AUSTRALIAN GEOLOGICAL SURVEY ORGANISATION

AUSTRALIAN PETROLEUM SYSTEMS

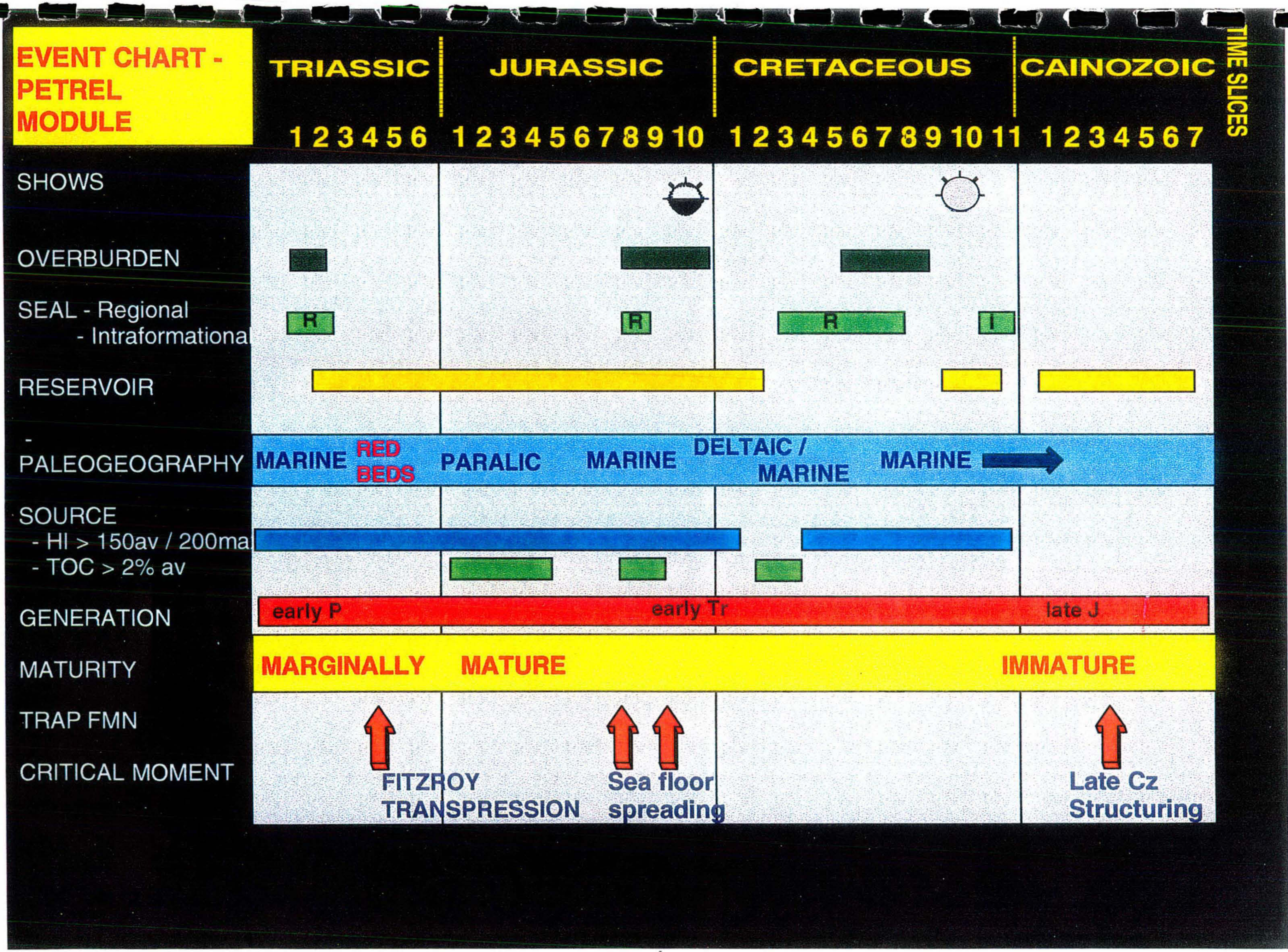
PETREL SUB-BASIN MODULE

VOLUME 1

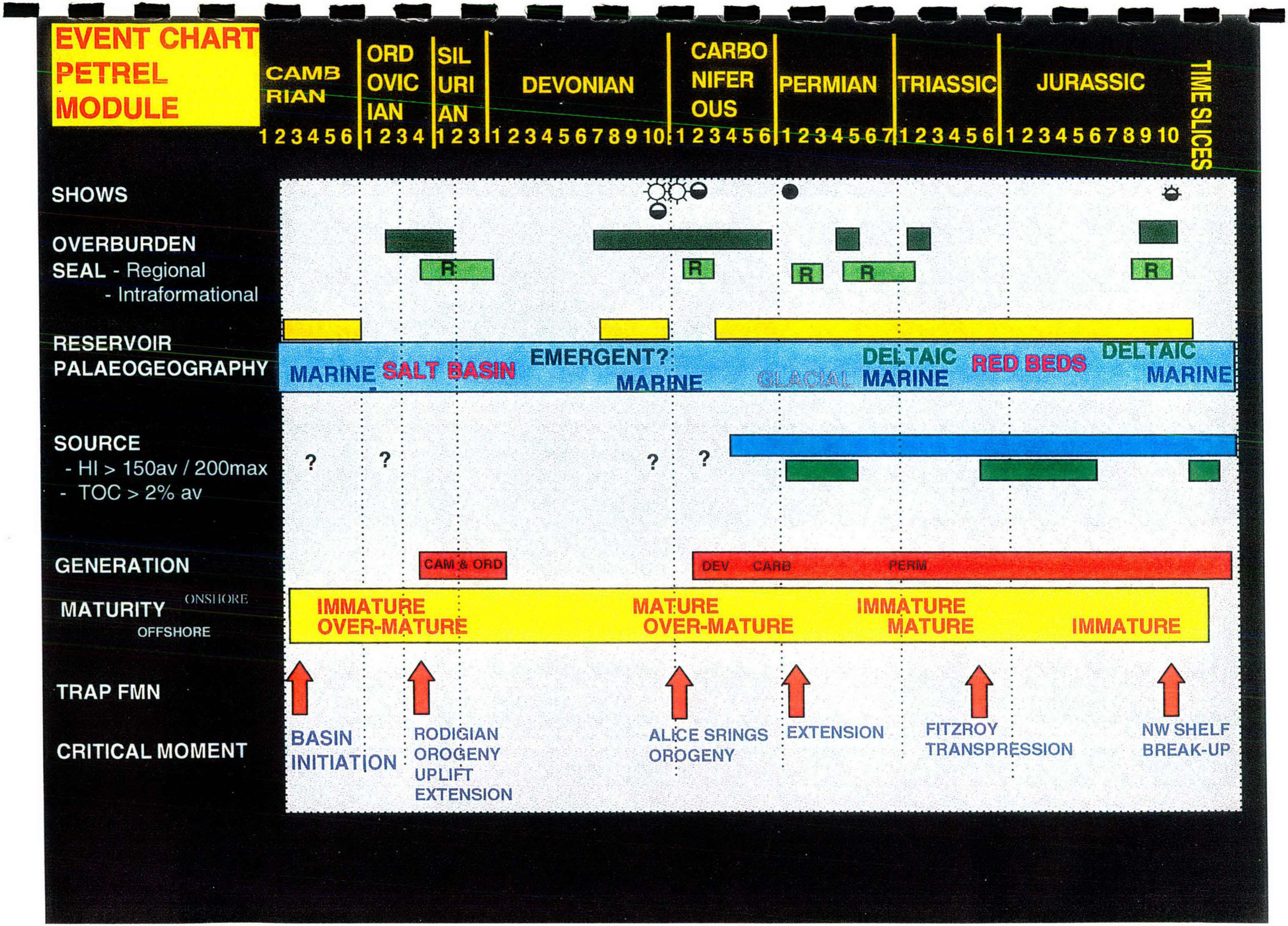
BY

BRUCE MCCONACHIE, MARITA BRADSHAW, SCOTT EDGECOMBE, CLINTON FOSTER, JOHN BRADSHAW, DAVID EVANS, BOB NICOLL & PETER JONES

AGSO RECORD NO 1995/7



EVENT CHART - PETREL MODULE
TRIASSIC
JURASSIC
CRETACEOUS
CAINOZOIC
TIME SLICES
1 2 3 4 5 6
1 2 3 4 5 6 7 8 9 10
1 2 3 4 5 6 7 8 9 10 11
1 2 3 4 5 6 7
SHOWS
OVERBURDEN
SEAL - Regional
- Intraformational
R
R
R
I
RESERVOIR
PALEOGEOGRAPHY
MARINE
RED BEDS
PARALIC
MARINE
DELTAIC / MARINE
MARINE
SOURCE
- HI > 150av / 200max
- TOC > 2% av
GENERATION
early P
early Tr
late J
MATURITY
MARGINALLY
MATURE
IMMATURE
TRAP FMN
CRITICAL MOMENT
FITZROY TRANSPRESSION
Sea floor spreading
Late Cz Structuring



EVENT CHART
PETREL
MODULE
CAMB RIAN
ORD OVIC IAN
SIL URI AN
DEVONIAN
CARBO NIFER OUS
PERMIAN
TRIASSIC
JURASSIC
TIME SLICES
1 2 3 4 5 6 1 2 3 4 1 2 3 1 2 3 4 5 6 7 8 9 10 1 2 3 4 5 6 1 2 3 4 5 6 7 1 2 3 4 5 6 1 2 3 4 5 6 7 8 9 10
SHOWS
OVERBURDEN
SEAL - Regional
- Intraformational
R
R
R
R
R
RESERVOIR
PALAEOGEOGRAPHY
MARINE
SALT BASIN
EMERGENT?
MARINE
GLACIAL
DELTAIC
MARINE
RED BEDS
DELTAIC
MARINE
SOURCE
- HI > 150av / 200max
- TOC > 2% av
?
?
?
?
GENERATION
CAM & ORD
DEV
CARB
PERM
MATURITY
ONSHORE
OFFSHORE
IMMATURE
OVER-MATURE
MATURE
OVER-MATURE
IMMATURE
MATURE
IMMATURE
TRAP FMN
CRITICAL MOMENT
BASIN INITIATION
RODIGIAN OROGENY UPLIFT EXTENSION
ALICE SRINGS OROGENY
EXTENSION
FITZROY TRANSPRESSION
NW SHELF BREAK-UP

AUSTRALIAN GEOLOGICAL SURVEY ORGANISATION

ISSN: 1039-0073

ISBN:

CONTENTS

FIGURES

TABLES

APPENDICES (Volume 2)

See separate PDF for Appendices (volume 2)

ENCLOSURES

ENCLOSURE: 16 DATA MAP
TIME SLICE Crb4 - LATE VISEAN to NAMURIAN

ENCLOSURE: 17 DATA MAP
TIME SLICE Crb5 to Crb6 - NAMURIAN to STEPHANIAN

ENCLOSURE: 18 DATA MAP
TIME SLICE P1 - ASSELIAN to SAKMARIAN

ENCLOSURE: 19 DATA MAP
TIME SLICE P2 to P4 - ARTINSKIAN to KUNGURIAN

ENCLOSURE: 20 DATA MAP
TIME SLICE P5 to P7 - LATE PERMIAN

ENCLOSURE: 21 DATA MAP
TIME SLICE Tr1 to Tr2 - EARLY to MIDDLE TRIASSIC (Griesbachian to Anisian)

ENCLOSURE: 22 DATA MAP
TIME SLICE Tr3 to Tr6 - MIDDLE to LATE TRIASSIC (Ladinian to Rhaetian)

ENCLOSURE: 23 DATA MAP
TIME SLICE J1 to J5 - Early to Mid Jurassic (Hettangian to Bajocian)

ENCLOSURE: 24 DATA MAP
TIME SLICE J6 to K2 - Mid Jurassic to Early Cretaceous (Bathonian to Hauterivian)

ENCLOSURE: 25 DATA MAP
TIME SLICE K3 and K4 - Early Cretaceous (Barremian to Aptian)

ENCLOSURE: 26 DATA MAP
TIME SLICE K5 to K11 - Early to Late Cretaceous (Albian-?Maastrichtian)

ENCLOSURE: 27 DATA MAP
TIME SLICE Cz4 to Cz7 - Tertiary to Quaternary (Oligocene to Pleistocene)

ENCLOSURE: 28 PALAEOGEOGRAPHIC INTERPRETATION MAP
TIME SLICE PRE-CAMBRIAN

ENCLOSURE: 29 PALAEOGEOGRAPHIC INTERPRETATION MAP
TIME SLICE C3 to ?O1 - CAMBRO-?ORDOVICIAN

ENCLOSURE: 30 PALAEOGEOGRAPHIC INTERPRETATION MAP
TIME SLICE ?O1 to D6 - ?ORDOVICIAN TO MIDDLE DEVONIAN

ENCLOSURE: 31 PALAEOGEOGRAPHIC INTERPRETATION MAP
TIME SLICE D7 and D8 - FRASNIAN

Line drawings of interpreted AGSO deep seismic sections at 1:400 000 horizontal scale.

ENCLOSURE 47
Seismic Lines 100/101 and 100/02

ENCLOSURE 48
Seismic Line 100/03 and magnetic intensity profile

ENCLOSURE 49
Seismic Lines 118/18, 100/07P1, 100/07P2 and 100/04

ENCLOSURE 50
Seismic Lines 100/05P1, 100/05P2, 100/06P1, 100/06P2, 100/06P3, 100/06P4 and 100/06P5

LIST OF ABBREVIATIONS

API	American Petroleum Institute
bbls	Barrels
BCFD	Billion (1 000 million) cubic feet per day
BMOD	Basin Modelling Program
BOPD	Barrels of oil per day
CAI	Conodont alteration index
CFPD	Cubic feet per day
cu ft	Cubic feet
DST	Drill stem test
GOR	Gas to oil ratio
HI	Hydrogen Index
hr	Hour
$kgcm^{-2}$	Kilograms per square centimetre
LPRM	Lower plate rift margin
mD	Millidarcy's permeability
MMBOIP	Million barrels oil in place
MMCFD	Million cubic feet per day
MMBOID	Million barrels oil per day
ms	Milliseconds
OID	Oil per day
ORGCHEM	Organic geochemical database
PEDIN	Petroleum exploration drilling database
RESFACS	Reservoir database
RFT	Repeat Formation Test
RMS	Root mean square
STB	Stock tank barrel
STRATDAT	Stratigraphic database
SCF	Standard cubic feet (0° C, 1 Atmosphere pressure)
TCF	Trillion cubic feet
TD	Total depth
TOC	Total organic carbon
TWT	Two way time
UPRM	Upper plate rift margin
VR	Vitrinite reflectance
ZOC	Zone of Cooperation

EXECUTIVE SUMMARY

The Petrel Sub-basin is located in northern Australia, underlying the Joseph Bonaparte Gulf, in both Western Australia and Northern Territory waters, and extending onshore (Figure 1). The sedimentary sequence (Figure 2) provides a record from the latest Proterozoic to the Recent, indicating that the sub-basin has been a marine embayment, as it is today, for much of this time. Climate, however has been a major variable, with the sub-basin being variously a desiccated evaporite basin, a tropical seaway fringed by reefs, an inlet into which glaciers flowed, and a temperate delta plain.

There is no production of oil or gas from this part of the Bonaparte Basin at present, but a number of important discoveries attest to the operation of at least three viable petroleum systems in the area. Best known are the gas discoveries at Petrel, Tern and more recently Fishburn 1, where hydrocarbons are reservoired in late Permian sandstones and are probably sourced from Permian deltaic sequences. Further inshore, oil has been recovered from Carboniferous and early Permian reservoirs at Turtle and Barnett. The source of the oil is considered to be Carboniferous anoxic marine shales. Onshore, there is a gas discovery at Garimala 1 and significant oil shows in Ningbing 1, in the late Devonian rocks. Geochemical analysis of the oil, shows it to be sourced from a carbonate marine source rock, distinctly different from the clastic derived oils obtained from Turtle 2 and Barnett 2.

Evidence is presented in this report of a potential Permian oil source rock on the northeastern flank of the sub-basin, distinct from the gas and condensate sources in the central depocentre. Other potential petroleum systems include a Mesozoic system dependent on a Jurassic source that is immature (except possibility in the Malita Graben) and of moderate quality. The onshore Cambro-Ordovician sequence is the age equivalent of proven oil source rocks in neighbouring basins, but its potential is low given risks of over-maturity and no yet recognised source facies.

The petroleum system concept, Magoon and Dow (1991,1994) and the classification of Australian petroleum systems presented by Bradshaw (1993) and Bradshaw et al. (1994) provided a framework for analysing the petroleum potential of the Petrel Sub-basin. This approach emphasises the linkages to other productive basins in Australia and elsewhere (Klemme, 1994). Figures 3 and 4 are stratigraphic diagrams of the Petrel Sub-basin

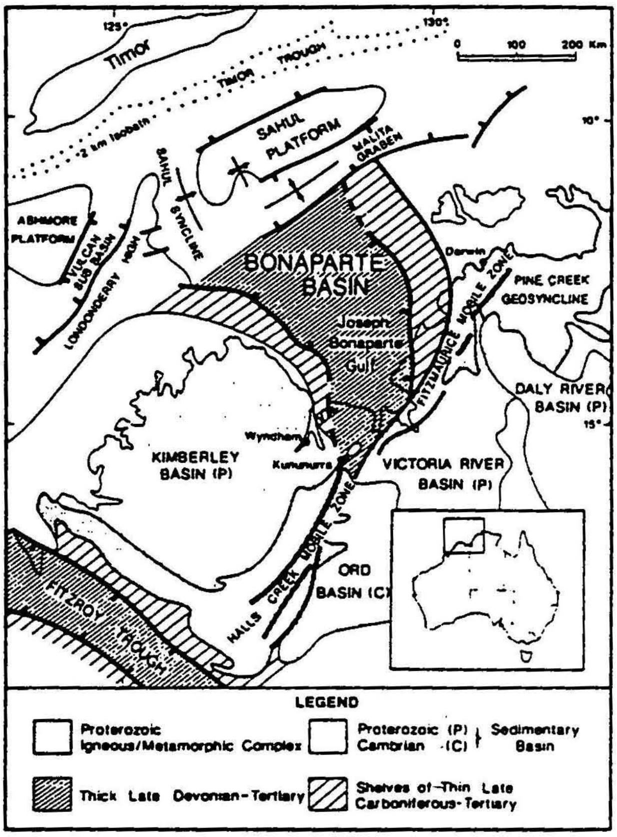


Figure 1 Locality map - Petrel Sub-basin (From Gunn, 1988)

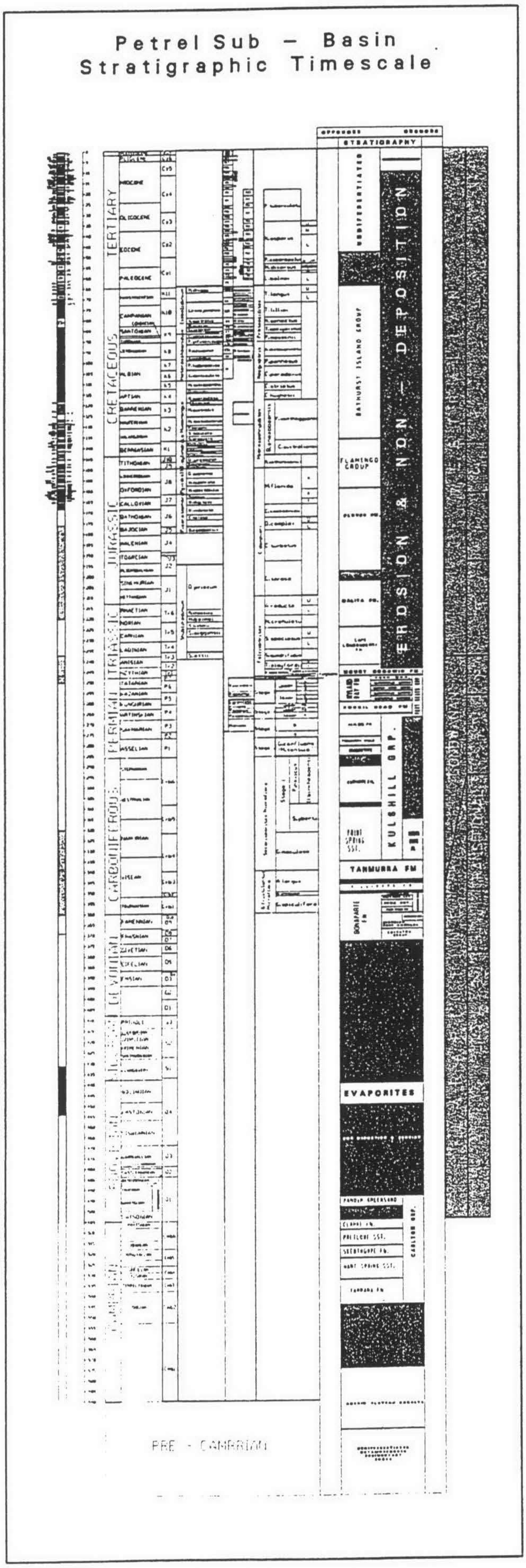


Figure 2 Time slices versus fossil zonations, stratigraphy and petroleum systems of the Petrel Sub-basin. See Enclosure 3 for full scale version and back pocket for A3 copy.

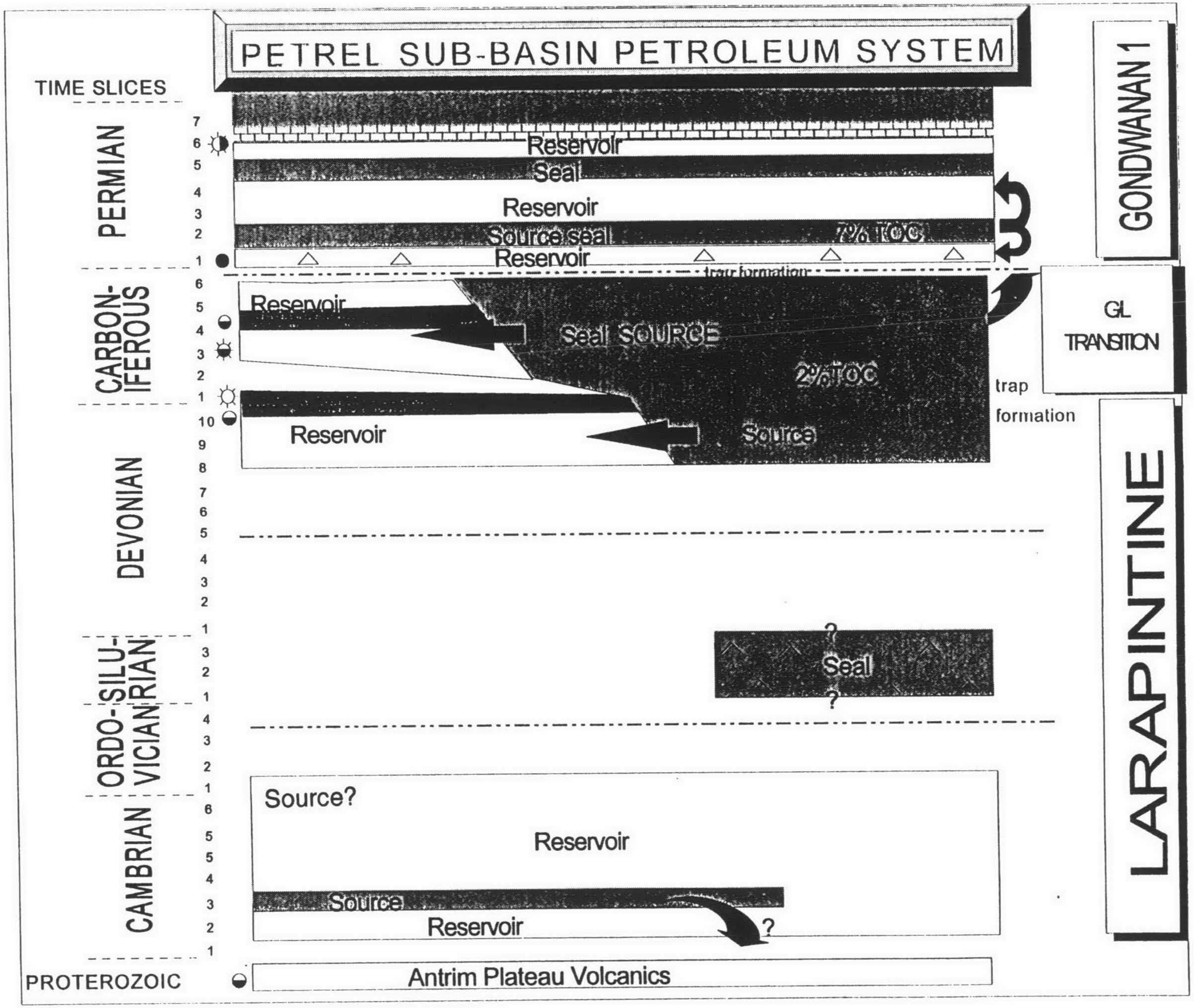


Figure 3 Petroleum systems for the Petrel Sub-basin, Palaeozoic

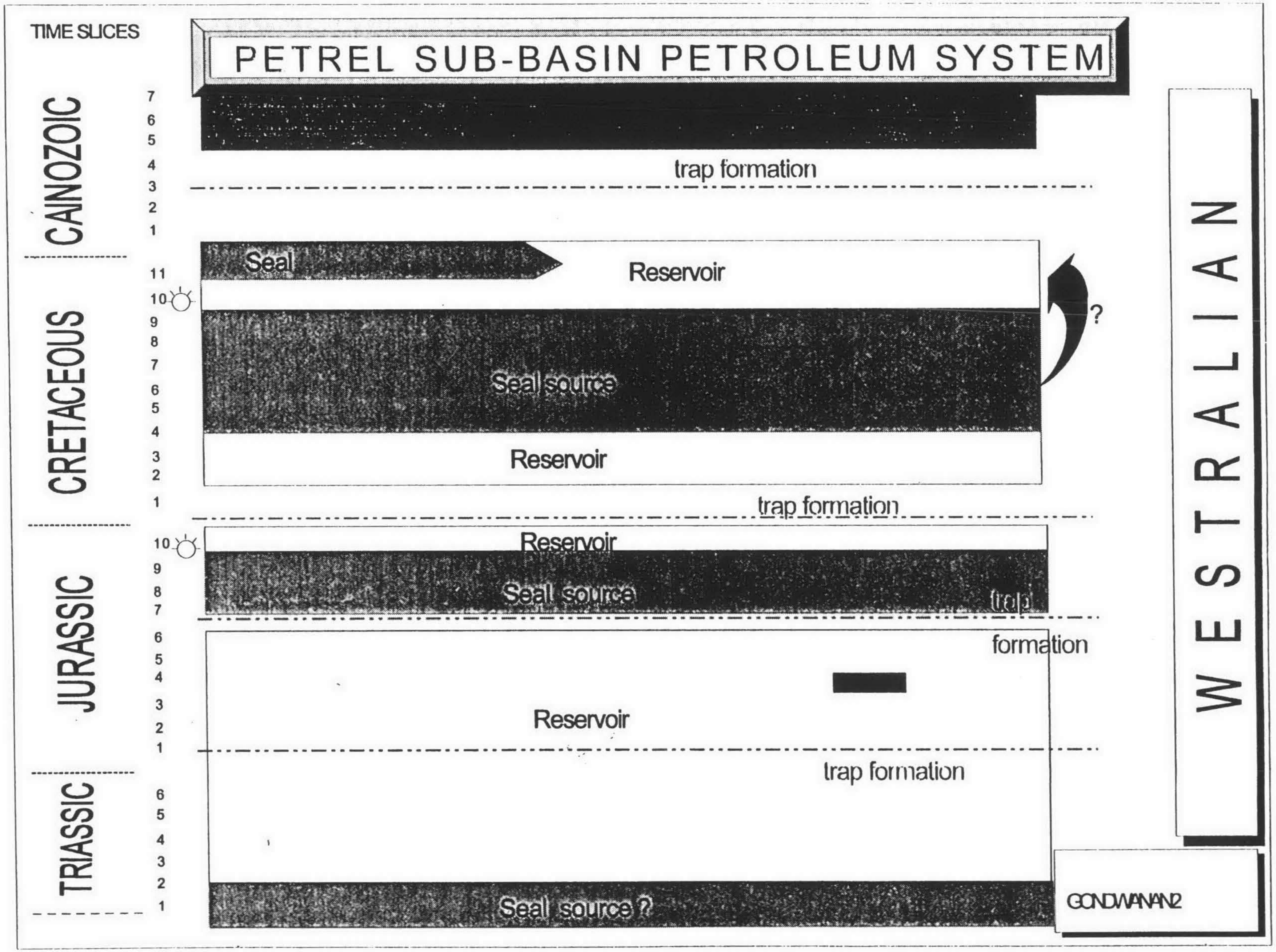


Figure 4 Petroleum systems for the Petrel Sub-basin, Mesozoic

petroleum systems and the coloured frontispieces are event charts plotting the key elements and processes of the systems against time.

The oldest unit in the Petrel Sub-basin is the latest Proterozoic or early Cambrian Antrim Plateau Volcanics that host an enigmatic oil show in the adjacent Ord Basin (Wade, 1924; Figure 3). The overlying Cambro-Ordovician sediments are the age equivalents of proven petroleum systems in the Amadeus, Arafura and Canning Basins, the **Larapintine 1 and 2** petroleum systems (Bradshaw et al., 1994). But no source rocks have been identified in the high energy shallow marine facies that crop out.

No dated late Ordovician to middle Devonian rocks have been penetrated in the Petrel Sub-basin, but seismic and other evidence indicates that a thick evaporite sequence was deposited at some time during this interval. This salt plays an important role in trap formation. The late Devonian **Larapintine 3** sequence is a proven petroleum system with an onshore gas discovery. Geochemical analysis of oil shows indicate the presence of a local marine carbonate source rock. The oil recovered from the Turtle and Barnett wells has a different geochemical signature having been derived from an anoxic marine shale - the Carboniferous Milligans Formation, the source rock of the **Larapintine/Gondwanan Transition** system.

The late Permian gas and condensate fields are part of the **Gondwanan** petroleum system. This sequence is capped by the regional seal of the early Triassic Mount Goodwin Formation (Figure 4) . The overlying Mesozoic **Westralian** sequence lacks a proven hydrocarbon source rock.

EXPLORATION OPPORTUNITIES

Apart from the well known plays such as the Petrel and Tern Gasfields additional opportunities abound in the Petrel Sub-basin. As a result of the current research on the Petrel Sub-basin, it is clear that three exploration plays stand out on the basis of their technical and economic merit.

The first is the untested Gondwanan 2, late Permian oil play on the northeast flank of the basin. This is a very large untested region with oil generative source rock in the upper Keyling and Fossil Head Formations capable of sourcing into the proven reservoirs of the upper Fossil Head and Hyland Bay Formations. Commercial data indicates that sufficient structuring is present for a variety of trap styles to exist. Timing of trap formation will be critical to the success of this play.

The second is the transitional Larapintine-Gondwanan play onshore in the Kulshill area where seismic data could be reprocessed and the potential for a Barnett 2 type discovery, at an acceptable cost, is favourable. Further work in the Kulshill area has the added bonus of potentially unlocking the secrets of the transitional Larapintine-Gondwanan play in the offshore Petrel Sub-basin where the 921 BOPD Barnett 2 well is a cased and suspended producer.

The third play relates directly to the recent discoveries at Elang 1 and 2, Laminaria 1, Kakatua 1 and Bayu 1. This is the Westralian 2 petroleum system. Detailed studies of source facies distribution and other critical controls on the accumulation of hydrocarbons in the nearby Sahul Platform may well enable similar successes in the closely related northwest Petrel Sub-basin. Gorter and Kirk (1995) described the Kimmeridgian marl in the Timor Sea as an important regional source rock for this play. However, discoveries in the Petrel Sub-basin may require long distance migration to make this play work, due to the quality and immature nature of the source interval.

ACKNOWLEDGMENTS

SANTOS is thanked for their assistance in providing digital logs and a number of well completion reports. Thanks also to WMC for providing additional log data. AGSO's Continental Margins Program provided copies of the deep seismic covering the Petrel Sub-basin.

In preparation of the Petrel Sub-basin Module the areas of responsibility were assigned to each member of the group, as listed below :-

Bruce McConachie and Marita Bradshaw were responsible for the geological, geophysical and geochemical interpretation presented in the report. Scott Edgecombe provided technical support and David Evans input the initial shows , porosity and permeability data into RESFACS.

John Bradshaw, manager/coordinator of the Australian Petroleum Systems Group, was largely involved with the organisation of various data inputs to the STRATDAT and RESFACS databases. John loaded the data, then guided the analysis of the information

contained within them, and its links to the ORGCHEM database. He also has provided valuable technical information and assistance throughout this project.

Clinton Foster, was mainly involved with the organisation of the STRATDAT database. He input the Permian and older biostratigraphic data; while the Mesozoic section was upgraded by Robin Helby, consultant biostratigrapher.

Dianne Edwards contributed towards the analysis and interpretation of geochemical data. Additional technical support, which ranged from data collation to generating the various products, was provided by John Needham, John Vizy, Giuliana Zuccaro, David Rowlands and Graham Moss.

Our colleagues in the Offshore Canning/Beagle team, Lynton Spencer and Jacques Sayers are thanked for their scientific and technical input to the study. Special mention must be made of Lynton's development of the Time Scale graphics and time slice definitions. The staff of the Continental Margins Program also provided valuable scientific contributions to the Petrel study, in particular Geoff O'Brien, Karen Romine and Jim Cowell.

INTRODUCTION

PURPOSE

The aim of the project is to analyse the palaeogeographic controls on source, seal, and reservoir distribution together with the structural and maturation history of the Petrel Sub-basin. This study builds upon previous work and concepts developed in the AGSO-APIRA Palaeogeographic Maps and Phanerozoic History of Australia Projects. Analyses are based on information from 57 wells with 32 studied in detail, 2500 km of AGSO deep seismic data plus selected commercial lines. Results are presented as time slice data and interpretation maps, regional well log cross sections, line drawings of interpreted compressed scale seismic sections, graphical plots and summary tabulations.

Recent published information (Mory, 1991; Petroconsultants, 1990) provided important insights into the geology of the Petrel Sub-basin and were found particularly useful during the preparation of this report. However, the authors interpretations differ significantly in some aspects from these accounts.

DIGITAL DATA

A series of digital databases containing prospectivity data (porosity, permeability, depositional environments, landform elements and hydrocarbon shows - called RESFACS) and biostratigraphic data (palynology, palaeontology and horizon based events - called STRATDAT) have also been prepared. This data was originally compiled from Excel (Windows) format and then checked and loaded into the Oracle databases. Hard copy summaries are included in Appendices 1 and 3 in spreadsheet format ordered by well and depth. Appendices 4 and 5 present the same information by time slice and in summary charts.

CROSS-SECTION AND MAP PRODUCTION

Four regional cross-sections and 18 time slice palaeogeography maps were produced as part of the current regional study of the Petrel Sub-basin. The Petrel Sub-basin is unusual in that its depositional record includes almost undeformed sequences covering almost all Phanerozoic time.

TIME SLICE DEFINITION AND BOUNDARIES

Biostratigraphic schemes used in the study were:

(1) Integrated dinoflagellate and spore-pollen zonation of the Australian Mesozoic developed by Helby et al (1987),

(2) Foraminiferal zonation for the North West Shelf (Wright, 1977; Heath and Apthorpe, 1981, and 1984; Apthorpe, 1988)

(3) Foraminiferal zonation for the Cainozoic (Blow, 1969, and 1979; Berggren, 1969; Kennett and Srinivasan, 1983)

(4) Australian Phanerozoic Timescales Volume 1 - 10 (Shergold, 1989; Webby and Nicoll, 1989; Strusz, 1989; Young, 1989; Jones, 1989; Archbold and Dickins, 1989; Balme, 1989; Burger, 1989 and 1989a; Truswell et al., 1989).

(5) Palynological zonation for the Permian (Draper et al, 1990)

(6) Palynological zonations for the Carboniferous (Kemp et al., 1977; Foster, 1990).

These schemes were referenced to the Harland 1982 Time Scale (Harland et al., 1982), although within STRATDAT, Haq and AGSO timescales may be selected.

The correlation, duration and absolute ages of the time slices were derived from previous projects after consultation with many biostratigraphers, industry sponsors and the State Geological Surveys.

In general, the time slice boundaries coincide with major changes in rates of sedimentation or changes in facies that are common to several basins. Some time slices are representative of geological events that have continent wide effects, for example, regional unconformities resulted from uplift and erosion. The selection criteria for the time slices are based on a broad correlation between key continent wide geological events and major biostratigraphic zones.

There are some difficulties in selecting time slices that are applicable across Australia due to contrasting depositional and tectonic regimes and correlation problems with the biostratigraphy such as correlating the spore-pollen zonations in Eastern Australia with the dinoflagellate zones of Western Australia.

The products in both the Palaeogeographic Maps Project and the Phanerozoic History of Australia project were based on the same time slice framework. Thus the details presented in this study can immediately be related to more regional concepts and incorporated into the existing regional maps. However, the definition of the Carboniferous time slices used in the Palaeogeographic Maps Project (Totterdell and Brakel, 1990) has been amended to better match with recent revisions to the palynological zonations.

The following section outlines the time slice definition and boundaries summarised from the BMR Palaeogeographic Atlas of Australia, Volume 1 - Cambrian (Cook, 1988), Volume 2 - Ordovician (Cook and Totterdell, 1992), Silurian (Walley et al, 1991), Volume 8 - Jurassic (Bradshaw and Yeung, 1993), Volume 9 - Cretaceous (Bradshaw et al, in press) and *Australia: evolution of a continent* (BMR Palaeogeographic Group, 1990). A Phanerozoic Time Scale chart is provided in Petrel Sub-basin Stratigraphy Chart (Enclosure 3) showing the relationship between time slice, stage and biostratigraphic zonations. Figure 2 is a small scale version of Enclosure 3 and an A3 version is also provided in the pocket at the back of the report. Table 1 lists time slice against age in millions of years.

Table 1 Timeslices and Harland et al (1982) Ages (Ma top and base) with AGSO ages for comparison

Timeslice	Top	Base	AGSO Top
Cz7	0.00	2.00	0
Cz6	2.00	5.10	
Cz5	5.10	11.90	
Cz4	11.90	29.20	
Cz3	29.20	38.07	
Cz2	38.07	50.50	
Cz1	50.50	65.00	
K11	65.00	70.00	65
K10	70.00	83.00	
K9	83.00	91.00	
K8	91.00	99.00	
K7	99.00	104.00	
K6	104.00	109.00	
K5	109.00	113.00	
K4	113.00	119.50	
K3	119.50	126.00	
K2	126.00	137.00	
K1	137.00	144.00	
J10	144.00	147.00	141
J9	147.00	150.00	
J8	150.00	162.00	
J7	162.00	167.00	
J6	167.00	177.00	
J5	177.00	180.00	
J4	180.00	189.00	
J3	189.00	190.50	
J2	190.50	200.00	
J1	200.00	213.00	
Tr6	213.00	222.00	205
Tr5	222.00	231.00	
Tr4	231.00	236.00	
Tr3	236.00	240.50	
Tr2	240.50	244.50	
Tr1	244.50	247.00	

Timeslice	Top	Base	AGSO Top
P7	247.00	249.50	251
P6	249.50	255.00	
P5	255.00	261.00	
P4	261.00	268.00	
P3	268.00	274.00	
P2	274.00	277.00	
P1	277.00	286.00	
Crb6	286.00	308.50	298
Crb5	308.50	322.00	
Crb4	322.00	340.00	
Crb3	340.00	350.00	
Crb2	350.00	352.00	
Crb1	352.00	360.00	
D10	360.00	360.50	354
D9	360.50	367.50	
D8	367.50	370.50	
D7	370.50	374.00	
D6	374.00	378.50	
D5	378.50	387.00	
D4	387.00	387.50	
D3	387.50	394.00	
D2	394.00	400.50	
D1	400.50	408.00	
S3	408.00	414.00	410
S2	414.00	427.40	
S1	427.40	437.00	
O4	437.00	469.00	434
O3	469.00	479.00	
O2	479.00	484.00	
O1	484.00	505.00	
Cmb6	505.00	518.00	490
Cmb5	518.00	526.00	
Cmb4	526.00	532.00	
Cmb3	532.00	538.00	
Cmb2	538.00	553.00	Base
Cmb1	553.00	590.00	545

TIME SLICE C1: CAMBRIAN: Early Cambrian

TIME SLICE C2: CAMBRIAN: Ordian

TIME SLICE C3: CAMBRIAN: Templetonian

TIME SLICE C4: CAMBRIAN: Florian to Undillan

TIME SLICE C5: CAMBRIAN: Boomerangian to Minyallan

TIME SLICE C6: CAMBRIAN: Idamean to Payntonian

TIME SLICE O1: ORDOVICIAN: Datsonian to Bendigonian

TIME SLICE O2: ORDOVICIAN: Chewtonian to Yapeenian

TIME SLICE O3: ORDOVICIAN: Darriwillian

TIME SLICE O4: ORDOVICIAN: Bolindian

TIME SLICE S1: SILURIAN: Llandovery to early Sheinwoodian

TIME SLICE S2: SILURIAN: Sheinwoodian to Ludfordian

TIME SLICE S3: SILURIAN: Pridoli

TIME SLICE D1: DEVONIAN: Lochkovian

TIME SLICE D2: DEVONIAN: Pragian

TIME SLICE D3: DEVONIAN: Emsian

TIME SLICE D4: DEVONIAN: Latest Emsian

TIME SLICE D5: DEVONIAN: Eifelian to early Givetian

TIME SLICE D6: DEVONIAN: Givetian

TIME SLICE D7: DEVONIAN: Early Frasnian

TIME SLICE D8: DEVONIAN: Late Frasnian

TIME SLICE D9: DEVONIAN: Late Franian to Famennian

TIME SLICE D10: DEVONIAN: Late Famennian

TIME SLICE Crb1: CARBONIFEROUS: Tournasian, *G. spiculifera* zone

TIME SLICE Crb2: CARBONIFEROUS: Early Visean, *G. praecipua* zone, where recognised.

TIME SLICE Crb3: CARBONIFEROUS: Visean, *A. largus* zone

TIME SLICE Crb4: CARBONIFEROUS: Late Visean to early Namurian, *G. maculosa* zone

TIME SLICE Crb5: CARBONIFEROUS: Late Namurian to early Westphalian, *S. ybertii* zone

TIME SLICE Crb6: CARBONIFEROUS: Middle Westphalian to Stephanian, *D. birkheadensis* zone.

TIME SLICE P1: PERMIAN: Asselain.
Biostratigraphically equivalent to palynological zone *PP1*. Carnarvon Basin areas are in high latitudes. Thick glacial ice cap retreating from Pilbara Craton area.

TIME SLICE P2: PERMIAN: early - middle Sakmarian.
Biostratigraphically equivalent to palynological zone *PP2.1*. Ice retreat and final deglaciation and sea level rise. Isostatic uplift due to unloading of craton probable.

TIME SLICE P3: PERMIAN: Late Sakmarian - middle Artinskian.
Biostratigraphically equivalent to palynological zone *PP2.2*.

TIME SLICE P4: PERMIAN: Middle Artinskian - Kungurian.
Biostratigraphically equivalent to palynological zones *PP4.2, PP4.1* and *PP3*

TIME SLICE P5: PERMIAN: Early Kazanian.
Biostratigraphically defined by the lower three quarters of the range of palynological zone *PP4.3*. Major transgression in much of eastern Australia.

TIME SLICE P6: PERMIAN: Middle Kazanian to middle Tatarian.
Biostratigraphically defined by palynological zones *PP5* upper PP4. The top occurs near the top of *PP5.2* and the base occurs near the top of *PP4.3*

TIME SLICE P7: PERMIAN: Late Tatarian.
Biostratigraphically defined by palynological zone *PP6* and *PP5.2*. The top of the zone is the top of palynological zone *PP6* and the base occurs near the top of *PP5.2*.

TIME SLICE Tr1: TRIASSIC: earliest Triassic, *P. samoilovichii* zone.

TIME SLICE Tr2: TRIASSIC: Late Scythian to early Anisian, *T. playfordii* zone.

__TIME SLICE Tr3__: TRIASSIC: Late Anisian to early Ladinian

__TIME SLICE Tr4__: TRIASSIC: Late Ladinian

__TIME SLICE Tr5__: TRIASSIC: Carnian to early Norian

__TIME SLICE Tr6__: TRIASSIC: Late Norian to Rhaetian

__TIME SLICE J1__: JURASSIC : Hettangian to Sinemurian.
The Jurassic/Triassic boundary is not marked biostratigraphically. It occurs within the *A. reducta* and *P. crenulatus* spore-pollen zones, and the *D. priscum* dinoflagellate zone.

__TIME SLICE J2__: JURASSIC: Pliensbachian to early Toarcian. Time Slice J2 corresponds to the *N. vallatus* datum. It is marked by facies change in many basins and the commencement of deposition in others, eg on the northwest margin there was a facies change from marginal marine clastic sediments to shallow water limestone.

__TIME SLICE J3__: JURASSIC: Early to middle Toarcian.
Time Slice J3 is marked by a distinct change in lithology and depositional environment in the Surat and other eastern Basins. It corresponds to *Applanopsis spp*, and is marked by the development of ironstone oolite beds within the Evergreen Formation and its equivalents, and corresponds to high sea level episode.

__TIME SLICE J4__: JURASSIC: Late Toarcian to early Bajocian.
Time Slice J4 corresponds to the commencement of deposition of the Hutton sandstone in the Eromanga and Surat Basins, the Algebuckina Sandstone in the Poolowanna Trough, the Cattamarra Coal Measures in the Perth Basin, and the expansion of deposition in the Papuan Basin. Biostratigraphically, it is loosely defined as occurring within the lower part of the *C. turbatus* zone.

__TIME SLICE J5__: JURASSIC: Early to middle Bajocian.
Time Slice J5 is marked by a marine transgression in the Perth Basin. It is biostratigraphically defined by the *D. caddaense* dinoflagellate zone. Ammonites contained within sediments of Time Slice J5 in the Perth Basin allow direct correlation with the European stages.

__TIME SLICE J6__: JURASSIC: Late Bajocian to early Callovian.
The base of Time Slice J6 equates with the top of the *D. caddaense* dinoflagellate zone. Stratigraphically, the base of the time slice coincides with the end of the Cadda transgression

in the Perth Basin and the top of the time slice equates to the regional "Callovian Unconformity" seen in several basins on the North West Shelf.

TIME SLICE J7: JURASSIC: Middle Callovian to early Oxfordian.
The base of Time Slice J7 equates with the bases of the *M. florida* and *W. digitata* zones and the top is defined by the base of the dinoflagellate zone *W. spectabilis*. It also represents an episode of uplift and erosion, prior to the commencement of sea floor spreading, on the North West Shelf. It also coincides with the transition of the Hutton Sandstone deposition to a lower energy shale prone Birkhead fluvio-lacustrine regime in Eastern Australia.

TIME SLICE J8: JURASSIC: Early Oxfordian to Kimmeridgian.
Time Slice J8 encompasses the time of maximum transgression in the Jurassic. The top boundary coincides with an unconformity on the North West Shelf, the Papuan and Laura Basins. It also coincides with a facies change in many other basins. Biostratigraphically, the base of the time slice equates to the base of the *W. spectabilis* dinoflagellate zone and the top corresponds to major zonation boundaries in both dinoflagellate and spore-pollen schemes.

TIME SLICE J9: JURASSIC: Early Tithonian.
The base of Time Slice J9 is marked by a regional unconformity observed in the Papuan and Bonaparte Basins. It is defined biostratigraphically by the *C. perforans* and *O. montgomeryi* dinoflagellate zones and is within the lower part of the *R. watherooensis* spore pollen zone. Time Slice J9 represents a phase of relative regression on the North West Shelf that corresponded to a shift in the Eromanga Basin from low energy Birkhead deposition to higher energy sand sheet regime of the Adori Sandstone.

TIME SLICE J10: JURASSIC: Late Tithonian.
The base of Time Slice J10 corresponds to the base of *D. jurassicum* dinoflagellate zone. The top of the time slice represents the Jurassic/Cretaceous boundary which lies within the *P. iehiense* dinoflagellate zone. The first appearance of *C. australiensis* pollen is used as the biostratigraphic definition of the base Cretaceous in Australia. Time Slice J10 also represents a transgressive phase following the regression of Time Slice J9.

TIME SLICE K1: CRETACEOUS: Berriasian to early Valanginian.
The base of Time Slice K1 is defined by the Jurassic/Cretaceous boundary, which is within the *P. iehiense* dinoflagellate zone and equates with the base of the *C. australianensis* spore-pollen zone.

TIME SLICE K2: CRETACEOUS: Valanginian to Hauterivian.

The base of Time Slice K2 represents a major unconformity in many basins, particularly on the western margin of the Australian continent. It also corresponds to a major sea level fall on the Haq et al (1987) chart. Biostratigraphically the base is defined by the *E. torynum / S. areolata* dinoflagellate zone and the *C. australianensis / F. wonthaggiensis* spore-pollen boundary. It equates to the M10 magnetic anomaly and to the start of a major phase of sea floor spreading along the western margin in the Perth, Cuvier and Gascoyne Abyssal Plains.

TIME SLICE K3: CRETACEOUS: Barremian.

This time slice is characterised by transgression of the sea into central and western Australia. There is no direct biostratigraphic correlation to the Barremian stage, but a working definition equivalent to the *M. australis* dinoflagellate zone.

TIME SLICE K4: CRETACEOUS: Aptian.

Time Slice K4 records the peak marine transgression across the Australian continent. It is biostratigraphically defined by the dinoflagellate zones *A. cinctum, O. operculata* and *D. davidii*; and the *C. hughesii* spore-pollen zone. Time Slice K4 corresponds to changes in stratigraphy in many basins with the deposition of marine shales over sandstones in offshore locations. Time Slice K4 may be absent and represented by a condensed sequence.

TIME SLICE K5: CRETACEOUS: Early Albian.

Time Slice K5 encompass a period of sea level retreat. It equates to the *C. striatus* spore-pollen zone and approximates the *M. tetracantha* dinoflagellate zone.

TIME SLICE K6: CRETACEOUS: Middle Albian.

Continued regression occurred during Time Slice K6. The base of the time slice equates to the base of *C. paradoxa* spore-pollen zone and the top equates to the top of *C. denticulata* dinoflagellate zone.

TIME SLICE K7: CRETACEOUS: Late Albian.

Time Slice K7 represents a transgressive episode and corresponds to a global oceanic anoxic event. Biostratigraphically it approximates the *P. ludbrookiae* dinoflagellate zone.

TIME SLICE K8: CRETACEOUS: Late Albian to Cenomanian.

During this time slice the sea retreated from the centre of the continent, but there is a rise in relative sea level on the western margin. It is biostratigraphically defined by the C2, C3a and

C3b foram zones, approximates the *X. asperatus* and *D. multispinum* dinoflagellate zones and *A. distocarinatus* spore-pollen zone.

<u>TIME SLICE K9</u>: CRETACEOUS: Turonian to Santonian.
Carbonate sedimentation became dominate on the western margin during this time slice. It is biostratigraphically defined by the C4 to C8 foram zones, the *C. triplex* and *T. pachyexinus* spore-pollen zones, and approximates the *P. infusorioides* to *I. cretaceum* dinoflagellate zones.

<u>TIME SLICE K10</u>: CRETACEOUS: Campanian to early Maastrichtian.
Time Slice K10 corresponds to the commencement of sea floor spreading in the Tasman Sea. It is biostratigraphically defined by the C4 to C8 foram zones, the *N. senectus* and *T. lilliei* spore-pollen zones, and approximates the *N. aceras* to *I. korojonense* dinoflagellate zones.

<u>TIME SLICE K11</u>: CRETACEOUS: Middle to late Maastrichtian.
Time Slice K11 is biostratigraphically defined by the C12 and C13 foram zones, the *M. druggii* dinoflagellate zone and the *T. longus* spore-pollen zone. Its top boundary represents the Mesozoic / Cainozoic boundary.

<u>TIME SLICE Cz1</u>: CAINOZOIC: Paleocene to early Eocene

<u>TIME SLICE Cz2</u>: CAINOZOIC: Middle to late Eocene

<u>TIME SLICE Cz3</u>: CAINOZOIC: Early Oligocene

<u>TIME SLICE Cz4</u>: CAINOZOIC: Late Oligocene to middle Miocene

<u>TIME SLICE Cz5</u>: CAINOZOIC: Late Miocene

<u>TIME SLICE Cz6</u>: CAINOZOIC: Pliocene

<u>TIME SLICE Cz7</u>: CAINOZOIC: Pleistocene to Recent

METHODOLOGY

A total 32 wells were fully analysed in this study, and in addition, information from another 25 wells was incorporated into the report.

Biostratigraphic data from Well Completion Reports and other published information were reviewed by consultant biostratigrapher Dr Robin Helby (palynology) and AGSO palaeontologist Dr Clinton Foster. The revised palynological and palaeontological data were further reviewed and documented into the STRATDAT database (Appendix 3) by Dr Foster.

Age/depth plots were constructed to provide quick-look interpretations of changes in sedimentation rates, condensed sections, unconformities and fault intersections. These plots also provide age estimates for depth intervals with poor biostratigraphic control. A schematic diagram of age/depth plot interpretations is shown in Figure 5. An example of an interpreted age/depth plot is shown in Figure 6. Age/depth plots for all the wells studied in the Petrel Sub-basin Module are provided in Appendix 2. Time slice boundaries are picked using all available biostratigraphic data correlated with wireline logs and age/depth plots. The time slice boundaries are further constrained by key sequence boundaries and major flooding surfaces interpreted from well log and seismic data.

Lithological descriptions from ditch cuttings, sidewall cores and conventional cores were used in conjunction with well log signatures to determine facies type and environments of deposition. Biostratigraphic data such as the diversity of fossil content, the relative abundance, and the ratio of spore-pollen to marine micro fossils provided additional information on the depositional environments.

Digital well log data were used to produce four well log cross sections (Enclosures 7 to 10), datumed on sea level. These were constructed to provide a regional coverage of the Petrel Sub-basin. The sections display the gamma and sonic curves together with codes representing the various depositional environments and landform elements and any significant hydrocarbon shows. The definition of the environment and landform element codes is shown in Figure 7 and Table 2. A tabulation of these codes for each of the study wells was entered into the palaeogeographic interpretation component of RESFACS. ORGCHEM and RESFACS timeslice summary charts are presented in Appendices 4 and 5 respectively.

BMOD burial history models for selected wells are presented in Appendix 8.

Over 2 500 km of seismic lines were interpreted for the Petrel Sub-basin Module (Figure 8). The emphasis of the seismic interpretation was on the resolution of specific geological problems (such as whether a well was drilled off the structure or adjacent to a major fault) and to provide a regional framework - mapping the extent of the various seismic

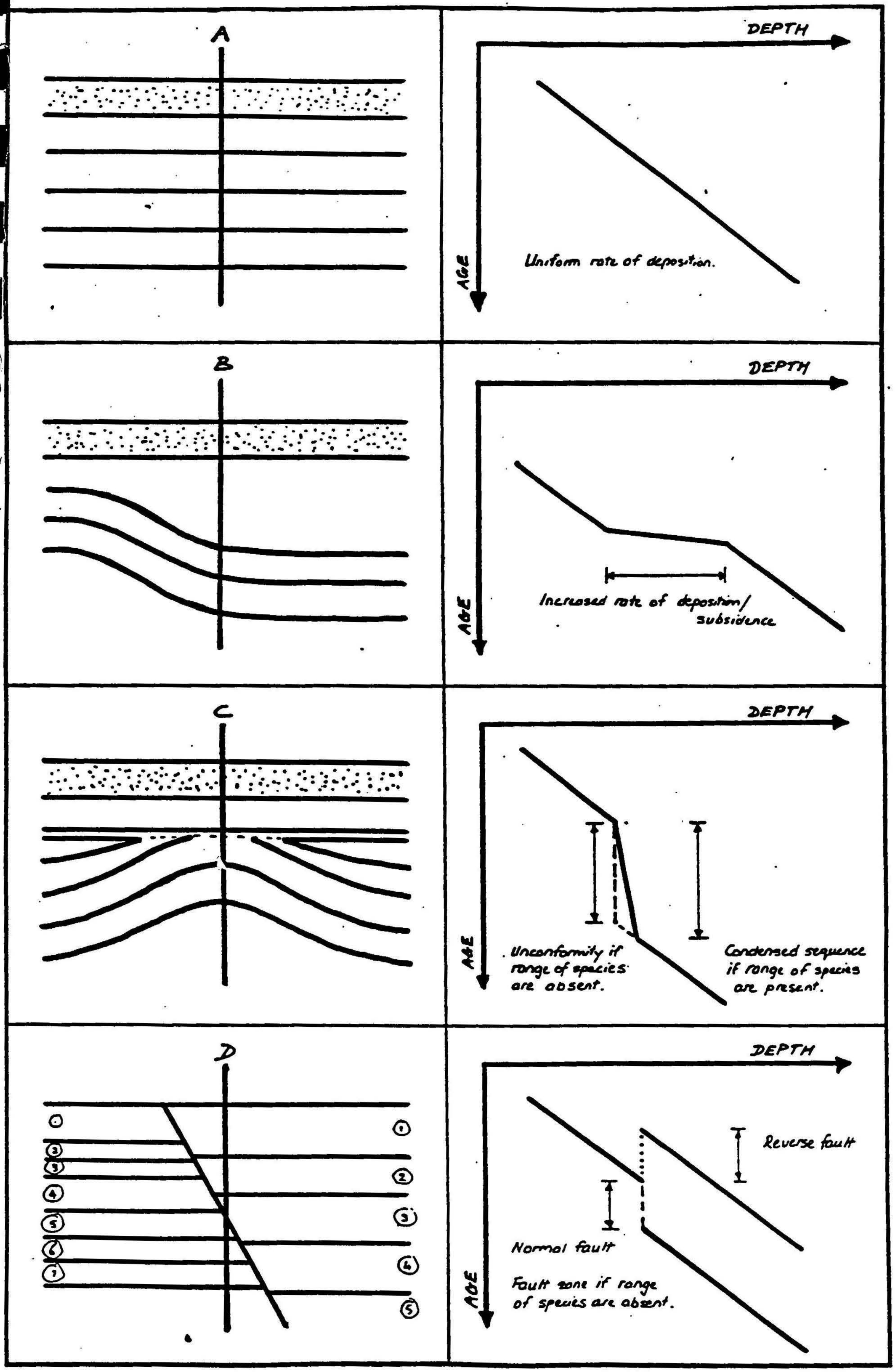
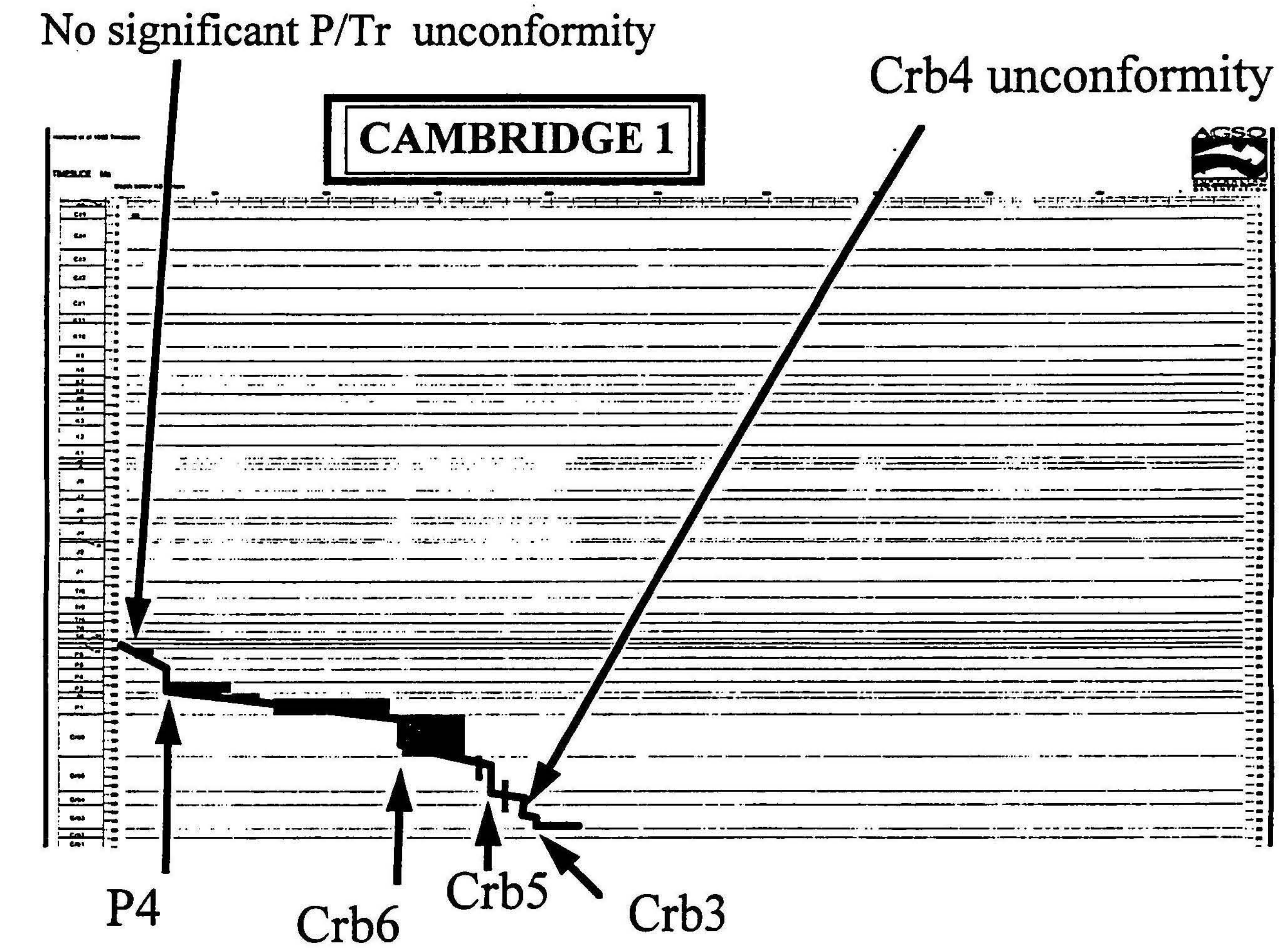


Figure 5 Schematic diagram of age/depth plot interpretations



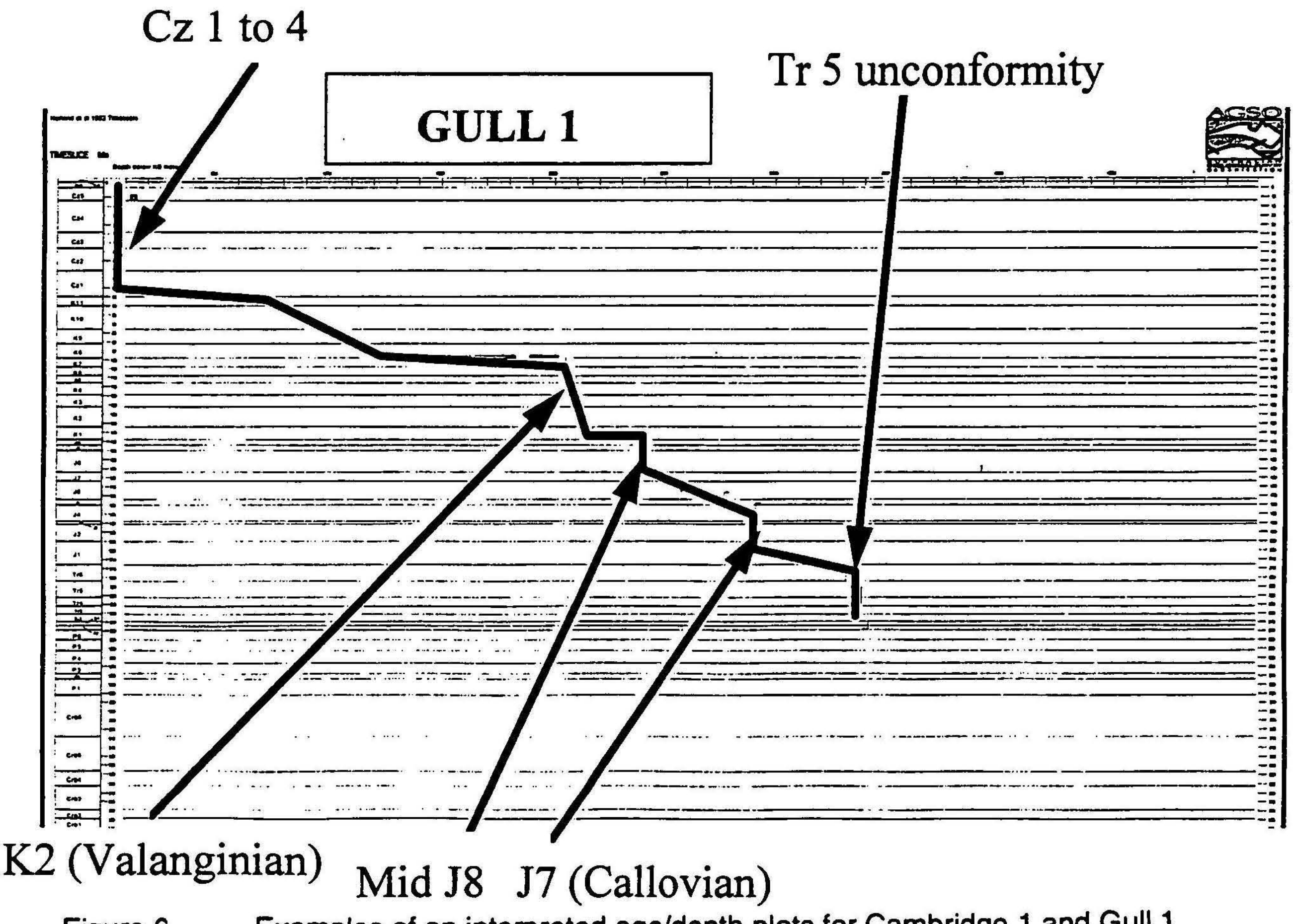
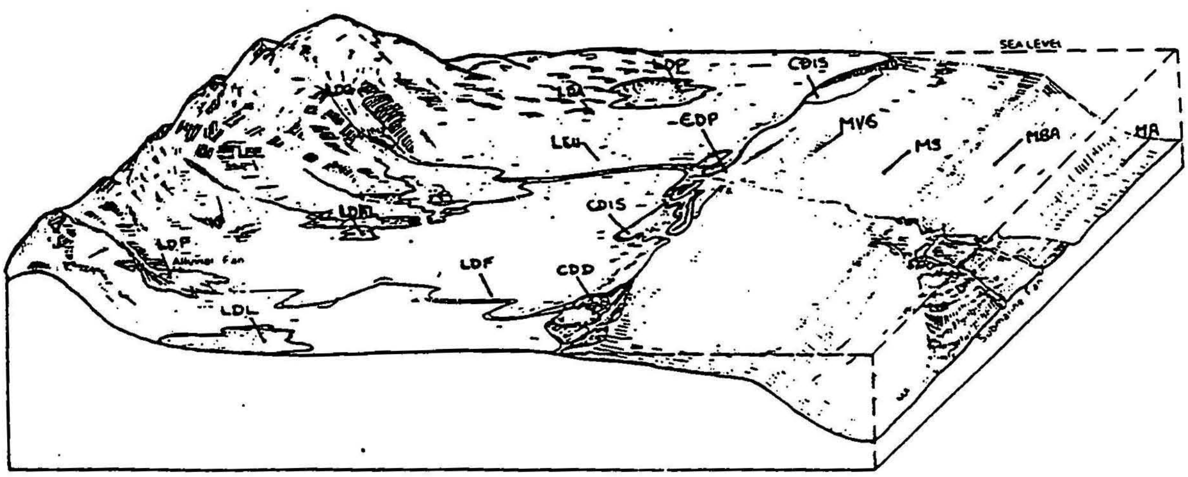


Figure 6 Examples of an interpreted age/depth plots for Cambridge 1 and Gull 1

CODE	ENVIRONMENT	WORKING DEFINITION
Land & land depositional environments		
LEU	Unclassified	Areas with no preserved sediments of time-slice age, interpreted as land, for example the Ashmore Platform. Also areas that are largely unknown that may have Jurassic sediments, such as the Queensland Plateau.
LEE	Erosional	Highland areas of sediment erosion, indicated by palaeocurrents, provenance studies, tectonic setting and the presence of igneous intrusions, for example the Arbum Arch.
LDF	Depositional, Fluvial	River deposits such as alluvial fans, braided and meandering channel deposits and coarser overbank sediments, and sand-dominated continental sequences with no evidence of aeolian or lacustrine deposition.
LDFL	Depositional, Fluvio-Lacustrine	Sediments deposited in low-energy river environments such as channels, overbanks, backswamps and shallow lakes on low-gradient floodplains; typically sequences dominated by fine-grained sediments and coal, with sheet geometry.
LDL	Depositional, Lacustrine	Deposits of deep, persistent lakes, usually in tectonically controlled basins. Distinguished from LDFL by thicker shales and more restricted distribution.
Coastal depositional environments		
CDP	Paralic	Deposits of coastal or marginal marine environments. Includes the range of environments situated at the land/sea boundary such as lagoonal, beach, intertidal, deltaic, etc., and is recognised by a variety of depositional facies ranging from coarse cross-bedded beach sand, to sand deposited in tidal deltas, to finely laminated organic sediment deposited in lagoons and estuaries (includes deltaic and intertidal-supratidal environments).
CDIS	Intertidal-Supratidal	Sediments deposited in the tidal zone, indicated by the presence of finely interlaminated fine and coarse detritus, herringbone cross-bedding, flaser bedding, evidence of periodic exposure, etc.
CDD	Deltaic	Deltaic deposits indicated by isopach patterns, upward-coarsening sequences and the map pattern of adjacent environments. Cuspate or lobate form of deltas on maps in some cases follows isopach pattern.
Marine environments		
MVS	Very Shallow (0-20 m water depth)	Marine sediments with evidence of deposition above wave base and/or occasional emergence, e.g. oolites, cross-bedding.
MS	Shallow (0-200 m water depth)	Marine sediments deposited on the continental shelf or on flanks of volcanic islands, e.g. sand, mud and limestone containing fossils that typically lived in shallow water; also includes areas along young, active spreading ridges (includes MVS).
MBA	Bathyal to Abyssal (> 200 m water depth)	Marine sediments with indicators of deep-water deposition, e.g. condensed sequences, turbidites, monotonous shale, and the presence of deeper-water organisms (includes abyssal environments).



