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PETREL SUB-BASIN STUDY
1995-1996

ORGANIC GEOCHEMISTRY OF OILS AND SOURCE ROCKS

BY

D.S. EDWARDS AND R.E. SUMMONS

AGSO RECORD 1996/42

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PREFACE

AGSO's 1995-96 Petrel Sub-basin Study was undertaken within AGSO's Marine, Petroleum and Sedimentary Resources Division (MPSR) as part of MPSR's North West Shelf Project. The study was aimed at understanding the stratigraphic and structural development of the basin as a framework for more effective and efficient resource exploration. Specifically, the study aimed to:

- define the nature of the major basement elements underlying the Petrel Sub-basin and their influence on the development of the basin through time,
- determine the nature and age of the events that have controlled the initiation, distribution and tectonic evolution of the basin;
- define the nature and age of the basin fill, and the processes that have controlled its deposition and deformation; and, importantly,
- determine the factors controlling the development and distribution of the basin's petroleum systems and occurrences.

This report summarises bulk geochemical analyses (TOC and Rock-Eval pyrolysis) and interprets biomarker and isotopic studies carried out on liquid hydrocarbons and source rocks in this basin. Oil-oil and oil-source rock correlations interpret these data in a geological context and allows integration with maturation studies. This report is not a 'stand-alone' product but is intended for use in conjunction with the study's other products, notably the Well Folio, Geohistory Modelling (AGSO Record 1996/43) and Summary Report (AGSO Record 1996/40). A digital source rock and maturity database is included for open file wells.

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OTHER PRODUCTS AVAILABLE FROM THE PETREL SUB-BASIN STUDY

Summary Report *(AGSO Record 1996/40, compiled by J. B. Colwell & J. M. Kennard).*
Summarises major results of the project.

Well Folio *(by J. M. Kennard).*
Provides well composites for 31 key wells in the basin, as well as 6 well-well cross-sections.

Map & Seismic Folio *(by J. B. Colwell, J. E. Blevin & D. J. Wilson).*
Includes 24 time-structure and time-isopach maps as well as select interpreted seismic lines.

Digital Database of Seismic Interpretations.
Covers ~ 8200 line km of AGSO deep- and conventional industry seismic data.

Petrel Stratigraphic Time Chart *(by P. J. Jones et al.).*
Shows latest understanding of the Petrel Sub-basin stratigraphy and event history against biozonations and AGSO's timescale.

Gravity Modelling Report *(AGSO Record 1996/41, by J. B. Willcox)*
Details 2-D gravity modelling undertaken on 3 of the AGSO deep-seismic lines.

Geohistory Modelling Report *(AGSO Record 1996/43 , by J. M. Kennard).*
Details geohistory subsidence and thermal maturation modelling of 20 wells and 6 pseudo-wells and hydrocarbon generation and expulsion models for 3 identified source intervals.

ABSTRACT

This report documents the geochemical and isotopic characteristics of Palaeozoic oils and their potential source rocks within each of the three petroleum systems identified in the Petrel Sub-basin: Ningbing-Bonaparte (Larapintine 3), Milligans (Larapintine 4) and Keyling-Hyland Bay (Gondwanan 1).

Oils and bitumens attributed to the Ningbing-Bonaparte Petroleum System, from the limited data available, occur in some onshore petroleum wells (Ningbing-1) and mineral holes and are probably sourced from the Late Devonian Ningbing and Bonaparte Formations. These oil shows are characterised by light carbon isotopic signatures (mean $\delta^{13}C_{sats}$ = -29.4 ‰; mean $\delta^{13}C_{arom}$ = -28.3 ‰). The abundance of the low molecular weight *n*-alkanes implies that these oils have been generated from algal and bacterial-rich sediments. Biomarker studies indicate that the oils analysed to date do not have a common source; notable differences are observed in the abundance of diasteranes, gammacerane and C_{30} steranes. A carbonate source affinity for some oils is highlighted by pristane/phytane ratios of around 1, a high abundance of steranes relative to diasteranes and low concentrations of rearranged hopanes. Few geochemical analyses exist for the Late Devonian sediments in the Petrel Sub-basin. Biomarker analyses carried out on Late Devonian sediments at Spirit Hill-1 did not match those of the oil stains in Ningbing-1 and outcropping Ningbing Limestone. However, organic-rich stylolites occur at Ningbing-1 (cores 1 and 2) and warrant further study.

Oils from the Milligans Petroleum System have been recovered onshore at Waggon Creek-1 in the Milligans Formation and offshore at Barnett-1, 2, Turtle-1 and 2 throughout the Carboniferous and Permian successions. They are mature oils derived from clay-rich marine source rocks. These oils are isotopically light (mean $\delta^{13}C_{sats}$ = - 28.1 ‰; mean $\delta^{13}C_{arom}$ = - 27.1 ‰) but they have slightly heavier carbon isotopic signatures than the Ningbing-Bonaparte oils. Their saturates chromatograms display unimodal *n*-alkane profiles with a maximum around *n*-C_{15}, and pristane/phytane ratios around unity. Their biomarker distributions are characterised by C_{27}/C_{29} sterane ratios of just below 1, an abundance of rearranged steranes, rearranged hopanes (dia- and neohopanes), tri- and tetracyclic terpanes (including the two unidentified peaks 'A' and 'B' which are diagnostic of this petroleum system) with minor gammacerane and 28,30-dinorhopane. Severe biodegradation has altered the composition of many of the shallower oils recovered at Barnett and Turtle, resulting in an overprint of 25-norhopanes.

Where penetrated in petroleum wells, the Milligans Formation comprises poor quality, gas-prone, Type III-IV kerogen derived from degraded land-plant (lycopods and ferns) remains. However, a strong correlation between the Barnett, Turtle and Waggon Creek oils has been made with anoxic marine mudstones in this formation. At mineral well NBF1002 immature, organic-rich oil-prone anoxic marine mudstones are present (mean TOC = 2.8 %; mean HI = 204 $mgS_2/gTOC$), suggesting that similar units with good source potential may be developed in depocentres adjacent to the Turtle-Barnett High and in the Carlton Sub-basin.

The Petrel-4 condensate, reservoired with the Permian Hyland Bay Formation, is the only sample analysed from the Keyling-Hyland Bay Petroleum System. It has a diagnostic ^{13}C-enriched isotopic signature ($\delta^{13}C_{sats}$ = - 24.6 ‰; $\delta^{13}C_{arom}$ = -23.1 ‰) and the biomarker assemblage is characterised by abundant rearranged steranes (C_{29} ethyldiacholestane) and hopanes (C_{30} diahopane). Source and maturity-sensitive molecular parameters indicate that the condensate has been generated from a mature clay-rich source rock containing a mixture of terrestrial and marine-derived organic matter. From data available, the most organic-rich Permian source rocks are the delta-plain coals (mean TOC = 35.2 %; mean HI = 230 $mgS_2/gTOC$) and marginal-marine shales (mean TOC = 2.8 %; mean HI = 95 $mgS_2/gTOC$) of the Keyling Formation and, to a lesser extent, pro-delta shales of the Hyland Bay Formation (mean TOC = 2 %; mean HI = 55 $mgS_2/gTOC$). Land-plant-rich Hyland Bay sediments are isotopically similar to the Petrel-4 condensate. Further isotopic and biomarker studies of the Keyling Formation are required before a more precise correlation can be made as to the origin of the Petrel condensate.

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1. INTRODUCTION

The aims of this organic geochemical study (part of AGSO's 1995-96 Petrel Sub-basin Study) were to identify potential source rocks, document the biomarker and carbon isotopic signatures of both organic-rich units and petroleums, and hence establish oil-to-source rock correlations between effective source rocks and reservoired oil/condensate within this sub-basin. The findings of the study are presented here using the Australian Petroleum Supersystems outlined by Bradshaw (1993) and Bradshaw *et al.* (1994).

Source rocks were identified using a combination of techniques including wireline log interpretation, sequence stratigraphy, kerogen compositional studies (maceral and palynological examinations) and organic geochemical analyses (*viz.* TOC and Rock-Eval pyrolysis). The oils were characterised by a number of methods; elemental analysis, gas chromatography (GC), gas chromatography-mass spectrometry (GC-MS) and stable carbon isotope analysis. From the results of these analyses, the source affinity and maturity of the oils were determined.

1.1 Geological Setting

The Petrel Sub-basin comprises the southern part of the Bonaparte Basin where it mostly underlies the Joseph Bonaparte Gulf and extends onshore in the south (Fig. 1). In plan view, the sub-basin is broadly V-shaped in outline with a northwest-trending axis, and straddles the Northern Territory-Western Australia border. It has a rock record extending from the Cambrian to the Tertiary. The sub-basin includes onshore features such as the Carlton Sub-basin (Moogarooga Deep) as well as offshore features such as the Cambridge Trough, Keep Inlet Sub-basin, Lacrosse Terrace and the Petrel Deep (Fig. 2).

The Petrel Sub-basin has had a complex geological history (Colwell & Kennard, 1996). It may have initially developed in the Early Cambrian as part of a failed rift system associated with the spreading of the Tethyan Ocean (Veevers, 1984). A major phase of upper-crustal extension occurred during the Late Devonian (?Givetian/Frasnian) to Early Carboniferous (Tournaisian), resulting in a complex rift architecture and the deposition of syn-rift sediments (Bonaparte Megasequence; Fig. 3). Post-rift (sag-phase) sediments were deposited throughout the Carboniferous, Permian and Early Triassic and generally thicken northwestwards.

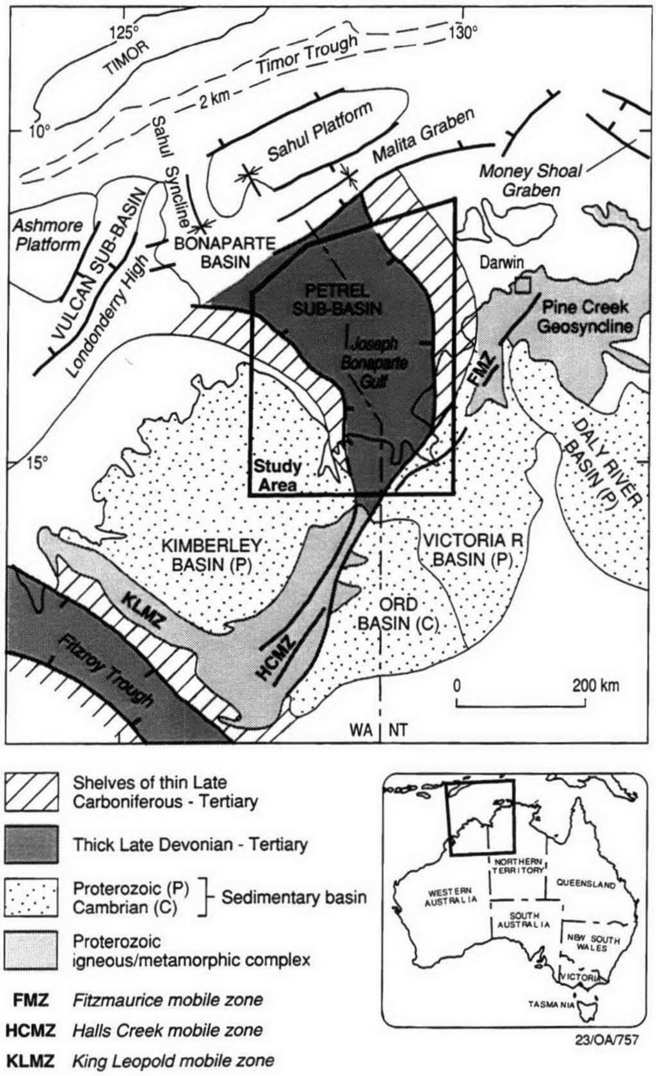


Figure 1 General location map. Base map after Gunn (1988).

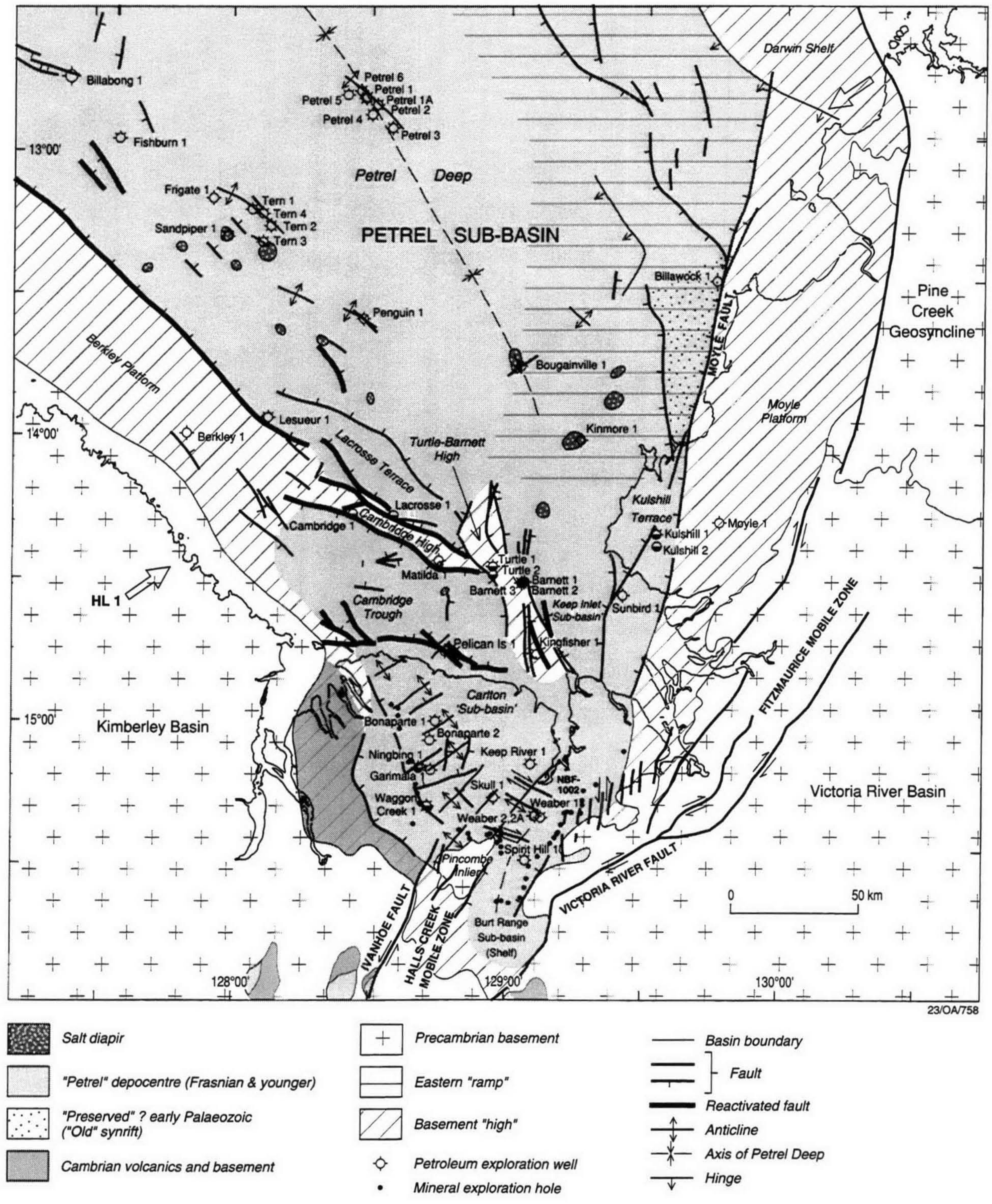


Figure 2 Structural elements of the Petrel Sub-basin and location of petroleum wells and mineral holes (from Colwell & Kennard, 1996).

Gentle folding of the basin fill occurred in the Middle Triassic-Early Jurassic during a period of uplift, inversion and erosion, known as the Fitzroy Movement. This was followed by deposition of sag-dominated Mesozoic and Cainozoic sediments, largely in the Petrel Deep (Colwell & Kennard, 1996).

The Petrel Sub-basin has been under shallow-marine conditions for much of its history into which varying proportions of terrestrial-derived material have been deposited. Climatic changes from warm tropical regimes in the Late Devonian and Early Carboniferous to glacial periods in the Permian have had a major influence on sedimentation styles. Evolutionary changes have also played an important role in the type of organic matter preserved in the sediments. Of particular note is the appearance of the gymnosperms in the Late Carboniferous (Namurian; *S. ybertii* assemblage). Prior to this event, the woody material in Late Devonian-Early Carboniferous sediments is thought to largely originate from arboreal (tree-form) lycopods.

1.2 Stratigraphy

A sequence stratigraphic approach was used in the AGSO Petrel Sub-basin Study to interpret well and seismic sections (Colwell & Kennard, 1996). Depositional sequences have been interpreted at a variety of scales to reflect both the tectonic evolution of the basin, and the development of the basin's petroleum systems (Fig. 3). The sequences defined within the prospective Late Devonian-Jurassic section, range from less than 100 to over 1000 m thick, and generally have a duration of between 1 and 20 million years. Within the non-prospective Cretaceous-Tertiary section (largely an overburden section for the basin's petroleum systems), only two supersequences have been interpreted, each of about 65-70 million years duration, and up to 1500 m thick.

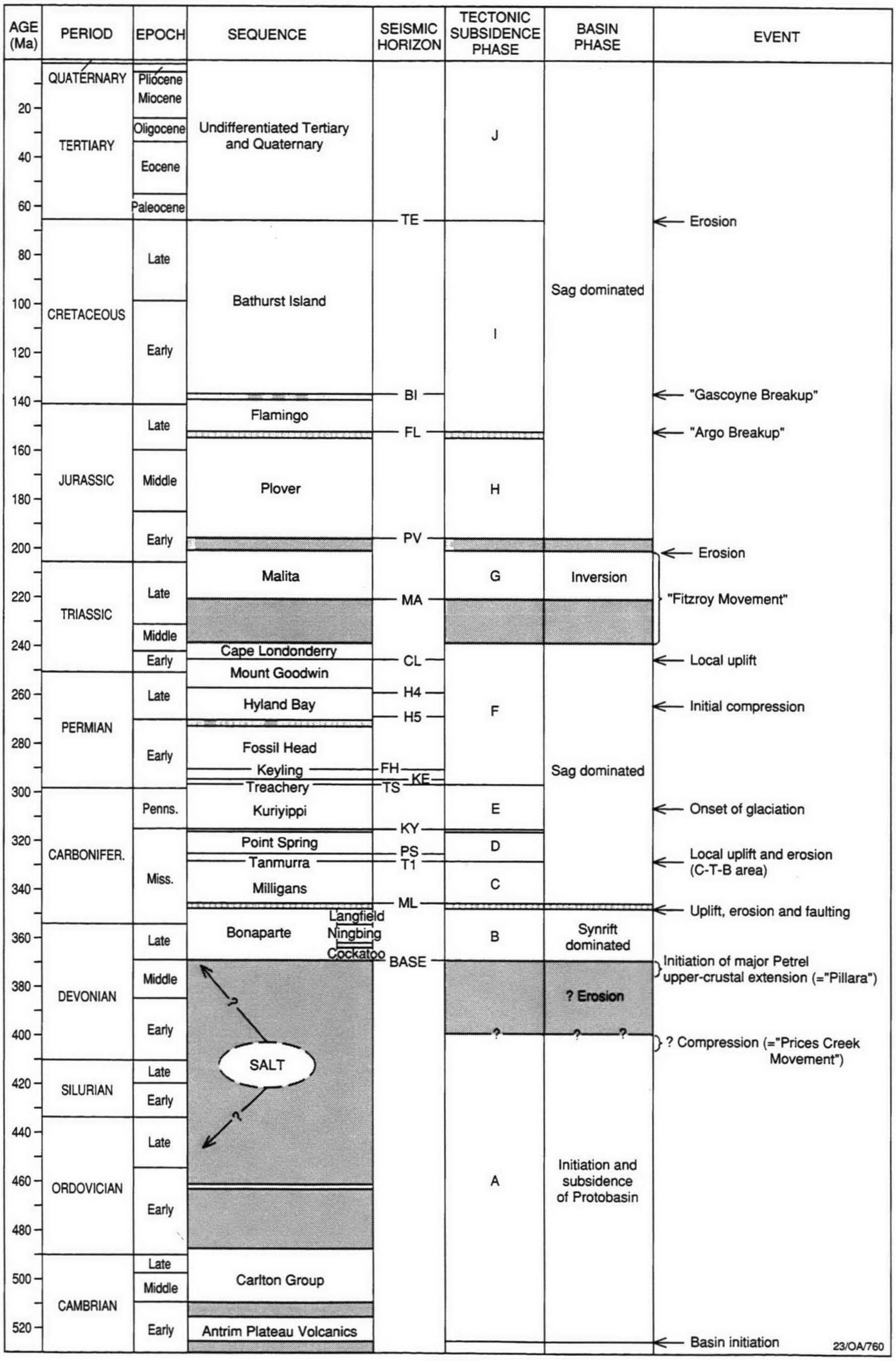


Figure 3 Stratigraphy of the Petrel Sub-basin.

1.3 Petroleum Occurrences

Evidence for the existence of significant hydrocarbons in the Petrel Sub-basin comes from a variety of sources including petroleum wells and mineral holes, and oil films in water wells. The most notable accumulations of gas in the sub-basin occur offshore at Petrel and Tern and onshore at Garimala-1, Keep River-1 and Weaber-1 and 2A, and oil flowed, albeit under jet pump, from Barnett-2 and Turtle-2. Details of the hydrocarbon shows encountered in each well are summarised on the composite logs in the AGSO Petrel Sub-basin Study Well Folio (Kennard, 1996a).

1.4 Petroleum Systems

Three petroleum systems are recognised in the Petrel Sub-basin, each named according to the ***proven (or probable) mature source rock*** that underpins them: Ningbing-Bonaparte Petroleum System (Larapintine 3), Milligans Petroleum System (Larapintine 4) and, Keyling-Hyland Bay Petroleum System (Gondwanan 1).

The delineation of these systems follows the concepts proposed by Bradshaw (1993) and Bradshaw *et al.* (1994) who defined a series of Australian-wide petroleum supersystems (*e.g.* Larapintine, Gondwanan) and systems (*viz.* Gondwanan 1 and 2). These supersystems are broader in scope than the original definition of a petroleum system proposed by Magoon and Dow (1991); namely, a mature source rock pod and all its generated hydrocarbons. The Australian supersystems are based on families of similar source rocks and their derived hydrocarbons that extend across many basins. In addition to shared source rocks, unifying structural, climatic and palaeogeographic factors have been emphasised in the recognition of Australian supersystems. Thus many of the systems are bounded by regional unconformities, and partly of fully equate with regional tectono-stratigraphic units (*e.g.*, a particular mega- or supersequence). Consequently, McConachie and co-workers (1995, 1996) attributed hydrocarbon occurrences within the Petrel Sub-basin to a particular petroleum system on the basis of age and present tectono-stratigraphic setting of the hydrocarbon accumulation, rather than the generative source rock *per se*.

The biomarker and isotopic analyses carried out in this study of existing oils and recent discoveries go someway towards defining these petroleum systems geochemically and are described chronologically in this report.

2. ANALYTICAL PROCEDURES

2.1 Samples

Oils and sediments from the Petrel Sub-basin that were selected for biomarker and isotopic studies are shown in Appendix A. Core and cuttings samples and oils from drill stem tests (DSTs) and repeat formation tests (RFTs) were obtained from the Core and Cuttings Laboratory, Petroleum Resources Branch, Bureau of Resource Sciences. Additional oils were donated by the petroleum industry (Western Mining Corporation and Amity Oil N.L.). Geochemical data (TOC and Rock-Eval pyrolysis) from ORGCHEM (AGSO's geochemical database; see Enclosure) was reviewed to identify possible source rocks.

Following sampling and further screening by TOC analysis and Rock-Eval pyrolysis, 16 mudstones from the Late Devonian Ningbing Supersequence and Early Carboniferous Milligans and Tanmurra Supersequences, and two samples from the Early Permian Keyling Supersequence were selected for oil-source rock comparisons. The Turtle-1, Turtle-2, Barnett-2, Petrel-4 and Waggon Creek-1 DST and RFT petroleum samples were supplemented by oil stains extracted from cores and cuttings in the wells Barnett-1, Cambridge-1, Lacrosse-1, Milligans-1 and Ningbing-1.

2.2 Preparation

The analytical procedures used in this report are presented in Appendix B1.1 to B1.6.

The rock samples were powdered and the soluble organic matter was extracted with organic solvents in Soxhlet apparatus. The extractable organic matter (EOM) and the oils were separated into saturated hydrocarbons (alkanes), aromatic hydrocarbons and a polar (non-hydrocarbon) fraction by standard liquid chromatography on silica gel. The alkane fraction was examined by gas chromatography in which the hydrocarbons were detected with a flame ionisation detector (FID). The on-column injection technique was used. The detailed instrumental parameters are documented in Appendix B1.4. The internal standard 3-methylheneicosane (AC22; 10 μg) was added prior to analysis.

An aliquot of the saturated hydrocarbon fraction was separated into *n*-alkane (silicalite adduct: SA) and branched/cyclic alkane (silicalite non-adduct: SNA) fractions on silicalite molecular sieve. The branched cyclics were eluted directly from the sieve with *n*-pentane and the *n*-alkane fraction was recovered by partitioning into *n*-pentane after destruction of the sieve matrix with hydrofluoric acid.

Biomarker distributions of the branched/cyclic alkane (SNA) fraction were determined by gas chromatography-mass spectrometry in the metastable reaction monitoring mode (MRM GC-MS) as detailed in Appendix B1.5. The concentrations of specific biomarker compounds were measured with reference to deuterated sterane internal standards (d_3 5α(H)-methylcholestane and d_4 5α(H)-ethylcholestane 20R; Chiron Laboratories, Norway; 100 ng per mg saturated hydrocarbons).

Aromatic maturity parameters, including the methylphenanthrene index (MPI-1), were measured by routine GC-MS in the selected ion monitoring mode (SIM GC-MS) and are documented in Appendix B1.6.

3 SOURCE ROCK ANALYSIS

Geochemical (TOC and Rock-Eval pyrolysis) and organic petrological data obtained from well completion reports, specialised studies (*e.g.* Robertson Research, 1979, 1981, 1987 and Analabs, 1985) and in-house analyses (see Enclosure) were collated in order to evaluate the hydrocarbon potential of the Petrel Sub-basin. These data have been summarised for each *stratigraphic sequence* in Appendix A (Tables A1 and A2), are depicted in Figures 4 to 21 as plots of Tmax versus hydrogen index (HI), and are presented on the well composites in the AGSO Petrel Sub-basin Well Folio (Kennard, 1996a). An explanation of Rock-Eval pyrolysis parameters and the criteria used in this study to define a source rock can be found in Tables A3 and A4, respectively.

For a sediment to have hydrocarbon potential, the minimum total organic carbon (TOC) content for a carbonate is taken to be 0.2 % and 0.5 % for a clastic sediment (Table A4), although TOC's in excess of 1.0 % are typically required if NW Shelf sediments are to have any significant petroleum potential. Immature samples often have poorly resolved S_1 and S_2 peaks, therefore Tmax values less than 380 °C were excluded from the compilation. Likewise, samples with small S_2 peaks (< 0.2 kg hydrocarbons/tonne) were considered to be unreliable and hence such samples have been omitted. In order to prevent migrated oil and contaminants interfering with the identification of source rocks, samples with anomalously high production indices (PI) were excluded from the source rock summary data (Table A1), the Tmax versus HI plots, and the well composite plots in the Well Folio. The cut off values applied were as follows; $PI \leq 0.1$ for immature sediments ($Rv \leq 0.5$ %), $0.1 > PI \leq 0.25$ for early mature sediments ($0.5 > Rv \leq 0.8$ %), and $0.25 > PI \leq 0.4$ for mature sediments ($0.8 > Rv \leq 1.2$ %). Hence, only a proportion of the total number of analyses carried out on sediments from the Petrel Sub-basin are shown in Figures 4 to 21.

A brief summary of source richness (TOC, potential yield), source quality (oil- or gas-prone) and kerogen type (determined from kerogen concentrates and maceral assemblages) is given in this report for each sequence. Kerogen concentrates are viewed in transmitted light and under blue-violet light whereas maceral studies are carried out on samples mounted in polished blocks and examined under reflected light as well as blue-violet-light. A definition of macerals and their origins are given in Table A5. In this study, a source rock has been assumed to be gas-prone if the hydrogen index is below a minimum of 150 $mgS_2/gTOC$, condensate-prone when the HI is between 150 and 200 $mgS_2/gTOC$ and oil-prone with some gas at higher values. Good oil-prone source rocks with HI > 300 $mgS_2/gTOC$ are a rare occurrence in the Petrel Sub-basin.

An assessment of thermal maturity was made using a combination of Tmax, production index, vitrinite reflectance (Rv), fluorescence alteration of multiple macerals (FAMM; courtesy of R. Wilkins & N. Russell, CSIRO), thermal alteration index (TAI), spore colouration index (SCI) and conodont alteration index (CAI). These data were entered into WinBury V2 allowing comparison of modelled maturity trends between wells, and extrapolation of maturity for sequences below the total depth (TD) drilled (Kennard, 1996b). The degree of thermal maturity required for the generation of hydrocarbons depends on the type of organic matter present in the source rock. The Palaeozoic succession of the Petrel Sub-basin comprises largely of shallow marine and coastal plain sediments which contain varying proportions of indigenous sapropellic material (disseminated remains of bacteria, algae, acritarchs, dinoflagellates *etc.*) and allochthonous land-plant-derived debris. Hence, the predominant type of hydrocarbon-prone organic matter within these sediments ranges from Type II to Type III kerogen. Higher maturities are usually required for the generation and expulsion of hydrocarbons from hydrogen-poor Type III kerogens than for Type II kerogens, thus:

Kerogen Type	Rv oil window	Tmax oil window
Type III	0.45-1.2 %	420-460 °C
Type II	0.55-1.3 %	435-470 °C

Using kerogen kinetic data and maturation modelling, refinements were made to the oil window for mid-Milligans (Rv = 0.7-0.9 %) and Keyling-Hyland Bay (Rv = 0.65-1.0 %) source units (Kennard, 1996b).

