/w

June 1986

WELL RESUME

6407/9-6

NSEP 86-11

Enclosures

1. INTRODUCTION

Well 6407/9-6 is located approx. 1.8 km west of well 6407/9-3 on the west flank of the field.

The main objectives of the well were as follows:

- to identify the western edge (pinch-out) of the Frøya Formation and by calibration of the impedance seismic data, delineate the pinch-out over the western and southwestern flanks

- to establish the reservoir properties and the development of the Unit III basal shales in the region of the Frøya sand pinch-out.

- to evaluate the water injection potential in an oil bearing interval of the reservoir sands.

- to calibrate the seismic velocity model and improve the structural interpretation of the western flank.

The well coordinates of the location are: -

64^{o} 19' 58.07" N	Northing 7 134 880.1 m
07^{o} 44' 23.70" E	Easting 439 100.7 m

The well was spudded on the 2th of January 1986 and reached TD of 1800 mbdf in the Middle Jurassic Upper Drake Formation eq. The well encountered light oil (40^{o} API) in the Upper Jurassic Frøya Formation with the top at 1617.5 mss and ODT at 1633 mss, at the top of the Unit III basal shale.

The well was suspended as a possible water injection well at 12 March 1986 after having carried out oil production and water injection tests.

Well 6407/9-6

Summary of Well Data:

Well Classification	:	Appraisal well
Location coordinates	:	64^{0} 19' 58.07"N
(final)		07^{0} 44' 23.70"E
Water depth	:	272 m
Derrick Floor Elevation	:	25 m
Contractor/Rig	:	Borgny Dolphin
BOP Stack	:	10 000 psi, 18 3/4"
Mudlogging Contractor	:	Gearhart
Start of Operations	:	31.12.85
Spudded	:	02.01.86
Completed	:	12.03.86
Objectives	:	- to identify the western edge of the Frøya Formation. - to establish the reservoir properties and development of the basal shale. - to evaluate the water injection potential in oil-bearing sand - to calibrate the seismic velocity.
Total depth	:	1800 m (drillers depth) 1796 m (loggers depth)
Formation at TD	:	Upper Drake Formation eq.
Results	:	Oil produced from Upper Jurassic Frøya Formation Tested interval: 1618-1631 mss Maximum rate: 6400 stb/d Oil gravity: 40^{0} API Water injected into same interval Maximum injection rate: 15,000 b/d
Costs		83.4 million NOK
Present Status	:	suspended
Casing Record	:	30" csg : 375 mbdf 20" csg : 804 mbdf 13 3/8" csg : 1619 mbdf 9 5/8" csg : 1776 m

2. SITE SURVEY REPORT

2.1 Introduction

A/S Norske Shell commissioned A/S Geoteam to conduct a rig site survey for location 6407/9-6. This location is 1700 m WNW of location 6407/9-3 which was previously surveyed by Geoteam in March 1985. The survey work was therefore planned to adjoin and overlap the previous survey grid, such that earlier data could be integrated in the data base to be interpreted for well 6407/9-6. Field work was carried out with M/V "Geo Surveyor" between 17 October and 14 November 1985. The survey was severely hampered by prolonged bad weather.

The purpose of the survey was to obtain bathymetric information and to detect any seabed obstructions or potential sub-seabed hazards to drilling operations by a semi-submersible drill rig.

Echo-sounder and side-scan sonar equipment were used to map bathymetry and seabed features. A deep towed sparker and an analog sparker were used to investigate the shallow strata. A digitally recorded sparker was used to investigate the deeper strata.

2.2 Survey Programme

The 4 km x 4 km site survey area was covered by 9 WNW-ESE profiles and 15 NNE-SSW profiles, with echo-sounder, side-scan sonar, deep towed sparker and analog sparker. The WNW profiles were spaced 400 metres apart and the NNE profiles were spaced 175 meters apart. Additionally, 9 WNW and 4 NNE profiles surveyed over location 6407/9-3 were included in the database.

Twelve high-resolution profiles were shot with digital equipment. Seven lines ran NNE-SSW (4 km, 175 m spacing) and five ran WNW-ESE (2.5 km, 500 m spacing). The programme was designed such that the five WNW profiles tied into the 6407/9-3 digital programme.

In addition, one soil sample was obtained with a 3 meters long gravity corer in the vicinity of the proposed location.

2.3 Summary

Survey centre position	:	Latitude 64^{o} 19' 57.98"N Longitude 07^{o} 44' 24.47"E
Water Depth	:	271 metres MSL
Seabed Slope	:	Between two SW trending plough marks, the nearest of which is approx. 8 m deep and 50 m wide. The location is on the northern shoulder of this plough mark.
Seabed Condition	:	Seabed is heavily scoured by icebergs.
Seabed Hazards	:	None
Sub-Seabed Conditions	:	271-282 m — Very soft glaciomarine clay. 282-390 m — Stiff to overconsolidated clays and sands. 390 m — Regional erosion surface. 400- m — Interbedded claystone and sand layers.
Drilling Hazards	:	Possibility of gas charged sediments at base of Quaternary, 365-390 m.

NAVIGATION AND POSITIONING
OF
BORGNY DOLPHIN
WELL 6407/9-F
A/S NORSKE SHELL

REPORT NO. 30407
FEBRUARY 1986

Prepared by

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1. INTRODUCTION

1.1 GENERAL

The drilling rig BORGNY DOLPHIN was navigated to the new location at Well 6407/9-F using Syledis and Decca Main Chain. Final position was derived from satellite passes, utilizing a Magnavox G.P.S. T-set in the fixed position mode.

Both operations were undertaken by A/S GEOTEAM in the period 29 December 1985 to 3 January 1986.

Final position, Well 6407/9-F, was:

DERRICK CENTRE

GEOGRAPHIC		UTM	
Latitude	64° 19' 58.07" N	Northing	7 134 880.1 m
Longitude	07° 44' 23.70" E	Easting	439 100.7 m

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

Observations	:	A period of 4 hours was used in final positioning, of which 1 hour was excluded due to an intermediate 3-satellite constellation.
Time	:	Observations completed at 0315 hours, 3 January 1986.
Rig heading	:	264 degrees
Deviation	:	The rig is 10.8 metres in direction 287 degrees from intended location.
Personnel	:	I. Jorde and J. Pangbourne
Syledis Derived Position	:	About 350 Syledis readings during 4 hours gave an average position of 6.9 m in direction 78 degrees from final satellite derived position.

2. NAVIGATION

2.1 GENERAL

While in transit to the new location in Block 6407/9 the rig was navigated by Decca Main Chain together with a Magnavox GPS T-set Satellite Receiver version 2.4. For the final approach to location, primary navigation system was Sercel Syledis utilizing the A/S GEOTEAM Haltenbanken Syledis Chain.

2.2 INTENDED LOCATION

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

INTENDED WELL CENTRE

GEOGRAPHIC		UTM	
Latitude	64° 19' 57.97" N	Northing	7 134 877 m
Longitude	07° 44' 24.48" E	Easting	439 111 m

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

2.2 SYLEDIS CHAIN DETAILS

During the period of the rig move to 6407/9-F, four stations of the A/S GEOTEAM Haltenbanken Syledis Chain were used with the following co-ordinates in UTM Zone 32, central meridian 09 degrees east:

BEACON STATION	NORTHING	EASTING	HEIGHT
Slettringen	7 060 218 m	463 591 m	48 m
Polar Pioneer, Well 6407/7-1	7 129 108 m	413 117 m	80 m
Halten	7 116 546 m	519 805 m	39 m
Kopparen	7 075 929 m	536 354 m	481 m

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

BEACON STATION	DELAY	RANGE	L.O.S.*	BEARING
Slettringen	296.6 m	78.6 km	1.4	162°
Polar Pioneer, Well 6407/7-1	443.2 m	26.6 km	0.4	258°
Halten	303.8 m	82.8 km	1.5	103°
Kopparen	296.6 m	113.8 km	1.0	121°

*Line of Sight ratio = Range/Line of Sight

The delay refers to total delay with Mobile S/N 517.

Delays onboard Borgny Dolphin:

Antenna	1.1 m
Main cable	126.8 m
	127.9 m
Mobile S/N 517	148.2 m
Total delay	276.1 m

Stations in use were:

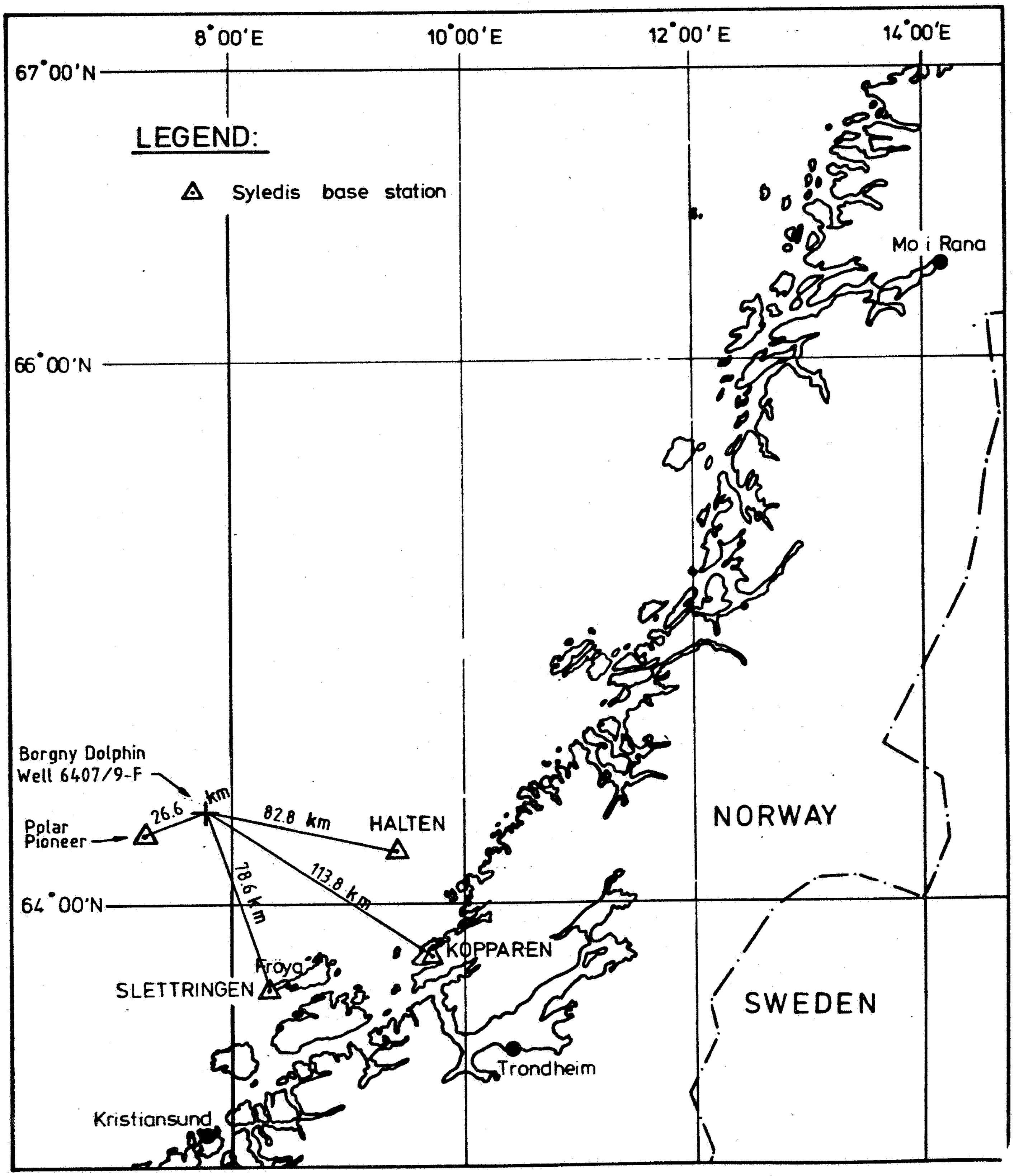
a) During run-in:
1 Slettringen
2 Polar Pioneer, Well 6507/7-1
3 Halten

b) On location and final fix:
1 Slettringen
2 Polar Pioneer, Well 6507/7-1
3 Kopparen

Signal strength was good (See Appendix 1). The standard deviation of measured ranges, obtained from the fix calculation was 0-2 metres.

During the run-in Kopparen was off the air due to storm damage. Kopparen was working from 1245 31 December 1985 and included in 3 range fix for better angle of cut.

The map below shows the Syledis beacon station locations:



2.4 NAVIGATION TO LOCATION

While in transit to the Haltenbanken Field, the rig was navigated by means of Decca Main Chain on the towing vessel - "Stadt Sailor".

A Sjark Decca Main Chain Receiver was installed on the rig. This did not perform too well on the approach giving a difference from the "Stadt Sailor" in position of approximately 5 mins in latitude and 2 mins in longitude. The antenna was repositioned on the port side of the pilothouse with an improved earth for the final Decca position. Better agreement was then obtained with the intended location.

The Magnavox GPS T-set Satellite Receiver was operated in the navigate mode. During the periods when the GPS satellites were in view and at least three were being received by the T-set, continuous positioning was obtained. There were two such daily periods, one from 1100 hours to 1600 hours and the other from 2200 hours to 0300 hours.

There was good agreement between the GPS position and the position supplied to the rig by "Stadt Sailor".

For the final approach to location and maneuvering with anchors, a Sercel Syledis Navigation System was used. The Syledis MR3-B mobile was interfaced to a Hewlett Packard 9845 S computer for computation of real time position, graphic display and data recording on magnetic tape.

The Syledis antenna was mounted at the top of the derrick and connected to the receiver in the wheel-house by a calibrated cable. Details of the antenna offset from derrick centre are given in Appendix 3.

At 0540 hours, 31 December, the rig was within the coverage area of the Syledis chain. At the same time Borgny Dolphin started transmission of synchronization signal for the chain.

The approach to location was made along the heading of anchor no. 5 which was the fist anchor to be dropped. This took place at 0910 hours, 31 December 1985.

Logging of Syledis and final satellite positioning commenced when tension test was completed at 0315 hours, 3 January 1986.

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 Accepted	Mean Range	Standard Deviation	Number of Omitted
Slettringen	350	78905.2 m	0.6 m	0
Polar Pioneer, Well 6407/7-1	348	27076.5 m	0.9 m	2
Kopparen	350	114066.9 m	0.4 m	0

Readings deviating 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 derrick co-ordinates, referenced to the European Datum 1950 have been calculated:

DERRICK CENTRE, SYLEDIS

GEOGRAPHIC		UTM	
Latitude	64° 19' 58.12" N	Northing	7 134 881.5 m
Longitude	07° 44' 24.21" E	Easting	439 107.5 m

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

This gives a position 6.9 metres in direction 78 degrees from the satellite derived position. (See Appendix 6).

After a least squares adjustment of the mean Syledis ranges, the standard error of observation of unit weight, one sigma, was found to be 1.5 metres with residuals as follows:

Beacon Station	Residual
Slettringen	0.8 m
Polar Pioneer	-0.7 m
Kopparen	-1.1 m

2.6 DECCA MAIN CHAIN

After the rig was in position the following data from Decca 4E Main chain was recorded.

Date	Time	Red	Green	Purple	Latitude	Longitude
1/1/86	1243	H13.11	C42.15	A66.37	64° 19.86' N	7° 44.55' E
1/1	1251	H13.09	C42.15	A66.38	64° 19.86' N	7° 44.55' E
1/1	1545	H13.10	C42.16	A66.40	64° 19.87' N	7° 44.54' E
1/1	1600	H13.13	C42.16	A66.42	64° 19.87' N	7° 44.54' E
				MEAN	64° 19.865'N	7° 44.545' E

No correction on any lane is used. Positions refer to the European Datum 1950.

Applying the antenna offset given in Appendix 3.3, the following Decca Main Chain position for the derrick centre, was calculated:

DERRICK CENTRE, DECCA MAIN CHAIN

GEOGRAPHIC		UTM	
Latitude	64° 19' 51.9" N	Northing	7 134 686 m
Longitude	07° 44' 35.2" E	Easting	439 251 m

This is 237 metres in direction 126 degrees from final position.

2.7 THEORETICAL DECCA READINGS

For derrick center well 6407/9-F, chain 4E, the theoretical readings are:

Red	H13.324
Green	C42.246
Purple	A67.011

3. GPS SATELLITE DATA

3.1 MAGNAVOX T-SET

The T-set consists of the following components:

- Antenna
- Coaxial cable
- Receiver
- Optional external clock input

The receiver unit is actually a Digital VT-103 video terminal with a PDP-11/23 processor card and a Magnavox GPS receiver card mounted at the backplane. The VT-103 terminal is also equipped with dual micro-floppy stations. The software is read at power-up from a micro-floppy. The software consists of RSX-11S operating system and Magnavox navigation software and are memory resident. The receiver board consists of 5 receiver channels: 4 channels for continuous tracking of the four currently best satellite signals, while the fifth channel gathers ephemeris data. At present, only software which can benefit from two channels is available.

The T-set can operate in 2-dimensional and 3-dimensional navigation mode. Data displayed on the CRT includes time, position, speed, and course of receiver. Further, satellite number, azimuth, elevation, signal-to-noise and range residuals of each channel are displayed as well as the dilution of precision (DOP), satellite alerts and status data. These data plus the almanac, ephemeris, and all pseudo-range measurements are available via the RS-232 data port.

The present software extension, version 2.4, may utilize the benefit of a rubidium or cesium frequency standard. The frequency standard outputs a 5 MHz 5 Volt sine wave and is connected through a coax cable.

The current T-set software can operate in 4 different modes:

A Altitude aiding
C Clock aiding
F Fixed position
N Normal mode

Attitude aiding holds the height fixed, hence it is possible to navigate with 3 satellites visible only.

Clock aiding will extend satellite observation period, in the way that positions may be achieved even when two satellites are visible only. This is an extension in the end of the navigation period, as the system will need 3 or 4 satellites to be able to synchronize the external and internal clocks.

Fixed position mode assumes that the antenna doesn't move. It removes most of the noise on the output co-ordinates which is typical in navigation mode.

3.2 OBSERVATION PERIODS

Visible satellites are shown in Appendix 4. The configuration figure will shift about 4 minutes earlier each day. The period of the satellites is 12 hours, and consequently two observation periods occur each day. Three or more satellites were available during both of the periods. The two periods were between 1040 - 1540 hours and 2110 -0340 hours. The best geometry occurred during the second period.

Satellites were observed during both periods with the rig stationary in its final position on 1 January - 2 January 1986.

3.3 GEOMETRY

The DOP values for north, east and height respectively are shown in Appendix 5 for both the day and night period. During the day period the time with good 4 satellite geometry is only approximately 2½ hours. The night period is a little longer, approximately 3½ hours with a loss of about 20 minutes between midnight and 0100 hours.

3.4 CORRECTION VALUES TO SATELLITE POSITIONS

A GPS T-set was set up and operated at a known point on Andøya by Kongsberg. During the period of observations Kongsberg passed to the Borgny Dolphin differential correction values to be applied to the Northings and Eastings (see chapter 5.2).

A more comprehensive list of the differential corrections, dN and dE, was provided to A/S GEOTEAM on magnetic tape on completion of the rig move, for post-processing quality control.

3.5. HP 9845 COMPUTER PROGRAM

The position, as provided by the T-set at the interface-port, is in the form of geographical coordinates in the satellite datum. The navigation program running the HP 9845 computer read one coordinate set each 3-4 seconds. The program had these highlights:

- 7 parameter datum transformation
- transformation into UTM-projection
- display of a realtime plot in optional scale referred to UTM grid
- optional paper dump of plot
- log on paper
- optional filtering of input position
- optional averaging of input position
- antenna offset reduction granted that correct heading is manually entered.
- logging on magnetic tape

3.6 GPS ANTENNA HEIGHT

The height from sea level to the electrical cable of the antenna was:

Roof of wheelhouse above sea level	21.9 m
Antenna height	1.8 m
	23.7 m

3.7 DATUM TRANSFORMATION

The following datum transformation parameters have been applied:

a) Between WGS-72 and NWL-9D, the Seppelin formulaes

$$Bw = Bn - 0.0232'' \cdot \sin 2B$$
$$Lw = Ln + 0.26''$$
$$Hw = Hn + 4.73 - 0.717 \cdot \sin^2 B$$

where B - latitude
L - longitude
H - ellipsoide height
w - indicate WGS-72
n - indicate NWL-9D

GPS Broadcast ephemeris apply WGS-72. Transit Precise ephemeris are approximately equal to NWL-9D.

b) Between Precise and Broadcast Transit ephemeris.

$$Dz = -1.22 \text{ m}$$
$$Ez = -0.054''$$
$$k = 0.049 \text{ ppm}$$

The parameters are defined from BE to PE.

c) Between Transit Broadcast ephemeris and ED-50.

$$Dx = 92.2 \text{ m}$$
$$Dy = 89.7 \text{ m}$$
$$Dz = 129.7 \text{ m}$$
$$Ez = 1.1''$$
$$k = -2.62 \text{ ppm}$$

This is the ordinary datum-shift used in Norwegian waters north of latitude 64 degrees. The parameters are defined from BE to ED-50.

4. GPS AND T-SET PERFORMANCE

4.1 SATELLITE NO. 8 SATUS

During the run-in to location on Monday, 30 December 1985, satellite no. 8 was included in the computation by the T-set but produced high residuals and standard deviations. It was manually taken out of the system and the standard deviation improved.

Tuesday morning, 31 December 1985, this satellite was not received by the T-set and was not included in the satellite alert prediction. It was present and giving a good fix when used on the evening of 31 December 1985.

4.2 CESIUM CLOCK - REFERENCE

Problems were experienced with the cesium frequency standard, model 3210 such that it did not operate and was therefore unable to be interfaced into the T-set.

4.3 CORRECTION VALUES

Kongsberg operated a GPS T-set on Andøya at a known reference point, and supplied corrections to the northings and eastings to input to the onboard HP9845 computer.

Andenes	69° 20' N	16° 10' E
Rig location	64° 20' N	7° 44' E

The corrections were received on satellite telephone every 30 minutes.

For the first hours of operation, the Andøya software calculated a correction in the magnitude of 30-40 metres in the northings. This turned out to be a software or operation error at Andenes, using wrong transformation parametres. The problem was solved 31 December at 1515 hours.

In periods with stable navigation, the corrections received were in the magnitude of less than 5 metres.

4.4 NAVIGATION PERFORMANCE

In periods when the satellite constellation indicated good signals, the T-set supplied a stable position. The position compared to Syledis showed good agreement in the whole period.

Two minor problems were discovered. The receiver has an automatic selection of satellites. In periods with change of satellites a jump in the DOP's and position could be observed. This could last about 5 to 10 minutes.

In periods there could be different satellites used in the rig fix and the Andøya fix, due to automatic fix configuration. This could have been guided by the operators at both stations by manual induction or exclusion of specific satellites.

However, a brief study of the post-processing showed no discrepancy that could date back to different fix configurations.

A second problem occurred at the beginning of one logging period. When the receiver should turn from idle mode to position calculation when 3 satellites were visible, no calculation started until the system was restarted by the operators.

4.5 FILTER SETTING

At location the filter was set to fixed position mode, which smoothed the output significantly. Unfortunately, this smoothed out the short time alterations that would have been of interest in the post-processing, and made adding of differential corrections doubtfull.

5. POST-PROCESSING OF SATELLITE DATA

5.1 PROCESSING

All satellite data stored on magnetic tapes were analysed and reprocessed on our VAX 11/780 computer.

5.2 COMPARISON OF THREE LOGGING PERIODS

Three logging periods were picked out for comparison. To give an idea of the uncertainty in the system, the corrections derived from the Andøya recording are listed below. The corrections are supposed to be a linear function in the interval between start and end of the period.

Period 1, 1 January 1986:

1230 hours:	dN = 4 m	dE = - 2.30 m
1320 hours:	dN = 0 m	dE = - 9.0 m

Period 2, 2 January 1986:

0000 hours:	dN = 4 m	dE = 4 m
0130 hours:	dN = 7 m	dE = - 1 m

Period 3, 3 January 1986:

0000 hours:	dN = 0 m	dE = 3 m
0100 hours:	.	dE = 3 m
0101 hours:	.	dE = -6 m
0130 hours:	dN = -4 m	dE = -6 m

Applying these corrections to the data recorded on the rig, the following rig antenna position is found:

Period 1:

Northing: 7 134 879 m
Easting : 439 075 m

Period 2:

Northing: 7 134 893 m
Easting : 439 073 m

Period 3:

Northing: 7 134 890 m
Easting : 439 065 m

As a conclusion to these figures there is no significant difference in the received position in the 3 different periods.

An analysis of the effect of corrections from Andøya, shows that in this case no significant improvement is achieved by applying them to the onboard position (due to filter setting of the two different T-sets). The effect is less than random drifting in the system, or small rig movements.

5.3 FINAL POSITION

The onboard position in period 3 is chosen as final position. That is, stabilized position was achieved 3 January 1986 at 0200 hours.

Final GPS antenna position:

Northing: 7 134 888.1 m
Easting : 439 066.0 m

The position is referenced to European Datum 1950, UTM Zone 32 with central meridian 09 degrees east.

5.4 REDUCTION TO WELL CENTER

The distances from satellite receiver antenna to the Well center were scaled from an as-built plan of the rig. The rig heading, read from the gyro-compass, was 264 degrees. See Appendix 3, Antenna Offsets. With these data, the derrick Center co-ordinates have been computed as:

DERRICK CENTRE

ED 50		UTM	
Latitude	64° 19' 58.07" N	Northing	7 134 880.1 m
Longitude	07° 44' 23.70" E	Easting	439 100.7 m

The co-ordinates refer the European Datum 1950 and UTM Zone 32 with central meridian 09 degrees east.

Final position is 10.8 metres in direction 287 degrees from intended location. See Appendix 6.

6. ACCURACY CONSIDERATIONS

The time series plot from the three final observation periods is shown in Appendix 8 for the rig, and Appendix 9 for the differential corrections from Andøya.

The differential corrections can be considered as true errors, and hence indicate the accuracy obtainable with a single point solution.

Reduction from antenna position to well centre position may introduce an additional error of ± 2 metres due to uncertainty in rig heading and the scaled antenna offsets.

Oslo, 20 February 1986
for A/S G E O T E A M

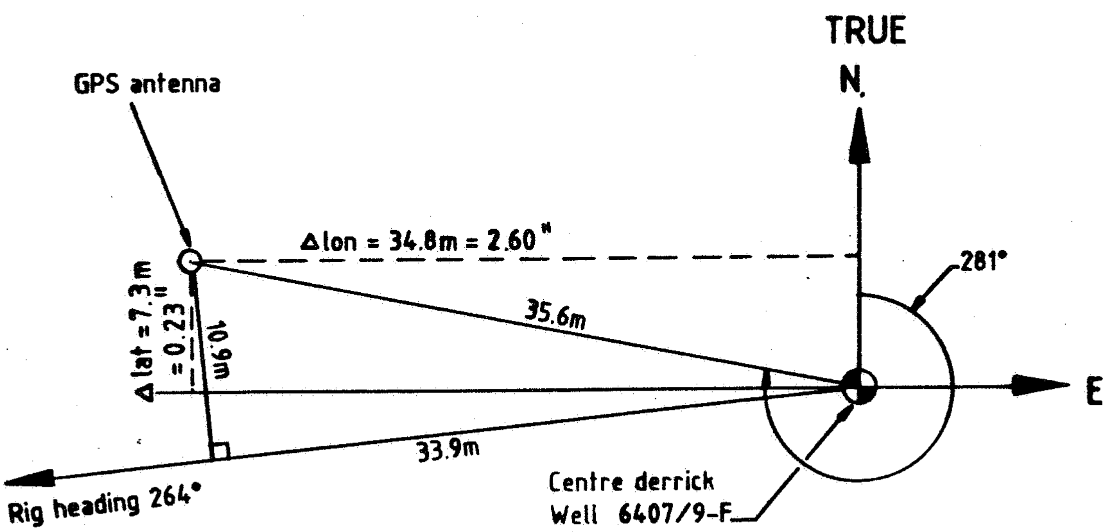
for Roar Normann Nilsen

Dag Hogvard

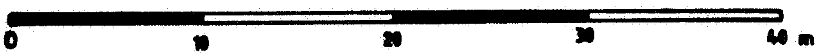
Ivar Jorde

GEOTEAM	Appendix no.: 3.1
	Project no.: 30407.8

GPS ANTENNA OFFSET



SCALE 1:400

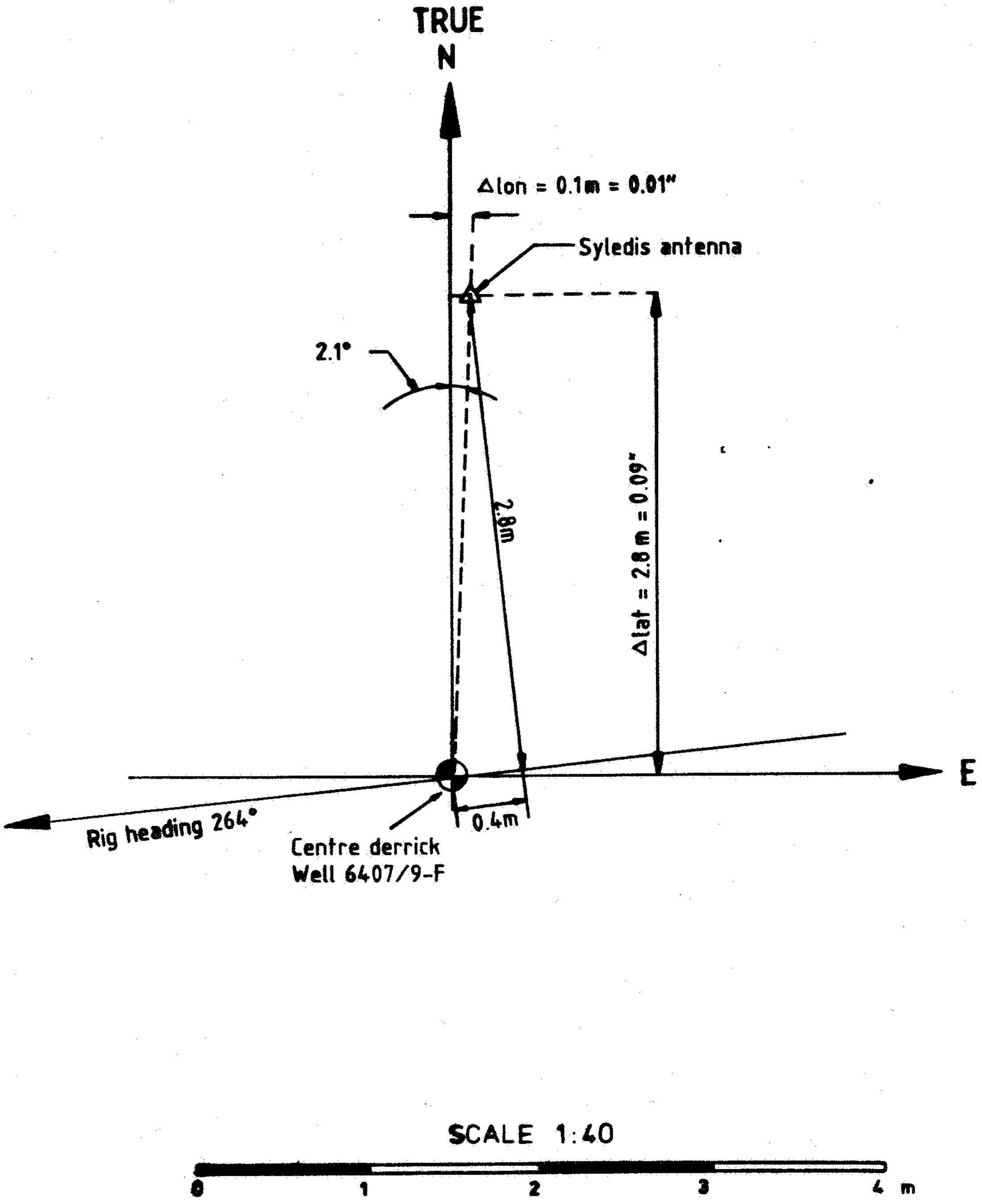


GEOTEAM

Appendix no.: 3.2

Project no.: 30407.8

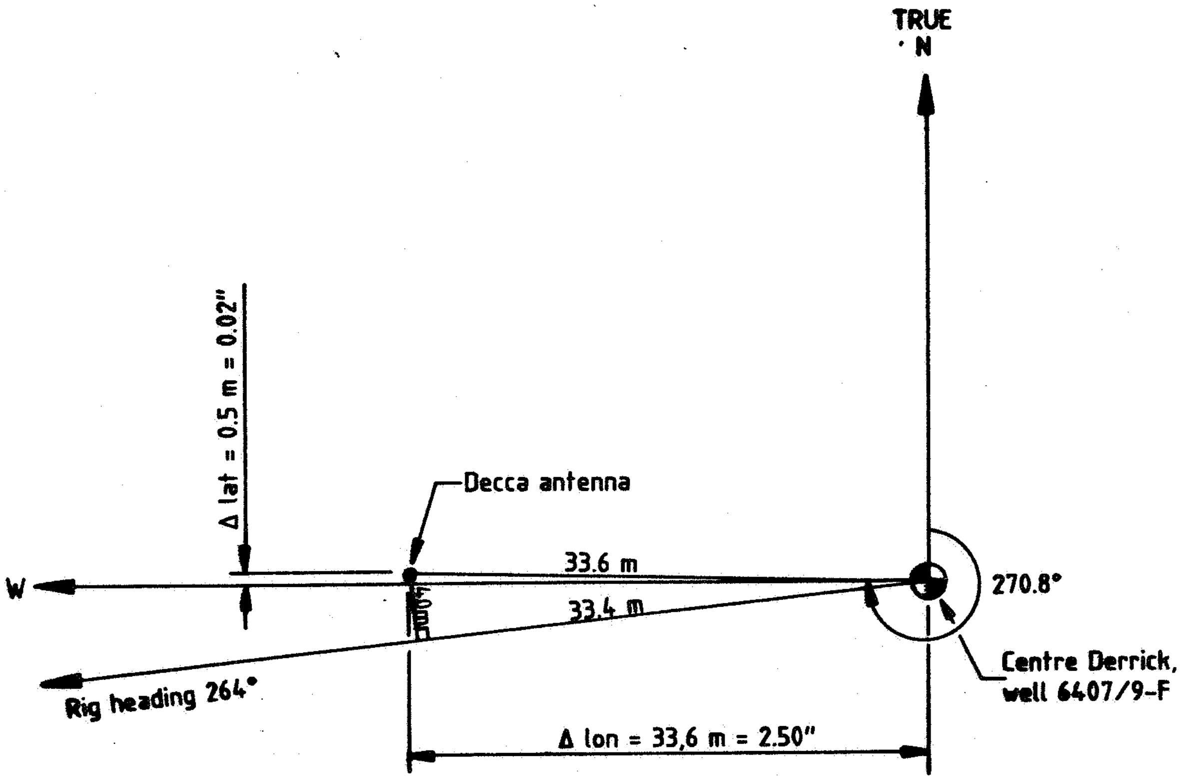
SYLEDIS ANTENNA OFFSET



Appendix no.: 3.3

Project no.: 30407.8

ANTENNA OFFSET
DECCA



SCALE 1: 500

0 10 20 30 40 50 m

DRILLING HISTORY 6407/9-6 (Borgny Dolphin)

The rig Borgny Dolphin commenced moving from the 7120/1-1 well location at 22:30 hrs on 26.12.85 and arrived at the Draugen 6407/9-F location at 08:30 hrs on 31.12.85. The rig was manoeuvered onto location with the Decca Main Chain, Syledis and G.P.S. satellite navigation systems, the anchors were run and the rig ballasted to drilling draught.

