(U-443)

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July 1985

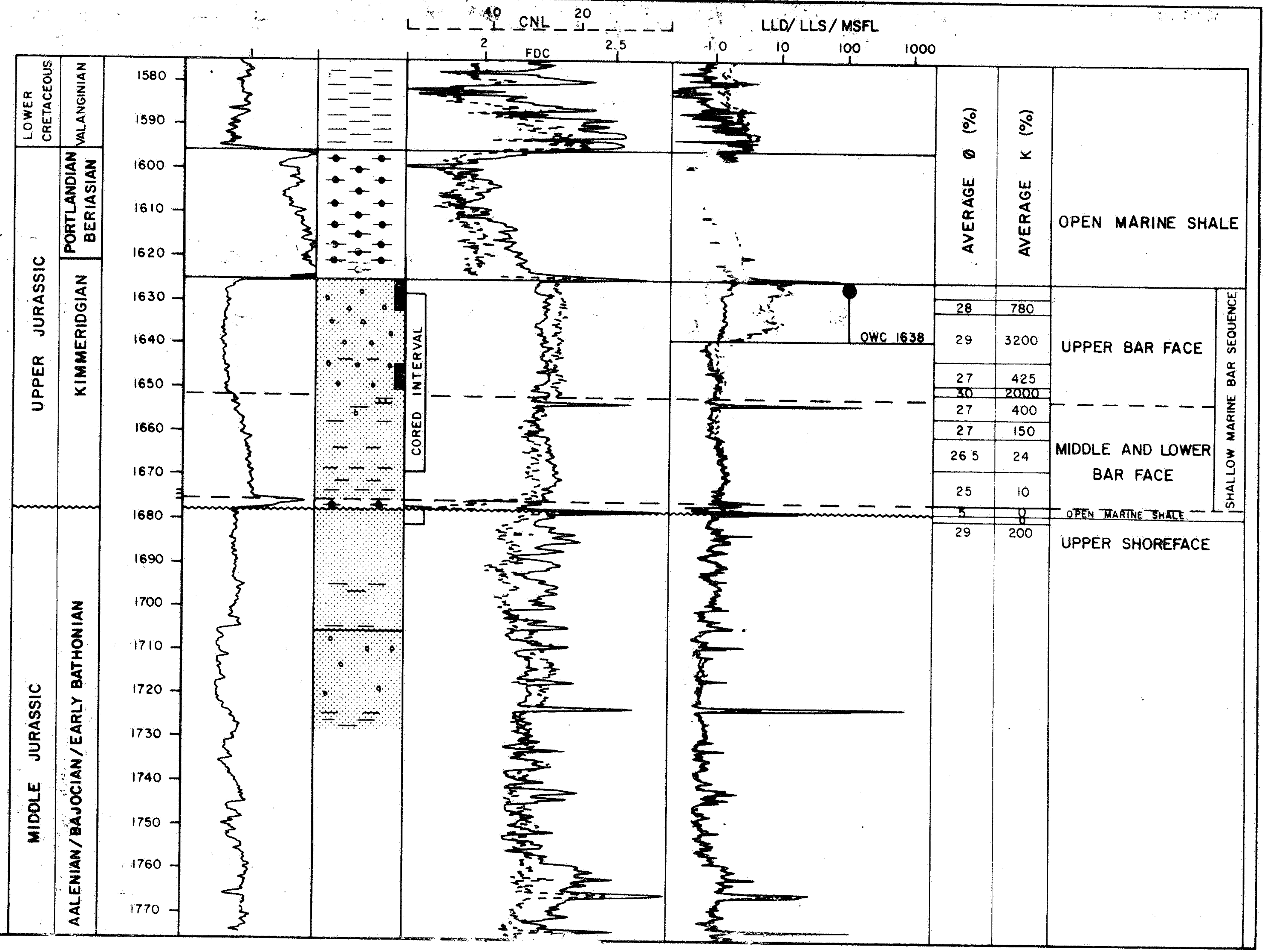
BA-85-3389-1.

Well resumé

6407/9-2

NSEP 238

Enclosures



A/S Norske Shell
EXPLORATION & PRODUCTION FORUS

WELL 6407/9-2 RESULTS

AUTHOR EPPP/21	FIG.	DATE APRIL 85
REPORT NO. NSEP 238	8.1	DRAW. NO. G 1847/11

SWC

Depth (m)	Recovery (mm.)	Lithology
1851,0	empty	
1850,5	15	SST: CLR-WH,MSL-CRSSU,(SRT). ANG-(ANG),(SPH),(CMT)-CMT, CALC CMT,(MIC),(QLC),(ARG)
1845,0	missing	
1835,0	58	SST: CLR-LT GY,FSL-FSL.SRT,ANG-(ANG) (SPH)FRI-(CMT),CALC-ARG CMT,MICROMIC
1827,0	40	CLST: MED DK GY,(SLT),FRM,CMB BRK,MICROMIC, NON CALC
1823,0	missing	
1818,5	47	CLST: MED DK GY(SLT),LOC FSL,FRM,CMB BRK, MICROMIC,NON CALC-((CALC))
1814,0	49	SLTST: MED(BRN)GY,LOC FSL,FRM,CMB-(FIS) BRK,MIC-MIC,CALC IP-(CALC)
1810,0	40	SLTST: MED GY,FSL IP,FRM,CMB BRK,CALC, PYR,(MIC)-MIC.
1800,0	35	SST: LT GY-LOC DK GY.FSL-FSU,SRT,(ANG) -(SND),(SPH),FRI,(CMT),(CALC)+KAOLIN (MIC)-MIC IP.
1794,5	35	SST: CLR-LT GY,FSL-FSU,SRT,ANG-(ANG), (SPH),FRI,(CMT),ARG-KAOLIN CMT,MIC,(GLC)
1787,0	27	SST: CLR-LT GY,FSL-FSU,SRT,ANG-(ANG) (SPH),FRI,(CMT),(CALC)-KAOLIN CMT,MIC, (GLC)
1784,0	28	SST: CLR-OFFWH,FSL-FSL,SRT,ANG-(ANG),(SPH) FRI,(CMT),CALC CMT,ARG-MIC,(GLO)
1780,5	42	SST: CLR-OFFWH,FSU-MSL,SRT,ANG-(ANG),(SPH) FRI,(CMT),(CALC)-KAOLIN CMT,MIC
1778,0	40	SST:CLR-OFF WH,FSL-FSU,SRT,ANG-(ANG),(SPH) FRI,(CMT),KAOLIN CMT,MIC-MIC,(GLC)
1772,0	45	SST: CLR-LTGY,FSL-MSU,SRT,(ANG)-(RND) (SPH),FRI,(CMT),ARG CMT,MIC
1769,0	45	SST: CLR-LTGY, FSL-MSL,LOC CRSSU,SRT;(ANG), (SPH),FRI,(CMT),ARG-KAOLIN CMT,MIC)
1766,0	45	SST: CLR-LT GY,FSL-FSU,SRT,(ANG)-(RND), (SPH),FRI,(CMT),(CALC)-KAOLIN CMT,MIC
1764,0	47	SST: MED GY,FSL-MSL,SRT,ANG-(ANG),(SPH) FRI,(CMT),(CALC)-ARG CMT,MIC
1754,0	50	SST: CLR-LT GY,FSU-MSU,SRT,(ANG)-(RND) (SPH),FRI,(CMT),(CALC)-KAOLIN CMT,(MIC)

Depth (m)	Recovery (mm.)	Lithology
1752,0	53	SST; CLR-LTGY,FSU-FSU,SRT,ANG-(ANG) (SPH),FRI,(CMT),(CALC)-ARG CMT,MIC-(MIC)
1749,5	54	SST: CLR-LT GY,FSL-FSU,SRT,ANG,(SPH) FRI,(CMT),ARG-KAOLIN CMT,MIC-(MIC)
1735,5	38	SST: CLR-OFF WH,FSL-CRSSL,(SRT),(ANG)-(RND) FRI(CMT),KAOLIN CMT,(PYR)
1734,5	45	SST: CLR-OFF WH,FSL-MSU,SRT;(RND),(SPH) FRI,(CMT),KAOLIN CMT,(MIC)
1728,5	33	SST: CLR-LT GY,FSL-FSL,SRT,LOC CRSSL,ANG -(ANG),(SPH),FRI,(CMT),KAOLIN CMT,MIC
1728,0	43	SST: LT-MED GY,FSU-FSU,SRT,(ANG),(SPH), FRI,(CMT),(CALC)-ARG CMT,MIC
1721,5	50	SST: LT-MED GY,FSL-FSL,SRT,(ANG),(SPH) FM,(CMT),CALC-ARG CMT,MIC IP
1720,0	42	SST: CLR-LT GY,FSL-FSU,SRT,ANG-(ANG) (SPH),FRI,(CMT),(CALC)-ARG CMT,MIC
1712,0	lost	
1705,0	45	SST: CLR-LTGY,FSL-FSU,SRT ANG-(ANG), (SPH),FRI,(CMT),(CALC)-ARG CMT,MIC-(MIC)
1701,0	55	CLST: LT(GN) GY,SFT-FRM,CMB BRK IP;(CALC) PYR
1700,0	50	CLST: DK(GY)BRN,(SLT),FRM,CMB-(FIS) BRK,(CALC),MICROMIC
1695,5	45	SST: LT-MED GY,FSL-FSU,SRT,(ANG),(SPH) FRI,(CMT),(CALC)-ARG CMT,MIC-MIC
1693,5	44	SST: LT-MED GY,FSL-FSL,SRT,(ANG)-LOC (RND),(SPH),FRI,(CMT),(CALC)-ARG CMT MIC-MIC
1691,0	47	SST: LT-MED GY,FSL-FSL,SRT,(ANG)-(RND) (SPH),FRI,(CMT),(CALC) - ARG CMT,MIC,(GLC)
1689,0	48	SST: LT-MED GY,FSL-FBU,SRT,(ANG)-ANG (SPH),FRI,(CMT),(CALC)-ARG CMT,MIC
1687,0	41	SST: MED(BRN)GY,FSU-FSU,SRT,ANG-(ANG) (SPH),FRI,(CMT),(CALC)-ARG CMT,MIC
1683,0	48	SST: LT GY,FSL-MSL,SRT,ANG-(ANG), (SPH),FRI,(CMT),(CALC)-(ARG)CMT,MIC-(MIC)
1678,5	lost	
1672,0	50	SST: LT(BRN)GY,FSL-CRSSU,(SRT),(ANG)-(RND),(SPH)-(ELONG),FRI,(CMT)-LOC CMT (CALC)CMT, (MIC),(GLC)

Depth (m)	Recovery (mm.)	Lithology
1656,0	44	SST: LT(BRN)GY,FSL-CRSSU,(SRT),(ANG) -(RND),(SPH),FRI(CMT),(ARG)CMT (MIC),(GLC)
1651,5	36	SST: PA(BRN)GY,FSL-CRSSL,(SRT),(ANG)-(RND),(SPH)-(ELONG),FRI,(CMT),(CALC)-(ARG)CMT,((MIC)),(GLC)
1649,5	35	SST: LT GY-PA (BRN)GY,FSU-FSU,LOC CRSSL,SRT,(ANG)-(RND),FRI,(CMT)-LOC CRSSL,SRT,(ANG)-RND),FRI,(CMT)-LOC CALC CMT,((MIC))
1648,5	36	SLTST: PA BRN,LOC FSL,FRM-MOD HD CMB BRK,CALC-DOL LOC,MICROMIC
1637,0	49	CLST: MED-DK BRN,FRM,(FIS)BRK,(CALC)
1633,0	47	CLST: DK(GY)BRN,(SLT)FRM,(FIS)BRK,((CALC)) -NON CALC,MICROMIC
1630,0	lost	
1627,5	43	CLST: MED,(GY)BRN,MOD HD,CMB-(FIS)BRK NON CALC-(CALC)IP,MICROMIC
1622,0	41	CLST: MED(GY)BRN,FRM-MOD HD,CMB (FIS) BRK,(CALC),MICROMIC
1618,0	15	LST: OFF WH,2A, CHK, MDST-WKST,MOD HD -HD,CMB-ANG BRK,(ARG)
1616,0	34	LST: OFFWH-LT GY,2A,CHK MDST-WKST, MOD HD-HD,CMB-ANG,BRK,ARG,PYR
1612,0	35	LST/MRL: LTGY -PA(GRN)GY,IA,COPT MDST MOD HD,CMB BRK,ARG,(PYR)
1611,0	25	LST: CRM,IA,COPT MDST,TRANSLUCIP,HD ANG BRK,(ARG),(PYR)
1608,5	52	CLST: RED BRN,SFT-FRM,PLAS,LOC CMB BRK,CALC,MICROMIC
1604,0	41	MRL: PA(GRN)GY,FRM,CMB BRK,CALC,ARG, PYR IP ,MICRO MIC
1602,5	53	CLST: RED BRN,SFT-FRM,PLAS-CMB BRK, CALC,MICROMIC IP
1594,5	42	MRL: PA(GRN)GY,FRM,CMB BRK,CALC, ARG PYR IP
1589,0	52	CLST: DK-(GRN)GY,SFT-FRM,PLAS-CMB,BRK, NON-(CALC)
1586,5	59	CLST: MED(GRN)GY,FRM-MOD HD ,CMB BRK,NON-(CALC),MICROMIC IP

Depth (m)	Recovery (mm.)	Lithology
1579	45	CLST: MED(GRN)GY,FRM,CMB BRK, CALC,MICROMIC IP
1572	52	CLST: GY - LT (BRN) GY WITH LT(GN), GY STREAKS SFT, CMB, BRK, (SLT) (GLAUC), NON CALC.
1571,5	27	CLST: GY - GY BRN, SFT, (SLT), NON CALC
1556	50	CLST: GY - DK GY, SFT, (SLT), NON CALC
1471	45	CLST: GY - (GN)GY, - SFT, (SLT), NON CALC
1455,5	46	CLST: GY - LT(GN)GY, SFT, (SLT), NON CALC
1451,5	47	CLST: GY-MOD GY, SFT, (SLT), (MIC), (CALC)
1441,5	34	CLST: GY-(BRN)GY, SFT, (SLT), (MIC), (CALC)
1441	52	CLST: GY_(BRN)GY, SFT, (SLT), MIC, ((CALC))
1427,5	55	CLST: GY-(BRN)GY, SFT, (SLT), (MIC), ((CALC))
1426,5	55	CLST: GY-(BRN)GY, SFT, SLT, (MIC), NON CALC
1386	46	CLST: MED GY-GY, SFT, (SLT), (MIC), ((CALC))
1384	53	CLST: GY-(BRN)GY SFT,(SLT), (MIC), (CALC)
1365	57	CLST: GY-(BRN)GY, SFT, (SLT),(MIC),((CALC))
1355	60	CLST: LTGY - LT(GN)GY SFT(SLT)(MIC) ((CALC))
1316	50	CLST: MED GY, SFT, (SLT), (MIC), NON CALC
1227	20	CLST: MED GY, SFT, (SLT), NON CALC
1221	10	CLST: GY-(GN)GY, SFT, (SLT), NON CALC
1215	15	CLST: GY-(GN)GY, SFT, ((CALC))
1212,5	52	CLST: GY-(BRN)GY, SFT, (SLT), ((CALC))
1202	40	CLST: GY-(BRN)GY, SFT, HYGROTURGID, (SLT)((CALC))
1194	45	CLST: GY-(BRN)GY, SFT, HYGROTURGID, (SLT), ((CALC))
1169,5	47	CLST: LTGY - GY, SFT, HYGROTURGID, (SLT) NON CALC
1049,5	15	CLST: GY-(BRN)GY, SFT, HYGRITURGID, NON CALC
1037,5	15	CLST: GY-(GN)GY, SFT, HYGROTURGID, ((CALC))
937	15	CLST: GY-(BRN)GY, SFT, HYGROTURGID

Depth (m)	Recovery (mm.)	Lithology
		((CALC))

1. Introduction

Well 6407/9-2 is located 4 km north of well 6407/9-1 in the northern part of the structure.

The main objective of the well were:

i) to improve confidence in the estimation of oil in place
ii) to evaluate the reservoir quality and sand development on the northern flank of the structure.
iii) calibration of seismic time pick and velocity model
iv) to evaluate the oil deliverability and water injection characteristics.

The coordinates of the final location were:

$64^{o}24'$ 01.31" N
$07^{o}48'$ 11.26" E

The well was spudded on 18 November 1984 and reached TD of 1865 mbdf in the Lower Jurassic Middle Drake equivalent. The well encountered light oil (40 API) in sandstones of the Upper Jurassic Frøya Formation. A water injection test and a production test were carried out; a maximum oil rate of 7400 BPD was achieved. The well was plugged and abandoned on February 1, 1985.

Well 6407/9-2

Summary of Well Data:

Well Classification	:	Appraisal well
Location coordinates	:	N 64° 24' 01.31"N
(final)		E 07° 48' 11.26"E
Water depth	:	247 m
Derrick Floor Elevation	:	25 m
Contractor/Rig	:	Dolphin Services A/S, "Borgny Dolphin"
BOP-Stack	:	10 000 psi, 18 3/4"
Mudlogging Contractor	:	Geoservices
Start of Operations	:	15.11.84
Spudded	:	18.11.84
Completed	:	02.02.85
Objectives	:	Upper Jurassic Frøya Formation
Total depth	:	1865 m drillers depth 1863 m (logger's depth)
Formation at TD	:	Middle Drake equivalent
Results	:	Oil produced from Upper Jurassic Frøya Formation
Tested interval	:	1651-1657 mbdf (production test) 1670-1775.5 mbdf (injection test)
Maximum rate	:	7400 BOPD
Oil gravity	:	40°API
Present Status	:	Plugged and abandoned
Casing Record	:	30" csg : 346 mbdf 20" csg : 800 mbdf 13 3/8" csg : 1575 mbdf 9 5/8" csg : 1852 mbdf

Norske Shell commissioned A/S Geoteam to conduct a marine rig site survey. The field work was carried out during the period 10-13 September 1984.

The purpose of the survey was to provide information on the seabed conditions and shallow geology within the survey area, with particular emphasis on the identification of hazards such as seabed obstructions, shallow gas-pockets, burried channels, faults etc. which could cause problems during the drilling of the proposed well.

Echosounder and side-scan sonar were used to map bathymetry and seabed features. A deep-towed sparker and a analog sparker were used to investigate the shallow strata. To investigate the deeper strata a grid of multichannel digitally recorded airgun lines were surveyed.

1. SITE SURVEY SUMMARY

Location:	Haltenbanken 6407/9-2
Proposed position:	Latitude 64^{o} 24' 00.8" Longitude 07^{o} 48' 10.4"
Water depth at proposed location:	240 metres (MSL)
Seabed slope at proposed location:	Approximately 3 degrees NNE
Seabed condition:	Seabed is heavily scoured by icebergs
Seabed hazards:	None.

Sub seabed conditions:

240-271 m	Stiff glaciomarine clay.
274 m	Sand layer with gas.
277-320 m	Layers of clay, silt and sand.
320-341 m	Hard clay
341 m	Sand layer with gas.
349-394 m	Hard clay
394 m	Sand layer with gas.
394-441 m	Layers of sand, silt and clay.
441-1790 m	Soft tertiary claystones with silt and sand layers.

Drilling hazards: Possible drilling hazards are gas charged sandlayers at 274 m, 341 m and 394 m (355 msec, 421 msec, 478 msec).

NAVIGATION AND POSITIONING

OF

BORGNY DOLPHIN

WELL 6407/9-2

A/S NORSKE SHELL

REPORT NO. 9868

DECEMBER 1984

Prepared by

A/S GEOTEAM
1320 Stabekk
Norway

C O N T E N T S

A P P E N D I C E S

1. INTRODUCTION

1.1 GENERAL

The drilling rig BORGNY DOLPHIN was navigated from old location at Well 31/2-15 to new location at Well 6407/9-2 using Syledis and Decca Main Chain. Final position was derived from satellite data.

Both operations were undertaken by A/S GEOTEAM in the period 10 November to 20 November 1984.

Final position Well 6407/9-2, was:

CO-ORDINATES			
Geographic		UTM	
Latitude	64° 24' 01.31" N	Northing	7 142 349.8 m
Longitude	07° 48' 11.26" E	Easting	442 297.1 m

The co-ordinates refer to European Datum 1950, UTM projection, Zone 32 with central meridian 09 degrees east.

Observations	: 53 accepted 3-D satellite passes included in final position.
Time	: Observations completed at 1440 hours, 20 November 1984.
Rig Heading	: 263 degrees.
Deviation	: The rig is 2.9 metres in direction 47.5 degrees from intended location.
Personnel	: A. Morse, O. Nordgaard.
Client's Representatives	: J.Christiansen, D.Cursiter.

1.2 FIELD LOG SUMMARY

All times refer to Local Norwegian Time

Mobilization at Flesland, Bergen.	1540 hours 10 November 1984
All navigation equipment operational	1400 hours 11 November 1984
Borgny Dolphin leaves location 31/2-15	1910 hours 15 November 1984
First anchor dropped	1354 hours 17 November 1984
Last anchor dropped	1825 hours 17 November 1984
Start of 3-D satellite computation	0300 hours 18 November 1984
Syledis and Decca equipment and Geoteam surveyor leave rig	1315 hours 18 November 1984
End of 3-D satellite positioning	1440 hours 20 November 1984
Demobilization in Kristiansund.	1740 hours 20 November 1984

2. NAVIGATION

2.1 GENERAL

While in transit from Troll Field, Well 31/2-15 to the new location in Block 6407/9-2 navigation was by Decca Main Chain together with a Magnavox MX-1502 Satellite Receiver operated in navigation mode. For the final approach to location, navigation was by Sercel Syledis utilizing the A/S GEOTEAM Haltenbanken Syledis Chain.

2.2 INTENDED LOCATION

Intended location, referenced to the European Datum 1950, was:

CO-ORDINATES

Geographic		UTM	
Latitude	64° 24' 01.24" N	Northing	7 142 347.8 m
Longitude	07° 48' 11.10" E	Easting	442 295.0 m

The UTM co-ordinates refer to Zone 32 with central meridian 09 degrees east.

2.3 SYLEDIS CHAIN DETAILS

At present the A/S GEOTEAM Haltenbanken Syledis Chain consists of five stations whose details are as follows:

BEACON STATION	NORTHING	EASTING	HEIGHT
Sklinna	7 232 655 m	593 436 m	40 m
Kopparen	7 075 897 m	536 372 m	485 m
Slettringen	7 060 218 m	463 591 m	48 m
Ross Isle	7 229 359 m	393 595 m	90 m
Halten	7 116 546 m	519 805 m	39 m

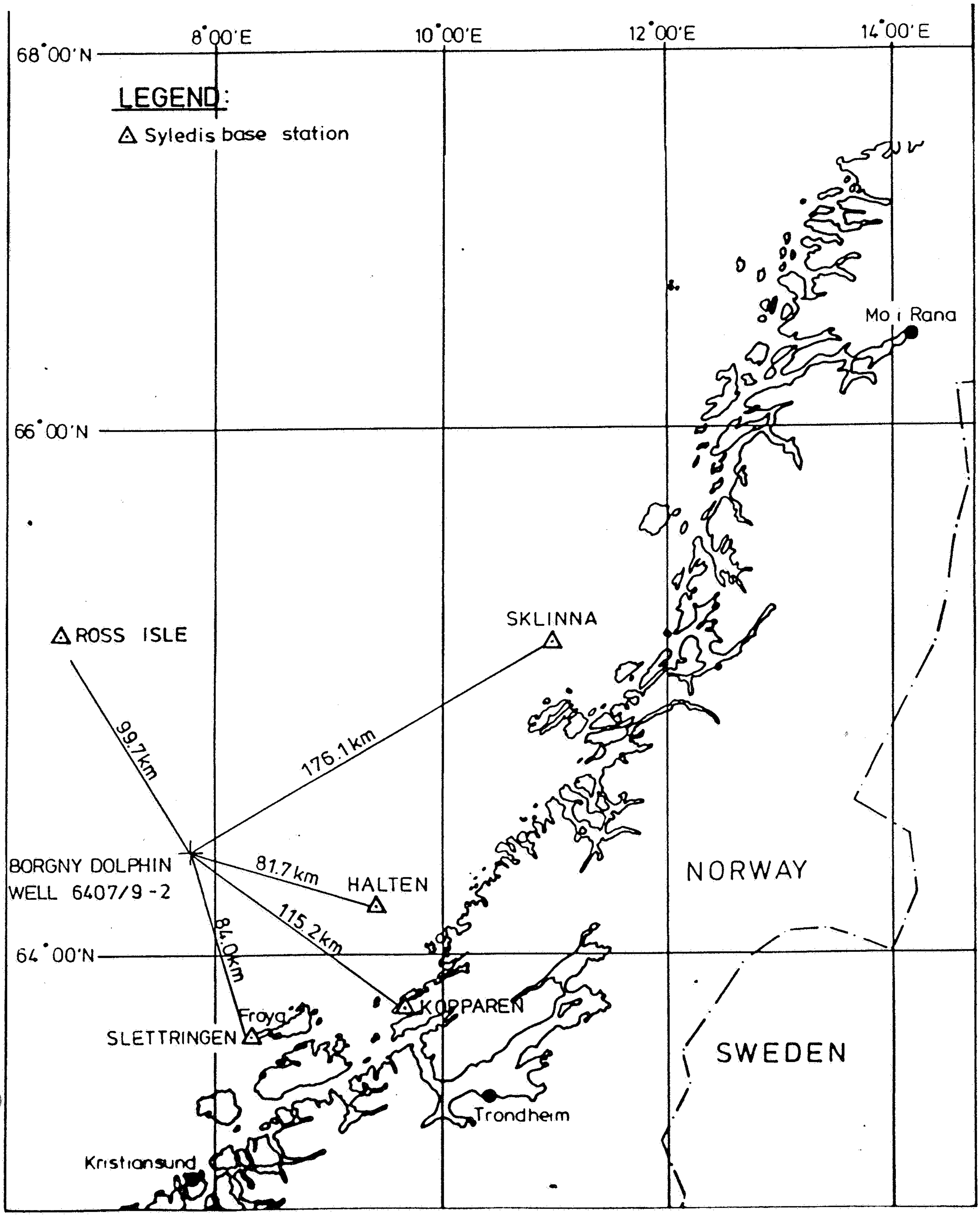
The following details are relevant to location 6407/9-2:

BEACON STATION	DELAY	RANGE	L.O.S.*	BEARING
Sklinna	-312.2	176.1 km	3.2	59.1°
Kopparen	-307.7	115.2 km	1.0	125.1°
Slettringen	-319.7	84.9 km	1.5	165.3°
Ross Isle	-449.75	99.7 km	1.5	330.5°
Halten	-326.9	81.7 km	1.5	108.2

*Line of Sight ratio = Distance /3.57 (h onboard + h remote).

The stations chosen for the 3 range fix were Slettringen, Halten and Kopparen which provided a favourable angle of cut at location. The strength of signals from Kopparen and Slettringen was good while from Halten the signal strength was rather variable. The standard deviation of the three way fix was between 7 m and 10 m. This is high for Syledis but similar results were obtained using different station combinations.

The map below shows the Syledis beacon station locations:



2.4 IN TRANSIT AND APPROACH TO LOCATION

While in transit from the Haltenbanken Field, the rig was navigated by means of a Decca Main Chain Receiver. The receiver provided continuous position fixing through the display of latitude and longitude. In addition, it provided bearing and distance to intended location and average speed.

Overall the Decca system performed well, the only exception being as the rig passed the boundary between the OE chain and the 4E chain. During this time the Sjark receiver could not lock into either chain for a period of approximately 2 hours.

The Magnavox MX-1502 Satellite Receiver was operated in Navigation Mode. In this mode the receiver computes a continuous rig position based on the updated position from the last satellite pass and the rig's speed and heading which are manually input by the user.

