A GEOCHEMICAL REVIEW OF THE GIPPSLAND BASIN, AUSTRALIA

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AND G. DUNGWORTH

Barracouta-1
Bream-2
Flathead-1
Hapuku-1
Perch-1
Tuna-1
Tuna-3

GIPPSLAND BASIN.
GEOCHEMICAL REPORT.

GIBBONS ETC.

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SUMMARY

The hydrocarbon accumulations of the Gippsland Basin have been sourced by mature, non-marine coals and carbonaceous shales of the Latrobe Group. These organic-rich sediments form a continuous series from humic coals, capable of generating large volumes of gas with some light oil/condensate, to algal/sapropelic coals and shales with the potential to generate abundant waxy, paraffinic oil. The initial input of land-derived plant debris was probably the same in all cases but the oil-prone kerogens are the end-products of a more severe microbial degradation. These "sapropelized" coals may have accumulated in stagnant, reducing, overbank swamps and abandoned meanders, in which case their lateral and vertical distribution within the main body of fluvial sediments will be irregular and unpredictable. Thick coal development is restricted to the west and centre of the basin; consequently, prolific source rocks are unlikely to be present east of the Kingfish-Mackerel-Flounder axis.

The oil generation threshold appears to dip to the south-east: in Barracouta-1 it lies at ca. 2360m and in Bream-2 at ca. 2670m. The zone of prolific oil generation probably lies at least 500m deeper. Generation at the base of the Latrobe Group in the depocentre may have commenced in Late Palaeocene to Early Eocene times. Immature coals are still subsiding below the OGT and present day generation could be as vigorous as at any time in the past.

In decreasing order of prospectivity, the available exploration permits are rated as follows: V 80-2, V 80-3, V 80-1 and V 80-4. Generally, the Latrobe Group is relatively thin and largely immature in permits V 80-1 and V 80-4. In terms of mature thickness of Latrobe sediments, the northern part of V 80-2 and the southern part of V 80-3 appear highly prospective. However, both permits lie to the east of the area of thick coal development and commerciality may be dependent on migration from the basin depocentre. Insufficient data were available to establish the presence or absence of lateral migration. The Strzelecki Group and the Gurnard Formation are unlikely to have sourced significant quantities of hydrocarbons.

Other southern Australian basins such as the Otway and Great Australian Bight differ from the Gippsland in containing a much smaller volume of coal/carbonaceous shale, little of which is of the oil-prone sapropelic type. Local climatic and physiographic conditions in the Gippsland Basin appear to have been particularly favourable for the production and preservation or microbial modification of terrestrial plant material.

1. INTRODUCTION

The intention of this report is to establish maturity trends and source rock potential in the Gippsland Basin, using previously unreported data from 7 offshore wells, and to compare the results with published data. More specific objectives, listed by Widdowson and Bee (11), include:

(i) Determination of the maturity and source potential of the Latrobe Group, particularly in open acreage.

(ii) To establish whether or not lateral hydrocarbon migration occurred from the depocentre into open acreage.

(iii) To establish the source potential of the Strzelecki Group and the Gurnard Formation.

Additionally, the geochemical characteristics of the formations concerned are briefly compared with those of sediments of similar ages in the Otway basin and Great Australian Bight to obtain an overview of hydrocarbon generation along the southern Australian margin.

The petroleum geology of the Gippsland Basin has been comprehensively reviewed by Widdowson and Maxwell (12) and this report is intended to be read in conjunction with their report. Consequently, this report includes 2 figures only: Figure 1 is an offshore well location map and also shows isopachytes for the Latrobe Group; Figure 2 shows the generalized stratigraphy of the basin. Unless stated otherwise, all geological data are from Widdowson and Maxwell.

2. LITERATURE REVIEW

Brooks and Smith (1) suggested the highly paraffinic oils of the offshore Gippsland Basin were generated from the wax esters of land-derived leaf, pollen and spore coatings. Artificial thermal diagenesis of the low-rank, onshore, Tertiary Yallourn pollen-coal resulted in n-alkane distributions similar to those of the offshore oils.

Powell and McKirdy (6) analysed 5 oils (Kingfish and 4 unnamed oils) from the Gippsland Basin using a variety of techniques. The oils had relatively high paraffin and wax contents and low sulphur and asphaltenes. Pristane/phytane ratios were generally high, and the Kingfish oil had a $\delta^{13}C_{-PDB}$ of $-28.1°/oo$. The oils are associated with lacustrine, fluviatile and paralic sediments of the Latrobe Group and the authors suggested that they were derived from higher plant debris.

Shibaoka et al. (7) analysed samples from 18 offshore wells, including 3 in the present study (Barracouta-1, Bream-2 and Tuna-3). Microscopic examination showed the upper part of the Latrobe Group to contain large amounts of exinite, up to 30% in some samples. The green-yellow to yellow fluorescence of this waxy, oil-prone material in virtually all samples indicated immaturity, which was confirmed by elemental analysis atomic ratios and vitrinite reflectance data (R_o from 0.3 to 0.7%). Few samples were available from the lower part of the Latrobe Group but it was suggested that if similarly high levels of exinite are present, then thermal breakdown of this lipid-rich material would yield sufficient oil to account for the known accumulations. High pristane/phytane ratios confirmed that most of the organic matter was land-derived. Extrapolation of reflectance data showed that, generally, the Strzelecki Group is too mature to have generated oil in the recent past. The source of most of the gas was considered to be the coals and coaly shales of the Latrobe Group.

Reflectance data indicated that, for a given depth, maturity decreases with distance from the present coastline. This was attributed to thermal disequilibrium (i.e. organic maturation lagging behind increases in formation temperature) due to rapid Tertiary burial, rather than regional variation in geothermal gradient (34°C/km in Kingfish-1 to 37°C/km in Barracouta-1). Since the basin continues to subside the authors suggested that oil-prone kerogens in the Latrobe Group are still being carried below the OGT and that vigorous present-day hydrocarbon generation and relatively rapid migration is consistent with all traps being full when discovered and the absence of bacterial alteration. Shibaoka et al. take a higher vitrinite reflectance (0.7%) than Sunbury (0.55%) to characterize the OGT. Using their data, Sunbury would place the offshore OGT closer to the top of the Latrobe Group.

Thornton et al. (8) attempted to establish the relationship between the oil accumulations of the Fortescue, Cobia and Halibut fields using a variety of oil-oil correlation techniques. It was claimed that oils from the Fortescue and Halibut fields differed due to local variations in source-rock quality. However, there were sound economic reasons for proving the two fields to be separate and discrete hydrocarbon accumulations, and an objective view of the data shows the two oils to be virtually identical.

