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ANNUAL REPORT, YEAR 3, T18P

BASS BASIN, TASMANIA

FOR

THE BASS STRAIT OIL AND GAS CONSORTIUM

T/18P Part 14.

AUGUST, 1983.

Petrecon Australia Pty. Ltd.

183002

PETRECON AUSTRALIA PTY. LTD.

Petroleum Exploration Consultants

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Dear

The Bass and Gippsland Basins have many structural, stratigraphic and geochemical similarities. After two decades of exploration, only a single F.I.T. of oil and several F.I.T.'s of gas/condensate have been recovered from Bass while the adjacent Gippsland Basin had an E.U.R. of the order of 4 billion barrels of oil and 10 trillion cubic feet of gas. The industry has attributed the poor success rate in Bass Basin to the lack of structure.

Petrecon has undertaken in-depth studies of Bass Basin and concluded several structures exist at the Top Eastern View (Top Latrobe Equivalent) in areas with highly favourable reservoir, source and seal characteristics.

Petrecon has prepared a farmout package on behalf of the permit holders of T14 and 18P. Your company is offered the opportunity to farmin to either or both permits. If you feel that a farmin on this basis offers too much exposure then feel free to express an interest in a fraction of the deal as we are prepared to sum a group of farminees to effect the drilling of these attractive prospects.

The basic statistics, interests and permit obligations are outlined below:

	PERMIT T14P
Area:	2,730 km approx.
Water Depth:	60-90 m
Distance from Shore	80-140 km
Date Granted:	9th January, 1980
Expiry:	8th January, 1986

Equity Interests

Cue Minerals N.L. (Operator)	35%
Cue Petroleum Pty. Ltd.	20%
Setright Oil & Gas Pty. Ltd.	20%
Romsey Resources Pty. Ltd.	10%
Galveston Mining Corp. Pty. Ltd.	10%
Cue Energy Resources N.L.	5%

Permit Committments

	Required Permit Expenditure $	Actual Permit Expenditure $
Year 1, Jan. 1980-81	75,000	76,621
Year 2, Jan. 1981-82	160,000	413,478
Year 3, Jan. 1982-83	2,200,000	178,039
Year 4, Jan. 1983-84	250,000	
Year 5, Jan. 1984-85	2,500,000	
Year 6, Jan. 1985-86	200,000	
	5,385,000	

Application has been made to the Designated Authority to have the third year committment postponed to Year 4.

PERMIT T18P

Area:	7,690 sq km approx.
Water Depth:	60-80 m
Distance from shore:	30-130 km
Date Granted:	23rd July, 1980
Expiry date:	22md July, 1986

Equity Interests

Bass Strait Oil & Gas N.L. (Operator)	35%
Tasmanian Oil & Gas N.L.	32.5%
Hampton Oil & Gas Group Pty. Ltd.	27.5%
Terrex Resources N.L.	5%

Permit Committments

	Permit Expenditure $	Work Programme
Year 1, July 1980-81	205,000	250 km seismic & evaluation
Year 2, July 1981-82	410,000	200 km seismic
Year 3, July 1982-83	2,000,000	Well No. 1
Year 4, July 1983-84	3,000,000	250 km seismic + Well No. 2
Year 5, July 1984-85	2,700,000	Well No. 3
Year 6, July 1985-86	3,000,000	Well No. 4
	11,315,000	

T14P The farminee will be required to undertake the committments for Year 4, 5 and 6 and will be invited to operate the permit. On completion of the Year 3 expenditure, the farminee will have earned a 40% net interest in the permit. The present permit holders will have the right to maintain, wholly or in part, a pro rata interest. On completion of the Year 4 expenditure, the farminee's interest will increase to 45%; at the end of Year 5, interest will increase to 75% and will reach a maximum of 80% of the permit term. These terms are negotiable.

T18P The farminee will undertake the committment for Year 4, 5 and 6 and will be invited to operate the permit. On the completion of the Year 3 committment well, the farminee will have earned a 30% net interest and will have earned 55% on completion of the second well. The present permit holders will have the right to maintain, wholly or in part, a pro rata interest. Subsequent interest earnings on completion of the obligation work programmes will be 70% after the fifth and 80% after the sixth. These terms are negotiable.