Provided the rigs speed and heading were updated regularly the MX 1502 gave a good agreement with the position from the Sjark Decca receiver.

For the final approach to location and manouvering with anchors a Sercel Syledis Navigation System operating in range mode and utilizing the SYLMID 1984 Syledis Chain. The Syledis Receiver was interfaced to a Hewlett Packard 9845 S computer for computation of real time position, graphic display and data recording.

The Syledis antenna was mounted at the top of the derrick and connected to the receiver in the wheelhouse by a calibrated cable. Details of the antenna offset from well centre are given in Appendix 2. The system was operational at 1400 hours on Sunday, 11 November and was checked using stations on the SYVEST Syledis Chain.

At 0800 hours on 17 November the Syledis mobile on board Borgny Dolphin took over broadcast of chain synchronization for the Haltenbanken chain from the seismic vessel Emerald. Unfortunately no signals could be received from station Slettringen, so the mobile was switched onto another set of timeslots. The system was operating satisfactorily by 0900 hours, 17 November.

The approach to location was made along the heading of anchor No. 5 which was the fist anchor to be dropped. A 4 nautical mile line running up to location through anchor No. 5 was plotted on the computer screen. The rig turned onto this line at 1255 hours, 17 November and No. 5 anchor was dropped at 1354 hours. The rig was stopped at location by 1425 hours.

All eight anchors had been run by 1825 hours and ballasting of the rig to operating draught was completed at 2315 hours when the tension test started. All anchors except No. 2 were holding, and so No. 2 anchor was reset and piggy backed. The tension test was satisfactorily completed at 0245 hours on 18 November.

Logging of Syledis and final satellite positioning commenced at this point with the rig in its final accepted position. Logging of Syledis was completed at 0813 hours 18 November when the Syledis and Decca Main Chain equipment was demobilized.

2.5 SYLEDIS STATISTICAL ANALYSIS

Below is a summary of all the logged Syledis ranges with their mean values and standard deviations.

Beacon Station	Number of Readings	Mean Range	Standard Deviation	Readings Omitted
Kopparen	898	115537.4 m	0.8 m	5
Slettringen	898	85201.7 m	0.5 m	5
Halten	847	82062.9 m	1.6 m	56

Readings which deviated by more than 3 sigma from the mean values were omitted from the computation.

By applying a least squares adjustment to the mean ranges, minimizing the range residuals, and applying the antenna offset, the well centre coordinates, referenced to the European Datum 1950 have been calculated:

CO-ORDINATES

Geographic		UTM	
Latitude	64° 24' 01.32" N	Northing	7 142 350.3 m
Longitude	07° 48' 10.36" E	Easting	442 285.1 m

The UTM co-ordinates refer to Zone 32 with central meridian 09 degrees east.

This gives a position 10.2 metres in direction 283.1° degrees from intended location. (See Appendix 3).

During the run-in and final positioning onto location, the AGC values on the Syledis receiver were monitored. AGC values of stations Slettringen and Kopparen were stable but the AGC of station Halten was seen to vary somewhat. The following values are typical:

Beacon	AGC(%)
Slettringen	40
Kopparen	52
Halten	25-35

An AGC value of 50% is considered to be good while an AGC value of 15% is taken to be the lowest usable value for a station.

The one sigma value of the three way fixes during the run-in and positioning was rather poor typically 7-10 metres, but the stability was good.

After a least squares adjustment of the mean Syledis ranges, the standard error of observation of unit weight, one sigma, was found to be 7.8 metres with residuals as follows:

Beacon Station	Residual
Kopparen	-6.0 m
Slettringen	2.1 m
Halten	4.6 m

These values are larger than would have been expected from a Syledis system. Also the fact that the residual values are large compared to the standard deviations of the recorded ranges indicates some systematic error in the system. One likely explanation is that one of the pieces of cable from the antenna to the mobile has been incorrectly calibrated which would mean the applied delays would be in error.

3. FINAL POSITIONING WITH SATELLITE DATA

3.1 OBSERVATIONS

The final position of BORGNY DOLPHIN was derived from recorded data from satellite observations, using the point positioning method. This method is the process of collecting data from multiple satellite passes at one location, along with predicted ephemeris, to determine the independent station position. Accuracy of the final position is largely dependent on the quality of the orbital prediction process. Sources of error are ionospheric and tropospheric refraction, movements of the antenna during the observation period, imbalance in satellite passes, reflection of signals, elevation of the satellites, etc.

The MX-1502 Geoceiver tracks signals from the TRANSIT satellites and stores the raw data on magnetic tape cassettes for post-processing. From good quality passes, 3-D positions are calculated online. These are sequentially adjusted positions.

Final observations on BORGNY DOLPHIN started at 0300 hours, 18 November and were completed at 1440 hours 20 November 1984.

During the observation period, 54 3-D satellite passes were calculated and recorded by the MX-1502 Geoceiver.

3.2 DATUM SHIFT

Since the computations are carried out on the satellite's geodetic system (NWL-10D datum), a datum shift must be applied to the co-ordinates of the satellite antenna to obtain a position in the European Datum 1950 (ED 50).

The transformation parameters shown below are applicable in the Norwegian Sea north of 64°, provided the station co-ordinates have been established using the satellites "Broadcast Ephemerides".

x	=	+ 92.2 m	
y	=	+ 89.7 m	Translation
z	=	+ 129.7 m	
x	=	+ 0.00"	
y	=	+ 0.00"	Rotation
z	=	+ 1.10"	
S	=	- 2.62 ppm	Scale correction

(X, Y and Z constitute a right-hand co-ordinate system fixed in the spheroid. X and Y lie in the equatorial plane and the Z-axis coincides with the rotation axis of the spheroid. X is positive towards the Prime Meridian and Y towards 90° E longitude. Z is positive towards the North).

3.3 PROCESSING

All the raw satellite data stored on magnetic tape cassettes were analysed and reprocessed on our VAX 11/780 computer, utilizing the Magnavox MAGNET programme. The main advantages of this programme compared to on-line processing are improved techniques for satellite orbit recovery and more sophisticated models for the tropospheric refraction correction. Further, the benefits of having all data available at the start of the processing, together with the general advantage of a larger computer should be appreciated.

The quality of a pass is normally characterized by the Root Mean Square (RMS) value for the scatter of all the Doppler counts in that particular pass, expressed in centimetres (cm). For onshore work a 25 cm acceptance limit is normally used, while rig observations are considered satisfactory if this value can be set to less than 40 cm.

Based on processing with different limits on the RMS value, the final position was determined with an RMS acceptance limit of 30 cm.

A total of 54 passes were accepted for the post processing 2-D computation by the Magnet program. 53 met the main acceptance criteria and were included in the final 3-D processing.

The following table describes the balance of passes:

NW	NE	SW	SE	TOTAL
14	16	12	11	53

N and S indicate a Northerly or Southerly ascension of the satellites and E and W indicate whether they passed to the East or the West of the observer.

By utilizing these passes we have found the antenna position, onboard BORGNY DOLPHIN, referenced to the satellite datum to be:

Latitude: 64° 24' 0.40" N
Longitude: 07° 48' 1.81" E

Applying the datum transformation parameters gives the position referenced to European Datum 1950:

CO-ORDINATES			
Geographic		UTM	
Latitude	64° 24' 01.51 N	Northing	7 142 356.6 m
Longitude	07° 48' 08.61" E	Easting	442 261.8 m

The UTM co-ordinates refer to Zone 32 with central meridian 09 degrees east.

3.4 REDUCTION TO WELL CENTRE

The distances from satellite receiver antenna to the Well centre were scaled from an as built plan of the rig. The rig heading, read from the gyrocompass, was 263 degrees. See Appendix 2, Antenna Offsets. With these data, the Well centre co-ordinates have been computed as:

CO-ORDINATES			
Geographic		UTM	
Latitude	64° 24' 01.31" N	Northing	7 142 349.8 m
Longitude	07° 48' 11.26" E	Easting	442 297.1 m

The co-ordinates refer to the European Datum 1950 and UTM Zone 32 with Central Meridian 09 degrees east.

Well centre is 2.9 metres off intended location in direction 45.3 degrees. See Appendix 3.

4. ACCURACY CONSIDERATIONS

Based on the scatter of the satellite observations, a one sigma value of 3.3 metres has been computed for the latitude, 2.3 metres for longitude, giving a horizontal position accuracy of 4.0 metres.

This is within the equipment manufacture's quoted accuracy obtained for single point positioning.

Uncertainty in the applied datum shift constants will influence the absolute position accuracy. The uncertainty between the satellite datum and the Norwegian Geodetic Network is believed to be better than 5 metres.

Offset from antenna position to Well centre position may introduce an additional error of 1-2 metres due to uncertainty in rig heading and distance measurements.

Stabekk, 7 December 1984
for A/S G E O T E A M

Roar Normann Nilsen

Roar Normann Nilsen

Andrew Morse

Andrew Morse

FIELD LOG

All Times are Local Norwegian Time

Saturday, 10 November 1984

1540 Depart Flesland

1610 Arrival on board Borgny Dolphin: A. Morse, O. Nordgaard and equipment.

1800 Mobilizing equipment.

2100 Decca Main Chain receiver and Magnavox 1502 satellite receiver operational.

Sunday, 11 November 1984

1200 Installing Syledis equipment.

1400 Syledis equipment operational, mobilization complete.

Monday, 12 November 1984

1000 Testing Syledis equipment on SYLVEST chain.

1300 Syledis working, but rather weak signals. Have requested another length of low loss antenna cable.

Tuesday, 13 November 1984

Standby all day.

Wednesday, 14 November 1984

Standby all day.

Thursday, 15 November 1984

1200 Rig starts pulling anchors.

1300 Another section of low loss antenna cable arrives and is installed.

1330 Syledis check against SYLVEST chain - working OK.

1910 All anchors in, heading for location 6407/9-2. Using Decca Sjark receiver and MX 1502 for navigation.

Friday, 16 November 1984

Steaming to next location.

Saturday, 17 November 1984

0800 Take over sync transmission on the Haltenbanken Syledis. Kopparen and Ross Isle locked in but no reply from Slettringen.

0900 Changed onto another set of time slots. All stations locked in.

1015 Station Halten put in instead of Ross Isle. Sigma rather high 10-12 metres.

1255 Turn onto 4 mile run in line. Sigma still high 7-10 metres.

1354 Drop anchor No. 5.

1425 Arrive on location, start running anchors.

1300 Anchor No. 1 on bottom.

1525 Anchor No. 4 on bottom.

1625 Anchor No. 8 on bottom.

1710 Anchor No. 6 on bottom.

1720 Anchor No. 2 on bottom.

1740 Anchor No. 3 on bottom.

1820 Start ballasting rig to operating draught.

1825 Anchor No. 7 on bottom.

2315 Finish ballasting, start tension test.

Sunday 18 November 1984

0015 All anchors except No. 2 holding.
0245 Anchor No. 2 reset and piggy-backed, tension test completed.
0300 Start final positioning with MX 1502 satellite receiver.
0310 Start logging Syledis position.
0813 Finish logging Syledis.
0900 Start demobilizing Syledis and Decca equipment.
1030 Demobilization of Syledis and Decca equipment complete.
1315 A. Morse and equipment depart rig.

Monday, 19 November 1984

Continuing MX 1502 positioning.

Tuesday, 20 November 1984

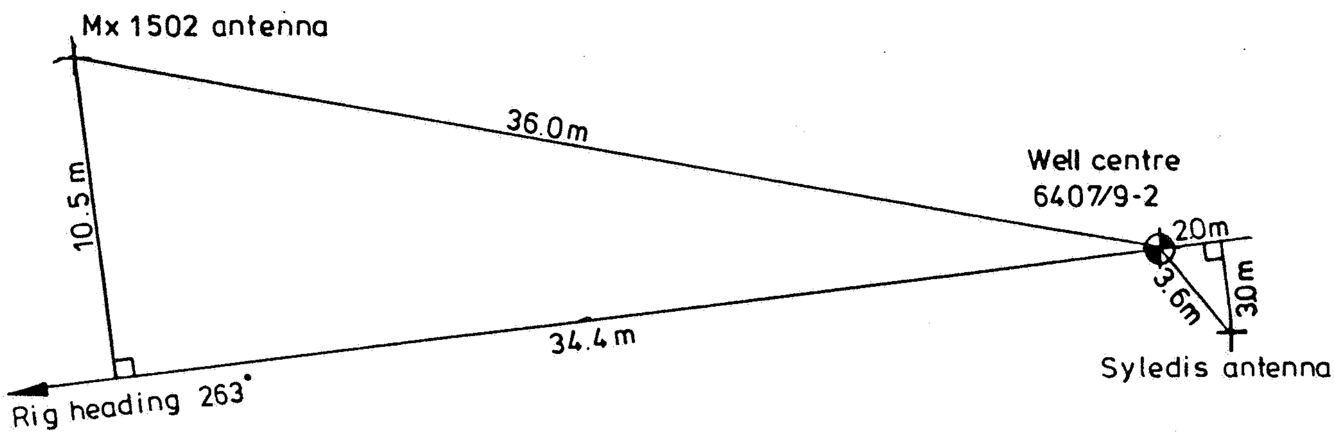
1440 MX 1502 logging completed. Demobilizing satellite navigation equipment.
1540 O. Nordgaard depart rig.
1740 Arriving Kristiansund N. airport.

Appendix no.: 2

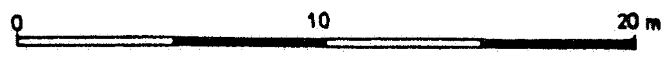
Project no.: 9868

ANTENNA OFFSETS

SCALE 1:250



SCALE 1:250

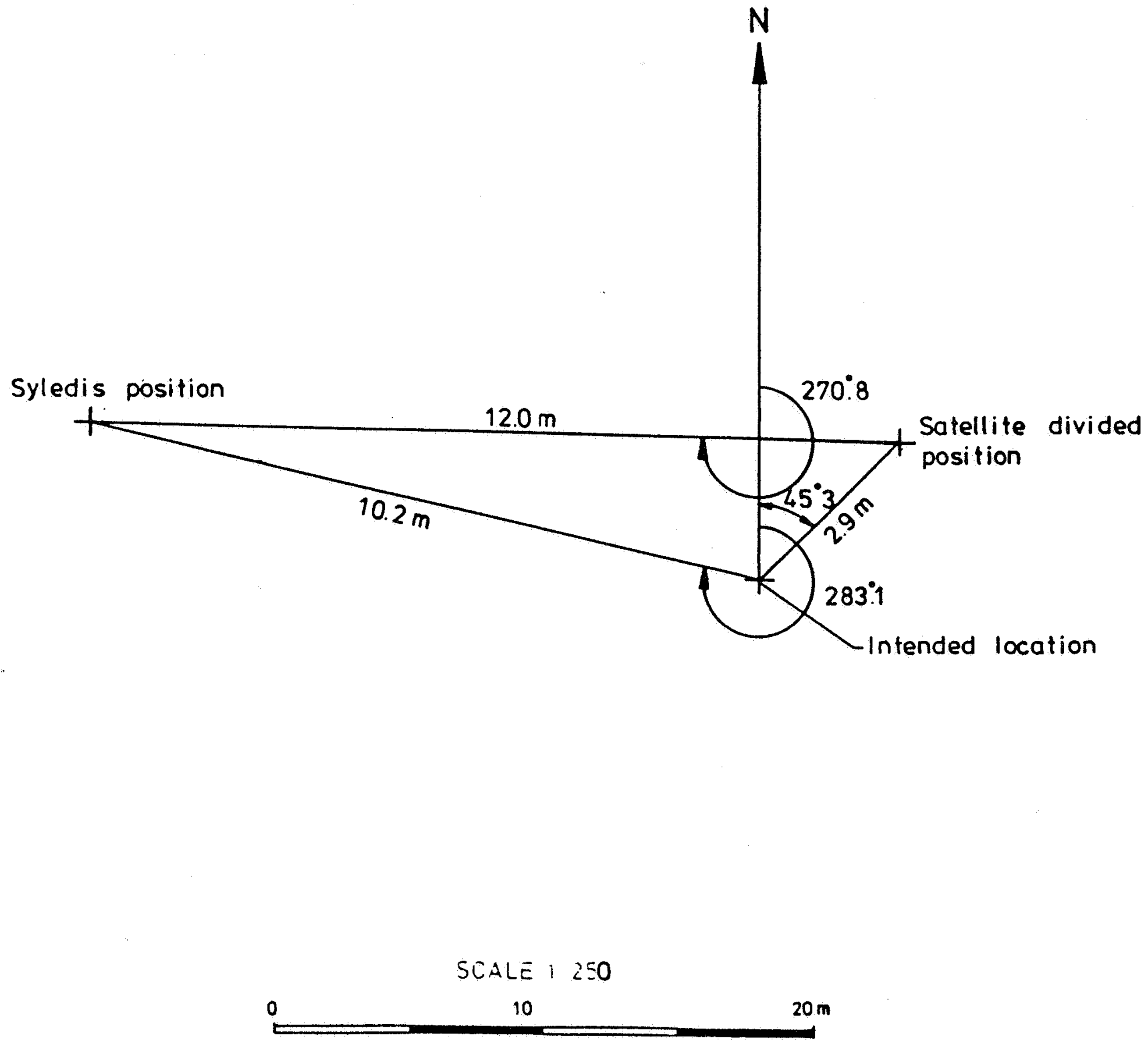


Appendix no.: 3

Project no.: 9868

POSITION PLOTS

SCALE 1:250



DRILLING HISTORY 6407/9-2 (BORGNY DOLPHIN)

The rig move to location 6407/9-B on Haltenbanken commenced at 19:30 hrs 15.11.84, with the Borgny Dolphin arriving on the location at 13:00 hrs 17.11.84. The anchors were run and the rig ballasted to drilling draught. The rig was manoeuvered onto location with the aid of SYLEDIS equipment and the final position was:

N 64 deg 24' 1.31 sec
E 07 deg 48' 11.26 sec

The temporary guide base was run and landed on seabed with an angle of 1.5 deg to port bow, observed by divers. The following distances were then established:

Derrick floor to sea bed	272 m
Water depth	247 m
	25

Whilst stabbing into the TGB in an attempt to break the guide ropes, the stabiliser tangled in both a guide wire and the TV umbilical, also breaking the TV frame. Divers untangled the wires and the camera was retrieved. At 15:30 hrs 18.11.84 well 6407/9-2 was spudded using a 26" bit and 36" hole opener and 36" hole was drilled to 291 m where the string was pulled due to no progress (one cone on the hole opener was found to be locked). A 26" pilot hole was drilled to 350 m BDF, using seawater and viscous pills with returns to seabed. The 26" pilot hole was opened up to 36" and before running the 30" X-52 310 lbs/ft casing viscous mud was spotted in the hole. 6 joints of 30" casing were run with the permanent guide base, the shoe at 346 m and the top of the housing at 270.5 m. The 30" casing was cemented, while being held in tension, using a thixotropic cement slurry to prevent any possible gas migration. Due to the special lead slurry the casing was kept in tension for 15 hrs to ensure that the cement had generated sufficient compressive strength. The 30" shoe track was drilled out using a 14-3/4" bit and 26" hole opener assembly to 350 m using seawater. No new formation was drilled.

The marine riser with hydraulic pin connector was run and latched onto the 30" housing. A 14-3/4" pilot hole was then drilled to 810 m encountering a hard layer between 440 and 446 m consisting of granite boulders, gas being encountered in insignificant amounts only. High viscosity mud of 1.11 SG was spotted in the open hole section and the following logs were run:

ISF/LSS/SP/GR	(Run no. 1)
LDL/CNL/GR	(Run no. 1)

(There was no indication of shallow gas on the logs).

The pilot hole was enlarged to 26" diameter with a hydraulic underreamer assembly and checked for gauge by running a BGT log. The log indicated that there were numerous ledges over several depth intervals and that from 600 m to TD the hole was undergauge. The 26" underreamer assembly was re-run and the open hole section was underreamed again. A repeat BGT log was run and confirmed the hole to be in-gauge and in good condition. A 17½" bit was run and 1200 bbls of 1.20 SG mud was spotted from TD to seabed to compensate for removal of the riser. The marine riser was circulated to seawater, the well observed dead for 2 hrs, and after unlatching the pin connector, the riser was pulled. Before running the casing, a third BGT log was run, confirming the hole to be satisfactory. 44 joints of 20" X-52 129 lbs/ft casing were run and cemented with the shoe at 800 m. Again a thixotropic lead slurry was used to reduce the possibility of gas migration. No problems were experienced while pumping the cement.

The running and landing of the BOP stack and riser was delayed for 34.5 hrs while waiting for a favourable weather window. After the BOP had been landed an increased tilt was observed on the PGB, which was confirmed as 2-1/4 deg SW by the diving team. Further subsea examination revealed a slight degree of rocking motion on the guide bases relative to the seabed. During the two observation dives made, before and after running the stack, no gas bubbles were observed around the wellhead (this was a problem experienced during drilling of the first well).

The BOP stack was tested successfully and a 17½" bit was run and soft cement drilled to 799 m whereon the hole was displaced to 1.30 SG KCL-polymer mud. 5 m of new formation were drilled to 815 m and a leak-off test performed to a stabilized equivalent mud weight of 1.46 SG.

17½" hole was drilled to 1584 m while gradually increasing the mud weight from 1.30 to 1.42 SG in response to indications that a pore pressure transition had been penetrated below +/- 950 m. During wiper trips, significant overpull was observed, frequently in excess of 100.000 lbs and bit number RR6 had to be pulled to clean the balled up bottom hole assembly, which had at one point packed off so severely that circulation became impossible. Both background and trip gas peaks confirmed the trends seen in the drilling exponent, and an estimated maximum pore pressure of 1.37 SG was calculated. Improvements were seen in hole condition, drag, cavings and background gas each time the mud weight was increased and after wiper trips. Magnetic multishot surveys run over the interval indicated a maximum hole deviation of 1 deg, but most surveys showed the hole to be less than ½ deg from vertical.

After a wiper trip at 1584 m, Schlumberger was rigged up and the following logs were run:

ISF/LSS/SP/GR	(Run no. 2)
LDT/CNL/CAL/GR	(Run no. 2)
CST	(Run no. 1)

A check trip was made and a further 3 m drilled to 1587 m to ensure enough casing pocket. 114 joints of 13-3/8" N-80 72 lbs/ft BTC casing were run and cemented with the shoe at 1575 m. Energizing of the casing hanger seal assembly failed and the seal asssembly was retrieved leaving the lower metal ring and the rubber packoff downhole. On the retrieved part of the seal assembly cement contamination was observed, indicating that channeling had occurred during the cement job. While waiting on the emergency seal assembly the riser was displaced to 1.25 SG mud which was to be used in the 12-1/4" hole section.

One of the anchors slipped due to bad weather, and the rig could not be maintained at the proper position. The riser was therefore displaced to seawater and unlatched at the lower marine riser package. After 37 hrs waiting on weather the rig was deballasted to 55 ft draft after which the anchor was re-sited and piggy backed. The rig was ballasted to 70 ft draft, repositioned over the well and the riser was latched on to the BOP.

The rubber part of the seal assembly was milled with a flush milltool and the emergency seal assembly was set and successfully tested to 5250 psi. The BOP was tested satisfactorily except for the outer kill valve. Again due to deteriorating weather, 27 hrs were lost before the BOP could be pulled. The outer kill valve was found to be washed out and was replaced. A malfunction in the acoustic operating system of the BOP was revealed, however this turned out to be a failure in surface test equipment for the system. The BOP stack was therefore rerun and landed and the BOP stack and the acoustic system subsequently successfully tested.

The 13-3/8" shoe track was drilled out as well as 5 m of new formation from 1587 - 1592 m. A leak off test was performed to a stabilized equivalent mud weight of 1.67 SG. The 12-1/4" hole was drilled to 1638 m at which depth coring commenced in the claystone overlying the reservoir. The following intervals were cored using a 12-1/4" fibre glass sleeve coring assembly:

Core no. 1	1638 - 1640 m	recovery 65 %
Core no. 2	1640 - 1642.5 m	recovery 44 %

Because of the slow coring rate (60-120 min/m) and the uncertainty of the thickness of the Kimmeridge clay overlaying the reservoir, drilling was resumed circulating bottoms up every 3 m. 12-1/4" hole was drilled to 1653.5 m and the top of the reservoir found at 1651 m. Coring was then resumed as follows:

Core no. 3	1653.5 - 1671.5 m	recovery 92 %
Core no. 4	1671.5 - 1684 m	recovery 74 %
Core no. 5	1684 - 1688 m	recovery 68 %
Core no. 6	1688 - 1700 m	recovery 48 %
Core no. 7	1700 - 1702 m	recovery 0 %
Core no. 8	1702 - 1706.3 m	recovery 97 %

(Total cored 57.3 m with 71 % recovery).

12-1/4" hole was drilled to TD at 1865 m, and TD logging carried out as follows:

ISF/LSS/SP/GR	(Run no. 3)	
LDT/CNL/GR/NGT	(Run no. 3)	
DLL/MSFL/GR	(Run no. 1)	
SHDT/GR	(Run no. 1)	
RFT-(HP-SG)	(Run no. 1)	Downtime caused by broken probe support plate. Failed to obtain segregated sample.
Velocity survey	(by SSL)	
CST	(Run no. 2)	60 fired, 55 recovered.
CBL/VDL/GR	(Run no. 1)	On 13-3/8" casing.

134 joints of 9-5/8" N-80 47 lbs/ft BTC casing were run after a check trip confirmed the hole condition to be good. The shoe was set at 1852 m and the casing tested to 4000 psi when the cement plug was bumped. A full stack test was completed, before starting the clean up programme prior to testing.

With bit and scraper in the hole, the well was initially displaced to seawater with high viscous slugs used to sweep out solids. A 50 bbl pill of 15 percent acid was followed by a 50 bbl pill of caustic, with half a circulation volume of seawater as a spacer between the two. These pills were circulated very slowly around the system for optimum effect. The well was circulated further with seawater before the hole was displaced to 1.15 SG brine ($CaCl_2$ flake, 77 % purity) filtered through 10 micron filters until the cleanliness was stabilised.

To check on the quality of the cement bonding a CBL/VDL/CET log was run on the 9-5/8" casing indicating good cement bond.

A dummy run was made with the EZ tree, lubricator valve and 4½" PH-6 tubing riser to check space out by landing the fluted hanger in the wearbushing and closing the 5" pipe rams to make a mark on the slick joint. The 4½" riser was pulled out and racked and the flowhead was made up on one single of 4½" tubing. The perforating guns and DST sub assembly were made up and run in the hole and pressure tested to 3000 psi against the closed Pressure Controlled Tester (PCT) valve. After the pressure test, the assembly was run in hole on 5" DP and the 4½" tubing riser including fluted hanger, slick joint and SSTT, and landed in the wearbushing.

A 1-11/16" CCL/GR correlation log was run inside the string to enable correct positioning of the guns. The packer was then set, the middle 5" pipe rams closed around the slick joint and the annulus pressure tested to 2000 psi. The Multiple Opening Reversing Valve (MORV) was opened and the tubing displaced to diesel, giving a drawdown of +/- 370 psi on the formation. After closing the MORV the detonating bar was run on wireline and with the well closed in at surface. The interval 1670 - 1675.5 m was perforated at 15.52 hrs on 26.12.84.

After pulling back the detonating bar, the PCT valve was closed and shut-in bottom hole pressure recorded for 1½ hr. The well was then flowed through a 40/64" adjustable choke for 25 bbls at an estimated rate of 3500 bpd before the PCT was closed for pressure build-up of ½ hr. When the PCT was reopened the well was found to be dead. The string contents were reversed out and samples collected, the lowest sailinity being measured at approximately 37000 ppm. Data recorded from the DST no. 1 flow period was as follows:

TIME MIN	THP PSI	PROD.RATE BBL/D	CUM.PROD BBLS
Opened PCT	160	-	-
3	120	4777	10
6	80	3650	17.6
8	63	3745	22.8
9	bleed off	3459	25.2 Closed PCT

A sand bailer run was made on wireline and hold up depth was found at 1596 m (24 m above the PCT valve), a sample of loose sand being recovered from the bailer. The string was displaced to diesel again and the well opened up, no flow was observed and the well was shut in. The diesel was reversed out and the well circulated to brine prior to unseating the packer and pulling the string out of the hole.