Schematic Diagram Showing
Classifications of Depositional Environments

Figure 7 Schematic diagram showing classification of depositional environments (after; BMR Palaeogeography Group, 1990).

Environment & Landform Elements Codes

ENVIRONMENT CODES					LANDFORM ELEMENT CODES			
	LEU	Unclassified						
	LEE	Erosional						
	LUD	Unclassified Depositional						
					V	Volcano		
					LF	Lava Field		
					VM	Volcano Mixed		
	LDF	Fluvial	LDFB	Braided	C	Channel		
					AF	Alluvial Fan	AFT	Fan Toe
							AFD	Debris Flow
							AFS	Sheet Flow
			LDFM	Meandering	PB	Point Bar		
					AC	Abandoned Channel		
					LE	Levee		
LAND					CS	Crevasse Splay		
					BS	Backswamp		
	LDL	Lacustrine			LD	Lacustrine Delta		
	LDFL	Fluvial-Lacustrine			OD	Overbank Deposits		
		Upper Shoreface						
	LDP	Playa			SF	Salt Flat		
					MF	Mud Flat		
					P	Pond		
	LDA	Aeolian			D	Dune		
					S	Swale		
	LDG	Glacial			GD	Glacial Deposit		
	CDP	Paralic						
	CDIS	Intertidal / Supratidal			B	Beach		
					BR	Beach Ridge		
	CDD	Deltaic	CDDU	Upper Delta Plain	SMB	Stream Mouth Bar		
			CDDL	Lower Delta Plain	IDB	Interdistributary Bay		
			CDDF	Delta Front	SML	Submarine Levee		
COASTAL			CDDP	Pro Delta	CE	Chenier		
	CDE	Estuarine			M	Marsh		
					LA	Lagoon		
	CSF	Shoreface	CSFU	Upper Shoreface				
			CSFM	Middle Shoreface				
			CSFL	Lower Shoreface				
	MU	Unclassified						
	MSS	Starved Shelf						
	MS	Shallow (0-200m)			OB	Offshore Bar		
					BB	Barrier Bar		
					BI	Barrier Island		
					F	Fan	FP	Fan Proximal
							FM	Fan Mid
							FD	Fan Distal
			MVS	Marine Very Shallow (0-20m)	R	Reef	RT	Reef Toe
							RF	Reef Front
MARINE							RB	Reef Back
	MBA	Bathyal to Abyssal (>200m)			CSH	Continental Shelf	CSHI	Continental Shelf Inner
							CSHM	Continental Shelf Middle
							CSHO	Continental Shelf Outer
					CSL	Continental Slope		
					TF	Turbidite Fan	TFP	Turbidite Fan Proximal
							TFM	Turbidite Fan Mid
							TFC	Turbidite Fan Complex
							TFD	Turbidite Fan Distal
			MA	Marine Abyssal			MFD	Mixed Fan Distal
					AP	Abyssal Plain		

AGSO AUSTRALIAN GEOLOGICAL SURVEY ORGANISATION

Table 2 Environment and Landform Element Codes

Australian Petroleum Systems Project

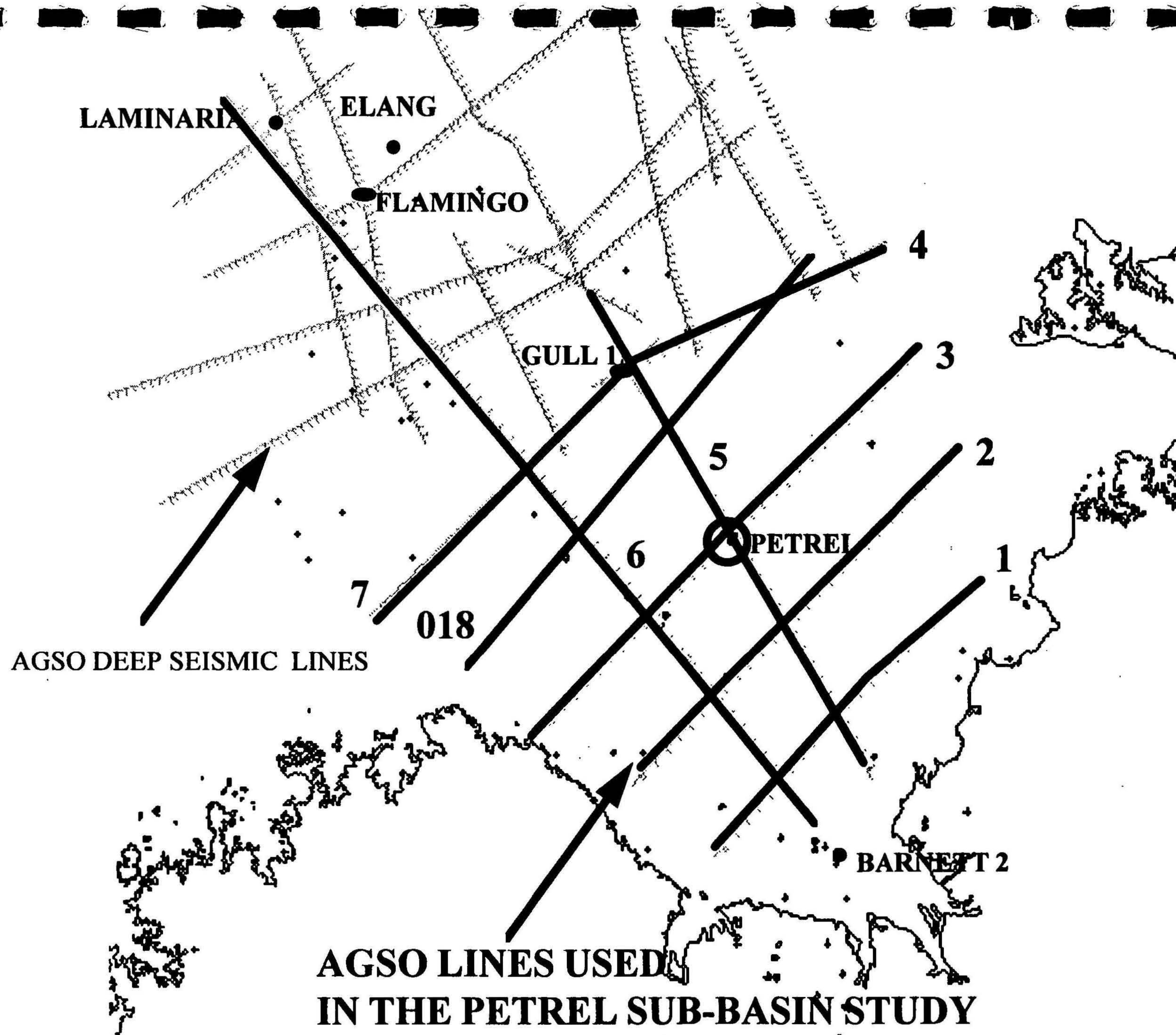


Figure 8 AGSO seismic line locations

packages recognised in the sub-basin. In addition, the seismic data helped in the delineation and correlation of megasequences (often previously miss-correlated and therefore miss-named) and provided estimates of depth to "basement" and thicknesses of sedimentary sections that were not intersected by any of the wells. Time structure contours and isochron maps are presented in Appendix 9. Line drawings of interpreted compressed scale regional seismic profiles illustrating the regional framework, plus structural and stratigraphic styles within the Petrel Sub-basin accompany the current report (Enclosures 47 to 50).

ORGCHEM data maps were compiled for each time slice to review source rock and maturity distribution (Appendix 6). Palaeogeographic data and interpretive maps were finally constructed for each time slice (Enclosures 11 to 46).

SIGNIFICANT HYDROCARBON OCCURRENCES

The following briefly summarises the most important hydrocarbon discoveries in the basin. Lavering and Ozimic (1989) presented the stratigraphic setting of the hydrocarbon occurrences in the Bonaparte Basin (Figure 9).

The first report of significant hydrocarbons in the Petrel Sub-basin came with the drilling of Kulshill-1 in the onshore area of the basin in 1966 where many oil shows were encountered but no flows obtained.

Significant gas accumulations include Petrel with reserves of 100 to 440 x 10^9 m^3 (3.3 to 13.6 TCF) and Tern with 40 x 10^9 m^3 (1.3 TCF) GIP. Barnett 2 had the first flow of oil (921 BOPD on jet pump). These hydrocarbon accumulations occur in a variety of geological settings, the host reservoirs ranging in age from late Devonian to Permian. When coupled with significant discoveries in the West Australian portion of the basin, all the evidence attests to the Petrel Sub-basin having generated significant quantities of both gaseous and liquid hydrocarbons.

Important gas discoveries have also been made at Fishburn 1 and Weaber 1. Fishburn 1 drilled a 51 m gross gas column with an average porosity of 15% and permeability of 10.4 mD in the Tern and Cape Hay Members of the Hyland Bay Formation. Weaber 1 flowed gas from the early Carboniferous Enga Sandstone, and Weaber 2A flowed gas from the overlying Milligans Formation. During the writing of the current report, Weaber 3 was drilled onshore as a stepout test of the Weaber Gasfield. Gas production potential was observed in the interval 1243 to 1428 m prior to TD at 1465 m. Garimala 1 flowed gas from the late

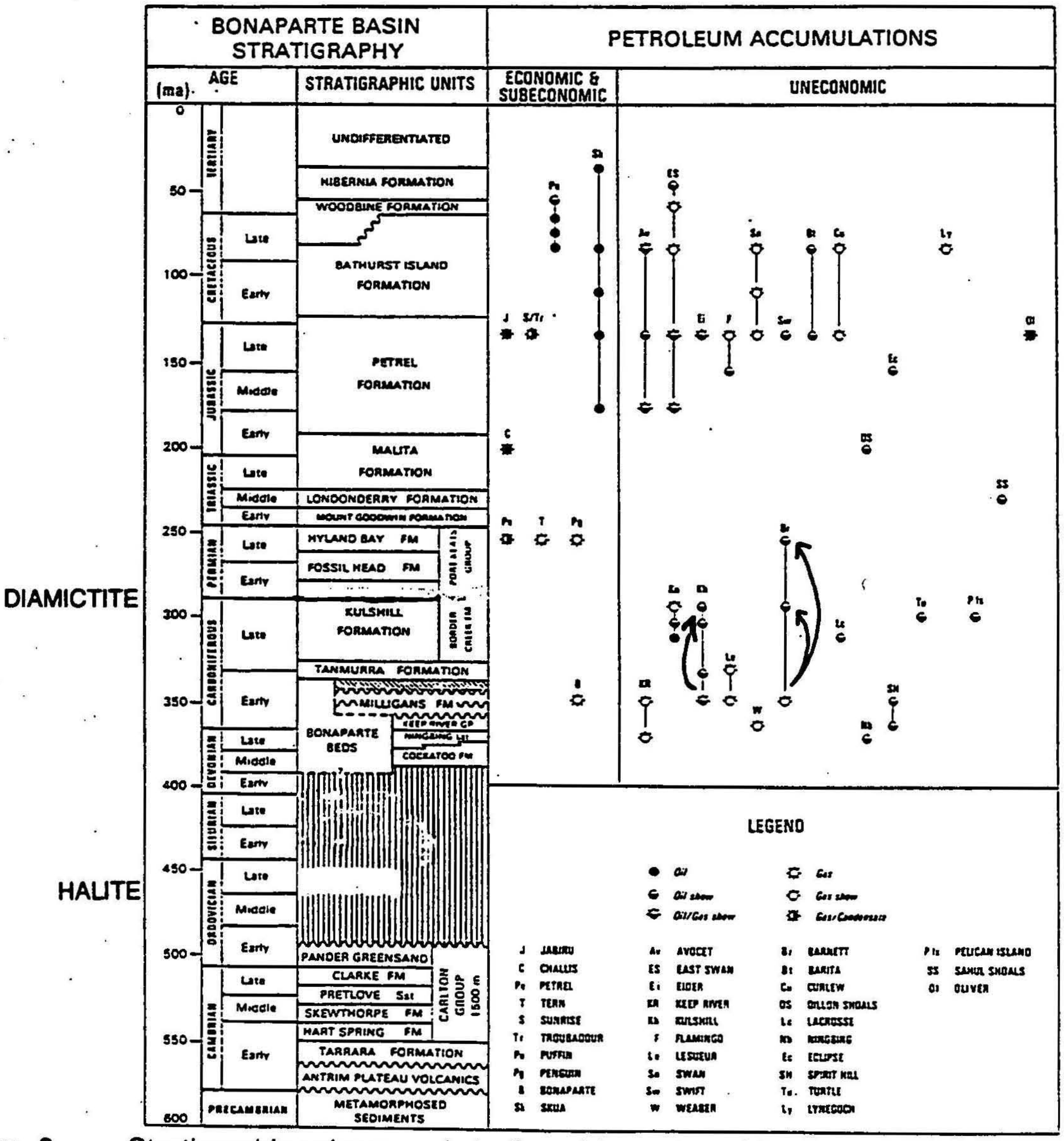


Figure 9 Stratigraphic column and stratigraphic setting of Bonaparte Basin petroleum accumulations (From Lavering & Ozimic, 1989)

Devonian Bonaparte Formation. DST 2 tested between 2401 and 2381 m recovering 0.75 MMCFD decreasing to 0.47 MMCFD over a period of 2 hours.

Stepout wells Tern 4 and Petrel 5 were drilled to further test the Tern and Petrel Gasfields. Tern 4 flowed 5.37 MMCFD through perforated intervals at 2542 to 2545 m, 2548 to 2563 m and 2566 to 2576 m from the Tern Member of the Hyland Bay Formation. Petrel 5 successfully tested the upper sandstone of the Cape Hay Member of the Hyland Bay Formation. Petrel 5 recorded the highest flow rate of all the wells drilled in the Petrel Field to date with a gas flow of 980 000 m^3 per day or 34.6 MMCFD, through a one inch choke. The gas was accompanied by an estimated 17 barrels per day of condensate. Prior to Petrel 5, Petrel 4 produced the highest flow rate from the field at 813 000 m^3 per day or 28.7 MMCFD through a 5/8 inch choke.

Although not actually contained within the Petrel Sub-basin, the recent major discoveries at Elang 1 and 2 (Young et al., 1995), Laminaria 1, Kakatua 1, Bayu 1 and Elang West 1 also offer considerable encouragement for similar discoveries in the northwest Petrel Sub-basin.

Elang 1, reported to be a tilted Jurassic fault block, production tested the interval 3006.5 to 3015.5 m at 830 BOPD through a 6 mm choke, 1280 psi and 57° API with GOR of 600 cu ft per STB, and 3006.5 to 3068 m flowed at a stabilised rate of 5800 BOPD through a 21 mm choke at a GOR of 600 cu ft per STB.

Elang 2 located 1.7 km west of Elang 1 production tested over the intervals 3054 to 3059 m and 3062 to 3067 m. The well flowed at a maximum stabilised rate of 6080 BOPD equivalent to 5300 STB OPD through a 40/64 inch choke with a GOR of 400 CFPB.

Laminaria 1 targeted Jurassic sandstones of the Flamingo and Plover Formations. Hydrocarbon indications were encountered over the interval 3208 to 3231 m and the well TD was 3260 m. The well was reported as having intersected a 52 m hydrocarbon column of 59° API oil. Non-essential personnel at Laminaria 1 were evacuated during drilling due to the presence of hazardous levels of hydrogen sulphide gas but no hydrogen sulphide was retrieved with the oil samples. Potential reserves are 300 MMBOIP (e+p Magazine, 1994/4, p20, Oil and Gas Exploration and Production in Australia).

TD for Laminaria 1 was 3400 m. Production tests were conducted as follows:

1. 3292 to 3302 m, stabilised flow of 5900 BOPD of 59° API oil with a GOR of 40 cu ft STB at 960 psi with no water cut and insignificant levels of hydrogen sulphide gas,
2. 3213 to 3240 m, flowed at 5700 BOPD through a half inch choke at 920 psi,
3. A further interval was perforated over 3259.5 to 3264.5 m and combined with the previous zone to produce a co-mingled flow of 7500 BOPD through a 5/8 inch choke at 775 psi. In both flows the gas/oil ratio was less than 40 SCF per barrel.

Kakatua 1 was located over an 11 km^2 Jurassic horst with Plover and Flamingo objectives. Production of over 8000 BOPD of 53° API oil was achieved from two thin sandstone intervals.

Bayu 1 was targeted on the Plover Formation but encountered a gas-condensate discovery in an upper Jurassic reservoir below 2930 m. Four DST's were conducted over a gross interval of 139 m. The combined rate through 1 inch chokes was 90 MMCFD plus 5250 BCPD.

Elang West 1 encountered hydrocarbon shows and three cores were cut over the interval 3013 m to 3045.6 m.

AGSO DEEP SEISMIC DATA

Over 2500 km of AGSO deep seismic data plus selected commercial lines were interpreted at compressed scale to compliment the well interpretation. These data are presented in Appendix 9 and Enclosures 47 to 50. These data comprise time structure contours, isochrons, clean skin sections and interpreted overlays. Example of a time structure contour and isochron are presented in Figure 10; and cartoon interpretations of AGSO seismic lines are shown in Figure 11 (a - h).

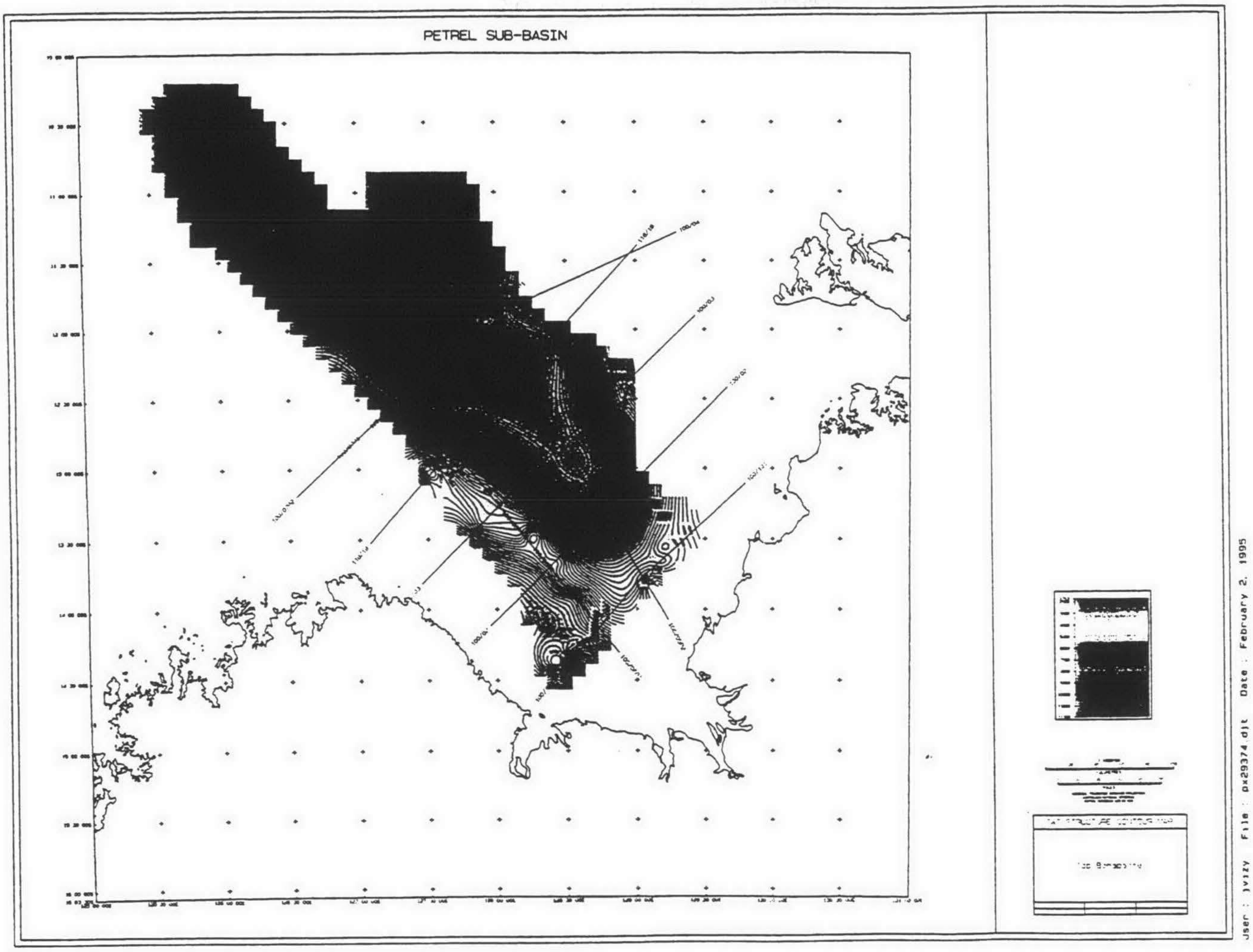
Table 3 indicates the seismic events interpreted and their lithostratigraphic correlations in the drillholes tied to the seismic grid. Two way times are shown against velocity and depth in Table 4.

SEISMIC STRATIGRAPHIC UNIT	MAPPED SEISMIC HORIZON TOPS	APPROXIMATE LITHOSTRATIGRAPHIC UNIT	LOWER BOUNDARY	UPPER BOUNDARY	INTERNAL REFLECTIONS
22		upper TERTIARY	E, O	SF	S
21		middle TERTIARY	E , O	E, SF	S
20		lower TERTIARY	E , O	E	S
19	**K11**	**upper BATHURST ISLAND**	E , O, D, C,	E, C, D	S
18		lower BATHURST ISLAND			
17	**K1**	**FLAMINGO**	D, C	C, E	S
16	**J6**	**PLOVER**	C	E, C	S
15	**J1**	**MALITA**	O, C	C	C
14	**Tr5**	**CAPE LONDONDERRY**	D, C	C	S
13	**Intra Tr2**	**MOUNT GOODWIN**	D, C	C	S
12	**Intra P6**	**HYLAND BAY (H5 -H4)**	C, D	C	S
11	**P5**	**FOSSIL HEAD**	C, O	C	C
10	**P3**	**KEYLING**	C, O	C	C
9	**P1**	**TREACHERY SHALE and DIAMICTITE (combined)**	C, D	C	S, Ob
8	**Crb6**	**KURIYIPPI**	C, D	C	Ob, S
7	**Intra Crb5**	**POINT SPRING SANDSTONE**	D, C	T, C	Ob, H, S
6		**TANMURRA**			
5	**Intra Crb3**	**MILLIGANS**	C, E	E, ?C	C
4		LANGFIELD			
3	**?Crb2**	**BONAPARTE**	E	?	H
2		NINGBING LIMESTONE			
1		COCKATOO			

E - Erosional truncation, O - Onlap, T - Toplap, D - Downlap, C - Concordance, S - Sigmoidal progradation
Ob - Oblique progradation, H - Hummocky
SF - Sea Floor ? - Unknown

Near tops of the bolded units were carried as horizons around the seismic data grid

Table 3 Seismic events and approximate lithostratigraphic correlations



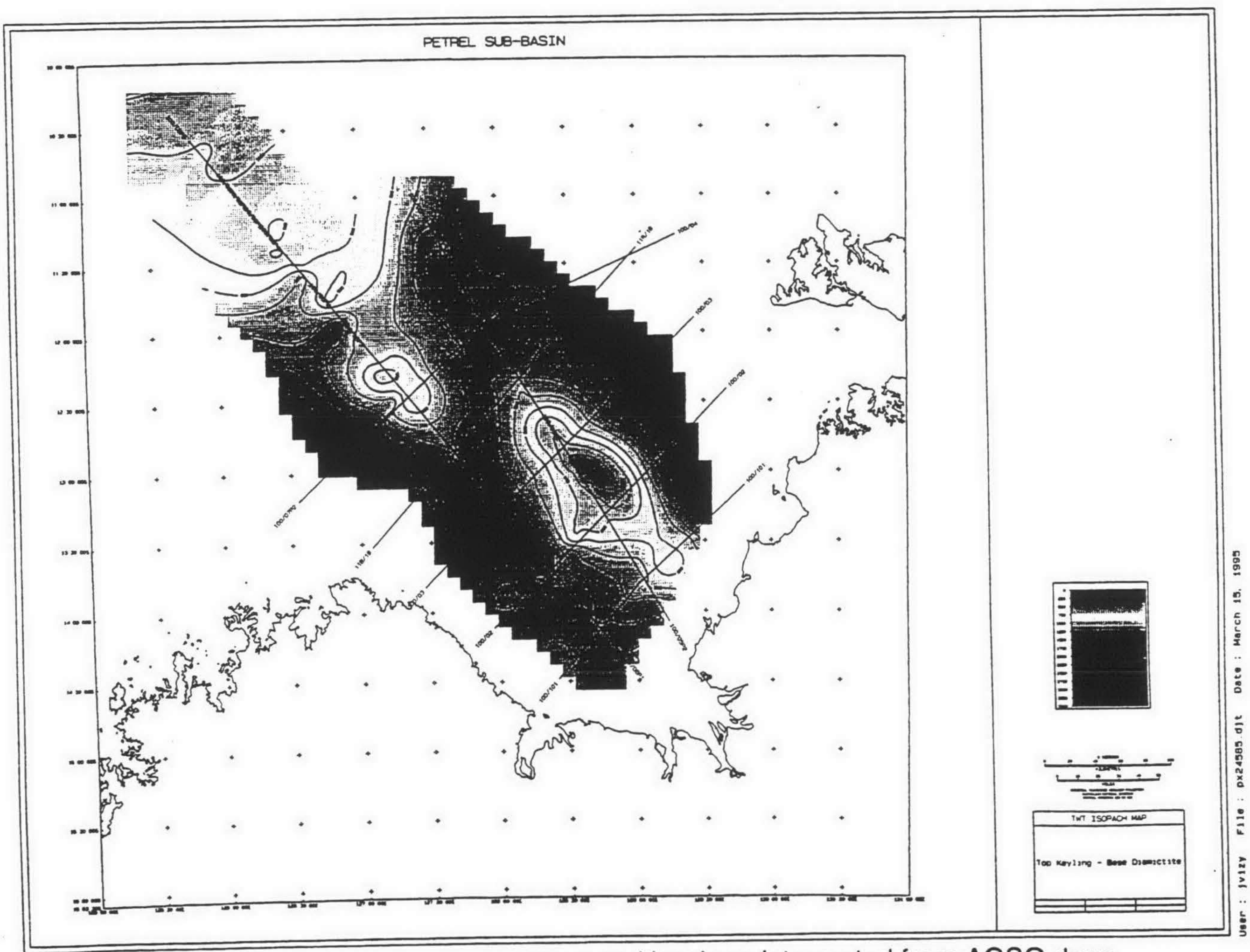


Figure 10 Example time structure contour and isochron interpreted from AGSO deep seismic data

AGSO SEISMIC LINE 100/101

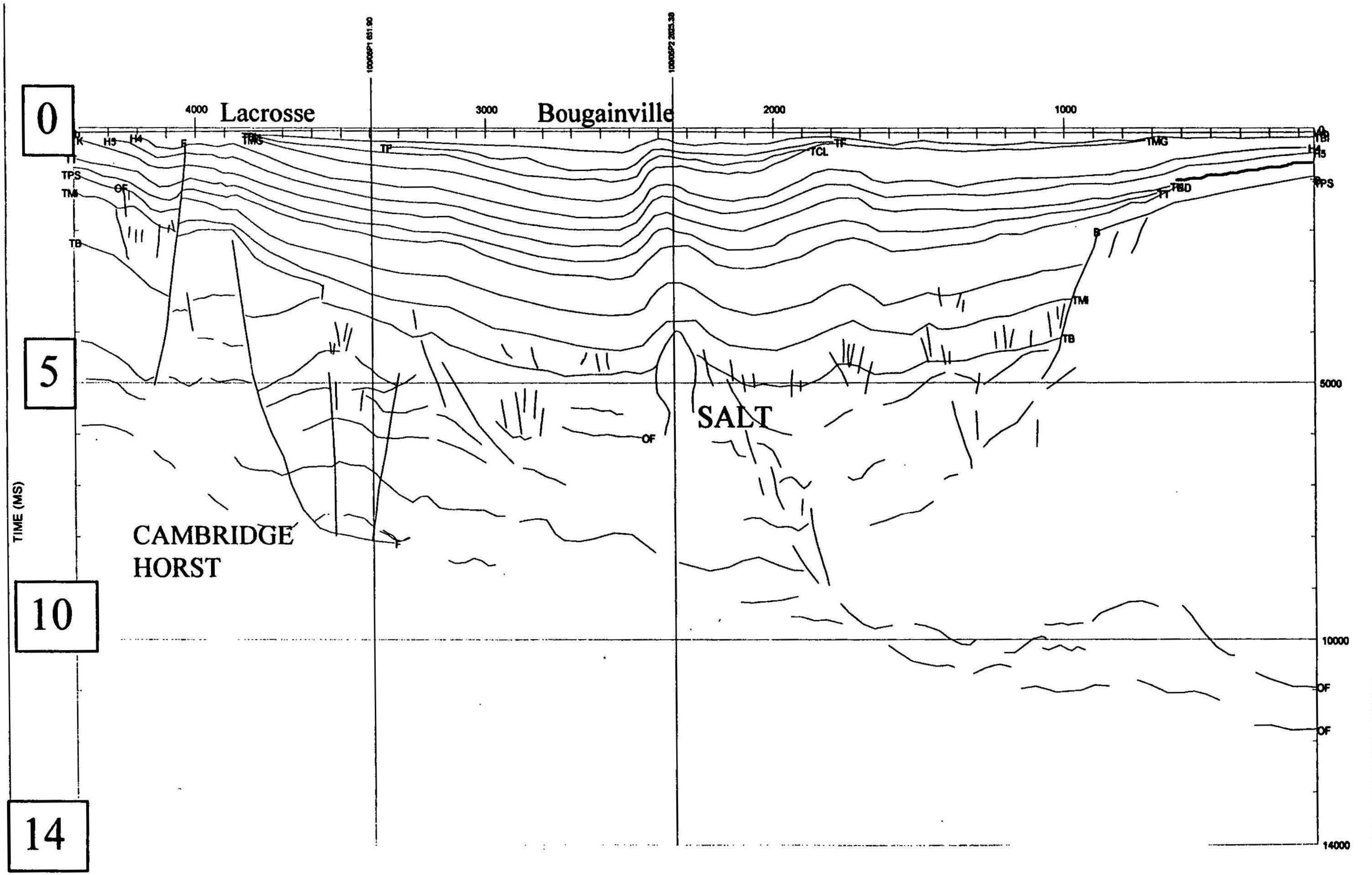


Figure 11a Cartoon interpretation of AGSO seismic line 100/01

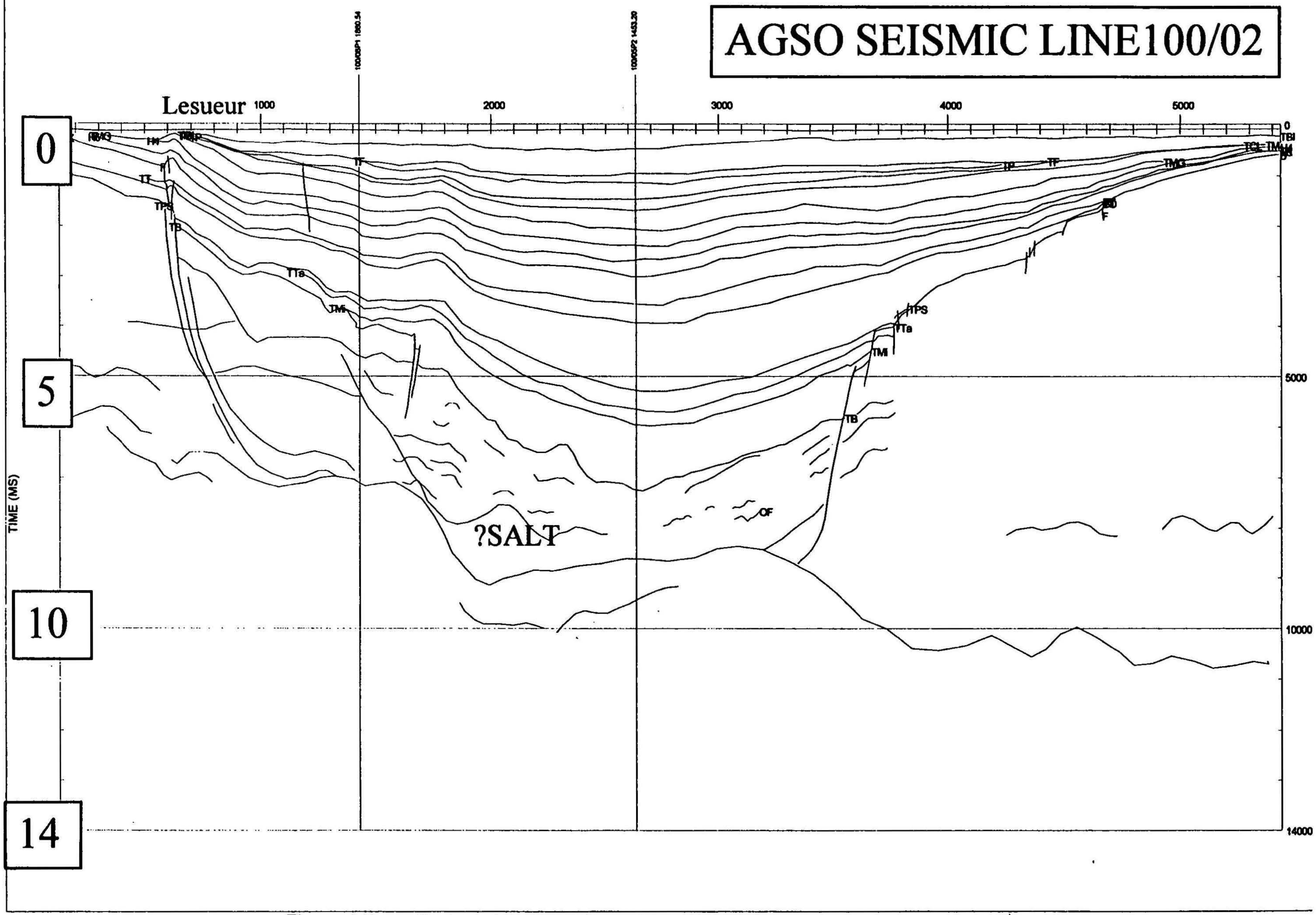


Figure 11b Cartoon interpretations of AGSO seismic line 100/02.

AGSO SEISMIC LINE 100/03

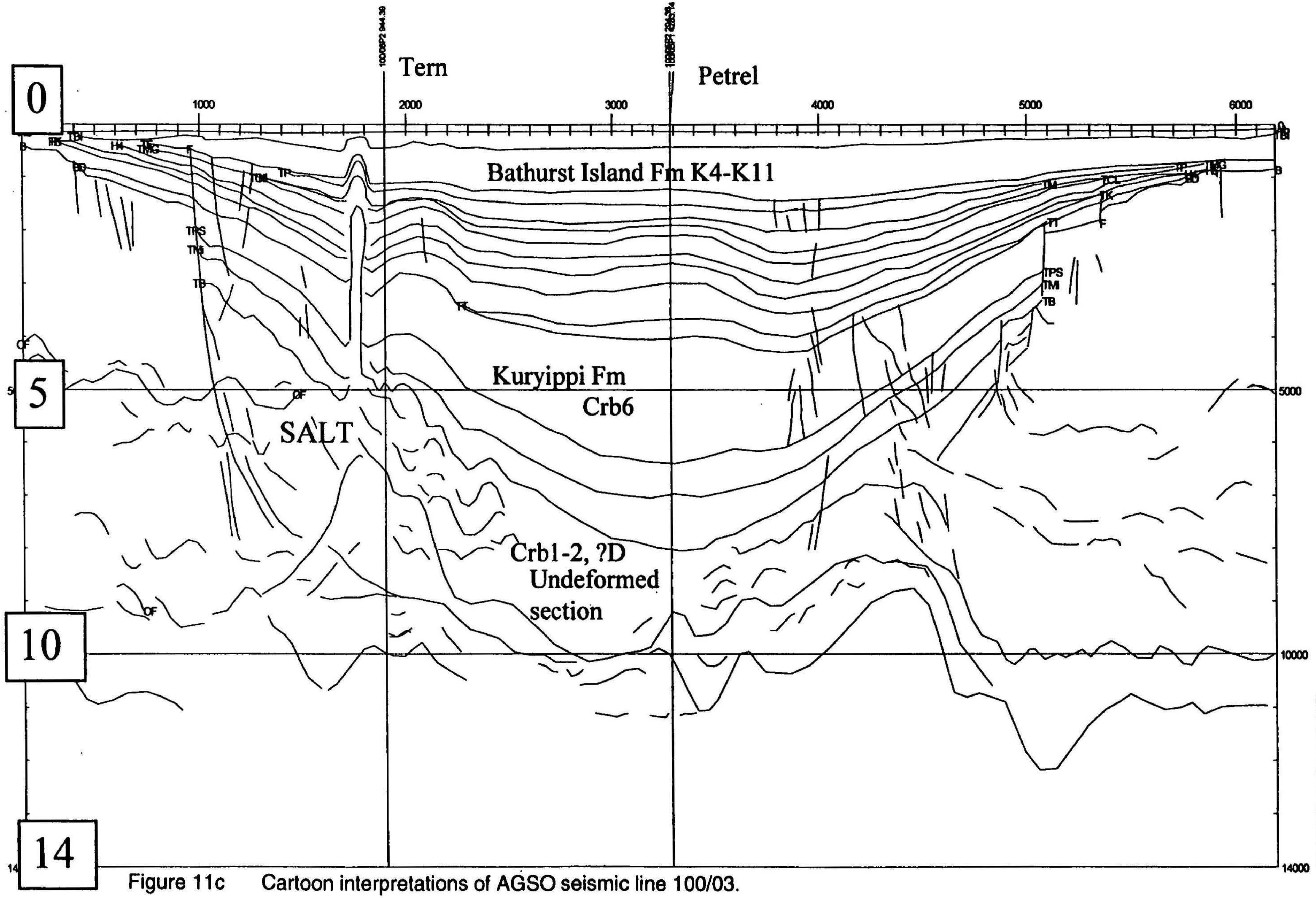
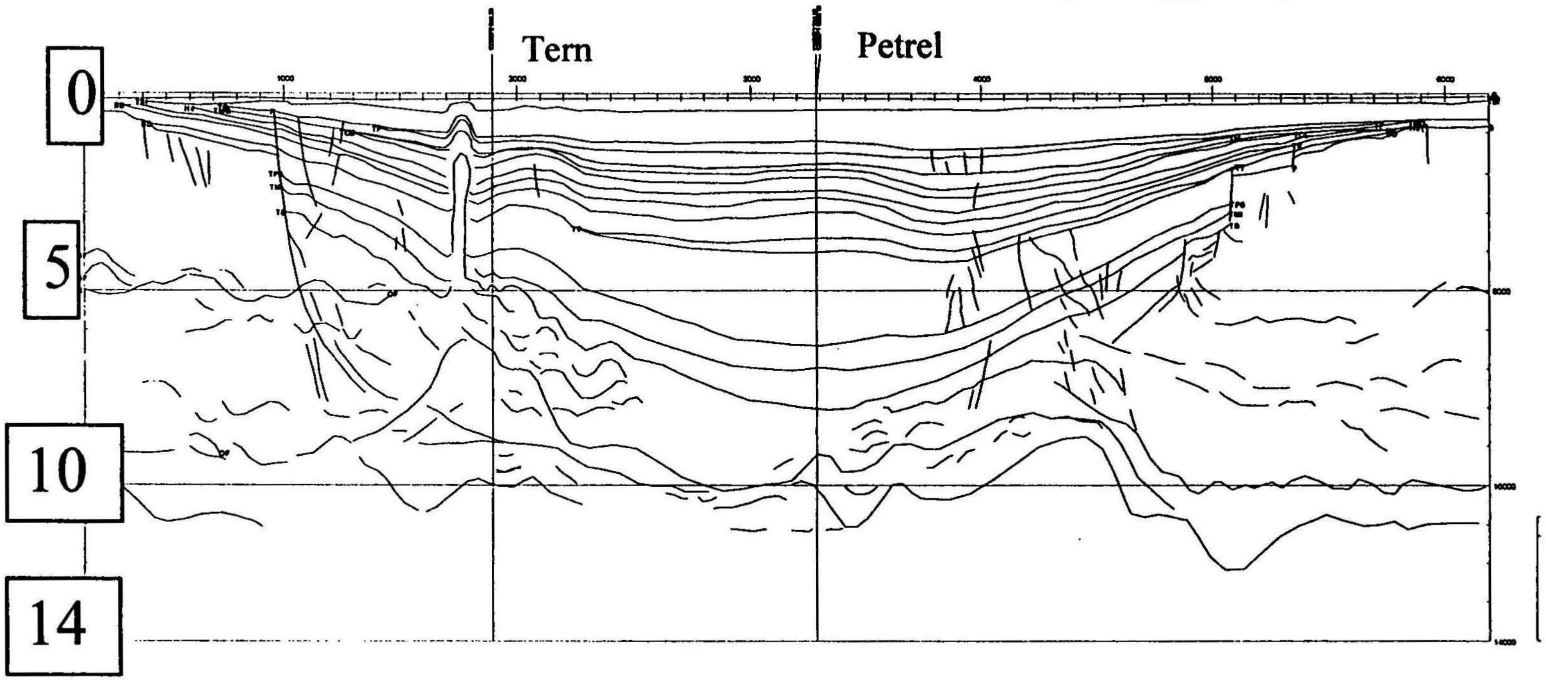


Figure 11c Cartoon interpretations of AGSO seismic line 100/03.

AGSO SEISMIC LINE 100/03



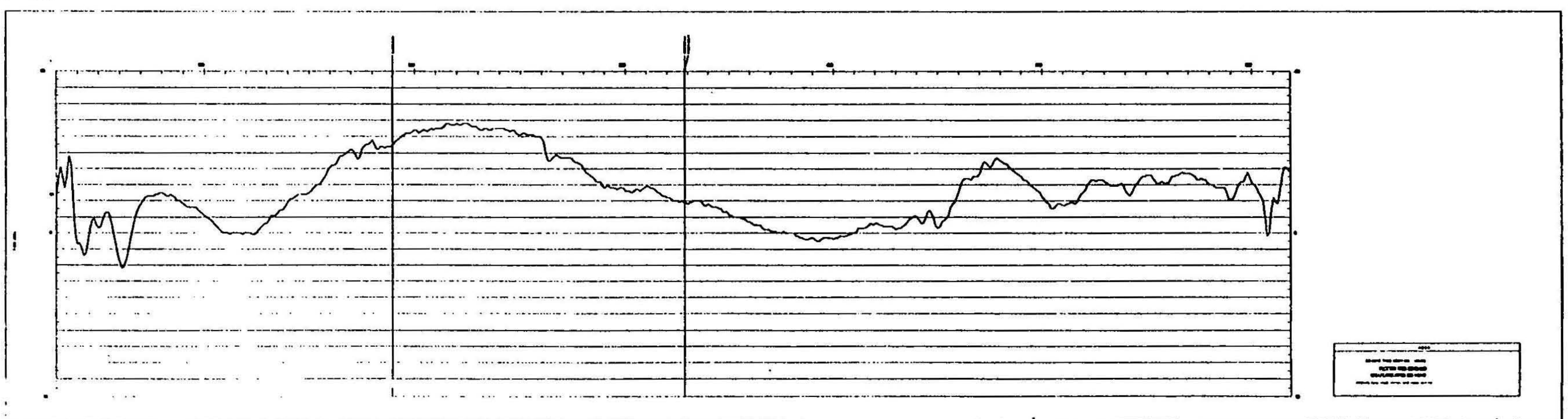


Figure 11d   Cartoon interpretation of AGSO Line 100/03 with total magnetic intensity ploted beneath the section

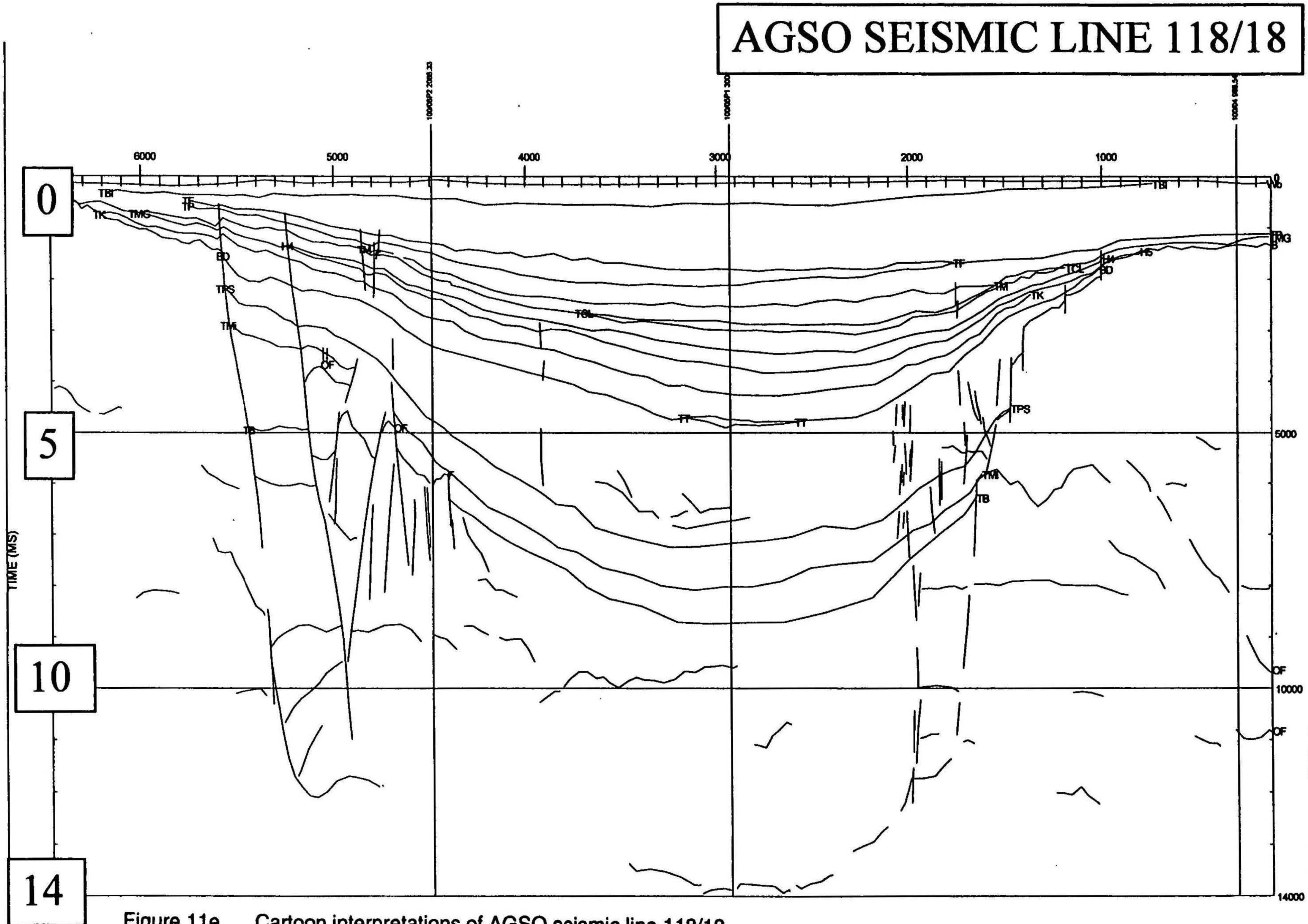


Figure 11e Cartoon interpretations of AGSO seismic line 118/18.

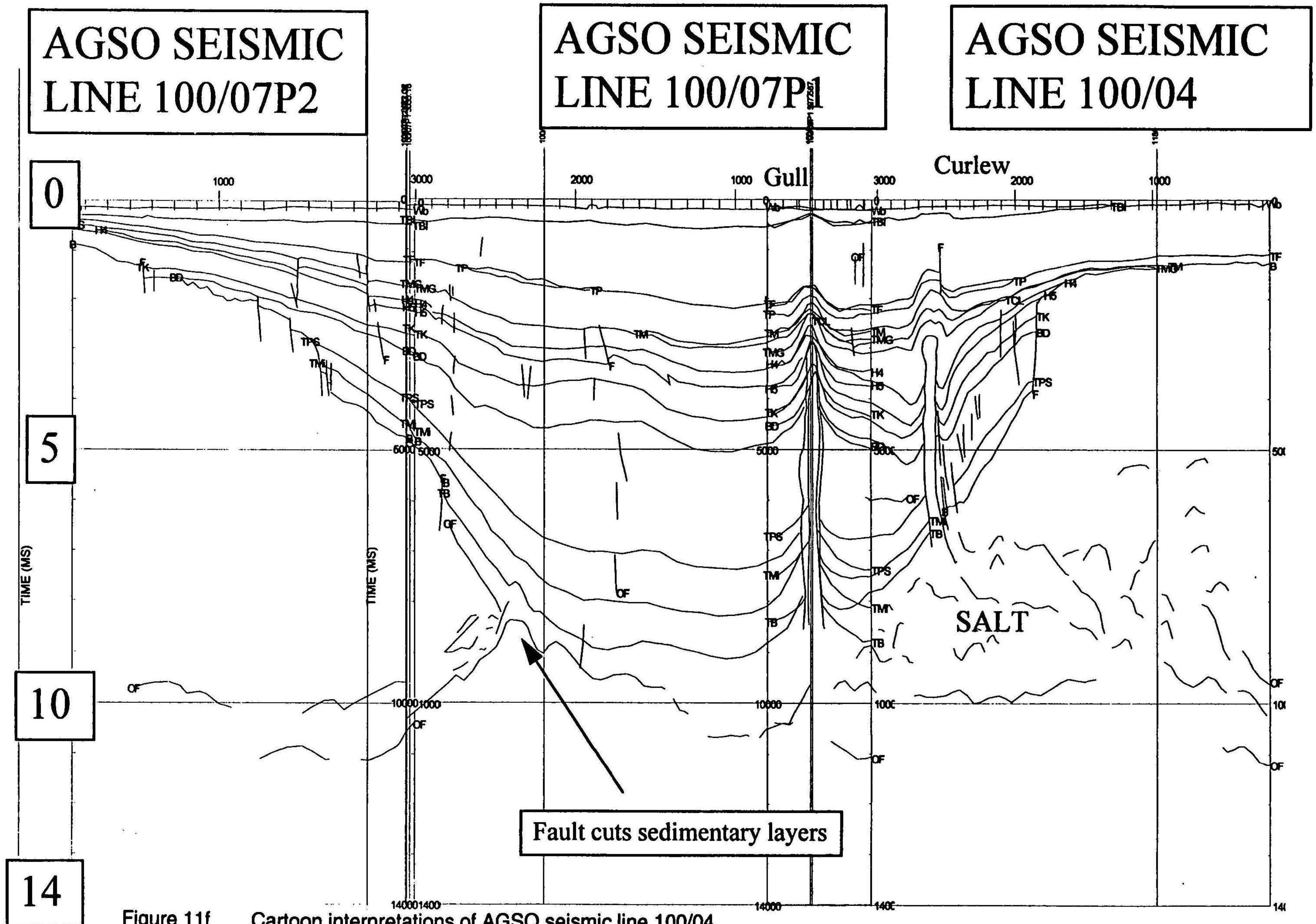


Figure 11f Cartoon interpretations of AGSO seismic line 100/04.

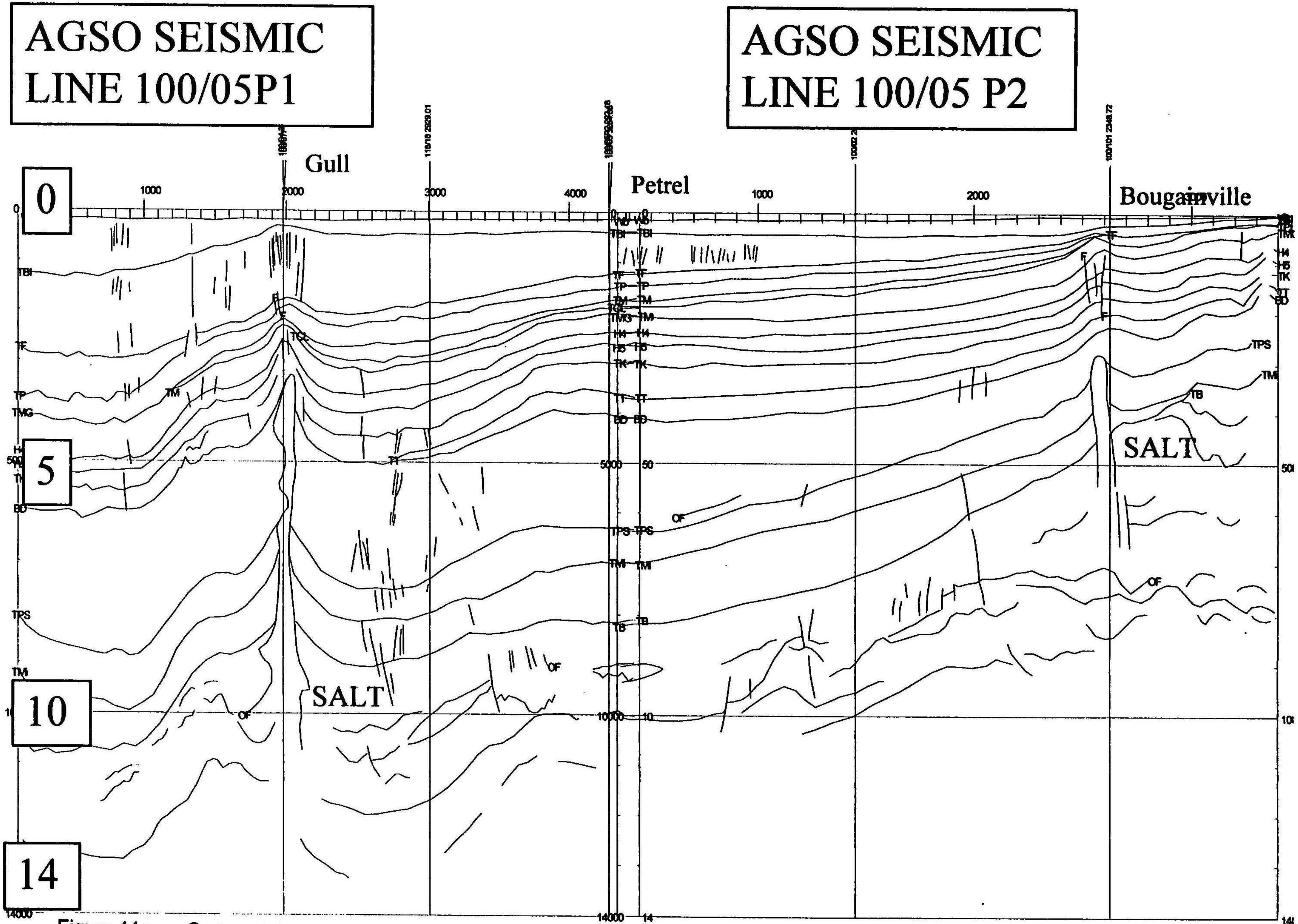


Figure 11g Cartoon interpretations of AGSO seismic lines 100/05 P2.

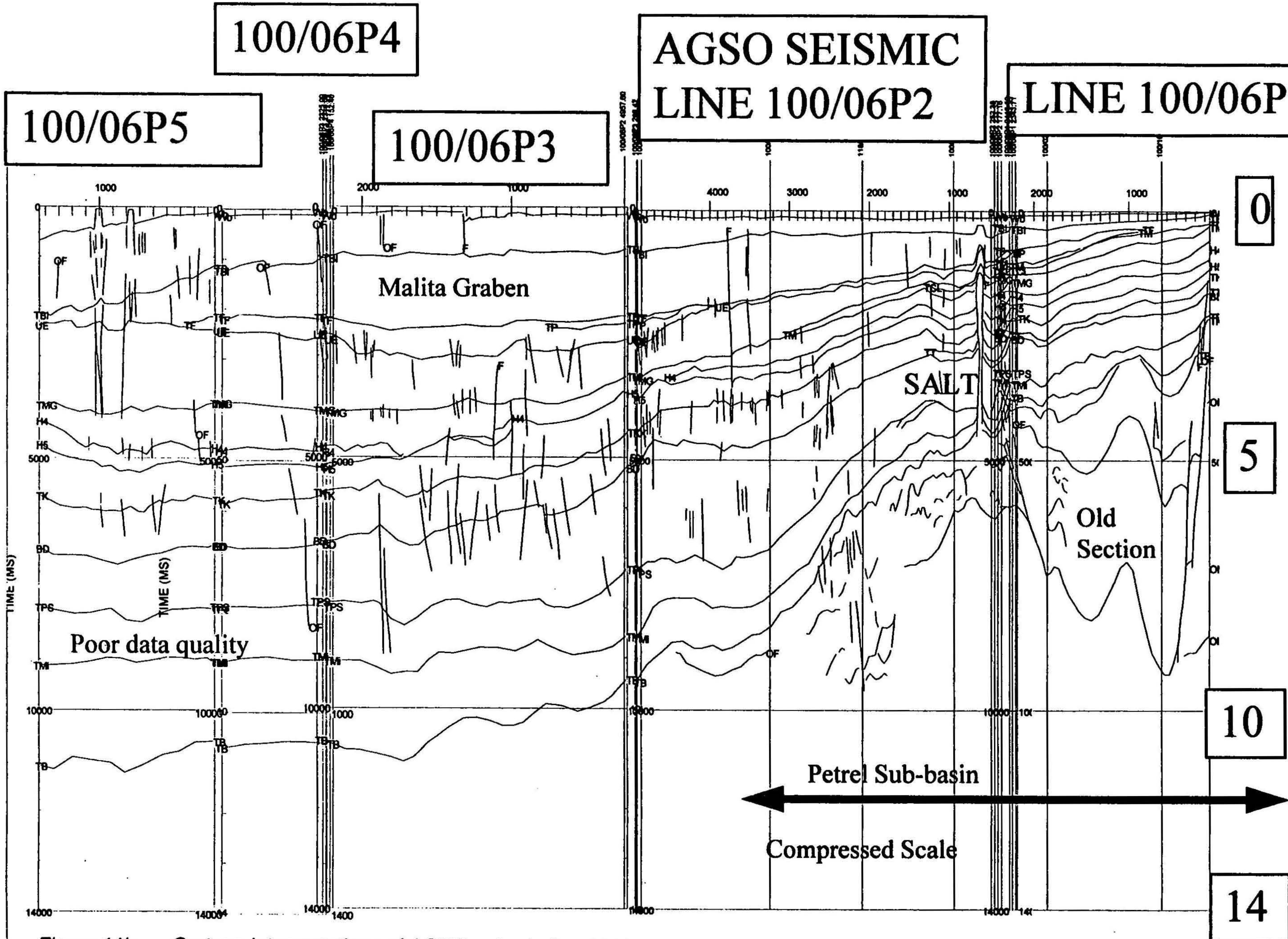


Figure 11h Cartoon interpretations of AGSO seismic line 100/06 P1.

TIME (sec)	RMS Velocity (m/sec)	DEPTH (km)
0.000	0	0
6.000	5000 ± 500	15
10.000	5800 ± 500	29
16.000	6500	52

Table 4 Two way times versus velocity and depth

TWT STRUCTURE CONTOUR MAPS

Regional structure contour maps on the following timeslices were produced to determine the architecture and accommodation within the Petrel Sub-basin. The deep AGSO seismic grid was well spaced for this task (Figure 8). Fault and erosional truncation of most horizons occurs on the northeast and southwest basin margins within the available seismic grid.

Near top Crb2 - (Top Bonaparte)

A narrow deep northwest trending rift trough broadening to an offset shelf break inboard of Gull 1 (at the boundary of the Tern and Curlew Compartments) is the key feature of this map. The disrupted sedimentary section below this event on many seismic lines suggests active rift spreading prior to this time.

Intra Crb3 - (Top Milligans)

Asymmetric broadening of the rift trough is observed on this map, about a pole inboard of Petrel.

Intra Crb5 - (Top Point Spring)

Structure at this time appears little different to Crb3 but with the first gentle onlap being observed on the northeast rift margin.

Top Crb6 - (Base Diamictite or top Kuriyippi)

This map which illustrates the Permian-Carboniferous boundary clearly shows the effect of the thick Carboniferous deposition that has caused the basin to shallow markedly in both the Barnett and Tern compartments.

Near top P1 - Top Treachery

Top P1 is interpreted to show the extent of glacial deposition in the basin. The structure on this map is controlled by the limited aerial extent of deposition. The contours suggest that active subsidence occurred under the site of the Petrel structure at this time.

Near top P3 - (Top Keyling)

Similar structure is suggested by the P3 map but with the boundary of the Tern and Curlew compartments moving inboard some 30 to 40 km. Basement faulting complicates the structure in both the Petrel and Tern features and the Petrel structure appears to show its deepest evidence of regional closure at this level.

Near top P4 - Top H5 (Fossil Head)

Structure contours on this level are very similar to P3.

Intra P6 - (Top H4)

Structure contours on this level are very similar to P4. Structure over Petrel appears slightly more subdued. Numerous salt domes such as Tern, Bougainville, Gull and Curlew show up particularly well on this horizon.

Intra Tr2 - (Top Mount Goodwin)

Structure contours on this level are very similar to P6 with some evidence of movement of the Curlew salt diapir.

Near top Tr2 - Top Cape Londonderry

The area of the Cape Londonderry Formation in the Petrel Sub-basin is of limited extent and the structure contour map has been truncated at the limit of the formation as determined from the available well control. The structure contours suggest gentle drape subsidence continuing.

Near top J1 - (Top Malita)

This event is also restricted by the available well control but similar though slightly older units probably occur in the Malita Graben. The map indicates subdued relief with gentle deepening to the northwest and slight steepening into the Malita Graben.

Near top J6 - Top Plover

This map shows broad gentle structuring with steepening into the Malita Graben, truncation of Plover Formation by younger formations around the edge of the basin over a much broader area than J1 and piercement by salt domes near Tern, Curlew and Gull.

