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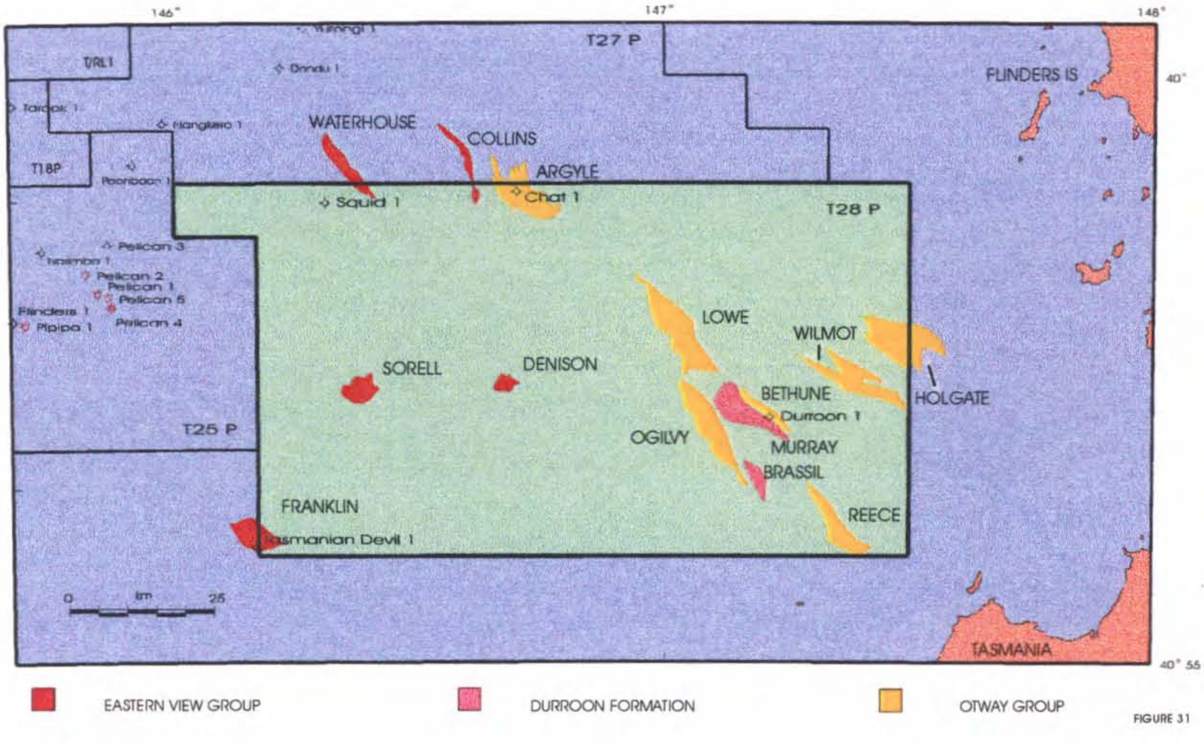
PETROLEUM POTENTIAL OF

T/28P

DURROON BASIN, TASMANIA



CUE ENERGY RESOURCES NL

GJ BLACKBURN
JG BAIRD
NOVEMBER 1995

BLACKBURN / BAIRD

OR-415

This report has been prepared as an internal document to assess the prospectivity of offshore exploration permit T/28P, and is for the sole use of the T/28P participants; Cue Energy Resources NL, Octanex NL and Bass Strait Group NL.

Every reasonable effort has been made by the authors to verify technical data used in this report. However G.J. Blackburn (Blackburn & Associates) and J.G.Baird (Adelmere Pty Ltd) accept no responsibility for any actions taken by any party as a consequence of statements, conclusions and recommendations made in this report.

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Introduction

The T/28P permit covers 7401 km^2 (114 graticular blocks), and lies offshore in the southeastern corner of the Bass Basin approximately 100km north of Launceston, Tasmania (Figure 1). It is covered by water depths of generally less than 90m and is administered by Tasmanian Development and Resources acting on behalf of the Commonwealth for the Joint Authority. The permit is held by Cue Energy Resources N.L. (40%) and operator, Octanex N.L. (30%) and Bass Strait Group N.L. (30%), and was granted 3 November 1994.

The following work program was committed to exploring the permit:

Primary programme:

Permit Year	Work committment	Indicative Expenditure ($A)
1 (1994/5)	Preliminary investigation and seismic mapping	200,000
2 (1995/6)	Seismic reprocessing and acquisition of 500 km seismic	500,000
3 (1996/7)	Seismic interpretation, one well	10,000,000
	Total:	**10,700,000**

Secondary programme:

Permit Year	Work committment	Indicative Expenditure ($A)
4 (1997/8)	Assessment and reinterpretation	750,000
5 (1998/9)	Acquire 1,000 km seismic	1,000,000
6 (1999/2000)	One well	10,000,000
	Total:	**11,750,000**

Total expenditure (indicative) committed to exploration of T/28P is $22,450,000 over these six years.

Permit History

Exploration in the Bass Basin began in the early 1960's with Esso and BHPP drilling 19 wells up until 1982. No commercial discoveries were made, although oil was encountered in Cormorant-1 and gas/condensate in the Pelican-1,2 & 3 wells. From 1980, exploration was led by the Bass Strait/Cue and the Bridge/Weaver consortiums. Amoco and Sagasco farmed into the Bass Strait/Cue group in 1985, when the first commercial discovery (Yolla-1) was made. BHPP, and subsequently Amoco held a small section across the middle of the T/28P permit as the then T/6P and later T/22P permits. A Bridge consortium held most of the area covered by the T/28P permit, as T/16P (relinquished in 1989) and the extensive T/15P permit which was relinquished in 1992.

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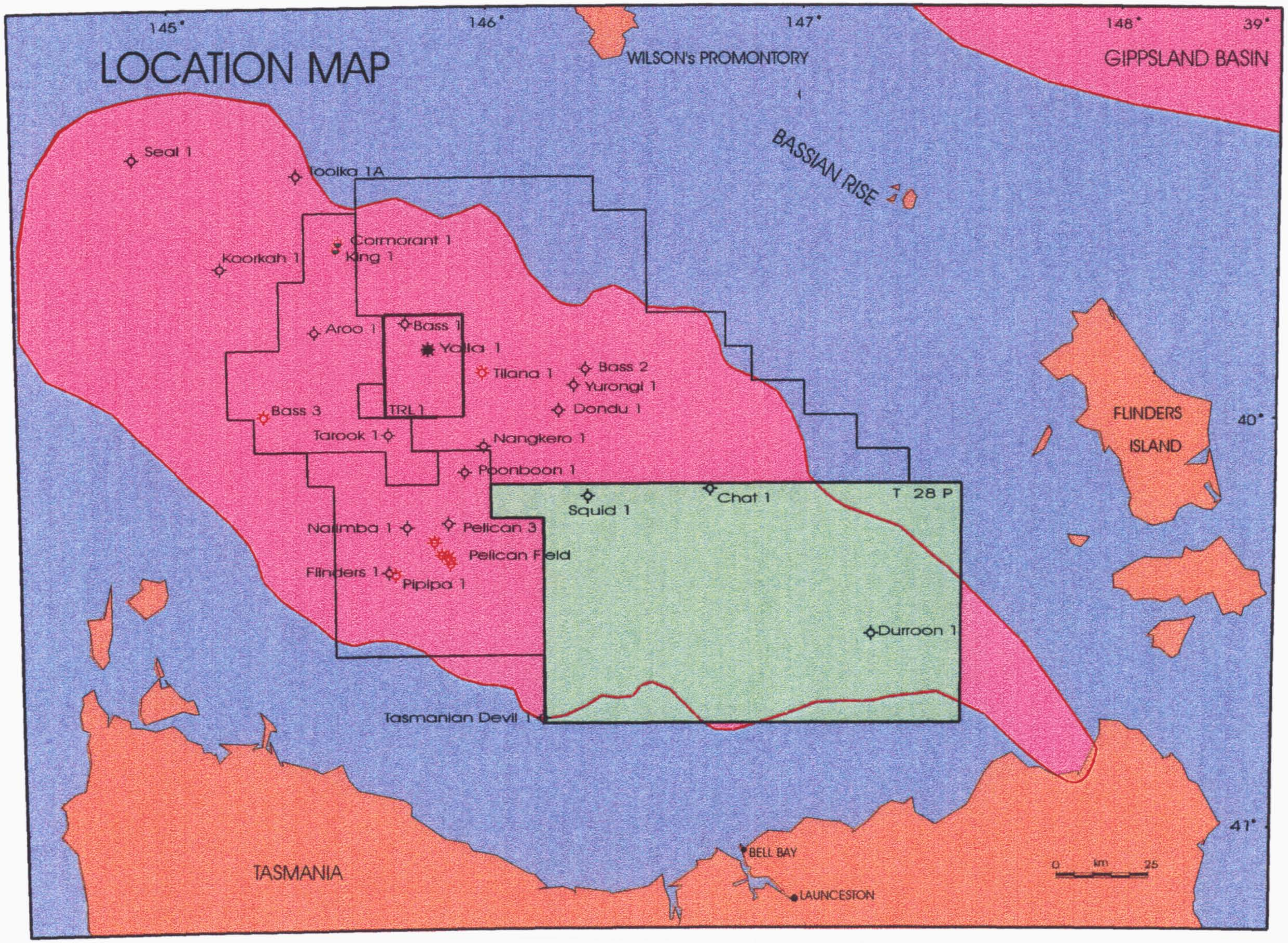

5 cm

FIGURE 1

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Geology and Prospectivity

Regional Geology & Tectonic Framework

The Bass Basin is located in Bass Strait between the northern coast of Tasmania and mainland Australia. It is separated from the gas province of the Otway Basin to the west by the King Island-Mornington Peninsula High, and from the oil and gas producing Gippsland Basin in the east by the Bassian Rise (Flinders Island across to Wilson's Promontory). T/28P lies within a region of the Bass Basin described as the Durroon Basin (Baillie & Pickering, 1991), which defines the area of earliest structural growth (i.e. Early Cretaceous), and contains up to 9 km of section in the deeper half grabens. It contains the greatest thickness of sediments within the depocentres of the Boobyalla, Bark and Anderson Sub-Basins (Figures 2,3,4 & 5), but may also extend for some distance further to the north and northwest below the overlying depocentre of the Bass Basin.

The Bass (and Durroon),Otway, and Gippsland basins all formed as a result of two major phases of rifting. The first phase occurred initially within the Durroon Basin across a 'basement' of Siluro/Devonian and Permo/Triassic sediments and metasediments, as well as granites and Jurassic dolerite. It resulted in Late Jurassic to Early Cretaceous intracratonic extension, and subsequent uplift. This can be related to the progressive east to west separation of the Australian and Antarctic plates (Davidson & Morrison, 1986, Hill *et al.*, 1995 and Willcox & Stagg, 1990). This event is recognised from rift/uplift related unconformities at 140? - 120 and 120 - 100 million years ago. This phase culminated at around 100 Ma. with production of the first oceanic crust at around 100-90 Ma. (Cande & Mutter, 1982, Veevers, 1986), and produced an angular unconformity at the top of the Otway Group.

The Late Cretaceous (100 - 80 million years ago) second phase of rifting affected the Durroon Basin in its state as a 'failed rift basin', and related to the opening of the Tasman Sea (Veevers *et al.*, 1991). Hill *et al.* (1995) document this phase as starting at 95 Ma. and it is synchronous with the Golden Beach Group of the Gippsland Basin. An angular unconformity recognised at the top of this group in the Gippsland Basin (Lowry, 1987, Lowry & Longley, 1991) is also present at a stratigraphically similar position in the Durroon Basin. An unconformity is also present within this succession (Figure 6), occurring within the *P. mawsonii* period (around 88 Ma.). The end of this rifting phase between 100-80 Ma., is marked by an angular unconformity (around 80 Ma.) and uplift around the southeastern Australian coast of between 1.5 - 4 km interpreted from fission track analysis, as well as considerably more uplift predicted for the basinal areas within Bass Strait (Dimitru, *et al.*, 1991). This unconformity is thought to mark the onset of sea floor spreading in the Tasman Sea (Smith, 1988, Lowrey & Longley, 1991). Faulting attributed to this phase of tectonic activity is characterised by a set of major rotational half grabens. These listric faults have considerable throw and have a substantial degree of syndepositional growth. The grabens are best developed in

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STRUCTURAL ELEMENTS

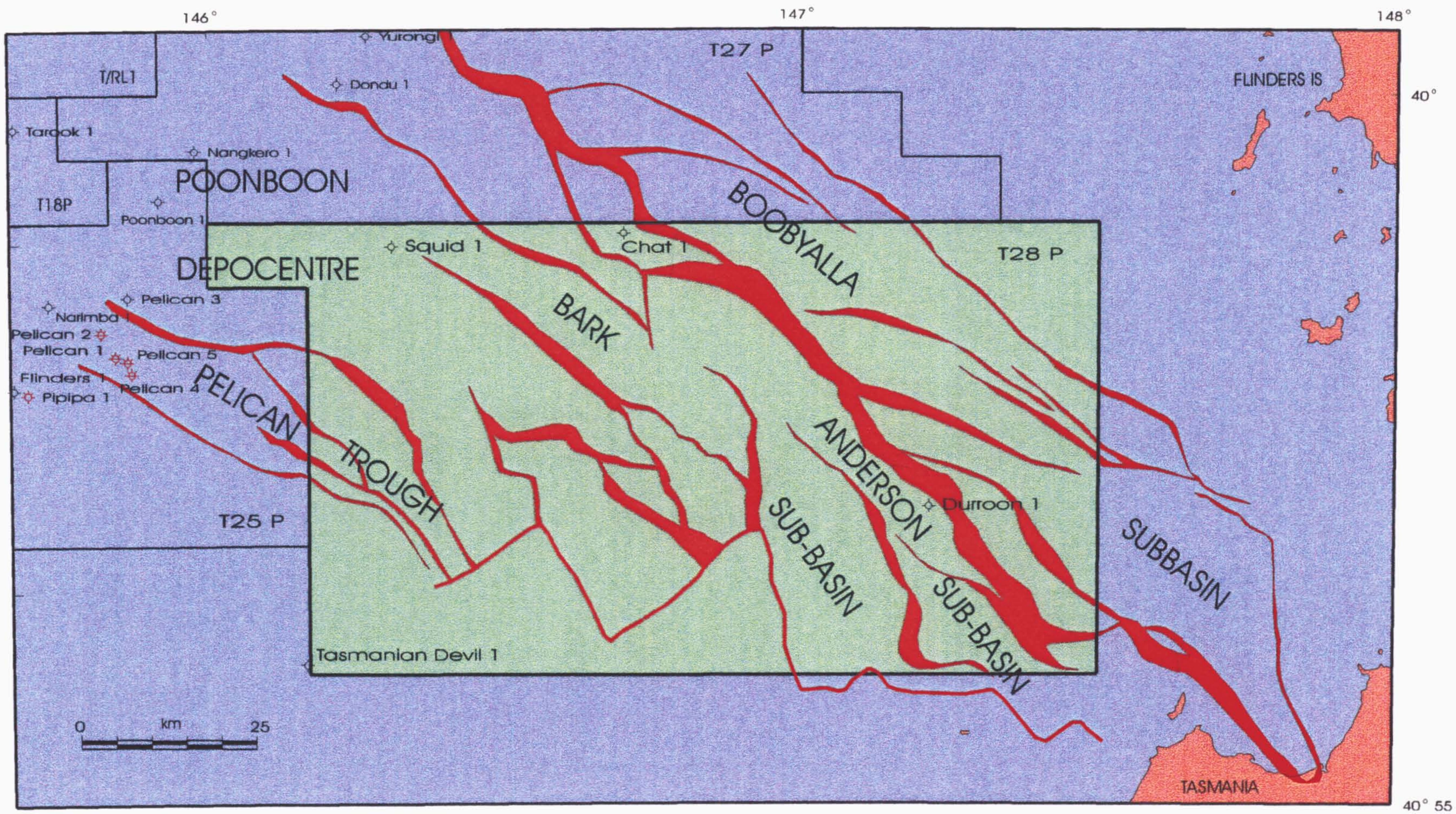

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FIGURE 2

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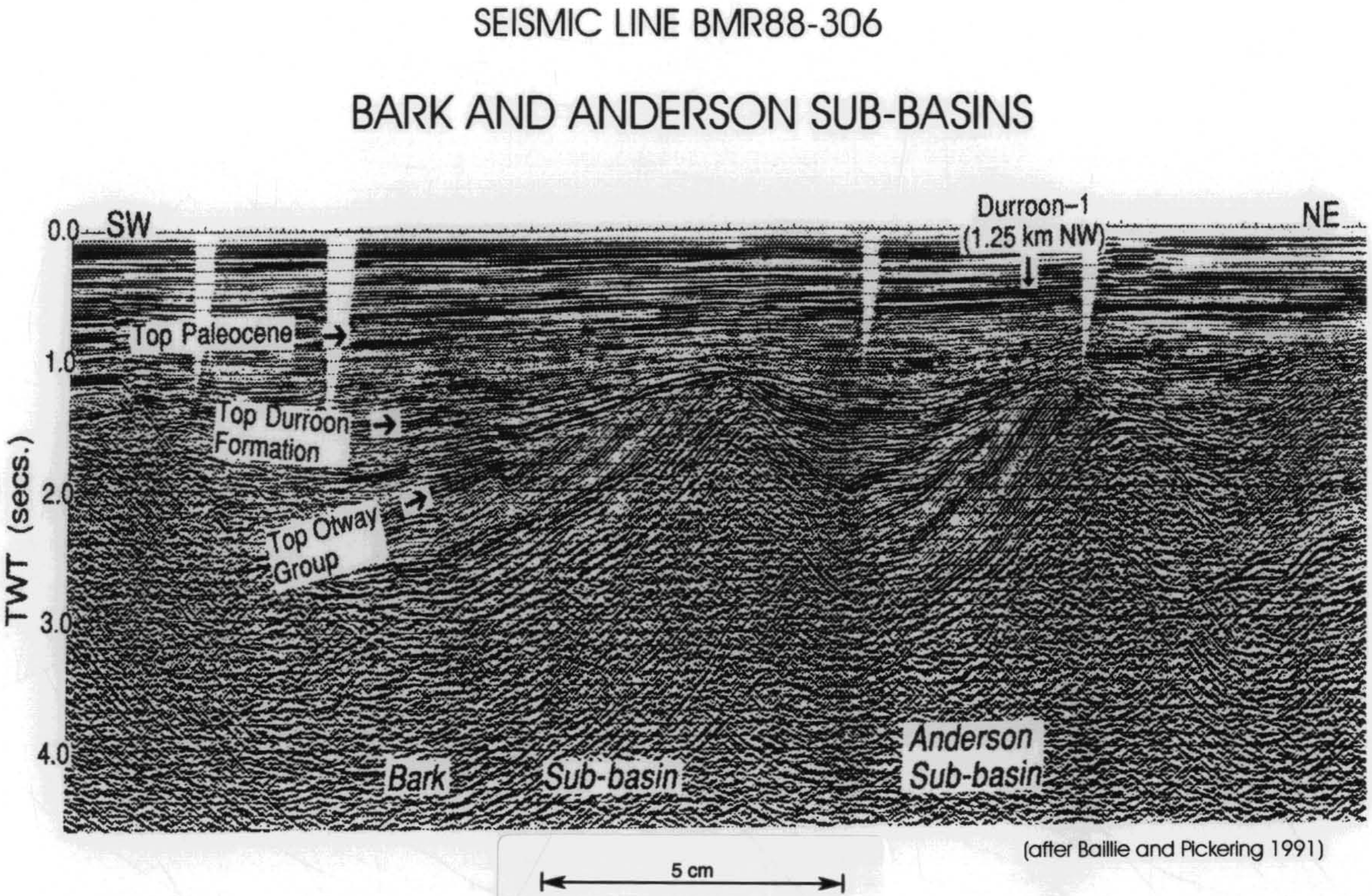
cue



(after Baillie and Pickering 1991)

FIGURE 3

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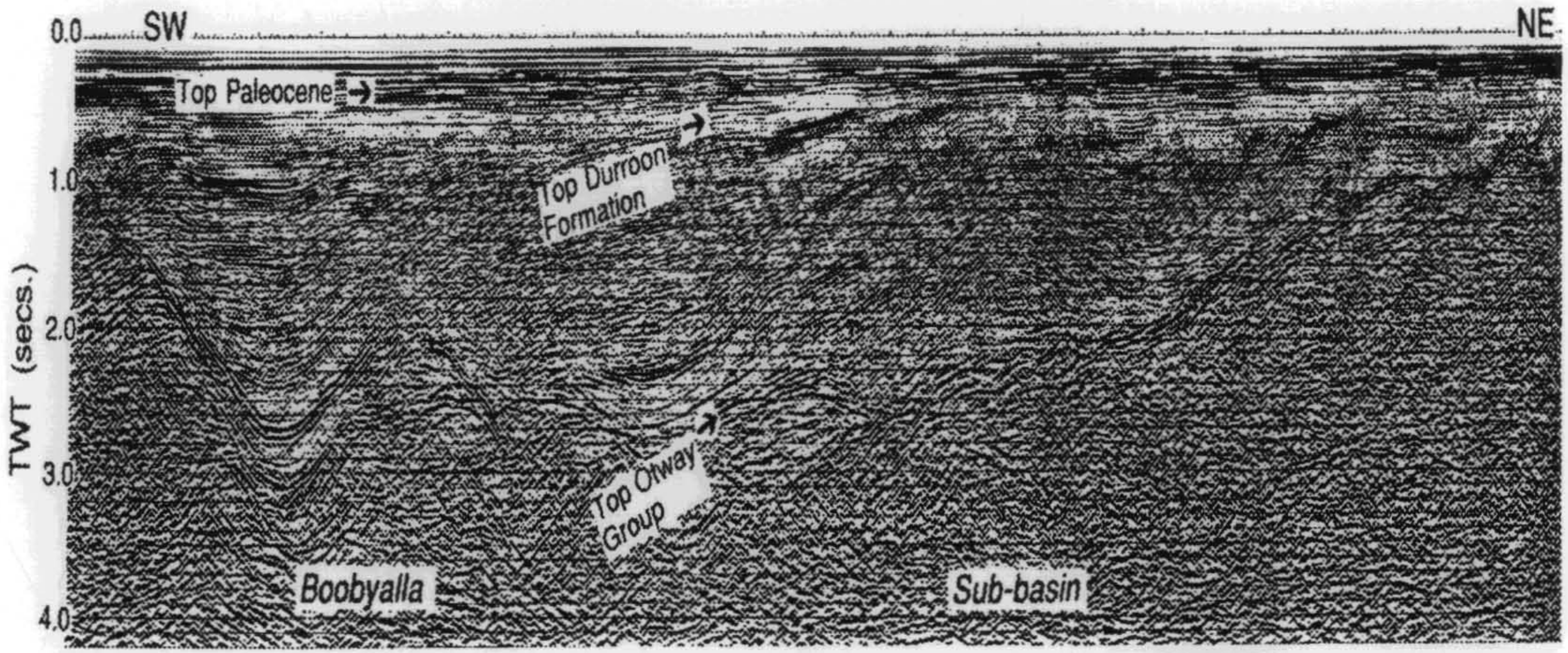
SEISMIC LINE BMR88-307

BOOBYALLA SUB-BASIN



(after Baillie and Pickering 1991)

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FIGURE 4

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LOCATION MAP - SEISMIC LINES

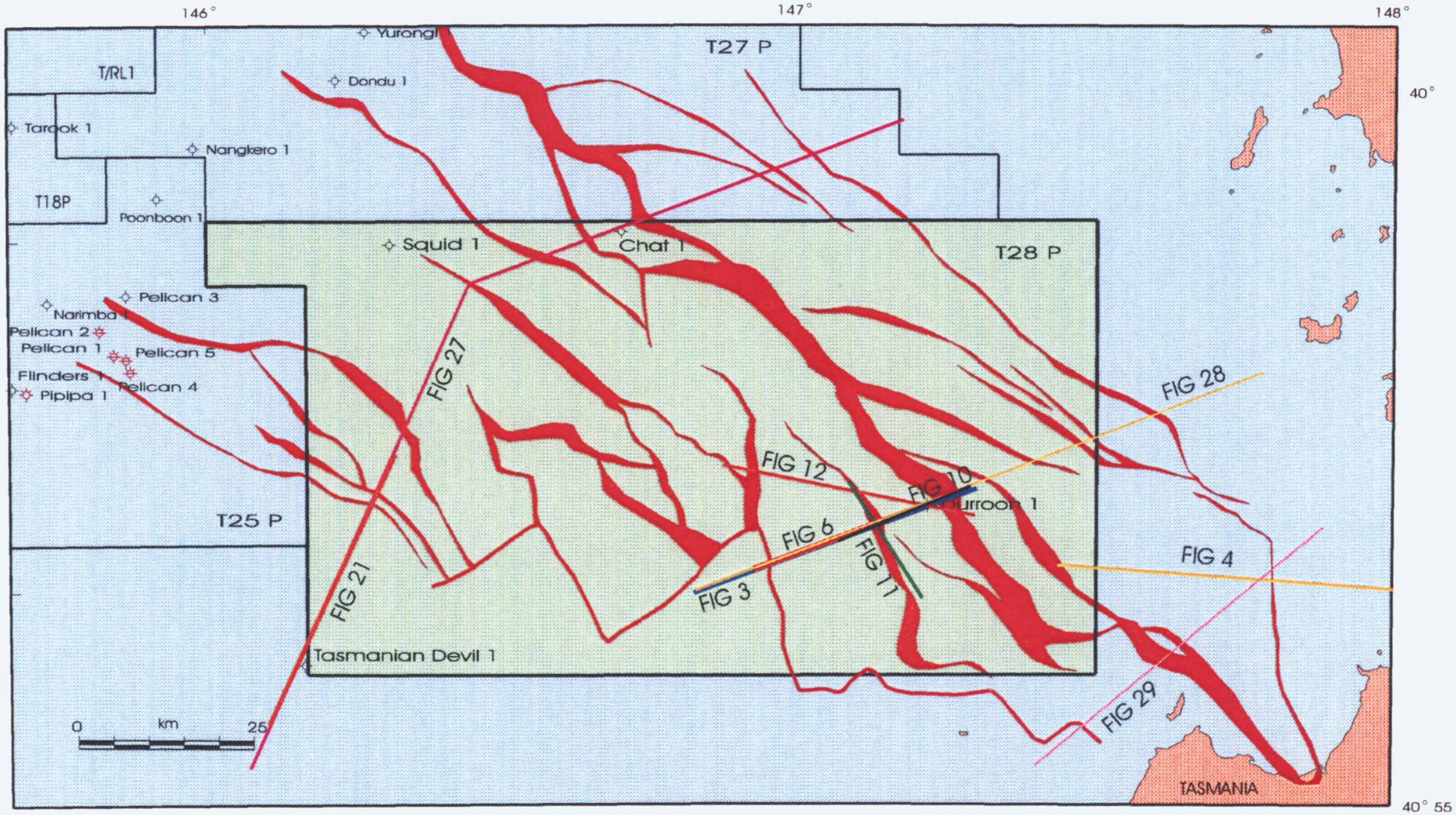

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FIGURE 5

7

BLACKBURN / BAIRD

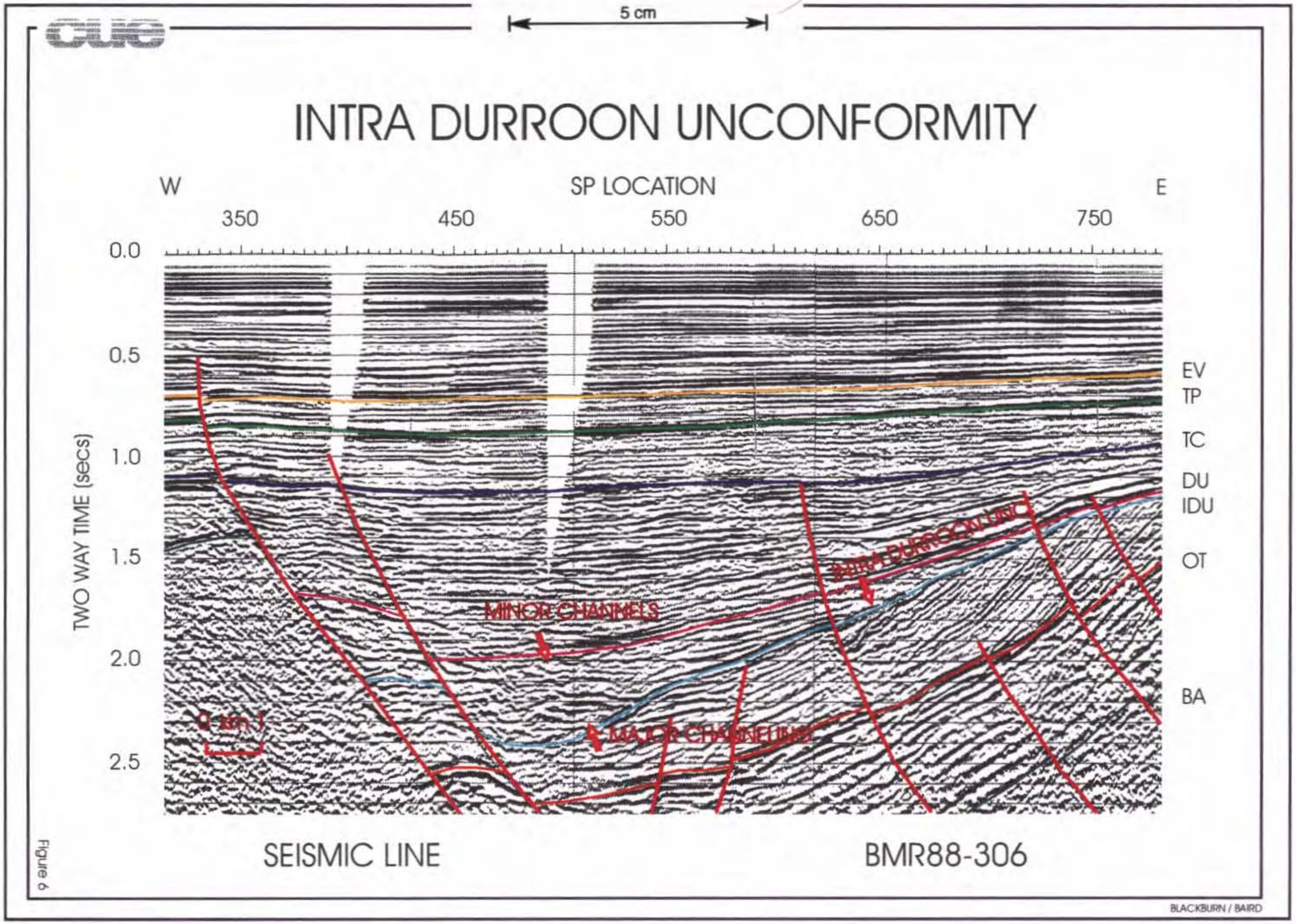
5 cm
INTRA DURROON UNCONFORMITY
W
SP LOCATION
E
350
450
550
650
750
0.0
0.5
1.0
1.5
2.0
2.5
TWO WAY TIME (secs)
EV
TP
TC
DU
IDU
OT
BA
MINOR CHANNELS
INTRA DURROON UNC
MAJOR CHANNEL UNC
SEISMIC LINE
BMR88-306
BLACKBURN / BAIRD

Figure 6

the Durroon Basin, where they contain up to 2.5 km of section attributed to the phase between 100 - 80 Ma (Figure 7).

These two rift periods represent the major basin defining and structuring events expressed in the Bass Basin. Major fault trends in the basin trend NNW - SSE, with a less pervasive NW - SE trend which becomes more common northwards away from the Durroon Basin.

Since rift activity ceased, 'post-rift' sedimentation has resulted in gradual subsidence, forming the Bass Basin. The depocentre for this phase shifted towards the north west near the Pelican field. Faulting of this section is expressed with minor throws in general, although some reactivation/inversion features are encountered in the more northerly parts of the Bass Basin, and adjacent to the basin's margins.

Stratigraphy

Figure 8 summarises the lithostratigraphy of the Bass and Durroon Basins. It is based on published accounts of the biostratigraphy (Helby et al., 1987 & Partridge, 1976), and stratigraphy (Robinson, 1974, Brown, 1976, Moore, W.R. *et al.*, 1984 and Williamson, P.E., *et al.*, 1985).

The Otway Group:

An initial phase of extensional block faulting is recognised from seismic interpretation of the Otway Group. Sediments deposited within these newly created grabens are believed to be time equivalent to the Crayfish Group of the Otway Basin (Kopsen & Scholefield, 1990), or initial high energy conglomerates of the Strzelecki Group in the Gippsland Basin (Smith, 1988). An angular unconformity estimated to lie between the *F. wonthaggiensis* and *C. hughesii* zones (approximately 120 Ma.), separates this initial section from the more conformable part of the Otway Group which overlies this unconformity.

Durroon-1(Figure 9 & 9a) in T/28P has intersected the oldest sediments penetrated in the basin, with 1378m of middle Aptian (Upper *C. hughesii*) to Late Albian (*P. pannosus*) litharenites, siltstones, shales and coals of the Otway Group. These sediments overlie the earliest Otway Group sediments and are separated from them by a distinct angular unconformity. Detailed examination of the Otway Group sediments intersected in Durroon-1 shows marked differences between this and the equivalent aged Eumeralla Fm. of the Otway Basin. Compositionally, the Eumeralla Fm. is dominantly non-marine argillaceous sandstones with claystone, coal and siltstone intervals. Reservoir sands of this section are described as lithic crystal tuffs or tuffaceous sandstones, being composed of fresh, angular to sub-angular volcanic lithic detritus. Deformed lithic grains are the main reason for reduced intergranular porosity, along with authigenic chlorite and kaolinite which further reduce permeability and porosity.

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ISOCHRON MAP - DURROON FORMATION

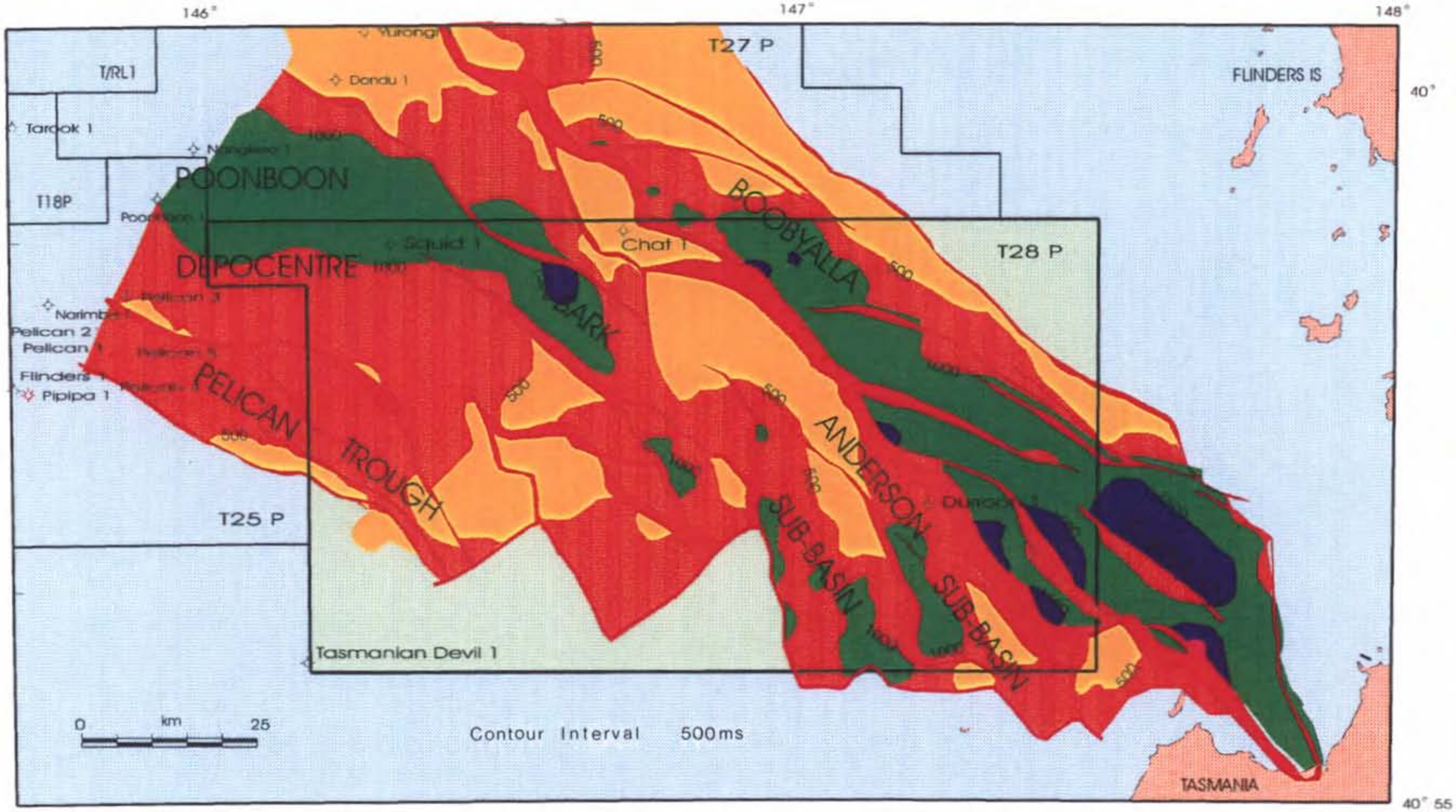

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FIGURE 7

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Figure 7

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LITHOSTRATIGRAPHY OF THE SOUTHERN BASS AND DURROON BASINS

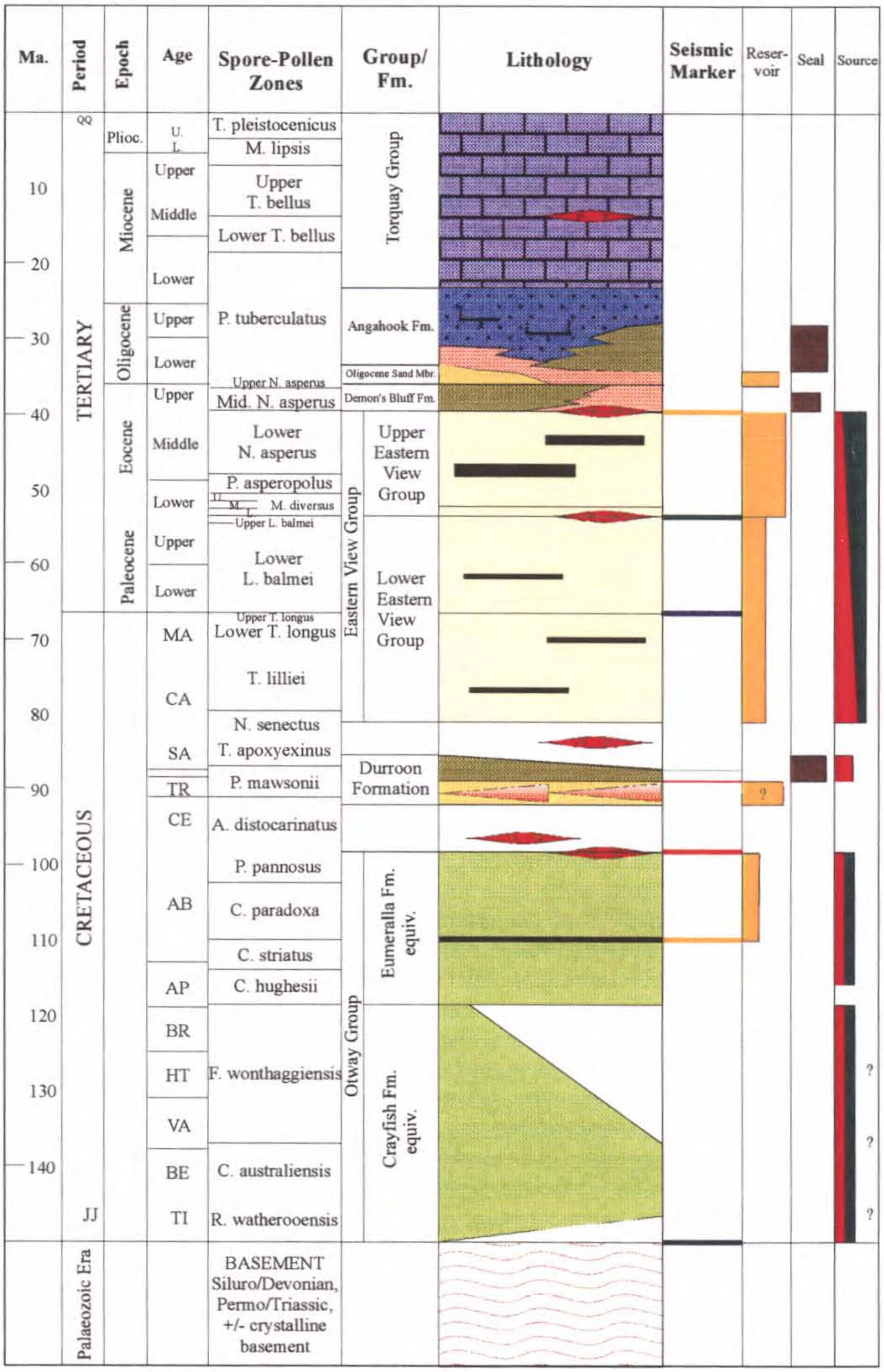

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FIGURE 8

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DURROON 1

WELL SUMMARY LOG

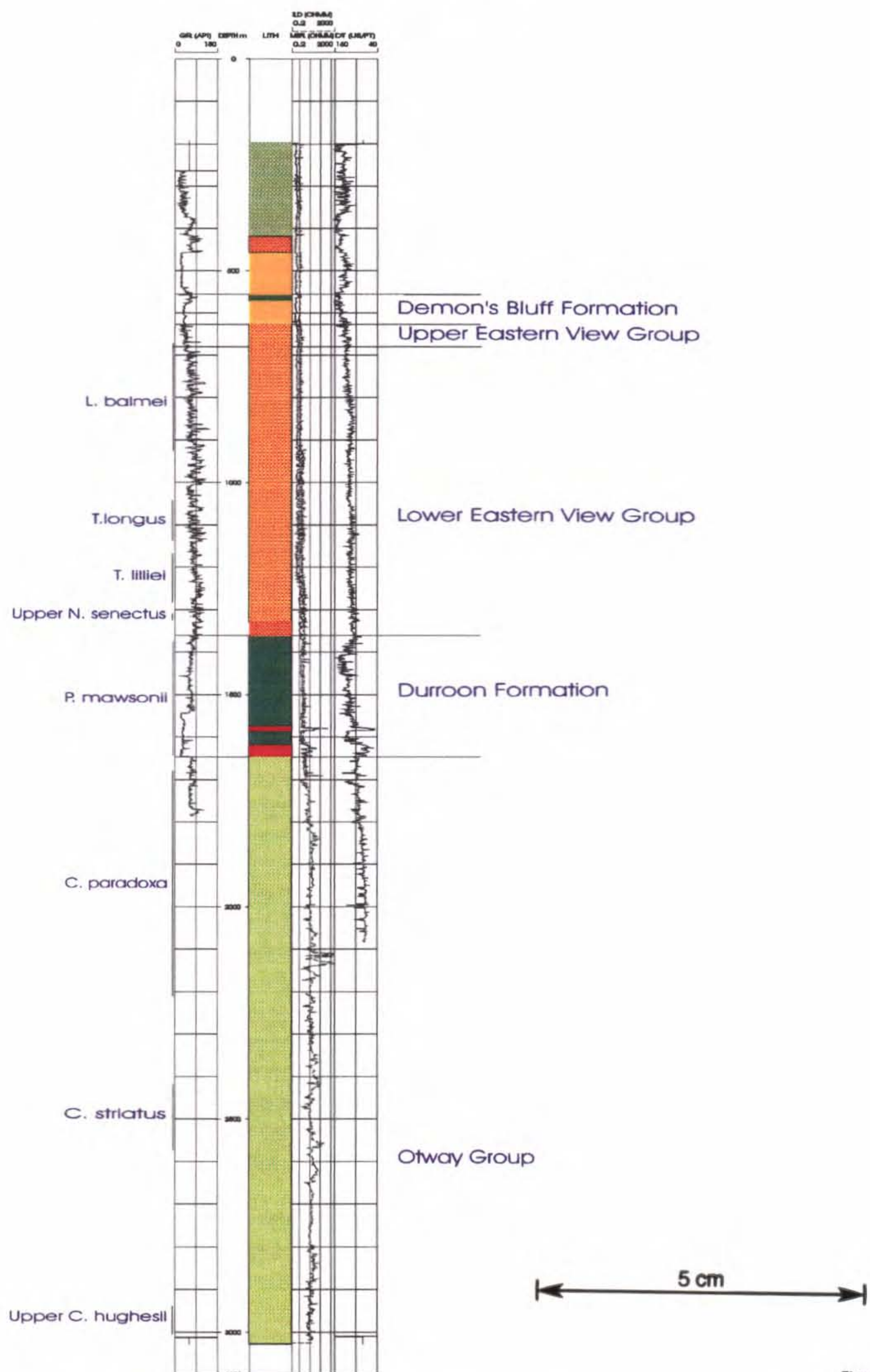

Figure 9

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Legend: Well Summary Logs

- Volcanics/shallow intrusives
- Calcarenite/Bioclastic Limestone
- Interbedded Calcilutite and Claystone
- Sandstone
- Siltstone
- Interbedded Shales, sandstones and siltstone
- Shale
- Interbedded sandstones, shales and coals
- Otway Group sediments

Figure 9A

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In contrast, the Otway Group of the Bass Basin is part of a much thinner initial non-marine rift-fill sequence. It is unlikely that it is directly comparable to the Eumeralla Fm., as there are numerous compositional differences. Otway Group sediments intersected in Durroon-1 are more quartz rich in their composition, being derived from local Tasmanian quartzites. Porosity versus depth trends for the Eumeralla Fm. and the Durroon-1 Otway Group show the Eumeralla Fm. as being somewhat less porous at comparable depths.

Konkon-1 in the north of the Bass Basin, had 40m of sediments interpreted to be Otway Group above a weathered volcanic flow, near T.D. These sediments were attributed to the Otway Group on the basis of lithology alone (Brown, 1976), as there was no palynological dating of this interval. The present study regards this age assignment as unlikely, as it would imply that the weathered volcanic flow was Early Cretaceous in age and therefore the only recorded volcanic flow seen within the Otway Group or other age equivalent formations in Southern Australia. It is more likely that these sediments belong to the Durroon Formation, and that the volcanic flow is therefore post Otway Group (as are other flows from the Bass Basin).

The Durroon Formation:

The Durroon Formation has only been penetrated in the Durroon-1 well (Figure 9), where 277m of mostly shale was intersected, along with two volcanic flows at the base. A seismically defined unconformity divides the unit into upper and lower subdivisions at Durroon-1. Lacustrine palynomorphs were identified in the upper subdivision, while the lower unit contains a small number of very thin coarse sand beds interpreted as the distal ends of coarse alluvial fan deposits. Onshore in the Boobyalla Sub-basin, an age equivalent section was penetrated in the Boobyalla-1 & -2 wells (Moore *et al.*, 1984).

Overall, the Durroon Formation is interpreted as a non-marine shale prone graben fill, but with significantly coarser facies deposited as alluvial fan deposits shed from elevated highs along the major fault trends. Onshore, the most proximal facies consists of poorly sorted boulder and pebble conglomerates, sandstones and mudstones. The dominant conglomeratic clasts are derived from Jurassic dolerites and sediments of the Parmeener Supergroup and Siluro-Devonian Mathinna Beds from the Cape Portland area. The dolerite from this area has been radiometrically dated as 101-102 Ma. (McClenaghan *et al.*, 1982).