3. SUNBURY GEOCHEMICAL DATA

Analyses were carried out on 54 samples from 7 wells:

Barracouta-1	(12 samples)
Bream-2	(11)
Flathead-1	(7)
Hapuku-1	(2)
Perch-1	(6)
Tuna-1	(10)
Tuna-3	(6)

The results are listed in Appendices I to VII. Analytical techniques comprised vitrinite reflectance (Tables 1), spore colour and visual kerogen determination (Tables 2), "Rock-Eval" pyrolysis and pyrolysis-gas chromatography (Tables 3), total organic carbon determination (Tables 4) and extract analysis and gas chromatography (Tables 5 and 6). The data are summarized on Enclosures 1 to 7.

Rather than describe the geochemical characteristics of each well, the following discussion concentrates on the major rock units, i.e. the Latrobe and Strzelecki Groups. A few samples from the Gurnard, Lakes Entrance and Gippsland Limestone Formations were also analysed. The units are discussed in order of decreasing age.

3.1 Strzelecki Group (?Jurassic to Albian)

This unit comprises several thousand metres of fluvial sandstones, siltstones and shales with occasional thin coals. Four shale samples were analysed, 2 from Flathead-1 (1058.5 and 1063.7m) and 2 from Perch-1 (2660.8 and 2666.9m). Vitrinite reflectance and spore colour data indicate that the Flathead-1 samples are immature, i.e. above the oil generation threshold (OGT), whereas the Perch-1 samples are mature and approaching the threshold of maximum oil generation (OGM). However, solvent extraction parameters demonstrate that the mature shales have not generated significant amounts of hydrocarbons to date, and pyrolysis and visual kerogen studies show them to have poor residual potentials, even at optimum maturity. In contrast, the immature shales appear capable of generating moderate amounts of oil and gas at higher levels of maturity, with maximum theoretical yields of 3.2 kg oil/tonne rock and 1.5 kg gas/tonne rock from the 1063.7m sample.

3.2 Latrobe Group (offshore, Late Cretaceous to Eocene)

This unit comprises interbedded sandstones, siltstones, shales and coals, reaching a maximum thickness of ca. 5 km in the offshore depocentre. The sediments were largely deposited in a meandering river system and include abundant, stacked, upward-fining sequences with channel floor conglomerates on an erosional surface

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passing up into point bar deposits which grade into overbank floodplain and swamp deposits. All the major hydrocarbon accumulations of the Gippsland basin have been found within the Latrobe Group. Point bar and crevasse splay sandstones are the main reservoirs in the western and central parts of the basin with distributory channel and distributary-mouth bar sands predominant in the east. Approximately 95% of the hydrocarbons are trapped by dip closure and eroded antiformal closure at top Latrobe level with the remainder in intra-Latrobe drape closure and the top Latrobe stratigraphic subcrop play.

Analyses were carried out on 47 samples from the Latrobe Group; 10 from Barracouta-1 (1070.4 to 2650.1m), 10 from Bream-2 (1876.8 to 3246m), 7 from Flathead-1 (472.4 to 516m), 1 from Hapuku-1 (2854.3m), 3 from Perch-1 (1152.1 to 1173.4m), 10 from Tuna-1 (2020.7 to 3537.6m) and 6 from Tuna-3 (1395.9 to 2017.7m).

Vitrinite reflectance and spore colour data show Barracouta-1 to be mature for significant oil generation below ca. 2360m. The OGT in Bream-2 is deeper at ca. 2670m. In Flathead-1 the entire section (T.D. 1065.5m) is immature. There are insufficient reliable data for Hapuku-1 but spore colours indicate that the only sample analysed (2854.3m) is from the optimum zone for oil generation. All 3 samples from Perch-1 are immature and even the deepest (1173.4m) is probably ca. 1000m above the OGT. Vitrinite reflectance data are rather variable for Tuna-1 and Tuna-3, but in conjunction with spore colours, they indicate an OGT between 2400 and 2800m.

Source rock quality can be summarized as follows. Pyrolysis data show coals and coaly shales and siltstones from Barracouta-1, Bream-2, Perch-1, Tuna-1 and Tuna-3 to have generally good to excellent potentials for oil and gas. The higher the coal content the higher the hydrocarbon yield, the relative amounts of oil and gas depending upon the coal type, i.e. whether predominantly humic or predominantly algal/sapropelic. Typical maximum theoretical yields are 95.6 kg oil/tonne rock and 36.3 kg gas/tonne rock for algal/sapropelic coals (Perch-1, 1164.9m), 62.6 kg oil/tonne rock and 50.7 kg gas/tonne rock for exinite-rich humic coals (Bream-2, 1938.4m) and 27.1 kg oil/tonne rock and 12.1 kg gas/tonne rock for carbonaceous shales (Tuna-1, 2458.1m).

As indicated above, pyrolysis-GC points to the presence of 2 types of coal/carbonaceous shale. Humic coals with higher than average amounts of exinite and capable of generating gas with associated light oil, and algal/sapropelic (boghead) coals with the potential to generate large amounts of oil. Good examples of the latter occur at 1725.1m in Barracouta-1 and 1164.9m in Perch-1. Mature, formerly hydrogen-rich kerogens of this type are almost certainly the source of the bulk of the Gippsland oil. Even though experience suggests that pyrolysis-GC of coaly sediments results in theoretical oil yields significantly in excess of those that would be obtained in the geological environment (and, conversely, smaller gas yields), the amounts of oil generated from the algal/sapropelic coals are appreciably greater than those produced by normal humic coals.

Extract analysis parameters for a limited number of samples and Rock-Eval P1 yields indicate that no coaly sediments have generated and retained large amounts of liquid hydrocarbons. However, few of the samples were mature and no coals from the optimum zone of oil generation were analysed.

Shales and siltstones with negligible coal contents have, at best, moderate to poor potentials for oil and gas. All sediments from Flathead-1 and Hapuku-1 (non-coaly sandstones, siltstones and mudstones) have insignificant to no source potential.

3.3 Gurnard Formation (?Late Eocene to Oligocene)

This formation is a glauconitic siltstone, locally argillaceous or sandy, and attains its maximum thickness (ca. 150m) in the Flounder area. None of the 3 samples analysed (Bream-2, 1861.6m; Hapuku-1, 2829.3m; Perch-1, 1134.4m) had significant source potential or contained appreciable amounts of reservoired hydrocarbons. One sample, a siltstone from Hapuku-1, was mature.

3.4 Lakes Entrance (Oligocene to Miocene) and Gippsland Limestone (Miocene) Formations

The Lakes Entrance Formation, typically a calcareous mudstone and with a maximum thickness of ca. 500m, is the major cap rock at the top Latrobe level. The Gippsland Limestone Formation, deposited in a carbonate shelf environment, attains a maximum thickness of ca. 1500m in the vicinity of Hapuku. One sample from each of these formations from Barracouta-1 was analysed. As expected, both were immature and had no source potential.