Near top K1 - (Top Flamingo)

An expansive but similar pattern to J6 is shown by this structure contour. Slight movement on the Curlew - Tern compartment boundary is suggested.

Near top K11 - (Top Bathurst Island)

Broad expansive deposition is indicated on this uppermost structure contour. Active deposition related to the passive margin boundary near Flamingo and Iris is shown clearly.

TWT ISOCHRON MAPS

Regional structure contour maps on the following timeslices were produced to determine the depositional patterns and accommodation within the Petrel Sub-basin.

Lower Crb3 - (Top Milligans to Top Bonaparte)

This lowermost isochron shows a variable subsidence pattern within the Petrel Sub-basin. Thickening of the timeslice to the northwest depends on poorly controlled interpretation in that area. The unit is thick under and inboard of Petrel and southwest of the Cambridge Horst. Truncated on three margins of the basin, the unit is also virtually absent over the Cambridge Horst.

Crb3, 4 & 5 - (Top Point Spring to Top Milligans)

A variable subsidence pattern continued during this interval with a thin sequence developed across the basin axis inboard and under Petrel.

Crb6 - (Base Diamictite (top Kuriyippi) to Top Point Spring)

Active deposition and fault control of the northeast basin margin are interpreted from this isochron. The unit thickens markedly under Petrel.

P1 - (Top Treachery to Base Diamictite - top Kuriyippi)

This map shows the extent of glacial deposition, which is areally limited to the Petrel Sub-basin proper and mostly within the main axis of the basin.

P1 to P3 - (Top Keyling to Base Diamictite - top Kuriyippi)

Deposition of this unit follows a pattern similar to the preceding glacial unit but with the offset between the Tern and Curlew compartments clearly visible. Thick deposition is interpreted over a much wider area than the Petrel Sub-basin.

P2 & P3 - (Top Keyling to Top Treachery)

Deposition of this unit over the area of the Treachery Shale is similar to that unit but extending further to the southwest.

P4 - H5 (top Fossil Head) to Top Keyling

Broad gentle contours with subtle variable changes are shown on this isochron. Gentle thinning to the northeast basin margin is a clear feature.

P5 & P6 - H4 to H5 (top Fossil Head)

This important isochron corresponding closely to the Hyland Bay Formation shows a moderately developed thick along the basin axis but with no offset at the Tern/Curlew compartment boundary. Thinning to absence is present in the northwest of the Petrel Sub-basin and at the site of the later Malita Graben. These thin areas are believed to correspond to non-deposition of the Hyland Bay delta. Reefal growth is interpreted to have occurred in these areas throughout this time.

Tr1 - (Top Mount Goodwin to H4)

Variable deposition is interpreted from this isochron. Thinning to the northeast basin margin and thickening outboard of Gull are indicated.

Tr2 - Top Cape Londonderry to Top Mount Goodwin

This isochron shows thickening of this unit inboard of Petrel. Significant local subsidence is interpreted.

Tr3 to J1 - (Top Malita to Top Cape Londonderry)

A thick in the north-northeast of the basin is a pronounced feature of this isochron. Thickening around the Petrel structure during this time suggests this area was already a relative high.

J2 to J6 - Top Plover to Top Malita

Variable thickening to the northwest is shown on this isochron. The Petrel structure is evident even at this regional scale.

J7 to K1 - (Top Flamingo to Top Plover)

Pronounced thickening over the site of the Malita Graben and variable thicknesses in the Petrel Sub-basin

K2 to K11 - Top Bathurst Island to Top Flamingo

Gentle broad thickening to the northwest is observed.

COMPOSITE TWT ISOCHRON MAPS

These maps summarise the three major time slice packages in the basin. Significantly different trends are apparent in each.

Carboniferous - (Base Diamictite - top Kuriyippi to Top Bonaparte)

Thick deposition corresponding to a narrow basin rift axis broadening to the northwest is the major characteristic of this Carboniferous isochron.

Permian - (H4 to Base Diamictite)

Confined deposition over the old rift axis with a pronounced offset at the Tern/Curlew compartment boundary was the main trend during the Permian.

Mesozoic & Cainozoic - Top H4 (equivalent to surface to H4 - Top Cainozoic ISOCHRON)

Mesozoic and Cainozoic shows far less control by the older structures in the basin. Thickening outboard of and over the site of the Malita Graben is pronounced. Thick section is also present under and inboard of Petrel.

REGIONAL GEOLOGY

BASIN DEFINITION

The Petrel Sub-basin was defined by Lee and Gunn (1988) as the "post-crustal opening" sedimentary pile accumulation that formed in a depressed "V" shaped area underlain by oceanic crust (Figure 12). Seismic data was believed to indicate that the main filling in this area was by the Kulshill Group. For the purpose of the current study, the Petrel Sub-basin is considered to comprise the latest Neoproterozoic and Phanerozoic sedimentary section cratonward from the Malita Graben.

Petroconsultants (1990) considered the offshore part of the Bonaparte Basin comprised a Palaeozoic northwest trending graben (the Petrel Sub-basin), overlain by a more extensive Mesozoic sedimentary cover. The Mesozoic cover thickens toward the northeast trending Malita Graben (Figure 11 g and h).

Onshore, successively older Palaeozoic sequences are exposed as the Petrel Sub-basin narrows and merges into northeast to north trending depocentres that are truncated by the Cockatoo Fault Zone, part of the Halls Creek-Fitzmaurice Mobile Zone. This zone bounds the Precambrian Victoria Basin and Pine Creek Geosyncline, located further to the east. To the southwest, the onshore margin is formed by a series of northwest trending related fault blocks of probable Pre-Cambrian age that step up along the boundary between the basins and the Kimberley Block in Western Australia.

Offshore the Palaeozoic basin margin is obscured by Mesozoic and Tertiary cover but Palaeozoic remnants of the basin can be mapped on seismic sections across the Sahul Platform and adjacent Sahul Syncline.

BASIN FORMATION

Several models have been proposed for the formation of the Petrel Sub-basin. Many have elements in common. All agree that the basin was initiated by rifting (Lee and Gunn, 1988; O'Brien et al., 1993). Gravity, magnetic, seismic and stratigraphic data provide the best constraints for the various models proposed.

Gravity data is presented in Figure 13. This illustrates a symmetric "V" shaped opening. Magnetic data in the form of a single transect along AGSO seismic line 100/003 (Figure 11 d, Enclosure 48) also appears symmetric when the variation in magnetic

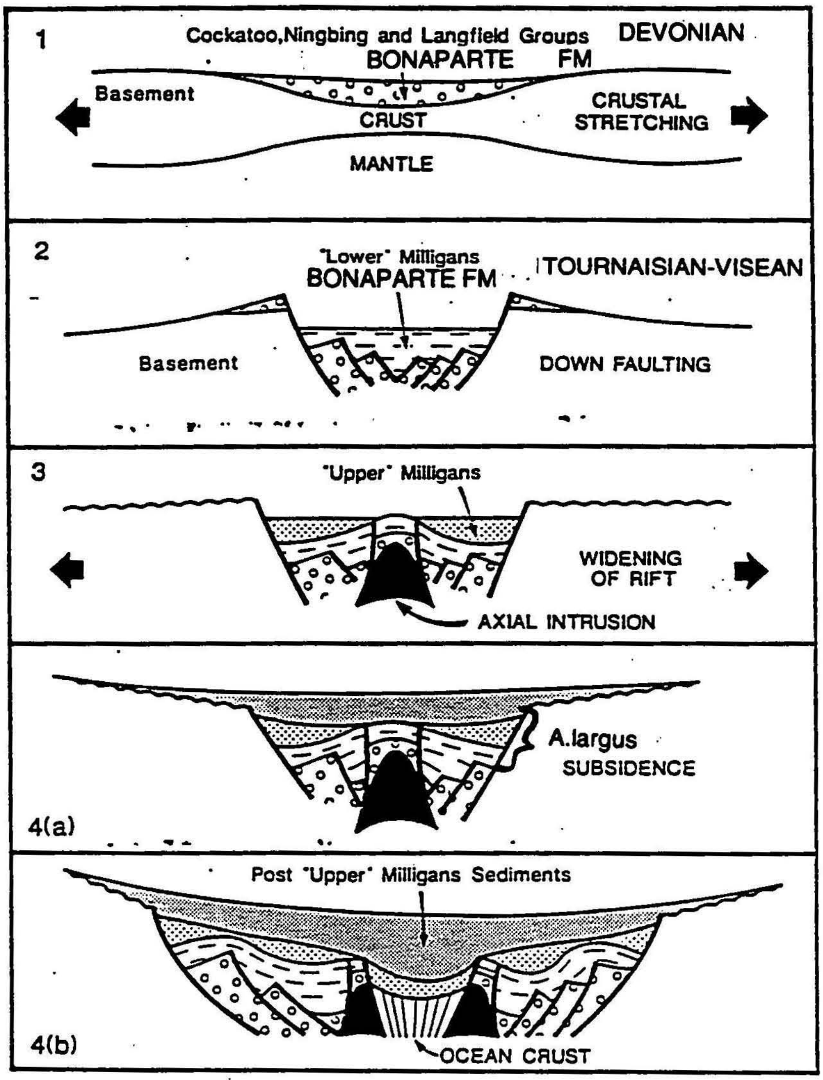


Figure 12 Model for the basin evolution of the Petrel Sub-basin (From Lee and Gunn, 1988)

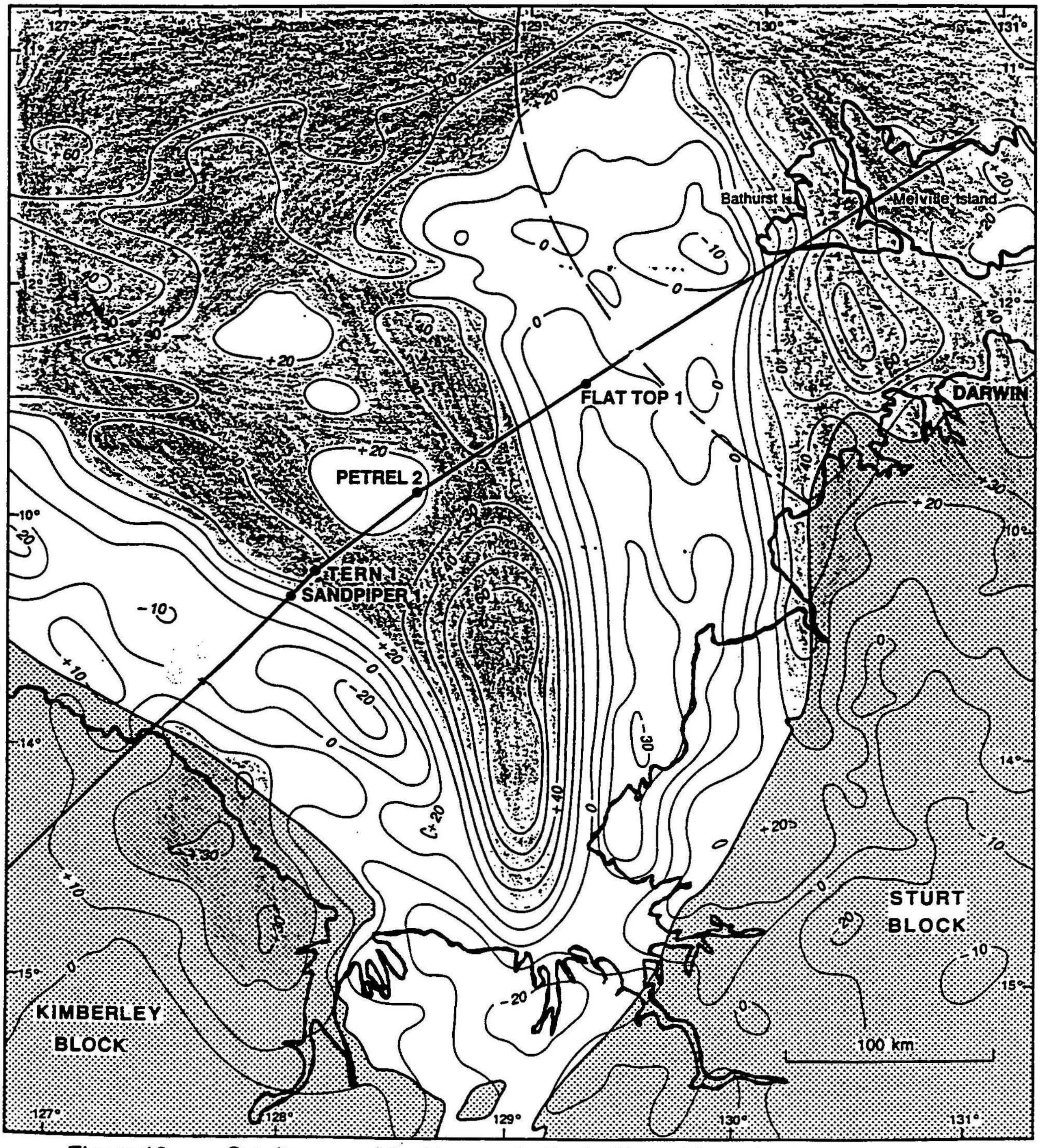


Figure 13 Gravity map of the Bonaparte Basin (From Mory 1991)

declination due to latitude is considered (Dr Peter Gunn, personal communication, 1995). This type of data provided much of the basis of the original basin evolution model of Lee and Gunn (1988; Figure 12).

AGSO deep seismic data provided the basis for a basin formation model proposed by O'Brien et al (1993). This was a composite model derived by Lister et al. (1991) but based on elements of "McKenzie" pure shear and "Wernicke" simple shear models as illustrated in Figure 14.

When the various proposed models are assessed along with the seismic time structure maps and isochrons, age/depth curves and stratigraphic data in the current report it is clear that a composite model best accounts for all the observed data. However, it is also apparent that rift extension was confined to the earliest period of the basins history (syn and pre *A. largus*) and most of the fill involved passive margin style deposition (See Basin Evolution - Table 6).

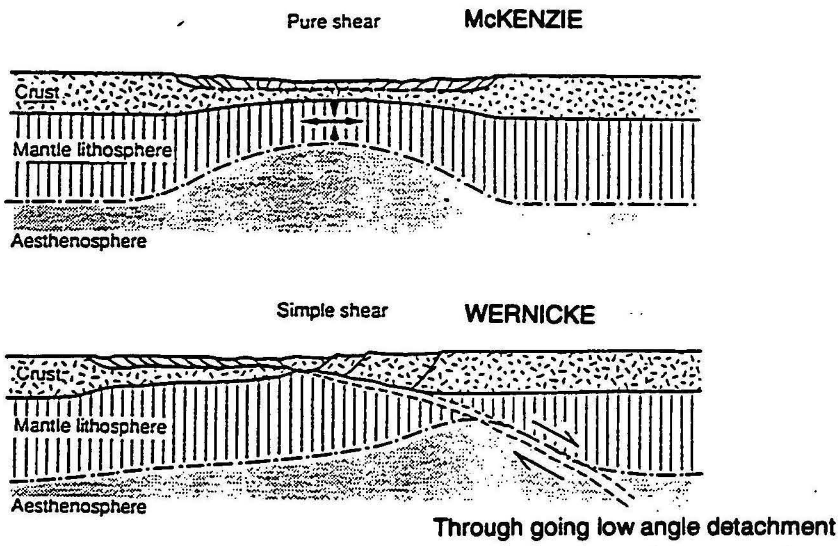
TECTONIC EVENTS

O'Brien et al. (1993) described the generalised structural history for the Timor Sea shown in Table 5. There is clear evidence of these regional events in the Petrel Sub-basin, in the form of sequence deformation and, particularly, initiation and cessation of deposition. The details for the studied wells in the Petrel Sub-basin are presented in Figure 15. Events in the Petrel Sub-basin can also be matched with those recognised in the Canning Basin (see Kennard et al., 1994) despite the basins being very different in character. Table 6 lists eight phases of basin evolution in the Petrel Sub-basin, noting the amount and direction of extension.

The middle Cambrian start of clastic deposition in the Petrel Sub-basin is interpreted to be the result of marine flooding and a general eustatic sea level rise across northern and central Australia. On the basis of the data from the Canning Basin, Ordovician extension produced fault blocks and basins for salt deposition in the Petrel Sub-basin.

In the Silurian to early Devonian, both the Amadeus and Canning Basins underwent tectonism - the Rodingan and Prices Creek Movements. These events produced uplift, tilting, exposure, truncation and angular unconformity that also corresponded to a major eustatic fall (Romine et al., 1994). This is the most dramatic and arguably the only basin-

End-member models of strain geometry in rifts (Buck, Steckler and Cochran 1988): (a) *pure shear* geometry with an upper brittle layer overlying a ductile lower layer, producing a symmetrical lithospheric cross-section. The ductile stretching may be accompanied by dilation due to intrusion of melts (cf. Royden *et al.* 1980). (b) *simple shear* geometry with a through-going low-angle detachment dividing the lithosphere into an upper 'plate' or hangingwall and a lower 'plate' or footwall. Thinning of the lower lithosphere is relayed along the detachment plane, producing a highly asymmetrical lithospheric cross-section (after Wernicke 1981, 1985).



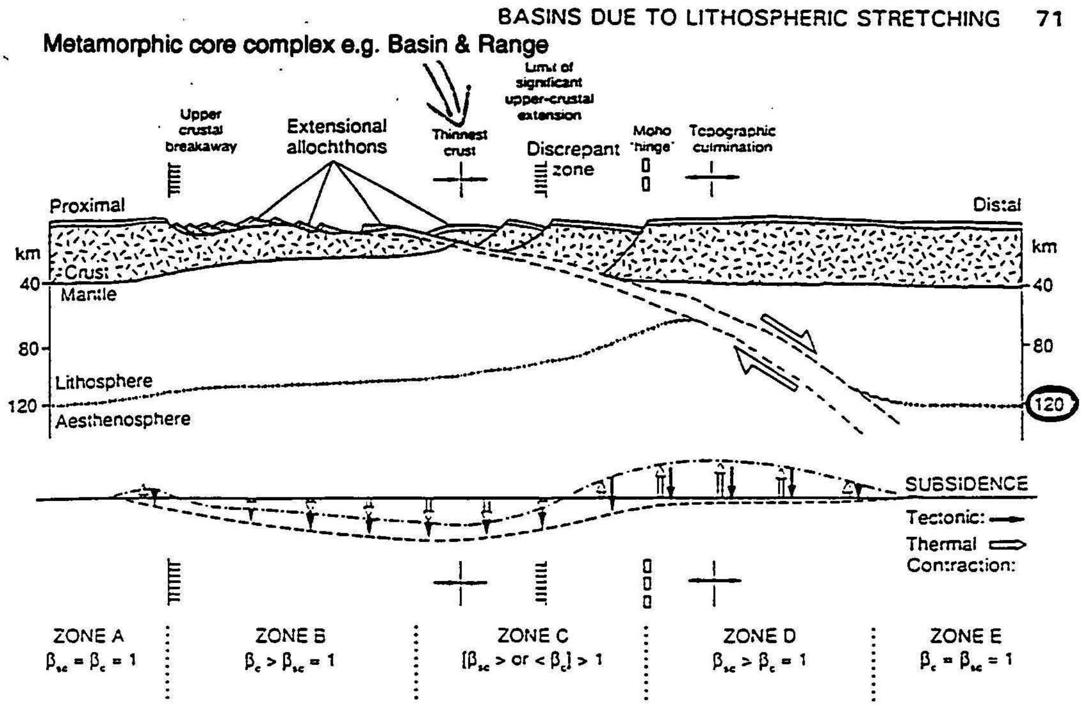


Figure 14 Models of rift basin formation (from Allen and Allen, 1990)

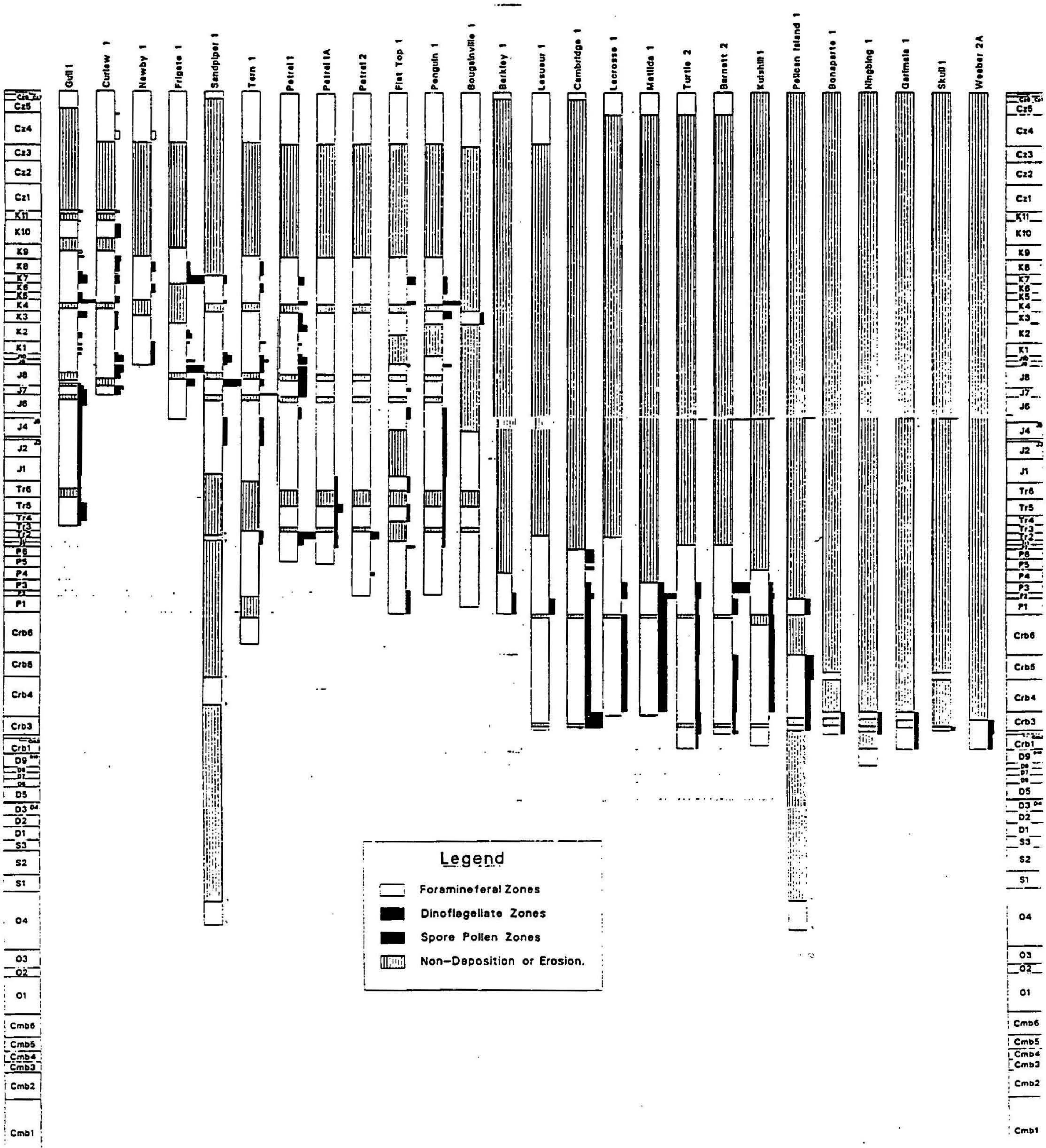


Figure 15 Petrel Sub-basin Basin Time Space Correlation Diagram. See Enclosure 2 for full scale version.

wide deformation event seen in the Petrel Sub-basin prior to the Miocene compression that produced an extensive and dramatic increase in salt diapir movement.

Late Devonian to early Carboniferous extension outboard of the Petrel Sub-basin is interpreted to have produced unconformities and caused the deposition of various Milligans fans. Early Permian extension produced volcanic intrusions interpreted on AGSO lines (100/5P2 and 118/018), similar to early Permian dykes in the Canning Basin (Reeckmann and Mebberson, 1984) and at Kulka 1 in the Arafura Basin.

The Petrel Sub-basin contains few of the major Carboniferous-Permian growth faults present in the Canning Basin. But the more continuous Mesozoic depositional record in the Petrel allows timing of the younger events to be more closely constrained (Figure 16). Thus, the Petrel Sub-basin is well placed to date the "Fitzroy Movement", which is loosely bracketed by early Triassic and middle Jurassic sediments in the Canning Basin (Kennard et al., 1994). In the Petrel Sub-basin, the Fitzroy Movement is constrained to the late Triassic, approximately the Norian/Carnian boundary, Tr5 time (Figure 2), on the basis of the unconformity corresponding to "Seismic Horizon 3" present in Tern 1, Petrel 2 and Gull 1 (Figure 16). In Gull 1, the *M. crenulatus* zone occurs above the unconformity and the *S. speciosus* zone below, thus precisely timing the Fitzroy Movement.

Late Triassic compression, inversion of structures, north south compression in the Petrel Sub-basin and left lateral transpression in the Arafura Basin (Bradshaw et al., 1990), and the Fitzroy Trough wrench movements seen in the Canning Basin; may all be related to some external shear as Sibumasu (Metcalf, 1993) rifted off the northwest margin of the Australian portion of Gondwana. Callovian northwesterly tilt, as breakup occurred, resulted in continuing subsidence and erosion in different areas of the Petrel Sub-basin. Finally, the Miocene was the time of major salt movement possibly due to compression caused by re-organisation of the Australian Plate.

STRUCTURE IN THE PETREL SUB-BASIN

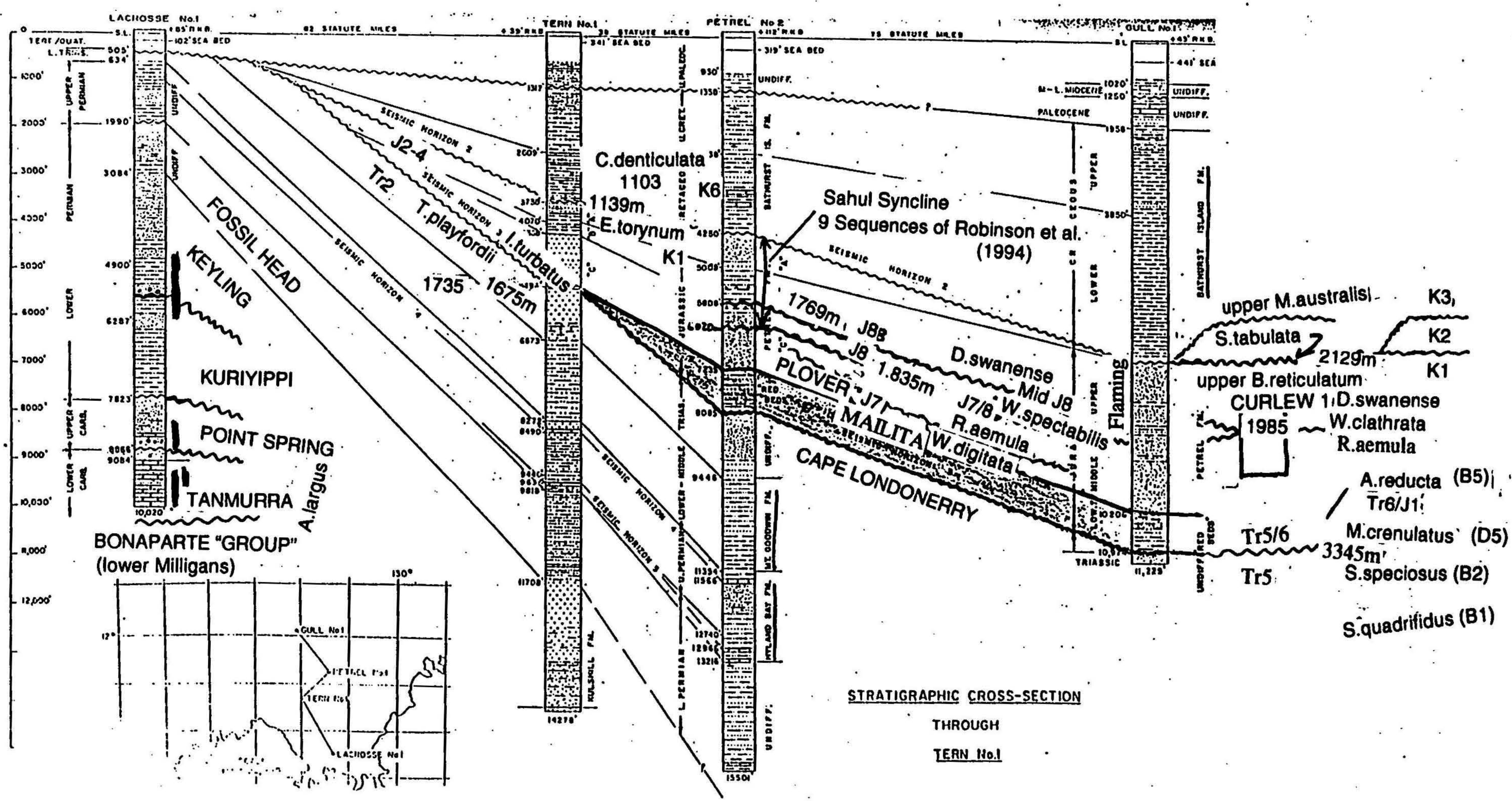


Figure 16 Structure in the Petrel Sub-basin (After Arco Australia Ltd, 1971a)

Generalised structural history for the Timor Sea (from O'Brien et al., 1993)

Late Devonian to early Carboniferous
Major extension event
Extension along a NW-trending rift system takes place in the late Devonian to early Carboniferous. A detachment surface at 9-10 seconds TWT developed during extension, with opposing rift margins having classic LPRM-UPRM geometries. The rift was sub-divided into at least three segments by NE-trending accommodation zones, with adjacent segments having opposite polarities. Virtually all of the large structures within the post-rift sequence are located over the LPRMs, as the large displacement and through-going structures on those margins reactivate readily, as well as allowing salt migration from the deep, pre-rift sequence.

Late Carboniferous-early Permian
Major extension event
Initiation of the Westralian Superbasin by continental extension/rifting. Thinning of pre-existing crust to 25 to 50% of original thickness via lower crustal thinning in an UPRM setting. Formation of NE-trending normal and NW-trending transfer fault arrays, at least in some instances by the reactivation of pre-existing ?Proterozoic basement fracture systems. Development of the Vulcan Sub-Basin (?and Malita Graben) as a small, flexural feature on the inboard part of the UPRM. Orthogonal overprinting of the NW-trending Petrel Sub-Basin rift system. This is the major basin forming event in the region and was responsible for most of the crustal thinning and thermally-driven subsidence.

Late Permian-End Triassic
Thermal subsidence.
Sequence thickens gradually to W/NW; little or no fault-related growth; up to 10-14 km of largely unstructured terrestrial to shallow marine sediment deposited.

Latest Triassic-early Jurassic
Regional structuring event
Also in Petrel Sub-Basin, Carnarvon, Arafura and Canning Basins. NS to NNW compression; oblique reactivation of Permo-Carboniferous Westralian Super-Basin fault systems; some strike-slip component on Permo-Carboniferous faults; (?) formation of N-S faults through Vulcan Sub-Basin via propagation from the Kimberley Block Event leads to low amplitude, crustal scale buckling producing broad, synclinal basins with intervening faulted anticlinal features. Some uplift along Vulcan Sub-Basin / Londonderry High Boundary Zone. Significant transpressional reactivation of LPRMs in the Petrel Sub-Basin.

Latest Callovian-early Oxfordian
Regional structuring event.
Far field effects of continental break-up result in rapid, low strain crustal NNE extension in the Vulcan Sub-Basin. Total amount of extension was typically less than 5%. An array of extensional half-grabens developed via the reactivation of the underlying Permo-Carboniferous normal faults. Grabens were offset across the underlying primary Permo-Carboniferous transfer faults (e.g. Swan and Paqualin Grabens). Extension was quickly followed by continental break-up, leading to the formation of the Callovian Unconformity. Subsidence following break-up, when combined with rising eustatic sea-level, causes rapid flooding of the half grabens, resulting in restricted deep water marine environments favourable to source rock deposition (Lower Vulcan Formation). Probably minor strike-slip movement (transtension) on many faults.

Late Jurassic-early Cretaceous
Regional structuring event.
NW-NNW compression slows and possibly stops sea-floor spreading in the Argo Abyssal Plain in the Tithonian.
Transpressional reactivation of Permo-Carboniferous normal fault network in Vulcan Sub-Basin, causing prominent uplift along the south-eastern margins of the half-grabens in particular.
Development of the Skua, Challis and Jabiru Horsts as significant features. Significant uplift along the Vulcan Sub-Basin/Londonderry High Boundary Zone.
Some strike-slip on many faults, with complex structures developing at the intersections of the NS, NW and NE-trending structural fault sets. Possible clock-wise rotation of Sahul Platform produces ENE-EW extensional faults along trend of Sahul Syncline/accommodation zone. Falling eustatic sea-level, in conjunction with tectonically-induced uplift, results in the shedding of large amounts of silici-clastic sediment from the horsts.

Mid-Miocene to Recent
Regional structuring event.
ENE-WNW compression related to collision and subduction along northern continental boundary. Dominated by reactivation of underlying faults; localised flexure of thinnest parts of pre-Permian crust.

Table 5 Structural history of the Timor Sea (From O'Brien et al., 1993)

Table 6 Phases of basin evolution in the Petrel Sub-basin
Note - α (alpha) in this table is used to qualitatively describe accommodation along the rift axis and during post-rift subsidence

Neoproterozoic **rifting** (β ≈ 3-5, direction unknown);
Cambrian to Ordovician **interior deposition**;
Silurian to early Devonian **?rift** trough infill (β ≈ 1.5, NE-SW);
Late Devonian to early Carboniferous northwest trending **rift/shelf** infill (β ≈1.5, NE-SW; α = ∞ to NW);
Early Carboniferous to Permian **shelf** infill (α= ∞ to NW);
Triassic to middle Jurassic shallow **shelf** infill (α = ∞ to NW)
Late Jurassic to Cretaceous **shelf** sedimentation associated with northeast trending rifting, followed by Valanginian continental breakup (α = ∞ to NW)
Late Cretaceous to Cainozoic trailing-edge **shelf** infill (marginal compressional flexure, α very small, sediments largely bypassed the sub-basin)

BASIN STRUCTURAL ELEMENTS

The main structural elements of the (greater) Petrel Sub-basin as described in the current report are shown on Enclosure 1 and Figure 17. They are described as follows -

The Petrel Sub-basin is a northwest trending rift containing Palaeozoic and Mesozoic rocks located mainly within the Joseph Bonaparte Gulf. It is bounded to the southwest and northeast by marginal faults and/or hinge lines separating it from shallow Proterozoic to Recent shelves, platforms, and terrace areas. To the north it is separated from the Malita Graben by a northeast trending faulted shelf break down-warped towards the northwest. The northwest structural trends of the Petrel Sub-basin are conspicuously oblique to the northeast trends of the Malita Graben.

In cross-section the Petrel Sub-basin is 200 km wide and resembles an asymmetric half graben dipping towards the northwest. Estimates of total sediment thickness commonly exceed 25 km on the deep AGSO seismic records. To the northeast, Palaeozoic rocks of the sub-basin onlap shallowing Proterozoic basement of the Darwin Shelf. Salt migration and vertical salt structuring are preferentially developed along major marginal fault zones. The location of these fault zones and associated salt structures switches from the eastern to the western and back again to the eastern margin down the length of the Sub-basin. O'Brien et al. (1993) divided the Petrel Sub-basin into three compartments - Barnett, Tern and Curlew -

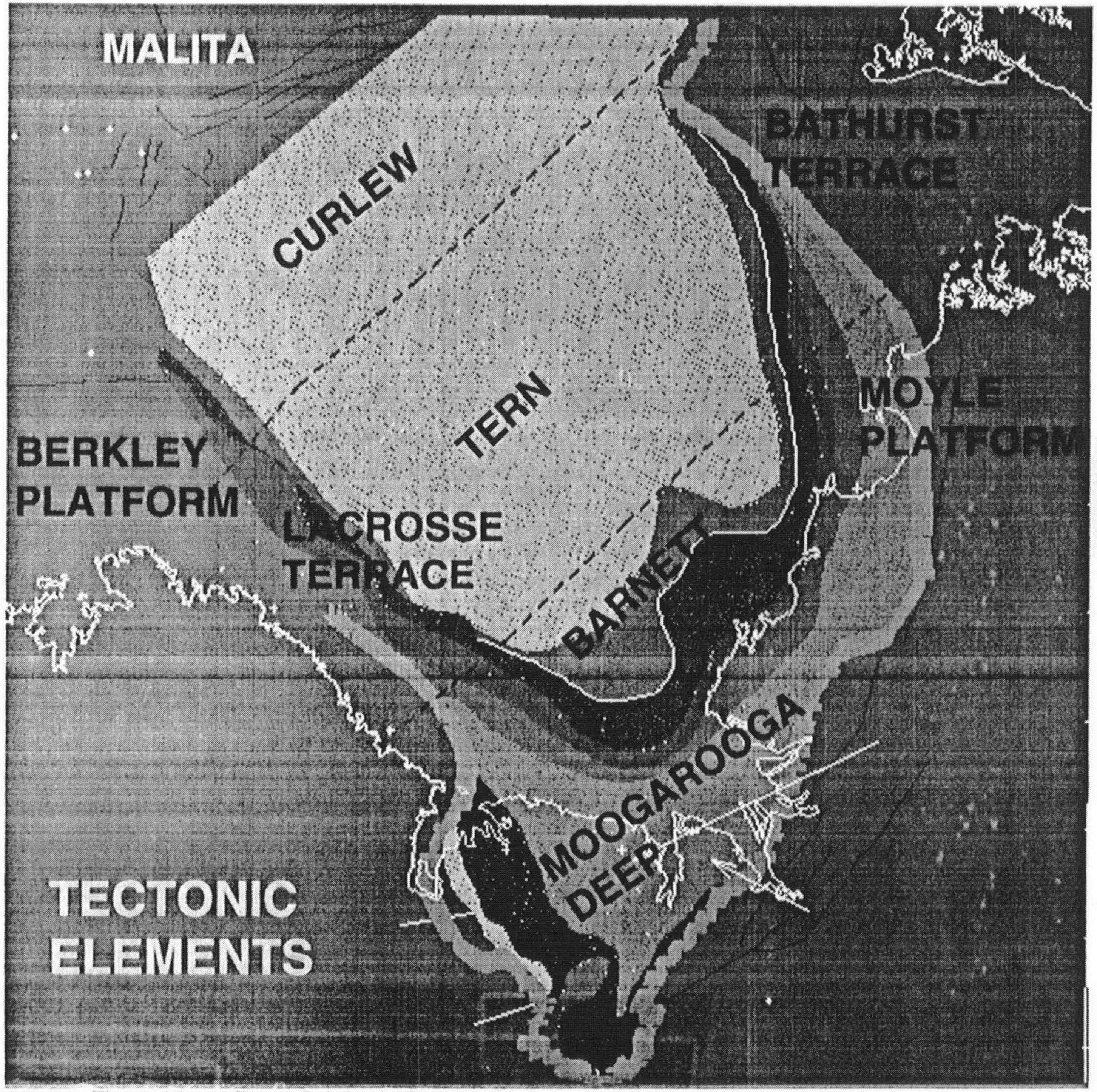


Figure 17 Petrel Sub-basin Tectonic Elements Map

bounded by accommodation zones at these switches in basin polarity (Figure 17, his Figure 6).

Regional cross-sections through the Petrel Sub-basin illustrate its setting on the Australian Shelf and relationship to the margin of the foredeep in Timor (Figures 18 and 19). The regional geology is presented in Figures 20 and 21.

Berkley Platform and Lacrosse Terrace

The Berkley Platform is an offshore extension of the Kimberly Block. It is located in the Western Australian portion of the basin and comprises shallow basement unconformably overlain by thin Permian, and Jurassic to Tertiary sections.

Basement across the Lacrosse Terrace lies at intermediate depths, between the adjacent Berkley Platform and the Petrel Sub-basin. Dipping basinwards and plunging to the northwest, this terrace comprises a thicker sequence of rocks than that across the Berkley Platform, including an early Palaeozoic to early Carboniferous section.

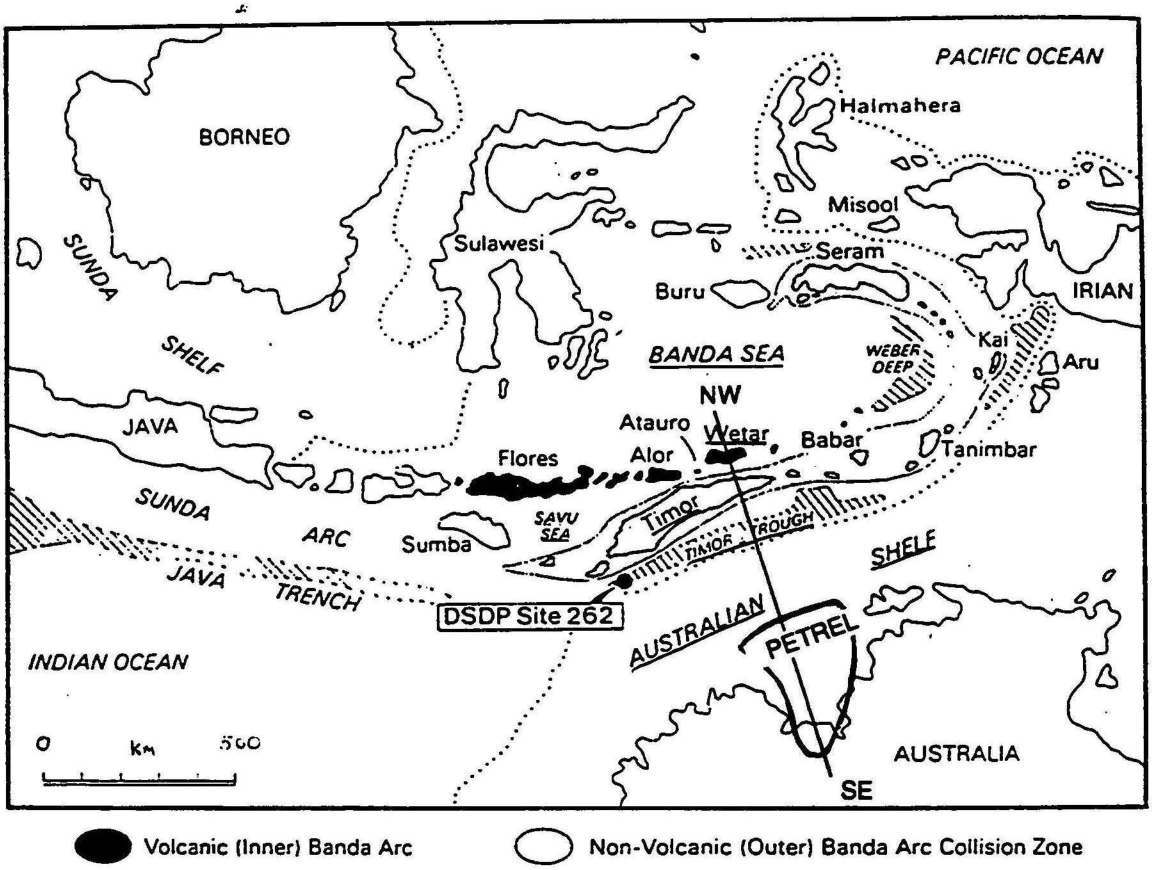
Moyle Platform and Bathurst Terrace

The Moyle Platform lies on the northeast side of the Petrel Sub-basin where it coincides with a zone of shallowing basement. Palaeozoic and Mesozoic rocks are progressively truncated across the Moyle Platform which may represent the updip depositional edge of the original southwest tilted half-graben located beneath the Petrel Sub-basin. In the south, the Moyle Platform is characterised by a series of en-echelon northwest trending faults which coalesce onshore and swing north-south becoming the Moyle Fault. The Bathurst Terrace lies in a similar setting further to the north.

Pincombe Inlier and Pincombe Ridge

The Pincombe Ridge and its surface expression, the Pincombe Inlier, are located onshore to the south of the Keep Inlet. During Devonian and Carboniferous times this ridge was a prominent structural feature controlling sediment deposition, forming a structural boundary between depocentres in the developing Carlton and Burt Range Sub-basins.

Carlton Sub-basin & Moogarooga Deep



Location map of Timor–Tanimbar Trough.

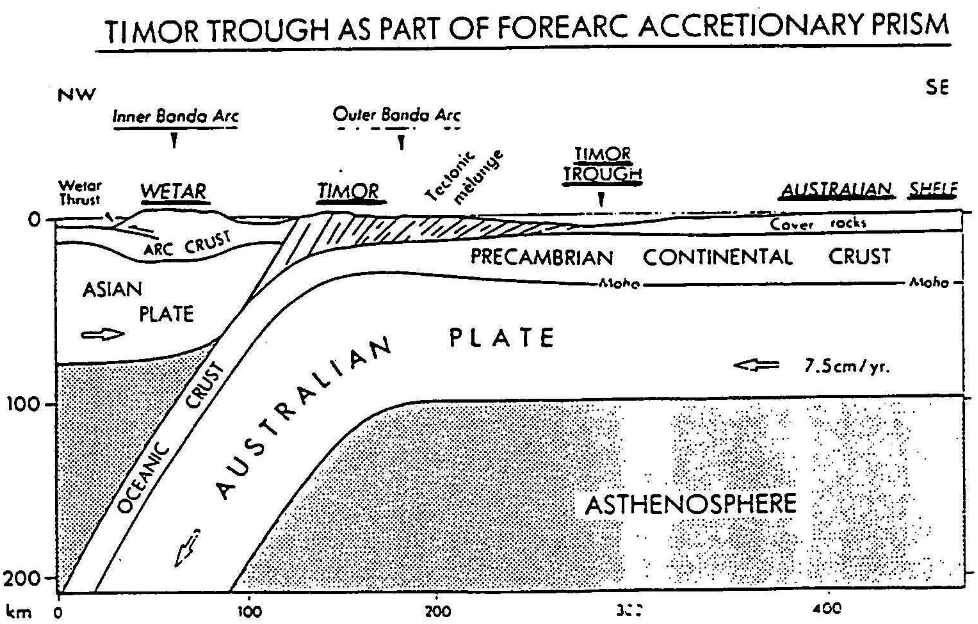


Figure 18 Regional cross-section through the Petrel Sub-basin (From Audley-Charles, 1986)

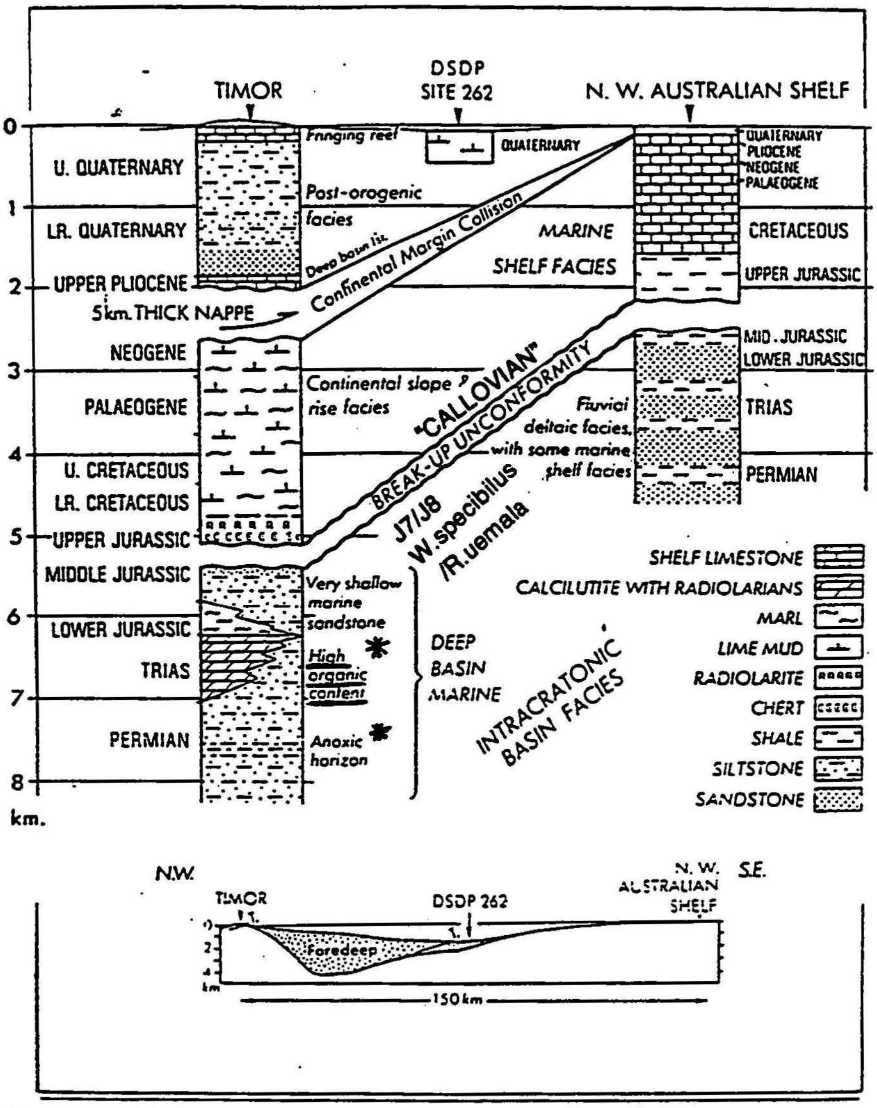


Figure 19 Stratigraphical column at the margin of the foredeep in Timor, in the Trough and on the Australian Shelf.
(From Audley-Charles, 1986)

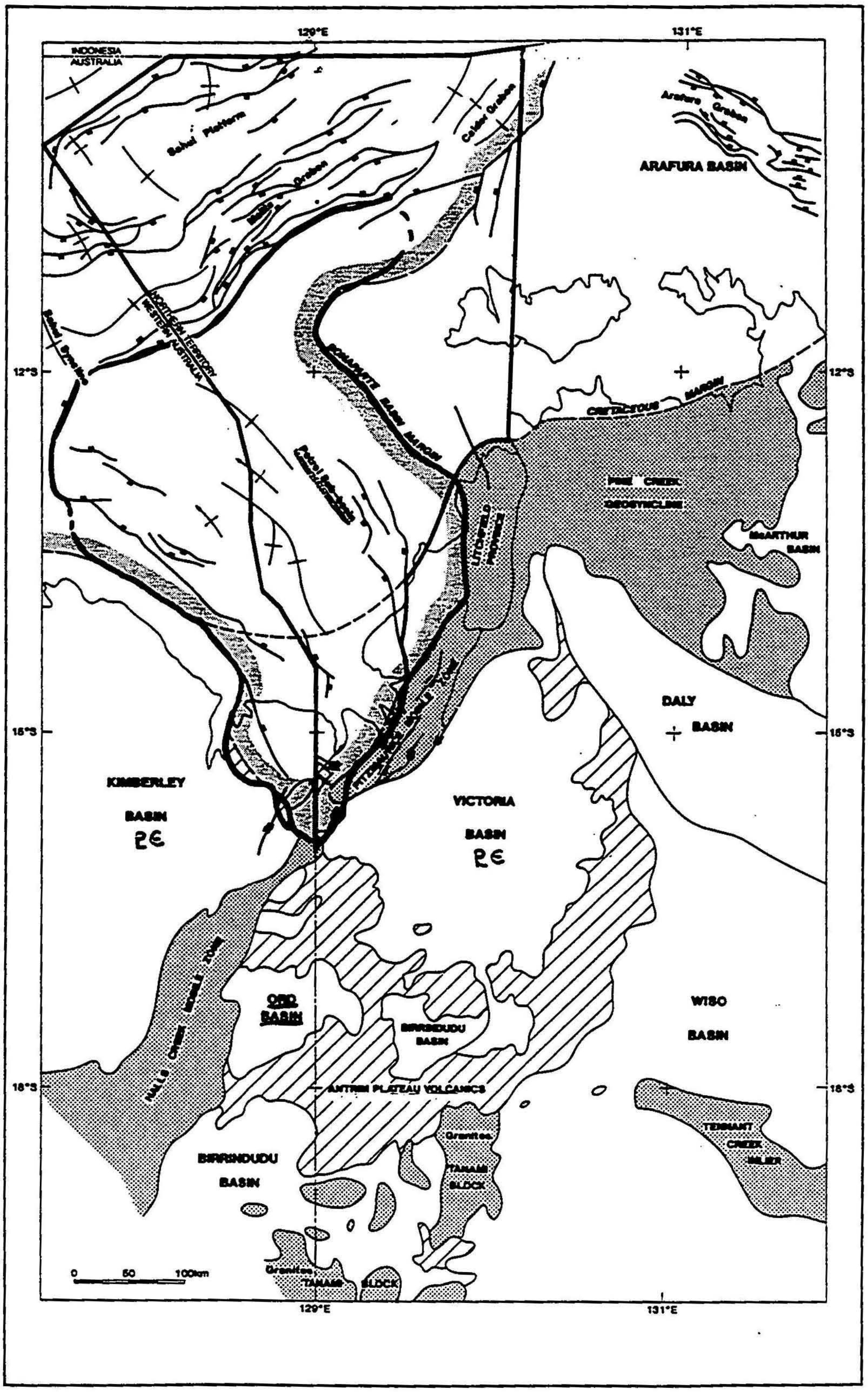


Figure 20 Regional geology of the onshore Petrel Sub-basin (From Petroconsultants, 1990)

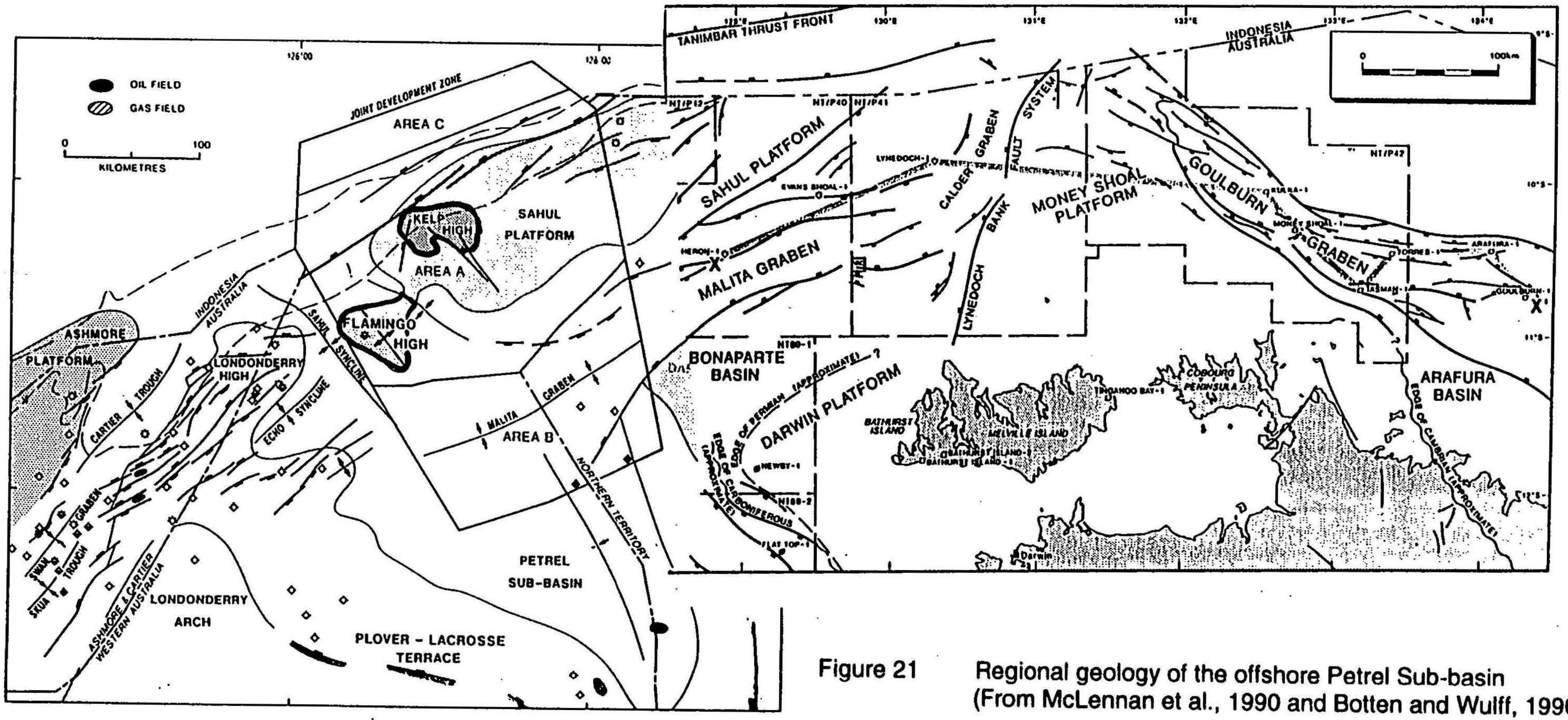


Figure 21 Regional geology of the offshore Petrel Sub-basin (From McLennan et al., 1990 and Botten and Wulff, 1990)

The Carlton Sub-basin lies largely to the northwest of the Pincombe Ridge. It may contain over 5000 m of mostly Palaeozoic siliciclastic marine sedimentary rocks, fluvio deltaic coarse clastics, and marine carbonates, the basin margins being the sites of carbonate reef and platform development during the Famennian. The southern margin exhibits a series of northwest trending faults of pre-late Devonian age onto which is superimposed a series of poorly defined northeasterly trending anticlines, possibly formed by movements along wrench faults (Laws, 1981) before the late Carboniferous.

The Moogarooga Deep is a term used in some reports (Garside, 1982) to describe the late Devonian and early Carboniferous deep basinal area, where fine silts and shales were deposited rather than the limestones and coarser clastics seen on the margins of the Carlton Sub-basin (Figure 17). The Moogarooga Deep is located in the northern part of the Carlton Sub-basin and trends north-northeast. The Bonaparte 1 and 2 wells are within the Moogarooga Deep.

Keep Inlet and Burt Range Sub-basins

The Keep Inlet Sub-basin is an approximately northeasterly trending tensional structure that developed during the late Devonian to late Carboniferous in the present onshore Petrel Sub-basin. Its average width is 18 km and depth to basement may be up to 4500 m (Blake, 1984). It is bordered to the east by the Cockatoo Fault and to the west by the Pincombe Ridge. The Sub-basin was a major structural feature during the late Devonian to late Carboniferous time and influenced the sedimentary patterns of the region. It became inactive once the offshore Petrel Sub-basin became a major Palaeozoic depocentre.

The Burt Range Sub-basin is at the far southern apex of the Bonaparte Basin, bounded by the Pincombe Inlier and Ridge to the west and the Halls Creek-Fitzmaurice Mobile Zone to the east. It contains approximately 4000 m of continental and shallow marine carbonates and clastics perhaps deposited on a major platform area.

ONSHORE STRUCTURE

Extensive outcrop has enabled the structural history of this part of the basin to be resolved, despite the paucity of good quality seismic data. Both normal and transcurrent faulting have been dominant influences on structure within the onshore portions of the basin. Compaction and drape over palaeotopographic highs has also been important locally.

The onshore structure of the Petrel Sub-basin is conspicuously oblique to that of the adjacent Palaeozoic Petrel Sub-basin. The Burt Range and Keep Inlet Sub-basin lie at an angle of about 110° to the Petrel Sub-basin, an angle typical of a triple arm aulacogen or failed arm of a rift system (Blake, 1984).

The Keep Inlet and Burt Range Sub-basins are bounded to the east by the Cockatoo Fault, which is mapped on the surface as a number of discrete en-echelon, synthetic, strike-slip faults, with individual fault planes trending north-south. This pattern of faulting is attributed to major left-lateral wrenching along the Halls Creek-Fitzmaurice Mobile Zone (Laws, 1981; Blake, 1984). The Pincombe Ridge parallels the Cockatoo Fault trend and is intersected by east-southeast antithetic strike-slip faults, especially in the area between the Keep River 1 and Spirit Hill 1 wells (Laws, 1981). Further to the west, across the Carlton Sub-basin, north-south faults intersect outcrops of the Ningbing Limestone. Also mapped are several northeast trending anticlinal axes that plunge into the basin. Much of the faulting is interpreted by Laws (1981) to be syndepositional with many of the faults apparently terminating near the unconformity at the top of the Weaber Group.

In addition to en-echelon faulting, lateral movements appear to have induced folding, anticlinal structures being located adjacent to the major basin-forming faults. Folds associated with the north-northeasterly trending left-lateral wrench faults normally would trend northeast (Harding, 1974). The most conspicuous of these is the Spirit Hill Anticline, the axis of which is doubly-plunging so that several closed structures are delineated along trend (e.g. Blake, 1984; his Enclosure 6).

South of Kulshill 1, a complex structural pattern probably occurs in the sub-surface, as this area coincides with the intersection of the dominant northeast Cockatoo fault trends and the dominant north-west Petrel Sub-basin trends. Here structures are most likely dominantly fault bounded blocks and fault related folds locally intruded by salt.

OFFSHORE STRUCTURE

The near Top Permian Time Structure Map (Figure 22) illustrates Palaeozoic structuring within the Petrel Sub-basin. Several additional horizons mapped by previous operators provided detailed structural information. In particular, Bocal, Arco and AAP undertook detailed mapping at several key late Palaeozoic and Mesozoic levels and Petroconsultants (1990) presented a near Base Cretaceous time structure map.

FISHBURN 1

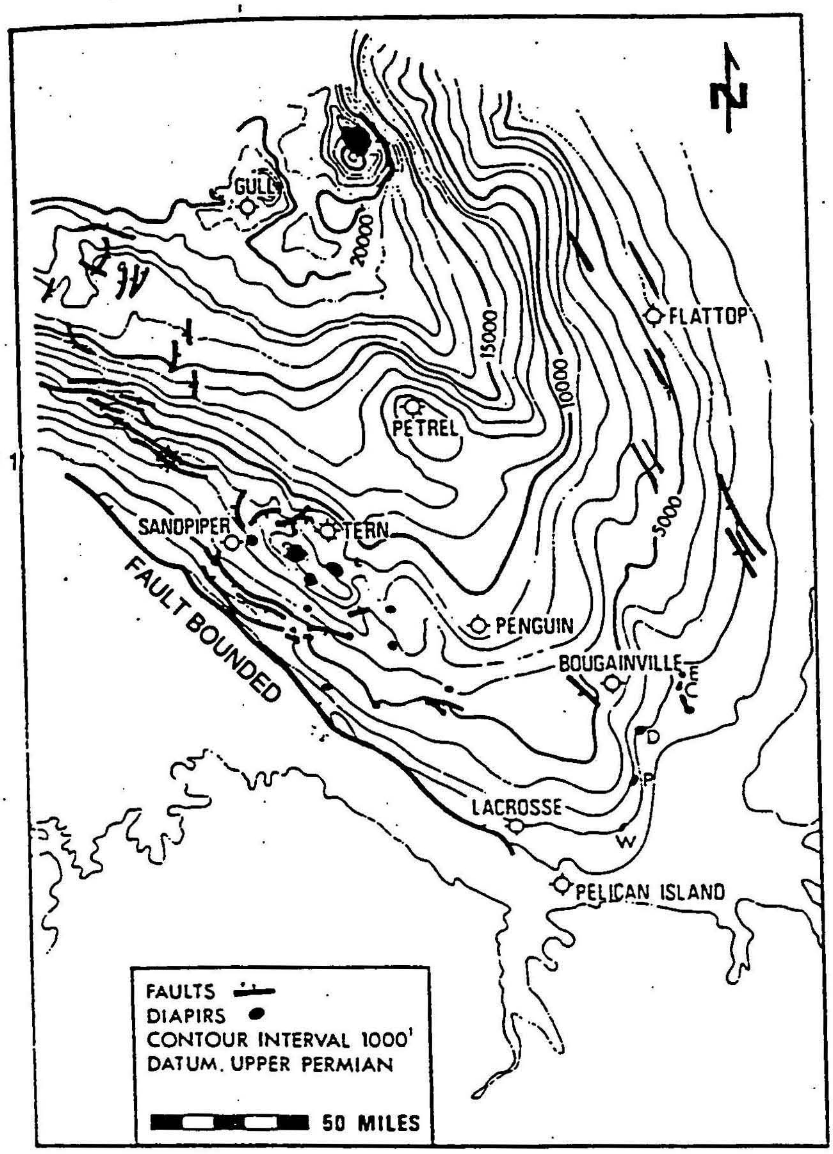


Figure 22 Near top of Permian structure contour map (H4 limestone) (From Lee & Gunn, 1988)

The near top Permian time structure map coincides with a prominent seismic reflection that has been tied to many wells and identified as the Pearce Member (H4 limestone) of the Hyland Bay Formation. This regional event has been mapped extensively.

The H4 horizon is present in the Petrel Sub-basin north of latitude 14°30' and across the Malita Graben and Sahul Platform. In the east the horizon is erosionally truncated along the Moyle Platform. At the Near Top Permian horizon there are few basin-forming faults identified. Older Palaeozoic structuring, responsible for the Sub-basin's formation, is blanketed by a thick sedimentary cover. However, several conspicuous basement ridges plunging to the northwest are evident, and these presumably represent drape over older, Palaeozoic basement highs. They include structural noses upon which the Petrel, Bougainville, and Turtle wells have been drilled.

It is clear from the AGSO deep seismic data that depocentres within the Petrel Sub-basin have varied between axial and marginal basinal subsidence possibly due to several factors. Carboniferous and early Permian deposition was axial down the centre of the sub-basin. Late Permian, Triassic and early Jurassic deposition mainly involved marginal loading adjacent to the Moyle and Berkley Terraces possibly due to basin margin faulting. Late Jurassic to early Cretaceous deposition was again axial, but late Cretaceous and Cainozoic sedimentation was again thickest near the basin margins. Some erosion of the Petrel structure which dominates the axis of the basin may even have occurred during this period.

Deep, tilted fault blocks are observed across a regional high located in the Turtle-Barnett area. This high is attributed by Gunn (1988) to axial doming formed during lithospheric heating and uplift, prior to rift breakup. According to this theory, oceanic crust should be present beneath this and much of the Petrel Sub-basin. Gunn (1988) supported this model with regional gravity and magnetic interpretations identifying the doming as confined to the offshore portions of the Petrel Sub-basin extending from Barnett in the south and splitting into two zones further northwest.

