scott Reef Trend and the Scott Plateau, Sahul and Ashmore Platforms form a similar large block and mark the western boundary of the Vulcan and Malita Grabens.

Near the end of the Middle Jurassic, faulting, commonly involving rejuvenation of pre-existing faults, was associated with the continental breakup along the western edge of the Scott Plateau, and with rifting to the west of the Exmouth Plateau. The event marks the continental separation of Australia from a landmass which was previously situated off the northwest coast of Australia. Seafloor spreading and the generation of new oceanic crust followed the actual breakup. The results of DSDP site 261 (Fig. 7) showed that Late Oxfordian sediments overlie oceanic pillow lavas near the western edge of the Scott Plateau (Veevers and Heirtzler, 1974). This dates the commencement of seafloor spreading as pre-Late Oxfordian. According to the Harland et al. (1982) scale, Magnetic Anomaly M25, which is the earliest seafloor spreading anomaly in the Argo Abyssal Plain, is dated as 159-160 Ma (mid-Oxfordian). This is in agreement with the results from DSDP 261. Basic lavas at Lombardina-1, Scott Reef-1 and 2A, Yampi-1 and Ashmore Reef-1 in the Browse Basin are associated with the breakup. Figure 16 shows a possible deep intrusive body in the southeastern Browse Basin.



Seismic Line near Scott Reef 1,
Browse Basin

Figure 15

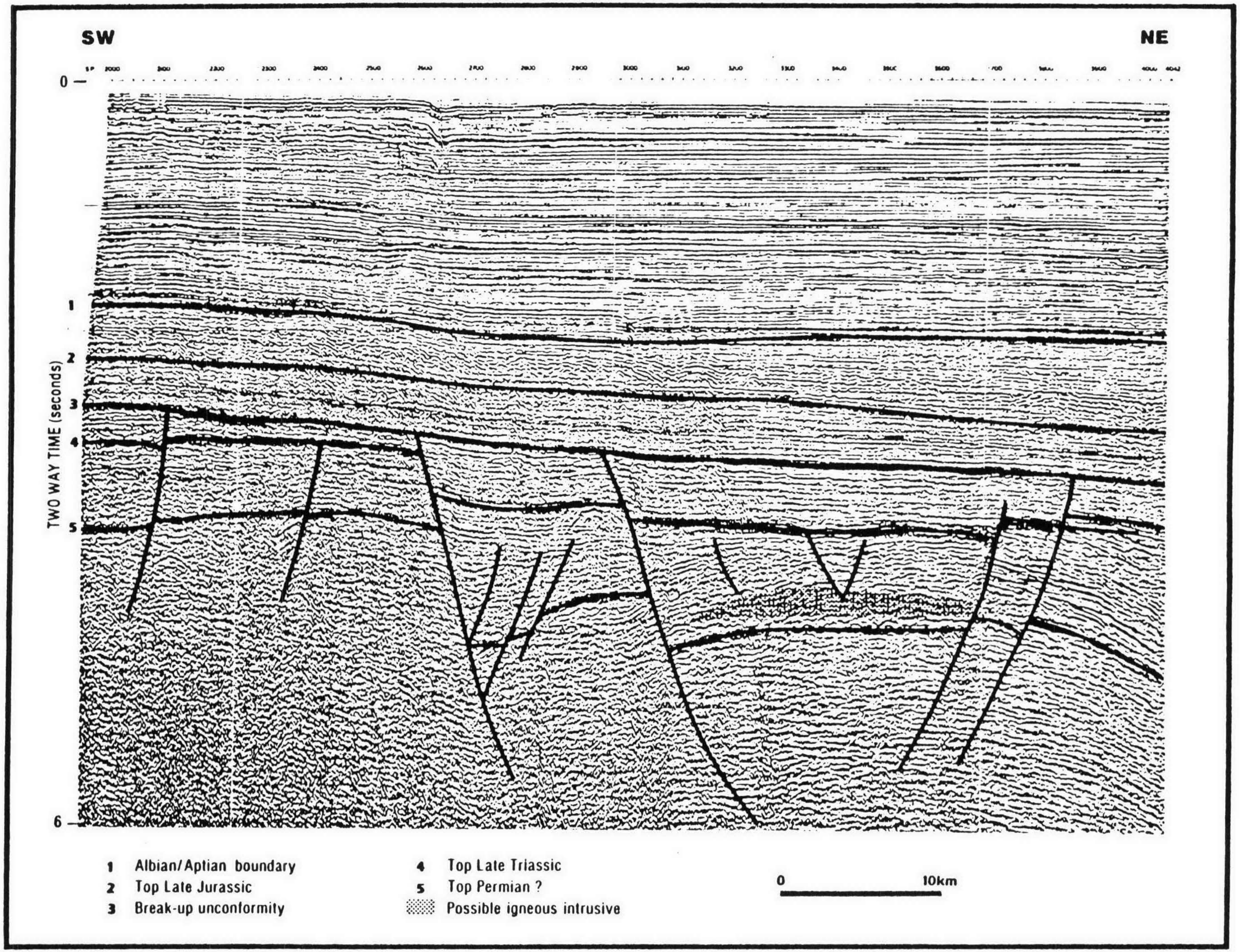


Figure 16

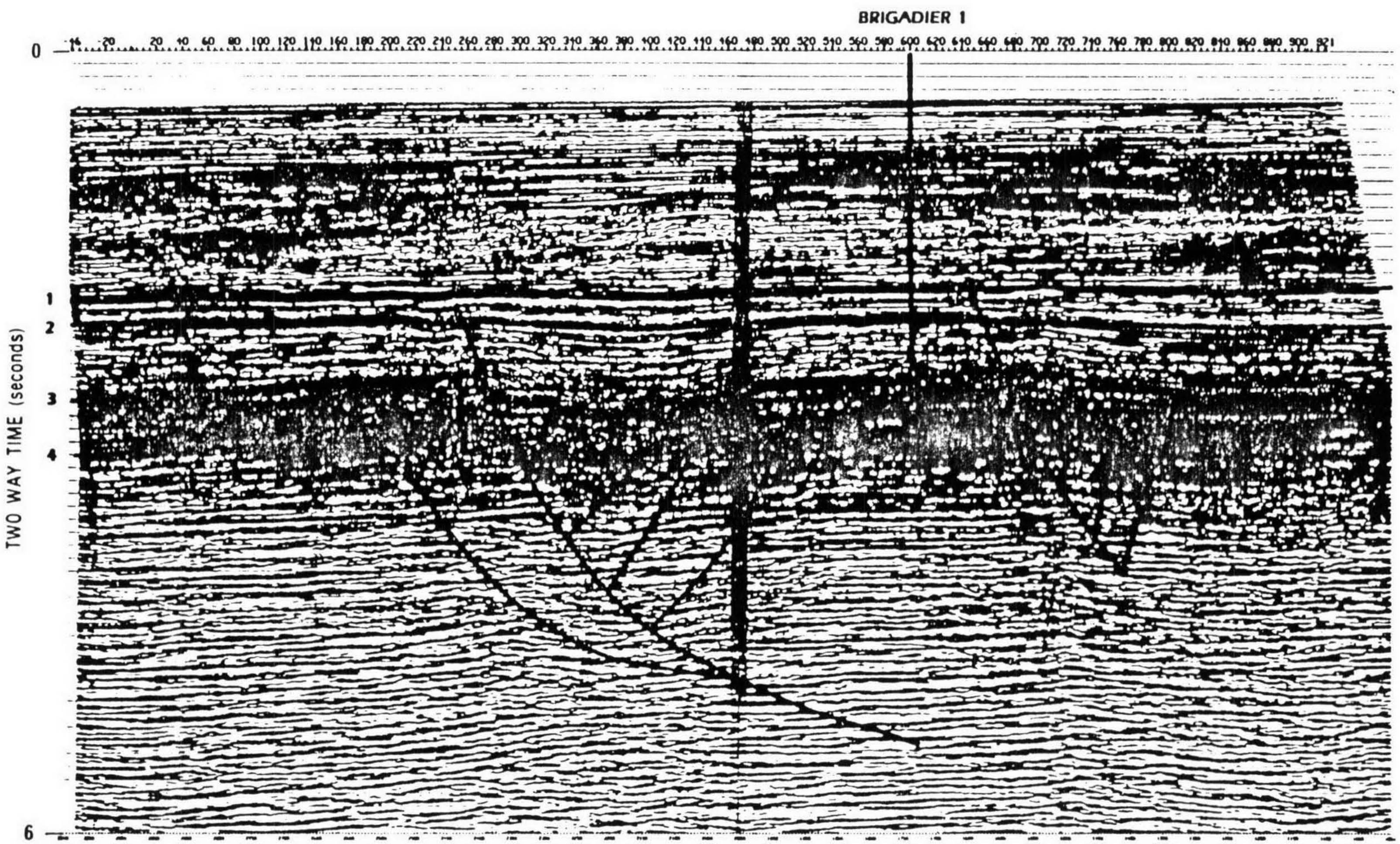
Seismic Line, Southern Browse Basin

Spreading is associated with a major recognised unconformity, the main breakup unconformity, which palynological evidence indicates is of Callovian age. This unconformity is recognised throughout the Northwest Shelf (Encl. 12). Figure 17, located near Brigadier-1, illustrates both the rift and breakup unconformities. The rift and breakup unconformities merge into one major unconformity over the Rankin Trend and the western half of the Exmouth Plateau (Fig. 18). Major platforms in the Carnarvon Basin (Rankin Platform to the west and Peedamullah/Preston Shelves in the east), bounding the drowned rift systems, were uplifted as much as 1-2 km (Kopsen and McGann, 1985). Similar unconformities exist in the Browse (Figs. 11 & 16) and Bonaparte Basins (Fig. 19).

During the Callovian, similar rejuvenation of the Ashmore/Sahul Platforms, Dillon Ridge and Van Cloon High, and subsidence in the Cartier, Vulcan and Malita Grabens, occurred in the Bonaparte and Browse Basins. The eastern platforms have been extensively eroded in an area from the Browse to the Carnarvon Basins.

Extension along north-south fault trends related to the Callovian breakup has created numerous rotated fault blocks on the Exmouth megablock. Some strike slip and wrench faulting occurred along the pre-existing NE-SW trending faults (Fig. 20). North-south faulting is not prominent in the Bonaparte and Browse Basins but is evident on the Scott Plateau. Major salt diapirism occurred in the Bonaparte Gulf (Fig. 21).

Following the Callovian breakup, rift development ceased, and the region became a mature, continental margin sag in response to continuation of the continental separation. Major transgression commenced, but it was not until Late Tithonian times that the Prudhoe Terrace, Leveque Platform and Scott Reef structures were transgressed. Most of the Beagle and Dampier fault blocks were covered by the Late Neocomian, while the Rankin Platform, Ashmore Block and Sahul Platforms remained elevated above sea level, and were not finally submerged until Aptian-Albian times.

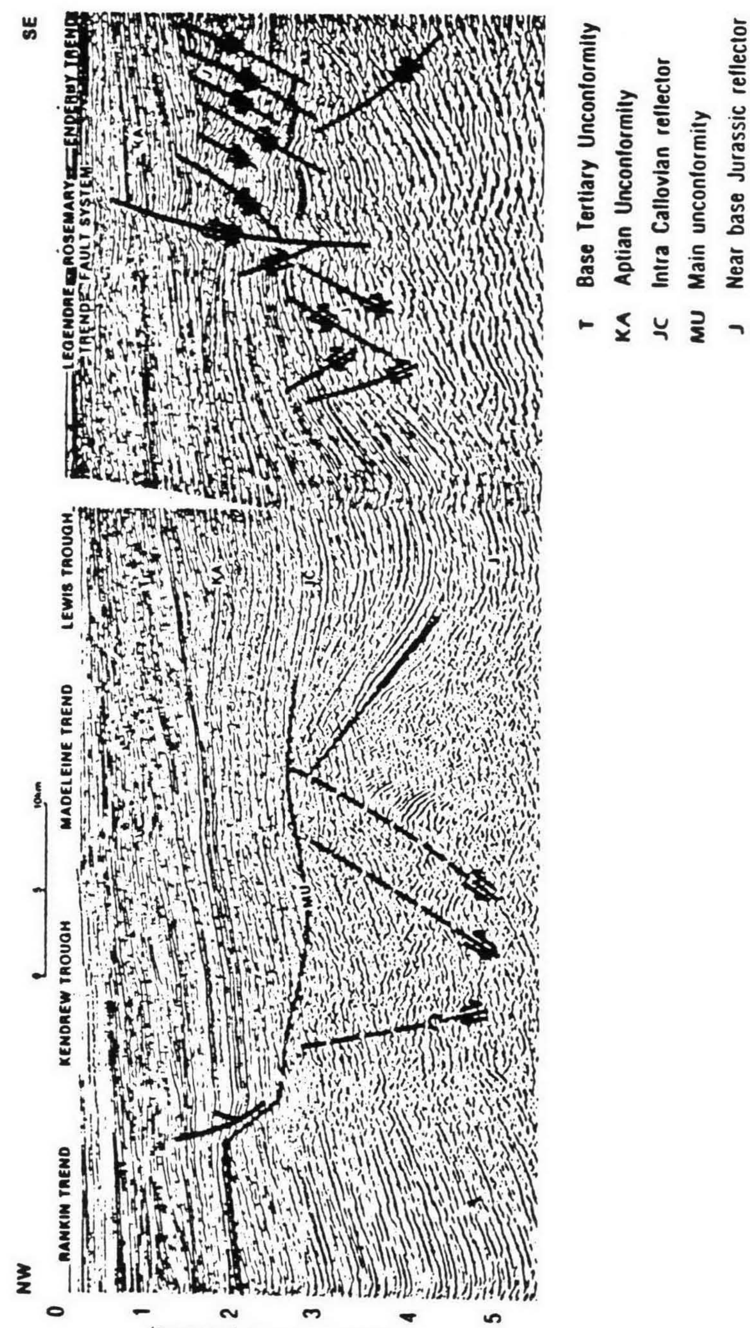


1 Base Tertiary
2 Break-up unconformity
3 Top North Rankin Beds
4 Top Mungaroo Fm.

0 5km

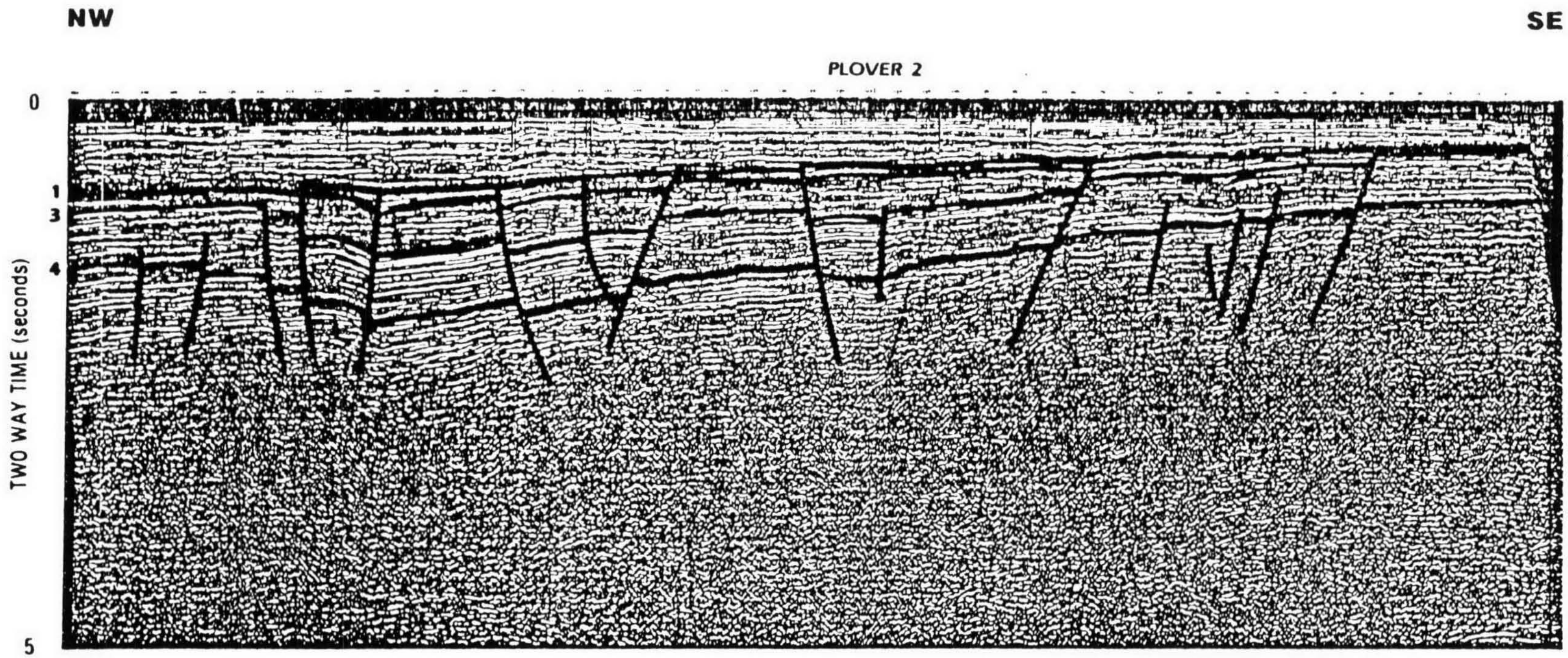
Seismic Line across Brigadier, Northern Carnarvon Basin

Figure 17



(After Veenstra, 1985)

Seismic Line from the Rankin to Enderby Trends, Northern Carnarvon Basin **Figure 18**



1 Top Petrel "A"
2 Top Petrel "C"
3 Top Permian
4 Top Early Permian

Seismic Line across Plover 2, Bonaparte Basin

Figure 19

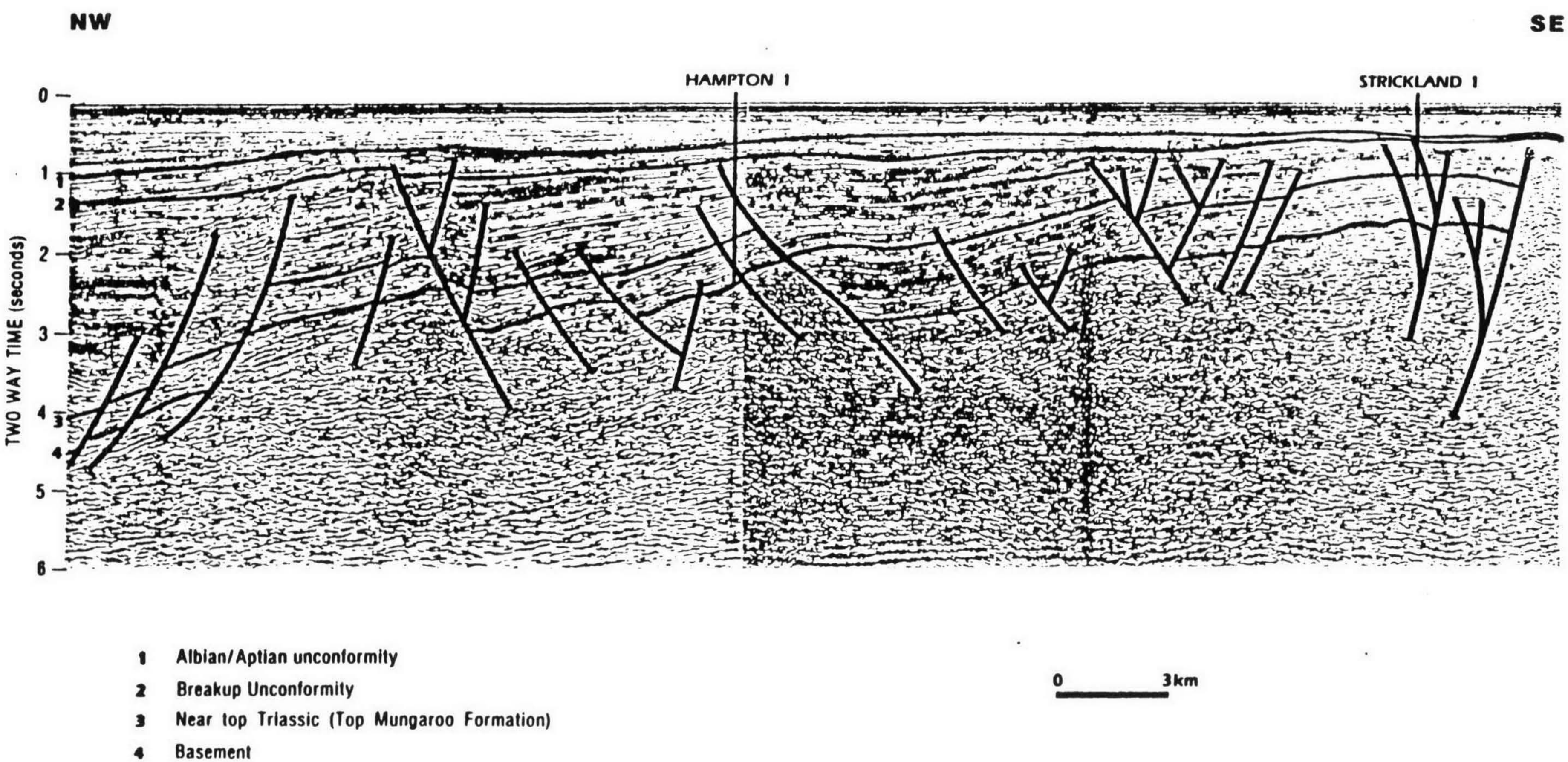


Figure 20

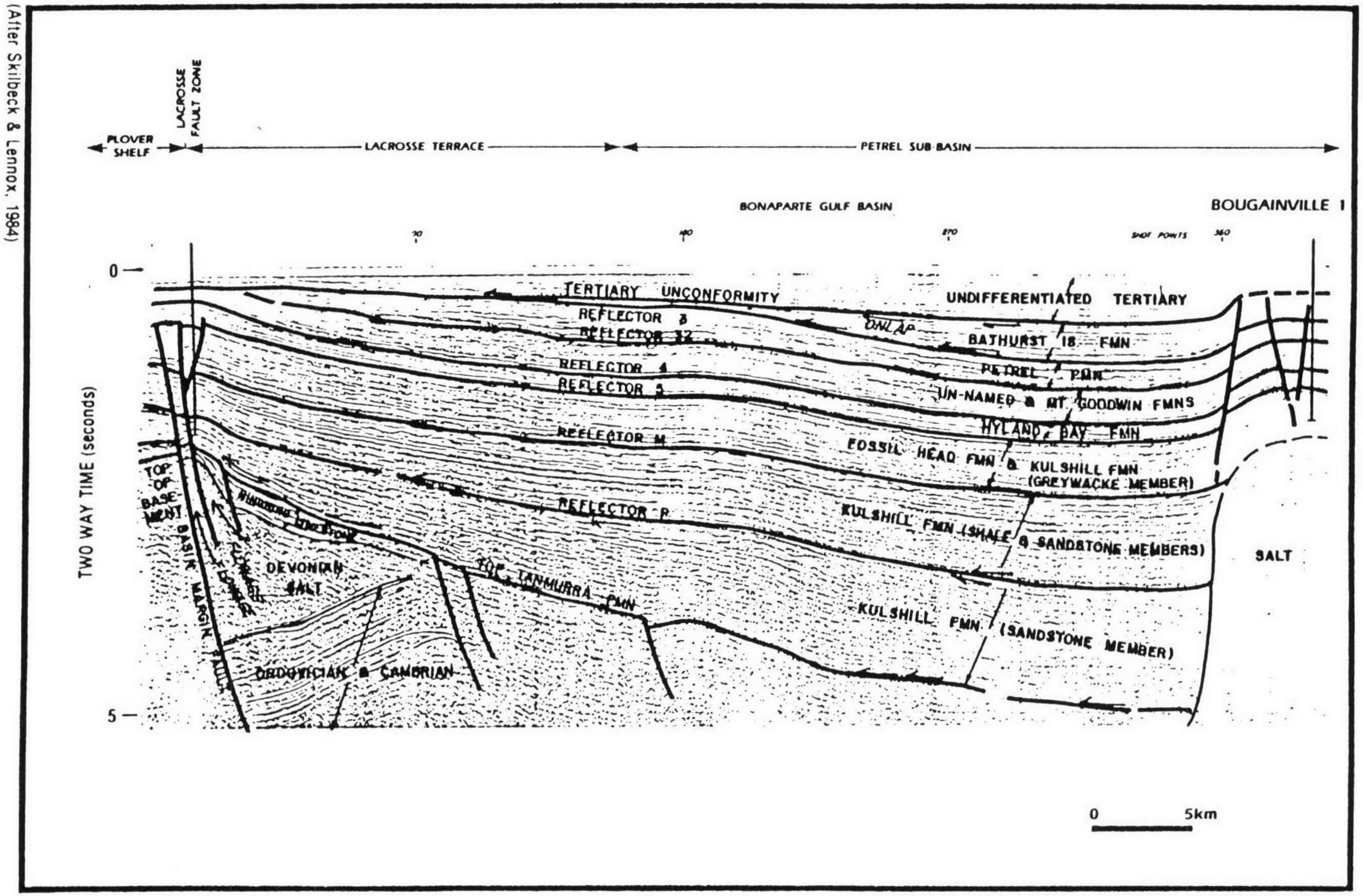
Seismic Line across the Enderby Terrace, Northern Carnarvon Basin

(Courtesy of Geophysical Service Inc.)

Seismic Line Petrel Sub-Basin, Bonaparte Basin

Figure 21

(After Skilbeck & Lennox, 1984)



A disconformity during the Tithonian resulted from rifting of the Gascoyne Abyssal Plain. Significant uplift in the southern Carnarvon Basin initiated the commencement of the regressive Barrow Group deltaic complex. A similar disconformity in the Bonaparte-Browse region marks the change from shallow marine shales to blanket shelfal sands. Subsidence caused further fault rotation of the Exmouth Plateau.

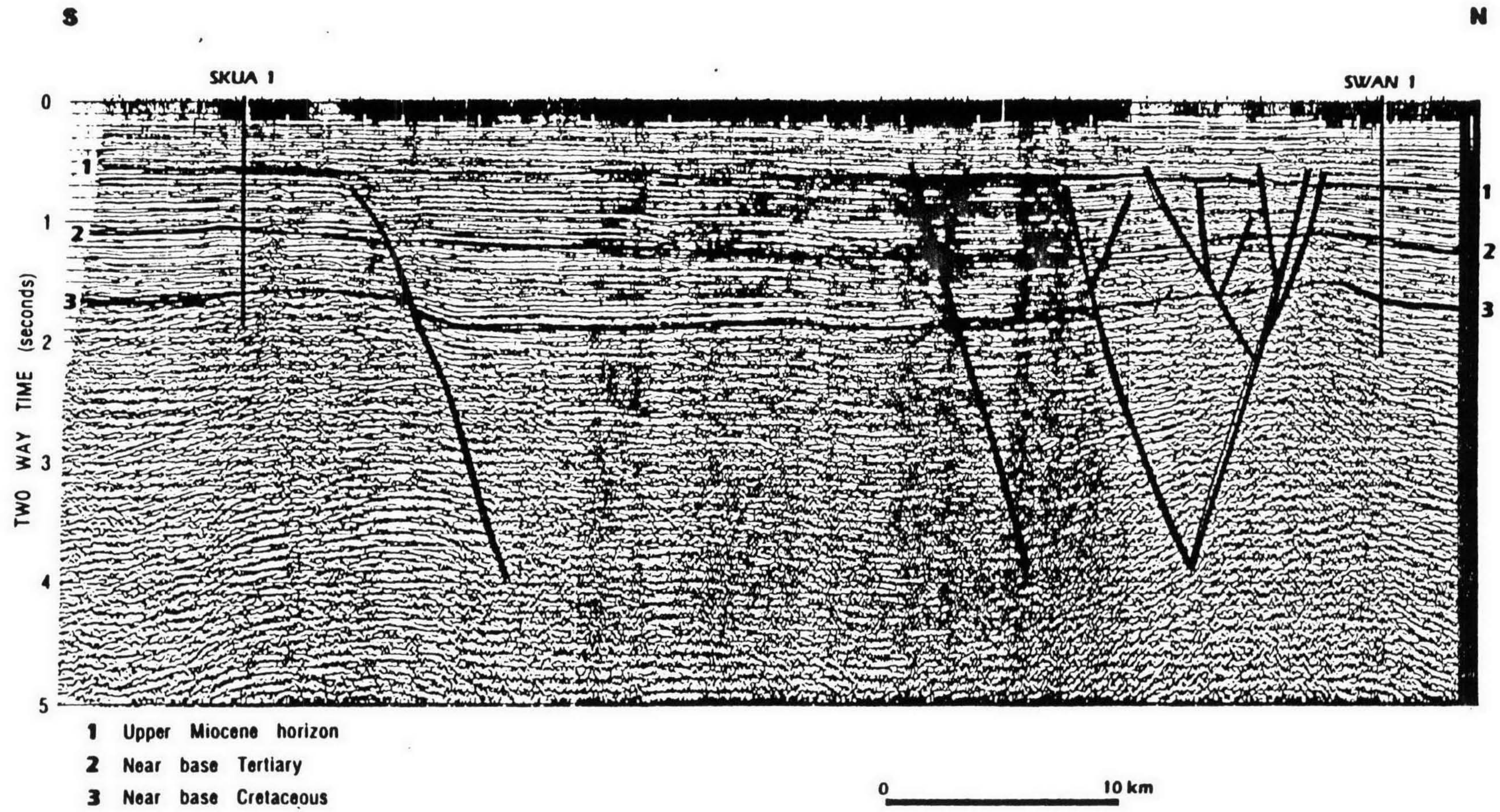
Breakup and sea floor spreading between India and Australia resulted in the formation of the Cuvier Abyssal Plain. Magnetic Anomaly M10 is dated as 132 Ma (Valanginian) which identifies the age of this event. The breakup is marked by a widespread disconformity, and coincides with the transition from regressive to transgressive cycles. In the Petrel Sub-basin, this event marks a change of environment from marginal marine and sub-aerial to distinctly marine. In the Carnarvon Basin, the transition is from the regressive Barrow Group to open marine shales. The disconformity coincides with a minor period of tilting and subsidence. Minor reactivation of faults also occurred.

A regional disconformity at the Albian-Aptian boundary is associated with northwestward tilting and subsidence. This disconformity marks a general change throughout the Northwest Shelf from argillaceous to carbonate deposition, and an increase in the ratio of pelagic/benthonic formaminifera. The hiatus is relatively short and is confined to the Early Albian.
By Albian times, the Indian Ocean was established following the foundering of the Scott and Exmouth Plateaux and Ashmore/Sahul Platforms. The marginal position of the region at the border of the Australian continent was fixed, and free circulating shelf conditions had replaced the restricted conditions of sedimentation.

A general deepening of depositional environment continued until approximately the Turonian, as part of the gross transgressive pattern. Maximum water depths were reached as tectonic tilting peaked. A minor regional disconformity is related to the change from transgressive to regressive sedimentation. An angular unconformity marks this event on Barrow Island; it was followed by the commencement of major arching of the Barrow Anticline. Reactivation of structures on the outer western flank of the Browse and Bonaparte Basins continued during the Late Cretaceous. Seismic data in the Barrow Sub-basin show major tectonic activity, with wrench-related structures being truncated by the unconformity. Right lateral movement occurred along the boundary between the Precambrian craton and the sedimentary basin, and initiated the formation of the NNE-orientated Barrow Anticline, Tryal Rocks and Dampier Madeleine Trends (Williams and Poynton, 1985).

The Browse Basin was infilled with regressive shallow water deposits, and the infilling probably reached sea level in the Early Maastrichtian. There was widespread disconformity in the Middle Maastrichtian. At the end of the Cretaceous, renewed erosion during the Early Paleocene removed Late Maastrichtian, and in places, older sediments. A minor structural event produced some large, gentle growth folding on the outer flanks of the Browse Basin and the Exmouth megablock; this was due to the isostatic adjustment of the underlying fault blocks. The oceanic environs surrounding the outer plateaux of the Northwest Shelf began to cool, and rapidly sank to abyssal depths, resulting in subsidence of the Exmouth and Scott Plateaux, and the progradation of the continental shelf.

Disconformities in the Middle Eocene and Middle Oligocene are related to isostatic adjustments similar to those in the Paleocene. A period of Middle Miocene folding, incorporating extensional wrenching and associated with the collision of the Australian and Asian continental plates, uplifted and inverted the Legendre-Barrow and Spar-Madeleine anticlinal trends. Late wrenching and growth initiated structures along the Rosemary Trend and Flinders Fault System (Fig. 18). Isostatic adjustment resulted in broad arching on the Exmouth and Scott Plateaux. Tensional forces established ENE-WSW faulting in the northern Browse Basin (Fig. 22). During this period, an important heat pulse occurred along the Northwest Shelf. Salt diapirism continued throughout the Tertiary period in the Bonaparte Basin.



Seismic Line-Vulcan Sub-basin, Browse Basin

Figure 22

6. HISTORY OF SEDIMENTATION

6.1 INTRODUCTION

Northwestern Australia during Palaeozoic times comprised the Canning and Bonaparte intra-cratonic basins, separated and bounded by the Precambrian Pilbara and Kimberley Blocks. The history of sedimentation since then on the Northwest Shelf reflects the progressive break-up of the Eastern Gondwanaland continental mass through the mechanism of rifting and sea floor spreading.

Subsidence began early in Late Carboniferous-Permian times, preceded by initial upwarp. In Permo-Triassic times, a NE-SW trough stretched along the Northwest Shelf area. Sedimentation was mainly fluvial and fluvio-deltaic, with a few widely spaced marine incursions.

The main rifting stage occurred from Late Triassic to Middle Jurassic, and again sedimentation was predominantly non-marine, except in the Northern Carnarvon Basin. Basic lavas have been encountered in a few wells and probably represent the onset of spreading. Spreading commenced in Callovian times and is marked by a regional unconformity. Subsequent sedimentation took place in a marine environment. Late Jurassic and Cretaceous deposition was predominantly fine clastic. A westward tilt late in Cretaceous times established open marine conditions and Tertiary deposition predominantly consisted of shelf carbonates.

A more detailed history of sedimentation for each of the basins follows. The basin histories are illustrated by a series of palaeogeographic sketches (Encl. 13-16) and well correlations (Encl. 17-21).

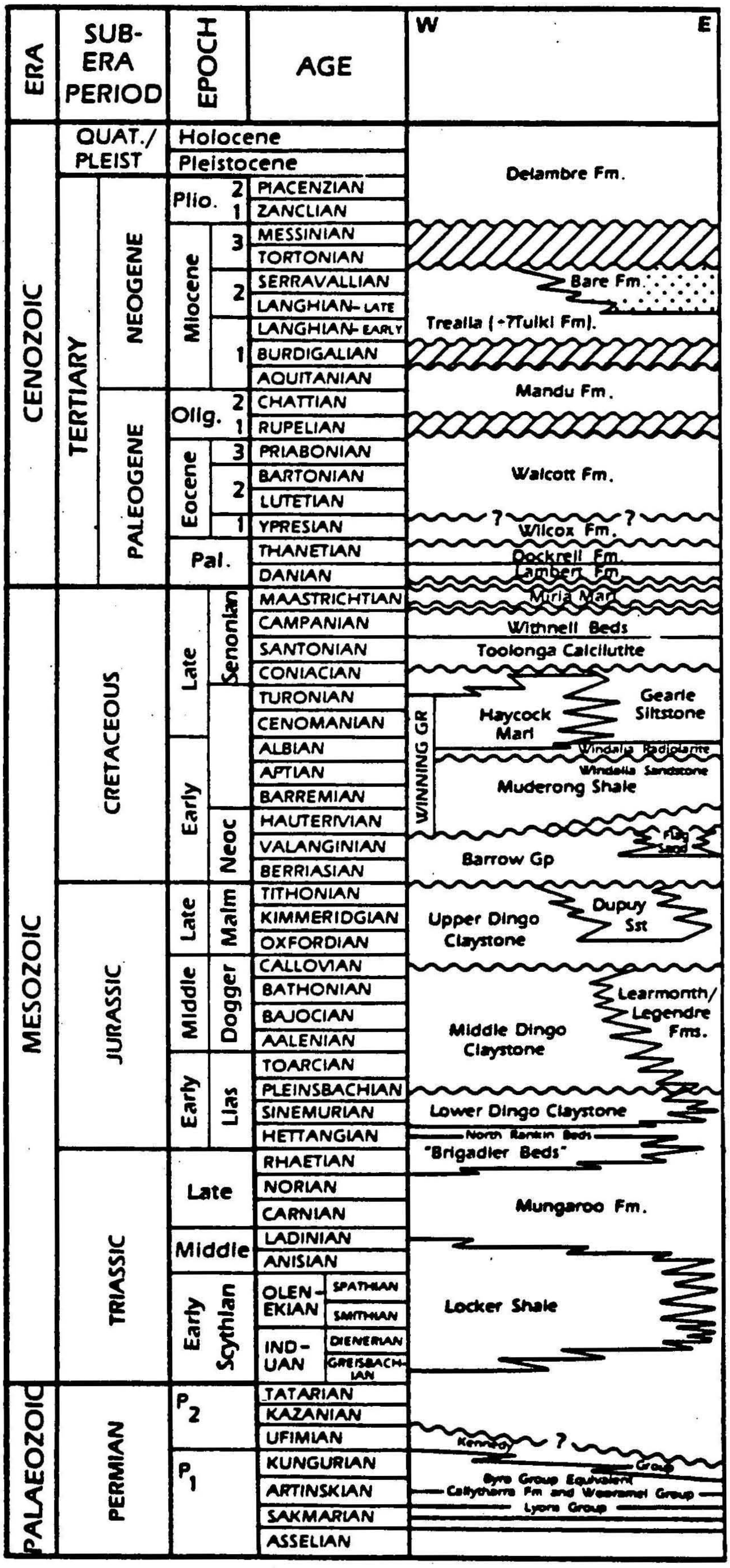
6.2 CARNARVON BASIN

This history of sedimentation has been prepared from interpretation of data in well completion reports and from published literature. A series of palaeogeographic maps has been prepared (Encls. 13 and 14), some of which are modified after Kopsen and McGann (1985). The stratigraphic nomenclature used in this report is detailed in Figure 23. Stratigraphic well correlations are shown on three sections across the basin (Encls. 17 and 18). Formation tops were checked and repicked if necessary (Appendix A), using new palynological interpretations (Appendix D) where ambiguities existed.

The Late Triassic to Late Jurassic section has been subdivided into informal units. The Brigadier Beds and North Rankin Beds of Crostella and Barter (1980) have been differentiated from the Mungaroo Formation by lithology and age. The informal subdivision of the Dingo Claystone into Lower, Middle and Upper Units (Barber, 1982) has also been adopted. In some cases, where it is difficult to subdivide the Dingo Claystone by lithology because of the uniform section, it has been subdivided in terms of age according to Figure 23. Prodelta shales equivalent to the Barrow Group have been separated from similar shales of the Upper Dingo Claystone and the Muderong Shale. This was done on the basis of age and a downward increase in log resistivity in each of the horizons.

6.2.1 Pre-Triassic

The pre-Triassic section has been penetrated in only a few wells, all of them in the eastern and southern shelfal areas of the Northern Carnarvon Basin. The sequence is beyond prospective drill depths west of the Flinders Fault zone and north of the Long Island Fault, i.e. in the basin proper.



Stratigraphic Nomenclature, Northern Carnarvon Basin

Figure 23

Equivalents of the Byro and Kennedy Groups of the Merlinleigh Sub-Basin have been intersected in several wells in the shelfal areas. They are likely to be present at depth throughout the Northern Carnarvon Basin. Seismic evidence points to a thick Palaeozoic section. The stratigraphy of the Merlinleigh Sub-basin has been detailed by Percival and Cooney (1985). Onslow-1 penetrated a nearly complete Permian section, ranging from Kennedy Group to Lyons Group (Thomas and Smith, 1976).

The Byro Group consists of shallow marine shales, siltstones and minor sandstones. Shales are often dark and contain relatively high amounts of organic carbon. More than 330m have been intersected, and total thickness to the south ranges up to 1500m. The overlying Kennedy Group consists mainly of shallow marine sandstones, with minor siltstones and limestones. Where they are not deeply buried, the sandstones have good reservoir properties. Over 400m of the Kennedy Group were penetrated in Hope Island-1.

Intermediate to basic igneous rocks have been penetrated below the Locker Shale in several shelfal wells.

6.2.2 Triassic

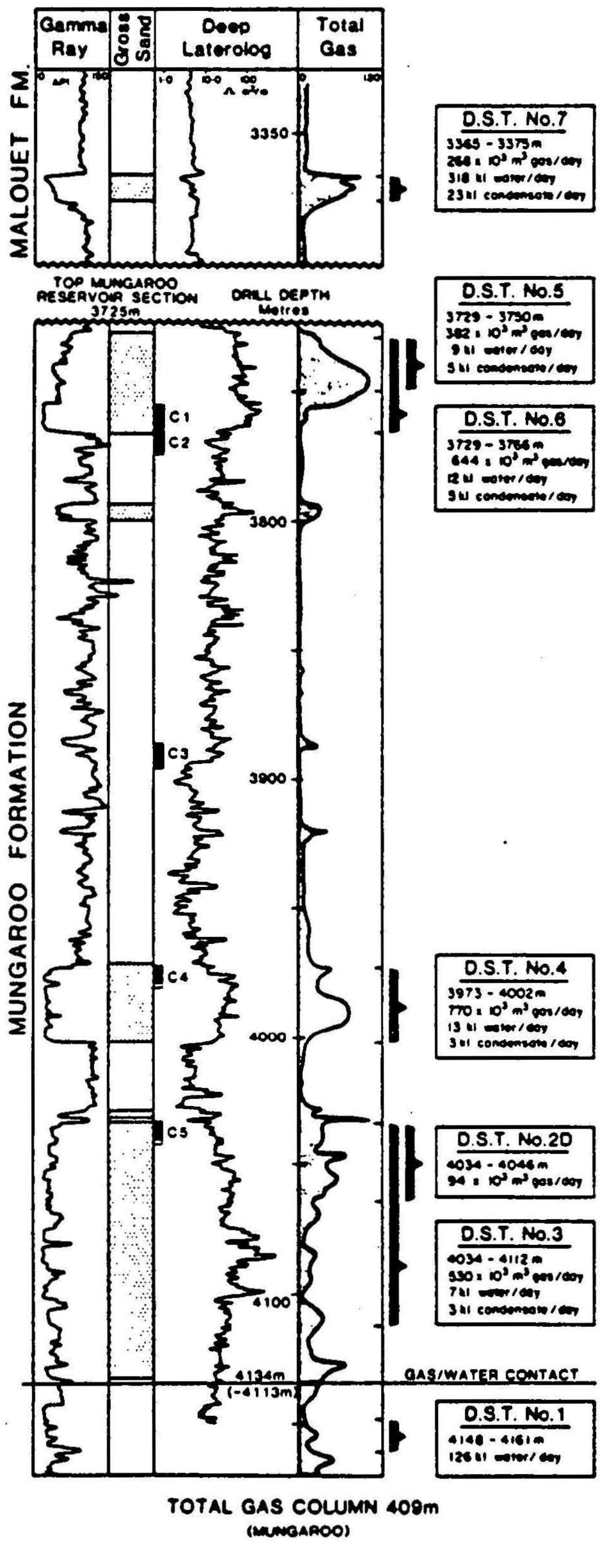
The transgressive Locker Shale marked the beginning of Triassic deposition. This transgression, which commenced in the Scythian, affected the entire western coastline, having been documented in the Bonaparte, Canning, Carnarvon and Perth Basins. The unit, which unconformably overlies Permian and older rocks, is characterised by thin basal sandstones and/or limestones overlain by relatively homogenous claystones and siltstones. Where it has been intersected to date, the Locker Shale was probably deposited in a shallow oxygenated sea with sediment sourced from the east (Encl. 13a).

Seismic evidence (submarine canyons) indicates a palaeo shelf edge near the Flinders Fault zone and water depths greater than 250m to the west of it (Kopsen and McGann, 1985; Kirk, 1985). The maximum thickness drilled to date is 980m in Flinders Shoal-1.

The Locker sea retreated towards the north in the Late Scythian to Ladinian (Encl. 13b). Fluviodeltaic sandstone beds become more common at the top of the unit, and it eventually grades into the predominantly fluvial Mungaroo Formation. On seismic data, low angle progradation can be recognized between the bland character of the Locker Shale and the higher amplitude, less continuous character of the fluvial Mungaroo Formation.

The Anisian to Rhaeto-Norian Mungaroo Formation is very widespread and consists of coarse fluvial sandstones, fine grained clastic marsh deposits and coals and lacustrine shales. Much of the hydrocarbon reserves on the Rankin-Gorgon Trend are reservoired in Mungaroo Formation sandstones, which have excellent reservoir characteristics due to their high quartz content and lack of primary clay matrix. Porosities reach 30% and permeabilities up to 4 darcies (Crostella and Barter, 1980). Although the formation is characterised by thick blocky sandstones easily recognised on logs (Figs. 24 and 25), there are significant thicknesses of shales present in some wells.

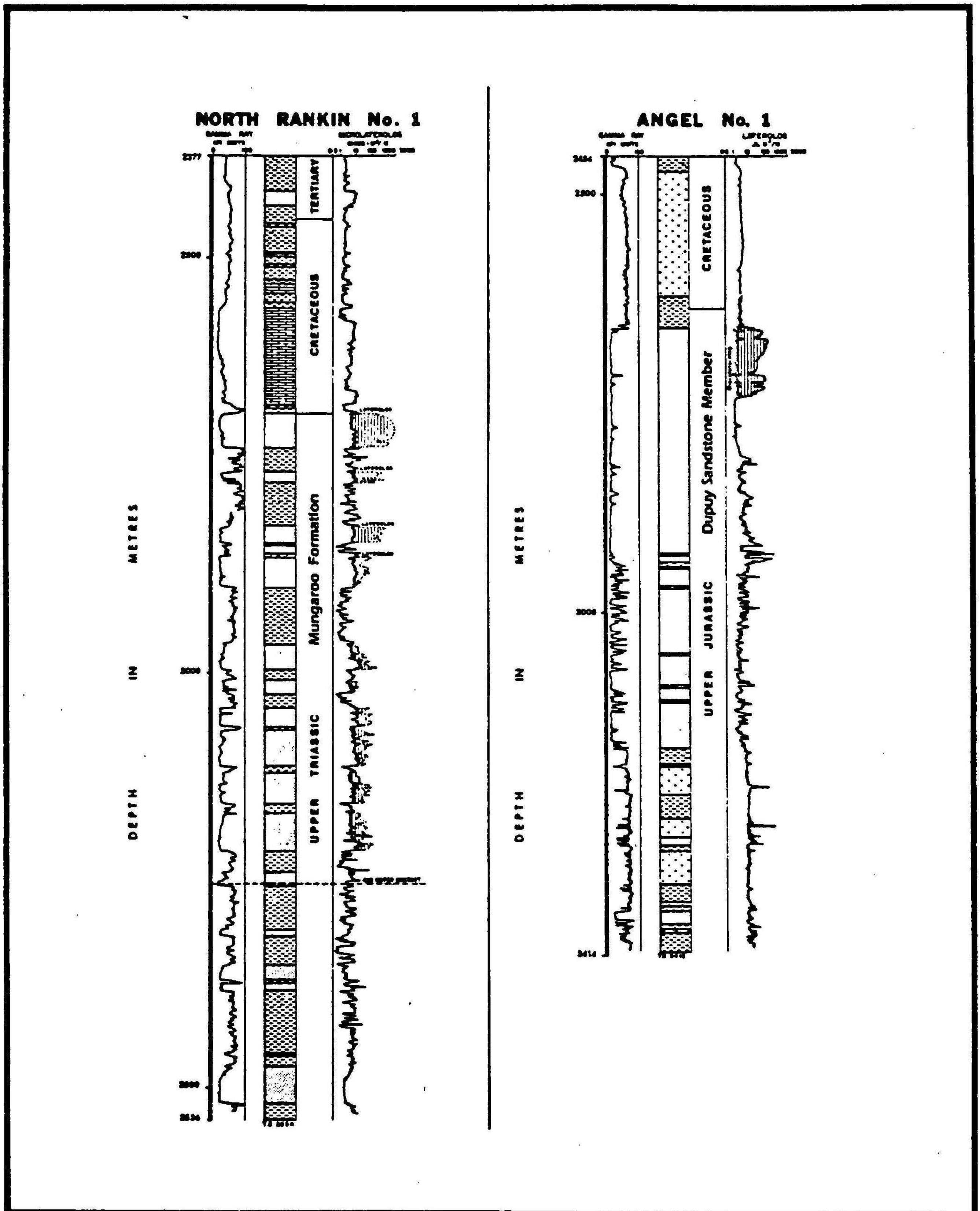
There is an overall change from alluvial plain deposition on the eastern side of the basin to lower delta plain facies in the west (Encl. 13c). Most of the thick shale beds have been intersected in the western region, although thick lacustrine shales have been intersected in some eastern shelf areas, e.g. Flinders Shoal-1. Evidence of marine influence has been recorded from several wells throughout the area. The flat topography prevailing at the time of deposition would have facilitated marine incursions.



(After Campbell & Smith, 1982)

Figure 24

Northern Carnarvon Basin
Gorgon-1, Reservoir Sections



(After Thomas & Smith, 1976)

Northern Carnarvon Basin **Figure 25**

Angel-1 and North Rankin-1, Reservoir Sections

Three cycles of fluvial sedimentation have been recognised in the Rankin area (Crostella and Barter, 1980). Cycles of braided stream sandstones, channel and flood plain deposits and final phase coal measure sediments have been recorded in the Early-Middle Carnian, Late Carnian-Middle Norian and Late Norian periods. Respective thicknesses are of the order of 1500m, 600m and 250m. The thickest intersection penetrated to date in the eastern area is 1062m at Observation-1. Thicknesses increase to the west; over 3000m were penetrated in Jupiter-1 on the Exmouth Plateau.

A widespread marine transgression commenced in latest Norian time and resulted in a shallow epeiric sea covering much of the area (Encl. 13c). Crostella and Barter (1980) informally defined Rhaetian to Early Hettangian sediments in the Rankin Platform area as the Brigadier Beds. They comprise mainly low energy deltaic shales, siltstones and sandstones. In this study, the Brigadier Beds have been distinguished from the Mungaroo Formation and have been correlated over most of the Barrow-Dampier and Beagle Sub-basins. Some gas pay has been recorded within the Brigadier Beds in the Rankin Platform-Exmouth Plateau area.

6.2.3 Jurassic

In the Rankin area, a thick, massive marine sandstone unit of the Hettangian-Sinemurian overlies the Brigadier Beds. This has been informally named the North Rankin Beds (Crostella and Barter, 1980) and is thought to have been deposited in a beach or nearshore environment. It reservoirs commercial hydrocarbons on the Rankin Platform.

During the Sinemurian, a widespread transgression occurred and fully marine conditions were established over most of the Barrow-Dampier and Beagle Sub-basins. Initial shallow water limestone and marl deposition (Sinemurian) was succeeded by deeper water shales of the Lower Dingo Claystone (Fig. 23). The limestone-clastic interface generates a widespread seismic reflector, which can be recognised over most of the Northern Carnarvon Basin.

An important period of structuring occurred in Pleinsbachian time. Subsidence in the major troughs (Victoria Syncline, Kangaroo Syncline, Lewis Trough, Cossigny Trough, Barrow Depocentre) increased markedly, as indicated by thickening of Early Jurassic sediments in the depocentres. The major positive elements such as the Rankin-Gorgon Trend thus began their growth at this time.

Uplift occurred in the southeastern basin margins of the northeast Barrow-Dampier and Beagle Sub-basins, and a large deltaic complex began prograding northwestward. Sediment was sourced from the southeast, and coarse grained marine to fluvial sandstones equivalent to the Learmonth Formation prograded from the area of the De Grey Nose (Encl. 14a). Progradational deltaic complexes also formed near major fault scarps in the Cape Range area. Elsewhere in the Barrow-Dampier Sub-basin, prodelta marine shales and siltstones of the Middle Dingo Claystone were being deposited. No seismic evidence exists for uplift east of Barrow Island in this time interval (Kirk, 1985). Thick black Toarcian shales have been intersected in many wells. Although these shales have moderate organic matter content and have been interpreted to have been deposited in a poorly oxygenated environment, the organic material is mainly terrestrial in nature.

Deltaic progradation continued in the north and south, until major uplift, associated with rifting, occurred in the Early to Middle Callovian.

By this time, fluvial sedimentation was occurring northwest of the Sable area. A condensed sequence of distal sediments was deposited on the Exmouth Plateau during the Early to Middle Jurassic.

Much of the Barrow-Dampier and Beagle Sub-basins, the Exmouth Plateau and Cape Range area became emergent during the Early to Middle Callovian, and widespread erosion took place. Seismic and other evidence indicates that in excess of 1000m of section has been eroded from parts of the Exmouth Plateau/Rankin Platform and the eastern shelf at the main breakup unconformity. Only the main trough areas of the Lewis Trough and Barrow Depocentre continued to receive sediment. This period of rifting resulted in the present structural configuration of the sub-basins. A series of en echelon horst blocks which comprise the Rankin Platform formed a barrier to the open sea. Marine shales and siltstones and turbiditic and mass flow sandstones were deposited in deep water in this restricted basin (Encl. 14b).

Widespread subsidence was renewed in the Late Callovian, which led to more extensive marine sedimentation. Relatively deep water conditions prevailed west of the Legendre Trend and the Flinders Fault at this time. Submarine fans, debris flows and turbidites were shed off narrow shelves, as illustrated in Enclosure 14c (Kopsen and McGann, 1985; Tait, 1985). Feeder canyons and fan geometry can be mapped seismically (Kirk, 1985). Large thicknesses of deep water sandstones of the Dupuy Sandstone Member accumulated along the eastern margin of the Barrow-Dampier Sub-basin. The thickest sequence penetrated to date is 750m in the Koolinda area, where there is a late phase of deposition not recorded north of Barrow Island (Tait, 1985). Younger uplift and erosion has removed the Dupuy Member equivalents from the eastern shelf area.

Marine sandstones were also deposited adjacent to high blocks, where sandy Triassic to Middle Jurassic sediments were exposed. Thick, shallow marine sandstones were deposited on narrow shelves in the north in the Legendre-Angel (Fig. 25) area, and a thin sequence of sandstones and relatively thin shales was deposited in the Cossigny Trough of the Beagle Sub-basin. These sandstones possess good reservoir properties and host oil and gas accumulations at Angel, Egret and Lambert. Fine grained basinal siltstones and claystones of the Upper Dingo Formation are laterally equivalent to these sandstones. A very condensed sequence was deposited over most of the positive Rankin Platform and Exmouth Plateau. The highest horst blocks on these areas remained emergent until they were covered by Early Cretaceous shales.

More than 4500m of Jurassic sediments are present in the Lewis Trough.

6.2.4 Cretaceous

Deposition continued through into the Early Cretaceous, and in most places the Cretaceous is conformable on the Jurassic.

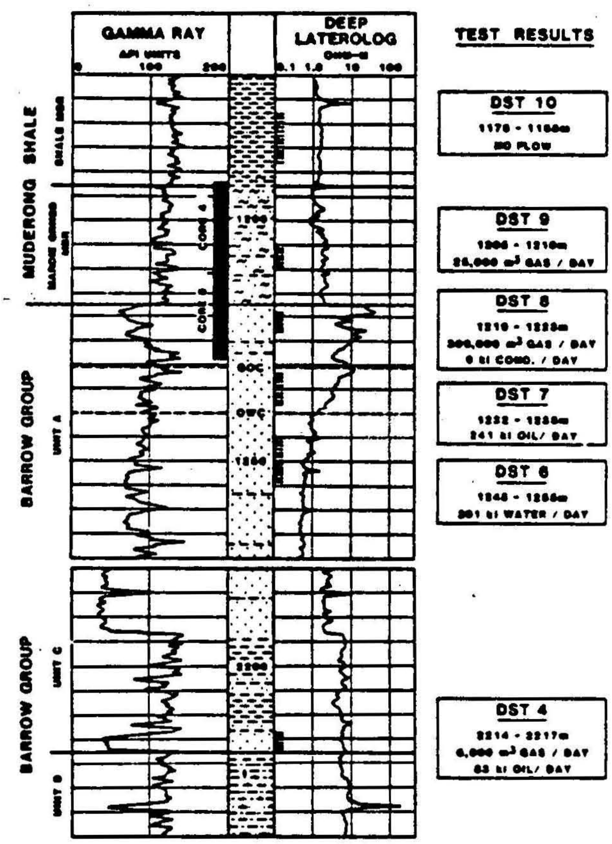
Uplift, associated with rifting south of the Cape Range Transform Fault during the Late Tithonian, provided a coarse clastic source for the Barrow Group delta. This event produced a minor unconformity in some places.

The delta prograded rapidly to the north, onlapping the Dupuy Member along the eastern edge of the basin. The subaerial topsets of the delta cover all of the southern Barrow-Dampier Sub-basin and a large part of the Exmouth Plateau (Encl. 14d). The Barrow Group delta sediments form a large scale, coarsening upward sequence, which has been described by Tait (1985). Basal distal turbidites grade up into coarser mass flow sandstones which reach 600m in thickness in the Barrow Island area. As these turbidite sediments fill topographic lows, this area is interpreted to have been in the deepest part of the basin at the time Barrow Group deposition began.

The turbidite sediments are overlain by bioturbated sandy claystones and poorly sorted sandstones, which are interpreted to have been deposited in an offshore slope environment. These are in turn overlain by coarse grained, shallow marine to fluvial sandstones (Fig. 26). This interpretation can be readily related to the seismic signature, which is one of large scale clinoforms (Fig. 27). The axis of subsidence in the sub-basin during this time was to the west of Barrow Island. Seismic data indicate that the delta was prograding into water depths of the order of 600m during the late stages of deposition (Tait, 1985). Maximum thickness is approximately 1200m, south of Barrow Island.

In the Mid-Valanginian, continental breakup south of the Cape Range Transform Fault, on the southern edge of the Exmouth Plateau, cut off the sediment supply and the delta progradation ceased, with the youngest foreset trending east-west through Barrow Island. Prodelta shales cover most of the Dampier Sub-basin, Beagle Sub-basin and Exmouth Plateau. A somewhat restricted environment is likely to have occurred in and around the Lewis Trough, as the Rankin Platform was positive, probably close to sea level, at this time. A narrow, shallow marine sand-prone facies belt on the edge of this trough (Encl. 14d) forms reservoirs for the oil accumulations at Legendre-1, and possibly at Talisman-1.

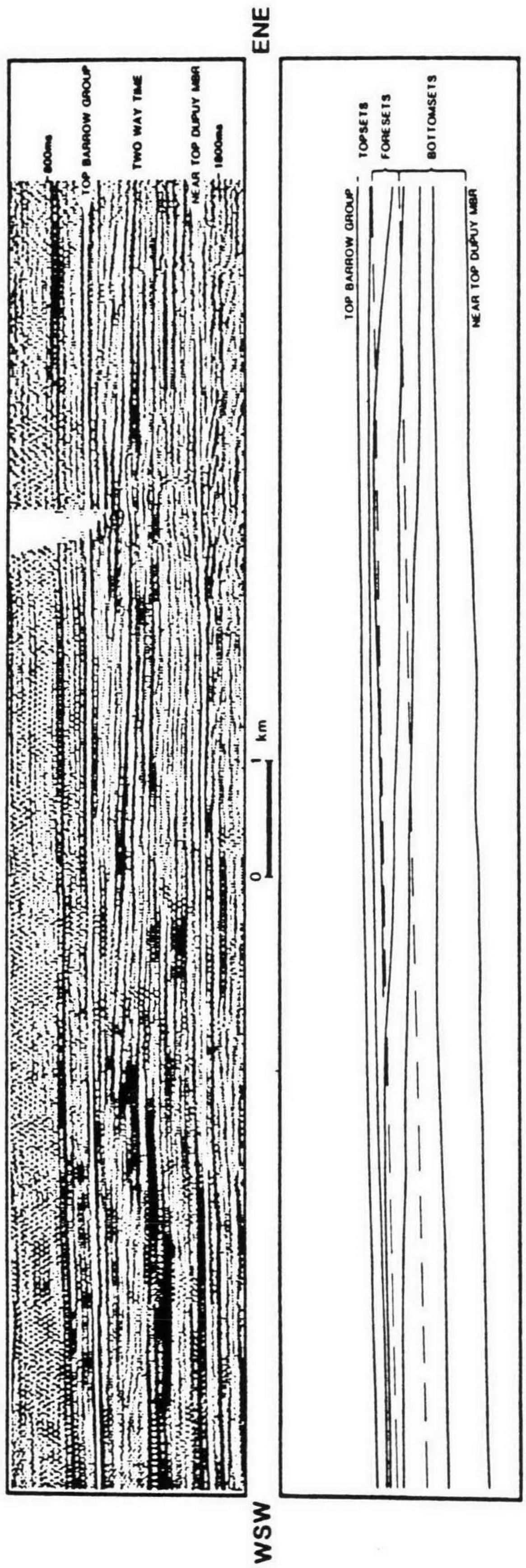
The Muderong Shale unconformably overlies the Barrow group sediments. In the more shelfal areas and where the underlying rocks were sandy, a basal paralic sandstone (Birdrong Sandstone, and Yarraloola Conglomerate in the Robe River area) and a laterally equivalent shelfal greensand (Mardie Greenstone Member) are developed. Oil and gas have been recovered from these units. The basal sand units lie east of the major basin bounding fault systems and south of an approximately east-west line through Barrow Island.



(After Williams & Poynton, 1985)

Northern Carnarvon Basin
South Pepper-1, Reservoir Sections

Figure 26



(After Tait, 1985)

Figure 27

Seismic Signature of Progradational Barrow Group
Northern Carnarvon Basin

The Muderong Shale forms the basal part of an overall transgressive sequence which lasted until the Senonian. It was deposited in open marine conditions which developed as continental separation continued. It forms the first substantial sealing lithology over many of the large Rankin Platform structures, outer Beagle Sub-basin horsts and parts of the Exmouth Plateau. The Windalia Sandstone member at the top of the formation is thought to be a storm-generated shelf deposit (Campbell et al., 1984). The Windalia Sandstone forms the major reservoir on Barrow Island. The Muderong Shale thins markedly over the Barrow Anticline, indicating that structural growth began in the Neocomian. Another episode of structuring occurred in the Late Turonian, when wrench-related faulting and folding formed the Harriet and South Pepper structures (Kopsen and McGann, 1985; Williams and Poynton, 1985). Considerable fault movement occurred on the Rankin Platform at this time (Apthorpe, 1979).

In the outer part of the Barrow-Dampier Sub-basin, the Windalia Radiolarite and the overlying, more carbonate rich shales and marls of the Gearle Siltstone equivalent (Haycock Marl) reflect the deepening open marine environment, formed as the Indian Ocean completely opened. The contact with the Muderong Shale is disconformable and has a good seismic expression which can be mapped regionally. Peneplanation of the provenance areas led to a decrease in clastic sediment supply. Water depths greater than 200m are inferred from seismic data, which indicate a shelf edge in the area of Withnell-1 (Kopsen and McGann, 1985).

The De Grey Nose-Sable-Ronsard area appears to have remained at or above sea level until the Turonian. Palaeogeographic reconstructions of time slices in the Cretaceous indicate that the Beagle Sub-basin experienced a tectonic history different from the Barrow-Dampier Sub-basin (Apthorpe, 1979).

The Toolonga Calcilutite, which can be readily correlated between most wells, was deposited during the Santonian. Renewed but minor clastic input then ensued, resulting in deposition of the Withnell Beds and the Miria Marl. Considerable subsidence of the Lewis Trough and Barrow depocentre continued throughout the Late Cretaceous, resulting in deposition of a thick wedge of sediments. The Victoria Syncline and Cossigny Trough, however, show little thickening of the section. Several minor unconformities are present in the Cretaceous section.

6.2.5 Tertiary-Quaternary

The base of the Tertiary is marked by a regional unconformity. Following this event, deep water conditions prevailed as the new oceanic crust surrounding the Exmouth Plateau began to cool and subside. The Exmouth Plateau foundered at this time and sank to near its present depth. Predominantly deep water clastics and marls were deposited during the Early Tertiary. The separation of the Australian and Antarctic continents, and the subsequent migration of the Australian continent northwards into equatorial regions by the Middle Eocene, introduced a climate suitable for carbonate sedimentation.

Progradation of the continental shelf occurred, resulting in a thick wedge of carbonates and minor clastics. The present shelf edge is near the Rankin Trend. Several unconformities have been recognised in the Cainozoic sequence. A major wrench-related structural episode occurred in the Middle Miocene. Uplift and folding occurred, resulting in the growth or formation of several large anticlinal trends such as the Barrow Island Anticline.

6.3 CANNING BASIN

Little is known about the Palaeozoic sequence in the sparsely explored offshore Canning Basin. The close of the Permian was marked by a tectonic episode, taking the form of initial rifting which preceded the eventual Callovian breakup. Deposition throughout the Triassic and Early-Middle Jurassic proceeded in a predominantly fluvial-deltaic environment, with a number of minor short-lived marine incursions. In the Bedout Sub-basin, more than 2300m of a predominantly sandstone sequence has been drilled, with minor thin interbedded claystones, siltstones and coals. Rare thin calcareous sandstones and calcilutites mark a marine incursion. A similar, but thinner sequence has been drilled in the Fitzroy Sub-basin.

After the Callovian breakup, the continental rift-fill environment was replaced by marine sedimentation. Initially, in the Late Jurassic and Early Cretaceous, water depths were shallow and a glauconitic sandstone and claystone sequence was laid down. By Late Cretaceous times, deeper marine conditions had become established and the sequence was predominantly comprised of marls and calcilutite. These conditions prevailed through Paleocene times. By the Middle Eocene, water depths were less and calcarenitic, inner shelf deposition was widely established. Continued regression since then has resulted in a prograding carbonate wedge covering the entire shelf. A number of unconformities, or disconformities, are present within the sequence, the most important marking the base of the Miocene.

6.4 BROWSE BASIN

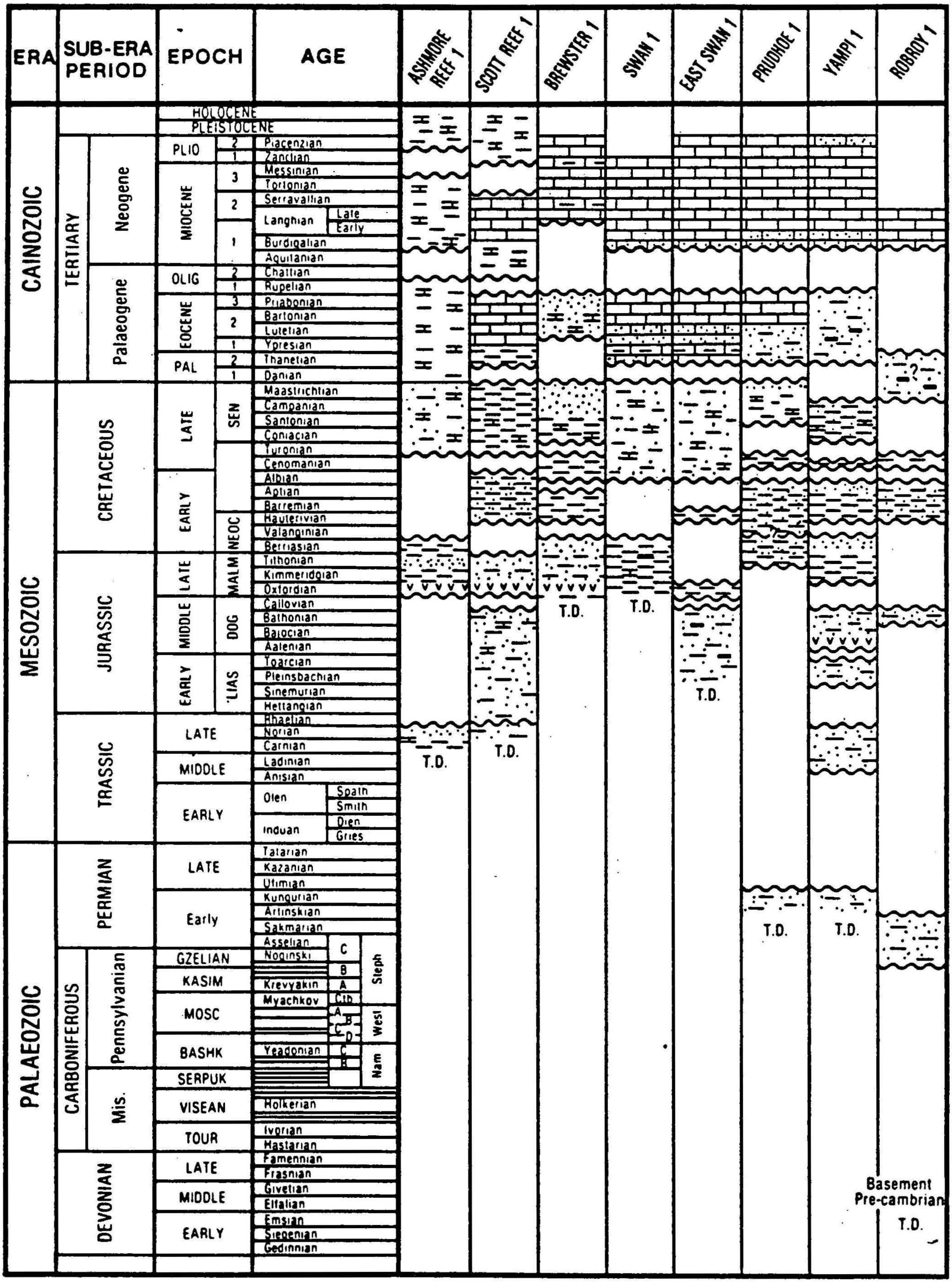
This history of sedimentation has been prepared from data in well completion reports and from published literature. A series of palaeogeographic maps has been prepared (Encl. 15). Since no formal stratigraphic nomenclature has been established for the sedimentary units in the Browse Basin, the sedimentary sequence has been divided according to its age (Fig. 28). The establishment of a defined lithostratigraphic sequence is beyond the scope of this report. It should also be noted that considerable systematic biostratigraphic work would be required to establish accurately the age of the section in numerous wells. As many wells are still confidential, it would be premature to erect and define a stratigraphic column without using all possible well control. Stratigraphic well correlations are shown on four sections across the basin (Encls. 19 and 20).

The sedimentary section in the basin can be divided into two series which are directly related to the evolution of the basin. The lower series, or pre-breakup sequence, was deposited in an intracratonic basin. Deposition was controlled by episodic tectonism due to crustal tensions (rift valley sediments). The upper series, or post-breakup sequence, was deposited under more stable conditions (marginal marine to marine). The boundary between these two series can be correlated with the timing of the breakup of the continental mass along the western side of the Scott Plateau.

Seismic and well data indicate several regional unconformities at the following levels:-

(a) Permian/Triassic
(b) Triassic/Jurassic
(c) Middle Jurassic Breakup Unconformity
(d) Early Cretaceous/Late Cretaceous
(e) Intra-Late Cretaceous
(f) Cretaceous/Paleocene
(g) Paleogene/Neogene

The main stratigraphic units used in this report are bounded by the above unconformities.



Chronostratigraphic Chart, Browse Basin

Figure 28

6.4.1 Palaeozoic

During the Early Palaeozoic, an intracratonic basin developed from north to south across the present coastline. Marine conditions accompanied transgression of the area by an arm of the Tethys sea during the Devonian. The whole region was probably uplifted and partially eroded during the Carboniferous.

In the Late Carboniferous, a marine transgression probably occurred through the Browse Basin, and deposited a sequence of paralic clastics and carbonates along the eastern side of the basin. These were overlain in the Early Permian (Rob Roy-1, Prudhoe-1) by a non-marine, probably glacial, sequence of sand and silt. This represented a westward regression toward the centre of the basin, where the section is probably more complete, and Late Permian sediments should be preserved. However, no wells have penetrated to the depths necessary to reach such a sequence.

In the Late Palaeozoic, major tensional movement produced troughs parallel to the present coastline (Powell, 1976). The troughs were superimposed on the Palaeozoic intracratonic basin. Block faulting, in association with this Late Permian and Early Triassic deformation, produced NE-SW structural trends, and uplifted areas of the Scott Plateau, Yampi Shelf and Prudhoe Terrace (Encl. 6).

6.4.2 Triassic

Subsequent erosion and non-deposition led to a stratigraphic break between the Permian and the Late Triassic (Lynher-1, Yampi-1) in the marginal areas. Poor seismic data at this level in the central part of the basin do not allow an accurate determination of the nature of the contact, but near the basin margins and the eastern flank of the Scott Plateau, an unconformity can be identified near the top of the Permian (Allen et al., 1978).

In the main Browse Basin, the Triassic sequence is largely confined to the area between the Prudhoe Terrace and the Scott Plateau. Early and Middle Triassic sediments probably overlie the Permian sequence in the central basin. However, the oldest Triassic sequence penetrated to date is Late Ladinian (Brecknock-1). This consists of marine recrystallised limestones and claystones, which continued upward to the Norian-Carnian (Scott Reef-1). They extend northward onto the Ashmore Platform, where a sequence of fine grained clastics with interbeds of carbonates was laid down (Ashmore Reef-1, North Hibernia-1, Brown Gannet-1) in a restricted marine environment (Encl. 15a). Along the eastern margin (Yampi-1), a fluvio-deltaic environment resulted in deposition of a sand and shale sequence, which extended to the south as far as Barcoo-1 and Lynher-1 (Encl. 15a). In the Vulcan Sub-basin, a nearshore Middle Triassic sequence is overlain by a more marine Late Triassic interval.

6.4.3 Early-Middle Jurassic

The early Late Triassic tectonic episode elevated the basin margins and increased erosion, and accelerated the regression of the Triassic seas.

Significant uplift, accompanied by a series of faults and erosion during the Late Triassic/Early Jurassic, formed the NW-trending Rob Roy Graben, and most of the structural features in the Browse Basin. The Scott Reef Trend, Scott Reef Plateau, Ashmore Block and Vulcan Sub-basin were formed during this time.