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4. DISCUSSION

All available geochemical data point to the coals and carbonaceous shales of the Latrobe Group as the source of the Gippsland basin hydrocarbons. Consequently, to establish prospectivity, it is necessary to define the vertical and lateral extent of the Latrobe Group, the distribution of the various coal types (algal/sapropelic vs humic), the regional OGT and the timing and duration of hydrocarbon generation and migration.

Isopachytes (in metres) for the Latrobe Group are shown on Figure 1. The maximum drilled thickness is 2805m but seismic evidence indicates a depocentre maximum thickness of ca. 5000m. Towards the north, west and south, the Latrobe Group thins out relatively rapidly. East of the depocentre the interval apparently thins to less than 700m and then maintains a fairly constant rate of thickness. Structure contours show that the top Latrobe unconformity dips towards the south-east, e.g. 1045m in Barracouta-1, 2821m in Hapuku-1.

Sunbury maturation data are too sparse to draw firm conclusions regarding depth to the OGT, but in conjunction with published results, they indicate the OGT is slightly deeper in the south-east, i.e. ca. 2670m in Bream-2 compared to ca. 2360m in Barracouta-1. Shibaoka et al (7) noticed a similar trend. Present day geothermal gradients range from 24° C/km (Flying Fish) to 39° C/km (Kingfish), averaging 32° C/km, i.e. close to the world-wide average of 30° C/km. However, all the significant discoveries have higher than average gradients, many in excess of 36° C/km, e.g. Barracouta and Tuna. Because the choice of generation threshold temperature is both crucial and arbitrary, present day formation temperatures are often poor guides to source rock maturation levels, although as a general rule, the higher the present day formation temperature, the shallower the OGT. In any case, where coaly sediments are concerned, the zone of prolific oil generation probably lies 500 to 1000m below the OGT due to expulsion problems (trapping of initially generated hydrocarbons in the kerogen network). Such a process may explain why all the oils are relatively light, i.e. many of the long-chain hydrocarbons are trapped until thermal cracking reduces the chain length, allowing them to escape.

With regard to the source rocks, most coals (and carbonaceous shales) appear to belong to a continuous series whose two end members are exinite-rich humic coal and algal/sapropelic coal. Both types probably had the same initial organic input of wholly land-derived plant debris (no marine indicators such as dinoflagellate cysts were observed), but the algal/sapropelic coals appear to have undergone a more intense bacterial and fungal degradation. A consequence of this "sapropelization" is that the kerogens are largely composed of amorphous material with few identifiable plant fragments. Thus, the only major justification for implying a significant algal input, is that the pyrolysis-

GC traces obtained from such samples are very similar to those given by established algal coals and other algal-rich deposits.

Unfortunately, there are insufficient data to determine the regional distribution of the various coal types. In any case, if as seems probable, the algal/sapropelic coals were deposited in stagnant, reducing swamps and ox-bow lakes (abandoned meanders) then they will occur as vertically and laterally random pockets throughout the main body of fluvial sediments. Algal/sapropelic coals or carbonaceous shales were observed in Barracouta-1, Bream-2, Perch-1 and Tuna-3. Possibly, such horizons have a sufficiently characteristic suite of wireline well-log responses to enable them to be distinguished from normal humic coals. In all probability, there are fairly rapid lateral facies changes as one coal type grades into another.

Thick coal development, and consequently source rock development, is restricted to fluvial sediments in the west and centre of the basin; equivalent sediments to the east of Kingfish, Mackerel and Flounder are prodelta mudstones with only thin coals and carbonaceous shales. The thickness of coal beds in the sequence decreases from west to east, e.g. in the Barracouta area coals can constitute more than 10% of the gross sediment column, with individual seams over 20m thick, compared to less than 5% in the Flounder area where individual seams rarely exceed 5m in thickness. Most of the coal occurs in the upper part of the Latrobe Group but there are indications that the lower horizons are also very coaly, which is significant since the upper part of the Latrobe Group is immature in the west of the basin.

Assuming the presence of source rocks and geothermal gradients similar to those of the present day, hydrocarbon generation at the base of the Latrobe Group probably commenced in the depocentre in Late Palaeocene to Early Eocene times. Since the basin continues to subside, immature Latrobe coals are still being carried below the OGT and consequently present-day generation is probably as vigorous as at any time in the past. Observations to substantiate the recent origin of at least part of the accumulations, are that all traps were full to spill-point when discovered and that no oils show signs of biodegradation.

On the basis of the available data, it is impossible to establish the presence or extent of lateral hydrocarbon migration. This is unfortunate since, in the absence of appreciable coal deposits east of Kingfish, Mackerel and Flounder, structures in open acreage in the south-east of the region (e.g. S.E. Kingfish, Herring and Haddock) could only be filled by hydrocarbons migrating up-dip, eastwards from the basin depocentre. A few non-source samples contained small amounts of migrant oil but the point of origin of these hydrocarbons could not be established.

The distribution of oil and gas fields in the Gippsland basin is unusual, i.e. gas is trapped up-dip from oil, resulting in a gas province in the west and an oil province in the south-east with an intermediate belt of mixed fields tending to condensate in the north-east.

A number of suggestions have been proposed to explain this atypical pattern, including downdip flushing of the oil by freshwater and displacement of oil by subsequently (deep) generated gas when the top Latrobe surface was still roughly horizontal. Another possible explanation is that the observed distribution of fields is a function of organic facies, i.e. the Latrobe sediments below the gas province contain a greater proportion of gas-prone humic coals. In view of the structural attitude and related maturity of the Latrobe Group, a consequence of this explanation is that the bulk of the gas must be of shallow, low-temperature origin. Carbon isotope analysis should resolve whether the gas is biogenic or early diagenetic or neither.

Another, less likely, explanation is that the gas comes from the deeper, more mature Strzelecki Group. Insufficient samples have been analysed to form firm conclusions about the source potential of this unit. Two shales from Flathead-1, presently immature, appeared capable of sourcing moderate amounts of hydrocarbons at optimum levels of maturity, but a very large volume of mature shale would be required to generate the observed volumes of gas. Lacking extensive coal deposits, the Strzelecki Group is an unlikely hydrocarbon source.

After consideration of source rock distribution and generation threshold depths, the available exploration permits are rated, in decreasing order of prospectivity, as follows: V 80-2, V 80-3, V 80-1 and V 80-4. Potential source rocks in V 80-1 are likely to be immature or early mature except in acreage adjacent to the depocentre. In any case, the volume of mature source is relatively small since the Latrobe Group rarely exceeds 1000m in thickness. Up-dip migration from the depocentre may have occurred but a lack of suitable structures is probably the main limiting factor.