The peak oil window was taken to correspond to vitrinite reflectances between 0.8 and 0.9 %, peak wet gas at Rv = 1.2 % and peak dry gas at Rv = 1.5 %. A minimum temperature of 170 °C (Rv > 1.2 %) was assumed to be required for the cracking of oil to gas. Sediments in which oxidised organic material (inertinite) or Type IV kerogen is prevalent are considered to be a source of methane and carbon dioxide at high thermal maturities, *i.e.* within the dry gas window (Rv = 1.4-4 %).

3.1 Hydrocarbon Potential of Palaeozoic Supersequences

In this section the hydrocarbon potential of each Palaeozoic sequence is discussed in detail. A definition of each of the supersequences and sequences referred to below can be found in the AGSO Petrel Sub-basin Summary Report (Colwell & Kennard, 1996; Chapter 4).

Late Devonian Cockatoo Supersequence

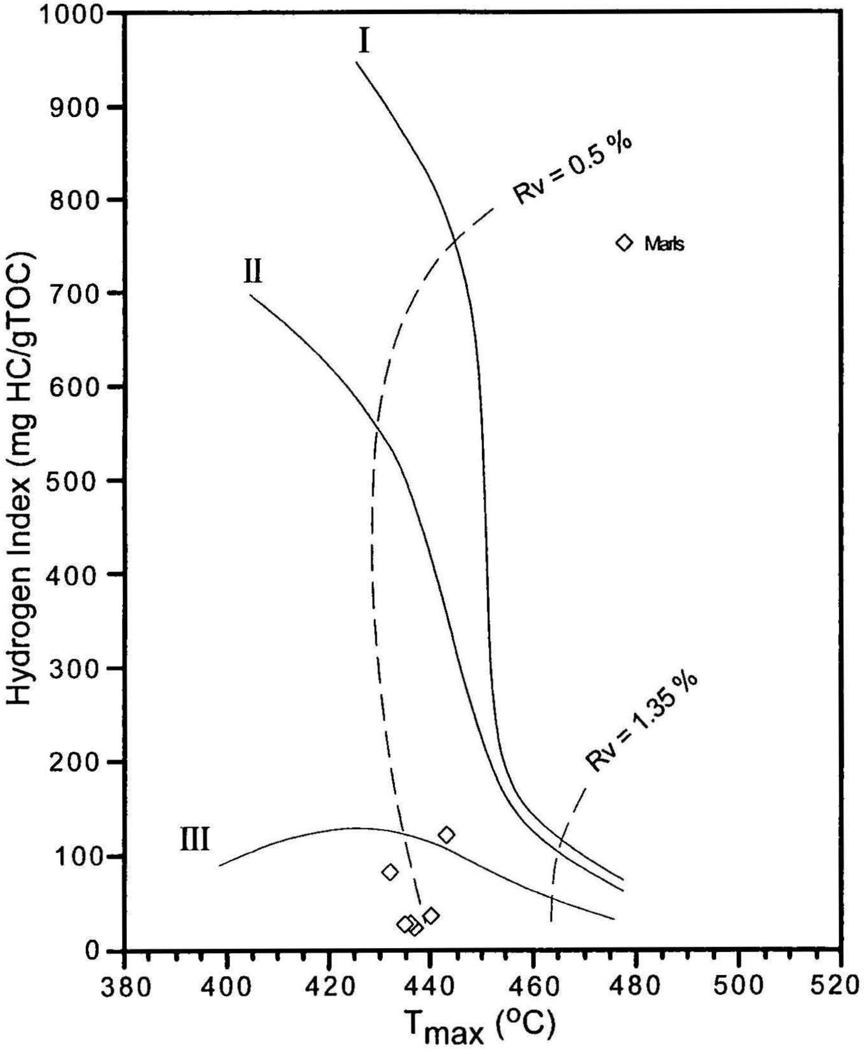
The sediments assigned to the Late Devonian (Frasnian) Cockatoo Supersequence are largely known from outcrop in the southern and western onshore portions of the sub-basin. However, the shallow marine carbonate and argillaceous sediments intersected at Bonaparte-1, Keep River-1, Kulshill-1, Ningbing-1 and Spirit Hill-1 are probable equivalents of this supersequence. Appraisal of the source potential of this supersequence could not be effectively carried out at Bonaparte-1, Kulshill-1 and Keep River-1 since these sediments lie within, and beyond in the latter well, the dry gas maturity zone. At Ningbing-1 this supersequence is presently within the peak oil window (CAI = 1.5-2; pers. comm., B. Nicoll, AGSO, December 1995). Although the organic richness of the carbonates at Ningbing-1 appears to be fair (mean TOC = 0.3 %), these moderate values are most likely due to oil staining, interpreted from low Tmax values (mean Tmax = 423 ^{o}C) and high production indices (PI = 0.6-2.2). Since the hydrogen indices are very low (mean HI = 39 mgS_2/gTOC), this supersequence at Ningbing-1 is not considered to be a source of hydrocarbons.

Late Devonian Ningbing Supersequence

The Late Devonian (Famennian) Ningbing Supersequence crops out in the onshore portion of the sub-basin, notably as an exhumed reef complex in the Ningbing Ranges. The reef complex comprises platformal, reef-margin and slope carbonates, and basinal shales with minor pelagic and detrital carbonates. This supersequence is penetrated by petroleum exploration wells in the Carlton and Keep Inlet Sub-basins and on the Kulshill Terrace. With the exception of Ningbing-1 and Spirit Hill-1, the Ningbing Supersequence is mature-overmature at Bonaparte-1, Garimala-1, Keep River-1 and Kulshill-1, precluding evaluation of their hydrocarbon potential in these wells.

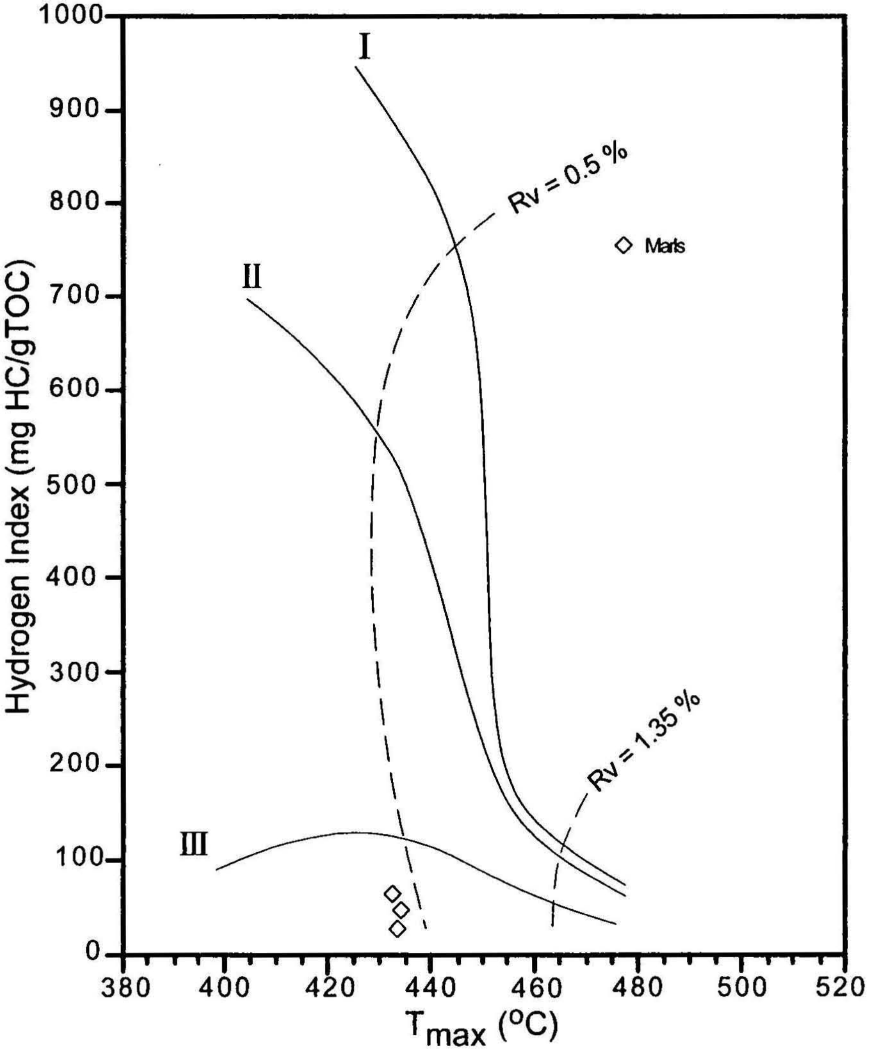
The limestones encountered in Ningbing-1 have no hydrocarbon source potential (mean TOC = 0.05 %). In this study, organic geochemical analyses of the Ningbing Supersequence are limited to Spirit Hill-1 (Fig. 4) between 613.5 and 752 m depth (see Well Folio, Plate 28). The maturity of the Ningbing Supersequence at Spirit Hill-1 is not well constrained being estimated from Rock-Eval parameters (range Tmax = 432- 443 ^{o}C; mean PI = 0.17) which indicate that these sediments are within the oil window.

Figure 4: Rock-Eval pyrolysis data for the Late Devonian (Famennian) Ningbing Supersequence.



Data compiled from Spirit Hill-1.

Figure 5: Rock-Eval pyrolysis data for the earliest Early Carboniferous Langfield Supersequence.



Data compiled from Spirit Hill-1.

The organic richness of these sediments at Spirit Hill-1 is good (mean TOC = 1.1 %) but their generative potential is poor (mean S_1+S_2 = 0.8 kg hydrocarbons/tonne). The low hydrogen indices (HI = 59 mgS_2/gTOC) indicate that overall these sediments are at best dry gas-prone containing Type III/IV kerogen (Fig. 4). Examination of kerogens from the most organic-rich sediments, Spirit Hill-1 670-671 m, shows that the organic matter is composed of cuticles and fern spores with lesser quantities of fragmented, possibly lycopod-derived, 'woody' material.

Early Carboniferous Langfield Supersequence

The Early Carboniferous (Tournaisian) Langfield Supersequence crops out on the Burt Range Shelf (Burt Range Formation, Enga Sandstone, Septimus Limestone and Zimmerman Sandstone) and has been intersected in many mineral exploration holes and several petroleum wells (Bonaparte-1 and 2, Garimala-1, Keep River-1, Spirit Hill-1 and Weaber-1). Little comment can be made on this supersequence since it is overmature at Bonaparte-1 and 2 and Keep River-1. Although it is only marginally mature at Spirit Hill-1, it has no hydrocarbon potential here as shown in Figure 5.

Minor oil and gas shows within the Cockatoo, Ningbing and Langfield Supersequences (Bonaparte Megasequence) at Bonaparte-1, Garimala-1, Keep River-1, Kulshill-1 and Ningbing-1 imply that some source facies may be developed locally within these Late Devonian-Early Carboniferous supersequences. From these limited analyses, it would appear that the dry gas accumulations at Garimala-1 is probably sourced from the marine basinal mudstones of the 'Bonaparte Formation' and equivalents, and that the carbonate facies have little or no source potential. Alternatively, these hydrocarbons may have been sourced from the Milligans Formation (Laws, 1981; Garside, 1983).

Early Carboniferous Milligans Supersequence

Dark grey marine mudstones of the Early Carboniferous (latest Tournaisian-late Visean) Milligans Supersequence occur both onshore and offshore in the Petrel Sub-basin, with the main depocentres occurring in the Carlton and Keep Inlet Sub-basins, the Cambridge Trough, and to the north of the Turtle-Barnett High (Figs. 2 and 6). The Milligans Supersequence has variable source richness (TOC = 0.5-4 %; mean TOC = 1.2 %; mean S_1+S_2 = 1.1 kg hydrocarbons/tonne). TOC profiles and sequence stratigraphic analysis indicates that the richest organic intervals penetrated in petroleum exploration wells generally occur in the upper portion of a second order transgressive systems tract near the middle of the Milligans Supersequence (Sequence Mill A5-A7, Well Folio, Kennard, 1996a). Overall, source quality is poor (mean HI = 57 mgS_2/gTOC: Fig. 7) being indicative of dry gas-prone Type III/IV kerogen. The low potential yields and low hydrogen indices of the mudstones may be explained by a combination of poor quality organic matter and high thermal maturity.

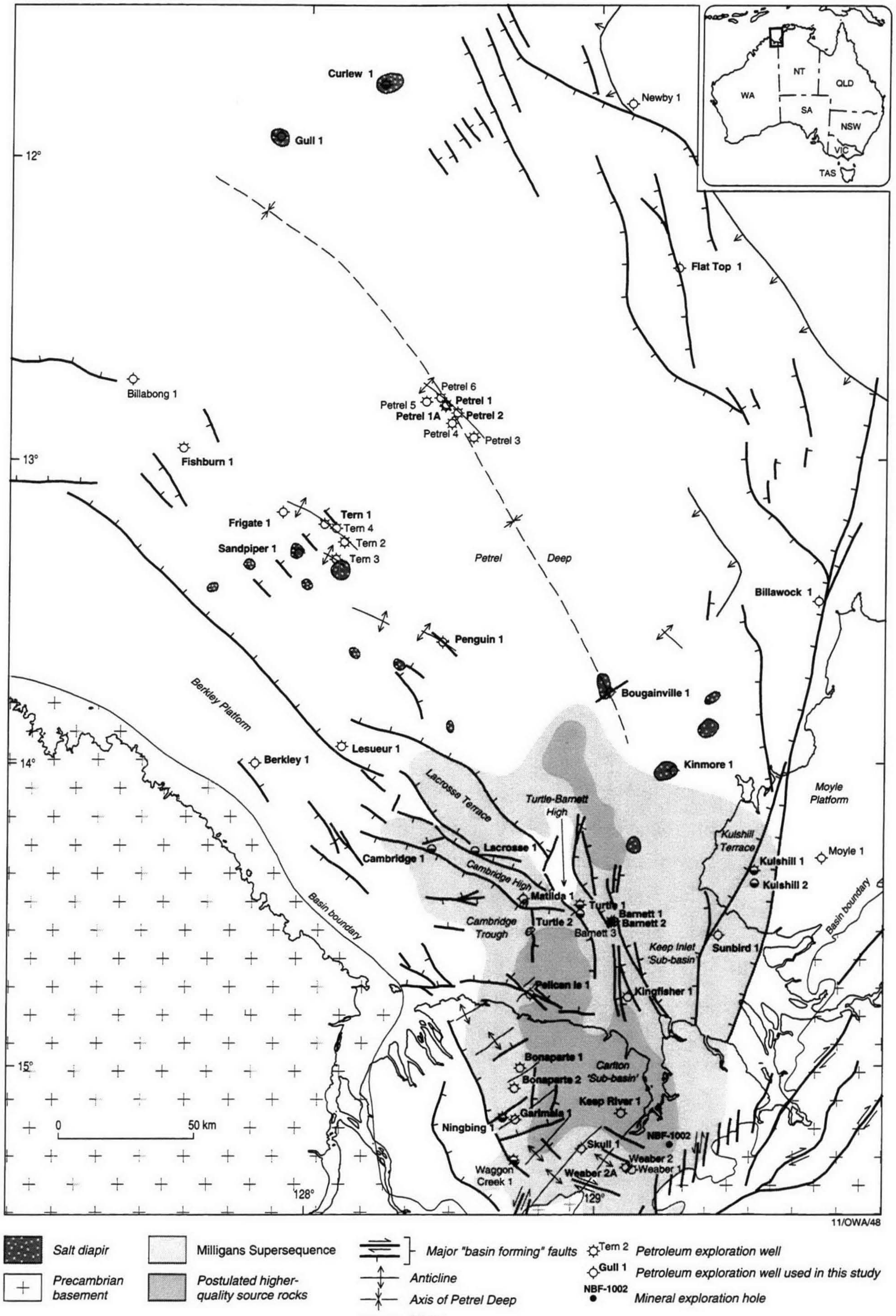


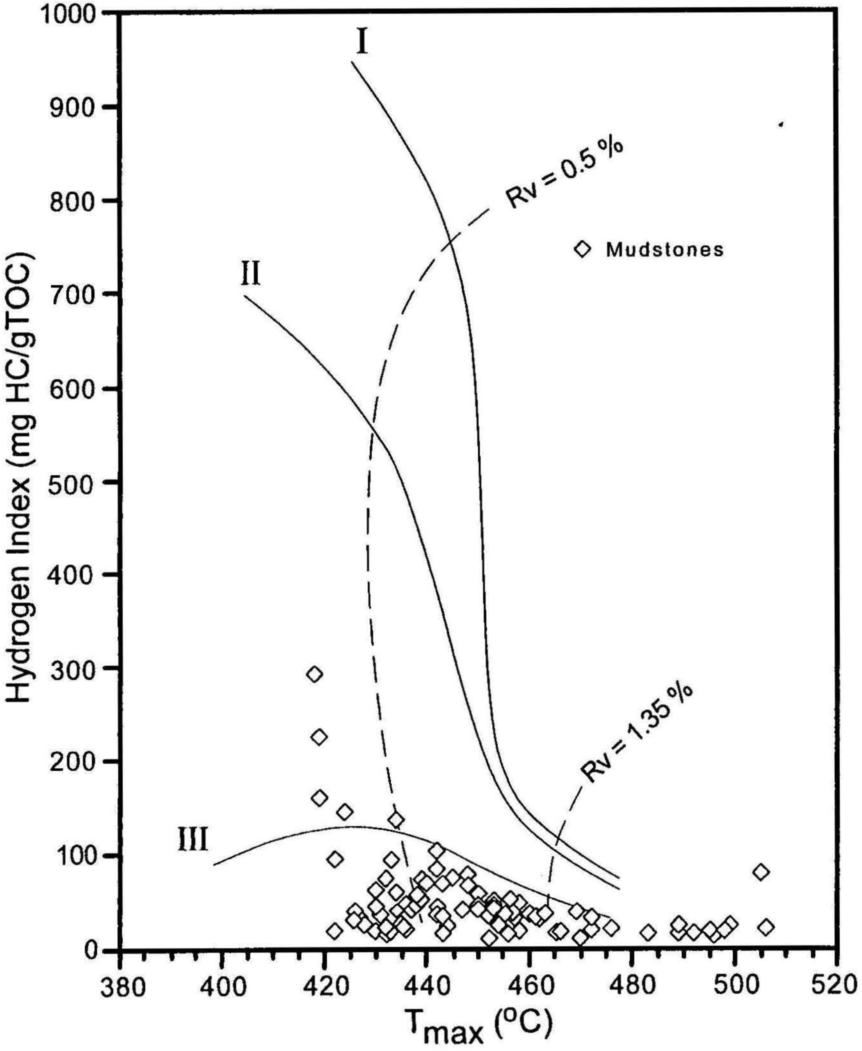
Figure 6 Distribution of the Milligans source rock unit.

The maturity of the Milligans Supersequence is fairly well constrained in the petroleum wells by a combination of maturity-sensitive parameters including vitrinite reflectance, FAMM, TAI, SCI and CAI. The most prospective mid-Milligans source interval lies within the oil and gas maturity zone at Barnett-2, Bonaparte-1, 2, Garimala-1, Kingfisher-1, Turtle-1 and 2. In the Keep-River area of the Carlton Sub-basin and Keep Inlet Sub-basin, the mid-Milligans source interval is over mature.

Maceral analyses of the Milligans Supersequence, obtained from the Kingfisher-1, Skull-1, Turtle-1 and Weaber-1 well completion reports, show that over much of the Carlton and Keep Inlet Sub-basins the dispersed organic matter consists predominantly of inertinite (oxidised woody tissue) with lesser quantities of liptinite (liptodetrinite, sporinite and cutinite) and reworked vitrinite. Trace quantities of alginite in the form of lamellae (lamalginite) and algal bodies (telalginite) are observed intermittently throughout the supersequence. Rare coaly lenses occur in which vitrinite is the predominant maceral with lesser quantities of inertinite and minor exinite. Also worthy of note is that the combination of abundant Type IV kerogen and high maturity means that this sequence has the potential to generate carbon dioxide which may contribute to the development of secondary porosity in under- and overlying carbonates.

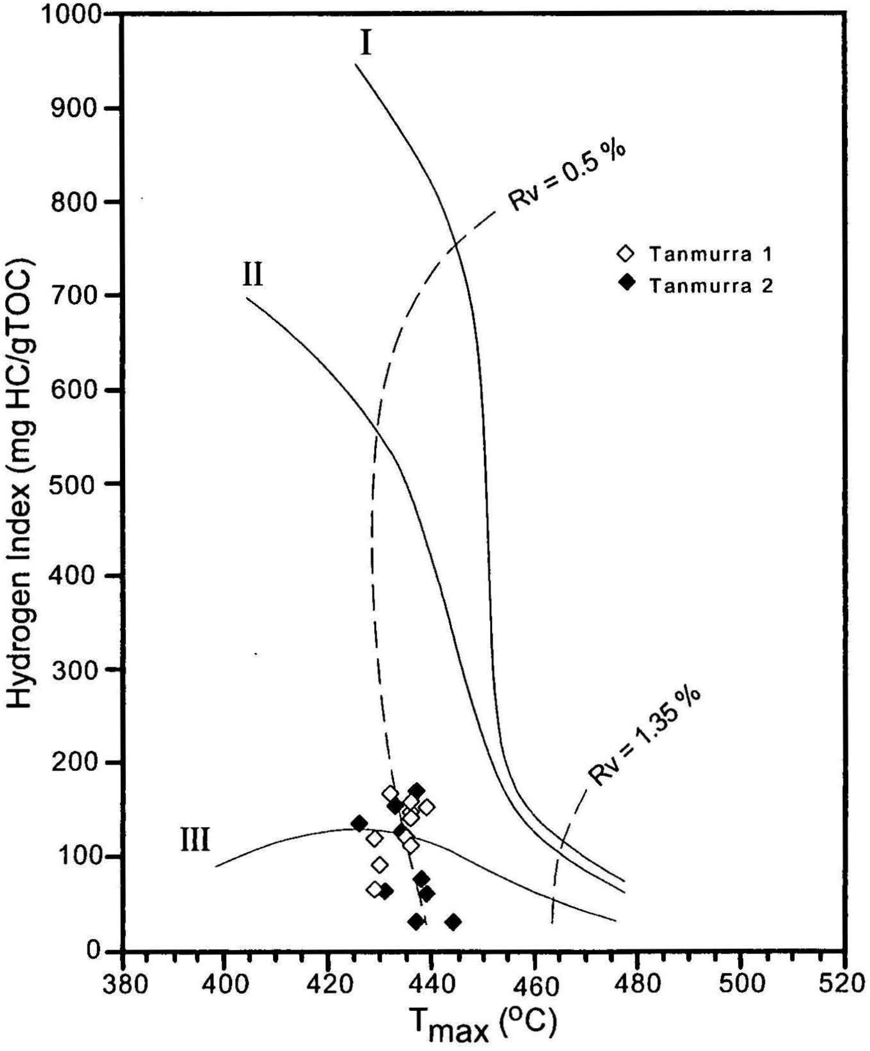
Palynological evaluation of the Milligans Supersequence from Barnett-1 and 2, Cambridge-1, Turtle-1 and 2 (Foster, 1984, 1985a, b, 1990a, b) complement the maceral analyses. The kerogen is bimodal, comprising of very fine amorphous debris (amorphogen) and larger, well sorted, equidimensional, woody fragments (hylogen) and comminuted miospores, pollen and leaf cuticles (phyrogen). Preservation of the organic matter is poor and degradation by microbial activity is common. Some samples contain acritarchs, tasmanitids and scolecodont (worm jaw) fragments which are indicative of open marine conditions whereas others contain spinose acritarchs (*Veryhachium* and *Michrystridium* sp.) more commonly associated with brackish water. Filaments, of probably cyanobacterial origin, were identified in Barnett-2 (core 2, 2557 m: pers. comm., C. B. Foster, AGSO, June 1996). These remains of marine biota are enriched in hydrogen but they are unlikely to have any hydrocarbon potential since they make up an insignificant proportion of the total kerogen. The depositional environments interpreted from these analyses are that of open marine to restricted or marginal marine (lagoonal) settings which supported colonies of algae into which was transported varying proportions of wind- and water-borne land-plant debris was transported. Anoxic conditions are indicated by an abundance of pyrite, both as cubes and framboids, in the sediments.

Figure 7: Rock-Eval pyrolysis data for the Early Carboniferous Milligans Supersequence.



Data compiled from Barnett-2, Bonaparte-1, Bonaparte-2, Cambridge-1, Keep River-1, Kingfisher-1, NBF1002, Pelican Island-1, Spirit Hill-1, Turtle-1, Turtle-2 and Skull-1.

Figure 8: Rock-Eval pyrolysis data for the Early Carboniferous Tanmurra Supersequence.



Data compiled from Barnett-1, Barnett-2, Cambridge-1, Kingfisher-1, Lacrosse-1, Lesueur-1 and Skull-1.

In contrast to the findings in the petroleum wells, the Milligans Supersequence in shallow mineral exploration holes around the margin of the basin (Fig. 2) are immature to marginally mature with vitrinite reflectance values between 0.44 and 0.68 %, with the latter value being a maximum since reworked vitrinite (detrovitrinite) was measured (le Tran *et al.*, 1980; Lacrampe *et al.*, 1981; O'Leary, 1987). CAI values range from 1 to 1.5 (pers. comm., R. Nicoll, AGSO, December 1995) and TAI values are around 2+ (pers. comm., C. B. Foster, AGSO, March 1996; see Enclosure). Moreover, in some of these mineral holes, the Milligans mudstones appear to contain a different type of kerogen. Mudstones analysed from the mineral well NBF1002 (Fig. 2) have good oil and gas-prone source potential with mean total organic carbon contents of 3 % and mean hydrogen indices of 206 mgS_2/gTOC. Kerogen concentrates are dominated by relatively thick organic tissue which may contain embedded pyrite framboids and/or small coccoid bodies (> 5 μm). The origin of this organic matter is unknown. Other organic matter includes rare woody debris (< 1 %), fern and lycopod spores (< 5 %), and very rare algal (tasmanitid-like) cysts. Scolecodont fragments indicate a shallow marine depositional environment. Current hydrocarbon potential of the kerogen is good to fair, as indicated by the high intensity and yellow colour of the organics under blue-violet fluorescence.

From the above analyses it can be determined that the Milligans mudstones were deposited in an anoxic, possibly restricted, marine setting with algae being the main contributors of indigenous organic matter, albeit often in very low concentrations. Highly oxidised and well sorted land-plant debris was transported into this depositional setting. Any liquid hydrocarbon potential would arise from the algal and bacterial components of the kerogen, with the terrestrial-derived organic matter being gas-prone.

From the compilation of Rock-Eval pyrolysis data and interpretations made in conjunction with maceral and kerogen analyses it is suggested that the gas accumulations within intra-Milligans reservoirs at Bonaparte-2, Keep River-1, Weaber-1 and Weaber-2A and gas shows at Bonaparte-1, Kulshill-1 and Skull-1 were sourced by the relatively widespread Milligans marine mudstones containing mixed marine and terrestrially-derived hydrogen-poor Type III/IV kerogen. In contrast, the oil produced from Barnett-2 and Turtle-2 and oil shows throughout the Early-Late Carboniferous and Permian sequences at Barnett-1, Cambridge-1, Turtle-1 and onshore within the Milligans Supersequence at Spirit Hill-1 and Waggon Creek-1, are most probably sourced from localised algal- and bacterial-enriched organic matter.

Early Carboniferous Tanmurra Supersequence

The latest Visean Tanmurra Supersequence comprises two sequences (Tanmurra 1 and 2) which incorporates the 'Upper Milligans Turtle Member' at Barnett-2 and the 'Medusa Beds' at Lacrosse-1. Shelf carbonates and clastics are penetrated on the Lacrosse Terrace, Cambridge and Turtle-Barnett Highs, in the Carlton and Keep Inlet Sub-basins and on the Kulshill Terrace. From seismic interpretations, this supersequence thickens markedly to the north of the Turtle-Barnett High. Therefore, the samples taken around the basin may not be representative of the total succession, and hence the hydrocarbon potential of this supersequence remains largely unknown.