This rifting system influenced sedimentation from the latest Triassic to the end of the Early Jurassic over much of the Browse Basin. This influence continued through to the Early Cretaceous. A stratigraphic break between the Late Triassic and the Early Jurassic along the southeastern flank of the basin (Yampi-1), and a change in depositional environments from marine to deltaic (Scott Reef-1) is evidence of structural uplift at this time.

Early to Middle Jurassic sediments are confined to the area between Prudhoe Terrace and the eastern flank of the Scott Plateau (Encl. 15b,c). A thick sequence of fluvio-deltaic to nearshore clastic sediments was deposited in the subsiding areas. These sediments are absent on the Ashmore Block, but to the south, they form a sequence of red to brown claystone and siltstone (Lombardina-1, Lynher-1), which could be correlated with similar sediments of Early-Middle Jurassic age in the Bonaparte Basin. The sequence in the Scott Reef area exhibits a greater marine influence (Encl. 15b,c).

In the extreme southern part of the Browse Basin and the Rowley Sub-basin, sedimentation continued almost uninterrupted (Lynher-1) from the Late Triassic to the Late Jurassic. The presence of basic lavas of Early Jurassic age in Yampi-1 may represent onset of rifting associated with tectonic activity. In contrast, lavas of Middle Jurassic age in Lombardina-1 and Ashmore Reef-1 are associated with continental breakup (Fig. 9). Reactivation of existing fault blocks took place in the Middle Jurassic, leading to a hiatus between the Middle and Late Jurassic sequence (Fig. 28). This hiatus is more pronounced on the eastern flank of the basin, and on the structural highs (Scott Reef-1, Lombardina-1, Yampi-1). This period of tectonic activity ended the deposition of the lower series (pre-breakup sequence).

The stratigraphy recorded in DSDP site 261 west of the Scott Plateau on the Argo Abyssal Plain indicates that separation of the Australian plate occurred at the end of the Middle Jurassic (Callovian) (Veevers and Heirtzler, 1974). Late Oxfordian sediments overlie oceanic pillow lavas near the western edge of the Scott Plateau, dating commencement of seafloor spreading at pre-Late Oxfordian. At the same time, similar rejuvenation of the Ashmore/Sahul Platforms, Dillon Ridge and Van Cloon High, with subsidence in the Cartier Trough and the Vulcan Graben, resulted in partial to complete erosion of Late Triassic to Middle Jurassic section from the highs (Anderdon-1, Puffin-1, Woodbine-1, North Hibernia-1), and infilling of grabens and troughs with marginal marine to deltaic sediments (Skua-1, East Swan-1, Swan-1).

6.4.4 Late Jurassic

Following breakup, the basin was subjected to a major marine transgression from the north-northwest, which led to the development of a large embayment. At the same time, the Vulcan and Cartier Troughs became a depocentre for Late Jurassic to Recent sediments (Encl. 15d). An increase in marine deposition upwards through the section is indicated by an increase in the clay/sand ratio, and in the microplankton population. A thick blanket of marine claystone and fine grained argillaceous sands was deposited extensively in the deeper part of the basin and in the Vulcan Graben (Swan-1, Scott Reef-1, Lombardina-1) at this time (Encl. 15d).

However, along the eastern and southern margins of the basin (Prudhoe-1, Yampi-1, Leveque-1, Lynher-1), coarse clastic sediments of nearshore to fluvio-deltaic facies were deposited (Encl. 15d). These sediments extend into the Early Neocomian, but the paucity of the wells along the Yampi Shelf hampers the accurate prediction of the distribution of the sandstones. The Ashmore Block and the southern part of the Londonderry High remained high during this time (Encl. 15d).

6.4.5 Cretaceous

Absence of Early Neocomian sediments in the basin in restricted areas may be due either to a regression, or to local uplift of the structures (e.g. Scott Reef-1, Lombardina-1, Buffon-1, and the eastern shelf area). Transgressive conditions, however, returned in the Late Neocomian, and extended on to the Yampi Shelf, where nearshore sandstones onlap Precambrian basement (Londonderry-1) (Fig. 29). The palaeontological evidence shows that marine conditions prevailed over the central basin and the Prudhoe Terrace during the Early Cretaceous, which resulted in deposition of shelf claystone, with minor interbeds of silt, sand and carbonates.

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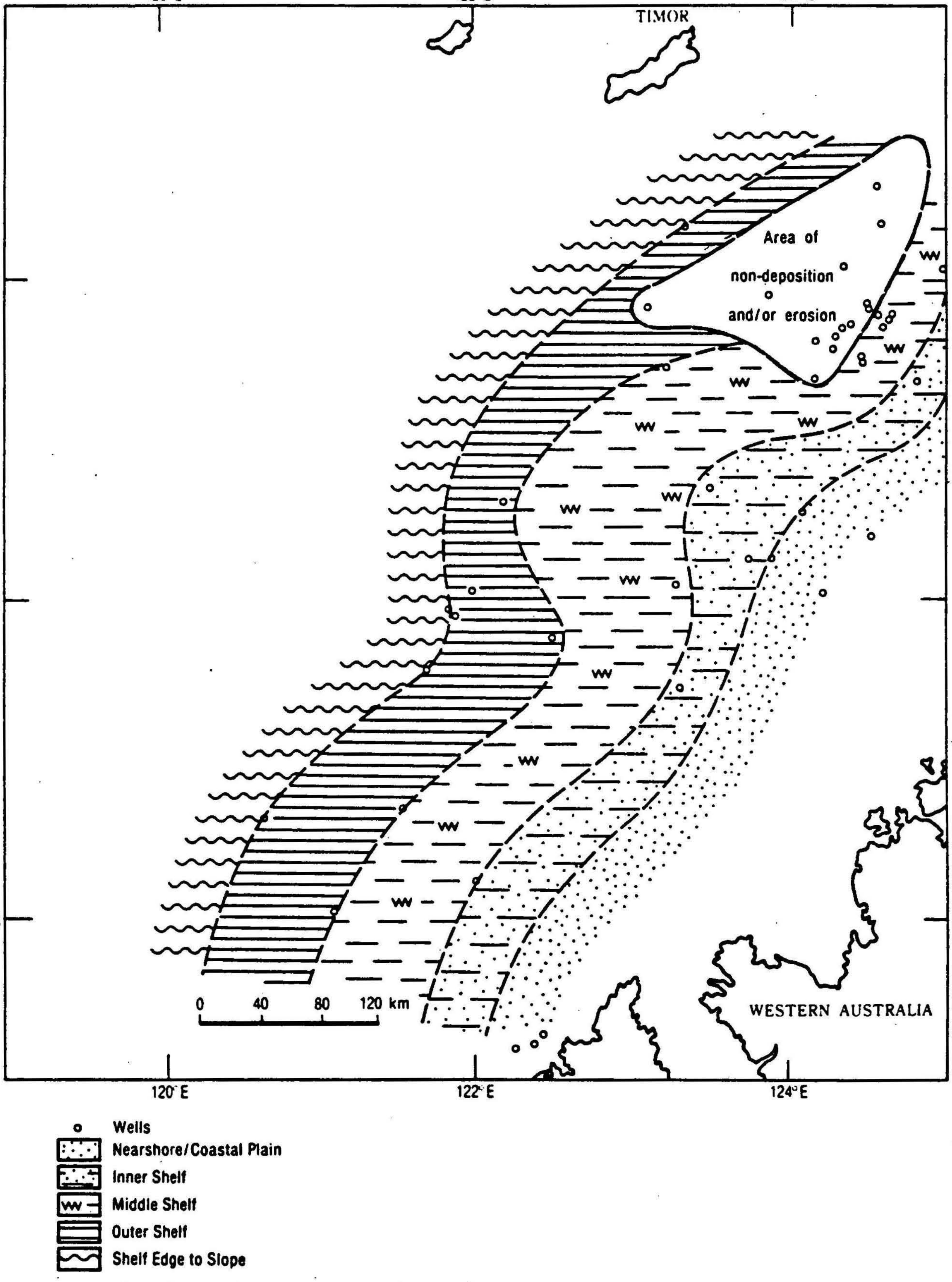

Browse Basin Palaeogeography
Early Cretaceous (Hauterivian-Aptian)

Figure 29

This transgression probably reached the southern part of the Vulcan Graben later during the Late Barremian, when fine grained clastics were laid down in East Swan-1, Swan-1 and Prion-1 (Fig. 29). Most of the Ashmore Block, and the horst blocks within the Vulcan Sub-basin, remained emergent during Early Cretaceous time, except the northwestern part (North Hibernia-1), which was partly inundated by the transgression.

By the Late Cretaceous, a marginal sag regime had been created, and the whole region was tilted westward. Full marine circulation spread over the area, with sedimentation changing from predominantly clastic to mainly carbonate in the western part of the basin (Fig. 30).

6.4.6 Tertiary

The Cretaceous and Cainozoic were generally times of tectonic stability. Sedimentary breaks in the stratigraphy throughout this time are the results of eustatic changes in sea level, and the regional tilting. Thick sandstones similar to those of the Late Cretaceous extend through the Eocene, along the eastern flank and southern central part of the basin. The sea retreated to the west during Oligocene time; this led to a stratigraphic break over most of the basin, except in the Scott Reef, Buffon, Lombardina and Barcoo areas.

The Late Tertiary was a period of basinwide carbonate sedimentation. A basal Miocene sandstone is succeeded by a prograding wedge of carbonate which reaches its maximum thickness near the outer edge of the shelf (over 2000m in the Scott Reef area).

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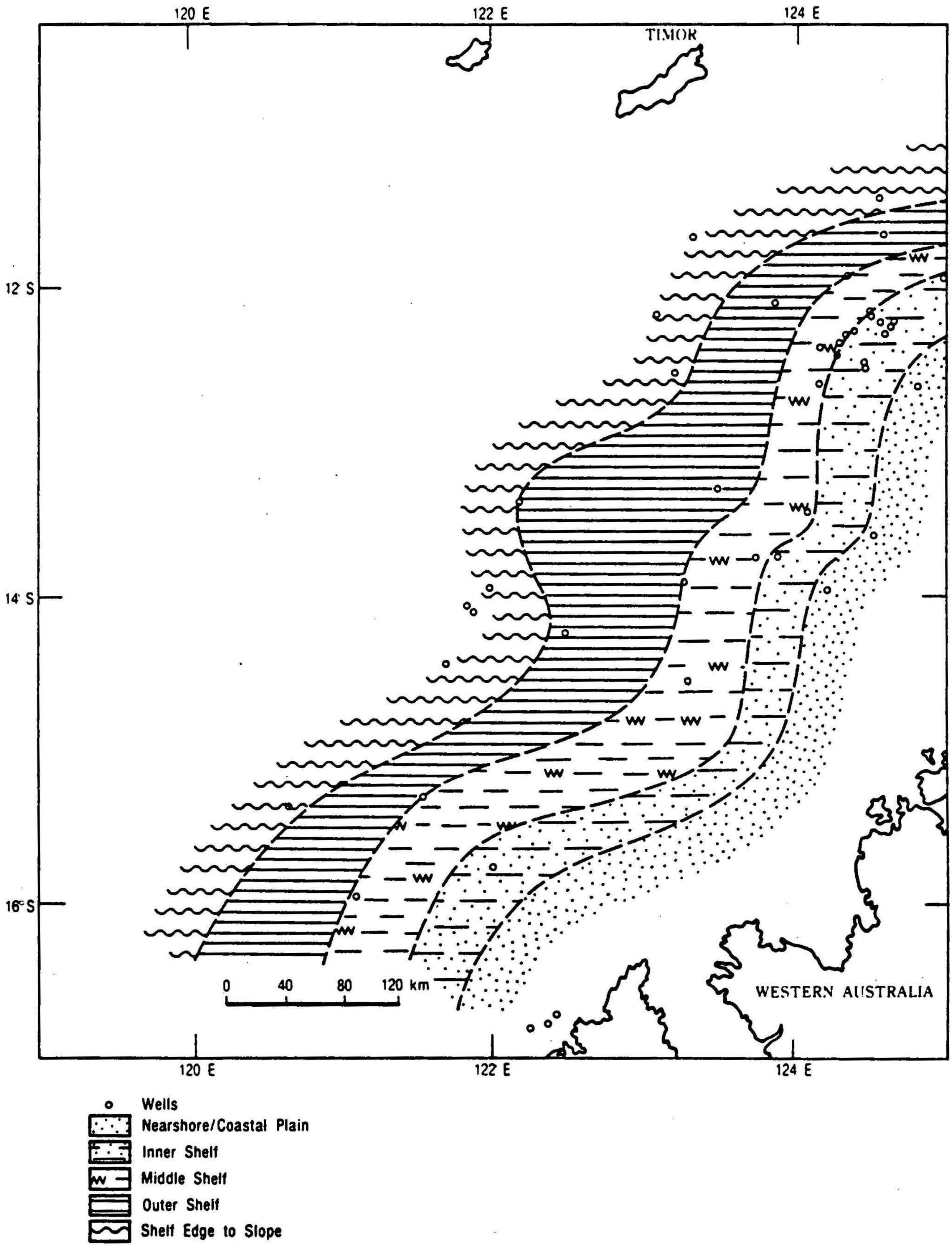


Browse Basin Palaeogeography
Late Cretaceous (Albian-Maastrichtian)

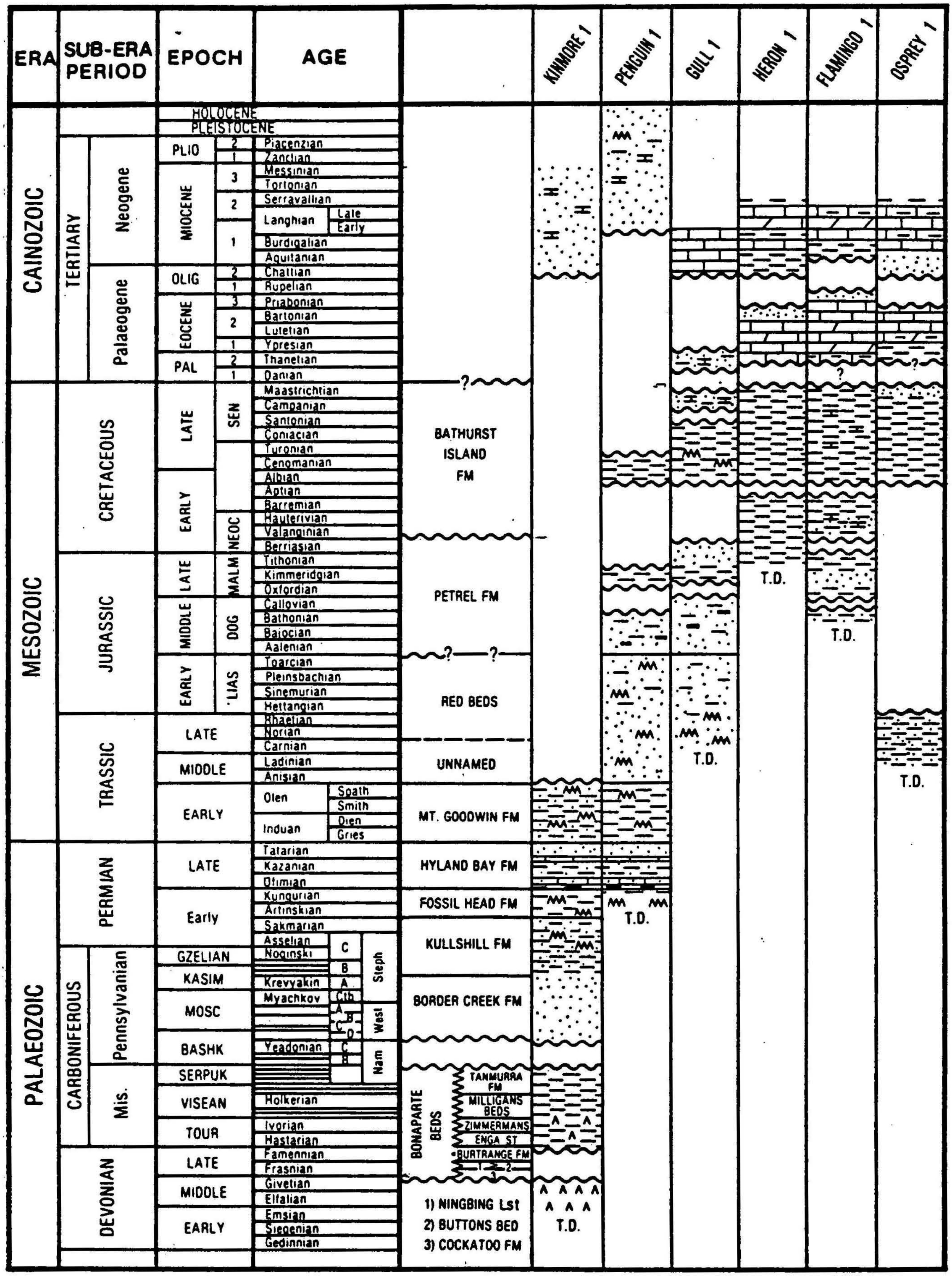
Figure 30

6.5 BONAPARTE BASIN

As with the other basins, the sedimentary history of the Bonaparte Basin has been prepared from interpretation of data in well completion reports and from published literature. Palaeogeographic maps (Encl. 16) and well correlations (Encl. 21) have been prepared to illustrate the history. The stratigraphic sequence which is used in this report is detailed in Figure 31. It follows the lithostratigraphy used in a number of publications, e.g. Laws and Brown (1973), with some exceptions.

Laws and Brown (1973) place the top of the Fossil Head Formation at the top of a widespread limestone, which is generally coincident with the Early-Late Permian boundary. In this study, both the transgressive shaly sequence, which usually underlies this limestone, and the limestone, have been included in the Hyland Bay Formation. The Fossil Head Formation is then distinguished from the overlying Hyland Bay Formation by its lithology and log characteristics. There is a change from an offshore marine shale at the base of the Hyland Bay Formation to the relatively thin, sandy beds underlain by a uniform silty carbonaceous shale of the Fossil Head Formation. A decrease in the gamma ray response and a slight increase in resistivity log is observed in the Fossil Head Formation. The Hyland Bay Formation has been divided into five members (Bhattia et al., 1984) which, in ascending order, are as follows: the basal member, H5 limestone member, Hay Member, H4 limestone member, and Tern member. The top of the Hyland Bay is characterised by a distinctive seismic reflector, resulting from the impedence contrast between the massive shale and siltstones of the basal Mount Goodwin Formation, and the calcareous sands in the uppermost part of the Hyland Bay Formation.

In many well completion reports, the Triassic section has been subdivided into three unnamed units. In this study, the Triassic sequence has been subdivided into two units, the Early Triassic Mount Goodwin Formation and the undifferentiated Middle-Late



Chronostratigraphic Chart, Bonaparte Basin — Figure 31

Triassic. The prodeltaic shales and claystones of the Early Triassic (Mount Goodwin Formation) can be easily differentiated from the overlying Middle to Late Triassic sequence by its distinctive log character and lithology. The Middle-Late Triassic sequence, which comprises the coarser clastic section, ranges in age from Rhaetian to Ladinian, and probably older. The upper part of this unit, in some wells, is composed of varicoloured sandstone, siltstone and shale. However, the red-bed characteristic of this unit diminishes with depth. The poor preservation of the spore, pollen and other macro and micro fauna throughout the Middle to Late Triassic section, hampers an accurate and reliable age determination. The Late Triassic sediments, however, are characterised by their varicoloured (usually red to brown) shale and clay content, which are thought to have been deposited in a continental environment with some paralic interludes. This facies extends into Early Jurassic time.

The Petrel Formation of Jurassic age has usually been informally subdivided into three members on the basis of age, lithology, depositional environment and the log characteristics. Study of the lithology, biostratigraphy and log characteristics of this formation in several wells in the Bonaparte Basin reveals that the lower member (Member 'C') in most parts of the basin is separated from the overlying two other members (Members 'B' and 'A') by a regional unconformity (breakup unconformity) of Callovian age. Although in this study Member 'C' has been included in the Petrel Formation, it is actually a different rock unit from the two upper members. Therefore, in strict stratigraphic usage, it should be treated as a different formation or rock unit, because its upper boundary is marked by an unconformity. It also has different facies characteristics, being deposited under a different depositional environment during the pre-breakup tectonic regime. However, it is beyond the scope of this study to redefine the stratigraphic units.

The upper part of the Petrel Formation (Member 'A') extends into the Early Neocomian (Cretaceous). This tripartite division of the Petrel Formation, distinct in the Petrel wells, is not recognizable northward toward the Malita Graben, the Sahul Syncline, the Vulcan Trough and in deeper parts of the basin, where the lithology becomes highly argillaceous.

6.5.1 Cambro-Ordovician

The Bonaparte Basin is one of several early Phanerozoic intracratonic basins preserved in the western two-thirds of the Australian continent. Its known history of sedimentation dates from the Early Cambrian, although in Proterozoic time, epeiric seas had already covered much of the northern and central portions of the continent. Basalts with interbedded tuffs and agglomerates of the Early Cambrian Antrim Plateau Volcanics mark the initial formation of the basin. The volcanics crop out along the southern basin margin. They are unconformably overlain by Late Cambrian to Early Ordovician clastics and carbonates, deposited in a shallow marine environment. The Cambro-Ordovician sediments crop out only on the northeastern flank of the Precambrian Kimberley Block. Uplift and the subsequent erosion of these deposits began in the Middle Ordovician.

6.5.2 Devonian

As few, if any, wells have penetrated the Devonian-Carboniferous section offshore, the geological history in that part of the basin is speculative. However, the onshore geology is well understood, and is discussed below.

Offshore, Kinmore-1, Pelican Island-1 and Sandpiper-1 were drilled in the southern part of the basin on seismically recognized piercement structures, and encountered salt. The age of the salt is tentatively determined as Early-Middle Devonian, although it could be older (Silurian). The original thickness is unknown, but from the seismic data, in excess of 3000m of salt can be inferred away from the diapirs. It is believed that the salt has laterally migrated from the centre of the basin towards the flanks. Hence, it created a higher gravity anomaly in the central part of the basin.

The Cockatoo Formation, which crops out in the southern part of the basin, is a thick clastic sequence. It was deposited as a result of a marine transgression and subsequent erosion of the basement fault blocks in Frasnian time. By Famennian time, a reef complex had developed on the shelfal area of the Kimberley and Sturt Blocks. A massive algal reef, with horizontally bedded back reef deposits (the Ningbing Limestone) formed along the outer margin of the shelf, while a dolomitic sandy facies (the Button Beds) developed in a more restricted environment closer to the shoreline. The reef growth was halted by uplift and subsequent erosion along the margin of the basin in the Early Tournaisian (Early Carboniferous).

Throughout the Late Devonian and Early Carboniferous, a thick shale and siltstone sequence (Bonaparte Beds) was deposited in deeper water beyond the shelf.

6.5.3 Carboniferous

While the Kimberley Block margin remained uplifted during most of the Early Carboniferous (Tournaisian), renewed cyclic carbonate and clastic sedimentation (Burt Range Formation and Zimmerman Sandstone) occurred in the extreme south of the basin. During Visean time, a thick sequence of shale and siltstone, with minor sandstone interbeds, was deposited over most of the southeastern Bonaparte Basin (the Milligans Beds). More than 2500m of this unit is faulted against the Sturt Block, suggesting the palaeoshoreline at this time was some distance to the east of the present basin limit. The final phase of sedimentation within the Early Carboniferous is represented by the Tanmurra Formation, which disconformably overlies the Milligans Beds. This formation, with an average thickness of 300m, grades from calcareous sands in the south to carbonates in the northeast.

Subsequent uplift and erosion of the basin flanks in the Middle Carboniferous resulted in widespread stripping of the Early Carboniferous sediments, which had been deposited beyond the present limit of the basin.

6.5.4 Late Carboniferous-Permian

The Middle Carboniferous hiatus was followed by a series of transgressional and regressional cycles from middle Late Carboniferous to Late Permian. This resulted in deposition of a sequence of deltaic to marine sediments, including the Kulshill, Fossil Head and Hyland Bay Formations. The Permian section thins toward the basin margin to the south, and over the Londonderry High and the Darwin Shelf. However,it thickens basinward, where it is present beyond the reach of the drill in the Sahul Syncline and the Malita Graben.

Deposition commenced with the lower sand member of the Kulshill Formation, which was laid down unconformably on the Early Carboniferous rocks as beach, barrier and bar sands, and gradually graded upward to channel and natural levee deposits. This continental environment continued into the earliest Permian, when sediments of a shale member were deposited in a low energy lacustrine environment. The presence of shale interbeds containing rounded to angular pebbles in this sequence suggests a glacial origin for this facies.

The continental environment, however, was replaced by a marine transgression during the middle Early Permian, which resulted in deposition of a predominantly sand sequence, with interbeds of thin limestones (greywacke member). By the late Early Permian, a prodeltaic environment followed the preceding marine transgression, resulting in deposition of the uniform silty carbonaceous shale of the Fossil Head Formation.

In Late Permian time, deposition continued with open marine shelfal argillaceous clastics and thin bedded limestones.

Subsidence and subsequent transgression resulted in deposition of thick shelf carbonate (H5 limestone member) in the northwest and north, gradually thinning southward toward the basin margin. While the carbonate deposition was continuing in the north and northwest, the rate of sediment influx exceeded the rate of subsidence in the Bonaparte Basin, and resulted in deposition of a coarsening upward cycle (Hay Member), in which prodelta shales grade upward into lenticular delta front sands. This formation thins out over the Sahul Platform (Troubadour-1) and is absent in Sunrise further to the northeast.

As the regression continued, lower delta plain shales and silts graded upward into upper delta plain and point bar complex facies (Encl. 16a). This member (Hay Member) constitutes the main clastic sequence of the Hyland Bay Formation, and thins out toward the Londonderry High (Sahul Platform) and the basin margins.

Rejuvenation of subsidence in the north and northwestern part of the basin (the Timor Trough) was accompanied by an increase in sea level, and resulted in deposition of the second shelfal carbonate horizon (H4 limestone member). Carbonate deposition was terminated in the Bonaparte Basin by progradation of the shoreline north and northwestward as far as the Tern and Petrel areas. This marked the culmination of the last Permian regressive phase. The result was deposition of shales and siltstones of a lower shore face facies, which are succeeded by an upper shore face sandy facies (Encl. 16a).

6.5.5 Triassic

Subsequent widespread marine transgression led to blanket claystone deposition (Mount Goodwin Formation) in the Early Triassic or latest Permian, conformably overlying the Permian sequence (Fig. 32). This formation is present on the Londonderry High and the Ashmore Block.

The sea retreated north and northwestward in the early Middle Triassic, and a variety of environments resulted, from shallow marine to a complex delta on the sites of the future Ashmore Block and the Bonaparte Basin respectively.

By Late Triassic time, the marine influence was more pronounced in the Ashmore Block and the northern part of the Bonaparte Basin. The central and southern parts of the Bonaparte Basin were more under the influence of continental environments, and a red bed sequence was deposited in a backshore to flood plain condition. This unit, which extends into the Early Jurassic, marks the culmination of the regressive phase. The Triassic sequence attenuates towards the basin margins, and has been completely eroded onshore to the south, and over the Van Diemen High.

6.5.6 Jurassic

The red bed sequence was followed in the Early Jurassic by fluviatile sand, with minor marine influence. This marine influence increased by Middle Jurassic time, when nearshore to deltaic environments resulted in deposition of a series of fine to coarse grained sandstone with shale interbeds (Member 'C') (Encl. 16b).

Following Middle Jurassic deposition, major tectonic activity, which was initiated in the Late Triassic, reached its culmination in the Callovian, and is represented by the breakup unconformity.

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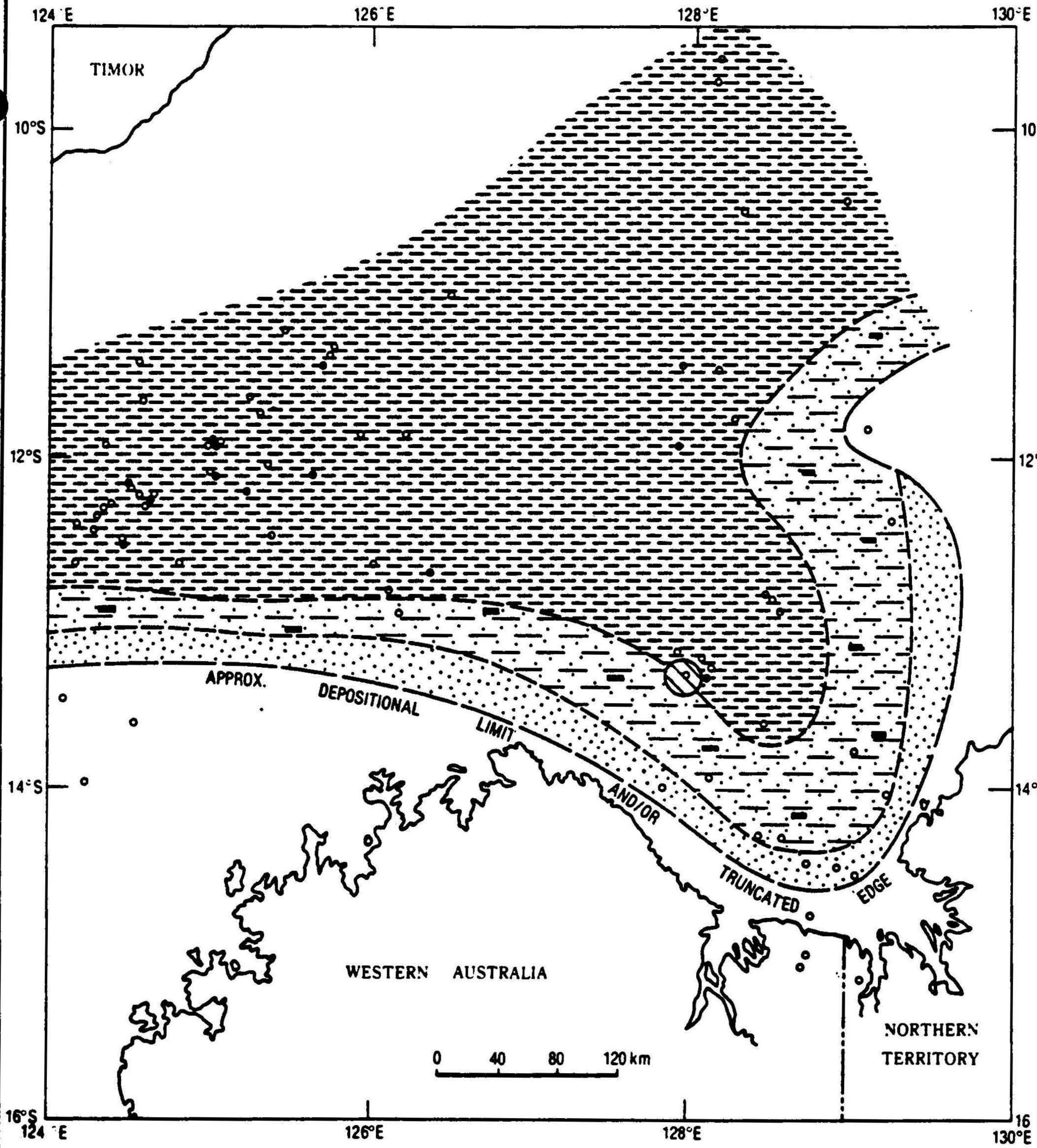

- Wells
- Prodelta/Marine
- Deltaic/Nearshore
- Postulated Fluvio-deltaic
- Uplifted and Eroded Areas

Bonaparte Basin Palaeogeography
Early Triassic (Mt. Goodwin Fm.)

Figure 32

As a consequence of this tensional stress, epeirogenic movements resulted in a series of NE-SW trending structural features, namely the Ashmore Block and the Sahul Platform being formed, and the Londonderry High was further faulted and uplifted. Late Triassic to Middle Jurassic sediments were partially removed from the highs, while the grabens and troughs became depocentres for Late Jurassic to Recent sediments.

The depositional hiatus, however, persisted for a longer period (to the Early Cretaceous) over the higher structural features, e.g. the eastern flank of the Londonderry High, the Sahul Platform, and the Van Diemen High. This resulted in partial or total removal of the Jurassic sediments from these areas (Encl. 16c). On the high areas, Cretaceous rocks unconformably overlie either the Triassic, or the Middle Jurassic (Member 'C' of the Petrel Formation) sequence. Marine conditions returned to most of the area in early Late Jurassic, and continued into Early Neocomian time. A massive sequence of shales and siltstones, with interbeds of sands (Members 'B' and 'A' of the Petrel Formation) filled troughs and grabens, while nearshore sands onlapped onto the relatively higher blocks (Encl. 16c). The highest uplifted blocks, however, were starved of sediments until at least the Late Neocomian.

6.5.7 Cretaceous

Deposition of the Petrel Formation ceased in the Early Neocomian, either due to a eustatic drop in the sea level and/or an epeirogenic uplift, which resulted in a regional break in deposition. This hiatus continued locally to the Aptian, and in some structurally higher areas such as the Van Diemen High, and the Londonderry High, it extends into Albian-Cenomanian time. A Late Neocomian marine transgression commenced with deposition of fine grained, glauconitic sands. In deeper parts of the basin, it is marked by radiolarian glauconitic shale, grading upward into open marine shale and carbonates (the Bathurst Island Formation) (Encl. 16d). This Cretaceous marine sequence provided blanket deposition over the most northwesterly shelf area. The facies became more arenaceous on palaeohighs, and more argillaceous and calcareous in troughs and northward towards the open marine shelf (Encl. 16d). The upper contact with Tertiary carbonates is conformable in the central basin, while along the marginal areas, a pronounced unconformity is evident. Deposition of the Late Cretaceous sequence virtually ceased along the east, south and southwestern margins, where there is marked thinning. This is probably due to a combination of erosion and non-deposition, resulting from initiation of a regional tilt during the Late Cretaceous.

6.5.8 Tertiary

The regional northward tilting, which was initiated in the Late Cretaceous, was accompanied by some movements along the older faults, and resulted in deposition of over 1000m of Tertiary sediments in the Sahul Syncline and the Malita Graben.

Carbonate deposition continued almost uninterrupted in the north, up to Late Eocene/Early Oligocene time. Consequently, the Miocene sequence was unconformably deposited over the Eocene or the Late Oligocene sediments. Towards the south in the Petrel Sub-basin, however, the Eocene sediments attenuate to zero thickness as a result of the northward tilt. In the southern area, a thick Miocene section unconformably overlies the Cretaceous sequence.

7. PREVIOUS EXPLORATION AND DEVELOPMENT

7.1 INTRODUCTION

The onshore discovery by West Australian Petroleum (WAPET) at Rough Range in 1953 stimulated exploration interest in the study area, and indeed throughout Australia. WAPET had been formed to operate licences originally acquired by Ampol in 1947. These permits covered all onshore prospective areas in Western Australia and also much of the offshore Carnarvon Basin. Following the Rough Range discovery, WAPET embarked on an exploration programme which made use of the numerous islands in the offshore Carnarvon Basin. Many stratigraphic holes were drilled, and the first exploration success was the Barrow-1 well in 1964, on Barrow Island.

By this time, a few other operators held very large licences which covered most of the continental shelf. Burmah Oil Company of Australia Ltd. (BOCAL) was operator for a group which held most of the northern Barrow and Dampier Sub-basins, the offshore Canning and the Browse Basins. These areas were originally granted to Woodside Oil in 1963. BOCAL and Shell farmed in after an initial aeromagnetic survey showed that a thick sedimentary sequence was present. First important successes for this group were the North Rankin-1 and Scott Reef-1 wells in 1971 (Table 1).

Arco and Australian Aquitaine were operators for groups which essentially held all the Bonaparte Basin and the adjoining Vulcan Sub-basin under licence. First successes for these groups were the Petrel and Tern gas discoveries in 1969 and 1971.

Not all of the successful wells listed above led to field developments. The Barrow oil field commenced production in 1967, peaked at 7150 kl/day (45,000 bbls/day) in 1970 and is currently producing some 2960 kl/day (18,600 bbls/day). Anticipated recoverable reserves are 41 million kl (258 million bbls).

TABLE 1

SUMMARY OF IDENTIFIED RECOVERABLE RESERVES AT 31 DECEMBER 1984

CARNARVON BASIN

(after Western Australia Mines Department)

	OIL (10^6kl)		GAS C_1+C_2 ($10^9 m^3$)		LPG C_3+C_4 (10^6kl)		CONDENSATE C_5+C_6 (10^6kl)	
	P1	P2	P1	P2	P1	P2	P1	P2
Producing Fields								
Barrow Island	8.33	8.95	-	10.97	0.05	0.05	-	0.38
North Rankin	-	-	221.70	275.10	15.80	18.20	19.20	22.10
TOTAL	8.33	8.95	221.70	286.07	15.85	18.25	19.20	22.48
Undeveloped Fields								
Angel	-	-	25.80	62.20	-	-	6.10	14.50
Chervil	0.58	0.58	-	-	-	-	-	-
Goodwyn	3.30	6.13	85.00	106.00	8.70	11.10	4.10	20.10
Gorgon	-	-	-	57.19	-	-	-	0.16
Central Gorgon	-	-	-	45.57	-	-	-	0.40
North Gorgon	-	-	-	130.34	-	-	-	1.66
Rankin	-	-	5.66	5.66	-	-	0.69	0.69
Harriet	1.68	1.68	-	-	-	-	-	-

	OIL $(10^6 kl)$		GAS C_1+C_2 $(10^9 m^3)$		LPG C_3+C_4 $(10^6 kl)$		CONDENSATE C_5+C_6 $(10^6 kl)$	
	P1	P2	P1	P2	P1	P2	P1	P2
North Herald	0.23	0.23	-	-	-	-	-	-
Scarborough	-	-	170.00	555.00	-	-	-	-
South Pepper	0.90	0.90	-	-	-	-	-	-
Spar	-	-	-	7.04	-	-	-	2.53
Tidepole	0.97	1.18	13.00	17.20	-	-	2.30	3.00
Tubridgi	-	-	2.14	2.16	-	-	-	-
West Tryal Rocks	-	-	-	80.73	-	-	-	3.93
Wilcox	-	-	54.40	91.20	-	-	-	-
TOTAL	7.66	10.70	356.00	1,160.29	8.70	11.10	13.19	46.97
TOTAL RESERVES	15.99	19.65	577.70	1,446.36	24.55	29.35	32.39	69.45

NOTES:

P1 probability 75%; P2 probability 25%.

C_1, C_2, C_3, C_4, C_5 and C_6 indicate methane, ethane, propane, butane, pentane and hexane respectively.

1 kilolitre (kl) = 6.2898 barrels; $1 m^3$ = 35.31 cu. ft.

The North Rankin field has been on production since mid-1984. It represents the first phase of the North West Shelf Project and is currently delivering gas to the West Australian domestic market at the rate of 7.3 MM CMPD (260 MM CFPD. Current plans call for the placement of a further two platforms to support LNG export to Japan, which is anticipated to commence in 1989. With estimated original gas in place of 310 x 10^9 CM (11 TCF), North Rankin is Australia's largest appraised gas-condensate field. It is linked to the mainland by a 102 cm (40") pipeline.

Petrel, Tern, Scott Reef and many other gas and gas/condensate discoveries remain undeveloped today despite having large volumes of hydrocarbons in place.

Two small oil fields have come onstream in the last few months, both made possible by comparatively inexpensive development schemes. The Harriet oil field is located in shallow water to the northeast of Barrow Island. Oil is being produced from three small platforms, with storage and shipping facilities located 8 kms distant on Lowendal Island. Harriet came onstream in March 1986. With estimated recoverable reserves of some 3.2 MM kl (20 MM bbls), it is currently producing over 1480 kl OPD (9300 BOPD).

The second small field, Jabiru, in the Vulcan Sub-basin, has a development system completely new to Australia. It is a one well field and produces through a sub-sea completion and moored column into a storage tanker permanently moored on location. Shuttle tankers periodically tranship the oil for export. Production commenced in mid-August. Daily production is currently 2200 kl OPD (13,800 BOPD) and estimated recoverable reserves have been quoted as of the order of 2.4 - 3.2 MM kl (15-20 MM bbls). The Challis field, located in the same permit area as Jabiru, and reported to be about twice as large as Jabiru, appears likely to be the next development in the area.

7.2 CARNARVON BASIN

Exploration drilling began just to the south of the study area in 1953, when WAPET drilled Rough Range-1. A flow of 87 kl OPD (550 BOPD) was recorded from the Cretaceous Birdrong Sandstone, but the find was subsequently proved by further drilling to be non-commercial at the time. The well was recently production tested at rates of 87 to 100 kl OPD (550 to 1000 BOPD).

Encouraged by the flow at Rough Range, WAPET undertook surface mapping of Barrow Island in 1954, 1956 and 1962. A small amount of aeromagnetics, gravity and seismic data was recorded, and Barrow-1 was drilled in 1964. A number of hydrocarbon zones were intersected, and the well was completed as a new field oil discovery in Late Jurassic sandstones (Dupuy Member). Further development drilling showed the initial discovery zones to be small and irregularly distributed, but the major, shallower Cretaceous (Windalia Sandstone) pool was discovered. More than 680 wells have now been drilled on the island, mostly into the Windalia Sandstone reservoir.

In 1963, the northern part of the Barrow-Dampier Sub-basin was granted to Woodside Oil N.L., joined in the following year by Shell and BOCAL. An aeromagnetic survey was recorded in 1963; seismic recording commenced the following year and has continued to the present day.

Between 1966 and 1968, WAPET carried out a programme of drilling stratigraphic wells on islands to provide control for future offshore drilling. The BMR carried out a regional gravity, magnetic and sparker survey in 1968. Offshore drilling commenced in June 1968 with the drilling of Legendre-1, which flowed oil from the Barrow Group sandstones. WAPET commenced offshore drilling in the southern Barrow Sub-basin in 1969.

The first well to be drilled on the Rankin Platform by the Woodside consortium was North Rankin-1 in 1971, a gas-condensate discovery. The early success rate was high, particularly in the north. By 1973, in addition to Legendre, the Eaglehawk oil find had been added to the Barrow Island discovery, while there had also been several gas discoveries.

Exploration drilling, which has continued to the present day, has resulted in numerous additional oil and gas discoveries. In the mid-1970's, reconnaissance seismic was recorded over the Exmouth Plateau, an area more than 200 km offshore, with water depths in excess of 1000m. The presence of large fault block structures similar to those on the Rankin Platform led to an increase in exploration activity. Large seismic programmes were recorded and a number of wells drilled. These resulted in several gas discoveries, e.g. Scarborough-1. Although gas volumes are very large, they are at present non-commercial because of the enormous development costs related to water depths and distance from shore.

The granting of permit areas to new joint venture consortia provided a further boost to exploration in the early 1980's. A string of oil discoveries have been made (Table 1); but only one, Harriet-Lenita, has been developed to date. Most of these later oil discoveries, which are generally reservoired in the Cretaceous Barrow Group, are fairly small.

Gas-condensate discoveries have continued to be made at a steady rate - generally on the Rankin Platform (Table 1). The most notable of these are the huge Gorgon-North Gorgon field(s) and the condensate-rich Wilcox and Goodwyn Main North (renamed Goodwyn-7) fields. The Goodwyn Main North well flowed 1.08 MM CMPD (38 MMCFPD) and 740 kl CPD (4670 BCPD) on test. Goodwyn-8 and 9 have confirmed the results of the No. 7 well. Newspaper reports quote Woodside spokesmen as estimating that there could be condensate reserves of 200 MM bbls in the Goodwyn Main North Field.

Approximately 140 exploration wells and many appraisal wells have been drilled to date. At the present time, only three fields have been developed, the giant North Rankin gas-condensate field and the Barrow Island and Harriet-Lenita oilfields.

Barrow Island currently produces 3,100 kl PD (18,600 BOPD) and Harriet/Lenita 1476 kl PD (9300 BOPD). Production at Harriet/Lenita may soon be increased to 2380 kl OPD (15,000 BOPD) by full utilisation of the two recently installed satellite platforms.

North Rankin produces 7.3 MM CMPD (260 MM CFD) and 1213 kl CPD (7640 BCPD) from seven wells for the domestic market. In 1985, the Woodside consortium committed to a liquefied natural gas (LNG) project. Construction of the LNG plant is in progress and deliveries are expected to begin in October, 1989. Sales agreements for 6 million tonnes of LNG per year have been finalized with a Japanese consortium. The LNG phase will require two additional platforms, with planned installation in 1989-1993 and 1997-2001. The location of the second new platform has yet to be decided. The very rich condensate yields from the northern part of the Goodwyn field have raised the possibility of a separate liquids scheme producing up to 15900 kl bbls (100,000 bbls) of oil and condensate per day.

A gas recycling plant is under construction on the existing North Rankin Platform, and is expected to be in operation early in 1987. Condensate production will be increased to 1900 kl PD (12,000 bbls PD) by processing additional gas, stripping the condensate and reinjecting the gas. Gas recyling is expected to increase the amount of condensate which can be recovered during the life of the field.

7.3 CANNING BASIN

The first well drilled in the offshore Canning was the Chirup-1 well in 1968. This was one of a series of stratigraphic tests drilled by WAPET on offshore islands. The first exploration well proper was Lacepede-1A which was drilled in 1970. Since that time, a further 12 wells have been drilled by various operators. This small number is a reflection of the lack of success, when compared to that enjoyed in the neighbouring Carnarvon and Browse Basins.

The only significant shows were logged in the Perindi-1 well, drilled by Esso in 1983. These shows occurred in the Permo-Carboniferous sediments; the well was drilled in a crestal position on a structure related to an igneous intrusion which had a significant, and relatively local, effect on host rock maturity.

7.4 BROWSE BASIN

The first offshore licences covering this basin were issued in 1964 to two consortia operated by Arco and BOCAL.

Over the next few years both aeromagnetic and seismic surveys were conducted. Following interpretation of these data, in October 1967 BOCAL spudded the Ashmore Reef-1, the first offshore well to be drilled off northwest Australia. The well was a structural/stratigraphic test of a very large anticlinal feature. It proved to be a dry hole and bottomed in Late Triassic sediments. A post mortem on the well cast doubts on the closure of the structure due to a surface velocity anomaly. This set the tone for the difficulties encountered in seismic interpretation in the area to the present day.

The first successful well was Scott Reef-1, also drilled by BOCAL, in 1971. It discovered a large gas/condensate accumulation which has not yet been developed. In 1972, Arco drilled the first successful oil well in the basin, Puffin-2. This tested better than 635 kl OPD (4000 BOPD) from a thin Cretaceous sand. Recoverable reserves proved to be small, however, and Puffin has not been developed.

The downturn in exploration in the late 1970's followed. This was accompanied by a re-evaluation of exploration philosophy for the area. From the earliest days, the biggest effort had been directed towards Cretaceous closures over older structural highs. Now comparisons were drawn with the successful North Sea exploration effort and it was recognised that the Browse, with the Vulcan Sub-basin, constituted a possible structural analogue. With the better quality seismic data which were now obtainable, Jurassic and Triassic targets were delineated in tilted fault blocks along the graben margins. Jabiru-1, drilled by BHP in late 1983 was successful proof of this new play concept. Although difficulties in mapping the reservoir horizons below an unconformity led to the subsequent drilling of two dry holes, the discovery well has been on production for some months and is currently producing some 2200 kl OPD (13,800 BOPD) from a Jurassic reservoir. Reference was made in Section 7.1 to the novel production scheme employed. While Jabiru proved to be a relatively small find, an estimated 2.4-3.2 MM kl (15-20 MM bbls) recoverable, it provided a necessary stimulant for the exploration effort. Challis-1, drilled in late 1984, also by BHP, discovered oil, reportedly in Triassic sandstones. Several appraisal wells have been successful and current reserves estimates are reportedly double those of Jabiru.

Although the exploration effort in the basin is currently at a low level, as it is worldwide, the successes of Jabiru and Challis should lead to the future discovery of other similar fields.

7.5 BONAPARTE BASIN

Following initial onshore regional work in the mid-1950's, the oil search moved offshore in 1960 when the BMR and the Scripps Institute of Oceanography conducted geological/geophysical surveys. Although onshore drilling proved disappointing, a number of oil companies applied for offshore licences. In 1964, licences which essentially covered the entire basin, were granted to two consortia operated by Arco and Australian Aquitaine.

Considerable amounts of seismic data were gathered over the next few years. From the interpretation of these data, a number of differing trap types were defined as exploration targets. These included salt-induced structures, basin margin pinchouts, tilted fault blocks and drape over basement highs, in addition to anticlinal, domal and faulted traps. Reservoirs ranging in age from Devonian to Cretaceous were thought to be present.

The first well, Lacrosse-1, was spudded in February 1969 by Arco. Qualified success was achieved by the second well, Petrel-1, later that year. This well, which was testing a large Permian anticline, blew out on penetrating a Hyland Bay Formation carbonate. In 1971, gas was also found in the large Tern structure. Successful appraisal wells have been drilled on both structures, proving up sizeable reserves, but to date they remain undeveloped. However, Aquitaine, present operators of the licences, have undertaken a feasibility study with the possibility of a development occurring in the 1990's.

To date, over 40 wells have been drilled in basin. Shows of oil and gas have been recorded from horizons of several ages, but commercial success has remained elusive. Currently the exploration effort is virtually at a standstill due to the depressed world crude oil price.

GEOCHEMISTRY

GEOCHEMISTRY

8. GEOCHEMISTRY OBJECTIVES AND INTERPRETIVE METHODS

8.1 GEOCHEMISTRY OBJECTIVES

The Northwest Shelf is a major hydrocarbon province with very large proven gas/condensate reserves and significant oil reserves. Giant and very large gas condensate fields occur in the Carnarvon Basin, together with one large (Barrow Island) and several smaller oil fields. The Browse Basin contains 2 small oil fields and several gas discoveries, while two very large gas fields have been found in the Bonaparte Basin. To date, no hydrocarbon discoveries have been made in the offshore Canning Basin, although several small oil fields have been found in the onshore part of the basin.

The scope and objectives of this regional geochemical study have been influenced by the published information on, and the current perception of, potential source rocks in the various basins. These factors vary for each of the basins, so that the problems requiring clarification vary from one basin to another.

In the past 10-12 years, a number of authors have interpreted geochemical data to identify potential source rocks in the northern Carnarvon Basin. The conclusions of most of the main workers are summarised in Table 2.

TABLE 2 - SUMMARY OF PREVIOUS GEOCHEMISTRY RESULTS, CARNARVON BASIN

Author	Year	Formation	Source Area	Oil or Gas Source
Thomas & Smith	1974	Jurassic Shales Cretaceous shales Triassic shales	Barrow & Dampier	Gas Oil Gas
Powell	1975	Late Jurassic	Between Rankin Platform and Dampier-Madeline Trend	Gas
		Cretaceous	Northern part Rankin Trend	Oil
Meath & Bird	1976	Middle & Late Jurassic	Barrow Sub-Basin	West Tryal Rocks gas
Woodhouse	1976	Early Cretaceous shales	Lewis Trough, Victoria Syncline	Oil
Crostella & Chaney	1978	Triassic-Early Cretaceous Jurassic most important	Dampier Sub-basin Lewis Trough	Good gas, fair oil
RRI	1979	Triassic-Middle Jurassic	Rankin Platform	Fair gas
		Late Jurassic	Dampier Sub-basin	Oil
		Cretaceous	Rankin Platform	Gas
Brikke	1982	Locker Shale	Rankin Platform	Rankin Plat. gas
		Jurassic	Lewis Trough	Oil
Barber	1982	Early-Late Triassic	Exmouth Plateau	Gas
		Late Jurassic	Exmouth Plateau	Oil
Philp et al.	1982	Inferred Late Jurassic	Barrow Island area	Oil
Volkman et al.	1983	Dingo Claystone	Barrow Depocentre	Oil
Kopsen & McGann	1985	Dingo Claystone	Lowendal Syncline	Oil
Cook et al.	1985	Mungaroo Fm.	Exmouth Plateau	Oil

The table indicates that since 1974, the Jurassic shales (Dingo Claystone) have generally been considered as the main source rock for the hydrocarbons of the northern Carnarvon Basin. However, there has been a variety of opinions as to the kitchen areas, although this may be related to the part of the Carnarvon Basin being reviewed in the various papers. The earlier reports tended to regard the Jurassic shales as gas-prone but since 1982, they have been interpreted as having potential for oil generation. At the same time the Cretaceous shales which were originally considered to have oil source potential, had not been interpreted as potential source rocks.

This was mainly due to an evolving consensus that many of the oils have been biodegraded (Alexander et al., 1983). The napthenic and anomatic oils of the eastern side of the basin (Barrow Island area) were originally interpreted by many workers as having been derived from an immature Cretaceous source. Their character is now believed to be a result of several stages of biodegradation of a mature paraffinic crude, very similar to that reservoired within the Jurassic at Barrow Island.

The Triassic Locker Shale and the Mangaroo Formation were considered in some papers as having gas potential but Cook et al. (1985) recognised oil potential on the Exmouth Plateau. Minor amounts of highly biodegraded oil found in many Rankin Platform liquid hydrocarbons indicate early oil generation from the Locker Shale and possibly the Mungaroo Formation.

The objectives of this study for the Carnarvon Basin were to determine the regional extent of the recognised source rocks, to identify, if possible, other potential source rocks not recognised in the literature and to determine oil-source correlations.

In the Browse Basin, oil discoveries have been made in the vicinity of the Vulcan Graben, with gas discoveries elsewhere in the basin. Few papers have been published on the source potential of the Browse Basin, although a reasonable amount of analytical data is publicly available. The identification of oil-prone source rocks in the Vulcan Sub-basin was a primary objective in this study. An attempt was then made to identify this source rock elsewhere in the basin. Some oil-source correlation was attempted but samples from only 3 Browse Basin wells were available.

No commercial oil discoveries have been made in the Bonaparte Basin, although the Tern and Petrel gas fields and the smaller Troubadour and Sunrise occurrences have been found. Again, little published information exists on source potential, although some analytical data are available. An objective in this basin was to identify good oil source rocks or, if none appears to be present, to explain their absence geologically and/or geochemically.

8.2 MATURITY INTERPRETATIVE METHODS

Organic matter in sedimentary rocks changes in composition during burial by the release of gaseous and liquid products. The amount of change in the composition of the organic matter is referred to as its maturity. During the earliest (immature) stage, water and carbon dioxide are released abruptly and liquid hydrocarbons begin to be liberated from suitable kerogen. This point marks the beginning of the mature stage. Eventually, the organic matter releases mainly gaseous hydrocarbons, marking the end of the mature stage and the beginning of the post-mature phase.

Maturity has been determined in this report using vitrinite reflectivity and spore colour index. The Robertson Research group prefers to use spore colour index rather than vitrinite reflectivity for determination of oil source rock maturity for several reasons:

1. Spore colour index is a numerical system for grading colour changes in sporopollenin, and sporopollenin is chemically very similar to oil-generating Type I and II kerogens, whereas vitrinite is a Type III gas-sourcing kerogen.

2. Vitrinite reflectivity and spore colour index measure quite different properties which are related to the combined effects of time and temperature. At unconformities, there is significantly different behaviour of these properties. During uplift, the increase in spore colour index ceases and does not restart until the maximum depth of burial is exceeded. However, vitrinite reflectivity continues to increase when the section is cooled during uplift and during renewed subsidence to the previous depth of burial. Unconformities are therefore marked by a difference in values of reflectance immediately above and below the unconformity, a difference that is preserved during subsidence.

   This phenomenon results in the vitrinite reflectance method predicting a higher level of maturity below unconformities than the spore colour method.

3. Vitrinite is a group name for several different macerals, each of which has different reflectance properties and therefore different reflectance measurements at any given depth. Although an experienced operator can recognise the different macerals, and measure only one in particular, misidentification of different vitrinite types does introduce scatter into the data, making the reflectance gradient less accurate.

4. The effects of reworking and caving of sporomorphs is more easily recognised than with vitrinite, for a microscopist with palynological experience.

Vitrinite reflectivity is used as a check on spore colour, and becomes of particular importance in determining the maturity and likely composition of the generated gas of both gas-prone organic matter types, i.e. vitrinite and post mature oil-prone organic matter.

Table 3 shows the relationship between temperature, SCI and Ro, and the hydrocarbon products at different maturity levels.

8.2.1 Spore Colour Index (SCI)

SCI measurements have been made on samples at approximately 300m intervals in suitable argillaceous lithologies. Values have been plotted, as well as depth profiles, through which best fit lines have been drawn.

Values of spore colour gradient correlate very well with present day geothermal gradients, and indicate an equivalence of 22°C to one spore colour index unit over the range SCI 1.0 to SCI 8.0. This equivalence is the same as determined in other basins with Mesozoic through Tertiary subsidence. It is therefore possible to use temperature gradients to determine the level of maturity of sections at their maximum temperature and to identify changes in temperature gradient which may have occurred before and after recent uplift. If sections have not continuously undergone periods of subsidence and have remained relatively static, spore colour indices change slowly at the rate of about 10% per 100 my.

The initial spore colour value used for determining spore colour gradients and amounts of section missing at surface is related to sea bed temperature; it has been placed relative to a scale of 1 SCI unit at 15°C, to 1.5 SCI units at 26°C.

TABLE 3

COMPARISON SCI AND Ro VALUES

Zone	Maximum Temperature °C	Spore Colour Index	Vitrinite Reflectance %	Likely Hydrocarbon Product
Im-mature	70	Up to 3.5	0.20-0.35	Biogenic, very dry gas, mostly methane
Early mature	105	3.5-5.0	0.35-0.50	Oils of API° gravity 30-35. Significant oil expulsion from source rocks takes place only if they are exceptionally organically rich in mostly oil-prone kerogens.
Middle mature	150	5.0-7.0	0.50-0.75	Main zone of generation of oils of API° gravity 35-45. Source rocks of average quality and thickness produce sufficient oil for effective migration.
Late mature	200	7.0-8.5	0.75-1.30	Light oil and condensate of API gravity 45-55 are generated.
Post mature	300	8.5-10.0	1.30-3.00	Gas is generated from gas and oil-prone source rocks. Oils present in reservoirs are flushed by migrating gas.

8.2.2 Vitrinite Reflectivity, Ro

Measurements of Ro have been made at approximately 300m intervals. The data for each sample have been analysed for the presence of reworked and caved populations, and the resulting averaged values of in situ vitrinite plotted on depth profiles, which also contain stratigraphic information. Best fit lines through the data points have been drawn between unconformities. Apart from being a check on spore colour, vitrinite reflectivity profiles through well sections can also be used to demonstrate the presence of faults and unconformities. Additionally, where vitrinite reflectivities best fit lines do not extrapolate back to R_o 0.18% to 0.20% at seabed or ground surface depth, the interpreted amount of missing section is an aggregate of the amounts of missing section at each unconformity in that well, above ground or sea level. In contrast, spore colour indicates only the amount of uplift since maximum temperature was reached (generally at maximum depth of burial).

Information on amount of uplift is useful in plotting the temperature history of source rocks and therefore in thermal modelling.

8.3 GEOTHERMAL GRADIENTS

Geothermal gradients for wells in the study area have been determined using bottomhole temperatures measured on logging runs and during drill stem tests. These values have been corrected using the method of Carstens and Finstad (1981) where stopped circulation times are known, or by using the AAPG correction curve where stopped circulation times are unknown. In detail, neither of these methods gives an accurate derivation of the true formation temperatures. However, in the absence of better correction methods, these have been used to maintain consistency in the geothermal gradients. Seabed temperatures have been calculated by assuming a surface temperature of 26°C and a decrease in sea temperature with depth of 0.046°C/m to a minimum of 5°C at 450m water depth.

8.4 SOURCE ROCK INTERPRETIVE METHODS

Source rocks in this study include shales, siltstones and coals, but not limestones or calcareous shales. Their environments of deposition range from upper delta plain through lower delta plain and delta front to deep water shales interbedded with turbidites. Their potential is constrained by thickness and by quality so that thin, rich source rocks such as coals, as well as thick, poor quality shale sources, have been evaluated on a comparative basis.

During the study, samples were chosen on the basis of lithology, E-log character and published information. After preliminary analyses and compilations, which were issued as interim reports, further analyses were carried out on the most promising sections in wells already analysed (e.g. Withnell-1) and wells with sections of interest not previously analysed (e.g. Kinmore-1).

The interpretation of pyrolysis data gives estimates of the amounts of algal sapropel (Type 1), exinitic or waxy sapropel (Type II), vitrinite (Type III) and inertinite (Type IV). Where a suite of analyses is available for a well section of interest, they are averaged. In order to compare well sections of a source rock which are at different levels of maturity, kerogen abundances are adjusted to a common base level, SCI 3.5, the adjustments being significant for the sapropelic components.

The abundances of kerogen types always show the presence of inertinite and therefore discrimination between different kerogen types is made by recognising an inertinite facies, only if inertinite is 51% or greater of the kerogen. For lower values of inertinite content, the kerogen facies is allocated to the most abundant kerogen type other than inertinite. Mapping of kerogen facies demonstrates the relations between kerogen facies and lithofacies and the trends and controls on organic sedimentation.

8.5 MIGRATION

Although significant amounts of oil may be generated, the amount of oil which can migrate from the immediate area of the generating source rock is limited by several factors which relate to both primary and secondary migration.

Primary migration is the movement of hydrocarbons out of fine grained, carbonaceous source rocks into non-carbonaceous, coarse grained aquifers. The oil-generating, amorphous kerogen of a good quality source rock is present as a partial coating on the mineral grains, so that pore spaces and pore throats have a significant surface area which is preferentially oil-wet when oil generation begins. In such cases, there is minimal surface tension barrier to oil migration. In poor quality source rocks, which are so common in the Carnarvon Basin, less amorphous kerogen is present and the surface tension barrier more effective, so that oil must accumulate in the pore space until it reaches a critical volume fraction. Calculations made by Robertson Research suggest that a minimum of 3000 ppm (w/w) of amorphous kerogen must be present in humic source rocks before oil generation leads to successful primary migration within the oil window. Otherwise oil is released as gas condensate in the post mature zone.

Secondary migration is the passage of oil through an aquifer under the influence of its own buoyancy. In forming a migration path, a measurable amount of oil is absorbed. If the aquifer is a clean sandstone with 10% porosity and the migration path occupies a vertical thickness of 3m with oil saturation at 50%, the amount of oil used up in forming a migration path is 1 million bbls oil/km^2. This becomes important when the source rock unit is a thick shale sequence with occasional sandstone interbeds. Although each sandstone will facilitate the drainage of the source rock, they will also each absorb 1 million bbls/km^2 of oil and the aggregate effect may be a significant limiting factor in the amount of oil available for migration beyond the oil generating zone.

The productivity of some of the better source rocks has been calculated in an attempt to quantify the amount of oil generated. It is calculated by the equation P = 480 f.c.m.t., where P is productivity in barrels of oil generated by source rock in reaching its present level of maturity; f is fraction of oil-generating kerogen in total kerogen; c is fraction of organic carbon in source rock (i.e. TOC/100); m is maturity function giving amount of oil (w/w) liberated per unit weight of residual oil-generating kerogen for maturity level reached, from tables; and t is thickness of source rock unit in metres.

9. NORTHERN CARNARVON BASIN

9.1 SOURCE ROCKS

Samples from 31 wells have been analysed for source potential in this study. Data from an additional 13 wells, either from the 1979 Robertson Research study, or from other open file reports, have been integrated in this project. Samples range in age from Permian to Tertiary. The source rock intervals identified in this study are sumarised in Table 4. Full results are included in Volume 2.

9.1.1 Pre-Triassic

No well samples older than the Permian have been analysed. Permian samples in Flinders Shoal-1 (Byro Group) and Sholl-1 (Kennedy Group and Byro Group) contain dark, carbonaceous shales within marine sandstone and siltstone sequences. The high level of maturity in Flinders Shoal-1 obscures the original composition of the kerogen, but organic carbon contents of around 2% suggest that there may have been some oil potential. The middle to late mature samples in Sholl-1 reveal that shales in the Kennedy and Byro Groups have organic carbon contents of 1 to 2%, but with only a minor component of oil- generating kerogen. It is possible that thickness and frequency of shales and their richness in oil-generating kerogen increases to the north and west away from the basin edge. However, in that direction, Permian source rocks will be over mature and would have entered the gas zone by the end of the Triassic.

9.1.2 Locker Shale

Where it has been penetrated to date, the Locker Shale consists of a sequence of shallow water shales and siltstones. However, seismic evidence suggests that it may pass rapidly northwestwards into a deep water facies beneath the Barrow-Dampier Basin (Encl. 13a). The shales are poorly carbonaceous and inertinitic in

TABLE 4

SUMMARY OF SOURCE ROCKS NORTHERN CARNARVON BASIN

WELL	DEPTH Interval (m)	AGE/FORMATION	LITHOLOGY	SCI	NET THICKNESS (m)	GHC PPM	OOGC PPM	AV TOC	ORIGINAL KEROGEN COMPOSITION				PRODUCTIVITY Bbls/km^2 (x10^6)	POTENTIAL Bbls/km^2 (x10^6)
									V	I	W	S		
Anchor-1	1945-2064	Upper Dingo Claystone; Dupuy Sat Mbr	Mudstone, medium-dark grey	5.5	100	1012	1960	1.45	50	35	15		1.730	3.384
	2317-2454	Upper Dingo Claystone	Mudstone, dark yellow brown, medium-light grey	6.25	130	2286	3352	1.44	60	30	30		5.138	7.533
Angel-2	3168-3296	Learmonth Fm	Thin Coals	5.0	8	193223	388235	61	10	30	20	40	26.725	5.370
	3454-3500	Learmonth Fm	Mudstone, medium-dark grey	5.0	18	3852	8309	4.1	10	60	20	10	1.186	2.569
	3930-4397	Learmonth Fm and Lower Dingo Clyst	Mudstone, medium to dark grey, dark grey	6.0	200	4006	6550	3.28	35	35	30		13.832	22.650
Bowers-1	2760-2820	Muderong Shale	Mudstone, olive grey	7.25	75	7711	8690	3.02	20	45	35		10.003	11.115
	3131-3106	Middle Dingo Claystone	Mudstone, medium-dark grey	VR 1.35%	175	-	-	2.06	50	50				
	3906-4300	Mungaroo Fm	Mudstone, medium-dark grey & thin coals	VR 1.65	142 (mdst) 3 (coal)	-	-	1.94 (mdst) 36.07 (coal)	50 50	50 50				
Brigadier-1	3885-3865	Brigadier Beds	Mudstone, medium-light grey	5.5	7	3550	6362	3.11	35	40	25		0.420	0.766
	4040-4050	Mungaroo Fm	Mudstone, light to very light grey	5.75	9	3640	6350	2.61	25	40	35		0.543	0.988
	4155-4165	Mungaroo Fm	Mudstone, dark grey, carbonaceous	5.75	3	4500	7870	6.46	30	50	20		0.222	0.395
Cape Range-2	1989-2258	Middle Dingo Claystone	Mudstone, medium to dark grey	6.0	260	4111	5918	1.86	65	15	20	10	18.480	26.602
Depuch-1	2587-3070	Learmonth Fm	Mudstone, medium-dark grey	5.0	100	7777	19425	7.1	10	45	35	10	21.118	46.930
	3210-3365	Learmonth Fm	Mudstone, medium-dark grey	5.5	45	10206	19764	7.73	25	30	30	15	2.274	3.211
	3470-3740	Learmonth Fm	Mudstone, dark grey-black	6.0	72	3740	6116	4.74	30	35	20	15	11.683	16.401

Table 4 Continued...

WELL	DEPTH Interval (m)	AGE/FORMATION	LITHOLOGY	SCI	NET THICKNESS (m)	GHC PPM	OOGC PPM	AV TOC	ORIGINAL KEROGEN COMPOSITION				PRODUCTIVITY Bbls/km^2 (x10^6)	POTENTIAL Bbls/km^2 (x10^6)
									V	I	W	S		
Depuch-1 (Cont'd).	4180-4300	Middle Dingo Claystone	Mudstone, dark grey-black	6.25	17	27090	39990	5.26	15	15	70		7.953	11.757
	2570-4300	Learmonth and Middle Dingo Claystone	Thin coals	5.5 (Av.)	44	44800	63000	44.47	10	50	30	10	90.106	156.425
Flag-1	1763.5-2143	Muderong Shale	Mudstone, medium-dark grey	4.5	300	1143	3837	2.35	30	45	25		5.928	19.908
	2210-2567	Barrow Gp	Mudstone, medium-dark grey, medium to light grey	5.0	120	3372	5566	3.68	20	50	25	5	6.990	15.734
	3293-3803	Upper Dingo Claystone	Mudstone, medium grey, medium-dark grey	6.75	500	6669	8281	2.21	20	35	45		57.650	71.605
Flinders Shoal-1	3305-3390	Byro Gp?	Mudstone, medium-dark grey, dark grey		85	?	?	2.95	?	?	?	?		
Hermite-1	2975-2985	Locker Shale Eqv.	Mudstone, light grey	6.25	10?	2430	3766	2.31	45	35	20		0.420	0.642
Koolinda-1	2530-2950	Upper and Middle Dingo Claystone	Mudstone, light olive grey	7.0	350	3140	3700	1.66	20	50	30		18.994	22.378
	3305-3485	Middle and Lower Dingo Claystone	Mudstone, light-olive grey	7.75	150	3600	3700	1.43	15	50	35		9.337	9.584
Lambert-1	3665-3700	Lower Dingo Claystone	Mudstone, light-medium grey	5.75	19	2240	3920	1.2	30	25	45		0.716	1.288
Lowendal-1	3222-3333	Mungaroo Fm	Mudstone, medium-dark grey	6.25	53	4668	6847	3.15	30	50	20		4.273	6.175
Pepper-1	1945-2058	Barrow Gp	Mudstone, light olive grey	5.25	60	980	2140	1.47	35	50	15		1.013	2.198
	2607-2616	Upper Dingo Claystone: Dupuy Sat Mbr	Mudstone, medium grey	6.5	9	1550	2080	1.22	55	20	25		0.222	0.323
Picard-1	2588-2942	Learmonth Fm	Mudstone, medium-dark grey and thin coals	4.75 (mdst)	91	2400	6697	4.13	30	50	20		3.779	10.497
	3256-3860	Learmonth Fm and Lower Dingo Claystone	Mudstone, medium-dark grey with thin coals	5.75	220	5142	8981	4.94	25	45	30		19.562	34.160

Table 4 Continued ...

WELL	DEPTH Interval (m)	AGE/FORMATION	LITHOLOGY	SCI	NET THICKNESS (m)	GHC PPM	OOGC PPM	AV TOC	ORIGINAL KEROGEN COMPOSITION				PRODUCTIVITY Bbls/km^2 (x10^6)	POTENTIAL Bbls/km^2 (x10^6)
									V	I	W	S		
Rosemary-1	2504-2762	Upper Dingo Claystone	Mudstone, light olive grey, medium-dark grey	4.0	220	377	2345	1.95	30	55	15		0.568	8.092
	3515-3567	Learmonth Fm	Mudstone, medium-dark grey, grey black	5.25	22	2950	6362	4.15	30	45	25		1.111	2.421
	3707-3774	Learmonth Fm	Mudstone, medium-dark grey	6.0	6	3100	5067	4.64	10	45	35		0.766	1.235
Sandy Point-1	2686-2950	Learmonth Fm and Brigadier Beds	Thin coals	6.75	7	290550	360750	78.00	?	?	?		35.173	43.669
Sholl-1	793-806	Locker Shale	Mudstone, medium grey	5.75?	?	2550	4452	1.03	?	?	?			
	854-869	Kennedy Gp	Mudstone, medium	5.75?	?	1428	2500	1.40	?	?	?			
	1159-1174	Byro Gp	Mudstone, medium grey	6.0?	?	2117	3554	1.04	?	?	?			
Spar-1	2530-2595	Muderong Shale	Mudstone, medium grey	5.0	65	1370	3420	2.38	45	35	20		1.531	3.829
	3135-3360	Barrow Gp	Mudstone, olive grey	6.0	230	3380	5490	2.12	45	20	35		13.437	21.835
Tryal Rocks-1	2503-2826	Muderong Shale	Mudstone, light-medium grey	6.25	300	6116	9029	2.33	40	20	40		31.616	46.683
	3509-3696	Upper Dingo Claystone	Mudstone, medium-grey, yellow grey	7.25	150	5438	5500	1.97	35	25	40		14.079	14.079
West Barrow-2	2341-2476	Muderong Shale	Mudstone, medium-grey, medium dark grey	5.5	?	2512	4397	1.85	35	35	25	5	?	?
	3016-3157	Barrow Gp Unit 'B'	Mudstone, medium-dark grey, siltstone brown grey-medium dark grey	7.0	?	3769	4438	1.08	10	45	45		?	?
	3220-3340	Barrow Gp Unit 'B'	Mudstone, yellow grey	7.25	?	3893	4388	1.00	15	40	45		?	?

Table 4 Continued...

WELL	DEPTH Interval (m)	AGE/FORMATION	LITHOLOGY	SCI	NET THICKNESS (m)	GHC PPM	OOGC PPM	AV TOC	ORIGINAL KEROGEN COMPOSITION				PRODUCTIVITY Bbls/km^2 (x10^6)	POTENTIAL Bbls/km^2 (x10^6)
									V	I	W	S		
West Muiron-2	1880-2000	Upper Dingo Claystone	Mudstone, pale yellow brown	3.75	120	0	2248	1.97	45	35	20		0	4.644
	2760-3000	Lower Dingo Claystone	Mudstone, medium-light grey	5.75	240	1160	2020	1.52	45	45	10		4.816	8.373
West Tryal Rocks-1	3264-3613	Mungaroo Fm	Mudstone, dark grey	5.5	112	3118	5469	2.54	35	40	20	5	6.027	10.596
	3787-3845	Mungaroo Fm	Mudstone, dark grey, black	6.0	7	31118	49186	12.73	20	40	AW 40		3.754	5.088
	3445-3491	Mungaroo Fm	Thin coals	5.5	8	67405	131699	31.05	20	35	AW 45		9.312	18.204
Withnell-1	2615-2710	Barrow Gp	Mudstone, olive grey	5.25	80	1962	4184	3.20	35	40	20		2.668	5.780
	2910-3720	Upper Dingo Claystone	Mudstone, medium grey-dark grey	6.25	700	2112	3112	1.44	30	40	30		25.663	37.667
	3720-3875	Upper Dingo Claystone	Mudstone, medium grey-dark grey	6.5	130	13775	18514	2.85	15	20	65		30.949	41.619
	3875-4065	Upper Dingo Claystone	Mudstone, medium-dark grey	6.75	170	3844	4773	2.77	25	50	25		11.288	14.030

CHC : Generated hydrocarbons
OOGC : Oroginal oil generating capacity
V : Vitrinite
F : Inertinite
S : Sapropel
W : Waxy Sapropel

Hauy-1 and Poissonier-1, grading to more carbonaceous (TOC 1-2.5%) and vitrinitic in Hampton-1, Sholl-1 and Observation-1. They contain a slight predominance of waxy kerogen in Hermite-1, thus making a good quality source rock. The trends suggest that the Locker Shale may be a good source rock in the Northern Carnarvon Basin, particularly if its deep water facies is represented by black shale deposited under stagnant, anoxic conditions. Such source rocks would have become mature by the end of the Triassic, and post-mature and gas-generating in the Late Jurassic.