The DST string was rerun on 5" drillpipe and 4½" tubing riser with 4 m of 5½" x 0.012" gauge wire wrapped screen at the bottom, replacing the guns. The other subassemblies were run as in the first test except for the PCT, this time being run in the locked open position. The string was spaced out such that the wire wrapped screens were across the perforations.

The well was circulated clean before 10 bbls of 15 % HCl was displaced to the perforations followed by 8 bbls of seawater and 68 bbls of brine. The packer was set and the tubing displaced to diesel. The well was opened up and flowed at a maximum rate of 250 BPD until dead, producing approximately 44.6 bbls. The tubing contents were reversed out and samples collected. However, no representative formation fluid was obtained. The well was subsequently flowed 5 more times producing a total of 323 bbls at a maximum flow rate never exceeding 250 BPD. After the 6th flow period, 3 bottom hole samplers were run before reversing out the tubing contents. One sampler worked and collected fluid with a salinity of approximately 37000 ppm. The string contents were reversed out and fluid samples confirmed that the bottom hole sample collected, was a representative formation fluid sample.

The string was displaced to seawater and pressure gauges run and landed in the RN nipple.

An injectivity test was performed for 8 hrs injecting clean seawater into the formation at approximately 7000 bbls/day with a maximum bottom hole pressure of 2758 psi. One hour pressure fall off was recorded on the two SSDP gauges, and the gauges retrieved. The test string was pulled, and a bailer run was made, hold up depth being found at 1796 m. To secure the watertest zone a cement plug was set from 1796 to 1640 m, dressed down to 1668 m and a Baker N-1 bridge plug set at 1666 m. The cement and bridge plug were pressure tested to 4000 psi and inflow tested with 350 psi drawdown on the formation.

A bit and scraper run was made on 5" DP to 1666 m and the hole circulated to seawater. To clean up the well, one viscous pill, an acid pill and a caustic pill were pumped around, and circulation continued until the solids level reached 1.5 NTU. With a viscous pill as spacer the hole was then displaced to 1.15 SG $CaCl_2$ brine (77% pure) which was filtered until the solids level had reached a minimum of 1.5 NTU. The hole cleaning operations took 16 hrs.

A Baker model D sump packer was set at 1661 m, after which the perforating assembly (with 6 m, 6", 12 spf Baker guns) was run on 3½" VAM tubing string and 5" DP with two white painted DP singles for space out purpose. When attempting to locate the sump packer with the collet locator, no locator overpull was noticed. The perforating gun was landed on the packer and the string was pulled up 3 m to repeat the procedure. This time the string landed off 10 m lower than before, and a wireline run confirmed the subassembly to be 10 m too low. After having pulled the string, it was found that the Baker mechanical tubing release had released itself. The guns were successfully fished and a dummy run with a locator and a G-22 seal assembly landing collar was made to the sump packer, locating the packer at the correct depth. The well was circulated clean, the string pulled and the guns were re-run on the 3½" tubing and 5" DP, this time leaving out the mechanical tubing release. After locating the sump packer the pipe rams were closed around the white painted DP joint for space out. The DP was pulled back and the 3½" tubing was run on the 4½" tubing riser and the string landed off on the wearbushing. All surface equipment was installed and tested before the Baker FH packer was hydraulically set. The sump was tested to 1000 psi and the annulus to 500 psi to check that the packer had set properly.

To activate and close the PCT which was run in open position, the annulus was pressured up to 2800 psi. The MORV was opened and the tubing displaced to diesel, giving a drawdown of 250 psi on the formation, the MORV closed again and the PCT reopened.

At 14:12 hrs on 07.01.85 the well was perforated over the interval 1651 - 1657 m, by running a detonating bar on wireline to fire the gun. The well was backsurged 10 bbls on a 32/64" choke before it was beaned back to 12/64" choke for a 5 hrs clean-up period flowing at a controlled rate of 300 BPD. The cummulative production was 98.2 bbls at various rates with no sand produced to surface. The well was killed by bullheading the tubing contents back to the formation with a viscous calcium carbonate pill followed by clean brine, the PCT closed and the MORV opened and the well circulated clean. The packer was unseated and the well observed static before again being circulated, to a turbidity level of 3 NTU. Because of losses (upto 60 bbl per hour) after pulling one joint of tubing, another viscous carbonate pill was spotted across the perforations to cure the losses. A total of 80 bbls of brine were lost to the formation. The perforating string was pulled and a sand bailer run was made on wireline indicating 3 m of sandfill in the sump. A clean out assembly was run on DP to 1665 m and the sand was circulated out. Another viscous carbonate pill was spotted across the perforations and 2 bbls was squeezed into the formation to cure minor losses.

A Baker gravel pack assembly with 5½" screens and special long stroke gravel pack extension, was run on 5" DP. Because of excessive heave (2.5 - 3 m), the string was hung off in the wellhead and 19 hrs were lost waiting on weather before the gravel pack was landed in the sump packer and the SC-1 packer was set at 1608 m. After identifying the four work string positions, the gravel pack operation started with a 47 bbls 15% HCL pre-acid job to clean up the perforations. After soaking the acid for ½ hr, 15 bbls prepad, 18 bbls gravel pack slurry (12 ppg), and 5 bbls post pad were pumped and displaced with brine. Screen out occurred 9 bbls earlier than anticipated at a surface pressure of 750 psi, a final screen out pressure of 1500 psi being applied. The excess gravel was reverse circulated out of the DP and the gravel pack was reconfirmed with 750 psi surface pressure. Following the acid soak, no returns were observed during the gravel packing, resulting in an additional brine loss to the formation of some 100 bbls.
The gravel pack work string was pulled out of the packer and a viscous brine pill was spotted above the reverse acting flapper valve. No losses were observed and the gravel pack work string was pulled out of the hole.

The 3½" C-75, VAM production string was run, spaced out, landed on 4½" C-75 hydril PH-6 tubing riser and pressure tested.
During landing of the string after having shattered the flapper valve, 20 bbls brine were lost to the formation before the seals entered the SC-1 packer. A total of 200 bbls brine had thus been lost to the formation during the completion phase. The PCT which was run in open position, was activated and closed and the MORV opened and the string displaced to diesel. The well died 5 times and had to be recirculated to diesel every time before it finally started flowing. The well was flowed for 8 hrs to clean up with a maximum rate of 1095 BOPD at 82 psig THP on a 48/64" choke.

To improve the flowrates, a 45 bbl 15 % HCl acid stimulation was performed with a 15 bbls viscous pill ahead for divertion. Again the well died three times before the well flowed to surface, initially through a 16/64" choke beaning up gradually to maximum rate as follows:

CHOKE 1/64"	THP PSIG	THT F	OIL BPD	GAS MSCF/D	GOR SCF/B	BSW %	DURATION HRS
32	309	52	1861	477	256	2	2
48	246	61	3071	753	245	1.5	4
72	192	68	4115	1049	255	1	3
128	136	72	5178	1352	261	TR	7

The well was shut in at the lubricator valve and 2 x SSDP and 1 x CRG gauges were run and landed in the F nipple at 1633 m. The well was re-opened and flowed at various rates as follows:

CHOKE 1/64"	THP PSIG	THT F	OIL BPD	GAS MSCF/D	GOR SCF/B	BSW %	DURATION HRS
20	484	52	1167	270	231	TR	4
36	350	58	2620	579	221	TR	3.5
80	190	72	4469	1139	255	TR	10

During the 10 hours flow period 4 pairs of PVT recombination samples were taken, and at the end of the flow period the well was shut in downhole at the PCT. After a 10 hrs build up period, two way pressure communication was discovered between the tubing and the annulus. When the production string was eventually pulled, after having killed the well, the single shot annulus reversing valve (SSARV) was checked and found to have operated thus creating communication between the tubing and the annulus.

A slickline sand bailer was run and confirmed that there had been no sand production during the test. A CNL/GR log was run to evaluate the gravel pack indicating the top of the gravel to be at 1635 m (16 m above the perforations).

A modified production string was run in the hole leaving out the space out seal assembly, and with the SSARV in the string for space out purposes, but plugged and locked closed. The chalk kill pill was circulated out before stinging into the packer. The tubing was displaced to diesel and the well was successfully brought live and cleaned up for 13 hrs with a maximum flow rate of 4495 BOPD at 124 psig THP on a 128/64" choke.

The well was shut in at surface for acid stimulation, however freezing problems were experienced due to severe cold weather, and the acid stimulation was not started until the kill wing and cement lines were un-frozen, and re-filled with anti-freeze solution. The oil was bullheaded back into formation with a 48 bbl 15% HCl acid pill pumping at a maximum rate of 3 bpm at 1000 psi. This was displaced with a 3 bbl brine spacer and a diesel cushion to fill the tubing. The acid was allowed to soak for 15 minutes before opening the well, which died within 1½ hours. The well flowed to surface after a second displacement to diesel and was cleaned up quickly to maximum rate as follows:

CHOKE 1/64"	THP PSIG	THT F	OIL BPD	GAS MSCF/D	GOR SCF/B	BSW %	DURATION HRS
36	368	48	2635	760	289	TR	1
44	348	52	3166	864	270	TR	1
64	250	60	4838	1292	267	TR	1
80	225	64	5342	1519	284	0	1
128	183	66	6460	1536	238	0	5.5

A further acid stimulation was then performed pumping 96 bbls of 15% HCl acid with a maximum rate of 5 bpm at 1000 psi, the acid being soaked for 1 hour. The tubing was displaced to diesel three times before the well again flowed to surface. The well was cleaned up quickly and flowed at an improved maximum rate of 7017 BOPD at 155 psig THP on a 128/64" choke after a total of 16 hours flowing.

The well was shut in at the sandtrap and pressure gauges (2 x SSDP and 1 CRG) were run. A maximum CITHP of 582 psig was recorded before the well was opened up and flowed as follows:

CHOKE 1/64"	THP PSIG	THT F	OIL BPD	GAS MSCF/D	GOR SCF/B	BSW %	DURATION HRS
40	359	50	3274	928	283	0	3.5
64	245	60	4719	1161	246	0	3.5
128 + 96	148	65	7400	1520	208	0	22

The planned 45 hour maximum flow period was curtailed, due to the discovery that control of some BOP functions had been lost as a result of the pod control line fluid freezing up. (the weather at this point was severe with winds between 50-60 knots and ambient air temperature around -10 deg C.). The PCT was closed and the shut-in period extended to 73 hours in total before sufficient BOP control was recovered to open the kill failsafe valve thereby allowing pressuring up of the annulus to reopen the PCT. The downhole gauges were recovered and the well killed by bullheading the oil back into formation using a 24 bbl viscous chalk pill.

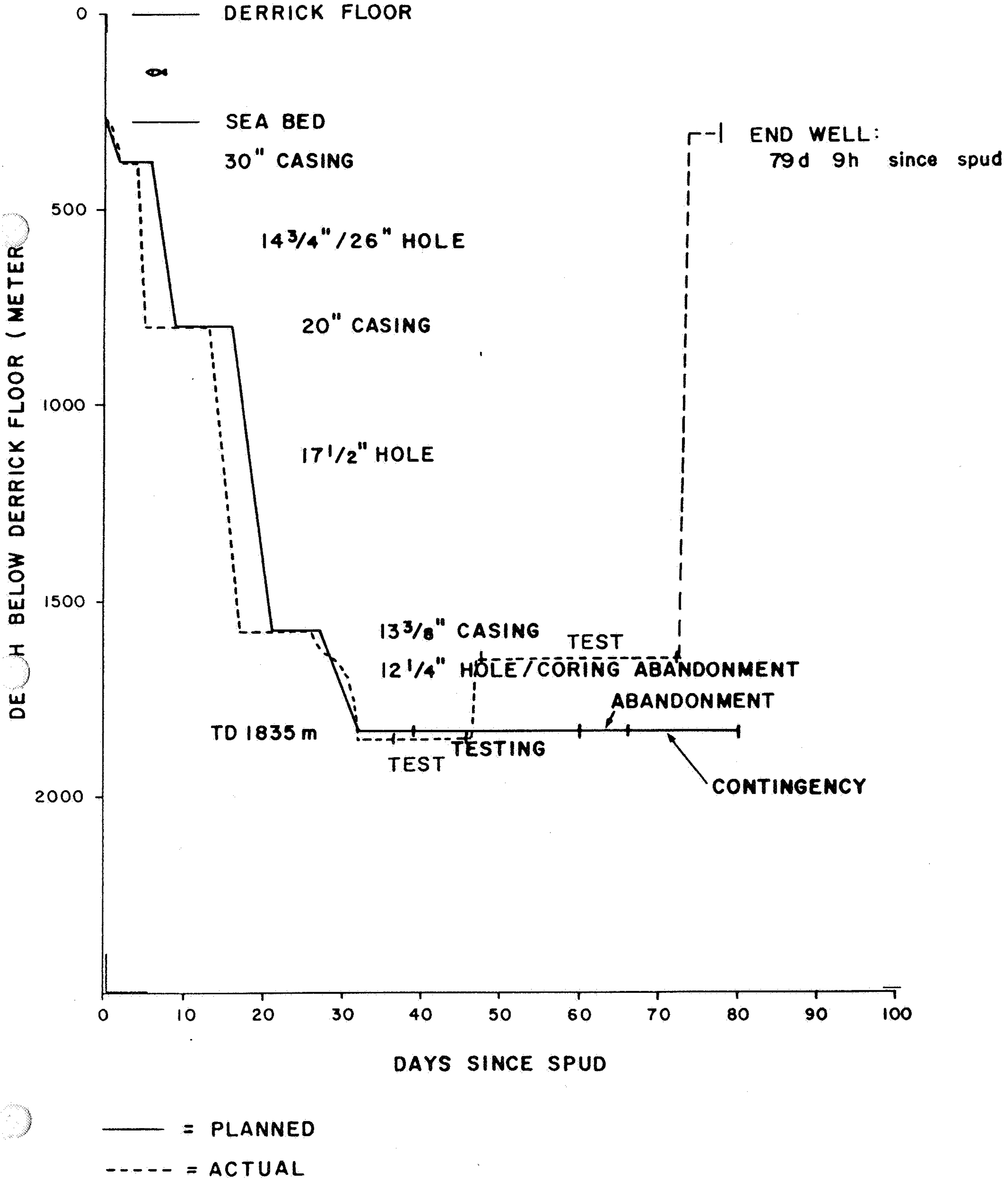
An attempt was made to perform a fracture test at this stage. However, when pumping at minimum rate the pressure continued to increase up to a maximum surface pressure of 2500 psi after only 4 bbls had been pumped, and the test was abandoned. The gauges which had been run to record the fracture test were pulled, the PCT closed, and the MORV opened.

After the hole volume had been reverse circulated, further time was lost after the EZ-tree was unlatched and the BOP was function tested. The shear rams were successfully closed, but could not be re-opened, so the control pod had to be pulled again. During these repairs the flowhead was rigged down, and when BOP control was recovered the EZ-tree was re-latched and the production string was pulled with no losses.

Abandonment cement plug no.2 was set across the perforations and squeezed with 2000 psi (no injectivity). Top of cement was located at 1450 m and an N-1 wireline bridge plug was set at 1435 m. The 9-5/8" casing was perforated at 315 m to check for gas before being cut at 696 m and recovered. Abandonment cement plug no.3 was set from 750 - 550 m covering the cut 9-5/8" casing. The plug was located at 562 m with 20,000 lbs, and pressure tested to 2000 psi. The 13-3/8" casing was perforated at 300 m to check for gas before being cut at 402 m and unsuccessful attempts made to pull. Two more cuts were made, at 374 m and 323 m respectively, without being able to pull the cut part. Abandonment plug no.4 was therefore set from 515 - 290 m inside the 13-3/8" casing covering all three cuts. The plug was located at 300 m and weight tested to 15.000 lbs. The riser was displaced to seawater and the riser and BOP stack was pulled. The 13-3/8", 20" and 30" casings were cut with an explosive cutter at 278 m. The cut casing and the PGB were retreived, whereafter the TGB was retrieved with a special retrieving hook. The divers were jumped to make a final seabed survey before deballasting the rig. The anchors were pulled and the last anchor was bolstered at 18.40 hrs on 02.02.85. The Borgny Dolphin was towed to the Sandefjord shipyard, and the contract between A/S Norske Shell and Dolphin A/S ended at 00.45 hr on 06.02.85.

6407/9-2 DRILLING PROGRESS CURVE

STARTED WELL	19:30 hrs	15.11.84
SPUDDED WELL	15:30 hrs	18.11.84
RIG OFF LOCATION	18:45 hrs	02.02.85
END OF WELL	00:45 hrs	06.02.85
TOTAL TIME	82 DAYS	5 1/4 hrs.



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BIT RECORD SUMMARY WELL NO 6407/9-2

RUN NO.	BIT NO.	BIT SIZE INCH	MFGR/TYPE	JET SIZE 1	JET SIZE 2	JET SIZE 3	JET SIZE 4	DEPTH OUT	MTRS	HRS	WOB (1000 LBS)	RPM	PUMP PRESS (PSI)	GPM	MUD WT	MUD VIS	CODE T	CODE B	CODE G	REMARKS
1	1	26	OSG-1GJ	18	18	18	-	291	19	4	10-30	80-100	2000	1100	1.05	100+	1	1	G	+ 36" hole opener viscous sweeps.
		36	Hole opener	18	18	18	-													
2	2	26	OSC 3AJ	24	22	22	-	350	59	4.5	10	80-120	1800	1100	1.05	100+	1	1	G	Drilled pilot hole;angle is 2.25 deg at 296 m.
3	2RR	26	OSC 3AJ	24	22	22	-	350	-	-	10-20	110	1750	1100	1.05	100+	-	-	-	Opened up pilot hole.
		36	Hole opener	18	18	18	-													
4	3	14-3/4	OSC - 3A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Drilled cmt 337 - 350 m.
		26	Hole opener	18	18	18	-													
5	3RR	14-3/4	OSC-3A	18	18	18	-	810	460	21	5-20	70-100	2350	900	1.11	39	5	6	G	Drilled pilot hole.
6	4	14-3/4	SEC S43	-	-	-	-	810	-	-	-	-	2200	1100	1.10	39	1	4	G	Opened up pilot hole.
		26	Tristate U-R	6 x 16													8	8	G	Hydraulic underreamer.
7	5	12-1/4	HTC-X1G	12	12	12	-	810	-	-	-	-	3000	1100	1.11	39	1	1	G	Re-underreamed pilot hole.
		26	Trisate U-R	6 x 16																Angle is 2 deg.
8	6	17½	Smith DSJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Check trip.
9	7	17½	Smith DSJ	18	18	18	-	943	133	8.5	20	80-100	2600	1100	1.30	48	3	2	1/16	Drilled shoe track soft cmt.
10	6RR	17½	Smith DSJ	16	16	16	18	1138	195	9	30	100	2700	1000	1.33	57	1	3	G	Pulled due to balled up BHA.
11	8	17½	Smith DTJ	18	18	18	-	1584	446	25.5	30	100-120	3000	850-1000	1.41	59	2	5	G	
12	8RR	17½	Smith DTJ	18	18	18	-	1587	3	1.5	40	100	2200	850	1.41	59	2	5	G	Check trip and deepened pocket.
13	9	12-1/4	HTC X1J	16	16	16	-	1638	51	7	30	120	2900	800	1.23	58	1	6	G	Drilled shoe track.
14	10	12-1/4	Weasel	Corehead				1640	2	5	10-40	120	780	350	1.24	55	5 % worn			Recovery 65 %.
15	10RR	12-1/4	Weasel	Corehead				1642.5	2.5	7	10-40	120	950	400	1.24	55	5 % worn			Recovery 44 %.
16	11	12-1/4	S 44 G	16	16	16	-	1653	10.5	5	20	60	3200	1000	1.24	54	1	1	G	
17	10RR	12-1/4	Weasel	Corehead				1671.5	18.5	1	15	120	780	350	1.24	54	7 % worn			Recovery 92 %.
18	10RR	12-1/4	Weasel	Corehead				1684	12.5	1	15	130	780	350	1.24	55	10 % worn			Recovery 74 %.
19	10RR	12-1/4	Weasel	Corehead				1688	4	1	15	130	780	350	1.24	56	10 % worn			Recovery 71 %.
20	10RR	12-1/4	Weasel	Corehead				1700	12	3	15	130	780	350	1.24	56	10 % worn			Recovery 47 %.
21	10RR	12-1/4	Weasel	Corehead				1702	2	3.5	10-25	70-130	780	350	1.24	56	10 % worn			Recovery 0 %.
22	10RR	12-1/4	Weasel	Corehead				1706	4	3	10-25	70-140	780	350	1.24	56	25 % worn			Recovery 97 %.
23	11RR	12-1/4	S 44 J	16	16	16	-	1865	159	21.5	35-40	75-80	3200	850	1.24	56	5	2	1/16	TD is 1865 m.

DEVIATION DATA WELL NO. 6407/9-2

(MAGNETIC DECLINATION 4^{o} W. OF TRUE NORTH)

(DISTANCE FROM DRILL FLOOR (DF) TO MEAN SEA LEVEL (M.SL) = 25 M)

DEPTH AH (M.BDF)	ANGLE (DEGREE FROM VERT.)	DIRECTION (DEGREE MAGNETIC)	DIRECTION (DEGREE TRUE)	DEPTH T.V. (M.SL)	NORTHING (M.FROM LOCN)	EASTING (M.FROM LOCN)	DOG LEG (^{o}/ 100 M)
289	1.50	-	Totco	264.00	-	-	-
296	2.25	-	"	271.00	-	-	-
315	2.50	-	"	390.00	-	-	-
350	1.00	-	"	325.00	-	-	-
452	1.50	-	"	427.00	-	-	-
641	1.00	-	"	616.00	-	-	-
810	1.00	-	"	785.00	-	-	-
810	1.00	60	56	785.00	-	-	-
905	1.00	53	49	879.99	1.01	1.31	0.13
937	0.75	50	46	911.98	1.34	1.67	0.79
1043	0.50	60	56	1017.98	2.08	2.56	0.26
1133	0.50	90	86	1107.97	2.32	3.27	0.29
1228	0.25	60	56	1202.97	2.47	3.86	0.33
1323	0.50	360	356	1297.97	3.00	4.00	0.46
1447	0.25	275	271	1421.96	3.54	3.69	0.43
1579	0.75	15	11	1553.96	4.40	3.57	0.63
1699	0.25	50	46	1673.95	5.35	3.91	0.47
1861	0.25	35	31	1835.95	5.90	4.35	0.04

CASING DATA WELL NO 6407/9-2

DATE RUN	SIZE	GRADE	WT/FT (LBS)	COUPLING	SHOE DEPTH (MBDF)	REMARKS
20.11.84	30"	X-52	310.0	Vetco ATD ST-II	346	Ran on hwdp. Good returns to seabed. Angle after cementation 1.25 degree.
27.11.84	20"	X-52	129.0	VETCO ATD LS-LH	800	Good returns to seabed. Ran on hwdp. No pressure test possible after bumping plug.
06.12.84	13-3/8"	N-80	72.0	BTC	1575	Ran on hwdp. Pack off did not set. An emergency pack off was used. Cement channeling to wellhead.
22.12.84	9-5/8"	N-80	47.0	BTC	1852	Ran on hwdp.

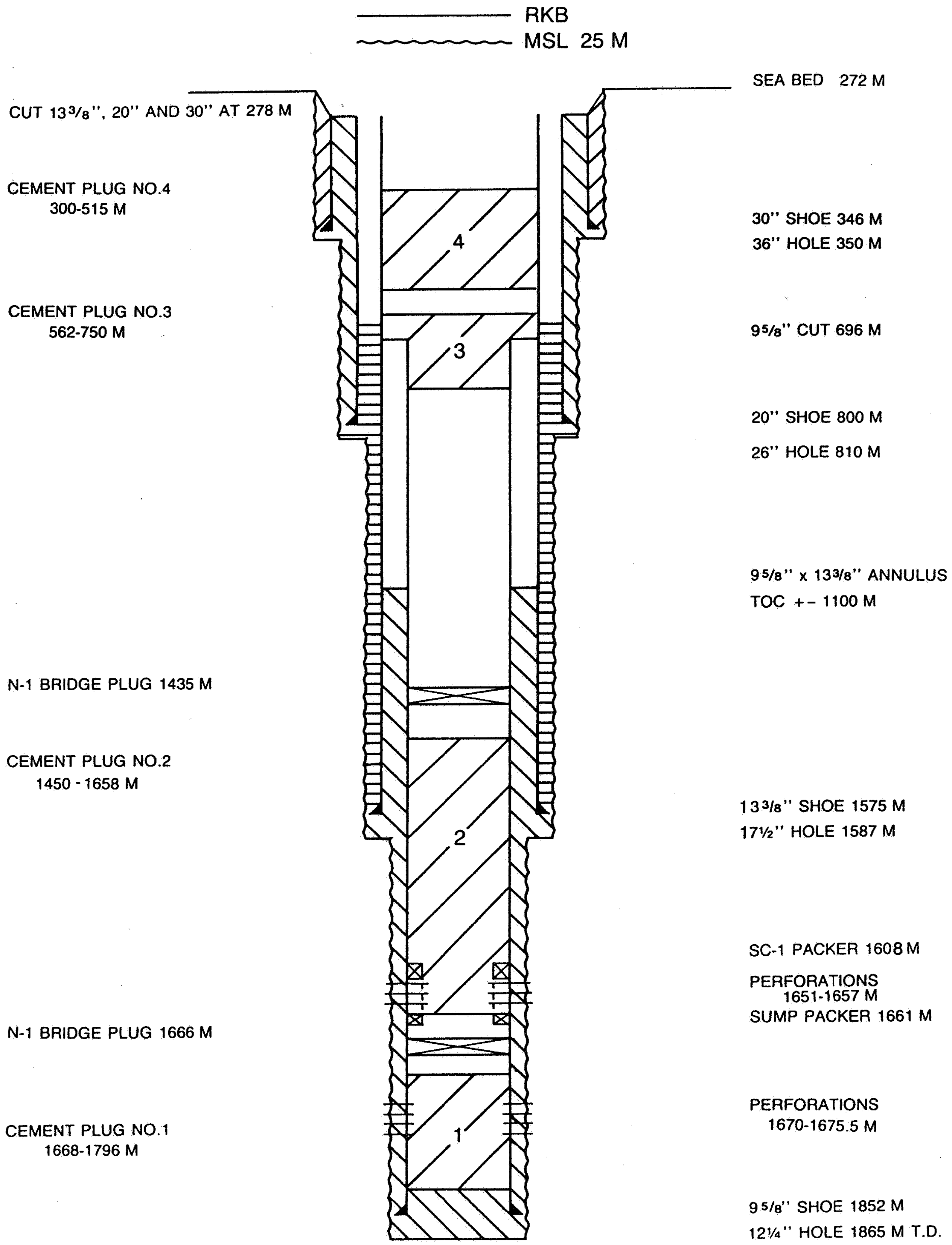
CEMENTATION DATA WELL NO 6407/9-2

JOB DATE	JOB DESCRIPTION	HOLE SIZE/ DEPTH (M. BDF)	CASING SHOE (M.BDF)	CEMENT TYPE	SACKS USED	SLURRY WEIGHT (PPG)	MIXWATER	ADDITIVES	LOSSES (BBLS)	REMARKS
20.11. 1984	30" Casing	36"/350	346	Class G	588 255	13.2 15.8	Seawater Seawater	1.35 gps econolite 0.17 lbs/sx caustic 3 % BWOC $CaCl_2$	-	Special thixotropic cement to prevent gas migration. Good cement returns to seabed.
27.11. 1984	20" Casing	26"/810	800	Class G	2218 364	13.3 15.9	Seawater Seawater	1.5 gps econolite 0.31 lbs/sx caustic 1 % BWOC $CaCl_2$	-	Thixotropic cement was used to prevent gas mingration. Good cement returns to seabed.
07.12. 1984	13-3/8" csg	17½"/1587	1575	Class G	1407 319	13.2 15.8	Freshwater Freshwater	0.36 gps econolite 0.2 gps CFR-2L	-	Cement channeled upto wellhead.
22.12. 1984	9-5/8" csg	12-1/4"/ 1865	1851.5	Class G	165 565	13.4 15.9	Freshwater Freshwater	0.15 gps CFR-2L 0.7 gps Halad 10L 0.1 gps Econolite 0.27 gps CFR-2L 1.23 gps Halad 10L 0.18 gps econolite	- -	TOC is approximately 1100 m.
02.01. 1985	Abandonment plug no.1	9-5/8"/ 1851.5	1851.5	Class G	181	15.8	Freshwater	0.15 gps CFR-2L	-	Cement plug: 1668 - 1796 m. No cement squeeze possible into perforations at 2000 psi.
28.01. 1985	Abandonment plug no.2	9-5/8"/ 1668	1851.5	Class G	207	15.8	Freshwater	0.15 gps CFR-2L	-	Cement plug: 1658-1450 m. No cement szueeze possible into perforations at 2000 psi.
29.01. 1985	Abandonment plug no.3	9-5/8"/ 1450	1575	Class G	407	15.8	Seawater	2 % BWOC $CaCl_2$	-	Cement plug: 750 - 562 m.
31.01. 1985	Abandonment plug no.4	13-3/8"/ 562	1575	Class G	525	15.8	Seawater	2 % BWOC $CaCl_2$	-	Cement plug: 515 - 300 m.