The final rig position was:

N 64 deg 19' 58.07 sec
E 07 deg 44' 23.70 sec

A seafloor penetration test resulted in 2 m penetration with 10.000 lbs weight on a 26" bit, and the following distances were established:

-	Seabed	297.5 m BDF
-	Water depth	272.5 m

The temporary guide base was run and landed on seabed at an angle of 1-3/4 degree on the slope indicator.

At 00:00 hrs on 02.01.86 well 6407/9-6 was spudded using a 17½" pilot bit assembly. 17½" hole was drilled to 354 m, the inclination of the pilot hole being recorded as up to 2 degrees. Consequently a 26" bit with a 36" hole opener was run and the hole was reamed and opened to 36" down to 336 m, reducing the inclination to 0.5 degrees. The 17½" pilot hole assembly was re-run and the pilot hole was drilled to 382 m, whereafter the 26" bit and 36" hole opener was run and the hole opened to 36" down to 382 m. 5 joints of 30" casing (X-52, 310 lbs/ft and 457 lbs/ft for the housing joint) were run and landed with the permanent guide base, the angle of the permanent guide base being observed as 1 degree starbord aft. The casing was cemented with the shoe at 375 m BDF and the 30" housing at 296 m (BDF), good cement returns to seabed being observed throughout the displacement. (note:- 200 percent excess cement slurry pumped over and above theoretical open hole annulus volume).

The marine riser with hydraulic pin connector and dump valve was run and latched onto the 30" housing. The diverter was function tested and a trial pressure test of the diverter system was carried out against the 30" casing to investigate its pressure integrity. At 40 psi, the diverter valves, flowline valve, and the slipjoint were leaking, the leakage from the slipjoint being stopped by increasing the seal operating pressure to 70 psi. The cement was then drilled out from 363 m with a 8½" bit and a 26" underreamer, and the well displaced to a NaCl-polymer mud designed to cope with freezing conditions (freezing point -6° C). An 8½" pilot hole was thereafter drilled to 431 m, through the zone at 390-415 m identified on the site survey as possibly containing shallow gas. A maximum gas reading of 0.077 percent C1 was recorded in the interval, at 410 m. After circulating bottoms up, no indications of gas were observed. A 14-3/4" assembly was thus run and 14-3/4" pilot hole was drilled to 810 m, a maximum deviation of 2½ degrees being recorded at 431 m, reducing to 1½ degrees at 756 m. A maximum gas reading of 0.24 percent C1 was recorded in the interval, at 550 m. After reaching 810 m the following logs were run:

DIFL/ACL/GR (Run no. 1)
CDL/CNL/GR/CAL (Run no. 1)

There was no indication of gas on the logs.

The hole was displaced to seawater in two stages, at 400 m and at TD, and monitored for flow at the dump valve at each stage, no flow was observed. 1.03 SG viscous mud was spotted in the open hole and the pin connector was unlatched and the riser pulled.

The pilot hole was opened to 26" down to 810 m with a 26" bit using sea water and high viscous pills on connections, and new formation was drilled to 812 m. On the following wipertrip tight spots were reamed from 420 - 438 m and 738 - 812 m. High viscosity mud was spotted in the open hole section before the string was pulled.

After 20.5 hrs waiting on weather a further wiper trip was performed, whereafter 43 joints of 20" X-52, 129 lb/ft Vetco LS-LH casing was run on HWDP and cemented with the shoe at 804 m, using a thixotropic cement slurry designed to achieve high gel strengths rapidly, thereby preventing gas migration. Good cement returns to sea bed were observed during displacement. (note:- 100 percent excess cement slurry pumped over and above theoretical open hole annular volume). The casing was pressure tested to 1000 psi on bumping the plug. Following two trips to clean the PGB, the BOP stack was run on the marine riser and successfully tested.

A 17½" bit was run to top of cement at 787 and cement and new formation drilled with seawater to 817 m. The well was displaced to KCl polymer mud of 1.35 SG and a leak off test performed to an equivalent mud weight of 1.44 SG. Due to increasing heave the riser was displaced to seawater, and after waiting on weather for 2½ hours a new 17½" BHA was run including a Gearhart MWD tool with deviation and gamma ray sensors. 17½" hole was drilled to 1472 m when the string was pulled to change out the MWD pulsar sub which had failed at approximately 1140 m, necessitating the taking of single shot deviation surveys every 100 m. The same assembly was run back in with a new pulsar sub and 17½" hole was drilled to 1628 m (casing point). Top Kimmeridge was identified from the drilling data and the MWD-GR (poor indications), at 1613 m. Minimal gas levels were recorded during the whole interval, an average background reading of 0.01 percent C1 being recorded, with peaks of 0.06 percent C1 at 950 and 1150 m, and traces of C2 coming in below 1608 m. The following logs were run:

DIFL/ACL/SP/GR (Run no. 2)
CDL/CNL/GR/CAL (Run no. 2)

Following a wiper trip 114 joints of 13-3/8" N80, 72 lb/ft, buttress casing were run and landed on HWDP with the shoe at 1619 m.

On the ensuing cement job, the cement was overdisplaced by sixty five barrels due to plug bypass/leakage, resulting in all of the cement slurry being displaced into the annulus, with a calculated top of cement at 532 m BDF, and bottom of the cement at 1492 m BDF. Following a sucessful BOP test, the float equipment was drilled out, the hole cleaned out to 1628 m, and 140 m 2-7/8" tubing was run in on 5" DP to 1627 m. 50 bbls of 15.8 ppg cement slurry was spotted on bottom and 31 bbls was squeezed at a maximum surface pressure of 1520 psi.

A 12-1/4" bit was run and top of cement was tagged at 1605 m. The cement and 4 meters of new formation was drilled out, whereafter a leak off test was carried out to a stabilized equivalent mud weight of 1.68

SG. The hole was then displaced to 1.20 SG non damaging chalk mud containing 4 ppg polyflow (a 100% acid soluble starch) to reduce the initial high water loss in the chalk mud.

Drilling of 12-1/4" hole proceeded and the top of the reservoir was found at 1644 m. The following intervals were cored, using a 12-1/4" fiberglass sleeve coring assembly:

Core no. 1	1646 - 1660 m	Recovery 84%
Core no. 2	1660 - 1672.7 m	Recovery 100%
Core no. 3	1672.7 - 1678.8 m	Recovery 70%
Core no. 4	1678.8 - 1691.5 m	Recovery 78%

After coring, the 12-1/4" hole was drilled to TD at 1800 m and the following logs were run:

DIFL/ACL/SP/GR	(Run no. 3)	
CDL/CNL/GR/CAL	(Run no. 3)	
DLL/MLL/GR	(Run no. 1)	
DIP	(Run no. 1)	
FMT	(Run no. 1)	
VSP	(Run no. 1)	
SWC	(Run no. 1A)	50 shots, 26 recovered, 17 lost and 5 empty.

A check trip was made, and the interval with the lost bullets was reamed before the logging continued:

SWC	(Run no. 1B)	25 shots, 4 fired, 3 recovered and 1 lost. The tool was pulled to be run decentralized.
SWC	(Run no. 1C)	25 shots 13 recovered, 8 lost and 4 empty.
CBL/VDL	(13-3/8" csg)	TOC in 13-3/8" x 20" annulus +/- 340 m, cement observed down to 1420 m, with a very poor bond in the interval 1420 - 1550 m, the later figure being considered to be the top of cement achieved during the cement squeeze.

The hole was conditioned and 117 joints of 9-5/8", (L-80, 47 lb/ft, VAM) casing was run and cemented with the shoe at 1776 m, the casing not being pressure testea as the plug was not bumped.

Following the sucessful completion of a BOP test, an 8½" bit and scraper was run to top of cement at 1738 m whereafter an RTTS was run to 1610 m and the casing was pressure tested above the packer to 4500 psi. The packer was pulled and the 5" drillpipe laid down whereafter Dresser Atlas was rigged up to run:-

Gyro multishot survey.
CBL/VDL. T.O.C. 9-5/8" csg +/- 1185 m.

A 8½" bit and scraper assembly was run in hole on 3½" drillpipe, picking up the DP whilst running in, and the well was displaced to seawater. Two viscous pills were circulated round at maximum rate before an acid pill and a caustic pill were pumped at 4 BPM. Following another 2 viscous pills the well was displaced to 1.15 SG $CaCl_2$ brine. The brine was filtered to a cleanliness of 2.5 NTU measured by a turbidity meter and the string pulled. Dresser Atlas was rigged up and the Baker F-1 production packer was set at 1660.6 m.

A space out run was made with the subsurface test tree (SSTT) and the 4½" tubing riser before the Schlumberger tubing conveyed perforating guns (13 m of 7-1/4" 12 shots/ft 120° phasing) and associated subassemblies were made up and pressure tested to 5000 psi. The assembly was run in the hole on 3½" tubing up to the position of the fluted hanger, whereafter one white painted joint was installed, and running in continued on 3½" DP to sting into the sump packer. The lower pipe rams were closed around the white painted single for impression and the string was pulled back to space out the perforating guns. The string was run back on the 4½" tubing riser including SSTT and lubricator valve, and pressure tested to 5000 psi. A GR correlation log was run inside the string and confirmed the guns to be on depth. The flowhead and flowlines were rigged up and the fluted hanger was landed into the wearbushing, positioning the guns in the interval 1643 - 1656 m BDF.

The flowhead was pressure tested to 5000 psi, brine circulated and the FH retrievable packer set at 1611 m by pressuring up the tubing to 3000 psi against a wireline plug. The middle pipe rams were closed around the slick joint and the annulus tested to 500 psi. The annulus was pressured up to 2500 psi to close the PCT which had been run in the locked open position, and the valve confirmed closed by wireline. The MORV was opened and the tubing was displaced to diesel giving a drawdown of +/- 400 psi on the formation. The PCT was then opened requiring 2800 psi annulus pressure, (compared with a theoretical operating pressure 1200 psi).

The detonating bar was run in on wireline and the interval 1643 - 1656 m (13 m) was perforated at 14:35 hours on 06.02.86.

The well was backsurged on a 124/64" choke into a separator full of water for 20 bbls of flow, and then flowed through 21-28/64" choke for clean up at low rate. When the produced fluids were clean (after +/- 8½ hours) the flow was directed through the separator on a 12/64" choke, THP 544 psi, 460 BPD oil and a GOR of 180 SCF/B. The well was then shut in at the PCT for a 2 hours pressure build up, whereafter the MORV was opened and the tubing contents reversed out. To kill the well a hi-viscous pill was circulated down to the MORV before it was closed. On the subsequent attempt to open the PCT the annulus pressure suddenly dropped. The viscous pill was reversed out, and after pulling the RP - kill valve it was seen that the shear pins of the valve were sheared. (The shear pins may have been partly sheared when opening the PCT at excessive annulus pressure prior to perforating).

A dummy was installed in the side pocket mandrell and another hi-viscous pill was pumped down to the MORV and squeezed into the formation with 180 psi at surface. The pill failed to block off the perforations. A second pill was tried with same result and finally a viscous carbonate pill was squeezed, to a surface pressure of 1200 psi, and the well was stable. The MORV was opened, the tubing displaced to 1.15 SG brine, the packer unseated, and the well observed stable before the perforating string was pulled. A sand bailer was run to a hold up depth of 1733 m indicating 5 m of fill.

A Baker gravel pack assembly with 5½" screens was run on 3½" drill pipe, landed in the sump packer, spaced out, and the FAB-1 packer set at 1597 m.

After identifying and marking the four work string positions the gravel pack operation started with a 50 bbls 15% HCL acid pre-flush. This was allowed to soak for half an hour to clean up the perforations before pumping 5 bbls brine spacer, 15 bbls pre-pad, 19 bbls of gravel slurry (15 PPG sand concentration, with 12/20 sand) and 5 bbls of post pad which were displaced with brine. No returns were observed following the acid reaching the formation. Screen out occured after 18 bbls with a pressure of +/- 750 psi, and a final screen out pressure of 1500 psi was applied. The excess gravel was reverse circulated out of the drill pipe, and the success of the gravel pack was reconfirmed after a 1 hour wait on the breaker to act, by attempting to circulate through the pack up to a surface pressure of 750 psi, without any circulation being achieved. The gravel pack workstring was pulled out of the packer and a 20 bbl viscous pill was spotted above the reverse acting flapper valve. No losses were observed and the work string was pulled out of the hole following 8 hours of circulation to filter the brine.

The tail pipe subassemblies and the SC-1L Baker packer of the tie back packer assembly were run on 3½" DP. The surface lines and circulating head were installed and the string lowered, shattering the flapper valve with 30000 lbs weight while circulating very slowly. The G-22 locator was set down with 10000 lbs on the FAB-1 packer and picked up 1.5 m. The HFT check valve was run on wireline and set in the 1.87 HF nipple. The Baker SC-1L hydraulic packer was set thereafter at 1586 m (top packer 1585 m) by pressuring up the DP slowly in 500 psi increments to 3000 psi, this pressure being held for 15 min to test the tie back packer assembly before pulling out with the SC-1 setting tool.

After having successfully pressure and function tested the BOP, the production test string sub assemblies were made up and run on 3½" VAM tubing up to the position of the fluted hanger, whereafter one white painted joint was installed and running in continued on the 4½" PH6 tubing riser. The G-22 locator was landed into the SC-1L packer and the variable pipe rams were closed around the white painted single for space out impression purposes. The string was pulled back to the white painted joint, spaced out, and run in on the 4½" PH6 tubing riser including fluted hanger, slick joint, SSTT and lubricator valve as used for the perforating clean up. The flowhead and surface lines were connected, pressure tested to 5000 psi and the fluted hanger landed in the wearbushing. The PCT, which was run in locked open position, was actuated and closed, a pressure of 3200 psi being necessary to close the valve (ie to shear the lock open device, as compared with 2500 psi theoretical requirement), before opening the MORV and displacing the string to diesel. The MORV was closed, the PCT opened and the well was flowed for 16 hours to clean up with a maximum rate of 1400 BPD at 115 psig THP on a 32/64" fixed choke.

A 100 bbls 15% HCL acid stimulation was performed with a 25 bbls viscous brine pill ahead for divertion. The acid was displaced with diesel and soaked for ½ hour. The well was re-opened but died after 30 mins (19 bbls) flow. The tubing contents were reversed out the tubing re-displaced to diesel and the well was re-opened, it died however after 5 mins flow.

Again the tubing contents were reversed out and the tubing re-displaced to diesel, whereafter the well flowed to surface, initially through a 20/64" adjustable choke beaning up gradually to maximum rate as follows:

CHOKE 1/64"	THP PSIG	THT ^oF	OILRATE BPD	GAS MSCF/D	GOR SCF/B	BSW %	DURATION HRS
20	500	50	1200	380	120	7	14½
32	480	62	3200	530	120	4	6½
40	455	70	4500	670	115	2	3½
48	405	70	5700	750	130	2	7
56 (on heater)	405	71	5700	650	110	2	2½
60 (adj)	394	72	6000	390	65	2	3

The well was shut in at surface and two HP crystal gauges with VALTOS memory module and one Flopetrol strain gauge were run and landed in the F-nipple at 1642 m. The well was re-opened and flowed at various rates as follows:

CHOKE 1/64"	THP PSIG	THT ^oF	OILRATE BPD	GAS MSCF/D	GOR SCF/B	BSW %	DURATION HRS
28	550	56	2350	340	150	0.1	12
44	460	66	4900	560	115	trace	12

During the flow period, PVT recombination samples and bulk oil samples were taken, and at the end of the flow period the well was shut in downhole at the PCT.

After a 24 hour build up period, the gauges were retrieved and 3 bottom hole samplers with one HP crystal gauge with EMR memory module were run. The well was opened for sampling on a 12/64" choke, THP 570 psi, at 170 BOPD. After closing the well at the choke manifold the sampling string was pulled. A second run with 3 bottom hole samplers and the same HP crystal gauge was made, 3 samples being recovered, however one was lost at surface. While checking the samplers a sand bailer was RIH, recovering dirty sand from the HUD of 1733 m.

The bubble point analysis of the bottom hole samples gave consistent bubble points of 500 psi, at 60^o F.

Three pressure gauges (1 HP-gauge with Valtos memory, 1 HP-gauge with EMR memory and 1 Flopetrol SDP Strain Gauge) were run and landed in the F-nipple, and an injectivity test was performed for 72 hours injecting clean seawater into the formation. An injection rate of 13000 BWPD was established with a surface pressure of approximately 1000 psi. After 16 hours at the same rate, the surface pressure had increased to 1542 psi. The injection rate was then increased to 16000 BWPD for three hours but the surface pressure increased rapidly to 2485 psi, whereafter the injection rate was cut back to 13000 BWPD with an initial surface pressure of 2170 psi, this rate being maintained for 52 hours, the final surface pressure stabilizing at approximately 2440 psi. A 24 hour pressure fall off was then recorded on the pressure gauges, and the gauges retrieved.

A 100 bbls 15% HCL acid stimulation was performed, the acid being overdisplaced into the formation with seawater at a rate of 13000 bwpd for one hour. Three new pressure gauges (2 HP/EMR-gauges and one Flopetrol/SDP-gauge) were run and a second injectivity test was performed for 12 hours injecting seawater at approximately 13000 BWPD initially, the surface pressure building up from 1680 to 2260 psi in 5 hours. An attempt was made to inject at 16000 BWPD, however the injection pressure increased to 2500 psi at 15000 BWPD. The rate was then cut back to 11000 BWPD for the remaining 5 hours, the surface pressure stabilizing at approximately 2200 psi. Following the injectivity test, a pressure fall off was recorded for 6 hours before the gauges were pulled. One of the HP/EMR-gauges had failed.

An attempt was made to rig up the Dresser Atlas BOP on top of the flowhead in order to run a photon log to evaluate the gravel pack, this was not possible however due to an overtorqued crossover from the flowhead to the W/L lubricator. A sandbailer run was performed to a HUD of 1727 m. In order to backflush the well by displacing it to nitrogen an attempt was made to open the SSD, however, the shifting tool stood up at 36 MBDF and came out covered with wax. A 1.5" W/L tool string was jarred through the restriction, but all other tools stood up at 36 m. A calcium carbonate pill was spotted at the perforations to kill the well and the tubing reversed clean. A dummy photon log was run to the closed PCT at 1573 m, but later W/L runs with gauge cutters again stood up at 36 m BDF. It was therefore decided to pull and clean the waxy tubing. The 4½" tubing riser and 22 joints of 3½" tubing were pulled, when W/L was run opening/closing the SSD, and the 2.7" kick over tool was run sucesfully, confirming the remaining tubing to be wax free.

New 3½" tubing was RIH to replace that layed down, and an abortive attempt made to close the MORV in order to test the string.

The string was pulled, the MORV removed and the rest of the BHA changed out. The new assembly was made up, tested and RIH on 3½" tubing and the 4½" tubing riser including SSTT and lubricator valve. The W/L "B" shifting tool was RIH to confirm the string to be open and the string was tested against a check valve in the HF-nipple. The lubricator was tested, the flowhead made up, the string landed, and the annulus tested to 500 psi. The PCT was actuated at 2500 psi annulus pressure, the SSD opened and the string displaced to xylene.

After having soaked the xylene in the string for 4 hours, the tubing contents were reversed out. The tubing was displaced to acid (HCl 15 %) and the sliding side door (SSD) was closed before the acid was squeezed through the perforations to dissolve the calcium carbonate kill pill. A total of 95 bbls of acid were pumped being followed by 97 bbls of xylene to clean the gravel pack itself, and followed by one string volume of seawater at a low rate. Seawater was then injected at a rate of 13200 BWPD with a surface pressure of 1770-1950 psi for 3 hours.

One GRC/EMR and two HP/EMR gauges were run and landed in the F-nipple at 1642 m, and an injectivity test was performed for 12 hours, injecting clean seawater into the formation. An injection rate of 13200 BWPD was established with an initial surface pressure of 1760 psi increasing to a maximum of 2065 psi after 2½ hours, remaining constant thereafter at approximately 2040 psi. Following the injection, a pressure fall off was recorded for 6 hours before the gauges were pulled.

Xylene (4 bbls) was spotted at the perforations, soaked for one hour and the seawater injection was resumed for 6 hours at a rate of 15100 BWPD and a tubing head pressure of approximately 2435 psi.

Following the completion of the water injection testing, a sand bailer was run to a hold up depth of 1727 m, whereafter Dresser Atlas was rigged up and ran a photon log across the gravel pack indicating a uniform gravel pack. Two runs were performed without being able to pass the O-ring seal sub at 1658 m in either case.

An AFH wireline plug was set in the AF ported nipple at 1636 m in the tie back packer assembly and tested to 3000 psi.

Preparations proceded in order to inflow test the plug with nitrogen by opening the SSD, however due to deteriorating weather, the tubing riser was disconnected and the marine riser displaced to seawater. 32 hours were spent waiting on weather before the marine riser was redisplaced to brine and the tubing riser reconnected.

The tubing was displaced to nitrogen down to 1100 m, the SSD closed and the tubing surface pressure bled off in steps of 500 psi down to 200 psi, and the AFH-plug satisfactorily inflow tested for two hours.

The tubing was pressured up with nitrogen to equalize the pressure across the SSD, the SSD opened with wireline, and the nitrogen reversed out. 25 kg of MCP-47 (a low melting point alloy consisting of Gallium, Indium and Tin) was dumped on top of the AFH-plug to cover the fishing neck, the PCT was locked open, and the production string pulled and laid down.

An S-1 packer plug was run in hole on 5" DP, however the weather deteriorated and the string was hung off in the well head and the riser displaced to seawater. A total of 20½ hours was spent waiting on weather including redisplacing the riser to brine and retrieving the string. Thereafter the packer plug was set in the SC-1 packer at 1585 m and the running string was pulled to confirm that the packer plug had been set sucessfully. Open ended drill pipe was run in hole to just below the wellhead, and 350 kg MCP-47 alloy was dumped on top of the plug.

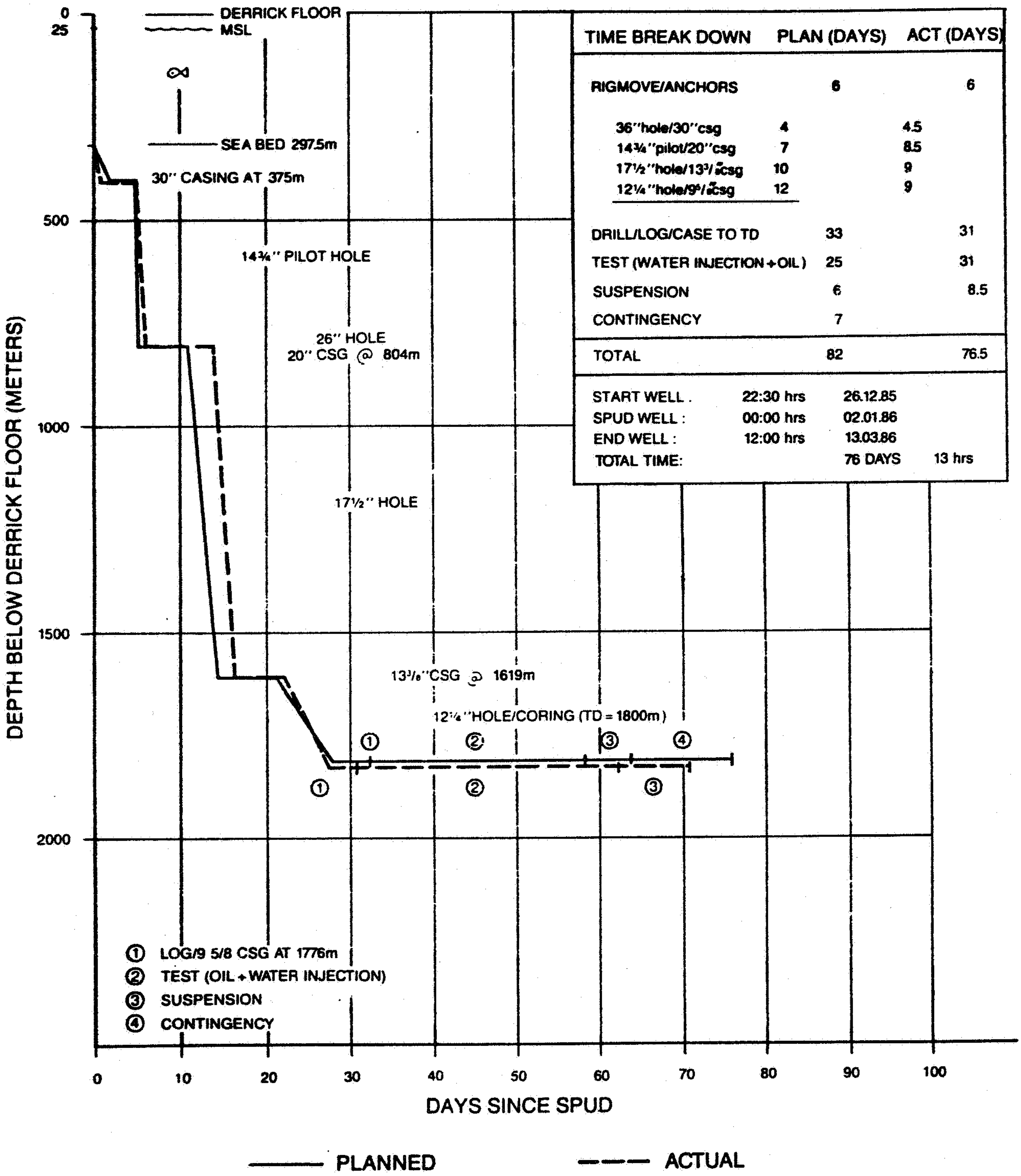
A Baker C-1 retrievable bridge plug was run and set at 1558 m, the running string pulled, and 240 m of 2-7/8" stinger was thereafter run on 5" DP to 1550 m. A 25 bbls pill of viscous brine was pumped, and 800 lbs of sand was dumped in the pipe and spotted on top of the bridge plug. The stinger was pulled back to 1450 m, and suspension cement plug no. 1 was set in the 9-5/8" casing from 1450 - 1253 m. The stinger was pulled and the cement plug located with an 8½" bit at 1253 m with 15.000 lbs weight.

The well was then displaced to 1.25 SG inhibited brine. The bit was pulled, the stinger re-run, and suspension cement plug no. 2 set from 600 - 400 m. The plug was located at 416 m with 10000 lbs weight and the string pulled and laid down. The BOP was unlatched, the riser and BOP pulled, and a corrosion cap was run and landed on top of the wellhead.

The R.O.V. was run to make a final wellhead inspection and during this survey an intermittent flow of gas bubbles was discovered escaping from the 20" x 30" annulus. A gas sample was taken and analysed through the gas chromatograph, showing only C1 (methane), indicating the gas to be coming from a shallow gas zone. Continous observation of the gas bubbles over a period of 63 hours showed the flow to remain stable without any sign of change. Authorisation to leave the well in this condition was given by the authorities, and the guide wires were then cut between the temporary and the permanent guide base. The rig was deballasted to towing draught, and the anchors were pulled and bolstered. At 12.00 hours 13.03.86 the anchor handling was completed and the rig commenced towing to location 7120/1-1.

An inspection programme for observation of the gas bubbles has been implemented, the first inspection taking place one week after the rig left location, a second two weeks later, and a third inspection four weeks thereafter. The surveys showed continued gas flow activity, but with no significant increase in flow rate. Further inspections will be carried out at six monthly periods to continue to monitor the wellhead and gas leak activity.