9.1.3 Mungaroo Formation

The Mungaroo Formation comprises alluvial, fluvial and deltaic sediments, dominated by sandstones, but containing variable thicknesses of red to green claystones, carbonaceous mudstones and coals. Three gross fining upward cycles have been recognised (Crostella & Barter, 1980). The fine grained sediments accumulated in ephemeral and more persistent lakes and lagoons in interdistributary areas between the upper delta plain and the seaward margin of these continental deposits (Encl. 22b).

Organic carbon contents of the shales are most frequently between 0.5 and 1.5% but the most carbonaceous shales approach 10%. Hydrogen indices are low and the kerogens are dominated by inertinite with subordinate vitrinite (Encl. 22c). Coals contain 80-100% vitrinite and are associated with crevasse splay and distributary mouth bar environments. In general, there is only a potential for gas sourcing, although the large aggregate thickness of shales in the distal coastal plain environments indicates that large amounts of gas could have been generated.

Within these generally poor quality, but thick, gas source rocks is an area of oil potential where Carnian coals and shales are enriched in exinite (Encl. 22c). This section is penetrated by

West Tryal Rocks-1 and extends to Lowendal-1 and towards Malus-1, and possibly Barrow Island. It appears to represent a lacustrine area isolated for a time from the main channels of sediment distribution. There are three source rock intervals in West Tryal Rocks-1, with an interval of coals likely to be the most productive. Aggregate productivity is 19 million bbl oil/km^2, which is indicative of a very good source rock unit (Encl. 22d).

9.1.4 Brigadier Beds

During the Rhaetian, a marine transgression restricted the area of deposition of the Mungaroo Formation to the eastern part of the basin. Over much of the basin, shallow water marine sediments grading into delta front sediments were deposited (Brigadier Beds). Occasionally, thin shales contain low quality oil source rocks, as in Brigadier-1.

9.1.5 Lower Dingo Claystone

The final stage of the marine transgression, which began in the Rhaetian, led to deep water conditions in the Sinemurian over most of the basin, into which the Lower Dingo Claystone was deposited. Carbonaceous, prodelta shales grade westwards into lean, calcareous shales. Carbon contents are between 1 and 4%. Kerogen contents are often inertinite-rich in shallow water sediments, passing into mixed vitrinite and inertinite in a westerly direction (Fig. 33). Increased exinite content appears in shales in Lambert-1, Angel-2 and Picard-1 but these are low quality source rocks with hydrogen indices usually between 150-200. Nevertheless, the thickness of the source rock unit in Angel-2 and Picard-1, including the basal shales of the Learmonth Formation reaches 200-300m, and has enabled it to generate 10-20 million bbls/km^2 in reaching its present level of maturity (Fig. 33). It is possible that this productive zone extends further along the depocentre axis than is shown on Figure 33.

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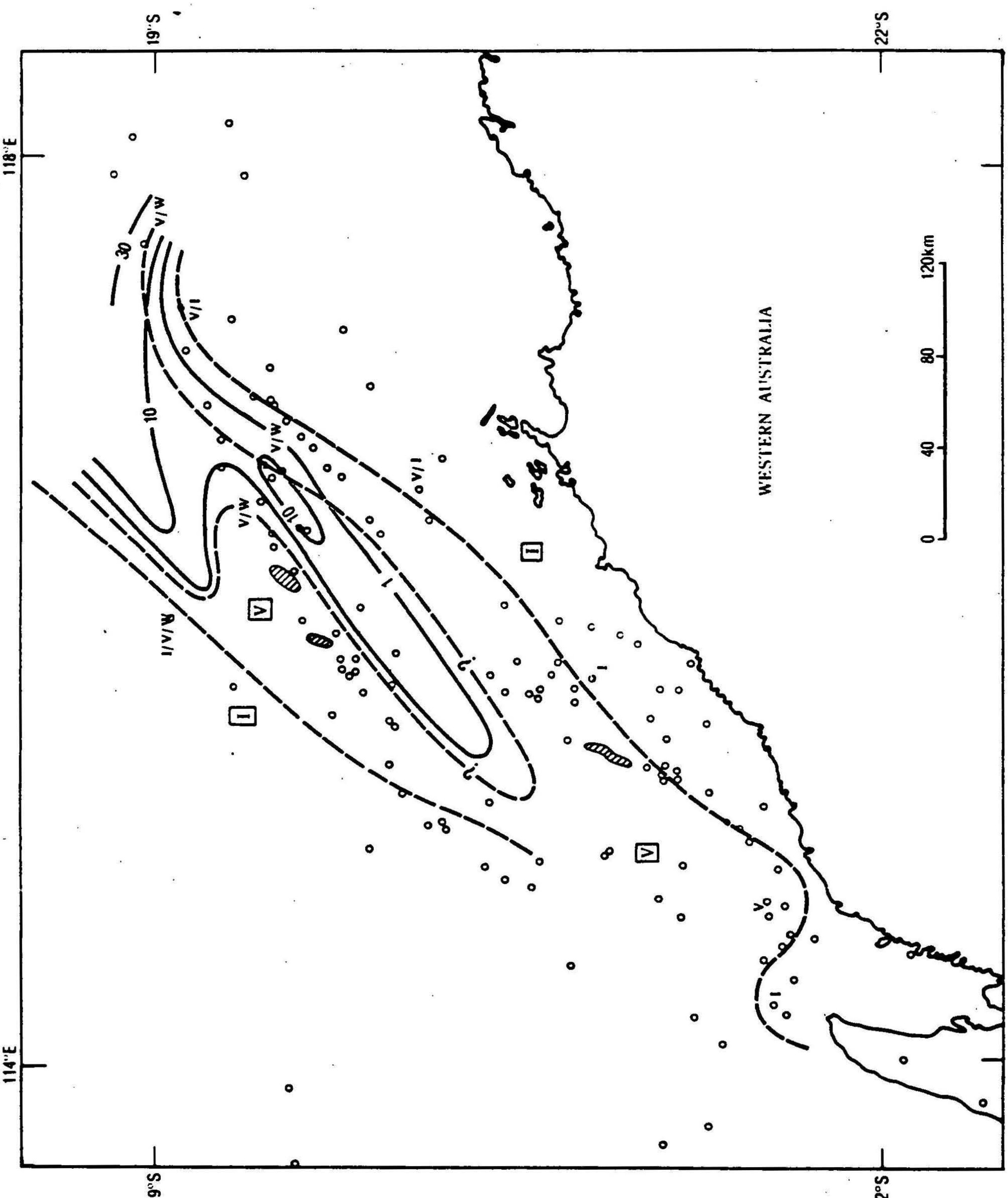

o Wells

Oil or Gas fields

W Waxy kerogen facies

I Inertinite facies

V Vitrinite facies

I/V Inertinite greater than Vitrinite

-1- Productivity mmBbls/sq. km

--- Kerogen facies boundary

Northern Carnarvon Basin
Kerogen Facies & Oil Productivity
Lower Dingo Claystone

Figure 33

9.1.6 Middle Dingo Claystone and Learmonth Formation

During the Pliensbachian to Early Callovian, marine shales were deposited over the western part of the basin, with deltaic sediments of the Learmonth Formation prograding from the east (Encl. 14a). The Rankin Platform may have acted as a sill which restricted water circulation in the basin at this time.

Source rocks in the Learmonth Formation, comprising drift coals and shales deposited in lagoons close to the shoreline, contain both exinite and algal kerogen in significant amounts (Fig. 34). A similar environment may have occurred in Sandy Point-1 but the carbonaceous shales are presently too mature to distinguish their original kerogen content.

Source rocks of this kind have been very productive (10-30 million bbls/km^2) in reaching their present levels of maturity but are of restricted areal distribution (Fig. 34).

The marine shales of the Middle Dingo Formation contain kerogens dominated by vitrinite and inertinite. However, an enrichment in oil- generating kerogen may be present to the west and north of Koolinda-1, which contains 350m of shale with average organic content of 1.7%. The subordinate amount of exinite in this source rock unit gives it a fair quality source rock status which, in reaching its present level of maturity, has generated 9 million bbls/km^2.

9.1.7 Upper Dingo Claystone

The most productive source rocks of the Barrow-Dampier Sub-basin are present within this formation. From the Late Callovian to Late Tithonian, deposition of marine shales took place within a deep water, restricted marine basin (Encl. 23b). Into this basin,

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Northern Carnarvon Basin
Kerogen Facies
Middle Dingo Claystone

o Wells

Oil or Gas fields

W Waxy kerogen facies

I Inertinite facies

V Vitrinite facies

I/V Inertinite greater than Vitrinite

Wc Waxy coals

Sc Sapropelic coals

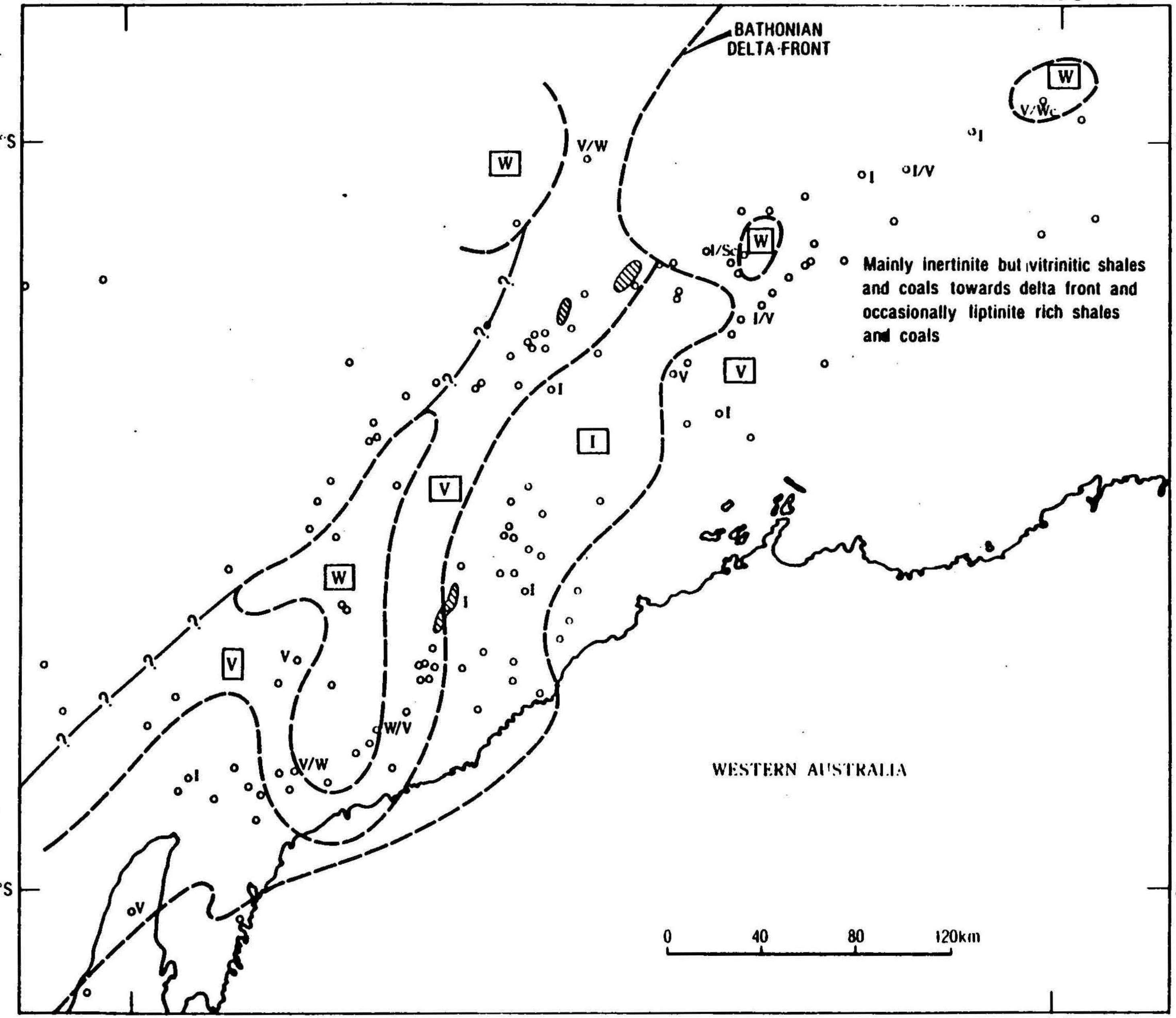

Figure 34

mass gravity flows were also shed from the shallow marine, sandy shelves on the eastern margin and on the Rankin Platform blocks. The shales are rarely very carbonaceous, with organic carbon contents usually between 1 and 3%. The kerogens are detrital and were derived from the delta plain and landmass to the east. On the margins of the basin, the kerogens are dominated by inertinite, but they become increasingly vitrinite-rich towards the basin centre (Encl. 23c). Within the central part of the basin, exinites become abundant, but rarely exceed 40% of the kerogen.

Except for rare, thin bands of fair to good quality source rock with hydrogen indices at 300 to 400, the sequence, as exemplified by Withnell-1, contains only fair quality source rocks.

The low quality of the source rocks is compensated by their thickness, so that in Withnell-1, the 1000m of source rock, having reached middle maturity, has generated 45 million bbls/km^2 of oil (Encl. 23d).

The highly productive area extends from the south side of the Rankin Platform as far east as Dampier-1, south to include Flag-1 and Koolinda-1, but not Anchor-1 or West Muiron-2.

9.1.8 Barrow Group

Orogenic events at the beginning of the Cretaceous uplifted the land mass to the west of North West Cape (Cape Range area), which became the source for a large northerly prograding delta system (Encl. 14d). The previously existing marine embayment, southeast of the Rankin Platform, became more constricted but continued to receive a steady supply of fine grained clastics, interspersed with mass gravity flows of sand and silt derived from the narrow shelf of marine sediments to the south.

Shales with organic carbon contents of 1 to 3% accumulated as both distal deltaic and prodelta deposits. There may have been a climatic change at this time to less arid conditions, since vitrinite is the most abundant kerogen in the sediments (Fig. 35). Inertinite-rich sediments are confined to the thin shales within the marine shelfal sediments. Some enrichment in exinite content occurs in deltaic shale in West Barrow-2. A trend to increasing exinite content is also apparent in the distal prodelta shales, based on subordinate amounts appearing in shales in Flag-1, Pepper-1, Rosemary-1 and Withnell-1. Although these are only poor to fair quality oil source rocks, their thicknesses are such that they have generated fair amounts of oil (10-15 million bbl/km^2) where fully mature.

9.1.9 Muderong Shale

Following an hiatus in the mid-Late Valanginian, a marine transgression led to widespread shale deposition throughout the Barrow-Dampier Sub-basins. These sediments of Late Valanginian to Aptian age comprise the Muderong Shale.

Over much of the basin, the shales are carbonaceous, with organic contents between 2% and 3%, and occasional richer horizons of 3% to 4%. The distribution of different types of kerogen is controlled by distance from shoreline, the kerogens all being clastic and land derived. Inertinite-rich kerogens dominate near shore sediments on the south easterly margin of basin and over the Rankin Platform (Encl. 24c). Towards the basin axis, there is first an enrichment of vitrinite and then of exinite in the kerogens at the expense of inertinite. This pattern does not apply to the west of Barrow Island, possibly due to a greater rate of supply of sediment from the land at this point. To the west of the Rankin Platform, open water marine conditions prevail and it is expected that carbonaceous content decreases and inertinite once again becomes the dominant kerogen.

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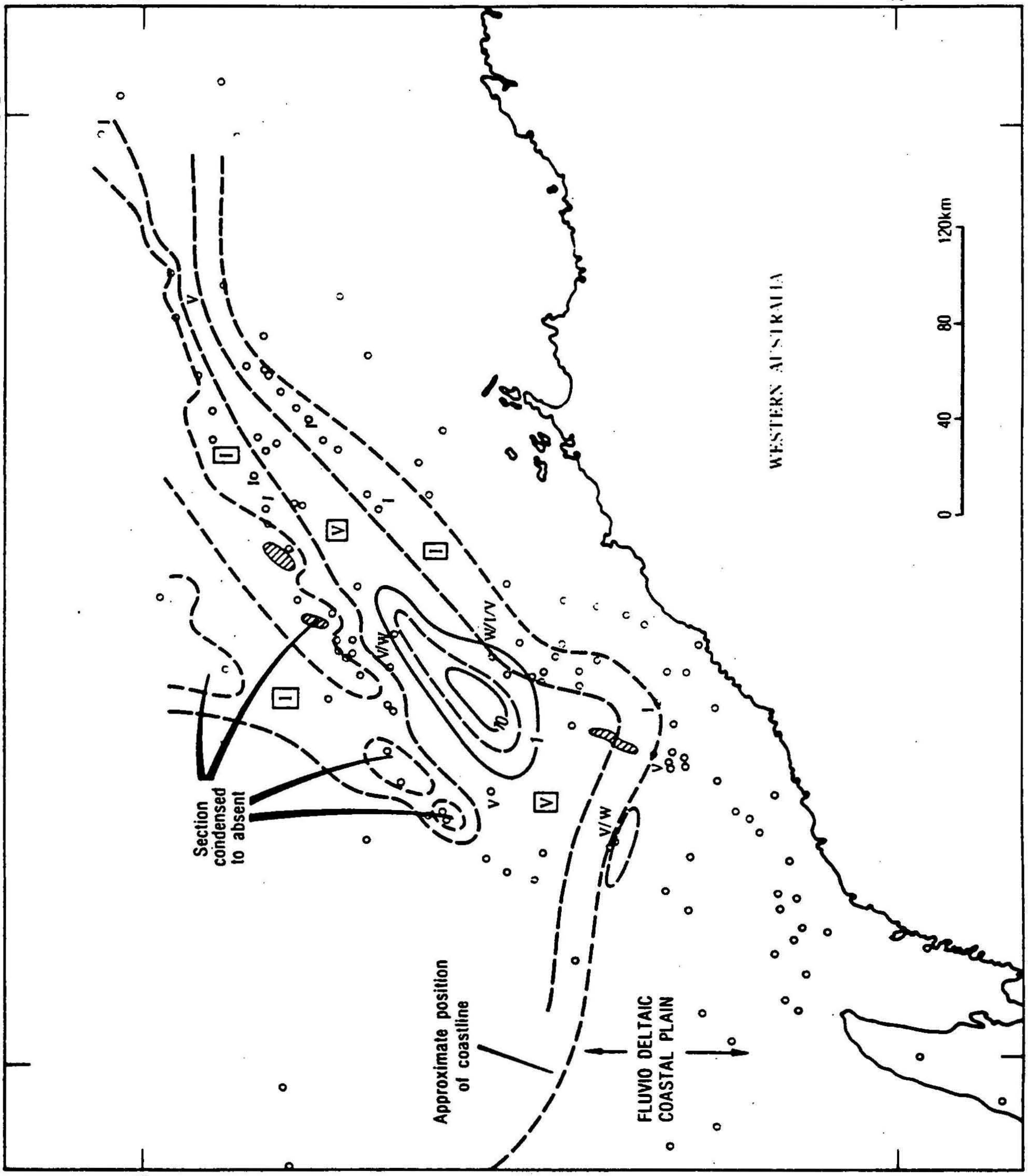

o Wells

Oil or Gas fields

W Waxy kerogen facies

I Inertinite facies

V Vitrinite facies

I/V Inertinite greater than Vitrinite

-1- Productivity mmBbls/sq. km

Northern Carnarvon Basin
Kerogen Facies & Oil Productivity
Barrow Group

Figure 35

Within the zone of exinite-enriched kerogens are fair to good quality source rocks which have reached middle maturity. Thicknesses of source rock reach 300m in well sections, so that good productivities of 30 million bbls of oil/km^2 have been achieved at the southern end of the Lewis Trough (Encl. 24d).

9.2 MATURITY

The maturity and maturity profiles in the Northern Carnarvon Basin are consistent with a history of steady subsidence; there are generally no large amounts of missing section at unconformities except on the southern and southeastern margins of the Barrow-Dampier Sub-basins and on the Rankin Platform. There is no strong evidence of a regional phase of increased heat flow, although minor igneous intrusives may have affected some well sections.

9.2.1 Present Day Temperature Gradients

The geothermal gradient map (Encl. 25), based on data from about 60 wells, shows a trend of decreasing gradient from 40°C/km to 20°C/km to the north west. It is also shown by heat flow data across the Montebello Arch and Exmouth Plateau (BMR, 1986). The trend is interrupted by zones of high values which coincide with the Rankin Platform and a ridge between Resolution-1 and Zeepard-1, and with the Cape Range and Barrow Anticlines. The Cossigny Trough, Lewis Trough, Kangaroo Syncline, mid-Enderby Terrace and western Barrow Sub-basin are areas of low heat flow. Generally these are areas with alignments following the axes of basin formation but a second, north-south pattern may also be discerned, particularly around Barrow Island; this may be due to basement inhomogeneity.

9.2.2 Maturity Gradients

For most of the analysed wells, spore colour index (SCI) gradient and temperature gradient show a good correlation, so that it has been possible to derive an SCI gradient map by converting temperature gradients for non-analysed wells (Encl. 26a). The SCI gradient map is used to determine depths to oil window, and level of maturity between wells for particular horizons where depth is known from seismic. These calculations also need some estimate of eroded section at surface and at unconformities.

Sections which are substantially above their maximum depth of burial occur along the Cape Range and Barrow Anticlines, where Late Miocene uplift and erosion has removed up to 1200m from the sections drilled. Other areas of Miocene to Recent uplift appear to have been adjacent to Hampton-1, Poissonier-1, Sable-1 and Zeepard-1.

Within the analysed sections, maturity data are most comprehensive in the Middle Jurassic to Early Cretaceous sequence (refer Volume 2). The breakup unconformity is estimated from vitrinite reflectivity data to represent 300 to 700m of eroded section in Brigadier-1, Eaglehawk-1, Hampton-1, West Tryal Rocks-1, North Tryal Rocks-1, North Rankin-1 and Zeepard-1. Similar amounts of missing section are represented by unconformities of late Early Cretaceous, or later, age in Flinders Shoal-1, at the base of the Tertiary in Flag-1, and within the Tertiary of Depuch-1. The largest amount of section missing is in Sholl-1, where more than 2500m of section has been removed from above the Locker Shale. Most of this was probably removed in the Middle Jurassic and Late Tertiary.

For the most part, straight best fit lines can be fitted to the maturity data, but strong curvature and high values of maturity at TD in Bowers-1, Cape Range-2 and Zeepard-1 indicate proximity to minor igneous intrustions. Irregularity in the data is more compatible with dykes than with sills, and the age of intrusion is younger than late Early Cretaceous. Lesser curvatures or actual changes in gradient occur in Eaglehawk-1, Hampton-1, Hermite-1, Ronsard-1 and West Muiron-2 but it is not possible to determine if they are due to igneous intrusion or a Tertiary heating event.

Finally, in the Dampier-1, Goodwyn-1 and Madeleine-1 wells, perturbations in the SCI profiles appear to be related to over-pressuring in the section. The same cause may be operative to a lesser extent in Malus-1, North Rankin-1 and North Tryal Rocks-1.

9.2.3 Maturity Distribution

Although oil generation begins at SCI 3.5, the generally low quality source rocks of the Carnarvon Basin are not likely to have generated enough oil for effective migration until SCI 5.0 is reached. The effective oil window is therefore taken to be from SCI 5.0 to SCI 8.5.

Over most of the basin, rocks older than mid-Triassic, including the Locker Shale, will have passed through the oil window and will have generated their oil potential, although these rocks are only early to middle mature in drilled sections on the margin of the basin (Encls. 17 & 18). The deepest sedimentary sections are even passing out of the gas zone into incipient regional metamorphic zones.

At the top of the Triassic (Encl. 22a), maturity rapidly increases into the Barrow and Dampier Sub-basin so that most of it is in the effective oil window. A large part, including the Barrow depocentre, northern Kangaroo Syncline and southern Lewis Trough, is in the post mature, gas zone. Some areas on the Rankin Platform have not reached the effective oil window, but this horizon in the Victoria Syncline has reached late maturity.

The top of the Upper Dingo Claystone, or, if absent, base Cretaceous, in the basinal areas is in the effective oil window, and between Spar-1 and Parker-1 reaches late maturity and possibly the gas zone (Encl. 23a). In the Victoria Syncline, this horizon is only just into the effective oil window.

Sediments within the effective oil window at top Aptian (Muderong Shale) are restricted to the Kangaroo Syncline, Lewis Trough, Barrow depocentre and possibly areas in the Victoria Syncline and close to the Cape Range Anticline (Encl. 24a). It is unlikely that this horizon reaches the late mature zone.

9.3 OIL-SOURCE ROCK CORRELATION

Further studies have been carried out on 30 source rocks, 22 migrant oils present as oil stain in drilled samples, and on 16 produced or tested oils. The analyses include gas chromatography-mass spectrometry (GC/MS) of alkane fractions, and carbon isotope ratio determination of alkane and aromatic fractions. In addition, oils have been analysed for their volatile content, gravity, pour point and sulphur content. The carbon isotope ratios in the following chapters will be expressed as parts per mil ($^{o}/_{oo}$) relative to PDB standard.

The whole assemblage of source rocks, migrant oils and oils has been derived from kerogens which are dominated by their land plant input. A comparison of biomarker and carbon isotope results shows that there is a very close similarity among the oils/migrant oils and some of the source rocks analysed. However, in spite of this close similarity, it is impossible to select a particular source rock for the oils and oil stains analysed from the Northern Carnarvon Basin. The variation in relative abundance of the biomarkers appears to be environmentally controlled but no specialised environments such as evaporitic, intertidal or lacustrine are particularly indicated for the oils and source rocks. The oil from Rough Range-1 and oil stain in Parker-1, however, have carbon isotope compositions that do not match any of the source rocks and may indicate derivation from intertidal sediments. Such sediments have not been encountered in the Triassic to Jurassic sequence.

The carbon isotope ratios are consistent with growth of both marine and land plants in cool temperature climates. The studies show that most of the oils and oil stain are mixed, containing one or more phases of biodegraded oil. The severely biodegraded oil component can only have been created from live oil by bacteria in meteoric water within 300m of ground level at the time. The geological significance of this is discussed in Section 9.4.

Separation of oils, migrant oils and source rocks into groups has been based on:

1. the relative abundance of 17 α(H) C_{29}-norphane and C_{30}-hopane in triterpane (m/z 191) fragmentograms. Ratios of various hopanes such as C_{29} (norhopane)/C_{30} (hopane) can be used both as source parameters and as maturity parameters. However, Robertson Research geochemists consider that the proportion of terpanes depends to some extent on the type of organic matter but has a greater dependence on thermal cracking of carbon-carbon bonds due to maturity. In this study, the predominance of C_{29} or C_{30} has been used only as an indicator for grouping source rocks, not as an age or source parameter.

2. the presence of compounds on m/z 191 fragmentograms:

   20(V): a compound co-eluting and overlapping with 17 α (H) trisnorhopane (tm); it is a terpane of unknown structure occasionally associated with coaly sediment.

   W: 28,30 bisnorhopane; usually associated with marine eutrophic, oxic conditions and variably in association with vitrinitic shales, phosphorites, diatomites, and limestones.

   Compounds 7 and 8:
   Two compounds eluting immediately after 17 α (H) norhopane. These are unidentified C_{29} and C_{30} triterpanes. Both Philp (1985) and Volkman et al. (1983) suggest that these compounds are terrestrial indicators, based on their occurrence in some Australian coals and in oil seepage from coal.

3. less negative (e.g. -23) or more negative (e.g. -31) carbon isotope ratios compared with the average range of values in the samples. The carbon isotope of the alkanes of an oil reflects that of its source kerogen. A low value of less negative (e.g. -20) indicates non-marine algae and a high value or more negative (e.g. -30) suggests a land plant source.

4. relative proportions of C_{27} and C_{29} steranes, used to discriminate between algal and land plant source. C_{29}/C_{27} greater than 1 indicate land plant sources.

5. the presence of bacterially demethylated (17 α (H), 25-norhopane and 17 α (H), 25,30-bisnorhopane, indicating the presence of severely biodegraded hydrocarbons.

9.3.1 Source Rocks (Refer Volume 2, Table IV.1, Figs. IV.1 - IV.3)

The GC/MS results indicate that the qualitative distribution of steranes is the same for almost all of the source rocks analysed.

This is confirmed by the sterane carbon number distribution which shows that C_{29} steranes are more abundant than C_{27} steranes in all samples except for the Bowers-1 (2790-2805m), Tryal Rocks-1 (2588-2604m), West Tryal Rocks-1 (3341-3354m) and West Barrow-2 (2461-2476m). Predominance of C_{29} steranes suggests a dominant contribution of terrestrially derived kerogen.

Carbon isotope values obtained for alkanes of the majority of source rock extracts are in the more negative range (-26.80 to -30.22), indicative of hydrocarbons generated predominantly by kerogen derived from terrestrial plants. Less negative carbon isotope ratios obtained for coal from Depuch-1 (4180-4190m) and shales from Angel-2 (4360-4375m) and Withnell-1 (2665-2670m) suggest a relatively high contribution of non-marine algal material into the source kerogen.

However, the study of the triterpane (m/z 191) distributions show that the following groups of source rocks can be distinguished:

Group 1

This group is typified by m/z 191 fragmentograms showing a limited number of components, relatively high content of moretanes, a norhopane/hopane ratio of one or higher, and, compound V in abundance. Examples of this group are:

Picard-1	2588-2601m	(Learmonth Fm)
Picard-1	2930-2942m	(Learmonth Fm)
West Tryal Rocks-1	3463-3476m	(Mungaroo Fm)

Group 1A

This sample is distinguished from other members of Group 1 by a more negative alkane carbon isotope ratio of -30.2.

Brigadier-1	4155-4165m	(Mungaroo Fm)

Group 2

This group shows an abundance of triterpanes and moretanes on m/z 191 fragmentograms, a norhopane/hopane of less than one, and the presence of compound W, bisnorhopane. Some of the samples in this group may be contaminated by traces of biodegraded oil.

Brigadier-1	3905-3925m	(Brigadier Beds)
Spar-1	2655-2665m	(Barrow Group)
Withnell-1	2665-2670m	(Barrow Group)
Withnell-1	3720-3730m	(Upper Dingo Claystone)
Zeewulf-1	3315-3330m	(Mungaroo Fm)

Group 3

Source rocks in this group show very similar triterpane distribution which are typified by norhopane/hopane ratios of less than one, and an absence of bisnorhopane (W), and bacterially demethylated hopanes. The age of these selected source rocks ranges from Permian to Early Cretaceous. The group is divided into two sub-groups.

Group 3A

This sub-group contains abundant compound 20(V).

Angel-2	3204-3220m	(Learmonth Fm)
Brigadier-1	3465-3475m	(Middle Dingo Claystone)
Depuch-1	3230-3235m	(Learmonth Fm)
Depuch-1	4180-4190m (mdst)	(Middle Dingo Claystone)
Depuch-1	4180-4190m (coal)	(" " ")
Lambert-1	3685-3695m (coal)	(Lower Dingo Claystone)
Lowendal-1	3280-3295m	(Mungaroo Fm)
West Tryal Rocks-1	3787-3799m	(" ")
West Tryal Rocks-1	3832-3845m	(" ")

Group 3B

This group shows no special characteristics, although small amounts of possible environmental or age - diagnostic biomarkers are present in variable quantities.

Anchor-1	2686-2701m	(Middle Dingo Claystone)
Angel-2	4360-4375m	(Lower Dingo Claystone)
Bowers-1	2790-2805m	(Muderong Shale)
Bowers-1	3825-3840m	(Middle Dingo Claystone)
Bowers-1	3970-3985m	(Mungaroo Fm)
Flag-1	2317-2332m	(Barrow Gp)
Flinders Shoal-1	3305-3323m	(Byro Gp)
Flinders Shoal-1	3372-3387m	(Byro Gp)
Koolinda-1	2530-2540m	(Upper Dingo Claystone)
Tryal Rocks-1	2588-2604m	(Muderong Shale)
West Tryal Rocks-1	3341-3354m	(Mungaroo Fm)
West Barrow-2	2461-2476m	(Muderong Shale)

9.3.2 Oils

9.3.2.1 Physical and Chemical Composition of the Analysed Oils

(Refer Vol. 2, Tables II.1, II.2, II.4, Figs. II.2, II.4, II.5)

The oils and condensates analysed from the Northern Carnarvon Basin are in reservoirs which range in age from Middle Triassic to Early Cretaceous. The analysed oils and condensates show a wide range of gross composition, from medium gravity oils (30-40° API) to light oils/condensates with gravities greater than 40° API, but the majority of the investigated oils from Northern Carnarvon Basin are light. The pour point values of the oils analysed vary between -42°C and +37°C. The sulphur content of the oils is in the 0.03% to 2.38% range, generally with heavier oils containing the most sulphur.

The gasoline range (C_4-C_7) hydrocarbon analysis data confirm that the oils and condensates with higher gravities contain the highest total abundance of C_4-C_7 hydrocarbon components. Compound ratios have been calculated for each of the oils. The results (Table II.2), especially heptane and isoheptane indices and kerogen type index values, suggest that the analysed oils are generated predominantly from a waxy sapropelic kerogen at relatively high maturity level.

The relative percentages of normal, branched and cyclic alkanes in the gasoline range (Table II.2, Fig. II.2) indicate that except for Gorgon-1 DST-6, and Saladin-1, the oils analysed have very similar values. The small differences observed in Gorgon-1 and Saladin-1 oils may be due to the effect of maturity.

The results obtained from liquid chromatography (Table II.1) show that the analysed oils have very similar composition. The insignificant differences in gross composition may be due to the maturity and, at least in part, to variation in source type.

Whole oil and alkane fraction gas chromatography indicate that three groups of oils can be distinguished. Oils from Angel-1, Goodwyn-3, Goodwyn-4, Barrow-1, Gorgon-1, Saladin, North Herald-2 and Rankin-1 show relatively narrow alkane distributions which are relatively poor in C_{22} normal alkanes (Brikke, 1982). The remaining oils analysed, except for Barrow-15 oil, exhibit wide alkane distribution with an appreciable fraction of waxy alkanes above $\underline{n}$-C_{23}. The oil from Barrow-15 is a biodegraded oil with very low $\underline{n}$-alkane content.

Slightly elevanted baselines in the chromatograms, indicating the possible presence of a biodegraded component, are shown by Barrow-1, Rankin-1, Goodwin-3, Gorgon-1 (DST7), Bambra-2, Harriet, Lenita-1, South Pepper-4 and Rough Range-1.

The pristane/phytane, pristane/$\underline{n}$-C_{17} and phytane/$\underline{n}$-C_{18} ratios (Table II.1) indicate an oxidising environment at the time of deposition of the source rocks. The CPI ratios (Carbon preference index) are very close to value one (1), indicative of oils derived from a middle to late mature source.

9.3.2.2 <u>Petroleum Geochemical Characteristics of the Analysed Oils</u> (Table II.1, Figs. II.1, II.3, II.6)

GC/MS and carbon isotope analyses have been carried out on the oils and selected migrant oils. Analysis of triterpane and sterane compositions ("biological markers") by GC/MS indicate that the qualitative distribution of steranes of almost all the oils analysed is virtually similar.

Both groups of oil show broadly similar sterane distributions (Fig. II.3) in which C_{29} sterane is more abundant than C_{27} steranes and shows that their sources have been rich in land plant-derived kerogen.

Except for the Rough Range-1A oil, the oils analysed are isotopically light, having fairly similar alkane and aromatic carbon isotope ratios of between -26.60 to -28.3 and between -25.6 to -27.10 respectively. The insignificant variation observed in carbon isotope values seems to be related to variation in maturity of the oils, and also to the fact that some of these oils appear to be mixtures of biodegraded oil and fresh paraffinic oil (live oil).

The oil from Rough Range-1A is marked by carbon isotope ratios less negative than other oils, with saturates of -24.7 and aromatics of -23.2. These values may be associated with intertidal plant communities although a source rock environment of this nature has not been recognised in the sections analysed. This oil has also been generated from an early mature, good quality source rock.

Based on triterpane (m/z 191) distribution, the following two groups of oils could be distinguished:

<u>Group 1 - oils which contain demethylated hopanes</u>

The presence of these demethylated hopanes (25-norhopane and 25,30-bisnorhopane) indicates that at the time of migration, the reservoir conditions were suitable for the biotransformation of hopanes into demethylated hopanes. These conditions exist only in near surface environments with low temperatures and an abundant supply of oxygenated meteoric water.

The oils of this group are from the Barrow-15, Barrow-1, Rankin-1, Goodwyn-3, Goodwyn-4, Angel-1, Gorgon-1 (DST7), Gorgon-1 (DST6), Bambra-2, Harriet and Lenita-1. Oils with a similar biodegraded component have been reported from Windalia oil, Barrow Island and Flinders Shoals (Alexander et al., 1983).

Eaglehawk-1 crude is composed largely of a less highly biodegraded oil and a subordinate n-alkane rich fraction (Alexander et al., 1983). The presence of demethylated hopanes in the n-alkane-rich oils of this group suggests that the mixing of oils with different histories of degradation had been occurring during migration.

Group 2 - oils with no demethylated hopanes

The oils in this group e.g. South Pepper-4 and Rough Range-1, may contain a lightly biodegraded oil component, but are dominantly n-alkane-rich, unbiodegraded oils. The other members of this group are Saladin-1, North Herald-2 and Wilcox-1.

In addition, the Group 2 oils contain reasonable amounts of moretanes and terpanes, which may suggest they were derived from a less mature source than the oils of Group 1.

9.3.3 Geochemical Characteristics of the Migrant Oils (Table III.1, Figs. III.1-III.3)

Gas chromatography of the alkanes of these oil stains shows that they represent a range of oils, from those which contain only biodegraded oil, e.g. North Rankin-1, to oils with no apparent biodegraded component. The alkane distributions suggest that all of the undegraded oil components are derived from terrestrial source rocks accumulated under oxic conditions.

The GC/MS analyses of the triterpanes of these oils show that where biodegraded components are present, their characteristics indicate severe (e.g. Pueblo-1 and West Barrow-1) to very severe (Withnell-1 and Parker-1) degradation. Anomalous concentrations of the more resistant tricyclic terpanes present in some oils may be a result of removal of the less resistant compounds. The steranes and non-demethylated hopanes are therefore usually contributed by the live oil component.

Two groups of oils can be distinguished by the presence and absence of 25-norhopane (demethylated) (29-hopane).

Present (i.e. biodegraded oils)	Not Detectable
Delambre-1	Angel-2
Egret-1	Hilda-1A
Flinders Shoal-1	Legendre-1
Hampton-1	North Rankin-1
Haycock-1	Pepper-1 (2445m)
Long Island-1	Rosemary-1
Pepper-1 (1860m)	Spar-1
Parker-1	Tryal Rocks-1
Pueblo-1	West Muiron-2 (1550m)
Poissonier-1	West Muiron-2 (2760m)
West Barrow-2	
Withnell-1	

Both groups contain oils with norhopane/hopane peak ratios greater than one. These are oils extracted from West Murion-2, Flinders Shoal-1, Egret-1, Haycock-1, Delambre-1 and Legendre-1.

Except for Poissonier-1, Flinders Shoal-1, and Parker-1, the carbon isotope ratios of alkanes and aromatics of the migrant oils (Fig. III.1) are all very similar and are also similar to those of analysed reservoired oils, ranging from -26.54 to -28.03 and -24.9 to -27.38 respectively. These data suggest that the migrant oils have been generated by a source containing mixed kerogen derived from higher plants and non marine algae.

The carbon isotope ratios of the oil fractions from Poissonier-1 and Flinders Shoal-1 are a little more negative than the others but not sufficiently different to be significant.

Migrant oil extracted from the Upper Dingo Claystone interval (4155m-4170m) of Parker-1 is isotopically relatively heavy, showing carbon isotope values of -23.37 and -22.43 for alkanes and aromatics respectively. These values may suggest that the oil, or part of the oil, was derived from a source rock deposited in an intertidal environment, not identified in any of the wells studied.

9.4 TIMING OF MIGRATION

Estimates of the timing of source rock maturation have been derived from maturity profiles and from maturity modelling. These have been linked with studies of oil and gas characteristics, which show the maturity levels of the source rocks which generated them. In addition, many deep reservoired oils and oil stains contain bacterially degraded components, such as the demethylated hopanes, which could only form by contact between meteoric water and oil within 300m of the surface.

The period of ingress is marked by an unconformity which must not be more than 300m above the reservoired oil, although the oil may have remigrated above the unconformity. Occasionally a degraded oil may migrate into an adjacent fault block and to an older stratigraphic level, so that possible remigration paths of degraded oil need to be examined. In the following interpretation, cross block migration into older reservoirs is not believed to have occurred and the dating of degradation, and therefore minimum age of oil, has been deduced from the relationship of oil reservoir with unconformities.

Although the biodegraded oils may not constitute a significant volume of the discovered oils, some effort has been devoted to determining the time of migration and entrapment of the biodegraded oils, because the source rock can then be deduced. The source rocks are believed to be significant oil sources, because the types of oils most susceptible to biodegradation (approximately 40° API) are generated in the early to middle mature phase from good source rocks. It follows that considerable amounts of late mature liquids would also be generated from these source rocks.

The large amounts of condensates present in the northern part of the Goodwyn field are probably generated from a late to post mature (SCI 8.5) oil source rock. This condensate was not analysed. The oils in the oil legs, and those which condense from gas, show by their gravities and gas chromatogram character, that they are middle mature (SCI 5 to 7), have been water washed, being low in C_4 to C_{10} components, and often contain a biodegraded component. They were sourced separately from the gas either in time or space. The gas, therefore, must have been quite dry, implying generation at a source rock maturity of Ro 1.5-2.0%. It picked up condensate by flushing oil in the reservoir and by displacement during migration.

9.4.1 Maturity Modelling

Four key sections, three of which illustrate the stratigraphy of deep basinal sections, have been investigated (Encl. 27). The interpreted stratigraphy of the depocentres has been derived from nearby wells and from seismic cross-sections; both maturity and temperature data have been allocated on the basis of regional trends and nearby wells. The results are summarised in Table 5 and show dating of entry into the effective oil window (Ro 0.5%, SCI 5.0). Two methods have been used. Using

TABLE 5

TIMING OF ENTRY INTO EFFECTIVE OIL WINDOW, NORTHERN CARNARVON BASIN

SECTION	AGE ENTRY INTO OIL WINDOW (Ma) Ro=0.5%	SCI=5.0
Victoria Syncline		
Base Lower-Middle Dingo Claystone	160	145
Middle Mungaroo Formation	205	210
Base Locker Formation	225	215
Lewis Trough		
Base Upper Dingo Claystone	95	90
Base Lower Dingo Claystone	145	135
Base Mungaroo Formation	190	160
Base Locker Formation	200	175
Flinders Shoal-1		
Top Upper Dingo Claystone	25	not reached
Top Mungaroo Formation	115	130
Top Locker Shale	195	160
Top Byro Group	220	210
Kangaroo Syncline		
Top Muderong Shale	60	55
Intra Barrow Group	90	95
Base Upper Dingo Claystone	100	105
Top Mungaroo Formation	200	210
Top Locker Shale	230	220

the subsidence plots and modelled vitrinite reflectivity plots prepared by Paltech Pty. Ltd., timing of reaching 0.5% R_o has been noted for chosen horizons (Encl. 27). The methodology and supporting figures for the Paltech modelling are included in Appendix C. In addition, the time at which the horizons reached the top of the oil window, based on spore colour index in measured wells, has been determined.

Within limits set by the knowledge of stratigraphy, particularly for the Late Tertiary, there is a surprisingly close agreement in the results. In particular, it seems that the uppermost Triassic sediments were generating oil, usually before the Early Cretaceous (Table 5).

9.4.2 Origin of Oils and Gases

Western side of basin

The severely biodegraded oils in Goodwyn-3 and -4 were emplaced prior to the Tertiary, probably during the Late Jurassic or Aptian. These hydrocarbons were generated from source beds at a depth of approximately 3000m. Hydrocarbons were probably generated from source rocks within the overall fault block, because the structurally unfavourable attitude of the beds adjacent to the block would have prevented migration into it. Potential source rocks range from the Locker Shale and basal Mungaroo Formation, if vertical migration occurred, to the Mungaroo Formation and Brigadier Beds in the deeper parts of the Victoria Syncline further to the north.

The biodegraded oils at Rankin-1 and Eaglehawk-1 have had a similar history of generation and entrapment.

The biodegraded oil recovered from the Mungaroo Formation in Gorgon-1 (DST7) was emplaced before the Early Neocomian, and almost certainly in the Callovian. This oil would have been sourced from sediments at a depth of about 2500m. The Locker Shale and basal Mungaroo Formations are the most likely sources. The oil recovered from the Malouet Formation in Gorgon-1 (DST6) is probably relocated Mungaroo Formation oil.

Oil at Angel-1 was first trapped in the Early Cretaceous, probably at the end of the Aptian. Potential source rocks include the Brigadier Beds and Lower Dingo Claystone within the confines of the structure and to the north in the Victoria Syncline, and the Middle Dingo Claystone in the Lewis Trough.

Source of Gas

The main phase of gas generation begins at SCI 8.5, (R_o 1.3%) and the gas contains less than 10% wet gas. Gas actually begins to be generated from vitrinite in small quanitites at lower levels of maturity, possibly as low at 0.8% R_o and has a wet gas content of up to 30%, but is only significant if sediments are rich in vitrinite or are coal bearing. At the same time, because of its diffusivity and solubility, the trapping of gas is a balance between supply and escape. As a generality, it may be assumed that, in a geological framework, gas accumulations are impermanent. Gas accumulations in the Carnarvon Basin are therefore likely to be Middle to Late Tertiary in age. The compositions of the gases on the Rankin Platform are usually referred to as dry and indicate main phase gas generation at values of maturity greater than SCI 8.5 and R_o 1.3%. The map of maturity for the top of the Triassic (Encl. 22a) shows maturity of this order to be present only to the west of Barrow Island

and gas source rocks must be at a deeper level. The most probable source, therefore, is the Locker Shale which could be at the pertinent level of maturity in both the Lewis Trough and the Victoria Syncline. At this stratigraphic level, migration paths from both areas lead to the Rankin Trend.

<u>Eastern Side of Basin</u>

a) Geochemical Evidence

Barrow Island Windalia oil has suffered at least two episodes of biodegradation, and is a combination of at least three oils (Alexander et al., 1983). Alexander et al (1983) have published a table showing the effects of biodegradation on the composition of a typical mature paraffinic oil, which is included here as Table 6.

This migration and biodegradation probably occurred during the Late Turonian structural event (intra-Gearle Siltstone time). Using maturity gradients as a simple means of estimating palaeomaturation, the source rock was in or below the lower part of the Upper Dingo Claystone.

The second phase of generation was responsible for the bulk of the oil now reservoired. It has been moderately biodegraded (Level 4), and was therefore migrating and being trapped when the reservoir was close to the surface. If it is assumed that a geothermal gradient similar to today applied in the Mid-Tertiary, and that the reservoir temperature was less than approximately 50°C (at which no biodegradation of the latest phase has occurred), this phase occurred <u>no later</u> than the <u>Mid-Miocene</u>. Evidence of tilting, sea level drops and structural rejuvenation in the

TABLE 6

THE EFFECTS OF BIODEGRADATION ON THE COMPOSITION OF A TYPICAL MATURE PARAFFINIC OIL
(After Alexander et. al., 1983)

Level	Chemical Composition	Extent of Biodegradation
1	Typical paraffinic oil; abundant n-alkanes.	Not degraded
2	Light and n-alkanes removed	Minor
3	> 90% n-alkanes removed	Moderate
4	Alkylcyclohexanes removed; isoprenoids reduced	Moderate
5	Isoprenoid alkanes removed	Moderate
6	C_{14}-C_{16} Bicyclic alkanes removed	Extensive
7	> 50% (20R)-5α,14α,17α (H)-steranes removed	Very extensive
8	Steranes altered; demethylated hopanes abundant	Severe
9	Demethylated hopanes predominate; no steranes	Extreme

Late Cretaceous (Apthorpe, 1979) and Early Tertiary would have presented opportunities to introduce bacteria via meteoric waters prior to the Mid-Miocene. This agrees with the observation of a (Windalia) perched gas cap, probably produced by Late Miocene tilting to the north (Campbell et al., 1984). Source beds would have been within the lower to middle part of the Upper Dingo Claystone.

A further minor input of mature light paraffinic oil has occurred since then, probably derived from the same, or slightly younger, source.

Oils in the Muderong Shale at Barrow Island are very similar to, and have suffered the same history, as the oil reservoired in the Windalia sandstone. Volkman et al. (1983) note that the oils in the Muderong Shale are slightly less biodegraded than the Windalia oil.

The oils in the top Barrow Group in the South Pepper field and at Flinders Shoal-1 have had a similar history to the Windalia oil at Barrow Island. The Flinders Shoal-1 oil is moderately biodegraded (Level 5), but also contains low concentrations of severely biodegraded crude similar to that at Mardie-1 (Level 7) in the Robe River area. The gas present may represent a late stage generative pulse similar to that in the Windalia oil, Barrow Island. The first generation and migration phase occurred in the Late Cretaceous (probably Turonian) while the second phase oil probably occurred in the Mid Tertiary. Both oils were probably sourced from the Upper Dingo Claystone (e.g. Volkman et al., 1983), but the Locker Shale on the high side of the Flinders Fault is also a possible source.

The intra-Barrow Group and Dupuy Member oils at South Pepper are 35° API, are genetically related, and resemble extracts from the Upper Dingo Claystones (Williams & Poynton, 1985). The oil at the top Barrow Group is 44° API, and is a mixture of two or three separate crudes - one severely altered, one as above, and another a late stage gas-condensate (Williams & Poynton, 1985). Williams and Poynton (1985) suggest that the oils were derived from source rocks rich in marine organic matter. However, analyses of oil from the South Pepper field in this study show a wide range alkane distribution, with relatively high proportions of waxy alkanes above $\underline{n}$-C_{23} and a relatively high pristane/phytane ratio. It is considered more likely that the oil has been generated at high maturity level by a source containing predominantly waxy saplopelic kerogen. The carbon isotope values obtained for South Pepper support this conclusion.

The timing and indicated source rock for the three crudes in South Pepper, assuming local generation, is Turonian from the basal Upper Dingo Claystone, and Mid-Miocene and a more recent phase, both from the Upper Dingo Claystone. Because the reservoir was deeper than at Barrow Island or Flinders Shoal-1 during the Miocene, biodegradation of the second phase did not occur.

Slight oil shows in the Mardie Greensand Member outside of closure in Dorrigo-1, Georgette-1 and Emma-1 consist of a substantially biodegraded Jurassic oil and a later phase of Jurassic saturate-rich oil(s) (Kopsen & McGann, 1985). A similar generation history to that of the Windalia crude is probable, the oils having migrated eastward to the basin edges. However, if a source in the immediate vicinity of the various wells is invoked, the Lower and Middle Dingo Claystone would have sourced the oils.

b) Structural Evidence

Significant residual oil legs have been noted in oil fields around Barrow Island. The 30m residual column cored in South Pepper-4 is thought to have resulted from (?)Miocene displacement along the South Pepper Fault, or westward tilting due to the Tertiary carbonate progradation (Williams & Poynton, 1985). Residual oil zones exist on the northern end of the Bambra and Harriet structures. These were caused by Late Miocene tilting (Kopsen & McGann, 1985). Both of these structures and the Barrow Island field were palaeoclosures during the Late Cretaceous.

10. CANNING

No new analyses have been carried out on wells in this basin and the following is a review of previously published data.

10.1 SOURCE ROCKS

Late Permian fluviodeltaic sediments at a late stage of maturity are present in Lynher-1 and Lacepede-1A. They are dominantly sandstones and siltstones with thin shales. Organic carbon contents are 1-2%, and the kerogen of the shale is probably vitrinitic. Source rocks may develop in more distal parts of this deltaic sequence.

The Triassic, where seen, is similar in character to the Late Permian, the shales in the dominantly sandstone sequence being vitrinitic or inertinitic and less carbonaceous.

The Early and Middle Jurassic sequence is represented by sandstones, siltstones and claystones of lower delta plain facies in which occasional coals and coaly shales show some source rock potential, but nowhere are they thick enough as individual units or as cumulative units, to be significant. Late Jurassic fluvio-deltaic sandstones and siltstones grade into paralic and marine sandstones and claystones in the offshore Canning Basin. The organic contents of the coal-associated shales are up to 15%, and up to 3% in marine shales. Hydrogen indices of 200 to 400 are typical of the coaly shales and show that they have some oil potential, but the marine shales are inertinite-rich.

The Early Cretaceous sediments of the Canning Basin are paralic to marine sandstones and claystones. The paralic claystones have organic carbon contents of up to 3% and the marine claystones, organic carbon contents of 1 to 2%, but their kerogen contents are dominantly inertinitic. It is unlikely that Early Cretaceous sediments become fully mature in the offshore Canning Basin.

10.2 MATURITY

In this report, the depth to the top of the effective generation and migration zone is taken to be at SCI 5.0 and R_o 0.5%. It is usually reached between 2500 and 3500m in the wells drilled in the Canning Basin, but some of the analysed sections are not at their maximum depth of burial, having been uplifted, probably in the Tertiary, by some 500 to 1500m. The data for Wamac-1 shows this very markedly (Elf Aquitaine, 1984). Most of the Mesozoic section in the wells is therefore either immature or only early mature. These are conclusions also reached by Kantsler et al. (1978), and by Burne and Kantsler (1977) who state that the Permian and older rocks are post-mature. There is evidence both in the well sections (e.g. Wamac-1) and from seismic that dolerite sills are intruded into the Permian, and are Permian in age. These dolerite intrusions may explain the rapid change to post maturity in the Permian, but as they are confined to particular areas or trends, less mature Permian may be present elsewhere.

11. BROWSE BASIN

11.1 SOURCE POTENTIAL

11.1.1 Introduction

Samples from fifteen wells in the Browse Basin have been analysed for source rock potential in this study. Additionally, six wells analysed in the 1979 Robertson Research study, and data on open file from 10 wells have been incorporated into this study. The data cover strata ranging from the Permian to Tertiary. The source rock intervals identified in this basin are summarised in Table 7.

11.1.2 Pre-Triassic

An intracratonic basin developed in the Browse Basin in the early Palaeozoic. Marine conditions prevailed through the Devonian. Uplift and erosion occurred over the whole basin during the Carboniferous before sedimentation recommenced in the Late Carboniferous with paralic clastics and carbonates. These sediments are overlain by an Early Permian, non-marine sequence of sand and silt deposited under glacial conditions.

Several wells located along the basin margin (Rob Roy-1, Prudhoe-1 and Lynher-1) have penetrated Early Permian sediments, which are the oldest sequence drilled in the Browse Basin. Analyses of the well sections show that they contain organically lean to average (TOC 1.13% - 2.72%), inertinitic mudstones with no oil or gas source potential. Organically rich mudstones and coals in the upper part of the Permian section analysed at Rob Roy-1 are caved from the Middle Jurassic section above.

TABLE 7

SUMMARY OF SOURCE ROCK INTERVALS BROWSE BASIN

WELL	DEPTH Interval (m)	AGE/FORMATION	LITHOLOGY	SCI	NET THICKNESS (m)	GHC PPM	OOGC PPM	AV TOC	ORIGINAL KEROGEN COMPOSITION V	I	W	S	PRODUCTIVITY Bbls/km^2 (x10^6)	POTENTIAL Bbls/km^2 (x10^6)
Barcoo-1	2740-2790	Late Turonian-Late Campanian	Mudstone, light grey, slty	4.0	20	303	2120	1.11	40	40	20		0.105	0.716
	3220-3350	Early Aptian-Middle Cenomanian	Mudstone, medium grey	4.75	130	432	1333	1.42	30	60	AW 10		0.963	2.989
	3350-3380	Early Aptian-Middle Cenomanian	Mudstone, medium grey-medium dark grey	4.75	30	7820	20665	4.74	10	45	AW 30	15	4.051	10.720
East Swan-1	2683-3039	Petrel Fm Mbr 'C' Eqv	Mudstone, medium-dark grey, dark grey	5.5	65	5275	8954	2.73	35	30	25	10	5.928	10.052
Heywood-1	4100-4570	Petrel Fm Mbr 'C' Eqv	Mudstone, medium grey, slty	6.5-8.0	No Log	?	?	1.52	?	?	?			
Lombardina-1	2085-2200	Late Neocomian -Albian	Mudstone, medium-dark grey	4.5	115	987	3313	2.35	35	45	20		1.951	6.595
Lynher-1	1457-1495	Callovian	Mudstone, dark grey	3.75	25	831	7257	6.72	25	60	10	5	0.346	3.137
	1543-1598	Callovian	Mudstone, medium-dark grey, dark grey	3.75	30	1102	9189	3.27	30	20	20	15	0.568	4.767
	1543-1598	Callovian	Coal, black	3.75	5	6655	31766	35.26	30	50	15	5	0.568	2.742
North Hibernia -1	2177-2375	Late Triassic	Mudstone, medium-dark grey	6.5	65	11128	13000	8.6	35	40	25		12.498	14.598
Rob Roy-1	1524-1545.5	Middle Jurassic	Mudstone, grey-brown	4.5	21.5	2985	14000	4.90	10	45	25	20	1.109	5.187
	1567-1570.5	Middle Jurassic	Mudstone, medium grey	4.5	3.5	2450	10000	5.19	35	35	5	25	0.148	0.605
Skua-1	2427-3084	Middle Jurassic	Coal, black	5.0	25	189189	357312	51.37	10	25	20	45	81.757	154.449
	2457-2674	Middle Jurassic	Mudstone, medium grey, dark grey	4.5	46	3423	9439	3.66	40	30	15	15	2.742	7.509
	2820-3048	Early Jurassic	Mudstone, dark grey	5.25	34	16355	26370	4.36	25	20	10	45	9.608	15.487

Table 7 Continued ...

WELL	DEPTH Interval (m)	AGE/FORMATION	LITHOLOGY	SCI	NET THICKNESS (m)	GHC PPM	OOGC PPM	AV TOC	ORIGINAL KEROGEN COMPOSITION				PRODUCTIVITY Bbls/km^2 (x10^6)	POTENTIAL Bbls/km^2 (x10^6)
									V	I	W	S		
Swan-1	2930-3067	Late Jurassic-Early Neocomian	Mudstone, dark grey, medium-dark grey, olive black	4.75	45	1203	300	1.78	35	40	20	5	0.934	2.321
	3184-3285	(?)Late Jurassic	Mudstone, medium-dark grey, dark grey	6.0	90	3295	4975	1.7	30	30	30	10	5.113	7.731
Yampi-1	3148-3260	Petrel Fm Mbr 'C' Eqv	Mudstone, medium-dark grey, dark grey	5.75	30	6670	10317	3.43	25	40	25	10	3.458	7.632

CHC : Generated hydrocarbons
OOGC : Original oil generating capacity
V : Vitrinite
F : Inertinite
S : Sapropel
W : Waxy Sapropel

The thick pre-Permian (Devonian-Carboniferous) sequence is unlikely to be a significant source since it would have been post oil mature in the basin depocentre during the Late Palaeozoic. These thick Palaeozoic sections may however, have generated gas during the Mesozoic and Tertiary.

11.1.3 Triassic

The Early to Middle Triassic sediments analysed in the Browse Basin were encountered in the wells on the Ashmore Block where they consist of fine grained clastics with interbeds of carbonates. They have low organic carbon contents and no significant hydrocarbon source potential.

Close to the basin margin, a predominantly sandy fluvio-deltaic sequence was deposited, which contains thin coals and organically rich mudstones with some possible gas source potential.

To the north of the Ashmore Block, a clastic sequence prograded southwards over carbonates during the Carnian-Norian. In North Hibernia-1, this sequence contains a thin source rock horizon deposited in a deltaic interdistributary bay.

Sediment appears to have been sourced from a land mass to the northwest. The exact distribution of the source unit is not known, but it is not seen in sediments of similar age to the south in Ashmore Reef-1 and Brown Gannet-1. It is probably therefore restricted to delta front sediments on the north and northwestern side of the Ashmore Block.

11.1.4 Jurassic

Rifting was initiated in the Permo-Triassic and reached its culmination in the Middle Jurassic. Early Jurassic sediments lie conformably on Triassic sediments and are represented by a fluvio-deltaic sequence of sands and shales over most of the area. Detailed facies analysis of sequences through the Jurassic shows that several cycles of prograding deltaic sequences are represented, each terminated by renewed marine transgression. These cycles consist of Late Triassic-Early Jurassic fluvio-deltaic sediments, Middle Jurassic fluvio-deltaic and marine sediments, and Late Jurassic to Early Cretaceous marine and fluvio-deltaic sediments.

The boundary between each cycle is marked either by an unconformity or a disconformity. A further minor uplift event, with erosion, occurred within the Late Jurassic sequence along the basin margins (Encl. 19).

Source rocks have been identified within each of the cycles and their distribution is controlled primarily by the environment of deposition. This has been demonstrated by a detailed study of the 11 wells of the Browse and Bonaparte Basin, in which Middle Jurassic sediments occur. Environments of deposition have been identified by using electric log characteristics, palaeontological and lithological data, and have been related to the abundance and type of kerogen (Encl. 28). This method has been used to describe the distribution of source rocks within the deltaic sequence, for Jurassic cycles in the Browse and Bonaparte Basins. It has also been applied to the Early Permian of the Bonaparte Basin.

Within the predominantly sandy sequences of the upper delta plain are thin mudstones with carbonaceous to lean organic contents. The kerogen content of these mudstones is dominantly inertinitic, with subordinate amounts of vitrinite and no significant content of oil-prone exinite or algal kerogen. In the lower delta plain sediments, thin, organically rich mudstones are present as channel fill and interdistributary deposits. These mudstones are predominantly inertinitic in the proximal part of the lower delta plain. However, towards the delta front, they become richer in organic matter, with an associated increase in algal and waxy kerogens. Close to the delta front, thick interdistributary bay shales and minor argillaceous distributary channel fill deposits are very good source rocks, with above average organic carbon contents and high contents of oil-prone kerogen (Encl 28). In particular, between the high areas of the Ashmore Block and Londonderry High, thick algal- rich coals and shales have formed in interdistributary bays and abandoned distributary channels.

Jurassic sediments of this type show their best development in Skua-1 where over 200m of interdistributary bay sediments are present.

In areas exposed to a more dynamic delta front environment in the central Browse Basin, the lithofacies show rapid vertical variation and no thick, algal-rich interdistributary coals or mudstones were deposited. In this area, source potential is lower and distributary channel fill and interdistributary bay deposits contain exinite rather than algal kerogens.

Prodelta shales developed offshore are generally organically rich but contain kerogen which is dominated by fine grained inertinite, with subordinate vitrinite. Further offshore towards the basin centres, fine grained exinitic and vitrinitic kerogens were deposited in the Vulcan Graben, from the Late Jurassic to Early Cretaceous. These sediments could be potential oil source rocks.

Source rocks developed in deltaic environments are therefore restricted to lower delta plain and delta front sediments and form narrow bands 50 to 80 km wide fringing the palaeocoastlines. Within these narrow bands, source rock potential can be good or very good but it also shows rapid lateral variation. The bands defined by such environmental and geochemical analyses are therefore better considered as areas with a high probability of containing good source rocks.

The source potential of the Early Middle and Late Jurassic-Early Cretaceous intervals are considered in more detail below.

11.1.4.1 Early Jurassic

The Early Jurassic palaeoenvironment map (Fig. 36) shows that the lower delta plain and delta front sediments extend in a band from the Vulcan Graben, across the centre of the Browse Basin and around the southern margin of what is now the Scott Plateau. Source rocks are thick, distributary channel fill, algal-rich shales, as seen in Skua-1 (TOC 4.0%, 45% algal kerogen) (Fig. 37). Early Jurassic delta front sediments were not penetrated in the basin centre. However, lower delta plain sediments, containing shales rich in inertinite, are present in Scott Reef-1, Lynher-1, Barcoo-1 and Lombardina-1.

There are insufficient data points to determine the source quality of this unit. It would seem likely that delta front deposits may be a good source throughout the Vulcan Graben and Vulcan Shoals Trough but the extent of the source to the southwest is unknown. However, the likely area of probable source potential can be delimited (Fig. 38). Around Skua-1, this source reaches productivities of up to 9 million bbls/km^2.

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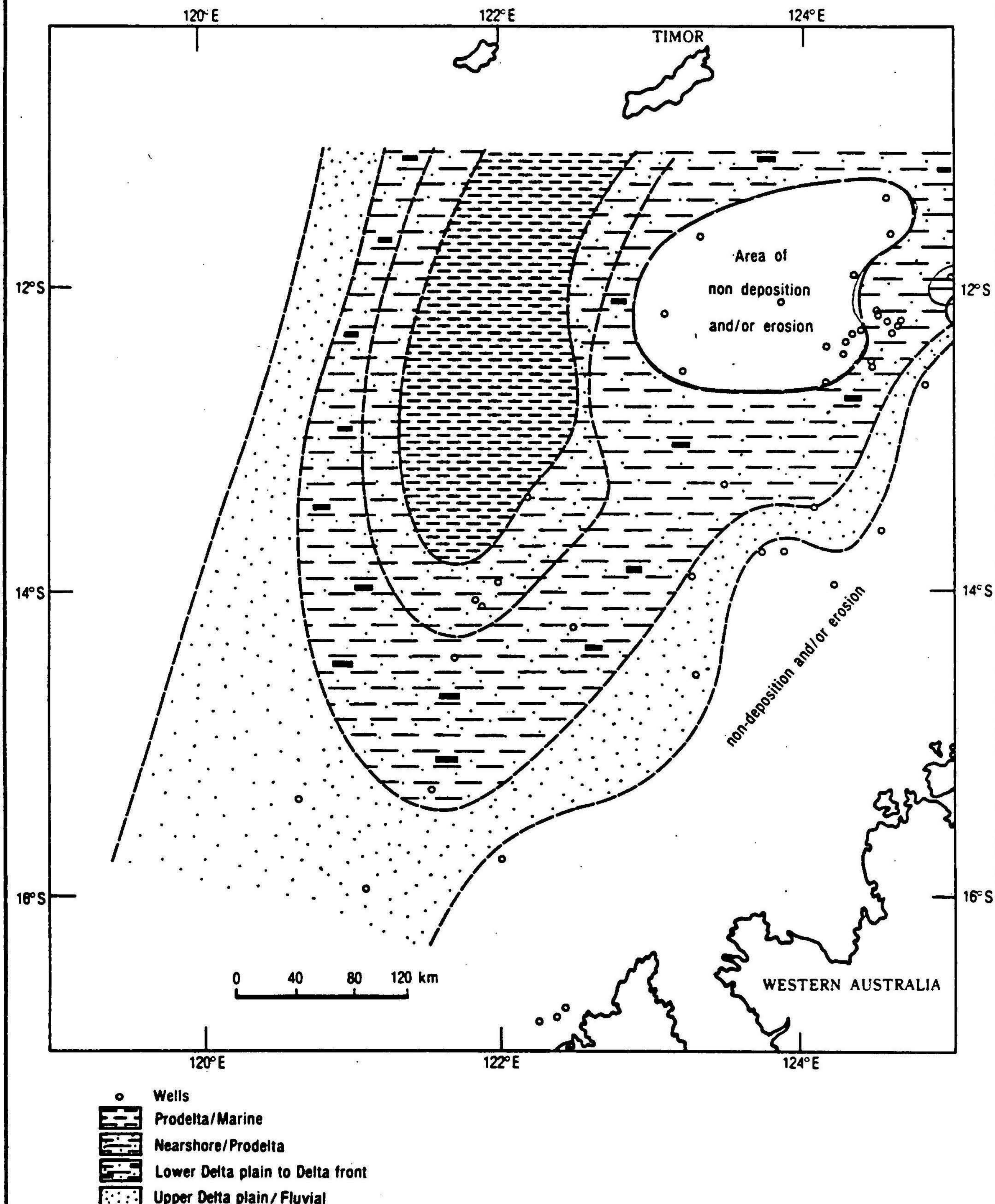

Browse Basin Palaeogeography
Early Jurassic

Figure 36

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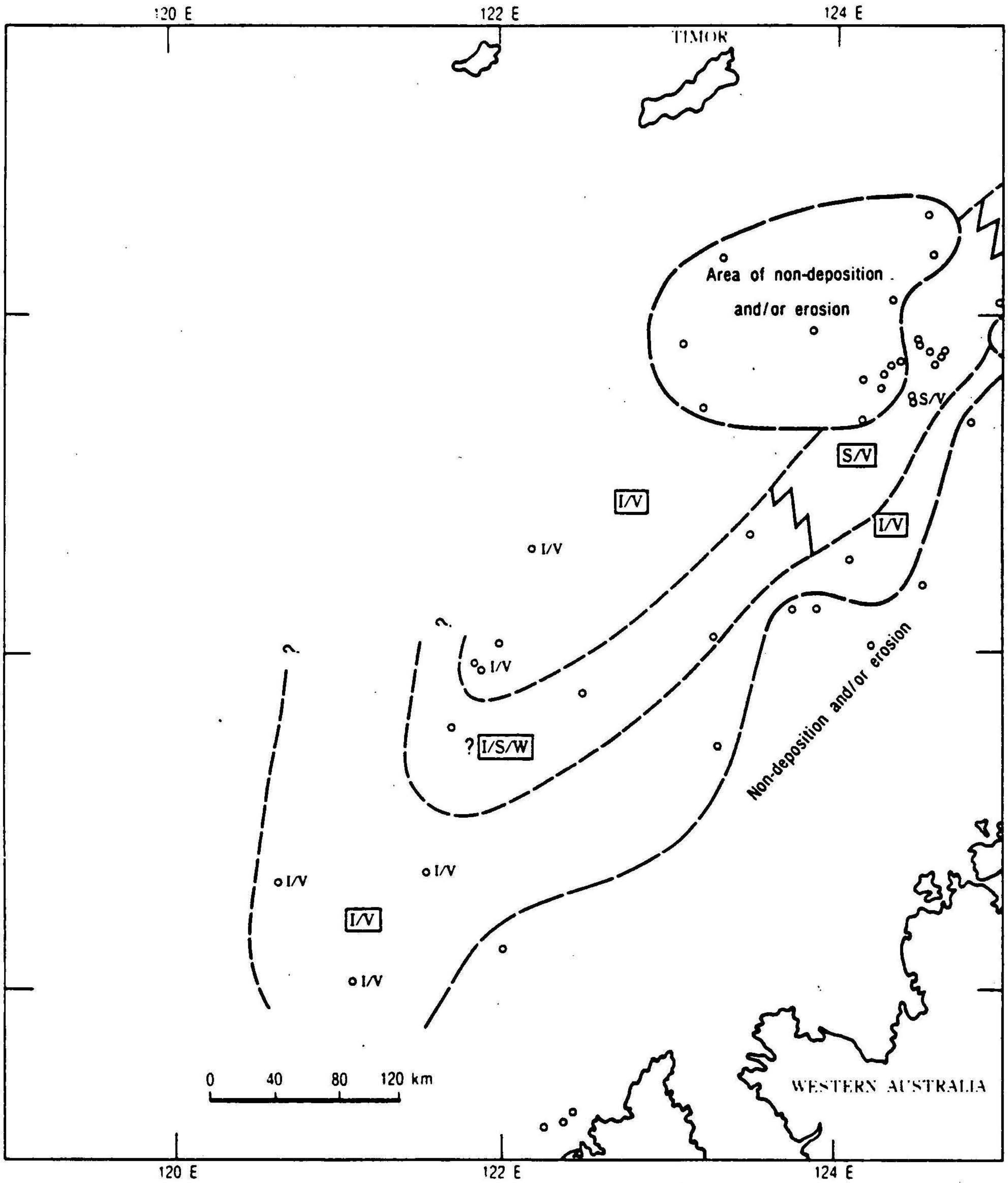

o Wells

W Waxy kerogen facies

I Inertinite facies

V Vitrinite facies

S Sapropel facies

I/V Inertinite greater than Vitrinite

Browse Basin Kerogen Facies
Early Jurassic

Figure 37

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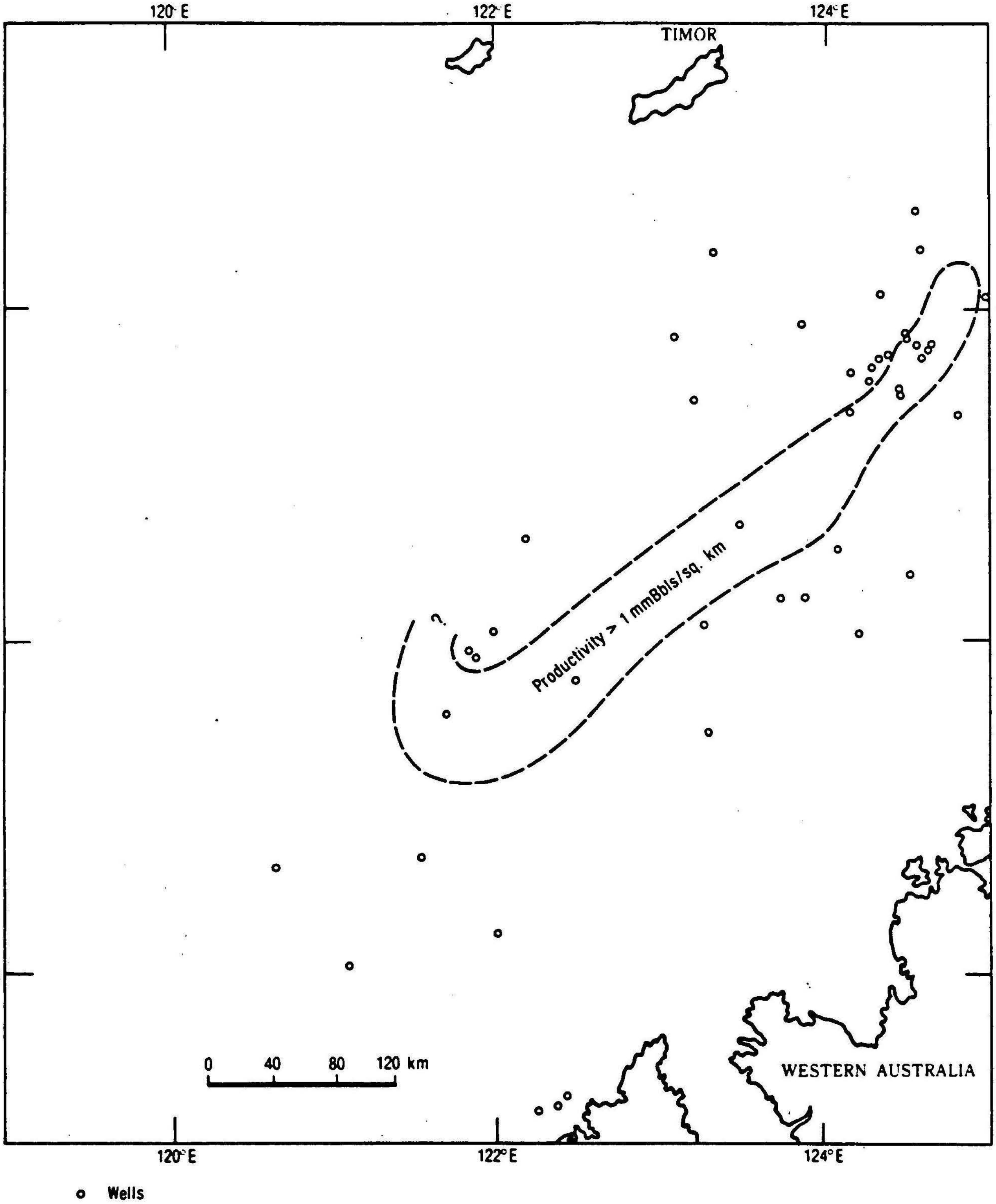

Browse Basin Source Rock Productivity
Early Jurassic

Figure 38

11.1.4.2 Middle Jurassic

The Middle Jurassic sequence contains the best source rock database; the section has been penetrated by East Swan-1, Skua-1, Barcoo-1, Brewster-1A, Buffon-1, Heywood-1, Lombardina-1, Lynher-1, Rob Roy-1, Yampi-1 and Scott Reef-1. The Middle Jurassic palaeoenvironment map (Encl. 29) shows that lower delta plain to delta front sediments are present around the Vulcan Graben and Vulcan Shoals Trough. They continue along the margin of the Browse Basin towards Lynher-1, before swinging to the west of Scott Reef-1. In this area, the sediments fringe the postulated landmass to the north and west of Scott Reef. Marine conditions are thought to have existed around and north of Scott Reef-1.