Offshore, alluvial fans have been delineated (from seismic) within the Anderson Sub-basin, they have dimensions of 2.5km wide, 3-4km long and 180m high at the highest point. More extensive fans are interpreted in the Boobyalla Sub-basin. The section penetrated in Durroon-1 is representative of the distal facies of one of these fans (Figures 10, 11 & 12). From log analysis, the section is interpreted to have minor beds of coarse sand within an otherwise shale dominated section. Generalisations about sediment transport direction indicate that basin architecture controls each discrete fan within these confined grabens (i.e. along the graben axes as well as perpendicular to this direction off the bounding high fault

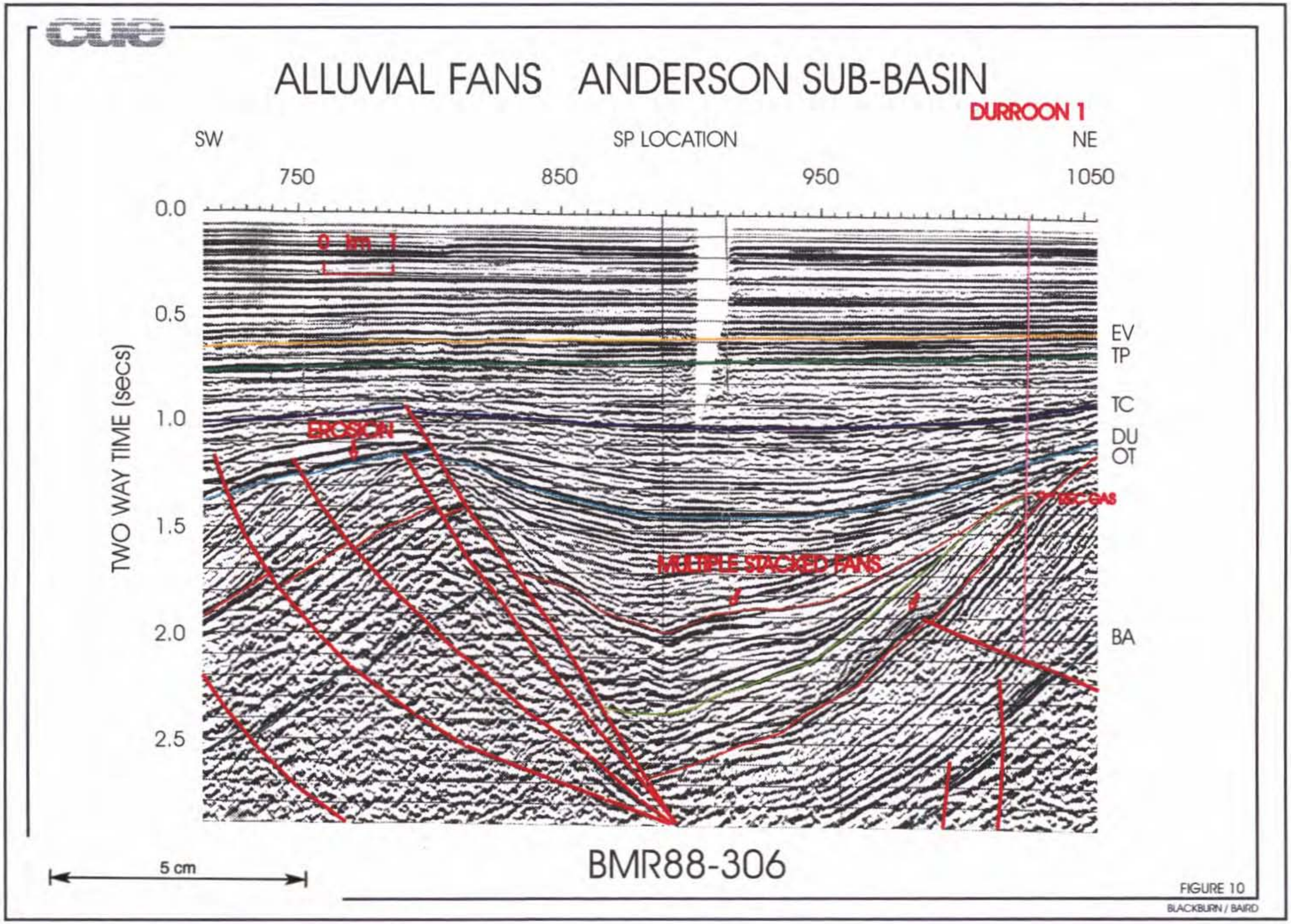

FIGURE 10
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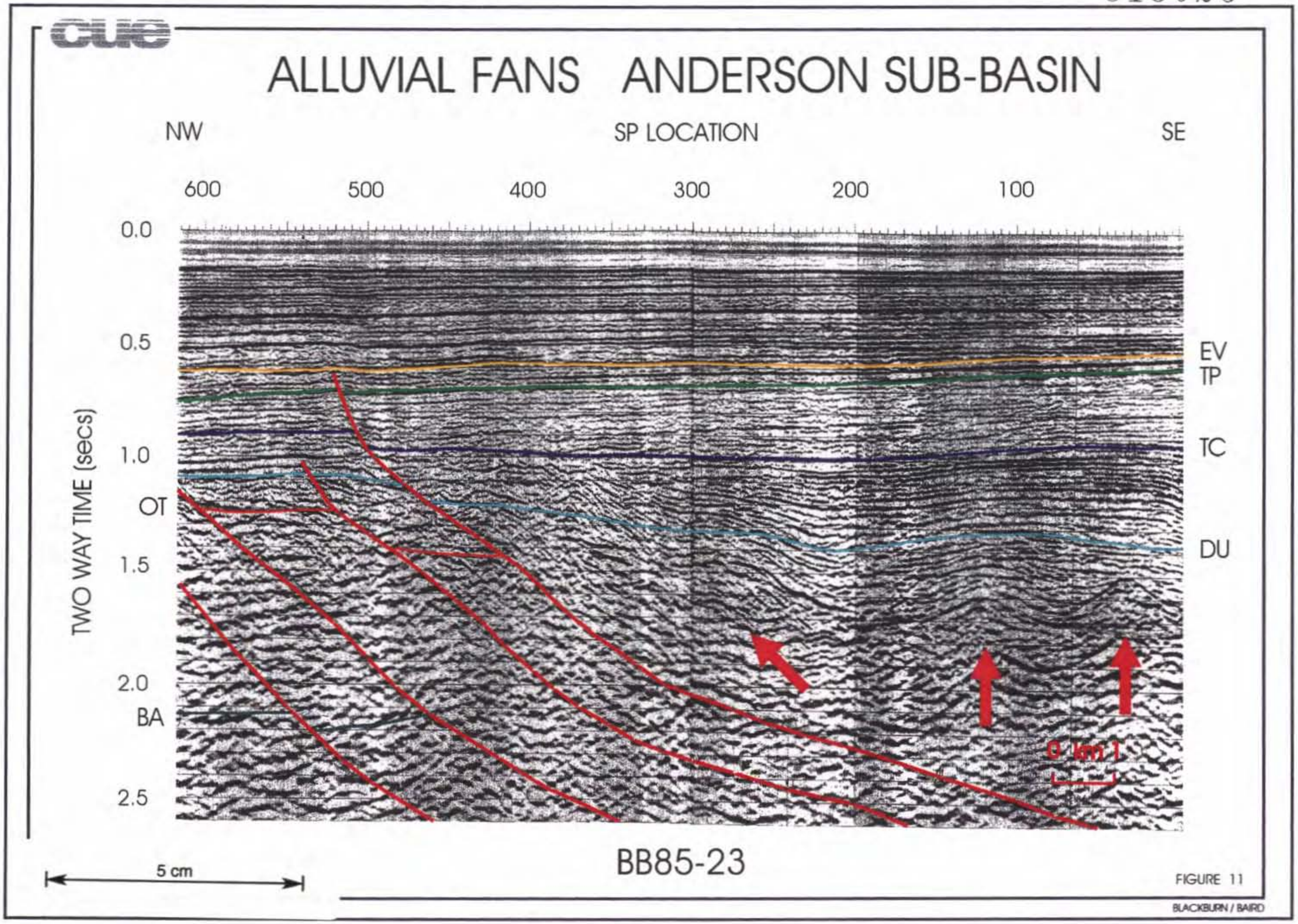

CUE
ALLUVIAL FANS ANDERSON SUB-BASIN
NW
SP LOCATION
SE
600
500
400
300
200
100
0.0
0.5
1.0
1.5
2.0
2.5
TWO WAY TIME (secs)
OT
BA
EV
TP
TC
DU
0 km 1
BB85-23
5 cm
FIGURE 11
BLACKBURN / BAIRD

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ALLUVIAL FANS ANDERSON SUB-BASIN

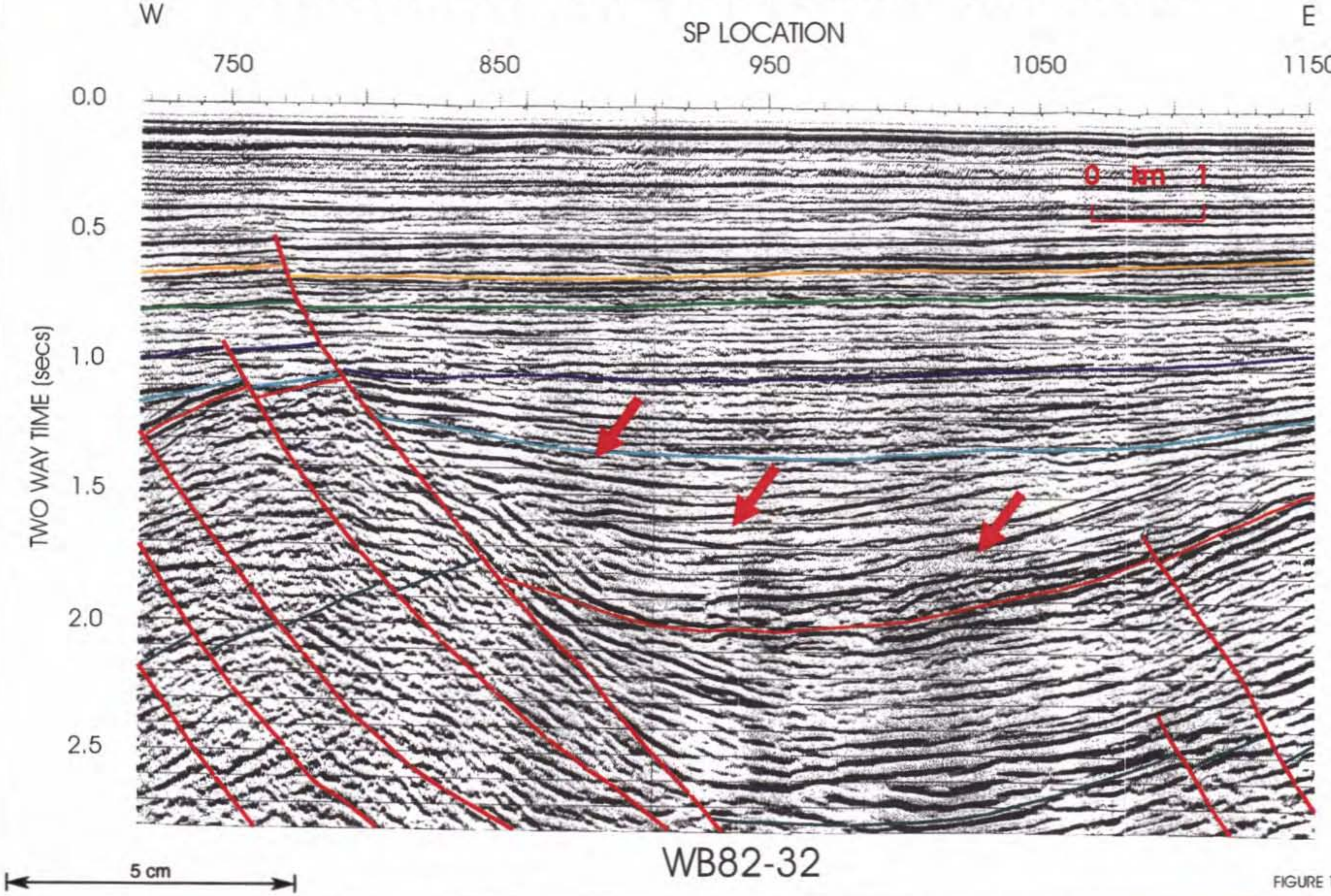

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FIGURE 12

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blocks). A basalt and tuffaceous sandstone at the base of the Durroon Formation in Durroon-1 is correlated with a similar tuffaceous sandstone in the Boobyalla-2 well onshore.

Two other wells in the basin have possible intersections of the Durroon Formation. As discussed above, Konkon-1 had 40m of possible 'Otway Group' sediments at the base which the present study interprets as probable Durroon Formation. Sediments at the base of Bass-2 (described as 44m of 'altered tuffaceous mudstone' in the well completion report) associated with weathered volcanic flows can also be attributed to the Durroon Formation on the basis of lithology. The original lithological desciption also describes the mudstone as having a 'white clay mineral' along bedding planes and filling fractures. This is most likely kaolinitic clay, whereas, the dominant clay mineral in the Otway Group is green chlorite. This distinction between clay types is also used to distinguish Golden Beach Formation from Strzelecki Group in the Gippsland Basin. If these sediments can reasonably be attributed to the Durroon Formation, then the overlying weathered volcanics could be age equivalent to other examples of volcanic flows overlying the top of the Durroon Formation in various parts of the basin. Interpretation of Durroon Formation at the base of Bass-2 and Konkon-1 expands its areal extent from only within the Durroon Basin (Baillie & Pickering, 1991) to cover most of the Bass Basin.

Seismic facies interpretation of this formation indicates that it is most likely shale prone, with large wedge shaped units (probably sand prone) encased within the shale. These wedges are often composed of chaotic facies (at the base), some have large internal scours and channels, and seem to shale out towards the highs. As discussed above, the wedge shaped units appear to represent coarse alluvial fans shed from the elevated footwall blocks of the half grabens, and shale out laterally across the graben. These distal ends may represent lacustrine facies (as intersected in Durroon-1) where the alluvial fans spill across the grabens into lakes. Reworking of the fans is indicated by channel and scour facies from seismic interpretation. In proximal positions, broad scours are identified which could indicate the action of braided channels, while more distal areas seem to be affected by more discrete, smaller channels indicative of meandering systems spilling into lakes etc.

The Eastern View Group:

The Eastern View Group (also called the Eastern View Coal Measures) ranges in age from Campanian to Middle Eocene, and is up to 5 km thick in the central part of the Bass Basin. It is a dominantly siliclastic succession, consisting of interbedded sandstone, mudstone, coal and volcanics. The group is informally divided into upper and lower subdivisions (Brown, 1976, Baillie & Bacon, 1989) Yolla-1, Chat-1 and Pelican-5 have good coverage of the Eastern View group and show the vertical variations of the two divisions (Figures 13, 14 & 15). The present study has found it convenient to put the division between upper and lower subdivisions at the Upper *L. balmei*/Lower *M. diversus* Zone boundary.

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YOLLA 1

WELL SUMMARY LOG

5 cm

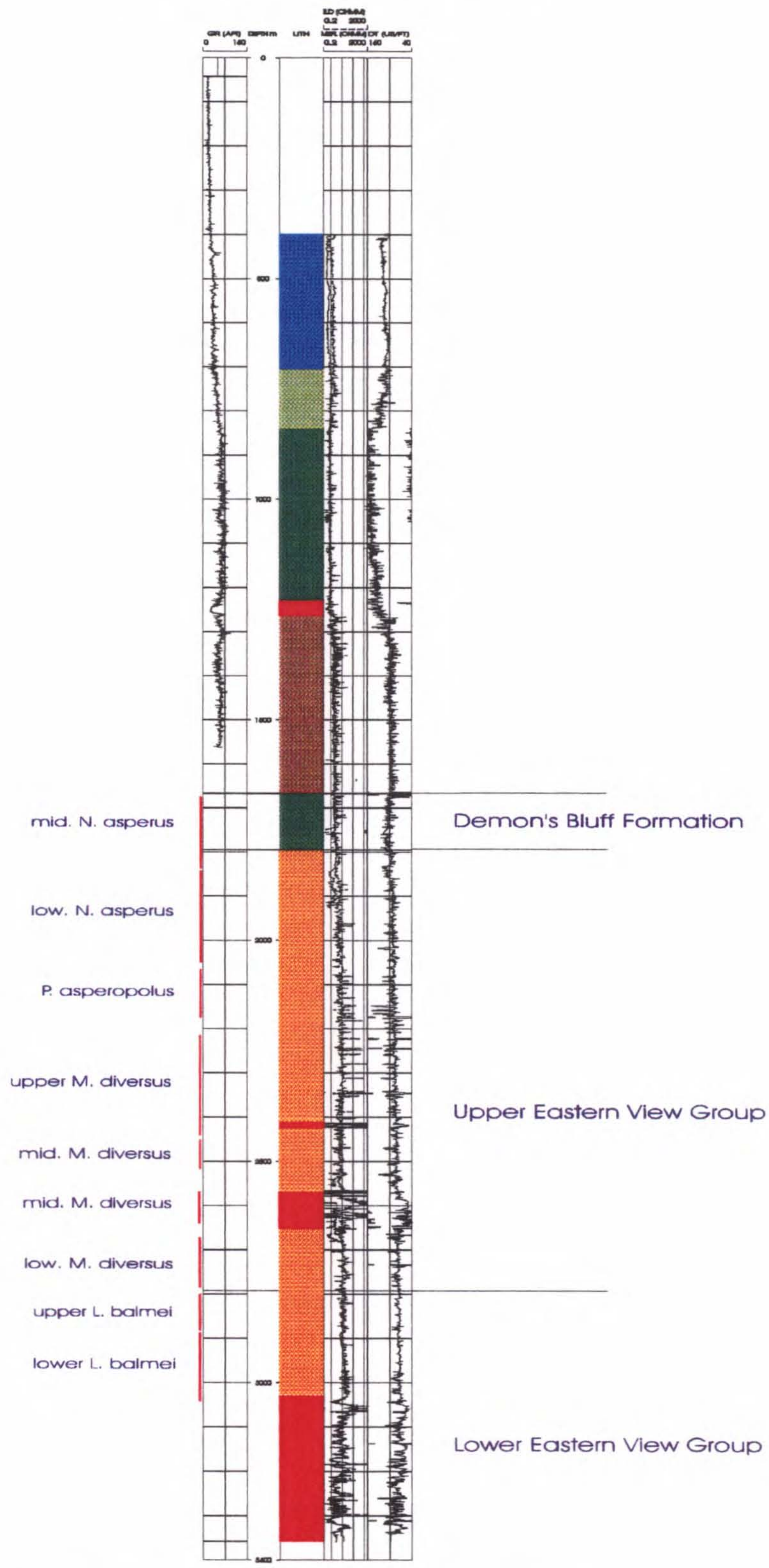

FIGURE 13

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5 cm

CHAT 1

WELL SUMMARY LOG

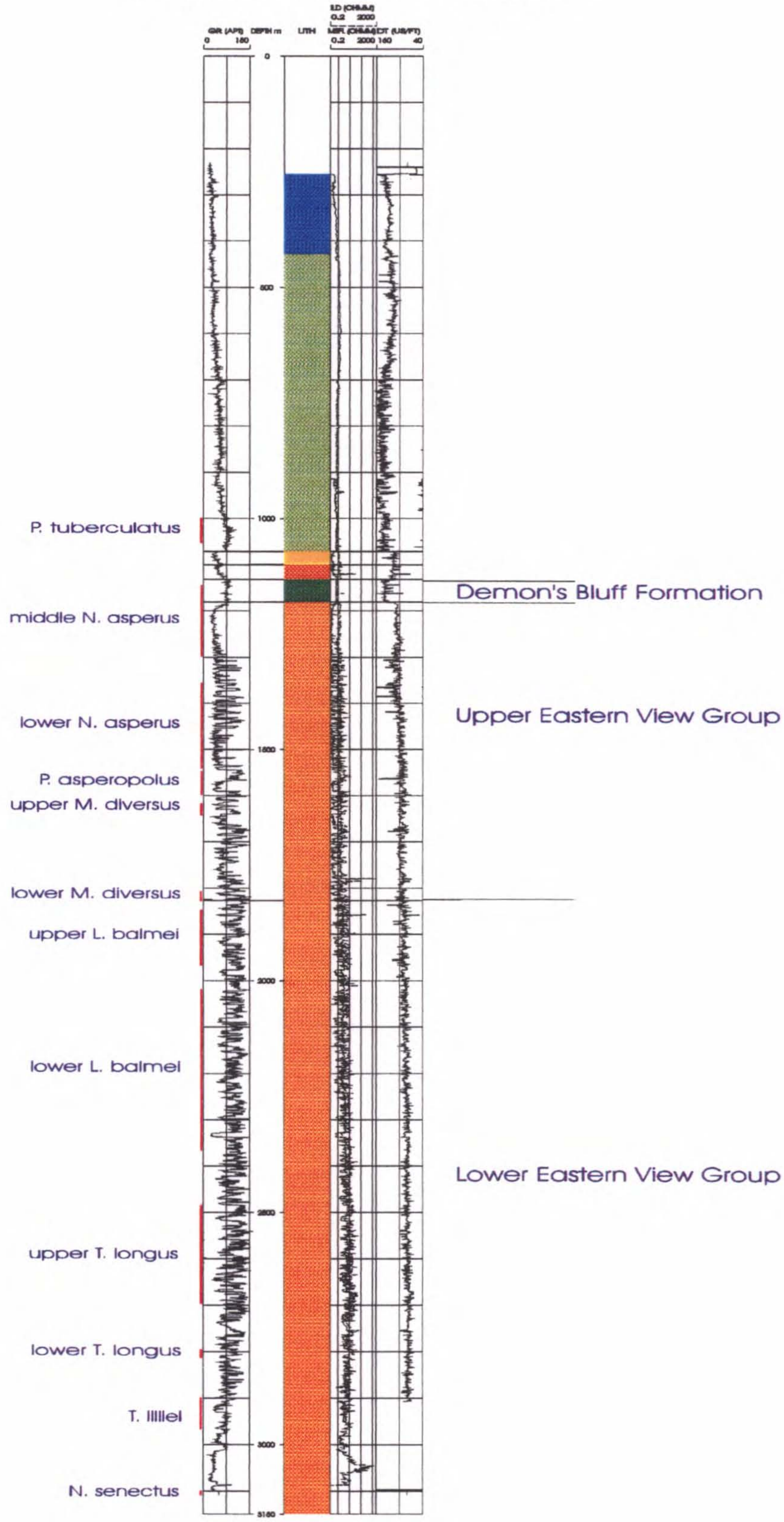

FIGURE 14

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5 cm

PELICAN 5
WELL SUMMARY LOG

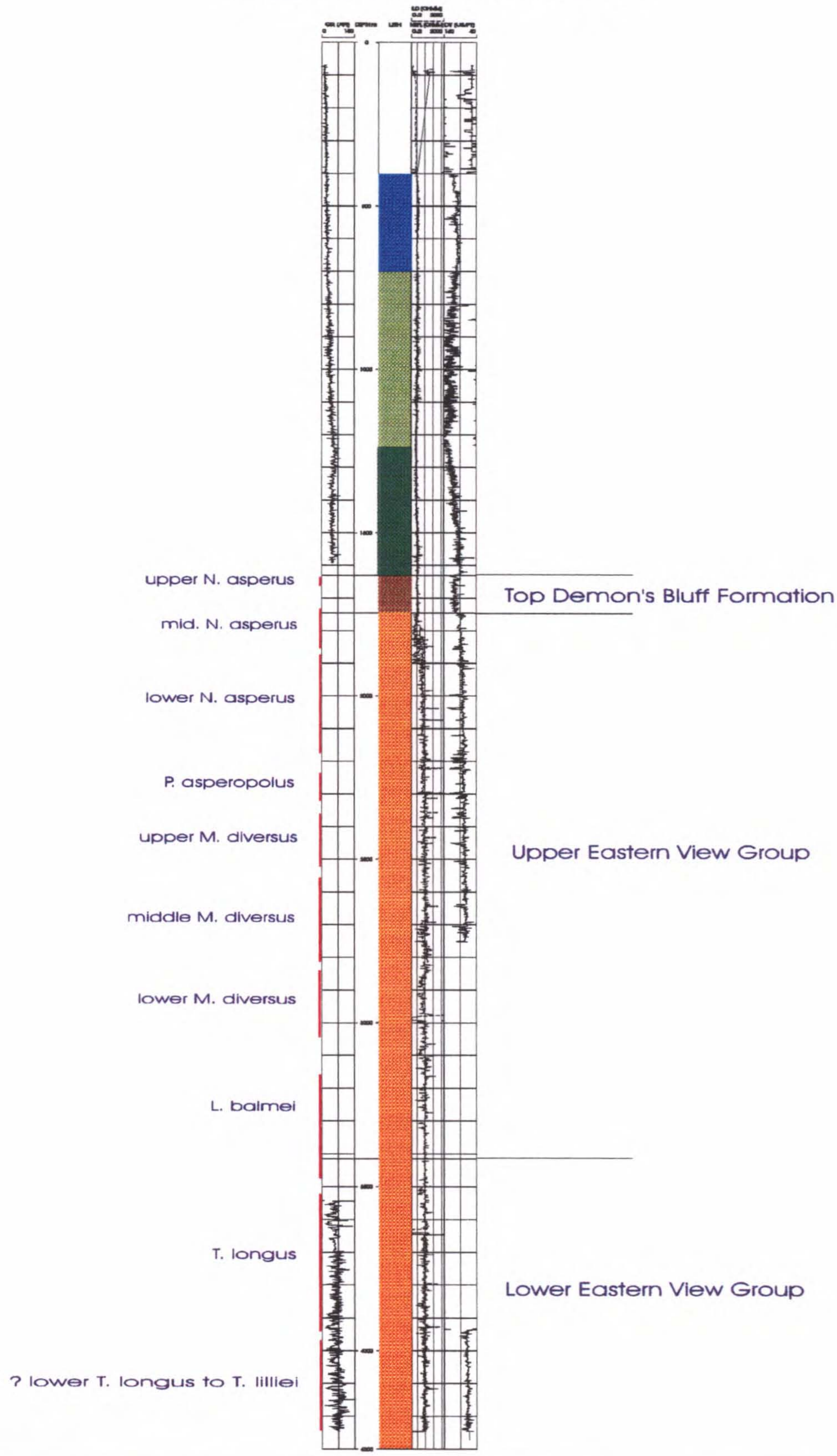

FIGURE 15

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Lithological characteristics show the lower Eastern View Group to be composed of Campanian (middle *N. senectus* to Upper *L. balmei* Zone) to earliest Eocene (Lower *M. diversus* to Lower *N. asperus* Zone) interbedded sandstones, mudstones, thin coals and volcanics. The upper Eastern View Group ranges in age from Lower to Middle Eocene (Lower *M. diversus* to Lower *N. asperus*). It is deposited under shallow marine to marginal marine-deltaic conditions (Baillie & Bacon, 1989), and contains thicker sands, and is more coaly than the lower subdivision.

Demons Bluff Formation:

The Demons Bluff Formation forms the regional seal across the Bass Basin. Within the Durroon Basin it is silty to sandy across much of the area, and only forms an adequate seal in the northwestern part of the T/28P permit, where it is a claystone (Figure 16).

Angahook Formation:

The Angahook Formation (Lower Oligocene to Lower Miocene) overlies the Demons Bluff Formation and is quite variable in facies. It is comprised of a nearshore sand facies (Oligocene sand member) which becomes silty in parts, and grades vertically to massive marine claystones. These claystones are slightly dolomitic, and become silty in some areas.

Torquay Group

The Torquay Group is comprised of calcilutite and biocalcarenites of Lower Miocene and younger age. Around the basin margins, claystones and silts are encountered at the base.

Well validity

Table 1 summarises the results of wells drilled in the vicinity of T/28P (Figure 17). It can be seen that many of the wells were invalid tests. The only valid wells in the basin resulted in mainly uncommercial discoveries (Pelican, Cormorant-1 and Bass-3), with the exception of Yolla-1.

Petrophysics

A more detailed discussion of the method used to analyse Durroon-1 is included as Appendix 1.

Summary

Detailed petrophysical analysis was undertaken on the Durroon-1 well after an anomalous gas show in the Durroon Formation was noted from the mud logs. The R.O.P. log (Rate of Penetration), was realigned with the mud log to determine if the gas kick seen in the shale could be correlated with the presence of possible thin hydrocarbon bearing zones as shown by the ROP and a log determination of

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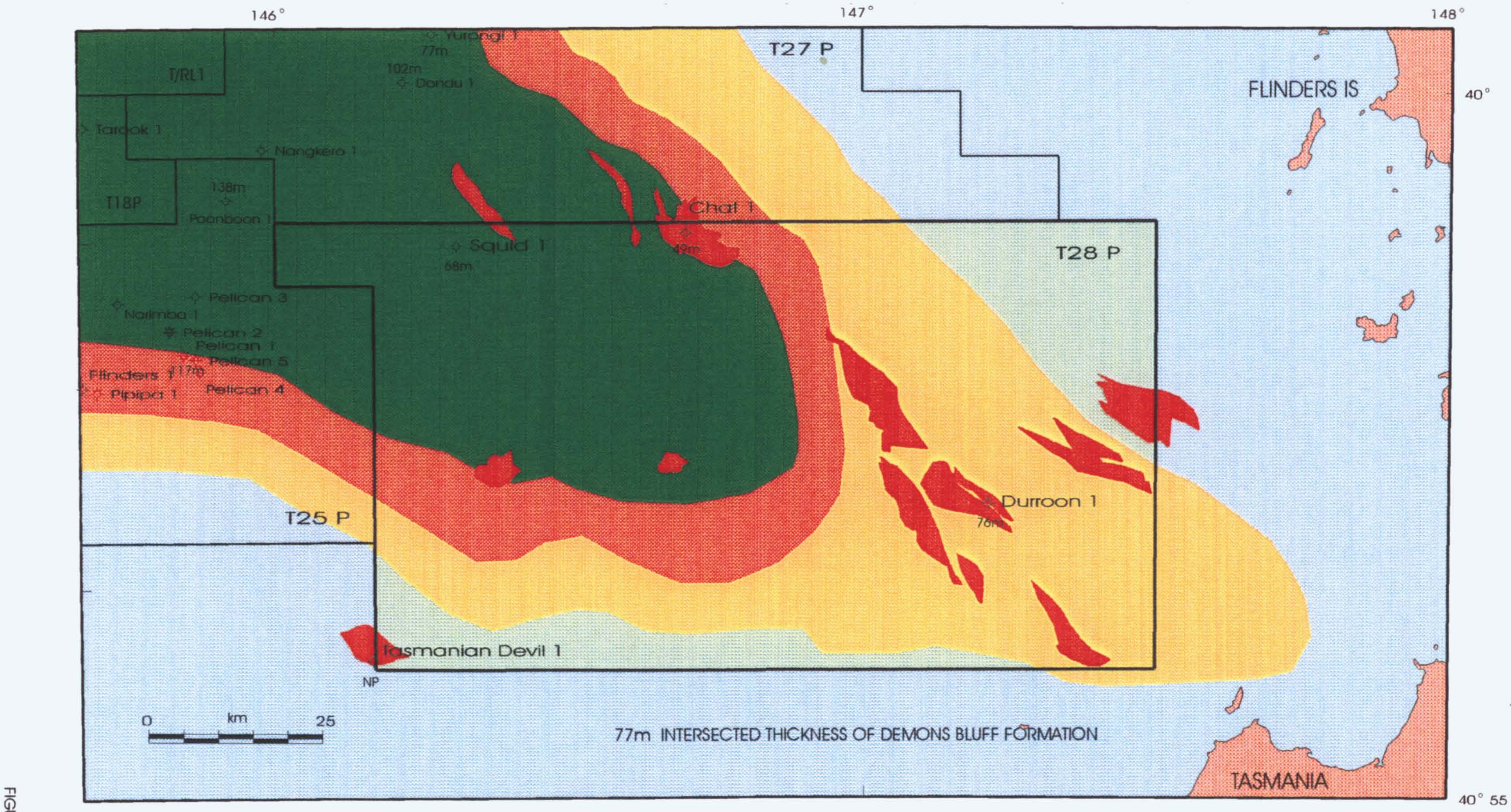
LITHOLOGY MAP

DEMONS BLUFF FORMATION



DOMINANTLY CLAYSTONE | INTERBEDDED CLAYSTONE, SILTSTONE & SANDSTONE | DOMINANTLY SANDSTONE

FIGURE 16

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TABLE 1: Well results from the Bass and Durroon Basins.

Well	Year & Operator	Water depth (m)	Location	K.B. Elev. (m.)	T.D. (m.K.B.) & Age	Play Type & Structure	Shows, Validity & Status	Comments
Bass-2	1966 Esso	85.3	Lat. 39°53′ 9″ Long.146°18′15″	9.4	1801.4 E.V.GP L. *L. balmei* or possible Durroon Fm.	Tertiary & Cret. sands in a faulted anticline	No shows. Invalid, seems to be drilled off structure. P&A	
Boobyalla-1	1976 Tas.Dept. of Mines	On-shore	Onshore limits of the Boobyalla Sub Basin		417m	Stratigraphic hole	Not applicable	Proximal mass flow deposits
Boobyalla-2	1981 Shell, (ext. in 1982 by Tas.Dept. of Mines	On-shore	Onshore limits of the Boobyalla Sub Basin		265m (Shell) 491m (Tas. Department of Mines)	Stratigraphic hole	Not applicable	Proximal mass flow deposits
Chat-1	1986 Bridge Oil	81.4	Lat. 40°10′53″ Long.146°41′55″	25.3	3104m E.V.GP Late Cret. Volcanics *N. senectus*	Oligocene to Upper Cret. sands in a high side fault dependent closure	No shows. Invalid, no closure at Mid Pal. to L.Cret. horizons & lateral seal problem at Top EVG. P&A	Formation tops quite different to prognosis. Demon's Bluff Fm. thins and becomes sandy towards the Chat structure
Dondu-1	1973 Esso	82	Lat. 39°59′13″ Long.146°13′3″ X: 433183E Y: 5573398N	9.8	2927m E.V.GP Paleocene *L. balmei*	E.V.GP sands in dip closed anticline	No shows. Invalid, no closure P&A	VR suggests that E.V.GP are mature below 2134m.

TABLE 1 (continued): Well results from the Bass and Durroon Basins.

Durroon-1	1972 Esso	68.6	Lat. 40°32′3″ Long.147°12′48″ X: 518079E Y: 5512917N	9.8	3024.2m Otway Group	Stratigraphic well	No significant shows. 200ms downdip from structural crest. No seal at top EVG. P&A	Section was much younger than prognosed
Flinders-1	1992 Sagasco		Lat. 40°22′52″ Long.145°40′19″		2723m	Eocene sands in highside fault closure	No shows P&A	
King-1	1992 Sagasco		Lat. 39°35′24″ Long. 145°31′9″		2222m		Oil and gas shows P&A	
Konkon-1	1973 Esso		Lat. 39°12′20″ Long. 145°3′40″		1537m	Stratigraphic pinchout of EVG	No shows P&A	
Koorkah-1	1985 Amoco		Lat. 39°37′57″ Long. 145°9′7″		3149m		No shows P&A	
Nangkero-1	1974 Hematite	79.6	Lat. 40°04′24″ Long.145°58′42″	9.8	2877.3m E.V.GP Paleocene	Eocene sands in a large unfaulted structure	No shows. Invalid?? Velocity problems with depth conv. P&A	No closure at the top of the E.V.GP, Intra E.V.GP seismic marker may have closure.
Pelican-1	1970 Esso	76.5	Lat. 40°20′21″ Long.145°50′37″ X: 385469E Y: 1030611N	30.5	3178.4m E.V.GP Eocene U. *L. balmei*	Early Paleocene - Late Cret. sands in faulted anticline	Valid. Recovered gas and cond. from 12 FIT tested sands P&A	Intb. sands had Por. ~ 20%, Perm. ~ 200Md. Abnormal pressures below 2895.6 m.S.S.
Pelican-2	1970 Esso		Lat. 40°18′30″ Long.145°49′12″		3068m	Early Paleocene - Late Cret. sands in faulted anticline	Gas condensate shows P&A	

TABLE 1 (continued): Well results from the Bass and Durroon Basins.

Pelican-3	1972 Esso	80.2	Lat. 40°15'45" Long.145°51'51" X: 403407E Y: 5542473N	9.8	2906.9m E.V.GP L. *L. balmei*	Step out to test northern fault block within Pelican field	Valid? Minor gas shows in Paleocene P&A	Prognosed L. *M. diversus* pay section was not present. Abnormal pressures below 2560m.
Pelican-4	1979 BHPP		Lat. 40°21'40" Long.145°52'15"		3051m		Gas condensate shows P&A	
Pelican-5	1985 Amoco	77	Lat. 40°20'43" Long.145°51'49"	22.3	4267m E.V.GP Campanian *T. longus/* *T. lilliei*	Test production potential of L.Eocene & Paleocene E.V.GP sands	Valid. DST#4: 3143-3162m 430 MCFD, 1" choke 35 PSI FTP P&A	DST#5:2869-2833m Some gas & cond. DST#6:2786-2790m 5.5 MCFD, 400 BCPD, 675 BWPD, 1" choke 520 PSI FTP
Poonboon-1	1973 Esso	78.9	Lat. 40°08'15" Long.145°55'01" X: 407742E Y: 5566398N	9.8	3265.9m E.V.GP *T. longus*	E.V.GP sands in an anticlinal closure	Valid?? Gas kick at 3185.2m may be HC bearing below a 3m thick coal P&A	Tops came in high due to slow velocs. Abnormal pressures below 2835m. (3255m = 11.2 ppg mwt. equiv.)
Pipipa-1	1982 Hematite	73	Lat. 40°23'14" Long.145°41'45" X: 389304E Y: 5528428N	21	2115m E.V.GP Early Eocene *M. diversus*?	E.V.GP sands in a faulted anticline	Invalid No shows. No closure at top E.V.GP P&A	No lateral fault seal with sand juxtaposition across fault (see also Flinders-1).
Squid-1st	1984 Weaver Oil & Gas	80.5	Lat. 40°11'54" Long.146°18'27"	22.3	2925m 2218m.TVD. E.V.GP Paleocene U. *L. balmei*	E.V.GP sands and Oligocene sands in a faulted anticline	No shows. Original mapping has seismic diffractions interp. as faults P&A	First test of Oligocene sand wedge. Interpreted to have laterally discontinuous sands and charge/timing problems

TABLE 1 (continued): Well results from the Bass and Durroon Basins.

Tasmanian Devil-1	1984 Weaver Oil & Gas	73.8	Lat. 40°44′16″ Long.146°09′45″	21.9	863.7m Oligocene basalts	E.V.GP sands in a high side fault closure	No shows. Invalid, didn't reach objective P&A	Section quite different to prognosis, age dating could be topical
Tillana-1	1985 Amoco		Lat. 39°53′37″ Long.145°58′42″		3900m		Gas shows P&A	
Yolla-1	1985 Amoco		Lat. 39°50′19″ Long.145°48′21″		3347m	EVG sands in high side fault closure.	Oil shows,Gas discovery. Susp. producer	
Yurongi-1	1973 Esso	82.9	Lat. 39°55′30″ Long.146°15′59″ X: 437307E Y: 5580296N	9.8	2438.4m E.V.GP L. *L. balmei*	E.V.GP sands in a lateral closure against low side fault	No shows. Structurally valid, but no lateral fault seal. P&A	Better reservoir than at Dondu-1. No charge/migration pathway

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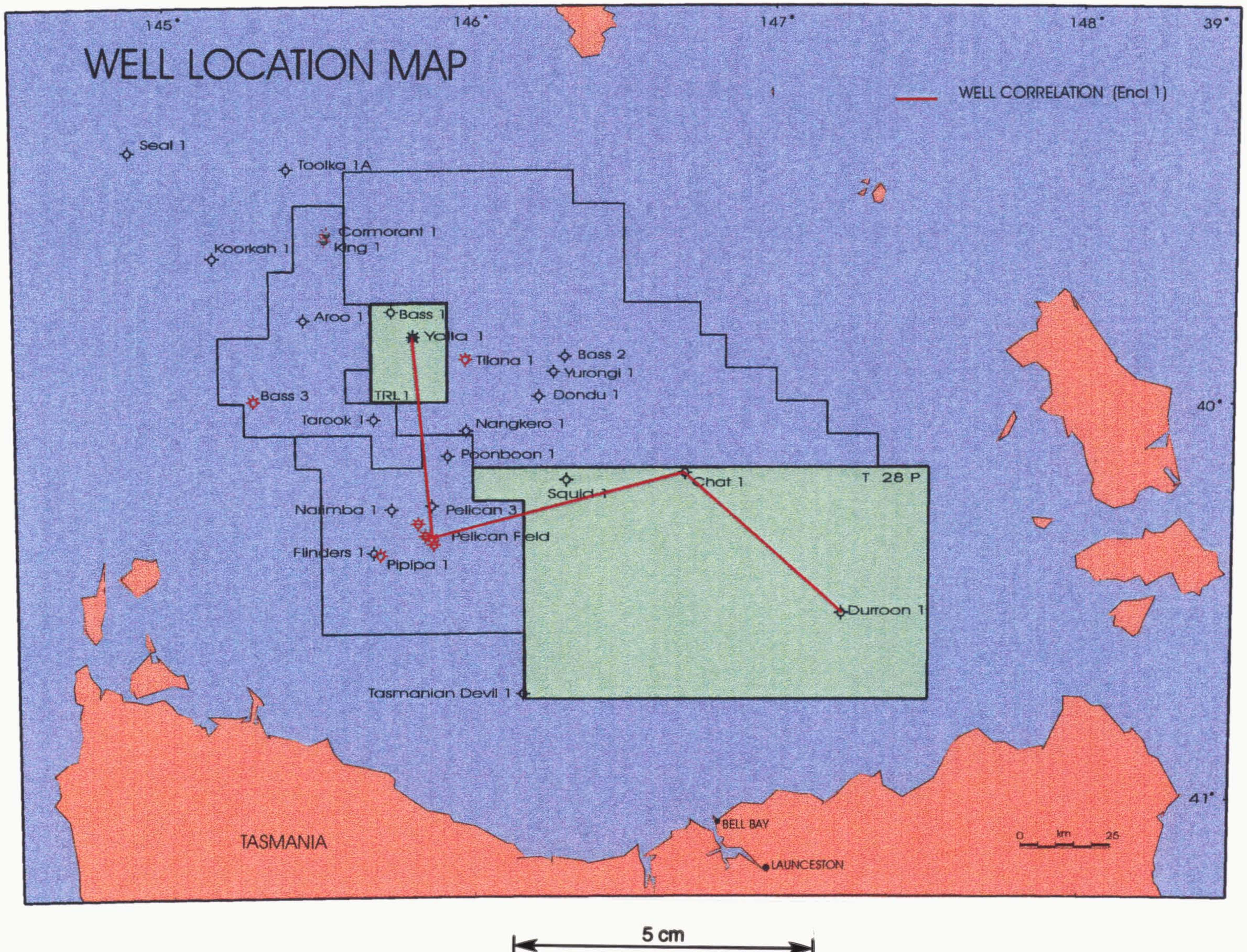

FIGURE 17

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porosity and water saturation. Porosity, shale content and water saturations were calculated using the relationships of Schlumberger (1989), within an EXCEL spreadsheet. In particular the Durroon Formation was examined to see if thin porous beds were present which were not sampled by sidewall cores. Further work was also conducted across the Otway Group to identify intervals with favourable porosities and permeabilities. Figure 18 shows the realigned R.O.P. curve compared to the other logs.

Reservoir

Core and log analyses from 9 wells were examined to produce the table of average reservoir characteristics for the major reservoir intervals in the Bass Basin (Table 2). The Durroon Formation had no core analysis, however, log interpretation provides approximate porosities for the thin pebble stringers which have been interpreted from this interval . Figures 19a, 19b & 20 show the core and log porosity vs depth and porosity vs permeability trends for all wells in this area.

<u>Otway Group:</u>

The Otway Group has only been intersected in Durroon-1 between 1646m.K.B. and T.D. It is age equivalent to the Eumerella Formation of the Otway Basin. Thin section descriptions from three cores of this interval shows they are litharenites (50-90% lithic clasts). Lithic clasts are dominantly siltsones, chert, andesite trachytic basalt, altered volcanics, quartz mica schist and quartzite. Other framework grains of volcanic quartz and feldspar (Oligoclase and Andesine) are present, within a chloritic matrix.

In contrast to the Otway Basin, this 'Eumerella Fm.' equivalent would seem to represent an initial rift-fill succession, sourced from the uplifted areas across the present Northern Tasmanian region. The seismic and lithological expression of this group suggests that Durroon-1 intersected most of the Otway Group section that is present in the Bass Basin. A core taken near T.D. shows that there are thin conglomerate beds, which perhaps represent the basal facies of this group. An increase in the log porosities below 2950m.K.B. supports this assertion of a coarser 'basal' facies.

The reservoir characteristics of this group are somewhat limited by the immature nature of these sands, however, the uppermost section still shows quite encouraging porosities and permeabilities above 1850m.S.S. (20-25% porosity and 10-30Md permeability). Seismic character of this unit around the area just south of Durroon-1 shows multiple stacked channels in the uppermost section of the Otway Group.

Likely reservoir intervals within the Otway Group were screened using results from the log analyses from Durroon-1. Sandstone intervals were flagged as potential reservoir zones if they had greater than 17% porosity and less than 20% Vsh. These cutoffs were determined after examining core porosity/permeability

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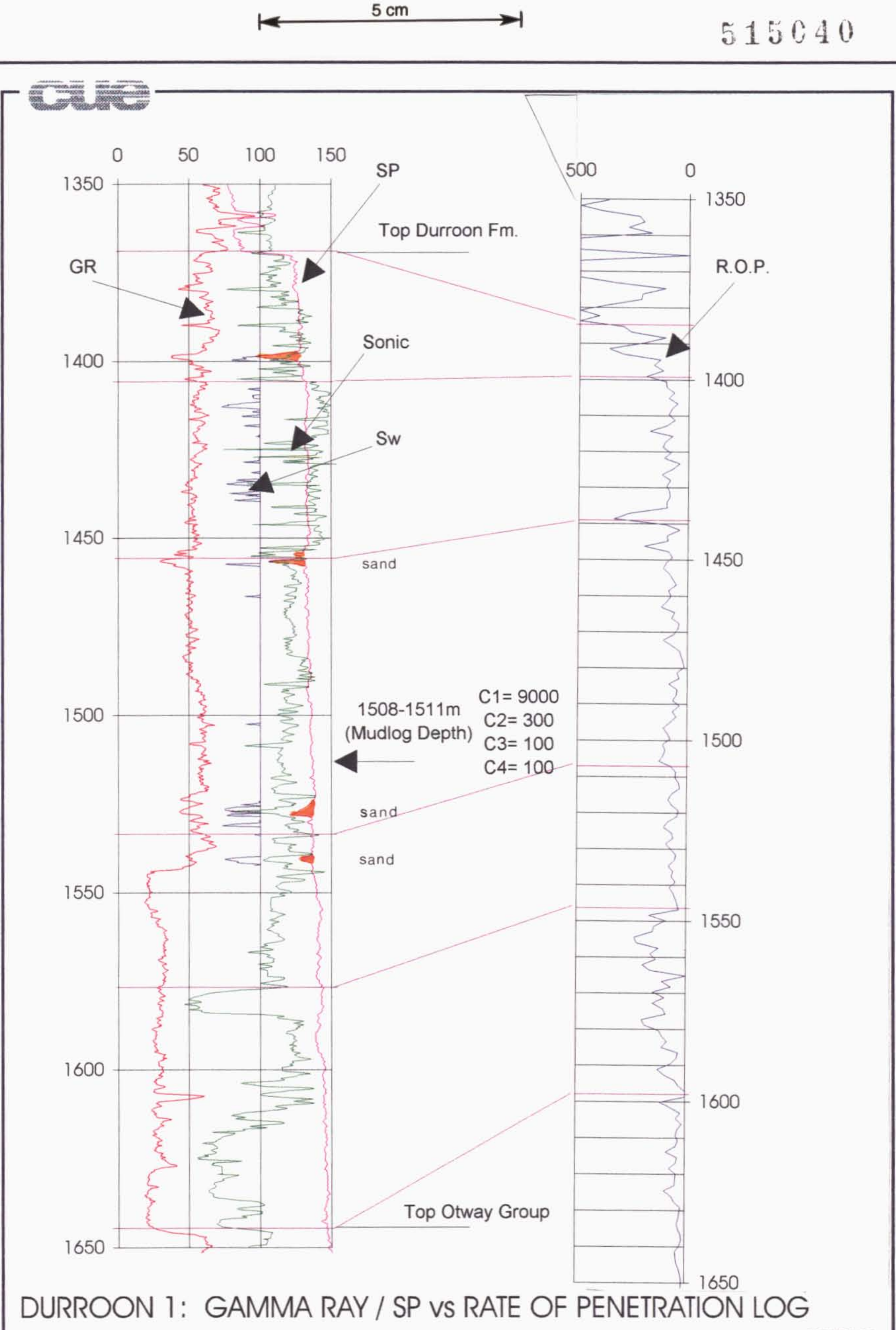

DURROON 1: GAMMA RAY / SP vs RATE OF PENETRATION LOG

FIGURE 18

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Table 2: Average reservoir characteristics for southern Bass Basin wells

Formation/Group	Porosity range (average)	Permeability range (average)
Upper Eastern View Group	7.7 - 37.4 (17.7%)	.01 - 1600 (76.1mD)
Lower Eastern View Group	7.7 - 36.3 (17.6%)	.01 - 1230 (66.4mD)
Durroon Formation (thin beds intersected in Durroon-1, from log analysis)	12 - 27 (18%)	
Otway Group	6.8 - 26.9 (13.6)	.01 - 310 (14.3)

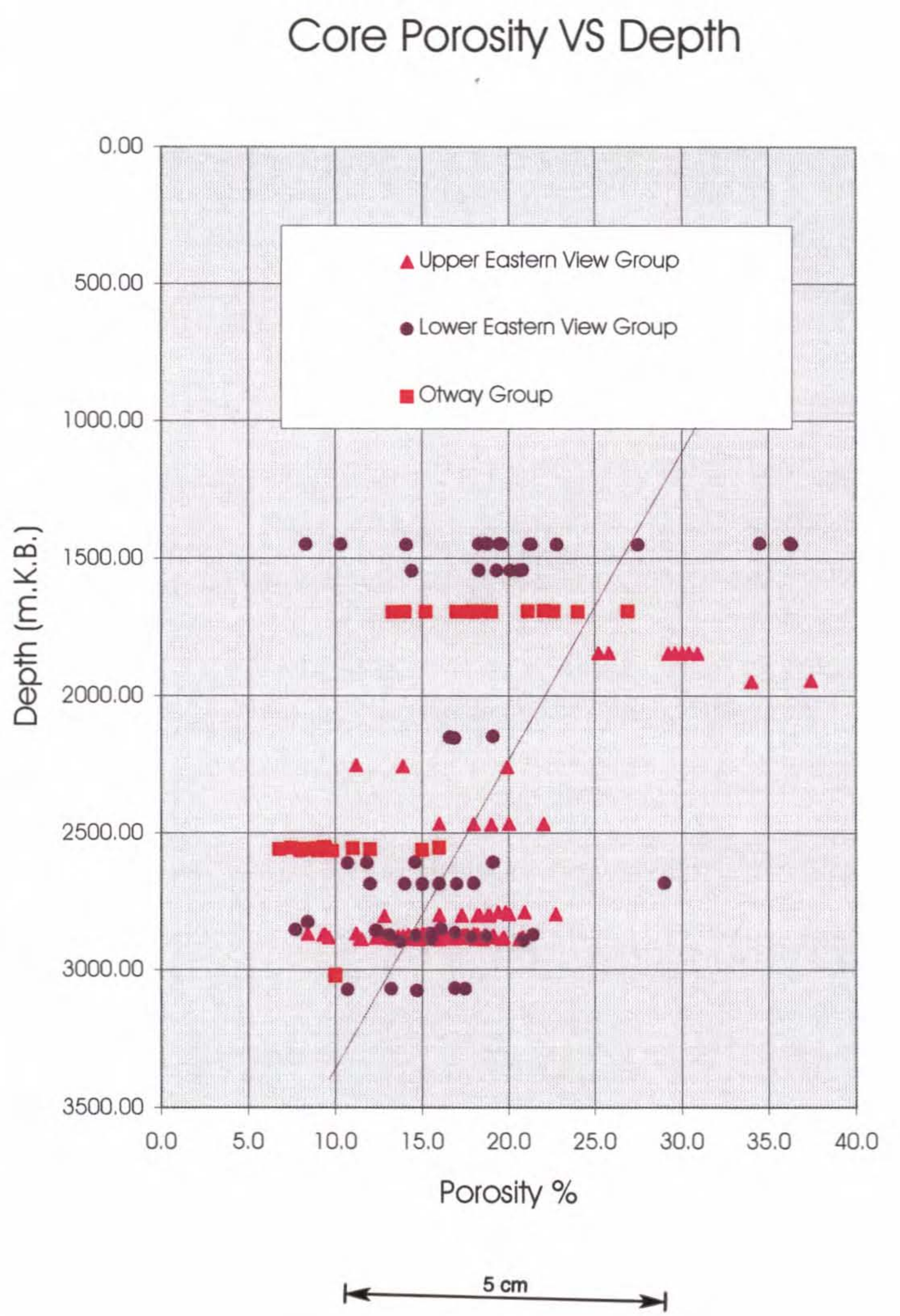

Figure 19a

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Eastern View Group

Log Porosity vs Depth

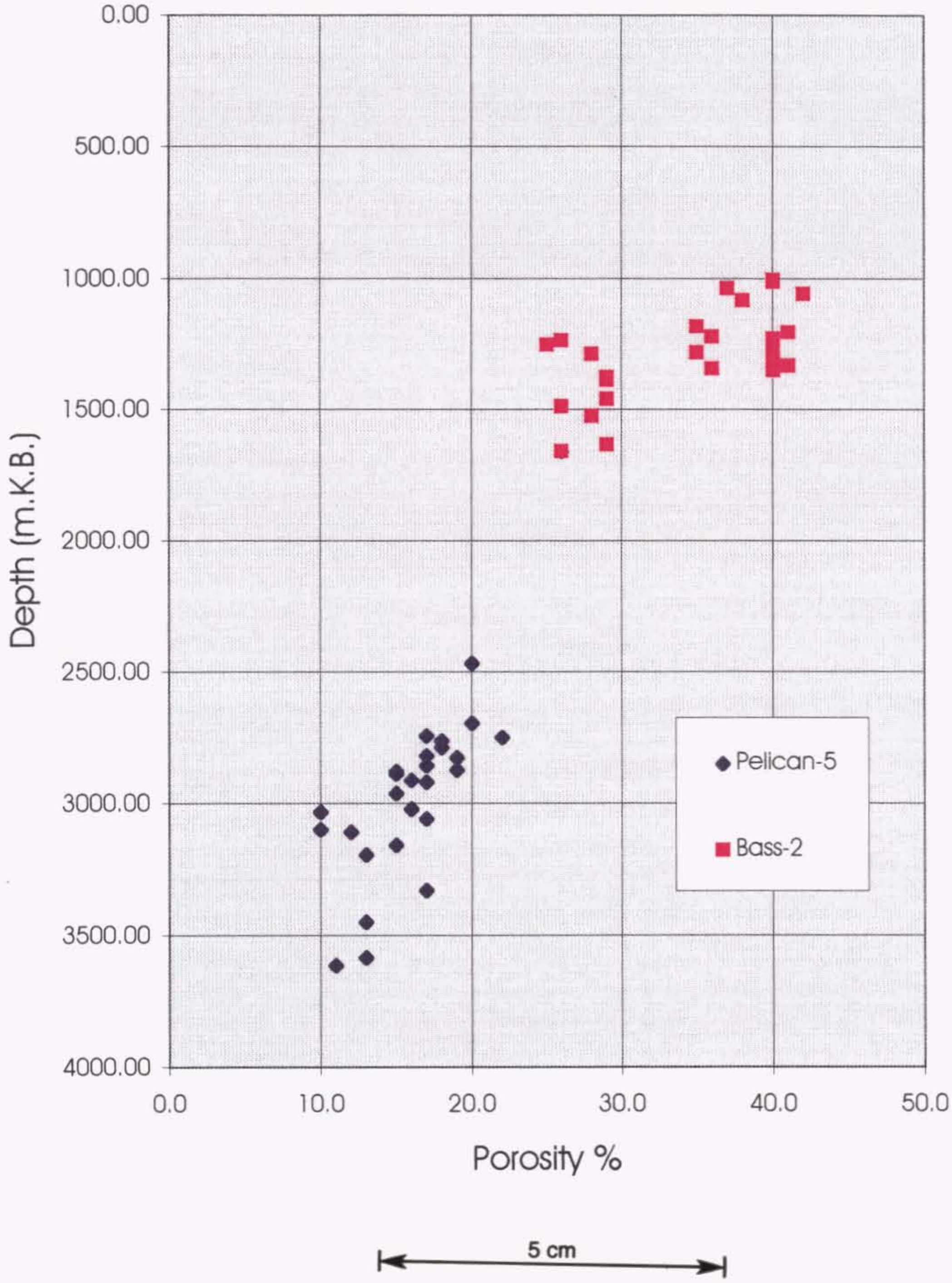

Figure 19b

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Porosity VS Permeability

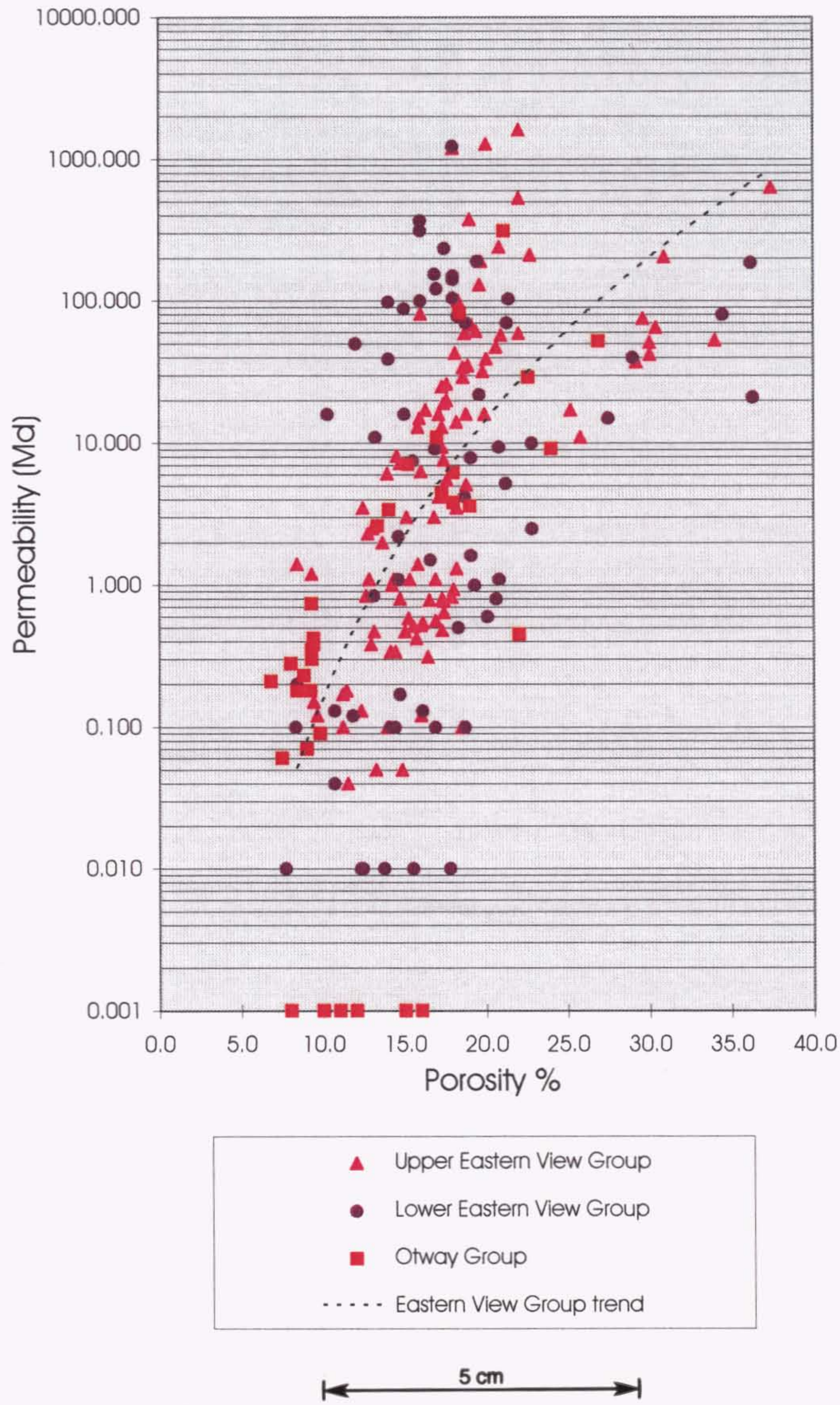

Figure 20

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relationships for the Eumerella Fm in the nearby Otway Basin, and seem to represent the equivalent cutoff of 1md permeability in Durroon-1. The uppermost 150m of the Otway Group in Durron-1 had 55% 'effective' reservoir using the above cutoffs to a depth of approximately 1850m.K.B. It should be noted that some of the horst blocks in the Durroon Basin are interpreted to have Otway Group at shallower depths than Durroon-1, and thus may have more favourable porosities.

