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NORWEGIAN GULF EXPLORATION Co. A/S

PRODUCTION LICENCE 058

Gulf

32/ 344

35/8-2 WELL

COMPLETION REPORT

NOVEMBER 1982

3

86-5231 BA

NORWEGIAN GULF EXPLORATION CO. A/S

PRODUCTION LICENCE 058

BA-86-5231-1

Jr. nr 82/017344-1
82 11 30

U-299

35/8-2 WELL

COMPLETION REPORT

November 1982

CONTENTS

TESTING

GENERAL

1. Introduction

Well 35/8-2 was drilled by Norwegian Gulf Exploration Co. A/S as the second committment well of Production Licence 058. The well is situated 145km northwest of Bergen, Norway, in the central part of the present Northern North Sea basin (figure 1).

Licencees of Block 35/8 and their interests are as follows:

Licencee	Percentage
Norwegian Gulf Exploration Co. A/S	30 (Operator)
Norske Getty Exploration Co. A/S	20
Den Norske Stats Oljeselskap A/S	50
TOTAL	100

Objectives

The principal objective of this well was to test the hydrocarbon potential of sandstones within the Jurassic section beneath the Late Cimmerian Unconformity. At the Location, these sandstones from a structural trap where they dip westwards within a N-S trending horst block (fig 2). The Jurassic section was anticipated to be comparable to that of the East Shetland Basin, but with a greater sand to shale ratio.

The absence of an appreciable Lower Cretaceous section was predicted so that no further reservoirs were anticipated above the Late Cimmerian Unconformity.

Results

The well was drilled to a Total Depth of 4332m (14213 ft) KB, bottoming in Early Jurassic (Sinemurian) age sediments. The well was plugged and abandoned as a gas/condensate discovery.

Indications of hydrocarbons while drilling occured in Upper Jurassic sandstones and shales and Middle and Lower Jurassic sandstones. Six cores, totalling 87.5m were cut in the Middle Jurassic Brent Sand reservoir. Coring continued until hydrocarbon shows were no longer encountered.

Two tests of Upper and Middle Jurassic sands, Heather and Brent respectively, resulted in no fluid recovery from the Heather sand, but the Brent flowed 0.487 $\cdot 10^6$ Sm^3 (17.2 MMSCFD) gas with 330.5 Sm^3 (2087 BCPD) condensate. Log analyses indicated a gross hydrocarbon column of 60m, a gross hydrocarbon sand thickness of 52m and an apparent net hydrocarbon sand thickness of 48m (Ø>9%). Average porosity in the net sand is 16.8% with an average water saturation of 25%. Values given for net sand count are provisional as reservoir quality is complex and cut-off values here may be in error.

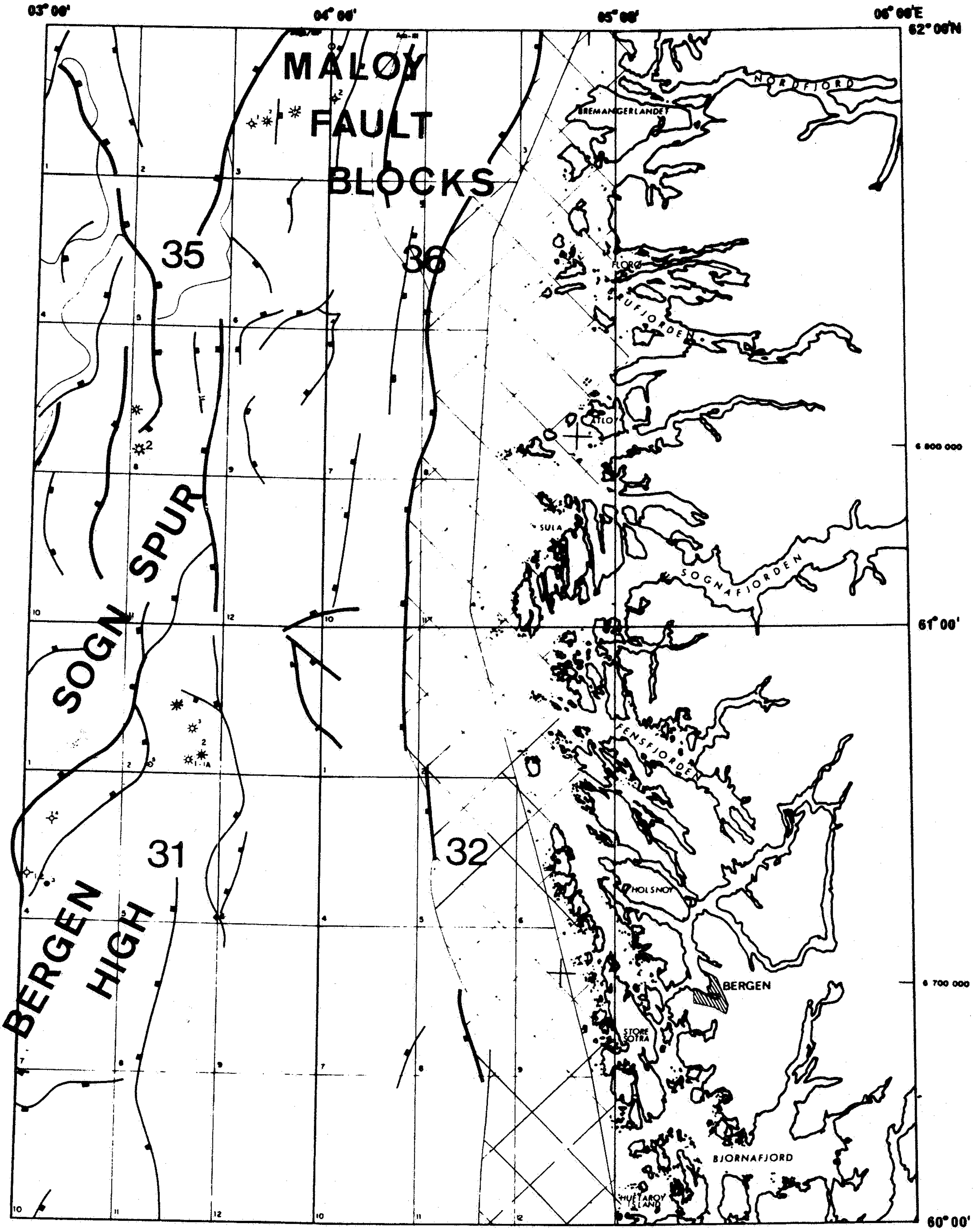
No residual oil was indicated below the gas column in the Brent Sand reservoir, but the Lower Jurassic sands (Intra Dunlin, Statfjord) had hydrocarbon shows while drilling. Subsequent log evaluation indicated that these sands were water-bearing.

2. Summary of Well Data

Operator	Norwegian Gulf Expl.Co. A/S
Area	Norwegian North Sea
Licence	PL 058
Well No.	35/8-2 & Sidetrack
Location	61º 16' 15.42" North 03º 21' 58.17" East
Seismic Location	79-1-4C Sp.478
RKB-MSL	26m (85 ft)
Water Depth	376.3m (1235 ft)
Rig	Sedco 704
Contractor	Southeast Drilling Company
Mobilized Rig	18 August, 1981
Spudded	30 August, 1981
Respudded	11 September, 1981
Sidetracked	14 February, 1982
Reached TD	17 April, 1982
Total Depth (Driller)	4336m (14226 ft)
Total Depth (Schlumberger)	4332m (14131 ft)
Status	Plugged and abandoned Gas/Condensate Discovery

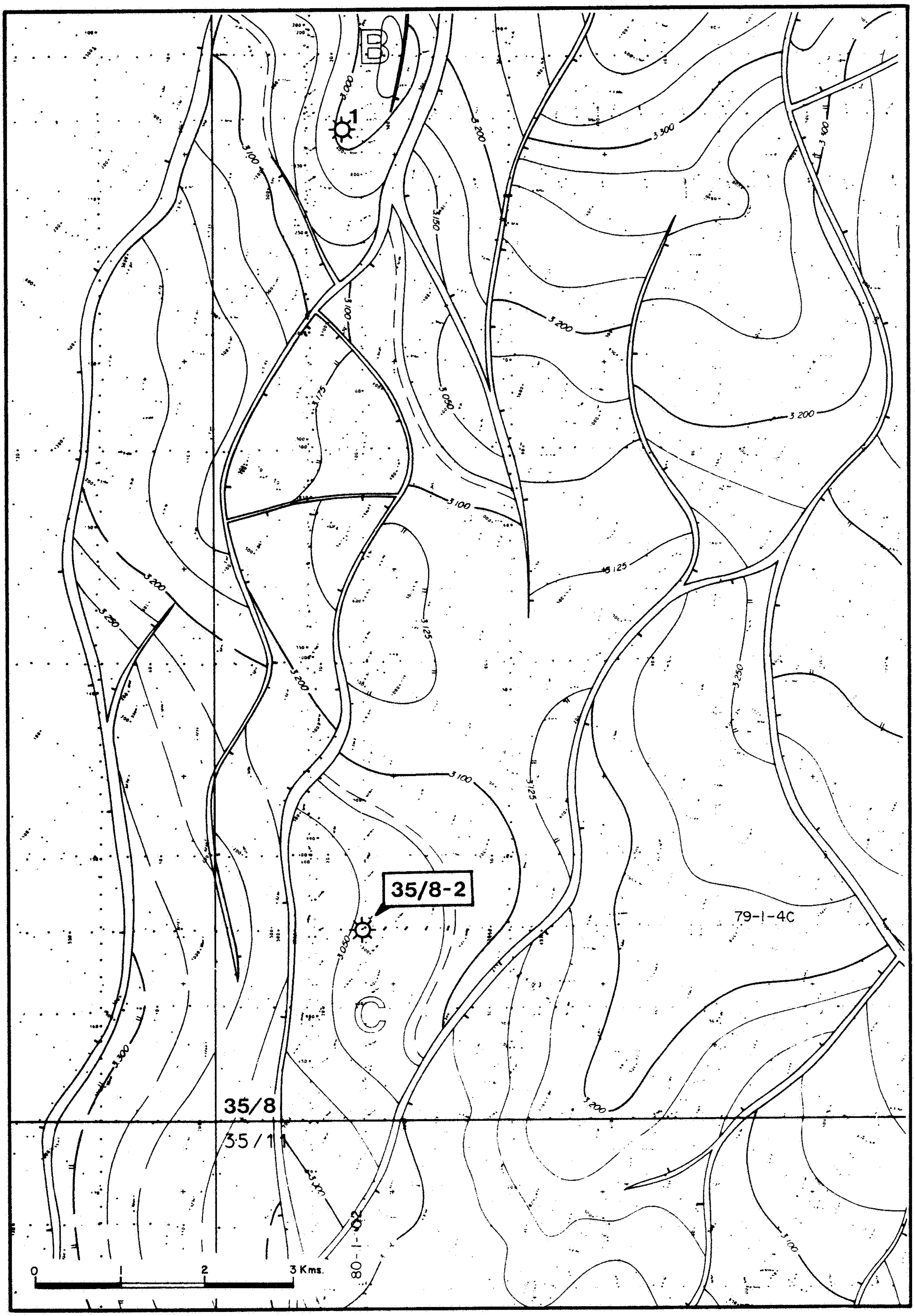
Test Results:

DST no.1	Choke:	175m (44/64 inch)
	Interval:	3694 - 3703m
	Flow rate:	487000 Sm^3 gas (17.2 mmcfg/d) 330.5 Sm^3 condensate (2087 bcpd) 46º API.
	GOR (SCF/STB):	1474 Sm^3/Sm^3 (8241 SCF/STB)
DST no.2A	Interval:	3306 - 3315m, 3321 - 3327m No flow



35/8-2 LOCATION DIAGRAM

Fig. 1



TOP BRENT SAND Time Map

Fig.2

3. Rig Positioning

The rig was moved to the location in Block 35/8 under its own power with towing assistance from m.v. Balder Vaasa, Smit Lloyd 112 and Maersk Battler.

Decca Survey Norway A/S contracted for the navigation of the rig which was carried out by using Pulse 8. Final position of the rig was determined by satellite navigation and is:

Latitude	61° 16' 15.42"N
Longitude	03° 21' 58.17"E

Position before respud:

Latitude:	61° 16' 15.31"N
	03° 22' 00.16"E

The final position is 30m on a bearing of 276° from previous location and 15m on a bearing of 296° from intended location.

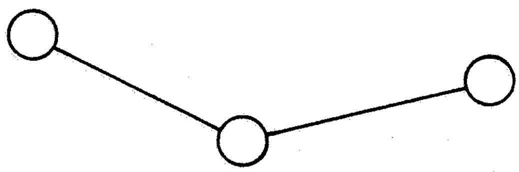
Bottom hole location and true vertical depth (TVD) was calculated by Sperry Sun International Inc. as being 79.10m on a bearing of 270° 01' from the surface location. True vertical depth at 4331.83m (14212.71 ft) KB is 4329.72m (14205.8 ft).

35/8-2

FINAL AND BOTTOM HOLE LOCATION DIAGRAM

FINAL LOCATION

61° 16' 15.42" N
03° 21' 58.17" E



FIRST LOCATION

61° 16' 15.31" N
03° 22' 00.16" E

REQUIRED LOCATION

61° 16' 15.2" N
03° 21' 59.1" E

SCALE 1:500

0 5 10 15 20 25 30 35 40 45 50m.

Fig.3

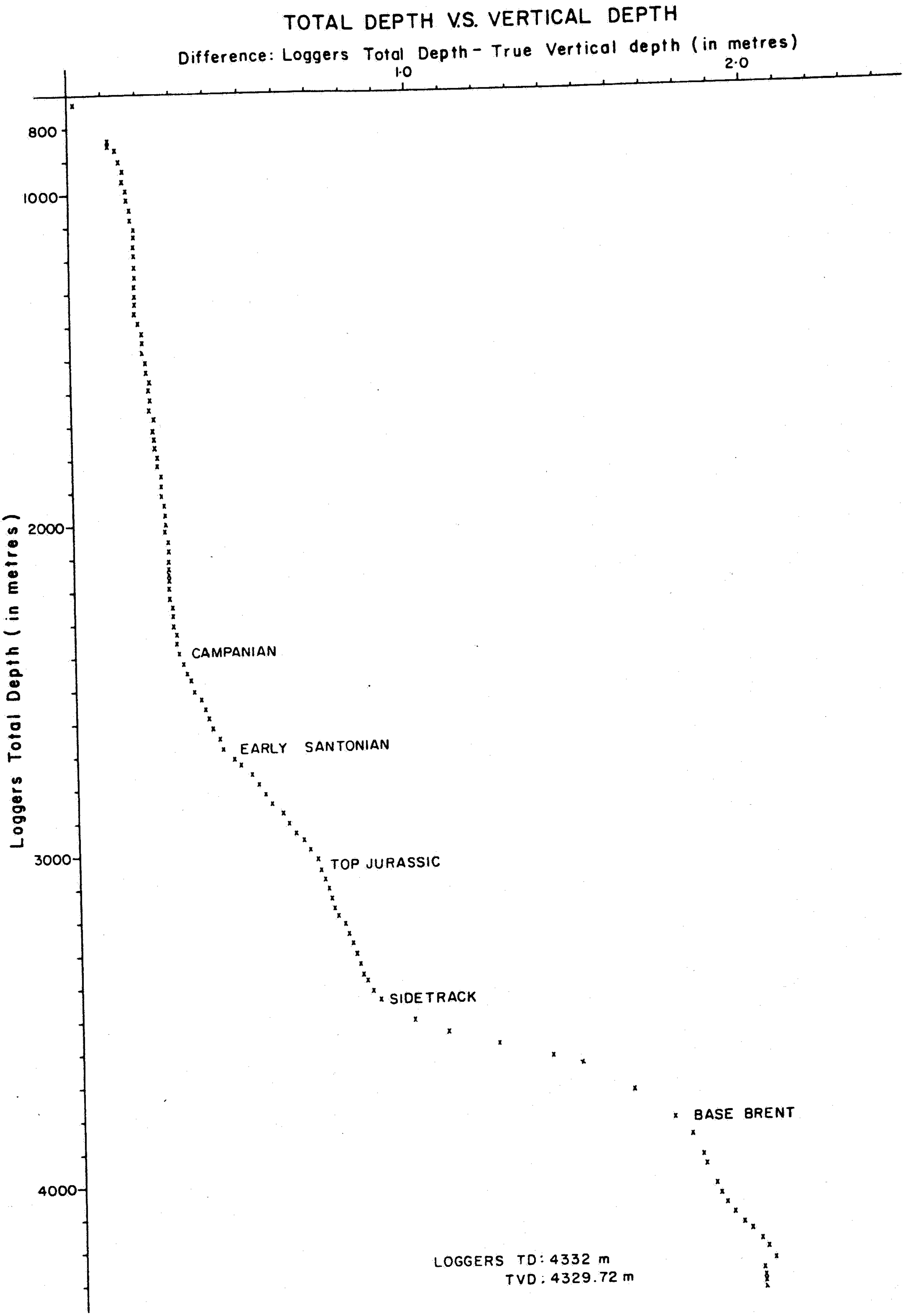

TOTAL DEPTH V.S. VERTICAL DEPTH
Difference: Loggers Total Depth - True Vertical depth (in metres)
1·0
2·0
800
1000
2000
3000
4000
Loggers Total Depth (in metres)
CAMPANIAN
EARLY SANTONIAN
TOP JURASSIC
SIDETRACK
BASE BRENT
LOGGERS TD: 4332 m
TVD: 4329.72 m

Fig. 4

SPERRY-SUN

INTERNATIØNAL INC.

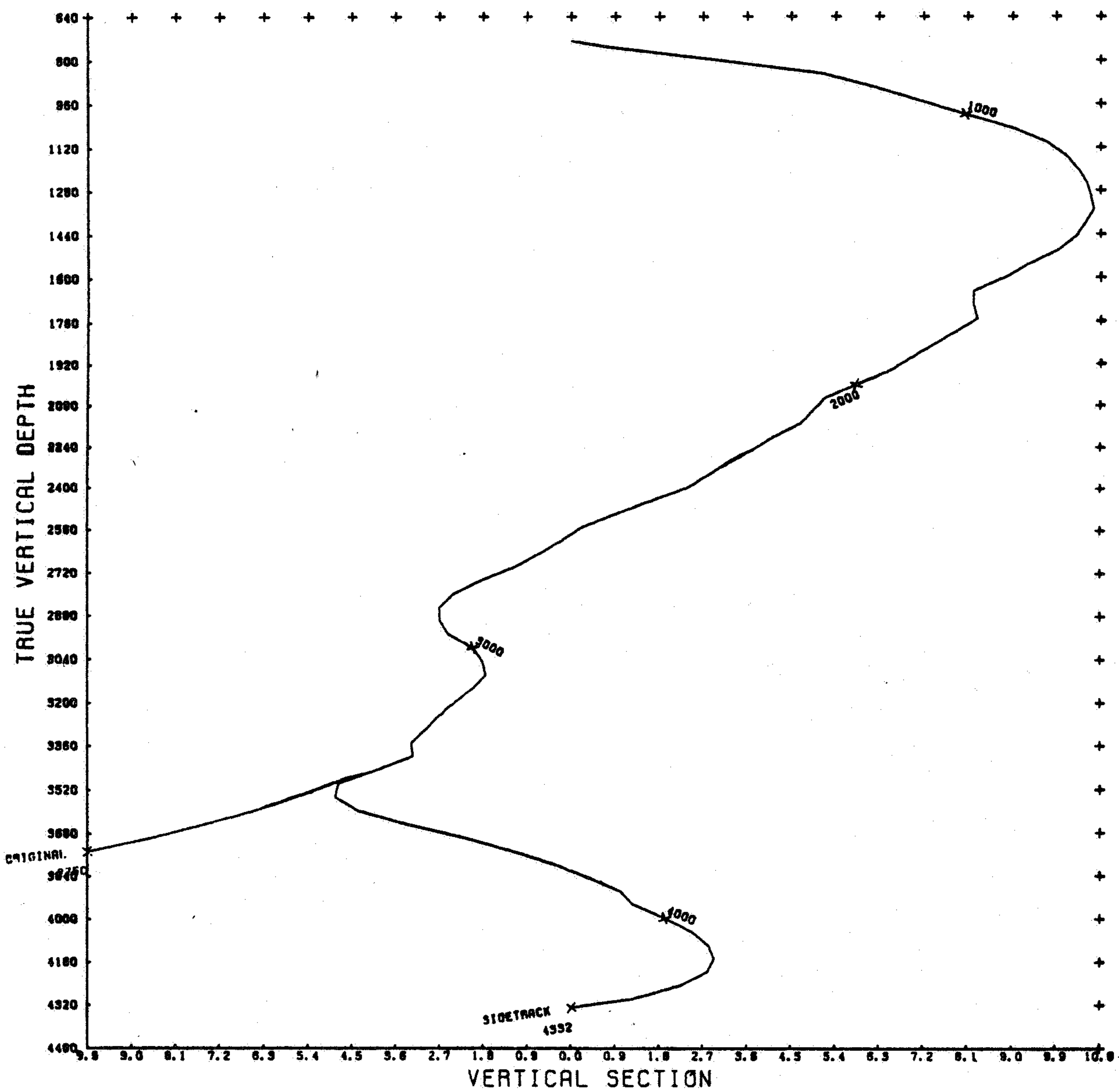
VERTICAL PROJECTION

NO WELLS HAVE BEEN EXTRAPOLATED

CUST. NØRSKE GULF A/S
JOB. NO.
START MD. = 0
SCALE IS 160/0.9 METERS/CM.
COURSE LENGTH = 50

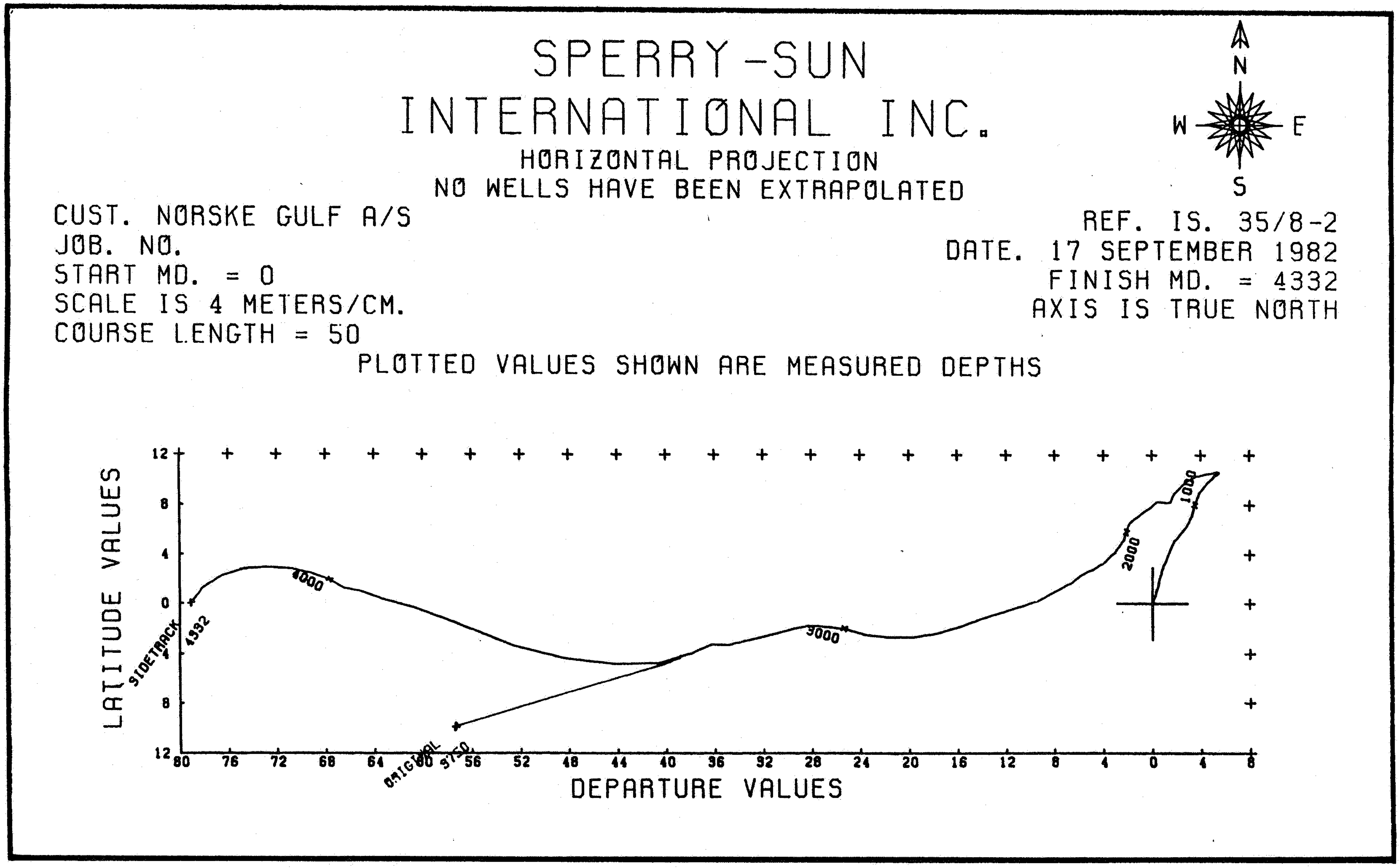
REF. IS. 35/8-2
DATE. 17 SEPTEMBER 1982
FINISH MD. = 4332
V. S. AZM. = 0.00

PLOTTED VALUES SHOWN ARE MEASURED DEPTHS



Hole Deriation - Vertical

Fig. 5



Hole Deviation-Horizontal

Fig.6

4. Site Investigation Survey

In compliance with NPD regulations, a site investigation survey was carried out prior to drilling. The survey was designed to investigate seabed conditions, predict shallow geology and detect any occurence of shallow gas.

A detailed report from Aquatronics is available from the operator, upon request, together with a report from Surcon International, who supervised the survey on behalf of Norwegian Gulf Exploration Company A/S.

Summary of results from Aquatronics Survey:

The water depth at the final proposed drilling site was predicted to be 376m (corrected to lowest astonomical tide). Actual depth was 376.3m.

The sea bed is gently undulating between 374m and 378m and consisting of a very soft silty clay. Sediment type and the presence of pock-marks indicated weak soils thus providing bad anchoring conditions. Because of this prediction piggy-back anchors were run on each primary anchor.

Small area of high amplitude anomalies on the shallow seismic records indicative of shallow gas accumulations, were found throughout the area at a level 113m below seabed. The gas could have migrated up-dip within the prograding Pliocene sequence and care was recommended to be taken within the whole of this sequence (113m-410m below seabed). At a level approximately 550m below seabed, a number of minor faults occur, but none appeared to intersect with the well location. This was confirmed by drilling, and at the same time no gas was detected.

5. Associated Report Listing

1	Well Site Assessment 715/w	(Fairfield Aquatronics)
2	Site Survey Supervision	(Surcon)
3	Navigation and Positioning of Sedco 704	(Decca)
4	Rig Positioning Supervision	(Surcon)
5	Well Comp. Report - Mud and Pressure Logging	(Baroid)
6	Well Summary - Mud Re-cap	(Anchor Drilling Fluids)
7	CPI Listing - Brent 11/11/81	(Schlumberger)
8	Geodip Listing, Log Run 4	(")
9	Core Analysis Results	(Scanwell)
10	Formation Testing, Service Report	(Halliburton)
11	Pressure Survey Report	(Flopetrol)
12	DST Operations Report	(EXPRO)
13	PVT Analysis, DST 1	(")
14	Test Procedure and Analysis of Data	(Gaffney Cline)
15	Stratigraphical/Paleontological Final Report	(Paleoservices)
16	Semi-quantitative Clay Analysis	(Paleoservices, HTC, Anchor)
17	Organic Geochemistry	(IKU)
18	Single Sample Analysis of Oil Extract from Core	(GS&T)
19	Nature of the Hydrocarbons Present in 35/8-2	(IKU)
20	Well Velocity Survey and CVL Report	(SSL)
21	Synthetic Seismogram Report	(SSL)
22	Vertical Seismic Profile Report	(SSL)
23	Offset Source Survey Report	(SSL)*
24	Significance of the 35/8-2 Gas/Cond. Discovery	(Gulf)*

Reports marked with an asterisk(*) are not included with the routine trade data. However, summaries of most of the conclusions from these and other reports are included in this completion report.

GEOLOGY

6. Geological Discussion

An adequate description of the lithologies can be found on the Composite Log, on the Mudlog and in the biostratigraphic report. Discussion here is limited to the reasons for choosing litho and chrono-stratigraphic boundaries, whether based on log character alone or on palæontological grounds. All depths are expressed in metres below RKB, as logged by ISF/Sonic and match those of the Composite Log. Samples were collected as follows:

Every 10 metres from 580m to 2700m	
Every 4 metres from 2700m to 3044m	
Every 2 metres from 3044m to 3667m	
Continuous core from 3667m to 3753.4m	
Every 4 metres from 3480m to 3670m	
Every 2 metres from 3670m to 3974m	Side track
Every 4 metres from 3974m to 4336m	

A 135 shot sidewall core programme resulted in 70 recoveries from the Upper and Lower Jurassic.

The stratigraphical nomenclature in this report is based in as far as is appropriate on the IGS/NPD publication 77/25. "A standard lithostratigraphic nomenclature for the Central and Northern North Sea". This also forms the basis from which the Paleoservices biostratigraphic report for the well was compiled.

Where possible, the first occurrence of significant microfossils has been included on the Composite Log. This has been done to facilitate correlation with other wells drilled by companies whose own interpretation of the chronostratigraphical significance of these 'typical' faunas and floras differs from Gulf's. All first occurrence depths given refer to the top of the interval from which the sample was taken. Well Data sheets and a geological synopsis (Figure 7) follow.

Well 35/8-2 STRATIGRAPHIC TOPS

Top Systems/Series/Stage/Unit	KB Depth meters	Subsea meters	Thickness meters	TWT secs.
L.Pleist-Recent SEA FLOOR	406.9	380.9	118.0	
Tertiary	525.0	499.0	1415.5	
NORDLAND GROUP	525.0	499.0	443.5	
Miocene Sand (?Utsira Fm)	791.0	765.0		0.894
(Miocene-Early Pliocene)	791.0	765.0		0.894
HORDALAND GROUP	968.5	942.5	738.8	1.054
Mid-Late Oligocene	968.5	942.5		1.054
Early-Mid Oligocene	1248.0	1222.0		1.340
Eocene - Oligocene	1305.0	1279.0		1.392
Mid-Late Eocene	1392.0	1366.6		1.478
Early-Mid Eocene	1502.5	1476.5		1.578
Late Paleocene-Early Eocene	1674.0	1648.0		1.728
ROGALAND GROUP	1707.0	1681.0	126.0	1.756
BALDER FORMATION	1707.0	1681.0	70.5	1.756
Late Paleocene	1774.5	1748.5		1.814
SELE FORMATION	1777.5	1751.5	55.5	1.816
MONTROSE GROUP	1833.0	1807.0	107.5	1.862
UP. LISTA FORM	1833.0	1807.0	56.0	1.862
LR. LISTA FORM.	1889.0	1863.0	39.0	1.916
Early-Mid Paleocene	1889.0	1863.0		1.916
MAUREEN FM.EQUVALT	1928.0	1902.0	12.5	1.950
Cretaceous	1940.5	1914.5	1120	1.958
SHETLAND GROUP	1940.5	1914.5	1120	1.958
Late Maastrichtian	1940.5	1914.5		1.958
Early-Late Maastrichtian	1980.0	1954.0		1.988
Campanian	2090.0	2064.0		2.070
Santonian	2090.0	2534.0		2.410
Turonian - Coniacian	2770.0	2744.0		2.552
Cenomanian	3059.0	3033.0		2.726
CROMER KNOLL GP.	3060.0	3034.0	18.5	2.728
Albian	3060.0	3034.0		2.728
Early Barremian-Hauterivian	3074.0	3048.0		2.736
Jurassic	3078.5	3052.5	1253.5	2.738
HUMBER GROUP	3078.5	3052.5	587.5	2.738
KIMMERIDGE CLAY FM.	3078.5	3052.5	125.5	2.738
Portlandian	3078.5	3052.5		2.738
Late Kimmeridgian	3100.0	3074.0		2.754
HEATHER FORMATION	3204.0	3178.0	462.0	2.828
Mid-Late Oxfordian	3204.0	3178.0		2.828
HEATHER SAND	3305.0	3279.0	32.0	2.888
L.HEATHER SHALE	3338.0	3312.0	328.0	2.904
Late Callovian-Early Oxf.	3338.0	3312.0		2.904
Mid Callovian	3472.0	3446.0		2.986
Callovian 'Unconformity'	3510.0	3484.0		3.016
Mid Bathon. - E-Callov.	c. 3510.0	3484.0		3.016
Early-Mid Bathonian	3603.0	3577.0		3.070
BRENT GROUP	3666.0	3640.0	219.0	3.108
TARBERT FORMATION	3666.0	3640.0	51.0	3.108
NESS FORMATION	3717.0	3691.0	68.5	3.134
G/W - Contact	3726.0	3700.0		3.140
Early Bajocian-Earl.Bath.	3762.0	5736.0		3.160
ETIVE FORMATION	3785.5	3759.5	28.5	3.170

Table 1 Well Data Sheet

Table 1 cont...

	KB Depth meters	Subsea meters	Thickness meters	TWT secs.
RANNOCH FORMATION	3814.0	3788.0	54.0	3.188
BROOM FORMATION	3868.0	3842.0	17.0	3.216
DUNLIN GROUP	3885.0	3859.0	318.0	3.224
DRAKE FORMATION	3885.0	3859.0	46.5	3.224
Toarcian-Early Bajocian	c. 3885.0	3859.0		3.224
COOK FORMATION	3931.5	3905.5	132.5	3.250
Late Pliensbachian - Early Toarcian	3952.5	3926.0		3.260
BURTON FORMATION	4064.0	4038.0	31.0	3.316
AMUNDSEN FORMATION	4095.0	4069.0	108.0	3.332
Sinemurian - Pliensbach.	4173.0	4147.0		3.370
STATFJORD GROUP	4203.0	4177.0	129.0	3.384
NANSEN FORMATION	4203.0	4177.0	22.5	3.384
ERIKSEN FORMATION	4225.5	4199.5	106.5	3.398
T.D.	4332.0	4306.0		

GEOLOGICAL SYNOPSIS

35/8-2

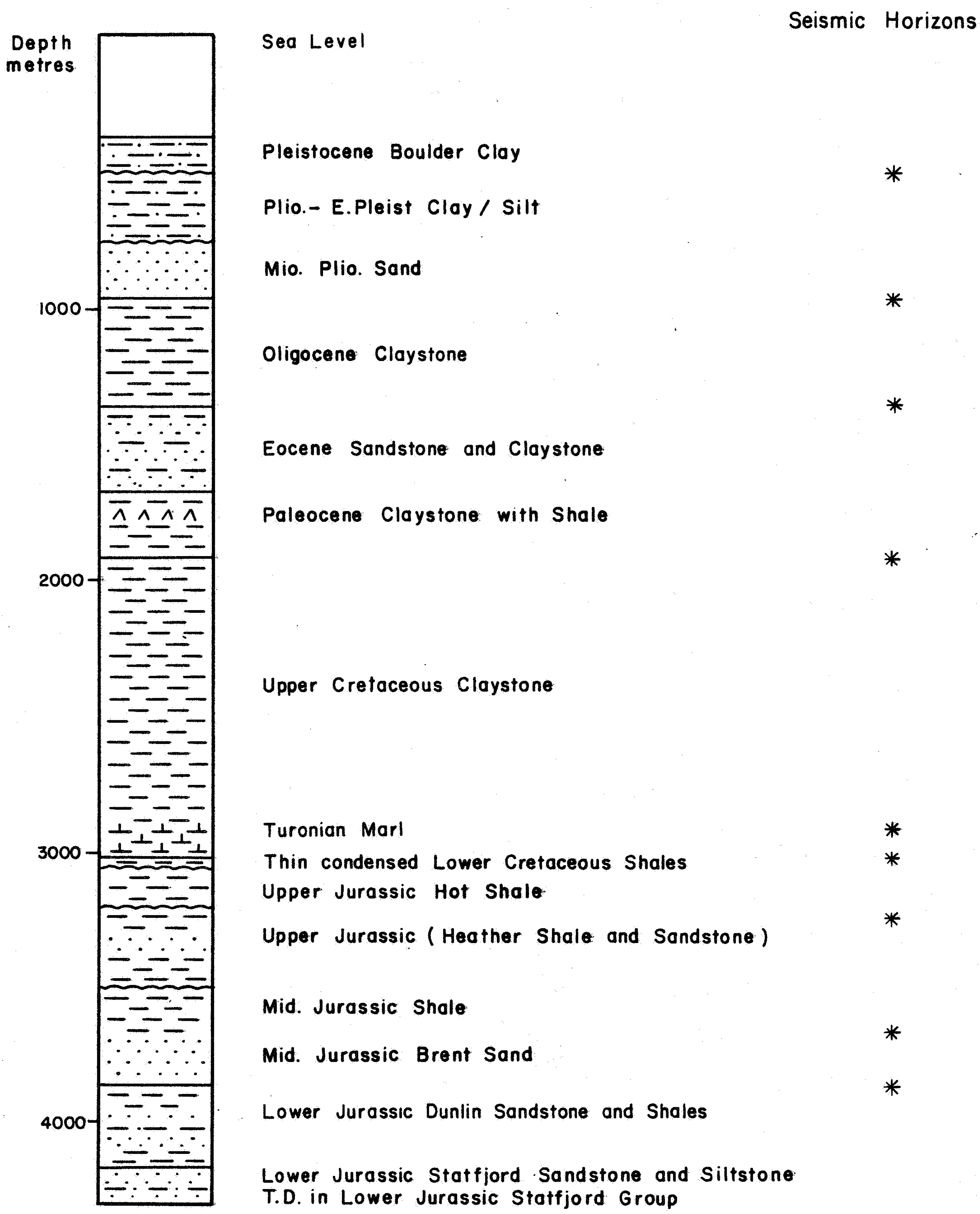


Fig. 7

Composite Log Picks:

Recent/Late Pleistocene (406.9 - c.525m)

By analogy with nearby 35/8-1, the interval from seafloor, 406.9m, to about 525m (estimated from shallow seismic) is dated as Recent - Late Pleistocene. It forms an essentially glacially - derived till, with boulders and smaller lithoclasts of metamorphic basement and chalk. The 30" casing was set below these glacial deposits, at 578m, and the interval was only examined from bit samples.

Tertiary (c.525m - 1940.5m)

NORDLAND GROUP (c.525m - 968.5m)

Late Pliocene - Early Pleistocene (c.525m - 791m)

The top of this unit was drilled without returns, and is equated with the shallow seismic reflector which, in well 35/8-1 was represented by a drop in gamma ray (through casing) level at the same depth. The first returns, from 578m were of siltstone and variably grain-sized sandstones which, below 600m contain a foram fauna typical of Late Pliocene - Early Pleistocene age. The appearance of Cibicides lobatulus grossa at 600m is usually considered a Late Pliocene marker, but its range may extend higher.

?MIOCENE SAND (?UTSIRA) FORMATION (791m - 968.5m)

?Miocene - ?Early Pliocene (791m - 968.5m)

No closely age-diagnostic fauna is present in this interval which comprises glauconitic sands. They lie beneath the extensive prograding Pliocene - Early Pleistocene deposits, but above silty claystone of Oligocene age, probably with an unconformable relationship in both cases. A Miocene - Pliocene age is indicated by the sparse fauna, and in the regional context of similar stratigraphically placed sands, they are dated as Miocene -?Early Pliocene.

HORDALAND GROUP (968.5m - 1707m)

Oligocene, Late (968.5m - 1248m)

The top of the Hordaland Group coincides with the marked lithological break at 968.5m, where the ?Miocene sands abruptly overlie a fine silty claystone. The abundance of sponge spicules in this claystone is regionally diagnostic of the top of the Hordaland Group. A Late Oligocene age is confirmed at 990m by the appearance downhole of Turrilina alsatica and Gyroidina soldanii girardana. A local sand body is present between 1178m and 1204m.

Oligocene, Early - Mid (1248m - 1305m)

The top of the Mid Oligocene is marked by the highest occurrence of Rotaliatina bulimoides, which coincides with a slight break in log character at 1248m.

Oligocene - Eocene (1305m - 1400m)

An indeterminate long-ranging but very abundant foram and diatom assemblage characterises this interval, which may span the Oligocene - Eocene stage boundary. A slight decrease in gamma ray, resistivity values and velocity are also present at 1305m. Traces of orange siderite occur in the uppermost 30m.

Eocene, Mid-Late (1400m - 1502.5m)

The top Eocene is tentatively placed at faunal break where the agglutinating foram fauna becomes more diverse downhole, particularly with the entry of Bathysiphon sp. Lithologically, the interval top shows a marked decrease in gamma ray response as the claystone becomes light green in colour, with thin harder interbeds. The top of an "Eocene Sand" falls within this unit, probably a more extensive unit than the Oligocene sand.

Eocene, Early - Mid. (1502.5m - 1674m)

The highest occurrence of the agglutinating foram Cyclammina acutidorsata indicates top Mid Eocene. The claystone, which alternates with thin sandstones throughout this interval, changes colour downwards from tea-green and light grey to a predominantly grey tone at about 1560m. At 1610m claystones become medium to dark grey, and at 1645m the appearance of a regionally widespread brick red claystone which characterizes the Early Eocene, is noted.

Late Palæocene - Early Eocene (1674m - 1774.5m)

This time-unit is recognized over a large area by the presence of the diatom, Coscinodiscus sp. 1, which is present in the claystone at 1674m.

ROGALAND GROUP (1707m - 1833m)

BALDER FORMATION (1707m - 1777.5m)

The Balder Formation, the highest lithostratigraphic unit of the Rogaland Group, represents the culmination of volcanic tuffaceous claystone deposition. As such, it is recognized downhole by the common occurrence of thin, graded tuff interbeds, and conveniently by thin hard grey siltstones with which they are interbedded.

Palæocene, Late (1775m - 1889m)

The downhole reappearance of agglutinating forams, including large Bolivinopsis spectabilis characterises the indisputable top Palæocene.

SELE FORMATION (1777.5m - 1833m)

The Sele Formation is identified on the basis of the disappearance of sand and volcaniclastic debris, the slight decrease in resistivity and sonic velocity, and by correlating with nearby wells. The top of the formation is conveniently marked by a hard, grey, radioactive shale which appears to be regionally extensive, passing down into the occasionally silty, non calcareous, grey claystone which characterises the unit. This formation is identifiable while drilling by a relatively high penetration rate compared with the Balder Formation above (20m/hr and 10 km/hr average, respectively).

MONTROSE GROUP (1833m - 1940.5m)

UPPER LISTA FORMATION (1833m - 1889m)

The Montrose Group top, and the top of the Upper Lista Formation, an event correlatable over Block 35/8, is marked by the appearance of dark grey, hard shaly claystone interbeds, comprising in all about 20% of the lithotype throughout the Upper Lista unit. It is marked also by a drop in penetration rate while drilling, down from 20 m/hr (Sele Fm.) to 10-15 m/hr average.

LOWER LISTA FORMATION (1889m - 1928m)

Palæocene, Early - Mid (1889m - 1940.5m)

The regional appearance of large sphærical reticulate Radiolaria is used to define the top of the Mid Palæocene. Foraminiferal species characteristic of, but not necessarily confined to the Early Palæocene are also present, suggesting the presence of strata of this age.

The Lower Lista Formation is somewhat less shaly than the upper Lista Formation, and tends to drill faster (about 15 m/hr average). The decreasing shaliness is also marked on electric logs, by a cutback in sonic velocity and a slight decrease in resistivity.

MAUREEN FORMATION EQUIVALENT (1928m - 1940.5m)

A thin marl and calcareous claystone at this level is equated with the regionally widespread equivalent of the Maureen Formation. In addition to the obvious lithological change from non-calcareous to calcareous claystones, a resistivity and velocity increase is apparent.

Cretaceous (1940.5m - 3078.5m)
Cretaceous, Late (1940.5m - 3060m)
SHETLAND GROUP (1940.5m - 3060m)

Maastrichtian, Late (1940.5m - 1979m)

A diverse assemblage of regionally distinct Late Maastrichtian planktonic foraminifera diagnose the top of the Late Cretaceous. These include *Pseudotextularia elegans*, *Globotruncana contusa*, *Racemiguembelina* fructicosa. The top of the Cretaceous coincides with the top of the Shetland Group, which is characterised by the appearance of pure white (chalk) limestones, interbedded with grey claystone which has a marked tendency to hydrate. The increase in velocity and resistivity on electric logs is matched by a drop in drill rate, down to less than 10 m/hr.

Maastrichtian, Early - Late (1979m - 2090m)

A regionally consistent Late Maastrichtian foram marker, the appearance downhole of the benthic Reussella szajnochae szajnochae with planktonic Abathomphalus mayaroensis, indicates the top of this time-unit.

Campanian (2090m - 2560m)

Youngest Campanian strata are recognized by the association of red claystone/marl, red-stained fossils, including the forams Globotruncana aff. arca and Pseudogaudryinella capitosa.

Santonian 2560m - 2770m

The highest occurrence of the foram Stensioeina granulata polonica is used regionally to mark the top of the Santonian. In this well, this event coincides with the consistent occurrence of sphaerical radiolaria, which is also characteristic of the Santonian.

Coniacian - Turonian

Planktonic forams, including Marginotruncana marginata are relatively common through this interval, and provide a distinctive marker for its top although the log break at 2731m would have to be considered if a break in the succession was sought. It is not possible to distinguish the top Turonian, although the early Coniacian - Turonian foram Gavelinella tourainensis occurring below 2988m, within the sandy limestones of the "Turonian Marls" must indicate an approximate boundary.

TURONIAN MARL "FORMATION" (2947m - 3059m)

This unit is characterized by an abundance of white - grey limestones, sometimes silty and glauconitic, which pass down into true marls.

?PLENUS MARL FORMATION (3059m - 3060m)

Cenomanian (3059m - 3060m)

The presence of the forams Arenobulimina gr. chapmani and Clavulina gaultina, together with the consistent occurrence of Hedbergella brittonensis within a 4m interval suggests the presence of a thin Cenomanian unit. This is equated with the thin green, waxy claystone, which in turn is believed to be represented on logs by the 1m thick radioactive low velocity unit, between 3059m and 3060m. Regional correlation suggests that this may be a section of the widespread "Plenus Marl Formation", a late Cenomanian event. The regional topmost Cenomanian marker (abundance level of Hedbergella brittonensis) was not, however, recorded, and the additional absence of early Cenomanian forms suggests considerable loss of section at this level.

CROMER KNOLL GROUP (3060m - 3078.5m)

Albian (3060m - 3073m)

A thin representative of the Cromer Knoll Group can be recognized in the well. Its upper boundary is the base of the Shetland Group (?Plenus Marl Formation). Further subdivision is not possible, although traces of light brown claystone suggest the presence of a thin Rødby Formation equivalent. Otherwise the remaining Lower Cretaceous section may be referrable to the Valhall Formation.

The planktonic foram Globigerinelloides caseyi, a Late-Mid Albian form occurs with Hedbergella delrioensis, defining the top of the Albian in the well.

Early Barremian - Hauterivian (3073m - 3078.5m)

Sediments of this age are based on the occurrence of the agglutinating forams Uvigerinammina moesiana and U."elongata" (int.sp.). These occur predominantly in a light brown limestone which regionally is characteristic of the Early Cretaceous transgressive sequence, overlying the Sub-Cretaceous Unconformity surface which here forms its base.

Jurassic (3078.5m - 4332m base not seen)
Jurassic Late (3078.5m - c.3510m)

HUMBER GROUP (3078.5m - 3666m)

KIMMERIDGE CLAY FORMATION (3078.5m - 3204m)
Portlandian (3078.5m - ?3100m)

The top of the low velocity, radioactive shales, immediately beneath the Sub-Cretaceous Unconformity, defines the top of the Kimmeridge Clay Formation, and the Humber Group.

A Portlandian age for these youngest Jurassic sediments may be assigned on the basis of the microflora, particularly Pterospermopsis aureolata, Sirmiodinium grossii, Wallodinium krutzschii and Tubotuberella apatela. This assemblage is of typically Berriasian - Late Kimmeridgian age. The radiolaria Lithostrobus sp. is also recorded from the top of the interval. Its occurrence is conventionally taken to indicate Portlandian age.

The presence of an unconformity is likely beneath earliest positively Cretaceous strata, and the omission of the Berriasian is therefore likely, particularly with the absence of the characteristic radiolarian Tricolocapsa sp.

Kimmeridgian, Late (c. 3100m - 3204m)

The abundance of the radiolarian Dictyomitra sp. at 3100m may correlate with a regional event marking top Kimmeridgian. No Early Kimmeridgian palynomorphs are recorded from the well, and strata of this age are probably absent.

HEATHER FORMATION (3204m - 3666m)
Oxfordian, Mid-Late, (3204m - 3338m)

The passage of 'hot' Kimmeridge Clay Formation down into less radioactive, faster velocity clays and shales is not so marked in this well as elsewhere regionally. However, a convenient break in the succession is suggested palæontologically at 3204m, coinciding with a change in kerogen type, from sapropelic down into predominantly humic. Beneath 3204m, a greater proportion of sand is registered, and this is taken as both top Heather Formation and Oxfordian, although the highest characteristic fossils are not recorded above the sidewall core at 3210.5m. These include Nannoceratopsis pellucida, Endoscrinium galeritum, Scriniodinium crystallinum, Gonyaulacysta jurassica, G.cladophora, and Adnatosphaeridium filamentosum.

A Heather Sand "Unit" top is indicated on the log at 3305m, being the top of the sandier reservoir facies within the Heather Formation proper. No formal lithostratigraphic term exists to accommodate this sand.

Callovian, Late - Oxfordian, Early. (3338m - 3472m)

Early Oxfordian sediments were penetrated by 3346.7m (sidewall core) where a diagnostic dinoflagellate cyst assemblage was encountered, comprising: Gonyaulacysta areolata Stephanelytron redcliffensis, Compositosphaeridium costatum, Adnatosphaeridium aemulum and Endoscrinium galeritum (abundant). Earliest Oxfordian (mariae zone) sediments were reached by 3366m, where Wanea digitata was recorded. By 3378m, the regionally characteristic Late Callovian assemblage, Mendicodinium groenlandicum associated with abundant Lithodinia spp. (including L.callomonii), appears down hole, although slightly deeper, at 3400m, the Early Oxfordian regional downhole occurrence of abundant agglutinating forams appears to be present. Deeper still, at 3432m, the extinction level of Pleurocythere borealis is observed, being regionally represented within Late Callovian - Earliest Oxfordian strata.

Mid Callovian (3472m - 3510m)

The upper limit of this interval is taken at the occurrence of relatively common Chytroeisphaeridia sp. 1 (C.hyadina, Raynaud), which does not occur above the Mid Callovian. Other, longer ranging dinoflagellates typically occur together in Mid Callovian - Bathonian sediments. The foram, Recurvoides aff. sublustris, which is typical of the Callovian in this area, occurs throughout the interval.

Mid Bathonian - Early Callovian (3510m - 3603m)

Based on correlation with other wells, the Callovian Unconformity is placed at the top of this interval, consistent also with the highest occurrence of the ostracod "Procytheridea" cf. pseudocrassa, a regional event within the Early Callovian.

Penetration of Early Callovian is also indicated by Dichadogonyaulax kettonensis at 3542m. Downhole, at 3572m, a limited diversity assemblage of dinoflagellates, comprising Chytrosphaeiridia "granulata" is regionally characteristsic of Late/Mid Bathonian sediments.

Bathonian, Early - Mid (3603m - 3762m)

The latest appearance of dinoflagellate cyst assemblages dominated by Gonyaulacysta filipicata and variants occurs within the Mid Bathonian in the North Sea, and 3603m in this well.

BRENT GROUP (3666m - 3885m)
TARBERT FORMATION (3666m - 3717m)

This lithostratigraphic top is taken at the abrupt downward transition from claystone and shale of the Heather Formation, to sandstone of the Brent Group. The Tarbert Formation represents a series of prograding deltaic sand deposits, the base of which lies above the last thick coal of the underlying Ness Formation.

NESS FORMATION (3717m - 3785.5m)

This interval is characterized by mudstones, thin sandstones, coals and silty beds, with occasional evidence of some marine influence.

Bajocian, Early - Bathonian, Earliest (3762m - 3885,)

The upper limit of this interval is conventionally taken at the first downhole appearance of the dinoflagellate cyst Nannoceratopsis gracilis.

ETIVE FORMATION (3785.5m - 3814m)

The top Etive Formation is invariably characterised by a clean, coarse, reworked barrier bar sand. In this well, this lithology is encountered at 3785.5m overlying a varied, sand with occasional thin shale and coal, sequence.

<u>RANNOCH FORMATION</u> (3814m - 3868m)

This formation comprises a single coarsening - up unit of generally fine, micaceous and occasionally calcareous sandstone, becoming argillaceous towards its base. The top is obvious from logs, by the increased gamma ray response in these fine micaceous sands, beneath the coarser, cleaner less radioactive sand of the Etive Formation.