The enclosure is an abbreviated comparison of the Bass and Gippsland Basins in terms of the critical exploration parameters; reservoir, source, seal and structure.

A two volume detailed Bass Basin technical package is available but if you have an interest in the farmout we suggest you contact us with the intention of receiving detailed reviews in Hobart.

Yours sincerely,

J. K. DAVIDSON.

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INTRODUCTION

This report relates to work carried out by Bass Strait Oil and Gas N.L. as Operator for the Consortium which holds title to T18P for the period 23rd July, 1982 to 22nd July, 1983. This is the final quarterly report for the third permit year.

During the period geological, geochemical and geophysical data were analysed for prospect evaluation. Processing of 144.7km of 48 fold seismic data was completed and an evaluation of the leads defined south of Bass -3 was undertaken.

The Consortium is presently attempting to farmout part of its interest in the permit.

GEOLOGICAL AND GEOPHYSICAL PROGRAMMES

Geological evaluations on T18P have been conducted simultaneously with similar studies on T14P. A comprehensive report is enclosed in the T14 and 18P farmout package which was submitted with the T14P Third Year Annual Report, January 7, 1983. An updated farmout package is enclosed with this report.

Geophysical evaluations have also been undertaken jointly between the two permits. 122 line km (144.7km with tails) of 48 fold data shot during the Second Permit Year were processed in the first quarter of Year Three. The most up to date mapping on T18P was also included in the farmout package submitted with T14P the Third Year Annual Report.

THIRD PERMIT YEAR EXPENDITURE

AND WORK PROGRAMME

EXPENDITURE REQUIREMENTS - T18P

	EXPENDITURE	WORK PROGRAMME
First Year	$205,000	Preliminary investigation and reappraisal and preliminary seismic.
Second Year	$410,000	Seismic.
Third Year	$2,000,000	Drilling of First Well.

ACTUAL EXPENDITURE - T18P

First Year	$678,450	Preliminary investigation and 731km seismic.
Second Year	$250,716	144.7km seismic, geological and burial history studies.
Third Year	$68,187	Farmout Programme.
	$997,353	

A breakdown of the Third Year Expenditure is as follows:-

Quarterly Period	Lease Fees (Rental)	Office Overhead	Field Work		
			Geological	Geophysical	Drilling
1st	590	9,464		23,839	
2nd		6,000		15,697	
3rd		3,788		2,012	
4th		4,553		2,244	
Year	590	23,805		43,792	

WORK PROGRAMME FOR PERMIT YEAR 4 AND VARIATION OF AGREEMENT

A letter dated August 24 has been sent to the Tasmanian Director

of Mines requesting extension of the Year 3 committment until April, 30 1984.

As you are aware, we have undertaken a vigorous farmout programme on T18 and 14P. This farmout was directed to 35 of the world's largest oil companies. As the letter to the Director explains, the departure of Esso and BHP from Bass Basin and the current world recession and resultant downturn in the industry have caused a remarkable lack of interest in the basin. The Federal Government has recognised this and shot a $2 million seismic survey, largely in Bass Basin, in order to attract exploration interest in the area.

As a result, we are requesting the D.A. to extend the year 3 committment to April 30, 1984 in order to (a) shoot a further 150km of seismic data over a major lead and bring to prospect level two compressional structures all in the SW part of the permit, and (b) undertake a concerted effort to farmout the permit to an Australian company or group of Australian companies. A copy of the farmout package is appended to this report.

REPORTS SUBMITTED DURING PERMIT YEAR 3.

First Quarter Report	23/7/82 - 22/10/82
Second Quarter Report	23/10/83 - 22/1/83
Third Quarter Report	23/1/83 - 22/4/83

BASS BASIN

LOCATION AND EXPLORATION HISTORY

Bass Basin is located in the Bass Strait area of south-eastern Australia between the mainland of Australia and the north coast of Tasmania. The essentially granitic Bassian Rise separates the basin from the Gippsland Basin to the northeast. Both basins were initiated during the Late Jurassic as a result of NE-SW orientated tensional stress associated with the early rifting of the Australian and Antarctic plates. The farmout permits, T14P and T18P, are located in the central portion of Bass Basin and are shown on Figure 1 on the accompanying montage.