The source rocks present in the Middle Jurassic are found associated with interdistributary bay environments, in which algal-rich mudstones and coals formed behind the high area of the Ashmore Block. Average TOC contents of 3%-6% with oil-prone kerogen contents of 20%-30% have been recorded from this zone. Exinite-rich coals were formed further south in interdistributary bay deposits, in which there were rapid vertical facies changes.

Uplift and erosion have subsequently reduced the original area of good source rocks by removing potential sources along the basin margins and possibly from the uplifted southern edge of the Ashmore Block. The source rock has also been eroded along the main basin fault around Prudhoe-1 (Encl. 29). The best areas of present day Middle Jurassic source potential are in the Vulcan Graben, Vulcan Shoals Trough and Cartier Trough. An area of good source potential also fringes the basin margin, from Rob Roy through Yampi to Lynher-1, in the southern part of the Browse Basin.

The Middle Jurassic source rock unit is extremely thick (over 1000 m based on seismic evidence) in the Vulcan Graben and Cartier Trough, and becomes thinner towards the central Browse Basin. It is around 500m thick along the Yampi Shelf (Yampi-1), but the Middle Jurassic section does not thicken towards the central Browse Basin (in Caswell-1 less than 500m) and thins out towards the Scott Reef structure (Encl. 19). It was a prolific source in the Vulcan Graben and Vulcan Shoals Trough, with productivities commonly in excess of 10 million bbls/km^2 and locally as high as 100 million bbls/km^2 where algal-rich coals are present, as in Skua-1 (Encl. 30).

11.1.4.3 Late Jurassic

The end of the Middle Jurassic was marked by breakup rifting in the Callovian, followed by a Late Jurassic marine transgressive prograding interval. In the main depocentres of the Browse Basin, i.e. the Vulcan Graben, the Cartier and Vulcan Shoals Trough and the Rowley Sub-basin, deposition of fine grained shaly sediments continued from the Late Jurassic into the Early Neocomian (Encl. 31). The Middle-Early Jurassic sediments (pre-breakup) were eroded from the present basin margin as the result of uplift and erosion during the breakup unconformity.

The Late Jurassic sediments apparently thin out towards the margin, in places to zero. This is mainly due to non-deposition and, to a lesser extent, to erosion, as shown in the Barcoo-1 to Leveque-1 cross-section (Encl. 19).

Kerogen facies mapping (Encl. 31) shows a transition from inertinite facies in Neocomian nearshore deltaic sediments at Rob Roy-1 and Prudhoe-1, to mixed humic kerogen in prodelta shales. These grade to a mixed humic and waxy sapropel-rich facies towards basin centres in the Vulcan Graben and Cartier Trough. From regional palaeoenvironment considerations, this source may extend towards the shelf edge in deeper water sediments of the Browse Basin.

Late Jurassic source rocks have been identified in the Kimmeridgian in Swan-1; by extension of the lithofacies and kerogen facies trends, they may also be present in this interval in the Cartier Trough and Vulcan Graben (Encl. 31). In Swan-1, these source rocks contain around 1.70% TOC and 40% oil-prone kerogen, with a productivity in excess of 5 million bbls/km^2 (Encl. 32). They may also extend through the central Browse Basin. However, the Late Jurassic section was probably not deposited on the outer shelf edge around Buffon-1 and Scott Reef-1 and has been eroded on the southern margin of the Ashmore Block. Present day source potential is therefore restricted to the Cartier Trough, Vulcan Graben and possibly in the central Browse Basin (Encl. 32). Insufficient well data have generally precluded an accurate assessment of the productivity of this source rock.

The areas of postulated source potential are all presently mature for oil generation and reach post-maturity in the deeper part of the Browse Basin (Encl. 32).

11.1.5 Cretaceous

No source rocks have been identified in the post-middle Neocomian sediments except in Barcoo-1 and Lombardina-1, where thin organically rich mudstones are present in Middle Cenomanian to Barremian, and Albian to Late Neocomian prodelta shales respectively. The extent of this source rock is unknown but it is probably restricted to the southern Browse Basin. In Barcoo-1, this source rock contains about 4.7% TOC and 40% oil-prone kerogen, with a productivity of approximately 4 million bbls/km^2.

11.1.6 Tertiary

No source rocks have been identified in Tertiary sediments. If there are good source rocks in the Tertiary which were not analysed in the study, they would only be immature to early mature and would not therefore be significant oil sources.

11.2 MATURITY

11.2.1 Present Day Temperature Gradient (Encl. 33b)

Geothermal gradients generally decrease from values of around 40°C/km on the Londonderry High to values of 25°C/km along the present day shelf edge. The major Jurassic and Cretaceous depocentres in the Browse Basin are marked by lower geothermal gradients of between 25 and 30°C/km. The Echuca Shoals Trend along the main basin fault is marked by higher present day thermal gradients with values 5 to 10°C/km above those of the basin centre.

The areas of thinner Jurassic and Cretaceous sediments towards the continental shelf edge and over the Ashmore Block and in the vicinity of the Dillon Ridge are marked by a trend of higher geothermal gradients up to 10°C/km above basin centre values.

The gradients show a good correlation with the basin geometry; areas of thinner crust and thick sedimentary fill are marked by low geothermal gradients, and areas of thin sedimentary fill and thicker crust have higher gradients.

11.2.2 Maturity : Regional Description

A total of 21 wells have been analysed for vitrinite reflectivity and spore colour index in the Browse Basin. Geothermal gradients have been calculated for a total of 27 wells and compared with SCI gradients.

The results show that the Browse Basin has experienced a more complex thermal history than the other basins analysed along the Northwest Shelf. The spore colour gradient does not correlate with geothermal gradients over an extensive area, in contrast with the relationship throughout much of the Bonaparte Basin and the Northern Carnarvon Basin. The lack of correlation shows that parts of the area have been affected by periods of high heat flow in the Late Jurassic and Late Tertiary.

The maturity data indicate that the well sections at Anderdon-1, and North Hibernia-1 have been affected by Late Jurassic igneous intrusions. The intrusive body in Rainbow-1 affects Triassic but not Cretaceous maturity gradients and has therefore been intruded between the Triassic and the Cretaceous. The most likely time for this intrusion would have been during the Late Jurassic, which is marked by volcanic activity throughout the Browse Basin. Paleocene and younger intrusives were emplaced at Puffin-1, Lombardina-1 and Scott Reef-1.

By comparing the maturity gradients and the present day geothermal gradient for Brewster-1A and Buffon-1, it is postulated that a thermal event took place during or after the Late Cretaceous. The dating for this event can be more accurately defined as Eocene or younger in Puffin-1, where Eocene and older sections are affected by high heat flows associated with an igneous intrusive.

It is difficult to assess Late Jurassic regional thermal events due to later overprinting. However, it is considered likely that Late Jurassic igneous activity was not accompanied by a regional increase in thermal gradient. Nevertheless, this is not the case for the Eocene-Early Miocene thermal event, which has caused regional heating and increased thermal gradients (e.g. in Buffon-1, Brewster-1A) (Fig. 39). It is likely that this regional heating is due to igneous activity, but the lack of any substantial extrusive igneous bodies of this age makes it difficult to substantiate such a claim.

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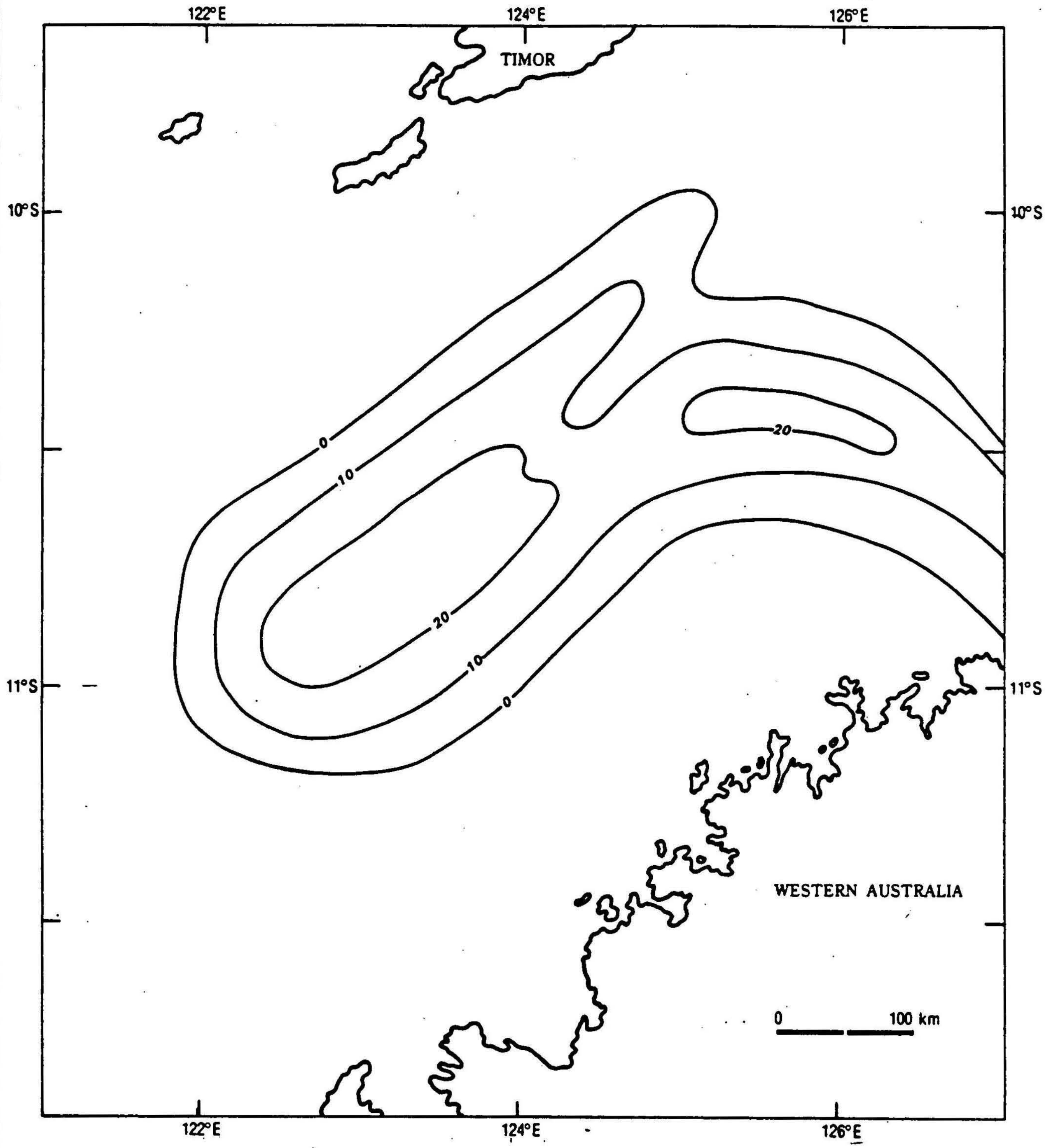


— 10 — Geothermal gradient °C/km

Browse Basin Tertiary Geothermal Anomaly

Figure 39

The Tertiary thermal event is most pronounced throughout the central Browse Basin, and on the Londonderry High. Its effect may also continue down the western Bonaparte Basin (Fig. 39).

11.2.2.1 Maturity : Uplift and Erosion

As well as indicating the maturity of the section, the maturity gradients, and in particular the vitrinite reflectance gradient, can be used to determine approximately the amounts of section missing at unconformities. Furthermore, extrapolation of maturity gradients to surface can be used to determine the maximum depth of burial of well sections and the cumulative amount of section missing above the first maturity measurements.

Compilation of the results (Table 8) suggests that the Londonderry High has experienced numerous phases of uplift from the Late Permian through to the present day. These movements have removed between 200m and 1000m of sedimentary cover from this stable block. The most important phase of uplift appears to have been during the Tertiary, probably in the Pliocene, with small episodes throughout the Jurassic and Cretaceous. Tertiary uplift of up to 700m has occurred on the Londonderry High. Northeast, in the Vulcan Graben, there is evidence for considerable uplift and erosion. This probably occurred during the Late Jurassic, along the edge of the Cartier Trough e.g. in Sahul Shoal-1 and Rainbow-1 and on an elevated horst block within the graben (East Swan-1). The northern part of the Ashmore Block also appears to have been uplifted during the Miocene-Recent (probably Pliocene).

In the troughs, subsidence has been continuous from the Jurassic through to the present day.

TABLE 8 - SUMMARY OF MATURITY DATA AND SECTION MISSING, BROWSE BASIN

WELL	SCI GRAD.	MAX. DEPTH OF BURIAL MAX. BURIAL	SECTION MISSING AT UNCONFORMITIES	COMMENTS	WATER DEPTH (m)	SEA BED °C
Buffon-1	2.35	Present day (P.D.)	No appreciable section missing		523	5
Caswell-1	1.9	Present day	No appreciable section missing		345	10
Barcoo-1	1.3	Present day	No appreciable section missing		720	5
North Hibernia-1	1.5	1000m greater than P.D. reached sometime from Eoc. -Rec.	1400m of Miocene -Rec. above 1155m	Maturity gradients affected by an igneous body below 3400m. One major unconformity above 1155m.	33	24
Anderdon-1	1.9	700m greater than P.D. reached during Miocene-Recent	600m, L.Cret-Triassic at 1427m. 800m Eoc.-Mio. at 481m, 1200m Mio.-Rec. at seabed.	Maturity gradient affected by igneous intrusive close to base of well section Several unconformities above 410m.	97	22
Lombardina -1	1.0	Present day	900m of Cret.-Rec. above 1500m	Well section affected by igneous intrusive near base of the well section. Several unconformities above 1500m.	175	18
Prudhoe-1	1.9	500m greater than P.D., reached during Eoc.-Rec.	600m Miocene-Recent above 735m, 300m Cret.-Pal. at 1330m, 300m E. Perm.-Jurassic at 2888m.	Possible high heat flow in the Early Permian section below 3100m. One major u/c above 705m.	175	18
Rob Roy-1	1.7	500m greater than P.D. reached sometime during Pal.-Rec.	200m E. Perm.-Mid. Jurassic at 1572m. 200m Mid. Jur.-Neoc. at 1448m. 600m Pal.-Rec. above 582m.		102	21
Leveque-1	2.0	300m greater than P.D. reached during Cret.-Rec.	450m of missing Cret.-Rec. section above 366m.	1 major u/c above 366m.	77.5	22

TABLE 8 - SUMMARY OF MATURITY DATA AND SECTION MISSING, BROWSE BASIN

WELL	SCI GRAD.	MAX. DEPTH OF BURIAL MAX. BURIAL	SECTION MISSING AT UNCONFORMITIES	COMMENTS	WATER DEPTH (m)	SEA BED °C
Osprey-1	2.7	Present day	No appreciable section missing	Igneous intrusive near to base of well section.	100	21
Yampi-1	1.4	Present day	500m. M.-L. Jurassic at 3135m, 330m E.-M.Jur. at 3390m, 1000m E.Perm.-L. Trias. at 3825m	Non linear SCI gradient below	91	22
Brewster-1A	2.5	Present day	No appreciable section missing		256	14
Rainbow-1. Cret.-Recent	1.25		1000m Triassic-Late Cret. section	Intrusive affects Cret.-Jur.-intruded in L.Jurassic.	135	20
2. Trias. and older	5.1			Trias. and older section reached maximum temperature during intrusion of igneous body in L. Jurassic.		
Lynher-1	1.4	600m greater than P.D. reached sometime during late Pal.-Rec.	1000m of L. Pal.-Rec. above 427m	1 major u/c above 427m	58	23
Swan-1	1.3	Present day	700m Early Cret. at 2630m. 200m Mio.-Rec. above 838m		109	21
E.Swan-1	1.4	Present day	200m L. Jur.-Cret. at 2330m	Maturity gradient affected by overpressure between 2300m-2400m	103	21
Skua-1	1.6	Present day	No appreciable section missing		80.5	22
Sahul Shoal-1	1.6	400m greater than P.D. reached sometime during Olig.-Rec.	1300m L.Trias.-Cret. at 1793m. 800m of Olig.-Rec. above 854m			

TABLE 8 - SUMMARY OF MATURITY DATA AND SECTION MISSING:

BROWSE BASIN

WELL	SCI GRAD.	MAX. DEPTH OF BURIAL MAX. BURIAL	SECTION MISSING AT UNCONFORMITIES	COMMENTS	WATER DEPTH (m)	SEA BED °C
Whimbrel-1	2.2	700m greater than P.D. reached sometime during Cret.-Rec.	800m of Cret.-Rec. above 915m	One major u/c above 915m	77	22
Scott Reef-1	1.0	200m greater than P.D.	200m Rec.-L.Jur./Neoc. 600m Maast.-Pal. 530m Ceno.-Turonian	Intrusive near base of well section (probably dyke)	49.5	24
Puffin-1	1.9	Present day	500m of L.Cret.-Rec. above 2119m	Maturity affected by igneous intrusive near base of the well section	102	21
Ashmore Reef-1	1.2	Present day	700m L. Jurassic to Cret. section at 2447m		37	24
Brown Gannet	1.8	Present day	No appreciable section missing		110	21

11.2.3 Maturity of Source Rock Horizons

The major source rocks of the Browse Basin are in the Middle and Late Jurassic deltaic sediments. They are about 1000m thick in most of the basin, but exceed 2500m in the basin centres, e.g. around Brewster-1A, and in the Cartier Trough. The maturity of the Jurassic source rocks has been approximated by using the calculated SCI values for the Callovian breakup unconformity surface. This horizon best approximates the maturity of the Late Jurassic source rocks, for which the horizon is essentially an estimate of the maximum maturity. The stratigraphic position of the main source rocks within the Late Jurassic is such that use of maturity of the base Cretaceous horizon would be less accurate. However, the maturity map of this level has been included for comparison (Encl. 32). The maturity for the Callovian breakup unconformity surface is a minimum estimate for the source rocks in the Middle Jurassic interval.

Calculation of the maturity at the Callovian breakup unconformity has been based on well and seismic control. The maturity at sea bed has been adjusted to correspond with sediment surface temperature. Adjustments have also been applied where data suggest the horizon is not presently at its maximum depth of burial.

The maturity map of the Callovian breakup unconformity (Encl. 30) shows that maturity at this level increases sharply into the Browse Basin from values of 3 to 4 SCI units (marginally mature) along the Yampi Shelf and Londonderry High to predicted values in excess of 9 SCI units, Ro 2.0%, (gas generation zone) around Bassett-1. Maturity values then decrease towards the present day continental slope and southwards towards Lombardina-1. This is more related to decreasing spore colour index gradients in these directions than to the depth of burial of the horizon mapped.

The Vulcan Graben and Vulcan Shoals Trough are not marked as areas of significantly higher maturity but the Skua-1 trend represents a pronounced low maturity zone, which separates the two graben structures. The Cartier Trough is an area of high maturity, due to the depth of burial of the mapped horizon. Enclosures 30 and 32 show that both Middle and Late Jurassic sediments are presently within the main oil generation zone over most of the basin. The deeper Browse Basin, Vulcan Graben and Vulcan Shoals and Cartier Troughs are good "kitchen" areas where they contain potential source rocks.

The Tertiary thermal event has had a great effect on the maturity of the sediments within the basin and has exaggerated the normal increase due to burial in central parts of the main Browse Basin and to a lesser extent in the southern parts of the Vulcan Graben and Vulcan Shoals Trough.

11.3 OIL SOURCE ROCK CORRELATION

11.3.1 Introduction

Analysis by GC/MS and carbon isotope mass spectrometry has been carried out on four crude oil samples (from the Puffin-2, Puffin-3, Jabiru-1A and North Scott Reef-1 wells) and seventeen oil stains representing migrant oil. This work has been carried out in order to determine:-

- Type of source rocks from which the oils have been generated,

- The maturity level at which they were generated, and

- The extent of any post-generation and post-migration changes in chemical composition.

In addition, eight source rocks were analysed for comparison with the oils and oil stains to try to assess the source of the oils and migrant oils.

The carbon isotope ratios in the following chapters will be expressed as parts per mil ($^{o}/_{oo}$) relative to the Pee Dee Formation Belemnite standard.

11.3.2.1 Physical and Chemical Composition of the Analysed Oils
(Refer Vol. 3, Tables II.1-II.4, Figs. II.2, II.4, II.5)

The oils analysed are medium to light, showing API gravities in the range 31.8° to 46.3°. Pour point values for Jabiru-1A and North Scott Reef-1 oils vary between 9° and 15°C. The sulphur content of the oils analysed are in the 0.10% to 0.23% range.

The gasoline range hydrocarbon data indicate that Puffin-2 and -3 oils contain a lower proportion of gasoline range hydrocarbons than the other two crude oils analysed. Pour point ratios calculated suggest that the oils have been generated from a middle to late mature source, rich in waxy, sapropelic kerogen.

Liquid chromatography results (Tables II.1 and II.3) show the analysed oils contain relatively high proportions (around 85%) of saturated hydrocarbons typical of paraffinic oils. Alkane/aromatic ratios indicate that the Jabiru-1A and Puffin-2 crude oils are less mature than those from Puffin-3 and North Scott Reef-1.

Whole oil gas chromatography shows a relatively wide alkane distribution with a fair proportion of light alkanes (below C_{12}) relative to heavier (C_{12+}) compounds. Lower proportions of light alkanes in the Puffin-3 oil may be caused by water washing.

Gas chromatography of the alkane fractions shows an alkane distribution with n-alkanes ranging from $\underline{n}$-C_{11} to $\underline{n}$-C_{31} and fair quantities of waxy alkanes above $\underline{n}$-C_{23}.

All four oils analysed have moderately high pristane/phytane, pristane/$\underline{n}$-C_{17} and phytane/$\underline{n}$-C_{18} ratios and CPI values very close to 1. These data suggest that the analysed oils have been generated from a middle mature source, rich in waxy kerogen and deposited in a nearshore marine environment.

11.3.2.2 Biomarker Characteristics of the Oils

(Refer Vol. 3, Table II.3, Figs. II.1, II.3, II.6)

GC/MS and carbon isotope analysis of the Browse Basin oils show that they can be divided into two categories.

Group-1 oils comprising North Scott Reef-1, Jabiru-1A and Puffin-2 have similar carbon isotope ratios for saturates and aromatics in the range of -26.5 to -27 and -24.5 to -26.5 respectively. They also have similar triterpane and sterane distributions. The triterpane distribution is dominated by the C_{29} and C_{30} hopanes; it is characterised by the presence of C_{29} and C_{30} pentacyclic compounds eluting between the C_{29} norhopane and C_{30} hopane (peaks 4 and 5).

These pentacyclic compounds appear to be the same as those identified by Philp et. al. (1982) and interpreted to be markers for terrestrial organic matter based on their occurrence in coals and in oil seepage from coal.

The sterane distributions also indicate the presence of a large terrestrial contribution to the kerogen.

The Group 2 oils from Puffin-3 differ from the other oils in having carbon isotope ratios of -22.9 (saturates) and -21.7 (aromatics). These values are typical of oil sourced from kerogen which was deposited in an intertidal environment. The oil also contains a characteristic biomarker eluting just before the C_{30} hopane, which is thought to be 18 α(H) oleanane. The sterane and triterpane distribution is similar to the Group 1 oils. Puffin-3 is probably best explained as a mixture of two oils, one similar to the Puffin-2, Jabiru-1A and North Scott Reef-1 oils, and one of an unknown composition derived from intertidal sediments.

11.3.3 Geochemical Characteristic of the Source Rocks

(Refer Vol. 3, Table IV.1, Figs. IV.1-IV.3)

Gas chromatography analysis of potential source rocks from the Browse Basin shows alkane distributions typical of hydrocarbons derived from mixed, terrestrially sourced waxy kerogens and algal kerogens. The relative proportion of hydrocarbons from these constituents varies; hydrocarbons sourced from terrestrially derived kerogen are dominant in Barcoo-1, Lynher-1, Swan-1, East Swan-1 and Yampi-1, while algal kerogens predominate in extracts from Skua-1.

Detailed geochemical analysis of these source rock extracts using GC/MS and carbon isotope analysis suggest that the source rock extracts can be separated into three groups based on the distribution of steranes and triterpanes and carbon isotope values.

(i) Group 1

Barcoo-1 (3370-3400m, Early to Late Cretaceous)
Lynher-1 (1540-1555m, Middle Jurassic)
Skua-1 (2427-2435m, Middle Jurassic)
Skua-1 (2637-2640m, Middle Jurassic)

These predominantly coaly samples are distinguished by a prominent unknown compound 17(V) which elutes at about the same time as 17 α(H) trisnorhopane. The extracts also contain several prominent tricyclic terpanes.

These source rock extracts are dominated by C_{29} steranes, indicative of predominantly terrestrial kerogen input in the sediments. The group may possibly be further subdivided on the basis of carbon isotope data into two groups. However, this is not thought to be a significant subdivision.

(ii) Group 2

East Swan-1	(2854-2869m, Middle Jurassic)
Swan-1	(3235-3247m, Late Jurassic-Early Neocomian)
Yampi-1	(3173.4m, Middle Jurassic)

These predominantly shaly source rocks are characterised by extracts containing the unknown C_{29} and C_{30} pentacyclic compounds (4 and 5). The triterpane distributions are also characterised by the lack of the unknown compound 17(V) found in Group 1 and the unknown compound (oleanane?) found in Group 3. The steranes of these extracts contain significant quantities of C_{27} steranes, indicating possibly some marine contribution to the source kerogens.

The group may be subdivided on the basis of carbon isotope data into two groups which correspond to Late Jurassic and Middle Jurassic sediments. The Late Jurassic sediments show significantly more negative $\delta 13C$ saturate values of between -27 to -28 compared to Middle Jurassic values of around -26. This difference may reflect a relatively greater proportion of terrestrially sourced waxy kerogen in the Late Jurassic source rocks. The source rock extract from Yampi-1 has significantly less negative saturate and aromatic carbon isotope ratios and it probably contains a migrant oil similar to the isotopically heavier oil seen in Puffin-3.

(iii) Group 3

Skua-1 (3021-3034m, Early Jurassic)

The one sample in this group contains a similar distribution of steranes and triterpanes to Group 2 extracts but is distinguished by the presence of the unknown compound (probably oleanane) eluting just before the C_{30} hopane.

11.3.4 Geochemical Characteristics of the Migrant Oil Stains
(Refer Vol. 3, Table III.1; Figs. III.1-III.3)

The oil stains analysed, with the exception of Lynher-1, Swan-1, Puffin-1, North Hibernia-1, Caswell-1 (3620m to 3635m) and possibly Lombardina-1 (1845m to 1855m) are mixtures of biodegraded and live oils. Detailed GC/MS and carbon isotope analyses suggest these migrant oils can be subdivided into three groups.

Group 1

Caswell-1	(3620-3635m, Early to Late Cretaceous)
Caswell-1	(4010-4025m, Early to Late Cretaceous)
Prudhoe-1	(2620-2630m, Early Cretaceous)
Puffin-1	(1022.5m, Eocene)
Swan-1	(3098-3113m, Late Jurassic to Early Neocomian)

This group of oil stains is distinguished by the presence of the C_{29} and C_{30} pentacyclic compounds 4 and 5 and the lack of either the unknown compounds 17(V), or the compound thought to be oleanane.

Carbon isotope data suggest that these migrant oils represent mixtures of oils derived from Middle and Late Jurassic sources.

GC/MS indications show that the migrant oils from this group have been generated at middle to late maturity.

Group 2

Anderdon-1	(2380-2395m, Early Triassic)
Brewster-1A	(3610-3630m, Early Cretaceous)
Lombardina-1	(2425-2435m, Middle Jurassic)
North Hibernia-1	(2805-2820m, Late Triassic)
Swan-1	(2360-2366m, Late Cretaceous)

With the exception of possibly Brewster-1A and Lombardina-1, these extracts are not biodegraded. The group is distinguished by the presence of the unknown C_{29} and C_{30} pentacyclic compounds 4 and 5 and the unknown compound eluting just before the C_{30} hopane. Carbon isotope values for this group vary from very negative values obtained for Anderdon-1, suggestive of mostly land plant input into the source kerogen, to values suggesting mixed algal and land plant-derived kerogen in the source of the Lombardina-1 migrant oil. This may represent facies differences in one source rock unit rather than separate sources or, alternatively, mixtures of one or more oils. The presence of the unknown compound eluting before the C_{30} hopane correlates these oil stains with the isotopically heavier fractions of the Puffin-3 oil and the Early Jurassic source rock seen in Skua-1.

Group 3

Buffon-1	(2355-2375m, Miocene 3675-3690m, Early to Late Cretaceous)
Lombardina-1	(1845-1855m, Early Cretaceous)
Rob Roy-1	(1537-1546m, Middle Jurassic)
Yampi-1	(4160-4175m, Early Permian)
Lynher-1	(1460-170m, Middle Jurassic)

This group of migrant oil stains is distinguished by the lack of significant quantities of the C_{29} and C_{30} pentacyclic (compounds 4 and 5) and the lack of compound thought to be oleanane. They do contain small quantities of the unknown compound 17(V) co-eluting with 17 α (H) trisnorhopane, with the possible exception of stains from Buffon-1. The predominance of the C_{29} over C_{30} hopane in the samples from Yampi and Lynher may separate these samples into a sub-group. The triterpane and sterane maturity indications demonstrate that these oils have been generated at middle maturity.

The triterpanes and steranes in these migrant oils are similar to those from coaly source rocks analysed in Lynher-1 and Skua-1. However, the lack of a significant peak around 17 α(H) trisnorhopane in Buffon-1 may suggest that this migrant oil is derived from a separate source.

11.3.5 Oil-Source Rock Correlation

Comparison of migrant oils, source rocks and reservoired oils shows that:

1. Carbon isotope values vary within each group, probably in response to slight changes in the relative content of algal and terrestrial detritus deposited in the source rocks.

It is probable that the carbon isotope results distinguish only two significant groups. One with less negative carbon isotope values includes the Puffin-3 oil, the biodegraded Puffin-1 oil stain and possibly the migrant oil interpreted in the source rock extract from Yampi-1. The second group, which has more isotopically light values, contains the remainder of the oils, migrant oils and source rocks. Oils and migrant oils of the first group are mixed, and indicate that the isotopically heavier fraction has a value of around -20 for saturates and aromatics. This is indicative of an intertidal environment of deposition. No source with these carbon isotope values has been identified in the study.

2. GC/MS data show that source rocks, oils and migrant oils can be characterised by the presence or absence of (i) C_{29} and C_{30} pentacyclic biomarkers, (Compounds 4 and 5), (ii) a biomarker compound eluting before the C_{30} hopane (probably oleanane), and (iii) a biomarker compound eluting with 17 α(H) trisnorhopane (Compound 17(V)).

Based on this classification, it can be concluded that migrant oils of Group 1 are sourced from either Middle Jurassic or Late Jurassic shales, or from both. These sources contain varying proportions of terrestrially sourced kerogens and algal kerogen. The lack of any oil stains, or oil containing significant quantities of the biomarker eluting between 18 α (H) and 17 α (H) trisnorhopanes (Compound 17(V)) seen in the coals analysed suggest that these coals are only of local significance and do not greatly contribute to the overall source potential of the Middle Jurassic sequence. Either a Middle Jurassic or a Late Jurassic source, or sources from both of these age intervals, has generated the oils in North Scott Reef-1, Jabiru-1A and Puffin-2.

3. Oil stains from Group 2 are characterised by the presence of the unknown compound (probably oleanane) eluting just before the hopane. This compound is also present in the Early Jurassic source rocks in Skua-1; these oil stains may therefore be derived from this source. The marker compound is also present in the isotopically lighter fraction of the Puffin-3 oil, an indication that this oil may be partly derived from the Early Jurassic.

4. Group 3 oil stains are characterised by a lack of any significant quantities of the marker compound thought to be oleanane and marker compounds 4 and 5 but may contain small quantities of the marker compound 17(V) co-eluting with the 17 α (H) trisnorhopane. These migrant oils correlate well with source rocks from Group 1 (coaly source rocks from the Middle Jurassic).

There are no source rocks which correlate to the isotopically heavier fraction of the Puffin-3 oil and the Puffin-1 oil stain. These oils have been generated from a source rock deposited in intertidal sediments not analysed in the study.

No analysis has been performed on gases discovered in the basin. Limited published data on gas from the gas condensate of the Scott Reef field show that the gas contains around 7% wet gas by volume. This gas has probably been generated from post-mature sediments near Scott Reef-1 and therefore must have been generated from Triassic and older sediments. Gas is unlikely to have been generated from sediments younger than Triassic over much of the study area of the Browse Basin, except in the central Browse Basin where a Tertiary heating event will probably have generated gas from any potential sources in Middle Jurassic and older sediments.

11.4 TIMING AND GENERATION

The timing of oil generation has been calculated from the maturity gradients of wells within the main areas of each source rock. These determinations have been cross-checked using maturity modelling in selected well sections and synthetic sections based on seismic data in basinal areas or areas of little well control (Table 9, Encl. 34). As indicated in Table 9, there is reasonable agreement between the two methods.

11.4.1 Late Triassic

The Late Triassic source rock in North Hibernia-1 is of limited areal extent and may be restricted to the northern half of the Ashmore Block. Based on the maturity gradient from North Hibernia, this source unit will have begun generating oil in large enough quantities for migration during the Miocene to Recent. Oil generation will have ceased in this area with Pliocene uplift and erosion.

TABLE 9 - TIMING OF ENTRY INTO EFFECTIVE OIL WINDOW

BROWSE BASIN

	Depth to horizon on TTI Chart	R_o = 0.5%	SCI = 5
East Swan-1			
Early Jurassic	3100	35 (E. Oligocene)	40
Middle Jurassic	3000	20 (E. Miocene	25
Late Jurassic	2700	5 (Pliocene)	10
Browse Depocentre			
Early Jurassic	4900	105 (E. Cretaceous)	100
Middle Jurassic	4700	80 (L. Cretaceous	90
Late Jurassic	4300	60 (E. Paleocene)	70-80
Cartier Trough			
Early Jurassic	3500	85 (L. Cretaceous)	75
Middle Jurassic	3300	70 (L. Cretaceous	65
Late Jurassic	3100	60 (E. Paleocene)	40-50

11.4.2 Early Jurassic

An Early Jurassic source in lower delta plain mudstones may be present in the central Browse Basin and in an area around Scott Reef-1. This source rock is presently at depths greater than 4500m and would have commenced generating oil in the Early Cretaceous based on present day temperature gradients and palaeo-maturity gradients.

Thermal maturity modelling of the synthetic section in the Browse Basin Depocentre (Encl. 34) shows the upper parts of the Early Jurassic in this area became mature around 105 Ma during the Early Cretaceous.

Maturity modelling of synthetic section at the southwestern end of Cartier Trough (Encl. 34) shows potential Early Jurassic source rocks in this area will have become mature during the Late Cretaceous (approximately 85 Ma). Towards the edges of the major depocentres (Browse Basin, Vulcan Graben, Vulcan Shoals Trough, Cartier Trough), Early Jurassic sources may not have reached maturity until the Eocene to Early Miocene. In different parts of the Browse Basin, the Early Jurassic will have generated oil through most of the Tertiary.

11.4.3 Middle Jurassic

The extent of Middle Jurassic source rocks along the southern boundary of the Browse Basin and in the Vulcan Graben, Vulcan Shoals Trough and Cartier Trough to the north, is shown on Enclosure 29.

Maturation modelling of a synthetic section for the Browse Basin depocentre and the Cartier Trough (Encl. 34) shows the Middle Jurassic became mature by the Late Cretaceous, 70-80 Ma. The main pulse of oil generation is likely to have been due to heating during the postulated Early Miocene thermal event.

On the basin edges, however, e.g. at East Swan-1, Middle Jurassic sources may have reached maturity only during the Early Miocene (20 Ma).

11.4.4 Late Jurassic

Sediments of this age are good source rocks in the Vulcan Graben and Cartier Troughs. They have contributed significantly to the oil discovered in Challis, Jabiru and Puffin. Maturity data at Swan-1 and East Swan-1 and the geological cross-section across the Cartier Trough (Encl. 20) suggest that this source rock only became mature during the Pliocene.

Maturation modelling for a synthetic section at the southern end of the Cartier Trough (Encl. 34) suggests the Late Jurassic sources became mature as early as the Early Paleocene in the northern depocentres. On the basin edges, potential sources are only just mature, or reached maturity during the Plio-Pleistocene.

Late Jurassic source rocks could also be present in the central Browse Basin. Maturation modelling for a synthetic section in the Browse Basin Depocentre (Encl. 34) shows that potential Late Jurassic sources in this area would also have become mature during the Early Paleocene. However, they would have generated the bulk of their oil source potential in the Miocene thermal event.

12. BONAPARTE BASIN

12.1 SOURCE ROCKS

12.1.1 Introduction

Fourteen wells from the Bonaparte Basin have been analysed in this study. Data from a further six wells on open file, together with wells analysed in the Robertson Research 1979 study have been incorporated in this report. Strata analysed range from the Late Carboniferous to Tertiary in age. The source rocks identified in this basin are summarised in Table 10.

12.1.2 Pre-Permian

The Bonaparte Basin was initially formed in the Early Cambrian and the earliest sediments deposited were the Early Cambrian volcanics. These are unconformably overlain by Late Cambrian to Early Ordovician clastics and carbonates, which were deposited in a shallow marine environment. Uplift and erosion of these sediments occurred during the Middle Ordovician. No wells have penetrated this section in the offshore Bonaparte Basin.

Following deposition of an Early to Middle Devonian evaporite sequence, Late Devonian clastics (Cockatoo Formation), and algal reefs (Ningbing Limestone) were deposited on the shelfal areas of the Kimberley and Sturt Blocks. The Late Devonian back reef deposits may have some source potential where sapropelic lagoonal sediments have been preserved. A dolomitic sandy facies (the Button Beds) was deposited in a nearshore environment. In the basin centre, a thick shale and siltstone sequence, the Bonaparte Beds, was deposited. The former is unlikely to have any significant source potential, but the hydrocarbon potential of the Bonaparte Beds in unknown.

TABLE 10

SUMMARY OF SOURCE ROCK INTERVALS, BONAPARTE BASIN

WELL	DEPTH Interval (m)	AGE/FORMATION	LITHOLOGY	SCI	NET THICKNESS (m)	GHC PPM	OOGC PPM	AV TOC	ORIGINAL KEROGEN COMPOSITION				PRODUCTIVITY Bbls/km² (x10⁶)	POTENTIAL Bbls/km² (x10⁶)
									V	I	W	S		
Bougainville-1	2561-2570	Kulshill Fm	Mudstone, medium-dark grey	5.5	9?	9900	16500	6.12	20	45	25	10	1.531	2.569
Eider-1	1646-1662	Bathurst Island	Mudstone, medium-dark grey	4.25	15	1960	9148	1.82	30	40	30		0.494	2.371
	1860-2125	Middle Jurassic	Mudstone, medium grey-medium-dark grey, grey black + thin coals	4.75	36	5329	12561	4.4	40	25	20	15	3.310	7.805
Flamingo-1	3018-3266	Bathurst Island and Flamingo Shale	Mudstone, medium-dark grey-dark grey	4.75	250	1879	5803	3.00	35	40	25		8.102	25.070
	3342-3379	Petrel Fm Mbr 'A'	Mudstone, medium-dark grey	5.0	15	2341	6043	1.83	35	30	35		0.593	1.556
	3379-3440	Petrel Fm Mbr 'B'	Mudstone, medium dark grey	5.0	18	1262	3259	1.79	45	35	20		0.371	1.013
	3440-3700	Petrel Fm Mbr 'C'	Mudstone, medium-dark grey, dark grey	5.25	30	3397	7485	2.73	40	30	30		1.754	3.878
Flat Top-1	899-906	Petrel Fm Mbr 'C'	Lignite, black	3.25	1	-	104000	53.45	20	50	20	10	0	1.803
	1659-1713	Kulshill Fm	Mudstone, dark grey, grey black	4.5	20	17500	52300	13.93	25	20	35	10	6.051	18.080
	1921-1967	Kulshill Fm	Mudstone, medium-light grey, medium grey	5.25	20	4100	7700	2.26	40	20	30	10	1.408	2.668
Gull-1	2210-2226	Petrel Fm Mbr 'A'	Mudstone, dark grey	5.0	4.5	6616	14389	2.19	30	10	35	25	0.519	1.112
Heron-1	3170-3520	Bathurst Island and Flamingo Shale eqv	Mudstone, dusky yellow brown, dark grey	VR 2.0%	300	?	?	2.60	?	?	?	?		
	3520-4208	Petrel Fm	Mudstone, dark-grey, dark olive grey	VR 2.5%	600	?	?	5.60	?	?	?	?		

Table 10 Continued ...

WELL	DEPTH Interval (m)	AGE/FORMATION	LITHOLOGY	SCI	NET THICKNESS (m)	GHC PPM	OOGC PPM	AV TOC	ORIGINAL KEROGEN COMPOSITION				PRODUCTIVITY Bbls/km^2 (x10^6)	POTENTIAL Bbls/km^2 (x10^6)
									V	I	W	S		
Kinmore-1	1455-1615	Kulshill Fm Greywacke Mbr	Mudstone, medium-dark grey +	5.0	28(mdst)	10075	26007	10 (mdst)	30	40	30		4.866 (mdst)	12.572
			coal, black		2(coal)	74949	193473	51.10 (coal)	20	40	40		7.459 (coal)	19.266
	1727-1830	Kulshill Fm Greywacke Mbr + Shale Mbr	Mudstone, grey black +	5.0	24(mdst)	6149	15873	7.99 (mdst)	35	40	25		2.544 (mdst)	6.595
			coal, black		8(coal)	56760	146520	42.65 (coal)	30	30	40		10.399 (coal)	26.849
Osprey-1	2686-3170	Hyland Bay and Fossil Head Fm	Siltstone, medium to dark grey and coal	8.25	335	?	?	2.13	?	?	?	?	?	?
Penguin-1	1125-1134	Red Beds, Early Jurassic	Mudstone, dark grey -black +	5.25	1	14746	120650 (mdst gy - blk)	14.97	5		65	35	0.255	2.075
			Mudstone, lt-medium grey		6.5	900	7100 (mdst, lt -med gy)	3.97	65	15	10	10	0.099	0.790
Plover-1	1335-1359.5	Red Beds, Early Jurassic	Unknown	3.75	20	700	5300	5.16	30	55	5	10	0.247	1.828
Tamar-1	2280-2315	Petrel Fm Mbr 'C'	Thin coals and carbargillites	5.5	4	183216	305359	40	10	30	10	50	14.375	21.118

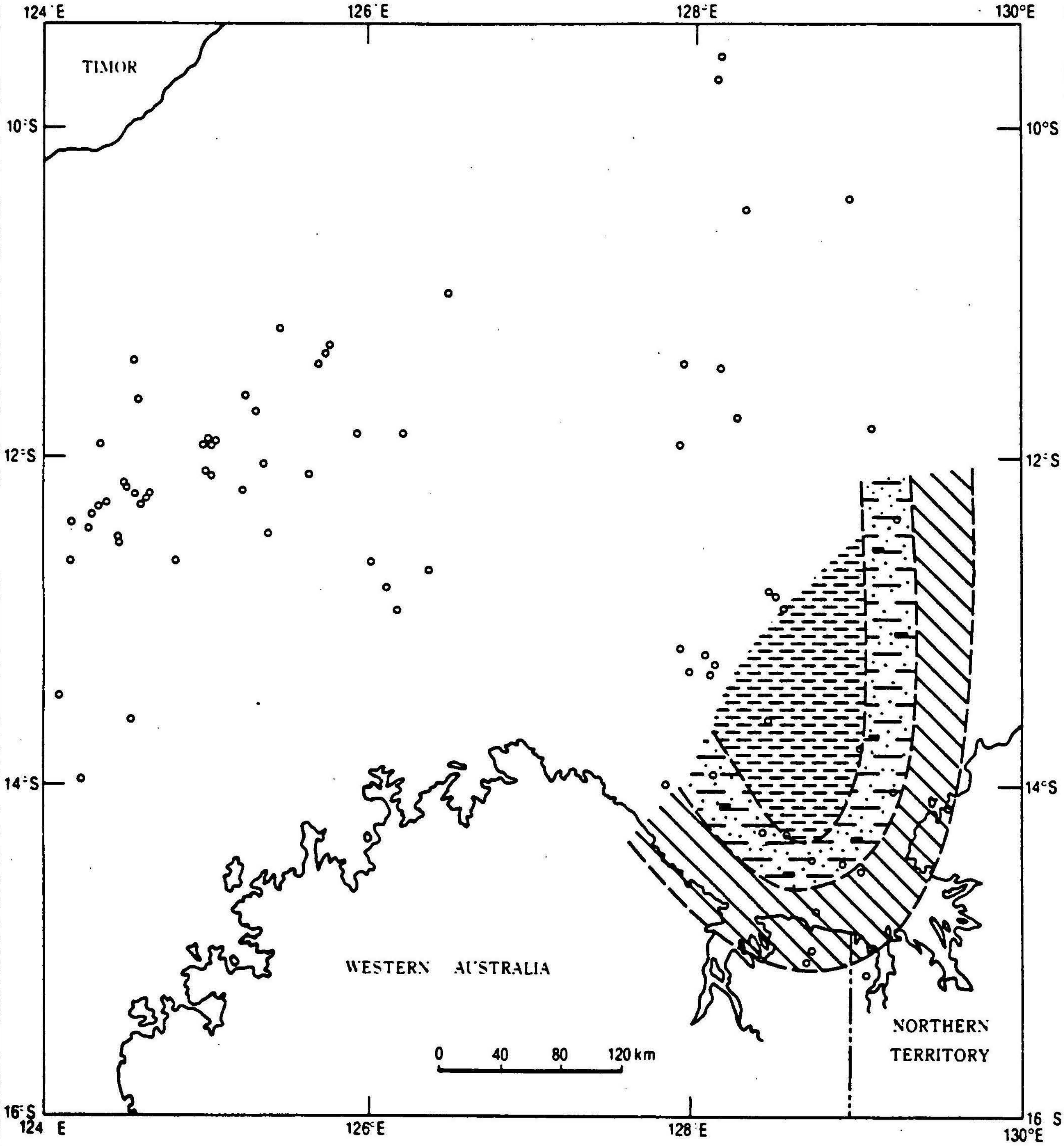
A cyclic carbonate and clastic sequence was deposited in the Carboniferous. It crops out and is also penetrated by several wells in the southern part of the Bonaparte Basin. Little is known of the source potential of the Carboniferous sediments, but where penetrated, they are generally organically lean. They are unlikely to constitute a major hydrocarbon source in the Bonaparte Basin.

12.1.3 Late Carboniferous-Permian

The Middle Carboniferous hiatus was followed by a sequence of transgressional and regressional cycles. Sedimentation started with deposition of the lower sand member of the Kulshill Formation. This grades upwards into a shale member deposited in a low energy lacustrine environment. The upper part of the shale member contains thin, exinite-rich coals and mudstones deposited in interdistributary bays or abandoned channels, in an arctic climate (Encl. 28).

The shale member is followed by the greywacke member which contains similar source rocks which were deposited in similar environments (Encl. 28). The limited well data (Flat Top-1, Bougainville-1, Kinmore-1 and Lacrosse-1), suggest that these environments are restricted to a narrow band flanking the eastern side of the Bonaparte Basin (Fig. 40). They occur within a sedimentary wedge prograding from the Darwin Shelf into the Petrel Sub-basin. Kerogen facies maps (Fig. 41), show predominantly inertinitic, upper delta plain sediments which grade into delta front facies. The delta front facies contain significant exinite content in lagoonal coals and shales and grade into inertinite/vitrinite-rich prodelta facies.

Robertson Research

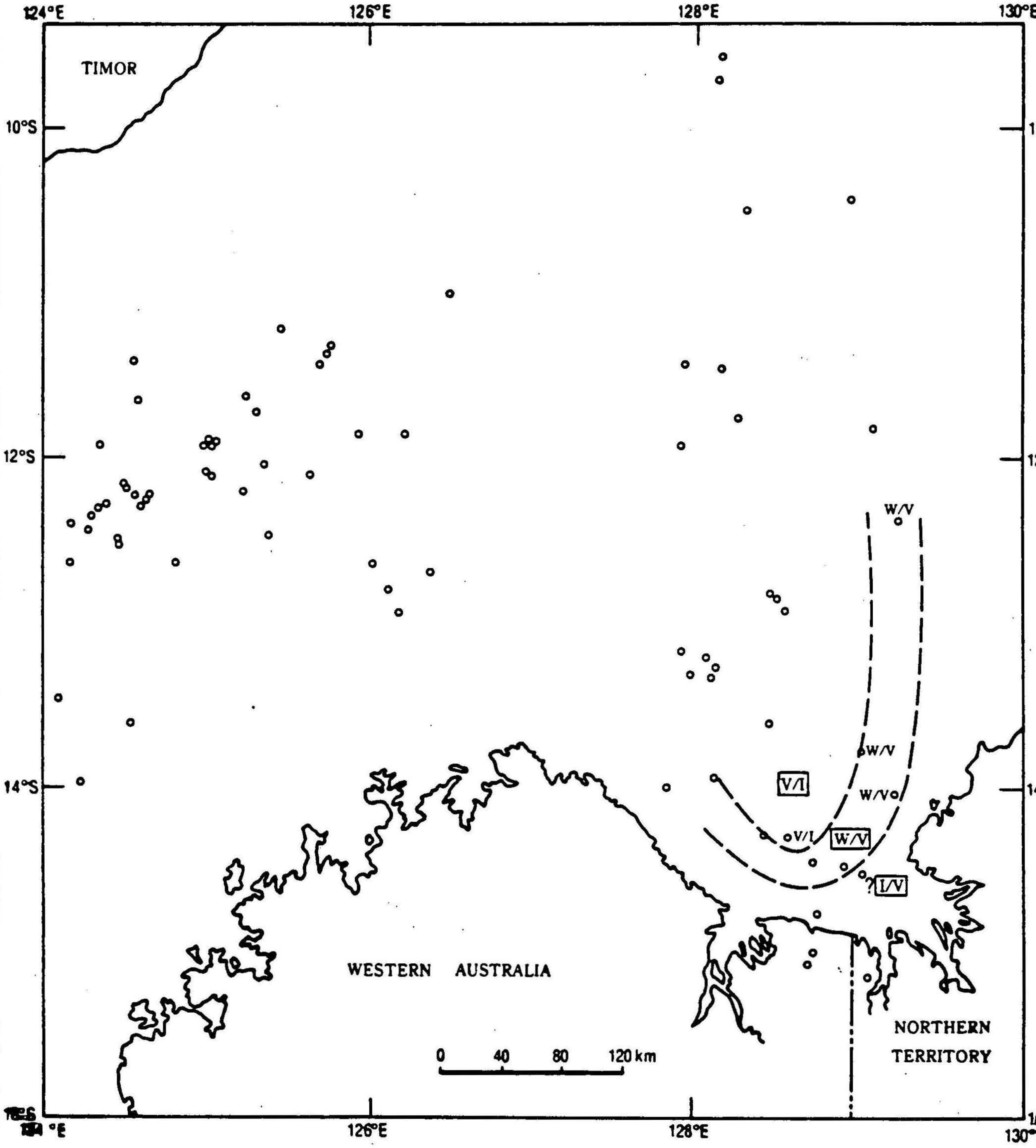


- Wells
- Nearshore marine
- Lower Delta plain to Delta front
- Postulated area of upper delta plain, presently eroded

Bonaparte Basin Palaeogeography
Kulshill Formation

Figure 40

Robertson Research



- o Wells
- W Waxy kerogen facies
- I Inertinite facies
- V Vitrinite facies
- I/V Inertinite greater than Vitrinite

Bonaparte Basin Kerogen Facies
Kulshill Formation

Figure 41

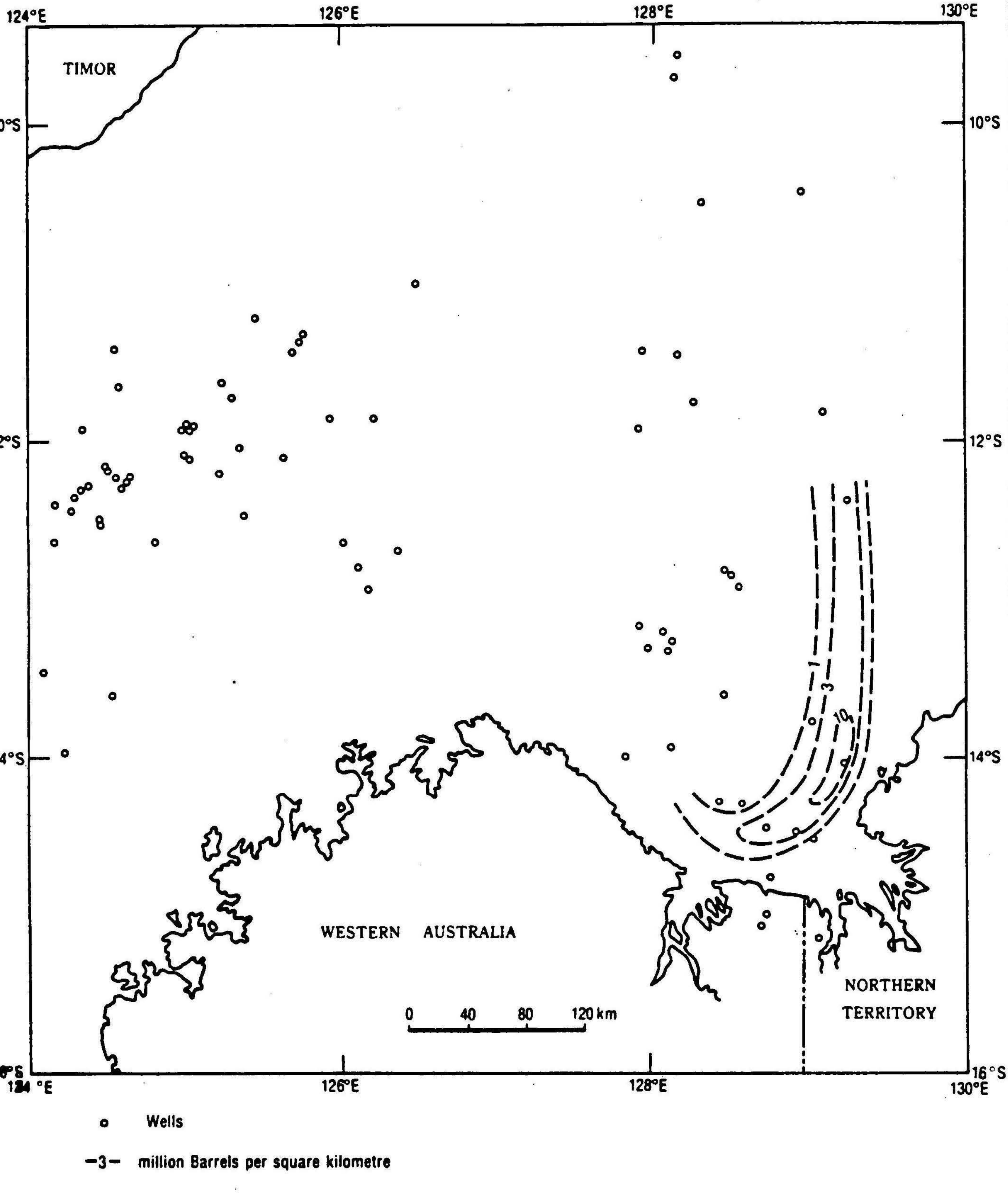
Little is known of the extent of the source rock units on the eastern flank of the Londonderry High. It is possible that they were removed by later uplift and erosion west of Lacrosse-1.

The greywacke member of the Kulshill Formation contains good source rocks in the area between Flat Top-1 and Kinmore-1 (Fig. 41), with TOC contents of 8-10% in shales with about 40% oil-prone kerogen content. Maximum productivities reached 25 million bbls/km^2 around Kinmore-1 during the Early Tertiary (Fig. 42). To the west, there is little well control to suggest where this source rock could be developed, but it is predicted from an interpretation of the regional palaeogeography to occur west and south of Kinmore-1.

By the upper Early Permian, prodelta shales rich in inertinite and having average organic carbon contents (TOC 1.5 to 2.5%) were deposited over the whole of the Bonaparte Basin. These shales constitute the Fossil Head Formation, which has no hydrocarbon source potential in the seven wells analysed.

Deposition continued in the Late Permian with shelfal limestone members of the Hyland Bay Formation, which are separated by clastics of the Hay Member. Carbonate deposition was terminated in the Petrel Trough in the Late Permian, when prograding clastic facies extended the shoreline as far north as Tern-1 and Petrel-1. These organically lean sediments constitute poor source rocks. The sediments contain mostly inertinitic kerogen material, suggesting oxic environmental conditions were present throughout the deposition of the Hyland Bay Formation.

Robertson Research



Bonaparte Basin Source Rock Productivity
Kulshill Formation

Figure 42

12.1.4 Triassic

Marine transgression in the Late Permian to Early Triassic was followed by deposition of the Early Triassic Mount Goodwin Formation. Where analysed, this formation is organically lean and has no hydrocarbon source potential.

Regression occurred during the early Middle Triassic with progradation of deltaic and shallow marine sediments over most of the Bonaparte Basin. This sequence is generally organically lean but may contain thin coals with possible gas source potential around the Londonderry High. The presence of red beds in the southern half of the Bonaparte Basin in the Late Triassic and Early Jurassic sediments suggests an arid, though cool, climate throughout this period.

12.1.5 Jurassic

As in the Browse Basin, the Jurassic can be separated into three regressive cycles, the first starting in the Late Triassic and continuing into the Early Jurassic, the second being represented by the Petrel 'C' member and the third by the Petrel 'A' and 'B' members. A minor tectonic or eustatic episode separates the 'B' and 'A' members. As in the Browse Basin, kerogen facies and source potential are related to the palaeoenvironment. Middle Jurassic source rocks are developed in interdistributary bay and delta front facies. Jurassic sources do not appear to be as thick or as laterally continuous in the Bonaparte Basin as in the Browse Basin. However, the well coverage in the critical areas immediately to the north and south of the Malita Graben, and within the Malita Graben itself, is poor.

12.1.5.1 Early Jurassic

Over most of the Early Jurassic, the southern half of the Bonaparte Basin was covered by fluvial, upper delta plain sediments (Fig. 43). These sediments are generally organically lean except for sporadic thin cannel coals developed in small lakes within the upper delta plain (e.g. in Penguin-1) (Fig. 44). Further, lower delta plain to delta front sediments were encountered in Plover-1, which contains a thin, fair quality source rock developed in distributary channel fill deposits. The areal extent of lower delta plain to delta front sediments which may contain potential source rocks is shown on Figure 45.

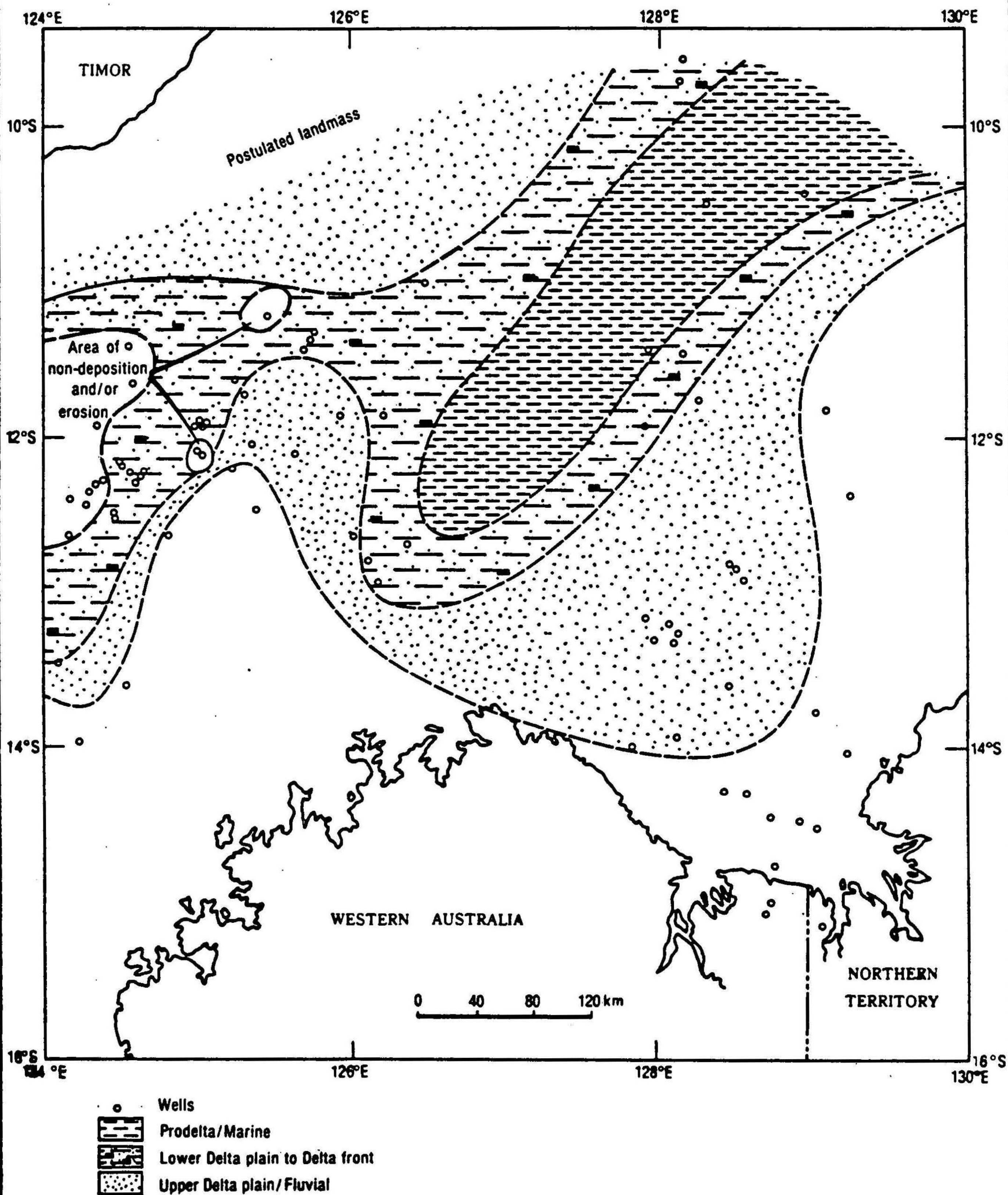
The Malita Graben in the northeastern Bonaparte Basin is believed to have been a marine embayment during the Early Jurassic. It was infilled with sediment derived from landmasses to the north of the Sahul Platform, from the southern Bonaparte Basin and from the Darwin Shelf.

Source rocks appear to be only sporadically present in the Early Jurassic in the Bonaparte Basin, although very few wells penetrated this section.

12.1.5.2 Middle Jurassic

The Middle Jurassic (member 'C' of the Petrel Formation) is a regressive sequence of mainly fluvio-deltaic sandstones in the southern half of the Bonaparte Basin, with progressively more marine influence towards the Malita Graben. Fluvial sediments south of Gull-1 (Encl. 29) contain varying organic carbon content. The shale and mudstone intervals deposited in abandoned channels and in interdistributary bays on the upper delta to proximal lower delta plains contain only mixed inertinite and vitrinitic kerogen, in which inertinite is predominant.

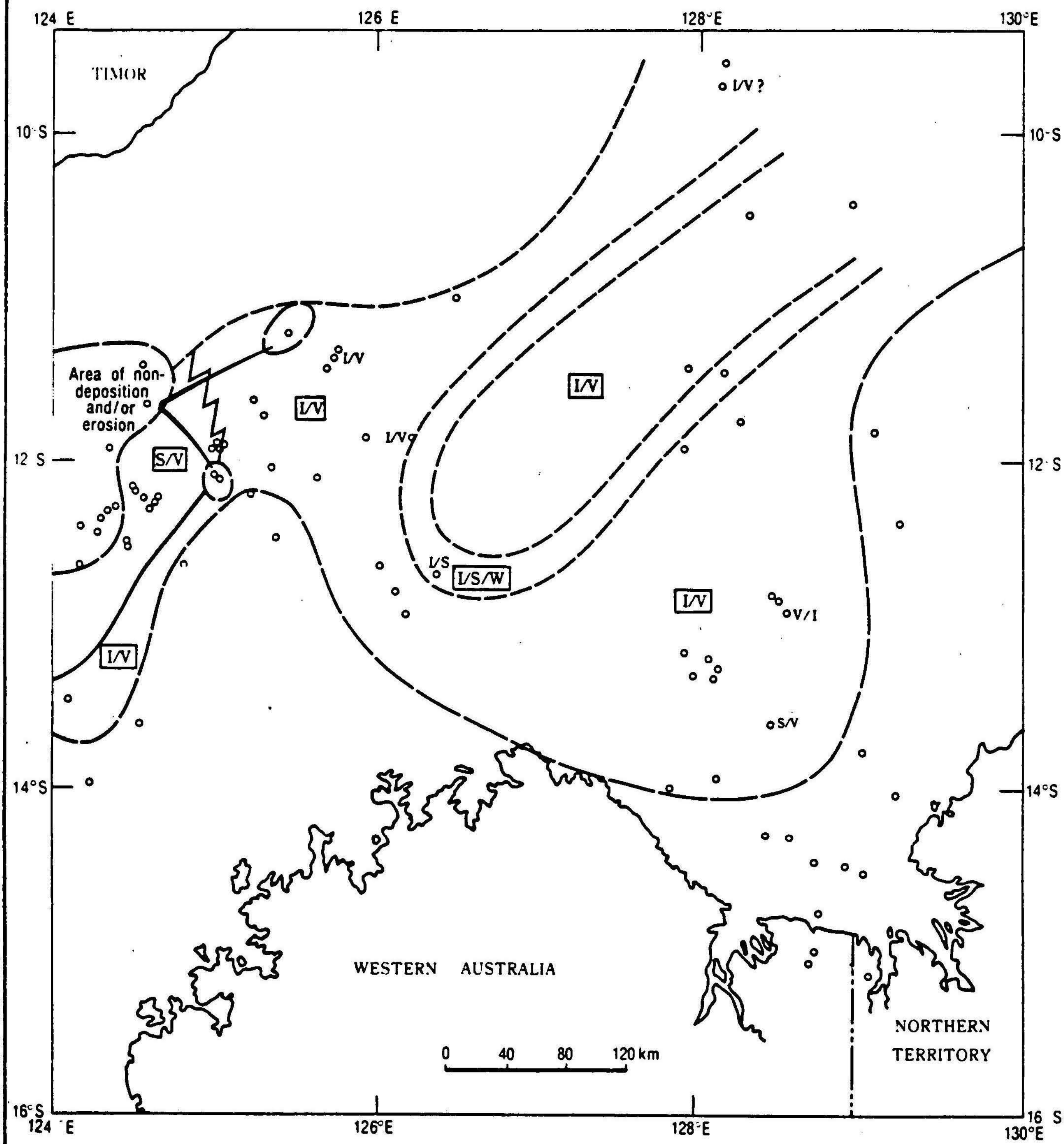
Robertson Research



Bonaparte Basin Palaeogeography
Early Jurassic

Figure 43

Robertson Research



- o Wells
- W Waxy kerogen facies
- I Inertinite facies
- V Vitrinite facies
- S Sapropel facies
- I/V Inertinite greater than Vitrinite

Bonaparte Basin Kerogen Facies
Early Jurassic

Figure 44

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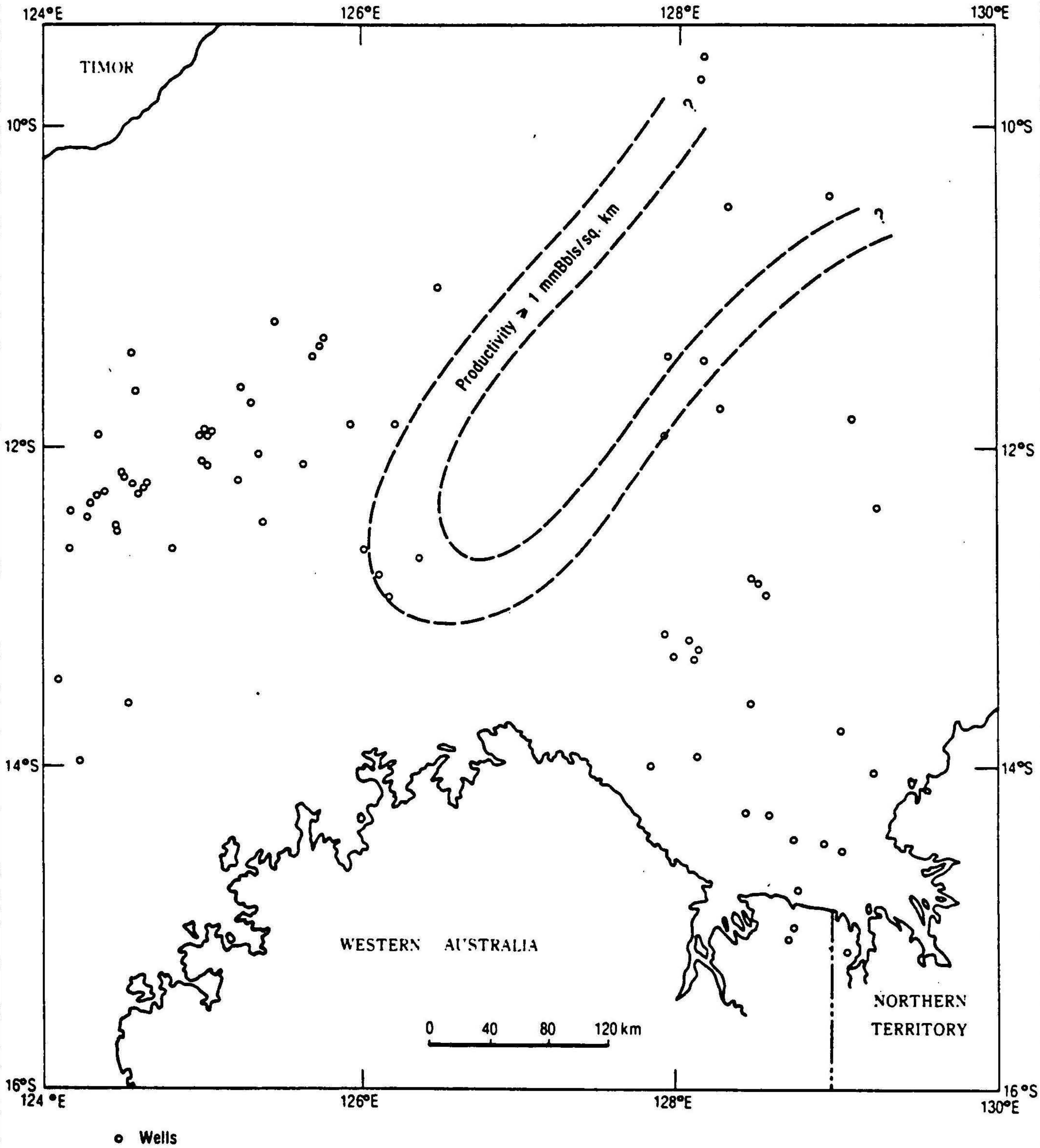

Bonaparte Basin Source Rock Productivity
Early Jurassic

Figure 45

Lower delta plain and delta front deposits occur northwards. At Tamar-1 and Eider-1, these sediments contain algal-rich coals and mixed exinite and algal-rich mudstones with good oil source potential (Encl. 29). TOC contents are approximately 4% with oil-prone kerogen contents of 35% in Eider-1. These sediments were deposited in interdistributary bays close to the delta front. The narrow band of lower delta plain to delta front sediments, which is likely to contain source rocks, may extend along the southern side of the Malita Graben, before trending northeast across the Bonaparte Basin north of Gull-1. Source rocks have productivities of 3-10 million bbls/km^2 over much of the area around Eider-1 and Tamar-1 (Encl. 30).