<u>BROOM FORMATION</u> (3868m - 3885m)

The coarse sand and gravel at 3868m defines the top of the Broom Formation, below the fine, micaceous Rannoch Formation. It is too thin to be easily identified by log character, but is obvious in cuttings. Similarly, the base Broom Formation is also represented by a thin coarse bed, at 3885m. The influx downhole of abundant <u>Nannoceratopsis gracilis</u>, at 3872m, is regionally a within Broom Formation marker.

<u>Jurassic</u>, Early (c.3885m - 4332m + base not seen)
<u>Toarcian</u> - Early Bajocian (3885m - 3952m)
<u>DUNLIN GROUP</u> (3885m - 4203m)
<u>DRAKE FORMATION</u> (3885m - 3931.5m)

The basal gravel of the Broom Formation above a marine claystone marks the Dunlin/Brent boundary and the top Drake Formation. Palaeontologically, the boundary also seems to be associated with a downhole appearance of ostracods, <u>Camptocythere foveolata</u> gr., <u>Camptocythere parvula</u>. At 3894m, the forams <u>Nodosaria regularis</u> and <u>Haplophragmoides kingakensis</u> are still suggesting an Early Bajocian - Toarcian age.

The influx of <u>N.gracilis</u>, followed by downhole appearances of ostracods, then forams, is regionally typical of the Brent/Dunlin boundary sequence in the northern North Sea.

The regionally extensive near - base Drake Formation ironshot limestone marker was recognized at about 3924m.

COOK FORMATION (3931.5m - 4064m)

The top of the Cook Formation is the first downhole sand encountered within the Dunlin Group, occurring in this well, as elsewhere, just below the ironshot marker horizon at 3924m.

Late Pliensbachian - Early Toarcian (3952m - 4173.5m)

Relatively common clusters of Spheromorph/Spheripollenites are typical of Early Toarcian age, and form a regional marker. A date no earlier than Late Pliensbachian is indicated at 4173.5m by the occurrence in a sidewall core of Nannoceratopsis gracilis.

BURTON FORMATION (4064m - 4095m)

The Burton Formation top is picked on logs as the radioactive shale below the Cook Formation sands. Lithologically, it characteristically is a dark green/brown shale.

AMUNDSEN FORMATION (4095m - 4203m)

Apparently rather sandier over the Horda Platform area than the Amundsen Formation in its type area, this unit is assigned to this Formation until an alternative status can be designated. It is recognized by the downhole return to essentially sandstone/siltstone sediments, although it appears to be fairly shaly in its higher part.

Sinemurian - Pliensbachian (4173.5m - 4332m base not seen)

The deepest occurrence of Nannoceratopsis gracilis at 4173.5m is no earlier than Late Pliensbachian. A more refined age-dating for this interval is impossible without further sidewall cores, as the ditch cuttings (turbo-drilled) are of poor quality. Regional correlation allows a Sinemurian - Pliensbachian age to be confidently assigned.

STATFJORD GROUP (4203m - 4332m base not seen)
NANSEN FORMATION (4203m - 4225.5m)

Top Statfjord Formation is identified as the first coarse, rather calcareous sand below the fine-grained Lower Dunlin unit. This is clearly seen at

4203m from electric logs. The coarse, cleaner sand is confined to and delineates the Nansen Formation.

ERIKSON FORMATION (4225.5m - 4332m base not seen)

The return to finer-grained, occasionally argillaceous sediments, beneath the cleaner Nansen Formation, occurs at 4225.5m and marks the top of the Erikson Formation. This unit extends to TD of the well, as the regionally widespead Statfjord Coals, beneath the Erikson Formation, were not penetrated.

Comparison of prognosis and results

The depth prognosis for well 35/8-2 was based on the correlation of seismic line 80-1-02 to well 35/8-1. Comparison of the prognosis to the observed results of the well, using sonic log, velocity log, VSP's and synthetic seismograms, shows the prognosis to be accurate with only minor discrepancies.

Figure 8 shows seismic line 80-1-02 at the well location together with the acoustic impedance log and synthetic seismogram. The displayed synthetic seismogram was produced by convolution with a 30 Hz minimum phase Ricker Wavelet, filtered with the same time variant filter as line 80-1-02, and shows an increase in acoustic impedance as a white trough. Two discrepancies are immediately noticeable:

1) Phase shift between the synthetic seismogram and the seismic section.

2) Rapid change in acoustic impedance is not always a seismic marker, nor does it necessarily appear on the seismic section or the synthetic seismogram.

Phase shift effects

The 80-series seismic survey lines are phase shifted from the 35/8-2 VSP data and the synthetic seismogram (Fig.8). By comparing Fig. (8) with Table (2), Lithostratigraphic Prognosis versus Results, it can be shown, in general, that correlations were made 1 cycle above the Tertiary and Sub-Cretaceous events, and 1 cycle below the Cretaceous events. In the first case, higher velocity was predicted than exists (Fig. 9), compensating for most of the correlation error. The opposite effect holds for Cretaceous events, where the velocity prognosis was in good agreement with the observed results. The shapes of the curves are similar and the deviation is less than 2%, which means that for the Sub-Cretaceous Unconformity level, the prediction was 48.0m too deep (or, the velocity was 1.7% too high).

Relationship of Acoustic Impedance to Seismic Event

The near source VSP data reveal why a rapid change in acoustic impedance does not always give a good seismic event. Generally, a seismic section contains residual multiples even after seismic processing. Interbed multiples will remain since it is most often not possible to distinguish these from primary events during processing. Top Brent Sand is particularly poorly defined on the seismic section (Fig.8), in spite of a pronounced increase in acoustic impedance. From the VSP data (Fig. 10, primaries coloured yellow, multiples green), a good white trough occurs at Top Brent level until multiples from Top Cretaceous (Maastrichtian) shales (1.950 sec TWT) and Eocene Volcanics (1.756 sec TWT) interfere with the primary. The Top Brent event is nearly cancelled since the multiples are phase shifted. For geophone depths between 2000m and 4294m Top Brent appears with good signal character. Accordingly, the signal character for the Top Brent is expected to change over the adjacent area, which makes it difficult to identify the horizon for mapping purposes.

Other Items

The offset source VSP confirms the good correlation between the near source VSP and the reprocessed seismic section line 80-1-02.

Conclusions

The minor correlation errors in our interpretation of the area around 35/8-2 were caused by slight phase shifts between our different seismic surveys. These errors were to some extent compensated for by the fact that the velocity used for depth prediction during prognosis was too high. VSP data confirm that residual multiples nearly cancel the reflection expected from the Top Brent.

LINE 80-1-02

35/8-2

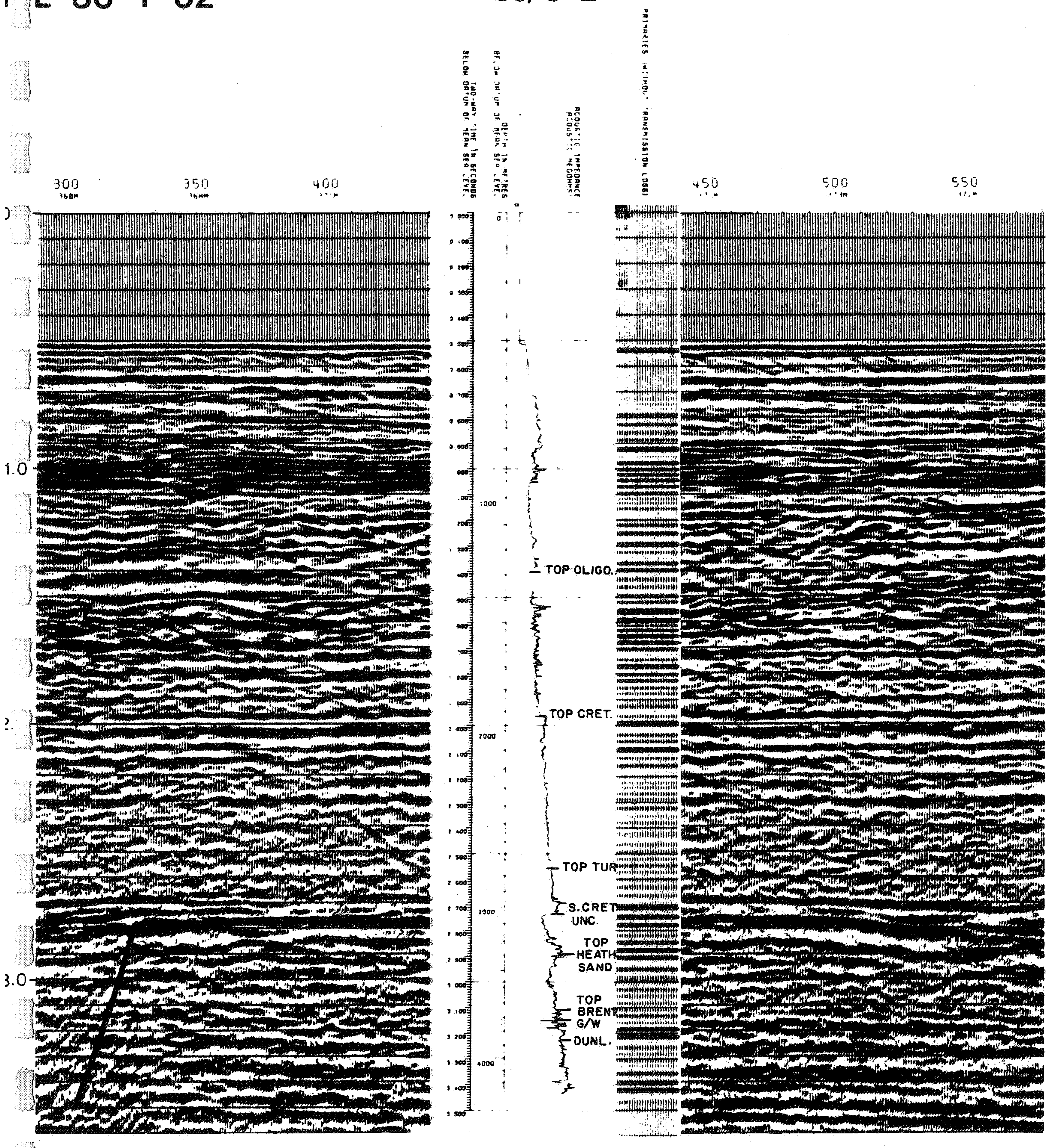


Fig.8

Lithostratigraphic Prognosis vs. Results

	Prognosis Sub-Sea (meters)	Prognosis TWT (sec)	Results Sub-Sea (meters)	Results TWT (sec)
Sea Bottom	376		380.9	
Base Pleistocene	500		499.0	
Plio/Miocene Sands	745	0.860	765.0	0.894
Oligocene Silt/Mudstones	935	1.030	942.5	1.054
Eocene Sands	1150	?		
Eocene Volcanic Marker	1725	1.755	1681.0	1.756
Palæocene Shales	1805	1.830	1807.0	1.862
UPPER CRETACEOUS				
Maastrichtian Shales	1960	1.950	1914.5	1.958
Campanian Shales	2145	2.095	2064.0	2.070
Turonian Marls	2990	2.685	2744.0	2.552
UPPER JURASSIC				
Kimmeridge Clay Fm.	3100	2.745	3052.0	2.738
Heather Sands	3140	2.770	3279.0	2.888
Heather Shales	3310	2.875	3312.0	2.904
MIDDLE JURASSIC				
Callovian Unconformity	3500	?	3484.0	3.016
Brent Sands	3610	3.060	3640.0	3.108
Dunlin Shales	3830	3.180	3859.0	3.224
Cook Sands	4000	3.265	3905.5	3.250
Statfjord Sands	4220	3.375	4177.0	3.384
Statfjord Coals	4410	3.475		
Final Total Depth	4500		4306.0	

TABLE 2

TIME / DEPTH PROGNOSIS VS RESULT

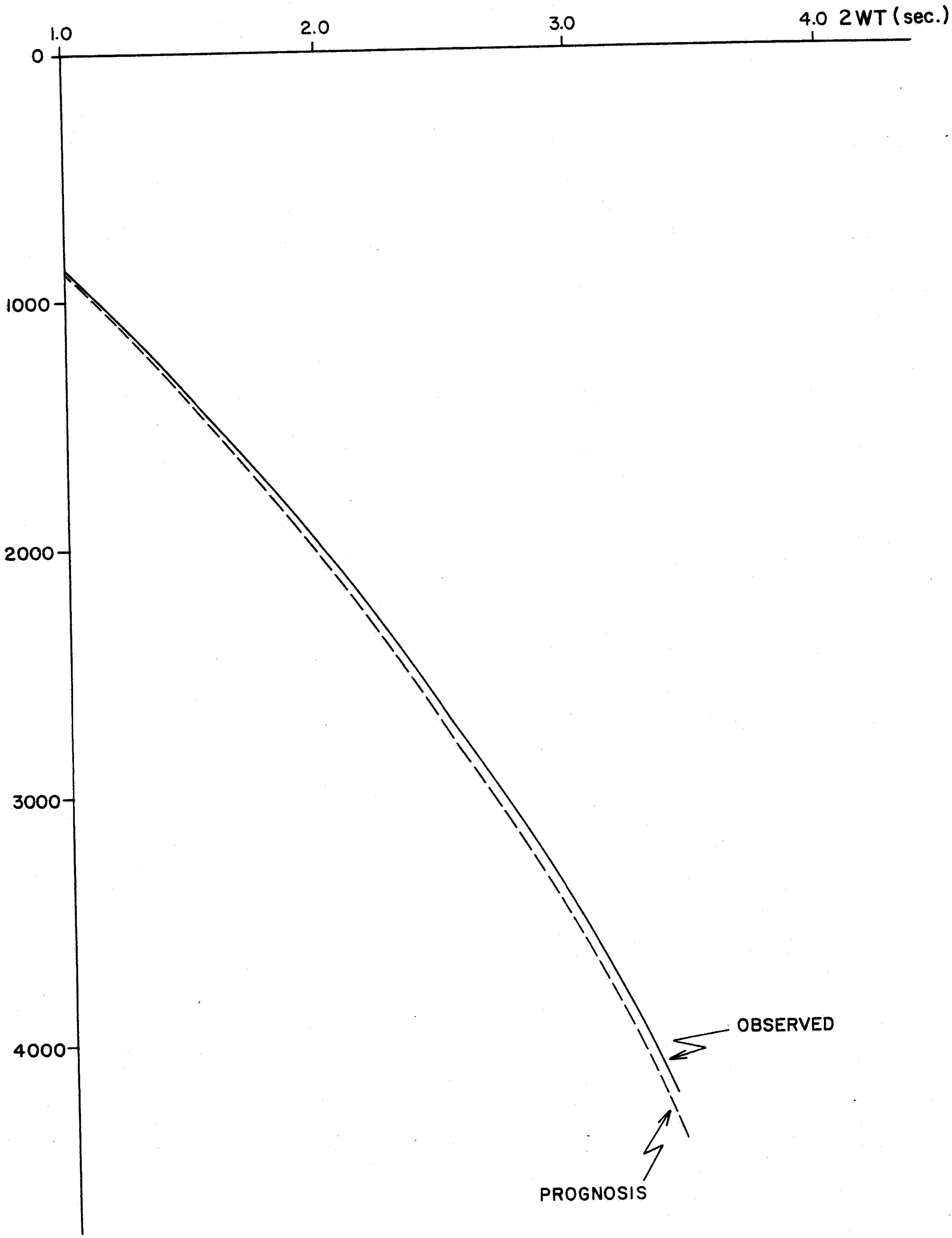


Fig.9

VSP UPGOING EVENTS

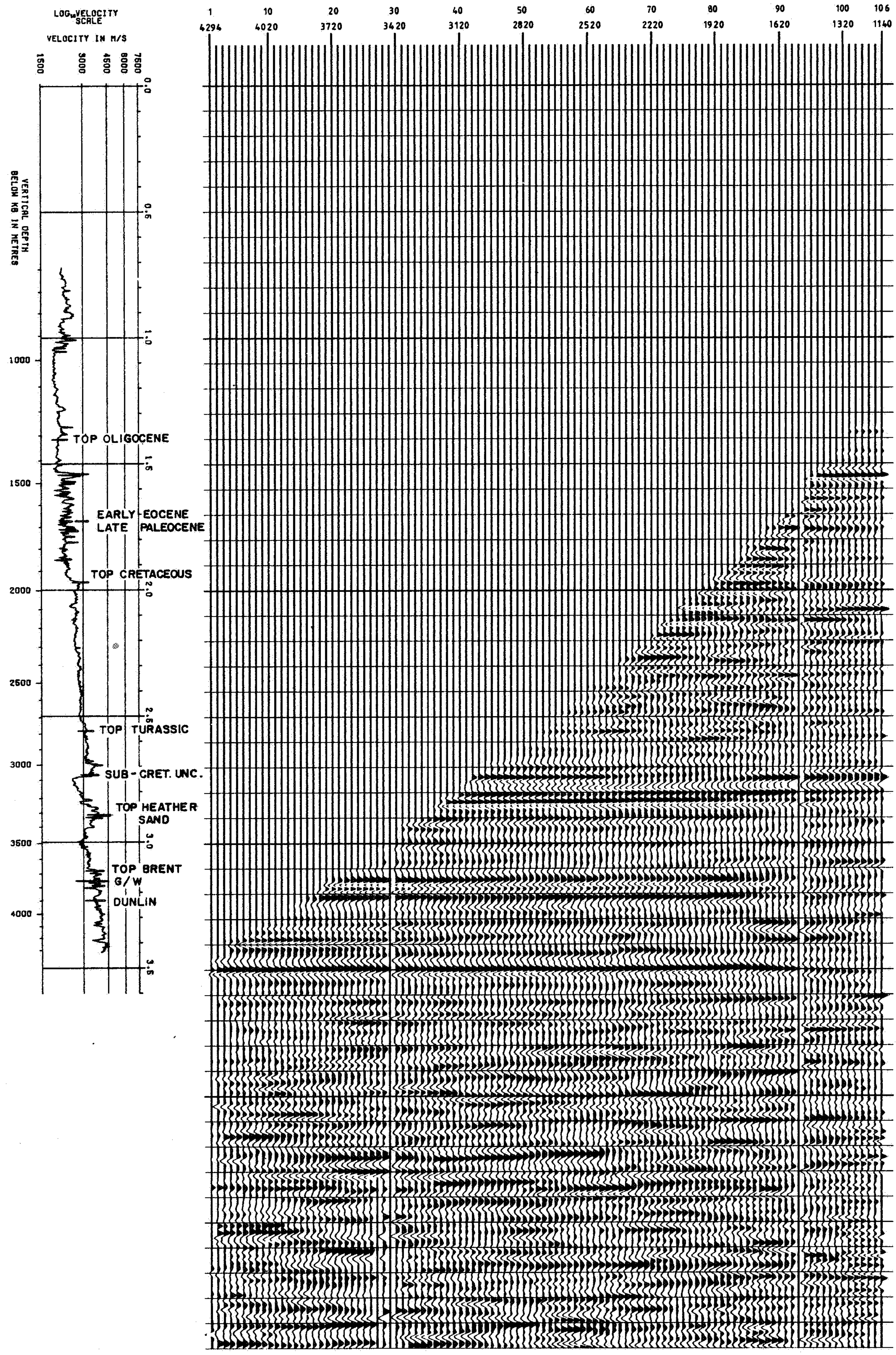


Fig 10

Core Analysis Results

Seven conventional cores were taken during the drilling of 35/8-2. Core no.1 (3317.0-3318.1m) is from the Heather Formation and cores 2-7 (3667.0-3753.4m) are from the Brent Formation. Attached is a complete listing of the porosities, permeabilities, and grain densities from the core plugs. Plugs were cut every metre in core no. 1 and every half metre in cores 2-7. Lithologies are described on the wellsite core-logs.

Core no.1 (3317.0-3318.1m) Heather Formation:

Depth (m RKB)	Ø%	Kmd.	Grain density
3317.1	1.9	0	2.75
3318.1	5.4	<0.01	2.75

Core no.2 (3667.0-3685.5m) Brent Formation

3667.6	28.5	3360.0	2.68
3668.1	9.1	0.12	2.73
3668.6	20.0	37.60	2.67
3669.1	18.5	2.65	2.68
3669.6	17.0	2.34	2.69
3670.1	18.4	5.38	2.70
3670.6	18.5	27.80	2.69
3671.1	18.3	33.31	2.67
3671.6	19.7	261.35	2.68
3672.1	18.3	70.42	2.69
3672.6	18.4	251.12	2.68
3673.1	19.2	38.92	2.70
3673.6	18.5	24.11	2.70
3674.1	19.8	133.62	2.67
3674.6	17.0	18.70	2.66
3675.1	17.0	16.02	2.67
3675.6	15.5	1.73	2.71
3676.1	18.4	10.81	2.68
3676.6	16.5	1.70	2.71
3677.1	17.8	4.06	2.69
3677.6	16.1	1.13	2.70
3678.1	17.7	4.04	2.67

Core no.2 (3667.0-3685.5m) Brent Formation

3678.6	15.0	0.79	2.68
3679.1	12.7	0.52	2.71
3679.6	15.4	2.17	2.70
3680.1	16.0	1.15	2.71
3680.6	14.3	0.44	2.73
3681.1	6.6	0.02	2.77
3681.6	16.8	1.02	2.71
3682.1	14.4	0.96	2.70
3682.6	13.6	0.50	2.71
3683.1	16.3	1.18	2.71
3683.6	17.1	1.11	2.72
3684.1	18.1	1.08	2.73
3684.6	17.0	0.87	2.73
3685.0	17.4	1.07	2.73
3685.45	16.7	0.83	2.71

Core no.3 (3685.5-3689.35)

3685.6	14.9	0.45	2.74
3686.1	16.7	1.06	2.71
3686.6	16.5	0.79	2.71
3687.1	18.2	0.77	2.75
3687.6	15.7	0.52	2.75
3688.1	17.6	0.98	2.72
3688.6	17.2	0.97	2.72
3689.1	16.8	0.67	2.71

Core no.4 (3689.35-3706.5)

3689.5	15.2	0.16	2.74
3690.1	10.3	Broken	2.69
3690.6	9.1	0.29	2.57
3691.1	3.3	0.01	2.60
3691.6	3.2	0.25	2.62
3692.1	3.5	0.01	2.61
3692.6	5.7	Broken	2.68
3693.1	17.4	2.29	2.66

Core no.4 (3689.35-3706.5m)

3693.6	16.7	15.46	2.66
3694.1	16.5	27.00	2.65
3694.6	22.6	10.14	2.66
3695.1	15.1	9.51	2.66
3695.6	12.6	2.25	2.67
3696.1	13.0	0.50	2.69
3696.6	14.3	2.75	2.67
3697.1	12.6	13.07	2.67
3697.6	16.7	3.26	2.68
3698.1	14.6	41.15	2.66
3698.6	13.6	3.83	2.67
3699.1	17.8	74.38	2.67
3699.6	18.0	117.15	2.67
3700.1	15.9	12.67	2.70
3700.6	16.7	52.84	2.68
3701.1	15.3	14.44	2.68
3701.6	9.6	0.35	2.69
3702.1	10,6	0.23	2.68
3702.6	11.8	0.46	2.69
3703.1	7.5	0.08	2.75
3703.6	22.2	319.30	2.70
3704.1	20.0	84.63	2.68
3704.6	9.2	0.17	2.70
3705.1	20.2	260.35	2.69
3705.6	19.4	287.44	2.67
3706.1	19.7	371.92	2.66

Core no.5 (3706.5-3725.05m)

3706.6	21.0	724.20	2.68
3707.1	17.1	46.16	2.69
3707.6	16.0	29.01	2.67
3708.1	16.6	25.19	2.68
3708.6	17.4	4.77	2.70
3709.1	18.9	13.04	2.70
3709.6	16.0	3.14	2.68
3710.12	10.1	0.24	2.76

Core no.5 (3706.5-3725.05m)

3710.6	16.5	2.63	2.72
3711.1	16.5	2.09	2.73
3711.6	18.3	2.54	2.73
3712.1	4.5	0.04	2.71
3712.6	6.9	0.03	2.81
3713.1	14.3	1.34	2.71
3713.6	14.0	3.74	2.70
3714.1	18.1	2.58	2.72
3714.6	12.0	Broken	2.69
3715.1	18.1	0.86	2.74
3715.6	16.4	1.40	2.71
3716.1	16.9	1.12	2.75
3716.6	6.2	Broken	1.42
3717.1	7.4	0.28	2.67
3717.6	14.1	0.33	2.73
3718.1	3.4	0.01	2.71
3718.6	4.4	0.05	2.70
3719.1	6.4	0.13	2.77
3719.6	4.1	0.13	2.68
3720.1	3.5	>0.01	2.49
3720.6	3.2	>0.01	2.62
3721.1	16.3	0.32	2.71
3721.6	19.0	0.16	2.71
3722.1	21.6	4.00	2.70
3722.6	17.8	1.21	2.71
3723.1	14.8	1.77	2.70
3723.6	20.7	3.36	2.71
3724.1	19.3	2.29	2.71
3724.6	16.6	0.58	2.72
3725.05	15.0	Broken	2.75

Core no.6 (3725.05-3743.76m)

3725.1	13.7	0.28	2.72
3725.6	5.5	0.16	2.74
3726.1	5.2	0.05	2.71
3726.6	4.6	Broken	1.30

Core no.6 (3725.05-3743.76m)

3727.1	11.2	0.16	2.73
3727.6	13.6	0.11	2.73
3728.1	16.1	0.11	2.71
3728.6	14.4	0.08	2.70
3729.1	9.6	0.21	2.72
3729.6	4.3	0.05	2.77
3730.1	5.7	0.04	2.75
3730.6	4.6	0.03	2.73
3731.1	17.3	0.32	2.70
3731.6	16.7	0.28	2.68
3732.1	16.3	0.27	2.67
3732.6	13.7	0.05	2.71
3733.1	9.7	0.04	2.73
3733.6	8.7	0.04	2.71
3734.1	7.6	Broken	1.32
3734.6	9.0	0.06	2.68
3735.1	3.5	Broken	2.59
3735.6	11.0	0.11	2.74
3736.12	8.0	0.04	2.74
3736.6	10.2	0.05	2.72
3737.1	7.5	0.10	2.75
3737.6	8.0	0.06	2.70
3738.1	10.9	0.04	2.73
3738.6	10.7	0.08	2.74
3739.1	12.2	0.11	2.73
3739.6	11.0	0.13	2.73
3740.1	9.3	0.10	2.73
3470.6	3.9	0.01	2.73
3741.1	7.7	0.06	2.73
3741.6	2.2	0.02	2.67
3742.1	6.4	Broken	1.32
3742.6	3.5	0.05	2.63
3743.1	3.8	0.07	2.71
3743.63	6.2	0.13	2.76

Core no.7 (3743.76-3753.4m)

3744.1	11.8	0.07	2.73
3745.1	10.4	Broken	2.80
3746.1	7.8	0.30	2.77
3747.1	8.5	0.21	2.75
3747.5	4.0	0.09	2.76
3478.1	7.6	0.07	2.74
3751.6	14.3	0.79	2.68
3752.9	14.2	0.86	2.71

Ave Ø cored interval = 13.3%

Ave perm. cored interval = 45.3md

Ave Ø of plug >10% Ø = 16.8%

Ave perm. of plug >10% Ø = 61.3md

BRENT SAND CORE ANA

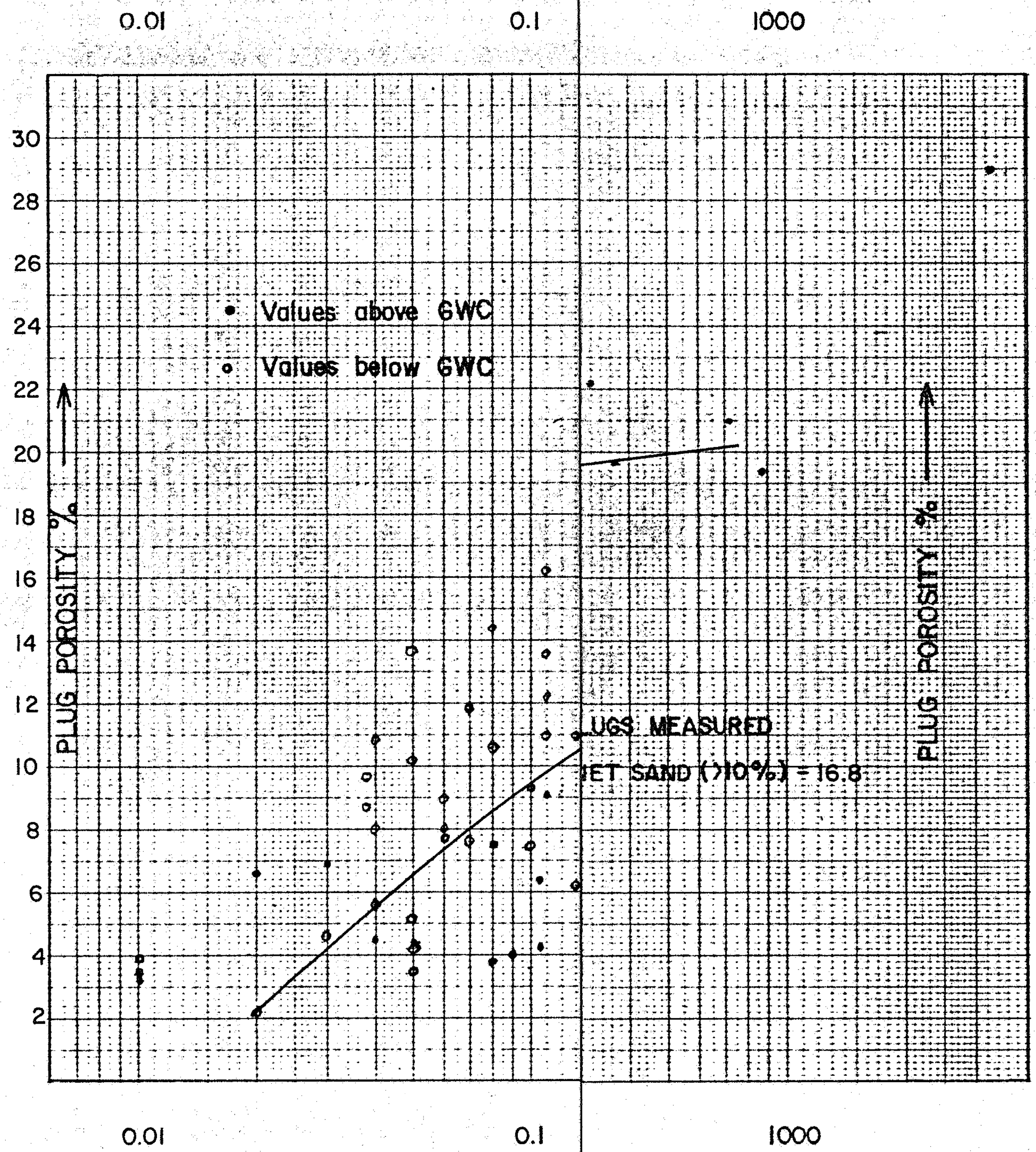


Fig.11

Sidewall core descriptions

Run 3/1 (recovered 34/90)

Depth (m RKB)

3210m - Sandstone: It, gry very fine to fine with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-3%) with coarse to very coarse grain size clasts of shale and coal (5-10%), friable dolomitic quartz sandstone. Poor porosity. Milky white fluor., very slow streaming milky white cut fluor., no cut colour.

3210.5m - Shale: v.drk. gry., fissile, sli. silty, dolomitic. No fluor., very very slow streaming milky white cut fluor., no cut colour.

3255m - argillaceous Sandstone: dark gry, very fine grained, silty, subround to subangular, poorly sorted, micaceous (5-10%), with coarse grain size clasts of shale and coal (10%), dolomitic clay matrix, friable, quartz sandstone. Very poor porosity. Dull pale yellow fluor., very slow streaming milky white cut fluor., no cut colour.

3263.2m - argillaceous Sandstone: drk, gray, very fine, silty, micaceous (5-10%), with coarse grain size clasts of shale and coal (10%), calcareous clay matrix friable, quartz sandstone. Very poor porosity. No fluor, no cut fluor., very slight milky white residual fluor. ring, no cut colour.

3279.5m - Sandstone: It. gry, very fine to fine with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-3%), with coarse to very coarse grain size clasts of shale and coal (5-10%), friable, dolomitic with slightly calcareous patches, quartz sandstone. Poor porosity. Dull milky white fluor., very slow streaming milky white cut fluor., no cut colour.

3280.5m - Sandstone: It. grey., very fine to fine with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-3%), with coarse to very coarse grain size clasts of shale and coal (5-10%), friable, calcareous, quartz sandstone. Fair porosity. Very dull pale yellow fluor, very very slow streaming milky white cut fluor., no cut colour.

3289.5m - argillaceous Sandstone: drk., grey to black, very fine, silty, subround -subangular, poorly sorted micaceous (5-10%), with medium to coarse grain size clasts of shale and coal (5%), silt size particles of coal (5-10%) scattered throughout, calcareous clay matrix, friable, quartz sandstone. One micro-seam of coal (1.00mm thick and 1.0cm long) observed. Very poor porosity. No fluor. No cut fluor., very slight milky white residual fluor.ring, no cut colour.

3306m - argillaceous Sandstone - dark gry, very fine, silty, subround to subangular, poorly sorted, micaceous (5-10%), with coarse grain size clasts of shale and coal (10%), dolomitic clay matrix, friable, quartz sandstone. Very poor porosity. Milky white fluor, very very slow streaming milky white cut fluor., no cut colour.

3306.5m - Sandstone: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-3%), with coarse to very coarse grain size clasts of shale and coal (5-10%), friable, calcareous, quartz sandstone. Poor porosity. Dull milky white fluor, very slow streaming milky white cut fluor., no cut colour.

3308m - Sandstone: lt. gry., very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-3%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic with slightly calcareous patches, quartz sandstone. Fair porosity. Very dull pale yellow fluor., very slow streaming milky white cut fluor., no cut colour.

3312.4m - Sandstone: lt. gry, very fine to fine, with scattered medium size grains, slty, poorly sorted, subround to angular, micaceous (0-3%), with coarse to very coarse grain size clasts of shale and coal (5%), very hard, dolomitic, quartz sandstone. No visible porosity. No fluor, no cut fluor., no residual fluor.ring.

3314m - Sandstone: lt.gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-3%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic with slightly calcareous patches, quartz sandstone. Fair porosity. Milky white fluor., very slow streaming milky white cut fluor., no cut colour.

3315.5m - Sandstone: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to subangular, micaceous, (0-3%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic with slightly calcareous patches, quartz sandstone. Poor - fair porosity. Dull milky white fluor, v. slow streaming milky white cut fluor., no cut colour.

3316m - Sandstone: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-3%), with coarse to very coarse grain size clasts of shale and coal (5%), friable calcareous, quartz sandstone. Fair porosity. Milky white fluor., very slow streaming milky white cut fluor., no cut colour.

3319.5m - Sandstone: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-3%), with coarse to very coarse grain size clasts of shale and coal (5%), friable calcareous, quartz sandstone. Poor - fair porosity, dull milky white fluor., very slow streaming milky white cut fluor., no cut colour.

3320.5m - Sandstone: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-3%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, quartz sandstone. Fair porosity. Very dull pale yellow fluor., very very slow streaming milky white cut fluor., no cut colour.

3321m - Sandstone: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-3%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, quartz sandstone. Fair porosity. Very dull pale yellow fluor., very very slow streaming milky white cut fluor., no cut colour.

3321.5m - <u>Sandstone</u>: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-3%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, quartz sandstone. Poor porosity. Dull milky white fluor. No immediate cut fluor. Slight milky white cut fluor after 15 minutes., no cut colour.

3322m - <u>Sandstone</u>: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, quartz sandstone. Poor porosity. Dull milky white fluor. No cut fluor., slight milky white fluor. residual ring, no cut colour.

3322.5m - <u>Sandstone</u>: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, with slightly calcareous patches, quartz sandstone. Very dull pale yellow fluor., very very slow streaming milky white cut fluor., no cut colour.

3323m - <u>Sandstone</u>: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, quartz sandstone. Fair porosity. Very dull milky white fluor., slow streaming milky white cut fluor., no cut colour.

3323.5m - <u>Sandstone</u>: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, with slightly calcareous patched, quartz sandstone. Fair porosity. Very dull milky white fluor., no cut fluor., very slight milky white fluor. residual ring, no cut colour.

3326m - <u>Shale</u> - brownish black, firm, fissile, traces of micromica, dolomitic., no fluor, no cut colour.

3326.5m - <u>Sandstone</u>: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, w/sli. calcareous patches, quartz sandstone. Fair porosity. Very dull pale yellow fluor., no immediate cut.fl., very slight milky white cut fluor after 15 minutes., no cut colour.

3327m - <u>Sandstone</u>: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, quartz sandstone. Fair porosity. Very dull pale yellow fluor., very very slow milky white cut fluor., no cut colour.

3327.7m - <u>Sandstone</u>: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, quartz sandstone. Fair porosity. Bright milky white fluor., slow streaming milky white cut fluor., no cut colour.

3332.5m - <u>Sandstone</u>: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, quartz sandstone. Fair porosity. Bright milky white fluor., slow streaming milky white cut fluor., no cut colour.

3333m - <u>Sandstone</u>: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, with slightly calcareous patches, quartz sandstone. Fair porosity. Dull milky while fluor., very very slow milky white cut fluor., no cut colour.

3334.2m - <u>Sandstone</u>: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, quartz sandstone. Fair porosity. Bright milky white fluor., slow streaming milky white cut fluor., no cut colour.

3334.5m - Sandstone: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, with slightly calcareous patches, quartz sandstone. Fair porosity. Very dull pale yellow fluor., no immediate cut fluor. Very slight milky white cut after 15 minutes., no cut colour.

3335m - Sandstone: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, quartz sandstone. Fair porosity. Milky white fluor., slow streaming milky white cut fluor., no cut colour.

3337.5m - Sandstone: lt. gry, very fine to fine, with scattered medium size grains, silty, poorly sorted, subround to angular, micaceous (0-2%), with coarse to very coarse grain size clasts of shale and coal (5%), friable, dolomitic, w/sli. calcareous patches, quartz sandstone. Fair porosity. Bright milky white fluor., slow streaming milky white cut fluor., no cut colour.

3346.7m - Shale: Brownish black, firm, fissile, dolomitic., no fluor, no cut fluor.

3392m - Claystone: black, firm to hard, silty, dolomitic., no cut fluor.

Run 5/2 (recovered 36/45)

3958m - Shale: drk. grey, fissile, firm, no fl., no cut fl.

3965.5m - Shale: drk. grey, fissile, firm, no fl., residual pale wht. cut fl.

3971m - Sandstone: quartzitic, wht - lt. grey, fine - med., mod. sort, subrnd., v.calc., tr.sh.clasts, friable, poor to fair por., wht. fl., no cut fl.

3980.5m - Sandstone: quartzitic, lt. grey - brn, v.fine to fine, mod sort, subang., calc., arg., mica, laminae of arg. silt, friable, poor por., v.dull yell. fl., v.v. slow str. pale wht. cut fl.

3990.5m - Sandstone: quartzitic, lt. grey, fine - med., mod. sort, subang., calc., tr.mica, tr.arg., friable, poor to fair por., v.dull wht. fl., no cut fl.

3995.5m - Sandstone: quartzitic, lt. grey - grey., fine - med, mod sort, subang, calc. mica, sli arg., friable, poor por., v.dull wht fl., residual pale wht. cut fl.

4020.5m - Sandstone: quartzitic, lt. grey, fine - med. mod.sort., subang. - subrnd., calc., mica, sli arg, friable poor - fair por., v.pale wht. fl., residual v.pale wht cut fl.

4026.5m - Sandstone: quartzitic, lt. grey, v.fine, mod well sort, subrnd, calc., mica, tr. sh clasts, friable, poor por., dull wht fl., residual pale wht cut fl.

4049.5m - Sandstone: quartzitic, lt. grey., fine - med., poor sort, subang - subrnd., calc., mica, sh. clasts, laminae of drk. grn. brn. sh., friable, fair porosity, v.pale wht fl., residual pale wht cut fl.

4069.5m - Shale: drk. grn. brn., soft, fissile, sli calc, no vis. por., no fl., no cut fl.

4075.5m - Sandstone: quartzitic, lt. grey - buff, fine, mod well sort. subang., tr.mica, friable, fair por., v.v. dull yell fl., residual pale wht cut fl.

4085m - Shale: drk. grn. brn, firm, fissile, sli silty, sli calc, no vis por., no fl., v.v.slow str. pale wht. cut fl.

4088.5m - Siltstone: quartzitic, dry grn. grey, silt, subrnd, v.arg., mica, firm, no vis por., v.dull yell fl., v.v.slow str. pale wht cut fl.

4099.5m - Sandstone: quartzitic, grn.grey., fine, mod well sort, subang., calc., arg., mica, friable, fair por., no fl., residual pale wht cut fl.

4121.5m - Shale: drk. grn.grey, firm, fissile, micromica, v.dull yell. fl., v.slow str. pale wht. cut fl.

4147.5m - Siltstone: quartzitic, drk. grn. grey., silt, mod sort, subrnd., v.arg., sli calc., mica., no vis por., spotted yell fl., v.slow str. pale wht cut fl.

4160.5m - Sandstone: quartzitic, lt. grey, fine, mod. sort., subang., v.calc., tr. shale clasts, friable, fair por., no fl., no cut fl.

4173.5m - Siltstone: quartzitic, v.drk grey, silt to fine, mod sort, subang - subrnd, v.arg., mica, no vis. por., dull wht. fl., residual v.v. pale wht cut fl.

4185.5m - Sandstone: quartzitic, drk. grey, silt to fine, poor sort, subang to subrnd., arg, calc, mica, tr.carbonaceous, friable, poor por., v.dull yell fl., residual pale wht cut fl.

4200.5m - Sandstone: quartzitic, drk. grey, silt to fine, poor sort, subang. to subrnd., v.arg., calc, mica, no vis por, v.dull yell fl., v.sl. str. pale wht. cut fl.

4204.5m - Sandstone: quartzitic, drk grey, v.fine to fine, mod. sort, subang. -subrnd., calc, arg, mica, poor por., dull wht. fl., residual v.v. pale wht cut fl.

4208.5m - Sandstone: quartzitic, lt. grey, fine - coarse, poor sort, subang., v.calc., tr. mica, friable, poor-fair por., dull wht.fl., residual v.v.pale wht cut fl.

4212.5m - Sandstone: quartzitic, lt grey, fine - coar., poor sort, subang., v.calc, tr.mica, friable, poor por., no.fl., residual v.v. pale wht. cut fl.

4219m - Sandstone: quarzitic, lt.grey., fine - med., mod sort, subang. to subrnd., calc., tr.mica, friable, poor por., dull wht fl., residual v.v. pale wht. cut fl.

4227.5m - Sandstone: quartzitic, drk. grey, v.fine to fine, mod.sort. subang. to subrnd., calc., arg., mica, poor por., no fl., residual pale wht cut fl.

4230.5m - Sandstone: quartzitic, v.drk. grey, silt - v.fine, poor sort, subang -subrnd., v.arg, calc, mica, no vis por., no fl., residual v. dull yell cut fl.

4235.5m - Sandstone: quartzitic, wht to lt.grey, fine - med., mod. well sort, subang., calc., tr.sh. clast, friable, v.poor por., wht. fl., residual v.v.pale wht. cut fl.

4243.5m - returned empty

4251.5m - Sandstone: quartzitic, buff, fine - med., mod sort, subang. to subrnd., calc., tr.sh.clasts, friable, poor por. dull wht. fl., residual v.v. pale wht cut fl.

4268.5m - Sandstone: quartzitic, lt.grey, fine, well sort, subang., calc., sli arg., tr.mica, friable, fair por., v.dull yell. fl., no cut fl.

4276.5m - Sandstone: quartzitic, grey to lt. brn, fine to med., poor sort, subang. to subrnd, calc., tr.sh. clasts, friable, fair vis por., dull to bright wht fl., residual pale wht cut fl.

4296.5m - Sandstone: quartzitic, grey - drk. grey, med - coar, poor sort, arg., v.micaceous, sli.calc, tr.sh.clasts, fair porosity, v.dull yell.fl., residual pale wht. cut fl.

4310m - Sandstone: quartzitic, tan, med - coar., poor sort, 5% shale clasts cement and por. indet. (unconsol. or pulverized by shot), dull yell.fl., residual v.v dull yell. cut fl.

4320.5m - <u>Sandstone</u>: quartzitic, wht. - lt. grey, med-. mod. sort., cement and por indet. (unconsol. or pulverized by shot), dull to bright patchy wht fl., residual pale wht cut fl.

4328.5m - <u>Sandstone</u>: quartzitic, grey, fine - med., subang - subrnd., mod.sort., arg., mica, poor por., dull wht fluor, residual pale white cut fl.

4330.5m - <u>Siltstone</u>: quartzitic, lt. brn, well sorted, calc., tr. mica and sh. clasts, no vis porosity, no fl., residual pale wht. cut fl.

4332.5m - <u>Sandstone</u>: quartzitic, white to lt.grey, med - coar., poor sort, subrnd., arg., sli calc., mica, tr. sh. lithoclasts, no vis porosity, dull wht. fl., residual v.v.pale wht. cut fl.

Shale analysis

XRD analyses on selected cuttings samples and sidewall cores were performed by HTC, Paleoservices, and Anchor Drilling Fluids Co.

This work was initiated on behalf of the drilling engineering department, with a view to quantifying the reactive clay content of the 35/8 Cretaceous and Upper Jurassic, and possible modification of the mud programme in 35/8-3. By not picking shale to be analysed from bulk cuttings, the samples examined contained over 75% non-clay mineral contaminants. Despite this, three gross intervals were recognized.

UPPER ZONE Cretaceous claystones

Chloritic claystones, with rather higher proportions of the swelling clays than illite or kaolinite. (Occasionally slightly sideritic). Drilled with KCl polymer mud system; KCl content up to 50 ppb.

MIDDLE ZONE Kimmeridgian - late Oxfordian shales/claystones

Disappearance of chlorite, (with appearance of abundant pyrite and dolomite) otherwise much the same as zone above.

LOWER ZONE Early Oxfordian and older Jurassic claystones/shales

Kaolinite tends to become dominant clay mineral, with relativly little swelling clays. (Siderite and pyrite occur).

The clay minerals show increasing maturity with age, as might be expected.

Chlorite, which is present only in the Cretaceous section, may reflect characteristics of the source area, where erosion of Caledonide chloritic meta-sediments was occurring. Alternatively, chlorite can be a common constituent of immature sediments, where it occurs as an alteration product of primary micas.

The middle zone (Upper Jurassic post-early Oxfordian) section is characterised by a similar clay mineralogy as the Cretaceous section, without chlorite. Abundant pyrite (and kerogen) attests to an environment of restricted circulation and anoxic bottom conditions, while relatively common dolomite suggests that, if not actually at the sea-floor, at shallow depth hypersaline conditions developed.

The lower unit, (Jurassic, pre - Early Oxfordian) consists of a series of clays or shales interbedded with the Jurassic reservoir sands of block 35/8. Kaolinite becomes the dominant clay mineral in this zone, as it is also as a matrix in the sand reservoirs. These results compare well with the single sample from 3425 -3430m in 35/8-2 which was processed by Anchor Drilling Fluids, and with the XRD, clay fraction only, analyses of five Heather Shale samples from 35/8-1 by Paleoservices. A granitic-gneissose Caledonide origin, as detrital feldspar, is postulated for kaolinite in both the lower zone clays and the Jurassic reservoir sands. In the sands, the kaolinite is demonstrably authigenic, while the instability of kaolinite in saline water makes a primary origin untenable for this mineral in the lower zone clays.

The scope of the analyses has been increased to encompass the Lower Tertiary in 35/8-2. Samples from immediately above and below the 13-3/8" casing point (Late Cretaceous) should be analysed to assess the effect on reactive clays of a KCl system, which was only used for the sections below the casing point.

Bridging of the 17½" hole at the top of the Cretaceous prevented wireline logging tools from reaching TD. This was thought to be due to the clay mineralogy of the Cretaceous being relatively rich in swelling clays compared with the overlying Tertiary. This problem cost an extra wiper trip and re-logging, and might have been avoided if the clays were supressed at an earlier stage during drilling. XRD analyses through this interval may assist in solving this problem and thereby save time in drilling well 35/8-3.

As the purpose of the analyses is to asses the clay mineralogy, related to drilling and mud properties, further work should be carried out on picked cuttings only.

Indications from previous drilling on block 35/8 and from the analyses carried out at HTC suggest that the mud system used to drill the 17½" hole should be converted from a seawater polymer system to a KCl or cheaper inhibitive system at about 1900m to maintain stability during logging, and more particularly running casing.

The continuing presence of reactive clays through the Upper Jurassic indicates that it has been correct to maintain an inhibitive system, such as KCl mud through this section, to TD of the 12½" hole only, and that this should be continued in subsequent wells.

Results of Shale Analysis, 35/8-2

Depth	Quartz	Feldspar	Calcite	Dolomite	Siderite	Pyrite	Mica	SM-IL ML or Smectite	Illite	Kaolinite	Chlorite	Zone
2240-50 (a)	54	5	4	-	10	-		8	11	4	4	
2440-50 (a)	69	7	2	-	-	TR		7	7	4	4	
2640-50 (a)	65	5	8	-	-	TR		7	7	4	4	Upper
2840-50 (a)	61	9	11	-	-	-		5	6	3	4	
3100-3102 (a)	44	5	7	5	-	16		10	9	4	-	
3198-3200 (a)	51	2	2	4	-	23		4	6	8	-	Middle
3210.5* (b)	18	4	-	-	-	5	37			36		
3263.2* (b)	15	4	-	-	1	1	32			47		
3289.5* (b)	17	13	1	2	-	1	37			29		
3306* (b)	21	9	-	-	18	-	14			38		
3326* (b)	8	13	-	-	-	5	27			47		Lower
3346.7* (b)	16	13	-	-		3	37			31		
3374-3376 (a)	38	2	10	5	9	9	-	6	10	10	-	
3425-30 (c)	11	2	5	-	3	2	-	3	37	27	10	
3450-3452 (a)	52	7	3	2	4	7	-	8	8	9	-	

*Sidewall cores (a) Analysis by HTC (b) Analysis by Paleoservices (c) Analysis by Anchor Drilling

Table 3

7. Biostratigraphy and Geochemistry

Introduction

Biostratigraphic analysis was conducted by Paleoservices Ltd. and was based on ditch cuttings collected at 10m intervals between 580m and 2700m, 4m intervals between 2700m and TD, with 2m intervals between 3044m and 3974m. Nine selected samples from cores cut in the Brent Formation, eleven sidewall cores and a bit sample from TD were also examined.

Micropalaeontological analyses have been undertaken throughout the well on an average of 9m intervals. A total of 131 samples have been palynologically analysed, distributed throughout the Early Cretaceous and Jurassic section only.

IKU conducted the geochemical evaluation. Canned geochemical samples were composited and collected every 100m from 1700m to 2700m, every 40m to the base of the Cretaceous, every 10m through the Upper Jurassic and every 40m to TD. The analyses performed are headspace gas, occluded gas, total organic matter, extractable organic matter, chromatographic separation, gas chromatographic analyses, vitrinite reflectance, visual kerogen, and Rock-Eval Pyrolysis.

STRATIGRAPHICAL SUMMARY
WELL 35/8-2 MAINHOLE

Interval	Age	Thickness
580m - 780m (F.S.R.)	Early Pleistocene-Late Pliocene	200m
?-UNCONFORMITY-?		
780m - 980m	Early Pliocene/Miocene	200m
UNCONFORMITY		
980m - 1,240m	Late Oligocene	260m
1,240m - 1,300m	Middle-Early Oligocene	60m
1,300m - 1,400m	Oligocene/Eocene	100m
1,400m - 1,500m	Late-Middle Eocene	100m
1,500m - 1,670m	Middle-Early Eocene	170m
1,670m - 1,770m	Early Eocene-Late Paleocene	100m
1,770m - 1,890m	Late Paleocene	120m
1,890m - 1,940m	Middle-?Early Paleocene	50m
?-UNCONFORMITY-?		
1,940m - 1,980m	Late Cretaceous (Late Maastrichtian)	40m
1,980m - 2,090m	Late Cretaceous (Late-Early Maastrichtian)	110m
2,090m - 2,560m	Late Cretaceous (Campanian)	470m
2,560m - 2,770m	Late Cretaceous (Santonian)	210m
2,770m - 3,060m	Late Cretaceous (Coniacian-Turonian)	290m
3,060m - 3,064m	Late Cretaceous (Cenomanian)	4m
3,064m - 3,074m	Early Cretaceous (Albian)	10m
UNCONFORMITY		
3,074m - 3,078m	Early Cretaceous (Early Barremian-Hauterivian)	4m
UNCONFORMITY		
3,078m - 3,210.5m	Earliest Cretaceous?-Late Jurassic (Ryazanian?-Portlandian-Late Kimmeridgian)	132.5m
UNCONFORMITY		

Interval	Age	Thickness
3,210.5m- 3,346.7m	Late Jurassic (Late-Middle Oxfordian)	136.2m
3,346.7m- 3,474m	Late Jurassic (Early Oxfordian-Late Callovian)	127.3m
3,474m - 3,510m	Late Jurassic (Middle Callovian)	36m
3,510m - 3,602m	Late-Middle Jurassic (Early Callovian-Middle Bathonian)	92m
3,602m - 3,753.4m T.D.	Middle Jurassic (Middle-Early Bathonian)	151.4m

WELL 35/8-2 SIDETRACK 1

3,490m - 3,514m	Late Jurassic (Middle Callovian)	24m
3,514m - 3,604m	Late-Middle Jurassic (Early Callovian-Middle Bathonian)	90m
3,604m - 3,762m	Middle Jurassic (Middle-Early Bathonian)	158m
3,762m - 3,882m	Middle Jurassic (Earliest Bathonian-Early Bajocian (=Aalenian))	120m
3,882m - 3,952m	Middle-Early Jurassic (Early Bajocian (=Aalenian)-Toarcian)	70m
3,952m - 4,173.5m	Early Jurassic (Early Toarcian-Late Pliensbachian)	221.5m
4,173.5m- 4,336m T.D.	Early Jurassic (Pliensbachian-Sinemurian)	162.5m

CONCLUSIONS
35/8-2 (MAINHOLE)

1. The shallowest sample examined, at 580m, is a littoral-inner sublittoral sand dated as Early Pleistocene/Late Pliocene.