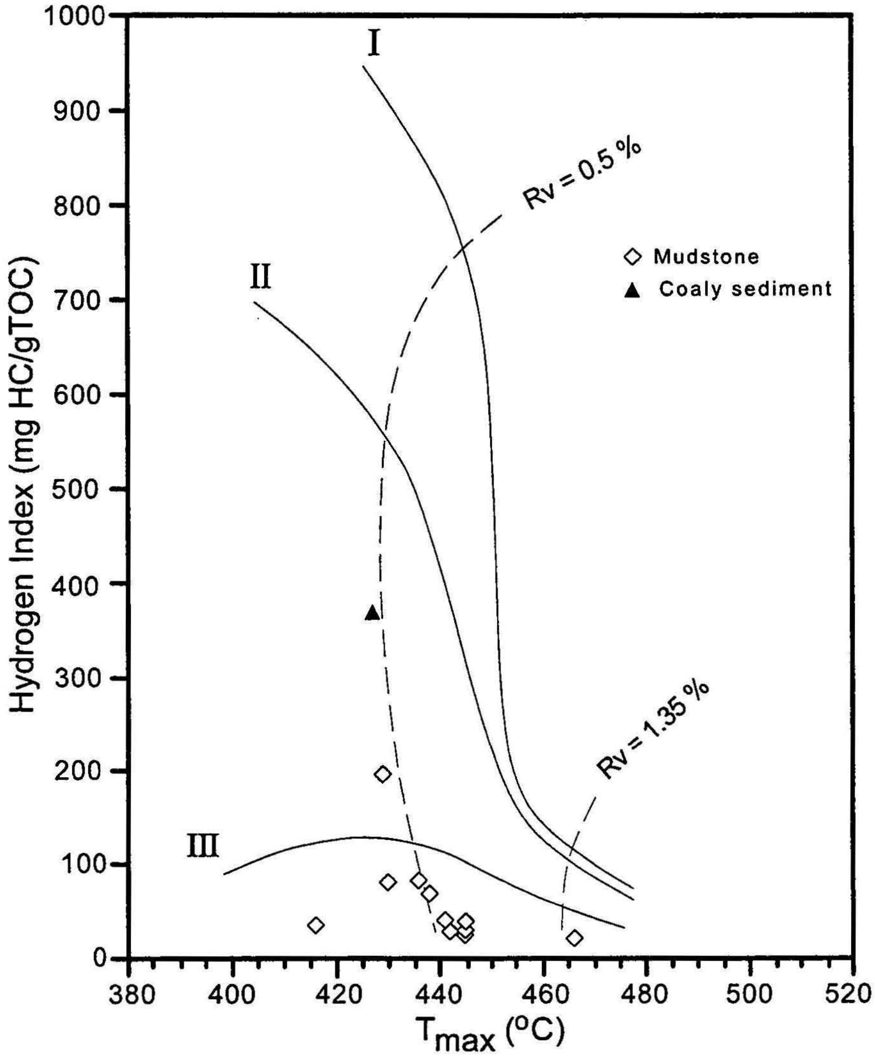
The Tanmurra Supersequence ranges from immature in the Carlton Sub-basin, marginally mature on the Turtle-Barnett High, to mature in the Keep Inlet Sub-basin, Kulshill and Lacrosse Terraces. Source rocks were only identified in four (Barnett-2, Cambridge-1, Kingfisher-1 and Skull-1) of the twelve wells that penetrate this sequence because of the overall low total organic carbon contents (< 0.5 %). However, even the most organic-rich mudstones have only poor source richness (mean TOC = 0.8 %: mean S_1+S_2 = 1.3 kg hydrocarbons/tonne), containing predominantly Type III kerogen (Fig. 7; Table 1A) which has the potential to generate gas and possibly minor condensate.

The dispersed organic matter throughout both the Tanmurra Supersequence consists predominantly of inertinite with lesser or equal amounts of liptinite (lamalginite, liptodetrinite, sporinite, resinite and cutinite) and vitrinite is rare. Even when liptinite makes up to 50 % of the total maceral assemblage no significant increase in the liquid hydrocarbon potential is observed with hydrogen indices between 65 and 136 mgS_2/gTOC being consistently recorded. Maceral analyses undertaken on the Tanmurra 2 Sequence at Barnett-1, Kingfisher-1, Skull-1 and Turtle-1 show that the coaly shales contain a similar proportion of vitrinite and inertinite with minor quantities of liptinite.

Early Carboniferous Point Spring Supersequence

The Namurian Point Spring Supersequence is penetrated along the Lacrosse Terrace, Cambridge and Turtle-Barnett Highs, in the Carlton and Keep Inlet Sub-basins and on the Kulshill Terrace. In the onshore portion of the Petrel Sub-basin, this supersequence consists of course fluvio-deltaic clastics and potential source rocks are not present. Fine grained pro-delta and distal distributary bay sediments are recognised at Kulshill-1 and in the offshore wells, but they have poor organic richness (mean TOC = 0.8 %) with overall poor source richness and source quality (mean S_1+S_2 = 0.6 kg hydrocarbons/tonne; mean HI = 59 mgS_2/gTOC; Fig. 9). By and large, the dispersed organic matter in this supersequence comprises immature gas-prone Type IV kerogen.

Figure 9: Rock-Eval pyrolysis data for the Early Carboniferous Point Spring Supersequence.



Data compiled from Barnett-2, Cambridge-1, Kulshill-1, Lacrosse-1 and Matilda-1.

The dispersed organic matter at Cambridge-1, Matilda-1 and Turtle-1 is predominantly inertinite with lesser or equal quantities of disseminated liptinite (liptodetrinite, sporinite, cutinite) and rare vitrinite. The only samples to have any petroleum potential are two samples from Barnett-2 which exhibit hydrogen indices in excess of 190 $mgS_2/gTOC$. However, these are immature for hydrocarbon generation. The Point Spring Supersequence is immature in the Carlton Sub-basin, marginally mature on the Turtle-Barnett High and mature in the Keep Inlet Sub-basin and on the Kulshill and Lacrosse Terraces. Oil shows occur throughout the sandstone reservoir at Kulshill-1.

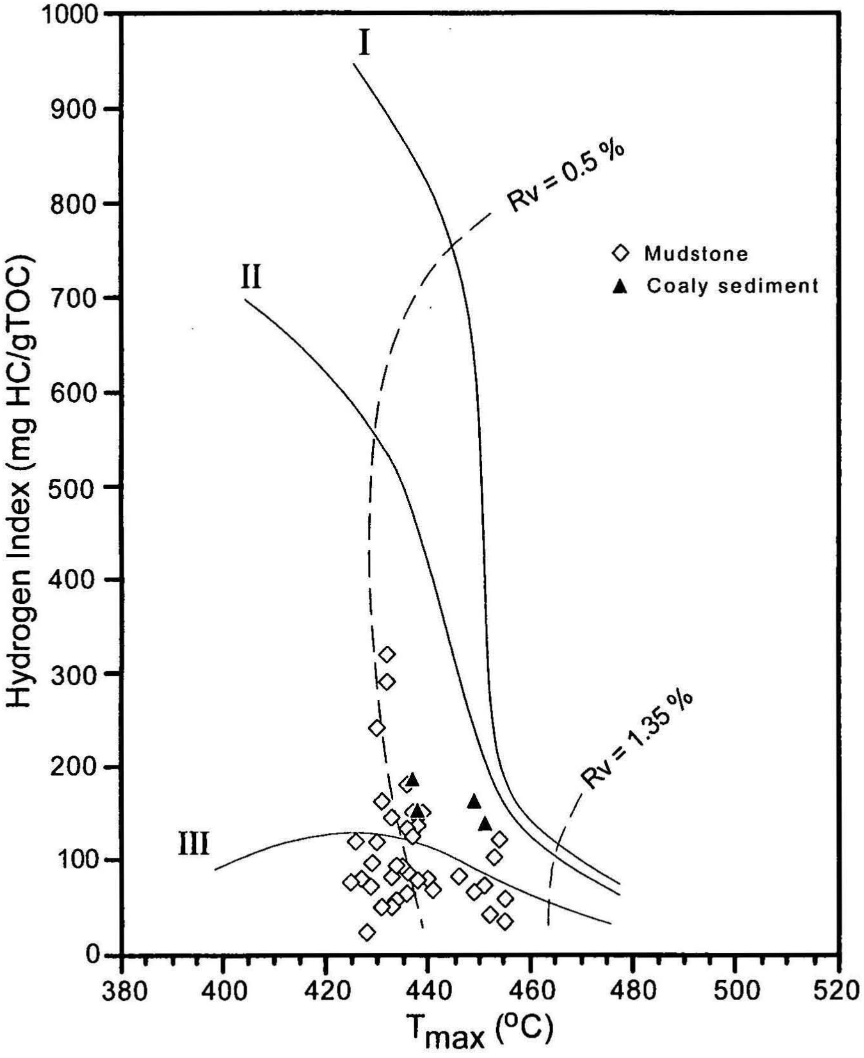
Late Carboniferous-Early Permian Kuriyippi Supersequence

The Late Carboniferous/Early Permian (Westphalian-Asselian) Kuriyippi Supersequence comprises a variety of sediments including braided river deposits (sandstones and mudstones), glacial sandstones and conglomerates. It is penetrated by wells along the Eastern Ramp, in the Keep Inlet and Carlton Sub-basins and on the Cambridge and Turtle-Barnett Highs. However, the sediments are considerably thinner (maximum 1 km) in these areas compared with the main depocentre lying to the far north of the Petrel Deep where it thickens to over 8 km. The majority of the organic matter in this supersequence comprises immature gas-prone Type III/IV kerogen (Fig. 10) which is in agreement with the inertinite-dominated maceral assemblages. At Barnett-1 there appears to be a general increase in the amount of liptinite preserved but the source quality remains poor and gas-prone (HI = 80 $mgS_2/gTOC$). Some improvement in the organic richness (maximum TOC = 5 %) and source quality (maximum HI = 321 $mgS_2/gTOC$) of the mudstones is observed both on the Eastern Ramp and in the Keep Inlet Sub-basin where condensate and oil-prone organic matter is present. Thin coals are developed at Kulshill-1 and Flat Top-1, being marginally mature and mature for hydrocarbon generation in the respective wells. Therefore, it is suggested that this supersequence may have the potential to generate gas and minor liquids in the Petrel Deep.

Early Permian Treachery Sequence

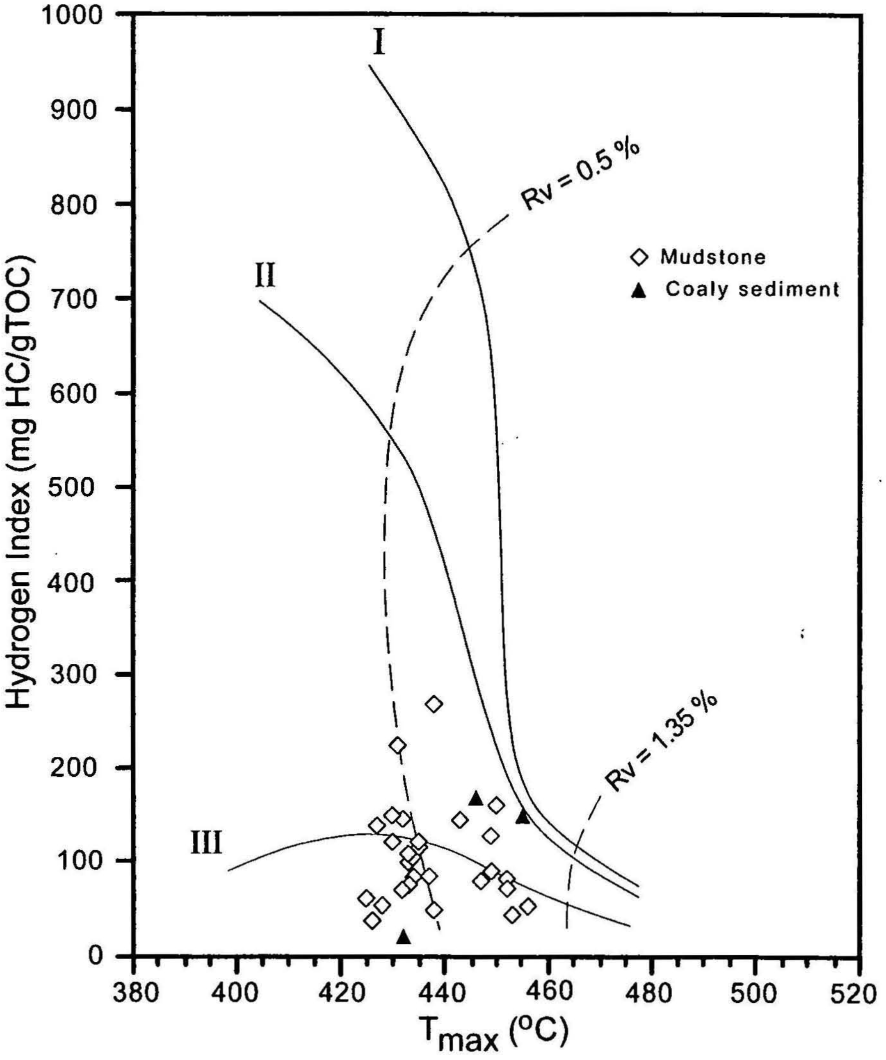
The Early Permian (Asselian) Treachery Sequence is largely composed of glacial sediments (tillites, diamictites, conglomerates) deposited within lacustrine and shallow marine environments. It has not been penetrated in the Petrel Deep where it is thickest but the sediments in the Kulshill Terrace depocentre are organically lean with the predominant Type III/IV kerogen having little hydrocarbon potential. At Flat Top-1 and Kinmore-1, organic-rich mudstones and coals containing Type II/III kerogen are identified (Fig. 11) and depending on their net effective thickness they could have significant hydrocarbon generating capability. This sequence is marginally mature on the Kulshill Terrace and Eastern Ramp. Oil staining occurs particularly in wells drilled on the Kulshill and Lacrosse Terraces and Cambridge and Turtle-Barnett Highs.

Figure 10: Rock-Eval pyrolysis data for the Late Carboniferous Kuriyippi Supersequence.



Data compiled from Billawock-1, Cambridge-1, Flat Top-1, Kingfisher-1, Kinmore-1, Kulshill-1, Lacrosse-1, Matilda-1 and Turtle-1.

Figure 11: Rock-Eval pyrolysis data for the Early Permian Treachery Sequence.



Data compiled from Barnett-1, Berkley-1, Flat Top-1, Kingfisher-1, Kinmore-1, Lacrosse-1 and Matilda-1.

Early Permian Keyling Supersequence

The Early Permian (late Asselian-early Sakmarian) Keyling Supersequence was deposited on a coastal plain and is dominated by marginal marine and fluvio-deltaic siltstones and mudstones, with thin coal seams being largely developed in the basal and upper portions of this supersequence. Well penetration of the Keyling Supersequence is good throughout all but the far northwest part of the Petrel Sub-basin (see Figs. 2 and 12) and it is believed that the analyses carried out to date give a fairly representative indication of the hydrocarbon potential of this sequence. The siliciclastic sediments have very good total organic carbon contents (mean TOC = 2.78 %) with overall fair potential yields (mean $S_1 + S_2 = 3.6$ kg hydrocarbons/tonne). Source quality ranges from dry gas-prone Type III/IV kerogen to oil-condensate-prone Type II/III kerogen (mean HI = 95 $mgS_2/gTOC$; Fig. 12). The Keyling Supersequence is particularly liquid-prone at Flat Top-1 and Kinmore-1, as recognised by Jefferies (1988) and McConachie *et al.* (1995). Visual examination of the kerogen at Barnett-1, Cambridge-1, Turtle-1 and Turtle-2 shows that the organic matter is fairly well preserved comprising various amounts of spores, pollen, cuticle and algae (phyrogen), woody tissues (hylogen and melanogen) and amorphous (amorphogen) organic debris. Some samples contain highly fluorescent kerogen indicating good petroleum potential. At some localities the intermittent development of brackish-fresh water lacustrine and/or lagoonal environments are indicated by the presence of algal bodies and cysts of the species *Botryococcus* sp. and *Maculatasporites* spp., respectively. An abundance of fern and lycopod spores, gymnosperm pollen and woody fragments indicates an influx of land-plant debris into this aquatic environment. At other locations (Lacrosse Terrace and Keep Inlet Sub-basin) some marine influence is suggested by the preservation of rare spinose acritarchs.

Coaly shales and coals are best developed on the Eastern Ramp at Kinmore-1 and Flat Top-1, although they are also rarely developed in wells on the Turtle-Barnett High and in the Keep Inlet Sub-basin. The coals show an improvement in both organic richness and source quality having mean total organic carbon contents of 35 % and excellent potential yields (mean $S_1 + S_2 = 78$ kg hydrocarbons/tonne). The hydrogen indices of these sediments are moderately high (mean HI = 230 $mgS_2/gTOC$) indicating the presence of good quality Type II/III kerogen which has the potential to generate oil, condensate and gas (Fig. 13). Although the coals are generally thin, hydrocarbon generation modelling suggests that if they attain a net effective thickness of more than 10-15 m (corresponding to 5 % of total modelled source rock), then the Keyling Supersequence could generate significant quantities of oil and gas (Kennard, 1996b).

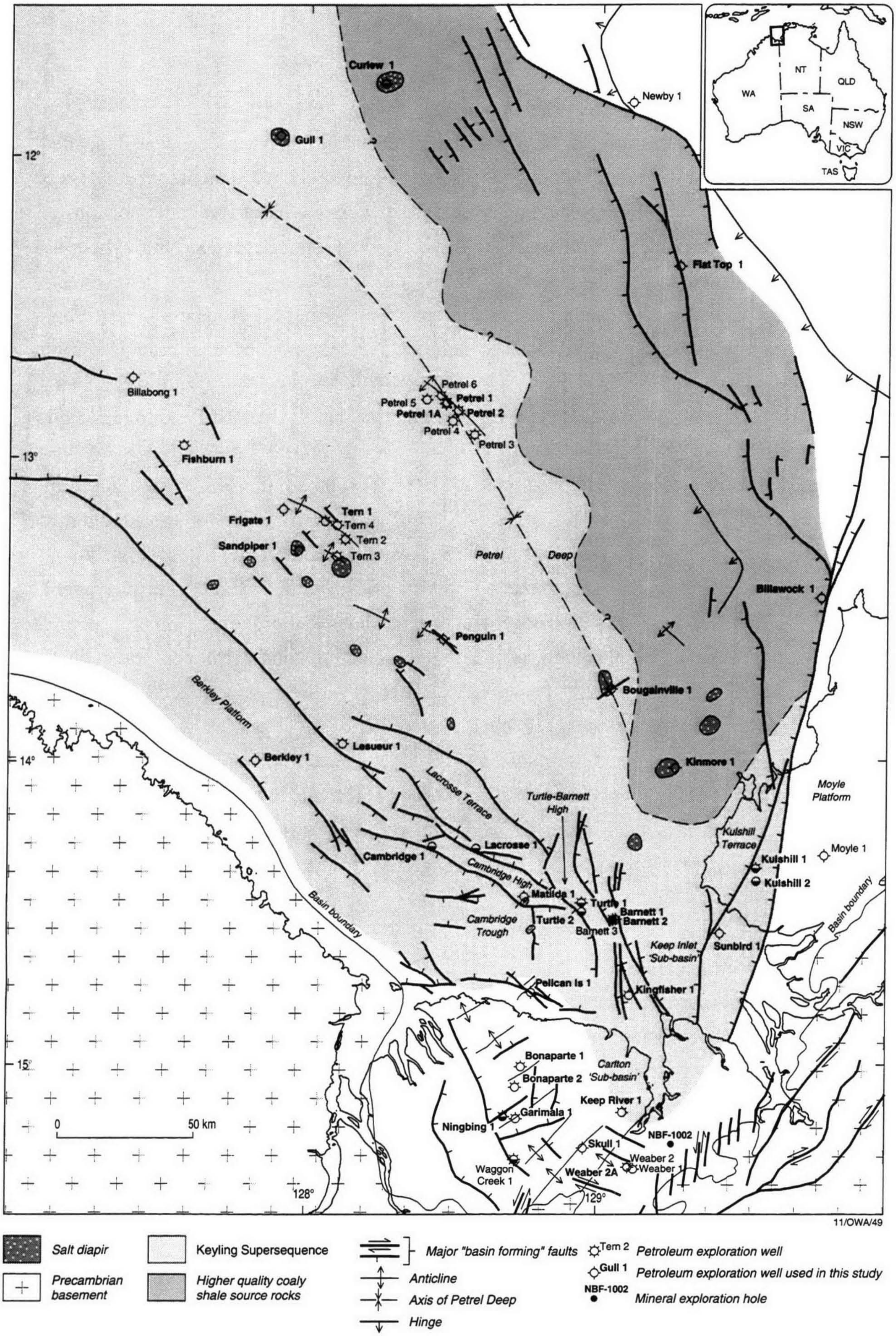
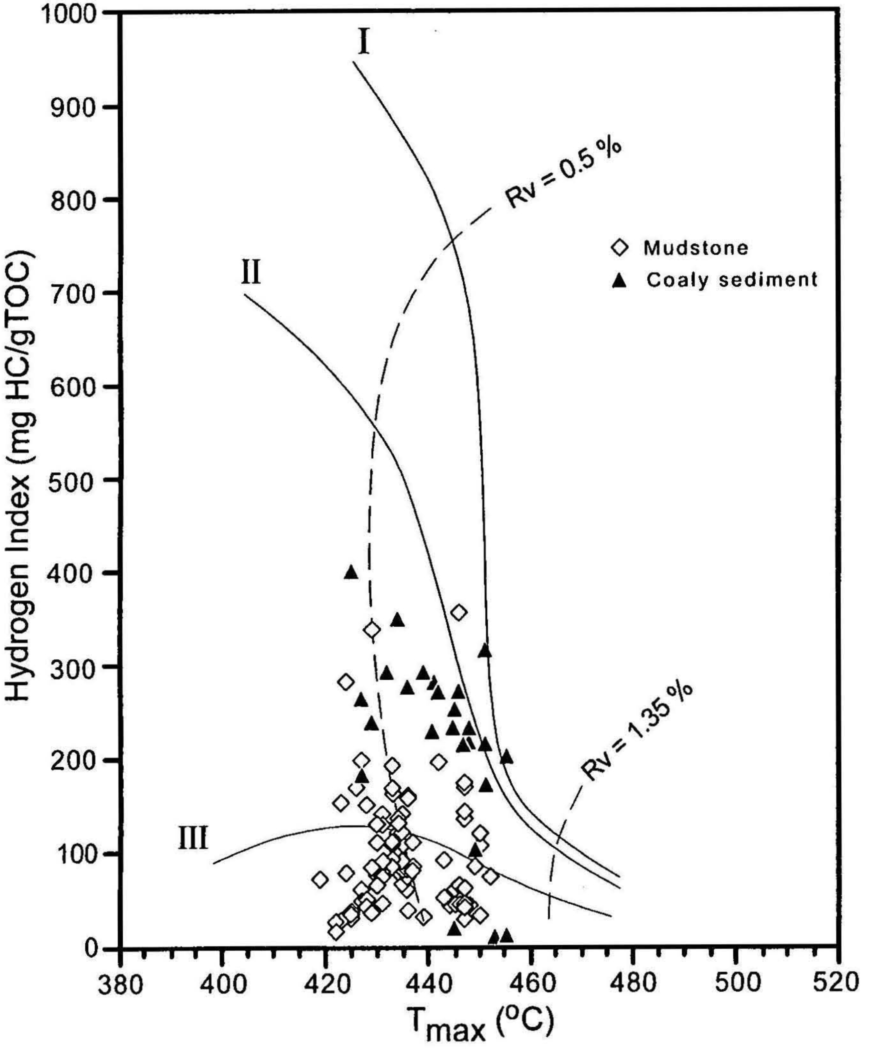


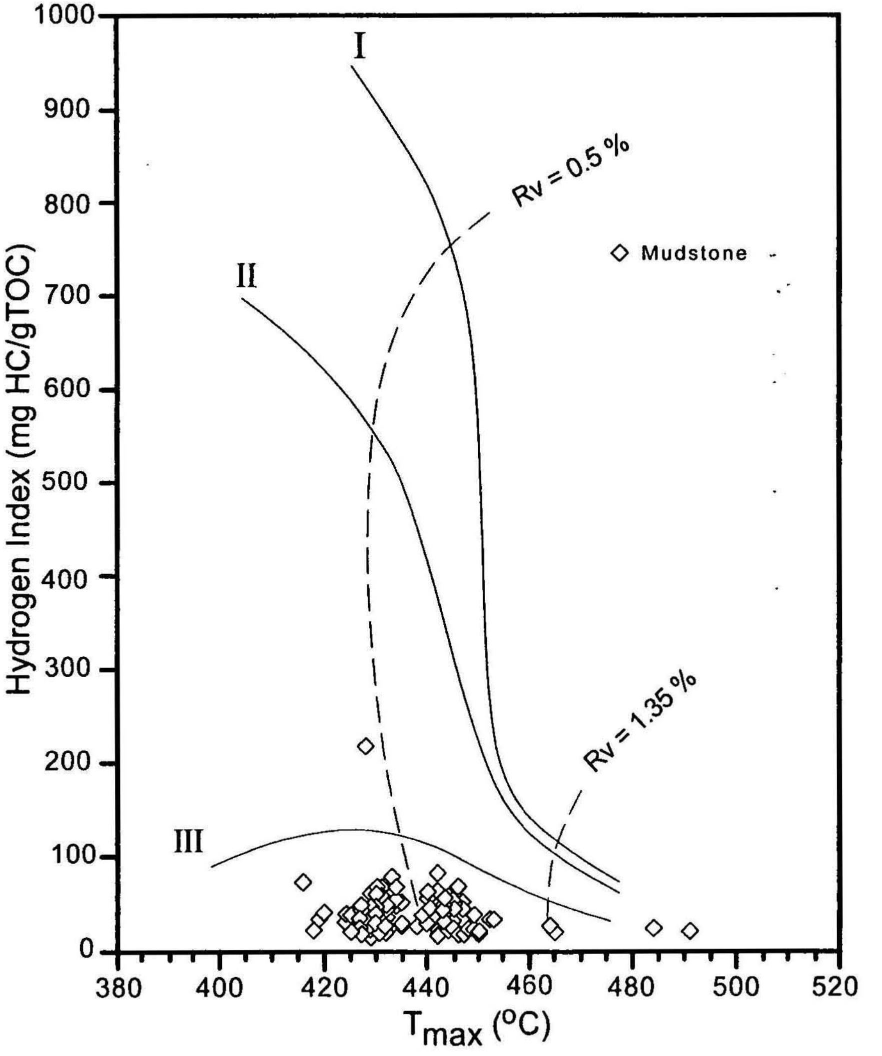
Figure 12 Distribution of the Keyling source rock unit.

Figure 13: Rock-Eval pyrolysis data for the Early Permian Keyling Supersequence.



Data compiled from Barnett-1, Berkley-1, Billawock-1, Bougainville-1, Cambridge-1, Flat Top-1, Kingfisher-1, Kinmore-1, Kulshill-1, Lacrosse-1, Matilda-1 and Turtle-1.

Figure 14: Rock-Eval pyrolysis data for the Early Permian Fossil Head Sequences.



Data compiled from Barnett-1, Barnett-2, Billawock-1, Bougainville-1, Cambridge-1, Fishburn-1, Flat Top-1, Kinmore-1, Matilda-1, Penguin-1, Petrel-2, Tern-1 and Turtle-1.

The Keyling Supersequence is immature for hydrocarbon generation on the Kulshill Terrace, in the Keep Inlet Sub-basin and across the Cambridge and Turtle-Barnett Highs. It is immature at Kinmore-1 and marginally mature at Flat Top-1.

Early Permian Fossil Head Sequences

The Early Permian (Sakmarian to early Kungurian) Fossil Head Formation comprises several (up to six or seven) transgressive sequences of marine and estuarine mudstones, siltstones and sandstones. It occurs over much of the present-day offshore portion of the Petrel Sub-basin, on and north of the Turtle-Barnett High. No significant source rocks have been identified. Although the organic content is good (mean TOC = 2.0 %), the potential yield of these marine sediments is consistently low ($S_1 + S_2 = 1.3$ mg hydrocarbons/tonne) and the source quality is exceptionally poor (mean HI = 41 mgS_2/gTOC). The exception is a sample from Cambridge-1 (598 m; HI = 218 mgS_2/gTOC; Fig. 14). The Fossil Head succession is immature in wells on the Cambridge and Turtle-Barnett Highs, but is mature for oil and wet gas at Tern and Petrel, respectively. The very high Tmax values (> 480 °C) in Figure 14 are from Petrel-2 and indicate the presence of reworked, highly oxidised dispersed organic matter.

Oxidised woody material (Type IV kerogen) is the predominant type of organic matter preserved in this sequence with lesser quantities of lamalginite being observed. Bacterially degraded spinose acritarchs and rare marine algal cysts were identified throughout this succession. However, dull fluorescence under UV light implies that this material has little capacity to generate hydrocarbons. The inferred depositional environment is one of an open marine setting into which there was a supply of oxidised terrestrial organic matter.

Late Permian Hyland Bay Sequences

The limestones, mudstones, siltstones and sandstones of the marine-deltaic Late Permian (Ufimiam-Dzhulfian) sequences of the Hyland Bay Formation have been penetrated in the Petrel Deep. However, the source potential of the main depocentre which lies northwest of the Petrel Field remains unevaluated, lying below TD at Gull-1 (Fig. 15). The main gas reservoirs at Petrel and Tern occur within the thick sandstones of the Cape Hay and Tern Members, respectively. The mudstones have variable total organic carbon contents (TOC = 0.5-10 %; mean TOC = 2 %) with overall poor generative potential ($S_1+S_2 = 1.3$ kg hydrocarbons/tonne) and contain mature Type III/IV kerogen which is at best gas-prone (Fig. 15). Inertinite and vitrinite make up the largest proportion of the maceral assemblages with minor quantities of sporinite, cutinite, liptodetrinite and lamalginite. This assemblage of organic remains is consistent with wind-borne pollen and highly oxidised water-borne terrestrial debris being transported into a marine-deltaic environment.