FORMATION LEAK OFF TEST DATA WELL 6407/9-2

NO.	DATE	CASING		HOLE		MUD Wt. IN USE		MAX.EQUIVALENT MUD Wt.		STAB.EQUIVALENT MUD Wt		REMARKS
		SIZE (")	DEPTH (M)	SIZE (")	DEPTH (M)	SG	PSI/ 1000 FT	SG	PSI/ 1000 FT	SG	PSI/ 1000 FT	
1	30.11.84	20	800	26 17-1/2	810 815	1.30	563	1.48	641	1.46	632	Leak-off test performed in step pumping, waiting 2 minutes at each step.
2	14.12.84	13-3/8	1575	17-1/2 12-1/4	1587 1592	1.23	533	1.67	723	1.66	719	"

ABANDONMENT DIAGRAM 6407/9-2



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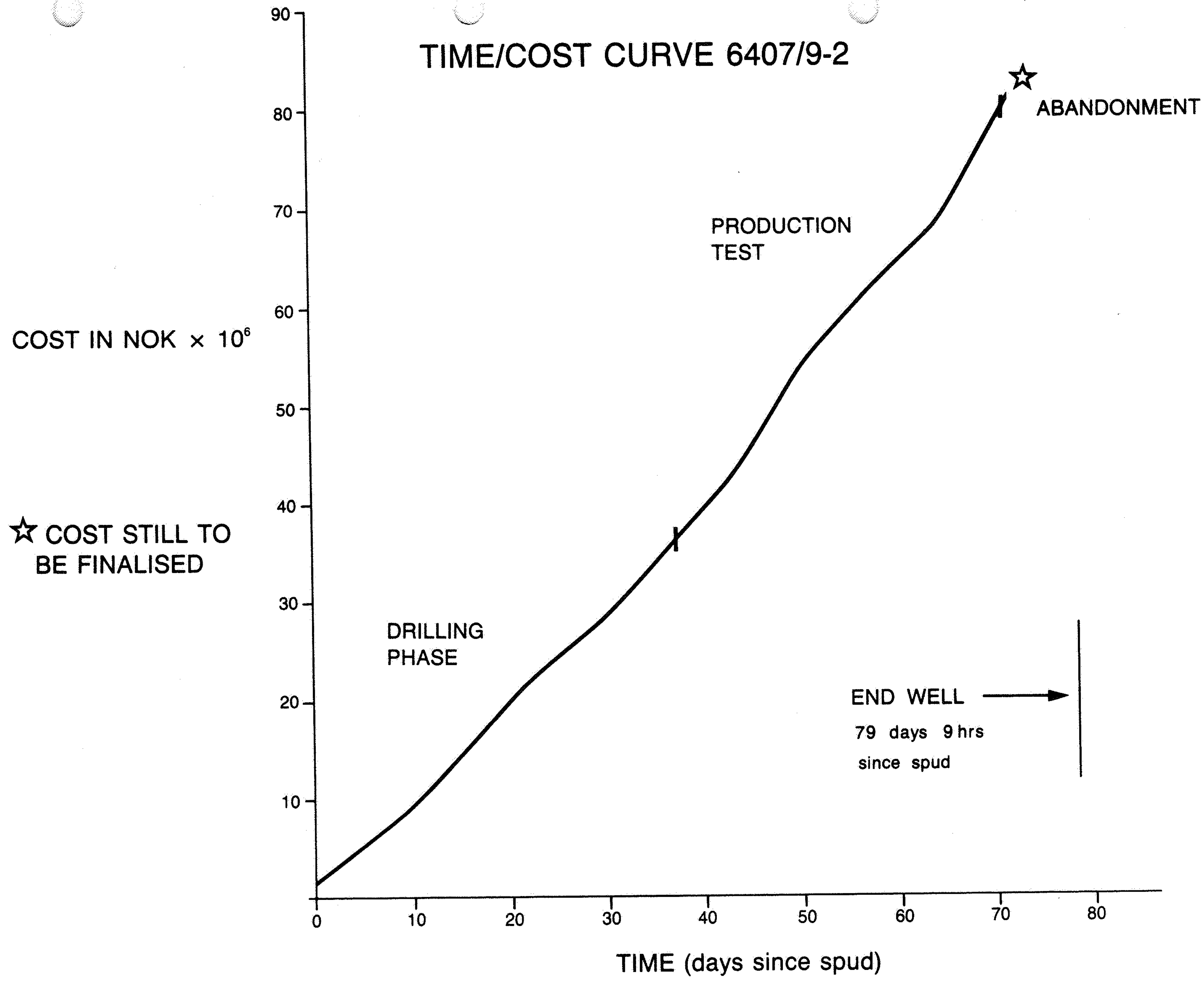
TIME ALLOCATION 6407/9-2

Started well at 19.30 hrs 15.11.84
Spudded well at 15.30 hrs 18.11.84
Abandoned well at 18.40 hrs 02.02.85
End of contract at 00.45 hrs 06.02.85

PHASE	ITEM	NOV	DEC	JAN	FEB	TOTAL HRS	%
PREPARATION	- Towing	41.5				41.5	2.1
	- Laying/ pulling anchors	10.5	5			15.5	0.8
	- General preparation	11.5				11.5	0.6
	Sub total					68.5	3.5
DRILLING	- Bit on bottom	30	77.5			107.5	5.5
	- Round tripping	50	81.5	49.5		181	9.2
	- Reaming/ enlarging	53	4.5			57.5	2.9
	- Circulation/ condition mud	18	27	19		64	3.2
	- Condition hole for casing		3			3	0.2
	- Running casing/drilling cement	19.5	33.5			53	2.7
	- Leak off test	1	1.5	2		4.5	0.2
	- Cementing & WOC	22.5	7.5			30	1.5
	- Running/ pulling riser BOP	35.5	22.5			58	2.9
	- Flanging up and testing	9	55.5	14		78.5	4.0
	- Fishing			0.5		0.5	
	- Repairs (pumps/ drawworks)	4	3	83.5		90.5	4.6
	- Surveys	4.5	8.5			13	0.7
	- Waiting on weather	36	61			97	4.9
	- Seal assy repair		16.5			16.5	0.8
	Sub total					854.5	43.3
EVALUATION	- Coring (on bottom)		24.5			24.5	1.2
	- Round trip with core barrel		37.5			37.5	1.9
	- Condition hole for coring		5			5	0.3
	- Recovery of core		10			10	0.5
	- Opened cored hole		2.5			2.5	0.1
	- Condition hole for logging		1			1	0.1
	- Logging	18	41			59	3.0
	- RFT testing		22.5			22.5	1.1
	Sub total					162	8.2
TESTING	- Condition hole for tubing		8.5			8.5	0.4
	- Running/ pulling tubing		44	92		136	6.9
	- Rigging up surface eqp. etc.		12	41		53	2.7
	- Circulation/ observing well		19	54.5		73.5	3.7
	- Bullheading/ gravel packing			15.5		15.5	0.8
	- Stimulation/ injectivity test		5.5	7.5		13	0.7
	- Testing BOP's etc.		10.5	6		16.5	0.8
	- Schlumberger wireline		8	15.5		23.5	1.2
	- Flopetrol wireline		12.5	41		53.5	2.7
	- Flowing well		47	162		209	10.6
	- Pressure build ups		2	20.5		22.5	1.1
	- Back-surge operation		15.5	9		24.5	1.2
	- Waiting on weather		7.5	26		33.5	1.7
	Sub total					682.5	34.5
ABANDONMENT	- Schlumberger perforating			21		21	1.1
	- Plugging back and WOC			20.5		20.5	1.0
	- Cutting/ retrieving casing			34	17	51	2.6
	- Pulling riser/ BOP stack			4	5.5	9.5	0.5
	- Laying down string			5.5	4	9.5	0.5
	- Preparing for move				7.5	7.5	0.4
	- Anchor handling				8.5	8.5	0.4
	Sub total					127.5	6.5
	- Towing until end of contract					78.25	4.0
	TOTAL HOURS					1973.25	100 %

Total time: 82 days 5 1/4 hours

TIME/COST CURVE 6407/9-2



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5. MUD REPORT

Mud Report prepared by Dresser was distributed to NPD and partners on April 30, 1985.

6. GEOLOGICAL REPORT

6.1 Sample Collection

Ditch Cuttings

Ditch samples were collected every 10 m from 350 m BDF to 1584 m BDF and every 3 m in the interval from 1584 m BDF to 1865 m BDF (TD).

Masterlog and Cuttings Log were distributed to NPD and partners on 10th January 1985 (see also Encl.1).

Sidewall Cores

Sidewall cores were taken in the 17 1/2" and 12 1/4" hole. A total of 90 sidewall samples was attempted, 79 of which were recovered. A detailed description of the samples is given in Encl.2.

Fiberglass Sleeve Cores

To enable a detailed sedimentological and petrophysical analysis of the reservoir formation, cores were cut in the Frøya Formation and the overlying Kimmeridge Clay Formation:

Core no.1	1638.0 - 1640.0	(recovery 65%)
Core no.2	1640.0 - 1642.5	(recovery 44%)
Core no.3	1653.5 - 1671.5	(recovery 92%)
Core no.4	1671.5 - 1684.0	(recovery 74%)
Core no.5	1684.0 - 1688.0	(recovery 68%)
Core no.6	1688.0 - 1700.0	(recovery 48%)
Core no.7	1700.0 - 1702.0	(recovery 0%)
Core no.8	1702.0 - 1706.3	(recovery 97%)

A detailed lithological description is presented in Encl. 3 and the summary of the reservoir geology and Sedimentology in Encl. 4.

6.2 STRATIGRAPHY

The sedimentary sequence penetrated by well 6407/9-2 is subdivided into lithostratigraphic groups and formations which are defined in the regional framework of the area, based mainly on log correlation supported by biostratigraphic evidence.

Formation tops and the biostratigraphic subdivision are presented in tables 6.1 and 6.2 respectively. The subdivision is also displayed on the completion log and the well summary sheet (Enclosures 1 and 5).

A lithological description of the different formations is summarised below.

Nordland Group/Hordaland Group (247(SF) - 1359 m)

From seafloor (247 m) to 350 m the hole was drilled with returns to seabed.

From 350 m to ca. 1100 m a light grey, very soft, sandy to silty hygroturgid clay was encountered, slightly carbonaceous and occasionally very glauconitic. The clay is dominantly non-calcareous to slightly calcareous and contains traces of quartz and lithic grains and occasional shell fragments.

From ca. 1100 m the clay becomes firmer and grades into a claystone, light to medium grey and occasionally slightly silty. Near the top of the Balder Formation the claystone becomes more brownish, locally red-brown and blue-grey. It locally contains tuffaceous fragments. From ca. 900 m some dolomite/limestone streaks are also encountered.

Rogaland Group (1359 - 1541.5 mss)

Balder Formation (1359 - 1395 mss)

The Balder Formation comprises medium-dark brown-grey claystone with multicoloured tuffaceous fragments and some dolomite/limestone streaks at the base.

Sele/Lista Formation (1395 - 1541.5 mss)

The Sele/Lista Formation is a sequence of light blue-grey, grey-brown, and medium grey claystones occasionally tuffaceous and intercalated with some dolomitic limestone streaks. Near the base of this formation the claystone becomes medium red-brown.

Shetland Group (1541.5 - 1569 mss)

The Shetland Group consists of a light medium grey claystone which is silty and slightly glauconitic. Near the base of this unit the claystone grades into a marl and is separated by an unconformity from the underlying Cromer Knoll Group.

Cromer Knoll Group (1569 - 1595.5 mss)

The Cromer Knoll Group consists at the top of an orange/red-brown mottled, locally calcareous claystone. The bottom part of this unit comprises a light grey to light green-grey marl locally grading into a limestone.

Humber Group

Kimmeridge Clay Equivalent (1595.5 - 1625.5 mss)

The Kimmeridge Clay Equivalent is a sequence of medium to dark grey, bituminous, pyrite-rich claystones.

Frøya Formation (1625.5 - 1677.0 mss)

The Frøya Formation comprises an overall coarsening upward sequence with grey silty and micaceous claystone at the base grading upwards into sandy claystone and micaceous sands which are laminated and strongly bioturbated. At the top a 25 - 30 m thick grey-brown, moderately sorted, CL-FU sand occurs, which is massive to bioturbated (see core description Encl.3 + 4). The base of the Frøya Formation consists of 2-2.5 m third dark grey bituminous claystone overlying a calcite cemented unconformity surface.

Haltenbanken Formation (1677.0 - 1778.5 mss)

The Haltenbanken Formation consists of light grey to light brown-grey, locally silty and sandy kaolinitic claystone at the base. This passes upwards into blocky to funnel-shaped, light to medium grey FU-CrsU, occasionally micaceous sand beds separated by thin micaceous and kaolinitic clays. Some dolomite streaks are also encountered at the base.

Dunlin Group (1778.5 - TD 1840 mbdf)

Upper Drake equivalent (1778.5 - 1804 mss)

The Upper Drake equivalent consists of medium grey, silty, occasionally kaolinitic claystone.

Middle Drake equivalent (1804 - TD 1840 mss)

The Middle Drake equivalent is a predominantly sandy sequence with occasionally thin intercalations of claystone. The sands are very fine to coarse grained, kaolinitic and micromicaceous. Occasionally dolomite streaks and coally layers occur.

TABLE 6.1

FORMATION TOPS

WELL 6407/9-2

	Top (mss)
Nordland Group	247.0
Hordaland Group	763.5
Rogaland Group	1359.0
Top Balder Fm	1359.0
Top Sele/Lista Fm	1595.5
Shetland Group	1541.5
Cromer Knoll Group	1569.0
Humber Group	
Kimmeridge Clay Eq	1595.5
Frøya Fm	1625.5
Haltenbanken Fm	1677.0
Dunlin Group	
Upper Drake Eq	1778.5
Middle Drake Eq	1804.0
Total Depth	1840.0

Table 6.2

Biostratigraphic in well 6407/9-2

Tertiary	Pliocene	430 m DRD - 820 m DRD
	Miocene - Oligocene	830 m DRD - 850 m DRD
	Oligocene	860 m DRD - 1194 m LGD
	Eocene	1202 m LGD - 1441.5 m LGD
	Paleocene	1451.5 m LGD - 1556 m LGD
Cretaceous	Campanian? - Maastrichtian	at 1571.5 m LGD
	Campanian	1572 m LGD - 1589 m LGD
	Aptian - E. Albian	at 1594.5 m LGD
	Hate Hauterivian - Barremian	at 1602.5 m LGD
	Hauterivian - L. Valanginian	at 1604 m LGD
	E-M Valanginian	at 1608.5 m LGD
	L. Berriasian - E. Valanginian	1611 m LGD - 1618 m LGD
	Berriasian	at 1622 m LGD
Jurassic	M-L Portlandian	1627.5 m LGD - 1633 m LGD
	L. Kimmeridgian - E. Portlandian	1637 m LGD - 1667.3 m LGD
	L. Kimmeridgian	1669.5 m LGD - 1675.7 m LGD
	E. Kimmeridgian	1676.5 m DRD - 1607 m LGD
	Oxfordian?/E. Kimmeridgian	1688.1 m DRD - 1700 m LGD
	Bajocian/Oxfordian?	1701 m LGD - 1794.5 m LGD
	M. Toarcian - E. Aalenian	1800 m LGD - 1818.5 m LGD
	L. Pleinsbachian - E. Aalenian	1827 m LGD - 1850 m LGD

LGD = LOG DEPTH
DRD = DRILLER's DEPTH

6.3 HYDROCARBON INDICATIONS

The following is a brief description of hydrocarbon indications as encountered while drilling. The shows are indicated on the completion log (Encl.1).

Tertiary/Quaternary (272 - 1567 mbdf)
In this hole section C_1 was registered (0.1 - 0.5%) down to approximately 1100 mbdf, with a peak of 1.8% around 475 m. Thereafter C_1 (0 - 2%) and traces of C_2 were registered. At 1330 mbdf a peak of C_1 (1 - 4%) and traces of C_2 occurred.

Shetland Group (1567 - 1594 mbdf)
C_1 gas readings of 0.2% up to 1% and traces of C_2 were recorded in this interval.

Cromer Knoll Group (1594 - 1620 mbdf)
C_1 gas readings (0 - 0.5%) and traces of C_2 were observed.

Humber Group (1620.5 - 1735.5)
Kimmeridge Clay Equivalent (1620.5 - 1650.5 mbdf)

Upon entering the Kimmeridge Clay Equivalent C_1, C_2 and C_3 were encountered, up to 1.8, 0.1 and 0.2% respectively.

Frøya Formation (1650.5 - 1702 mbdf)

Gas readings of C_1, C_2, C_3 and C_4 were recorded at the top of the Frøya Fm prior to coring. Direct pale yellowish/white fluorescence was observed in the CORES of the interval between 1651 - 1664 m bdf. Below this depth a yellowish pinpoint fluorescence and occasionally bright cut fluorescence was observed.

Haltenbanken Formation-Dunlin Group (1702 - 1865 mbdfTD)

From the Haltenbanken Formation down to TD (1865 m) occasional traces of C_1 were recorded.

6.4 Seismostratigraphy

Seismic Calibration

A velocity survey was carried out by SSL, with checkshot levels between 524 to 1850 mbdf. Those levels below 1325 mbdf were at 25 m intervals and have been used for VSP processing.

Table 6.3 summarises the times and interval velocities, as defined by the calibrated velocity log, between the major seismic horizons.

Gamma Ray, Sonic and Density logs have been displayed at linear time scale together with the resulting zero phase synthetic seismogram (Encl. 5) for the stratigraphic identification of seismic reflectors. Encl. 6 illustrates the good correlation between the synthetic and seismic section.

Table 6.3

Seismic Interval Velocities 6407/9-2

	Depth mss	Time ms	Velocity m/s
Unconformity 1	408	514	1740
Unconformity 2	612	689	2334
Unconformity 3	764	813	2455
Unconformity 4	835	876	2256
Top Balder	1359	1420	1925
Base Tertiary	1542	1599	2039
Top Lower Cretaceous	1569	1625	2148
Top Kimmeridge Clay	1596	1645	2598
Top Frøya Fm	1626	1673	2143
Top Haltenbanken	1677	1710	2784
Top Dunlin	1779	1784	2743

Times and Velocities are from SSL calibrated velocity log.

Reservoir geology

The Upper Jurassic Frøya Formation was found to be oil-bearing. It consists of a 50 m thick overall coarsening upwards sand sequence interbedded in Kimmeridge Clay Formation.

Based on core analysis the reservoir formation can be subdivided in three distinct lithological units (see Encl. 4):

Unit I (1625.5 - 1651.5 mss) consists of coarse to medium/fine grained, bimodal sands which are moderately sorted, slightly micaceous and argillaceous. Sedimentary structures are poorly developed, mainly comprising burrowing and horizontal laminations.
Porosity ranges between 27 and 32% and permeability between 1 and 6 Darcies with small intervals of 0.2 - 0.4 Darcies. The OWC at 1638 mss falls within this unit.

Unit II (1651.5 - 1674.5) consists of fine-grained, argillaceous and strongly micaceous sands grading downwards into silty micaceous claystone. This coarsening upwards succession is laminated and strongly bioturbated. Open marine fossils (belemnites) are found in this interval. The increase in argillaceous and mica content upwards and decrease in grain size are reflected in a decrease in reservoir properties downwards; porosity ranges from 27% at the top to 25% at the base ; permeability at the top is 200 - 300 mD with thin intervals of 500 mD but rapidly drops to 5 mD and < 1 mD near the base.

Unit III (1674.5 - 1677.5) comprises a 2.5 m thick layer of laminated ,bituminous shales with open marine fauna.

7. Petrophysical Evaluation

A summary of the Schlumberger wireline logs run in the borehole is presented in Table 7.2, and the main logs run over the reservoir are plotted in Figure 7.1.

The top of the reservoir is found at 1625.5 mss, and the reservoir is oil bearing down to an oil-water contact at 1638 mss, which is clearly indicated by the response of the Dual Laterolog curves (see Figure 7.1). The caprock, the Kimmeridge Clay Formation, is identified by a very high Gamma Ray and a very low Sonic log response.

Calculated porosity values indicate the porosity to be fairly constant throughout the reservoir at approximately 27%. Hydrocarbon saturation (plotted in track 6 of Figure 7.1) averages 65% in the oil column.

The Frøya Formation was cored from 1613-1681 mss, with good recoveries between 1627 and 1665 mss. The conventional air permeabilities are plotted in track 4 of Figure 7.1. Permeabilities of upto 5 Darcy were measured in the oil bearing interval, decreasing gradually to 20mD towards the base of the reservoir. (The core permeabilities, porosities and grain densities are tabulated in Table 7.3.).

Two production tests were carried out in the well. The first was in the waterbearing interval (1645-1650.5 mss) and the second in the oil zone (1626-1632 mss). Water samples produced during the water test had a total dissolved solids content of 64,000 ppm.

Crossplots of core porosity (corrected for compaction with an assumed correction factor of 0.95) versus bulk density from the Litho Density log (corrected for borehole effects) has established the following relationships for wells 6407/9-1 and 6407/9-2 over the oil zone and water zone:

$$\text{Ø} = \frac{2.68 - \text{Rhobulk}}{2.68 - \text{Rhofl}}$$

with Rhofl = 1.00 g/cm^3 in the oil zone

and Rhofl = 1.08 g/cm^3 in the water zone

Fig. 7.2 illustrates that the accuracy of the above relationship is approximately 2.5 porosity units.

The hydrocarbon saturation was calculated with the Archie equation, with an assumed value of 2 for the parameters m and n. Core measurements are currently being conducted in order to establish the clay effect (CEC). A crossplot of the Laterolog deep resistivity (LLD) versus the compaction corrected core porosity ($Ø_c$) over the water-bearing cored interval (Figure 7.3) suggests the following relationship:

$$LLD = RwØ_c^{-2}, \text{ with } R_w = 0.08 \text{ Ohmm}$$

The formation water resistivity was taken as 0.08 ohmm to ensure that 100% water saturation was calculated in the waterleg with this saturation model.

Table 7.1

Summary of the Evaluation Parameters:

Porosity - LDL calibration	:	Rhoma = 2.68 g/cm^3 Rhofl = 1.08 g/cm^3 (in water zone) Rhofl = 1.00 g/cm^3 (in oil zone)
Formation temperature	:	67^oC
Formation water resistivity	:	0.08 Ohmm
Porosity exponent (m)	:	2
Saturation exponent (n)	:	2
Average hydrocarbon saturation	:	65%
Net pay thickness	:	12,5 m
Free water level	:	1638.5m

Table 7.2

Main Schlumberger operations in well 6407/9-2

DEPTH CASING mBDF	DEPTH DRILLING mBDF	BIT SIZE inches	LOG TYPE	RUN NO	INTERVAL LOGGED mBDF	DATE	REMARK
346	810	14 3/4	ISF/SLS/GR	1	347 - 814	23.11.84	
			LDL/CNL/GR	1	347 - 813	23.11.84	
		26	BGT/GR	1	347 - 810	25.11.84	
			BGT/GR	2	346 - 810	26.11.84	
			BGT/GR	3	347 - 810	26.11.84	
810	1584	17 ½	ISF/SLS/GR	2	799.5 - 1583	04.12.84	
			LDL/CNL/GR	2	799.5 - 1583	05.12.84	
			SWS/GR	1	802 - 1572	05.12.84	30 samples
1575	1865	12 1/4	ISF/LSS/SP/GR	3	1574 - 1862	19.12.84	
			LDT/CNL/NGT/CAL	3	1574 - 1862	19.12.84	
			MSFL/DLL/GR	1	1574 - 1858	20.12.84	
			SHDT/GR	1	1574 - 1863	20.12.84	
			RFT (pressure)	1	1652.5- 1745.5	21.12.84	28 pressures
			RFT (sample)	2	tool plugged, no recovery		
			SWS	2	1579 - 1851	21.12.84	55 samples
			CBL/VDL/GR/CCL	1	450 - 1574	21.12.84	on 13 3/8" csg
			WST			21.12.84	
			CBL/VDL/GR	2		25.12.84	on 9 5/8" csg
			CNL/GR			18.01.85	over gravel pack

TABLE 7.3
FINAL REPORT

GECO
GEOPHYSICAL COMPANY OF NORWAY A.S
Petroleum laboratory

COMPANY : SHELL
WELL : 6407/9-2
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 3

PAGE: 1

DATE: JANUARY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	horizontal k_{el}	vertical k_a	vertical k_{el}	Porosity (%) He	Porosity (%) Sum.	Pore saturation S_o	Pore saturation S_w	Grain dens. g/cc	Formation Description
	1653.50										
1	1653.65	249	228	293	270	25.8		13.4	53.9	2.66	
2	1654.00	1095	1042			27.5				2.66	
3	1654.30	2007	1929			29.7		17.3	61.1	2.65	
4	1654.60	542	508			28.9				2.66	
5	1655.00	1016	965			27.7				2.66	
6	1655.35	1394	1332			29.2		16.1	60.5	2.65	
7	1655.65	663	625			30.1				2.66	
8	1656.00	664	626			29.6				2.67	
9	1656.35	542	508			28.9		9.2	60.5	2.67	
10	1656.65	890	843	495	463	29.8				2.66	
11	1657.00	775	733			29.7				2.67	
12	1657.30	1026	975			30.3				2.67	
13	1657.65	1306	1246			31.7		12.0	47.9	2.67	
14	1658.00	1173	1117			29.7				2.65	
15	1658.35	nmp				nmp					
16	1658.65	1298	1240			30.6		19.7	52.1	2.66	
17	1659.00	nmp				nmp					
18	1659.35	2338	2252			28.1				2.67	
19	1659.65	4399	4272			29.9		13.0	42.6	2.64	
20	1660.00	2492	2403	1082	1029	28.9				2.65	
21	1660.30	4103	3982			30.8				2.65	
22	1660.65	6013	5859			30.4		14.3	56.6	2.64	
23	1661.00	1729	1658			29.2				2.65	
24	1661.35	322	298			26.0				2.65	
25	1661.65	1444	1380			27.9		13.6	69.9	2.65	
26	1662.00	1076	1024			27.4				2.65	
27	1662.35	992	942			26.3				2.65	

TABLE 7.3
FINAL REPORT

COMPANY : SHELL
WELL : 6407/9-2
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 3 (cont.)