However, no well has yet penetrated sufficiently deeply to encounter the postulated oceanic crust, and doming could also be due to salt tectonics. Edgerley and Crist (1974) previously interpreted this axial gravity high as an indication that salt migrated from the centre of the basin towards the margins. Salt thicknesses of over 3000 m are inferred from seismic sections and deep continuous reflectors observed on sections across Barnett suggest salt is present locally and its involvement in producing the doming cannot be discounted.

Although not necessarily a true indication of original thickness, it does show that considerable quantities of evaporites were deposited within the rift setting. AGSO deep seismic data indicates many domed features that presumably are the result of tectonism acting on thick evaporite sequences.

Numerous salt related structures have been mapped within the Petrel Sub-basin (Crist and Hobday, 1973; Edgerley and Crist, 1974; Gunn and Ly, 1989). Locally these are associated with fault dependent and independent closures. Salt occurs in a number of Palaeozoic basins in northwestern Western Australia with occurrences in the Bonaparte Basin being confined mainly to the Petrel Sub-basin and adjacent onshore areas (Pelican Island and Kulshill area). However, salt also has been intersected in the Paqualin 1 in the Vulcan Sub-basin (O'Brien et al. 1993). Seismic coverage indicates that in the sub-surface the salt takes several structural forms, with examples of simple pillows, walls and piercements being observed within the Petrel-Sub-basin.

Gunn and Ly (1989) suggested that the results of isopach studies are consistent with the Tern anticline having been created as a result of salt withdrawal towards the Sandpiper diapir to the west and a diapir towards Tern 3; that is, the anticline is a turtle-back structure. Similarly, the Petrel anticline shows anomalous isopach variations suggesting it too may be salt related. AGSO data, particularly Line 100/003 supports this interpretation.

Piercement structures, where vertical salt movement has pierced the overlying sedimentary strata (Warren, 1989) occur at several locations including Bougainville 1 and Kinmore 1. These structures tend to be extensively faulted in the crestal areas. Peripheral synclines formed by the lateral withdrawal of salt, accompanying its vertical movement, are evident around some structures (e.g. Curlew). Salt movement appears to have been protracted with some diapirs showing late Permian movements, and others moving vertically until the early Tertiary.

The **Near Base Cretaceous** coincides with a prominent seismic reflection, which, when tied to several well locations, is correlated with a low stand in the early Cretaceous, and is regionally coincident with a limestone marker around the Albian/Aptian level (Petroconsultants, 1990). In the southern areas it coincides with the Valanginian Unconformity. Considerable erosion at this time is noted across wide areas including those outside of the basin, such as the Arafura Basin (Petroconsultants, 1990). The associated eustatic event has been attributed previously to changes in ocean basin geometry, caused by changes in the rate of seafloor spreading (MacDaniel, 1988).

Petroconsultants (1990) compiled a Near Base Cretaceous Time Structure Map from early Arco, AAP, Tricentrol and Bocal mapping, and more recent Magnet Petroleum Pty Ltd and WMC mapping. Within the Petrel Sub-basin, there is little structural complexity at this level. Faulting is confined to a small number of local features as the surface dips relatively uniformly to the northwest, plunging from about 200 ms to 2.0 seconds (TWT) in the deepest portion of the Sub-basin. The horizon is draped over prominent structural noses, also evident at the deeper Near Top Permian level and associated with the Petrel, Bougainville and Turtle structures. Differential subsidence of the unconformity surface by up to 600 ms (TWT) within the main depocentre of the Petrel Sub-basin indicates the degree of post-Valanginian subsidence in this area. It appears to have been facilitated by sagging, maximum sag being evident around the northeastern margin. Local faulting is associated with salt diapirs at this level.

PETROLEUM SYSTEMS AND PLAY ANALYSIS

The Petrel Sub-basin depositional sequences range from the Neoproterozoic to the Holocene and potentially contain four of the recognised petroleum supersystems of Bradshaw (1993) and Bradshaw et al (1994). Discoveries prove the viability of three petroleum systems--

* Larapintine 3 (?Devonian gas and oil in late Devonian and earliest Carboniferous reservoirs),
* Larapintine/Gondwanan Transition (Carboniferous oil in Carboniferous and early Permian reservoirs), and
* Gondwanan 2 (?Permian gas and condensate in late Permian reservoirs).

This study points to potential petroleum systems in the Cambro-Ordovician (Larapintine 1 and 2) and Mesozoic (Westralian). The relationship between the components of these systems - source rocks, reservoirs, seal and overburden - together with the timing of trap formation and source maturation, is shown in Figure 23 a and b.

The following tables (7 to 10) summarise the critical features of the proven and potential petroleum systems in the Petrel Sub-basin.

EARLY CARBONIFEROUS/LATE DEVONIAN PLAY
Supersystem: *Larapintine 3*
Successful play: Gas accumulation in late Devonian Bonaparte Formation at Garimala 1
Analog: Blina oil field in Canning Basin
Proven Reservoirs: Late Devonian Bonaparte Formation; early Carboniferous Enga Sandstone
Potential Reservoirs: Early Carboniferous dolomites of Langfield Group; late Devonian Ningbing Limestone and clastics in Ningbing and Cockatoo Groups
Proven Seal: Early Carboniferous Milligans Formation, regional top seal
Potential Seals: Late Devonian Bonaparte Formation
Probable and Possible Sources: Overlying Milligans Formation - marine, clastic, anoxic; migration up dip from Bonaparte Formation shales; local carbonate source for oil shows in Ningbing Limestone supported by geochemistry in Ningbing 1; and from source units related to Ordovician/Silurian evaporites?
Traps: Reefs, tilted fault blocks, channel stratigraphic traps
Intersections: Bonaparte 2, Barnett 2, Skull 1, Weaber 1, 2A, Spirit Hill 1, Keep River 1, Ningbing 1, Garimala 1
Shows: Gas flows from Bonaparte Formation in Garimala 1; and Enga Sandstone in Weaber 1, gas shows in Keep River 1; oil indications in Spirit Hill 1, Barnett 2, Ningbing 1; plus oil indications in mineral holes immediately underlying the Milligans seal.
Distribution: Onshore, depocentre to southwest of Cambridge 1 in offshore sub-basin
Risks: Over maturity - oil window at the surface; trap preservation; reservoir development - gas flows from fracture and secondary porosity.

Table 7 Larapintine 3 petroleum system in the Petrel Sub-basin

CARBONIFEROUS PLAY
Supersystem: ***Larapintine/Gondwanan Transition***
Analog: Production from the Anderson Formation at Lloyd in the Canning Basin
Potential Reservoirs: Late Carboniferous marine Point Spring Sandstone; Tanmurra Formation limestones - generally tight, rely on fracture porosity; turbidite sands within the early Carboniferous Milligans Formation
Potential Seal: Tanmurra Formation and Milligans Formation shales
Probable Source: Milligans Formation. - marine, clastic, anoxic; migration into overlying Gondwanan reservoirs; early generation with rapid burial and salt withdrawal later uplift and tilting kept in oil window?
Traps: Faulted anticlines, non-faulted roll-overs, flanks of salt structures, drape anticlines, carbonate buildups, turbidite fans
Intersections: Bonaparte 2, Kulshill 1, 2, Moyle 1, Lacrosse 1, 2, Bougainville 1, Lesueur 1, Kinmore 1, Pelican Island 1, Cambridge 1, Matilda 1, Barnett 1, 2, Turtle l, 2, Skull 1, Weaber 1, 2A, Spirit Hill 1, Keep River 1
Shows: Sub-commercial gas flows from Milligans Formation in Weaber 2A, Keep River 1, Bonaparte 2, Barnett 2; Oil recovered from Barnett 2, Turtle 2; oil indications at Kulshill 1, 2, Pelican Island 1, Barnett 1, 2, Turtle 1, 2
Distribution: Barnett compartment
Risks: Reservoir development; favourable juxtaposition of reservoir and seal facies

Table 8 Larapintine/Gondwanan Transition petroleum system in the Petrel Sub-basin

LATEST CARBONIFEROUS/EARLY PERMIAN PLAY
Supersystem: ***Gondwanan 1***
Successful play: Oil flow from latest Carboniferous glacigene Kuriyippi Formation in Barnett 2.
Proven Reservoir: Latest Carboniferous glacigene Kuriyippi Formation
Potential Reservoir: Early Permian Keyling Formation
Proven Seal: Early Permian Fossil Head Formation
Potential Seal: Early Permian Treachery Shale
Probable Source: Underlying Carboniferous marine shales
(Gondwanan/Larapintine Transitional Supersystem)
Potential Source: Treachery Shale
Traps: Salt diapirs, drape anticlines
Intersections: Tern 1, Bonaparte 2, Kulshill 1, 2, Moyle 1, Lacrosse 1, 2, Flat Top 1, Bougainville 1, Lesueur 1, Kinmore 1, Pelican Island 1, Cambridge 1, Matilda 1, Barnett 1, 2, Turtle 1, 2, Billawock 1
Shows: Oil flow from latest Carboniferous glacigene Kuriyippi Formation in Barnett 2; oil recovered from Keyling Formation in Turtle 2; oil indications at Lacrosse 1, Kulshill 1, 2 Kinmore 1, Pelican Island 1, Cambridge 1, Matilda 1, Barnett 1, Turtle 1,
Distribution: Barnett and Tern compartments
Risks: Favourable juxtaposition of reservoir and seal facies adequacy of indigenous sources trap viability - biodegraded oil in crestal faulted anticlines
LATE PERMIAN PLAY
Supersystem: ***Gondwanan 2***
Successful play: Gas and condensate field at Petrel, gas field at Tern, gas flow at Penguin 1
Proven Reservoirs: Shoreface sandstones at the top of the late Permian Hyland Bay Formation in Tern field; deltaic sandstones within the Hyland Bay Formation in the Petrel field; sandstones in the underlying Fossil Head Formation in Penguin 1
Potential Reservoir: Sandstones within the overlying early Triassic Mount Goodwin Formation
Proven Seals: Mount Goodwin Formation in the Tern field; intra Hyland Bay Formation in the Petrel field; basal Hyland Bay Formation at Penguin 1
Probable Source: Underlying Permian section
Potential Source: Overlying Mount Goodwin Formation, poor source quality
Traps: Salt diapirs, drape anticlines, fault traps, stratigraphic pinchouts
Intersections: Tern 1, 2, 3, Petrel 1, 2, 3, 4 and 5, Penguin 1, Bougainville 1, Flat Top 1, Lesueur 1, Kinmore 1
Shows: Gas and condensate field at Petrel, gas field at Tern, gas flow at Penguin 1 and Fishburn 1
Distribution: Curlew and Tern compartments
Risks: Relative timing of trap formation and hydrocarbon migration - salt diapir tests at Bougainville 1 and Tern 3 unsuccessful

Table 9 Gondwanan 1,2 petroleum systems in the Petrel Sub-basin

MIDDLE TRIASSIC - MIDDLE JURASSIC PLAY
Supersystem: *Westralian 1*
Analog: Jabiru oil field in the Vulcan Sub-basin
Potential Reservoir: Fluvial sands in the redbed late Triassic/early Jurassic Malita Formation and fluvial to paralic sands in the middle Jurassic Plover Formation
Potential Seal: Intra-formational shales, overlying seal of the late Jurassic marine Flamingo Group, restricted to sub-basin centre?
Probable Source: Unconformably overlying marine shales (Frigate Shale) in late Jurassic Flamingo Group, poor source quality
Potential Sources: Local sources unlikely, poor source quality; migration from underlying Gondwanan sources unlikely due to early Triassic regional seal
Traps: Salt diapirs, drape anticlines, combination structural stratigraphic traps at Callovian unconformity
Intersections: Gull 1, Curlew 1, Tern l, 2, 3, Petrel 1, 2, 3, 4 and 5, Frigate 1, Sandpiper 1, Penguin 1, Bougainville 1, Flat Top 1, Lesueur 1
Shows: None
Distribution: Curlew and Tern compartments
Risks: Poor quality source
Tests: Fishburn 1, dry at this level, gas in the Permian
Potential: Low in the Petrel Sub-basin
LATE JURASSIC - NEOCOMIAN PLAY
Supersystem: *Westralian 2*
Analog: Skua oil field in the Vulcan Sub-basin, also see Klemme (1994) for international analogs
Potential Reservoir: Marine sands (Sandpiper Sandstone) in late Jurassic Flamingo Group; and sands at the base of the Bathurst Island Formation, best sands not the top of porosity
Potential Seal: Intra-formational marls and shales, overlying regional seal of Bathurst Island Formation, but has sandy base - thief zone?
Probable Source: Underlying marine shales (Frigate Shale) in Flamingo Group, poor source quality
Potential Source: Underlying Cretaceous Bathurst Island Formation, poor source quality, open marine shallow shelf depositional environment, low maturity
Traps: Salt diapirs, all tested?, potential for other trap styles?
Intersections: Gull 1, Curlew 1, Tern 1, 2, 3, Petrel 1, 2, 3, 4, Frigate 1, Sandpiper 1, Penguin 1, Bougainville 1, Flat Top 1
Shows: Gas indication at Curlew 1
Distribution: Curlew compartment
Risks: Poor quality source, maturity, juxtaposition of good quality reservoir to adequate seal
LATE CRETACEOUS PLAY
Supersystem: *Westralian 3*
Analog: Puffin oil field in the Vulcan Sub-basin
Potential Reservoir: Offshore bar sands at the top of the Bathurst Island Formation
Potential Seal: Intra-formational marls and shales, no overlying regional seal
Potential Source: Underlying Cretaceous Bathurst Island Formation, poor source quality, open marine shallow shelf depositional environment, low maturity
Traps: Salt diapirs, all tested?, potential for other trap styles?
Intersections: Gull 1, Curlew 1, Tern 1, 2, 3, Petrel 1, 2, 3, 4, Frigate 1, Sandpiper 1, Penguin 1, Flat Top 1,
Shows: Weak gas indication at Curlew 1
Distribution: Curlew compartment
Risks: Poor quality source, maturity, adequate seal

Table 10 Westralian 1,2,3 petroleum systems in the Petrel Sub-basin

PROTEROZOIC TO EARLY ORDOVICIAN - LARAPINTINE 1 & 2:

The oldest unit in the Petrel Sub-basin is the latest Proterozoic or early Cambrian Antrim Plateau Volcanics. An enigmatic oil show was reported from vesicles in the Antrim Plateau Volcanics in the adjacent Ord Basin (Wade, 1924) that may have been sourced from the underlying Proterozoic Victoria River and Birrindudu basins or from the Cambro-Ordovician.

Deposition in the Petrel Sub-basin was probably established in an intracratonic depression following lithospheric sag after rifting related to the extrusion of the Antrim Plateau Volcanics. Initial sedimentation occurred during the early middle Cambrian (Ordian) transgression across an area probably much larger than that currently regarded as the Petrel Sub-basin (Mory, 1988). Only a few remnants are today preserved in outcrop along the southwestern edge of the Petrel Sub-basin as the shallow to marginal marine siliciclastic and carbonate sediments of the Carlton Group.

Age equivalents of the Carlton Group in the neighbouring Arafura and Canning Basins have proven oil source rocks in the middle Cambrian and early Ordovician, the Larapintine 1 and 2 petroleum systems (Bradshaw et al., 1994). The possibility of a **Larapintine 1** petroleum system in the Petrel Sub-basin cannot be eliminated entirely but no source rocks have been identified so far. The **Larapintine 2** petroleum system could be viable in the Petrel Sub-basin if section similar to the Canning Basin is preserved in fault blocks and grabens. At the time of writing the existence of such section is speculative based mainly on deep seismic data. Additionally most potential areas are small and probably over-mature. Fault block traps formed during Ordovician extension and sealed by overlying evaporites would have been in place during generation of hydrocarbons from basinal areas through the Silurian to Devonian (Figure 23). However, these accumulations would have been largely destroyed by tectonism and deep burial in the late Devonian through to the Carboniferous. Accumulations trapped onshore in less mature parts of the basin may have been preserved. Perhaps the oil show in the Antrim Plateau Volcanics, represents a flux of Larapintine oil pushed to the basin margins during basin filling in the Carboniferous.

The stable platform and basinal development established during the Cambrian was interrupted during the later Ordovician. Between early Ordovician and late Devonian time there is a large gap in the depositional record (150 million years) as reflected by the onshore Petrel Sub-basin sequences. The absence of section may be due to possible arching, sea withdrawal, exposure and erosion during the middle to late Ordovician, a time when such events were occurring in the Arafura Basin (Bradshaw et al., 1990).

LATE ORDOVICIAN TO MIDDLE DEVONIAN

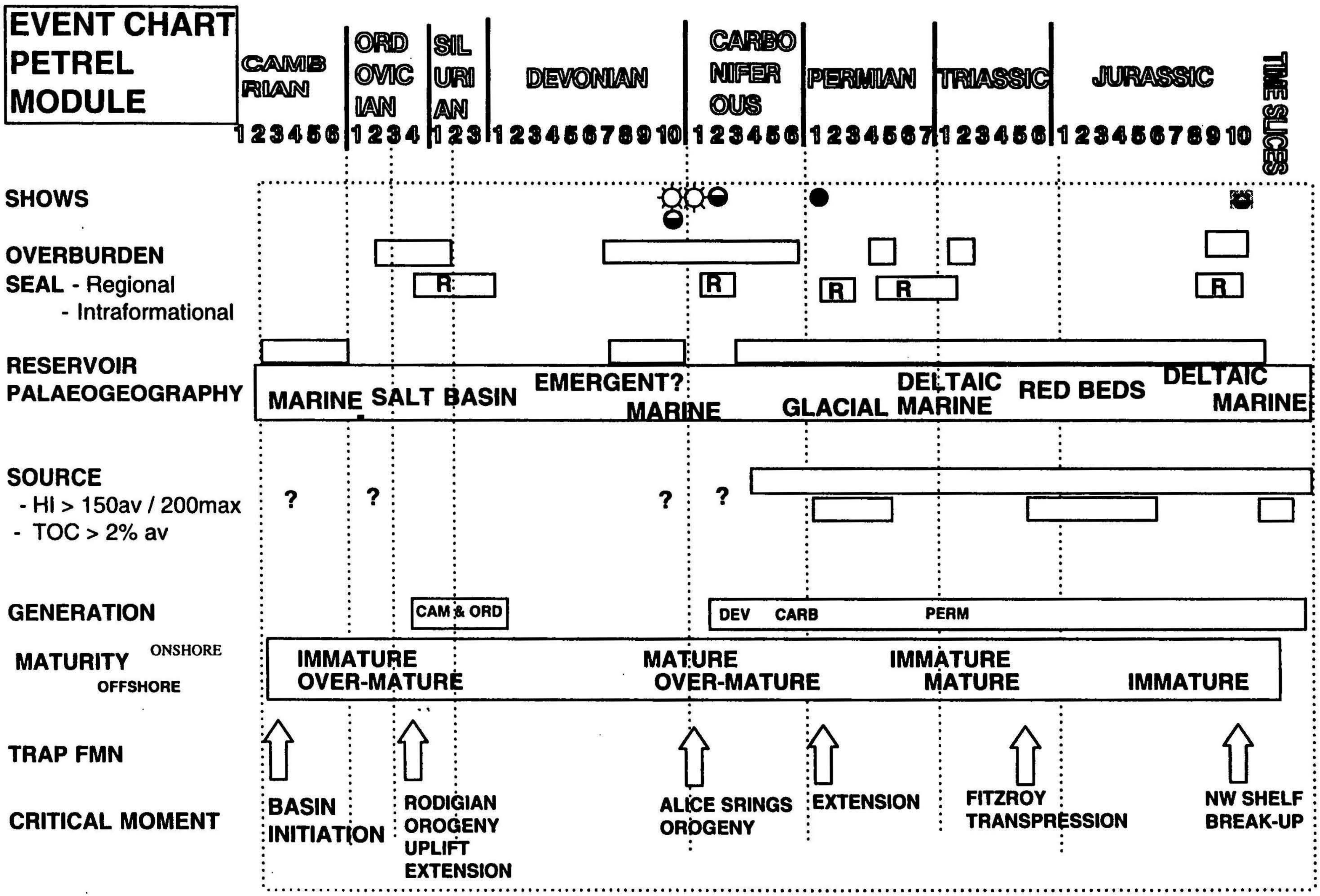


Figure 23a Event chart for the Petrel Sub-basin, Palaeozoic

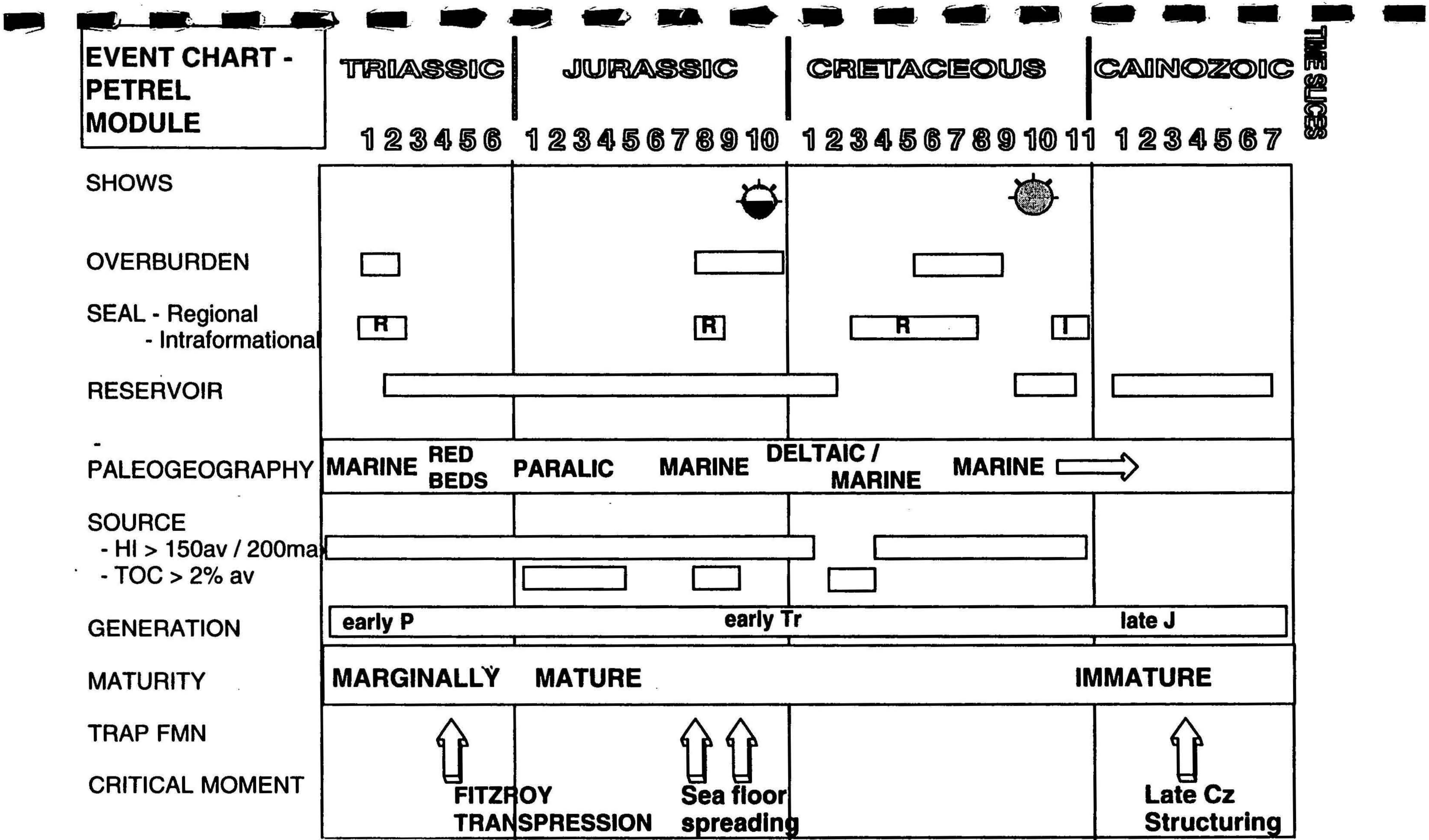


Figure 23b Event chart for the Petrel Sub-basin, Mesozoic

Uplifted crustal blocks seen on seismic, may have provided barriers blocking and/or restricting seaways through the Petrel Sub-basin from open marine environments to the north. In this setting, the offshore portions of the basin may have become centres of evaporite deposition under prevailing arid conditions.

Salt can play a vital role in a number of processes in petroleum systems - acting as a seal, source and trap mechanism. In the Petrel Sub-basin, the basinal salt would have provided an excellent seal facies to the underlying Ordovician sequences, being regional at the time of deposition, but becoming progressively dismembered and localised due to salt flowage and tectonism. The Bongabinni Formation algal coals (54% TOC) from the Carribuddy Group of the Canning Basin (Kennard et al., 1994) are an example of high quality source rocks associated with evaporites from a neighbouring basin. Most importantly in the Petrel Sub-basin, has been the role of salt in trap formation at various times from the Carboniferous through to the Recent (Figure 11a-g and Enclosures 47 to 60).

LATE DEVONIAN TO EARLY CARBONIFEROUS - LARAPINTINE 3

Extensive sedimentation in the Petrel Sub-basin recommenced in the late Devonian (Frasnian). This deposition was accompanied by structural activity involving tensional movements initially dominated by incipient northwest trending down-faulting and sag. It approximately coincides with the onset of renewed sedimentation in the Arafura Graben to the north (Bradshaw et al., 1990) and widespread tensional tectonism in north-west Australia. These events and the continuing tectonism in the Carboniferous reflect the impact of the peak of the Alice Springs Orogeny in the Bonaparte Basin (Bradshaw et al., 1990, 1994).

As the outer structural barriers foundered, a series of transgressions occurred, the first involving initial deposition onto a marked regional unconformity. Three transgressive-regressive depositional cycles dominated the late Devonian to earliest Carboniferous interval; the Cockatoo, Ningbing and Langfield Groups. Each was characterised onshore by initial deposition of coarse clastics shed from active fault escarpments bounding the adjacent southern and western basin margins. The Cockatoo Group exceeds a thickness of 2700 m. Basinward, these clastics merged with marginal marine sediments, basinal shales, and carbonates, that formed reef structures around emergent topography such as the Pincombe Ridge. In the distal regions of the offshore basin up to 3000 m of shallow marine shales and thin sandstones (Bonaparte Formation), were deposited. Reef growth was terminated following uplift and the onset of increased sediment supply with the deposition of the Tournaisian Langfield Group. Devonian and early Carboniferous sediments thinned, onlapped, and were draped across the Pincombe Ridge (Laws, 1981).

The oldest confirmed petroleum system in the Petrel Sub-basin is the **Larapintine 3** (Bradshaw et al., 1994) which is best exemplified by the gas accumulation in the late Devonian Bonaparte Formation in Garimala 1. Its analogue is the Blina oil field in the Canning Basin. Proven reservoirs in the Petrel Sub-basin comprise the late Devonian Bonaparte Formation and the early Carboniferous Enga Sandstone (Weaber 1 - gas flow). The proven seal and a possible source are the overlying marine shales of the early Carboniferous Milligans Formation. Potential reservoirs are the early Carboniferous dolomites of Langfield Group and the late Devonian Ningbing Limestone. Probable source rocks are late Devonian marine carbonates and shales. Many trap styles exist within this system including reefs, tilted fault blocks and channel and fan stratigraphic traps. Traps and the regional Milligans seal were clearly in place prior to the main phase of generation in the Carboniferous (Figure 23). Continued burial during the later Carboniferous and Permian would have destroyed accumulations in the main offshore depocentres.

The Larapintine 3 system is confined mostly to the onshore area of the Petrel Sub-basin. Shows produced from the wells were: gas flows from Bonaparte Formation in Garimala 1 and Enga Sandstone in Weaber 1; oil indications in Spirit Hill 1, Keep River 1, Barnett 2, Weaber 1, 2A and Ningbing 1; plus oil indications in mineral holes immediately underlying the Milligans Formation seal. The critical risks with this play type appear to be overmaturity, trap preservation and reservoir development. Gas flows appear to come from fracture and secondary porosity.

EARLY CARBONIFEROUS - LARAPINTINE/GONDWANAN TRANSITION

Rapid subsidence and deposition was abruptly interrupted during the Visean by uplift and erosion in the Petrel Sub-basin. This break is here interpreted to coincide with the boundary between the Bonaparte and Milligans Formations. Onshore, these structural movements resulted in the Milligans Formation unconformably overlying the Langfield Group. Rapid subsidence recommenced with continued deposition of thick marine sediments into the Petrel Sub-basin, comprising the predominantly fine grained deposits of the

Milligans Formation. Alternate stratigraphies (Gunn, 1988a) divide the Milligans into an "upper" and "lower" unit separated by the Visean unconformity.

The rate of sedimentation and subsidence decreased towards the end of the Visean, and deposition occurred comprising shallow marine carbonates of the Tanmurra Formation and its partial equivalent the fluvio-deltaic Point Spring Sandstone. Offshore clastics, perhaps including turbidites, were deposited in the south. The termination of Tanmurra deposition coincided with a marked regression and climatic cooling with the onset of glaciation during the Namurian.

The **Larapintine/Gondwanan Transition** petroleum system (Bradshaw et al., 1994) is a Carboniferous play analogous to the oil production from the Anderson Formation at Lloyd in the Canning Basin. Potential Reservoirs are the marine Point Spring Sandstone and Tanmurra Formation limestones. Where drilled to date these rocks have generally been tight but fracture porosity has been recognised. Turbidite sandstones within the early Carboniferous Milligans Formation are also potential reservoirs. Potential seals are the Tanmurra and Milligans Formation shales and intraformational seals in the Point Springs Sandstone. Probable source rocks are the Milligans Formation marine, clastic, anoxic shales that could have generated early with rapid burial and salt withdrawal. Traps are faulted anticlines, non-faulted roll-overs, salt structures, drape anticlines, carbonate buildups and turbidite fans.

Shows have been observed in the form of gas flows from Milligans Formation in Weaber 2A, Keep River 1, Bonaparte 2, Barnett 2. Oil was recovered from Barnett 2. Oil indications were reported at Kulshill 1 and 2, Pelican Island 1, Barnett 2 and Turtle 1 and 2.

The Larapintine/Gondwanan Transition play is confined to the Barnett compartment (O'Brien et al., 1993) in the offshore Petrel Sub-basin. The main risks are reservoir development and favourable juxtaposition of reservoir and seal facies. The burial history plot from Kulshill 1 (Appendix 8) suggests that the main phase of generation from the Milligans Formation throughout most of the basin, occurred in the Carboniferous. Initially lateral migration may have occurred, out of the depocentre to the basin margins, along porous zones in the Milligans, such as fan sandstones and eventually been confined by surrounding shales and the Tanmurra limestones. Accumulations on the basin margins would rely on dip reversal or a stratigraphic component to the trap; thief zones are a risk in the coarser grained facies of the basin margin. Later with fault development and occlusion of porosity in deeper formations, reservoirs in the Point Springs Sandstone should have been well placed to receive vertically migrating hydrocarbons, though these traps would be reliant on patchy intraformational seals. The main phase of generation was prior to the deposition of regional seals in the early Permian (Figure 23).

LATE CARBONIFEROUS TO EARLY PERMIAN- GONDWANAN 1

Widespread erosion and non-deposition, attributed in part to the effects of glaciation, continued during the Westphalian. Movements at this time coincide with marked compression in central and eastern Australia (Alice Springs Orogeny), and Central Europe and Spain (Variscan Orogeny), movements which Peck and Soulhoul (1986) attribute to the closing of the Tethyan Sea. More locally these movements had the effect of isolating the Petrel Sub-basin from major marine influences during the late Carboniferous.

Late Carboniferous to early Permian deposition consisted predominantly of clastics of the Kulshill Group. The lower unit, the Kuriyippi Formation, exhibits a strong glacial influence. Onshore, the overlying Treachery Shale contains lacustrine to estuarine deposits formed following the retreat of the ice sheet to the adjacent hinterland (Mory, 1988). Offshore, marine to deltaic siliciclastic sequences of the Treachery Shale preceded the deposition of an upper unit, the Keyling Formation, comprising marginal marine sands and shales, with minor limestones and coals.

The **Gondwanan 1** petroleum system (Bradshaw et al., 1994) is a latest Carboniferous to early Permian play which has achieved the most encouraging oil flows in the Petrel Sub-basin to date. An oil flow of 921 BOPD was achieved from the glacigene sediments in Barnett 2. Potential reservoirs are developed in the early Permian Keyling Formation where burial and diagenesis are less. Seals are the Treachery Shale and early Permian Fossil Head Formation. Geochemical analysis indicates that the probable source rocks are the underlying Milligans Formation and potential sources occur in the Treachery Shale and Tanmurra Formation.

Gondwanan 1 system traps are salt diapirs and drape anticlines. Shows include the oil flow from the glacigene Kuriyippi Formation in Barnett 2; oil recovered from the Keyling Formation in Turtle 2; and oil indications at Lacrosse 1, Kulshill 1 and 2, Kinmore 1, Pelican Island 1, Cambridge 1, Matilda 1, Barnett 1, Turtle 1. Distribution of the petroleum system is confined to the Barnett and Tern compartments (O'Brien et al., 1993) within the Petrel Sub-basin. Outboard the system is overmature today and inboard the rocks were not deposited or have been subsequently eroded. Risks include the favourable juxtaposition of reservoir and seal facies, adequacy of indigenous sources and trap viability from the standpoint of oil preservation. Biodegraded oil was reported in the crestal faulted anticline trap at Turtle 1 (Jefferies, 1988).

As discussed above, the main phase of generation from the Milligans Formation in the basin depocentre occurred in the Carboniferous, prior to the deposition of the enhanced reservoir facies in the glacigene units and before the emplacement of the Treachery Shale regional seal. However, given the shelving nature of the basin, less buried Milligans probably continued to generate well into the Permian. This may have provided the oil seen in Turtle and Barnett throughout the Carboniferous and early Permian sections, right up into the Keyling Formation above the fault-breached Treachery Shale seal.

LATE PERMIAN TO EARLY TRIASSIC - GONDWANAN 2

A rise in sea level in the late early Permian resulted in the Keyling Formation deltaic sands being overlain by the estuarine to marine siltstones and sandstones of the Fossil Head Formation. These were in turn overlain by the deltaic clastics and marine carbonates of the Hyland Bay Formation, deposited during a series of abrupt transgressive-regressive cycles during the late Permian.

The latest Permian to middle Jurassic was a period marked by the change from older northwest trending Palaeozoic basin margin structuring to the dominant northeast Mesozoic structuring associated with the rifting of Gondwana. MacDaniel (1988) envisaged initially broad regional sags which became major depocentres in the late Triassic. As rifting progressed, true rift basins developed with down-faulting along northeast trends. Being nearly orthogonal to the Palaeozoic trends, Mesozoic structuring did not necessarily reactivate the older northwest trends, which penetrated the craton in the Petrel Sub-basin, Arafura Basin and Fitzroy Graben (Canning Basin).

Basin subsidence associated with this tectonism resulted in transgression during the early Triassic, and deposition of the shale sequences of the Mount Goodwin Formation over the Hyland Bay Formation. The Mt Goodwin Formation is coeval with shale prone units in the Canning Basin (Blina Shale), Carnarvon Basin (Locker Shale) and the Perth Basin (Kockatea Shale).

The **Gondwanan 2** petroleum system (Bradshaw et al., 1994) is represented by the successful late Permian gas play within the Petrel Sub-basin. The gas and condensate field at Petrel, gas field at Tern and Fishburn and gas flow at Penguin 1 attest to the success of the play. Proven reservoirs are the stream mouth bar and shoreface deltaic sandstones near the top of the late Permian Hyland Bay Formation and similar sandstones less commonly developed in the underlying Fossil Head Formation such as in Penguin 1 and probably Petrel 1. Proven seals are the Mount Goodwin Formation at Tern and Fishburn and the intraformational shaly limestones (Dombey and Pearce Members of the Hyland Bay) at Petrel and Penguin 1. Probable source rocks occur in the underlying Permian Keyling and Fossil Head Formations.

Traps in the Gondwanan 2 petroleum system are mainly salt diapirs and drape anticlines but fault blocks and stratigraphic traps could be important. Its distribution is confined to the Curlew and Tern compartments (O'Brien et al., 1993). Risks involve the relative timing of trap formation and hydrocarbon migration. The main phase of generation from the basin centre was in the Triassic and Jurassic (Figure 23). The late formed salt diapirs tested at Bougainville 1 and Tern 3 were unsuccessful. A poorly defined pure stratigraphic test at Flat Top 1 also failed to encounter any hydrocarbons. However, geochemical analyses from this well point to a potential Gondwanan 2 oil play in this part of the basin where the Permian source facies are more oil prone and less thermally altered than in the basin centre.

MIDDLE TRIASSIC TO EARLY CRETACEOUS- WESTRALIAN 1 & 2

Marine conditions continued to dominate during the middle Triassic with deposition of the Cape Londonderry Formation within the Malita Graben and Petrel Sub-basin, and shallow marine, carbonate dominated conditions across the Sahul Platform. In the later part of the Triassic, regressive siliciclastics were deposited over the Petrel Sub-basin and Sahul Platform. Regression culminated with red bed deposition of the Malita Formation in the late Triassic to early Jurassic in an arid continental environment. Subsequent transgression in the middle Jurassic resulted in the deposition of thick fluvial to deltaic sediments of the Plover Formation, including the important reservoir sands on the Sahul Platform.

The deposition of thick sequences during this time probably initiated and reactivated salt movement. In the western part of the Petrel Sub-basin (e.g. over the Tern Structure).

Salt movement was probably responsible for erosion and non-deposition of parts of the Malita Formation.

During the late Jurassic the region tilted to the northwest and the Malita Graben subsided with local uplift and erosion along fault blocks. The Flamingo Group represents a prominent late Jurassic marine transgression during which the Frigate Shale was deposited throughout the main troughs of the Petrel Sub-basin. The upper part of the Flamingo Group, the Sandpiper Sandstone, represents a fluvial to deltaic siliciclastic cycle which covers a much greater area of the Petrel Sub-basin, transgressing the basin margins not covered by the Frigate Shale. The regional early Cretaceous Valanginian Unconformity resulted in considerable erosion across structural highs of the Petrel Sub-basin.

Plays in the Westralian petroleum system (Bradshaw 1993; Bradshaw et al., 1994) have been most successfully explored beyond the Petrel Sub-basin, in the Vulcan Sub-basin (Jabiru, Challis, Skua) and in and adjacent to the ZOC (Laminaria, Elang). However, the cratonward extent of the system is yet to be delimited, and deserves further consideration given the recent spate of discoveries around the Sahul Syncline, the extension of the Petrel Sub-basin, beyond the cross-cutting Mesozoic Malita Graben.

Elements of the **Westralian 1** middle Triassic - middle Jurassic play, which was successful at Challis, occur in the Petrel Sub-basin. Potential reservoirs are the fluvial sandstones in the red bed late Triassic/early Jurassic Malita Formation and fluvial to paralic sandstones in the middle Jurassic Plover Formation. Seals comprise intra-formational shales and the overlying regional seal of the late Jurassic marine Flamingo Group that is present throughout the central and northwest parts of the Petrel Sub-basin.

Probable source rocks for the Westralian 1 system are the unconformably overlying marine shales (Frigate Shale) of the late Jurassic Flamingo Group. In the Petrel Sub-basin, poor quality source facies and low maturities are problems. Migration from the underlying Gondwanan sources is unlikely due to the regional seal deposited in the early Triassic. Traps include salt diapirs, drape anticlines, and combination structural/stratigraphic traps at the mid-Jurassic unconformity. The elements of the system are present throughout the Curlew and Tern compartments. The Westralian 1 system is interpreted to have been tested without success in the Petrel Sub-basin and is therefore considered to have low prospectivity.

The onset of more rapid basin subsidence following the Valanginian event resulted in the submergence of the Sahul Platform, and enhancement of the Malita Graben and Vulcan

Sub-basin as important depocentres. Continued tilting to the west resulted in a regional marine transgression with the deposition of the Bathurst Island Group across the Darwin Shelf to the east, and Arafura Basin to the north.

The **Westralian 2** petroleum system in the Petrel Sub-basin involves a late Jurassic to Neocominian (J6 to K2) play analogous to the Skua oil field in the Vulcan Sub-basin and probably the recent Elang, Laminaria and Kakatua discoveries. The potential reservoirs are the marine sandstones (Sandpiper Sandstone) in the late Jurassic Flamingo Group and sandstones at the base of the Bathurst Island Formation. The best reservoir sandstones are not the top of the porous section. Seals are the intra-formational marls and shales with the overlying regional seal of the Bathurst Island Formation that commonly has a sandy thief zone near its base. Probable source rocks are the underlying marine shales (Frigate Shale) in Flamingo Group, although these are of poor quality where tested. Traps include fault blocks, compaction drape rollovers and salt diapirs, although the anticlinal tops of the large salt domes at Gull and Curlew are already tested.

A poor gas show and an oil show (attributed in the well completion report to diesel from the drilling mud) were detected at Curlew 1. The system is distributed throughout the Curlew compartment.

The major risks for the Westralian 2 play in the Petrel Sub-basin are poor quality source rock, low maturities and juxtaposition of good quality reservoir to adequate seal. Given the recent successes on the opposite side of the Malita Graben and Sahul Syncline, the Westralian 2 play is probably source rock controlled and might yet prove to be successful in the Petrel Sub-basin. The role of long distance migration will prove to be crucial.

CRETACEOUS TO CAINOZOIC - WESTRALIAN 3

Rapid eustatic fluctuations resulted in poor preservation of the post-Valanginian to Aptian marine sequences. Much of onshore Australia was under water at this time and a starved marine shelf environment prevailed in the Petrel Sub-basin. In the late Albian, carbonates were deposited and buried beneath a younger thick sequence of siltstones, mudstones, and shales. Shoreline sandstones of Cenomanian age on the eastern side of the Petrel Sub-basin, indicate the emergence of the Darwin Shelf at this time. Sediments became progressively more open marine towards the Turonian sea level maximum, prior to a series of sea level falls during the late Cretaceous. Falls in sea level resulted in strandline sequences being deposited around the basin margins.

The **Westralian 3** petroleum system is extremely shallow to absent throughout the Petrel Sub-basin. This late Cretaceous play targets offshore bar sands at the top of the Bathurst Island Formation, analogous to the Puffin oil field in the Vulcan Sub-basin. The lack of traps, seal and maturity are the main problems with this system in the Petrel Sub-basin.

The open shelf marine conditions in the Malita Graben and shallower shelf conditions in the Petrel Sub-basin continued throughout the Cainozoic, with the onshore areas the site of non-deposition and erosion. The early Tertiary section is sandy and grades upwards into shelfal carbonate development with a hiatus occurring in the Oligocene. Structuring involving reactivated down-faulting across the flanks of the Sahul Platform and tilting of the Malita Graben westwards appears to have continued during the Tertiary, some faults having present day bathometric expression

Reactivation of some faults in the Petrel Sub-basin in the middle Miocene, at about 15 Ma may reflect the collision of the outer Australian continental margin with the Southeast Asian plate. Compression and/or continued sediment loading has also reactivated several salt structures during the Cainozoic, faulting and continued local uplift being locally observed across some diapiric structures.

PALAEOGEOGRAPHIC RECONSTRUCTIONS

METHODOLOGY

Time slice data maps and palaeogeographic interpretation maps have been constructed for a series of time slices covering the Neoproterozoic through most of the Phanerozoic. The late Permian time slices have been subdivided using detailed sequence stratigraphy. Several time slices with either poor data control or limited environmental variation have been combined to make composite time slice maps.

Each time slice data map shows the location of the wells used in the study in bold type. Each of the study wells that intersect the time slice has a blocked in gamma ray, or self potential log profile at a vertical scale of 1:10,000 posted near the well location and the hydrocarbon indications shown by the well symbol. If the time slice is not penetrated or absent from a study well, or if insufficient biostratigraphic control exists to determine its presence or absence a symbol is shown by the well location. Palaeogeographic data maps (Enclosures 11 to 27) presented with the compressed scale deep AGSO seismic data (Enclsoures 47 to 50), combine to give a powerful visual representation of the thickness variations and distribution of each time slice throughout the basin.

Palaeogeographic interpretation maps have been compiled for those time slices with sufficient information to allow such an interpretation (Enclosures 28 to 46). Detailed descriptions on the palaeogeographic interpretation and prospectivity of each time slice interval are provided in the following section; and A3 versions of the interpretations maps are provided in the pocket at the back of the report.

A summary of the organic chemistry is provided for several important time slices. This data is a synthesis of AGSO's ORGCHEM database and data from open file geochemical and well completion reports. It is shown as time slice maps of Total Organic Carbon (TOC), Hydrogen Index (HI) and Vitrinite Reflectance (VR) in Appendix 6.

Figure 24 shows the orientation of the four well log cross sections. Each cross section shows detailed time slice correlations, time slice facies interpretations, regional unconformities/disconformities, flooding surfaces and condensed sections. Interpreted environments of deposition and landform elements are provided in the form of codes (Introductory Section Figure 7 and Table 2) on the well log cross sections. The well log cross sections, which correlate wells, are provided in Enclosures 7 to 10 and should be referred to

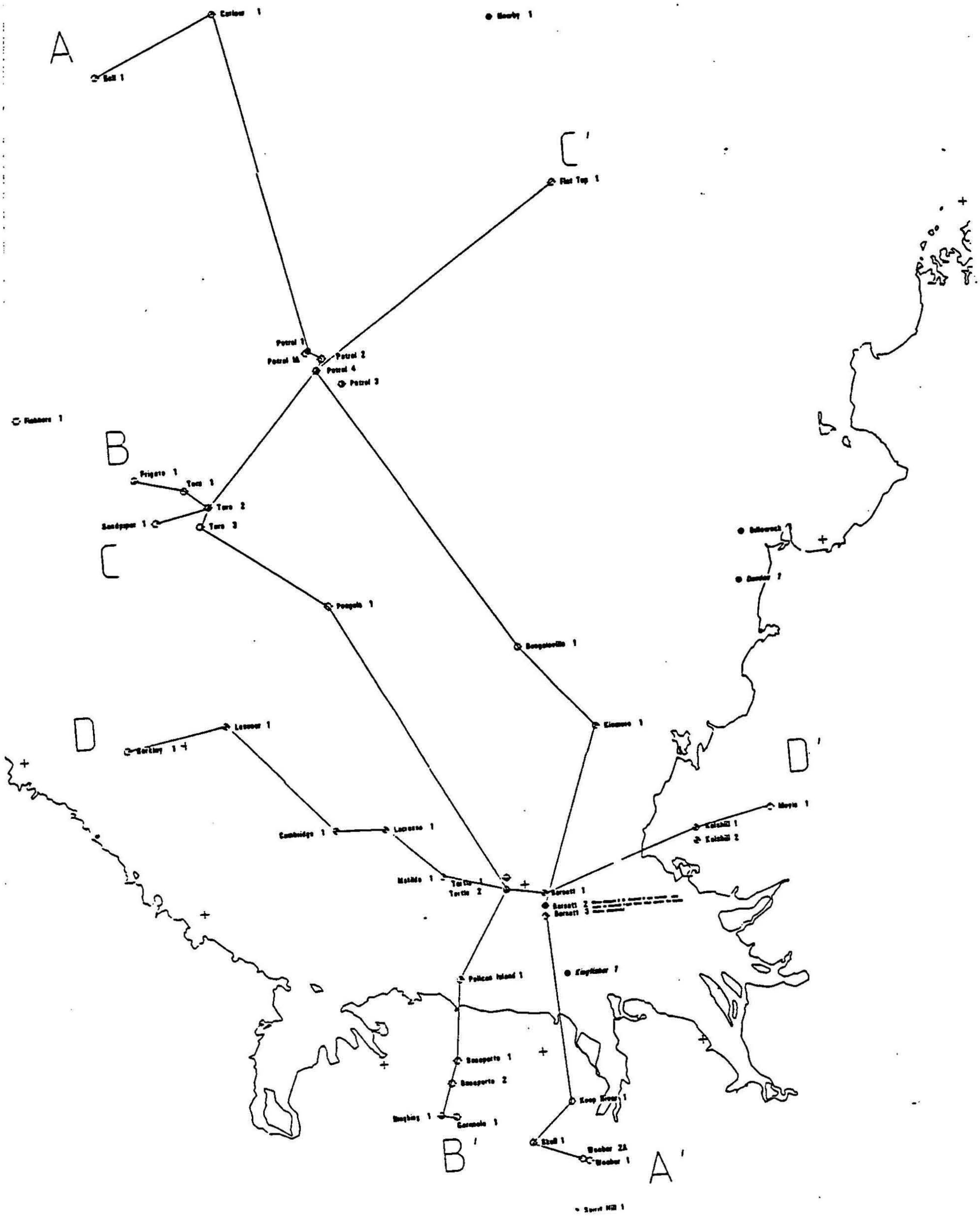


Figure 24 Location Map of the Petrel Sub-basin shows and Well Log Cross Sections

in conjunction with the palaeogeographic interpretation maps and accompanying notes. Depositional environment data is tabulated in Appendix 1.

PALAEOGEOGRAPHIC INTERPRETATIONS AND PROSPECTIVITY OF TIME SLICES

PRE-CAMBRIAN

SUMMARY (Enclosure 28)

The initiation of the Petrel Sub-basin is believed to be associated with the extrusion of the Antrim Plateau Volcanics and extension across a northwesterly trending rift axis. Transfer faults that later formed shelf break flexures in the younger sedimentary section are thought to have been initiated at this time.

PALAEOGEOGRAPHIC INTERPRETATION

The Antrim Plateau Volcanics are taken as the basal unit of the Petrel Sub-basin. These tholeiitic basalts outcrop along the south-western margin of the basin (Figure 20) and unconformably overlie the Proterozoic sedimentary rocks of the Kimberley, Birrindudu and Victoria River Basins. Similar volcanic rocks are distributed over a wide area of central and northern Australia, from the margins of the Ord, Daly, Georgina, Wiso and Officer Basins. The extrusion of such large volumes of magma presumably initiated the Petrel Sub-basin. The basalts are interpreted as subaerial flows related to an episode of crustal extension during the breakup of a late Proterozoic supercontinent (Veevers, 1984; Lindsay et al., 1987). During this breakup, most of central and northern Australia, including the Petrel Sub-basin, is interpreted to have been uplifted and emergent. Terrigenous clastic units interbedded within the Antrim Plateau Volcanics, including aeolian sandstones, reaffirm the continental environment of deposition (Mory and Beere, 1988).

The basalts underlie fossiliferous Cambrian sediments in several basins and an isotopic date of 575 ± 40 Ma (Compston, 1974) is available for the associated Table Hill Volcanics in the Officer Basin. Revision of the age of the base of the Cambrian (Bowring et al., 1993) to around 544 Ma indicates that there is a significant time break between the Antrim Plateau Volcanics and the overlying middle Cambrian to early Ordovician Carlton

Group of the Bonaparte Basin, even though the contact is described as "conformable" in Mory (1990).

PROSPECTIVITY

Non prospective.

Hydrocarbon shows

There are enigmatic occurrences of asphalt in vesicles in the Antrim Plateau Volcanics in the Ord Basin (Wade, 1924) to the south of the study area (Figure 18), that prompted an unsuccessful drilling program in the 1920s. The source of the hydrocarbons remains undetermined. They may have been derived from the underlying Proterozoic rocks of the Victoria River and Birrindudu basins (Jones, 1976) or the overlying Cambrian sequences

Source Rock

There is no source potential in the basalt or associated continental deposits.

Reservoir

Little is known about the subsurface reservoir characteristics of the Antrim Plateau Volcanics. Vuggy porosity occurs in the Antrim Plateau Volcanics in the Ord Basin.

TIME SLICE C3 to ?O1 - CAMBRO-?ORDOVICIAN

SUMMARY (Enclosure 29)

The Cambrian to Ordovician sedimentary rocks that are exposed in outcrop in the southern onshore Bonaparte Gulf comprise intertidal to supratidal rocks with shallow to very shallow marine deposits interpreted to be present under the site of the modern Joseph Bonaparte Gulf.

PALAEOGEOGRAPHIC INTERPRETATION

Thermal sag following basalt extrusion, combined with a general eustatic rise in sea level across the Australian continent in the middle Cambrian, initiated shallow marine deposition in Petrel Sub-basin. This first sedimentary package is the Carlton Group (Mory and Beere, 1988), made up of over 2000 m of clastic and carbonate rocks of Cambro-Ordovician age (Kaulback and Veevers, 1969; Jones, 1971; Laws, 1981; Mory and Beere, 1988), that are exposed along the western basin margin. These rocks unconformably overlie the tholeiitic basalts of the Neoproterozoic Antrim Plateau Volcanics. The identification of this section in the subsurface, especially offshore, is tentative. On offshore seismic profiles such as AGSO line 118/018 (Enclosure 49) this section is correlated with bedded sequences dipping back into the basin margins on deep fault blocks, which are down-thrown basinwards and to the northwest (Figure 11 a and g).

The initial deposition resulted in the accumulation of up to 400m of the early middle Cambrian Tarrara Formation, a shallow marine to intertidal siliciclastic and dolomitic unit deposited in a shallow epeiric sea. The overlying Hart Spring Sandstone (Templetonian to Boomerangian) attains a thickness of 300 m, and was deposited in a tidally dominated environment on a shallow shelf (Mory and Beere, 1988). The age equivalent rocks in the Arafura, Georgina and Amadeus basins include organic rich shales (Bradshaw et al., 1994) that were deposited in lower energy marine environments (See C3 time slice from Cook, 1988). The Hart Spring Sandstone is overlain abruptly by the 120 m (maximum) thick Boomerangian to Mindyallan Skewthorpe Formation, an interbedded series of oolitic and stromatolitic carbonates, and shoaling shale to sandstone cycles (Mory and Beere, 1988). The Pretlove Sandstone conformably overlies and interdigitates with the equivalent facies of the Skewthorpe Formation. The Pretlove Formation is 125 m thick and was deposited in intertidal to subtidal environments (Mory and Beere, 1988) during the Mindyallan.

Deepening marine waters are indicated by the change to the glauconitic Clark Sandstone, a 320 m thick unit deposited during the Idamean to Payntonian (late Cambrian) on an open marine shelf. The only late Cambrian to earliest Ordovician rocks preserved form the latest Payntonian to early Arenigian Pander Greensand. This unit is thought to lie conformably upon the Clark Sandstone and reaches 120 m thickness. It was deposited in moderately deep marine waters according to Mory and Beere (1988). The Pander Greensand is the age equivalent of the Pacoota Sandstone, the productive oil and gas reservoir in the Amadeus Basin.

It is unknown whether additional Ordovician sediments were deposited above the eroded top of the Pander Greensand. Early Ordovician sequences in the Bonaparte Basin were likely to be shale units, the equivalents of oil source rocks in the Canning (Goldwyer Formation) and Amadeus (Horn Valley Siltstone) basins. An episode of block faulting seen on seismic sections (Figure 11 a and g) can be correlated to the late Ordovician to early

Silurian Rodingan Orogeny. This timing suggests that Goldwyer equivalents may have been deposited and since eroded onshore, back to the more resistant lithology of the Pander Greensand, leaving the possibility open that early Ordovician oil source rocks are preserved in the subsurface. Alternatively, the Pander Greensand may have been the last unit deposited and the faulting may correlate with the early Ordovician tectonism that initiated the Canning Basin (Kennard et al., 1994).

PROSPECTIVITY

Very low prospectivity. Larapintine 1 or 2 plays have a far greater probability of success in the Arafura Basin; where there is a much larger potential play area underlain by oil mature Cambro-Ordovician sediments and there is a proven middle Cambrian oil source rock (Bradshaw et al., 1990).

Hydrocarbon shows

None.

Source Rock

Mory and Beere (1988) noted that the Cambro-Ordovician in the Bonaparte Basin has no prospectivity since it is overmature, being buried to greater than 3.5 km. However, this observation does not negate potential hydrocarbon generation in less deeply buried areas. Gorter et al. (1994) provided a generalised plate reconstruction for the time slice showing the locations of known source beds (Figure 25).

No source rock studies have been carried out on rocks of this age in the Petrel Sub-basin. High energy shallow water facies dominate the outcrop of the Larapintine Supersystem in the Bonaparte Basin (Mory, 1988). However, deeper-water facies in the Cambro-Ordovician sequence interpreted on seismic in the offshore (Lee and Gunn, 1988) may be organic rich, similar to the correlative units in the neighbouring basins in the middle Cambrian and early Ordovician, however overmaturity is likely (Durrant et al., 1990).

Reservoir

Little is known about the subsurface reservoir characteristics of the Carlton Group rocks. The presence of feldspars and other labile grains within the sandstones of the Carlton Group may lead to the development of secondary porosity in these rocks, and the oolitic carbonates of the Skewthorpe Formation may have potential for secondary reservoir

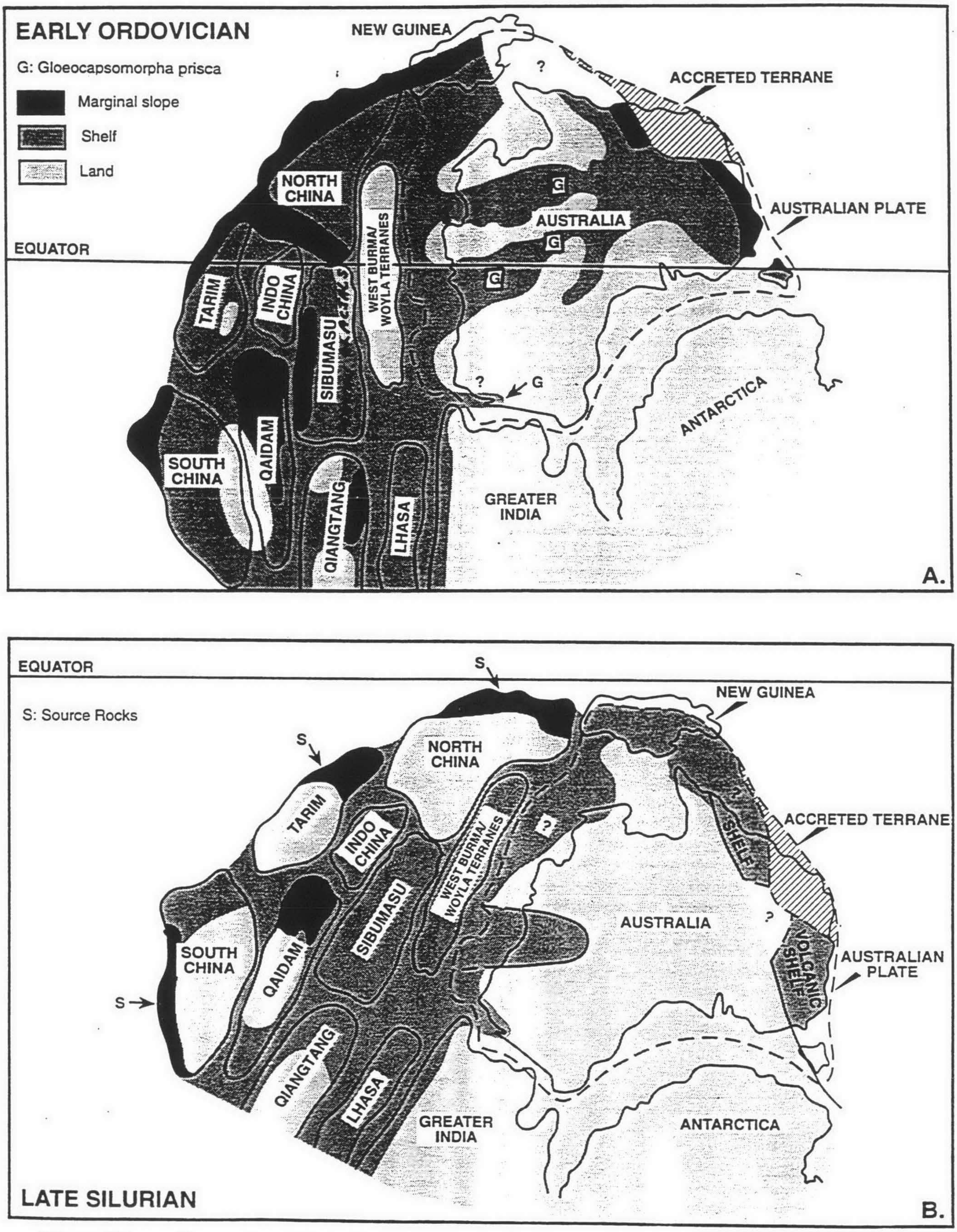


Figure 25 Generalised Early Ordovician (A) and Late Silurian (B) palaeogeographic reconstructions showing location of known source beds (From Gorter, Nicoll and Foster, 1994)

enhancement. Fracturing of carbonates may have also led to the formation of extensive networks of permeability, and allowed percolation of fluids resulting in the creation, or enlargement, of pore spaces. Mory and Beere (1988) suggested good reservoir potential based on their detailed outcrop studies of these rocks.

TIME SLICE ?O1 to D6 - ?ORDOVICIAN - SILURIAN, THROUGH TO MIDDLE DEVONIAN

SUMMARY (Enclosures 11 and 30)

Data for this time slice is fragmentary with clear evidence only existing for salt deposition. A Hercynian (Mediterranean) model of barred basin salt deposition is proposed. Playa lakes and salt flats controlled by the underlying rift structure are considered likely.

PALAEOGEOGRAPHIC INTERPRETATION

Unnamed evaporitic unit

Following the Cambro-Ordovician Carton Group, the next oldest rocks identified in the onshore and offshore Petrel Sub-basin are Frasnian age. AGSO deep seismic data suggests that thicknesses appropriate for additional Silurian to early Devonian section underlies the Frasnian section in the centre of the basin. These rocks may be equivalent to those of the Canning Basin that were reported by Lehmann (1984).

Sedimentation at this time may have been confined to the deeper portions of the older Palaeozoic depressions. Subsequent movement of fault blocks or crustal upwelling may have resulted in the proto-Petrel Sub-basin being isolated from deeper open marine conditions to the north (Edgerley and Crist, 1974) and consequently, enabled evaporitic conditions to develop. Salt, of presumed Silurian age, is the only other evidence for a pre-Frasnian sequence similar to the Canning Basin. The depth of burial implies a high level of maturity and corresponding low prospectivity for this sequence.

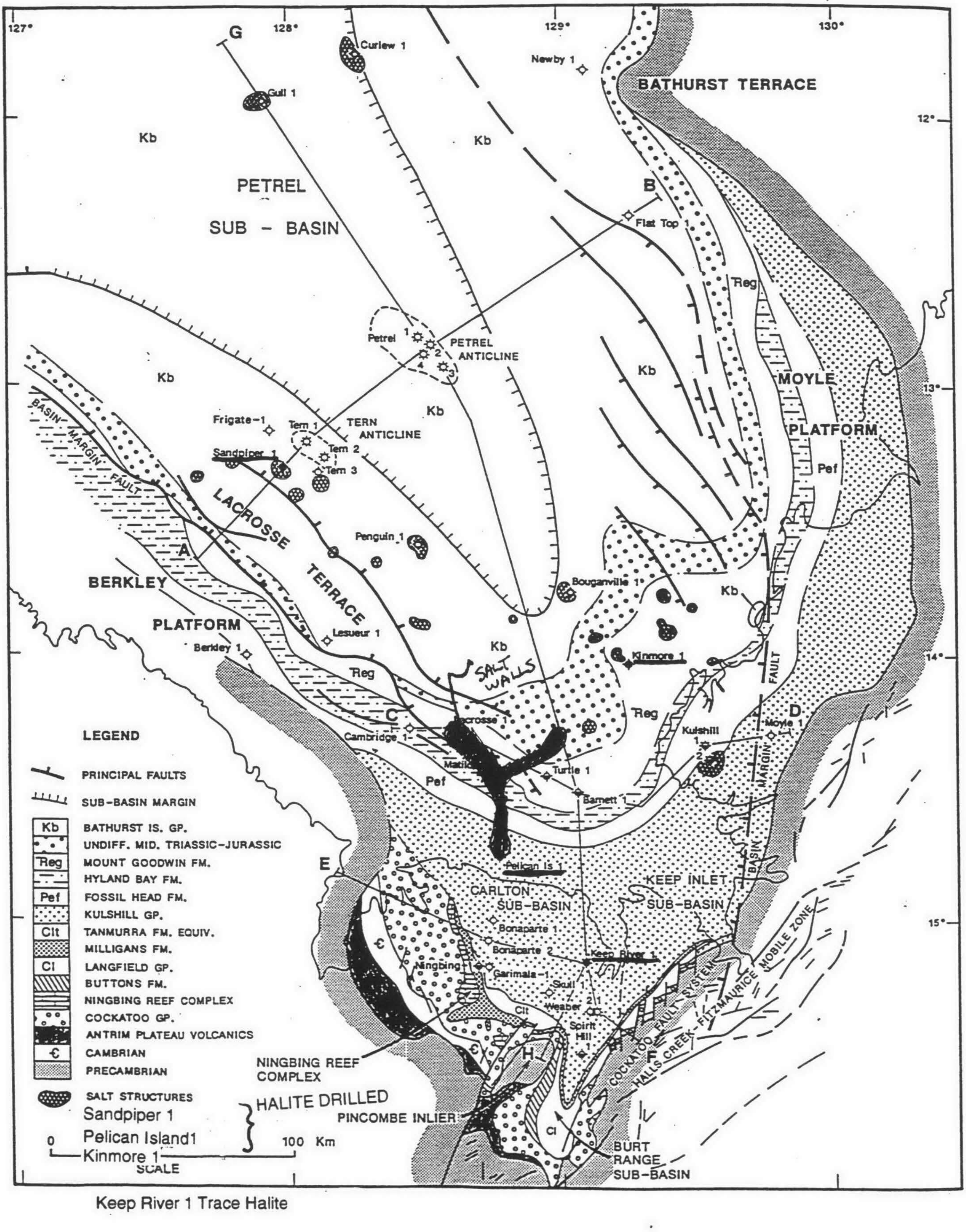
The main evaporites in the Bonaparte Basin are known from seismic data, where structures appear to have formed by salt remobilised from a much deeper sequence. Seismic interpretations show salt diapiric penetration of the later Palaeozoic to Tertiary section in several other locations in the Petrel Sub-basin and Malita Graben . The unit is not formally named as its original stratigraphic relationships and thickness can only be poorly estimated from seismic sections. Intersections of salt diapirs in Kinmore 1, Pelican Island 1, and Sandpiper 1 consist of halite with minor amounts of gypsum and calcite (salt has also been intersected out at Paqualin 1 in the Timor Sea). In areas where seismic data show no evidence of salt remobilisation, it is assumed that little remobilisation of the halite has occurred. A similar situation has been interpreted from the Willara and Kidson Sub-basins of the Canning Basin (Romine et al., 1994) where thick halite is not remobilised (Brooke 1 - 735 m of halite with minor shale and rare anhydrite; Kidson 1- 500m of halite)

Salt (density 2.2) achieves a positive density contrast with the surrounding sedimentary rocks at about 600 m burial in the Texas Gulf Coast region. The differential hydrostatic pressure ranges up to 98 $kgcm^{-2}$ which is enough to cause solid flowage of salt. Some salt domes have formed under as little as 1000 m of overburden. This behaviour pattern suggests salt movement was an early initiated and continuing phenomenon within the Petrel Sub-basin affecting the subsidence patterns throughout the entire history of the basin. No clear diapir movement appears to have occurred prior to the Triassic with disturbances of strata as young as Tertiary age evident on some of the salt stocks.