2. Early Pleistocene-Late Pliocene shallow marine to littoral sandy clays and sands were penetrated between 580m-780m. They rest, probably unconformably, on a poorly dated shallow marine glauconitic sand unit of Early Pliocene or Miocene date (780m-980m). This sand unit rests, probably unconformably, on Late Oligocene siltstones.

3. Oligocene siltstones and claystones with some sand beds were penetrated between 980m-1,300m; they were deposited in outer sublittoral and bathyal environments. They overlie an interval of uncertain age (Oligocene/Eocene) of similar lithology but with undiagnostic microfaunas (1,300m-1,400m).

   The sands were probably deposited in relatively deep water as turbidites or massflow deposits.

4. The Eocene (1,400m-1,670m) is represented by claystones with interbedded sands, deposited in a bathyal environment. The sands are probably turbidites or massflow deposits.

5. The basal Eocene-Late Paleocene Balder and Sele Formations were penetrated between 1,670m-1,770m. They were deposited in a restricted marine sublittoral or bathyal environment, during a widespread volcanic episode.

6. Paleocene sediments of the Lista and ?Maureen Formations comprise claystones, resting on marls (1,770m-1,940m). They were deposited predominantly in a bathyal environment.

   Late and Middle Paleocene faunas are recognisable; the presence of Early Paleocene sediments is uncertain due to the absence of short-ranging microfossils and an unconformity may be present at 1,940m.

7. The Late Cretaceous sequence (1,940m-3,064m) is represented predominantly by claystones with occasional carbonate units, of Maastrichtian to Cenomanian age, typical of the Shetland Group in this region. The diverse marine microfauna shows fluctuations in relative proportions of calcareous and agglutinating taxa which may be related to variation in the carbonate compensation depth, as deposition took place predominantly in a bathyal environment. The limestones of the basal Coniacian-Turonian are a regional feature which probably reflect deposition at shallower, outer sublittoral depths during this period.

8. A thin interval (3,064m-3,074m) of Early Cretaceous (Albian) claystones unconformably overlies a limestone unit dated microfaunally as Early Barremian-Hauterivian (3,074m-3,078m). Deposition of both units was in a marine, sublittoral environment.

9. There is a marked hiatus at 3,078m; at this depth Early Barremian-Hauterivian limestone rests directly on organic-rich claystones dated palynologically as Ryazanian?-Portlandian-Late Kimmeridgian.

10. The Kimmeridge Clay Formation (3,078m-3,210.5m), is represented by black bituminous claystones ranging in age from possibly Early Cretaceous (?Ryazanian) to Late Jurassic (Portlandian-Late Kimmeridgian). Deposition was in a restricted marine environment.

11. Palynological evidence indicates that no Early Kimmeridgian sediments are present in this well and therefore the Late Kimmeridgian rests unconformably on the Late Oxfordian at 3,210.5m.

12. The Heather Formation, (3,210.5m-3,666m) comprises a thick sequence of claystones, siltstones, sandstones and limestones ranging from Late Jurassic (Late Oxfordian) to Middle Jurassic (Bathonian) age. The sequence is apparently complete and lies conformably on the underlying Brent Formation. Deposition was in a marine, sublittoral, environment.

13. The well penetrated only the upper part of the Brent Formation (Tarbert and Ness Members), 3,666m-3,753m, which are dated palynologically as Middle Jurassic, Bathonian.

35/8-2 (SIDETRACK 1)

1. Only the lower part of the Heather Formation was penetrated in sidetrack 1, comprising the Middle Callovian to Bathonian part of this Formation.

2. The complete Brent Formation (3,668m-3,882m) is represented in the well comprising the Tarbert, Ness, Etive, Rannoch and Broom Members, and ranging in age from Bathonian to Early Bajocian (=Aalenian). The sequence is dominated by sands, although the Ness Member (3,686m-c.3,782m), is an interbedded sequence of claystones, sands and coal and there is a prominent claystone within the Rannoch at 3,854m. Palynological evidence suggests that the Broom to Ness Members represent a regressive sequence from a high energy marginal marine regime to cyclic delta plain conditions.

3. The Dunlin Formation (3,882m-4,204m) ranges in age from Early Bajocian (=Aalenian) to Pliensbachian or possibly Sinemurian age. The claystones in the upper part (3,882m-3,930m) contain a fauna and flora typical of the Drake Member, but below 3,930m the sequence is dominated by sands; the Cook, Burton and Amundsen Members cannot be differentiated. The use of a diamond drilling bit in the lower part, below 3,964m, has destroyed most of the fossils and therefore dating is difficult at this level. Deposition throughout the Dunlin Formation was in a marine, probably sublittoral environment.

4. The samples through the section assigned to the Statfjord Formation (4,204m-4,336m) are dominated by drilling artifacts with occasional medium to coarse grained sands. The sands were probably deposited in a marginal marine environment. Although fossils are scarce, tentative palynological evidence and regional comparisons suggest that this sequence is no older than Early Jurassic, Sinemurian.

Geochemical Summary (IKU)

The maturity of the analysed sequence (1700-4336m) from the well 35/8-2 is based mainly on vitrinite reflectance, spore colouration and T_{max} values from Rock-Eval pyrolysis. The richness of the sample is based on TOC and Rock-Eval pyrolysis with additional evidence from the abundance of light hydrocarbons and $C_{15}+$ extractable hydrocarbons. Source rock quality is based mainly on pyrolysis and visual kerogen examination with support from the gas chromatographic results.

Zones A,B,C and D; (1700-3090m): Claystones are dominant throughout this sequence, becoming increasing silty with increasing depth. Minor contributions of limestones are present in zones A and D, while sandstones are found in zone C. TOC values for the claystones range from ca. 0.6% to 1%, the higher values being associated with the grey silty/sandy claystones common in zone C. The limestones in zone A and zone D (the Turonian Marl) have low TOC values.

The organic matter is mainly amorphous, with variable contributions of herbaceous material, inertinite and cuticles (the latter especially in the top of zone A (1750m)), deposited in an oxidising environment. A mixture of poor type III kerogen (dominant) and type II + III is indicated by Rock-Eval data. The high content of cuticles at 1750m is not reflected in the Rock-Eval data; this is common in North Sea Cretaceous sediments and is due to extensive sapropelisation of terrestrial material, giving a potential only for gas. T_{max} values indicate all zones to be immature; vitrinite reflectance measurements indicate immature in zone A grading to moderate mature in zone D.

A high production index in some samples suggests the presence of introduced hydrocarbons ie., migrated or mud additive. The occurrence of migrated hydrocarbons is suggested by the light hydrocarbon analyses, especially in samples from zone C (2410-2640m).

The entire sequence can be described as having a poor to fair potential as a source rock for gas.

Zone E; (3090-3300m). Dark grey, organic rich (TOC=4-6%) carbonaceous claystones (of the Kimmeridge Formation) dominate this zone. The claystone becomes siltier and more sandy with increasing depth (the Heather Shale), giving a corresponding decrease in TOC values. Sandstones of the Heather Formation occur towards the base of the zone. The organic matter is comprised mainly of cuticles (especially in the upper claystones) with some amorphous and herbaceous material. The presence of cuticles is also indicated by the gc's of the saturated and aromatic hydrocarbons. Rock-Eval data indicates a mixture of type II and III kerogen, but hydrogen index values are high, especially in the upper section. The potential as source rock oil and gas is rich, the high cuticle content probably giving a heavy, paraffinic oil. Maturity based on T_{max} values is moderate.

Zone F; (3300-3400m). This zone consists mainly of sandstones (the Heather Sand) and dark grey and brown-grey claystones. The claystones (Lower Heather Shale) have high TOC values similar to those in zone E, decreasing slightly with increasing depth. Visual kerogen indicates a high content of herbaceous material with some amorphous and cuticle content.

Rock-Eval data indicates mainly type II kerogen for the dark grey claystones and type II + III kerogen for the brown-grey claystones. The zone is considered to be moderate mature, bordering oil window maturity, and the claystones can be described as having a rich potential for gas (brown-grey claystones) or oil + gas (dark grey claystones in the upper section).

Zone G; (3400-3670m). Dark grey and grey-brown claystones dominate this zone. The claystones become increasingly silty with increasing depth and are carbonaceous towards the base of the zone. Both claystones have similar TOC content (ca. 2-3%), and the limestones and marls appearing as a minor contribution throughout the section have a lower value (ca.1%).

The organic matter is mainly mixed cuticular and herbaceous material; the Rock-Eval data indicate type II and III kerogens, with an increased proportion of type II in the claystones of the upper section (to 3560m). T_{max} values indicate a mature zone, although vitrinite reflectance measurements suggest a lower maturity - probably due to the influence of bitumen staining.

Source rock potential is rich for oil and gas, the oil being mainly paraffinic, especially in the 3500-3550m section.

Zone H, I; (3670-3970m). These zones are comprised mainly of sandstones from the Brent and Dunlin Formation, with coals appearing mainly between 3700m and 3850m. Silty claystones with TOC values of 3-4% make a minor contribution throughout the section.

The zone is mature and the coal has a rich potential as a source rock for gas. Rock-Eval data suggests the occurrence of free hydrocarbons in the upper part of the sandstone. The sandstone has no potential as a source rock for hydrocarbons.

Zone J; (3970-4060m). Mud additives (lignite) were predominant in samples from the zone. The real lithology is probably a continuation of the sandstone found in zones H and I.

Zone K; (4060-4180m). A grey claystone with a TOC value in the range 1.-1.6% is dominant in this zone. Coals are occasionally present. Kerogen type as indicated by Rock-Eval pyrolysis is type III; visual kerogen analysis indicates herbaceous material to be dominant. The zone has an oil window maturity and can be considered as having a poor to fair potential as a source rock for gas.

Zone L; (4180-4336m). A white sandstone, occasionally brown-stained, comprises the dominant lithology (the Statfjord Formation). The thin coals found in zone K, continue into this zone which is terminated in a shale. TOC values are low, except for the anomalous occurrence of a black shale between 4240m and 4270m having a TOC value of 3%. At least some of the coal is probably mud additive. The zone is probably of oil-window maturity but the sandstone has little or no potential as a hydrocarbon source rock. There are no indications of free hydrocarbons in the sandstone.

IKU Geochemical Zones

Zone	Depth
A	1700 - 2140
B	2140 - 2410
C	2410 - 2640
D	2640 - 3090
E	3090 - 3300
F	3300 - 3400
G	3400 - 3670
H	3670 - 3840
I	3840 - 3970
J	3970 - 4060
K	4060 - 4210
L	4210 - 4336

Hydrocarbon analysis of core sample extract, Heather Formation (GS&T)

A piece of core no. 1, depth 3317.3m from well 35/8-2 contained 0.019% extractable organic material which consists of 53.6% saturated hydrocarbons, 14.4% aromatic hydrocarbons, 18.6% resins, and 13.4% asphaltenes. Both the saturated and aromatic hydrocarbon distribution are typical for oils.

Fig. 12 shows that the distribution of saturated hydrocarbons ranges from compounds with 12-37 carbon atoms being enriched in the 19-24 carbon chains and depleted in carbon numbers below 17. The CPI is 1.11 suggesting that the hydrocarbon distribution is mature. Pristane/phytane, pristane/n-C_{17} and phytane/n-C_{18}ratios are 1.72, 0.63 and 0.35 respectively, the two latter ratios confirming the mature nature of the extract (<1.0).

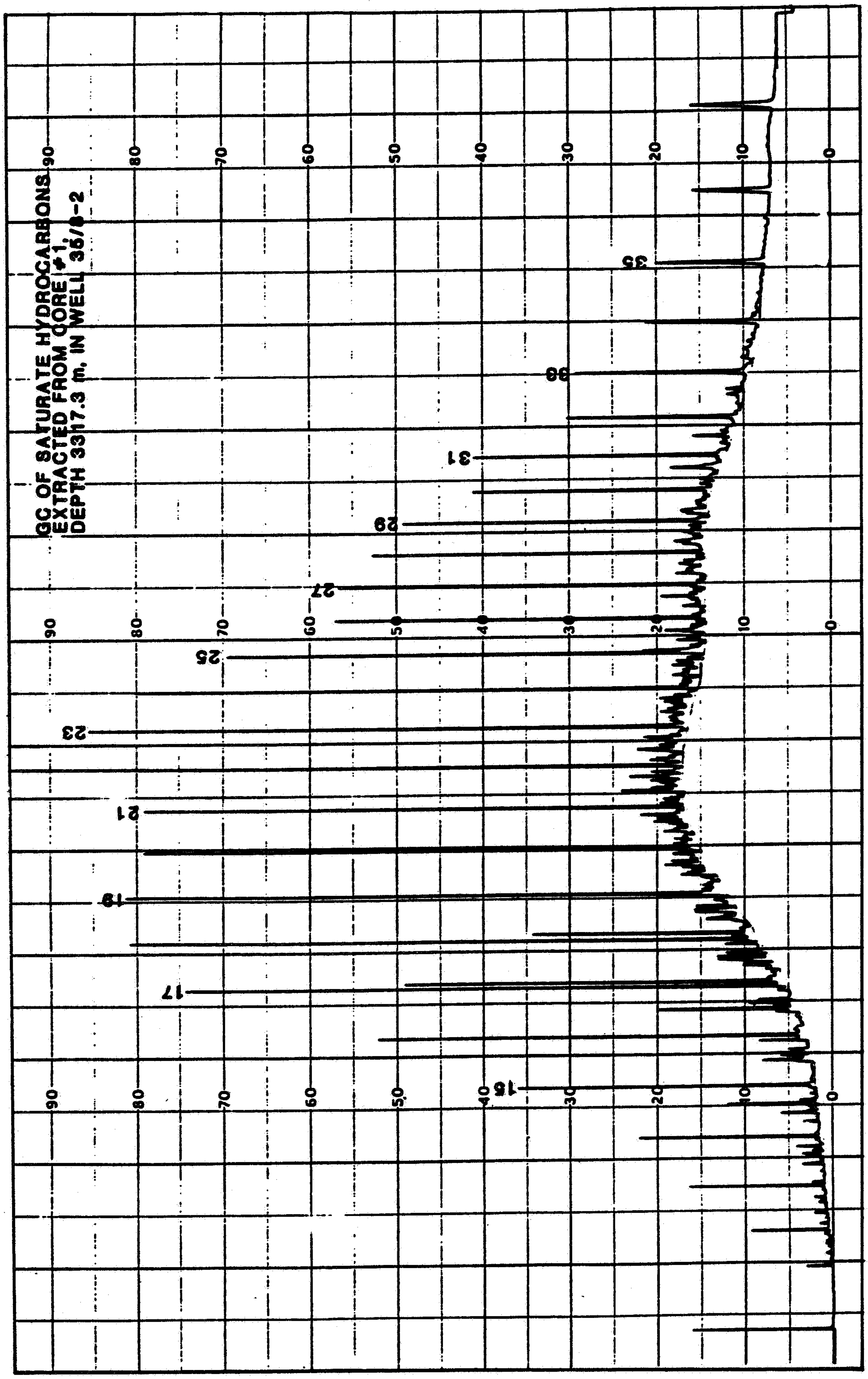
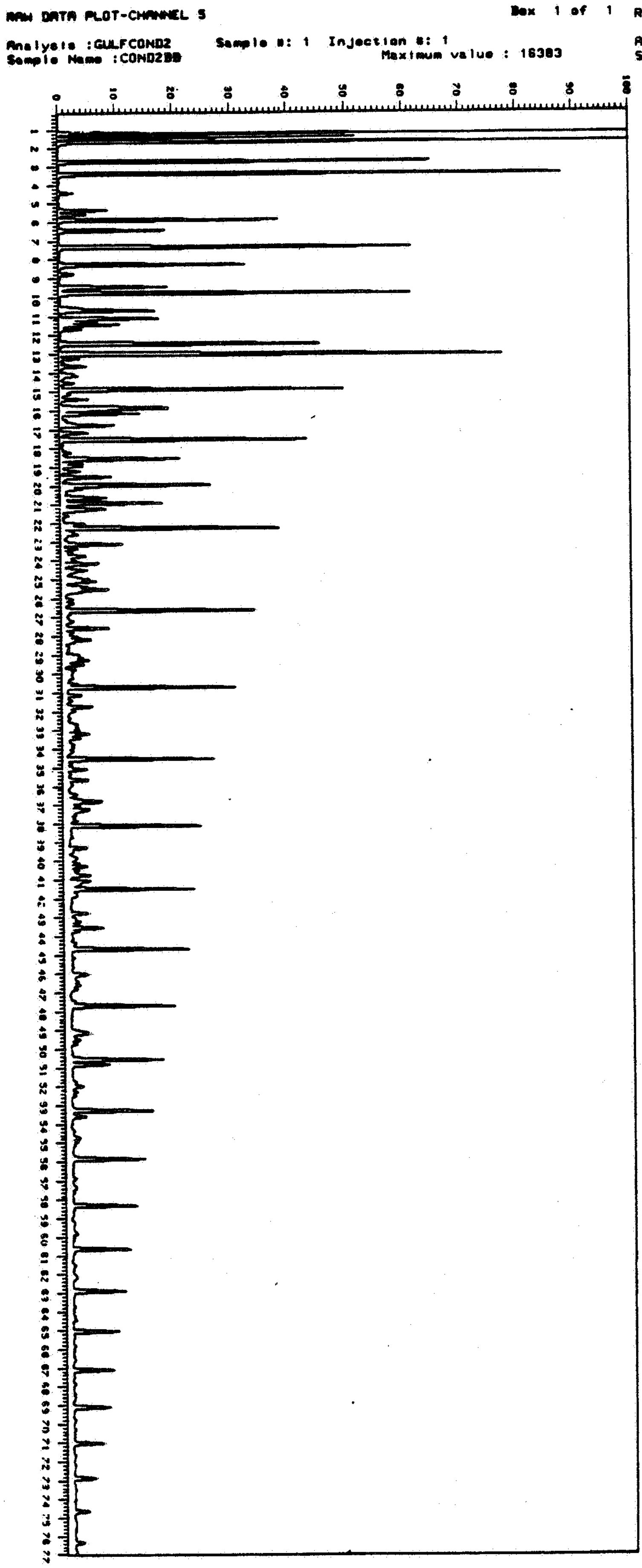

GC OF SATURATE HYDROCARBONS
EXTRACTED FROM CORE #1,
DEPTH 3317.3 m. IN WELL 35/8-2
15
17
19
21
23
25
27
29
31
33
35
0
10
20
30
40
50
60
70
80
90

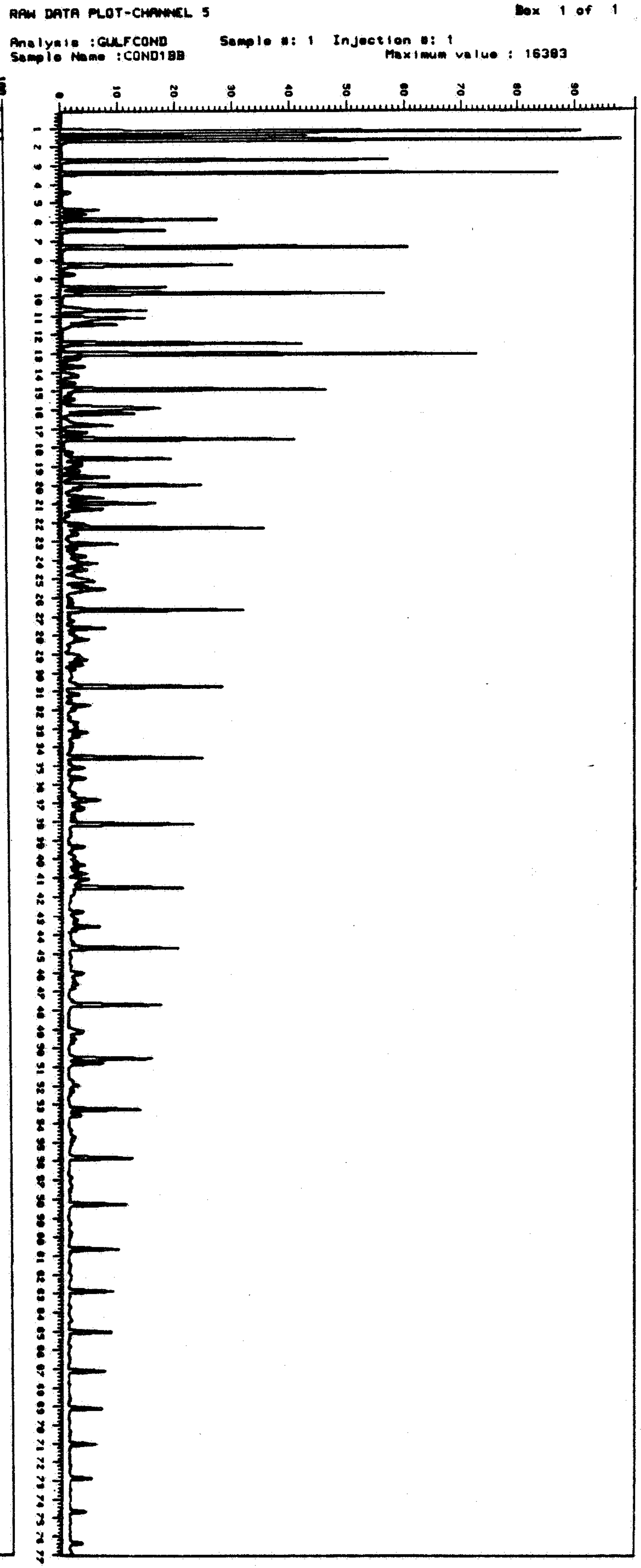
Fig. 12

Gas chromatographic analyses of dst-1 and 2 samples, and solvent extracts from Brent and Heather test zones.

Due to remarkable similarities between condensate obtained in 35/8-2 DST-1 and DST-2 (Brent and Heather respectively) and pressures which could indicate chanelling behind casing between test zone 1 3694m-3703m and 2, 3306m-3315m, fluid samples from the two tests were taken to IKU (Trondheim) and run through their gas chromatograph. At the same time solvent extracts obtained from core chips of the same intervals went through the same procedure. The condensates were by 99% certainty identical (Fig. 13). Solvent extracts were also very similar in composition, the primary difference appears to be that the lighter paraffins are depelted in the Brent Formation relative to the Heather Sands (Fig. 14). This could be interpreted as a result of higher reservoir temperatures in the Brent. Discrepancies were also present in the range between C_{21} and C_{24}. To obtain any further correlations, treatment with gas chromatograph/mass spectrometer is required, but was not recommended in order to reach a conclusion. The condensates were identical, and the solvent extracts had minor differences but were looked upon as originating from the same source. Therefore, gas chromatographic analyses were of little use in determining whether or not channeling behind casing had occurred.

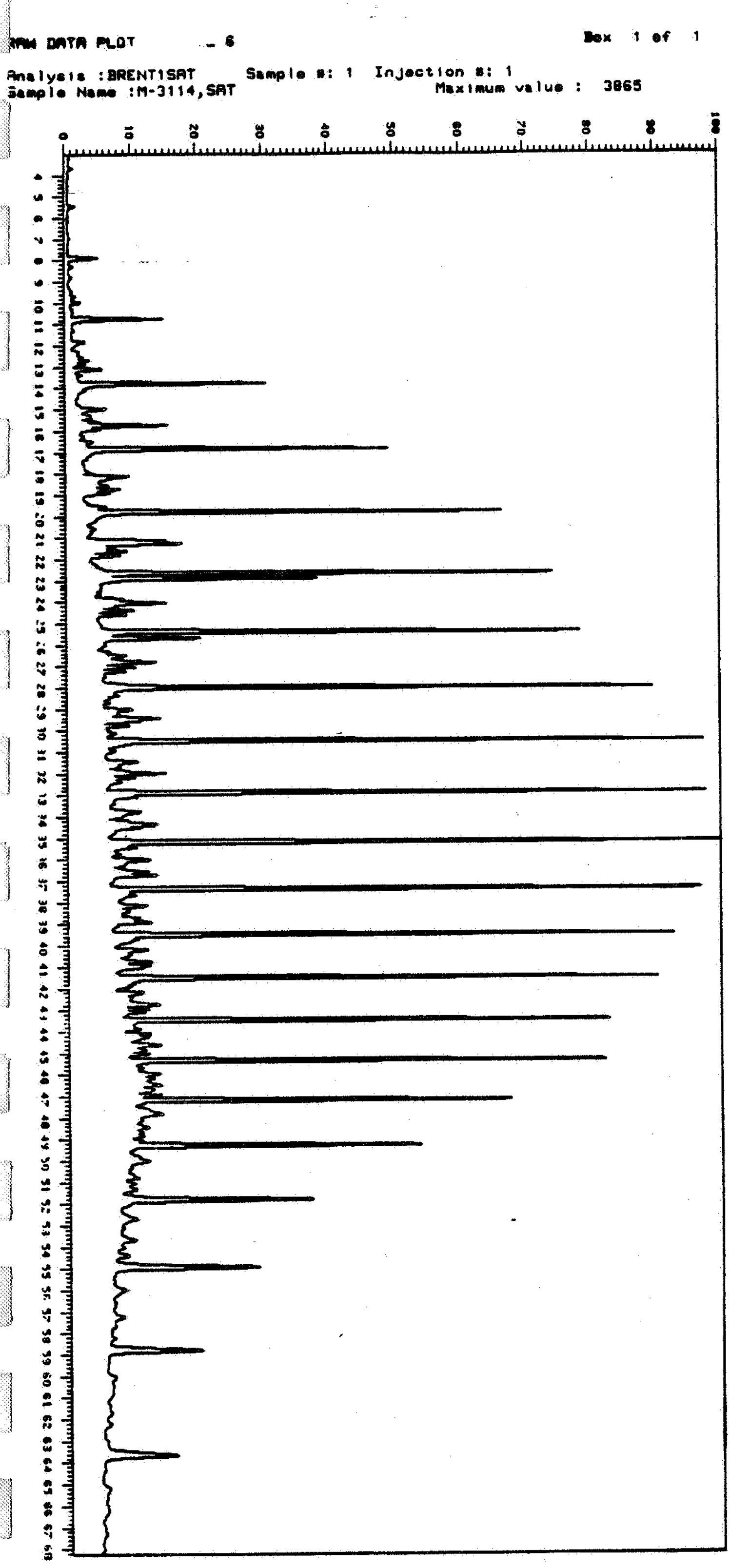


DST 1

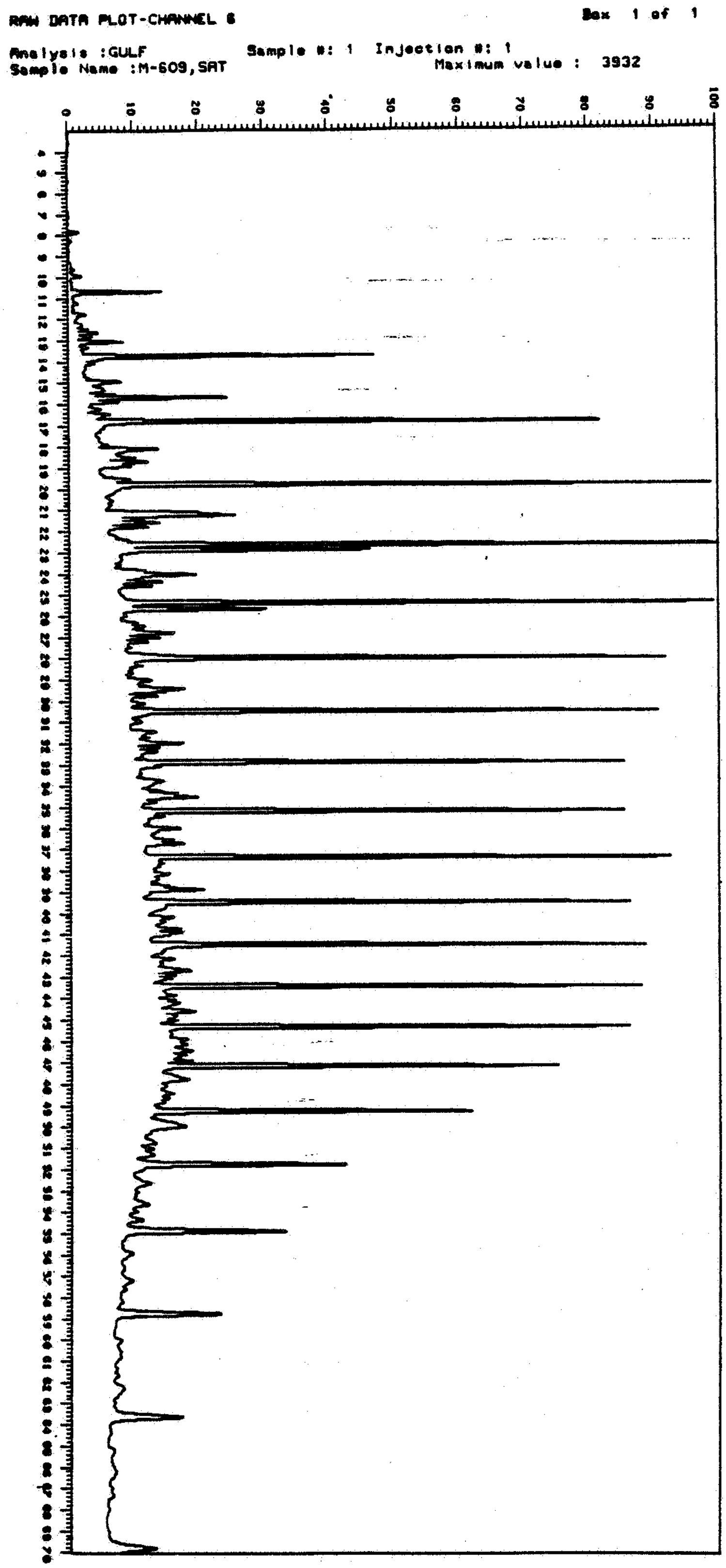


DST 2

Fig. 13



Brent Solvent Extract



Heather Solvent Extract

Fig.14

LOGGING

8. Mud Logging and Hydrocarbon shows.

A Norsk Petroleum Services A/S computerized MWD-1000 Logging Unit was used from surface to Total Depth.

Methane was recorded while drilling in the Middle and Upper Tertiary from 582m - 1365m. Total gas never exceeded 0.6%.

No significant gas was recorded in the Lower Tertiary and Cretaceous section.

Below the Sub-Cretaceous Unconformity the gas level increased in the Kimmeridge clay, reaching a peak in the Heather Sands (3204m-3338m) with 0.7% gas and C_1-C_4 present. Hydrocarbon traces from cores in this interval had milky white fluorescence with streaming milky white cut.

Below the Heather sands, the gas level became less than 0.2% with C_1 and traces of C_2 and C_3 present.

When the Jurassic Brent Sand reservoir was penetrated at 3666m the gas level increased, reaching a maximum of 5.2% at 3720m with C_1-C_5 present. The cores cut from 3666m - 3754m had strong petroliferous odour, bright blue direct fluorescence, colourless cut, blue cut fluorescence and white-yellow residual ring fluorescence above an apparent GWC at 3733m. Below this level, drilled gas diminished, and only a trace of dull orange fluorescence was detectable. The gas level became insignificant below 3933m, with thin coals producing small C_1-C_3 peaks.

From 3960, to TD no drilled gas was recorded probably due to circumstances created by the use of a Turbo-drill throughout this section. Sidewall cores, taken in the Dunlin and the Statfjord Groups showed pale white-yellow direct fluorescence and very pale white cut fluorescence from 3958m - 4332.5m.

BAROID ppm LOG
SHOW EVALUATION REPORT

COMPANY GULF NORWAY

WELL 35/8-2

LOCATION N. SEA NORWAY

FORMATION HEATHER SANDSTONE

DEPTH 3334-3341 metres

PROBABLE PRODUCTION GAS CONDENSATE

MUD ANALYSIS

	BACKGROUND	NET INCREASE	
		PLOT 1	PLOT 2
		DEPTH 3336	DEPTH 3340
METHANE - ppm C_1	1,500	7,700	6,100
ETHANE - ppm C_2	300	800	600
PROPANE - ppm C_3	100	320	200
BUTANE - ppm C_4	Trace	100	Trace
PENTANE+ - ppm C_{5+}			
METHANE %_ UNITS_			
TOTAL %_UNITS_	4	22	14
CHLORIDES			

DRILLING RATE: MT ~~FT~~/HR X MIN/FT

FROM 2·5 TO 11·9

LITHOLOGY SDST-clr, off wh, f grn-m grn, sub ang - sub sphal, hd qtz, well cmtd, dolic cmt, cpct, dns, - Fluor.

REMARKS DRLG RATE AT 3334 mt. 2·5. DRLED 3335 mt 11·9. INTERVAL 3336-3340 mt AV DRLG RATE 3. DRLG RATE DECRING TO 1·5 AT 3341 mt.

NEW ORDERS

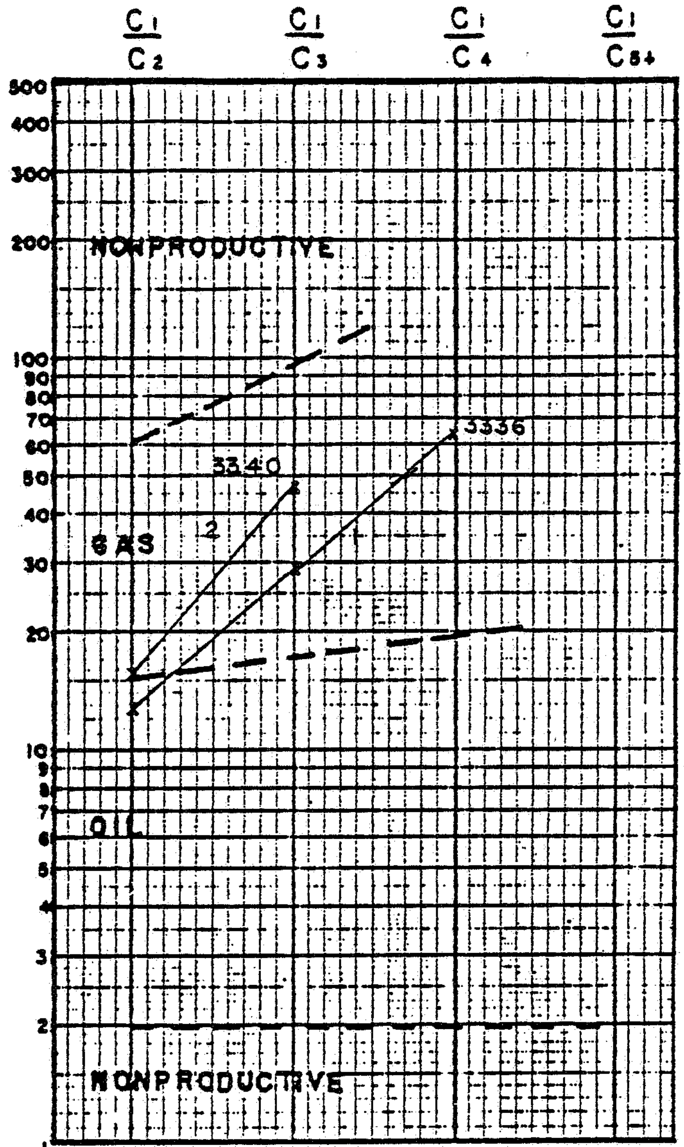
CALLED IN BY

TALKED TO

DATE 15/12/81 TIME AM PM

BR-30615

HYDROCARBON RATIOS



USE ONLY GAS INCREASE OVER BACKGROUND

C_1: 6,200 M C_3: 220 M C_4: 100 M C_{5+}: ____ M

C_2: 500 M

C_1/C_2: 12·4 C_1/C_3: 28·2 C_1/C_4: 62 C_1/C_{5+}: ____

1. PLOT RATIOS ON LINES INDICATED.
2. EVALUATE SECTION FOR PROBABLE PRODUCTION AS INDICATED BY THE PLOTTED CURVE WITHIN THE FOLLOWING LIMITS:
   a. PRODUCTIVE DRY GAS ZONES MAY SHOW ONLY C_1 BUT ABNORMALLY HIGH C_1 ONLY SHOWS ARE USUALLY INDICATIVE OF SALT WATER.
   b. IF THE C_1/C_2 RATIO FALLS LOW IN THE OIL SECTION AND THE C_1/C_4 RATIO FALLS HIGH IN THE GAS SECTION THE ZONE IS PROBABLY NONPRODUCTIVE.
   c. IF ANY RATIO (C_1/C_5 EXCEPTED IF OIL MUD IS USED) IS LOWER THAN A PRECEDING RATIO THE ZONE IS PROBABLY NONPRODUCTIVE. FOR EXAMPLE, IF C_1/C_4 IS LESS THAN C_1/C_3 THE ZONE IS PROBABLY WET.
   d. THE RATIOS MAY NOT BE DEFINITIVE FOR TIGHT, LOW PERMEABILITY ZONES.

Fig. 15

BAROID ppm LOG
SHOW EVALUATION REPORT

COMPANY GULF NORWAY

WELL 35/8-2

LOCATION N SEA NORWAY

FORMATION ORIGIN HEATHER SHALES

DEPTH TRIP GASES FROM 3458 & 3494 mtrs

PROBABLE PRODUCTION GAS CONDENSATE

MUD ANALYSIS

	BACKGROUND	NET INCREASE	
		PLOT 1	PLOT 2
		DEPTH 3458	DEPTH 3494
METHANE — ppm C_1		24,700	10,400
ETHANE — ppm C_2		2,500	1,000
PROPANE — ppm C_3		1,840	720
BUTANE — ppm C_4		420	250
PENTANE+ — ppm C_{5+}			
METHANE % — UNITS —			
TOTAL % — UNITS —		85	35
CHLORIDES			

DRILLING RATE: FT/HR ___ MIN/FT ___

FROM ______ TO ______

LITHOLOGY ______

REMARKS 85 UNITS OF TRIP GAS FROM 3458 m.
35 UNITS OF TRIP GAS RECORDED FROM 3494 m.

MW ORDERS ______

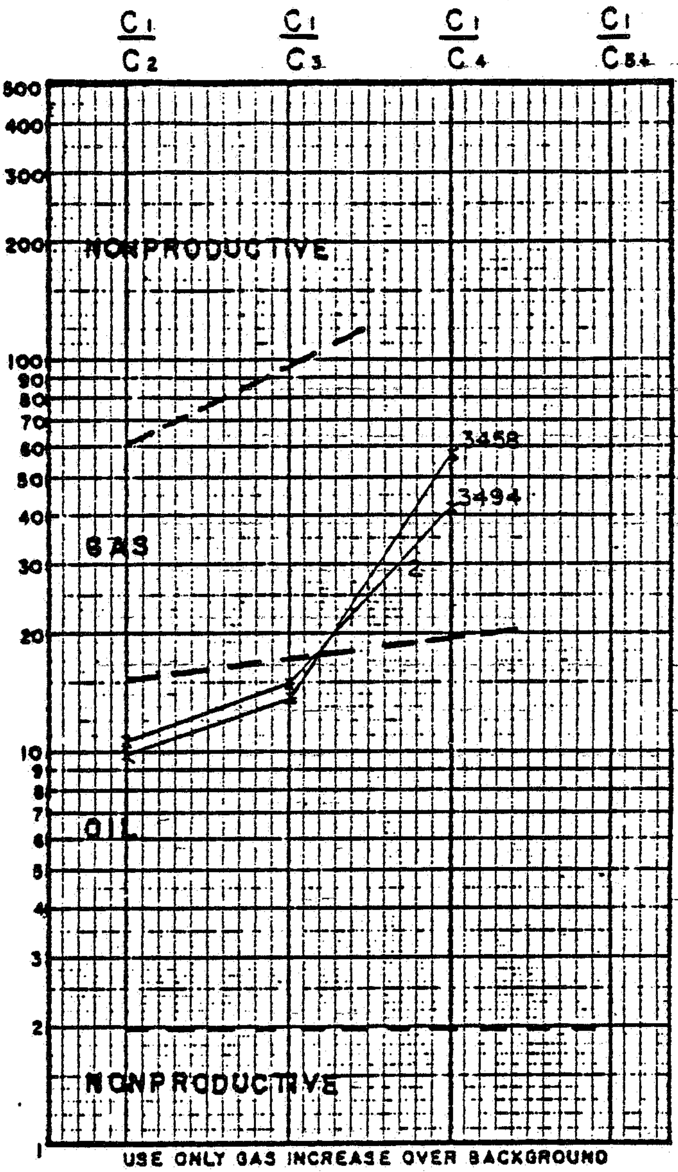
CALLED IN BY M. STRIDER

TALKED TO ______

DATE 20/02/82 TIME ______ AM ___ PM ___

BR-30615

HYDROCARBON RATIOS



USE ONLY GAS INCREASE OVER BACKGROUND

C_1: 24,700 M C_3: 1,840 M C_4: 420 M C_{5+}: ___ M

C_2: 2,500 M

C_1/C_2: 9.9 C_1/C_3: 13.4 C_1/C_4: 58.8 C_1/C_{5+}: ___

1. PLOT RATIOS ON LINES INDICATED.
2. EVALUATE SECTION FOR PROBABLE PRODUCTION AS INDICATED BY THE PLOTTED CURVE WITHIN THE FOLLOWING LIMITS:
   a. PRODUCTIVE DRY GAS ZONES MAY SHOW ONLY C_1 BUT ABNORMALLY HIGH C_1 ONLY SHOWS ARE USUALLY INDICATIVE OF SALT WATER.
   b. IF THE C_1/C_2 RATIO FALLS LOW IN THE OIL SECTION AND THE C_1/C_4 RATIO FALLS HIGH IN THE GAS SECTION THE ZONE IS PROBABLY NONPRODUCTIVE.
   c. IF ANY RATIO (C_1/C_5 EXCEPTED IF OIL MUD IS USED) IS LOWER THAN A PRECEDING RATIO THE ZONE IS PROBABLY NONPRODUCTIVE. FOR EXAMPLE, IF C_1/C_4 IS LESS THAN C_1/C_3 THE ZONE IS PROBABLY WET.
   d. THE RATIOS MAY NOT BE DEFINITIVE FOR TIGHT, LOW PERMEABILITY ZONES.

Fig 16

BAROID ppm LOG
SHOW EVALUATION REPORT

COMPANY GULF NORWAY

WELL 35/8-2

LOCATION N. SEA NORWAY

FORMATION BRENT SANDSTONE

DEPTH 3667 metres

PROBABLE PRODUCTION GAS CONDENSATE

MUD ANALYSIS

X N.B. PLOT 1 IS NOT FROM THE STEAM STILL RESULTS

	BACKGROUND	NET INCREASE	
		PLOT 1	PLOT 2
		DEPTH 3667	DEPTH 3667
METHANE – ppm C_1		18,360	18,600
ETHANE – ppm C_2		1,800	4,200
PROPANE – ppm C_3		720	3,360
BUTANE – ppm C_4		240	2,200
PENTANE+ – ppm C_{5+}			
METHANE % – UNITS –			
TOTAL % – UNITS –			
CHLORIDES			

DRILLING ~~RATE~~ BREAK : MT ~~FT~~/HR X MIN/FT __

FROM 2·6 TO 14·1

LITHOLOGY SDST – clr, milky, c grn, sub rnd, aly. srtd, uncons, qtz

REMARKS 94 UNITS OF GAS RECORDED FROM BOTTOMS UP SAMPLE 3667 m. MUD GAS CUT. –VE FLOW CHECK

NEW ORDERS

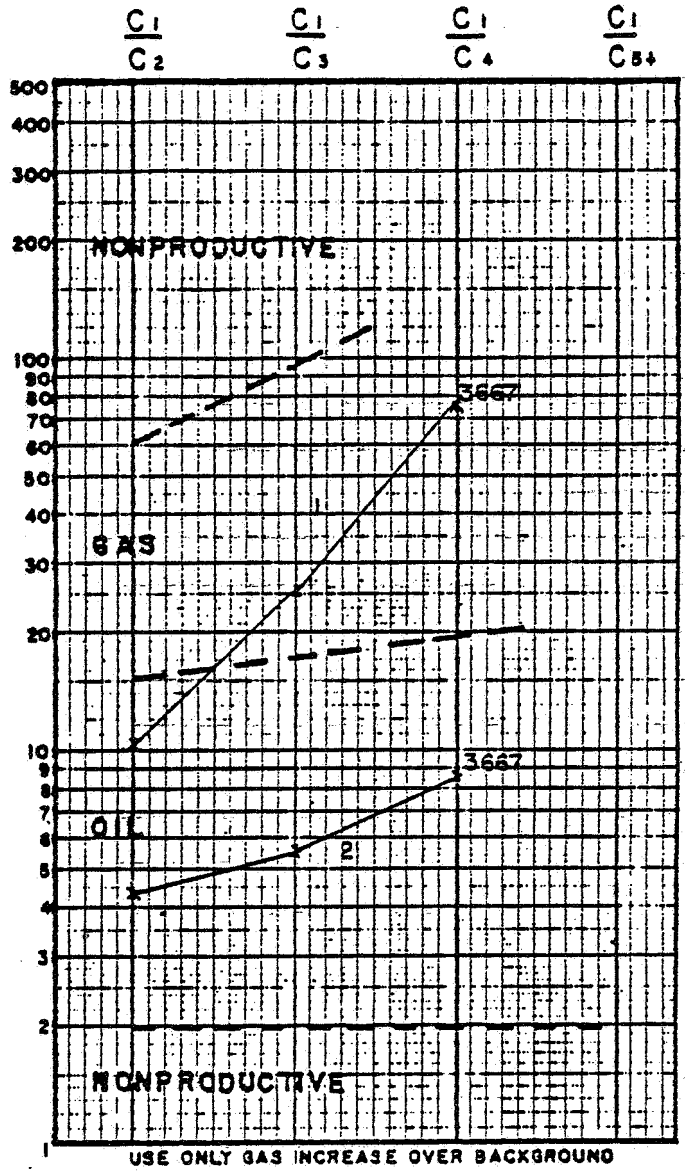
CALLED IN BY M J OATES

TALKED TO

DATE 04/01/82 TIME 0230 AM X PM __

BR-30615

HYDROCARBON RATIOS



USE ONLY GAS INCREASE OVER BACKGROUND

C_1: 18,360 M C_3: 720 M C_4: 240 M C_{5+}: ____ M

C_2: 1,800 M

C_1/C_2: 10·2 C_1/C_3: 25·5 C_1/C_4: 76·5 C_1/C_{5+}: ____

1. PLOT RATIOS ON LINES INDICATED.
2. EVALUATE SECTION FOR PROBABLE PRODUCTION AS INDICATED BY THE PLOTTED CURVE WITHIN THE FOLLOWING LIMITS:
   a. PRODUCTIVE DRY GAS ZONES MAY SHOW ONLY C_1 BUT ABNORMALLY HIGH C_1 ONLY SHOWS ARE USUALLY INDICATIVE OF SALT WATER.
   b. IF THE C_1/C_2 RATIO FALLS LOW IN THE OIL SECTION AND THE C_1/C_4 RATIO FALLS HIGH IN THE GAS SECTION THE ZONE IS PROBABLY NONPRODUCTIVE.
   c. IF ANY RATIO (C_1/C_5 EXCEPTED IF OIL MUD IS USED) IS LOWER THAN A PRECEDING RATIO THE ZONE IS PROBABLY NONPRODUCTIVE. FOR EXAMPLE, IF C_1/C_4 IS LESS THAN C_1/C_3 THE ZONE IS PROBABLY WET.
   d. THE RATIOS MAY NOT BE DEFINITIVE FOR TIGHT, LOW PERMEABILITY ZONES.

Fig 17

BAROID ppm LOG
SHOW EVALUATION REPORT

COMPANY GULF NORWAY

WELL 35/8-2 ST I

LOCATION N. SEA NORWAY

FORMATION BRENT SANDSTONE

DEPTH 3671 & 3675 metres

PROBABLE PRODUCTION GAS CONDENSATE

MUD ANALYSIS

	BACKGROUND	NET INCREASE	
		PLOT 1	PLOT 2
		DEPTH 3671	DEPTH 3675
METHANE – ppm C_1		27,800	16,000
ETHANE – ppm C_2		3,100	2,100
PROPANE – ppm C_3		2,300	700
BUTANE – ppm C_4		630	Trace
PENTANE+ – ppm C_{5+}			
METHANE % – UNITS –			
TOTAL % – UNITS –			
CHLORIDES			

DRILLING ~~RATE~~ BREAK: MT ~~FT~~/HR X MIN/FT __
FROM 12·2 TO 4·9

LITHOLOGY SDST – clr, wh, crm, c grn, sub rnd–rnd, well srtd, uncons, qtz.

REMARKS DRILLING BREAK, REDUCE W.O.B.
57 UNITS OF GAS RECORDED AT 3671 m,
GAVE FLOW CHECK.

NEW ORDERS ________

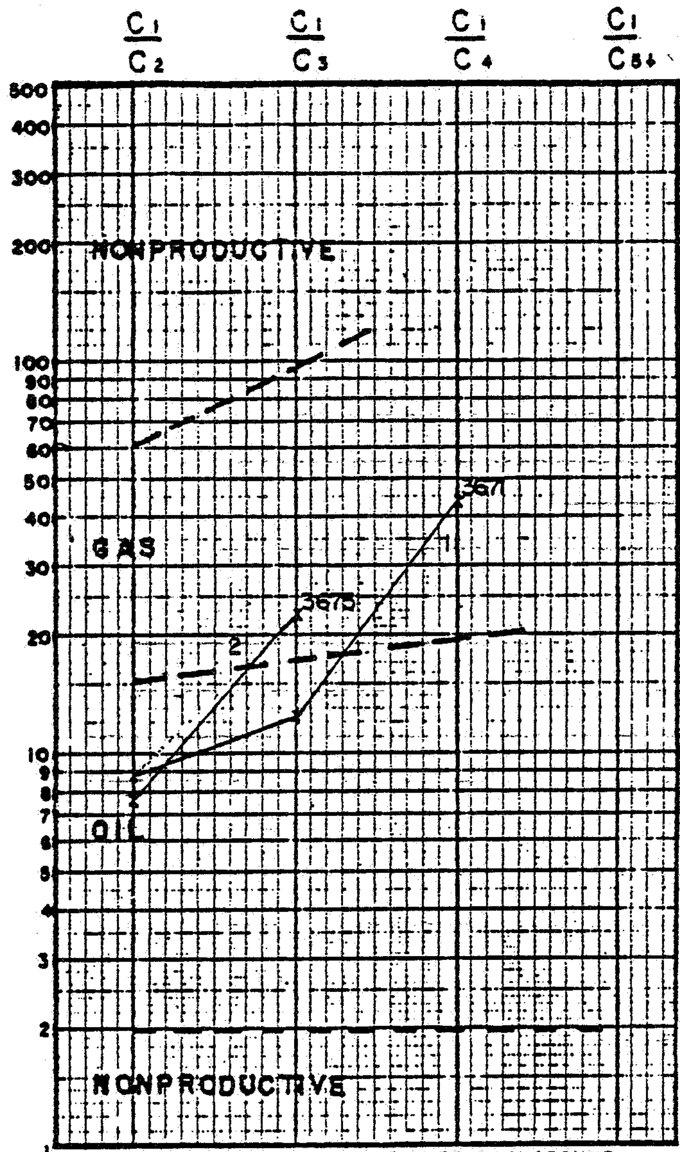
CALLED IN BY ________

TALKED TO ________

DATE 20/02/82 TIME ______ AM __ PM __

BR-30615

HYDROCARBON RATIOS



USE ONLY GAS INCREASE OVER BACKGROUND

C_1: 27,800 M C_3: 2,300 M C_4: 630 M C_{5+}: ____ M
C_2: 3,100 M

C_1/C_2: 8·97 C_1/C_3: 12·1 C_1/C_4: 44 C_1/C_{5+}: ____

1. PLOT RATIOS ON LINES INDICATED.
2. EVALUATE SECTION FOR PROBABLE PRODUCTION AS INDICATED BY THE PLOTTED CURVE WITHIN THE FOLLOWING LIMITS:

   a. PRODUCTIVE DRY GAS ZONES MAY SHOW ONLY C_1 BUT ABNORMALLY HIGH C_1 ONLY SHOWS ARE USUALLY INDICATIVE OF SALT WATER.

   b. IF THE C_1/C_2 RATIO FALLS LOW IN THE OIL SECTION AND THE C_1/C_4 RATIO FALLS HIGH IN THE GAS SECTION THE ZONE IS PROBABLY NONPRODUCTIVE.

   c. IF ANY RATIO (C_1/C_5 EXCEPTED IF OIL MUD IS USED) IS LOWER THAN A PRECEDING RATIO THE ZONE IS PROBABLY NONPRODUCTIVE. FOR EXAMPLE, IF C_1/C_4 IS LESS THAN C_1/C_3 THE ZONE IS PROBABLY WET.

   d. THE RATIOS MAY NOT BE DEFINITIVE FOR TIGHT, LOW PERMEABILITY ZONES.