6407/9-6 DRILLING PROGRESS CURVE



TIME BREAK DOWN	PLAN (DAYS)	ACT (DAYS)
RIGMOVE/ANCHORS	6	6
36"hole/30"csg	4	4.5
14¾"pilot/20"csg	7	8.5
17½"hole/13³/₈csg	10	9
12¼"hole/9⁵/₈csg	12	9
DRILL/LOG/CASE TO TD	33	31
TEST (WATER INJECTION + OIL)	25	31
SUSPENSION	6	8.5
CONTINGENCY	7	
TOTAL	82	76.5

START WELL .	22:30 hrs	26.12.85
SPUD WELL :	00:00 hrs	02.01.86
END WELL :	12:00 hrs	13.03.86
TOTAL TIME:	76 DAYS	13 hrs

A/S Norske Shell

G2199/2

CASING DATA WELL NO 6407/9-6

DATE RUN	SIZE	GRADE	WT/FT (LBS)	COUPLING	SHOE DEPTH (MBDF)	REMARKS
04.01.86	30"	X-52	Housing: 457 Casing: 318	ST-2	375 m	Top joint 1.5" wall thicknes
12.01.86	20"	X-52	129	LS-LH	804 m	
19.01.86	13 3/8"	N-80	72	BTC	1619 m	
31.01.86	9-5/8"	N-80	47	VAM	1776 m	Top of housing: 295.5 m

CEMENTATION DATA WELL 6407/9-6

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
04.01.86	30" Casing	36"/382	375	Class G	780 lead 770 tail	13.2 15.8	Seawater Seawater	0.36 GPS Econolite 3% BWOC $CaCl_2$	- -	Cement to seabed.
12.01.86	20" Casing	26"/812	804	Class G	2247 lead 445 tail	13.2 15.8	Seawater Seawater	1.5 GPS Econolite 0.31 LBS/SX caustic 1 PCT BWOC $CaCl_2$	- - -	Cement to seabed
20.01.86	13-3/8" Csg	17½"/1628	1619	Class G	1599 lead 258 tail	13.2 15.8	Fresh Water Fresh Water	0.36 GPS Econolite 0.22 CFR - 21	- -	Cement overdisplaced due to plug bumping TOC = 340 m.
22.01.86	Squeeze cmt job 13-3/8" csg shoe		1619	Class G	242	15.8	Freshwater	-	-	Pumped 50 bbls slurry. Squeezed 27.8 bbls cement into formation/annulus.
31.01.86	9-5/8" Csg.	12-1/4"/ 1800	1776	Class G	165 lead 457 tail	13.5 15.8	Freshwater Freshwater	0.27 GPS CFR - 21 1.23 GPS halad 101 0.18 GPS econolite 0.15 GPS CFR - 21 0.70 GPS halad - 101 0.10 GPS econolite	- -	TOC = 1185 m.
08.03.86	Suspension plug no. 1	9-5/8"/ 1558	1776	Class G	235	15.8	Freshwater	-	-	Plug set from 1450 - 1253 m
08.03.86	Suspension plug no. 2	9-5/8"/ 1253	1776	Class G	230	15.8	Seawater	2 pct BWOC $CaCl_2$	-	Plug set from 600 - 416 m.

code: cement data 6407/9-6/WELL

BIT RECORD SUMMARY WELL NO 6407/9-6

RUN NO.	BIT NO.	BIT SIZE INCH	EMFGR/TYPE	JET SIZE 1	2	3	4	DEPTH OUT	MTRS	HRS	WOB (1000 LBS)	RPM	PUMP PRESS (PSI)	GPM	MUD WT	VIS	CODE T	B	G	REMARKS
1	1	26	HTC OSC 3AJ	-	-	-														Performed penetration test.
2	2	17½	Sec S3GJ	18	18	18		354	57	5	5	85	950	600	Seawater + visc. pills		1	1	I	POOH high incl.
3	1RR	26	HTC OSC 3AJ	20	20	20		336	39	5	3/4	100	1600	1000	Seawater + visc. pills					Open pilot hole.
	3	36	Hole opener	22	22	22	22	335	38											
4	2RR	17½	Sec S 3GJ	18	18	18		382	28	2½	2/3	90	950	600	Seawater + visc. pill		1	1	0	Drilled to 30" setting depth.
5	1RR	26	HTC OSC 3AJ	20	20	20		382	46	4	5/10	110	1250	1000	Seawater + visc. pill		3	3	0	Open pilot hole.
	3RR	36	Hole opener	22	22	22	22	381	46											
6	4	14-3/4	S 13 G	24	24	24		387	5	½					Seawater + visc. pill		-	-	-	Drilled out cement + 5 m formation.
	5	26"	Underreamer	16	16	16		386	4											
7	6	8½	HTC X3A	16	16	16		431	44	4	5				1.06		-	-	-	8½" pilot to check for shallow gas.
8	4RR	14-3/4	REED S13 G	16	16	16		573	186	12.5	5/15	120	2250	800	1.10	40	-	-	-	
9	4RR	14-3/4	Reed S13G	16	16	16		810	237	15.5	5/10	120	2000	750	1.10	40	3	3	0	Drilled to 20" setting depth.
10	7	26	Hughes R1	20	20	20		812	426	19	5/10	100	2500	1000	seawater		7	7	0	Opened pilot hole
11	7RR	26	Hughes R1	-	-	-														checktrip.
12	2RR	17½	SEC S3GJ	18	18	18		817	5	½	10	100	2500	1000	S/W					Drilled shoetrack + 5 m formation.
13	8	17½	SEC S3GJ	22	22	22		1472	655	39	10/30	100/110	2900	900	1.39 - KCl	55	3	6	I	
14	9	17½	Smith DGJ	22	22	22		1628	156	16	30/45	105	3100	875	1.39 - KCl	65	2	4	I	
15	9RR	17½	Smith DGJ	22	22	22														Checktrip.
16	10	12-1/4	HTC X1G	18	18	18														Drilled shoetrack.
17	11	12-1/4	HTC/X1G	18	18	18		1646	18	3	20	85	2500	600	1.40 - KCl	47	1	1	1/8	Drilled to coring point.
18	12	12-1/4	Reed Weasel	3 corehead				1660	14	2.5	12	80-120	600	400	1.20 - chalk	46	22% worn			Core no. 1.
19	12RR	12-1/4	Reed Weasel	3 corehead				1672.7	12.7	5	20	80-120	600	400	1.20 - chalk	49	100% worn			Core no. 2.
20	13	12-1/4	Reed shark	corehead				1678.8	6.1	6.5	20	125	1000	500	1.20 - chalk	46	15% worn			Core no. 3.
21	14	12-1/4	Reed Weasel	3 corehead				1693.5	14.7	4	12	120	500	450	1.20 - chalk	49	25% worn			Core no. 4.
22	11RR	12-1/4	HTC X1G	16	16	16		1800	106.5	12	25	120	2800	450	1.21 - chalk	46	4	4	2	TD.

FORMATION LEAK OFF TEST DATA WELL 6407/9-6

NO.	DATE	CASING		HOLE		MUD Wt. IN USE		EQUIVALENT MUD Wt.		REMARKS
		SIZE (")	DEPTH (M)	SIZE (")	DEPTH (M)	SG	PSI/ 1000 FT	SG MAX/STAB	PSI/ 1000 FT MAX/STAB	
1	14.01.86	20"	804	17½ 26	817 812	1.35	585	1.44/1.42	624/615	2.1 bbls pumped in 0.5 bbls increments 0.6 bbls returned.
2	23.01.86	13-3/8"	1619	12-1/4 17½	1633 1628	1.36	590	1.68/1.68	728/728	Leak off test performed after squeeze cem. job at 13-3/8" csg. shoe. 2.1 bbl pumped 1.6 bbl returned

DEVIATION DATA WELL NO. 6407/9-6

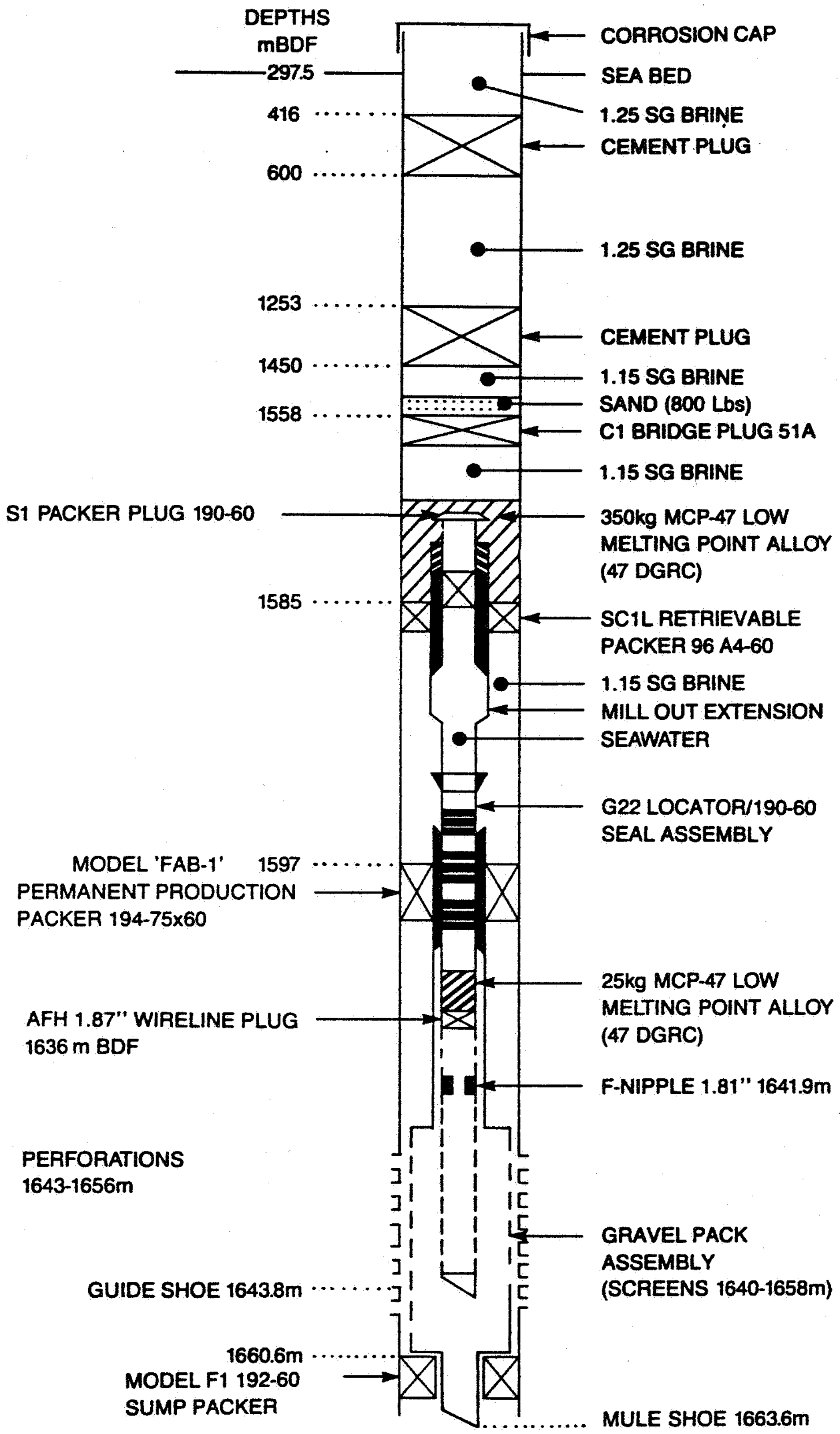
(DISTANCE FROM DRILL FLOOR (DF) TO MEAN SEA LEVEL (M.SL) = 25 M)

DEPTH AH (M.BDF)	ANGLE (DEGREE FROM VERT.)	DIRECTION (DEGREE TRUE)	DEPTH T.V. (M.SL)	NORTHING (M.FROM LOCN)	EASTING (M.FROM LOCN)	DOG LEG (^{o}/ 100 M)
297	Tie-in coordinates		297	0.00	0.00	0.00
400	1.91	219.7	399.96	- 2.20	- 1.77	0.08
500	1.76	214.4	499.90	- 4.98	- 3.86	0.10
600	1.57	208.3	599.86	- 7.39	- 5.26	0.03
700	1.32	202.0	699.83	- 9.67	- 6.19	0.05
800	1.29	191.6	799.80	- 11.88	- 6.79	0.01
900	0.90	190.7	899.78	- 13.77	- 7.23	0.06
1000	0.83	180.6	999.77	- 15.27	- 7.43	0.02
1100	0.69	182.3	1099.76	- 16.47	- 7.35	0.05
1200	0.50	189.2	1199.76	- 17.53	- 7.43	0.04
1300	0.33	177.6	1299.75	- 18.29	- 7.48	0.03
1400	0.27	192.3	1399.75	- 18.78	- 7.47	0.07
1500	0.32	330.8	1499.75	- 18.82	- 7.72	0.09
1600	0.55	12.7	1599.75	- 17.92	- 7.68	0.04
1700	0.98	335.9	1699.73	- 16.61	- 8.10	0.02
1725	1.06	318.6	1724.73	- 16.24	- 8.34	0.13

Note: Survey points from Sperry Sun Gyroscopic Multishot Directional Survey.

Rig coordinates : N 64 Deg 19' 58.07 sec. in UTM : N 7134880.1 m
E 07 Deg 44' 23.70 sec. E 439100.7 m

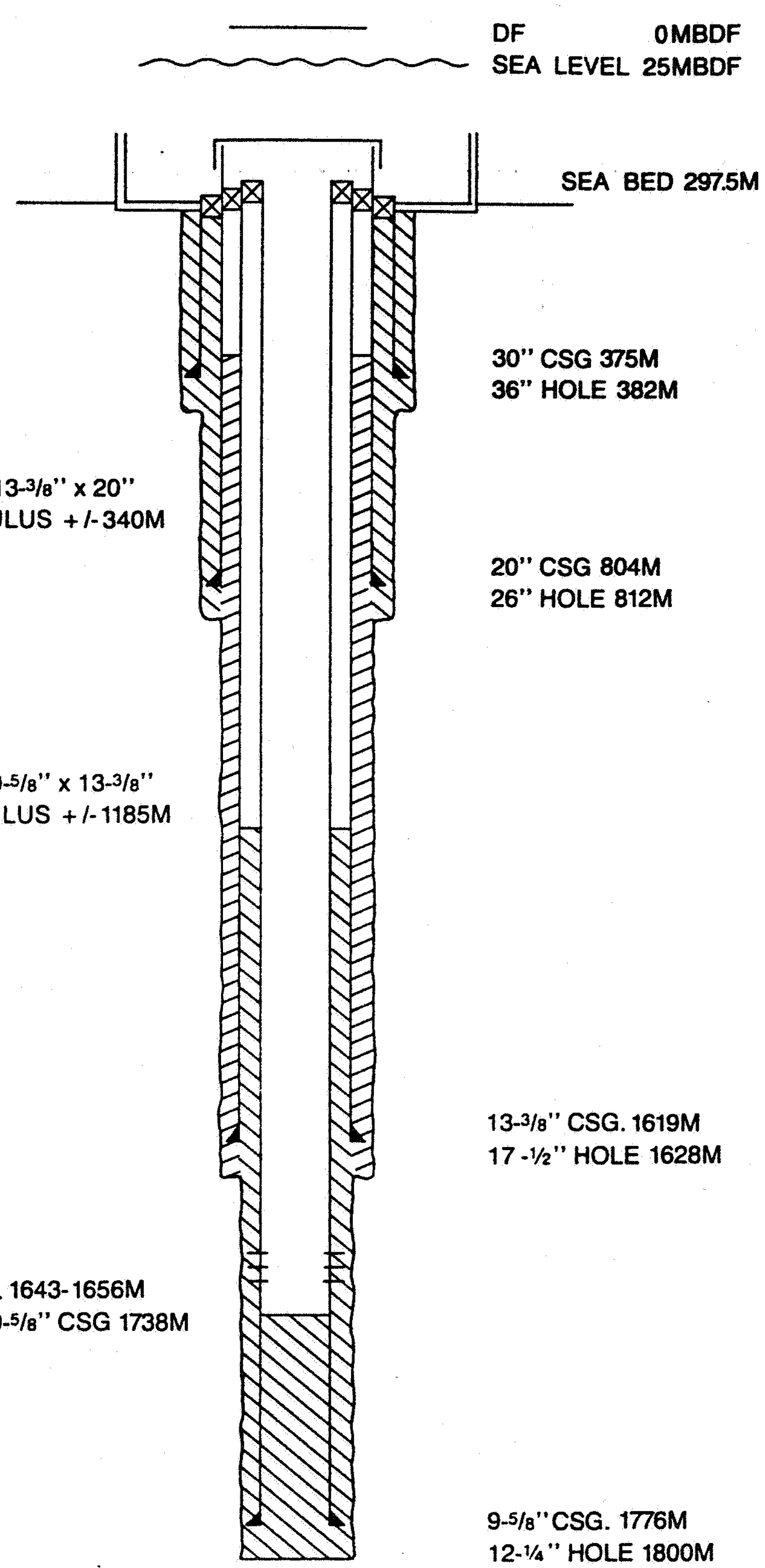
SUSPENSION PLUG STATUS 6407/9-6



A/S Norske Shell

G. 2220/2

CASING STATUS 6407/9-6



A/S Norske Shell

G. 2220/1

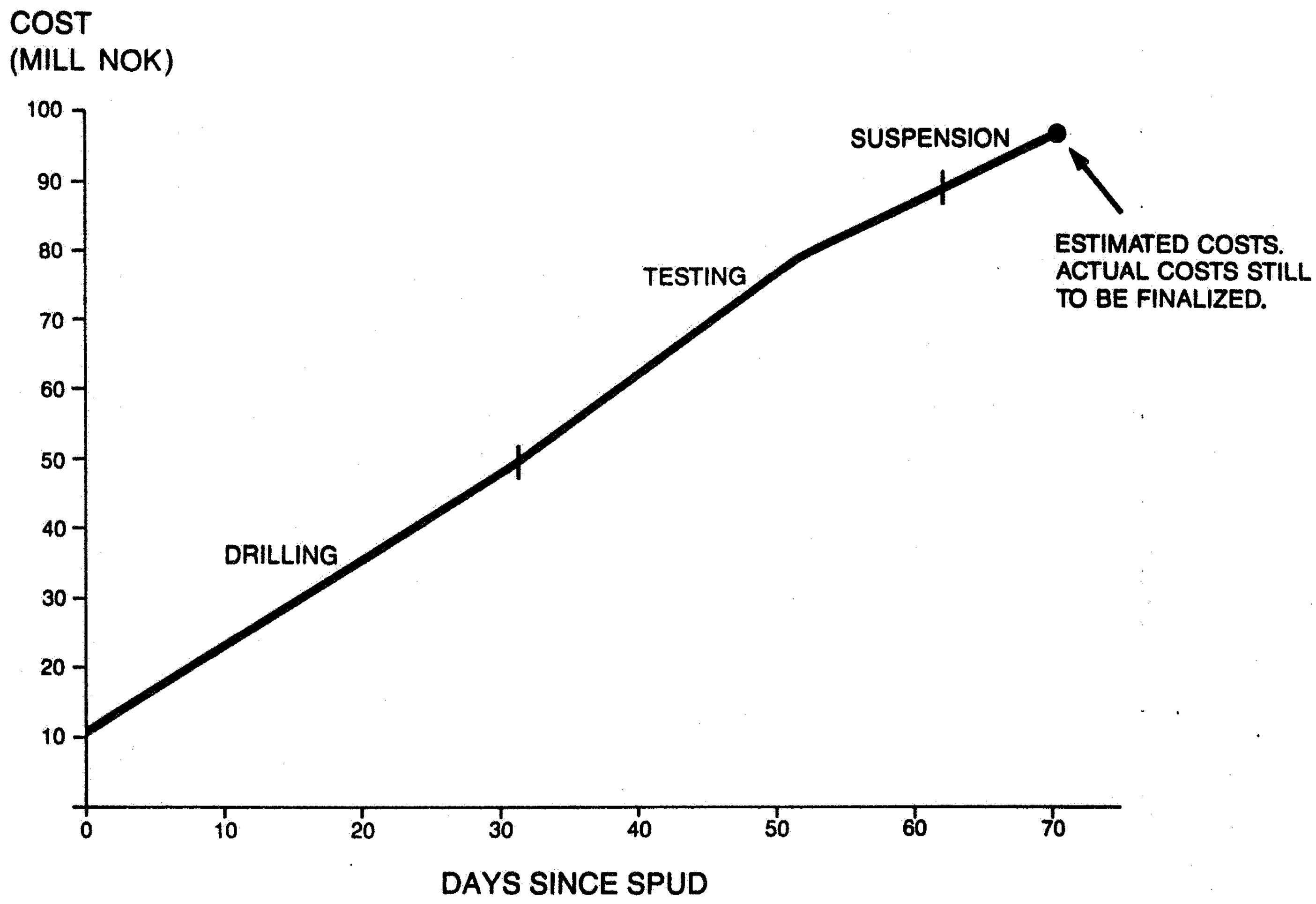
TIME ALLOCATION 6407/9-6

Started well at 22:30 hrs 26.12.85.
Spudded well at 00:00 hrs 02.01.86.
Finished well at 12:00 hrs 13.03.86.

PHASE	ITEM	DEC.	JAN.	FEB.	MARCH	TOTAL HRS	%
PREPARATION	- Towing	97				97	5.3
	- Laying/ pulling anchors	24				24	1.3
	- General preparation		20			20	1.1
	Sub total					141	7.7
DRILLING	- Bit on bottom		107.5			107.5	5.9
	- Round tripping		168	19.5		187.5	10.2
	- Reaming/ enlarging		44	1		44	2.4
	- Circulation/ condition mud		52.5	1		53.5	2.9
	- Condition hole for casing		5			5	0.3
	- Running casing/drilling cement		59	1		60	3.3
	- Leak off test		3			3	1.2
	- Cementing & WOC		22			22	2.5
	- Running/ pulling riser BOP		46			46	1.3
	- Flanging up and testing		19.5	5		24.5	0.7
	- Repairs (pumps/ drawworks)		11.5	2		13.5	1.5
	- Surveys		24	4		28	0.4
	- Observe		7			7	1.3
	- Waiting on weather		23			23	
	Sub total					624.5	34.0
EVALUATION	- Coring (on bottom)		18			18	1.0
	- Round trip with core barrel		26			26	1.4
	- Circulating for samples		4.5			4.5	0.2
	- Recovery of core		6.5			6.5	0.4
	- Condition hole for logging		2	4		6	0.3
	- Logging		53			53	2.9
	- RFT testing		5.5			5.5	0.3
	- Waiting on weather		16.5			16.5	0.9
	Sub total					136	7.4
TESTING	- Running/ pulling tubing			121.5		121.5	6.6
	- Rigging up surface eqp. etc.			26		26	1.4
	- Circulation/ observing well			99		99	5.4
	- Bullheading/ gravel packing			7.5		7.5	0.4
	- Stimulation/injectivity test			89	31.5	120.5	6.6
	- Testing BOP's etc.			9.5		9.5	0.5
	- Dresser wireline			6.5	9.5	16	0.9
	- Expro wireline & Press testing			112	6	118	6.4
	- Flowing well			44.5		44.5	2.4
	- Pressure build ups & fall offs			56	6	62	3.4
	- Back-surge operation & Clean up			53		53	2.9
	- Waiting on weather & Daylight			11	1.5	12.5	0.7
	Sub total					690	37.6
SUSPENSION	- Plugging back and WOC/Susp.				71.5	71.5	3.9
	- Pulling riser/ BOP stack				13	13	0.7
	- Laying down string				23	23	1.3
	- Anchor handling				19	19	1.0
	- Waiting on weather				50.5	50.5	2.7
	- Observ wellhead				63	63	3.4
	- Preparing for move				5.5	5.5	0.3
	Sub total					245.5	13.3
		TOTAL HOURS				1837	100%

Total time: 76 days 13 hours

TIME COST CURVE 6407/9-6



A/S Norske Shell

G2199/1

5. MUD REPORT

The mud report, prepared by Gearhart was distributed to NPD and partners on 18 June, 1986.

6. GEOLOGICAL REPORT

6.1 Sample Collection

Ditch Cuttings

Ditch samples were collected every 10 m from 408 to 1530 mbdf, every 6 m in the interval from 1530-1602 mbdf and every 3 m in the interval from 1602 mbdf to 1800 mbdf (TD).

The Cuttings Log was distributed to NPD and partners on 16.06.86 (see also Encl.1).

Sidewall Cores

Sidewall cores were taken in the 12 1/4" hole. A total of 79 sidewall samples were attempted, 40 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 Upper Jurassic Frøya Formation and the Middle Jurassic Haltenbanken Formation:

Core no.1	1646.0 - 1660.0 m	(recovery 84%)	DD to LD shift: -1.20
Core no.2	1660.0 - 1672.7 m	(recovery 100%)	DD to LD shift: -0.60
Core no.3	1672.7 - 1678.8 m	(recovery 70%)	DD to LD shift: -0.60
Core no.4	1678.8 - 1693.5 m	(recovery 78%)	DD to LD shift: +0.30

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 6407/9-6 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.

The stratigraphic names have been given according to the existing Shell terminology, but the units are correlatable with those defined by Statoil and Saga in the Haltenbanken area. The names may be subject to changes when the stratigraphic nomenclature for the Haltenbanken area is formalised.

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 10).

A lithological description of the different formations is summarised below.

Nordland Group (272 mss - 832 mbdf)

From seafloor (272 m) to 440 mbdf no returns to surface.

From 440 mbdf to 832 mbdf a light brown to grey, very soft, sandy to silty hygroturgid clay was encountered. The clay is occ. glauc, dominantly non-calcareous to slightly calcareous and contains intercalations of very fine to coarse sand beds and occasionally shell fragments.

Hordaland Group (832 - 1343 mbdf)

The Hordaland Group comprises medium brown to grey, silty clay which is soft but below 1100 mbdf becomes moderately hard, occasionally silty claystone. The clay and claystone are hygroturgid, occ. carbonaceous and slightly glauconitic. At the base of the formation an increasing amount of tuff is observed.

Rogaland Group (1343 - 1541 mbdf)

Balder Formation (1343 - 1377 mbdf)

The Balder Formation comprises medium-dark olive-grey,occasionally brown, silty, claystone with multicoloured tuffaceous fragments.

Sele/Lista Formation (1377 - 1541 mbdf)

The Sele/Lista Formation is a sequence of grey-brown and medium grey silty, claystones which are occasionally calcareous and non-swelling. At the top of the formation tuffaceous fragments still occur.

Shetland Group (1541 - 1611 mbdf)

The Shetland Group consists of brown to dark grey-brown claystone which is slightly calcareous, micaceous and becomes occasionally red - brown.

Cromer Knoll Group (1579 - 1618.5 mbdf)

The Cromer Knoll Group consists of an orange/red-brown, soft, non-calcareous claystone. The top part comprises a dark grey claystone. The bottom part contains grey-white marly limestone.

Humber Group (1611 - 1662 mbdf)

Kimmeridge Clay Equivalent (1611 - 1642.5 mbdf)

The Kimmeridge Clay Equivalent is a sequence of brown-black, slightly silty and micaceous, hard claystone, which is non calcareous and becomes bituminous at the base. The top of the formation contains buff-white limestone beds.

Frøya Formation (1642.5 - 1662 mbdf)

The Frøya Formation comprises a 17 m thick fine to coarse grained, moderately to poorly sorted sand which becomes at the base slightly micaceous. Indications of oil were found. This sand is underlain by a 2 m thick bituminous and silty clay interval.

Vestland Group (1662 - 1774.5 mbdf)

Haltenbanken Formation (1662 - 1774.5 mbdf)

The Haltenbanken Formation consists of light grey to light brown-grey, silty and sandy micaceous claystone at the base. This passes upwards into light to medium grey, medium grained sand sequences. The top of the formation contains well sorted fine grained sands which are cross-bedded.

Dunlin Group (1674.5 - TD 1800 mbdf)

Upper Drake Formation equivalent (1774.5 - TD 1800 mbdf)

The Upper Drake Formation comprises light to medium grey silty claystone.

Table 6.1

FORMATION TOPS WELL 6407/9-6

	TOP(mss)
Nordland Group	272.0
Hordaland Group	807.0
Rogaland Group	
Top Balder Fm.	1318.0
Top Sele/Lista Fm.	1352.0
Shetland Group	1516.0
Cromer Knoll Group	1547.0
Humber Group	
Kimmeridge Clay Eq.	1586.0
Frøya Fm.	1617.5
Vesta Group	
Haltenbanken Fm.	1637.0
Dunlin Group	
Upper Drake Fm. Eq.	1749.5

Table 6.2

SUMMARY OF BIOSTRATIGRAPHY WELL 6407/9-6

1623.9 m	:	Berriasian (zone 11)
1629.9	:	Not diagnostic
1635 - 1638.4 m	:	Early Portlandian (zone 10.1)
1639.9 - 1645.5 m	:	Late Kimmeridgian/Early Portlandian
1646.3 - 1655.20 m	:	Not diagnostic/Not found
1656.5 - 1657.9 m	:	Early Kimmeridgian (zone 9.2 - 9.1)
1658.4 - 1660.55 m	:	Oxfordian - Early Kimmeridgian (zone 8 - 9.1)
1661.5 - 1690.25 m	:	Not diagnostic
1724.7 m	:	Bathonian or older (zone 4)
1726.4 - 1730.1 m	:	Not diagnostic
1730.9 - 1785.4 m	:	Bajocian or older (zone 3)
1787.6	:	Aalenian - Late Toarcian (zone 2 -3)

6.3 Hydrocarbon Indications

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

Tertiary/Quaternary (272 mss - 1541 mbdf)
In this hole section traces of C_1 were registered (0.01 - 0.3%) with a peak of 0.3% at 550 m.

Shetland Group (1541 - 1572 mbdf)
C_1 gas readings were recorded in this interval, with an average of 0.03%.

Cromer Knoll Group (1572 - 1611 mbdf)
C_1 gas readings (0.01 - 0.08%) were observed.

Humber Group (1611 - 1662 mbdf)

Kimmeridge Clay Equivalent (1611 - 1642.5 mbdf)

Upon entering the Kimmeridge Clay Equivalent C_1 (0.01 - 0.08%) and traces of C_2 were encountered. At the base also C_3 and C_4 were observed and the C_1, C_2 and C_3 gas readings gradually increased towards the base.

Frøya Formation (1642.5 - 1662 mbdf)

Gas readings of C_1, C_2, C_3, C_4 and C_5 were recorded at the top of the Frøya Fm. Direct pale yellowish fluorescence was observed in the core samples.

Vestland Group (1662 - 1774.5 mbdf)

Haltenbanken Formation (1662 - 1774.5 mbdf)

Yellowish-white fluorescence was observed in core samples. Between 1665 and 1671 mbdf fluorescence gradually decreased and below 1671 mbdf no fluorescence was observed and only C_1 (0.04%) C_2 (0.01%) and traces of C_3 were measured.

Dunlin Group

Upper Drake Formation eq. (1774.5 - TD 1800 mbdf)

Traces of C_1 and C_2 were observed.

6.4 Seismostratigraphy

A velocity survey was carried out by SSL with check shot levels between 420 and 1778 mbdf. Table 6.3 summarises the times, depths and interval velocities for the major seismic horizons. Encl. 5 shows sonic, density and acoustic impedance logs displayed at linear time scale together with the zero phase bandpass filtered (10-55 H_z) reflectivity and acoustic impedance synthetic traces, which have been used for stratigraphic identification of seismic reflectors. Encl. 6 illustrates the good correlation between synthetic and seismic data.

Table 6.3

Check shot data well 6407/9-6

Horizon	Actual (Prognosed) Depth(mss)	Checkshot Time (ms)	Interval Velocity (m/s)
Seabottom	272.0 (271.0)	366.5	1484.3
Unconformity 1	383.0 (389.0)	494.0	1741.2
" 2	610.0 (612.0)	704.8	2153.7
" 3	724.0 (727.0)	797.9	2449.0
" 4	807.0 (806.0)	875.5	2139.2
Top Balder	1318.0 (1318.0)	1409.3	1914.6
Base Tertiary	1516.0 (1502.0)	1605.4	2019.4
Top Kimmeridge Clay	1586.0 (1589.0)	1665.1	2345.1
Base Kimmeridge Clay	1617.5 (1617.0)	1692.3	2316.2
Top Haltenbanken	1637.0 (1632.0)	1710.3	2166.7
Top Drake	1749.5 (1736.0)	1786.9	2937.3

6.5 Reservoir Geology

Light oil was encountered in the Upper Jurassic Frøya Formation. The Frøya Formation consists of a 17.5 m thick unconsolidated sandy sequence which is subdivided in three distinct lithological units with varying reservoir characteristic:

Unit I (1617.5 - 1630 mss) consists of fine to medium grained very well to well sorted sand. Sedimentary structures vary from bioturbated between 1628.5 - 1630 mss and massive, bioturbated and often x-bedded between 1617.5 and 1628.5 mss. The cross-bedded sets often contain coarse clasts at the base and mm-scale clay/organic lamination on top of the foresets. Reservoir qualities are very good; core porosity ranges from 32-35% with average of 33.5% and measured air permeability ranges between 1.3 - 16D with average permeability of 6.7D.

Unit II (1630 - 1635 mss) consists of a gradually coarsening upwards interval from silty claystone at the base into clayey and strongly to slightly micaceous sands at the top. The increased mica and clay content are reflected in moderately to poor reservoir quality. The upper 1.5 m and the lower 0.5 m of this unit are cored and the plug measurements show that porosity and permeability in the upper sandy part are 32% and 0.4D respectively and in the lower clayey part are 18-23% and 2mD respectively Calcite cemented concretions are found at 1631.7 and 1634.5 mss.

Unit III (1635 - 1637 mss) is a 2 m thick interval of slightly silty shale which is predominantly laminated and contains abundant pyrite nodules.