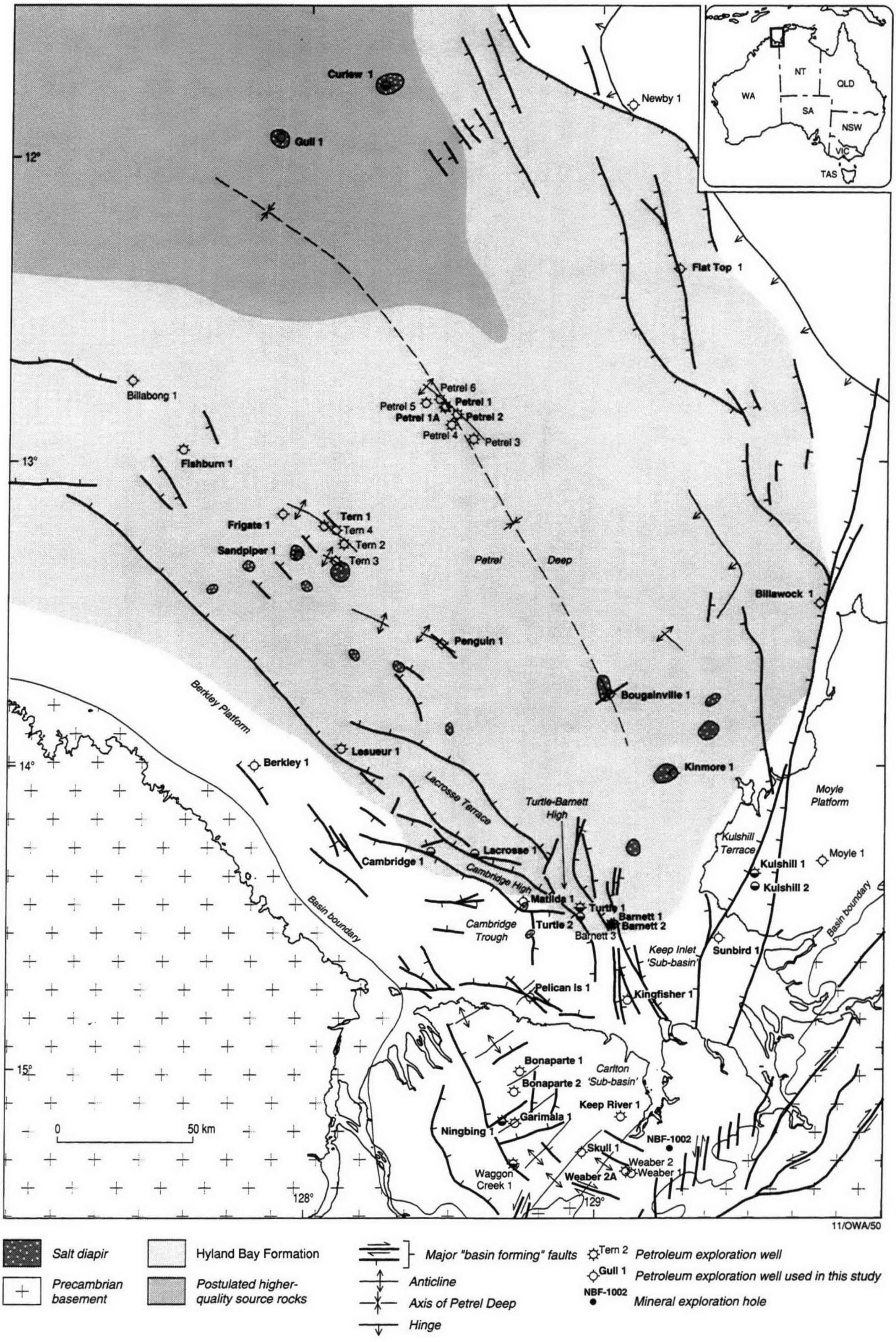
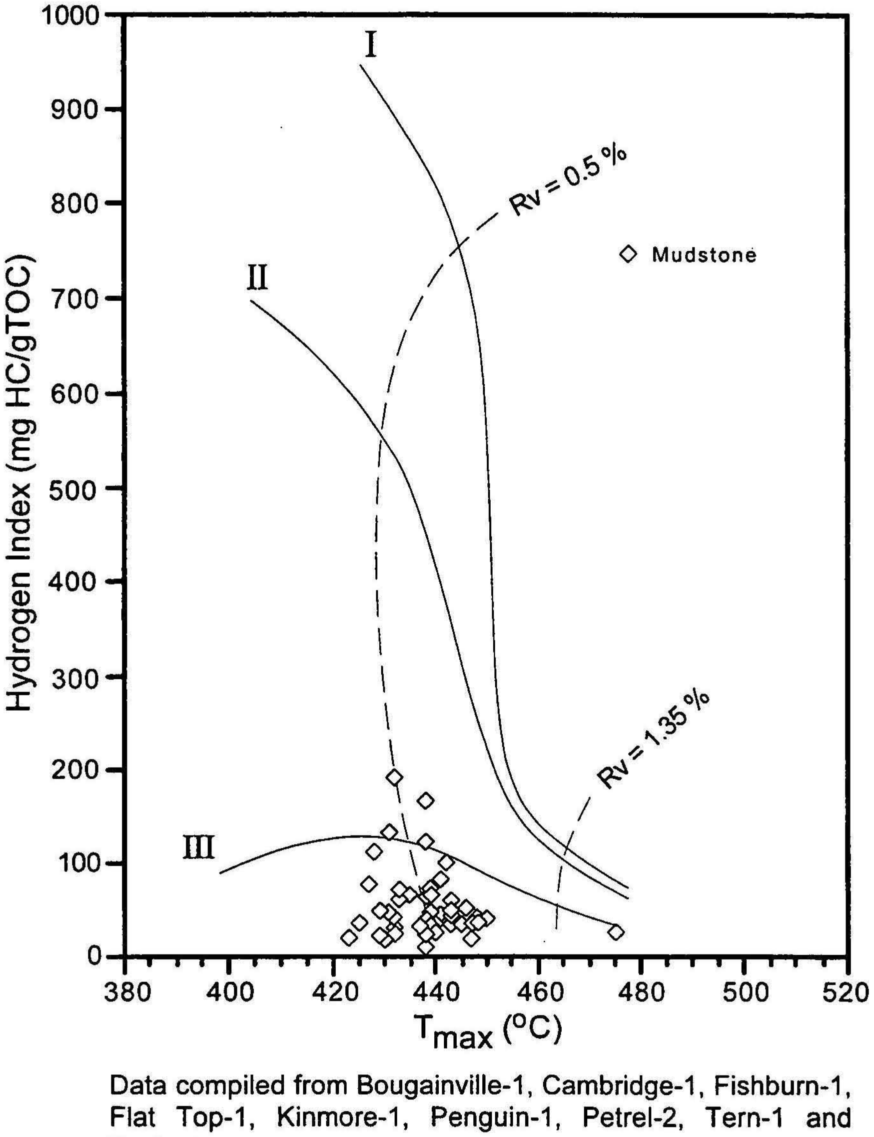


Figure 15 Distribution of the Hyland Bay source rock unit.

Figure 16: Rock-Eval pyrolysis data for the Late Permian Hyland Bay Sequences.



Data compiled from Bougainville-1, Cambridge-1, Fishburn-1, Flat Top-1, Kinmore-1, Penguin-1, Petrel-2, Tern-1 and Turtle-1 .

Some improvement in source quality is observed north of the Cambridge and Turtle-Barnett Highs, particularly on the western margin of the Petrel Sub-basin. Hence, this succession is believed to have the potential to generate gas and possibly condensate in the Petrel Deep where sufficient maturity has been attained.

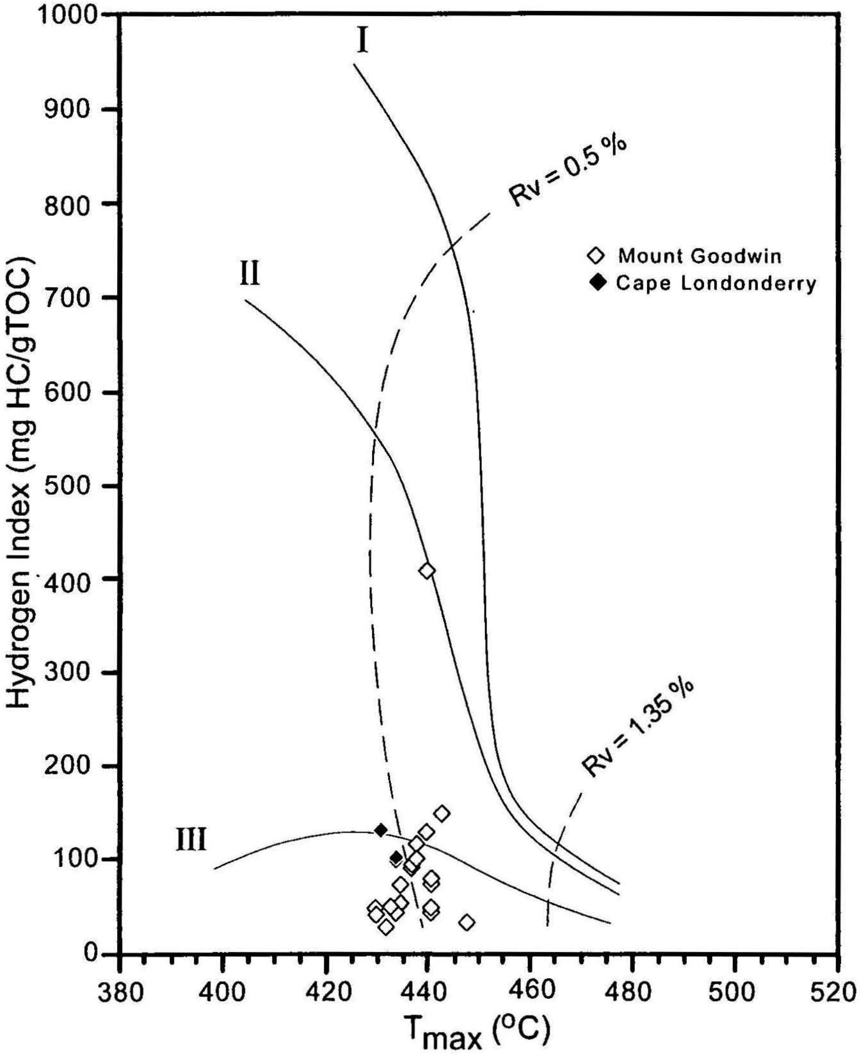
3.2 Hydrocarbon Potential of Mesozoic Supersequences

The major Mesozoic depocentre (the Malita Graben), comprising the Mount Goodwin-Cape Londonderry, Malita, Plover, Flamingo and Bathurst Island Supersequences, lies to the north of the Petrel Sub-basin (Fig. 1). Assessment of the petroleum potential of these sequences in the outer Petrel Deep has been made from TOC and Rock-Eval pyrolysis analyses at Curlew-1, Gull-1 and Petrel-2 and the sediments flanking this depocentre have been appraised at Fishburn-1, Flat Top-1, Penguin-1 and Tern-1.

Table A1 and Figures 17 and 21 show that in general the marginal-shallow marine sediments of the Triassic Mount Goodwin-Cape Londonderry and Cretaceous Bathurst Island Supersequences, respectively, have little hydrocarbon potential. Although these supersequences have fair to good organic richness (mean TOC = 0.8-1.5 %), their potential yields are consistently poor (mean $S_1+S_2 < 1.4$ kg hydrocarbons/tonne). The organic matter in these supersequences is predominantly gas-prone Type III/IV kerogen, as reflected by the low hydrogen indices (mean HI = 70-109 $mgS_2/gTOC$). However, a marked improvement in source quality occurs in the Mount Goodwin Supersequence at Fishburn-1 where source rocks with both liquid and gas potential are developed (mean HI = 201 $mgS_2/gTOC$). Where penetrated, the Mount Goodwin-Cape Londonderry Supersequence is mature for oil but not for gas generation and the Bathurst Island Supersequence is immature (Tmax < 435 °C; Rv = 0.45 %). Source rocks are not developed in the Triassic-Jurassic red beds of the Malita Supersequence (Fig. 18).

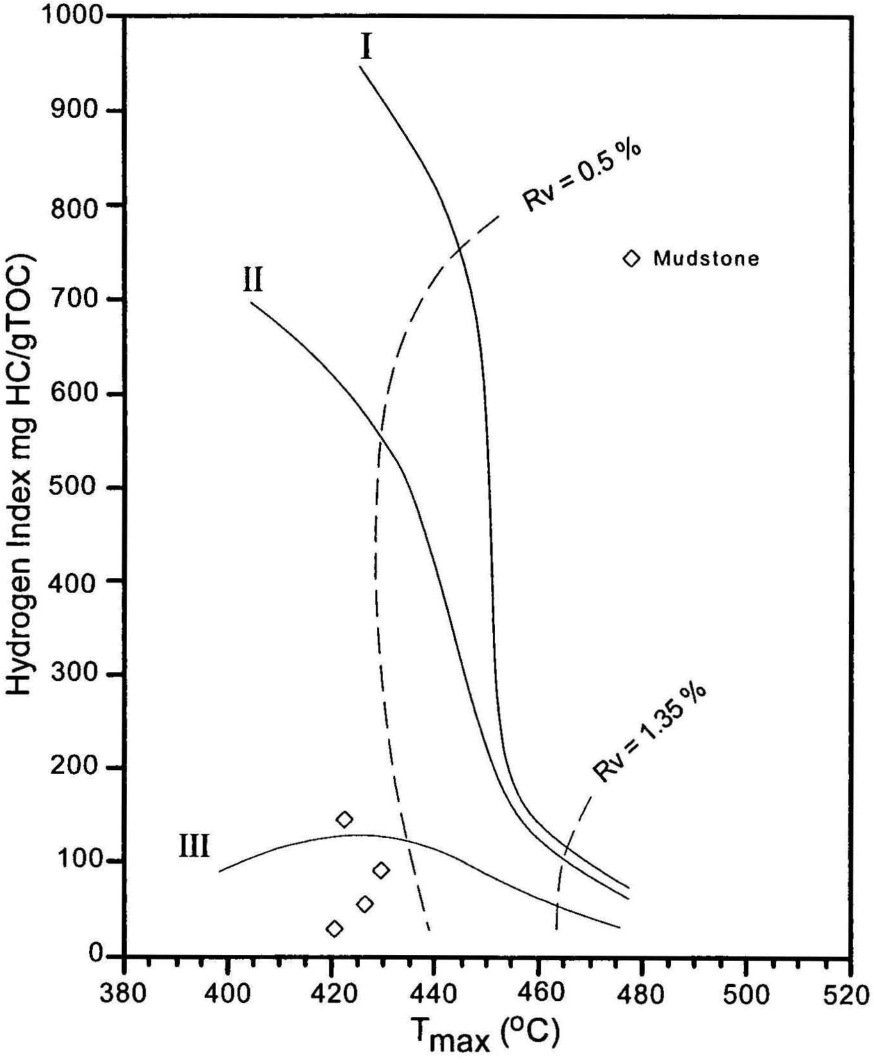
The marine mudstones of the lower part of the Flamingo Supersequence (Frigate Shale) and fluvio-deltaic mudstones of the Plover Supersequence (Table A1) have similar mean total organic carbon contents to the other Mesozoic supersequences, but their source richness shows some improvement with mean potential yields of 2.3 kg hydrocarbons/tonne for the Flamingo Supersequence and 2.6 kg hydrocarbons/tonne for the Plover Supersequence. The kerogen is predominantly composed of terrestrial organic matter, the most abundant maceral is inertinite with lesser quantities of vitrinite and liptinite. Hence, these sequences are mainly gas-prone (mean HI = 141 and 96 $mgS_2/gTOC$, respectively).

Figure 17: Rock-Eval pyrolysis data for the Late Permian-Middle Triassic Mount Goodwin-Cape Londonderry Supersequence.



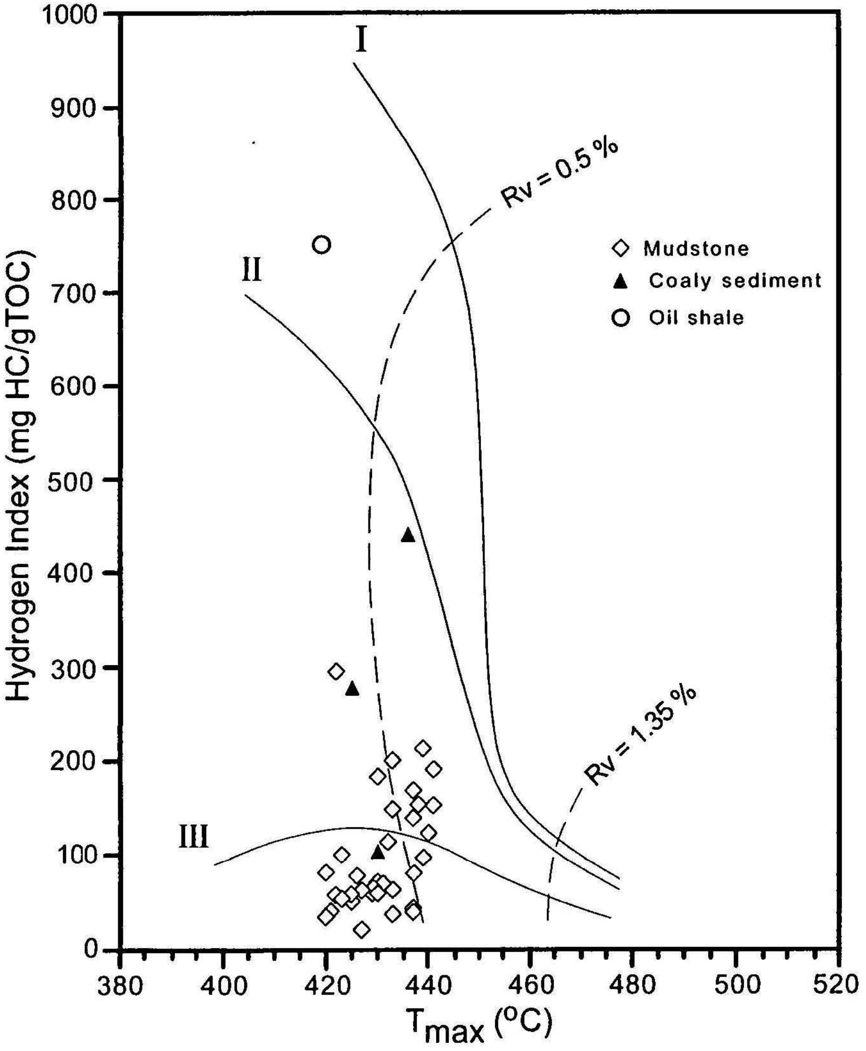
Data compiled from Fishburn-1, Flat Top-1, Penguin, Petrel-2 and Tern-1.

Figure 18: Rock-Eval pyrolysis data for the Late Triassic-Early Jurassic Malita Supersequence.



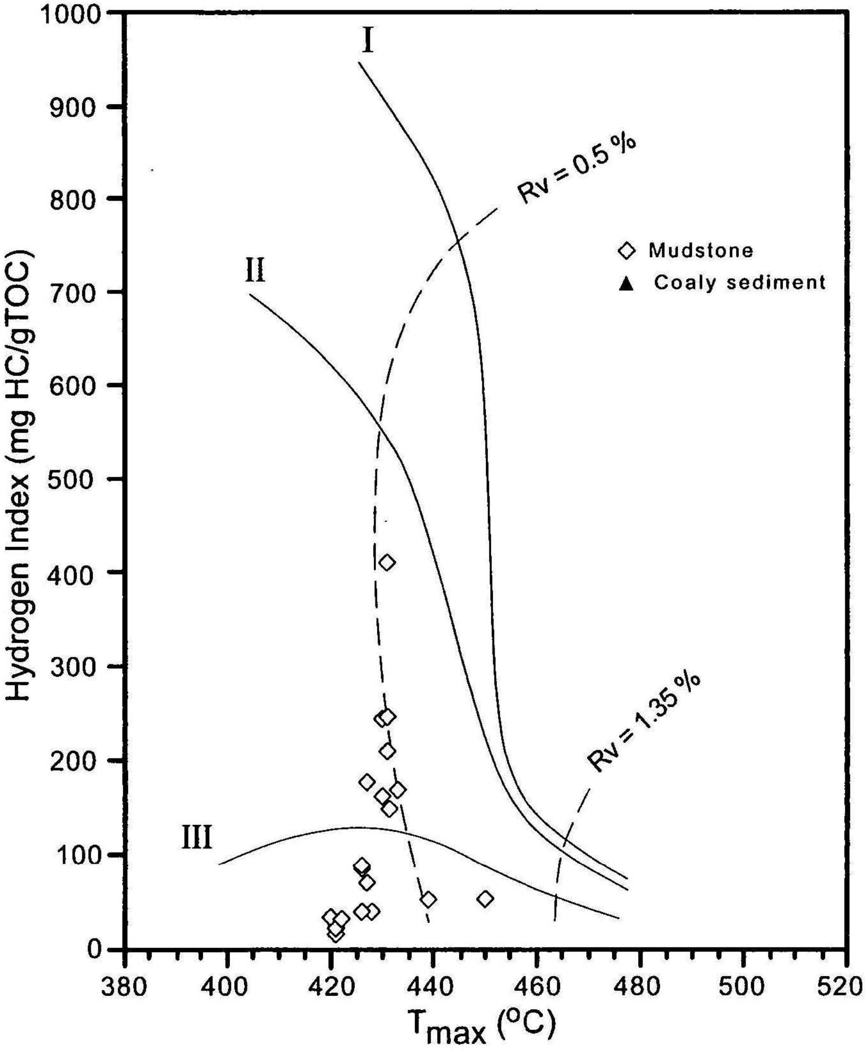
Data compiled from Petrel-2.

Figure 19: Rock-Eval pyrolysis data for the Early-Late Jurassic Plover Supersequence.



Data compiled from Curlew-1, Fishburn-1, Flat Top-1, Gull-1, Penguin-1, Petrel-2 and Tern-1.

Figure 20: Rock-Eval pyrolysis data for the Late Jurassic-Early Cretaceous Flamingo Supersequence.



Data compiled from Curlew-1, Fishburn-1, Gull-1 and Petrel-2.

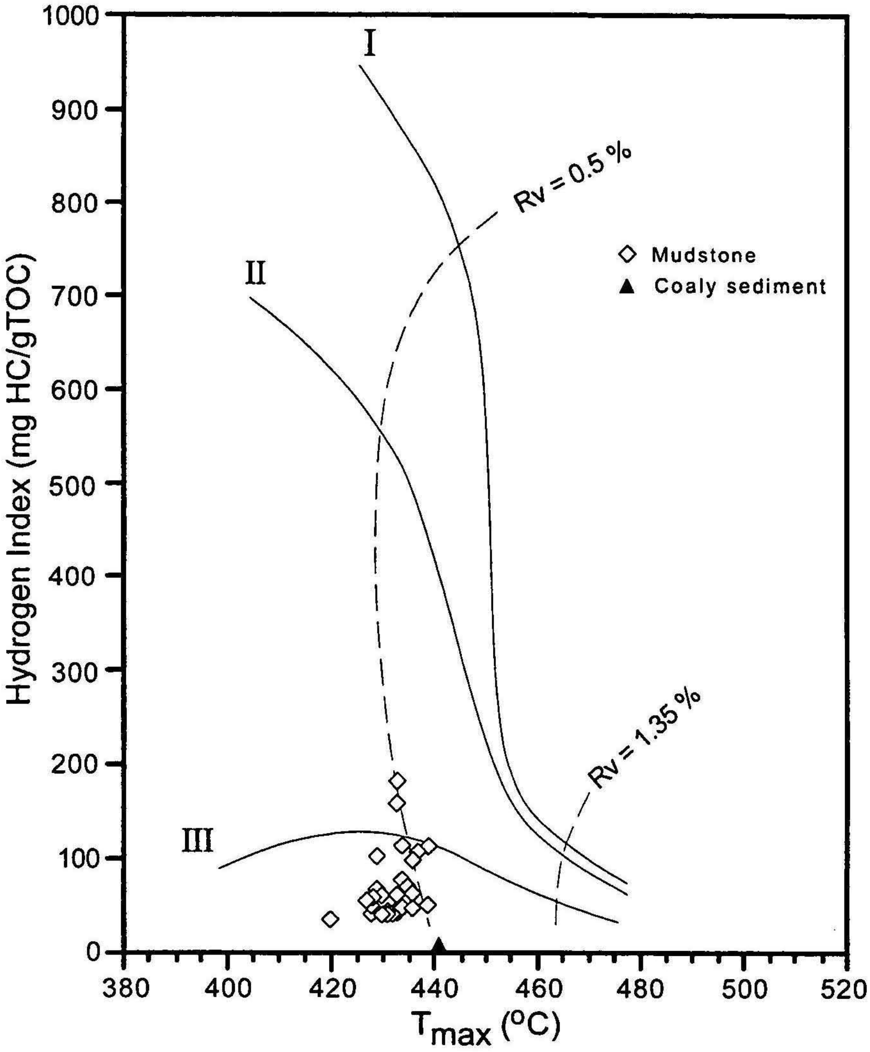
Figures 19 and 20 show that some mudstones, particularly in wells located in the Petrel Deep, have fair to very good generative potential and contain marginally mature Type II/III kerogens which are condensate-prone. An increase in the abundance of the hydrogen-rich maceral lamalginite in these sequences may account of the increased liquid potential of these mudstones, although inertinite is still the most ubiquitous maceral within these sediments. Coals within the Plover Supersequence at Flat Top-1 and an oil shale in Penguin-1 have very good generative potential containing Type II kerogen. However, these oil-prone source rocks are immature in the aforementioned wells and may be of little significance elsewhere since they are thin and appear to be of limited lateral extent.

3.3 Summary

Source potential and maturation studies have shown that the best source rocks of Palaeozoic identified within the Petrel Sub-basin *per se* are the organic-rich marine mudstones and coals of the Early Permian Keyling Supersequence which are largely gas and condensate-prone. The Early Permian Treachery Sequence and Late Carboniferous Kuriyippi Supersequence have, to a lesser extent, some hydrocarbon potential. Although humic coals within the aforementioned sequences have excellent source richness and quality, volumetrically, even within the Keyling Supersequence, they represent only a small proportion of the total sediment thickness and hence their hydrocarbon potential is limited.

Overall, the Milligans Supersequence is interpreted to be largely gas-prone and has probably sourced the gas flows at Bonaparte-2, Keep River-1, Waggon Creek-1, Weaber-1 and 2A. The greatest proportion of the kerogen comprises oxidised and fragmented remains of woody material and microbially degraded spores and pollen derived from lycopods and ferns. Hydrogen-rich algal material is generally present in only trace quantities. The offshore oil discoveries in the Carboniferous and Permian succession at Barnett and Turtle and the onshore oil discoveries in the Early Carboniferous Milligans Formation at Waggon Creek-1 attests to the presence of oil-prone source rocks in the southern Petrel Sub-basin. Immature, oil-prone source rocks have been identified only in the onshore Milligans mudstones at NBF1002. Localised source pods containing similar organic-rich sediments are presumed to occur in the depocentres north and south of the Turtle-Barnett High and in the Carlton Sub-basin and may have sourced the Barnett, Turtle and Waggon Creek-1 oils.

Figure 21: Rock-Eval pyrolysis data for the Early-Late Cretaceous Bathurst Island Supersequence.



Data compiled from Curlew-1, Fishburn-1, Flat Top-1, Gull-1 and Tern-1.

Oil-prone carbonate source rocks have not been identified in the Late Devonian supersequences penetrated by petroleum exploration wells, although some potential for gas and minor liquids is recognised in the Ningbing Supersequence at Spirit Hill-1. The Ningbing Supersequence is thermally mature in the Carlton Sub-basin and may have sourced the gas flows at Garimala-1. Nevertheless, the persistent oil-shows recognised at Ningbing-1 and in the many mineral holes drilled around the margins of the Carlton Sub-basin suggest that oil-prone carbonates of Late Devonian age may exist in the onshore Petrel Sub-basin.

The lower section of the Late Jurassic Flamingo Supersequence (Frigate Shale) and the Early-Late Jurassic Plover Supersequence have source rocks with fair to good generative potential for gas, condensate and possibly minor quantities of oil. Liquid hydrocarbons in the neighbouring Vulcan Sub-basin have been generated from time-equivalent source rocks in the Lower Vulcan Formation and the Plover Formation. This study has demonstrated that these moderate quality source rocks are widespread and extend into the outer Petrel Deep where they are mature for hydrocarbon generation.

4. GEOCHEMICAL ANALYSES

4.1 Ningbing-Bonaparte Petroleum System (Larapintine 3)

Oil staining and bitumen-filled vugs and veins are a common phenomenon in the shallow mineral holes drilled along the margin of the Carlton Sub-basin (Table A6). These hydrocarbons are believed to have been generated from Late Devonian carbonates and mudstones of the Bonaparte Megasequence. The following geochemical data on Late Devonian marine carbonate-derived oils were compiled from research carried out during this project and from unpublished company reports.

4.1.1 Late Devonian-Sourced Oils

Two Late Devonian carbonates impregnated with oil were analysed; oil stains were extracted from the Cockatoo Supersequence in Ningbing-1 (core 4, #8571) and from an outcrop sample of Ningbing Limestone (#4934) near Sorby Hills (Table A7). Oil staining of the Ningbing-1 core is indicated by a high production index (PI = 0.47: Table A8). Although this calcareous mudstone sample lies within the early oil window and has a good total organic carbon content, indigenous liquid hydrocarbons are unlikely to have been generated since its hydrogen index is very low ($HI = 55\ mgS_2/gTOC$).