Durroon Formation:

The only positive well intersections of the Durroon Formation are from Durroon-1, which intersected 206 metres of shale and a 71 metre zone at the base with volcanic flows and weathered volcanic derived sediments.

The entire formation displays a wedge shaped morphology thickening into rapidly deepening, narrow half grabens. In the deeper grabens it is interpreted to be up to 9km thick, which suggests that the graben was growing at the rate of 1 metre per 350 years. It is interpreted that this formation represents a thick alluvial fan sequence shedding from the elevated margins of the half grabens, and from the southeast (i.e. along the deepest part of the half graben axis, sourced from the Early Palaeozoic quartz-rich turbidites and granitoids of the East Tasmanian Terrain. These fans are interpreted to become shaley towards the elevated margins of the half grabens.

Seismic interpretion divides this formation into an upper and lower section separated by an unconformity. Seismic facies of the lower section shows chaotic, and at times slumped units close to the major rotational half graben fault (i.e. coming off the footwall), with channelling that would indicate along strike transport of sediment. Detailed log analysis of the mainly shaley section intersected at Durroon-1 (see Log Analysis section) indicates a number of very thin beds with increased porosity within an otherwise completely shale prone unit. Mud log descriptions report occasional rounded quartz pebbles from cuttings within the shale, which could indicate that these minor beds of increased porosity are perhaps thin gravelly sands. Thus the facies at Durroon-1 are consistent with the distal end of an alluvial fan (i.e. shale dominated). The basal part of the Durroon Formation is interpreted to be more sand prone than the upper unit, although both would become sandier approaching the foot wall of the half graben fault.

There are no well penetrations of the intrerpreted proximal fan facies of the basal Durroon Fm., although excellent reservoir characteristics would be expected from braided alluvial deposits. It may be possible to seismically define an area of good potential reservoir along these grabens and across to a mid point where the sands begin to shale out.

Eastern View Group:

Sands within the Upper and Lower Eastern View Group comprise the conventional reservoir objectives of the Bass Basin. All petroleum shows and discoveries to date in the basin are reservoired within these sands.

These prograding delta sands display excellent reservoir characteristics. Core derived data from 9 wells show the following:

Formation	Average Porosity (%)	Average Permeability (Md)
Upper Eastern View Group	17.66	76.10
Lower Eastern View Group	17.56	66.36

Oligocene sands of the Torquay Group

A sand interval at the base of the Torquay Group has been a secondary objective in a number of wells in the Basin. Chat-1 intersected 50m and Squid-1ST penetrated 200m with an additional 160m of sand overlying this unit unconformably. The interval has not been cored in any of the wells drilled to date, thus providing no reliable porosity/permeability data.

Seal

The Durroon Basin relies primarily on the Durroon Formation as the major sealing lithology for both structural and stratigraphic plays. Durroon-1 also showed that the Otway Group may have some minor intraformational seals (5-8 metres thick). The more 'regional' seal for the northern part of the Bass Basin (Demons Bluff Fm.) is silty/sandy in this part of the basin. The Demon's Bluff Formation, which is 50m thick at Chat-1, becomes progressively sandier southwards towards Durron-1.

Figure 16 shows an isopach of the Demons Bluff Formation over T/28P and its' interpreted lithology (from well intersections). It can be seen that over the southeastern half of the permit, the Demon's Bluff Formation is not considered to be a suitable sealing lithology.

One play has been formulated which would rely on weathered volcanic facies with overlying claystones of the Angahook Formation for seal (Figure 21). Igneous intrusives and flows have been intersected at many levels within the Bass Basin from the top of the Otway Group through to the Miocene. Facies range from dolerite and basalts to pyroclastic flows. Individual flows are moderately weathered and have a high clay content, and could thus provide a seal over moderately extensive areas. The flows seem to be associated with the major graben bounding faults which have probably acted as magma conduits.

Tasmanian Devil-1 intersected weathered volcanics which in conjunction with the 218 metres of massive claystone (interpreted marginal marine) with some sand stringers at the base (Angahook Formation) could provide an excellent seal for stratigraphic plays against this southern basement margin which is interpreted to be acting as a base seal.

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STRATIGRAPHIC PINCHOUTS SEALED BY WEATHERED VOLCANICS

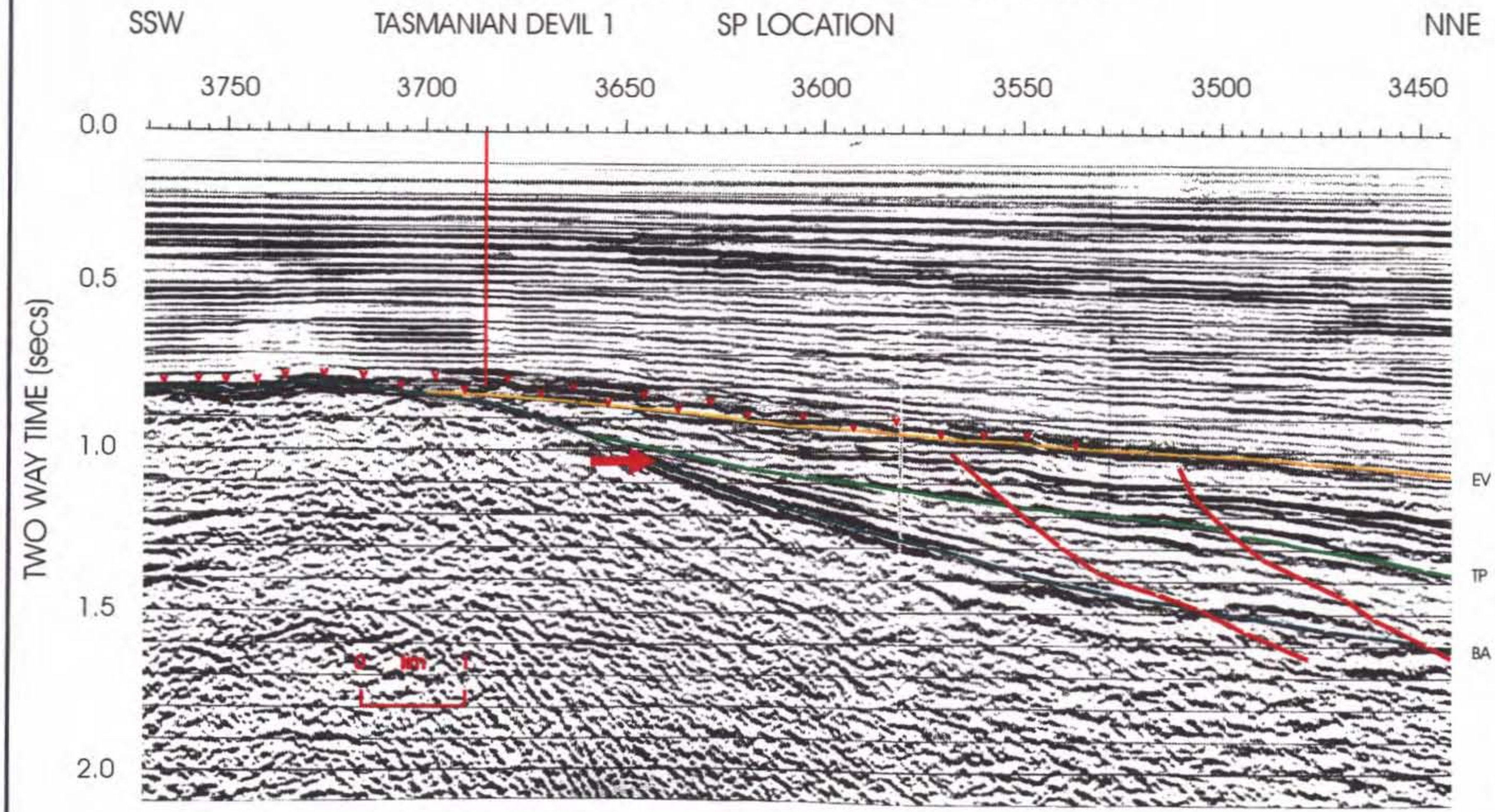

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FIGURE 21

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Source

Source intervals:

Rock-Eval pyrolysis data has been analysed for 13 Bass Basin wells. A plot of the percentage of total organic carbon shows that many of the sediments in the basin have high TOC values, including many of the non-coal lithologies (Figure 22).

All the source intervals in the Durroon Basin are terrestrial in origin (as in the Gippsland Basin), which is supported by the land plant biomarkers recovered from live oil encountered in the wells. Oil recovered from RFT#3 in Pelican-5 has biomarker characteristics common to higher land plants.

A Van Krevelen plot (Figure 23) shows that the source rocks are mainly type II and III., with the Eastern View Group showing excellent HI values (relative to other known Australian source rocks). Both Upper and Lower Eastern View Coals have high HI values and plot as type II source rocks. The volumetrically more important shales plot as type II/III, and also have many excellent HI values.

Lacustrine shales of the Durroon Formation were identified by Bridge as being a good oil source due to the algal content (identified from palynology). Rock Eval analyses show these sediments to have very low TOC values and HI/OI characteristics indicative of a poor type III (gas prone) source.

The Otway Group coals are also recognised as having favourable source characteristics, and in many parts of the Durroon Basin are at sufficiently shallow depths to be viable for the generation of oil.

Source Type and Potential:

The Eastern View Group is dominantly a type II/III source facies (see Van Krevelen diagram). If the sequence is examined carefully, it appears that there are two populations of source rocks within this section (Figure 24 showing the relationship of HI to TMax). Those intervals with lower HI values are generally from the parts of the section dominated by lacustrine sedimentation. In contrast the higher HI values belong to coals (distributed throughout the entire section), and basal shales from 'coarsening upwards' delta slope facies. In this instance the organic material is likely to have been derived via distributary channels from swampy areas behind this 'marginal marine' environment.

The Cretaceous shales of the Eastern View Group at Pelican-5 are overmature (presently dry gas prone Type III kerogen), and as such have depleted HI values. However, they are interpreted to have had considerable oil source potential on the basis of their high bituminite content.

Upper Eastern View Group resinite rich coals and shales at Yolla-1 are currently mature (VR = 0.55-0.92%) and show direct indications of generating oil (oil and exsudatinite are present in shales and coals) over a 625m interval. It is likely that this interval has already generated some oil, as generation for this type of source material begins at VR values as low as 0.4%. Gas Chromatography-MS analysis of an Early Paleocene sample in Yolla-1 has confirmed a probable parent

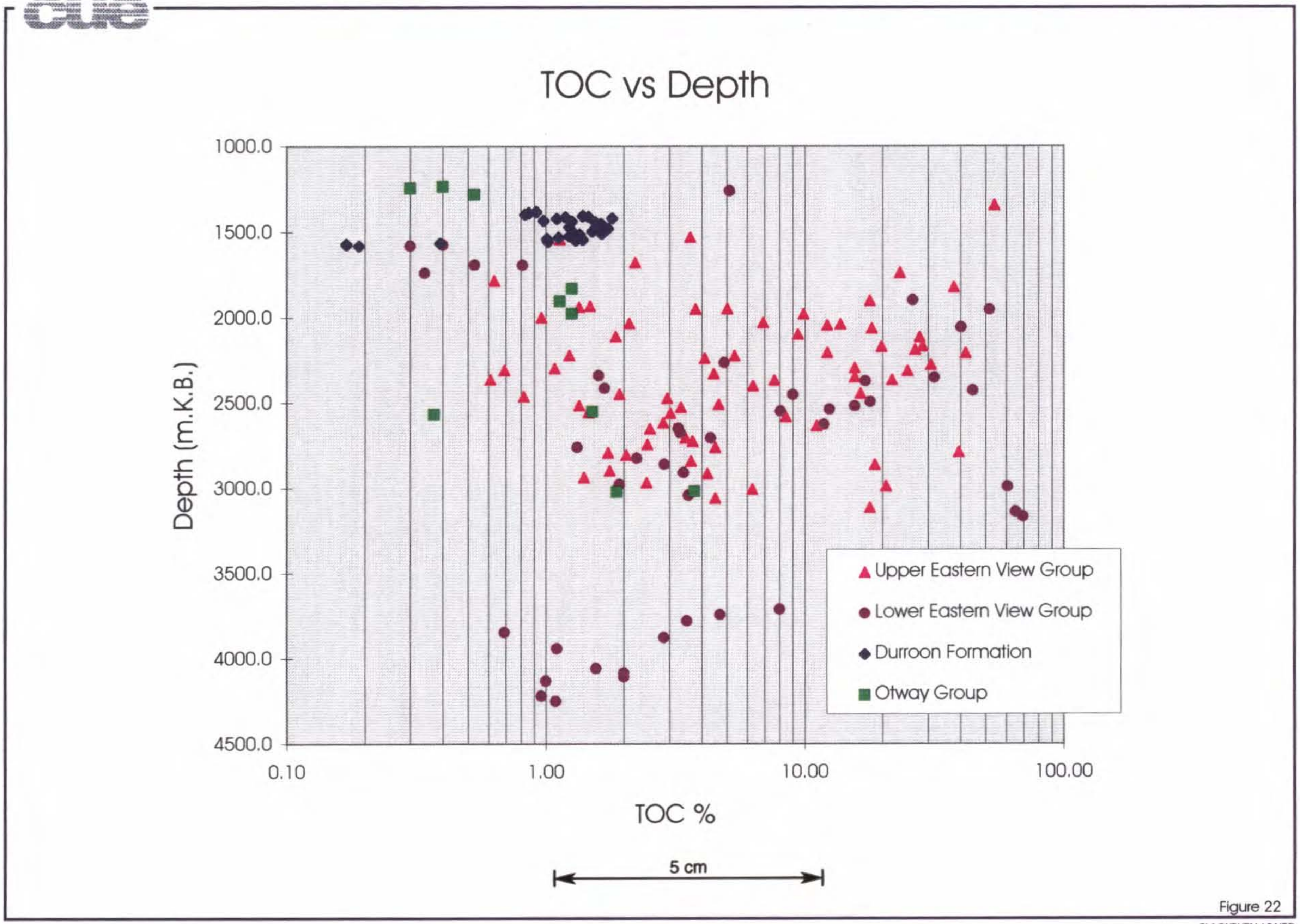

Figure 22
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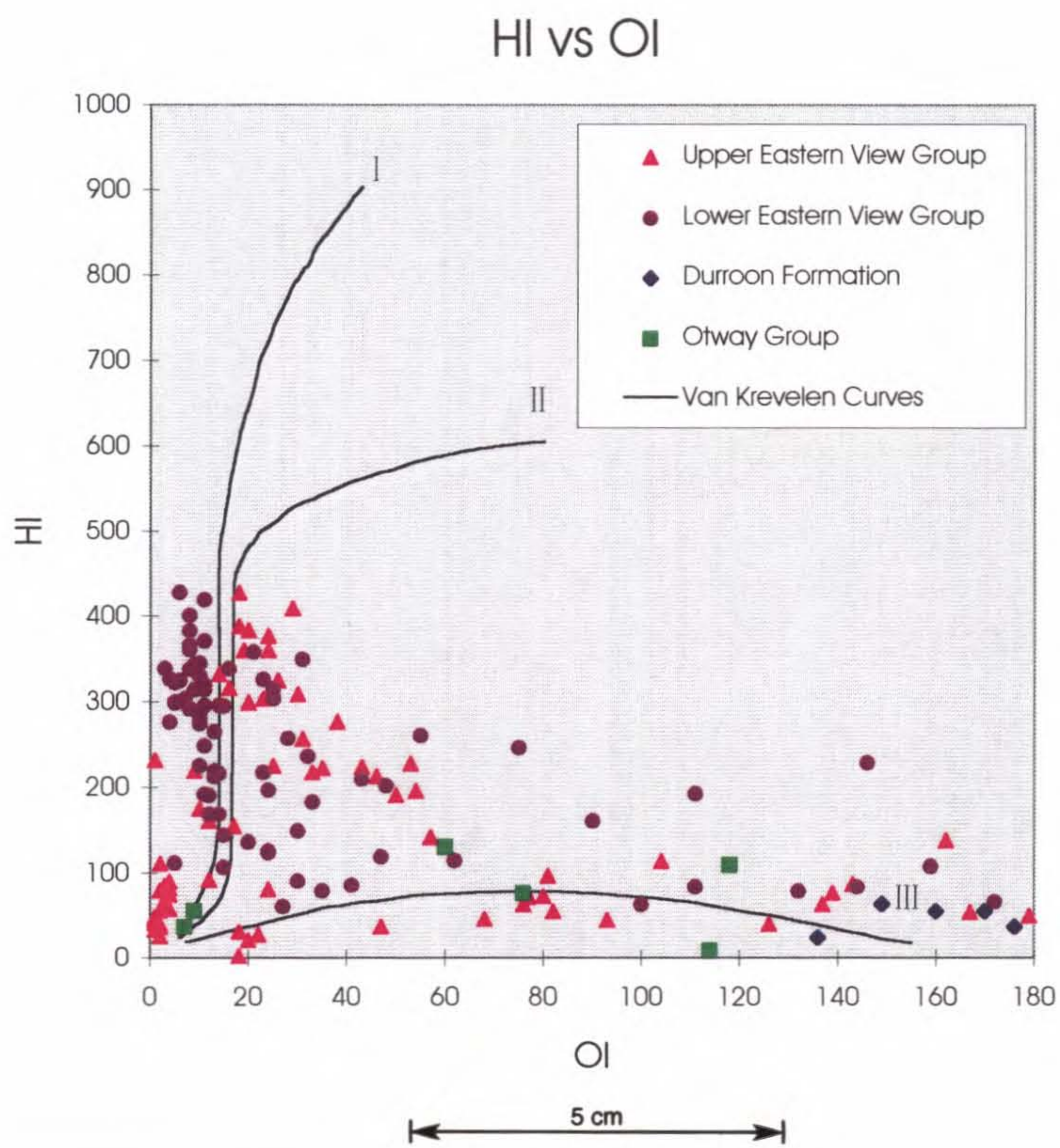

Figure 23

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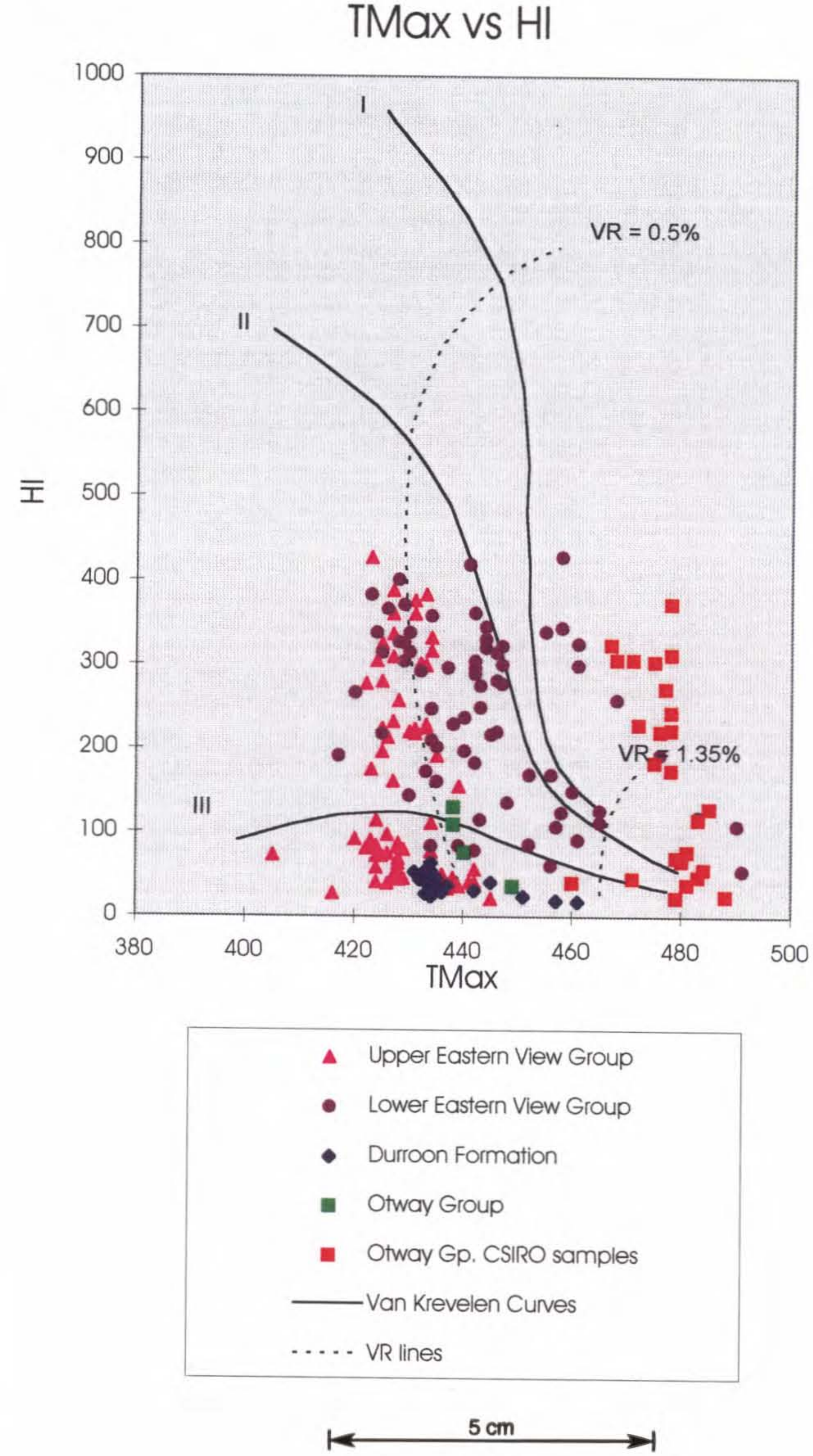

FIGURE 24

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relationship with the Upper Eastern View Group. These oils have a significant low maturity component, whereas a deeper gas condensate sample indicates a different, significantly more mature parent.

The Durroon Formation shales intersected at Durroon-1 were examined in detail by Bridge Petroleum. These shales were identified as containing a significant proportion of lacustrine algae (noted by the palynologist) and were therefore thought to have potential to be an excellent oil source. The Rock-Eval analyses, however, do not seem to support the excellent rating. For example, the average TOC% for these shales is 1.22%, while shales from the Upper and Lower Eastern View Group are 10.2% and 6.1% respectively. Plotting the Rock Eval analyses onto a Van Krevelen Diagram (Figure 23) shows that the Durroon Formation shale is a poor Type III source. These low HI values correspond to relatively low VR (0.4%VR), indicating that these are not artificially depleted by overmaturiy.

The Otway Group has only been intersected at Durroon-1, where only five samples have undergone complete Rock Eval analysis. They are dominantly Type III organic matter, although, the depleted HI values obscure their original characteristics. Analyses were undertaken by CSIRO who extensively sampled the Otway Group of Durroon-1, as well as the Eastern View Group in 16 other Bass Basin wells. OI values were not available for these analyses as S_3 determinations were not made. The TMax values were also innacurate due to lack of equipment calibration. These analyses were not used for the present graphical representation, however, they provide information on lateral HI variations within the dominantly coaly lithologies which were preferentially sampled. The highest HI values (up to 422) are found in the Eastern View Group around the depocentre for this group (i.e. Pelican-1 to 5, Narimba-1, Poonboon-1 etc.). More recent and reliable analyses show that Squid-1 and Chat-1 also have excellent source potential for the Eastern View Group in this deep basinal area. It is interesting to note that the Otway Group analyses from Durroon-1 (again mainly coal lithologies) also exhibit quite high HI values. While it is noted that the TMax values are unreliable, it can be seen from Figure 24 that these values suggest the Otway Group coals to be a Type II source.

Source affinities of HC's from Pelican-5 and Yolla-1:

Detailed geochemical investigations have been conducted on hydrocarbons recovered from Pelican-5, and point to the Eastern View Group as being the primary source of these.

Paraffinic condensate recovered on DST from an Eocene reservoir (2786-2790mKB), is relatively immature (VR=0.69%), of land plant origin, and is interpreted to be generated insitu from adjacent Upper Eastern View coals. Biomarkers indicate a significant component of conifer leaf resin, similar to those which are common in Mesozoic oils from the Gippsland Basin (Clark & Thomas, 1988).

Trace amounts of oil observed throughout the Eocene-Cretaceous section are also interpreted to be the result of insitu generation from the Lower Eastern

View shales and coals. Chromatograms of this oil closely resemble the condensate recovered from the Eocene DST.

Yolla-1 oils have similar land plant origins indicated by conifer leaf resin biomarkers. Insitu generation is indicated for the upper Eastern View Group with relatively immature oils produced. A more mature gas condensate sample is interpreted to have been generated by a similar land plant derived source, but at greater depths within the basin.

Maturity:

As was discussed previously, the Eastern View Group is a similar source type to the Latrobe Group of the Gippsland Basin. In the case of the Latrobe Group there are two schools of thought as to the level of maturity required for the generation of oil. The first favours generation at relatively low maturities (VR = 0.4 to 0.8), which would imply little or no migration for oil encountered in Latrobe Group reservoirs (Smith & Cook, 1984). The other proposes that oil generation does not occurr until much deeper levels in the Latrobe Group at VR = 0.9 to 1.2 (approximately 4 to 5km depth), and gas generation at VR = 1.2 to 2.4 (5 to 6km depth), and thus undergoes significant vertical and lateral migration (Saxby, 1980 and Clark & Thomas, 1988). This agrees with the maturities derived from crude oils in various parts of the Gippsland Basin which range from VR = 0.9 to 1.16 (Burns *et al.*, 1987). This work relies on Gas chromotography - mass spectroscopy to characterise biomarkers which indicate maturity. Unfortunately, there are no oil or source rock samples from zones which would be within this higher maturity oil window.

Detailed analysis of Pelican-5 shows that much of the Eastern View Group shales and coals are presently mature for the generation of oil. Figure 25a & b shows that early generation of oil and gas begins at 0.7%VR (note decline in the early maturity indicator biomarkers iC4/nC4 & iC5/nC5 - Figure 25b). Peak oil and gas generation is indicated by the S2/TOC decline which begins at around 0.85%VR and finishes at 1.15%VR. Gas condensate is then generated between 1.15-1.35%VR. Note also that the higher levels of S1/TOC correspond to oils shows associated with migrated and insitu hydrocarbons (Figure 25a).

The upper Eastern View Group is presently in the early stages of generation at Yolla-1, with indications of more mature liquid hydrocarbon migration from deeper parts of the basin.

An examination of basin wide maturity trends based on VR data (from 16 wells) is shown in Figure 26a & b. A regression line through these points shows that the oil window for the Eastern View Group coal/shale source (%VR=0.7 - 1.2) lies between 2700-3800m.S.S. The gas window then continues down further to 4100m.S.S. (%VR=1.35). If similar depths are considered applicable to Otway Group source facies, then there are considerable amounts of this interval which lie within the oil window.

Given that most of the wells to date are drilled on relative highs, then it would be expected that the maturity isotherms will deepen somewhat within the

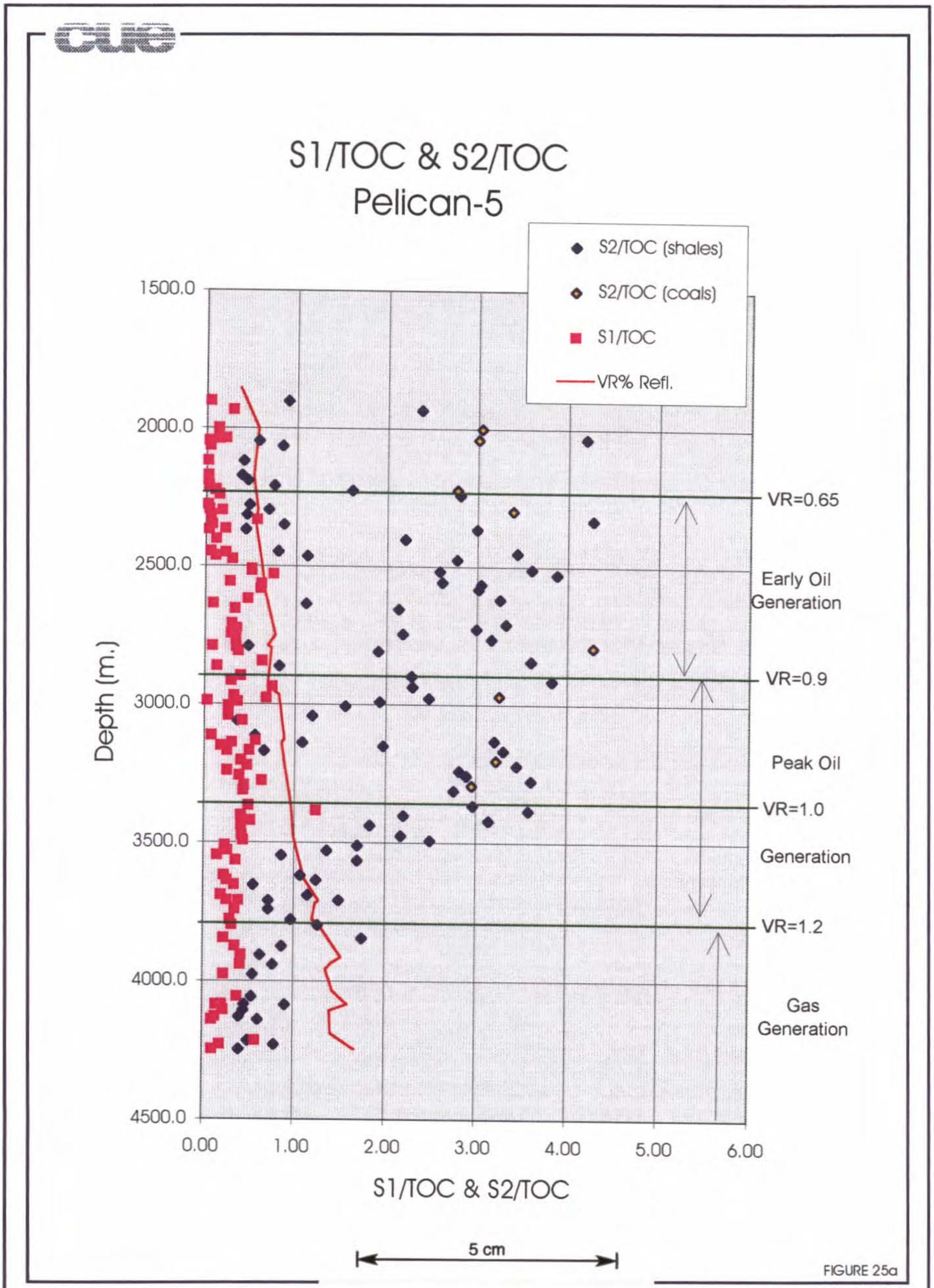

FIGURE 25a

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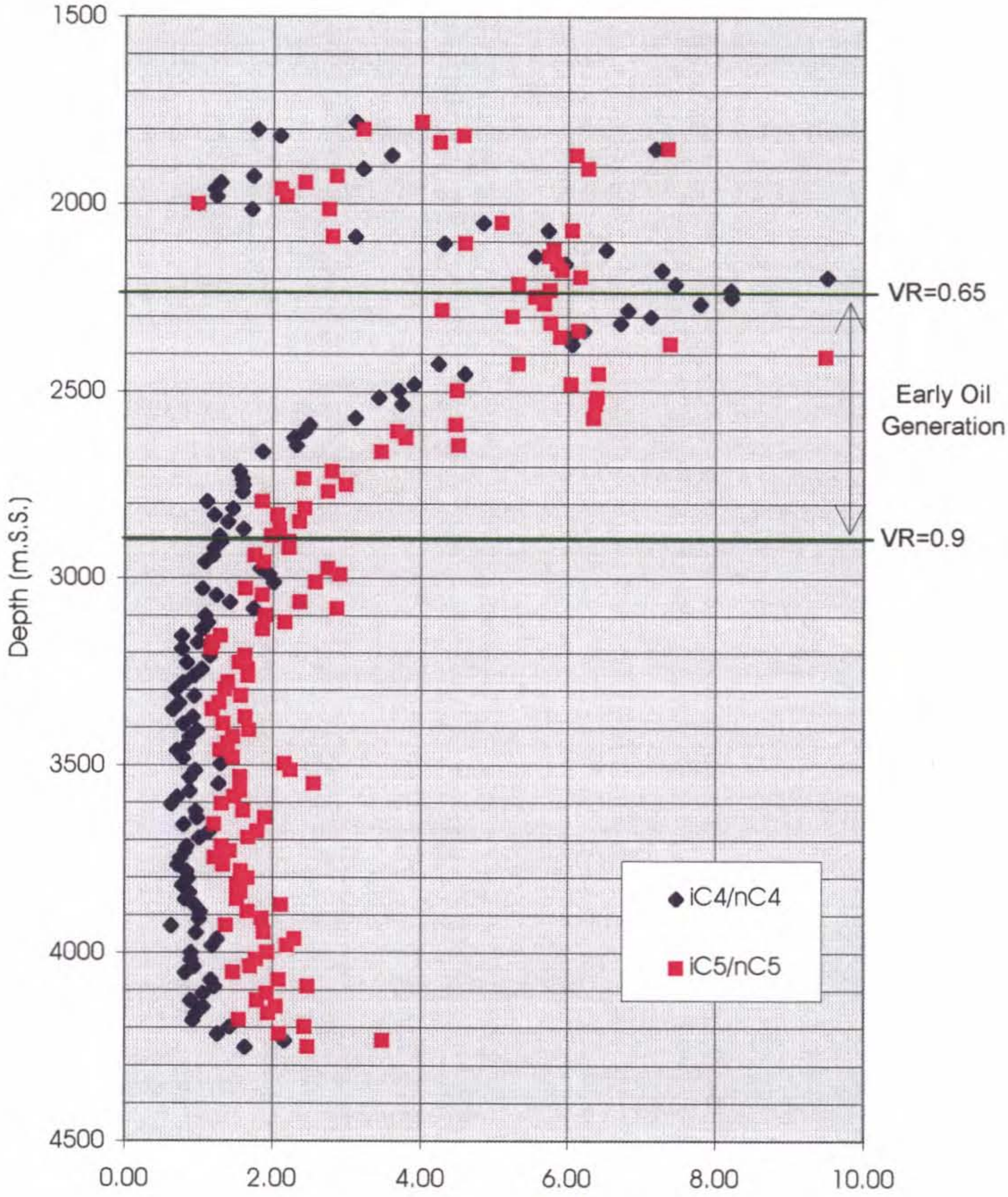
iC4/nC4 & iC5/nC5
Pelican-5



(SCALE?)

FIGURE 25b

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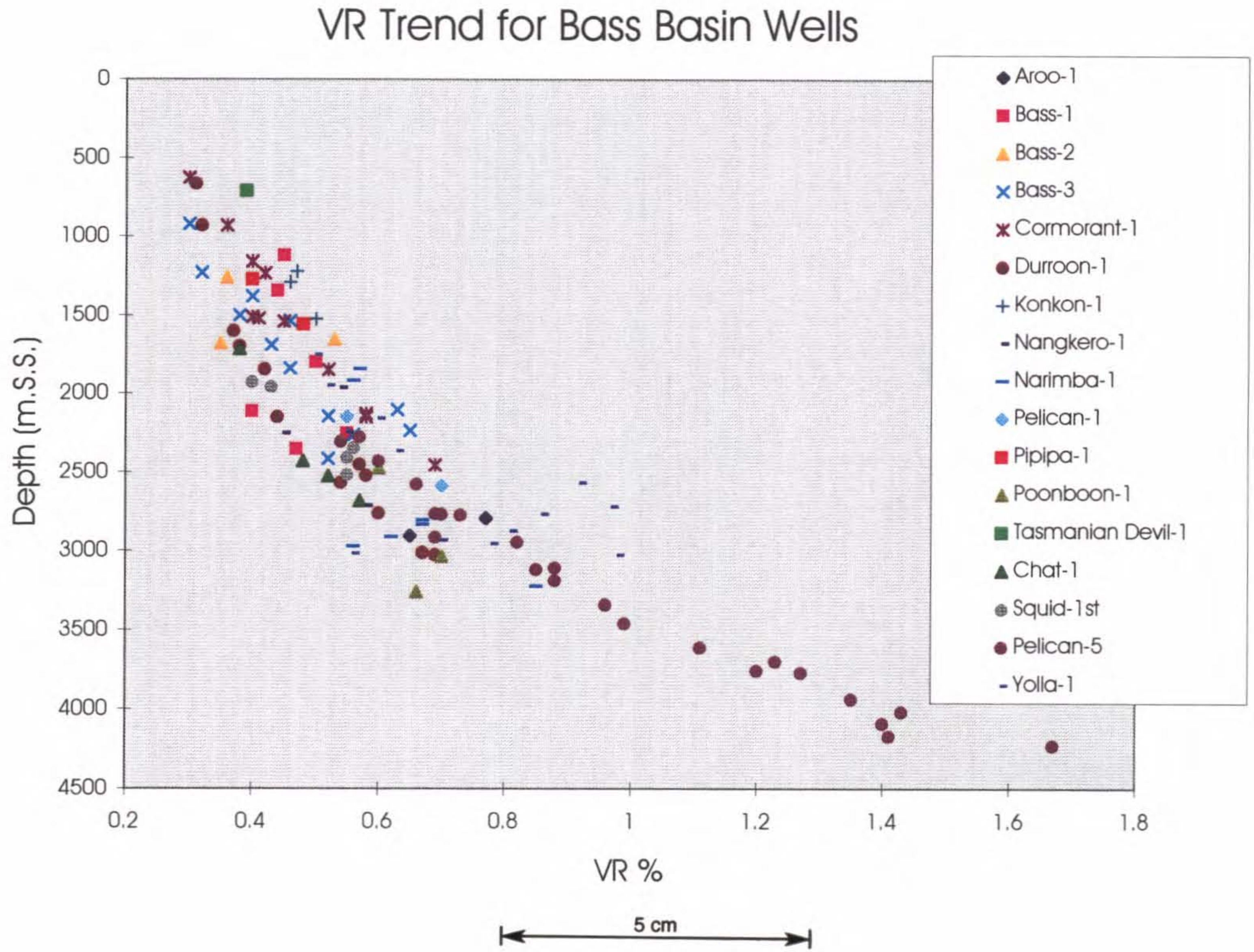

Figure 26a

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VR / Depth Trend for Bass Basin

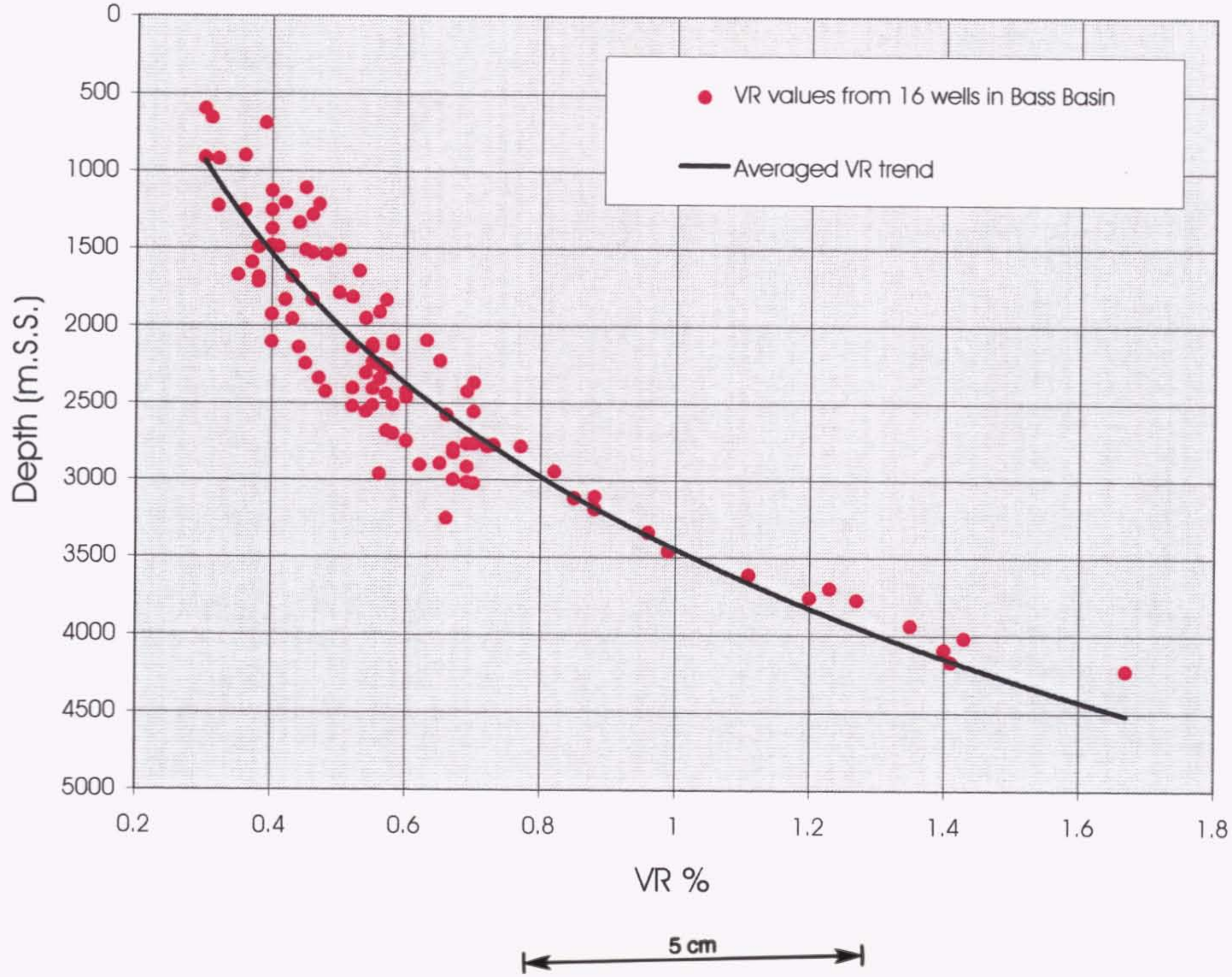

Figure 26b

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intervening troughs. This places considerably more Eastern View and Otway Group within the oil window. It is also possible that the Durroon Formation will develop better source characteristics within these grabens, where it too would be within the oil window.

Nevertheless the large majority of the permit has source section which present day lies within the gas generation window.

Thermal History & Migration

Regional migration trends for the Durroon Basin indicate updip migration pathways from the depocentre of grabens around Pelican-1, Squid-1 and Chat-1, to the structurally higher southern margin of the Basin covered by T/28P (Figures 27 & 28). A substantial depocentre is also present in the Boobyalla Sub Basin (Figure 29) where a considerable thickness of Durroon Formation is present.

Play Types

As can be seen from the discussion of the Bass Basin's geology, the structure, charge and timing histories have been similar to the Otway and Gippsland basins. The Bass Basin, however, is sufficiently different from these other provinces to demand an entirely different approach to evaluating its prospectivity and elucidating play types.

In general, large closures are not present at the top of the Eastern View Group as they are in the equivalent top of the Latrobe Group in the Gippsland Basin. A lack of significant Miocene inversional structures indicates that earlier traps must be targetted in the Durroon Basin. The considerable Cretaceous - Tertiary relief in this restricted basin allows scope for traps controlled by a combination of facies change and relief, effected over a much smaller area than the surrounding basins.

There is considerable evidence to suggest that the Durroon Basin has a very favourable configuration of structures and charge/timing characteristics. Most of the structures are quite early, and well intersections indicate that generation (from the Eastern View Group at least) is going on at present. More of the Eastern View section would be expected to have experienced recent generation in deeper parts of the grabens. The Durroon Basin is well placed to receive charge from the more basinal areas to the north, as well as locally from Otway and Eastern View Group source intervals within the deep grabens of this region.