This evaporitic sequence can be identified from 'turtle' structures on seismic sections. These structures are evident on several AGSO deep seismic profiles where they appear to underlie the Bonaparte Formation. Figure 26 presents a map of the possible extent of salt deposition based on diapir and wall occurrences plus recognition of possible turtle structures based on seismic interpretation. It is based on salt structures from Figure 2 of Gunn and Ly (1989) and salt walls from Figure 10 of Durrant et al. (1990). Salt is believed to extend to the onshore areas (particularly Kulshill). Figure 6 of Laws (1991) locates gravity minima possibly related to the onshore extension of salt.

Salt is known largely from piercement structures and salt swells that intrude late Devonian and younger rocks in various areas of the Petrel Sub-basin. The distribution of diapirs and walls appears to be influenced by major faults which bound tilted blocks along the Lacrosse Terrace and along a line of faults which run northeast from Pelican Island. Near Turtle 1, in the area of the Suzanne Seismic Survey the evaporitic sequence appears to be about 2000 m thick. The AGSO deep seismic line 100/003 (Enclosure 48) suggests a similar thickness may have been present under the Petrel structure in the centre of the basin.

No dates have been obtained directly from drilled salt samples (which are all from diapirs) but a late Devonian age was determined from the section overlying salt in the Sandpiper-1 drillhole, and a sample from 1748m in Pelican Island 1 contains *A. largus* (Visean) above salt in the base of the well with no cap rock. A late Ordovician to Silurian



Keep River 1 Trace Halite

Figure 26 Salt location map (From Lee and Gunn, 1988) age for salt deposition is deduced by analogy with the evaporite sequences of the Carribuddy Group in the Canning Basin (Romine et al., 1994) and the Kalbarri Group in the Carnarvon Basin (Gorter et al., 1994). Lavering (1989, his Figure 2) tentatively arrived at a similar conclusion, placing the evaporites as late early Silurian to late Silurian.

In contrast, Lee and Gunn (1988) suggested that evaporitic sequences may have formed at various times during the Devonian and Carboniferous. They interpreted the existence of salt at three separate stratigraphic levels in different parts of the basin. These are pre-late Devonian on the basin margins from the drilling results at Sandpiper 1 and Kulshill 1, "lower" Milligans Formation in the southern central tilted fault block area evidenced by seismic interpretation, and “upper” Milligans Formation in the central axial part of the basin, where Lee and Gunn (1988) interpret no older sedimentary rocks to be present. In support of this interpretation, the Milligans (?Bonaparte) Formation is a 2000 m thick red-bed carbonate sequence in Kulshill-1 and halite hoppers have been recorded from two cores in the Famennian Ningbing Limestone in Keep River-1. However, the halite hoppers are only indicative of evaporative brines generated on tidal flats, rather than the special structural and hydrological conditions required to produce giant basinal salt deposits present in the Petrel Sub-basin.

This study prefers a late Ordovician to Silurian age for the thick salt sequence in the Petrel Sub-basin. A probable history is as follows - extension in the Ordovician created a barred basin in which salt could be deposited. Evaporite deposition ceased during an episode of uplift and erosion in the late Silurian to early Devonian related to the Prices Creek Movement in the Canning Basin (Romine et al., 1994), which effectively disconnected the Petrel Sub-basin from a source of marine brine, and left it high and dry until deposition recommenced in the Frasnian. In the late Devonian, the climate was remained sufficiently arid to produce redbeds, and hypersaline brines in coastal lagoons that then formed isolated diagenetic halite hoppers in suitable sediments. However, the topographic conditions that had previously allowed deposition of thick basin centred evaporites no longer pertained.

The large quantity of evaporites present in the basin clearly indicates that hypersaline conditions prevailed during early deposition in the Petrel Sub-basin. From the distribution of salt structures seen on seismic sections, Edgerley and Crist (1974) suggested that the evaporite sequence accumulated in the southern Petrel Sub-basin between the Lacrosse Terrace and Darwin Shelf. The AGSO deep seismic data implies that the evaporite basins were more widely distributed and possibly linked at one time to the salt basins in the Vulcan Graben and Canning Basin. The salt distribution does not appear confined to small isolated Ordovician rifts or restricted only to the large displacement margin within the Petrel Sub-basin. The pattern of present distribution reflects post-depositional movement at various times. Salt walls were possibly pushed out by Milligans fans (Durrant et al., 1994). Diapirism and salt redistribution also appears to have occurred due to Carboniferous, Permian and Mesozoic sequence deposition plus younger tectonic movement in the sub-basin.

The salt sequence is composed predominantly of crystalline halite with little recorded gypsum or anhydrite indicating that the basin was sufficiently hydrologically isolated to prevent the reflux of heavy halite brines back to the ocean. This implies that there may have been episodic filling of the basin across a sill, then desiccation to dryness during sill closure. Cathro et al. (1992) described halite in Canning Basin, as deposited in shallow brine ponds. A probable marine source was postulated for the brines with some continental influence. A similar environment is proposed for the Petrel Sub-basin salt - largely land-locked brine ponds, episodically desiccated and flooded again with marine waters. The model is a deep desiccated basin, barred from ocean exchange producing a massive halite. Seismic interpretation suggests widespread salt deposition within the Petrel Sub-basin.

Better seismic imaging of salt structures in the Petrel Sub-basin could provide a range of new test opportunities. At present, the hydrocarbon entrapment potential at the various stratigraphic levels associated with each of the major diapirs is poorly known. Techniques such as those described by Ratcliff and Weber (1994) might well enable the validity of the various drillholes on the major salt diapirs to be better assessed.

PROSPECTIVITY

Very low prospectivity, no reservoir or source facies intersected, depth of burial implies high level of maturity.

Hydrocarbon shows

None

Source Rock

As the nature of sediments deposited in this time interval remains speculative, little can be said about their source potential. However, evaporitic environments can produce and preserve appreciable amounts of organic matter and constitute excellent source rocks. In

Kinmore 1 the presence of sapropel with halite was noted and this may have been original algal material.

In the Canning Basin potential source rocks have been found in association with evaporites - a mineral drillhole in the Admiral Bay Fault Zone intersected very organic rich, but thin, 'algal coals' with TOC's up to 45 percent in the Bongabinni Formation, the basal unit of the evaporitic Carribuddy Group (Kennard et al., 1994). Oil samples from mineral holes in the late Devonian had a biomarker signature indicative of an evaporitic source rock (D. Edwards, AGSO personal communication, 1995). However, the probable source is evaporitic sediments in the late Devonian rather than migration from the major salt unit.

Reservoir

As the nature of sediments deposited in this time interval remains speculative, little can be inferred about their reservoir potential.

TIME SLICE D7 and D8 - FRASNIAN

SUMMARY (Enclosures 12 and 31)

The Frasnian of the Petrel Sub-basin was a time of paralic deposition in the southern part of the basin where the unit is encountered in drillholes. Alluvial fans and offshore bars were present with deeper marine conditions proposed for the area under the site of the modern Gulf.

PALAEOGEOGRAPHIC INTERPRETATION

Cockatoo Group

Petroconsultants (1990) considered that sedimentation during this interval was associated with a sequence of discrete transgressive/regressive cycles. During the first cycle up to 2700 m of the Cockatoo Group sediments were deposited (Laws, 1981; Mory and Beere, 1988). Coarse clastics are associated with the eastern and western faulted basin margins and grade basinward into marine siliciclastics. Interbeds of dolomite, marl and limestone are found along the western margin. The sediments become more marine to the northwest.

Sedimentation commenced during the early Frasnian (Jones and Druce, 1966; Druce, 1969) with alluvial fan deposits accumulating along active fault scarps. Broad braided rivers flowed to the north and northeast. Aeolian and fluvial conditions, prevailing during the middle Frasnian, merged basinwards into fluvio-deltaic and tidal environments. Further north, marine environments are indicated by stromatoporoid and algal reefs during later Frasnian time. Thus, the Cockatoo Group records deposition during a marine transgression corresponding to a general eustatic sea level rise at this time. A global sea level fall occurred at the end of the Frasnian (Johnson et al., 1985) and this is reflected by regression at the end of Cockatoo Group deposition. The offshore marine equivalent of the Cockatoo Group is the lower part of the Bonaparte Formation.

Bonaparte Formation

In offshore areas, during the late Devonian to early Carboniferous, up to 3000 m of shallow marine shales and thin sandstones attributed to the Bonaparte Formation were deposited. The Bonaparte Formation has been variously correlated with the Frasnian Cockatoo, Famennian Ningbing, Tournaisian Langfield and younger Weaber Groups in the onshore portion of the basin. However, the basinal shales within each of these sediment packages may be separate and unrelated. More precision in biostratigraphy is required to clarify the relationship of the "Bonaparte Formation" with these groups e.g. Jones (1989a) and Foster (1990).

The 'Bonaparte Beds' were originally defined as a subsurface unit that consists of shale, siltstone, and sandstone of late Devonian to Visean age (Veevers and Roberts, 1968). Veevers and Roberts (1968) designated the type section as the interval 497-3210 m in Bonaparte 1. Mory and Beere (1988) recognised an unconformity at 2280 m in this well and restricted the name 'Bonaparte Formation' to the sequence of shale, siltstone, sandstone, and minor sandy limestone between 2280 and 3210 m in Bonaparte 1. So defined, the Bonaparte Formation is restricted to the late Devonian to early Carboniferous (Tournaisian) sequence, whereas the Visean sequence (497 to 2280 m in Bonaparte 1) which was previously included in this unit was distinguished as the "Milligans Formation". In the type section, the boundary between the two units is marked by a distinct change on the gamma-ray log and the presence of a dipmeter unconformity.

In the offshore Petrel Sub-basin the Bonaparte Formation has been confused with the lithologically similar, but younger Milligans Formation. The Milligans Formation can be distinguished from the Bonaparte Formation by the unconformity that often separates the two units. The Milligans Formation is interpreted as missing from highs in the Petrel Sub-basin where the Tanmurra Formation has an unconformable lower contact as shown in Turtle 1 (Durrant et al., 1990), and possibly below Lacrosse 1 on seismic sections (Figure 4 of Mory, 1991). Using this criteria, the 'Lower Milligans Formation' of Lee and Gunn (1988) is equivalent to the Bonaparte Formation since it disconformably underlies 'Upper Milligans Formation'. This confusion was exacerbated by the *A. largus* palynological zone having been interpreted as occurring both above (Bonaparte 1) and below the unconformity (Turtle 1, Foster, 1984).

Recognition of the new pre-*A. largus* zone, the *Grandispora* sp. cf *G. praecipua* zone, in the Bonaparte Formation in Barnett 2 by Foster (1990) provided the potential to differentiate Bonaparte from Milligans Formation biostratigraphically (see Enclosures 3, 7 and 10). The interval from 2531.5 to 2671 m, below the unconformity at 2486 m in Turtle 1, previously interpreted as *A. largus* by Foster (1984), was correlated with the *Grandispora* sp. cf *G. praecipua* interval in Barnett 2 by Foster (1990). Recent examination of additional samples from Core 1 at 2486 m has extended the range of the new zone in Turtle 1. In this report the Bonaparte Formation is considered to be Frasnian to earliest Visean in age, time slice D7 to Crb2, and to contain the *G. spiculifera, Grandispora* sp. cf *G. praecipua* and the undifferentiated *G. frustulentus* Microflora zonations, while the Milligans Formation is Visean in age, time slice Crb3 and dating within the *A. largus* zone (Enclosure 3). Mory (1991), without the benefit of recognition of the *Grandispora* sp. cf *G. praecipua* zone, accommodated the problem of the *A. largus* zone apparently occurring in both the Milligans and Bonaparte formations by suggesting that the *A. largus* and *G. spiculifera* zones are coeval (Mory, 1991, Figure 8).

The type section of the Bonaparte Formation consists of shale and siltstone, interbedded with sandstone and minor amounts of sandy limestone. It differs from the Milligans Formation in that it is sandier and contains chlorite and carbonate. In Keep River 1, two fining-up sequences of Bonaparte Formation are present (3222-3446 m and 3446-3571 m). Each sequence consists of basal sandstone or sandy limestone overlain by calcareous siltstone and silty shale (More and Beere, 1988).

The Bonaparte Formation is unconformably to conformably overlain by the Milligans Formation. In the onshore part of the basin it is laterally equivalent to the Langfield, Ningbing and Cockatoo Groups of Mory (1991). Offshore, the unit is unconformably overlain by the Tanmurra Formation. In Keep River 1 and Weaber 1, the Bonaparte Formation lies conformably between the Enga Sandstone and Ningbing Group.

The Bonaparte Formation is known only in the southern Petrel Sub-basin, primarily from seismic sections and exploration wells. The most northerly intersections are in Turtle 1, and Barnett 2 and possibly in the Sandpiper 1 diapir. Up to 930 m has been intersected, but the base of the unit has not been penetrated. Seismic data indicate that the unit is locally more than 3000 m thick.

A diverse fauna and flora has been identified in the Bonaparte Formation from Bonaparte 1 (Le Blanc, 1964), Kulshill 1 (Duchemin et al., 1966) and Keep River 1 (Caye, 1969). A late Devonian to early Carboniferous (late Tournaisian) age is indicated by the fauna, and by stratigraphic relationships with the Ningbing and Langfield Groups (Mory, 1991). Recognition of the *Grandispora* sp. cf *G. praecipua* zone, in the Bonaparte Formation suggests that it could extend into the earliest Visean.

The Bonaparte Formation was probably deposited under low-energy shelf to open-marine conditions. Sandstones in the unit were probably deposited by mass flow or turbidity currents, the fining-up sequences in Keep River 1 are probably due to fan abandonment.

PROSPECTIVITY

Low prospectivity, some reservoir facies observed, but no local source identified. The clastic and carbonate reservoirs of the Cockatoo Group have not been petroleum targets since the mid 1960s following the disappointing results of the initial drilling phase within the onshore basin. Nevertheless, fair to good reservoir and source beds, juxtaposed with sealing shales in tilted fault blocks and stratigraphic pinchouts, could form viable exploration plays. Recognition by Petroconsultants (1990) that the source beds are oil mature to depths of about 1500 m, and gas mature under deeper burial, suggests that rocks of this age should not be discounted as viable petroleum targets. However, the long time between deposition of the potential reservoirs, several episodes of faulting, and the relatively late-stage attainment of oil maturity, suggests exploration for such targets will be a high risk venture. The relative ease of access and proximity to transport, and shallowness of objectives could enable a low budget program to be mounted.

Hydrocarbon shows

Traces of oil have been reported from shallow mineral holes drilled in the Cockatoo Sandstone along on the eastern basin margin (Laws, 1981, his Figure 4).

Source Rock

Mory and Beere (1988) noted that the Cockatoo Group rocks had generally poor source rock characteristics, being non-marine to tidal deposits in the present onshore areas where the rocks have been studied. The marine equivalents in the lower part of the Bonaparte Formation may have some source potential, though over-maturity is a major risk.

Reservoir

Mory and Beere (1988) noted "excellent (reservoir) characteristics" in outcrops of the Cockatoo Group. The presence of arkosic sandstones and carbonates suggests that secondary porosity may be developed. Back reef facies within the Cockatoo Group interpreted by Gunn and Ly (1989) suggest that reef complexes and associated carbonates could also provide petroleum reservoirs. In Ningbing 1, the Cockatoo Group sandstone penetrated and cored was found to have good porosity (16 %) and permeability (71 mD), and residual oil staining. Primary porosity was preserved in these cross-bedded quartz sandstones interpreted as having been deposited in a beach ridge environment and derived from reworked older sedimentary rocks such as the Cambrian Carlton Group (Garside, 1982).

TIME SLICE D9 and D10 - FAMENNIAN

SUMMARY (Enclosures 13 and 32)

Famennian algal reefs were common in the southern Petrel Sub-basin. Landward of these fringing reefs, paralic environments occurred while deeper marine rocks were deposited in the central parts of the basin. Turbidites and fan sedimentation was associated with features such as the Waggon Channel in the southwest of the basin.

PALAEOGEOGRAPHIC INTERPRETATION

Ningbing Group

Carbonate deposition of the Famennian Ningbing Group (Mory & Beere, 1988) began following a reduction of the high rate of clastic sedimentation of the Cockatoo Group. Carbonate deposition involved algal reef development on isolated bathometric highs. The Famennian Ningbing Group contains reefal developments similar to those found in the northern Canning Basin, albeit much smaller in scale (Playford et al., 1966; Playford, 1982; Veevers, 1969, 1970). A reef complex of the Ningbing Group, some 500 m thick (Lee and Gunn, 1988) with associated back reef, small patch reef, and forereef facies is documented in outcrop and penetrated by wells drilled onshore. Reef growth may have been directly influenced by eustatic sea level changes. Several mineral exploration boreholes have encountered porosity developments within the reef that contain bitumen staining, and oil was recovered from vugs in Ningbing Group limestone in Ningbing 1 (Garside, 1982).

Bonaparte Formation (see above) of equivalent age to the Ningbing Group is thought to represent a basinal facies equivalent. This unit could provide an excellent seal, and possible source facies may also be developed within it. Petroconsultants (1990) interpreted this unit as a maximum flooding surface deposit (Figure 27).

PROSPECTIVITY

Moderate prospectivity. A gas discovery (Garimala 1) and numerous oil shows occur in the late Devonian, and it is in good company both locally (Canning Basin) and internationally as a petroliferous interval. Laws (1981) compared the Petrel Sub-basin with the productive late Devonian reef trends in Alberta, and suggested similar exploration plays could occur. To date, the major onshore target has been the Ningbing Reef Complex, which has been compared to the reef systems of the Canning Basin (Blina Oil Field) and the prolifically producing Devonian reef systems of Alberta (Laws, 1981). These algal carbonate rocks occur in the Famennian Ningbing Group and have little in common with the Frasnian stromatoporid reefs of Alberta. Local oil sources have been recognised geochemically, but prediction of porosity within the carbonates remains a major challenge.

Hydrocarbon shows

Garimala 1 is an onshore gas discovery in a reservoir that is poorly age constrained (*A. largus* to *R. lepidophyta* - Visean to late Devonian, see Appendix 3). In this study the gas zone is attributed to the time slice interval D9-10. DST 2 tested the Bonaparte Formation between 2401 and 2381 m recovering 0.75 MMCFD decreasing to 0.47 MMCFD over a period of two hours, and is rated G4, a potential gas zone. Ningbing 1 produced good fluorescence and a slight oil bleed from fractures in core at 1018 to 1035 m in the Ningbing Limestone (Garside, 1982). Two DST's conducted failed to produce any significant

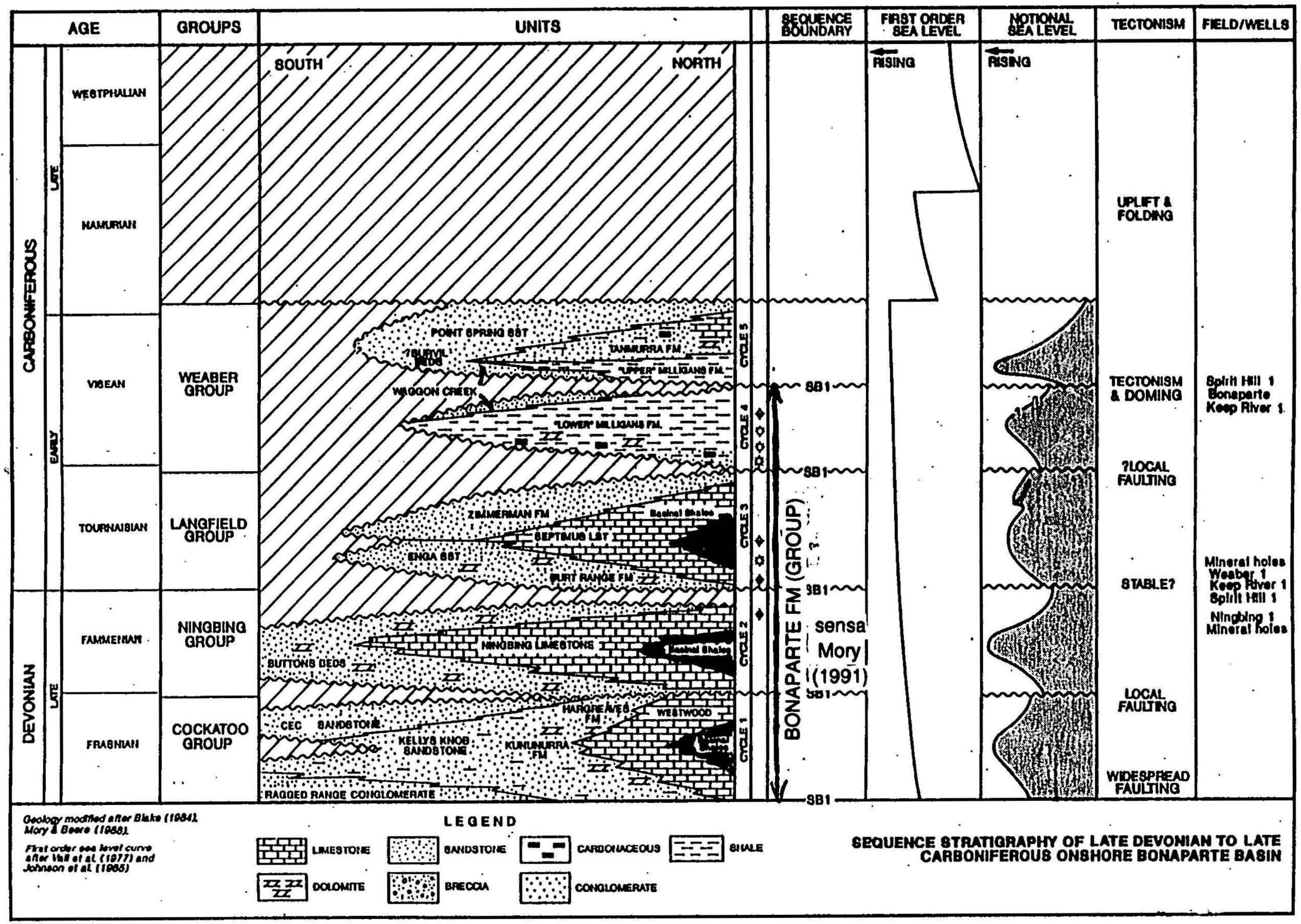


Figure 27 Sequence stratigraphy of the late Devonian to late Carboniferous onshore Bonaparte Basin (From Petroconsultants, 1990)

hydrocarbon shows. Numerous oil shows have been reported from shallow mineral holes drilled along the Ningbing Limestone outcrop belt on the eastern basin margin (Laws, 1981, his Figure 4). Gas indications are noted in tight clastics in Bonaparte 1 and from fractured reefal limestone in Keep River 1.

Source Rock

In the onshore Petrel Sub-basin, indications of oil staining in the vuggy Ningbing Group carbonates, the Enga Sandstone and Septimus Limestone, led Laws (1981) to infer that the source of this oil was the overlying basal Bonaparte Formation (that is, Milligans Formation, see Enclosure 3). In addition, Mory and Beere (1988) observed that the shows occurring in shallow mineral holes in the Ningbing and Langfield Groups have chromatographic signatures similar to oil from shales in the Milligans Formation, suggesting that the Milligans may be the source. Values of Hydrogen Index (HI) and Total Organic Carbon Content (TOC) mapped for the few intersection of time slice interval D9-10 in Appendix 6 indicate poor source rock quality, supporting the conclusion that the source of the oil shows is not local to the Ningbing Group.

However, geochemical analysis of oil recovered from Ningbing 1 shows it to be sourced from a carbonate algal source, distinct from the anoxic, clastic signature of Milligans oils (D. Edwards, R. Summons, personal communications, 1995). Apart from this oil, consistent with a source rock deposited in a back-reef or inter-reef environment, another oil type was found from mineral hole samples which had a biomarker signature indicative of an evaporitic source rock (D. Edwards, personal communications, 1995). This observation is consistent with the halite hoppers noted in the reefal late Devonian section in Keep River 1. Such crystals grow diagenetically in unconsolidated sediments when evaporitic brines generated in back-reef lagoons seep seaward. These geochemical results strongly support a local late Devonian source for at least some of the Ningbing Group oil shows.

Reservoir

Laws (1981) noted that porosity is very rarely observed in outcrops of the Ningbing Group limestones because any primary or secondary porosity present was probably infilled during recent subaerial weathering. The barrier margin and reefal facies of the Ningbing Group is algal in origin compared to the Frasnian stromatoporid framework reefs such as Golden Spike in Canada. Consequently the original porosity of the Ningbing Limestone was probably poor.

In the petroleum exploration wells that penetrate the Ningbing Group limestone (Keep River 1, Ningbing 1 and Weaber 1), porosity's and permeability's have been negligible (Mory and Beere, 1988). However, in Weaber 1, Garside (1983) noted the presence of calcite rhombs below 1793 m within the Ningbing limestones indicating fractures or vuggy porosity. Several gas shows appeared to be associated with microfractures and a 3 m interval (1880.5 - 1883.5 m) was considered to have "very good" permeability (Linderdown and Whitehouse, in Garside, 1983).

In Keep River 1, drillstem tests of the Ningbing Group below 3720 m revealed very low permeability's although log interpretation had indicated fair porosity in 2 to 5 m thick intervals (Caye, 1969). Cores from shallow mineral exploration holes indicated that secondary porosity is widely developed below the contact with the overlying transgressive Langfield Group. Vuggy porosity is common, intercrystalline and fracture porosity are subsidiary. Porosities of up to 20 percent are not unusual, with the average around 7 percent (Laws, 1981).

In these shallow wells, secondary porosity extends down more than 100 m from the contact with the overlying shales and is not confined to any one facies. Porosity has been encountered in the barrier margin and marginal slope facies of the Ningbing Group, as well as the back reef and lagoonal carbonates of the Burt Range Formation and Septimus Limestone (Langfield Group). The porosity is largely due to dolomitisation which probably took place in the late Carboniferous after the deposition of the overlying Milligans Formation (Laws, 1981; Mory and Beere, 1988).

The late Devonian limestone cored in Ningbing 1 is a finely crystalline massive algal boundstone with areas of fibrous sub-marine cement indicating early porosity loss. There was a later stage of porosity in-fill related to fracture filling at moderate depths of burial, with scalenohedral calcite and saddle dolomite (Garside, 1982). Porosity up to 3.8% and permeability of 17.0 mD related to fractures were measured from the core (Garside, 1982).

Possible subsurface extensions of the reef trend may occur along the northeastern extension of the Pincombe Ridge and along the eastern basin margin (Gunn and Ly, 1989), and eustatic sea level changes through the Famennian may have led to the development of basin-floor fans and karstic porosity within limestone exposed during sea level falls (Petroconsultants, 1990).

In Kulshill 1 (Duchemin et al., 1966), the Ningbing Group Equivalent sandstones are well consolidated and strongly silicified with silicification increasing towards the base of the well. Porosity is generally less than 1% (maximum 6.5%) and permeability practically nil. Log interpretation indicated minor porosity at 4206 m, possibly due to fracturing.

TIME SLICE Crb1 and Crb2 - TOURNAISIAN

SUMMARY (Enclosure 14 and 33)
A narrow erosional land-bounded rift valley is believed to have existed throughout this time. Thick monotonous marine deposits suggest deeper water conditions along with limited areas of paralic sedimentation.

PALAEOGEOGRAPHIC INTERPRETATION

The onset of deposition of the Tournaisian Langfield Group (Keep River Group of Laws, 1981) marks the termination of reef growth, as uplift increased the supply of clastic sediments. The Langfield Group consists mostly of limestone and sandstone with minor shales (Mory and Beere, 1988) deposited in a shallow, clastic influenced shelf setting. The group comprises two carbonate to clastic sequences interpreted as representing progradation of shoreline clastics over shelf carbonates (Mory and Beere, 1988). Significant quantities of gas were encountered in the Enga Sandstone of the Langfield Group at Weaber 1.

Bonaparte Formation (see above) of equivalent age to the Langfield Group is again thought to represent a basinal facies equivalent. This unit could provide an excellent seal, and possible source facies may also be developed within it. Petroconsultants (1990) interpreted this unit as a maximum flooding surface deposit (Figure 27).

PROSPECTIVITY

Moderate prospectivity. The Langfield Group lies below the potential regional source and seal of the Milligans Formation. Horsts and tilted fault blocks and channel like features seen on seismic lines may form a range of potential traps (Gunn and Ly, 1989). Sediments of the time slice interval Crb1-2 contain a gas discovery in Weaber 1, however from the limited intersections no local source is identified and porosity development is patchy both due to primary lithology's and diagenesis.

Hydrocarbon shows

Weaber 1 was re-entered in 1985 and DST 1 over the interval 1281-1313 m flowed dry gas at 56 600 m^3 /day, while DST 4 over the interval 1273 to 1421 m flowed dry gas at a maximum of 127 400 m^3 /day. Later analysis of pressure data revealed that formation damage may have impaired the test results and that flow rates as high as 480 000 m^3/day could be achieved from the Enga Sandstone. In Bonaparte 1 there is a strong gas indication in an isolated sand within a predominantly fine grained sequence. There are also gas shows in Keep River 1, where some fractured calcareous sandstones produced small gas anomalies.

Oil was recovered from the time slice interval Crb1-2 in Barnett 2. Trace residual oil shows have been reported from the Burt Range Formation in Spirit Hill 1 (Gunn, 1988a).

Source Rock

The Langfield Group is not a recognised source rock interval, as supported by the HI and TOC maps for this interval in Appendix 6.

Reservoir

Carbonates in the Langfield Group probably have similar reservoir characteristics to the Ningbing Group. In Weaber 1, limestones within the lower Burt Range Formation were generally tight (Garside, 1983), and similar poor porosity was noted in Keep River 1 by Caye (1969). Ooid shoals may provide porous intervals within the carbonate complexes, although extensive reef growth is unlikely in this group (R. Nicoll, personal communication, 1994)

The Enga Sandstone produced gas at Weaber 1. Laws (1981) noted a single analysis available from a mineral exploration core hole gave a porosity of 22% in a sample of Enga Sandstone at 230 m, but thought it doubtful that porosities of this level could be maintained deeper in the Keep Inlet Sub-basin. Furthermore, at Kulshill 1 (Duchemin et al., 1966), the Langfield Group (? Burt Range Formation) is shaly and contains no reservoirs. The Enga Sandstone encountered at Weaber 1 (14.0 sand) had fair porosity where medium grained, but cuttings showed most of the sandstone to be dolomite cemented and tight. The good gas flows tested from this sand (Willink, 1989) may be due to fracture enhanced permeability. In the Keep River 1 well, the correlative unit is tight, suggesting that the increased overburden pressure has kept closed any similar fractures (Petroconsultants, 1990).

TIME SLICE Crb3 - EARLY VISEAN

SUMMARY (Enclosure 15 and 34)

Active rifting is believed to have again occurred during this time with predominantly very shallow marine and reefal deposition (Tanmurra Formation) in the Petrel Sub-basin. Movements along the fault margins of the basin resulted in paralic and estuarine conditions around the edges with deep marine conditions interpreted further offshore (Milligans Formation). Gas has flowed from this interval in onshore wells and in the offshore, the Milligans Formation is considered to be the source of the oil recovered in the Turtle and Barnett wells.

GENERAL DISCUSSION

The Weaber Group (Traves, 1955; Mory and Beere, 1988) consists of the Milligans Formation (early Visean), Tanmurra Formation, and Point Spring Sandstone (late Visean to Namurian) in the offshore part of the basin. Other units present in the group, but not represented offshore, include the Waggon Creek Formation, Utting Calcarenite, Burvill Formation, and Border Creek Member of the Point Spring Sandstone (Mory and Beere, 1988). The group conformably to unconformably overlies the Bonaparte Formation. The angular unconformity often visible on seismic data at the base of the Tanmurra Formation (Figure 4 of Mory 1991) was interpreted by him to indicate that the Milligans Formation (at the base of the group) was missing in some areas.

The group may be up to 4000 m thick under the Petrel structure. On seismic sections, the basal unit (Milligans Formation) appears conformable on the underlying Bonaparte Formation north of Petrel. Between Pelican Island 1 and Turtle 1, however, there is a disconformable relationship between the two units (Figure 4 of Mory, 1991).

Along the basin margins, the Weaber Group can be differentiated into a basal shale, referred to as the "lower" Milligans Formation, the sandstone dominated Waggon Creek Formation, the "upper" Milligans Formation, a sandstone and carbonate unit called the Tanmurra Formation, and an upper sandstone and shale sequence, the Point Spring Sandstone deposited during Crb4 and 5 (Figure 27).

The Weaber Group forms a thick, coarsening and shallowing-up sequence that was interpreted very simplistically by Mory (1991) to have formed by delta progradation into the basin. The interpretation of the Weaber Group presented by Petroconsultants (1990) was extensively modified from that published by Mory and Beere (1988), and somewhat different to the stratigraphic successions illustrated by Lee and Gunn (1988) and Gunn (1988).

Petroconsultants (1990) interpretation (Figure 27) followed a sequence stratigraphic analysis utilising the principles of Van Wagoner et al. (1987) and Vail (1987), and recognised important unconformities and depositional sequences which are tied, where possible, by palaeontology and seismic profiles.

During the Visean, in response to a period of active subsidence, the southern Bonaparte Basin received marine sediments of the "lower" Milligans Formation. The "lower Milligans Formation in Keep River 1 is clearly correlated to Weaber 1 and 2A, and Spirit Hill 1 by logs and palynological control (Wood, 1988). Several upwards coarsening cycles are readily recognised and correlated on the gamma ray logs in these wells.

In Keep River 1 (2380 - 3450 m) Petroconsultants (1990) recognised and described five discrete units. The basal sandstone of unit 1 is correlated with the "130" sandstone at Weaber 1 (Garside, 1983). This sandstone is interpreted as the basal lowstand wedge deposit of the "lower" Milligans Formation in this area. The unit fines upwards into calcareous shales containing marine fossils and ooids, and then coarsens up to a highstand sandstone section.

Units 2 and 3 are also interpreted by Petroconsultants (1990) as shoal cycles. At Weaber 2A, unit 3 questionably contains the *A. largus* unit A assemblage (Wood, 1988), and thus correlates with the gas bearing zone at Bonaparte 2. Overpressured shales were reported in this interval at Weaber 1 (Garside, 1983), although a reservoir was absent. At Weaber 1, the "lower" Milligans Formation lies between 1300 m and 655 m (Garside, 1983), and unit 3 shoal cycle is identified between 1206 m and about 1095 m. The cycle coarsens upwards from carbonaceous shales to interbedded calcareous siltstones and shales.

Unit 4 is a monotonous series of interbedded shales, siltstones and thin carbonates, with some ooids reported from Keep River 1. Minor gas shows occur towards the top of this unit at Keep River 1 (Caye, 1969) and overpressured shales occur at Weaber 1. The *A. largus* unit B assemblage is present in the unit at Weaber 2A (Wood, 1988).

At Keep River 1 the lower part of unit 5 (2771-2899 m) is a shoal cycle. This unit commences with shale, and coarsens upwards through weakly calcareous quartz siltstone with foraminifera (2719 to 2771 m), to interbedded crinoidal shale and siltstone with thin beds of calcareous, medium grained, gas bearing sandstone (2646 to 2652 m) and interbedded calcareous mudstone and biosparite conglomerates. Sandstone beds up to 1.5 m thick increase upsection and consist of fine to medium grained, calcareous beds with crinoids, brachiopods and foraminiferal remains. Palaeocurrents interpreted from the dipmeter suggest a southerly source and low energy shallow water deposition (Caye, 1969).

The lower part of unit 5 lies between 775 and 825 m at Weaber 1. The sandstones of unit 5 are well sorted, fine to medium grained, and occur in beds up to 2.5 m thick. The uppermost beds of unit 5 are mainly siltstones and shale with minor interbedded calcareous sandstone in beds up to 1.5 m thick. Unit 5 at Weaber 2A contains the *A. largus* unit C assemblage (Wood, 1988). Carbonates, averaging some 300 m in thickness, were developed over the mid-basin area. These carbonates grade into siliciclastic sequences to the southeast, and northwest into thicker shale sequences in the deeper parts of the basin. The siliciclastics, laterally equivalent to the carbonates, are referred to as the lower portion of the Point Spring Sandstone (Mory and Beere, 1988).

The more clastic dominated sequence, referred to as the main Point Spring Sandstone after Mory (1988), contains fluvial to shoreface facies in the onshore sections, whereas offshore the unit contains thick shales. In both the offshore and onshore areas the Point Spring Sandstone has a thickness between 200 m and possibly 1000 m to the north of Petrel. At Kulshill 1 over 800 m of section has been assigned to the sequence (Mory, 1988). These variations in section thickness suggest that the Kulshill wells were located in a variably subsiding sub-basin during the main period of Point Spring Sandstone deposition.

The Tanmurra Formation consists primarily of shelf carbonates, but in onshore wells a large clastic input is evident, presumably from deltas of the Point Spring Sandstone

PALAEOGEOGRAPHIC INTERPRETATION

The Milligans Formation is the basal unit of the Weaber Group and consists predominantly of fossiliferous shale and siltstone. The name was first used as 'Milligans Beds' by Utting (1958) for Carboniferous shales which underlie the Keep River plain, and by Oil Development N.L. (1961) for Visean shale and siltstone in Spirit Hill 1. The type section is the interval 44 - 155 m in Milligans No. I Bore (Veevers and Roberts, 1968). Veevers and Roberts (1968) restricted this unit to the Burt Range and Carlton Shelves. Mory and Beere (1988) extended the unit into the Petrel Sub-basin to include the latest Tournaisian to Visean shale, which Veevers and Roberts (1968) had included in their 'Bonaparte Beds'. The interval 497-2280 m in Bonaparte 1, previously part of the type 'Bonaparte Beds', is designated a reference section for the Milligans Formation since the type section represents only a small part of the unit. Lee and Gunn's (1988) attempt to divide the unit into an 'Upper' and 'Lower' sequence is considered suspect, as this subdivision is based on log correlations of onshore wells (Lee, *in* Barnes and Lee, 1984) in which the monotonous siltstone and mudstone succession has a correspondingly indistinct log signature. Although Lee and Gunn (1988) assigned a Visean age to the 'Lower Milligans Formation', their unit appears to be equivalent to the Bonaparte Formation, at least in offshore wells, based on its stratigraphic position disconformity below the 'Upper Milligans Formation' and recognition of the *Grandispora* sp. cf. *G. praecipua* zone (see above).

The Milligans Formation consists predominantly of grey to black silty shale which is locally calcareous, gypsiferous, or pyritic. Interbedded sandstone, siltstone, limestone, pebbly sandstone, and conglomerate are also present in the onshore intersections of this unit. In Kulshill 1, the Milligans Formation (2831 - 3216 m) is considerably more sandy than the reference section, which probably reflects a position closer to the basin margin during deposition. Northeasterly prograding wedges up to 100 m thick, visible on seismic sections between Pelican Island 1 and Turtle 1, probably consist of sandstone similar to that in the Waggon Creek Formation in the onshore part of the basin.

The Milligans Formation unconformably overlies older units (AGSO deep seismic lines 100/101, 100/02 and 100/03, Enclosures 47 & 48), except in deeper parts of the Petrel Sub-basin where the unit is conformable on the Bonaparte Formation (AGSO deep seismic line 118/018, Enclosure 49).

The Milligans Formation is known primarily from deep exploration wells in the onshore part of the basin, and from seismic data. It reaches a maximum thickness of 2142 m in Keep River 1. In Kulshill 1, 1563 m of Milligans Formation was intersected. In complete offshore well intersections include Turtle 2, Lesueur 1 and Cambridge 1.

The Milligans Formation contains a diverse and abundant macrofauna in Bonaparte 1 and 2, and Keep River 1 (Le Blanc, 1964,1965; Caye, 1969). Foraminifers described by Mamet and Belford (1968) from Bonaparte 1 indicate an age of latest Tournaisian (Tn3c) to late Visean (V3b-c). By comparison, Veevers and Roberts (1968) and Grey (1983) determined an early to late Visean age for the unit. The *A. largus* Assemblage, which has been identified from the unit (Kemp et al., 1977), is Visean.

The Bonaparte Formation (see above) may have been mistaken for Milligans Formation in some drillholes such as Lacrosse 1 as the two formations are lithologically similar.

The presence of several submarine fans (Waggon Creek Formation; Beere, 1984) and shelf carbonates (Utting Calcarenite) within the Milligans Formation in the onshore part of the basin indicates an outer-shelf environment of deposition. Sandstones deposited as prograding wedges south of Turtle 1 probably represent submarine fans similar to those described by Mory and Beere (1988) from the Waggon Creek Formation in the onshore part of the basin.

The Tanmurra Formation was defined in an unpublished report by Le Blanc (1964) as the interval of sandstone with minor amounts of limestone, siltstone, and dolomite, from 194 to 497 m in Bonaparte 1 (Veevers and Roberts, 1968, 1966). The name has since been applied to the predominantly carbonate interval of the same age in the offshore Petrel Sub-basin. ARCO geologists originally named the Formation 'Medusa Beds' in the Lacrosse 1 well completion report (ARCO, 1969).

The Tanmurra Formation disconformably to unconformably overlies the Bonaparte Formation and conformably overlies the Milligans Formation. It is a possible lateral equivalent, in part, to the Point Spring Sandstone, as well as the Burvill Formation and Utting Calcarenite. The latter two units are confined to the Carlton Shelf in the onshore part of the basin (Mory and Beere, 1988). Towards the centre of the Petrel Sub-basin, a similar facies change from carbonate to siliciclastic lithology's is evident from the change in the seismic character of the Tanmurra Formation.

Unlike the other formations in the group the Tanmurra Formation is known only from the subsurface. The unit is restricted to the southern Petrel Sub-basin where it ranges from 100 to 465 m in thickness.

Foraminifers in Bonaparte 1 indicate a late Visean to early Namurian age for the Tanmurra Formation (Mamet and Belford, 1968). In Bonaparte 1 and 2, and Pelican Island 1, palynomorphs of the *A. largus* assemblage have been identified in this unit. In Lacrosse 1, by comparison, the *G. maculosa* Assemblage is present. In all other offshore wells, the unit contains few palynomorphs, and lies between occurrences of the *A. largus* Assemblage (below) and the *G. maculosa* assemblage (above).

PROSPECTIVITY

Moderate prospectivity. The Milligans Formation is considered the source rock for the Larapintine-Gondwanan Transition petroleum system. Significant gas flows were obtained from this interval in Weaber 2A, Bonaparte 2 and Keep River 1, and oil was recovered in Turtle 2. Porosity remains a major risk due to primary facies and diagenesis. Turbidite fans provide potential exploration targets, where reservoir facies may be encased in surrounding Milligans Formation shales acting as seal and source.

Hydrocarbon shows

Bonaparte 2, Keep River 1 and Weaber 2A produced gas flows from the Milligans Formation. Oil shows occurred in the Tanmurra Formation at Turtle 1 (Jefferies, 1988), although these were not tested. Shows were also encountered at Turtle 2, where oil was recovered from the Milligans and Tanmurra formations. Oil and gas shows were reported from the Tanmurra Formation at Barnett 1, with a small quantity gas recovered on DST at Barnett 2 from 2413.5 to 2421 m. Several oil and gas shows were encountered during the drilling of Lesueur 1 mostly between 3000 m and 3500 m in the Tanmurra and Milligans (called Bonaparte in the well completion report) Formations.

Source Rock

Oil/source rock correlations point to the Milligans Formation being an oil source, but there is little evidence of source rock quality material in the Milligans sampled to date (see Appendix 6). However, Mory and Beere (1988) reported up to 2% TOC in the Milligans Formation of the Weaber Group. Jefferies (1988), in his analysis of the oil recovered in Turtle 1, suggested that the source of oil found in the upper Kuriyippi Formation sands was the underlying marine shales of the Milligans Formation, a section not sampled at that location but fingerprinted in onshore wells (P.J. Gunn, personal communication, 1995). The gas recovered from the Enga Sandstone (Langfield Group) at Weaber 1 (McKirdy in Garside, 1983) may have been generated off-structure from exinitic and vitrinitic kerogens of the Milligans Formation.

Lavering (1989) stated that oil-prone organic matter is present in the Milligans Formation in areas near the basin margin, and away from the basin margins the Milligans Formation is mainly gas prone.

The Tanmurra Formation also may have some source potential recognised by Dr Clinton Foster (personal communication, 1994) in the Turtle 1 and 2 wells .

Reservoir

Carbonates within the Tanmurra Formation may have fracture porosity, and some secondary porosity associated with ooid shoals is possible. In Keep River 1, the Tanmurra Formation is a good reservoir (Caye, 1959) with little cementation or matrix reported from the sandstone. Core porosities range from 1.4 to 17.5% with patchy development of up to 285 mD of permeability. Permeability is more consistent in the lower part of the formation (Core 2) with 35 to 145 mD measured, and a porosity range of 11.6 to 16.6%. Better porosity is also reported from cuttings in the lower Tanmurra at Weaber 1 (Garside, 1983) where cuttings have fair to good visual porosity compared to tight to fair in the upper part. The same phenomenon occurs at Weaber 2A (Turner and Badcock, 1989), although some good inferred porosity occurs at shallow depth, possibly due to decalcification of cement.

The Tanmurra Formation at Kulshill 1 (Duchemin et al., 1966) has 2-3% core derived porosity and very low permeability's. Log derived porosity values range from 5-7% over the same interval.

Sandstone intervals within the Weaber Group are rare, but thick developments sometimes occur. A good example is the Waggon Creek Sandstone at Keep River 1. This sandstone is a multiphase unit and may have developed in channels cut during sea level falls such as the Waggon Creek channel (Petroconsultants, 1990). Such turbidite sands, including basin-floor fans and related slope fan features, may have developed during the complex structural history of the Weaber Group. A variety of plays, associated with halokinesis slumping, doming and syndepositional structuring (Gunn and Ly, 1989), combined with sea level fluctuations, provide several potential reservoir targets potentially encased in Milligans Formation source beds (Petroconsultants, 1990).

In Bonaparte 2, 43m of net sandstone was penetrated in the "Bonaparte" (Milligans) Formation between 1384 m and 1970 m (Laws, 1981). The sandstones are fine to occasionally very coarse grained and reported to be of poor to fair porosity. One core analysis at 1387 m gave a porosity of 16 percent and a permeability of 16 mD (Le Blanc, 1965), while porosities derived from the sonic log ranged from 16 percent down to 9 percent. At Keep River 1 this interval is tight but numerous shows of gas were present (Caye, 1969).

Shallow core hole data from the Milligans Formation along the basin margin indicate a considerable increase in porosity and sandstone percentage occurs in these areas. Porosity's of 25 percent, and permeability's of 500 mD, have been measured in these core holes. Thus, reservoir quality can be expected to be better developed to the south where sediments are coarser grained and at shallower depths of burial (Petroconsultants, 1990).

At Weaber 1, the basal sand of the 'lower" Milligans Formation (13.0 sand) has generally tight to fair porosity in cuttings (Garside, 1983) but flowed gas on drillstem test. However, at Weaber 2A, the same interval was tight due to carbonate cementation (Turner and Badcock, 1989). This was also the case at Keep River 1 (Caye, 1959).

The basal sandstones of the Weaber Group at Kulshill 1 (Duchemin et al., 1966) are tight with porosity's less than 50% and permeability's below 0.1 mD. The best reservoir interval (3328 - 3362 m) has up to 6% porosity but is tight due to silicification resulting in interlocking quartz grains. Poikilitic dolomitic cements further reduced porosity. Feldspathic sands are rare and potential secondary porosity developments at this level are discounted.

The middle Weaber Group Waggon Creek Formation lowstand deposits also have reservoir potential. At Weaber 1 visual porosity was described as good (Garside, 1983) but no porosity was described from cuttings in the correlative section at Weaber 2A (Turner and Badcock, 1989). At Keep River 1 these sands are tight due to calcareous cementation (Caye, 1969). Fractures in similar calcareous sandstones higher in the Waggon Creek Formation in this well produced 15.5 m^3 of slightly fluorescent water (Caye, 1959). The upper Waggon Creek Formation at Keep River 1 is tight due to silica cement. Gas shows in the interval are probably due to fractures.

The basal Waggon Creek sandstones are tight due to silicification and/or calcite cementation at Kulshill 1 (Duchemin et al., 1966). Minor ferruginous cement and clay matrix also downgrade the reservoir potential, but the presence of labile potassium feldspar grains suggest the potential for secondary porosity development under suitable conditions. In the "upper" Milligans Formation of this well, the hard dolomitic limestones have measured 1-2% core porosities and only fracture permeability (Petroconsultants, 1990).

Oil shows were reported in the Milligans Formation at Turtle 2 . The well kicked at 2635 m in this formation with the influx of gas and minor oil. Subsequently, two drillstem tests recovered oil from this zone indicating porosity and permeability is possible in this formation at depth.

TIME SLICE Crb4 - LATE VISEAN to NAMURIAN

SUMMARY (Enclosure 16 and 35)

This time slice contains marine paralic/estuarine and alluvial deposition roughly corresponding to a narrower version of the modern Joseph Bonaparte Gulf. Offshore bars and fringing shallow marine were present south of the Barnett and Turtle areas. The Point Springs sandstone deposited at this time, is arguably the oldest reliable reservoir unit in the Petrel Sub-basin.

PALAEOGEOGRAPHIC INTERPRETATION

The Point Spring Sandstone (Traves, 1955) consists of sandstone and pebbly sandstone with minor amounts of conglomerate and siltstone (Mory and Beere, 1988). Veevers and Roberts (1968) designated the type section 6 km east-northeast of Point Spring, below conglomerate of the 'Border Creek Formation' Mory and Beere (1988) recognised the lenticular; interfingering relationship of the conglomerate, and assigned it member status in the Point Spring Sandstone. The member is restricted to onshore sections and is not described here.

In the subsurface, the top of the Point Spring Sandstone corresponds to an abrupt change in lithology from shale to sandstone which appears to coincide with the top of the *S. ybertii* Assemblage. So defined, the lower part of the 'Kulshill Formation' of Duchemin et al. (1966) and Hughes (1978) belongs within the Point Spring Sandstone. In Kulshill 1, the interval here identified as the Point Spring Sandstone also includes a section which Duchemin et al. (1966) assigned to the Tanmurra Formation and 'Milligans Beds'. Correlation of the Point Spring Sandstone in Kulshill 1 with other wells is hindered by, the lack of good onshore seismic data, and by the electric-log response in this well, which appears to have been affected by radioactive elements.

In outcrop, the Point Spring Sandstone consists of sandstone, pebbly sandstone, and minor amounts of siltstone, arranged in fining- and coarsening-up cycles generally less than 20 m thick. In the subsurface, the unit contains considerably more shale and includes minor amounts of calcareous sandstone and limestone, in fining-up cycles up to 70 m thick. Correlation of these cycles between wells is difficult, presumably due to relatively rapid phase changes. Prograding clinoforms are evident on the AGSO deep seismic lines running down the axis of the basin.

The Point Spring Sandstone conformably overlies the Tanmurra Formation in the subsurface and the Burvill Formation in outcrop. Laterally the unit is equivalent, in part, to the Burvill Formation and Tanmurra Formation.

The Point Spring Sandstone is exposed in an arcuate belt between Weaber Range and Utting. In this belt the unit is 180 to 380 m thick (Mory and Beere, 1988). In the subsurface the unit has been intersected as far north as Lesueur 1 and generally ranges in thickness from 187 to 385 m, in Kulshill 1, however, the unit is 876 m thick.

In outcrop, the Point Spring Sandstone contains a diverse fauna and flora of which only the brachiopods have been fully described (Thomas, 1962; Roberts, 1971). Two distinct brachiopod faunas, from the base and top of the formation, indicate a late Visean to Namurian age. In Kulshill 1, brachiopods, ostracods, conodonts, and foraminifers from the interval between cores 21 and 23 (1880 - 2044 m) also indicate a late Visean to Namurian age for the unit. In other petroleum exploration wells, the palynomorph assemblages *G. maculosa* and *S. ybertii* have been identified in this unit. The ages of these assemblages are based on faunal determinations in Kulshill 1.

In the onshore sections the Point Spring Sandstone was deposited in shoreface, fluvial, distributary mouth, and crevasse environments on a delta plain. Consequently the thick shale sections present in the offshore sections probably represent prodeltaic to distal distributary deposits.

PROSPECTIVITY

Moderate prospectivity. The reservoir facies of the Point Springs Sandstone are well placed to receive a hydrocarbon charge, as they overlie the source beds of the Milligans and the Tanmurra formations. However, regional seals were not in place until the Permian, after the main phase of generation in the Carboniferous (Figure 23a), hence the timing of hydrocarbon migration and seal emplacement needs to be carefully weighed for any time slice Crb4 prospects.

Hydrocarbon shows

Oil shows occurred in the Point Spring Sandstone at Turtle 1 (Jefferies, 1988), although these were not tested. In Barnett 1 oil was recovered from a repeat formation test between 2095.5 and 2036 m at the top of the Point Spring Sandstone, and several gas peaks occurred between 2195 m to 2245 m. There were oil indications at Kulshill 1 and Pelican Island 1.

Source Rock

Some source potential may be present in the fine grained marine units that interdigitate with the lower part of the Point Springs Sandstone. Appendix 6 indicates that no source rock quality sediments have been sampled in this time interval.

Reservoir

The Point Spring Sandstone at Kulshill 1 contains generally argillaceous or calcareous sandstones with free oil reported (Duchemin et al., 1966). Silicification is generally poorly developed. Reservoir quality sandstones occur between 2012 and 2044 m with an average 25% porosity estimated from sonic and neutron logs, and cores, with permeability's up to 20 mD. Despite the apparent low permeability, FIT 1 (2015 m) and DST 4 (2008-2045 m) produced good flows of gas cut salt water. An upper reservoir, between 1864 to 2012 m and consisting of sandstone interbedded with shale, has sonic log-derived porosities of 10-15%, but drillstem testing (DST 5) showed the interval to be tight. The sandstones are generally very fine with variable amounts of clay matrix and calcareous cement. Only minor silicification is present. Oil was noted in non-reservoir lithology's between 1859 m and 1890 m in this well.

The Point Spring Sandstone in Kulshill 2 contains several reservoir sands. Although the sandstones of this interval are fine grained and commonly interbedded with shales and siltstones, they are moderately porous and permeable (Creevey, 1966). Core porosity's range up to 20% but permeability's are generally lower than 3.7 mD. However, a good flow of salt water was obtained from DST 3 (1660 m - 1680 m). As noted by Creevey (1966), the salinity of the water recovered from this DST (14178 ppm NaCl equivalent) is in strong contrast to the 40 970 ppm measured for water from DST 4 at the equivalent level in Kulshill 1. These disparate salinity results indicate a probable fault barrier between the reservoir in the two Kulshill wells. Seismic data used to define the local structure is poor quality and probably amenable to reprocessing and reinterpretation.

Porosity and permeability in this formation is also present in offshore wells. The Point Spring Sandstone had oil shows in the Turtle 1 well (Jefferies, 1988). In the Lacrosse 1 well, this section is very fine grained, grading to very coarse quartz sandstones, in part calcareous, and interbedded with siltstones and shales. The lower portion of the section contained sandstones that showed 9 - 12% sonic log-derived porosities, with an upper sandstone displaying up to 20% porosity.

TIME SLICE Crb5 to Crb6 - NAMURIAN to STEPHANIAN

SUMMARY (Enclosure 17 and 36)

Paralic conditions prevailed in the late Carboniferous of the southern Petrel Sub-basin with deeper marine conditions interpreted offshore where thicker but undrilled deposits can be interpreted from seismic data. Fans and barrier bars fringed the southern basin with uplift and erosion of older basin strata in the modern onshore areas.

PALAEOGEOGRAPHIC INTERPRETATION

This time slice comprises the upper part of the Point Springs Sandstone described above and the Kuriyippi Formation.

Kuriyippi Formation (Pre-glacials)

Over 1500 m of Kulshill Group sediments are recognised in Kulshill 1 (Mory, 1988), which is the type section for the Kulshill Group and some of the constituent formations. According to Mory (1988), deposition commenced with a glacial to fluvial, coarse siliciclastic phase (Kuriyippi Formation). Recurring glacigene conditions led to the deposition of lacustrine to estuarine shales (Treachery Shale).

Lee and Gunn (1988) inferred a depocentre that contains up to 7000 m of Kulshill Group rocks in the middle of the Petrel Sub-basin, but the reported thickness may include parts of the underlying Weaber Group (Mory, 1988). As indicated at the Moyle 1 and Berkley 1 well locations, the upper part of the Kulshill Group transgressed the basin margin faults.

Mory (1988) defined the Kuriyippi Formation as a lower series of upwards fining, thick, clean sandstone overlain variously by siltstone, sandstone, pebbly sandstone, conglomerate and tillite.

The upper section is characterised by relatively higher gamma ray counts than the lower part of the formation (Mory, 1988, his Figure 16). This higher radioactivity is presumably caused by the igneous pebbles, mica and feldspar contained in sediments deposited in areas proximal to the Precambrian provenance areas. This log character is not consistent away from the Kulshill 1 area (see also Figure 3 in Lee and Gunn, 1988).

Mory (1988) suggested that the Kuriyippi Formation was deposited initially by fluvial processes (that is the upwards fining cycles present in the type section at Lesueur 1) succeeded by a glacial sequence. However, in Kulshill 1 at least five grossly upwards coarsening cycles are present from the gamma ray and sonic log profiles (Petroconsultants, 1990) and occasional glauconite is reported from cores (Duchemin et al., 1966). Fisher and Associates (1987) suggested periglacial-marginal marine - tide dominated transgressive sequences. However, the presence of varves and plant fossils in cores, and the lack of definitive marine indicators in the numerous palynological preparations (Duchemin et al. 1966; Kemp et al., 1977) argue for a non-marine environment. Furthermore, in the Kinmore 1 well, boron concentrations in the Kuriyippi Formation are consistently very low and glauconite is very rare to absent (Laws and Clerc, 1974). No marine organisms are present in palynological preparations. All of this evidence points to a non-marine depositional environment

The upper Kuriyippi Formation at Kulshill 1 consists of a series of upwards coarsening cycles. Depositional indicators include common glauconite in some cores, and brackish water algae (*Botryococcus* sp) in the lower part, and coaly laminae in the upper part with no associated glauconite. The sandstones are often calcitic compared to the lower part of the formation where calcareous cement is rare (Duchemin et al., 1966). Fisher and Associates (1987) ascribed a "regressive sub-tidal, fluvial-deltaic - glacial origin" to these sandstones. Petroconsultants (1990) considered some marine influence was present during deposition.

Laws and Clerc (1974, p13) interpreted deposition of the Kuriyippi Formation to have taken place "largely in a high energy, near shore environment, including sands from beach, barrier bar and related environments, grading up to channel and natural levee deposits". An overall marine regression was interpreted throughout this sequence. Lee and Gunn (1988) suggested that the upper Kuriyippi sediments are "glacigene clastics resulting from a major glacial event associated with an eustatic lowering of sea level". Thus, they thought deposition of the uppermost Kuriyippi Formation to be a result of increased glaciation (lowered sea levels).

The upper Kuriyippi section thins offshore, and while the boundary with the overlying Treachery Shale is said to be gradational at Kinmore 1 (Laws and Clerc, 1974), a possible unconformity appears to be present below the Treachery Shale at Barnett 1. A clear unconformity is present in Lesueur 1 at 1940 m below thick pebbly diamictite.

The formation contains the *D. birkheadensis* and *G. confluens* palynological zones, indicating a Stephanian to Asselian age.

PROSPECTIVITY

Moderate prospectivity. There is the development of some reservoir and source facies within the Crb5-6 time slice interval, and the results of the Turtle and Barnett wells show that migration from the underlying Milligans source rock has occurred. Intraformational seals are required to trap hydrocarbons at this level, as the overlying diamictite is also a reservoir facies and the top of porosity under early Permian Treachery Shale which provides a seal of limited areal extent.

Hydrocarbon shows

The Crb 5-6 time slice interval contains oil indications in many wells within the Petrel Sub-basin - Barnett 1, Cambridge 1, Kimnore 1, Lesueur 1, Lacrosse 1, Kulshill 1, Turtle 1 and 2.

Source Rock

HI and TOC values mapped for this time interval in Appendix 6 show some good quality source rock, mostly associated with paralic environments landward of a barrier bar system. Coaly beds within the non-marine Kuriyippi at Kulshill 1 contain up to 22% TOC with mixed oil and gas generative ability, (Analabs, 1985), suggesting that the Kuriyippi itself may be the source for at least some of these shows (cf. Jefferies, 1988).

HI data indicate good oil potential source beds at current maturation states in coals within the Kuriyippi Formation at Cambridge 1, Barnett 2, Bougainville 1 and Kinmore 1.

Reservoir

The lower Kuriyippi Formation in Kulshill 1 has an average sonic log derived porosity of 10%, but core porosities up to 15% have been measured (Duchemin et al., 1966). All the potential sandstone reservoirs are partly silicified and permeability is generally low. The best reservoir was tested by DST 2 (1444 m - 1463 m) and produced a good flow of salt water. Core 15 cut at this level had porosity's of 15.9% and permeability's from 100 mD to one Darcy. In Kulshill 2 (Creevey, 1966), DST 1 (1269- 1284 m) produced a moderate flow of salty water from this interval, indicating permeability.

In Kinmore 1 (Laws and Clerc, 1974) average log-derived porosity in the lower part of the Kuriyippi Formation is 6.5% for a net 29 m of reservoir, defined by zones of filter cake build-up and microlog separation. No tests were run

In the Turtle and Barnett wells the lower Kuriyippi Formation exhibited poor reservoir development. The structural setting of Turtle 1 and Barnett 2 are shown in Figures 28 and 29.

TIME SLICE P1 - ASSELIAN to SAKMARIAN

SUMMARY (Enclosure 18 and 37)

This interval comprises the glacial epoch in the Petrel Sub-basin. Ice caps are envisaged in the highlands to the south with glaciers and meltwater deposition extending into the basin. Proximal deposits of diamictite (oil reservoir in Barnett 2) are believed to grade basinward into fine grained estuarine and marine shales (seal and possible source facies). The extent of glaciation and its suggested influence on the Petrel Sub-basin are illustrated in Figure 30.

PALAEOGEOGRAPHIC INTERPRETATION

The AGSO regional seismic lines show that the **Treachery Shale** and **diamictite** lag (in Lesueur 1) are a package of limited aerial extent located mostly within the central offshore Petrel Sub-basin. Sometimes a distinctive diamictite lag is present such as at Lesueur 1, however the equivalent unit at Turtle and Barnett is a sandstone.

Mory (1991) defined the Treachery Shale as consisting of carbonaceous shale with tillite. The unit was named after Treachery Bay southwest of Port Keats. The type section is the interval 1094-1227 m in Kulshill 1. Intersections of the Treachery Shale range from 51 to 219 m thick and the unit is present in the southern Petrel Sub-basin, and on the Lacrosse Terrace and Plover Shelf. The Treachery Shale can be recognised on logs by a distinctive interval of monotonous high gamma ray values overlying the Kuriyippi Formation.