DATE: JANUARY 1985

GECO
GEOPHYSICAL COMPANY OF NORWAY A/S
Petroleum laboratory

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	horizontal k_{el}	vertical k_a	vertical k_{el}	Porosity (%) He	Porosity (%) Sum.	Pore saturation S_o	Pore saturation S_w	Grain dens. g/cc	Formation Description
28	1662.65	6468	6307			30.5				2.65	
29	1663.00	1091	1038			26.9				2.69	
30	1663.35	6625	6461	1853	1779	29.1				2.66	
31	1663.70	13469	13216			30.7				2.65	
32	1664.00	3867	3750			29.0				2.65	
33	1664.35	5413	5269			29.9				2.66	
34	1664.65	4620	4489			32.2				2.67	
35	1665.00	2569	2478			28.3				2.65	
36	1665.35	1807	1734			28.4				2.65	
37	1665.65	3741	3626			31.7				2.64	
38	1666.00	4135	4013			30.7				2.65	
39	1666.40	5248	5107			28.1				2.65	
40	1666.65	5026	4888	1829	1756	29.6				2.64	
41	1667.00	2281	2197			29.4				2.64	
42	1667.35	2510	2421			30.0				2.65	
43	1667.65	2273	2189			26.7				2.65	
44	1668.00	865	819			30.7				2.64	
45	1668.35	1159	1103			26.8				2.64	
46	1668.65	5056	4917			31.1				2.64	
47	1669.00	387	360			26.2				2.65	
48	1669.40	633	596			29.7				2.65	
49	1669.65	342	317	224	205	26.2				2.66	
	1670.00										

TABLE 7.3
FINAL REPORT

COMPANY : SHELL
WELL : 6407/9-2
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 4

PAGE: 1

DATE: JANUARY 1985

GECO
GEOPHYSICAL COMPANY OF NORWAY A/S
Petroleum laboratory

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	horizontal k_{el}	vertical k_a	vertical k_{el}	Porosity (%) He	Porosity (%) Sum.	Pore saturation S_o	Pore saturation S_w	Grain dens. g/cc	Formation Description
	1671.50										
50	1671.65	191	174	195	177	25.0				2.65	
51	1672.00	3886	3768			30.0				2.66	
52	1672.35	2270	2186			30.0				2.67	
53	1672.65	468	437			27.1				2.65	
54	1673.00	2732	2638			33.8				2.66	
55	1673.35	1480	1416			29.3				2.66	
56	1673.65	191	174			26.0				2.65	
57	1674.00	483	451			27.7				2.68	
58	1674.40	376	349			28.9				2.71	
59	1674.65	361	335			30.2				2.65	
60	1675.00	1408	1346	923	875	32.0				2.67	
61	1675.35	170	153			29.3				2.65	
62	1675.65	0.014	0.010			3.3				2.68	1
63	1676.00	482	451			30.8				2.66	
64	1676.35	227	208			28.2				2.70	2
65	1676.65	248	228			29.3				2.66	
66	1677.00	219	200			29.2				2.65	
67	1677.35	330	305			29.0				2.66	
68	1677.65	301	278			29.2				2.65	
69	1678.00	802	758			30.8				2.66	
70	1678.35	275	253	276	254	31.5				2.66	
71	1678.65	167	151			29.1				2.66	
72	1679.00	58.5	50.5			27.7				2.65	
73	1679.35	158	143			30.6				2.65	
74	1679.65	552	517			33.4				2.66	
75	1680.00	116	103			28.7				2.66	
76	1680.65	npp									
	1684.00										

TABLE 7.3

FINAL REPORT

COMPANY : SHELL
WELL : 6407/9-2
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 5

DATE: JANUARY 1985

GECO
GEOPHYSICAL COMPANY OF NORWAY A/S
Petroleum laboratory

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	k_{el}	vertical k_a	k_{el}	Porosity (%) He	Sum.	Pore saturation S_o	S_w	Grain dens. g/cc	Formation Description
	1684.00										
77	1684.00	12.8	10.2			23.5				2.65	
78	1684.35	119	106			29.9				2.67	
79	1684.65	158	142			30.8				2.67	
80	1685.00	256	235	162	146	33.2				2.67	
81	1685.35	124	111			31.4				2.67	
82	1685.80	2.9	2.5			16.3				2.62	
	1688.00										

GECO
GEOPHYSICAL COMPANY OF NORWAY A·S
Petroleum laboratory

TABLE 7.3

FINAL REPORT

COMPANY : SHELL
WELL : 6407/9-2
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 6

PAGE: 1

DATE: JANUARY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	horizontal k_{el}	vertical k_a	vertical k_{el}	Porosity (%) He	Porosity (%) Sum.	Pore saturation S_o	Pore saturation S_w	Grain dens. g/cc	Formation Description
	1688.00										
83	1688.00	50.2	43.1	7.5	6.5	27.4				2.66	
84	1688.35	59.3	51.4			29.2				2.67	
85	1688.65	75.3	65.8			30.4				2.67	
86	1689.00	51.9	44.6			28.7				2.67	
87	1689.35	12.7	10.3			25.0				2.67	
88	1689.60	40.8	34.6			27.9				2.67	
89	1690.00	9.4	8.3			25.1				2.66	
90	1690.35	16.7	13.6			25.3				2.66	
91	1690.65	20.6	16.9			26.4				2.66	
92	1690.95	3.9	3.3			22.8				2.66	
93	1691.35	20.8	17.1	8.9	6.9	27.3				2.67	
94	1691.65	9.4	7.4			25.8				2.66	
95	1692.00	2.5	2.1			25.5				2.68	
96	1692.35	42.9	36.5			28.9				2.68	
97	1692.65	38.1	32.2			32.0				2.66	
	1700.00										

2

TABLE 7.3

FINAL REPORT

GEOPHYSICAL COMPANY OF NORWAY A-S
Petroleum laboratory

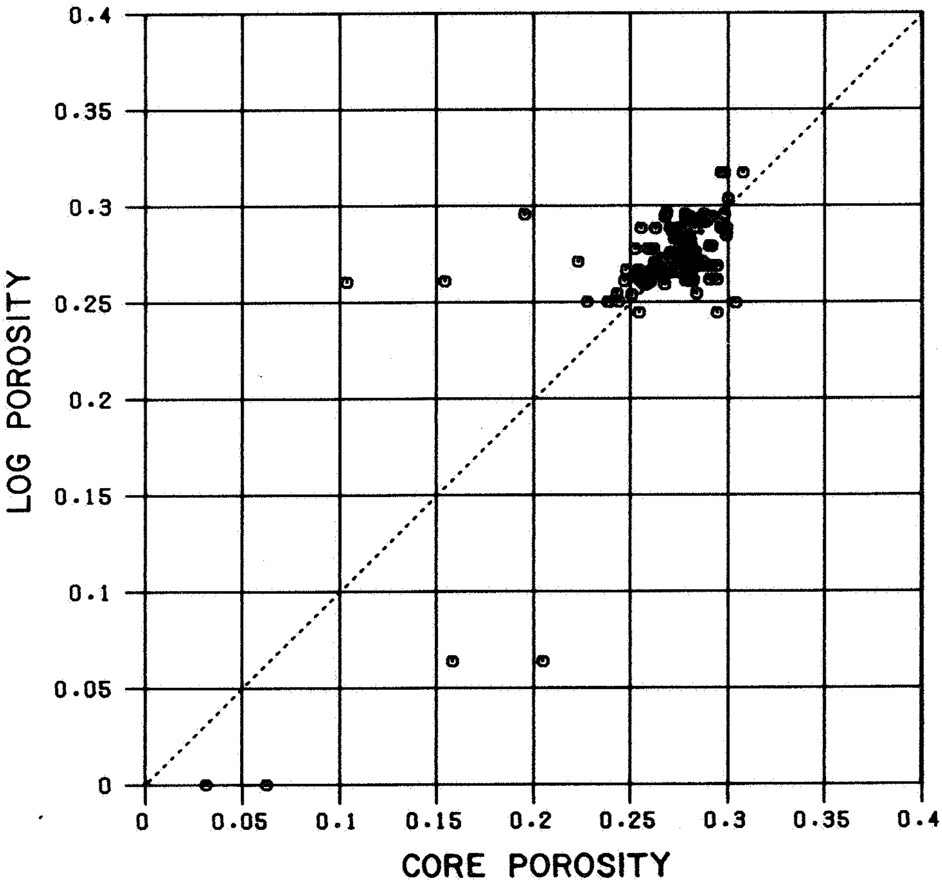
COMPANY : SHELL
WELL : 6407/9-2
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 8

DATE: JANUARY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	k_{el}	vertical k_a	k_{el}	Porosity (%) He	Sum.	Pore saturation S_o	S_w	Grain dens. g/cc	Formation Description
	1702.00										
98	1702.35	<0.01	<0.01			2.5				2.76	
99	1702.65	0.037	0.027			5.0				2.73	
100	1703.00	0.79	0.61	0.15	0.11	13.9				2.69	
101	1703.35	166	150			28.1				2.64	
102	1703.65	85.9	75.5			26.0				2.66	
103	1704.00	132	118			27.3				2.65	3
104	1704.35	249	228			29.1				2.64	
105	1704.65	155	140			28.8				2.67	
106	1705.00	310	287			32.4				2.66	
107	1705.35	284	262			31.5				2.66	
108	1705.65	229	209			31.0				2.66	
109	1706.00	310	287	183	166	32.5				2.66	
	1706.30										

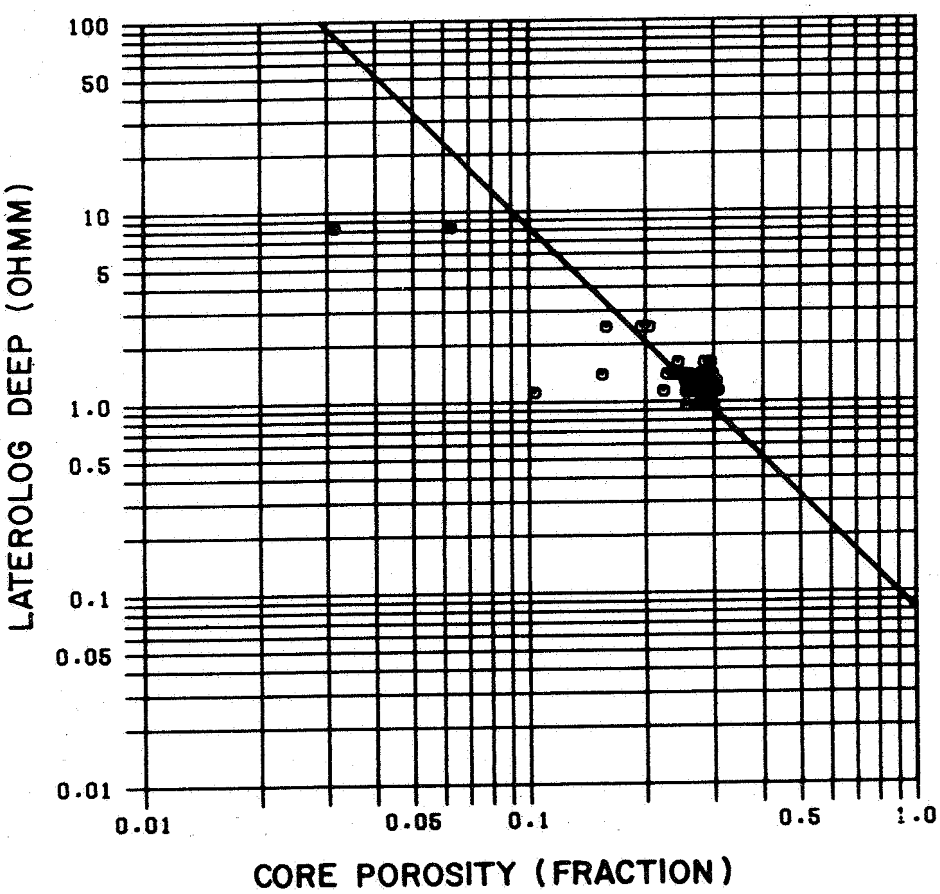
COMPARISON OF LOG POROSITY TO CORE POROSITY



CROSSPLOT OF LOG POROSITY VERSUS CORE POROSITY. THE CORE POROSITY IS COMPACTION CORRECTED WITH A FACTOR .95. DATA OF THE WHOLE CORED INTERVAL IS INCLUDED.

A/S Norske Shell EXPLORATION & PRODUCTION FORUS			
COMPARISON OF POROSITIES			
AUTHOR EPPP/32	FIG	DATE JAN. 1985	
REPORT NO. NSEP 238	7.2	DRAW. NO. G 1847/9	

CROSSPLOT OF LATEROLOG DEEP VERSUS CORE POROSITY OVER WATER BEARING INTERVAL



CROSSPLOT OF LATEROLOG DEEP VERSUS CORE POROSITY. ONLY WATER BEARING SANDS ARE INCLUDED (BELOW 1563.5 MAH). THE ASSUMED WATER TREND LINE RD = .08 * PHI ** -2 IS DRAWN IN. THE LOG IS BOREHOLE CORRECTED.

A/S Norske Shell EXPLORATION & PRODUCTION FORUS			
CROSSPLOT LLD-CORE POROSITY			
AUTHOR EPPP/32	FIG	DATE JAN. 1985	
REPORT NO NSEP 238	7.3	DRAW NO. G 1847/10	

Chapter 8

PRODUCTION TEST EVALUATION

8.1 SUMMARY

Prior to testing several runs were made with the RFT: the reservoir pressure measured was hydrostatic, 2392 psia at a datum of 1630 m ss. The OWC could not be accurately determined using the RFT pressures. No downhole sample was recovered due to repeated plugging of the sampling probe.

The waterzone was perforated from 1645 to 1650.5 m ss. Formation water samples recovered contained an equivalent of some 64,000 ppm NaCl. Laboratory analysis has shown that the sample may not be representative of formation water. An eight hours water injection test at rates up to 8000 b/d did not reveal any immediate problems related to injection of unfiltered clean seawater. The (semi-steady state) water injectivity index (clean cold seawater), assuming a skin of 20, is 19 b/d/psi.

After abandonment of the waterzone test the oilzone was perforated from 1626 to 1632 m ss. The well was gravelpacked and rates up to 7400 stb/d of 40^{o} API oil were achieved. The evaluation showed a permeability of 2.6 Darcy. Observed productivity indices after gravel packing varied from 10.7 to 15.2 stb/d/psi. Skins calculated ranged from 117 to 174. The reservoir pressure from build-up surveys was 2390 psia at datum. Due to weather related problems no downhole samples were recovered.

8.2 OBJECTIVES

The objectives for testing the waterzone were:

1. to obtain representative formation water samples
2. to determine reservoir properties
3. to evaluate short term water injectivity

The objectives for testing the oilzone were:

1. to determine reservoir quality/parameters
2. to determine oil deliverability
3. to collect oil samples, both at surface and downhole
4. to evaluate the need for sand exclusion techniques in a possible future development

8.3 OPERATIONAL REVIEW

8.3.1 RFT Surveys

The objective of the RFT surveys was to measure reservoir fluid pressures and gradients and to collect a downhole oil sample. To obtain high quality pressure data a Hewlett Packard crystal gauge was used.

On the first run an attempt was made to collect a segregated sample. Plugging of the sample probe occurred immediately and no further data could be collected. Numerous successful pressure measurements, both in the Frøya and Haltenbanken Formations (see Table 8.2), were made on run number 2. No attempt to collect a sample could be made due to a tool failure occurring after 24 pre-tests. Several pre-tests were repeated on run three prior to an unsuccessful sampling attempt. A final attempt, run four, to collect a segregated sample was made with the tool equipped with a modified ("Martino") sampling probe. This attempt failed too.

A total of 28 successful RFT pressure readings were obtained on the four runs that were made (see Table 8.2 and Fig. 8.4). Of these 9 were in the hydrocarbon bearing column in the Frøya

Formation, 13 were in the waterleg of this formation and the remaining 6 were in the underlying waterbearing Haltenbanken Formation. All pressures appeared to be fully built up.

The gauge used throughout was a Hewlett Packard crystal gauge. This resulted in the acquisition of high quality pressure data.

8.3.2 Water Zone Testing

8.3.2.1 Sequence of Events

The 9-5/8" casing was perforated under some 300 psi drawdown with a tubing conveyed gun on 5" drillpipe (12 shots/ft) from 1645 to 1650.5 m ss in the water leg of the Frøya Formation (Fig. 8.1). The well was allowed to flow (DST-1) some 25 bbls on a 40/64" bean in 8-1/2 minutes and was shut in at the PCT-valve to record a 35 minutes pressure build-up (see Table 8.3). After re-opening the PCT-valve, the well did not flow due to a sand bridge at 1571 m ss in the tubing (24 m above the valve). The test-string was pulled to circulate out the sand. Some 80 bbls of brine were lost whilst cleaning out the hole.

Subsequently the test assembly was rerun with sand screens. An acid wash of 10 bls 15% HCl (+ additives) was carried out. The well was circulated to diesel and allowed to flow (DST-2). This operation had to be repeated five times as the well died when the water/brine/spent acid reached surface. After a cumulative production of 323 bbls the water salinities measured did not change significantly anymore and uncontaminated formation water was probably being produced.

Before reverse circulating out the final tubing contents three bottomhole samples were taken on one run, only one of which was successful.

The water injection test was started at an initial rate of 8000 b/d of seawater. The rate was reduced after one hour to 7000 b/d in order not to exceed a surface injection pressure of 800 psig. This rate was maintained for 7-1/2 hours. The downhole PCT-valve was immediately shut afterwards to record the fall off pressures during one hour, after which the test interval was abandoned.

During the injection period the cleanliness of the seawater injected was monitored. Filtering was considered unnecessary as the turbidity was very low and the particle size less than 15 microns.

8.3.3 Oil Zone Testing

8.3.3.1 Sequence of Events

On completion of the waterleg test during which some sand was produced immediately after perforating, it was decided to test the oilbearing interval using an interval gravel-pack.

After perforation of the interval 1626 to 1632 m ss with a 12 shots/ft tubing conveyed gun the well was flowed briefly (PT-1A) at low rates just to clean the perforation tunnels. The interval was then gravel-packed through 5" drillpipe using 12 ppg of 10/20 gravel (see Fig. 8.2 for the completion diagram).

After gravel packing the well could be flowed (PT-1B, see also Fig. 8.3 for the ensuing events) at a maximum rate of only some 1000 stb/d of oil. The well was stimulated with 45 bbls 15% HCl (+ additives) directed with 15 bbls of gel. Subsequently (PT-1C), after reversing to diesel three times, the well came live again. The final flow rate measured was 5178 stb/d on a 2" bean. Detailed data on this flow period and other periods is given in Table 8.4.

A three rate drawdown test (PT-1D) was carried out. During the final period, which lasted 11 hours, the well was flowed at rates between 4400 and 4500 stb/d on a 80/64" bean. Four sets of separator recombination samples were taken during this flow period. During the first 15 minutes of the ensuing 10 hours pressure build-up (PBU) survey the well was disturbed by pumping fluids into the annulus and the downhole recorded pressures were somewhat affected. Due to mechanical problems the PCT-valve could not be reopened after the PBU and the tubing had to be pulled.

At this stage the objectives of testing the oil column had not entirely been met: oil rates achieved were not very high and no downhole samples had been collected. The well was therefore recompleted.

After flowing the well for half a day (PT-1E) the oilzone was stimulated a second time with 48 bbls 15% HCl (+ additives).

The flowing/stimulating cycle was repeated once more with this time 96 bbls 15% HCl (+ additives), as the rate of 6479 stb/d achieved during PT-1F was thought to be surpassable.

During PT-1G after this third and final acid job the well flowed at a maximum rate of 6984 stb/d on a 2" bean.

A second three rate drawdown test (PT-1H) and PBU survey was carried out. It was planned to flow the well at maximum rate for 45 hours to investigate possible productivity improvement with time. However, this flow period had to be restricted to 22 hours; a combination of high winds and sub-zero temperatures resulted in severe icing and in mechanical problems. The maximum rate achieved was some 7400 stb/d waterfree production through simultaneously a 2" fixed and a 1-1/2" variable bean. No improvement with time was observed.

Due to the mechanical problems experienced the PBU survey lengthened to 3 days, thus yielding interesting data on pressure oscillations caused by variations in the lunar and solar gravitational forces (see also Section 8.4.3).

At this stage testing had to be abandoned and consequently no bottomhole samples were recovered.

8.3.3.2 Oil Zone Fluid Sampling

Details of the samples collected are given in Table 8.6.

As no water was produced no surface water samples were collected. No downhole oil samples were recovered.

Analysis of the surface recombination samples is presently being carried out. Bubble points at reservoir temperature will be determined prior to selecting one particular set for detailed PVT analysis. In addition separator flashes and saturated oil viscosity measurements at a low temperature of 40^0F (subsea flowlines!) will also be carried out.

Measured separator oil gravities during testing varied from 0.8227 - 0.8290 g/cm^3 (40.3 - 39.0^0 API). Separator gas gravities ranged from 0.935 to 1.16 (air = 1). No H_2S was recorded, while 1% CO_2 was present.

8.4. EVALUATION OF TESTS

8.4.1 RFT Surveys

The water gradient, calculated at 0.443 psi/ft, is identical to the gradient observed in well 6407/9-1.

The oil gradient yielding the best fit is 0.372 psi/ft, compared to 0.326 psi/ft in well 6407/9-1. Taking into consideration that during testing 0.326 psi/ft was measured in this well and that the oil column is relatively thin, 0.326 psi/ft has also been used in the evaluation of these RFT measurements.

The resulting pressures at datum (1630 m ss) are tabulated in Table 8.2. A datum pressure of 2392 psia is indicated as initial pressure.

From RFT pretests permeability may be calculated using an empirical Schlumberger equation. Some values are shown in the comment column of Table 8.2. These could only be calculated, because the HP gauge has a very good resolution of 0.01 psi.

8.4.2 Water Zone

8.4.2.1 Theoretical Well Model

The analysis of a PBU survey in general is based on a Horner type of pressure - time plot. The theoretical pressure response (transient state) in a partially perforated well after a rate change is shown in Fig. 8.5.

The selection of the appropriate semi-log straight line is normally solved by the Gringarten type curve matching technique. This technique depends on the presence of wellbore storage effects (i.e. afterflow), in which case a log   p versus log   t plot shows an initial straight line section. Fig. 8.11 shows an representative example of this type of plot for this well. As in very highly permeable reservoirs, such as this one, afterflow effects may completely mask the early PBU data a downhole valve has been used in the well completion. Consequently no afterflow effects are present and the Gringarten technique cannot be used.

A second technique, which has been used throughout in this test, depends on calculation of the approximate times either until which only the perforated interval thickness contributes to flow or after which the total sand thickness contributes. These two times, which are illustrated in Fig. 8.5, are respectively:

$$t_A = \frac{0.06\ Ø\ u\ c\ hp^2}{0.000264\ k_v} \qquad \text{hrs}$$

$$t_B = \frac{0.13\ Ø\ u\ c\ h^2\ (1 + \cos \quad b)}{0.000264\ k_v} \qquad \text{hrs}$$

where

- $Ø$ = porosity (fraction)
- u = fluid viscosity (cP)
- c = total system compressibility (psi^{-1})
- hp = thickness perforated interval (ft)
- h = thickness total interval (ft)
- k_v = vertical permeability (mD)
- b = fractional completion, hp/h

for

$Ø$ = 0.29	we find	t_A = 2.2 secs
u = 0.7 cP		
c = 0.00002 psi^{-1}		
hp = 20 ft		t_B = 1.5 mins
h = 85 ft		
k_v = 1000 mD		
b = 0.15		

This means that the "Horner" semi-log straight line for the total layer thickness may be drawn through all points more than 1.5 mins after closing in. As a general rule in this evaluation the "Horner" semi-log straight line is taken to begin for t = 3 mins.

8.4.2.2 DST-1 Evaluation

The well produced 25.2 bbls of water in 8.5 minutes. The flowing bottom hole pressures increased with time due to the increasing hydrostatic head, some sand production and the backpressure on the choke manifold.

A constant flowrate can be calculated (given the constant inner diameter of the drillstring) for the observed periods with linearly increasing bottomhole pressures. Such a constant rate implies that the rate is independent of drawdown. This suggests that the flow is choked by the completion equipment below the pressure gauge depth, which means that the recorded flowing bottomhole pressure data are invalid and the flow period can not be analysed.

In the evaluation of the 35 minutes build-up period the Gringarten type curve analysis could not be used due to the extremely short afterflow period. Application of the second technique described above assumes a homogeneous interval. However, core permeabilities indicate the perforated interval to be bounded by sands with permeabilities of a factor 10 lower. This can result in a time t_B in the order of 6 minutes before the total thickness of the sand layer is sensed. The "Horner" semilog straight line, drawn from point 38 (45 seconds) to point 47 (3 minutes) probably represents therefore only the perforated interval. The permeability thickness product is about 22700 mD. ft and resulted in a permeability in the order of 1260 mD. (Fig. 8.7, Table 8.7 for basic data). This corresponds with the average core plug permeability of 1150 mD of the perforated interval.

The extrapolated pressure is 2353 psig at 1638.5 m bdf, which corresponds to 2395 psia at a datum depth of 1630 m ss.

The results give only an order of magnitude assessment of the sand quality close to the perforated interval.

8.4.2.3 DST-2 Evaluation

Although a water sample with low salinities was recovered during DST-1, no validity check could be made by collecting further samples due to the presence of a sand blockage above the PCT-valve after DST-1. The well was therefore recompleted with as main objective the recovery of additional formation water samples. This required the well to be circulated to diesel and be allowed to produce to surface six times. The resistivity measured on-site was 0.16 Ohm.meter at $60^{0}F$. This is equivalent to a salinity of 51000 ppm NaCl.

One run was made with a bottomhole sampler, recovering one sample only (37500 ppm Cl^-) before the last surface samples were reversed out of the tubing. A detailed laboratory water analysis is also given in Table 8.8

Laboratory work recently carried out has shown that the water composition, as given in Table 8.8, will be unstable at reservoir conditions and that the watersample therefore cannot be representative.

8.4.2.4. Water Injection Test Evaluation

Two straight lines are present in the semi-log plot, the last one of which extrapolates to the initial pressure at the end of the closed in period (see Figs. 8.8 and 8.8). This line over the interval from 39 to 60 minutes (point 38 to 49) was therefore used in the Horner analysis, which yielded a permeability thickness product of 92400 mD ft using a warm water viscosity of 0.468 cP and a skin value of 61.

The high skin value is almost entirely due to the presence of cold injection water. With a cumulative injected volume of 2490 bbls of seawater the injection radius ranges from 20 ft to 30 ft. This leads to a skin introduced by the cold water bank of 41. With a partial completion skin of 15 the Darcy skin has to be about 5.

Calculation of the starting time t_B of the second radial flow period indicates that the total sand thickness contributes to the permeability thickness product. This means that the average permeability of 1100 mD for the 26 m sand does not agree well with the measured core permeabilities of about 2-3 Darcy.

The (semi-steady state) water injectivity index (clean cold seawater), assuming a skin of 20 is calculated to be 19 b/d/psi.

The extrapolated pressure of 2399 psia at 1664.0 m bdf is equivalent to a pressure of 2390 psia at datum depth of 1630 m ss.

8.4.3 Oil Zone Evaluation

Transient state drawdown analysis proved to be impossible in this highly permeable reservoir. Pressure fluctuations caused by slightly varying rates, wellhead temperatures and pressures mask the transient pressure response.