On the northern side of the Malita Graben, source rocks were being deposited in the delta front sediments which fringed a landmass to the north of the present Sahul Platform. These sediments occur in Flamingo-1 and may extend onto the Sahul Platform. Sediments in this area have lower TOC contents (1.7-2.7%) and contain 20-30% oil-prone kerogen. Productivities are low with values of about 2-3 million bbls/km^2 (Encl. 30).

12.1.5.3 Late Jurassic - Early Neocomian

Deposition of the Petrel 'C' member ceased following continental breakup and sea floor spreading to the north of the Bonaparte Basin. This tectonic episode was accompanied by uplift and erosion and partial removal of sediments from the basin margin, e.g. on the Sahul Platform, Londonderry High and Van Diemen High. Subsequent Late Jurassic deposition in the southern Bonaparte Basin during a major marine transgression consisted of nearshore marine sediments, which graded into prodelta shales in the Petrel Sub-basin northwest of the Petrel structure (Member 'A' and 'B' of Petrel Formation). A thick sequence of prodelta shales was deposited in the rapidly subsiding Malita Graben (Encl. 31).

The sections analysed in the Late Jurassic are generally organically lean to average. They show a gradation from predominantly inertinitic kerogen in nearshore marine to deltaic sequences south of Penguin-1, to a mixed inertinite-vitrinite facies between Tern-1 and Gull-1 (Encl. 31). A trend of decreasing inertinite content and increasing waxy sapropel content to a proposed mixed waxy sapropel/vitrinite is observed towards the Malita Graben (Encl. 31).

There are only a limited number of wells which penetrate the Petrel Formation ('A' and 'B' Members) in the area of interest around the Malita Graben. In one of these, Heron-1, high maturity levels have made it impossible to determine the original source potential. However, the fair quality sources in nearshore sediments to the north and south of the graben in Flamingo-1 and Gull-1 (TOC 2-3%, oil-prone kerogen content 20-50%) may represent the edges of a better source rock which could be developed in the Malita Graben. The Late Jurassic source rock generally has low productivities of around 1 million bbls/km^2 at Flamingo-1 (Encl. 32).

12.1.6 Early Cretaceous

Following Late Jurassic to Early Neocomian deposition , there was a brief regional break in sedimentation caused by eustatic changes and by uplift of the southern Bonaparte Basin and surrounding highs. Following this movement, marine conditions were established over most of the basin. The initial shale unit (Flamingo Shale Member) deposited in the northern Bonaparte Basin within the Sahul Syncline and Malita Graben is organically rich at Flamingo-1 and Heron-1. It is not present in the Petrel Sub-basin.

Analysis of the Flamingo Shale at Flamingo-1 shows it to be a good source rock, being both organically rich (TOC 3% average, 20% waxy sapropel content) and thick (250m). The shale probably thickens (Encl. 21) and is likely to increase in source quality towards the centre of the Malita Graben. This source rock unit seems to be a continuation of the Late Jurassic source and represents the maximum extent of restricted conditions in the Malita Graben before open marine conditions prevailed during deposition of the Bathurst Island and subsequent formations. The source rocks extend upwards into the base of the Bathurst Island Formation in the graben centre. Productivities of this source rock unit at the edge of the Malita Graben are as high as 8 million bbls/km^2 and may be in excess of 20 million bbls/km^2 in the graben depocentre.

12.1.7 Late Cretaceous

A thick sequence of marine shelfal deposits (shales and carbonates) infilled the Malita Graben during the Late Cretaceous, and regional tilting with subsidence of the Sahul Platform restored open water circulation. This interval is generally organically lean and contains mostly vitrinitic kerogen. It has no hydrocarbon source potential.

12.1.8 Tertiary

Carbonate deposition thickening towards the present day shelf edge occurred throughout the Tertiary. Although not covered in detail by analyses, this section is unlikely to have significant hydrocarbon potential.

12.2 MATURITY

12.2.1 Present Day Geothermal Gradients (Encl. 33)

Geothermal gradients decrease from values of around 40°C/km on the Londonderry High and 50°C/km on the Van Diemen High to about 30°C/km in the main depocentres of the Petrel Sub-basin and the Malita Graben. Higher values of 35° to 40°C/km are also recorded on the Sahul Platform.

As is the case for the Browse Basin, there is a good correlation of low geothermal gradient to areas of thick sedimentary fill and thinner crust, and of high geothermal gradients to areas of thin sedimentary cover and thicker crust.

In the Petrel Sub-basin, marked variations in local geothermal gradient are due to salt diapirs.

12.2.2 Maturity : Regional Interpretation

A total of 16 wells have been analysed for vitrinite reflectivity and spore colour index. Best fit lines have been drawn onto plots of data against depth, sections missing at unconformities estimated, and SCI gradients calculated and compared with geothermal gradients from a total of 23 wells.

The results show that the basin has a relatively simple thermal history with heat flows similar to those of the present day over most of the area. An exception is the eastern part of the Londonderry High and the Plover Shelf, which may also be affected by the Tertiary thermal event noted in the Browse Basin (Fig. 39).

The spore colour gradient map (Encl. 33) shows high values due to the Tertiary thermal event, around the nose of the Londonderry High, near Osprey-1 and Whimbrel-1. The lower values are present in the Sahul Syncline, Malita Graben and Petrel Sub-basin where sediment fill over thinned crust is substantial. Gradients rise from values of below 1.5 SCI units/km in these areas to 2.0 SCI units/km on the Van Diemen High and Sahul Platform, where sedimentary cover is thinner and the crust correspondingly thicker.

12.2.2.1 Maturity : Uplift and Erosion

The history of uplift and erosion at unconformities within the Bonaparte Basin is more difficult to interpret from maturity data than in the Browse Basin. There is poorer data coverage in this basin and a lack of any geochemistry analysis in sections younger than Triassic in the southern part of the basin. Compilation of maturity data from the wells studied (Table 11) suggests that the southern part of the Bonaparte Basin has been uplifted several times from the Triassic to Recent. Burial history evidence (Encl. 34) suggests that the maximum depth of burial was reached during the Early Tertiary. Further north, along the boundary of the Malita Graben and on the Sahul Platform, the major period of uplift has been between the Eocene and Early Miocene.

In the northern part of the Petrel Sub-basin, in the most westerly parts of the Malita Graben and in the Sahul Syncline, subsidence probably continues to the present day.

TABLE 11 - SUMMARY OF MATURITY DATA AND SECTION MISSING, BONAPARTE BASIN

WELL	SCI GRAD.	MAX. DEPTH OF BURIAL MAX. BURIAL	SECTION MISSING AT UNCONFORMITIES	COMMENTS	WATER DEPTH (m)	SEA BED °C
Bougainville-1	1.2	800m greater than P.D. reached sometime during the L.Cret-Rec.	2000m of M.Jur-Rec. above 271m	Spore colour index affected by nearby salt diapir. Section missing from several M.Jurassic to Rec. u/cs.	36	24
Troubadour -1	1.9	200m greater than P.D.	500m of Cret.-Rec. above 1575m	Several u/cs above 1575m.	109	21
Plover-1	1.9	Present Day	No appreciable section missing		58	23
Tamar-1	1.8	No data	No data		64	23
Eider-1	1.7	Present day	No appreciable section missing		100	21
Tern-1	2.0	400m greater than P.D. reached sometime during Late Jur.-Rec.	200m Triassic-Middle Jurassic at 1674m, 600m Late Jur.-Rec. above 1139m.	Spore colour index gradient affected by nearby salt diapir	92	22
Gull-1	1.7	300m greater than P.D. reached during Eocene-Rec.	250m of E.-Cret. at 2128m - 300m of Paleocene to Rec. above 473m	Spore colour index affected by nearby salt diapir	134	19
Kinmore-1	1.3	700m greater than P.D. reached during Triassic-Rec.	In excess of 2000m of Triassic-Recent above 200m	Spore colour index gradient affected by nearby salt diapir. Section missing at several Triassic-Rec. u/cs above 200m.	26.5	25
Flamingo-1	1.3	Present day	No appreciable section missing		96	22
Heron-1	1.9	800m greater than P.D. reached during Eocene-Recent	800m of Tertiary-Rec. above 530m	Marked non-linearity in maturity gradients below 2800m due to igneous intrusive. One major u/c above 530m.	38	24

TABLE 11 - SUMMARY OF MATURITY DATA AND SECTION MISSING, BONAPARTE BASIN

WELL	SCI GRAD.	MAX. DEPTH OF BURIAL MAX. BURIAL	SECTION MISSING AT UNCONFORMITIES	COMMENTS	WATER DEPTH (m)	SEA BED °C
Penguin-1	1.7	400m greater than P.D. reached during L. Cret.-Rec.	700m of Late Cret. -Rec. above 418m	Several u/cs above 418m. Fault at around 2700m with 400m of vertical movement.	69	23
Lacrosse-1	1.8	600m greater than P.D.	750m of missing Triassic younger section above 234m	One major u/c above 234m	33.5	24
Flat Top-1	1.8	Present Day	850m of missing Late Jurassic-Rec. above 899m	Several u/cs above 899m.	41	24
Petrel-2	2.0	200m greater than P.D. reached during Tertiary-Rec.	1000m of Tertiary to Rec. at u/cs above 1250m	Several u/cs above 1250m. Spore colour index gradient affected by nearby salt diapir.	97	22

12.2.2 Maturity of Source Rock Horizons

Three major source rock horizons have been identified within the Bonaparte Basin. These are the Kulshill Formation in the Petrel Sub-basin, and the Petrel and Flamingo Shale Formations in the northern part of the Petrel Sub-basin, Malita Graben, Sahul Syncline and on the submerged parts of the Dillon High and Van Cloon High. The maturity of each of these source rocks is discussed separately.

12.2.2.1 Permian-Kulshill Formation

The maturity map of source rocks present within the Kulshill Formation (Fig. 46) has been derived from measured maturity values, well data, seismic sections and the time contour map drawn for a horizon near the top of the Late Permian (Encl. 11).

The maturity map (Fig. 46) shows that the maturity of the Kulshill Formation increases rapidly from the Plover Shelf and Van Diemen High (3.5-4.0 SCI units) into the Petrel Sub-basin (6.0-9.0 SCI units). On the western side of the Bonaparte Basin, to the northwest of Plover-1, values increase because of the geothermal anomaly in this region. The Kulshill Formation is expected to be post mature, if it is present, throughout the Malita Graben and Sahul Syncline.

12.2.2.2 Middle Jurassic - Early Neocomian (Petrel Formation)

These source rocks, which are developed in the Browse Basin, also continue around the Londonderry High and into the Bonaparte Basin, where they are mapped as the Petrel Formation.

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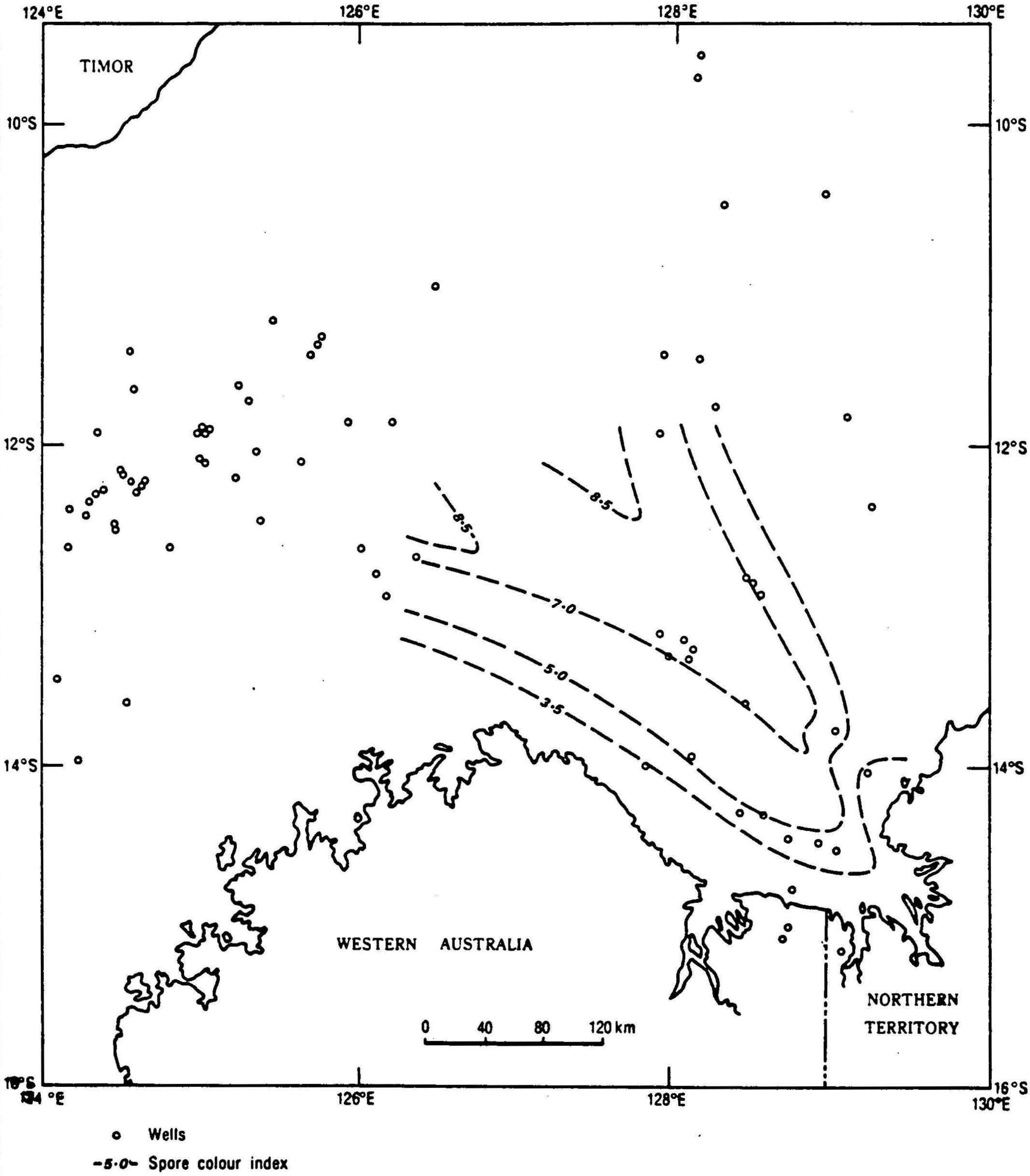


Bonaparte Basin Spore Colour Index
Kulshill Formation

Figure 46

The maturity of the Petrel Formation (Encl. 30) increases sharply into the Malita Graben in response to deep burial during the Cretaceous and Tertiary. Middle mature sediments extend south into the Petrel Sub-basin. The Dillon Ridge and Londonderry High generally contain early mature Jurassic sediments, while a broad area of middle mature Jurassic sediments occurs on the Sahul Platform. The Londonderry High has been affected by the Tertiary thermal event, so that middle mature Jurassic sediments are present at relatively shallow depths between Whimbrel-1 and Tamar-1.

12.2.2.3 Early Cretaceous - Flamingo Shale and Bathurst Island Formation

The Early Cretaceous maturity map (Encl. 32) shows that over most of the southern Bonaparte Basin, the base of the Bathurst Island Formation is immature to early mature. The maturity of this horizon increases sharply into the Malita Graben due to deep burial throughout the Cretaceous and Tertiary. On the Dillon Ridge, the base of the Cretaceous reaches early maturity. Throughout the Echo Syncline and over the area between Whimbrel-1 and Tamar-1, the horizon is middle mature due to increased heating during the Tertiary thermal event. The Sahul Platform is present as a broad area of middle maturity due to Tertiary burial, while over other palaeohighs, e.g. south of the Plover Shelf and the Darwin Shelf, the base of the Bathurst Island Formation has not been deeply buried and is immature.

12.3 OIL SOURCE ROCK CORRELATION

12.3.1 Introduction

Seventeen oil stains and nine source rock extracts from Early Permian to Late Cretaceous sediments have been investigated using gas chromatography-mass spectrometry and carbon isotope analysis to determine the relationship between the source rocks identified and migrant oils within the Bonaparte Basin.

12.3.2 Petroleum Geochemical Characteristics of the Source Rocks

(Refer Vol. 3, Table VI.1, Figs. VI.1-VI.3)

Eight source rock extracts selected from the the Kulshill Formation in Bougainville-1, Flat Top-1 and Kinmore-1 and the Middle Jurassic Petrel 'C' Formation in Eider-1 and Tamar-1 have been investigated in detail by gas chromatography, GC/MS, and carbon isotope analyses.

Gas chromatography analysis of these samples shows they contain a wide range of n-alkanes with high pristane to phytane ratios, common "waxy" alkanes above $\underline{n}$-C_{23} and odd over even carbon number preference.

GC/MS analysis of these samples shows similar triterpanes and sterane distributions, the source rocks being distinguished by the presence of the unknown compound 17(V) co-eluting with the 17α trisnorhopane. The C_{30} hopane is dominant over the C_{29} hopane. The sterane distribution is dominated by C_{29} steranes. The distributions of steranes and triterpanes suggest that these source rocks contain terrestrially sourced kerogens. Triterpane maturity ratios confirm the source rocks are early to middle mature.

Except for Kinmore-1, carbon isotope values obtained for the alkanes and aromatics of the source rock extracts are similar to each other, ranging from -28.80 to -29.90 and -25.50 to -27.80 respectively. Such highly negative (isotopically light) carbon isotope values confirm the GC/MS results, indicating that the higher plant kerogens in these source rocks are land derived.

Carbon isotope ratios of -26.84 and -25.54 obtained for alkanes and aromatics of the Kinmore-1 extract (Kulshill Formation, 1736-1760m) are slightly heavier compared to those of other source rock extracts analysed. These less negative values may be due to a minor input from a non-marine, fresh or brackish water algal source. The bulk sample from Kinmore-1, selected for extraction, contains, in addition to mudstone, quantities of coal with about 30% hydrogen-rich, sapropelic algal kerogen. Hydrocarbons generated from this coal could have been mixed with those generated from the mainly humic kerogen present in the mudstone, making the carbon isotope values less negative.

On the basis of the distributions of steranes and triterpanes and the carbon isotope data, the source rock extracts cannot be separated into geochemically distinguishable groups. All of the source rock extracts analysed have very similar biomarker distributions and carbon isotope values. This probably reflects the predominance of terrestrial kerogens, in all of the source rocks analysed.

12.3.3 Petroleum Geochemical Characteristics of the Analysed Migrant Oils (Refer Vol. 3, Table V.1, Figs. V.1 - V.3)

A total of seventeen migrant oils from the Bonaparte Basin were analysed in detail using GC/MS and carbon isotope analysis. Initial gas chromatography analysis of these samples shows a significant biodegraded oil component in the extracts from Flat Top-1 (1713m) and Lacrosse-1 (1750-1751m). The remaining samples contain predominantly *n*-alkanes in the range *n*C_{15} to *n*-C_{33}, usually with significant *n*-C_{23+} waxy alkanes. In most samples, pristane is dominant over phytane. The alkane gas chromatograms suggest most of the oil stains are derived from middle to late mature sources, containing mostly terrestrially sourced, waxy kerogens.

On the basis of GC/MS data, it is possible to distinguish three groups of migrant oils. It must be noted however, that the triterpane distributions seen in all the samples are very similar. All could be derived from a similar source, or several sources deposited under similar conditions.

Group 1

Bougainville-1	(2012-2027m Fossil Head Formation)
Bougainville-1	(2204-2220m Fossil Head Formation)
Flat Top-1	(1713m Kulshill Formation)
Heron-1	(3247-3262m Bathurst Island Formation)
Heron-1	(3390-3406m Flamingo Shale Equivalent)
Heron-1	(4043-4052m Petrel Formation Time Equivalent)
Plover-1	(2305-2317m Hyland Bay Formation)
Plover-1	(2348-2360m Hyland Bay Formation)
Tern-1	(2848-2863m Hyland Bay Formation)
Tern-1	(3552-3576m Fossil Head Formation)

These migrant oils are distinguished by the presence of an unknown compound, possibly oleanane, eluting just before the C_{30} hopane, and the lack of significant quantities of the unknown C_{29} and C_{30} pentacyclic compounds 4 and 5 seen in Group 2 oil stains. This group also contains relatively abundant low molecular weight resin-derived terpanes.

The sterane distributions of oil stains in this group are very similar and are dominated by the C_{29} steranes. The oil stain extracted at 3552-3576m in Tern-1 contains more C_{27} steranes, perhaps indicating more marine kerogen input into the source of this oil stain.

Carbon isotope values of alkane vary between around -25.50 to -27.50. The GC/MS and carbon isotope data are consistent with the oil stains being derived from a source containing predominantly terrestrially sourced kerogen. The high quantities of resin derived terpanes suggest a relatively resin rich source for these migrant oils.

Group 2

Flamingo-1	(3345-3360m Petrel Formation: Member 'A')
Flamingo-1	(3671-3686m Petrel Formation: Member 'C')
Lacrosse-1	(1750-1751m Kulshill Formation: Shale Member)
Troubadour-1	(2160-2175m Petrel Formation: Member 'C')
Troubadour-1	(2235-2245m Petrel Formation: Member 'C')

This group contains significant quantities of the unknown C_{29} and C_{30} pentacyclic compounds 4 and 5. The sterane distributions of these migrant oil stains show that, although the C_{29} steranes are predominant, relatively large quantities of the C_{27} steranes are also present.

Carbon isotope values of alkanes and aromatics range from -27.7 to -29.2 and -26.0 to -28.0.

The triterpane and sterane distributions and the carbon isotope values from this group of oil stains suggest that they have been derived from a middle-late mature source, containing mostly terrestrially sourced kerogens, but possibly mixed with some marine or brackish water algal kerogen.

Group 3

Sunrise-1	(2195-2210m Petrel Formation: Member 'C')

This sample contains similar sterane and triterpane distributions to the Group 2 migrant oils but is distinguished by a large content of tricyclic terpanes and anomalously light carbon isotope values of -33.15 (saturates) and -31.2 (aromatics). This migrant oil has been derived from a source containing only terrestrially derived kerogen.

12.3.4 Oil Source Rock Correlation

The detailed investigation of source rocks in this study has shown that source rocks of different ages, but deposited under similar environments, have similar triterpane and sterane distributions. Although the climatic conditions were different during the Early Permian (cold) and Jurassic to Late Cretaceous (temperate), the source rocks from similar environments in the Kulshill Formation and in the Petrel 'C' have similar carbon isotope and GC/MS biomarker compositions.

Similarly, the migrant oil stains analysed (with the exception of Sunrise-1) are all very similar and are only separated into groups based on small differences in the triterpanes distributions . The C_{29} and C_{30} pentacyclics compounds 4 and 5 and the compound thought to be oleanane, on which migrant oils have been distinguished, are not present in significant quantities in the source rock analysed. The pentacyclic compounds (4 and 5) may be present in the source rocks in very small quantities. However, there is no evidence to suggest that the compound thought to be oleanane is present in any of the source rock extracts. Also none of the migrant oils contain the unknown compound 17(V) found in the source rock extracts.

Geochemically, therefore, there is little conclusive evidence to correlate the migrant oils with potential source rocks in the basin. There are good geological reasons, however, to consider that extracts from the southern part of the Petrel Trough (i.e. Lacrosse-1, Tern-1, Flat Top-1, Bougainville-1) are sourced from either the Kulshill Formation or deeper sources not identified in this study. The only quantitatively significant oil stains in this area are those at Flat Top-1 and Lacrosse-1 in the Kulshill Formation. Other stains are present only in small amounts (< 5000 ppm). These oil stains show similar distributions to the Permian sources at Flat Top-1, Kinmore-1 and Bougainville-1, except that they lack significant quantities of the unknown compound 17(V). This may suggest that they are derived from shales interbedded with the coals, which contain less of this compound (i.e. Bougainville 2561-2570m), or that this compound is lost during oil generation and migration.

Oil stains from the northern end of the Petrel Trough and from the Malita Graben and Sahul Syncline (Flamingo-1, Heron-1, Plover-1, Troubadour-1 and Sunrise-1) are likely to have been derived from Jurassic to Early Cretaceous source rocks in this area. This is especially true for oil stains in Flamingo-1 and Heron-1, which are likely to have been sourced from the source intervals with which they are interbedded.

Unfortunately, no good source sections from the Early Cretaceous source interval were free of oil stain and therefore no good triterpane, sterane and carbon isotope data are available for this source. Geologically, it is likely that oils derived from this source will have very similar triterpane and sterane distribution to the oil stain from Heron-1.

The Early Cretaceous oil stains do not correlate with Jurassic source rocks in Tamar-1 and Eider-1. However, the small amounts of oil stain in Plover-1 are likely to be derived from a similar source to the Jurassic source rock, based on the lack of the unknown pentacyclic compounds 4 and 5 in these oil stains.

The gas discoveries made at Tern and Petrel fields have not been sampled but are referred to in the literature as being mostly dry gas. They are probably derived from a post mature source and must therefore be derived from Early Permian or older gas sources in this area.

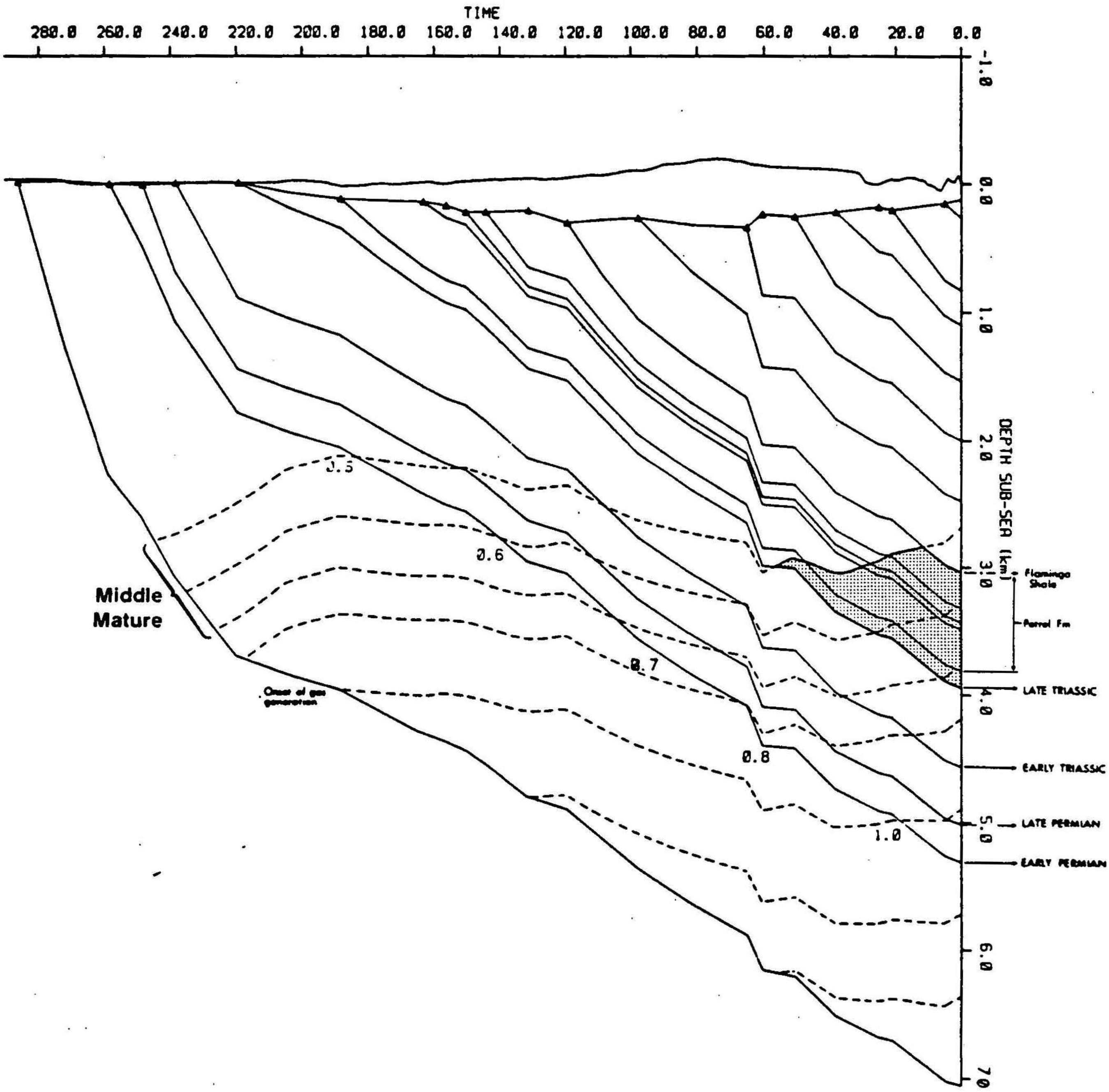
12.4 TIMING AND GENERATION

12.4.1 Introduction

The timing of oil generation has been calculated from the maturity gradients of wells within the main areas of each source rock. These determinations have been cross-checked (Table 12) using maturity modelling in Heron-1 (Encl. 34) and Flamingo-1 (Fig. 47). The correlation between the methods for Flamingo-1 is not as good as for other wells. This could be an indication that the present day temperature gradient is high relative to past gradients, or the temperature data may be in error. In any event, maturation results for Flamingo-1 are applied with caution in discussion of timing of generation.

12.4.2 Kulshill Formation

The Early Permian Kulshill Formation is the major source rock identified in the southern part of the Bonaparte Basin (Fig. 42). The source rock is presently middle mature and, based on burial history studies, reached its maximum depth of burial during the Early Tertiary. The main phase of oil generation from this source rock occurred during this deepest phase of burial.



Bonaparte Basin Maturation Model, Flamingo-1

Figure 47

TABLE 12 - TIMING OF EFFECTIVE ENTRY INTO OIL WINDOW -

BONAPARTE BASIN

	Depth (m)	R_o=0.5%		SCI=5
Heron-1				
Late Jurassic	4100	125	(E. Cretaceous)	110-120
Flamingo Shale	3250	120	(Barremian)	80-90
Flamingo-1				
Middle Jurassic	3800	50	(E. Eocene)	10
Late Jurassic	3400	30	(L. Oligocene)	2
Flamingo Shale	3010	15	(M. Miocene)	not yet mature

12.4.3 Middle Jurassic, Petrel Formation, Member 'C'

Member 'C' of the Petrel Formation is a significant source in the northwest quadrant of the Bonaparte Basin around Eider-1, Tamar-1 and Flamingo-1. It may also be a source on the northern margin of the Petrel Sub-basin.

The source area around Eider-1 and Tamar-1 has reached middle maturity during the Early to Middle Miocene and has continued to generate oil until the present day. At Flamingo-1, the maturation model (Fig. 47) shows the Middle Jurassic source reached middle maturity during the Early Eocene and has continued to generate oil to the present day. SCI data would suggest a later timing of maturation. Possible Middle Jurassic source rocks in the northern part of the Petrel Sub-basin became mature during the Early-Late Tertiary.

12.4.4 Late Jurassic to Early Neocomian

The mudstones of the Petrel Formation, Members 'A' and 'B', and Flamingo Shale, constitute the major source rock units within the northern part of the Bonaparte Basin; they occupy most of the Malita Graben and Sahul Syncline. In the centre of the Malita Graben, especially towards the northeast, e.g. Heron-1 (Encl. 34), these source rocks probably began to generate oil in the Early Cretaceous. Towards the edges of the graben and in the Sahul Syncline, the same source rock probably did not generate significant amounts of oil until the Late Tertiary. On the high blocks e.g. Van Cloon High, Early Cretaceous sediments are still only early mature.

13. PROSPECTIVITY

It is beyond the scope of this study to review all of the parameters which affect the prospectivity for petroleum of the Northwest Shelf. However, in this chapter, the conclusions reached concerning source potential have been summarised. Some speculation on the potential of the various basins has been attempted and suggestions of possible directions which future exploration might follow have been made.

The prospectivity of each of the basins is considered in more detail below.

13.1 NORTHERN CARNARVON BASIN

The offshore northern Carnarvon Basin is a relatively mature exploration area by Australian standards (though immature by international criteria). The existing wells, however, have not yet adequately tested all of the plays in this geologically complex basin, or all of the traps on the established, successful plays. A considerable volume of hydrocarbons remains to be discovered and developed.

All of the ingredients for the accumulation of large hydrocarbon reserves exist at various stratigraphic levels in different parts of the basin, as indicated by results to date. The bulk of the reserves occur around the main depocentres, with most of the gas being reservoired in the pre-breakup (main) unconformity section, and most of the oil in the post-rift section. The main source beds are probably the Locker Shale, Mungaroo Formation and Brigadier Beds (gas/condensate), and the Upper Dingo Claystone (oil).

One of the most important considerations in evaluating the prospectivity of the area is the timing of hydrocarbon generation and migration versus trap formation. The Locker Shale and the Upper Dingo Claystone have been generating hydrocarbons since the Late Triassic and Early Cretaceous respectively. Large volumes of the hydrocarbons generated have not been trapped due to relatively late trap formation. This is borne out by widespread evidence of biodegraded oils.

In exploration of the Northern Carnarvon Basin, great care must therefore be taken in reconstructing, if possible, the history of the trap (e.g. by isopaching, taking note of palaeontological environmental indicators). Mature source beds should be mapped and their attitude to the trap at the time of migration carefully considered. For example, it appears that the Rankin Platform structures have been sourced from the Victoria Syncline to the north (Encl. 35). This is evident from the regional dip to the north and the listric nature of the faults on the southeast margin of the platform, and the related west to northwest dip of the downthrown beds into these faults. This adverse dip was probably present in the Early Cretaceous, and has increased since then. Source from the north or northwest is supported by maturation models on the Goodwyn field. The amount of wet gas at various horizons within the field can be broadly related to maturation levels in the same stratigraphic intervals in the kitchen to the north.

Most of the hydrocarbons generated in the Upper Dingo Claystone in the Lewis Trough are likely to have migrated eastward.

Because of the "early" peak generation of the lower source beds, traps formed by juxtaposition of sands and shales within the pre-breakup unconformity sequence must be rated highly, as they were formed at about the time of peak generation. These traps will be difficult to find, but areas of low sand-shale ratios in the Mungaroo (and shaly Lower and Middle Dingo Claystone) can be highgraded. Improved seismic resolution has enabled recognition and mapping of pre-breakup unconformity fault blocks which have little expression at the main unconformity, e.g. Wilcox.

A brief summary of the main play types is included; they are illustrated diagrammatically on Enclosure 35.

(1) Tilted fault blocks of pre-breakup main unconformity section sealed by:-

- (a) draped regional Late Jurassic to Early Cretaceous shales;
- (b) sand-shale juxtaposition across faults within the pre-breakup unconformity sequence;
- (c) a combination of the above;
- (d) intraformational base seal and regional top seal.

This is the major play in the basin in terms of overall hydrocarbon reserves. It is well developed, and has been successfully exploited on the western side of the basin. The sub-breakup unconformity fault block play has oil potential on the Dampier-Madeleine Trend and Kendrew Terrace, where it is adjacent to the Upper Dingo Claystone source. Targets must be younger than the Mungaroo Formation due to depth of burial. In areas where there was little erosion at the breakup unconformity, e.g. in the Madeleine-North Rankin area, there may be Bathonian deltaic sandstones preserved. Seal in this area may be a problem, however, as large thicknesses of Tithonian sandstones are present immediately to the north.

The play has not been as successful on the eastern side of the basin, primarily due to adverse regional dip and lack of regional top seal. The Mardie Greensand and Birdrong Sandstone, which form a sandy basal unit of the Muderong Shale, effectively destroy any top seal and Goodwyn-type plays. In the shelfal areas, the base Muderong Shale unconformity surface dips relatively uniformly to the west, and structural relief is small.

Type (b) plays, particularly in and around the Flinders Fault Zone, must be considered prospective, e.g. Elder-1, which flowed gas. Permian sandstones beneath the Locker Shale regional seal are also prospective on the eastern shelf. This play may be most prospective near the Flinders Fault Zone, west of which the Locker Shale may be a good source.

Regional intraformational seals, such as the Lower to Middle Dingo Claystone in the Enderby-Dorrigo area, should be carefully mapped to evaluate the integrity of individual fault block traps. It is unlikely that these fault blocks (Mungaroo Formation reservoir) would have access to oil generated from the Upper Dingo Claystone in the Lewis Trough. Potential sources, which include the Lower to Middle Dingo Claystone, Locker Shale and Permian sediments, would need to be studied for maturity and timing of generation.

In the southern shelfal area and southern Barrow Depocentre, the Birdrong Sandstone and Barrow Group sediments present a poor top seal. At Hilda-1, on the Alpha Arch, Barrow Group sands immediately overlie Triassic sandstones of the horst block. On structurally lower blocks, lower Barrow Group shales probably form a seal. Further to the south, on the shelf, there has been considerable erosion at the breakup unconformity level. The predominantly sandy Mungaroo Formation is commonly overlain by the Birdrong Sandstone, and thus the only viable pre-breakup unconformity target consists of faulted Permian sandstones (Kennedy Group) sealed by the Locker Shale.

The Exmouth Plateau region appears to have had an unfavourable thermal history, relative to structuring. A relatively high heat flux and consequent rapid coalification and maturation occurred in the Triassic. Considerable uplift occurred in the Early to Middle Jurassic. Subsequent burial has been generally very slow, and the heat flux has been low. It is likely that the older source rocks - Locker Shale and Mungaroo Formation, reached peak maturity in the Late Triassic to Early Jurassic, and have not substantially changed maturation levels since. Cook et al., 1985, note that the Mungaroo Formation contains good oil source rocks in the Exmouth Plateau area. This generation was prior to the main structural event.

Barber (1982) has reported Early Jurassic structuring. If structures of this age can be mapped, they may represent attractive targets. Structures adjacent to more deeply buried younger source rocks, such as the Brigadier Beds and Lower and Middle Dingo Claystones, may be valid oil and gas prospects. Such depocentres include the Kangaroo Syncline and the previously discussed Victoria Syncline.

Structures are well developed in the Outer Beagle Sub-basin, but there has been little success to date in this area. Due to the presence of the interbedded sands and shales of the Early to Middle Jurassic Learmonth Formation beneath the breakup unconformity, there is a lower chance of seals across faults within the pre-rift section. Because of the sandy nature of the sediments, differential compaction effects are likely to be much less than on the Rankin Platform. There is potential for oil and gas within this region, but careful mapping of sand and shale-prone units away from well control and the relation of these to structure, would be necessary to identify valid plays. Available seismic data indicates that this may be extremely difficult. Potential for intraformational traps may be greater west of the Toarcian delta front, i.e. the Sable-Ronsard Trend.

(2) Post-breakup unconformity Anticlines

These structures have been produced by differential compaction over horsts and/or Tertiary structuring. Targets include:-

(a) Biggada Sandstone and other basal Upper Dingo Claystone Sandstones;
(b) Tithonian Sandstones;
(c) Barrow Group Sandstones;
(d) Birdrong Sandstone/Mardie Greensand;
(e) Windalia Sandstone.

The main oil occurrences on the eastern side of the basin have been sourced from the Upper Dingo Claystone in the depocentres. Hydrocarbon generation began in the Early Cretaceous and reached its peak prior to the Mid-Miocene. Available evidence strongly suggests that generation and migration later than this has been relatively unimportant volumetrically. This conclusion indicates that structures formed prior to the Mid-Miocene are likely to be the most prospective. Of course, generation from the older source beds within the main depocentres will have occurred earlier than this.

A Turonian period of structuring seems to be very important to the establishment of timely structures. Some of the major structural features, such as the Rosemary-Legendre Trend, formed very late and thus may be expected to have trapped only late phase and/or relocated oil.

Oil has been recovered from all the stratigraphic levels mentioned above, but the best reservoirs, and therefore the prime targets, are the Tithonian and Barrow Group Sandstones. Windalia Sandstone reservoirs are very limited in extent; reservoir quality sandstones are localised over a palaeotopographic high at Barrow Island.

(3) Stratigraphic Traps

There is considerable potential for stratigraphic hydrocarbon entrapment throughout the section. The main potential, however, exists within the Late Jurassic to Early Cretaceous sediments. Updip shale-out, and depositional morphology of turbidite and submarine fan sandstones of Late Callovian (Biggada Sandstone Equivalent), Tithonian (Dupuy Sandstone Member) and Early Neocomian (Barrow Group) ages, are likely to have formed traps. Scarborough-1, on the Exmouth Plateau, discovered a large gas field in a turbidite fan complex of the Barrow Group. Kirk (1985) presented many examples of the seismic signature of these deep water sandstones. Areas of most potential are the eastern shelf and the front of the Barrow Delta Complex.

Other stratigraphic plays include onlap of basal Triassic sandstones onto pre-existing highs on the eastern shelf (Kirk, 1985), and possible reservoir sequences which onlap the Madeleine-Dampier Trend. The presence of a shaly (Locker facies) lower Mungaroo Formation at Flinders Shoal-1, may indicate possibilities of Mungaroo Formation stratigraphic traps to the west of the well.

Severe channelling in the Locker Shale near the Flinders Fault Zone (Kirk, 1985) may set up traps within the basal sandstone of the Locker Shale.

13.2 CANNING BASIN

Results of exploratory drilling to date have been extremely disappointing. A summary of the source and maturity data, Chapter 10, indicates that the hydrocarbon potential for the area is apparently poor.

The Palaeozoic sequence appears to be post-mature for oil. The Mesozoic and Tertiary sequence is largely immature and apparently gas-prone. Excellent reservoirs are present, particularly in the Jurassic sequence. The Cretaceous sequence is largely fine grained and acts as a regional seal.

It is possible that some favourable indicators have been overlooked in previous exploration of the offshore Canning Basin that might bear re-examination.

(a) The advanced maturity of the Permian section may be due to the localised effects of dolerite intrusions and elsewhere the Permian may be in, or only recently geologically passed through, the oil window.

(b) By analogy with the Carnarvon, Browse and Bonaparte Basins, source rocks could occur in facies-restricted zones, in particular, in the delta front environment and in distal marine sediments, usually in silled basins.

Further studies of lithostratigraphy and seismic stratigraphy may help to improve these possibilities.

13.3 BROWSE BASIN

Exploration within the Browse Basin has been rejuvenated following the Jabiru and Challis discoveries in 1983 and 1985 within the Vulcan Sub-basin, although other oil and gas discoveries had been made previously (oil in Puffin and Caswell-1, gas in Scott Reef and Brewster-1A). In this section, the prospectivity of the Vulcan Sub-basin is discussed and the potential of the remainder of the Browse Basin is assessed. Particular attention is paid to the southern part of the Browse Basin where release of acreage for tender is anticipated in late 1986 - early 1987.

The Browse Basin is divided into 3 areas for this appraisal - northern (Vulcan Sub-basin and adjacent high areas), central and southern Browse.

13.3.1 Northern Browse Basin

The Northern Browse Basin contains several potential source rock intervals, the most significant of which are Middle Jurassic deltaic sediments and Late Jurassic marine prodelta shales. Further sources are probably present in the Early Jurassic deltaic sequence in the Vulcan Graben, Vulcan Shoals and Cartier Troughs, and in the Late Triassic on the northwest and northern Ashmore Block. However, there is only limited control on the source potential of the Late Triassic and Early Jurassic intervals.

Oil generation in the Cartier Trough would have started at different times in the Late Cretaceous to Early Paleocene from Early, Middle and Late Jurassic source rocks. In the Vulcan Graben and Vulcan Shoals Trough, the Middle and Late Jurassic intervals would have reached middle maturity in the Miocene. Any Early Jurassic sources would have entered the oil window in the Oligocene.

Migration would have been out of the various depocentres as shown on Enclosure 36. However, because there is a complex system of horsts and grabens within the Vulcan Sub-basin, the migration directions are regional trends only. Structures formed during the Early Tertiary would have been timely for oil generated from the Middle and Late Jurassic source rocks, which are the probable sources of most of the oil discovered to date.

Migration paths will have been affected by the numerous major faults which can have acted as conduits during the Miocene. Oil staining at the Eocene-Miocene unconformity in Puffin-1, East Swan-1 and Skua-1 is evidence of these vertical migration paths.

On the northwest of the Ashmore Block, initial oil migration from a possible Late Triassic source during the Miocene will have been updip to the southeast. Miocene faulting in this area may have allowed leakage from earlier formed traps. Pliocene uplift in this area may have caused remigration of oil to the northwest.

Good reservoirs occur at several levels in the northern Browse Basin - Late Triassic (?Challis), Jurassic (Jabiru), Late Cretaceous (Puffin).

Potential traps include drape over horst blocks and palaeohighs associated with continental breakup (Skua, Puffin), rotated fault blocks (Puffin, Jabiru, Challis) and small compressional anticlines associated with wrenching along the boundary faults. Miocene faulting has reactivated many of the horst blocks and rotated fault blocks.

13.3.2 Central Browse

The central Browse Basin contains the Scott Reef and Brewster gas/condensate discoveries, and other wells with numerous oil and gas shows, e.g. Caswell-1, Brecknock-1.

Middle Jurassic source rocks have been identified in two areas of the central Browse Basin (Encl. 36), although part of the original area of good source rock has been removed by erosion along the basin margin. Based on regional trends, Late Jurassic to Early Neocomian source rocks may be present in the central Browse Basin NE of Brewster-1A but have not been positively identified. Similarly Early Jurassic source rocks could be present in the central part of this area but no source rock analyses are available.

The Middle Jurassic source rocks basinwards of the Prudhoe Terrace would have entered the oil window during the Late Cretaceous while the postulated source rocks west and southwest of Scott Reef would have become mature during the Miocene. The main pulse of oil generation from Middle Jurassic would have been during the Miocene thermal event. This heat pulse would have generated condensate from any sources basinwards of the Prudhoe Terrace. Migration from both areas would have been to the south east, as shown on Enclosure 36.

The oil-source rock correlation indicates a Middle and/or a Late Jurassic source for the Scott Reef condensate analysed in this study. The Scott Reef structure is in a suitable position to trap oil migrating from the postulated Middle Jurassic source to the southwest. The gas in Scott Reef has probably been sourced from Triassic or older sediments.

If the Early Jurassic is a source rock in the central Browse Basin, it would have reached middle maturity during the Early Cretaceous. Migration would initially have been to the northwest, but with subsequent reversal of regional dip during the Miocene migration, would have been to the southeast.

If the Late Jurassic has source potential in the central Browse Basin, it would have entered the oil window during the Paleocene, with migration mainly to the southeast (Encl. 36).

In Brewster-1A, gas (C_1-C_5) was encountered in two zones; one in the upper Late Jurassic and the second in lower Late Jurassic - Middle Jurassic. The source of the gas is not known but, based on the regional maturity gradient, is likely to have been generated from Middle Jurassic or older sources.

In the central Browse, reservoir sandstones are present immediately below and above the breakup unconformity. The reservoir properties of these sands are greatly influenced by secondary dolomitisation, as is evidenced in the Scott Reef wells and in Brewster-1A.

However, hydrocarbon-bearing shelfal sands of Cretaceous age were encountered in Caswell-1, and sandstones with 25%-30% porosity were penetrated in Bassett-1A with no shows. Test results in Buffon-1 show that volcanics of Middle Jurassic age have poor to tight permeability with porosity ranging from 5%-20%, while Early Neocomian to Late Jurassic sands have fair permeability and porosity.

Trapping mechanisms in the Central Browse Basin are provided mainly by draping of Late Jurassic and younger sediments over the deep seated horst blocks of pre-Callovian age (Bassett-1A). Top seals are provided mainly by Cretaceous claystones in addition to the intraformational seals which may be present in the Late Jurassic section.

13.3.3 Southern Browse Basin

Some good Middle Jurassic source rocks are present in the southern Browse Basin on the basin margin from Lynher-1 to Yampi-1 (Fig. 48), but the Late Jurassic does not appear to have source potential in this area. However, thin organic rich shales of Early Cenomanian to Aptian age with moderate productivity have been recorded from Barcoo-1. They may possibly represent a potential oil source within the Rowley Sub-basin. These sources would have been mature in the Late Tertiary to Recent.

Potential reservoirs in the southern Browse Basin include sands within the Permian to Middle Jurassic clastics of delta front and delta plain facies. Permian fluviodeltaic argillaceous sandstones with occasional beds of very fine grained sandstone, have low (3-9%) porosities at Yampi-1. Early Permian delta plain clastics in Rob Roy-1 exhibited higher porosities (6-12%); however, permeabilities are less than 21 md where tested. Due to the great burial depths, and hence reduced porosity, away from the basin margins, the Permian sediments provide poor reservoirs.

Late Triassic sandstones in Yampi-1 are dominantly fine grained, argillaceous in part, and cemented with silica. Sandstone beds are up to 14m thick but porosities are low. Medium grained, Early to Middle Jurassic sandstones in

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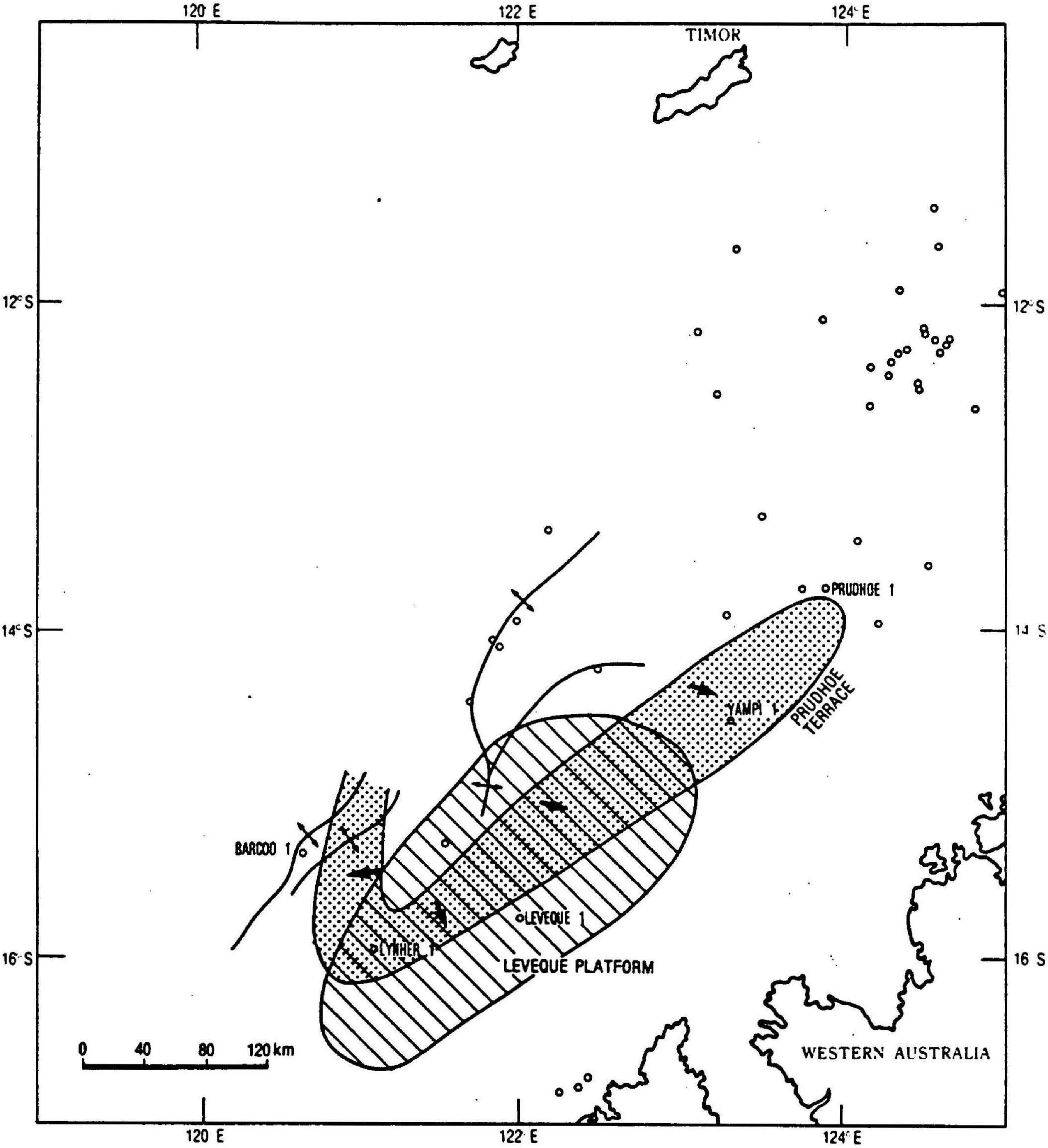

Wells

Middle Jurassic Source

Proposed area for gazettal

Possible migration path

Southern Browse Basin Prospectivity Map

Figure 48

Yampi-1 are up to 30m thick and are interbedded with thin claystones. The sandstones contain up to 25% cement and exhibit trace to poor visible porosity (12% from logs). Locally, they are recrystallised below the Middle Jurassic volcanics.

In Rob Roy-1, Middle Jurassic littoral sandstones have good intergranular porosities (19-30%). Tithonian sandstones in Brewster-1 have good porosities (13-17%), while significant oil shows were encountered in Neocomian sands at Caswell-1.

Basin margin structures would be favourably positioned to receive hydrocarbons migrating from the major depocentres. Pre-breakup horst blocks draped and sealed by differentially compacted Late Jurassic to Early Cretaceous sediments provide the major play type in the area. Additional traps associated with down-to-the-basin faulting, reverse dips adjacent to these faults, and stratigraphic pinchouts, particularly in the Late Triassic section on the basinward side of the fault block, or as combination traps developed in downfaulted re-entrants, may be present. Post-breakup drape over horst blocks and palaeohighs provides a shallower target; this play type contains oil at Caswell-1 in the central Browse Basin.

13.4 BONAPARTE BASIN

Exploration within the Bonaparte Basin is at a relatively immature stage with only 39 exploration wells, being drilled offshore in an area of approximately 250,000 km^2. Nevertheless, results have been disappointing compared with the Browse and Carnarvon Basins, with only 2 large gas fields, Tern and Petrel, being discovered and minor oil and gas shows in several wells. In this section, reasons for the lack of oil discoveries are proposed and the oil potential for the basin is assessed. The basin can be conveniently divided into 2 segments for this assessment, the southeastern part comprising the Petrel Sub-basin and adjacent shelves and terraces, and the northwestern segment - the Malita Graben, Sahul Syncline, Echo Syncline and the shallower sections bordering these depocentres.

13.4.1 Petrel Sub-basin and associated structural elements

The Early Permian Kulshill Formation contains good oil-prone source rocks in a narrow zone around the southeastern offshore part of the Bonaparte Basin (Encl. 37). This zone of good source potential is now middle-late mature (Fig. 46). The main phase of oil generation from this area occurred during the Early Tertiary, with the primary migration direction to the south and southeast.

Further to the north, e.g. in Tern and Petrel wells, only the upper part of the Kulshill Formation has intersected. It is possible that prodelta shales and nearshore sands will comprise the Kulshill Formation in this area; they will have no oil, but possibly gas potential.

Analysis of the gas from Petrel-2 (Arco, 1971) gave the following result:

methane	(C_1)	89.4%
ethane	(C_2)	4.7%
propane	(C_3)	2.0%
n-butane	($\underline{n}$-C_4)	0.5%
iso-butane	($\underline{i}$-C_4)	0.5%
pentane	(C_5)	fracl.
carbon dioxide	(CO_2)	3.6%

The proportions of wet gas (C_2-C_4) to the total gas (C_1-C_4) (8%) suggests the source had a maturity of Ro 1.3-1.5%. Vitrinite reflectance profiles at Tern-1 and Petrel-2 suggest that the source is within the Kulshill Formation.

A DST at Petrel-3 flowed oil at 50° API gravity at a rate of 180 bbls and 481,389 CMPD gas. This probably represents small quantities of oil dissolved in gas during migration and deposited in the reservoir.

This is supported by the lack of either residual oil staining in these wells and by the fact that these structures contain no significant quantities of oil. This evidence suggests they have not had access to an oil charge. The structures have a complex history of growth due to underlying salt pillowing from the Late Permian to Miocene times. Maximum structuring was in the Miocene. These structures are unfavourably placed to receive oil generated from sources in the Kulshill Formation to the south and west during the Early Tertiary. They are, however, in a position to receive gas from post mature sediments in the centre of the Petrel Sub-basin.

The Middle Jurassic Petrel 'C' Formation may be an oil source on the northern margin of the Petrel Sub-basin. These source rocks would have become mature during the Early-Late Tertiary and migration directions would have been to the southwest and south (Encl. 37).

Potential reservoirs in the southeastern Bonaparte Basin include the Late Carboniferous to Early Permian beach barrier and bar sands of the Kulshill Formation, which would be sealed by the overlying shale of the Fossil Head Formation. The deltaic channel sands and point bar sands of the Late Permian Hay Member and the barrier/bar sands of the Late Permian Tern Member, sealed by intraformational shales and the Early Triassic Mt. Goodwin Formation, are other potential reservoirs. Middle to Late Triassic and Middle to early Late Jurassic nearshore to fluviatile sands provide excellent reservoirs throughout the Petrel Sub-basin.

Hydrocarbons which geochemical analysis has shown to represent biodegraded oil residue, were encountered in Lacrosse-1 in an 18 metre thick interval of interbedded, thin sands and shales of Early Permian (greywacke member of Kulshill Formation). The core-derived porosity of these sands is between 5.46% and 23.63%. Much of the porosity was rendered ineffective by the presence of disseminated white clay. Permeabilities have an even wider range, varying from less than 0.01 md to 514.4 md. However, DST-1 in this interval showed very poor permeability and recovered only water-cut mud. Although good permeability is present in places, lateral movement of fluids is greatly restricted by the lenticular nature of the sandstones which are surrounded by impermeable shale and siltstone sequences.

Similar situations may be the case in other wells (Barnett-1 and Turtle-1) where oil shows have been encountered. Discontinuity of the reservoirs has hindered effective migration and appears to be the major factor in preventing the commercial accumulation of oil in the Early Permian sequence in the southeastern part of the Bonaparte Basin. A comprehensive reservoir study is required to determine the distribution of the porous sands within the Early Permian section in this area, where proven mature oil-prone source rock is present.

Potential traps include anticlines resulting from salt pillowing (Tern and Petrel), rollover into boundary faults, anticlines associated with wrenching along bounding faults, and complex fault and domal structures associated with salt diapirism.

13.4.2 Northwest Bonaparte Basin

The Middle Jurassic Petrel 'C' Formation is an important oil-prone source rock developed in the northwest Bonaparte Basin (Encl. 37). It is middle mature on the Sahul Platform and post mature in the Sahul Syncline and Malita Graben.

At Flamingo-1 on the edge of the Sahul Syncline, the maturation model (Fig. 47) shows that the Middle Jurassic source reached middle maturity during the Early Eocene and has continued to generate oil to the present day. However, SCI data would suggest a later timing of maturation. Migration from this area is mainly to the northeast.

Eperiogenic movements associated with continental breakup during the Callovian created a series of NE-SW trending horsts and grabens in the northwest Bonaparte Basin. The thick, post breakup shales in the Petrel Formation in the grabens could contain good potential source rock. Evidence from wells on the high areas bordering the Sahul Syncline and the Malita Graben indicates that good oil source rock could be developed extensively within these depocentres. The Late Jurassic to Early Neocomian sequence is middle to post mature throughout the area of predicted good source potential.

The maturation model for Heron-1, which is located in the shallow part of the Malita Graben, shows that the Late Jurassic reached middle maturity in Early Cretaceous time. It started generating gas in Late Cretaceous time. In the centre of the Malita Graben, the Late Jurassic source rocks would have begun to generate oil earlier than on the edge of the graben, possibly very early in the Early Cretaceous.

Gas generation would have commenced late in the Early Cretaceous. Migration directions were towards the SE and NW from the Malita Graben and towards the NE and SW from the Sahul Syncline. The gas and condensate in Sunrise-1 and Troubadour-1 may have been sourced from this sequence in the Malita Graben. However, they are located a considerable distance from the kitchen areas in the Malita Graben. An alternative possibility would be Late Jurassic sediments northwest of the Sahul Platform.

Generated hydrocarbons could be trapped within the shelfal to nearshore sands of the Late Jurassic to Early Neocomian Petrel 'A' Formation, which are in turn sealed by overlying shales and claystones of the Bathurst Island Formation.

Potential traps include salt-induced anticlines and stratigraphic wedging of the Petrel 'A' Formation between the underlying Petrel 'B' and overlying Cretaceous shales, towards the basin margins. However, gas and condensate in Sunrise-1 and Troubadour-1 occur in a Middle Jurassic reservoir below Bathurst Island Formation seal. Late Jurassic section appears to be missing in that area. Presumably the Sunrise and Troubadour structures were in existence, at least by Late Cretaceous times.

Possible reasons for the lack of oil discoveries in the Bonaparte Basin and an assessment of its prospectivity are summarised as follows:

1) The main source rock in the Petrel Sub-basin, the Early Permian Kulshill Formation, is generally late or post-mature. Oil trapped during generation from the Kulshill Formation may have been lost from most traps by tilting in the Cretaceous.

2) Reservoir quality in the southeastern Bonaparte is fairly poor, while the regional seal, the Cretaceous Bathurst Island Formation, becomes less effective towards the south (thinner and more arenaceous). This is the area where the Kulshill Formation is presently in the oil window.

3) Good, mature to late mature Jurassic to Early Neocomian source rocks occur in the Malita Graben and in the Sahul Syncline; they would have been in the oil window from the Early Cretaceous in the Malita Graben in the Sahul Syncline.

4) Reservoir quality is poor in the depocentres but improves on the high blocks. Lack of success in wells drilled on the high blocks may be related both to unsuitable juxtaposition of source to reservoir and the lack of efficient migration pathways. Timing of hydrocarbon generation relative to structural development may not have been as favourable as in the Vulcan Sub-basin, where the source rocks entered the oil window in the Late Cretaceous-Early Tertiary.

5) Finally, in much of the northwest Bonaparte Basin, the seismic quality is such that it is difficult to interpret structures below the base Cretaceous. Hence interpretation of closure subtle features may not be accurate.

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APPENDICES

NORTHERN CARNARVON BASIN

APPENDIX A

FORMATION TOPS

WELL NAME : ANCHOR-1

Details: WAPET 1969
RT Elev. ASL 24.4m (80ft)
TD 3048m (10,000ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	42	139
Toolonga Calcilutite	531	1743
Gearle Siltstone	657	2155
Windalia Radiolarite	1106	3630
Muderong Shale	1188	3899
Birdrong Sandstone	1221	4335
Barrow Group	1343	4407
Upper Dingo Claystone	1554	5100
Dupuy Sst Mbr	1554-1642	5100-5389
Middle Dingo Claystone	2286	7500
Lower Dingo Claystone	2703	8870
T.D.	3048	10000

WELL NAME : ANGEL-2

Details: BOCAL 1972
RT Elev. ASL 9.5m (31ft)
TD 4397m (14425 ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	96	315
Miria Marl	1955	6415
Toolonga Calcilutite	2167	7110
Gearle Siltstone	2229	7315
Muderong Shale	2363	7755
Barrow Group	2493	8180
Upper Dingo Claystone (Dupuy Sst Mbr eq.)	2694	8840
Learmonth Fm	3139	10300
Lower Dingo	4294	14090
TD	4397	14425

WELL NAME: ANGEL-1

Details: BOCAL 1971
RT Elev ASL 9.5m (31 ft)
TD 3411 (11190 ft)

Seabed (Tertiary undiff.)	89	293
Miria Marl	1898	6228
Toolonga Calcilutite	2121	6960
Gearle Siltstone	2182	7160
Muderong Shale	2329	7642
Barrow Group	2463	8080
Upper Dingo Clayst	2655	8712
Dupuy sst Mbr (eq.)	2655-3410	8712-11190
TD	3411	11190

WELL NAME : BARROW-1

Details: WAPET 1964
RT Elev ASL 55.2m (181 ft)
TD 2982m (9785ft)

	DEPTH	RKB
Tertiary undiff.	3	11
Toolonga Calcilutite	2591	823
Gearle Siltst	282	926
Windalia Radiolarite	628	2060
Muderong Shale (Windalia Sand Mbr)	661	2170
Barrow Group	928	3045
Upper Dingo Claystone	1929	6329
Dupuy Sst Mbr	1929-2181	6329-7155
TD	2982	9785

* In many wells interval described as Seabed (Tertiary undiff.) also contains Quaternary sediments.

WELL NAME : BARROW DEEP-1

Details: WAPET 1973
RT Elev. ASL 46.6m (153 ft)
TD 4650 m (15,256 ft)

FORMATION	DEPTH R.T. Metres	Ft
Tertiary undiff.	8	27
Toolonga Calcilutite	200	657
Gearle Siltstone	268	880
Windalia Radiolarite	605	1984
Muderong Shale	617	2024
Windalia Sst Mbr	617-653	2024-2143
Mardie Greensand Mbr	845-885	2773-2903
Barrow Group	885	2903
Upper Dingo Claystone	1985	6512
Dupuy Sst Mbr	1985-2177	6512-7143
Middle Dingo Claystone	4343	14250
TD	4650	15256

WELL NAME : BRUCE-1

Details: Stirling Petroleum 1979
RT Elev. ASL 21m (69 ft)
TD 2168m (7110 ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	99	325
Muderong Shale	998	3273
Mungaroo Fm	1048	3437
Locker Shale	2086	6842
TD	2168	7111

WELL NAME : BRIGADIER-1

Details: WOODSIDE 1978
RT. Elev. ASL 8m (26ft)
TD. 4292m (14078ft)

Seabed (Tertiary undiff.)	321	1053
Miria Marl	2607	8551
Toolonga Calcilutite	2702	8863
Haycock Marl	2745	9003
Muderong Shale	2811	9220
Middle Dingo Claystone	2827	9272
Lower Dingo Claystone	3491	11451
North Rankin Beds	3558	11670
Brigadier Beds	3612	11847
Mungaroo Fm	3968	13015
TD	4292	14078

WELL NAME : CAMPBELL-1

Details: WAPET 1979
RT. Elev. ASL 21.2m (69.5ft)
TD 2750m (9020ft)

Seabed (Tertiary unidff.)	62	204
Gearle Siltstone	1094	3558
Windalia Radiolarite	1200	3936
Muderong Shale	1258	4126
Barrow Group	2200	7216
Upper Dingo Claystone (Dupuy Sst. Mbr.)	2536	8318
TD	2750	9020

WELL NAME : CAPE RANGE -2

Details: WAPET 1956
RT. Elev. ASL 285.3m (936ft)
TD 4623.8m (15170ft)

FORMATION	DEPTH R.T. Metres	Ft
Tertiary undiff.	282	924
Toolonga Calcilutite	471	1547
Gearle Siltstone	485	1592
Windalia Radiolarite	939	3080
Muderong Shale	1059	3476
Birdrong Sst Mbr	1112	3647
Upper Dingo Claystone	1130	3707
Middle Dingo Claystone	2225(?)	7298
TD	4624	15170

WELL NAME : DAMPIER-1

Details: BOCAL 1968
RT. Elev. ASL 9.1m (30ft)
TD 4141.6m (13588ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	85	280
Miria Marl	1546	5072
Toolonga Calcilutite	2157	7077
Gearle Siltstone	2170	7120
Muderong Shale	2426	7960
Barrow Group	2633	8640
Upper Dingo Claystone	2900	9515
(Dupuy Sst. Mbr.)	2900-3296	9515-1081
TD	4142	13588

WELL NAME : COSSIGNY-1

Details: BOCAL 1972
RT Elev ASL 12.5m (41ft)
TD 3203.4 (10510ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	125	411
Miria Marl	1330	4365
Toolonga Calcilutite	1577	5173
Gearle Siltstone	1646	5399
Learmonth Fm	1796	5894
Mungaroo Fm	2294	7527
TD	3203	10510

WELL NAME: DE GREY-1

Details: BOCAL 1971
RT Elev ASL 29m (95ft)
TD 2087.9m (6850ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	123	405
Miria Marl	1105	3625
Toolonga Calcilutite	1212	3975
Gearle Siltstone	1266	4154
Muderong Shale	1297	4256
(Birdrong Mbr)		
Learmonth Fm	1384	4540
unnamed Early Jurassic	2024	6640
TD(in Brigadier Beds?)	2088	6850

WELL NAME : DELAMBRE-1

Details: WOODSIDE 1980
RT Elev ASL 10m (32)
TD 5495m (18023)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	894	2932
Miria Marl	2069	6786
Toolonga Calcilutite	2150	7052
Haycock Marl	2200	7216
Muderong Shale	2286	7498
Barrow Group	2318	7603
Learmonth Fm	2344	7688
Middle Dingo Claystone	3372	11060
Lower Dingo Claystone	3964	13001
North Rankin Beds	4180	13710
Brigadier Beds	4286	14058
Mungaroo Fm	4615	15137
TD	5495	18023

WELL NAME : EAGLEHAWK-1

Details: BOCAL 1972
RT Elev ASL 12.5m (41ft)
TD 3490m (11450ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	133	436
Miria Marl	2582	8470
Toolonga Calcilutite	2700	8860
Haycock Marl	2721	8928
Muderong Shale	2740	8990
Brigadier Beds	2750	9023
Mungaroo Fm	2908	9540
TD	3490	11450

WELL NAME : DEPUCH-1

Details: BOCAL 1974
RT Elev ASL 10m (32)
TD 4300m (14104)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	153	502
Miria Marl	1636	5366
Toolonga calcilutite	1855	6084
Gearle Siltstone	1952	6403
Muderong Shale	2133	6996
Barrow Group	2360	7740
Learmonth Fm	2512	8239
Middle Dingo Claystone	3800	12464
TD	4300	14104

WELL NAME : EGRET-1

Details: BOCAL 1972
RT Elev ASL 12.5m (41ft)
TD 3658m (12000ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	131	429
Miria Marl	2589	8495
Toolonga Calcilutite	2758	9050
Haycock Marl	2803	9195
Muderong Shale	2906	9535
Barrow Group	2981	9780
Upper Dingo Claystone (Dupuy Mbr eq.)	3118	10230
Brigadier Beds	3298	10820
Mungaroo Fm	3445	11302
TD	3658	12000

WELL NAME: ENDERBY-1

Details: BOCAL 1970
RT Elev ASL 9.4m (31ft)
TD 2149m (7051ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	54	177
Withnell Fm	261	857
Gearle Siltstone	413	1355
Muderong Shale	555	1820
(Mardie Greensand Mbr)	621-753	2038-2470
Learmonth Fm	753	2470
Middle Dingo Claystone	853	2798
Lower Dingo Claystone	1301	4270
Mungaroo Fm	1570	5150
Locker Shale	1737	5700
Rhyolite	2081	6828
TD	2149	7051

WELL NAME : FISHER-1

Details: WOODSIDE 1981
RT Elev ASL 8m (26)
TD 3762m (12339)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	96	315
Miria Marl	2651	8097
Toolonga Calcilutite	2820	9250
Haycock Marl	2840	9315
Muderong Shale	3038	9965
Upper Dingo Claystone		
(Dupuy Sst Mbr eq.)	3097	10158
Learmonth Fm	3388	11113
Lower Dingo Claystone	3526	11565
Brigadier Beds	3660	12004
TD	3762	12339

WELL NAME : FINUCANE-1

Details: WOODSIDE 1978
RT Elev ASL 8m (26)
TD 3300m (10824)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	147	482
Miria Marl	2456	8056
Toolonga Calcilutite	2594	8508
Gearle Siltstone	2662	8731
Muderong Shale	2740	8987
Barrow Group	2814	9230
Upper Dingo Claystone		
(Dupuy Sst Mbr eq.)	2983	9784
Learmonth Fm	3105	10184
TD	3300	10824

WELL NAME : FLAG-1

Details: WAPET 1970
RT Elev ASL 23m (76ft)
TD 3803m (12476)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	60	196
Toolonga Calcilutite	488	1600
Gearle Siltstone	1112	3650
Windalia Radolarite	1203	3948
Muderong Shale	1310	4298
Barrow Group	2143	7030
Upper Dingo Claystone	2567	8422
(Dupuy Sst Mbr)	2567-3037	8422-996[illegible]
TD	3803	12476

WELL NAME : FLINDERS SHOAL-1

Details: WAPET 1969

RT Elev ASL 26m (84ft)

TD 3616m (11,864ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	40	133
Gearle Siltstone	325	1067
Windalia Radiolarite	591	1938
Muderong Shale	621	2038
(Mardie Greensand Mbr)	768-786	2520-2580
Barrow Group	786	2580
Upper Dingo Claystone	1062	3485
(Dupuy Sst Mbr)	1062-1557	3485-5110
Mungaroo Fm	1892	6208
Locker Shale	2304	7560
Byro Group?(Permian)	3284	10773
TD	3616	11864

WELL NAME : GOODWYN-1

Details: BOCAL 1971

RT Elev ASL 29m (94ft)

TD 3536 (11,600ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	154	507
Miria Marl	2464	8084
Toolonga Calcilutite	2615	8580
Haycock Marl	2682	8800
Muderong Shale	2774	9102
Mungaroo Fm	2797	9176
TD	3536	11600.