The Treachery Shale consists predominantly of carbonaceous, argillaceous, tillitic and varved siltstone. Claystone and minor amounts of sandstone are also present. In Kulshill 1, the Treachery Shale was described as dominantly tillite (1094 to 1227 m) consisting of

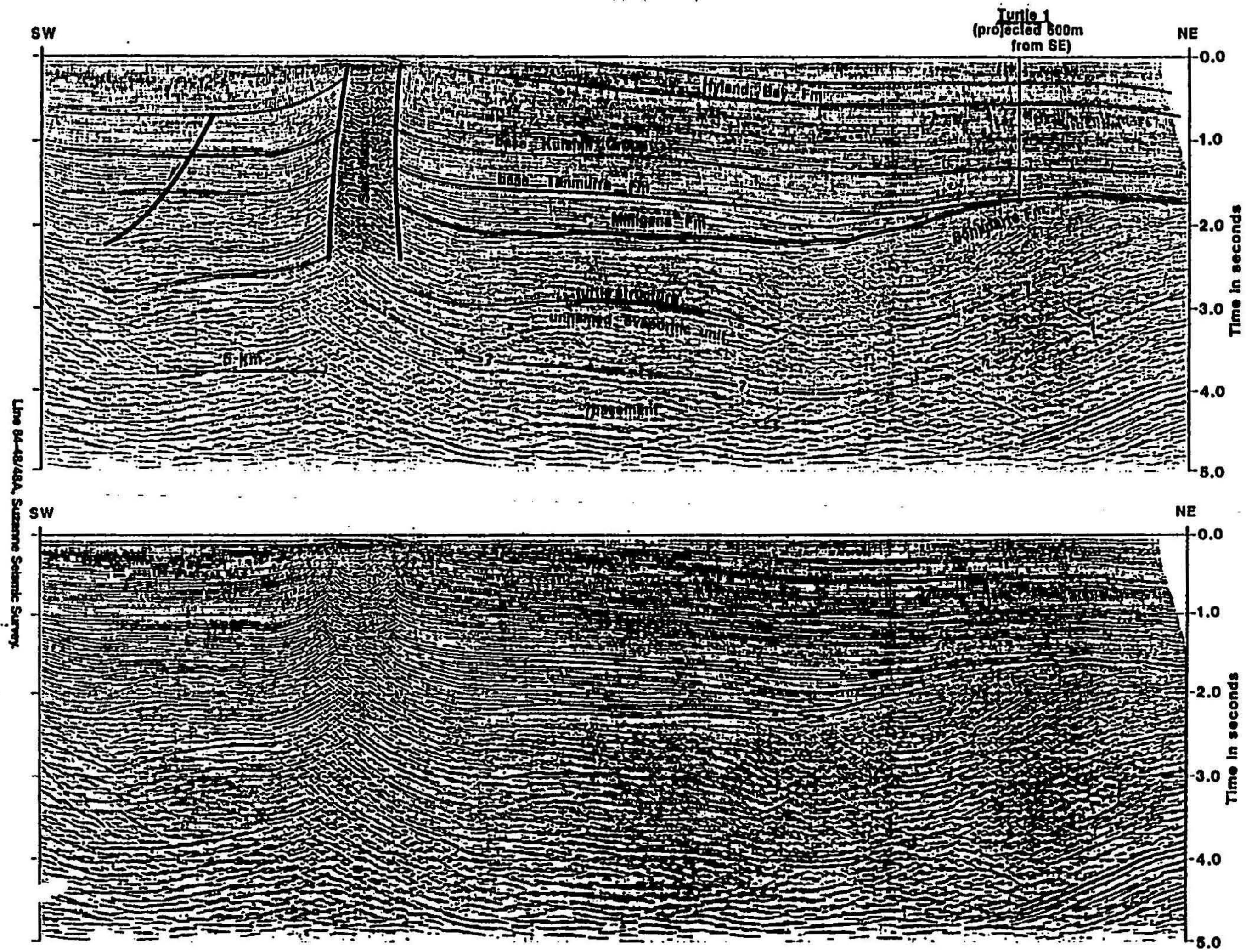


Figure 28 Seismic section 84-48/48A through the Turtle 1 structure (From Mory, 1991)

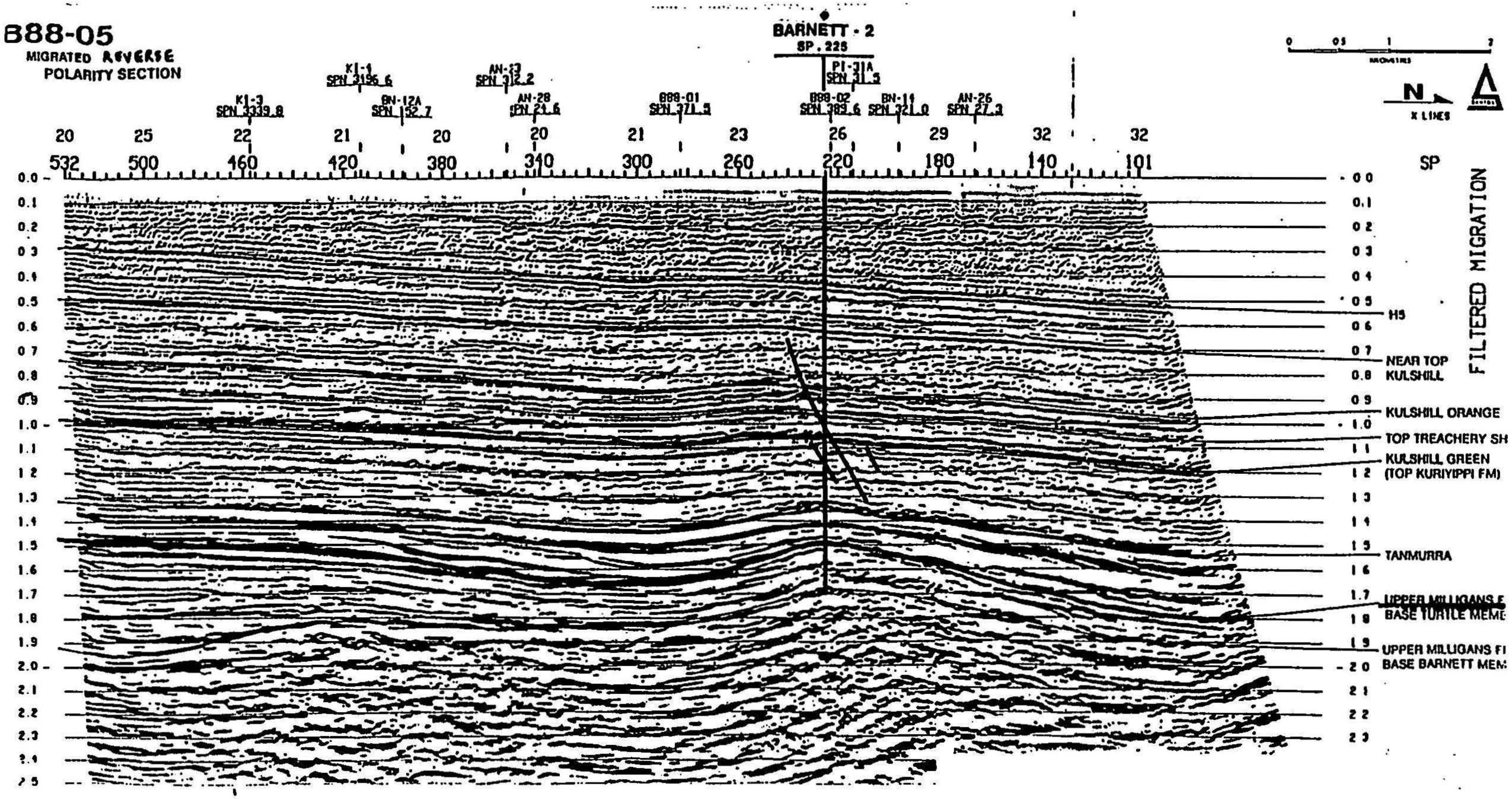
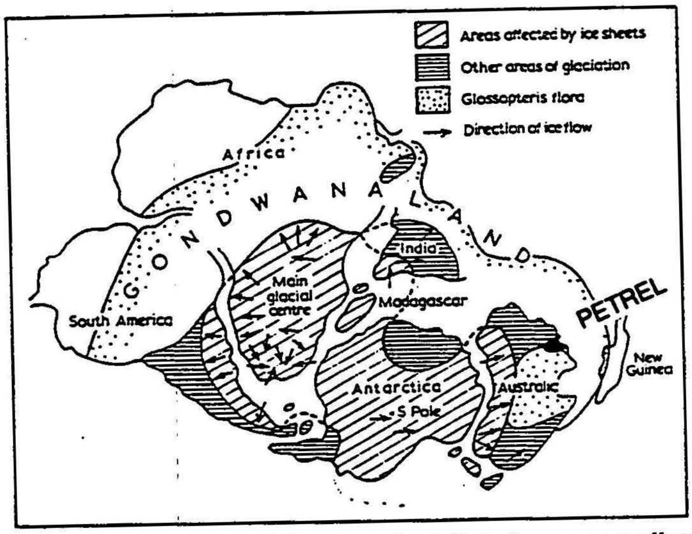
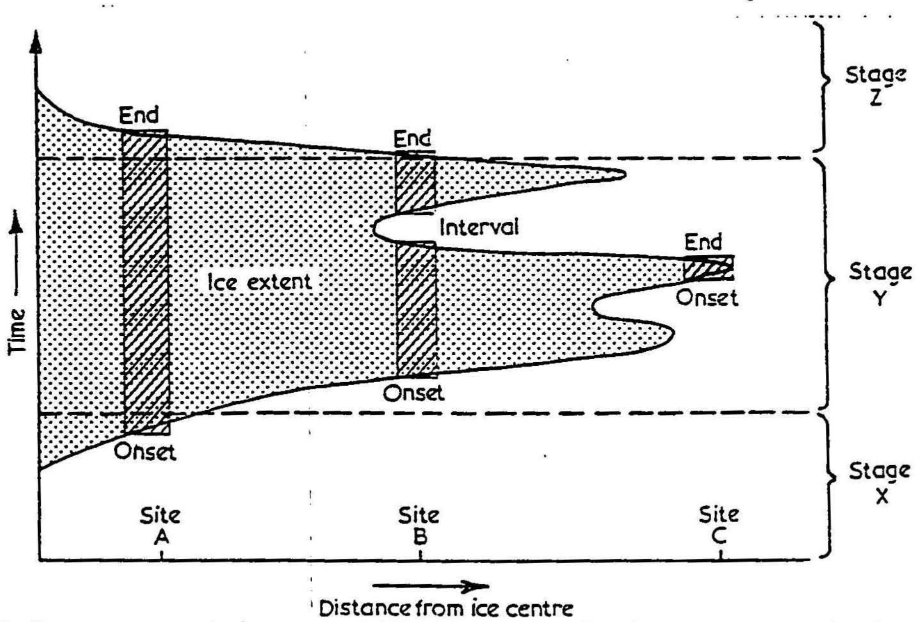


Figure 29 Seismic section B88-05 through the Barnett 2 well (From Faehrmann, 1990)



The Permo-Carboniferous glaciation of Gondwanaland. Not all areas were affected by glaciers at the same time; in general, South America and southern Africa were affected earliest, and eastern Antarctica and Australia latest. Within the area of *Glossopteris* flora many regions were intermittently submerged by the sea.



Idealized diagram to show how the divisions of geologic-climatic stratigraphy are related to time. At site A the first glacial deposits are laid down during stage X, and there is continuous glaciation for a great length of time. At site B the onset of glaciation is later, and there is an interval between two glacial 'stadia'. At site C glacial deposits are laid down during a very brief period in the middle of stage Y.

Figure 30 Glaciation in the Permo-Carboniferous of Gondwanaland and its influence on the Petrel Sub-basin (From John, 1979) "common angular to subangular quartz grains and polygenic rock fragments up to five inches (12.5 cm) diameter, occasionally faceted or striated in an argillaceous or shaly matrix. The rock fragments are mainly quartz and andesite or dolerite with few sedimentary and metamorphic rocks Shales and siltstones are slightly micaceous and pyritic" and "pure shales are commonly varved". The sandstones are "fine with common larger angular grains and small rounded pebbles, feldspathic, common lithic fragments" (Duchemin et al., 1966, p26).

The Treachery Shale at Moyle 1 (Brophy, 1966) is also tillitic, with about 10% granular or pebbly grains distributed throughout a silty mudstone matrix. A lagoonal or lacustrine depositional environment is suggested by the presence of *Botryococcus* algae and rare Tasmanitid acritarchs. Varves are present in cores, with faceted and striated rafted pebbles to 8x3 cm in disturbed, laminated finer clastics.

In Kinmore 1 the Treachery Shale is less clearly defined than in wells to the southeast, but has been here placed between about 2118 and 2235 m, in a section displaying the characteristic high gamma ray values with an uncharacteristic sand sequence in the middle. Boron values are extremely low (less than 40 ppm) in this section suggesting a fresh water depositional environment, although very rare glauconite is reported from sidewall cores.

It is clear from these descriptions that the name Treachery Shale is in many instances a misnomer; the high gamma values characteristic of the unit are probably more related to the high component of exotic rock components, including feldspars and micas.

AGSO regional seismic data analysis indicates the Treachery Shale/diamictite package commonly unconformably overlies the Kuriyippi Formation, especially in the vicinity of Barnett 1 and Turtle 1. Lee and Gunn (1988, their Figure 3) indicated an unconformable relationship with the Kuriyippi Formation at Lesueur 1, Cambridge 1 and Lacrosse 1, and probably at the Tern Field. An unconformable contact over a veneer of Kuriyippi Formation is also suggested by these authors at Moyle 1. A dipmeter determined unconformity is present below the Treachery Shale at Kulshill 1 (Brophy, 1966) where it separates "true...tillite from the underlying microconglomeratic shale" (p 22). Thus, the base of the Treachery Shale is unconformable on the basin margins and over the central domed province (Barnett area) in the Petrel Sub-basin becoming conformable in the vicinity of the Petrel Gas Field prior to reaching a pinchout further northwest. The base of the unit corresponds to a Type 1 sequence boundary in the terminology of Van Wagoner et al. (1987).

Microfloras of the *G. confluens* Oppel-zone (Foster and Waterhouse, 1988) are present throughout the Treachery Shale, but also range in to the enclosing formations. Marine macrofaunas associated with this zone in the Canning Basin are of early Permian (Asselian) age (Foster and Waterhouse, 1988). Because of the lack of marine faunas and the presence of well developed palynomorph assemblages, Mory (1991) interpreted the unit to have been formed as glacial outwash in lacustrine or estuarine environments following the retreat of ice sheets on the surrounding Kimberley and Sturt blocks similar to the environments reported for the Canning Basin (Goldstein and Hubbard, 1984; Redfern and Millward, 1994, Figure 31).

PROSPECTIVITY

Moderate prospectivity. The P1 time slice contains the reservoir and seal couplet of the diamictite and Treachery Shale. In Barnett 2 the diamictite produced the best oil flow from the Petrel Sub-basin. This unit has reasonable quality reservoir, has access to hydrocarbons generated in the underlying Carboniferous section, and is sealed by the overlying Treachery Shale. The seal is of limited areal extent and has been breached in structures such as Turtle (Figure 28).

Hydrocarbon shows

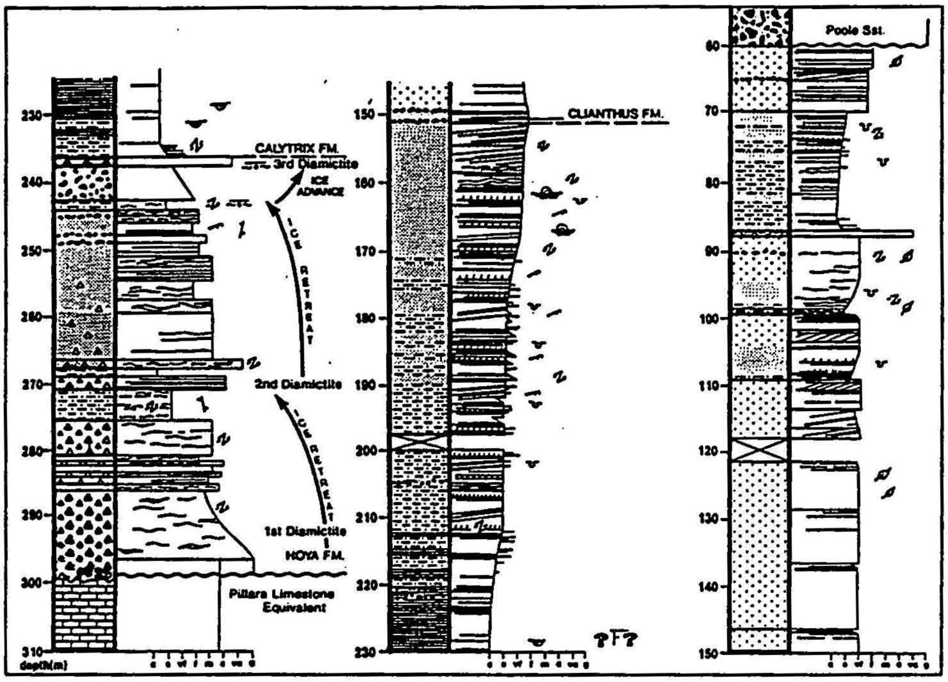
In Barnett 2 flowed 917 BOPD from the P1 diamictite, and 32.7 bbls of oil were recovered from Turtle 1. Oil indications were reported Turtle 2 and Cambridge 1.

Source Rock

HI and TOC values mapped for the P1 interval in Appendix 6 show some good quality source rock, mostly associated with estuarine environments. Notable is Flat Top 1 with a maximum HI value of 269 and a maximum TOC of 35.5 %.

Reservoir

The diamictite can be considered the top of porosity for the Carboniferous and early Permian sequence, the uppermost reservoir in the sand prone section between the Milligans Formation and the sealing Treachery Shale. In Kinmore 1 (Laws and Clerc, 1974) up to 15% porosity was calculated in the P1 interval.



Typical facies log from the Upper Grant Group on the Barbwire Terrace. Well Pratia – 1 (WMC).

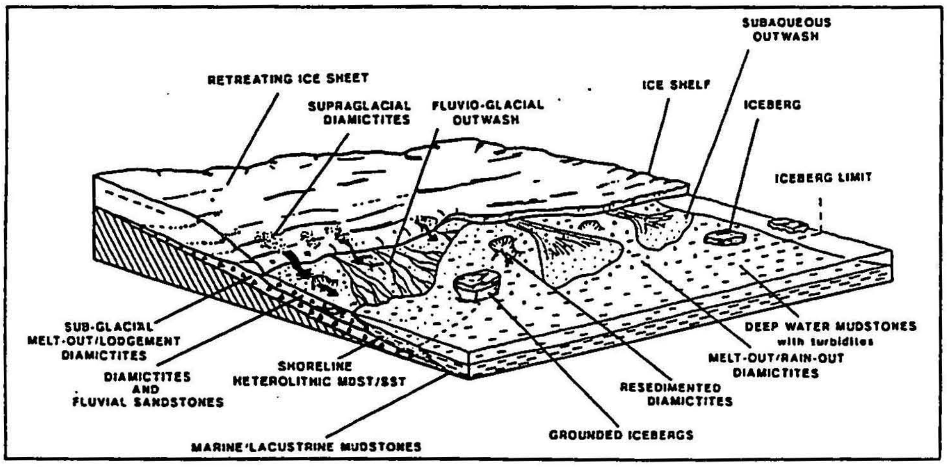


Figure 31 Log facies and depositional models for glaciogenic sediments and rocks in the Canning Basin (From Redfern and Millward, 1994)

A fair sandstone reservoir was encountered between 1227 and 1237 m in Kulshill 1 (Duchemin et al., 1966). Core 13 from this interval had oil impregnations over 15 cm and porosity ranging from 4.9 to 19.1% with permeability's of 0.02 to 113 mD. However, these values, while moderate, were considered by the well operator to be too low and variable to give possible oil production. Furthermore, DST 1 (1215 to 1233.5 m) gave no flow. Calculated formation fluid salinities of 6000 ppm NaC1 equivalent suggest only residual oil saturation.

Potential flushing by meteoric waters of shallow reservoirs is of concern, however, the discontinuous nature of the sediments may have left unflushed sands effectively sealed by intraformational shales. On the other hand, the 5.2 m³ (32.7 bbls) of oil recovered from Turtle 1 was reportedly biodegraded (Jefferies, 1988). This particular reservoir sandstone exhibits up to 20% neutron density log calculated porosity. Bacteria were presumably introduced by percolating groundwaters.

The highest oil flow reported from the basin to date was 921 BOPD from the diamictite in the Barnett 2 well.

TIME SLICE P2 to P4 - ARTINSKIAN to KUNGURIAN

SUMMARY (Enclosure 19 and 38)

Initially, deltaic and shallow marine deposition (Keyling Formation) held sway in the Petrel Sub-basin. Later, with increasing marine influence the shoreline shifted landward and thin reefal limestones and abundant fine grained rocks (Fossil Head Formation) were deposited in a broad marine embayment. Emergent land surrounded the basin and thick marine deposits accumulated in the site of the old rift basin axis. Good quality source rock facies were deposited during the P2 to P4 interval and sandstones of this age are gas reservoirs in Penguin 1.

PALAEOGEOGRAPHIC INTERPRETATION

Mory (1991) defined the **Keyling Formation** as a predominantly siliciclastic sequence with minor amounts of coal and limestone at the top of the Kulshill Group. The name is from Keyling Inlet in southeastern Joseph Bonaparte Gulf. The type section is the interval from 254 to 1094 m in Kulshill 1. The formation is approximately equivalent to the 'Greywacke Member' of Duchemin et al. (1966) and Hughes (1978). In Kulshill 1 the

'Sandstone member' of Duchemin et al. (1966) informal 'Sugarloaf Formation' is included in the Keyling Formation. The presence of Stage 3 palynomorphs suggests that the 'Kulshill Formation' in drillhole NTGS 82147 at Anson Bay probably belongs to the Keyling Formation (Mory, 1991).

The Keyling Formation consists largely of interbedded sandstone and siltstone with upward-fining, and lesser upward-coarsening, cycles in the lower half of the formation. Minor amounts of coal and limestone are also present.

The Keyling Formation conformably overlies the Treachery Shale. Onshore, coeval rocks in drillhole NTGS 82147 disconformably overlie granitic basement. The Keyling Formation is known in the southern Petrel Sub-basin south from Tern 1, and on the Lacrosse Terrace and Plover Shelf. It ranges in thickness from 19 to 1017 m; the thinnest sections are in Berkley 1 and Moyle 1 on the southwest and northeast basin margins respectively (both 19 m).

The presence of coal lenses and *Botryococcus* algae are indicative of a lagoonal to lacustrine origin for the middle part at Kulshill 1 (Duchemin et al., 1966). Chamositic ooids noted within the middle part of the unit at Kulshill 1 (Duchemin et al., 1966) are suggestive of shallow brackish water to nearshore marine conditions (Core 5). Lee and Gunn (1988) indicated a marginal marine depositional environment and Mory (1988) postulated a fluvio-deltaic setting in a post-glacial climate. Laws and Clerc (1974) interpreted a transgressive marine depositional environment at Kinmore 1.

The presence of minor amounts of limestone throughout this unit (especially in Barnett 1), and coaly horizons, suggest the Keyling Formation was deposited in a paralic to marginal marine environment. Mory (1991) suggested that an upward increase in fauna in both Kulshill 1 and Lesueur 1 indicates increasing marine influence towards the top of the formation. Regional correlations within the upper part of the Keyling Formation are difficult to make as regional seismic events appear to have been masked by facies changes as deltaic environments replace fluvial environments.

The Keyling Formation contains microfloras of the *G. confluens* Oppel-zone and Stage 3a that indicate an Asselian to Sakmarian age. In Cambridge 1, Stage 3b palynomorphs are also present in the top two metres of this unit. In Lesueur 1 the entire Stage 3b appears to be represented in the Keyling Formation based on the lower *G. trisinus* Zone of Helby *(in* Lane, 1981). The fauna present in this formation appears to be impoverished. However;

appraisals of the microfauna have been made only in the early wells drilled in the basin, such as Kulshill 1 and Lacrosse 1.

Stratigraphically overlying the Kulshill Group, the **Fossil Head Formation** covered the Petrel Sub-basin with silty, carbonaceous shales. The basal beds unconformably overlie the Kulshill Group at Tern 1, Lacrosse 1, Kulshill 1 and Kinmore 1. AGSO regional seismic data indicates a more conformable relationship outboard of the Petrel Gas Field. Seismic profiles in the vicinity of the Petrel Field show no evidence of an angular relationship between the Fossil Head and Keyling Formation. Lee and Gunn (1988) also indicated that the base of the Fossil Head Formation is confomable upon the Kulshill Group with no evidence of unconformity.

The Fossil Head Formation is some 575 m thick at the Tern 1 well and thins onto the basin margin areas, as at Kulshill 1, where about 200 m is preserved below the Tertiary weathering profile. Palynological evidence suggest that the Fossil Head Formation is equivalent, in part, to the upper part of the Keyling Formation (Mory, 1991).

Mory (1991) noted that although the name of the Fossil Head Formation comes from Fossil Head, the contained macrofauna suggested that the sequence at that locality 'Fossil Head Sandstones' of Brown (1895) was probably equivalent to the lower part of the Hyland Bay Formation. The Fossil Head Formation, as defined by Mory (1991), is equivalent to the 'Shale member' of Duchemin et al. (1966) informal 'Sugarloaf Formation'. Subsequent workers associated the name Fossil Head Formation with the sequence of carbonaceous siltstone and mudstone with sandstone and minor limestone which underlies the Hyland Bay Formation in the subsurface (e.g. Laws and Brown, 1976). This definition is currently used. The type section is the interval from 2993 to 3569 m in Tern 1 (Mory 1988). Although Hughes (1978) described the enclosing formations, he did not mention this unit. This omission was probably due to his miscorrelation of the basal limestone in Flat Top 1 (the only well from his study in which the Fossil Head Formation is present) with the Pearce Member of the Hyland Bay Formation. Although the basal shales of the Hyland Bay Formation are similar to those of the Fossil Head Formation, the top of the formation is generally marked by a small disconformity, or a 10 to 15 m thick limestone, at the base of the overlying Hyland Bay Formation.

The Fossil Head Formation consists of grey to black siltstone and sandstone with some fossiliferous limestone. Trace quantities of shell fragments, pyrite, chert, and anhydrite occur in the finer grained lithology's. Most occurrences of the Fossil Head Formation are in the southern Petrel Sub-basin, south of Petrel 1, where it varies in thickness from 116 to 590 m. Seven to eight shoaling cycles can be interpreted from the gamma and sonic log patterns at Petrel 2, suggesting minor regressions or stillstands in an overall transgressive regime. Similar cycles are present at Tern 1, but cannot be directly correlated to the Petrel wells on the current data set. In the thinner sections towards the basin margins, shoaling cycles are not readily discernible. The upper part of the Fossil Head Formation is coarser grained in places with discrete sand bodies developed (e.g. Petrel 2).

The Fossil Head Formation contains the stage 3b to upper 4b microfloras indicating Artinskian to Kungarian age. Abundant fossil fragments (including bryozoans, brachiopods, echinoderms, corals, gastropods, and ostracods) have been observed from cuttings, but only the microflora has received systematic attention. In nearly all wells, Stage 3b palynomorph characterised by the presence of *G. trisinus* have been identified throughout the formation. In Lesueur 1, by comparison, Helby *(in* Lane, 1981) identified the *P. sinuosus* and upper *G. trisinus* Zones in this unit. He correlated these zones with upper Stage 4 and lower Stage 4 of Kemp et al. (1977). Similarly Helby (in Chan, 1981) identified the *M. villosa* and *P. sinuosus* Zones (upper Stage 4a and 4b) in Tern 2 from the top of the Fossil Head Formation. Dickins et al. (1972) reported Artinskian age limestones from the Kuriyippi Hills. In Flat Top 1, Mory (1988) noted a basal limestone section in the Fossil Head Formation. In the more basinal wells (eg Tern 1, Petrel 2), the basal beds are dark grey to black shales (silty, micaceous and carbonaceous), interbedded with fine to medium grained well sorted sandstone and siltstone, and biomicritic limestone stringers containing bryozoa and crinoids. Acritarchs are present in the basal beds at Kulshill 1 (Duchemin et al., 1966).

Marine fossils throughout the Fossil Head Formation, and its predominantly shaly character; suggest that deposition took place in marine-shelf conditions away from major clastic input. A marine to estuarine depositional environment for the Fossil Head Formation was proposed by Lee and Gunn (1988). Mory (1991) considered the lower part of the Fossil Head Formation was probably deposited as prodeltaic muds, as the lower part of the unit is coeval with the deltaic Keyling Formation.

Petroconsultants (1990) reported a high amplitude, cross-cutting seismic reflector at Bougainville 1, intersecting the well base at about 1829 m in the Fossil Head Formation, in part corresponding to a 2 m thick high gamma ray interval in an otherwise apparently sandy section. The reflector may indicate a sill, but there is no evidence of igneous rocks from the sidewall core description at this depth, and maturation profiles do not show any perturbations in gradient at this level. (See burial history and thermal modelling for further discussions on Petrel Sub-basin intrusions).

PROSPECTIVITY

Moderate to good prospectivity. Reservoir, source and seal facies all occur within the P2-P4 time slice interval. To date, a gas accumulation has been discovered at Penguin 1 and oil has been recovered from Turtle 1.

Hydrocarbon shows

A trace of oil was recovered in a Repeat Formation Test of an upper Keyling Formation sand in the Turtle 1 well (Jefferies, 1988). There were also oil indications in the P2-P4 interval in Barnett 1, Cambridge 1, Matilda 1 and Turtle 2. The gas flow in Penguin 1 is from upper Fossil Head sandstones, immediately below the basal unnamed shale member of the Hyland Bay Formation, although in Figure 32 (Figure 4 of Bhatia et al., 1984) this sandstone is shown lying at the base of the Basal Member of the Hyland Bay. There are also strong gas indications in Petrel 2 at this level and the original blowout in Petrel 1 was probably in the time slice interval P2-P4.

Source Rock

HI and TOC values mapped for the P2 to P4 interval in Appendix 6 show some excellent quality source rocks in Flat Top 1, Bougainville 1 and Kinmore 1, especially in the lower part of the interval, the Keyling Formation.

The Keyling Formation exhibits a more marine influence than the other formations of the Kulshill Group. The unit contains organic-rich sections in several wells. The organic matter is dominantly humic and associated with coals. TOC values of up to 13.6% were measured at Flat Top 1 (Analabs, 1985) with up to 65.8% recorded at Kinmore 1 (Robertson Research International, 1979). Generally lower values were reported at Kulshill 1 (maximum TOC 4.56%) and Bougainville 1 (maximum TOC 6.12%).

The Fossil Head Formation is not generally regarded as a potential hydrocarbon source despite its partial marine origin and TOC as high as 2.99% at both Bougainville 1 and Kinmore 1 (Robertson Research, 1979). These good source rock richness values occur in the lower part of the formation. Poorer sources are indicated at Kulshill 1 and Petrel 2, where

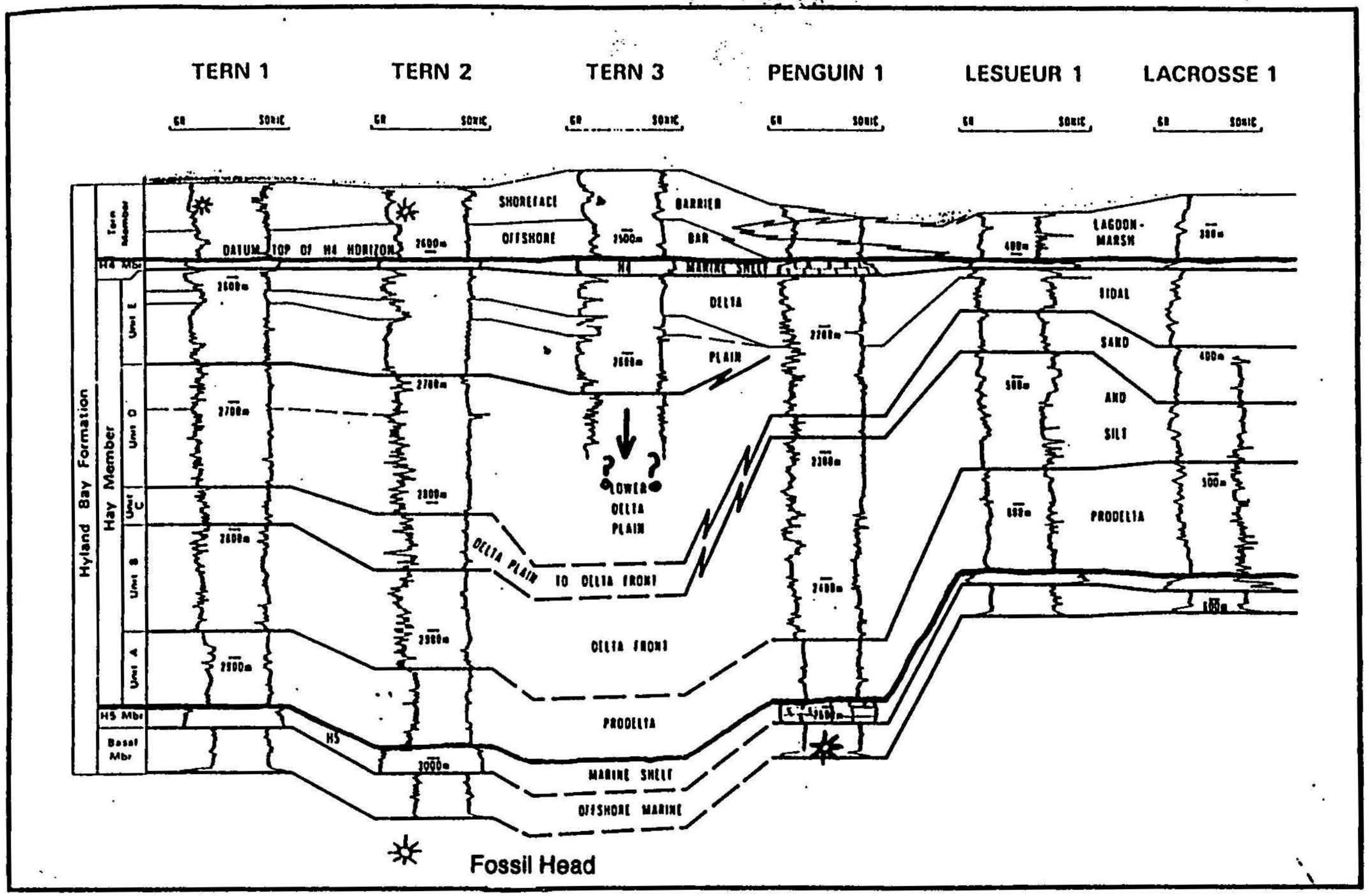


Figure 32 Tern 1 to Lacrosse 1 correlation and facies of the Hyland bay Formation (From Bhatia et al., 1984)

maximum TOC content seldom exceeds 2%. At Flat Top 1, coaly intervals are present in this formation which also contains thick limestone beds. HI data indicate good oil potential source beds at current maturation states lie in the Keyling and Fossil Head Formations at Bougainville 1 and Flat Top 1.

Additional Rock Eval pyrolysis work on Flat Top-1 undertaken as part of the current study indicated good source rock potential in the early Permian section of the well (Table 11).

Reservoir

The Keyling Formation has good to excellent porosity and permeability in Kulshill 1. Porosity up to 38% is present, reducing with depth to about 26% in Core 8 near the base of the formation. Permeability's are variable, however, and appear to be related to the feldspar or argillaceous content of the sandstone, but range up to 900 mD. Over 400 m of reservoir quality sandstone is present in this well. Drillstem testing of the interval (DST 6, 262 m - 315 m) recovered only drilling mud suggesting extensive contamination and invasion by the drilling fluid. Fair to good porosities are also present in the Keyling Formation at Kulshill 2 (Creevey, 1966) and permeability is good due to the general lack of clay matrix.

In Kinmore 1, Laws and Clerc (1974) calculated over 230 m of reservoir with 19% porosity and permeability, indicated by mud cake and micrologs. At Moyle 1, very high visual porosity and permeability estimates were confirmed by cores and logs (Brophy, 1966). The porosity averages 30% in the upper part (Cores 1 and 2) with 2.9 to 180 mD measured, and decreases with depth to an average of 20% (Core 3) at 313 m with permeability varying from 0.03 to 14.8 mD. Log derived porosities of up to 30% have been calculated in this well.

At Bougainville 1, where the Keyling Formation consists of very fine grained sandstones, there is little porosity due to silica cementation and argillaceous matrix. Where the sands are clean, quartz cementation has considerably reduced the permeability. Core 1 from the top of the formation (2380 m), however, has 13.3 to 20.3% porosity and 1.1 to 234 mD permeability indicating fair oil reservoir characteristics. Horizontal permeability is considerably better than vertical permeability in this core.

The uppermost section of the Fossil Head Formation in the middle of the Petrel Sub-basin, in the Penguin 1, Tern 1 and Petrel 2 wells, contains calcareous sandstone and interbeds of hard limestone and grades into very calcareous sequences in certain wells, for example, Flat Top 1. Where thick limestone is developed a coarsening upward stream mouth bar cycle develops usually with good reservoir immediately under the H5 limestone.

AGSO No.	BASIN	INFORMATION	DEPTH	TMAX	S 1	S 2	S 3	P I	S2/S3	PC	TOC	HI	OI
8149	Petrel	Flat Top 1	4830 ft	430	0.07	0.22	0.23	0.24	0.96	0.02	0.68	32	34
8150	Petrel	Flat Top 1	4890 - 5000 ft	435	0.06	0.38	0.15	0.14	2.53	0.04	1.32	29	11
8151	Petrel	Flat Top 1	5450 ft	427	4.07	64.93	4.61	0.06	14.08	5.73	24.42	266	19
8152	Petrel	Flat Top 1	5870 ft	433	0.36	2.49	1.32	0.13	1.89	0.24	2.94	85	45
8153	Petrel	Flat Top 1	6000 ft	432	0.74	6.70	1.40	0.10	4.79	0.62	4.62	145	30

TABLE 11 Geochemical analyses from Flat Top 1 in the Northeast Petrel Sub-basin

This zone produced gas in Penguin 1 and is thought to be the level of the original blowout in Petrel 1. The operator of Penguin 1 commented that the zone is permeable with 8.5 m (28 ft) of net pay, but subcommercial. Sonic log-derived porosity for this sand at the Penguin 1 well was in excess of 30%, with reported horizontal permeability's varying from 0.1 to 18 mD.

Porosities of 22% were calculated for the Fossil Head in Kinmore 1 (Laws and Clerc, 1974), between 847 and 1321m. Twelve metres of sandstone near the top of the formation of Bougainville 1 display good log porosity, with the more argillaceous sands showing generally poor porosity but some permeability.

TIME SLICE P5 to P7 - LATE PERMIAN

SUMMARY (Enclosure 20 and 39)

The late Permian of the Petrel Sub-basin was a period of widespread environmental changes during the deposition of the Hyland Bay Formation. Reefal environments were present almost across the entire sub-basin at both the onset and close of this period. During the time slice interval a delta front with numerous channel switches and wave reworking of stream mouth bars built out over the area. To the northwest where the limestones at the top and base of this sequence coalesce, reefal conditions prevailed throughout the interval. Lagoonal facies and thin coals (potential source rock) preserved in the deltaic deposits evoke an image of broad lower deltaic plains at the time of greatest progradation. The deltaic and shoreline sands are the major gas and condensate reservoirs in the Petrel Sub-basin.

PALAEOGEOGRAPHIC INTERPRETATION

Hyland Bay Formation

The late Permian Hyland Bay Formation (Hughes, 1978; Bhatia et al., 1984), has been split into five members (Bhatia et al., 1984) based on lithologic characteristics. Only two of these five members were formally named by Bhatia et al. (1984). These were the uppermost unit, the Tern Member, which forms the reservoir for the Tern gas field, and the middle Hay Member, which forms the bulk of the formation and hosts the gas accumulation at the Petrel Field. Mory (1988) renamed the Hay Member as the Cape Hay Member. The five sub units of the Cape Hay Member, recognised by Bhatia et al. (1984) can be correlated through several wells in the southeastern Petrel Sub-basin (Figures 32 and 33).

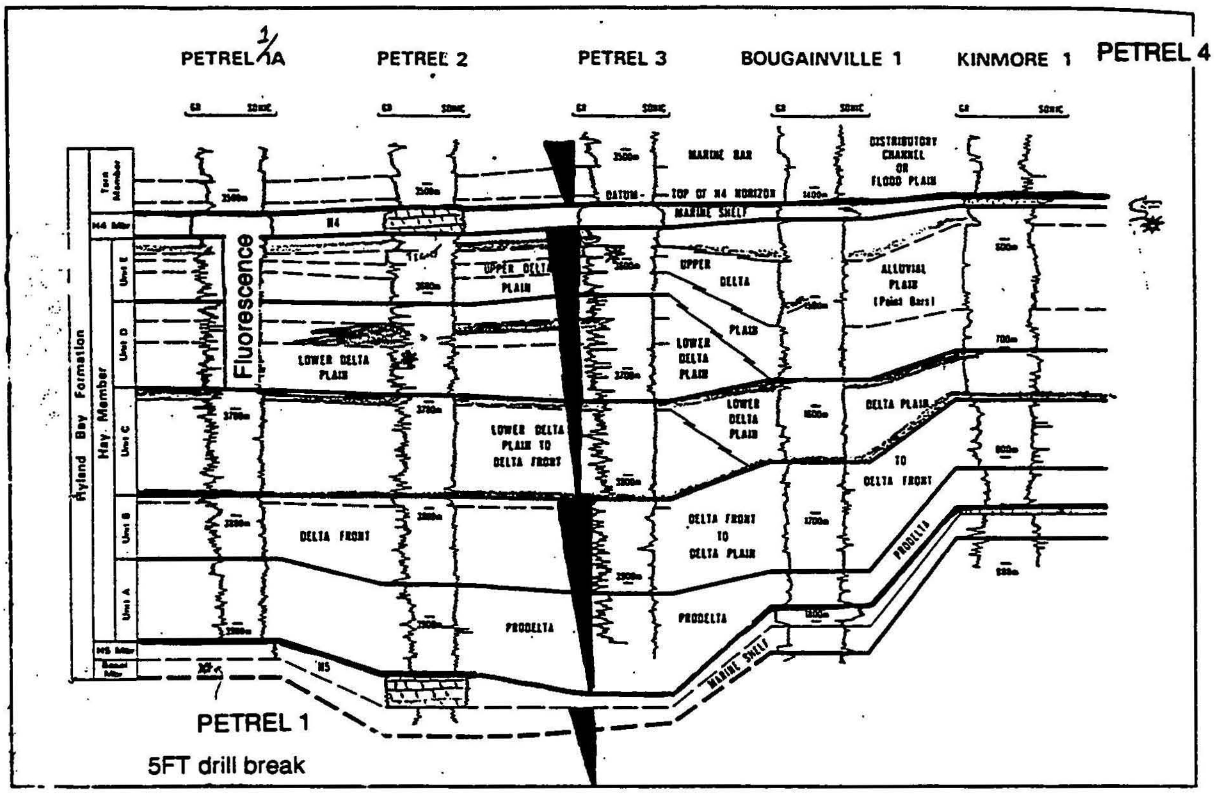


Figure 33 Petrel 1/1A to Kinmore 1 correlation and facies of the Hyland bay Formation (From Bhatia et al., 1984)

The Hyland Bay Formation was named in the Petrel 2 well completion report (ARCO, 1971b) for the sequence of sandstone, siltstone, shale, and limestone between 3461 and 4028 m. Hughes (1978), however; gave the type section as the interval 3464 - 3980 m in Petrel 1. Petrel 2 was designated by Mory (1991) as a reference section since Petrel 1 did not penetrate the base of the Hyland Bay Formation. Mory (1991) named four members in this formation: Pearce, Cape Hay, Dombey, and Tern Members. The informal Basal Member of Bhatia et al. (1984) was retained within the Hyland Bay Formation by Mory (1991), who noted that it may warrant formal treatment in the future. The Hyland Bay Formation now comprises a basal unit, overlain by fossiliferous limestone (Pearce Member), sandstone, mudstone and siltstone with minor amounts of coal (Cape Hay Member), a second fossiliferous limestone (Dombey Member), and uppermost sandstone and mudstone (Tern Member).

Mory (1991) considered that in the onshore part of the Petrel Sub-basin, the informal 'upper Permian marine beds', 'plant-bearing beds' and 'marine horizon of Fossil Head' of Dickins et al. (1972) are lithologically similar to the Hyland Bay Formation. Based on depositional environment, these three informal units parallel the offshore subdivision of the formation. The Tern and Dombey Members appear equivalent to the 'upper Permian marine beds', the Cape Hay Member equates to the 'plant-bearing beds'; and the Pearce Member and basal undifferentiated Hyland Bay Formation apparently correspond to the 'marine horizon of Fossil Head'. The 'upper Permian marine beds', however; are early Tatarian in age compared to a Kungarian to Kazanian age for the Hyland Bay Formation in the southeastern, offshore part of the Petrel Sub-basin. Drummond (1963) divided the sequence drilled in the coal bores (1904 1908) between Port Keats and Cliff Head into five informal units ('Formations I to V). However these units have not been used by other workers. The correlations of Dickins et al. (1972) suggest that in the Port Keats bores the lower half of 'Formation I', 'Formation II', and the base of 'Formation III' (Drummond, 1963, his Figure 6) are equivalent to the Hyland Bay Formation.

To the northwest, beyond the Petrel Sub-basin on the Londonderry High, the formation contains two thick carbonates enclosed by a siliciclastic sequence. In wells such as Osprey 1, Dillon Shoals 1, and Anderdon 1 the Hyland Bay Formation contains a basal shale and two thick carbonate units which are overlain and separated by two thin siliciclastic units. These northwestern well sections are analogous to those in the southeastern Petrel Sub-basin in that they contain two distinct carbonate horizons. The carbonate horizons in the northwest have been correlated with the two in the southeast of the basin by seismic mapping, although palynological evidence suggests that the northwestern carbonates could be younger (Mory, 1991). Consequently, members have not been differentiated in the northwestern sections. In Osprey 1, the 363 m of shale and minor sandstone below the basal limestone is difficult to distinguish from the underlying Fossil Head Formation on lithological grounds alone. Mory (1991) considered that although the presence of the *Dulhuntyispora* Assemblage in the upper 75 m of this section suggested that this interval is the Hyland Bay Formation, part of the underlying section may belong to the Fossil Head Formation. In Flat Top 1 on the Darwin Shelf, the formation consists largely of carbonate. Seismic correlations indicate that these carbonates are thickened equivalents of the H4 and H5 limestones. An additional coarsening upward cycle containing good reservoir is developed above a thick limestone in the upper part of the Fossil Head Formation at Flat Top 1.

Although the Hyland Bay Formation appears to conformably overlie the Fossil Head Formation, the absence of Stage 4b at this level in many of the offshore sections suggests a disconformable relationship. Only in Tern 2 has Stage 4b been preserved. The unit also disconformably overlies granitic basement onshore in the Cliff Head No. 1 coal bore, and offshore in Troubadour 1.

Most intersections of the Hyland Bay Formation are in the southern Petrel Sub-basin where the unit ranges from 176 to 520 m in thickness according to Mory (1991). It is also known from the west of the sub-basin (Plover 1 and 2) and on the Londonderry High (Osprey 1, Whimbrel 1, Dillon Shoals I, and Anderdon 1). The thickest intersections in that area are from Osprey 1(428 m) and Anderdon 1 (489 m). According to Mory (1991), in Osprey 1, the lower limit of the formation is difficult to distinguish from the underlying Fossil Head Formation, and it may be thicker than 428 m in that well. In Anderdon 1, the formation has not been fully penetrated. Thin intersections of late Permian carbonates in Sahul Shoals 1 (53 m) and Troubadour 1 (21 m), on the Ashmore and Sahul Platforms respectively, are questionably assigned to the Hyland Bay Formation. The only complete section in the onshore part of the basin is in the Port Keats No. 4 coal bore (approximately 101-402 m).

In the southeastern Petrel Sub-basin, the Hyland Bay Formation contains a prolific Stage 5 microflora (Kungurian to Kazanian, early to late Permian). Helby *(in* Lane, 1981; *in* Chan, 1981 and 1982) proposed five assemblage zones from this formation. These were named the *D. dulhuntyi, D. ericianus, D. parvithola, D. stellata,* and *Weylandites* Zones (in ascending order). In more recent work, Helby has adopted the *D. granulata* Zone as equivalent to his *D. dulhuntyi* Zone. In the northeast of the basin, the Hyland Bay Formation contains microfloras equivalent to the Tatarian *P. Microcorpus* Zone of Helby et al. (1987), as well as *Dulhuntyispora* Microfloras. In Osprey 1, Helby *(in* ARCO Australia Ltd, 1972b) identified microfloras from the *P. reticulatus* or *L. pellucidus* Assemblages in the upper limestone of the Hyland Bay Formation; this is the only well to date in which palynological evidence suggests that the unit may extend into the earliest Triassic.

The diverse fauna present in this formation in offshore wells have been documented by Grenfell (1987). Various well reports have described the presence of foraminifers, ostracods, gastropods, and bryozoans. Considerable work has been completed on brachiopod, mollusc, and bryozoan faunas collected from the outcrops in the Port Keats area.

In the southeast of the basin, deposition of the Hyland Bay Formation commenced in an open-marine environment (basal shale and limestone, plus Pearce Member). This was followed by deltaic progradation (Cape Hay Member) probably due to uplift along the Halls Creek Orogen. The regressive deltaic sedimentation was followed by a marine transgression and the deposition of marine carbonates. The following clastic sequence (Tern Member) was deposited by a prograding barrier-island complex, of offshore to shoreface and lagoonal environments (Bhatia et al., 1984; Grenfell, 1987). In the northwest of the basin, open-marine conditions prevailed with deposition of fine siliciclastics and carbonates. Bhatia et al. (1984) published a detailed study of the depositional framework of the Hyland Bay Formation, in particular the Cape Hay Member and Tern Member siliciclastics. They interpreted the depositional environment of the Cape Hay Member as a mixed river, wave and tide-dominated delta system because of the sedimentary facies recognised from cores and lack of characteristic seismic reflection patterns. The Tern Member was interpreted as the deposits of a prograding shoreline with lateral facies changes from offshore to barrier bar and inshore lagoon-marsh and flood plain environments.

Late Permian siliciclastics crop out along the coast in the Port Keats area (Dickins et al., 1972). The abundant marine fauna and erosional breaks with channelled surfaces and basal conglomerates, are suggestive of interfingering nearshore to non-marine environments probably a proximal facies of the Hyland Bay Formation.

The Dombey and Pearce Members (H4 and H5 limestones) are biomicritic to biosparitic limestones containing abundant shell fragments, bryozoans and crinoids indicative of open marine shelf deposition. Ooids and coral debris were observed in Tern 1, suggesting turbulent conditions, possibly in a near reef or bank setting. Localisation of such reefal or bank buildups probably required the presence of some bathometric relief, such as that caused by active faulting or salt tectonics. However, no thickening on seismic sections, suggestive of thick local reef development has been seen, although the conspicuous uplift observed across the Tern structure may have commenced at this time (Petroconsultants, 1990).

The thick late Permian carbonates present at Osprey 1 and other western wells suggest that the shelf beyond the Petrel Sub-basin was predominantly a site of carbonate deposition at this time. The Hyland Bay siliciclastics present to the southeast are the result of the intrusion of a deltaic sequence into the broad carbonate shelf environment that developed along the northern margin of the continental block (MacDaniel, 1988).

A detailed study of the depositional environments of the various members of the Hyland Bay Formation were undertaken by Grenfell (1987) who recognised a decrease in marine phytoplankton and increase in spores and pollens within the Cape Hay Member.

Pearce Member

The name 'Pearce Member' replaced the informal 'H5 Member' for the fossiliferous limestone low in the Hyland Bay Formation (Mory, 1988). The name is from Pearce Point, south-southwest of Port Keats. The informal name arose from the association of ARCO seismic horizon 'H5' with the limestone. The type section is the interval 3952-3983 m in Petrel 2.

The Pearce Member consists of biomicritic to biosparitic limestone, which contains abundant shell fragments, bryozoans and crinoids (Bhatia et al., 1984). The Pearce Member lies conformably between undifferentiated Hyland Bay Formation (below) and the Cape Hay Member (above).

In spite of its thickness (5-57 m), the Pearce Member has been recognised on seismic sections over a wide area in the Petrel Sub-basin, from the Darwin Shelf across to the Londonderry High.

Apart from the presence of an abundant marine fauna, acritarchs and palynomorphs have been identified from the Pearce Member Helby (in Lane, 1981, and Chan, 1982) identified his *D. ericianus* Zone from this member in Lesueur 1. In Tern 2 the member lies between occurrences of the *D. ericianus* and *D. parvithola* Zones. These zones range from lower Stage 5a to upper Stage 5a (Kungurian to Kazanian), and suggest that the member may be diachronous.

The Pearce Member was deposited on an open-marine shelf.

Cape Hay Member

The Cape Hay Member ('Hay Member' of Bhatia et al., 1984) is the interval of sandstone, mudstone, and siltstone which lies between the two limestone members of the Hyland Bay Formation. The name has been used previously for the Hay River Formation in the Georgina Basin and so the full geographic name should be used to avoid confusion. The type section is the interval 3549-3918 m in Petrel 1. The Petrel gasfield reservoir lies within this unit. The member is here considered to be lithologically equivalent to the 'middle non-marine beds' of Dickins et al. (1972) which are exposed in coastal sections in the Northern Territory

The Cape Hay member is a predominantly siliciclastic unit in which two coarsening-upward cycles are present. Bhatia et al. (1984) recognised five lithological units in the member: The lower cycle consists of dark mudstone and siltstone, overlain by bioturbated, interbedded sandstone and mudstone. The sandstone in this interval is commonly lenticular; and contains flasers, cross-beds, and ripple cross-laminations. The upper cycle consists of carbonaceous mudstone and siltstone with sandstone interbeds, at the base, overlain by sandstone with mudstone and minor amounts of coal, overlain in turn by uppermost medium- to coarse-grained, cross-bedded sandstone with minor argillaceous, coaly beds. Although the lithology of the Cape Hay Member is similar in Turtle 1 and Lacrosse 1 where the unit contains common coaly bands, the Cape Hay Member in Lesueur 1 appears to have marked marine affinities and contains common limestone bands. Further subdivision and regional correlation on the basis of the environments of deposition resulting from deltaic progradation and subsidence/sea level rise should be possible within the Cape Hay Member. Grenfell (1987) described the palynology of the informal units but made little use of the cyclical patterns recognisable on the well logs recorded through the member.

The Cape Hay Member lies conformably between the Pearce Member (below) and the Dombey Member (above). It is probably equivalent, in part, to the Pearce Member; as the Dombey Member appears to be time transgressive (Mory, 1991).

The Cape Hay Member has a similar distribution to the overlying Dombey Member and underlying Pearce Member. It occurs throughout most of the Petrel Sub-basin. Based on well intersections, it varies in thickness from 200 to 450 m. Northwest of Tern 1, the H4 and H5 limestones merge, at the expense of the Cape Hay Member which was probably not deposited in that area.

Helby *(in* Lane, 1981) identified palynomorphs of the *D. ericianus* and *D. parvithola* Zones in the Cape Hay Member in Lesueur 1, whereas in Tern 2 he recognised the *D. stellata* Zone in addition to the former two zones (in Chan, 1982). These zones range from lower Stage 5b to upper Stage 5b, (latest Kungurian to Kazanian).

The Cape Hay Member was deposited in a deltaic environment. The lower coarsening-up cycle resulted from progradation from a prodeltaic to delta-front environment. The upper cycle represents a continuation of that progradation from estuarine deposits of the delta-front and lower delta-plain, to upper delta-plain alluvial point-bar deposits (Bhatia et al., 1984).

Dombey Member

The name 'Dombey Member' replaced the informal 'H4 Member' for the limestone horizon high in the Hyland Bay Formation (Mory 1988). The name is from Cape Dombey at the northern end of Hyland Bay. The informal name comes from the association of ARCO's 'H4' seismic horizon with the limestone. Mory (1991) defined the interval 3523-3549 m in Petrel 1 as the type section.

The Dombey Member a similar to the Pearce Member. It consists of biomicritic to biosparitic limestone with abundant shell fragments, bryozoans, and crinoids (Bhatia et al., 1984).

The Dombey Member is conformable between the Cape Hay Member (below) and the Tern Member (above). The Dombey Member has been recognised on seismic sections over a wide area in the southern half of the basin between the Darwin Shelf and Londonderry High. According to Mory (1991) it ranges in thickness from 5 to 30 m across the Petrel Sub-basin and Darwin Shelf.

In the southern Petrel Sub-basin the Dombey Member contains microfloras of the *D. stellata* Zone (Helby, *in* Lane, 1981; Chan, 1982) which indicate an upper Stage 5b-c: (late Kazanian) age. The Dombey Member was deposited in an open marine shelf environment.

Tern Member

The Tern Member (Bhatia et al., 1984) is the sandstone and mudstone sequence at the top of the Hyland Bay Formation. The type section is the interval 2521 to 2585 m in Tern 1. Sandstone in the member is the Tern gas field reservoir.

The Tern Member generally consists of a fossiliferous coarsening-up sequence of mudstone and sandstone, although the sequence is, in some areas, composed entirely of mudstone (e.g. in Lacrosse 1 and Lesueur 1) or sandstone (e.g. in Bougainville 1). The Tern Member appears to conformably overlie the Dombey Member at the top of the Hyland Bay Formation.

The Tern Member is present throughout the southern Petrel Sub-basin. It has been intersected as far north as the Petrel area. The unit is 30 to 70 m thick. The Tern Member contains unidentified shelly material and trace fossils from the Cruziana Association (Bhatia et al., 1984). Helby *(in* Lane, 1981; and *in* Chan 1982) identified palynomorphs of the *Dulhuntyispora stellata* and *Weylandites* Zones from this unit. These zones indicate and upper Stage 5b-c: (late Kazanian) age (Mory 1991).

The coarsening-up, regressive marine cycle of the Tern Member was interpreted as a barrier-bar sequence by Bhatia et al. (1984). Within this environment, the shelly, cross-bedded and laminated sandstones represent upper shoreface or foreshore deposits, and interbedded bioturbated sandstone and mudstone represent lower shoreface deposits. Siltstone- and mudstone -dominated sections of this member; such as at Lacrosse 1 and Lesueur 1, were deposited landwards of the barrier island in a lagoonal environment (Bhatia et al., 1984). The characteristics of distributary mouth bar deposits in a subaqueous delta plain are shown in Figure 34. Gamma logs through the Cape Hay and Tern Members show many features in common with this subaqueous delta plain environment. A measured section from the Yoredale Series provides a good comparative model for the formation (Figure 35).

PROSPECTIVITY

Moderate to good prospectivity. The P5-P7 interval is the major gas and condensate reservoir in the Petrel Sub-basin. Excellent reservoir facies overlie Permian and Carboniferous source rocks, intraformational seals exist and the early Triassic Mount Goodwin Formation provides a regional seal. Most of the large structures have been already drilled successfully, but additional potential remains as shown by the recent Fishburn 1 gas

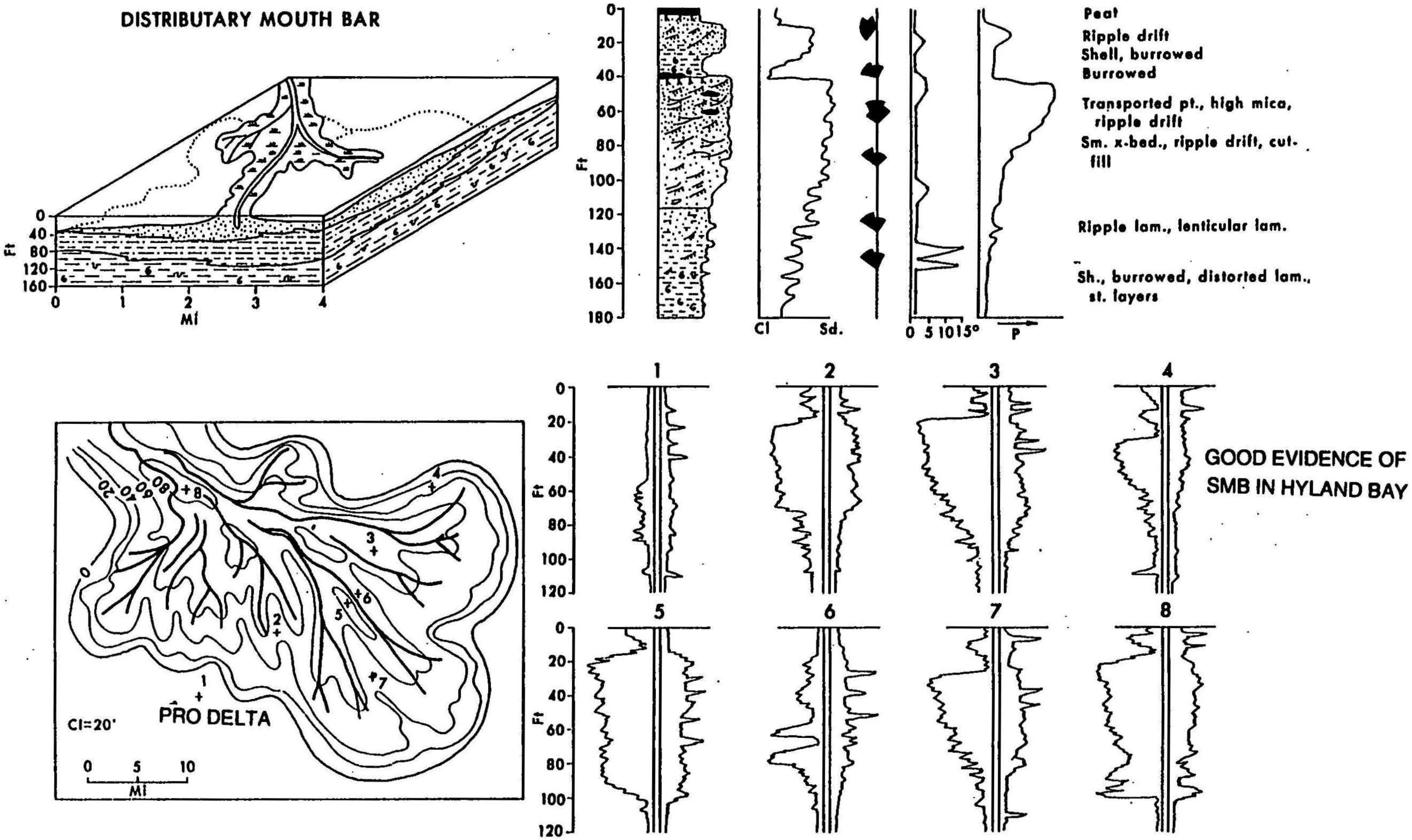


Figure 34 Summary diagram illustrating the major characteristics of the distrubutary-mouth bar deposits in the subaqueous delta plain
(From Busch and Link, 1985)

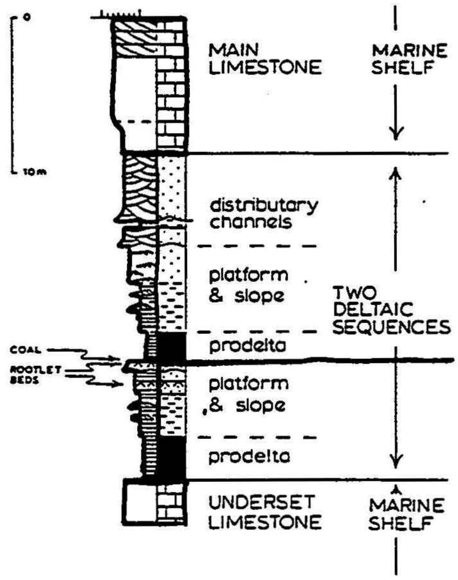


Figure 35 Measured section of Yoredale Series illustrating upward coarsening cycles interpreted as deltaic progradation (From Selley, 1970)

discovery. There is also a potential oil play in the less mature, northeast section of the sub-basin. The structure of the near top Permian is shown in Figure 22. This diagram suggests regional migration in the Hyland Bay Formation was mostly dispersed to the basin flanks except to the southeast of the Petrel structure where a structural nose provided a focus. This Permian oil play is **untested** at the time of writing.

Hydrocarbon shows

Gas and condensate field at Petrel, gas fields at Tern and Fishburn, and oil indication (L2) at Cambridge 1.

Source Rock

In contrast to the P2 to P4 interval, the HI and TOC values mapped for the P5 to P7 interval in Appendix 6 show little source rock quality sediments. The marine to deltaic (Bhatia et al., 1984) Hyland Bay Formation contains generally lean source rocks where drilled. Despite TOC values of 2.8 % at Petrel 2, 9.95% at Bougainville 1 and 2.97% at Kinmore 1, HI values are generally below 100. The exception is Cambridge 1, with a maximum value of 262, which is interpreted to have had a lagoonal environment, close to a point of fluvial input to the sub-basin (Appendix 6, Enclosure 39). Lee and Gunn (1988) considered the underlying marine shales were the probable source sequences for the Hyland Bay Formation hydrocarbons.

A degraded oil show detected in organic matter extracts from 1713 m in the Flat Top 1 well is probably migrated and does not represent a source rock (Figure 36). Early migration of hydrocarbons probably occurred from the basin depocentre to the flanks.

Reservoir

The Hyland Bay Formation contains two regionally extensive reservoir units developed over the Petrel Sub-basin; the Cape Hay Member, reservoir to the Petrel Gas accumulation in Petrel 2 to 5, and the Tern Member, reservoir to the Tern Gas Field. Bhatia et al. (1984) discussed the depositional and diagenetic alterations to the reservoirs of these two large accumulations. Modal composition of the sandstone grains suggest more reworking in the Tern Member (Figure 37) indicating greater wave domination of the delta (Figure 38).

