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WELL COMPLETION REPORT

VOLUME 2
INTERPRETED DATA

BLACKBACK-2

GIPPSLAND BASIN
VICTORIA

ESSO AUSTRALIA LIMITED

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ENCLOSURES

1. Summary of Well Results

Formation/Horizon	Predicted Depth mTVDSS	Post Drill Depth mTVDSS
Gippsland Limestone (seafloor)	-375	-370.4
Lakes Entrance Formation	-2520	-2517.7
Top of Latrobe Group Unconformity	-2760	-2756.7
Total Depth	**-3100**	**-3137.7**

2. Introduction

Blackback-2 was drilled as an appraisal well designed to test the reservoir quality and producibility of the interpreted Paleocene (L. balmei) channel fill sequence in the Central block of the Blackback/Terakihi field immediately southwest of Hapuku-1.

The Blackback/Terakihi structure is a faulted erosional remnant at the Top of Latrobe Group level in the western part of VIC/P24. A series of N. asperus to L. balmei channel fills underlie the Top of Latrobe Group unconformity. The environment of deposition of the channel fills ranges from lower shoreface in the L. balmei and lower M. diversus to distal marine in the Upper M. diversus and N. asperus. The channels cut into excellent reservoir quality Upper T. longus shoreface sands. The distribution of the channels is partially controlled by underlying intra Latrobe Group fault patterns.

Blackback-2 intersected the Top of Latrobe Group unconformity at -2756.7mSS, 3.3m high to prognosis. A 19m thickness of Upper M. diversus Flounder Formation equivalent was encountered at the Top of Latrobe Group level. Underlying this were two Lower M. diversus gas sands from -2776.2mSS to -2781.2mSS and -2786.2mSS to -2798.5mSS respectively. These sands have not been previously encountered in the Blackback field. The gas sands overlie an oil bearing interval extending from -2802.5mSS to an interpreted oil-water contact. The contact was determined at -2832.7mSS by quantitative log analysis and at -2833.2mSS by pressure gradients. The depth for the contact used on the well completion log (Enclosure 2) is -2832.7mSS to match the analysis curves presented on the log. This closely approximates the interpreted Blackback/Terakihi field oil-water contact at

-2834mSS. A gas-oil contact was not observed in the well. The oil is 802 psi below bubble point at reservoir pressure, indicating that the gas is a separate hydrocarbon system. This is supported by pressure data, which is interpreted to indicate that the two gas sands and the oil sand are all separate pressure systems (Appendix 5).

Two intervals in the oil zone were production tested. Production test 1 was carried out over the interval from -2818.7 to -2824.2mSS and flowed oil at a rate of 1602 STB/D and gas at a rate of 1.71 MSCF/D through a 48/64" choke. This test was considered invalid due to an obstruction in the tubing string. The zone was retested (production test 1A) and flowed oil at a rate of 6640 STB/D and gas at a rate of 7.88 MSCF/D through a 64/64" choke. Production test 2, carried out over the interval from -2807.2 to -2811.7mSS, flowed oil at rate of 5659 STB/D and associated gas at a rate of 8.24 MSCF/D through a 64/64" choke (see Appendix 6 for details).

The well was drilled to a total depth of -3137.7mSS, intersecting the base of the Paleocene channel at -2854.7mSS and an intra Cretaceous unconformity at -2913.7mSS. Blackback-2 was plugged and abandoned as a successful appraisal well.

3. Structure

The Blackback Top of Latrobe Group structure is mapped primarily as an erosional remnant. A maximum of 75m vertical closure was mapped at this level prior to the drilling of Blackback-2. Intra Latrobe Group faulting divides the field into four separate blocks (see Figure 2): Terakihi, Northeast, Central and Southwest. The faulting has also at least partially controlled the distribution of the channels in the Upper Latrobe Group section. Channel fill sediments were interpreted predrill to be mainly restricted to the Central and Northeast blocks. These blocks are interpreted to have been downthrown with respect to the Terakihi and Southwest blocks at the time of channel formation. The intra Latrobe Group structuring has since been inverted resulting in the uplifting of the Central and Northeast blocks. This, along with erosion associated with the Top of Latrobe Group unconformity, has controlled the form of the Blackback Top of Latrobe Group closure. Blackback-2 was designed to intersect the crest of the Blackback erosional feature.

Blackback-2 intersected the Top of Latrobe Group unconformity at -2756.7mSS, 3.3m high to prognosis. This has resulted in the amount of vertical closure increasing to 79m in post drill mapping. The mapped extent of the Paleocene channel fill section has been reduced as a result of the Blackback-2 well tie on the Central block of the field and seismic character within the Central and Southwest blocks.

Analysis of FMS data (Appendix 3) indicates the presence of an unconformity within the Late Cretaceous (T. longus) section of the well. Above the unconformity, which is interpreted at -2913.7mSS, the average structural dip is 2.1° towards an azimuth of 275°. Below the unconformity, the average structural dip is 5.3° towards an azimuth 285°. Previous interpretation has associated dips of around 2° exclusively with the Paleocene channel fill sediments. Late Cretaceous has been previously mapped only where structural dips of around 5° have been interpreted on seismic. This change has supported the mapping of larger volumes of the potentially better quality Late Cretaceous reservoir section above the oil water contact in the Central and Southwest blocks of the field. The extent of the channel fill sediments in the Central block has been reduced and the southwest block is now interpreted to consist entirely of Late Cretaceous sediments at the Top of Latrobe Group level (Figure 3).

4. Stratigraphy

The Blackback/Terakihi field contains three distinct reservoir units. The first is a Late Cretaceous section of excellent quality upper shoreface sandstones as penetrated at the Top of the Latrobe Group in the Terakihi-1 well. The Cretaceous section has been incised by two subsequent channelling events, one in the Paleocene and one in the Eocene. The sedimentary fills of these channels make up the two remaining reservoir units. The Eocene channel is filled with poor quality N. asperus age sandstones as in the Blackback-1 well. These sandstones contain abundant glauconite, pyrite, siderite and mica and are interpreted as representing a marine channel fill unit. Despite the apparently poor quality of the Eocene unit, a production test rate of 1507 STB/D of oil was achieved from this section in the Blackback-1 well. The Paleocene channel is filled with L. balmei to M. diversus age sandstones and siltstones as penetrated in the Hapuku-1 well. The sandstones are composed of quartz, glauconite, siderite and abundant intergranular clays and were deposited in a lower shoreface environment. Reservoir quality within this unit is intermediate between that of the Cretaceous and Eocene channel fill units. The distribution of the channels which have been infilled by these units was partially controlled by the intra-Latrobe structure at the time of channel formation.

At the Top of the Latrobe Group, Blackback-2 was expected to intersect 25m of M. diversus section underlain by 55m of Upper to Lower L. balmei section. These sections were expected to be channel fill units similar to that seen in Hapuku-1. An Upper T. longus section of upper shoreface to nearshore sandstones was expected to subcrop the Paleocene channel fill. A transition from the marine Upper T. longus section into a predominantly non marine Lower T. longus section was predicted within the programmed total depth of -3100mSS.

As stated, the Top of Latrobe Group unconformity was intersected 3.3m high to prognosis at -2756.7mSS. A 19m section of Upper M. diversus black-grey siltstone was encountered at the Top of the Latrobe Group. This unit is interpreted as an equivalent of the Flounder Formation. Underlying this unit is a 78m thick Lower M. diversus to Lower L. balmei section. This section is interpreted as a channel fill succession which can be correlated to the Paleocene channel fill sequence in Hapuku-1. The section is predominantly composed of glauconitic sandstone. Three separate hydrocarbon sands are present within this section. Based on pressure tests, the three sands are interpreted to be separate pressure systems.

The base of the Paleocene channelling event is marked by the 63MA sequence boundary, which is interpreted at -2854.7mSS. The Paleocene channel is cut into Upper T. longus marine sands which in turn overlie Lower T. longus coastal plain sands, silts and coals. Based on palynological information the boundary between the Upper and Lower T. longus can only be constrained to the interval between -2901.7mSS and -3116.7mSS. An unconformity has been interpreted within the T. longus section at -2913.7mSS based on analysis of FMS data (see Appendix 3) but this cannot be definitively tied to the break between Upper and Lower T. longus.

Partial top seal is provided by the Upper M. diversus siltstones interpreted to be an equivalent of the Flounder Formation (Appendix 1). The regional seal is provided by the Lakes Entrance Formation. Reservoir quality in the two gas zones is good with an average porosity of 20%. The two zones are separated from each other and from the main oil zone by silty to argillaceous cemented sands and minor siltstone. Reservoir quality in the main oil zone is variable with mean porosity values ranging from 14 to 21%. Variations in porosity are largely due to variations in the amount of matrix (argillaceous and particularly glauconite) and cement (dolomitic and siliceous) present. Two intervals in the oil zone were production tested. Zone 1, from -2818.7 to -2824.2mSS flowed oil at a rate of 6640 STB/D while zone 2, from -2807.2 to -2811.7mSS flowed oil at a rate of 5659 STB/D. Reservoir quality in the underlying Late Cretaceous section is generally very good with porosities averaging between 20-25% down to -3013mSS. Below this point the section becoms more silty and argillaceous and the sands are generally thin, with porosities in the 10-15% range. Sands in the Cretaceous section are generally cleaner than in the Paleocene channel fill section, particularly with respect to glauconite. The amount of cementation in the Late Cretaceous sands is also much less than in the Paleocene section. A detailed core mineralogy report is contained in Appendix 4.

5. Hydrocarbons

Three hydrocarbon zones, one oil and two gas, were encountered in the Blackback-2 well. The gas zones extend from -2776.2 to -2781.2mSS and from -2786.2 to -2798.7mSS and are Lower M. diversus in age. Preliminary log analysis indicates that both zones have gas on rock. This is confirmed in the lower zone by recovery of gas and condensate by RFT from -2798.4mSS. No gas oil contact was observed in the well. The oil zone extends from -2802.5mSS to the interpreted oil-water contact and is L. balmei in age. The oil-water contact was determined by log analysis at -2832.7mSS and by pressure gradients at -2833.2mSS. Oil shows in the core chip samples place the contact between -2833.0mSS and -2834.2mSS in core depth (see Enclosure 1). The interpreted oil-water contact closely matches the oil water contact seen in Blackback-1 at -2833mSS and the interpreted Blackback/Terakihi field oil water contact at -2834mSS.

The preliminary log analysis (Appendix 2) was carried out using a simple sand/shale model to determine porosity. All three hydrocarbon zones are present in sands which contain common glauconite, at least some of which is structural. The presence of glauconite leads to suppression of the resistivity logs, increased gamma ray readings and increases shale separation on the neutron/density logs. This is particularly noticeable in the oil zone between -2803 and -2817mSS. Reservoir quality in this section is primarily determined by clay content and the sandstone contains abundant glauconite. Where the glauconite is structural this will lead to an underestimation of porosity and hydrocarbon saturation when using a simple sand/shale model. The final log analysis will use petrographic information as a basis for building a forward reservoir model. This method should better account for the reservoir mineralogy when determining porosity and saturation.

Oil was recovered from two production tests as well as two MDT sample runs. PVT analysis of the MDT oil samples indicated an oil gravity of 47 API and a gas/oil ratio of 2250 SCF/STB. The bubble point of the oil is 802psi below the reservoir pressure, indicating that there is no gas cap associated with the oil zone. The gas zones are therefore interpreted not to be in communication with the oil system. This interpretation is supported by pressure data which indicates that the oil zone and the two gas zones are all separate pressure systems. A detailed fluid analysis report is contained in Appendix 7.

Gas samples were recovered from MDT and cased holed RFT runs. Small amounts of condensate (gas-oil ratios of 9222-11738 SCF/STB) were associated with these samples. The gravity of the gas samples was 0.962 sg (where air = 1), while gravities of the associated condensate ranged from 46.5 to 57.4 API. The reading of 46.5 API is not considered reliable and the reading of 49 API obtained for the two preserved cased hole RFT samples is considered the most reliable result (see Appendix 7 for details).

6. Geophysical Discussion

Blackback-2 intersected the Top of Latrobe Group (TOL) 3.3m high to prediction at 2356.7mSS. This represents an error of 0.14%.

Although the resultant depth required only minor changes to the map at the crest of the Blackback structure, the entire southwestern gradient of the field was remapped. The G89AB 3D seismic survey covers the Blackback discovery and was used exclusively to produce the updated depth structure map in Enclosure 5. The production of a synthetic seismogram (Enclosure 3) at Blackback-2 also allowed a more confident tie at the well location and into the SW portion of the field.

The depth conversion (time-depth curve included in Enclosure 4) procedure remained unchanged from the pre-drill method. The water depth combined with a water bottom to TOL isopach were used to produce the depth structure map of the TOL unconformity.

7. Geological Discussion

Blackback-2 was primarily designed to test reservoir quality in the Paleocene channel fill section. The producibility of this reservoir section was confirmed by two production tests from -2818.7 to -2824.2mSS and from -2807.2 to -2811.7mSS. These tests yielded stabilised oil flow rates of 6640 STB/D and 5659 STB/D respectively.

The results of the well and the post drill mapping have resulted in two changes in the structural interpretation of the Blackback field. The amount of vertical closure in the field at the Top of Latrobe Group has been increased from 75m predrill to 79m post drill. The extent of the Paleocene channel fill was also reduced in the Central and Southwest blocks of the field based on the Blackback-2 well tie and seismic geometries. The Paleocene channel fill is now interpreted to be absent in the southwest block. This has increased the proportion of sediments above the field oil-water contact which are assigned to the potentially better reservoir quality Cretaceous units. Analysis of FMS data also indicated the presence of an intra Cretaceous unconformity at -2913.7mSS. The presence of structural dips of 2° in the Cretaceous section above this unconformity differs from previous interpretations which have restricted such low structural dip angles to the Paleocene channel fill section.

The Flounder Formation equivalent siltstone, and the two gas sands at the Top of Latrobe Group have not been observed in the field previously. The Blackback/Terakihi field was previously thought to contain oil only. The presence of these gas intervals and the non-net seals between the gas and oil sands has reduced the maximum height of the oil column on the field.

FIGURES

FIGURES

BLACKBACK – 2 LOCALITY MAP

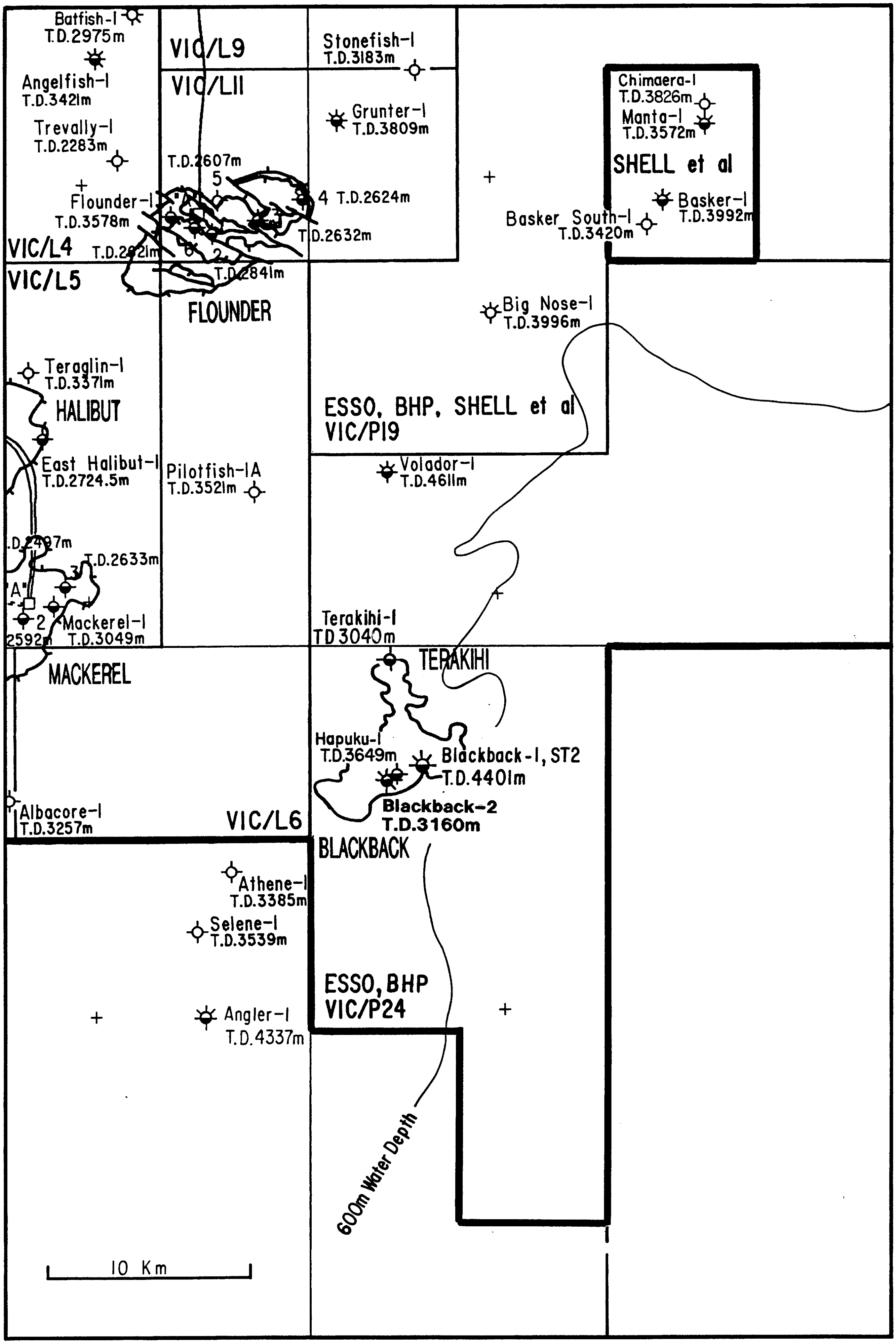
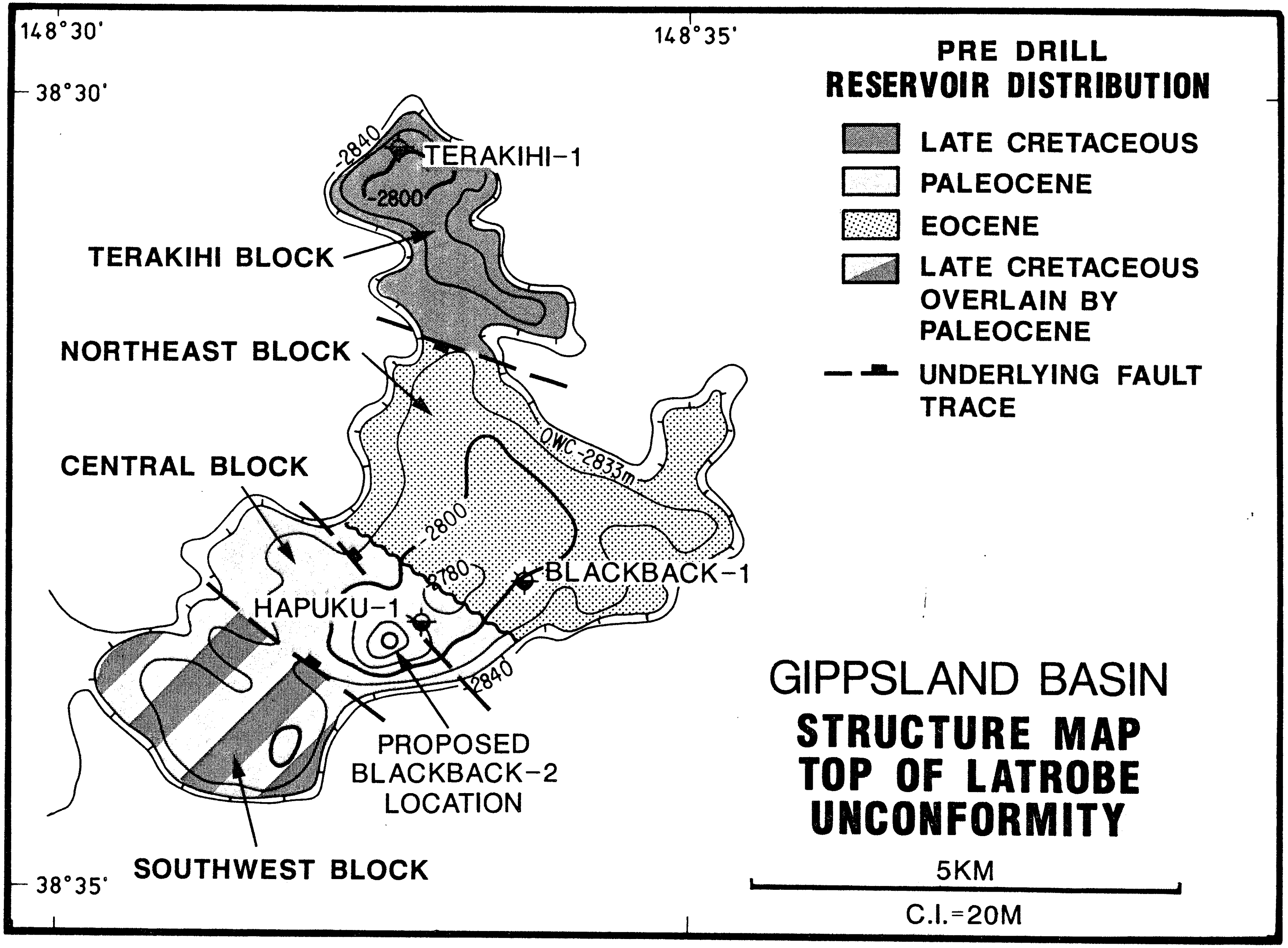


FIGURE 1

Dwg. 2486/OP/1



2486/OP/2

FIGURE 2

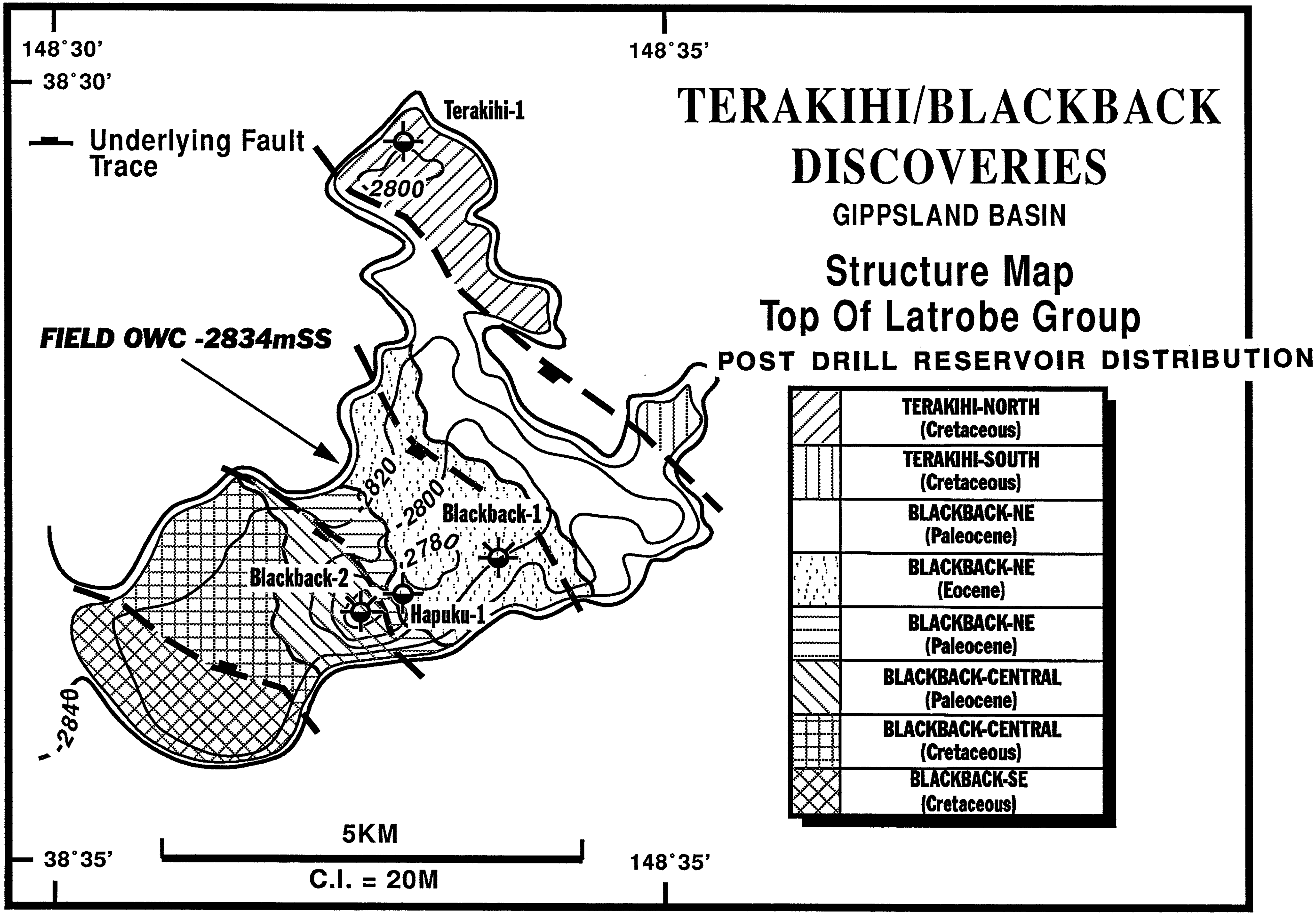

148°30'
38°30'
148°35'
TERAKIHI/BLACKBACK DISCOVERIES
GIPPSLAND BASIN
Structure Map
Top Of Latrobe Group
POST DRILL RESERVOIR DISTRIBUTION
Underlying Fault Trace
Terakihi-1
-2800
FIELD OWC -2834mSS
-2820
-2800
-2780
Blackback-1
Blackback-2
Hapuku-1
-2840
TERAKIHI-NORTH (Cretaceous)
TERAKIHI-SOUTH (Cretaceous)
BLACKBACK-NE (Paleocene)
BLACKBACK-NE (Eocene)
BLACKBACK-NE (Paleocene)
BLACKBACK-CENTRAL (Paleocene)
BLACKBACK-CENTRAL (Cretaceous)
BLACKBACK-SE (Cretaceous)
5KM
C.I. = 20M
38°35'
148°35'
GPV00333

FIGURE 3

APPENDIX 1

PALYNOLOGICAL ANALYSIS OF SIDEWALL CORES FROM BLACKBACK-2, GIPPSLAND BASIN

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INTERPRETED DATA

INTRODUCTION

This is an initial palynological report on Blackback-2 as it only summarises the palynological analyses on 23 sidewall cores and a single sample from conventional core-2 which had been collected at the rig site and dispatched for urgent age dating. At the time of preparation of this report the remaining conventional cores recovered over the interval 2797-2869m were not available for inspection and selection of palynological samples as they were still packed in wax for analysis involved with formation evaluation. Because of the uncertainty of when it will be possible to perform palynological analyses on additional samples from the conventional cores a formal report is prepared on the currently available results. Note also that the depth of the single core sample analysed has not been tied to the logs and may be out of order with respect to the sidewall cores. For this reason the spore-pollen and microplankton assemblages from this sample are not included on the range charts.

All the sidewall cores were inspected, and 20 of the 21 recovered sidewall cores (out of 42 shot) from the Latrobe Group were selected for palynology processing. The only exception was SWC 7 at 3091m which was considered too coarse grained to contain palynomorphs. From the Seaspray Group the deepest 3 of 11 recovered sidewall cores were selected.

The palynological slides were prepared by Laola Pty Ltd in Perth and returned to the author for examination and recording of their contained spores, pollen and microplankton to derive the data and interpretations in this report.

Between 8 to 20 grams (average 13.8g) of each sidewall core was processed for palynological analysis. In anticipation of similar yields to those obtained from the adjacent Hapuku-1 and Blackback-1 wells as much of the sidewall cores were sampled as possible, without jeopardising the potential for other analyses on the samples. As expected 16 or 70% of the sidewall cores gave low to very low residue yields. Fortunately the palynomorph concentration on the slides from many of these samples was high enough to result in confident age datings. Preservation of palynomorphs overall was fair to good and at times exceptional. Average spore-pollen diversity was a moderate 17+ species and average microplankton diversity in productive samples a low 8+ species. Both averages are low reflecting the initial low yields.

Lithological units and palynological zones from the base of the Seaspray Group to Total Depth are given in the following summary. The interpretative data with zone identification and Old and New Confidence Ratings are recorded in Table-1 and basic data on residue yields, preservation and diversity are recorded on Tables-2 and 3. All species, recorded from the sidewall cores, which have been identified with binomial names are tabulated on separate range charts for spore-pollen and microplankton. Relinquishment lists for palynological slides and residues from samples analysed in Blackback-2 will be prepared after analysis of additional conventional core samples.

PALYNOLOGICAL SUMMARY OF BLACKBACK-2

AGE	UNIT/FACIES		SPORE-POLLEN ZONES (DINOFLAGELLATE ZONES)	DEPTHS (mKB)
MIOCENE - OLIGOCENE	SEASPRAY GROUP		*P. tuberculatus*	2725.0-2778.5
EARLY EOCENE	LATROBE GROUP	Flounder Formation Equivalent	Upper *M. diversus* *(D. waipawaensе)*	2780.5-2796.5 (2780.5-2796.5)
	LATROBE GROUP	"Hapuku Marine Sands"	Lower *M. diversus*	2807.6-2812.5
PALEOCENE	LATROBE GROUP	"Hapuku Marine Sands"	Upper *L. balmei* *(A. homomorphum)*	2835.5-2839.5 (2835.5-2839.5)
	LATROBE GROUP	"Hapuku Marine Sands"	Lower *L. balmei* *(E. crassitabulata)*	2872.0 (2872.0)
MAASTRICHTIAN	LATROBE GROUP	Undifferentiated sand, shales and minor coals.	Upper *T. longus* *(M. druggii)*	2899.5 (2899.5-2924.0)
			Lower *T. longus*	3139.0-3141.0

GEOLOGICAL COMMENTS

1. Because of the very low yields and hence low recorded diversity the three samples from the Seaspray Group can only be assigned a broad Oligocene to Early Miocene age.

2. The interval with an overall higher gamma ray reading between 2779.5-2798.5m is assigned to the Flounder Formation based on its predominant black-grey siltstone lithology and spore-pollen and dinoflagellate content.

3. The interval between 2798.5m to probably 2897m which on sidewall core lithologies is predominantly a glauconitic sandstone is equated to the Paleocene to Early Eocene condensed section in Hapuku-1. This section is here informally referred to as the "Hapuku Marine Sands". It contains similar well preserved microplankton assemblages as found in Hapuku-1 (Partridge, 1975a) and probably has similar low depositional rates. The four conventional cores cut between 2797-2869m in Blackback-2 will need to be sampled and analysed to obtain a detailed correlation to Hapuku-1. This whole section was missing due to erosion by the "*N. asperus* Channel" in Blackback-1 (Partridge & Hannah, 1990).

4. The characteristic K/T (Cretaceous/Tertiary) boundary section in the Gippsland Basin, where the *T. evittii* dinoflagellate Zone overlies the *M. druggii* dinoflagellate Zone in a shaly interval, is not present in Blackback-2 (for comparison see Roundhead-1, Partridge 1989). In this Blackback-2 is similar to Hapuku-1 where the 63 Ma Sequence Boundary of Haq *et al.* (1987, 1988) within the Paleocene is considered to cut down into the underlying Maastrichtian *T. longus* Zone. In Hapuku-1 this sequence boundary is picked at 2890m. In Blackback-2 it lies between the *E. crassitabulata* Zone at 2872m and first reliable Upper *T. longus/M. druggii* Zone pick at 2899.5m. The best log pick for the 63 Ma Sequence Boundary in Blackback-2 would appear to be 2897m.

5. The interval of high gamma ray values between 2897-2939m which is predominantly sandstone based on the sidewall core lithologies (Table-2) is considered to be a marine unit within the Upper *T. longus* Zone. All analysed samples contain dinoflagellates diagnostic of the *M. druggii* dinoflagellate Zone.

6. Between the base of the above unit at 2939m (or base of *M. druggii* Zone at 2924m) and the two samples assigned to the Lower *T. longus* Zone near the bottom of Blackback-2 (at 3139m & 3141m) there are no reliable sidewall core samples.

   Thus the boundary between the Upper and Lower *T. longus* Zone and transition from marine to predominantly non-marine coastal plains facies are not adequately picked. However, over this 200+ metres of section there are a number of shales which may be datable on cuttings. Based on high gamma ray readings and the widest separation on the bulk density/neutron porosity logs the cutting intervals that could be analysed lie at 2990-93m; 3035-39m; 3042-48m; 3060-63m; the thick shale between 3069-3083m; the probable coal at 3083.5-85m and underlying shale at 3085-90m.

BIOSTRATIGRAPHY

Zone and age determinations are based on the spore-pollen zonation scheme proposed by Stover & Partridge (1973), partially modified by Stover & Partridge (1982) and Helby, Morgan & Partridge (1987), and a dinoflagellate zonation scheme which has only been published in outline by Partridge (1975b, 1976). Other modifications and embellishments to both zonation schemes can be found in the many palynological reports on the Gippsland Basin wells drilled by Esso Australia Ltd. Unfortunately this work is not collated or summarised in a single report. Note also that the name of the Upper *T. longus* Zone has not been changed to conform with recent nomenclature change to the name of the eponymous species *Forcipites* (al. *Tricolpites*) *longus* (Stover & Evans) Dettmann & Jarzen 1988.

Author citations for most spore-pollen species can be sourced from Stover & Partridge (1973, 1982), Helby, Morgan & Partridge (1987) or other references cited herein. Author citations for dinoflagellates can be found in the indexes of Lentin & Williams (1985, 1989) or in the papers of Wilson (1988) and Marshall & Partridge (1988) or other references cited herein. Species names followed by "ms" are unpublished manuscript names.

Proteacidites tuberculatus Zone: 2725.0-2778.5 metres Oligocene-Miocene.

The three sidewall cores analysed from the Seaspray Group all gave meagre yields with limited but overall similar assemblages. The two deepest samples can be assigned to the *P. tuberculatus* Zone on the occurrence of the key spore *Cyatheacidites annulatus*, whilst the shallowest sample contains the eponymous species *Proteacidites tuberculatus*. The remaining spore-pollen species recorded are not particularly diagnostic but are consistent with this zone assignment.

The microplankton assemblages can be assigned to the informal *Operculodinium* spp. Association of Partridge (1976) based on the frequent to common occurrence of the long ranging *Operculodinium centrocarpum* associated with the Oligocene or younger index species *Protoellipsodinium simplex* ms.

Upper *Malvacipollis diversus* Zone: 2780.5-2796.5 metres and
Dracodinium waipawaense Dinoflagellate Zone: 2780.5-2796.5 metres
Early Eocene.

Of the four samples over this interval only the shallowest at 2780.5m can be confidently assigned to the Upper *M. diversus* Zone on the presence of *Myrtaceidites tenuis* and *Proteacidites pachypolus*. The three underlying samples, although they contain moderate to high diversity spore-pollen assemblages lack these key indicator species and are assigned to the zone based on assemblage composition and the presence of key dinoflagellates which elsewhere in the Gippsland Basin are not known to range below the Upper *M. diversus* Zone. A low confidence rating by definition has to be assigned to the base of the zone.

The spore-pollen assemblages are all dominated by *Dilwynites* spp. (22%-54%) with *Haloragacidites harrisii* (Casuarina), *Proteacidites* app. and *Nothofagidites* spp. the next most abundant.

Microplankton dominate the total count in all samples with average abundance 60% (range 36%-95%). The zone index *Dracodinium waipawaense* occurs in the shallowest 2780.5m and deepest 2796.5m samples. Other species which support this zone assignment are *Homotryblium tasmanense* which represents 40% of the microplankton assemblage at 2780.5m and is also recorded at 2795m, and the characteristic species of the Flounder Formation *Deflandrea flounderensis* which occurs in all four samples. Of particular interest is the records of the acritarch *Tritonites bilobus* Marshall & Partridge 1988 at 2780.5m and 2787.5m. This species was first recorded in the Gippsland Basin as a reworked form in the "*N. asperus* channel-fill" unit in Blackback-1 (Partridge & Hannah, 1990, p.7).

Lower *Malvacipollis diversus* Zone: 2807.6-2812.5 metres Early Eocene.

Of the two samples assigned to the Lower *M. diversus* Zone the shallowest is the core sample at 2807.6m which is assigned on the presence of the species *Myrtaceoipollenites australis* Harris 1965, *Proteacidites grandis, P. incurvatus, Malvacipollis subtilis* and frequent *Haloragacidites harrisii* and no younger indicator species. The deeper sample at 2812.5m was even less diagnostic containing only a fragment of *P. grandis* in a limited assemblage recorded from only the kerogen slide. It is assigned to the zone principally on the absence of older indicator species. The zone assignment for both samples is of very low confidence.

Significant microplankton only occur in the core sample at 2807.6m where they comprise 22% of total count. The presence of *Deflandrea dartmooria, Diphyes colligerum, Achomosphaera septata* and the long spined variety of *Apectodinium homomorphum* support the spore-pollen zone assignment.

Upper *Lygistepollenites balmei* Zone: 2835.5-2839.5 metres and *Apectodinium homomorphum* Dinoflagellate Zone: 2835.5-2839.5 metres Late Paleocene.

The top of the Paleocene *L. balmei* Zone is recorded in Blackback-2 at 2829m based on the youngest occurrence of *Lygistepollenites balmei* but the spore-pollen assemblage is too limited for confident assignment to the Upper subdivision. This sample could just as likely be assigned to Lower *M. diversus* Zone. The next two underlying samples however can be confidently assigned to the Upper *L. balmei* Zone. At 2835.5m *L. balmei* (1.4%) is associated with the LADs (Last Appearance Datums) of *Australopollis obscurus* and *Gambierina rudata*, whilst the deeper sample at 2839.5m, which contains common *L. balmei* (8%), is considered no older than the Upper *L. balmei* Zone based on the FAD (First Appearance Datum) of *Proteacidites annularis*. Both spore-pollen assemblage are dominated by gymnosperm pollen (55%-59%) with *Dilwynites* spp. (24%) dominant in the shallower and *Podocarpidites* spp. (25%) dominant in the deeper sample.

The microplankton average 21% of the total count whilst microplankton diversity is a moderate 12 species. The occurrence of the short spined variety of *Apectodinium homomorphum* associated with *Deflandrea dartmooria* in both samples confirms the presence of the *A. homomorphum* dinoflagellate Zone.

Lower *Lygistepollenites balmei* Zone: 2872.0 metres and
***Eisenackia crassitabulata* Dinoflagellate Zone: 2872.0 metres**
Early Paleocene.

The single samples at 2872m is assigned to the Lower *L. balmei* Zone on the presence of *Proteacidites angulatus*. Other significant species are *Lygistepollenites balmei* (1.5%), *Australopollis obscurus* (<1%), *Gambierina* spp. (3.8%) and *Peninsulapollis gillii* (11%). Overall the spore-pollen assemblages are dominated by gymnosperm pollen (57%) with *Phyllocladidites mawsonii* (20%), *Podocarpidites* spp. (18%) and *Dilwynites* spp. (7%) being most abundant.

Upper *Tricolpites longus* Zone: 2899.5 metres and
***Manumiella druggii* Dinoflagellate Zone: 2899.5-2924.0 metres**
Maastrichtian.

Of the three sidewall cores analysed over this interval only the shallowest at 2899.5m could be confidently assigned to there Upper *T. longus* Zone based on the presence of *Stereisporites (Tripunctisporis)* spp. and the common occurrence of *Gambierina rudata* (8%). In addition this sample contained a number of species whose last appearances indicate an age no younger than this zone. These include *Proteacidites clinei* ms, *P. reticuloconcavus* ms, *P. wahooensis* ms, *Tricolpites confessus*, *Triporopollenites sectilis*, and the eponymous species *Forcipites (al. Tricolpites) longus*. The two deeper samples on the basis of their contained spore-pollen can only be assigned to the broader *T. longus* Zone.

All three samples contain members of the *Manumiella* species complex enabling confident assignment to the *M. druggii* dinoflagellate Zone. The shallowest sample at 2899.5m contains the key species *M. druggii* and *M. seelandica*. The two deep samples in contrast are essentially monospecific with only *M. conorata* confidently identified, although lots of broken specimens which could only be referred to *Manumiella* spp. were present. This latter category is the dominant palynomorph in the deepest sample at 3924m but this is partly an artefact of the very low yield.

Indeterminate Interval

Although four samples were analysed over the 215 metre interval between the base of the Upper and top of the Lower *T. longus* Zones only one sample could be broadly assigned to the Late Cretaceous. The other samples contained negligible *insitu* palynomorphs. The shallowest at 2996.5m was apparently contaminated with the algal(?) cyst *Nummus*. Assignment of the specimens to any fossil species of *Nummus* is questionable as the specimens were very pale and showed no sign of maturation.

Lower *Tricolpites longus* Zone: 3139.0-3141.0 metres Maastrichtian.

The shallower sample is assigned to the Lower *T. longus* Zone on the presence of the eponymous species *Forcipites longus* and *Grapnelispora evansii* Stover & Partridge 1984. Other spore-pollen species in both samples whilst consistent with this zone assignment can range into the immediately older *T. lilliei* Zone. The deeper sample is retained within the Lower *T. longus* Zone because it is only 2 metres deeper.

Both samples can be characterised by their high *Nothofagidites* spp. content (47% at 3139m; 10% at 3141m). The other dominant categories in the counts are *Podocarpidites* spp. and *Proteacidites* spp., whilst *Tricolpites waiparaensis* at 12% is also characteristic in the shallower sample.

A good specimen of the monoporate pollen *Aglaoreidia qualumis* was recorded at 3139m. This is a significant anomalous occurrence as this species does not normally range below the Late Eocene Middle *N. asperus* Zone. A similar anomalous occurrence of this species was recorded from an open marine environment in the Upper *M. diversus* Zone, in Whaleshark-1 (Partridge 1993, p.10).

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TABLE-1: INTERPRETATIVE PALYNOLOGICAL DATA FOR BLACKBACK-2, GIPPSLAND BASIN.

SHEET 1 OF 2

SAMPLE TYPE	DEPTH (M)	SPORE-POLLEN ZONES	*CR OLD	*CR NEW	MICROPLANKTON ZONES OR ASSOCIATIONS	*CR OLD	*CR NEW	COMMENTS
SWC 47	2725.0	*P. tuberculatus*	1	B2	(*Operculodinium* spp.)	1	B3	*Proteacidites tuberculatus* present.
SWC 45	2774.0	*P. tuberculatus*	0	B2	(*Operculodinium* spp.)	0	B3	*Cyatheacidites annulatus* present.
SWC 43	2778.5	*P. tuberculatus*	0	B2	(*Operculodinium* spp.)	0	B3	FAD *Cyatheacidites annulatus.*
SWC 42	2780.5	Upper *M. diversus*	0	B1	*D. waipawaense*	0	B2	Microplankton 36%. *T. bilobus* present. *Homotryblium tasmaniense* 14%.
SWC 40	2787.5	*M. diversus*	2	B4	(*Tritonites bilobus*)	0	B2	Microplankton 52%.
SWC 38	2795.0	*M. diversus*	2	B4				Microplankton 56%. *Glaphyrocysta retiintexta* 21%.
SWC 37	2796.5	Upper *M. diversus*	2	B4	*D. waipawaense*	1	B2	Microplankton 95%.
CORE-2	2807.6	Lower *M. diversus*	2	B4				Depth needs to be adjusted to logs!
SWC 32	2812.5	Lower *M. diversus*	2	B5				Very low yield, kerogen only.
SWC 29	2829.0	*L. balmei*	2	B5				Microplankton 54%.
SWC 27	2835.5	Upper *L. balmei*	0	B1	*A. homomorphum*	0	B2	Microplankton 20%. *L. balmei* common.
SWC 26	2839.5	Upper *L. balmei*	0	B2	*A. homomorphum*	1	B3	FAD *Proteacidites annularis.*
SWC 25	2859.5	Indeterminate						Low yield, insuffient species present.
SWC 21	2872.0	Lower *L. balmei*	0	B1	*E. crassitabulata*	0	B2	*Proteacidites angulatus* present.
SWC 20	2878.5	Indeterminate						Virtually barren.
SWC 18	2899.5	Upper *T. longus*	0	B1	*M. druggii*	0	B3	Microplankton 6%. *S. (Tripunctispories)* spp. present.
SWC 17	2912.5	*T. longus*	0	B2	*M. druggii*	1	B3	Microplankton <5%.
SWC 16	2924.0	*T. longus*	2	B5	*M. druggii*	1	B3	Microplankton 74%. Mostly *Manumiella conorata.*

TABLE-1: INTERPRETATIVE PALYNOLOGICAL DATA FOR BLACKBACK-2, GIPPSLAND BASIN.

SAMPLE TYPE	DEPTH (M)	SPORE-POLLEN ZONES	*CR OLD	*CR NEW	MICROPLANKTON ZONES OR ASSOCIATIONS	*CR OLD	*CR NEW	COMMENTS
SWC 12	2996.5	Indeterminate						Probably contaminated.
SWC 6	3094.5	Indeterminate						Virtually barren.
SWC 5	3117.0	*T. longus*						Zone species extremely rare.
SWC 3	3132.5	Indeterminate						Very low yield.
SWC 2	3139.0	Lower *T. longus*	1	B1				*Nothofagidites* spp. 46%. *Grapnelispora evansii* present.
SWC 1	3141.0	Lower *T. longus*	1	B4				*Nothofagidites* spp. 10%.

*CR = Confidence Ratings OLD & NEW
FAD = First Appearance Datum
LAD = Last Appearance Datum

CONFIDENCE RATINGS

The concept of Confidence Ratings applied to palaeontological zone picks was originally proposed by Dr. L.E. Stover in 1971 to aid the compilation of micropalaeontological and palynological data and to expedite the revision of the then rapidly evolving zonation concepts in the Gippsland Basin. The original or OLD scheme which mixes confidence in fossil species assemblage with confidence due to sample type has gradually proved to be rather limiting as additional refinements to existing zonations have been made. With the development of the STRATDAT computer database as a replacement for the increasingly unwieldy paper based Palaeontological Data Sheet files a NEW set of Confidence Ratings have been proposed. Both OLD and NEW Confidence Ratings for zone picks are given on Table 1, and their meanings are summarised below:

OLD CONFIDENCE RATINGS

0 SWC or CORE, Excellent Confidence, assemblage with zone species of spore, pollen and microplankton.
1 SWC or CORE, Good Confidence, assemblage with zone species of spores and pollen or microplankton.
2 SWC or CORE, Poor Confidence, assemblage with non-diagnostic spores, pollen and/or microplankton.
3 CUTTINGS, Fair Confidence, assemblage with zone species of either spore and pollen or microplankton, or both.
4 CUTTINGS, No Confidence, assemblage with non-diagnostic spores, pollen and/or microplankton.

NEW CONFIDENCE RATINGS
Alpha codes: Linked to sample type
A Core
B Sidewall core
C Coal cuttings
D Ditch cuttings
E Junk basket
F Miscellaneous/unknown
G Outcrop
Numeric codes: Linked to fossil assemblage
1 **Excellent confidence:** High diversity assemblage recorded with key zone species.
2 **Good confidence:** Moderately diverse assemblage recorded with key zone species.
3 **Fair confidence:** Low diversity assemblage recorded with key zone species.
4 **Poor confidence:** Moderate to high diversity assemblage recorded without key zone species.
5 **Very low confidence:** Low diversity assemblage recorded without key zone species.

BASIC DATA

TABLE 2: BASIC SAMPLE DATA

TABLE 3: BASIC PALYNOMORPH DATA

RELINQUISHMENT LISTS

SPORE-POLLEN RANGE CHART
(ATTACHMENT)

MICROPLANKTON RANGE CHART
(ATTACHMENT)

TABLE-2: BASIC SAMPLE DATA FOR BLACKBACK-2, GIPPSLAND BASIN.

SAMPLE TYPE	DEPTH (M)	LITHOLOGY	SAMPLE WT (g.)	RESIDUE YIELD
SWC 47	2725.0	Med grey calcisiltite/lutite	11.0	Very low
SWC 45	2774.0	Med grey calisiltite tr. glauc.	15.4	Very low
SWC 43	2778.5	Med grey clac. clay/calcisiltite	14.7	Very low
SWC 42	2780.5	Dk. gry-blk siltstone	12.4	Moderate
SWC 40	2787.5	Med gry-brn siltstone w/glauconite (20%)	10.5	Low
SWC 38	2795.0	Dk gry-blk siltstone (no obvious glauc.)	18.3	Moderate
SWC 37	2796.5	Blk-grn glauconitic siltstone	9.8	Low
CORE-2	2807.6		15.0	Moderate
SWC 32	2812.5	Coarse qtz & glauconitic sst.	13.3	Very low
SWC 29	2829.0	Med gry-grn glauconitic sandstone	16.7	Low
SWC 27	2835.5	Lt gry-grn pyritic glauc. f.g. sandstone	20.6	Low
SWC 26	2839.5	Grey grn glauconitic sandstone	16.1	Low
SWC 25	2859.5	Lt gry glauconitic sandstone	11.2	Very low
SWC 21	2872.0	Grn-gry glauconitic sandstone	13.3	Very low
SWC 20	2878.5	Lt gry-grn pebbly glauc. sandstone	19.6	Very low
SWC 18	2899.5	Lt gry mottled qtz sandstone	11.7	High
SWC 17	2912.5	Gry carbonaceous sst with laminae	17.5	High
SWC 16	2924.0	Med gry glauconitic sandstone	17.4	Low
SWC 12	2996.5	Lt gry argillaceous sandstone tr. glauc.	15.0	Very low
SWC 6	3094.5	Lt gry silty sandstone	10.8	Very low
SWC 5	3117.0	Med gry silty-v.f.g. sandstone	9.8	High
SWC 3	3132.5	Med gry argillaceous sandstone	11.2	Low
SWC 2	3139.0	Lt gry med sst with clay clasts	13.4	High
SWC 1	3141.0	Dk gry brn claystone	8.4	High

TABLE-3: BASIC SAMPLE DATA FOR BLACKBACK-2, GIPPSLAND BASIN.

SAMPLE TYPE	DEPTH (M)	PALYNOMORPH CONCENTRATION	PRESERVATION	*No S/P SPECIES	MICROPLANKTON ABUNDANCE	*No. MP SPECIES
SWC 47	2725.0	Moderate	Fair-good	11	Very abundant	7
SWC 45	2774.0	High	Fair	18	Very abundant	9
SWC 43	2778.5	Moderate	Poor	13	Very abundant	7
SWC 42	2780.5	High	Fair-good	33	Abundant	17
SWC 40	2787.5	High	Poor-good	27	Very abundant	17
SWC 38	2795.0	Moderate	Poor-good	33	Very abundant	17
SWC 37	2796.5	High	Good	13	Very abundant	19
CORE-2	2807.6	Moderate	Good	30	Common	10
SWC 32	2812.5	Low	Fair	13	Frequent	4
SWC 29	2829.0	Low	Fair	15	Very abundant	12
SWC 27	2835.5	High	Fair-good	39	Common	14
SWC 26	2839.5	Moderate	Good	23	Common	10
SWC 25	2859.5	Low	Fair	5	Rare	1
SWC 21	2872.0	High	Good	29	Abundant	10
SWC 20	2878.5	Very low	Poor	1	Rare	1
SWC 18	2899.5	Moderate	Good	28	Frequent	6
SWC 17	2912.5	Low	Fair-good	19	Rare	2
SWC 16	2924.0	Very low	Fair-good	4	Common	2
SWC 12	2996.5	Very low	Poor	1	(Frequent)	(1)
SWC 6	3094.5	Very low	Fair	2		
SWC 5	3117.0	Very low	Fair-good	16	Rare	1
SWC 3	3132.5	Very low	Poor	2		
SWC 2	3139.0	High	Fair	32		
SWC 1	3141.0	Low	Fair	20	Very rare	1

Microplankton species shown in (brackets) = contamination

***DIVERSITY:**

Very low	=	1- 5 species
Low	=	6-10 species
Moderate	=	11-25 species
High	=	26-74 species
Very high	=	75+ species

APPENDIX 2

APPENDIX 2

BLACKBACK 2

QUANTITATIVE FORMATION EVALUATION

INTRODUCTION

The Blackback 2 exploration well has been evaluated for reservoir quality and hydrocarbon saturation. The Latrobe reservoirs evaluated are of Paleocene age all being deposited in deeper water marine environments. The well was production tested over two intervals separately with Test 1 from 2841m to 2846.5m MDKB and Test 2 from 2829.5m to 2834m MDKB. The first production test flowed oil at a stabilised rate of 6640 STBD while the second production test flowed oil at an average stabilised rate of 5659 STBD.

The Latrobe was analysed from 2798.5m MDKB to 2876.4m MDKB. The petrophysical logs were acquired conventionally on wireline with a wellbore deviation of 1 degree at 3152m MDKB total depth. Whole core was recovered from 2797m MDKB to 2869m MDKB using a low invasion coring system and resin injection. An extensive special core analysis programme is being undertaken to characterise the petrophysical and petrographic reservoir quality and will be reported upon when completed. Reservoir quality is controlled by grain size, amount of matrix content from bioturbation, compaction, and secondary diagenesis. Authigenic quartz, disseminated pyrite and poikilotopic dolomite all occur as pore filling cements which reduce the total porosity available for hydrocarbon fill. The petrographic study will serve as the basis for building a forward reservoir model based on least squares inversion for the Blackback reservoirs. Until that work is completed this preliminary interpretation based on the VOLAN shaly sand model will be used. The attached Table 1 and Figure 1 summarise the formation evaluation for the Blackback 2 exploration well.

SUMMARY

Oil Reservoirs

Reservoir Interval 2839.5m MDKB to 2854.9m MDKB

The main oil bearing reservoir from 2839.5m MDKB to 2854.9m MDKB has been segmented into two discrete intervals and can be described as a coarse to medium grain feldspathic litharenite. Below 2845.7m MDKB the total porosity varies significantly from the presence of authigenic dolomite cement. The oil-water contact in this reservoir is located at 2855.0m MDKB as determined from log water saturations and formation tester pressure gradients.

The reservoir interval from 2839.5m MDKB to 2845.6m MDKB contains 6.1 metres of net pay with an average effective (AE) porosity of 21 percent and an AE water saturation of 11 percent. This interval most likely represents the reservoir which contributed to the 6640 STBD flow rate during production test 1. The average effective permeability to oil from the production test was 3500 md and the Klinkenberg corrected air absolute permeability from core was greater than 3000 md. The reservoir pressure from the MDT quartz gauge at 2843m MDKB is 4013.8 psia.

A petrographic analysis from thin section and X-Ray diffraction at 2841.4m MDKB (2835.4m core depth) can be described as a poorly sorted coarse grained lithic arkose with an average grain size of coarse sand. The predominant framework grains are monocrystalline igneous quartz with common microcline feldspar, minor glauconite, biotite, polycrystalline quartz and trace of clay-altered grains. The cements in this sample contained minor amounts of authigenic quartz and trace pyrite. The porosity is excellent intergranular and shows minor compaction effects.

The reservoir interval from 2845.7m MDKB to 2854.9m MDKB contains 5.2 metres of net pay with a net/gross ratio of 57 percent. The AE porosity is 15 percent and AE water saturation 15 percent. This interval contains a significantly variable concentration of authigenic dolomite cement contributing to the reservoir quality heterogeneity. The Klinkenberg corrected air absolute permeability varies from 0.5 md to >3000 md in this interval. The reservoir pressure from the MDT at 2854.24m MDKB is 4022.9 psia.

A petrographic analysis at 2846.2m MDKB (2840.2m core depth) shows the extent to which dolomite cement can destroy intergranular porosity. This medium grained well sorted feldspathic litharenite contains a framework of monocrystalline igneous quartz with minor polycrystalline quartz, common microcline feldspar and glauconite, minor biotite, and trace of chert, muscovite and clay altered grains. The thin section is extremely well lithified with abundant poikilotopic dolomite and trace of pyrite cements. The porosity in this sample is extremely poor comprising a few microporous grains.

Reservoir Interval 2824.1m MDKB to 2839.4m MDKB

This uppermost oil bearing reservoir package in Blackback 2 is subdivided into 3 separate reservoir compartments based on reservoir quality. The better quality reservoir unit within this gross interval is from 2829.7m MDKB to 2834.4m MDKB. Production Test 2 tested this reservoir package which flowed at a stabilised rate of 5659 STBD with an average effective permeability to oil of 900 md. The Klinkenberg air permeability at overburden confining stress varies from 8 md to 2134 md. The net oil bearing reservoir is 4.5 metres with an AE porosity of 18 percent and AE water saturation of 33 percent. Within this 4.5 metres the porosity is stratified and varies greatly from 12 to 25 percent bulk volume. The reservoir pressure at 2833.8m MDKB is 4007.2 psia from the MDT formation tester.

A petrographic analysis at 2831.6m MDKB (2826.8m core depth) characterises this sample as a fine grained poorly sorted argillaceous glauconitic litharenite with fair porosity and permeability. Abundant clay is comprised as an indeterminate matrix with minor authigenic kaolinite, minor corrensite containing potassium and iron. The distribution of primary matrix is controlled by bioturbation while authigenic clays have been precipitated in the more porous zones. The cements are comprised of authigenic quartz, trace siderite and disseminated pyrite. The extensive matrix restricts development of some cements, especially authigenic quartz.

The next two intervals comprise poorer quality reservoir facies with low permeability to oil. These two intervals which are the upper and lower bounding reservoir units for Production Test 2 most likely contributed negligible flow to the test. The reservoir interval from 2834.5m MDKB to 2839.4m MDKB contains 4.4 metres of net oil reservoir with an AE porosity of 14 percent and an AE water saturation of 39 percent. The average core porosity over this interval is 18 percent porosity and Klinkenberg air permeability ranges from 1 md to 20 md. This interval is comprised of the base of core 3 and top of core 4 with approximately 1.5 metres of core missing at this interface.

A petrographic analysis at 2835.2m MDKB (2830.4m core depth) characterises this poorer quality reservoir facies as a fine grained moderately sorted argillaceous, micaceous glauconite feldspathic litharenite. Petrophysical measurements from an adjacent core plug at 2830.2m core depth yield a porosity of 16.6 percent and permeability to air of 0.24 md at overburden net confining pressure. The predominant framework grains are monocrystalline igneous quartz, common albite and microcline feldspars, glauconite, biotite and minor clay-altered grains. Trace amounts of muscovite and zircon are present. The clays are comprised of authigenic kaolinite as a pore-filling mineral and corrensite which lines detrital grains. The structural clay is associated with glauconite. Common dispersed pyrite as framboids and authigenic quartz form the precipitated cements. The porosity can be decomposed into a few small isolated intergranular pores and common micropores associated with degraded minerals and clays.