The bulk chemical compositions of these Late Devonian oils are shown in Table A9. The Ningbing-1 oil stain is dominated by saturated hydrocarbons whereas, oil from the Ningbing Limestone outcrop contains a very high abundance of polar compounds, probably as a result of weathering with the saturated and aromatic hydrocarbons being removed by a combination of evaporation, oxidation, water washing and biodegradation.

Gas chromatograms of the saturated fraction of these oil stains are shown in Figure 22. The C_{12+} *n*-alkane distributions display a unimodal distribution centred around C_{16}-C_{18} which do not show any odd or even carbon-number preference. The pristane to phytane, pristane/*n*-C_{17} and phytane/*n*-C_{18} ratios in both samples are low (Table A10; see Appendix D for molecular structures). These data imply that the oils are mature and were generated from algal and bacterial organic matter deposited under sub-oxic conditions in a marine environment. The gas chromatogram of the Ningbing Limestone outcrop oil stain also exhibits an abundance of biomarker compounds, specifically hopanes, and these may have been concentrated as either a result of weathering or be a feature inherited from the source rock.

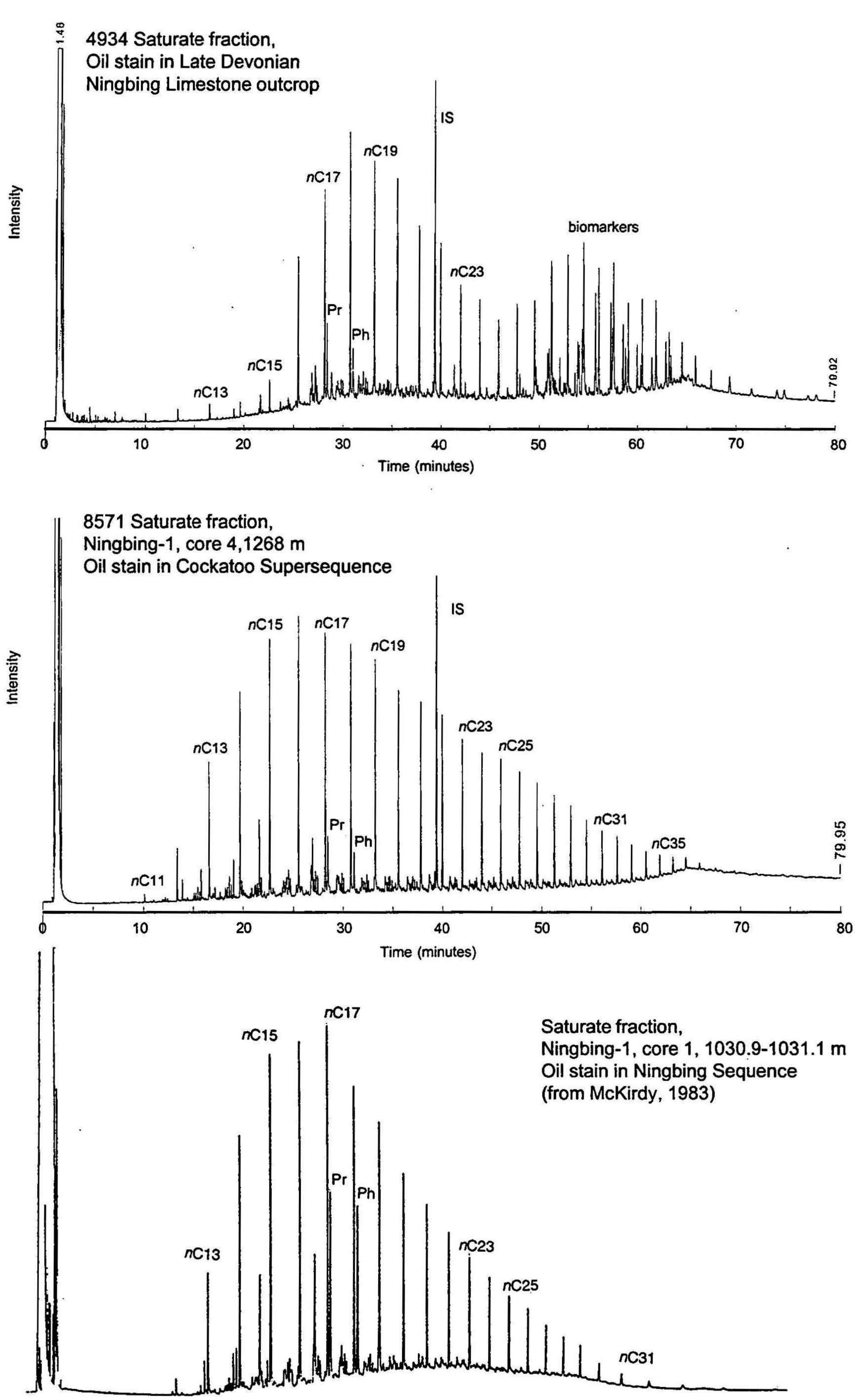


Figure 22 Gas chromatograms of Late Devonian reservoired oil stains. Peak annotations are defined in Appendix D.

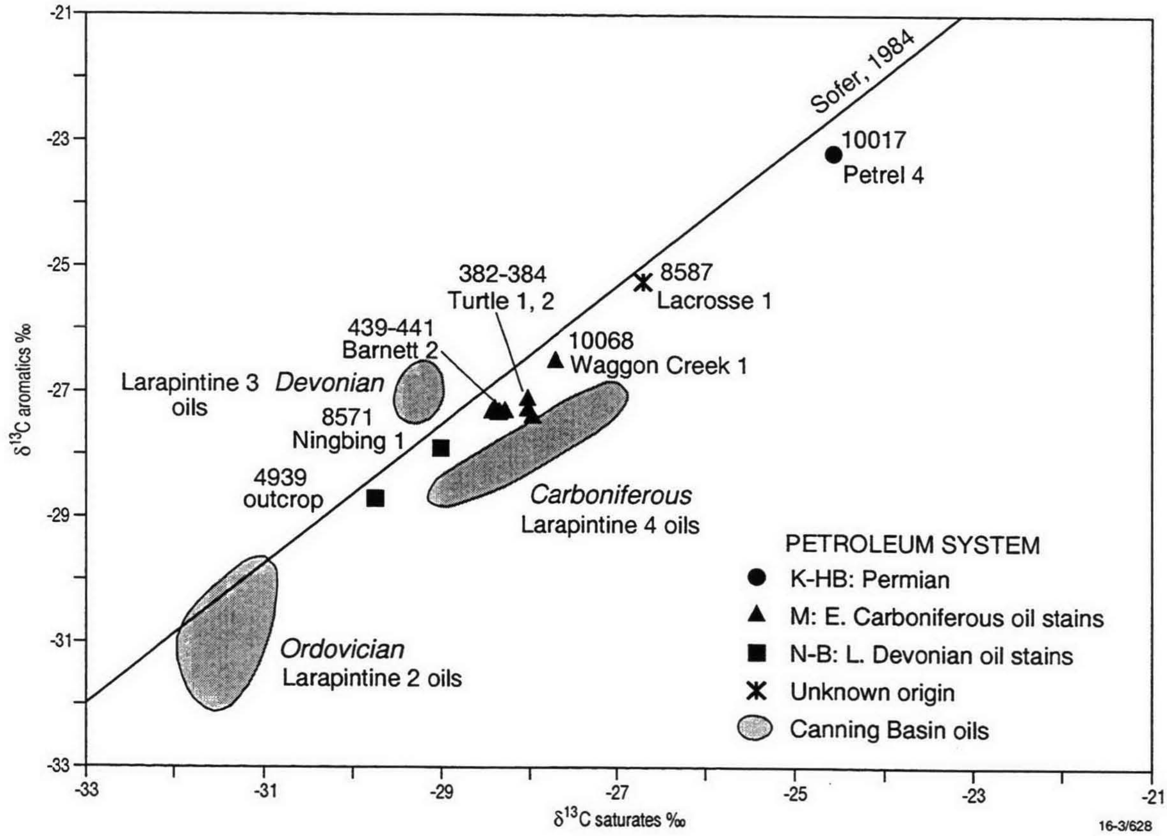


Figure 23 Carbon isotopic composition of Petrel Sub-basin petroleums (N-B Ningbing-Bonaparte; M Milligans; K-HB Keyling-Hyland Bay).

Other Late Devonian carbonate-reservoired oils that have been analysed include oil stains in the Ningbing Supersequence in Ningbing-1 (core 1; McKirdy, 1983) as shown in Figure 22, and oil stains and bitumens in numerous mineral holes (le Tran *et al.*, 1980). The saturated hydrocarbon distributions of these oils are similar to the Ningbing-1 oil analysed in this study in that the low molecular weight *n*-alkanes are predominant, exhibiting a maximum around C_{17}. Thus algal and bacterial sources can be inferred for these oils. However, the pristane/phytane ratios and the pristane/*n*-C_{17} and phytane/*n*-C_{18} ratios are variable, suggesting that they may have several different origins. However, without GC-MS analyses the number of oil families, the lithology of their source beds and the maturity at the time of generation cannot be determined.

Isotopically, both of the Late Devonian-reservoired oil stains are light (range $\delta^{13}C_{sats}$ = -29.0 to - 29.8 ‰; range $\delta^{13}C_{arom}$ = -27.9 to -28.7 ‰; Table A9, Figure 22). The oil obtained from the Ningbing Limestone outcrop sample is about 1 ‰ lighter than that obtained from the Ningbing-1 core. This latter sample has an isotopic composition somewhere between that of Devonian and Carboniferous-sourced oils of the Canning Basin, but it is significantly more depleted in ^{13}C than the oils found at Barnett, Turtle and Waggon Creek.

The biomarker distribution of the Late Devonian reservoired oil stains confirms their derivation from algal and bacterial enriched kerogens. The C_{27}:C_{28}:C_{29} sterane distributions show a similar abundance of C_{27} and C_{29} steranes in the Ningbing-1 oil stain and an abundance of ethylcholestane (C_{29} sterane) in the Ningbing Limestone outcrop sample (Table A11) which is in keeping with other Palaeozoic oils and sediments (Summons and Powell, 1990). C_{27} steroids are abundant in marine phytoplankton and although C_{29} steranes commonly arise from land-plant precursors, in this case marine algae are the most likely source of C_{29} steranes (Volkman, 1986). C_{30} desmethyl sterane (24-*n*-propylcholestane) is present in the outcrop sample but is undetected in the Ningbing-1 oil stain (Appendix E). This C_{30} sterane is highly diagnostic of marine organic matter (Moldowan *et al.*, 1985, 1990). The absence of the C_{30} sterane from the Ningbing-1 oil stain possibly infers that its source bed was deposited in a lagoon or a restricted marine environment which was unfavourable to support the pre-requisite biota necessary for its production and/or preservation. The high abundance of gammacerane in the Ningbing-1 oil stain (gammacerane/hopane = 0.5: Table A12) is indicative of a stratified water column which is commonly associated with hypersaline conditions (Brassell *et al.*, 1987; Fu Jiamo *et al.*, 1986; ten Haven *et al.*, 1989; Sinninghe Damsté *et al.*, 1995). C_{30} 3β-methyl steranes, rather than 4-methyl steranes, are present in both oil samples which is consistent with their Palaeozoic age (Summons and Capon, 1988, 1991), probably originating as a result of microbial modification of the organic matter. A substantial input of bacterial lipids to the source kerogen is indicated by abundant C_{27}-C_{35} hopanes and lesser quantities of methyl hopanes in both oils.

The low abundance of tricyclic terpanes and rearranged steranes, an absence of diahopanes, and the presence of 30-norhopanes and methyl hopanes imply that the oil in the Ningbing Limestone outcrop was generated from a carbonate source rock (Fig. 23). In contrast, the source of the Ningbing-1 oil appears to have been a calcareous mudstone which was deposited under hypersaline (abundant gammacerane), anoxic (abundant 28,30-dinorhopane) conditions.

The maturation-dependent parameters listed in Table A14 shows that both oils are moderately mature with the hopane and sterane epimerisation reactions being equilibrated (parameters 1, 2, 3 & 7). The Ningbing outcrop sample was generated at a slightly higher thermally maturity than the Ningbing-1 oil since the C_{27}-C_{30} sterane distributions exhibit a greater abundance of $\alpha\beta\beta$ isomers than $\alpha\alpha\alpha$ isomers (parameter 4).

The Late Devonian-reservoired oil at Ningbing-1 shows no evidence of biodegradation in the reservoir. Its *n*-alkane and biomarker distributions appear unaltered and 25-norhopanes (degradation products of hopanes formed by *in situ* microbial activity) were not detected. Elsewhere in the onshore Petrel Sub-basin, le Tran *et al.* (1980) and McKirdy (1983) report that the majority of oils and bitumens recovered from the Ningbing Limestone and Enga Sandstone at shallow depths in mineral holes are biodegraded.

4.1.2 Late Devonian Source Rocks

Few organic-rich carbonates and calcareous mudstones of Late Devonian age have been identified the Petrel Sub-basin. Although many mineral holes have penetrated Late Devonian and earliest Early Carboniferous carbonate successions (Bonaparte Megasequence), organic geochemical analyses are scarce and detailed biostratigraphic correlation between the mineral holes have not been undertaken. At Ningbing-1, carbonates with organic-rich stylolites were found in the Ningbing Supersequence (cores 1 and 2) and TOCs up to 0.7 % were recorded in the Cockatoo limestones . However, in this well any indigenous organic matter appears to be at best gas-prone and oil staining hampers oil-source correlations.

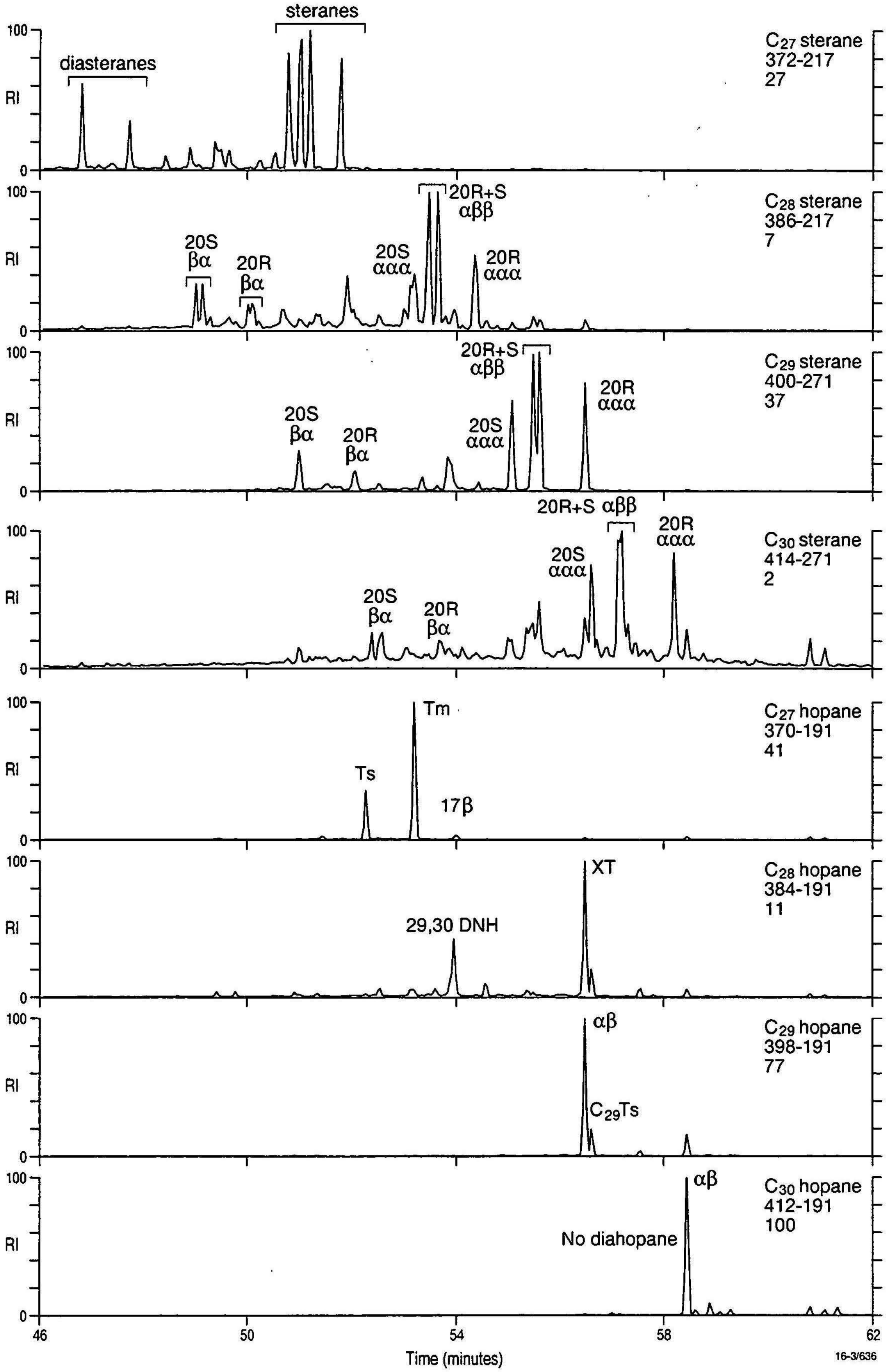


Figure 24 GC-MS (MRM) chromatograms showing the distribution of steranes and triterpanes in a Late Devonian reservoired oil (sample #4934). Chromatograms are identified by carbon number, reaction transition and relative abundance of the most intense peak. Peak assignments for the steranes and hopanes are defined in Appendix E.

An organic-rich calcareous mudstone unit within the Ningbing Supersequence was identified at Spirit Hill-1 (Tables A7 and A8). The gas chromatogram of this calcareous mudstone extract (#8544) has a high pristane/phytane ratio (Pr/Ph = 2.5) and high wax content (Fig. 35). The kerogen in this sample is largely composed of spores and cuticles with a minor woody component. Hence, it is likely that the waxy *n*-alkanes originate from the hydrogen-rich fern and lycopod spores as opposed to algal biopolymers. However, some algal input, not observed in the kerogen concentrates, is suggested by the odd-carbon-number preference in the low molecular weight *n*-alkanes (C_{15}-C_{19}).

The biomarker signature of this sample differs from that of the previously mentioned Late Devonian oils in that it contains a greater proportion of diasteranes relative to steranes, an abundance of dia- and neohopanes and tetracyclic terpanes, and a different distribution of C_{19}-C_{26} tricyclic terpanes. Overall, this source rock shows a greater affinity to the overlying Milligans Supersequence and Milligans oils which are discussed in section 4.2.3.

4.2 Milligans Petroleum System (Larapintine 4)

The Milligans Petroleum System includes the oils reservoired throughout the Carboniferous and Permian successions in wells drilled within the southern most portion of the Petrel Sub-basin. The most notable accumulations occur at Barnett-2, Turtle-1, 2 and Waggon Creek-1 being sourced from the Early Carboniferous Milligans Supersequence.

4.2.1 Early Carboniferous-Sourced Oils

Many geochemical analyses have been carried out on the oil accumulations found at Barnett-1 and 2 and in Turtle-1 and 2 (Lee, 1987; Jefferies, 1988; McKirdy, 1987a, b; Summons and Hope, 1989). Further analyses of these oils were undertaken to facilitate comparison with the newly discovered oil at Waggon Creek-1 and to make oil-source correlations. The results presented herein complement these earlier studies and with the addition of isotopic analyses and basin maturation studies (see Geohistory Modelling Report, Kennard, 1996b), a more comprehensive understanding of this petroleum system has been achieved.

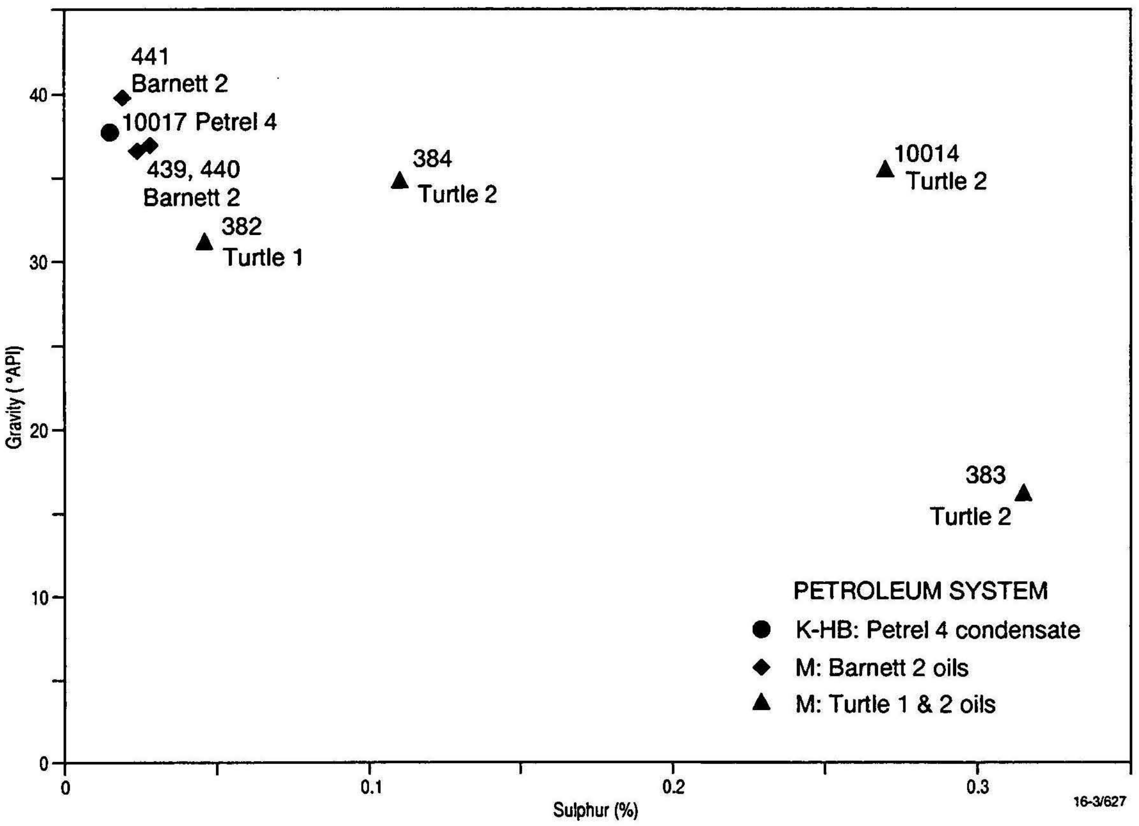


Figure 25 Bulk compositions of Petrel Sub-basin petroleums.

The oils analysed from the Milligans Petroleum System are shown in Table A7. In addition to the Barnett-2, Turtle-1, 2 and Waggon Creek-1 drill stem test (DST) samples and the Turtle-2 repeat formation test (RFT) sample, oil stains from Barnett-1, Cambridge-1, Milligans-1, Turtle-1 and 2 were also analysed. These latter samples were included to determine whether the oils found throughout the Carboniferous and Early Permian successions were generated from one or more source rocks. Moreover, determining the origin of the oils found above and below the Treachery Shale would establish whether or not the Treachery Shale was an effective seal and/or a potential source rock.

The bulk composition of the oils are shown in Table A9. The Barnett and Turtle oils recovered from the drill stem and repeat formation tests are medium (31-40 °API) crudes with low sulphur contents ($S < 0.3$ %), with the Turtle crudes having slightly higher sulphur contents than the Barnett crudes. Decreases in the API gravity and increases in the sulphur contents of the oils shown in Figure 24 can be partly explained by biodegradation and water washing. However, the increased sulphur contents in the least altered Turtle-2 oils (#384, #10014) with respect to the fresh Barnett-2 oil (#439) necessitates some additional source differences.

Representative gas chromatograms of the saturated fraction of Early Carboniferous to Early Permian-reservoired oils are shown in Figures 26 and 27. The saturated hydrocarbon distribution of some oils, for example the DST oils Barnett-2 (#439), Turtle-2 (#384, #10014) and Waggon Creek-1 (#10068), appear unaltered, whereas others have been biodegraded, varying in extent from a reduction in the lower molecular weight *n*-alkanes to the complete removal of both normal and isoprenoid alkanes (Table A10a). There is a general trend to more highly altered oils in the shallowest reservoirs. However, as pointed out by Jefferies (1988), the degree of biodegradation does not increase proportionally to reduction in depth of the reservoir in all the Barnett and Turtle wells. Instead the degree of biodegradation has most probably been effected by the height of the oil column and the proximity of the oil sample to the oil-water-contact (OWC). Figure 27 shows differences in the degree of biodegradation with depth in Turtle-2.

The saturates chromatograms of the non-biodegraded Barnett and Turtle oil accumulations indicate that they comprise mature oils, derived from algal and bacterial lipids, being characterised by a unimodal *n*-alkane profiles which have a maximum at C_{13} or C_{15} and show no odd or even carbon number preference, low pristane/phytane ratios (Pr/Ph =1.1-2.3) and moderately low isoprenoid/normal alkane ratios ($Pr/n\text{-}C_{17}$ and $Ph/n\text{-}C_{18} = 0.4\text{-}0.8$: Fig. 28).

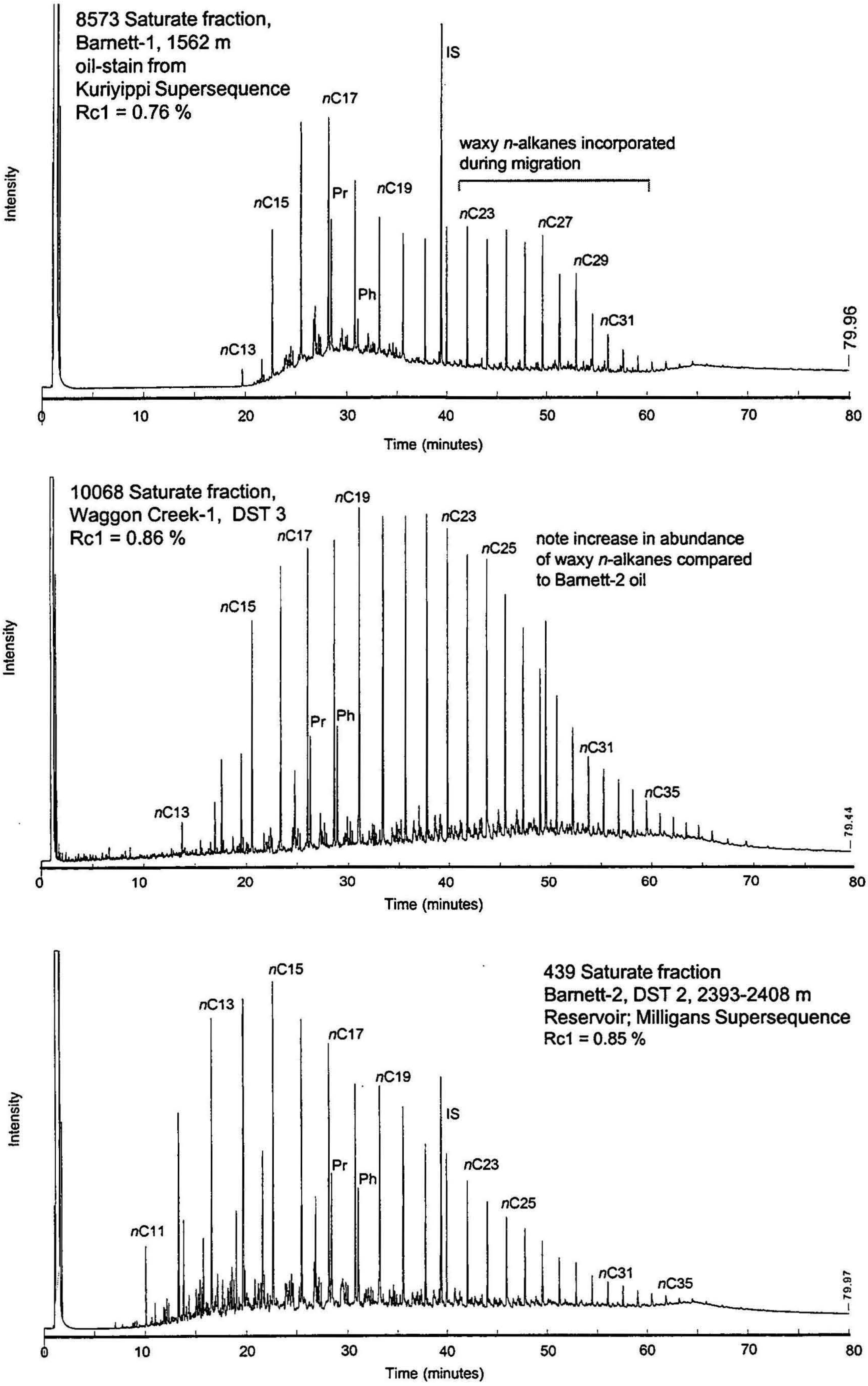


Figure 26 Gas chromatograms showing oils of the Milligans Petroleum System.