Reservoir parameters and detailed facies analysis indicates that there is scope for the conventional top of Eastern View Group plays, potential Durroon Formation reservoir facies in mainly stratigraphically controlled plays, and shallow Otway Group structures. Lack of lateral seal (for the top of Eastern View Group plays) is a problem which has hampered wells drilled to date in the Durroon Basin. The major sealing lithology in the Durroon Basin is the upper part of the Durroon Formation. In addition, intraformational seals in the Otway Group and Eastern View Group are also expected. Two leads have been evaluated which rely on overlying partly weathered volcanic flows for seal. Additional interest in these

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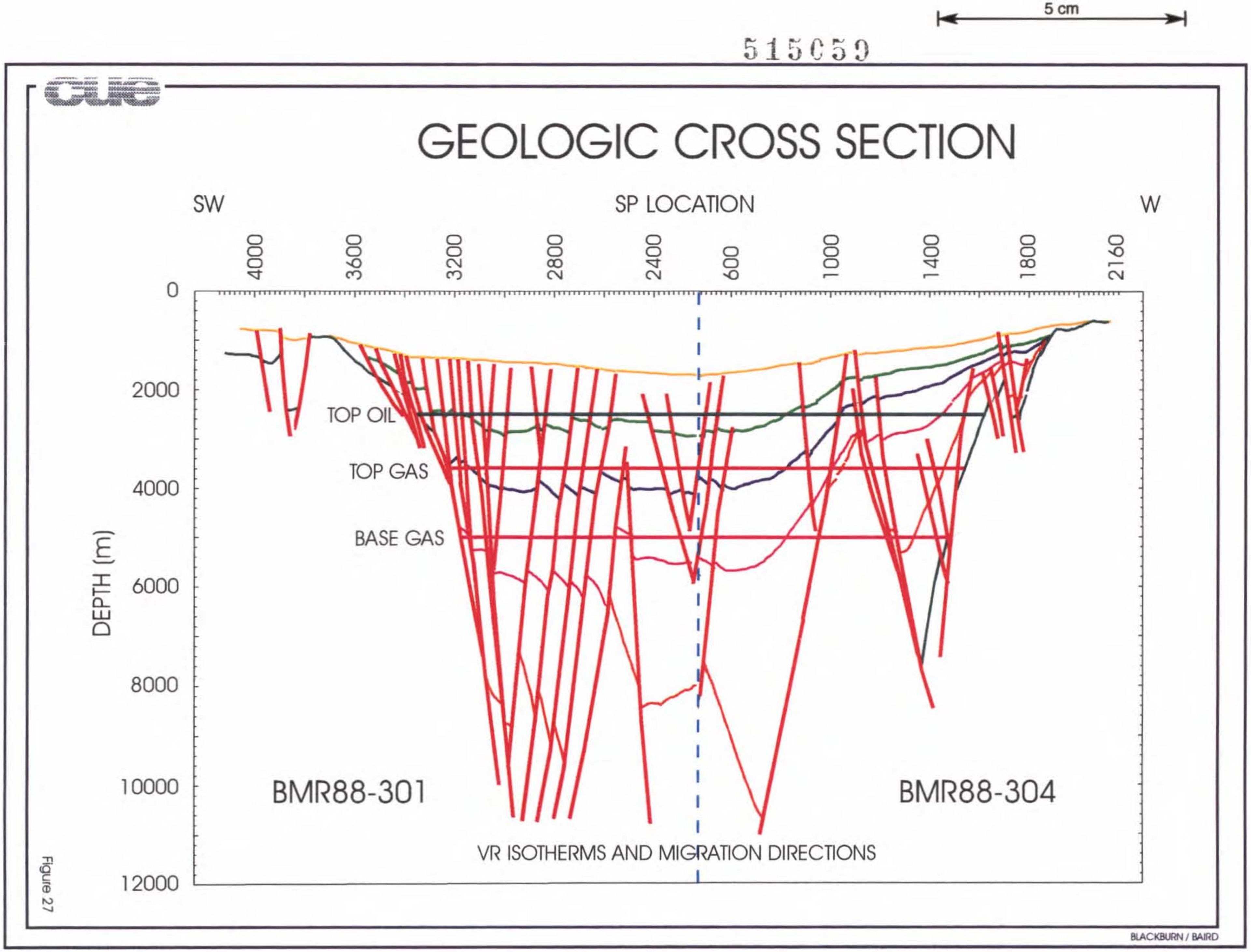

Figure 27

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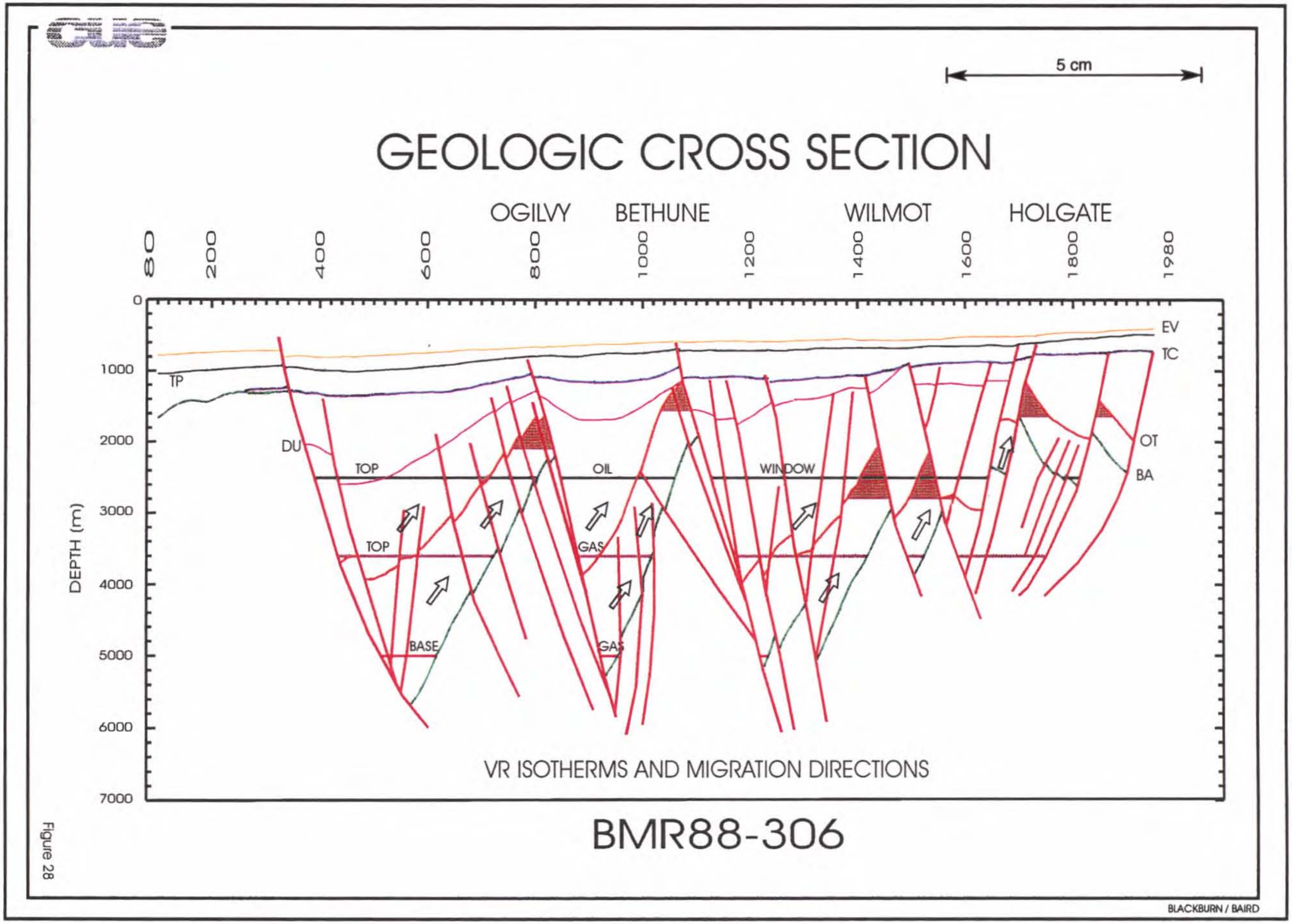

Figure 28

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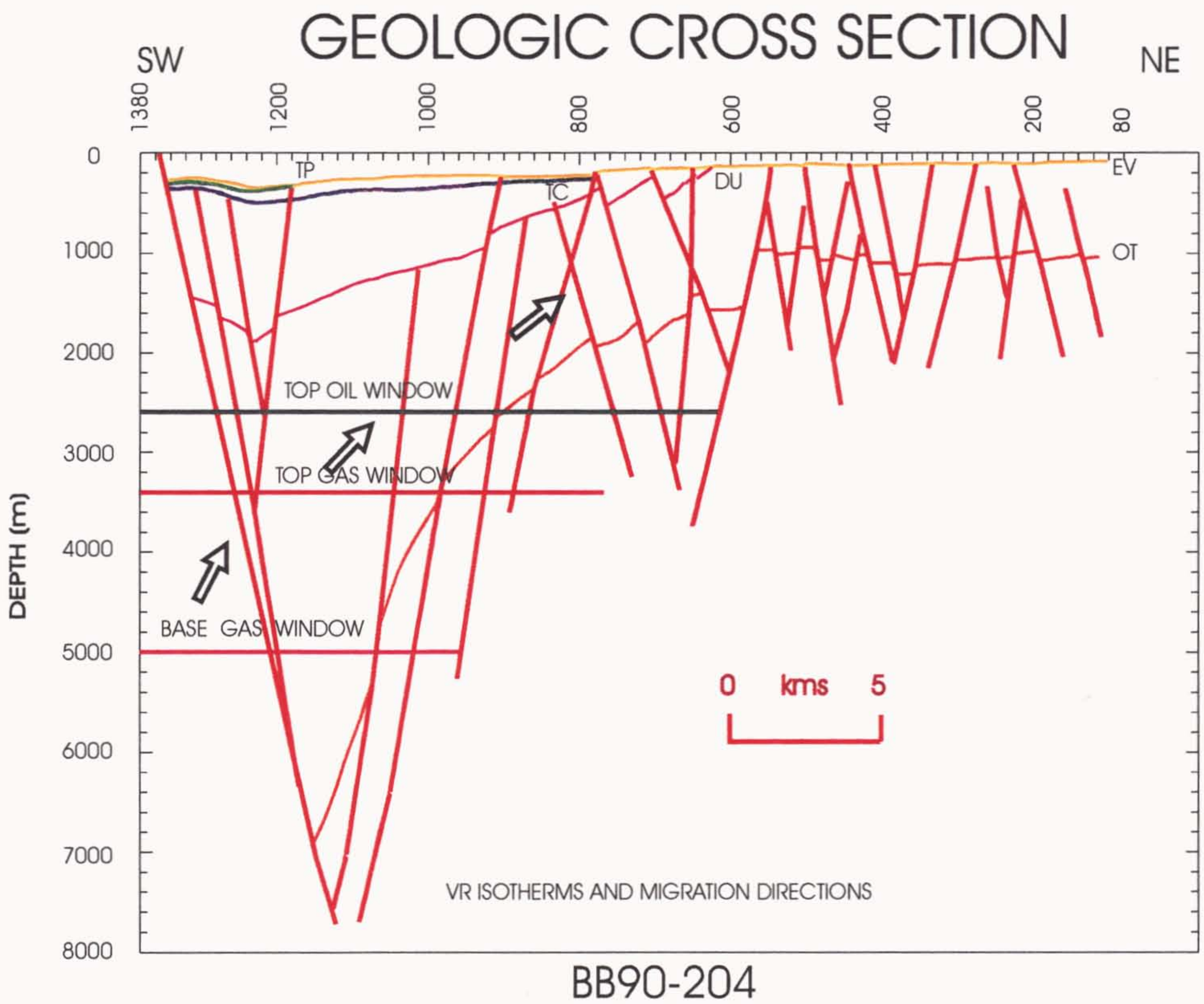

Figure 29

leads is provided by the presence of anomalous seismic events which may be possible direct hydrocarbon indications that have been noted on multiple vintages of seismic over these features.

Play types of the Durroon Basin can be characterised in the following way:

- Eastern View Group sands in tilted fault blocks with intraformational or Demon's Bluff Formation seal. Source provided from Eastern View Group shales and coals
- Stratigraphic traps with lower Durroon Formation reservoir in an alluvial fan wedge against basement, top-sealed by the upper Durroon Formation shales. Sourced by Otway Group coals and shales, or juxtaposed Eastern View Group sediments faulted down dip.
- Highside closures against rotational half graben forming faults, with shallow (less than 1800m.S.S.) Otway Group reservoir. Seal provided by volcanic flows over the surface of the top Otway Group unconformity, or upper Durroon Formation shales, and possibly intraformational Otway Group shales. Sourced by Otway Group coals or fault juxtaposed Eastern View Group sediments in a down dip position.
- Wedgeout of Eastern View Group reservoir against basement (providing base seal). Sealed by a volcanic flow and/or massive claystones (Angahook Formation) at the southern margin of the basin. Sourced by Eastern View Group coals and shales to the north in grabens near the Pelican Field.
- Oligocene sands in tilted fault blocks sealed by overlying shales of the Torquay Group. This play relies on having either quite large, or alternately very small fault throws to avoid leak due to juxtaposition of sands across the bounding faults.

The Eastern View Group and Oligocene sand plays will have significant seal risk if they rely entirely on intraformational or Demon's Bluff Fm. seals, as fault throws at these levels are close to the average shale bed thickness. This could present problems for reservoir continuity and lateral fault seal.

Highside tilted fault block closures with Otway or Eastern View Group reservoirs seem to be set up by the rapidly varying strike of major graben defining faults. Closures are most likely to occur at deflection points along these faults.

Four-way dip closed plays are unlikely in this part of the Bass Basin which has experienced very little late inversion.

Seismic Interpretation

Seismic coverage

A moderately good seismic grid is present across the area (Figure 30), except for the southwestern and northwestern corners of the permit, where very

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SEISMIC LOCATION MAP

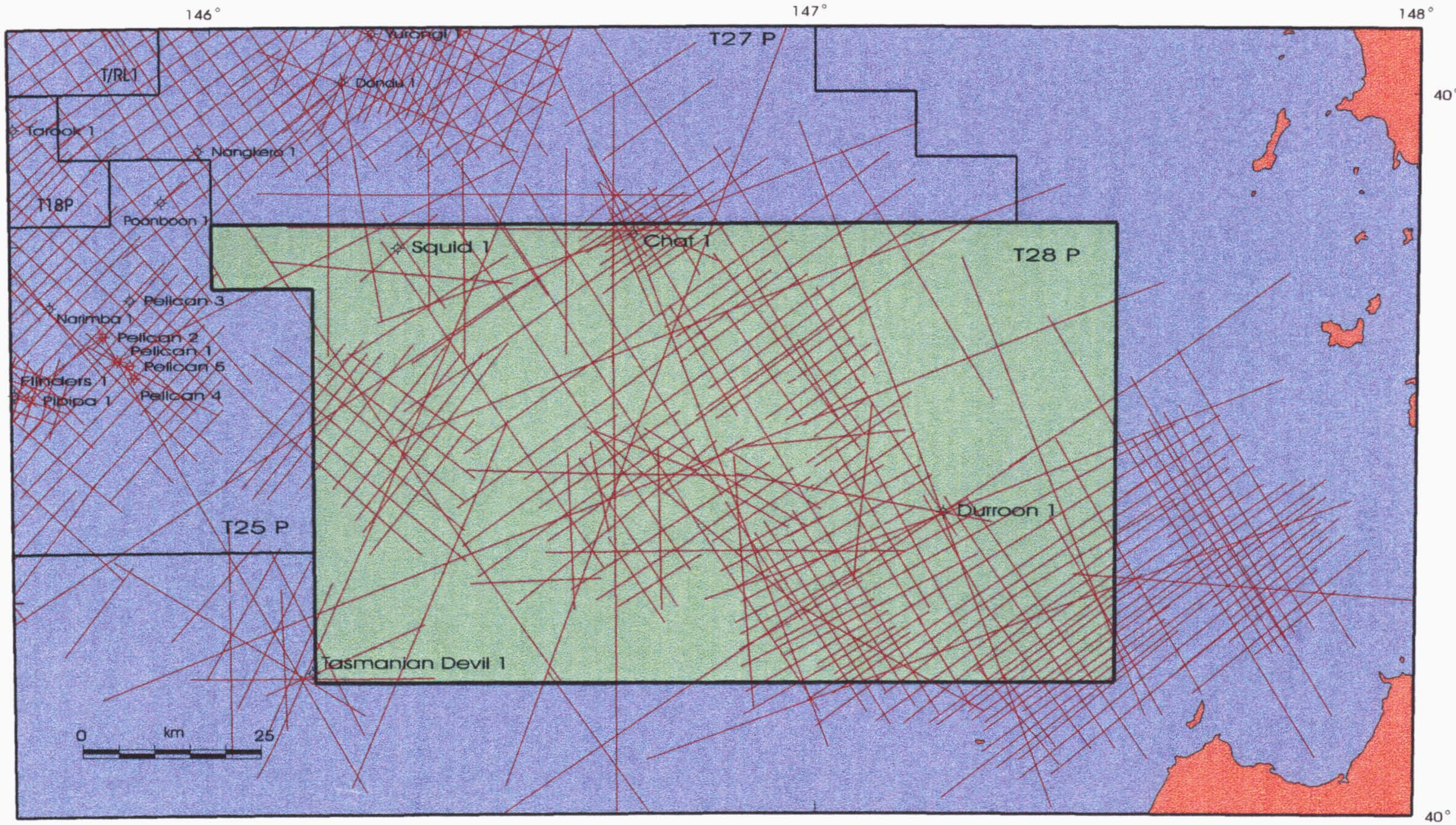

FIGURE 30

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few lines are available. On average, a 2.5 X 2.5 km grid is present across about 30 % of the permit, with good regional correlations provided by the 1988 BMR survey.

Most of the post 1975 data (13 surveys) were interpreted (see Table 3), a small percentage of which have been reprocessed (mainly by Bridge). The different vintages vary in frequency content, phase, and not all of the data is migrated.

Data quality

Seismic data quality varied from generally good to poor. This was in part due to poorly reproduced transparencies, or more commonly poor acquisition and processing parameters. Differences of phase, scale and frequency further hampered correlation between the different survey vintages.

Well Ties

Well ties were made at Bass-2, Chat-1, Dondu-1, Durroon-1, Nangkero-1, Pelican-1, Pelican-3, Pelican-5, Pipipa-1, Poonboon-1, Squid-1, Tasmanian Devil-1 and Yurongi-1. These were based on time/depth graphs, except for Pelican-5 where a zero phase synthetic was available from the well completion report.

Seismic interpretation

The following horizons have been interpreted: Top Demon's Bluff Formation*, Top Eastern View Group, Top Paleocene unconformity, Top Cretaceous unconformity, Top Durroon Formation, intra Durroon unconformity*, intra Durroon alluvial fan*, Top Otway Group and Basement*.

* = these horizons were not interpreted over the entire map area.

The Top Demon's Bluff Formation is the top of the regional seal over the Bass Basin, however, it is silty and/or sandy across much of the Durroon Basin. The character of this event varies due to the change in lithology from sand at Durroon-1 to shale within the Poonboon Depocentre. The palaeogeographic map of the Demons Bluff Formation (Figure 16) was in part constructed from the seismic signature of this interval as well as well control. This unit provides the regional seal for the Top Eastern View Group. Knowledge of the seal quality and thickness is vital for any prospect risk assessment as evidenced at Chat-1 where the fault throw on the Chat structure was greater than the Demons Bluff seal thickness, thereby allowing leakage of hydrocarbons from the Eastern View Group to the overlying Oligocene sand unit.

TABLE 3: Seismic vintages used in the T/28P interpretation

Year	Survey	Migrations
1975	HB75A	stacks only
1980	HB80A	migration
1981	WB81	migration
1982	WB82	stacks only (13 reprocessed migrations)
1982	BMR82	migration (some reprocessed 1985)
1985	BB85	migration (2 lines as stacks only)
1985	TQH	migration
1988	BB88	squash migrations and stacks
1988	BMR88	migration
1990	BB90	migration
1991	BD91	migration

The Top Eastern View Group Marker, which represents the transition from an excellent marine sand to the overlying marine shale, is a distinctive event throughout the permit. However the event misties on different vintages due to different signal character.

The Top Paleocene unconformity is a fairly distinct event and presents the boundary between the Upper and Lower Eastern View Group.

The Top Cretaceous unconformity is also a fairly well defined event, although this horizon may be picked incorrectly within the Boobyalla Sub-basin where there is no well tie. The Top Paleocene and Top Cretaceous unconformities have been interpreted to help define the hydrocarbon kitchen areas and likely migration directions.

The Top Durroon Formation is well defined within the Anderson Sub-basin, near the Durroon-1 well, but is less certain within the thick Boobyalla Sub-basin where the seismic signature is relatively bland. This unit marks the top of a thick seal unit at Durroon-1. The Durroon Formation provides the seal for the intra Durroon alluvial fans and the lower Otway Group reservoirs.

The Intra Durroon unconformity is a prominent erosion event within the Bark Sub-basin and is probably associated with alluvial fan deposition within the Anderson and Boobyalla Sub-basins.

The Top Otway Group is a most prominent seismic marker throughout the permit area and has been used as the key correlation event in interpreting across faults.

The basement is taken to represent the base of good coherent reflectivity and has been mapped only in the shallower areas. This event is more faulted than the overlying Top Otway Group and there is considerable evidence that a further unconformity exists within the Otway Group, which probably corresponds to the Unconformity between the Eumeralla Formation and the Crayfish Group in the neighbouring Otway Basin.

Mapped horizons

Regional maps at 1:50,000 scale (10 map sheets to cover the permit and immediate surrounds) for the Top Otway Group and Top Eastern View Group were contoured and subsequently reduced to 1:100000 scale. The Top Durroon Formation was locally contoured were appropriate and a regional isochron map generated (Figure 7).

Velocity analysis

There is little well velocity control within the permit. A regional velocity function was derived from the Pelican-5 and Durroon-1 time-depth curves which penetrated the deepest interval and geological time unit respectively. In general the two curves are in good agreement but diverge at Durroon-1 within the Otway Group section due to the relatively higher velocities within this unit.

Depth conversion

It was beyond the scope of this project to generate depth maps within the permit. However the regional velocity function was used to create geological cross-sections for each prospect and the function was used to estimate indicative depths to the top of each prospect and isopach thicknesses in calculating reserve volumes.

Prospects and Leads

Risk Analysis

For a prospect to be successful, the following factors must be present-source, maturity, migration, reservoir, seal and structure/timing of structure. The absence of one or more factors will invalidate a prospect. Risk factors have been assigned to each of these parameters. The following guide lines have been used in determining the probability values for each of the six parameters in determining the overall risk:

a) Certain: A reasonable certainty in exploration terms that the parameter exists and has proved to be effective in the basin / prospect. This has been assigned a risk probability of 0.9, where 1.0 is absolute certainty (100.0% probability) and 0.0 is absolute failure (0.0% probability).

b) Probable: There is sufficient evidence to support or suggest through inference and deduction that the parameter is likely to be present, and should prove to be effective in the basin / prospect. This has been assigned a risk probability of 0.67 (67% probability)

c) Possible: The degree of inference is either not so clearly supported through geological deduction, or adverse evidence is available to suggest that the effectiveness of some parameter(s) should be downgraded within the basin / prospect and has been given an uncertainty of 0.55 (55% probability).

d) Unlikely: There are some reasons to identify some specific factor(s), either through geological deduction or from the presence of specific adverse evidence, which significantly downgrades the exploration parameter(s) within the basin / prospect. The unlikely case is given a probability of 0.32 (32% probability).

For simplicity the six factors have been combined to form three parameters 1) Source presence in the vicinity of the trap and its maturity 2) Reservoir in the trap and its communication with the source and 3) Structural (either tectonic or sedimentary) presence including timing of structuring and the presence of seal. The probability for each of the three parameters is assigned by multiplying their individual risk probabilities. For example if the presence of reservoir is certain (0.9) and communication with the source is possible (0.55) a combined parameter probability is 0.5 (0.9*0.55). Probabilities are assigned so that if all critical factors are certain the prospect probability is 0.5 (i.e. 0.8*0.8*0.8 = 0.5 or 50% probability). Thus where all factors are certain the chance of discovery is 50% or 1 in 2. If all factors are probable or equal numbers are certain and possible the chance of discovery is one in eleven or 9%. If all factors are unlikely the chance of discovery is one in a thousand. This approach ensures that a probable outcome for all factors results in a *real world* type exploration risk of 0.09 (0.67*0.67*0.67*0.67*0.67*0.67) or a 1 in 11 chance of a discovery (1/0.09 = 11), which closely approximates the Bass Basin historic discovery rate (2 discoveries, Yolla and Pelican from 24 exploration wells as shown in figure 1. Clearly geological reasons must be identified for any discrepancy (positive or negative) between the Exploration Risk that has been derived from the prospect evaluation and the average finding rates within the basin. Such a comparison should help eliminate both unsupported optimism and unnecessary pessimism in the prospect assessment.

Prospect Inventory

Fourteen prospects and leads (seven Otway Group, two Durroon Formation and five Eastern View Group) have been mapped (figure 31) and identified and described in Appendix 2.

Otway Group Propects

These prospects, targeting the Upper Eastern View Group sands sealed by the overlying Durroon Formation shales, have potentially large recoverable reserves (Figures 32 & 33) but are assigned high risk (Table 4). These structural types have only been penetrated at Durroon 1, where the well can be shown to be 200ms downdip from the crest (the Bethune Prospect). The play has been tested with some success in the neighbouring Otway Basin, however there are sufficient differences (eg reservoir quality) and unknowns (the quality of the lateral seal on the downthrown side of the rotated high blocks) to describe this as a new play type. Despite their low chance of success, ranging from 1 in 11 (9%) to 1 in 24 (4%) for oil and gas, their risked recoverable reserves are still relatively high (Figures 34 &35). While potential reserves are large as they have been calculated on the maximum structural closure to the spill point, volumes are likely to be much

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LEADS AND PROSPECTS

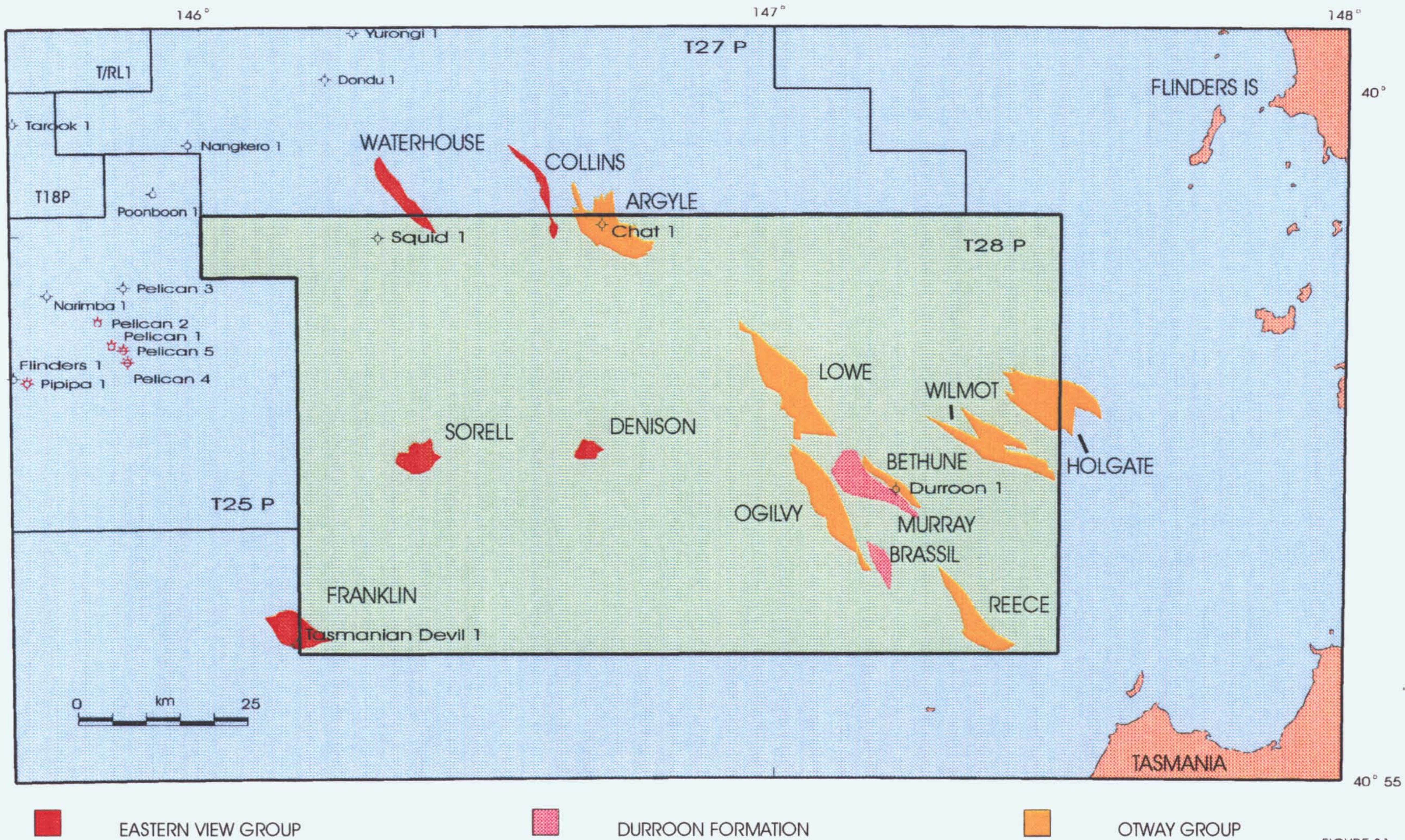

FIGURE 31

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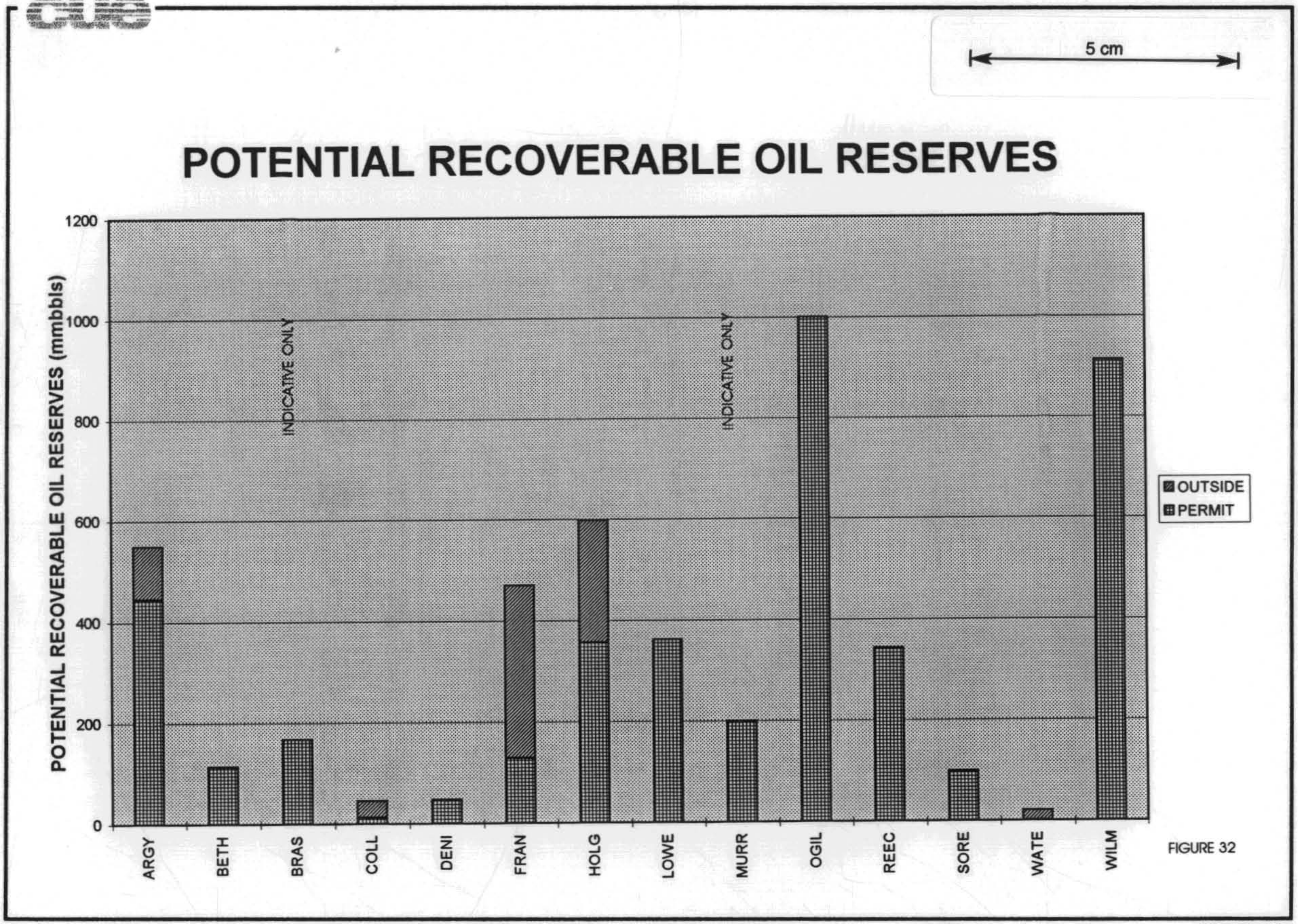

FIGURE 32

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POTENTIAL RECOVERABLE GAS RESERVES

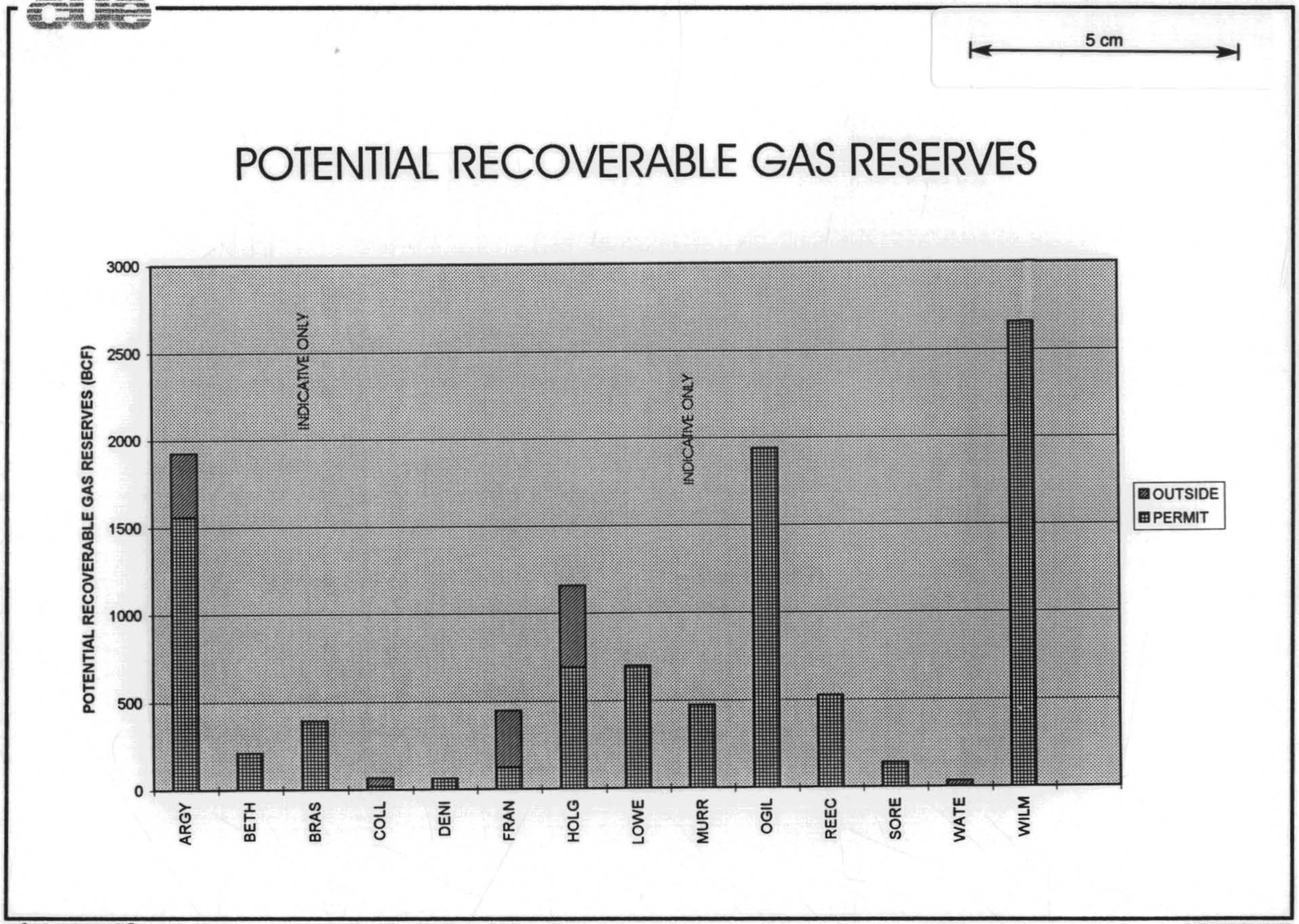

FIGURE 33.

PROSPECT	Structure	Seal	Probability	Reservior	Communication	Probability	Source		Maturity		Probability		Chance of Success	
							Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
OTWAY GROUP PROSPECTS														
ARGYLE	PROB	UNLI	0.30	PROB	CERT	0.55	PROB	PROB	UNLI	PROB	0.30	0.45	5.0%	7.4%
BETHUNE	PROB	UNLI	0.30	PROB	CERT	0.55	PROB	PROB	CERT	CERT	0.55	0.55	9.1%	9.1%
HOLGATE	PROB	UNLI	0.30	PROB	POSS	0.37	PROB	PROB	POSS	POSS	0.37	0.37	4.1%	4.1%
LOWE	PROB	UNLI	0.30	PROB	CERT	0.55	PROB	PROB	CERT	CERT	0.55	0.55	9.1%	9.1%
OGILVY	PROB	UNLI	0.30	PROB	CERT	0.55	PROB	PROB	CERT	CERT	0.55	0.55	9.1%	9.1%
REECE	PROB	UNLI	0.30	PROB	CERT	0.55	PROB	PROB	CERT	CERT	0.55	0.55	9.1%	9.1%
WILMOT	PROB	UNLI	0.30	PROB	CERT	0.55	PROB	PROB	PROB	CERT	0.45	0.55	7.4%	9.1%
DURROON FORMATION PROSPECTS														
BRASSIL	PROB	PROB	0.45	PROB	CERT	0.55	PROB	PROB	CERT	PROB	0.55	0.45	13.6%	11.1%
MURRAY	PROB	PROB	0.45	PROB	CERT	0.55	PROB	PROB	CERT	PROB	0.55	0.45	13.6%	11.1%
EASTERN VIEW GROUP PROSPECTS														
COLLINS	PROB	POSS	0.37	CERT	CERT	0.80	PROB	CERT	CERT	PROB	0.55	0.55	16.3%	16.3%
DENISON	PROB	PROB	0.45	CERT	CERT	0.80	PROB	CERT	CERT	PROB	0.55	0.55	19.8%	19.8%
FRANKLIN	PROB	PROB	0.45	CERT	CERT	0.80	PROB	CERT	CERT	PROB	0.55	0.55	19.8%	19.8%
SORELL	PROB	PROB	0.37	CERT	CERT	0.80	PROB	CERT	CERT	PROB	0.55	0.55	16.3%	16.3%
WATERHOUSE	PROB	PROB	0.45	CERT	CERT	0.80	PROB	CERT	CERT	PROB	0.55	0.55	19.8%	19.8%

TABLE 4: PROSPECT RISK ASSESSMENT

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RISKED POTENTIAL RECOVERABLE OIL RESERVES

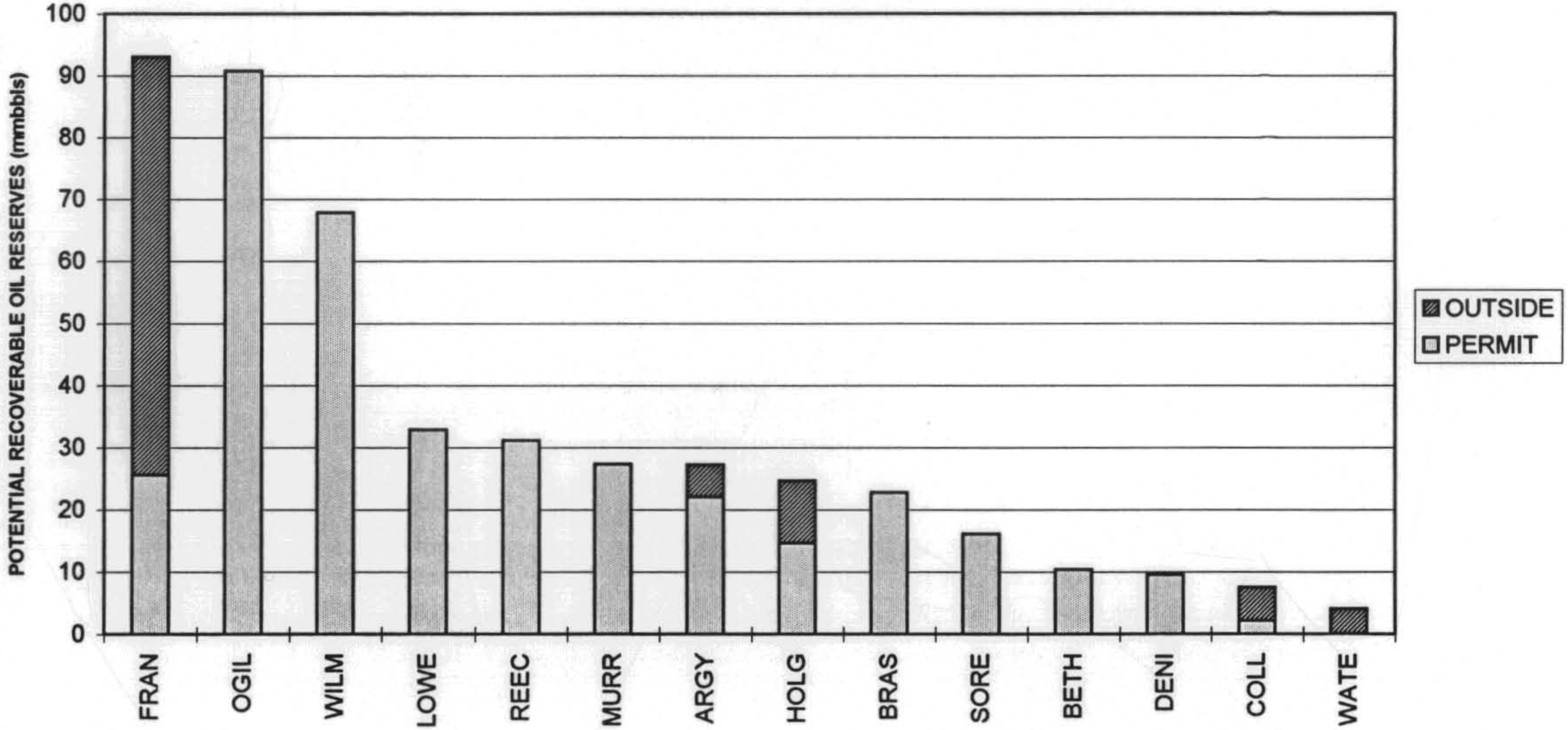

FIGURE 34

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RISKED POTENTIAL RECOVERABLE GAS RESERVES

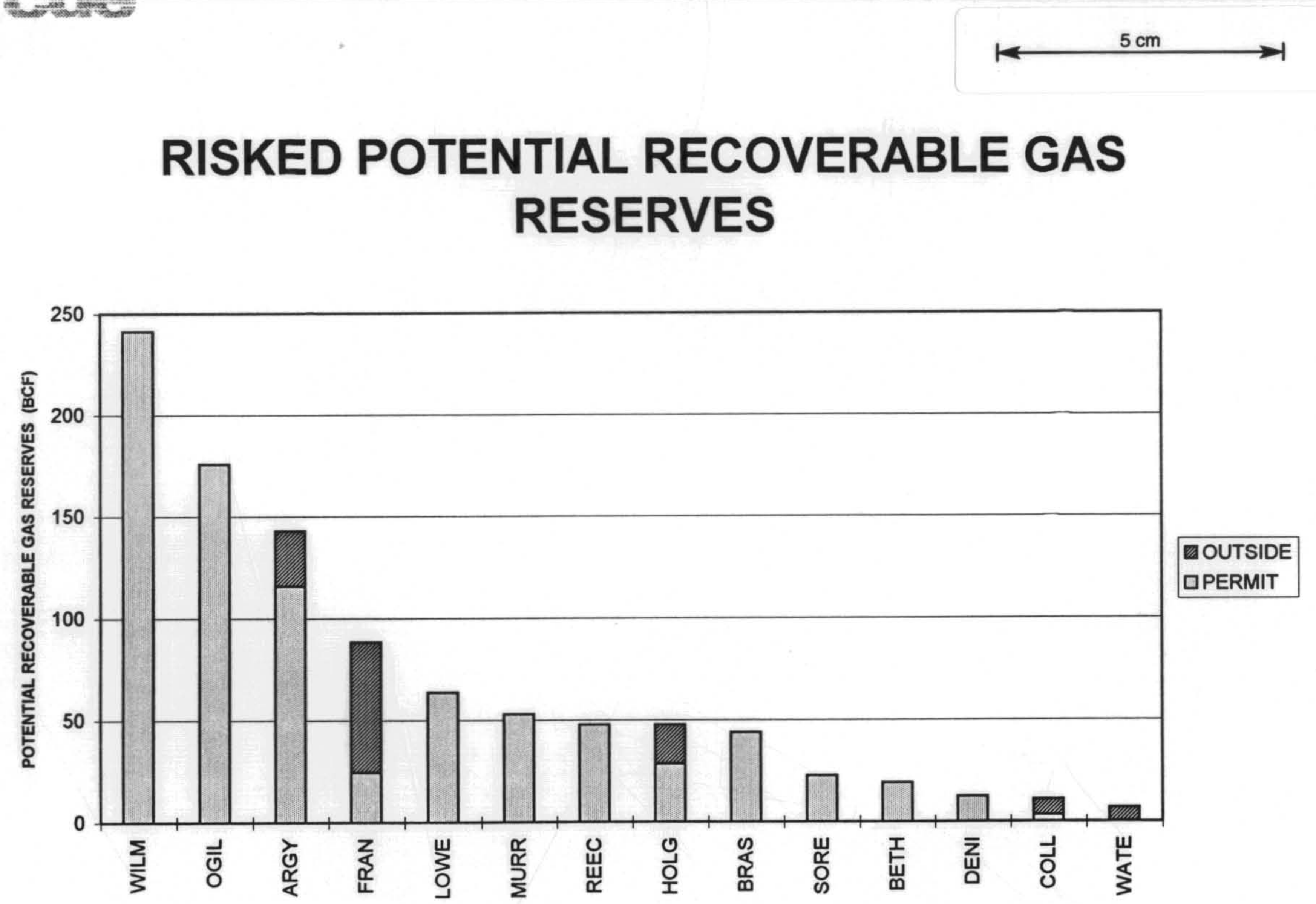

FIGURE 35

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less as they rely on lateral fault seal for their integrity. As all Otway Group prospects rely on fault seal they have been assigned an unlikely probability rating for seal. Lateral fault seal is effective where the net/gross sand ratios are low (eg at Yolla and Pelican). Net/gross ratios in general decrease within increasing geological age within the basin with Otway Group prospects being sealed by a combination of Durroon and Lower Eastern View Group. As both these formations thicken considerably into the neighbouring troughs there is some uncertainty as to their lithology. However seismic evidence suggests that the section is probably shale prone but containing alluvial fans shed from the neighbouring highs. The Bethune, Lowe, Ogilvy and Reece prospects are assigned the best chance of success. Argyle, the deepest of the prospects has a low probability for oil, as its drainage area draws mainly from the gas kitchen, while Holgate rates poorly due to lack of access to mature source rocks. Flat seismic events have been noted at the Reece prospect within the upper portion of the Otway Group where the best reservoir porosities are predicted and is regarded by the authors as the best Otway prospect. Further interpretation either by displaying and manipulation the seismic data on a work-station or reprocessing the data is required to further enhance the prospectivity.

In estimating potential recoverable reserves, the porosity of Otway Group was taken to be 17% (the bottom line cut-off porosity as described in the section Reservoir, Otway Group) the net/gross 30% which is less than that determined from log analysis of the Durroon-1 well (section Reservoir, Otway Group) and recovery factors are relatively low at 25% for oil and 60% for gas reflecting the uncertainty in the sand permeability since the better quality sands, based on log interpretation , were not cored.

Durroon Formation Prospects

These prospects, targeting alluvial fan sands encased within Durroon Formation shales have not been tested within the basin although hydrocarbons have been found in a similar setting and age section along the northern margin of the neighbouring Gippsland Basin. The distal fan facies has been interpreted to have been intersected at Durroon-1 (see section Reservoir, Durroon Formation and Appendix 1) where one thin pebbly sand corresponded to a gas show on the mud log (C_1-C_4) and a SWC sample taken some 26m above the sand had C_1=7000ppm (Figure 18). The proximal fans have been interpreted using seismic stratigraphic techniques and are described in the section Stratigraphy, Durroon Formation. Both the Murray and Brassil prospects lie within the Anderson Sub-basin where the Durroon-1 well provides stratigraphic control, however the play type is more widespread and alluvial fans have been interpreted to have formed within the Bark and Boobyalla Sub-basins, and are probably associated with erosion during the Intra Durroon Formation Unconformity. For example, these fans may be a speculative secondary target over the Holgate and Wilmot Prospects. It is difficult to ascribe reservoir properties to the proximal fans but good reservoir sands could be present. Crude log analysis at Durroon-1 using very poor wireline logs suggest an average porosity of 18% but such a value is speculative. Due to the stacked nature of the fans and the rapid variation over small distances (Figure 11) it was beyond the scope of this project to map this section in detail. Further close spacing, high resolution seismic control would also be required to further mature these prospects. Indicative reserves have however been estimated as a guide only (Figures 32 & 33). Many seismic lines have flat events, that could be associated with hydrocarbons, lying within the interpreted fans. Despite the uncertainties both the Murray and Brassil prospects have been risked favourably with oil (13.6% probability or one chance in 7.3 wells) more likely than gas (11.1% probability or one chance in 9 wells) (Table 4).

Eastern View Group Prospects

These prospects target the excellent Upper Eastern View Group sands sealed beneath the Demons Bluff Formation or in the case of Franklin sealed by a volcanic extrusive and claystones of the Torquay Group. With the exception of Franklin, the potential recoverable reserves are less than for the Durroon and Otway prospects (Figures 32 &33) however, they are thought to have lower risk (Table 4) and thus are attractive targets. The low risk factors are in keeping with the basin as there are few valid tests due to the lack of structuring at this level throughout the basin. Yolla 1 has significant hydrocarbon volumes at this level. Lateral fault seal, whereby the fault throws are greater than the Demons Bluff seal thickness (eg at Chat-1) or where seal quality may be downgraded (eg at Sorell and Collins where the probability for seal is assessed to be possible, see Figure 16 and Table 4) are the greatest risks for these prospects. The average reservoir porosity of 22% that was used for calculating prospect volumes is realistic for the target depths of these prospects (Figure 19a) as is the net/gross of 75% (Figure 14). Significant amplitude anomalies were noted at the top Eastern View Group at the Denison prospect and these require further investigation in order to deduce their origin. Collins and Waterhouse have the majority of their reserves outside the permit, however to the poor seismic coverage over these prospects further extensions into the permit may be possible. The Franklin prospect extends into vacant acreage.

Future seismic requirements

Table 5 shows the proposed trial reprocessing program, which addresses a selection of documented leads with four lines (Figure 36). Seismic line HB80-414 over the Lowe prospect was selected to ascertain if the Top Otway Group reflector could be enhanced as the section scaling was very poor on the original processing. The two seismic lines over the Denison prospect (WB81-21 and WB81-22) both have large amplitude anomalies at the Top Eastern View Group. Processing would

Prospect	Seismic Line	SP Range	SP Interval (m.)	Kms.
Lowe	HB80-414	1-746	25	18.63
Denison	WB81-21	100-1686	25	39.65
	WB81-22	100-1200 (part line)	25	27.50
Franklin	WB82-50	1-920	25	22.98

TOTAL KMS	**108.75**
ESTIMATED COST/KM	**$110.**
ESTIMATED TOTAL COST	**$11,963.**

Table 5: Proposed trial seismic reprocessing program

PROPOSED SEISMIC REPROCESSING PROGRAM

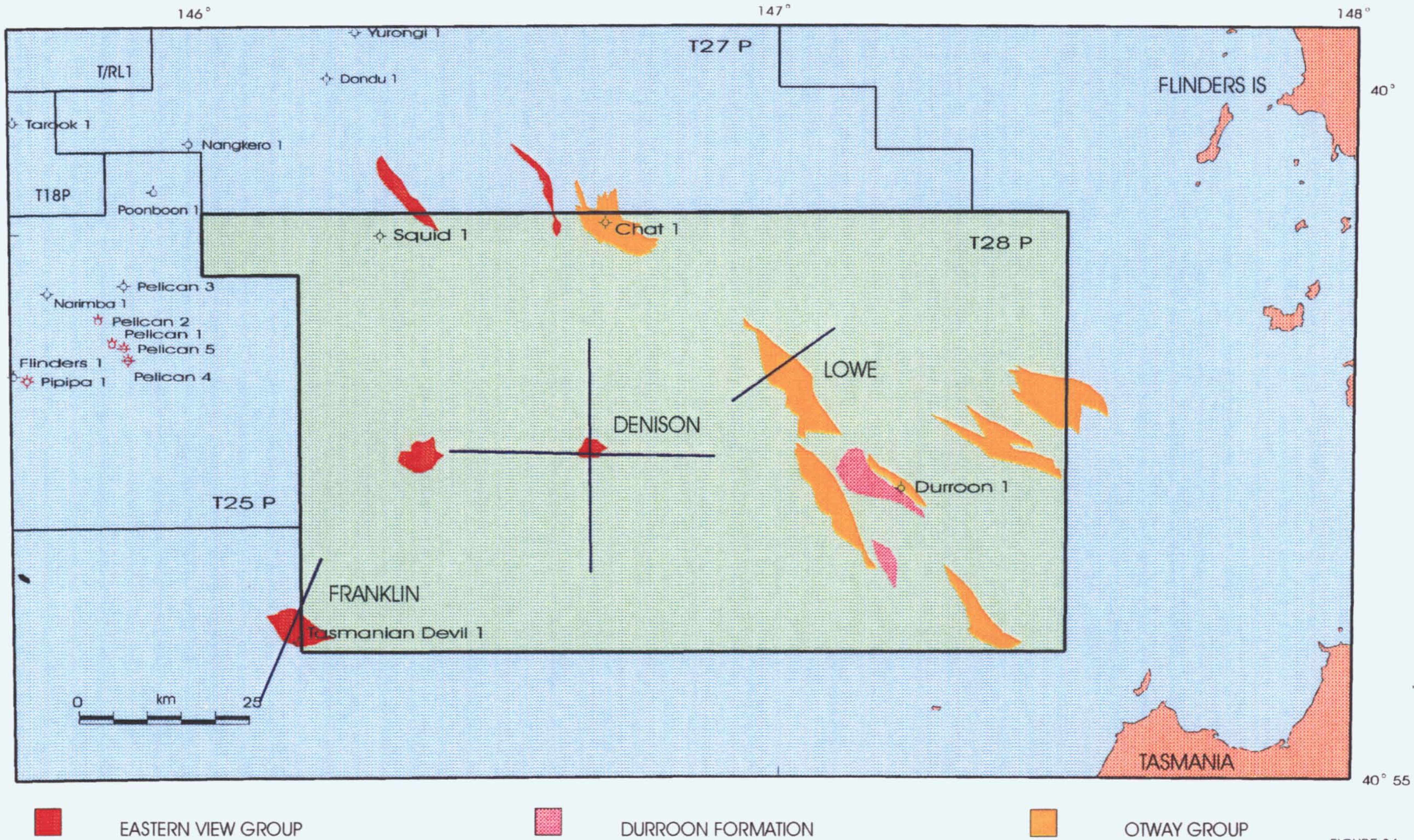

FIGURE 36

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5 cm

be directed at enhancing these anomalies. AVO studies should also be incorporated to see if the anomalies could be associated with hydrocarbons. The WB82 seismic lines over the Franklin prospect were not migrated as part of the original processing. Seismic line WB82-50 has been selected to ascertain if further reprocessing can further help to define the pinchout edge as well as define the overlying volcanic distribution. It is further recomended that the seismic grid over the Reece (20 lines, approximately 300kms), Franklin (10 lines, approximately 200kms) and Denison prospects (11 lines, approximately 200kms) be reprocessed. It may be stategic not to reprocess the Franklin grid until after the vacant acreage immediately to the west of T/28P has been gazetted and awarded.