The final oil bearing reservoir interval from 2824.1m MDKB to 2829.6m MDKB contains 4.0 metres of net oil with an AE porosity of 14 percent and an AE water saturation of 48 percent. The core porosity over this interval is approximately 18 percent and Klinkenberg air permeability 0.2 md to 28 md. The higher core porosity to log porosity reflects the micro-porosity associated with the clays and feldspars which is measured in the core plug. The present preliminary log interpretation results in an effective porosity, whereas the core plug porosity represents total porosity in the sample.

A sample at 2826.8m MDKB (2822.0m core depth) contains similar composition to the previous described interval, however this sample contains a better reservoir quality with permeability to air of 9.2 md and porosity of 19.1 percent from a plug at 2821.75m core depth. This sample is a fine grained, poorly sorted, massive glauconitic lithic arkose. The framework grains are monocrystalline quartz, common microcline and lesser albite feldspar and glauconite, minor biotite and clay altered grains. The primary clay matrix contains pore-filling authigenic kaolinite, minor corrensite and clay-altered grains, and common glauconite. The cements are early stage authigenic quartz overgrowths, common disseminated pyrite and localised pore-filling pyrite and trace siderite. Matrix and authigenic clays restrict development of cements. Overall porosity is fair but heterogeneous and interconnectivity of pores is low.

The remaining gas and water bearing reservoir intervals are summarised in Table 1. As stated previously the reported reservoir petrophysical properties is preliminary and will be finalised upon completion of the core petrology and special core analysis.

Table 1

BLACKBACK 2

CLAM ANALYSIS SUMMARY

PRELIMINARY
EAL PETROPHYSICS

Net porosity cut-off..........: 0.120 volume per volume
Net water saturation cut-off..: 0.650 volume per volume

Net Porous Interval based on Porosity cut-off only.
Both Porosity and Sw cut-offs invoked when generating Hydrocarbon-Metres.

	GROSS INTERVAL (metres) (top) -(base)	Gross Metres	NET POROUS INTERVAL Net Metres	Net to Gross	Mean Vsh	(Std.) (Dev.)	Mean Porosity	(Std.) (Dev.)	Mode Porosity	Mean Sw	INTEGRATED HYDROCARBON PORE VOLUME	
MDKB	2798.5-2803.4	4.9	4.4	91 %	0.13	(0.045)	0.19	(0.030)	0.19	0.44	0.470	GAS
MDKB	2808.6-2818.1	9.5	9.0	94 %	0.16	(0.080)	0.21	(0.033)	0.21	0.17	1.559	GAS
MDKB	2820.3-2820.8	0.5	0.5	100 %			0.14			0.33		GAS
MDKB	2824.1-2829.6	5.5	4.0	74 %	0.41	(0.054)	0.14	(0.012)	0.14	0.48	0.296	OIL
MDKB	2829.7-2834.4	4.7	4.5	97 %	0.23	(0.088)	0.18	(0.035)	0.16	0.33	0.560	OIL
MDKB	2834.5-2839.4	4.9	4.4	89 %	0.33	(0.057)	0.14	(0.011)	0.13	0.39	0.370	OIL
MDKB	2839.5-2845.6	6.1	6.1	100 %	0.10	(0.038)	0.21	(0.031)	0.22	0.11	1.173	OIL
MDKB	2845.7-2854.9	9.2	5.2	57 %	0.07	(0.015)	0.15	(0.027)	0.13	0.15	0.685	OIL
MDKB	2855.0-2863.7	8.7	6.9	80 %	0.11	(0.047)	0.17	(0.028)	0.19	1.00	0.000	WATER
MDKB	2865.0-2876.4	11.4	10.9	95 %	0.18	(0.025)	0.19	(0.029)	0.19	1.00	0.000	WATER

TOTAL NET GAS 13.4 metres

TOTAL NET OIL 24.2 metres

TOTAL NET HYDC 37.6 metres

PE600796

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DATE_RECEIVED =	04/05/1993
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WELL_NAME =	Blackback-2
CONTRACTOR =	ESSO
CLIENT_OP_CO =	ESSO

(Inserted by DNRE - Vic Govt Mines Dept)

APPENDIX
3

APPENDIX 3

APPENDIX 3

Blackback-2 FMS Analysis

The Formation Micro-Scanner (FMS) data has been interpreted for structural and stratigraphic information in the Paleocene and Cretaceous reservoirs in the Blackback-2 well. The attached figures show the results of analysis for structural orientation and stratigraphic features, particularly crossbeds. Table 1 contains a list of the results. The effect of structural dip has been removed from the crossbed orientations, so that the crossbed dips are given with respect to the depositional slope.

An overview of the data analysis is given in Figure 1, which shows the orientation of structural surfaces and various types of crossbeds from 2790 to 3148mMDKB. These events were interpreted at Esso Australia Ltd using the FMS Fracview interpretation software provided by Schlumberger.

Structural Analysis

The results of analysis of structural information are shown in Figures 2 and 3. Two structural domains have been interpreted to be separated by an unconformity surface at 2936mMDKB. The unconformity lies within the Late Cretaceous T. longus section. Above the unconformity, the average structural dip is 2.1° towards an azimuth of 275°. Below the unconformity, the average structural dip is 5.3° towards an azimuth of 285°. The unconformity surface itself is not recognisable on the FMS images.

Stratigraphic Analysis

The results of analysis of stratigraphic features are shown in Figures 4 to 22. All crossbed orientations are given with the effects if structural dip removed. Crossbeds are present in most of the reservoir sands and lower energy silty facies in Blackback-2. Figures 4 and 5 shows the crossbed sets identified in the Paleocene and Cretaceous respectively. The Paleocene and Cretaceous reservoirs were broken down into flow packages on the basis of paleocurrent interpretation. The crossbeds in the Cretaceous section in particular yielded very good information about paleocurrent directions. Figures 7 to 15 shows the results of analysis of individual flow packages in the Paleocene section, while Figures 16 to 22 show the results in the Cretaceous section. The average orientations of all these flow units are listed in Table 1.

Figure 6 shows a good example of FMS images of crossbeds. The crossbeds are high angle, flatten upwards and are bounded by truncation or reactivation surfaces. The individual bedset is 0.6m in thickness. The white portion of the image above the crossbeds at 3112.6mMDKB is due to the presence of nodular siliceous or dolomitic cement.

Dip azimuths of Paleocene crossbeds vary from northwest to northeast. Figure 11 shows a good set of crossbeds at 2840mMDKB. These crossbeds have a dip of 34° towards an azimuth of 274° and lie near the top of the high energy channel which extends from 2840 to 2863mMDKB. This channel includes the lower portion of the main oil zone. The dip of the crossbeds indicates that the depositional environment was high energy. Figure 14 shows data from near the base of this channel indicating a paleocurrent direction towards an azimuth of 183°. The change of paleocurrent direction from the base to the top of the Paleocene channel has been interpreted to indicate that this sequence consists of stacked distal marine channel complexes.

Table 1

Blackback 2 FMS Interpretation Summary

Structural Analysis

	Dip Magnitude	Dip Azimuth
Paleocence		
2795m MDKB	2.1	275
Cretaceous		
3070m MDKB	5.3	285

Stratigraphic Analysis

Paleocene Crossbeds		
cbd.2799-2803	5.8	334
cbd.2808-18	5	123
cbd.2823-30	7.1	86
cbd.2833-35.5	2.2	292
cbd.2839-40.5	34.1	274
cbd.2841.5-2846	11.4	133
cbd.2847-50	8.4	97
cbd.2857-60	18.7	183
cbd.2860-61.5	23	54
Cretaceous Crossbeds		
cbd.3012-16	24.4	135
cbd.3091-95.5	15.5	59
cbd.3102.5-04	15.4	358
cbd.3104-06	8.1	299
cbd.3108-11	15.2	235
cbd.3112-15	17.3	195
cbd.3142-48	17.1	326

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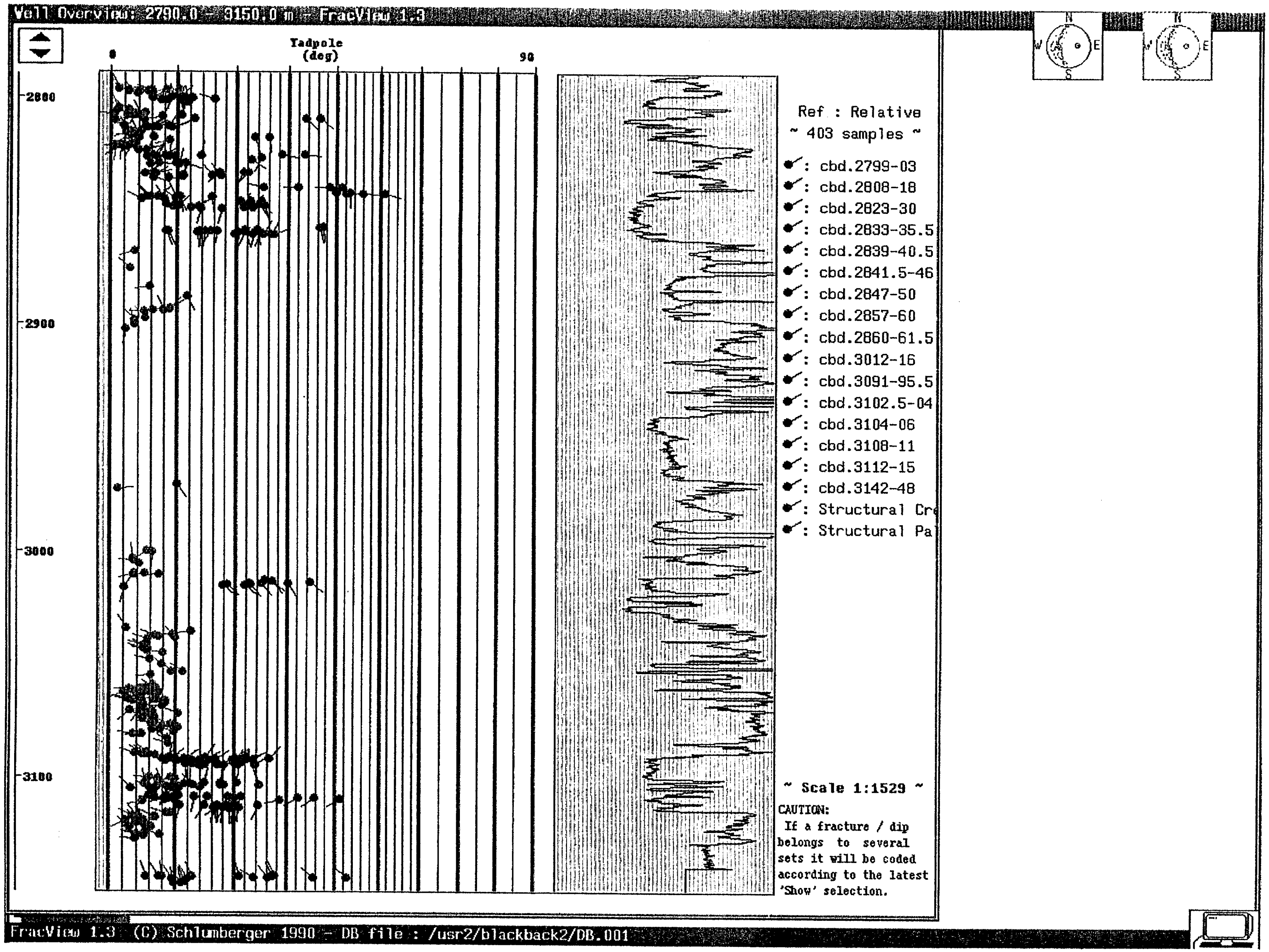

FIGURE 1 FMS WORKSTATION INTERPRETATION OF STRUCTURAL AND STRATIGRAPHIC BEDDING AND CROSSBEDS.

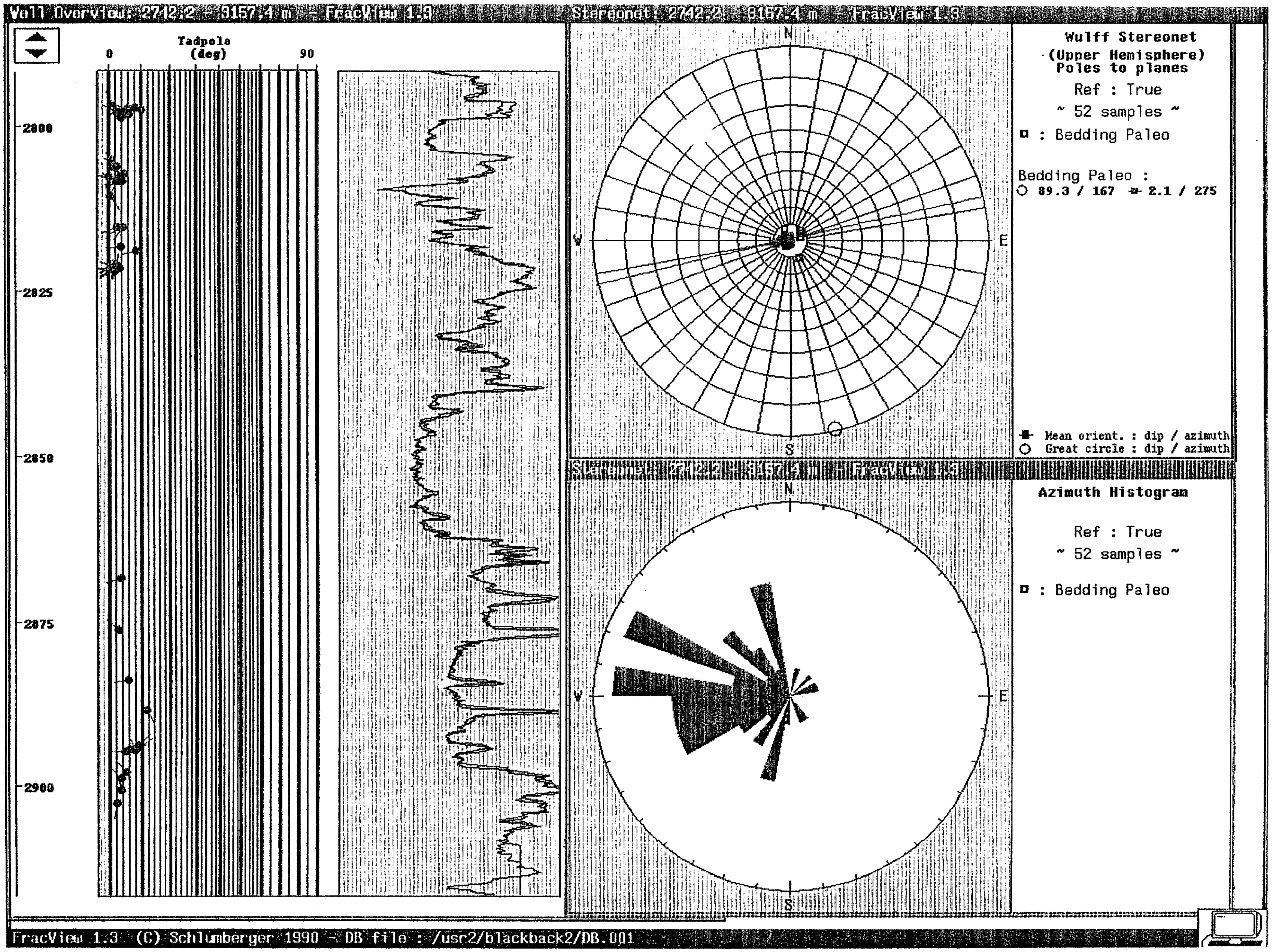

FIGURE 2 **POST INTRACRETACEOUS UNCONFORMITY STRUCTURAL DIP 2.1° AZIMUTH 275°**

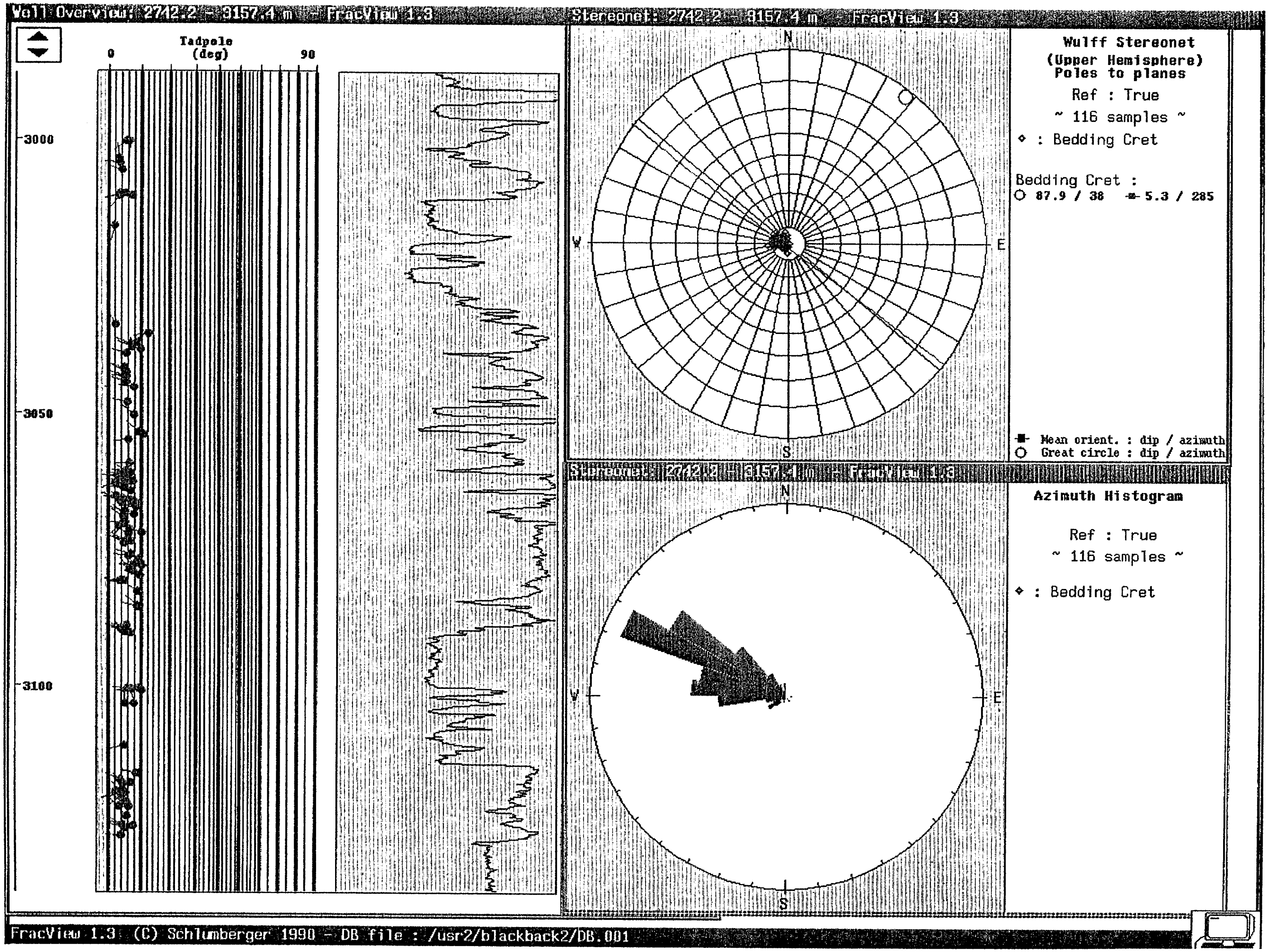

FIGURE 3 PRE INTRA CRETACEOUS UNCONFORMITY STRUCTURAL DIP 5.3° AZIMUTH 285°

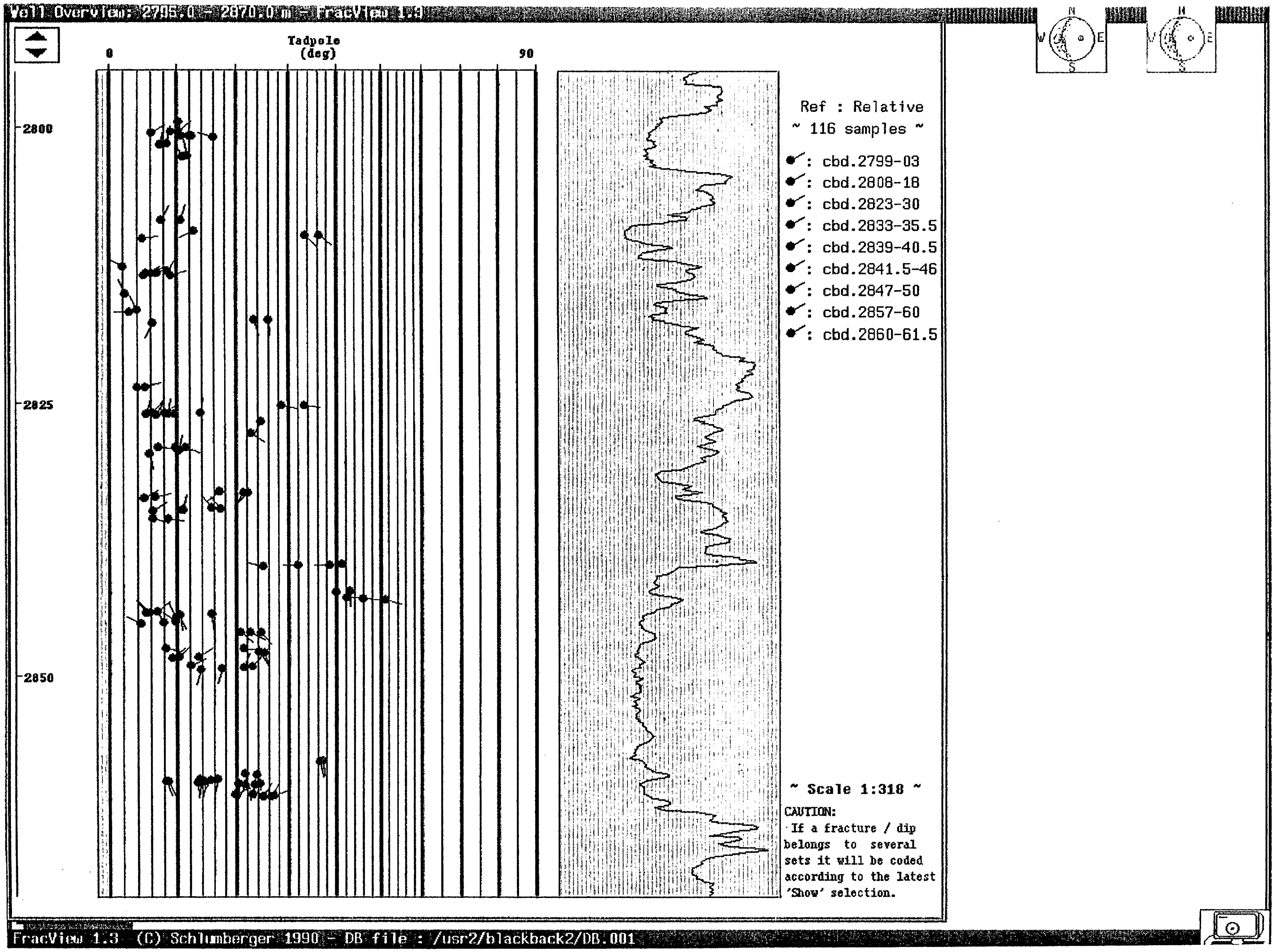

FIGURE 4 PALEOCENE CROSSBED SETS STRUCTURAL DIP REMOVED.

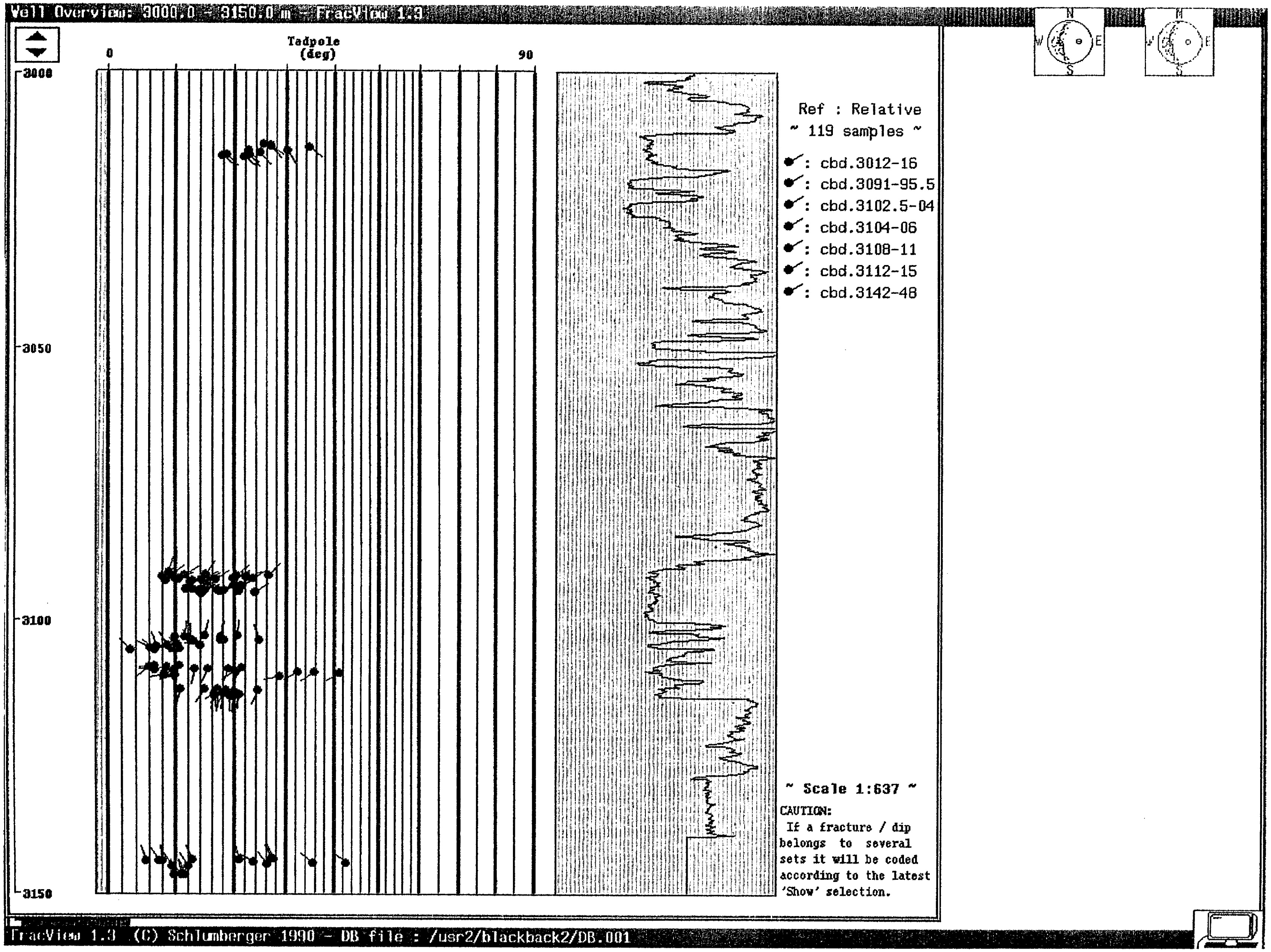

FIGURE 5 CRETACEOUS CROSSBED SETS STRUCTURAL DIP REMOVED.

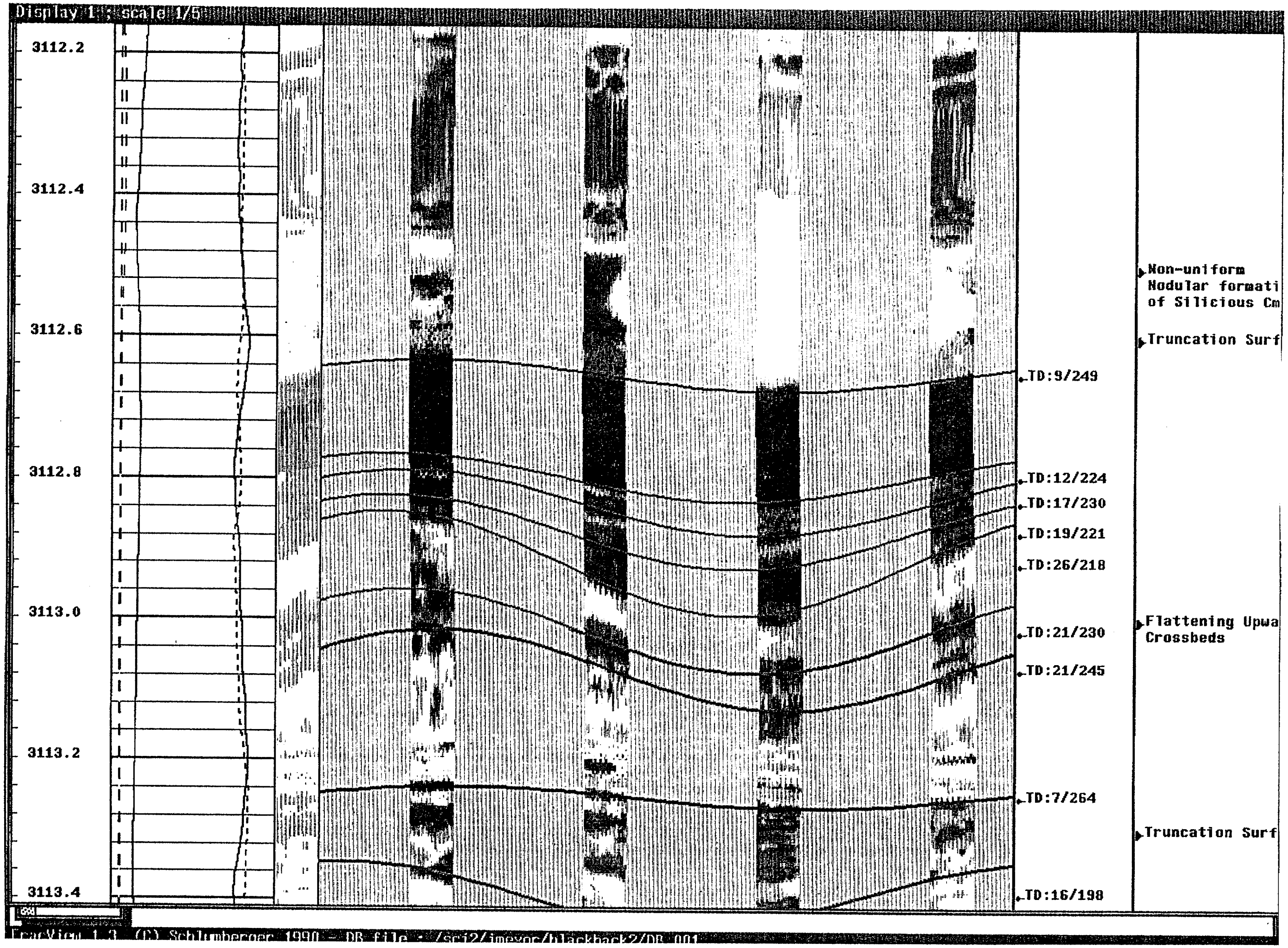

FIGURE 6 FMS IMAGE ANALYSIS OF HIGH ANGLE CROSSBEDS FLATTENING UPWARDS BOUNDED BY TRUNCATION SURFACES.

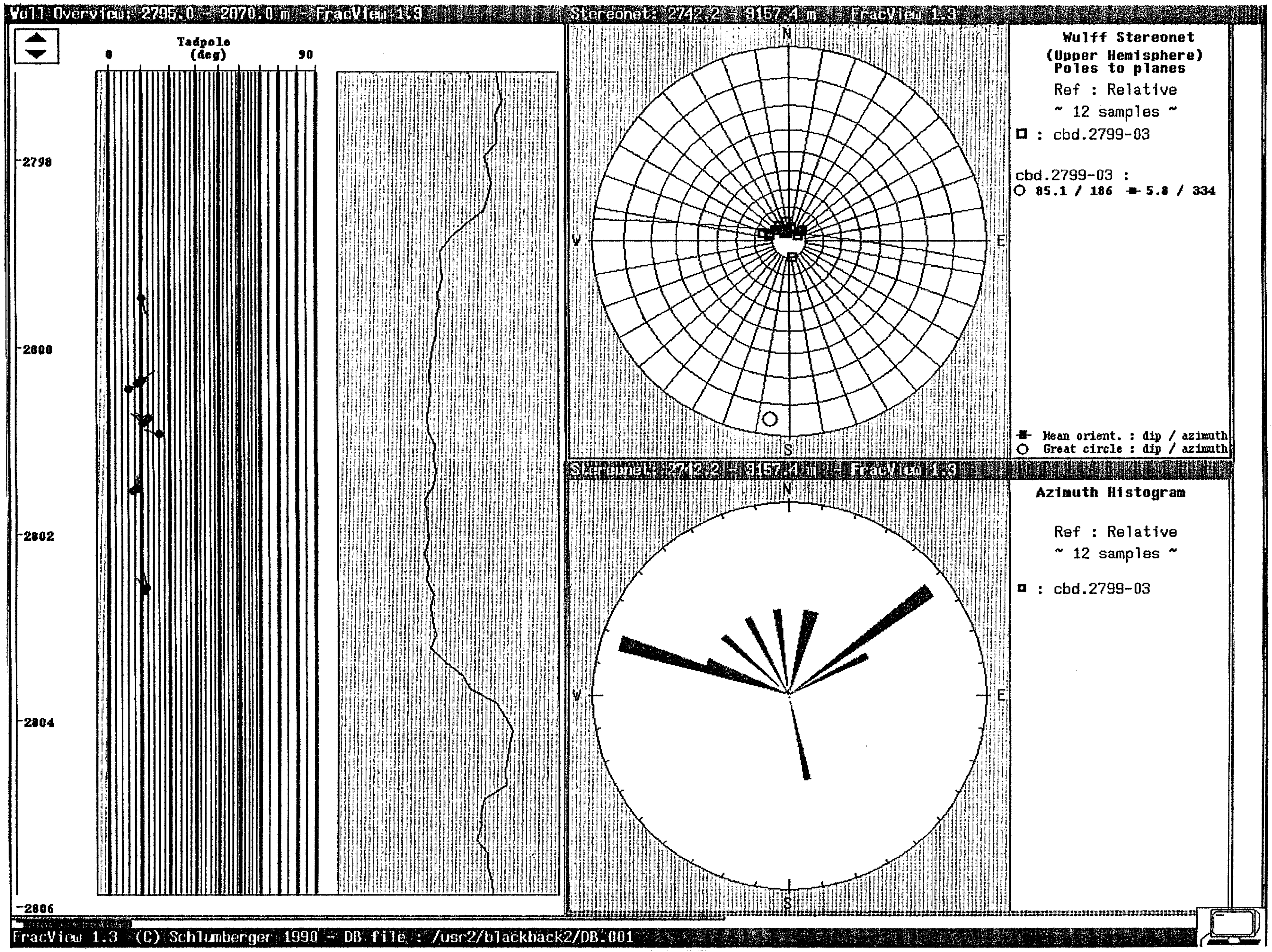

FIGURE 7 PALEOCENE UPPERMOST GAS SAND CROSSBEDS 2799M TO 2803M DIP 5.8° AZIMUTH 334° .

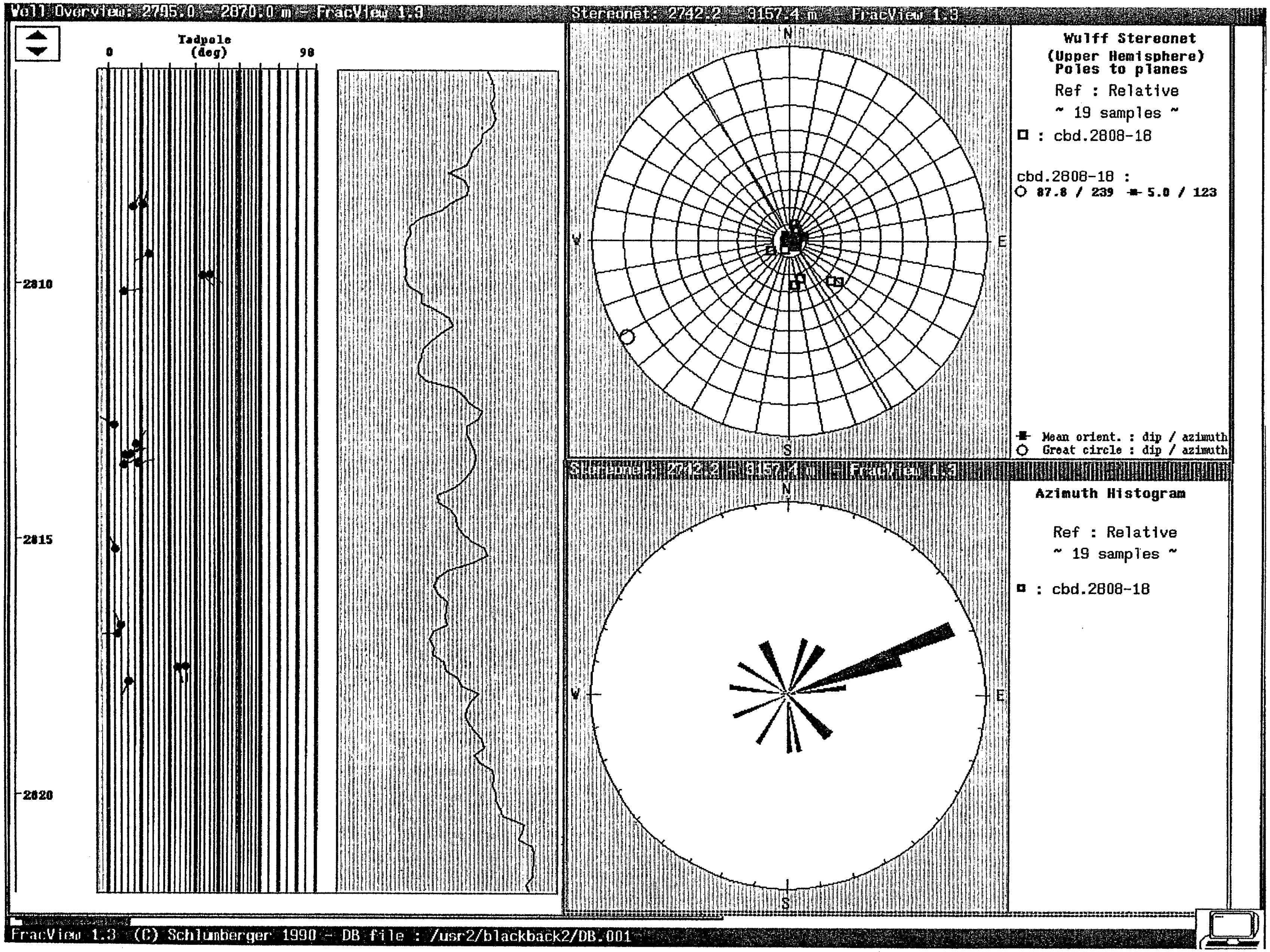

FIGURE 8 PALEOCENE LOWER GAS RESERVOIR CROSSBEDS 2808M TO 2818M DIP 5.0° AZIMUTH 123° .

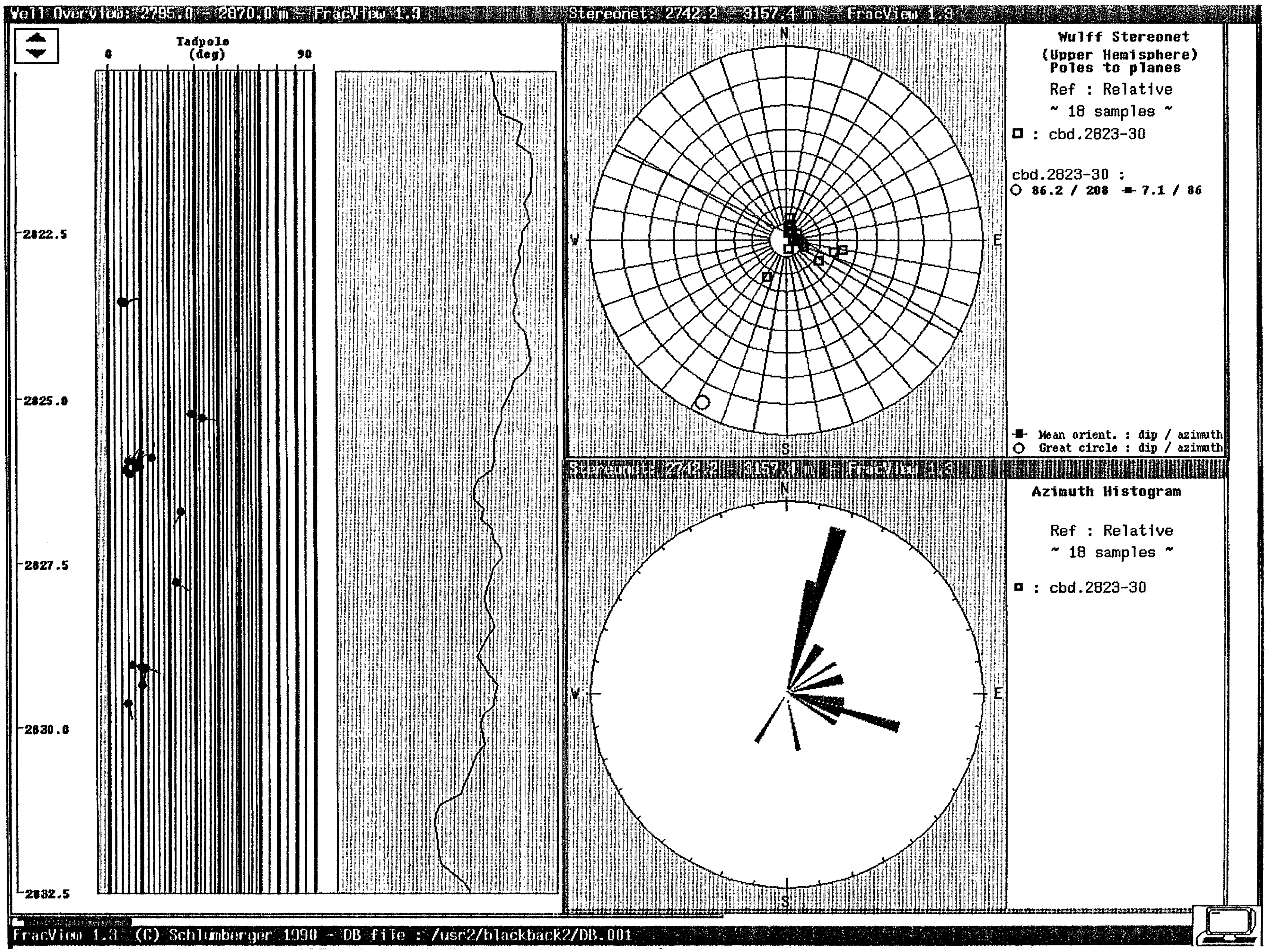

FIGURE 9 PALEOCENE UPPERMOST OIL RESERVOIR 2823M TO 2830M DIP 7.1° AZIMUTH 86° .

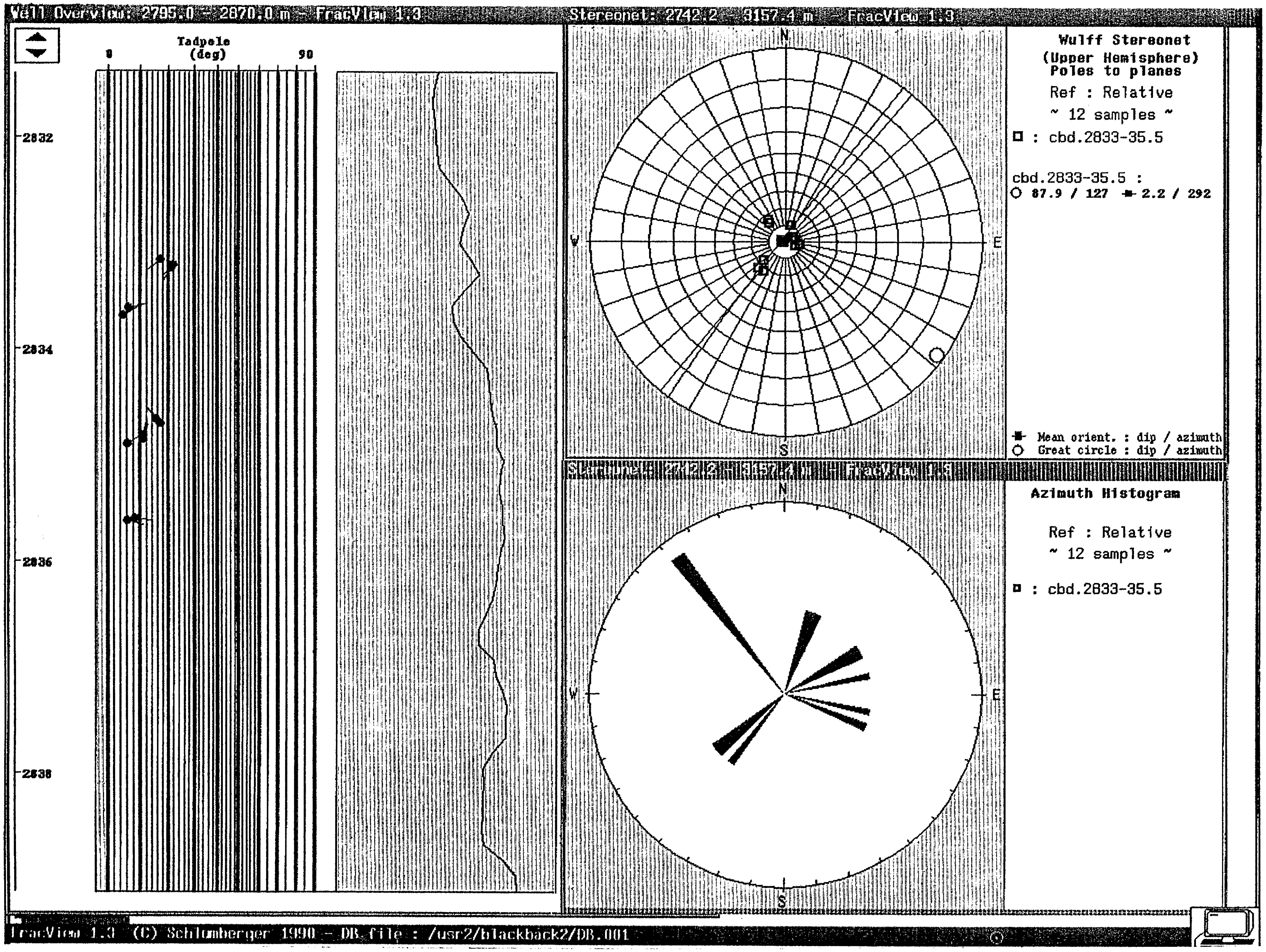

FIGURE 10 PALEOCENE PRODUCTION TEST 2 RESERVOIR 2833M TO 2835.5M DIP 2.2° AZIMUTH 292°.

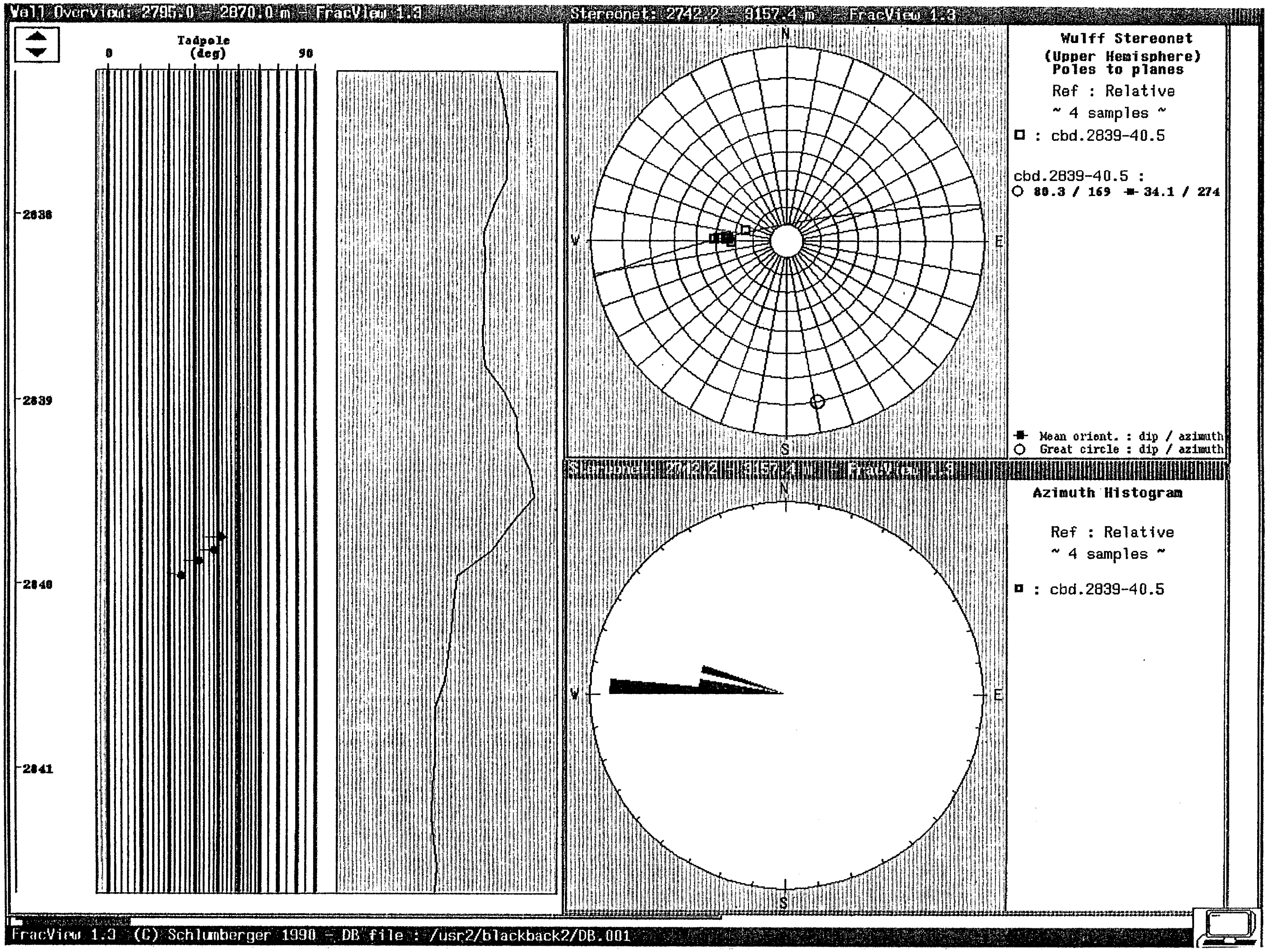

FIGURE 11 PALEOCENE CROSSBEDS 2839M TO 2840.5M DIP 34.1° AZIMUTH 274° .

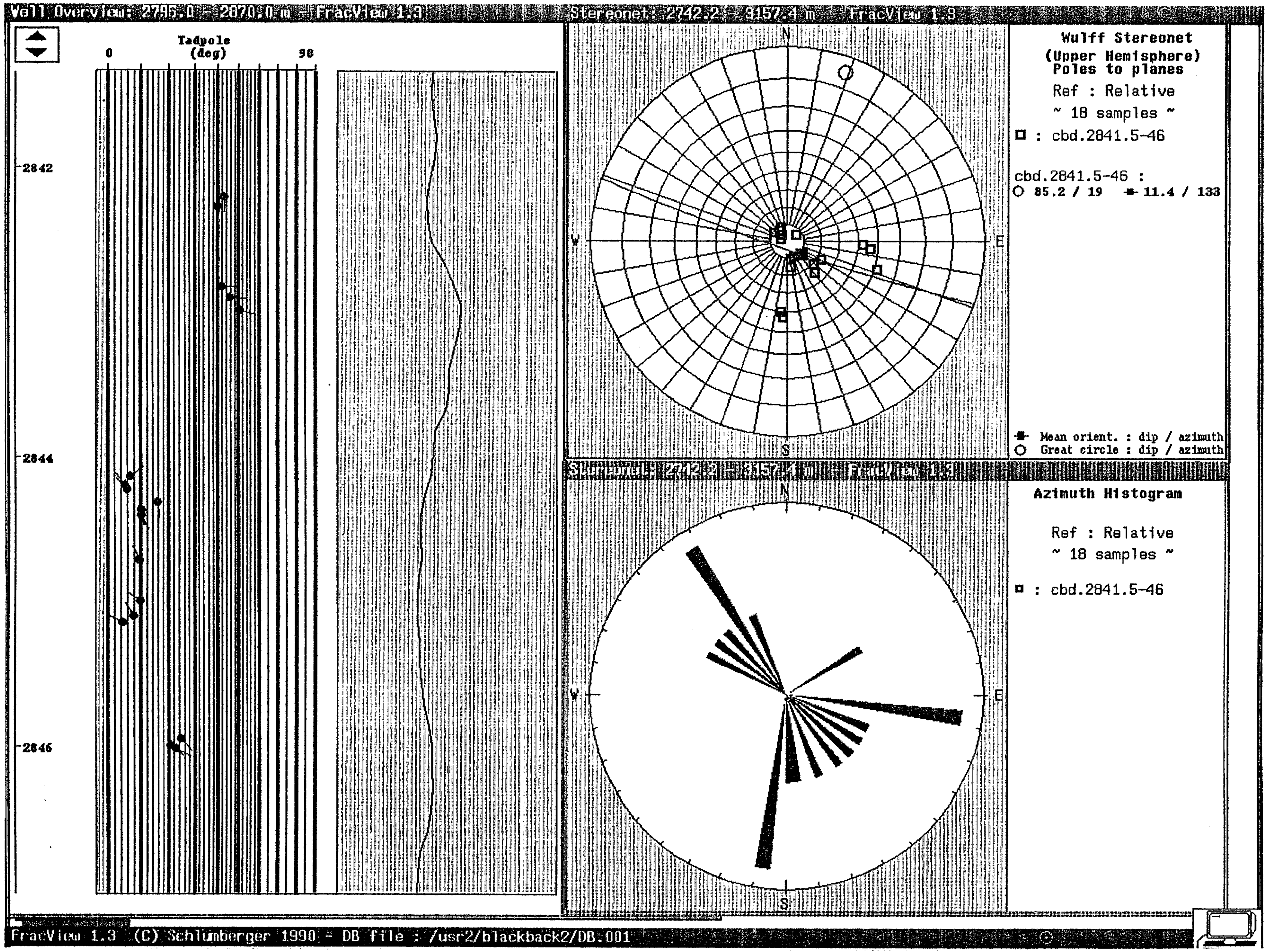

FIGURE 12 PALEOCENE PRODUCTION TEST 1 RESERVOIR 2841.5M TO 2846M DIP 11.4° AZIMUTH 133° .

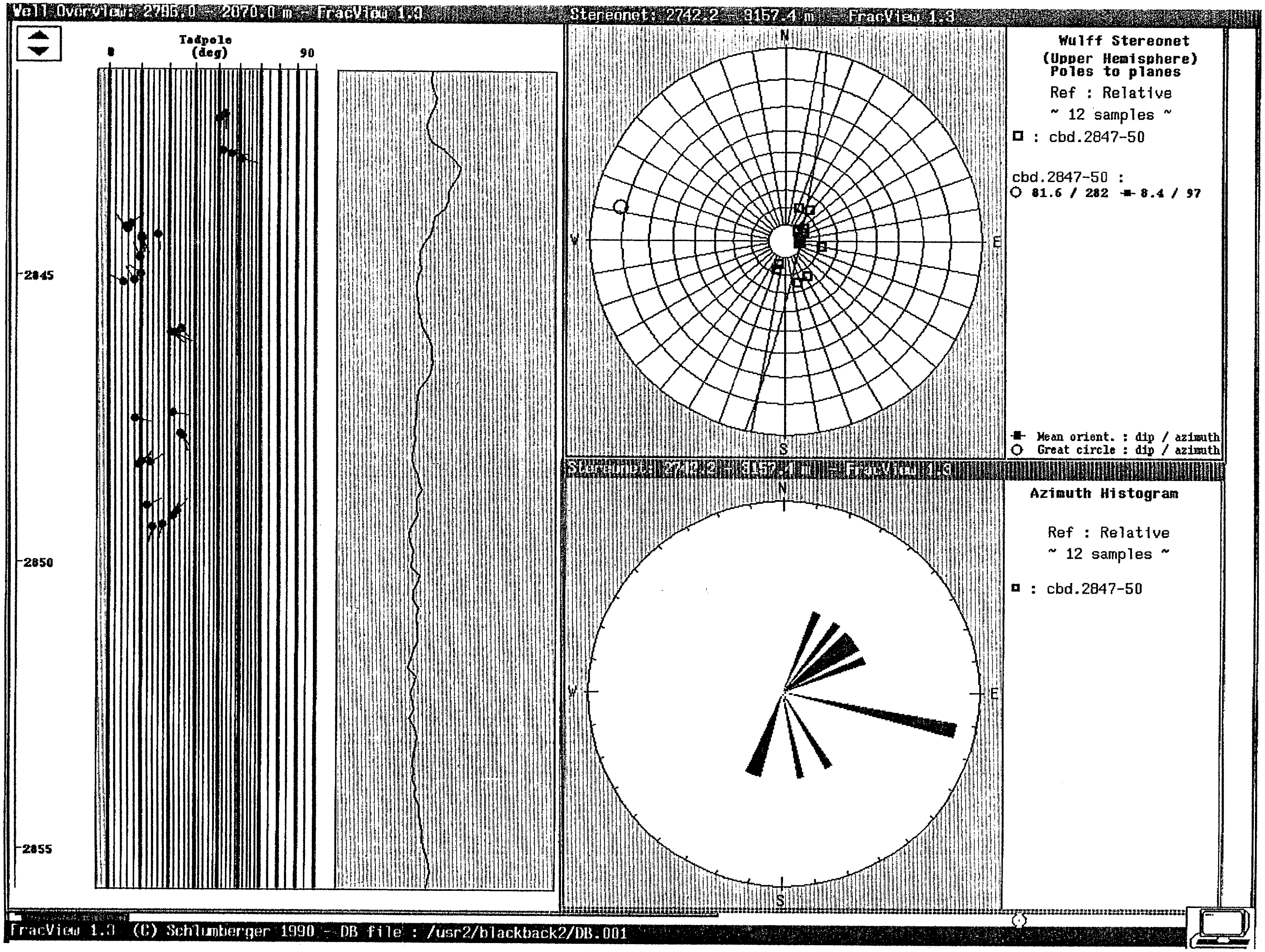

FIGURE 13 PALEOCENE LOWER OIL RESERVOIR 2847M TO 2850M DIP 8.4° AZIMUTH 97° .