Fig. 19

BAROID ppm LOG
SHOW EVALUATION REPORT

COMPANY GULF NORWAY

WELL 35/8-2 STI

LOCATION N. SEA NORWAY

FORMATION BRENT SANDSTONE

DEPTH 3678 & 3680 metres

PROBABLE PRODUCTION GAS CONDENSATE

MUD ANALYSIS

	BACKGROUND	NET INCREASE	
		PLOT 1	PLOT 2
		DEPTH 3678	DEPTH 3680
METHANE – ppm C_1		35,700	42,000
ETHANE – ppm C_2		4,600	4,800
PROPANE – ppm C_3		3,400	3,400
BUTANE – ppm C_4		1,500	1,500
PENTANE+ – ppm C_{5+}			
METHANE % – UNITS –			
TOTAL % – UNITS –			
CHLORIDES			

DRILLING RATE: MT ~~FT~~/HR X MIN/FT __

FROM 9·1 TO 11·2

LITHOLOGY SDST – clr, c. grn, sub rnd – sub ang, mod srtd, uncons, occ partially calc cmt.

REMARKS

NEW ORDERS

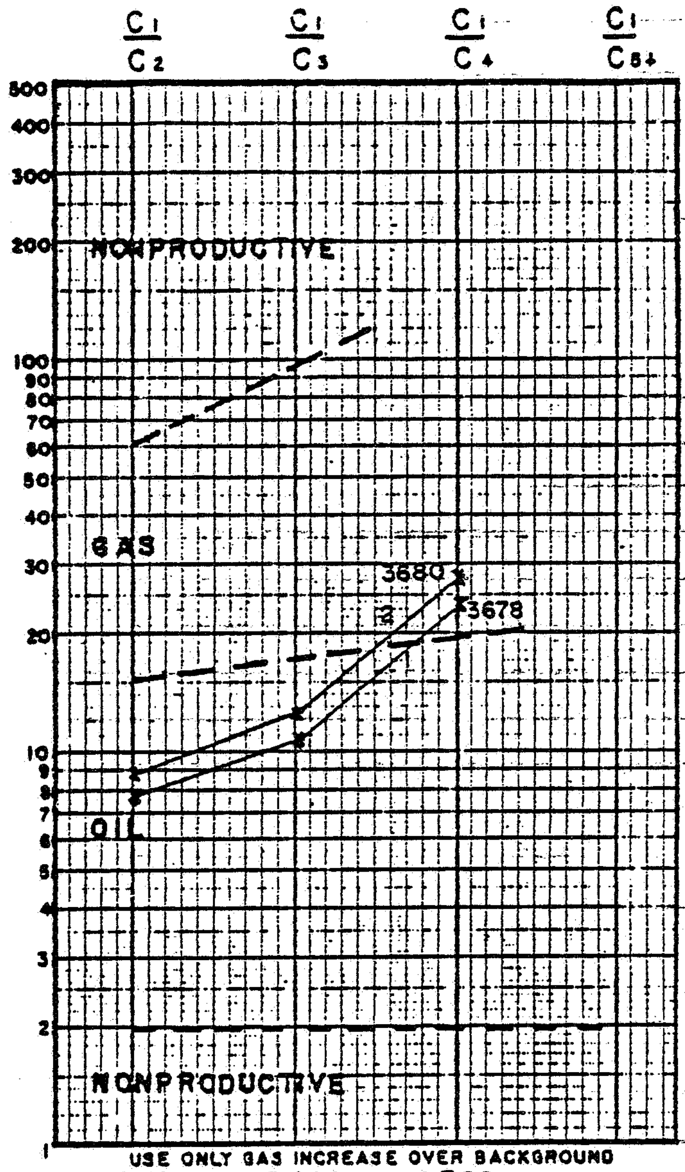
CALLED IN BY

TALKED TO

DATE 21/02/82 TIME ____ AM __ PM __

BR-30615

HYDROCARBON RATIOS



USE ONLY GAS INCREASE OVER BACKGROUND

C_1: 35,700 M C_3: 3,400 M C_4: 1,500 M C_{5+}: ____ M

C_2: 4,600 M

C_1/C_2: 7·8 C_1/C_3: 10·5 C_1/C_4: 23·8 C_1/C_{5+}: ____

1. PLOT RATIOS ON LINES INDICATED.
2. EVALUATE SECTION FOR PROBABLE PRODUCTION AS INDICATED BY THE PLOTTED CURVE WITHIN THE FOLLOWING LIMITS:
   a. PRODUCTIVE DRY GAS ZONES MAY SHOW ONLY C_1 BUT ABNORMALLY HIGH C_1 ONLY SHOWS ARE USUALLY INDICATIVE OF SALT WATER.
   b. IF THE C_1/C_2 RATIO FALLS LOW IN THE OIL SECTION AND THE C_1/C_4 RATIO FALLS HIGH IN THE GAS SECTION THE ZONE IS PROBABLY NONPRODUCTIVE.
   c. IF ANY RATIO (C_1/C_5 EXCEPTED IF OIL MUD IS USED) IS LOWER THAN A PRECEDING RATIO THE ZONE IS PROBABLY NONPRODUCTIVE. FOR EXAMPLE, IF C_1/C_4 IS LESS THAN C_1/C_3 THE ZONE IS PROBABLY WET.
   d. THE RATIOS MAY NOT BE DEFINITIVE FOR TIGHT, LOW PERMEABILITY ZONES.

Fig 19

BAROID ppm LOG
SHOW EVALUATION REPORT

COMPANY GULF NORWAY

WELL 35/8-2 ST1

LOCATION N. SEA NORWAY

FORMATION BRENT

DEPTH 3686 & 3696 metres

PROBABLE PRODUCTION GAS CONDENSATE

MUD ANALYSIS

	BACKGROUND	NET INCREASE	
		PLOT 1	PLOT 2
		DEPTH 3686	DEPTH 3696
METHANE – ppm C_1		59,500	18,900
ETHANE – ppm C_2		7,700	2,700
PROPANE – ppm C_3		5,900	2,000
BUTANE – ppm C_4		3,800	1,000
PENTANE+ – ppm C_{5+}			
METHANE % – UNITS –			
TOTAL % – UNITS –		233	70
CHLORIDES			

DRILLING RATE: MT ~~FT~~/HR __ MIN/FT __
FROM 5·0 TO 4·1

LITHOLOGY SDST-clr, c gr, sub ang-sub rnd, w srtd, uncons, also calc cmt at 3686 m. SDST – a/a, org stn, v.f [illegible]n, ang, calc cmt, vit. at 3696 m.

REMARKS __________

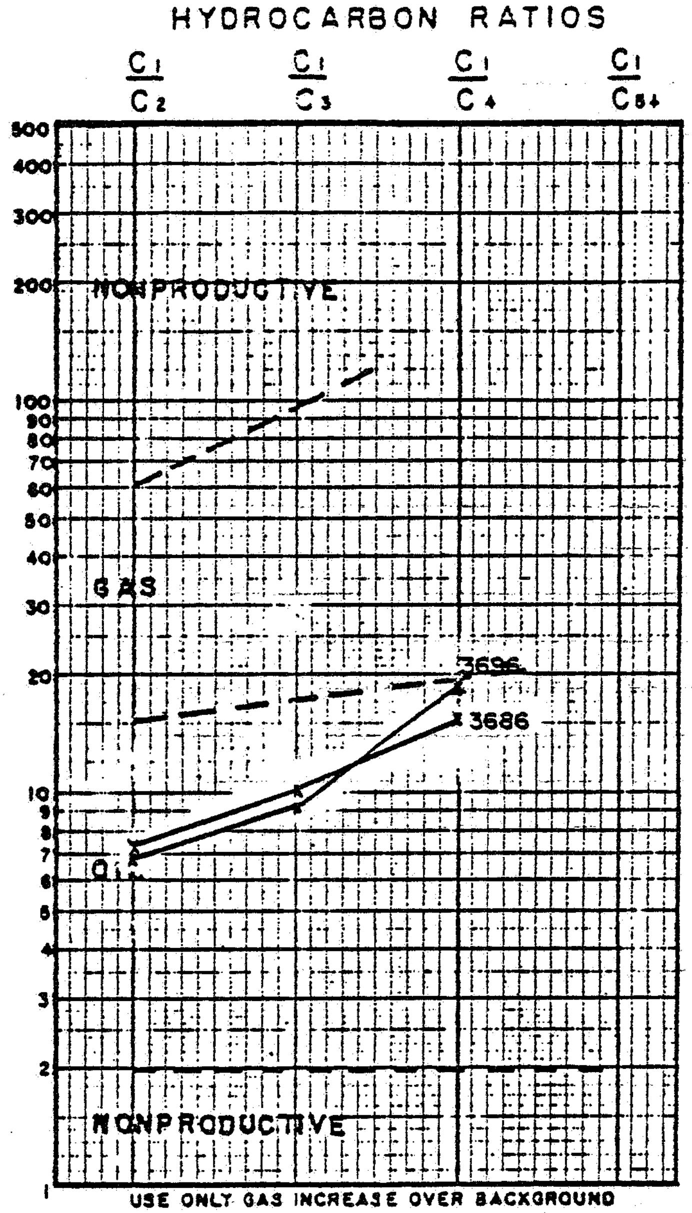
NEW ORDERS __________

CALLED IN BY __________

WALKED TO __________

DATE 21/02/82 TIME ______ AM __ PM __

BR-30615



USE ONLY GAS INCREASE OVER BACKGROUND

C_1: 59,500 M C_3: 5,900 M C_4: 3,800 M C_{5+}: ____ M
C_2: 7,700 M

C_1/C_2 7·7 C_1/C_3: [illegible] C_1/C_4: 15·7 C_1/C_{5+}: ____

1. PLOT RATIOS ON LINES INDICATED.
2. EVALUATE SECTION FOR PROBABLE PRODUCTION AS INDICATED BY THE PLOTTED CURVE WITHIN THE FOLLOWING LIMITS:
   a. PRODUCTIVE DRY GAS ZONES MAY SHOW ONLY C_1 BUT ABNORMALLY HIGH C_1 ONLY SHOWS ARE USUALLY INDICATIVE OF SALT WATER.
   b. IF THE C_1/C_2 RATIO FALLS LOW IN THE OIL SECTION AND THE C_1/C_4 RATIO FALLS HIGH IN THE GAS SECTION THE ZONE IS PROBABLY NONPRODUCTIVE.
   c. IF ANY RATIO (C_1/C_4 EXCEPTED IF OIL MUD IS USED) IS LOWER THAN A PRECEDING RATIO THE ZONE IS PROBABLY NONPRODUCTIVE. FOR EXAMPLE, IF C_1/C_4 IS LESS THAN C_1/C_3 THE ZONE IS PROBABLY WET.
   d. THE RATIOS MAY NOT BE DEFINITIVE FOR TIGHT, LOW PERMEABILITY ZONES.

Fig. 20

BAROID ppm LOG
SHOW EVALUATION REPORT

COMPANY GULF NORWAY

WELL 35/8-2 STI

LOCATION N. SEA NORWAY

FORMATION BRENT SANDSTONE

DEPTH 3703,3706 & 3707 metres

PROBABLE PRODUCTION GAS CONDENSATE

MUD ANALYSIS

	BACKGROUND	NET INCREASE	
		PLOT 1	PLOT 2
		DEPTH 3706	DEPTH 3707
METHANE – ppm C_1		15,500	16,000
ETHANE – ppm C_2		4,500	2,300
PROPANE – ppm C_3		3,100	1,700
BUTANE – ppm C_4		1,800	1,100
PENTANE+ – ppm C_{5+}		900	700
METHANE % – UNITS –			
TOTAL % – UNITS –			
CHLORIDES			

DRILLING RATE: MT ~~FT~~/HR X MIN/FT __

FROM 3·7 TO 4·5

LITHOLOGY SDST – clr, m. grn, occ f. grn – c. grn, sub ang – sub rnd, mod srtd, uncons, occ well cmtd, on Calc cmt.

REMARKS 45 UNITS OF GAS RECORDED AT 3707m.

NEW ORDERS

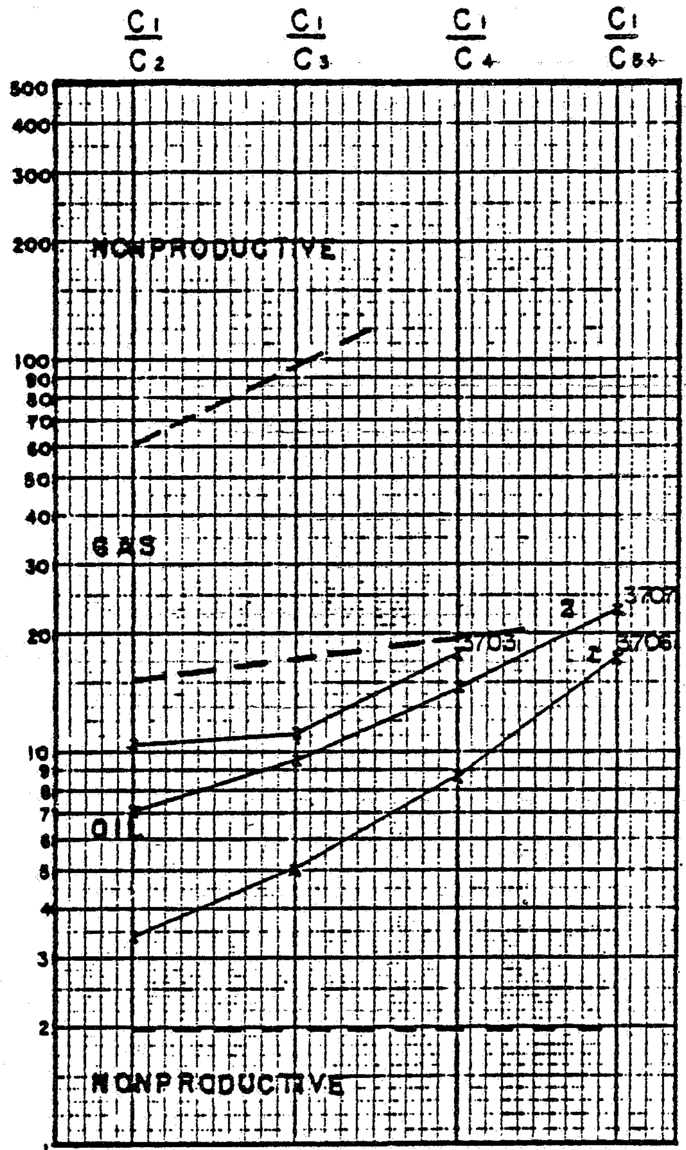
CALLED IN BY

TALKED TO

DATE 21/02/82 TIME ______ AM __ PM __

BR-30615

HYDROCARBON RATIOS



USE ONLY GAS INCREASE OVER BACKGROUND

C_1= 15,500 M C_3= 3,100 M C_4= 1,800 M C_{5+}= 900 M

C_2= 4,500 M

C_1/C_2= 3·4 C_1/C_3= 5 C_1/C_4= 8·6 C_1/C_{5+}= 17·2

1. PLOT RATIOS ON LINES INDICATED.
2. EVALUATE SECTION FOR PROBABLE PRODUCTION AS INDICATED BY THE PLOTTED CURVE WITHIN THE FOLLOWING LIMITS:
   a. PRODUCTIVE DRY GAS ZONES MAY SHOW ONLY C_1 BUT ABNORMALLY HIGH C_1 ONLY SHOWS ARE USUALLY INDICATIVE OF SALT WATER.
   b. IF THE C_1/C_2 RATIO FALLS LOW IN THE OIL SECTION AND THE C_1/C_4 RATIO FALLS HIGH IN THE GAS SECTION THE ZONE IS PROBABLY NONPRODUCTIVE.
   c. IF ANY RATIO (C_1/C_5 EXCEPTED IF OIL MUD IS USED) IS LOWER THAN A PRECEDING RATIO THE ZONE IS PROBABLY NONPRODUCTIVE. FOR EXAMPLE, IF C_1/C_4 IS LESS THAN C_1/C_3 THE ZONE IS PROBABLY WET.
   d. THE RATIOS MAY NOT BE DEFINITIVE FOR TIGHT, LOW PERMEABILITY ZONES.

Fig. 21

BAROID ppm LOG
SHOW EVALUATION REPORT

COMPANY GULF NORWAY

WELL 35/8-2

LOCATION N. SEA NORWAY

FORMATION BRENT

DEPTH PLOT 1 3709 PLOTS 2-4 3713 mts

PROBABLE PRODUCTION GAS CONDENSATE

MUD ANALYSIS

	BACKGROUND	NET INCREASE			
		PLOT 1&2		PLOT 3&4	
		3709	3713	DEPTH 3713m	
METHANE — ppm C_1		6333	10,000	5333	8700
ETHANE — ppm C_2		540	870	280	740
PROPANE — ppm C_3		208	320	120	256
BUTANE — ppm C_4		58	120	29	75
PENTANE+ — ppm C_{5+}					
METHANE % — UNITS —					
TOTAL % — UNITS —		15	20	4	10
CHLORIDES					

BREAK INTERVAL

RILLING ~~RATE~~: MT ~~FT~~/HR ___ MIN/FT ___

FROM 1·9 TO 3·6 3708–3714

ITHOLOGY SDST – c – m gr. at 3709 mts.

SDST – f – m gr. at 3713 mts.

AMPLE FROM CORE BARREL.

EMARKS GAS RECORDED DURING CORING.

EW ORDERS

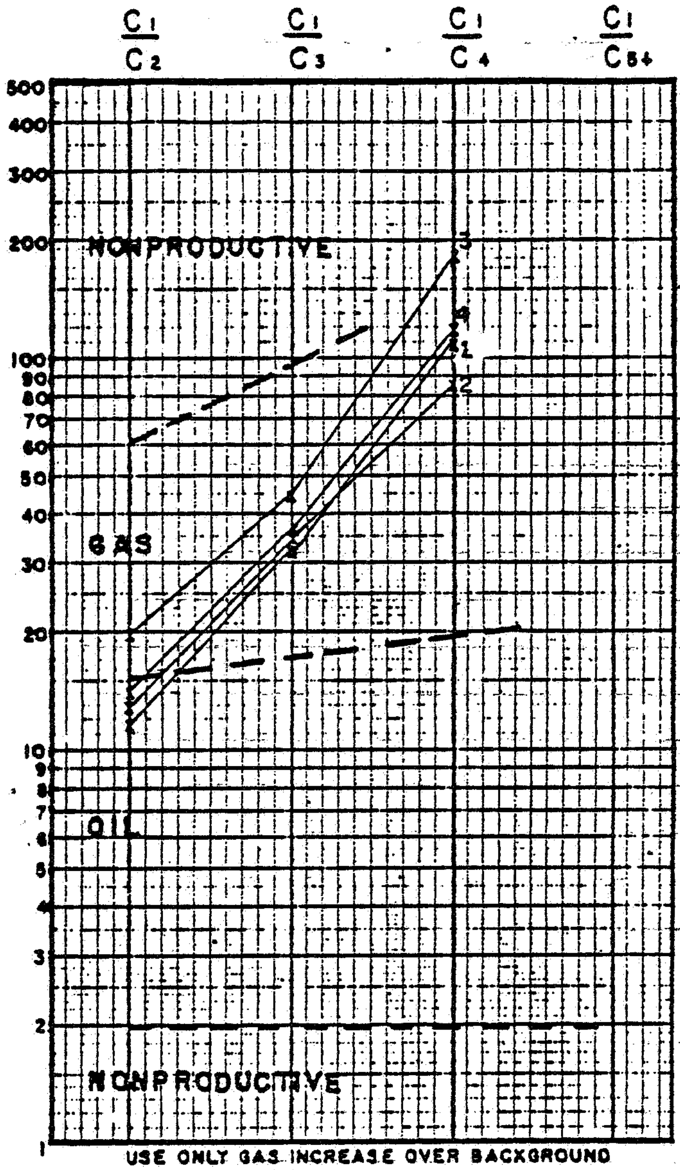
ALLED IN BY M.J.OATES

ALKED TO

TE 9/01/82 TIME 0300–0500 AM ___ ~~PM~~ ___

BR-30615

HYDROCARBON RATIOS



USE ONLY GAS INCREASE OVER BACKGROUND

C_1: 6333 M C_3: 208 M C_4: 58 M C_{5+}: ___ M

C_2: 540 M

C_1/C_2: 11·7 C_1/C_3: 30·4 C_1/C_4: 109·1 C_1/C_{5+}: ___

1. PLOT RATIOS ON LINES INDICATED.
2. EVALUATE SECTION FOR PROBABLE PRODUCTION AS INDICATED BY THE PLOTTED CURVE WITHIN THE FOLLOWING LIMITS:
   a. PRODUCTIVE DRY GAS ZONES MAY SHOW ONLY C_1 BUT ABNORMALLY HIGH C_1 ONLY SHOWS ARE USUALLY INDICATIVE OF SALT WATER.
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   d. THE RATIOS MAY NOT BE DEFINITIVE FOR TIGHT, LOW PERMEABILITY ZONES.

BAROID ppm LOG
SHOW EVALUATION REPORT -

COMPANY GULF NORWAY
WELL 35/8-2
LOCATION N.SEA NORWAY
FORMATION BRENT
DEPTH 3722 metres
PROBABLE PRODUCTION

MUD ANALYSIS

	BACKGROUND	NET INCREASE	
		PLOT 1	PLOT 2
		DEPTH 3722	DEPTH
METHANE - ppm C_1		600	
ETHANE - ppm C_2		200	
PROPANE - ppm C_3		200	
BUTANE - ppm C_4		175	
PENTANE+ - ppm C_{5+}		Trace	
METHANE % - UNITS -			
TOTAL % - UNITS -			
CHLORIDES			

DRILLING RATE: FT/HR __ MIN/FT __
FROM ___ TO ___

LITHOLOGY SDST - f - m. gr, occ c. gr.
SAMPLE FROM CORE BARREL.

REMARKS GAS CAUGHT IN CORE BARREL.

NEW ORDERS

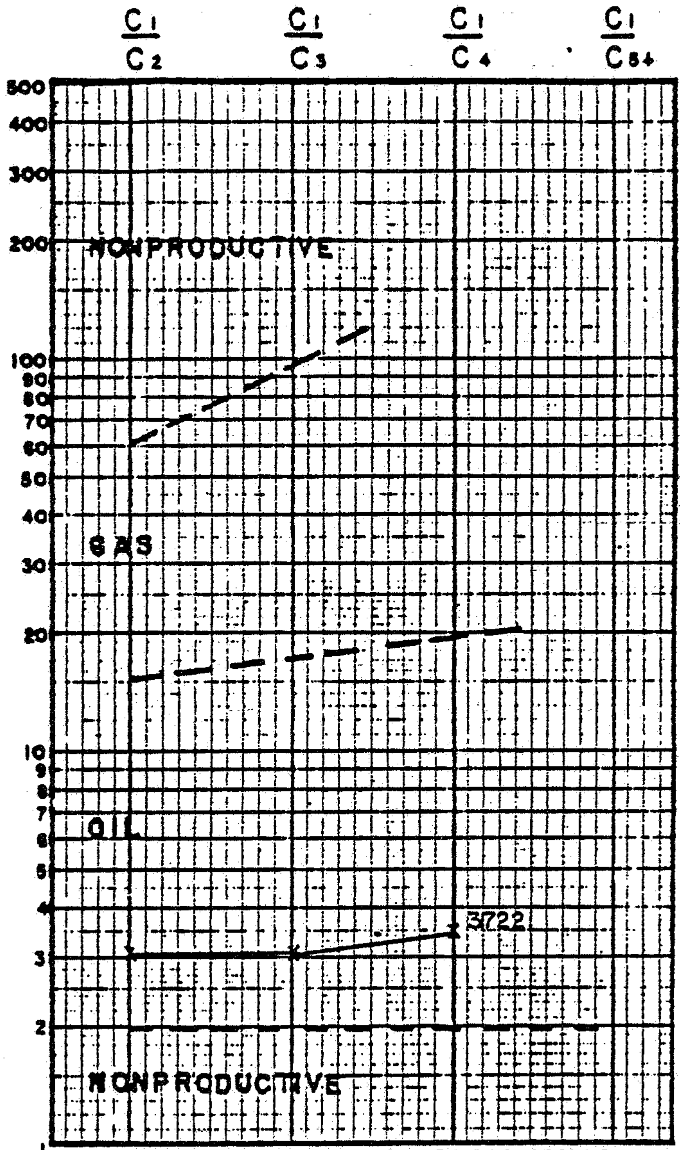
CALLED IN BY

TALKED TO

DATE 9/01/82 TIME 1700 ~~AM~~ __ PM __

BP 30615

HYDROCARBON RATIOS



USE ONLY GAS INCREASE OVER BACKGROUND

C_1: 600 M C_3: 200 M C_4: 175 M C_{5+}: __ M
C_2: 200 M
C_1/C_2: 3 C_1/C_3: 3 C_1/C_4: 3.4 C_1/C_{5+}: __

1. PLOT RATIOS ON LINES INDICATED.
2. EVALUATE SECTION FOR PROBABLE PRODUCTION AS INDICATED BY THE PLOTTED CURVE WITHIN THE FOLLOWING LIMITS:
   a. PRODUCTIVE DRY GAS ZONES MAY SHOW ONLY C_1 BUT ABNORMALLY HIGH C_1 ONLY SHOWS ARE USUALLY INDICATIVE OF SALT WATER.
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   d. THE RATIOS MAY NOT BE DEFINITIVE FOR TIGHT, LOW PERMEABILITY ZONES.

9. Pore Pressure Detection (Baroid)

Methods of Pore Pressure Detection

During drilling of 35/8-2, the following methods of pore pressure detection and prediction were used:

A) Corrected D Exponent.

This was the major quantitative method used whilst drilling. It is a pore poreeure - drilling rate model which attempts to normalize the drilling rate for changes in weight on bit, rotary speed, hole size and mud weight. It is best suited to a shale - sandstone sequence where normal compaction trends can be established, and where overpressuring originates from a lack of or hindrance to normal compaction. The corrected D Exponent plot is adversely affected by large differential pressures at the bit (in excess of 500 psi); this suppression is such that little response may occur from a large change in differential pressure. This factor is of particular interest on this well as overbalance during much of the overpressured section was in excess of 1,000 psi. Also of importance is the fact that the D Exponent is best suited to sequences of pure shales and claystone which were not common in this well. Nevertheless the pore pressure of the Brent Sand was accurately calculated using D Exponent and Eatons formula:

$$\text{Pore pressure} = \text{Overburden} - \left(\text{Overburden} - \begin{matrix}\text{Normal pore}\\ \text{Pressure}\end{matrix}\right) \times \left(\frac{\text{Observed Dc Exponent}}{\text{Normal Dc Exponent}}\right)^{1.2}$$

B) Gas.

Although the amount of gas present in the mud cannot be used quantatively to calculate pore pressures, it is nevertheless a very good indicator of pore pressure changes relative to mud weight. Of particular use is connection gas and trip gas. On this well it helped to indicate the increase of pore pressure on drilling into the Kimmeridge, the reversal below this, and the increase again below 3400 m.

C) Shale Density.

This was of little use as it was very sensitive to shale and claystone impurities present throughout most of the well.

D) Shale Factor.

This is effectively a measure of the montmorillonite in a cuttings sample of shale or claystone and gives an indication of the amount of compaction. Although not quantative in itself it proved useful with the interpretation of other data it indicated the pressure increase in the Kimmeridge, the reversal below and the increase below 3400 m.

E) Flowline Temperature.

With a 381 m marine riser its usefulness was limited. It did nevertheless show a gradual increase up to 3400 m followed by a slow but steady decrease.

F) General drilling data such as Torque, Drag, Hole Fill, Mud Cutting, changes in Chlorides and size and shape of cuttings, were noted and taken into consideration when interpretating other data.

G) Wireline Logs.

Sonic and Resistivity were all plotted after each log run and used to confirm the drilling data predictions. Of these the Sonic proved to be the most useful. Eaton's Formula:

$$\text{Pore Pressure} = \text{Overburden} - \left(\text{Overburden} - \text{Normal Pore Pressure}\right) \times \left(\frac{\text{Normal sonic Transit Time}}{\text{Observed sonic Transit Time}}\right)^{3.0}$$

was used throughout the well and generally gave good agreement with Dc Exponent and RFT's.

The Resistivity plot was more sensitive to silt and sand in the claystones shales and proved to be much less quantitatively useful in pore pressure calculation.

Pore Pressure Discussion

The section from the mud line to the Upper Cretaceous is all normally pressured and contained no shallow gas accumulations. Pore pressure was taken to be 0.452 psi/ft, equivalent to 8.7 ppg.

Evidence of the first increase in pore pressure occurred at 2660 m when a small cut back from the normal D exponent trend was noted. A pore pressure of 0.463 psi/ft (8.9 ppg) was calculated. Sonic and resistivity has later confirmed this. The pore pressure then appears to remain constant down to 2900 m where another cutback from the D exponent trend was noted. An increase in the shale factor, reversing a normal decreasing trend present throughout the cretaceous, confirmed this. A pore pressure of 0.468 psi/ft (9.0 ppg) was calculated and later confirmed by the sonic and resistivity logs.

On drilling into the Kimmeridge clay at 3085 m a sharp decrease in the D exponent, increase in shale factor, increase in background gas and more significantly the presence of connection gas and high trip gas indicated a rapid increase in pore pressure. The pore pressure calculated at this time from the D exponent plot was 0.608 psi/ft, equivalent to 11.7 ppg. The electric logs confirmed this pressure increase and from calculations indicate a pore pressure as high as 0.712 psi/ft (13.7 ppg) using Eatons formula (to the power of 3) and 0.634 psi/ft (12.2 ppg) using the depth of seal method.

Below the Kimmeridge there appears to be a pressure reversal. This is shown by the sonic log and confirmed by a RFT of 0.489 psi/ft equivalent to 9.4 ppg at 3322 m. The D exponent plot indicates a levelling off of the pore pressure below the Kimmeridge and even the most favourable interpretation would only indicate a very slight drop off in pressure. The shale factor does show evidence of a drop off in pore pressure and the decrease in background and trip gas can be interpreted as indicating a decrease in pore pressure. The 'none response' of the D exponent to this pressure reversal may in part be due to the impure nature of the shales and claystones and the high overbalance.

Below 3400 m the mud logging parameters D exponent, shale factor, background and trip gas, all indicate a gradual increase in pore pressure in the shale/claystone sequence above the Brent. At 3538 m where drilling was stopped to set 9 5/8" casing a pore pressure of 0.645 psi/ft equivalent to 12.4 ppg was calculated from the D exponent plot. This was confirmed by the sonic when electric logs were run prior to casing.

On resuming drilling D exponent calculations indicated a 0.634 - 0.645 psi/ft (12.2 - 12.4 ppg) pore pressure and 0.645 psi/ft (12.4 ppg) pore pressure for the claystone immediately above the Brent sandstone. Drilling and coring continued through the Brent sandstone with no sign of a change in pore pressure from 0.645 psi/ft (12.4 ppg).

Due to stuck pipe TD at 3750 m the section from 3489 m was redrilled in the sidetrack. Pore pressure calcualtions in the claystones from the D exponent indicated a pore pressure of 0.640 - 0.650 psi/ft (12.3 - 12.5 ppg), although in the Brent sandstone cuttings gas was higher than in the original hole.

On drilling into the Dunlin shales the D exponent indicated a small increase in pore pressure to 0.681 psi/ft (13.1 ppg). This was not substantiated by any of the other parameters. At 3954 m drilling was stopped to set 7" liner. RFT's taken in the Brent sandstone indicated a pore pressure of 0.629 - 0.645 psi/ft (12.1 - 12.4 ppg) agreeing very well with the D exponent and sonic results. An RFT of 0.645 psi/ft (12.4 ppg) taken in a sandstone in the Dunlin differs from the calculated D exponent pore pressure but is substantiated by the sonic log. The discrepancy may well be due to the fact that the shales/claystones are very impure and the overbalance was in excess of 1000 psi.

The 6 1/8" hole was almost entirely drilled with a diamond bit on a turbine. This and the lack of any pure shales/ claystones made the drilling rate and D exponent less useful than on previous sections. Other mud logging data did not show any further pressure changes. This conclusion was substantiated when final electric logs were run at TD at 4336 m.

Fracture Gradient

The fracture gradient for the well was calculated using Eaton's Formula:

$$F = K\ (o) + P$$

where F = Fracture Pressure (psi/ft)
K = Matrix Stress Coefficient
o = Overburden Pressure (psi/ft)
P = Pore Pressure

The overburden was obtained from a cumulative sonic density plot. The Matrix stress coefficient was tkane from the Texas Gulf Coast model in Eaton's paper. A table of actual and calculated leak-off test data is given below:

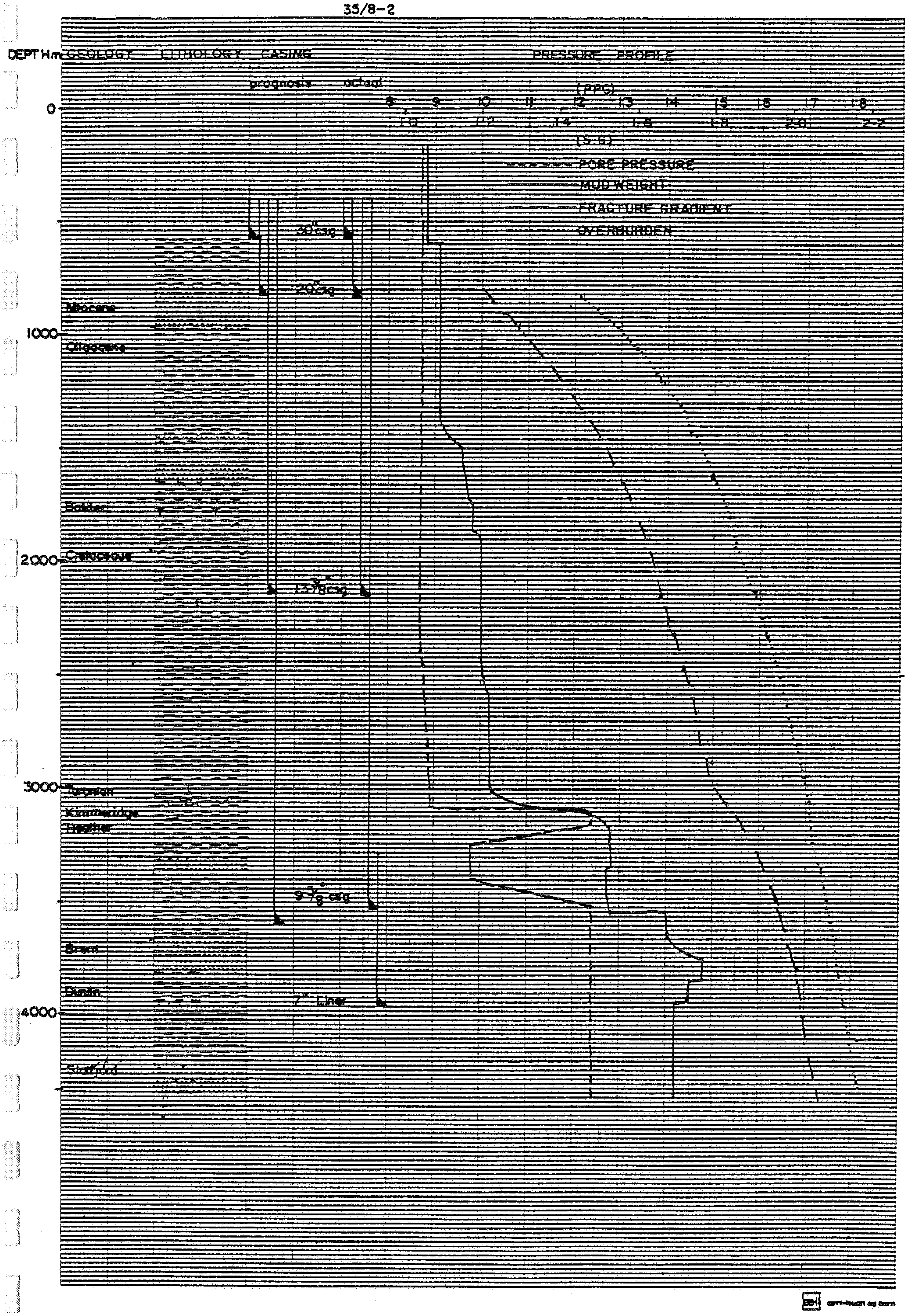
Depth	Leak-Off Data		Overburden Gradient	Pore Press. Grad.	Gulf Coast K Val.	Calcul. Fracture Grad.
Metres	ppg	K	psi/ft	psi/ft		ppg
840	11.9	0.938	0.628	0.45	0.387	10.0
2158	13.8	0.706	0.827	0.45	0.715	13.9
3530	16.4	0.784	0.909	0.64	0.818	16.6
3958	16.7	0.796	0.925	0.64	0.835	16.9

From the data is can be seen that calculated values and actual values are very close, apart from the one at 840 m. This is obviously an erroneous reading since back calculation gives a Matrix stress coefficient K of 0.938, which is greater than the deepest value on the well and very close to its limiting value of 1.00. This value is only approached at depth due to the increase in plasticity of formations with depth and/or pressure. When K = 1.00 the formation fracture gradient is equal to the overburden gradient.

On 35/8-2 after setting 30" conductor pipe, a 17 1/2" pilot hole was drilled to 842 metres and opened out to 26". 20" casing was set at 830 metres. The cement was drilled out with a 17 1/2" bit to 840 metres and the leak-off test carried out. Thus no new formation had been drilled and only cemented formation was tested!!

The leak-off test at 3958 metres was not taken to leak-off and thus the calculated value of 16.9 ppg is probably nearer to correct than 16.7 ppg.

35/8-2


DEPTH m
GEOLOGY
LITHOLOGY
CASING
prognosis
actual
PRESSURE PROFILE
(PPG)
8
9
10
11
12
13
14
15
16
17
18
1.0
1.2
1.4
1.6
1.8
2.0
2.2
(S.G)
PORE PRESSURE
MUD WEIGHT
FRACTURE GRADIENT
OVERBURDEN
0
1000
2000
3000
4000
Miocene
Oligocene
Balder
Cretaceous
Tarbert
Kimmeridge
Heather
Brent
Dunlin
Statfjord
30" csg
20" csg
13 3/8" csg
9 5/8" csg
7" Liner

10. Wireline logging

Schlumberger were contracted to provide wireline logging services for 35/8-2. A Cyber Service Unit (CSU) was used for all logging runs.

Attached is a listing of all logs run. Problems while logging are discussed below:

Logging run 1:	No problems.
Logging run 2:	ISF/LSS run in two stages. First stage reached 1938m. Second stage reached 2140m with a wiper trip in between stages.
Logging run 3:	ISF/LSS would not repeat due to movement of blocks during running of repeat section. LDT/CNL would not reach TD (3538m) due to sticky hole. Deepest point logged is 3400m.
Logging run 4:	ISF would not repeat. DLL/MSFL log is a splice of two runs due to sticky hole.
Logging run 5:	No problems.

Well 35/8-2

LOGGING RUN 1

Tool	Run No.	Interval (m)	Date	Scale
CCL & PR	1/1	486.2-484.6	15/9-81	200
	1/2	451.1-449.5	17/9-81	200
	1/3	425.2-423.6	18/9-81	200
	1/4	416.9-416	20/9-81	200
BACKOFF	1	Collar - 458	9/9-81	200
HRT	1/1-4	573 - Muleshoe	17-19/9-81	200, 500
ISF/LSS/GR/SP	1/1	842-578 (Gr-407)	1/10-81	200, 500
FDC/GR/CAL	1/1	841.5-578	1/10-81	200, 500

BHT 23.3°C after 8½ hours.

Rmf = 0.452 at 20°C

Mud - Gel Caustic, 9.3 ppg, V = 60, pH = 9.

Well 35/8-2

LOGGING RUN 2

Tool	Run No.	Interval (m)	Date	Scale
ISF/LSS/GR/SP	2/2	2140-829.5	19/10-81	200, 500
FDC/GR/CAL	2/2	2135.5-829.5	19/10-81	200, 500
HRT	2/5	1154-400	22/10-81	200, 500
CCL & PR	2/5	2137.2-2136.5	26/10-81	200
CBL	2/1	2137.5-400	23-24/10-81	200

BHT 46.1°C after 25.50 hours.

Rmf = 1.05 at 21.1°C

Mud - Gel/Poly/Ligno., 10 ppg, V = 65, pH = 10.5

Well 35/8-2

LOGGING RUN 3

Tool	Run No.	Interval (m)	Date	Scale
ISF/LSS/GR	3/3	3536-2143	23/12-81	200, 500
LDT/CNL	3/3	3329-2143	23/12-81	200, 500
LDT/CNL w/o Pef.	3/3	"	"	200, 500
DLL/LSS/GR	3/1	3533-2143	23/12-81	200, 500
DLL/MSFL	3/1	3536-2096	23/12-81	200, 500
Cyberlook	3/1	3326-3200	"	200
HDT/GR	3/1	3536-2143	23/12-81	20
Dipmeter	3/1	3537-2143	24/12-81	200
Cyperdip	3/1	3537-2143	24/12-81	500
CVL from HDT	3/1	3536-2143	23/12-81	500
HDT, Comp.Aero.	3/1	"	"	200
RFT	3/1	-	25/12-81	-
RFT Quicklook	3/1	-	"	-

BHT 83.8 after 33 hours.

Rmf = 0.061 at 14°C

Mud - KCl polymer, 12.8 ppg, V = 53, pH = 10.1.

Well 35/8-2

LOGGING RUN 4

Tool	Run No.	Interval (m)	Date	Scale
ISF/BHC/GR	4/4	3951-3538	2/3-82	200, 500
LDT/CNL/GR/CAL	4/4	3953-3300	2/3-82	200, 500
" + Pef.	"	"	"	"
" + Pef., Bar. all.	"	"	"	"
" + Pef., Bar.disall.	"	"	"	"
" w.Comp. Ø scales	"	"	"	"
DLL/MSFL/GR/CAL	4/2	3952-3531	3/3-82	200, 500
Cyberlook	4	3830-3625	3/3-82	200
Dipmeter	4	3953-3480	3/3-82	200
Cyberdip	4/2	"	"	200
" Arrow	4/2	"	"	200, 500
" Pooled Arrow	4/2	"	"	200, 500
CVL from HDT	4/2		"	-
RFT	4/2	-	3/3-82	-
RFT (alt.display)			"	-
CORIBAND (Proc.1)	4	3940-3600	17/3-82	200
Geodip	4	3950-3650	27/8-82	20

BHT = 125 °C after 24.55 hours.
Mud = Lignosulfonate/Lignite 14.5 ppg V = 55 pH = 10.5
Rmf = 0.130 at 12.2°C.

Well 35/8-2

LOGGING RUN 5

Tool	Run No.	Interval (m)	Date	Scale
ISF/LSS/GR/SP	5/5	4330-3952	18/4-82	200, 500
LDT/CNL/GR	5/5	4331-3951	18/4-82	200, 500
Dipmeter	5/3	4321-3952	18/4-82	200
Cyberdip	5/3	"	"	200
Cyberlook	5/1	4229-3954	"	200
Sonic W-form	5/1	3951-3300	"	200
NGT (2 displays)	5/1	4331-3952	"	200, 500
Cased hole NGT	5/1	3952-3050	"	200, 500
CBL	5/2	3952-578	19/4-82	200

BHT Max 147.7°C after 30 hrs.

RMF 0.192 at 19.4°C

Mud Lignosulf/Lignite, 14.2 ppg v = 68 pH = 10.8

11. Velocity Survey

The 35/8-2 velocity survey was conducted by Seismograph Service Limited (SSL) and included both a conventional VSP (from 4294m to 965m) and an offset VSP (from 4294m to 1620m). The downhole geophone interval for both of these was 30m, and the energy source for the offset survey was placed 1500m from the rig on a bearing of approximately N 20°E. Check shots were fired at three levels between 965m and the 30-inch casing shoe at 590m. Decca Survey Norway A/S provided positioning service for the offset VSP with a trisponder system (Miniranger and theodolite).

The 35/8-2 survey was planned with similar objectives in mind, with the singular exception that at 35/8-2 an offset VSP, in contrast to the offset source survey run at 35/8-1, would be conducted to enable further study of our problem of time-depth conversion using the seismic velocities. An offset VSP is operationally the same as conventional VSP except that the energy source is offset horizontally from the borehole. At 35/8-2 the conventional and offset VSP's were run simultaneously, with the rig and offset sources alternately firing for each subsurface geophone location. The conventional VSP was recorded from 4294m to 965m, at which the noise level on the record became unacceptably high; the offset VSP was also started at 4294m but was terminated at 1620m owing to equipment difficulties.

Two technical points were made by SSL personnel during the survey:

1) While rigging up the downhole geophone, SSL cautioned that their tool is much less sensitive.

2) When asked about reverberations seen on the field records, SSL indicated that these could be very effectively removed by deconvolution during processing. In the 35/8-1 survey, reverberations had been minimized by firing of a second smaller (40 cu in) air gun to compensate for the bubble pulse from the larger (80 cu in) gun; however, this procedure can result in lack of consistency of the source signature. In the 35/8-2 survey, single air guns (80 cu in each at 1500-1800 psi) were used at both source positions, and SSL felt that this configuration in combination with effective deconvolution would result in a more consistent source signature.

Several equipment difficulties encountered during the survey need to be noted:

1) The deepest geophone position reached during the survey was 4294m (TD is 4336mm). The geophone was not placed at TD at the start of the survey because the tool could not be lowered deeper than 4294m without difficutly and SSL rightly did not want to force it.

2) Operations in the open hole (below approximately 3950m) proceeded slowly owing to the difficulty encountered in achieving good contact between the geophone and the borehole wall. Operations in the cased hole, where the tool was dragged upward without retracting its arm, proceeded much more quickly.

3) The digital record counter on SSL's recording unit malfunctioned early in the survey. This problem was corrected by SSL personnel (a defective integrated circuit had to be replaced) with minimum delay.

4) The clocks used to time firing and recording between the offset source on the Balder Vaasa and the rig could not be kept in synchronization. Adjustment of these instruments required that the offset equipment be brought to the rig for recalibration, resulting in operational delays. After adjustment the clocks usually stayed in synchronization for about 4-5 hours; following the third occurrence of this problem while operating at 1620m (approximately 18 hours into the survey), the offset survey was terminated while the conventional survey continued. SSL personnel indicated that certain equipment which can automatically maintain synchronization of the clock was not on the rig for the survey.

5) The high-temperature geophone requested for the survey was not available from SSL on the short notice given for mobilization. Apparently the low-temperature tool which was provided functioned properly, even through operating near its temperature limit (the temperature at TD in 35/8-2 is approximately 300°F).

12. RFT Summary

Run 3/1

One run was made with the RFT tool as a part of the logging program before setting 9 5/8" casing. (Run no.1 was actually the third trip in the hole with the RFT tool, the first two trips resulted in tool failure). The purpose was to measure formation pressures in the Upper Jurassic sands and to take a fluid sample. Depth correlation was based on the GR of the DLL/MSFL/CAL log recorded during the same logging run.

RFT No.	Logging Run	TD metres	Max BHT
1	3	3538.2	100.3 DC

Each test has been given a two digit number indicating the run number and the test number, e.g. 1/2 indicates the second test taken during the first trip into the hole with the RFT tool. A 20,000 psi pressure gauge calibrated to 16,000 psi was used. (A 10,000 psi gauge was used on the first unsuccessful run into the hole and consistently gave erroneously high readings in the mud column and was therefore replaced with a back-up gauge).

A total of 27 pressure tests were attempted, 24 resulted in seal failure, 1 failed by probe plugging, and 2 were successful in measuring formation pressure (See table 4). A segregated sample using two 2 3/4 gallon chambers was taken at 3322m (test 1/27).

Pressure Interpretation (run 3/1): Formation pressures recorded by the RFT are 5281 psi at 3312m (hydrostatic = 7361 psi) and 5309 psi at 3322m (hydrostatic = 7380 psi) indicating an overbalance of approximately 2075 psi in the zones where formation pressures were recorded. Pore pressure calculated by d-exponent in this same zone is 6745 psi, indicating that the formation pressure is anomalously low. There are at least two possible explanations for this situation: 1) The sandstones in this interval, sandwiched between an upper overpressured shale section (Kimmeridge Clay) and a lower overpressured shale (Heather Shales), are in communication, up dip, with a normally pressured permeable zone or 2) the parameters normally used for calculating d-exponent are not valid in this area. Further studies will be required to elaborate on this subject.

No interpretation of formation pressure gradient has been attempted due to the availability of only 2 data points separated by only 10 meters.

Sample Recovery

RFT 1/27 (3322m)

The lower chamber (2 3/4 gal) was opened first and filled in 44 minutes. The upper chamber (2 3/4 gal) was subsequently opened and filled in 51 minutes. The contents of both chambers were examined at the well-site. Recovery was as follows:

Lower Chamber (2 3/4 gal) 6 liters of mud and 4.2 liters of mudfiltrate.

Upper Chamber (2 3/4 gal) 10.3 liters of mud filtrate

R_{sample} = 0.0643 at 21°C, K^+ = ppb, Cl = 75,000 ppm, ph = 8.8
(R_{mf} = 0.0615 at 14°C, K^+ = 50 ppb, Cl = 78,000 ppm, ph = 10.0)

TABLE 4

PRE-TEST RESULTS (Run 3/1)

Well 35/8-2
Date: Dec. 26, 1981
Run 3/1

Mud weight: 12.8t

Test no.	Depth (m)	Test Failed	Final Build-up uncorrected	Final Build-up corrected	Mud Hydrostatic uncor. Before/ After	Mud Hydrostatic cor. Before After	Comments
1	3280.5	S			7292 7293	7287 7288	
2	3280	?(S)	7425	7420	7290 7292	7285 7287	Pres > hydro supercharge?
3	3306	S			7353 7356	7348 7351	
4	3308	S			7362 7365	7357 7360	
5	3307.6	S			7356 7353	7351 7348	
6	3312		5287	5281	7366 7363	7361 7358	Good Test
7	3314	S			7375 7376	7370 7371	
8	3313.6	S			7371 7370	7366 7365	
9	3318.9	S			7381 7381	7376 7376	
10	3321.8	S			7389 7391	7384 7386	
11	3321.4	S			7386 7386	7381 7381	
12	3322.2	S			7389 7393	7384 7388	

Test no.	Depth (m)	Test Failed	Final Build-up uncorrected	Final Build-up corrected	Mud Hydrostatic uncor. Before/ After	Mud Hydrostatic cor. Before After	Comments
13	3324.8	S			7399 7400	7394 7395	
14	3325	S			7393 7393	7388 7388	
15	3325	S			7393 7392	7388 7387	
16	3324	S			7399 7402	7394 7397	
17	3327.7	S			7405 7403	7400 7398	
18	3334.6	P			7414 7414	7409 7409	
19	3334.6	S			7414 7415	7409 7410	
20	3334.6	S			7420 7420	7415 7415	
21	3333	S			7412 7417	7407 7412	
22	3333.1	S			7412 7414	7407 7409	
23	3334.5	S			7413 7413	7408 7408	
24	3337	S			7418 7420	7413 7415	
25	3333	S			7409 7409	7404 7404	

Test no.	Depth (m)	Test Failed	Final Build-up uncorrected	Final Build-up corrected	Mud Hydrostatic uncor. Before/ After	Mud Hydrostatic cor. Before After	Comments
26	3327.7	S			7396 7396	7391 7391	
27	3322		5315	5309	7385 7383	7380 7378	Good Test Took Sample

Sample Summary

	Start	Finish	Pressure when sealed Uncorrected	Pressure when sealed Corrected
Lower Chamber	0335	0419	5318	5312
Upper Chamber	0420	0511	5295	5289

Pressure stabilized at 5297 psi (Corrected) after upper chamber sealed.