WELL NAME : GANDARA-1

Details: HUDBAY 1979

RT Elev ASL 21m (69ft)

TD 4361m (140304ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	326	1069
Miria Marl	2676	8777
Toolonga Calcilutite	2774	9099
Haycock Marl	2844	9328
Muderong Shale	2893	9489
Middle Dingo Claystone	2932	9617
North Rankin Beds	3440	11283
Brigadier Beds	3473	11391
Mungaroo Fm	3832	12569
TD	4361	14304

WELL NAME : HAMPTON-1

Details: BOCAL 1974

RT Elev ASL 30m (98ft)

TD 2584m (8476ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	83	272
Gearle Siltstone	410	1345
Muderong Shale	534	1752
(Mardie Greensand Mbr)	592-732	1942-2401
Learmonth Fm	732	2401
Lower Dingo Claystone	1332	4369
Mungaroo Fm	1573	5159
Locker Shale	2086	6842
Pre Mesozoic	2478	8128
TD	2584	8476

WELL NAME : HAUY-1

Details: BOCAL 1972

RT Elev ASL 30m (99ft)

TD 825m (2708ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	96	314
Muderong Shale	555	1820
(Birdrong Sst. Mb.r)	592	1942
Locker Shale	680	2230
(basal sst.)	782	2567
Basic Igneous Rocks	805	2642
T.D.	825	2708

WELL NAME : HAYCOCK-1

Details: WOODSIDE 1977

RT Elev ASL 8m (26ft)

TD 3668 (12034ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	93	305
Miria Marl	2696	8845
Toolonga Calcilutite	2842	9324
Gearle Siltstone	2888	9475
Muderong Shale	3098	10164
Unnamed Callovian	3200	10498
Brigadier Beds	3232	10603
Mungaroo Fm	3435	11269
T.D.	3668	12034

WELL NAME : HERMITE-1

Details: WAPET 1977

RT Elev ASL 27m (88ft)

TD 3300m (10827ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	44	144
(Dupuy Sst Mbr.)	?930	3051
Upper Dingo Claystone	1069	3507
(Biggada Sst. Mbr)	1460	4790
Middle Dingo Claystone	1466	4810
Lower Dingo Claystone	2045	6709
North Rankin Beds	2140	7021
Brigadier Beds	2207	7241
Mungaroo Fm	2500	8202
Locker Shale (eq.)	2850	9350
T.D.	3300	10827

WELL NAME : HILDA-1

Details: WAPET 1974

RT Elev ASL 12m (39ft)

TD 3466m (11371ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed	157	515
Trealla Limestone	875	2871
Mandu Calcilutite	1290	4232
Cardabia Group	1652	5420
Korojon Calcilutite	1662	5453
Toolonga Calcilutite	1720	5643
Upper Gearle Siltstone	1849	6066
Lower Gearle Siltstone	1911	6269
Windalia Radiolarite	2448	8031
Muderong Shale	2468	8097
Barrow Group	2668	8753
Mungaroo Fm	2958	9704
T.D.	3466	11371

WELL NAME : HOPE ISLAND-1

Details: WAPET 1968

RT Elev ASL 9m (30ft)

TD 1426m (4680ft)

FORMATION	DEPTH R.T. Metres	Ft
Tertiary undiff.	4	14
Toolonga Calcilutite	352	1154
Gearle Siltstone	427	1400
Windalia Radiolarite	786	2580
Muderong Shale	840	2757
(Birdrong Sst Mbr)	890-911	2920-2989
Locker Shale	911	2989
(Basal Sst)	988-1030	3240-3375
Kennedy Group	1030	3375
TD	1426	4680

WELL NAME : KOOLINDA-1

Details: WAPET 1978

RT Elev ASL 31m (103ft)

TD 3732m (12240ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	49	162
Gearle Siltstone	477?	1565
Windalia Radiolarite	1004	3293
Muderong Shale	1093	3585
(Mardie Greensand Mbr)	1230-1244	4034-4080
Barrow Group	1244	4080
Upper Dingo Claystone	1858	6094
(Dupuy Sst Mbr)	1858-2304	6094-7557
TD	3732	12240

WELL NAME : JARMAN-1

Details: UNION 1978

RT Elev ASL 8m (26ft)

TD 2906m (9351ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	142	466
Miria Marl	1745	5723
Toolonga Calcilutite	2035	6625
Gearle Siltstone	2116	6940
Muderong Shale	2227	7304
Barrow Group	2415	7921
Upper Dingo Claystone	2551	8367
(Dupuy Sst Mbr eq.)	2578	8456
Middle Dingo Claystone	2660	8725
Learmonth Fm	2757	9043
TD	2906	9532

WELL NAME : LAMBERT-1

Details: BOCAL 1973

RT Elev ASL 10m (33ft)

TD 3700m (12136ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	135	443
Miria Marl	2502	8206
Toolonga Calcilutite	2675	8774
Haycock Marl	2705	8872
Muderong Shale	2808	9210
Barrow Group	2872	9420
Upper Dingo Claystone	3101	10171
(Dupuy Sst Mbr eq.)	3101-3518	10171-11539
Lower Dingo Clayst	3637	11931
TD	3700	12136

WELL NAME : LEGENDRE-1

Details: BOCAL 1968

RT Elev ASL 9m (30ft)

TD 3473m (11393ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	70	200
Miria Marl	1010	3315
Toolonga Calcilutite	1223	4014
Gearle Siltstone	1306	4285
Muderong Shale	1646	5400
Barrow Group	1893	6211
Upper Dingo Claystone	2164	7100
(Dupuy Sst Mbr)	2164-2374	7100-7790
Learmonth Fm	2612.1	8570
TD	3472.6	11394

WELL NAME : LEWIS -1A

Details: BOCAL 1975/76

RT Elev ASL 30m (100ft)

TD 3400m (11,152ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	90	295
Miria Marl	1095	3592
Gearle Siltstone	1295	4248
Muderong Shale	1600	5248
Barrow Group	1950	6396
Upper Dingo Claystone	2013	6603
(Dupuy Sst Mbr eq.)	2051-2311	6727-7580
Middle Dingo Claystone	2744	9000
TD	3400	11152

WELL NAME : LEGENDRE-2

Details: BOCAL 1970

RT Elev ASL 9m (31ft)

TD 3618m (11,871ft)

FORMATION	DEPTH R.T. Metres	Ft
Seafloor (undiff.)	57	188
Miria Marl	1112	3650
Toolonga Calcilutite	1291	4235
Gearle Siltstone	1382	4565
Muderong Shale	1844	6050
Barrow Group	2033	6670
Upper Dingo Claystone	2073	6800
(Dupuy Sst Mbr eq.)	2073-2246	6800-7370
Learmonth Fm	2315	7595
Middle Dingo Claystone	2563	8410
TD	3618	11871

WELL NAME : LOCKER-1

Details: WAPET 1967

RT Elev ASL 4m (13ft)

TD 766m (2512ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)		
Toolonga Calcilutite	177	582
Gearle Siltstone	224	735
Windalia Radiolarite	461	1512
Muderong Shale	533	1750
(Birdrong Sst Mbr)	606-634	1988-208
Mungaroo Fm	634	2081
T.D.	765	2512

WELL NAME : LONG ISLAND-1

Details: WAPET 1966
RT Elev ASL 9m (30ft)
TD 2158m (7081ft)

FORMATION	DEPTH R.T. Metres	Ft
Tertiary undiff	180	592
Toolonga Calcilutite	378	1240
Gearle Siltstone	430	1411
Windalia Radiolarite	641	2103
Muderong Shale	718	2356
(Birdrong Sst Mbr)	787-794	2582-2605
Mungaroo Fm	794	2605
Locker Shale	1992	6535
TD	2158	7081

WELL NAME : INVESTIGATOR-1

Details : ESSO 1979
RT Elev ASL m (ft)
TD 3746m (12290ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary unidff.)	851	2792
Muderong Shale	1330	4363
Barrow Group	1512	4960
Upper Dingo Claystone	3111	10206
Mungaroo	3364	11036
TD	3746	12290

WELL NAME : JUPITER-1

Details: PHILLIPS 1979
RT Elev ASL m (ft)
TD 4946m (16227ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	968	3176
Toolonga Calcilutite	1435	4708
Gearle Siltstone	1520	4987
Muderong Shale	1623	5325
Upper Dingo Claystone	1857	6092
Lower Dingo Claystone	1872	6142
Brigadier Beds	1895	6217
Mungaroo	1934	6345
TD	4946	16227

WELL NAME : LOWENDAL-1

Details: BOCAL 1974

RT Elev ASL 30m (98ft)

TD 3642m (11945ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	115	377
Miria marl	2715	8905
Toolonga Calcilutite	2861	9384
Haycock Marl	2931	9614
Muderong Shale	3041	9974
Brigadier Beds	3107	10190
Mungaroo Fm	3222	10568
TD	3642	11945

WELL NAME : MALUS-1

Details: BOCAL 1972

RT Elev ASL 9m (31ft)

TD 3659m (12000ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	95	312
Miria Marl	2992	8830
Toolonga Calciltite	2845	9330
Haycock Marl	2918	9570
Muderong Shale	3010	9875
Barrow Group	3055	10020
Upper Dingo Claystone	3073	10080
(Dupuy Sst Mbr)	3089-3109	10132-10198
Mungaroo Fm	3109	10198
TD	3659	12000

WELL NAME : MADELEINE-1

Details: BOCAL 1969

RT Elev ASL 9m (30ft)

TD 4429m (14526ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	78	256
Miria Marl	1927	6320
Toolonga Calcilutite	2192	7190
Gearle Silstone/ Haycock Marl	2279	7475
Muderong Shale	2480	8137
Barrow Group	2622	8600
Upper Dingo Claystone	2891	9485
(Dupuy Sst Mbr)	2891-3064	9485-10050
Middle Dingo Claystone	4229	13870
TD	4429	14526

WELL NAME : MERMAID-1

Details: WAPET 1978

RT Elev ASL 31m (102ft)

TD 1271m (4169ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	55	182
Gearle Siltstone	155	508
Windalia Radiolarite	218	715
Muderong Shale	295	968
(Mardie Greensand Mbr)	387-447	1269-1446
Mungaroo Fm	447	1466
Locker Shale	734	2408
Kennedy Group	1230	4034
Basement (Pre-Cambrian)	1259	4130
TD	1271	4169

WELL NAME : MUIRON-1

Details: WAPET 1967
RT Elev ASL 9m (30ft)
TD 1785m (5857ft)

FORMATION	DEPTH R.T. Metres	Ft
Quaternary undiff.	5	16
Tertiary undiff	341	1119
Toolonga Calcilutite	913	2997
Gearle Siltstone	969	3180
Windalia Raiolarite	1278	4193
Muderong Shale	1312	4303
Upper Dingo Claystone	1366	4482
TD	1785	5857

WELL NAME : NORTH RANKIN-1

Details: BOCAL 1971
RT Elev ASL 30m (100ft)
TD 3533m (11593ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	152	500
Miria Marl	2447	8030
Toolonga Calcilutite	2554	8380
Haycock Marl	2627	8620
Muderong Shale	2682	8800
Mungaroo Fm	2687	8816
TD	3533	11593

WELL NAME : NELSON ROCKS-1

Details: BOCAL 1973
RT Elev ASL 9m (31ft)
TD 2190 (7183ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	85	279
Miria Marl	1125	3690
Toolonga Calcilutite	1265	4149
Gearle Siltst	1355	4444
Muderong Shale	1833	6012
Barrow Group	1958	6422
Upper Dingo Claystone	2057	6747
(Dupuy Sst Mbr eq.)	2057-2190	6747-7183
TD	2190	7183

WELL NAME : NORTH TRYAL ROCKS-1

Details: WAPET 1972
RT Elev ASL 12 (40ft)
TD 3656m (11995ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	119	390
Miria Marl	2618	8588
Toolonga Calcilutite	2685	8810
Haycock Marl	2786	9140
Windalia Radiolarite	2883	9460
Muderong Shale	2902	9520
Brigadier Beds	3074	10086
Mungaroo Fm	3298	10820
TD	3656	11995

WELL NAME : OBSERVATION-1

Details: WAPET 1968

RT Elev ASL 9m (30ft)

TD 2292m (7520ft)

FORMATION	DEPTH R.T. Metres	Ft
Quaternary undiff	4	14
Tertiary undiff	290	950
Toolonga Calcilutite	512	1680
Gearle Siltstone	558	1830
Windalia Radiolarite	798	2617
Muderong Shale	852	2795
(Birdrong Sst Mbr)	913-930	2996-3052
Mungaroo Fm	930	3052
Locker Shale	1992	6535
TD	2292	7520

WELL NAME : PEAK-1

Details: WAPET 1967

RT Elev ASL 9m (30ft)

TD 2141m (7026ft)

FORMATION	DEPTH R.T. Metres	Ft
Quaternary/Tertiary undiff.	4	14
Toolonga Calcilutite	561	1840
Gearle Siltstone	602	1976
Windalia Radiolarite	1066	3496
Muderong Shale	1121	3678
Upper Dingo Claystone	1199	3935
Middle Dingo Claystone	1983	6505
TD	2141	7026

WELL NAME : PARKER-1

Details: WOODSIDE 1980

RT Elev ASL 8m (26ft)

TD 4737m (15537ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	88	289
Miria Marl	2434	7984
Toolonga Calcilutite	2758	9046
Gearle Siltstone	2837	9305
Muderong Shale	3084	10116
Barrow Group	3478	11408
Upper Dingo Claystone	3603	11818
(Dupuy Sst Mbr)	3635-3893	11923-12769
Middle Dingo Claystone	4194	13756
TD	4737	15537

WELL NAME : PEPPER-1

Details: WAPET 1970

RT Elev ASL 30m (98ft)

TD 2743m (9000ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	36	117
Muderong Shale	1039	3410
(Mardie Greensand Mbr)	1234-1257	4049-4123
Barrow Group	1257	4123
Upper Dingo Claystone	2391	7845
(Dupuy Sst Mbr)	2391-2743	7845-9000
TD	2743	9000

WELL NAME : PICARD-1

Details: BOCAL 1972

RT Elev ASL 9m (31ft)

TD 4216m (13,832ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	150	493
Miria Marl	1891	6205
Toolonga Calcilutite	2004	6575
Gearle Siltstone/ Haycock Marl	2038	6688
Muderong Shale	2077	6815
Learmonth Fm	2325	7629
Lower Dingo Claystone	3615	11860?
?North Rankin Beds	3939	12925
?Brigadier Beds	3997	13114
TD	4216	13832

WELL NAME : PUEBLO-1

Details: WOODSIDE 1979

RT Elev ASL 30m (98ft)

TD 3485m (11430ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	142	465
Miria Marl	2593	8505
Toolonga Calcilutite	2735	8907
Haycock Marl	2811	9220
Muderong Shale	2904	9525
Mungaroo Fm	2938	9636
TD	3485	11430

WELL NAME : POISSONIER-1

Details: BOCAL 1974

RT Elev ASL 30m (98ft)

TD 1962m (6435ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)		
Late Cretaceous undiff.	113	371
Toolonga Calcilutite	776	2545
Haycock Marl	845	2771
Muderong Shale	903	2962
Barrow Group	937	3073
Upper Dingo Claystone	987	3237
(Dupuy Sst Mbr eq.)	987-1013	3237-3322
Learmonth Fm	1032	3385
Mungaroo Fm	1124	3686
Locker Shale	1616.5	5302
Intermediate -Basic Igneous	1947	6386
TD	1962	6435

WELL NAME : RIPPLE SHOALS-1

Details: WAPET 1970

RT Elev ASL 24m (79ft)

TD 2279m (7476ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)		
Late Cretaceous	56	183
Gearle Siltstone	397	1302?
Windalia Radiolarite	847	2779
Muderong Shale	881.5	2892
(Mardie Greensand Mbr)	1055-1080	3460-3542
Barrow Group	1080	3542
Upper Dingo Claystone	1858	6095
(Dupuy Sst Mbr)	1858-2279	6095-7476
TD	2279	7476

WELL NAME : RONSARD-1

Details: BOCAL 1973

RT Elev ASL 10m (32ft)

TD 2848 (9341ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	170	557
Miria Marl	1959	6426
Toolonga Calcilutite	2133	6996
Gearle Siltstone/ Haycock Marl	2215	7265
Muderong Shale	2256	7399
Learmonth Fm	2294	7524
Lower Dingo Claystone	2766?	9072?
TD	2848	9341

WELL NAME : SABLE-1

Details: BOCAL 1972

RT Elev ASL 12m (41ft)

TD 3971 (13030ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	163	536
Miria Marl	2315	7595
Toolonga Calcilutite	2457	8060
Gearle Siltstone	2488	8164
Middle Dingo Claystone	2514	8248
Lower Dingo Claystone	3063	10050
North Rankin Beds	3551	11652
Brigadier Beds	3597	11800
Mungaroo Fm	3783	12410
TD	3971	13030

WELL NAME : ROSEMARY-1

Details: BOCAL 1973

RT Elev ASL 9m (31ft)

TD 3909m (12825ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	74	244
Miria Marl	?409	?1343
Gearle Siltstone	1098	3602
Muderong Shale	1500	4920
(Sst Mbr)	1823-1929	5980-6330
Barrow Group	2155	7070
Upper Dingo Claystone	2198	7210
(Dupuy Sst Mbr)	2198-2495	7210-8187
Middle Dingo Claystone	3121	10240
Learmonth Fm	3283	10772
TD	3909	12825

WELL NAME : SANDY POINT-1

Details: WAPET 1967

RT Elev ASL 115m (378ft)

TD 3045m (9991ft)

FORMATION	DEPTH R.T. Metres	Ft
Tertiary undiff.	4	12
Toolonga Calcilutite	756	2480
Gearle Siltstone	798	2618
Windalia Radiolarite	1147	3764
Muderong Shale	1159	3802
Learmonth Fm	1176	3853
Brigadier Beds	2830	9285
TD	3045	9991

WELL NAME : SATURN-1

Details: PHILLIPS 1981

RT Elev ASL 10 (34ft)

TD 4000m (13120ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	1088	3568
Miria Marl	2527	8285
Toolonga Calcilutite	2706	8875
Haycock Marl	2813	9226
Muderong Shale	2868	12687
Barrow Group	2916	9564
Upper Dingo Clyastone	2984	9787
Lower Dingo Claystone	3022	9912
Brigadier Beds	3207	10519
Mungaroo Fm	3536	11598
TD	4000	13120

WELL NAME : SPAR-1

Details: WAPET 1977

RT Elev ASL 30m (98ft)

TD 3721 (12241ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	144	474
Toolonga Calcilutite	1307	4287
Gearle Siltstone	1498	4913
Windalia Radiolarite	2229	7311
Muderong Shale	2260	7413
Barrow Group	2601	8531
TD	3721	12241

WELL NAME : SHOLL-1

Details: WAPET 1967

RT Elev ASL 9m (30ft)

TD 1272m (4172ft)

FORMATION	DEPTH R.T. Metres	Ft
Quaternary/Tertiary undiff	4	13
Toolonga Calcilutite	67	220
Gearle Siltstone	74	244
Windalia Radiolarite	231	758
Muderong Shale	296	970
(Birdrong Sst Mbr)	296-338	970-1109
Locker Shale	338	1109
Kennedy Group	832	2730
Byro Group	1061	3480
TD	1272	4172

WELL NAME : TORTOISE-1

Details: WAPET 1966

RT Elev ASL 9m (30ft)

TD 2134m (7000ft)

FORMATION	DEPTH F.T. Metres	Ft
Quaternary/Tertiary undiff	4	13
Toolonga Calcilutite	228	747
Gearle Siltstone	389	1278
Windalia Radiolarite	893	2930
Muderong Shale	989	3246
(Birdrong Sst Mbr)	1137	3730
Upper Dingo Claystone	1231	4040
TD	2134	7000

WELL NAME : TRYAL ROCKS-1

Details: WAPET 1970
RT Elev ASL 28m (93ft)
TD 3696m (12123ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	75	245
Toolonga Calcilutite	1274	4180
Gearle Siltstone	1348	4422
Muderong Shale	?2042	6700
Barrow Group	2853	9363
Upper Dingo Claystone	3409	11184
TD	3695	12123

WELL NAME : WALCOTT-1

Details: BOCAL 1979
RT Elev ASL 8m (28ft)
TD 4382m (14372ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	89	294
Miria Marl	2050	6724
Toolonga Calcilutite	2330	7642
Haycock Marl	2418	7931
Muderong Shale	2601	8531
Barrow Group	2710	8889
Upper Dingo Claystone	3004	9853
(Dupuy Sst Mbr)	3004-3236	9853-10614
TD	4382	14372

WELL NAME : VLAMING HEAD-1

Details: CANADA NORTHWEST
RT Elev ASL 25m (82ft)
TD 2068m (6783ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	361	1184
Toolonga Calcilutite	1074	3522
Gearle Siltstone	1102	3615
Windalia Radiolarite	1553	5094
Muderong Shale	1565	5133
(Birdrong Sst Mbr)	1603-1635	5258
Barrow Group	1635	5363
TD	2068	6783

WELL NAME : WEST MUIRON-2

Details: WAPET 1976
RT Elev ASL 30m (98ft)
TD 3320m (10,890ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	91	298
Toolonga Calcilutite	862	2827
Gearle Siltstone	902	2959
Windalia Radiolarite	1014	3356
Muderong Shale	1048	3437
(Birdrong Sst Mbr)	1069	3506
Barrow Group	1084	3556
Upper Dingo Claystone	1096	3595
Middle Dingo Claystone	2067	6780
Lower Dingo Claystone	2430	7970
North Rankin Beds	3044	9984
Brigadier Beds	3070	10070
TD	3320	10890

WELL NAME : WEST TRYAL ROCKS-1

Details: WAPET 1972
RT Elev ASL 12m (40ft)
TD 3866m (12,685ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	150	492
Toolonga Calcilutite	2256	7402
Gearle Siltstone	2267	7438
Windalia Radiolarite	2566	8419
Muderong Shale	2627	8620
Mungaroo Fm	3264	10709
TD	3866	12685

WELL NAME : WITHNELL-1

Details: BOCAL 1976
RT Elev ASL 30m (98ft)
TD 4650m (15252 ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	105	344
Miria Marl	1435	4707
Toolonga Calcilutite	2054	6737
Haycock Marl	2172	7121
Windalia Radiolarite	2318	7603
Muderong Shale	2336	7662
Barrow Group	2627	8617
Upper Dingo Claystone	2948	9669
?Middle Dingo Claystone	4442	14570
TD	4650	15252

WELL NAME : WEST TRYAL ROCKS-2

Details: WAPET 1974
RT Elev ASL 12m (39ft)
TD 3825m (12546ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	138	453
Toolonga Calcilutite	2245	7304
Gearle Siltstone	2257	7403
Windalia Radiolarite	2612	8567
Muderong Shale	2684	8804
Mungaroo Fm	3225	10578
TD	3825	12546

WELL NAME : ZEEPARD-1

Details: ESSO 1980
RT Elev ASL 10m (32ft)
TD 4215m (13825ft)

FORMATION	DEPTH R.T. Metres	Ft
Seabed (Tertiary undiff.)	750	2460
Miria Marl	1320	4330
Toolonga Calcilutite	1520	4986
Gearle Siltstone	1632	5352
Muderong Shale	2625	8610
Barrow Group	2815	9233
Upper Dingo Claystone	3925	12876
Mungaroo Fm	3981	13058
TD	4215	13825

CANNING BASIN

WELL NAME : BEDOUT-1

Details : BOCAL P&A 1971

RT Elev. ASL : 28.6m (94ft)

TD : 3073m (10,082ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	170	559
J. Miocene to Pleistocene	170	559
L-M Miocene	492	1615
L. Paleocene-Eocene	643	2108
Danian	771	2530
Campanian-Maastrichtian	794	2605
Santonion-Coniacion	1064	3490
Turonion	1112	3648
Albian-Cenomanian	1125	3692
L. Neocomian-Aptian	1259	4130
Tithonian-L. Neocomian	1648	5406
M. Jurassic	1798	5900
E. Jurassic	2160	7087
L. Triassic	2911	9550
Volcanics	3021	9911
T.D.	3073	10082

WELL NAME : EAST MERMAID-1

Details : Shell Dev. (Aust) P&A 1973

RT Elev ASL : 11m (37ft)

TD : 4068m (13,345ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	399	1309
Pliocene	490	1607
M-L Miocene	549	1800
E. Miocene	792	2600
Oligocene	1262	4140
L. Eocene	1292	4240
M. Eocene	1483	4864
L. Paleocene	1597	5240
Maastrichtian	1628	5340
E. Campanian	1704	5590
Santonian	1737	5700
Coniacian	1753	5750
Albian	1792	5880
Aptian	1939	6360
Neocomian	2301	7550
M. Jurassic	2883	9460
E. Jurassic	3624	11890
Liassic	3917	12850
T.D.	4068	13345

WELL NAME : KERAUDREN-1

Details : (Hematite Petroleum) P&A 1973

RT Elev ASL : 30m (98ft)

TD : 3844m (12,612ft)

FORMATION	DEPTH RT Metres	Ft
Seafloor	125	410
E. Tertiary	527	1729
L. Cretaceous	600	1969
E. Cretaceous	950	3117
L. Jurassic	1445	4741
M. Jurassic	1543	5062
E. Jurassic	1650	5413
L. Triassic	2460	8071
M. Triassic	2801	9190
T.D.	3844	12612

WELL NAME : LACEPEDE-1

Details : (BOCAL) P&A 1970

RT Elev ASL : 9m (31ft)

TD : 2286m (7500ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	68	223
Quaternary, Tertiary	68	223
L. Cretaceous	303	993
E. Cretaceous	541	1775
L. Jurassic	1204	3950
M. Jurassic	1486	4875
E. Jurassic	1596	5235
L. Permian	1998	6555
T.D.	2286	7500

WELL NAME : WAMAC-1

Details : (Amax Petroleum) P&A 1973

RT Elev. ASL : 10m (33ft)

TD : 2764m (9068ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	85	279
L. Cretaceous	357	1171
Aptian	405	1329
Neocomian-L. Aptian	930	3051
Tithonian	1190	3904
M. Jurassic	1325	4347
L. Palaeozoic	2071	6795
TD	2764	9068

CENTRAL AND SOUTHERN BROWSE BASIN

WELL NAME : BARCOO-1

Details: (WOODSIDE) P&A 1979

RT Elev ASL ASL 11m (36ft)

TD: 5109m (16761ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	731	2398
M.to Early Miocene	1125	3691
Oligocene	2232	7322
Eocene	2325	7628
Paleocene	2538	8326
Maastrichtian	2702	8865
Late Campanian to Late Turonian	2749	9019
M.Cenomanian to Barremian	3007	9865
Neocomian	3695	12122
Oxfordian to Late Callovian	3795	12450
Bathonian to ? Aalenian	3830	12565
Early Jurassic	4128	13543
Rhaetian to Norian	4748	15577
TD	5109	16761

WELL NAME :BASSETT-1A

Details: (WOODSIDE) P&A 1978

RT Elev ASL 8m (26ft)

TD: 2706m (8878ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	372	1220
Basal Pleistocene to late Miocene	416	1365
Eocene	986	3235
Paleocene	1833	6013
Maastrichtian to Turonian	1943	6374
Albian	2669	8756
TD	2706	8878

WELL NAME: BRECKNOCK-1

Details: (WOODSIDE) P&A 1979

RT Elev ASL 11m (36ft)

TD: 4300m (14107ft)

FORMATION	DEPTH RT Metres	Ft
Seabed(Eocene to Recent)	555	1821
Paleocene	3310	10860
Maastrichtian to Turonian	3427	11243
E. Cenomanian to M. Albian	3573	11722
E. Aptian to Necomian	3752	12309
Late Callovian (volcanics)	3809	12496
Early Jurassic	3864	12677
Carnian to Ladinian	3966	13012
TD	4300	14107

WELL NAME: BREWSTER-1A

Details: (WOODSIDE) P&A 1980

RT Elev ASL 8m (26ft)

TD: 4703m (15430ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	264	866
Pliocene to M. Miocene	644	2112
Late-M. Eocene	1169	3835
Maastrichtian to Coniacian	1900	6233
Cenomanian to Aptian	2425	7956
Late Neocomian	3310	10860
Berriasian	3863	12674
Tithonian	3942	12933
Kimmeridgian	4173	13691
M. Jurassic	4455	14619
T.D.	4703	15430

WELL NAME: BUFFON-1

Details: (WOODSIDE) P&A 1980

RT Elev ASL 10m (33ft)

TD: 4787m (15705ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	543	1781
Miocene	843	2765
Late Oligocene	2725	8940
Eocene	2865	9399
Paleocene	3267	10718
Late Maastrichtian	3478	11410
Coniacian	3484	11430
Early Cenomanian to Albian	3487	11440
Aptian	3762	12342
M. Jurassic (volcanics)	3775	12385
Bathonian to Aalenian	4447	14589
Early Jurassic	4500	14764
TD	4787	15705

WELL NAME : CASWELL-1

Details: (WOODSIDE) P&A 1978

RT Elev ASL 8 (26ft)

TD: 4097m (13441ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	358	1174
Pliocene to Miocene	675	2214
Late Paleocene	1945	6381
Maastrichtian to Coniacian	2595	8513
Cenomanian to Neocomian	3348	10984
TD	4097	13441

WELL NAME : HEYWOOD-1

Details: (BOCAL) P&A 1974

RT Elev ASL 10m (33ft)

TD: 4572m (15000ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	45	147
Pliocene to Miocene	377	1237
Eocene	808	2651
Paleocene	1074	3523
Maastrichtian to Santonian	1590	5216
Cenomanian to Albian	2278	7473
Basal Aptian to Middle Neocomian	3093	10147
Early Neocomian	3345	10974
Tithonian to Oxfordian	3405	11171
Jurassic (undiff)	4140	13582
TD	4572	15000

WELL NAME : LEVEQUE-1

Details: (BOCAL) P&A 1970

RT Elev ASL 9.5m (31ft)

TD: 899m (2951ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	87	286
Pliocene to Miocene	137	450
Maastrictian to Santonian	334	1098
Cenomanian to Neocomian	415	1362
Late Jurassic	814	2672
Pre-Cambrian	896	2939
TD	899	2951

WELL NAME : LOMBARDINA-1

Details: (BOCAL) P&A 1974

kT Elev ASL 30m (98ft)

TD: 2855m (9366ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Miocene to Recent)	175	98
Oligocene	637	2090
Eocene	674	2211
Paleocene	927	3041
Maastrictian to Turonian	976	3202
Albian to Late Neocomian	1276	4186
Berriasian to Tithonian	2308	7572
Oxfordian to ?Bathonian	2432	7979
Volcanics (E. to M. Jurassic)	2572	8438
Early Jurassic	2701	8861
TD	2855	9366

WELL NAME : LONDONDERRY-1

Details: (BOCAL) P&A 1973

RT Elev ASL 13m (42ft)

TD: 1145m (3756ft)

FORMATION	DEPTH RT Metres	Ft
Seabed(Miocene to Recent)	103	338
Eocene	529	1735
Paleocene	618	2027
Maastrichtian to Santonian	707	2319
Cenomanian to Albian	769	2523
Late Neocomian	1037	3402
Basement	1135	3724
TD	1145	3756

WELL NAME : LYNHER-1

Details: (BOCAL) P&A 1970

RT Elev ASL 9.5m (31ft)

TD: 2725m (8940ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	77	252
Eocene	292	960
Late Paleocene	413	1355
Maastrichtian to Santonian	489	1605
Turonian to Neocomian	731	2398
Early Neocomian to Tithonian	1310	4300
Kimmeridgian to Oxfordian	1338	4392
Callovian	1455	4775
Early Jurassic	1722	5652
Late Triassic	2426	7960
Permian (undiff.)	2639	8860
TD	2725	8940

WELL NAME : PRUDHOE-1

Details: (BOCAL) P&A 1974

RT Elev ASL 30m (98ft)

TD: 3322m (10899ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	205	672
Pliocene to Miocene	512	1679
Eocene	817	2680
Paleocene	1209	3966
Maastrichtian to Santonian	1330	4363
Cenomanian to L. Albian	1797	5895
Basal Aptian to Neocomian	2135	7004
Tithonian	2759	9052
Early Permian	2888	9475
TD	3322	10899

WELL NAME : ROB ROY-1

Details: (BOCAL) P&A 1972

RT Elev ASL 9.5m (31ft)

TD: 2286m (7500ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	111	366
Pliocene to Miocene	426	1400
Paleocene	566	1859
Maastrichtian	700	2296
Cenomanian to Albian	774	2540
Aptian	1189	3902
Neocomian	1231	4040
Bathonian to E. Callovian	1448	4750
Early Permian Late Carboniferous	1572	5159
Proterozoic	2255	7400
TD	2286	7500

WELL NAME : SCOTT REEF-1

Details: (BOCAL) Temp. abandoned gas well, 1971

RT Elev ASL 9.5m (31ft)

TD: 4730m (15520ft)

FORMATION	DEPTH RT Metres	Ft
Seabed(Miocene to Recent)	59	194
Oligocene	2275	7464
Eocene	2363	7752
Paleocene	3383	11100
Maastrichtian to Turonian	3497	11473
Cenomanian to Late Neocomian	3671	12044
Late Jurassic	4259	13975
Volcanics(late Jurassic)	4289	14072
M. to Early Jurassic	4293	14084
Late Triassic	4355	14290
TD	4730	15520

WELL NAME : YAMPI-1

Details: (BOCAL) P&A 1973

RT Elev ASL 13m (42ft)

TD 4176m (13700ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	104	341
Pliocene to Early Miocene	408	1338
Eocene/Palaeocene	789	2588
Campanian to Coniacian	1014	3326
Albian	1549	5082
Aptian to L. Neocomian	1832	6010
E. Neocomian	2555	8382
Berriasian to Tithonian (Petrel "A" eq.)	2570	8432
Tithonian to Kimmeridgian (Petrel "B" eq.)	2830	9285
Oxfordian to Bajocian (Petrel "C" eq.)	3135	10285
Volcanics	(3305-3390)	(10843-11122)
Jurassic (undiff)	3390	11122
Late Triassic	3587	11768
Permian	3825	12549
TD	4176	13700

NORTHERN BROWSE BASIN

(VULCAN SUB-BASIN, ASHMORE BLOCK)

WELL NAME : ANDERDON-1

Details : (BHP) P&A 1985

RT Elev. ASL : 8.3m (27ft)

TD : 2905m (9531ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	97	318
Miocene/Recent	105	344
Eocene	481	1578
Paleocene	759	2490
Cretaceous	998	3274
Mt Goodwin	1427	4682
Hyland Bay	2416	7926
T.D.	2905	9531

WELL NAME : ASHMORE REEF-1

Details : (BOCAL) P&A 1968

RT Elev ASL : 12m (40ft)

TD : 3914m (12843ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Quaternary/ Pliocene)	49	160
Middle to Late Miocene	321	1053
Early Miocene	803	2635
Oligocene	933	3062
Eocene	1222	4009
Paleocene	2090	6857
Cretaceous	2191	7190
Late Jurassic	2447	8030
Volcanics	2469	8102
Late Triassic	2786	9143
TD	3914	12843

WELL NAME : BROWN GANNET-1

Details : (ARCO) P&A 1972

RT Elev ASL : 34m (112ft)

TD : 2743m (9000ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	144	474
Miocene	275	904
Oligocene	793	2603
Eocene	905	2970
Paleocene	1768	5800
Late Cretaceous	1947	6390
Late Triassic	2167	7110
TD	2743	9000

WELL NAME : DILLON SHOALS-1

Details : (BOCAL) P&A 1974

RT Elev ASL : 12m (39ft)

TD : 3970m (13025ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	137	449
Pliocene	563	1847
Miocene	634	2080
Oligocene	811	2660
Eocene	823	2700
Paleocene	1027	3369
Campanian to Late Turonian	1513	4964
Cenomanian to Late Albian	1735	5692
E. Aptian to L. Neocomian	1804	5919
Late Middle Triassic	1811	5941
Mt. Goodwin	3292	10800
Hyland Bay	3682	12080
TD	3970	13025

WELL NAME : EAST SWAN-1

Details : (CITCO & ARCO) P&A 1978

RT Elev ASL : 21m (70ft)

TD : 3038 (9969ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Miocene/Recent)	124	408
Eocene	728	2388
Paleocene	1286	4221
Cretaceous	1824	5985
Oxfordian (Petrel B eq.)	2330	7645
Callovian and older (Petrel 'C' eq.)	2694	8840
TD	3038	9969

WELL NAME : GREBE-1

Details : (ARCO) P&A 1979

RT Elev ASL : 30m (98ft)

TD : 3000m (9843ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Miocene/Recent)	69	227
Eocene	1054	3460
Paleocene	1746	5730
Cretaceous	2061	6762
Late Triassic	2697	8850
TD	3000	9843

WELL NAME : MT. ASHMORE-1B

Details : (WOODSIDE) P&A 1980

RT Elev ASL : 11m (36ft)

TD : 2655m (8710ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	634	2080
Miocene	1120	3413
Eocene	1225	4019
Paleocene	1483	4865
Cretaceous	1524	5000
Late Neocomian	1933	6342
Mid Tithonian to Oxfordian	1956	6417
Volcanics	2094	6870
Late Triassic	2112	6929
TD	2655	8710

WELL NAME : NORTH HIBERNIA-1

Details : (BOCAL) P&A 1974

RT Elev ASL : 13m (42ft)

TD : 4000m (13123ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	66	216
Miocene	315	1033
Oligocene	1076	3530
Eocene	1382	4534
Paleocene	1610	2582
Maastrichtian to Albian	1663	5456
Aptian to Late Neocomian	1958	6424
Late Triassic	1983	6506
TD	4000	13123

WELL NAME : PRION-1

Details : (ARCO) P&A 1974

RT Elev ASL : 25m (82ft)

TD : 2960 (9713ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Miocene/Recent)	95	311
Eocene	1054	3460
Paleocene	1850	6071
Cretaceous	2114	6938
Late to Middle Triassic	2646	8682
TD	2960	9713

WELL NAME : PUFFIN-1

Details : (ARCO) P&A 1972

RT Elev ASL : 34m (113ft)

TD : 2961 (9715ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Miocene/Recent)	136	449
Eocene	1021	3350
Paleocene	1743	5721
Late Cretaceous	1999	6560
Late to Middle Triassic	2347	7703
TD	2961	9715

WELL NAME : PUFFIN-2

Details : (ARCO) P&A 1974

RT Elev ASL : 25m (82ft)

TD : 2560m (8400ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Miocene/Recent)	103	339
Eocene	1041	3418
Paleocene	1734	5689
Late Cretaceous	1986	6516
Late Triassic	2449	8036
TD	2560	8400

WELL NAME : PUFFIN-3

Details : (ARCO) P&A 1975

RT Elev ASL : 25m (82ft)

TD : 2469m (8103ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Miocene/Recent)	123	404
Eocene	1015	3330
Paleocene	1735	5695
Late Cretaceous	2022	6635
Triassic	2394	7857
TD	2469	8103

WELL NAME : RAINBOW-1

Details : (BHP) P&A 1985

RT Elev ASL : 8m (26ft)

TD : 2700m (8858ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	135	443
Miocene/Recent	143	469
Eocene	1036	3399
Paleocene	1885	6184
Cretaceous	2194	7198
Triassic (undiff.)	2392	7848
TD	2700	8858

WELL NAME : SAHUL SHOAL-1

Details : (BOCAL) P&A 1970

RT Elev ASL : 9.5m (31ft)

TD : 3802m (12475ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Miocene/Recent)	37.8	124
Oligocene	875	2873
Eocene	1161	3810
Paleocene	1600	5250
Cretaceous	1661	5450
Late Triassic	1793	5885
Middle Triassic	2767	9080
Mt. Goodwin (eq.)	3261	10700
Hyland Bay (eq.)	3740	12272
TD	3802	12475

WELL NAME: SKUA-1

Details : (ARCO) P&A 1974

RT Elev ASL : 29.5m (97ft)

TD : 3048m (10000ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	110	361
Eocene	815	2675
Paleocene	1372	4503
Maatrichtian to Late Albian	1898	6228
M. Jurassic	2418	7935
E. Jurassic	2803	9195
TD	3048	10000

WELL NAME : SWAN-1

Details : (ARCO) P&A 1973

RT Elev ASL : 34m (112ft)

TD : 3284m (10775ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	143	470
Miocene	296	973
Eocene	873	2866
Paleocene	1570	5153
Late Cretaceous	2153	7063
E. Neocomian to Late Jurassic	2630	8629
TD	3284	10775

WELL NAME : WOODBINE-1

Details : (WOODSIDE) P&A 1979

RT Elev ASL : 8m (26ft)

TD : 3502m (11489ft)

FORMATION	DEPTH RT	
	Metres	Ft
Seabed	197	646
Miocene	515	1689
Eocene	1082	3549
Cretaceous	2065	6775
Late Triassic	3076	10092
TD	3502	11489

BONAPARTE BASIN

WELL NAME : BOUGAINVILLE-1

Details : (AUSTRALIAN AQUITAINE) P&A 1972

RT Elev ASL : 12.8m (42ft)

TD : 2676m (8780ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	49	160
Tertiary (undiff.)	192	630
Bathurst Island	250	820
Late Jurassic	313	1029
Triassic (undiff.)	457	1500
Mt. Goodwin	892	2927
Hyland Bay	1342	4404
H4	(1415-1427)	4644-4682
H5	(1785-1798)	5856-5900
Fossil Head	1822	5980
Kulshill	2372	7782
TD	2676	8780

WELL NAME : CURLEW-1

Details : (ARCO) P&A 1971

RT Elev ASL : 25m (83ft)

TD : 2035m (6678ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	103	337
Miocene (undiff.)	250	820
Bathurst Island	339	1112
Petrel 'A'	1725	5660
Petrel 'B'	1813	5950
Petrel 'C'	1992	6535
TD	2035	6678

WELL NAME : EIDER-1

Details : (ARCO) P&A 1972

RT Elev ASL : 34m (113ft)

TD : 2834m (9300ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Early to M. Miocene)	134	441
Eocene	523	1716
Paleocene	867	2846
Bathurst Island	1177	3862
E. Neocomian to Late Jurassic	1828	6000
Middle Jurassic	1862	6110
Redbed (eq.)	2331	7650
Triassic (undiff.)	2680	8794
TD	2834	9300

WELL NAME : FLAMINGO-1

Details : (ARCO) P&A 1971

RT Elev ASL : 34m (113ft)

TD : 3700m (12139ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	130	428
Miocene	277	910
Oligocene	838	2750
Eocene	1106	3630
Paleocene	1540	5053
Bathurst Island	2006	6584
Flamingo Shale	3046	9995
Petrel 'A'	3266	10718
Petrel 'B'	3379	11088
Petrel 'C'	3440	11288
TD	3700	12139

WELL NAME : FLAT TOP-1

Details : (AUSTRALIAN AQUITAINE) P&A 1970

RT Elev ASL : 12m (40ft)

TD : 2173m (7131ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Recent/Tertiary undiff.)	55	180
Bathurst Island	189	620
Late Jurassic	743	2440
Triassic (undiff.)	978	3210
Mt. Goodwin (eq.)	1182	3880
Hyland Bay	1292	4240
H4	1304-1323	4280-4343
H5	1417-1444	4650-4740
Fossil Head	1452	4765
Kulshill	1578	5180
Basement	2165	7105
TD	2173	7131

WELL NAME : FRIGATE-1

Details : (ARCO) P&A 1978

RT Elev ASL : 21.3m (70ft)

TD : 1585m (5200ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Recent/Tertiary undiff.)	112.3	368
Bathurst Island	369	1210
Petrel 'A'	1020	3346
Petrel 'B'	1142	3746
Petrel 'C'	1241	4071
TD	1585	5200

WELL NAME : GULL-1

Details : (ARCO) P&A 1971

RT Elev ASL : 13m (43ft)

TD : 3421m (11225ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Recent to Miocene)	134	441
Paleocene	381	1250
Bathurst Island	596	1958
Petrel 'A'	2128	6984
Petrel 'B'	2399	7870
Petrel 'C'	2439	8002
Red Beds	3108	10200
Triassic (undiff.)?	3349	10974
TD	3421	11225

WELL NAME : HERON-1

Details : (ARCO) P&A 1972

RT Elev ASL : 50m (165ft)

TD : 4208m (13808ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Recent to Late Miocene)	88	291
Middle To Early Miocene	253	830
Eocene/Paleocene	533	1750
Bathurst Island	1028	3374
Flamingo Shale (eq.)?	3304	10842
Petrel Fm. (Early Neocomian to ?latest Tithonian)	3520	11550
TD	4208	13808

WELL NAME : KINMORE-1

Details : (AUSTRALIAN AQUITAINE) P&A 1974

RT Elev ASL : 11.5m (38ft)

TD : 3250m (10663ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	38	124
Mt. Goodwin	202	663
Hyland Bay	505	1657
H4	562-570	1844-1870
H5	847-854	2779-2802
Fossil Head	867	2844
Kulshill (Greywacke)	1321	4334
Shale Member	1795	5889
Sand Member	2505	8218
Early Carboniferous	2931	9616
Devonian Salt	3046	9993
TD	3250	10663

WELL NAME : LACROSSE-1

Details : (ARCO) P&A 1969

RT Elev ASL : 26m (85ft)

TD : 3054m (10020ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Tertiary/Recent)	59.5	188
Mt. Goodwin	154	505
Hyland Bay	186	610
H4	332-335	1090-1100
H5	585-593	1920-1947
Fossil Head	606	1990
Kulshill (Greywacke)	940	3084
Shale Member	1463	4800
Sand Member	1913	6278
Border Creek	2384	7823
Late Carboniferous		
Tanmurra	2702	8866
Early Carboniferous		
TD	3054	10020

WELL NAME : NEWBY-1

Details : (AUSTRALIAN AQUITAINE) P&A 1969

RT Elev ASL : 12m (40ft)

TD : 1148m (3768ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Tertiary/Recent)	87	285
Bathurst Island	259	850
Late Jurassic	960	3150
Basement	1115	3660
TD	1148	3768

WELL NAME : OSPREY-1

Details : (ARCO) P&A 1972

RT Elev ASL : 34m (112ft)

TD : 3185m (10451ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	134	442
Miocene	265	870
Eocene	454	1490
Paleocene	553	1815
Bathurst Island	731	2398
Triassic (undiff.)	1256	4123
Mt. Goodwin	1834	6017
Hyland Bay	2471	8108
H4	2518-2624	8262-8610
H5	2700-2821	8860-9255
Fossil Head?	2825	9270
TD	3185	10451

WELL NAME : PELICAN ISLAND-1

Details : (ARCO) P&A 1972

RT Elev ASL : 20m (66ft)

TD : 1988m (6525 ft)

FORMATION	DEPTH RT Metres	Ft
(Carboniferous Border Creek)	Surface	
Tanmurra	360	1180
Bonaparte Beds	859	2820
Salt (Devonian)	1791	5877
TD	1988	6525

WELL NAME : PENGUIN-1

Details : (ARCO) P&A 1972

RT Elev ASL : 34m (113ft)

TD : 2757m (9045ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Tertiary/Recent)	103	338
Bathurst Island	387	1270
Petrel 'B'	802	2634
Petrel 'C'	862	2830
Red Beds (Early Jurassic)	1100	3610
Triassic (undiff.)	1278	4195
Mt. Goodwin	1611	5287
Hyland Bay	2130	6990
H4	2145-2157	7040-7078
H5	2492-2508	8178-8230
Fossil Head	2534	8315
TD	2757	9045

WELL NAME : PETREL-1A

Details : (ARCO) S 1970

RT Elev ASL : 34m (113ft)

TD : 4039m (13253ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Tertiary/Recent)	134	441
Bathurst Island	286	940
Petrel 'A'	1325	4350
Petrel 'B'	1528	5015
Petrel 'C'	1816	5960
Red Bed	2226	7304
Triassic (undiff.)	2478	8130
Mt. Goodwin	2922	9588
Hyland Bay	3523	11561
H4	3590-3601	11781-11816
H5	4017	13180
TD	4039	13253

WELL NAME : PETREL-2

Details : (ARCO) S 1971

RT Elev ASL : 34m (113ft)

TD : 4725m (15501ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Tertiary/Recent)	131	432
Bathurst Island	411	1350
Petrel 'A'	1295	4250
Petrel 'B'	1492	4895
Petrel 'C'	1770	5808
Red Beds	2159	7084
Triassic (undiff.)	2464	8085
Mt. Goodwin	2878	9445
Hyland Bay	3460	11352
H4	3526-3533	11569-11630
H5	3952-3983	12968-13070
Fossil Head	4014	13170
TD	4725	15501

WELL NAME : PLOVER-1

Details : (ARCO) P&A 1972

RT Elev ASL : 34m (113ft)

TD : 2438m (8000ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Recent-Miocene)	58	190
Bathurst Island	388	1275
Petrel 'A'	1051	3450
Petrel 'B'	1173	3850
Petrel 'C'	1186	3892
Red Beds	1306	4286
Triassic (undiff.)	1493	4900
Mt. Goodwin	1685	5530
Hyland Bay	2149	7050
H4	(2219-2225)	(7280-7300)
TD	2438	8000

WELL NAME : PLOVER-2

Details : (ARCO) P&A 1974

RT Elev ASL : 25m (83ft)

TD : 1524m (5000ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	59	194
Miocene (undiff.)	91	300
Bathurst Island	359	1177
Petrel 'A'	615	2020
Petrel 'B'	680	2230
Mt. Goodwin	713	2340
Hyland Bay	1136	3728
H4	(1189-1196)	(3900-3925)
H5	(1425-1432)	(4675-4700)
Fossil Head Fm.	1463	4800
TD	1524	5000

WELL NAME : SANDPIPER-1

Details : (ARCO) P&A 1971

RT Elev ASL : 11.8m (39ft)

TD : 1891m (6206ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Tertiary undiff.)	98	323
Bathurst Island	243	800
Petrel 'A'	504	1654
Petrel 'B'	590	1936
Petrel 'C'	669	2296
Triassic (undiff)	914	3000
Early Carboniferous	944	3097
Late Devonian (Salt Cap Rock)	1732	5683
Late Devonian (Salt Plug)	1793	5885
TD	1891	6206

WELL NAME : SHEARWATER-1

Details : (ARCO) P&A 1974

RT Elev ASL : 25m (83ft)

TD : 3177m (10425ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Miocene/Recent)	94	311
Eocene to Paleocene	640	2100
Bathurst Island	1566	5138
Petrel 'C' (Time eq.)	3054	10020
TD	3177	10425

WELL NAME : SUNRISE-1

Details : (BOCAL) P&A 1975

RT Elev ASL : 30m (98ft)

TD : 2341m (7680ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Recent/ Pleistocene)	189	620
Pliocene to late Oligocene	492	1614
E. Oligocene	1092	3583
Eocene	1116	3661
Paleocene	1398	4586
Bathurst Island	1472	4829
Petrel C (E. Oxforidan to Bajocian)	2096	6878
TD	2341	7680

WELL NAME : TAMAR

Details : (GETTY OIL) P&A 1979

RT Elev ASL : 31m (101ft)

TD : 2863m (9393ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	95	311
Miocene	411	1348
Eocene	516	1693
Paleocene	652	2139
Bathurst Island	1062	3484
Flamingo Shale	2001	6565
Petrel 'A'	2011	6597
Petrel 'B'	2066	6778
Petrel 'C'	2140	7021
Red Beds	2379	7805
Triassic (undiff.)	2718	8917
TD	2863	9393

WELL NAME : TERN-1

Details : (ARCO) S 1971

RT Elev ASL : 11.8m (39ft)

TD : 4352m (14278ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Tertiary undiff.)	104	341
Bathurst Island	403	1324
Petrel 'A'	1139	3738
Petrel 'B'	1240	4070
Petrel 'C'	1331	4368
Triassic (undiff.)	1674	5494
Mt. Goodwin	2034	6673
Hyland Bay	2521	8272
H4	2584-2589	8480-8497
H5	2936-2952	9634-9687
Fossil Head	2992	9818
Kulshill	3568	11708
TD	4352	14278

WELL NAME : TROUBADOUR-1

Details : (BOCAL) P&A 1974

RT Elev ASL : 12.5m (41ft)

TD : 3495m (11466ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	121.5	398
Miocene	420	1378
Oligocene	867	2844
Eocene	1007	3304
Paleocene	1241	4071
Bathurst Island	1402	4599
Petrel C (Oxfordian to Bajocian)	2158	7080
Red Bed (eq.)	2471	8107
Triassic (undiff.)	2755	9038
Mt. Goodwin	3003	9852
Permian undiff.	3298	10820
Basement	3315	10876
TD	3495	11466

WELL NAME : TURNSTONE-1

Details : (ARCO) P&A 1974

RT Elev ASL : 25m (82ft)

TD : 2019m (6625ft)

FORMATION	DEPTH RT Metres	Ft
Seabed (Recent to Miocene)	143	469
Eocene	358	1176
Paleocene	685	2250
Bathurst Island	923	3029
Flamingo Shale (eq.)?	1410	4628
Petrel 'A'	1425	4675
Petrel 'B'	1432	4700
Petrel 'C' (eq.)?	1436	4712
E. Jurassic/L. Triassic	1453	4770
TD	2019	6625

WELL NAME : WHIMBREL-1

Details : (ARCO) P&A 1974

RT Elev ASL : 25m (83ft)

TD : 2058m (6754ft)

FORMATION	DEPTH RT Metres	Ft
Seabed	102	335
Miocene/Recent	237	778
Eocene/Paleocene	399	1310
Bathurst Island	594	1950
Petrel 'A' (eq.)	1100	3610
Triassic (undiff.)	1128	3700
Mt. Goodwin	1535	5038
Hyland Bay	1881	6170
H4	1941-1952	6370-6405
H5	2014-2042	6610-6700
TD	2058	6754

APPENDIX B

ANALYTICAL PROCEDURES AND TECHNIQUES FOR PETROLEUM GEOCHEMISTRY

ANALYTICAL PROCEDURES AND TECHNIQUES FOR PETROLEUM GEOCHEMISTRY

B1 INTRODUCTION

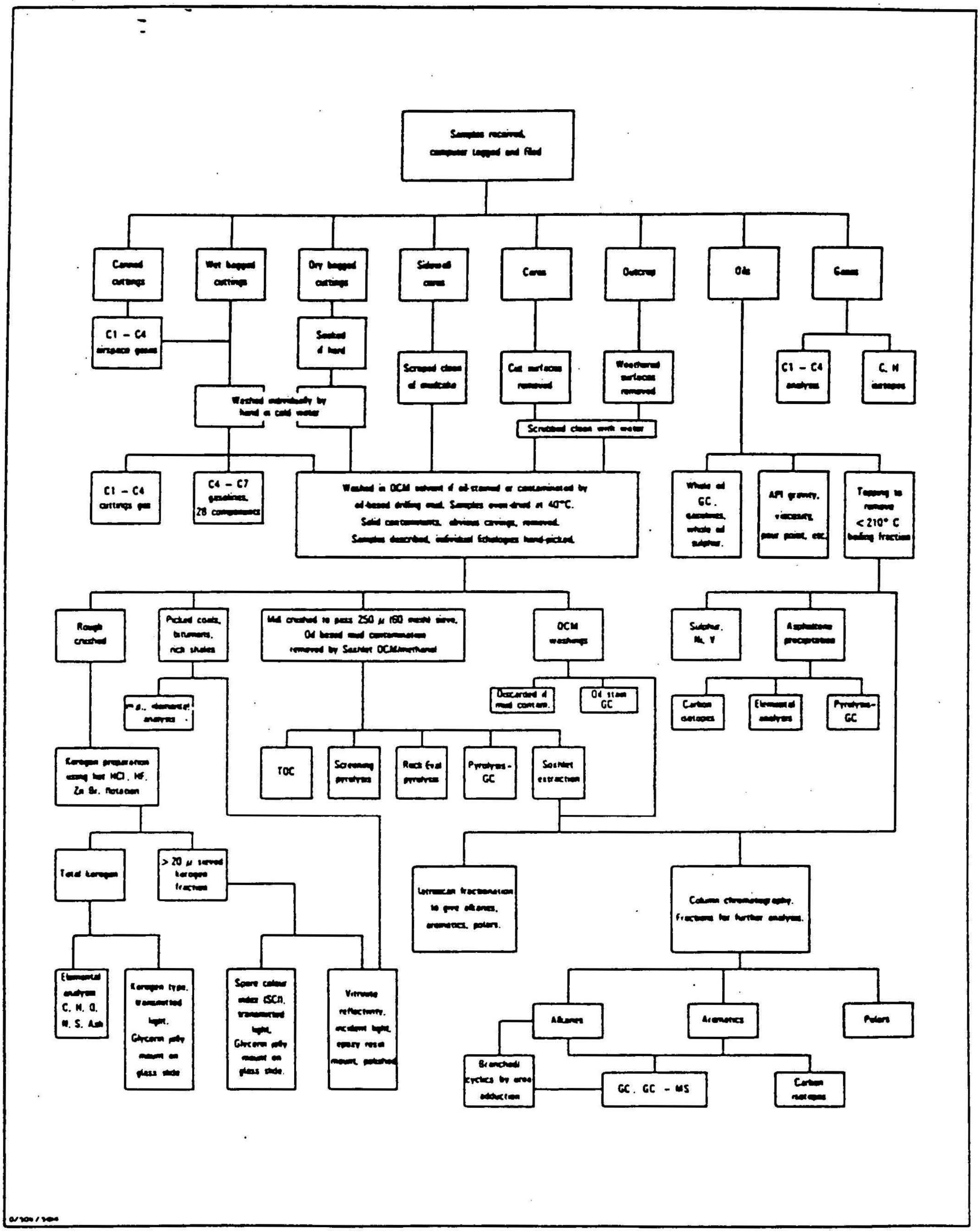
This Appendix summarises the main steps in the petroleum geochemical analyses carried out in the North West Shelf Phase II study. Analytical pathways are shown on the flow chart (Fig. B1) and details of laboratory procedures and techniques are given in the text. These may in certain circumstances be adapted to suit particular samples or conditions. Interpretation guidelines are also defined.

B2 SAMPLE PREPARATION

B2.1 INTRODUCTION

The samples were received into the laboratory in the form of ditch cuttings, conventional core pieces and crude oil samples. Each sample was assigned a number which was entered into a computer system to monitor sample selection and progress. Preparation techniques were directed towards obtaining clean samples, free of drilling mud and additives, obvious caving contamination and indeterminate fine material. Washing with cold water was standard but further washing with solvent (dichloromethane, DCM) was carried out if oil-based mud was present, after which samples were dried, described and individual lithologies hand-picked where practicable. Samples were rough crushed to approximately pea-sized fragments for kerogen preparation or finely milled for chemical analysis.

FLOW CHART FOR GEOCHEMICAL ANALYSIS



APPENDIX FIGURE B1

B2.2 KEROGEN PREPARATION

Kerogen concentrates for microscopic examination and elemental analysis were prepared using standard palynological procedures but omitting oxidation or acetolysis. Acid maceration involved the use of hot hydrochloric acid (HCL) to remove carbonates and hot 60% hydrofluoric acid (HF) to remove or break down silicates. Mineral residues were separated from the kerogen by a combination of ultrasonic vibration and zinc bromide flotation. Kerogen samples for spore colour and kerogen typing were mounted on glass slides in glycerin jelly, those for vitrinite reflectivity were dried and mounted in epoxy resin. Kerogen residues were stored in methanol.

B3 MATURITY EVALUATION

The techniques employed for interpreting maturity and thermal history were based mainly on spore colouration, vitrinite reflectivity measurement and thermal modelling (TTI), supplemented by data obtained from pyrolysis Tmax, and hydrocarbon analysis, including gas chromatography and gas chromatography-mass spectrometry.

B3.1 SPORE COLOURATION

Sporomorph colour was assessed using a> 20u sieved kerogen fraction viewed in transmitted light on a standard palynological microscope. Unusual hues were checked using incident blue/UV light fluorescence. Measurement was made by eye against reference sets of single grain spore mounts by trained operators, thus achieving a high degree of accuracy and reproducibility. The 1 to 10 Spore Colour Index (SCI) scale was designed for linearity with increasing depth and temperature and correlates approximately with the following zones of oil generation: up to 3.5, immature, 3.5 to 5.0, early mature, generation of low gravity oils (28° to 35° API); 5.5 to 7.0, middle mature, generation of medium gravity oils (35° to 42° API); 7.0 to 8.5, late mature, generation of light oils (42° API) and condensates; 8.5 to 10, post mature, generation of condensate, wet gas and, ultimately, dry gas. Linearity of scale is of great value in prediction, by extrapolation, of the depth to any part of the oil generation sequence. The value of SCI measurement lies in the objective selection of measured grains, so minimising problems of caving and reworking, and in its more direct correlation against oil generation than vitrinite reflectivity measurement. Limitations in its use concern the difficulty of correlation against other colour scales and the insensitivity of the scale in the late to post mature region. Anomalous colours may result from bleaching or staining during deposition and diagenesis. The correlation of SCI against Thermal Alteration Index (TAI) given on the SCI versus depth plot in the well reports was made by direct comparison of Staplin's standard slides with SCI standard slides.

B3.2 VITRINITE REFLECTIVITY

The majority of preparations examined under reflected light in the Robertson Research laboratories were made using >20u sieved kerogen, mounted on slides and polished with carborundum and alumina, although total kerogen may be used when sample size was limited. Picked coals, organic-rich shales or limestones containing solid bitumen were mounted directly in resin blocks and polished in the usual way. Measurement was made on a Carl Zeiss microscope fitted with a photometer. Values obtained were punched into a computer for data processing for each sample. The system was calibrated against glass standards and reflectance values were expressed as arithmetic means of measurements taken in oil immersion (R_o or R_m oil). R_{max} and R_{min} may be measured and quoted in certain circumstances but the difference is insignificant below about R_o 1.0%. Some operator selection of particles during measurement was essential and obvious contaminants or non-vitrinite material were noted but not necessarily quoted. The value quoted on data tables is that which is interpreted as most appropriate, but other possibilities may also be given. Plotted figures assume a logarithmic increase of reflectance with depth. R_o 0.50% is a widely accepted threshold value for the onset of oil generation, although as the kinetics of oil generation may not be identical to those of vitrinite reflectivity development, this must be seen only as a general guide. The floor for oil generation is characterised by a reflectance value of about 1.3%. Wet gas generation peaks at a value of about 1% and ceases at the 2% level. Dry gas generation peaks at a reflectance of about 1.5% and ceases at the 3% to 4% level. Correlation of reflectance values with other maturity parameters may not be universal because of time-temperature factors and is best made on a local basis.

Reflectivity measurement is a widely used and versatile tool which may be readily calibrated against easily obtained standards. It is applicable over a wide range of maturity stages from immature to post mature (0.2% to 5% R_o). High surface intercepts on plotted figures and discordances at faults and unconformities can give realistic estimates of the amount of section missing. It is of limited value in Early Palaeozoic sections where land plant material is absent, although a general guide to maturity may be obtained from chitinous organic matter. Even a skilled operator may have difficulty in distinguishing indigenous vitrinite from some forms of inertinite, anomalously reflecting 'pseudovitrinite', cavings and reworked fragments.

B3.3 ROCK-EVAL PYROLYSIS, GAS CHROMATOGRAPHY (GC) AND GAS CHROMATOGRAPHY-MASS SPECTROMETRY (GC-MS) IN MATURITY ANALYSIS

These three analytical processes measure parameters which are functions of both maturity and kerogen type. Data from them may give a general guide to maturity but if the kerogen types are known, more specific conclusions may be drawn. From Rock-Eval data, the temperature of maximum rate of pyrolysis, Tmax, is the most useful datum; gas chromatograms of alkanes, separated from source rock extracts or oils, yield carbon preference indices (CPI) and isoprenoid ratios; GC-MS quantitative fragmentograms provide abundance ratios for specific compounds which are particularly useful in assessing the level of maturity at which source rock hydrocarbons or oils have been generated. All these supplementary data may be used to confirm results from visual analysis or supplant them if poor or unavailable.

B4 SOURCE ROCK EVALUATION

B4.1 TOTAL ORGANIC CARBON CONTENT (TOC)

Organic carbon values were obtained by treating 0.1g of crushed rock sample with hot, concentrated HCL to remove carbonates. The washed residue was filtered on to a glass fibre pad and ignited in a Leco carbon analyser. For screening purposes, samples were analysed singly but where further analyses, such as pyrolysis or solvent extraction were anticipated, a duplicate sample was run. Blanks and standards were run as routine and where values from duplicated samples did not concur within strict accuracy limits, they were rerun. Where samples were heavily stained with oil, either from natural deposits or drilling mud, TOC was repeated on the dried, solvent extracted sample.

TOC measurement is fundamental in assessing source rock quality, since, when combined with kerogen type and maturity, a full description of the potential to generate oil may be given. It is found in practice that sediments containing less than 0.3% TOC are unlikely to have any source potential; those containing between 0.3% and 1% may be marginal sources but the better quality sources contain in excess of 1% TOC. Screening by TOC is therefore an inexpensive and rapid method of selection of samples for further analysis in source potential evaluation.

B4.2 ROCK-EVAL PYROLYSIS

Pyrolysis data were obtained using the IFP-Fina Rock-Eval apparatus. A sample of 100 mg of crushed, whole rock either from bulk sample or picked lithology was weighed accurately into a crucible and introduced into a furnace at 250°C. Free hydrocarbons (roughly equivalent to solvent extractable hydrocarbons) were volatilised and quantified by flame ionisation detector (FID) to give Peak 1 (S_1, ppm). The furnace temperature was increased to 550°C at 25°C/minute and within this range, kerogens crack to give hydrocarbons, measured by FID to give Peak 2 (S_2, ppm) and carbon dioxide, measured by thermal conductivity detector (TCD) to give Peak 3 (S_3, ppm). The temperature at the maximum rate of evolution of cracked volatiles (Tmax) was measured automatically but can also be monitored visually. The instrument was calibrated daily using standards both at the beginning of the work period and at regular intervals thereafter and crucible blanks were run as routine. The tabulated data in reports comprised the following parameters:

Tmax °C	-	temperature of maximum rate of Peak 2 hydrocarbon evolution.
Hydrogen Index (HI)	-	S_2/TOC (mg/g) or ratio of released hydrocarbon to organic carbon content. This is a measure of the hydrocarbon generating potential remaining in the kerogen as opposed to that of the whole rock.
Oxygen Index (OI)	-	S_3/TOC (mg/g) or ratio of released carbon dioxide to organic carbon content.
Production Index (PI)	-	S_1/S_1+S_2, or ratio of the amount of hydrocarbons released in the first stage of heating to the total amount of hydrocarbons released and cracked during pyrolysis.
Potential Yield (PY)	-	S_1+S_2 (ppm or kg/ton) or total of free hydrocarbons and hydrocarbons released during cracking of kerogen compared to original weight of rock.

Tmax, hydrogen index and oxygen index are each functions of both maturity and kerogen type. Using published and empirical data, it has been possible to assemble a model to show the relationships of these factors to maturity as measured by spore colouration and vitrinite reflectivity for a selection of pure kerogen types. The kerogen types used are algal sapropel (type I), waxy sapropel (type II), vitrinite (type IIIA) and inertinite (type IIIB) and a computer program has been devised by which the amounts of these components may be calculated from the HI, OI, Tmax and maturity data for any sample. These are the values expressed in the 'kerogen composition by calculation' columns tabulated in the reports.

The hydrogen index is a measure of the hydrocarbon generating potential of the kerogen and is analogous to the atomic H/C ratio. Immature, organically rich source rocks and oil shales give values above 500, mature oil source rocks give values between 200 and 550. For a given kerogen type, these values progressively dimish with increasing maturity.

The temperature of maximum rate of pyrolysis depends partly on the kerogen type but the transition from immature to mature organic matter is marked by temperatures between 415° and 435°C. The maturity transition from oil and wet gas generation to dry gas generation is marked by temperatures between 455° and 460°C. In practice, greater variation than these ideal temperature ranges may be seen, but they are nevertheless useful as general guides to the level of maturity attained by the sediment.

The production index increases with maturity from values near zero for immature organic matter to maximum values of 0.15 during the late stages of oil generation. Anomalously high values indicate the presence of oil or contaminants. The potential yield is an indication of the predicted yield of hydrocarbons from the source rock at optimum maturity and is a measure of the quality of the source rock. For immature sediments, values of 0 to 2 kg/ton (0 to 2000 ppm) of hydrocarbon characterise a poor source rock, 2 to 6 kg/ton (2000 to 6000 ppm) fair, 6 to 20 kg/ton (6000 to 20000 ppm) good, and above 20 kg/ton (20000 ppm) very good.

Pyrolysis techniques have in recent years provided a major advance in the assessment of source rock quality and generating potential. Hydrocarbon yields from immature source beds examined on-structure may be translated into actual oil productivity from the same beds in mature basinal, off-structure situations. Models relating maturity and kerogen type may be used to define original source rock quality grades which are of great value in mapping organic facies. Amorphous kerogen types, indistinguishable in microscopic preparations over a wide range of chemical properties, may be readily differentiated by pyrolysis. The problem of analysing bulk samples containing mixed kerogens has been largely overcome by the kerogen type/maturity model and anomalous results arising from the presence of caving contamination and drilling mud additives can usually be explained by inspection. High oxygen indices sometimes occur as a result of the presence of metastable carbonates and in such cases the sample is acid decarbonated and re-run.

B4.3 DETAILED INTERPRETATION OF PYROLYSIS DATA

The calculation of kerogen type abundance and the determination of source rock quality and productivity in this report have been based on the interpretation of Rock-Eval pyrolysis data.

Kerogen type abundance by calculation

The values of hydrogen index (HI), oxygen index (OI) and temperature of maximum pyrolysis rate (Tmax) for algal sapropel, waxy sapropel, anoxic waxy sapropel, and vitrinite were plotted in Figure B2 to show their maturation paths. Although to some extent still empirical and subject to minor modifications, these paths conform with the available literature of pyrolysis indices, atomic H/C, and atomic O/C ratios. Using this model, the relative amounts of each of the kerogen types in Figure B2 can be calculated for an analysed source rock if the following assumptions are made:

1) The hydrogen index or oxygen index of a kerogen mixture is the sum of the fractional hydrogen or oxygen indices of the components. These fractional indices are derived by multiplying the fractional abundance of each individual component by its own hydrogen or oxygen index.

2) Tmax for a mixture has a value between the highest and lowest values of Tmax of the pure components in proportion to the amounts of hydrocarbon generated by each of these components during pyrolysis.

3) The hydrogen and oxygen indices for inertinite are zero.

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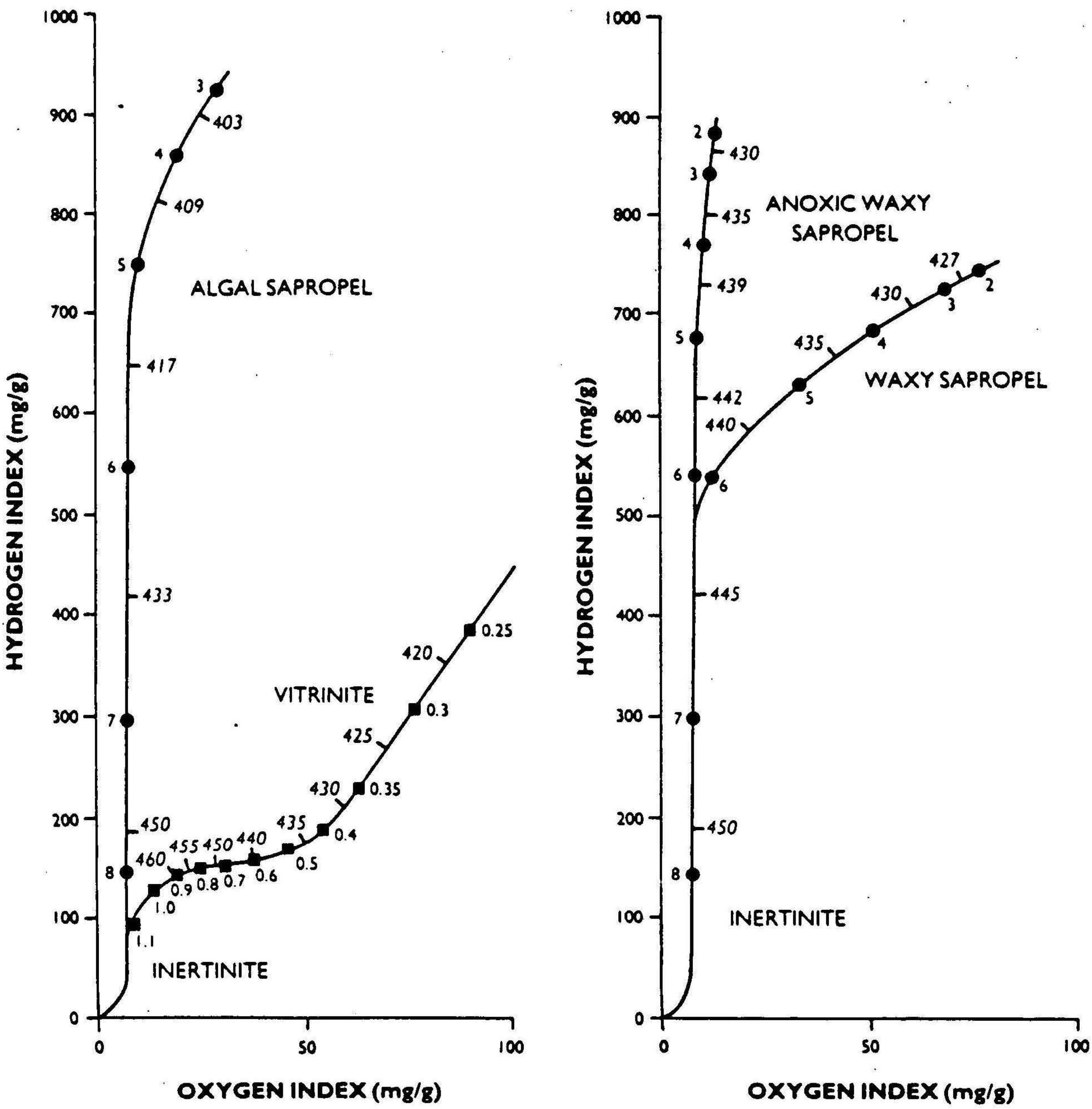

Spore Colour Index 6

Vitrinite Reflectivity 1.0

Temperature of Maximum
Rate of Pyrolysis C 430

Variation of kerogen pyrolysis properties with maturation

Figure B 2

From these assumptions a programme has been derived for a computer on which the amounts of inertinite and three other selected kerogen components are calculated from the HI, OI and Tmax values of the mixture, and of the pure components at the same level of maturity.

Original kerogen composition; kerogen facies

During maturation, each kerogen component, except inertinite, loses hydrocarbons and decreases in mass and therefore changes in proportion to the other components. The 'maturity correction factor' was used to calculate the proportions of the kerogen components at a base level of spore colour index (SCI) 3.5. This factor (at SCIm) may be defined as the mass of a kerogen at SCI 3.5 divided by the mass of that kerogen at SCIm. In order to calculate this factor, the following assumptions were made:

1) Residual kerogen after maturation or pyrolysis has a composition of C_2H.

2) The maturation of pyrolysis hydrocarbon product has a composition of CH_2.

3) Immature kerogen is composed of potential hydrocarbon (CH_2), potential carbon dioxide (CO_2) and residue (C_2H).