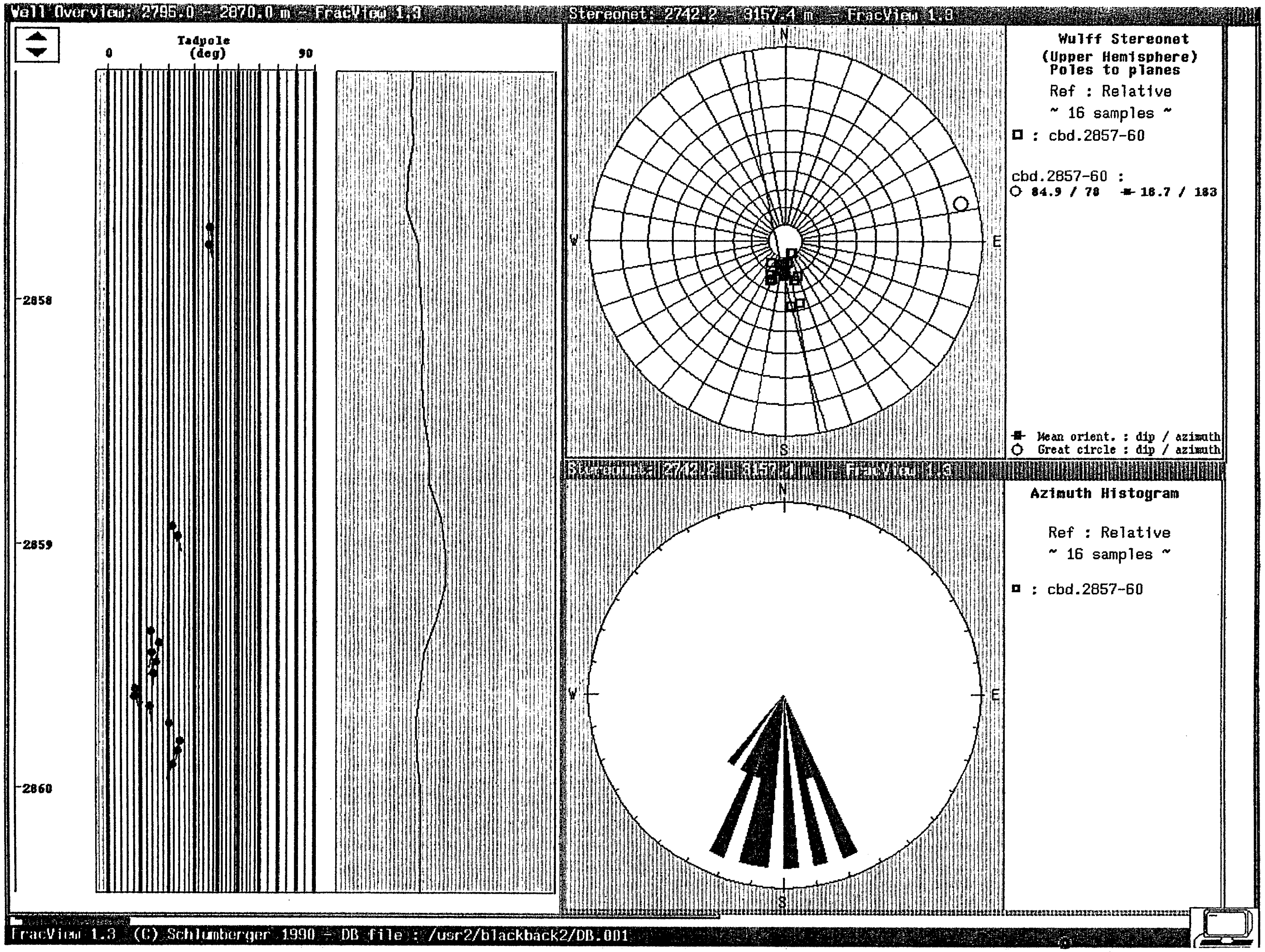

FIGURE 14 PALEOCENE WATER LEG CROSSBEDS 2857M TO 2860M DIP 18.7 AZIMUTH 183° .

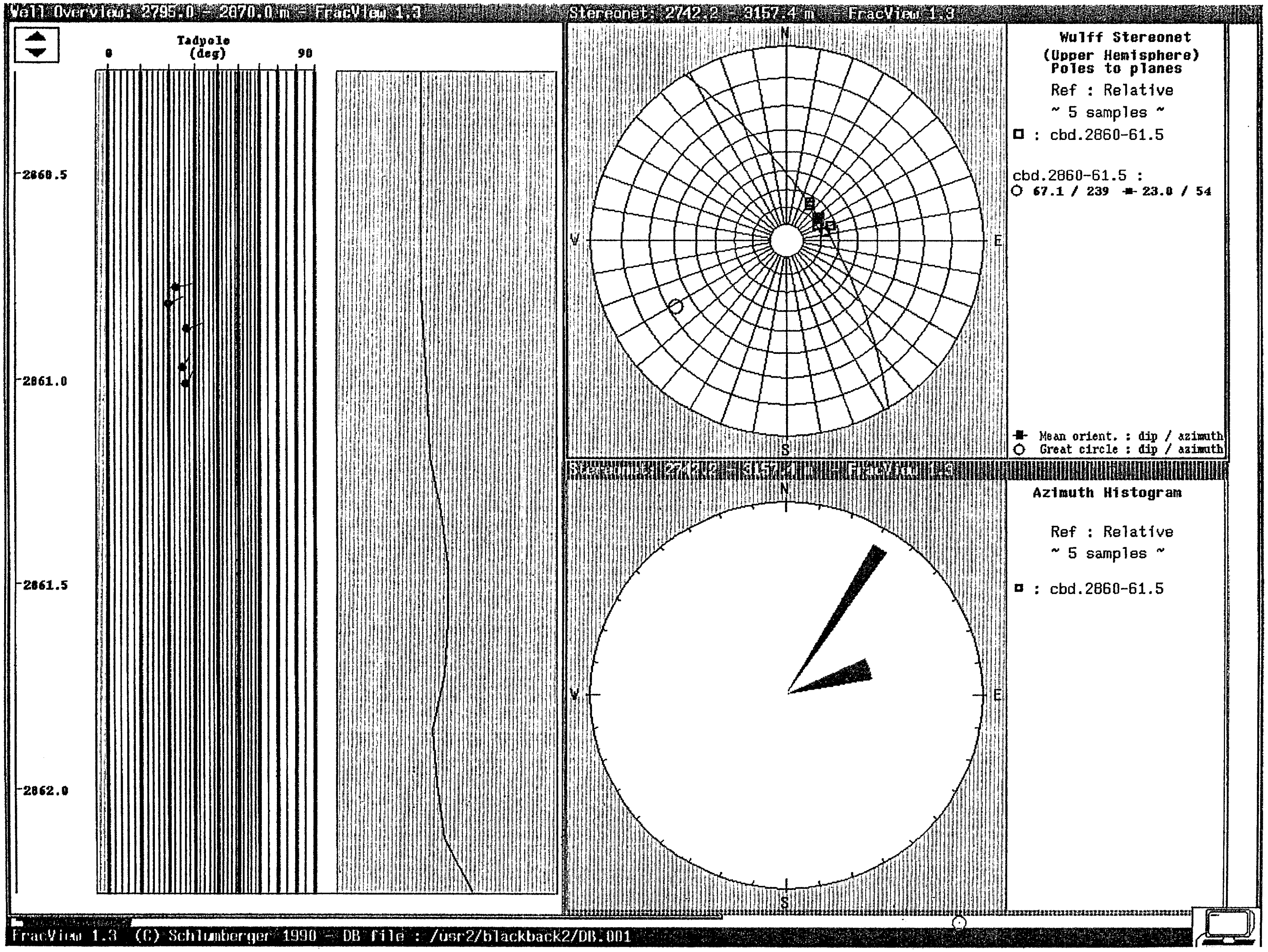

FIGURE 15 PALEOCENE CROSSBEDS 2860M TO 2861.5M DIP 23° AZIMUTH 54° .

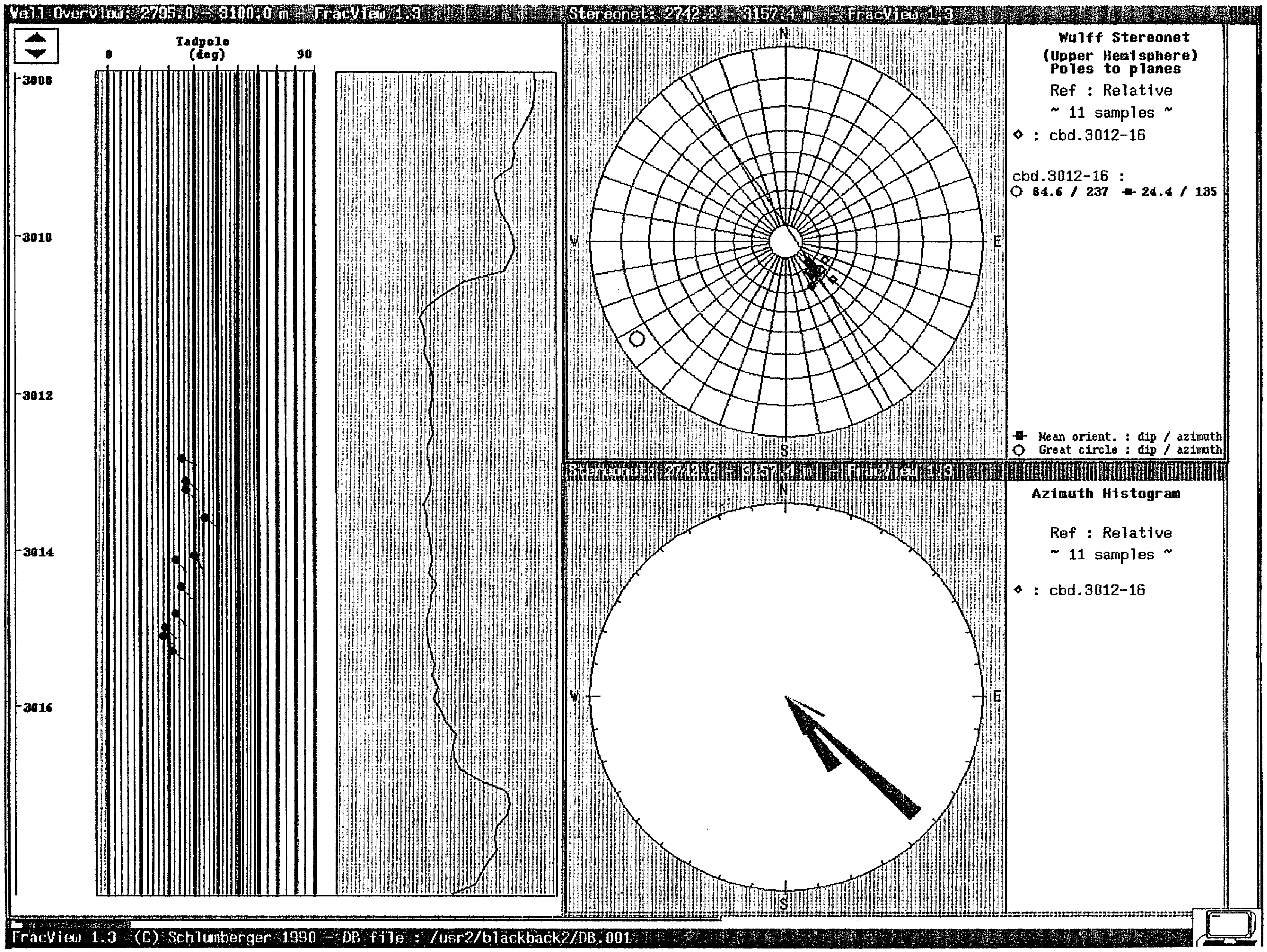

FIGURE 16 CRETACEOUS CROSSBEDS 3012M TO 3016M DIP 24.4° AZIMUTH 135° .

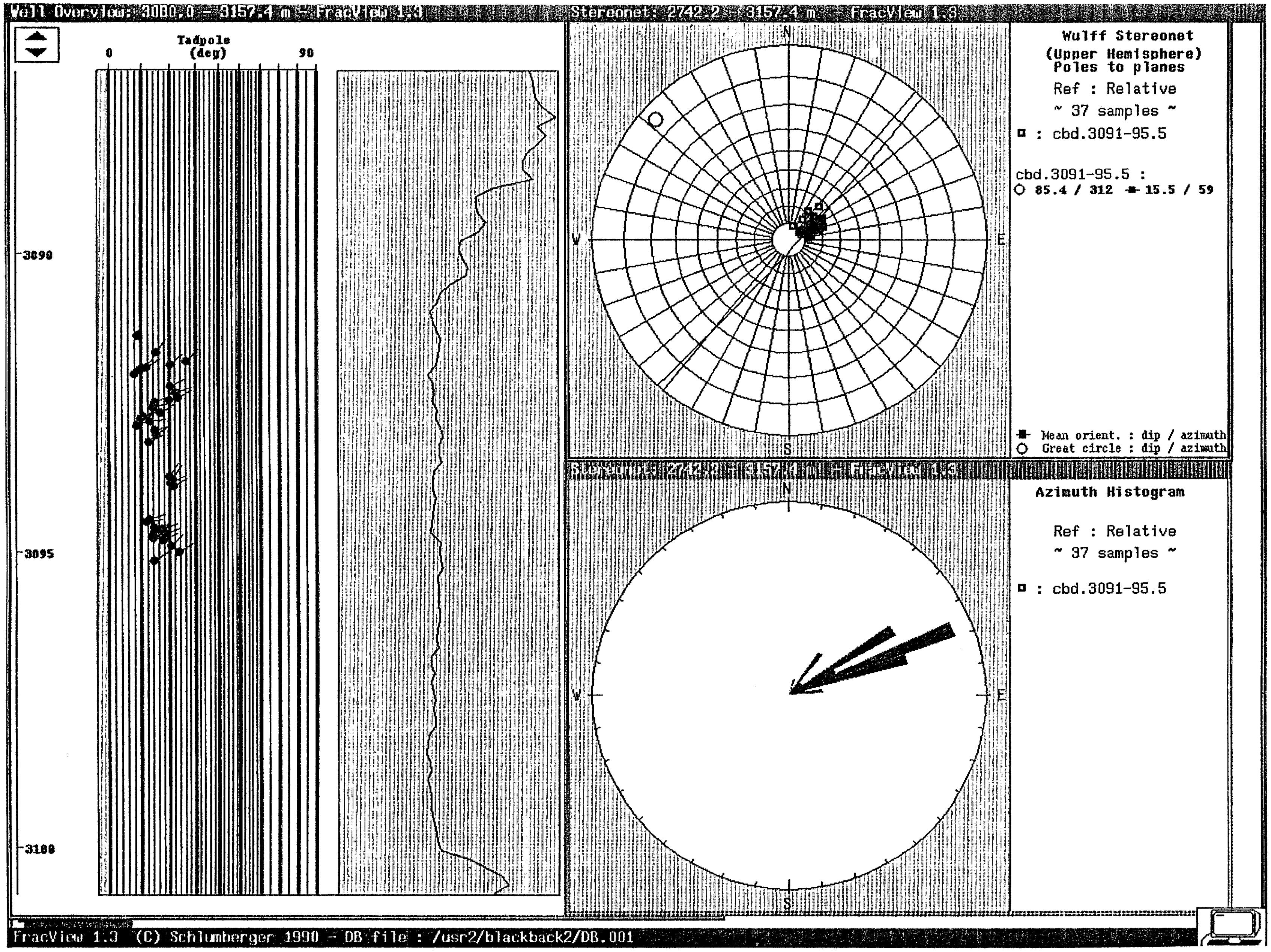

FIGURE 17 CRETACEOUS CROSSBEDS 3019M TO 3095.5M DIP 15.5° AZIMUTH 59° .

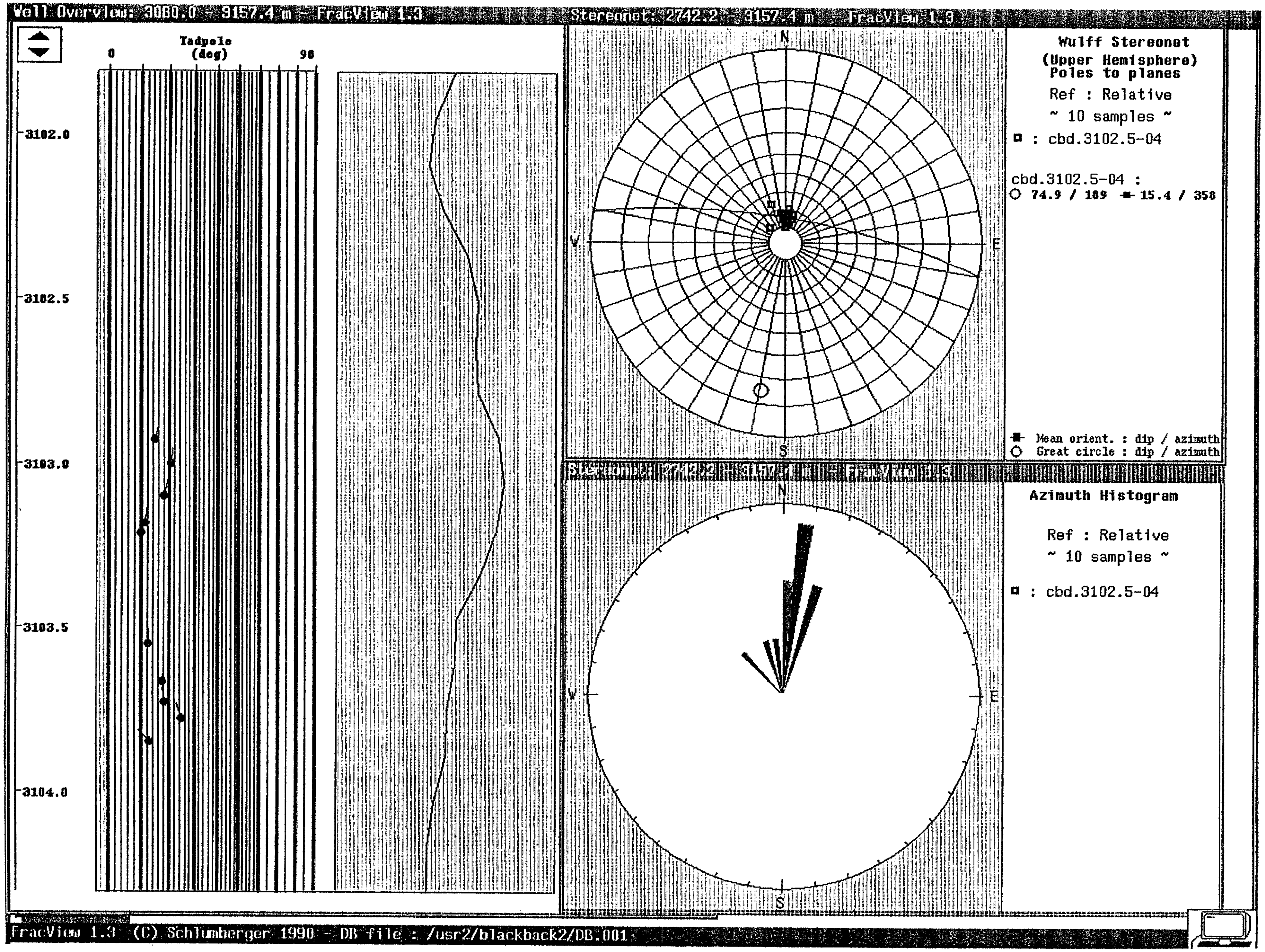

FIGURE 18 CRETACEOUS CROSSBEDS 3102.5M TO 3104M DIP 15.4° AZIMUTH 299° .

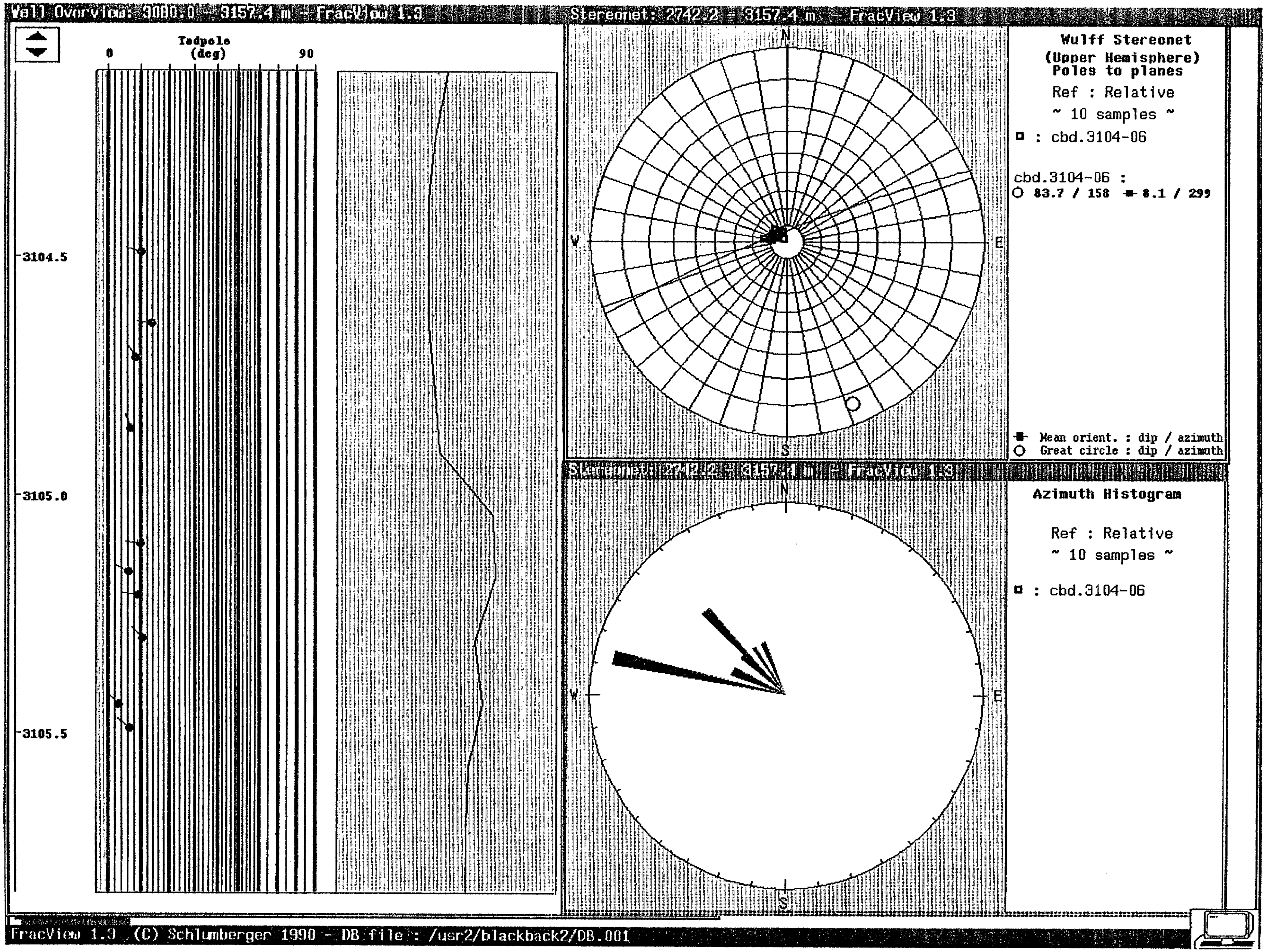

FIGURE 19 CRETACEOUS CROSSBEDS 3104M TO 3106M DIP 8.1° AZIMUTH 299° .

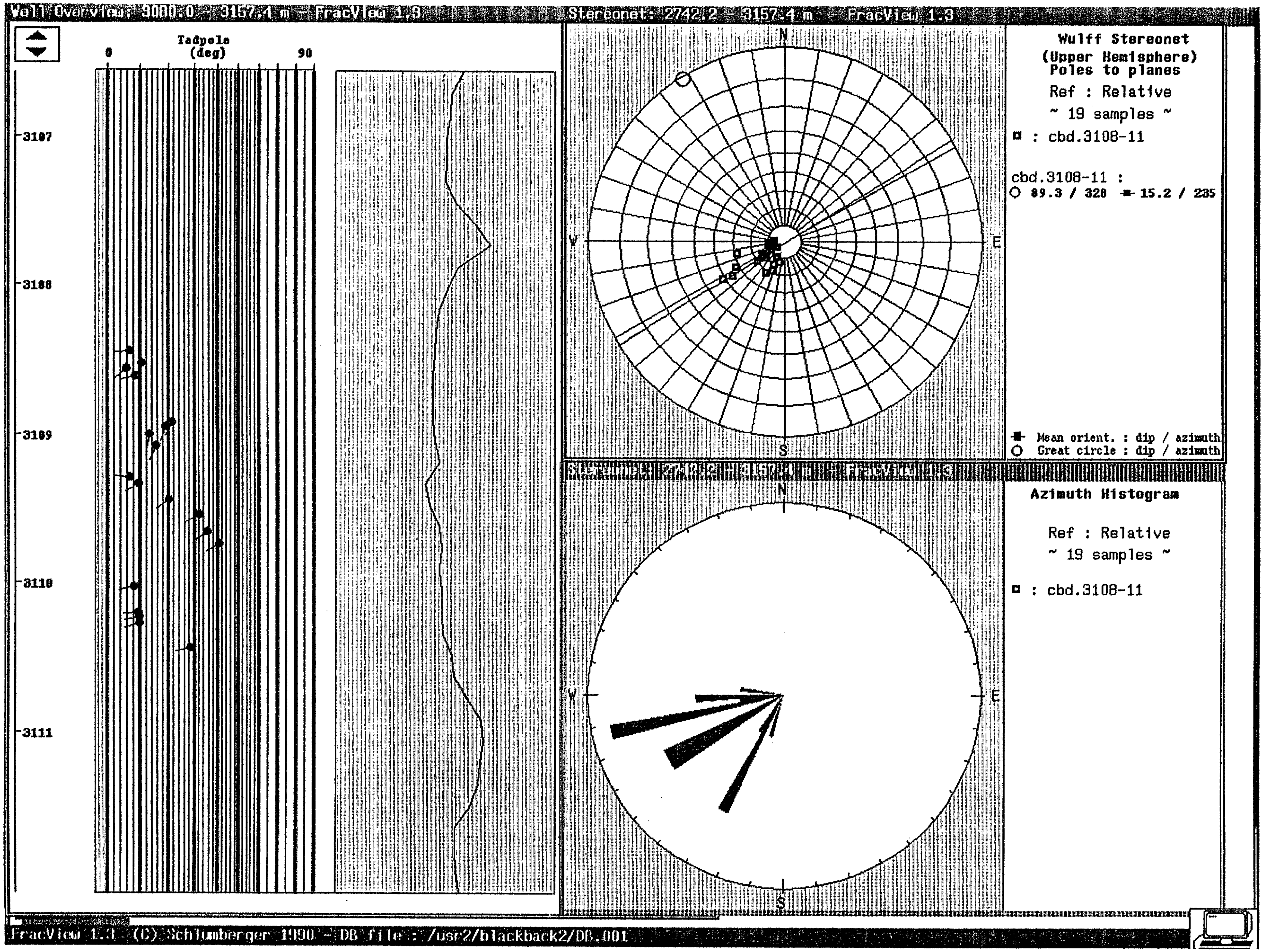

FIGURE 20 CRETACEOUS CROSSBEDS 3108M TO 3111M DIP 15.2° AZIMUTH 235° .

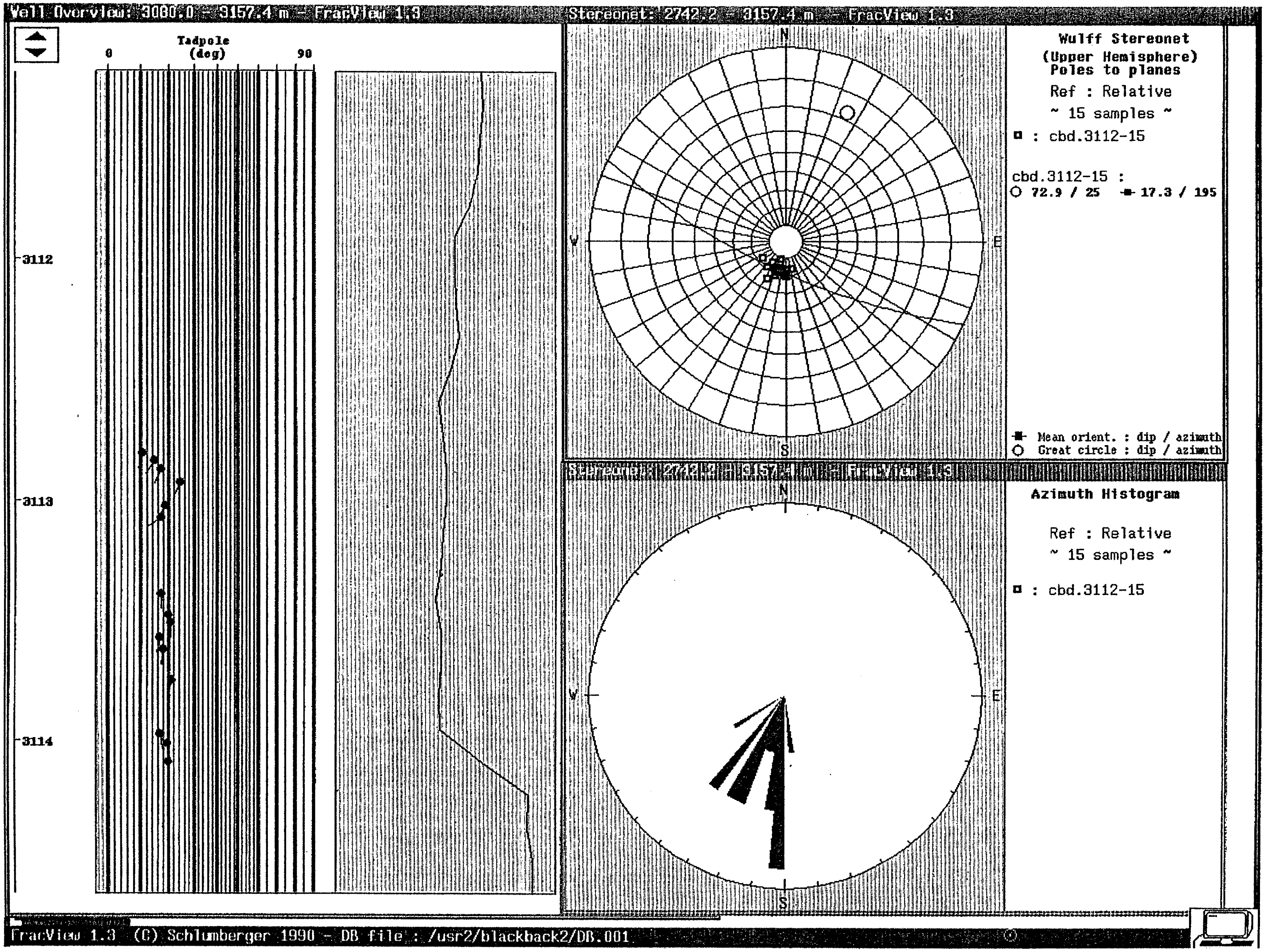

FIGURE 21 CRETACEOUS CROSSBEDS 3112M TO 3115M DIP 17.3° AZIMUTH 195° .

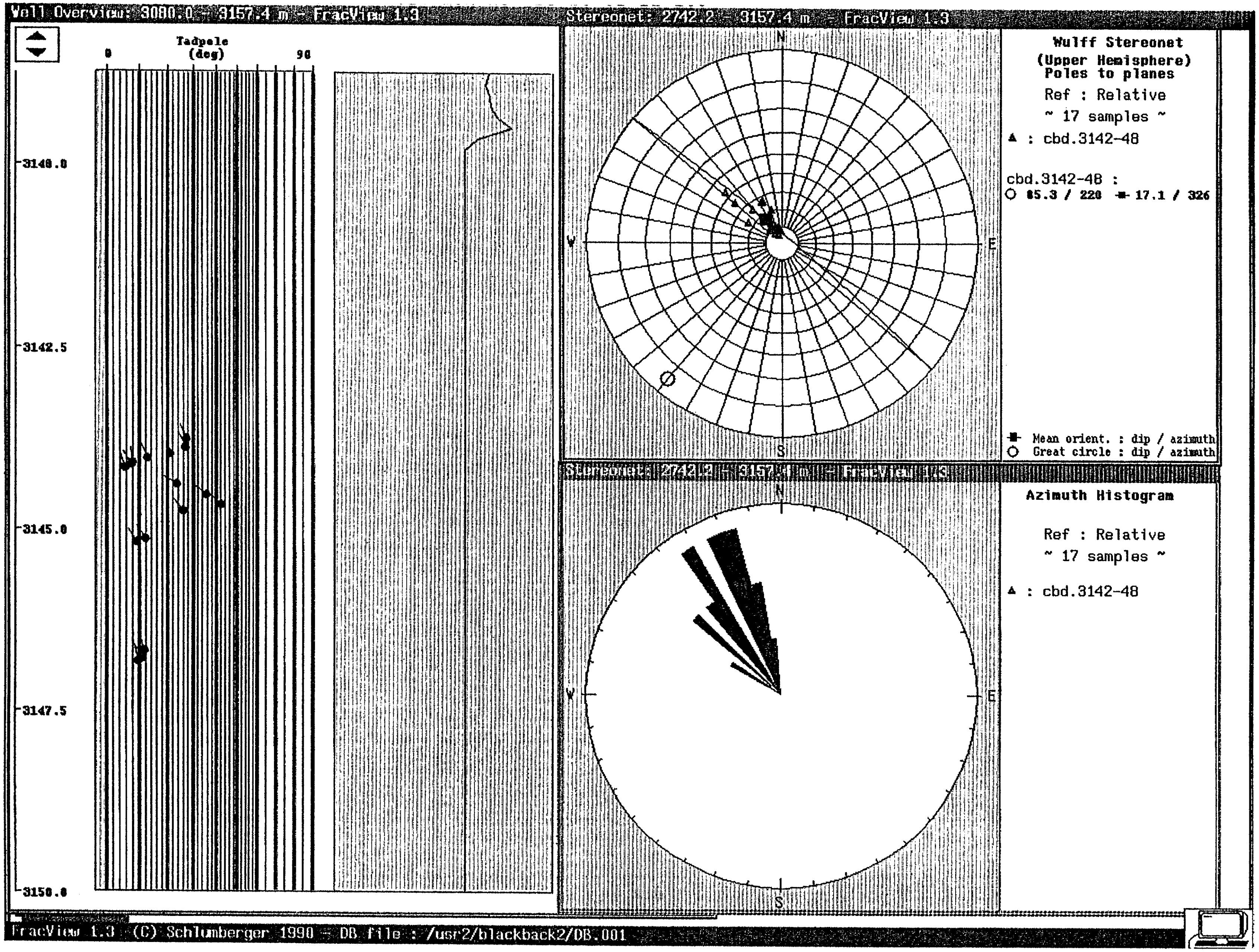

FIGURE 22 CRETACEOUS CROSSBEDS 3142M TO 3148M DIP 17.1° AZIMUTH 326° .

PE600797

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CONTRACTOR = ESSO
CLIENT_OP_CO = ESSO

(Inserted by DNRE - Vic Govt Mines Dept)

APPENDIX
4

APPENDIX 4

Esso Australia Limited

Blackback #2

Thin Section Petrography

Scanning Electron Microscopy

and X-Ray Diffraction

December, 1992

FILE # GSA 92029

PETROGRAPHY AND SEM BY : RICK DE BOER

X-RAY DIFFRACTION BY: WEI-JUI CHANG

SUMMARY

Lithology : All samples are sandstone with the exception of 2804.2m which is a granulestone. Composition is mainly feldspathic litharenite with minor litharenite, sublitharenite, subarkose, and lithic arkose.

Average Grainsize : Mostly fine grained with minor coarse to granule size.

Sorting : Mainly poorly to moderately well, minor well. Occasionally bimodal.

Angularity : Subrounded to angular.

Lithification : Generally moderate above 2824.4m. Sample 2804.2m is loose sand, sample 2830.4m is well lithified, 2835.4m is poorly lithified. Below 2840.2m the samples are well to extremely well lithified.

Grain Types : Monocrystalline igneous quartz dominates in all samples, glauconite and feldspar are generally common, as is biotite. Minor minerals include clay-altered lithics, hornblende, zircon, muscovite, sedimentary rock fragments and organic matter.

Clay Mineralogy and Distribution : Clays range from trace to abundant. Above 2830.4m clays are generally common to abundant, except for coarser grained samples which contain traces of clay. From 2830.4m to 2851.7m clay is trace. Sample 2958.4m contains abundant matrix. Clays comprise kaolinite, illite and an iron - potassium rich clay which is probably corrensite. Detrital matrix and authigenic clays are interspersed which makes them difficult to resolve. Glauconite and partially altered lithics such as biotite will be detected as illite by Mineralog. Glauconite may be detected as illite by XRD.

Cements : Above 2835.4m cements comprise early stage authigenic quartz, minor disseminated pyrite and traces of siderite. Traces of anhydrite were observed at 2835.4m.

Below 2835.4m extensive poikilotopic dolomite cement is present in all samples, except 2858.9m which has abundant phosphate rich matrix. Sample 2815.2m contains abundant dolomite.

Visible Porosity : Mostly poor to fair with localised highly porous zones. Dolomite cemented samples exhibit minimal porosity.

Porosity Controls : Primary matrix content, bioturbation and compaction influence porosity in samples above 2835.4m. Extensive dolomite cement restricts porosity in samples between 2840.2m and 2851.7m. Dissolution of early diagenetic anhydrite cement is suspected.

Reservoir Quality : Generally fair, but locally very good. The coarse grained highly porous zones will exhibit high permeability.

Formation Damage Potential : Argillaceous rich samples may be prone to fines migration and sensitivity to incompatible fluids. Poorly lithified sands may be prone to sanding. Dolomite cemented sands are acid sensitive.

Log Response : Significant variations in the content of naturally radioactive minerals, dense minerals, and microporous phases will effect all logs. Logs may be unable to discriminate thinly laminated sandstone/claystone sequences from bioturbated sandstones/claystones. Non bioturbated sands are likely to be well sorted, and will exhibit better reservoir quality.

Depositional Environment : All the samples are of marine origins. Sample 2858.9m may reflect a hiatus.

INTRODUCTION

Seventeen samples from the Blackback #2 well were submitted for Thin Section, Scanning Electron Microscopy (SEM) and X-Ray Diffractive analysis (XRD). A list of sample depths and analyses is presented in Table 1.

The main objectives of this report are to identify and characterise the mineralogy of the framework grains, matrix, and cements, to assess the visual porosity, permeability, factors controlling reservoir quality, formation damage potential and, wherever possible, determine a probable depositional environment.

Thin Section and Scanning Electron Microscopy descriptions and photomicrographs for selected samples are provided.

Several samples exhibit heterogeneity at Thin Section scale. These heterogeneities are reflected by variations in observations and mineralogy between different analyses from the same depth.

Core analysis information was provided by Esso Australia Limited.

DISCUSSION

General Lithology

All the samples are sandstones with the exception of 2804.2m which is a granulestone, however, as it has a similar composition to the sandstones it will be treated as one in text. Sandstone composition is generally feldspathic litharenite with minor lithic arkose, subarkose, sublitharenite and litharenite (Figure 1).

The samples are predominantly fine grained, with minor coarse and granule size. Grainsize information is detailed in Table 2. Grains are mainly subrounded, with minor angular and well rounded grains. Grain contacts are straight to point in all samples except those cemented by dolomite or phosphate, which have predominantly point contacts.

Samples between 2797.0m and 2824.4m are mostly moderately lithified with the exception of sample 2804.2m which is loose sand. Sample 2830.4m is well lithified, sample 2835.4m is poorly lithified. Samples 2840.2m to 2851.7m are cemented by extensive dolomite. Sample 2858.9m is lithified by phosphate.

Most samples are massive with only minor faint lamination and grain imbrication observed. Finer grained samples have been bioturbated.

Framework Grain Mineralogy

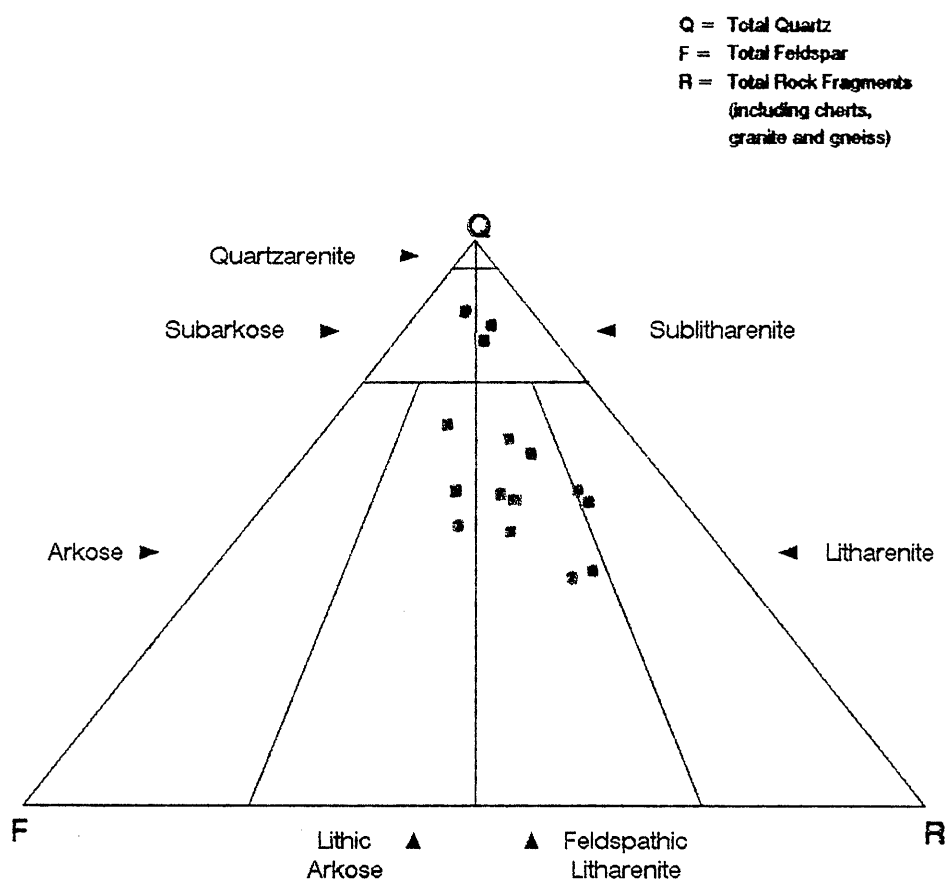
Monocrystalline igneous quartz dominates in all samples, polycrystalline quartz is minor in coarse grained samples, feldspar and glauconite are common throughout. Green biotite is present in all samples. Minor components include muscovite, chert, lithic fragments, clay-altered grains, organic matter, zircon, hornblende, and rock fragments.

The monocrystalline quartz is generally free of straining, however does occasionally contain inclusions and is believed to be of igneous origins, some is possibly volcanic.

Biotite is a chemically unstable lithic and is unlikely to survive excessive subaerial exposure. Its abundance suggests proximity to the provenance. The green colour of biotite may be due to alteration, however the occurrence of green and brown biotite together suggests it is relatively unaltered. Some biotite is altered to glauconite.

The prevalence of polycrystalline quartz in coarser grained samples is not unusual.

Figure 1
Folk's Classification (1974)



ESSO AUSTRALIA LTD	- LEGEND -
Well: Blackback # 2	Core samples ■ Blackback # 2

Other trace minerals are typical of clastics derived from an igneous source. Some of the clays and clay-altered grains may be altered volcanic rock fragments.

Matrix and Clays

Above 2830.4m clays are generally common to abundant, below 2830.4m clays are trace in dolomite cemented, and coarse grained sandstones. Sample 2858.9m contains abundant phosphate rich matrix.

Clays comprise primary matrix, authigenic clays and structural clays. Structural clays include detrital clay-rich grains, such as glauconite and grain-replacive authigenic clays. Kaolinite, illite, chlorite and corrensite have been identified.

Kaolinite was identified by XRD, Mineralog™ and was observed in Thin Section and SEM. Both XRD and Mineralog™ indicate that kaolinite is present in trace to minor quantities in the more argillaceous samples. Both show the highest concentration of kaolinite around 2808.8m. Authigenic kaolinites were observed under SEM as rare pore-filling clusters within patches of cleaner sandstones in bioturbated samples. Most of the kaolinite is probably detrital and is not readily identifiable in thin section or SEM.

Illites range from trace to common in Mineralog™ and XRD (Table 3, Appendix 1). Illites comprise mainly detrital clays associated with matrix and glauconite. Minor authigenic illites form as grain replacive clays, no pore-bridging authigenic illite was observed. Both Mineralog™ and XRD have not discriminated between illites and micas. Petrographic analyses indicate that biotite and glauconite account for a significant percentage of the illite detected by Mineralog™.

Minor chlorites were detected by Mineralog™. Energy dispersive x-ray analysis indicated the chloritic clays contain both iron and potassium, suggesting they are mixed chlorite and smectite (corrensite).

Corrensite was observed in trace amounts in several samples. It forms pore-lining wavy platelets which have been partially enclosed by authigenic quartz.

Cements

Lithification ranges from unlithified to extremely well lithified. Samples above 2835.4m are mainly moderately lithified. Samples below 2840.2m are predominantly well lithified. Cements comprise authigenic quartz, pyrite, siderite and dolomite.

Authigenic quartz is present as a minor cement in most samples, with the exception of the extensively dolomite cemented samples. Quartz cementation is in the early stages and forms small euhedral overgrowths, which are nucleated on detrital grains. Available nucleation sites are limited by primary and authigenic clays. Textural relationships with other cements and clays suggest the quartz is relatively late in the diagenetic sequence.

Pyrite was observed in all samples in trace to rare amounts. Pyrite generally forms isolated very fine crystals, and framboidal clusters. Minor pore-filling pyrite was observed. Pyrite texturally precedes all other cements.

Traces of siderite were observed in most samples. The siderite forms small crystals which are associated with organic matter. Texturally siderite appears to be an early diagenetic mineral.

Traces of anhydrite were observed at 2835.4m. The anhydrite is partially dissolved, however markings on detrital grains suggest it formed a pore-filling cement associated with the dolomite.

Pore-filling dolomite was observed at 2840.2m, 2849.4m and 2851.7m. Traces of dolomite were observed at 2804.2m. Dolomite forms a poikilotopic cement which predates quartz cementation. The dominance of point contacts on detrital grains within dolomite cemented sands suggests dolomite cementation precedes compaction. Dolomite was observed as a pore-filling cement at 2815.2m.

Depositional Environment

All the samples exhibit a strongly marine character. They contain common pelletal glauconite in association with visible bioturbation.

Bioturbation has obscured most primary bedding, however minor laminations and imbricated grains were noted. This suggests deposition by tractive currents. The variation in grainsize from granule to very fine sand reflects changes in energy conditions. Granules may represent channel lag deposits.

The abundance of argillaceous material and the extent of bioturbation suggests periods of relative quiescence. In the absence of other sedimentological evidence a tentative interpretation is that the sediments were deposited on a shallow marine substraight by migrating sand waves and channels.

A middle to lower shoreface environment in a tidally influenced, possibly estuarine, environment is likely. Channel deposits probably represent migrating tidal channels.

The sediments are texturally and chemically immature, which suggests proximity to the source terrain. The abundance of unstrained monocrystalline quartz, free of inclusions and potassium feldspars, suggest a granitic provenance, however the presence of clay-altered possible volcanics indicates a minor volcanic influence.

Diagenesis

The diagenetic sequence based on textural relationships is outlined in Figure 2.

Porosity

Porosity ranges from excellent to poor, most samples exhibit fair to good porosity.

Pores comprise mostly primary intergranular pores with minor dissolution pores. Abundant microporosity is present within the matrix, authigenic clays, glauconite and degraded minerals.

Samples 2804.2m and 2835.4m display excellent porosity. Pore throats observed at 2835.4m are up to 0.2mm wide, and are highly interconnected.

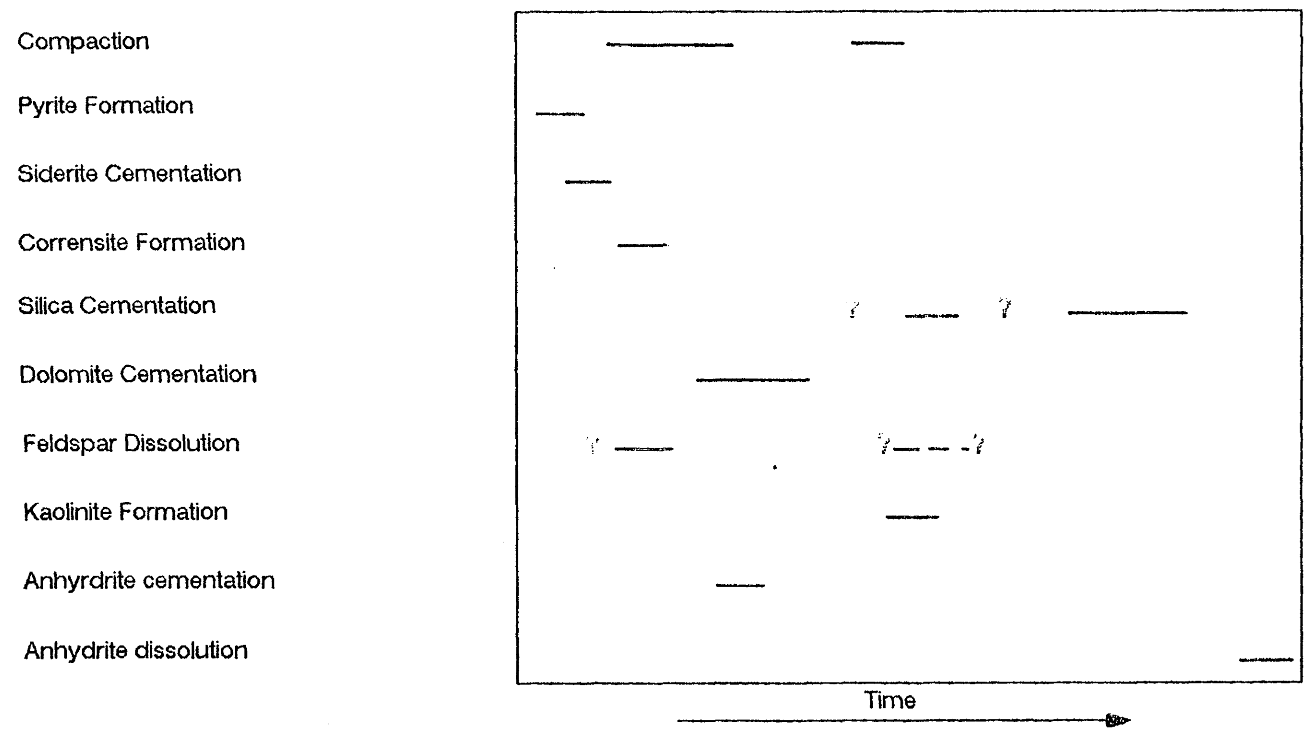
Dolomite cemented samples display negligible porosity, however there are some indications that patches of porous sand may be present within the dolomite cemented sandstones.

Potential Production Problems

The following are petrographically identified characteristics of the reservoir which have the potential to damage the formation and may need further evaluation in the laboratory to assess and measure their influence on reservoir behaviour during drilling, testing, completion and production.

CORE LABORATORIES

Figure 2: Idealized Diagenetic Sequence



1) Fines Migration : Authigenic kaolinite is present in most samples and may migrate and block pore throats if critical velocities are exceeded. This problem often manifests during depletion, when the relative permeability to water increases.

2) Acid Sensitivity : Corrensite, iron rich minerals and clays may contain ferric iron. Ferric iron can form ferric hydroxide, an insoluble precipitate, if reacted with HCl, especially in the presence of carbonates which will spend acid rapidly and give rise to low pH. Dolomite cemented zones will be sensitive to HF.

3) Clay Swelling : Corrensite is a mixed chlorite-smectite and is likely to be water sensitive to fresh water or excessive rates of salinity change.

4) Mud Solids Invasion : All the samples are contaminated by KCl and occasionally by drill solids. Highly porous zones may have large pores which will exceed the bridging capacity of the mud, and may be damaged.

5) Sand and Other Fines Production : Poorly lithified sands may be dissaggregated during production.

Wireline Log Response

Gamma Ray : All samples contain glauconite, potassium feldspars, and biotite, all of which contain potassium and have high natural radioactivity. Extreme care is required in using the gamma ray as a shaliness indicator.

Neutron : Most samples contain significant matrix, microporous minerals and rugose grain surfaces all of which may "bind" water. High immobile water saturations are expected.

Density : Localised variations in the content of high density cements such as pyrite and dolomite need to be considered when evaluating porosity from density logs.

Resistivity : Water bearing microporous minerals and clays may influence the effective electrical pathways as water saturation decreases. This may result in a low saturation exponent 'n' and cementation factor 'm'. 'm' and 'n' will vary between facies.

REFERENCES

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Folk, R.L., 1974, Petrology of sedimentary rocks, published by Hemphill Publishing Co., 184 pp.

Odin, G.S. and A. Matter, 1981, De glauconiarum origine, Sedimentology, v.28: p.611-641.