The Petrel wells encountered the Cape Hay Member pay zones at depths of around 3500 m. Porosities range from 6 to 23%, the value depending very much on the respective

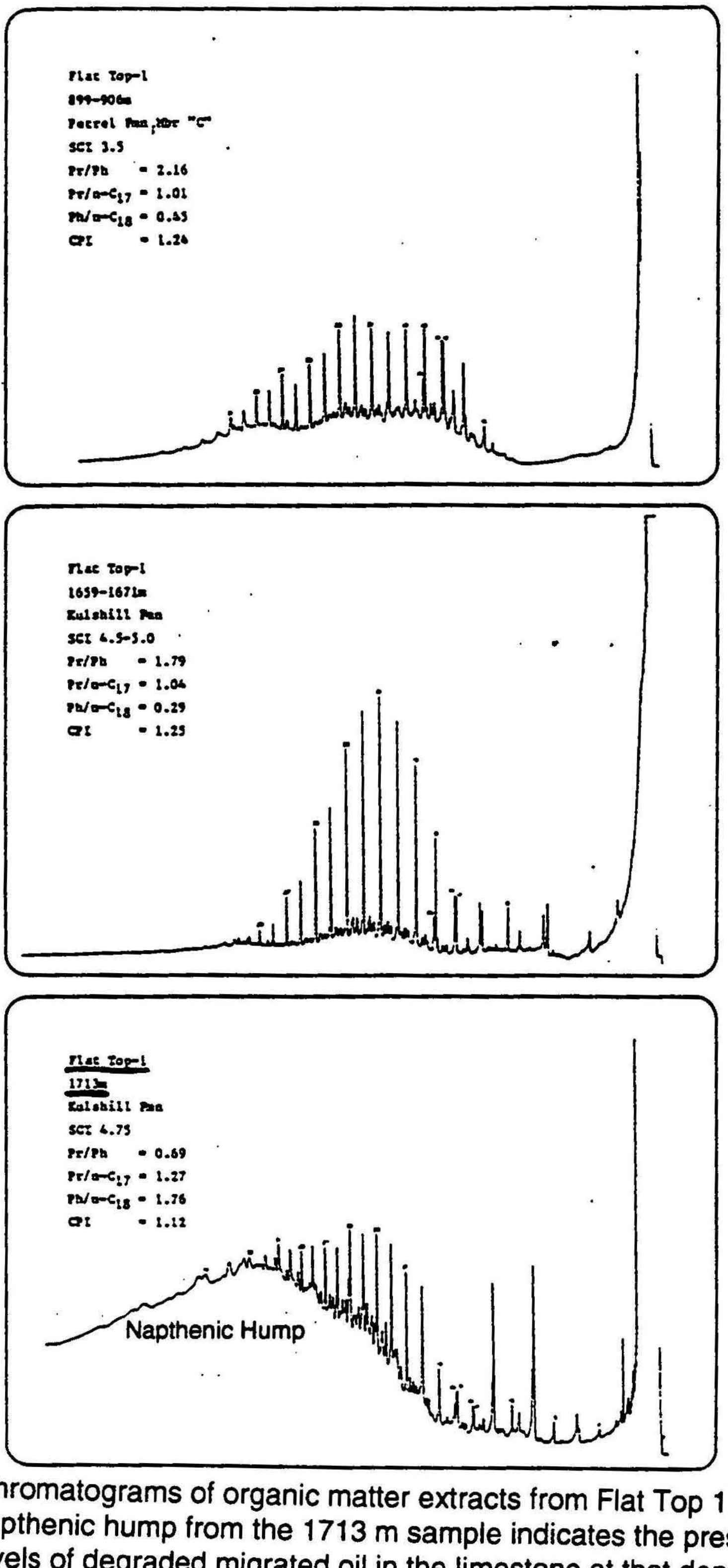


Figure 36 Chromatograms of organic matter extracts from Flat Top 1 samples. The napthenic hump from the 1713 m sample indicates the presence of trace levels of degraded migrated oil in the limestone at that depth (From Robertson Research Australia Pty Ltd, 1986)

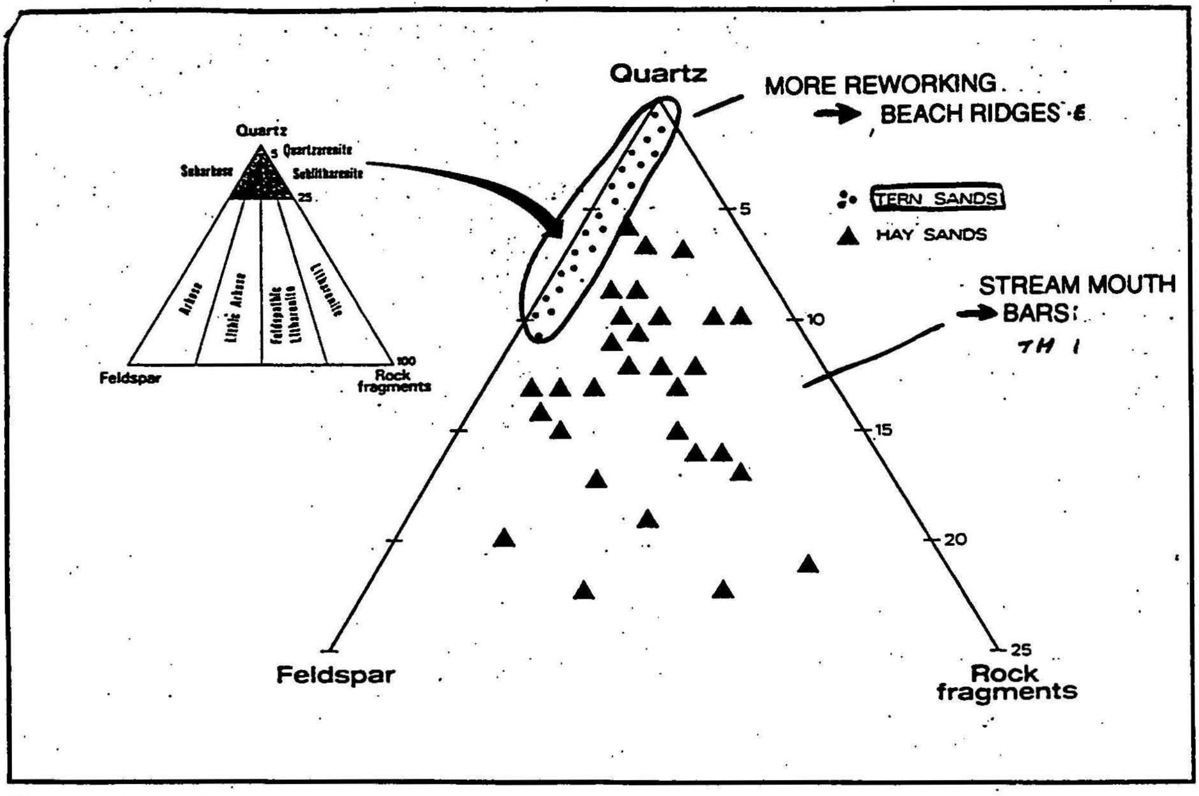


Figure 37 Modal composition of the Hay and Tern Member sandstone grains (From Bhatia et al., 1984)

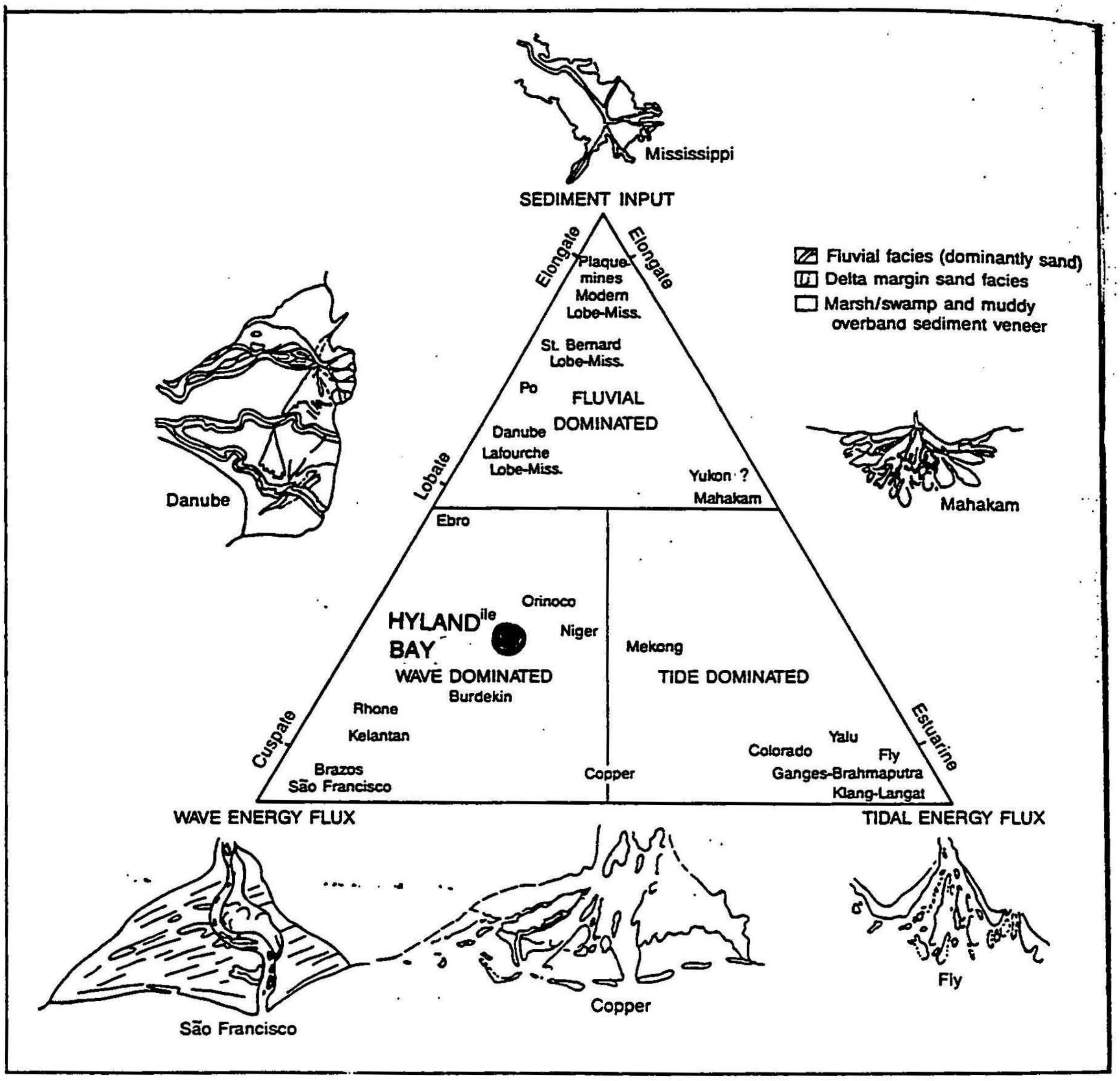


Figure 38 Interpretation of the Hyland Bay delta as a mostly wave dominated system (Diagram from Busch and Link, 1985)

depositional facies and degree of diagenesis. The Cape Hay Member in the Petrel structure is interpreted as deltaic stream mouth bar. Silicification of sandstones formed in the high energy depositional environments of the delta have substantially reduced the porosity of this section, whereas the shalier facies of the delta have retained their near original porosities owing to clay coating on the quartz grains inhibiting silicification. Other forms of diagenesis, including calcite cementation, also acted to reduce the primary porosity of the reservoir.

The Tern Member reservoirs in the Tern structure lie at 2500 m in Tern 1 and 2. The porosity of the Tern Member reservoir ranges from 1 to 24%, depending on the facies and degree of diagenesis. Diagenetic effects include carbonate cementation and the growth of clay minerals, both of which have reduced primary porosity. In the finer grained facies the clay fraction has inhibited calcite cementation.

The Hyland Bay Formation at Kinmore 1 has an average calculated porosity of 31% (505 - 847m) according to Laws and Clerc (1974). Good reservoir characteristics are also present in the formation at Bougainville 1, as shown by the very coarse sands in sidewall cores. These clean sands constitute about 36% of the formation and have an average porosity of 24%. Formation tests showed good permeability at 1344m.

TIME SLICE Tr1 to Tr2 - EARLY to MIDDLE TRIASSIC (Griesbachian to Anisian)

SUMMARY (Enclosure 21 and 40)

During this period thick monotonous prodelta sediments (Mount Goodwin Formation) were deposited throughout most of the Petrel Sub-basin. Coarser siliciclastic deltaic deposits (Cape Londonderry Formation) overlie the prodelta environments following the marine regression towards the end of this time slice interval. Deeper marine environments are interpreted further offshore and alluvial environments were present landward of the deltas fronts. The Mount Goodwin Formation provides a regional seal in the Petrel Sub-basin to the Permian Gondwanan petroleum system (Bradshaw et al, 1994). It is one of several thick early Triassic shale sequences deposited along the western margin, and the equivalent unit in the Perth Basin (the Kockatea Shale) is a proven oil source rock.

PALAEOGEOGRAPHIC INTERPRETATION

Latest Permian to early Triassic marine siltstones and shales comprise the **Mount Goodwin Formation**. The formation has an average thickness of 600 m across the central

Petrel Sub-basin and thins to the southern and eastern basin margins. Early Triassic siliciclastic sediments are exposed in the Port Keats area (Dickins et al., 1972).

The sudden introduction of this thick, fine grained siliciclastic unit has been used by Mory (1988) to infer a new phase of tectonic subsidence with a northeast trending structural grain cross-cutting the earlier northwest trend of the Petrel Sub-basin.

The Mount Goodwin Formation consists predominantly of siltstone and shale; it was named after Mount Goodwin, near Port Keats. The formation is equivalent to the 'Lingula shales' of Caye (1968). The type section was first defined in an unpublished report by Helby (1974a) as the interval from 2887 to 3464 m in Petrel 1. Hughes (1978) cited the interval 2892 -3464 m for the type section; the 2892 m level is incorrect as it is from Petrel 1A (ARCO and Aquitaine, 1971).

The Mount Goodwin Formation consists of dark to light grey shale with minor amounts of siltstone and thin interbeds of fine-grained sandstone. Glauconite is often present in the siltstone. Offshore, the Mount Goodwin Formation generally conformably overlies the Hyland Bay Formation. Spore-pollen zones present in both units indicate that this contact is diachronous. In the Londonderry High area, vitrinite reflectance data suggest that the Mount Goodwin Formation may be locally disconformable on the underlying formation. Onshore, there is no evidence for a latest Permian age for the Mount Goodwin Formation, which suggests that it disconformably overlies the Hyland Bay Formation.

MacDaniel (1988) stated that the boundary with the Hyland Bay Formation is disconformable, but Mory (1988) suggested a diachronous but conformable contact as the *T. playfordii* microflora is present in wells to the west (Osprey 1) within the upper Hyland Bay, and within the lower Mount Goodwin Formation. However, the older *P. samoilovichii* zone is also present in the Mount Goodwin Formation, suggesting either miscorrelation of the upper Hyland Bay limestone in the Osprey 1 area, or poorly controlled palynofacies. Helby (1974a) noted that the *T. playfordii* assemblages recovered from Sahul Shoals 1 were interpreted "with some difficulty" (his Figure 8) in the section equated with the Mt Goodwin Formation by Mory (1988, his Figure 19). For the Mount Goodwin in Osprey 1 (Mory's Figure 19) an early to mid Scythian age is suggested by Helby (1974a, his Figure 5), who also noted a general early Scythian age for the Mount Goodwin Formation. The presence of the *P. samoilovichii and T. playfordii* assemblages is consistent with a mid Scythian to early

Anisian age (Helby et al., 1987), and supports a disconformable lower boundary. Onshore, there appears to be structural concordance between the late Permian and Triassic strata (Dickens et al., 1972).

The Mount Goodwin Formation is present over most of the basin. A maximum thickness of almost 670 m was intersected in Dillon Shoals 1. The formation extends onshore in the Port Keats area, but is less than 20 m thick. It thins over the Sahul Platform to 89 m in Troubadour 1. The unit has been removed by erosion south of Turtle 1 and has not been penetrated west of 124° E.

The Mount Goodwin Formation contains palynofloras equivalent to the *P. microcorpus, L. pellucidus* and *P. samoilovichii* spore-pollen Zones of Helby et al. (1987). These zones indicate a Tatarian (latest Permian) to Smithian (early Triassic) age. Dickins et al. (1972) recorded that lingulid brachiopods, vertebrate remains, brachiopods (identified as estheriids) and unidentifiable plants were collected from outcrops in the Port Keats area. In Sahul Shoals 1, bivalves, pyritized ammonites, and worm burrows were recorded from core at the top of this unit. Halobidae bivalves and the ammonite *Nicomedites* sp. indicated an early Anisian (middle Triassic) age which is anomalous when compared to the older ages suggested by palynomorphs (Mory, 1991).

The Mount Goodwin Formation is coeval with similar shale prone units in the Canning Basin (Blina Shale), Carnarvon Basin (Locker Shale) and Perth Basin (Kockatea Shale). They were all deposited during a basal Triassic eustatic rise following the Tatarian (tern) regressive episode. The fossils recovered from the Port Keats bores and outcrop indicate correlation to the interval 3204 to 3231 m in Petrel 1, and suggest brackish water depositional environments (Dickins et al., 1972).

Mory (1991) considered the lack of coarse clastic rocks in the thick fossiliferous shale of the Mount Goodwin Formation suggested a distal marine environment such as the outer shelf or slope. In the Port Keats and Petrel 1 area, the presence of conchostracans (which have no other macrofaunal or macrofloral associates where they occur) indicated that at least part of the unit was deposited in freshwater or brackish fades (Tasch and Jones, 1979). Tasch and Jones (1979, p. 28) considered that the sparsity of biotic associates also implied that the water bodies within the Petrel Sub-basin were ephemeral. The presence of lingulid brachiopods indicates that marine environments interfingered with these marginal-marine sections, or that the conchostracans were transported. The marginal-marine environments were possibly restricted to the edge of the basin while open-marine conditions were established to the northwest, similar to the early Triassic Fitzroy embayment in the Canning Basin.

The **Cape Londonderry Formation** is a regressive siliciclastic Triassic sequence deposited over the entire Petrel Sub-basin. The Cape Londonderry Formation ('Londonderry Formation' of Helby, 1974a) is equivalent to the 'Undifferentiated middle to upper Triassic' below the 'upper Triassic redbeds' of ARCO Australia Ltd (1971a). The type section is the interval 2471-2887 m in Petrel 1 (Helby, 1974a). The Cape Londonderry Formation consists predominantly of quartzitic sandstone with scattered pebbles in the courser grained horizons. Minor siltstone and mudstone interbeds and traces of coal are also present.

The Cape Londonderry Formation conformably overlies the Mount Goodwin Formation. The formation is coeval with the Sahul Group in the west of the basin. The Cape Londonderry Formation is restricted to the central part of the Petrel Sub-basin north of Penguin 1, and the eastern side of Londonderry High as far west as Peewit 1. It ranges in thickness from 280 to 450 m. The unit is thickest in the Petrel Sub-basin and thins onto the basin margins and over the Petrel Gas Field. A thickening into the Malita Graben occurs to the northeast but thinning is apparent to the northwest. Onshore correlatives are unknown.

Palynological data from the Cape Londonderry Formation are sparse; the unit is interpreted, from its stratigraphic position, to be Smithian to Ladinian (early to middle Triassic) in age. This is confirmed by the presence of *T. playfordii* Zone in Tern 3 (Helby *in* Chan, 1982). The identification of *L. pellucidus* and *P. microcorpus* near the base of the unit in Plover 1 indicates a slightly older age (Griesbachian to Smithian) and suggests that the unit may have a diachronous lower contact with the Mount Goodwin Formation (Mory, 1991).

Helby (1974a) dated the Cape Londonderry Formation as ?Ladinian to late Scythian and noted its conformable relationship with the underlying Mount Goodwin Formation. Deposition was probably curtailed by a sharp sea level fall during the Ladinian shown by eustatic sea level curves published by Haq et al. (1987).

The predominance of coarse-grained siliciclastic lithology's throughout the Cape Londonderry Formation indicates a fluvial braided-stream environment. Finer grained rock types and rare thin coals are probably overbank deposits.

Low prospectivity. Despite excellent reservoir quality in the Cape Londonderry Formation there are no hydrocarbon shows in the interval. It is quarantined from the mature source rocks in the underlying Gondwanan petroleum system by the intervening Mount Goodwin Formation shale seal; and no effective source rocks are recognised in the Mesozoic Westralian sediments in the Petrel Sub-basin. At this level there is a lack of deep faults that could act as conduits from mature sources below (Figure 11, Enclosures 47 to 50).

Hydrocarbon shows

None

Source Rock

Unlike the coeval Kockatea Shale in the Perth Basin, the Mount Goodwin Formation is not considered a source rock. However, HI and TOC maps in Appendix 6 show some marginal source rock quality in the Tr1 to Tr2 interval in Penguin 1 (HI max of 214, TOC max of 3.5 %). The sand dominated Cape Londonderry Formation is not a potential source rock.

Reservoir

The middle to late Triassic Cape Londonderry Formation is laterally equivalent to the reservoir section encountered in the Challis Oil Field of the Vulcan Graben. The unit is widespread over the southeast Petrel Sub-basin and locally has a massive sand development containing 13-21% sonic- derived porosity values in the basin centre (Petrel 2) with slightly higher porosity values in the thinner basin margin areas, such as at Flat Top 1, where a sonic porosity of 25% was calculated. Cores in the interval at Petrel 2 had up to 165 mD of vertical permeability and 59 mD of horizontal permeability.

TIME SLICE Tr3 to Tr6 - MIDDLE to LATE TRIASSIC (Ladinian to Rhaetian)

SUMMARY (Enclosure 22 and 41)

The middle to late Triassic was a regressive interval in the Petrel Sub-basin. The area of deposition contracted and the marine and deltaic environments of the early Triassic were replaced by fluvial and coastal plain regimes with a red bed character.

PALAEOGEOGRAPHIC INTERPRETATION

Malita Formation

In the Petrel Sub-basin the youngest Triassic rocks are the red beds of the Malita Formation. This formation attains a thickness of approximately 300 m in the Petrel wells, and thins to the basin margins to the east and south. The formation is not known in the onshore area.

The Malita Formation (Helby, 1974a) is equivalent to ARCO's 'Lower Jurassic - Upper Triassic Redbeds'. The unit is presumably named after the Malita Shelf Valley of Van Andell and Veevers (1967). The type section is the interval 2229-2471m in Petrel 1 (Helby, 1974a). In the type section, and generally elsewhere, the unit is distinguished from the sand-dominated Cape Londonderry Formation (below) and Plover Formation (above) by the predominance of fine-grained clastics in the redbed sequence. In areas where the contact is gradational, the top is below the lowest coal in the Plover Formation.

The Malita Formation is characterised by multicoloured siliciclastic rock types (redbeds), especially siltstone and mudstone. Fine to coarse grained sandstone is also common throughout the unit, which contains rare occurrences of glauconite and shell fragments.

In most of the Petrel Sub-basin the Malita Formation lies conformably between the Cape Londonderry Formation (below) and the Plover Formation (above). In the Tern - Petrel area the Malita Formation is absent, or the lower parts of the unit are missing, presumably due to salt-induced uplift prior to deposition. Onlap of the Malita Formation onto locally emergent areas resulted in non-deposition, or partial deposition, of the unit. West of the Londonderry High the Malita Formation conformably overlies the Sahul Group, or has been removed by late Jurassic erosion. Limited available palynological data indicate that the upper and lower contacts are probably diachronous.

The Malita Formation is present in the central part of the Petrel Sub-basin, north of 13°45' S, and extends west onto the northern part of the Londonderry High and eastern Ashmore Platform. It is also present on the western side of the Ashmore Platform. In the Vulcan Sub-basin and Malita Graben, the Malita Formation has probably been downfaulted to a considerable depth. On the Sahul Platform, western Ashmore Platform, and basin margins, the unit has been removed by erosion. It has a maximum thickness of 392 m in Petrel 3.

Palaeontological evidence for the age of the Malita Formation is sparse. However; spores and pollen of the *S. speciosus*, *M. crenulatus* and *C. torosa* Zones of Helby et al.

(1987) are present in this formation in the west of the basin. These zones indicate a Carnian (late Triassic) to Pliensbachian (early Jurassic) age. In the Petrel Sub-basin, the *C. torosa* Zone is present high in the sequence, and indicates a time transgressive upper contact.

Helby (1974a) showed that the oldest known Malita Formation rocks occur at Gull 1, where the *S. quadrifidus* microflora (Anisian - Ladinian) is present. However, these rocks may be also correlated with the upper Cape Londonderry Formation. A Triassic to early Jurassic age is indicated at Plover 1 (Helby, 1974a). Mory (1988) ascribed a Carnian to Pleinsbachian age to the Malita Formation.

The red bed character of the Malita Formation suggests a generally non-marine, possibly arid environment (Petroconsultants, 1991). Mory (1991) considered the paucity of marine fossils, and the presence of 'redbeds' throughout the Malita Formation indicated a strongly oxidising, probably non-marine environment of deposition. Rare shell fragments and glauconite may have been washed in from adjacent open-marine environments.

PROSPECTIVITY

Low prospectivity. Good reservoir but no access to mature hydrocarbon source rocks.

Hydrocarbon shows

None

Source Rock

The red bed lithology of the Malita Formation contain little recognised source rock potential for either oil or gas in the Petrel Sub-basin. However, Penguin 1 is again anomalous, having a source rock quality sample (HI max of 754, TOC max of 15 %) at the very top of the interpreted Tr3 to Tr6 interval (Appendix 6, Enclosure 8), which is more characteristic of the overlying early Jurassic sequence.

Reservoir

The late Triassic to early Jurassic Malita Formation contains very fine to coarse grained sandstones with sonic derived porosities of between 12-22%. This range is comparable to core porosities, measured at Petrel 2, of 13.2 to 21.7%. A maximum 1480 mD of horizontal permeability was measured in this well at 2550m.

TIME SLICE J1 to J5 - Early to mid Jurassic (Hettangian to Bajocian)

SUMMARY (Enclosure 23 and 42)

Following Malita Formation deposition, an early Jurassic transgression resulted in the deposition of fluvial to deltaic sediments of the **Plover Formation** (formerly the Petrel A unit of Helby, 1974). The red beds were overlain by coaly sediments, though the pattern of depositional environments remained very similar to that seen in the late Triassic. An alluvial plain on the western side of the sub-basin merged basinwards into paralic environments; and estuarine conditions prevailed in the eastern embayment.

PALAEOGEOGRAPHIC INTERPRETATION

Sediments of J1 to J5 age occur in Penguin 1 and all study wells basinwards of this location. The package thickens from the basin margins to over 500 m in the centre of the Petrel Sub-basin. Sections around 200 m thick have been intersected in centrally located wells (Petrel 1, Gull 1) with intersections less than 100 m on the eastern and western margins (Tern 1, Flat Top 1). The sediments are blocky sands with minor coal and shale deposited in fluvial to coastal environments. At Flat Top 1 the frequent shaly breaks suggest a lower energy estuarine depositional regime.

The J1 to J5 package approximates the bulk of the Plover Formation. However, the Malita Formation does extend part-way into the J1 Time Slice, as the *C. torosa* zone occurs in both it, and the overlying Plover Formation (Mory, 1988). The marine influenced sands at the top of the Plover are described in the next time slice interval - J6 to K2.

The Plover Formation consists largely of sandstone, but significant siltstone and claystone interbeds occur throughout the unit. The sandstone is fine to coarse grained and often slightly glauconitic. Siltstone and claystone interbeds are usually carbonaceous, but may be slightly calcareous with rare shell fragments and glauconite. Limestone and coal are minor constituents.

PROSPECTIVITY

Low prospectivity. Good reservoir facies and some organic rich rock but the interval is immature in the Petrel Sub-basin.

Hydrocarbon shows

None.

Source Rock

The time slice interval J1 to 5 has the highest TOC (53% max, 3.5% average in ORGCHEM) and HI (750 max, 120 average in ORGCHEM) values of any the Mesozoic time slices (Appendix 5). It contrasts markedly with the low TOC's in the underlying late Triassic red beds and low hydrogen indices in the marine Cretaceous sediments.

Other studies have also recognised that the Plover Formation contains potentially fair to good oil source rocks. TOC values extend up to 2.85% at Petrel 2 (average 1.37%, 19 values, Robertson Research, 1979; Analabs, 1985), 1.36% at Bougainville 1 (average 0.90%, 6 values, Analabs, 1985), 1.11% at Curlew 1 (average 0.83%, 2 values, Analabs, 1985). According to Petroconsultants (1990), the Petrel Sub-basin contains the best source rocks in this time interval in the region. Unfortunately, in this location these rocks are immature to marginally mature at best; however in the Malita Graben and Sahul Syncline they may constitute a major source (Robinson et al., 1994) and might be implicated in recent discoveries in that area.

Reservoir

The Plover Formation, a thick sand dominated unit, has been the subject of several investigations of reservoir quality. As with the Permian Hyland Bay Formation reservoirs, the degree of diagenesis is a big factor in determining the reservoir quality of the Plover Formation. The shallower section contains more porous sandstones. In some wells, the Plover sandstones are of excellent reservoir quality (e.g. Petrel 2), but in other wells they are tight. The Plover Formation could prove to be a significant hydrocarbon-bearing reservoir for the northern Bonaparte Basin where it is buried at depths shallower than 3000 m and has log derived porosity values of between 15% and 30% (provided source rock and maturity problems can be overcome). Good reservoir characteristics are shown by the upper Plover Formation at Petrel 1, where cores have 14.3 to 24.3% porosity and vertical and horizontal permeability's in medium grained sandstones at 1970 m of 377 to 567 mD, and 359 to 943 mD, respectively. Calcareous cementation has led to erratic porosity development in the lower part of the formation. Examination of the plot in Appendix 5 shows that rocks in the J1 to 5 package have lower permeability's than in the underlying late Triassic red beds or in the sands in overlying J6 to K2 time slice interval.

TIME SLICE J6 to K2 - Mid Jurassic to early Cretaceous (Bathonian to Hauterivian)

SUMMARY (Enclosure 24 and 43)

Partially restricted marine environments became established in the outer parts of the Petrel Sub-basin, as the Plover Formation was succeeded by the Flamingo Group. Reservoir facies occur in the coastal plain deposits at the top of the Plover; and in marine sands within and at the top of the Flamingo. Intercalated Flamingo Group shales can act as localised seals and may have some source potential dependent on the level of maturation.

Enclosure 43 contains a generalised palaeogeography for the J6-K2 interval. There is a fringe of fluvial environments around the inner margin of the Petrel Sub-basin. A broad coastal plain extends beyond and wraps around the southern, eastern and northern margins to partially enclose a marine embayment.

PALAEOGEOGRAPHIC INTERPRETATION

The sands and shales of this time slice interval were intersected in Penguin 1 and in the other study wells outboard of this location. The recent discoveries on the margins of the Sahul Syncline are interpreted as being within this interval, and the age equivalent shales in the Vulcan Sub-basin have been typed as the oil source in the producing fields (Woods, 1994). Lithostratigraphically, the interval covers the top of the Plover Formation and the Flamingo Group (Mory, 1988), but lithostratigraphy has been shown to be an inadequate tool to decipher this package of sediments (Messent et al., 1994). Detailed sequence stratigraphic studies have been published on this interval in the southern Bonaparte Basin (Messent et al., 1994) and the Sahul Syncline (Robinson et al., 1994) and these results have been incorporated in this analysis.

Up to eleven depositional sequences have been recognised in this interval by Robinson et al (1994; Figure 39), but not all of these can be resolved in the Petrel Sub-basin. Two of the main sequence boundaries have been used to further divide the J6-K2 time slice package - the J7/J8 (*R. aemula/W. spectabilis* boundary) and the mid-J8 unconformity *(W. spectabilis/W. clathrata* boundary; see Enclosures 7, 8 and 9).

The J7/J8 unconformity approximates the top of the Plover Formation and is the boundary between Robinson et al. (1994) Sequences I and II. It is not the direct equivalent of the Callovian Unconformity of Woods (1994) shown to be at the *W. digitata/R. .aemula* boundary in the Vulcan Sub-basin, which differs again from the Base Callovian

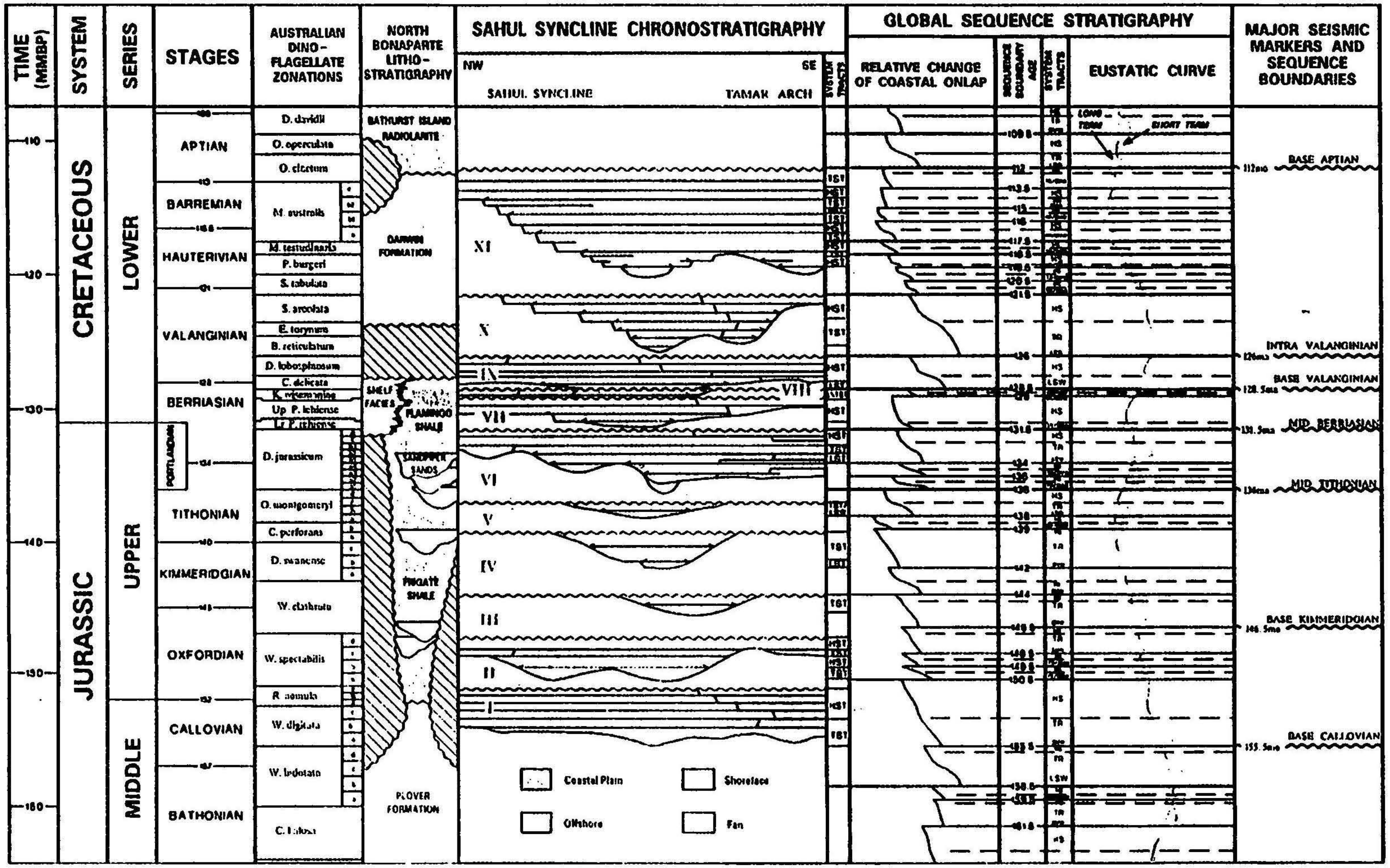


Figure 39 Sahul Syncline stratigraphy from Robinson et al. (1994)

Unconformity of Robinson et al. (1994) which is shown at the *W. indotata/W. digitata* boundary.

The Callovian Unconformity mapped by Messent et al. (1994) is shown as the coalescence of all these unconformities (Figure 40), with the hiatus stretching from top Plover in the *W. indotata* zone to the Lower Flamingo Cycle in *W. spectabilis.* In contrast to Messent et al. (1994), this study interprets the uppermost Plover package, *W. digitata* to *R. aemula*, to be present in the Petrel Sub-basin, intersected in Gull 1, Curlew 1, Petrel 1, Tern 1, Frigate 1 and Flat Top 1. It is a sandy unit deposited in coastal plain environments similar to the rest of the Plover Formation.

The Plover Formation is overlain by a basal Flamingo *W. spectabilis* package, equivalent to the widespread transgressive Sequence II of Robinson et al. (1994) and the LF1 (Lower Flamingo) sequence of Messent et al. (1994). This package is generally a sand, occasionally with a shaly base (Petrel 1), so that the Plover/Flamingo contact is often sand on sand.

At Gull 1, a *W. spectabilis* shale (2403-2440 m) is interpreted, relying on a date with a low confidence rating (Enclosure 7). Alternatively this shale can be considered as the top of the Plover Formation directly overlain by early Cretaceous Flamingo Group sands (Messent et al., 1994, his Figure 12). An incomplete section would be expected on a salt structure such as Gull, and this is indeed the interpretation at Curlew 1 where the *W. spectabilis* package is absent.

The top of the *W. spectabilis* package is the other boundary carried in this study within the J6-K2 interval, the mid-J8 unconformity. It approximates the *W. spectabilis/W. clathrata* boundary and is commonly overlain by J8 to J10 shales, dating from *W. clathrata* through to *D. jurassicum* that equate to Robinson et al. (1994) trough- restricted Sequences III, IV and V and the widespread *D. jurassicum* Sequence VI (Frigate Shale). Messent et al. (1994) also recognise a maximum flooding event in the *D. jurassicum* zone. Lithostratigraphically, the term Frigate Shale (Mory, 1988) could be applied to these shales.

There was salt movement at this time emphasising bathometric differences, producing more restricted environments in the troughs (Messent et al. (1994) and thinner sections on the active salt structures. Curlew 1 has a thin sandy section that still allows identification of the *D. jurassicum* maximum flooding surface (Enclosure 7). At Sandpiper 1, the *W. spectabilis*

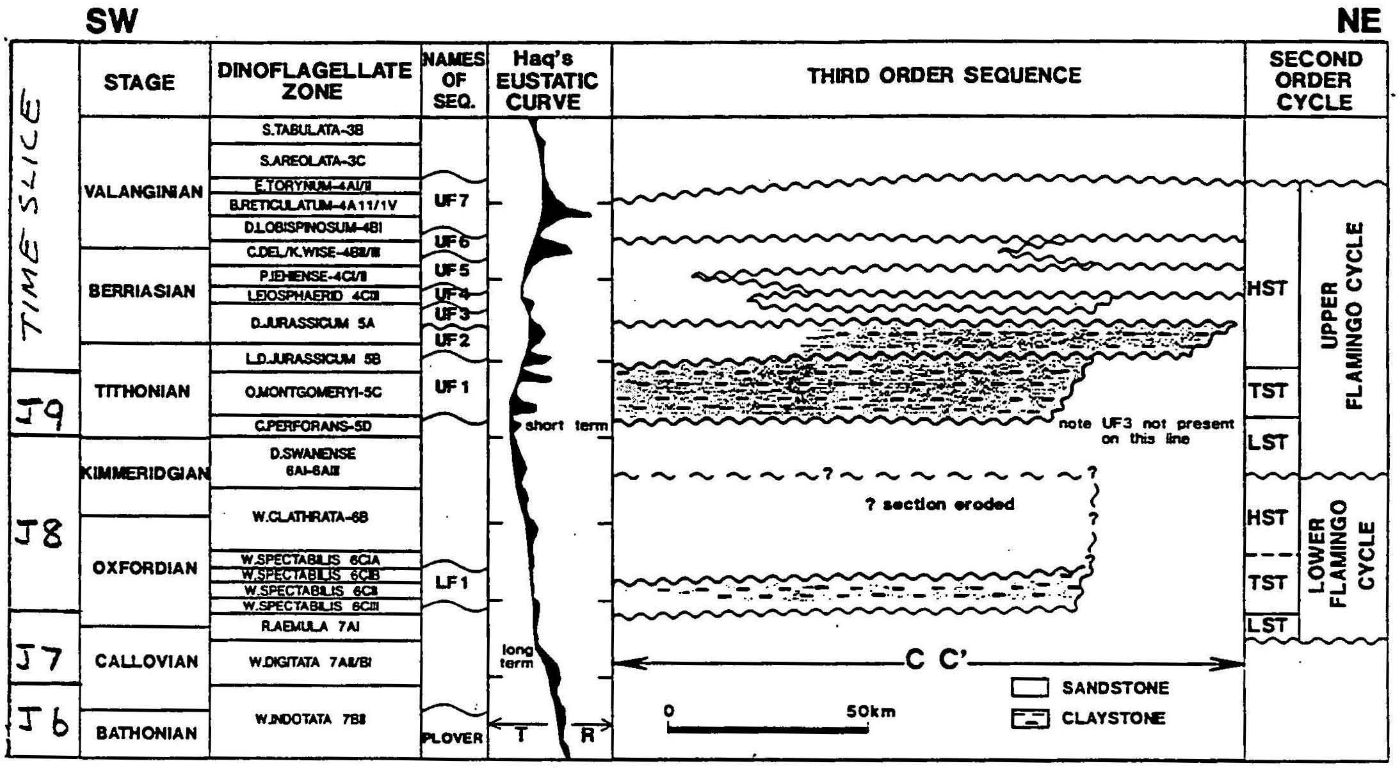


Figure 40 Petrel Sub-basin stratigraphy from Messent et al. (1994)

sand is overlain by a *C. perforans* sand. This unconformable contact correlates with the Kimmeridgian Unconformity of Woods (1994) in the Vulcan Sub-basin. At Gull 1, the *W. clathrata* to *D. jurassicum* package is absent, with the *W. spectabillis* shale directly overlain by a sand containing a *P. iehenese* (K1) date.

The K1 (*P. iehenese* to *E. torynum*) sands are the last major package in the J6-K2 interval. They represent the Sandpiper Sandstone (Mory, 1988), in the upper part of the Flamingo Group and Robinson et al. (1994) Sequences VII and IX. These reservoir quality sands were deposited in marine to paralic environments during a major progradational phase when the shoreline built out into the Malita Graben (Robinson et al., 1994, Figure 14B). The K1 sands are unconformably overlain by thin glauconitic sediments representing a condensed section deposited on a starved marine shelf of K3 to K4 age (*M. australis* to *D. davidii*). Sediments of K2 age (*S. areolata* to *M. testudinaria*) are poorly represented in the Petrel Sub-basin due to very condensed section or non-deposition.

PROSPECTIVITY

Low prospectivity. Reservoir and seal facies occur in the J6-K2 package, and some source rock quality sediments have been intersected, but low maturity is a major risk.

Hydrocarbon shows

A show comprising 300 mL of light oil (similar to diesel) and 0.55 cu. ft of gas was recovered from the late Jurassic in Curlew 1. On the balance of evidence the oil is considered to be a contaminant.

Source Rock

Some source quality samples of Frigate Shale have been reported from the Petrel Sub-basin. A maximum TOC of 1.86% was measured at Petrel 2 with an average of 1.23% (19 samples, Robertson Research, 1979; Analabs, 1985). At Tern 1, only 1 sample was analysed, with a TOC of 1.1% recorded. In the Curlew 1 well, a maximum of 1.0% TOC was reported (Analabs, 1985) with an average of 0.83% TOC (9 samples). In Fishburn 1 measured TOC in side well cores ranges between 1 and 1.5%, with hydrogen indices of around 200; and ΔlogR analysis predicts TOC of 2.5% in the *D. jurassicum* zone at the time of maximum flooding (Messent et al., 1994).

Bradshaw et al (1988) suggested that in restricted marine environments in the Sahul Syncline, Malita Graben and parts of the Petrel Sub-basin organic rich shales were deposited during the late Jurassic. The analyses from Fishburn 1 (Messent et al., 1994) support this prediction. Age equivalent shales in the Vulcan and Dampier sub-basins are proven oil source rocks and the recent discoveries in the Sahul Syncline (Elang, Laminaria, Kakatua) may prove to have a similar source. Figure 41 shows the comparative structural settings of the two areas. However, in the Petrel Sub-basin maturation must be a major risk, and long range migration from the Malita Graben must be invoked. Maturation modelling in the Fishburn area reported by Messent et al. (1994) indicates that there has not been sufficient burial for maturation to occur. The maturation model for Gull 1 presented in this report (Appendices 7 and 8) shows the Flamingo Group being early mature for oil (0.5 - 0.7 % R_o) from the Eocene to the present day.

Reservoir

In the Sandpiper Sandstone, log calculated porosities vary from 20-30% in basin margin locations to 15% in the mid-basin areas such as Curlew 1. At Petrel 1 the Sandpiper Sandstone has very good visual porosity in fine to coarse grained sandstones having log-derived porosities from 9 to 27%, supported by core porosity measurements of 10 to 26%. Permeability's from the core could not be measured owing to the unconsolidated nature of the sediment. At Flat Top 1, Steveson (1983) noted a depth-dependent change from minor diagenesis to higher degrees of quartz authigenesis with increasing burial of the Sandpiper Sandstone. However, the degree of diagenesis is low enough that cementation has not significantly reduced primary porosity. It is possible that the high silicification noted by Steveson from cuttings in the lower part of the section may be derived from quartzitic pebbles (Petroconsultants, 1990). Log derived porosities range between 25 to 30% and a FIT indicated a permeability of 450 mD. Killick and Robinson (1994) described the late stage diagenetic kaolin formation in these rocks as having been inhibited by oil where it is present.

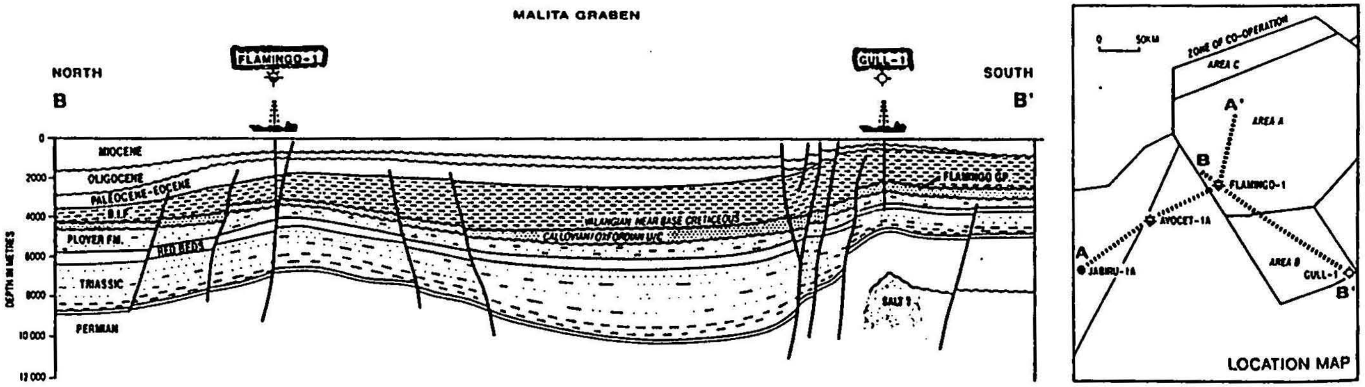


Figure 41 Schematic cross-section between Flamingo-1 and Gull-1 displaying tectonic framework of the Malita Graben (From Botten and Wulff, 1990)

TIME SLICE K3 to K4 - Early Cretaceous (Barremian to Aptian)

SUMMARY (Enclosures 25 and 44)

The Petrel Sub-basin comprised a shallow to very shallow marine starved shelf with thin but widespread deposition rich in glauconite (Darwin Formation of the Bathurst Island Group). Much of Australia was submerged at this time (BMR Palaeogeography Group, 1990) and the Petrel Sub-basin was far removed from the shoreline, except for its western margin.

PALAEOGEOGRAPHIC INTERPRETATION

The K3 to K4 interval is a few tens of metres thick or less in well intersections in the Petrel Sub-basin (Enclosures 7, 8, and 9). These sediments, along with any preserved K2 section recognised, represent the initial Bathurst Island Group deposits, the Darwin Formation. They resulted from a regional marine transgression over the Valanginian (K1/K2) unconformity. The late Valanginian to Aptian Darwin Formation is not well preserved across the Petrel Sub-basin due to subsequent erosion, probably caused by sea level fluctuations. An unnamed basal to mid Albian unit of greensand/radiolarite shale was then deposited. This unit too is poorly preserved.

The Bathurst Island Group (Bathurst Island Formation of Hughes and Senior; 1974; Hughes, 1978) is a lithologically variable group which consists of siltstone, mudstone, marl, limestone, and sandstone. It overlies the 'Valanginian unconformity', and is conformably or disconformably overlain by Cainozoic carbonate and clastic rocks. The bulk of the group is made up of the younger Wangarlu Formation (K5 to K11).

Early Cretaceous marine sandstones and shales are present in the Port Keats area (Dickins et al, 1972). The precise stratigraphic equivalence of these outcrops is uncertain, but the age and abundant radiolarians reported suggest correlation with either the Darwin Formation or the overlying unit.

PROSPECTIVITY

Non prospective

Hydrocarbon shows

None, excepting the assumed diesel contamination in Curlew 1.

Source Rock

This time slice interval has little potential as a viable source rock being thin and probably immature throughout the Petrel Sub-basin (Appendix 6, VR maps). However, at Flat Top 1 source rock quality sediments have been sampled (HI max 183, TOC max 44 %; Appendix 6).

Reservoir

Reservoir is absent in this time slice.

TIME SLICE K5 to K11 - Early to late Cretaceous (Albian-?Maastrichtian)

SUMMARY (Enclosure 26 and 45)

Shallow marine environments with sporadically developed reefs and offshore bars prevailed throughout the later Cretaceous of the Petrel Sub-basin.

PALAEOGEOGRAPHIC INTERPRETATION

In the later Albian (C1-C2 foram zones), a sequence of carbonates, called the Brown Gannet Limestone, was deposited across the basin. The carbonates thin eastwards and in some areas (e.g. Shearwater 1 area) grade into shales. Overlying the carbonates are the thick siltstones, mudstones, shales and minor limestones of the Wangarlu Formation, which was deposited on the inner to distal shelf. The sequence is more sandy towards the basin margins and becomes more calcareous to the northwest. In excess of 2000 m of this unit was deposited in the Malita Graben and Sahul Syncline thinning to the south and west over the basin margins, as well as to the north over the Sahul Platform.

During the Turonian sea level maximum (Haq et al., 1987), a series of eustatic events led to the deposition of shoaling cycles and incursion of the Moonkinu Sandstone member from the east. The offshore facies equivalent of the Moonkinu is the Vee Formation, which was deposited in shelf to outer shelf environments. The sequence is condensed to the northwest where marls become the dominant lithology (Mory, 1991).

Eustatic falls in sea level during the later Cretaceous (Campanian and Maastrichtian), possibly accompanying structural movements of the basin margin to the northwest, resulted in the deposition of the marine siliciclastic sequences. The Curlew 1, Jacaranda 1 and Darwinia 1A wells contain glauconitic sands, which become shalier basinward and are equivalent to the Turnstone Formation marls in the Sahul Platform wells. Outer shelf and slope deposits have been recognised in the top Cretaceous sequence (C12 foram zone) at Shearwater 1, based on foraminifera.

PROSPECTIVITY

Low prospectivity. Reservoir facies occur in the upper part of the interval, above the regional shale seal. Access to mature source rock is unlikely.

Hydrocarbon shows

Gas indication in upper Cretaceous sands at Curlew 1.

Source Rock

In the offshore area, the mid to late Cretaceous Bathurst Island Group generally has poor to fair source potential as indicated by TOC values, and where contents are sufficiently rich, the organic matter appear to be gas-prone. BP reported 5.5% TOC from picked cuttings in the Petrel Sub-basin in the Wangarlu Formation, and 1.26% was measured in the Wangarlu Formation at Petrel 2.

Reservoir

Campanian glauconitic sandstones, and Maastrichtian sandstones of the Puffin Formation, occur at shallow depth in Curlew 1 in the northern portion of the Petrel Sub-basin. These sandstones are time equivalent to the oil-bearing sands tested in the Puffin wells in the Vulcan Graben. The sands and sandstones are mainly medium to very coarse grained with mild burial induced diagenesis and some calcareous cementation (Rahdon, 1982). Some sideritic cementation was noted by Steveson (1983) at Curlew 1.

TIME SLICE Cz4 to Cz7 - Tertiary to Quaternary (Oligocene to Pleistocene)

PALAEOGEOGRAPHIC INTERPRETATION (Enclosure 27 and 46)

The northward tilt of the Petrel Sub-basin, established during the Cretaceous was maintained throughout the Cainozoic. Along the axis of the Petrel Sub-basin and in the Malita Graben and Sahul Syncline, Paleocene to Miocene sediments were deposited with a hiatus occurring during the Oligocene (Mory, 1988). The lower section is generally a sandy sequence grading upwards into a widespread shelfal carbonate development during Miocene time which appears to have transgressed the palaeotopographic highs.

PROSPECTIVITY

Non prospective

Hydrocarbon shows None.

Source Rock

These rocks are thin to absent within the Petrel Sub-basin.

Reservoir

Reservoir characteristics of the Tertiary formations have not been investigated in this study.

GEOCHEMISTRY ANALYSES

INTRODUCTION

This geochemical analysis is based on the analysis and integration of Rock-Eval data from the ORGCHEM database. Printouts of these summarised data have been compiled in Appendix 5. Graphical plots of TOC's, HI's, vitrinite reflectance's and Tmax values are presented in Figure 42 and Appendix 7. Plots of the data for each timeslice studied are contained in Enclosures 11 to 27.

As a general exploration philosophy, it is necessary to understand the spatial and temporal distribution and the type of petroleum source rocks. Figures 3 and 4 show the outline of key parameters required in defining the petroleum systems and providing better prediction of prospective targets. Due to limited resources and time constraints, this study has only focussed on the key parameters for each of the timeslices studied. An earlier work by Kraus and Parker (1979) treated the subject similarly but concentrated on only five timeslices.

Figures 3, 4 and 9 show the relative stratigraphic and structural positions of the major oil and gas accumulations intersected by the study wells. The definition of the hydrocarbon show symbols is outlined in Appendix 1. Most of the hydrocarbon discoveries have been made in late Permian and Carboniferous rocks. The hydrocarbons are generally considered to have been sourced from the Devonian, Carboniferous and Permian intervals and several phases of hydrocarbon generation have clearly occurred within the Petrel Sub-basin.

The following list is a guide to maturity evaluation. It compares vitrinite reflectance values and their interpreted hydrocarbon generation phases:

Ro (0.5% - 1.2%)	window for oil generation
Ro (1.0%)	peak wet gas generation
Ro (2.0%)	limit of wet gas generation
Ro (1.5%)	peak dry gas generation
Ro (3.0% - 4.0%)	limit of dry gas generation

Maturity levels required for hydrocarbon generation are significantly affected by source rock type. Source rock type is determined by the organic matter (kerogen) content.

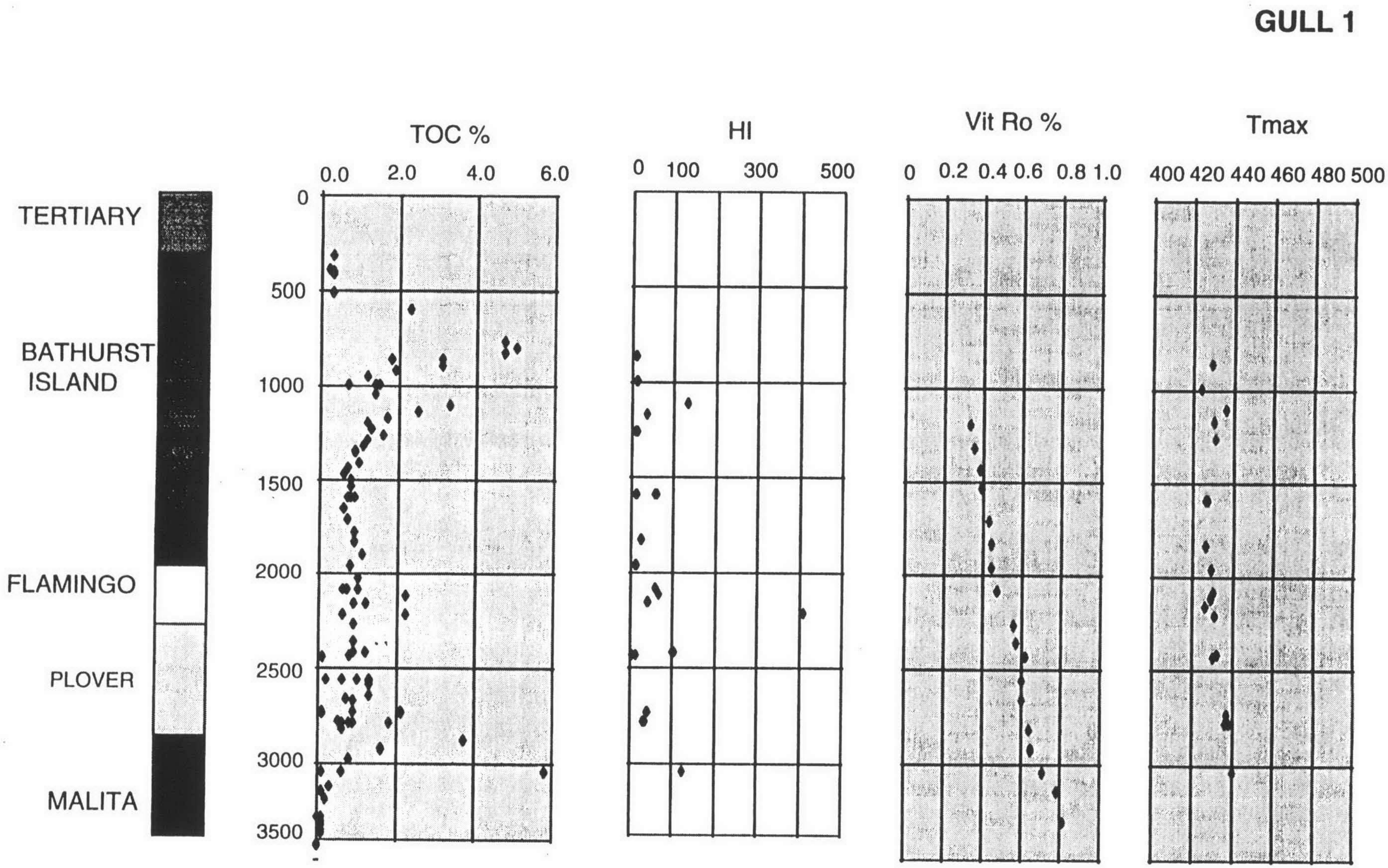


Figure 42 Example profiles of vitrinite reflectance, Tmax, TOC, and HI for Gull 1 well in the Petrel Sub-basin.

Hydrocarbons are generated when the organic matter is chemically altered due to increasing temperature. Pyrolysis provides a guide to the type of organic matter that is present in the sample (Espitalie et al, 1977; Tissot and Welte, 1978).

Three peaks are normally observed in pyrolysis analysis. The S1 peak represents already existing bitumen (soluble hydrocarbons) and the S2 peak represents hydrocarbons generated from the thermal breakdown of kerogen. The S3 response is produced by oxygen bearing compounds released at high temperatures.

The S1 and S2 peaks can be used to assess the oil generating potential of the sample. The S2 and S3 peaks can be used to calculate hydrogen index and oxygen index, which together indicate the type of kerogen present in the sample. The temperature corresponding to the S2 peak, and the S1/ (S1+S2) ratio indicate the level of thermal maturity.

A petroleum charge only occurs when hydrocarbons generated in a source rock are effectively expelled and migrated to a trap. The timing of expulsion is dependent on the kerogen type and its associated maturation requirements.

According to Espitalie et al (1977), petroleum expulsion is probably caused by microfracturing of the source rock after an overpressure build up due to hydrocarbon generation. Lean source rocks may not generate sufficient volume of oil to cause expulsion but at higher maturity, the generated oil may eventually 'crack' to gas and develop sufficient pressure for expulsion. Rich source rocks have a high efficiency of oil expulsion.

Mackenzie and Quigley (1988) were able to classify three types of source rocks, based on their generative and expulsion efficiency. Petroleum Generation Index is the fraction of petroleum-prone organic matter that has been transformed into petroleum and the Petroleum Expulsion Efficiency (PEE) is the fraction of petroleum fluids generated in the source rock that have been expelled.

Class I are rich source rocks containing mainly labile kerogen at concentrations greater than 10 kg/tonne. Generation starts at about 100°C as labile kerogen generates an oil-rich fluid and rapidly saturates the source rocks. Between 120-150°C, 60-90% of the petroleum is expelled as oil with dissolved gas. The remaining fluid is cracked to gas at higher temperatures and expelled as a gas phase initially rich in dissolved condensate.

Class II are lean source rocks comprising labile kerogen at concentrations of less than 5 kg/tonne. Expulsion is very inefficient up to 150°C because insufficient oil-rich petroleum is generated. Petroleum is expelled mainly as gas-condensate formed by cracking above 150°C, followed by some dry gas.

Class III source rocks contain mostly refractory kerogen. Generation and expulsion takes place only above 150°C, and the petroleum fluid is relatively dry gas.

Geochemical composite logs are presented in Appendix 7. The vitrinite reflectance and Tmax profiles provide a visual estimate of the maturity levels at the well location. The Total Organic Content and HI profiles provide an estimate of the source richness and the remaining potential yield. The Hydrogen Index profile provides a guide to the source type and when compared with the other curves, its relative maturity level.

From the geochemical composite logs, a qualitative assessment of the main source interval timeslices were made, based on the following criteria:

Ro (0.0%-0.5%) immature
Ro (0.5%-1.0%) oil window
Ro (1.0%-1.2%) oil/gas transition
Ro (>1.2%) gas window
Tmax (<415°C) immature
Tmax (415°C-435°C) transition to oil window
Tmax (435°C-460°C) oil window
Tmax (>460°C) gas window
Total Organic Content (0.0%-1.0%) Poor source rock quality
Total Organic Content (1.0%-2.0%) Fair-Good source rock quality
Total Organic Content (>2.0%) Good source rock quality
S1+S2 (0-2 kg/tonne) Poor source rock quality
S1+S2 (2-5 kg tonne) Fair to good source rock quality, late expulsion
S1+S2 (>5 kg/tonne) Good source rock quality, early expulsion
Hydrogen Index (0-200 mg HC/ g C) Gas prone, post mature source rock
Hydrogen Index (200-500 mg HC/ g C) Oil/gas prone, mature source rock
Hydrogen Index (>500 mg HC/ g C) Oil prone, immature source rock

TOC, HI and Ro (VR) for each time slice are shown in Appendix 5.

The geochemical plots indicate that Type III source rocks are dominant in the Petrel Sub-basin although Type II source rocks were deposited at various times. Type I source rocks were not identified but may be present in various deeper areas not yet sampled. The general implication is that most hydrocarbons generated in the Petrel Sub-basin are likely to be gas prone.

Type III source rocks are humic, that is, they contain kerogens that are made up of essentially vitrinite and inertinite. Vitrinite is derived from the lignin and cellulose component of plant tissues, and generates predominantly gas (Allen and Allen, 1990). Inertinite is also from lignin and plant cellulose but has been oxidised or biologically degraded and has little (gas) or no generating potential. The transition zones between source rock types are gradational and therefore source rocks deposited at various palaeogeographic locations may contain varying proportions of each organic matter type.

In some areas, the source rock quality is much better ranging from fair to good with Type II organic matter present. This implies that TOC levels are high and the source rocks are more prone to generating significant volumes of oil and gas at much lower maturity levels. However, the areas with lean source rocks are likely to generate light oils and condensates due to the higher maturity levels required to efficiently expel the hydrocarbons into the system. Source rocks in the Carboniferous Milligans, Tanmurra and Keyling Formations and the late Permian Fossil Head Formation have the best oil source potential and could be expected to have produced as yet undiscovered Larapintine-Gondwanan Transition/Gondwanan 1, 2 oil fields in the basin areas where the timing of these systems can work. Good source rock intervals are also present in intervals ranging from late Triassic to early Cretaceous. Additional work is required to assess detailed palaeogeographic controls on oil prone source rock distribution. Maturity levels, migration pathways and the timing of trap formation need detailed assessment to mature the potential large oil plays within the Petrel Sub-basin.

PETREL SUB-BASIN SOURCE POTENTIAL (quantity and quality)

As indicated above, the presence of hydrocarbons in the form of oil recoveries from Turtle 2 and Barnett 2, plus gas at Weaber 1, and the substantial gas reserves in the Petrel and Tern structures indicate that the Petrel Sub-basin has generated considerable quantities of hydrocarbons.

The amount and quality of total organic carbon (TOC) contained within a rock is a prime determinant of its source potential. In clastic rocks 0.5% TOC is generally accepted as the minimum requirement to constitute a viable, hydrocarbon source rock, although as little as 0.2% may be adequate for carbonates (Tissot and Welte, 1978). The average TOC values for selected timeslices, calculated by averaging all measured TOC contents for available wells, are plotted in Appendix 5.

BURIAL AND THERMAL GEOHISTORY

The timing of hydrocarbon generation is variable across the Petrel Sub-basin, primarily due to the level of maturation of the source rocks. Burial geohistory plots in Appendix 8 provide a good cross-section of the maturation timing within basin. Figures 43, 44 and 45 are examples of burial history plots, modelled heat flows and maturation timing for Gull 1. The plots indicate the onset of the hydrocarbon generation varies shoreward along the axis of the basin due to increasing and earlier depths of burial. Flamingo 1 (Arco Australia Ltd, 1971b) is included to provide a regional perspective.

The following section describes some of the subsidence and thermal history details that were included in the modelling. The AGSO regional deep seismic data indicates two important "shelf break" features that are each believed to be important controls on maturation timing within the basin.

VITRINITE REFLECTANCE

Vitrinite reflectance data ($R_o$max %) for individual wells in the Petrel Sub-basin are plotted against depth (KB) in Appendix 7. The measurements come from the ORGCHEM database and include sources such as Robertson Research (1979), Analabs (1984, 1985) and BP (Heffernan and Mason, 1984).

A description of maturity in each of the main basin regions follows.

Offshore Petrel Sub-basin. At Bougainville 1, the $R_o$max data show a steady increase in maturation with depth. The top of the main oil generation window is at about 2800 m with the rocks at total depth only just achieving this level (Robertson Research values). Values from other wells are scattered but no maturation level higher than that of the main oil zone was observed in any of the wells studied. The Curlew 1 data may indicate a

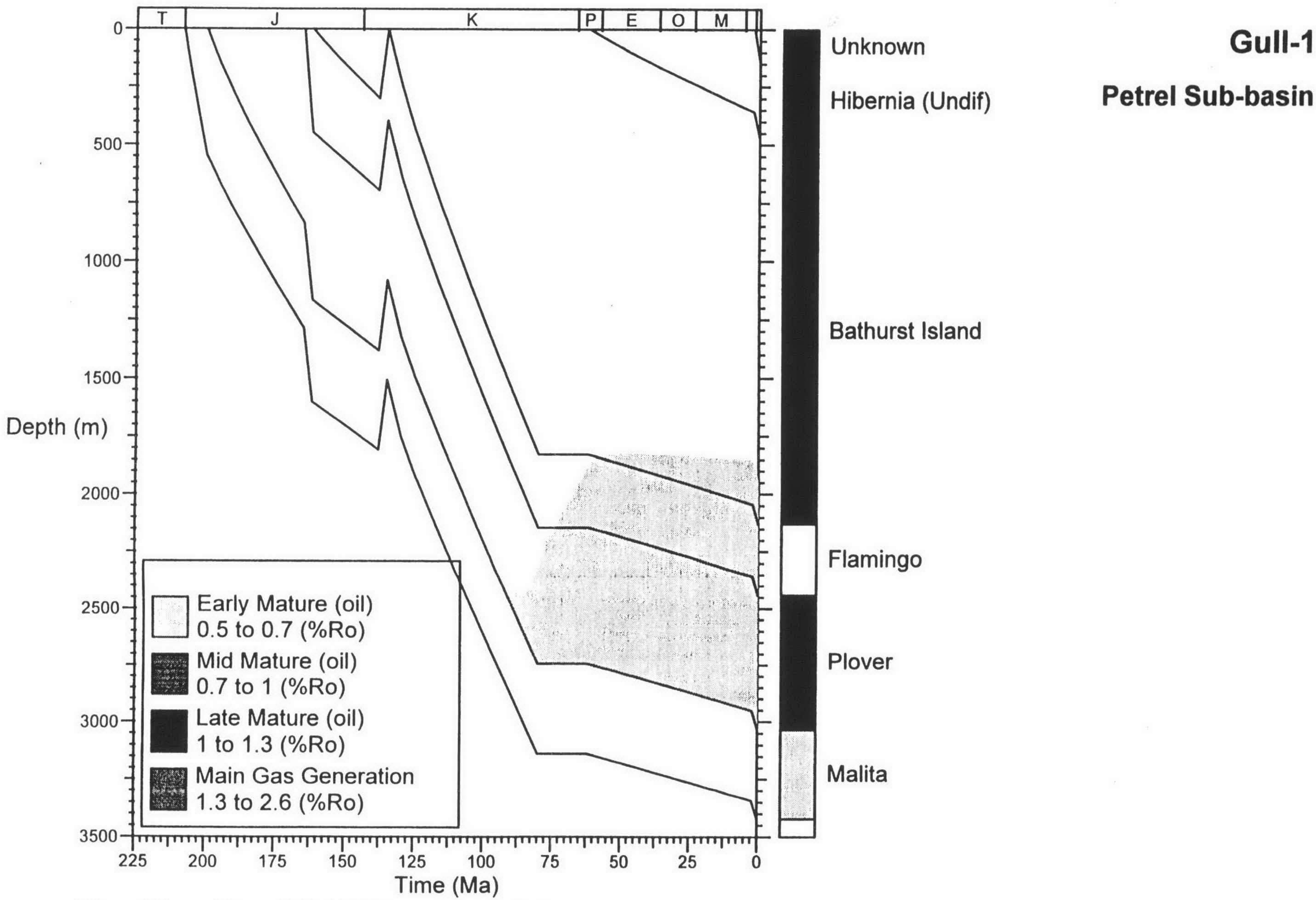


Figure 43 Example burial history plots for Gull 1 well in the Petrel Sub-basin.