The following equation (based on these assumptions) describes the reactions that occur during pyrolysis and maturation:

$$4C_xH_yO_z = nCH_2 + 2zCO_2 + (2x-2n-z)C_2H$$

kerogen	potential hydrocarbon	potential carbon dioxide	residue

and is resolved using available HI and OI values since:

1) HI = 14000n/12x.

2) O/C = z/x (O/C values derived from published OI:O/C correlations).

3) x may be taken as any convenient positive integer at SCI 3.5.

4) (2x-2n-z) is constant at any level of maturity, within the oil window.

Thus the values of x, y, and z are calculated at various levels of maturity for each kerogen type and from these can be derived values of the maturity correction factor. Hence it is also possible to plot the progress of kerogen depletion and hydrocarbon and carbon dioxide generation with maturity for each kerogen type, as shown in figure B3.

Source rock productivity

The use of pyrolysis potential yield as a measure of source rock oil productivity is limited by the contribution made by vitrinite. However, as outlined in the previous section on original kerogen composition, the potential hydrocarbon and carbon dioxide of a particular kerogen type may be calculated from the known HI and OI data. The difference in amount between the potential hydrocarbon of the oil-prone kerogen components at SCI 3.5 and the potential hydrocarbon of these kerogens at a higher level of maturity is the amount of oil which has been generated, i.e. the productivity.

A set of conversion factors derived from the same data used to calculate the maturity correction factors is used to calculate the hydrocarbon productivity of each oil-prone kerogen component. The definitions and uses of these factors are outlined below.

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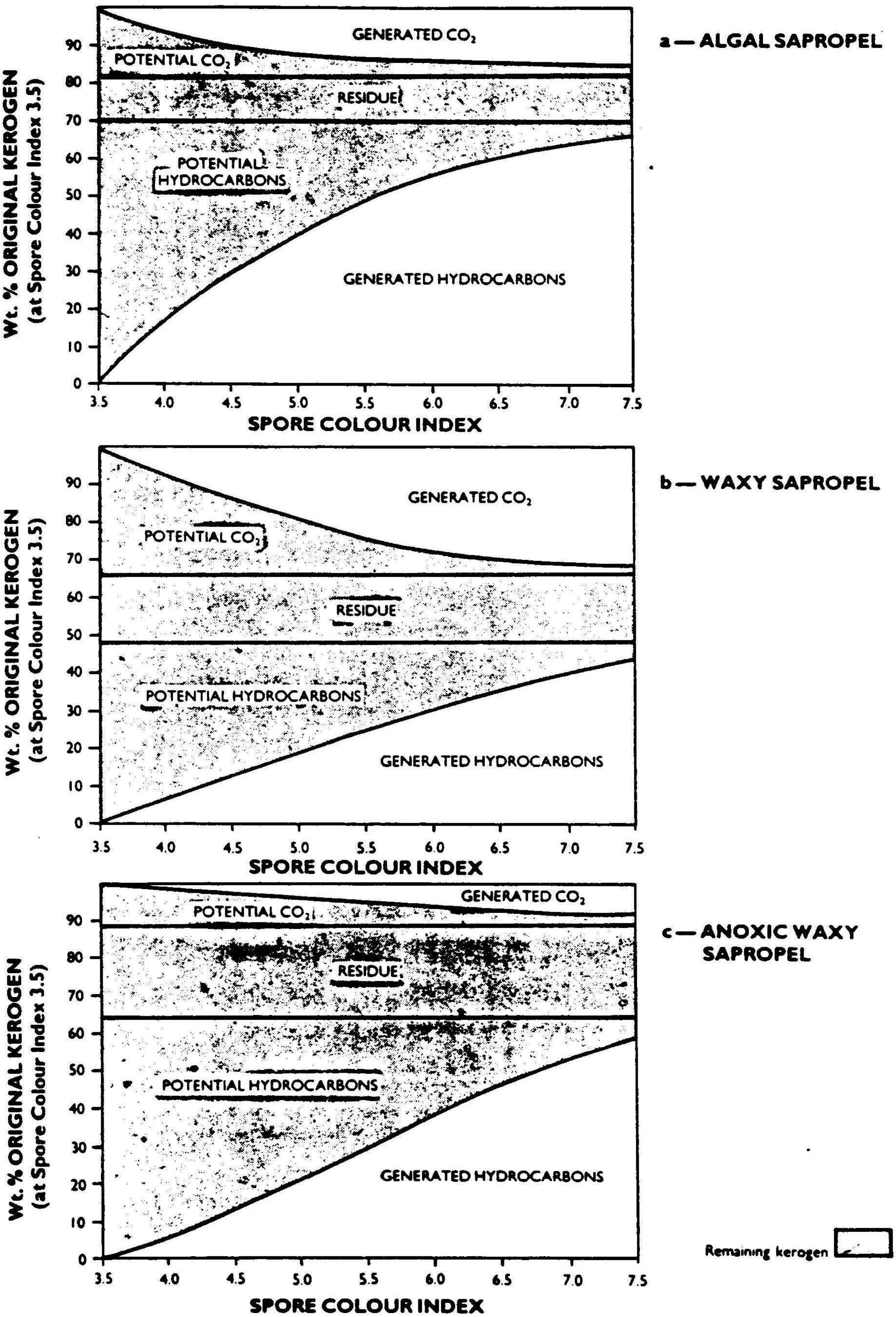


Changes in composition of oil generating kerogen during oil generation

Figure B 3

1) The kerogen organic carbon factor is the weight fraction of carbon in the kerogen component. This factor allows the total organic carbon content value to be divided into kerogen organic components. For convenience, inertinite is taken to have a molecular formula of C_2H.

2) The potential hydrocarbon factor is defined as the ratio of potential hydrocarbon (i.e. pyrolysis hydrocarbon) to kerogen organic carbon (i.e. the hydrogen index divided by 1000).

3) The generated hydrocarbon factor is defined as the ratio of generated hydrocarbon to the kerogen organic carbon. This factor allows the quantity of hydrocarbon, generated by maturation of each kerogen type, to be calculated.

Hence, the amount of oil which has been generated per unit of rock may be calculated. This figure, multiplied by the thickness of the source rock unit and a constant (1 ppm oil = 17.29 $bbl/km^2/m$), gives productivity in bbl/km^2.

Source rock quality, original oil generating capacity

Based on the methods described above, it is possible to re-define the terms used to describe source rocks. The measure of source rock quality is given by the original oil generating capacity (at SCI 3.5) of the source rock unit expressed in bbl/km^2. This measure is both quantitative and independent of the level of maturity.

At this point, it is useful to make the following definitions:

1) The productivity of a source rock unit is the amount of oil generated by the unit whilst attaining its present level of maturity.

2) The potential of a source rock unit is the amount of oil that could be generated by that unit in passing from its present level of maturity to a state of late maturity.

3) The original oil generating capacity of a source rock unit is the sum of its productivity and potential.

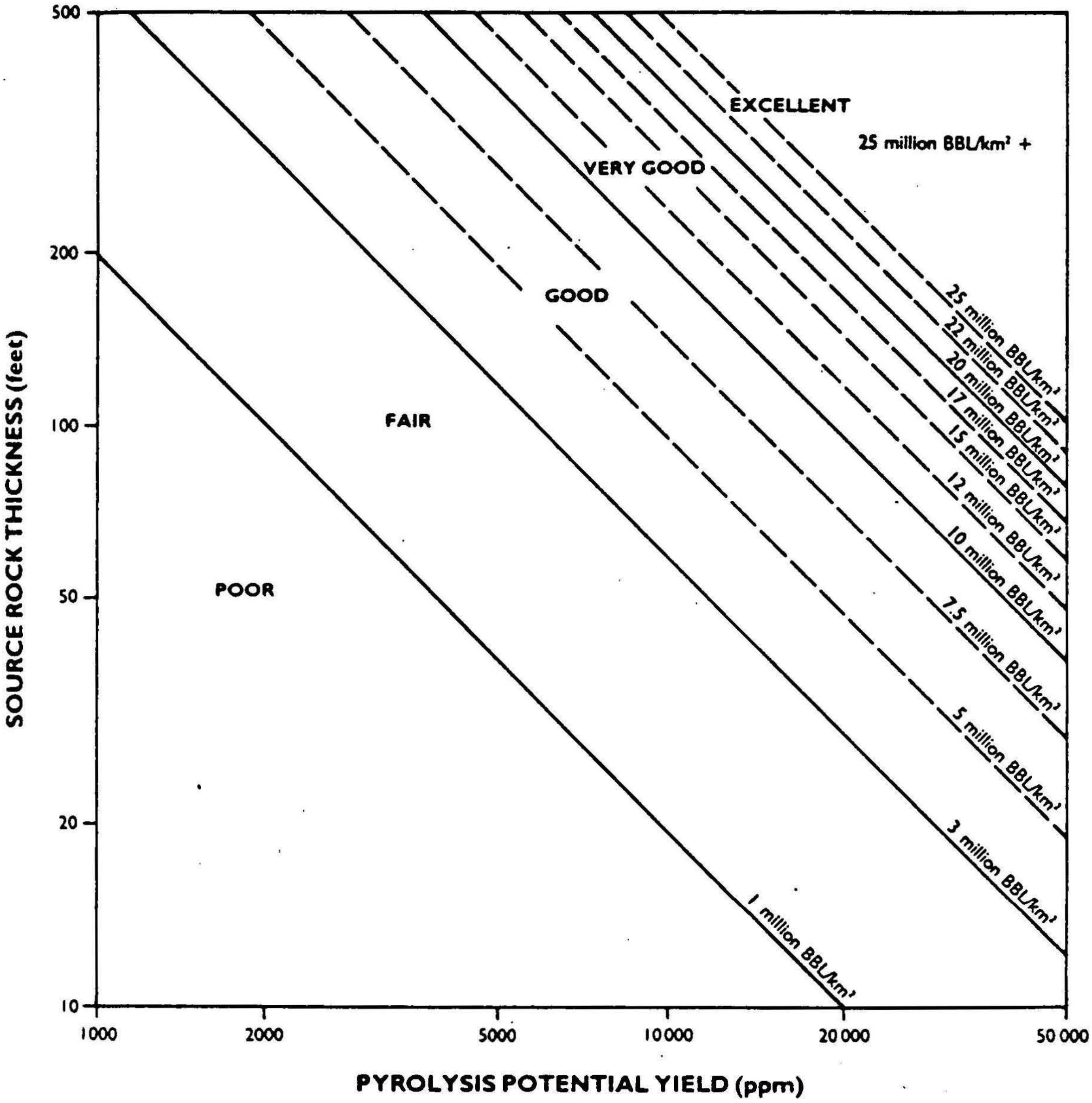
With the progress of maturation, the oil potential of a source rock unit decreases and its productivity increases. However, the sum of these two figures is constant and represents the original oil generating capacity of the source rock unit and gives an absolute definition of source rock quality. The potential and productivity may be derived directly from the potential hydrocarbon and generated hydrocarbon of each kerogen component, as outlined in the previous section.

The following source rock and descriptive categories of original oil generating capacity are used in this report:

Original Oil Generating Capacity (Bbl/km^2 ($x10^6$)		Descriptive Category
1		Poor
1 - 3		Fair
3 - 5	)	
5 - 7.5	)	Good
7.5- 10	)	
10 - 12	)	
12 - 15	)	Very good
15 - 17	)	
17 - 20	)	
720		Excellent

The combination of original source rock richness and thickness required to give the various categories of source rock is plotted in Figure B4. The values in Bbl/km^2 used to define poor, fair, good, very good and excellent, original oil generating capacity, can be further applied to productivity and potential as outlined in the following examples:

Robertson Research



Notes 1. Pyrolysis potential yields are calculated for the sapropelic component of kerogen in an immature state (SCI 3.5).
2. Barrels/km² yields are expressed as the ultimate oil yield of a source rocks at late maturity (SCI 7.5).

Source rock grades

Figure B4

1) An early mature source rock with a potential of 4 million bbl/km^2 and productivity of 0.5 million bbl/km^2 is a good source rock (original oil generating capacity of 4.5 million bbl/km^2), with good potential but poor productivity.

2) A mature source rock with a potential of 2.0 million bbl/km^2 and productivity of 2.5 million bbl/km^2 is a good source rock, with fair potential and fair productivity.

3) A post mature source rock with a potential of 0.5 million bbl/km^2 and productivity of 4 million bbl/km^2 is a good source rock with poor potential and good productivity.

Using these descriptive terms and definitions, situations can be avoided in which for example:

- the late mature source rock interval of a major field can be described as a poor source rock; or

- 3m of sapropelic shale with 4% total organic carbon content can be described as a good source rock.

Using the described methods and parameters, a good source rock is always described as such, whether immature or mature, and descriptions of source quality are not confused with the quantity of oil that can be generated.

B4.4 VISUAL EXAMINATION OF KEROGEN CONCENTRATES

All palynological preparations on which SIC determinations are made were also examined for kerogen type. Visual estimations of the relative abundance of the broad groups vitrinite, inertinite and sapropel were made on the total kerogen slide mount but reference is also made to the 20u sieved fraction to assist in identification. The scheme of identification is shown in appendix table B1. Full use was made of incident blue/UV light in distinguishing immature or early mature oil-prone kerogen from gas-prone kerogen.

Kerogen Typing Scheme for Transmitted White and Incident Blue/U.V. Light

General Properties	RRI Report Data Tables	Type *
Sapropelic (Oil-prone gas-prone at high maturity)	Algal Sapropel	Type I
	Waxy Sapropel	Type II
Humic (Gas-prone)	Vitrinite	Type IIIA
	Inertinite	Type IIIB

<table>
<tr><th colspan="2">Amorphous</th><th colspan="2">Structured</th></tr>
<tr><th>Non-Fluorescent</th><th>Fluorescent</th><th>Non-fluorescent</th><th>Fluorescent</th></tr>
<tr><td>Type I/II
at high
maturity
(SCI >7.5)</td><td rowspan="2">Type I
Sapropel
Type II
(degraded
spores)
Soft bitumens</td><td>Vitrinite (Type IIIA)
brown/black, woody
tissue</td><td rowspan="2">Cuticle
Spores
Pollen
Dinocysts
(Type II)</td></tr>
<tr><td>Type IIIA/B</td><td rowspan="2">Inertinite (Type IIIB)
very dark brown/black,
woody tissue</td></tr>
<tr><td colspan="2" rowspan="5">Oil residues (bitumens)
Mineral (undigested)
Grease contamination
Mud additives</td><td rowspan="4">Resinite
Algae
(Tasmanites,
Botryococcus
etc.)

(Type I)</td></tr>
<tr><td>Solid bitumen - brown/
black (oil residue)
often with crystal
imprints</td></tr>
<tr><td>Microforaminifera,
chitinozoa etc.
(Not usually important)</td></tr>
<tr><td>Spores, cuticle etc.
at high maturity
levels</td></tr>
<tr><td colspan="2">Mud Additives - walnut etc.</td></tr>
</table>

* Types I, II, III approximately <u>sensu</u> Tissot et al but Type III subdivided into IIIA (vitrinite) and IIIB (inertinite)

TABLE B1.

B4.5 EXTRACT ANALYSIS

The soluble organic materials present in rocks can be extracted with organic solvents, fractionated and analysed. The type and amount of material extracted depends largely upon the nature of the contained kerogen and its maturity, although the presence of migrant oil or drilling contamination may be the determining factors.

A maximum of 40g of crushed sample was extracted for a minimum of 12 hours in a Soxhlet apparatus using laboratory redistilled dichloromethane (DCM). The solvent and the more volatile components (approximately up to $\underline{n}$-C_{15}) were lost by evaporation in an air flow and the resulting total extract was weighed, dissolved in hexane and separated into alkane (saturate) hydrocarbon, aromatic hydrocarbon, resene and asphaltene (polar) fractions by silica absorption chromatography in the Iatroscan process.

Larger fractions, suitable for further analysis, were obtained by column chromatography. The extract was run through a short glass column packed with silica and alumina and eluted with hexane (to give the saturate fraction), 3:1 hexane: toluene mixture (to give the aromatic fraction) and methanol (to give the polar, or resene and asphaltene fraction). A small proportion of non-eluted polar compounds usually remained on the column.

The data tabulated in reports comprised the following parameters:

Total extract	-	soluble organic matter, heavier than about $\underline{n}$-C_{15}+, expressed as ppm of weight of rock.
Hydrocarbons	-	sum of alkane and aromatic hydrocarbons, expressed as ppm of weight of rock.

Total extract mg/g of organic carbon	-	total extract normalised to 1g of organic carbon.
Hydrocarbons mg/g of organic carbon	-	total hydrocarbons normalised to 1g of organic carbon.
Alkanes % extract	-	percentage of saturated hydrocarbons in the extract.
Aromatic % extract	-	percentage of aromatic hydrocarbons in the extract.
Polars % extract	-	percentage of heteroatomic compounds in the extract.

The extractability of oil-prone sapropelic organic matter increases rapidly in the oil generation zone and diminishes to very low values in post mature sediments. Overall the extractability of sapropelic organic matter is greater than that of gas-prone humic organic matter for similar levels of maturity. Samples with extractabilities of greater than 20% generally contain migrant oil or are contaminated with mud additives.

As maturation proceeds in the oil generation zone, the proportion of hydrocarbons in the total extract increases from less than 20% to a maximum in the most productive horizons of around 60%. This trend is reversed as the oil-condensate zone is entered. The relative proportions of alkanes to aromatics can be used as a check for low levels of contamination. Fractions of the extract, separated by column chromatography, were retained for further analysis by gas chromatography or for stable carbon isotope determination.

B4.6 CAPILLARY GAS CHROMATOGRAPHY OF C_{15+} ALKANES

A portion of the Soxhlet extract was eluted with hexane through a short silica column to yield the saturate hydrocarbon fraction. This fraction was evaporated in a stream of dry nitrogen at room termperature. A small portion of the fraction was then taken up in hexane and introduced into a 25 metre, wall-coated, open tubular glass capillary column coated with OV-1, or equivalent, mounted in a Carlo Erba gas chromatograph which was temperature programmed from 70°C to 270°C at 3°C/minute.

C_{15+} chromatograms were inspected for the distributions of n-alkanes, and the presence and abundance of isoprenoids (particularly pristane and phytane), steranes and triterpanes and unresolved envelopes of naphthenic compounds. The ratios pristane:phytane and pristane:n-C_{17} were calculated. Carbon Preference Index (CPI) values quoted are those as defined by Philippi as the ratio $2C_{29}$ to $(C_{28}+C_{30})$ unless otherwise stated. Chromatography may reveal information about the kerogen type of the source rock, its maturity and condition of deposition and, if migrant oil is present, whether this has been water-flushed or biodegraded. Contaminant drilling mud additives may be identified.

B4.7 GAS CHROMATOGRAPHY-MASS SPECTROMETRY

Mass spectrometry is a technique in which molecules are bombarded with high energy electrons causing ionisation and fragmentation of the molecules into ions of varying mass (m) and charge (z). The way in which a molecule fragments into ions of various m/z values is known as its fragmentation pattern, or mass spectrum and is unique. When linked to a gas chromatograph the mass spectrometer can be used in two different modes:

1) Full Scan Mode: A mass spectrum is obtained of each peak eluting from the gas chromatograph and a structural identification of the compound producing that peak can be made.

2) Multiple or Single Ion Monitoring Mode: The mass spectrometer is tuned to certain m/z values to detect whether a compound, eluting from the gas chromatograph, fragments to give an ion at that value. Certain fragmentations are indicative of specific compound types and the most commonly monitored fragment ions used in petroleum geochemistry are those with m/z values of 191, 217 and 259 which are the principal fragment ions obtained from groups of alkanes known as triterpanes, regular steranes and rearranged steranes respectively. These are compounds containing 27 to 35 carbon atoms arranged in a polycyclic, normally 4 or 5 ring, structure, occurring in the $\underline{n}$-C_{26} to $\underline{n}$-C_{35} region of a gas chromatogram. The basic molecular skeletons of these compounds are very similar to those of the original organic matter deposited in the sediment and so these 191, 217 and 259 distribution plots, known as mass fragmentograms or mass chromatograms, form a pattern characteristic of the source material. This technique of 'fingerprinting' is also one of the more exact methods of correlating an oil to its source, or to another oil.

B4.8 CARBON ISOTOPE ($^{13}C/^{12}C$) RATIO ANALYSIS

Carbon has two stable isotopes, the more abundant ^{12}C isotope and the heavier ^{13}C isotope, which in nature forms about 1% of carbon. Deviations from the $^{13}C/^{12}C$ ratio are extremely small and carbon isotope ratios, as measured by mass spectrometry, are expressed as deviations from a standard, the Pee Dee Belemnite carbonate (PDB standard) in parts per thousand (parts per mil, $^{o}/_{oo}$). Positive deviations indicate ^{13}C enrichment and conversely, negative deviations indicate ^{13}C impoverishment.

While the carbon isotope ratios of oils and rock extracts can range from -20 to $-32^{o}/_{oo}$ depending on the source organic matter type, the difference between a specific oil and its source is small. Measurements are usually made on the C_{15+} alkane and aromatic hydrocarbon fractions separately and there should be no more than $1^{o}/_{oo}$ difference between the oil and its source for either fraction. If there is any doubt that the source rock extracts are not indigenous to the source rock kerogen, the carbon isotope ratio of the extracted source rock kerogen can be measured.

B5 OIL ANALYSIS

Robertson Research laboratories offer a wide range of oil analyses both for geochemical purposes and industrial use. Physical property determinations are based mainly on IP methods and are available for lubricating oils, fuels and greases as well as crudes. Frequently measured properties of crude oils presented in geochemistry reports include: API gravity, pour point, viscosity and contents of water, sulphur, wax, asphaltene, nickel, vanadium and other metals. Chemical analysis of oils involves the following:

Whole oil gas chromatography	- using split syringe injection and a temperature programme from -20°C or -30°C up to 270°C at 4°C/minute.
Associated gas	- if oil has high gas/oil ratio.
Gasoline analysis	- as for gasolines in rock samples but a weighted quantity of oil is used.
Topping of the oil	- this is equivalent to the removal of the fraction boiling below about 210°C and gives a more standardised product for comparison of gas chromatograms of the C_{15+} fraction.
Column chromatography and gas chromatography	- as for solvent extracts. Analysis is carried out on topped oil.

B5.1 ASPHALTENES CONTENT (ASPHALTENES PRECIPITATION)

The material was dissolved in n-heptane and the insoluble material, consisting of asphaltenes and waxy substances, was separated by filtration through a fine filter-paper. The waxy constituents were extracted under hot reflux with n-heptane, and asphaltenes were isolated by extraction with toluene.

In normal practice toluene was used instead of benzene. The precision of the method when using toluene has been found to be the same as when using benzene.

B7 PRINCIPLES OF INTERPRETATION FOR THE CORRELATION OF OILS AND SOURCE ROCKS

Correlation of oil to oil and oil to source rock involves comparison of the chemical composition of particular components of both the oil and source rock and, ideally, those properties selected for comparison should not be significantly affected by maturation or migration.

Where a number of oils are involved, it is necessary to group them into families for which the analytical data suggest a common source. The results for each family are then compared with the results from those intervals which have been shown to contain effective source rocks.

Detailed oil to oil and oil to source rock correlations are usually carried out using two methods:

- Correlation by geochemical fossils.
- Correlation by $^{13}C/^{12}C$ carbon isotope ratios.

Correlation by geochemical fossils

Geochemical fossils have carbon skeletons derived from the original biogenic source with little alteration. The distribution of these compounds usually reflects the type of organic matter and the depositional environment. The following geochemical fossils are most commonly used:

- C_{15+} normal alkanes
- Isoprenoid alkanes (pristane, phytane, etc.)
- Polycyclic alkanes (steranes and triterpanes)

The normal alkane and isoprenoid alkane distribution patterns can be deduced from gas chromatographic analysis of the alkane fraction of oils or source rock extracts. However, amounts of polycyclic alkanes eluting in the $\underline{n}$-C_{26} to $\underline{n}$-C_{35} region of these chromatograms are often low and their presence is marked by dominant straight chain alkanes. Gas chromatography-mass spectrometry (GC-MS), which can focus specifically on these polycyclic alkanes, is used to allow the distribution of these compounds to be examined.

Normal alkanes

Although normal alkanes are generated during maturation of kerogen, their distribution in an oil or source rock can be used to give information on the type of organic matter and depositional environment. Oil generated from a kerogen containing organic matter derived from predominantly algal material will show an $\underline{n}$-alkane profile centred around $\underline{n}$-C_{15} to $\underline{n}$-C_{17} and contain few longer chain length (C_{25+}) alkanes. Terrestrially dominated kerogens will contain much higher concentrations of C_{25+} alkanes, some of which, if derived from higher plant waxes, carry an odd carbon number predominance over to oils generated at a low level of thermal maturity. In highly reducing environments, and particularly with carbonate source rocks, an even-over-odd $\underline{n}$-alkane predominance is often apparent and this may be present in oils generated from these source rocks even at relatively high maturity levels.

Isoprenoid alkanes (pristane and phytane)

The relative abundance of these branched chain C_{19} and C_{20} alkanes, which are predominantly derived from plant chlorophyll, depends both on the type of organic matter and the environment of deposition. Pristane is often more abundant than phytane, markedly so in land plant-derived organic matter, but in a highly reducing depositional environment phytane will predominante. Since the relative abundance of these two compounds is often unchanged from the source to the oil, pristane or phytane dominance can be a useful correlation parameter. It should be noted, however, that the precise ratio is sensitive to changes in maturation level.

Polycyclic alkanes (steranes and triterpanes)

Steranes and triterpanes contain 27 to 35 carbon atoms arranged in 4 and 5 rings respectively. The relative amounts of steranes and triterpanes give an indication of organic matter type, and the distribution patterns and ratios of certain components are characteristic of the original source material. The thermal stabilities of many of these compounds vary so that their ratios can give an indication of the maturity level of a source rock or the maturity level at which an oil has been generated.

The ratios and compound distribution patterns used for oils and source rocks are given below. They are calculated using integrated peak areas, which are proportional to amounts of the relevant compounds. Each ratio is given a number on the tables for ease of reference.

Ratio 1: 18α(H) Trisnorhopane:17α(H) Trisnorhopane

This ratio is mose useful in correlations at middle to late levels of maturity as values are variable at low maturity levels when they are mainly controlled by kerogen facies. The ratio increases from a value of 1.2 at spore colour index 5.5, to 1.7+ at spore colour index 7.0 (end of main oil generation zone).

$$\text{Ratio 1} + \frac{\text{Peak area (m/z 191) 18}\alpha\text{(H) trisnorhopane}}{\text{Peak Area (m/z 191) 17}\alpha\text{(H) trisnorhopane}}$$

Ratio 2 and 3: nororetane:norhopane and moretane:hopane ratios (17β(H), 21α(H): 17α(H), 21β(H) C_{29} and C_{30} triterpanes

Source rocks at low levels of maturity contain significant amounts of moretanes but the amounts of these components decrease rapidly with increasing maturity. The ratio decreases from a value of 0.6 at spore colour index 2.0 (immature) to about 0.1 at spore colour index (5.5 (main oil generation zone) and is thus a useful indicator of oils generated at low levels of maturity.

$$\text{Ratios 2 \& 3} + \frac{\text{Peak Area (m/z 191) normoretane/moretane}}{\text{Peak Area (m/z 191) norhopane/hopane}}$$

Ratio 4: Homohopanes ratio (17α(H), 21β(H) 22S:17α(H), 21β(H) 22R C_{31} hopanes)

The ratio of these extended hopanes has been shown to increase with increasing levels of thermal maturity. This ratio increases to an equilibrium value of 1.4 to 1.6 at an early stage of thermal maturity but is of little use at higher maturity levels. The presence of co-eluting peaks can affect the value of this ratio.

$$\text{Ratio 4} = \frac{\text{Peak Area (m/z 191) 22S homohopane}}{\text{Peak Area (m/z 191) 22R homohopane}}$$

Ratio 5: Hopane:sterane Ratio (C_{30} hopane/C_{29} steranes)

Low values of this ratio (0-2) are generally associated with depositional environments in which algal organic matter is predominant, whereas higher values (2+) are attributed to a greater contribution from terrestrially derived organic matter.

$$\text{Ratio 5} = \frac{\text{Peak Area (m/z (191) } 17\alpha(H), 21\beta(H) \text{ hopane } (C_{30})}{\begin{array}{c}\text{Peak Areas (m/z 217) } 5\alpha(H), 14\alpha(H), 17\alpha(H) \\ \text{20R + 20S } C_{29} \text{ steranes} \\ + \text{ Peak Areas (m/z) 218) } 5\alpha(H), 14\beta(H), 17\beta(H) \\ \text{20R + 20S } C_{29} \text{ steranes}\end{array}}$$

Ratio 6: $\dfrac{18\alpha(H) \text{ Trisnorhopane} + 17\alpha(H) \text{ Trisnorhopane}}{C_{30} \text{ hopane}}$

The ratio of these hopanes with various carbon numbers can be used as a maturity parameter although it is partially controlled by kerogen facies. The ratio increases with maturity with samples in the main zone of oil generation (SCI 5.0-7.0) showing values of around or above 0.5.

$$\text{Ratio 6} = \frac{\begin{array}{c}\text{Peak area of 18a(H) Trisnorhopane (m/z 191)} \\ + 17 \text{ (H) Trisnorhopane (m/z 191) Trisnorhopane (m/z/91)}\end{array}}{\text{Peak area of } 17\alpha(H)\ 21\alpha(H) \text{ hopane } (C_{30}) \text{ (m/z/91)}}$$

Ratio 7: %20S form of $5\alpha(H), 14\alpha(H), 17\alpha(H)$ C_{29} steranes

Living organisms contain sterols with the 20R configuration, but fossil organic matter generally contains mixtures of the 20R and 20S stereoisomers. The percentage of the 20S isomer increases with maturity to an equilibrium value of about 60% in mature sediments. The ratio is a reliable measure of the maturity levels of sediments within the oil generation window and gives useful information on the levels of maturity at which an oil was generated.

$$\text{Ratio 7} = \frac{\text{Peak Area (m/z 217) 20S}}{\text{Peak Area (m/z 217) 20S + Peak Area (m/z 217) 20R}} \times 100\%$$

This ratio has been of little use in distinguishing the maturity levels at which the oils were generated, with most of the oils showing higher values than expected for early mature oils. Tannenbaum and Aizenshtat (1984) have also found that this ratio is of little use for heavy oils generated from carbonate source rocks.

Ratio 8-10: Carbon number distribution of the 5α(H), 14α(H), 17α(H) 20R steranes

The carbon number distribution of steranes with a particular stereochemistry in an oil or source rock reflects the distribution of sterols in the original organic input to the sediment. A triangular plot of the C_{27}, C_{28} and C_{29} steranes can be used to characterise the organic matter type and depositional environment of a source rock. High abundances of C_{29} steranes are thought to be characteristic of land plant input, whereas high proportions of C_{27} steranes probably reflect the presence of marine-derived algal organic matter.

$$\%C_{27} = \frac{\text{Peak Area (m/z 217) } 5\alpha(H),\ 14\alpha(H),\ 17\alpha(H)20R\ C27}{\text{Peak Areas (m/z 217) } 5\alpha(H),\ 14\alpha(H),\ 17\alpha(H)20R\ C_{27},\ C_{28} \text{ and } C_{29}} \times 100\%$$

$$\%C_{28} = \frac{\text{Peak Area (m/z 217) } C_{28}}{\text{Peak Areas (m/z 217) } C_{27} + C_{28} + C_{29}} \times 100\%$$

$$\%C_{29} = \frac{\text{Peak Area (m/z 217) } C_{29}}{\text{Peak Areas (m/z 217) } C_{27} + C_{28} + C_{29}} \times 100\%$$

'Fingerprints'

In addition to these calculated ratios and percentages, certain features or 'fingerprints' of the GC-MS traces (fragmentograms) can be used to obtain information on oils or source rock extracts.

Tricyclic and tetracyclic terpanes

This series of compounds elutes in the _n_-C_{18} to _n_-C_{28} region of the m/z 191 fragmentograms. These compounds are thought to be of algal or microbial origin and are known to be more stable to biodegradation and maturation effects than their pentacyclic counterparts. The patterns of these components can be used for oil to oil and oil to source rock correlation.

Gammacerane

Gammacerane, a C_{30} triterpane, elutes immediately after the C_{31} hopane doublet on the m/z 191 fragmentogram. It is probably of bacterial origin and is commonly found in source rocks with a hypersaline, evaporitic depositional environment.

Resin-derived hydrocarbons

Both diterpenoid (eluting at _n_-C_{18} to _n_-C_{22}) and triterpenoid (eluting at _n_-C_{28} to _n_-C_{34}) hydrocarbons are generated from resin-rich terrestrial organic matter. These compounds are characterised by large 123, 163, 191, 217 and 259 fragmentation peaks.

Bisnorhopane and 18 trisnorhopane

Bisnorhopane (a C_{28} triterpane) and 18α(H) trisnorhopane (a C_{27} triterpane) are commonly associated in oils and source rocks. Bisnorhopane elutes before the C_{29} triterpane, norhopane, on the m/z 191 fragmentogram, whereas (18α(H) trisnorhopane can be seen on the m/z 177 fragmentogram eluting between the 18α(H) trisnorhopane and 17α(H) trisnorhopane. Although the source of these compounds is uncertain, their presence in oils and source rocks can be used for correlation purposes. Their abundance, relative to the regular hopane series, decreases with increasing maturity.

Correlation by $^{13}C/^{12}C$ carbon isotope ratios

Carbon has two stable isotopes, the more abundant ^{12}C isotope and the heavier ^{13}C isotope which in nature forms about 1% of organic carbon.

Variations in this ratio are extremely small but differences can be measured very accurately by mass spectrometry and are expressed as deviations from the Pee Dee Belemnite standard. Positive deviations indicate ^{13}C enrichment and negative deviations indicate ^{12}C enrichment.

The carbon isotope ratio of oils can range from $-18^o/_{oo}$ to $-32^o/_{oo}$, but the difference between an oil and its source is small. Measurements are usually made on the C_{15+} alkane and aromatic hydrocarbon fractions of both the oil and source rock extracts and there should be around $1^o/_{oo}$ difference between the oil and its postulated source for either fraction.

The average values for alkanes of subtropical source rocks are:

- hot water lagoons (algae) - $-18^o/_{oo}$
- brackish marsh (algae + plants) - $-22^o/_{oo}$
- marine (plankton) - $-26^o/_{oo}$
- land plants - $-32^o/_{oo}$

It should be noted, however, that variation in climate and age of source rock can cause significant variations in carbon isotope values. Whole oils, source rock extracts, and kerogens are polycomponent mixtures and carbon isotope measurements on these will give values dependent on the relative abundance of individual fractions. In general there is a progressive enrichment in ^{13}C in the series alkanes-aromatics-asphaltanes-kerogens.

The canonical variable based on Sofer (1984) has been calculated using the equation:

$$C.V. = -2.53 \ {}^{13}C \text{ (alkanes)} + 2.22 \ {}^{13}C \text{ caronatics} - 11.65$$

Values of this variable of less than 0.47 are thought to indicate a mostly marine source whilst those greater than 0.47 indicate a mostly terrestrial source. The majority of the values in this study are below 0.47, although other indicators show a predominantly terrestrial source. This is thought by Sofer to be due to water washing or biodegradation of the oils. However, in this study, the source rocks analysed also have markedly negative values and suggest that this is a source-dependent function.

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APPENDIX C

GEOHISTORY MODELLING

Paltech Pty Ltd

GEOHISTORY MODELLING

C1 METHODOLOGY

The method of geohistory modelling used in this study is based on that developed by Falvey and Deighton (1982), and currently marketed by Paltech Pty. Ltd. The interactive computer program includes input of a number of key geological parameters, which are not standard on simplified geohistory plots. These are considered to be of key importance in the accurate evaluation of subsidence and maturation history.

C1.1 Compaction

The basic geohistory diagram is constructed by stepping backwards through time, and progressively stripping overlying sedimentary layers. Underlying layers are then decompacted according to the inverse porosity depth formula applicable to those layers given by Falvey and Middleton (1981). The formula is defined for each layer, and represents, in theory, an accurate description of the reduction of porosity and thickness of layers with progressive burial.

C1.2 Variable Sea Level Datum

It is well known that sea level, the standard datum, has varied through geological time, and a more or less continuous function is available for the Mesozoic and Cainozoic. This variable datum has been used throughout to plot the geohistory diagram.

C1.3 Unconformities

Since an unconformity is an absence of a time rock unit, the basic stratigraphic data reveals nothing about the missing unit. However, a burial geohistory diagram, being a continuous and complete record of uplift and/or subsidence, can reflect differences, such as between non-depositional and erosional unconformities. The most valid method of estimating amount of erosion comes from an interpolation of missing reflectors on seismic cross-sections where structure is present.

C1.4 Thermal Conductivity

One of the most important physical properties of rocks applied to the estimation of palaeotemperatures at depth is layer thermal conductivity. In geotectonic terms, heatflow out of the basement will be constant, and the temperature gradient within the sedimentary pile will depend on conductivity, according to the heatflow equation. Thermal gradients can vary markedly, depending on variations in layer conductivity. The program estimates the change in layer conductivity with burial.

C1.5 Surface Temperature

Another variable parameter of importance in calculation of maturation level at depth is surface or seabed temperature. This can be estimated from palaeolatitude information, and standard climatic and oceanographic parameters. It can be shown, in certain circumstances, to have a considerable influence on the temperature history of a bed.

C1.6 Heatflow

Virtually all standard geohistory programs incorporating geothermal analyses assume a constant heatflow through geological time. This assumption is, however, known to be generally invalid in a subsiding sedimentary basin. Most commonly, heatflow declines nearly exponentially with time, and this can be estimated from geotectonic theories of basin subsidence and palaeotemperature indicators.

In addition to the conventional geohistory, plotting the output from this modelling system includes the following:-

- an accurate calculation of present day heatflow;
- theoretical level of maturation as represented by vitrinite reflectance;
- an estimate of equivalent basement subsidence in the absence of sedimentation and variable sea level using an AIRY isostatic assumption (i.e. the basin subsidence driving mechanism).

The geohistory model output allows prediction of the onset of hydrocarbon generation for any particular source bed as a function of geological time. When comparisons are made between adjacent geohistory plots, an estimation of migration path - is also possible.

C2 GENERAL LIMITATIONS

The result of geohistory modelling is critically dependent on the quality of input data. In particular:-

- the accurate determination of stratigraphy;
- its accurate correlation with an absolute geological time scale;
- the accurate estimation of erosion or non-deposition at unconformities;
- the evaluation of compaction functions by detailed study of porosity vs. depth for key formations;
- the correct estimation of palaeowater depth, or an estimation of palaeoland elevation;
- the correct determination of thermal conductivity, both present day <u>in situ</u>, and its variation with porosity as a function of compaction;
- the determination of bottom hole termperature corrected for drilling mud circulation effects;
- the accurate estimation of long term average land surface or seabed temperature, and its variation with geological time;
- the accurage measurement and assessment of present day vitrinite reflectance data for model comparison;
- the correct assessment of palaeoheatflow based on geotectonic factors.

C3 LIMITATIONS OF THE MODELS DERIVED IN THIS STUDY

A number of these parameters, which are considered critical for reliable modelling, were limiting with respect to this study:

- only a very generalised porosity/depth function was incorporated, as detailed studies of this were not incorporated into the scope of this overall study;

- generalised assumptions regarding palaeowater depth were used (e.g. Exon and Willcox, 1980; Swift et al., 1986).

- the present sea surface temperature was taken as 24°C. Palaeolatitudes were estimated from Habricht (1979).

However, as a regional study, the comparative results are considered generally reliable. To support the validity of the technique, the Time Temperature, palaeoheatflow and computed vs observed vitrinite reflectance plot for each of the models referred to in the text have been included in this Appendix (Figs. C1-27).

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APPENDIX D

PALYNOLOGICAL DATA

by Dr. R. Helby

PALYNOLOGICAL DATA

INTRODUCTION

Palynological data from a number of wells were reassessed. The wells fall into two groups. In the first group palynological preparations from selected sections were borrowed from the relinquishment collection of the Geological Survey of Western Australia and examined at rapid reconnaissance level. The results of these examinations were interpreted in terms of the zonal scheme outlined by Helby, Morgan & Partridge (in press) and a summary of these interpretations for each well is listed below. In the case of wells in the second group, information, available on open file, was reinterpreted in terms of the Helby, Morgan & Partridge zonation. Wells from the second group are listed below.

Group 1 Wells - Rapid Reconnaissance Results

Bedout-1 — **Canning Basin**

Depth ft	Age	Zone
3712-3782	Mid to Late Albian	*Pseudoceratium ludbrookiae* or older
3960	Late Aptian	*Diconodinium davidii*
4080	Aptian	*Odontochitina operculata* or younger
4200-4610	Late Valanginian to Lower Aptian	*Phoberocysta burgeri* to *Odontochitina operculata*
5110-5390	Berriasian	Lower *Batioladinium reticulatum*

5500-5590	Berriasian	Dissimulodinium lobispinosum
5705-5800	Berriasian	Cassiculosphaeridia delicata
5888	Berriasian	Kalyptea wisemaniae
5910-6440	Bathonian or older	Caddosphaera halosa
6675-7715	Toarcian to Bajocian	Callialasporites turbatus
8205-9230	Early Jurassic	Corollina torosa
9343-10005	Possibly Triassic	

Buffon-1 **Browse Basin**

Depth m	Age	Zone
3490-3526	Upper Late Albian	*Xenascus asperatus*
3530	Late Albian	*Pseudoceratium ludbrookiae*
3557-3644	Early to Mid Albian	*Canninginopsis denticulata*
3655-3726	Early Albian	*Muderongia tetracantha*
3762	Late Aptian	*Diconodinium davidii*
3870-3990	Mid to Late Jurassic	Indeterminate
4447.5-4485	Bajocian to Bathonian	Lower *Caddosphaera halosa* to *Dissiliodinium caddaense*
4507-4754.5	Early Jurassic	*Corollina torosa* to *Callialasporites turbatus*

Keraudren-1 **Canning Basin**

Depth m	Age	Zone
611-714	Late Cretaceous	Indeterminate
847-898	Cenomanian to Turonian	*Diconodinium multispinum* to *Palaeohystrichophora infusorioides*

Depth m	Age	Zone
911.5-1049.5	Late Albian	Pseudoceratium ludbrookiae
1149	Aptian or older	Odontochitina operculata or older
1212.5	Valanginian	Senoniasphaera tabulata
1448	Late Tithonian to Early Berriasian	Pseudoceratium iehiense
1535	Tithonian	Omatia montogomeryi
1542	Oxfordian to Kimmeridigian	Wanaea spectabilis or younger
1647-1649	Bathonian	Lower Caddosphaera halosa
2010	Toarcian to Bajocian	Callialasporites turbatus
2122-2226	Early Jurassic	Corollina torosa
2953-3807	Late Early Triassic to Anisian	Triplexisporites playfordii

Koolinda-1 Carnarvon Basin

Depth (m)	Age	Zone	Formation
520	Cenomanian	Diconodinium multispinum	Gearle Siltstone
800.30	Mid to Late Albian	Pseudoceratium ludbrookiae	Gearle Siltstone
1050.70	Aptian	Diconodinium daviddii or older	Windalia Radiolarite
1076.96-1235	Neocomian to Aptian	Odontochitina operculata or older	Windalia Radiolarite - Muderong Shale
1850	Tithonian or older	Pseudoceratium iehiense older	Malouet Formation
2050.60	As above	Dingodinium jurasicum or older	Dupuy Sst Mbr
2450-2660	Basal Kimmeridgian or older	Wanaea clathrata or older	Dingo Claystone
2650-3460	Jurassic	Indeterminate	Dingo Claystone

* Residues below 2650, are essentially overmature.

Lombardina-1 Browse Basin

Depth (m)	Age	Zone
1539-1572	Mid to Late Albian	Pseudoceratium ludbrookiae
1577	Early Albian	Lower Muderongia tetracantha
1598.5-1656	Late Aptian	Diconodinium davidii
1648-1966	Aptian	Odontochitina operculata
1955	Barremian to Early Aptian	Ovodinium cinctum
2000-2030	Hauterivian	Muderongia testudinaria
2275-2292.5	Valanginian	Systematophora areolata or younger
2312	Berriasian	Batioladinium reticulatum
2337-2380	Berriasian	Cassiculosphaeridia reticulata
2396-2412	Late Tithonian to Berriasian	Pseudoceratium iehiense
2430	Tithonian	Dingodinium jurassicum or younger
2433.2-2505	Oxfordian	Wanaea spectabilis

Lombardina-1 (Cont'd.)

Depth (m)	Age	Zone
2522.5-2558	Mid Bajocian to Bathonian	*Dictyotosporites complex*
2575-2740	Early Jurassic	*Inaperturopollenites turbatus* *Corollina torosa*

Rob Roy-1 Browse Basin

Depth (ft)	Age	Zone
4502	Valanginian or younger	*Senoniasphaera tabulata* or younger
4755-5080	Bathonian to Early Callovian	*Caddosphaera halosa* to *Wanaea indotata*
5169	Latest Carboniferous to basal Permian	Stage 2/3

Yampi-1 Browse Basin

Depth (m)	Age	Zone
2172.2-2217	Late Barremian to basal Aptian	*Ascodinium cinctum*
2226-2364	Upper Neocomian	*Muderongia australis* to *Muderongia testudinaria*

Yampi-1 (Cont'd.)

Depth	Age	Zone
2380-2468	Late Valanginian to Hauterivian	Phoberocysta burgeri to Muderongia testudinaria
2495-2538	Valanginian	Systematophora areolata or younger
2555-2601	Berriasian to Valanginian	Systematophora areolata or older
2636	Berriasian	Cassiculospaheridia delicata or older
2681-2958	Tithonian to basal Berriasian	Dingodinium jurassicum to Pseudoceratium iehiense
2979-3096	Tithonian	Dingodinium jurassicum
3107.0	Basal Tithonian	Omatia montgomeryi
3117.0	Basal Tithonian	Cribroperidinium perforans
3127-3130	Kimmeridgian	Dingodinium swanense
3152-3224.5	Oxfordian	Wanaea spectabilis
3235.0	Latest Callovian or younger	Rigaudella aemula or younger

Yampi-1 (Cont'd.)

Depth	Age	Zone
3252-3278.6	Bajocian to Oxfordian	Callaialsporites dampieri
3281-3299	Bajocian to Bathonian	Caddosphaera halosa or older
3341-3546	Jurassic undiff.	Indeterminate
3591-3651	Ladinian to Carnian	Samaropollenites speciosus
3733-3863	Permian undiff.	Indeterminate

GROUP 2 WELLS - AVAILABLE ON OPEN FILE

Flamingo-1
Frigate-1
Gull-1
Heywood-1
Jarman-1
Parker-1
Penguin-1
Petrel-2
Plover-1
Sandpiper-1
Tern-1
Troubadour-1

VICTORIA SYNCLINE

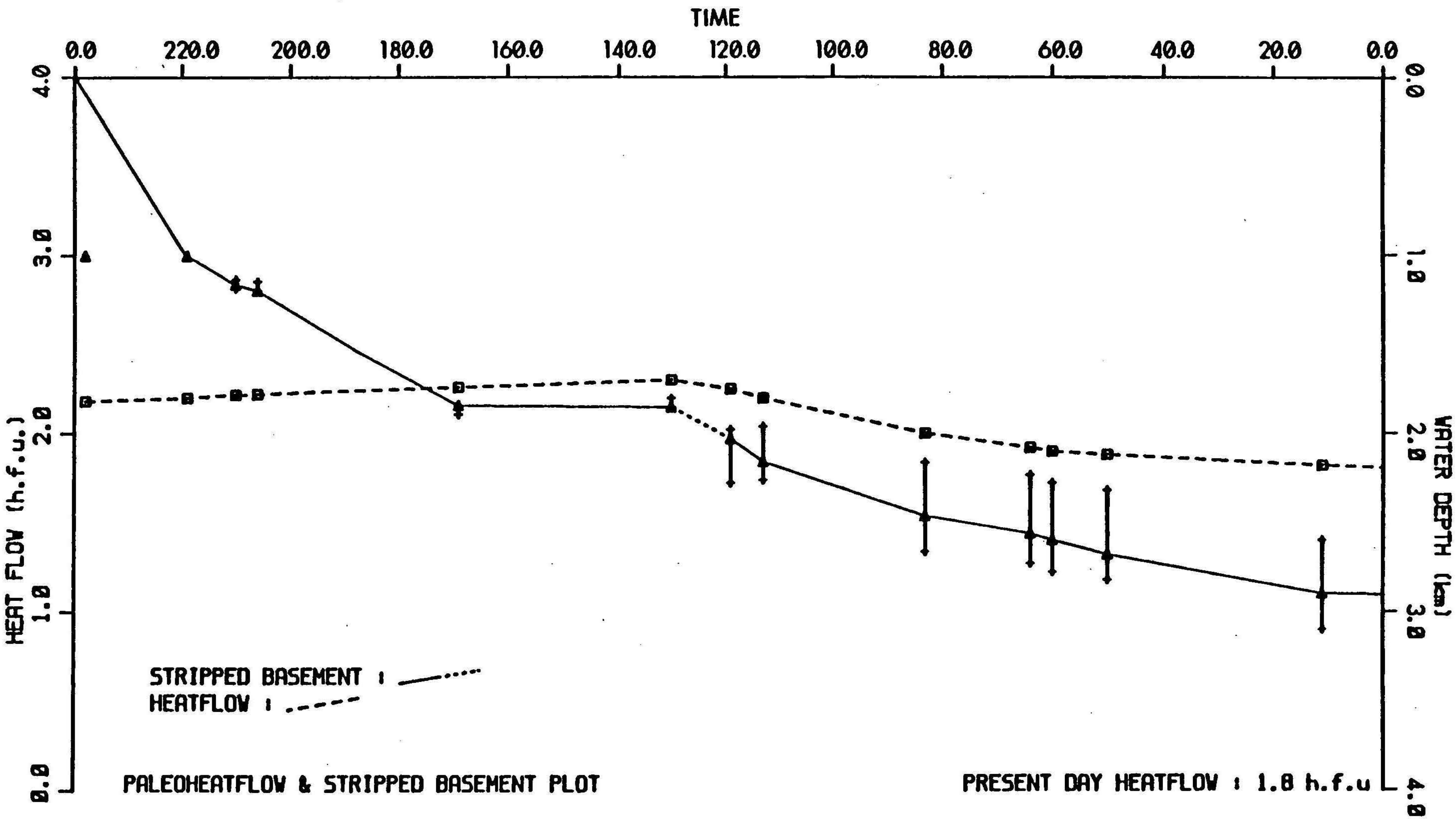


Figure C1

VICTORIA SYNCLINE

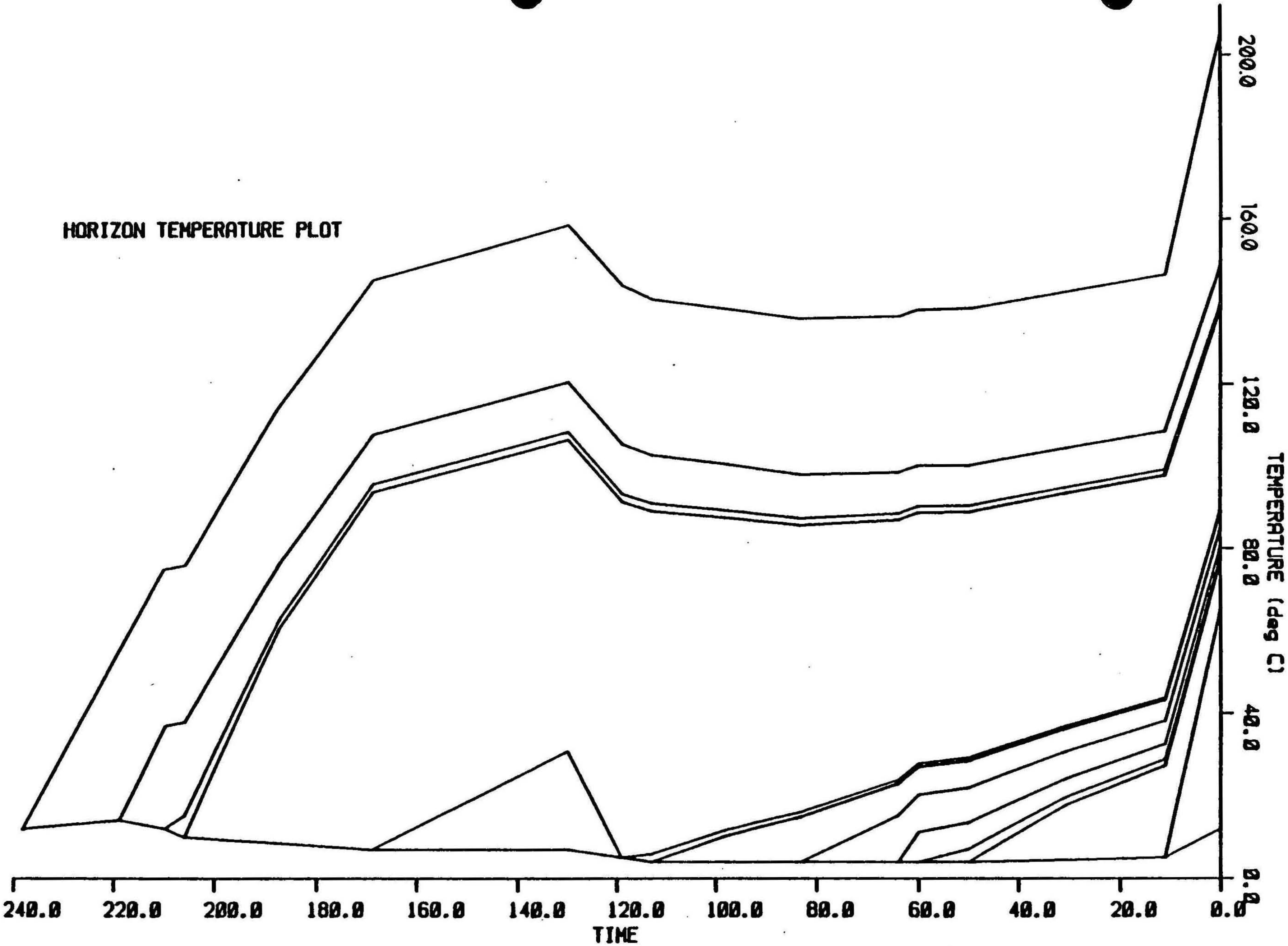
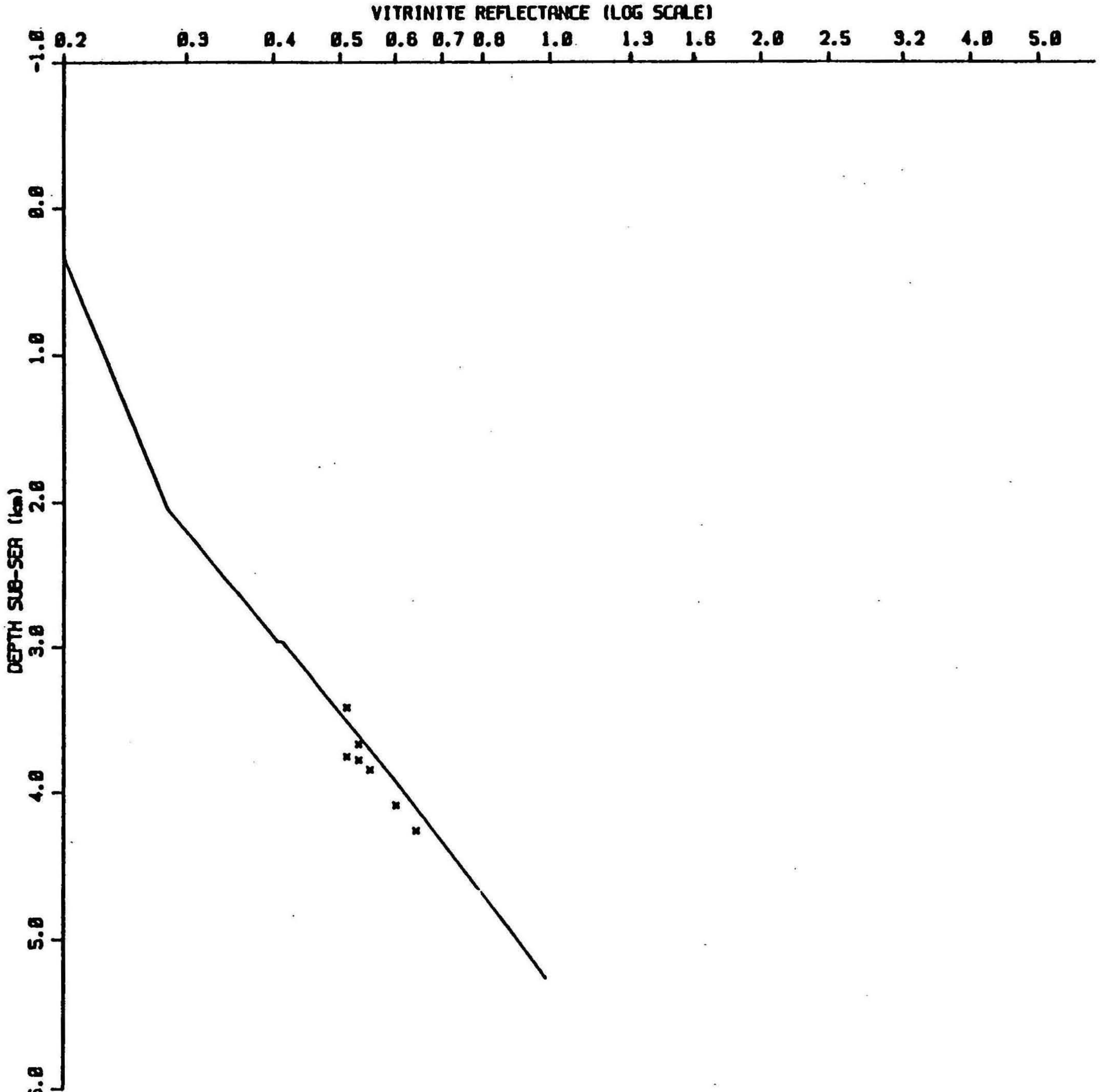


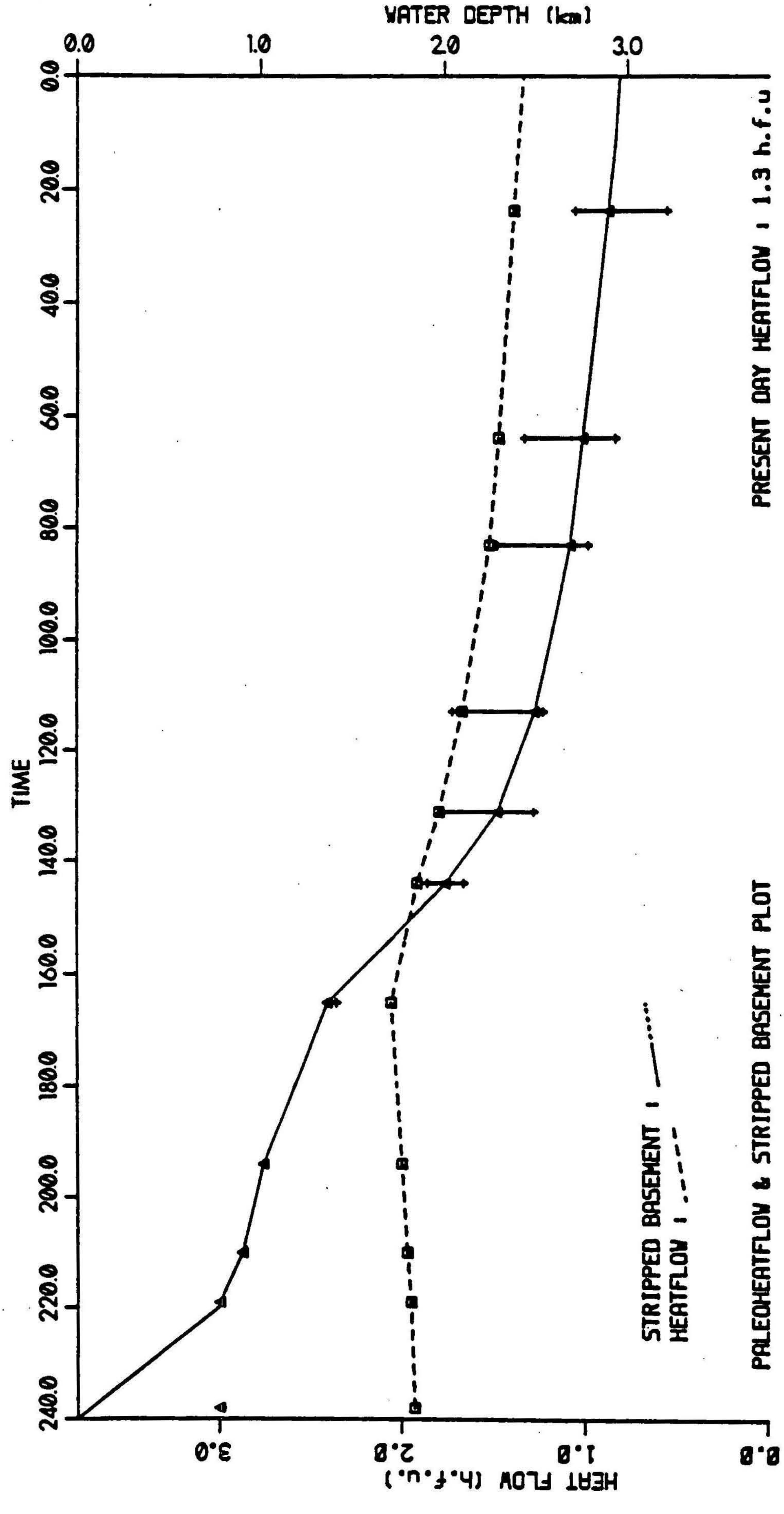
Figure C2

VICTORIA SYNCLINE



COMPUTED vs OBSERVED VITRINITE REFLECTANCE PLOT

Figure C3



LEWIS TROUGH

Figure C4

LEWIS TROUGH

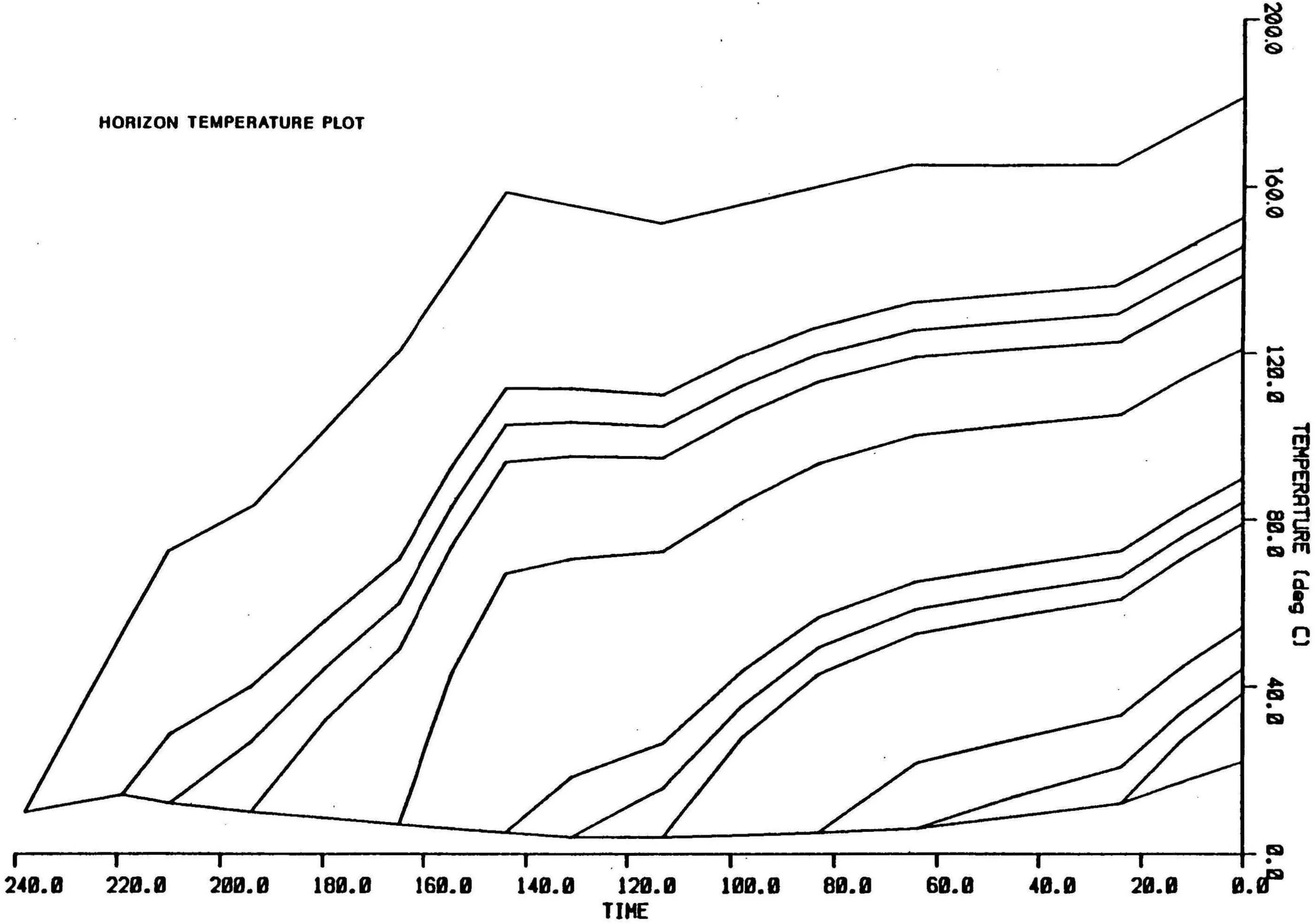
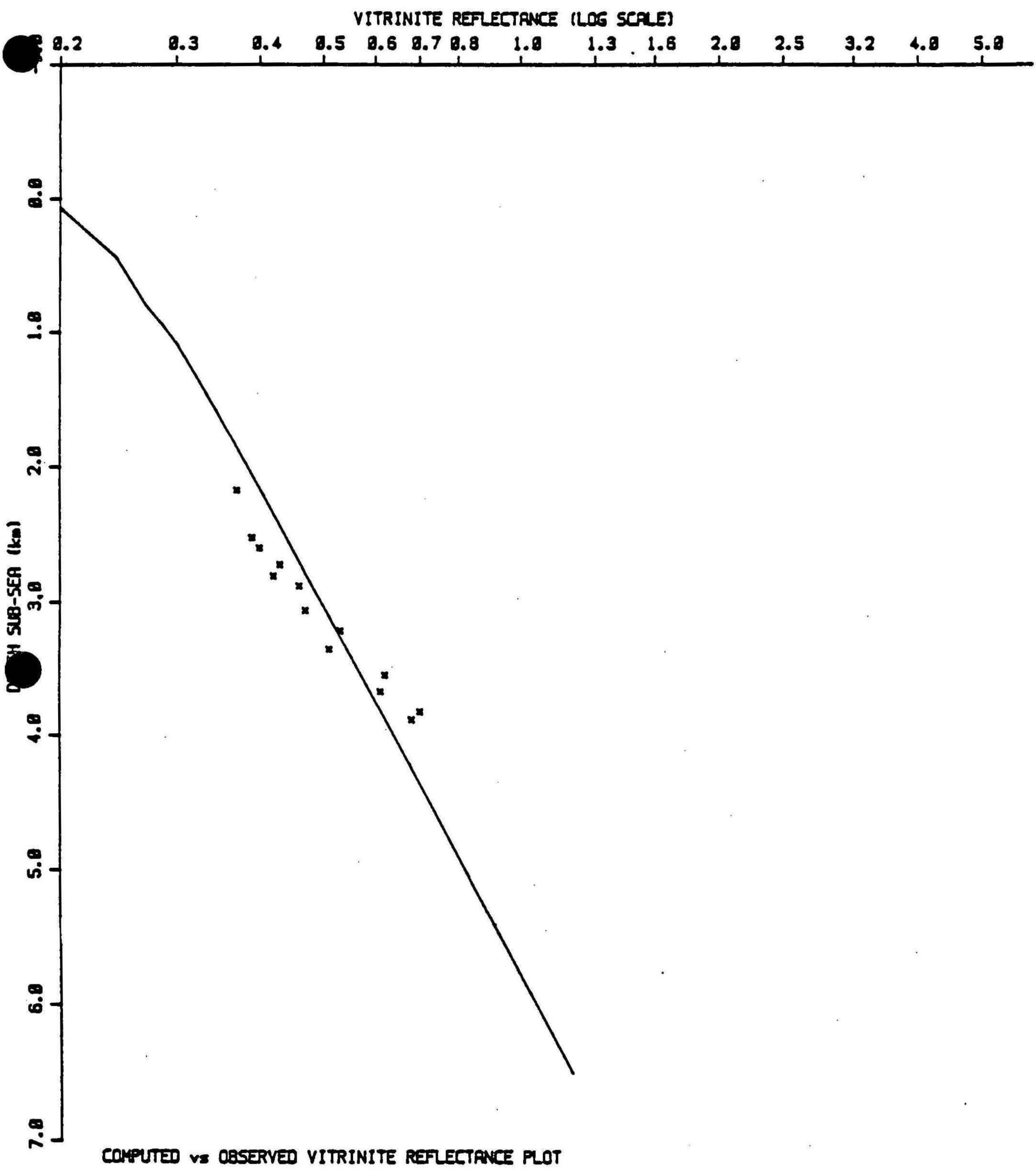