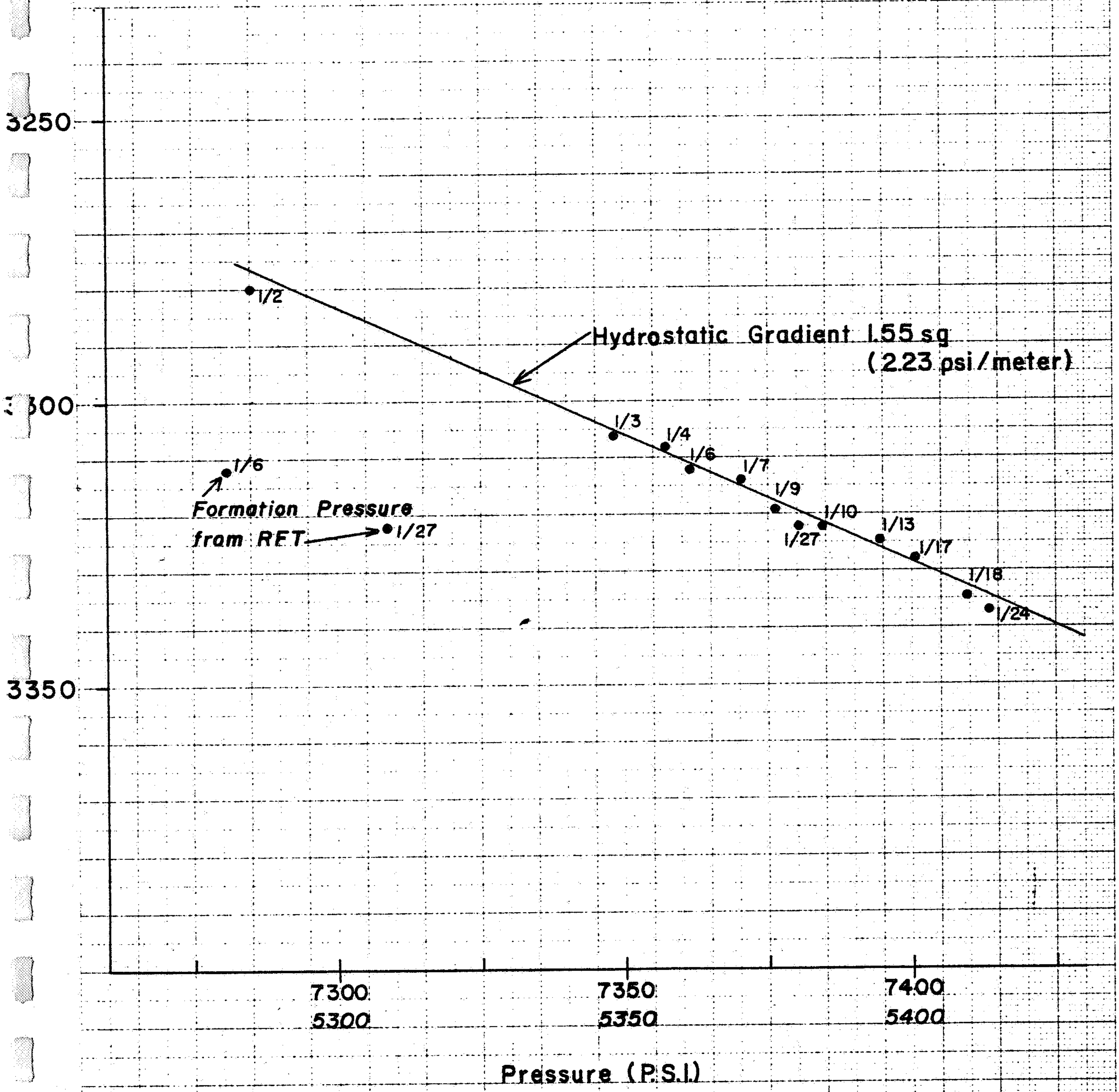
Lower chamber contained mud (6.0 liters) and mud filtrate (4.2 liters).

Upper chamber contained mud filtrate (10.3 liters). Mud Engineer's analysis of sample UC-1 (upper chamber)

K^+ = 50 ppb
Cl = 75,000 ppm
ph = 8.8

Analysis of mud filtrate from flow line:

K^+ = 50 ppb
Cl = 78,000
ph = 10.0



Results from pressure tests-RFT run no. 3/1.

To read hydrostatic pressures use scale drafted in block numerals.

To read formation pressures use scale drafted in italic numerals.

Fig. 25

Run 4/2

One run was made with the RFT tool as a part of the logging program before setting the 7" liner. The purpose was to measure formation pressures in the Brent and Cook sands. Depth correlation was based on the GR of the ISF/BHC/GR log recorded during the same logging run.

RFT No.	Logging Run	TD metres	Max BHT
2*	4	3954	125.0 DC

(*RFT No.1 was run during logging run no.3)

Each test has been given a two digit member indicating the run number and the test number, e.g. 2/3 indicates the third test taken during the second trip into the hole with an RFT tool. A 10,000 psi gauge calibrated to 11,000 psi was used. No formation fluid sampling was attempted, only formation pressure testing.

Pressure Interpretation (run 4/2):

Formation pressures measured with the RFT are plotted on figure 1. Hydrostatic pressure measured in the mud column are plotted on figure 2. The symbols indicate the following: X = good test, (X) affected by supercharging, /X/ probably affected by supercharging. Four tests in the hydrocarbon zone (3/4, 2/5, 2/20, 2/7) and one test in water zone (2/16) are valid tests. Test nos. 2/6 and 2/19 are definitly affected by supercharging (pre-test chambers were by-passed in an attempt to get readings in tight zones) and test nos. 2/14 and 2/15 are probably affected by supercharging.

Pressures in the hydrocarbon zone range from 7797 psi at 3671m to 7831 psi at 3723m. The gradient between these two points is 0.64 psi/meter which corresponds to a fluid density of 0.45 sg. This value is comparable to fluid densities calculated in the Brent Formation in 35/8-1. The reservoir is overpressured by approximately 2300 psi (assuming formation water density of 1.05 sg.).

Three pressure measurements were recorded below the hydrocarbon/water contact (3726m). It is felt that pressure tests 2/14 and 2/15 are probably affected by supercharging while test 3/16 is probably valid. If a visual best-fit line is drawn through these points, the resulting gradient is 2.59 psi/meter, which corresponds to a fluid density of 1.82 sg. (15.1 lbs/gal). This value far exceeds the density of common formation fluids thus either the pressure readings are erroneous, or the three points are separated by impermeable barriers. Test 2/16 was recorded at 3788.5m and test 2/14 recorded at 3811m. Only thin streaks of shale lie between these points thus it is doubtful that different pressure regimes could exist between these points. Between tests 2/4 and 2/15 (Cook Sand) a significant shale section does exist and it is conceivable that differential pressuring could occur in this zone but this phenomena is not supported by other pressure detecting methods, e.g. decreasing resistivity, increasing transit time, or d'exponents. Therefore the pressure gradient observed between tests 2/16, 2/14, and 2/15 is interpreted to be due to the supercharging effect on tests 2/14 and 2/15, rather than overpressure.

Test 2/16 is interpreted to be valid because the gradient between 2/16 and 2/7 is 1.06 psi/meter (fluid density = 0.71 sg.), which is actually lower than expected since 2/7 is at the base of the hydrocarbon zone and 2/16 is in the water zone (gradient in a water zone with a fluid density of 1.05 sg. is 1.49 psi/meter). Since supercharging results in erroneously high formation pressure measurements, a much higher gradient would have been observed had supercharging affected the test. One could interpret the anomalously low gradient between 2/7 and 2/16 as indicating that the hydrocarbon/water contact lies between these two points, the low gradient resulting from averaging the hydrocarbon fluid density (0.45 sg.) and the formation water density (1.05 sg.). To determine where the theoretical hydrocarbon/water contact does occur from analysing pressure data alone, a formation water gradient of 1.49 psi/meter (fluid density 1.05 sg.) is drawn through 2/16. Next, the hydrocarbon gradient of 0.64 psi/meter (fluid density = 0.45 sg.) is extended downward from 2/7 until it intersects with the formation water gradient. This pivot point, the "theoretical" hydrocarbon/water contact, occurs at 3759m. This is 23 meters lower than the hydrocarbon/water contact (3726m) observed from resistivity logs. It is possible that residual hydrocarbons below the hydrocarbon/water contact at 3526m have lowered the formation fluid density enough to cause the discrepancy but one cannot be certain especially since there is only one valid point in the water zone to work with.

Thus the following conclusions can be made from the RFT results:

1) Reservoir pressure in the hydrocarbon zone ranges from 7797 psi at 3671 meters to 7831 psi at 3723 meters.

2) Hydrocarbon density as calculated from RFT measurements is 0.45 sg.

3) The reservoir is overpressured with respect to normal hydrostatic by 2300 psi.

4) Formation pressure in the Cook sand is no greater than 8328 psi. This pressure test (2/15) appears to have been affected by supercharging and is probably erroneously high.

5) Drawdown permeability are listed on table 6 but the absolute values are not valid. They may be useful in a qualitative sense however. A list of buildup permeabilities will be appended to this report when computation is completed.

Table 5

Pre-test results (run 4/2)

Well: 35/8-2

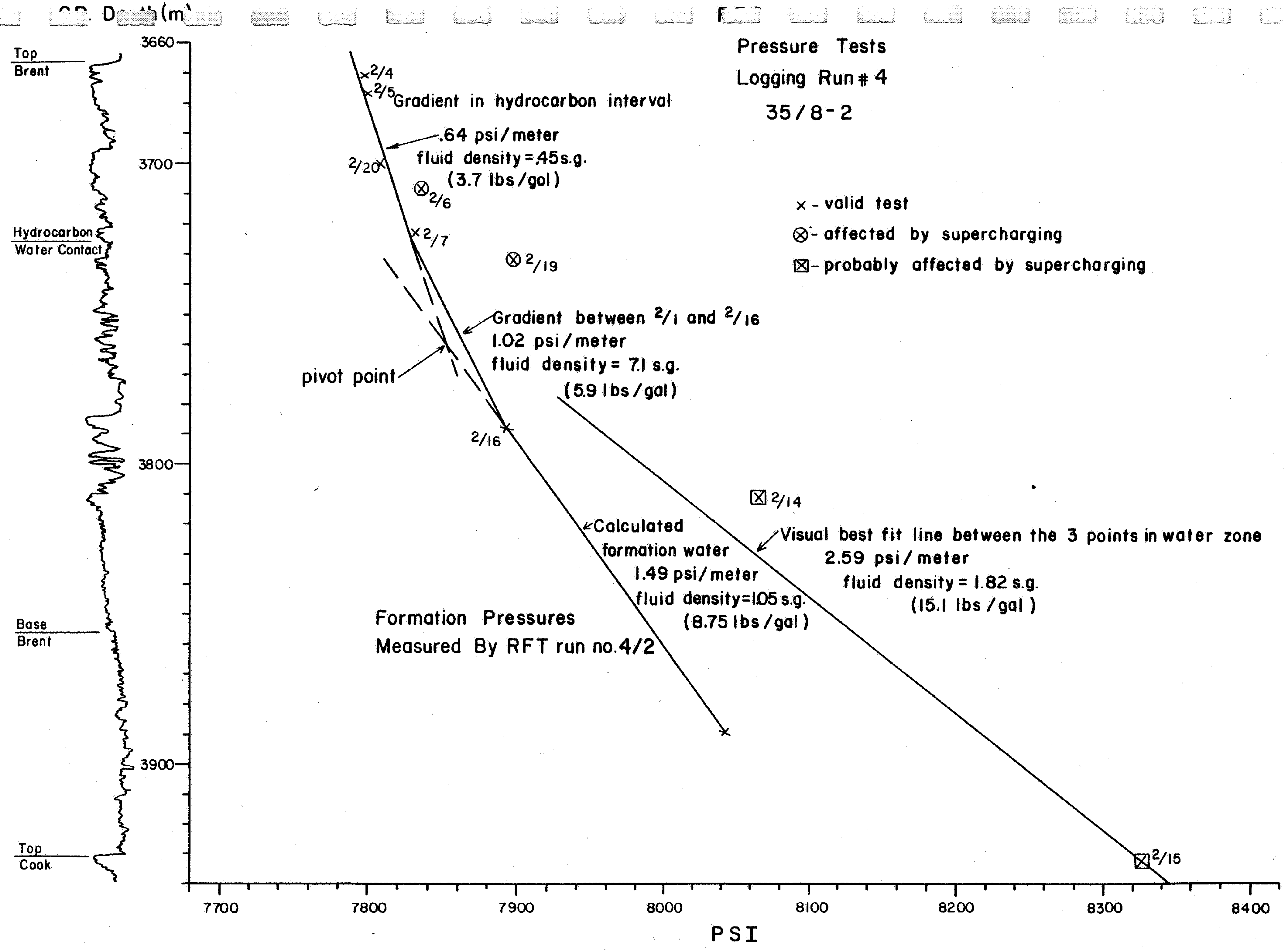
Date: March 4, 1982

Mud weight: 14.5 lb/gal

Run 4/2

Test no	Depth	Test Failed	Final Build up (psi) uncorrected	corrected	Mud Before/ after	Hydro-static cor. Before/ after	Comments
1	3667	T			9170 9170	9160 9160	
2	3667.5	T			9170 9168	9160 9158	
3	3666.6	T			9167 9168	9157 9168	
4	3671		7812	7797	9178 9180	9168 9170	Good
5	3677.5		7814	7799	9194 9194	9184 9184	Good
6	3708		7851	7836	9270 9270	9260 9260	Supercharge
7	3723		7846	7831	9308 9306	9298 9296	Good
8	3754	T			9383 9383	9373 9373	
9	3753.5	T			9383 9383	9373 9373	
10	3745	T			9364 9360	9354 9350	
11	3792	T			9477 9477	9467 9467	
12	3791.5	T			9477 9477	9467 9467	

13	3796.5	T			9488 9490	9878 9480	
14	3811		8080	8065	9524 9518	9514 9508	Prob. Supercharge
15	3932.5		8341	8328	9817 9815	9808 9805	Prob. Supercharge
16	3788.5		7908	7893	9460 9456	9450 9446	Good
17	3765.5	T			9410 9412	9400 9402	
18	3770	T			9420 9422	9410 9412	
19	3732		7913	7898	9328 9321	9318 9311	Supercharge
20	3700		7824	7809	9244 9244	9234 9234	Good



Pressure Tests
Logging Run # 4
35/8-2
× - valid test
⊗ - affected by supercharging
⊠ - probably affected by supercharging
Gradient in hydrocarbon interval
.64 psi/meter
fluid density = .45 s.g.
(3.7 lbs/gal)
Gradient between 2/1 and 2/16
1.02 psi/meter
fluid density = 7.1 s.g.
(5.9 lbs/gal)
pivot point
Calculated
formation water
1.49 psi/meter
fluid density = 1.05 s.g.
(8.75 lbs/gal)
Visual best fit line between the 3 points in water zone
2.59 psi/meter
fluid density = 1.82 s.g.
(15.1 lbs/gal)
Formation Pressures
Measured By RFT run no. 4/2
2/4
2/5
2/20
2/6
2/7
2/19
2/16
2/14
2/15
Top Brent
Hydrocarbon Water Contact
Base Brent
Top Cook
Depth (m)
3660
3700
3800
3900
7700
7800
7900
8000
8100
8200
8300
8400
PSI

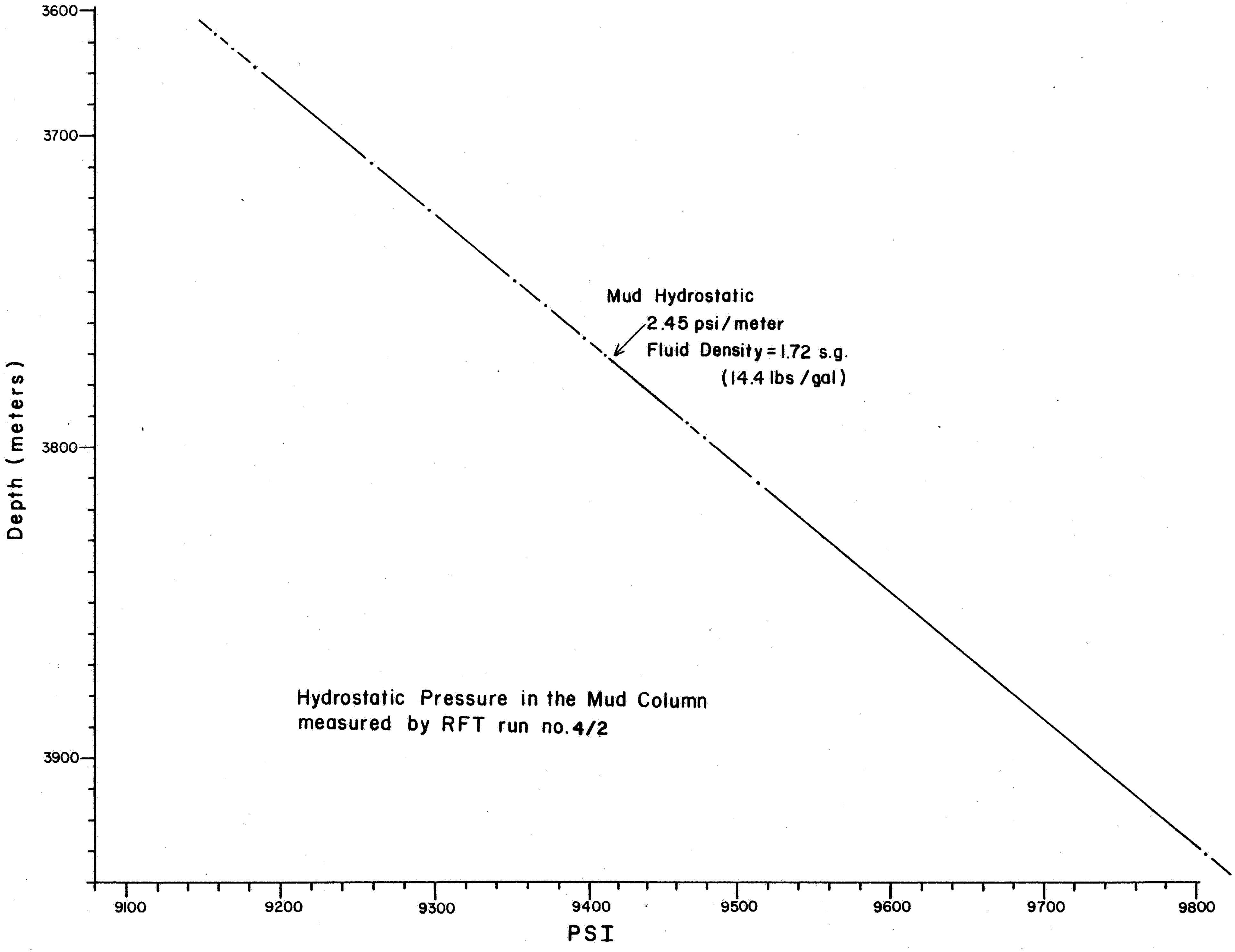

3600
3700
3800
3900
Depth (meters)
9100
9200
9300
9400
9500
9600
9700
9800
PSI
Mud Hydrostatic
2.45 psi/meter
Fluid Density = 1.72 s.g.
(14.4 lbs/gal)
Hydrostatic Pressure in the Mud Column
measured by RFT run no.4/2

Fig. 37

Table 6

Drawdown Permeabilities calculated from analog pressure recording

Test no.	Depth (m)	Permeability
2/4	3671	0.36 md
2/5	3677.5	0.91 md
2/7	3708	0.43 md
2/14*	3811	0.25 md
2/15*	3932.5	0.19 md
2/16	3788.5	0.54 md
2/20	3700	4.38 md

*Tests probably affected by supercharging

12 1/4" and 8½" Hole Section cont'd

Due to heavy treatment with prehydrated Bentonite, Lignite and Lignosulphonate the HPHT fluid loss had been reduced to circa 17.8 ml at the time the bit was stuck at 12015 ft. It is clear from this that conversion to Lignite/Lignosulphonate should be started much sooner to ensure that the filtration properties of the system can be properly maintained throughout the coring intervals and that pore pressure predictions are closely monitored.

(C) Received an amendment/addition to the mud programme during the well which called for and HPHT fluid loss of less than 14.9 ml through the 8½" hole section - this proved to be very difficult to achieve even with relatively heavy treatment and would have been even worse with only gradual treatment.

16. BIT HYDRAULIC

AND

BOTTOMHOLE ASSEMBLY RECORD (BAROID)

NORSK PETROLEUM SERVICES A/S
c/o Dolphin Services A/S
4056 Tananger, Norway. Telephone 04-696524. Telex 33235

B.H.A. RECORD

WELL NAME: 35/8-2

OPERATOR: Norwegian Gulf Explor. Co. A/S

PUMPS:

CONTRACTOR: Sedco

OPERATOR REPR:

RIG: Sedco 704

NPS A/S ENGINEER:

Date	Bit no.		
	RR	17 1/2" BIT/BIT SUB/9 1/2" MONEL/DC/9 1/2" DC/17 1/2" STAB/9 1/2" DC/17 1/2" STAB/	(390.76 m)
		3 x 9 1/2" DC/XO/6 x 8" DC/XO	
	RR	26" BIT/36" HO/XO/9 1/2" MONEL DC/9 1/2" DC/36" STAB/5 x 9 1/2" DC/XO/6 x 8" DC/	(1317.62 m)
		XO/31 x HWDP	
	1	17 1/2" BIT/26" HO/9 1/2" MONEL DC/26" STAB/5 x 9 1/2" DC/XO/6 x 8" DC/XO/31 x HWDP	(1315.31 m)
	2	26" BIT/36" HO/XO/9 1/2" MONEL DC/36" STAB/5 x 9 1/2" DC/XO/6 x 8" DC/XO/31 x HWDP	(1315.31 m)
	2nd SPUD		
	1	17 1/2" BIT/BIT SUB/9 1/2" MONEL DC/9 1/2" DC/17 1/2" STAB/9 1/2" DC/17 1/2" STAB/	(670.26 m)
		4 x 9 1/2" DC/XO/14 x 8" DC/XO	
	2	26" BIT/36" HO/BIT SUB/9 1/2" DC/36" STAB/5 x 9 1/2" DC/XO/14 x 8" DC/XO	(645.69 m)
	2RR	26" BIT/BIT SUB/6 x 9 1/2" DC/XO/14 x 8" DC/XO/24 x HWDP	(1355.70 m)

NORSK PETROLEUM SERVICES A/S
c/o Dolphin Services A/S
4056 Tananger, Norway. Telephone 04-696524. Telex 33235

B.H.A. RECORD

WELL NAME: 35/8-2 OPERATOR: Norwegian Gulf Explo. Co. A/S PUMPS:

CONTRACTOR: Sedco OPERATOR REPR:

RIG: Sedco 704 NPS A/S ENGINEER:

Date	Bit no.		
	2RR	26" BIT/BIT SUB/6 x 9 1/2" DC/XO/14 x 8" DC/XO/24 x HWDP	(1355.70 m)
	2RR	26" BIT/BIT SUB/6 x 9 1/2" DC/XO/14 x 8" DC/XO/25 x HWDP	(1385.10 m)
	2RR	26" BIT/BIT SUB/6 x 9 1/2" DC/XO/24 x HWDP	(920.30 m)
	2RR	26" BIT/BIT SUB/6 x 9 1/2" DC/XO/24 x HWDP	(920.30 m)
	3/1RR	17 1/2" BIT/26" HO/6 x 9 1/2" DC/XO/6 x 8" DC/XO/24 x HWDP	(1111.92 m)
	4	17 1/2" BIT/17 1/2" NB STAB/9 1/2" MONEL DC/17 1/2" STAB/4 x 9 1/2" DC/XO/JAR/	(994.51 m)
		XO/2 x 9 1/2" DC/XO/24 x HWDP	
	3RR	17 1/2" BIT/26" UNDER REAMER/BIT SUB/6 x 9 1/2" DC/XO/JAR/2 x 8" DC/XO/24 x HWDP	(1026.09 m)
	5	17 1/2" BIT/26" UNDER REAMER/BIT SUB/6 x 9 1/2" DC/XO/JAR/2 x 8" DC/XO/24 x HWDP	(1027.76 m)
	2RR	26" BIT/BIT SUB/2 x 9 1/2" DC/26" STAB/4 x 9 1/2" DC/XO/JAR/2 x 8" DC/XO/24 x HWDP	(1023.97 m)
	2RR	26" BIT/BIT SUB/2 x 9 1/2" DC/26" STAB/4 x 9 1/2" DC/XO/JAR/2 x 8" DC/XO/44 x HWDP	(1622.12 m)

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4056 Tananger, Norway. Telephone 04-696524. Telex 33235

B.H.A. RECORD

WELL NAME: 35/8-2 OPERATOR: Norwegian Gulf Explo. Co. A/S PUMPS:

CONTRACTOR: Sedco OPERATOR REPR:

RIG: Sedco 704 NPS A/S ENGINEER:

Date	Bit no.		
	6	17 1/2" BIT/BIT SUB/9 1/2" MONEL DC/17 1/2" STAB/2 x 9 1/2" DC/17 1/2" STAB/	(1598.10 m)
		3 x 9 1/2" DC/XO/1 x 8" DC/JARS/2 x 8" DC/XO/42 x HWDP	
	7	SAME AS 6	
	8	SAME AS 6	
	5RR	SAME AS 6	
	9	12 1/4" BIT/BIT SUB/MONEL DC/9 x 8" DC/JAR/2 x 8" DC/STAB/42 x HWDP	
	10	12 1/4" BIT/STAB/SHOCK SUB/12 1/4" STAB/SHOCK SUB/12 1/4" STAB/MONEL DC/	(1678.03 m)
		11 x 8" DC/XO/42 x HWDP	
	11	SAME AS 10	
	12	12 1/4" BIT/JUNK SUB/MONEL DC/11 x 8" DC/XO/42 x HWDP	(1644.88 m)
	13	SAME AS 12	

NORSK PETROLEUM SERVICES A/S
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4056 Tananger, Norway. Telephone 04-696524. Telex 33235

B.H.A. RECORD

WELL NAME: 35/8-2 OPERATOR: Norwegian Gulf Explo. Co. A/S PUMPS:

CONTRACTOR: Sedco OPERATOR REPR:

RIG: Sedco 704 NPS A/S ENGINEER:

Date	Bit no.		
	14	SAME AS 12	
	15	12 1/4" BIT/NB STAB/SUB/12 1/4" STAB/MONEL DC/12 1/4" STAB/1 x 8" DC/12 1/4" STAB/	(1722.08 m)
		2 x 8" DC/12 1/4" STAB/8 x 8" DC/JARS/2 x 8" DC/XO/1 x HWDP/DART/41 x HWDP	
	16	12 1/4" BIT/NB STAB/SHOCK SUB/12 1/4" STAB/MONEL DC/12 1/4" STAB/2 x 8" DC/	(1442.32 m)
		12 1/4" STAB/2 x 8" DC/12 1/4" STAB/7 x 8" DC/JARS/2 x 8" DC/XO/1 x HWDP/DART SUB/	
		30 x HWDP	
	17	12 1/4" BIT/NB STAB/SHOCK SUB/12 1/4" STAB/MONEL DC/12 1/4" STAB/2 x 8" DC/	(1504.18 m)
		12 1/4" STAB/2 x 8" DC/12 1/4" STAB/9 x 8" DC/JARS/2 x 8" DC/XO/1 x HWDP/DART SUB/	
		30 x HWDP	
	18	12 1/4" BIT/JUNK SUB/12 174" STAB/SHOCK SUB/12 1/4" STAB/MONEL DC/12 1/4" STAB/	(1506.93 m)
		2 x 8" DC/12 1/4" STAB/2 x 8" DC/12 1/4" STAB/9 x 8" DC/JARS/2 x 8" DC/XO/1 x HWDP/	

NORSK PETROLEUM SERVICES A/S
c/o Dolphin Services A/S
4056 Tananger, Norway. Telephone 04-696524. Telex 33235

B.H.A. RECORD

WELL NAME: 35/8-2 OPERATOR: Norwegian Gulf Explo. Co. A/S PUMPS:

CONTRACTOR: Sedco OPERATOR REPR:

RIG: Sedco 704 NPS A/S ENGINEER:

Date	Bit no.		
		DART SUB/30 x HWDP	
	18RR	12 1/4" BIT/NB STAB/SHOCK SUB/12 1/4" STAB/MONEL DC/12 1/4" STAB/2 x 8" DC/	(1503.12 m)
		12 1/4" STAB/2 x 8" DC/12 1/4" STAB/9 x 8" DC/JARS/2 x 8" DC/XO/1 x HWDP/	
		DART SUB/30 x HWDP	
	19	SAME AS 18RR	
	16RR	12 1/4" BIT/JUNK SUB/12 1/4" STAB/MONEL DC/12 1/4" STAB/2 x 8" DC/12 1/4" STAB/	(1490.81 m)
		2 x 8" DC/12 1/4" STAB/9 x 8" DC/JARS/2 x 8" DC/XO/1 x HWDP/DART SUB/30 x HWDP	
	CORE 1	8 1/2" CORE HEAD/8 1/2" CORE BARREL STAB/6 3/4" CORE BARREL/8 1/2" CORE BARREL STAB/	(1486.03 m)
		6 3/4" CORE BARREL/8 1/2" CORE BARREL STAB/XO/CIRC SUB/1 x 8" DC/12 1/4" STAB/	
		2 x 8" DC/12 1/4" STAB/9 x 8" DC/JARS/2 x 8" DC/XO/1 x HWDP/DART SUB/30 x HWDP	
	20	12 1/4" BIT/NB STAB/SHOCK SUB/12 1/4" STAB/MONEL DC/12 1/4" STAB/2 x 8" DC/	(1504.12 m)

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B.H.A. RECORD

WELL NAME: 35/8-2
OPERATOR: Norwegian Gulf Explo. Co. A/S
PUMPS:
CONTRACTOR: Sedco
OPERATOR REPR:
RIG: Sedco 704
NPS A/S ENGINEER:

Date	Bit no.		
		12 1/4" STAB/2 x 8" DC/12 1/4" STAB/9 x 8" DC/JARS/1 x HWDP/DART SUB/30 x HWDP	
	21	SAME AS 20	
	22	SAME AS 20	
	22RR	SAME AS 20	
	23	8 1/2" BIT/JUNK SUB/BIT SUB with FLOAT/18 x 6 1/2" DC/XO/1 x HWDP/DART SUB/30 x HWDP	
	24	8 1/2" BIT/BIT SUB/18 x 6 1/2" DC/XO/1 x HWDP/DART SUB/30 x HWDP	(1506.33 m)
	25	8 1/2" BIT/NB STAB/XO/SHOCK SUB/XO/2 x 6 1/2" DC/ 8 1/2" STAB/1 x 6 1/2" DC/	(1629.00 m)
		8 1/2" STAB/15 x 6 1/2" DC/JARS/2 x 6 1/2" DC/XO/1 x HWDP/DART SUB/30 x HWDP	
	CORE 2	8 15/32" CORE HEAD/6 3/4" CORE BARREL/XO/8 1/2" STAB/2 x 6 1/2" DC/8 1/2" STAB/	(1676.17 m)
		1 x 6 1/2" DC/8 1/2" STAB/15 x 6 1/2" DC/JARS/2 6 1/2" DC/XO/1 x HWDP/DART SUB/	
		30 x HWDP	

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B.H.A. RECORD

WELL NAME: 35/8-2 OPERATOR: Norwegian Gulf Explo. Co. A/S PUMPS:

CONTRACTOR: Sedco OPERATOR REPR:

RIG: Sedco 704 NPS A/S ENGINEER:

Date	Bit no.		
	CORE 3	8 15/32" CORE HEAD/6 3/4" CORE BARREL/XO/CIRC SUB/XO/8 1/2" STAB/2 x 6 1/2" DC/	(1685.09 m)
		8 1/2" STAB/1 x 6 1/2" DC/8 1/2" STAB/3 x 6 1/2" DC/8 1/2" STAB/12 x 6 1/2" DC/	
		JARS/2 x 6 1/2" DC/XO/1 x HWDP/DART SUB/30 x HWDP	
	CORE 4	8 15/32" CORE HEAD/6 3/4" CORE BARREL/XO/CIRC SUB/XO/3 x 6 1/2" DC/8 3/8" STAB/	(1675.13 m)
		3 x 6 1/2" DC/8 1/2" STAB/12 x 6 1/2" DC/JARS/2 x 6 1/2" DC/XO/1 x HWDP/DART SUB/	
		30 x HWDP	
	CORE 5	SAME AS CORE 4	
	CORE 6	SAME AS CORE 4	
	CORE 7	SAME AS CORE 4	
	26	8 1/2" BIT/NB STAB/CIRC SUB/SHOCK SUB/XO/8 1/2" STAB/MONEL DC/8 1/2" STAB/	(1637.15 m)
		2 x 6 1/2" DC/8 1/2" STAB/3 x 6 1/2" DC/8 1/2" STAB/12 x 6 1/2" DC/JARS/2 x 6 1/2" DC/	

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B.H.A. RECORD

WELL NAME: 35/8-2 OPERATOR: Norwegian Gulf Explo. Co. A/S PUMPS:

CONTRACTOR: Sedco OPERATOR REPR:

RIG: Sedco 704 NPS A/S ENGINEER:

Date	Bit no.		
		XO/1 x HWDP/DART SUB/30 x HWDP	
	27	8 1/2" BIT/NB STAB/MONEL/16 x 6 1/2" DC/XO/JAR/XO/2 x 6 1/2" DC/XO/12 x HWDP	(1102.19 m)
	28	8 1/2" BIT/BIT SUB/MONEL/STAB/1 x 6 1/2" DC/STAB/15 x 6 1/2" DC/XO/DALEY JARS/	(1012.32 m)
		XO/1 x 6 1/2" DC/XO/1 x HWDP/DART SUB/11 x HWDP	
	29	8 1/2" BIT/NB STAB/MONEL/XO/WO/STRING MILL/XO/1 x 6 1/2" DC/STAB/1 x 6 1/2" DC/	(1023.34 m)
		STAB/14 x 6 1/2" DC/XO/DALEY JARS/XO/2 x 6 1/2" DC/XO/1 x HWDP/DART SUB/11 x HWDP	
	30	8 1/2" BIT/NB SUB/MONEL/STAB/1 x 6 1/2" DC/STAB/3 x 6 1/2" DC/STAB/STAB/	(1057.98 m)
		6 x 6 1/2" DC/STAB/4 x 6 1/2" DC/XO/JARS/XO/2 x 6 1/2" DC/XO/1 x HWDP/DC/DART SUB/	
		11 x HWDP	
	35	6 1/8" BIT/CEMENT SCRAPER/BIT SUB/17 x 4 3/4" DC/JAR/3 x 4 3/4" DC	(656.71 m)
	36	6 1/8" BIT/JUNK SUB/BIT SUB/17 x 3 3/4" DC/JAR/3 x 4 3/4" DC	(660.53 m)

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B.H.A. RECORD

WELL NAME: 35/8-2 OPERATOR: Norwegian Gulf Explo. Co. A/S PUMPS:

CONTRACTOR: Sedco OPERATOR REPR:

RIG: Sedco 704 NPS A/S ENGINEER:

Date	Bit no.	
	37	6 1/8" DIAMOND BIT/E.W. 260 STAGE 5" TURBODRILL/MONEL/16 x 4 3/4" DC/JAR/ (711.54 m)
		3 x 4 3/4" DC

NL Baroid

BIT AND HYDRAULIC RECORD

WELL NAME: GULF 35/8-2 OPERATOR: GULF EXP. (NORWAY) PUMPS: OILWELL 1700 PT

CONTRACTOR: SEDCO OPERATOR REPR.: GREER, OGDEN, McAULY

RIG: 704 BAROID ENGINEER: CAMERON, COUILLARD, JEWERS, WALLBANK

Date	Bit No.	Type	Size	Jet Size 32 nds	Depth Out	Interval Drilled	Hours Run	Weight on Bit	Bit R.P.M.	Bit Cond. T-B-G	Pump Output	Pump Pressure spm/	Annular Velocity DP/DC	DP/DC Size	Jet Velocity	Bit HP/in^2	Remarks
30·8·81	RR	OSC3AJ	17.5	3x20	1900	565	10	0-20	70-120	4·4·1	1006	2600/200	88/114	5/9½	350	5·7	pilot hole
31·8·81	RR	OSC3AJ	26 /36 HO	3x16													hole opener failed
1·9·81	1	X3A	17.5 /26 HO	3x16	1900	344	9	5-10	100-110		956	1500/190	36/40	5/9½	520		
2·9·81	2	R1	26 /36 HO	3x16	1565	9	4.5	0-10	100-120		1006	1600/200	19/20	5/9½	548		twisted off
11·9·81	1	OSC1GJ	17.5	3x16	1900	565	12.5	10-15	60-80	3·3·1	704	1500/140	61/80	5/9½	385	2·1	moved rig 100' respud
12·9·81	2	OSC3AJ	26 /36 HO	3x16	1901	566	41	10-15	100		855	1900/170	16/17	5/9½	446		
16·9·81	2RR	OSC3AJ	26	3x16	"												wash & ream 30" csg
17·9·81	2RR	OSC3AJ	26	3x16	"												"
18·9·81	2RR	OSC3AJ	26	3x16	"												"
19·9·81	2RR	OSC3AJ	26	3x16	"												"
20·9·81	2RR	OSC3AJ	26	3x16	"												"
21·9·81	3 1RR	OSC1GJ	17.5 /26 HO	3x15 3x24	1910	9	3	10-15	30	2·2·1	805	1030/160					drill out shoe
29·9·81	4	OSC1GJ	17.5	3x15	2763	853	17.37	10-15	95-120	5·5·1	593	1650/120	52/67	5/9½	333		pilot hole
	3RR	OSC1GJ	17.5	3x15	2715	819	13.5	0-10	80-100	4·8·1	593	1600/118	25/27	5/9½	333		under ream to 26" hole
3·10·82	5	X3A	17.5	3x15	2763	48	·6	7-11	90	1·1·1	593	1650/120	25/27	5/9½	333		under ream to 26" hole
4·10·81	2RR	OSC3AJ	26	3x16	2763												log bottom
10·10·81	6	X3A	17.5	3x16	4246	1483	19·4	20	80-95	3·4·1/8	805	3000/160	69/92	5/9½	436	3·1	

Baroid

BIT AND HYDRAULIC RECORD

WELL NAME: GULF 35/8-2 OPERATOR: GULF EXP. (NORWAY) PUMPS: OILWELL 1700 PT

CONTRACTOR: SEDCO OPERATOR REPR.: GREER, OGDEN, McAULY

RIG: 704 BAROID ENGINEER: GAMERON, COUILLARD, JEWERS, WALLBANK

Date	Bit No.	Type	Size	Jet Size 32 nds	Depth Out	Interval Drilled	Hours Run	Weight on Bit	Bit R.P.M.	Bit Cond. T-B-G	Pump Output	Pump Pressure spm/	Annular Velocity DP/DC	DP/DC Size	Jet Velocity	Bit HP/in^2	Remarks
12·10·81	7	XDC	17 1/2	3x15	5832	1586	25·0	15 – 25	90–110	5·7·1/8	704	3000/160	59/79	5/9 1/8	435	2·8	
15·10·81	8	DGJ	17 1/2	3x15	6588	756	21·3	30–35	85–110	4·4·1	695	3000/136	59/79	5/9 1/2	427	2·7	balled bit
17·10·81	5RR	X3A	17 1/2	3x15	7071	483	16·8	30–35	90–105	5·5·1	654	3000/138	52/75	5/9 1/2	423	2·6	
23·10·81	9	J3	12 1/4	3x14	7030												drill out float
26·10·81	10	J3	12 1/4	open						3·1·1							drill out bridge plug
	11	FLATBTM MILL								25 %							drill out retainer
11/11/81	12	S44	12 1/4	3X18						3·2·1/16							drill out retainer & cmt
11/11/81	13	S44F	12 1/4	3X14						4·4·1/16							drill out retainer & cmt
13/11/81	14	S44	12 1/4	3X14	7200	129	7·5	20–25	120–130	5·4·1/8	584	2500/120	111/164	5/8	406	4·3	drill out shoe
14/11/81	15	J22	12 1/4	3X14	9014	1814	80·1	30–50	75–90	2·7·1	473	3100/94	95/140	5/8	380	3·3	
26/11/81	16	H77	12 1/4	3X14	9025	11	2·5	10–20	60	2.3.1							mill on junk
27/11/81	17	J22	12 1/4	3X14	9891	866	96	45–50	75	3·5·1	580	3000/112	113/164	5/8	409	4·4	
3/12/81	18	J22	12 1/4	3 X14	9905	14	2·3	40–45	75		568	2800/110	115/166	5/8	413	4·5	
3/12/81	18RR	J22	12 1/4	3 X14	9987	82	169	45–50	75	2·2·1	558	3050/104	107/154	5/8	384	4·2	
6/12/81	19	J22	12 1/4	3 X14	10880	893	106·2	46–54	68–75	5·7·1	527	3100/102	102/148	5/8	370	4·0	
13/12/81	16RR	H77	12 1/4	3 X14	10882	2	·33	20	70	2·3·1	527	3100/102	102/148	5/8	370	4·0	mill on junk
13/12/81	CORE 1	C19	8 1/2	◊	10885	3	3·2	10–15	100	50%	258	820/50	51/73	5/8			

NL Petroleum Services (UK) Ltd.

NL Baroid

BIT AND HYDRAULIC RECORD

PUMPS OILWELL 1700 PT

NO.	LINER SIZE	STROKE
1	6·5"	12"
2	6·5"	12"

WELL NAME: GULF 35/8-2 OPERATOR: GULF EXP (NORWAY)

CONTRACTOR: SEDCO OPERATOR REPR.: GREER, OGDEN, McAULY

RIG: 704 BAROID ENGINEER: CAMERON, COUILLARD, JEWERS, WALLBANK.

DATE	BIT NO.	TYPE	SIZE in	JET SIZE 32nds	DEPTH OUT ft	INTERVAL DRILLED ft	HOURS RUN	WEIGHT ON BIT x 1000 lbs.	BIT R.P.M.	BIT COND.	PUMP OUTPUT gal/min	PUMP PRESSURE	ANNULAR VELOCITY DP/DC f/min	JET VEL	D.P/DC SIZE	HP/in²	REMARKS
15/12/81	20	J 22	12 1/4	3 X 14	11346	461	70·4	45–55	75	3·5·1	517	3050/100	101/147	368	5/8	3·8	
18/12/81	21	J 22	12 1/4	3 X 14	11460	114	14·1	45–55	75	3·5·1	511	3050/100	100/146	363	5/8	3·8	pulled after washout
19/12/81	22	J 22	12 1/4	3 X 14	11608	148	26·7	40–45	68–75	1·5·1	496	2950/96	97/141	353	5/8	3·5	
24/12/81	22RR	J 22	12 1/4	3 X 14	11608					1·5·1	480	2860/93	94/137	341	5/8	2·9	tag btm
30/12/81	23	OWVJ	8 1/2	3 X 14	11610	2	6	15–20	60	7·8·1	443	3000/88	219/334	324	5/6·5	6·1	
31/12/81	24	J 22	8 1/2	3 X 14	11747	137	25	30–35	75	4·4·1	443	3000/85	219/334	324	5/6·5	6·1	scoop inserts
1/1/82	25	J 22	8 1/2	3 X 14	12032	285	52	30–35	75	2·2·1	422	3000/85	219/331	321	5/6·5	6	
4/1/82	CORE 2	C 22	8 15/32	◊ TFA ·7	12092	60	8·5	15–20	95	–	211	1100/42	115/174	128	5/6·5	3·2	core 2
5/1/82	CORE 3	C 20	8 15/32	◊ ·6	12103	11	2	"	"	–	"	"	"	"	"	"	core 3
6/1/82	CORE 3 RR	"	"	◊ ·6	12156	53	12·3	"	90/100	–	"	1200/42	"	"	"	"	core 4
8/1/82	"	"	"	◊ ·6	12216	60	6·7	"	80/100	–	"	"	"	"	"	"	core 5
9/1/82	"	"	"	◊ ·6	12276	60	8·2	"	100	–	"	"	111/167	121	"	"	core 6
10/1/82	"	"	"	◊ ·6	12303	27	5·5	"	"	–	"	1320/42	"	"	"	"	core 7
11/1/82	26	J 22	8 1/2	3 X 13	–												stuck in hole
14/2/82	27	J 22	8 1/2	3 X 14	11916	466	79·1	30–35	75–80	6·8·1	439	2560/85	214/341	313	"	5·5	sidetrack I.
18/2/82	28	J 22	8 1/2	3 X 14	12178	262	32·5	"	"	2·6·1	439	2650/85	228/341	313	"	5·5	
21/2/82	29	J 22	8 1/2	3 X 13	12759	581	66·7	"	"	6·8·1	424	2950/82	220/329	350	"	6·9	

NL Petroleum Services (UK) Ltd.
NL Baroid
BIT AND HYDRAULIC RECORD

WELL NAME: GULF 35/8-2 ST I

OPERATOR: GULF EXP (NORWAY)

CONTRACTOR: SEDCO

OPERATOR REPR.: GREER, OGDEN, McAULY

RIG: 704

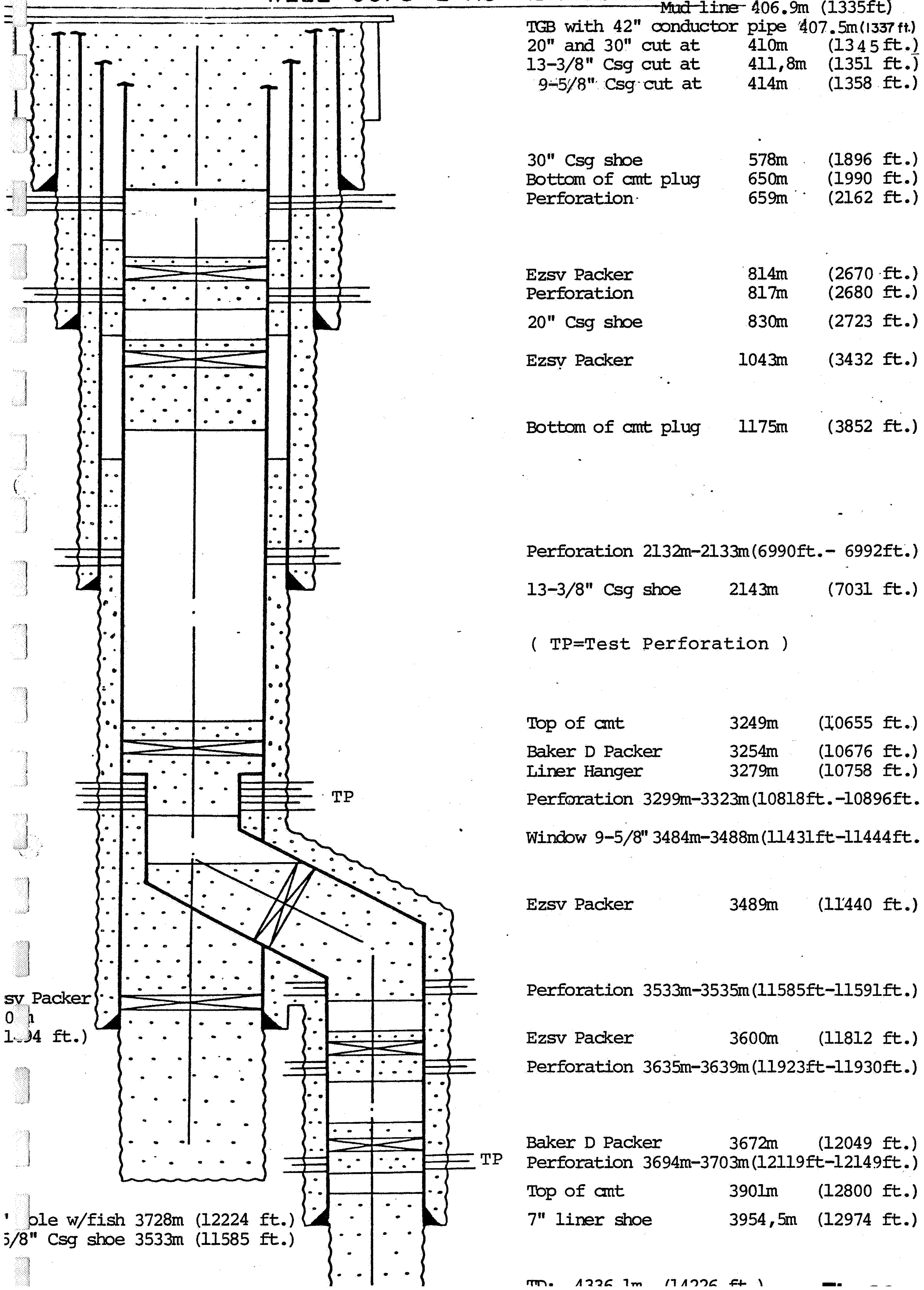
BAROID ENGINEER: CAMERON, COUILLARD, JEWERS, WALTERS

PUMPS OILWELL 1700 PT

NO.	LINER SIZE	STROKE
1	6·5"/ 5·5"	12"
2	6·5"/ 5·5"	12"

DATE	BIT NO.	TYPE	SIZE in	JET SIZE 32nds	DEPTH OUT ft	INTERVAL DRILLED ft	HOURS RUN	WEIGHT ON BIT x 1000 lbs.	BIT R.P.M.	BIT COND.	PUMP OUTPUT gal/min	PUMP PRESSURE	ANNULAR VELOCITY DP/DC ft/min	JET VEL	D.P/DC SIZE	HP/in²	REMARKS
27/2/82	30	J 22	8 1/2	3 X 13	12974	205	32·1	30-35	75-85	2·4·1	424	2950/82	210/330	350	5/6·5	6·9	set 7" liner
7/3/82	31	REG'D S 21 JJ	8 1/2	–	10720	62	1·5	5-10	80	–	460	1600/90					drill cement
4/4/82	32	W7R 2J	6 1/8	–	10757	37	6	0-5	50	6·7·1/8	450	1400/87					drill cement
5/4/82	33	W7J	6 1/8	–	10795	38	1	5-10	50	6·7·1/8	450	1750/87					drill cement
6/4/82	34	W7J	6 1/8	–	12975	47	5·5	5-10	40	6·7·1/4	450	1750/87					wash, ream, drl cmt, shoe
7/4/82	35	W7J	6 1/8	3 X 12	12984	9	1·5	10-15	45	7·8·1/8	350	2300/95	250/560	340	5/3·5/4·7	10	drill rat hole
8/4/82	36	J 33	6 1/8	3 X 12	13019	35	11	10-15	45	1·4·1	350	3300/95	330/570	340	3·5/4·75	10	
10/4/82	37	ACC SHREW III TS	6 1/8	0 TFA ·6	14226	1207	79·3	10-20	1100	70%·1/8	428 /185	4100/120	182/298	99	3·5/4·75	·4	Split flow sub, turbodrill.
20/4/82	38	DGJ	5 7/8	–	14006												wash, ream.

WELL 35/8-2 AS ABANDONED



12 1/4" and 8½" Hole Section

The 12 1/4" hole section was largely trouble-free with the KCl/Polymer system remaining stable throughout. The tight spots which were encountered usually only during first trips through newly drilled hole were probably due to the number and location of stabilizers in the string - we will recommend lubricant to alleviate this problem in the future.

The main area of concern with this well has been the lower 12 1/4" section and the 8½" section and there are two specific points which should be considered.

(A) With an extend coring programme in the lower 12 1/4" section drilled solids and Polymer concentration tends to deplete quite rapidly resulting in poor control of HPHT fluid loss. Lignite and Lignosulphonate be started at this point and gradually increased throughout the remainder of the section to improve filtration properties. At the start of the 8½" hole section the system can then be properly conditioned and properties adjusted without excessive treatment in a short period of time.

(B) Due to the experience with gas kicks during the previous well the mud weight throughout the 8½" hole section was kept consistently high as per Company Representative instructions. This of course resulted in reduced rate of penetration and an increased likelihood of differential sticking. Gradual mud weight reductions were recommended on several occasions, and every effort was made to improve HPHT filtration and filter cake properties prior to and during coring interval of this section. The Bariod A.D.T. engineers were reporting pore pressure predictions of 12.4 ppg (3500 m - 3640 m approx.) and 12.8 ppg (3640 m - 3840 m approx.).

We were therefore in excess of 1000 psi overbalanced at the point the bit was stuck, mud weight of 13.8 ppg would provide a safety margin of 250 psi without riser.

TESTING

18. Formation Testing Report (Gaffney, Cline & Assoc.)

Gulf Oil Exploration and Production, Houston, asked Gaffney, Cline and Associates (GCA) to provide on-site petroleum engineering supervision and evaluation for the duration of drill-stem testing operations at the exploration well 35/8-2 in the Norwegian sector of the North Sea (Fig 1). The licence block is jointly owned by Norwegian Gulf Exploration Company A/S (30%), Getty Oil Corporation (20%) and Statoil (50%), Gulf being the operator.

The testing programme had two prime objectives. Firstly, to test a selected sand within the Brent Formation and to confirm that the reservoir fluid was wet gas, as had been established for the corresponding interval in well 35/8-1 on a similar structure 9.5 km away to the north. Secondly, to determine if the Heather Formation contained produceable hydrocarbons; these were potentially considered to be oil by preliminary log and sidewall core analysis.

Operations commenced on the 25th April and gas condensate was tested from the Brent during a successful drill-stem test (DST-1). Following an invalid test (DST-2) on the Heather formation, during which sections of the Brent were inadvertently retested, the initial programme was suspended on the 4th May. A remedial cement squeeze job was required to isolate the Heather from the Brent formation because of an inadequate primary cementing operation. A successful rerun (DST-2A) proved that permeability of the Heather reservoir sand was very low and too small to allow formation fluids to be recovered in the drillpipe.

Testing operations were completed by the 15th May, after which the well was prepared for abandonment.