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APPENDIX 1

PETROPHYSICS ANALYSIS OF DURROON-1

Appendix 1: Petrophysical analysis of Durroon-1

Summary

Detailed petrophysical analysis was undertaken on the Durroon-1 well from digitized logs obtained via Wiltshire Geological Services. Porosity, shale content and water saturations were calculated using the relationships of Schlumberger (1989), within an EXCEL spreadsheet. In particular the Durroon Formation was targeted to see if a significant gas kick recorded on the mudlog could be quantified by determining water saturations within that zone. Further work was also conducted across the Otway Group to identify intervals with favourable porosities and permeabilities.

Introduction

Durroon-1 was selected for basic log analysis after an anomalous gas show in the Durroon Formation was noted from the mud logs. After digitising the rate of penetration (R.O.P.) curve and comparing this with a gamma ray/SP cross plot, it was noted that the R.O.P. appeared to be variably displaced by up to 20 metres (Figure 18). A calibration of the R.O.P. log was undertaken just above the top of the Durroon Fm. and a considerable depth below the volcanics within the Otway Group. It is inferred that the depth readings between these two points (an interval of approximately 300m) are innaccurate due to the drill rate changing while going through the Durroon Fm. shales and volcanics below.

It was noted that although the gamma ray response of the Durroon shale was atypical (i.e. high carbonaceous content within the shale was resulting in low radioactivity), this could be used with the S.P. response to infer the presence of thin sands within the shale unit. Further support was provided by the mudlog and S.W.C. descriptions. For example, the upper Durroon shale is described in the mudlog as light grey-brown claystone, soft, sticky and non calcareous, while the lower section of the shale is described as "dark grey to black, claystone to mudstone, becoming firmer and grading to shale (non calcareous), sticky, and with traces of white, rounded quartz pebbles". The presence of pebbles in the lower unit gives support to the notion that the S.P. and gamma ray deflections within the shale are due to thin pebbly sands in an otherwise entirely shale interval.

The gas shows on the mud log (C_1-C_4 and C_1=7000ppm) reported from a side wall core at 1510.3m.K.B. are from a slightly micaceous shale. As the location of the SWC was based on the ROP / gas show logs whose depths as shown above are likely to be in error, these shows may in fact correspond to interpreted thin pebbly sands (1526-1527m.K.B.) which represent the distal portion of alluvial fans within the Anderson Sub-basin.

The only other notable shows correspond to interpreted insitu generation from Otway Group coals which are just marginally mature for the generation of hydrocarbons.

Log analysis methods

The Durroon-1 logs analysed were:

CALI	Caliper
DT	Sonic
GR	Gamma Ray
IND	IL-Deep Resistivity
NPHI	Neutron Porosity
RHOB	Bulk Density
SFL	Spherical Focusing Log
SP	Spontaneous Potential

The dual water method of analysing shaley formations was used to analyse the Durroon Formation. The basic Archie water saturation equation was used.

$$Sw = \text{Sqrt}\left[\frac{F_R * Rw}{Rt}\right] * 100$$

Rw = resistivity of the formation water at formation tempurature

Rt = IND

$F_R = a * \phi^{-m}$

a = 0.81

m = 2

$$Rw = \frac{Rt * (Ft + 7)}{(75 + 7)}$$

Note: This is for a standard reservoir at 75°F

Ft = Formation temperature

Eastern View Group Rw = 0.132

Otway Group Rw = 0.496

		Durroon Formation	Otway Group
ρsh =	Shale point (density)	2.29	2.29
ρm =	Matrix point (density)	2.65	2.65
ρf =	Fluid point (density)	1.00	1.00
ρdc =	Dry clay point (density)	3.06	3.06
Φsh =	Shale point (neutron porosity)	75	65
Φm =	Matrix point (neutron porosity)	-2	-2
Φf =	Fluid point (neutron porosity)	100	100
Φdc =	Dry clay point (neutron porosity)	60	60

			Durroon Formation	Otway Group
A =	$\rho sh - \rho m$	=	-0.36	-0.36
B =	$\Phi sh - \Phi m$	=	77	67
C =	$(\rho f - \rho m)$	=	-1.65	-1.65
D =	$(\Phi m - \Phi f)$	=	-102	-102
E =	$(\Phi dc - \Phi m)$	=	62	62
F =	$(\rho dc - \rho m)$	=	0.41	0.41

$$\text{Eff}\phi = \frac{B * (RHOB - \rho m) - A * (NPHI - \Phi m)}{(A * D) + (B * C) * 100}$$

$$Vsh = \frac{RHOB - C * (\text{Eff}\phi dc / 100) - \rho m}{A * 100}$$

$$\text{Eff}\phi dc = \frac{E * (RHOB - \rho m) - F * (NPHI - \Phi m)}{(F * D) + (E * C) * 100}$$

$$Vshdc = \frac{RHOB - C * (\text{Eff}\phi dc / 100) - \rho m}{F * 100}$$

Sw corr. = Shale corrected SW

Sw corr. = $Sw - (Vsh * Rw / (0.4 * \text{Eff}\phi * 2)$

For the Otway Group, a method of determining possible reservoir zones was undertaken selecting sands with greater than 17% porosity, and less than 20% Vsh. This was done to identify the distribution of relatively clean sands with good porosities.

APPENDIX 2

PROSPECTS AND LEADS INVENTORY

515087

ARGYLE PROSPECT

BLACKBURN / BAIRD

PROSPECT:	**ARGYLE**
PERMIT:	T28P
BASIN:	Bass Basin, Tasmania
OPERATOR:	Cue Energy Resources NL
WATER DEPTH:	78m
TRAP TYPE:	Rotated horst block
PRIMARY OBJECTIVE:	Early Cretaceous sandstones of the Otway Group
SEAL:	Late Cretaceous shales of the Durroon Formation & lower section of Lower Eastern View Group
SOURCE:	Early Cretaceous shales and coals of the Otway Group, Durroon Fm & Eastern View Group.

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	TOTAL AREA (sq kms)	PERMIT AREA (sq kms)	TOTAL VOLUME (m3)	PERMIT VOLUME (m3)
2133	2862	0.000	0.000		
2200	2988	0.695	0.665	43,785,000	41,895,000
2300	3174	5.641	4.847	633,033,000	554,511,000
2400	3360	23.984	21.177	3,388,158,000	2,974,743,000
2500	3550	55.901	41.001	10,977,233,000	8,881,653,000

RESERVOIR PRESSURE (psi):	4065.8 psi	
RESERVOIR TEMPERATURE (C):	103.7 C	218.7 F
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	**GAS**
POROSITY:	0.17	0.17
NET/GROSS:	0.30	0.30
HYDROCARBON SATURATION:	0.75	0.75

BLACKBURN / BAIRD

FORMATION VOLUME FACTOR:	1.20	0.004623
RECOVERY FACTOR:	0.25	0.60

IN PLACE	**2,200 mmbbls**	**3,208 BCF**
RECOVERABLE	**550 mmbbls**	**1,925 BCF**
IN PLACE WITHIN PERMIT	**1,780 mmbbls**	**2,595 BCF**
RECOVERABLE WITHIN PERMIT	**445 mmbbls**	**1,557 BCF**

GAS COMPOSITION	MOLE FRACTION (%)	CRITICAL CONSTANTS Tc (F)	Pc (psi)
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE -116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE 667.8 psi

PSUEDO REDUCED TEMPERATURE 1.977754584
PSUEDO REDUCED PRESSURE 6.088301462

FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR 0.98

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS UNLIKELY

GAS SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS PROBABLE

PROBABILITY RISK FACTOR OIL 0.30

PROBABILITY RISK FACTOR FOR GAS 0.45

BLACKBURN / BAIRD

515090

2) RESERVOIR IN THE VICINITY OF THE TRAP IS PROBABLE AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR 0.55

3) STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS UNLIKELY

PROBABILTY RISK FACTOR 0.30

CHANCE OF SUCCESS (OIL)	**5.0% (1 IN 20.0)**
CHANCE OF SUCCESS (GAS)	**7.4% (1 IN 13.5)**
RISKED OIL RESERVES (TOTAL) mmbbls	**27.2**
RISKED OIL RESERVES (PERMIT) mmbbls	**22.0**
RISKED GAS RESERVES (TOTAL) BCF	**142.9**
RISKED GAS RESERVES (PERMIT) BCF	**115.6**

BLACKBURN / BAIRD

5 cm

515091

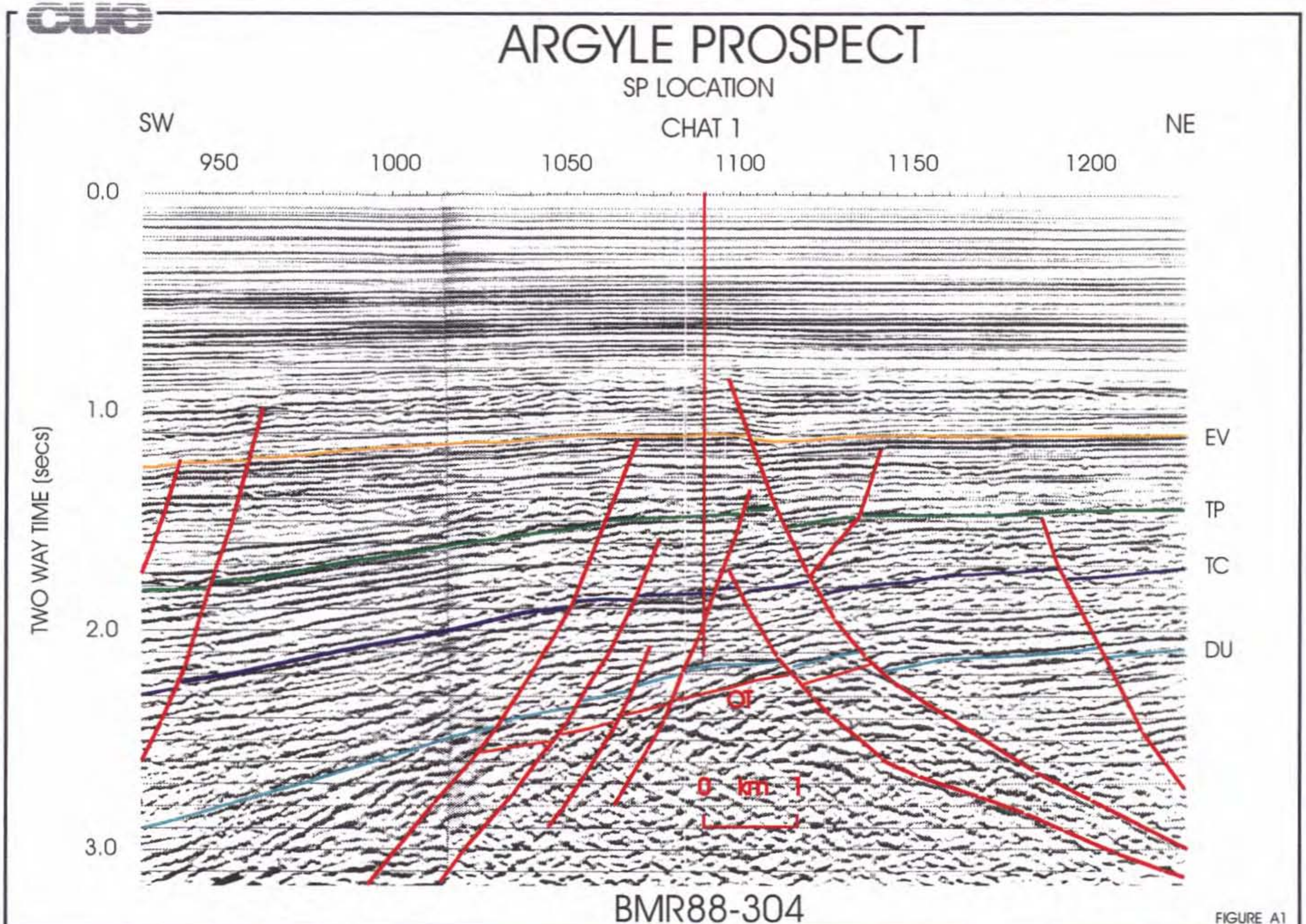
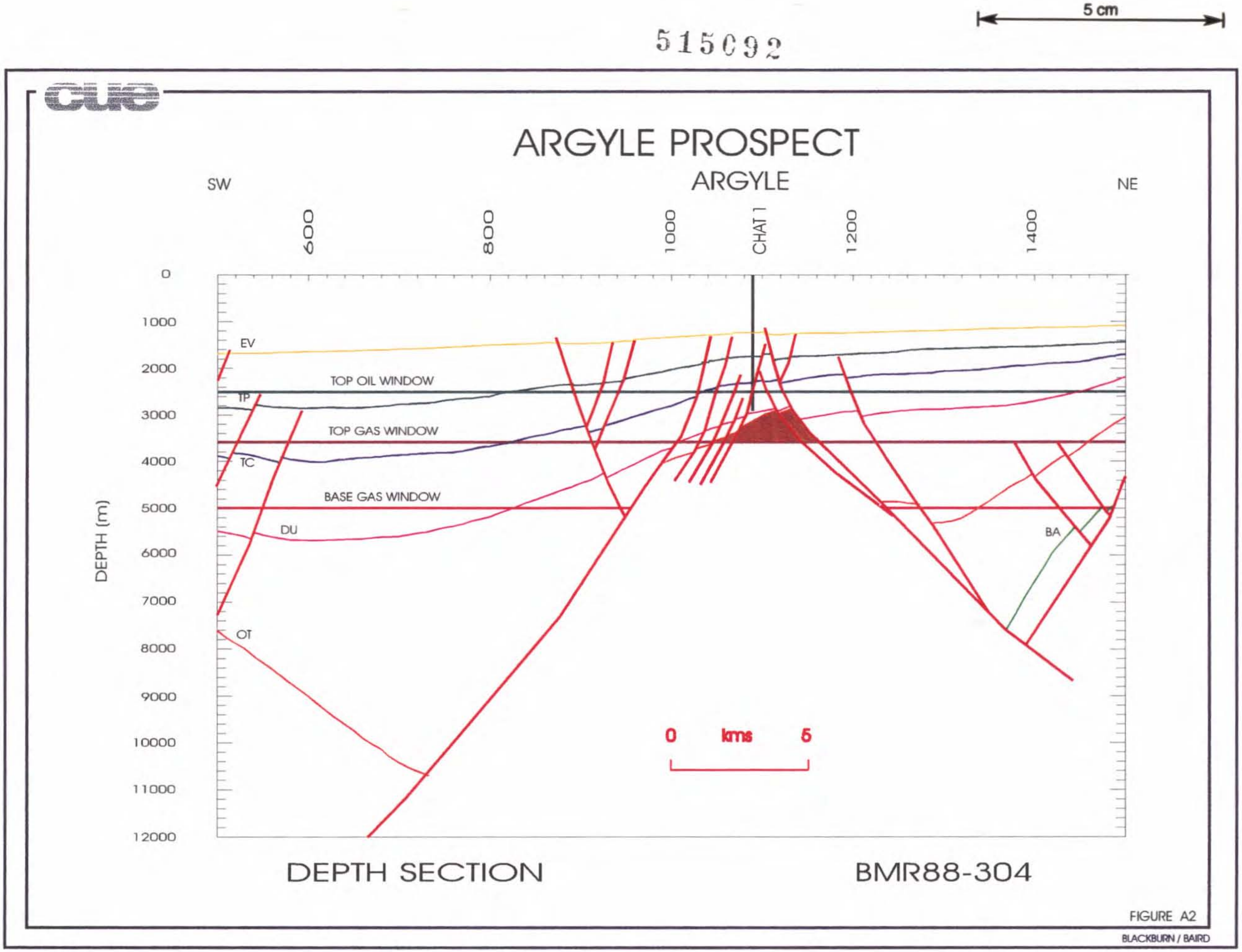


FIGURE A1

BLACKBURN / BAIRD

515092


5 cm
cue
ARGYLE PROSPECT
SW
ARGYLE
NE
600
800
1000
CHAT 1
1200
1400
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
11000
12000
DEPTH (m)
EV
TOP OIL WINDOW
TP
TOP GAS WINDOW
TC
BASE GAS WINDOW
DU
OT
BA
0 kms 5
DEPTH SECTION
BMR88-304
FIGURE A2
BLACKBURN / BAIRD

515093

ARGYLE PROSPECT

TIME STRUCTURE MAP

OTWAY GROUP

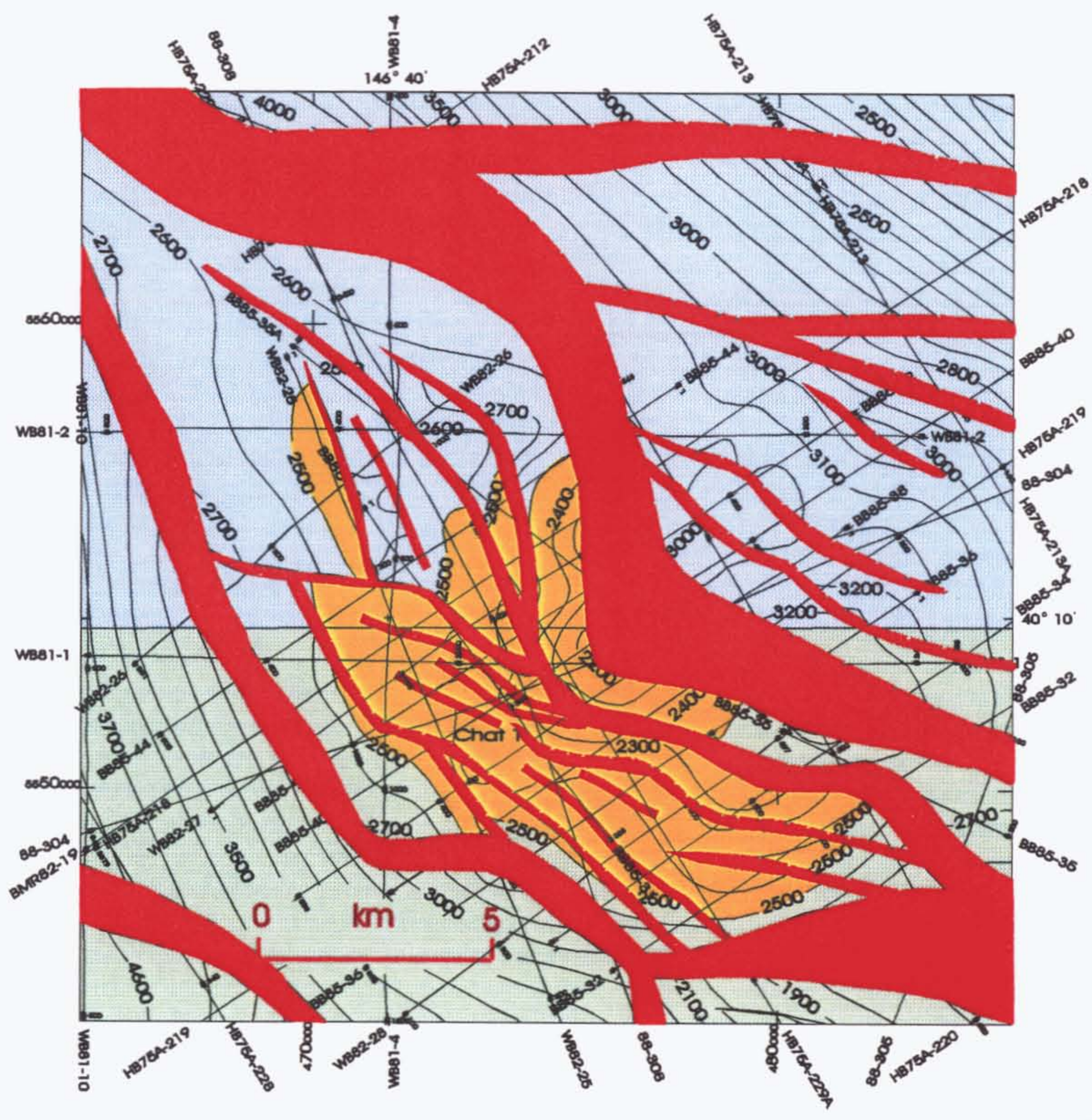


FIGURE A3

BLACKBURN / BAIRD

BETHUNE PROSPECT

BLACKBURN / BAIRD

PROSPECT: BETHUNE

PERMIT: T28P

BASIN: Bass Basin, Tasmania

OPERATOR: Cue Energy Resources NL

WATER DEPTH: 66m

TRAP TYPE: Rotated horst block

PRIMARY OBJECTIVE: Early Cretaceous sandstones of the Otway Group

SEAL: Late Cretaceous shales of the Durroon Formation & Lower Eastern View Group

SOURCE: Early Cretaceous shales and coals of the Otway Group

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	AREA (sq kms)	VOLUME (m3)
1021	1163	0.000	
1100	1259	2.474	118,537,999
1200	1380	6.104	638,364,799
1300	1501	9.680	1,595,664,399
1350	1567	11.067	2,282,390,099

RESERVOIR PRESSURE (psi): 1651.8 psi

RESERVOIR TEMPERATURE (C): 51.0 C 123.9 F

HYDROCARBON TYPE: Similar to the Yolla Oil gas is methane

	OIL	GAS
POROSITY:	0.17	0.17
NET/GROSS:	0.30	0.30
HYDROCARBON SATURATION:	0.75	0.75
FORMATION VOLUME FACTOR:	1.20	0.008788738
RECOVERY FACTOR:	0.25	0.6

BLACKBURN / BAIRD

IN PLACE	458 mmbbls	351 BCF
RECOVERABLE	114 mmbbls	210 BCF

GAS COMPOSITION	MOLE FRACTION (%)	CRITICAL CONSTANTS Tc (F)	Pc (psi)
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.701
PSUEDO REDUCED PRESSURE	2.474
FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR	**0.88**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

GAS SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

PROBABILITY RISK FACTOR OIL 0.55

PROBABILITY RISK FACTOR FOR GAS 0.55

2) RESERVOIR IN THE VICINITY OF THE TRAP IS PROBABLE AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR 0.55

3) STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS UNLIKELY

PROBABILTY RISK FACTOR 0.30

BLACKBURN / BAIRD

Cue

CHANCE OF SUCCESS (OIL)	(1 in 11.0)	9.1%
CHANCE OF SUCCESS (GAS)	(1 in 11.0)	9.1%
RISKED RECOVERABLE OIL RESERVES mmbbls		10.4
RISKED RECOVERABLE GAS RESERVES BCF		19.1

BLACKBURN / BAIRD

5 cm

515098

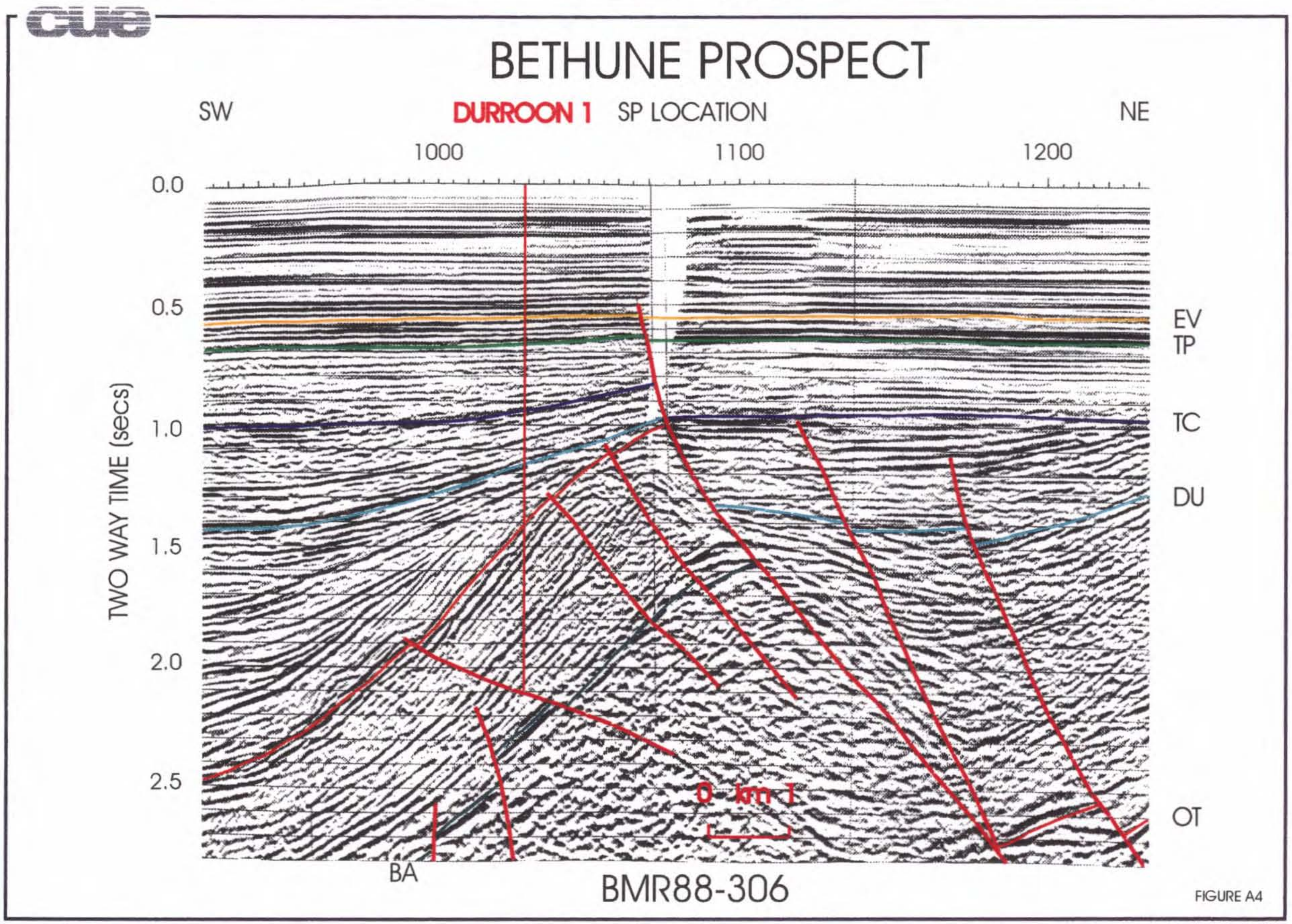
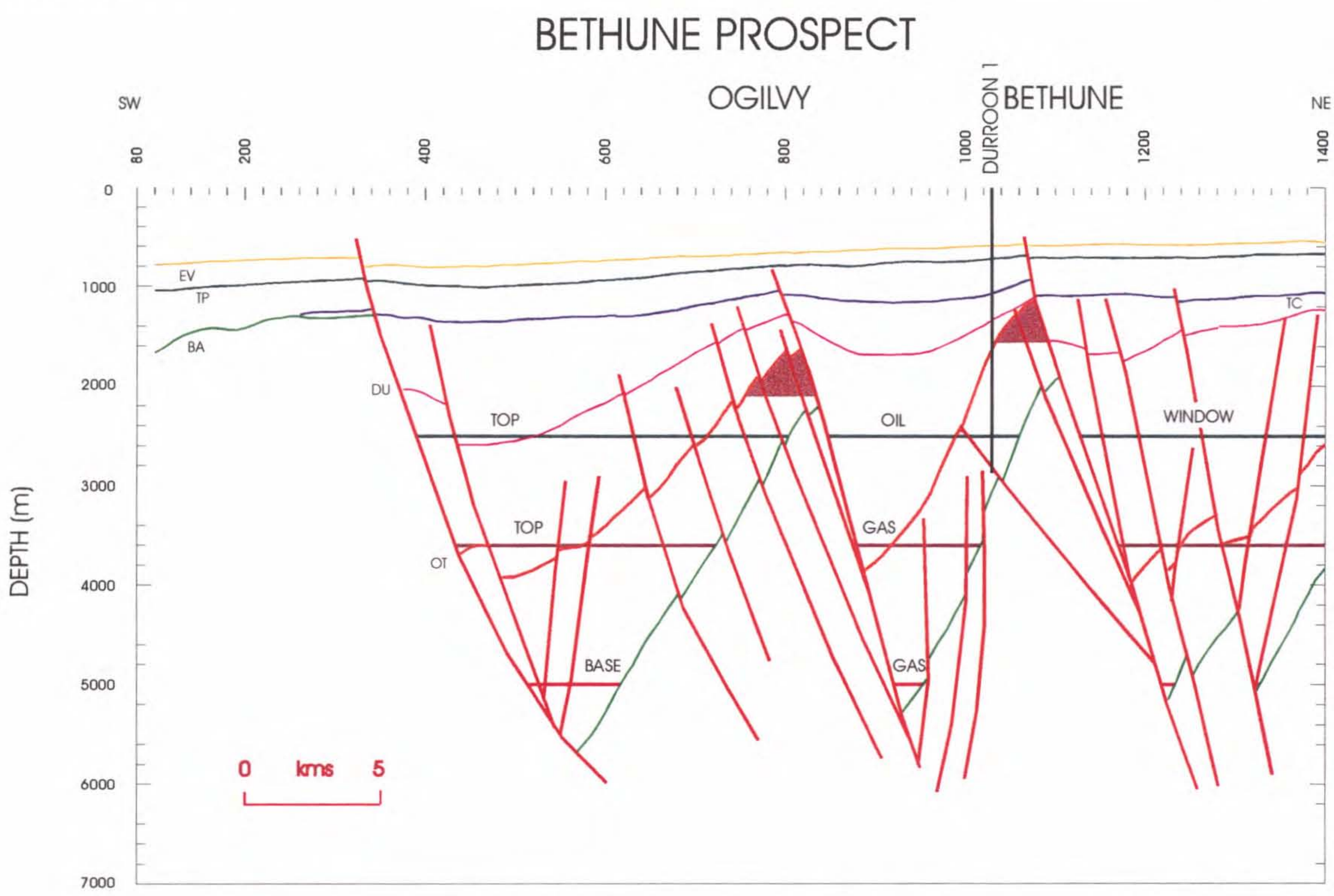


FIGURE A4

BLACKBURN / BAIRD

515090



DEPTH SECTION BMR88-306

FIGURE A5
BLACKBURN / BAIRD

5 cm

515100

BETHUNE PROSPECT

TIME STRUCTURE MAP

TOP OTWAY GROUP

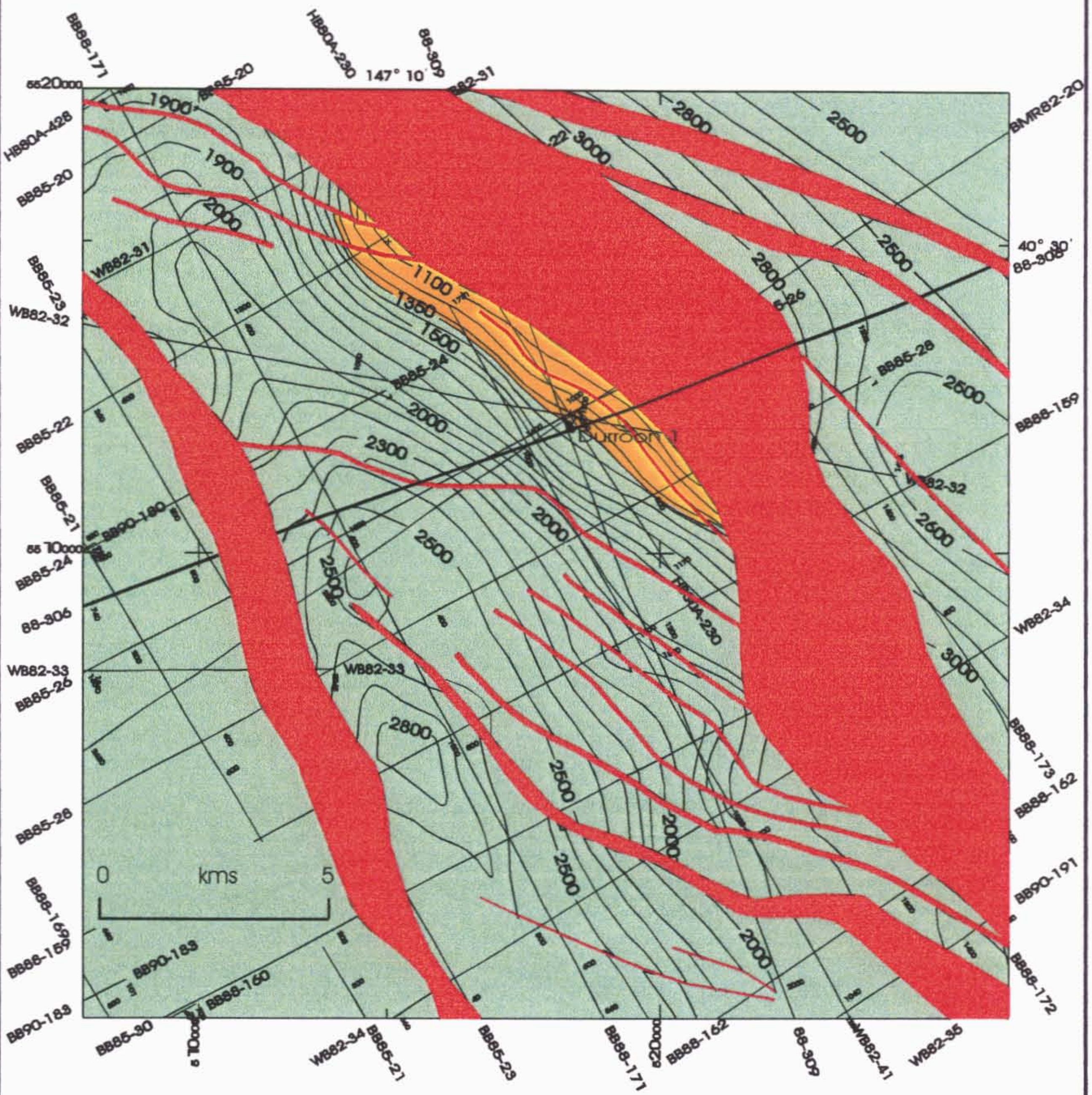


FIGURE A6

BLACKBURN / BAIRD

515101

Cue

HOLGATE PROSPECT

BLACKBURN / BAIRD

PROSPECT: HOLGATE

PERMIT: T28P

BASIN: Bass Basin, Tasmania

OPERATOR: Cue Energy Resources NL

WATER DEPTH: 46m

TRAP TYPE: Rotated horst blocks

PRIMARY OBJECTIVE: Early Cretaceous sandstones of the Otway Group

SEAL: Late Cretaceous shales of the Durroon Formation

SOURCE: Early Cretaceous shales and coals of the Otway Group, Durroon Fm & Eastern View Group.

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	TOTAL AREA (sq kms)	PERMIT AREA (sq kms)	TOTAL VOLUME (m3)	PERMIT VOLUME (m3)
1070	1222	0.000	0.000		
1100	1259	2.915	2.062	53,029,327	37,518,090
1200	1380	21.706	12.522	1,545,007,388	921,308,490
1300	1501	38.152	22.401	5,175,340,503	3,039,388,440
1400	1634	64.332	38.975	11,959,748,203	7,102,479,640

RESERVOIR PRESSURE (psi): 1736.3 psi

RESERVOIR TEMPERATURE (C): 52.9 C   127.2 F

HYDROCARBON TYPE: Similar to the Yolla Oil   gas is methane

	OIL	GAS
POROSITY:	0.17	0.17
NET/GROSS:	0.30	0.30
HYDROCARBON SATURATION:	0.75	0.75
FORMATION VOLUME FACTOR:	1.20	0.008361077

BLACKBURN / BAIRD

RECOVERY FACTOR:	0.25	0.6

IN PLACE	**2,397 mmbbls**	**1,932 BCF**
RECOVERABLE	**599 mmbbls**	**1,159 BCF**
IN PLACE WITHIN PERMIT	**1,424 mmbbls**	**1,147 BCF**
RECOVERABLE WITHIN PERMIT	**356 mmbbls**	**688 BCF**

GAS COMPOSITION	MOLE FRACTION (%)	CRITICAL CONSTANTS Tc (F)	Pc (psi)
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.711
PSUEDO REDUCED PRESSURE	2.600

FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR **0.875**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS POSSIBLE

GAS SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS POSSIBLE

PROBABILITY RISK FACTOR OIL 0.37

PROBABILITY RISK FACTOR FOR GAS 0.37

2) RESERVOIR IN THE VICINITY OF THE TRAP IS PROBABLE AND COMMUNICATION IS POSSIBLE

PROBABILITY RISK FACTOR 0.37

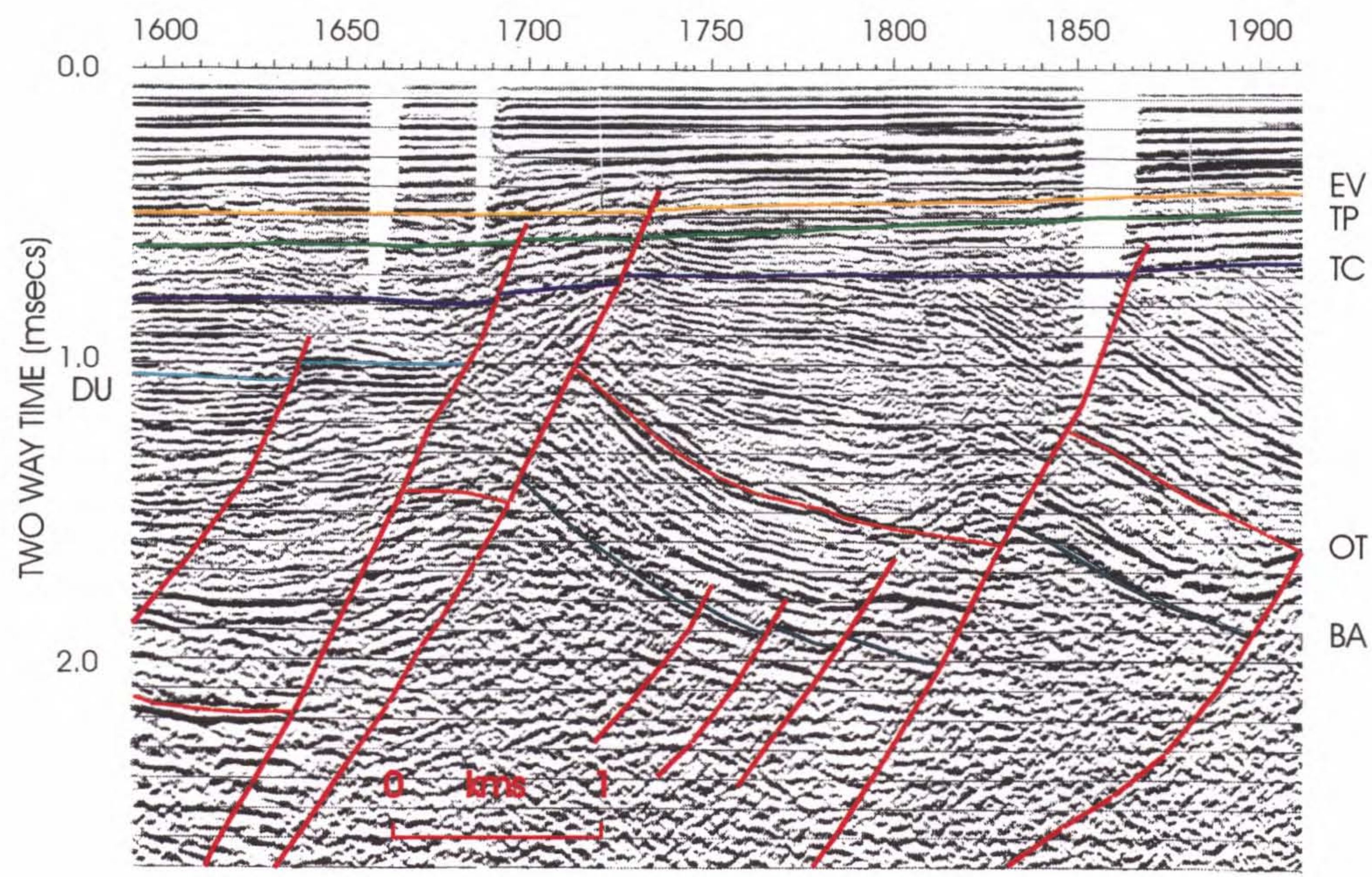
BLACKBURN / BAIRD

3) STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS UNLIKELY

PROBABILTY RISK FACTOR		0.30
CHANCE OF SUCCESS (OIL)	**(1 in 24.3)**	**4.1%**
CHANCE OF SUCCESS (GAS)	**(1 in 24.3)**	**4.1%**
RISKED OIL RESERVES (TOTAL) mmbbls		**24.6**
RISKED OIL RESERVES (PERMIT) mmbbls		**14.6**
RISKED GAS RESERVES (TOTAL) BCF		**47.6**
RISKED GAS RESERVES (PERMIT) BCF		**28.3**

515105

HOLGATE PROSPECT



BMR88-306

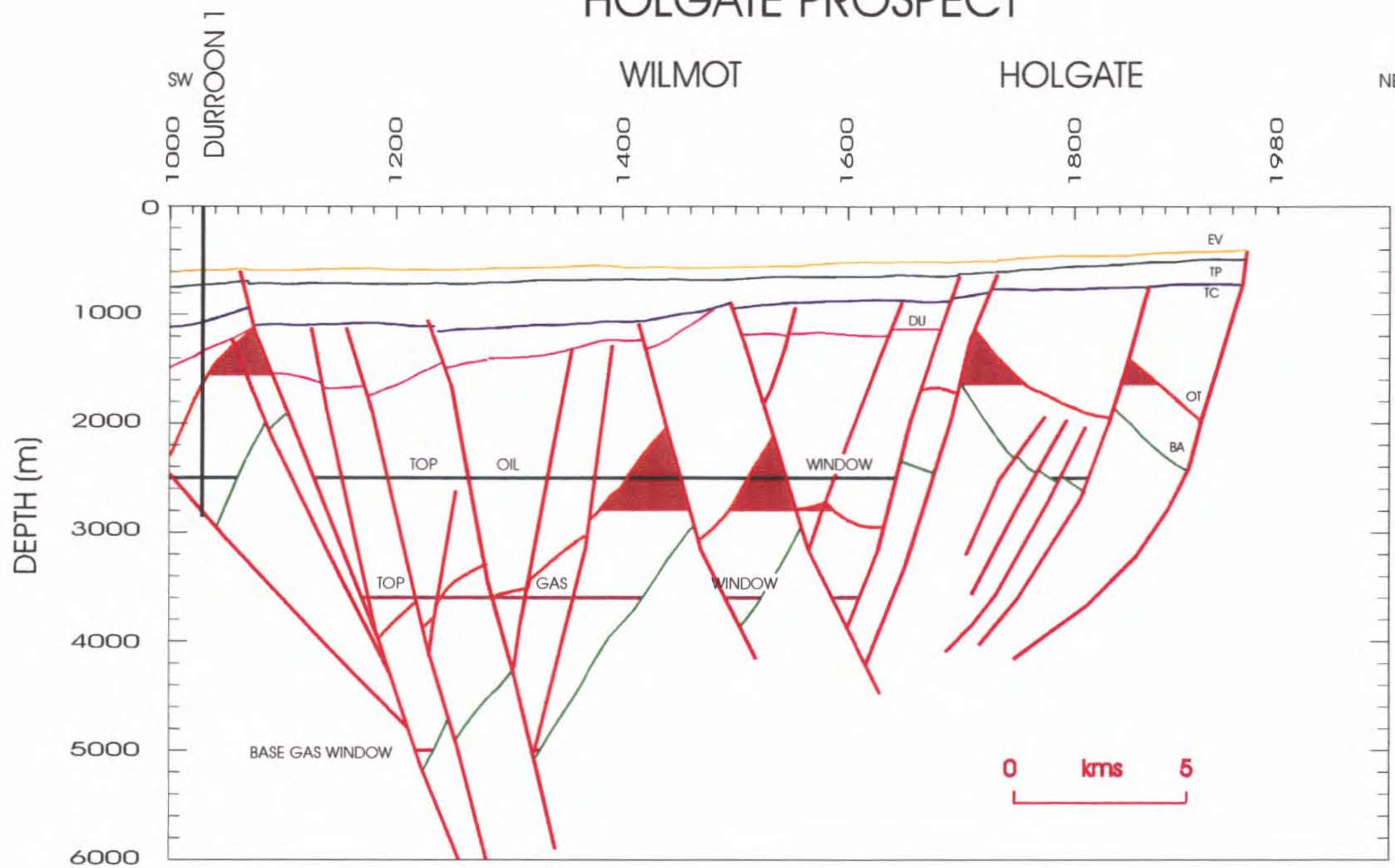
FIGURE A7

BLACKBURN / BAIRD

5 cm

51510C

HOLGATE PROSPECT



DEPTH SECTION BMR88-306

FIGURE A8

BLACKBURN / BAIRD

5 cm

515107

HOLGATE PROSPECT

TIME STRUCTURE MAP

OTWAY GROUP

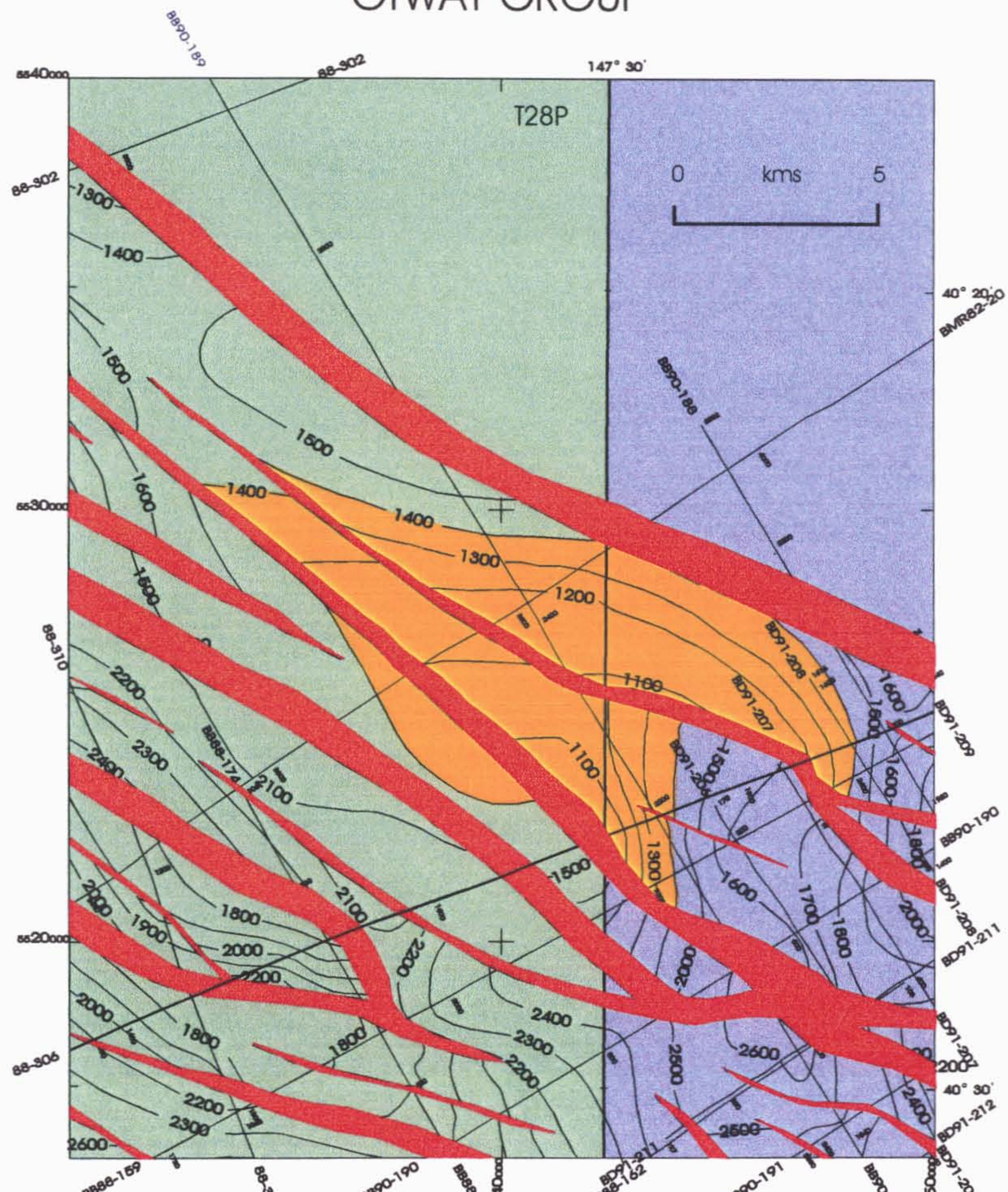


FIGURE A9

BLACKBURN / BAIRD

LOWE PROSPECT

PROSPECT:	LOWE
PERMIT:	T28P
BASIN:	Bass Basin, Tasmania
OPERATOR:	Cue Energy Resources NL
WATER DEPTH:	75m
TRAP TYPE:	Rotated horst block
PRIMARY OBJECTIVE:	Early Cretaceous sandstones of the Otway Group
SEAL:	Late Cretaceous shales of the Durroon Formation & Lower Eastern View Group
SOURCE:	Early Cretaceous shales and coals of the Otway Group, Durroon Fm & Eastern View Group.
BULK ROCK VOLUME:	Note mapping is on Durroon Formation Otway Group level would have greater volume

TWT (ms)	DEPTH (m)	AREA (sq kms)	VOLUME (m3)
1077	1231	0.000	
1100	1259	0.057	795,121
1150	1380	3.319	205,374,662
1200	1501	12.838	1,185,290,647
1250	1634	21.137	3,434,435,647
1300	1777	31.503	7,221,883,647

RESERVOIR PRESSURE (psi):	1748.3 psi	
RESERVOIR TEMPERATURE (C):	53.2 C	127.7 F
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	**GAS**
POROSITY:	0.17	0.17
NET/GROSS:	0.30	0.30
HYDROCARBON SATURATION:	0.75	0.75

BLACKBURN / BAIRD

FORMATION VOLUME FACTOR:	1.20	0.008357581
RECOVERY FACTOR:	0.25	0.6

IN PLACE	**1,448 mmbbls**	**1167 BCF**
RECOVERABLE	**362 mmbbls**	**700 BCF**

GAS COMPOSITION	**MOLE FRACTION (%)**	**CRITICAL CONSTANTS Tc (F)**	**Pc (psi)**
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.712
PSUEDO REDUCED PRESSURE	2.618
FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR	**0.88**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