In terms of mature thickness of the Latrobe Group, the northern part of V 80-2 appears highly prospective. However, it lies outside the area of thick coal development and structures may be full only if migration from the basin depocentre has taken place. The same proviso applies to the southern part of V 80-3, where, in addition, the Latrobe Group rarely exceeds 1500m in thickness. In the northern part of V 80-3 and almost all of V 80-4 Latrobe sediments are relatively thin, probably non-coaly and largely immature. It has been suggested that the Gurnard formation is a possible source rock in open acreage since it thickens and becomes more argillaceous as it dips eastwards into the maturation zone. However, none of the 3 samples analysed had any significant hydrocarbon potential.

5. HYDROCARBON GENERATION ALONG THE SOUTHERN AUSTRALIAN MARGIN: A GEOCHEMICAL COMPARISON OF THE GIPPSLAND BASIN WITH THE OTWAY BASIN AND THE GREAT AUSTRALIAN BIGHT.

The Otway basin may be divided into 3 stratigraphic intervals (10): firstly non-marine clastic sediments of Early Cretaceous age (the Otway Group, equivalent to the Strzelecki Group) which accumulated in an east-west trending rift valley; secondly alternating marine and non-marine interbedded sandstones and shales of Late Cretaceous age (the Sherbrook Group, equivalent to the lower part of the Latrobe Group); and finally a series of prograding marine carbonate/clastic wedges of Tertiary age. Samples for geochemical analysis were obtained from Pecten-1 (2) and Voluta-1 (3).

The principal difference between the two basins with regard to source rocks is that the Otway contains much less coal than the Gippsland. Since coals are the major hydrocarbon source in the Gippsland basin, a lack of similar deposits accounts for the poor exploration record of the Otway basin. Suggested alternative source, such as the Upper Cretaceous Belfast Mudstone, have shown no appreciable source potential to date. Depth to the OGT is slightly greater in the Otway basin but this is not significant compared to the source rock problem.

No detailed geological data were available for the Great Australian Bight but the general stratigraphic sequence appears comparable to other basins on the southern Australian margin, i.e. rift valley, interbedded sandstones, shales and coals of Early to Late Cretaceous age overlain by marine shales and carbonates of Late Cretaceous and Tertiary age. Samples for geochemical analysis were obtained from Platypus (5) and Potoroo (4). Coals from the non-marine sections of both wells had excellent potentials to source gas with associated oil. However, the coals appear to be of the normal humic type with no sapropelized or exinite-rich horizons. Also the volume of coal present appears to be considerably less than in the Gippsland basin. Insufficient data are available to generalize about depth to the OGT in the Great Australian Bight.

In conclusion, the important differences between the 3 basins are that the Gippsland basin non-marine sequence contains a much greater volume of coal/carbonaceous shale than comparable sequences in the other basins, and that a significant proportion of the kerogen comprises a type of oil-prone algal/sapropelic material that has not yet been detected in the Otway basin and Great Australian Bight. The greater organic input to the Gippsland basin suggests the area was more humid and vegetated than the other south Australian basins. The impeding effects of vegetation on soil erosion and channel migration combined with a high organic productivity and a near-surface water table, would have been conducive to stagnation and consequent sapropelization and preservation of organic matter.

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STRATIGRAPHY OF OFFSHORE GIPPSLAND BASIN

(ADAPTED FROM THRELFALL ET AL 1976)

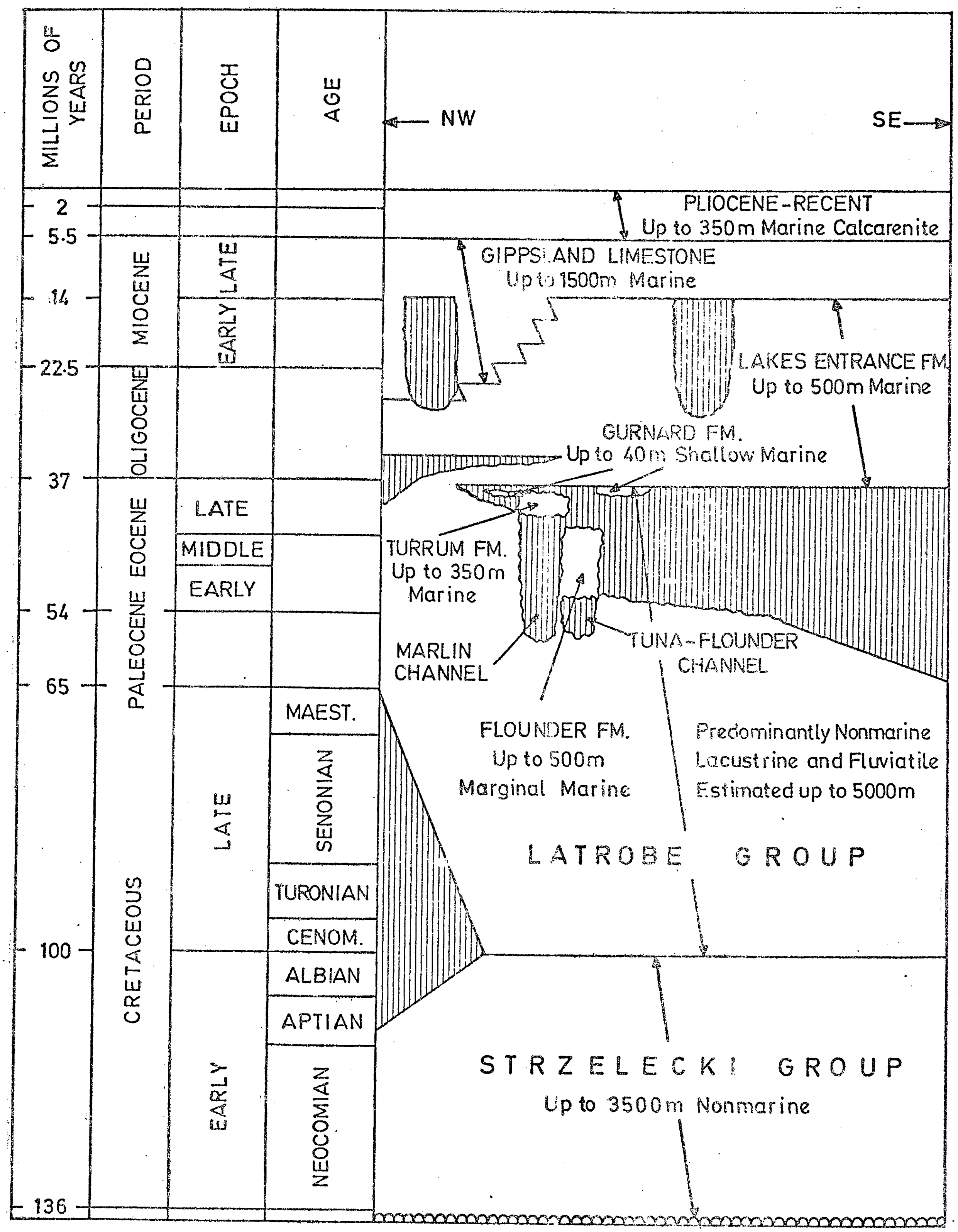

FIG. 2.