Exploration by the BHP - Esso consortium in both basins commenced in 1962 and following the lack of success in Bass and the large discoveries in Gippsland, Esso left the area in 1975 having drilled thirteen wells. BHP drilled a further five wells and in 1983 relinquished their remaining interests.

Sixteen seismic surveys, comprising some 16,000 km have been conducted in Bass. The more recent seismic work, the BCS 81 (T14P) and BBS 81 (T18P) surveys of 550 kms and 730 kms, respectively, were shot by Cue Minerals N.L. and Bass Strait Oil & Gas N.L. in 1981. These surveys were of a regional nature and tied most of the wells in the basin. Subsequently, two detailed seismic surveys were shot in 1982. There is now seismic grid coverage of approximately 4 km on average, over T14P and T18P.

To date, eighteen wells have been drilled of which ten are located within the T14P and T18P permits.

STRATIGRAPHY AND HYDROCARBON SHOWS

The Bass and Gippsland Basins are stratigraphically similar. (Fig. 2).

Lower Cretaceous

The Strzelecki Group is a sequence of non-marine greywackes, shales and minor coals, deposited in the initial basinal troughs and grabens in Gippsland Basin. The sediments are very immature and the sandstones have poor reservoir qualities. In the southeastern extremity of Bass Basin, the Lower Cretaceous Otway Group comprises interbedded fine to medium grained lithic sandstone, siltstones and shales with rare thin conglomerates and coals. To the northwest, lithic sandstones with interbedded weathered volcanics have been recorded. No other intersections within the basin have been noted.

Upper Cretaceous - Eocene

Throughout the Cretaceous to Eocene, Bass Basin was almost land-locked with intermittent marine incursions via the Torquay Embayment between Mornington Peninsula and King Island. In contrast, Gippsland Basin had an eastward opening to the Tasman Sea since at least late in the Late Cretaceous.

The Eastern View Group constitutes the principal exploration objective of Bass Basin and ranges from Late Cretaceous through to the basal Late Eocene. The Eastern View is equivalent to the Latrobe Group of Gippsland Basin (see Fig. 2).

The chronostratigraphic sections of Gippsland and Bass Basins show the distribution of the various sedimentary sequences within the Latrobe and Eastern View Groups as a function of geological time (Figs. 3 and 4). Each sequence is depicted as onlapping the basin margin at its base and being truncated towards the margins at its top. The sediments near the margins comprise a complex alluvial and braided stream deposits which grade into flood and delta plain deposits. The major direction of stream flow and sediment movement has been from the northwest in Gippsland, with minor clastics from the south, while in Bass Basin sediment supply was essentially from the southeast and to a lesser degree from the NE and SW. The northern margin provided sediment from the Mid Eocene following structural growth which culminated in anticlinal growth such as Cormorant and in Bass and in the Latrobe Unconformity in Gippsland.

The overall trend in the Gippsland Basin was a progressive northwesterly marine encroachment of successive sequences from the Paleocene to Oligocene. As this landward encroachment occurred a progressively broader zone of non deposition developed in a seaward direction to the southeast.

The earliest marine dinoflagellate incursion in Bass was in the Upper L. balmei zone and extended as far as Bass -2 and Poonboon. Dinoflagellates are sporadically distributed within the Lower and Middle M. diversus zones and their irregular distribution suggests a number of short duration incursions. Dinoflagellates in the Upper M. diversus, P. asperopolus and Lower N. asperus zones are found at Tarook and Cormorant in the NW and are almost basinwide in the Middle N. asperus coinciding with the Upper Eocene marine Demons Bluff shale.

The marginal marine facies in Gippsland consists of stacked sequences of beach, shoreface and offshore sediments. In Bass, shallow water bay deposits form the marginal marine facies and consequently lack excellent reservoir characteristics of some of the marginal marine facies of Gippsland.