TABLE 1

SAMPLE DEPTH AND ANALYSES

	DEPTH (M)	THIN SECTION	SEM	XRD
1	2797.0	X	X	X
2	2803.0	X	X	X
3	2804.2	X	-	X
4	2808.8	X	X	X
5	2815.2	-	X	X
6	2816.4	X	-	-
7	2817.6	X	-	-
8	2818.8	X	X	X
9	2822.0	X	X	X
10	2824.4	X	-	-
11	2826.8	-	X	X
12	2830.4	X	X	X
13	2835.4	X	X	X
14	2840.2	X	X	X
15	2849.4	X	X	X
16	2851.7	X	X	X
17	2858.9	X	X	X
	TOTAL	**15**	**13**	**14**

TABLE 2
PETROGRAPHIC ANALYSES

DEPTH	2797.0M	2803.0M	2804.2M	2808.8M
Lithology	Sandstone, coarse grained, feldspathic litharenite	Sandstone, fine grained, feldspathic litharenite	Granulestone, granule subarkose	Sandstone, fine grained argillaceous lithic arkose
Sorting	Poorly (? bimodal)	Poorly	Moderately well	Moderately well to well
Texture	Massive	Faintly laminated	Grain mounted sample	Bioturbated
Grain size Minimum Maximum Average	0.02mm (silt) 3.50mm (granule) 0.80mm (coarse sand)	0.02mm (silt) 0.85mm (coarse sand) 0.22mm (fine sand)	0.04 (silt) 5.00mm (pebble) 2.5mm (granule)	0.02mm (silt) 0.21mm (fine sand) 0.12mm (fine sand)
Angularity and Shape of Grains	Subangular Equant	Subrounded Equant	Subrounded	Angular to subangular
Grain Contacts	Straight > slightly embayed	Straight > point >> floating	N/A Loose sand	Straight > point > floating
Lithifaction	Moderate	Moderate	Nil Loose sand	Moderately well
Cements	Minor authigenic quartz, rare siderite	Minor authigenic quartz, trace pyrite	Trace dolomite	Trace pyrite and siderite, trace quartz
Clays	Common glaucony, minor corrensite	Common primary matrix, common glauconite, pore-lining corrensite	Trace matrix, trace glauconite	Abundant dispersed matrix, common glauconite
Porosity	Good	Fair	Probably excellent	Poor to fair
Porosity Types	Intergranular	Intergranular >> dissolution	Probably intergranular	Intergranular
Porosity Reducing Agents	Compaction, especially of soft lithics and matrix	Compaction, >> cementation, matrix	Minor compaction	Compaction, cementation, matrix

TABLE 2
PETROGRAPHIC ANALYSES

DEPTH	2816.4M	2817.6M	2818.8M	2822.0M
Lithology	Sandstone, fine grained litharenite	Sandstone, fine grained litharenite	Sandstone, fine grained, feldspathic litharenite	Sandstone, fine grained lithic arkose
Sorting	Moderately well	Moderately well	Moderately	Poorly
Texture	Bioturbated	Bioturbated	Bioturbated	Massive
Grain size Minimum Maximum Average	 0.02mm (silt) 0.23mm (fine sand) 0.11mm (fine sand)	 0.01mm (silt) 0.20mm (fine sand) 0.08mm (very fine sand)	 0.01mm (silt) 0.28mm (medium sand) 0.13mm (fine sand)	 0.02mm (silt) 0.91mm (coarse sand) 0.21mm (fine sand)
Angularity and Shape of Grains	Subrounded to subangular Equant	Subangular to subrounded Equant	Subangular	Subrounded
Grain Contacts	Straight > point > floating	Straight > point > floating	Straight > point > floating	Straight > point
Lithifaction	Moderate	Moderate	Moderately well	Moderate
Cements	Authigenic quartz, trace pyrite and siderite	Trace pyrite and siderite, rare quartz	Minor siderite, minor dispersed pyrite. Rare quartz	Authigenic quartz, patchy pyrite and siderite
Clays	Abundant dispersed matrix, common glauconite	Abundant dispersed primary matrix, common glauconite	Abundant dispersed matrix, chlorite, glauconite	Abundant matrix, common chlorite, common glauconite
Porosity	Poor	Poor to fair	Poor	Fair
Porosity Types	Trace intergranular	Intergranular	Intergranular	Intergranular
Porosity Reducing Agents	Bioturbation, compaction, matrix	Bioburbation, compaction, matrix	Bioturbation compaction cementation, matrix	Compaction, cementation, matrix

TABLE 2
PETROGRAPHIC ANALYSES

DEPTH	2824.4M	2830.4M	2835.4M	2840.2M
Lithology	Sandstone, fine grained, feldspathic litharenite	Sandstone, fine grained, feldspathic litharenite	Sandstone, coarse grained lithic arkose	Sandstone, medium grained felspathic litharenite
Sorting	Moderately	Moderately well	Poorly	Well
Texture	Massive	Massive	Faintly laminated	Massive
Grain size Minimum Maximum Average	 0.01mm (silt) 3.10mm (granule) 0.22mm (fine sand)	 0.01mm (silt) 0.80mm (coarse sand) 0.16mm (fine sand)	 0.02mm (silt) 4.20mm (granule) 0.53mm (coarse sand)	 0.02mm (silt) 0.35mm (medium sand) 0.26mm (medium sand)
Angularity and Shape of Grains	Angular Equant	Angular Equant	Subangular Equant	Subangular Equant
Grain Contacts	Straight > point	Straight > point	Point > straight	Point > floating
Lithifaction	Moderately well	Well	Poorly	Extremely well
Cements	Minor authigenic quartz, trace siderite and pyrite	Disseminated pyrite, minor quartz, minor siderite	Minor authigenic quartz, trace pyrite, anhydrite	Abundant poikilotopic dolomite
Clays	Dispersed primary matrix, glauconite	Dispersed matrix, glauconite	Trace dispersed matrix, glauconite	Trace matrix, glauconite
Porosity	Poor	Poor	Excellent +	Very poor
Porosity Types	Trace intergranular	Trace intergranular	Intergranular	Trace dissolution
Porosity Reducing Agents	Primary matrix, compaction, cementation	Pyrite cement, compaction, matrix	Minor compaction	Extensive dolomite cement

TABLE 2
PETROGRAPHIC ANALYSES

DEPTH	2849.4M	2851.7M	2858.9M	
Lithology	Sandstone, medium to very coarse grained sublitharenite	Sandstone, coarse grained sublitharenite	Sandstone, coarse grained, feldspathic litharenite	
Sorting	Bimodal	Poorly/biomodal	Poorly/bimodal	
Texture	Massive	Faintly laminated	Massive	
Grain size Minimum Maximum Average	 0.04mm (silt) 4.00mm (granule) 0.36mm (medium sand)	 0.04mm (silt) 3.30mm (granule) 0.80mm (fine sand)	 0.01mm (silt) 2.80mm (granule) 0.50mm (coarse sand)	
Angularity and Shape of Grains	Subrounded Equant	Subrounded Equant >> elongate	Angular > subangular Equant	
Grain Contacts	Point > straight	Point > straight	Straight > point	
Lithifaction	Very well	Very well	Well	
Cements	Poikilotopic dolomite, trace pyrite	Abundant poikilotopic dolomite	Minor quartz, trace pyrite,	
Clays	Trace matrix, glauconite	Trace matrix, glauconite	Abundant matrix, compaction, cementation	
Porosity	Poor	Nil	Poor	
Porosity Types	Intergranular > dissolution	None observed	Trace intergranular	
Porosity Reducing Agents	Dolomite cement	Extensive dolomite cement	Minor compaction cementation, matrix	

X-RAY DIFFRACTION DATA
TABLE 3

SAMPLE	2797.0M	2803.0M	2804.2M	2808.8M	2815.2M	2818.8M	2822.0M
	(wt%)	(wt%)	(wt%)	(wt%)	(wt%)	(wt%)	(wt%)
Albite	3.7	7.2	0	8.3	0	6.5	4.4
Biotite+Illite	3.8	7.5	0	7.2	6.7	17.9	3.4
Dolomite	0	0	0.1	0	31.2	0	0
Fluorapatite	0	0	0	0	0	0	0
Kaolinite	0.4	0.6	0	3.1	0.1	7.4	0.9
Microcline	6.9	9.9	3.6	7.8	9.6	6.4	12.1
Pyrite	0	7.4	0	3.4	5.4	4.8	11.5
Quartz	84.1	65.5	96.1	68.0	46.8	51.7	67.3
Siderite	0.9	1.6	0	1.8	0	4.9	0
Sylvite	0	0	<0.1	0	0	<0.1	<0.1

SAMPLE	2826.8M	2830.4M	2835.4M	2840.2M	2849.4M	2851.7M	2858.9M
	(wt%)	(wt%)	(wt%)	(wt%)	(wt%)	(wt%)	(wt%)
Albite	5.2	9.8	2.9	0	0	0	0
Biotite+Illite	1.5	8.3	0.4	1.5	1.2	0	4.3
Dolomite	0	0	0	38.4	15.1	1.9	0
Fluorapatite	0	0	0	0	0	0	15.9
Kaolinite	0	0.7	0	0.1	0.1	0	0
Microcline	7.3	9.6	10.8	18.4	8.4	8.2	26.2
Pyrite	2.5	6.2	0.2	0	0	0	12.2
Quartz	83.0	64.1	85.4	40.5	74.8	89.7	41.1
Siderite	0.1	0.8	0	0	0	0	0
Sylvite	0	0	0	0	0	0	0

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POINT COUNT ANALYSIS (based on 250 points)

SAMPLE DEPTH (metres)	2797.0		2803.0	
QUARTZ		54.8		32.4
Monocrystalline	50.4		31.2	
Polycrystalline	4.4		1.2	
FELDSPAR		10.0		10.4
Microcline	2.0		1.2	
Plagioclase	0.4			
Untwinned	7.6		9.2	
Kaolinitized	Tr		Tr	
Clay Replaced	Tr		Tr	
Granitic R.F				
LITHICS AND ACCESSORIES		16.4		26.8
Chert	0.4		0.4	
Volcanic R.F.				
Metamorphic R.F.				
Sandstone R.F.				
Shale/Mudstone R.F.				
Carbonate R.F.				
Clay Replaced R.F.	Tr		Tr	
Biotite	4.0		2.4	
Muscovite	0.4		Tr	
Chlorite				
Tourmaline				
Zircon	Tr		Tr	
Horneblende	Tr		0.4	
Haematite				
Pyrite				
Phosphate				
Glaucony	11.6		20.8	
Organics	Tr		2.8	
Other	Tr			
FOSSILS		0.0		0.0
CLAY AND MATRIX		3.6		8.8
Undifferentiated Clay	1.6		4.0	
Kaolinite	Tr		2.0	
Corrensite	2.0		2.8	
CEMENTS		2.4		12.0
Silica	1.2		3.0	
Siderite	0.4		Tr	
Pyrite	0.8		9.0	
VISIBLE POROSITY		12.8		9.6
Intergranular	12.0		9.6	
Dissolution	0.8		Tr	
TOTAL	100.0	100.0	100.0	100.0

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POINT COUNT ANALYSIS (based on 250 points)

SAMPLE DEPTH (metres)		2804.2		2808.8
QUARTZ		86.4		26.8
Monocrystalline	53.6		26.4	
Polycrystalline	32.8		0.4	
FELDSPAR		6.0		12.0
Microcline	1.0		2.4	
Plagioclase	0.4			
Untwinned	4.6		9.2	
Kaolinitized	Tr		0.4	
Clay Replaced			Tr	
Granitic R.F				
LITHICS AND ACCESSORIES		4.8		10.0
Chert	Tr		Tr	
Volcanic R.F.				
Metamorphic R.F.				
Sandstone R.F.				
Shale/Mudstone R.F.				
Carbonate R.F.				
Clay Replaced R.F.	Tr		Tr	
Biotite	1.2		4.8	
Muscovite	Tr		2.0	
Chlorite				
Tourmaline				
Zircon	0.4		Tr	
Horneblende	Tr		Tr	
Haematite				
Pyrite				
Phosphate				
Glaucony	0.8		2.8	
Organics	Tr		0.4	
Other	2.4			
FOSSILS		0.0		0.0
CLAY AND MATRIX		2.4		35.2
Undifferentiated Clay	2.4		32.8	
Kaolinite	Tr		0.4	
Corrensite	Tr		2.0	
CEMENTS		0.4		4.4
Silica	0.4		0.4	
Siderite	Tr		Tr	
Pyrite	Tr		4.0	
VISIBLE POROSITY		0.0		11.6
Intergranular	0.0		11.6	
Dissolution	0.0		Tr	
TOTAL	100.0	100.0	100.0	100.0

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POINT COUNT ANALYSIS (based on 250 points)

SAMPLE DEPTH (metres)		2816.4		2817.6
QUARTZ		35.6		32.0
Monocrystalline	35.6		32.0	
Polycrystalline	0.0		0.0	
FELDSPAR		7.6		6.0
Microcline	1.6		Tr	
Plagioclase	Tr			
Untwinned	4.0		4.8	
Kaolinitized	Tr		0.0	
Clay Replaced	2.0		1.2	
Granitic R.F				
LITHICS AND ACCESSORIES		20.0		21.2
Chert	Tr			
Volcanic R.F.				
Metamorphic R.F.				
Sandstone R.F.				
Shale/Mudstone R.F.				
Carbonate R.F.				
Clay Replaced R.F.	2.0		6.4	
Biotite	10.0		5.2	
Muscovite	1.2		Tr	
Chlorite				
Tourmaline				
Zircon	Tr		0.4	
Horneblende				
Haematite				
Pyrite				
Phosphate				
Glaucony	6.8		9.2	
Organics	Tr		Tr	
Other			Tr	
FOSSILS		0.0		0.0
CLAY AND MATRIX		31.2		37.6
Undifferentiated Clay	27.2		36.0	
Kaolinite	Tr		0.4	
Corrensite	4.0		1.2	
CEMENTS		4.4		1.6
Silica	0.8		0.4	
Siderite	Tr		Tr	
Pyrite	3.6		1.2	
VISIBLE POROSITY		1.2		1.6
Intergranular	1.2		1.6	
Dissolution	Tr		Tr	
TOTAL	100.0	100.0	100.0	100.0

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POINT COUNT ANALYSIS (based on 250 points)

SAMPLE DEPTH (metres)		2818.8		2822.0
QUARTZ		32.8		39.6
Monocrystalline	32.4		39.2	
Polycrystalline	0.4		0.4	
FELDSPAR		11.6		15.2
Microcline	1.6		2.6	
Plagioclase	Tr			
Untwinned	8.0		11.4	
Kaolinitized	Tr		0.0	
Clay Replaced	2.0		1.2	
Granitic R.F				
LITHICS AND ACCESSORIES		14.0		12.4
Chert	0.8		0.8	
Volcanic R.F.				
Metamorphic R.F.				
Sandstone R.F.				
Shale/Mudstone R.F.				
Carbonate R.F.				
Clay Replaced R.F.	2.4		1.2	
Biotite	0.8		3.6	
Muscovite	1.6		Tr	
Chlorite				
Tourmaline				
Zircon	0.4		Tr	
Horneblende				
Haematite				
Pyrite				
Phosphate				
Glaucony	3.6		6.8	
Organics	1.6		Tr	
Other	2.8		Tr	
FOSSILS		0.0		0.0
CLAY AND MATRIX		31.2		17.6
Undifferentiated Clay	24.0		15.2	
Kaolinite	3.6		0.4	
Corrensite	3.6		2.0	
CEMENTS		10.0		6.8
Silica	1.2		1.2	
Siderite	0.8		Tr	
Pyrite	8.0		5.6	
VISIBLE POROSITY		0.4		8.4
Intergranular	0.4		8.0	
Dissolution	Tr		0.4	
TOTAL	100.0	100.0	100.0	100.0

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POINT COUNT ANALYSIS (based on 250 points)

SAMPLE DEPTH (metres)	2824.4		2830.4	
QUARTZ		40.0		42.8
Monocrystalline	39.6		42.8	
Polycrystalline	0.4		Tr	
FELDSPAR		13.6		14.4
Microcline	2.0		1.6	
Plagioclase	Tr		Tr	
Untwinned	9.6		12.8	
Kaolinitized	Tr		0.0	
Clay Replaced	2.0		Tr	
Granitic R.F				
LITHICS AND ACCESSORIES		17.6		23.6
Chert	0.4		Tr	
Volcanic R.F.				
Metamorphic R.F.				
Sandstone R.F.				
Shale/Mudstone R.F.				
Carbonate R.F.				
Clay Replaced R.F.	2.0		4.0	
Biotite	7.6		9.2	
Muscovite	Tr		Tr	
Chlorite				
Tourmaline				
Zircon	Tr		Tr	
Horneblende				
Haematite				
Pyrite				
Phosphate				
Glaucony	7.6		10.4	
Organics	Tr		Tr	
Other			Tr	
FOSSILS		0.0		0.0
CLAY AND MATRIX		13.2		11.2
Undifferentiated Clay	13.2		11.2	
Kaolinite	Tr		Tr	
Corrensite	Tr		Tr	
CEMENTS		5.6		7.2
Silica	0.4		Tr	
Siderite	Tr		Tr	
Pyrite	5.2		7.2	
VISIBLE POROSITY		10.0		0.8
Intergranular	10.0		0.8	
Dissolution	Tr		Tr	
TOTAL	100.0	100.0	100.0	100.0

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POINT COUNT ANALYSIS (based on 250 points)

SAMPLE DEPTH (metres)	2835.4		2840.2	
QUARTZ		56.8		38.4
Monocrystalline	52.0		35.6	
Polycrystalline	4.8		2.8	
FELDSPAR		12.0		7.2
Microcline	2.4		1.2	
Plagioclase	Tr		Tr	
Untwinned	9.6		5.2	
Kaolinitized	Tr		0.8	
Clay Replaced	Tr		Tr	
Granitic R.F				
LITHICS AND ACCESSORIES		8.4		10.0
Chert	1.2		0.8	
Volcanic R.F.				
Metamorphic R.F.				
Sandstone R.F.				
Shale/Mudstone R.F.				
Carbonate R.F.				
Clay Replaced R.F.	2.0		0.8	
Biotite	3.2		2.4	
Muscovite	Tr		0.4	
Chlorite				
Tourmaline				
Zircon	Tr		Tr	
Horneblende				
Haematite				
Pyrite				
Phosphate				
Glaucony	2.0		5.6	
Organics	Tr		Tr	
Other				
FOSSILS		0.0		0.0
CLAY AND MATRIX		2.0		4.0
Undifferentiated Clay	1.2		4.0	
Kaolinite	Tr		Tr	
Corrensite	0.8			
CEMENTS		1.6		40.4
Silica	1.2		0.4	
Dolomite			38.4	
Pyrite	0.4		1.6	
VISIBLE POROSITY		19.2		0.0
Intergranular	19.2		0.0	
Dissolution	Tr		Tr	
TOTAL	100.0	100.0	100.0	100.0

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POINT COUNT ANALYSIS (based on 250 points)

SAMPLE DEPTH (metres)	2849.4		2851.7	
QUARTZ		59.6		60.4
Monocrystalline	45.2		49.2	
Polycrystalline	14.4		11.2	
FELDSPAR		4.4		5.2
Microcline	Tr		1.2	
Plagioclase			Tr	
Untwinned	3.2		3.6	
Kaolinitized	Tr		Tr	
Clay Replaced	1.2		0.4	
Granitic R.F				
LITHICS AND ACCESSORIES		6.4		6.0
Chert	0.4		0.4	
Volcanic R.F.	0.4			
Metamorphic R.F.				
Sandstone R.F.			0.8	
Shale/Mudstone R.F.				
Carbonate R.F.				
Clay Replaced R.F.	1.2		0.8	
Biotite	0.8		2.0	
Muscovite	0.8		0.4	
Chlorite				
Tourmaline				
Zircon	Tr		Tr	
Horneblende	0.4			
Haematite				
Pyrite				
Phosphate				
Glaucony	2.0		1.6	
Organics	0.4		Tr	
Other				
FOSSILS		0.0		0.0
CLAY AND MATRIX		0.4		0.0
Undifferentiated Clay	0.4		Tr	
Kaolinite				
Corrensite				
CEMENTS		26.8		26.4
Silica				
Dolomite	25.6		26.0	
Pyrite	1.2		0.4	
VISIBLE POROSITY		2.4		2.0
Intergranular	2.4		2.0	
Dissolution	Tr		Tr	
TOTAL	100.0	100.0	100.0	100.0

ESSO AUSTRALIA LTD
BLACKBACK # 2

File No. GSA 92029

POINT COUNT ANALYSIS (based on 250 points)

SAMPLE DEPTH (metres)		2858.9
QUARTZ		31.2
Monocrystalline	30.0	
Polycrystalline	1.2	
FELDSPAR		9.2
Microcline	2.0	
Plagioclase		
Untwinned	6.0	
Kaolinitized	Tr	
Clay Replaced	1.2	
Granitic R.F		
LITHICS AND ACCESSORIES		26.4
Chert	Tr	
Volcanic R.F.		
Metamorphic R.F.		
Sandstone R.F.	0.8	
Shale/Mudstone R.F.		
Carbonate R.F.		
Clay Replaced R.F.		
Biotite	4.4	
Muscovite	Tr	
Chlorite		
Tourmaline		
Zircon	Tr	
Horneblende	Tr	
Haematite		
Pyrite		
Phosphate		
Glaucony	21.2	
Organics	Tr	
Other		
FOSSILS		0.0
CLAY AND MATRIX		22.0
Undifferentiated Clay / Phosphate	22.0	
Kaolinite	Tr	
Corrensite		
CEMENTS		5.2
Silica		
Dolomite		
Pyrite	5.2	
VISIBLE POROSITY		6.0
Intergranular	6.0	
Dissolution	Tr	
TOTAL	100.0	100.0

ANALYTICAL PROCEDURES

Thin Section Preparation

Samples were vacuum impregnated with blue-dyed epoxy to facilitate porosity evaluation. The impregnated samples were mounted on glass slides, and cut and lapped in water to approximately 30 microns. Each slide was stained with Alizarin Red-S and potassium ferricyanide, using the method of Evamy (1963) to aid in distinguishing carbonate minerals and to identify iron bearing carbonates. The reaction of carbonate minerals to this stain is:

Calcite	red-pink
Fe-calcite	mauve to purple
Dolomite	no stain
Fe-dolomite	bright aqua-blue

Sandstones are classified according to Folk (1974). Modal (point-count) analyses were performed using a Swift model F point-counter, using 250 data points per sample.

SEM Analyses

Samples for Scanning Electron Microscopy/Energy Dispersive Spectroscopy (SEM/EDS) analyses were broken to form fresh uncontaminated surfaces. Each sample was mounted on a 10 mm aluminium stub, affixed with carbon glue and coated with gold. The carbon was applied manually, and the gold film was applied using a Sputter Coating Unit. SEM photomicrographs are back scattered electron images taken with a polaroid camera attached to a Scanning Electron Microscope operating at various kV. Qualitative elemental data of selected phases observed during SEM study are obtained through the use of an interfaced Energy Dispersive Spectroscopy Unit.

XRD Analyses

Sample Preparation

All the submitted samples were ground with an automatic mortar and pestle to homogenise the sample and reduce particle sizes. Powder of - 5µm fraction of each sample was separated from the bulk using sedimentary method. For quantitative XRD analysis, randomly orientated specimens were prepared by pressing the pulverised samples onto aluminium holders making disks of depth 2mm and diameter 30mm. Preferred orientation specimens were prepared for clay minerals identification.

X-Ray Diffractometry

X-ray powder diffraction patterns were recorded at room temperature using a Philips PW1700 automatic diffractometer. X-rays generated from a copper X-ray tube operated at 45kV and 40mA were diffracted by a graphite monochromator for the production of monochromatic radiation. Both pulse-height discriminator and automatic diverging slits were used. Each specimen was scanned at 1° per minute for 2Θ range from 2° to 45° for the clay mineral identification.

Positions and intensities of the diffraction lines were calculated using an on-line computer. Diffraction results were searched through 32,000 reference patterns of minerals and inorganic compounds which are stored in the memory of the computer.

APPENDIX 5

APPENDIX 5

BLOCK VIC/P24

Blackback-2

MDT and Cased Hole RFT Analysis Report

Date of test: October 92

Prepared by: Mike Scott, Reservoir Technology

Blackback-2 - MDT and Cased Hole RFT Analysis Report

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1.0 Conclusions and Summary

This report details the analysis and interpretation of the MDT and Cased Hole RFT data obtained in the Blackback-2 exploration/delineation well. BB-2 was the fourth well to be drilled on the Blackback structure and lies approximately 20km south-east of the Mackerel Field.

During the 6th and 7th of October 1992 the Schlumberger Modular Formation Dynamics Tester (MDT) tool was used to evaluate the Blackback-2 well. Following further evaluation work this was supplemented by the Schlumberger Cased-Hole RFT on 24th October 1992.

Pressure data and samples confirmed the presence of two independent gas zones and a 26m oil column which was bounded by an OWC at 2855.5 m MDRKB (2833.25 m TVDSS). Reservoir pressure of the oil zone is 4023.6 psia at the interpreted OWC. The lower and upper gas sands are 52.4psi and 70.7 psi respectively higher pressure than the oil zone.

The Gippsland Aquifer is 79.3 psi below it's original pressure at discovery. This is as expected due to production drawdown from other reservoirs in the basin.

The gas and oil zones were identified to be separate systems because of the pressure discontinuity measured between the sands. The gas sands are thought to be isolated from the regional pressure system.

Blackback is not expected to have a gascap because of the undersaturated nature of the crude.

PVT analysis on the MDT bottomhole sample indicates that the oil has a high GOR at 2250 scf/stb, a formation volume factor of 2.436 rb/stb, a gravity of 47 degrees API and a bubble point of 3210 psia. The bubble point is 802 psi below reservoir pressure indicating that there is no associated gascap in communication with the oil leg.

PVT analysis on the two gas samples reveal that the gases are very similar with a GOR of 11,000 scf/stb, a gas expansion factor of 260 scf/rcf and a residual liquid gravity of 49 degrees API. The measured dewpoint of the samples is approximately 1000 psi above the reservoir pressure. This is most probably an anomaly caused by liquid dropout during sampling and is not considered to be significant.

No H_2S was measured in the gas or oil samples or at the wellsite.

Wellsite data and pressure analysis also suggests that the reservoir in the vicinity of Blackback-2 is highly stratified and this may result in some sands having limited pressure communication with the regional Gippsland Aquifer.

In general the testing can be considered to be successful with all the characterization objectives being met.

2.0 MDT Pressure Tests

A total of 40 pressure tests were attempted in the Top of Latrobe interval in Blackback-2. The pretests consisted of; 31 good, 5 tight, 3 plugged probe and 1 software failure.

Figure 1 details the full pressure dataset for Blackback-2 and Table 1 the individual pressure test details.

As can be seen from Figure 1 the current aquifer pressure is 79.3 psi below the original Gippsland Aquifer gradient[1] at discovery. This is as expected due to production from the other reservoirs in the basin and indicates that the aquifer is in good communication with the regional aquifer.

Figure 1 also demonstrates the discontinuity of the gas zones from the oil pressure regime indicating that they are not in communication with the oil leg.

Figure 2 details the oil zone pressures in Blackback-2. As can be seen from Figure 2 the oil zone is in pressure communication with the aquifer giving an OWC at 2855.5 m MDRKB (2833.25 m TVDSS). Pressure and PVT analysis confirms the oil gradient to be 0.772 psi/m.

Points 15 and 16 can be seen to be slightly overpressured in relation to the normal oil pressure gradient. This is interpreted to be due to the lack of pressure communication of the sands in this area with the aquifer. The stratified nature of the sands around points 15 and 16 have not permitted pressure dissipation as the pressure in the aquifer has reduced.

Figure 3 demonstrates the gas zone pressures. Pressure analysis and PVT work confirm the fluid gradients of these sands to be 0.417 psi/m and 0.431 psi/m for the upper and lower sands respectively. As can also be seen from Figure 3; the sand in the vicinity of point 9 is not drawn down by the same degree as the overlying sand indicating that vertical permeability barriers exist within the reservoir section preventing vertical equilibrium.

If the gas sands were in pressure communication with the aquifer the gas/water contacts of the upper and lower sands would be at 2914 m MDRKB and 2897 m MDRKB respectively. This would result in gas columns in excess of 100m which is thought to be unlikely. These gas sands are most probably isolated from the regional aquifer system.

3.0 MDT Vertical Permeability Tests

Schulmberger's MDT tool was used on Blackback-2 to gain a quantitive measure of vertical communication across small FMS log identified shale barriers. The MDT tool quantifies vertical heterogeneities by small scale vertical interference testing via offset probes on the tool body.

Four vertical permeability (Vp) tests were attempted with the MDT tool. The initial two tests in the gas zones at 2800.1m and 2815.92m MDRKB were successful. Due to probe plugging in the two subsequent tests at 2832.25 and 2841.34m MDRKB these tests were unsuccessful. Table 2 details the individual test data and results.

Figure 3 demonstrates the tests Vp1 and Vp2 in the gas zones.

Schlumberger analysis[3] of Vp1 indicates that the horizontal permeability (Kh) in the upper gas zone is 95md with a vertical permeability (Kv) of 5md. This gives a Kv/Kh ratio of 0.053.

Analysis of the Vp2 test[3] gives a horizontal permeability (Kh) of 1250md and a vertical permeability (Kv) of 10md. This gives a Kv/Kh ratio of 0.008 demonstrating that the formation has an effective permeability barrier between the probes.

Tests Vp3 and Vp4 in Figure 2 were unsuccessful due to probe plugging. This indicates that the reservoir formation is relatively soft and friable in these locations. This observation is confirmed by wellsite observation of core samples.

As can be seen from Figures 2 and 3 the vertical permeability pressures appear to be consistently 5 psi above the MDT measured formation pressures and the horizontal sink probe appears to be 2 psi below the vertical sink probe. These differences in pressures are due to the gauge types being used and their pressure resolution. The MDT pressure tests were measured using the latest CQG schlumberger gauge, which is temperature self-correcting, whilst the MDT vertical permeabilities were measured using the standard strain gauge. The differences in pressure are not significant.

The testing for vertical permeability and heterogeneities via the MDT tool is relatively new technology. The results from these tests indicated that a quantitive measure of reservoir heterogeneity is possible and the tool should be considered for future use for reservoir characterization.

4.0 Cased Hole RFT Samples

To confirm the presence of gas, condensate yield and hydrocarbon composition in the upper two gas zones, cased hole RFT's were run on 24th October 92. Four tests in total were run. Test number 2 failed due to a firing failure. Two preserved samples were taken in runs 3 and 4.

Figure 3 details the cased hole RFT positions.

Table 3 details the results of the cased hole RFT's.

5.0 PVT Analysis

In total four bottomhole preserved fluid samples were taken in the Blackback-2 well. Two samples were obtained by the MDT tool and two samples via the cased hole RFT tool.

Additionally, four MDT and four cased hole RFT unpreserved wellsite samples confirmed the reservoir fluids in place.

PVT analysis of the preserved samples in all cases confirmed the fluid type and reservoir density gradient.

Table 3 details the MDT sample runs and Table 4 the cased hole RFT.

Solution GOR in the BB-2 oil sample is higher than previously measured in Hapuku-1, Blackback-1 or Terakihi-1 at 2250 scf/stb. Formation volume factor is also correspondingly high at 2.436 rb/stb. The oil bubble point is 802 psi below the reservoir pressure of 4012 psi indicating the lack of an associated gascap. No H_2S was measured in the PVT analysis or at the wellsite.

The two cased hole RFT gas samples are very similar in composition with minor variations in the higher hydrocarbon fractions. The differences in the samples may be due to sampling or fractionation through the hydrocarbon column.

Both the gas samples have a measured dewpoint approximately 1000 psi above the reservoir pressure. This is not considered to be significant and most likely caused by liquid dropout during sampling.

6.0 References

1. Reservoir Simulation of the Gippsland Basin
   Henzell, Young, Khurana. The APEA Journal 1984

2. MDT, Modular Formation Dynamics Tester, Schlumberger.
   SMP-5124 August 90. NAM.

3. Modular Formation Dynamics Tester (MDT)
   Blackback-2 Interpretation Report. Peter Goode, Jakarta, Oct 92.

Table 1

Blackback–2 MDT Pressure Tests
Date: 6th October 1992
KB: 22.25 m

Run #	Seat #	Depth m MDRKB	Pressure (psia)	Comments	Fluid Tested	Pretest Drawdown/Buildup Keff (md)
1	1	2800.5	4059.3	Software failure – retest	gas	
1	1	2800.5	4059.2	Good	gas	
1	2	2803.0	4060.2	Good	gas	
1	3	2807.2	0.0	Very tight – abandoned	gas	
1	4	2809.6	4044.4	Good	gas	146/8
1	5	2811.6	4045.2	Good	gas	238/14
1	6	2814.0	4046.4	Good	gas	
1	7	2814.8	4046.8	Good	gas	
1	8	2816.8	4047.8	Good	gas	
1	9	2820.6	4049.9	Good	gas	
1	10	2823.7	0.0	Tight	?	
1	11	2825.4	4017.1	Tight?	?	
1	12	2827.5	0.0	Tight – abandoned	?	
1	13	2832.0	4005.3	Good	oil	140/28
1	14	2833.0	4006.2	Good	oil	192/1916
1	15	2836.5	4014.7	Semi–tight	oil	
1	16	2838.0	4013.0	Good (possibly semi–tight)	oil	
1	17	2840.3	4011.8	Good	oil	5/4
1	18	2843.0	4013.8	Good	oil	621/39
1	19	2846.5	4016.5	Good	oil	
1	20	2847.9	4017.6	Good	oil	
1	21	2852.9	4018.5	Very tight (nearly fully built–up)	oil	
1	22	2855.7	4023.9	Good	oil	
1	23	2856.8	4025.5	Good	water	
1	24	2861.0	4031.0	Good	water	–/23
1	25	2868.0	4041.6	Good	water	
1	26	2875.1	4051.4	Good	water	
1	27	2882.0	4061.8	Good	water	
1	28	2890.4	4073.3	Very good	water	
1	29	2914.0	4107.0	Good	water	
1	30	2941.0	4146.1	Good	water	
1	31	2953.0	4163.3	Good	water	
1	32	2964.0	4178.9	Very good	water	
1	33	2987.1	4211.7	Good	water	
1	34	3013.1	4248.9	Good	water	
1	35	2854.2	4022.9	Good	oil	
1	36	2833.8	4007.2	Good	oil	
1	37	2817.9	0.0	Probe plugged	gas	
1	38	2817.7	0.0	Probe plugged	gas	
1	39	2809.5	0.0	Probe plugged – test point	gas	

Table 2

Blackback−2 MDT Vertical Permeability Tests

Date: 6th/7th October 1992

KB: 22.25 m

Test					Interpretation			
Run #	Seat #	Probe	Depth m MDRKB	Pressure (psia)	Probe Pretests Keff (md)	Formation Perm. Kh (md)	Formation Perm. Kv (md)	Kv/Kh (fraction)
2	40	Vertical	2800.1	4064.1	135			
2	40	Sink	2800.8	4064.3	17	95	5	0.0526
2	40	Horizontal	2800.8	4062.3	168			
2	41	Vertical	2815.9	4052.4	1350			
2	41	Sink	2816.6	4052.8	1853	1250	10	0.0080
2	41	Horizontal	2816.6	4049.8	1364			
2	42	Vertical	2832.3	4010.7	481	Sink probe plugged.		
2	42	Sink	2832.0	4010.7	733	No interpretation possible.		
2	42	Horizontal	2832.0	4008.7	1513			
2	43	Vertical	2841.3	4017.4	80	Sink probe plugged.		
2	43	Sink	2842.0	4018.0	1657	No interpretation possible.		
2	43	Horizontal	2842.0	4015.3	1252			

Table 3

Blackback−2 MDT Sample Runs

Date: 7th October 1992

KB: 22.25 m

Run #	Seat #	Depth m MDRKB	Pressure (psia)	Chamber size (gal.)	Preserved (Y/N)	Fluid Recovered	Comments	API (degrees)	GOR (scf/stb)	FVF (rb/stb)
3	45−2	2800.4	4056.9	2−3/4	N	gas	–	53.3	12000	–
3	44	2800.5	4194.0	2−3/4	N	mud	–	–	–	–
3	45−1	2800.0	4058.8	1	N	mud/gas	–	–	–	–
4	49	2841.6	4011.0	12	N	oil	–	50	1080	–
4	49	2841.6	4011.0	2−3/4	Y	oil	Check only	–	–	–
4	49	2841.6	4011.9	1	Y	oil	–	46.5	2256	2.4362
4	50	2820.5	0.0	2−3/4	N	mud	Lost seat	–	–	–
4	51	2820.7	0.0	1	N	gas/mud	Lost seat	–	–	–

Table 4

Blackback−2 Cased Hole RFT Samples

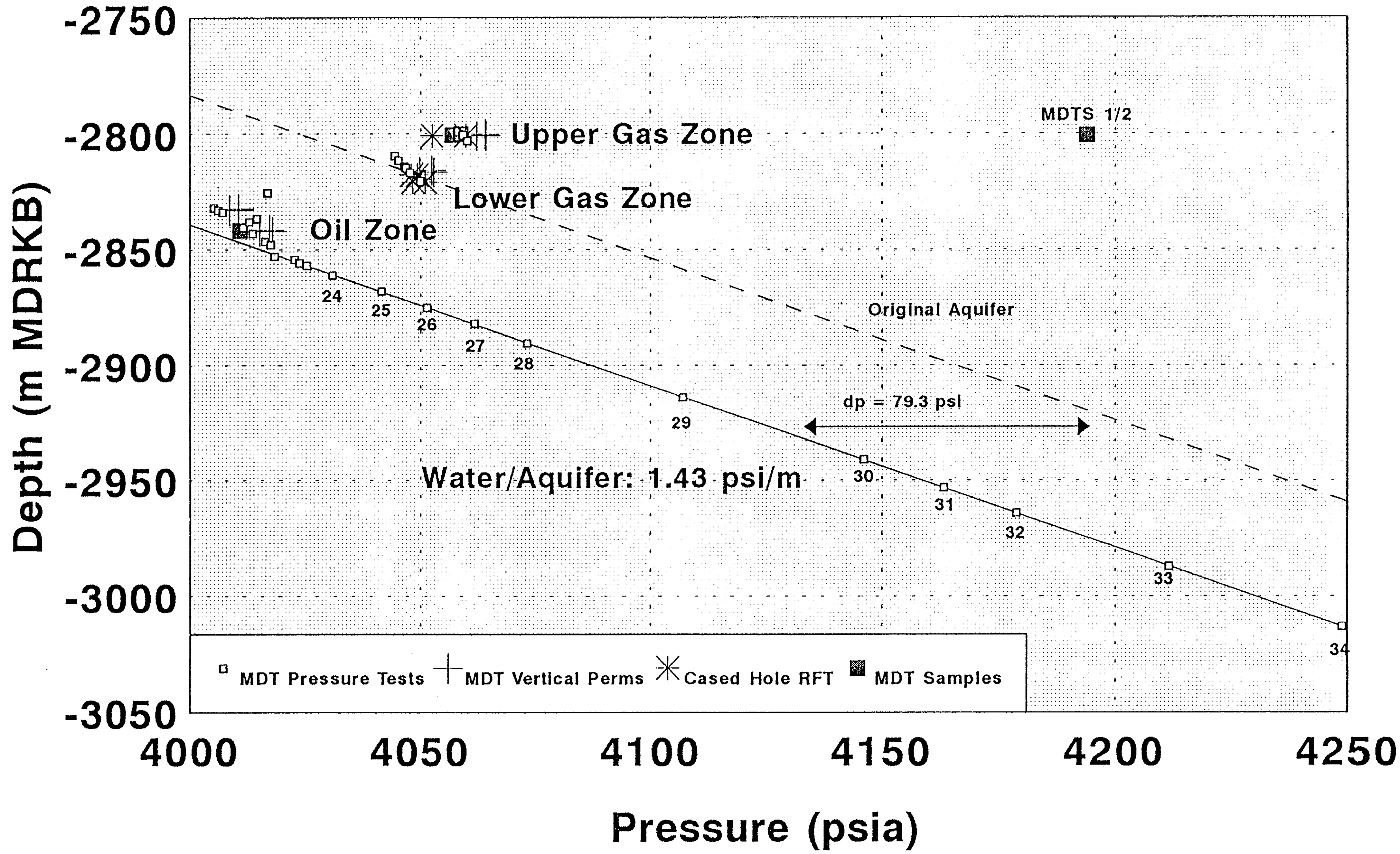
Date: 7th October 1992

KB: 22.25 m

Run #	Seat #	Depth m MDRKB	Pressure (psia)	Chamber size (gal.)	Preserved (Y/N)	Fluid Recovered	Comments	API (degrees)	GOR (scf/stb)	Bg (scf/rcf)	Dewpoint (psia)
5	52	2817.8	4049.3	12	N	Gas cond.	–	54.9	9852	–	–
5	52	2817.8	4048.0	1	N	Gas cond.	–	54.9	9540	–	–
6	53	2820.7	0.0	6	N	–	Failed	–	–	–	–
6	53	2820.7	0.0	1	N	–	Failed	–	–	–	–
7	54	2820.7	4051.0	6	N	Gas cond.	–	46.5	11130	–	–
7	54	2820.7	4048.3	1	Y	Gas cond.	–	49	11738	263.3	4930
8	55	2800.7	4052.5	12	N	Gas cond.	–	57.4	9222	–	–
8	55	2800.7	4059.9	1	Y	Gas cond.	–	49	10762	257.3	4985

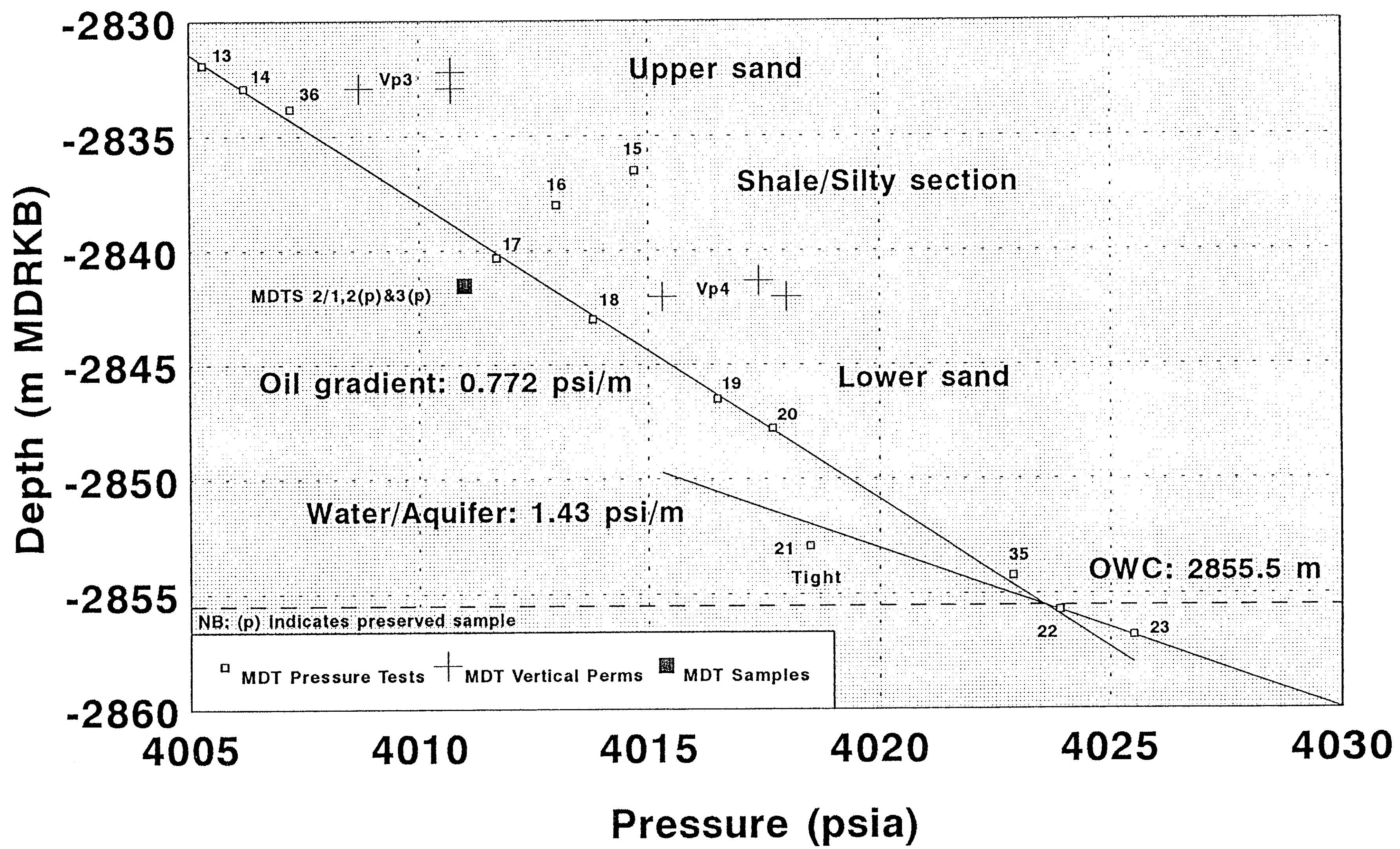
(mts/dec92/bb2reprt)

Figure 1 - Blackback-2
Full Pressure Dataset



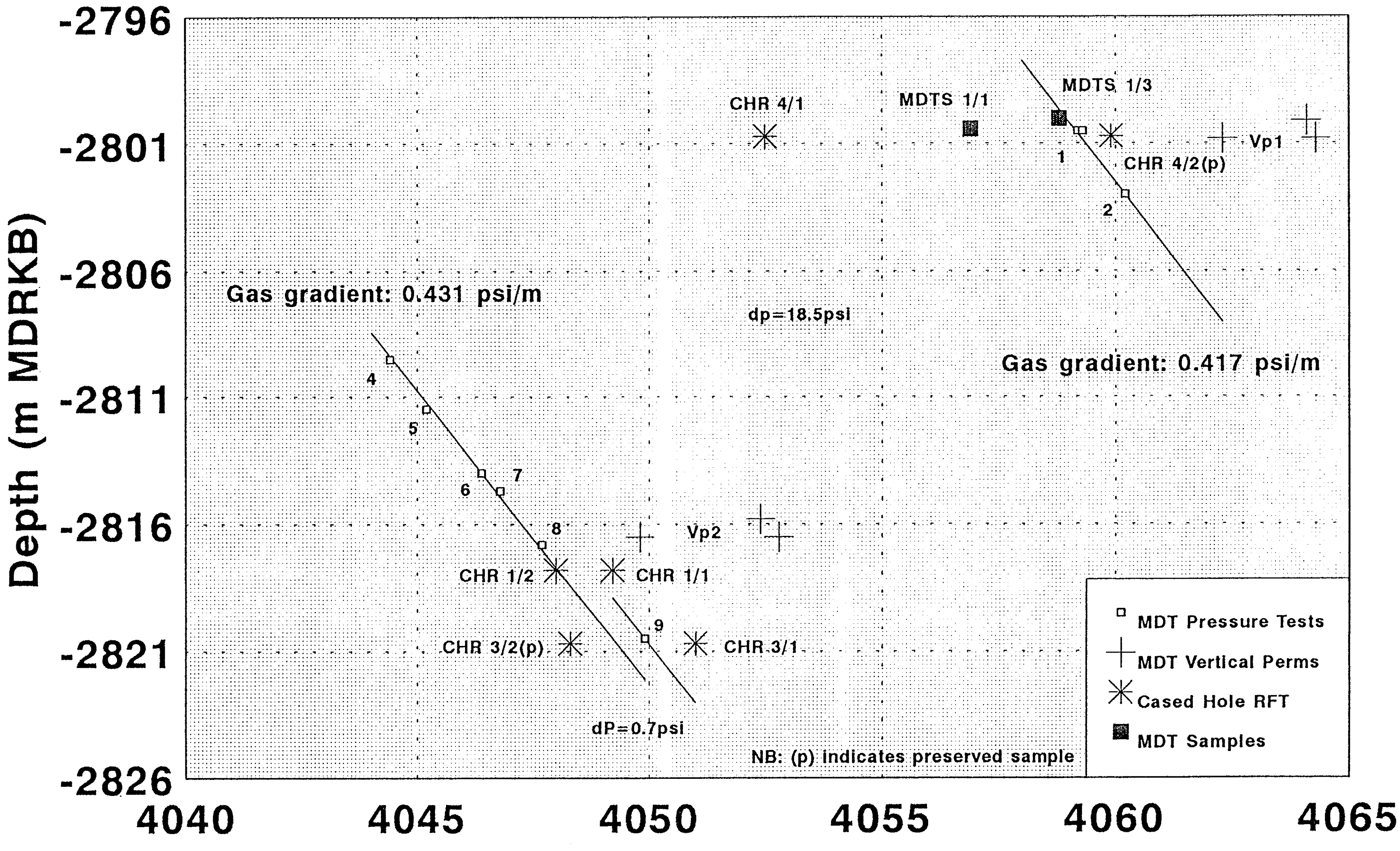
(mts/oct92/bb2rft)

Figure 2 - Blackback-2
Oil Zone Pressures



(mts/oct92/bb2rft2)

Figure 3 - Blackback-2
Upper and Lower Gas Zone Pressures



(mts/oct92/bb2rft3)

APPENDIX 6

BLOCK VIC/P24

Blackback-2

Welltest Analysis Report

Date of test: October 92

Prepared by: Mike Scott, Reservoir Technology

__Blackback-2 Welltest Analysis Report__

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1.0 Introduction

This report details the analysis of the Blackback-2 (BB-2) welltest which was executed during October 1992.

BB-2 was the fourth well to be drilled on the Blackback structure and lies approximately 20km south-east of the Mackerel Field. The well encountered two gas bearing zones below the Top of Latrobe unconformity followed by an oil zone which was in turn bounded by an oil water contact interpreted at 2855.5 m MDRKB. The gas and oil zones are interpreted to be separate systems by RFT/MDT pressure tests.

In the BB-2 oil zone several sand facies could be identified via the logs and RFT/MDT pressure tests. The logs showed that some of the sands were more silty/shaley than the other sand sections and the RFT/MDT showed that there were some very tight sections and also many high permeable zones and streaks. Figure 1 details the log section in the BB-2 oil zone.

Two main zones were identified in BB-2 for testing. The first zone was 2841.0-2846.5m MDRKB and the second zone 2829.5-2834.0m MDRKB. The lower zone was recognized early on in the well program to be of better rock quality than the upper zone.

In total three welltests were carried out in the BB-2 well and the pressure responses are demonstrated in Figure 2.

Test #1 was the initial test of the lower zone. Due to a mechanical problem, whereby a surface readout gauge was stuck in the tubing, the well did not reach its full production potential. For more information the reader is directly to the Final Well Report, Model 'E' Adapter Sub, Equipment Failure Report.

Test #1A was a retest of the lower zone and was completely successful.

Test #2 was a successful test of the upper zone.

All the Halliburton ASCII gauge data was processed using SAS on the EAL mainframe and the individual tests were analyzed using the EPS Pansystem software for welltest analysis.

For a complete description of the welltests the reader is directed to the BB-2, Final Well Report, Engineering Reports, Well Testing Summary. This memorandum will only concern the analysis of the welltest data.

2.0 Conclusions and Summary

1. Two reservoir oil zones encountered in the Blackback-2 well were successfully and safely tested.

2. Both welltests of the zones were successful in identifying reservoir parameters and demonstrating productivity.

3. The lower reservoir zone was tested with an average stabilized oil rate of 6640 stb/d, a productivity index of 87 stb/d/psi, a calculated permeability of 3500 md with good productivity/production potential and very good reservoir support. The zone had an initial skin of zero and an increased skin of 9 following damage caused by killing the well between tests #1 and #1A.

4. The upper reservoir zone was tested with an average stabilized oil rate of 5659 stb/d, a productivity index of 23 stb/d/psi and has a permeability of 900 md with a reduced production potential as compared to the lower zone. The zone had a calculated skin of 3. The aquifer support to this zone is less than that experienced in the lower zone and may ultimately reduce reserves estimations in this sand.

5. Future core analysis will aid in confirming the welltest analysis

6. The Gippsland tide has a minimal effect on the bottomhole pressure response and subsequent analysis and is expected to introduce a negligible error into the parameter definition.

7. TCP underbalance perforation with 24 shots per foot was very successful in minimizing formation damage during completion. This perforation method should be considered for future exploration and development wells.

9. The LPR-N bottomhole shut-in valve totally removed wellbore storage and afterflow effects thereby allowing a successful welltest analysis to take place. Bottomhole shut-in should always be considered for well testing.

10. The SRO gauge, although causing problems during this welltest, should still be considered for partially and fully saturated crude reservoirs where test control and hence validity of data is of utmost importance.

3.0 Welltest Analysis

3.1 General Observations and Comments

Tests #1 & #1A of the BB-2 welltest demonstrated what could be termed as *"super steady state"* test responses. The tests demonstrated very little or no transient or late transient pressure responses and almost immediately entered a steady state period which indicates that the aquifer pressure support is very strong in the lower sands of the BB-2 well section. The buildups were as equally impressive with very quick buildup times to initial pressure. Figures 3 and 7 demonstrate the well bottomhole pressure responses and flowrates.

Test #2 demonstrated completely different producing characteristics. The test entered a semi steady state period very early in the test and continued to follow this trend. The test also demonstrated slower buildup characteristics with the initial reservoir pressure not being regained after 12 hours shut-in. This possibly indicates there is reduced pressure support to the sand as compared to the lower zone.

Due to the quality of the reservoirs the standard Horner plot analysis has been supplemented with the Miller, Dyes and Hutchinson (MDH) buildup analysis. This has been done because welltest analysis only relates to transient conditions which will only exist for small periods in reservoirs of this quality. The mathematics of Horner allows for "straight line conditions" to prevail after transience and can give misleading results. Using MDH it is relatively more easy to identify the transience period and an MDH plot classically breaks away from "straight line conditions" once transience is complete. In good quality reservoirs such as BB-2 transience only exists for short periods after shut-in and therefore MDH is a better indicator for analysis.

Due to the difficulty in obtaining stable wellsite production conditions the pressure data obtained during the drawdown phase of the welltests is unstable and noisy. Subsequently no drawdown analysis of the data has been attempted as it would be unlikely to yield meaningful results.

TCP underbalance perforation at 24 shots per foot was very successful in reducing formation completion damage. The method should be considered for adoption in all exploration welltests and development wells.

The LPR-N bottomhole shut-in valve used during the test was extremely successful in removing any wellbore storage effects that could have occurred during testing. Due to the quick buildup experienced during these tests if wellhead shut-in had occurred no useful data could have been extracted from the pressure data due to well afterflow effects. The use of this valve is highly recommended for future exploration welltesting.

Although the SRO gauge caused an estimated total of 2.6 days (A$370K) delay and was subsequently not required, due to the low drawdown pressures experienced, its use should not be totally negated for future exploration well testing. The reason for carrying out welltesting is to characterize the reservoir. If the SRO gauge allows the test to be controlled thereby gaining better data then its use should be considered.

3.2 Tidal Effect On Welltest Pressure Analysis

Figure 2 demonstrates the Gippsland semi-diurnal tide over the period of the welltesting and Figures 4, 8 and 12 demonstrate the effect of the tide on the buildup pressures of Tests #1, #1A and #2 respectively.

As can be seen from the above figures the Gippsland tide has varying degrees of influence on the reservoir pressure buildup response on each of the tests. When the tide rises or falls the downhole gauge pressure can be seen to be following the same trend.

An attempt was made to extract this pressure anomaly from the buildup pressure data. However, since there was no static period long enough to witness several cycles of the tide a tidal extract could not be performed.

Although the buildup pressures have been affected by the tide movement it is thought that this will not introduce a large error into the pressure buildup analysis. Where the tidal effect is witnessed most however is in late time Horner and MDH plots and this must not be confused with the doubling of slope or boundary interpretations. These late time tidal effects can be witnessed in Figures 5, 6, 9, 10, 13 and 14.

By inspection of the downhole pressure data no physical reservoir boundaries were identified by the welltests.

3.3 *Test #1 Analysis*

Test #1 was in the lower sand zone from 2841.0-2846.5 m MDRKB.

As previously discussed, Test #1 experienced a mechanical problem which prevented the full potential of the zone being realized. A very small drawdown of 8.8 psi was experienced for the flow of 1602 stb/d.

Because of this small drawdown it is very difficult to identify a transient period following the well shut-in. However, a straight line can be drawn at early shut-in time which agrees with the Test #1A analysis thereby confirming the interpretation.

Figure 5 demonstrates the MDH buildup analysis and Figure 6 the Horner buildup analysis. The results of these methods for welltest analysis are in agreement and both demonstrate a formation permeability of 3500 md.with zero mechanical skin. The full analysis data is listed in Table 1.

The radius of investigation of the welltest is calculated to be 1800m.

The zero mechanical skin demonstrates the effectiveness of TCP underbalance perforation.

3.4 *Test #1A Analysis*

Test #1A was a retest of the same zone as Test #1.

This test was much more successful and demonstrated that high rates are possible from the Blackback formation. The well flowed at an average rate of 6640 stb/d with a maximum rate of 7100 stb/d. Figure 7 demonstrates the total pressure response from the welltest. As can be seen from Figure 7 the well exhibited good pressure support characteristics and, as the PI calculation in Table 1 demonstrates, physically cleaned up during the welltest.

Figure 8 demonstrates the buildup response which was analyzed via MDH and Horner plots (Figures 9 & 10).

As expected the buildup is completed very quickly. Because the drawdown was larger than Test #1 the transience period was slightly longer which permitted an easier analysis. Formation permeability for Test #1A can be calculated to be 3500 md, similar to Test #1, with a mechanical well skin of 9. The results of this analysis are tabulated in Table 1.

The increase in mechanical skin from zero in Test #1 to 9 in Test #1A is simply due to the fact that the well had to be killed with a high viscosity brine slug and overbalance mud between the two tests so that the tubing could be pulled and the stuck SRO gauge removed.

Depth of investigation calculated for this welltest is 1400m.

3.5 Test #2 Analysis

Test #2 was in the upper sand zone from 2829.5-2834.0 m MDRKB.

As can be seen from the total pressure response in Figure 11, the drawdown characteristics of this test are completely different from tests #1 and #1A. During the latter part of the drawdown the well pressure response seems to exhibit a semi-steady state pressure response (Figure 11). The response is rather disconcerting as the drawdown is 3.05 psi/hr which would not be expected if the reservoir had good pressure support.

Inspection of Figures 11 and 12 also reveal that the reservoir was 13.8 psi below the initial reservoir pressure after 12 hours shut-in. This is a concern, especially for a 900 md sand. A positive note is that the slope of the pressure buildup curve is still quite large at the end of the buildup (Figure 12) which may be indicative of pressure support albeit reduced.

The hypothesis is that the upper sand has partial pressure support and is in communication with the aquifer or other reservoir sands via some reduced permeability barrier. The pressure support is not as full as the lower zone and may ultimately reduce reserves estimations for this sand.

Utilizing the pressure buildup response in Figure 12 the MDH and Horner plots (Figures 13 & 14) give similar analysis with formation permeability of 900 md and a mechanical skin of 3.

The depth of investigation for this test was estimated to be 980 m.