GAS SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

PROBABILITY RISK FACTOR OIL 0.55

PROBABILITY RISK FACTOR FOR GAS 0.55

2) RESERVOIR IN THE VICINITY OF THE TRAP IS PROBABLE AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR 0.55

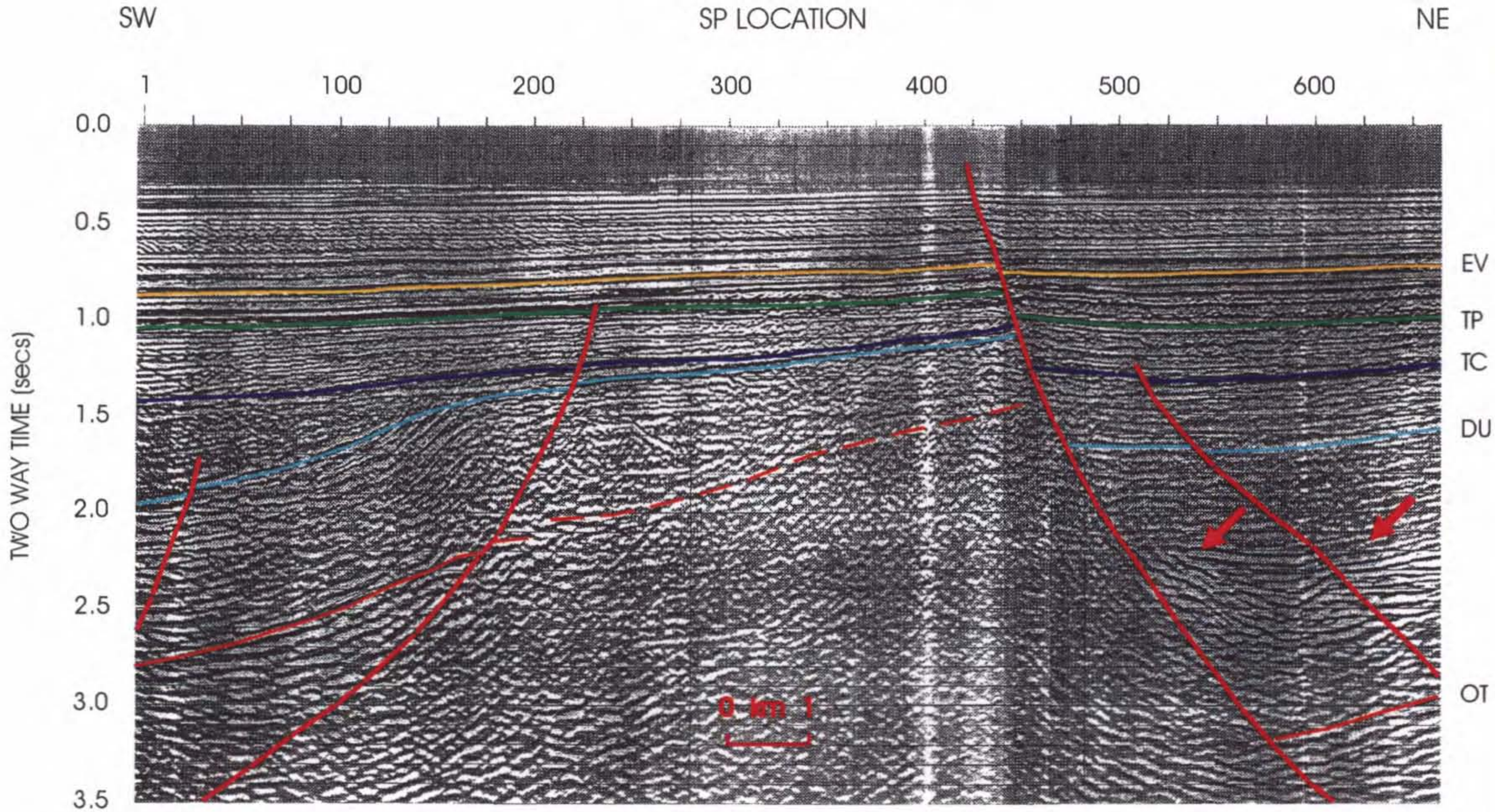
3) STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS UNLIKELY

PROBABILTY RISK FACTOR		0.30
CHANCE OF SUCCESS (OIL)	**(1 in 11.0)**	**9.1%**
CHANCE OF SUCCESS (GAS)	**(1 in 11.0)**	**9.1%**
RISKED RECOVERABLE OIL RESERVES mmbbls		**32.8**
RISKED RECOVERABLE GAS RESERVES BCF		**63.6**

5 cm

515112

LOWE PROSPECT



SEISMIC LINE HB80A-414

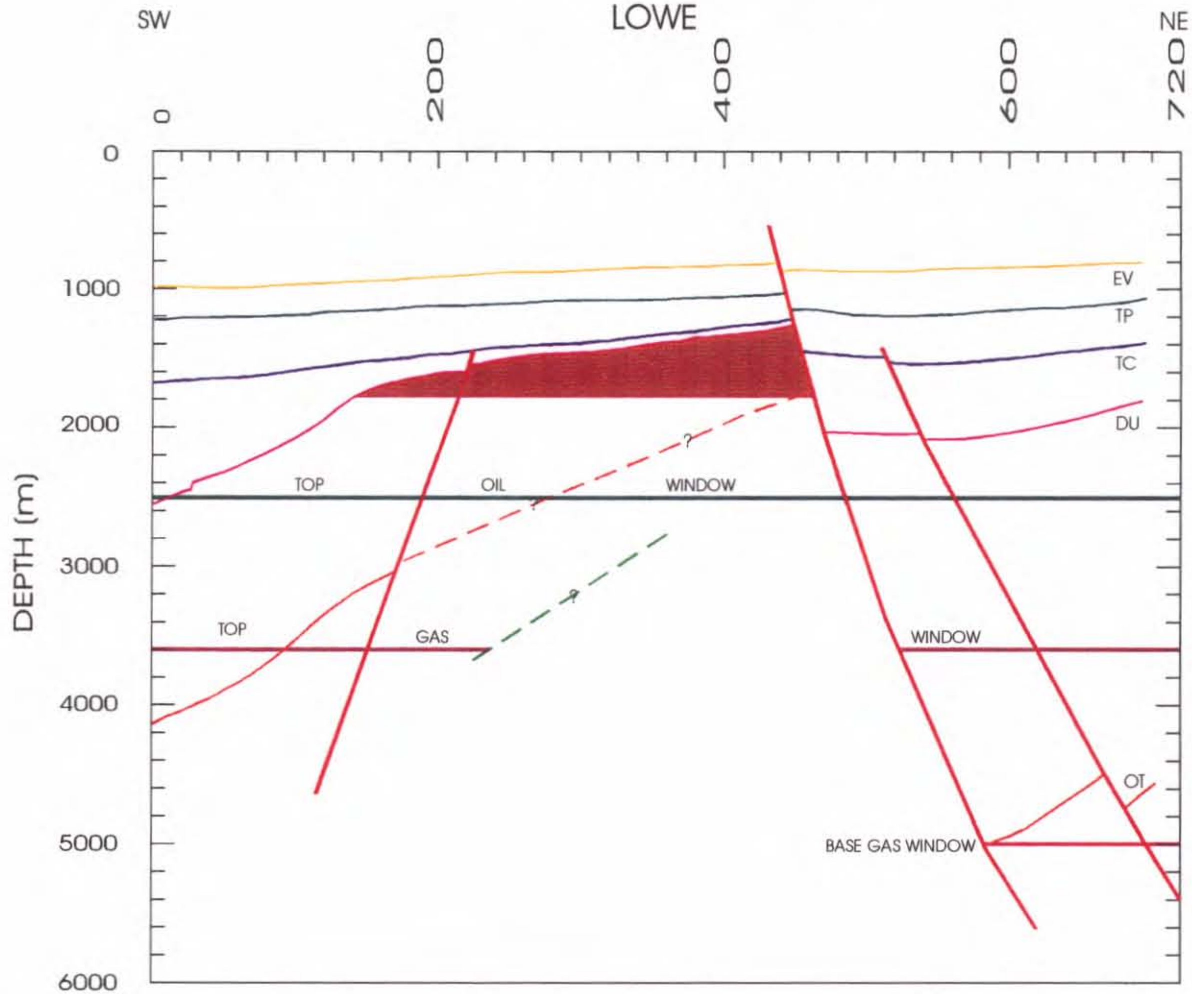
Figure 10A

BLACKBURN / BAIRD

5 cm

515113

LOWE PROSPECT



DEPTH SECTION HB80A-414

FIGURE 11 A

BLACKBURN / BAIRD

5 cm

515114

LOWE PROSPECT

TIME STRUCTURE MAP

DURROON FORMATION

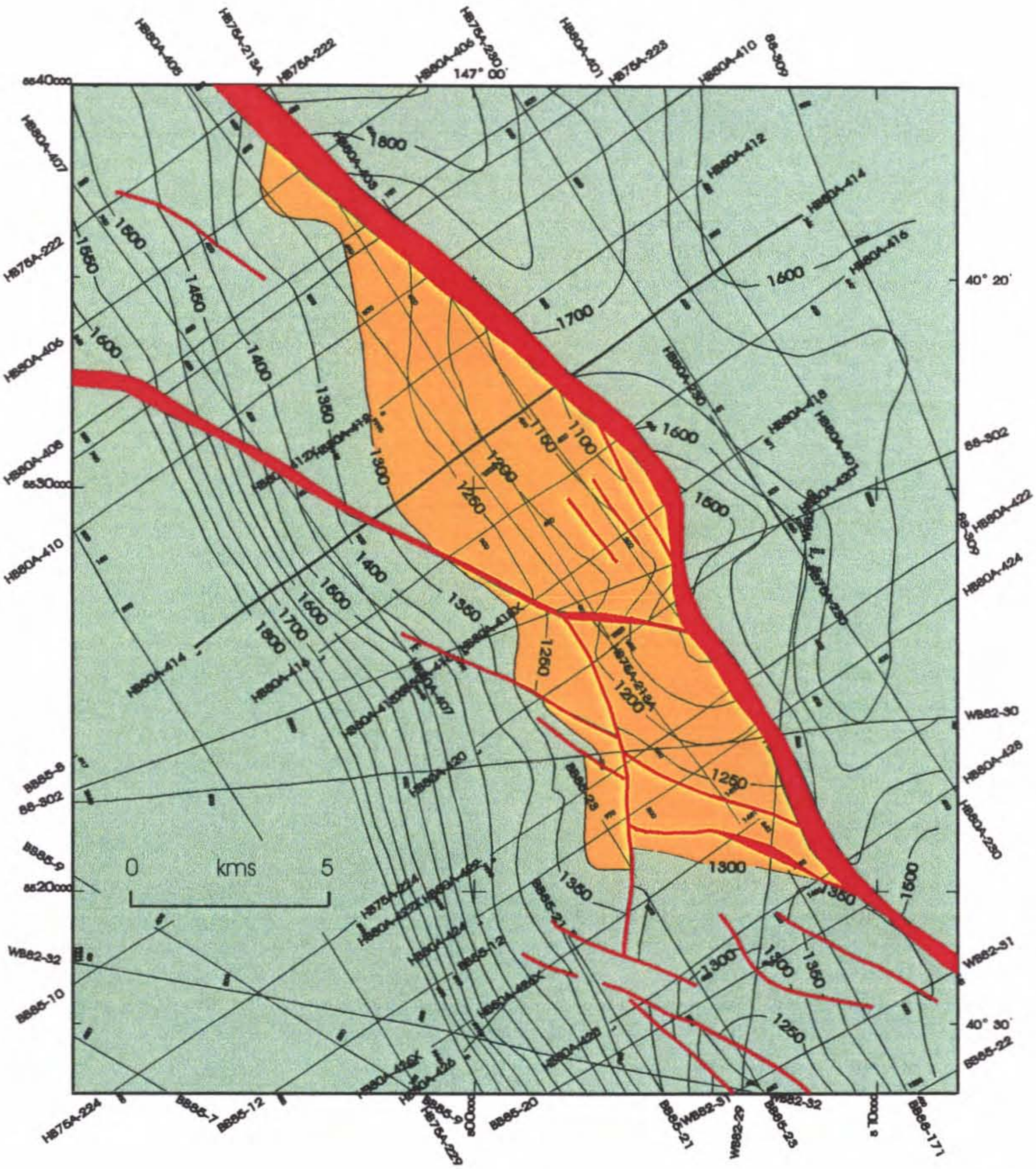


FIGURE A12

BLACKBURN / BAIRD

515115

OGILVY PROSPECT

BLACKBURN / BAIRD

PROSPECT: OGILVY

PERMIT: T28P

BASIN: Bass Basin, Tasmania

OPERATOR: Cue Energy Resources NL

WATER DEPTH: 68m

TRAP TYPE: Rotated horst block

PRIMARY OBJECTIVE: Early Cretaceous sandstones of the Otway Group

SEAL: Late Cretaceous shales of the Durroon Formation

SOURCE: Early Cretaceous shales and coals of the Otway Group & Durroon Fm

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	AREA (sq kms)	VOLUME (m3)
1071	1223	0.000	
1100	1259	0.057	1,002,545
1200	1380	3.319	205,582,085
1300	1501	12.838	1,185,498,070
1400	1634	21.137	3,434,643,070
1500	1777	31.503	7,222,091,070
1600	1935	39.717	12,837,788,070
1700	2096	49.139	19,972,924,870

RESERVOIR PRESSURE (psi):	1738.0 psi	
RESERVOIR TEMPERATURE (C):	52.9 C	127.3
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	**GAS**
POROSITY:	0.17	0.17
NET/GROSS:	0.30	0.30
HYDROCARBON SATURATION:	0.75	0.75

BLACKBURN / BAIRD

FORMATION VOLUME FACTOR:	1.20	0.008354078
RECOVERY FACTOR:	0.25	0.6

IN PLACE	**4,004 mmbbls**	**3229 BCF**
RECOVERABLE	**1,001 mmbbls**	**1938 BCF**

GAS COMPOSITION	MOLE FRACTION (%)	CRITICAL CONSTANTS Tc (F)	Pc (psi)
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.711
PSUEDO REDUCED PRESSURE	2.603
FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOF	**0.875**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

GAS SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

PROBABILITY RISK FACTOR OIL 0.55

PROBABILITY RISK FACTOR FOR GAS 0.55

2) RESERVOIR IN THE VICINITY OF THE TRAP IS PROBABLE AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR 0.55

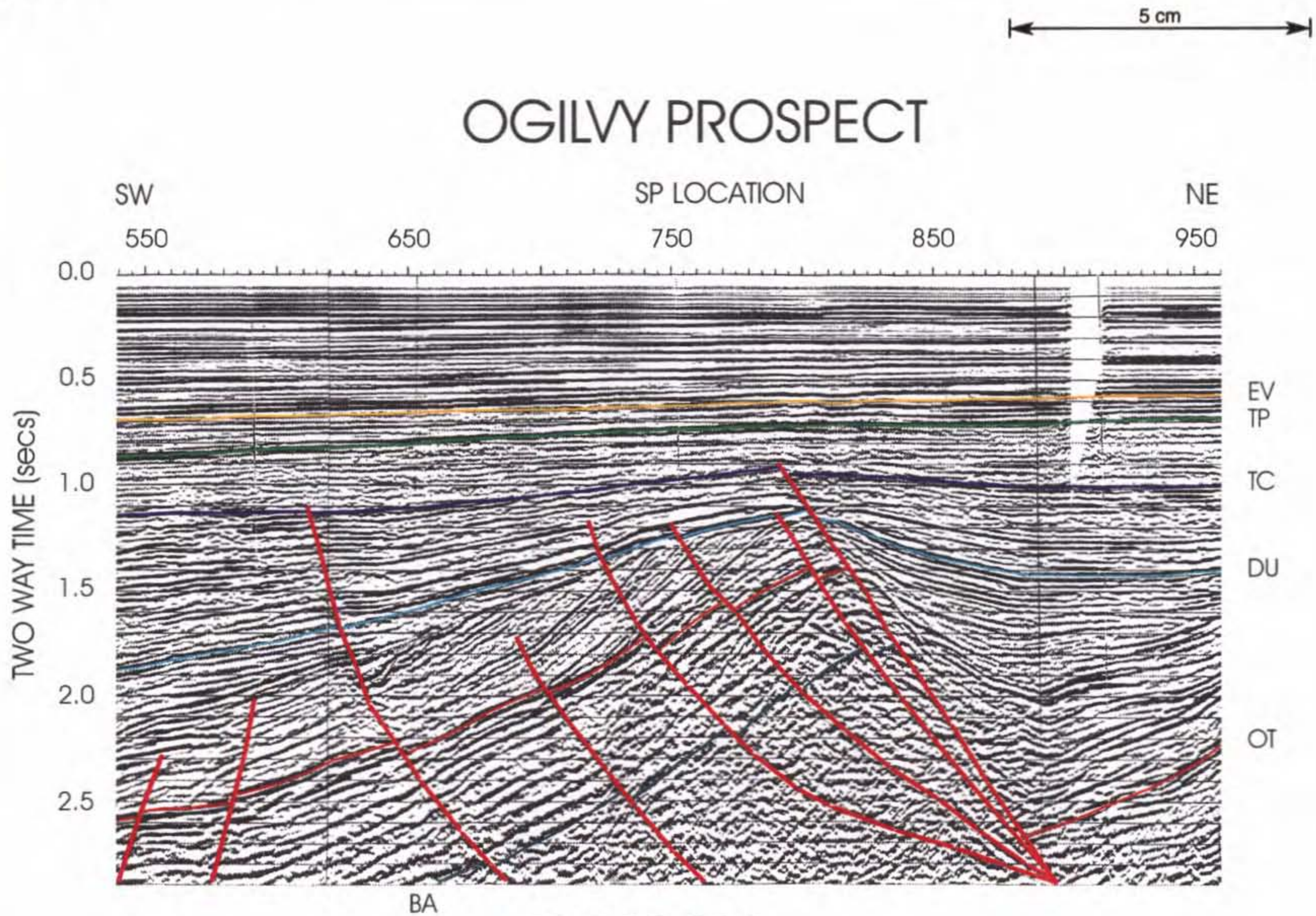
3) STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS UNLIKELY

PROBABILTY RISK FACTOR		0.30
CHANCE OF SUCCESS (OIL)	**(1 in 11.0)**	**9.1%**
CHANCE OF SUCCESS (GAS)	**(1 in 11.0)**	**9.1%**
RISKED RECOVERABLE OIL RESERVES mmbbls		**90.8**
RISKED RECOVERABLE GAS RESERVES BCF		**175.8**

515110

cue

OGILVY PROSPECT



BMR88-306

FIGURE A13

BLACKBURN / BAIRD

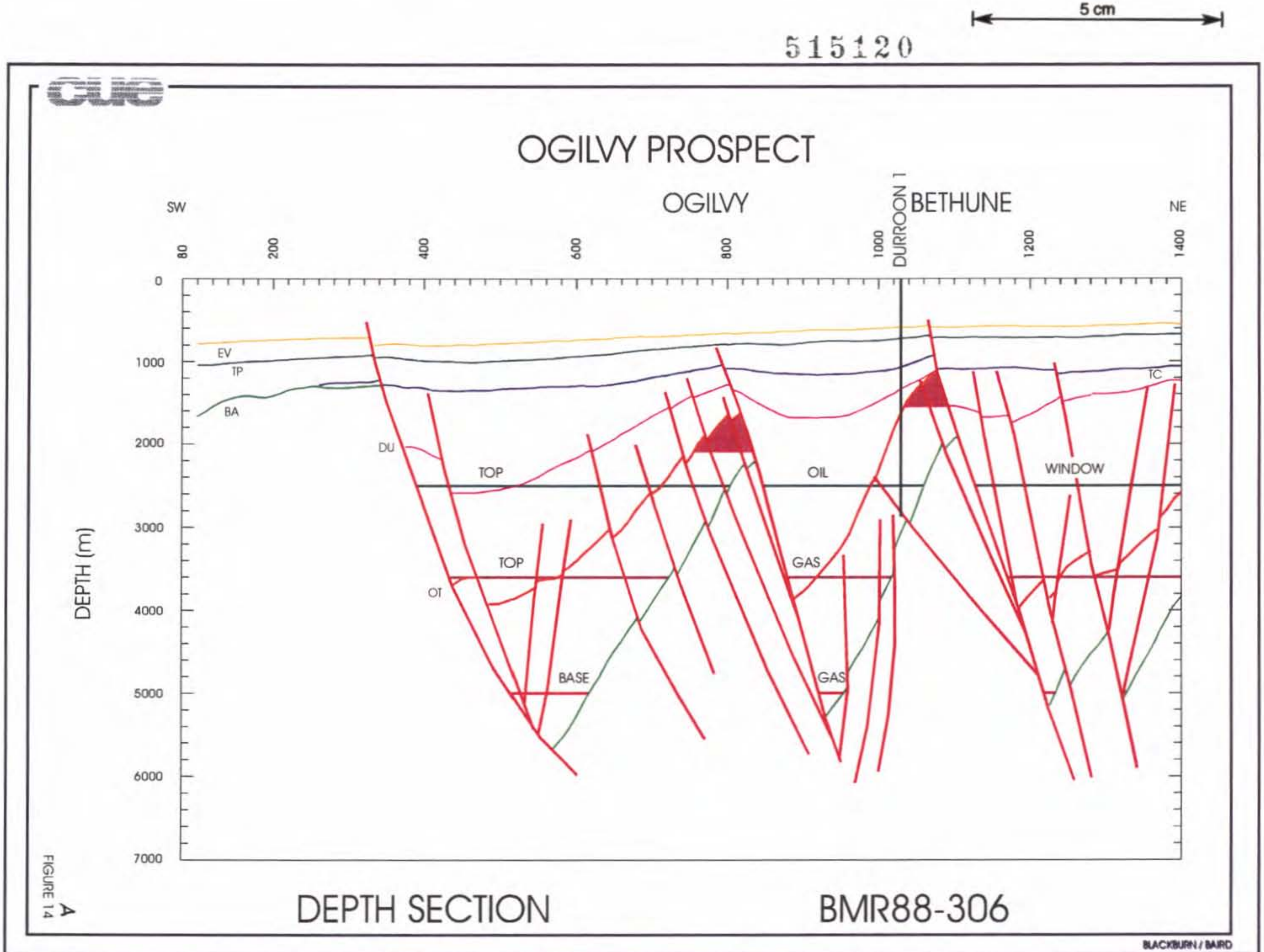

5 cm
OGILVY PROSPECT
SW
OGILVY
DURROON 1
BETHUNE
NE
80
200
400
600
800
1000
1200
1400
0
1000
2000
3000
4000
5000
6000
7000
DEPTH (m)
EV
TP
BA
TC
DU
TOP
OIL
WINDOW
TOP
GAS
OT
BASE
GAS
DEPTH SECTION
BMR88-306
BLACKBURN / BAIRD

FIGURE 14 A

5 cm

515121

CUE

OGILVY PROSPECT

TIME STRUCTURE MAP

TOP OTWAY GROUP

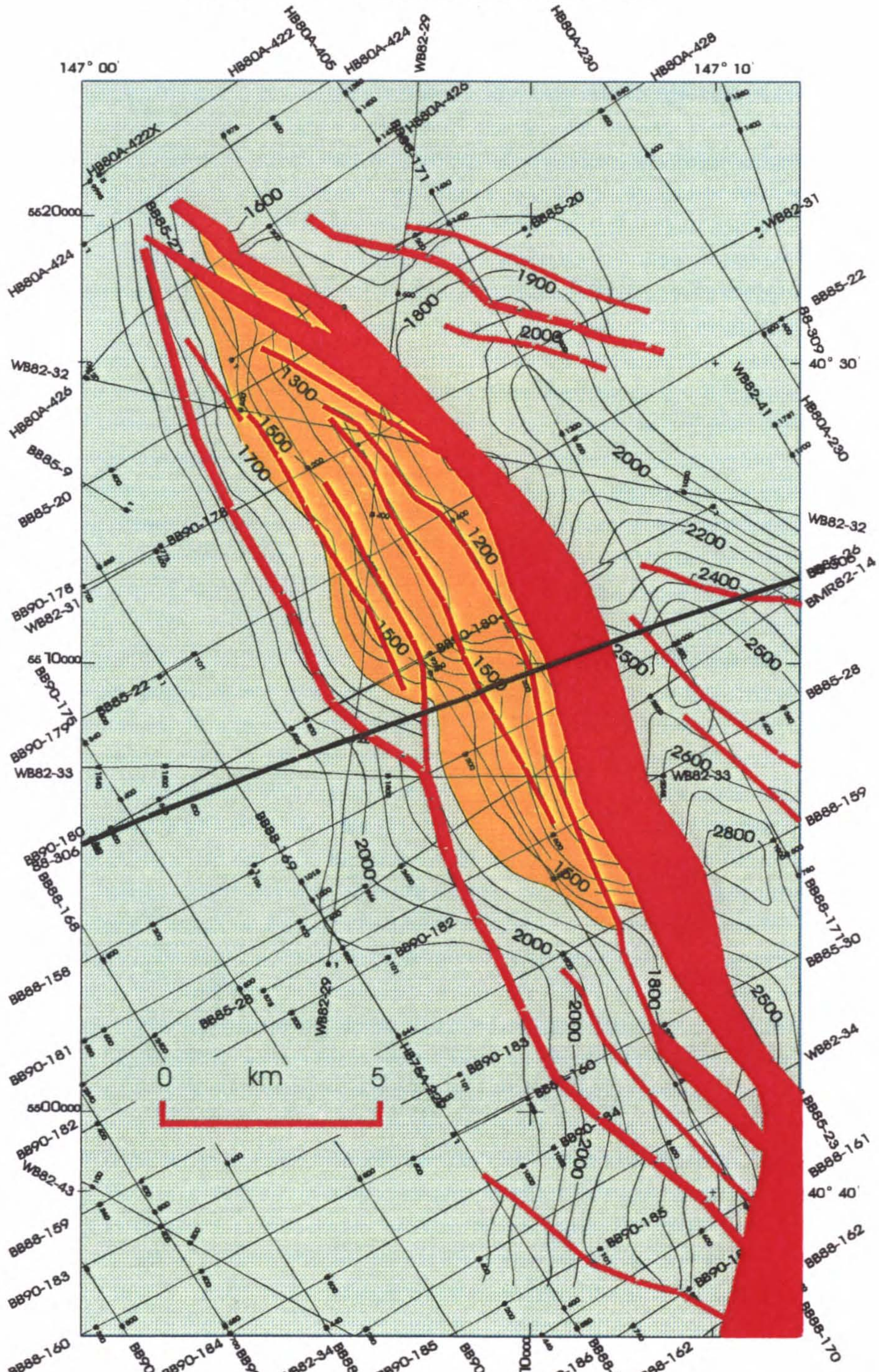


Figure A15

BLACKBURN / BAIRD

REECE PROSPECT

BLACKBURN / BAIRD

PROSPECT:	**REECE**
PERMIT:	T28P
BASIN:	Bass Basin, Tasmania
OPERATOR:	Cue Energy Resources NL
WATER DEPTH:	52m
TRAP TYPE:	Rotated horst block
PRIMARY OBJECTIVE:	Early Cretaceous sandstones of the Otway Group
SEAL:	Late Cretaceous shales of the Durroon Formation & Lower Eastern View Gp
SOURCE:	Early Cretaceous shales and coals of the Otway Group

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	AREA (sq kms)	VOLUME (m3)
849	954	0.000	
900	1015	0.200	6,060,000
1000	1137	3.586	238,324,965
1100	1259	8.949	998,566,650
1200	1380	16.211	2,523,262,650
1300	1501	25.030	5,024,529,300
1350	1567	29.657	6,834,665,690

RESERVOIR PRESSURE (psi):	1355.3 psi	
RESERVOIR TEMPERATURE (C):	44.6 C	112.2 F
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	**GAS**
POROSITY:	0.17	0.17
NET/GROSS:	0.30	0.30
HYDROCARBON SATURATION:	0.75	0.75
FORMATION VOLUME FACTOR:	1.20	0.010557873

BLACKBURN / BAIRD

RECOVERY FACTOR:	0.25	0.6

IN PLACE	**1,370 mmbbls**	**874 BCF**
RECOVERABLE	**343 mmbbls**	**525 BCF**

GAS COMPOSITION	MOLE FRACTION (%)	CRITICAL CONSTANTS Tc (F)	Pc (psi)
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO_2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.667
PSUEDO REDUCED PRESSURE	2.029
FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR	**0.885**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

GAS SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

PROBABILITY RISK FACTOR OIL 0.55

PROBABILITY RISK FACTOR FOR GAS 0.55

2) RESERVOIR IN THE VICINITY OF THE TRAP IS PROBABLE AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR 0.55

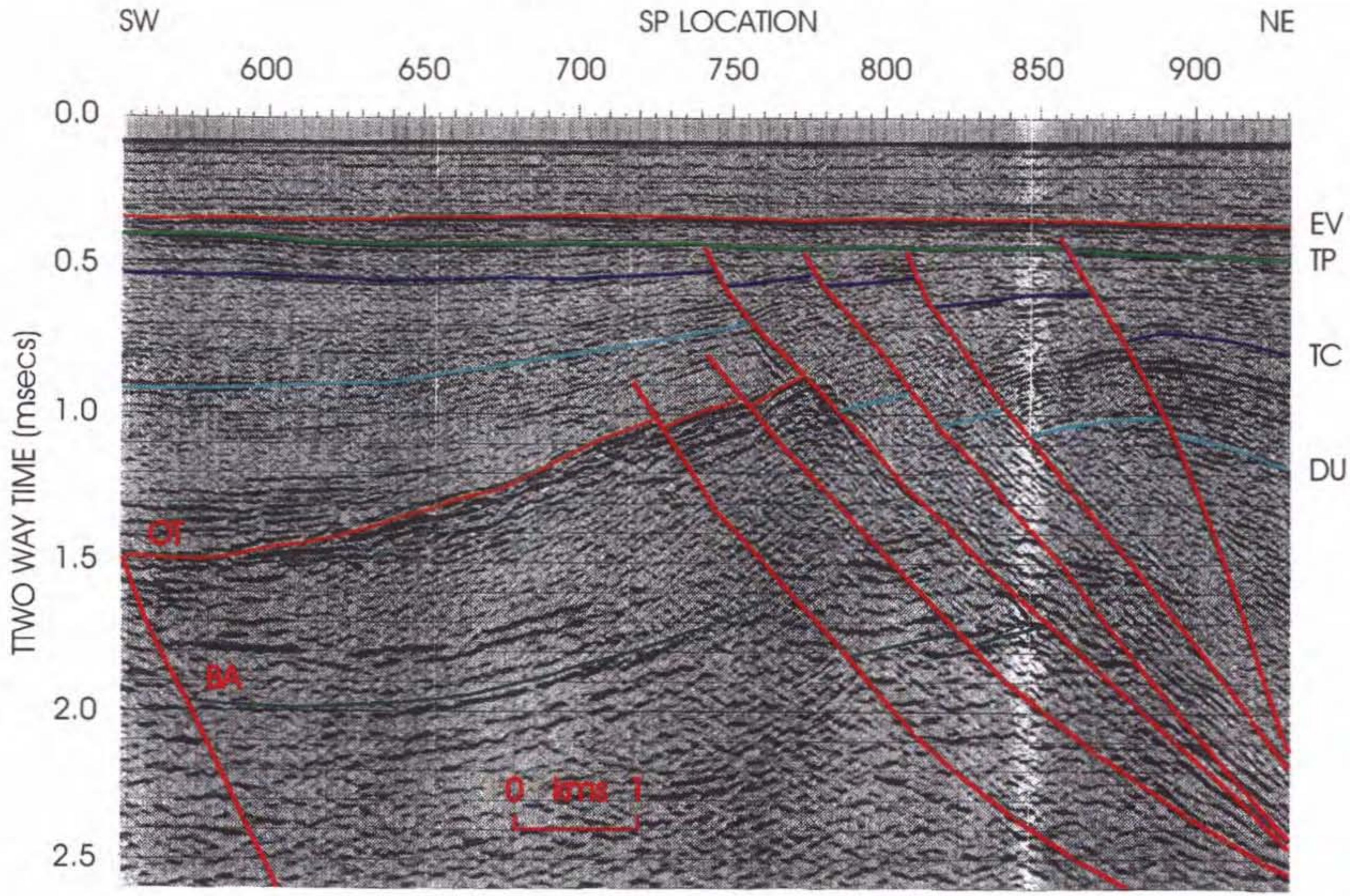
3) STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS UNLIKELY

PROBABILTY RISK FACTOR		0.30
CHANCE OF SUCCESS (OIL)	**(1 in 11.0)**	**9.1%**
CHANCE OF SUCCESS (GAS)	**(1 in 11.0)**	**9.1%**
RISKED RECOVERABLE OIL RESERVES mmbbls		**31.1**
RISKED RECOVERABLE GAS RESERVES BCF		**47.6**

5 cm

515126

REECE PROSPECT



BB90-195

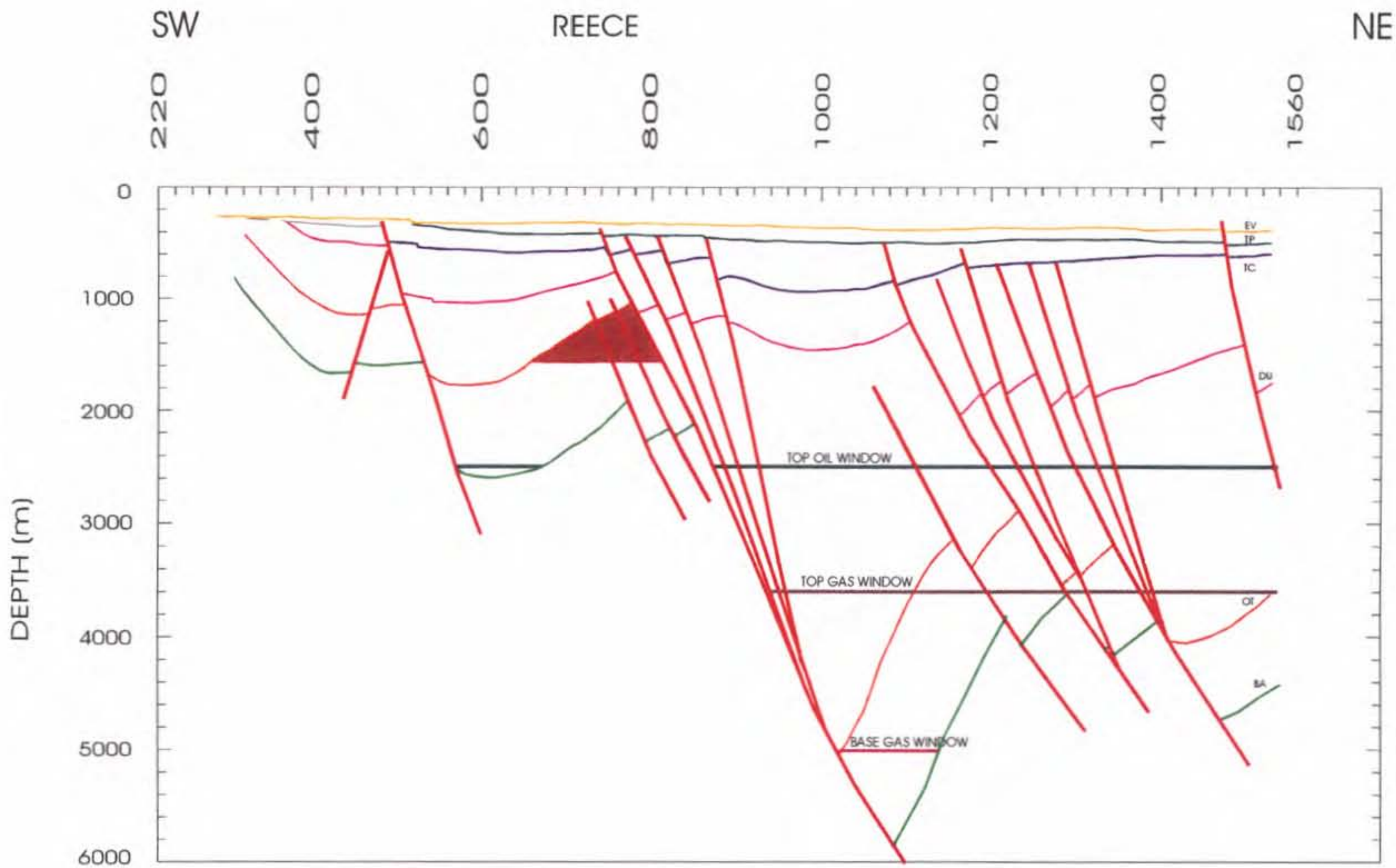
FIGURE A16

BLACKBURN / BAIRD

5 cm

515127

REECE PROSPECT



DEPTH SECTION BB90-195

FIGURE A17

BLACKBURN / BAIRD

5 cm

515128

REECE PROSPECT

TIME STRUCTURE MAP

TOP OTWAY GROUP

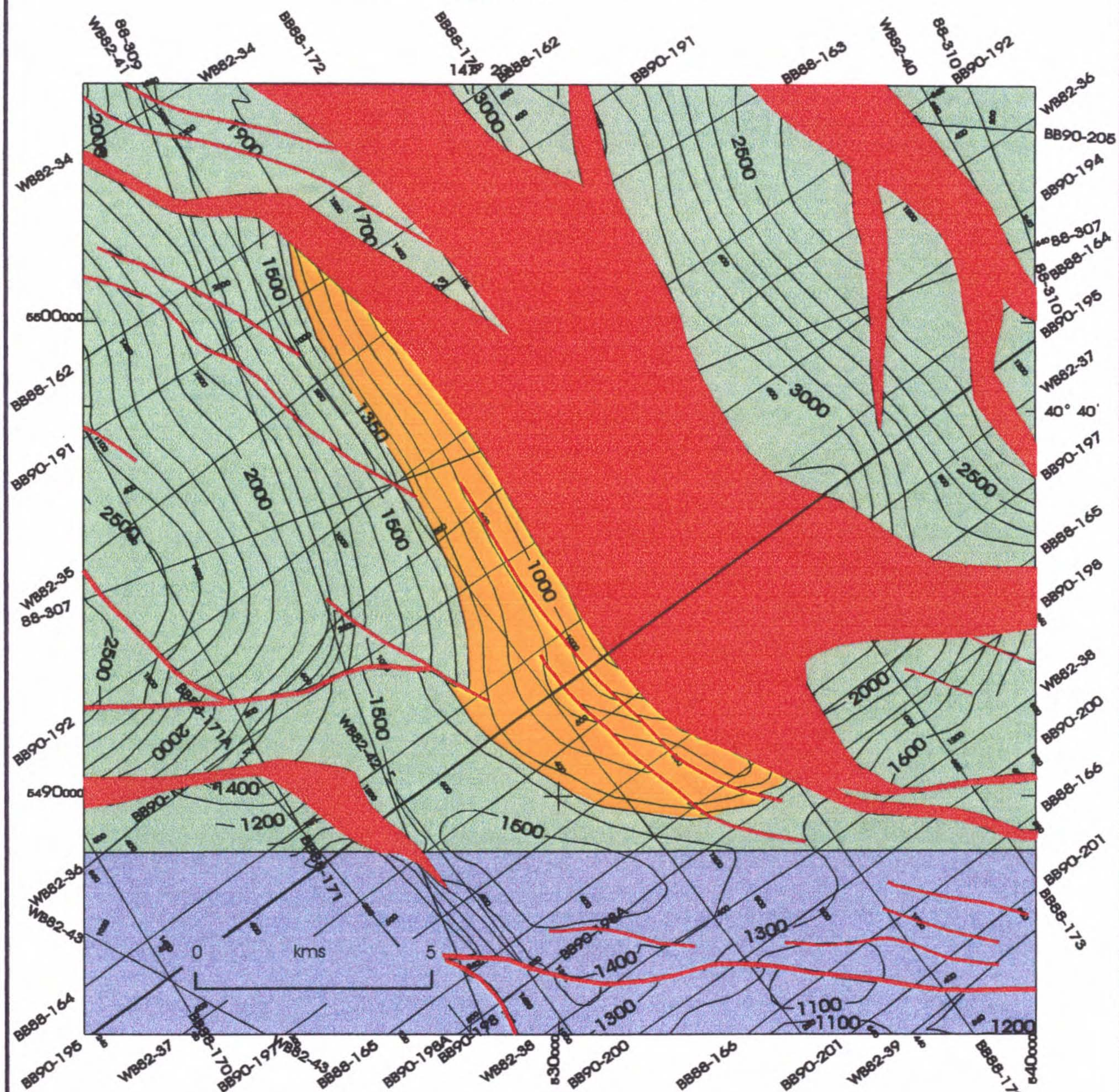


FIGURE A18

BLACKBURN / BAIRD

WILMOT PROSPECT

BLACKBURN / BAIRD

PROSPECT:	WILMOT
PERMIT:	T28P
BASIN:	Bass Basin, Tasmania
OPERATOR:	Cue Energy Resources NL
WATER DEPTH:	53m
TRAP TYPE:	Rotated horst block
PRIMARY OBJECTIVE:	Early Cretaceous sandstones of the Otway Group
SEAL:	Late Cretaceous shales of the Durroon Formation
SOURCE:	Early Cretaceous shales and coals of the Otway Group & Durroon Fm

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	AREA (sq kms)	VOLUME (m3)
1681	2065	0.000	
1800	2259	11.264	1,089,870,848
1900	2432	24.713	4,214,473,298
2000	2611	36.286	9,658,634,048
2100	2800	54.634	18,232,390,048
2200			

RESERVOIR PRESSURE (psi):	2933.8 psi	
RESERVOIR TEMPERATURE (C):	79.0 C	174.2 F
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	**GAS**
POROSITY:	0.17	0.17
NET/GROSS:	0.30	0.30
HYDROCARBON SATURATION:	0.75	0.75
FORMATION VOLUME FACTOR:	1.20	0.005558602

BLACKBURN / BAIRD

RECOVERY FACTOR: 0.25 0.6

IN PLACE	**3,655 mmbbls**	**4,431 BCF**
RECOVERABLE	**914 mmbbls**	**2,658 BCF**

GAS COMPOSITION	**MOLE FRACTION (%)**	**CRITICAL CONSTANTS Tc (F)**	**Pc (psi)**
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE -116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE 667.8 psi

PSUEDO REDUCED TEMPERATURE 1.848130896
PSUEDO REDUCED PRESSURE 4.393247709

FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR 0.91

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS PROBABLE

GAS SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

PROBABILITY RISK FACTOR OIL 0.45

PROBABILITY RISK FACTOR FOR GAS 0.55

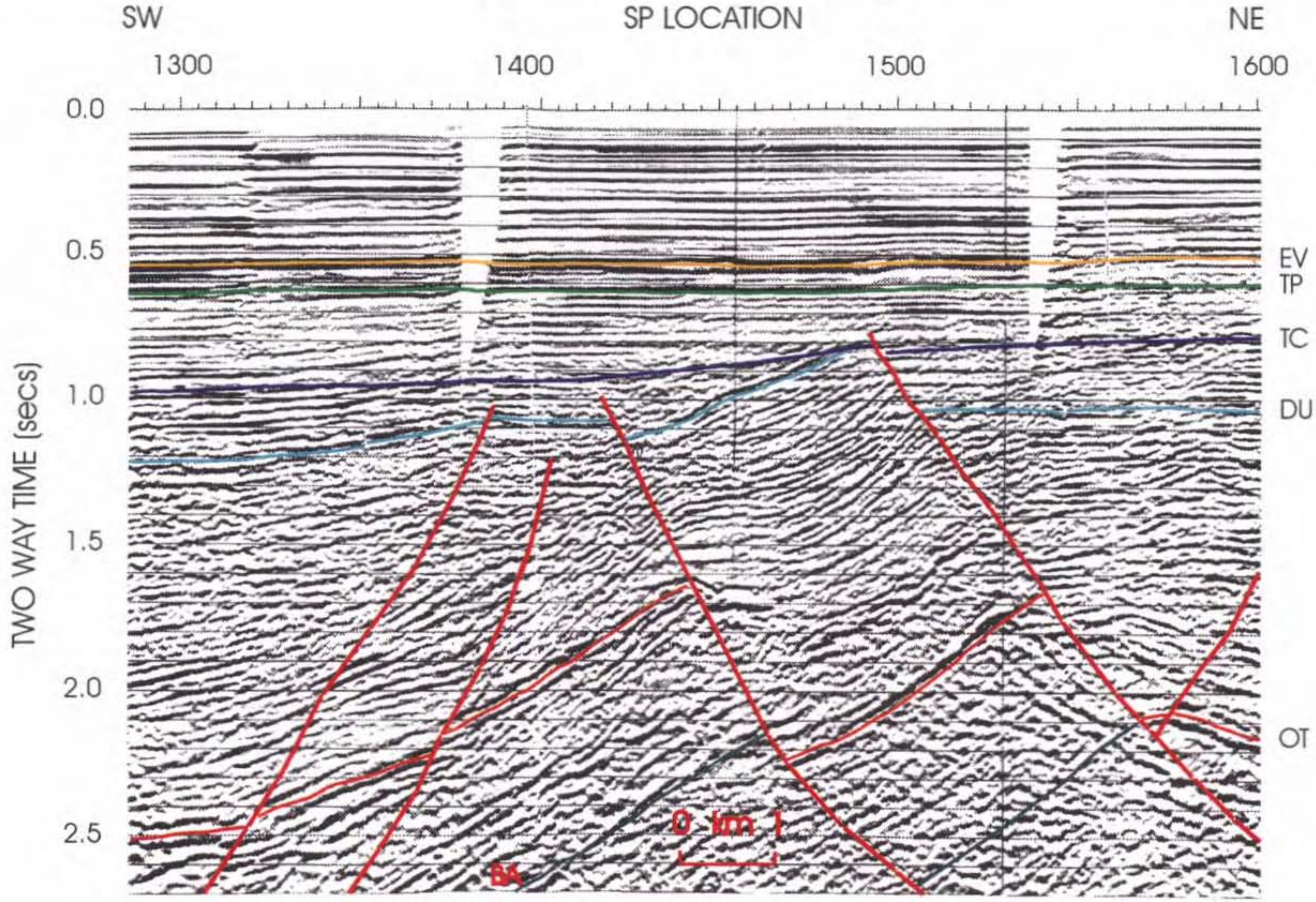
2) RESERVOIR IN THE VICINITY OF THE TRAP IS PROBABLE AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR 0.55

3)	STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS UNLIKELY	
	PROBABILTY RISK FACTOR	0.30

CHANCE OF SUCCESS (OIL)	**(1 in 13.5)**	**7.4%**
CHANCE OF SUCCESS (GAS)	**(1 in 11.0)**	**9.1%**
RISKED RECOVERABLE OIL RESERVES mmbbls		**67.8**
RISKED RECOVERABLE GAS RESERVES BCF		**241.2**

WILMOT PROSPECT

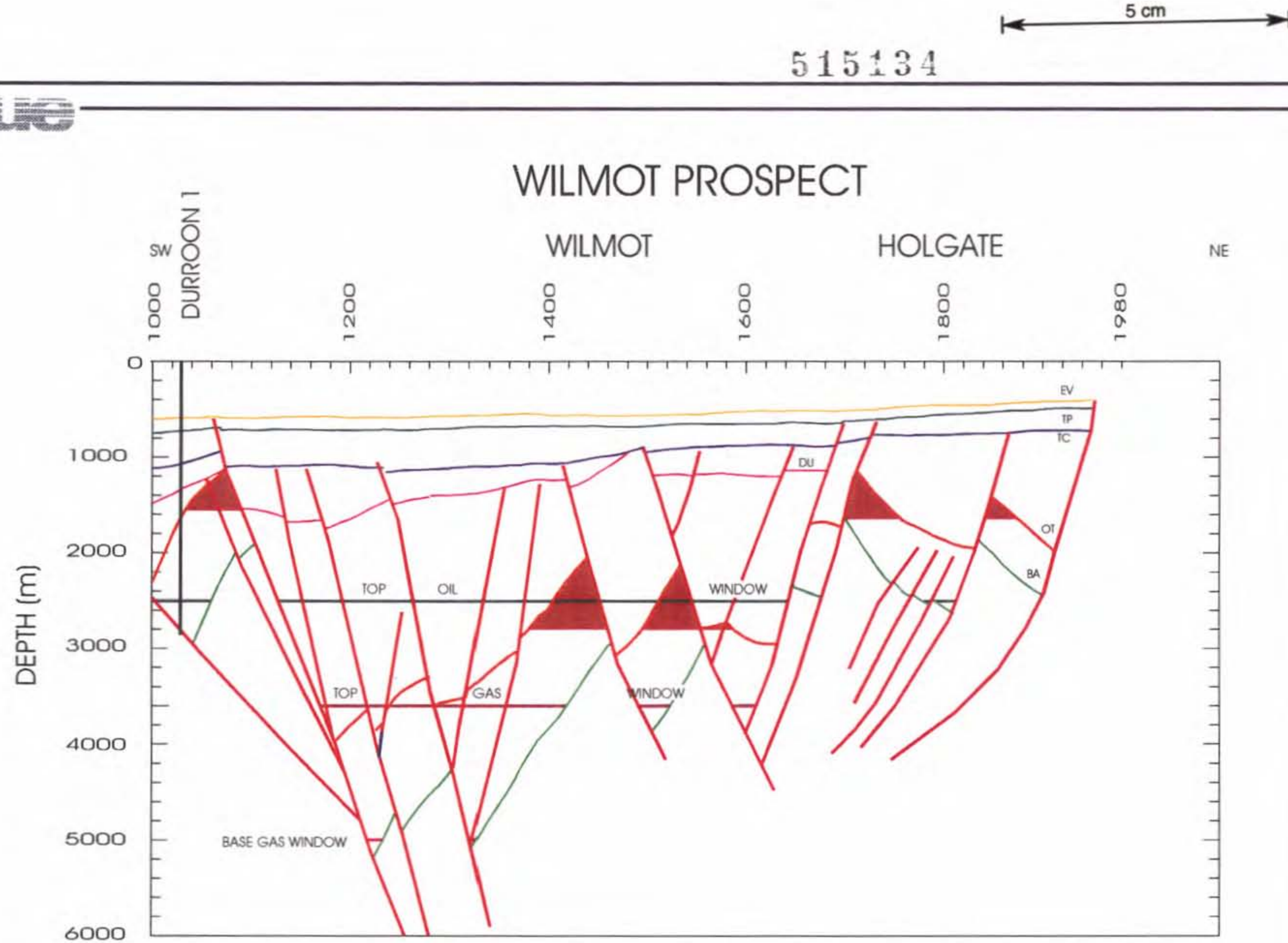


BMR88-306

FIGURE A19

BLACKBURN / BAIRD

515134



DEPTH SECTION BMR88-306

FIGURE 20A

BLACKBURN / BAIRD

515135

5 cm

WILMOT PROSPECT

TIME STRUCTURE MAP

OTWAY GROUP

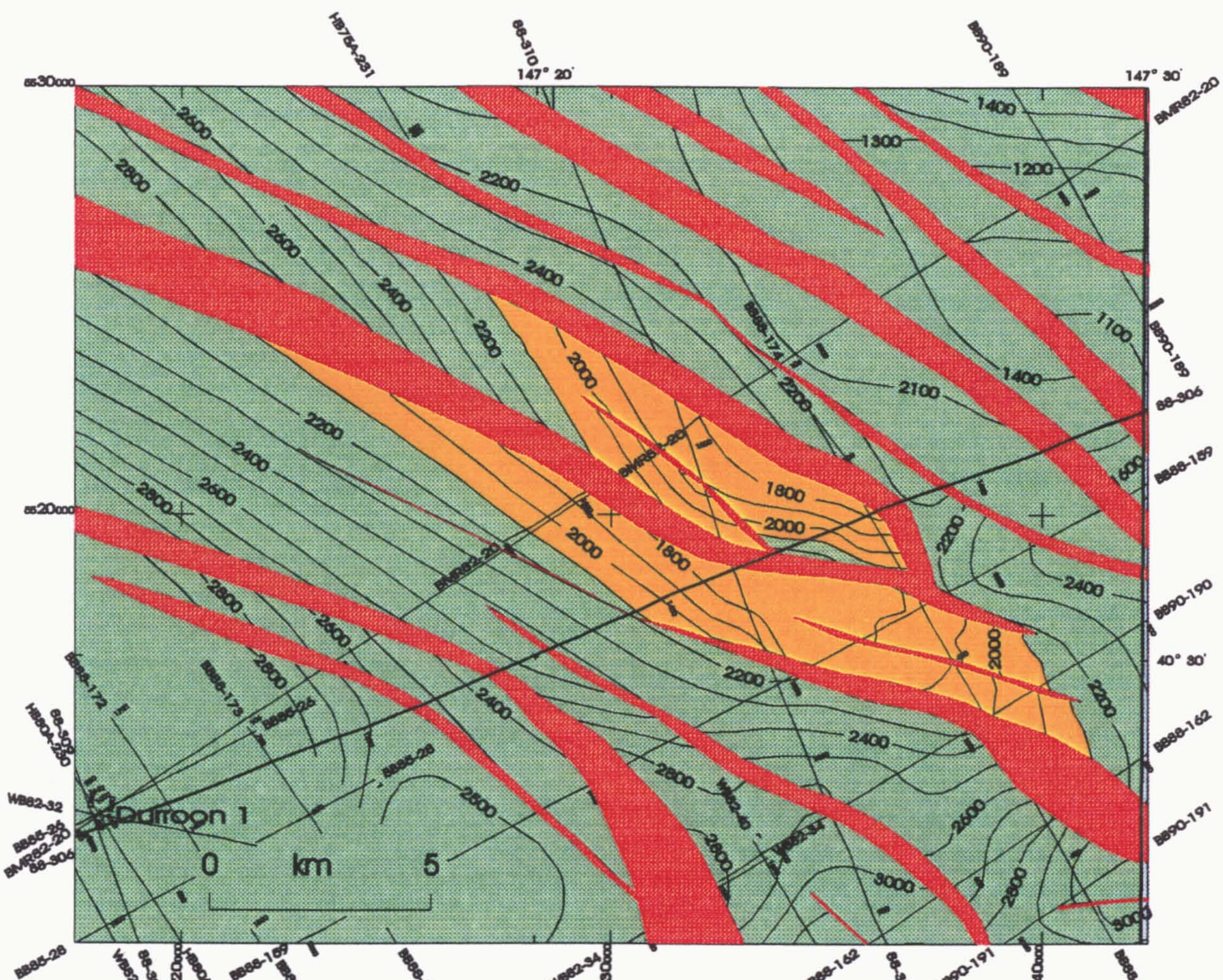


FIGURE A21

BLACKBURN / BAIRD

BRASSIL PROSPECT

BLACKBURN / BAIRD

PROSPECT:	BRASSIL
PERMIT:	T28P
BASIN:	Bass Basin, Tasmania
OPERATOR:	Cue Energy Resources NL
WATER DEPTH:	70m
TRAP TYPE:	Stratigraphic alluvial fan
PRIMARY OBJECTIVE:	Late Cretaceous sandstones of the Durroon Fm.
SEAL:	Late Cretaceous shales of the Durroon Formation & basement
SOURCE:	Early Cretaceous shales and coals of the Otway Group