APPENDIX I

ANALYTICAL DATA FOR BARRACOUTA - 1

TABLE 1

VITRINITE REFLECTANCE DATA

WELL: BARRACOUTA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	REFLECTANCE VALUES(%RO)	COMMENTS
713.2	.4(15)	L/V+B PAR/OCC B W
1019.2	.38(4).77(1)	BAR/F V PAR VAR
1070.4	.39(20)	DOM B S/B W/G VW+PAR/NO I
1447.7	.52(20)	DIRTY COAL/NO I
1725.1	.43(20)	DOM I PAR/HEAVY BS/OCC DIRTY VW
1868.3	.45(21)	L-M/B W+I PAR/S VW+G VST/LOOSE COAL FR
1965.9	.32(20)	L-M/G VW+PAR/S B W/NO I
2062.2	.54(20)	COAL-MASSIVE/STRUCTURELESS
2208.5	.54(20)	L/I PAR+SUB V/S B W
2351.4	.54(21)	M/M I PAR+R/F V PAR+VST/B W
2649.2	.61(20)	L-M/M LARGE I PAR/F VW+VST/B W
2650.1	.65(21)	30% COAL-STRUCTURELESS V/SHALE-I PAR+VW

FIGURES IN PARENTHESES INDICATE NUMBER OF READINGS
SEE LIST OF ABBREVIATIONS OVERLEAF

TABLE 2

VISUAL KEROGEN DESCRIPTIONS

WELL: BARRACOUTA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	SPORE COLOUR	SOURCE POTENTIAL
713.2	2	POOR OIL
1019.2	2/3	NONE
1070.4	2/3	MODERATE-GOOD GAS
1447.7	N.D.	GOOD GAS?
1725.1	3	GOOD GAS/SUBORDINATE OIL?
1868.3	3	FAIR-GOOD GAS?
1965.9	3	GOOD GAS
2351.4	3	POOR-MODERATE GAS
2649.2	4	NONE-POOR GAS
2650.1	3	GOOD GAS

TABLE 3

ROCK-EVAL AND PYROLYSIS DATA

WELL: BARRACOUTA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	P1 KG/TONNE	P2 KG/TONNE	GOGI	OIL YIELD KG/TONNE	GAS YIELD KG/TONNE
713.2	Ø	.2			
1019.2	Ø	Ø			
1070.4	1	6.8	.28	5.3	1.5
1447.7	.1	3.7	.72	2.2	1.5
1725.1	4.3	85.5	.27	67.3	18.2
1868.3	.2	1.4			
1965.9	.2	2.8	.35	2.1	.7
2062.2	.3	.6			
2208.5	Ø	Ø			
2351.4	.2	1			
2649.2	.1	.2			
2650.1	1	2Ø.2	.36	14.9	5.3

TABLE 4

LITHOLOGY AND TOC DATA

WELL: BARRACOUTA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	AGE	PICKED LITHOLOGY	%TOC	%CARBONATE
713.2	MIOCENE	N-MARL	0.4	51.6
1019.2	OLIGOCENE	N-MDST/SH	N.D.	N.D.
1070.4	EOCENE	N-SHALE	N.D.	N.D.
1447.7	EOCENE	N-SH/COAL BANDS	N.D.	N.D.
1725.1	U-CRETACEOUS	N-SLTST/COAL	31.4	5.5
1868.3	U-CRETACEOUS	N-SLTST/COAL	N.D.	N.D.
1965.9	U-CRETACEOUS	N-SLTST/COAL	0.9	4.2
2062.2	U-CRETACEOUS	N-SST/COAL BAND	1.4	5.4
2208.5	U-CRETACEOUS	N-SANDSTONE	0.3	3.9
2351.4	U-CRETACEOUS	N-SILTSTONE	1.9	4.6
2649.2	U-CRETACEOUS	N-SANDSTONE	0.8	6.2
2650.1	U-CRETACEOUS	N-SH/COAL BANDS	6.2	4.3

SAMPLE TYPES :-
N-CORE SAMPLE
S-SIDEWALL CORE
O-OUTCROP
C-CUTTINGS

TABLE 5

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: BARRACOUTA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	TOC %WT	TSE/TOC 0/00	SAC/TOC 0/00	CPI	ASPHALTENES %WT
1725.1	31.4	43	10	1.5	15.5
1965.9	.9	63	20	1.29	N.D.
2650.1	6.2	43	13	1.2	15

TABLE 6

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: BARRACOUTA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	%SAC	%TSE	PRIST/PHYT	PRIST/C-17	PHYT/C-18
1725.1	22.7	1.348	8.4	3.5	.4
1965.9	32.1	.057	5	5.3	.9
2650.1	29.3	.265	6.2	2.6	.3

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APPENDIX II

ANALYTICAL DATA FOR BREAM - 2

TABLE 1

VITRINITE REFLECTANCE DATA

WELL: BREAM-2
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	REFLECTANCE VALUES(%RO)	COMMENTS
1861.1	.44(21)	L/GN V=I PAR
1876.8	.45(20)	L/V+B PAR/S BS
1903.4	.39(22)	L-M/B W+LOCALLISED S/VW+PAR/NO I
1906.7	.41(21)	M/RICH B W+LOCALLISED S/VW+STRINGERS/TR I
1927.2	.48(20)	STRONG BS+W/L V PAR+W-COR/TR I
1938.4	.94(21)	COAL-G CLEAN STRUCTURELESS V
2724.8	.71(21)	RICH/VAR COAL/V+I/SHALE-B SATURATED
2741.5	.57(20)	STRONG BS/M-RICH VW-COR/SUB I PAR
2746.7	.62(22)	M-RICH/STRONG BS/V=I W+PAR+STRINGERS
2753.7	.5(21)	STRONG BS/M-RICH IN VW/V=I+R
3246	.55(23)	BS+W/M-RICH I+R PAR/VW+STRINGERS-VAR