Table 1 details the full results of Test #2

Table 1 – Blackback–2 Welltest Summary

Test	Perforation Depth (m) Top (MDRKB)	Perforation Depth (m) Bottom (MDRKB)	Perforation Length (metres)	Time (dd:hh:mm)	Operation Description	Choke (64th's)	Oil Flow (stb/d)	Gauge Pressure (psia)	Pressure Drawdown (psi)	Calculated PI (stb/d/psi)	Average Log Phi (%)	Average Log Sw (%)	Formation Height (h) (metres)	Calculated Permeability (md)	Calculated Total Skin
#1	2841.0	2846.5	5.5	–	Initial pressure	–	–	4002.7		–	22	10	6.0	3500	0
				17:07:17	Open well	16	355	3999.9	2.8	127					
				17:10:08	Increase choke	32	735	3998.9	3.8	193					
				17:11:00	Increase choke	48	1602	3993.9	8.8	182					
				17:20:00	Close well	–	–	–	–	–					
				18:15:08	Final pressure	–	–	4002.5	0.2	–					
#1A	2841.0	2846.5	5.5	–	Initial pressure	–	–	3996.3	–	–	22	10	6.0	3500	9
				20:04:40	Open well	16	950	3978.8	17.5	54					
				20:06:30	Increase choke	32	2800	3952.4	43.9	64					
				20:07:25	Increase choke	48	4500	3939.3	57.0	79					
				20:08:33	Increase choke	64	6640	3919.8	76.5	87					
				20:12:30	Increase choke	96	7100	3911.3	85.0	84					
				20:13:00	Close well	–	–	–	–	–					
				21:01:00	Final pressure	–	–	3996.3	0.0	–					
#2	2829.5	2834.0	4.5	–	Initial pressure	–	–	3993.4	–	–	17	35	4.5	900	3
				22:19:07	Open well	32	3000	3883.1	110.3	27					
				22:21:49	Increase choke	64	5659	3745.5	247.9	23					
				23:03:11	Close well	–	–	–	–	–					
				23:15:11	Final pressure	–	–	3979.6	13.8	–					

Additional Analysis Data

Well radius	0.51 feet	Oil density	33.86 lb/ft3	Oil compressibility	2.48E–05 psi–1
		Water density	62.77 lb/ft3	Water compressibility	2.65E–06 psi–1
		Bo	2.40 rb/stb	Gas compressibility	1.50E–04 psi–1
		Bw	1.02 rb/stb	Rock compressibility	3.30E–06 psi–1
		Oil viscosity	0.204 cp		
		Water viscosity	0.540 cp		

(mts/dec92/bb2wtsum)

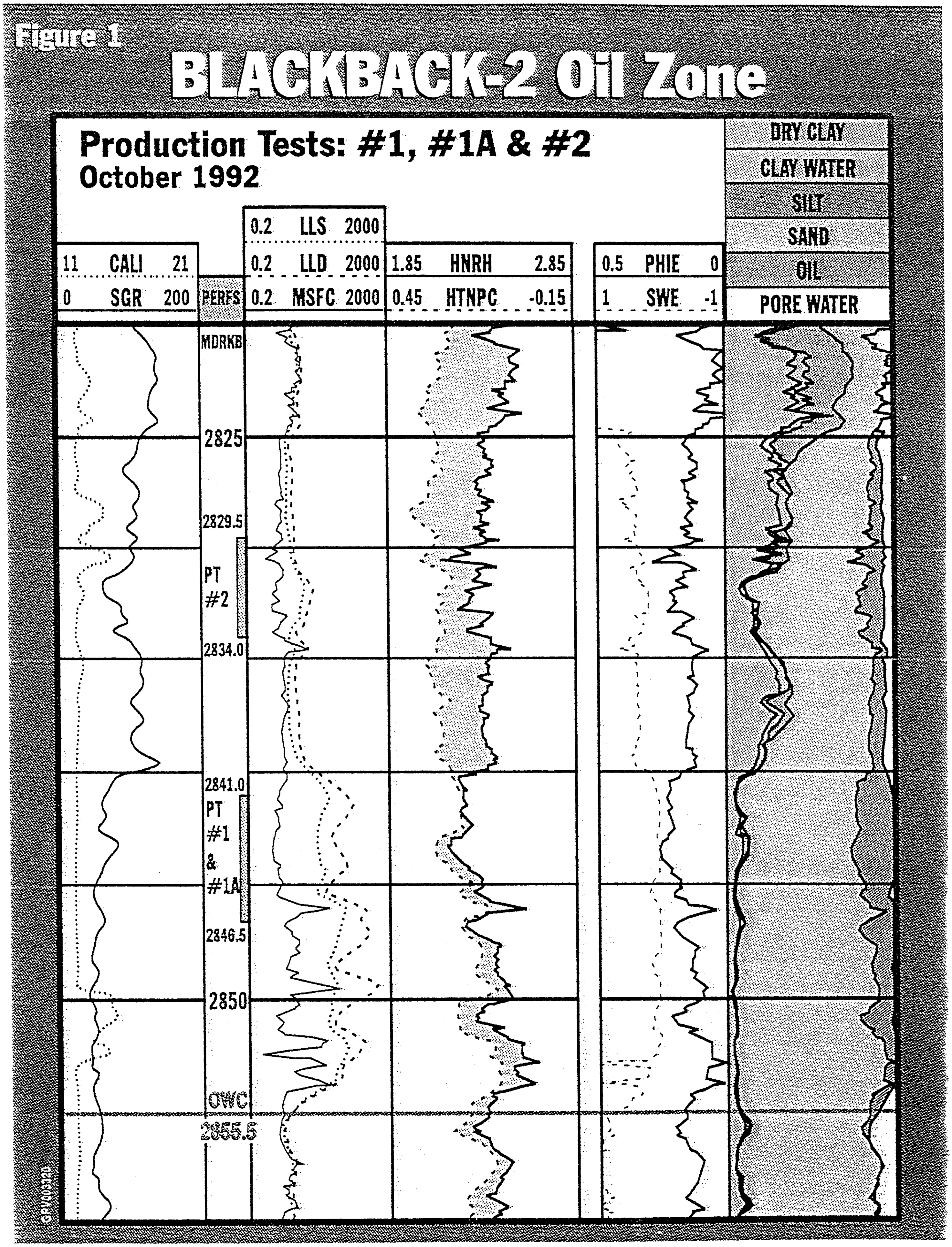
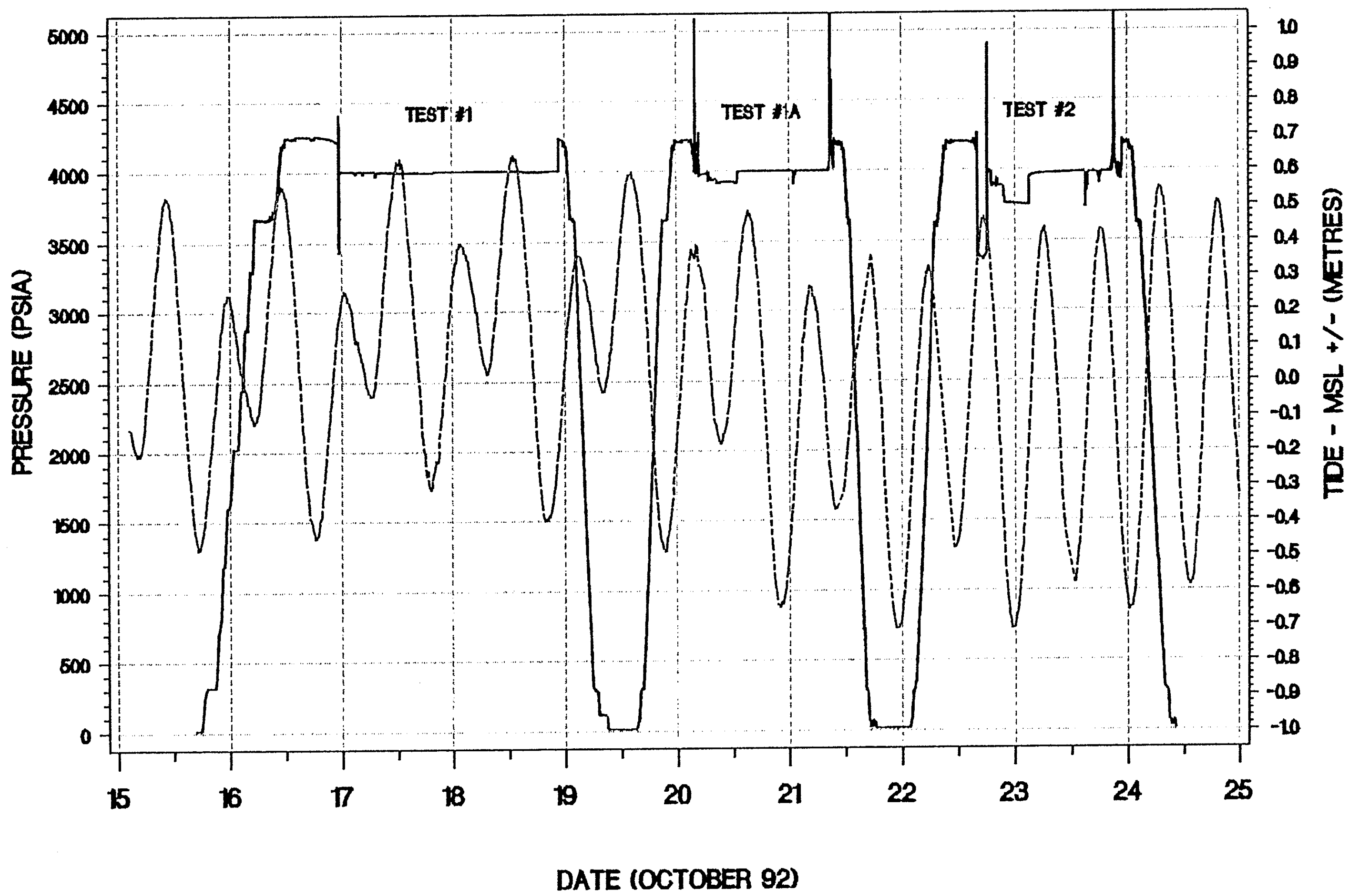


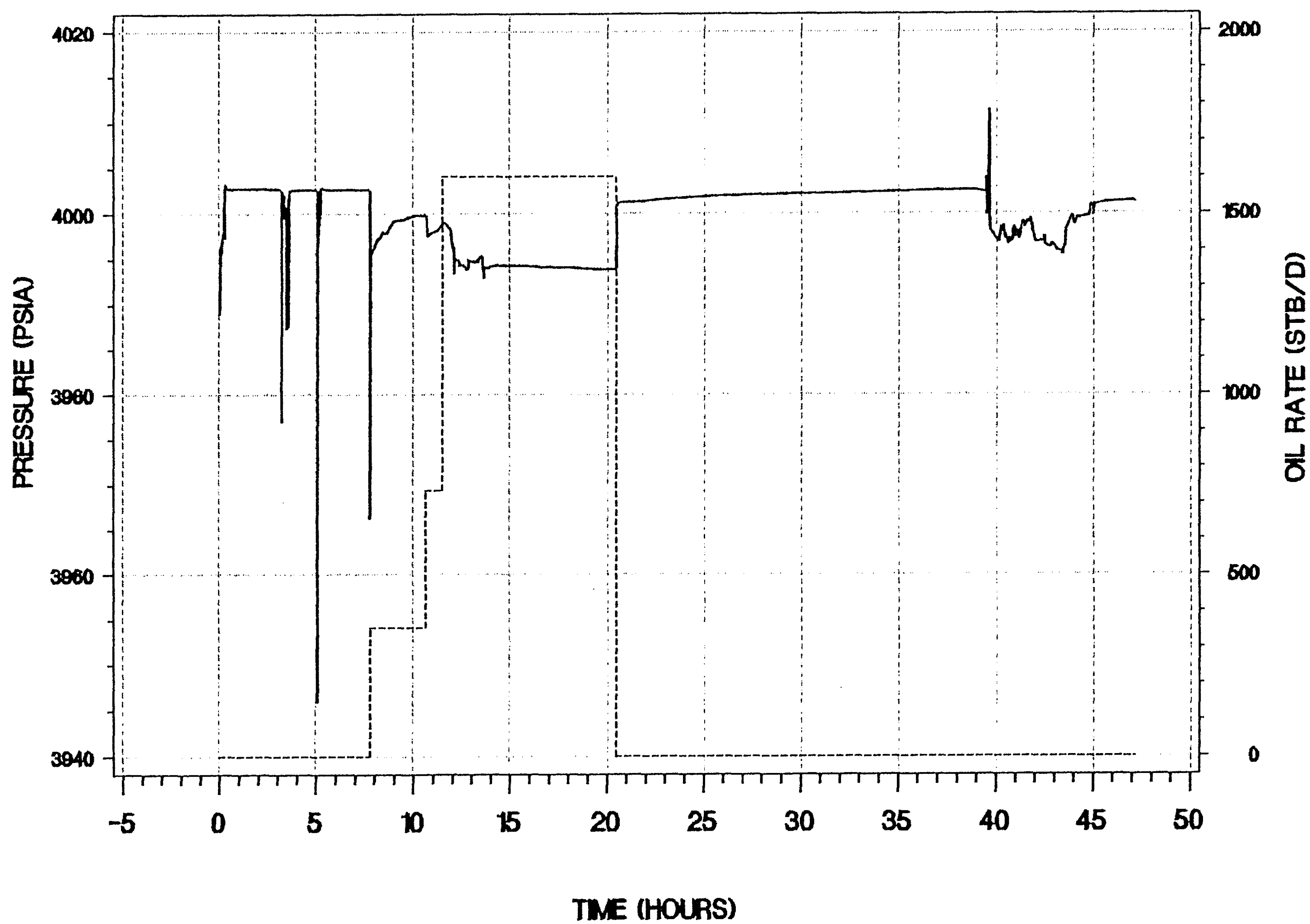
Figure 1
BLACKBACK-2 Oil Zone
Production Tests: #1, #1A & #2
October 1992
DRY CLAY
CLAY WATER
SILT
SAND
OIL
PORE WATER
0.2 LLS 2000
11 CALI 21
0.2 LLD 2000
1.85 HNRH 2.85
0.5 PHIE 0
0 SGR 200
PERFS
0.2 MSFC 2000
0.45 HTNPC -0.15
1 SWE -1
MDRKB
2825
2829.5
PT #2
2834.0
2841.0
PT #1 & #1A
2846.5
2850
OWC
2855.5
GPV00320

FIGURE 2 - BLACKBACK-2 PRODUCTION TEST
BOTTOMHOLE GAUGE PRESSURE AND TIDE DATA



(CREATED BY: MTSCOTT, 13:20, TUESDAY, 8DEC92. SAS VERSION: 5.18)

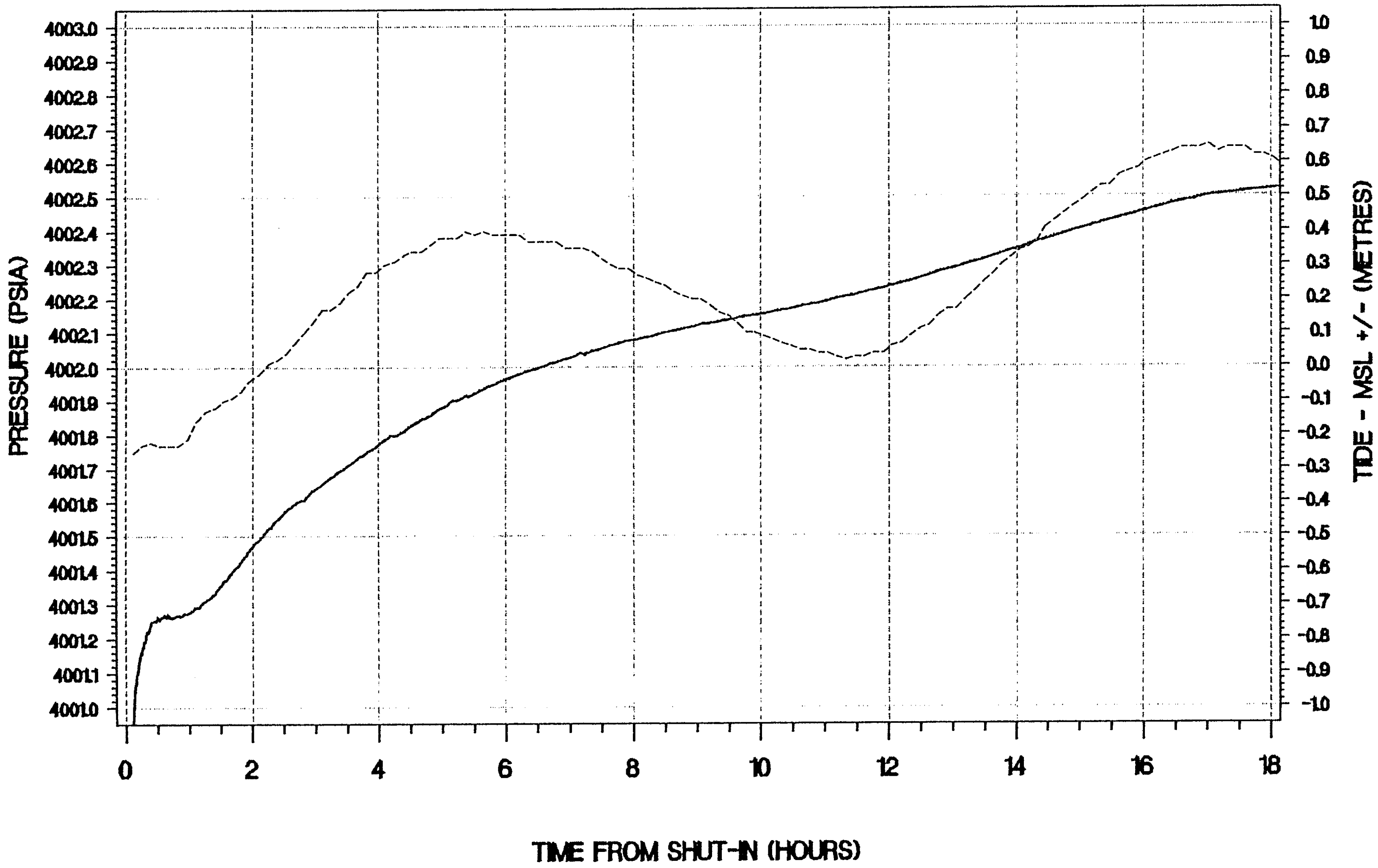
FIGURE 3 - BLACKBACK-2 PRODUCTION TEST
TEST #1 (16TH-19TH OCTOBER 92) - BOTTOMHOLE GAUGE PRESSURE AND OIL RATE



(CREATED BY: MTSCOTT, 14:04, TUESDAY, 8DEC92. SAS VERSION: 5.18)

FIGURE 4 - BLACKBACK-2 PRODUCTION TEST

TEST #1 (16TH-19TH OCTOBER 92) - BOTTOMHOLE GAUGE PRESSURE AND TIDE



(CREATED BY: MTSCOTT, 15:46, TUESDAY, 8DEC92. SAS VERSION: 5.18)

Figure 5 - Blackback - 2 Test #1 (MDH Buildup)

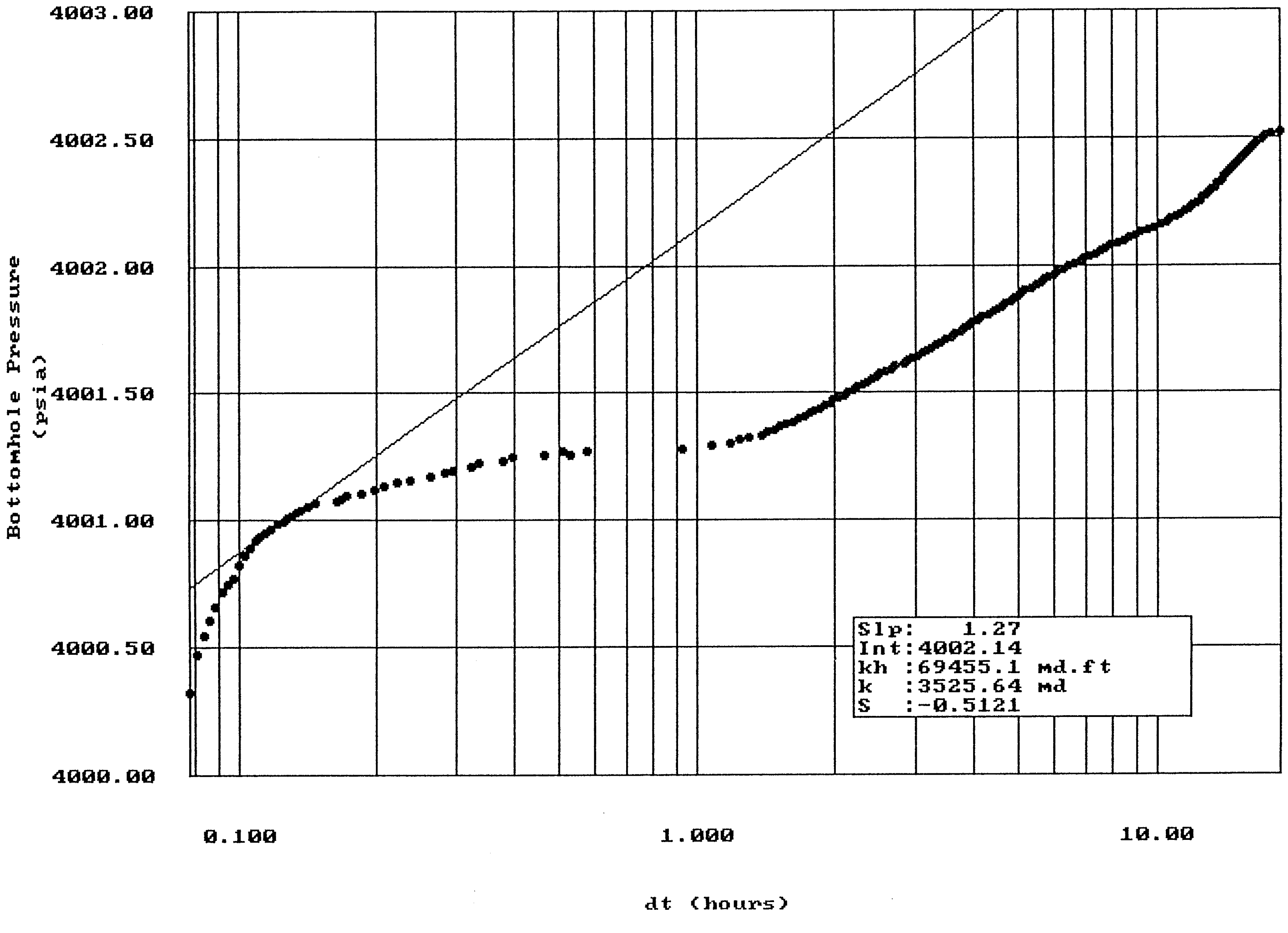


Figure 6 - Blackback - 2 Test #1 (Horner Plot)

Tp =10.030

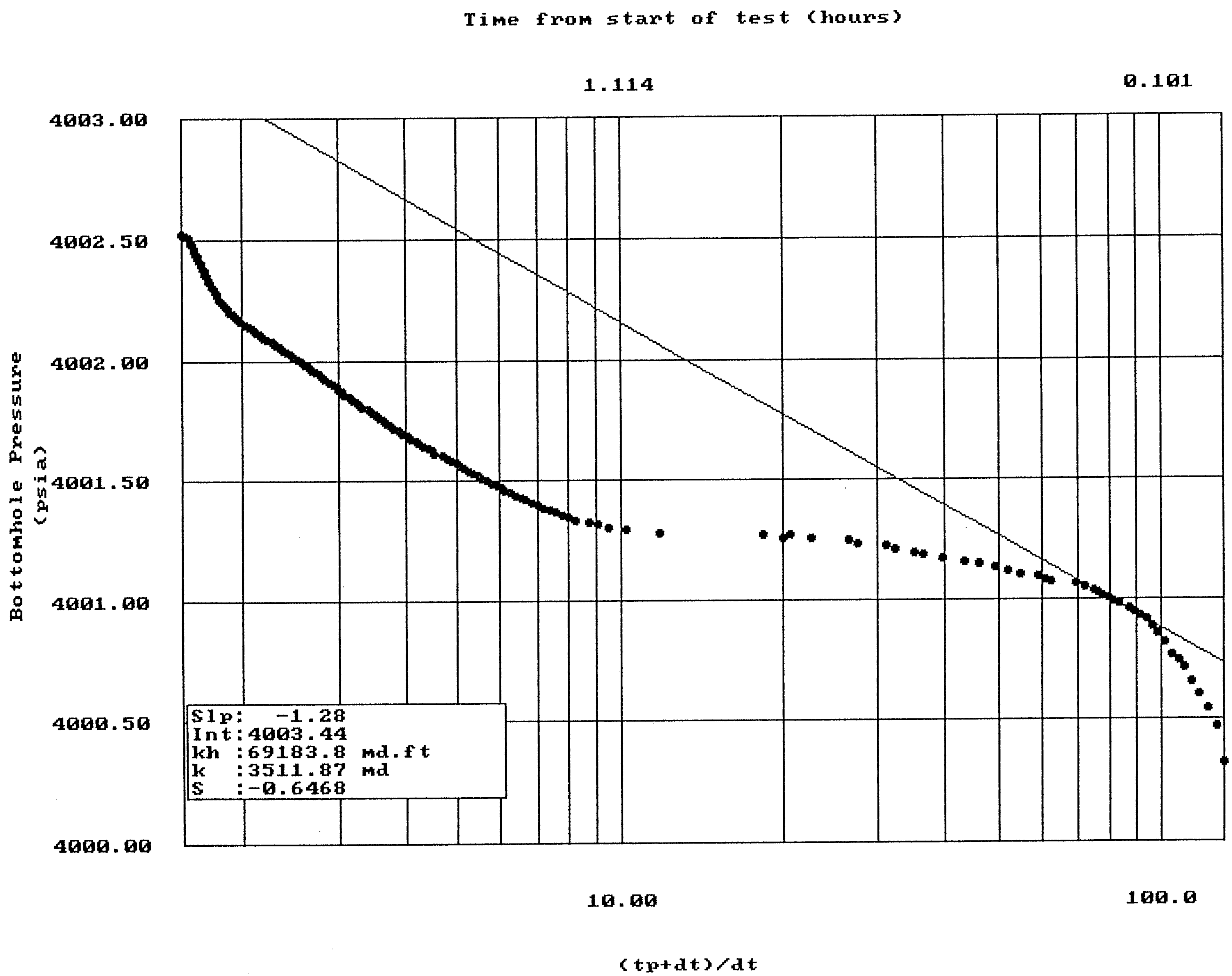
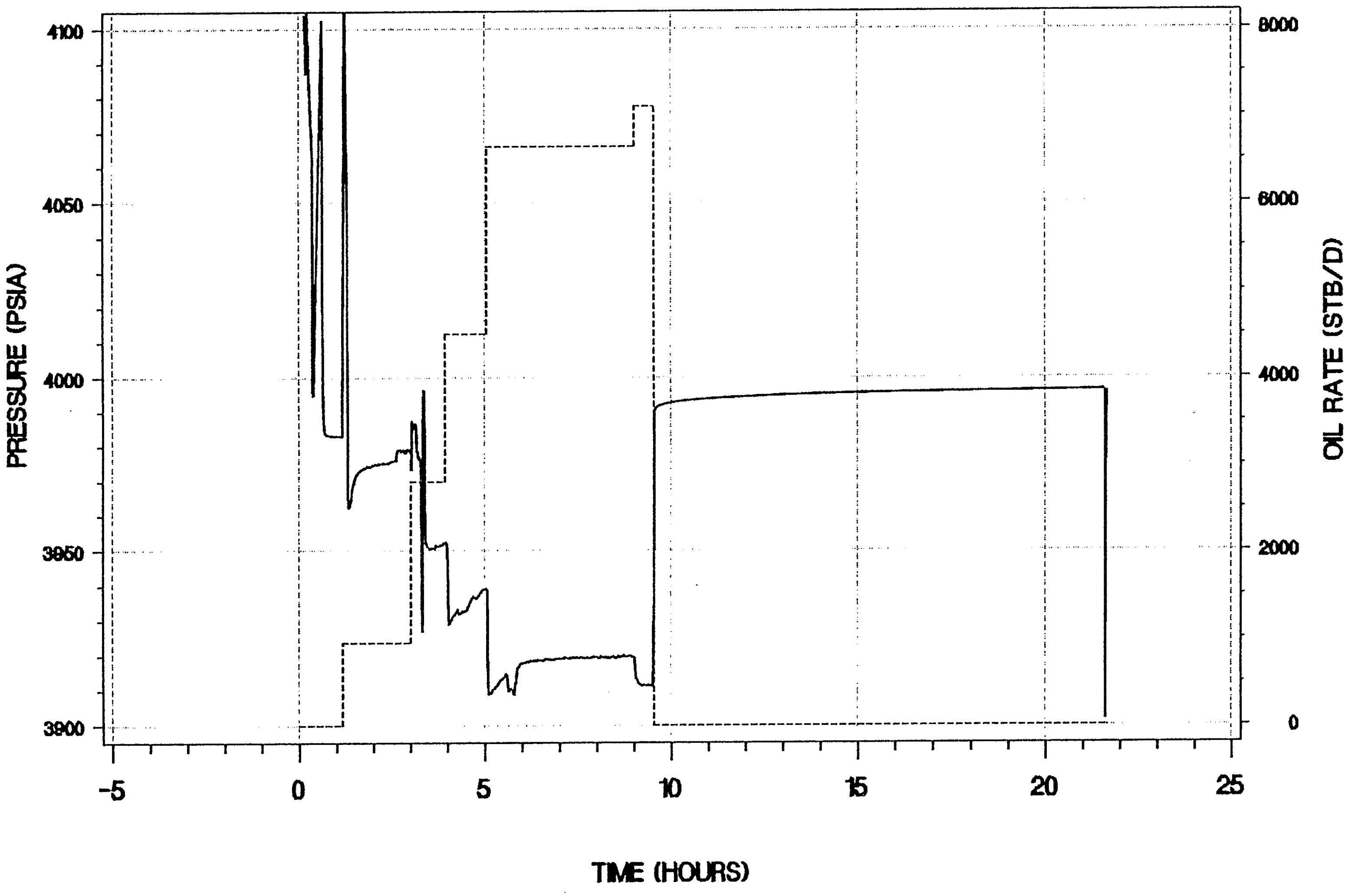
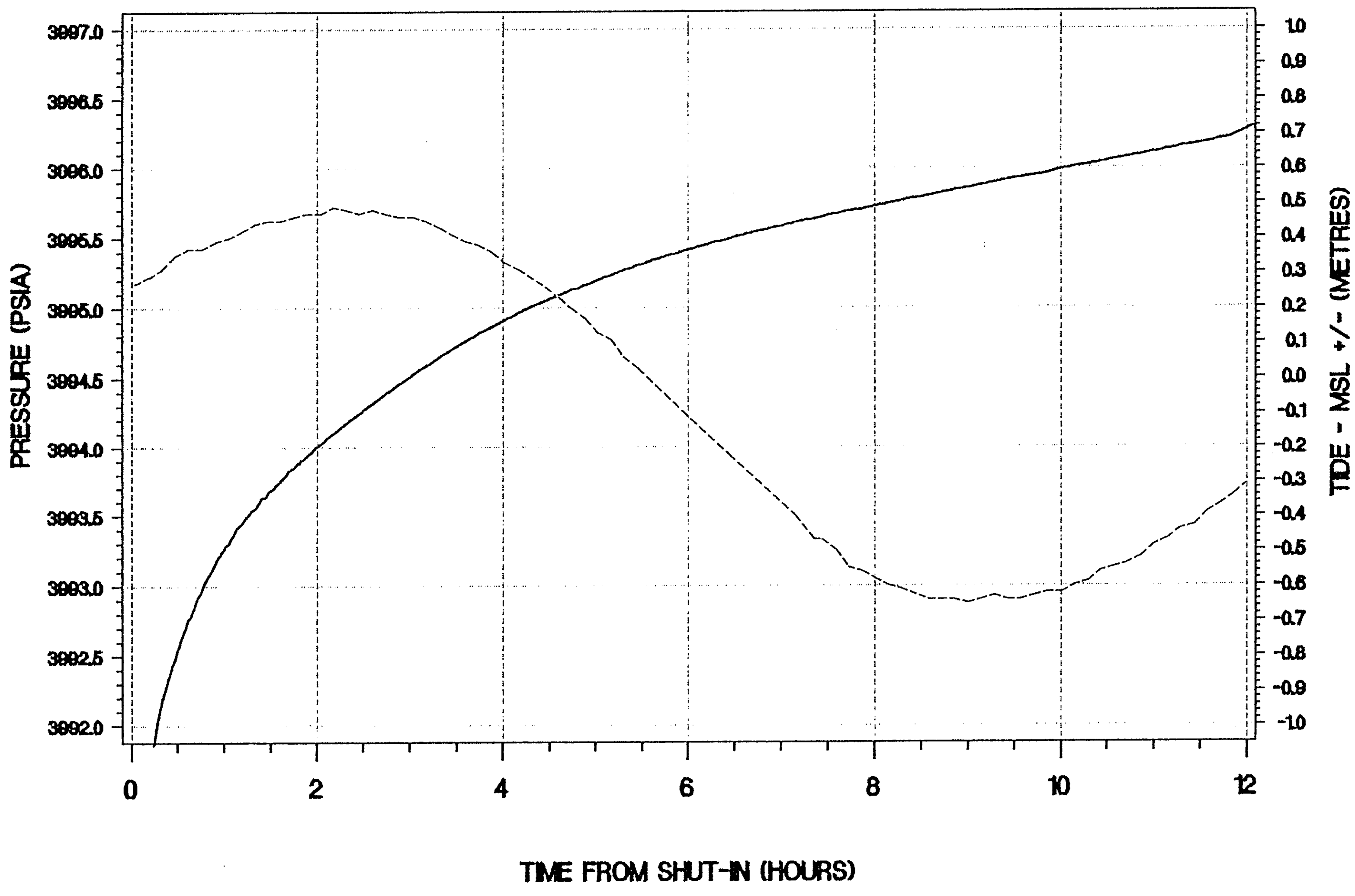


FIGURE 7 - BLACKBACK-2 PRODUCTION TEST
TEST #1A (20TH/21ST OCTOBER 92) - BOTTOMHOLE GAUGE PRESSURE AND OIL RATE



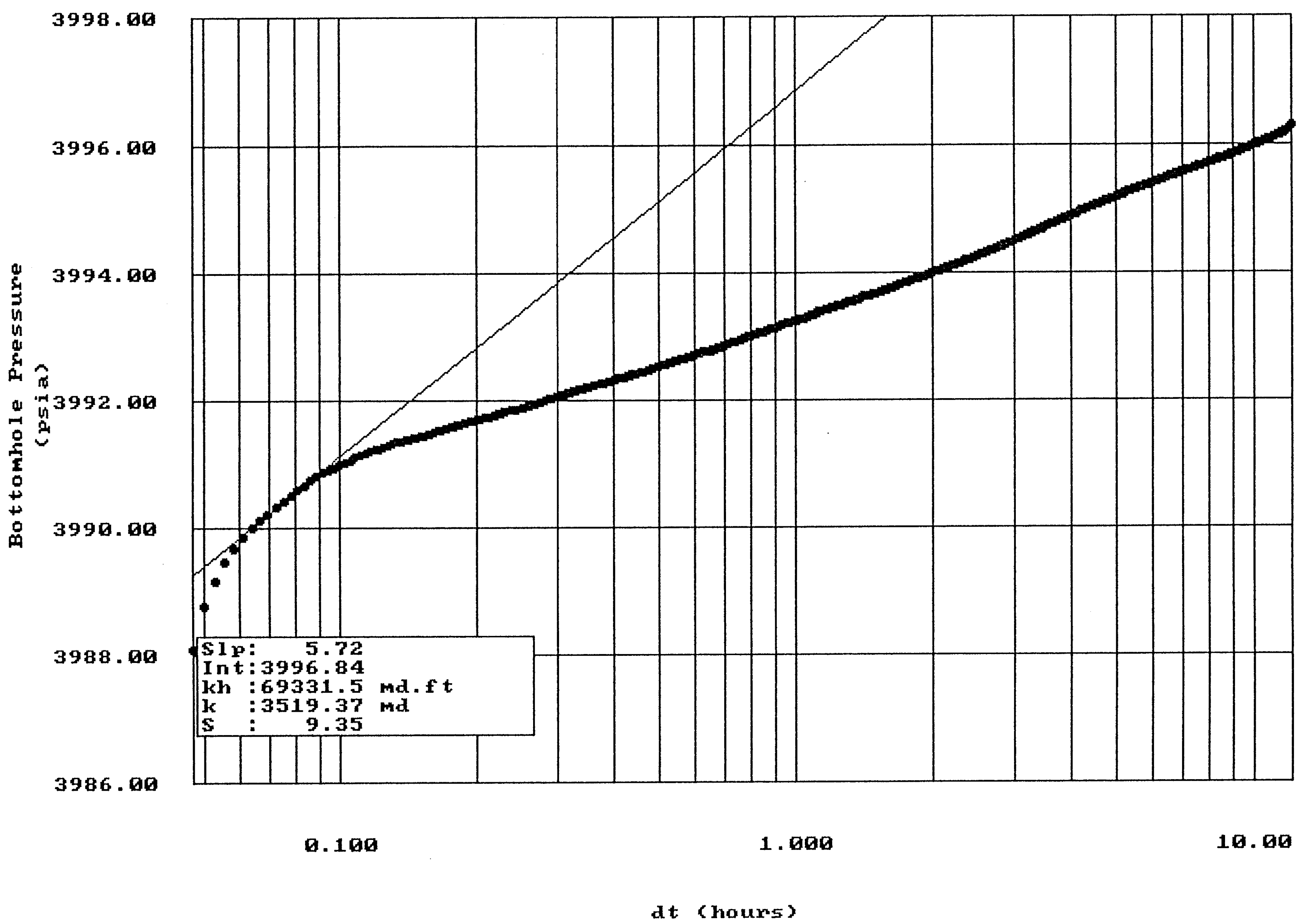
(CREATED BY: MTSCOTT, 14:50, TUESDAY, 8DEC92. SAS VERSION: 5.18)

FIGURE 8 - BLACKBACK-2 PRODUCTION TEST
TEST #1A (20TH/21ST OCTOBER 92) - BOTTOMHOLE GAUGE PRESSURE AND TIDE



(CREATED BY: MTSCOTT, 15:41, TUESDAY, 8DEC92. SAS VERSION: 5.18)

Figure 9 - Blackback - 2 Test #1A (MDH Buildup)



Tp =5.570

Figure 10 - Blackback - 2 Test #1A (Horner Plot)

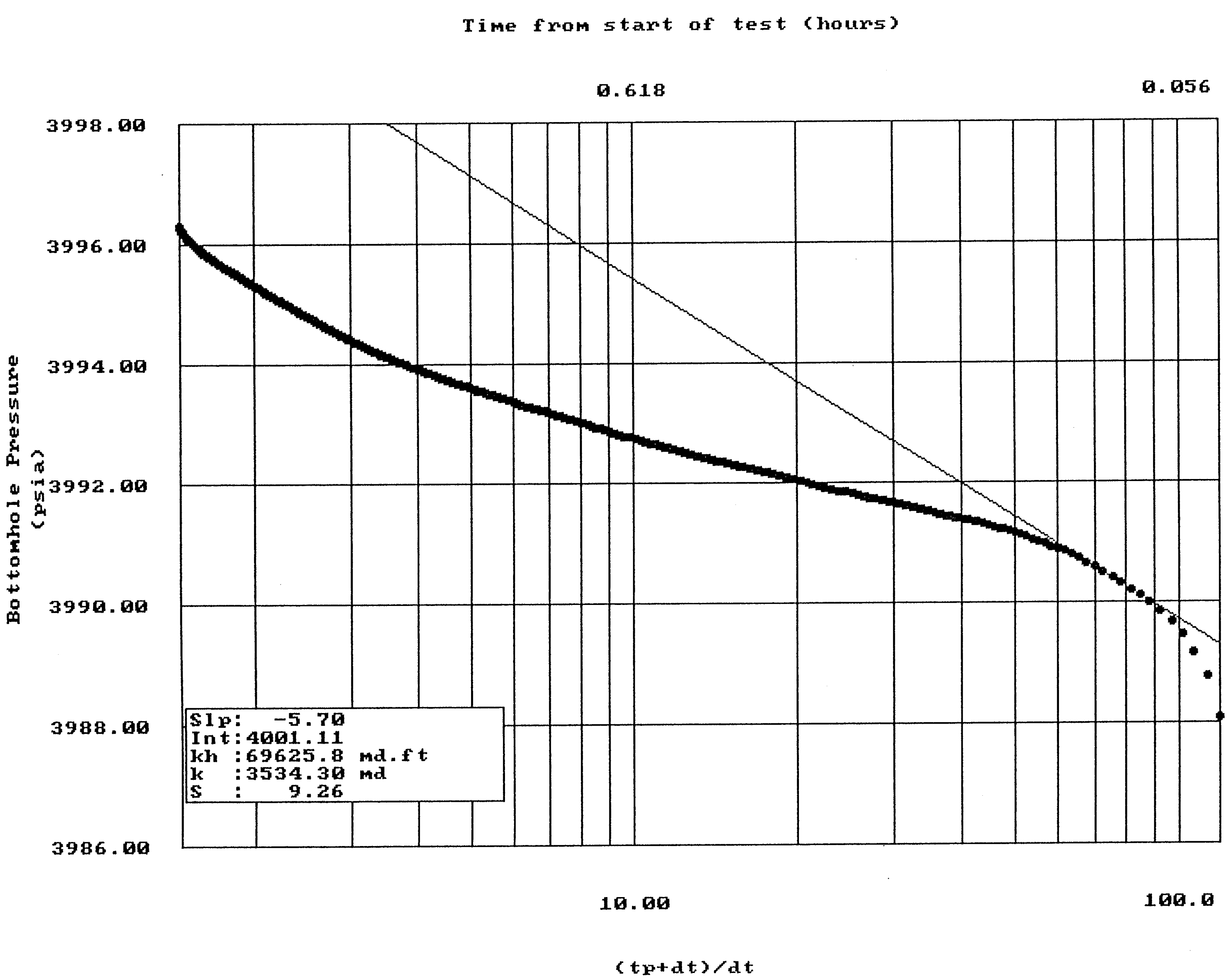
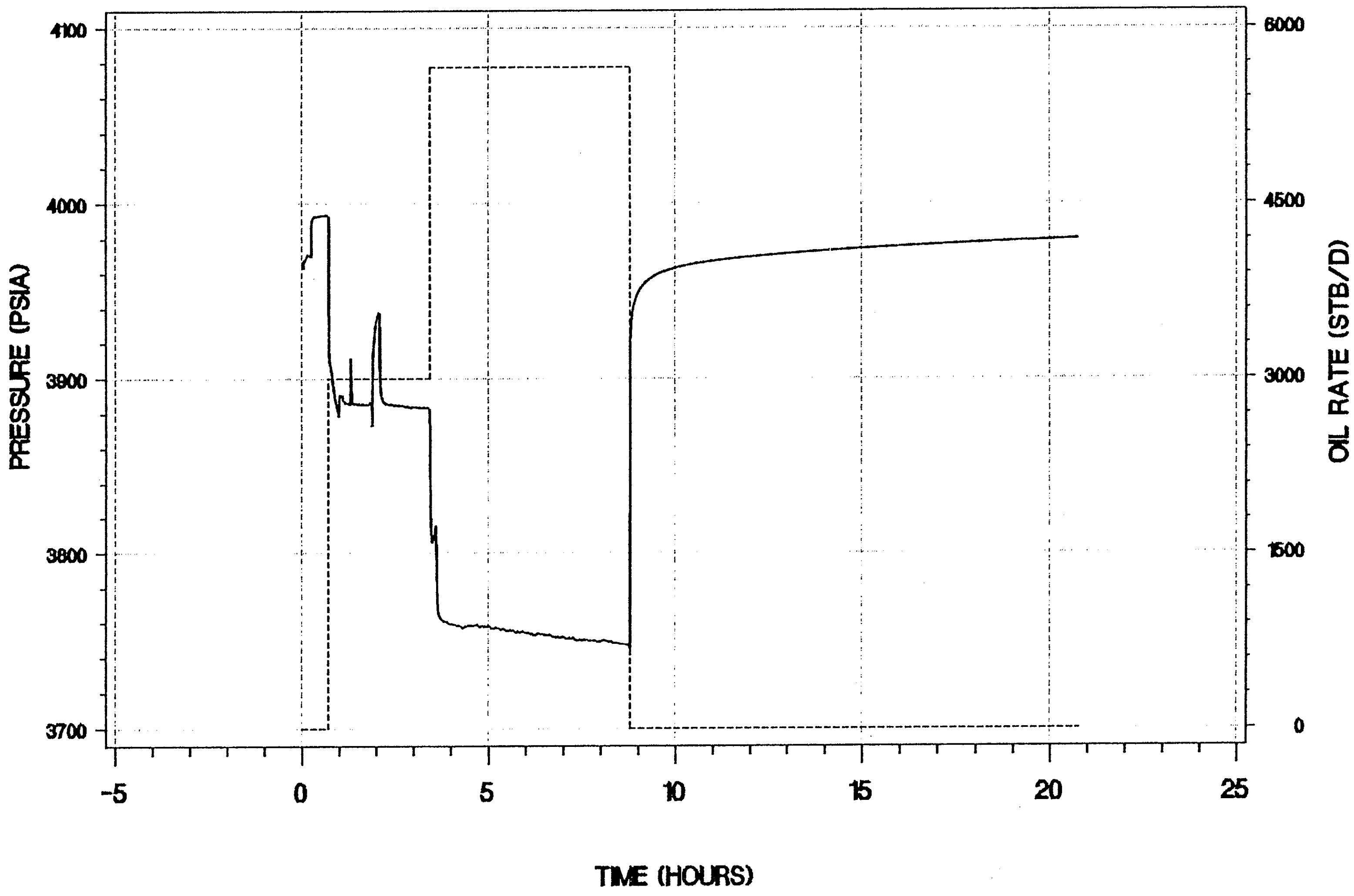


FIGURE 11 - BLACKBACK-2 PRODUCTION TEST

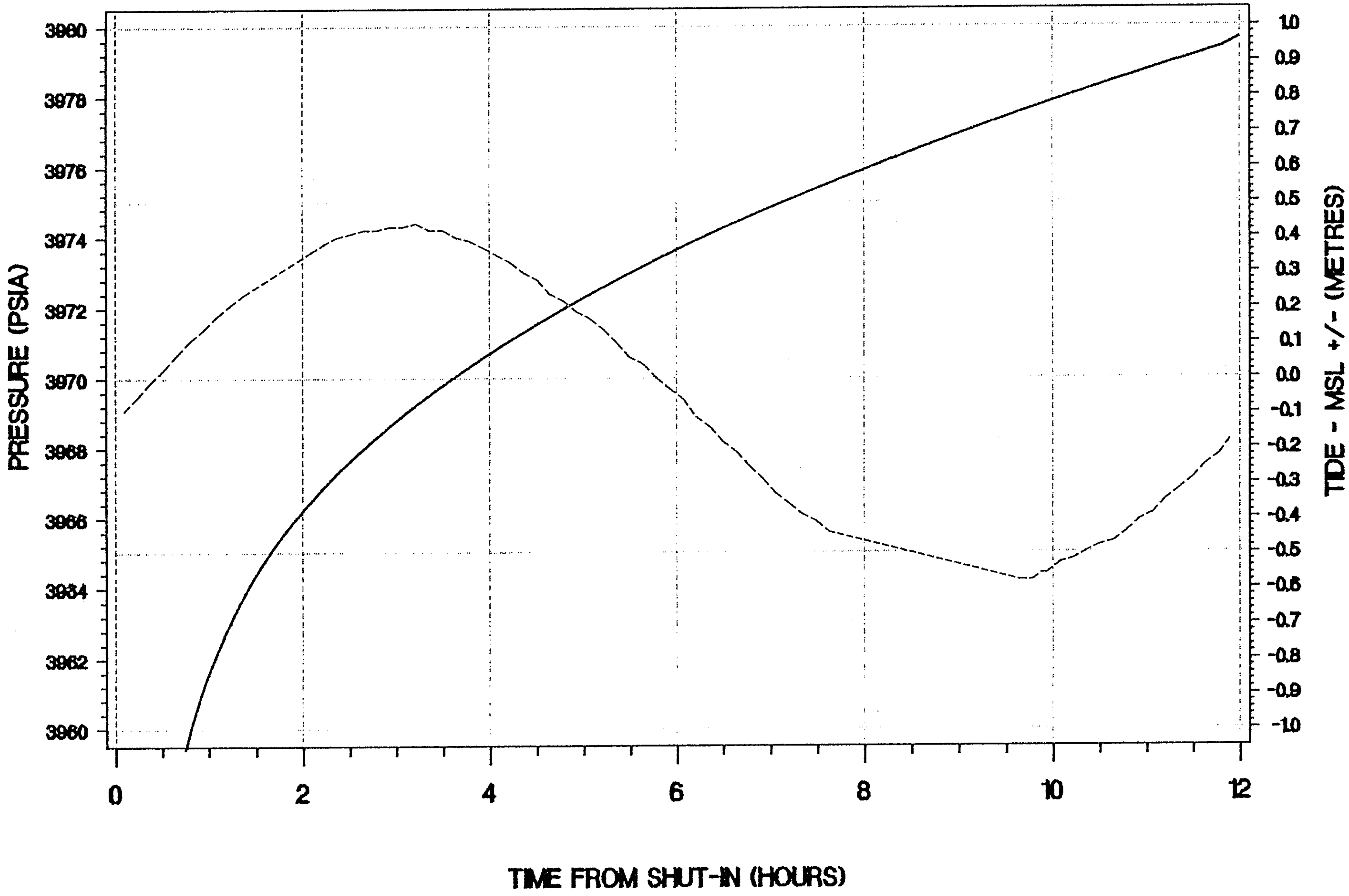
TEST #2 (22ND/23RD OCTOBER 92) - BOTTOMHOLE GAUGE PRESSURE AND OIL RATE



(CREATED BY: MTSCOTT, 15:50, TUESDAY, 8DEC92. SAS VERSION: 5.18)

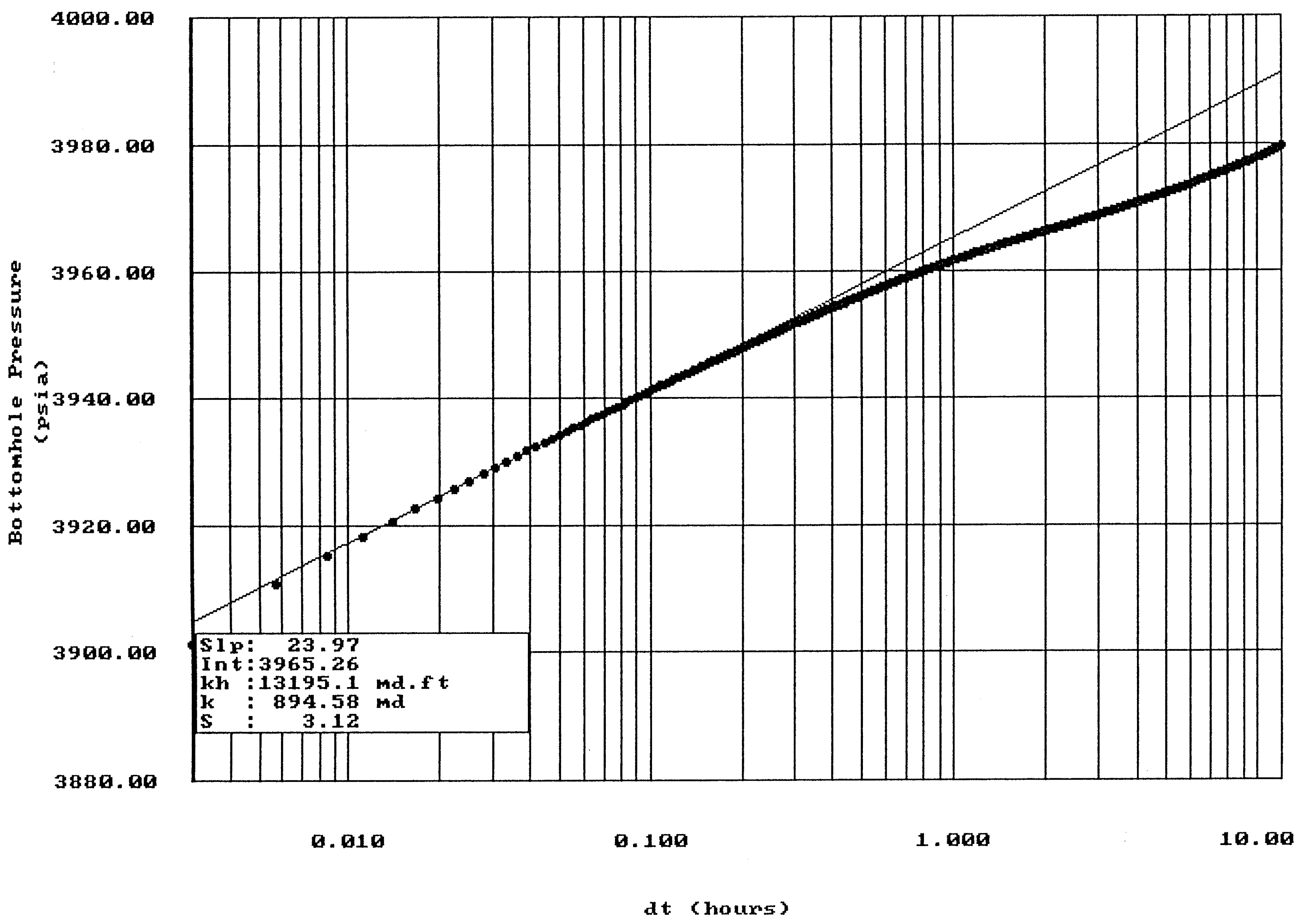
FIGURE 12 - BLACKBACK-2 PRODUCTION TEST

TEST #2 (22ND/23RD OCTOBER 92) - BOTTOMHOLE GAUGE PRESSURE AND TIDE



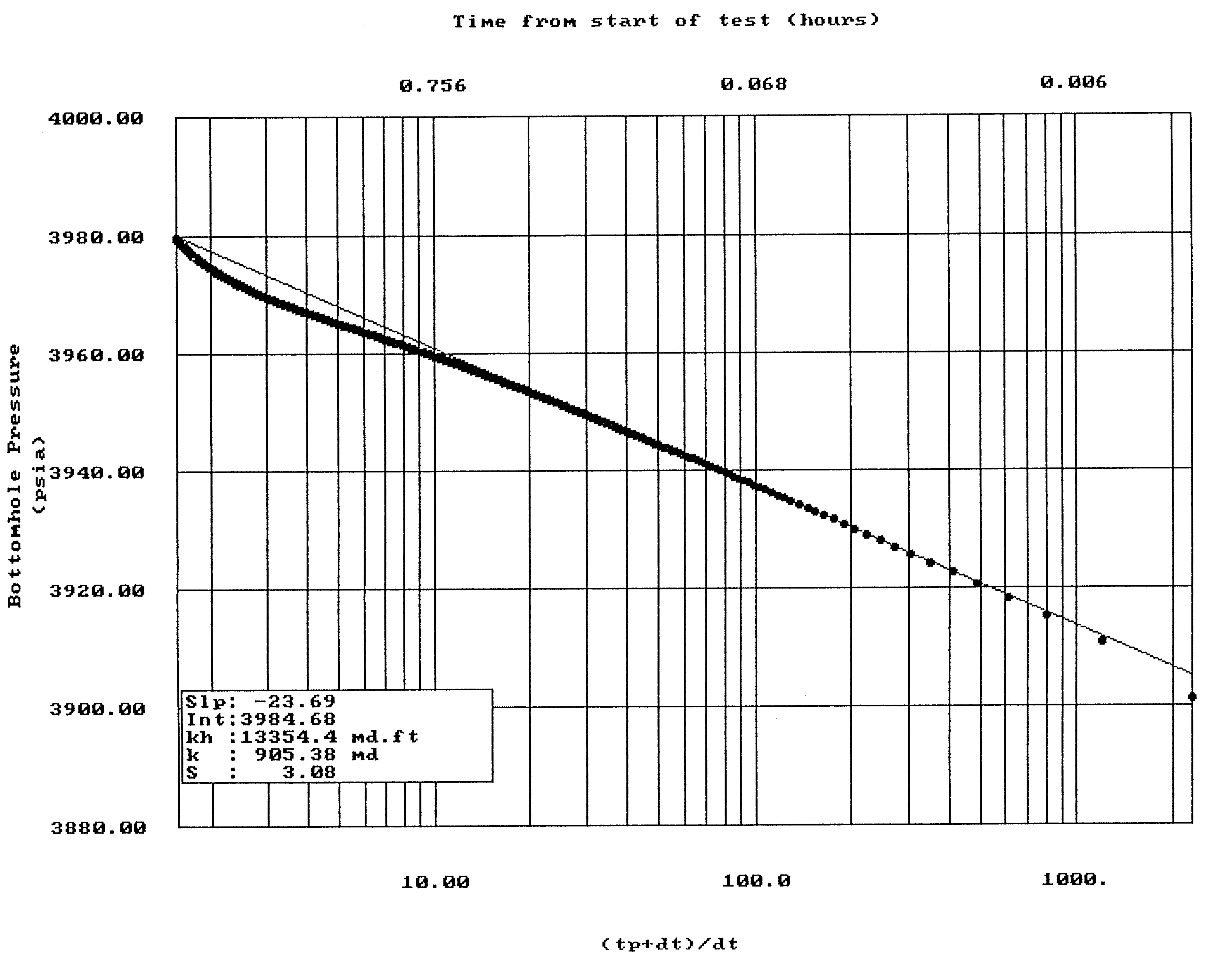
(CREATED BY: MTSCOTT, 15:58, TUESDAY, 8DEC92. SAS VERSION: 5.18)

Figure 13 - Blackback - 2 Test #2 (MDH Buildup)



Tp =6.807

Figure 14 - Blackback - 2 Test #2 (Horner Plot)



APPENDIX 7

APPENDIX 7

47 Woodforde Road, Magill,
South Australia, 5072
P.O. Box 410,
Magill, South Australia, 5072

PETROLAB

Fax: 364 1500
Telex: AA88214
Tel: (08) 364 1500
(08) 333 0787

Reservoir Fluid and Core Services, Laboratory Consulting and Analysis

Adelaide, January 24, 1993
P. O. Box 410
Magill
S. A. 5072

Esso Australia Ltd.
360 Elizabeth Street
GPO Box 400 C
Melbourne, Vic 3001

Subject: Reservoir Fluid Study
Well: Blackback # 2
File: E - 92039

Attention: Mr. Kumar Kuttan

Dear Sirs,

Petrolab received two bottom hole samples from the subject well in Schlumberger's R F T chambers # R F S - AD 1131 and # R F S - AD 1114 in December 1992 and was instructed to transfer the samples into high pressure laboratory storage cylinders.

The results of reservoir fluid analyses performed on these samples are presented in the following report.

The compositions of the bottom hole reservoir fluids were determined by flashing the samples under atmospheric conditions into two phases. Through measurements of densities, molecular weights, quantities produced and compositions of the evolved stock tank gas and liquid from the flash experiment, we were able to mathematically recombine these products into the desired fluid composition.

The composition was extended to C-12+ by means of capillary column gas chromatography on flashed stock tank liquid.

When charged to visual P V T cells, it was observed that both chambers had sampled some free liquid together with the gas condensates, as during constant composition expansions at the reservoir temperature of 194 ° F, we measured on both reservoir fluids, which had very similar compositions, dew point pressures some 1000 psig above the reported reservoir pressures. The retrograde liquids observed from these high pressures to the reservoir pressures had solid wax particles precipitating from them.

Other data obtained during these Pressure - Volume relations experiments, include relative volume versus pressure, gas compressibility, specific volume and gas expansion above the dew point and the distribution of retrograde liquid versus pressure below it.

The reservoir fluids were then produced by means of a constant volume differential depletions. At each depletion pressure the amount, and composition of the produced wellstream was determined and the retrograde liquid observed. Together with other measured gas properties this data allowed us to calculate the compositions of the retrograde liquid remaining in the cell.

The produced compositions and volumes from the depletion study were used in conjunction with published equilibrium constants to calculate cumulative stock tank liquid and separator gas recoveries resulting from conventional separation.

We thank Esso Australia Ltd. for the opportunity to be of service. Please do not hesitate in contacting us should you require any further information or if we can assist you in any other way.

Yours Sincerely,

Jan G. Bon
Manager

PETROLAB

Company : Esso Australia Ltd.
Well : Blackback # 2
File : E 92039

REPORT INDEX

Page

RFS – AD – 1131

REPORT INDEX (CONTINUED)

Page

RFS – AD – 1114

SUMMARY OF TRANSFER RESULTS

RFT # 1

Depth :	2820.7 (MDRKB)
RFT Chamber # :	RFS # AD – 1131
Capacity :	1 Gallon
Reservoir Pressure :	4033 psig
Reservoir Temperature :	90 °C
Opening Pressure :	2250 psig @ 20 deg C

Injected 80 cc's of mercury in chamber to stir up sample.Chamber compressed to 5000 psig with approximately 675 cc's of water behind piston. Transferred 1800 cc's into Petrolab cylinders # L–096, L–048 and L–161 @ 5000 psig. Flashed rest of sample to atmosphere. Recovered back all mercury, an additional 10 cc's of condensate and 550 cc's of muddy water.Tool dismantled and cleaned of all mercury and shipped to Schlumberger Sale on November 16, 1992.

RFT # 2

Depth :	2800.7 (MDRKB)
RFT Chamber # :	RFS # AD – 1114
Capacity :	1 Gallon
Reservoir Pressure :	4045 psig
Reservoir Temperature :	90 °C
Opening Pressure :	2300 psig @ 15 deg C

Injected 80 cc's of mercury in chamber to stir up sample.Chamber compressed to 5000 psig with approximately 1025 cc's of water behind piston. Transferred 1800 cc's into Petrolab cylinders # L–134, L–101 and L–076 @ 5000 psig. Flashed rest of sample to atmosphere. Recovered back all mercury, an additional 10 cc's of condensate and 50 cc's of muddy water.Tool dismantled and cleaned of all mercury and shipped to Schlumberger Sale on November 16, 1992.