Checked: JA
Approved:
Date: June '82

WELL TEST SUMMARY

Test No.	1	2	2A
Formation	Brent	Brent	Heather
Perforated Interval (m RKB)	3694.0- 3703.0	3306.0- 3315.0	3306-3315 3321-3327
Main Flow, Identification Data			
Choke (64th's)	44.0	40.0	-
Gas Flow - Separator (MMSCFD)	15.8	7.6	-
Gas Condensate Ratio (SCF/STB)	8244.0	5891.4	-
Condensate Flow (STBD)	1920.0	1290.0	
Gas gravity (air = 1)	0.67	0.67	-
Stock Tank Gravity (°API)	46.0	46.0	-
Separator temperature (°F)	85.0	72.0	-
Separator pressure (psig)	640.0	400.0	-
Wellhead temperature (°F)	112.0	54.0	-
Wellhead pressure (psig)	2200.0	2060.0	-
Production time (hours)	15.75	12.79	-
Analysis Results			
In-situ fluid phase	Gas	Gas	Unknown
Extrapolated pressure - initial (psig)	7803.0	7085.0	-
final (psig)	7830.0	7425.0	5505.0
Gauge depth for pressure measurement (MRKB)	3689.0	3273.0	3269.5
Estimated Bottom hole temperature (°F)	272.0	260.0	224.0
Flow capacity (md-ft)	328.0	106.0	>0.7
Permeability (md)	4.55	-	0.014
Skin Factor	14.4	-	-
Productivity Index (SCFD/psi)	4954.0	-	-
Completion efficiency	0.32	-	-
Radius of investigation (m)	223.0	-	-
Turbulence factor - calculated	5.45x10	-	-
Inertial turbulent factor - calculated	0.091	-	-

Notes

1. No flow to surface on DST-2A, extremely tight formation indicated.
2. Due to mechanical communication behind casing, DST-2 (an attempted test of the Heather) was a Brent test.
3. Brent test produced condensate rich gas, probably near critical point at initial conditions.
4. Skin factor calculated includes inertial/turbulent effects.

CONCLUSIONS

1. The Brent Formation

i) DST-1 successfully tested a selected reservoir sand within the Brent, which produced gas and condensate to the surface. The gas/liquid ratio was lower than was obtained during testing of a corresponding interval in well 35/8-1, though the gas and condensate properties were similar.

ii) The reservoir sand exhibited a low flow capacity and an effective permeability to the in situ fluid (probably gas) of 4.55 md.

iii) The extrapolated reservoir pressure was 7830 psig at 3689 m RKB, this agrees well with the data obtained from RFT analysis and confirms the test section to be considerably overpressured.

iv) The sequence of operations during DST-1 did not allow the direct evaluation of turbulent and inertial effects. However, calculation using the available test results indicated that these factors are potentially significant.

v) DST-2, an attempted test in the Heather Formation, resulted in a second Brent test. This was due to mechanical communication between the two formations in the wellbore.

vi) It is likely that DST-2 tested a Brent sand interval other than that of DST-1; a low flow capacity, approximately one third of that calculated for the latter, being indicated by analysis. Moreover, a liquid/gas ratio significantly higher than that observed during DST-1 was witnessed and also extrapolated reservoir pressures for DST-2 are considered indicative of a zone less overpressured than that tested by DST-1.

2. The Heather Formation

i) Subsequent to the failure of DST-2 to test the selected section of the Heather Formation, the remedial squeeze job successfully isolated that section from the underlying Brent Formation.

ii) DST-2A successfully tested the selected Heather sands.

iii) The tested sands proved to have a very low effective permeability, in the order of 0.014 md. This precluded significant formation fluids from being produced into the wellbore.

Computerised log interpretation carried out by Schlumberger (Fig 31) identified hydrocarbons in the Brent from 3665 m to 3727.5 m, where an apparent water contact is seen. (It should be noted that unless otherwise stated, all depths referred to in this report are given in metres RKB). No water contact was seen in the Heather though the only interpretation available to the GCA engineer, a Schlumberger quick look computerised interpretation, was considered suspect with seemingly unrealistic water saturation trends throughout the interval. It is likely that the porosities indicated in the zone of interest are lower than might be the case in reality.

The bond log indicated a generally poor primary cement job across the 7" liner and the results of DST-2 indicated mechanical communication in the wellbore between the Brent and Heather.

The test string used for each test remained essentially unchanged and was based on Halliburton APR tools with a Baker 'model D' production packer and stinger/seal assembly. Expro provided all surface equipment required for testing, together with a team of operators.

A comprehensive sampling programme was completed whilst performing DST's 1 and 2 and this included surface sampling for recombination PVT analysis. The preferred method for taking gas samples for PVT analysis was to fill directly into evacuated bottles without blowing through before sealing. The PVT samples obtained are considered valid for preliminary and identification analysis though by standard practice, because of the nature of the tests, are not considered suitable for refinery evaluation.

DST-2A did not recover hydrocarbon fluids and as a result no samples could be taken.

CASED HOLE DST-1

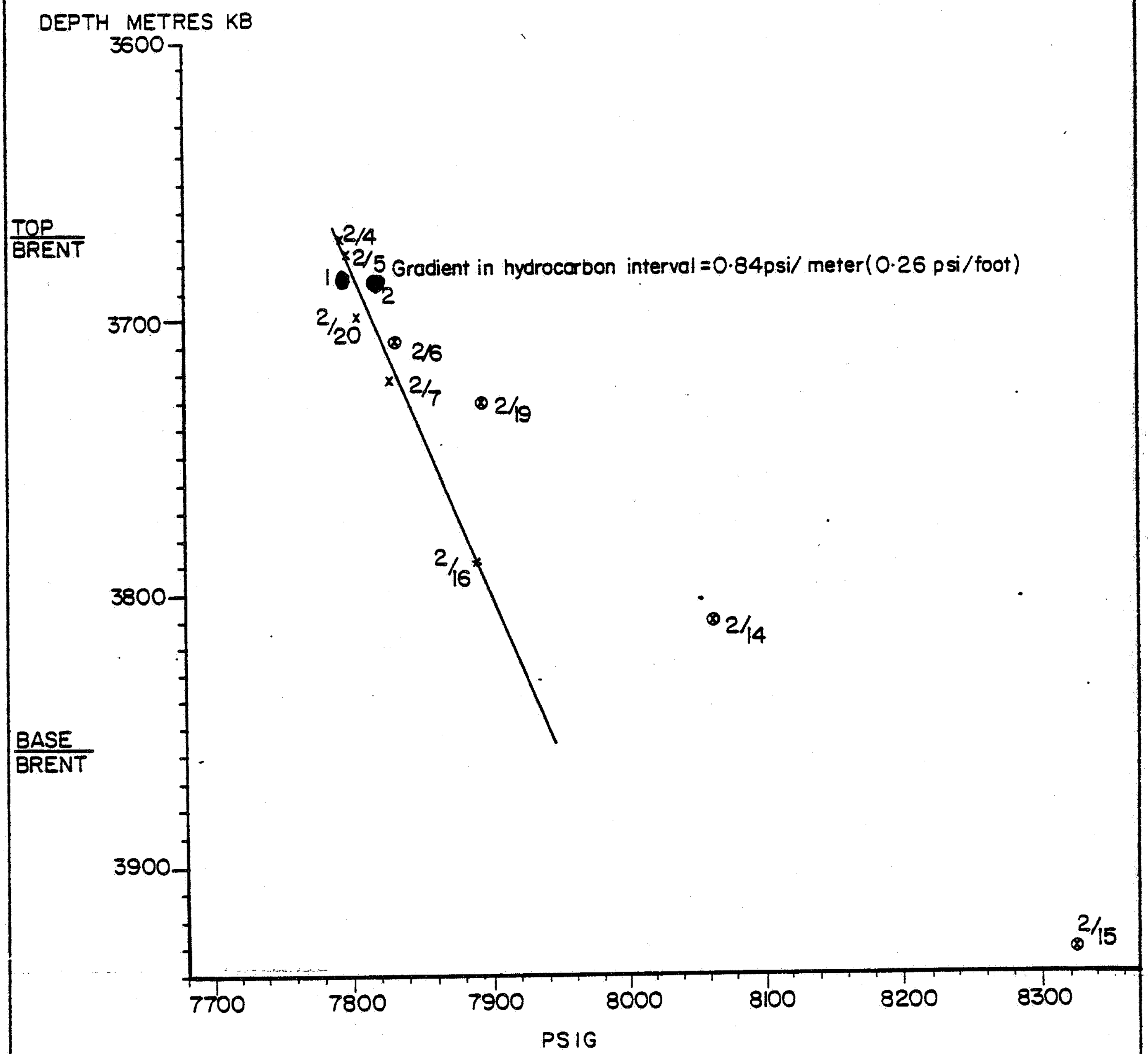
Perforations
3694 - 3703m

Commentary

The zone of this test (3694 - 3703m) was in the middle section of the Jurassic Brent formation. The objective of the test was to confirm the fluid content of the zone, (which in many respects was seen on logs and cores to be similar to the Brent section in 33/8-1 which tested gas and condensate) and to determine reservoir quality. RFT testing (Fig 30) had indicated a static reservoir pressure of approximately 7815 psig at 3700m which, it is understood, compared favourably with the results of testing on the previous well. . Review of the Schlumberger CPI (Fig 31) and base logs with Gulf geologists showed a possible barrier immediately above the perforated interval comprising some 4m of coal and shale. Similarly, a 4m limestone stringer at 3717m was considered to be potentially areally extensive and these were accepted for purposes of subsequent analysis, as the limits of the producing horizon. Quick-look porosity was about 13%, water saturation around 35% and an oil/water contact possibly located at 3726m.

On test, the well cleaned up very quickly to achieve an averaged, stabilised, rate of around 16 MMSCFD and 1920 BCPD with no water production on a 44/64 choke.

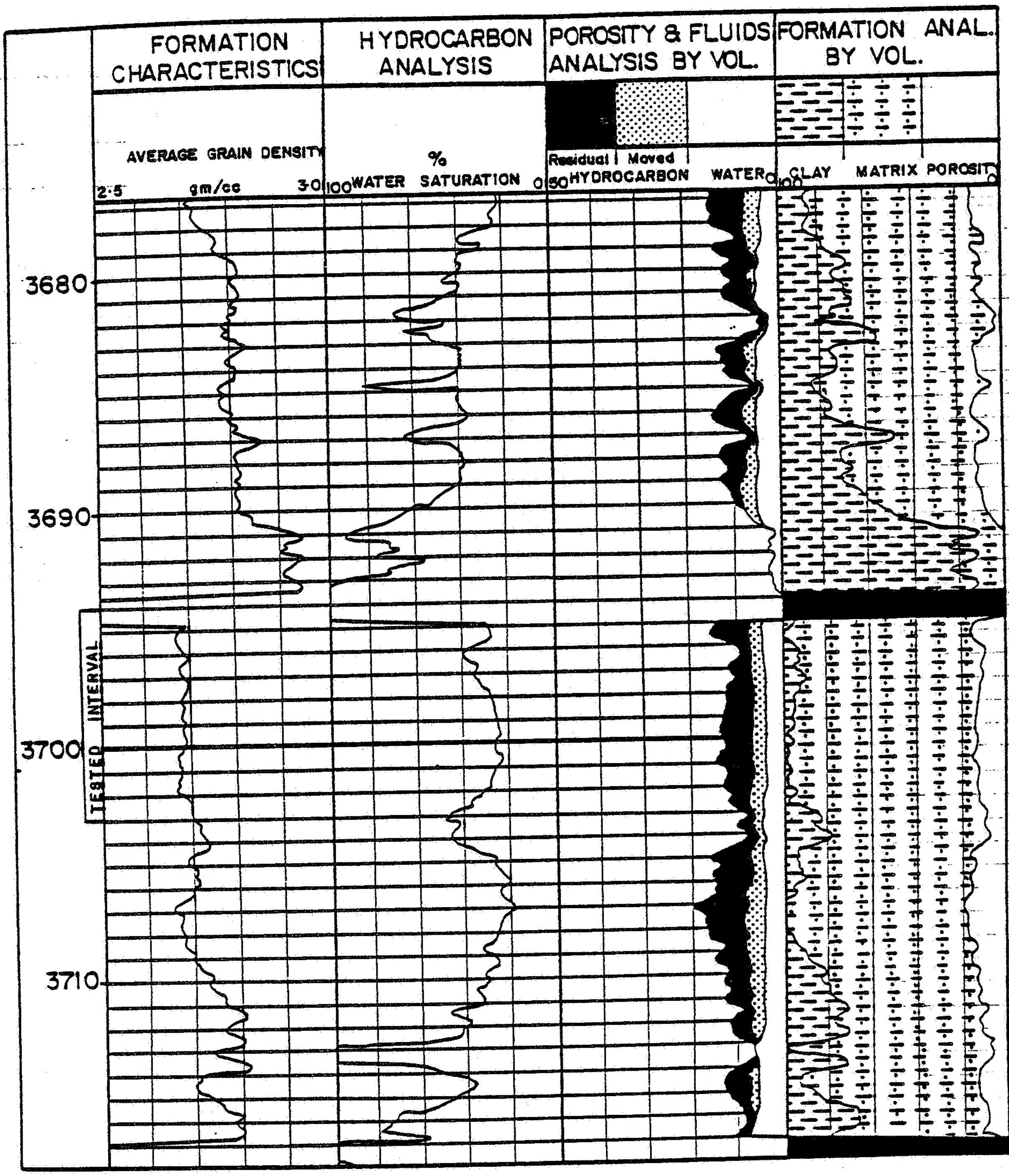
The cement bond log (Fig 32) had indicated a less than ideal bond below the perforated interval to the water contact. However, a review of that data suggested that a cement squeeze would probably not be required in order to obtain a valid test. This was discussed with the Gulf Drilling Superintendent in Bergen. After further discussions between Gulf Bergen and Gulf Houston a previous decision to squeeze before testing was reversed. The absence of produced water on test upheld the course of action as taken.



2/4 Run 2, Test 4
x valid test
⊗ probably affected by supercharging
● DST 1 extrapolated pressures, 1 initial
2 final

(RFT DATA AFTER NORWEGIAN GULF)

Norwegian Gulf Exploration Co. A/S		
WELL 35/8-2 RFT PRESSURE MEASUREMENTS BRENT FORMATION		
Prepared by: GAFFNEY, CLINE & ASSOCIATES		
Date: JUNE '82	Proj No: B507/01	Checked: JA
Scale: AS SHOWN		Fig No: 30



(INTERPRETATION BY SCHLUMBERGER)

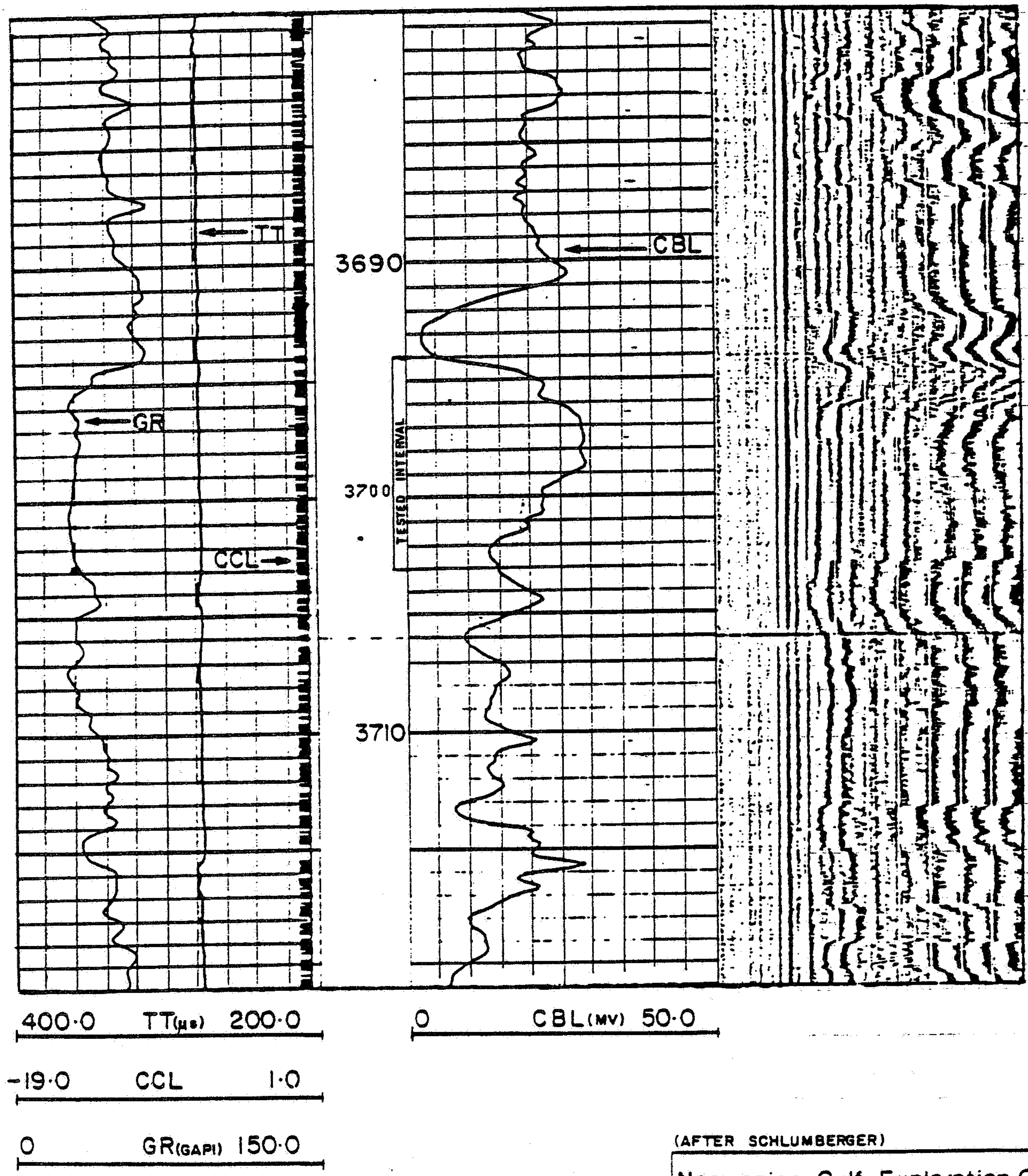
Norwegian Gulf Exploration Co.A/S

WELL 35/8-2
DST-1
LOG INTERPRETATION
BRENT FORMATION

Prepared by: GAFFNEY CLINE & ASSOCIATES		
Date: JUNE '82	Proj No 0507/01	Checked: YA
Scale: AS SHOWN		Fig No: 31

Some difficulty was encountered in opening the APR-N tester valve at the start of the initial flow. Because of this, together with a concern to obtain valid and unimpaired test results, it was intended that reversing out the contents of the tubing after the main flow period should be left until the end of the build-up period. In the event the drilling crew was directed by the rig superintendent to reverse out early in the shut in period and subsequently a satisfactory down-hole shut-in was lost when the Halliburton tester re-opened the APR-N during an unsuccessful attempt to shear the APR-M circulating valve and the former became stuck in the open position. A wrong shearing sequence was erroneously used. Forty-five minutes unstable flow followed this incident, during repeated attempts to shear the APR-M, after which the rig superintendent agreed to allow a surface shut-in. Subsequent release of pressure on the annulus reclosed the APR-N. These events precluded an accurate analysis to determine skin damage though the nature of the bottom hole pressure response was subsequently seen to be such that a reasonable approximation could nevertheless be made. It was again recommended that a further attempt to shear the APR-M be deferred in order to 'protect' the buildup data from the potentially harmful effects of afterflow, which would have been significant if both the APR-N and the APR-M again became stuck in the open position and the well had been held only on a surface shut-in. In the event the required shear was left until the end of the build-up.

The condensate tested was brown/yellow in colour and clear at 80°F though once cooled to around 60°F, waxlike crystals formed and the liquid went opaque. At around 40°F the liquid appeared to gel. The gas/liquid ratio was considered low for a typical gas condensate reservoir fluid and there must be at least some doubt as to whether the reservoir fluid would be in the gaseous or the liquid form at initial conditions, probably lying somewhere near the critical point.



(AFTER SCHLUMBERGER)

Norwegian Gulf Exploration Co. A/S		
WELL 35/8-2 DST-1 CEMENT BOND LOG BRENT FORMATION		
Prepared by GAFFNEY, CLINE & ASSOCIATES		
Date JUNE '82	Proj No: 0507/01	Checked: JM
Scale AS SHOWN		Fig No: 32

When recovered, the Halliburton BT gauge and one Flopetrol SSDR gauge (No. 81048) had recorded the whole test. The second SSDR (No. 81049) had failed during the main flow period having accurately recorded the first build up. Subsequent discussions with Flopetrol indicated that this could be due to the fact that the gauge was operating at the limit of its temperature tolerance. However, the two SSDR gauges were in good agreement whilst both were recording, which indicated that the data obtained could be used with confidence in the analysis.

Notwithstanding the mechanical problems discussed above DST-1 was considered a successful test of the zone perforated.

Test Analysis

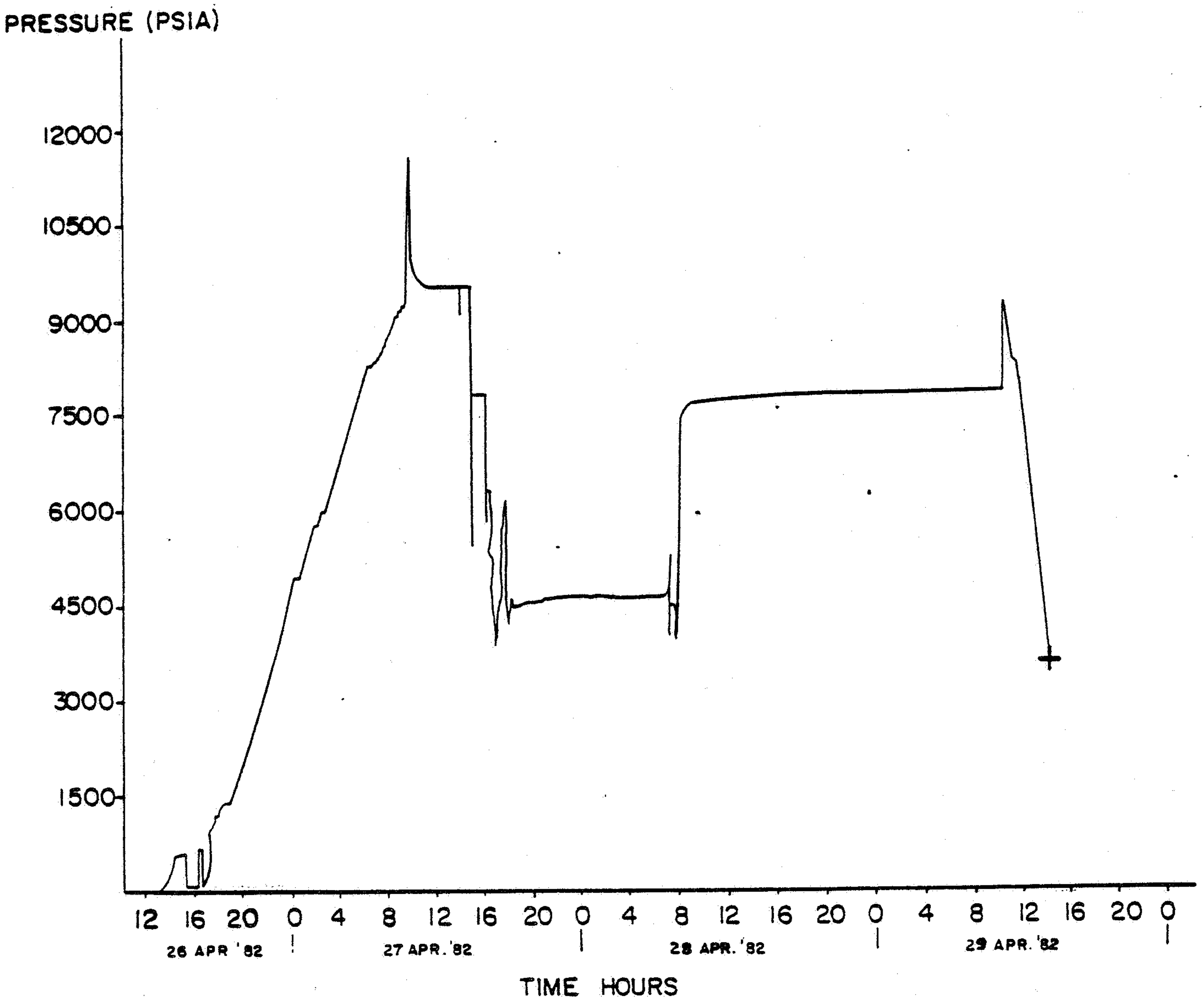
A review of the complete pressure record (Fig 33) indicated immediately that drawdown data, obtained on 'stable' production during the main flow period, was unsuitable (i.e. not monotonically decreasing) for the usual analysis. Build-up data, however, from both initial and final periods, was seen to be acceptable and all effort was concentrated accordingly. Fig.34 is a log/log plot of build-up data from the final period and indicates that conditions suitable for 'Horner Analysis' were obtained after less than ten minutes of shut-in. Figure 35 shows the good agreement between initial and final estimates of extrapolated (reservoir) pressure.

Analysis has yielded the following:

Formation flow capacity (md-ft)	328.0
Effective Permeability (md)	4.55
Extrapolated pressure - initial (psig)	7803.0
final (psig)	7830.0
Gauge Depth (m)	3689.0
Skin	14.4
Radius of Investigation (m)	223.0
Productivity Index (SCFD/psi)	4954.0
Flow Efficiency	0.32
Turbulence Factor (calculated)	5.45x10
Inertial Turbulent Factor (calculated)	0.091
Bottom Hole Temperature (°F)	272

It should be noted that the Turbulence and Inertial Turbulent Factors are considered significant and the resulting high skin factor is reflective of this observation and is therefore not a good measure of mechanical damage. This uncertainty, therefore, is in turn incorporated in the calculation of productivity index and flow efficiency.

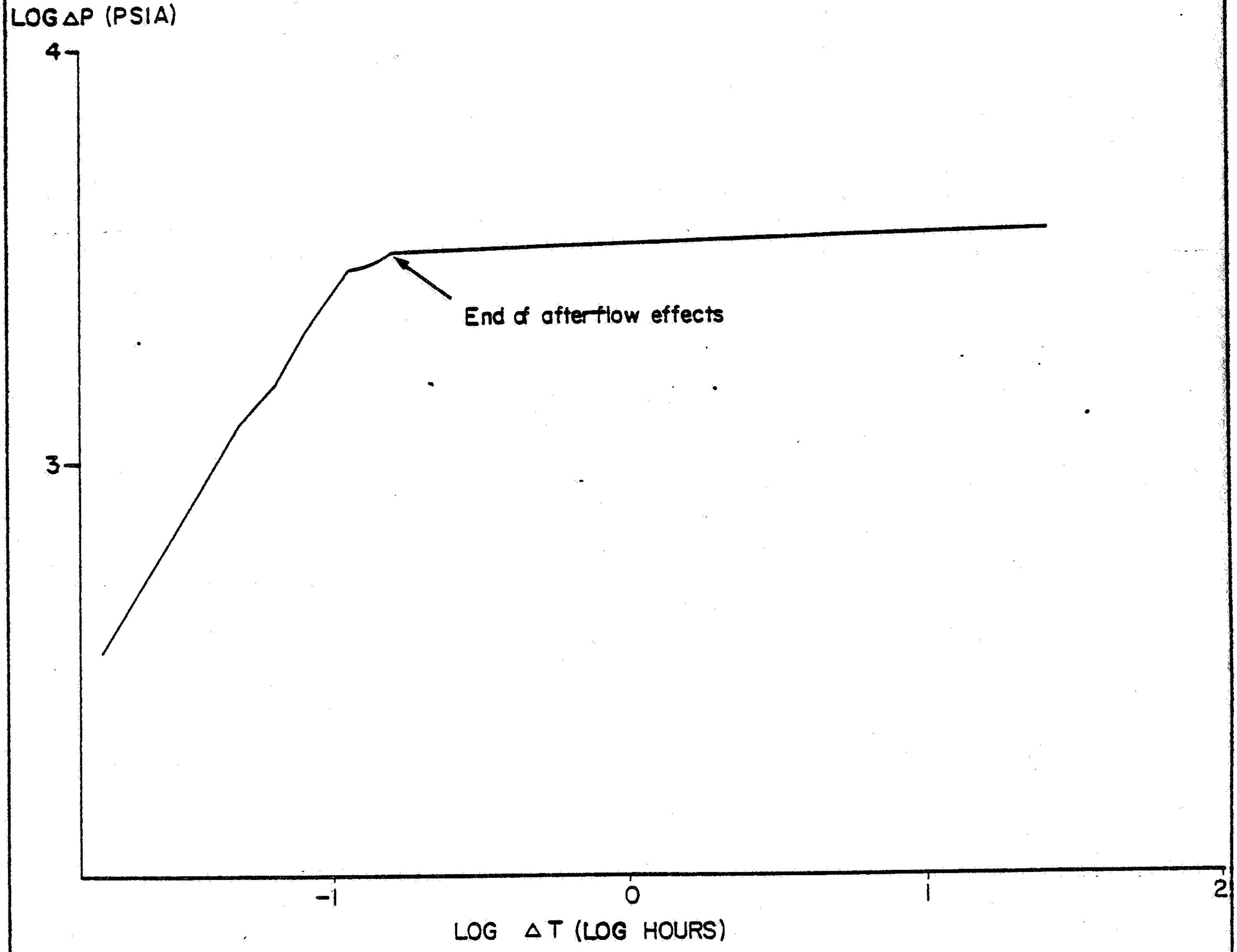
Both initial and final extrapolated pressures have been overplotted on the graph of RFT data (Fig 31) and the excellent agreement between the two sets of data indicates that as estimates of reservoir pressure they may be taken with full confidence.



GAUGE No. SSDR 81048

GAUGE SENSOR DEPTH : 3689 M

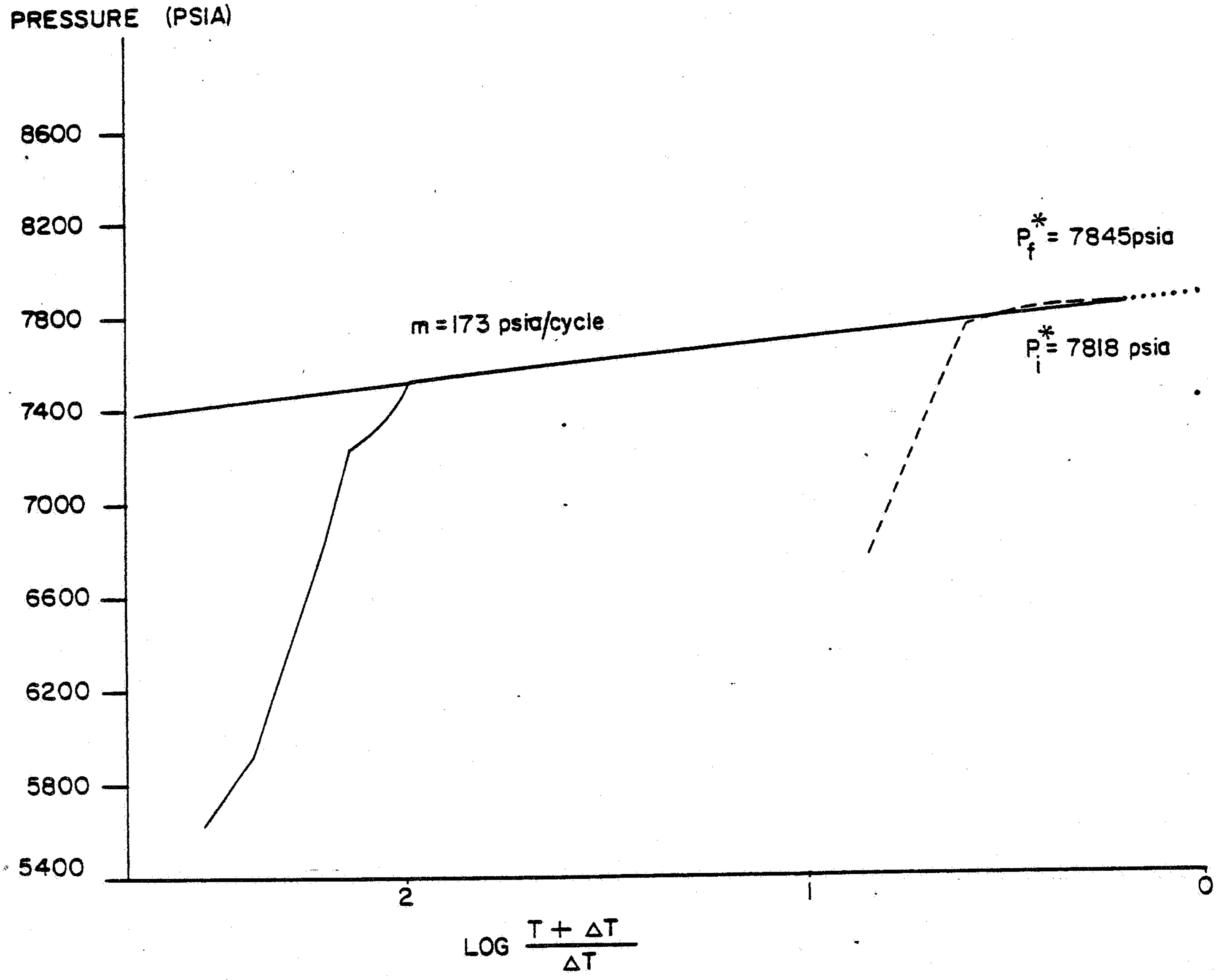
Norwegian Gulf Exploration Co. A/S	
WELL 35/8-2 DST I BOTTOM HOLE PRESSURE CHART	
Prepared by GAFFNEY CLINE & ASSOCIATES	
Date JUNE '82 Proj No 0507/01	Checked JTA
Scale AS SHOWN	Fig No 33



GAUGE No. SSDR 81048

GAUGE SENSOR DEPTH : 3689M

Norwegian Gulf Exploration Co. A/S		
WELL 35/8-2 DST-1 PRESSURE BUILD UP LOG-LOG PLOT		
Prepared by : GAFFNEY, CLINE & ASSOCIATES		
Date JUNE '82	Proj No:0507/01	Checked: JR
Scale: AS SHOWN		Fig No 34



GAUGE No. SSDR 81048

GAUGE SENSOR DEPTH: 3689 M

— Main build-up

--- Initial build-up

Norwegian Gulf Exploration Co. A/S		
WELL 35/8–2 DST–1 HORNER PLOT		
Prepared by GAFFNEY, CLINE & ASSOCIATES		
Date JUNE '82	Proj No: 0507/01	Checked
Scale: AS SHOWN		Fig No 35

CASED HOLE DST-2

Perforations

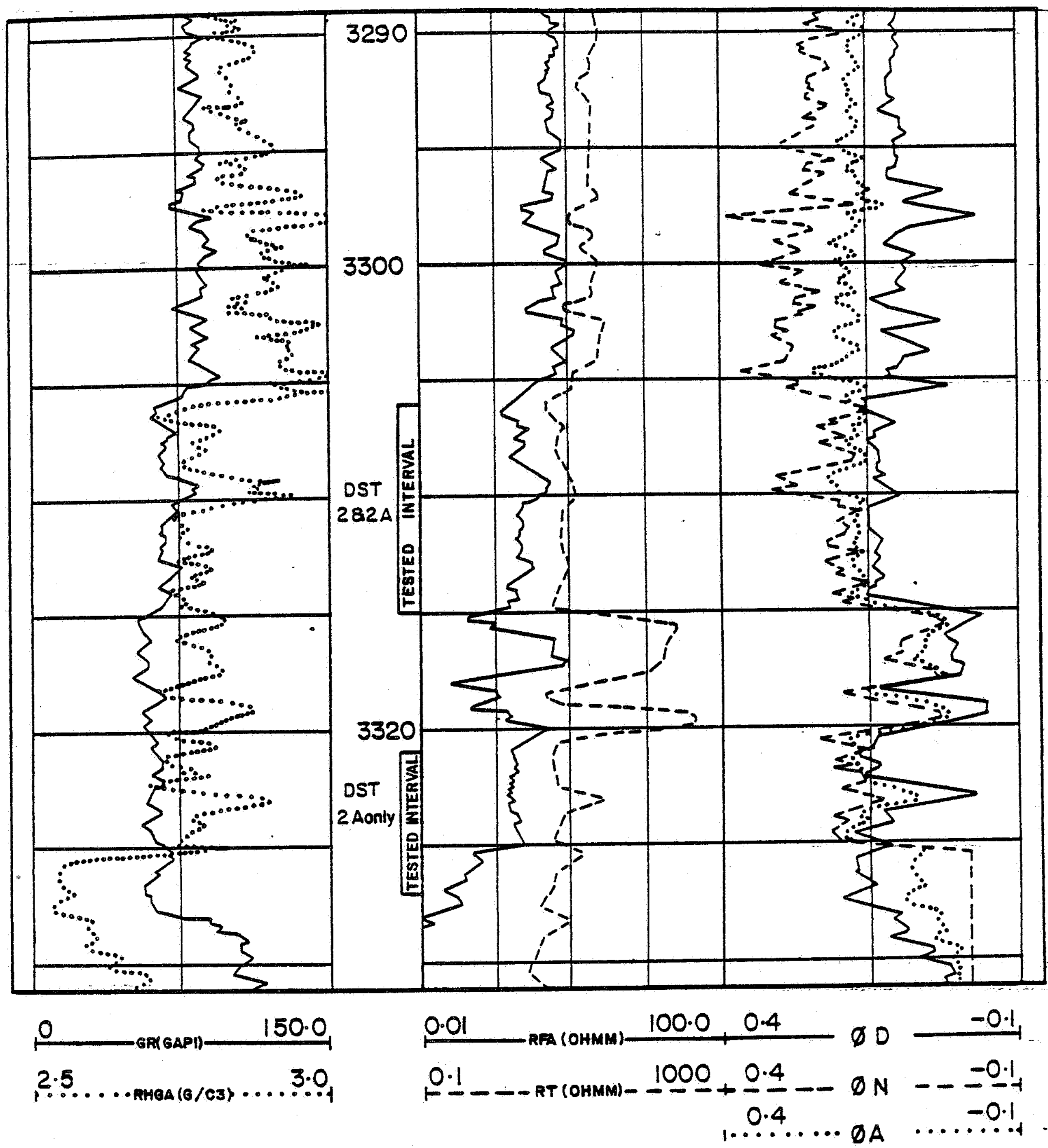
3306 - 3315m

Commentary

The zone perforated for this test was in the lower section of the Upper Jurassic Heather Formation. Log interpretation carried out by Schlumberger and Gulf had indicated that hydrocarbons could be present within the section though only limited intervals of moveables were postulated, water saturations seemingly being high and hydrocarbons possibly being reduced to residual for the most part. The log interpretation was hampered by a lack of information pertaining to water resistivity and also by problems of mineralisation and therefore was considered only in a semi-quantitative fashion. It was understood that sidewall core analysis had supported the view that hydrocarbons were present, possibly in the liquid phase.

Prior to testing, the mud weight was taken down from 14.5 ppg to 12.7 ppg in order to reduce the differential pressure across the APR-N tester valve to an acceptable level, internal pressure being provided by only a partial water cushion of some 2133 metres. A full water cushion was not used since a reservoir pressure of around 5300 psig was expected from RFT data and it was considered necessary to maintain an underpressure of around 1500 - 2000 psig if the formation was to be given a fair chance to flow.

The well began to clean up very quickly when opened for the main flow period and some 45 bbl of water cushion was recovered in 40 minutes. However, another 15 minutes were required to seemingly recover 3.5 bbl of viscous gel that had been spotted above the APR-N valve and with all other flowing conditions unaltered this seemed to indicate more recovery than could be accounted for.



(AFTER SCHLUMBERGER)

Norwegian Gulf Exploration Co. A/S		
WELL 35/8—2 DST-2 & 2A CYBERLOOK LOG HEATHER FORMATION		
Prepared by: GAFFNEY, CLINE & ASSOCIATES		
Date: JUNE'82	Proj No: 0507/01	Checked:
Scale AS SHOWN		Fig No 36

Thereafter, the well produced gas and condensate and obtained stable conditions similar to those observed during DST-1. Moreover, gas and condensate were seen to be identical in quality to that which flowed in the earlier test though the gas/liquid ratio was lower and therefore indicative of a possibly richer in situ fluid. These facts, together with an ongoing suspicion that the CBL/VDL indicated poor cement from the Heather test zone some 457 metres down to the hydrocarbon bearing zones tested previously in the Brent, began to indicate that communication behind casing had taken place and that, in fact, the Heather was not being tested.

This scenario was confirmed subsequent to the test when an analysis of bottom hole data indicated that the reservoir pressure was in line with that expected from the significantly overpressured Brent and that similarly the reservoir temperature was too high to be representative of the Heather. As a final indicator samples of condensate from each test were taken for analysis to a laboratory at Trondheim and it is understood that these proved to be identical. DST-2 was therefore declared an invalid test of the Heather, though obviously much of the data obtained had relevance to the Brent.

Again, a full sampling programme had been completed, including PVT, and valid specimens should have been obtained.

In an operational sense this test had progressed significantly more smoothly than the previous one. The only slight mechanical problem which arose occurred when, (as with DST-1) the contents of the tubing were reversed out soon after the well had been shut-in to record the main buildup. This involved bleeding down the contents of the tubing, filling the string with mud and then reversing out. The action of bleeding down the tubing pressure allowed a slow leak to develop across the APR-N valve and as can be seen (Fig 39) the characteristic of the Horner plot was significantly and detrimentally affected.

It is considered poor practice to reverse out with such timing and certainly if only a relatively short build up had been practicable (because of weather or other considerations) the analysis could have been rendered totally invalid.

Test Analysis

It was considered imprudent to attempt a full data analysis for DST-2, even assuming it to be a Brent test. With production downhole presumably taking place in channels behind up to 400m of casing it would have been difficult to visualise how some of the calculated parameters (skin etc) could have been realistically related to a tested 'zone'. Indeed, several intervals within the Brent were seen from log interpretation to contain moveable hydrocarbons and there was no way to positively identify exactly which zone or zones had produced. Certainly the gas/liquid ratio obtained was significantly different from that previously tested and is probably indicative of production, at least in part, from a zone overlying that tested in DST-1.

Nevertheless, it was considered valid to carry out an outline analysis to determine estimates of reservoir pressure and an indication of the flow capacity of the contributing zone(s). A specification of parameters used in the analysis together with relevant calculations is included in Apendix IV. Only the data from Flopetrol Gauge SSDR No. 81058 were used and a summary of these is included in Appendix III, together with surface data recorded by Expro.

Fig **37** indicates that throughout the main flow period the test 'zone' appeared to continue be 'cleaning up' - significantly different from the relative stability witnessed (Fig**33**) during DST-1. However, it is possible that a comparison of the differences observed between initial and final build up periods throws light on this. Fig**38**, the log/log plot for the final buildup period indicates that conditions suitable for Horner analysis were again obtained approximately ten minutes after shut-in. Fig**39**, on the other hand, does not see the good agreement between initial and final extrapolated pressures as witnessed in DST-1 with the latter value (7425 psig) being some 340 psi higher than the former.

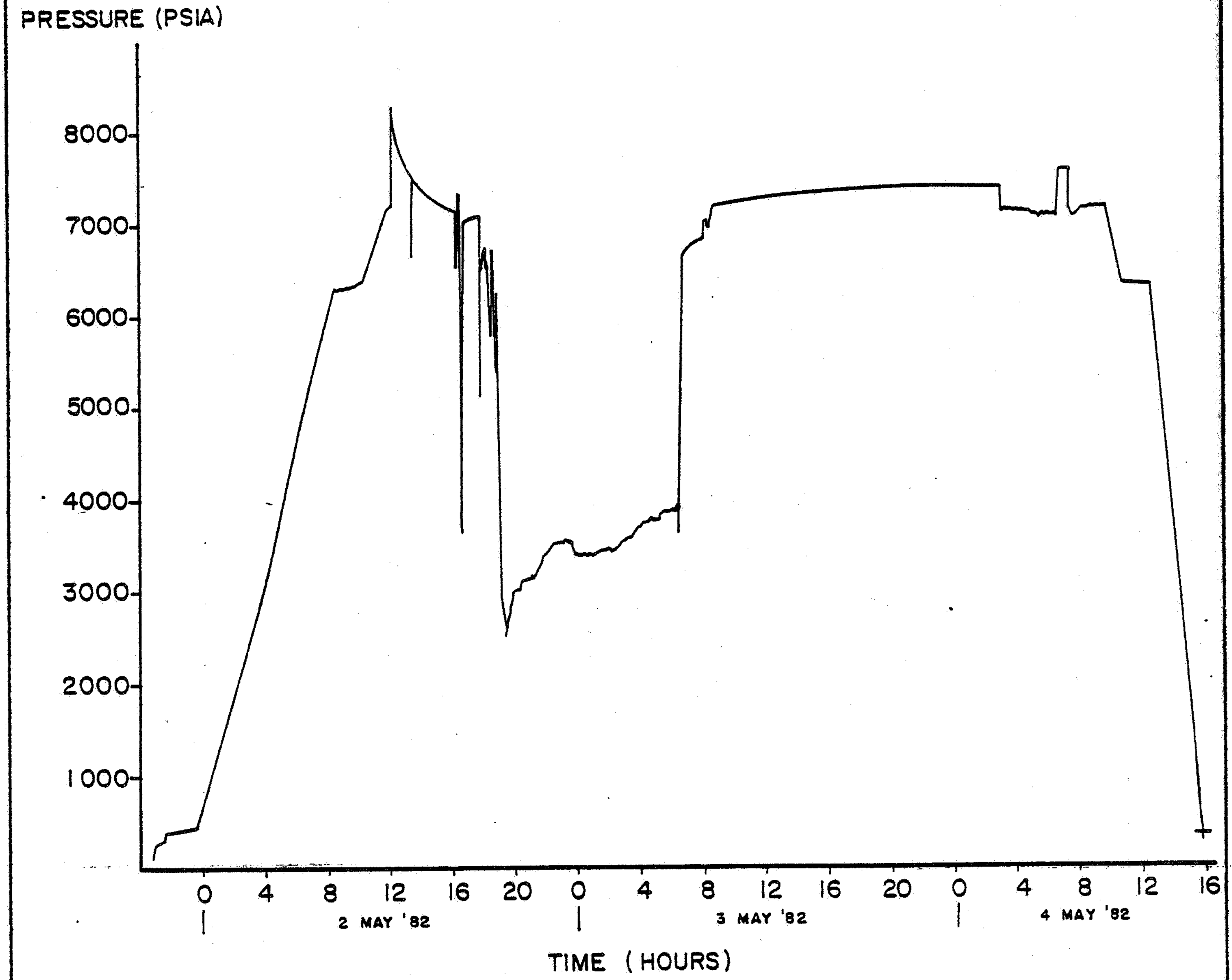
Taking these observations, together with the premise of flow behind casing, it is considered likely that during the main flow period the ongoing 'clean up' witnessed was, in fact, due to continued breakdown of cement behind casing. Therefore, the final buildup was indicative of a zone lower than that tested by the initial buildup and seemingly with a higher pressure.

The analysis yielded the following results:

Formation Flow capacity (md-ft)	106
Extrapolated Pressure - initial (psig)	7085
final (psig)	7425
Gauge depth (m)	3273
Bottom Hole Temperature (°F)	260

Since it was not possible to determine from which zone production had taken place, it was in turn impossible to determine a contributing formation thickness and therefore the flow capacity could not be resolved to determine a value of permeability.

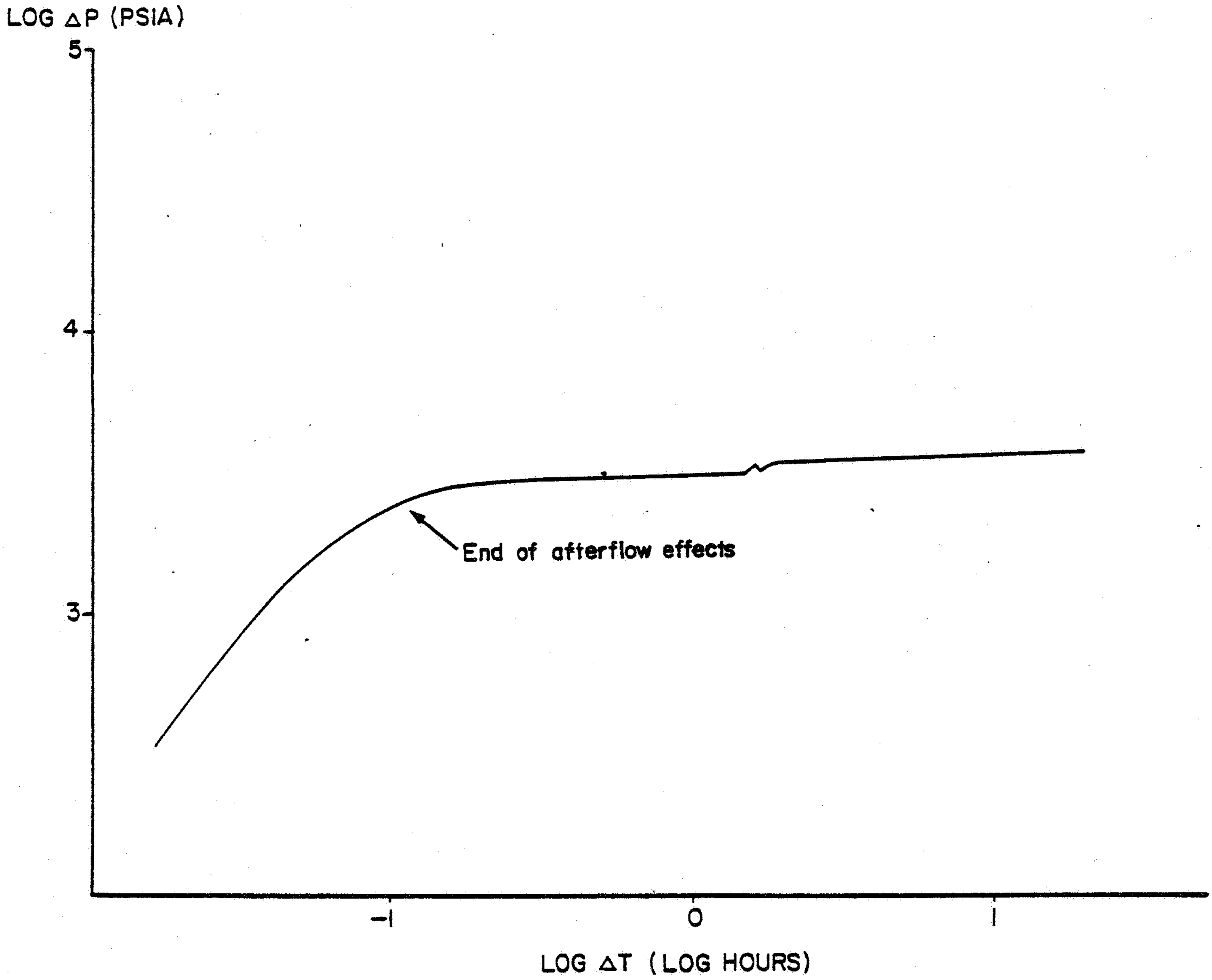
An attempt was made to 'correct' the final extrapolated pressure using a range of acceptable wellstream gradients to the depth of DST-1. However, by this exercise the tested zone was seen to be significantly less overpressured than the zone of DST-1 and for this reason the corrected pressure was too low to be included on Fig30, for purposes of comparison with the other Brent RFT/DST pressures.