This overall coarsening upwards sequence has been interpreted as part of a shallow marine sand bar. The reduced thickness (from 55 m in well 6407/9-3 to 17.5 m in this well) confirms the pinch out of the Frøya Formation on the west flank. Each unit thins gradually towards the west but reservoir quality close to the pinch-out remains very high. The basal shale is considered to form a fieldwide barrier between the mainly oil-bearing Frøya and waterbearing Haltenbanken Formation.

6.6 Dipmeter

The dipmeter curves Encl. 8 show some characteristics of the Frøya and Haltenbanken Formations. The response of the Frøya sands show a serrate character which is a reflection of the cross-bedding, occasional lamination (1645 - 1650 mbdf) and the occurrence of coarse grains (1651 mbdf). The dip directions however are rather scattered. In the interval between 1649 and 1653 the dips are seen to be constant low and south-eastern but as this interval is bioturbated, do not represent sedimentary nor structural dips.

The Haltenbanken sands show a smooth dipmeter curve with very few correlatable events. The dips are also scattered. Although a more constant southwesterly dip of 2-5 degrees occurs between 1676 and 1685 mbdf and cross-bedding is present throughout this interval the reliability of these measurements are taken in doubt since the cross-bedded sets have a trough shape. A constant south-easterly dip is observed in the shale interval between 1745 and 1765 mbdf, reflecting structural dip. A marked change in degree of dip is seen at 1755 mbdf which may be the indication of a small fault.

7. PETROPHYSICAL EVALUATION

A summary of the Schlumberger wireline logs run in the borehole is presented in Table 7.1, and the main logs run over the reservoir are plotted in Enclosure 9.

Frøya Fm

The Frøya Formation is oil-bearing from the top at 1617.5 mss down to the base of Unit IIa at 1633.5 mss. Average reservoir quality over this 16 m interval is very good, with a calculated hydrocarbon saturation of 79% and an average porosity of 31%. Core permeabilities in the oil bearing interval typically range between 1 and 10 Darcy.

Haltenbanken Fm

The Haltenbanken formation was only partially penetrated in this well. The interpreted interval extends from the top of Unit 1 at 1637 mss to the bottom of the logged interval at 1770 mss.

The Haltenbanken formation is interpreted as fully water bearing below 1646 mss, however low hydrocarbon saturations are calculated in the interval 1637 - 1646 mss. These are confirmed by the observed fluorescence in the cores over this interval and by Dean-Stark fluid saturation measurements (See Table 7.2b). This is somewhat at variance with the assumed field oil-water contact of 1638 mss.

FMT pressure data

Additional information which tends to confirm the assumed field oil-water contact is provided by an FMT pressure survey with a quartz gauge which interpreted a free water level at 1638 mss. The survey yielded an oil gradient of 0.325 psi/ft and a water gradient of 0.443 psi/ft. The datum pressure (at 1630 mss) was 2395 psia. These results are in line with observations in the earlier Draugen wells. For details about the FMT survey refer to Table 8.4.1 and section 8.4.1.

Core measurements

Routine porosity-permeability measurements on the core were performed by GECO. The core permeabilities, porosities, grain densities and pore saturation measurements are tabulated in Table 7.2.

The core porosities plotted in Enclosure 9 are corrected for compaction effect and smoothed by taking a 1:2:1 weighted average with adjacent plugs. The core permeabilities are smoothed but not corrected for compaction. The core values are plotted on log depth.

A compaction correction factor of 0.96 was obtained from special core measurements on stressed plugs of wells 6407/9-1, 6407/9-2 and 6407/9-3. Integration of the Density log of well 6407/9-1 gave an in situ effective vertical stress of 2100 psi at reservoir depth. A crossplot of porosities at this in situ stress versus the porosities at standard conditions yielded a value of 0.96 for the slope of the best-fit line forced through the origin.

The method of porosity calculation has been changed as a result of a review of all the available core and log data from the six Draugen wells. Porosity is now calculated from the Density log after correction for hydrocarbon effect using the borehole corrected microresistivity log. The value of mud filtrate resistivity, Rmf, was determined by calibration in clean water-bearing sands. The value so derived, 0.05 ohm.m, agreed well with the value of 0.041 ohm.m inferred from the wellsite measurement.

The matrix density was determined from the average grain density measured on core plugs. No significant difference was found between the Froya and Haltenbanken grain densities, a value of 2.662 gm/cc was therefore used throughout.

The in situ hydrocarbon density was derived from the FMT pressure gradient in the oil bearing interval. A value of 0.751 gms/cc corresponding to the observed gradient of 0.325 psi/ft was used.

The apparent in situ density of the mud filtrate was determined by plotting compaction corrected core porosity against the borehole corrected Density log in water bearing zones. The regression line forced through the matrix point yielded an apparent water density of 1.110 gm/cc. This was confirmed by comparing the log derived porosities to compaction corrected core porosities in the oil bearing intervals. Plots showing only data from well 6407/9-6 are attached as figures 7.1 and 7.2.

In well 6407/9-6, the density log appears to be miscalibrated; the separation with the CNL is unusually large and density readings are low compared to core porosity. To correct it to the general trend the log was bulk-shifted by +0.035g/cm. Fig. 7.1 shows the density-core porosity crossplot in the waterleg after the shift.

Saturation calculation

Hydrocarbon saturation is calculated with the Waxman-Smits shaly sand equation. The virgin zone resistivity in the oil bearing interval is calculated from the borehole corrected Laterolog curves by a computerized version of the "Tornado" chart. Over the Haltenbanken Fm interval the resistivity is taken from the borehole corrected Induction log.

Formation water resistivity

A formation water resistivity of 0.10 Ohm.m is used for the evaluation and this results in 100% watersaturation in the water bearing intervals of the Draugen wells.

Produced formation water obtained in well 6407/9-4 has an Equivalent NaCl concentration of 37,500 ppm. A temperature of $130^{o}F$ is necessary to obtain the required water resistivity value of 0.10 Ohm.m.

Static formation temperatures derived from log temperatures range between 111^{o} and $130^{o}F$ while production test results indicate a value of $160^{o}F$. The reason for this difference is not clear and may result from cooling in the vicinity of the borehole at the time of logging. The value of $130^{o}F$ has been adopted in order to arrive at Sw=100% in the waterleg, given the measured salinity of 37,500 ppm.

Other parameters

The Saturation Exponent n^{*} was taken as 1.97, the average value measured on coreplugs of the Frøya Formation. The measurements were made by injecting Toluene into brine saturated samples while recording the resistivity. The resulting datapoints are plotted in Figure 7.3.

The Cation Exchange Capacity was estimated from a relationship between Qv and porosity. Qv and porosities measured on core plugs have established the following relationships:

$$Qv = \frac{0.363-\emptyset}{1.6\ \emptyset} \qquad \text{Frøya Unit I}$$

$$QV = \frac{0.351-\emptyset}{0.75\ \emptyset} \qquad \text{Frøya Unit II}$$

$$Qv = \frac{0.358-\emptyset}{1.07\ \emptyset} \qquad \text{Haltenbanken Fm}$$

To avoid unrealistically high Qv values in tight streaks the estimated Qv was limited to 0.4 mEq/ml.

Figure 7.4 shows Qv-porosity crossplots for the three formations, Frøya Unit I, Frøya Unit II and Haltenbanken Fm.

The Formation Factor-porosity relationship for the Frøya Fm was established from special core analysis

$$F^* = 0.162\ \emptyset^{-3.3} \qquad \text{(Fig. 7.5)}$$

The parameters A* and m* for the Haltenbanken Fm have been estimated from a crossplot of calculated F* values from logs versus the log porosity, over the water bearing intervals of 6407/9-4 and -5:

$$F^* = 0.314\ \emptyset^{-2.69} \qquad \text{(Fig. 7.6)}$$

A summary of the evaluation parameters is listed in Table 7.3.

Table 7.1

Logging Operations in well 6407/9-6

DEPTH CASING M BDF	DEPTH DRILLING M BDF	BIT SIZE INCHES	LOG TYPE	RUN NO.	INTERVAL LOGGED M BDF	DATE	REMARKS
375	810	14.75	DIFL/ACL/GR	1	278-808	08.01.86	
			CDL/CN/GR	1	365-807	08.01.86	
804	1628	17.5	DIFL/ACL/GR	-		18.01.86	Sonic Failed
			DIFL/ACL/GR	2	675-1607	19.01.86	HUD 1607 m
			CDL/CN/GR	2	785-1603	19.01.86	
1619	1800	12.25	DIFL/ACL/GR	3	1572-1799	28.01.86	
			CDL/CN/SPL	3	1572-1799	28.01.86	
			DLL/MLL/GR	1	1612-1795	28.01.86	Cal. Failed
			Diplog	1	1616-1794	29.01.86	
			FMT-Hp	1	12 pre-test.	Sample at 1652.5 m	
			Velocity Survey			29.01.86	
			SWS	1		29.01.86	Rec.26
			CBL/VDL	1	302-1628	29.01.86	13 3/8" csg.
			SWS	2		30.01.86	Rec.3
			SWS	3		30.01.86	Rec.11
1776			CBL	2		02.02.86	9 5/8" csg
			Photon Log	1		03.03.86	over gravel pack.

Table 7.2.a

FINAL REPORT

COMPANY : SHELL
WELL : 6407/9-6
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 1

PAGE: 1

DATE: MARCH 1986

GECO
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
	1646.00										
1	1646.35	9798	9590			32.5				2.68	
2	1646.65	7619	7441			33.8				2.67	
3	1647.00	16039	15757	7311	7137	36.2				2.66	
4	1647.35	6546	6384			32.5				2.65	
5	1647.65	nmp				nmp					
6	1648.00	11687	11456			34.4				2.65	
7	1648.35	9263	9063			32.8				2.65	
8	1648.65	12708	12464			34.5				2.65	
9	1649.00	11154	10929			35.0				2.66	
10	1649.35	12011	11775			34.6				2.65	
11	1649.65	3859	3742			32.5				2.65	
12	1650.00	nmp		1097	1043	nmp					
13	1650.35	9218	9018			33.5				2.65	
14	1650.65	16494	16208			34.2				2.65	
15	1651.00	5211	5071			34.4				2.65	
16	1651.35	9063	8865			34.4				2.66	
17	1651.65	2598	2506			32.1				2.65	
18	1652.00	6508	6346			33.8				2.65	
19	1652.35	6366	6207			34.8				2.65	
20	1652.65	2807	2711			34.4				2.65	
21	1653.00	2861	2763	2222	2139	33.6				2.65	
22	1653.35	8010	7826			33.8				2.65	
23	1653.65	1461	1397			32.4				2.66	
24	1654.00	2582	2490			32.9				2.64	
25	1654.35	1621	1553			32.5				2.65	
26	1654.65	982	932			32.2				2.65	
27	1655.00	4440	4313			35.3				2.65	

COMPANY : SHELL
WELL : 6407/9-6
FIELD : 6407/9
STATE : NORWAY

FINAL REPORT

CORE NO.: 1 (cont.)

PAGE: 2

DATE: MARCH 1986

GECO
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
28	1655.35	1361	1300			33.0				2.64	
29	1655.65	2428	2340			34.4				2.65	
30	1657.00	596	560	1176	1120	32.4				2.66	
31	1657.65	368	342			24.6				2.70	
	1657.77										

Table 7.2.a

Table 7.2.a

GECO Petroleum laboratory

FINAL REPORT

COMPANY : SHELL
WELL : 6407/9-6
FIELD : 6407/9
STATE : NORWAY

PAGE: 1

CORE NO.: 2

DATE: MARCH 1986

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
	1660.00										
32	1660.05	<0.04	<0.02	<0.04	<0.02	5.3				2.72	
33	1660.35	2.0	1.6			20.7				2.66	
34	1660.65	1.5	1.2			26.6				2.74	
35	1663.00	6768	6683	9412	9308	37.5				2.66	
36	1663.35	4543	4477			36.5				2.67	
37	1663.70	4942	4872			37.0				2.65	
38	1664.00	4823	4754			36.1				2.64	
39	1664.35	4701	4633			36.5				2.65	
40	1664.65	4096	4033			37.0				2.65	
41	1665.00	4589	4523			37.2				2.66	
42	1665.35	3950	3889			36.9				2.64	
43	1665.65	2148	2106			36.7				2.64	
44	1666.00	3235	3181	2064	2023	37.0				2.64	
45	1666.35	3307	3253			38.9				2.65	
46	1666.65	2151	2109			36.2				2.66	
47	1667.00	2364	2320			36.2				2.66	
48	1667.35	2818	2768			38.4				2.66	
49	1667.65	2914	2863			37.2				2.66	
50	1668.00	6080	6001			35.3				2.66	
51	1668.65	15174	15034			35.4				2.65	
52	1669.00	8674	8576	8881	8781	34.6				2.66	
53	1669.35	10072	9964			34.1				2.65	
54	1669.65	8874	8774			35.6				2.65	
55	1670.00	10927	10813			34.9				2.66	
56	1670.35	9631	9526			32.6				2.65	
57	1671.00	10071	9926			32.9				2.65	
58	1671.35	4181	4118			31.5				2.68	

COMPANY : SHELL
WELL : 6407/9-6
FIELD : 6407/9
STATE : NORWAY

FINAL REPORT

CORE NO.: 2 (cont.)

DATE: MARCH 1986

GECO 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
59	1671.65	4848	4779			32.6				2.70	
60	1672.00	7652	7560	3661	3603	33.8				2.66	
61	1672.35	npp									
	1672.70										

Table 7.2.a

GECO Petroleum laboratory

FINAL REPORT

PAGE: 1

COMPANY : SHELL
WELL : 6407/9-6
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 3

DATE: MARCH 1986

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	Permeability (mD), horizontal k_{el}	Permeability (mD), vertical k_a	Permeability (mD), vertical k_{el}	Porosity (%) He	Porosity (%) Sum.	Pore saturation S_o	Pore saturation S_w	Grain dens. g/cc	Formation Description
	1672.70										
62	1673.00	<0.04	<0.02			1.0				2.69	
63	1673.35	<0.04	<0.02			0.7				2.68	
64	1673.65	<0.04	<0.02			0.5				2.69	
65	1674.00	5409	5335			33.6				2.67	
66	1674.35	10267	10158			36.5				2.65	
67	1674.65	15275	15135			38.7				2.65	
68	1675.00	19343	19181	9044	8943	38.8				2.66	
69	1675.35	6911	6825			37.1				2.65	
70	1675.65	6717	6632			36.4				2.66	
71	1676.00	13244	13116			37.6				2.65	
72	1676.35	5030	4959			34.8				2.66	
73	1676.65	6962	6875			35.9				2.65	
	1676.95										

COMPANY : SHELL
WELL : 6407/9-6
FIELD : 6407/9
STATE : NORWAY

FINAL REPORT

CORE NO.: 4

DATE: MARCH 1986

GECO 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
	1678.80										
74	1679.35	7421	7331			36.2				2.64	
75	1679.65	5027	4956			34.3				2.65	
76	1680.00	5083	5012	490	473	33.5				2.65	
77	1680.35	7581	7490			35.3				2.65	
78	1680.65	5310	5237			34.6				2.65	
79	1681.00	4671	4604			34.0				2.64	
80	1681.35	2620	2573			33.2				2.65	
81	1681.65	6266	6185			35.7				2.65	
82	1682.00	4156	4093			34.3				2.65	
83	1682.35	3076	3024			34.7				2.64	
84	1682.65	4354	4289			35.1				2.64	
85	1683.00	5504	5429	2186	2144	34.9				2.65	
86	1683.35	4638	4571			35.6				2.64	
87	1683.65	5715	5639			35.5				2.65	
88	1684.00	4656	4588			35.1				2.65	
89	1684.35	2734	2685			33.5				2.64	
90	1684.65	5078	5007			35.4				2.65	
91	1685.00	2655	2608			33.6				2.64	
92	1685.35	2960	2909			33.7				2.66	
93	1685.65	2673	2625			35.4				2.66	
94	1686.00	2017	1977	385	371	38.4				2.66	
95	1686.35	2021	1981			33.9				2.66	
96	1686.65	2736	2688			34.5				2.66	
97	1687.00	5175	5103			40.1				2.66	
98	1687.35	524	507			30.2				2.69	
99	1687.65	1709	1673			33.7				2.66	
100	1688.00	611	592			37.0				2.66	

Table 7.2.a

Table 7.2.a

GECO Petroleum laboratory

FINAL REPORT

COMPANY : SHELL
WELL : 6407/9-6
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 4 (cont.)

DATE: MARCH 1986

Plug No.	Depth (meter)	Permeability (mD), horizontal		vertical		Porosity (%)		Pore saturation		Grain dens. g/cc	Formation Description
		k_a	k_{el}	k_a	k_{el}	He	Sum.	S_o	S_w		
101	1688.35	290	278			25.4				2.64	
102	1688.65	60.3	55.7			28.1				2.65	
103	1689.00	926	901	1980	1940	31.1				2.25	
104	1689.35	768	746			24.8				2.65	
	1690.25										

GECO

DEAN STARK

WELL: 6407/9-6

Depth (m)	Pore saturation (%) S_o	S_w	Por (%)	Gr.dens. (g/cc)
1663.70	1.5	55.0	37.0	2.65
1664.65	7.7	56.3	37.0	2.65
1666.65	8.1	57.1	36.7	2.64
1668.65	10.4	55.2	35.4	2.65
1670.35	8.3	44.9	32.6	2.65
1671.65	5.4	81.1	32.6	2.70

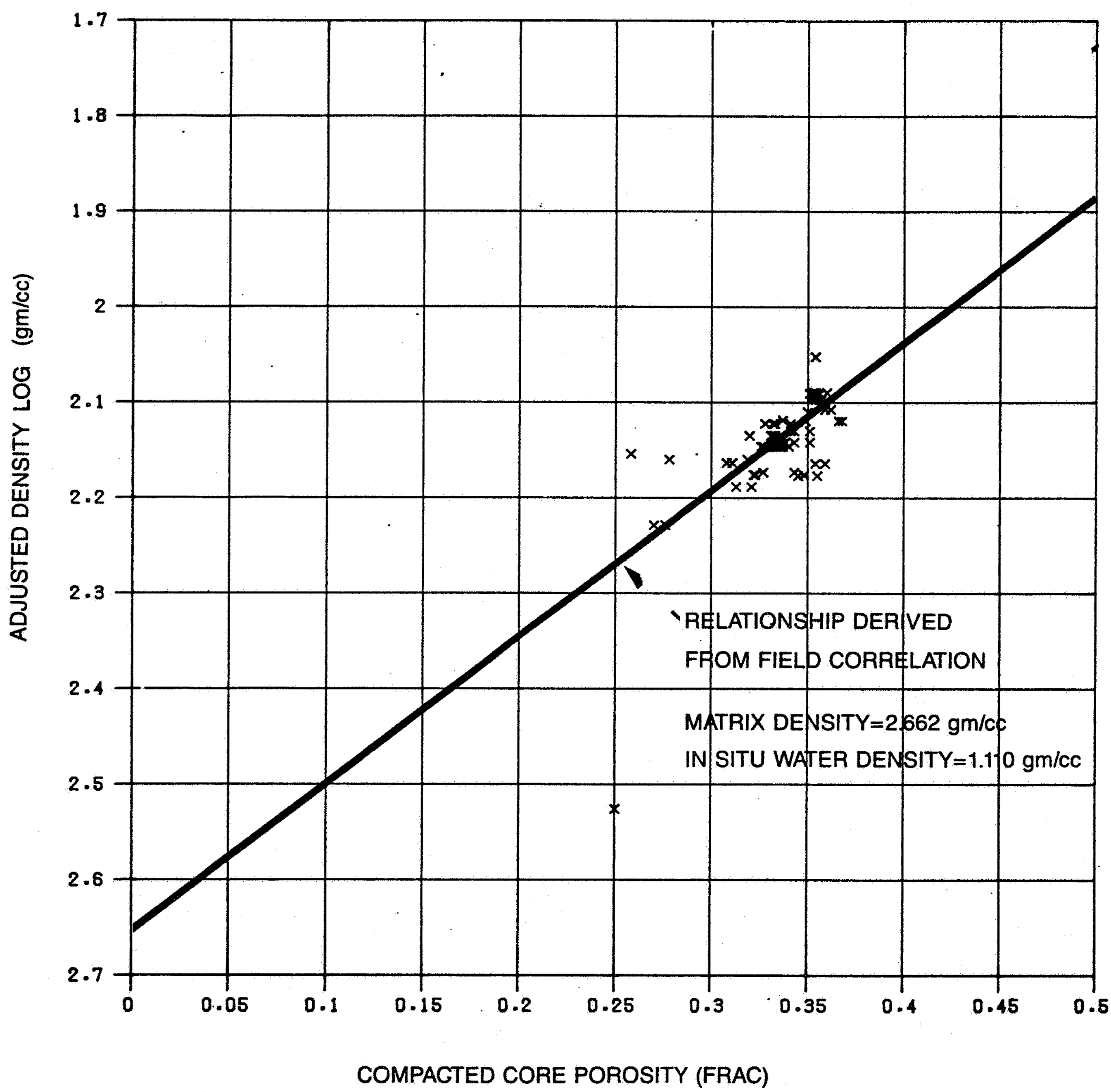
Table 7.3

Summary of the Evaluation Parameters

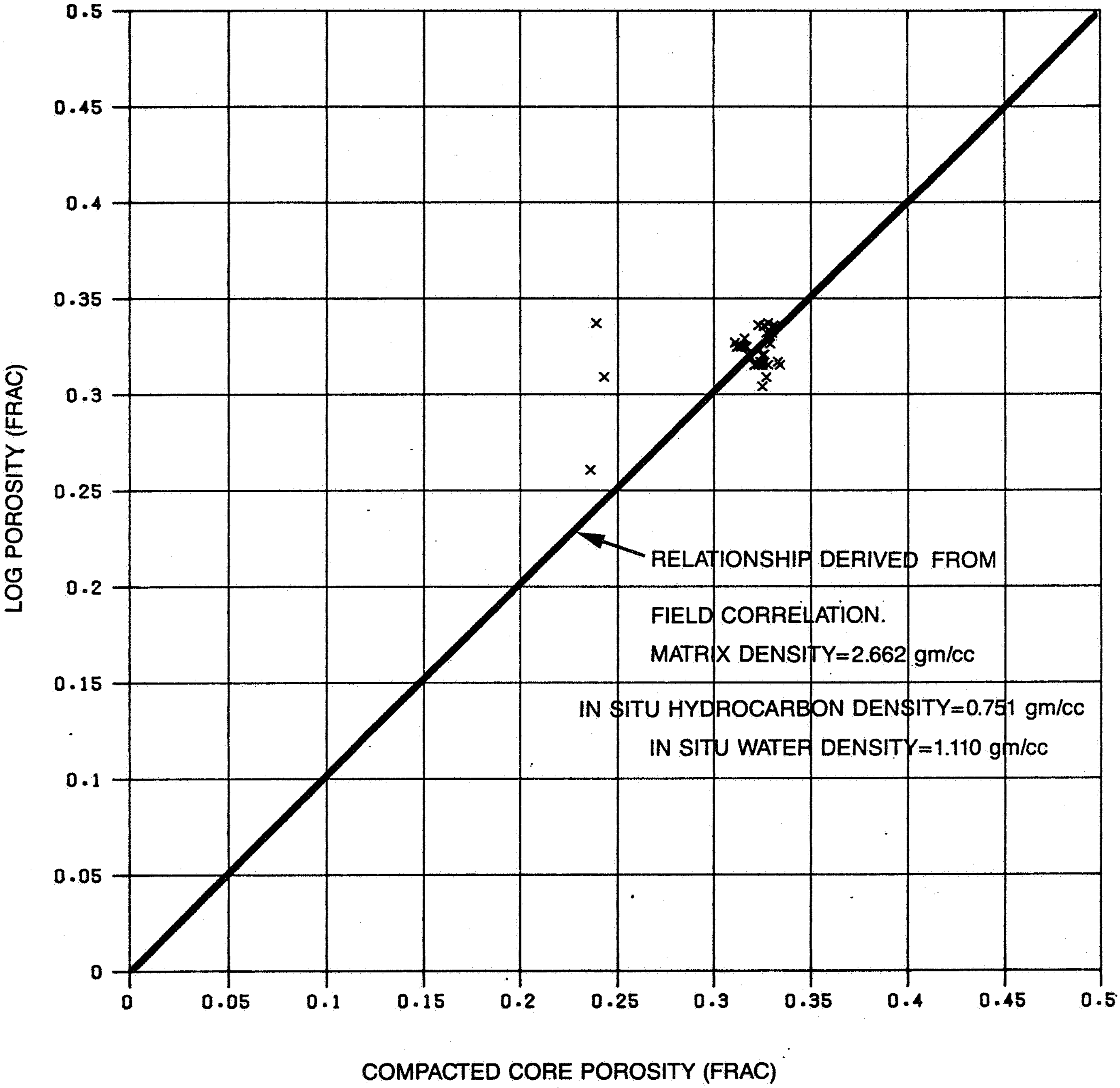
Matrix Density	: 2.662 gm/cc	
In situ hydrocarbon density	: 0.751 gm/cc	
In situ mud filtrate density	: 1.110 gm/cc	
Porosity Compaction	: Insitu porosity = 0.96 x surface porosity	
Logging temperature	: $130^{o}F$ at 1630 mss	
Formation water resistivity	: Rw = 0.10 Ohm-m	
Mud Filtrate resistivity	: Rmf = 0.05 Ohm-m	
Formation Factor	: $F^* = 0.162\ \emptyset^{-3.30}$	Frøya Fm
	: $F^* = 0.314\ \emptyset^{-2.69}$	Haltenbanken Fm
Saturation Exponent	: $n^* = 1.97$	
CEC	: $Qv = \dfrac{0.363-\emptyset}{1.60\emptyset}$	Frøya Unit I
	: $Qv = \dfrac{0.351-\emptyset}{0.75\emptyset}$	Frøya Unit II
	: $Qv = \dfrac{0.358-\emptyset}{1.07\emptyset}$	Haltenbanken Fm
Qv limit	: 0.4 mEq/mL	

Average porosity in Frøya	: 31%
Average hydrocarbon saturation	: 79%
Net pay thickness in Frøya	: 16 m
Oil down to	: see text
Water up to	: see text

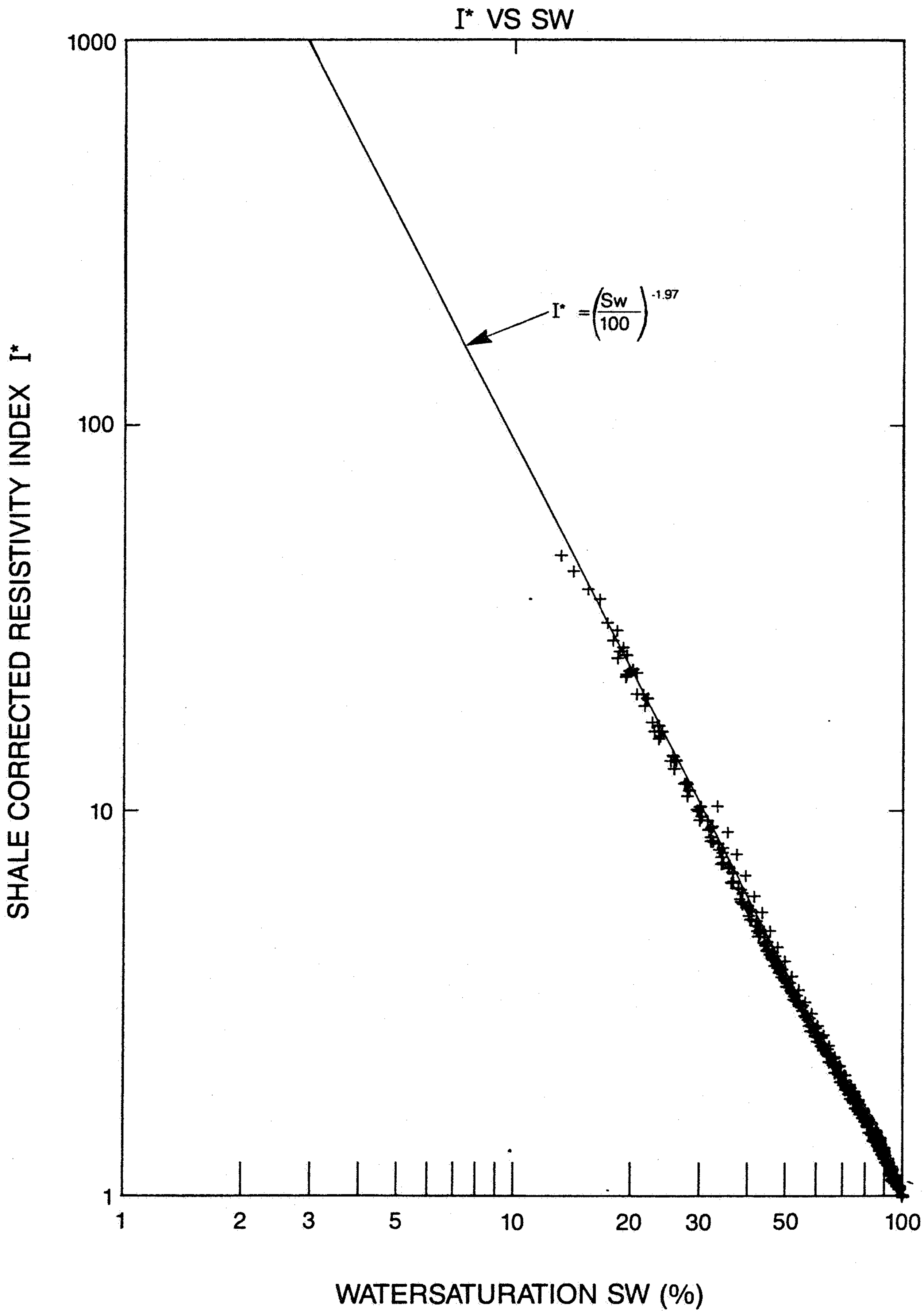
ADJUSTED DENSITY LOG VERSUS CORE POROSITY OVER WATER BEARING INTERVALS OF WELL 6407/9-6



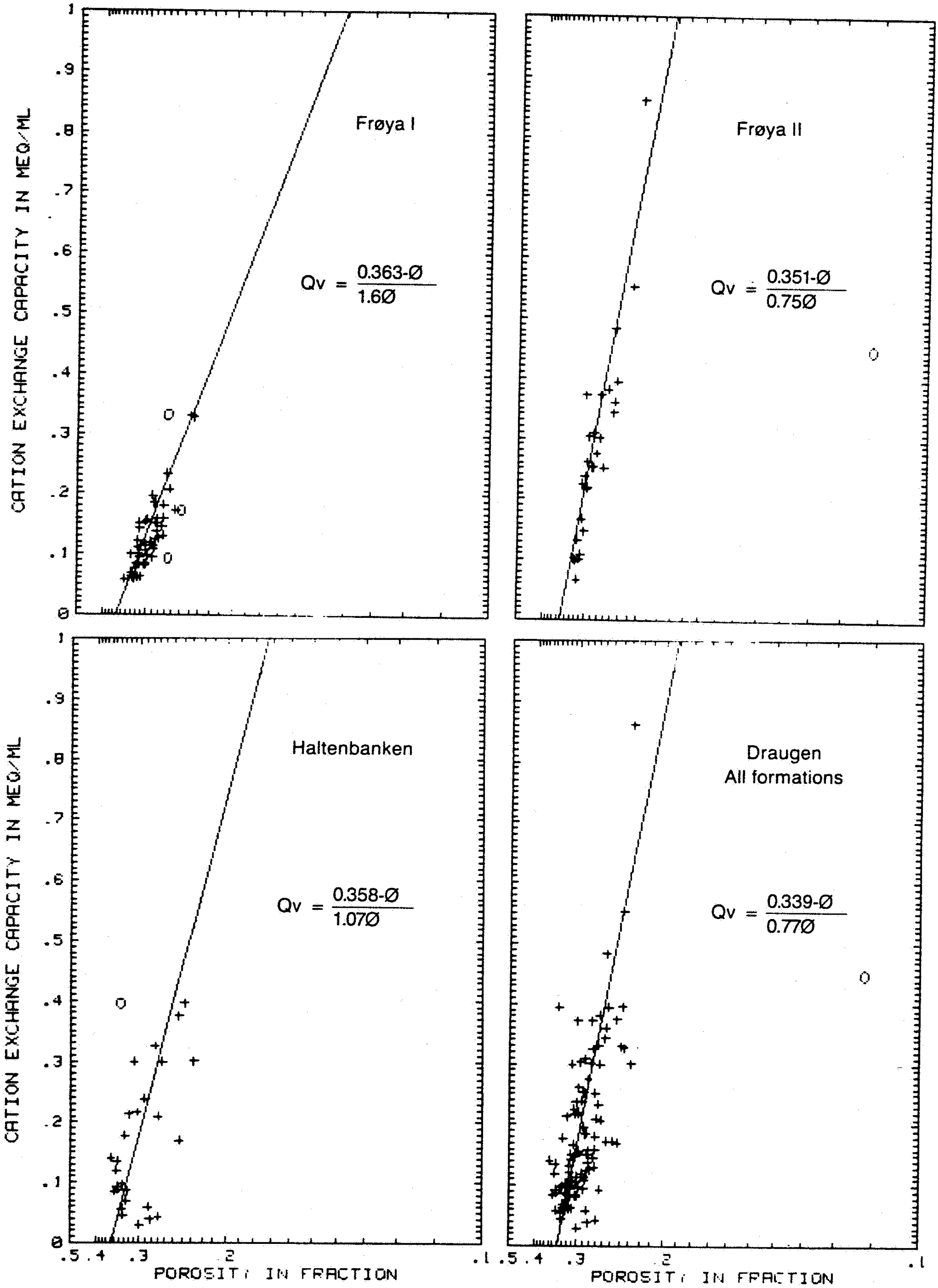
POROSITY DERIVED FROM HYDROCARBON EFFECT CORRECTED ADJUSTED DENSITY LOG VERSUS CORE POROSITY OVER OIL BEARING INTERVAL, WELL 6407/9-6