For the evaluation of the pressure build up survey after PT-IH the actual flowrates were squared into three periods of constant rate, which together with the recorded bottomhole pressures are plotted in Figure 8.10. A "Horner" plot constructed using the superposition technique for transient pressure analyses is shown in Fig. 8.11. Apart from the unconventional bending character this plot also shows an oscillating pressure response for later times. Fig. 8.12 shows the last section of the PBU enlarged in a p- t plot. An approximate 12 hours cycle can be readily recognised. Further investigation showed that the phasing of the oscillations could be correlated with the phasing of the tides in Bergen - Western Norway. Both evidently result from the varying lunar and solar gravitational forces. This phenomenon has been observed before in well testing in the Statfjord field (Ref. 1). The hand-filtered PBU "Horner" plot is shown in Fig. 8.13.

Using the technique described above the "Horner" semi-log straight line is drawn from point 41 resulting in a kh product of 223 Darcy.ft or a permeability of 2.6 D. The bending of the "Horner" plot may possibly be explained by assuming improving reservoir qualities away from the subject well. An evaluation of the later part yielded a permeability of some 5 D at a time when the radius of investigation was over 1.5 km, almost halfway to well 6407/9-1 where a permeability of over 7 D has been observed.

The evaluated formation pressure translated to datum depth was 2389.35 psia before and 2390.21 psia after PT-1H. Indications are that the pressure was not fully build-up before this multirate test. The well had only been closed in for 5.6 hours in between PT-1G and -1H.

A summary of the evaluation of all the PBU surveys is included as Table 8.9

Skins calculated using a permeability of 2.6 D were 120, 146 and 118 for flow periods 1, 2 and 3 of PT-1H (crystal gauge). As the pressure during flow was measured amidst turbulent flow inside the tailpipe some pseudo rate dependency will have been introduced in the PI and skin. Rate dependency of skin and PI was particularly noticeable during PT-1D (see Fig. 8.15 for PI's and Table 8.9 for skins at different rates). Of the total skin measured 13 resulted from partial penetration effects, the remainder being the result of drilling damage, lost fluids, gravel packing etc.

A summary of PI measurements is given in Table 8.10

8.4.4 Reservoir Pressure

The average reservoir pressure established during the RFT surveys was 2392 psia (at datum 1630 mss). The extrapolated reservoir pressure after the first DST was 2395 psia (at datum) and after the water injection test 2385 psia (at datum). A summary of datum pressures for the oil test is given in Table 8.11. The evaluated pressures ranged from 2388 to 2391 psia (at datum).

The absolute accuracy of the gauges used is $\pm$ 5 psi for the strain gauges and $\pm$ 3.5 psi for the crystal gauge.

8.5. RESULTS AND CONCLUSIONS

8.5.1 RFT Surveys

i) The water gradient was established as 0.443 psi/ft, identical to well 6407/9-1

ii) The Frøya and the underlying Haltenbanken Formations belong to the same hydrostatic pressure regime

iii) A pressure of 2392 psia at a datum depth of 1630 m ss was established

iv) Due to the unconsolidated nature of the Frøya Formation downhole RFT sampling was unsuccessful

8.5.2 Water Zone Testing

i) Formation water recovered contains some 36400 ppm Cl^-, R_w = 0.16 Ohm.m (at 60^o F) equivalent to 64,000 total dissolved solids. Later laboratory work suggests that the water sample may not be representative of formation water.

ii) Formation parameters evaluated from the fall-off test were:

- reservoir pressure 2395 psia at 1630 m ss
- permeability to water $\pm$ 1150 mD for the 26 m sand
- injectivity index 19 b/d/psi (for a skin of 20)

iii) Injection of clean unfiltered seawater at 8000 and 7000 b/d presented no problems, but high "cold water"skins were calculated. In total 2409 bbls were injected

8.5.3 Oil Zone Testing

i) The well produced up to 7400 stb/d of 40^o API oil from the interval 1626 - 1632 m ss, the separator GOR was 210 scf/stb. Cumulative oil production amounted to 20500 stb

ii) Observed PI's varied from 10.7 to 15.2 stb/d/psi for the gravel-pack completion

iii) Skins varied from 118 to 175, equivalent to 92 to 95% of the total drawdown. A partial penetration skin of 13 was calculated

iv) The evaluated kh product was 223 Dft, equivalent to a effective oil permeability of 2.6 D

v) The calculated ideal PI was some 230 stb/d/psi with zero skin or equivalent to 75 stb/d/psi with a partial completion skin of 13 and a Darcy skin of 5

vi) The reservoir pressure calculated was 2390 psia at datum (1630 m ss)

vii) No downhole samples were recovered

8.6. REFERENCES

1. "Pulse Testing in the Statfjord Field", by M.J. Rathbone et.al., SPE paper 10267, October 1981

2. "Well Testing Report, 6407/9-2, by Flopetrol, Report no. 85/2301/05, February 1985

3. Pressure Survey Reports:

   - "PT-1A, MRPG Gauges", by Sperry Sun, Report No. NR-MS-40251, February 1985
   - "PT-1D, Flopetrol Gauges", by Flopetrol, Report Nos. ELS-85.05A, B and C, February 1985
   - "PT-1H, Flopetrol Gauges", by Flopetrol, Report Nos. ELS-85.09A, B and C, February 1985

WELL : 6407/9-2
WATER TEST SUMMARY
INTERVAL 1645 - 1650.5 m ss

Test	DST-1	Water Inj. Test		
Date	26.12.84	28.12.84		
Flow Period, mins	8.5	60	450	60
Average Rate, b/d	4270	-8000	-7000	0
Cumulative, bbls	25.2	- 330	-2490	0
THP, psig	0-160	800	722	-
Final FBHP, psig	2300	2674	2758	-
Final CIBHP, psig	2353	-	2405	2405
kh, mD.ft	22700	-	-	92400
k, mD	1260	-	-	1080
Skin 2)	- 2.2	-	61	-

Comments

1. DST-1; prior to opening the downhole valve, the tubing was filled with diesel. Gauge depth 1638.5 m bdf

2. Water Injection Test; gauge depth 1664.0 m bdf. The total skin of 61 is composed of a partial completion skin of 15, a Darcy skin of 5 and a skin due to injection of cold water of 41

3. DFE is 25 m above MSL

4. Formation water salinity is 36400 ppm Cl^-

5. Cold seawater injectivity is 19 b/d/psi (assuming a skin of 20)

WELL : 6407/9-2

WATER ZONE TEST : SEQUENCE OF EVENTS

FLOW PER.	TIME OF START	THP psig	BHP (1638.5 m) psig	CUM. PROD. bbls	PROD. RATE b/d (est.)	COMMENTS
DST-1	26.12.84					
						Displace tbg to
	15:50		1994.7 (133^{o}F)			diesel
	15:51		1992.1			Perforate
	15:54	336				1670-1675.5 m bdf
	15:55		2349.0			Close PCT valve
	17:35		2349.3 (133^{o}F)			
	17:37:15	-	2279.0			Open PCT valve
	17:38	160	2275.9			and flow on
	17:39	135	2280.0			40/64 inch choke
	17:40	120	2286.2	10.0	5236	
	17:41	98	2290.3			
	17:42	90	2293.0			
	17:43	80	2294.9	17.6	3650	
	17:44	71	2296.4			
	17:45	63	2300.1	22.8	3745	
	17:45:45	-	2302.5	25.2	4608	Close PCT
						P.B.U. survey
	18:21	-	2352.8			Open PCT
						no flow, due
						to sand bridge
	18:28		2351.8			Close PCT
	19:10					Open MORV
	19:40					Reverse out

Whilst reversing out recovered samples

Sandbailer indicated hold up depth = 1595 m bdf which is some 38 m above the packer. Pulled test string to circulate out sand

WELL : 6407/9-2

WATER ZONE TEST : SEQUENCE OF EVENTS

DATE TIME	DESCRIPTION
27.12.84	Pulled DST-1 assembly Lost 80 bbls brine whilst circulating out sand Ran DST-2 assembly
28.12.84	Circulated 10 bbls 15% HCl (+ additives), set packer, closed PCT valve, opened MORV, circulated tubing to diesel
19:00	DST-2a: Opened PCT, flowed well, cum. prod. 44.6 bbls
29.12.84	
00:30	Closed PCT, reversed out, took samples. Circulated tubing to diesel
02:00	DST-2b: Opened PCT, flowed well, cum. prod. 96.5 bbls
13:00	Closed PCT, reversed out, took samples Circulated tubing to diesel
15:30	DST-2c: Opened PCT, flowed well, cum. prod. 142.4 bbls
22:00	Closed PCT, reversed out, took samples Circulated tubing to diesel
30.12.84	
00:30	DST-2d: Opened PCT, flowed well, cum. prod. 193.7 bbls
08:30	Closed PCT, reversed out, took samples Circulated tubing to diesel
11:00	DST-2e: Opened PCT, flowed well, cum. prod. 258.1 bbls
19:00	Closed PCT, reversed out, took samples Circulated to diesel
21:00	DST-2f: Opened PCT, flowed well, cum. prod. 323.4 bbls
31.12.84	
04:30	Ran 3 BHS + gauge, took 3 samples simultaneous
09:00	Closed PCT, reversed out, took samples Circulated to seawater for water injection test Opened PCT. Ran 2 SDP-gauges and hung off in RN-nipple
15:00	Closed PCT
18:30	Opened PCT. Performed seawater injection test at 8000 b/d and 7000 b/d
01.01.85	
03:00	Closed PCT and recorded fall off test
04:00	Ran in with wireline and retrieved gauges Closed PCT, reversed out seawater, spotted viscous brine, circulated to brine, pulled DST-2 assembly with packer, abandoned water test zone

WELL : 6407/9-2

SUMMARY OF SEPARATOR DATA

DATE TIME	THP/THT psig/°F	OIL-RATE stb/d	GOR scf/stb	Psep/Tsep psig/°F	BHP psia	COMMENTS
07.01.85						PT-1A 2D
						BHP 1622.5 m bdf
20.30	470/44	239	354	60/100	2328.9	Oil Grav. =
21.00	478/44	450	192	60/103	2329.0	0.8227
21.45	490/44	260	160	60/89	2333.4	
22.30	487/42	98	505	57/90	2334.3	Gas Grav. =
23.00	487/42	90	509	60/87	2334.3	0.99 (air = 1)
23.30	487/42	100	459	60/89	2334.0	
13.01.85						PT-1B 12Dd
17.00	142/48	743	307	77/104	--	
17.30	137/48	855	312	69/110	--	1% CO_2
18.00	135/48	884	291	69/116	--	0 ppm H_2S
18.30	131/48	909	280	69/117	--	
19.00	129/48	893	280	66/118	--	
19.30	128/48	862	288	67/118	--	Oil Grav. =
20.00	125/48	897	277	66/118	--	0.834
20.30	93/48	1730	233	49/118	--	
21.00	87/48	1182	347	37/117	--	Gas Grav. =
21.30	84/48	1151	348	37/117	--	1.16 (air = 1)
22.00	82/48	1095	351	38/118	--	
22.30	79/48	1044	360	37/118	--	
23.00	77/48	909	398	36/118	--	
23.30	75/48	991	353	37/116	--	
14.01.85						PT-1C 6Dd
13.00	286/50	1665	257	86/120	--	32/64" bean
13.30	289/50	1679	263	89/121	--	Oil Grav. = 0.8317
14.00	295/50	1681	275	92/122	--	Gas Grav. =
14.30	299/50	1772	267	89/122	--	1.005 (air = 1)
15.00	301/50	1795	262	90/122	--	
15.30	304/50	1847	255	91/122	--	0 ppm H_2S
16.00	307/52	1887	252	91/122	--	1% CO_2
16.30	309/52	1861	256	92/122	--	
17.00	263/54	2487	248	97/122	--	44/64" bean
14.01.85						PT-1C 7Dd
18.00	236/57	2957	244	104/125	--	48/64" bean
18.30	239/58	3005	241	105/124	--	
19.00	242/60	3059	236	104/124	--	
19.30	243/60	2969	245	104/124	--	
20.00	244/60	3053	240	106/126	--	
20.30	246/61	3071	245	106/124	--	

WELL : 6407/9-2

SUMMARY OF SEPARATOR DATA

DATE TIME	THP/THT psig/°F	OIL-RATE stb/d	GOR scf/stb	Psep/Tsep psig/°F	BHP psia	COMMENTS
14.01.85						PT-1C 8Dd
21.00	198/64	3898	239	105/126	--	60/64" bean
21.30	189/64	3974	255	96/124	--	72/64" bean
22.00	188/66	3945	264	92/124	--	
23.00	192/68	4109	254	92/124	--	
24.00	193/68	4214	250	-/-	--	
15.01.85						PT-1C 9Dd
01.00	132/72	4933	277	62/105	--	2" bean
02.00	132/72	5015	273	62/104	--	Oil Grav. =
03.00	133/72	5042	267	62/104	--	0.8260
04.00	134/72	5107	263	62/104	--	Gas Grav. =
05.00	134/72	5099	265	63/104	--	1.005 (air = 1)
06.00	136/72	5135	264	63/105	--	0 ppm H_2S
07.00	136/72	5178	261	63/105	--	0.5% CO_2
15.01.85						PT-1D 1Dd
13.00	486/52	1209	221	97/123	2292.23	20/64" bean
13.30	487/52	1164	230	97/121	2290.17	
14.00	486/52	1212	223	96/121	2290.65	BHP data from
14.30	485/52	1185	228	96/121	2291.93	CG 83780
15.00	485/52	1167	230	96/121	2290.80	1644 m bdf
15.30	474/52	1167	231	95/121	2289.45	
15.01.85						PT-1D 2Dd
16.00	351/58	2773	203	136/120	2163.02	36/64" bean
16.30	350/58	2522	231	131/122	2161.22	Oil Grav. =
17.00	350/58	2557	228	130/122	2160.06	0.8264
17.30	350/58	2603	223	131/123	2160.01	Gas Grav. =
18.00	350/58	2575	225	130/123	2159.56	0.943
18.30	350/59	2593	222	130/122	2158.87	0 ppm H_2S
19.00	350/59	2620	221	131/122	2158.57	1% CO_2
15.01.85						PT-1D 3Dd
20.30	187/68	4362	262	90/124	1972.75	80/64" bean
21.00	187/70	4353	263	90/125	1970.33	
22.00	187/70	4424	260	91/124	1966.89	
23.00	188/71	4406	262	91/122	1965.35	PVT sampleset 1
24.00	188/71	4433	262	92/122	1964.30	PVT sampleset 2
01.00	189/71	4469	256	95/121	1964.37	PVT sampleset 3
02.00	189/72	4406	255	95/123	1963.25	
03.00	189/72	4433	257	95/122	1962.94	PVT sampleset 4
04.00	189/72	4460	255	95/121	1962.68	
05.00	189/72	4460	255	95/121	1962.35	BSW = 0%

WELL : 6407/9-2

SUMMARY OF SEPARATOR DATA

DATE TIME	THP/THT psig/°F	OIL-RATE stb/d	GOR scf/stb	Psep/Tsep psig/°F	BHP psia	COMMENTS
06.00	190/72	4469	255	95/122	1961.96	
19.01.85						PT-1E 2Dd
13.30	284/43	2232	222	115/116	--	36/64" bean
14.00	287/43	2080	244	110/119	--	
15.30	180/51	3589	279	88/119	--	64/64" bean
16.00	180/51	3625	275	88/120	--	
16.30	163/53	3868	295	78/120	--	80/64" bean
17.30	122/56	4495	290	60/101	--	128/64" bean
18.00	124/56	4495	291	60/106	--	
18.30	125/57	4558	287	60/106	--	
19.00	125/60	4602	287	60/106	--	
20.01.85						PT-1F 5Dd
13.00	428/40	--	--	123/160	--	24/64" bean
13.30	430/40	1396	312	124/158	--	
14.00	435/40	1428	314	125/158	--	
14.30	363/47	2653	351	97/168	--	36/64" bean
15.00	368/48	2635	289	90/130	--	
15.30	345/51	3104	276	97/126	--	44/64" bean
16.00	348/52	3166	270	95/126	--	
16.30	249/59	4838	265	106/128	--	64/64" bean
17.00	250/60	4838	267	109/127	--	
17.30	224/64	5342	284	103/128	--	80/64" bean
18.00	225/64	5342	284	103/128	--	
19.00	181/66	6336	234	105/112	--	2" bean
20.00	183/66	6398	233	105/110	--	Oil Grav. =
21.00	182/66	6398	236	103/110	--	0.825
22.00	182/68	6362	241	104/110	--	Gas Grav. =
23.00	183/68	6443	238	104/110	--	0.935 (air = 1)
21.01.85						PT-1G 8Dd
10.00	380/38	1053	333	65/109	--	24/64" bean
11.00	390/38	1177	285	59/94	--	
14.00	313/53	2755	270	110/133	--	44/64" bean
21.01.85						PT-1G 9Dd
16.00	152/64	6526	229	60/90	--	2" bean
17.00	152/64	6766	229	63/96	--	
18.00	152/66	6908	226	63/98	--	Oil Grav. =
19.00	154/68	6842	224	66/100	--	0.8248
20.00	155/68	6864	232	69/104	--	Gas Grav. =
21.00	155/68	7017	221	66/102	--	0.965

WELL : 6407/9-2

SUMMARY OF SEPARATOR DATA

DATE TIME	THP/THT psig/°F	OIL-RATE stb/d	GOR scf/stb	Psep/Tsep psig/°F	BHP psia	COMMENTS
22.00	156/68	6984	225	67/100	--	
22.01.85						PT-1H 1Dd
05.00	360/48	3237	294	97/144	2144.54	40/64" bean
06.00	355/50	3173	293	98/124	2133.95	BHP data from
07.00	358/52	3283	254	92/118	2133.07	CG 83780
08.00	359/52	3274	283	95/136	2132.49	1641.69 m bdf
22.01.85						PT-1H 2Dd
09.00	247/60	4773	272	102/132	2008.18	64/64" bean
10.00	246/60	4747	269	101/129	2004.17	
11.00	245/60	4818	251	100/114	2002.45	
12.00	240/61	4763	--	--	1997.17	
22.01.85						PT-1H 3Dd
13.00	153/64	7351	243	64/111	1915.99	2+1-1/2 beans
14.00	152/64	7452	212	62/92	1910.64	
15.00	152/65	7430	212	61/89	1905.64	0 ppm H_2S
16.00	152/65	7418	210	60/90	1902.16	1% CO_2
17.00	151/65	7452	209	60/90	1900.88	
18.00	150/65	7401	209	60/91	1901.02	
19.00	150/65	7379	210	60/91	1902.60	Oil Grav. =
20.00	150/65	7396	209	60/90	1904.48	0.825 - 0.829
21.00	148/65	7283	212	60/91	1905.40	
22.00	148/65	7317	211	60/91	1906.66	Gas Grav. =
23.00	148/65	7379	209	60/91	1907.63	0.96-0.97 (air=1)
24.00	147/65	7351	210	60/91	1908.33	
23.01.85						
01.00	145/65	7345	210	60/90	1909.02	BSW 0%
02.00	145/66	7323	210	60/90	1909.48	
03.00	145/66	7312	208	60/90	1909.00	
04.00	146/66	7286	207	60/91	1909.58	
05.00	147/67	7281	209	60/91	1908.23	
06.00	147/67	7292	208	61/91	1908.30	
07.00	147/67	7270	205	61/91	1909.82	
08.00	147/66	7320	205	61/91	1907.61	
09.00	147/66	7230	207	62/90	1907.38	
10.00	145/66	7292	203	62/90	1907.89	

Table 8.5

WELL : 6407/9-2

TECHNICAL DATA GAUGES : PT-1

TEST PT-1A

GAUGE NUMBER	COMPANY	TYPE*	SAMPLING RATE	DELAY TIME	DEPTH
0214/1939	Sperry Sun	MRK III S.G.	2 mins	1024 mins	1622.5 m bdf
098/1977	" "	"	2 "	512 "	1622.5 "
0478/9083	" "	"	2 "	512 "	1622.5 "

TEST PT-1D

GAUGE NUMBER	SDP 83023	SDP 83051	SDP/CRG 83780
COMPANY	Flopetrol	Flopetrol	Flopetrol
TYPE*	S.G.	S.G.	C.G.
DELAY TIME, hrs	21	0.5	3
SAMPLING RATE, secs	10	30	30
AVERAGING	no	16	16
RELATIVE VALUES	yes	yes	yes
COMPRESSION ALG.	no	yes	no
COMPRESSION LEVEL	N.A.	8	N.A.
DEPTH, m bdf	1637.40	1640.40	1644.00

TEST PT-1H

GAUGE NUMBER	SDP 83023	SDP 83051	SDP/CRG 83780
COMPANY	Flopetrol	Flopetrol	Flopetrol
TYPE*	S.G.	S.G.	C.G.
DELAY TIME, hrs	54	0.5	3
SAMPLING RATE, secs	10	30	60
AVERAGING	no	16	16
RELATIVE VALUES	yes	yes	yes
COMPRESSION ALG.	no	yes	no
COMPRESSION LEVEL	N.A.	8	N.A.
DEPTH, m bdf	1635.15	1638.11	1641.69

* S.G. denotes Strain Gauge
C.G. denotes Crystal Gauge

Note : A compression level of 8 means a window of 8 times the gauge resolution (8 x 0.02 psi). Subsequent pressures within the window will not be memorised unless the time exceeds 256 times the sampling rate

WELL : 6407/9-2

PT-1D : OIL SAMPLES RECOVERED

(a) PVT samples: 4 x 700 ml oil and 4 x 20 litres gas.

	NO.	OIL stb/d	GAS Mscf	BOTTLE NO.	SAMPLING psig	SAMPLING ^{o}F	SAMPLE VOLUME	GAS CAP VOLUME	HG LEFT IN BOTTLE
oil	1	4406		811503	91	122	640 ml	20 cc	15 cc
gas	1		1152	1015	91	108	20 l		
oil	2	4433		811450	92	122	650 ml	10 cc	15 cc
gas	2		1163	1012	92	104	20 l		
oil	3	4460		811501	95	123	600 ml	65 cc	10 cc
gas	3		1141	1002	95	104	20 l		
oil	4	4433		811420	95	122	600 ml	65 cc	10 cc
gas	4		1137	1003	95	103	20 l		

(b) Bulk samples: 3 x 1 bbl dead oil

NO.	TIME TAKEN	OIL PROD. (stb/d)
1	01.30	4451
2	03.15	4433
3	04.20	4460

oil gravity during sampling 0.8274 g/cm^3
gas gravity during sampling 0.990 - 1.005 (air = 1)
H_2S zero percent
CO_2 one percent

WELL 6407/9-2

BASIC DATA USED IN EVALUATIONS

	WATER ZONE	OIL ZONE
	0.27	0.29
Swc	1.0	0.20
C_w (psi^{-1})	.0000035	0.0000035
C_{eff} (psi^{-1})	.0000200	0.0000200
u_w (cP)	.5	-
u_o (cP)	-	0.67
B_w (rb/stb)	1.02	-
B_o (rb/stb)	-	1.185
h_{res} (ft)	18.05	85.30
r_w (ft)	0.51	0.51

WELL: 6407/9-2

COMPARISON LABORATORY AND ON-SITE WATER ANALYSES

(mg/l)	Laboratory	On-site
Sodium	12500	n/a
Potassium	345	n/a
Calcium	10580	n/a
Magnesium	550	n/a
Barium	12	20
Strontium	34	n/a
Total iron	205	n/a
Dissolved iron	29	n/a
Chloride	39940	36392
Sulphate	24	45
Bicarbonate	52	140
Carbonate	nil	nil
Hydroxide	nil	nil
Total dissolved solids	64070	n/a
Resistivity (m)	0.164	0.168
pH	5.7	5.2
SG (60^{o}F)	1.046	1.043

(n/a : not analysed)

WELL : 6407/9-2

SUMMARY RESULTS PT-1 PBU SURVEYS

Test	PT-1D	PT-1D	PT-1D	PT-1H	PT-1H
Gauge	SG 83023	SG 83051	CG 83780	SG 83051	CG 83780
kh, D.ft	210	220	187	254	223
k, D	2.5	2.6	2.2	3.0	2.6
CIBHP before, psia	--	2388.61	2389.72	2389.04	2389.35
Pres after, psia	2390.80	2389.34	2390.45	2389.64	2390.21

Test/	PI (stb/d/psi)			Total Skin		
Rate (stb/d)	SG 83023	SG 83051	CG 83780	SG 83023	SG 83051	CG 83780
PT-1D 1167	--	11.2	11.7	--	139	117
2620	--	11.0	11.4	--	158	131
4469	9.9	10.1	10.5	174	178	145
PT-1H 3724	--	14.3	14.6	--	138	120
4763	--	12.2	12.3	--	169	146
7350	--	15.0	15.2	--	136	118

WELL : 6407/9-2

PRODUCTIVITY VERSUS OILRATE

TEST	OILRATE (stb/d)	ACTUAL PI (stb/d/psi)
PT-1A 2Dd	140	23.5
	90	15.7
	140	23.1
	100	16.3
PT-1D 1Dd	1212	13.8
	1167	13.3
	1167	13.1
PT-1D 2Dd	2773	12.9
	2522	11.6
	2557	11.7
	2603	11.9
	2629	12.0
PT-1D 3Dd	4362	10.7
	4415	10.7
	4469	10.7
	4460	10.7
PT-1H 1Dd	3173	12.4
	3283	12.8
	3274	12.7
PT-1H 2Dd	4773	12.5
	4818	12.5
	4665	12.0
	4719	12.2
PT-1H 3Dd	7418	15.2
	7390	15.2
	7286	15.1

WELL : 6407/9-2

EVALUATED FORMATION PRESSURE

PT-1A

TEST	GAUGE	PRESSURE	BEFORE/AFTER	DEPTH
PT-1A	SS 0214/1939	2340.1 psig	A	1622.5 m bdf
PT-1A	SS 0478/9083	2338.4 psig	A	1622.5 m bdf

TEST	GAUGE	DATUM PRESSURE	BEFORE/AFTER
PT-1A	SS 0214/1939	2389.3 psia	A
PT-1A	SS 0478/9083	2387.6 psia	A

- From the RFT survey (1630 m ss) - 2392 psia

- DFE 25 m
  Datum level 1630 m ss
  Oil Gradient 0.3255 psi/ft (from gradient surveys)

WELL : 6407/9-2

EVALUATED FORMATION PRESSURE

PT-1D and PT-1H

TEST	GAUGE	PRESSURE	BEFORE/AFTER	DEPTH
PT-1D	CG 83780	2378.0 psia	B	1644.00 m bdf
PT-1H	SG 83051	2371.0	B	1638.11
PT-1H	CG 83780	2375.1	B	1641.69
PT-1D	SG 83023	2372.0	A	1637.40
PT-1D	CG 83780	2378.7	A	1644.00
PT-1H	SG 83051	2371.6	A	1638.11
PT-1H	CG 83780	2376.0	A	1641.69

TEST	GAUGE	DATUM PRESSURE	
PT-1D	SG 83023	2390.80 psia	A
PT-1D	CG 83780	2389.72	B
PT-1D	CG 83780	2390.45	A
PT-1H	SG 83051	2389.04	B
PT-1H	SG 83051	2389.64	A
PT-1H	CG 83780	2389.35	B
PT-1H	CG 83780	2390.21	A

- From the RFT survey (1630 m ss) - 2392 psia

- DFE 25 m
  Datum level 1630 m ss - 1655 m bdf
  Oil Gradient 0.3255 psi/ft (from gradient surveys)