FIGURES IN PARENTHESES INDICATE NUMBER OF READINGS
SEE LIST OF ABBREVIATIONS OVERLEAF

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TABLE 2

VISUAL KEROGEN DESCRIPTIONS

WELL: BREAM-2
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	SPORE COLOUR	SOURCE POTENTIAL
1861.1	3	MODERATE GAS/OIL
1876.8	4/5	NONE
1903.4	3	GOOD GAS
1906.7	3	GOOD GAS
1927.2	3	GOOD GAS/SUBORDINATE OIL
2724.8	3/4	GOOD GAS/SUBORDINATE OIL
2741.5	3/4	MODERATE-GOOD GAS
2746.7	3/4	MODERATE GAS
2753.7	3/4	GOOD GAS/OIL
3246	4	POOR-MODERATE GAS

TABLE 3

ROCK-EVAL AND PYROLYSIS DATA

WELL: BREAM-2
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	P1 KG/TONNE	P2 KG/TONNE	GOGI	OIL YIELD KG/TONNE	GAS YIELD KG/TONNE
1861.1	Ø	.1			
1876.8	.1	.1			
1903.4	.9	6.2	.27	4.9	1.3
1906.7	.1	.1			
1927.2	.6	3.5	.25	2.8	.7
1938.4	7.1	113.3	.81	62.6	5Ø.7
2724.8	6.7	113.6	.37	86.6	32
2741.5	.5	5.6	.31	4.3	1.3
2746.7	.5	3.5	.45	2.4	1.1
2753.7	1.7	2Ø.6	.46	14.1	6.5
3246	Ø	.1			

TABLE 4

LITHOLOGY AND TOC DATA

WELL: BREAM-2
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	AGE	PICKED LITHOLOGY	%TOC	%CARBONATE
1861.1	OLIGOCENE?	N-SHALE	1.3	13
1876.8	U-CRET/EOCENE?	N-SANDSTONE	N.D.	N.D.
1903.4	U-CRET/EOCENE?	N-SHALE/SLTST	3	3.8
1906.7	U-CRET/EOCENE?	N-SLTST/SST	Ø.6	11
1927.2	U-CRET/EOCENE?	N-SILTSTONE	3.1	6.6
1938.4	U-CRET/EOCENE?	N-COAL	7Ø	8.7
2724.8	U-CRET/EOCENE?	N-SHALE/COAL	N.D.	N.D.
2741.5	U-CRET/EOCENE?	N-SILTSTONE	4	8.7
2746.7	U-CRET/EOCENE?	N-SLTST/COAL	3.9	8.7
2753.7	U-CRET/EOCENE?	N-SHALE/COAL	9.4	8.4
3246	U-CRET/EOCENE?	N-SST/SLTST	Ø.1	5.4

SAMPLE TYPES :-
N-CORE SAMPLE — O-OUTCROP
S-SIDEWALL CORE — C-CUTTINGS

TABLE 5

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: BREAM-2
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	TOC %WT	TSE/TOC 0/00	SAC/TOC 0/00	CPI	ASPHALTENES %WT
1903.4	3	56	14	1.06	22.2
2741.5	4	48	11	1.16	25.5
2753.7	9.4	65	21	1.14	19.5

TABLE 6

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: BREAM-2
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	%SAC	%TSE	PRIST/PHYT	PRIST/C-17	PHYT/C-18
1903.4	24.5	.169	4.8	.6	.1
2741.5	22.4	.193	6.7	4.6	.6
2753.7	32.7	.612	6.6	4.2	.5

APPENDIX III

ANALYTICAL DATA FOR FLATHEAD - 1

TABLE 1

VITRINITE REFLECTANCE DATA

WELL: FLATHEAD-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	REFLECTANCE VALUES(%RO)	COMMENTS
472.4	.43(3)	BAR/F I PAR/DOUBTFUL V PAR
478.5	.42(20)	M/B W+STRINGERS/M I PAR/POOR V PAR
482.5	.5(21)	M/GN PAR V+I+R/DOUBTFUL V/OCC B W
504.4	.35(20)	M/GN PAR V+I/V-R DIFFERENTIATION DIFFICULT
516	.39(19).76(1)	M/B W/GN PAR I+R/VW+PAR-VAR
1058.5	.37(20)	STRONG BS/VW+STRINGERS/I PAR
1063.7	.41(20)	M-RICH/BS+W/I PAR/G VW+STRINGERS

FIGURES IN PARENTHESES INDICATE NUMBER OF READINGS
SEE LIST OF ABBREVIATIONS OVERLEAF

TABLE 2

VISUAL KEROGEN DESCRIPTIONS

WELL: FLATHEAD-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	SPORE COLOUR	SOURCE POTENTIAL
472.4	2/3	NONE-LEAN
478.5	3	NONE-POOR GAS
482.5	3	NONE
504.4	3	POOR-MODERATE GAS
516	3	POOR-MODERATE GAS
1058.5	3/4	GOOD GAS/SUBORDINATE OIL
1063.7	3	GOOD GAS

TABLE 3

ROCK-EVAL AND PYROLYSIS DATA

WELL: FLATHEAD-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	P1 KG/TONNE	P2 KG/TONNE	GOGI	OIL YIELD KG/TONNE	GAS YIELD KG/TONNE
472.4	.1	Ø			
478.5	.4	1.1	.37	.8	.3
482.5	Ø	.1			
504.4	Ø	.3			
516	Ø	.2			
1063.7	.1	4.7	.48	3.2	1.5

TABLE 4

LITHOLOGY AND TOC DATA

WELL: FLATHEAD-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	AGE	PICKED LITHOLOGY	%TOC	%CARBONATE
472.4	EOCENE?	N-SST/MDST	N.D.	N.D.
478.5	EOCENE?	N-MUDSTONE	1.4	12.6
482.5	EOCENE?	N-MUDSTONE	Ø.6	12.2
504.4	EOCENE?	N-MUDSTONE	Ø.7	14.7
516	EOCENE?	N-SANDSTONE	Ø.7	13.9
1058.5	L-CRETACEOUS	N-SHALE	N.D.	N.D.
1063.7	L-CRETACEOUS	N-SHALE	3.6	2Ø.6

SAMPLE TYPES :-
N-CORE SAMPLE
S-SIDEWALL CORE
O-OUTCROP
C-CUTTINGS

TABLE 5

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: FLATHEAD-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	TOC %WT	TSE/TOC 0/00	SAC/TOC 0/00	CPI	ASPHALTENES %WT
478.5	1.4	160	62	N.D.	2.3
1063.7	3.6	21	8	1.99	7

TABLE 6

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: FLATHEAD-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	%SAC	%TSE	PRIST/PHYT	PRIST/C-17	PHYT/C-18
478.5	38.8	.225	N.D.	N.D.	N.D.
1063.7	38.8	.074	5.4	1.4	.4