GAUGE No. SSDR 81058

GAUGE SENSOR DEPTH: 3273M

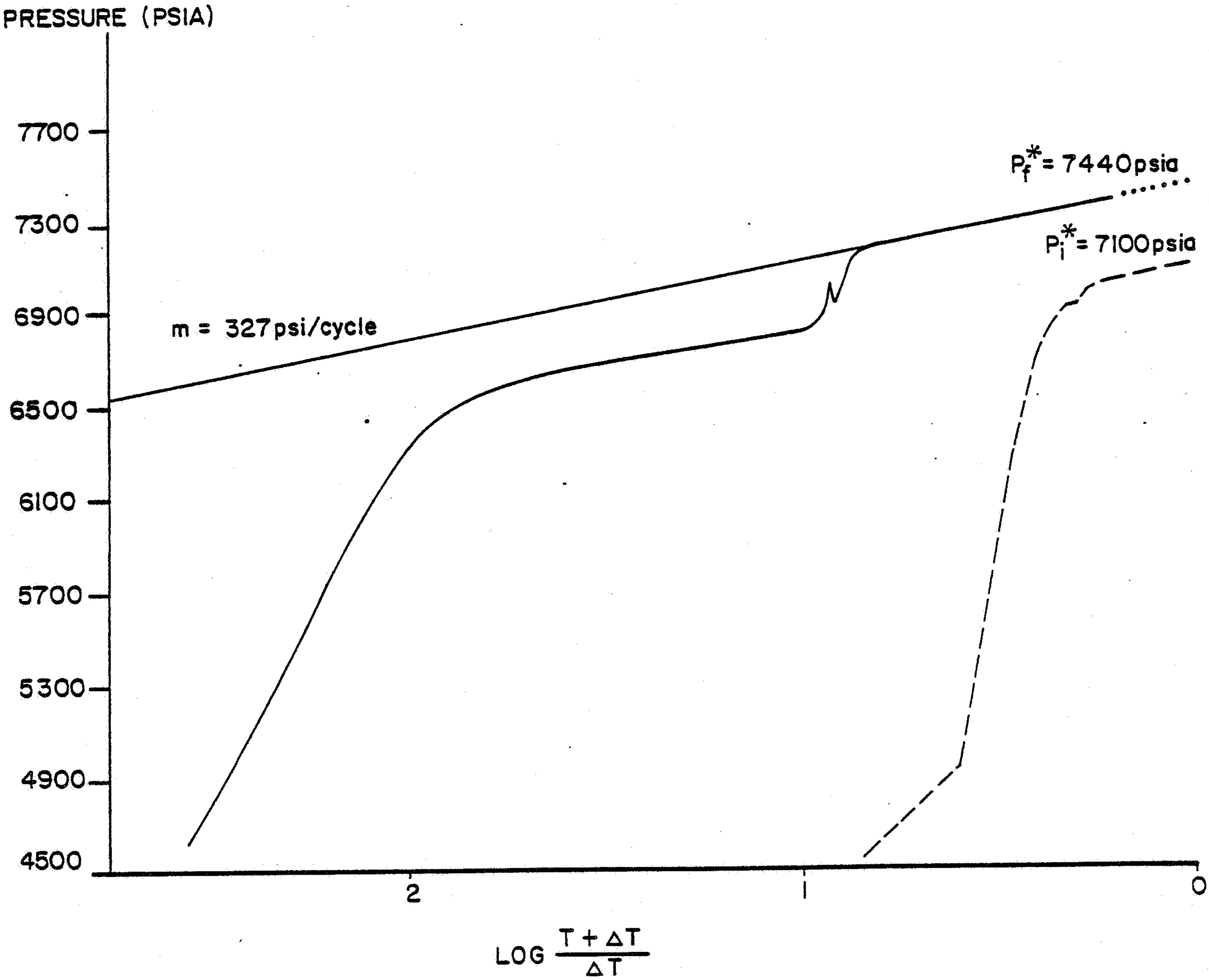
Norwegian Gulf Exploration Co. A/S		
WELL 35/8-2 DST-2 BOTTOM HOLE PRESSURE CHART		
Prepared by: GAFFNEY CLINE & ASSOCIATES		
Date: JUNE '82	Proj No: D 507/01	Checked: gA
Scale: AS SHOWN		Fig No 37



GAUGE No. SSDR 81058

GAUGE SENSOR DEPTH : 3273 M

Norwegian Gulf Exploration Co. A/S	
WELL 35/8-2 DST-2 PRESSURE BUILD-UP LOG-LOG PLOT	
Prepared by: GAFFNEY, CLINE & ASSOCIATES	
Date: JUNE '82 Proj No: 0507/01	Checked: JA
Scale: AS SHOWN	Fig No: 38



GAUGE No. SSDR 81058
GAUGE SENSOR DEPTH : 3273 M

—— Main build-up
– – – Initial build-up

Norwegian Gulf Exploration Co. A/S		
WELL 35/8-2 DST-2 HORNER PLOT		
Prepared by : GAFFNEY, CLINE & ASSOCIATES		
Date : JUNE '82	Proj No: D507/a	Checked: JA
Scale : AS SHOWN		Fig No: 39

CASED HOLE DST 2A

Perforations 3306 - 3315m; 3321 - 3327m

Commentary

There was unequivocable evidence from DST-2 that mechanical communication had existed between the Heather and Brent Formation which thus required a remedial cement job to isolate the two. Two squeeze cementations were carried out into perforations at 3634 -3636m (175 sacks) and 3531 - 3533m (350 sacks), respectively and the Heather sand was then perforated, 3321 - 3327.5m and 3306 - 3315m. The mud weight during perforation was kept at 13.4ppg, giving an overbalance of 2260 psig, in case the squeeze jobs had been unsuccessful and in such an event it would have been necessary to control the higher Brent pressure. No losses or gains were recorded after perforating.

The string was landed and after pressure testing surface equipment the annulus was pressured up to 1600 psig to open the tester valve. There were no surface indications of flow even though only a partial water cushion of some 2438m had been employed to give a differential into the wellbore of around 1500 psig. Several attempts were made to induce the APR-N tester valve to open but still without any indications at the bubble hose. The annulus pressure was then bled off and the well left closed in for thirty minutes to record a minimum build-up, just in case the tool had, in fact, opened. As a final attempt to open the APR-N the string was picked up to open the hydraulic bypass in order to release any supercharged pressure from under the tester valve. The string was relanded and pressure applied to the annulus to open the APR-N, the well was left open for 2 hours but no significant indications of flow were witnessed at the surface. The annulus pressure was bled off and after a nominal shut in period of one hour the reverse circulating valves were sheared and the well circulated to mud. The string was then pulled to retrieve the gauges.

Subsequent review of pressure charts clearly indicated that the well had indeed been open for a period of some twenty-three minutes prior to a build up of thirty minutes. The APR-N had, however, failed to reopen after the hydraulic bypass had been actuated. An inspection of the Baker seal assembly revealed a long scratch over the whole length of the seals and it was concluded, therefore, that the seal bore was almost certainly damaged when attempting to stab into the packer, subsequent to the thirty minute buildup. The resulting communication across the packer had made it mechanically impossible for the APR-N to open.

There was no evidence either during the test, or when reversing out the tubing contents, that the formation had produced any significant amount of fluid.

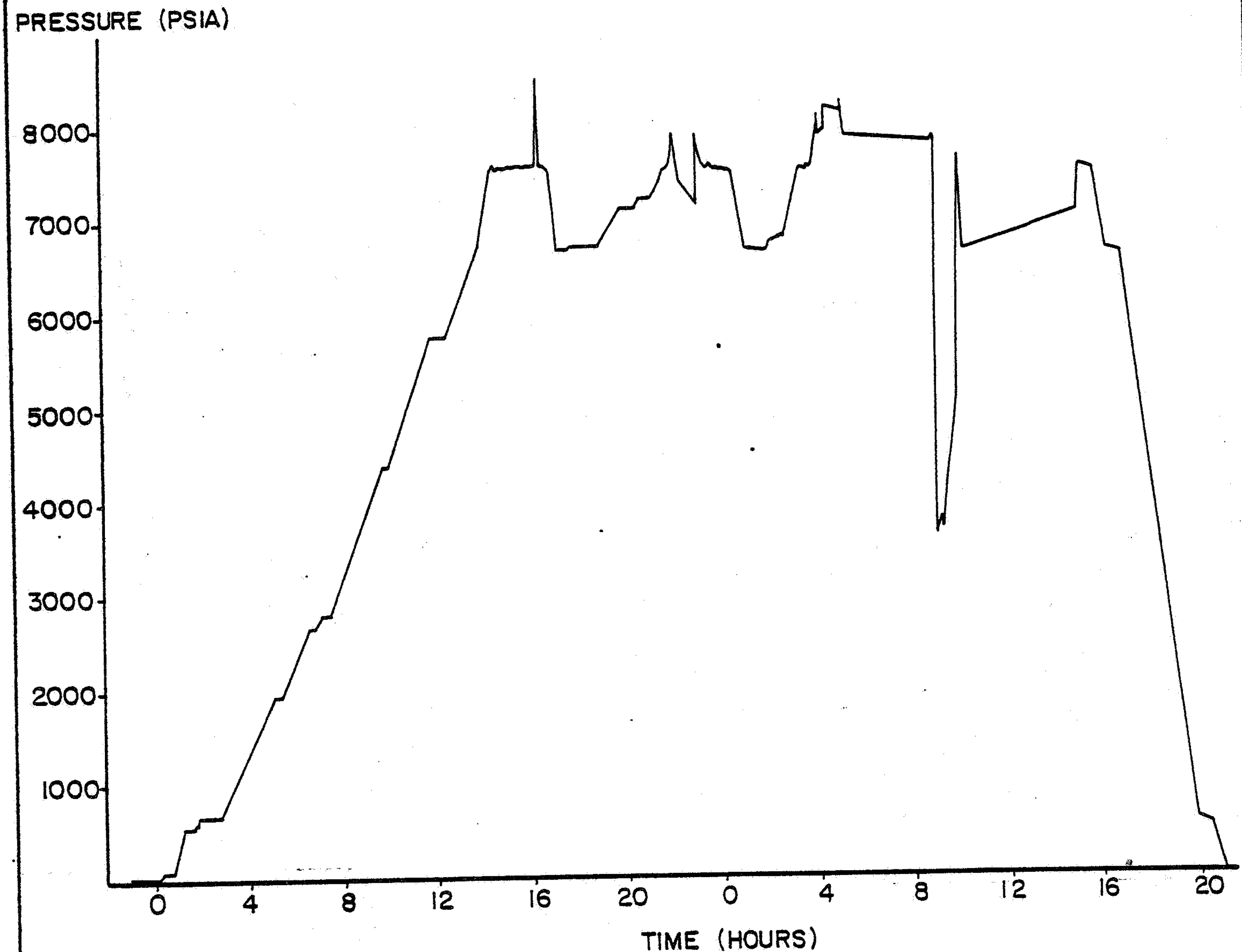
Test Analysis

Whilst it was impossible to determine a significant entry of fluids into the wellbore, for purposes of an outline analysis it was assumed that flow of water at a nominal rate of 10 BWPD resulted in the pressure drawdown seen in the pressure record, Fig 40.

Fig 41 , the log/log plot indicates that Horner conditions were not really established during the thirty minute buildup. Consequently, extrapolation of the pressure buildup (Fig 42) to a pressure of 5505 psig could only yield an upper boundary to the true reservoir pressure and indeed, this was seen to be significantly higher (when corrected for depth) than the two estimates of 5287 psig at 3312m and 5309 psig at 3322m provided by RFT analysis. In turn, the following estimate of flow capacity will therefore be a minimum:

Flow capacity (md-ft)	> 0.7
Extrapolated pressure (psig)	5505
Gauge depth (m)	3265.6
Bottom Hole Temperature (°F)	224

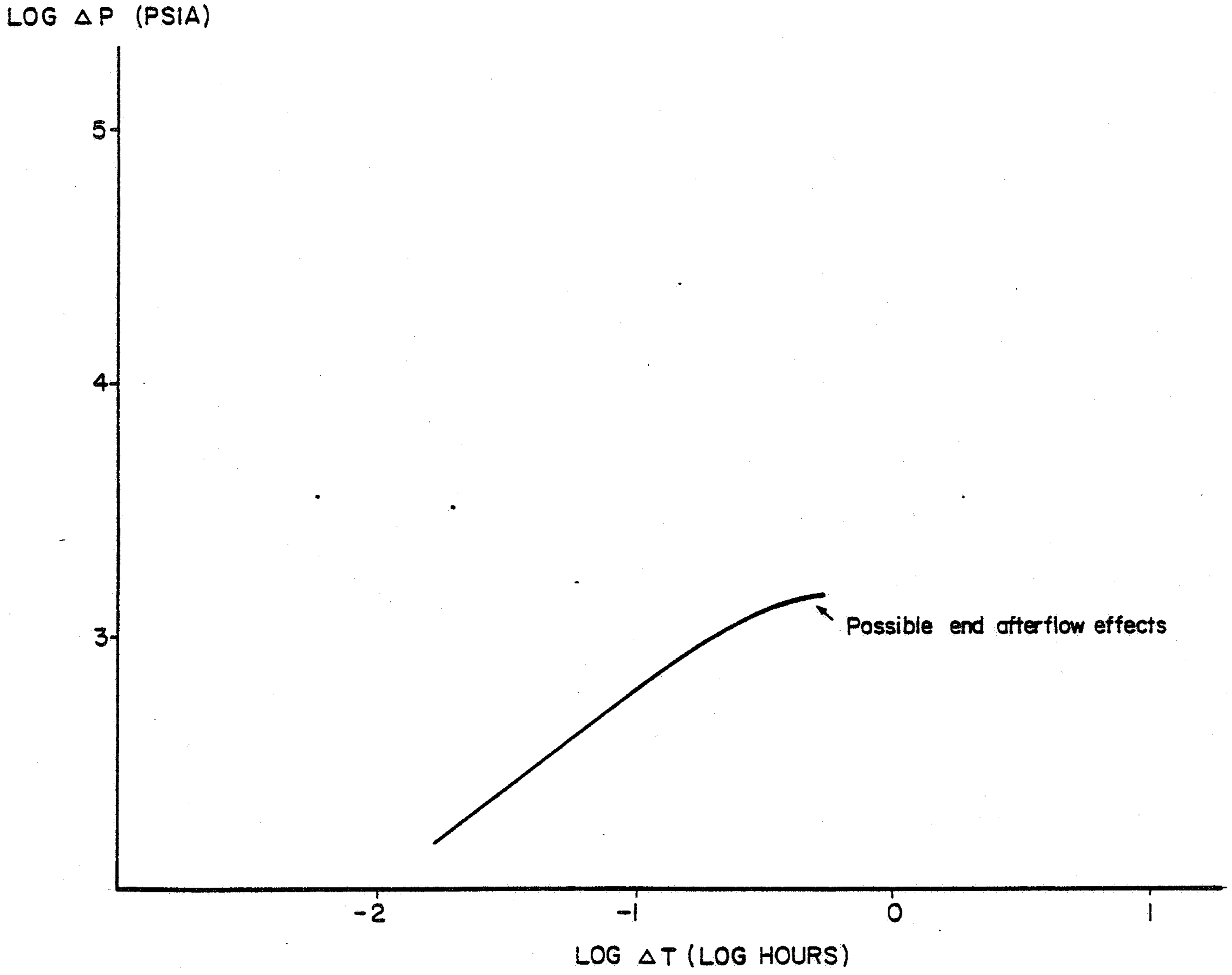
Nevertheless, this estimate of flow capacity, together with the insignificant entry of fluids into the wellbore, is considered sufficient to characterise the formation tested as being extremely tight with an effective permeability significantly less than 1 md.



GAUGE No. SSDR 81048

GAUGE SENSOR DEPTH : 3269·5 M

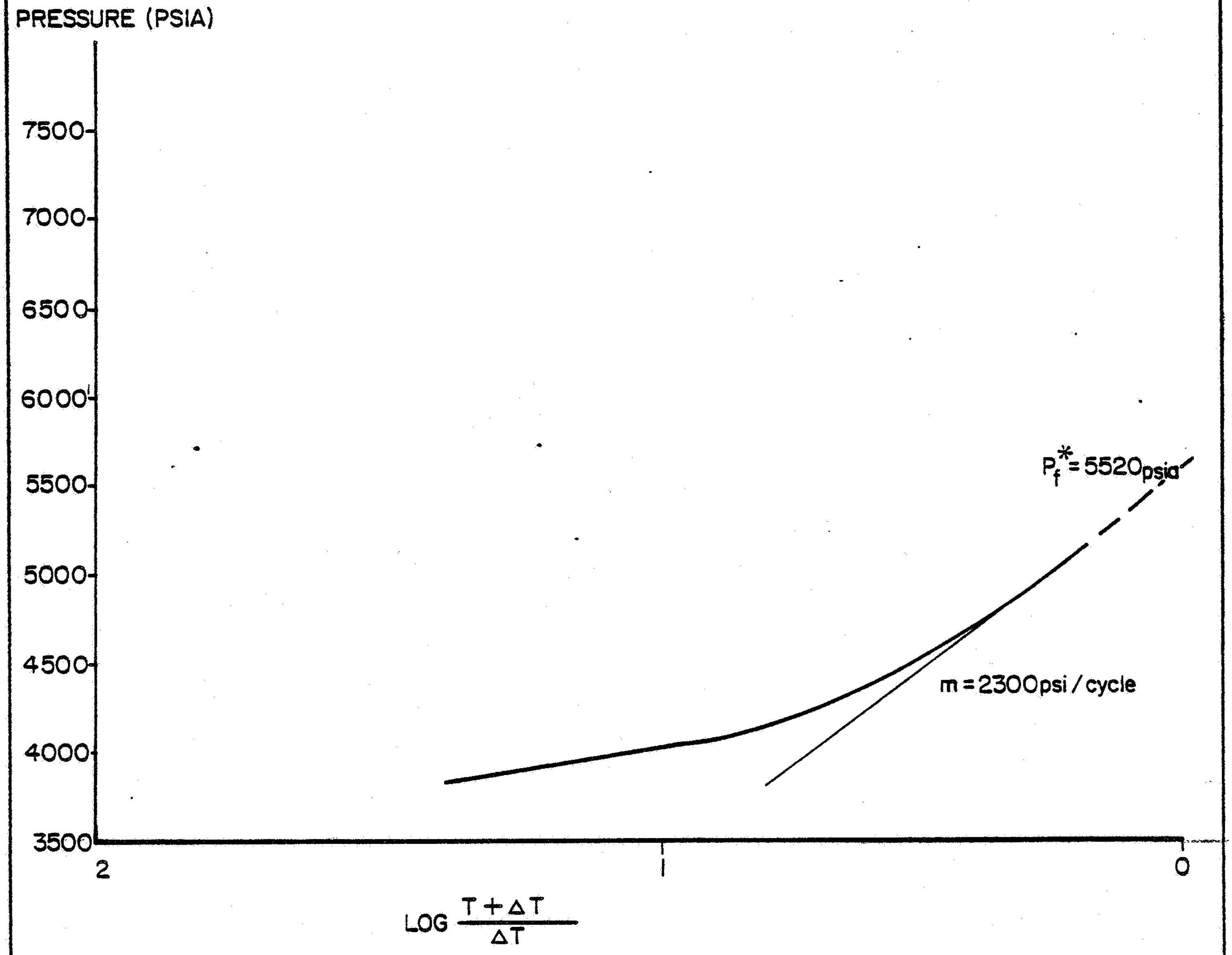
Norwegian Gulf Exploration Co. A/S		
WELL 35/8-2 DST-2 A BOTTOM HOLE PRESSURE CHART		
Prepared by : GAFFNEY, CLINE & ASSOCIATES		
Date : JUNE '82	Proj No: 507/01	Checked: JA
Scale: AS SHOWN		Fig No: 40



GAUGE No. SSDR 81048

GAUGE SENSOR DEPTH : 3269·5M

Norwegian Gulf Exploration Co. A/S		
WELL 35/8-2 DST - 2A PRESSURE MEASUREMENT LOG-LOG PLOT		
Prepared by : GAFFNEY, CLINE & ASSOCIATES		
Date : JUNE '82	Proj No : 0507/01	Checked: JA
Scale : AS SHOWN		Fig No 41



GAUGE No. SSDR 81048
GAUGE SENSOR DEPTH:3269·5M

Norwegian Gulf Exploration Co A/S		
WELL 35/8-2 DST-2A HORNER PLOT		
Prepared by: GAFFNEY, CLINE & ASSOCIATES		
Date: JUNE'82	Proj No:0507/01	Checked: J.A
Scale: AS SHOWN		Fig No 42

19. PRESSURE TEMPERATURE MEASUREMENTS (FLOPETROL)

DISTRICT: EMR / NOB

BASE : STAVANGER

REPORT N°: ELS 82 / 21

HIGH ACCURACY PRESSURE TEMPERATURE MEASUREMENTS

Company: GULF OIL CO.
Country: NORWAY

Field: 35/8
Well: 35/8-2

Zone: BRENT
Date: 26.- 29.APRIL 1982

PERF.INT.: 12119 - 12149 Ft. RKB

DST 1

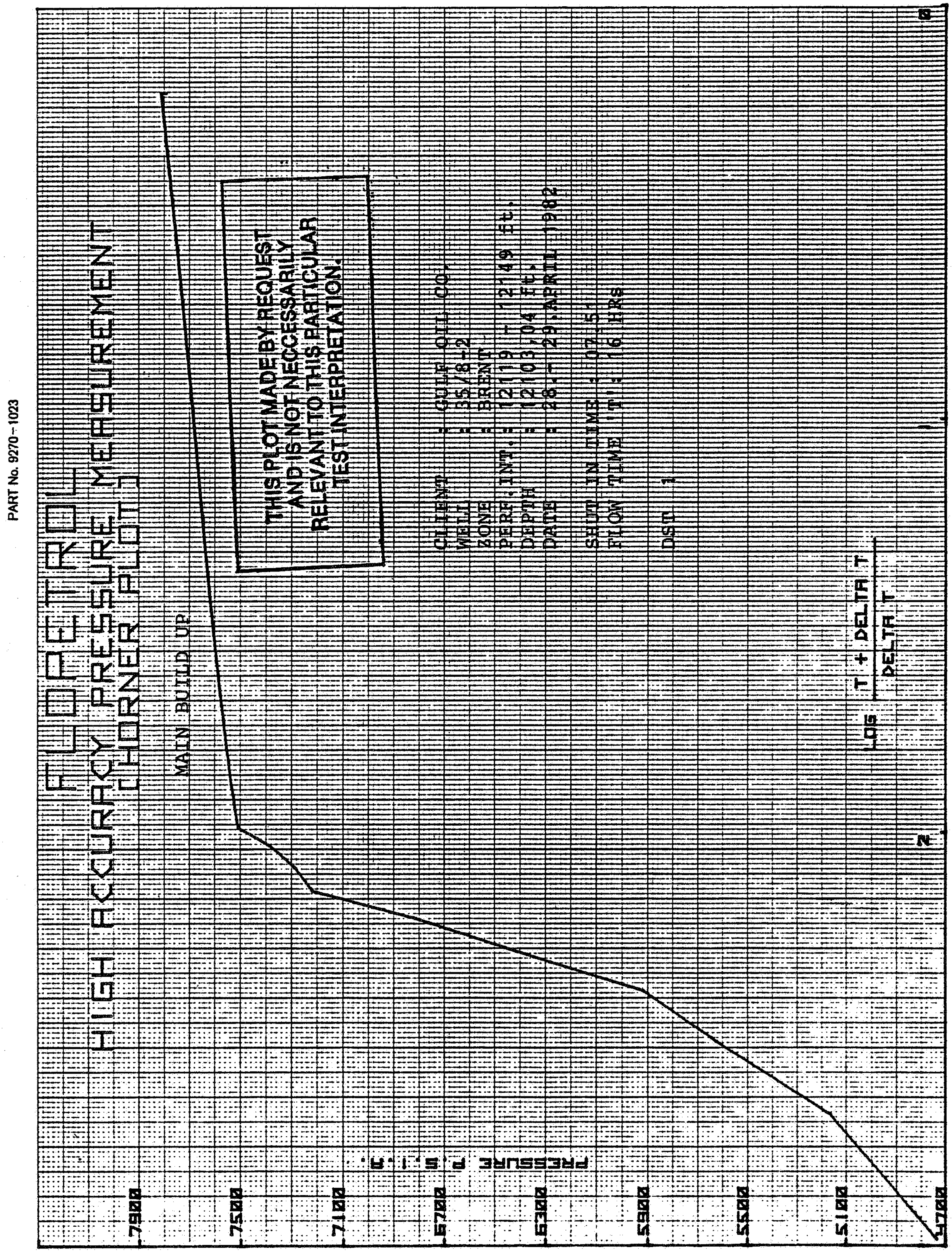

HEWLETT PACKARD
PART No. 9270-1023
FLOPETROL
HIGH ACCURACY PRESSURE MEASUREMENT
(HORNER PLOT)
MAIN BUILD UP
THIS PLOT MADE BY REQUEST AND IS NOT NECCESSARILY RELEVANT TO THIS PARTICULAR TEST INTERPRETATION.
CLIENT : GULF OIL CO.
WELL : 35/8-2
ZONE : BRENT
PERF.INT. : 12119 - 12149 ft.
DEPTH : 12103,04 ft.
DATE : 28. - 29. APRIL 1982
SHUT IN TIME : 07.5
FLOW TIME 'T' : 16 HRs
DST 1
LOG T + DELTA T / DELTA T
PRESSURE P.S.I.A.
7900
7500
7100
6700
6300
5900
5500
5100
4700
2

Figure 43

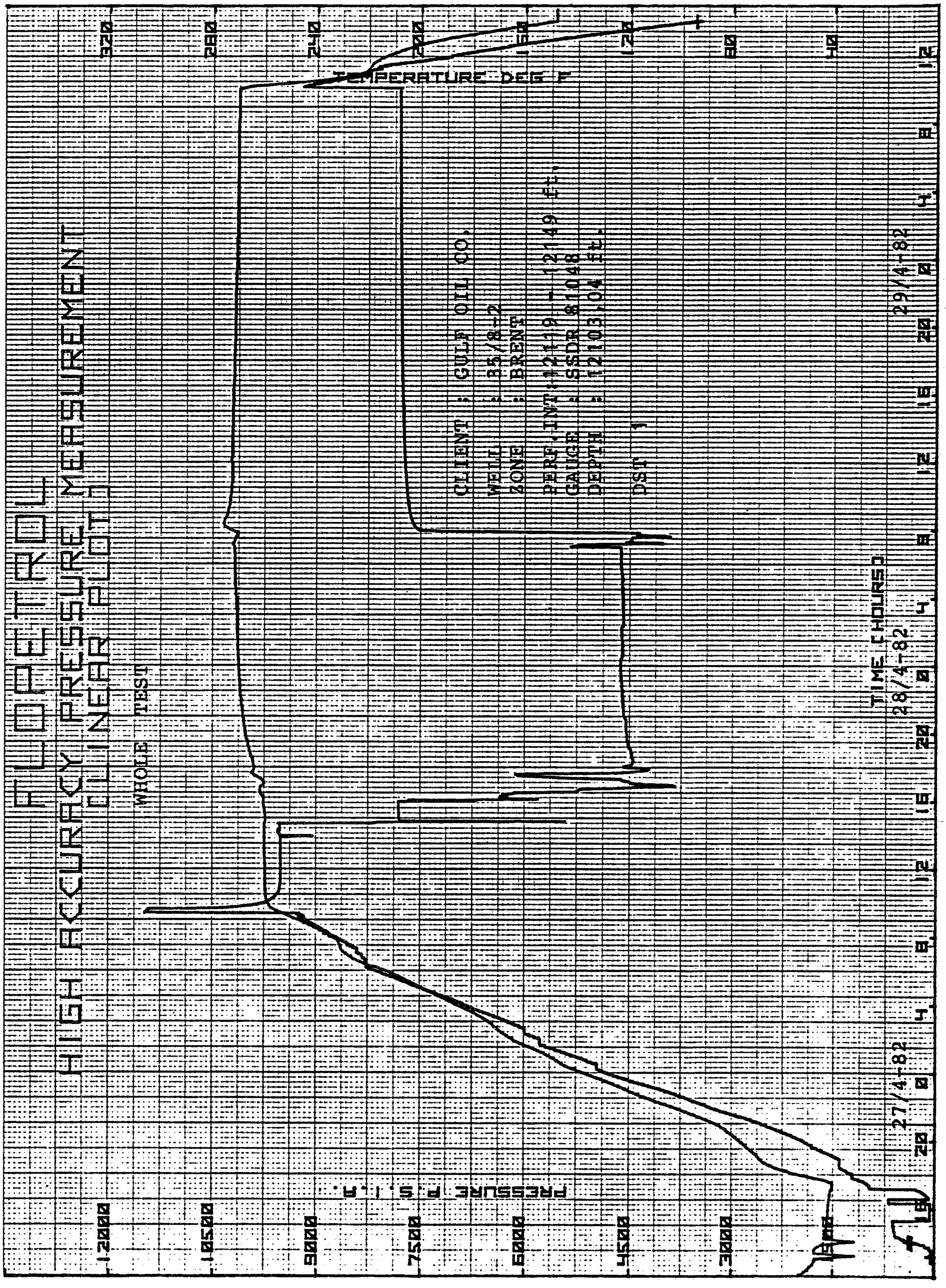
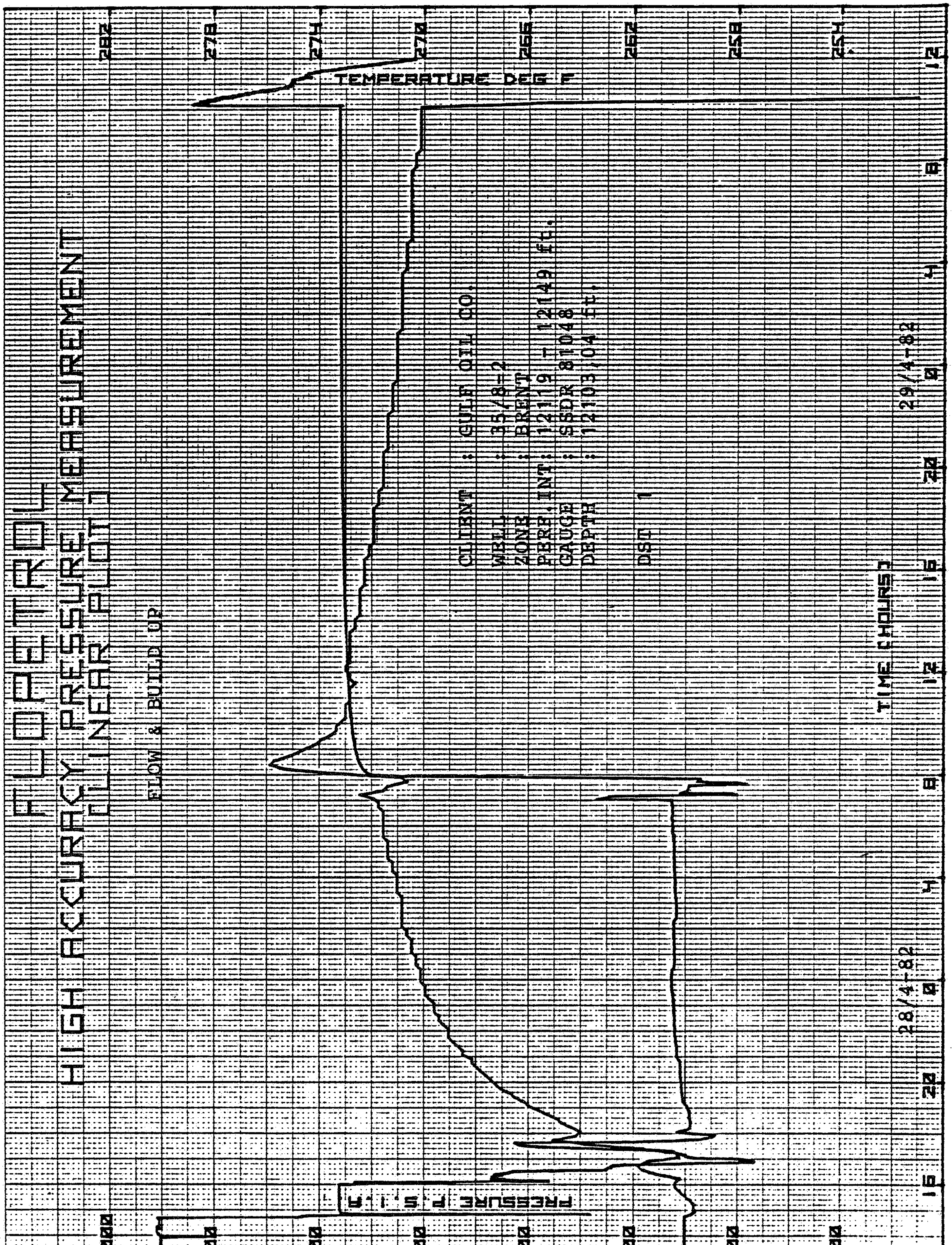

FLOPETROL
HIGH ACCURACY PRESSURE MEASUREMENT
(LINEAR PLOT)
WHOLE TEST
TEMPERATURE DEG F
320
280
240
200
160
120
80
40
PRESSURE P.S.I.A.
12000
10500
9000
7500
6000
4500
3000
1500
CLIENT : GULF OIL CO.
WELL : 35/8-2
ZONE : BRENT
PERF.INT:12119 - 12149 ft.
GAUGE : SSDR 81048
DEPTH : 12103.04 ft.
DST 1
TIME (HOURS)
16 20 0 4 8 12 16 20 0 4 8 12 16 20 0 4 8 12
27/4-82
28/4-82
29/4-82

Figure 44


FLOPETROL
HIGH ACCURACY PRESSURE MEASUREMENT
(LINEAR PLOT)
FLOW & BUILD UP
TEMPERATURE DEG F
CLIENT : GULF OIL CO.
WELL : 35/8-2
ZONE : BRENT
PERF. INT : 12119 - 12149 ft.
GAUGE : SSDR 81048
DEPTH : 12103.04 ft.
DST 1
PRESSURE P.S.I.A
10000
9000
8000
7000
6000
5000
4000
3000
282
278
274
270
266
262
258
254
TIME (HOURS)
16
20
0
4
8
12
16
20
0
4
8
12
28/4-82
29/4-82

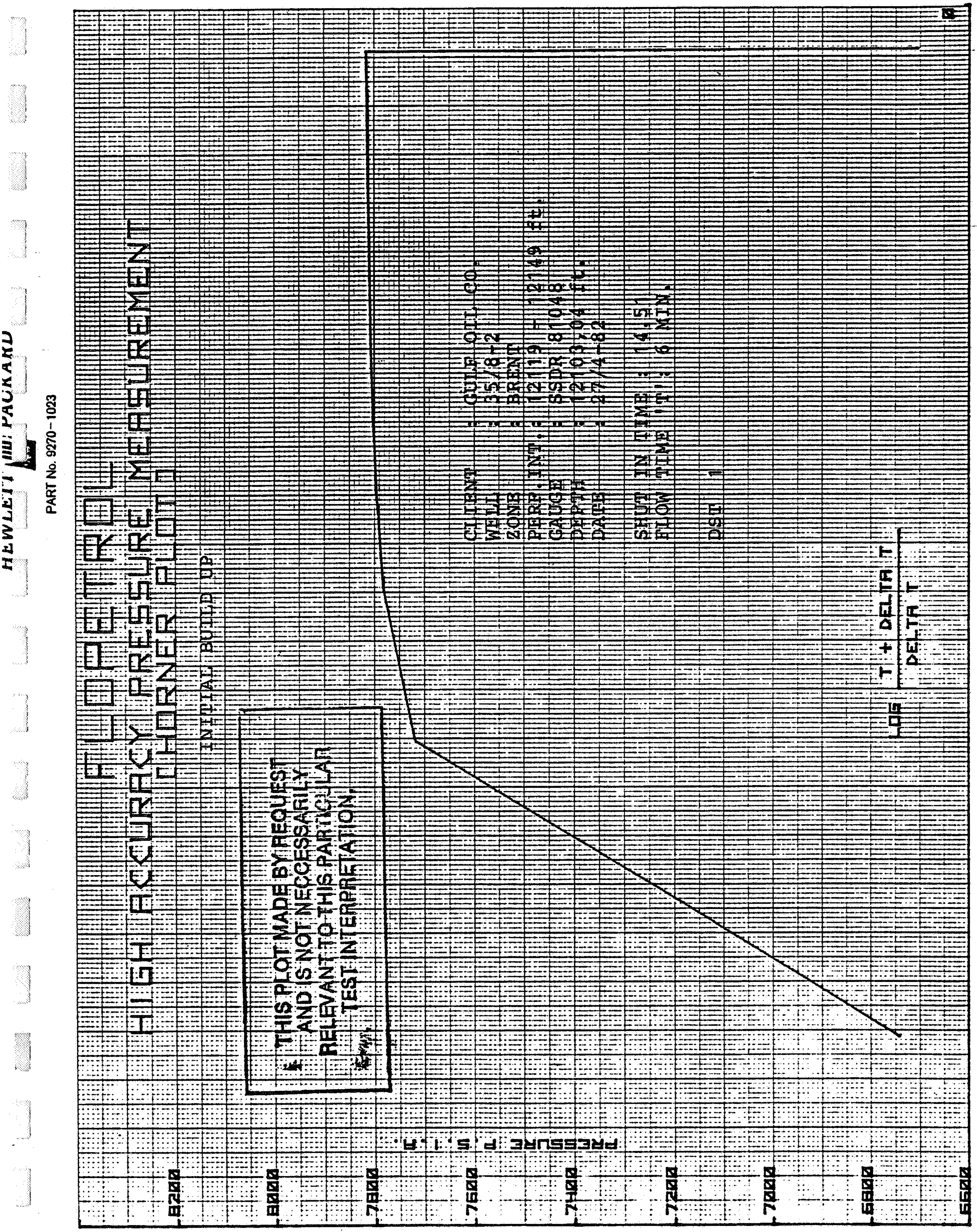

HEWLETT PACKARD
PART No. 9270-1023
FLOPETROL
HIGH ACCURACY PRESSURE MEASUREMENT
HORNER PLOT
INITIAL BUILD UP
CLIENT : GULF OIL CO.
WELL : 3 5/8-2
ZONE : BRENT
PERF. INT. : 12119 - 12149 ft.
GAUGE : SSDR 81048
DEPTH : 12103.04 ft.
DATE : 27/4-82
SHUT IN TIME : 14.51
FLOW TIME 'T' : 6 MIN.
DST 1
THIS PLOT MADE BY REQUEST AND IS NOT NECCESSARILY RELEVANT TO THIS PARTICULAR TEST INTERPRETATION.
PRESSURE P.S.I.A.
8200
8000
7800
7600
7400
7200
7000
6800
6600
LOG (T + DELTA T / DELTA T)

Figure 46

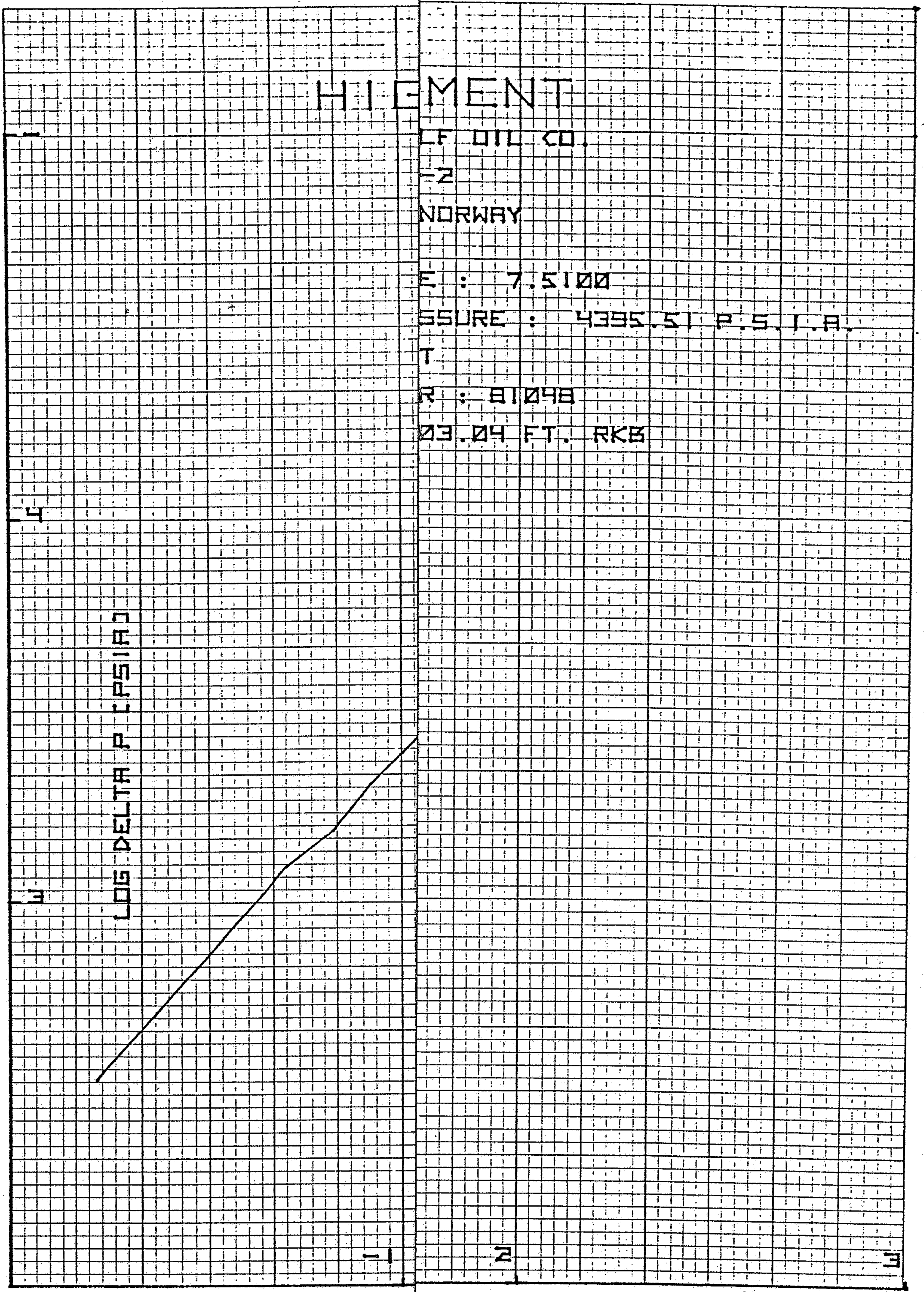
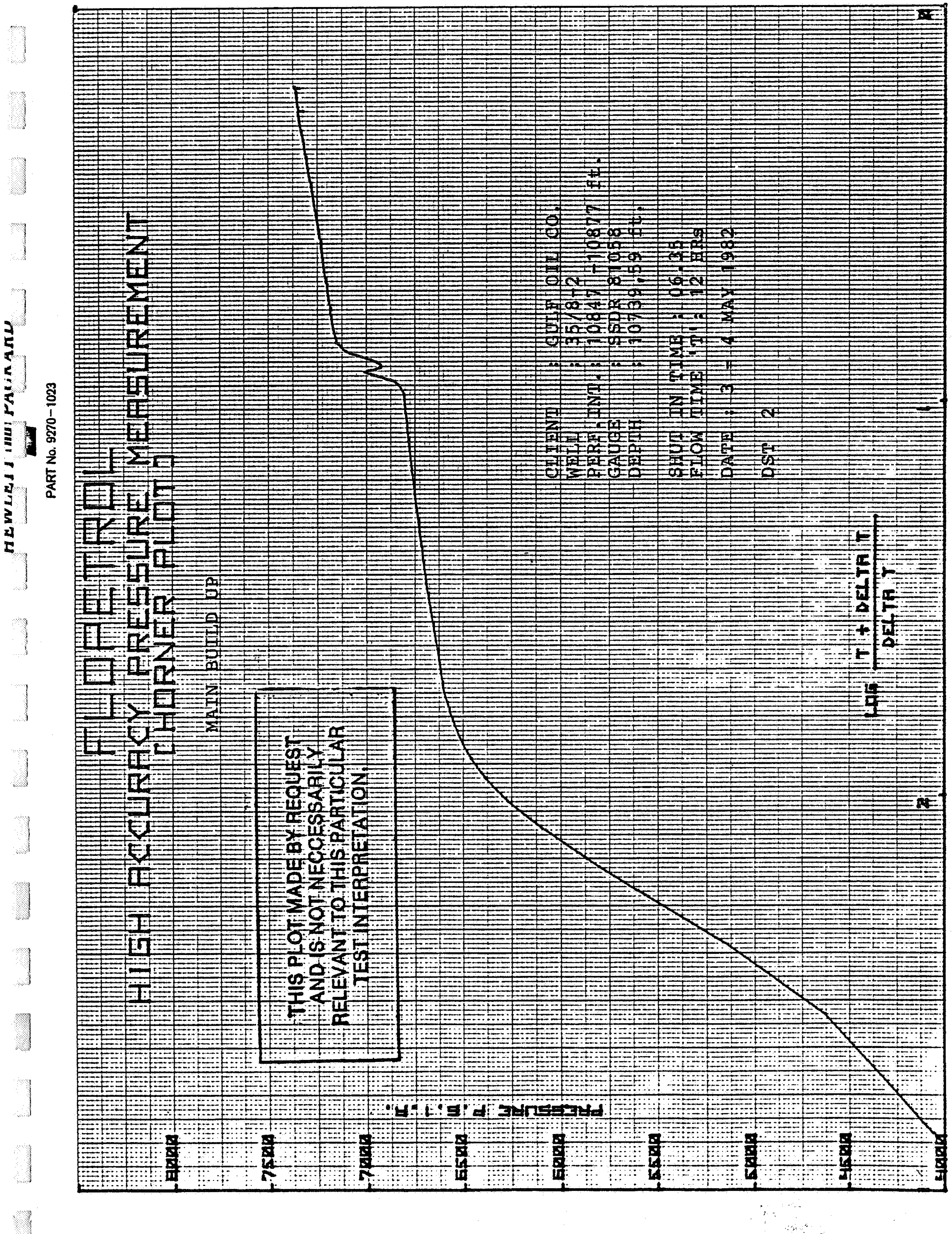

HIGMENT
LF OIL CO.
-2
NORWAY
E : 7.5100
SSURE : 4395.51 P.S.I.A.
T
R : 81048
03.04 FT. RKB
LOG DELTA P (PSIA)
4
3
1
2
3
HEWLETT hp PACKARD
PART No. 9270-1004

Figure 47


HEWLETT PACKARD
PART No. 9270-1023
FLOPETROL
HIGH ACCURACY PRESSURE MEASUREMENT
HORNER PLOT
MAIN BUILD UP
THIS PLOT MADE BY REQUEST AND IS NOT NECCESSARILY RELEVANT TO THIS PARTICULAR TEST INTERPRETATION.
CLIENT : GULF OIL CO.
WELL : 35/8-2
PERF. INT. : 10847 - 10877 ft.
GAUGE : SSDR 81058
DEPTH : 10739.59 ft.
SHUT IN TIME : 06.35
FLOW TIME 'T' : 12 HRs
DATE : 3 - 4 MAY 1982
DST 2
LOG (T + DELTA T / DELTA T)
PRESSURE P.S.I.A.
8000
7500
7000
6500
6000
5500
5000
4500
4000

DISTRICT: EMR/NOB

BASE : STAVANGER

REPORT N°: ELS 82/23

HIGH ACCURACY PRESSURE TEMPERATURE MEASUREMENTS

Company: GULF OIL CO. Country: NORWAY

Field: 35/8 Well: 35/8-2 S.T.1

Zone: HEATHER Date: 14-15 MAY 1982

PERF.INT.: 10846 - 10876 Ft. RKB
10896 - 10917 Ft. RKB

DST 2 A

GAUGE : SSDR 81058

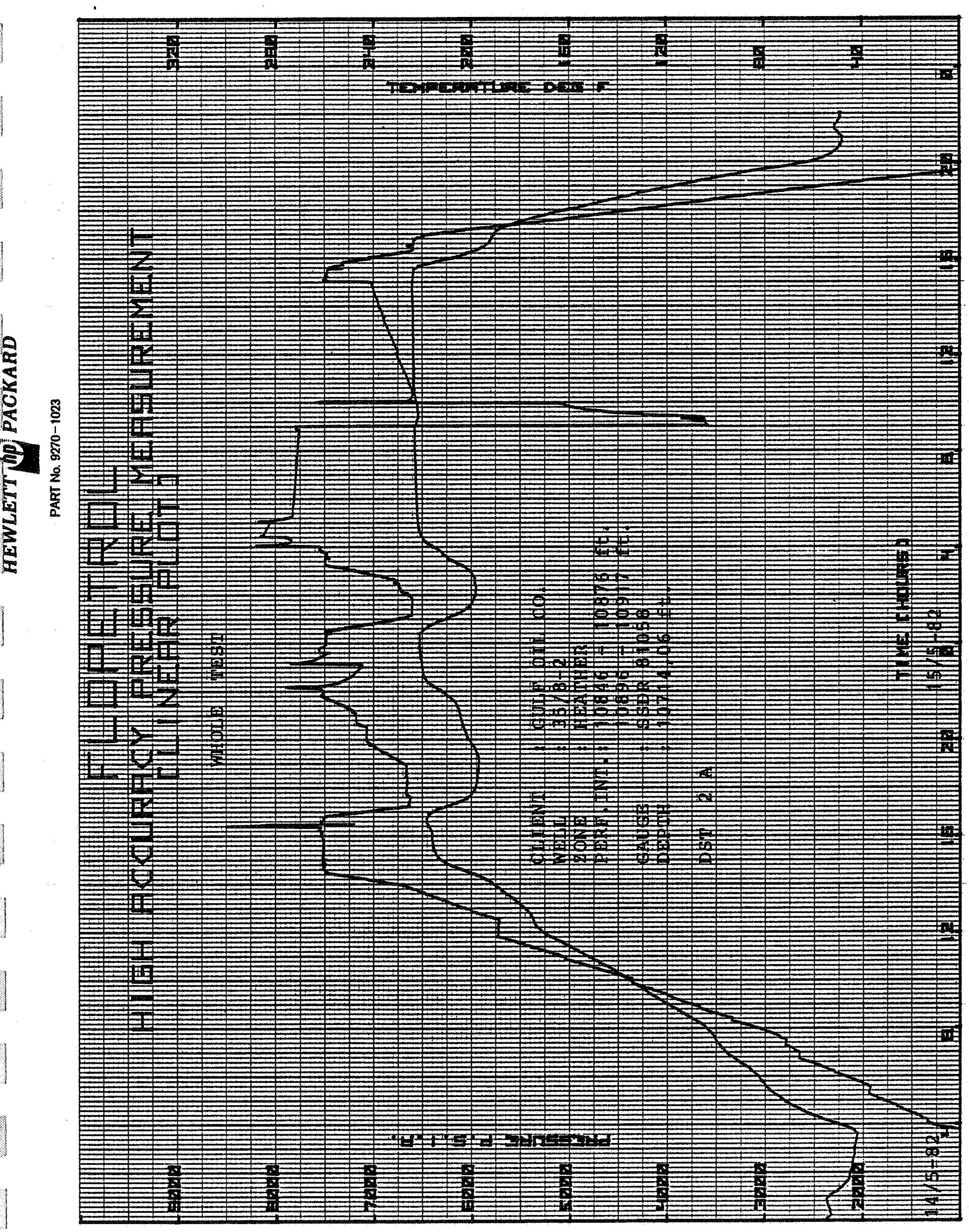

HEWLETT PACKARD
PART No. 9270-1023
HIGH ACCURACY PRESSURE MEASUREMENT
FLOPETROL
LINEAR PLOT
WHOLE TEST
CLIENT : GULF OIL CO.
WELL : 35/8-2
ZONE : FEATHER
PERF.INT. : 10846 - 10876 ft.
10896 - 10917 ft.
GAUGE : SSDR 81058
DEPTH : 10714.06 ft.
DST 2 A
TEMPERATURE DEG F
PRESSURE P.S.I.A.
TIME (HOURS)
14/5-82
15/5-82

Figure 57

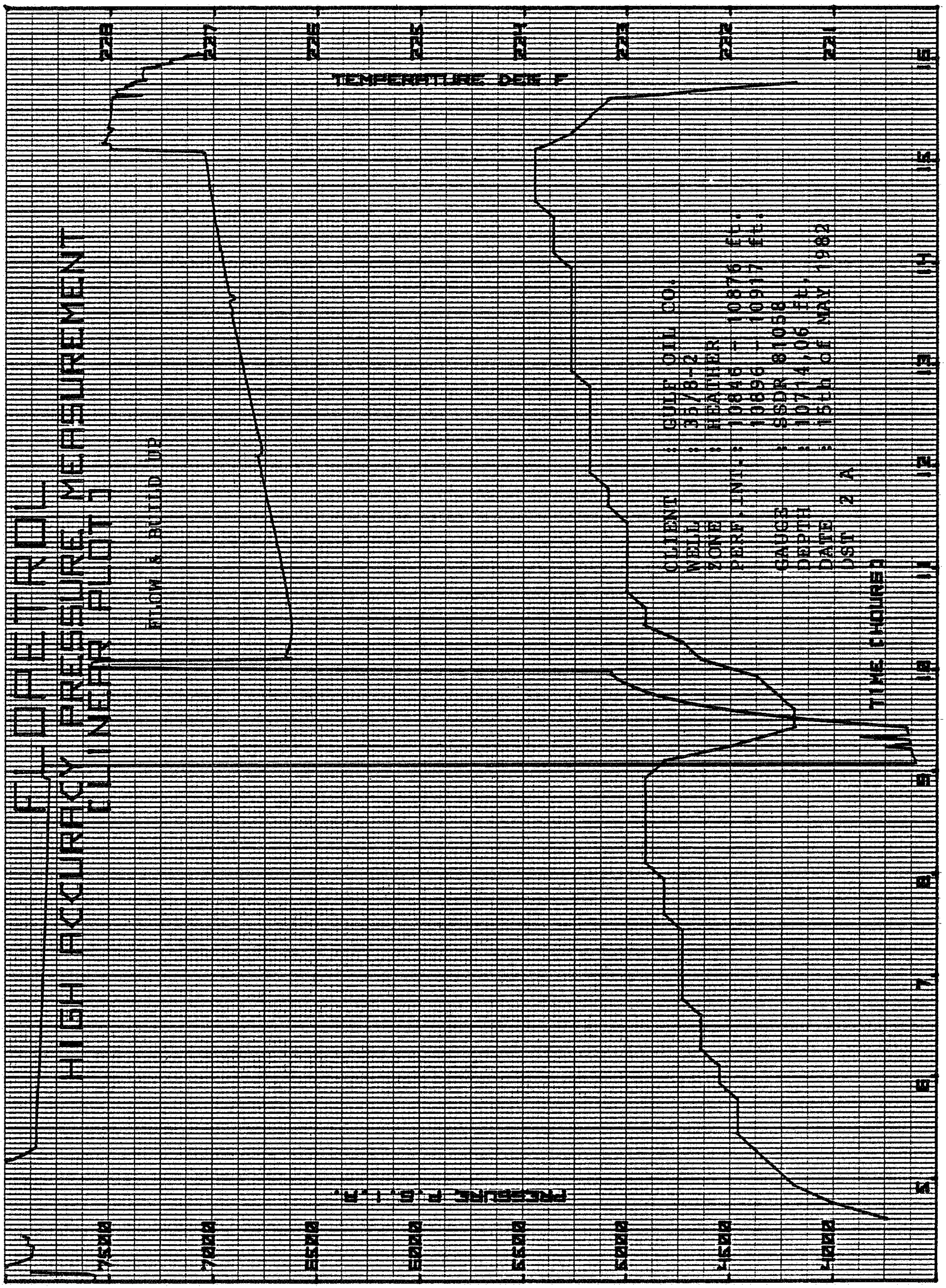

FLOPETROL
HIGH ACCURACY PRESSURE MEASUREMENT
(LINEAR PLOT)
FLOW & BUILD UP
PRESSURE P.S.I.A.
TEMPERATURE DEG F
TIME (HOURS)
7500
7000
6500
6000
5500
5000
4500
4000
228
227
226
225
224
223
222
221
5
6
7
8
9
10
11
12
13
14
15
16
CLIENT : GULF OIL CO.
WELL : 35/8-2
ZONE : HEATHER
PERF.INT. : 10846 - 10876 ft.
10896 - 10917 ft.
GAUGE : SSDR 81058
DEPTH : 10714,06 ft.
DATE : 15th of MAY 1982
DST 2 A

Figure 58

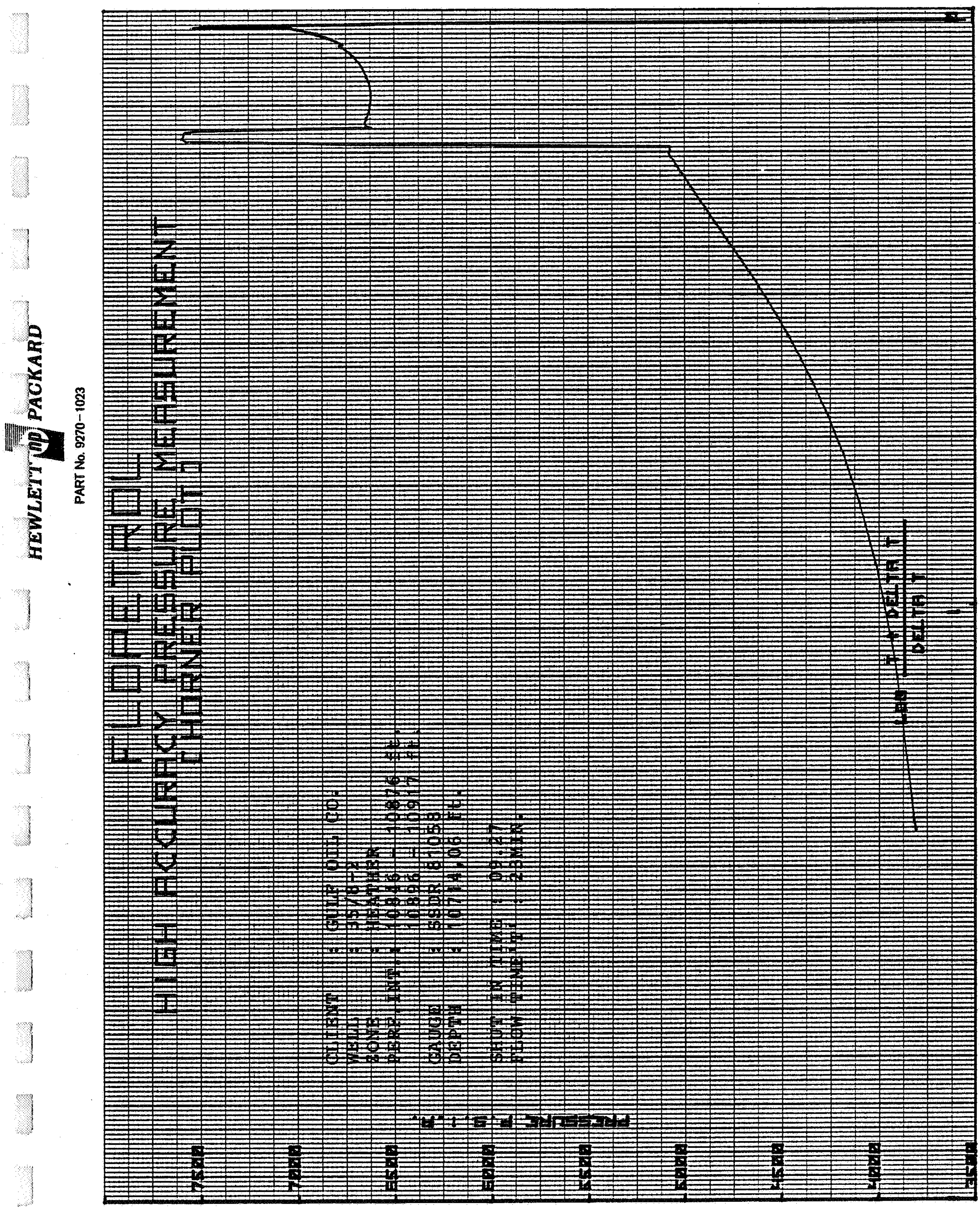

HEWLETT PACKARD
PART No. 9270-1023
FLOPETROL
HIGH ACCURACY PRESSURE MEASUREMENT
(HORNER PLOT)
CLIENT : GULF OIL CO.
WELL : 35/8-2
ZONE : HEATHER
PERF.INT.: 10846 - 10876 ft.
10896 - 10917 ft.
GAUGE : SSDR 8.058
DEPTH : 10714,06 ft.
SHUT IN TIME : 09.27
FLOW TIME : 23MIN.
PRESSURE (P.S.I.A.)
7500
7000
6500
6000
5500
5000
4500
4000
3500
LOG (T + DELTA T) / DELTA T

Figure 59

taken circa. three hours before the end of the flow period.