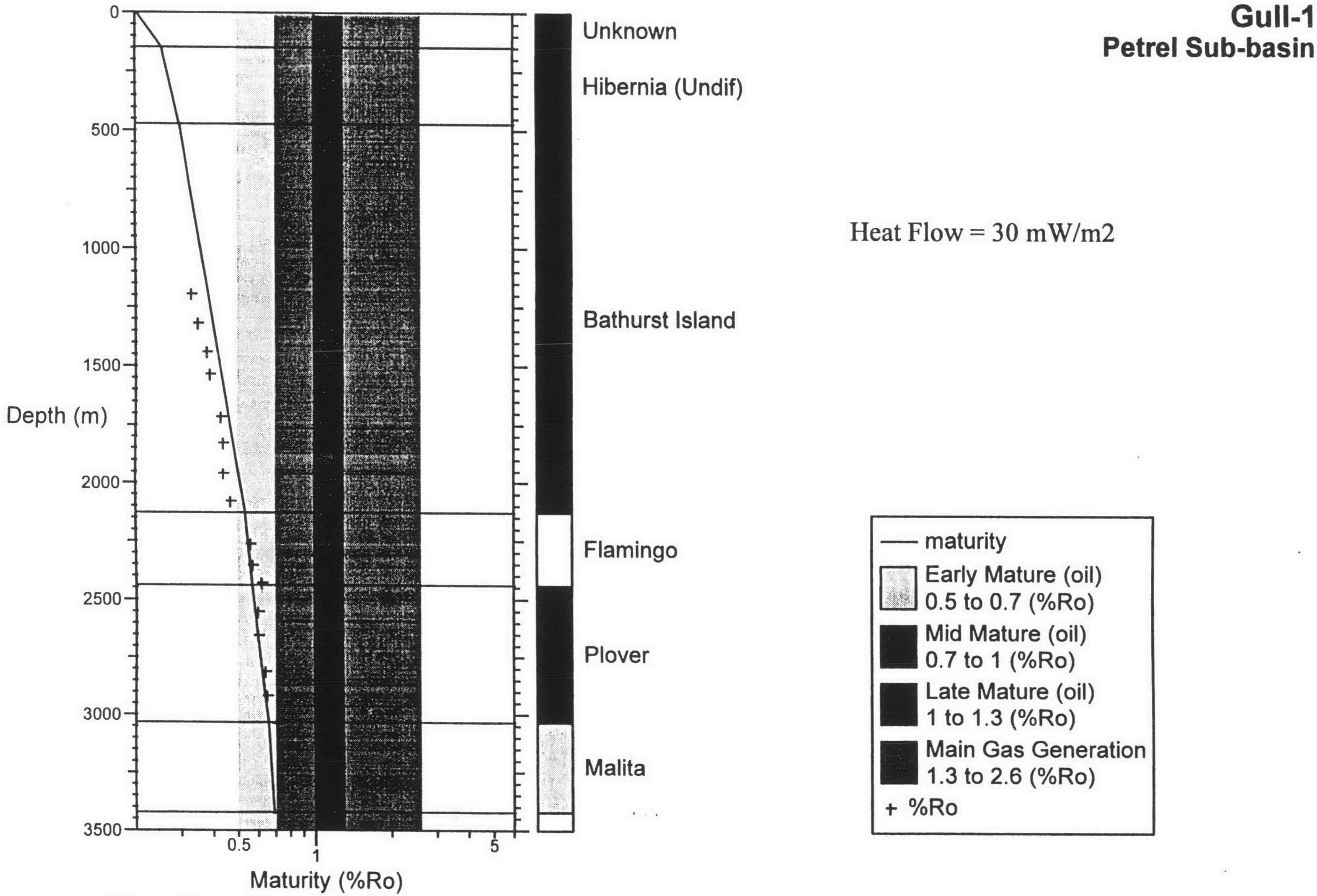


Figure 44 Example modelled heat flows for Gull 1 well in the Petrel Sub-basin.

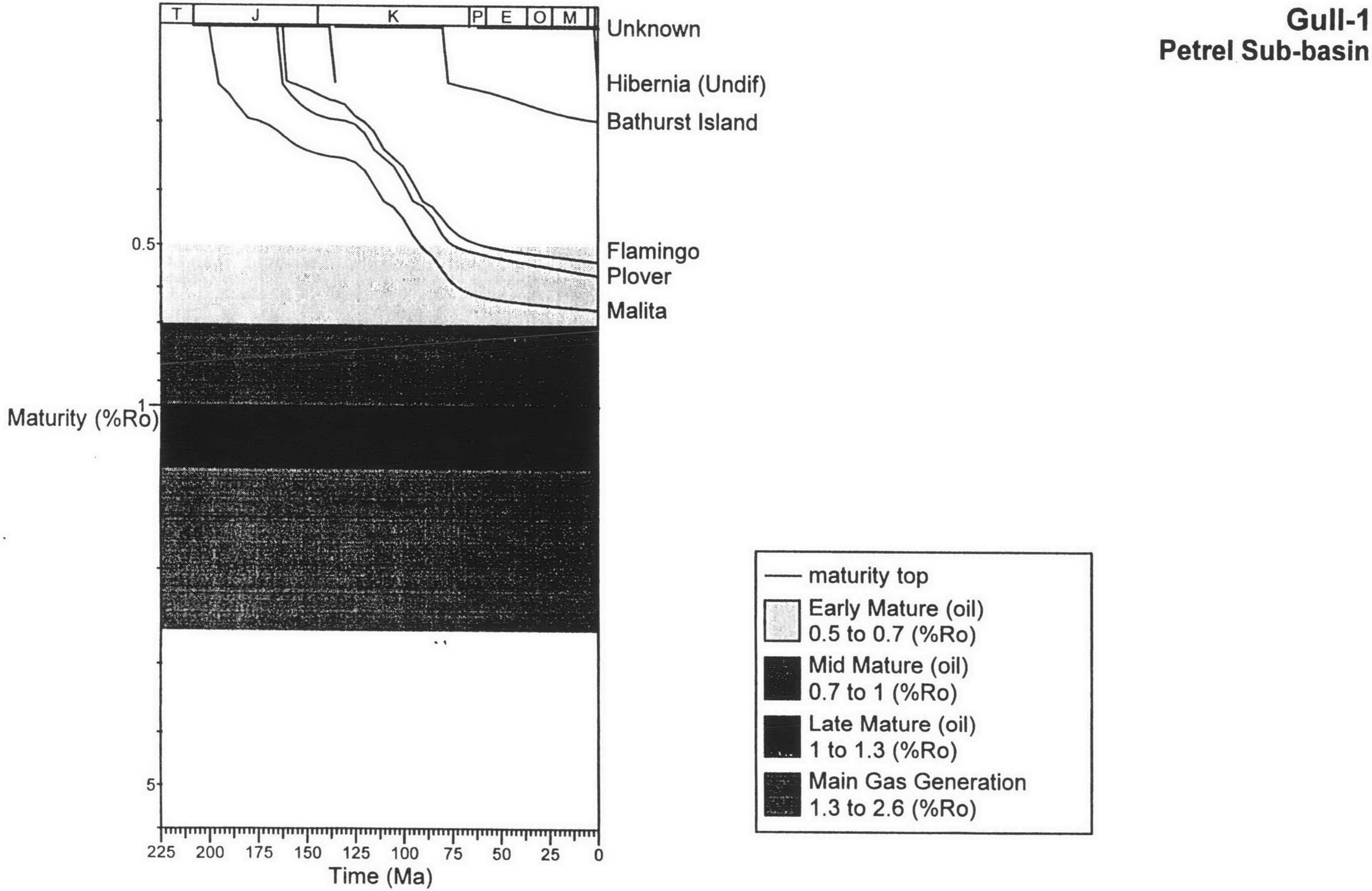


Figure 45 Example maturation timing for Gull 1 well in the Petrel Sub-basin.

slightly higher maturation curve, possibly related to the quite recent uplift of the structure, as evidenced on seismic profiles. Scattered high maturity values from Flat Top 1 may be the result of reworking of older vitrinites into younger sediments in this near basin-margin well or possibly related to hydrothermal fluid flow through the regional aquifer system within the Hyland Bay Formation during basin compaction.

The best sampled well is Petrel 2. Rocks at a depth of about 1850 m are currently in the phase of main oil generation, with the onset of the late oil generation stage occurring at a depth of about 3350 m.

Onshore Petrel Sub-basin. There is a paucity of maturation values for the onshore area of the Petrel Sub-basin. Data for Weaber 1, Kulshill 1, and Kulshill 2 suggest a relatively steady maturity gradient, with the onset of the main oil generating zone at about 1200 m. The base of the oil zone is not well constrained but is possibly as deep as 4000 m. The gas in Weaber 1 was probably generated at depth and migrated into the structure.

The data from Keep River 1 indicate a very different maturity profile from that at Kulshill 1, and show a very steep gradient (Appendix 7) and a rapid passage through the oil generation zone (about 2000 m). Hydrothermal fluids may have moved through aquifers at the site of Keep River 1 which exhibits a maximum vitrinite reflectance level of 6% (semi-anthracite) prior to lower values nearer to TD.

PRISTANE TO PHYTANE RATIOS AND DERIVATIVES

A plot of pristane/n C_{17} against phytane/n C_{18} (Connan and Cassou, 1980) can give information regarding the origin of the kerogen and the maturation stage reached. Available data were plotted by Petroconsultants (1990) for several source rocks horizons in the late Carboniferous to early Permian (Kulshill Group) timeslices .

Kuriyippi Formation kerogens from Kulshill 1 (Figure 46) plot as humic sources with moderate maturity. This maturity is consistent with the $R_o$max at 1332 m of 0.67%, that is, early mature. The pristane/phytane values are high (3.9 to 4.26) confirming the low maturity, and suggest a peat-swamp depositional environment. Dr A. Murray (personal communication, 1995) suggested pristane/phytane ratios are a function of both oxidation and maturity. A ratio greater than 3 suggests oxidised non-marine deposition, 1 to 3 fluvio-deltaic deposition and less than 1 marine anoxic conditions.

prystone/phystone ratio f (oxygen, maturity) >3 oxidised non-marine 1-3 fluvio-deltaic <1 marine anoxic

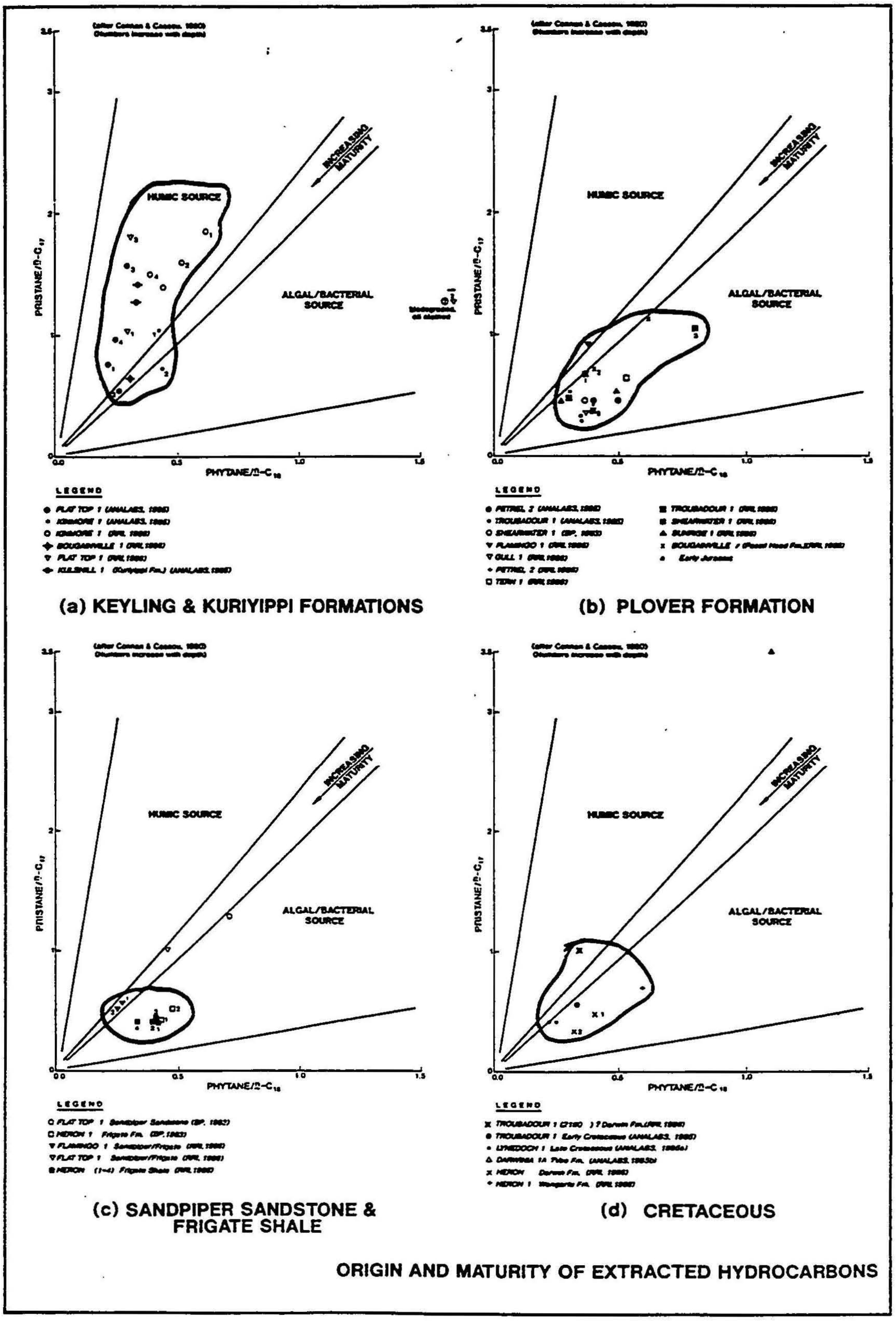


Figure 46 Origin and maturity of extracted hydrocarbons from the Petrel Sub-basin (From Petroconsultants, 1990)

Similarly, kerogens for the Keyling Formation at Flat Top 1 (Appendix 7) exhibit low to moderate maturity and were derived from humic sources, consistent with the fluvio-deltaic origin of the Keyling (Mory, 1988). $R_o$max values range from 0.63 to 0.84% in the well in line with the indicated maturity. The pristane/phytane values (2.53 - 4.23) are also consistent with a peat-swamp environment. At Kinmore 1, the Keyling has similar attributes, but an algal/bacterial source character is also present suggesting possible bacterial degradation of the original humic source material (Petroconsultants, 1990). Low maturity is suggested by $R_o$max values between 0.48 and 0.56%.

At Petrel 2, Plover Formation samples plot as early mature algal/bacterial sources. This is confirmed by low pristane/phytane values (0.83 to 1.85) and $R_o$max in the range 0.55 to 0.58% (Petroconsultants, 1990).

Flamingo Group kerogens plot as mostly algal/bacterial sources except when the facies is distinctly sandy (Sandpiper Sandstone). When they plot as mixed algal/bacterial and humic sources (Flat Top 1), this probably reflects a greater input of land plant derived organic matter (Petroconsultants, 1990).

Later Cretaceous kerogens show a wide scatter of source affinities. Most are interpreted as being of algal/bacterial affinity.

CONODONT COLOUR ALTERATION INDEX

Conodont colour alteration indices (CAI, Epstein et al., 1977) are available for several onshore wells (Weaber 1, Spirit Hill 1, Kulshill 1, Keep River 1, Bonaparte 1 and 2), several shallow mineral exploration holes and outcrop.

In general, CAI's from outcrop and shallow boreholes are CAI 1 (Dr R. Nicoll personal communication, 1994), whereas those from the deeper wells are indicative of higher maturation. In addition, a single conodont recovered from cuttings between 560 and 590 m in Weaber 1 has a CAI of 1 to 1.5 (Jones and Nicoll, 1983, in Garside, 1983), indicating prime oil maturity in the Waggon Creek Formation of that well (Petroconsultants, 1990). It is clear from the available data that most of the onshore Petrel Sub-basin rocks are at least mature for oil generation. Post-oil maturity occurs in Famennian rocks at about 3970 m in Kulshill 1 and the lower section at Keep River 1.

DISCUSSION

Low maturation in the Milligans Formation is shown by vitrinite reflectance data (Lacrampe et al., 1981) from between 76 and 147 m in a series of shallow mineral exploration holes near the Bonaparte wells, and north and northeast of Spirit Hill 1, where the highest $R_o$max is only 0.68% and most values are less than 0.5%. Conodont colour indices from outcrop and shallow boreholes in the same areas support this immaturity for the surficial sediments, irrespective of age of the formation sampled. In general, the rocks do not enter the main phase of oil generation until about 1200 m (Petroconsultants, 1990).

The notable exception to this generalisation is at Keep River 1, where both vitrinite and CAI indicate a very high maturity gradient with depth (Appendix 7). Petroconsultants (1990) considered these high vitrinite values may be related to several factors.

a) Proximity to igneous intrusions (although not known in the basin).

b) Reworked vitrinites from an older terrain (unlikely unless of Cambro-Ordovician age and therefore not vitrinite).

c) Misidentification of organic macerals as vitrinite (possible although unlikely).

d) Carbonisation of cutting samples by heating on well site (possible but unlikely to be of long enough duration).

e) Proximity to mineralising fluids causing locally enhanced thermal maturation (the Sorby Hills Mississippi Valley Type lead-zinc deposit occurs nearby, Jorgensen et al., 1990; Rowley and Lee, 1986).

The CAI data from the Keep River 1 well are extremely high. While CAI is known to be influenced by epithermal mineralisation, there is no alteration of the conodonts at Keep River 1 (Dr R. Nicoll, personal communication, 1995). Furthermore, no mineralisation is reported from the well (Caye, 1969). The reason for these high maturities remains uncertain. It is possible that the $R_o$max readings may be affected by mineralisation. Alternatively, salt intrusion into the area corresponding to the no record seismic zone to the south of the well is a possibility, with enhanced maturation due to the proximity of the salt stock (Petroconsultants, 1990). The highest maturity in Kulshill 1 occurs at the base of the well where the rocks may be in closest contact with the underlying diapiric salt core.

Maturity data from the onshore Petrel Sub-basin does not support any marked change in maturity gradients in this area, at least in rocks younger than the late Carboniferous. However, wells in the Malita and Calder Grabens, and on the immediate flanks of these structural features, show a marked change in maturity gradients at about the Albian - Aptian boundary. It has been suggested by Petroconsultants (1990) that this change reflects the relatively sudden cessation of rifting in the grabens and relocation of the heat source elsewhere, probably to the north and west of the, Sahul Platform, sometime in the early Cretaceous. This event is approximately coincident with the initiation of new oceanic floor in the mid Valanginian, and it is tempting to consider the two are related (Petroconsultants, 1990).

High geothermal gradients in the Bonaparte Basin have been noted by several authorities (e.g. George, 1972), who invoked proximity to volcanic activity. There is some supporting evidence for volcanic sources from basaltic intrusions (Reeckmann and Mebberson, 1984) and a probable intrusion is evident on AGSO deep seismic line 100/5P1 at 6 to 7 seconds depth under SP 2800 (Enclosure 50). But such intrusions are thought to be early Permian in age and some sections showing high geothermal gradients are younger. Alternatively the high geothermal gradients may be an artefact of very high thermal conductivity associated with salt intrusion. Local anomalously high heat flows, more than double the ambient level, are well documented around salt piercement structures (Warren, 1989).

GEOTHERMAL GRADIENTS

Petroconsultants (1990) determined geothermal gradients using maximum bottom-hole temperatures recorded on the logging runs and adding an arbitrary 10% to compensate for the lack of equilibrium between the circulating mud and surrounding formation, and a surface intercept temperature of 25° C, following Horstman (1988). In the current study these data were calculated from modelled maturity profiles based on burial history models and the available reflectance data (Figures 43, 44 and 45; Appendix 8).

Petroconsultants (1990) observed that in several older wells inconsistencies were noted in the bottom hole temperatures recorded on the log headers, and often the period since circulation had stopped was not recorded. It was also noted that several wells either bottomed within, or adjacent to evaporites, which may give spuriously high geothermal gradients depending on the heat conductivity of the salt (Warren, 1989). The presence of faulting associated with salt diapirism producing convective fluid flow is also possible. Similarly, as outlined above, the basin may have been subjected to several heating events, which in some regions may still be manifest as high ambient heat flow levels.

Petroconsultants (1990) contoured temperature gradients at 5° C/km interval. A region of high geothermal gradient occurs in the southern Petrel Sub-basin, and another is associated with the Malita Graben and Sahul Platform (see also Horstman, 1988; his Figure 3). The high gradient in the southern Petrel Sub-basin may be due to the presence of thick evaporitic sequences beneath the basin. The reason for the increasing gradient on the Sahul Platform and Malita Graben is unknown, but may also be related to evaporites at depth or possibly Tertiary tectonism.

In the current study, a high calculated heat flow in Curlew 1 was determined from burial history analysis compared with a low calculated heat flow for Gull 1 suggesting that local variations may be complex (Appendix 8).

CONCLUSIONS

The various areas of the Petrel Sub-basin have undergone substantially different geothermal histories and consequently display characteristic and different thermal maturation profiles.

The onshore portions of the basin show no evidence for excessive or changing geothermal heating in the Kulshill area, and a virtual straight line maturity gradient can be assumed. In the Kulshill area the oil floor may also be as deep as 4000 m (Petroconsultants, 1990). Marked changes in gradients may be caused by movement of Mississippi Valley type mineralising fluids. These may explain the anomalous Keep River 1 maturity profile.

The Malita and Calder Grabens, and immediately adjacent areas were subjected to a higher geothermal gradient possibly due to incipient rifting which probably ceased about mid-Valanginian time. Subsequently a normally decaying geothermal gradient was established. This higher heating is not observed in the data from the Petrel Sub-basin.

CONCLUSIONS

The Petrel Sub-basin is sparsely explored in many areas. Apart from the plays identified during the current and previous studies, with further exploration there is considerable scope for identifying and refining many additional play types and targets. The petroleum systems that offer potential for economic hydrocarbon accumulations are well constrained and the sub-economic oil and gas fields discovered to date provide a firm basis for the belief that future commercial discoveries will be made.

To date many of the well tests, particularly in the upper Permian, have been biased towards the deeper, and hence more mature, portions of the basin where sequences are likely to be gas prone. There are several untested prospects in along the eastern margin of the Petrel Sub-basin. Some of these could be early traps capable of determining the late Permian oil potential of the basin. This Gondwanan play is untested in the favourable southeast part of the basin.

Future exploration efforts directed in offshore areas towards shallower Cretaceous reservoirs and reservoirs located in structurally shallower basinal positions appear difficult to justify given the lack of source rock, low maturities and consistent failures of such tests to date. Part of the reason for these failures compared to the nearby and similar Sahul Platform may be the lack of fault conduits to enable hydrocarbon charge of the shallower section. The distribution and character of source rock in the Malita Graben is also poorly defined. The probable lack of significant gas charge from the graben could mean that Westralian tests at the very margin and within the Malita Graben are a better strategy.

Onshore, detailed seismic coverage should enable far superior definition of structural and stratigraphic traps located in what are now established oil and gas bearing sequences. The Kulshill area, which is stratigraphically similar to the sections that recovered oil at Turtle and Barnett, holds significant promise for potentially economic Barnett 2 type discoveries.

The existing acreage opportunities within the Petrel Sub-basin, particularly the late Permian oil play inboard of the Petrel Gas Field and south of Flat Top 1, offer much scope for future successes.

REFERENCES

ALLEN, P.A. and ALLEN, J.R., 1990 -- Basin Analysis Principles and Applications. Blackwell Scientific Publications, pp 451.

ANALABS, 1984 -- Petroleum geochemical assessment for Jacaranda -No.1 in Tricentrol, 1985. Well Completion Report, Jacaranda No.1 (Unpublished). Northern Territory Geological Survey, Reference Number PR 85/9B.

ANALABS, 1985 -- Petroleum Geochemistry. Geochemical data for eleven wells from the Bonaparte Gulf Basin of the Northern Territory (Unpublished). Northern Territory Geological Survey, Reference Number PR 85/033.

APTHORPE, M., 1988 -- Cainozoic depositional history of the Northwest Shelf, in Purcell P.G. and R.R., (Eds), The North West Shelf, Australia: Proceedings of Petroleum Exploration Society Australia Symposium, Perth, 55-84.

ARCHBOLD, N., AND DICKINS, J.M., 1989 -- Australian Phanerozoic Timescales 6: Permian. Bureau of Mineral Resources, Australia, Record 1989/38.

ARCO AUSTRALIA LIMITED and AUSTRALIAN AQUITAINE PETROLEUM PTY LTD, 1969 -- Petrel No. 1 - Well completion report. (Unpublished).

ARCO AUSTRALIA LIMITED and AUSTRALIAN AQUITAINE PETROLEUM PTY LTD, 1971 -- Petrel No. 1A - Well completion report. (Unpublished).

ARCO AUSTRALIA LIMITED and AUSTRALIAN AQUITAINE PETROLEUM PTY LTD, 1972 -- Sandpiper No 1 - Well completion report. (Unpublished).

ARCO AUSTRALIA LIMITED, 1969 -- Lacrosse No. 1 - Well completion report. (Unpublished).

ARCO AUSTRALIA LTD, 1971 -- Well Completion Report Gull No.1 (Unpublished).

ARCO AUSTRALIA LTD, 1971a -- Well Completion Report Tern No. 1 (Unpublished).

ARCO AUSTRALIA LTD, 1971b -- Flamingo No.1 Well Completion Report (Unpublished).

ARCO AUSTRALIA LIMITED, 1971c -- Petrel No. 2 - Well completion report. (Unpublished).

ARCO AUSTRALIA LIMITED, 1972 -- Pelican Island No. 1 - Well completion report. (Unpublished).

ARCO AUSTRALIA LIMITED, 1972a -- Penguin No. 1 - Well completion report. (Unpublished).

ARCO AUSTRALIA LTD, 1972b -- Osprey No. 1 Well completion report. (Unpublished).

ARCO AUSTRALIA LIMITED, 1974 -- Curlew No. 1 - Well completion report. (Unpublished).

ARCO AUSTRALIA LIMITED, 1978 -- Frigate No. 1 - Well completion report. (Unpublished).

AUDLEY-CHARLES, M.G., 1986 -- Timor-Tanimbar Trough: foreland basin to evolving Banda Orogen. In: Allen, P.A. and Homewood, P. (Eds). Foreland Basins. International Association of Sedimentologists Special Publication 8, 91-102.

AUSTRALIAN AQUITAINE PETROLEUM (AAP), 1969 -- Keep River No. 1 O.P. 162 Northern Territory Well Completion Report Compiled by Caye, J.P. (Unpublished). Northern Territory Geological Survey, Reference Number PR 69/009.

AUSTRALIAN AQUITAINE PETROLEUM (AAP), 1970 -- Newby No. 1 NT/P 17 Northern Territory Well Completion Report (Unpublished). Northern Territory Geological Survey, Reference Number PR 69/015.

BALME, B., 1989 -- Australian Phanerozoic Timescales 7 : Triassic. Bureau of Mineral Resources, Australia, Record 1989/38.

BARNES, G. and LEE, R.J., 1984 -- Skull No. 1- Well completion report. Australian Aquitaine Petroleum Pty Ltd. (Unpublished).

BEERE, G.M., 1984 -- The Waggon Creek Formation - an Early Carboniferous submarine fan deposit in the Bonaparte Gulf Basin, Western Australian Geological Survey, Report, 12, 7-14.

BERGGREN, W.A., 1969 -- Cainozoic chronostratigraphy, planktonic foraminiferal zonation and the radiometric time scale. *Nature*, 224, 1072-1075.

BHATIA, M.R., THOMAS, M. and BOIRIE, J.M., 1984 -- Depositional framework and diagenesis of the late Permian gas reservoirs of the Bonaparte Basin. *Australian Petroleum Exploration Association Journal*, 24(1), 299-313.

BLAKE, R, 1984 -- Review of Geology and Hydrocarbon Potential, OP 186, Onshore Bonaparte Basin Northern Territory. Prepared for Alliance Petroleum International United. Northern Territory Geological Survey, Reference Number PR 84/033.

BLOW, W.H., 1969 -- Late Middle Eocene to Recent planktonic foraminiferal biostratigraphy. *In:* Bronniman, P., and Renz, H.H., (Eds) - Proceedings of the 1st International Conference on Planktonic Microfossils, Geneva, 1967, I, 199-422.

BLOW, W.H., 1979 -- The Cainozoic Globigerinida. A study of the morphology, taxonomy, evolutionary relationships and the stratigraphical distribution of some Globigerinida (mainly Globigerinacea). E.J. Brill, Leiden.

BMR Palaeogeographic Group, 1990 -- Australia: Evolution of a Continent. Bureau of Mineral Resources, Australia.

BOTTEN, P. and WULFF, K. 1990 -- Exploration potential of the Timor Gap Zone of Co-operation. *Australian Petroleum Exploration Association Journal,* 30(1) 68 - 90.

BOWRING, S.A., GROTZINGER, J.P., ISACHSEN, C.E., KNOLL, A.H., PELECHATY, S.M. and KOLOSOV, 1993 -- Calibrating rates of early Cambrian evolution. *Science* 261, 1293.

BRADSHAW, J., 1990 -- Geological cross-section across the Petrel sub-basin, Bonaparte Basin. Palaeogeography 24. *Bureau of Mineral Resources, Geology and Geophysics, Record, 1990/72. pp16.*

BRADSHAW, M. T., 1993 -- Australian Petroleum Systems, Petroleum Exploration Society of Australia, Journal 21, p 43-53.

BRADSHAW, J., NICOLL, R.S. AND BRADSHAW, M.T., 1990 -- The Cambrian to Triassic Arafura Basin, Northern Australia. The APEA Journal, 30(1), 107-127.

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

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

BRADSHAW, M.T., AND YEUNG, M., 1992 -- BMR Palaeogeographic Atlas of Australia. Volume 8 - Jurassic. Bureau of Mineral Resources, Australia.

BRADSHAW, M.T., YEUNG, M., BEYNON, R.M., AND BURGER, D., (in press) -- BMR Palaeogeographic Atlas of Australia. Volume 9 - Cretaceous. Bureau of Mineral Resources, Australia.

BROPHY, F., 1966 -- Moyle No. 1 Well Completion Report (Unpublished). Northern Territory Geological Survey, Reference Number PR 66/009.

BROWN, C.M., 1979. Bonaparte Gulf Basin, explanatory notes and stratigraphic correlations, Bureau of Mineral Resources Australia, Geology and Geophysics Record, 1979/52 (Unpublished).

BROWN, H.Y.L., 1895 -- Government geologists report on explorations in the Northern Territory: South Australian Parliamentary Paper (Adelaide) 82.

BURGER, D., 1989 -- Australian Phanerozoic Timescales 8 : Jurassic. Bureau of Mineral Resources, Australia, Record 1989/38.

BURGER, D., 1989a -- Australian Phanerozoic Timescales 9 : Cretaceous. Bureau of Mineral Resources, Australia, Record 1989/38.

BUSCH, D.A. and LINK, D.A., 1985 -- Exploration methods for sandstone reservoirs. OGCI Publications, Tulsa. pp 327.

CATHRO, D.L., WARREN, J.K. WILLIAMS, G.E., 1992 -- Halite salterns in the Canning Basin, Western Australia: a sedimentological analysis of drill core from the Ordovician-Silurian Mallowa Salt. Sedimentology, 39, 983-1002.

CAYE, J.P., 1968 -- The Timor Sea - Sahul Shelf area. APEA Journal, 8 (2), 3541.

CAYE, J.P., 1969 -- Keep River No. 1 Well Completion Report (Unpublished). Northern Territory Geological Survey, Reference Number PR 69/009.

CHAN, P.N.K., 1981 -- Tern No. 2 - Well completion report. Australian Aquitaine Petroleum Pty Ltd. (Unpublished).

CHAN, P.N.K., 1982 -- Tern No. 3 - Well completion report. Australian Aquitaine Petroleum Pty Ltd. (Unpublished).

CHOMAT, C., and COISY, P., 1985 -- The Tern Gas Field case history, Exploration Geophysics, 16 (2/3), 186-189.

COOK, P.J., 1988 -- Palaeogeographic Atlas of Australia Volume 1: Cambrian. *Australian Bureau of Mineral Resources.*

COOK, P.J. & TOTTERDELL, J.M., 1992 -- Palaeogeographic Atlas of Australia Volume 2: Ordovician. *Australian Bureau of Mineral Resources.*

COMPSTON, W., 1974 -- The Table Hill Volcanics of the Officer Basin - Precambrian or Palaeozoic? *Journal of the Geological Society of Australia*, 21 (4), 403-412.

CONNAN, J. and CASSOU, A.M., 1980. Properties of gases and petroleum liquids derived from terrestrial kerogen at various maturation levels. Geochimica et Cosmochimica Acta, 44, 1-23.

CREEVEY, K, 1966 -- Kulshill No. 2 Well Completion Report (Unpublished). Northern Territory Geological Survey, Reference Number PR 66/007.

CRIST, R.P., and HOBDAY, M., 1973 -- Diapiric features of the offshore Bonaparte Gulf Basin, North West Australian Shelf, Australian Society of Exploration Geophysicists Bulletin, 4 (1), 43-46.

DICKINS, J.M., ROBERTS, J. and VEEVERS, J.J., 1972 -- Permian and Mesozoic geology of the northeastern part of the Bonaparte Gulf Basin. Bureau of Mineral Resources Australia, Geology and Geophysics, Bulletin 125, 75-102.

DRAPER, J.J., PALMIERI, V., PRICE, P.L., BRIGGS, D.J.C. and PARFREY, S.M., 1990 -- A biostratigraphic framework for the Bowen Basin, in: Beeston, J.W. (compiler), BOWEN BASIN SYMPOSIUM 1990, PROCEEDINGS. Geological Society of Australia (Queensland Division), Brisbane, 26 35.

DRUCE, E.C., 1969 -- Devonian and Carboniferous conodonts from the Bonaparte Gulf Basin, northwestern Australia and their use in international correlation. *Bureau of Mineral Resources Australia, Geology and Geophysics Bulletin*, 98.

DRUMMOND, J.M., 1963 -- Compilation and review of the geology of Bonaparte Gulf Basin, 1962: Australia. BMR Record 1963/133. (Unpublished).

DUCHEMIN, A.E., CREEVEY, K., LABOUYSSE, M. and BROCQ, R., 1966 -- Aquitaine Kulshill No. 1 - Well completion report. Australian Aquitaine Petroleum Pty Ltd. (Unpublished).

DURRANT, J.M., FRANCE, R.E., DAUZACKER, M.V. and NILSEN, T., 1990 -- The Southern Bonaparte Gulf Basin - New Plays. *Australian Petroleum Exploration Association Journal*, 30(1), 52-67.

EDGERLEY, D.W. and CRIST, R.P., 1974 -- Salt and diapiric anomalies in the southeast Bonaparte Gulf Basin. *Australian Petroleum Exploration Association Journal*, 14, 85-94.

EPSTEIN, A.G., EPSTEIN, J.B., HARRIS., L.D. 1977 -- Conodont colour alteration - An index to organic metamorphism. U.S. Geological Survey Professional Paper, 995, 1-27.

ESPITALIE, J., LAPORTE, J.L., MADEC, M., MARQUIS, F., LEPLAT, P., PAULET, J., and BOUTEFEU, A., 1977 -- Methode rapide de caracterisation des roches meres de leur potentiel petrolier et de leur degre d'evolution. Rev. Fr. Pet., 32, p 23-42.

EXON, N.F. and WILCOX, J.B., 1980 -- The Exmouth Plateau: stratigraphy, structure and petroleum potential. *Bureau of Mineral Resources Australia, Geology and Geophysics Bulletin*, 199.

FAEHRMANN, P., 1990 -- Barnett 2 - Well completion report. Santos Limited. (Unpublished).

FISHER, L.W. and ASSOCIATES -- The Hydrocarbon Potential of Exploration Permit (EP) 3. Southeast Bonaparte Basin Northern Territory. Prepared for Barbara Investments Pty Ltd. Northern Territory Geological Survey, Report PR87/036.

FOSTER, C.B., 1984 -- Palynological report, Turtle 1. In WESTERN MINING CORPORATION LTD, 1984 -- WA-128P- Turtle 1 - Well completion report. Volume 1. (Unpublished).

FOSTER, C.B., 1990 -- Palynological report, Barnett 2. In FAEHRMANN, P., 1990 -- Barnett 2 - Well completion report. Santos Limited. (Unpublished).

FOSTER, C.B., O'BRIEN, G.W., and WATSON, S.T, 1986 -- Hydrocarbon source potential of the Goldwyer Formation, Barbwire Terrace, Canning Basin, Western Australia. APEA Journal 26 (1), 142-155.

FOSTER, C.B. and WATERHOUSE, J.B., 1988 -- The Granulatisporites confluens Oppel-Zone and Early Permian marine faunas from the Grant Formation on the Barbwire Terrace, Canning Basin, Western Australia. *Australian Journal of Earth Sciences*, 35, 135-157.

GARSIDE, I.E., 1982 -- Ningbing No.1 Well Completion Report: Australian Aquitaine Petroleum Pty Ltd Report No. PG/174/82 (Unpublished).

GARSIDE, I.E., 1983 -- Weaber No.1 Well Completion Report: Australian Aquitaine Petroleum Pty Ltd Report No. PG/196/83 (Unpublished). Northern Territory Geological Survey, Reference Number PR 83/044.

GARSIDE, I. and FORDER, F., 1982 -- Petrel No. 3 - Well completion report. Australian Aquitaine Petroleum Pty Ltd. (Unpublished).

GEORGE, E.R., 1972 -- Subsurface Temperature Gradients Timor Sea, Bonaparte Gulf Area, Australia (Unpublished). Northern Territory Geological Survey, Reference Number PR77/003.

GOLDSTEIN, B.A. and HUBBARD, J.J., 1984 -- Comparison and geologic interpretation of alternative dipmeter analyses from a permo-carboniferous sequence in the Fitzroy Graben. In: PURCELL, P.G. (Ed.) The Canning Basin W.A., Proceedings of the GSA/PESA Canning Basin Symposium, Perth W.A. pp 505-519.

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

GORTER, J.D., NICOLL, R.S. and FOSTER, C.B., 1994 -- Lower Palaeozoic facies in the Carnarvon Basin, Western Australia: Stratigraphy and hydrocarbon prospectivity. *In*: PURCELL, P.G., AND R.R., (Eds). *The sedimentary basins of Western Australia*. Proceedings of the PESA Symposium, Perth, 1994, 373-396.

GRENFELL, H.R., 1987 -- Palynology of the middle to late Permian sediments from the Bonaparte and Canning Basins, Northwestern Australia. Volumes 1 and 2. PhD Thesis, University of Sydney, (Unpublished).

GUNN, P.J., 1988 -- Hydrocarbon discoveries in the Bonaparte Basin. *In*: PURCELL, P.G., AND R.R., (Eds). *The North West Shelf, Australia*. Proceedings of the PESA Symposium, Perth, 1988, 419-424.

GUNN, P.J., 1988a -- Bonaparte Basin: Evolution and structural framework. *In*: PURCELL, P.G., AND R.R., (Eds). *The North West Shelf, Australia*. Proceedings of the PESA Symposium, Perth, 1988, 275-285.

GUNN, P.J., 1988b -- Bonaparte Rift Basin, effects of axial doming and crustal spreading. Exploration Geophysics, 19 (1/2), 8587.

GUNN, P.J. and LY, K.C., 1989 -- The prospectivity of the Joseph Bonaparte Gulf area, northwestern Australia. *Australian Petroleum Exploration Association Journal*, 29(1), 509-526.

HAQ, B.U., HARDENBOL, J.and VAIL, P.R., 1987 -- Chronology of fluctuating sea levels since the Triassic. Science 235, 1156-1167.

HARDING, T.P. 1974 -- Petroleum traps associated with wrench faults. American Association of Petroleum Geologists Bulletin, 58, 97-116.

HARLAND, W.B., COX, A.V, LLEWELLYN, P.G., PICKTON, C.A.G., SMITH, A.G., AND WALTERS, R., 1982 -- A geologic time scale. Cambridge University Press, Cambridge.

HARRISON, M. and SCOTT, P., 1982 -- Berkley No. 1 - Well completion report. WA-77-P. Magnet Metals Limited (Unpublished).

HAYS, J., 1967 -- Surfaces and laterites in the Northern Territory, *In*: J.N. Jennings and J.A. Mabbutt (Eds), *Landform studies from Australia and New Guinea*. ANU Press, Canberra. pp 182-210.

HEATH, R.S., and APTHORPE, M.C., 1984 -- New formation names for the Late Cretaceous and Tertiary sequence of the southern North West Shelf. Geological Survey of Western Australia. Record 1984/7.

HEFFERNAN, M.J, and MASON, PC., 1984 -- Geochemical data for the Malita Graben, North West Shelf Australia. BP Research Centre (Unpublished). Northern Territory Geological Survey, Reference Number PR 85/043.

HELBY, R.J., 1974 -- A palynological study of the Petrel Formation. Report to Arco Australia United (Unpublished).

HELBY, R.J, 1974a -- A palynological study of the Cambridge Gulf Group. Report to Arco Australia United (Unpublished).

HELBY, R.J., MORGAN, R, and PARTRIDGE, A.D., 1987 -- A palynological zonation of the Australian Mesozoic. Association of Australasian Palaeontologists Memoir 4.

HORSTMAN, E.L, 1988 -- Source maturity, over pressures and production, North West Shelf Australia in Purcell, P.G., and R.R, (Eds). The North West Shelf, Australia Proceedings of Petroleum Exploration Society Australia Symposium, Perth, 1986, 529-537.

HUGHES, R.J., 1978 -- The geology and mineral occurrences at Bathurst Island, Melville Island and Cobourg Peninsula, Northern Territory. *Bureau of Mineral Resources Australia, Geology and Geophysics Bulletin,* 177.

HUGHES, R.J. and SENIOR, B.R., 1974 -- New stratigraphic names for Cretaceous and Cainozoic units of Bathurst and Melville Islands and Cobourg Peninsula, Northern Territory: Australian Oil and Gas Review, 20 (2), 10-17.

JEFFERIES, P.J., 1988 -- Geochemistry of the Turtle oil accumulation, offshore southern Bonaparte Basin. *In*: PURCELL, P.G., and R.R., (Eds). *The North West Shelf, Australia.* Proceedings of the PESA Symposium, Perth, 1988, 563-569.

JOHN, B.S., 1979 -- *The Winters of the World.* The Jacaranda Press, Milton Queensland. pp 256.

JOHNSON, J.G., KLAPPER, G., and SANDBERG, C.A, 1985 -- Devonian eustatic fluctuations in Euramerica. *Geological Society of America Bulletin*, 96, 567-587.

JONES, P.J, 1971 -- Lower Ordovician conodonts from the Bonaparte Gulf Basin and the Daly River Basin, northwestern Australia, *Bureau of Mineral Resources Australia, Geology and Geophysics* Bulletin 117.

JONES, P.J., 1976, Ord Basin -- *In*: LESLIE, R.B., EVANS, H.J. and KNIGHT, C.L., (Eds), *The Australian Institute of Mining and Metallurgy*, Monograph Series No. 7, 242-246.

JONES, P.J., 1989 -- Australian Phanerozoic Timescales 5 : Carboniferous. Bureau of Mineral Resources, Australia, Record 1989/38.

JONES, P.J., 1989a -- Lower Carboniferous ostracoda (Beyrichicopida and Kirkbyocopa) from the Bonaparte Basin, northwestern Australia. *Bureau of Mineral Resources, Geology and Geophysics, Bulletin* 228, pp 97.

JONES, P.J., and DRUCE, E.C., 1966 -- Intercontinental Conodont correlation of the Palaeozoic sediments of the Bonaparte Gulf Basin, northwestern Australia, *Nature*, 211, 357-359.

JONES, P.J., and NICOLL, R.S., 1983 -- Ostracod and Conodont faunas from Elf Aquitaine Weaber No.1, Bonaparte Basin, in Weaber No. 1 Well Completion Report prepared by Garside, I.E., for Australian Aquitaine Petroleum. Northern Territory Geological Survey, Reference Number PR83/044.

JORGENSEN, G.C., DENDLE, P.K., ROWLEY, M. and LEE, R.J., 1990 -- Sorby lead-zinc-silver deposit. *In:* F. E. HUGHES (Ed.), *Geology and Mineral Deposits of Australia and Papua New Guinea*. The Australasian Institute of Mining and Metallurgy, Melbourne, 1097-1101.

KAULBACK, J.A, and VEEVERS, J.J., 1969 -- Lower Palaeozoic geology of the Bonaparte Gulf Basin, *Bureau of Mineral Resources Australia, Geology and Geophysics Bulletin,* 109.

KEMP, E.M., BALME, B.E., HELBY, R.J., KYLE, R.A, PLAYFORD, G., and PRICE, P.L., 1977 -- Carboniferous and Permian palynostratigraphy in Australia and Antarctica: a review. *Bureau of Mineral Resources Journal of Australian Geology and Geophysics,* 2, 177-208.

KENNARD, J.M., JACKSON, M.J., ROMINE, K.K., SHAW, R.D. and SOUTHGATE, P.N., and 1994 -- Depositional sequences and associated petroleum systems of the Canning Basin, WA. *In*: PURCELL, P.G., and R.R., (Eds). *The sedimentary basins of Western Australia.* Proceedings of the PESA Symposium, Perth, 1994, 275-289.

KENNETT, J.P., & SRINIVASAN, S., 1983 -- *Neogene Planktonic Foraminifera.* Hutchinson Ross Publishing company, Pennsylvania, 1-265.

KILLICK, M.F. and ROBINSON, P.H., 1994 -- The good and bad of diagenesis - A review of sandstone reservoirs in the North Bonaparte Basin. *In*: PURCELL, P.G., and R.R., (Eds). *The sedimentary basins of Western Australia.* Proceedings of the PESA Symposium, Perth, 1994, 275-289.

KLEMME, H.D., 1994 --Petroleum systems of the world involving Upper Jurassic source rocks. In MAGOON, L.B. AND DOW, W.G., (editors) 1994 - The petroleum system - from source to trap. American Association of Petroleum Geologists Memoir 60, 51-73.

KRAUS, G.P. and PARKER, K.A., 1979 -- Geochemical evaluation of the petroleum source rock in Bonaparte Gulf - Timor Sea region, northwestern Australia. *American Association of Petroleum Geologists Bulletin*, 63(11), 2021-2041.

LACRAMPE, G., CONNAN, J., CASSOU, A.M., and PENIGUEL, G., 1981-- Bonaparte 2 (Australia) (1) Optical and geochemical study of the organic matter (1500-6000') (2) Comparison with Lesueur 1, Keep River 1 and mining exploration boreholes. SNEA (P). Northern Territory Geological Survey, Reference Number PR 82/008.

LANE, C., 1981 -- Lesueur 1 - Well completion report. Australian Aquitaine Petroleum Pty Ltd. (Unpublished).

LAVERING, I., 1989 -- Bonaparte Basin Report. Oil and Gas Australia November 1989; 17-19.

LAVERING, I.H. and OZIMIC, S., 1988 -- Bonaparte Basin petroleum accumulations. *In*: PURCELL, P.G., and R.R., (Eds). *The North West Shelf, Australia.* Proceedings of the PESA Symposium, Perth, 1988, 331-337.

LAVERING, I.H. and OZIMIC, S., 1989 -- Bonaparte Basin, N.T. and W.A. Australian Petroleum Accumulations Report 5, Resource Assessment Division, *Bureau of Mineral Resources, Geology and Geophysics*, Canberra. pp 120.

LAWS, R. and CAMPBELL, N., 1972 -- Bougainville No. 1 - Well completion report. Australian Aquitaine Petroleum Pty Ltd. (Unpublished).

LAWS, R., and CLERC, R., 1974 -- Kinmore No. 1 Well Completion Report (Unpublished). Northern Territory Geological Survey, Reference Number PR 74/021.

LAWS, R., 1981 -- The petroleum geology of the onshore Bonaparte Basin. *Australian Petroleum Exploration Association Journal*, 21(1) 5-15.

LAWS, R.A, and BROWN, R.S., 1976 -- Bonaparte Gulf Basin-southeastern part, in Leslie, R.B., Evans, M.J. and Knight, C.L., (Eds.), Economic Geology of Australia and Papua New Guinea 3, Petroleum. Australian Institute of Mining and Metallurgy, Monograph Series, No.7, 200-208.

LE BLANC, M.C., 1964 -- Bonaparte 1 - Well completion report. Alliance Oil Development Australia. (Unpublished).

LE BLANC, M.C., 1965 -- Bonaparte 2- Well completion report. Alliance Oil Development Australia. (Unpublished).

LEE, R.J. and BAFFRAY, P.H., 1985 -- Barnett 1 - Well completion report. Australian Aquitaine Petroleum Pty Ltd. (Unpublished).

LEE, R.J. and GUNN, P.J., 1988 -- The Bonaparte Basin. In: *Petroleum in Australia - The First Century*. Australian Petroleum Exploration Association Publication, 252-269.

LEHMANN, P.R., 1984 -- The stratigraphy and petroleum potential of the Lower to lower Upper Devonian sequence in the Canning Basin. In: PURCELL, P.G. (Ed.) The Canning Basin W.A., Proceedings of the GSA/PESA Canning Basin Symposium, Perth W.A. pp 253-275.

LINDSAY, J.F., KORSCH, R.J. AND WILFORD, J.R., 1987 -- Timing the breakup of a Proterozoic supercontinent: evidence from Australian intracratonic basins. Geology, 15, 1061-1064.

LISTER, G.S., ETHERIDGE, M.A. and SYMONDS, P.A., 1991 -- Detachment models for the formation of passive margins. *Tectonics*, 10, 1038-1064.

MACDANIEL, R.P., 1988 -- The geological evolution and hydrocarbon potential of the western Timor Sea region, in Petroleum in Australia: The First Century. APEA Publication, 270-285.

MACKENZIE, A.S., AND QUIGLEY, T.M., 1988 -- Principles of geochemical prospect appraisal. Bulletin of the American Association of Petroleum Geologists, 72, p 399-415.

MAGOON, L.B. AND DOW, W.G., 1991-- The petroleum system - from source to trap. *American Association of Petroleum Geologists Bulletin*, 75 (3), 627.

MAGOON, L.B. AND DOW, W.G., (editors) 1994 -- The petroleum system - from source to trap. *American Association of Petroleum Geologists Memoir* 60.

MAMET, B.L., and BELFORD, D.J., 1968 -- Carboniferous foraminifera, Bonaparte Gulf Basin, northwestern Australia, *Micropaleontology*, 14 (3), 339-347.

McGUIRE, S. and FORD, C., 1991 -- Barnett 3 - Well completion report. Santos Limited. (Unpublished).

McKIRDY, D.M., 1983 -- Source rock analysis of seven cuttings samples, Weaber No. 1 OP 186, Bonaparte Basin, in Weaber No. 1 Well Completion Report prepared by Garside, I.E., for Australian Aquitaine Petroleum. Northern Territory Geological Survey, Reference Number PR83/044.

McLENNAN, J.M., RASIDI, J.S., HOLMES, R.L. and SMITH, G.C., 1990 -- The geology and petroleum potential of the western Arafura Sea. *Australian Petroleum Exploration Association Journal*, 30(1) 91-106.

MESSENT, B.E.J., GOODY, A.K., COLLINS, E. and TOBIAS, S., 1994 -- Sequence stratigraphy of the Flamingo Group, southern Bonaparte Basin. *In*: PURCELL, P.G., and R.R., (Eds). *The sedimentary basins of Western Australia.* Proceedings of the PESA Symposium, Perth, 1994, 243-258.

METCALF, I., 1993 -- Southeast Asian terranes: Gondwanaland origins and evolution. In: R.H. Findlay et al. (Eds). Gondwana eight. pp181-200.

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

MORY, A.J. 1990 -- Bonaparte Basin. In*: Geology and mineral resources of Western Australia.* Western Australia Geological Survey, Memoir 3, 380-415.

MORY, A.J., 1991 -- Geology of the offshore Bonaparte Basin northwestern Australia. Western Australia Geological Survey, Report 29. pp 47.

MORY, A.J. and BEERE, G.M., 1988 -- Geology of the onshore Bonaparte and Ord Basins. *Western Australia Geological Survey, Bulletin* 134. pp 184.

MORY, A.J. and DUNN, P.R., 1990 -- Bonaparte, Canning, Ord and Officer Basins - Regional geology and mineralisation. *In:* F. E. HUGHES (Ed.), *Geology and Mineral Deposits of Australia and Papua New Guinea.* The Australasian Institute of Mining and Metallurgy, Melbourne, 1089-1096.

MULLE, S. and BRANGER, J., 1970 -- Flat Top No. 1, P.17 - Northern Territory - Well completion report. Australian Aquitaine Petroleum Pty Ltd. (Unpublished).

NUGENT, O.W., 1989 -- Garimalia 1 - Well completion report. Santos Limited. (Unpublished).

O'BRIEN, G.W., ETHERIDGE, M.A., WILLCOX, J.B., MORSE, M., SYMONDS, P., NORMAN, D.J., and NEEDHAM, D.J., 1993 -- The structural architecture of the Timor Sea, North-Western Australia: Implications for basin development and hydrocarbon exploration. *Australian Petroleum Exploration Association Journal*, 33 (1), 258-278.

OFFSHORE OIL, 1986 -- NT/P 28 Farmout Package. pp26 (Unpublished).

OIL DEVELOPMENT N.L, 1961 -- Well Completion Report Spirit Hill Well No. 1. Oil Permit No. 3, Northern Territory (Unpublished). Northern Territory Geological Survey, Reference Number PR 61/012.

PECK, M.J., and SOULHOLB., 1986 -- Pre Tertiary tensional periods and their effects on the petroleum potential of eastern Indonesia, Proceedings of the 15th Annual Convention, Indonesian Petroleum Association, 1, Jakarta, 341-370.

PETERS, K.E., 1986 -- Guidelines for evaluating petroleum source rock using programmed pyrolysis. American Association of Petroleum Geologists Bulletin, 70 (3), 318329.

PETROCONSULTANTS AUSTRALASIA PTY LTD, 1990 -- Bonaparte Basin. Northern Territory Geological Survey, Petroleum Basin Study. (Unpublished).

PLAYFORD, G., 1971 -- Lower Carboniferous spores from the Bonaparte Basin, Western Australia and Northern Territory. *Bureau of Mineral Resources, Geology and Geophysics, Bulletin* 115. pp105.

PLAYFORD, G., 1982 -- A latest Devonian palynoflora from the Buttons Beds, Bonaparte Gulf Basin, Western Australia, *Bureau of Mineral Resources Australia, Geology and Geophysics Journal*, 7, 149-157.

PLAYFORD, P.E., VEEVERS, J.J., and ROBERTS, J., 1966 -- Upper Devonian and possible Lower Carboniferous reef complexes in the Bonaparte Gulf Basin, Australia Journal of Science, 28, 436-437..

RAHDON, A.E., 1982 -- Diagenesis of sandstones from the Bonaparte Basin, North Australia. A pilot study. Shell Development (Australia) Pty Ltd. (Unpublished). Northern Territory Geological Survey, Reference Number PR 82/029.

RATCLIFF, D.W. and WEBER, D.J., 1994 -- Mahogany salt images show key role of velocity model. *Oil and Gas Journal*, October 24, pp43-52.

REDFERN, J. and MILWARD, E., 1994 -- A review of the sedimentology and stratigraphy of the Permo-Carboniferous Grant Group, Canning Basin, Western Australia. *In*: PURCELL, P.G., and R.R., (Eds). *The sedimentary basins of Western Australia*. Proceedings of the PESA Symposium, Perth, 1994, 753-756.

REECKMANN, S.A. and MEBBERSON, A.J., 1984 -- Igneous intrusions in the north-west Canning Basin and their impact on oil exploration. In: PURCELL, P.G. (Ed.) The Canning Basin W.A., Proceedings of the GSA/PESA Canning Basin Symposium, Perth W.A. pp 389-399.

ROBERTS, J., 1971. Devonian and Carboniferous brachiopods from the Bonaparte Gulf Basin, northwestern Australia, *Bureau of Mineral Resources Australia, Geology and Geophysics Bulletin*, 122.

ROBERTS, J., JONES, P.J., and DRUCE, E.C., 1967 -- Palaeontology and correlations of the upper Devonian of the Bonaparte Gulf Basin, Western Australia and Northern Territory, in Oswald, D.H., (Ed), International Symposium on the Devonian System, Alberta Society of Petroleum Geologists, 2, 565-578.

ROBERTSON RESEARCH AUST. PTY LTD, 1986 -- Northwest shelf Australia - Phase II, Petroleum geology and geochemistry. 77 Pacific Highway, North Sydney. Vols 1 and 3.

ROBERTSON RESEARCH INTERNATIONAL, 1979 -- Petroleum Geochemistry of the Australian North West Shelf, 2, (Unpublished).

ROBINSON, P.H., STEAD, H.S., O'REILLY, J.B. and GUPPY, N.K., 1994 -- Meanders to fans: A sequence stratigraphic approach to upper Jurassic - lower Cretaceous sedimentation in the Sahul Syncline, North Bonaparte Basin. *In*: PURCELL, P.G., and R.R., (Eds). *The sedimentary basins of Western Australia*. Proceedings of the PESA Symposium, Perth, 1994, 223-242.

ROMINE, K.K., SOUTHGATE, P.N., KENNARD, J.M. and JACKSON, M.J., 1994 -- The Ordovician to Silurian phase of the Canning Basin WA: Structure and sequence evolution. *In*: PURCELL, P.G., and R.R., (Eds). *The sedimentary basins of Western Australia*. Proceedings of the PESA Symposium, Perth, 1994, 677-696.

ROWLEY, M. and LEE, R.J., 1986 -- The Sorby Hills (W.A.) lead-zinc province. *In*: D.A. Berkman (Ed.). *Publications of the 13th CMMI Congress*, Volume 2, Geology and Exploration, 173-180.

SANTOS, 1983 -- OP-186 Onshore Bonaparte Gulf Re-evaluation of the Weaber No. 1 Well (Unpublished). Northern Territory Geological Survey, Reference Number PR 83/044.

SELLEY, R.C., 1970 -- Ancient Sedimentary Environments. Chapman and Hall Ltd, London. pp 237.

SHERGOLD, J. H., 1989 -- Australian Phanerozoic Timescales 1 : Cambrian. Bureau of Mineral Resources, Australia, Record 1989/38.

STEVESON, B.G., 1983 -- Petrography of sandstones from Bonaparte Basin offshore wells (Unpublished). BP Petroleum Development Pty Ltd. Northern Territory Geological Survey, Reference Number PRSS/043.

STRUSZ, D.L., 1989 -- Australian Phanerozoic Timescales 3 : Silurian. Bureau of Mineral Resources, Australia, Record 1989/38.

TASCH, P. and JONES, P.J., 1979 -- Lower Triassic Conchostraca from the Bonaparte Gulf Basin, northwestern Australia (with a note on Cyzicus

(Euestheria) minuta (?) from the Carnarvon Basin. *In:* Carboniferous, Permian and Triassic Conchostracans of Australia three new studies. *Bureau of Mineral Resources Australia, Geology and Geophysics Bulletin,* 185, 23-30.

THOMAS, G.A, 1962 -- The Carboniferous stratigraphy of the Bonaparte Gulf Basin, Compte Rendu du Quatriéme Congrés pour l'avancement des études de stratigraphie et de géologie du Carbonifére, Heerlen, Tome III, 727-732.

TISSOT, B.P., and WELTE, D.H., 1978 -- Petroleum Formation and Occurrence. Springer, Berlin.

TOTTERDELL, J.M. and BRAKEL, A.T., 1990 -- Carboniferous data package. BMR Record 1990/26

TRAVES, D.M., 1955 -- The geology of the Ord-Victoria region, northern Australia. Bureau of Mineral Resources Australia Geology and Geophysics Bulletin 27.

TRUSWELL, E.M., CHAPRONIERE, G.C.H., SHAFIK, S., 1989 -- Australian Phanerozoic Timescales 10 : Cainozoic. Bureau of Mineral Resources, Australia, Record 1989/38.

TURNER, M., and BADCOCK, M., 1989. Weaber 2/2A Well Completion Report, compiled for Santos Ltd (Unpublished). Northern Territory Geological Survey, Reference Number 88/053.

UTTING, E.P., 1958 -- Progress geological report, Permit No. 3, Bonaparte Gulf Basin (1957). Westralian Oil Ltd. (Unpublished).

VAIL, P.L, 1987 -- Seismic stratigraphy interpretation procedure. American Association of Petroleum Geologists Studies in Geology, 27 (1).

VAN ANDEL, T.J.H., and VEEVERS, J.J., 1967 -- Morphology and sediments of the Timor Sea, *Bureau of Mineral Resources Australia, Geology and Geophysics* Bulletin, 83.

VAN WAGONER, G.C., MITCHUM, R.M., JL, POSMANTIER, H.W., and VAIL, P.L, 1987. -- The Key Definitions of Sequence Stratigraphy. *American Association of Petroleum Geologists Studies in Geology,* 27(1).

VEEVERS, J.J., 1969 -- Sedimentology of the Upper Devonian and Carboniferous Platform sequence of the Bonaparte Gulf Basin. *Bureau of Mineral Resources Australia, Geology and Geophysics Bulletin,* 109.

VEEVERS, J.J., 1970 -- Upper Devonian and Lower Carboniferous calcareous algae and stromatolites from the Bonaparte Gulf Basin, northwestern Australia. *Bureau of Mineral Resources Australia, Geology and Geophysics Bulletin,* 116, 173-188.

VEEVERS, J.J, (Ed.), 1984 -- *Phanerozoic Earth History of Australia.* Clarendon Press, Oxford.

VEEVERS, J.J., 1976 -- Early Phanerozoic events on and alongside the Australian-Antarctic platform. *Journal of the Geological Society of Australia*, 23, 183-206.

VEEVERS, J.J., and ROBERTS, J., 1966 -- Littoral talus breccia and probable beach rock from the Visean of the Bonaparte Gulf Basin, *Geological Society of Australia Journal*, 13, 387-403.

VEEVERS, J.J., and ROBERTS, J., 1968 -- Upper Palaeozoic rocks, Bonaparte Gulf Basin of northwestern Australia, *Bureau of Mineral Resources Australia, Geology and Geophysics* Bulletin, 97.

WADE, A., 1924 -- Petroleum Prospects, Kimberley District of Western Australia and Northern Territory. *Commonwealth Government Parliamentary Papers*, 142, Melbourne.

WALLEY, A.M., STRUSZ, D.L. & YEATES, A.N., 1991 -- Palaeogeographic Atlas of Australia Volume 3: Silurian. *Australian Bureau of Mineral Resources.*

WARREN, J., 1989 -- Evaporite - Hydrocarbon Association: The Importance of Salt Structures. *Petroleum Exploration Society of Australia (PESA) Journal*, 15, September 1989; 32-36.

WEBBY, B. D., AND NICOLL, R.S., 1989 -- Australian Phanerozoic Timescales 2 : Ordovician. Bureau of Mineral Resources, Australia, Record 1989/38.

WELLS, A.T., FORMAN, D.F., RANFORD, L.C., and COOK, P.J., 1970 -- Geology of the Amadeus Basin, Central Australia. Bureau of Mineral Resources Australia, Geology and Geophysics Bulletin 100.

WESTERN MINING CORPORATION LTD, 1984 -- WA-128P- Turtle 1 - Well completion report. Volume 1. (Unpublished).

WESTERN MINING CORPORATION LTD, 1985 -- WA-128P- Cambridge 1 - Well completion report. Volumes 1 and 2. (Unpublished).

WESTERN MINING CORPORATION LTD, 1985a -- WA-128P- Matilda 1 - Well completion report. Volumes 1 and 2. (Unpublished).

WESTERN MINING CORPORATION LTD, 1990 -- WA-128P- Turtle 2 - Well completion report. Volume 1. (Unpublished).

WILLINK, G.R., 1989 -- A methodical approach to critical well re-evaluation. APEA Journal, 29 (1), 269-286.

WOOD, G.R, 1988 -- Palynology Report No. 1988/43 Weaber No. 2A Santos Ltd. in Santos (1989) Well Completion Report, Weaber No. 2/2A O.P. 186 Northern Territory.

WOODS, E.P., 1994 -- A salt related detachment model for the development of the Vulcan Sub-basin. *In*: PURCELL, P.G., and R.R., (Eds). *The sedimentary basins of Western Australia.* Proceedings of the PESA Symposium, Perth, 1994, 259-274.

WRIGHT, C.A., 1977 -- Distribution of Cainozoic Foraminifera in the Scott Reef No. 1. Well, Western Australia. *Journal of the Geological Society of Australia.* 24, 269-277.

YOUNG, G.C., 1989 -- Australian Phanerozoic Timescales 4 : Devonian. Bureau of Mineral Resources, Australia, Record 1989/38.

YOUNG, I.F., SCHMEDJE, T.M. and MUIR, W.F., 1995 -- The Elang oil discovery establishes new oil province in the Timor Sea (Timor Gap Zone of Cooperation). *Australian Petroleum Exploration Association Journal,* 35 (1), 44-64.