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APPENDIX IV

ANALYTICAL DATA FOR HAPUKU - 1

TABLE 1

VITRINITE REFLECTANCE DATA

WELL: HAPUKU#1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH (M)	REFLECTANCE VALUES(%RO)	COMMENTS
2829.3	.33(1).81(1)	BAR/BS
2854.3	.31(5).57(1)	B/COAL/VW

FIGURES IN PARENTHESES INDICATE NUMBER OF READINGS
SEE LIST OF ABBREVIATIONS OVERLEAF

4%65

TABLE 2

VISUAL KEROGEN DESCRIPTIONS

WELL: HAPUKU#1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH(M)	SPORE COLOUR	SOURCE POTENTIAL
2829.3	4/5	NONE/POOR GAS/OIL?
2854.3	4/5	NONE

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TABLE 3

ROCK-EVAL AND PYROLYSIS DATA

WELL: HAPUKU#1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH (M)	P1 KG/TONNE	P2 KG/TONNE	GOGI	OIL YIELD KG/TONNE	GAS YIELD KG/TONNE
2829.3	Ø	Ø			
2854.3	Ø	.1			

TABLE 4

LITHOLOGY AND TOC DATA

WELL: HAPUKU#1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH(M)	AGE	PICKED LITHOLOGY	%TOC	%CARBONATE
2829.3	OLIGOCENE?	SILTSTONE	0.32	10.3
2854.3	U-CRET/EOCENE?	SILTSTONE	0.25	3.8

SAMPLE TYPES :-
N-CORE SAMPLE
S-SIDEWALL CORE
O-OUTCROP
C-CUTTINGS

TABLE 5

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: HAPUKU#1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH (M)	TOC %WT	TSE/TOC 0/00	SAC/TOC 0/00	CPI	ASPHALTENES %WT
2829.3	.32	73	51	N.D.	N.D.
2854.3	.25	16	5	N.D.	N.D.

TABLE 6

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: HAPUKU#1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH(M)	%SAC	%TSE	PRIST/PHYT	PRIST/C-17	PHYT/C-18
2829.3	65.6	.025	N.D.	N.D.	N.D.
2854.3	31.7	.004	N.D.	N.D.	N.D.

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APPENDIX V

ANALYTICAL DATA FOR PERCH - 1

TABLE 1

VITRINITE REFLECTANCE DATA

WELL: PERCH#1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH (M)	REFLECTANCE VALUES(%RO)	COMMENTS
1134.4	.38(20)	DOM BS/FBW
1152.1	.44(22)	BS/OCC VW
1164.9	.35(23)	OAL/V
1173.4	.31(20)	BS/DOM VW
2660.8	.68(21)	VW/OCC I/BW
2666.9	.68(20)	L/TR VW/OCC BW

FIGURES IN PARENTHESES INDICATE NUMBER OF READINGS
SEE LIST OF ABBREVIATIONS OVERLEAF

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TABLE 2

VISUAL KEROGEN DESCRIPTIONS

WELL: PERCH#1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH(M)	SPORE COLOUR	SOURCE POTENTIAL
1134.4	3	GOOD GAS
1152.1	3	GOOD GAS/OIL
1164.9	3	GOOD GAS
1173.4	3	GOOD GAS
2660.8	4/5	MODERATE-GOOD GAS
2666.9	5	POOR GAS

TABLE 3

ROCK-EVAL AND PYROLYSIS DATA

WELL: PERCH#1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH (M)	P1 KG/TONNE	P2 KG/TONNE	GOGI	OIL YIELD KG/TONNE	GAS YIELD KG/TONNE
1134.4	.2	.6			
1152.1	.4	5.1	.27	4	1.1
1164.9	12.9	131.9	.38	95.6	36.3
1173.4	.3	4	.39	2.9	1.1
2660.8	Ø	.7			
2666.9	Ø	.2			

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TABLE 4

LITHOLOGY AND TOC DATA

WELL: PERCH#1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH(M)	AGE	PICKED LITHOLOGY	%TOC	%CARBONATE
1134.4	OLIGOCENE	SHALE	2.4	12.3
1152.1	U-CRET/EOCENE?	SHALE	7.4	16.5
1164.9	U-CRET/EOCENE?	COAL	58.6	8.4
1173.4	U-CRET/EOCENE?	SHALE	7	3.8
2660.8	L-CRETACEOUS	SHALE	Ø.92	9
2666.9	L-CRETACEOUS	SHALE	Ø.62	5.5

SAMPLE TYPES :-
N-CORE SAMPLE
S-SIDEWALL CORE
O-OUTCROP
C-CUTTINGS

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TABLE 5

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: PERCH #1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH (M)	TOC %WT	TSE/TOC 0/00	SAC/TOC 0/00	CPI	ASPHALTENES %WT
1134.4	2.4	41	6	N.D.	3
1152.1	7.4	48	5	2.3	12
1164.9	58.6	58	3	2	30
1173.4	7	42	4	2.2	12
2660.8	.92	10	3	N.D.	N.D.
2666.9	.62	8	2	N.D.	N.D.

TABLE 6

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: PERCH#1
LOCATION: GIPPSLAND BASIN AUSTRALIA

DEPTH(M)	%SAC	%TSE	PRIST/PHYT	PRIST/C-17	PHYT/C-18
1134.4	14	.098	N.D.	N.D.	N.D.
1152.1	11.3	.354	1.4	Ø	Ø
1164.9	5.5	3.4	2.4	Ø	Ø
1173.4	11	.292	2.2	Ø	Ø
2660.8	24.3	.009	5	Ø	Ø
2666.9	23.6	.005	N.D.	N.D.	N.D.