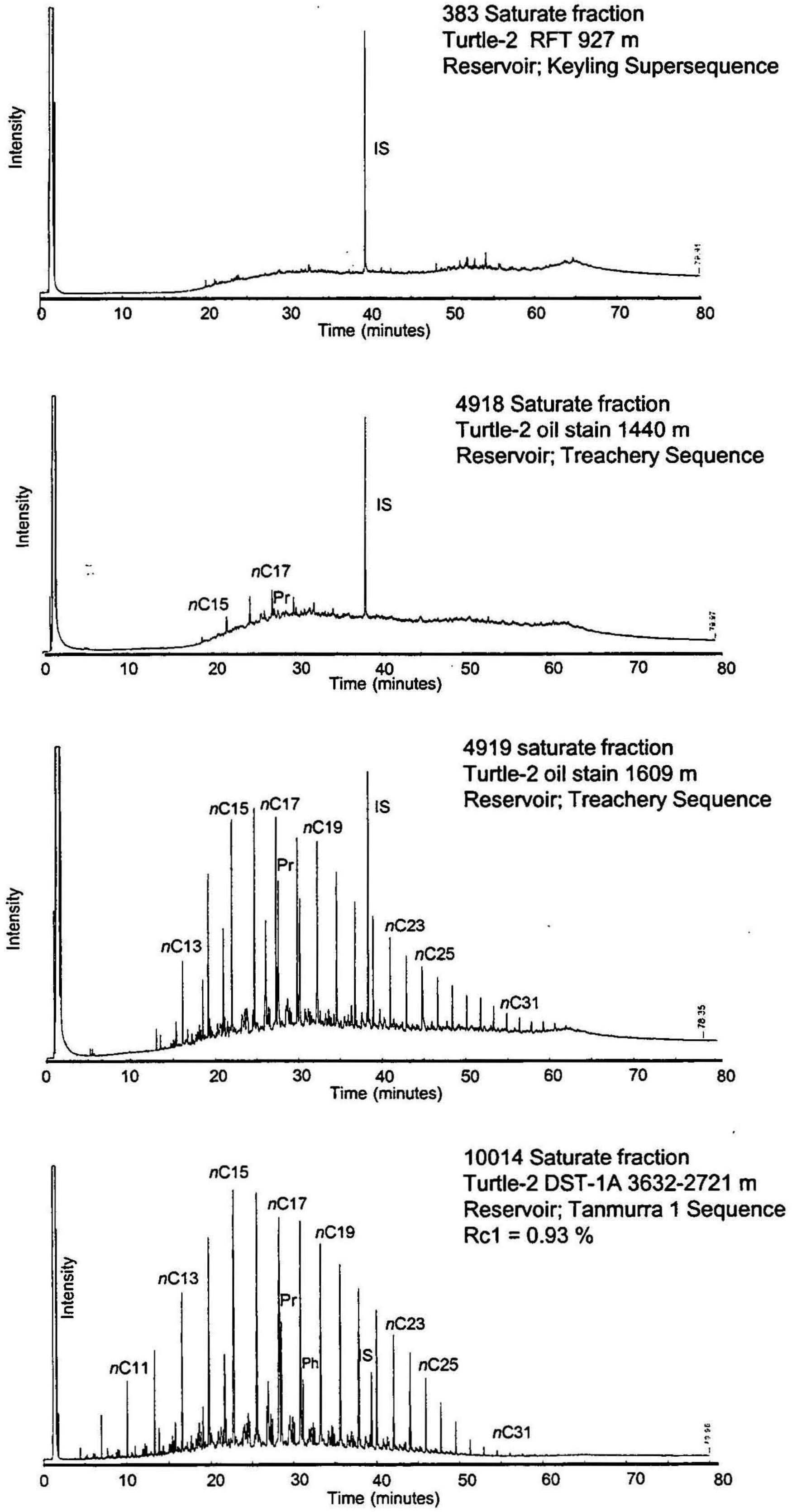


Figure 27 Gas chromatograms showing the biodegradation profile in Turtle-2 oils.

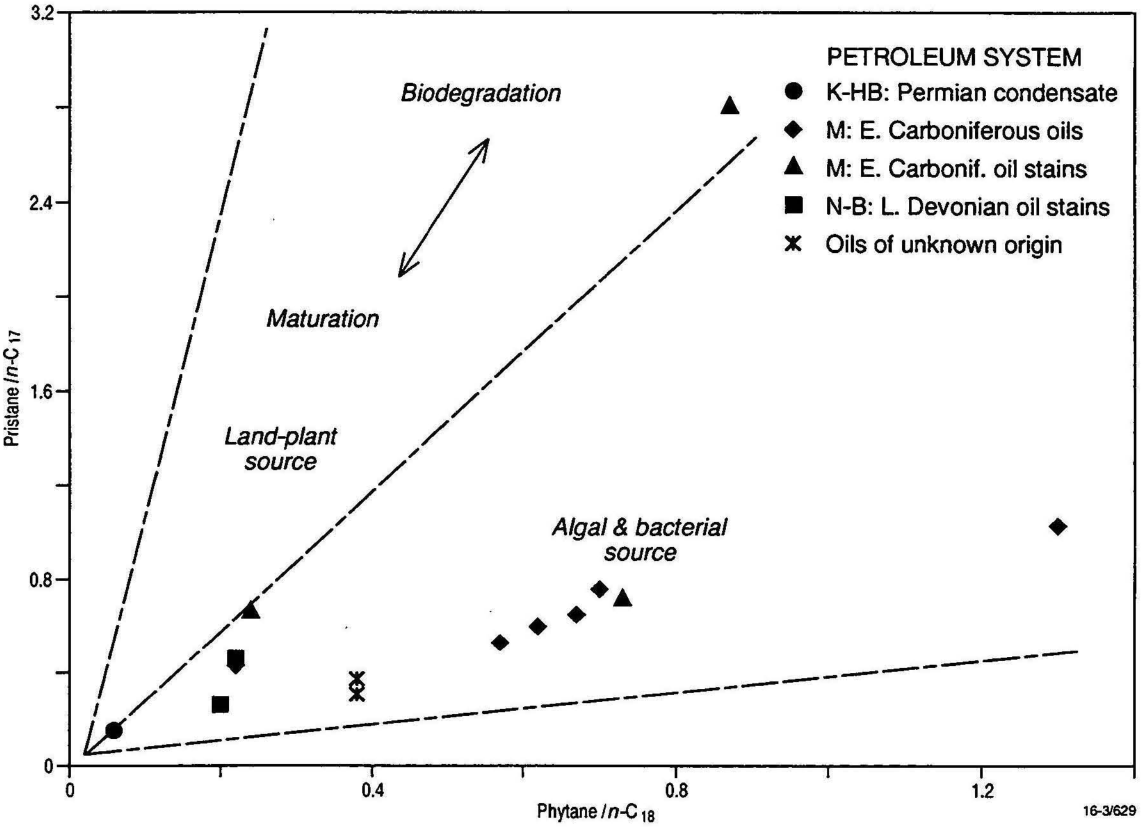


Figure 28 Plot of phytane/n-C_{18} versus pristane/n-C_{17} for petroleums.

The gas chromatogram of the Waggon Creek-1 oil differs from that of the non-biodegraded Turtle and Barnett oils in that it has a significant contribution of waxy *n*-alkanes and the pristane to phytane ratio is lower (Pr/Ph = 0.9). The higher molecular weight *n*-alkanes may be derived from either land-plants (lycopod, fern and fungal spores) or from algeanans which are biochemically resistant algal-derived biopolymers that produce aliphatic hydrocarbons upon thermal maturation (de Leeuw & Largeau, 1993).

Carbon Isotopic Signature

The carbon isotopic signatures of the Barnett and Turtle oils are relatively light (δ^{13}Csat = - 28.0 to -28.4 ‰; δ^{13}Carom = - 27.0 to -27.4 ‰) irrespective of the age of the reservoir, and the Waggon Creek-1 oil is only slightly (1 ‰) heavier (Fig. 22). Although the Barnett and Turtle oils have undergone differing degrees of biodegradation, the bulk carbon isotopic ratios are still similar. As an overall generalisation, oils have become isotopically heavier throughout the Palaeozoic, with extremely depleted δ^{13}C values in the order of -34 ‰ being recorded for Cambrian and Ordovician oils, to heavier isotopic signatures of around -24 ‰ for Permian oils (Stahl, 1977; Morante *et al.*, 1994; Summons *et al.*, 1995). The isotopic signatures of the Barnett, Turtle and Waggon Creek oils are comparable to Carboniferous aged oils in the neighbouring Canning Basin (Fig. 23).

Biomarker Assemblages

The biomarker assemblage of the Barnett, Turtle and Waggon Creek-1 oils contain a standard complement of C_{27} to C_{35} hopanes with C_{30} hopane being the dominant homologue (C_{29}/C_{30} hopane < 1: Table A12). The high sterane/hopane ratio (Table A11) together with an abundance of C_{23} and C_{24} tricyclic terpanes implies that there was a high input of marine algal (relative to bacterial) lipids to the kerogen. In addition to the usual C_{19} to C_{26} tricyclic terpane distributions, significant concentrations of an as yet unidentified ?tetracyclic compound ('A') elutes prior to the C_{24} tricyclic terpane. A second unknown compound ('B') elutes after the C_{25} tricyclic terpane homologues and before the C_{24} tetracyclic terpane (Fig. 37). C_{27} and C_{29} steranes are present in either similar proportions or there is a predominance of ethylcholestane (C_{29} sterane) and as a result the oils cluster in the transitional field in Figure 28a. Grantham and Wakefield (1988) demonstrated that ethylcholestane is abundant in Proterozoic and Early Palaeozoic oils with the proportion of C_{29} to C_{28} steranes decreasing in marine oils over geological time. The C_{28}/C_{29} sterane ratio of 0.34-0.57 for the Barnett, Turtle and Waggon Creek-1 oils is consistent with the proposed Carboniferous age for these oils. Low concentrations of 24-*n*-propylcholestane were detected in all of the above oils with the C_{30} sterane index being between 0.02 and 0.06 (Table A11). C_{30} 3β-methyl steranes, and to a lesser extent 2α-methyl steranes, are present in all of the above oils. Trace quantities of 4α-methyl steranes were detected, although dinosterane could not be positively identified. This is not surprising since dinoflagellates, which synthesis the dinosterane precursors, are not observed in the sedimentary record until the Middle Triassic (Summons *et al.*, 1987, 1992; Thomas *et al.*, 1993). Dinosteroid compounds which are detected in older acritarch-rich sediments do not appear to be common in Carboniferous and Permian oils and sediments (Moldowan *et al.*, 1995).

Further evidence of a pre-Permian age for the oils comes from the absence of diterpanes. Compounds of this class include labdane, pimarane, phyllocladane and kaurane which are largely, but not exclusively, derived from the resins of gynmosperms (Alexander *et al.*, 1987, 1988, 1992) which evolved during the Late Carboniferous and became abundant in the Permian. Labdane is present in the Barnett and Turtle oils and may have a microbial origin since Dimmler *et al.*, (1984) reported an abundance of this compound in biodegraded Athabasca oils.

An abundance of diasteranes in the Barnett, Turtle and Waggon Creek-1 oils highlights the clay-rich nature of their source beds, since these rearranged steranes form during diagenesis from clay-catalysed backbone rearrangements of their functionalised steroid precursors. The diasterane/sterane ratio is ≥ 1 in most samples (Table A11; Figure 29a). The relationship between the abundance of rearranged hopanes (diahopanes and neohopanes) and depositional environment is less clear, but high concentrations of neohopanes (Ts and C_{29}Ts) have been observed in Toarcian shales deposited under hypersaline, low Eh conditions, and their associated bitumens (Moldowan *et al.*, 1986; Rullkötter and Marzi, 1988). High abundances of the neohopanes in the Barnett, Turtle and Waggon Creek-1 oils cause the Ts/Ts+Tm ratio (Table A14), widely used as a maturity parameter, to be anomalously high.

With the exception of Barnett-2 (#439), gammacerane is present in minor quantities in all of the oils where it may have been concentrated by biodegradation (see below). The presence of this biomarker suggests salinity stratification of the depositional environment. In addition, the presence of 28,30-dinorhopane in the Barnett, Turtle and Waggon Creek-1 oils, together with the low pristane/phytane ratios, indicates deposition under anoxic marine conditions.

It also must be mentioned that the Turtle-2 DST-1A oil (and oil stains extracted from Milligans-1 cuttings) contained the exotic biomarker bicadinane and its methylated analogues. Several different samples of this drill stem test were obtained, courtesy of Western Mining Corporation, and all contained this biomarker. Since bicadinane originates predominantly from tropical angiosperm resins, the presence of this biomarker is believed to be indicative of contamination from drilling additives/lubricants.

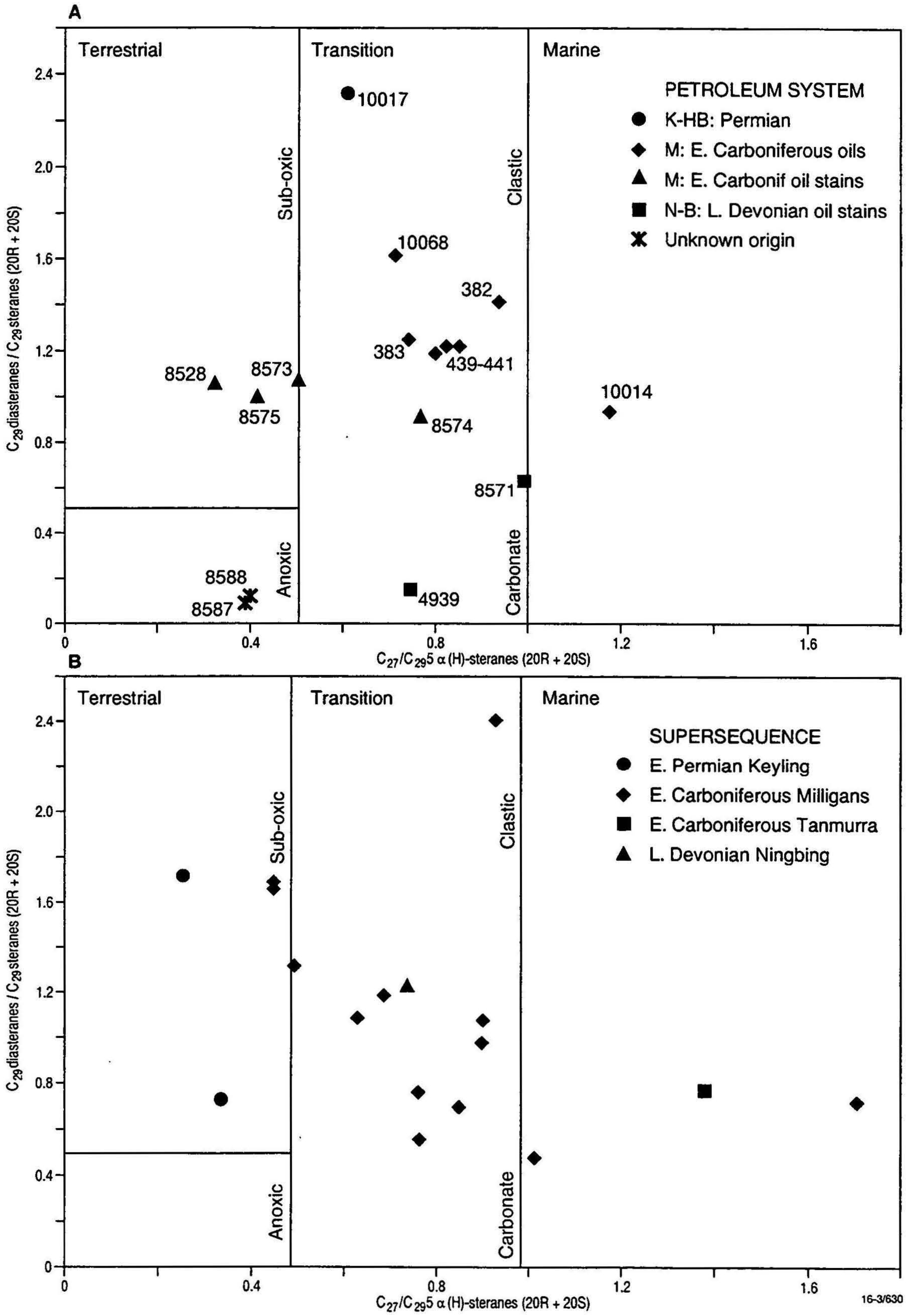


Figure 29 Plot of the source-dependent parameters ΣC_{29} diasteranes/ΣC_{29} 5α(H)-steranes versus C_{27}/C_{29} $\alpha\alpha\alpha$ steranes (20R+20S) in A) petroleums and B) source rocks.

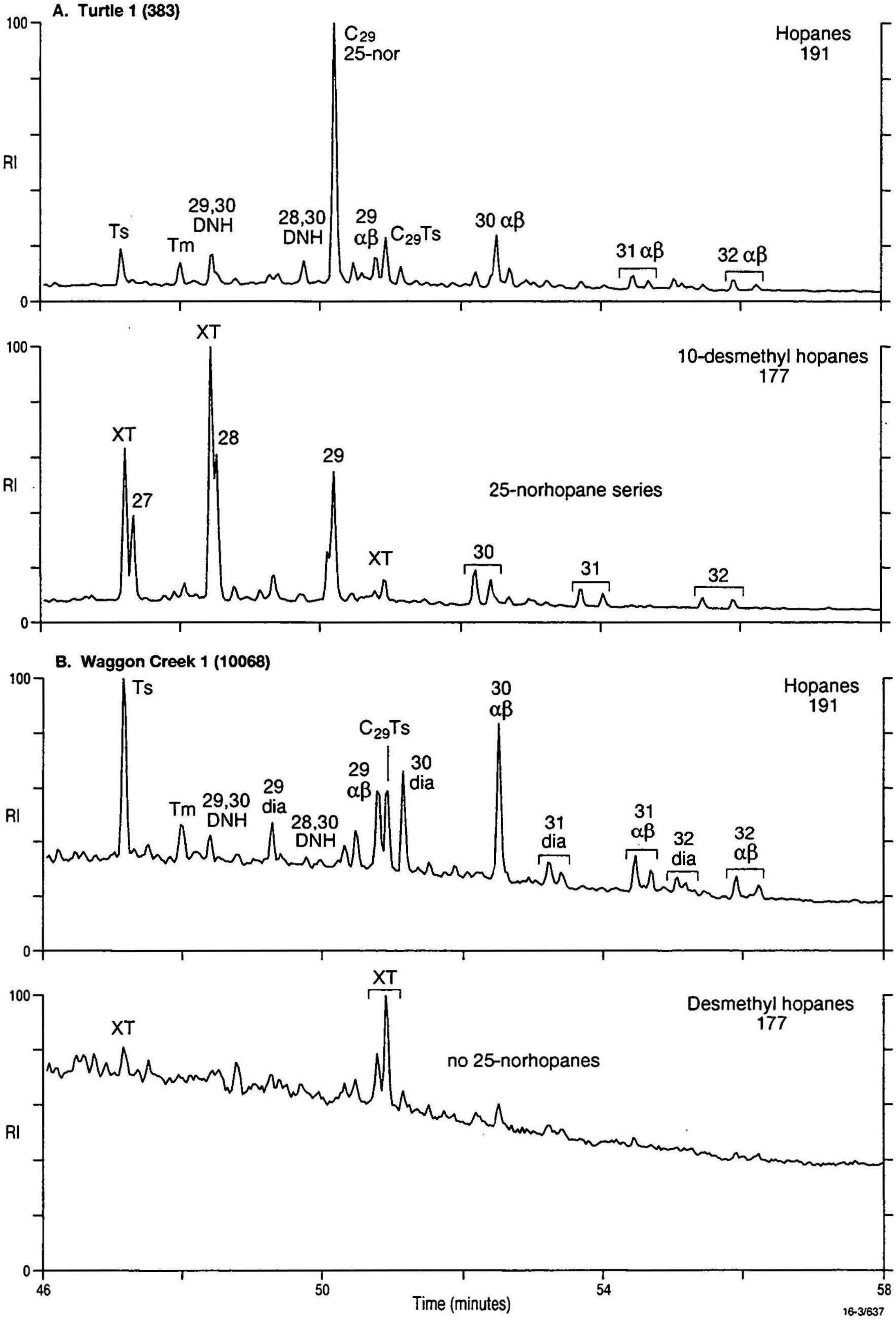


Figure 30 GC-MS (MRM) chromatograms showing the distribution of hopanes (m/z = 191) and desmethyl hopanes (m/z = 177) in a) a biodegraded crude oil (note chromatogram is dominated by 25-norhopane) and b) a unaltered crude oil.

Biodegradation

Biodegradation of the Turtle-1 and 2 oils is evident from the saturates chromatograms which exhibit a general depletion of the *n*-alkanes, a naphthenic hump and altered isoprenoid to normal alkane ratios, as shown in Figures 27 and 28. Biomarker analyses show that a series of demethylated hopanes, 25-norhopanes, are present in the majority of the oils analysed (parameter o; Table A12) shown in Figure 30. 25-Norhopanes are believed to result from *in situ* aerobic bacterial degradation of the regular hopanes in shallow oil reservoirs and indicate a heavy degree of biodegradation (Moldowan and McCaffrey, 1995; Peters *et al.*, 1996: Table A16). The only oils to have intact *n*-alkane profiles and in which no 25-norhopanes were detected are the deepest drill stem test oils recovered from Barnett-2 (#439) and Turtle-2 (#384 and #10014) and the Waggon Creek-1 oil. Some oils, for example Barnett-2 (#440 and #441) and Turtle-2 (#4919), contain 25-norhopanes (consistent with heavy biodegradation) but appear to have unaltered or only slightly altered *n*-alkanes profiles. As suggested by Jefferies (1988), these biomarker assemblages can be explained by a secondary pulse of fresh oil mixing with the remains of a heavily palaeobiodegraded crude oil. In the case of the Turtle-1 oil (#382), this later oil charge has also undergone contemporary light biodegradation. Due to differences in microbial populations and reservoir conditions, there are still uncertainties as to the order which compounds are biodegraded, particularly when 25-norhopanes are present. In the most biodegraded oil (Turtle-2 sample 383), the biological 20R epimer has been preferentially removed with respect to the geological 20S epimer in the C_{27}-C_{29} $\alpha\alpha\alpha$ steranes. Hence, maturity parameters involving these isomerization reactions are unreliable.

Gammacerane is highly resistant to biodegradation and is present in significant quantities in most of the Barnett and Turtle oils, but is below the level of detection in the freshest Barnett-2 oil (sample 439: Table A12). This would imply that the biomarker distributions in the Barnett and Turtle oils may have been considerably altered from that of the parent oil. Having said this, the relatively high abundance of gammacerane in the Waggon Creek-1 oil, which shows no evidence of biodegradation, may arise due to source differences.

Maturity

The maturity of the oils was assessed by using sterane and hopane biomarker parameters (Table A14), the aromatic hydrocarbon ratios MNR-1, DNR-1 and the methylphenanthrene index (MPI-1; Table A17). With the exception of the oil stained samples discussed below, the Barnett, Turtle and Waggon Creek-1 oils are mature with the hopane and sterane isomerisation reactions being equilibrated (Fig. 31). The MPI-1 is believed to reflect the maturity of the oil's inferred source rock at the time of primary migration.

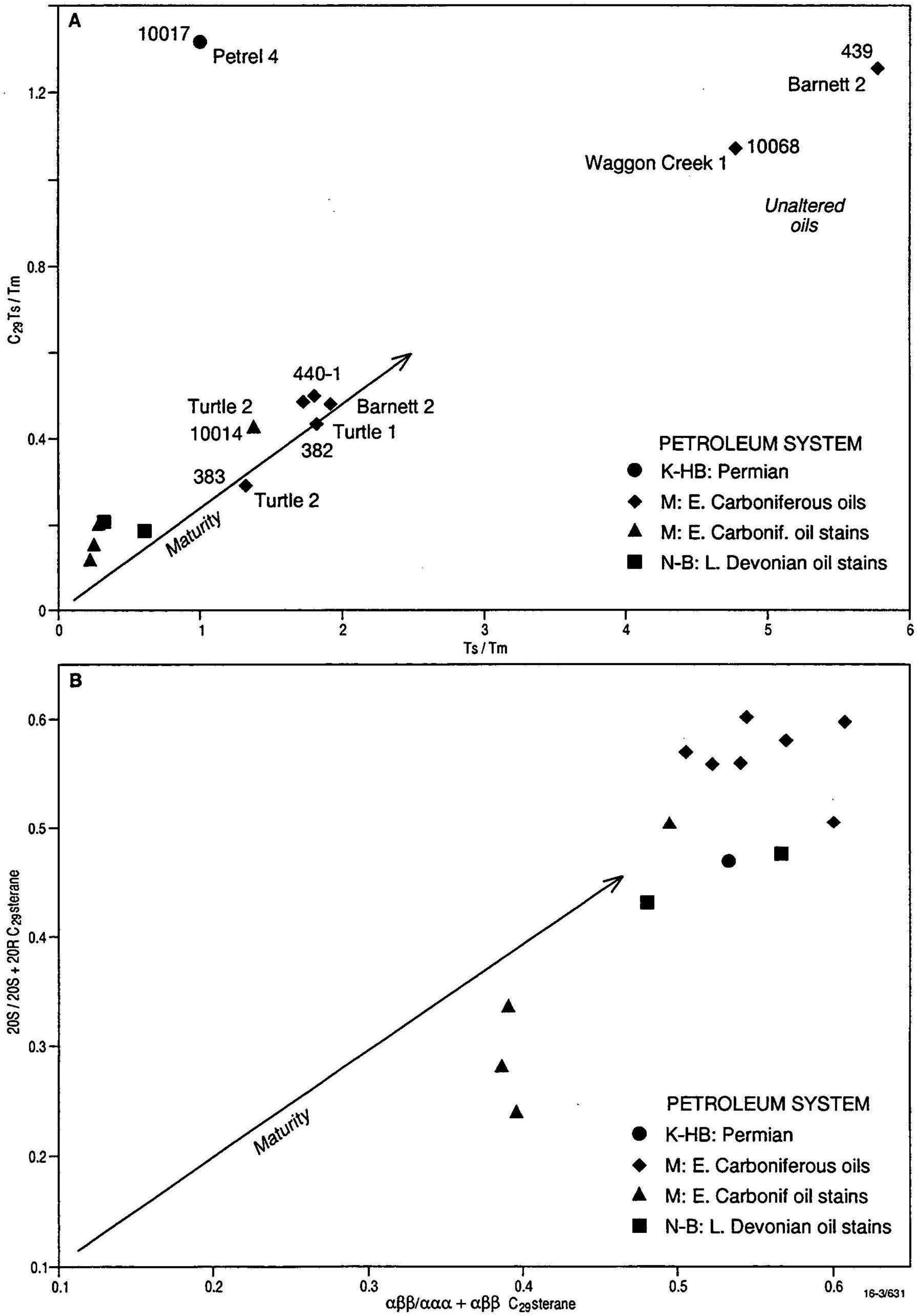


Figure 31 Plot of maturity-sensitive parameters A) C_{29}Ts/Tm versus Ts/Tm and B) 20S/20R+20S 5α(H)-steranes versus αββ/ααα + αββ C_{29} steranes (20R+20S).

However, this ratio is prone to biodegradation effects (see Table A16) and must be used with caution. Calculated vitrinite reflectance values from the MPI-1 are between 0.76 and 0.93 % for the Barnett, Turtle and Waggon Creek oils, demonstrating that they are indeed mature oils. The oils at Barnett and Turtle show more variation in their aromatic maturity parameters than expected. This lack of consistency may be explained by a combination of biodegradation effects and the reservoiring of multiple oil pulses.

Permian-reservoired Oils Containing Exotic Biomarkers

In contrast to the drill stem test oils, the Barnett-1 (#8573), Cambridge-1 (#8528) and Turtle-1 (#8575) samples obtained by extracting oil-impregnated cores of Permian age have a greater proportion of C_{23+} *n*-alkanes ($C_{17}/C_{27} > 0.6$) that exhibit an odd carbon-number-predominance in the range C_{23}-C_{31}, and generally higher pristane/phytane ratios (Pr/Ph = 2.0-3.8). These signatures can be attributed to either land-plant waxes or algal lipids. The biomarker signatures of these oil stains are in many ways similar to those of the drill stem test oils (viz. they contain gammacerane, 25-norhopane and unknown terpanes) but these samples contain a higher proportion of ethylcholestane (Fig. 28) and additional pteridosperm (seed ferns) and/or conifer-derived biomarkers *e.g.* diterpanes and aromatic hydrocarbons including retene (Table A17). Gymnosperms evolved during the Late Carboniferous and proliferated during the Permian. Hence, this distinctly terrestrial signature is believed to have been inherited from the host rocks, the Late Carboniferous Kuriyippi Formation in the case of the Barnett-1 and Cambridge-1 oil stains and the Early Permian Treachery Shale in the Turtle-1 sample. High production indices (PI = 0.6-0.7) and anomalous maturity (calculated vitrinite reflectance (Rc1) Barnett-1 = 0.76 %: Rc1 Turtle-1 = 0.91%: Table A17), indicate the presence of migrated hydrocarbons. However, the oil stained cores have significant organic carbon contents (*e.g.* Barnett-1, cores 3 & 4, TOC = 0.6-1 %, S_2 = 1-2.5 kg hydrocarbons/tonne: HI = 184-438 mgS_2/gTOC) and since they are within the early oil window (Rv = 0.65 %), hydrocarbons have probably been generated *in situ*. The presence of indigenous hydrocarbons also accounts for the abundance of the biologically inherited 20R sterane and 22R hopane stereoisomers, and explains the lower degree of thermal maturity estimated from saturated biomarker ratios compared with the maturity determined from aromatic hydrocarbon ratios (Tables A14 and A17: Fig. 31).