SATURATION EXPONENT N* MEASURED ON COREPLUGS OF THE DRAUGEN FIELD



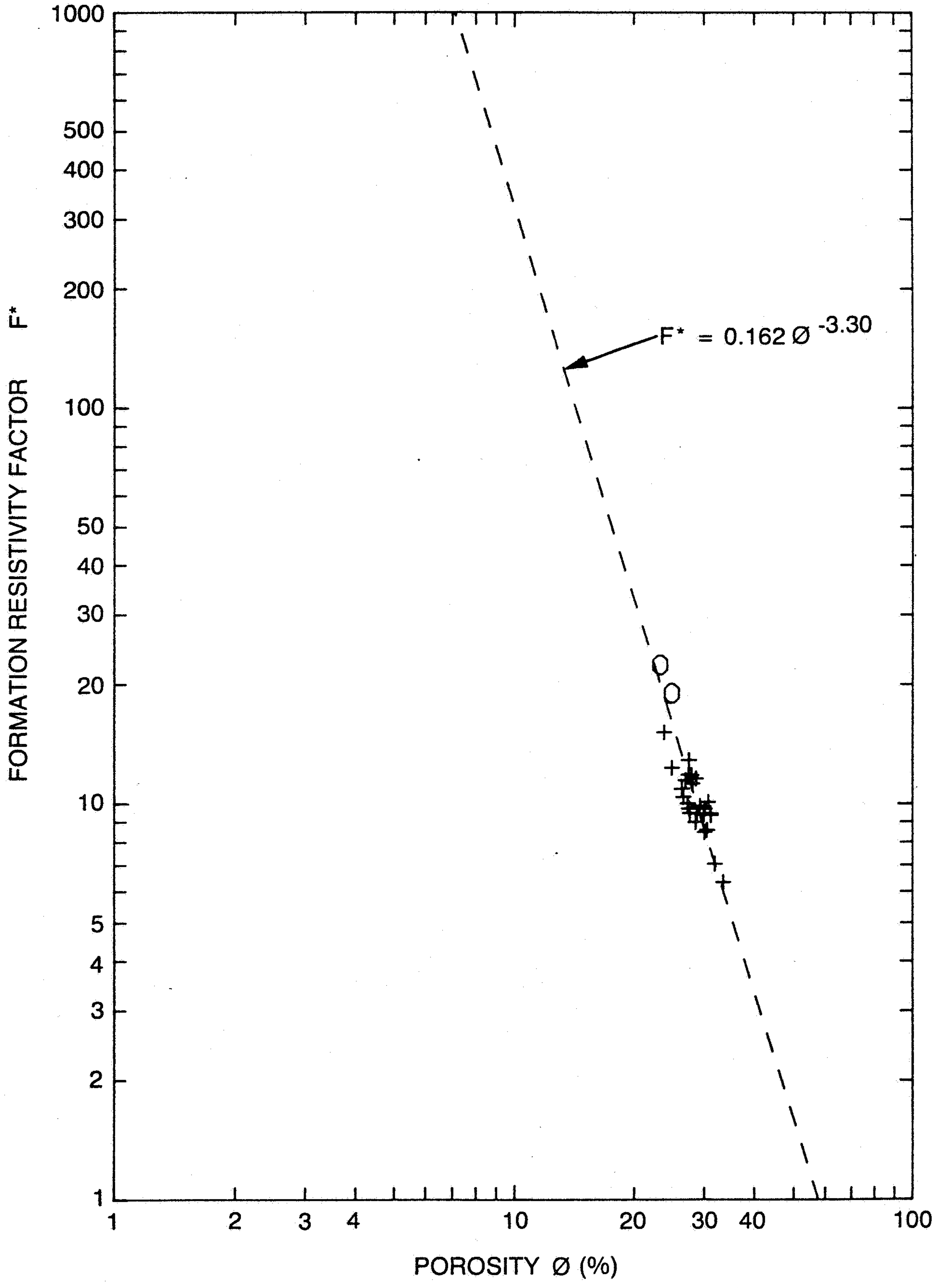
DRAUGEN
Qv vs POROSITY



Porosity Compaction Factor = 0.96

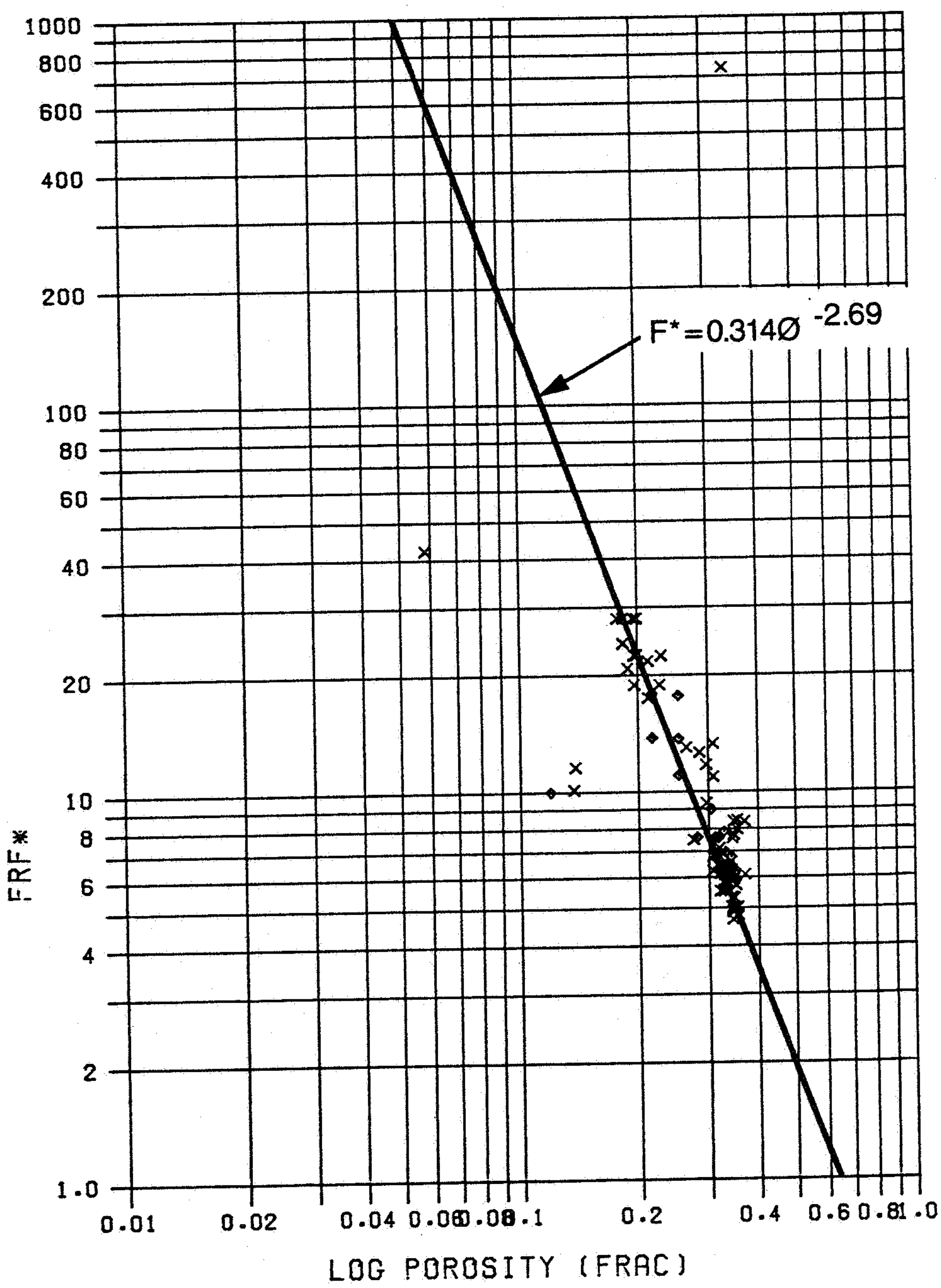
F* VERSUS Ø RELATIONSHIP OVER FRØYA FORMATION

(DERIVED FROM CORE ANALYSIS)



F* VERSUS Ø RELATIONSHIP OVER HALTENBANKEN FORMATION

(DERIVED FROM LOG DATA)



× 6407/9-4

◇ 6407/9-5

WELL TEST EVALUATION REPORT
Chapter 8

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SUMMARY

Well 6407/9-6, the fifth Draugen appraisal well, was drilled 1.5 km west of 6407/9-3. The well came in almost as prognosed, encountering 17 m of fully oil bearing Frøya sand, the top 14-15 m of which are of high permeability.

Prior to testing, an FMT survey was carried out. Measured reservoir pressure was hydrostatic, 2395 psia at datum of 1630 m.ss. The OWC established at 1638.5 m.ss. in well 6407/9-2 has not been contradicted by the FMT survey. However, recent core measurements have indicated the presence of hydrocarbons in the interval 1637 - 1646 m.ss.

The oil column was perforated from 1618 to 1631 m.ss. After gravelpacking and acidising, flowrates of up to 6400 stb/d were achieved during the clean up. A 24 hour two rate drawdown test followed by a 24 hour buildup survey was carried out following clean up. Evaluation of the pressure buildup survey showed an average permeability of 5.9 Darcy over 15 m. Calculated skins averaged 10 and average post gravelpack PI was 135 stb/d/psi. Ideal PI of 260 stb/d/psi (skin=0) was calculated. Average reservoir pressure was 2394 psia at datum.

After the pressure buildup survey, water injection into the oil column commenced. The first injection test, lasting 72 hours, achieved rates of up to 16 200 bwpd followed by a 24 hour pressure fall off survey. Evaluation of the pressure fall off survey yielded an average water permeability of 1.2 Darcy, skins between 10 and 38, and II decreasing from 30 bwpd/psi to 8 bwpd/psi. Average reservoir pressure at datum was 2393 psia.

After acidising to improve injectivity, a 12 hour injection test with injection rates of up to 15 000 bwpd followed by a 6 hour pressure fall off survey was performed. Evaluation of the pressure fall off survey yielded an average water permeability of 0.9 Darcy, skins between 13 and 30, and II decreasing from 9 to 7 bwpd/psi.

A third injection test commenced after the tubing string and the gravel pack were treated with xylene to remove wax deposits. An average constant water injection rate of 13 300 bwpd was sustained for ca. 12

water permeability, skins, and II from the pressure fall off analysis were 1.7 Darcy, 43, and 10 bwpd/psi respectively. Average reservoir pressure was 2396 psia at datum.

Pressure fall off analyses were complicated by temperature and fluid mobility effects. Some of the problems encountered during the fall off analyses were traced back to incorrect Hewlett-Packard crystal gauge temperature measurements. More detailed analyses of the pressure fall off survey in 6407/9-6 have to be performed with a numerical thermal simulator.

8.2 INTRODUCTION

8.2.1 Background

Well 6407/9-6 is the fifth appraisal well on the Draugen structure in block 6407/9 (see Fig. 8.2.1). Previous wells: 6407/9-1, 6407/9-2 and 6407/9-3 delineated an areally extensive oil accumulation in a relatively thin Upper Jurassic Frøya sandstone formation. These wells encountered net oil thicknesses of 39, 12 and 34 m respectively and with an oil gravity of 40^{o} API.

Well 6407/9-4, located on the western flank of the northern accumulation confirmed pinch out of the Frøya formation and encountered similar oil in the underlying Haltenbanken formation. Initial conditions of pressure and oil water contact (1638.5 m.ss.) were similar to those encountered in the Frøya formation accumulation.

Well 6407/9-5, located in the southern culmination (Frøya South) encountered an 18 m oil column. Initial conditions of pressure (2392 psia) and oil water contact (1639 m.ss.) were similar to those encountered in the northern accumulation. This well confirmed the trend of declining bubble point and gas-oil ratio (GOR) from north - north east to south - south west across the Draugen structure.

The five appraisal wells in the Draugen structure were tested at high rates (greater than 6000 b/d) with a maximum rate of 15,700 b/d achieved in well 6407/9-3. Injectivity tests performed in the water zones in wells 6407/9-2 and 6407/9-4 obtained injection rates of up to 13,080 bwpd (achieved in 6407/9-4).

The objectives of well 6407/9-6 were: to evaluate the water injection potential in the oil bearing interval of the Frøya sands, to delineate the pinch-out over the western and southwestern flanks, and to improve the structural interpretation of the western flank. Well 6407/9-6 was drilled in January - March 1986 and came in almost as prognosed, encountering 17 m of fully oil bearing Frøya sand, the top 14-15 m of which are of high permeability (see Fig. 8.2.2).

This report describes the operational details and evaluations of the tests carried out on this well.

8.2.2 Test Objectives

The objectives of testing the well were:

1) To establish the oil deliverability, rock properties and reservoir fluid properties of the Frøya sand.

2) To evaluate sea water injectivity into the Frøya sands.

8.3 OPERATIONS

8.3.1 FMT Survey

The objectives of the FMT (Formation Multi Tester) survey were: to define oil and water gradients, measure initial formation pressures in the Frøya and Haltenbanken formations, and to collect a fluid sample from the hydrocarbon bearing Frøya formation.

The FMT tool of Dresser was equipped with a 10 000 psi strain gauge and a 10 000 psi quartz crystal gauge.

A total of 12 pretests were carried out successfully. On completion of pretests, a 1 gallon segregated oil sample was obtained at 1627.9 m.ss. Probe plugging which plagued previous tests was not experienced.

8.3.2 Oil Zone Production Test

8.3.2.1 Sequence of Events

The well was perforated under a 347 psi drawdown from 1618 - 1631 m.ss. using a 7 1/4" tubing conveyed gun (12 shots per foot) (Fig. 8.3.1). The well was backsurged over a fully open adjustable choke for 10 bbls then flowed over a 12/64" choke at around 450 b/d to clean. Final flowing tubing head pressure (FTHP) was 544 psig, BSW 0%, H_2S 0 ppm and CO_2 0.1 %. The well was then shut-in down hole for a 2 1/2 hour pressure build-up. A summary of the sequence of events and the separator data in this flow period and the ensuing flow periods is given in Appendices A and B.

After releasing the shearkill valve in the side pocket mandrel, attempts to kill the well using viscosified brine were unsuccessful. Seventy-five barrels of brine were lost before a carbonate pill was placed. Viscosified brine (HEC) was recommended for use in this well because a review of the performance of the previous appraisal wells had indicated that formation damage due to the use of a chalk pill was evident.

The perforating string was then recovered and the well gravel packed with 12/20 mesh gravel. Fluid losses during this phase amounted to 67 bbls. The production string (Fig. 8.3.2) was then run and tested. After displacing to diesel the well was produced at rates of up to 1250 b/d of clean oil on a 32/64" choke to stabilise the gravel pack (PT-1B). The well was then acidised using 100 bbls of 15% HCl. Well clean up proceeded by increasing the rate in steps of 2000 b/d to achieve a maximum rate. Maximum rates were limited due to liquid carry-over problems in the flow lines. A maximum rate of ca. 6400 b/d was achieved on a 60/64" choke. Fig. 8.3.3. shows the test performance for this and ensuing flow periods. At the end of the flow period the producing separator GOR was 68 SCF/STB at a separator pressure of 315 psig, the FTHP was 394 psig and the BSW 2%. The oil gravity during this period was 42^{o} API and the gas gravity 0.814 (Air = 1).

The well was then shut-in and 3 pressure gauges (2 Hewlett-Packard crystal gauges and 1 Flopetrol SDP strain gauge) were run and hung off at 1616.9 m.ss.

A two rate drawdown test (PT-1D) was carried out. The well was flowed at a rate of ca. 2300 b/d for 12 hours over a 28/64" choke. The separator GOR was ca. 140 SCF/STB, separator pressure of 68 psig, FTHP of 548 psig, and trace of BSW. The rate was then increased to 4900 b/d over a 44/64" choke. This rate was maintained for 12 hours; over the period, the producing separator GOR was ca. 115 scf/stb, separator pressure was ca. 190 psig, FTHP was 459 psig and BSW was a trace. Oil gravity and gas gravity over the entire flow period were 41^{o} API and 0.810 (air = 1) respectively. Six sets of separator samples were taken during the second flow period. The well was then shut in for a 24 hour buildup.

Gauges were then recovered and 5 bottom hole samples were taken whilst flowing the well at ca. 300 b/d. All sample bottles were specially cleaned to ensure sample quality for interfacial tension measurements.

8.3.3 Oil Zone Water Injection Test

8.3.3.1 Sequence of Events

After the oil production test, water injection testing commenced (PT-1F)*. Water injection was initiated by bullheading the tubing which was full of crude oil with cold sea water (+/- 6^{o}C). Injection testing commenced at an initial rate of some 12 700 bwpd. This continued for about 17 hours when the pump rates were increased. An injection rate of ca. 16280 bwpd was maintained over a period of 3 hours. Pump rates were then reduced to an injection rate of 13200 bwpd. The reduction in injection rate was necessary so as not to exceed a surface pressure constraint of 2500 psig. The maximum allowable surface pressure was constrained such as to avoid formation fracture. This rate continued until a leaking pump forced a change in pumps. Injection rate subsequently increased to ca. 13300 bwpd. This rate was maintained until injection stopped, about 40 hours later, and fall off testing commenced. Injection rates were calculated from pumpstrokes and by assuming an efficiency of 97%. At the end of the test period, the gauges were removed from the hole. Fig. 8.3.4 shows a schematic test performance plot for this injection period and the ensuing injection periods.

To improve the injectivity of the well, the well was acidised with 100 bbls of 15% HCl. Three gauges (2 Hewlett-Packard crystal gauges and 1 SDP strain gauge) were run down hole. A second water injection test (PT-1G) was then carried out. An improvement in injectivity was seen but this did not last very long. Injection rates of up to 15000 bwpd were attained with a final injection rate at just over 11300 bwpd. Following a fall off the gauges were recovered.

Whilst attempting to run an SSD shifting tool, the tool hung up just below sea level and waxy-looking deposits were recovered on it. The well was subsequently killed with a carbonate pill and the 4 1/2" tubing part of the 3 1/2" tubing

* Injection tests and production tests have been abbreviated to "PT" in line with contractor reports.

was pulled and cleaned. After cleaning the string was rerun and circulated to xylene to clean out any remaining wax-like deposits. The carbonate pill was dissolved with 15% HCl acid. A total of 95 bbls of acid followed by 97 bbls of xylene were pumped to clean the gravel pack. Water injection resumed at an injection rate of some 13200 bwpd. This was maintained for 3 hours at surface pressures of 1770 - 1950 psi. Three gauges(2 Hewlett-Packard gauges and one GRC gauge) were then hung off down hole. Injection then resumed at the previous rate of 13200 bwpd for 12 hours with surface pressures increasing from 1760 to 2040 psig. Injection was then terminated and a 6 hour pressure fall off survey commenced.

The gauges were then recovered and an additional 4 bbls of xylene was spotted at the perforations and allowed to soak for 1 hour. Seawater injection then resumed at rate of 15 100 bwpd (PT-1J) at a stable tubing head pressure of 2435 psig. No gauges were run in the hole in this injection period.

On completion of testing, a photon log run across the gravel pack indicated uniform gravel pack. The well was then suspended as a potential future water injector.

8.3.3.2 Pressure Gauges

Pressure gauges were run during the initial flow period (back surge) PT-1A, the main flow period and shut-in period of PT-1D, the bottom hole sampling period PT-1E, the first seawater injection period PT-1F, the second seawater injection period PT-1G, and the third seawater injection period PT-1H.

Two types of gauges were run in the backsurge period (PT-1A): 2 Hewlett-Packard crystal gauges and one Valstar gauge. One Hewlett-Packard gauge failed and the Valstar gauge gave "noisy" data. In the main flow period (PT-1D), two types of gauges were run: 2 Hewlett-Packard crystal gauges and 1 Flopetrol strain gauge. All three gauges gave acceptable responses. During the bottom hole sampling period (PT-1E) a Hewlett-Packard crystal gauge was run.

In the first injection test (PT-1F), two Hewlett-Packard crystal gauges and a Flopetrol SDP strain gauge were run. One Hewlett-Packard gauge gave unrealistic data and the SDP strain gauge ran out of memory. Two Hewlett-Packard crystal gauges and one Flopetrol SDP strain gauge were run in the second injection test (PT-1G). One Hewlett-Packard gauge failed while the other recorded unuseable data. The Flopetrol strain gauge gave acceptable results. In the third injection test (PTt-1H), three gauges: 2 Hewlett-Packard crystal gauges and one GRC strain gauge were run. One crystal gauge registered unrealistic data and the GRC strain gauge failed. A more detailed review of gauge performance in PT-1F, -1G and -1H is given in Section 8.4.3.4.

8.3.3.3 Fluid Sampling

Details of the samples collected during the oil test are given in Table 8.3.2.

A total of 5 oil bottom hole samples (BHS) and 6 sets of recombined oil and gas samples were recovered. Bubble point measurements were subsequently carried out on two of the bottom hole samples taken during PT-1E. Both samples had measured bubble points of 689 psig at reservoir conditions (160^{o}F). These results confirms the general trend of decreasing bubble point pressures from north - north east to south - south west.

8.4. EVALUATIONS

8.4.1 FMT survey

The FMT survey obtained a water gradient of 0.443 psi/ft in the Haltenbanken and an oil gradient of 0.325 psi/ft in the Frøya. These results are identical to the gradients observed in previous wells. The calculated datum pressure (at 1630 m.ss.) was 2395 psia using HP gauge data, very much in line with the previously established datum pressure of 2392 psia. (See Table 8.4.1, Figs. 8.4.1 and 8.4.2). The OWC established at 1638.5 m.ss. in well 6407/9-2 has not been contradicted by the FMT survey. However, recent core measurement have indicated the presence of hydrocarbons in the interval 1637 - 1645 m.ss. For further details see Section 7 (Petrophysical Evaluation).

Fluid samples taken during the FMT survey were not very useful as the conditions at which the fluid was transferred by the contractor, did not meet the fluid transfer specifications (pressure higher than initial reservoir pressure and reservoir temperature). Opening pressures of the bottles were 400 psig, thus the measured bubble points are suspect. This was not a disastrous situation as other bottom hole data were available.

8.4.2 Oil Zone Production Test (Pressure Buildup Analysis)

8.4.2.1 Main Flow Period and Pressure Buildup Survey

During the back surge and pressure buildup (PBU) after perforation of the oil zone, two of the three gauges successfully recorded pressure data. As in well 6407/9-5, no strain gauge was used as it had been seen in previous production tests on 6407/9-2, -3, and -4 that no useful information could be gathered by the strain gauge because large pressure fluctuations made any analysis impossible. Permeability-thickness product (kh) and skin cannot be evaluated from the backsurge. The average PI observed was 350 stb/d/psi using a final buildup pressure of 2392 psia, an average flowing pressure of 2390.7 psia and an average oil flowrate of 450 stb/d.

After the two rate drawdown period, a 24 hour buildup commenced. All three downhole gauges successfully recorded acceptable pressure data. No wellbore storage effects were present as a downhole shut-off tool successfully eliminated wellbore storage. Figs. 8.4.3, 8.4.4, and 8.4.5 show the pressure response over the entire test period as recorded by the Flopetrol strain gauge and the two Hewlett-Packard crystal gauges.

The superposed log time plot of the PBU as recorded by the Flopetrol strain gauge is shown in Fig. 8.4.6. Tidal effects can be seen towards the end of the buildup period. Fig. 8.4.7. and 8.4.8 are the superposed log time plots of the PBU as recorded by the gauges HP/Valstar 003/1141/098 and HP/Valstar 067/0929/126 respectively. As with the Flopetrol gauge, tidal effects are seen towards the end of the buildup period. These effects were not filtered out as the tidal effects seen here are very minor and thus did not pose any problems in the analysis.

In Figs. 8.4.6, 8.4.7 and 8.4.8 a continually rising slope is seen towards the end of the pressure buildup survey. The degree of rise seems to be similar for all three gauges. This phenomenon has been seen in previous pressure buildup surveys in the Draugen structure (6407/9-1, -2, -3, -4 and -5). An investigation of this phenomenon will be carried out in an overall review of production tests in the Draugen structure. Thus, for the purpose of the following analysis, the continually rising slope seen towards the end of the pressure buildup plots (Figs. 8.4.6, 8.4.7 and 8.4.8) is not considered.

From Fig. 8.4.6, 8.4.7, and 8.4.8., it is clear that two straight lines can be drawn through the early and late time data. For analysis, the total interval drained is assumed to be 50 ft (15 m). In Fig. 8.4.6 the first straight line (points 29 to 37) yielded a kh of 275 D-ft which corresponds to a permeability of 5518 md. The second straight line (points 41-95) yielded a kh of 211 D-ft which corresponds to an average permeability of 4220 md.

From Figure 8.4.7 the first straight line can be drawn through points 43 to 86 and the second straight line through points 92 to 105. The first straight line yielded an average permeability of 5931 md and the second straight an average permeability of 3651 md. The kh products were 296 D-ft and 182 D-ft respectively.

In Figure 8.4.8, the first straight line can be drawn through points 65 to 91 and the second straight line through points 98 to 130. The first straight yielded an average permeability of 6297 md and the second straight line yielded an average permeability of 3955 md. The kh products were 315 D-ft and 197 D-ft respectively.

Of all the main PBU's in the Draugen appraisal wells this was the only production test in which all the gauges run recorded useable data. Thus this production test offers the unique opportunity to compare the results obtained from the three gauges.

A tabular summary of the calculated parameters from the pressure buildup evaluation (PT-1D) is given below:

Gauge	kh (D-ft)	k(md)	Average Skin	Extrapolated Reservoir Pressure at Datum (psia)
SDP Strain Gauge	276	5518	8.1	2393
HP/Valstar 003/1141/098	296	5931	10.0	2393
HP/Valstar 067/098/126	315	6297	10.9	2393

From the above tabulation it is clear that the reservoir pressure (2395 psia at datum) established during the FMT survey compares well with the values obtained by extrapolating the second straight line in Figs. 8.4.6, 8.4.7 and 8.4.8. A complete summary of the pressure buildup evaluation and the following water injection evaluation is presented in Table 8.4.2. It is obvious from the above table that all three gauges yielded different values of permeability and consequently skin. The significance of these differences were investigated by evaluating the gauge calibration data for each gauge. The Flopetrol SDP strain gauge had a sensitivity range of between ±1 psi to ca. ±1.5 psi. This translates to an error of 10-15% over the measured range of pressure (ca. 10 psi) during the buildup period. The Hewlett-Packard crystal gauge HP/Valstar 003/1141/098 had a sensitivity of ±1 psi. This is equivalent to error of ±10% over the 10 psi pressure range of the buildup evaluation. Similarly the other Hewlett-Packard crystal gauge HP/Valstar 067/0928/126 had a sensitivity ±1 psi. This would mean an error of ±10% over the 10 psi pressure range of the buildup. It is then obvious that within the range of accuracy with which pressure data is measured, the differences between the evaluated parameters are insignificant.

From Figures 8.4.6, 8.4.7, and 8.4.8, a 30% change in slope is apparent at a superposed log time value of approximately 8000 stb/d. This corresponds to a shut-in time of approximately 0.65 hours into the buildup. If the change in slope is due to a reservoir feature i.e. a pinch-out, the distance to the event from the wellbore can be estimated from:

$$L = 0.01217\ (K\Delta t/\emptyset\mu C_T)^{0.5}$$

where

K	=	permeability, md	: 5518 - 6297
Δt	=	shut in time at which slope change occurs, hours	: 0.63 - 0.68
$\emptyset$	=	porosity, fraction	: 0.30
μ	=	viscosity, cp.	: 0.67
C_T	=	total compressibility, 1/psi	: $44 * 10^{-6}$

(Gray, K.E. "Approximating Well-to-Fault Distance From Pressure Build-Up Tests,"J. Pet. Tech- (July 1965) 761-767).

The above relation, though not strictly applicable to reservoir features of a non-sealing nature, can still be used to estimate the distance to the reservoir feature. From the equation a reservoir feature was detected at a distance of 243, 252, and 262 feet away from the well bore using the Flopetrol SDP strain gauge, HP/Valstar 003/1141/098 and HP/Valstar 067/0928/126 respectively. The actual distance to the reservoir feature is most probably greater than the value calculated from the equation above. This is because the equation above assumes an image well producing at the same rate at a distance 2 L from the wellbore. A better estimate of the distance to the reservoir feature can be obtained through a time consuming trial and error type curve matching technique.

The cause of the slope change could be due to many factors, the most obvious being a change in the interval drained or an abrupt change in permeability. A change in the interval drained is consistent with seismic data and is within the distance calculated from pressure data. (See Fig. 8.2.1). There is also some evidence of a small fault within the calculated distance this however is not well defined because of seismic definition and is not included in the present map (see Fig. 8.2.1).

In this report the most obvious case, reservoir heterogeneity is the basis of the analysis.

8.4.3 Oil Zone Water Injection Test (Pressure Fall off Analysis)

8.4.3.1 PT - IF (First Injection Test)

After completion of the bottom hole sampling period of PT-1E water injection testing commenced (PT-1F). Water injection commenced at an initial rate of 12700 bwpd which was then increased to 16280 bwpd after 17 hours. This rate was decreased to 13200 bwpd after 3 hours. A change in pumps due to a leak increased the rate to ca. 13300 bwpd. This rate was maintained for approximately 40 hours. Total injection time was approximately 72 hours.

After the injection test, a 24 hour pressure falloff test was successfully recorded by a Hewlett-Packard crystal gauge. The Flopetrol SDP strain gauge did not record any pressure fall off data because it ran out of memory. The SDP strain gauge, programmed for a 10 second sampling rate and a compression level of 0.16 psia, ran out of memory because the continuous pressure change experienced during the injection period of PT-1F was unexpected. The other Hewlett-Packard crystal gauge recorded unuseable date (see Fig. 8.4.9). From this figure it can be seen that pressure increases (unrealistically) during the fall off period. An explanation of this obvious gauge failure is given in Section 8.4.3.4.

As in the pressure buildup survey, no wellbore storage effects were present as a downhole shut-in tool was used successfully. Figure 8.4.10 shows the pressure response of the reservoir over the entire test period. It is interesting to note the large pressure drop when water injection ceases.

The continuously changing skin seen during the injection period did not pose any problems in the fall off analysis. This is because the fall off behaviour is affected only by the last skin at the well. However, the changing skin makes any analysis of the injection period impossible.

Fig. 8.4.11 shows the superposed log time plot of the pressure fall off survey period. It is clear from this plot that two straight lines sections can be drawn through the early and late time of the pressure data respectively. As in the pressure buildup analysis, a total Frøya injected interval of 50 ft (15 m). was used for the purpose of analysis. The analysis of the pressure fall off survey data supposes that the fluid distribution around the well can be schematically described by Fig. 8.4.12. Fig. 8.4.12 indicates two zones of interest: the cold water bank (Zone 1) and the hot oil bank (Zone 2). Radial distance to the hot oil bank is designated r_{f1}. The rather simplistic representation of the fluid distribution during an injection test is necessary as the methods of analyses are based on radial systems. By virtue of the method of analysis, the transition zone between the cold water zone and hot oil zone is ignored.