APPENDIX VI

ANALYTICAL DATA FOR TUNA - 1

TABLE 1

VITRINITE REFLECTANCE DATA

WELL: TUNA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	REFLECTANCE VALUES(%RO)	COMMENTS
2020.7	.48(21)	COAL-WHOLLY V/SHALE-O BS/VW+I -
2258.5	.46(20)	M/G VW+STRINGERS+PAR/B W+BS/TR I
2458.1	.5(20)	M/BS/G VW+STRINGERS/TR I
2666.9	.45(21)	BS+W+BLEBS/V STRINGERS+I+R PAR
2679.1	.43(2)	BAR/BS+BLEBS/DOUBTFUL V?
2849.7	.63(20)	M-RICH/B W/DOM R+I/L COR VW
3087.5	.5(3)	L/DOM I+R-COR/P VW+PAR/LOCALLISED BS
3325.2	.76(5)	L/B W/GN R+I PAR/VW-COR
3515.7	0(0)	BAR/S I+R/OCC B W/NDP
3537.6	.74(20)	M-RICH/GN I+R/TR P VW+PAR/B W

FIGURES IN PARENTHESES INDICATE NUMBER OF READINGS
SEE LIST OF ABBREVIATIONS OVERLEAF

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TABLE 2

VISUAL KEROGEN DESCRIPTIONS

WELL: TUNA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	SPORE COLOUR	SOURCE POTENTIAL
2020.7	3	GOOD GAS
2258.5	3	MODERATE GAS
2458.1	3	GOOD GAS
2666.9	3	GOOD GAS
2679.1	3	MODERATE? GAS
2849.7	3/4	POOR-MODERATE GAS
3087.5	4	NONE
3325.2	4/5	NONE
3515.7	4/5	NONE
3537.6	4/5	POOR-MODERATE? GAS

TABLE 3

ROCK-EVAL AND PYROLYSIS DATA

WELL: TUNA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	P1 KG/TONNE	P2 KG/TONNE	GOGI	OIL YIELD KG/TONNE	GAS YIELD KG/TONNE
2020.7	2.2	32.9	.29	25.5	7.4
2258.5	1.4	14.9	.3	11.5	3.4
2458.1	1.4	33.8	.56	21.7	12.1
2666.9	.4	2.5	.61	1.6	.9
2679.1	.2	.4			
2849.7	.2	1.7	.67	1	.7
3087.5	Ø	Ø			
3325.2	.1	.6			
3515.7	Ø	Ø			
3537.6	.1	.5			

TABLE 4

LITHOLOGY AND TOC DATA

WELL: TUNA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	AGE	PICKED LITHOLOGY	%TOC	%CARBONATE
2020.7	U-CRET/EOCENE?	N-SHALE/COAL	12.7	3.4
2258.5	U-CRET/EOCENE?	N-SHALE	3.9	4.4
2458.1	U-CRET/EOCENE?	N-SHALE/COAL	7.9	3
2666.9	U-CRET/EOCENE?	N-SHALE	1.9	8.4
2679.1	U-CRET/EOCENE?	N-SST/COAL	1.9	6.6
2849.7	U-CRET/EOCENE?	N-SHALE	2.9	6.8
3087.5	U-CRET/EOCENE?	N-SHALE	Ø.4	15.8
3325.2	U-CRET/EOCENE?	N-SHALE	1.3	22.2
3515.7	U-L CRETACEOUS?	N-SHALE	Ø.1	14.3
3537.6	U-L CRETACEOUS?	N-SHALE	1.4	7

SAMPLE TYPES :-
N-CORE SAMPLE
S-SIDEWALL CORE

O-OUTCROP
C-CUTTINGS

TABLE 5

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: TUNA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	TOC %WT	TSE/TOC 0/00	SAC/TOC 0/00	CPI	ASPHALTENES %WT
2020.7	12.7	30	8	2.32	17.4
2849.7	2.9	30	4	1.32	30
3537.6	1.4	24	5	N.D.	N.D.

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TABLE 6

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: TUNA-1
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	%SAC	%TSE	PRIST/PHYT	PRIST/C-17	PHYT/C-18
2020.7	27.8	.385	7	3.6	.5
2849.7	14.7	.037	6.5	6.3	.9
3537.6	19.1	.034	N.D.	N.D.	N.D.

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APPENDIX VII

ANALYTICAL DATA FOR TUNA - 3

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TABLE 1

VITRINITE REFLECTANCE DATA

WELL: TUNA-3
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	REFLECTANCE VALUES(%RO)	COMMENTS
1395.9	.36(21)	L-M/VW+PAR/BS+W/NO I OR R
1951.8	.53(20)	M-RICH/GN I+R PAR/F V PAR+W/BS
1967.4	.48(21)	BS/G VW+STRINGERS/I PAR/S LOOSE COAL FR
1976.5	.51(20)	B SATURATED/G V STRINGERS+LARGE I FR
1989	.53(20)	RICH/S COAL FR/SHALE-B SATURATED/V=I
2017.7	.35(21)	M/B SATURATED/G VW+STRINGERS-VAR/V=I

FIGURES IN PARENTHESES INDICATE NUMBER OF READINGS
SEE LIST OF ABBREVIATIONS OVERLEAF

TABLE 2

VISUAL KEROGEN DESCRIPTIONS

WELL: TUNA-3
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	SPORE COLOUR	SOURCE POTENTIAL
1395.9	2/3	POOR GAS?
1951.8	3	MODERATE-GOOD GAS
1967.4	3	GOOD GAS
1976.5	3	GOOD GAS
1989	3	GOOD GAS
2017.7	3	GOOD GAS

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TABLE 3

ROCK-EVAL AND PYROLYSIS DATA

WELL: TUNA-3
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	P1 KG/TONNE	P2 KG/TONNE	GOGI	OIL YIELD KG/TONNE	GAS YIELD KG/TONNE
1395.9	.1	.1			
1951.8	.1	1.4			
1967.4	4.5	43.3	.26	34.4	8.9
1976.5	4.4	30.9	.44	21.5	9.4
1989	9.4	78.7	.32	59.6	19.1
2017.7	.8	43.6	.2	36.3	7.3

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TABLE 4

LITHOLOGY AND TOC DATA

WELL: TUNA-3
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	AGE	PICKED LITHOLOGY	%TOC	%CARBONATE
1395.9	U-CRET/EOCENE?	N-SILTSTONE	1.8	10.1
1951.8	U-CRET/EOCENE?	N-SILTSTONE	1.9	10.1
1967.4	U-CRET/EOCENE?	N-SHALE/COAL	18.5	3.5
1976.5	U-CRET/EOCENE?	N-SHALE/COAL	16.3	5.6
1989	U-CRET/EOCENE?	N-SLTST/COAL	20.2	4.3
2017.7	U-CRET/EOCENE?	N-SHALE	8.8	3.7

SAMPLE TYPES :-
N-CORE SAMPLE
S-SIDEWALL CORE
O-OUTCROP
C-CUTTINGS

TABLE 5

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: TUNA-3
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH (M)	TOC %WT	TSE/TOC 0/00	SAC/TOC 0/00	CPI	ASPHALTENES %WT
1967.4	18.5	32	9	1.9	8.1
2017.7	8.8	23	9	2.26	7

TABLE 6

SEDIMENTS SOLUBLE EXTRACT DATA

WELL: TUNA-3
LOCATION: GIPPSLAND BASIN, VICTORIA, AUSTRALIA

DEPTH(M)	%SAC	%TSE	PRIST/PHYT	PRIST/C-17	PHYT/C-18
1967.4	29	.591	9.3	2.1	.3
2017.7	33.9	.202	8	3.4	.3