Oil Shows from Lacrosse-1

Oil shows at Lacrosse-1 were initially assumed to have been generated from the same source as the Barnett and Turtle oils. Oil stains extracted from cuttings samples in the Treachery (1588-1591 m) and the Keyling successions (1451-1454 m) were also analysed. Biomarker and isotopic data shows that these oils may not be indigenous to the Petrel Sub-basin. The saturates chromatograms have a limited range of *n*-alkanes (C_{13}-C_{27}). Their biomarker assemblages indicate derivation from anoxic marine carbonate source rocks, *i.e.* they have low diasterane/sterane and diahopane/hopane ratios, C_{30} steranes, gammacerane and 28,30-dinorhopane were detected (Tables A11 and A12). It was initially believed that these oils may have been generated from Late Devonian carbonates of the Ningbing-Bonaparte Petroleum System since at Lacrosse-1 Permian sediments are faulted above the Bonaparte Megasequence. However, these oils differ markedly from the oils reservoired in the onshore Late Devonian sediments as shown by Figures 28 and 29. Furthermore, the isotopic composition of these oils are anomalously heavy (δ^{13}Csat = - 26.7 ‰; δ^{13}Carom = - 25.2 ‰), plotting outside the range of Late Devonian and Carboniferous oils of the Petrel and Canning Basins (Fig. 23).

Until further analyses of Late Devonian carbonate-sourced oils prove otherwise, the oil shows analysed from Lacrosse-1 must be regarded with suspicion, possibly being contaminants introduced during drilling.

Summary

Irrespective of the age of their reservoirs, the Barnett, Turtle and Waggon Creek-1 oils have similar biomarker assemblages and isotopic signatures that infer derivation from algal and bacterial-rich siliciclastic facies deposited in a marine environment. Since the maturity of these oils are out-of-place with respect to their host rocks and the deepest oils recognised to date are found within Early Carboniferous reservoirs, their source rocks are most likely to be the marine mudstones of the Milligans Formation, as proposed by McKirdy (1987b) and Jefferies (1988).

4.2.2 Early Carboniferous Source Rocks.

Determining the source potential of the Milligans Supersequence and evaluating oil-source rock correlations is difficult due to a number of factors. Firstly, this supersequence is thickest in depocentres in the Cambridge Trough and to the north of the Turtle-Barnett High where it has not been drilled (Figs. 2 and 6). Secondly the Milligans Supersequence penetrated in offshore wells is difficult to correlate with onshore sections. Thirdly, in the majority of wells the most organic-rich interval of the Milligans Supersequence (the mid-Milligans Sequences Mill A5-7) lies within the oil window and in the central Carlton Sub-basin (Keep River-1, Kulshill-1) is overmature. Although less mature samples were obtained from the mineral hole NBF1002, the cores have been exposed to the weather over the last 15 or so years resulting in the degradation of the organic matter.

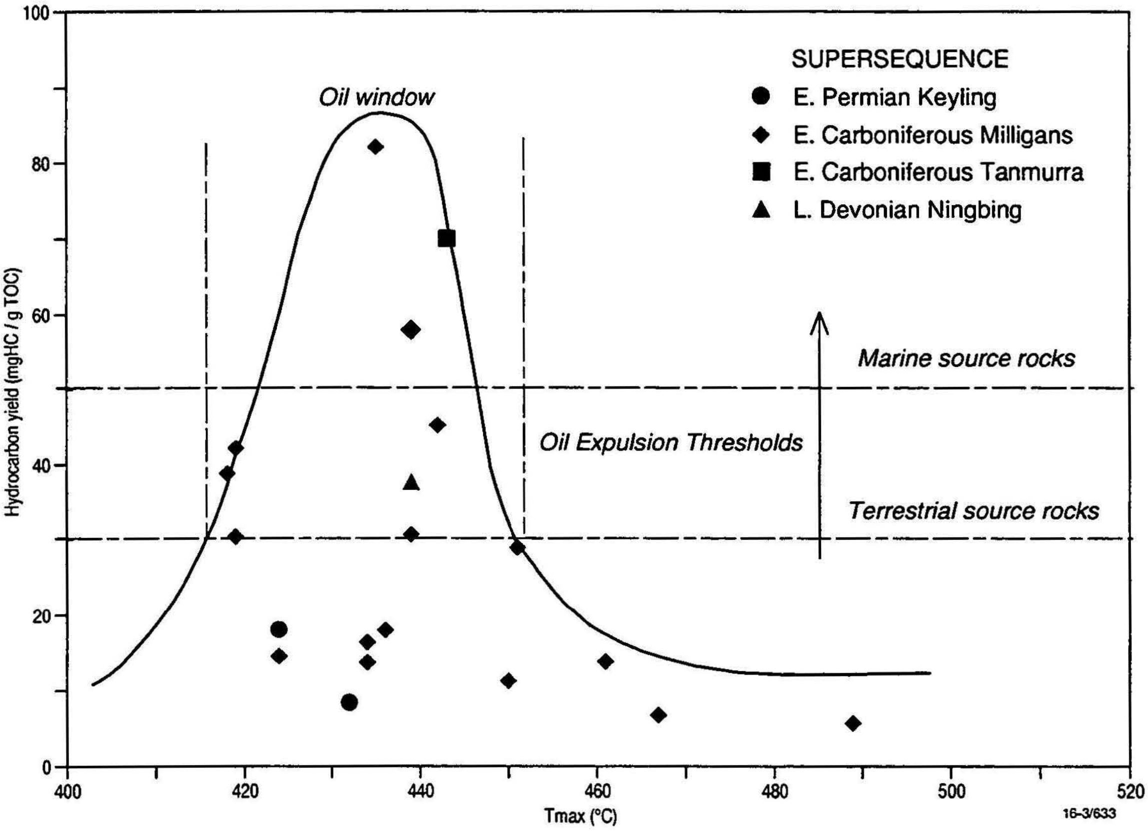


Figure 32 Plot of sediment extract yield (sum of saturated and aromatic hydrocarbons in mg/gTOC) versus Tmax.

Source Richness

Despite the above difficulties, source rock extracts of the Milligans Supersequence were undertaken from a number of wells as listed in Table A7b. In addition, a mudstone from the overlying Tanmurra 1 Sequence at Lesueur-1 was analysed. Rock-Eval pyrolysis data for these extracts are shown in Table A8. Geochemical data from previous studies of Early Carboniferous source rocks are included where appropriate. Immature organic-rich Milligans mudstones were sampled from the mineral well NBF1002 (CAI = 1; Rv = 0.45 %). Assuming that the threshold for oil generation can be equated to a hydrogen index of 200, the mudstones in NBF1002 are both oil and gas-prone. Maturity data is not available for Pelican Island-1 and Spirit Hill-1, but estimates from Tmax values (Tmax = 434-439 °C) place samples from the Milligans Supersequence within the early oil window. The kerogens in samples from these latter two wells are composed predominantly of lycopod and fern spores and cuticles, and differ markedly from the thick tissues identified in kerogens from NBF1002. At Barnett-2 and Bonaparte-1 and 2 the mudstones of the Milligans Supersequence are not ideal for biomarker analyses since these sediments are within and above the peak oil window, hence their low hydrogen indices, but the lack of alternative locations necessitated that these wells were sampled.

TOC content and rock extract data were used to further define source rock quality and estimate the temperature at which expulsion occurred. From the plot of Tmax versus the yield of extractable hydrocarbons (mg/gTOC) the maximum yield of hydrocarbons occurred around 439 °C with few samples having sufficient oil-prone kerogen for expulsion to occur (Fig. 32).

Gas Chromatography

The gas chromatograms of Early Carboniferous mudstone extracts shown in Figures 33 and 34 are a representative selection from the GC's in Appendix E. They are characterised by an abundance of low molecular weight *n*-alkanes $< C_{23}$ with a maximum peak around C_{15}-C_{19} and relative low pristane/phytane ratios (Pr/Ph = 1-2.6: Table A10b), plotting within the algal and bacterial field in Figure 35. The selective depletion of the C_{12}-C_{25} *n*-alkanes and enhanced isoprenoid alkane abundances in the NBF1002 core samples are a result of weathering as indicated by the samples which plot in the top right corner of Figure 35.

Extracts of the Early Carboniferous mudstones show some variation in the abundance of their waxy *n*-alkanes (range C_{27}/C_{17} = 0.05-0.6) and in the abundance of normal alkanes relative to isoprenoid alkanes (Fig. 35). For example, extracts of the Tanmurra 1 Sequence at Lesueur-1 (8551) and the Milligans Supersequence at Bonaparte-2 (7976) and Pelican Island-1 (8557) have low wax contents and low Pr/*n*-C_{17} and Ph/*n*-C_{18} ratios, closely

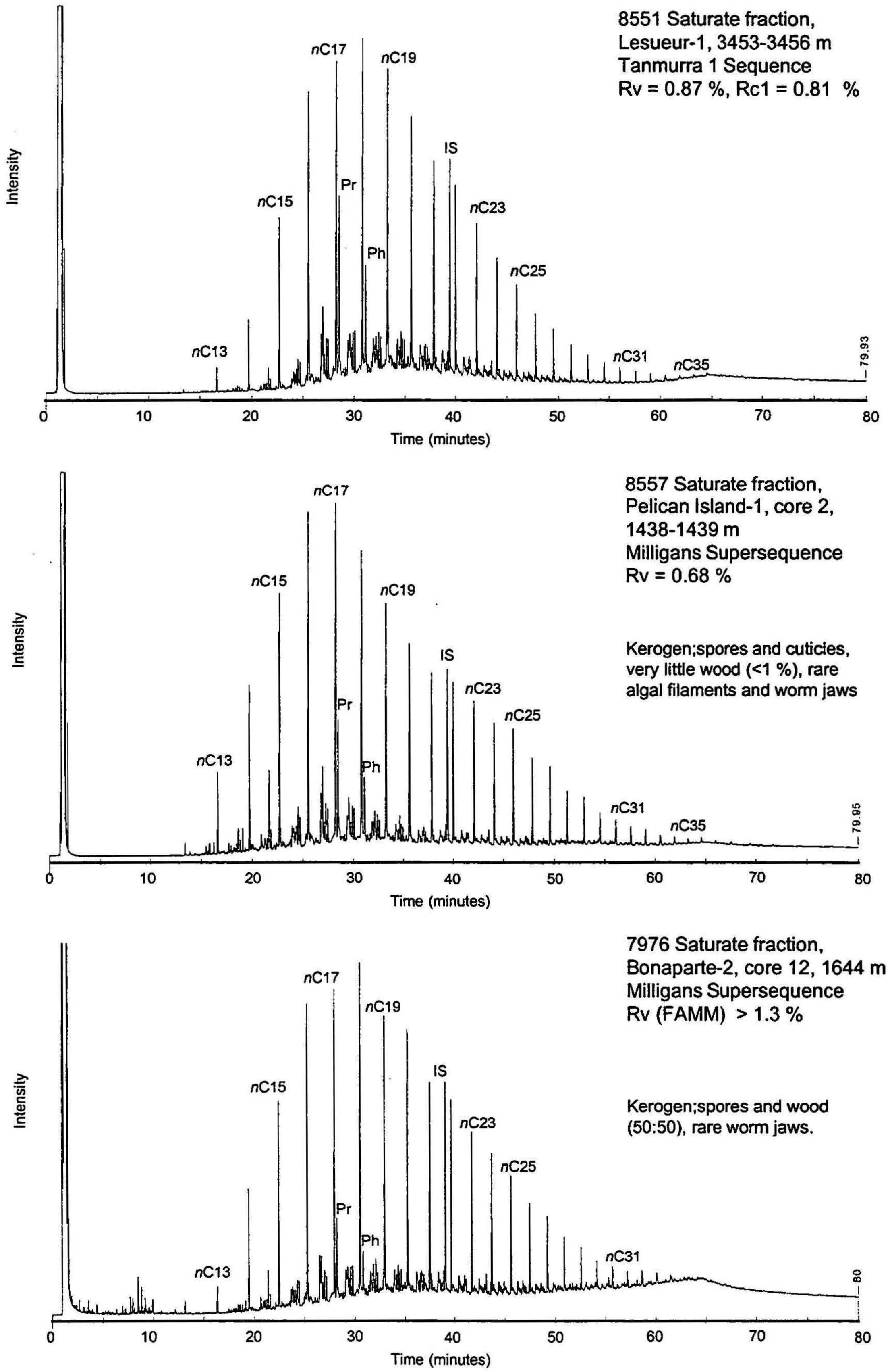


Figure 33 Representative gas chromatograms of Early Carboniferous non-waxy source rock extracts.

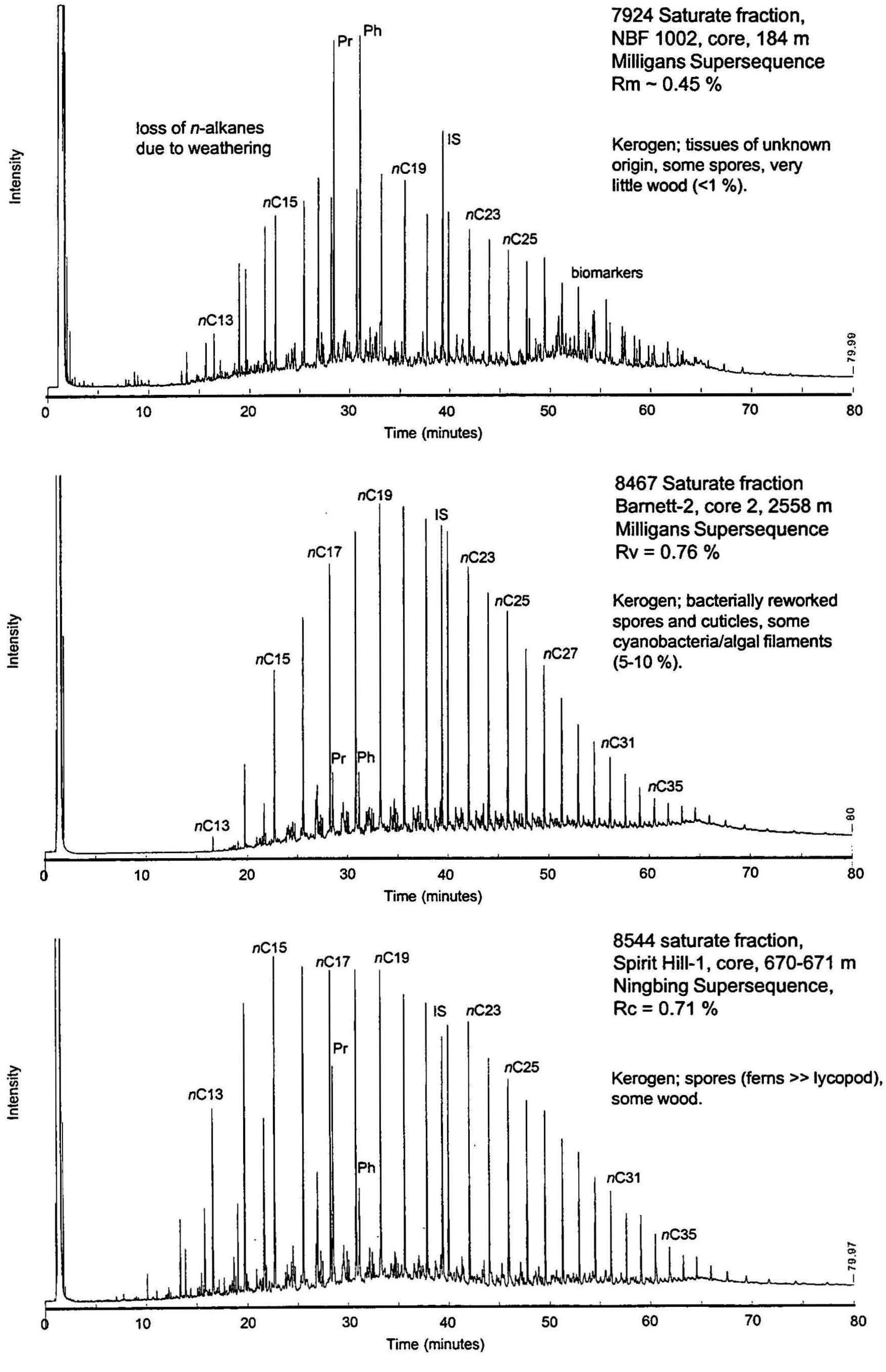


Figure 34 Representative gas chromatograms of Early Carboniferous source rock extracts; comparison with Late Devonian extract from Spirit Hill-1.

resembling the Barnett and Turtle oils. Other extracts of the Milligans Formation *e.g.* at Bonaparte-2 (#7970, #7972), contain a high proportion of C_{23}-C_{31} *n*-alkanes. Gas chromatograms of the Bonaparte-1 extracts show a naphthenic hump indicative of oil staining which may have arisen from mud additives since bicadinanes were detected in these samples. Similar contamination problems are apparent in the source rock extracts carried out by Lacrampe *et al.* (1981) at Bonaparte-2 since naphthenic humps are again present and in the sample from 1237 m only high molecular weight *n*-alkanes were present.

Isotopes

The Milligans extracts have variable ^{13}C values being in the order of 0.5 to 3 ‰ heavier than those of the Barnett, Turtle and Waggon Creek-1 oils (Fig. 36). The exception is the extract from Pelican Island-1 (8557) which is depleted in ^{13}C relative to these oils. The kerogens from Pelican Island-1, Spirit Hill-1 and Bonaparte-2 are very similar being composed of fern and lycopod spores and cuticles, some woody fragments (<1 %) and the rare occurrence of algae, cyanobacteria and scoleronts (worm jaws). The kerogen from NBF1002 is different to the other Early Carboniferous samples being composed of tissue-like material of possible plant origin, and yet its isotopic composition is not noticeably different.

Biomarker Assemblages

The biomarker assemblages of the Early Carboniferous extracts are broadly similar, irrespective of their stratigraphic position (Milligans A1 to A5). The relative proportions of C_{27}, C_{28} and C_{29} sterane are about 1.6 : 1 : 2. Their marine source affinity is indicated by an abundance of the C_{23} and C_{24} tricyclic terpanes and the presence of 24-*n*-propylcholestane. The C_{30} sterane index is around 0.03 (Table A11) and 3β-methyl-24-ethylcholestane is the dominant methyl sterane. C_{30} hopane is commonly, but not always, the dominant hopane homologue. The range in the diasteranes to sterane ratio of these extracts arises due to both lithological variations and maturity-effects (Fig. 28b). The low abundance of diasteranes in the NBF1002 samples may be explained by their lack of maturity, whereas the high abundance of diasteranes in a Pelican Island-1 sample (8563) probably reflects a change in depositional and diagenetic conditions.

Other source-dependent biomarker ratios show some variability between samples which probably arises from heterogeneity in the source rocks. For example, significant concentrations of 28,30-dinorhopane are found only in samples from NBF1002 (7923) and Pelican Island-1 (8561 and 8563). Likewise, appreciable amounts of gammacerane and the two unidentified tetracyclic terpanes ('A' and 'B') occur in some but not all samples (Fig. 37).

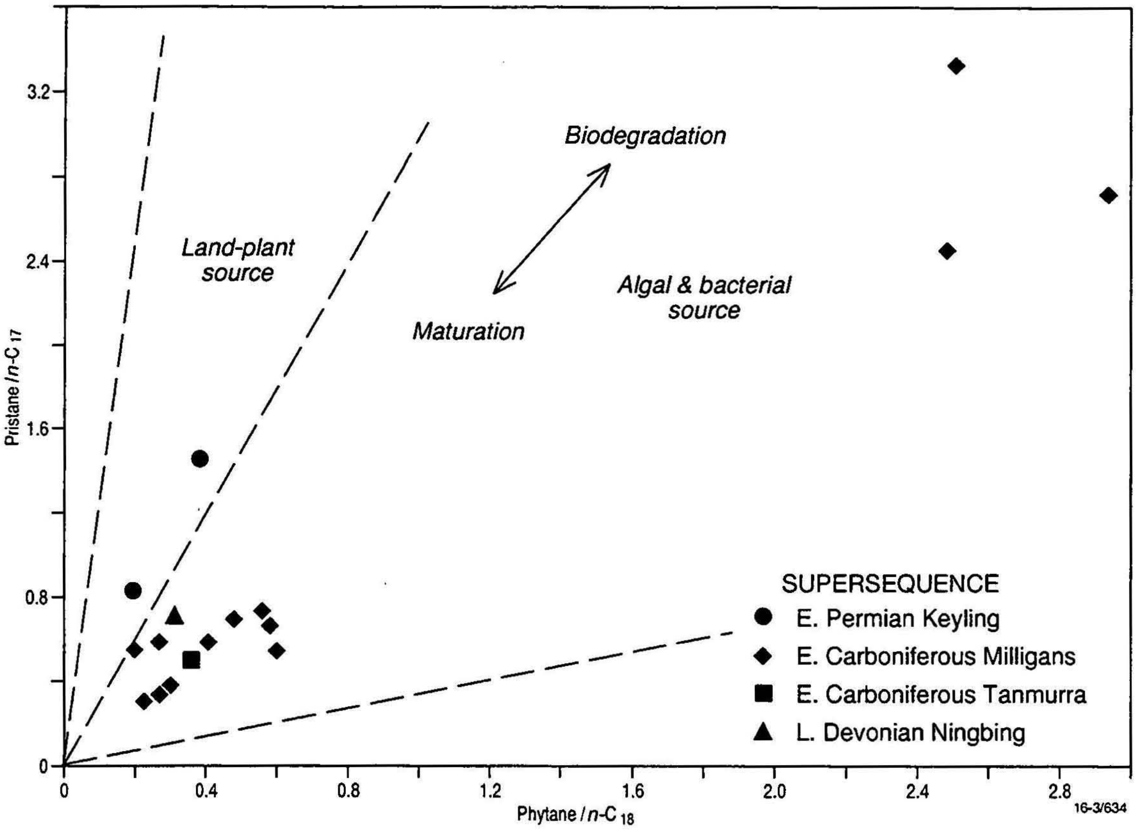


Figure 35 Plot of phytane/n-C_{18} versus pristane/n-C_{17} for source rock extracts.

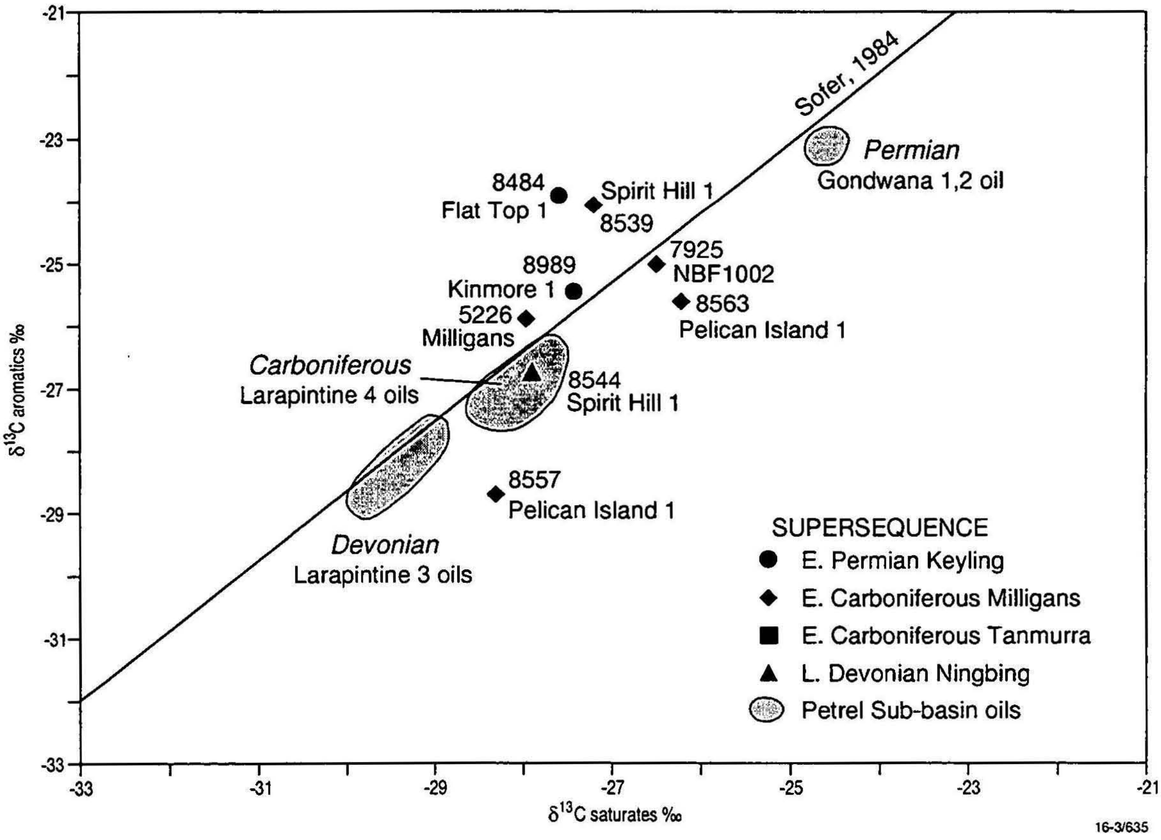


Figure 36 Carbon isotopic composition of source rock extracts.

4.2.3 Oil-Source Rock Correlations

The Early Carboniferous marine mudstones of the Milligans Formation are believed to have sourced the oils found throughout the Carboniferous and Early Permian successions. The most oil-prone source rocks were identified at NBF1002, however the precise biological origins of these Type II/III kerogens could not be determined. Although, the isotopic and biomarker signatures of any single extract is not identical to the oils, the generation and accumulation of hydrocarbons from these different source facies may collectively result in oils with geochemistries similar to those of the Barnett, Turtle and Waggon Creek-1 oils. Figure 38 illustrates the correlation between the biomarker (steranes and hopanes) assemblages of the Milligans mudstone at Pelican Island-1 and oil recovered from Turtle-2. Biomarker parameters which are common to both oils and source rocks include; an abundance of diasteranes, diahopanes and neohopanes, C_{27}/C_{29} sterane ratios of around 1, the presence of minor gammacerane and 28,30-dinorhopane and methyl hopanes. Further evidence to support this correlation comes from the tri- and tetracyclic terpane distributions which in some mudstones are the same as those of the oils and include similar proportions of the exotic but as yet unidentified compounds (labelled 'A' and 'B' in Fig. 37).

Furthermore, the variability shown in the pristane/phytane ratio of Milligans Supersequence extracts and the Barnett, Turtle and Waggon Creek oils means that this ratio cannot be used in isolation to differentiate between Larapintine 3 and 4 oils found in mineral holes in the Carlton Sub-basin.

To complicate matters further, the isotopic signature of a Late Devonian mudstone from the Ningbing Supersequence at Spirit Hill-1 (8571) is almost identical to those of the Barnett, Turtle and Waggon Creek-1 oils, as shown in Figure 36. Although the saturates chromatogram of this extract comprises some waxy *n*-alkanes like that of the Waggon Creek-1 oil, its pristane/phytane ratio is markedly higher (Table A10). The biomarker signature of the Late Devonian Spirit Hill sample differs only slightly from those of the Milligans extracts and the Larapintine 4 oils with variations being seen in the tri- and tetracyclic terpane distributions. In addition to the prominent C_{23} and C_{24} tricyclic terpanes seen in the Larapintine 4 oils and source rocks, the C_{19}, C_{20} and C_{21} tricyclic terpanes and the C_{24} tetracyclic terpane are equally abundant. Moreover, the Spirit Hill sample does not contain the characteristic, exotic ?tetracyclic 'A' and 'B' terpane peaks. Since the Milligans source rocks and oils presently assigned to the Milligans Petroleum System show a degree of variability, some contribution from mature Late Devonian mudstones cannot be discounted.