From Figure 8.4.11 the first straight section can be drawn through points 64 to 77 and the second straight line section through points 92 onwards. The first straight line section describes the properties of the cold water bank (Zone 1). Using a water viscosity of 1.25 cp. and an injection temperature of 55^{o}F, the first straight line yielded a permeability to water, kw, of 1290 md. Analysis of the second straight line section is complicated by the fact that the transient effects are controlled by the properties of <u>both</u> Zone 1 and the transition zone. Any analysis of the second straight line would be suspect and speculative. It is however possible to estimate the mobilities in Zone 1 and Zone 2. Assuming that the compressibility of the system did not change considerably, the mobility ratio between Zone 1 and Zone 2 can be estimated from the ratio of second straight line slope to the first straight line slope obtained from Fig. 8.4.11. Thus the mobility ratio of Zone 1 to Zone 2 is 0.2 and the mobility of the second zone is 5160 md/cp. Using the same oil viscosity used in the PBU analysis, the second straight line of Fig. 8.4.11 yields a permeability of 3176 md. This value is very similar to those obtained from the second slope of the PBU analysis.

From Figure 8.4.11 the radial extent of the Zone 1 can be estimated from:

$$r_{f1} = (0.0002637 * (K/\mu)_1 * \Delta t_{fx}/(\varnothing C_T)_1 * t_{Dfx})^{0.5}$$

where

$(K/\mu)1$ = mobility of Zone 1, md/cp: 1032

Δ tfx = extrapolated intersection time of the two straight line sections in Figure 8.4.11, hours: 0.10.

t_{dfx} = dimensionless shut in time determined by the intersection of the two straight line sections in Fig. 8.4.11: 0.65.

$(\varnothing\ Ct)_1$ = porosity - total compressibility product of Zone 1, psi^{-1}: 12 * 10^{-6}.

(Merrill, L.S., Kazemi, H., Gogarty, W.B.:
"Pressure Fall off analysis in Reservoirs with Fluid Banks",
J. Pet. Tech. (July 1974) 809 - 818).

From the above equation the radial extent of the injected water was estimated to be 60 feet. Applying a material balance relationship, the radius of Zone 1 can be independently estimated using:

$$r_{f1} = ((5.615Wi)/\pi \text{Ø} hSw)^{0.5}$$

where

Wi	=	barrels of water injected: 39 000
h	=	injected interval, ft: 50
Sw	=	Change in water saturation: 0.5

Thus from a material balance relationship the radius of the water zone was estimated as 96 feet. This value is close to the value obtained from the fall off analysis.

It is interesting to note that the steepening slope change seen in the PBU was not seen in Fig. 8.4.11. The slope change could have been masked by the water bank and the transitionary effects. Because of temperature effects and possibly plugging, skin for the entire test period varied from 9.5 to 38 (Appendix D). The injectivity index, II, decreased from a high of 30 bwpd/psi to 8 bwpd/psi (Table 8.4.2). Using the first straight line slope and the final skin, the pressure drop due to skin is ca. 1200 psi. The ideal II using the last injection rate is ca. 28 bwpd/psi. How much of skin pressure drop, is due to the gravel pack and how much is due to temperature effects is difficult to determine.

Extrapolated reservoir pressure using the second straight line, was 2393 psia at datum. This compares well with the reservoir pressure at datum established by the FMT survey, of 2395 psia (see Table 8.4.1), and the pressure buildup evaluation of 2393 psia (see Table 8.4.2).

8.4.3.2 PT - 1G (Second Injection Test)

After the completion of PT-1F, the well was acidised to improve the injectivity. Water injection commenced at an initial rate of 13375 bwpd and was maintained for ca. 6 hours. Injection rate increased to just over 15000 bwpd, which was maintained for ca. 1/2 hour. An injection rate of ca. 13200 bwpd was then maintained for ca. 2 hours and a final injection rate of ca. 11300 bwpd for approximately 3 1/2 hours. Total injection time was just over 12 hours.

Following the end of water injection, a 6 hour pressure fall off test was successfully recorded by a Flopetrol SDP strain gauge. Of the two Hewlett-Packard crystal gauges used in the test, one recorded increasing pressure during the fall off period (see Fig. 8.4.13 and Section 8.4.3.4) and one failed to record any data.

As in the previous water injection test no wellbore storage effects are present as a downhole shut-in tool was used successfully. Figure 8.4.14 shows the pressure response over the test period of PT-1G. It is interesting to note the large pressure drop at end of the injection period and the beginning of the pressure fall off period. Note that bottom hole pressure generally increases but at the last period prior to the fall off, bottom hole pressure increased and then decreased. This decrease could be due to formation fracturing or that material plugging the gravel pack was pushed through the gravel pack.

Using the Breckels and Van Eekelen correlation for calculating the minimum in-situ horizontal stress, a value of 3630 psia was obtained; a lower value is probably more correct because of formation cooling. At times, bottom hole pressure during the last injection period exceeded 4200 psia. As the pressure drop across the gravel pack exceeds 1000 psi it was unlikely that formation fracturing occurred.

Figure 8.4.15 shows the superposed log time plot of the pressure fall off survey period of PT-1G. From this plot it is clear that two straight line sections can be drawn through the early and late time pressure data respectively. As in the previous analysis the total Frøya injected interval of 50 feet (15 m) was used for the sake of analysis. Analysis of this pressure fall off survey again assumes that the situation depicted in Fig. 8.4.12 exists.

From Fig. 8.4.15, the first straight line can be drawn through points 59 to 63 and the second straight line point 71 onwards. The first straight line was analysed using a water viscosity of 1.25 cp. This yielded a permeability of 907 md. As mentioned earlier the second straight line section is complicated by transient effects controlled by Zone 1 and the transition zone.

Pressure fall off analysis of PT-1G was accomplished using the methods of analysis outlined in the previous water injection test analysis (8.4.3.1). A summary of the main test results is given:

Permeability of Zone 1	= 907 md
Mobility ratio of Zone 1 to Zone 2	= 0.13
Mobility of Zone 2	= 5582 md/cp
rfl (with t_{fx} of 0.2 hours and t_{Dfx} of 0.65)	= 75 feet.

From material balance relationships the radial extent of the water bank was estimated as 110 feet. As in the previous injection test, the slope change seen in the PBU was not seen in this pressure fall off either. The slope change, as stated earlier, could have been masked by the water bank and the transitionary effects. If the second slope is analysed with the oil viscosity used in the PBU analysis, a permeability of 3686 md will be obtained. This permeability is very similar to permeabilities obtained from the second slope in PT-1D and PT-1G pressure analyses.

Skin over the total test period varied from 15 to 32 (Appendix D). The II decreased from ca. 15 bwpd/psi to 7 bwpd/psi (Table 8.4.2). Using the first straight line slope and the final skin, the pressure drop due to skin is ca. 1100 psi. The ideal II using the last injection rate is ca. 22 bwpd/psi. As stated earlier, the pressure drop due to the gravel pack and the pressure drop due to temperature effects is not possible to determine.

Extrapolated reservoir pressure, using the second straight line, was 2406 psia. This value is not in line with the extrapolated pressure values of 2393 psia obtained from the pressure buildup evaluation and 2395 psia from the FMT survey. The SDP strain gauge used in PT-1G was also used in PT-1D, and PT-1F. The gauge is assumed to be out of calibration (the gauge contractor did not recommend the use of the same gauge three times over the course of production testing).

8.4.3.3 PT-1H (Third Injection Test)

After the completion of PT-1G, the second injection test, the tubing string was cleaned of wax-like deposits and acid pumped downhole to dissolve the carbonate kill pill. Xylene was then circulated downhole to clean out any remaining wax-like deposits. Injection of seawater then commenced at a constant rate of ca. 13320 bwpd for approximately 3 hours. Three gauges were then run and the injection rate of 13320 bwpd resumed and maintained for ca. 12 1/2 hours.

After the injection test, a 6 hour fall off test was recorded successfully by a Hewlett-Packard crystal gauge. No data was recorded by the GRC gauge whereas the other Hewlett-Packard crystal gauge recorded increasing pressure during the fall off period (see Fig. 8.4.16). This is unrealistic and the reason for the pressures recorded by this gauge during the fall off period is covered in Section 8.4.3.4.

As in all the previous tests no wellbore storage effects were recorded because of the use of a downhole shut-in tool. Figure 8.4.17 shows the pressure response over the entire test period. As in the other injection tests, a large pressure drop is seen at the start of the pressure fall off survey. Figure 8.4.18 is the plot of bottom hole pressure vs. superposed log time over the water injection period of PT-1H. Analysis of this period is impossible due to the pressure fluctuations recorded.

Fig. 8.4.19 is the superposed log time plot of the pressure fall off survey period of PT-1H. It is clear from this plot that three straight line sections can be drawn through the pressure versus superposed log time data. As in previous analyses, a total injected interval of 50 ft was used. From Fig. 8.4.19 the first straight line can be drawn through points 35 to 61, the second straight line through points 81 to 99 and the third straight line through points 106 onwards. The analysis of this pressure fall off was based on two possible scenarios. The first scenario (Case 1) is depicted by Fig. 8.4.20 and the second scenario (Case 2) by Fig. 8.4.21. Fig. 8.4.20 indicates three zones of interest: the cold water zone (Zone 1), the hot water zone (Zone 2), and the hot oil zone. Radial distances to the hot water zone and the hot oil zone are designated r_{f1} and r_{f2} respectively. As mentioned earlier, transition zones are ignored by the method of analysis.

Figure 8.4.21 depicts a situation where gravity segregation of previously injected fluid has occurred. This leads to the reservoir behaving like a layered system; transients in the "upper" layer (hot oil zone) will behave differently from transients in the "lower" layer (hot water zone).

Assuming that Case 1 exists, the first straight line describes the properties of the cold water bank. As no analytical method is available for analysing a system in which a Case 1 situation exists, a more definite analysis can only be performed using a numerical thermal simulator.

The first straight line section yields a permeability of 1777 md with a water viscosity of 1.25 cp. As in previous analyses, any analysis of the second and third straight lines will be speculative.

From material balance relationships the radial extent of the cold water bank was estimated as 61 feet. A comparison between the radius of the cold water bank obtained from material balance relationships and the radius of the cold water bank obtained from analytical well test techniques was not made. This is because of the lack of an analytical method for a Case 1 situation.

Assuming that Case 2 exists, the first straight line would still describe the properties of the water bank. A detailed analysis of the scenario depicted by Fig. 8.4.21 can only be done using a thermal simulator.

Extrapolated reservoir pressure using the third straight line was 2396 psia at datum. This value compares well with the values obtained from the previous fall off survey; PT-1F (2393 psia), the pressure buildup evaluation on (2393 psia), and the FMT survey (2395 psia). The II over the test period was ca. 10 bwpd/psi with an average total skin of 43; the ideal II was ca. 40 bwpd/psi. A summary, in tabular form, of the evaluated parameters from the fall off surveys in PT-1F, -1G and -1H is presented below:

Test	Gauge	kh (D-ft)	kw(md)	Average Skin	Extrapolated Reservoir Pressure (psia)
PT-1F	HP/Valstar 067/0928/126	64	1290	38	2393
PT-1G	SDP Flopetrol Strain Gauge	45	907	29.6	2406
PT-1H	HP/EMR 59654/1018/449	88	1777	43	2396

A summary of the evaluated parameters from this period and other periods is presented in Table 8.4.2. Over the course of the water injection tests: PT-1F, PT-1G and PT-1H, pressure drops due to the last skin were approximately 1200 psi, 1100 psi, 1000 psi respectively. Improved completion techniques will obviously decrease the skin pressure drop which will then improve the injectivity of future Draugen water injectors.

8.4.3.4 Temperature Effects

Increasing values of pressure, recorded during the fall off periods of PT-1F, PT-1G and PT-1H (Fig. 8.4.9, 8.4.13 and 8.4.16) were due to temperature effects. Hewlett-Packard gauges run downhole during the production test were calibrated over the temperature range 70°F - 250°F. During the course of the water injection tests and pressure falloff surveys downhole temperatures in the low and mid-50's were recorded.

In all three cases the same gauge, HP/EMR 64984/0125/455, recorded data that were unuseable. An investigation by the contractor (Stavanger Oilfield Services) concluded that the pressure anomaly seen in the plots of bottom hole pressure vs. superposed log time (Figs. 8.4.9, 8.4.13 and 8.4.16) were due to an anomalous transient temperature response of the temperature gauge in this particular HP/EMR combination.

Hewlett-Packard gauges require accurate temperature readings to determine accurate pressure measurements. Thus errors in temperature response can adversely affect the pressure data recorded by the gauge. A summary of the effects of temperature on gauge accuracy, as specified by the gauge manufacturer, is given below:

Temperature Accuracy Range	Pressure Accuracy Range
1.8°F	+/- 0.5 psi/+0.025% of reading
18°F	+/- 1 psi/+ 0.1% of reading
36°F	+/- 5 psi/+ 0.25% of reading

8.5 RESULTS AND CONCLUSIONS

8.5.1 FMT Survey

1. The oil and water gradient of 0.325 and 0.443 psi/ft respectively, were identical to the previous values obtained in wells 6407/9-1, 2, 3, 4 and 5.

2. The Frøya and Haltenbanken Formations belong to the same hydrostatic pressure regime.

3. The average reservoir was 2395 psia at datum of 1630 m.ss. and is within measurement accuracy of the previously established initial reservoir pressure of 2392 psia at datum.

8.5.2 Oil Zone Test (Pressure Buildup Analysis)

1. ~~The well was produced up~~ to a maximum of 6400 stb/d of 40^{0} API oil from the interval 1618 to 1631 m.ss. Separator GOR was measured at 68 scf/stb.

2. The buildup plots exhibited an increase in slope some 0.65 hours into the buildup. One explanation is a change in the interval drained at ca. 250 feet from the wellbore; this is consistent with seismic data.

3. The evaluated kh product,based on the first straight line, averaged 295 D-ft. This is equivalent to an average permeability of 5900 md for the drained interval of 50 ft.

4. Average post gravel pack PI was 135 stb/d/psi. Total skin was 10 and partial penetration skin was 1. The average ideal PI (skin=0) was calculated as 260 stb/d/psi.

5. Initial reservoir pressure was calculated as 2393 psia at datum (1630 m.ss.). The previously established value of 2392 psia (at datum) is within the accuracy of the gauges.

8.5.3 Oil Zone Water Injection Test (Pressure Fall off Analysis)

1. A maximum rate of some 16300 bwpd was achieved for a short period. Injectivity problems due to temperature effects and plugging were remedied somewhat in PT-1J and an average stable rate of ca. 15 000 bwpd was eventually achieved.

2. Evaluation of the various pressure fall off surveys indicated an average kh product of 64 D.-ft. This is equivalent to an effective water permeability of 1.3 Darcy for the 50 ft (15 m) injection interval.

3. Average final II from PT-1F, -1G and -1H was ca. 10 bwpd/psi. Skin factors averaged from ca. 10 to 50 with a partial penetration skin of 1.

4. Improved completion techniques will improve the injectivity of this well and future Draugen water injectors.

5. Evaluated reservoir pressure from the fall off surveys averaged 2395 psia at datum.

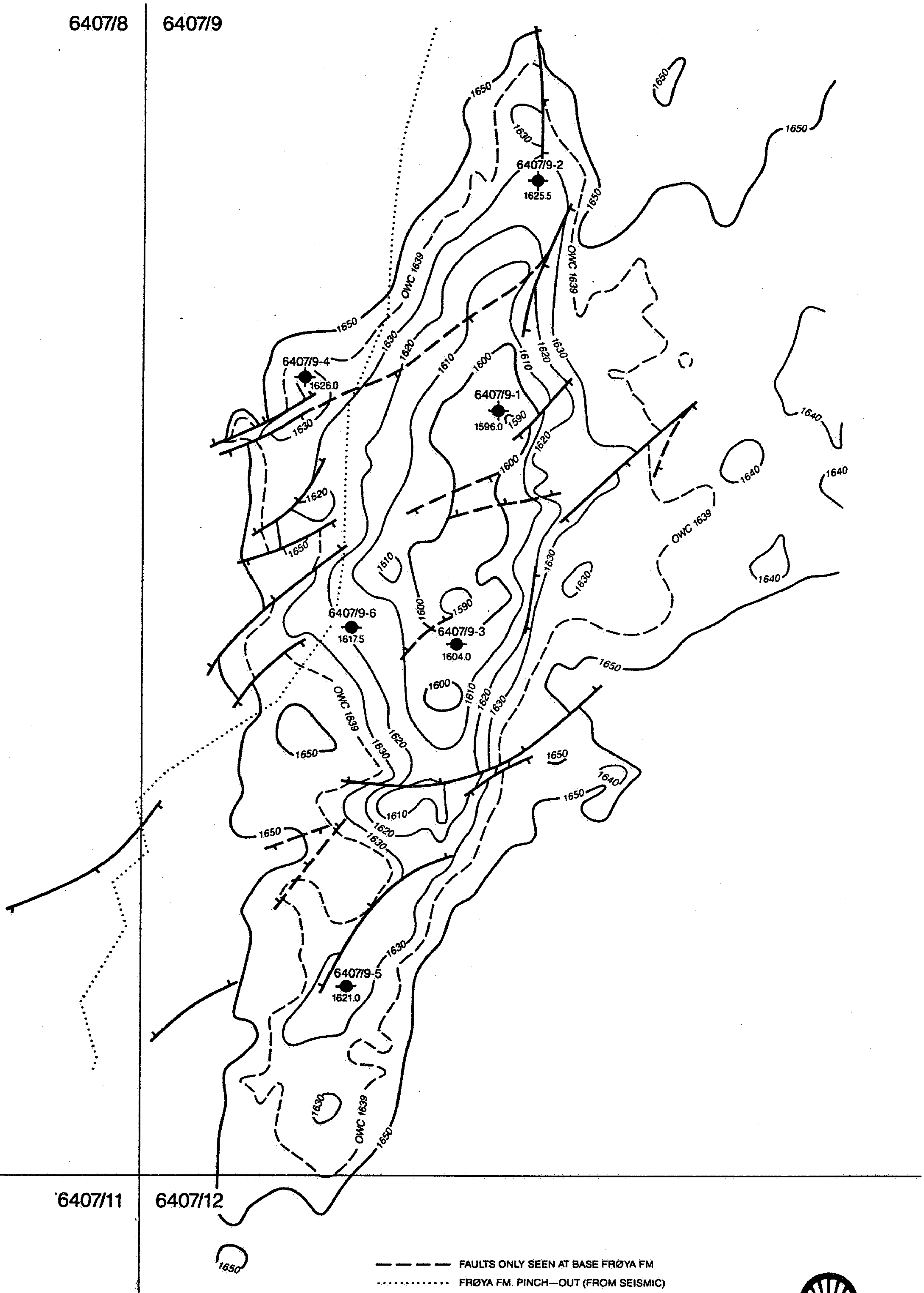
6. Test responses cannot be definitely evaluated using analytical techniques in view of varying mobilities (temperatures). A numerical thermal simulator would be needed to carry out a definitve evaluation.

7. Temperature effects have adversely affected the quality of pressure data recorded by Hewlett-Packard crystal gauges. HP/EMR combinations are definitely unsuited for measuring bottomhole pressure data when downhole temperature variations are expected to be great.

8.6 RECOMMENDATIONS

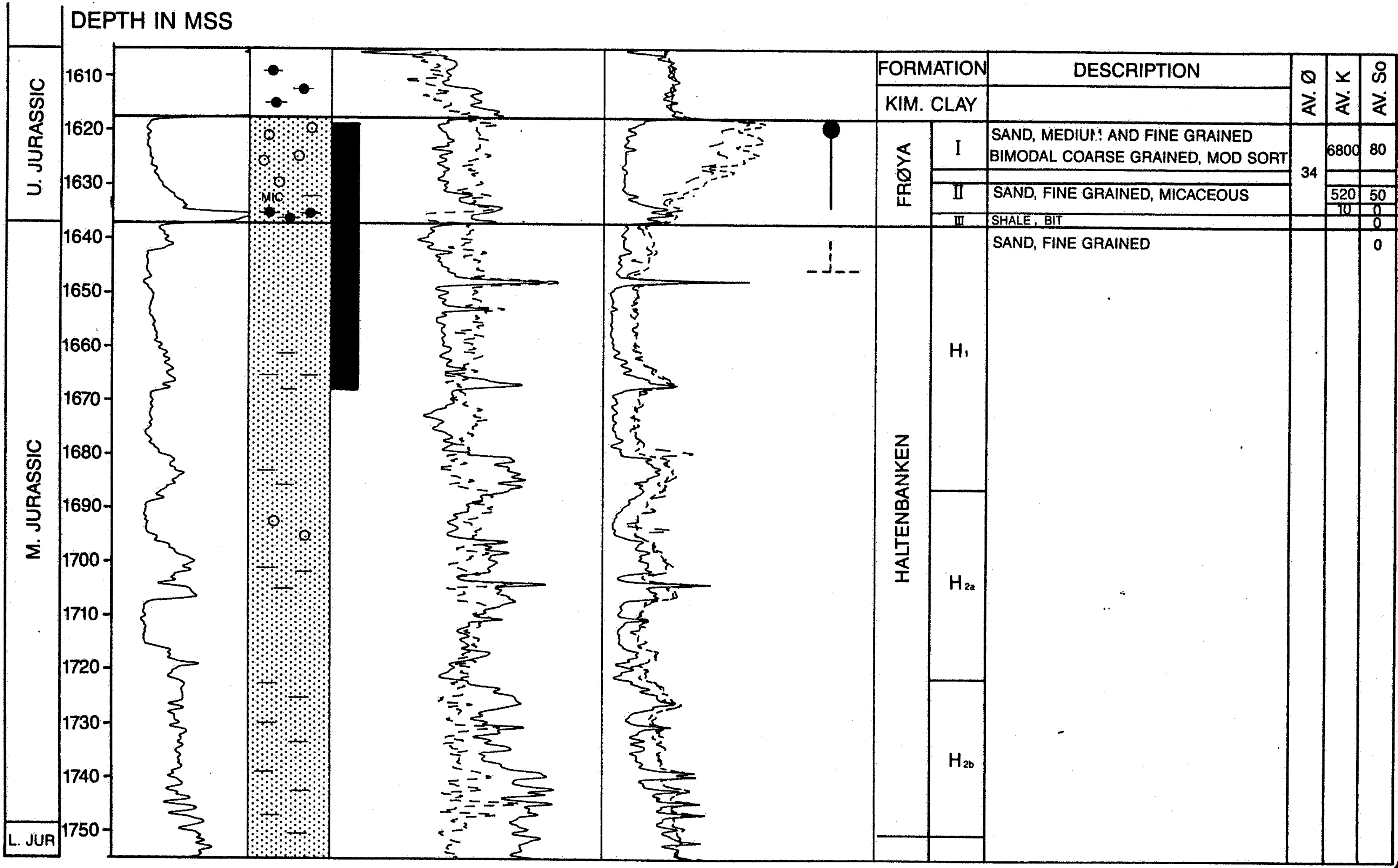
In light of the generally poor performance of some of the pressure gauges run in 6407/9-6, it is recommended that a detailed review of gauge problems encountered during production testing in the Draugen field be carried out.

DRAUGEN FIELD
TOP RESERVOIR STRUCTURE MAP



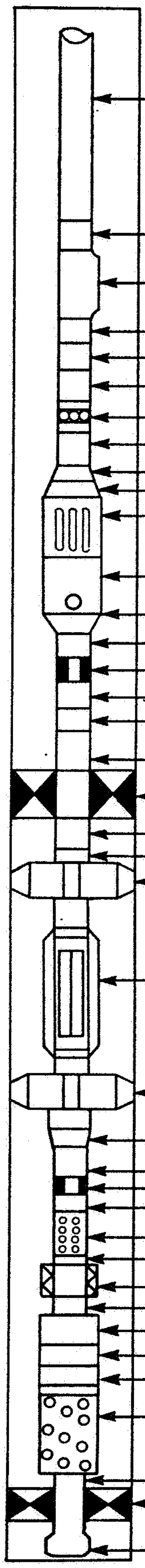
A/S Norske Shell

WELL RESULTS 6407/9-6



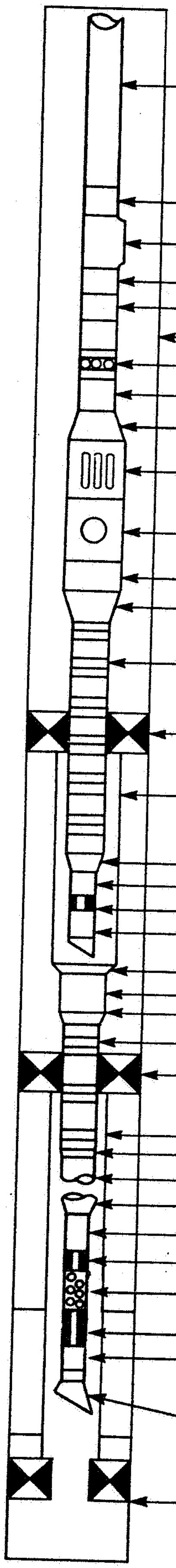
A/S Norske Shell

6407/9-6
TUBING CONVEYED PERFORATING STRING

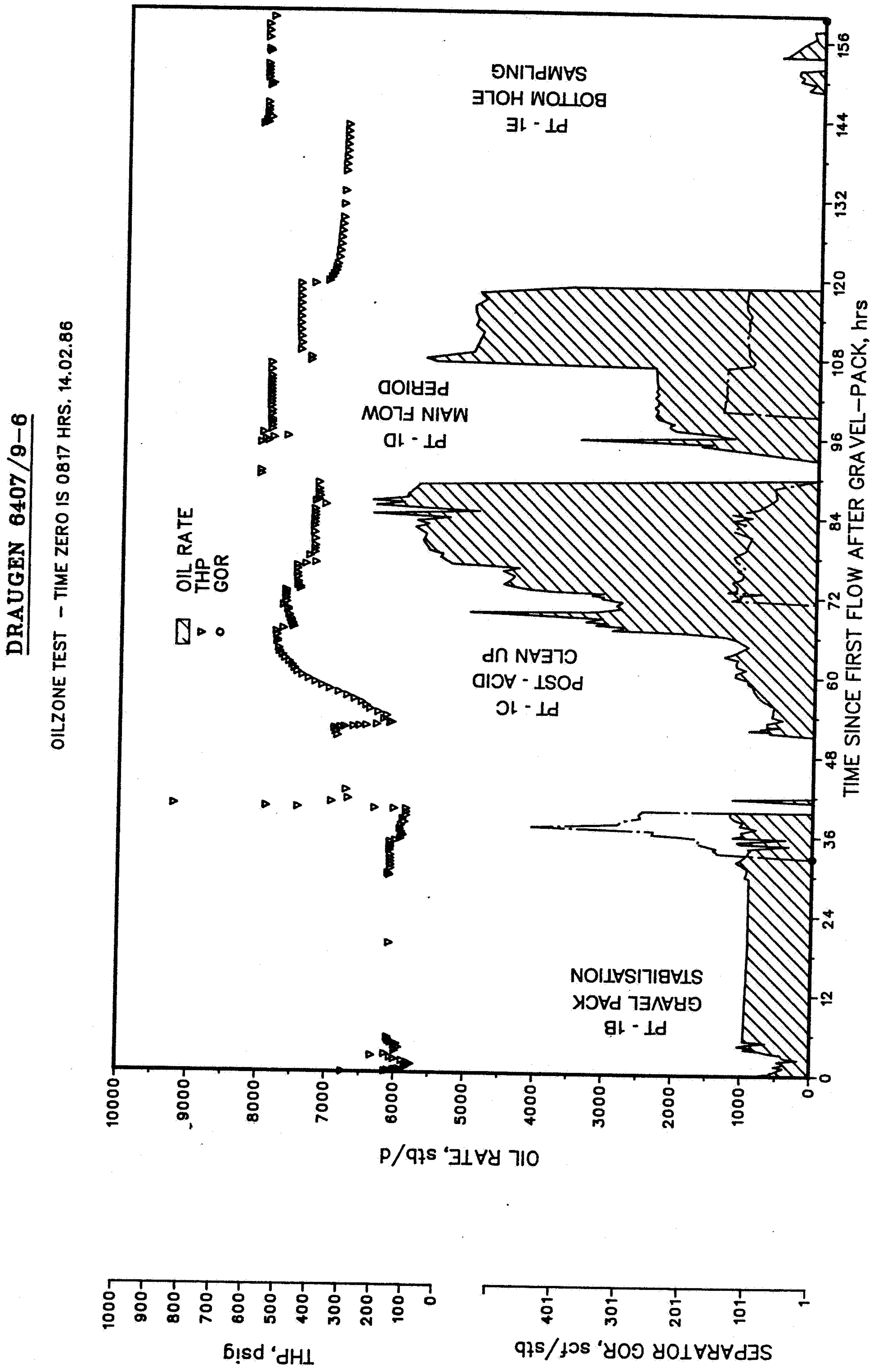


	MIN ID.	MAX O.D.
3½" L80 VAM 10-2ppf TUBING	2.797	3.885
PUP JOINT 3½ VAM (B x P)		
OTIS 'LB' S.P.M. VAM(BxP)	2.91	5.62
PUP JOINT 3½ VAM (B x P)		
X-OVER: 3½ VAM(B) x 3½ CS(P)		
PUP JOINT 3½ CS (B x P)		
3½ X A S.S.D. 3½ CS(B x P)	2.75	
PUP JOINT 3½ CS(B x P)	2.797	
X-OVER 3½ CS(B) x 3½ IF(P)	2.25	5.000
RADIOACTIVE TRACER SUB 3½ IF(B x P)	2.25	5.000
M.O.R.V. 3½ IF(B x P)	2.25	5.000
P.C.T. 3½ IF(B x P)	2.25	5.000
X-OVER 3½ IF(B) x 2 7/8 VAM(P)	2.25	5.000
PUP JOINT + 2 7/8 VAM(B x P)	2.260	3.330
HF TOP NO GO NIPPLE 2 7/8 VAM (B x P)	2.125	3.690
PUP JOINT 2 7/8 VAM(B x P)	2.260	3.335
X-OVER 2 7/8 VAM(B) x 3½ EU(P)	2.250	3.730
PUP JOINT 3½ EU(B) x 3½ EU(P)	2.992	4.495
BAKER FH PACKER 51 A4	3.000	8.437
PUP JOINT 3½ EU(B) x 3½ EU(P)	2.992	4.520
X - OVER 3½ EU(B) x 3½ IF(P)	2.235	5.155
DRAG BLOCK 3½ IF(B) x 3½ IF(P)	2.25	
BUNDLE CARRIER 3½ IF(B) x 3½ IF(P)	2.25	
DRAG BLOCK 3½ IF(B) x 3½ IF(P)	2.25	
X-OVER 3½ IF(B) x 2 7/8 VAM(P)	2.441	5.00
PUP JOINT 2 7/8 VAM(B x P)	2.220	3.330
AF TOP NO GO NIPPLE 2 7/8 VAM(B x P)	1.87	3.645
PUP JOINT 2 7/8 VAM (BxP)	2.220	3.345
PERFORATED PUP JOINTS 2 7/8 VAM(B) x 2 7/8 EU(P)	2.441	3.680
CIRCULATING SUB 2 7/8 EU(B x P)		
SHOCK ABSORBER 2 7/8 EU(B x P)		
PUP JOINT 2 7/8 EU(B) x (P)		
FILL SUB		7.25
FIRING HEAD		7.25
BLANK SUB		7.25
7¼ 12 SPF GUN		7.25
X - OVER 2 7/8 EU PIN DOWN		
BAKER F1 SUMP PACKER 192-60		
BAKER, 190-60 INDICATING COLLET		