WELL 640792 SURVEY DATE 201284

HP GAUGE DATA

RESERVOIR DATA:-

FLUID CONTACTS (M-TVSS)
DATUM DEPTH = 1630.0
GOC = .0
OWC = 1638.0

FLUID GRADIENTS (PSI/M)
GAS = .000
OIL = 1.058
WATER = 1.452

GEOLOGICAL DATA:-

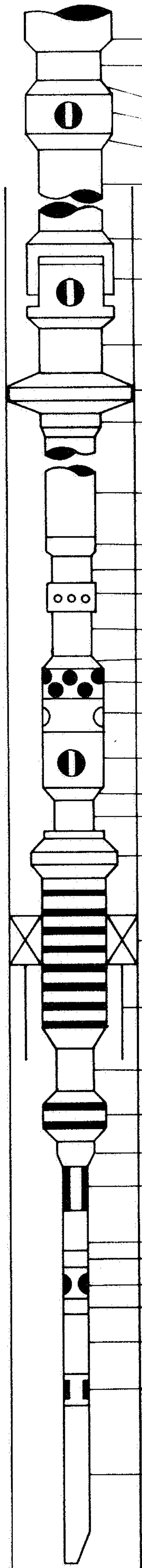
FORMATION TOP	DEPTH (M-TVSS)
KIMMERIDGE	1595.5
FROYA FORM	1625.5
HALTENBANK	1677.0

PRESSURE DATA:-

GEOLOGICAL ZONE	DEPTH(M) AHBDF	TVSS	PRESSURE (PSIA) MEASURED	DATUM	MUD(PRE-SETTING)	COMMENT
FR	1652.5	1627.5	2389.1	2391.7	2967.8	RUN 2
FR	1654.0	1629.0	2390.8	2391.9	2970.8	340 MD
FR	1656.0	1631.0	2393.5	2392.4	2973.9	240 MD
FR	1657.0	1632.0	2394.9	2392.8	2976.5	110 MD
FR	1658.0	1633.0	2395.5	2392.3	2978.4	320 MD
FR	1660.0	1635.0	2398.5	2393.2	2981.6	200 MD
FR	1661.0	1636.0	2399.7	2393.4	2984.5	6000 MD
FR	1662.0	1637.0	2400.8	2393.4	2985.6	1050 MD
FR	1663.0	1638.0	2401.9	2393.4	2988.3	140 MD
FR	1664.0	1639.0	2403.3	2393.4	2989.4	
FR	1665.0	1640.0	2404.5	2393.1	2990.8	TIGHT/PLUGGING??
FR	1666.0	1641.0	2407.0	2394.2	2992.0	65 MD
FR	1667.0	1642.0	2408.4	2394.1	2993.6	105 MD
FR	1668.0	1643.0	2410.0	2394.3	2995.8	
FR	1671.0	1646.0	.0	-20.1	.0	2X SEAL FAILURE
FR	1671.5	1646.5	2414.1	2393.3	3001.3	16 MD
FR	1674.0	1649.0	2418.3	2393.9	3005.8	24 MD
FR	1675.0	1650.0	2419.5	2393.6	3007.0	
FR	1679.5	1654.5	2426.1	2393.7	3014.4	
HA	1730.0	1705.0	2497.2	2391.5	3103.0	2225 MD
HA	1736.5	1711.5	2507.1	2391.9	3114.4	1580 MD
HA	1738.5	1713.5	2510.6	2392.5	3118.4	
HA	1742.5	1717.5	2517.0	2393.1	3127.0	
FR	1668.0	1643.0	2407.4	2391.7	2993.5	RUN 3
FR	1674.0	1649.0	2417.5	2393.1	3005.8	
FR	1679.5	1654.5	2425.2	2392.8	3015.0	
HA	1730.0	1705.0	2497.9	2392.2	3104.8	
HA	1738.5	1713.5	2509.8	2391.7	3120.0	
FR	1668.0	1643.0	2410.3	2394.6	2996.1	

52:)

PRODUCTION TEST STRING 6407/9-2



	DEPTH(m)	ID inch	OD inch
X - over flowhead to riser 6½" acme (B) x 4½" PH - 6 (P)			
Tubing riser 4½" PH - 6 (B) 19.2 lb/ft L- 80		3.515	5.313
X-over 4½" PH-6 (B) x 4½" acme (P)		3.000	5.313
Lubricator valve 4½" acme		3.000	10.750
X - over 4½" acme (P) x 4½" PH-6 (P)		3.000	5.313
Tubing riser 4½" PH-6 19.2 lb/ft L-80		3.515	5.313
X-over 4½" PH-6 (B) x 4½" acme (P)		3.000	5.313
SSTT Flopetrol type EZ 4½" acme		3.000	10.750
Slick joint (5") 4½" acme C-75		3.000	5.000
Fluted hanger for 9-5/8" wear bushing		3.000	15.000
X-over 4½" acme (P) x 3½" VAM (P)		3.000	5.313
Tubing 3½" 10.2 lb/ft C-75		2.797	3.917
X-over 3½" VAM (B) x 3½" CS (P)		2.797	5.313
Pup joint 3½" CS 10.3 lb/ft L-80		2.878	3.609
SSD Otis XA 3½" CS		2.750	4.280
Pup joint 3½" CS 10.3 lb/ft L-80		2.878	3.609
X-over 3½" CS (B) x 3½" IF (P)		2.250	5.000
MORV Multi opening reversing valve 3½"IF		2.250	5.000
SSARV single shot annular reversing valve		2.250	5.000
PCT Pressure controlled test tool		2.250	5.000
X-over 3½" IF (B) x 3½" CS (P)		2.250	5.000
Pup joint 3½" CS 10.3 lb/ft L-80		2.878	3.609
Seal assembly Baker G-22 190-47 3½" CS BxP		3.000	4.750
Packer Baker type SC-1 size 96A4-47		4.750	8.440
Gravel pack extension Baker			
Pup joint 3½" Cs 10.3 lb/ft L-80		2.878	3.609
Space out sub Baker type 190-47		3.000	4.750
X-over 3½" CS (B) x 2-7/8" VAM (P)		2.347	3.760
Landing nipple Otis type RN 2-7/8" VAM		1.937	3.760
Pup joint 2-7/8" VAM 8.6 lb/ft C-75		2.347	3.197
X-over 2-7/8" VAM (B) x 2-7/8" EU (P)		2.347	3.197
Ported pump open sub, ava, 2-7/8" VAM		1.75/2.5	4.320
X-over 2-7/8" EU (B) x 2-7/8" VAM (P)		2.347	3.197
Pup joint 2-7/8" VAM 8.6 lb/ft C-75		2.347	3.197
Landing nipple Baker type F 2-7/8" VAM		1.875	3.197
Tubing joint 2-7/8" VAM 8.6 lb/ft C-25		2.347	3.197
Half mule shoe			

A/S Norske Shell
EXPLORATION & PRODUCTION FORUS

WELL 6407/9-2

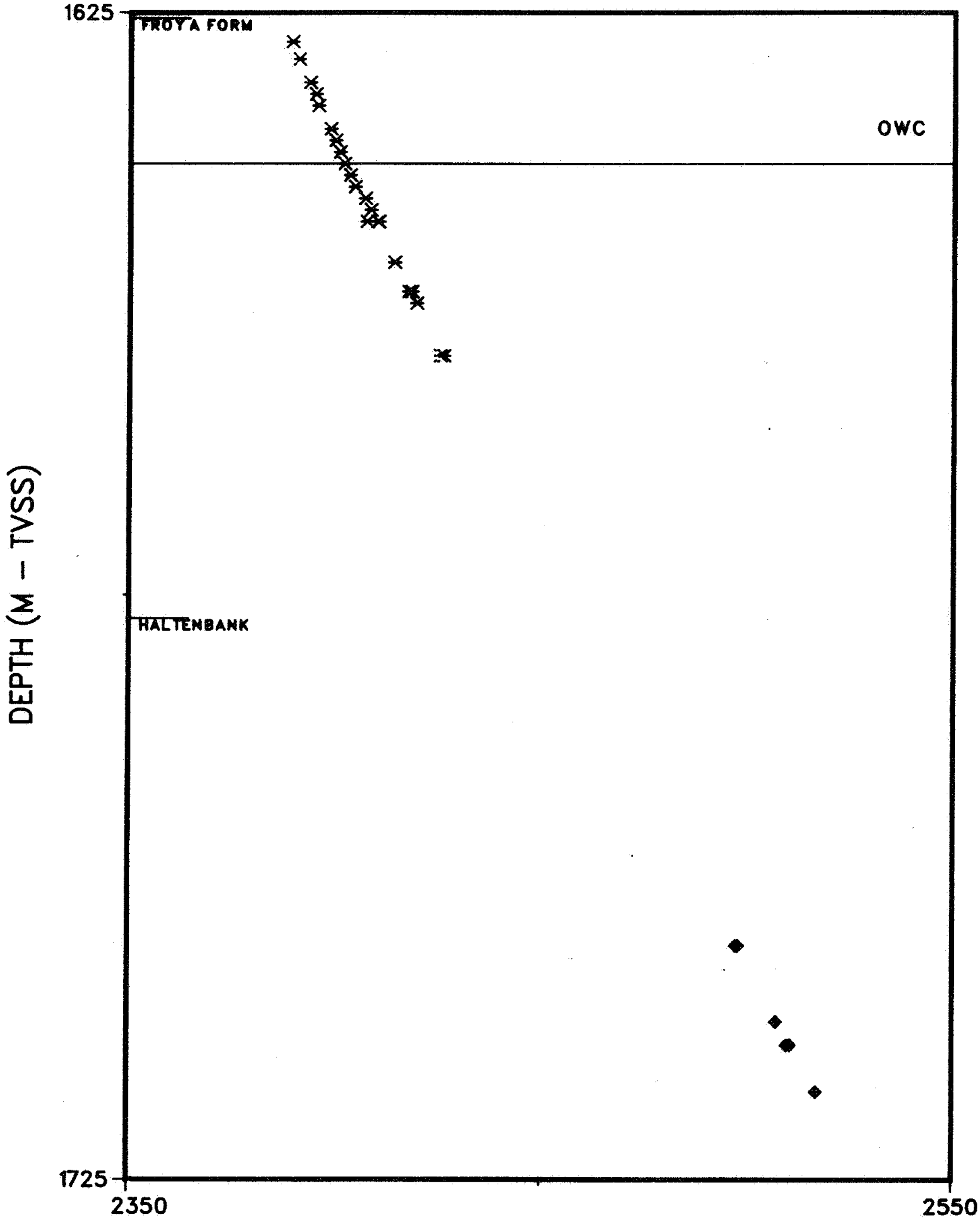
PRODUCTION TEST STRING

AUTHOR EPPP/21 FIG 8.2 DATE MARCH '85
REPORT NO NSEP 238 DRAW NO G 1847/12

RFTPLOT

RFT 640792

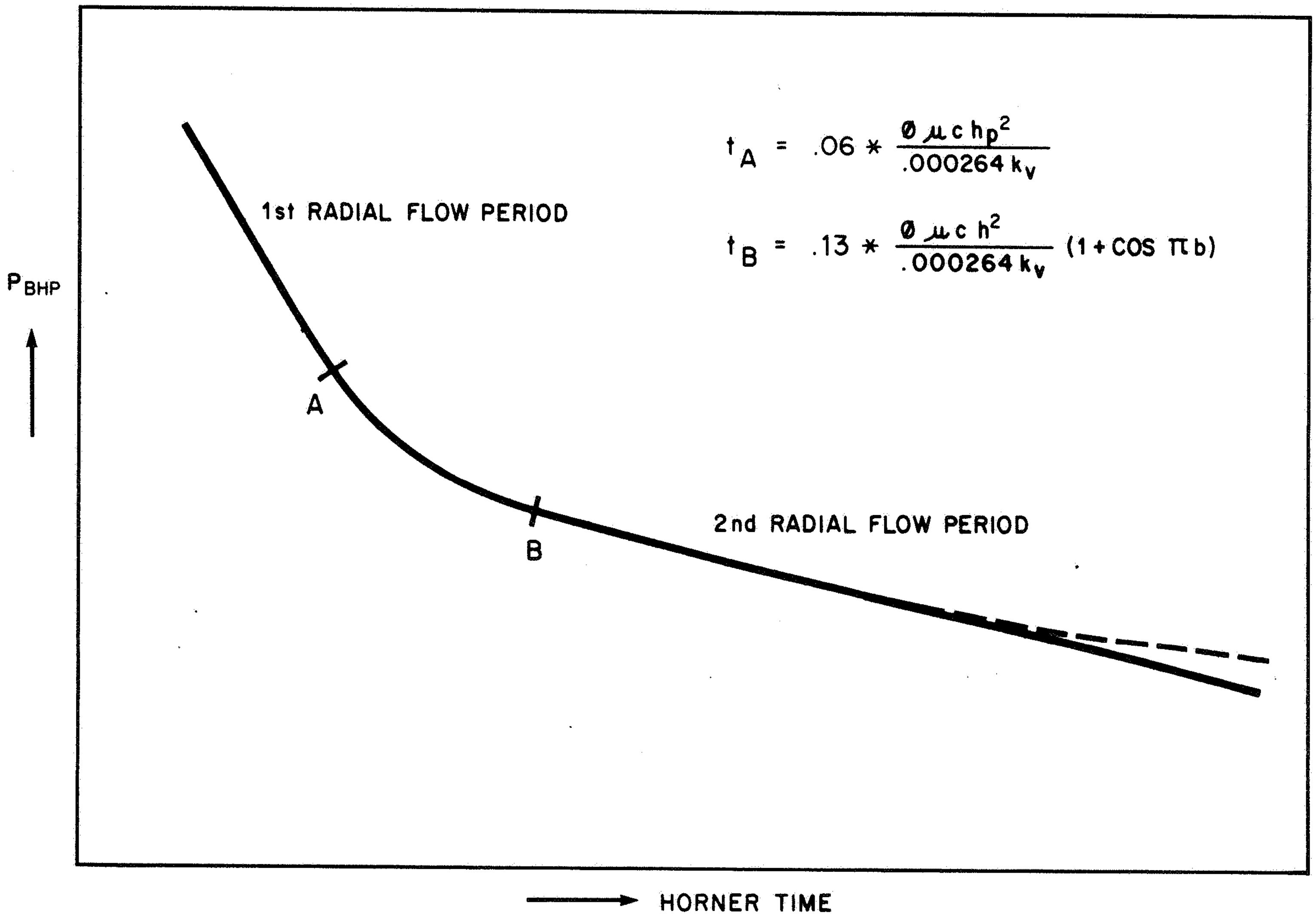
DATE 201284



HALTENBANKEN 6407/9 AREA

A/S Norske Shell EXPLORATION & PRODUCTION FORUS		
WELL 6407/9-2 REF MEASURED PRESSURES		
AUTHOR EPPP/21 REPORT NO. NSEP 238	FIG 8.4	DATE MARCH '85 DRAW NO. G 1847/14

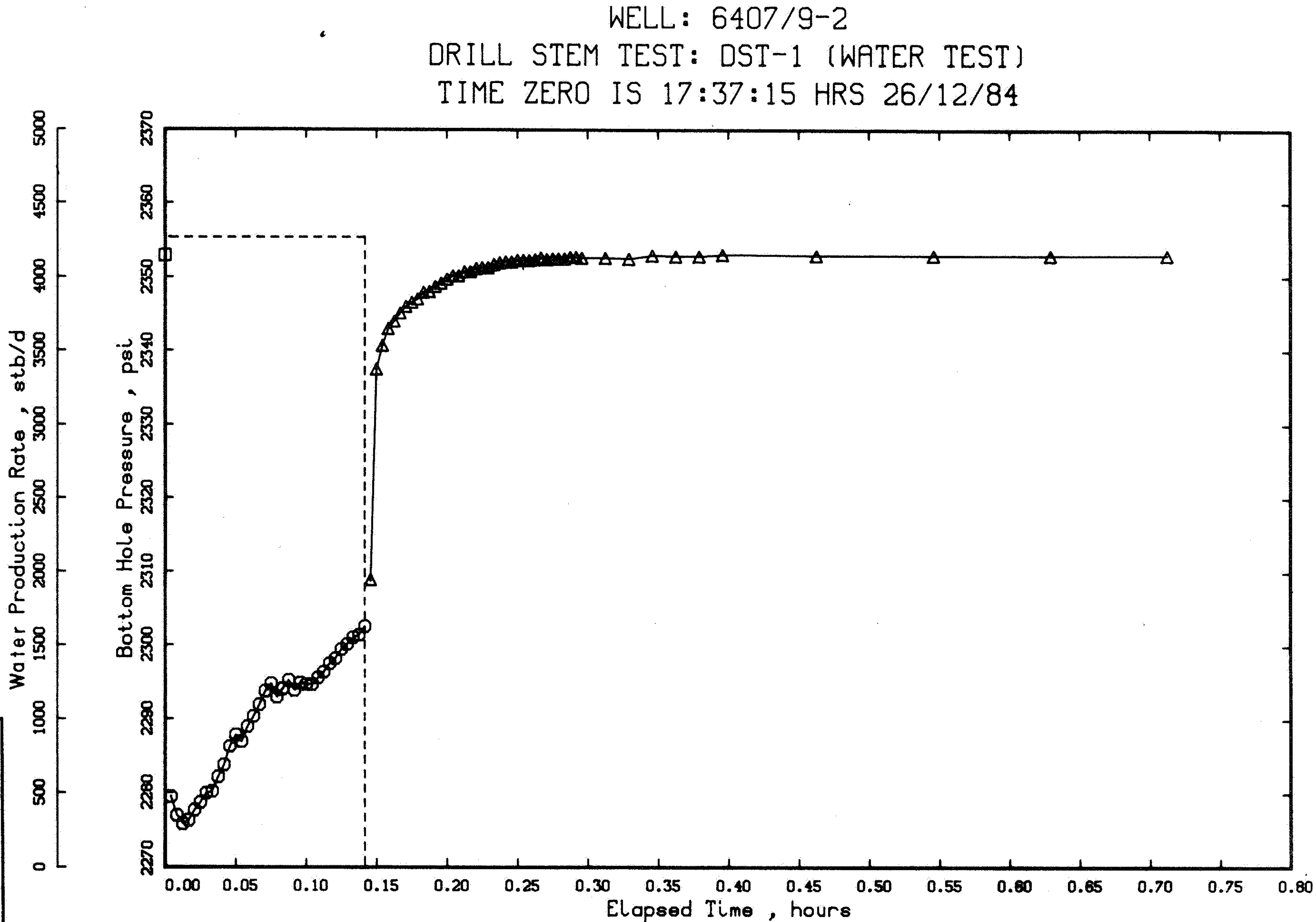
"HORNER" ANALYSIS



A/S Norske Shell
EXPLORATION & PRODUCTION FORUS

HORNER RESPONSE
FOR PARTIALLY
PENETRATING WELLS

AUTHOR: EPPP/21	FIG.	DATE MARCH '85
REPORT NO. NSEP 238	8.5	DRAW. NO. G 1847/15



A/S Norske Shell
EXPLORATION & PRODUCTION FORUS

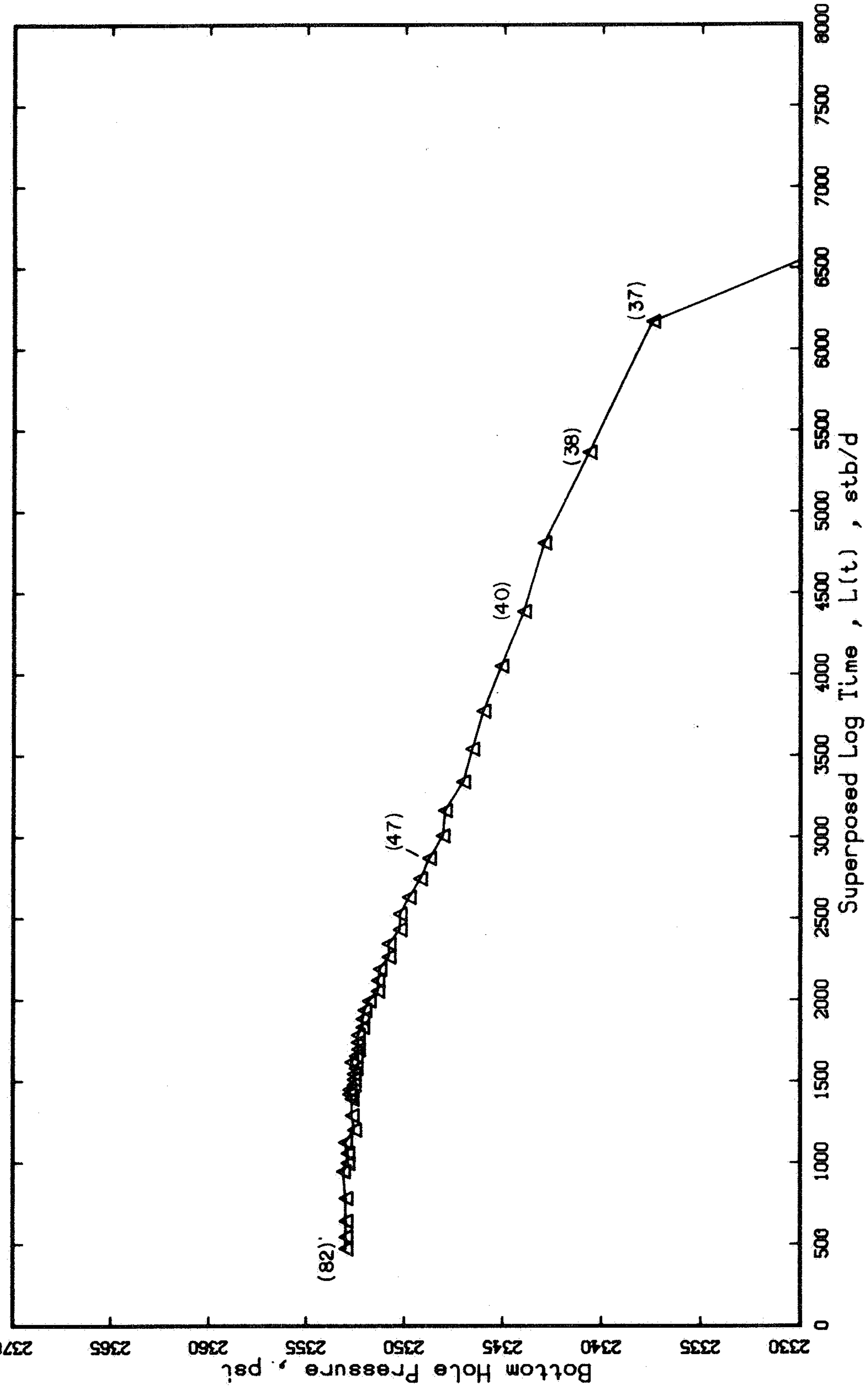
Well 6407/9-2

SEQUENCE OF EVENTS DST-1

1670 - 1675,5 mbdf

AUTHOR EPPP/21	FIG	DATE MARCH '85
REPORT NO. NSEP 238	8.6	DRAW NO G 1847/16

WELL: 6407/9-2
DRILL STEM TEST: DST-1 (WATER TEST)
TIME ZERO IS 17:37:15 HRS 26/12/84



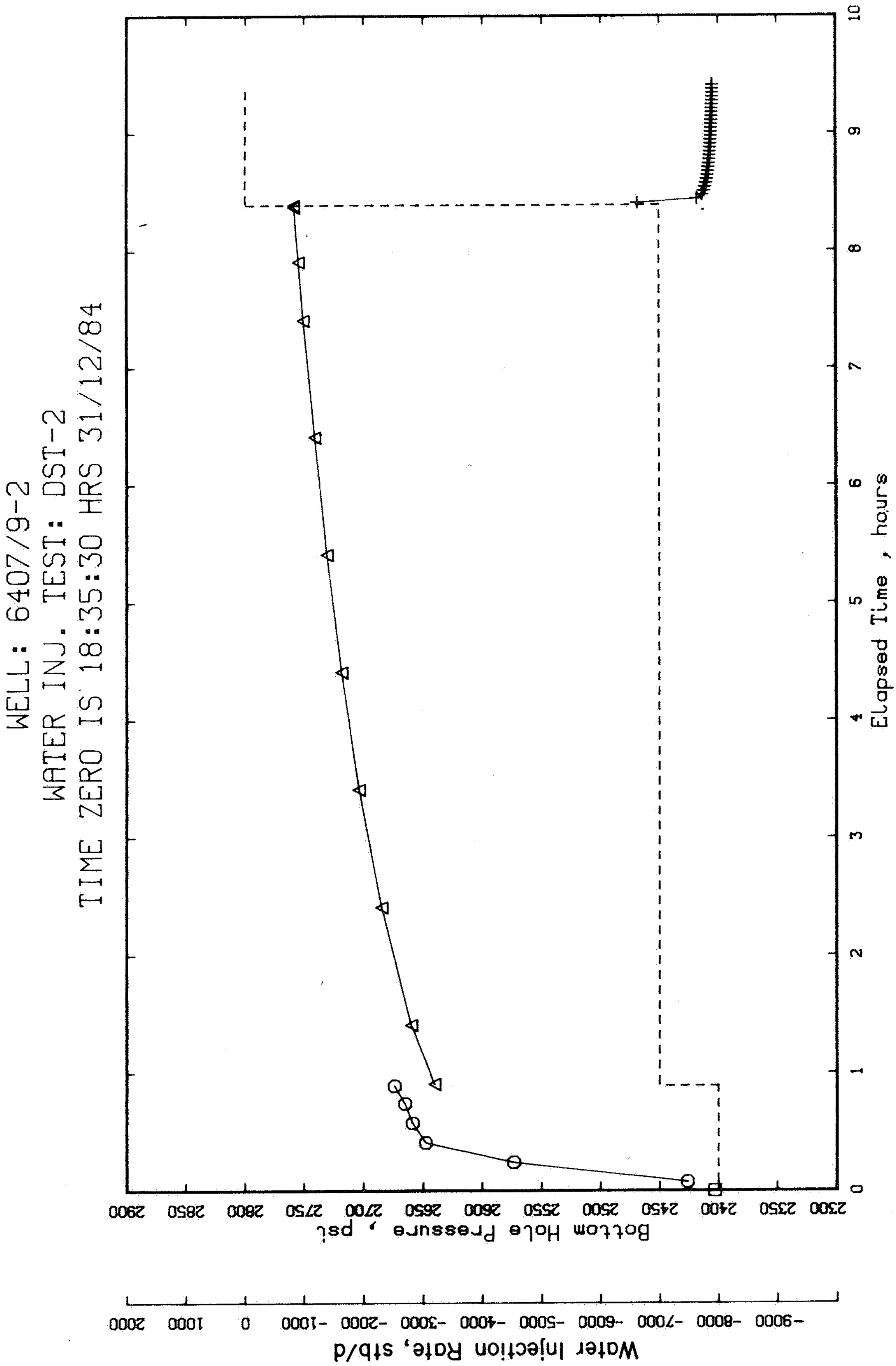
A/S Norske Shell
EXPLORATION & PRODUCTION FORUS