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Company: Esso Australia Ltd.	Page: 2 of 60
Well: Blackback # 2	File : E 92039

SUMMARY OF RESULTS

RFT Chamber # RFS – AD # 1131

SATURATED VAPOUR:

Reservoir Temperature (°F)	:	194
Dew Point Pressure (psig)	:	4915
Gas Formation Volume Factor (Bg)	:	0.00344
Gas Expansion Factor (E)	:	290.54
Gas Deviation Factor (Z)	:	0.918
Specific Volume (CFT/LB)	:	0.04787
Density (gm/cc)	:	0.3346
Viscosity (centipoise)	:	0.044
Molecular Weight	:	27.30
Gas Gravity (Air = 1.000)	:	0.962
Gross Heating Value (BTU/ft3)	:	1628

Total Plant Products in Dew Point Fluid (GPMM):

Ethane	:	2583
Propane	:	1525
Butanes	:	1058
Pentanes Plus	:	3632

FLASH DATA:

1st Separator Pressure (psig)	:	400
1st Separator Temperature (°F)	:	86
2nd Separator Pressure (psig)	:	--
2nd Separator Temperature (°F)	:	--
Stock Tank Pressure (psig)	:	0
Stock Tank Temperature (°F)	:	60
1st Separator GOR (scf/bbl)	:	10378
2nd Separator GOR (scf/bbl)	:	--
Stock Tank GOR (scf/bbl)	:	450
Total GOR (scf/bbl)	:	10828
1st Sep.Gas/Prod. WS (mscf/mmscf)	:	884
2nd Sep.Gas/Prod. WS (mscf/mmscf)	:	--
ST T Liq/Produced W/S (stb/mmscf)	:	85.19

Total Plant Products in Primary Separator Gas (GPMM):

Ethane	:	2373
Propane	:	1201
Butanes	:	606
Pentanes Plus	:	287

Total Plant Products in Secondary Separator Gas (GPMM):

Ethane	:	--
Propane	:	--
Butanes	:	--
Pentanes Plus	:	--

FIELD CHARACTERISTICS:

		RFS-AD-1131	RFS-AD-1114
Formation Name	:	--	--
Date first well completed	:	October 1992	October 1992
Original reservoir pressure (psia)	:	4048.3	4059.9
@ datum (m mDRKB)	:	2820.7	2800.7
Original Gas-Liquid Ratio SCF/STB)	:	--	--
Separator pressure (psia)	:	--	--
Separator temperature (°C)	:	--	--
Liquid gravity (°API @ 60 °F)	:	--	--

WELL CHARACTERISTICS:

Depth datum (m mDRKB)	:	2820.7	2800.7
Elevation above MSL (m)	:	--	--
Total depth (m mDRKB)	:	--	--
Producing interval (m)	:	2820.7	2800.7
Perforated intervals (m mDRKB)	:	--	--
Tubing size (inch)	:	3 1/2	3 1/2
Reservoir temperature (°F)	:	194	194
Last reservoir pressure (psia)	:	4048.3	4059.9
@ datum (ft KBMD)	:	2820.7	2800.7
date	:	October 1992	October 1992
Status of well	:	P&A	P&A

BOTTOM HOLE SAMPLING CONDITIONS:

RFT Chamber No.	:	RFS-AD-1131	RFS-AD-1114
Chamber Size	:	1 Gallon	1 Gallon
Date sampled	:	October 1992	October 1992
Sampled by	:	Schlumberger	Schlumberger

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Company : Esso Australia Ltd.	Page : 4 of 60
Well : Blackback # 2	File : E 92039

COMPOSITIONAL ANALYSIS OF BOTTOM HOLE SAMPLE RFS – AD # 1131

Component		Stock Tank Liquid Mol %	Stock Tank Gas Mol %	Reservoir Fluid Mol %
Hydrogen Sulphide	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.01	0.50	0.48
Nitrogen	N2	0.00	0.49	0.47
Methane	C1	0.45	75.44	73.08
Ethane	C2	0.38	10.14	9.83
Propane	C3	0.78	5.66	5.51
Iso–Butane	iC4	0.51	1.43	1.40
N–Butane	nC4	0.99	1.93	1.90
Iso–Pentane	iC5	1.10	0.79	0.80
N–Pentane	nC5	1.35	0.75	0.77
Hexanes	C6	5.76	1.07	1.22
Heptanes	C7	16.83	1.07	1.57
Octanes	C8	16.19	0.41	0.91
Nonanes	C9	16.03	0.20	0.70
Decanes	C10	10.05	0.08	0.39
Undecanes	C11	5.98	0.03	0.22
Dodecanes Plus	C12+	23.60	0.01	0.75
TOTAL		100.00	100.00	100.00

Ratios

Molar Ratio	:	0.0315	0.9685	1.0000
Mass Ratio	:	0.1540	0.8460	1.0000
Gas Liquid Ratio	:	1.0000	24063 SCF	--

Stream Properties

Molecular Weight	:	133.4	23.8	27.3
Density obs. (gm/cc)	:	0.7849	--	-- @ PT*
Gravity (AIR = 1.000)	:	48.6	0.827	--
GHV (BTU/scf)	:	--	1417	--

Hexanes Plus Properties

Mol %	:	94.43	2.87	5.76
Molecular Weight	:	137.9	96.7	118.0
Density (gm/cc @ 60 F)	:	0.7922	0.6847	0.7458
Gravity (API @ 60 F)	:	47.0	75.0	58.0

Heptanes Plus Properties

Mol %	:	88.67	1.80	4.54
Molecular Weight	:	141.2	104.2	127.0
Density (gm/cc @ 60 F)	:	0.7971	0.6946	0.7616
Gravity (API @ 60 F)	:	45.9	72.0	54.1

Decanes Plus Properties

Mol %	:	39.63	0.12	1.36
Molecular Weight	:	182.6	140.3	179.0
Density (gm/cc @ 60 F)	:	0.8227	0.7338	0.8161
Gravity (API @ 60 F)	:	40.3	61.1	41.7

Undecanes Plus Properties

Mol %	:	29.57	0.04	0.97
Molecular Weight	:	200.2	152.8	198.1
Density (gm/cc @ 60 F)	:	0.8307	0.7451	0.8277
Gravity (API @ 60 F)	:	38.7	161.0	39.3

Dodecanes Plus Properties

Mol %	:	23.60	0.01	0.75
Molecular Weight	:	214.4	168.3	213.7
Density (gm/cc @ 60 F)	:	0.8368	0.7579	0.8359
Gravity (API @ 60 F)	:	37.4	55.0	37.6

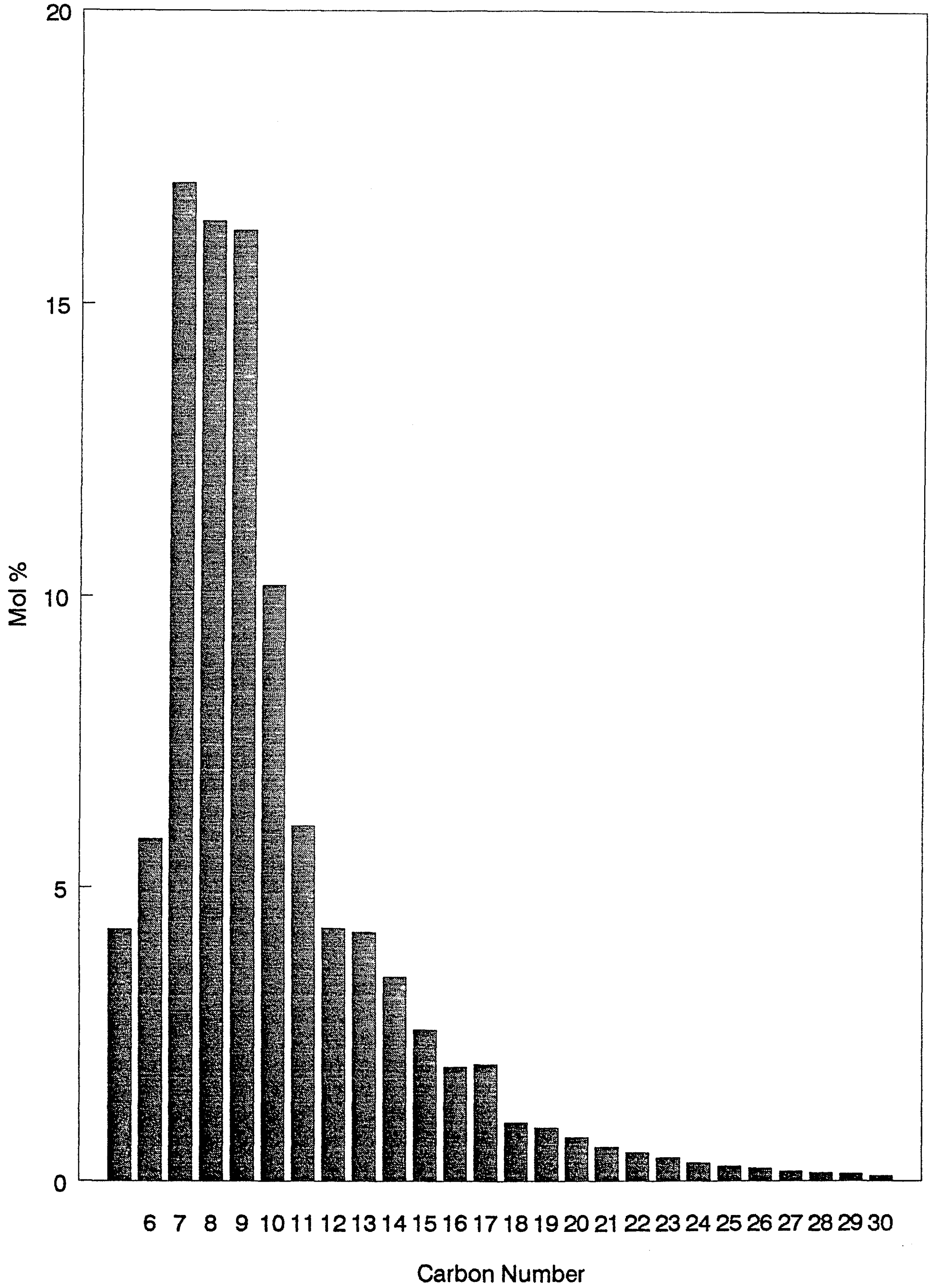
* (P)ressure 4915 psig, (T)emperature 194 °F

FINGERPRINT ANALYSIS BY CAPILLARY GAS CHROMATOGRAPHY RFS – AD # 1131

Component		Mol %
Hexanes minus	C6–	4.29
Hexanes	C6	5.84
Heptanes	C7	17.06
Octanes	C8	16.41
Nonanes	C9	16.25
Decanes	C10	10.19
Undecanes	C11	6.06
Dodecanes	C12	4.31
Tridecanes	C13	4.25
Tetradecanes	C14	3.49
Pentadecanes	C15	2.58
Hexadecanes	C16	1.94
Heptadecanes	C17	1.99
Octadecanes	C18	1.00
Nonadecanes	C19	0.91
Eicosanes	C20	0.73
Heneicosanes	C21	0.58
Docosanes	C22	0.48
Tricosanes	C23	0.39
Tetracosanes	C24	0.30
Pentacosanes	C25	0.25
Hexacosanes	C26	0.21
Heptacosanes	C27	0.16
Octacosanes	C28	0.13
Nonacosanes	C29	0.11
Triacontanes plus	C30+	0.09
TOTAL		100.00

Molecular weight:	136.0
Density @ 60 °F:	0.7764

FINGERPRINT ANALYSIS BY CAPILLARY GAS CHROMATOGRAPHY RFS – AD # 1131



CONSTANT MASS STUDY
@ 194 °F

RFS – AD # 1131

Pressure (psig)	Relative Volume (V/Vsat) (1)	Formation Volume Factor (Bg) (2)	Gas Expansion Factor (E) (3)	Deviation Factor (Z)	Specific Volume (CFT/LB)
6000	0.9232	0.00318	314.72	1.034	0.04419
5900	0.9297	0.00320	312.51	1.024	0.04450
5800	0.9355	0.00322	310.56	1.013	0.04478
5700	0.9416	0.00324	308.57	1.002	0.04507
5600	0.9469	0.00326	306.84	0.990	0.04532
5500	0.9533	0.00328	304.77	0.979	0.04563
5400	0.9610	0.00331	302.33	0.969	0.04600
5300	0.9680	0.00333	300.15	0.958	0.04633
5200	0.9752	0.00336	297.92	0.947	0.04668
5100	0.9817	0.00338	295.96	0.935	0.04699
5000	0.9916	0.00341	292.99	0.926	0.04747
4915 *	1.0000	0.00344	290.54	0.918	0.04787
4034 **	1.1035	0.00380	263.28	0.832	0.05282

* Dew Point Pressure

** Reservoir Pressure

(1) Cubic feet of gas at indicated pressure and temperature per cubic foot at saturation pressure

(2) Cubic feet of gas at indicated pressure and temperature per cubic foot at 14.696 psia and 60 °F

(3) Cubic feet of gas at 14.696 psia and 60 °F per cubic foot at indicated pressure and temperature

CONSTANT MASS STUDY
@ 194 °F

RFS – AD # 1131

Pressure (psig)	Relative Volume (V/Vsat) (1)	Retrograde Liquid Deposit (Bbl/MMSCF) (2)	Retrograde Liquid Deposit (Volume%) (3)
4915 *	1.0000	0.00	0.00
4600	1.0264	5.65	0.92
4346	1.0591	11.77	1.92
4034 **	1.1022	17.43	2.84
3842	1.1348	24.49	4.00
3592	1.1852	32.33	5.27
3088	1.3275	55.10	8.99
2582	1.5469	72.58	11.84
2073	1.9215	89.82	14.65
1415	2.9297	99.25	16.19

* Dew Point Pressure

** Reservoir Pressure

(1) Cubic feet of gas at indicated pressure and temperature per cubic foot at saturation pressure

(2) Barrels of liquid at indicated pressure and temperature per MMSCF of original reservoir fluid

(3) Percent of reservoir hydrocarbon pore space at dew point

CONSTANT VOLUME DEPLETION STUDY @ 194 °F

RFS – AD # 1131

Pressure (psig)	Cumulative Produced Fluid (1)	Deviation Factor (Z)		Gas Viscosity (Centipoise)	Retrograde Liquid	
		Liberated Gas	Two Phase		(Bbl/MMSCF) (2)	(Vol. %) (3)
4915 *	0.000	0.918	0.918	0.0440	0.00	0.00
4034 **	7.762	0.855	0.864	0.0335	18.89	3.08
3523	14.558	0.827	0.817	0.0284	32.44	5.29
3010	23.494	0.801	0.782	0.0244	50.76	8.28
2498	34.505	0.781	0.760	0.0212	69.47	11.33
2018	46.537	0.784	0.756	0.0184	75.76	12.36
1502	59.861	0.831	0.755	0.0160	77.99	12.72
998	72.552	0.883	0.734	0.0144	77.26	12.60
510	84.744	0.945	0.683	0.0132	73.96	12.06

* Dew Point Pressure

** Reservoir Pressure

(1) Wellstream produced : Cumulative volume percent of initial fluid

(2) Barrels of liquid at indicated pressure and temperature per MMSCF of original reservoir fluid

(3) Percent of reservoir hydrocarbon pore space at dew point

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PRODUCED WELLSTREAM COMPOSITIONS

Pressure (psig):		4915 *	4034	3523
Component		Mol %	Mol %	Mol %
Hydrogen Sulphide	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.36	0.36	0.37
Nitrogen	N2	0.51	0.52	0.53
Methane	C1	72.92	74.36	75.53
Ethane	C2	9.65	9.64	9.61
Propane	C3	5.53	5.48	5.40
Iso-Butane	iC4	1.42	1.38	1.33
N-Butane	nC4	1.88	1.80	1.73
Iso-Pentane	iC5	0.75	0.70	0.65
N-Pentane	nC5	0.69	0.64	0.59
Hexanes	C6	1.17	1.05	0.92
Heptanes	C7	1.89	1.91	1.62
Octanes	C8	1.01	0.72	0.64
Nonanes	C9	0.76	0.59	0.45
Decanes	C10	0.42	0.28	0.18
Undecanes	C11	0.23	0.18	0.13
Dodecanes Plus	C12+	0.80	0.39	0.31
TOTAL		100.00	100.00	100.00

Stream Properties

Molecular Weight	:	27.71	25.98	24.95
Gravity (AIR = 1.000)	:	0.962	0.902	0.866
Gross HV (BTU/SCF)	:	1628	1535	1479
Nett HV (BTU/SCF)	:	1486	1399	1347
Wobbe Index	:	1660	1617	1590
Critical Pressure (psia)	:	642.8	647.3	650.2
Critical Temperature (°R)	:	444.6	434.3	427.1

G P M Content

Ethane Plus	:	8.798	7.995	7.455
Propane Plus	:	6.215	5.415	4.883
Butanes Plus	:	4.690	3.904	3.394
Pentanes Plus	:	3.632	2.884	2.413

Heptanes Plus Properties

Mol %	:	5.12	4.07	3.34
Molecular Weight	:	125.7	116.4	114.4
Density (gm/cc @ 60 °F)	:	0.7766	0.7660	0.7635
Gravity (°API @ 60 °F)	:	50.5	53.1	53.6

Octanes Plus Properties

Mol %	:	3.23	2.16	1.72
Molecular Weight	:	143.2	134.5	131.8
Density (gm/cc @ 60 °F)	:	0.7949	0.7861	0.7832
Gravity (°API @ 60 °F)	:	46.3	48.3	49.0

Decanes Plus Properties

Mol %	:	1.45	0.85	0.62
Molecular Weight	:	180.0	167.2	165.3
Density (gm/cc @ 60 °F)	:	0.8283	0.8173	0.8157
Gravity (°API @ 60 °F)	:	39.2	41.5	41.8

Undecanes Plus Properties

Mol %	:	1.03	0.57	0.44
Molecular Weight	:	198.8	183.4	178.1
Density (gm/cc @ 60 °F)	:	0.8432	0.8311	0.8267
Gravity (°API @ 60 °F)	:	36.2	38.6	39.5

Dodecanes Plus Properties

Molecular Weight	:	213.7	200.3	191.1
Density (gm/cc @ 60 °F)	:	0.8542	0.8443	0.8372
Gravity (°API @ 60 °F)	:	34.0	35.9	37.4

* Dew Point fluid composition by material balance

Recovery Factor,500 psi abandonment pressure:	0.8984	0.8856	0.8739

PRODUCED WELLSTREAM COMPOSITIONS

Pressure (psig):		3010	2498	2018
Component		Mol %	Mol %	Mol %
Hydrogen Sulphide	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.37	0.37	0.37
Nitrogen	N2	0.54	0.55	0.55
Methane	C1	76.61	77.39	78.01
Ethane	C2	9.57	9.63	9.71
Propane	C3	5.32	5.26	5.25
Iso-Butane	iC4	1.28	1.25	1.25
N-Butane	nC4	1.66	1.61	1.61
Iso-Pentane	iC5	0.61	0.58	0.59
N-Pentane	nC5	0.55	0.53	0.52
Hexanes	C6	0.80	0.70	0.68
Heptanes	C7	1.47	1.27	0.90
Octanes	C8	0.49	0.39	0.25
Nonanes	C9	0.37	0.27	0.18
Decanes	C10	0.13	0.08	0.06
Undecanes	C11	0.09	0.05	0.03
Dodecanes Plus	C12+	0.14	0.07	0.04
TOTAL		100.00	100.00	100.00

Stream Properties

Molecular Weight	:	23.99	23.27	22.64
Gravity (AIR = 1.000)	:	0.832	0.807	0.785
Gross HV (BTU/SCF)	:	1427	1388	1354
Nett HV (BTU/SCF)	:	1299	1262	1231
Wobbe Index	:	1565	1545	1529
Critical Pressure (psia)	:	652.9	655.1	657.0
Critical Temperature (°R)	:	420.5	415.3	411.0

G P M Content

Ethane Plus	:	6.956	6.590	6.293
Propane Plus	:	4.395	4.013	3.694
Butanes Plus	:	2.928	2.562	2.246
Pentanes Plus	:	1.985	1.645	1.329

Heptanes Plus Properties

Mol %	:	2.69	2.13	1.46
Molecular Weight	:	109.5	106.5	105.6
Density (gm/cc @ 60 °F)	:	0.7577	0.7538	0.7528
Gravity (°API @ 60 °F)	:	55.1	56.0	56.3

Octanes Plus Properties

Mol %	:	1.22	0.86	0.56
Molecular Weight	:	125.9	121.9	121.1
Density (gm/cc @ 60 °F)	:	0.7768	0.7724	0.7715
Gravity (°API @ 60 °F)	:	50.5	51.5	51.7

Decanes Plus Properties

Mol %	:	0.36	0.20	0.13
Molecular Weight	:	156.5	152.1	148.2
Density (gm/cc @ 60 °F)	:	0.8078	0.8037	0.8000
Gravity (°API @ 60 °F)	:	43.5	44.4	45.2

Undecanes Plus Properties

Mol %	:	0.23	0.12	0.07
Molecular Weight	:	169.2	164.2	160.4
Density (gm/cc @ 60 °F)	:	0.8192	0.8148	0.8114
Gravity (°API @ 60 °F)	:	41.1	42.0	42.7

Dodecanes Plus Properties

Molecular Weight	:	183.5	176.5	170.5
Density (gm/cc @ 60 °F)	:	0.8312	0.8254	0.8203
Gravity (°API @ 60 °F)	:	38.6	39.8	40.8

Recovery Factor,500 psi abandonment pressure: 0.8576 0.8333 0.7934

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PRODUCED WELLSTREAM COMPOSITIONS

Pressure (psig):		1502	998	510
Component		Mol %	Mol %	Mol %
Hydrogen Sulphide	H_2S	0.00	0.00	0.00
Carbon Dioxide	CO_2	0.38	0.38	0.38
Nitrogen	N_2	0.55	0.55	0.52
Methane	C1	78.47	78.18	76.17
Ethane	C2	9.92	10.15	10.52
Propane	C3	5.25	5.40	6.00
Iso−Butane	iC4	1.25	1.29	1.54
N−Butane	nC4	1.62	1.66	1.99
Iso−Pentane	iC5	0.58	0.61	0.77
N−Pentane	nC5	0.52	0.55	0.70
Hexanes	C6	0.64	0.61	0.79
Heptanes	C7	0.46	0.36	0.30
Octanes	C8	0.17	0.13	0.16
Nonanes	C9	0.11	0.08	0.12
Decanes	C10	0.04	0.03	0.02
Undecanes	C11	0.02	0.01	0.01
Dodecanes Plus	C12+	0.02	0.01	0.01
TOTAL		100.00	100.00	100.00

Stream Properties

Molecular Weight	:	22.08	22.01	22.78
Gravity (AIR = 1.000)	:	0.765	0.763	0.790
Gross HV (BTU/SCF)	:	1324	1321	1363
Nett HV (BTU/SCF)	:	1202	1199	1239
Wobbe Index	:	1513	1512	1533
Critical Pressure (psia)	:	659.0	659.5	657.7
Critical Temperature (°R)	:	407.1	407.2	414.9

G P M Content

Ethane Plus	:	6.045	6.090	6.728
Propane Plus	:	3.390	3.373	3.912
Butanes Plus	:	1.942	1.884	2.257
Pentanes Plus	:	1.022	0.938	1.125

Heptanes Plus Properties

Mol %	:	0.82	0.62	0.62
Molecular Weight	:	106.4	105.2	106.8
Density (gm/cc @ 60 °F)	:	0.7538	0.7523	0.7543
Gravity (°API @ 60 °F)	:	56.0	56.4	55.9

Octanes Plus Properties

Mol %	:	0.36	0.26	0.32
Molecular Weight	:	119.7	118.0	116.9
Density (gm/cc @ 60 °F)	:	0.7699	0.7680	0.7666
Gravity (°API @ 60 °F)	:	52.1	52.6	52.9

Decanes Plus Properties

Mol %	:	0.08	0.05	0.04
Molecular Weight	:	145.0	142.0	144.0
Density (gm/cc @ 60 °F)	:	0.7969	0.7939	0.7958
Gravity (°API @ 60 °F)	:	45.9	46.6	46.1

Undecanes Plus Properties

Mol %	:	0.04	0.02	0.02
Molecular Weight	:	156.1	154.0	154.0
Density (gm/cc @ 60 °F)	:	0.8074	0.8055	0.8055
Gravity (°API @ 60 °F)	:	43.6	44.0	44.0

Dodecanes Plus Properties

Molecular Weight	:	165.1	161.0	161.0
Density (gm/cc @ 60 °F)	:	0.8156	0.8119	0.8119
Gravity (°API @ 60 °F)	:	41.8	42.6	42.6

Recovery Factor,500 psi abandonment pressure:	0.7064	0.5305	0.0124

CALCULATED RETROGRADE LIQUID COMPOSITIONS

Pressure (psig):		4034	3523	3010
Component		Mol %	Mol %	Mol %
Hydrogen Sulphide	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.28	0.28	0.28
Nitrogen	N2	0.31	0.30	0.28
Methane	C1	53.06	50.30	47.93
Ethane	C2	9.81	9.98	10.16
Propane	C3	6.27	6.68	6.98
Iso–Butane	iC4	2.04	2.22	2.37
N–Butane	nC4	3.08	3.26	3.43
Iso–Pentane	iC5	1.66	1.73	1.80
N–Pentane	nC5	1.63	1.70	1.75
Hexanes	C6	3.30	3.62	3.90
Heptanes Plus	C7+	18.56	19.93	21.12
TOTAL		100.00	100.00	100.00

Stream Properties

Molecular Weight	:	49.4	51.0	52.4
Density @ P & T	:	0.496	0.499	0.500

Hexanes Plus Properties

Mol %	:	21.86	23.55	25.02
Molecular Weight	:	135.1	132.0	129.5
Density (gm/cc @ 60 °F)	:	0.769	0.766	0.763
Gravity (°API @ 60 °F)	:	52.3	53.1	53.8

Heptanes Plus Properties

Molecular Weight	:	144.2	140.7	137.9
Density (gm/cc @ 60 °F)	:	0.779	0.776	0.773
Gravity (°API @ 60 °F)	:	49.9	50.7	51.4

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CALCULATED RETROGRADE LIQUID COMPOSITIONS

Pressure (psig):		2498	2018	1502
Component		Mol %	Mol %	Mol %
Hydrogen Sulphide	H_2S	0.00	0.00	0.00
Carbon Dioxide	CO_2	0.27	0.25	0.22
Nitrogen	N_2	0.25	0.22	0.18
Methane	C1	44.72	38.11	33.66
Ethane	C2	9.83	9.47	8.59
Propane	C3	7.19	7.48	7.60
Iso–Butane	iC4	2.51	2.66	2.73
N–Butane	nC4	3.65	3.89	3.98
Iso–Pentane	iC5	1.91	2.05	2.17
N–Pentane	nC5	1.84	2.00	2.09
Hexanes	C6	4.34	4.87	5.29
Heptanes Plus	C7+	23.49	29.00	33.49
TOTAL		100.00	100.00	100.00

Stream Properties

Molecular Weight	:	55.5	62.3	67.4
Density @ P & T	:	0.509	0.532	0.543

Hexanes Plus Properties

Mol %	:	27.83	33.87	38.78
Molecular Weight	:	128.1	127.1	126.0
Density (gm/cc @ 60 °F)	:	0.761	0.760	0.759
Gravity (°API @ 60 °F)	:	54.1	54.4	54.7

Heptanes Plus Properties

Molecular Weight	:	136.3	134.3	132.6
Density (gm/cc @ 60 °F)	:	0.771	0.769	0.768
Gravity (°API @ 60 °F)	:	51.8	52.3	52.7

CALCULATED RETROGRADE LIQUID COMPOSITIONS

Pressure (psig):		998	510 *
Component		Mol %	Mol %
Hydrogen Sulphide	H2S	0.00	0.00
Carbon Dioxide	CO2	0.18	0.09
Nitrogen	N2	0.11	0.03
Methane	C1	26.06	10.86
Ethane	C2	7.51	5.10
Propane	C3	7.52	6.36
Iso-Butane	iC4	2.87	2.85
N-Butane	nC4	4.28	4.16
Iso-Pentane	iC5	2.36	2.38
N-Pentane	nC5	2.30	2.34
Hexanes	C6	6.29	7.57
Heptanes Plus	C7+	40.52	58.26
TOTAL		100.00	100.00

Stream Properties

Molecular Weight	:	76.4	97.0
Density @ P & T	:	0.565	0.607

Hexanes Plus Properties

Mol %	:	46.81	65.83
Molecular Weight	:	125.9	127.1
Density (gm/cc @ 60 °F)	:	0.759	0.761
Gravity (°API @ 60 °F)	:	54.7	54.4

Heptanes Plus Properties

Molecular Weight	:	132.4	132.7
Density (gm/cc @ 60 °F)	:	0.767	0.768
Gravity (°API @ 60 °F)	:	52.7	52.7

* Abandonment Pressure Liquid Phase analysed

EQUILIBRIUM RATIOS (K – VALUES) *

PRESSURE (psig)

Component		4034	3523	3010	2498	2018	1502	998	510
Carbon Dioxide	CO2	1.290	1.297	1.323	1.362	1.496	1.702	2.111	4.000
Nitrogen	N2	1.653	1.775	1.950	2.190	2.530	3.005	4.896	17.333
Methane	C1	1.401	1.502	1.598	1.730	2.047	2.331	3.000	7.014
Ethane	C2	0.982	0.963	0.942	0.979	1.025	1.154	1.351	2.057
Propane	C3	0.874	0.808	0.762	0.732	0.702	0.691	0.718	0.945
Iso–Butane	iC4	0.675	0.599	0.542	0.499	0.468	0.458	0.450	0.570
N–Butane	nC4	0.585	0.532	0.484	0.441	0.413	0.407	0.388	0.466
Iso–Pentane	iC5	0.421	0.379	0.341	0.306	0.285	0.267	0.259	0.303
N–Pentane	nC5	0.391	0.346	0.313	0.285	0.262	0.250	0.239	0.278
Hexanes	C6	0.319	0.255	0.206	0.162	0.139	0.121	0.097	0.098
Heptanes Plus	C7+	0.219	0.167	0.127	0.091	0.051	0.024	0.015	0.011

* Mol percent Component (i) in Produced Gas Phase divided by
Mol percent Component (i) in Calculated Liquid Phase.

P E T R O L A B

CALCULATED CUMULATIVE RECOVERY DURING DEPLETION
RFS – AD # 1131

Cumulative Recovery per MMSCF of Original Fluid*	Initial In Place	Dew Point 4915	4034	3523	3010	2498	2018	1502	998	510
			Reservoir Pressure							
Well Stream – MSCF	1000	0	77.62	145.58	234.94	345.05	465.37	598.61	725.52	847.44
Stock Tank Liquid – °API @ 60 °F		64.8	67.8	68.6	70.3	71.5	73.1	74.9	76.4	78.8
Cumulative Produced (Bbl)	0.00	0.00	5.12	8.76	12.55	16.23	19.16	21.14	22.63	24.45
Remaining in Vapor (Bbl)	85.19	85.19	56.32	40.47	27.38	17.73	10.29	4.42	2.18	1.36
In Retrograde Liquid (Bbl)	0.00	0.00	23.76	35.96	45.26	51.23	55.75	59.63	60.38	59.37
Primary Separator Gas – MSCF	884.12	0.00	70.26	132.90	216.56	321.01	436.70	566.67	691.03	809.48
Second Stage Gas – MSCF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stock Tank Gas – MSCF	38.35	0.00	2.47	4.27	6.20	8.14	9.79	11.01	12.01	13.56

Total " Plant Products " – Gallons

In Well Stream :

Ethane	2583	0	200	375	604	888	1200	1554	1899	2242
Propane	1525	0	117	218	350	509	684	876	1065	1267
Butanes	1058	0	79	146	230	331	441	564	684	822
Pentanes Plus	3632	0	224	388	565	746	906	1042	1161	1299

In Primary Separator Gas :

Ethane	2373	0	183	341	547	802	1081	1396	1702	2008
Propane	1201	0	94	177	285	419	567	732	896	1068
Butanes	606	0	48	91	148	220	303	399	496	604
Pentanes Plus	287	0	23	44	71	106	147	200	255	312

In Secondary Separator Gas :

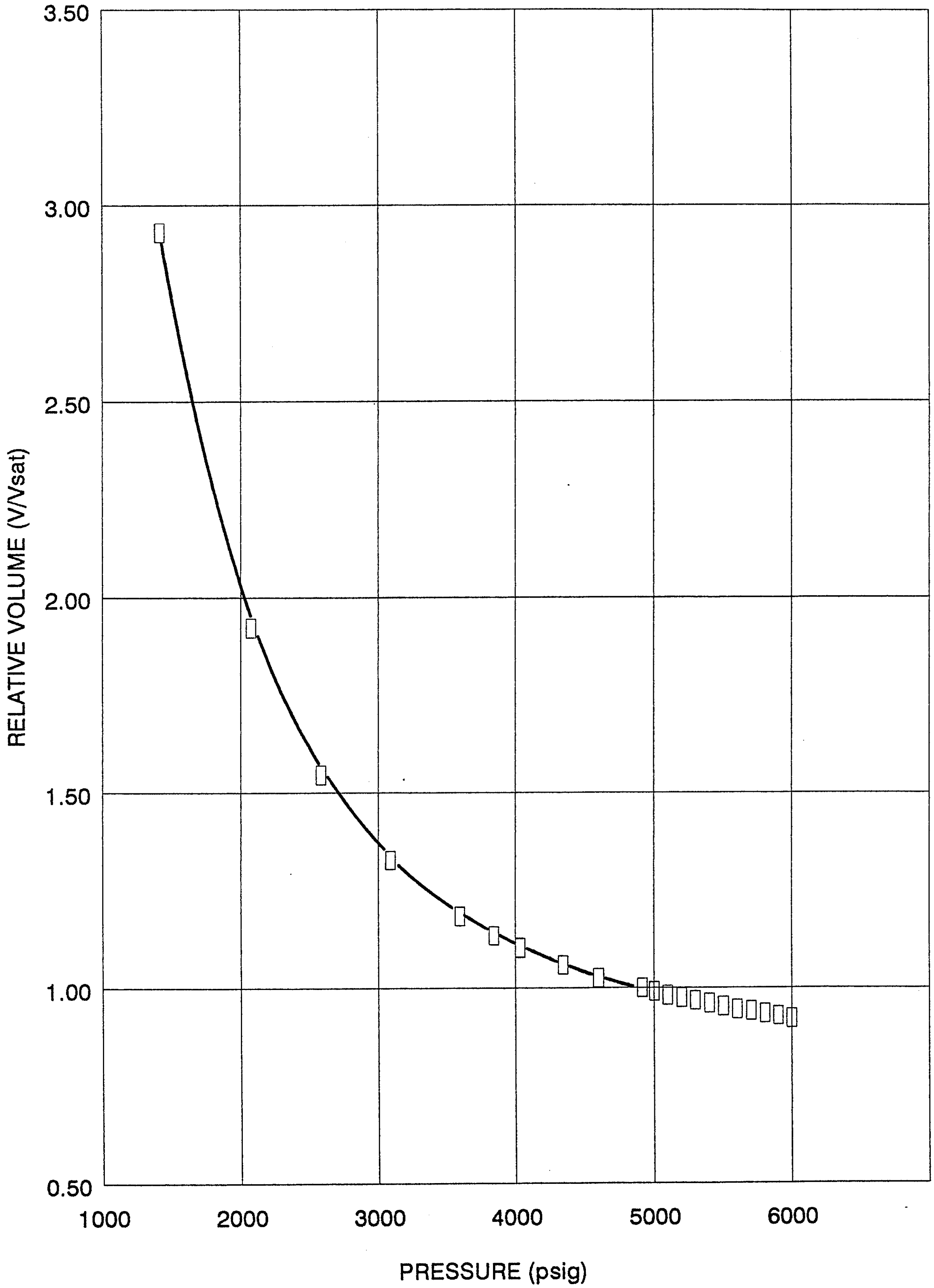
Ethane	0	0	0	0	0	0	0	0	0	0
Propane	0	0	0	0	0	0	0	0	0	0
Butanes	0	0	0	0	0	0	0	0	0	0
Pentanes Plus	0	0	0	0	0	0	0	0	0	0

Gas Oil Ratio *

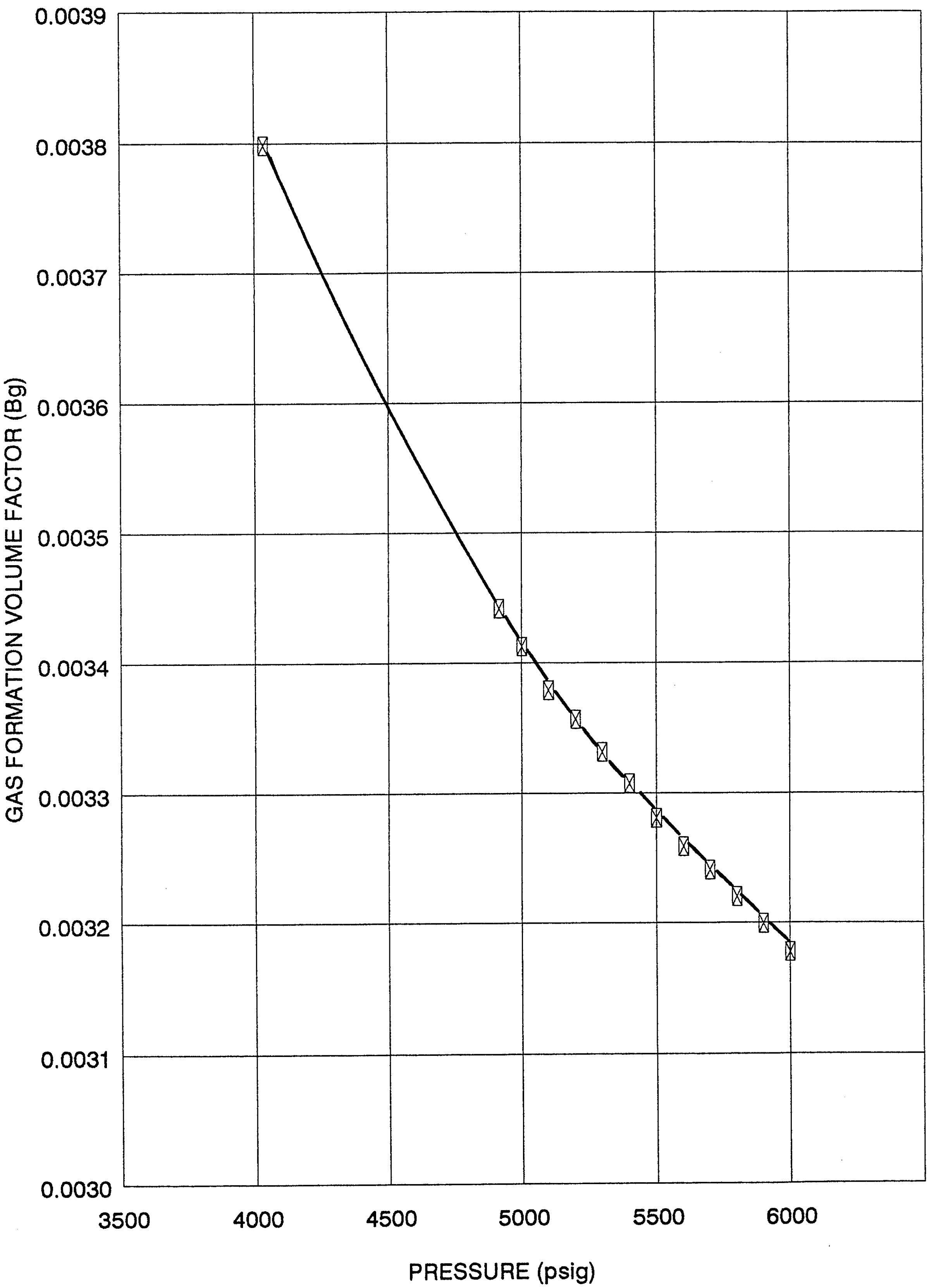
1st Sep. Gas/Stock Tank Liquid (SCF/BBL)		10378	13734	17179	22052	28420	39542	65461	83752	64759
1st+2nd Sep. Gas/Stock Tank Liquid (SCF/BBL)		10378	13734	17179	22052	28420	39542	65461	83752	64759
1st Sep. Gas/Produced WellStream (MSCF/MMSCF)		884	905	922	936	949	961	975	980	972
1st+2nd Sep. Gas/Produced WS (MSCF/MMSCF)		884	905	922	936	949	961	975	980	972
Stock Tank Liquid/Produced WS (STB/MMSCF)		85.19	65.91	53.65	42.46	33.38	24.31	14.90	11.70	15.00

* Primary Separator @ 400 psig and 86 °F; Stock Tank @ 14.696 psia and 60 °F; No second stage