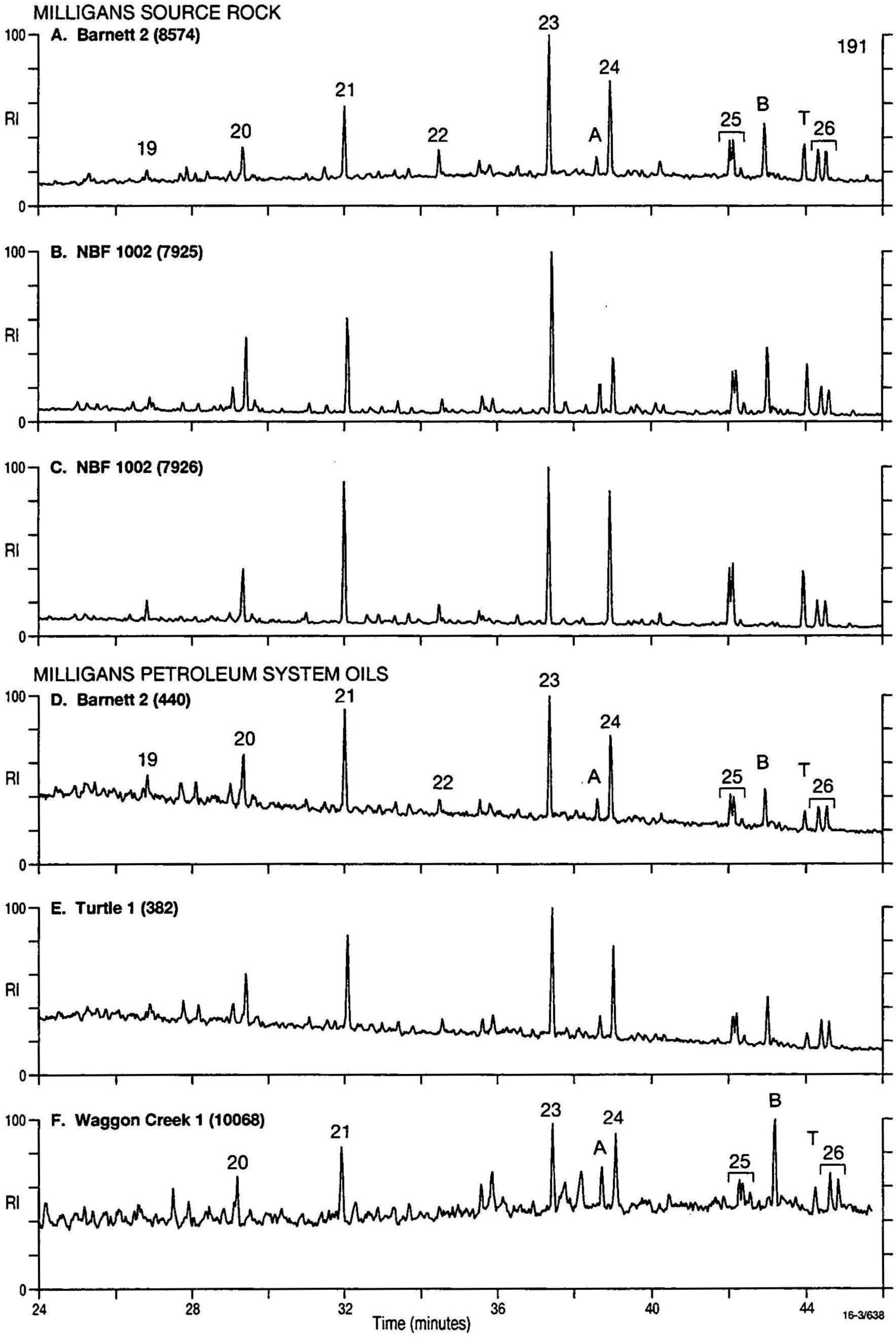
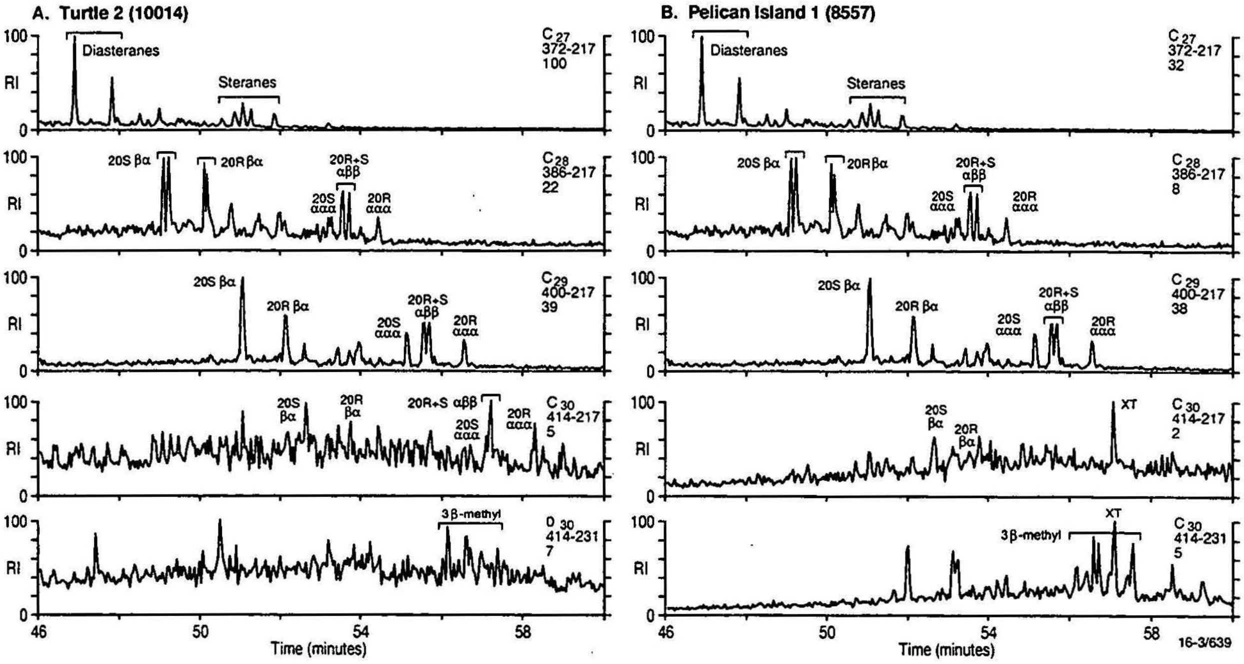


Figure 37 GC-MS (MRM) chromatograms showing the distribution of tri- and tetracyclic terpanes in Milligans mudstones and selected oils. Numbered peaks refer to carbon number of tricyclic terpanes; T denotes C_{24} tetracyclic terpane, and 'A' and 'B' denotes as yet unidentified peaks.

A Steranes



B Hopanes

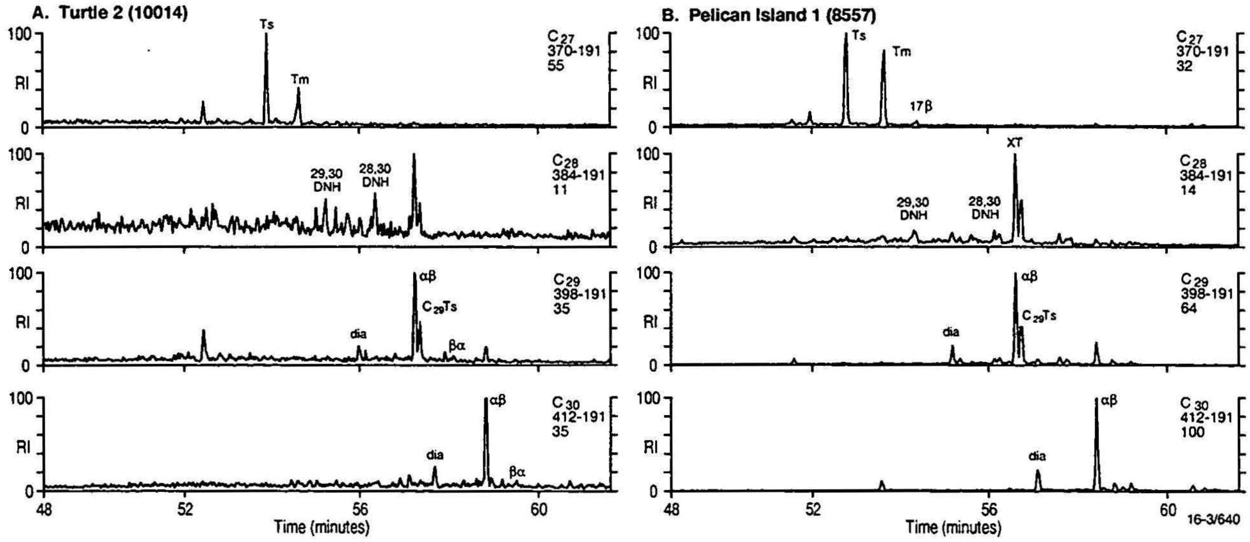


Figure 38 GC-MS (MRM) chromatograms showing the distribution of A) steranes and B) hopanes in representative Milligans oil (Turtle-2) and mudstone (Pelican Island-1) samples. Chromatograms are identified by carbon number, reaction transition and relative abundance of the most intense peak. Peak assignments for the steranes and hopanes are defined in Appendix E.

4.3 Keyling-Hyland Bay Petroleum System (Gondwanan 1)

The Keyling-Hyland Bay Petroleum System (Gondwanan 1) comprises economic gas reserves in the Tern (1.3 TCF gas-in-place) and Petrel (3.3-13.6 TCF) Fields which are reservoired in the Late Permian Hyland Bay Formation. Significant gas flows also occurred from the Hyland Bay Formation at Penguin-1 and Fishburn-1. Condensates are associated with the gas in the Petrel Field (*e.g.*, Petrel-3, DST-1, 200 BOPD from gas flows of 22 MMCFD) and are the focus of the following discussion.

4.3.1 Permian-Sourced Condensate

Condensate at Petrel-4 (DST 4) was recovered from a depth of 3570-3586 m in the Late Permian Hyland Bay Formation. The condensate is an aromatic-intermediate, medium gravity (37 °API), non-waxy crude that is low in sulphur (S = 0.02 %: Table A9a). The whole oil gas chromatogram of the Petrel-4 condensate is dominated by aromatic hydrocarbons which do not display any evidence of *in situ* alteration by microbial activity and water washing. Hence, the high aromatic content (51 %) of the condensate can be assumed to be a characteristic inherited from its source beds. Low sulphur, aromatic-intermediate crudes are frequently generated from marine siliciclastic sediments containing marine or a mixture of marine and terrestrially-derived organic matter deposited in a reducing environment (Tissot & Welte, 1984).

The saturates fraction has a unimodal *n*-alkane profile dominated by the low ($<C_{23}$) molecular weight alkanes (Fig. 39) which do not exhibit any carbon-number preference. The pristane/phytane ratio (Pr/Ph = 3.5) is high suggesting deposition of terrestrial-derived organic matter in relatively oxic conditions, although this result may be unreliable due to the low concentration of isoprenoid alkanes in the sample. The pristane/*n*-heptadecane and phytane/*n*-octadecane ratios are low (Table A10a), being typical of a mature condensate. Remarkably similar results were obtained for a condensate (DST 1, 3823-3863 m) produced from Petrel-3 (McKirdy, 1982). Hence, it is believed that the Petrel-4 condensate is probably representative of the Petrel Field.

The Petrel-4 condensate is isotopically heavy (δ^{13}Csat = - 24.57 ‰; δ^{13}Carom = - 23.12 ‰; Fig. 22) being comparable to the Whicher Range-1 condensate in the Perth Basin (Summons *et al.*, 1995).

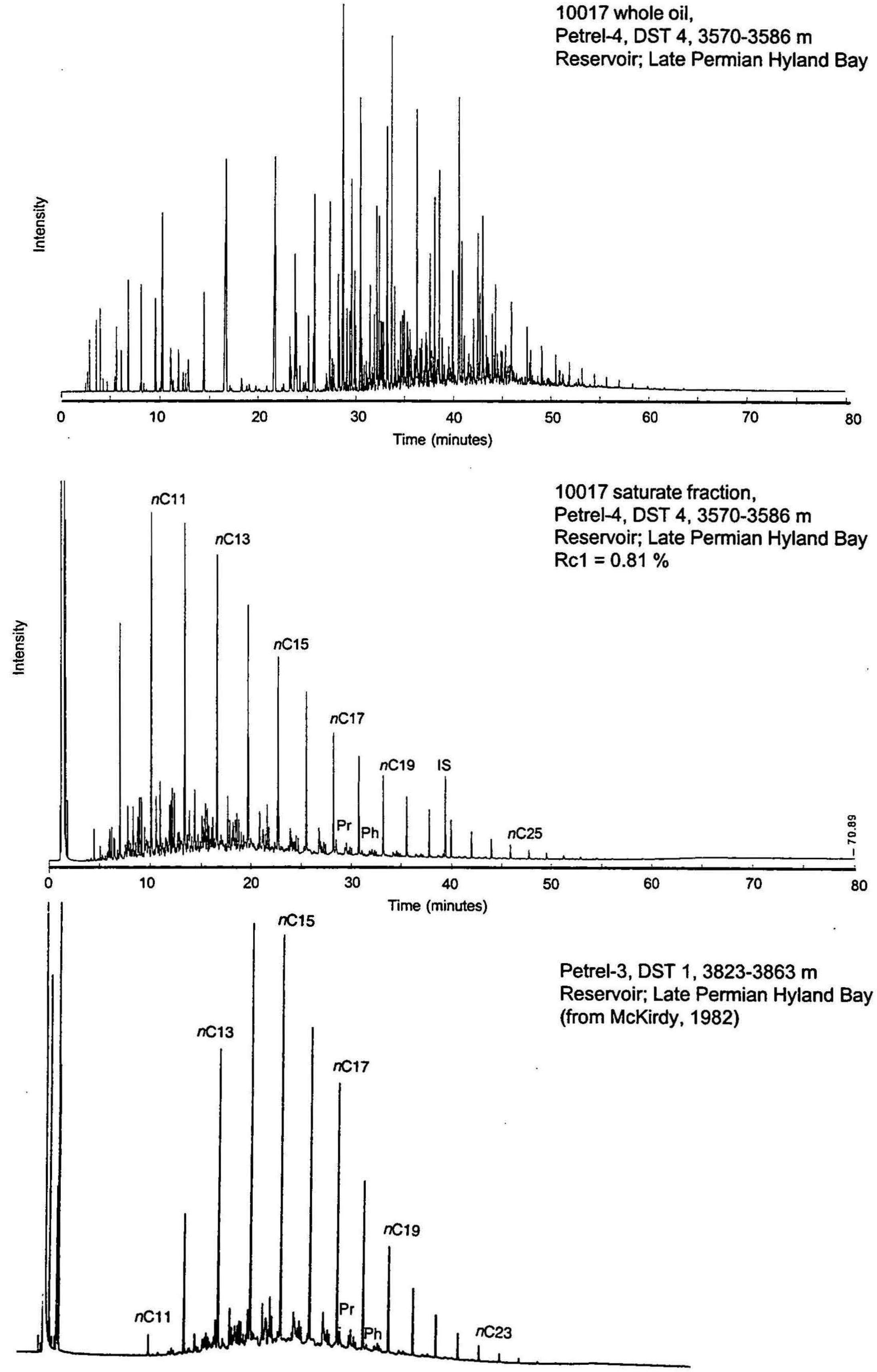


Figure 39 Gas chromatograms of Petrel Field condensates.

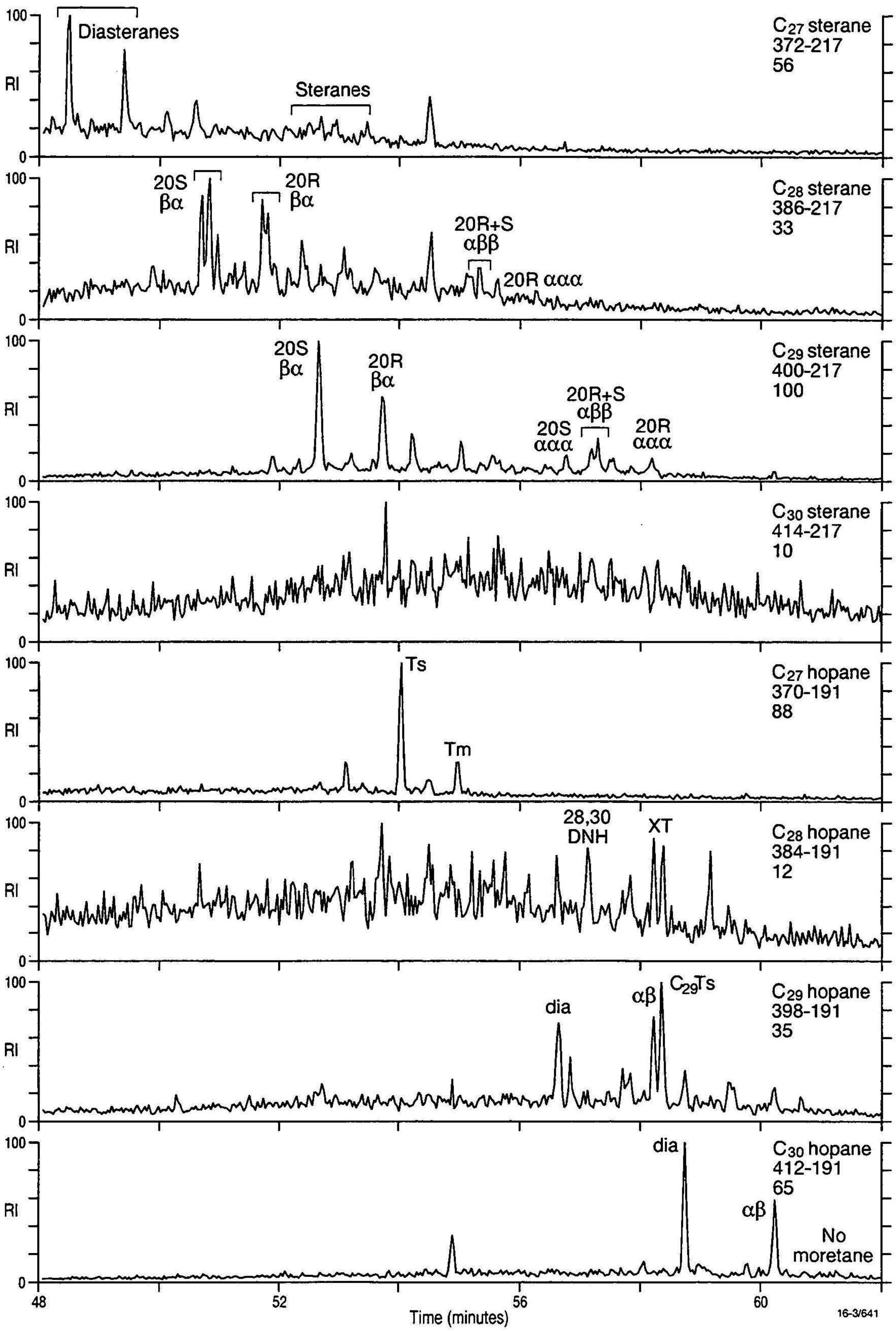


Figure 40 GC-MS (MRM) chromatograms showing the distribution of steranes and hopanes in Petrel-4 condensate. Chromatograms are identified by carbon number, reaction transition and relative abundance of the most intense peak. Peak assignments for the steranes and hopanes are defined in Appendix E.

The biomarker distribution of the Petrel-4 condensate is shown in Figure 40. Ethylcholestane is the dominant homologue in the C_{27}-C_{30} sterane distribution and plots within the transitional field in Figure 28. This sterane distribution could arise solely from algal remains or from a mixture of algal and land-plant detritus. Likewise the high sterane to hopane ratio also indicates an abundance of either land-plant or algal-derived hydrocarbons with respect to bacterial lipids. A high abundance of C_{19} and C_{20} tricyclic terpanes ($C_{19}/C_{23} = 7$: Table A12) support some input of land-plant material to its source rock. The absence of retene and diterpanes would tend to suggest that gymnosperms did not contribute significantly to the condensate, although these compounds may be either absent or present in only trace quantities in many other North West Shelf oils and condensates. The clastic nature of the source rock is determined from the higher concentration of C_{30} hopane relative to C_{29} hopane (C_{29}/C_{30} hopane = 0.6; Table A12) and the greater abundance of diasteranes to steranes (C_{29} diaster/ster =2.3; Table A14). High maturity could partially account for the predominance of diasteranes and diahopanes since these rearranged biomarkers are more stable at high temperatures than their regular isomers. The high abundance of rearranged hopanes (diahopanes, Ts and C_{29}Ts) may also be related to the type of kerogen and/or depositional environment of their source rocks, since glaciogene sediments elsewhere in Australia exhibit similar signatures.

The Petrel-4 condensate appears to have been generated at thermal maturities consistent with the peak oil window. The isomer ratios for steranes and hopanes indicate that thermodynamic equilibrium has been reached; moretanes are absent and the Ts/Ts+Tm ratio is high (Table A14). The maturity calculated from the aromatic maturity parameter MPI-1 indicates generation from a source rock with an equivalent vitrinite reflectance of around 0.8 %. Hence, the Petrel-4 accumulation appears to have been generated from gas and condensate-prone primary material rather than from the cracking of oil which takes place at temperatures greater than 170 °C ($R_v > 1.2$ %).

In summary, the biomarker and isotopic analyses of the condensate do not definitively identify the source components of its parent kerogen, but it is suggested that the condensate is sourced from a mixture of marine and terrestrially-derived organic matter deposited in a marginal marine setting.

4.3.2 Early Permian Source Rocks

In this study two liquid hydrocarbon-prone samples from the Early Permian Keyling Supersequence were analysed; a marginally mature coaly shale from Flat Top-1 (8484) and an immature mudstone from Kinmore-1 (8989: Tables 7b and 8).

The *n*-alkane profiles are bimodal with maxima at C_{17} and C_{23} in the Flat Top-1 sample and at C_{16} and C_{25} in the Kinmore-1 sample, which suggests a duel input of lipids from algae and land-plant waxes into the sediments (Appendix D). Compositional features that are characteristic of land-plant derived organic matter which accumulated under oxic conditions include; a pronounced odd-carbon-number preference in the C_{23}-C_{27} *n*-alkanes, high pristane/*n*-heptadecane ratios (Pr/*n*-C_{17} > 0.8: Fig. 35) and high pristane/phytane ratios (Pr/Ph > 3.5).

Bulk carbon isotopic compositions of the Keyling source rock extracts show marked variations between the saturated and aromatic hydrocarbon fractions (δ^{13}Csat = - 27.6 and -27.4 ‰; δ^{13}Carom = - 23.9 to -25.4 ‰: Fig. 36). Since these sediments are marginally mature, isotopic analysis of pyrolysates are required to obtain a better indication of the isotopic composition of the generated hydrocarbons.

The biomarker assemblages of the Keyling extracts indicates that partially oxidised terrestrially-derived material has been transported into an anoxic paralic environment. Biomarkers indicative of terrestrial-derived organic matter include; a high abundance of the C_{19} and C_{20} triterpane homologues, an ethylcholestane-dominated C_{27}-C_{30} sterane distribution and an abundance of retene. Evidence that the land-plant debris were microbially reworked and deposited in an anoxic marginal marine sediments comes from the abundance of 28,30-dinorhopane and trace amounts of 24-*n*-propylcholestane.

4.3.3 Oil-Source Rock Correlations

As demonstrated by Figures 28 and 35, there are considerable differences between the source-dependent biomarker ratios of the Petrel-4 condensate and the Keyling sediments. However, these differences are probably emphasised by maturity effects since the Petrel-4 condensate is mature and the Keyling sediments are quite immature. From the calculated maturity of 0.8 % it is assumed that the Petrel-4 condensate has been generated from liquid-prone organic matter and not via cracking of an oil accumulation. The thermal immaturity of the Keyling sediments is indicated by the abundance of the biologically inherited stereoisomers (*viz.* 14β(H),17β(H)- and 14α(H),17β(H)-hopanes 22R isomers and 5α(H),14α(H),17α(H)-sterane 20R isomers).

Condensate-source rock correlations are difficult to make because these petroleums by definition consist largely of gasoline-range components, and biomarkers (if present) constitute a very small percentage of the condensate. Even then, the biomarker signature of the condensate may not be representative of its source rock due to secondary effects such as solubilization, maturation and biodegradation. Having said this, the gas chromatograms of the Late Permian Hyland Bay and Late Permian-Triassic Mount sediment extracts shown in the well completion reports for Petrel-3 and Tern-2 appear to resemble the Petrel condensates more closely than do the Keyling extracts.

Heavy carbon isotopic signatures of around -24 ‰, as observed in the Petrel-4 condensate, are uncommon in the Palaeozoic, and for that matter in early Mesozoic oils and sediments. Permian oils and source rocks show an enrichment of ^{13}C which is largely attributed to global changes that occurred at this time. Detailed isotopic studies carried out at Fishburn-1, Petrel-4 and Tern-3 by Morante *et al.* (1994) and Morante (1995), showed that the organic-rich sediments of the Triassic Mount Goodwin Formation have light carbon isotopic signatures (around -30 ‰), whereas the Late Permian Hyland Bay sediments are generally heavy ($\delta^{13}C$ = -24 ‰). By combining isotopic and palynological studies for sediments of this age it has been shown that woody tissue is enriched in ^{13}C whereas acritarch-rich kerogens are typically isotopically light (Gorter *et al.*, 1995; Foster & Summons, 1996; Logan *et al.*, 1996).

In this study liquid-prone source rock were identified throughout the Early Permian Keyling Supersequence, and within the upper Hyland Bay and lowermost Mount Goodwin successions at Fishburn-1 and Petrel-2. Combining source rock and isotope studies for the most oil-prone sediments in the Hyland Bay and Mount Goodwin successions, it is apparent that the Petrel condensates source affinity is greatest with the land-plant-rich Hyland Bay sediments. However, the Keyling Supersequence cannot be ruled out as insufficient carbon isotopic data exists to define the signature of these coaly sediments.

5. Conclusions

1. Source rock and maturation studies have shown that the Mesozoic and Palaeozoic sediments within the Petrel Sub-basin are by and large organically lean containing predominantly gas-prone Type III/IV kerogen. In general, the kerogen comprises varying proportions of marine planktonic and benthonic remains and fragmented land-plant debris. Potential source rocks for liquids were identified at various stratigraphic levels, namely the Early Permian Keyling Supersequence and the Early Carboniferous Milligans Supersequence in *localised* areas, and to a lesser extent, the Jurassic Plover and Flamingo Supersequences.

2. Three chemically distinct oil families are recognised in the Petrel Sub-basin; Late Devonian marine carbonate oils, Early Carboniferous siliciclastic marine oils and Permian deltaic condensate. These crudes have been assigned to the Ningbing-Bonaparte (Larapintine 3), Milligans (Larapintine 4) and the Keyling-Hyland Bay (Gondwanan 1) Petroleum Systems, respectively.

3. The Ningbing-Bonaparte (Larapintine 3) oils occur in mineral holes and onshore petroleum wells in the Carlton Sub-basin. They are characterised by light carbon signatures. From the limited samples available the isotopic and biomarker signatures show some variability indicating localised generation from Late Devonian-?earliest Early Carboniferous marine carbonate and anoxic hypersaline source facies in the Bonaparte Megasequence.

4. Oils attributed to the Milligans Petroleum System (Larapintine 4) occur at Waggon Creek in the Carlton Sub-basin and in wells immediately offshore, notably at Barnett and Turtle. These oils are isotopically comparable to Carboniferous oils of the Canning Basin. Characteristic features of these oils include pristane/phytane and C_{27}/C_{29} steranes ratios just below unity, an abundance of tricyclic terpanes, diasteranes and diahopanes and the presence of gammacerane and 28,30-dinorhopane. These oils have been correlated with anoxic marine mudstones of the Early Carboniferous Milligans Supersequence. To date, immature organic-rich sediments containing oil-prone Type II/III kerogen have been identified only in the mineral well NBF1002. Severe biodegradation has altered the composition of most Milligans Petroleum System oils where present in offshore wells. In the shallowest reservoired oils, 25-norhopanes dominate the biomarker signatures. Initial biodegradation was probably contemporaneous with migration and occurred in shallow sediments containing oxygenated pore waters.

5. Gas flows at Fishburn, Penguin and Tern and gas with minor condensate at Petrel are believed to have been sourced by from Permian deltaic source rocks and constitute the

Keyling-Hyland Bay Petroleum System (Gondwanan 1). The Petrel-4 condensate has a diagnostically heavy isotopic signature and a biomarker assemblage dominated by rearranged steranes and rearranged hopanes, features which may be diagnostic of the Gondwanan Petroleum System.

6. Further Work

1. Biostratigraphic correlations are needed for the Late Devonian and Early Carboniferous supersequences intersected in mineral holes. Further geochemical studies are essential to fully understand and differentiate between oils generated from the Ningbing-Bonaparte and Milligans Petroleum Systems in the Carlton Sub-basin. Attention needs to be focussed on the oil stains and bitumens described in the mineral holes.

2. Hydrous pyrolysis experiments on immature Milligans mudstones are planned to confirm that the composition of these generated hydrocarbons resemble those of the Larapintine 4 oils. Likewise, artificial maturation and pyrolysis-GC-MS studies of immature Keyling and Hyland Bay kerogens would enable a better understanding of the origins of the Tern and Petrel gases and condensates.

3. Bulk and compound specific isotopic analyses of the Waggon Creek-1 oil and Early Carboniferous arboraceous lycopod wood and spores are required to determine whether these sources, rather than algeanans, have sourced the high molecular weight *n*-alkanes seen in this oil. Compound specific isotope analyses on Tertiary lacustrine, deltaic and marine oils and sediments by Murray and co-workers (1994) have shown that the *n*-alkane isotopic profiles of algal-derived oils are flat, whereas the profiles of fluvio-deltaic sediments containing predominantly bacterially-reworked angiosperm remains and/or a mixture of algal and land-plant-derived remains become isotopically lighter with increasing molecular weight. Similar results have been obtained for marine and terrestrial-derived organic matter in Permian and Triassic sequences on the North West Shelf (pers. comm., C. B. Foster and G. Logan, AGSO, June 1996). It would also be interesting to determine whether the *n*-alkane isotopic profiles of Late Devonian-Early Carboniferous lycopod 'woods' differ from those of Late Carboniferous-Permian gynmosperms.

4. More condensate samples are required to determine how representative the Petrel-4 condensate is of the Petrel Field. The composition of gas recovered from Penguin is different to the composition of the Petrel and Tern gases. Hence, further analyses are required to determine the source of the condensates and gases. Attention also needs to be concentrated on the biomarker and carbon isotopic composition of Keyling and Hyland Bay sediments as likely sources for the Petrel condensate, and to establish source parameters for Gondwanan oils.

7. Acknowledgments

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Enclosure: AGSO ORGCHEM Database - Petrel Sub-basin Data

Disc containing compilation of TOC, Rock-Eval Pyrolysis and Maturity Data
(IBM format, Microsoft Excel version 5)