The coastal plain facies in Bass were very widespread in the Paleocene and diminished in area as the marginal marine facies transgressed landward with time. The Eastern View marine trangressions culminated in a widespread Eocene shale (Demons Bluff). Only in the northern part of the basin near E-W Gambier Gabo Lineament is there any real development of an uncomformity. As it overlies this lineament, Gippsland experienced major uplift and erosion resulting in the Top Latrobe Unconformity.

The chronostratigraphic sections illustrate the interplay of reservoir and seal rocks. In Gippsland, the majority of the hydrocarbons occur at the top of the Latrobe Group and are sealed by the Oligocene Lake Entrance Formation. The reservoirs are the massive time transgressive beach barrier sandstone deposits that have resulted from the reworking of the deltaic sediments and nearshore marine sands, Intra-Latrobe seals are formed by shales of lower delta plain to shallow marine origin. Reservoirs within the non-marine facies include alluvial and braided stream sands in the landward portion of the facies, with point bar sands and stream mouth bar deposits associated with lower deltaic plain deposition. The hydrocarbons in Gippsland are distributed throughout the Latrobe Group.

In Bass, the primary play is at the Top Eastern View Group sealed by the Upper Eocene Demons Bluff and Oligocene Torquay Group shales. The reservoirs are

massive Mid Eocene beach and alluvial braided stream and marginal marine sands.

The widespread coastal plain and bay deposits of the Paleocene and Early Eocene contain limited reservoir potential with excellent sealing potential eg., Pelican Poonboon and the deeper parts of Cormorant. The best reservoirs are the braided stream and fluvial sands of the upper delta plain facies. Thus the best reservoirs form a horseshore zone about the NE and SE and SW margins. This are affords the best opportunity for intra-Eastern View Group plays equivalent to the intra-Latrobe Group plays.

The pronounced shalines of the basal Tertiary part of the Eastern View gives rise to a Base Tertiary play in which the Upper Cretaceous reservoirs are sealed by the Paleocene shales. Apart from the Top Eastern View, this is the most extensive play in Bass. However, it is probably significant only in the above "horse shoe" area do to excessive depth of burial and over pressuring of the Paleocene and Lower Eocene nearer the basin axis. Apart from the deep Tuna accumulation this play is quite restricted in Gippsland.

The significant hydrocarbon tests are summarised on Table 1.

Oligocene - Recent

The Lakes Entrance Formation of Gippsland is an open marine shale as is the Oligocene part of the Torquay Group in Bass. However, where the Oligocene is totally a marine shale over the Latrobe between the north and south bounding faults, the Oligocene in Bass becomes sandy near the northeastern and southeastern margins, at least. The overlying Miocene to Recent Gippsland

Petrecon Australia Pty Ltd

BASS BASIN

	WELL	DATE DRILLED	AGE OF SHOW	UNIT	SOURCE	TRAP
	Bass -3 F.I.T. 500 cm^3 condensate 0.82 m^3 gas	1967	Paleocene	deltaic fluvial	Lower Eastern View Group	Anticline
	Cormorant -1 F.I.T. 22L oil	1970	Eocene	"	"	Anticline/ Stratigraphic
Petrecon est. reserves two trillion cu. ft. gas 300 million bbls. liquid	Pelican -1 F.I.T. 600 cm^3 condensate 5.9 m^3 gas	1970	Paleocene	"	"	Anticline
	Pelican -2 F.I.T. 750 cm^3 condensate 1.05 m^3 gas	1970	Paleocene	"	"	"
	Pelican -4 recovered gas and condensate		Paleocene	"	"	"

Table 1.

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Formation consists of a generally thick section of marls and limestones. A similar marine section, the upper part of Torquay Group, was deposited in Bass.

SOURCE

The vitrinite reflectance maturation profiles for both basins are very similar (Figures 5 and 6) and indicate that none of the wells were deep enough to have penetrated a mature rock section. The deep wells in Bass, appear to have been terminated just above the zone of initial hydrocarbon generation, as did Barracouta -3 in Gippsland. Thus the Upper Cretaceous and earliest Paleocene in both basins are within the maturation window. This conclusion is supported by the CSIRO and BMR from which the bulk of the geochemcial data are derived. However, it must be remembered that such statements are based on the assumption that maturation does not become significant until Ro reaches 1%. Figs. 5 and 6 show that the log-normal nature of the graphs could indicate significant generation prior to 1%, say at 0.07%, since significant volumes of hydrocarbons were generated at Pelican at this level of maturation.