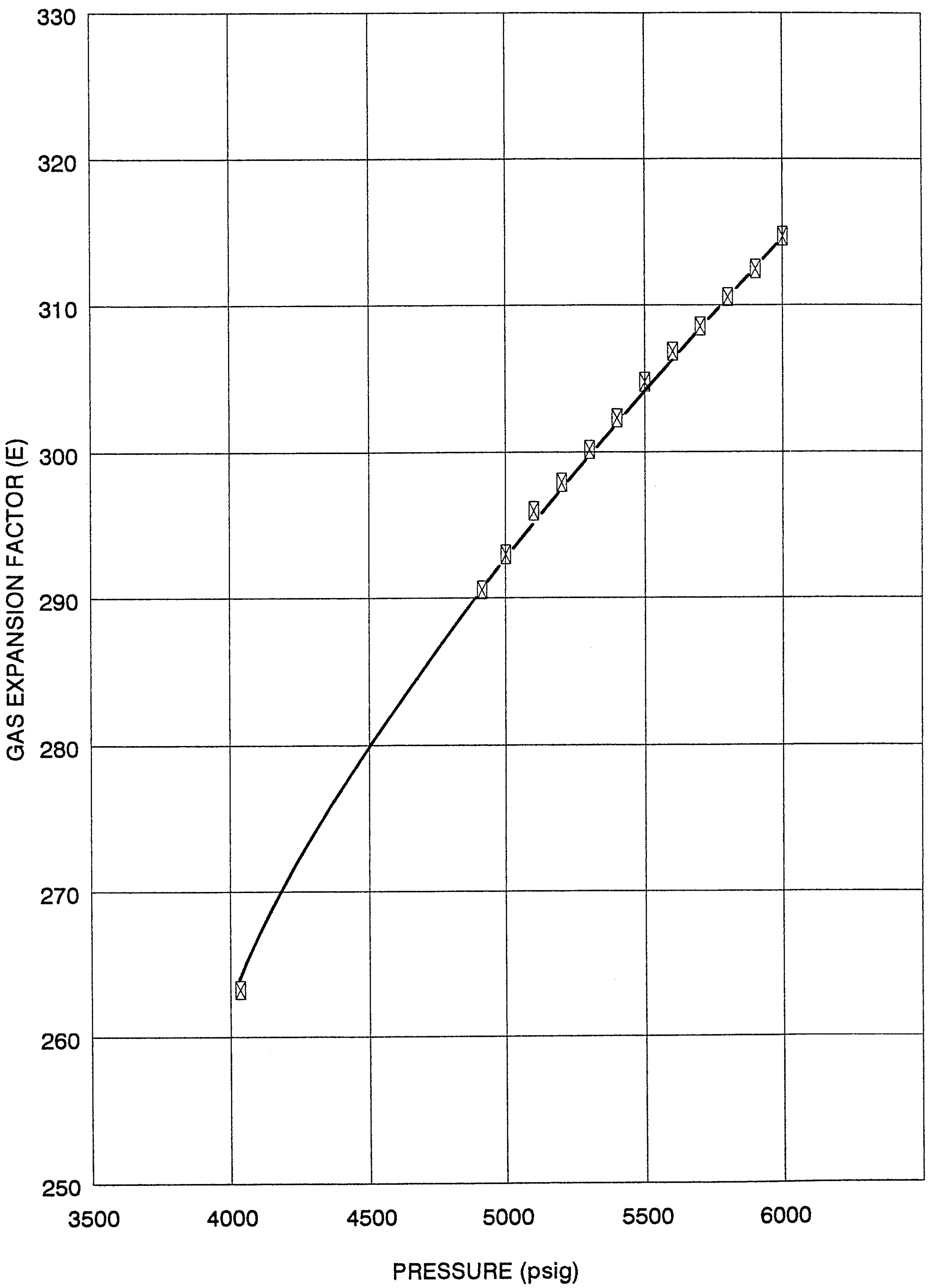
RELATIVE VOLUME



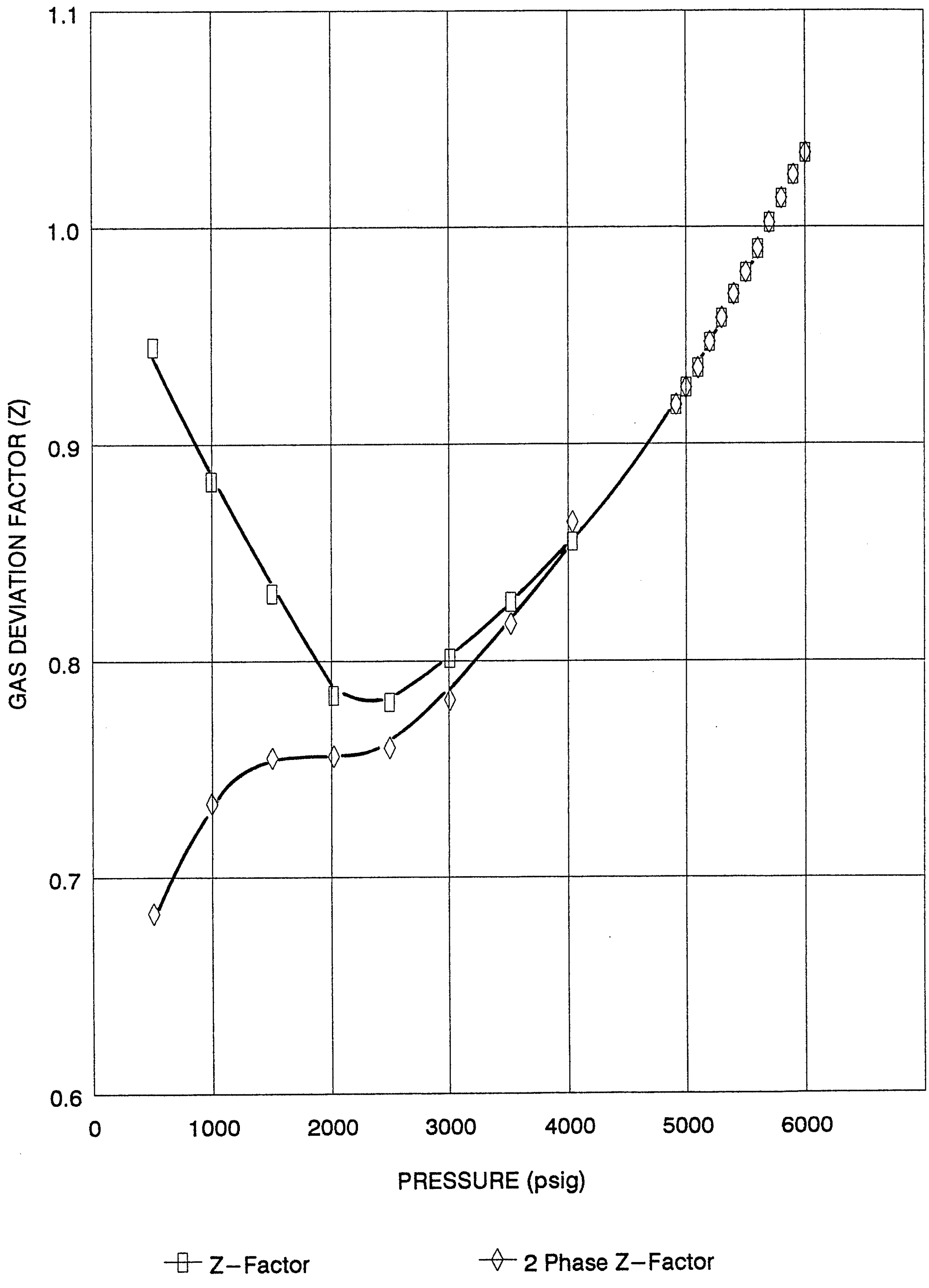
GAS FORMATION VOLUME FACTOR



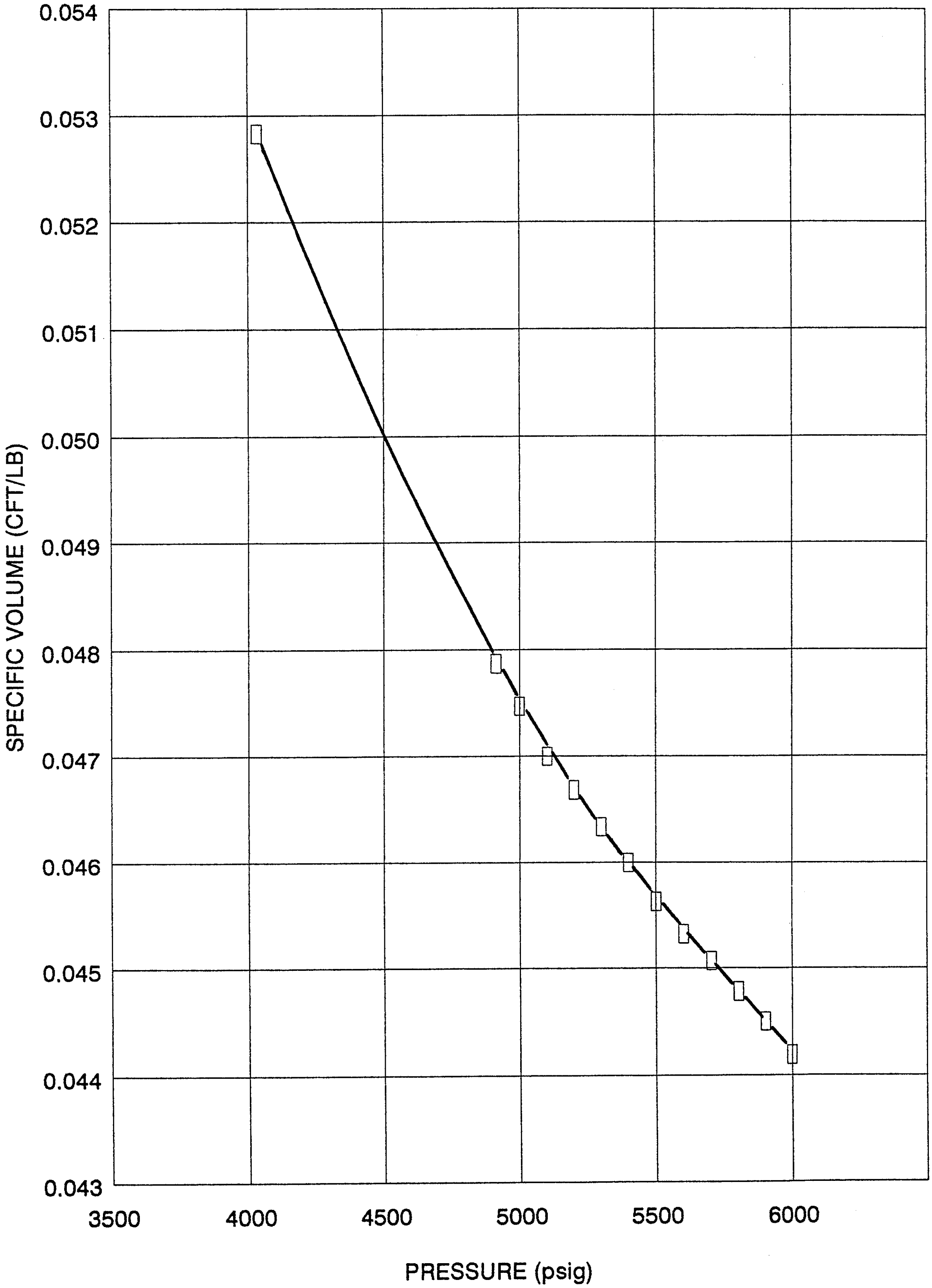
GAS EXPANSION FACTOR



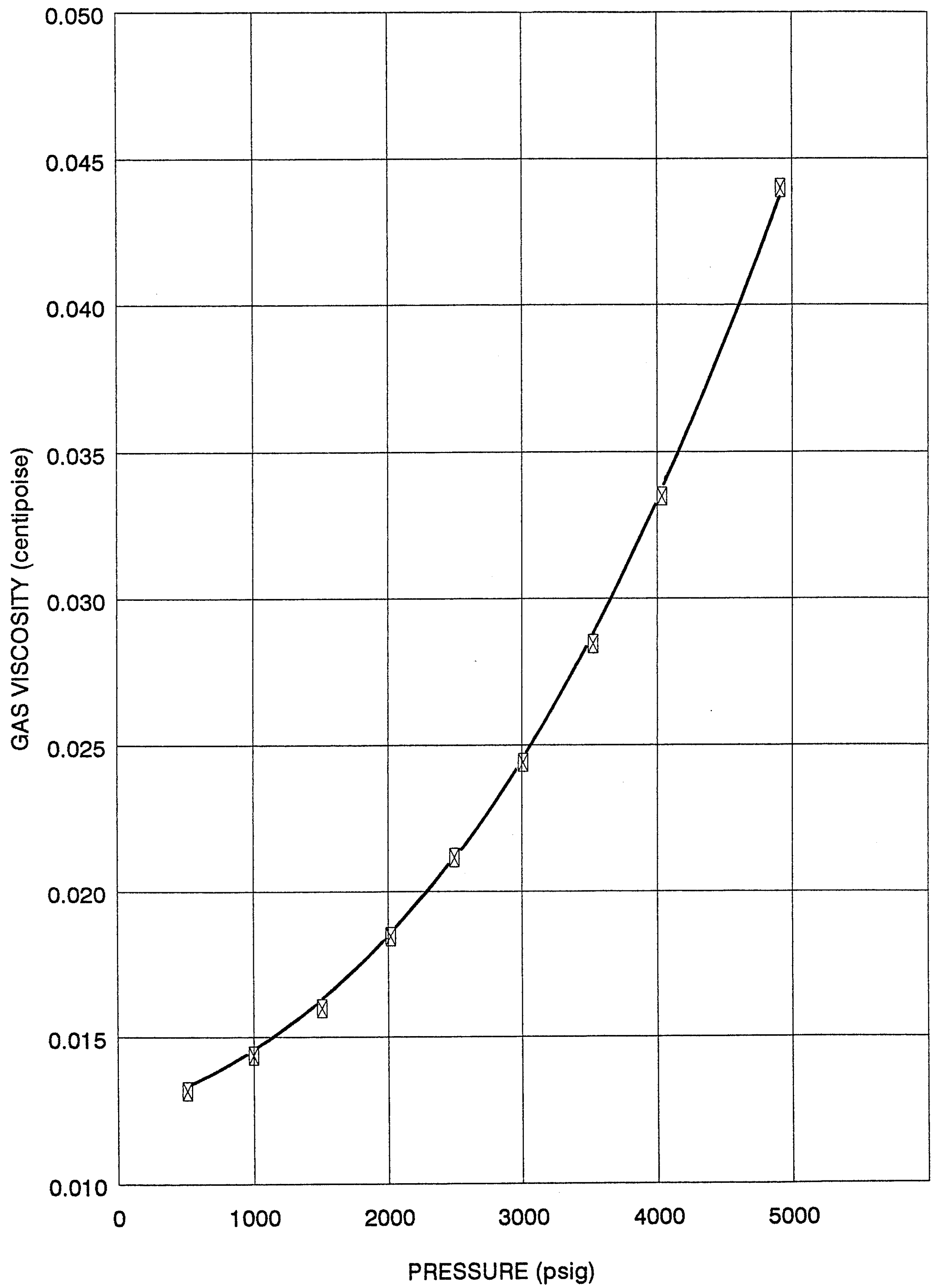
GAS DEVIATION FACTOR



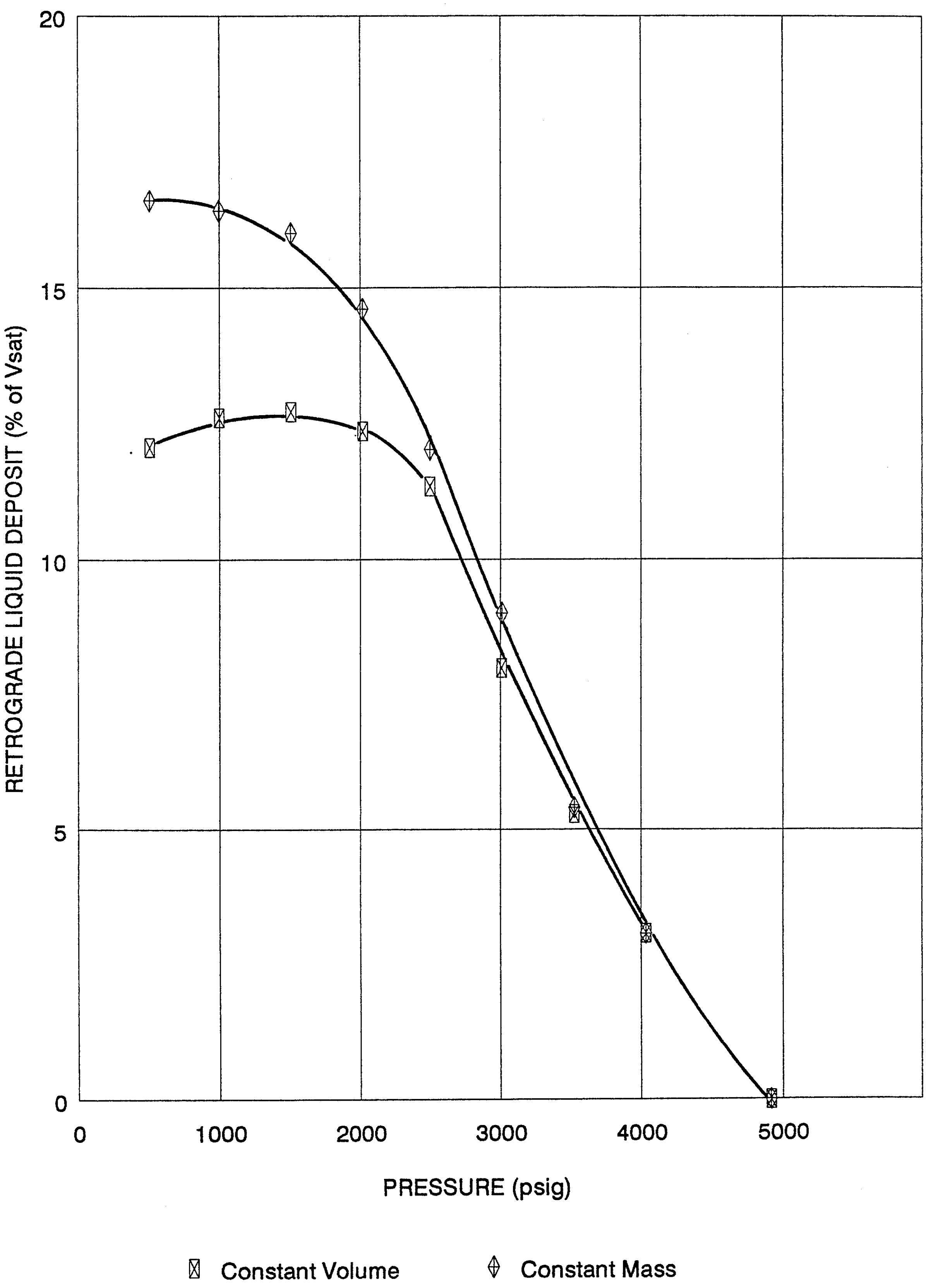
RESERVOIR FLUID SPECIFIC VOLUME



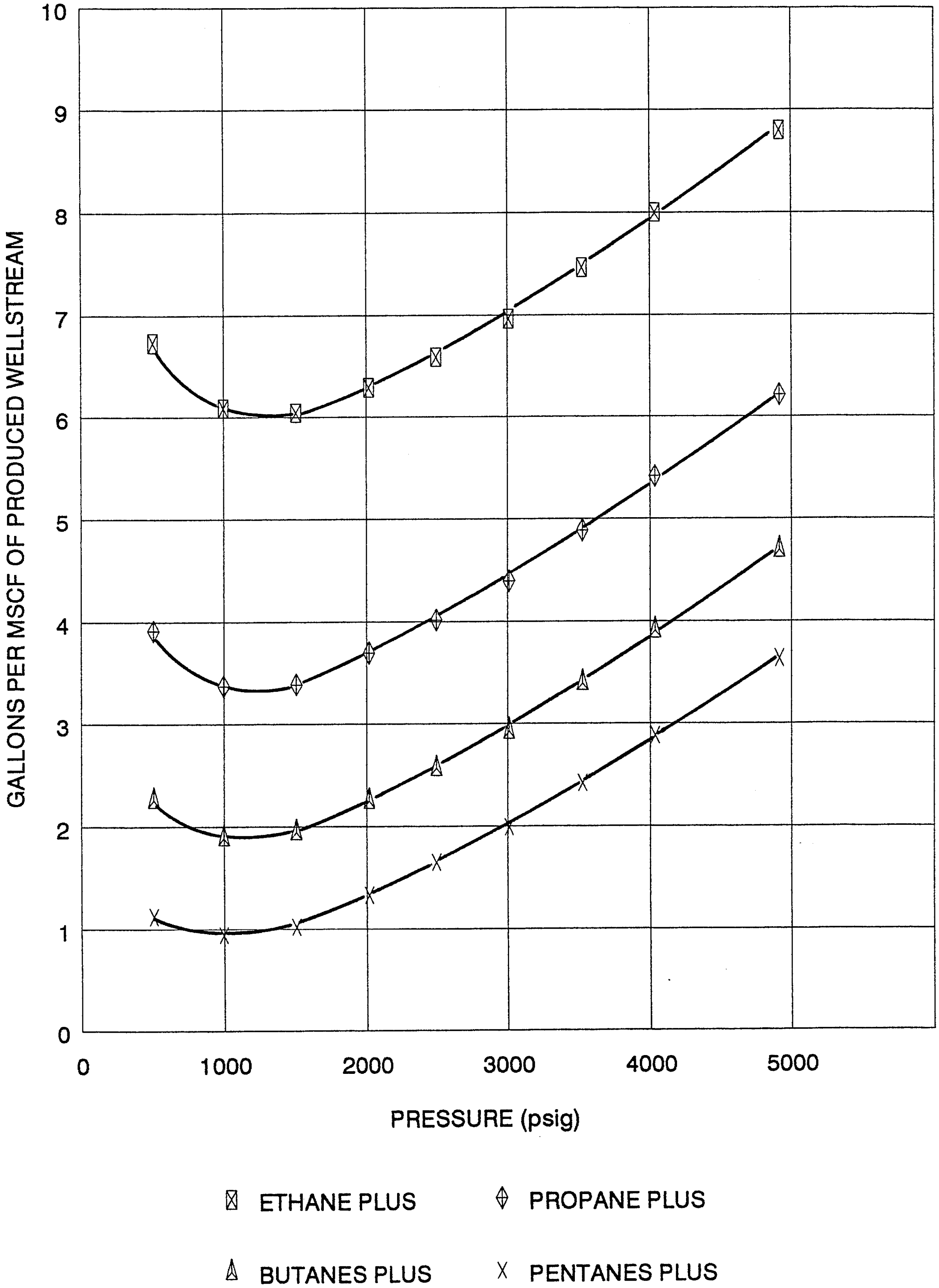
VISCOSITY OF RESERVOIR FLUID



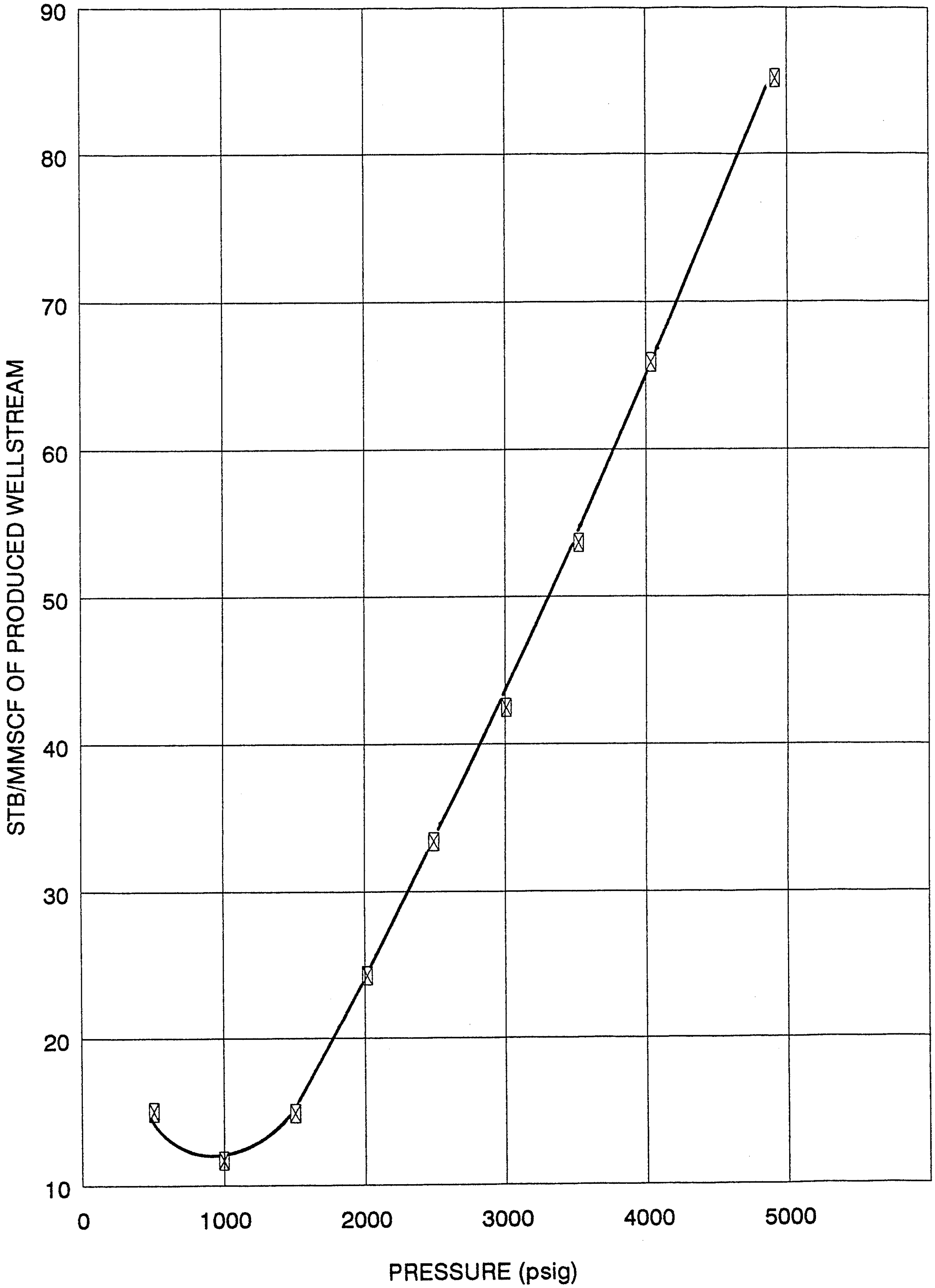
RETROGRADE CONDENSATION



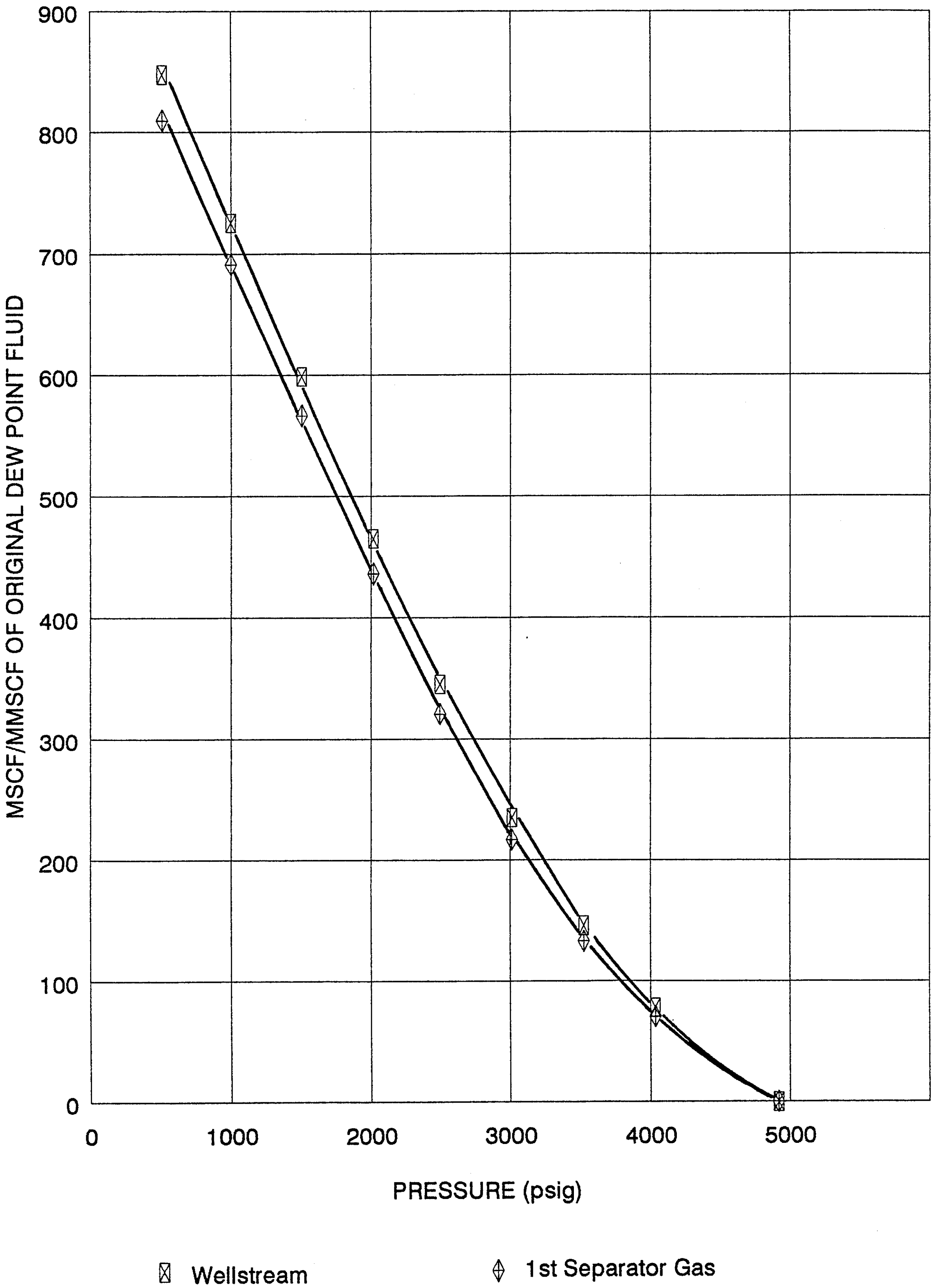
GPM CONTENT IN PRODUCED WELLSTREAM



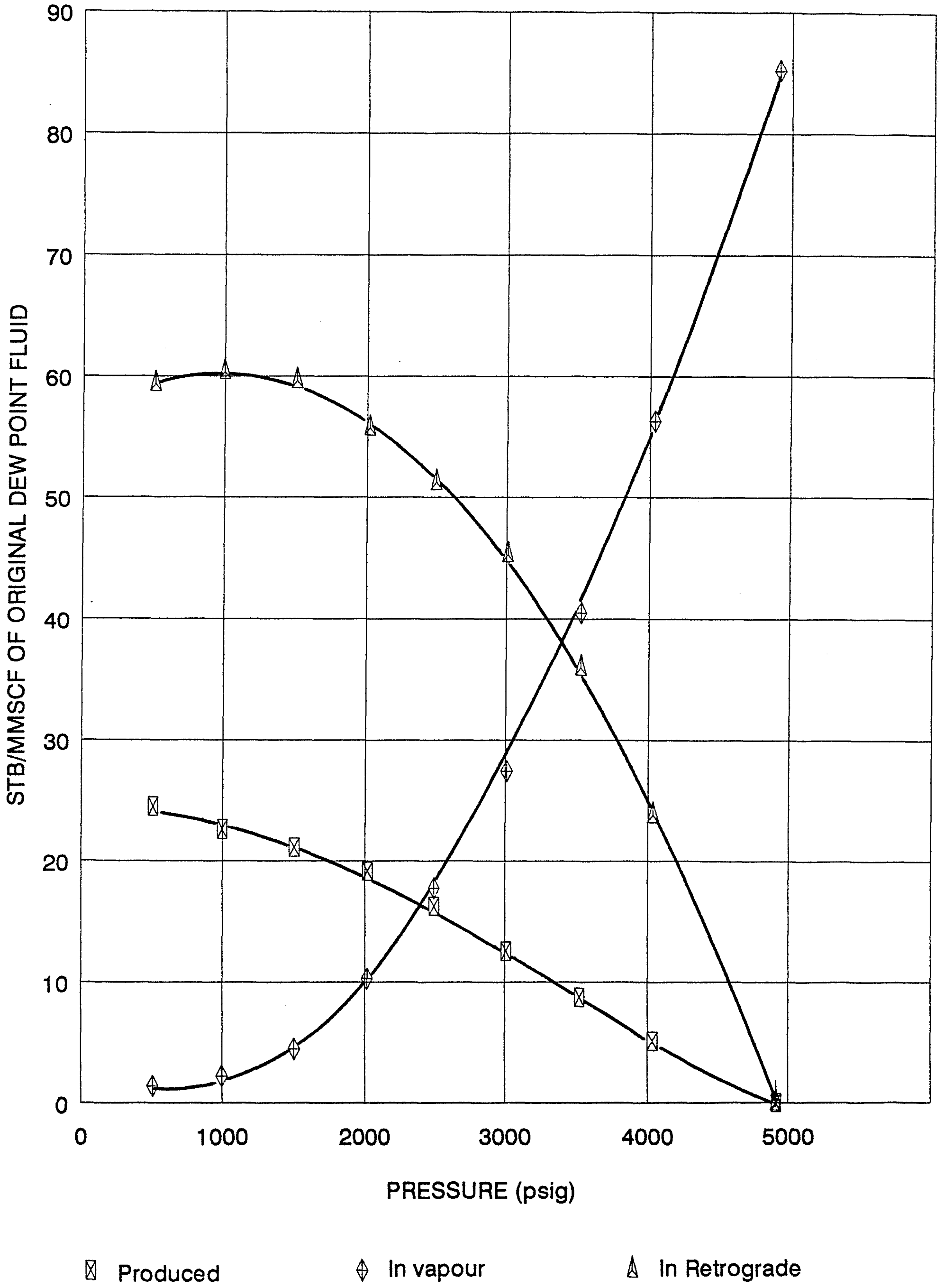
STOCK TANK LIQUID IN PRODUCED WELLSTREAM



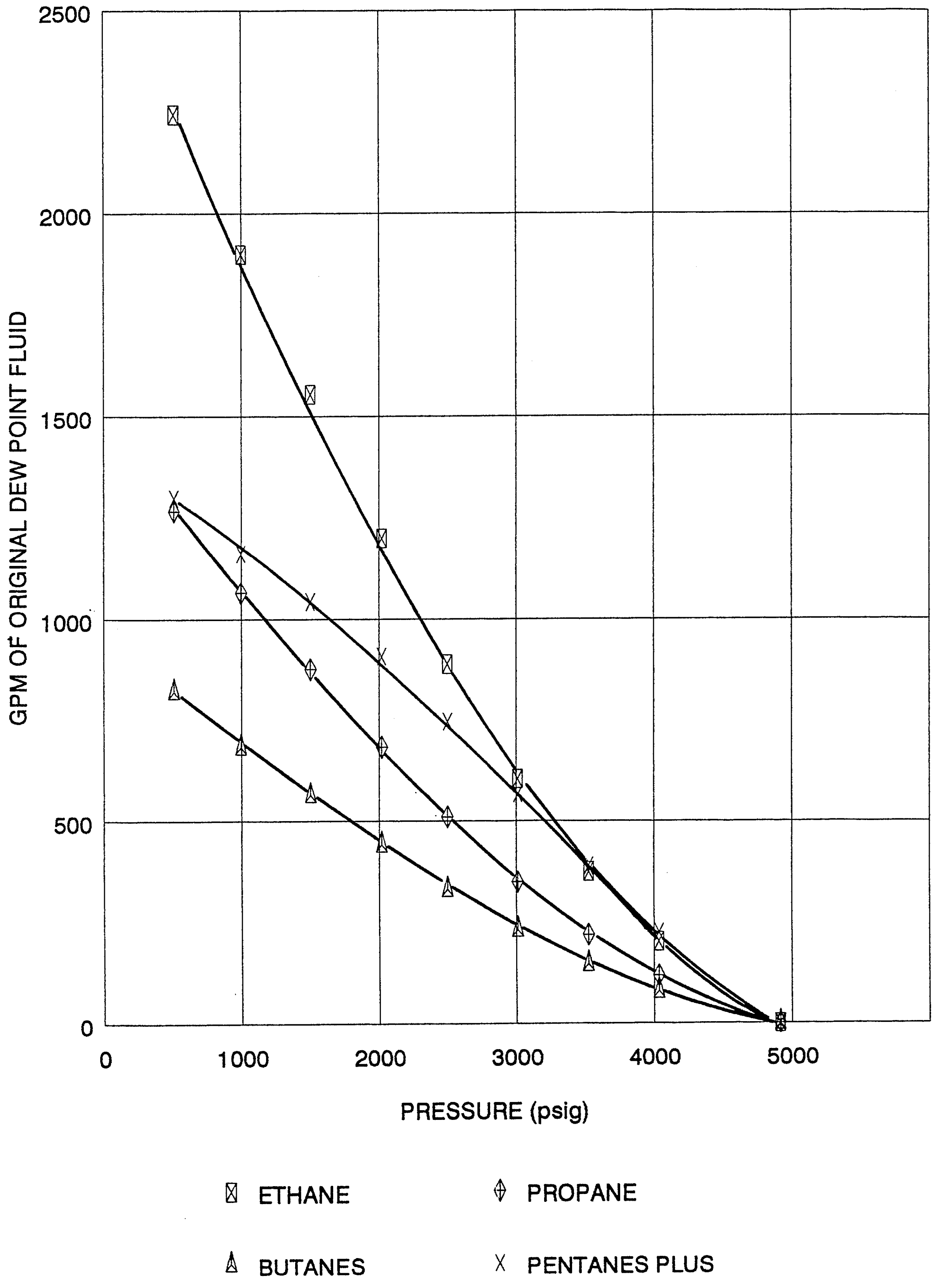
CUMULATIVE VOLUMES PRODUCED



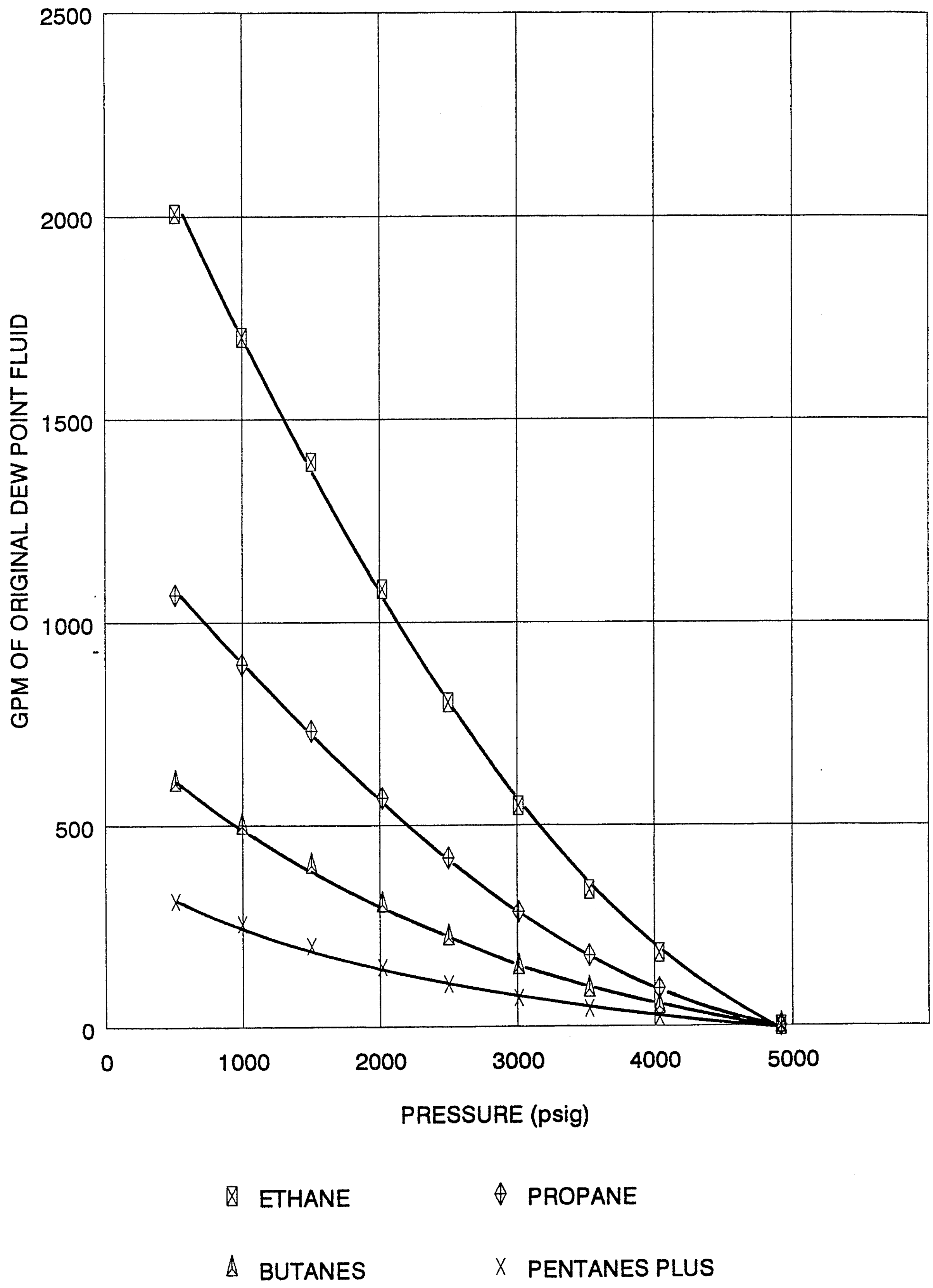
CUMULATIVE STOCK TANK LIQUID PRODUCTION AND CONDENSATION



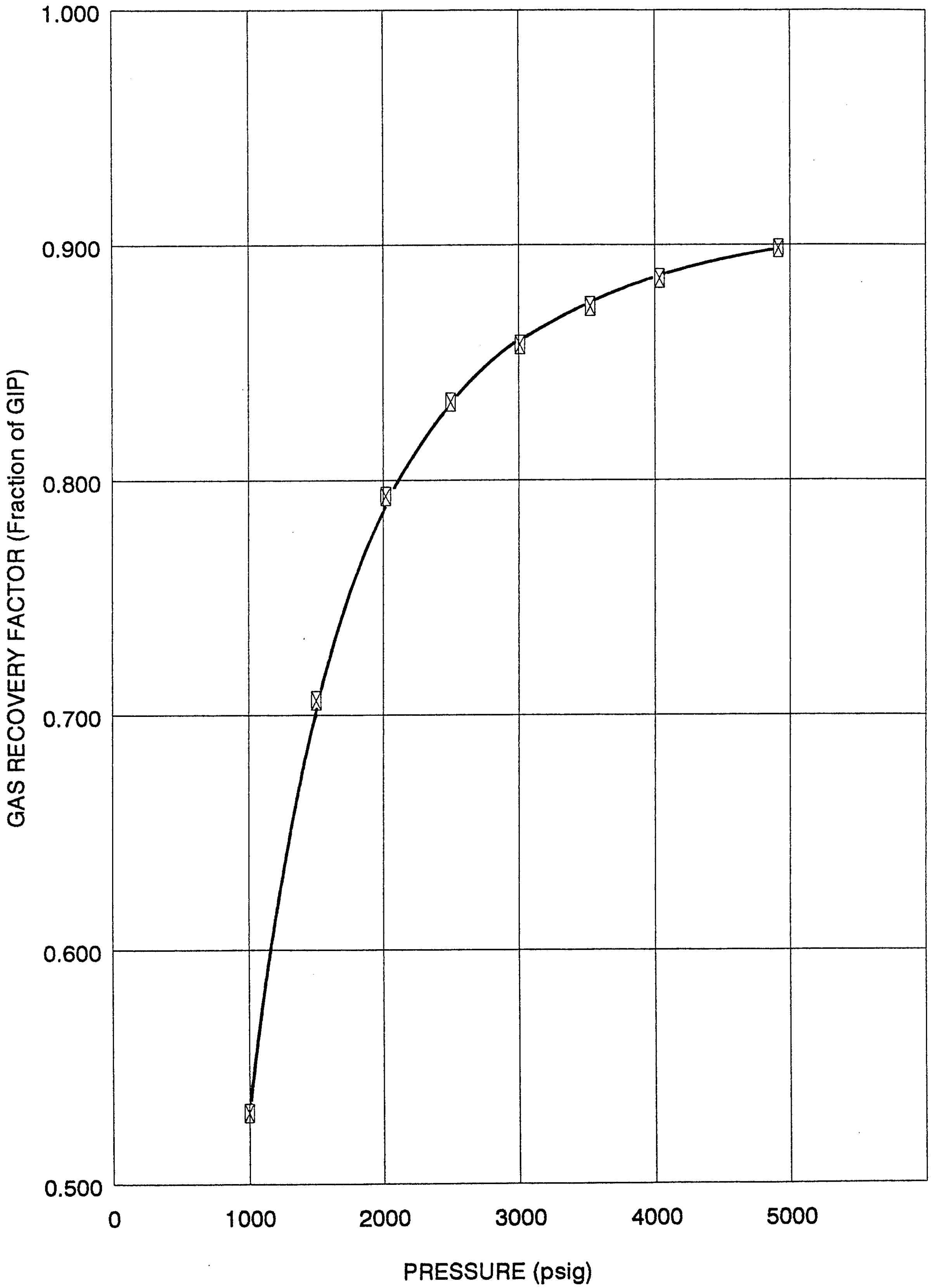
PLANT PRODUCTS
IN PRODUCED WELLSTREAM



PLANT PRODUCTS IN PRIMARY SEPARATOR GAS



GAS RECOVERY FACTOR



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SUMMARY OF RESULTS

RFT Chamber # RFS – AD # 1114

SATURATED VAPOUR:

Reservoir Temperature (°F)	:	194
Dew Point Pressure (psig)	:	4970
Gas Formation Volume Factor (Bg)	:	0.00351
Gas Expansion Factor (E)	:	284.78
Gas Deviation Factor (Z)	:	0.947
Specific Volume (CFT/LB)	:	0.04883
Density (gm/cc)	:	0.3280
Viscosity (centipoise)	:	0.0418
Molecular Weight	:	27.40
Gas Gravity (Air = 1.000)	:	0.986
Gross Heating Value (BTU/ft3)	:	1666

Total Plant Products in Dew Point Fluid (GPMM):

Ethane	:	2548
Propane	:	1412
Butanes	:	1140
Pentanes Plus	:	4059

FLASH DATA:

1st Separator Pressure (psig)	:	400
1st Separator Temperature (°F)	:	86
2nd Separator Pressure (psig)	:	--
2nd Separator Temperature (°F)	:	--
Stock Tank Pressure (psig)	:	0
Stock Tank Temperature (°F)	:	60
1st Separator GOR (scf/bbl)	:	9353
2nd Separator GOR (scf/bbl)	:	--
Stock Tank GOR (scf/bbl)	:	468
Total GOR (scf/bbl)	:	9821
1st Sep.Gas/Prod. WS (mscf/mmscf)	:	869
2nd Sep.Gas/Prod. WS (mscf/mmscf)	:	--
ST T Liq/Produced W/S (stb/mmscf)	:	92.92

Total Plant Products in Primary Separator Gas (GPMM):

Ethane	:	2314
Propane	:	1077
Butanes	:	616
Pentanes Plus	:	337

Total Plant Products in Secondary Separator Gas (GPMM):

Ethane	:	--
Propane	:	--
Butanes	:	--
Pentanes Plus	:	--

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Company : Esso Australia Ltd.	Page : 33 of 60
Well : Blackback # 2	File : E 92039

COMPOSITIONAL ANALYSIS OF BOTTOM HOLE SAMPLE
RFS – AD # 1114

Component		Stock Tank Liquid Mol %	Stock Tank Gas Mol %	Reservoir Fluid Mol %
Hydrogen Sulphide	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.01	0.42	0.41
Nitrogen	N2	0.00	0.44	0.43
Methane	C1	0.45	75.39	73.07
Ethane	C2	0.38	10.03	9.73
Propane	C3	0.74	5.26	5.12
Iso–Butane	iC4	0.63	1.73	1.70
N–Butane	nC4	1.00	1.88	1.85
Iso–Pentane	iC5	1.48	1.02	1.03
N–Pentane	nC5	1.43	0.76	0.78
Hexanes	C6	7.14	1.32	1.50
Heptanes	C7	16.08	1.10	1.56
Octanes	C8	17.61	0.42	0.95
Nonanes	C9	14.52	0.15	0.60
Decanes	C10	9.64	0.05	0.35
Undecanes	C11	5.69	0.02	0.20
Dodecanes Plus	C12+	23.19	0.01	0.72
TOTAL		100.00	100.00	100.00

Ratios

Molar Ratio	:	0.0310	0.9690	1.0000
Mass Ratio	:	0.1500	0.8500	1.0000
Gas Liquid Ratio	:	1.0000	24565 SCF	--

Stream Properties

Molecular Weight	:	132.6	24.0	27.4
Density obs. (gm/cc)	:	0.7834	--	-- @ PT*
Gravity (AIR = 1.000)	:	48.9	0.834	--
GHV (BTU/scf)	:	--	1430	--

Hexanes Plus Properties

Mol %	:	93.86	3.07	5.88
Molecular Weight	:	137.4	94.8	115.9
Density (gm/cc @ 60 F)	:	0.7914	0.6820	0.7422
Gravity (API @ 60 F)	:	47.1	75.8	59.0

Heptanes Plus Properties

Mol %	:	86.73	1.75	4.38
Molecular Weight	:	141.5	102.9	126.5
Density (gm/cc @ 60 F)	:	0.7976	0.6928	0.7614
Gravity (API @ 60 F)	:	45.7	72.5	54.2

Decanes Plus Properties

Mol %	:	38.53	0.08	1.27
Molecular Weight	:	184.0	141.8	181.4
Density (gm/cc @ 60 F)	:	0.8238	0.7352	0.8191
Gravity (API @ 60 F)	:	40.1	60.8	41.1

Undecanes Plus Properties

Mol %	:	28.89	0.03	0.92
Molecular Weight	:	201.7	154.7	200.0
Density (gm/cc @ 60 F)	:	0.8317	0.7468	0.8294
Gravity (API @ 60 F)	:	38.5	161.0	38.9

Dodecanes Plus Properties

Mol %	:	23.19	0.01	0.72
Molecular Weight	:	215.8	168.3	215.1
Density (gm/cc @ 60 F)	:	0.8378	0.7579	0.8369
Gravity (API @ 60 F)	:	37.2	55.0	37.4

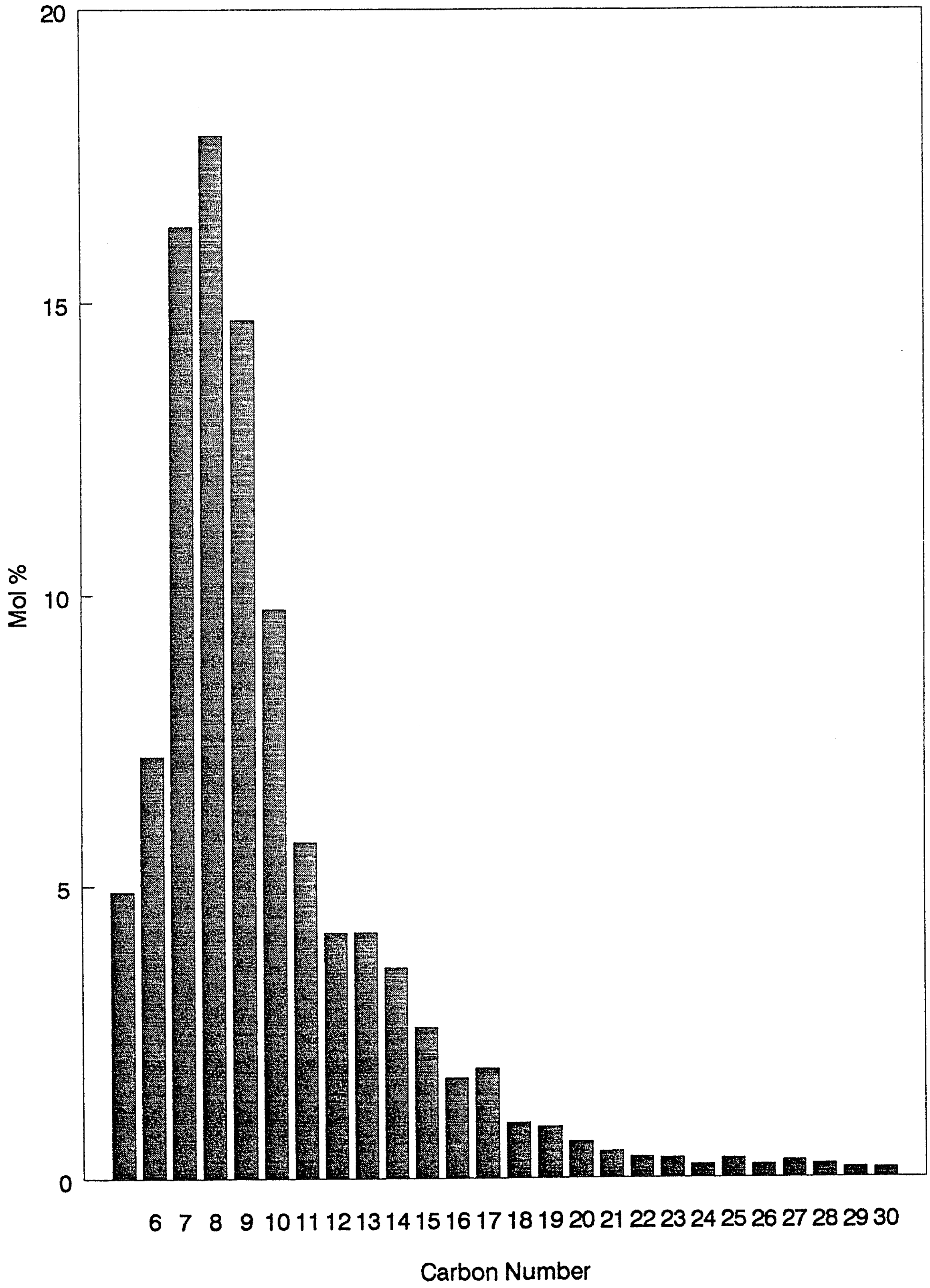
* (P)ressure 4970 psig, (T)emperature 194 °F

FINGERPRINT ANALYSIS
BY CAPILLARY GAS CHROMATOGRAPHY
RFS – AD # 1114

Component		Mol %
Hexanes minus	C6–	4.90
Hexanes	C6	7.23
Heptanes	C7	16.29
Octanes	C8	17.84
Nonanes	C9	14.71
Decanes	C10	9.77
Undecanes	C11	5.77
Dodecanes	C12	4.20
Tridecanes	C13	4.21
Tetradecanes	C14	3.61
Pentadecanes	C15	2.59
Hexadecanes	C16	1.74
Heptadecanes	C17	1.90
Octadecanes	C18	0.95
Nonadecanes	C19	0.88
Eicosanes	C20	0.63
Heneicosanes	C21	0.46
Docosanes	C22	0.36
Tricosanes	C23	0.34
Tetracosanes	C24	0.22
Pentacosanes	C25	0.33
Hexacosanes	C26	0.22
Heptacosanes	C27	0.29
Octacosanes	C28	0.23
Nonacosanes	C29	0.17
Triacontanes plus	C30+	0.16
TOTAL		100.00

Molecular weight:	135.0
Density @ 60 °F:	0.7750

FINGERPRINT ANALYSIS BY CAPILLARY GAS CHROMATOGRAPHY RFS – AD # 1114



CONSTANT MASS STUDY
@ 194 °F

RFS – AD # 1114

Pressure (psig)		Relative Volume (V/Vsat) (1)	Formation Volume Factor (Bg) (2)	Gas Expansion Factor (E) (3)	Deviation Factor (Z)	Specific Volume (CFT/LB)
6000		0.9329	0.00328	305.27	1.066	0.04556
5900		0.9380	0.00329	303.61	1.054	0.04581
5800		0.9433	0.00331	301.92	1.042	0.04606
5700		0.9487	0.00333	300.18	1.030	0.04633
5600		0.9544	0.00335	298.40	1.018	0.04661
5500		0.9621	0.00338	296.00	1.008	0.04698
5400		0.9682	0.00340	294.13	0.996	0.04728
5300		0.9746	0.00342	292.22	0.984	0.04759
5200		0.9811	0.00345	290.26	0.972	0.04791
5100		0.9890	0.00347	287.95	0.961	0.04830
5000		0.9972	0.00350	285.59	0.950	0.04870
4970	*	1.0000	0.00351	284.78	0.947	0.04883
4045	**	1.1060	0.00388	257.50	0.853	0.05401

* Dew Point Pressure

** Reservoir Pressure

(1) Cubic feet of gas at indicated pressure and temperature per cubic foot at saturation pressure

(2) Cubic feet of gas at indicated pressure and temperature per cubic foot at 14.696 psia and 60 °F

(3) Cubic feet of gas at 14.696 psia and 60 °F per cubic foot at indicated pressure and temperature

CONSTANT MASS STUDY
@ 194 °F

RFS – AD # 1114

Pressure (psig)	Relative Volume (V/Vsat) (1)	Retrograde Liquid Deposit (Bbl/MMSCF) (2)	Retrograde Liquid Deposit (Volume%) (3)
4970 *	1.0000	0.00	0.00
4586	1.0400	10.26	1.64
4328	1.0666	15.18	2.43
4045 **	1.1060	22.20	3.55
3656	1.1701	34.08	5.45
3307	1.2455	44.40	7.10
3062	1.3122	53.45	8.55
2449	1.5981	72.12	11.53
1552	2.6475	92.60	14.81
1004	4.3403	99.92	15.98

* Dew Point Pressure

** Reservoir Pressure

(1) Cubic feet of gas at indicated pressure and temperature per cubic foot at saturation pressure

(2) Barrels of liquid at indicated pressure and temperature per MMSCF of original reservoir fluid

(3) Percent of reservoir hydrocarbon pore space at dew point

P E T R O L A B

CONSTANT VOLUME DEPLETION STUDY @ 194 °F

RFS – AD # 1114

Pressure (psig)		Cumulative Produced Fluid (1)	Deviation Factor (Z) Liberated Gas	Deviation Factor (Z) Two Phase	Gas Viscosity (Centipoise)	Retrograde Liquid (Bbl/MMSCF) (2)	Retrograde Liquid (Vol. %) (3)
4970	*	0.000	0.947	0.947	0.0418	0.00	0.00
4045	**	9.882	0.853	0.863	0.0337	23.15	3.70
3505		16.805	0.829	0.810	0.0284	27.82	4.45
2986		25.157	0.803	0.766	0.0245	44.59	7.13
2525		35.807	0.782	0.753	0.0217	53.46	8.55
2042		48.278	0.791	0.756	0.0187	69.99	11.19
1528		61.186	0.838	0.753	0.0161	81.22	12.99
1019		73.503	0.887	0.731	0.0143	80.57	12.88
519		84.993	0.942	0.669	0.0130	73.94	11.82

* Dew Point Pressure

** Reservoir Pressure

(1) Wellstream produced : Cumulative volume percent of initial fluid

(2) Barrels of liquid at indicated pressure and temperature per MMSCF of original reservoir fluid

(3) Percent of reservoir hydrocarbon pore space at dew point

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PRODUCED WELLSTREAM COMPOSITIONS

Pressure (psig):		4970 *	4045	3505
Component		Mol %	Mol %	Mol %
Hydrogen Sulphide	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.35	0.36	0.36
Nitrogen	N2	0.43	0.43	0.43
Methane	C1	72.17	73.02	74.26
Ethane	C2	9.52	9.54	9.57
Propane	C3	5.12	5.08	5.01
Iso−Butane	iC4	1.68	1.64	1.59
N−Butane	nC4	1.87	1.83	1.76
Iso−Pentane	iC5	1.11	1.07	1.00
N−Pentane	nC5	0.84	0.80	0.75
Hexanes	C6	1.65	1.56	1.42
Heptanes	C7	2.04	2.13	1.82
Octanes	C8	1.12	1.08	0.91
Nonanes	C9	0.69	0.67	0.56
Decanes	C10	0.39	0.34	0.28
Undecanes	C11	0.21	0.16	0.13
Dodecanes Plus	C12+	0.80	0.28	0.15
TOTAL		100.00	100.00	100.00

Stream Properties

Molecular Weight	:	28.37	27.05	25.94
Gravity (AIR = 1.000)	:	0.986	0.939	0.900
Gross HV (BTU/SCF)	:	1666	1594	1535
Nett HV (BTU/SCF)	:	1521	1455	1399
Wobbe Index	:	1678	1645	1617
Critical Pressure (psia)	:	640.4	643.5	646.8
Critical Temperature (°R)	:	450.1	443.1	435.4

G P M Content

Ethane Plus	:	9.159	8.578	8.014
Propane Plus	:	6.611	6.025	5.453
Butanes Plus	:	5.199	4.624	4.071
Pentanes Plus	:	4.059	3.509	2.995

Heptanes Plus Properties

Mol %	:	5.26	4.67	3.85
Molecular Weight	:	124.6	113.1	110.6
Density (gm/cc @ 60 °F)	:	0.7747	0.7613	0.7583
Gravity (°API @ 60 °F)	:	51.0	54.2	54.9

Octanes Plus Properties

Mol %	:	3.22	2.54	2.03
Molecular Weight	:	142.8	127.5	123.7
Density (gm/cc @ 60 °F)	:	0.7939	0.7779	0.7737
Gravity (°API @ 60 °F)	:	46.6	50.2	51.2

Decanes Plus Properties

Mol %	:	1.40	0.78	0.56
Molecular Weight	:	182.3	161.4	153.7
Density (gm/cc @ 60 °F)	:	0.8294	0.8115	0.8044
Gravity (°API @ 60 °F)	:	38.9	42.7	44.2

Undecanes Plus Properties

Mol %	:	1.01	0.44	0.28
Molecular Weight	:	200.9	182.6	173.3
Density (gm/cc @ 60 °F)	:	0.8441	0.8297	0.8220
Gravity (°API @ 60 °F)	:	36.0	38.9	40.5

Dodecanes Plus Properties

Molecular Weight	:	215.1	203.0	196.2
Density (gm/cc @ 60 °F)	:	0.8545	0.8456	0.8404
Gravity (°API @ 60 °F)	:	33.9	35.7	36.7

* Dew Point fluid composition by material balance

Recovery Factor,500 psi abandonment pressure:	0.8959	0.8854	0.8722

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Company : Esso Australia Ltd.	Page: 40 of 60
Well : Blackback # 2	File : E 92039

PRODUCED WELLSTREAM COMPOSITIONS

Pressure (psig):		2986	2525	2042
Component		Mol %	Mol %	Mol %
Hydrogen Sulphide	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.37	0.37	0.37
Nitrogen	N2	0.44	0.45	0.45
Methane	C1	75.19	75.81	76.30
Ethane	C2	9.60	9.63	9.68
Propane	C3	4.95	4.94	4.92
Iso-Butane	iC4	1.52	1.52	1.50
N-Butane	nC4	1.67	1.66	1.65
Iso-Pentane	iC5	0.93	0.90	0.88
N-Pentane	nC5	0.68	0.68	0.65
Hexanes	C6	1.25	1.23	1.16
Heptanes	C7	1.69	1.37	1.18
Octanes	C8	0.79	0.69	0.64
Nonanes	C9	0.50	0.43	0.37
Decanes	C10	0.24	0.19	0.16
Undecanes	C11	0.10	0.08	0.06
Dodecanes Plus	C12+	0.08	0.05	0.03
TOTAL		100.00	100.00	100.00

Stream Properties

Molecular Weight	:	25.18	24.59	24.14
Gravity (AIR = 1.000)	:	0.874	0.853	0.837
Gross HV (BTU/SCF)	:	1493	1461	1437
Nett HV (BTU/SCF)	:	1360	1330	1308
Wobbe Index	:	1597	1582	1570
Critical Pressure (psia)	:	649.1	650.9	652.3
Critical Temperature (°R)	:	429.8	425.6	422.4

G P M Content

Ethane Plus	:	7.603	7.309	7.086
Propane Plus	:	5.034	4.732	4.495
Butanes Plus	:	3.669	3.370	3.138
Pentanes Plus	:	2.644	2.348	2.126

Heptanes Plus Properties

Mol %	:	3.40	2.81	2.44
Molecular Weight	:	108.6	108.1	107.4
Density (gm/cc @ 60 °F)	:	0.7559	0.7552	0.7544
Gravity (°API @ 60 °F)	:	55.5	55.7	55.9

Octanes Plus Properties

Mol %	:	1.71	1.44	1.26
Molecular Weight	:	121.1	119.7	118.2
Density (gm/cc @ 60 °F)	:	0.7708	0.7691	0.7674
Gravity (°API @ 60 °F)	:	51.9	52.3	52.7

Decanes Plus Properties

Mol %	:	0.42	0.32	0.25
Molecular Weight	:	147.8	145.2	142.6
Density (gm/cc @ 60 °F)	:	0.7988	0.7962	0.7936
Gravity (°API @ 60 °F)	:	45.5	46.0	46.6

Undecanes Plus Properties

Mol %	:	0.18	0.13	0.09
Molecular Weight	:	166.1	161.5	157.8
Density (gm/cc @ 60 °F)	:	0.8157	0.8116	0.8082
Gravity (°API @ 60 °F)	:	41.8	42.7	43.4

Dodecanes Plus Properties

Molecular Weight	:	190.0	184.8	179.3
Density (gm/cc @ 60 °F)	:	0.8357	0.8314	0.8269
Gravity (°API @ 60 °F)	:	37.7	38.5	39.4

Recovery Factor,500 psi abandonment pressure: 0.8553 0.8338 0.7925

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PRODUCED WELLSTREAM COMPOSITIONS

Pressure (psig):		1528	1019	519
Component		Mol %	Mol %	Mol %
Hydrogen Sulphide	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.38	0.38	0.38
Nitrogen	N2	0.47	0.46	0.44
Methane	C1	77.03	76.94	75.61
Ethane	C2	9.77	10.00	10.30
Propane	C3	4.91	5.09	5.58
Iso–Butane	iC4	1.51	1.59	1.76
N–Butane	nC4	1.61	1.66	1.92
Iso–Pentane	iC5	0.84	0.83	1.00
N–Pentane	nC5	0.61	0.62	0.73
Hexanes	C6	1.04	1.06	1.21
Heptanes	C7	0.86	0.61	0.42
Octanes	C8	0.46	0.37	0.30
Nonanes	C9	0.30	0.25	0.21
Decanes	C10	0.14	0.10	0.10
Undecanes	C11	0.05	0.03	0.03
Dodecanes Plus	C12+	0.02	0.01	0.01
TOTAL		100.00	100.00	100.00

Stream Properties

Molecular Weight	:	23.47	23.20	23.55
Gravity (AIR = 1.000)	:	0.814	0.804	0.817
Gross HV (BTU/SCF)	:	1400	1386	1406
Nett HV (BTU/SCF)	:	1273	1260	1279
Wobbe Index	:	1552	1545	1555
Critical Pressure (psia)	:	654.5	655.6	655.0
Critical Temperature (°R)	:	417.4	416.1	420.4

G P M Content

Ethane Plus	:	6.746	6.696	7.076
Propane Plus	:	4.131	4.020	4.319
Butanes Plus	:	2.777	2.616	2.780
Pentanes Plus	:	1.775	1.571	1.598

Heptanes Plus Properties

Mol %	:	1.83	1.37	1.07
Molecular Weight	:	108.0	108.0	109.6
Density (gm/cc @ 60 °F)	:	0.7551	0.7550	0.7570
Gravity (°API @ 60 °F)	:	55.7	55.7	55.2

Octanes Plus Properties

Mol %	:	0.97	0.76	0.65
Molecular Weight	:	118.7	117.6	118.4
Density (gm/cc @ 60 °F)	:	0.7680	0.7667	0.7676
Gravity (°API @ 60 °F)	:	52.6	52.9	52.7

Decanes Plus Properties

Mol %	:	0.21	0.14	0.14
Molecular Weight	:	140.9	139.4	138.7
Density (gm/cc @ 60 °F)	:	0.7920	0.7904	0.7898
Gravity (°API @ 60 °F)	:	47.0	47.3	47.5

Undecanes Plus Properties

Mol %	:	0.07	0.04	0.04
Molecular Weight	:	154.7	152.8	150.5
Density (gm/cc @ 60 °F)	:	0.8054	0.8035	0.8014
Gravity (°API @ 60 °F)	:	44.0	44.4	44.9

Dodecanes Plus Properties

Molecular Weight	:	174.0	170.0	161.0
Density (gm/cc @ 60 °F)	:	0.8225	0.8191	0.8112
Gravity (°API @ 60 °F)	:	40.4	41.1	42.8

Recovery Factor,500 psi abandonment pressure: 0.7072 0.5356 0.0292

CALCULATED RETROGRADE LIQUID COMPOSITIONS

Pressure (psig):		4045	3505	2986
Component		Mol %	Mol %	Mol %
Hydrogen Sulphide	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.27	0.28	0.26
Nitrogen	N2	0.33	0.30	0.25
Methane	C1	45.06	42.11	44.43
Ethane	C2	8.66	8.71	8.75
Propane	C3	6.38	6.67	6.67
Iso−Butane	iC4	2.80	2.95	3.05
N−Butane	nC4	3.33	3.57	3.78
Iso−Pentane	iC5	2.51	2.64	2.77
N−Pentane	nC5	2.08	2.23	2.29
Hexanes	C6	4.94	5.27	5.46
Heptanes Plus	C7+	23.64	25.27	22.29
TOTAL		100.00	100.00	100.00

Stream Properties

Molecular Weight	:	70.9	64.7	59.0
Density @ P & T	:	0.606	0.567	0.535

Hexanes Plus Properties

Mol %	:	28.58	30.54	27.75
Molecular Weight	:	178.9	146.5	138.3
Density (gm/cc @ 60 °F)	:	0.812	0.782	0.773
Gravity (°API @ 60 °F)	:	42.6	49.4	51.4

Heptanes Plus Properties

Molecular Weight	:	198.8	159.6	151.6
Density (gm/cc @ 60 °F)	:	0.826	0.794	0.787
Gravity (°API @ 60 °F)	:	39.7	46.6	48.2

CALCULATED RETROGRADE LIQUID COMPOSITIONS

Pressure (psig):		2525	2042	1528
Component		Mol %	Mol %	Mol %
Hydrogen Sulphide	H2S	0.00	0.00	0.00
Carbon Dioxide	CO2	0.24	0.22	0.20
Nitrogen	N2	0.21	0.16	0.11
Methane	C1	34.59	31.49	26.36
Ethane	C2	8.36	8.05	7.69
Propane	C3	7.05	7.12	7.03
Iso–Butane	iC4	3.32	3.45	3.27
N–Butane	nC4	4.15	4.21	4.26
Iso–Pentane	iC5	3.27	3.41	3.46
N–Pentane	nC5	2.56	2.76	2.83
Hexanes	C6	6.25	6.72	6.99
Heptanes Plus	C7+	30.00	32.41	37.80
TOTAL		100.00	100.00	100.00

Stream Properties

Molecular Weight	:	69.2	72.0	76.4
Density @ P & T	:	0.570	0.573	0.576

Hexanes Plus Properties

Mol %	:	36.25	39.13	44.79
Molecular Weight	:	135.6	133.4	128.6
Density (gm/cc @ 60 °F)	:	0.770	0.768	0.762
Gravity (°API @ 60 °F)	:	52.1	52.7	53.9

Heptanes Plus Properties

Molecular Weight	:	146.4	143.7	136.9
Density (gm/cc @ 60 °F)	:	0.782	0.779	0.772
Gravity (°API @ 60 °F)	:	49.4	50.0	51.5

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CALCULATED RETROGRADE LIQUID COMPOSITIONS

Pressure (psig):		1019	519 *
Component		Mol %	Mol %
Hydrogen Sulphide	H2S	0.00	0.00
Carbon Dioxide	CO2	0.15	0.08
Nitrogen	N2	0.06	0.07
Methane	C1	19.09	8.58
Ethane	C2	6.34	4.06
Propane	C3	6.62	5.10
Iso–Butane	iC4	3.21	3.06
N–Butane	nC4	4.47	4.22
Iso–Pentane	iC5	3.93	4.14
N–Pentane	nC5	3.15	3.45
Hexanes	C6	7.87	9.09
Heptanes Plus	C7+	45.11	58.15
TOTAL		100.00	100.00

Stream Properties

Molecular Weight	:	85.8	105.7
Density @ P & T	:	0.594	0.627

Hexanes Plus Properties

Mol %	:	52.98	67.24
Molecular Weight	:	128.5	134.9
Density (gm/cc @ 60 °F)	:	0.762	0.797
Gravity (°API @ 60 °F)	:	54.0	45.9

Heptanes Plus Properties

Molecular Weight	:	136.2	142.8
Density (gm/cc @ 60 °F)	:	0.772	0.809
Gravity (°API @ 60 °F)	:	51.7	43.3

* Abandonment Pressure Liquid Phase analysed

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EQUILIBRIUM RATIOS (K – VALUES) *

PRESSURE (psig)

Component		4045	3505	2986	2525	2042	1528	1019	519
Carbon Dioxide	CO2	1.301	1.304	1.401	1.499	1.655	1.926	2.550	4.750
Nitrogen	N2	1.279	1.449	1.763	2.101	2.769	4.287	7.945	21.209
Methane	C1	1.621	1.763	1.692	2.191	2.423	2.953	4.064	8.718
Ethane	C2	1.101	1.099	1.097	1.151	1.202	1.270	1.577	2.530
Propane	C3	0.797	0.751	0.742	0.700	0.691	0.698	0.768	1.075
Iso–Butane	iC4	0.585	0.538	0.499	0.457	0.435	0.461	0.495	0.575
N–Butane	nC4	0.551	0.493	0.441	0.401	0.391	0.377	0.371	0.445
Iso–Pentane	iC5	0.425	0.381	0.335	0.275	0.257	0.242	0.210	0.237
N–Pentane	nC5	0.385	0.335	0.298	0.265	0.236	0.215	0.197	0.209
Hexanes	C6	0.316	0.269	0.229	0.197	0.172	0.148	0.134	0.129
Heptanes Plus	C7+	0.197	0.152	0.153	0.094	0.076	0.028	0.016	0.019

* Mol percent Component (i) in Produced Gas Phase divided by
Mol percent Component (i) in Calculated Liquid Phase.