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	AREA (sq kms)	VOLUME (m3)
1795	2250	0.000	
	2500	10.000	1,250,000,000

<u>no mapping was undertaken on individual fans so volumes are indicative only</u>

RESERVOIR PRESSURE (psi):	3196.4 psi	
RESERVOIR TEMPERATURE (C):	84.8 C	184.6 F
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	GAS
POROSITY:	0.17	0.17
NET/GROSS:	0.50	0.50
HYDROCARBON SATURATION:	0.75	0.75
FORMATION VOLUME FACTOR:	1.20	0.005014085

BLACKBURN / BAIRD

RECOVERY FACTOR:	0.40	0.7

IN PLACE	**418 mmbbls**	**561 BCF**
RECOVERABLE	**167 mmbbls**	**393 BCF**

GAS COMPOSITION	**MOLE FRACTION (%)**	**CRITICAL CONSTANTS Tc (F)**	**Pc (psi)**
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.878
PSUEDO REDUCED PRESSURE	4.786
FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR	**0.88**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

GAS SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS PROBABLE

PROBABILITY RISK FACTOR OIL — 0.55

PROBABILITY RISK FACTOR FOR GAS — 0.45

2) RESERVOIR IN THE VICINITY OF THE TRAP IS PROBABLE AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR — 0.55

BLACKBURN / BAIRD

3) STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS PROBABLE

PROBABILTY RISK FACTOR 0.45

CHANCE OF SUCCESS (OIL)	**(1 in 7.3)**	**13.6%**
CHANCE OF SUCCESS (GAS)	**(1 in 9.0)**	**11.1%**
RISKED RECOVERABLE OIL RESERVES mmbbls		**22.7**
RISKED RECOVERABLE GAS RESERVES BCF		**43.8**

515140

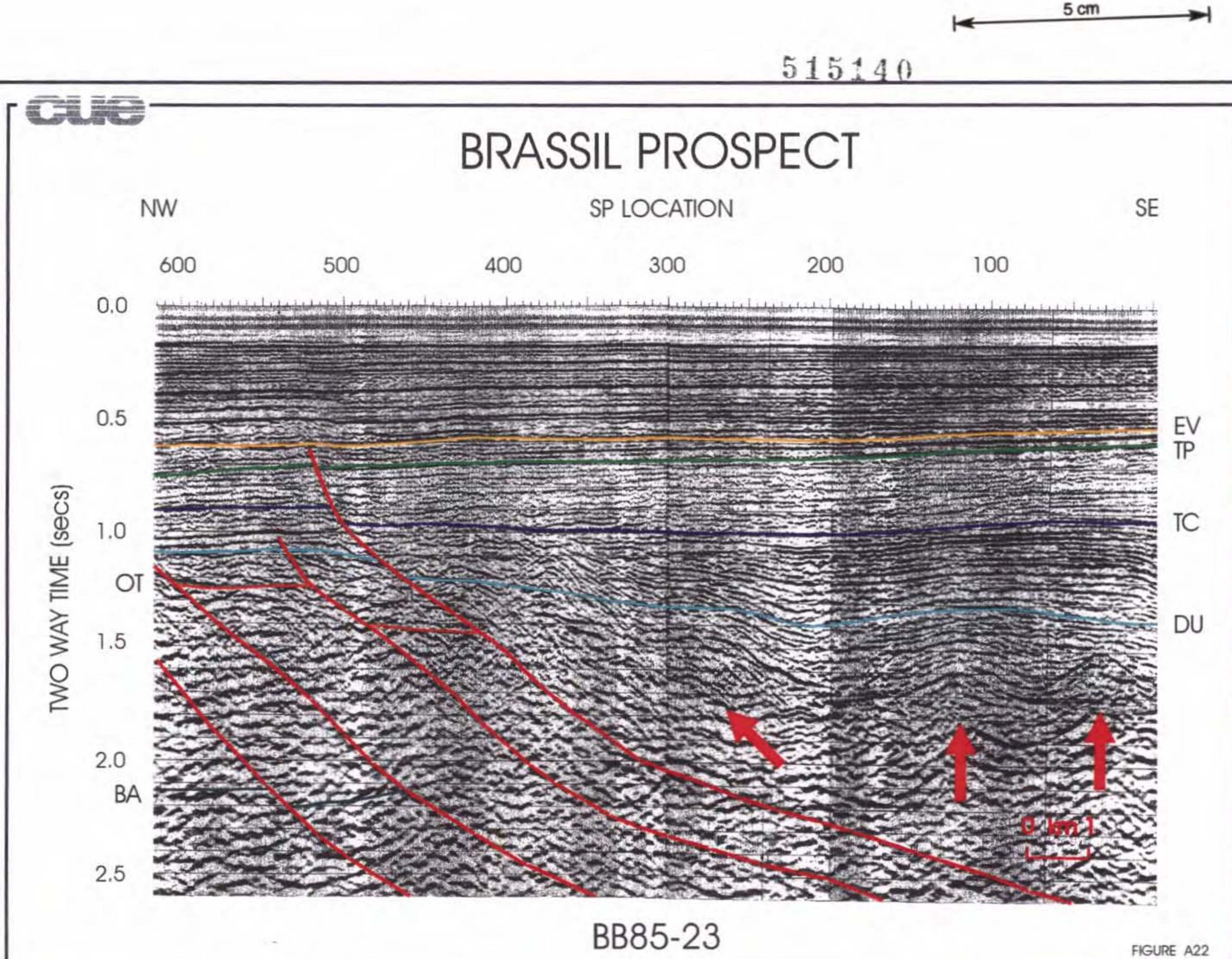


FIGURE A22

BLACKBURN / BAIRD

5 cm

515141

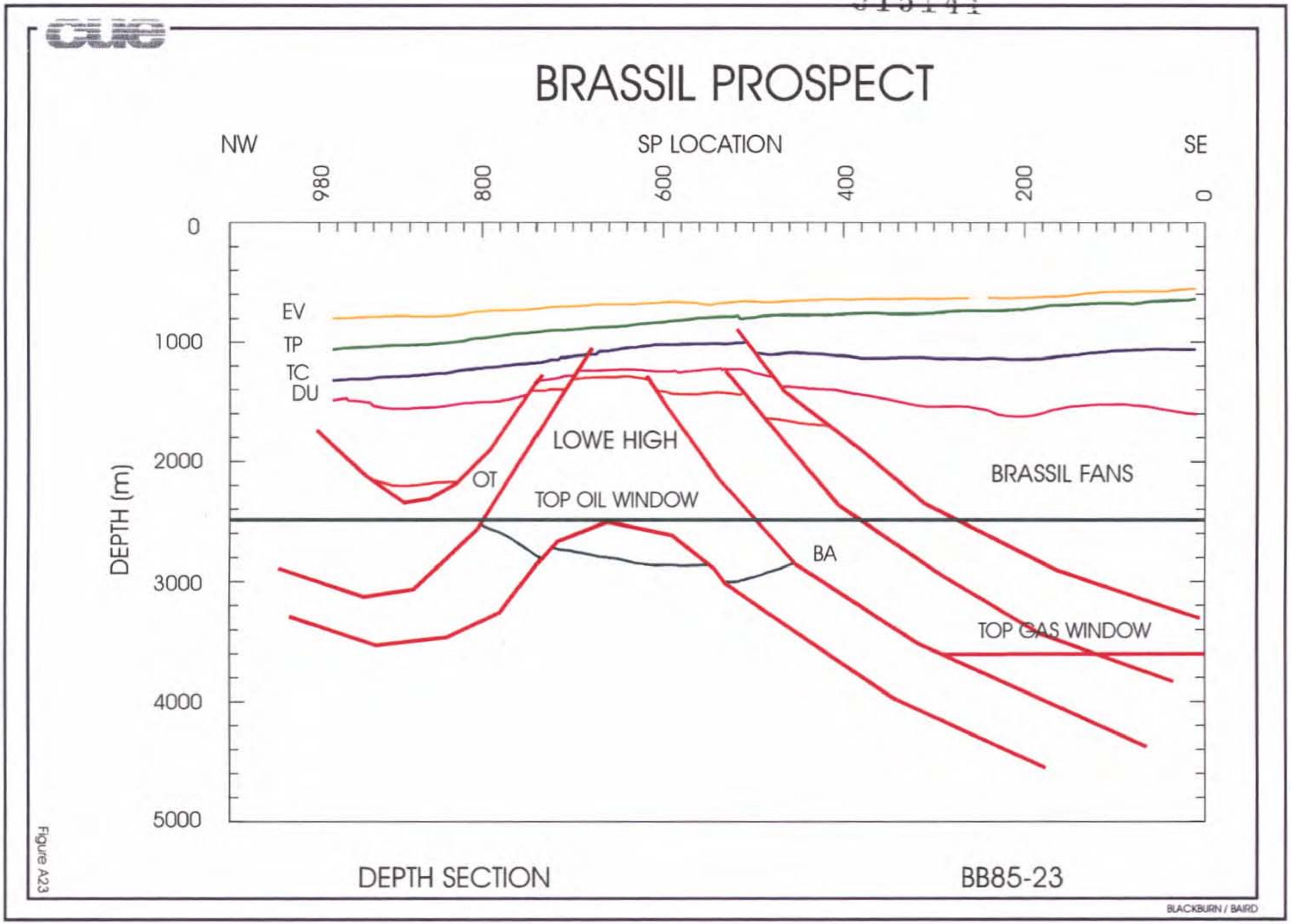


Figure A23

5 cm

515142

BRASSIL PROSPECT

TIME STRUCTURE MAP

TOP OTWAY GROUP

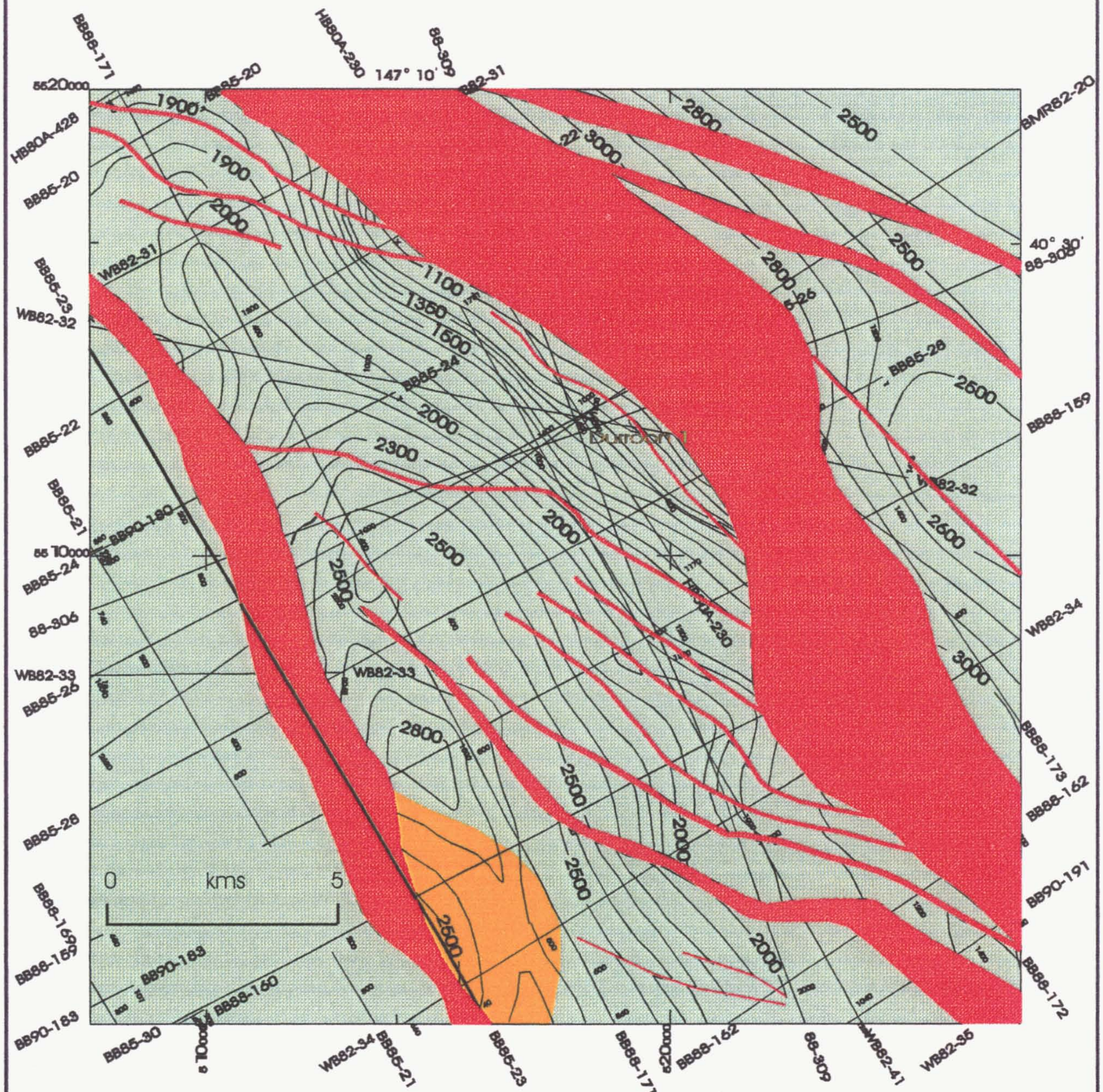


Figure A24

BLACKBURN / BAIRD

MURRAY PROSPECT

PROSPECT:	**MURRAY**
PERMIT:	T28P
BASIN:	Bass Basin, Tasmania
OPERATOR:	Cue Energy Resources NL
WATER DEPTH:	70m
TRAP TYPE:	Stratigraphic alluvial fan with partial fault dependence
PRIMARY OBJECTIVE:	Late Cretaceous sandstones of the Durroon Fm.
SEAL:	Late Cretaceous shales of the Durroon Formation
SOURCE:	Early Cretaceous shales and coals of the Otway Group

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	AREA (sq kms)	VOLUME (m3)
1800	2259	0.000	
	2559	10.000	1,500,000,000

no mapping was undertaken on individual fans so volumes are indicative only
if stratigraphically trapped with pinchout edge near Durroon 1 possible areal closure could be of the order of 50 sq kms

RESERVOIR PRESSURE (psi):	3209.1 psi	
RESERVOIR TEMPERATURE (C):	85.0 C	185.1 F
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	**GAS**
POROSITY:	0.17	0.17
NET/GROSS:	0.50	0.50
HYDROCARBON SATURATION:	0.75	0.75
FORMATION VOLUME FACTOR:	1.20	0.004998001

BLACKBURN / BAIRD

RECOVERY FACTOR:	0.40	0.7

IN PLACE	**501 mmbbls**	**676 BCF**
RECOVERABLE	**200 mmbbls**	**473 BCF**

GAS COMPOSITION	**MOLE FRACTION (%)**	**CRITICAL CONSTANTS Tc (F)**	**Pc (psi)**
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.880
PSUEDO REDUCED PRESSURE	4.806

FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR **0.88**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

GAS SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS PROBABLE

PROBABILITY RISK FACTOR OIL 0.55

PROBABILITY RISK FACTOR FOR GAS 0.45

2) RESERVOIR IN THE VICINITY OF THE TRAP IS PROBABLE AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR 0.55

3) STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS PROBABLE

PROBABILTY RISK FACTOR 0.45

CHANCE OF SUCCESS (OIL)	**(1 in 7.3)**	**13.6%**
CHANCE OF SUCCESS (GAS)	**(1 in 9.0)**	**11.1%**
RISKED RECOVERABLE OIL RESERVES mmbbls		**27.3**
RISKED RECOVERABLE GAS RESERVES BCF		**52.7**

5 cm

515147

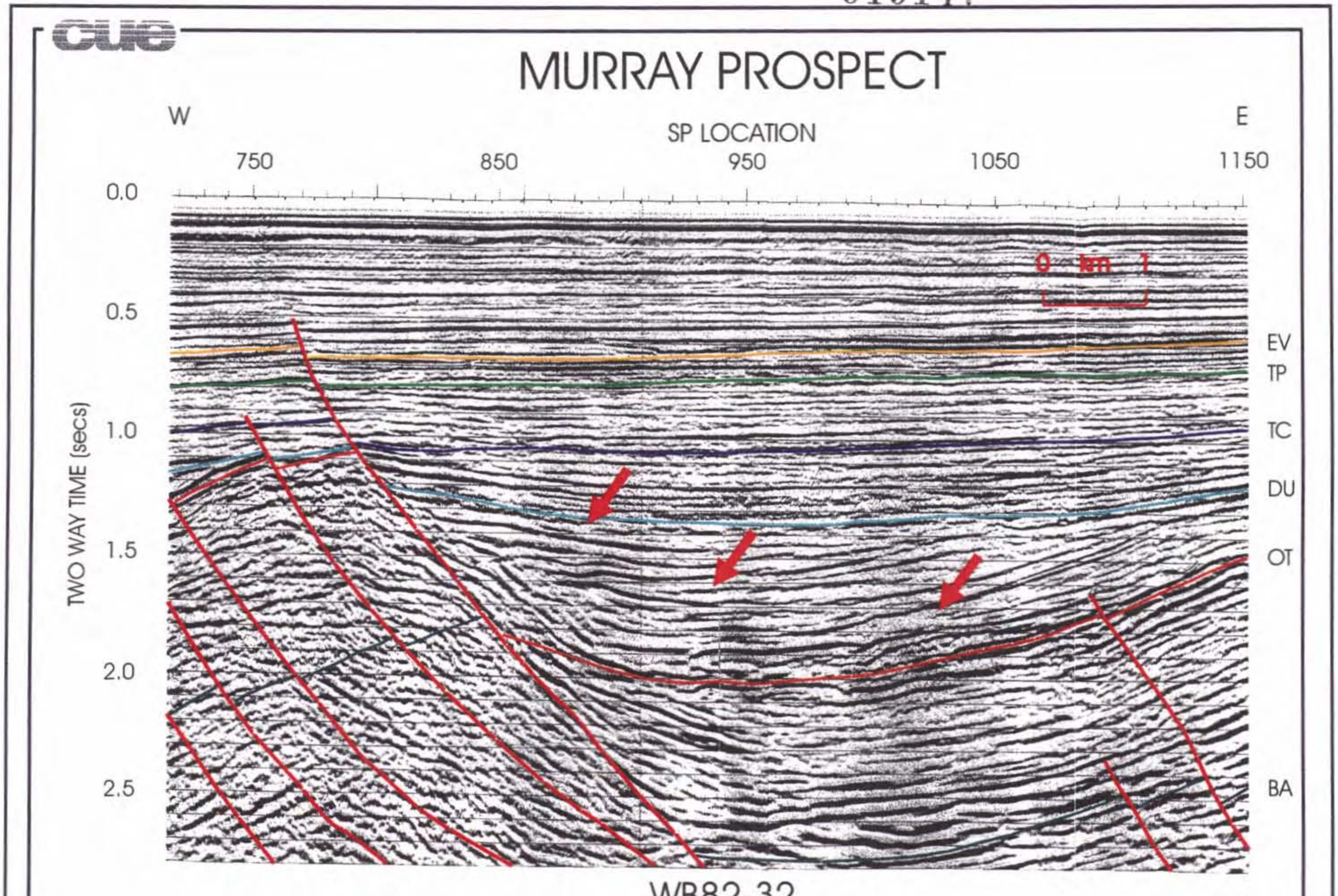


FIGURE A25

BLACKBURN / BAIRD

5 cm

515148

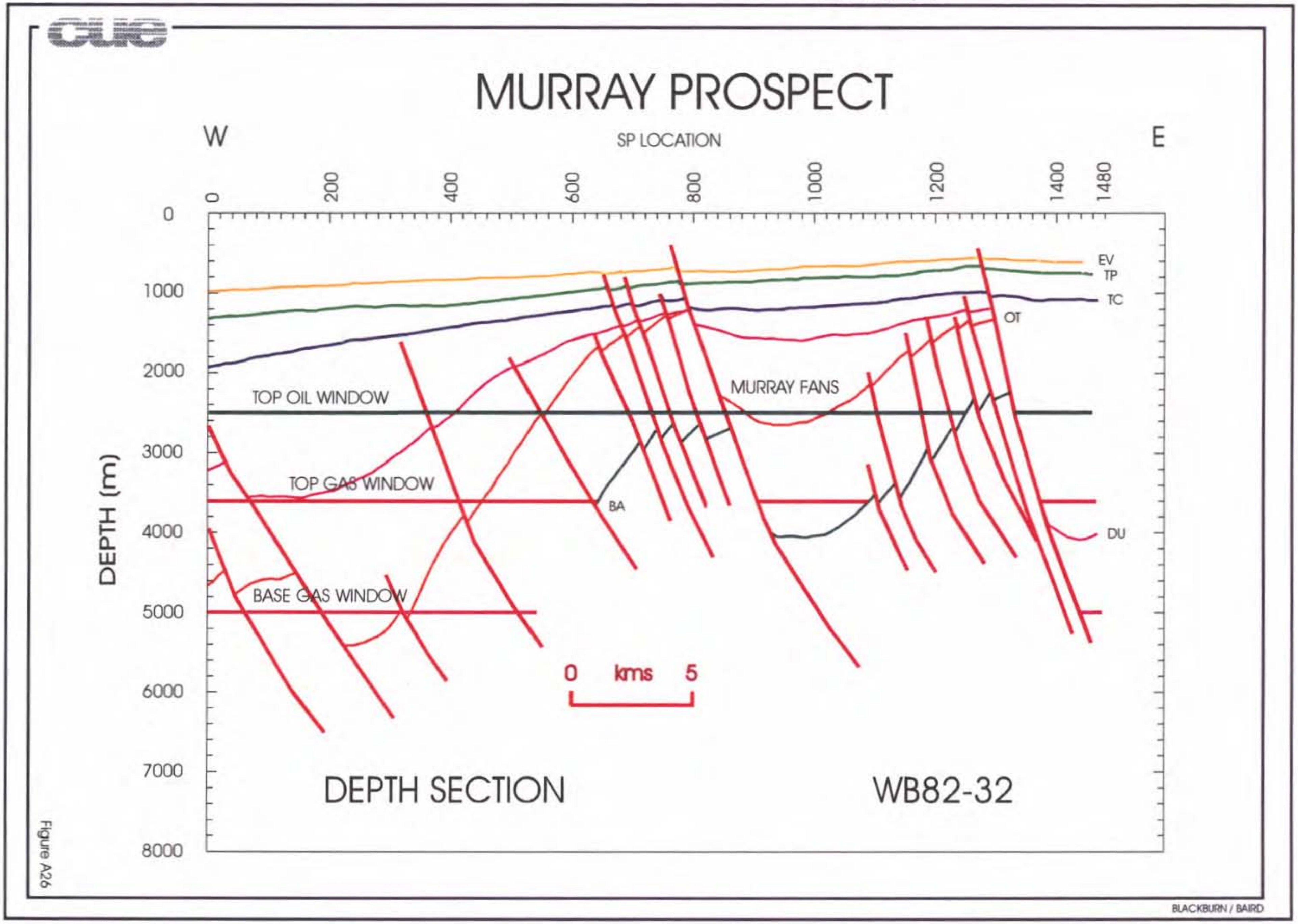


Figure A26

5 cm

515149

MURRAY PROSPECT

TIME STRUCTURE MAP

TOP OTWAY GROUP

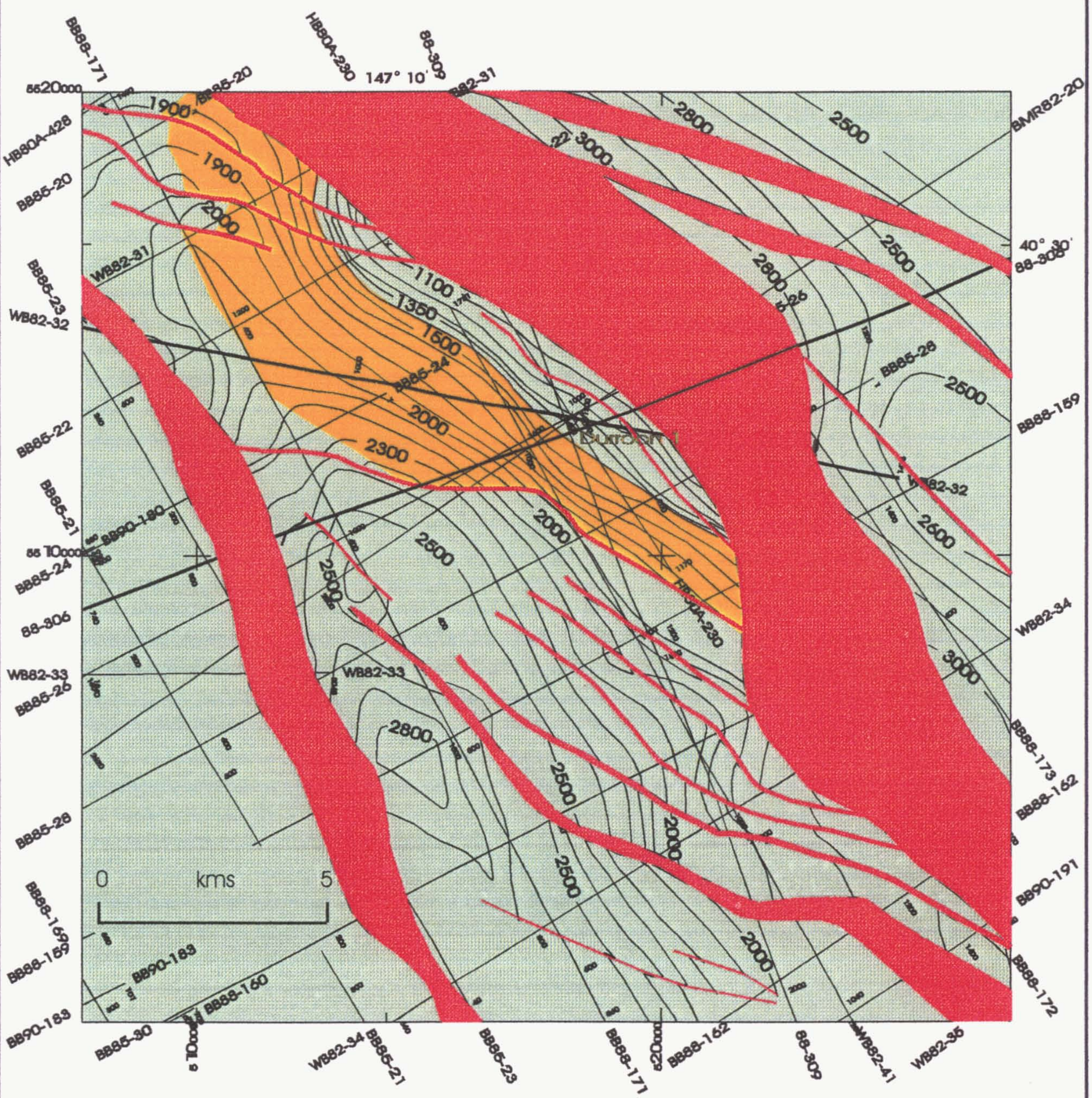


FIGURE A27

BLACKBURN / BAIRD

COLLINS PROSPECT

BLACKBURN / BAIRD

PROSPECT:	COLLINS
PERMIT:	T28P
BASIN:	Bass Basin, Tasmania
OPERATOR:	Cue Energy Resources NL
WATER DEPTH:	81m
TRAP TYPE:	Antithetic rotated fault block
PRIMARY OBJECTIVE:	Early Tertiary Upper Eastern View Group
SEAL:	Shales of the Demons Bluff Fm.
SOURCE:	Late Cretaceous shales and coals of the Durroon Fm & Eastern View Group.

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	TOTAL AREA (sq kms)	PERMIT AREA (sq kms)	TOTAL VOLUME (m3)	PERMIT VOLUME (m3)
1208	1390	0.000	0.000		
1220	1404	2.608	1.167	18,981,024	8,493,426
1240	1428	7.014	1.603	135,695,884	42,093,526
1245	1434	11.350	1.977	191,384,714	52,949,876

RESERVOIR PRESSURE (psi):	1973.9 psi	
RESERVOIR TEMPERATURE (C):	58.1 C	136.5 F
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	**GAS**
POROSITY:	0.22	0.22
NET/GROSS:	0.70	0.70
HYDROCARBON SATURATION:	0.75	0.75
FORMATION VOLUME FACTOR:	1.20	0.007556783
RECOVERY FACTOR:	0.40	0.65

BLACKBURN / BAIRD

IN PLACE	116 mmbbls	103 BCF
RECOVERABLE	46 mmbbls	67 BCF
IN PLACE WITHIN PERMIT	32 mmbbls	29 BCF
RECOVERABLE WITHIN PERMIT	13 mmbbls	19 BCF

GAS COMPOSITION	MOLE FRACTION (%)	CRITICAL CONSTANTS Tc (F)	Pc (psi)
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.738
PSUEDO REDUCED PRESSURE	2.956

FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR **0.885**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

GAS SOURCE IN THE VICINITY OF THE TRAP IS CERTAIN AND MATURITY IS PROBABLE

PROBABILITY RISK FACTOR OIL 0.55

PROBABILITY RISK FACTOR FOR GAS 0.55

2) RESERVOIR IN THE VICINITY OF THE TRAP IS CERTAIN AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR 0.80

3)	STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS POSSIBLE		
	PROBABILTY RISK FACTOR		0.37

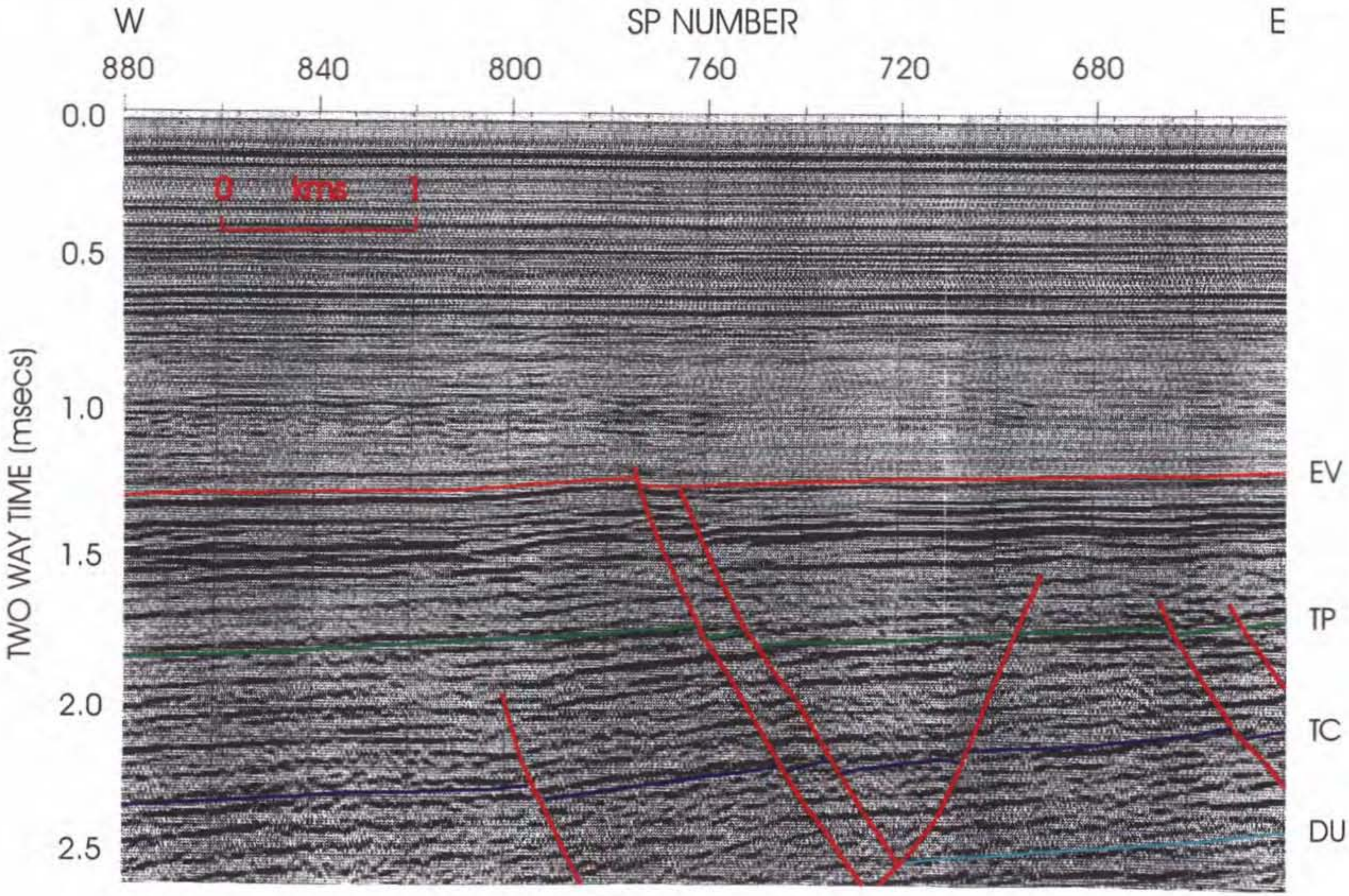
CHANCE OF SUCCESS (OIL)	**(1 in 6.1)**	**16.3%**
CHANCE OF SUCCESS (GAS)	**(1 in 6.1)**	**16.3%**
RISKED OIL RESERVES (TOTAL) mmbbls		**7.5**
RISKED OIL RESERVES (PERMIT) mmbbls		**2.1**
RISKED GAS RESERVES (TOTAL) BCF		**10.9**
RISKED GAS RESERVES (PERMIT) BCF		**3.0**

BLACKBURN / BAIRD

5 cm

515154

COLLINS PROSPECT



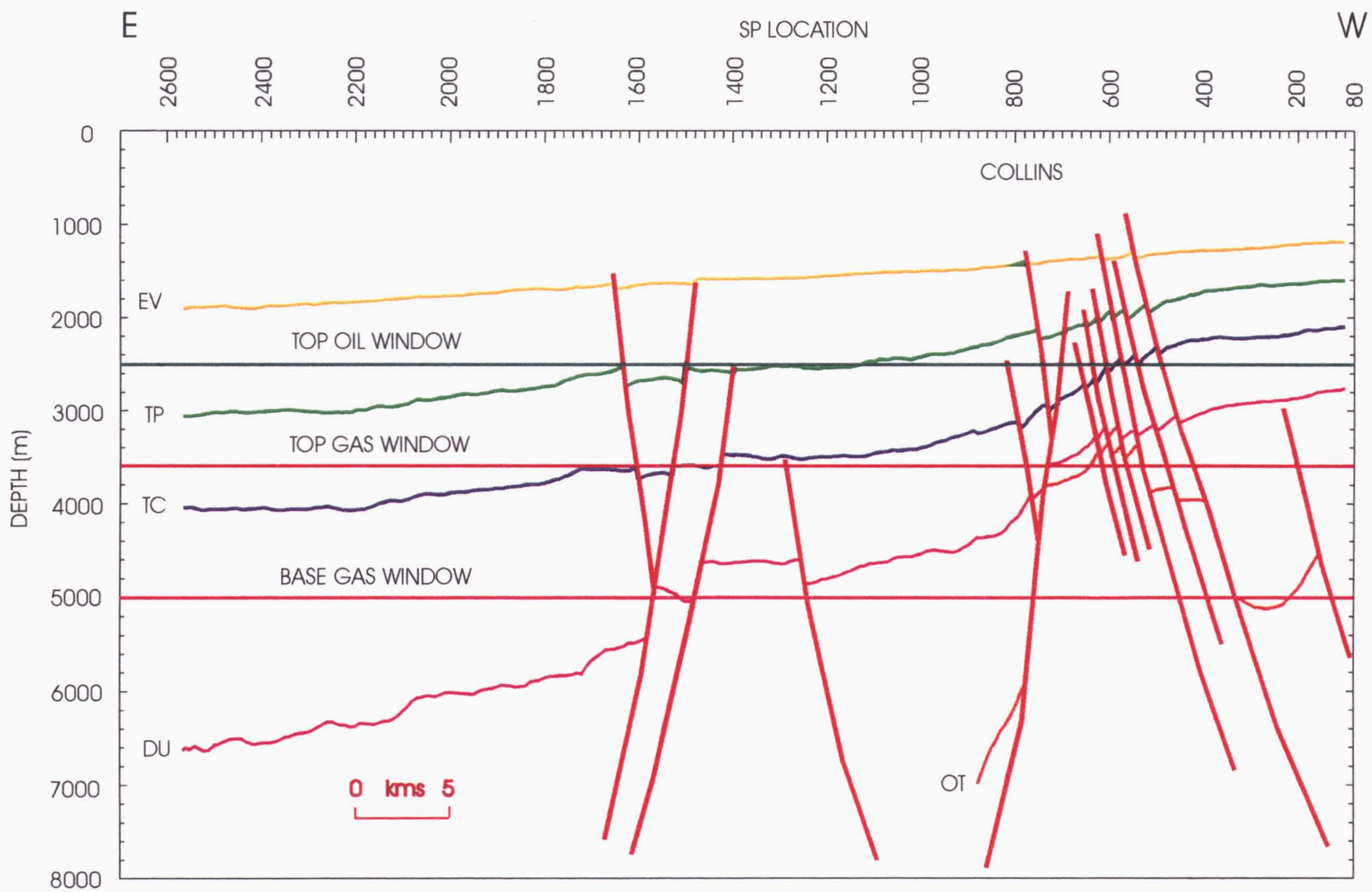
WB81-02

FIGURE A28

BLACKBURN / BAIRD

515155

COLLINS PROSPECT



DEPTH SECTION WB81-02

Figure A29

BLACKBURN / BAIRD

5 cm

515156

COLLINS PROSPECT

TIME STRUCTURE MAP

EASTERN VIEW GROUP

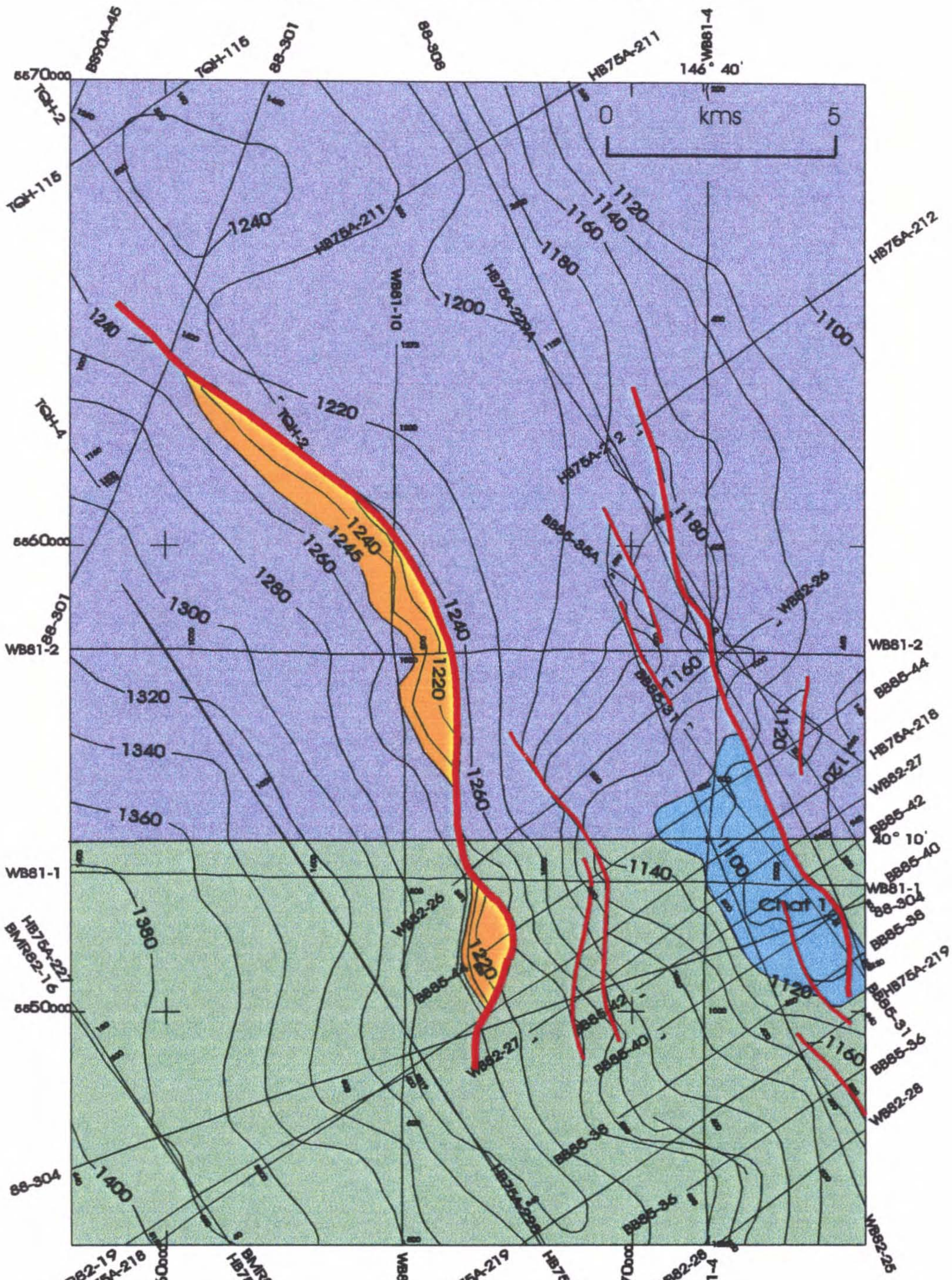


FIGURE 30

BLACKBURN / BAIRD

DENISON PROSPECT

BLACKBURN / BAIRD

PROSPECT:	**DENISON**
PERMIT:	T28P
BASIN:	Bass Basin, Tasmania
OPERATOR:	Cue Energy Resources NL
WATER DEPTH:	77m
TRAP TYPE:	Faulted anticline
PRIMARY OBJECTIVE:	Early Tertiary Eastern View Group
SEAL:	Shales of the Demons Bluff Fm.
SOURCE:	Late Cretaceous shales and coals of the Durroon Fm & Eastern View Group.

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	AREA (sq kms)	VOLUME (m3)
1059	1209	0.000	
1060	1210	0.566	343,279
1070	1222	3.052	22,286,449
1080	1234	7.669	87,309,314
1090	1246	10.599	198,104,734

RESERVOIR PRESSURE (psi):	1717.3 psi	
RESERVOIR TEMPERATURE (C):	52.5 C	126.5 F
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	**GAS**
POROSITY:	0.22	0.22
NET/GROSS:	0.70	0.70
HYDROCARBON SATURATION:	0.75	0.75
FORMATION VOLUME FACTOR:	1.20	0.00844264
RECOVERY FACTOR:	0.40	0.65

BLACKBURN / BAIRD

IN PLACE	120 mmbbls	96 BCF
RECOVERABLE	48 mmbbls	62 BCF

GAS COMPOSITION	MOLE FRACTION (%)	CRITICAL CONSTANTS Tc (F)	Pc (psi)
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.709
PSUEDO REDUCED PRESSURE	2.572
FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR	**0.875**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

GAS SOURCE IN THE VICINITY OF THE TRAP IS CERTAIN AND MATURITY IS PROBABLE

PROBABILITY RISK FACTOR OIL 0.55

PROBABILITY RISK FACTOR FOR GAS 0.55

2) RESERVOIR IN THE VICINITY OF THE TRAP IS CERTAIN AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR 0.80

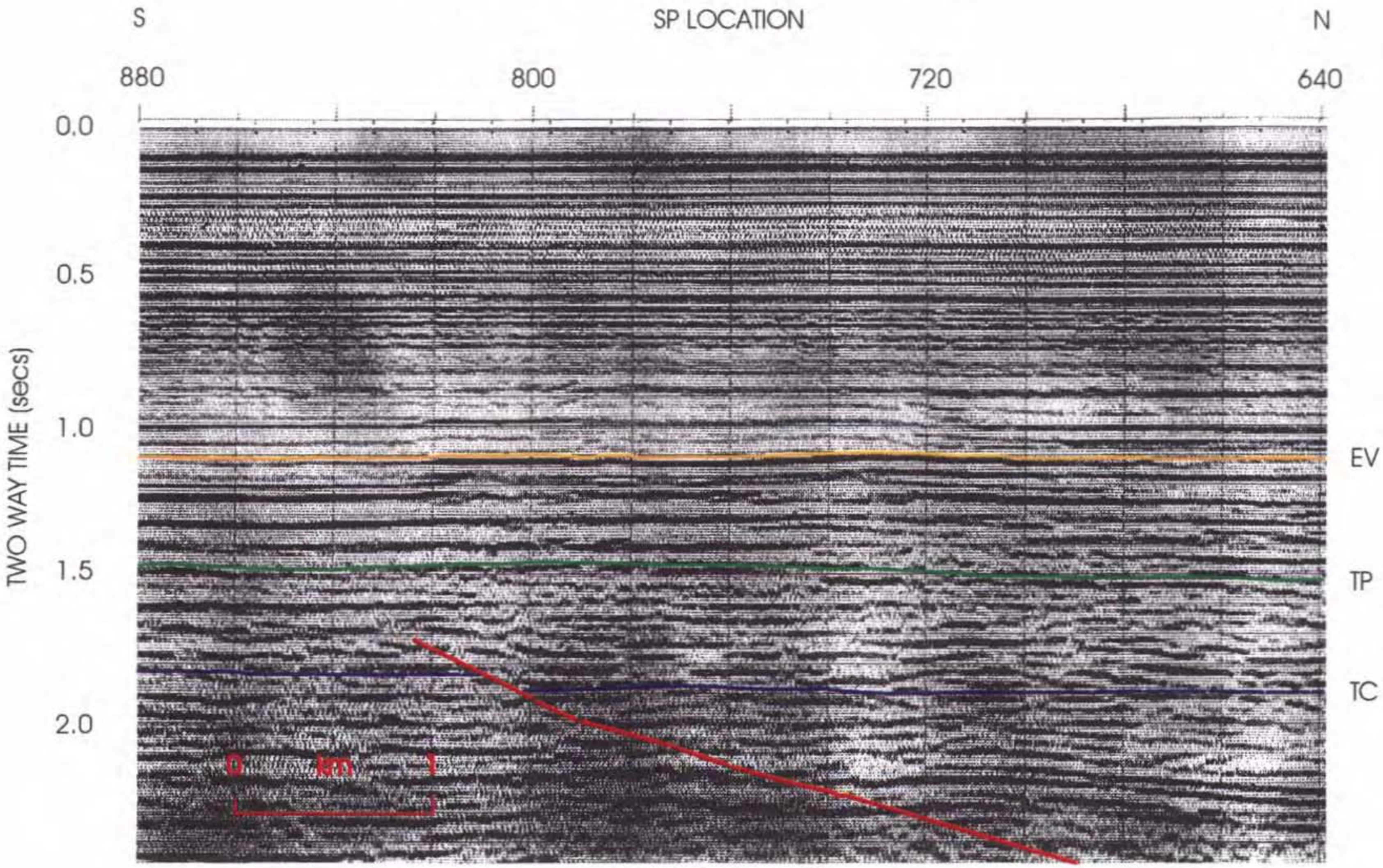
3) STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS PROBABLE

PROBABILTY RISK FACTOR		0.45
CHANCE OF SUCCESS (OIL)	**(1 in 5.1)**	**19.8%**
CHANCE OF SUCCESS (GAS)	**(1 in 5.1)**	**19.8%**
RISKED RECOVERABLE OIL RESERVES mmbbls		**9.5**
RISKED RECOVERABLE GAS RESERVES BCF		**12.3**

5 cm

515161

DENISON PROSPECT

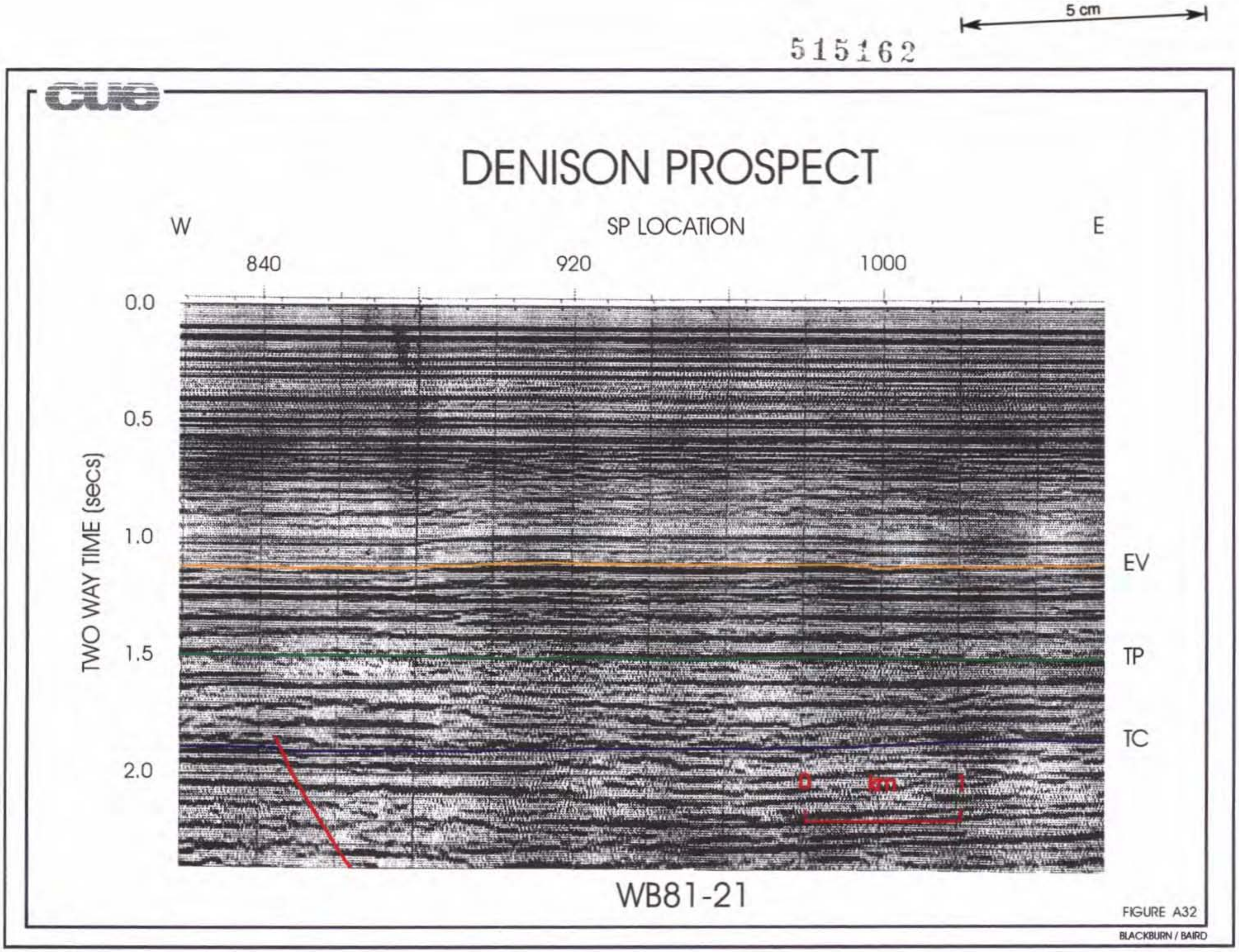


WB81-22

FIGURE A31

BLACKBURN / BAIRD

515162



5 cm
DENISON PROSPECT
W
SP LOCATION
E
840
920
1000
0.0
0.5
1.0
1.5
2.0
TWO WAY TIME (secs)
EV
TP
TC
0
km
1
WB81-21
FIGURE A32
BLACKBURN / BAIRD