Fig. 7 shows that the lowest Paleocene - Upper Cretaceous section has good oil source richness and, as in Gippsland, is considered to be the primary oil source. H/O ratios are in excess of 5 (11 to 19) and the samples can be considered as oil prone source rocks.

Good source potential is indicated for the Paleocene to Early Eocene section, both in the deep basin and on the flanks but appears to be gas/condensate prone (Pelican). A fair to good potential for the overlying Early to Late Eocene section. Despite its immaturity, this section has some source potential, eg., at 1500' in Cormorant in the intra Eastern View, a full F.I.T. chamber of oil was recovered below a shale in which the T.O.C. was 10% and the Ro was only 0.04%.

The gross lithologies, maturation and migration data have been presented on schematic sections through both basins in order to understand the hydrocarbon distribution and potential hydrocarbon areas. The N-S cross section in Gippsland Basin (Figure 8) shows that the oil generating window lies within the Upper Cretaceous - Basal Tertiary section and is convex upward over the basin depocentres At the Top Latrobe Group level, the accumulation of hydrocarbons was afforded by vertical migration up growth faults through the excellent reservoir rocks like beaches (Kingfish) and braided streams (Barracouta). Potential intra Latrobe plays may exist in the lower delta plain facies where local seals may occur (eg. Tuna). The oil province of the Kingfish Mackeral Halibut trend is due to vertical migration from the mature oil source. This was also the case along the Snapper trend but generation of gas from the same oil source rocks or from overmature source rocks accounts for the prepondence of gas in the Barracouta-Snapper-Marlin area. The gas-oil province of the Tuna-Flounder area is accounted for by the same mechanism ie., oil from exinite and gas from vitrinite from the same source rocks.

The NE-SW cross section through Bass (Figure 9) indicates two major half graben trough systems (the north eastern trough being dominantly L. balmei age while the south-western graben is of Lower M. diversus age), overlain by a broad uniform simple depression. The oil generating window lies within Paleocene-Late Cretaceous sediments and does notparallel gross basin geometry due to the higher heat flow nearer the basin margins. Hydrocarbons generated near the centre of the basin are trapped and are inhibited from vertical migration due to the presence of the shale prone wer Eocene-Paleocene section and a lack of growth faults. Lateral migration towards the margin is enhanced by the increasing sand percentages and reservoir quality in these directions while some vertical migration along growth faults to the Top Eastern View level is likely.

Oil potential is good near the margins as shown by the Bass -3 F.I.T. test which recovered 0.8 litres of condensate and 820 litres of gas from Paleocene sands. This can be considered a light oil receovery with a G.O.R. of 1200.

The areas of favourable oil generation and migration correspond with the area of best reservoir development.

STRUCTURE

Gippsland Basin is located on the Gambier Gabo Lineament and Bass Basin lies, for the most part, south of this zone between the King and Flinders Islands basement blocks. The basins were initiated in the Late Jurassic (?) by the rotational separation of Antarctica from Australia.

The extent of the depocentres and the Latrobe and Eastern View Groups is shown in Figure 10. Commencing in the Late Eocene, the Gippsland Basin was subjected to an east-west right lateral shear which initiated en echeleon anticlines which after modification be extensive erosion, provided the traps for oil and gas accumulation. Shearing was active during the Late Eocene to Early Oligocene and again during the Mid Miocene and is now probably localised along the northern margin. This wrench system had only minor effects in Bass, mainly north of Cormorant. Bass has been dominated by NE - SW extensional stress although compressional features of Mid Miocene age occur south of Bass -3.

Seismic interpretation with the aid of regional magnetic data have been used to outline a number of structures along the northeast and southwest margins of the basin. Seismic coverage along these margins is sporadic and often of pre-mid 70's vintage.