P E T R O L A B

CALCULATED CUMULATIVE RECOVERY DURING DEPLETION

Cumulative Recovery per MMSCF of Original Fluid*	Initial In Place	Dew Point 4970	4045	3505	2986	2525	2042	1528	1019	519
			Reservoir Pressure							
Well Stream – MSCF	1000	0	98.82	168.05	251.57	358.07	482.78	611.86	735.03	849.93

Stock Tank Liquid – °API @ 60 °F		64.0	67.5	68.7	69.1	70.1	70.7	71.5	73.3	76.1
Cumulative Produced (Bbl)	0.00	0.00	7.83	12.40	17.17	22.40	27.79	32.16	35.59	38.65
Remaining in Vapor (Bbl)	92.92	92.92	69.02	50.83	37.65	27.71	18.98	10.29	5.37	2.53
In Retrograde Liquid (Bbl)	0.00	0.00	16.06	29.69	38.10	42.81	46.15	50.48	51.96	51.73
Primary Separator Gas – MSCF	869.03	0.00	87.12	149.40	225.61	323.95	440.15	562.24	679.69	789.02
Second Stage Gas – MSCF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stock Tank Gas – MSCF	43.53	0.00	3.92	6.27	8.74	11.55	14.51	17.01	19.18	21.53

Total " Plant Products " – Gallons

In Well Stream :

Ethane	2548	0	252	430	644	919	1242	1579	1909	2226
Propane	1412	0	138	234	348	493	662	837	1010	1187
Butanes	1140	0	110	185	270	379	505	635	763	899
Pentanes Plus	4059	0	347	554	775	1025	1290	1519	1713	1896

In Primary Separator Gas :

Ethane	2314	0	228	387	579	824	1110	1408	1699	1978
Propane	1077	0	107	182	273	389	526	670	813	959
Butanes	616	0	62	106	159	228	311	401	493	589
Pentanes Plus	337	0	34	58	87	126	172	222	274	327

In Secondary Separator Gas :

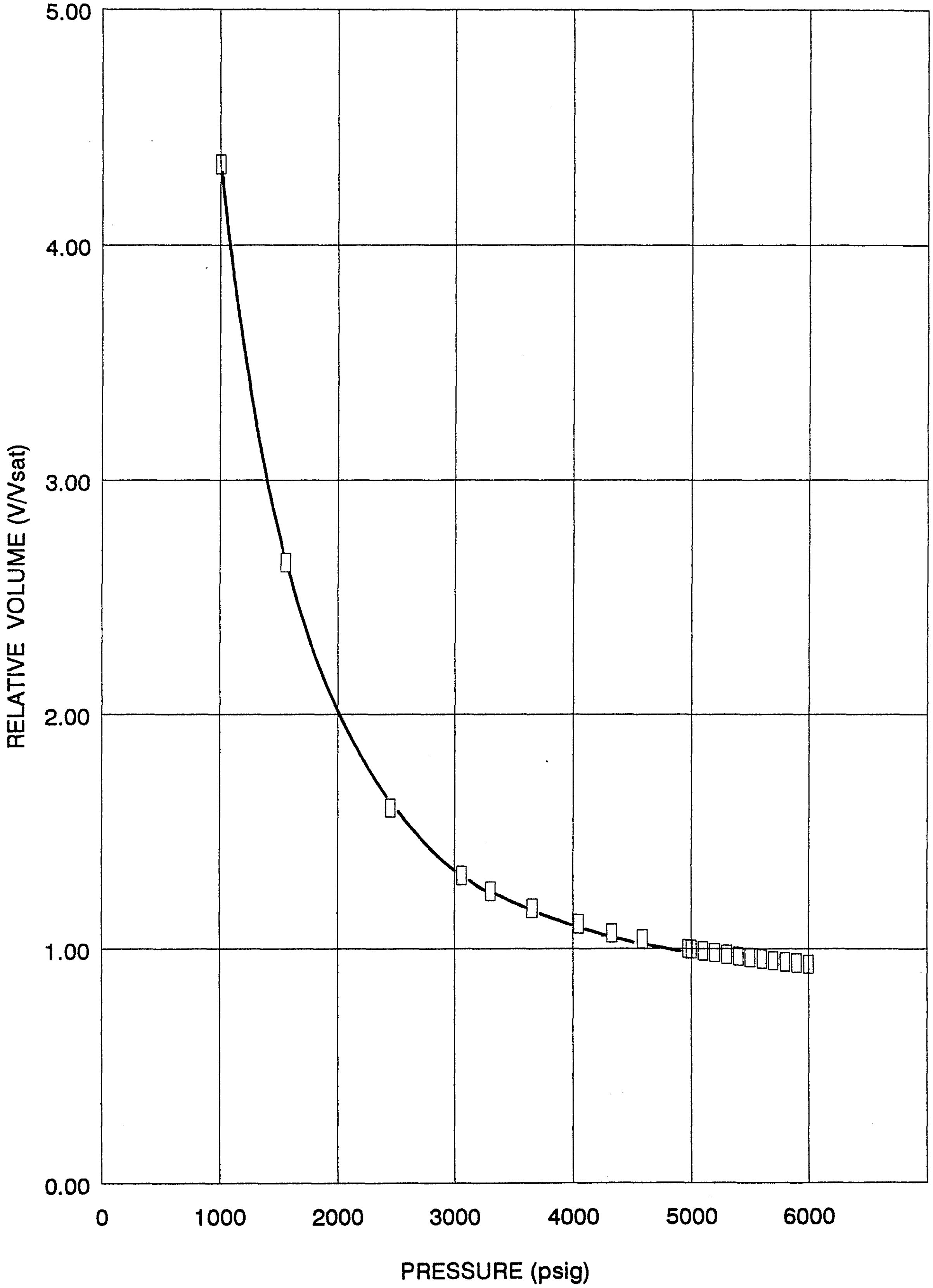
Ethane	0	0	0	0	0	0	0	0	0	0
Propane	0	0	0	0	0	0	0	0	0	0
Butanes	0	0	0	0	0	0	0	0	0	0
Pentanes Plus	0	0	0	0	0	0	0	0	0	0

Gas Oil Ratio *

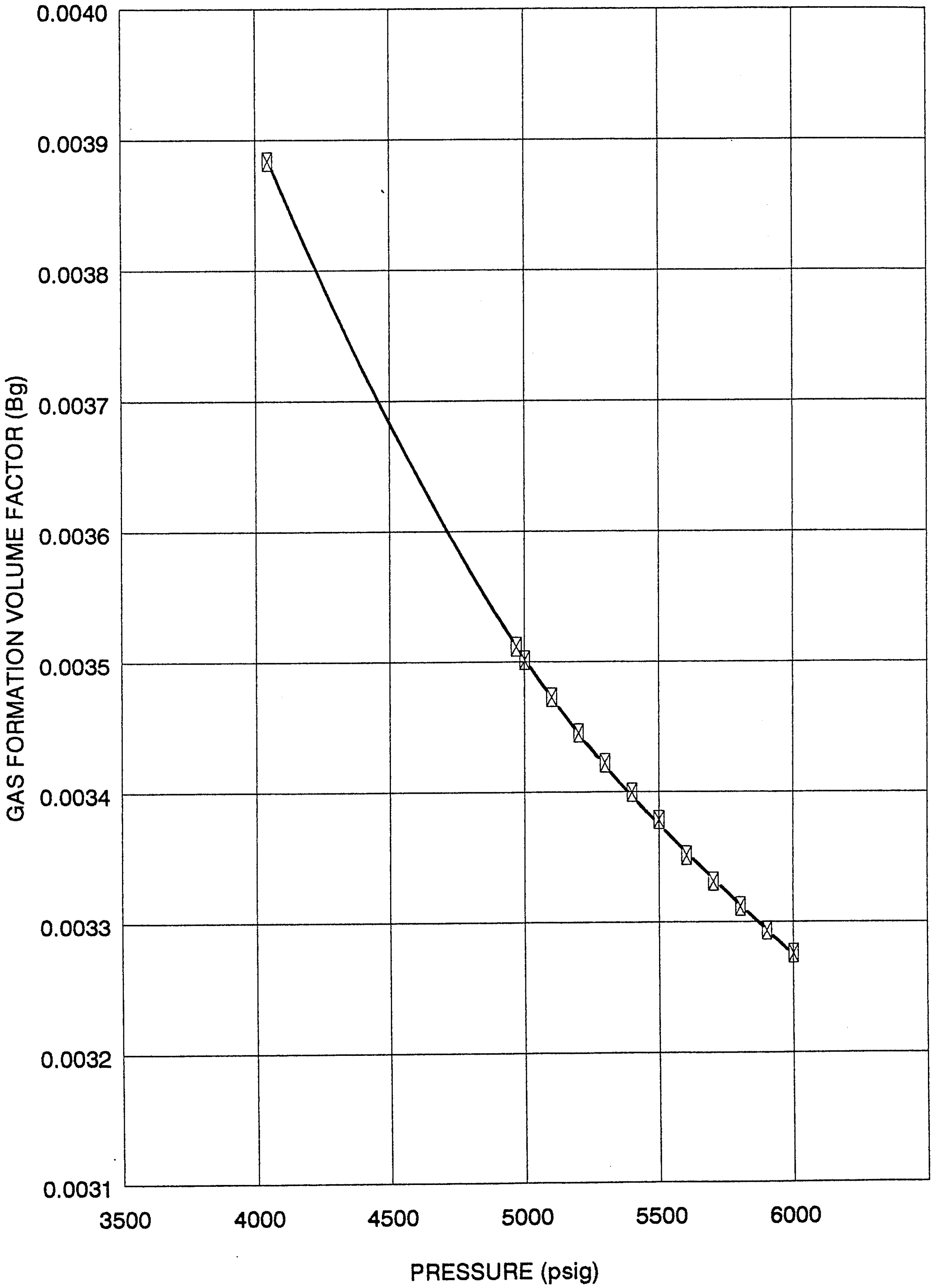
1st Sep. Gas/Stock Tank Liquid (SCF/BBL)		9353	11121	13640	15978	18799	21538	27984	34237	35639
1st+2nd Sep. Gas/Stock Tank Liquid (SCF/BBL)		9353	11121	13640	15978	18799	21538	27984	34237	35639
1st Sep. Gas/Produced WellStream (MSCF/MMSCF)		869	882	900	912	923	932	946	954	952
1st+2nd Sep. Gas/Produced WS (MSCF/MMSCF)		869	882	900	912	923	932	946	954	952
Stock Tank Liquid/Produced WS (STB/MMSCF)		92.92	79.28	65.95	57.11	49.12	43.26	33.80	27.85	26.70

* Primary Separator @ 400 psig and 86 °F; Stock Tank @ 14.696 psia and 60 °F; No second stage

RELATIVE VOLUME



GAS FORMATION VOLUME FACTOR

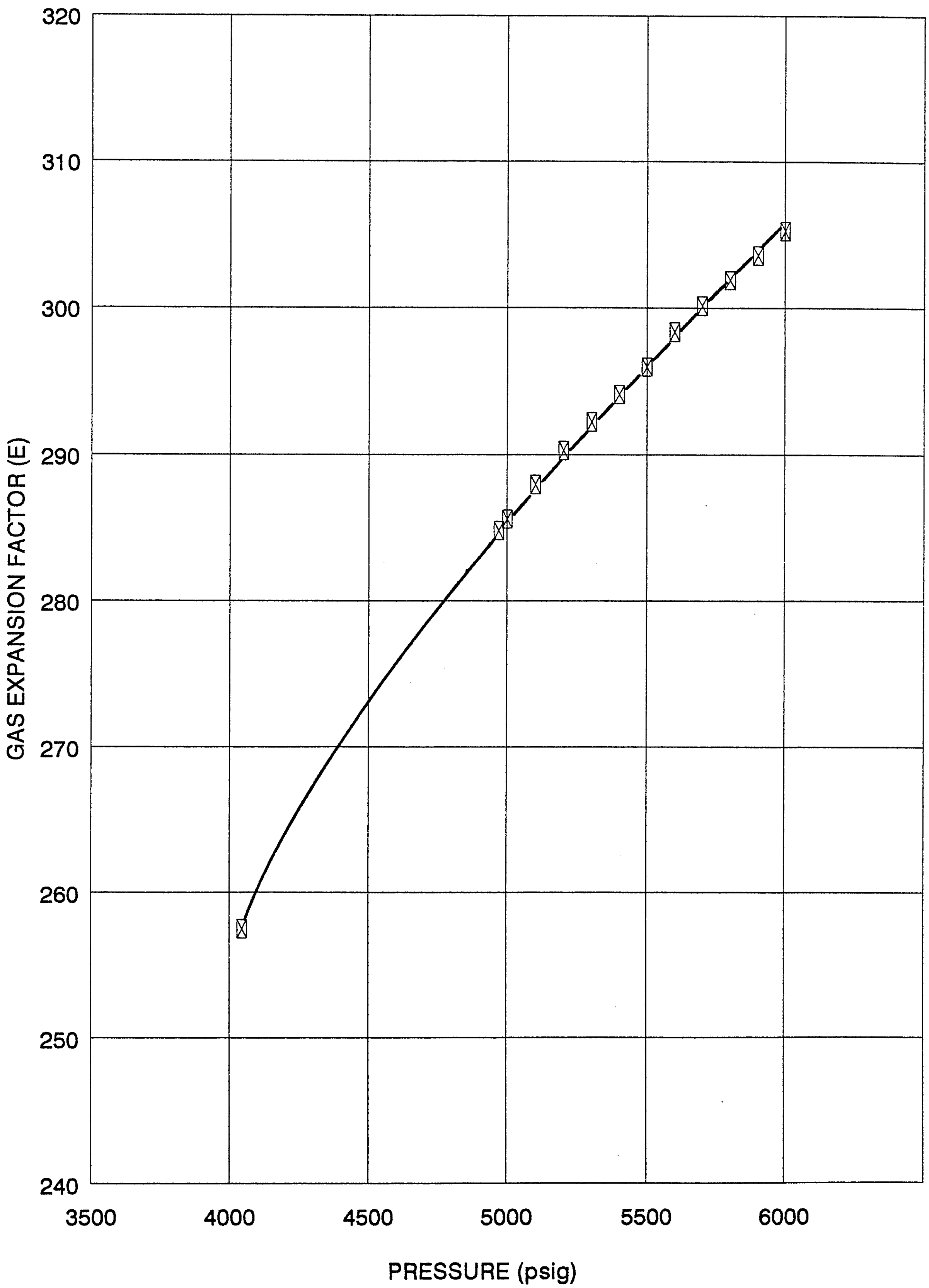


P E T R O L A B

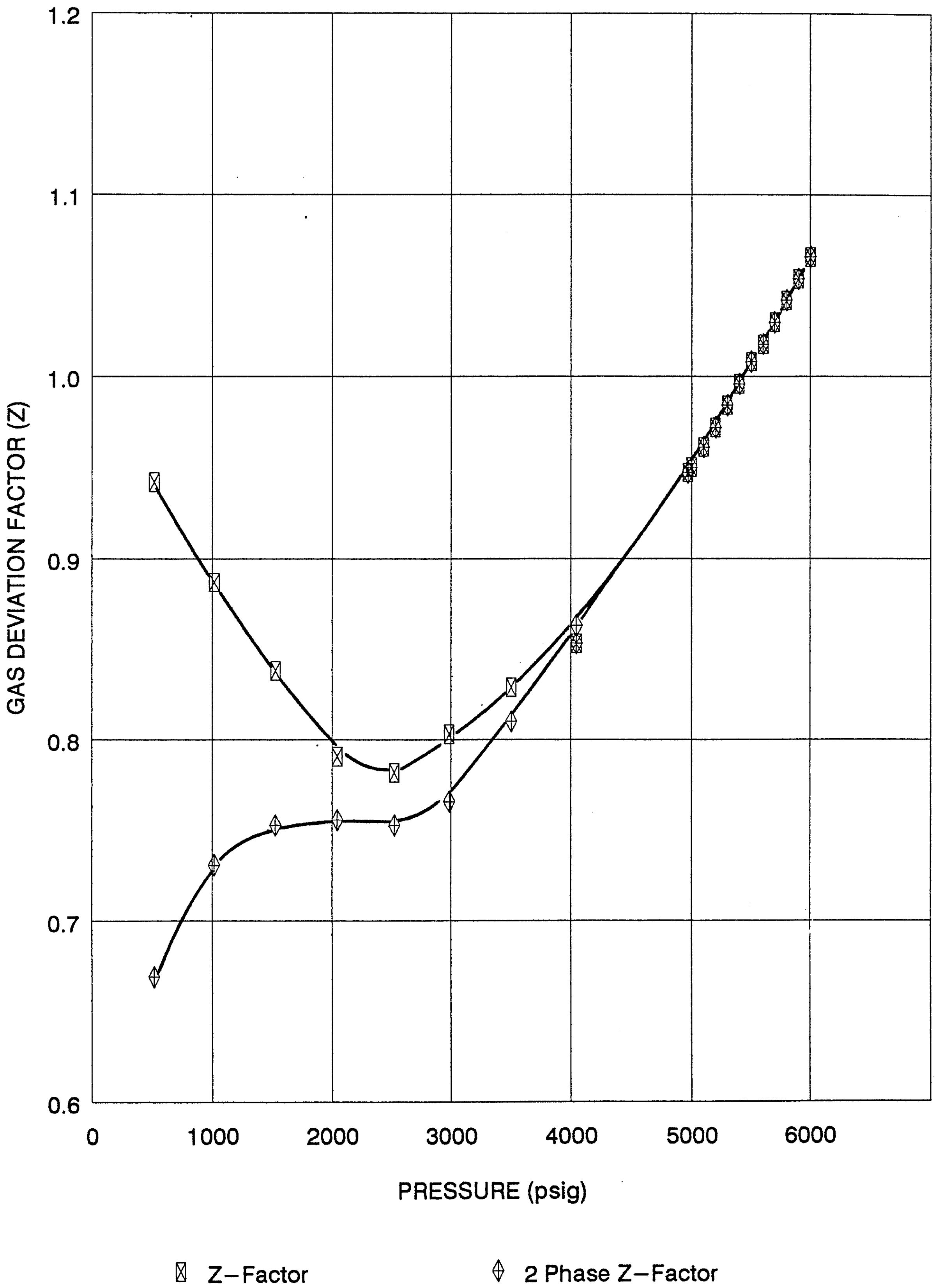
Company: Esso Australia Ltd.
Well: Blackback # 2

File : E 92039

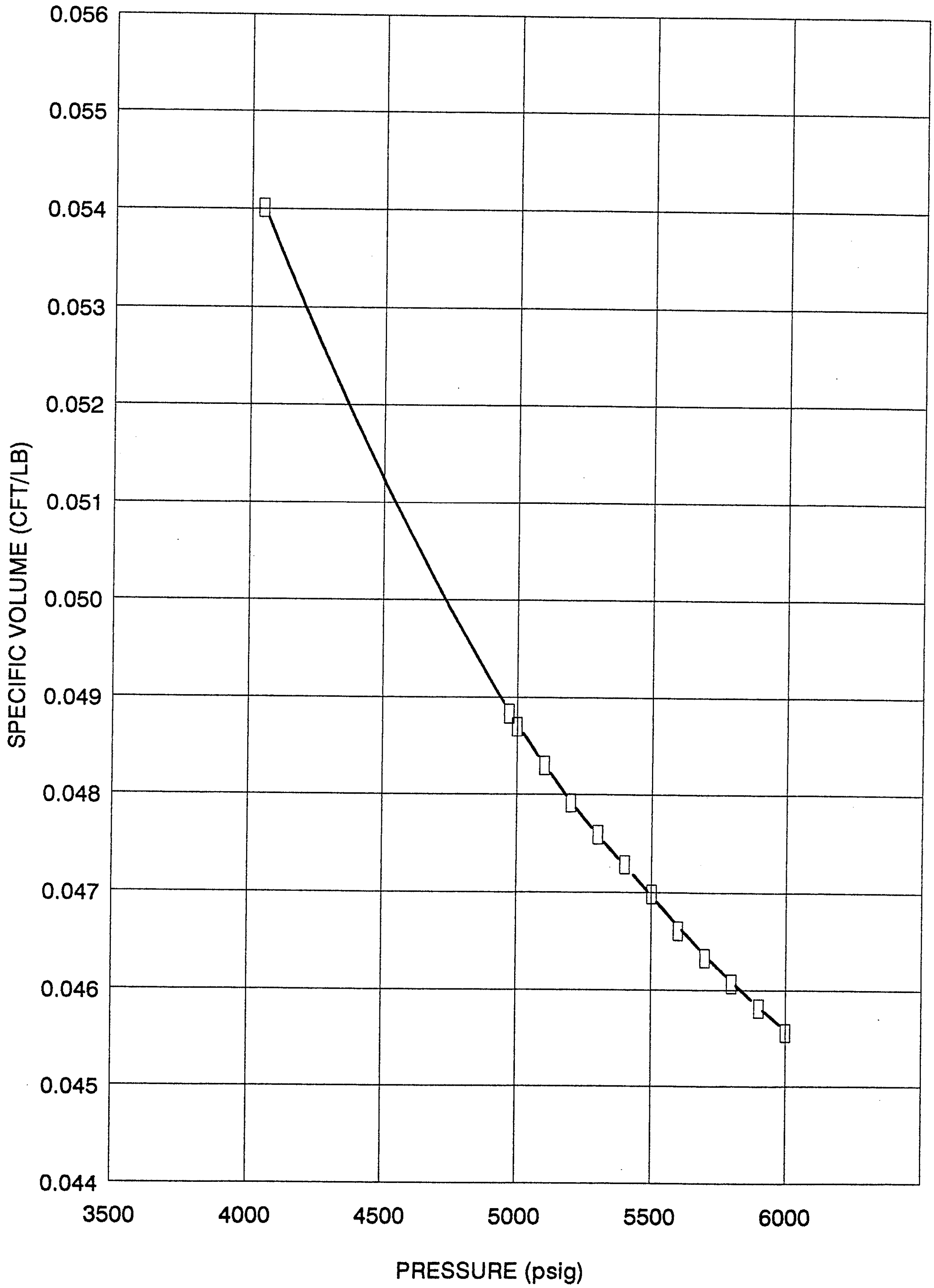
GAS EXPANSION FACTOR



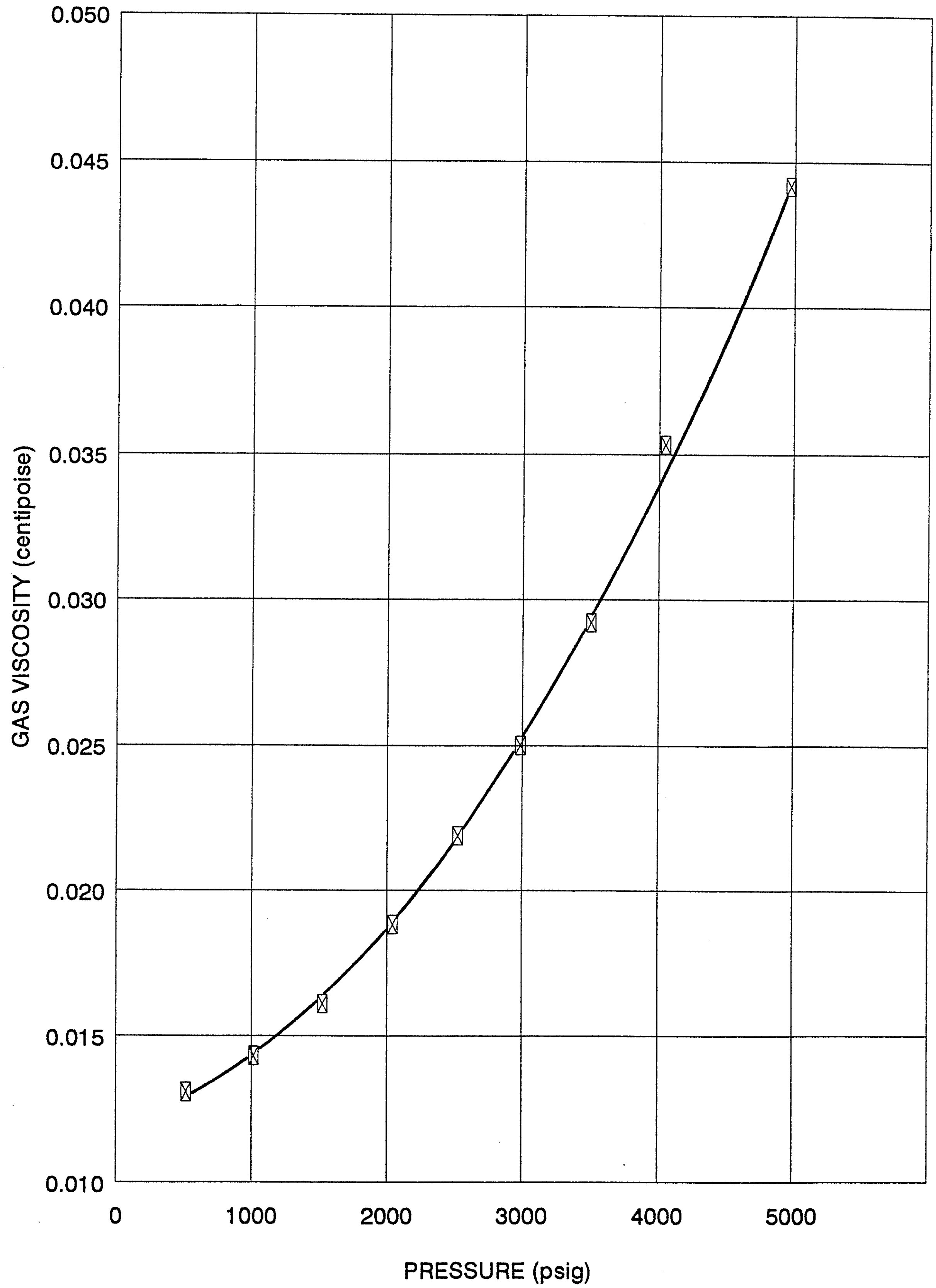
GAS DEVIATION FACTOR



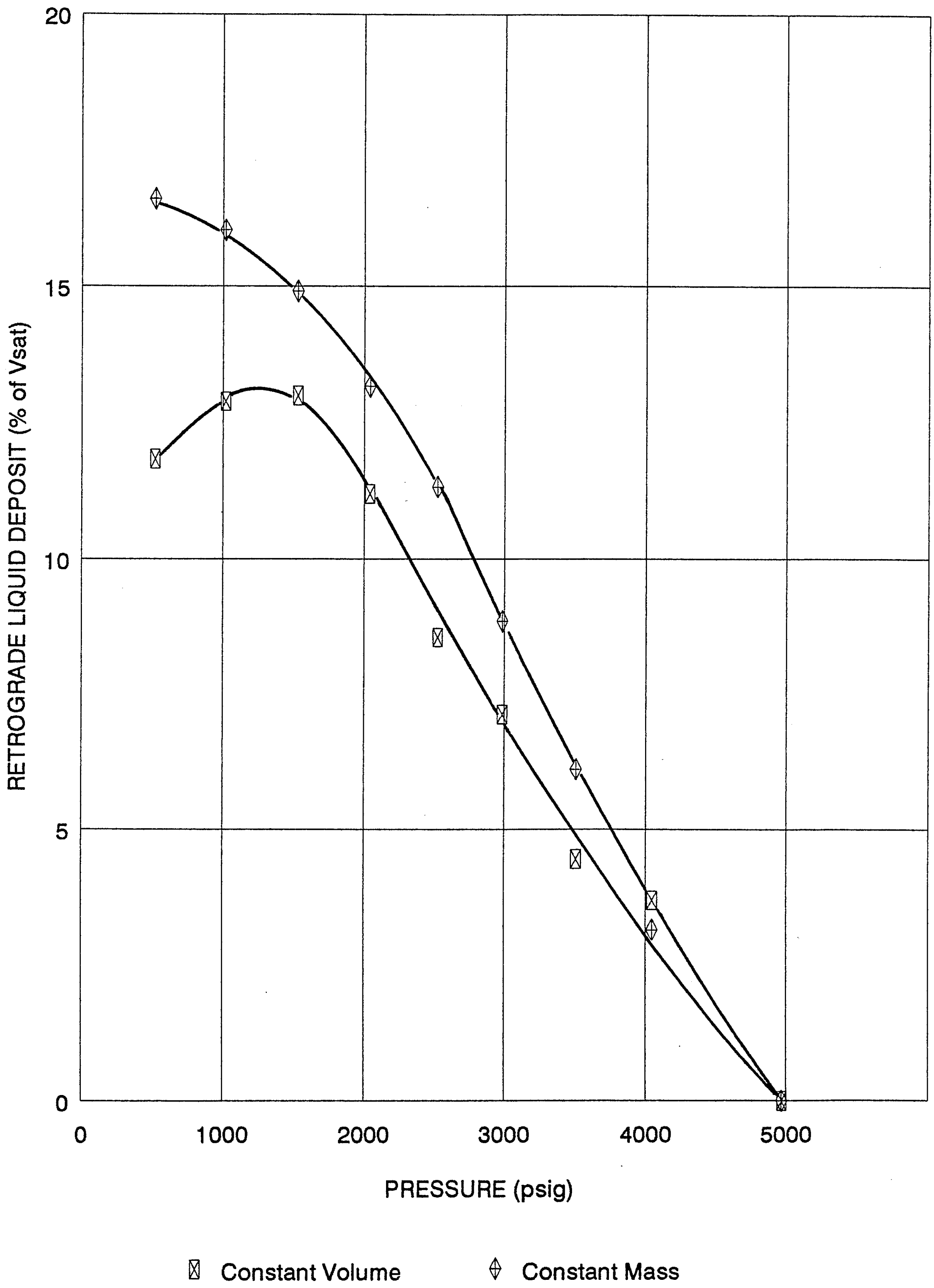
RESERVOIR FLUID SPECIFIC VOLUME



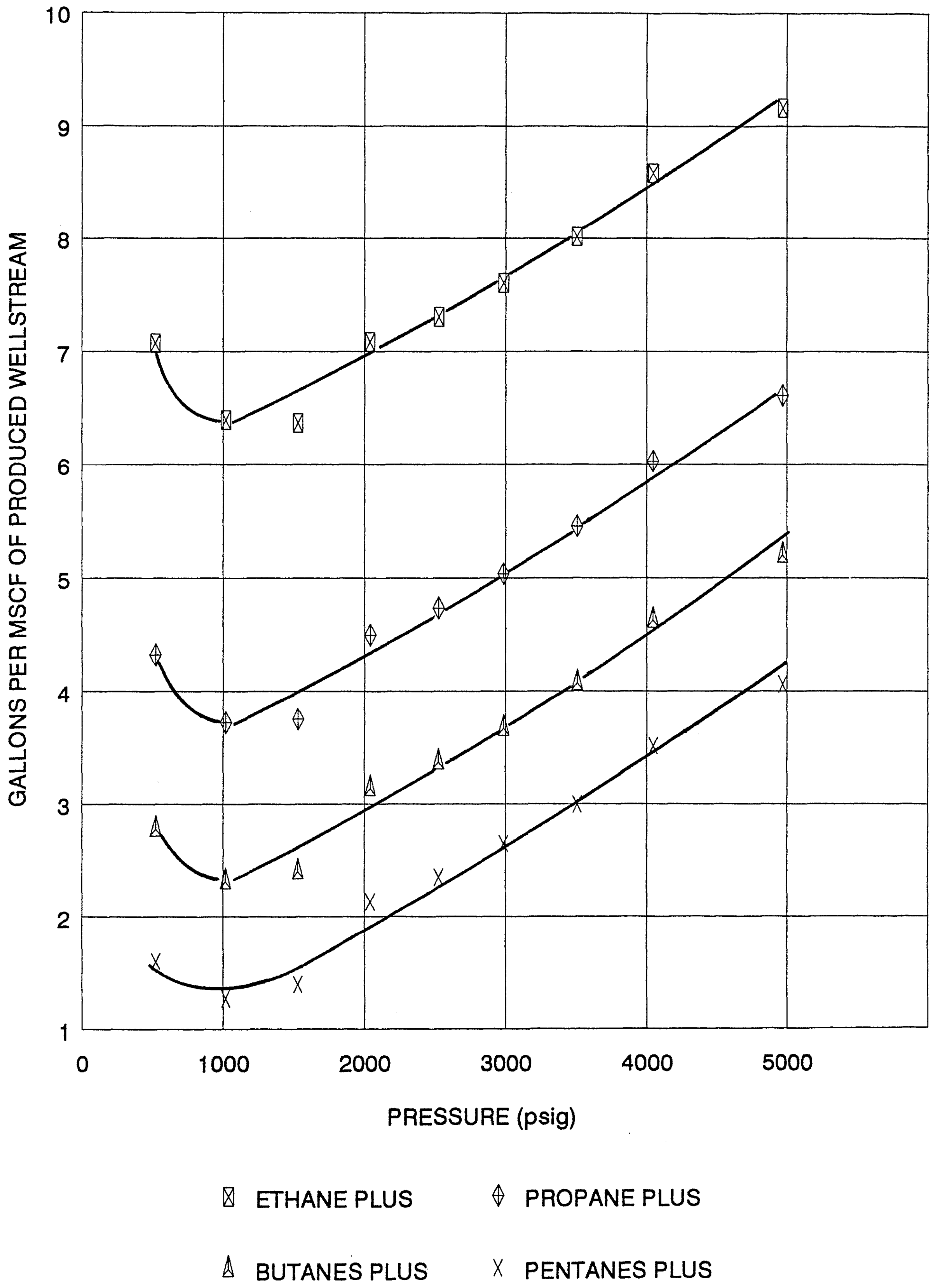
VISCOSITY OF RESERVOIR FLUID



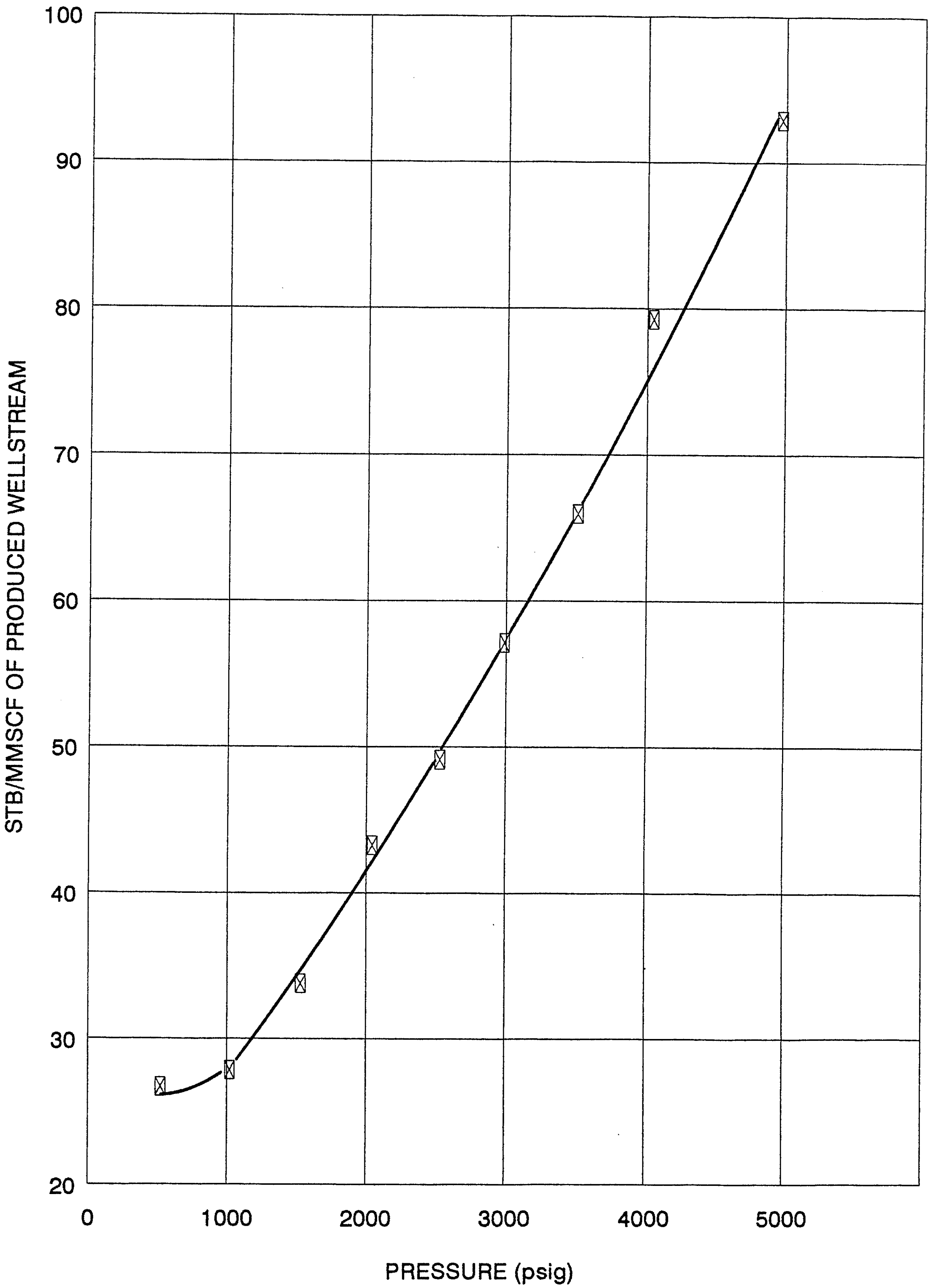
RETROGRADE CONDENSATION



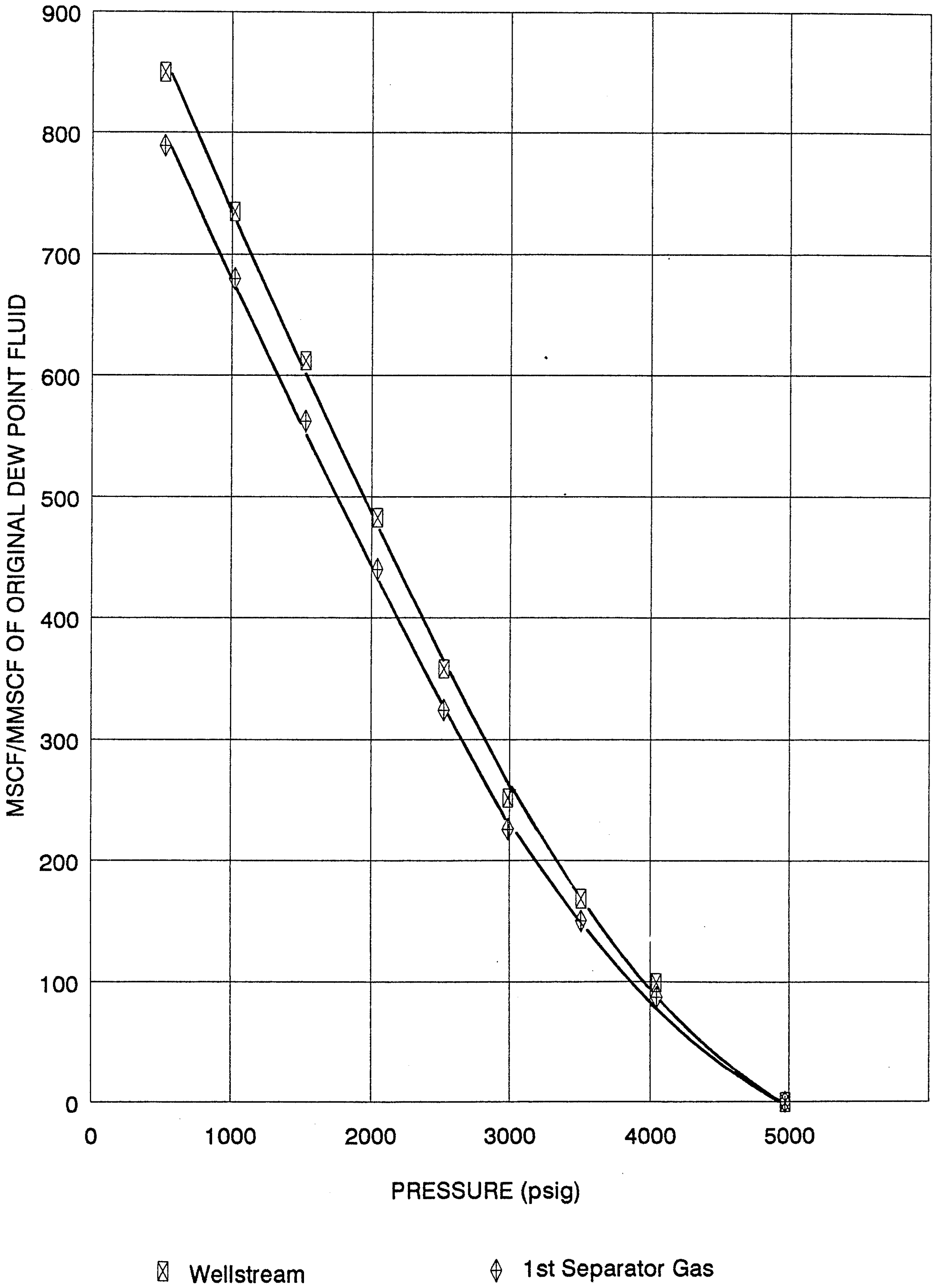
GPM CONTENT IN PRODUCED WELLSTREAM



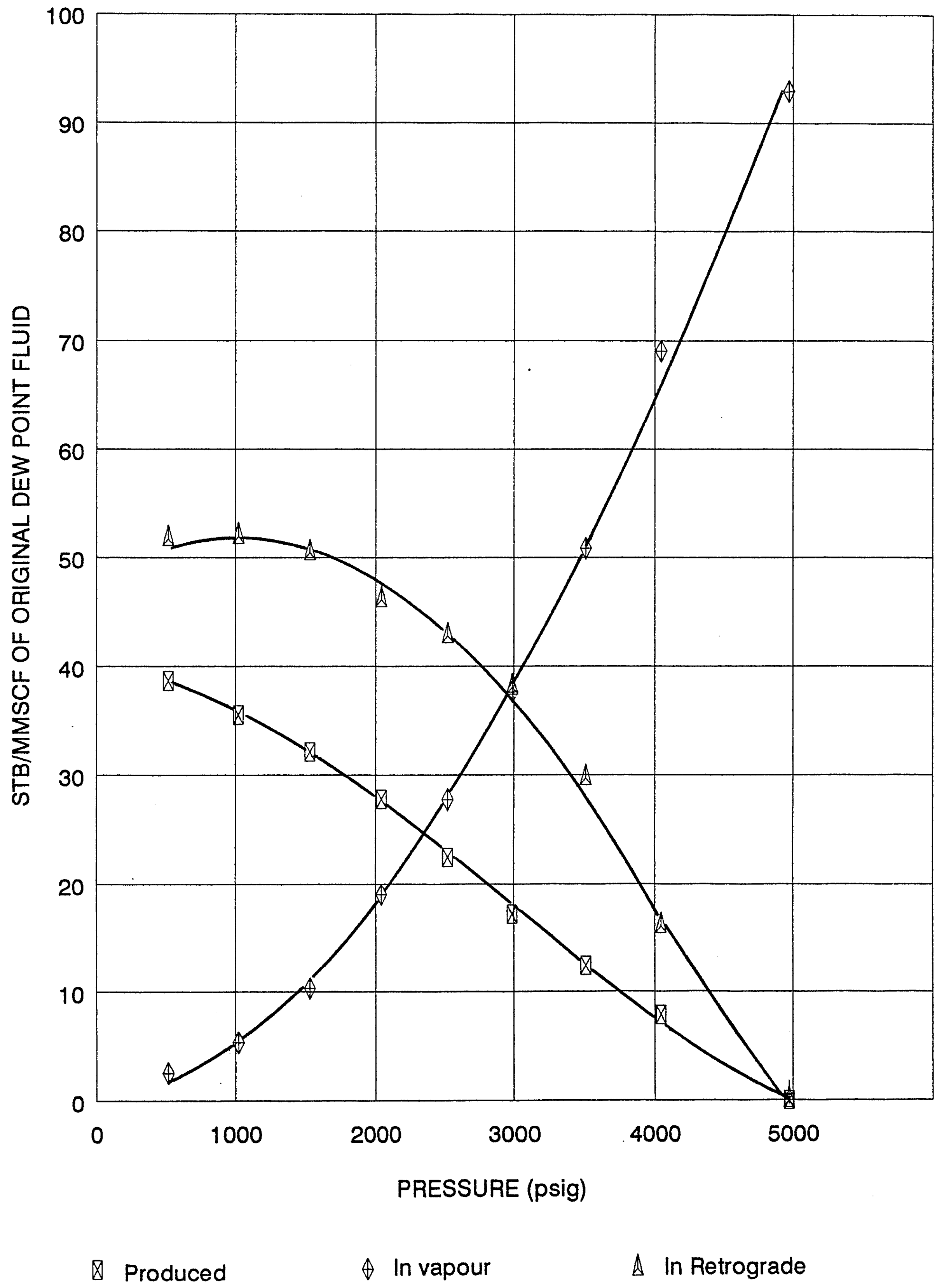
STOCK TANK LIQUID IN PRODUCED WELLSTREAM



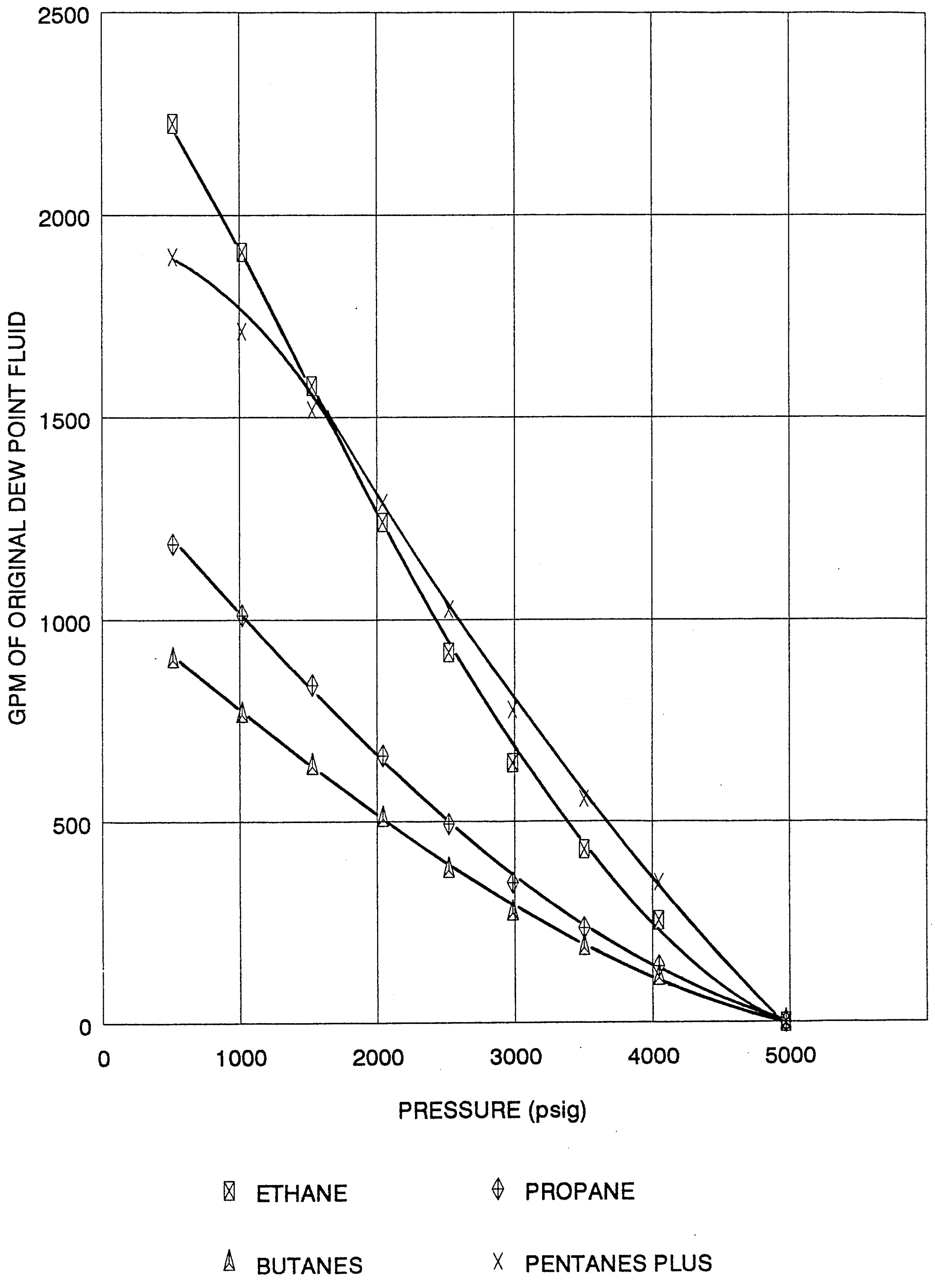
CUMULATIVE VOLUMES PRODUCED



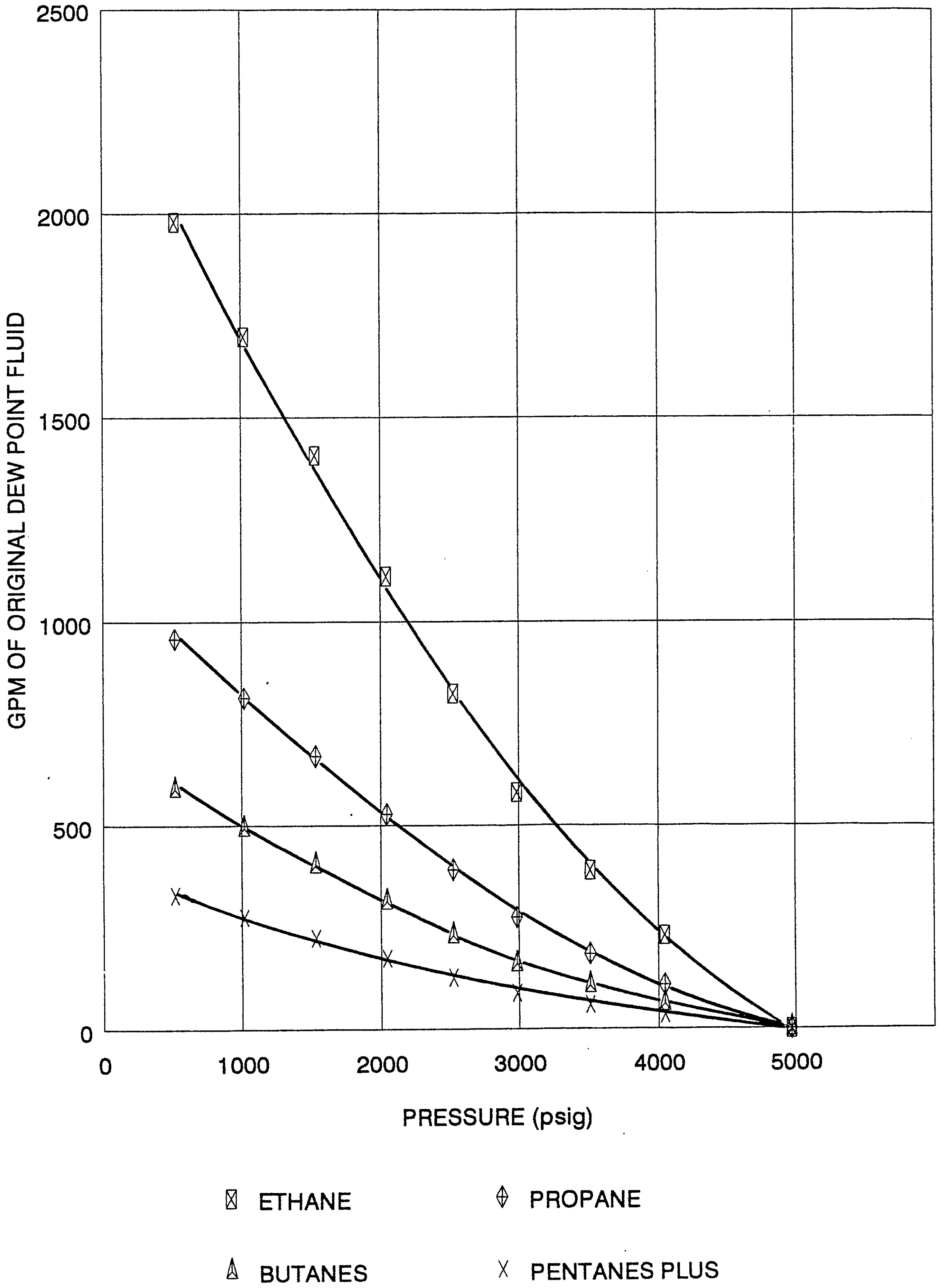
CUMULATIVE STOCK TANK LIQUID PRODUCTION AND CONDENSATION



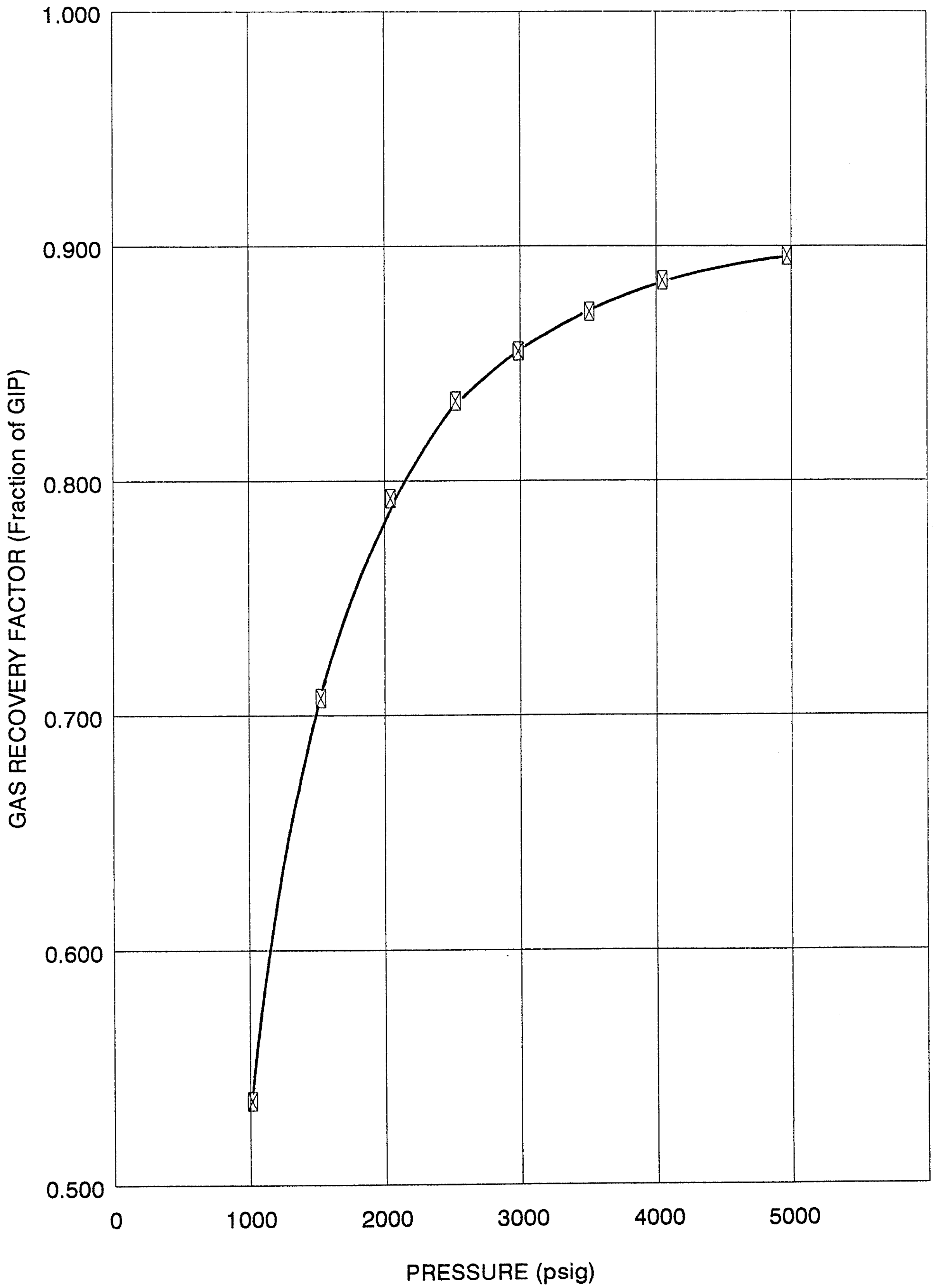
PLANT PRODUCTS IN PRODUCED WELLSTREAM



PLANT PRODUCTS IN PRIMARY SEPARATOR GAS



GAS RECOVERY FACTOR



ENCLOSURES

ENCLOSURES

PE600798

This is an enclosure indicator page.
The enclosure PE600798 is enclosed within the container PE900972 at this location in this document.

The enclosure PE600798 has the following characteristics:

ITEM_BARCODE = PE600798
CONTAINER_BARCODE = PE900972
NAME = Formation Evaluation Log
BASIN = GIPPSLAND
PERMIT = Vic/P24
TYPE = WELL
SUBTYPE = well log
DESCRIPTION = Formation Evaluation Log
REMARKS =
DATE_CREATED = 04/10/1992
DATE_RECEIVED = 04/05/1993
W_NO = W1072
WELL_NAME = Blackback-2
CONTRACTOR = ESSO
CLIENT_OP_CO = ESSO

(Inserted by DNRE - Vic Govt Mines Dept)

PE600799

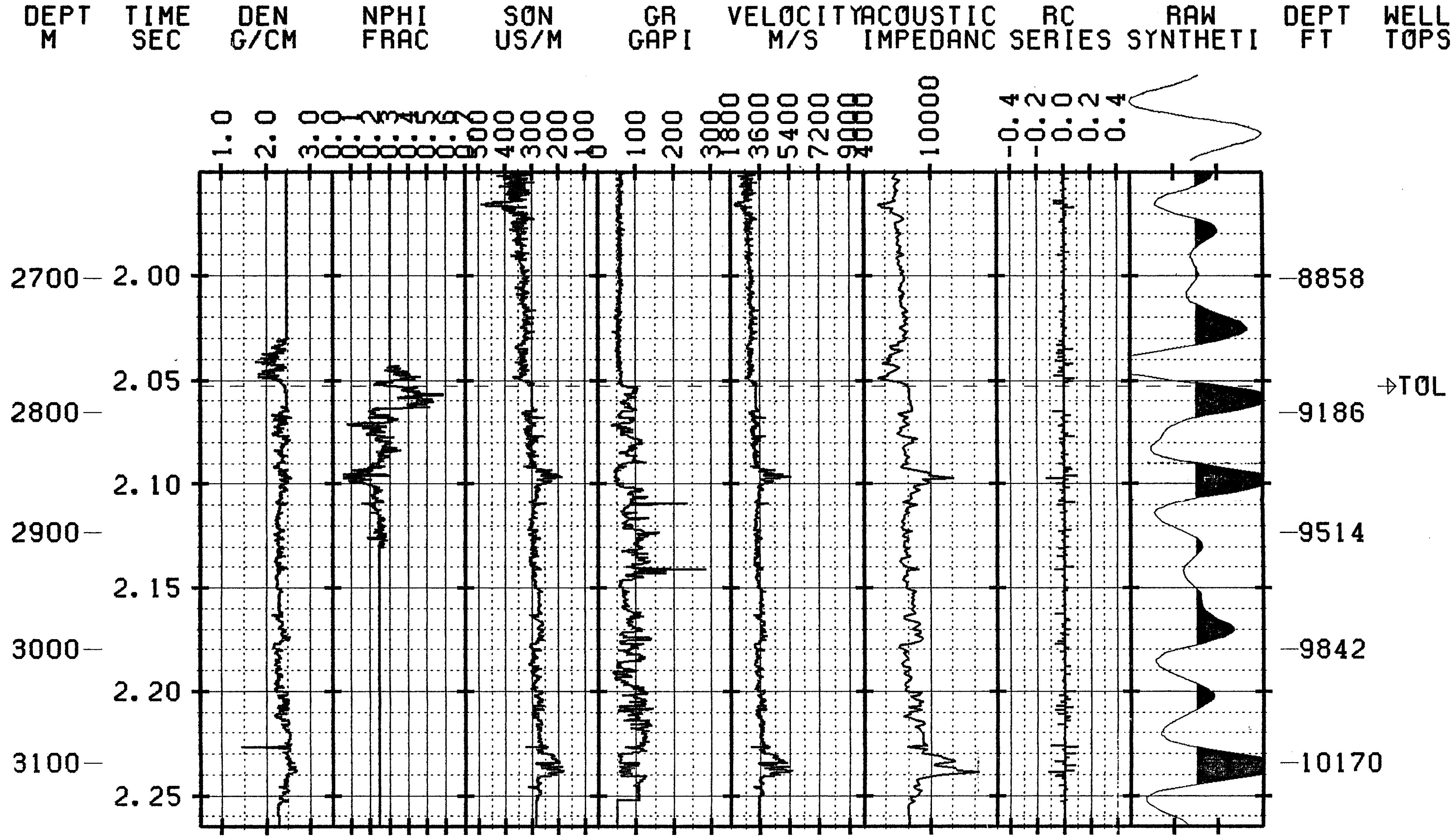
This is an enclosure indicator page.
The enclosure PE600799 is enclosed within the container PE900972 at this location in this document.

The enclosure PE600799 has the following characteristics:

ITEM_BARCODE =	PE600799
CONTAINER_BARCODE =	PE900972
NAME =	Well Completion Log
BASIN =	GIPPSLAND
PERMIT =	
TYPE =	WELL
SUBTYPE =	COMPOSITE_LOG
DESCRIPTION =	Well Completion Log
REMARKS =	
DATE_CREATED =	31/03/1993
DATE_RECEIVED =	04/05/1993
W_NO =	W1072
WELL_NAME =	Blackback-2
CONTRACTOR =	ESSO
CLIENT_OP_CO =	ESSO

(Inserted by DNRE - Vic Govt Mines Dept)

SYNTHETIC SEISMIC TRACE



BLACKBACK-2

SYNTHETIC SEISMIC TRACE

ENCLOSURE 3

PE600800

This is an enclosure indicator page.
The enclosure PE600800 is enclosed within the container PE900972 at this location in this document.

The enclosure PE600800 has the following characteristics:

ITEM_BARCODE = PE600800
CONTAINER_BARCODE = PE900972
NAME = Seismic Calibration Log
BASIN = GIPPSLAND
PERMIT = Vic/P24
TYPE = WELL
SUBTYPE = well log
DESCRIPTION = Seismic Calibration Log
REMARKS =
DATE_CREATED = 20/10/1992
DATE_RECEIVED = 04/05/1993
W_NO = W1072
WELL_NAME = Blackback-2
CONTRACTOR = ESSO
CLIENT_OP_CO = ESSO

(Inserted by DNRE - Vic Govt Mines Dept)

PE900973

This is an enclosure indicator page.
The enclosure PE900973 is enclosed within the container PE900972 at this location in this document.

The enclosure PE900973 has the following characteristics:

ITEM_BARCODE =	PE900973
CONTAINER_BARCODE =	PE900972
NAME =	Structure Map Top of Latrobe Unconformity
BASIN =	GIPPSLAND
PERMIT =	
TYPE =	SEISMIC
SUBTYPE =	HRZN_CONTR_MAP
DESCRIPTION =	Structure Map Top if Latrobe Unconformity
REMARKS =	
DATE_CREATED =	30/04/1993
DATE_RECEIVED =	04/05/1993
W_NO =	W1072
WELL_NAME =	Blackback-2
CONTRACTOR =	ESSO
CLIENT_OP_CO =	ESSO

(Inserted by DNRE - Vic Govt Mines Dept)