WELL 6407/9-2

HORNER PLOT DST - 1

1670 - 1675,5 m bdf

AUTHOR EPPP/21	FIG	DATE MARCH 85
REPORT NO. NSEP 238	8.7	DRAW NO. G 1847/17



A/S Norske Shell
EXPLORATION & PRODUCTION FORUS

WELL 6407/9-2

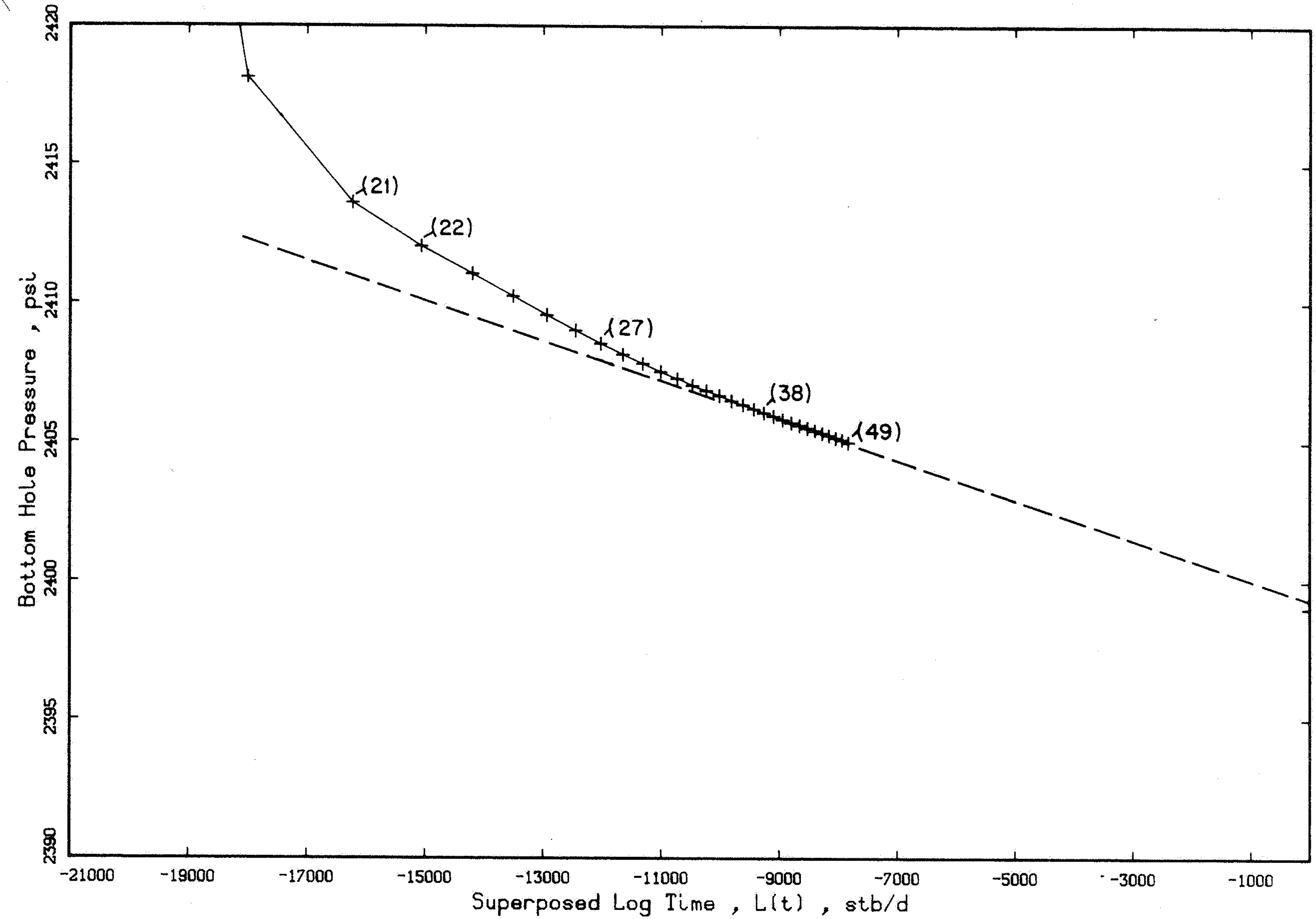
WATER INJECTION TEST
SEQUENCE OF EVENTS

AUTHOR EPPP/ 21	FIG	DATE MARCH '85
REPORT NO. NSEP 238	8.8	DRAW NO G 1847/18

WELL: 6407/9-2

WATER INJ. TEST: DST-2

TIME ZERO IS 18:35:30 HRS 31/12/84



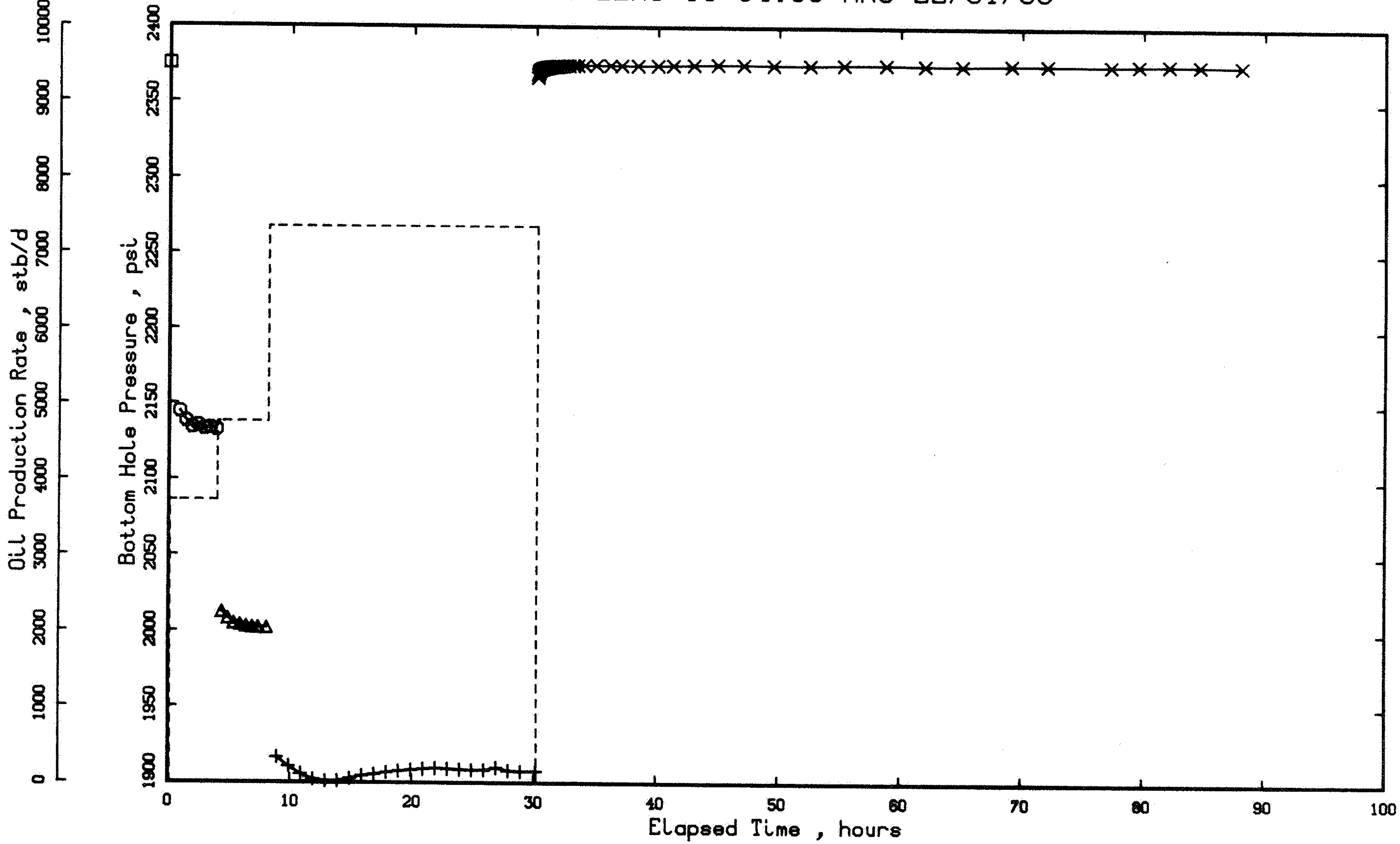
A/S Norske Shell
EXPLORATION & PRODUCTION FORUS

WELL 6407/9-2

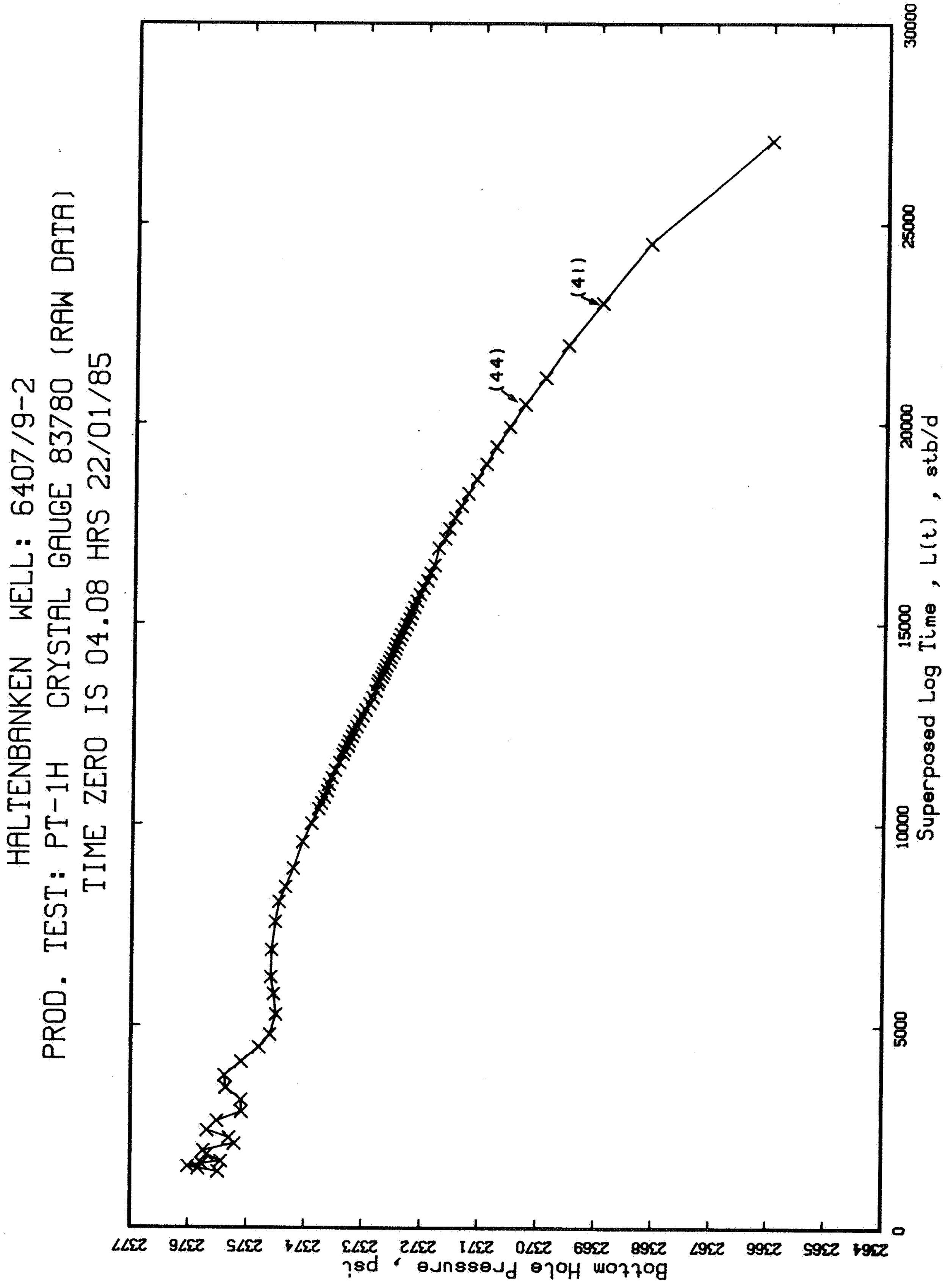
"HORNER" TYPE PLOT
WATER INJECTION TEST

AUTHOR EPPP/ 21 | FIG. 8.9 | DATE MARCH '85
REPORT NO. NSEP 238 | | DRAW. NO. G 1847/19

HALTENBANKEN WELL: 6407/9-2
PROD. TEST: PT-1H CRYSTAL GAUGE 83780 (RAW DATA)
TIME ZERO IS 04.08 HRS 22/01/85



A/S Norske Shell EXPLORATION & PRODUCTION FORUS		
WELL 6407/9-2		
PT-IH SEQUENCE OF EVENTS		
AUTHOR: EPPP/21	FIG. 8.10	DATE: MARCH '85
REPORT NO. NSEP 238		DRAW. NO.: G 1847/20



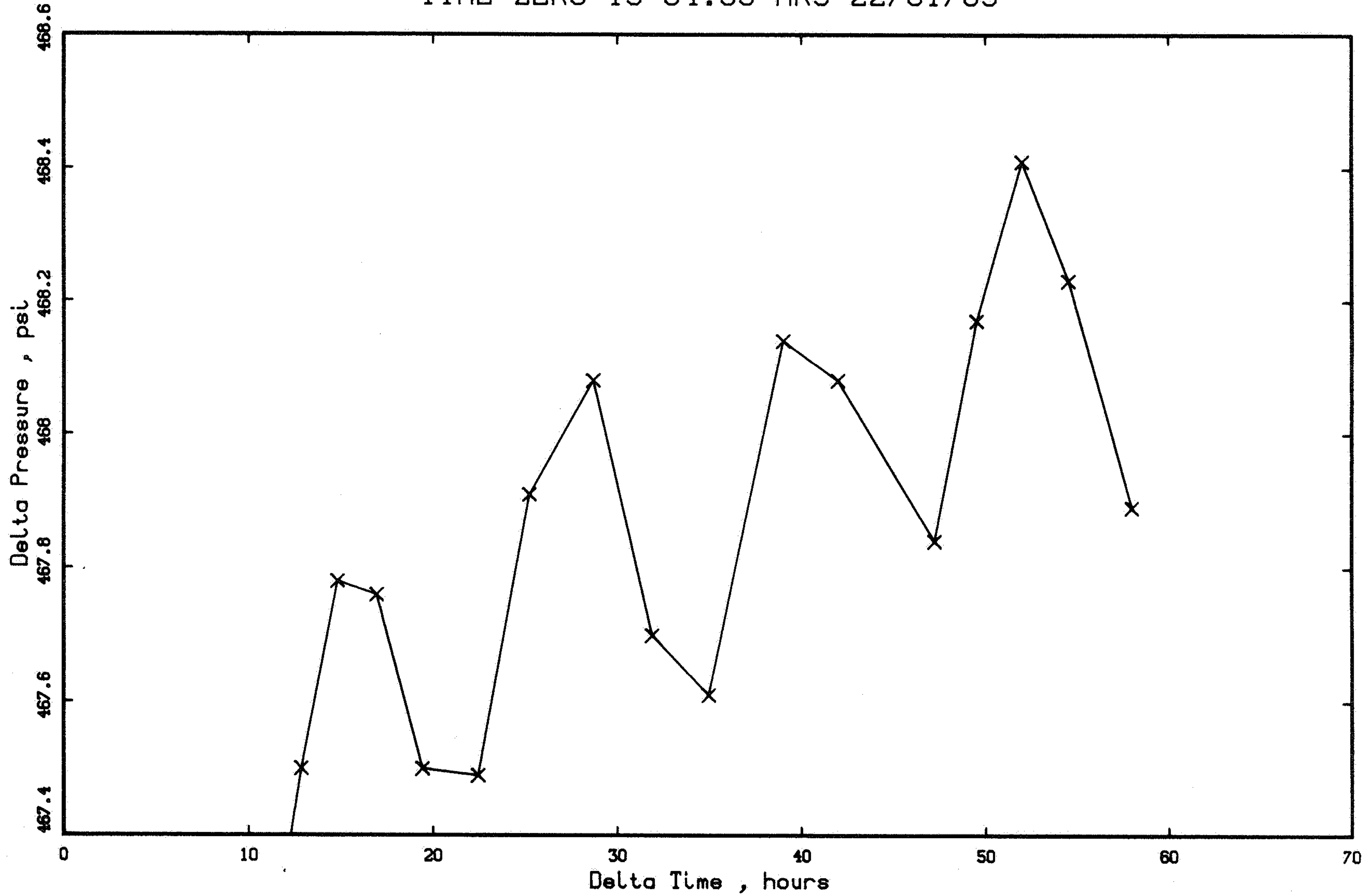
A/S Norske Shell
EXPLORATION & PRODUCTION FORUS

WELL 6407/9-2

PT-IH "HORNER" PLOT
(CRG 83780 RAW DATA)

AUTHOR EPPP/21	FIG	DATE MARCH '85
REPORT NO. NSEP 238	8.11	DRAW. NO. G 1847/21

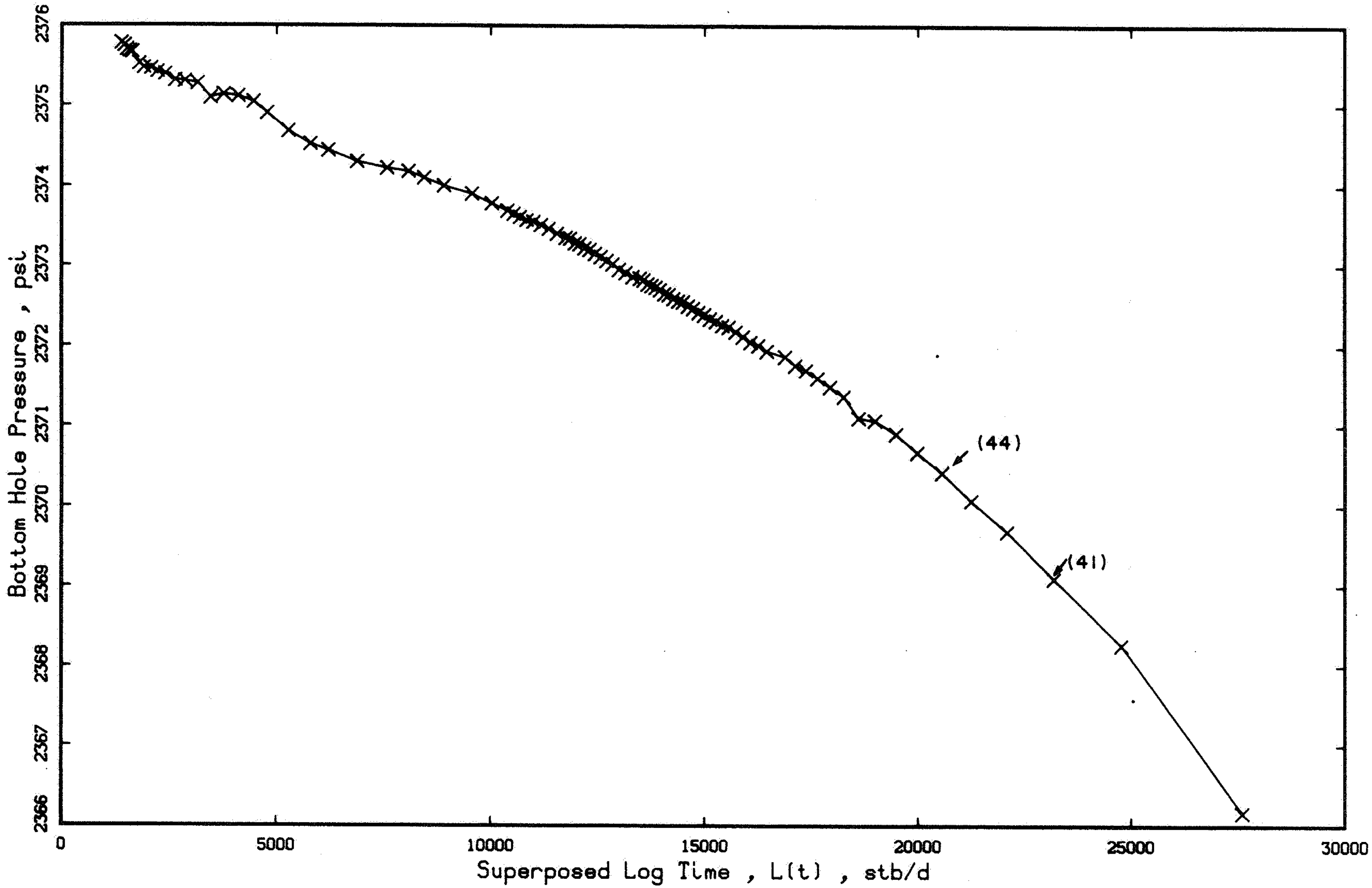
HALTENBANKEN WELL: 6407/9-2
PROD. TEST: PT-1H CRYSTAL GAUGE 83780 (RAW DATA)
TIME ZERO IS 04.08 HRS 22/01/85



A/S Norske Shell
EXPLORATION & PRODUCTION FORUS
WELL 6407/9-2
PT-IH LATE TIME DATA (CRG 83780)

AUTHOR EPPP/21	FIG 8.12	DATE MARCH '85
REPORT NO. NSEP 238		DRAW. NO. G 1847/22

HALTENBANKEN WELL: 6407/9-2
PROD. TEST: PT-1H CRYSTAL GAUGE 83780 (FILTERED)
TIME ZERO IS 04.08 HRS 22/01/85

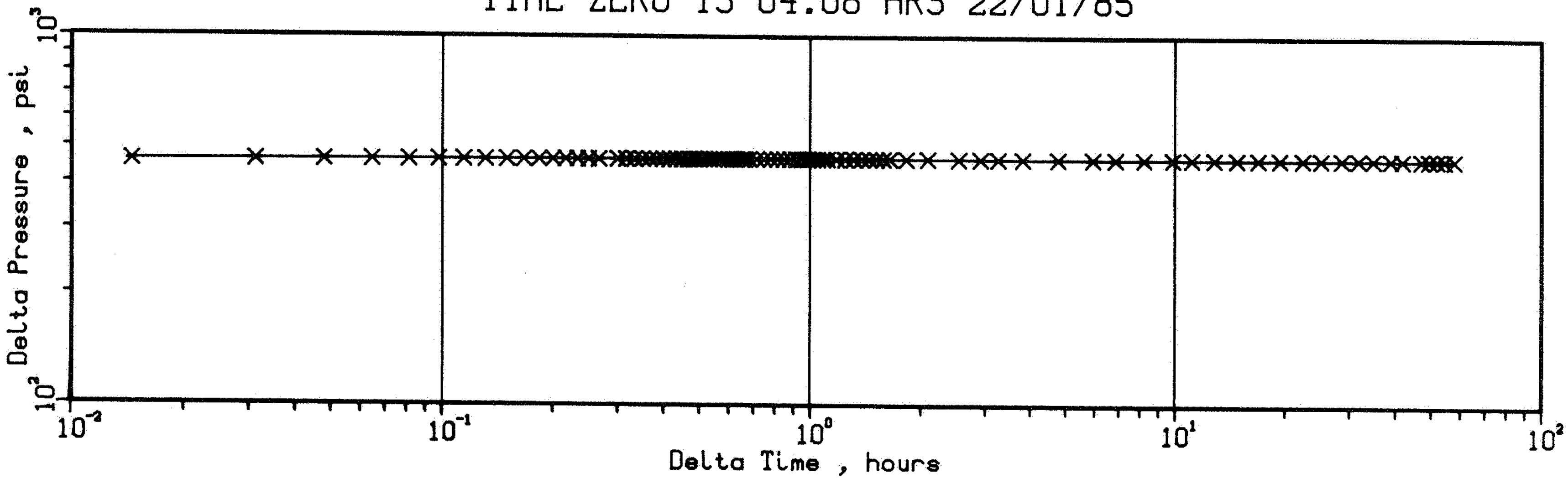


A/S Norske Shell
EXPLORATION & PRODUCTION FORUS

WELL 6407/9-2
PT-IH "HORNER" PLOT
CRG 83780 FILTERED DATA

AUTHOR EPPP/21	FIG 8.13	DATE MARCH '85
REPORT NO NSEP 238		DRAW NO G 1847/23

HALTENBANKEN WELL: 6407/9-2
PROD. TEST: PT-1H CRYSTAL GAUGE 83780 (FILTERED)
TIME ZERO IS 04.08 HRS 22/01/85



A/S Norske Shell
EXPLORATION & PRODUCTION FORUS

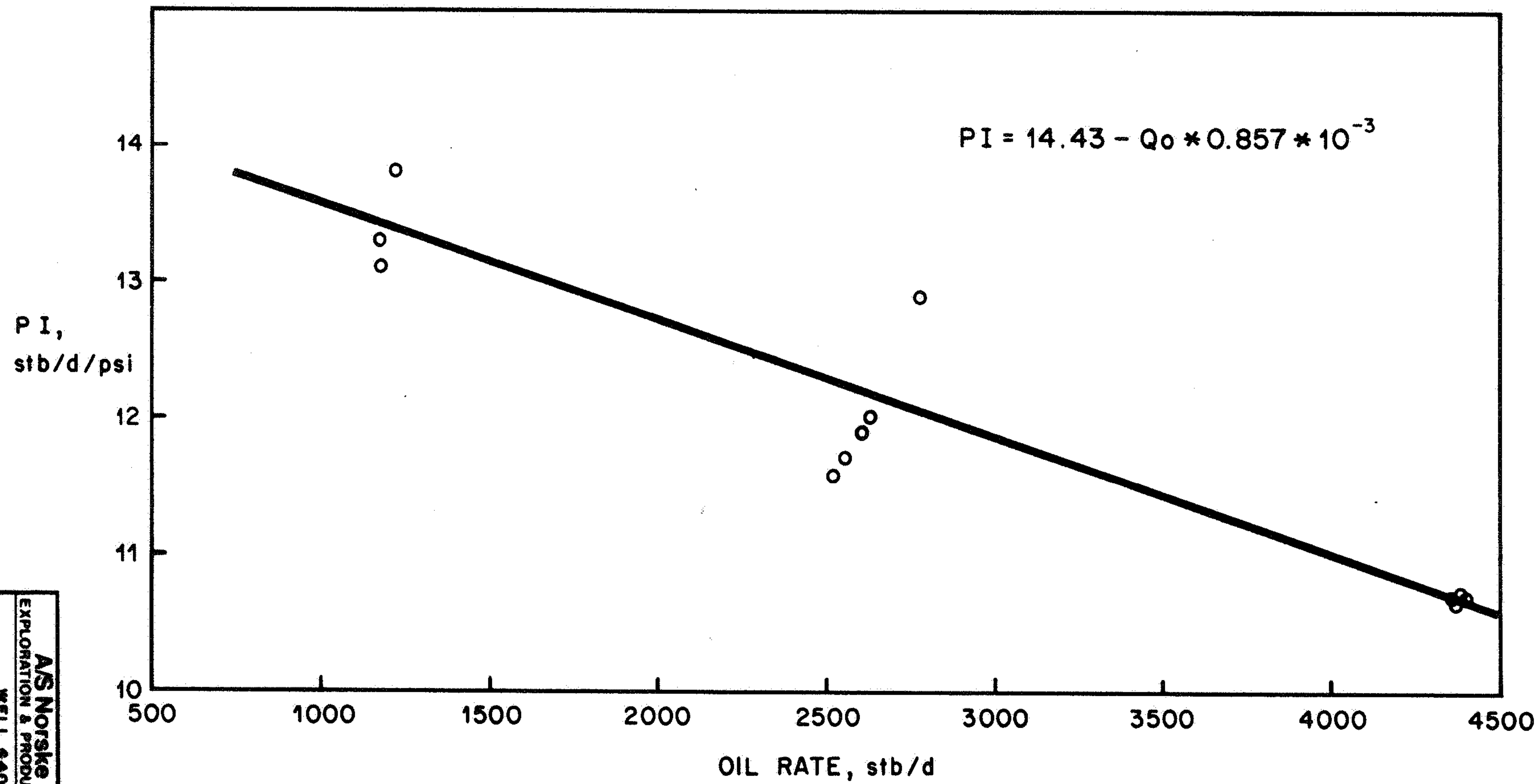
WELL 6407/9-2

PT-IH LOG ΔP-LOGΔT
RELATION (CRG 83780)

AUTHOR EPPP/21	FIG	DATE MARCH '85
REPORT NO. NSEP 238	8.14	DRAW NO. G 1847/24

HALTENBANKEN WELL: 6407/9-2

PRODUCTION TEST PT-ID, CRYSTAL GAUGE 83780



A/S Norske Shell
EXPLORATION & PRODUCTION FORUS

WELL 6407/9-2

PT-ID: RATE
DEPENDENCY OF PI

AUTHOR: EPPP/21	FIG.	DATE: MARCH '85
REPORT NO. NSEP 238	8.15	DRAW. NO. G 1847/25