T14P - Top Eastern View

A map of leads and prospects in permit T14P is shown in Figure 12. Remapping of the area particularly noting basement trends as displayed by the aeromagnetics, has shown that Bass -2 was located on the low side of a SW trending fault while Yurongi -1 and Dondu -1 were dependent on fault seal; Nangkero was dependent on a velocity gradient for closure while Bass -1, the first well spudded in the basin, had a Miocene reef as its target and was not a closure at the Top Eastern View. Thus none of the five wells drilled on the permit have been drilled on a valid trap at the top of the Eastern View Group.

Paipan Prospect

The Paipan Prospect is a Top Eastern View trapdoor normal fault block 10 km south east and updip from Bass -1. Seismic line BCS81-5 (Fig. 11), runs northeast over the crest of the trapdoor. Growth faults could act as conduits for vertical migration of hydrocarbons from the Upper Cretaceous to the Top Eastern View.

BHP shot a survey in 1973 which identified the crest of the feature but missed the high as it extends to the south. The 1982 shooting by Cue confirmed the geometry of the feature and has detailed the prospect to drillable status.

T18P - Top Eastern View

Figure 15 is a time structure map at the Top Eastern View in the southern panhandle portion of T18P. Magnetic contours are superimposed on the map. The map shows a normal fault closure in the far NW. Another feature has been mapped a little further to the NW of the figure. These features are structurally similar to that at Bass -3.

to the SE except that both appear to have a thicker sedimentary section and are closed. Bass -3 drilled a very doubtful closure with an Upper Cretaceous section resting on basement. Following the Bass -3 high to the south, the sedimentary section thickens and the effects of compression are apparent. Three compressional anticlines are mapped. The most prominent being the middle one shown on line BBS81-15 (Figure 13). The feature has clear 4-way dip. The anticline immediately to the NW is updip from the light oil show in the Paleocene at Bass -3.

T18P - BASE TERTIARY

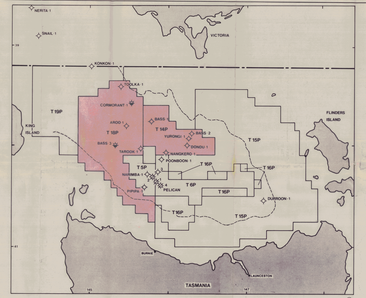
Figure 16, the time structure map near the Base Tertiary is located near the centre of Figure 15. Two highs are mapped near one of the horst blocks. If the spill point is at 1850 msec the structure forms a single Base feature. This prospect is a base Tertiary play with an Upper Cretaceous source and reservoir, sealed by Paleocene shales. Further structures are evident both to the NW and SE and it would appear that the lack of exploration in this part of the basin was due to the fact that the prominent Base Tertiary event was probably previously considered as basement, (like Bass -3).

A most promising lead, the "eyeball", at the Base Tertiary level is a tilted normal fault block as shown on lines BB82A-11 and BBS81-12. (Figures 14 and 17). It derives its name from the anomalous flat lying event below the basal Tertiary black seismic event which, over the top of the structure, looses considerable amplitude and could be evidence for the presence of hydrocarbons (BBS81-12). The orientation of the magnetic contours shows that the large uncontrolled area in the southern part of the lead is probably closed and a further 150 kms of seismic data is to be shot to firm this lead to prospect status.

CONCLUSIONS

Bass and Gippsland Basins have major similarities in terms of reservoir, source and seal characteristics. Where the eroded Top Latrobe anticlines form obvious traps in Gippsland, Bass has been considered essentially structureless at the equivalent Top Eastern View.

In a major basin rework and based on data acquired in 1981 and 1982 and the effective use of 1960-61 aeromagnetic data, it is apparent that this conclusion is incorrect. Several normal and reverse fault related prospects have been identified on the NE and SW margins of the basin both at the Top Eastern View Level and also at the Base Tertiary, the latter constituting a new and prospective play.



T 15P
T 18P - HEMATITE PETROLEUM PTY. LTD.
T 18P - CUE MINERALS N.L.
T 18P - WEAVER OIL & GAS AUSTRALIA
T 18P - BASS STRAIT OIL & GAS N.L.
T 15P - PERTHSHIRE PETROLEUM LTD.