Figure C5



LEWIS TROUGH

Figure C6

FLINDERS SHOAL 1

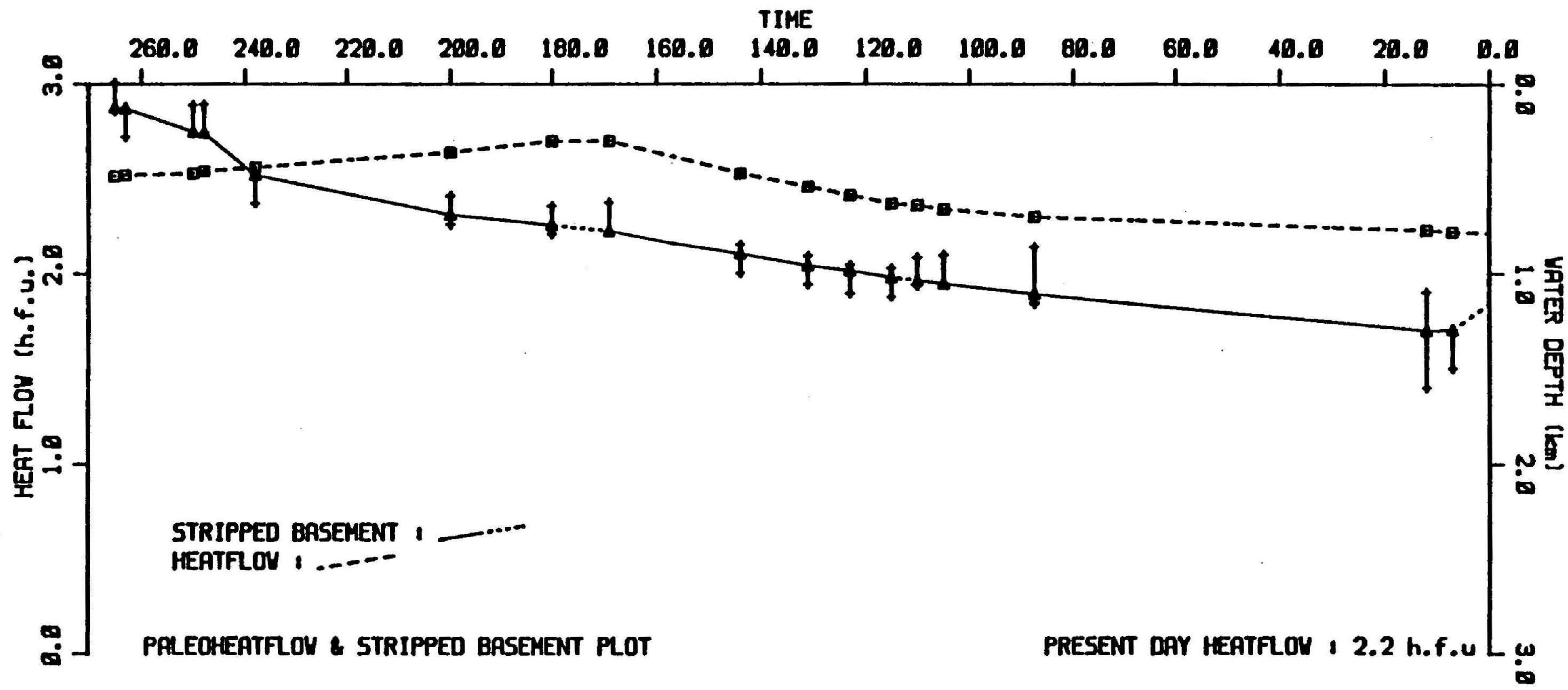


Figure C7

FLINDERS SHOAL 1

HORIZON TEMPERATURE PLOT

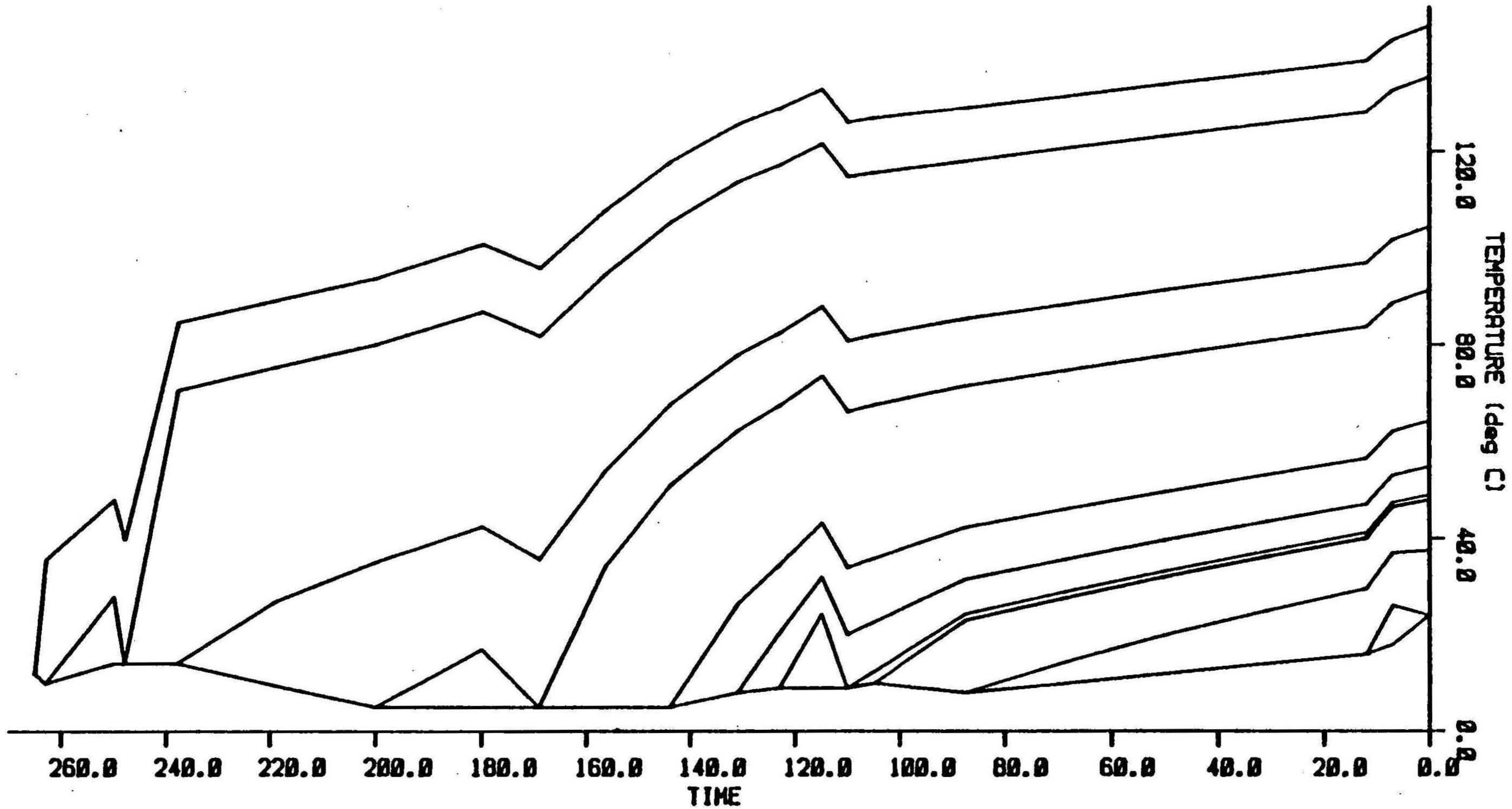
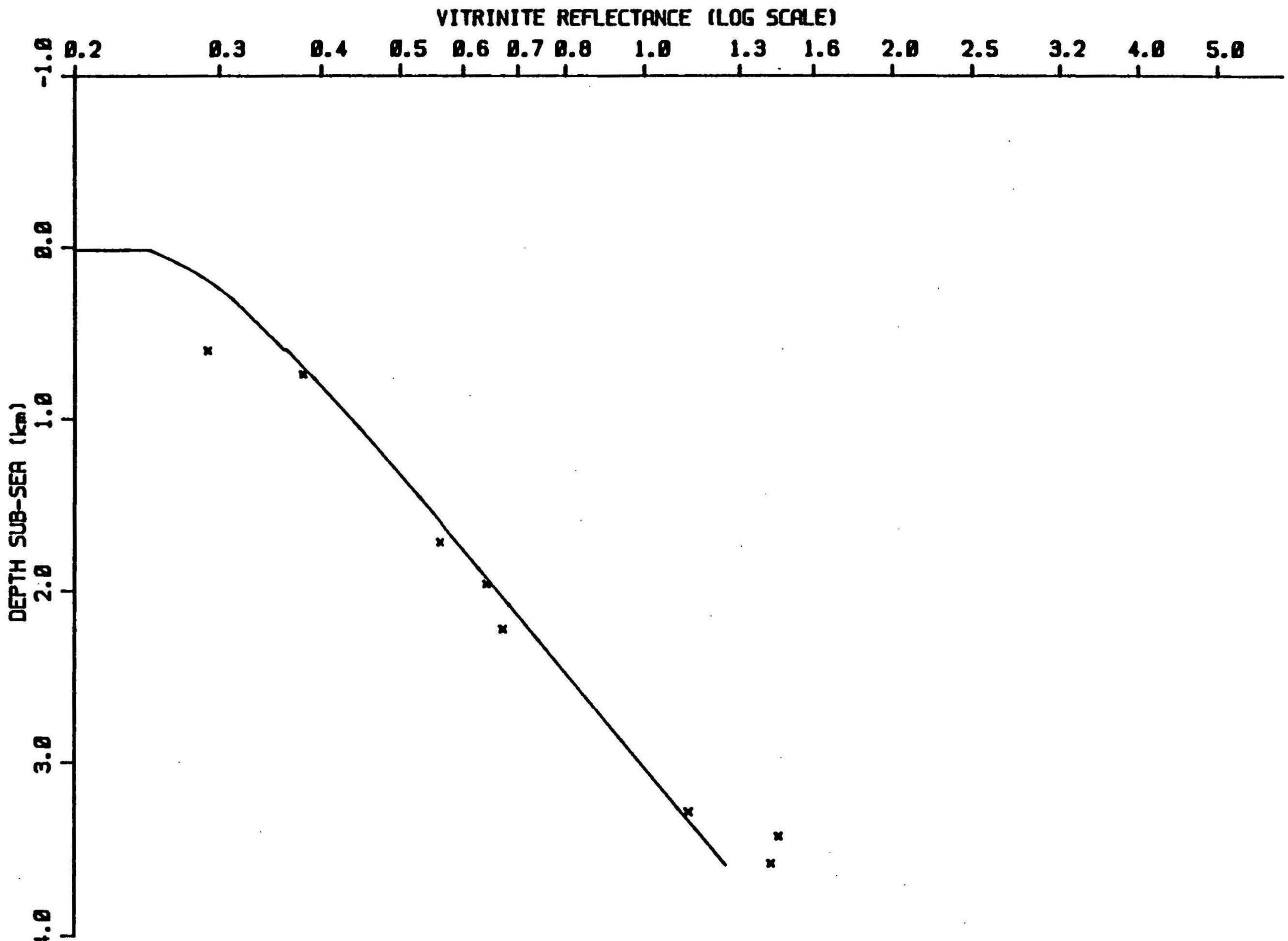


Figure C8

FLINDERS SHOAL 1



COMPUTED vs OBSERVED VITRINITE REFLECTANCE PLOT

Figure C9

KANGAROO TROUGH

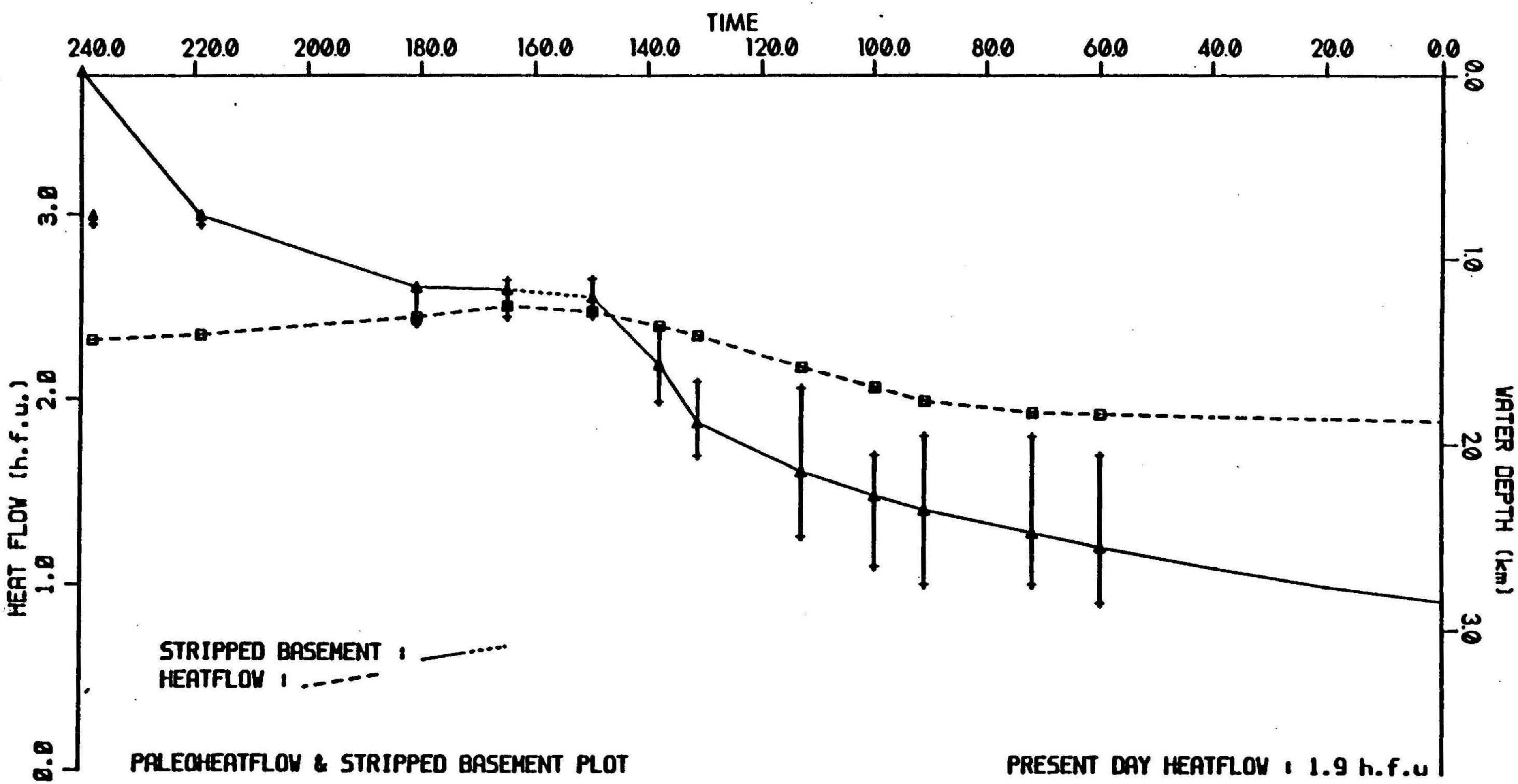


Figure C10

KANGAROO TROUGH

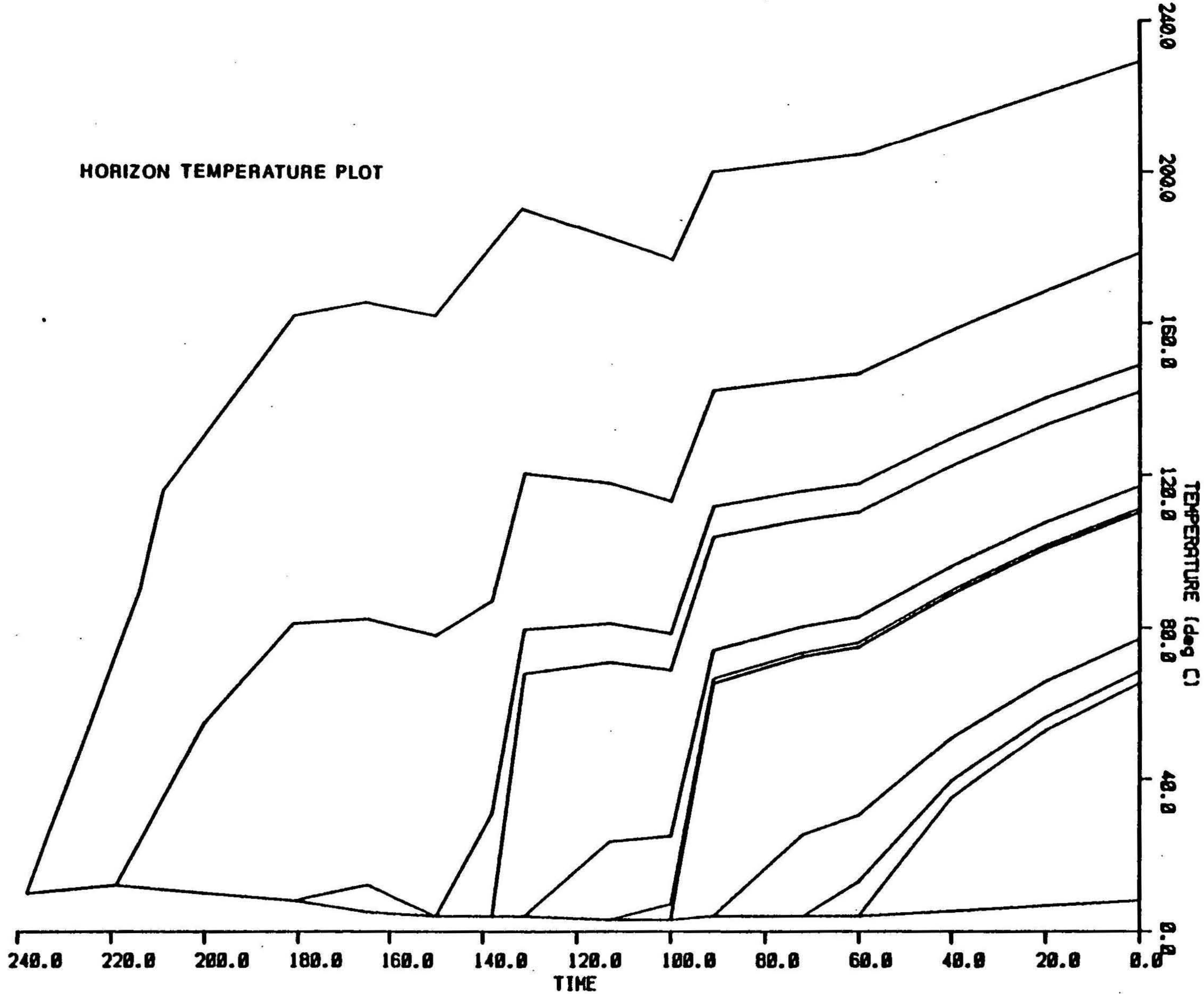
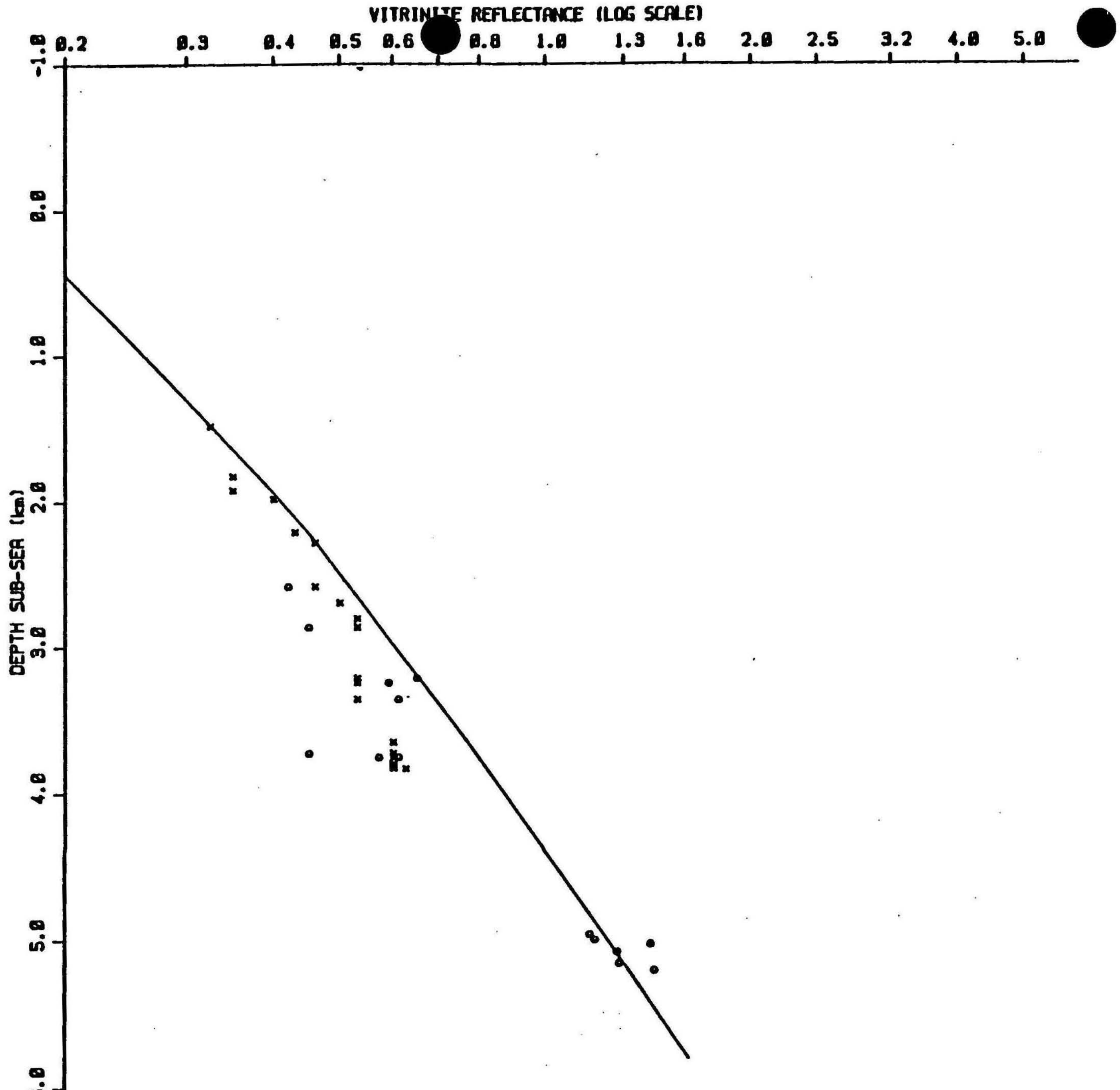


Figure C11

KANGAROO TROUGH



COMPUTED vs OBSERVED VITRINITE REFLECTANCE PLOT

Figure C12

CARTIER TROUGH

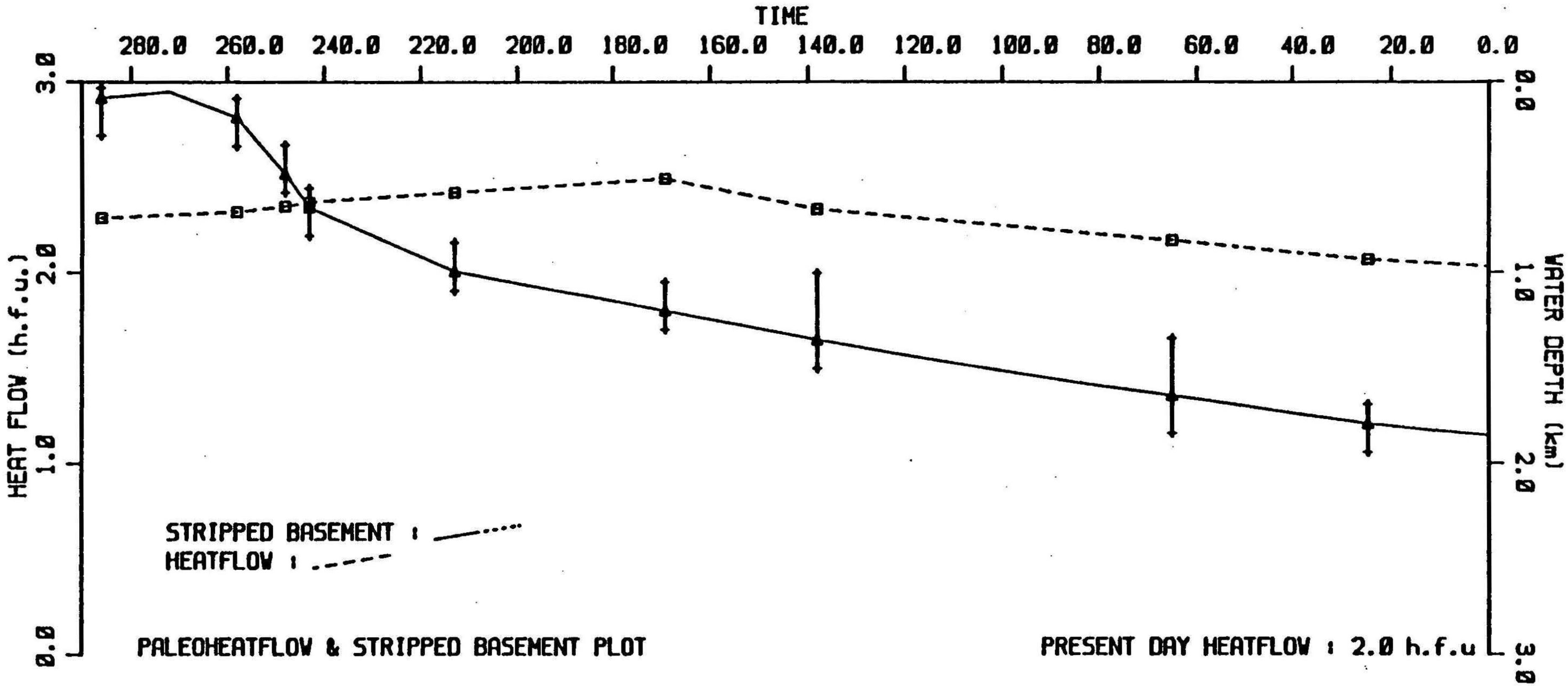
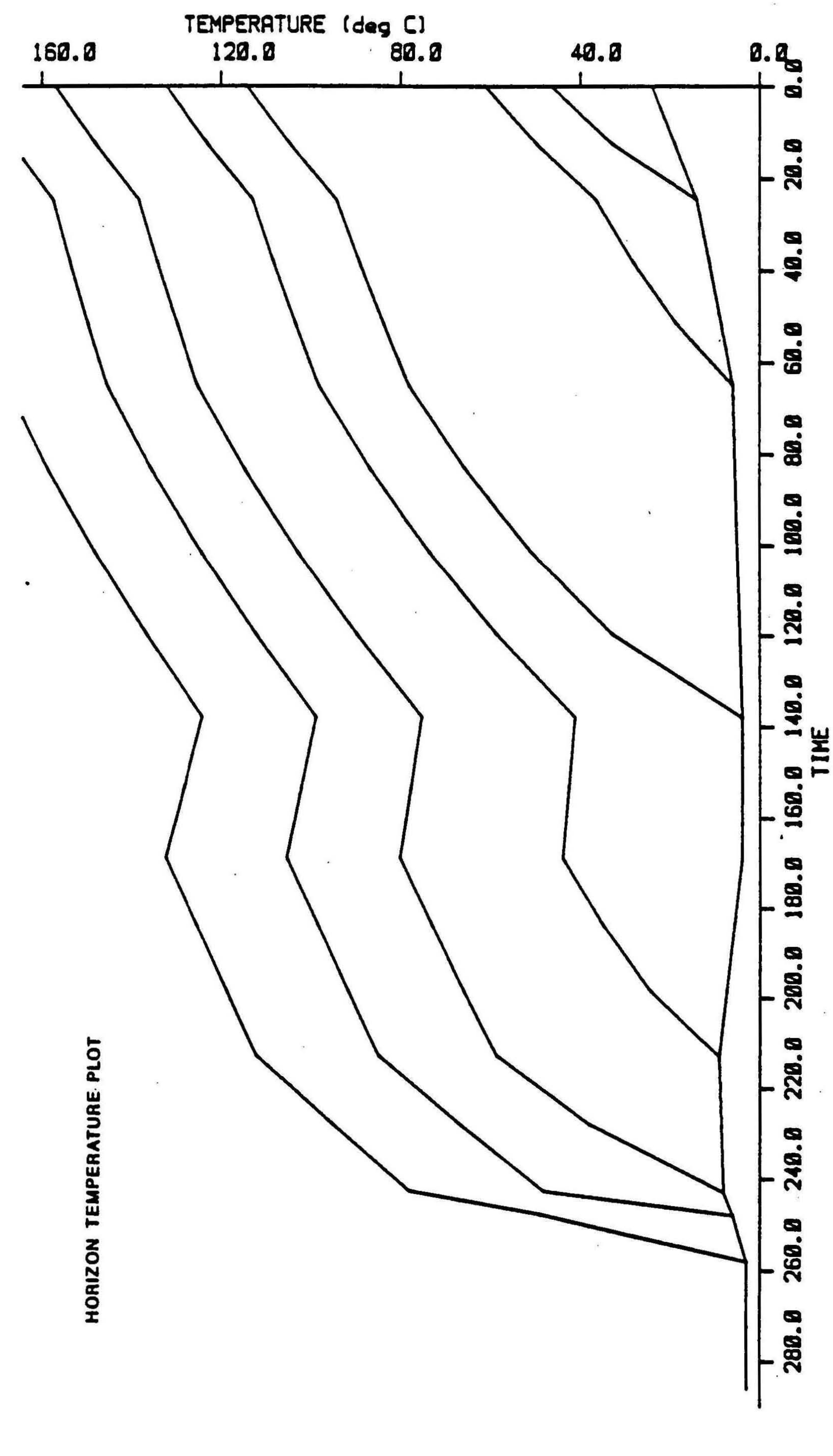


Figure C13



CARTIER TROUGH

Figure C14

CARTIER TROUGH

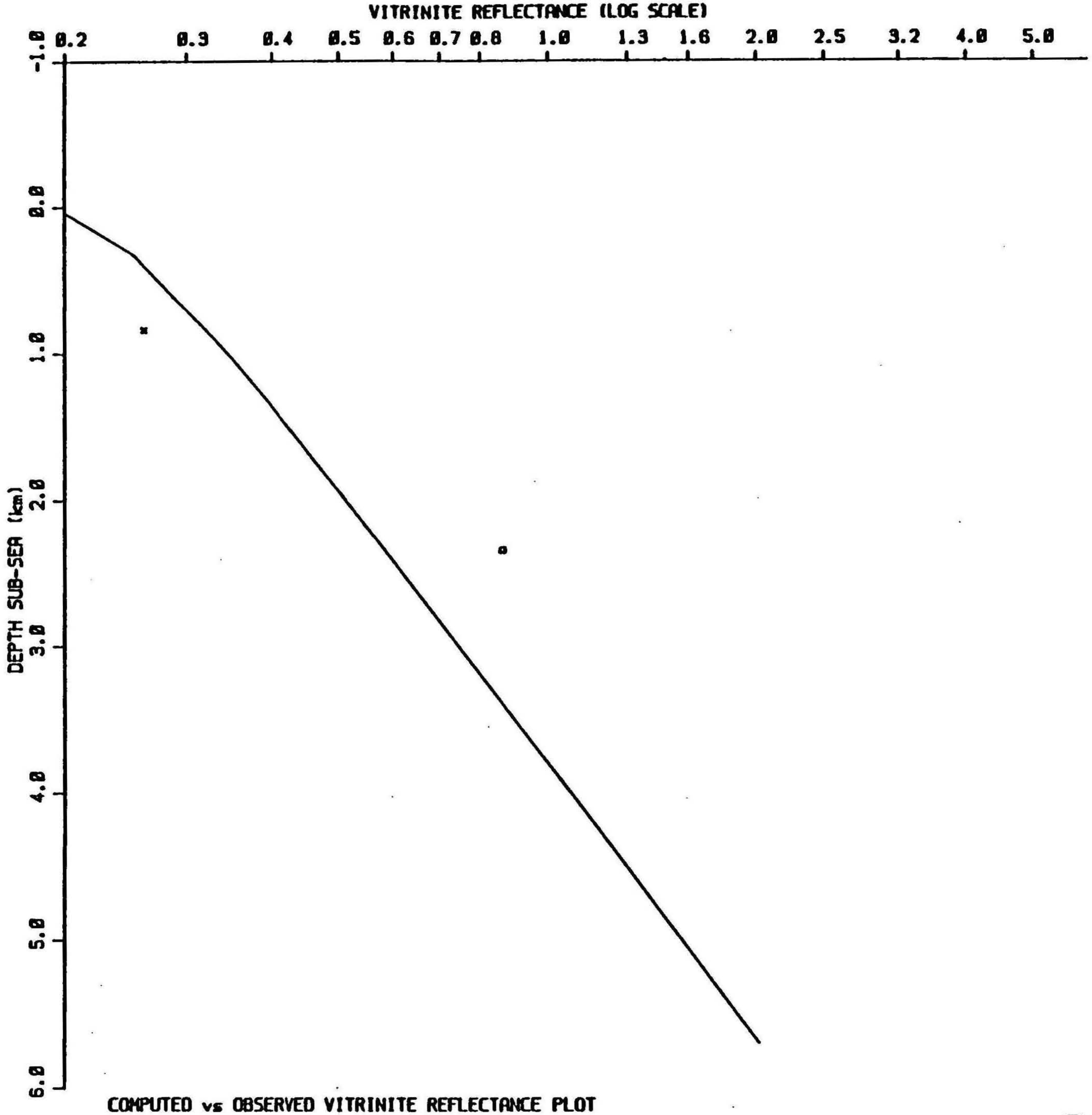


Figure C15

BROWSE DEPOCENTRE

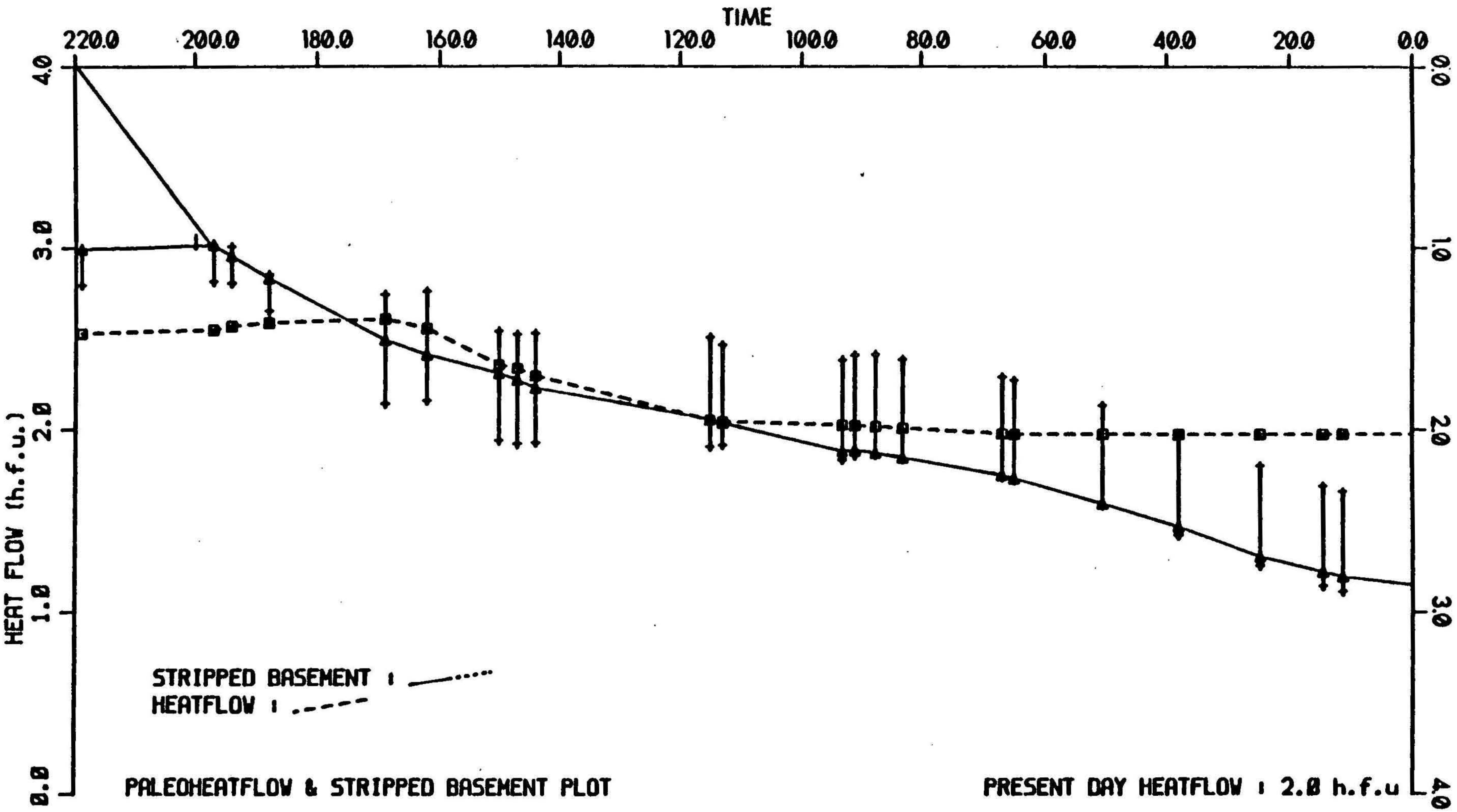


Figure C16

BROWSE DEPOCENTRE

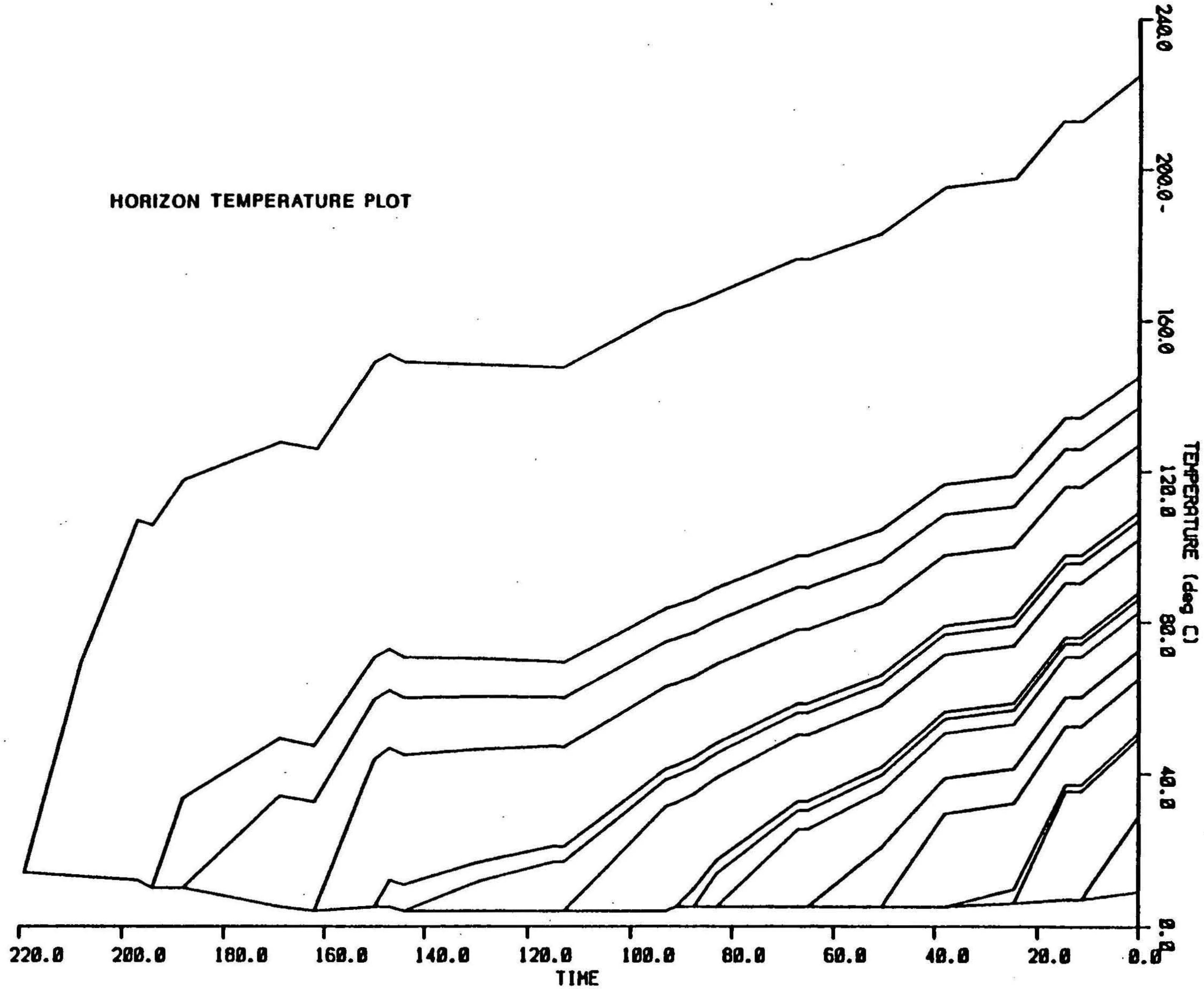
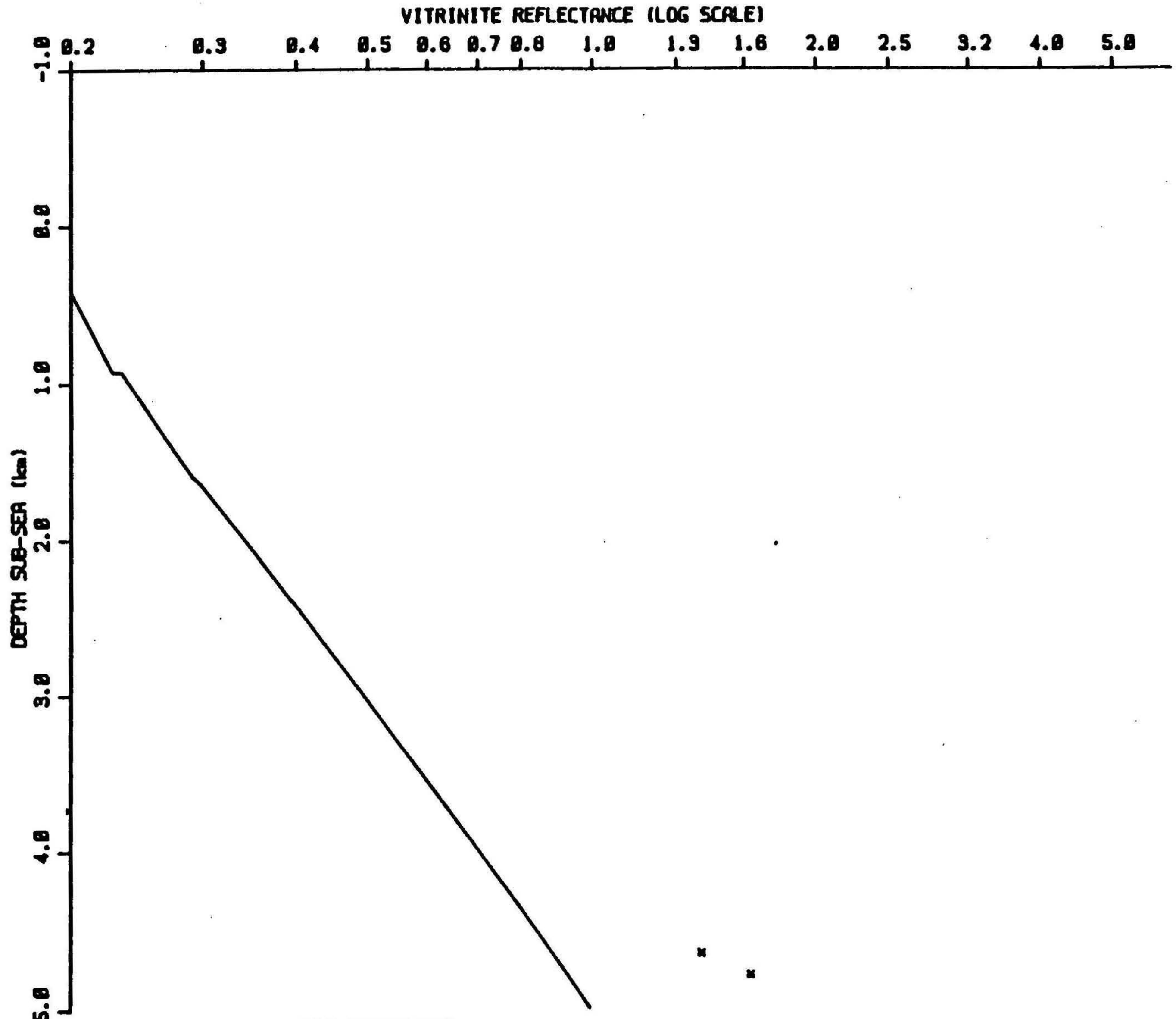


Figure C17

BROWSE DEPOCENTRE



COMPUTED vs OBSERVED VITRINITE REFLECTANCE PLOT

Figure C18

HERON 1

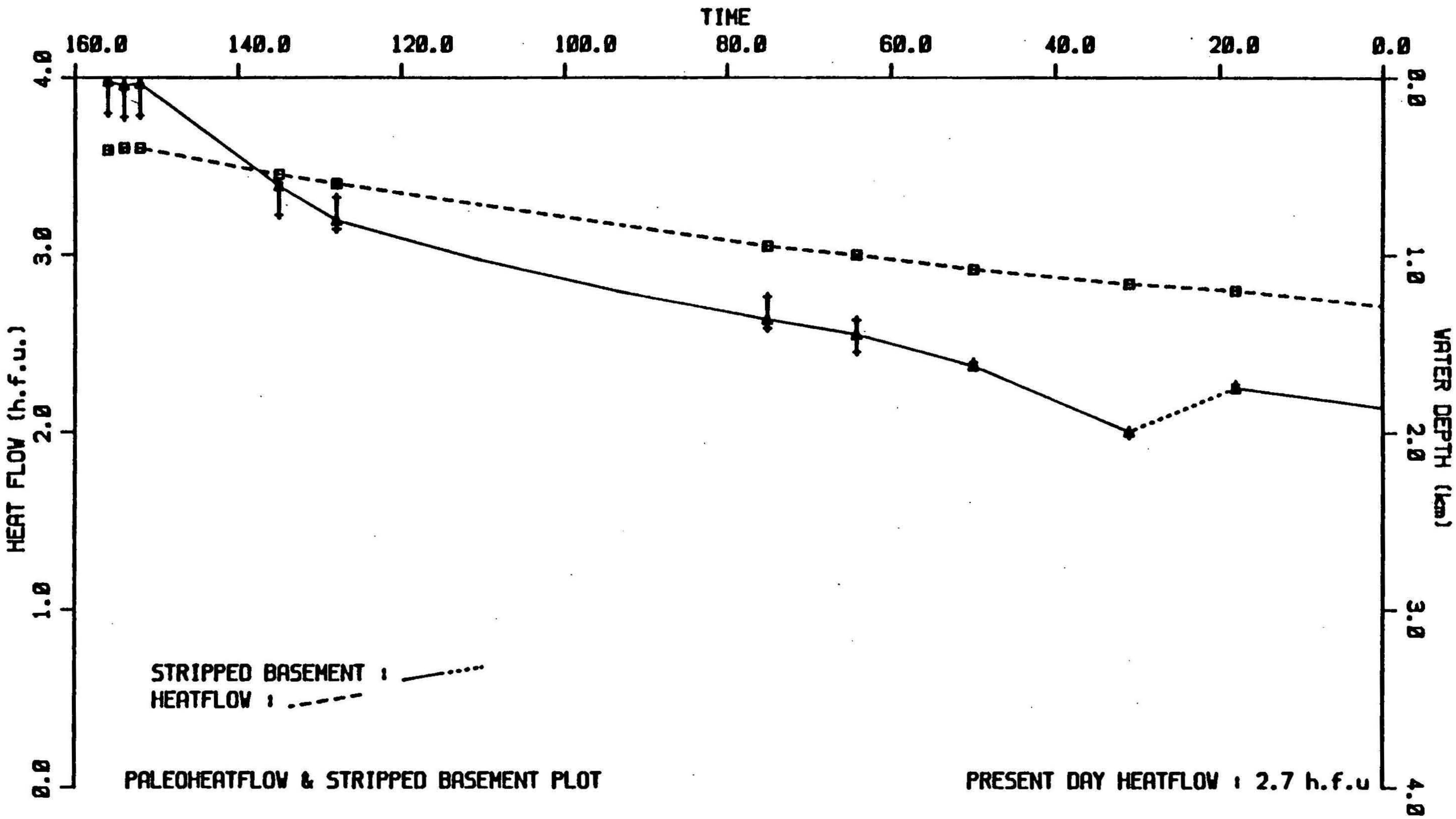


Figure C19

HERON 1

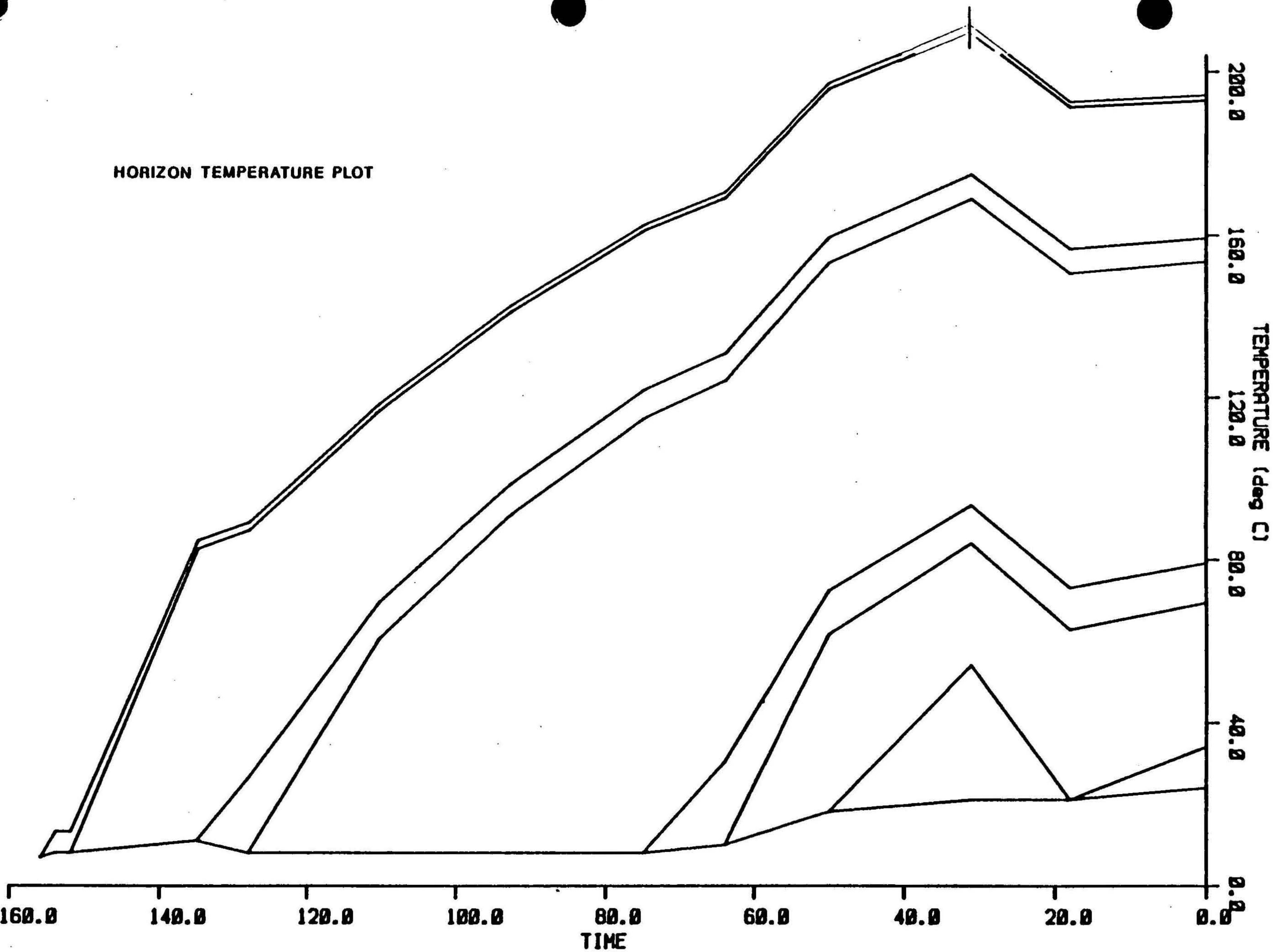
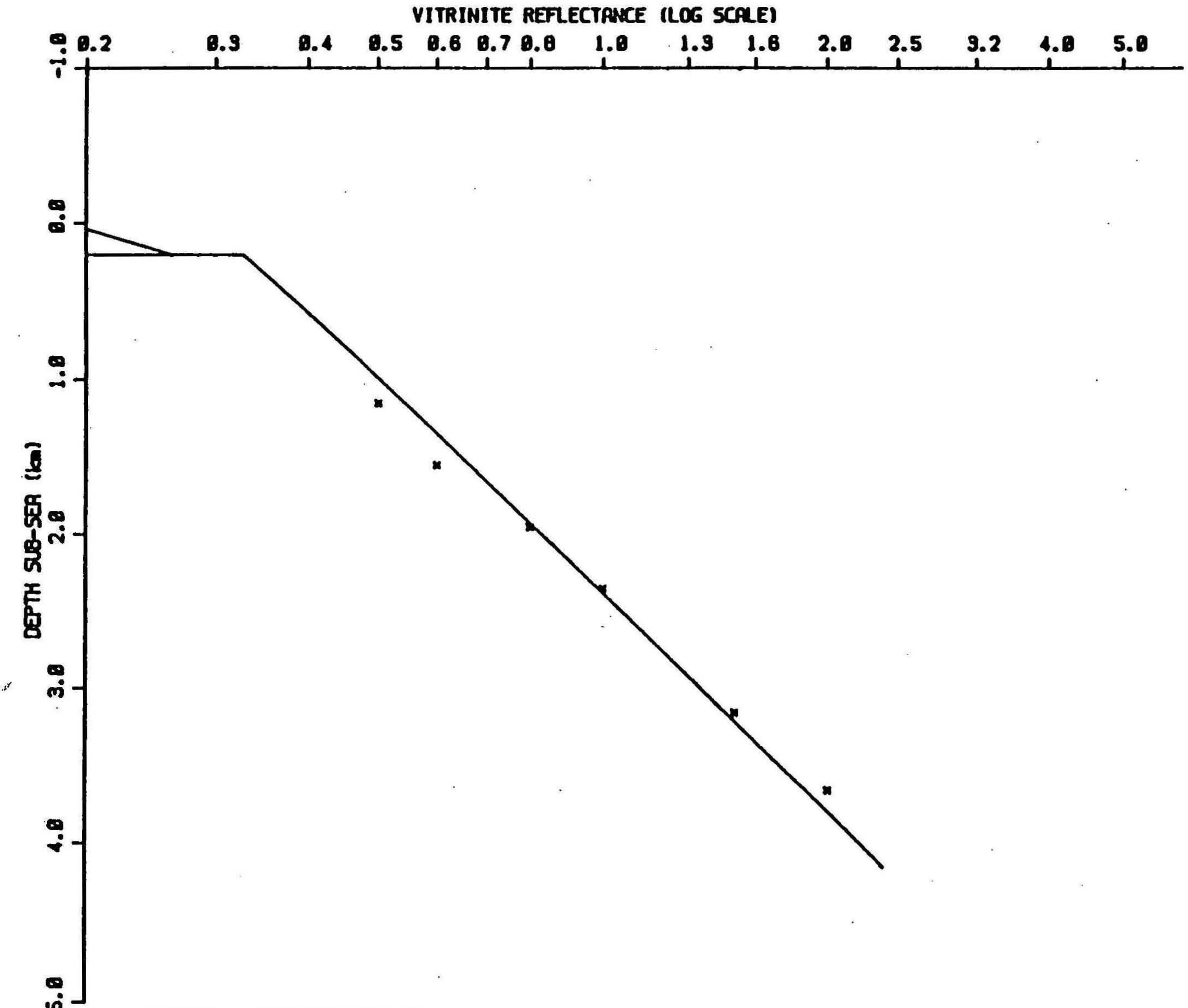


Figure C20

HERON 1



COMPUTED vs OBSERVED VITRINITE REFLECTANCE PLOT

Figure C21

EAST SWAN 1

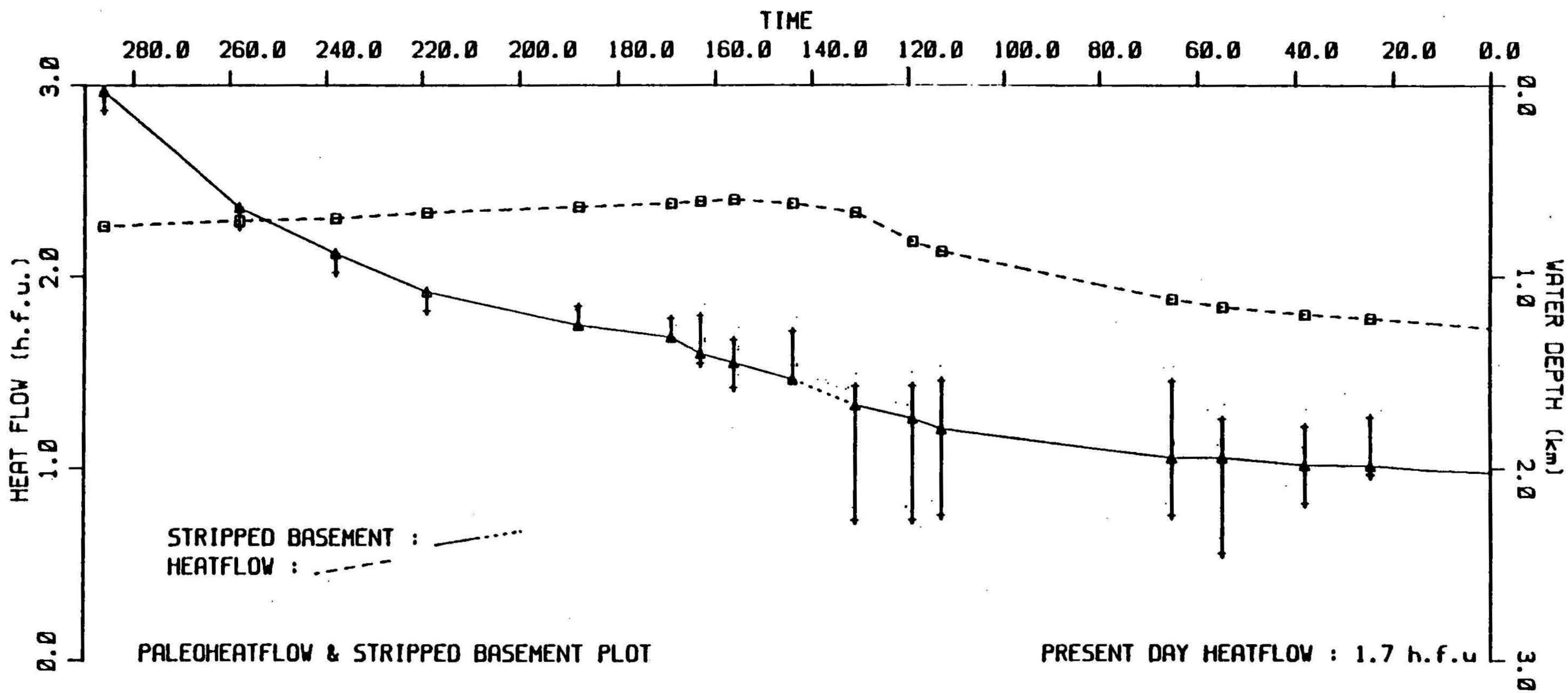


Figure C22

EAST SWAN 1

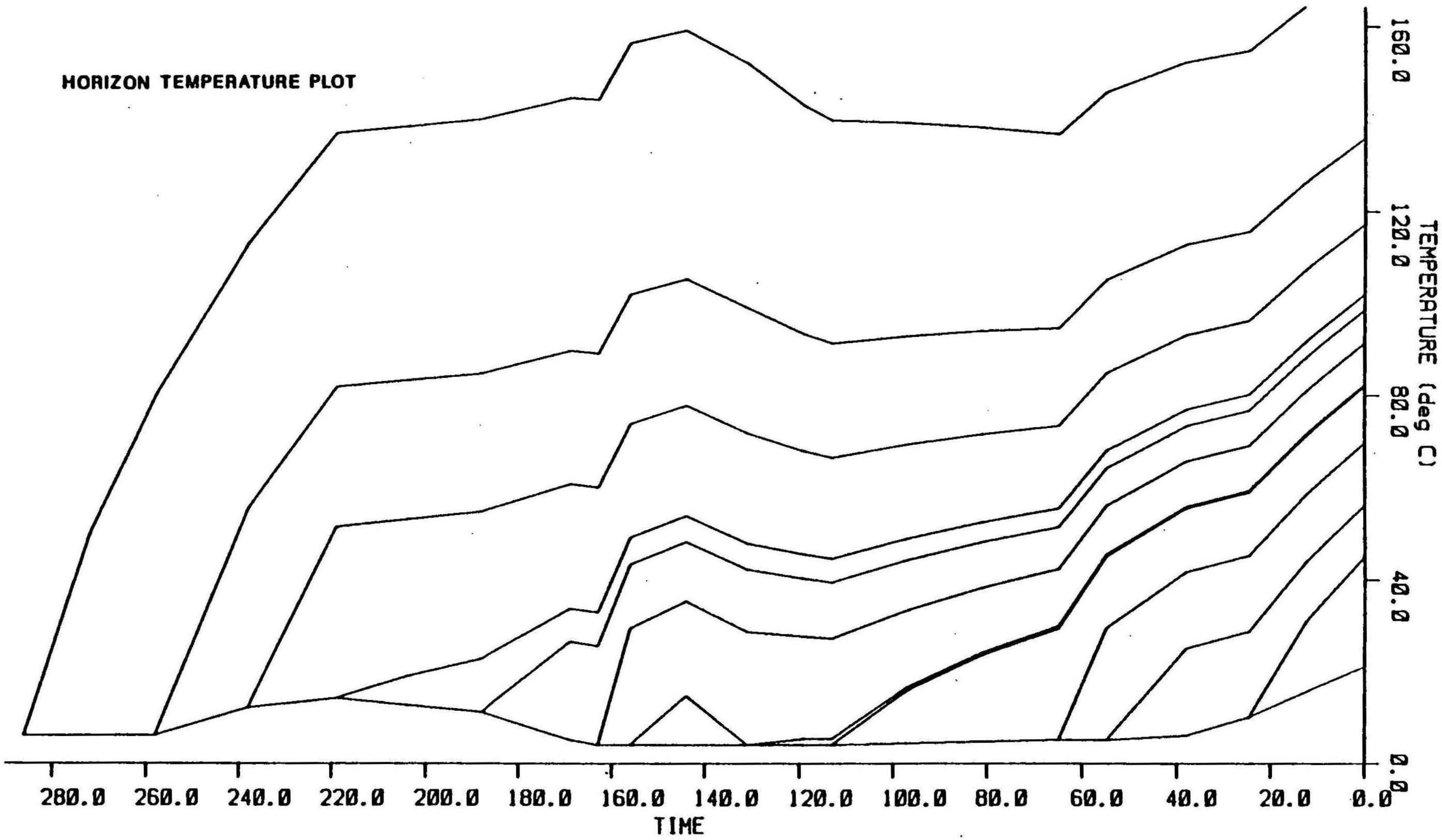
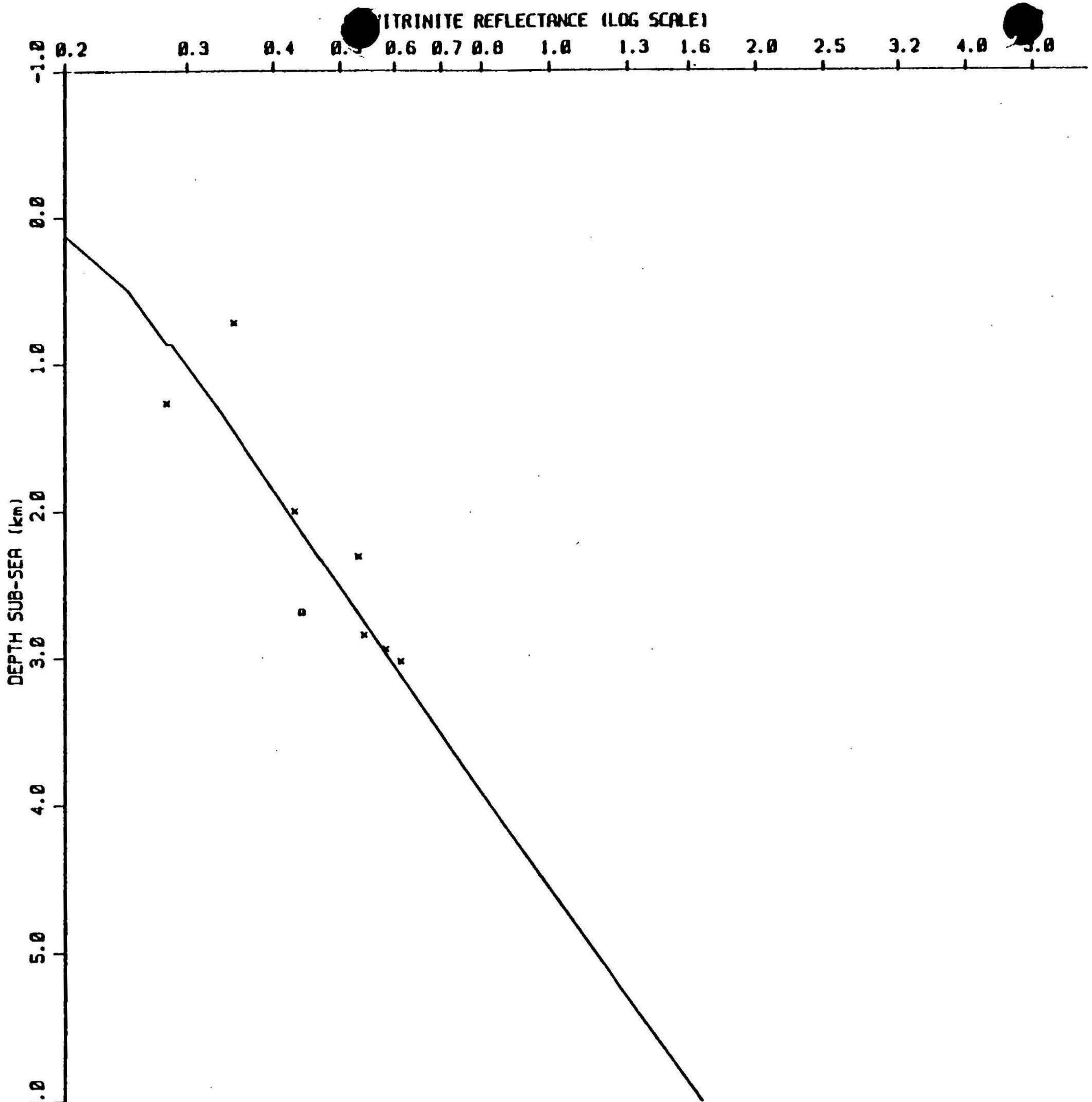


Figure C23

EAST SWAN 1



COMPUTED vs OBSERVED VITRINITE REFLECTANCE PLOT

Figure C24

FLAMINGO 1

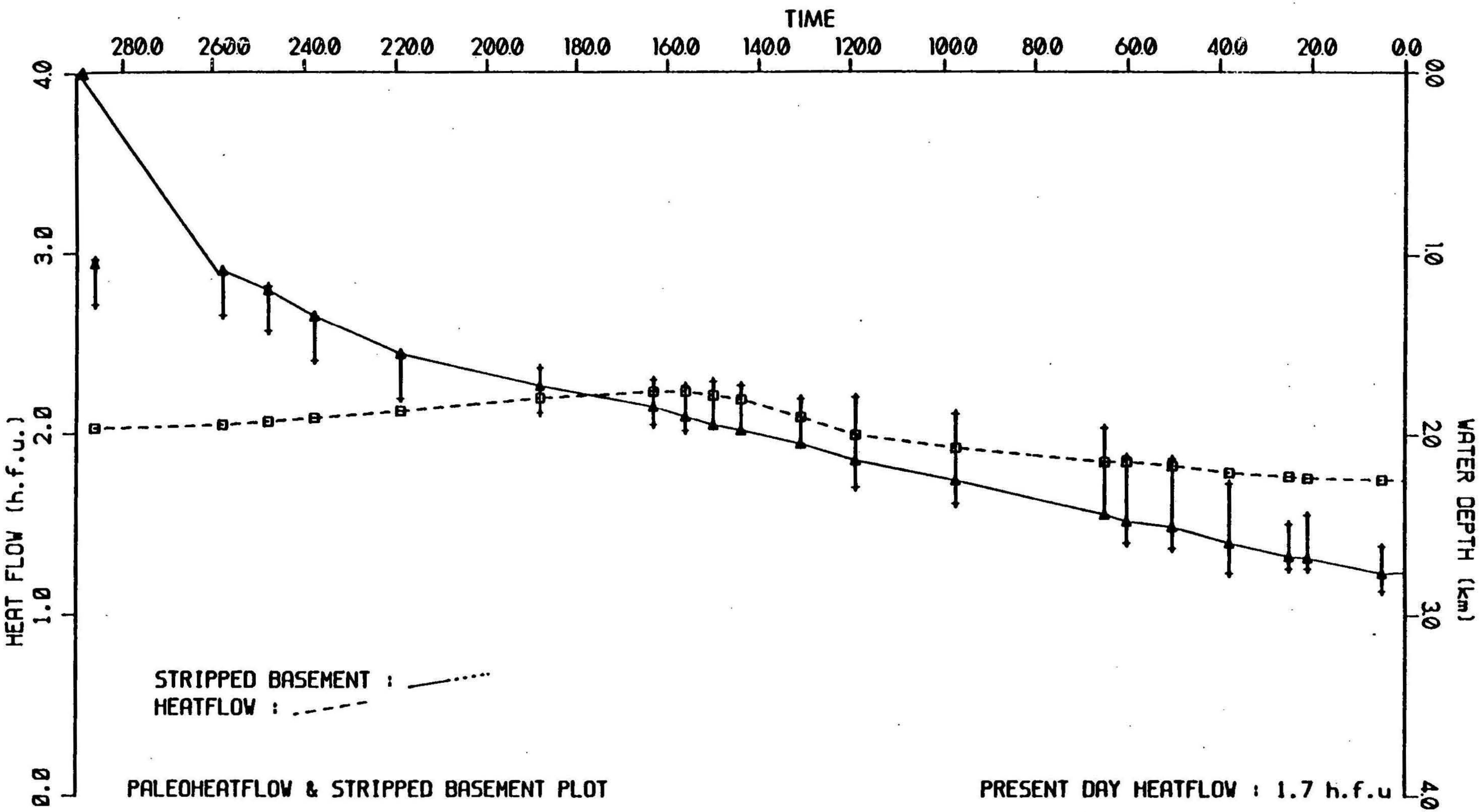


Figure C25

FLAMINGO 1

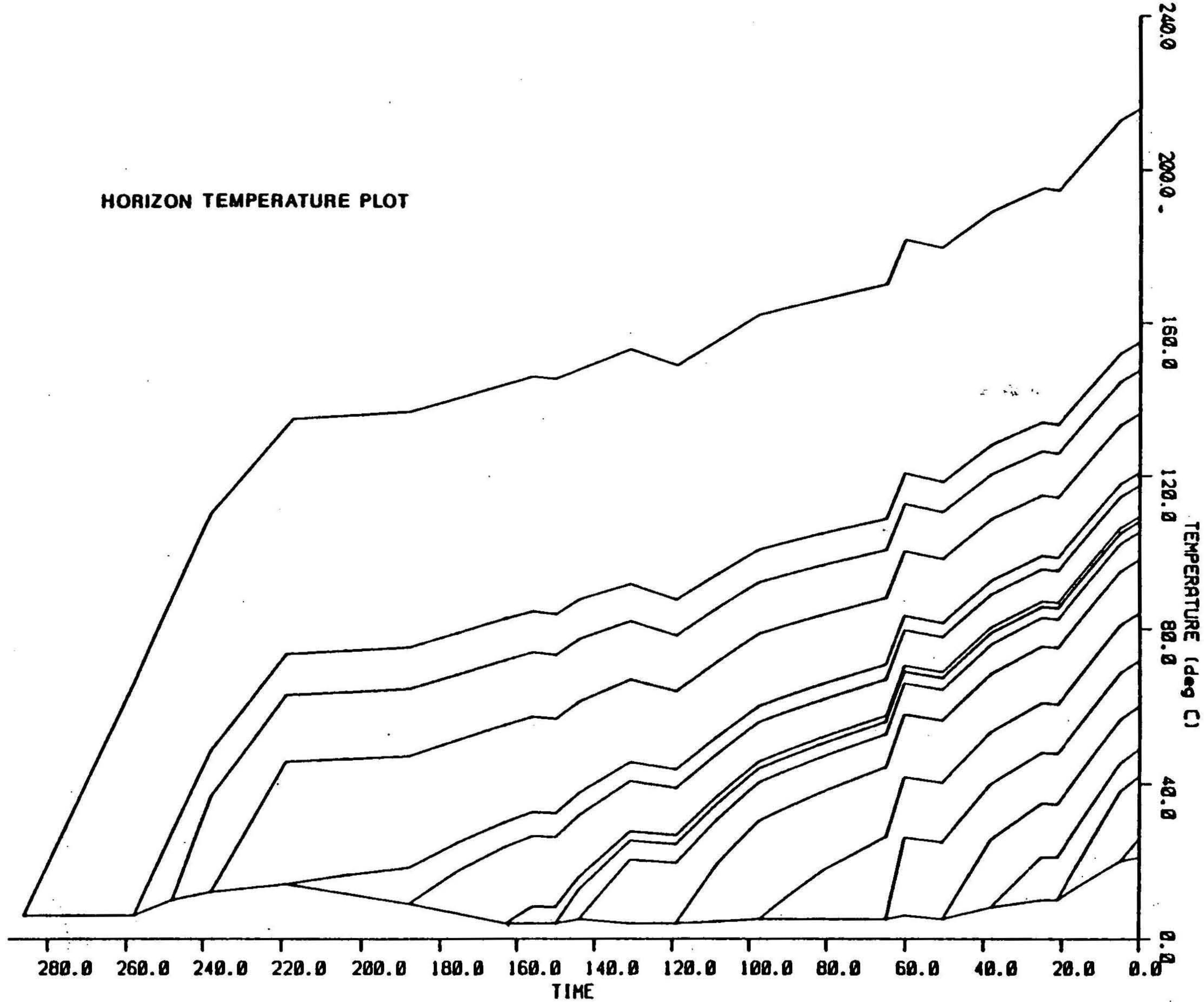
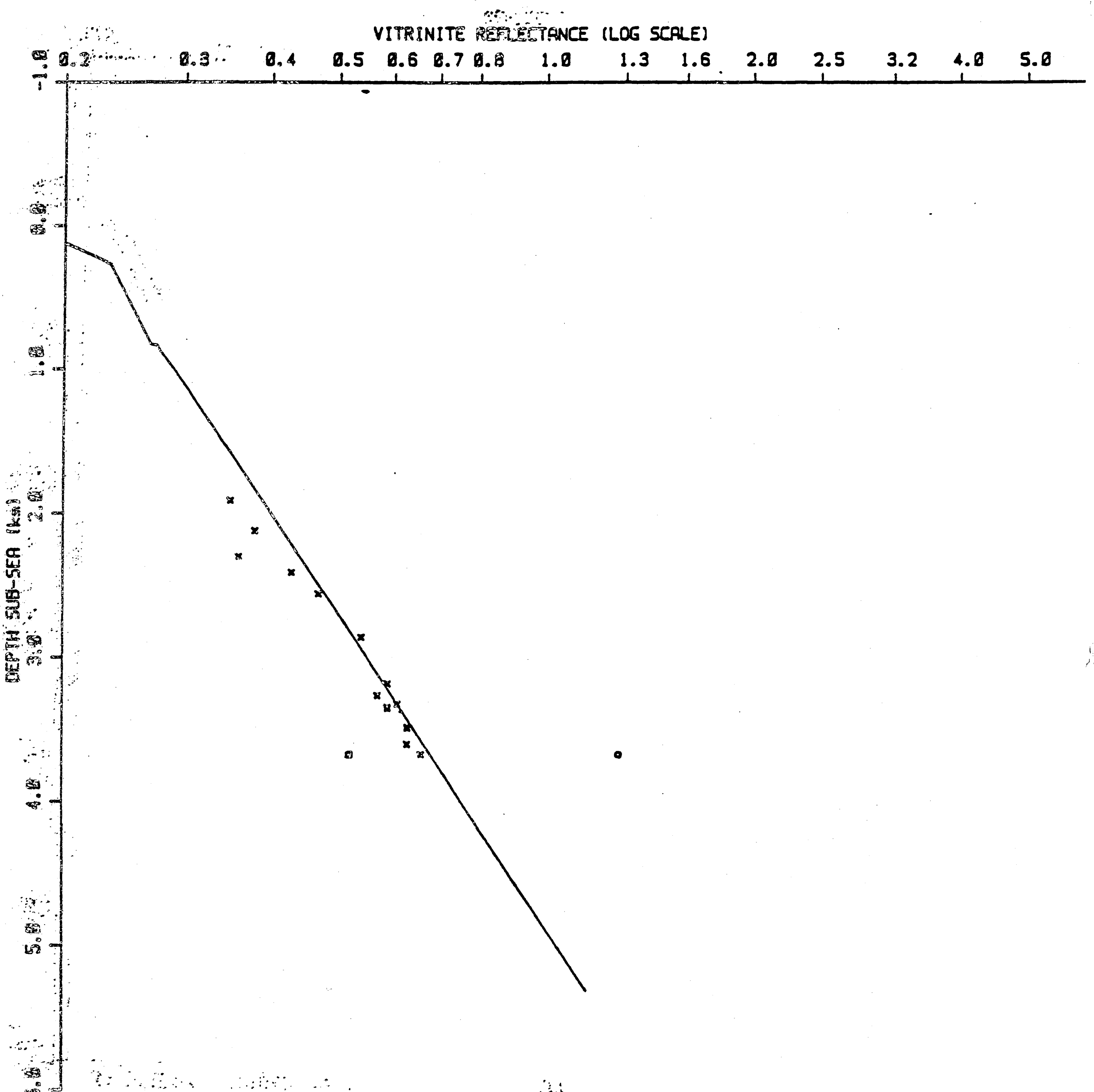


Figure C26



COMPUTED vs OBSERVED VITRINITE REFLECTANCE PLOT

FLAMINGO 1

Figure C27