5 cm

515163

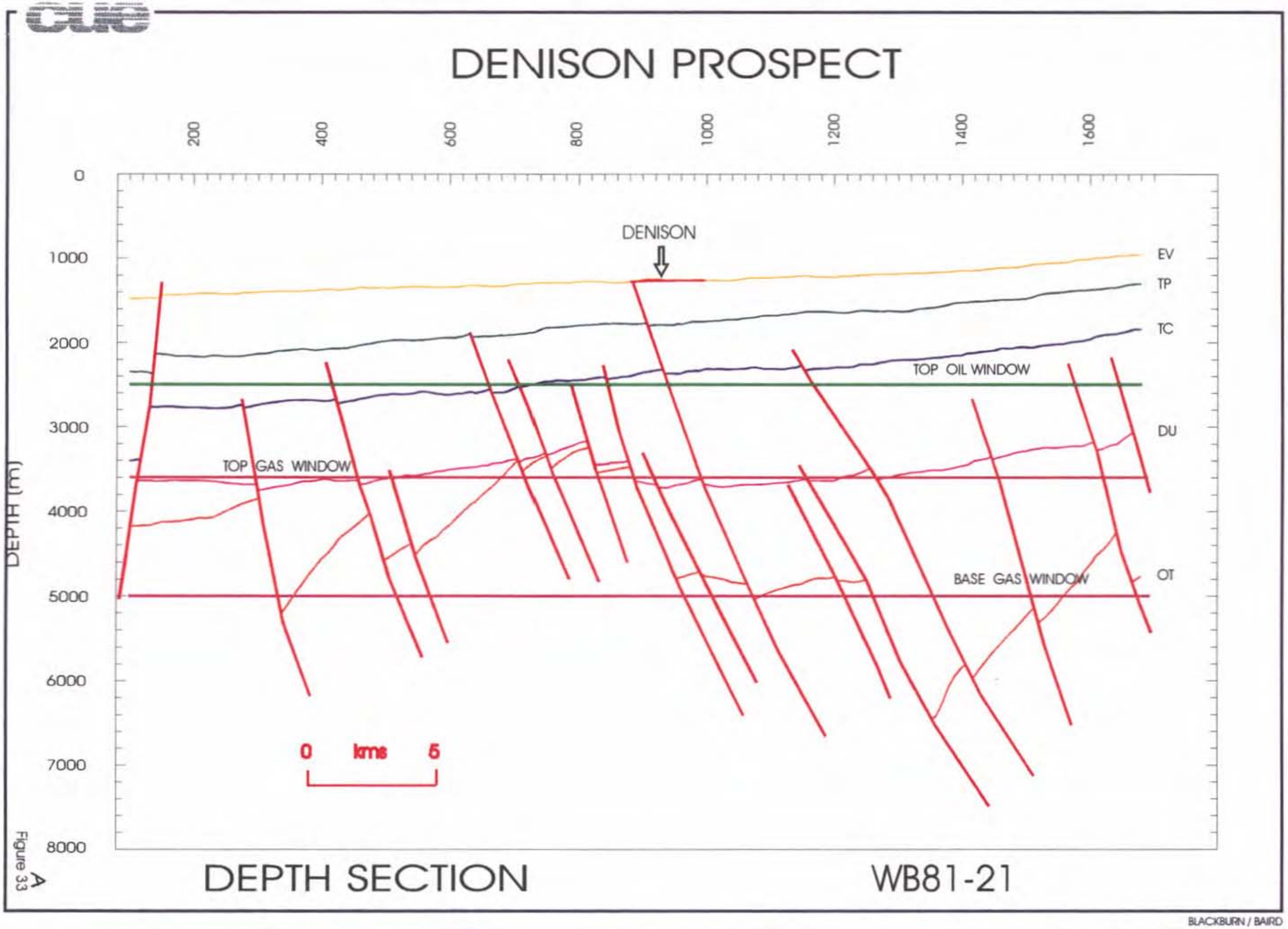


Figure 33 A

5 cm

515164

DENISON PROSPECT

TIME STRUCTURE MAP

EASTERN VIEW GROUP

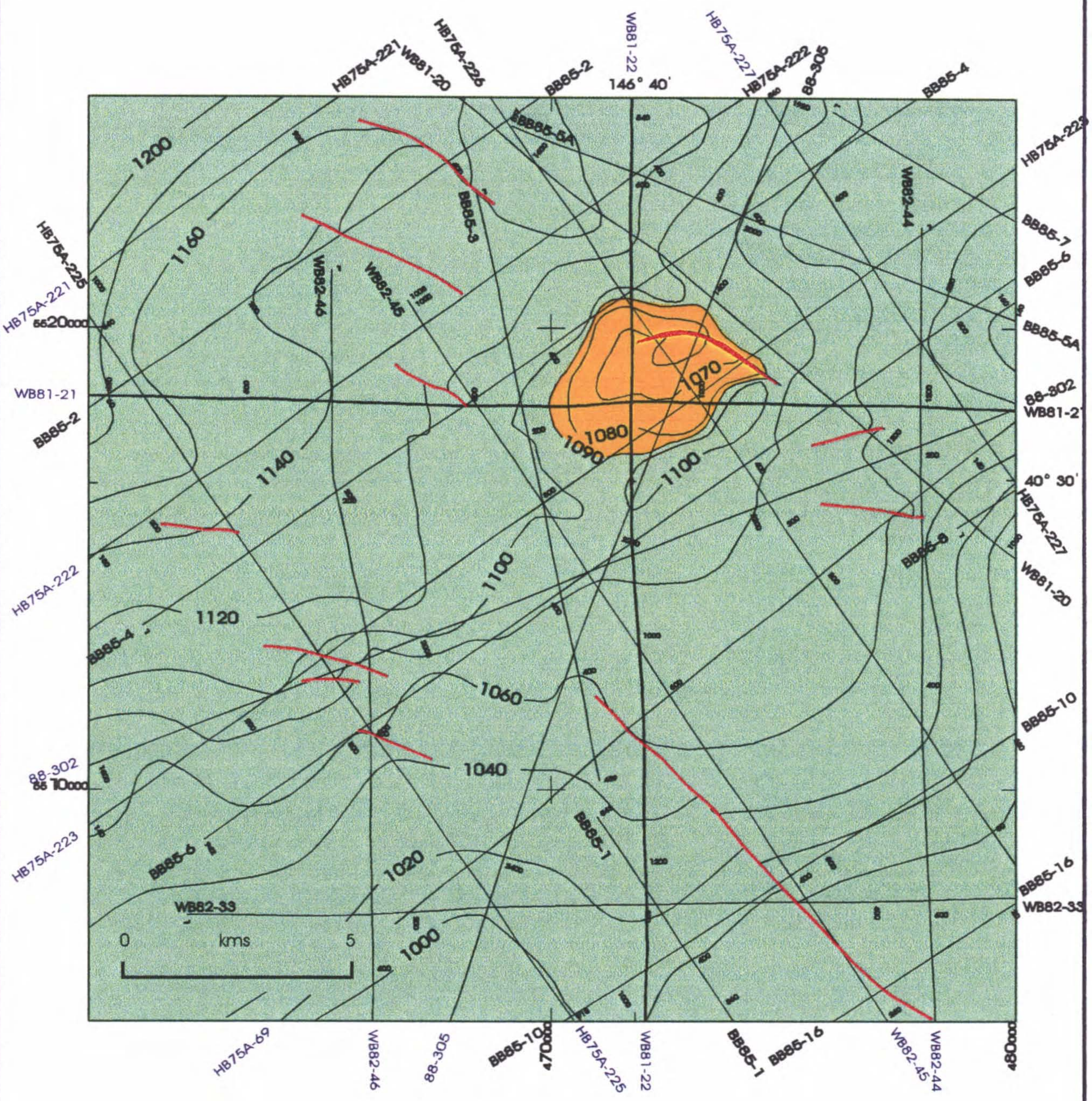


FIGURE A34

BLACKBURN / BAIRD

FRANKLIN PROSPECT

BLACKBURN / BAIRD

PROSPECT:	**FRANKLIN**
PERMIT:	T28P
BASIN:	Bass Basin, Tasmania
OPERATOR:	Cue Energy Resources NL
WATER DEPTH:	70m
TRAP TYPE:	Anticlinal stratigraphic pinchout
PRIMARY OBJECTIVE:	Early Tertiary Eastern View Group
SEAL:	Volcanics and claystones of the Torquay Fm.
SOURCE:	Late Cretaceous shales and coals of the Durroon Fm & Eastern View Group.

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	TOTAL AREA (sq kms)	PERMIT AREA (sq kms)	TOTAL VOLUME (m3)	PERMIT VOLUME (m3)
775	860	0.000	0.000		
780	866	1.330	0.000	4,108,155	0
800	891	3.118	0.041	58,188,539	498,560
820	916	6.403	0.805	177,769,787	11,124,320
840	940	11.290	2.534	396,450,323	52,394,360
860	965	18.752	5.784	767,765,735	155,204,840
880	990	23.722	7.532	1,292,744,375	319,790,600
900	1015	28.725	9.692	1,940,989,295	532,679,240

RESERVOIR PRESSURE (PSI)	1221.9 psi	
RESERVOIR TEMPERATURE (C):	41.7 C	107.0 F
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	**GAS**
POROSITY:	0.22	0.22
NET/GROSS:	0.70	0.70

BLACKBURN / BAIRD

HYDROCARBON SATURATION:	0.75	0.75
FORMATION VOLUME FACTOR:	1.20	0.011537671
RECOVERY FACTOR:	0.40	0.65

IN PLACE	**1,175 mmbbls**	**686 BCF**
RECOVERABLE	**470 mmbbls**	**446 BCF**
IN PLACE WITHIN PERMIT	**322 mmbbls**	**188 BCF**
RECOVERABLE WITHIN PERMIT	**129 mmbbls**	**122 BCF**

GAS COMPOSITION	MOLE FRACTION (%)	CRITICAL CONSTANTS Tc (F)	Pc (psi)
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.652
PSUEDO REDUCED PRESSURE	1.830

FROM STANDING AND KATZ CHART COMPRESSIBILITY **0.88**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE+B110 AND MATURITY IS CERTAIN

GAS SOURCE IN THE VICINITY OF THE TRAP IS CERTAIN AND MATURITY IS PROBABLE

PROBABILITY RISK FACTOR OIL 0.55

PROBABILITY RISK FACTOR FOR GAS 0.55

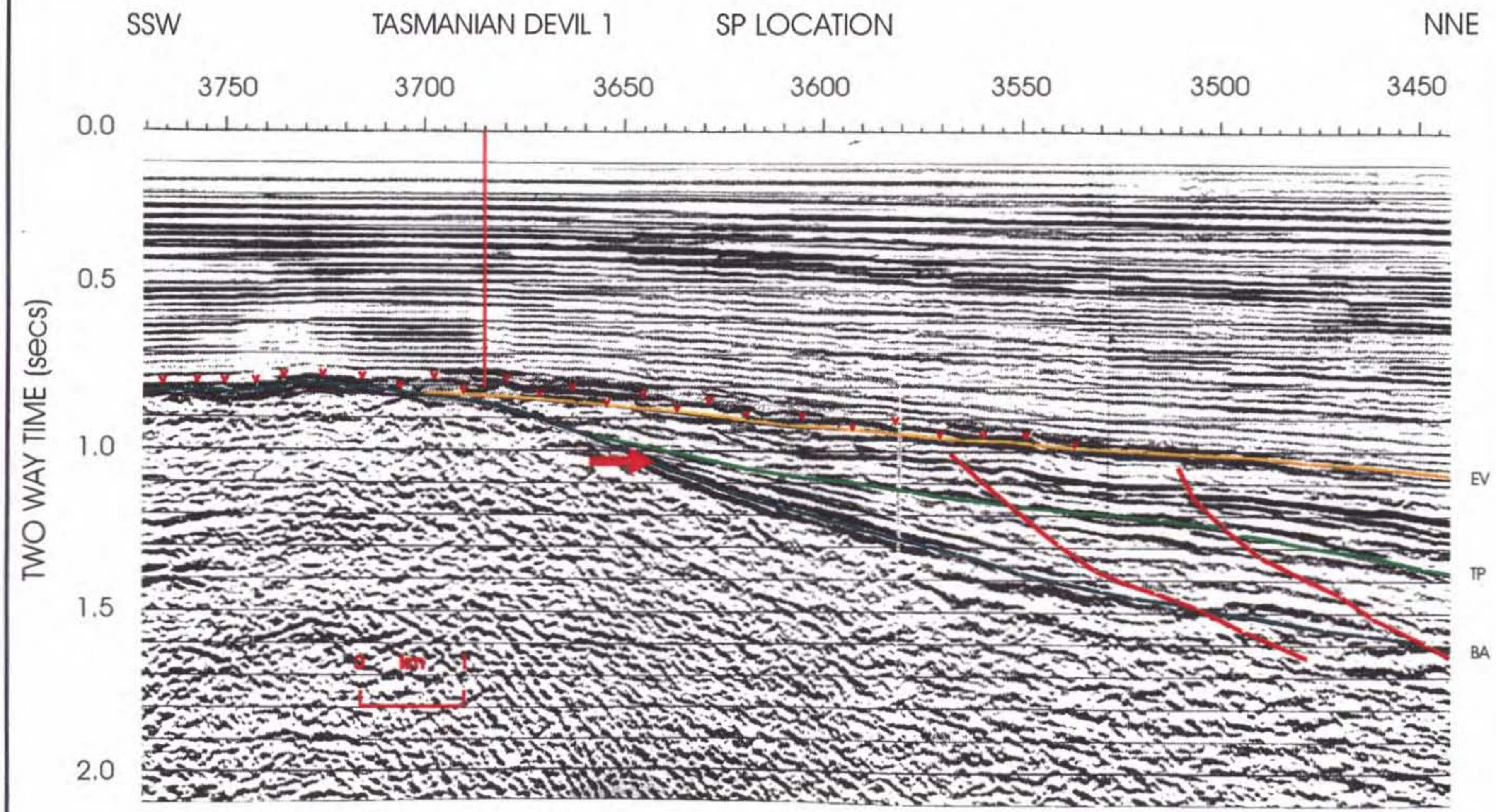
2)	RESERVOIR IN THE VICINITY OF THE TRAP IS CERTAIN AND COMMUNICATION IS CERTAIN	
	PROBABILITY RISK FACTOR	0.80
3)	STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS PROBABLE	
	PROBABILTY RISK FACTOR	0.45

CHANCE OF SUCCESS (OIL)	**(1 in 5.1)**	**19.8%**
CHANCE OF SUCCESS (GAS)	**(1 in 5.1)**	**19.8%**
RISKED OIL RESERVES (TOTAL) mmbbls		**93.1**
RISKED OIL RESERVES (PERMIT) mmbbls		**25.5**
RISKED GAS RESERVES (TOTAL) BCF		**88.3**
RISKED GAS RESERVES (PERMIT) BCF		**24.2**

5 cm

515169

FRANKLIN PROSPECT

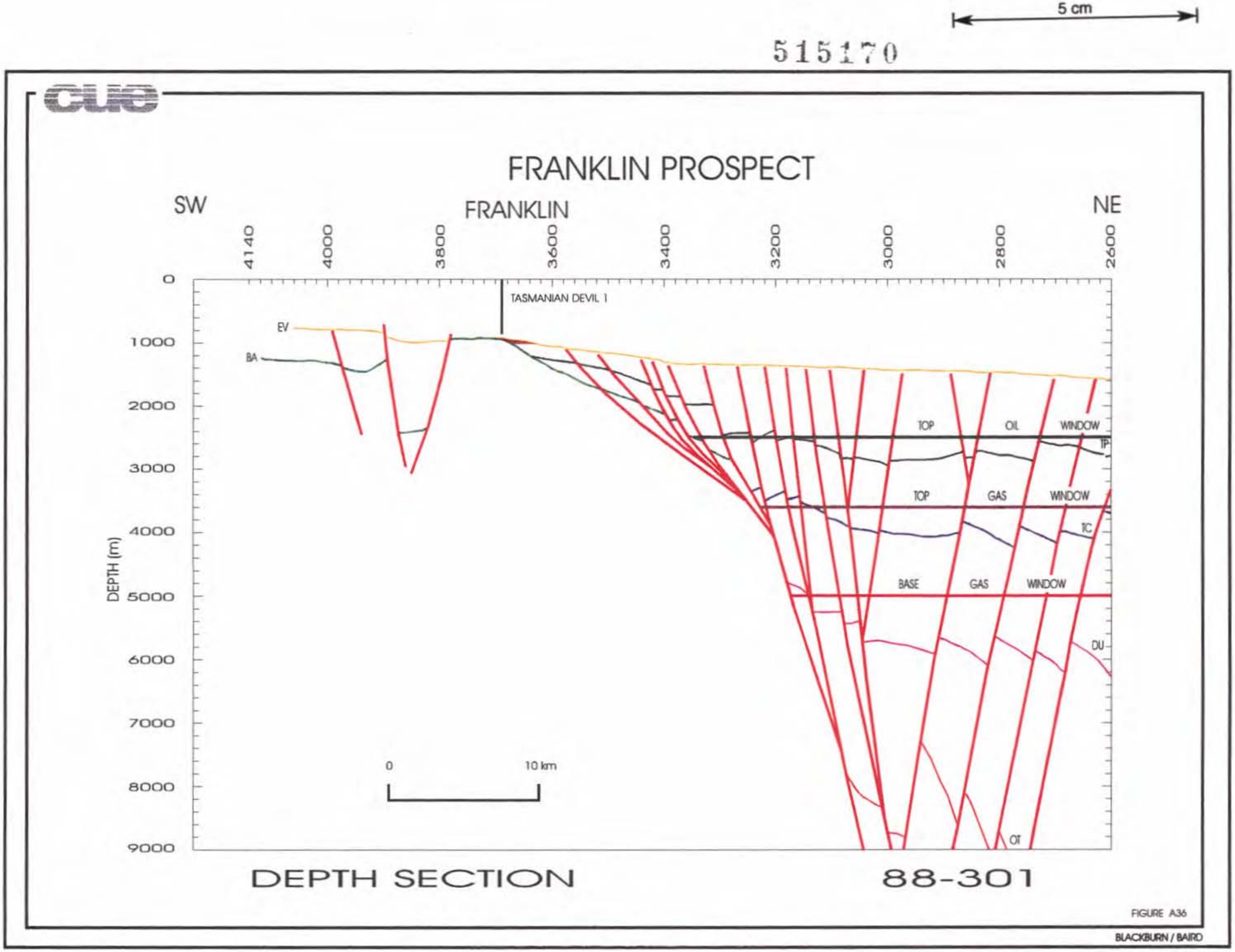


BMR88-301

FIGURE A35

BLACKBURN / BAIRD

515170



5 cm
cue
FRANKLIN PROSPECT
SW
FRANKLIN
NE
4140
4000
3800
3600
3400
3200
3000
2800
2600
TASMANIAN DEVIL 1
DEPTH (m)
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
EV
BA
TOP OIL WINDOW
TP
TOP GAS WINDOW
TC
BASE GAS WINDOW
DU
OT
0
10 km
DEPTH SECTION
88-301
FIGURE A36
BLACKBURN / BAIRD

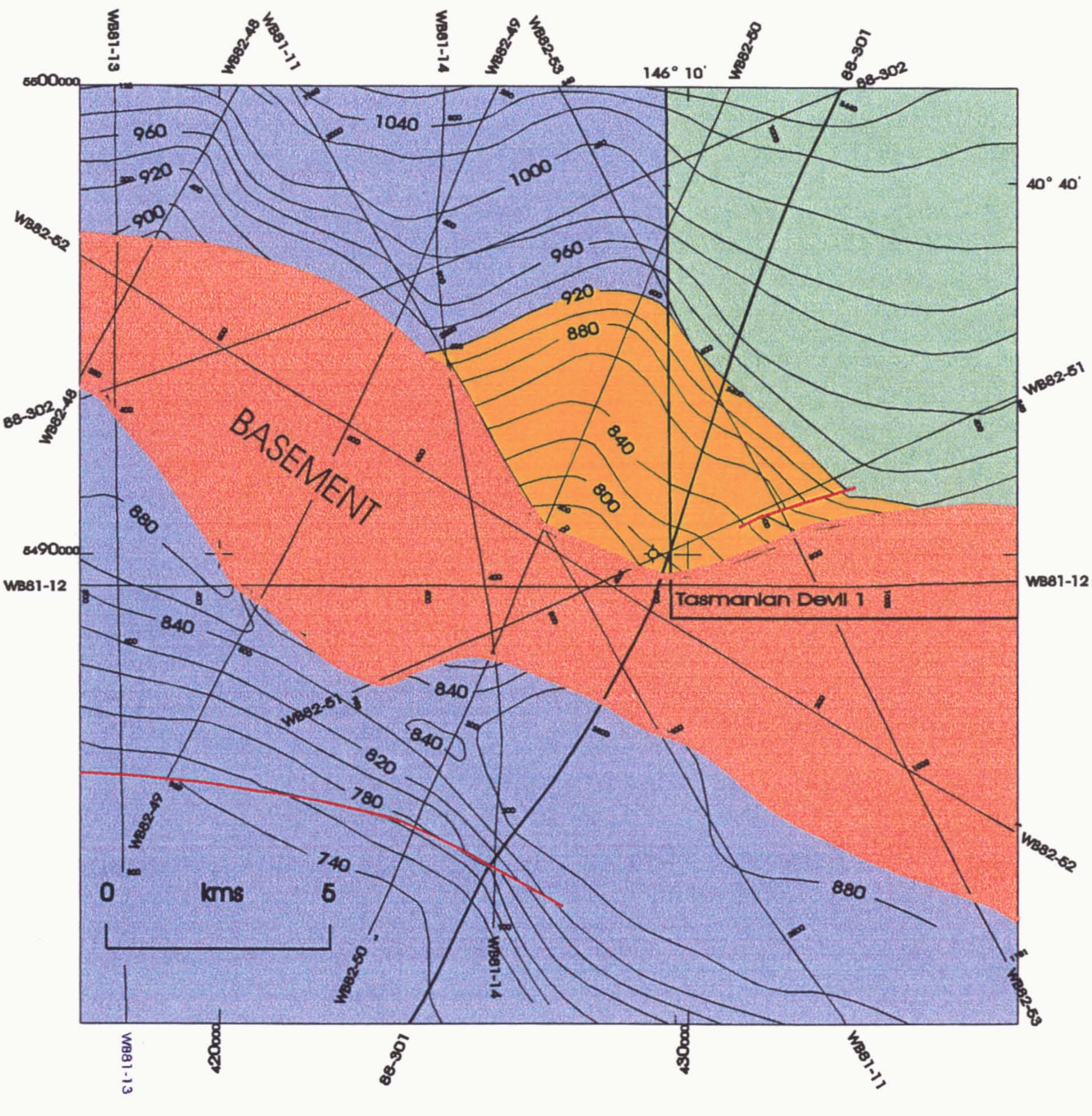
5 cm

515171

FRANKLIN PROSPECT

TIME STRUCTURE MAP

EASTERN VIEW GROUP



A
FIGURE 37

BLACKBURN / BAIRD

SORELL PROSPECT

BLACKBURN / BAIRD

CUE

PROSPECT:	**SORELL**
PERMIT:	T28P
BASIN:	Bass Basin, Tasmania
OPERATOR:	Cue Energy Resources NL
WATER DEPTH:	77m
TRAP TYPE:	Anticline
PRIMARY OBJECTIVE:	Early Tertiary Eastern View Group
SEAL:	Shales of the Demons Bluff Fm.
SOURCE:	Late Cretaceous shales and coals of the Durroon Fm & Eastern View Group.

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	AREA (sq kms)	VOLUME (m3)
1148	1317	0.000	
1150	1319	0.147	178,164
1160	1331	0.864	6,304,824
1170	1343	1.891	23,000,124
1180	1356	2.610	50,278,608
1190	1368	5.548	99,718,512
1200	1380	19.429	251,079,132
1205	1386	32.813	409,372,392

RESERVOIR PRESSURE (psi):	1870.6 psi	
RESERVOIR TEMPERATURE (C):	55.8 C	132.5 F
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	**GAS**
POROSITY:	0.22	0.22
NET/GROSS:	0.70	0.70
HYDROCARBON SATURATION:	0.75	0.75

BLACKBURN / BAIRD

FORMATION VOLUME FACTOR:	1.20	0.007785647
RECOVERY FACTOR:	0.40	0.65

IN PLACE	**248 mmbbls**	**214 BCF**
RECOVERABLE	**99 mmbbls**	**139 BCF**

GAS COMPOSITION	MOLE FRACTION (%)	CRITICAL CONSTANTS Tc (F)	Pc (psi)
C1	100	-116.68	667.8
C2	0	90.1	707.8
C3	0	206.01	616.3
iC4	0	274.96	529.1
nC4	0	305.62	550.7
iC5	0	369.03	529.1
nC5	0	385.6	488.6
CO2	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.726
PSUEDO REDUCED PRESSURE	2.801

FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR **0.87**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

GAS SOURCE IN THE VICINITY OF THE TRAP IS CERTAIN AND MATURITY IS PROBABLE

PROBABILITY RISK FACTOR OIL 0.55

PROBABILITY RISK FACTOR FOR GAS 0.55

2) RESERVOIR IN THE VICINITY OF THE TRAP IS CERTAIN AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR 0.80

3) STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS UNLIKELY

PROBABILTY RISK FACTOR		0.37
CHANCE OF SUCCESS (OIL)	**(1 in 6.1)**	**16.3%**
CHANCE OF SUCCESS (GAS)	**(1 in 6.1)**	**16.3%**
RISKED RECOVERABLE OIL RESERVES mmbbls		**16.1**
RISKED RECOVERABLE GAS RESERVES BCF		**22.7**

5 cm

515176

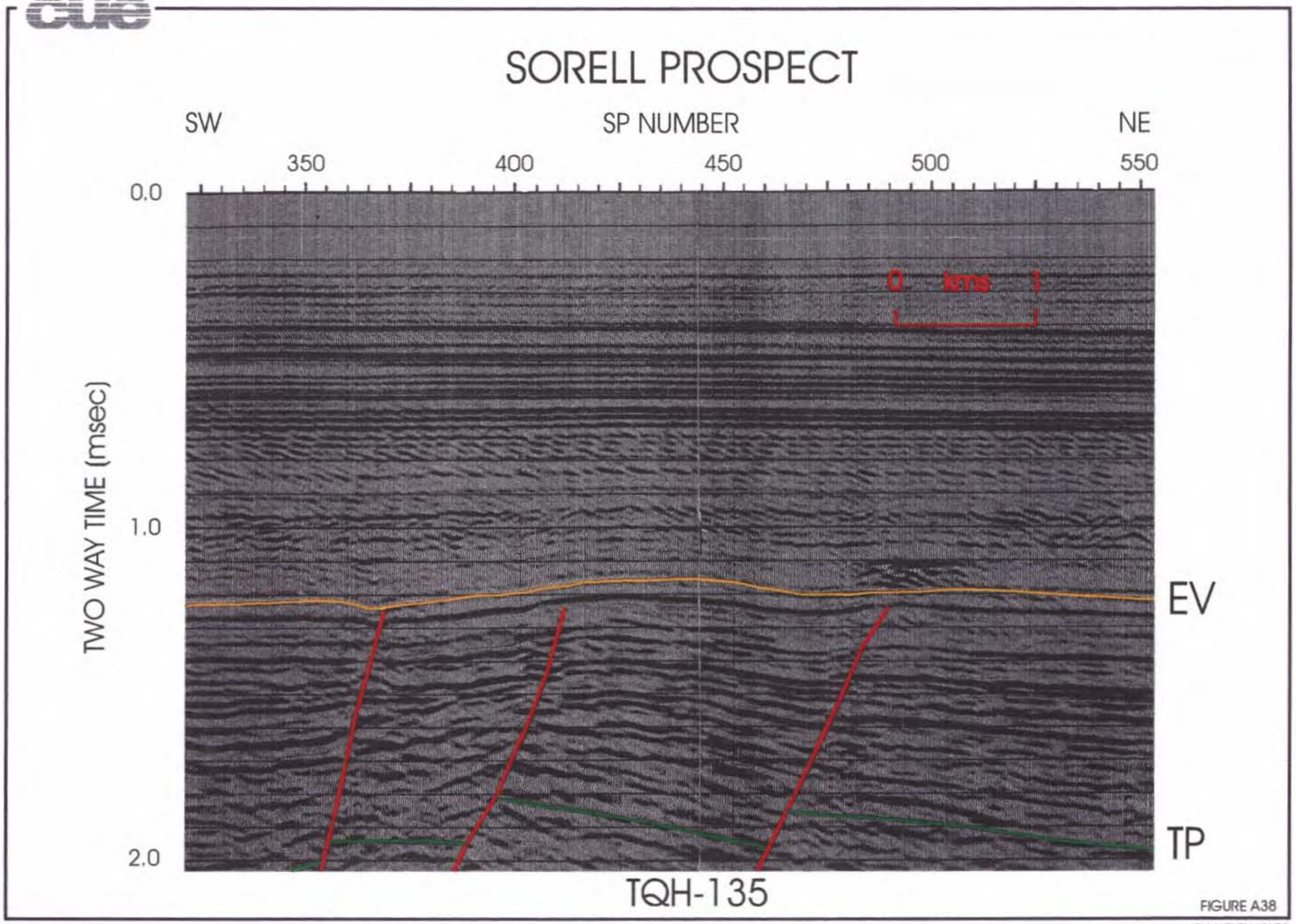


FIGURE A38

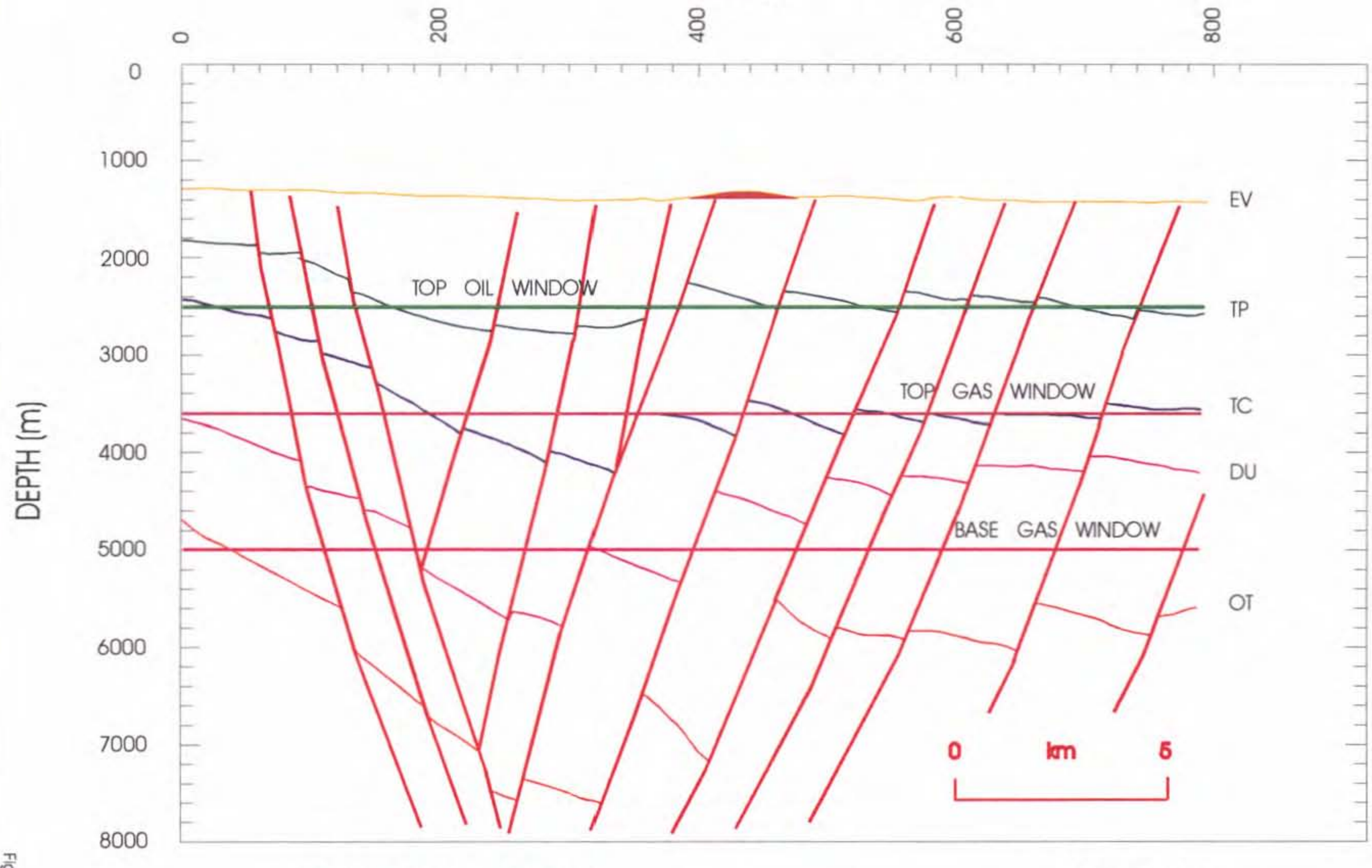
BLACKBURN / BAIRD

5 cm

515177

SORELL PROSPECT

SORELL



DEPTH SECTION

TQH-135

Figure A39

BLACKBURN / BAIRD

5 cm

515178

SORELL PROSPECT

TIME STRUCTURE MAP

EASTERN VIEW GROUP

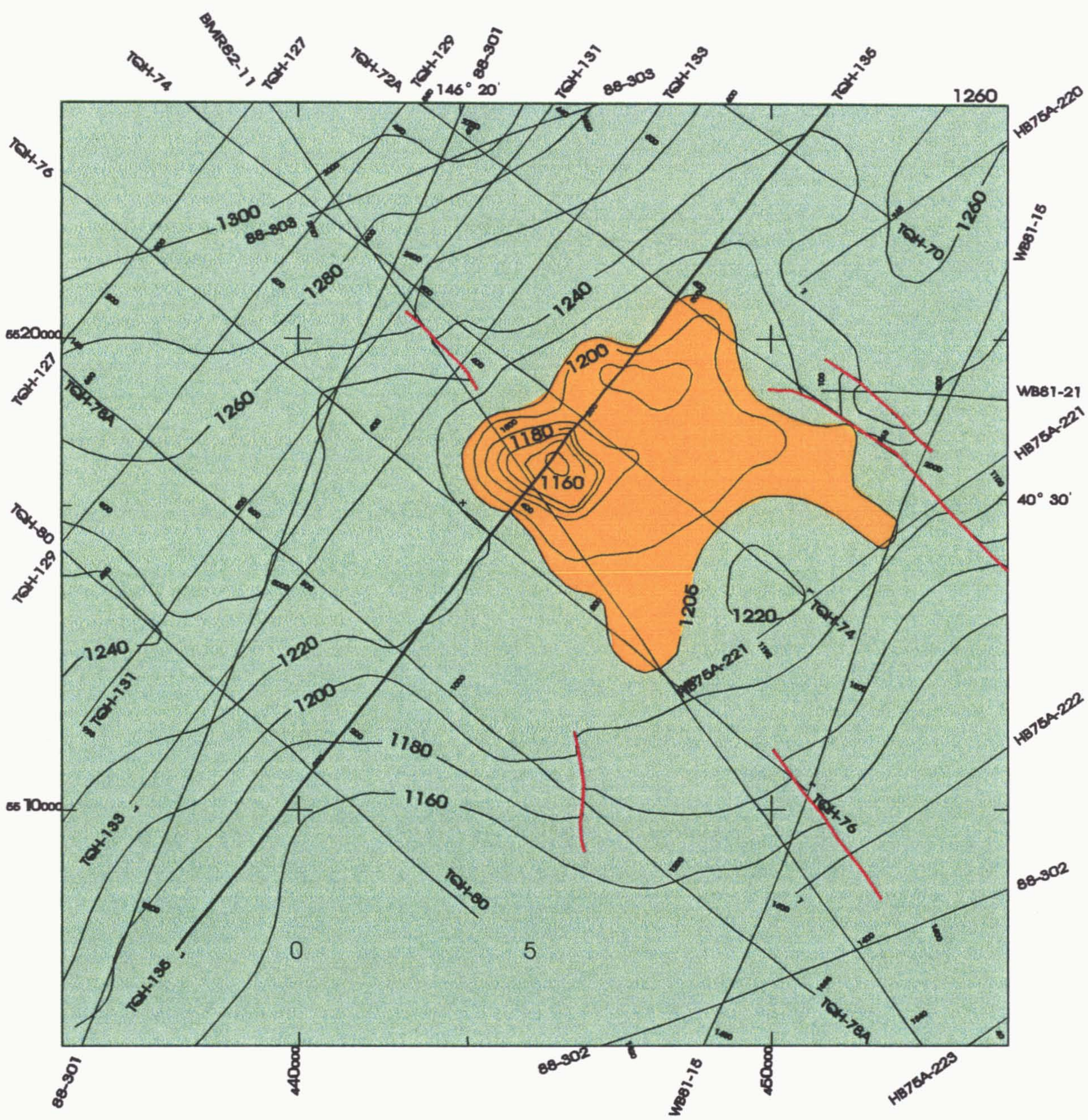


FIGURE A40

BLACKBURN / BAIRD

WATERHOUSE PROSPECT

PROSPECT:	**WATERHOUSE**
PERMIT:	T28P
BASIN:	Bass Basin, Tasmania
OPERATOR:	Cue Energy Resources NL
WATER DEPTH:	65m
TRAP TYPE:	Rotated fault block
PRIMARY OBJECTIVE:	Early Tertiary Eastern View Group
SEAL:	Shales of the Demons Bluff Fm.
SOURCE:	Late Cretaceous shales and coals of the Durroon Fm & Eastern View Group.

BULK ROCK VOLUME:

TWT (ms)	DEPTH (m)	TOTAL AREA (sq kms)	TOTAL VOLUME (m3)
1404	1639	0.000	
1410	1648	0.147	634,599
1420	1660	0.864	6,756,204
1430	1673	1.891	24,663,704
1440	1687	2.610	56,173,504
1445	1694	5.548	84,727,904

ONLY A SMALL PORTION OF THE PROSPECT LIES WITHIN T28P
NO RESERVES HAVE BEEN CALCULATED FOR THE SMALL PORTION WITHIN T28P

RESERVOIR PRESSURE (psi):	2328.7 psi	
RESERVOIR TEMPERATURE (C):	65.8 C	150.5 F
HYDROCARBON TYPE:	Similar to the Yolla Oil	gas is methane
	OIL	**GAS**
POROSITY:	0.22	0.22
NET/GROSS:	0.70	0.70
HYDROCARBON SATURATION:	0.75	0.75

BLACKBURN / BAIRD

FORMATION VOLUME FACTOR:	1.20	0.006555176
RECOVERY FACTOR:	0.40	0.65

IN PLACE	**51 mmbbls**	**53 BCF**
RECOVERABLE	**21 mmbbls**	**34 BCF**

GAS COMPOSITION	MOLE FRACTION (%)	CRITICAL CONSTANTS Tc (F)	Pc (psi)
C1			
C2	100	-116.68	667.8
C3	0	90.1	707.8
iC4	0	206.01	616.3
nC4	0	274.96	529.1
iC5	0	305.62	550.7
nC5	0	369.03	529.1
CO2	0	385.6	488.6
	0	87.87	1071

PSUEDOCRITICAL TEMPERATURE OF GAS MIXTURE	-116.68 F
PSUEDOCRITICAL PRESSURE OF GAS MIXTURE	667.8 psi
PSUEDO REDUCED TEMPERATURE	1.779
PSUEDO REDUCED PRESSURE	3.487
FROM STANDING AND KATZ CHART COMPRESSIBILITY FACTOR	**0.885**

RISK ASSESSMENT

1) OIL SOURCE IN THE VICINITY OF THE TRAP IS PROBABLE AND MATURITY IS CERTAIN

GAS SOURCE IN THE VICINITY OF THE TRAP IS CERTAIN AND MATURITY IS PROBABLE

PROBABILITY RISK FACTOR OIL 0.55

PROBABILITY RISK FACTOR FOR GAS 0.55

2) RESERVOIR IN THE VICINITY OF THE TRAP IS CERTAIN AND COMMUNICATION IS CERTAIN

PROBABILITY RISK FACTOR 0.80

BLACKBURN / BAIRD

3) STRUCTURE AND ITS EFFECTIVENESS WITHIN THE BASIN IS PROBABLE AND SEAL (LATERAL / VERTICAL) IS PROBABLE

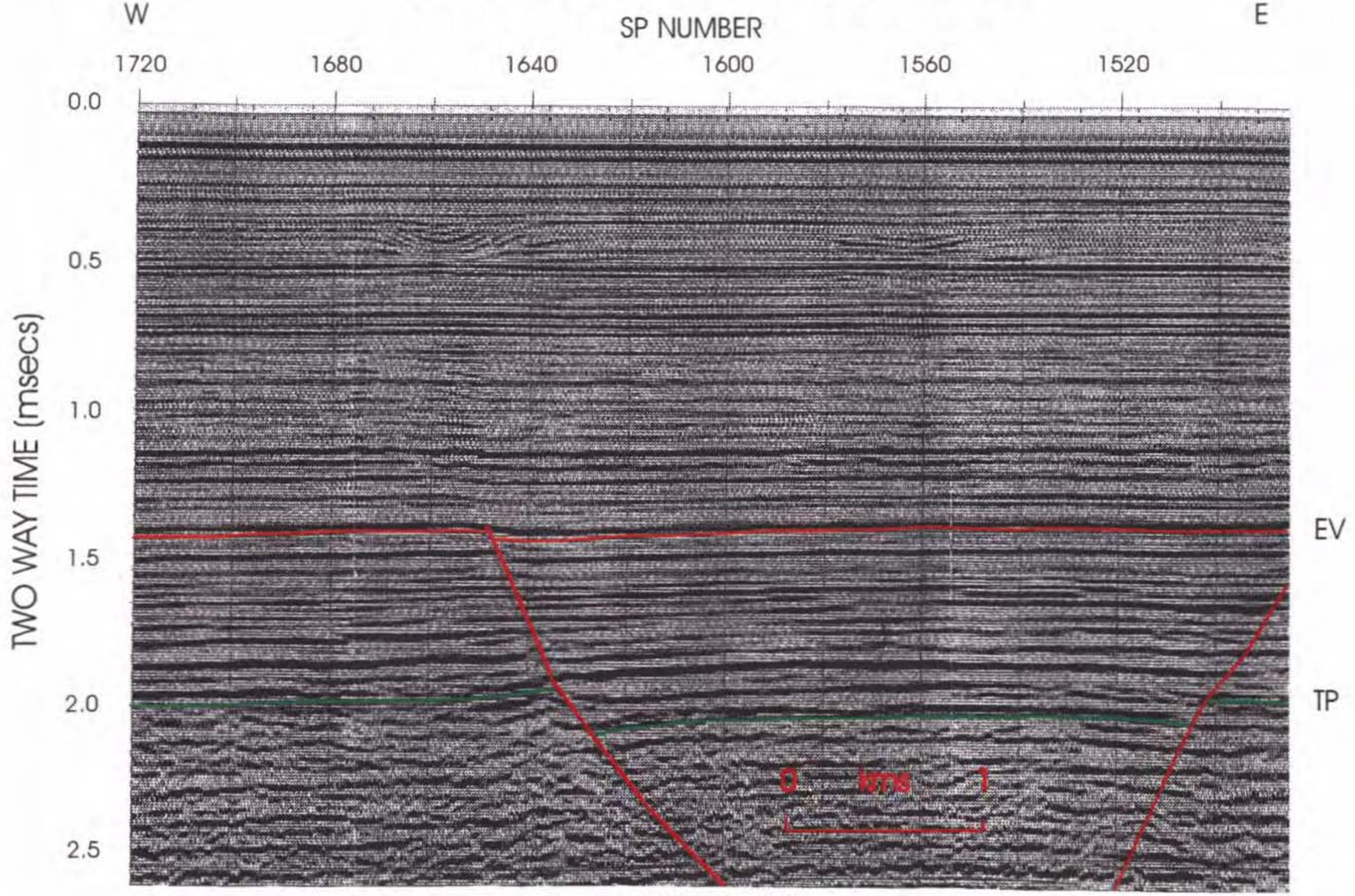
PROBABILTY RISK FACTOR 0.45

CHANCE OF SUCCESS (OIL)	**(1 in 5.1)**	**19.8%**
CHANCE OF SUCCESS (GAS)	**(1 in 5.1)**	**19.8%**
RISKED RECOVERABLE OIL RESERVES mmbbls		**4.1**
RISKED RECOVERABLE GAS RESERVES BCF		**6.8**

5 cm

515183

WATERHOUSE PROSPECT



WB81-02

FIGURE A41

BLACKBURN / BAIRD

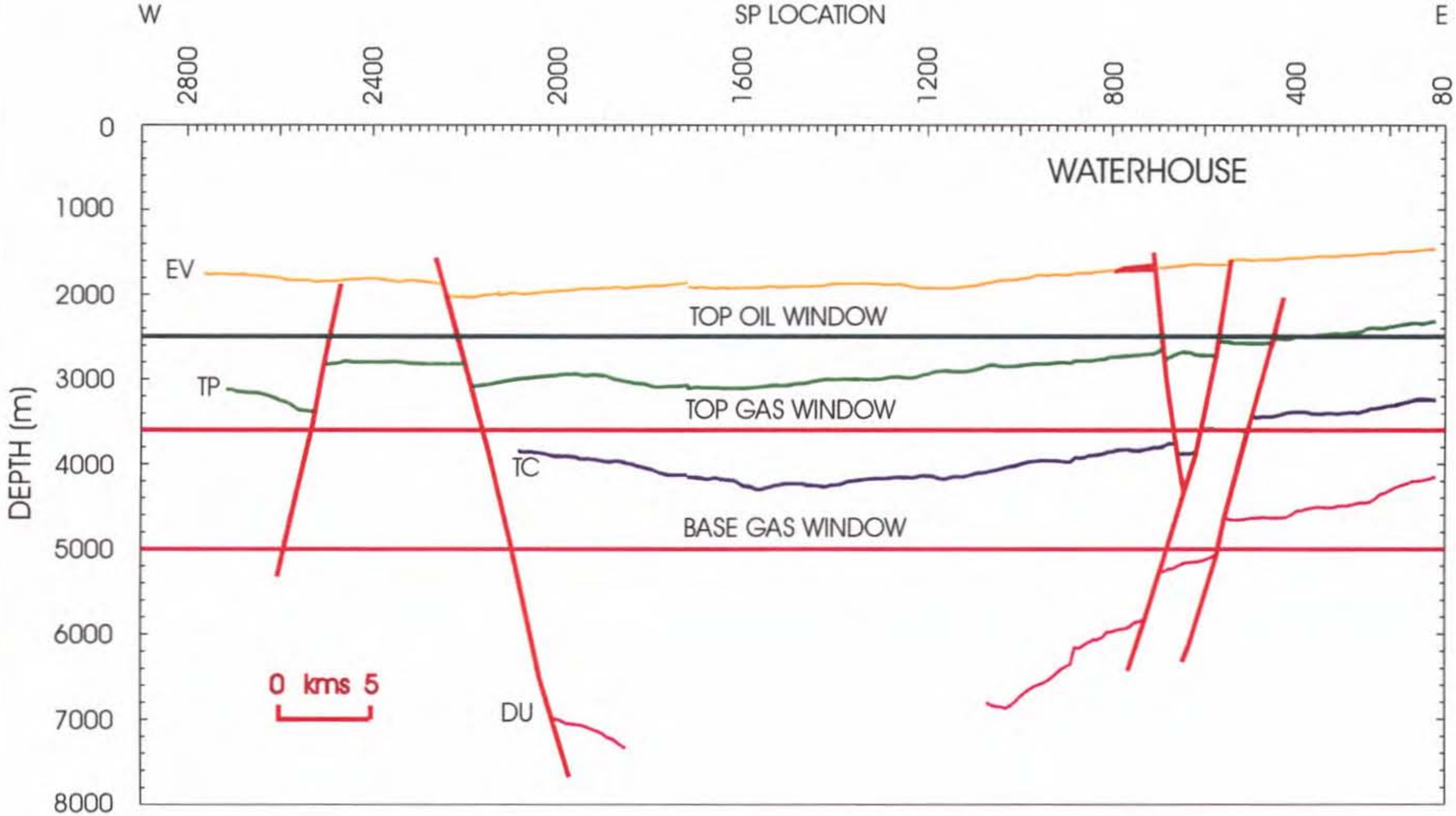
5 cm

515184

66

CUE

WATERHOUSE PROSPECT



DEPTH SECTION

WB81-03

Figure A42

BLACKBURN / BAIRD

5 cm

515185

WATERHOUSE PROSPECT

TIME STRUCTURE MAP

EASTERN VIEW GROUP

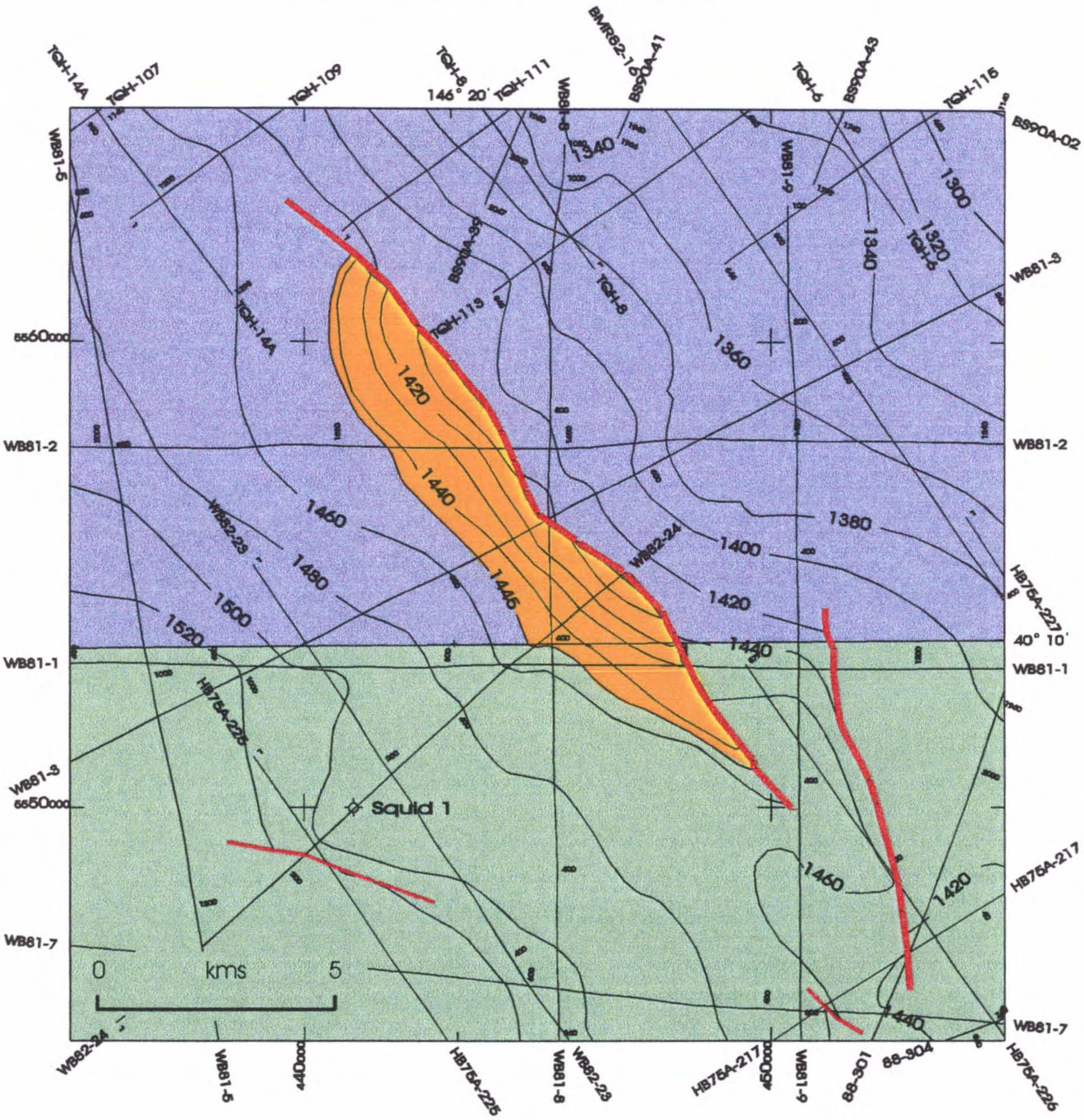


FIGURE A43

BLACKBURN / BAIRD