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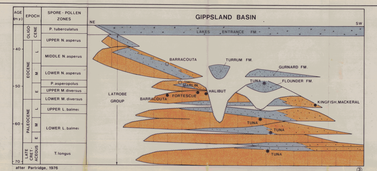

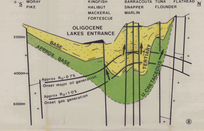

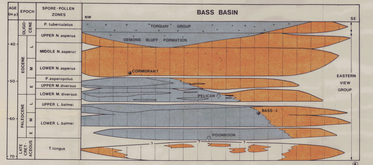

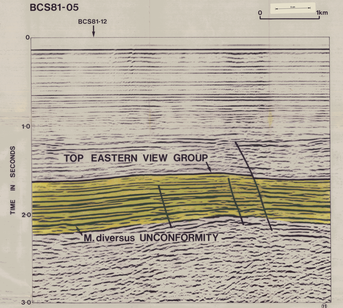

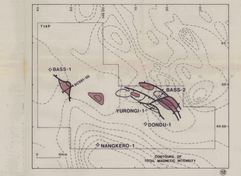

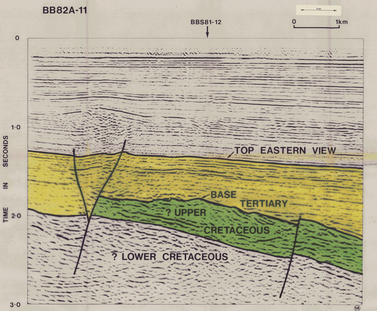

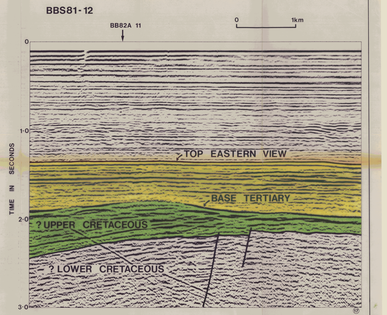

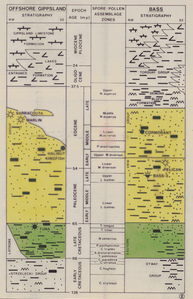

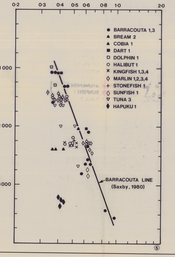

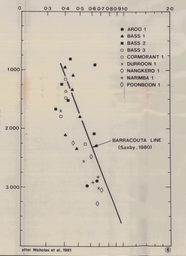

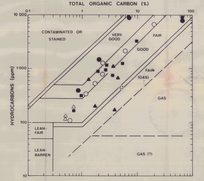

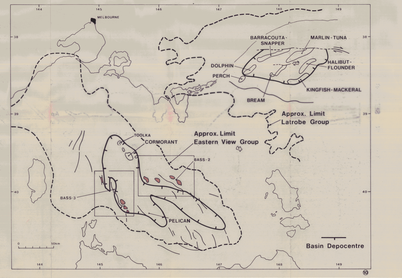

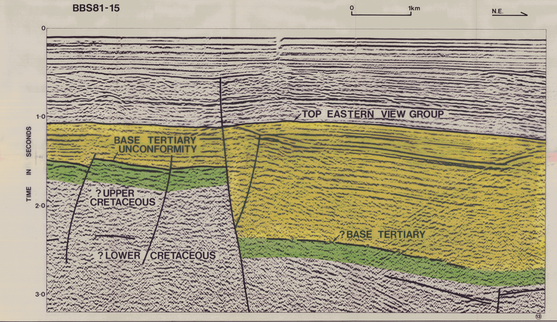

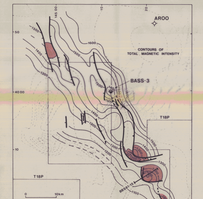

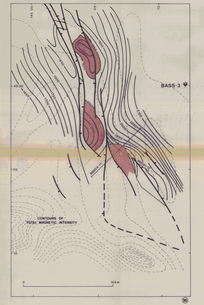

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CUE MINERALS N.L.

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T14P/T18P FARMOUT

MONTAGE

PREPARED J.A.D.(L.D.) DRAWN W.K.D. DATE AUG. '90

Fig.1