Because of the gas oil structure of the condensate the well stream was heated to give a condensate temperature of circa. 65°F in the separator at which temperature the oil condensate was a viscous fluid.

Forty minutes before the end of the flow period the separator was by-passed because of a failure in the instrument air system. Twenty minutes later flow was re-established through the separator for the final twenty minutes of the flow period.

PRODUCTION TEST NO. 2A

PERFORATIONS

10896.2' - 10917.5'
10847' - 10876.5'

Perforated with 4" hyperjet guns with 90° phased, 4 shots/ft.

SUMMARY OF EVENTS

After Production Test No. 2 a cement squeeze was done, as results from this test indicated that there was communication from the lower zone.

The interval was perforated and the DST tools run in the hole on 3½" PH6 Hydril Tubing containing 7600' of fresh water cushion with a viscous pill above the APR-N valve. The string was then stung into the packer and the S.S.T.T. landed in the 9 5/8" wear bushing. The string was then pulled and an alteration made to the space out below the S.S.T.T. The string was again run in the hole and stung into the packer. All surface equipment and lines were then pressure tested as per program. The APR-N was opened for 14 minutes, then closed. As there was no indication at the bubble hose, the APR-N was cycled a further twice. As there was still no indication at the bubble hose the string was picked up to open the hydraulic by-pass and landed back in wear bushing. The APR-N was open for two hours and shut in for one hour and eight minutes. The annulus pressure was then increased gradually and the APR-N sheared. The tubing contents were then reversed out to the flare. Seven samples were caught towards the end of the circulation. None of these showed any traces of hydrocarbons.

299

35/8-2

Part of Completion Rep.

21. PVT Condensate Study (Expro)

On receipt of the samples their validity was established by the determination of their saturation pressures at separator temperature (TABLE 8). As can be seen from this table only the third container (TX23-531-HL) gave a bubble point that agreed with the separator pressure, this sample was chosen for further work.

After heat soaking the container for over 2 hours a sample of separator gas was drawn off for hydrocarbon analysis (TABLE 10) The separator liquid was charged to a Ruska visual cell and taken to separator temperature to determine the saturation volume and pressure. This was followed by a flash in single phase to atmospheric conditions (TABLE 9) to give oil and gas for hydrocarbon analysis (TABLE 10).

The field GOR was corrected using laboratory gas gravity and compressibility factors and data used to mathematically recombine the separator products giving a fluid composition (TABLE 10) for the wellstream.

The physical recombination was carried out by injecting liquid into separator gas at the specified ratio. This was carried out in a Ruska "see thru" cell, where a light source is transmitted through the sample to the observation window.

Immediately after recombination the fluid was a bright uniform orange colour, however on reducing the pressure there could be seen considerable movement of bands of different shades of orange within the fluid. This appeared to be a type of phase change and was taken to be a dewpoint of 9445 psia. As this was so far above the reservoir pressure an effort was made to reduce it by injecting more gas, however, this only increased the "dewpoint" to 9571psia in spite of increasing the GLR by over 200%. This dewpoint was extremely indeterminate and did not conform to what normally happens; it was very difficult to fix the pressure.

As part of the investigation programme an attempt was made to produce a volatile oil by injection of a fraction of the full GLR and so obtain a bubble point. The initial ratio used was only 30% of the original GLR, but still it was not possible to obtain a buble point, however there was a clearly defined dewpoint of 5902psia. The dewpoint was marked by a complete blackout which is usually caused by small droplets of liquid forming a cloud in the fluid which occludes the transmitted light. The liquid dropout increased very rapidly below this pressure. As it was impossible to produce a volatile oil except at unrealistically low GLR (0-5%) it was decided to increase the GLR until we reached a dewpoint in the region of the reservoir pressure.

After measuring the GLR to 40% of the original figure the fluid began to behave in a non-typical fashion. At a point 100psi below the dewpoint a large column of liquid had dropped out, however the gas/liquid contact was unusual in that rather than a clearly defined boundary it was diffused and indeterminate. The junction was more like that between two liquids of slightly different densities i.e. whiskey and water than a gas/liquid boundary. The colouring also saw a gradient from a pale yellow at the top of the gas column to a dark orange in the liquid. This continuous change in the intensive properties of the fluid may mean that the fluid was close to its critical point. When the pressure was further reduced the boundary became more clearly defined.

The GLR was gradually increased all the way up to the field ratio, after each gas injection the dewpoint was measured (TABLE 13; FIGURE 65). In between 75 - 100% the dewpoint was again becoming less clearly defined but as we now knew exactly what to look for it was far easier to see. The dewpoint at 100% original GLR was established at 8504 psia, below this pressure liquid dropout became significant. This dewpoint was checked again by recombining on two separate occasions at 90% GLR and again at 100% GLR this confirmed the curve given in TABLE 13; FIGURE 65). The GLR was again increased to see if the dewpoint would decrease, however although the gradient of the curve diminished with increasing GLR it will remained a positive gradient even up to 200% GLR.

A portion of fluid recombined at the full GLR was flashed out of a condensate cell at 9000psia (TABLE 11) to give oil and gas for hydrocarbon analysis (TABLE 12) and a comparison with the calculated wellstream composition showed no significant difference. A pressure-volume relationship was carried out on the remaining recombined fluid; this was achieved by withdrawing known amounts of mercury from the cell, stabilising and recording the pressure (TABLE 14; FIGURE 66). Once the pressure had fallen below the established dewpoint liquid dropout occurred; these liquid volumes were measured and recorded (TABLE 15; FIGURE 67).

A depletion study of the reservoir fluid was carried out at several pressures below the determined dewpoint pressure. At each of these depletion steps the retrograde liquid volumes were measured (TABLE 17; FIGURE 71). The produced gases from each step were measured and analysed on a Perkin-Elmer Gas Liquid Chromatograph. (TABLE 16; FIGURE 68 and 69). During each step a small amount of condensate was collected but the volume from each step was insufficient to enable compositional analysis. However the condensate from all the depletion steps was bulked together to enable an overall compositional analysis to be undertaken. At the end of the depletion study the remaining residual oil was also collected and analysed. This enabled the produced wellstream composition to be calculated.

TABLE 7

Sampling Details

Field	:	Wildcat
Well No.	:	35-8-2
Producing Zone	:	Brent Sands
Perforations	:	12,119' - 12,149'
Sampling Time	:	0537 - 0602
Sample Type	:	Separator Gas and Separator Liquid
Bottom Hole Pressure	:	
Bottom Hole Temperature	:	
Reservoir Pressure	:	7830 psig
Reservoir Temperature	:	272°F
Wellhead Pressure	:	2212 psig
Wellhead Temperature	:	111°F
Separator Pressure	:	640 psig
Separator Temperature	:	84°F
Customers Indentification	:	GULF
Container Nos.	:	Gas TX22-499 TX22-481 TX22-489 Oil TX23-531 TX23-536 TX23-535

TABLE 8

Sample Validity Check

Container No.	Separator Temp. °F	Separator Pressure psig	Saturation Pressure psig
TX23-535-HL	71	640	597
TX23-536-HL	71	640	612
TX23-531-HL	84	640	640

The contact pressure at 60°F of all three separator gas containers (TX22-489-HG, TX22-481-HG, TX22-499-HG) was 600 psig

TABLE 9

Data for Recombination

Separator Gas (TX22-499-HG)

Field Gravity (Air = 1.0)	:	0.674
Lab. Gravity (Air = 1.0)	:	0.686

Separator Oil (TX23-531-HL)

Saturation Pressure at 84°F	:	655 psia

Single Stage Flash at 84°F from 5703 psia to atmospheric conditions

G.O.R. SCF/STB	:	403
Gas Gravity (Air = 1.0)	:	1.155
Oil Gravity at 60°F	:	0.8010 ≡ 45.11°API
Oil Volume Factor Bo[1]	:	1.297

[1] Oil Volume Factor Bo: Oil Volume at Saturation Pressure, Per Volume of Stock Tank Oil at STP

Recombination Conditions

Pressure	=	9000 psia
Temperature	=	272°F
G.O.R (corrected)	=	8337.7 SCF/Sep. Bbl.

TABLE 10

Hydrocarbon Anlaysis of Separator Products
and Calculated Wellstream

Component	Separator Gas	Separator Fluid		Calculated Wellstream	
	Mol %	WT %	Mol %	WT %	Mol %
N_2	0.71	0.11	0.43	0.69	0.69
CO_2	3.24	0.49	1.23	4.81	3.06
C_1	84.48	2.31	15.90	44.71	78.21
C_2	6.55	1.63	5.99	6.97	6.50
C_3	3.20	2.93	7.34	5.62	3.57
iC_4	0.41	0.94	1.79	1.11	0.54
nC_4	0.81	2.92	5.55	2.57	1.24
iC_5	0.15	1.45	2.22	0.87	0.34
nC_5	0.16	2.12	3.24	1.13	0.44
C_6	0.14	3.47	4.45	1.64	0.53
C_7	0.09	7.16	7.89	2.87	0.80
C_8	0.05	8.69	8.40	3.32	0.82
C_9	0.01	5.13	4.42	1.89	0.41
C_{10+}	-	60.65	31.15	21.82	2;85

Average Molecular Weight of C_{10+} fraction = 215

TABLE 11

Reservoir Flash to Stock Tank Conditions

Dewpoint Pressure, psia	:	8504
Temperature ^{o}F	:	272
G.O.R, SCF/STB	:	13,600
Gas Gravity (Air = 1.0)	:	0.735
Oil Gravity at $60^{o}F$	:	0.8134 ≡ 55.77 ^{o}API
Oil Volume Factor Bo_1,	:	7.227

[1] Oil volume factor; oil volume at dewpoint pressure per oil volume of stock tank oil at $60^{o}F$

TABLE 12

Hydrocarbon Analysis from Reservoir Fluid Flash.

Component	Wt. %	Mol. %
N_2	0.68	0.68
CO_2	4.85	3.08
C_1	44.76	78.14
C_2	7.00	6.52
C_3	5.67	3.60
iC_4	1.09	0.53
nC_4	2.63	1.27
iC_5	0.90	0.35
nC_5	1.18	0.46
C_6	1.65	0.54
C_7	2.86	0.80
C_8	3.35	0.82
C_9	1.91	0.42
C_{10+}	21.47	2.79

Average Molecular weight of C_{10+} Fraction = 215

TABLE 13

Dewpoint Vs GOR

Gas Oil Ratio Scf/Sep bbl.		Observed Dewpoint psia
2501	(30%)	5902
3335	(40%)	6775
4169	(50%)	7230
5003	(60%)	7580
5732	(68.75%)	7845*
6670	(80%)	8108
7504	(90%)	8313
8337.7	(100%)	8504 **
12507	(150%)	8981
16675	(200%)	9208

** Dewpoint Pressure

* Reservoir Pressure

TABLE 14

P.V. Relationship During Constant Composition Expansion at 272^{0}F

Pressure psia	Relative Volume V.D.P. = 1.000	Gas Deviation Factor Z
10000	0.954	1.495
9750	0.961	1.467
9500	0.967	1.440
9250	0.975	1.413
9000	0.983	1.386
8750	0.991	1.359
8504 **	1.000	1.332
8000	1.020	
7845 *	1.027	
7500	1.044	
7000	1.072	
6500	1.108	
6000	1.153	
5500	1.208	
5000	1.279	
4500	1.370	
4000	1.491	
3500	1.658	
3000	1.890	
2500	2.226	

** Dewpoint Pressure

* Reservoir Pressure

TABLE 15

Retrograde Condensation During Constant Composition

Expansion at 272°F

Pressure psia	Retrograde Liquid Volume per cent of Dewpoint Volume
** 8504	0.00
8000	0.82
* 7845	1.08
7500	1.76
7000	2.99
6500	4.66
6000	6.90
5500	9.11
5000	10.82
4500	12.11
4000	13.02
3500	13.67
3000	14.13
2500	14.45
2000	14.66

** Dewpoint Pressure

* Reservoir Pressure

TABLE 16

Depletion Study at 272°F

Hydrocarbon Analysis of Produced Wellstream - Mol per cent

Component	Reservoir Pressure, psia				
	7083	5660	4238	2816	1394
N_2	0.70	0.67	0.62	0.60	0.61
CO_2	3.34	3.35	3.32	3.32	3.36
C_1	78.49	79.45	80.63	80.75	80.79
C_2	6.58	6.62	6.68	6.72	6.74
C_3	3.43	3.49	3.55	3.60	3.64
iC_4	0.46	0.48	0.50	0.50	0.50
nC_4	1.12	1.16	1.20	1.24	1.24
iC_5	0.28	0.29	0.32	0.33	0.33
nC_5	0.38	0.39	0.39	0.40	0.41
C_6	0.52	0.48	0.41	0.50	0.51
C_7	0.89	0.75	0.54	0.55	0.59
C_8	0.85	0.66	0.45	0.44	0.43
C_9	0.60	0.44	0.31	0.22	0.18
C_{10+}	2.36	1.77	1.08	0.83	0.67
Gas Gravity (Air = 1.00)	0.730	0.727	0.719	0.735	0.732
Z Produced	1.173	1.051	0.955	0.898	0.926
Wellstream Produced Cumulative % Initial	6.45	15.02	29.07	47.31	69.21
G.P.M. From Smooth Composition					
C_{3+}	4.35	3.81	3.12	3.32	3.00
C_{4+}	3.41	2.85	2.14	2.32	2.00
C_{5+}	2.91	2.33	1.59	1.76	1.44

TABLE 17

Retrograde Condensation During Depletion at 272^{o}F

Pressure psia	Retrograde Liquid Volume per cent of Dewpoint volume
** 8504	0.00
7082	4.03
5660	9.19
4238	13.62
2816	14.83
1394	14.81

** Dewpoint Pressure

TABLE 18

Calculated Cumulative Recovery During Depletion at 272^{0}F

Cumulative Recovery per MMSCF of Original Fluid	Initial in Place	Reservoir Pressure, psia					
		8504**	7083	5660	4238	2816	1394
Wellstream MSCF	1000	0	64.49	150.17	290.65	473.10	692.11
Ambient Conditions							
Stock Tank Liquid - bbls	81.74	0	3.23	6.45	9.68	12.91	16.13
STP Gas - MSCF	916.93	0	61.21	143.61	280.82	459.98	675.72

TABLE [illegible]

Calculation of Stock Tank Liquid Production and Reservoir Precipitation During Constant Volume Production - Part 1

(1)	(2)	(3)	(4)	(5)	(6)
		Gas Oil Ratio			
Reservoir Pressure psia	Produced GOR (SCF/STB)	SCF Reservoir GAS per Bbl. Stock Tank Oil	Bbl Stock Tank Oil per MMSCF Reservoir Fluid	Incremental Reservoir Fluid Production (Fraction)	Incremental Stock Tank Oil Produced (STB/MMSCF Res. Fluid)
** 8504	11,218	12,234	81.74	0.0000	0.00
7083	18,972	19,988	50.03	0.0645	3.23
5660	25,541	26,558	37.65	0.0857	3.23
4238	42,527	43,543	22.97	0.1405	3.23
2816	55,532	56,549	17.68	0.1824	3.23
1394	66,868	67,884	14.73	0.2190	3.23

** Dewpoint Pressure

TABLE 19b

Calculation of Stock Tank Production and Reservoir Precipitation During Constant Volume Production - PART 2

Pressure psia	(7) Cumulative Stock tank oil Produced (Bbl STO/MMSCF Reservoir Fluid)	(8) Fluid reamining in Reservoir (fraction)	(9) Portion of Reservoir Fluid remaining in Vapour Phase - Retrograde (fraction)	(10) Cumulative Portion of original reservoir fluid in vapour phase (fraction)	(11) Cumulative STO reamining in vapour phase (STB/MMSCF Res fluid)	(12) Cumulative STO remaining in liquid phase (STB/MMSCF Res. Fluid)
**8504	0.00	1.0000	1.000	1.000	81.74	0.00
7083	3.23	0.9355	0.9597	0.8978	44.92	33.59
5660	6.45	0.8498	0.9098	0.7732	29.11	46.17
4238	9.68	0.7093	0.8707	0.6176	14.18	57.88
2816	12.91	0.5269	0.8521	0.4490	7.94	60.89
1394	16.13	0.3079	0.8519	0.2623	3.86	61.74

** Dewpoint Pressure

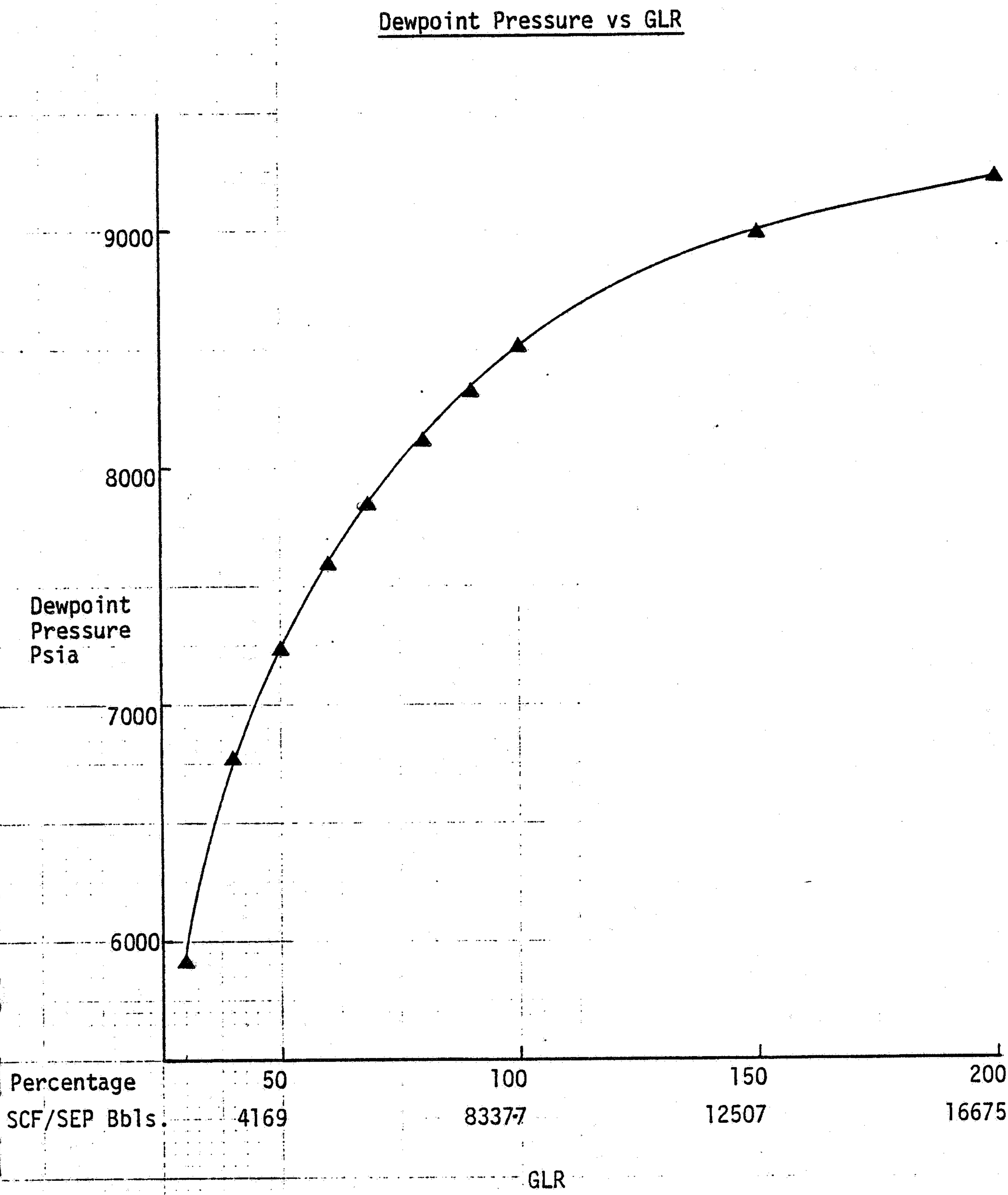

Dewpoint Pressure vs GLR
9000
8000
7000
6000
Dewpoint
Pressure
Psia
Percentage
50
100
150
200
SCF/SEP Bbls.
4169
83377
12507
16675
GLR

FIGURE 65

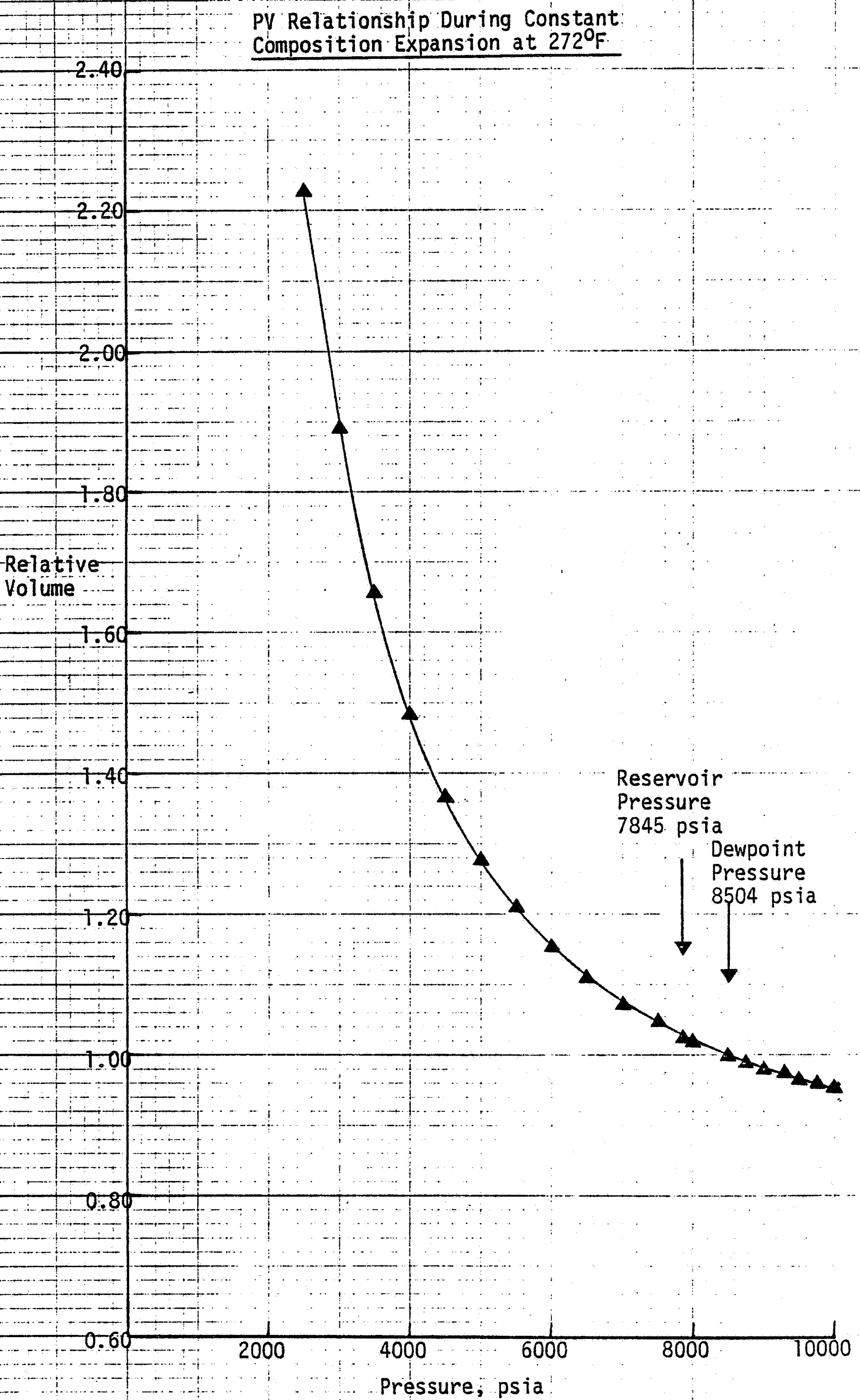

PV Relationship During Constant Composition Expansion at 272°F
2.40
2.20
2.00
1.80
1.60
1.40
1.20
1.00
0.80
0.60
Relative Volume
Reservoir Pressure 7845 psia
Dewpoint Pressure 8504 psia
2000
4000
6000
8000
10000
Pressure, psia

FIGURE 66

Retrograde Liquid Volume per cent of
Dewpoint Volume (DPV) v Pressure
During Constant Composition Expansion at 272^{o}F

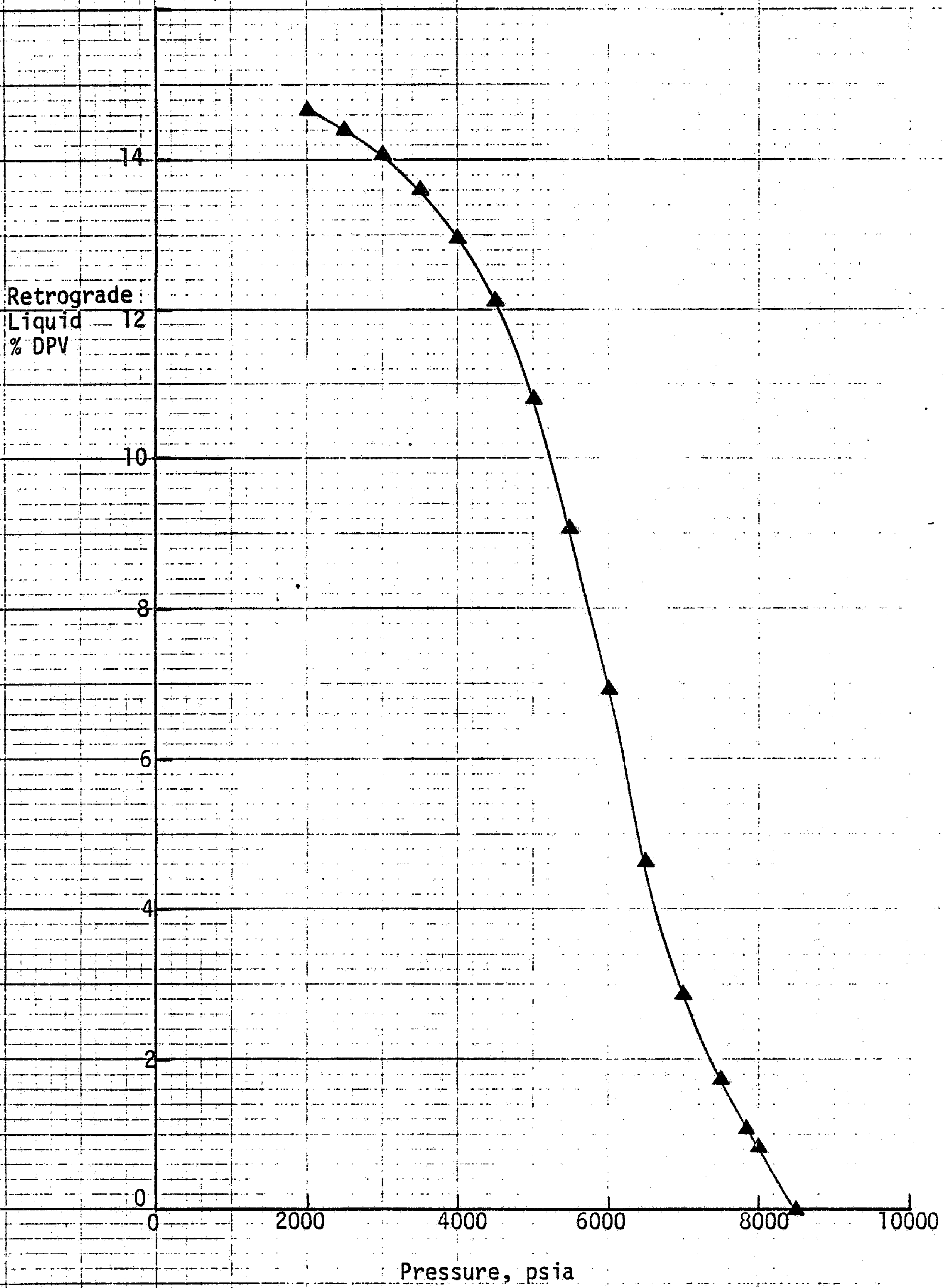


FIGURE 67

Hydrocarbon Analysis of Produced Wellstream
During Constant Volume Depletion at 272°F

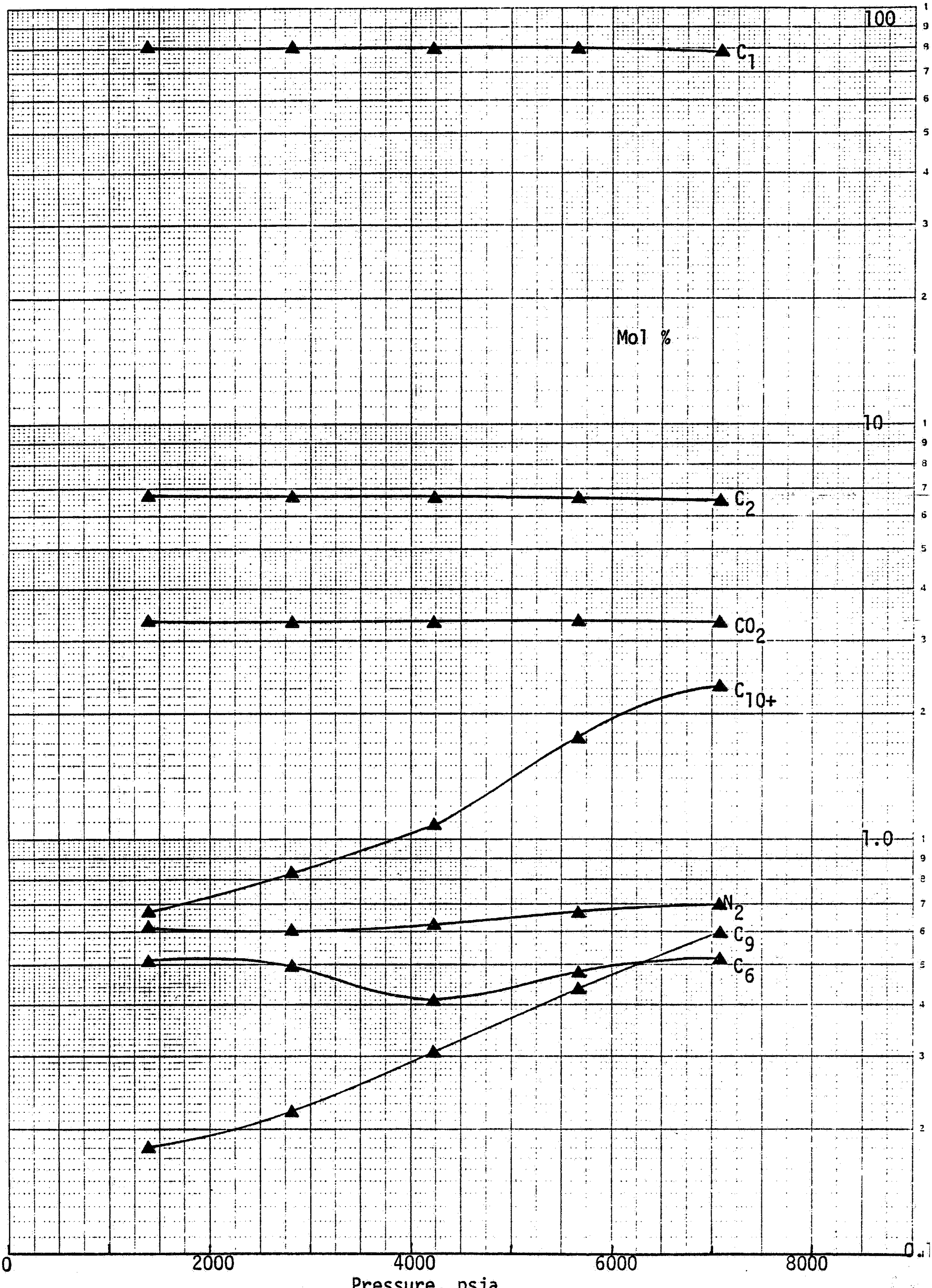
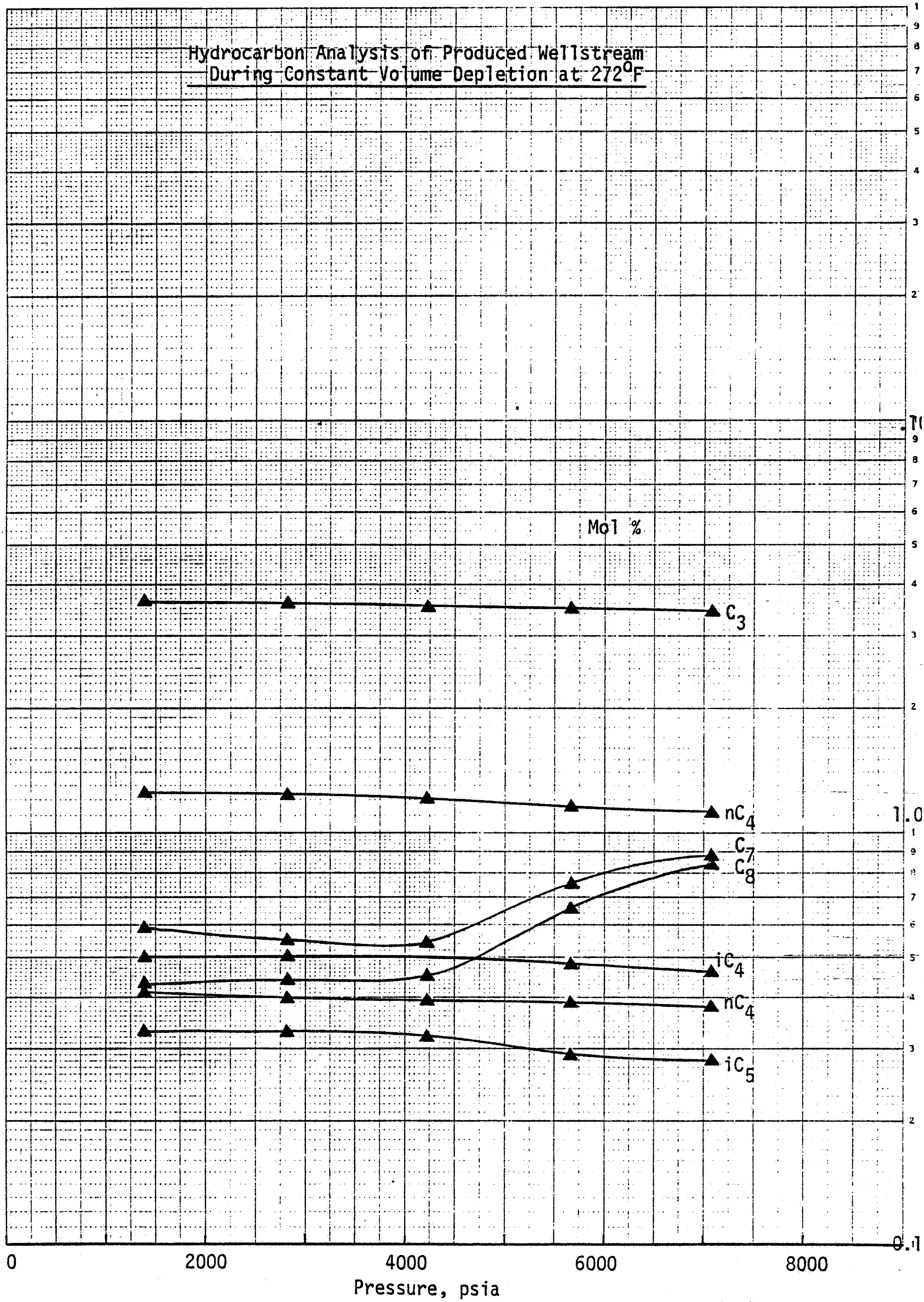


FIGURE 68



Hydrocarbon Analysis of Produced Wellstream
During Constant Volume Depletion at 272°F
Mol %
C3
nC4
C7
C8
iC4
nC4
iC5
1.0
0.1
0
2000
4000
6000
8000
Pressure, psia

FIGURE 69

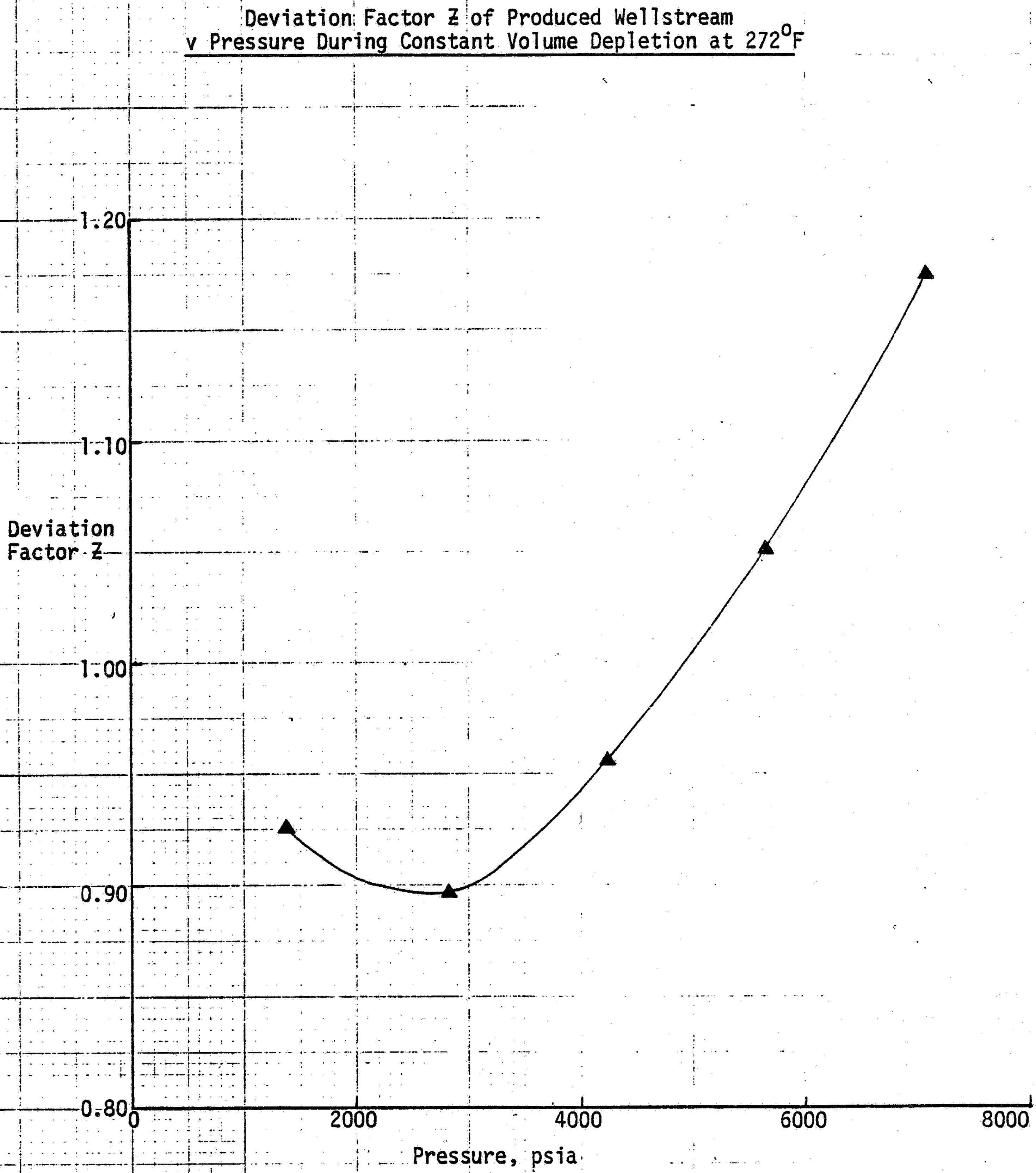

Deviation Factor Z of Produced Wellstream
v Pressure During Constant Volume Depletion at 272°F
1.20
1.10
Deviation
Factor Z
1.00
0.90
0.80
0
2000
4000
6000
8000
Pressure, psia

FIGURE 70

Retrograde Liquid Volume per cent of Dewpoint Volume (DPV) v Pressure During Constant Volume Depletion at 272^{o}F

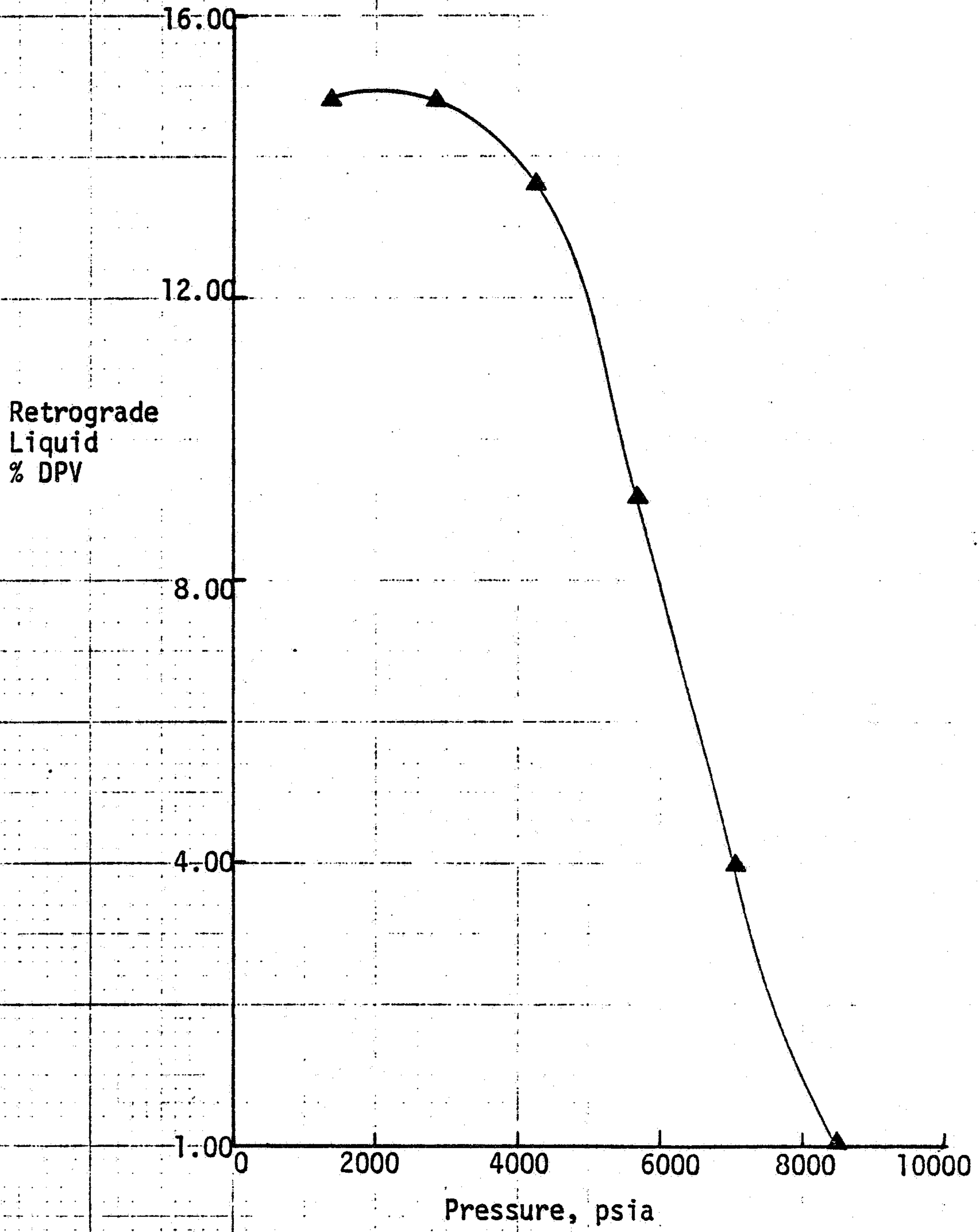


FIGURE 71

Cumulative Volume per cent of Wellstream Produced v Pressure During Constant Volume Depletion at 272°F

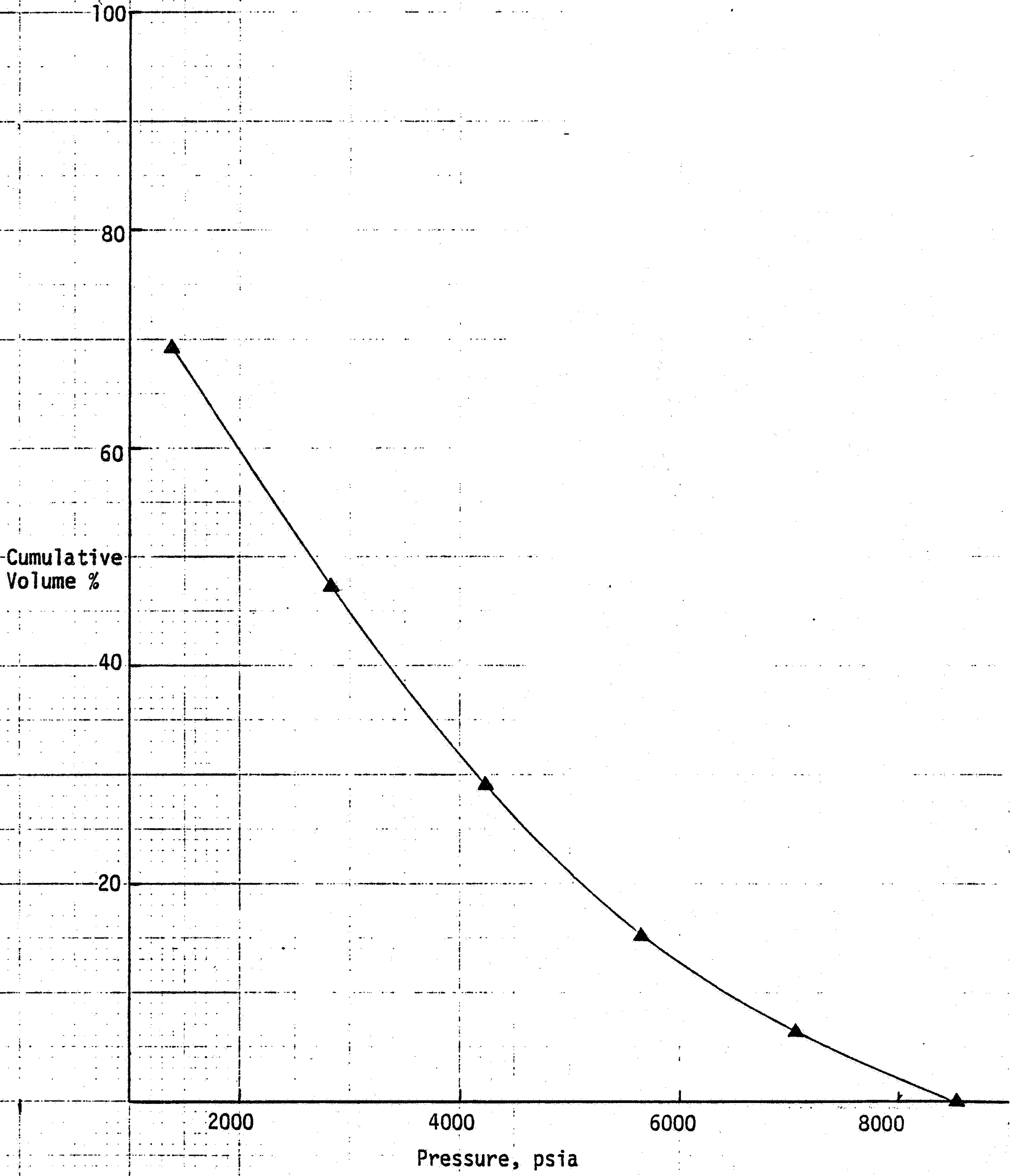


FIGURE 72