6407/9-6
PRODUCTION TEST STRING

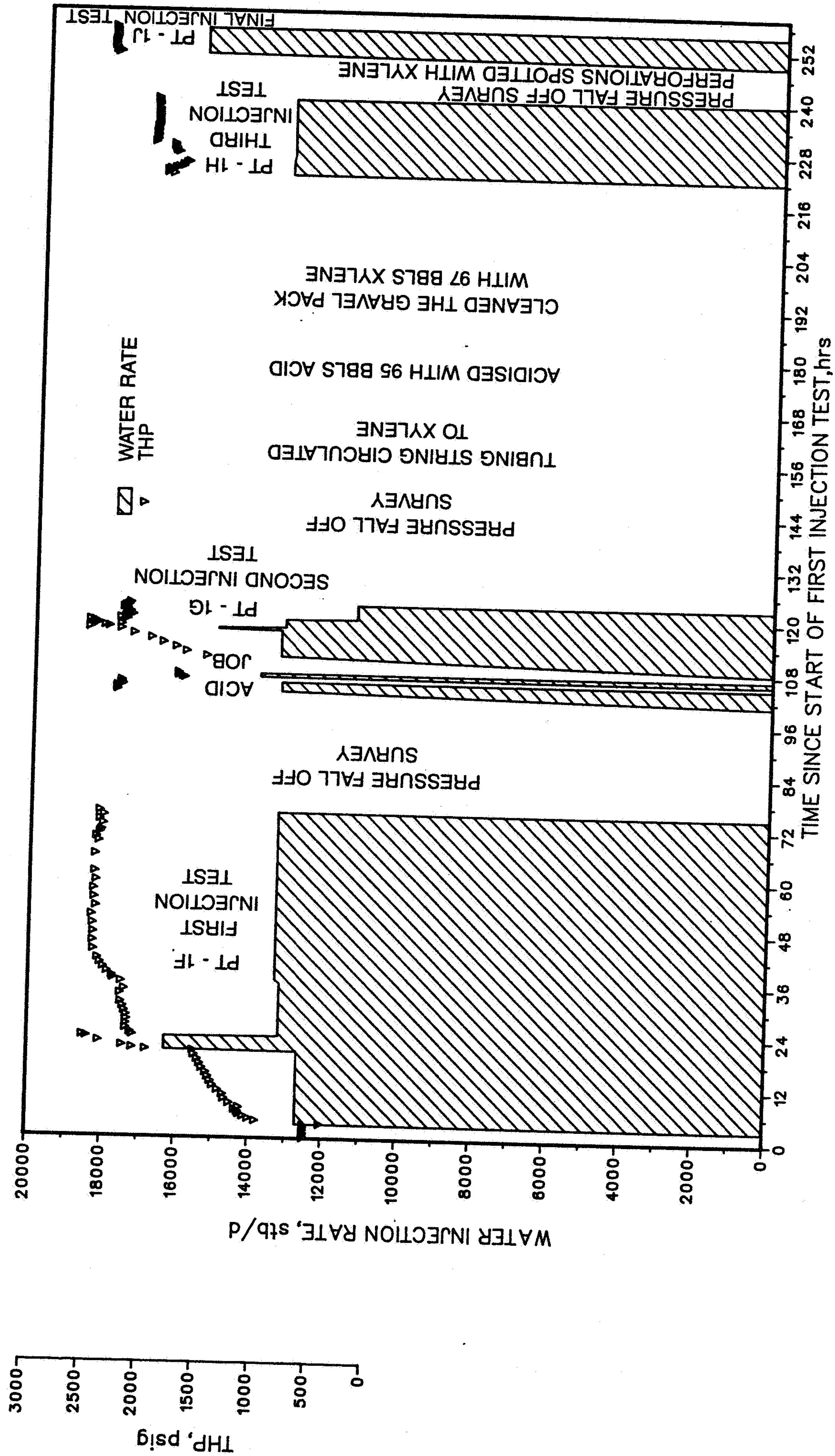


Component	MIN ID	MAX O.D.
3½" L80 VAM 10-2ppf TUBING	2.797	3.885
PUP JOINT 3½ VAM (B) x 3½ VAM (P)	2.992	3.885
OTIS'LB' S.P.M. 3½ VAM (B) x 3½ VAM (P)	2.91	5.62
PUP JOINT 3½ VAM (B)x(P)	2.992	3.885
X - OVER 3½ VAM (B) x 3½ CS (P)	2.900	3.920
PUP JOINT 3½ C.S (B) x 3½ CS (P)		
3½ XA. SSD 3½ CS (B) x 3½ CS (P)	2.75	
PUP JOINT 3½ CS (B) x 3½ CS (P)		
X - OVER 3½ CS (B) x 3½ IF (P)	2.25	5.000
FLOPETROL MORV 3½ IF (B) x 3½ IF(P)	2.25	5.000
FLOPETROL PCT 3½ IF(B) x 3½ IF(P)	2.25	5.000
X - OVER 3½ IF (B) x 3½ CS (P)	2.25	5.000
G-22 LOCATOR 3½ CS BOX UP	4.875	6.250
SEAL ASSEMBLY 190-60 20FT STANDARD SEALS	4.875	6.000
BAKER SC1L PACKER 96 A4-60	6.00	8.450
20FT MILL OUT EXTENSION 7⅝ S.T.C.(P) x LTC(P)		7.705
BOTTOM SUB × 2⅞ VAM (P) DOWN	2.220	5.960
PUP JOINT 2⅞ VAM (B) x 2⅞ VAM (P)	2.220	3.3350
BAKER H.F. TOP NO GO NIPPLE 2⅞ VAM (B x P)	2.125	3.690
WIRELINE ENTRY GUIDE 2⅞ VAM (B) UP	2.220	3.905
X-OVER 7⅝ LTC (B) × 5" VAM (P)		8.240
2 x 5" VAM PUP JOINT (B x P)	4.283	5.598
G22 LOCATOR 5" VAM(B) UP	4.875	6.250
SEAL ASSEMBLY 190-60 10FT PREMIUM SEALS	4.875	6.000
BAKER FAB1 PACKER 194-75 x 60	6.00	
BAKER I.G.P.		
BOTTOM SUB 3½ VAM (P) DOWN		5.970
TUBING 3½ VAM (B x P)		4.870
x-OVER 3½ VAM (B) x 2⅞ VAM (P)	2.125	3.880
PUP JOINT 2⅞ VAM (B) x 2⅞ VAM (P)	2.220	3.340
BAKER A.F TOP NO GO NIPPLE 2⅞ VAM (B x P)	1.87	3.645
PERFORATED PUP JOINT 2⅞ VAM (PxB)	2.350	3.685
BAKER F TOP NO GO NIPPLE 2⅞ EU (B x P)	1.81	3.090
PUP JOINT 2⅞ VAM (B x P)	2.22	3.34
X-OVER 2⅞ VAM (B) x 2⅞ EU	2.35	3.670
FLAPPER KNOCKOUT SUB/WIRELINE ENTRY GUIDE	2.425	4.450
BAKER F1 SUMP PACKER 192-60	6.00	8.220


DRAUGEN 6407/9-6
OILZONE TEST - TIME ZERO IS 0817 HRS. 14.02.86
OIL RATE
THP
GOR
PT - 1B GRAVEL PACK STABILISATION
PT - 1C POST - ACID CLEAN UP
PT - 1D MAIN FLOW PERIOD
PT - 1E BOTTOM HOLE SAMPLING
TIME SINCE FIRST FLOW AFTER GRAVEL-PACK, hrs
0 12 24 36 48 60 72 84 96 108 120 132 144 156
OIL RATE, stb/d
0 1000 2000 3000 4000 5000 6000 7000 8000 9000 10000
THP, psig
0 100 200 300 400 500 600 700 800 900 1000
SEPARATOR GOR, scf/stb
1 101 201 301 401

DRAUGEN 6407/9-6

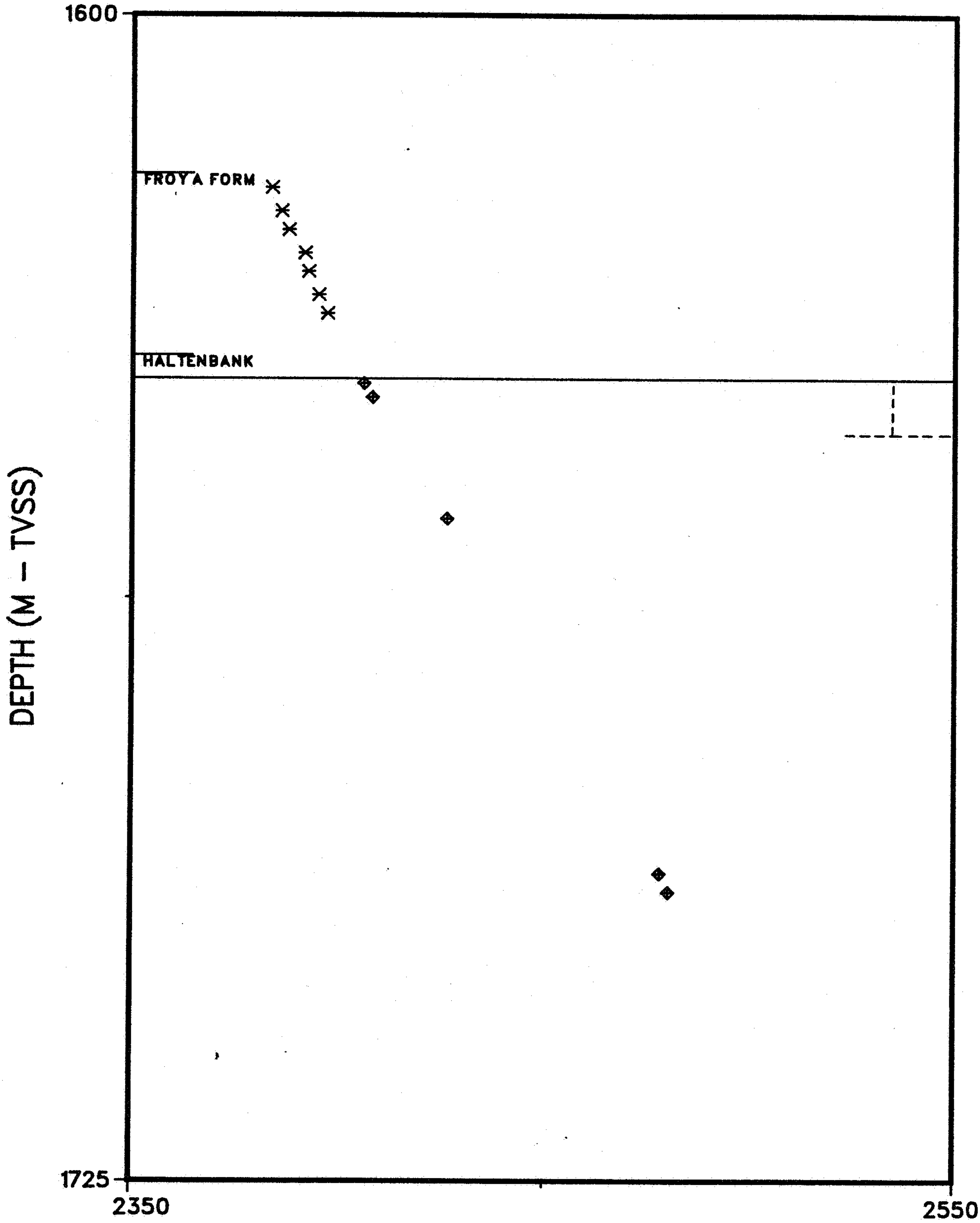
WATER INJECTION TEST, TIME ZERO IS 0608 20/2/86



FMT PLOT

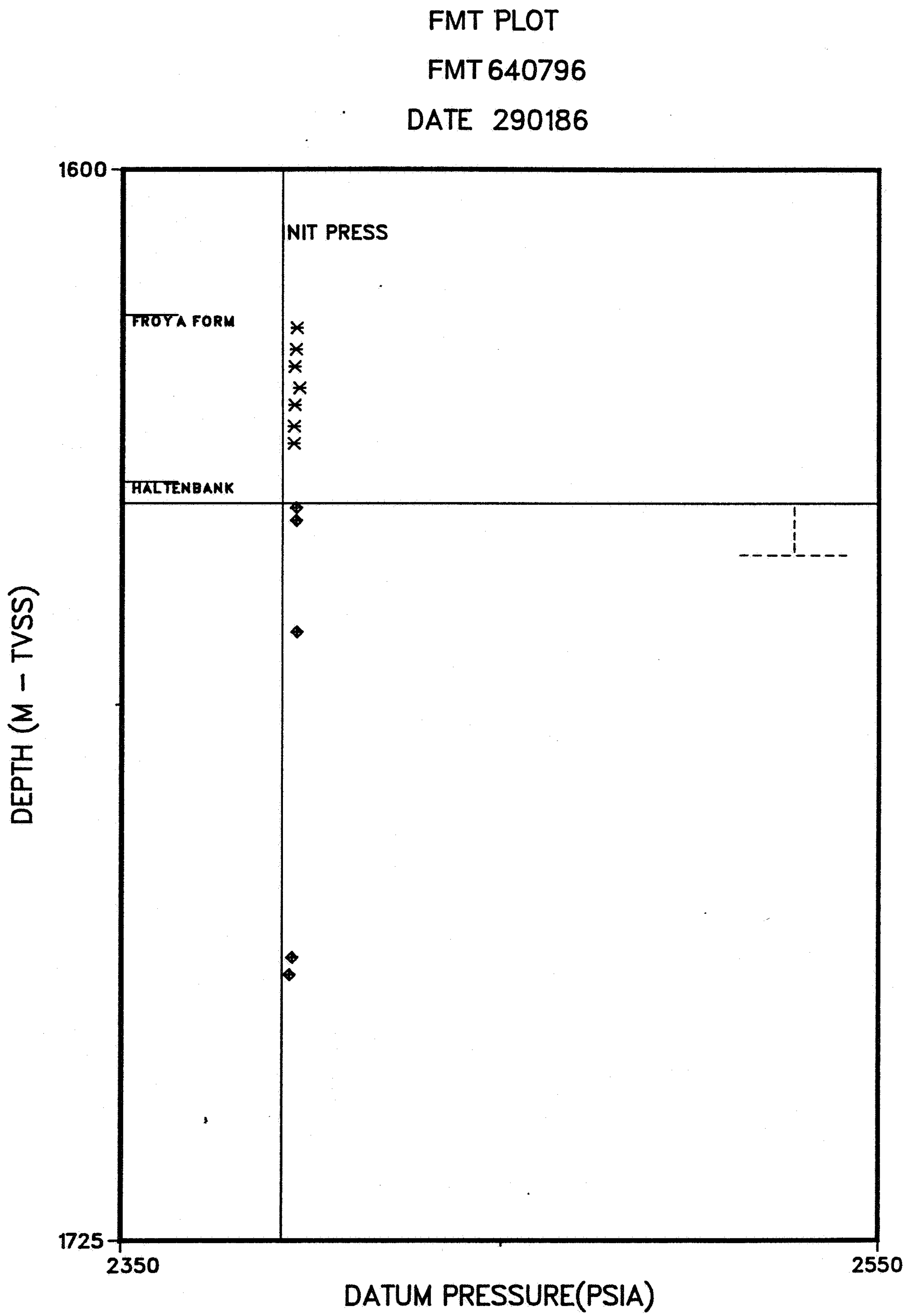
FMT640796

DATE 290186



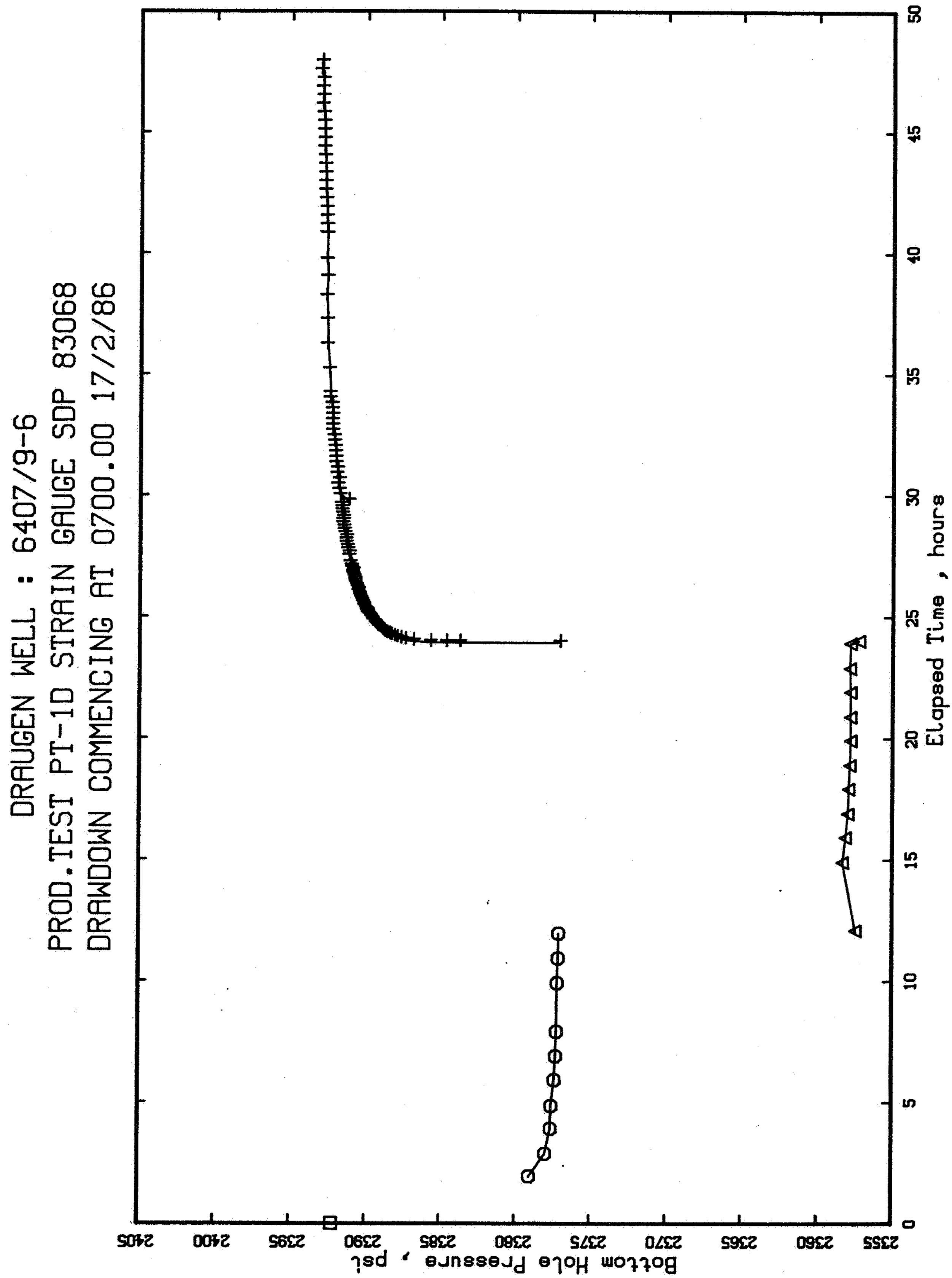
DRAUGEN FIELD

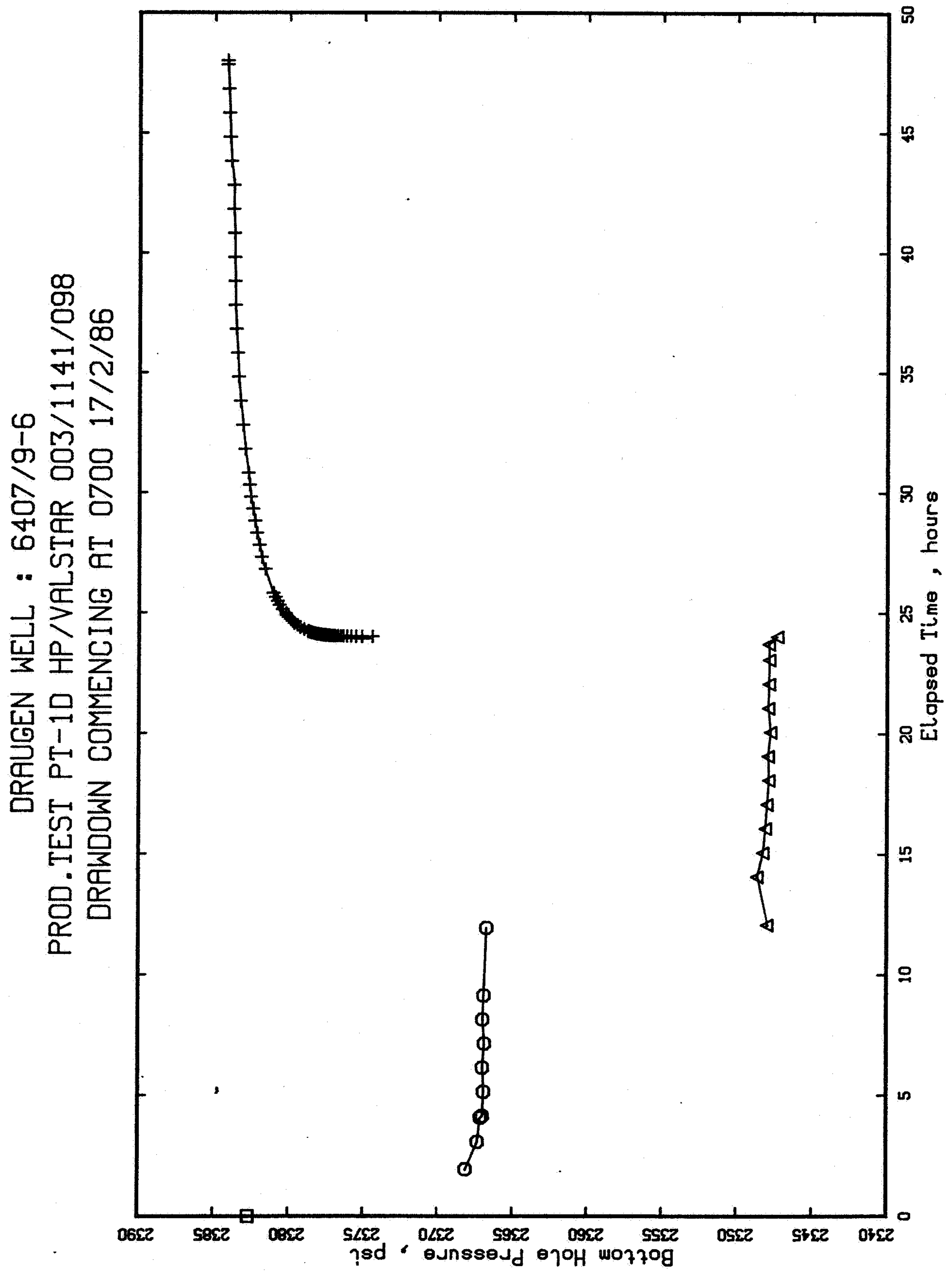
A/S Norske Shell

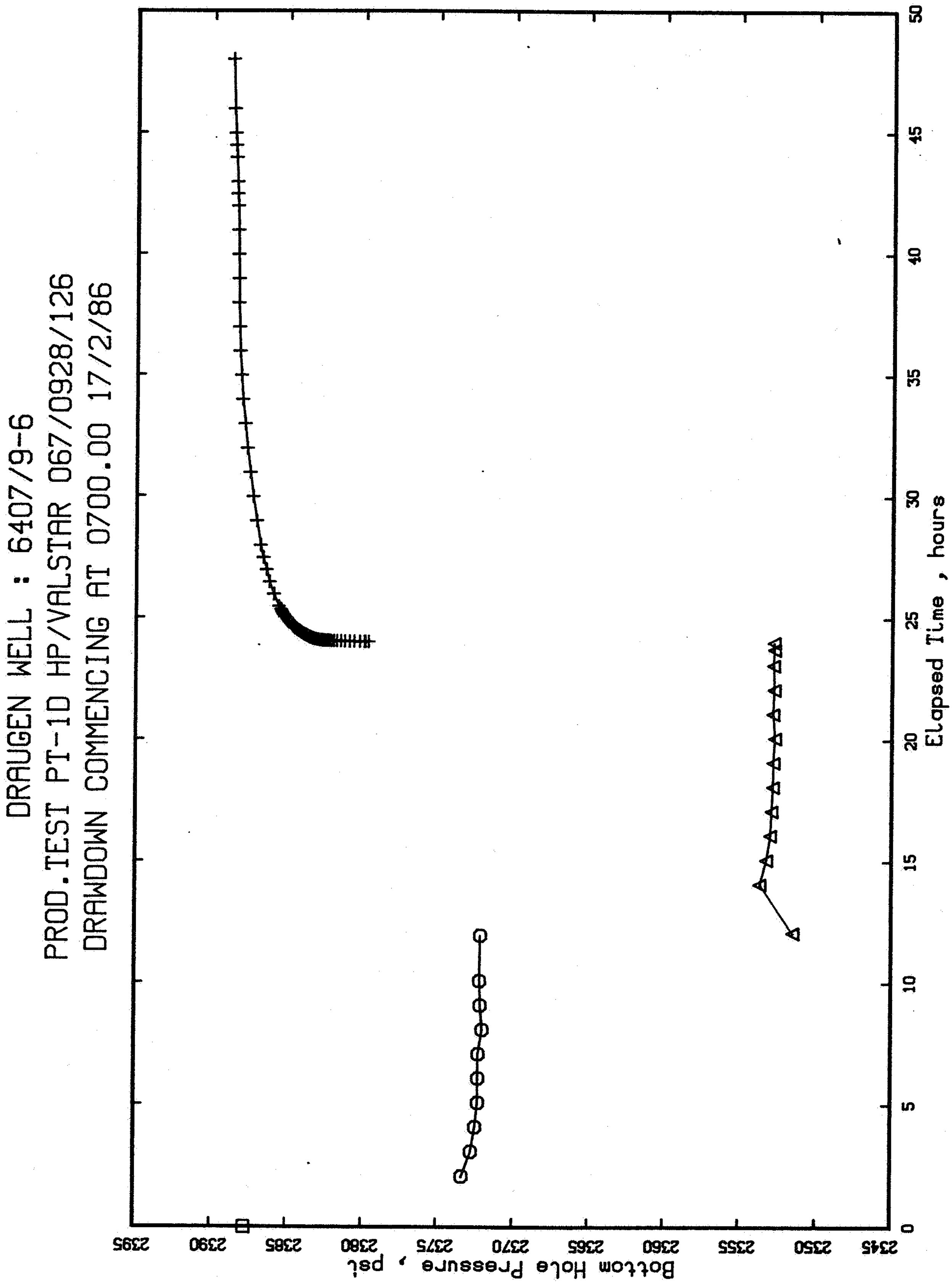


DRAUGEN FIELD

A/S Norske Shell


DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D STRAIN GAUGE SDP 83068
DRAWDOWN COMMENCING AT 0700.00 17/2/86
Elapsed Time , hours
0
5
10
15
20
25
30
35
40
45
50
Bottom Hole Pressure , psi
2355
2360
2365
2370
2375
2380
2385
2390
2395
2400
2405


DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D HP/VALSTAR 003/1141/098
DRAWDOWN COMMENCING AT 0700 17/2/86
Bottom Hole Pressure , psi
2390
2385
2380
2375
2370
2365
2360
2355
2350
2345
2340
Elapsed Time , hours
0
5
10
15
20
25
30
35
40
45
50


DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D HP/VALSTAR 067/0928/126
DRAWDOWN COMMENCING AT 0700.00 17/2/86
Elapsed Time , hours
0
5
10
15
20
25
30
35
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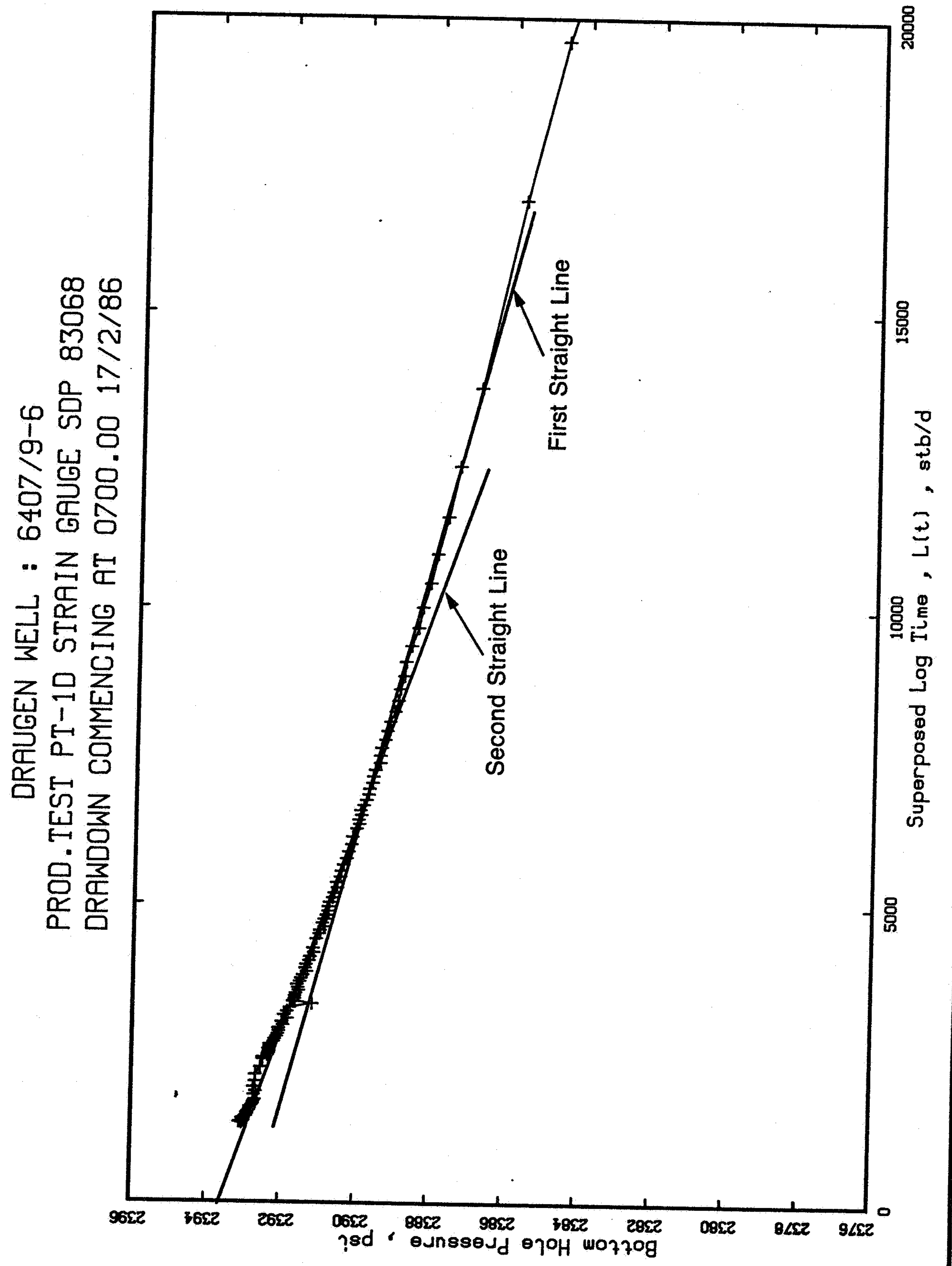
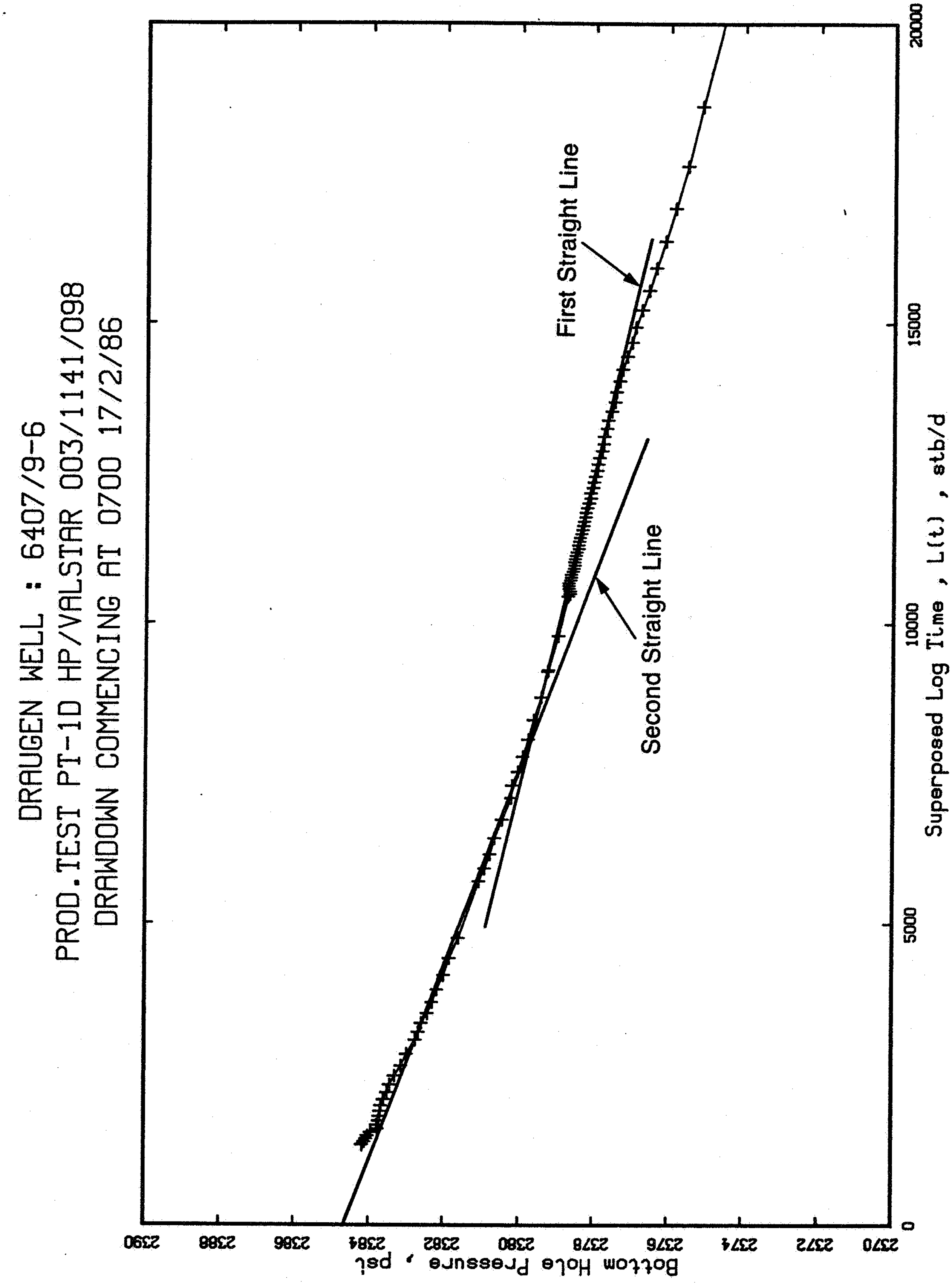
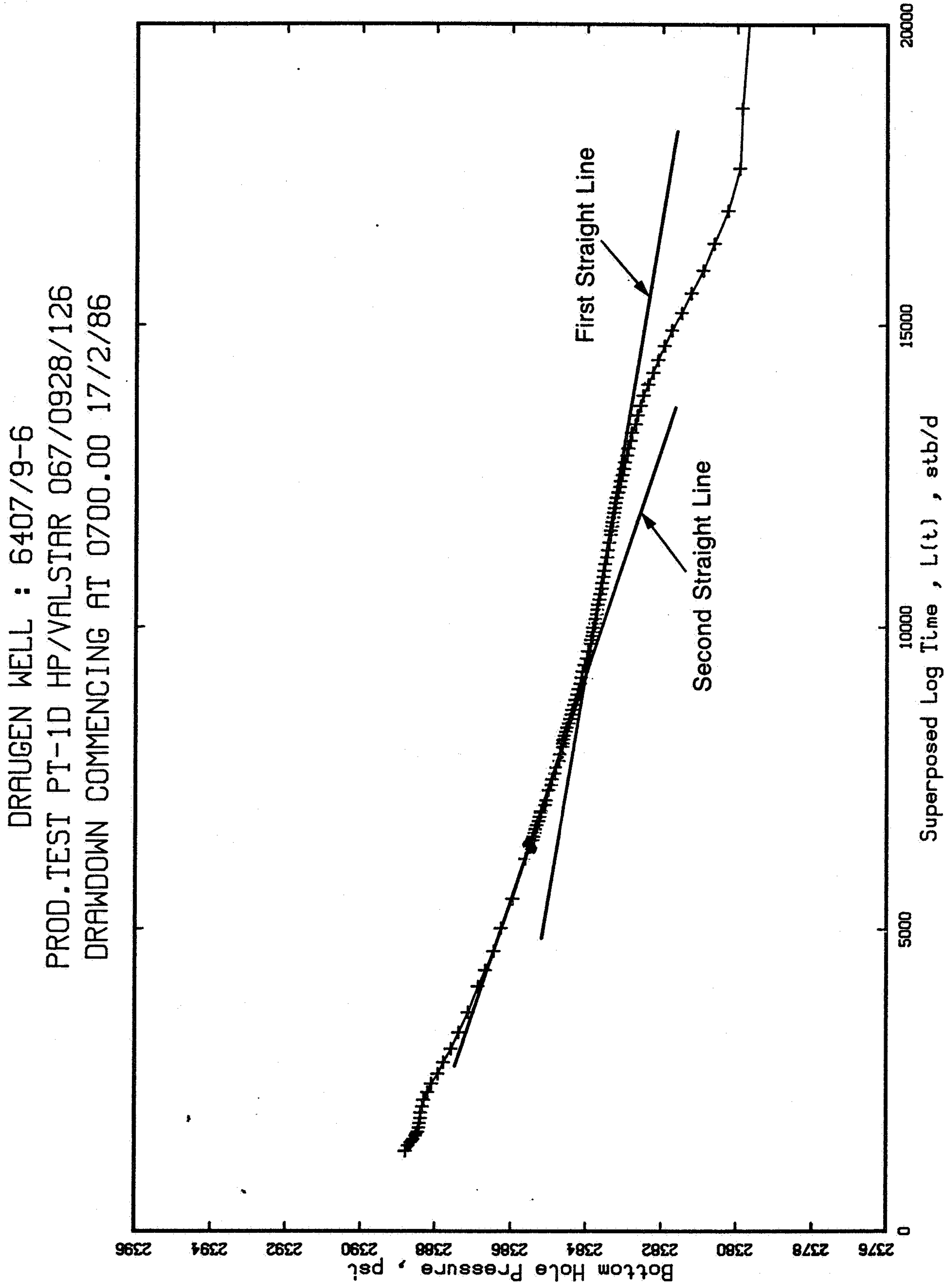
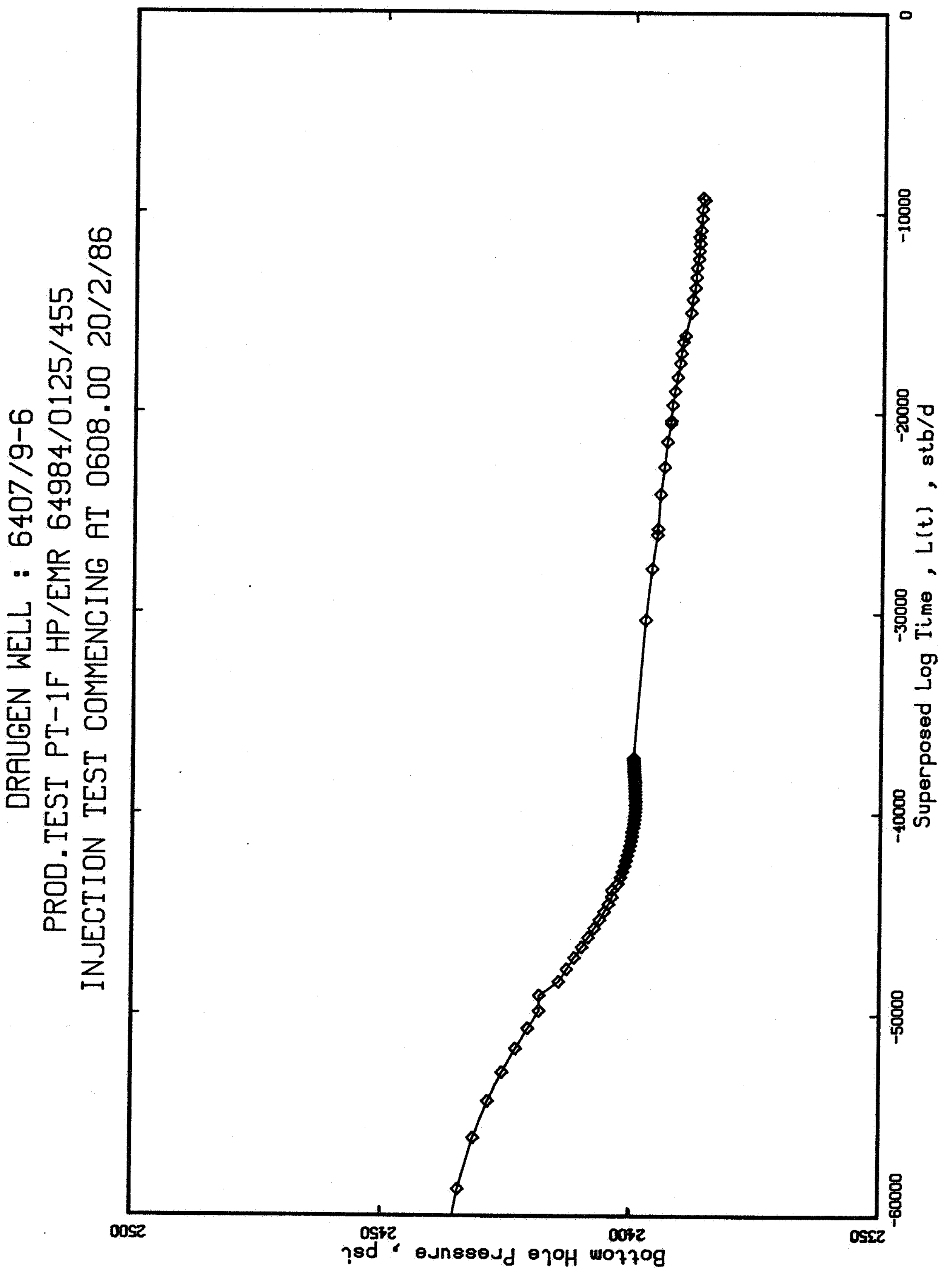
2380
2385
2390
2395

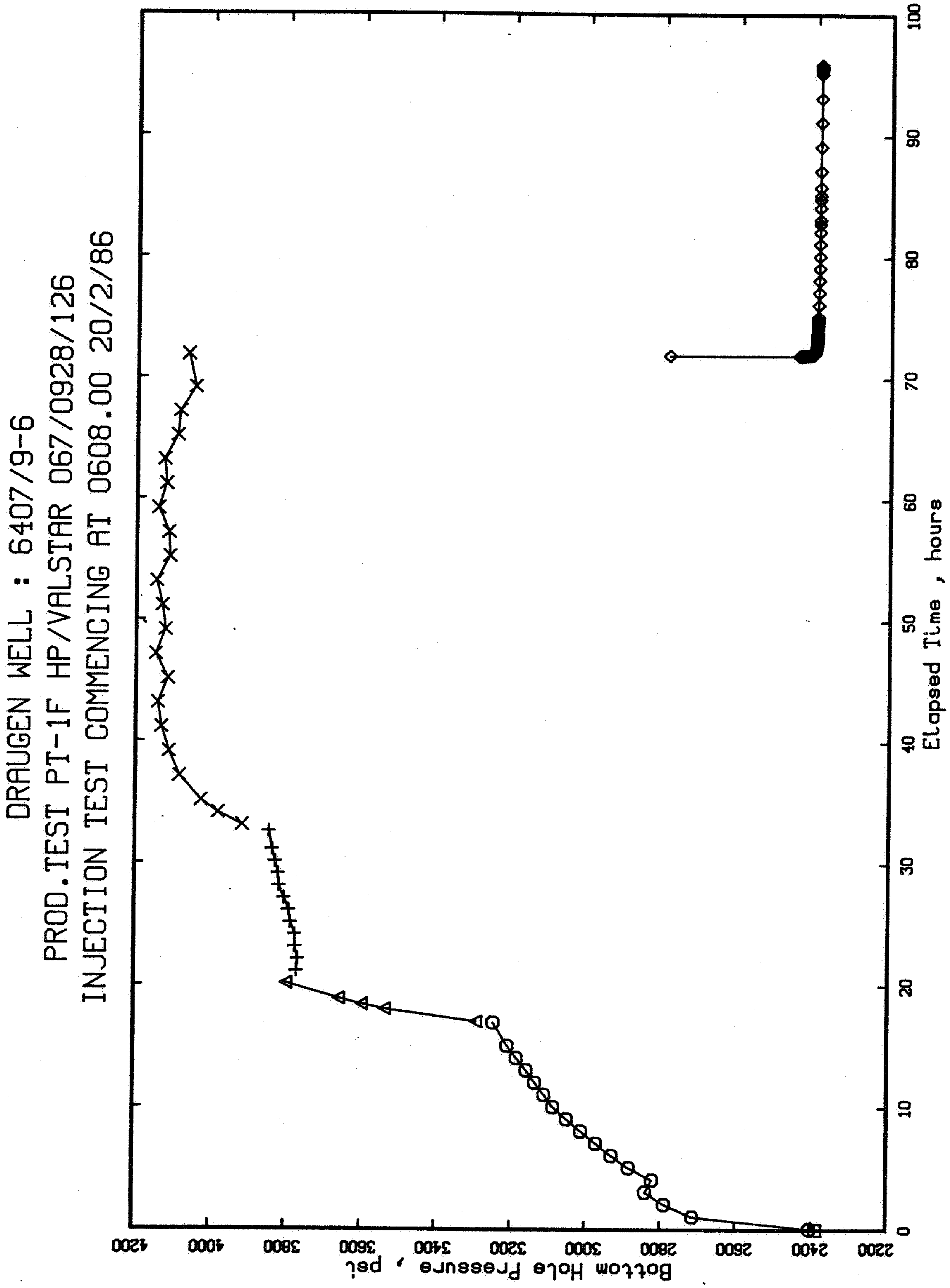

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D STRAIN GAUGE SDP 83068
DRAWDOWN COMMENCING AT 0700.00 17/2/86
First Straight Line
Second Straight Line
Bottom Hole Pressure , psi
2376
2378
2380
2382
2384
2386
2388
2390
2392
2394
2396
Superposed Log Time , L(t) , stb/d
0
5000
10000
15000
20000

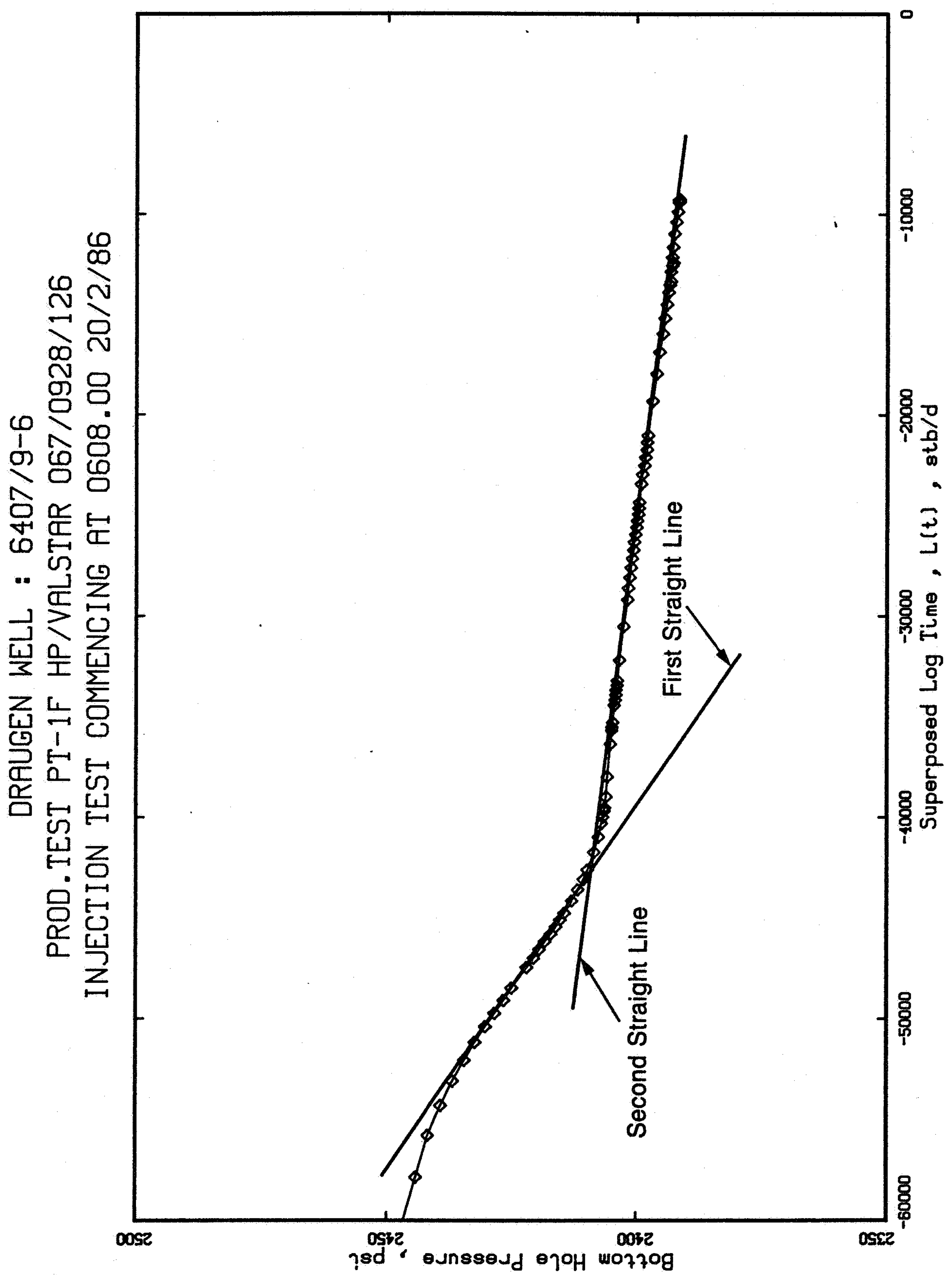

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D HP/VALSTAR 003/1141/098
DRAWDOWN COMMENCING AT 0700 17/2/86
First Straight Line
Second Straight Line
Superposed Log Time , L(t) , stb/d
0
5000
10000
15000
20000
Bottom Hole Pressure , psi
2370
2372
2374
2376
2378
2380
2382
2384
2386
2388
2390



A/S Norske Shell

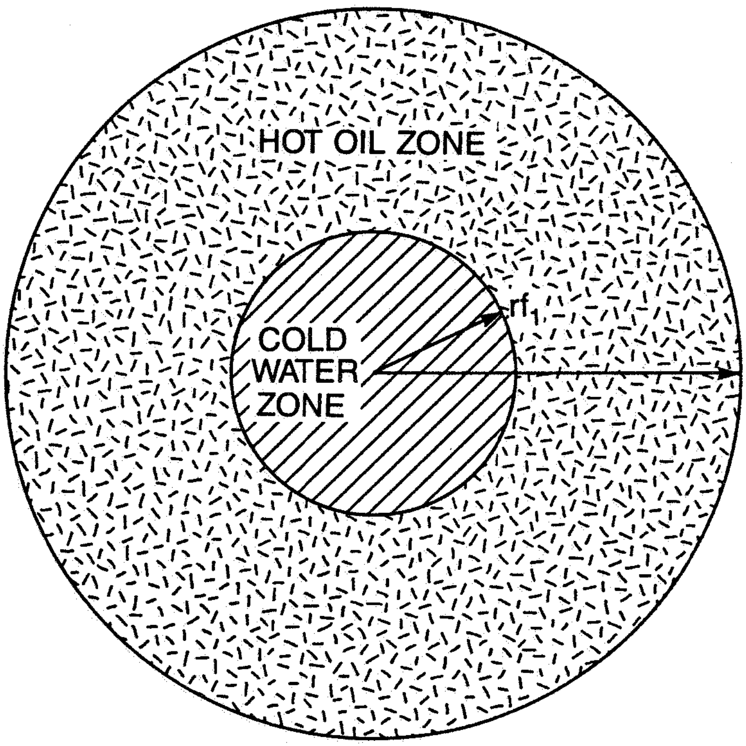

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1F HP/EMR 64984/0125/455
INJECTION TEST COMMENCING AT 0608.00 20/2/86
Superposed Log Time , L(t) , stb/d
0
-10000
-20000
-30000
-40000
-50000
-60000
Bottom Hole Pressure , psi
2350
2400
2450
2500

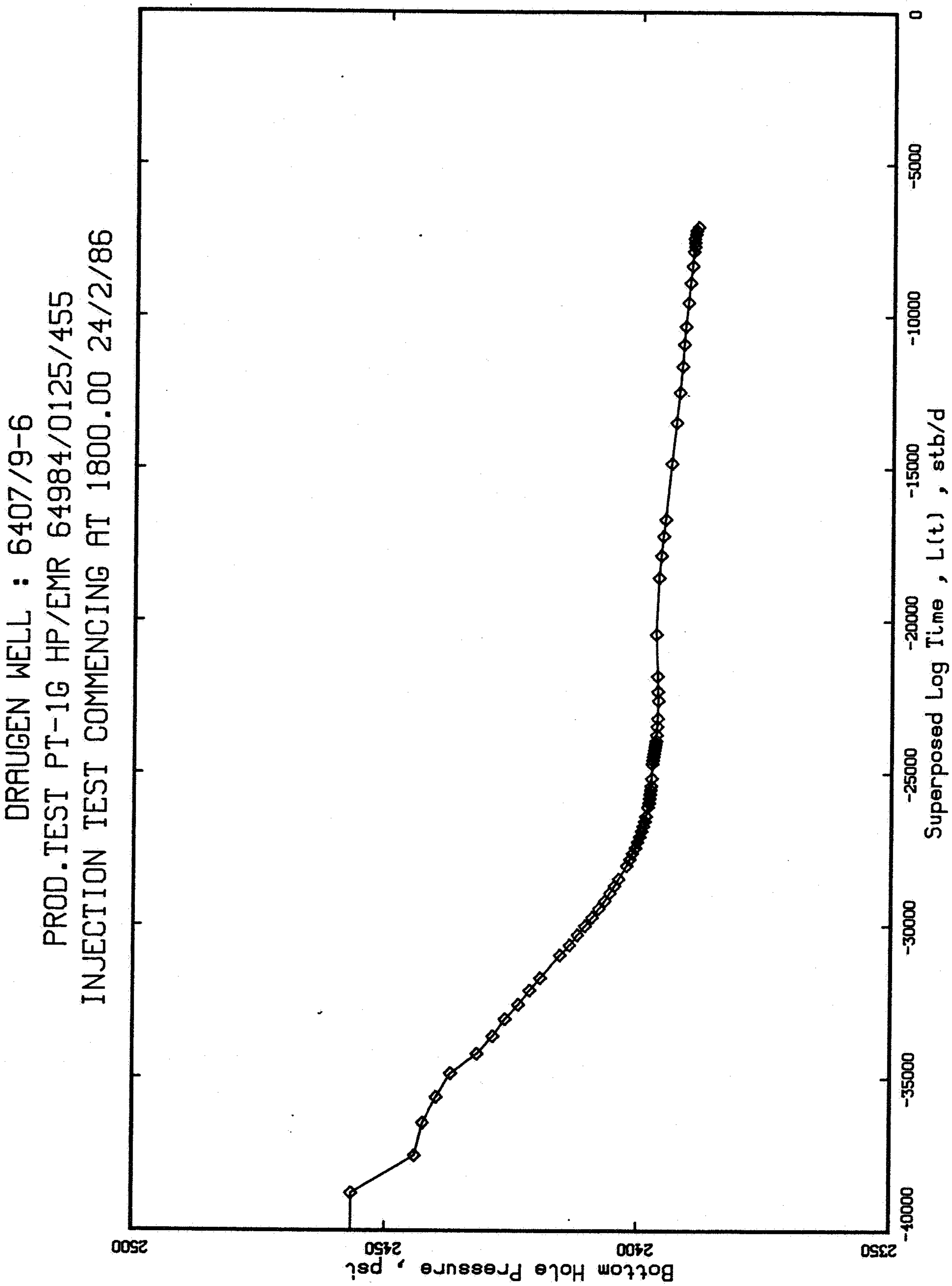

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1F HP/VALSTAR 067/0928/126
INJECTION TEST COMMENCING AT 0608.00 20/2/86
Bottom Hole Pressure , psi
2200
2400
2600
2800
3000
3200
3400
3600
3800
4000
4200
Elapsed Time , hours
0
10
20
30
40
50
60
70
80
90
100


DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1F HP/VALSTAR 067/0928/126
INJECTION TEST COMMENCING AT 0608.00 20/2/86
First Straight Line
Second Straight Line
Bottom Hole Pressure , psi
2500
2450
2400
2350
Superposed Log Time , L(t) , stb/d
0
-10000
-20000
-30000
-40000
-50000
-60000

SCHEMATIC DIAGRAM

OF FLUID DISTRIBUTION AROUND AN INJECTION WELL




DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1G HP/EMR 64984/0125/455
INJECTION TEST COMMENCING AT 1800.00 24/2/86
Superposed Log Time , L(t) , stb/d
Bottom Hole Pressure , psi
0
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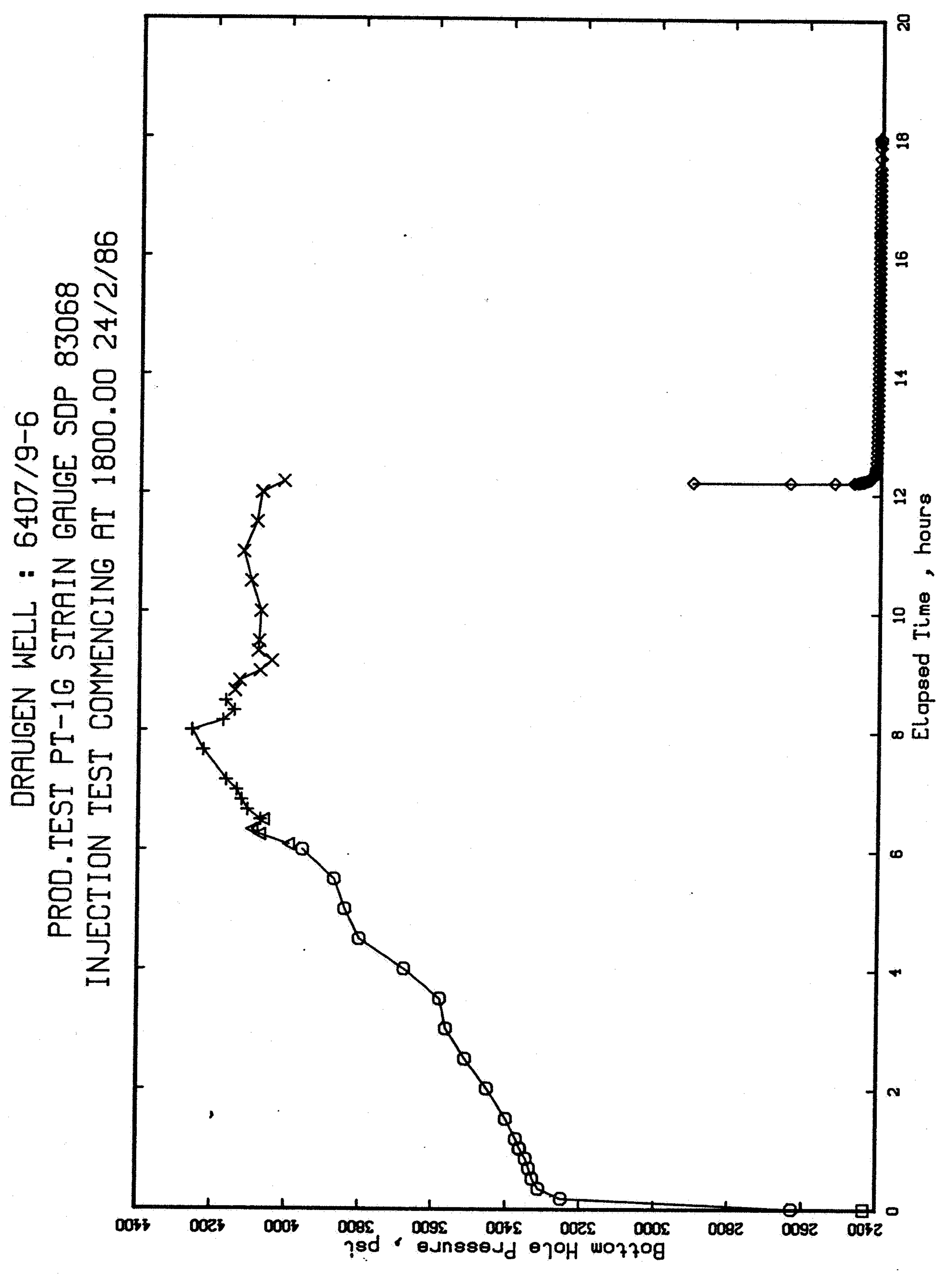
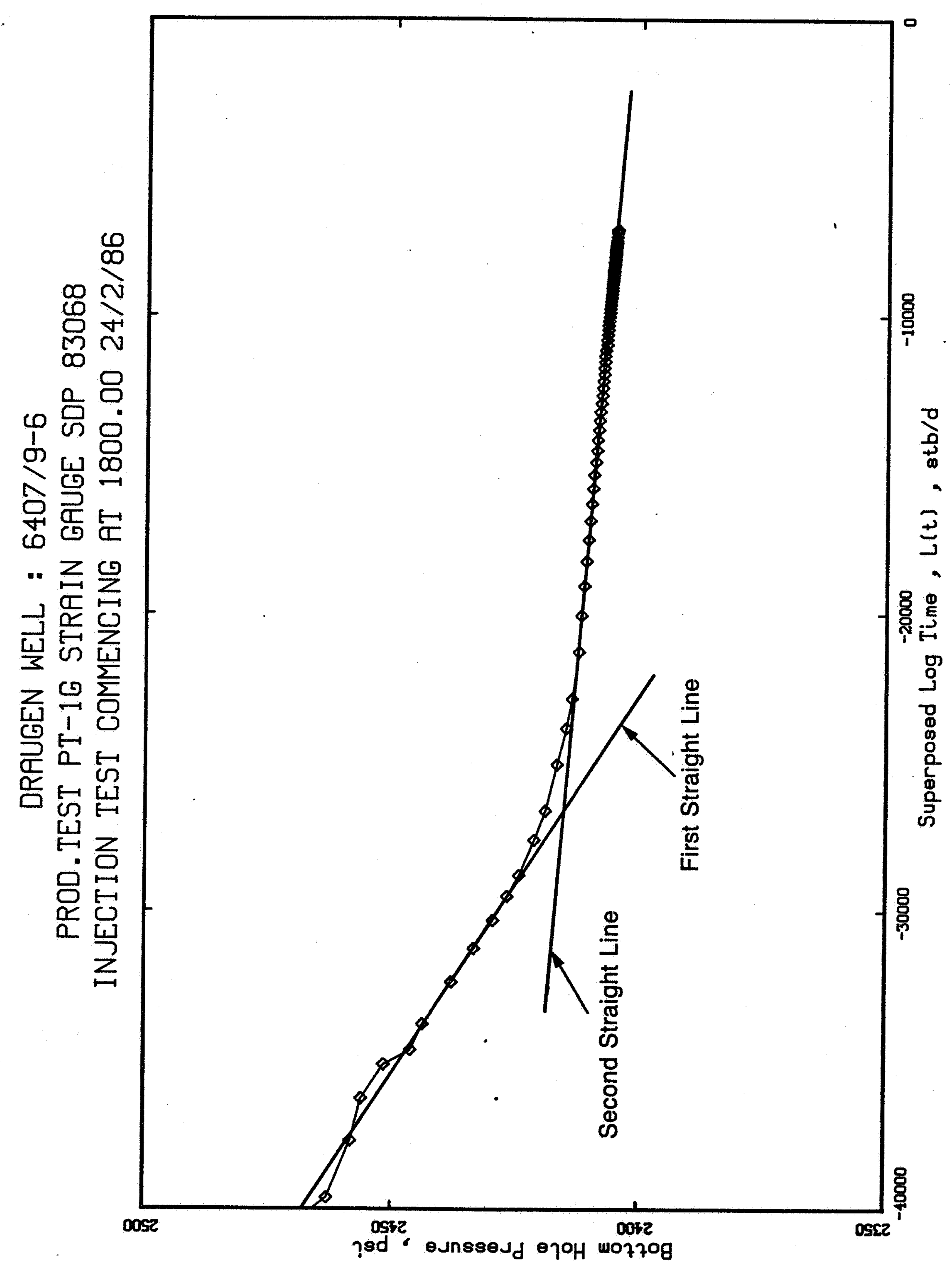
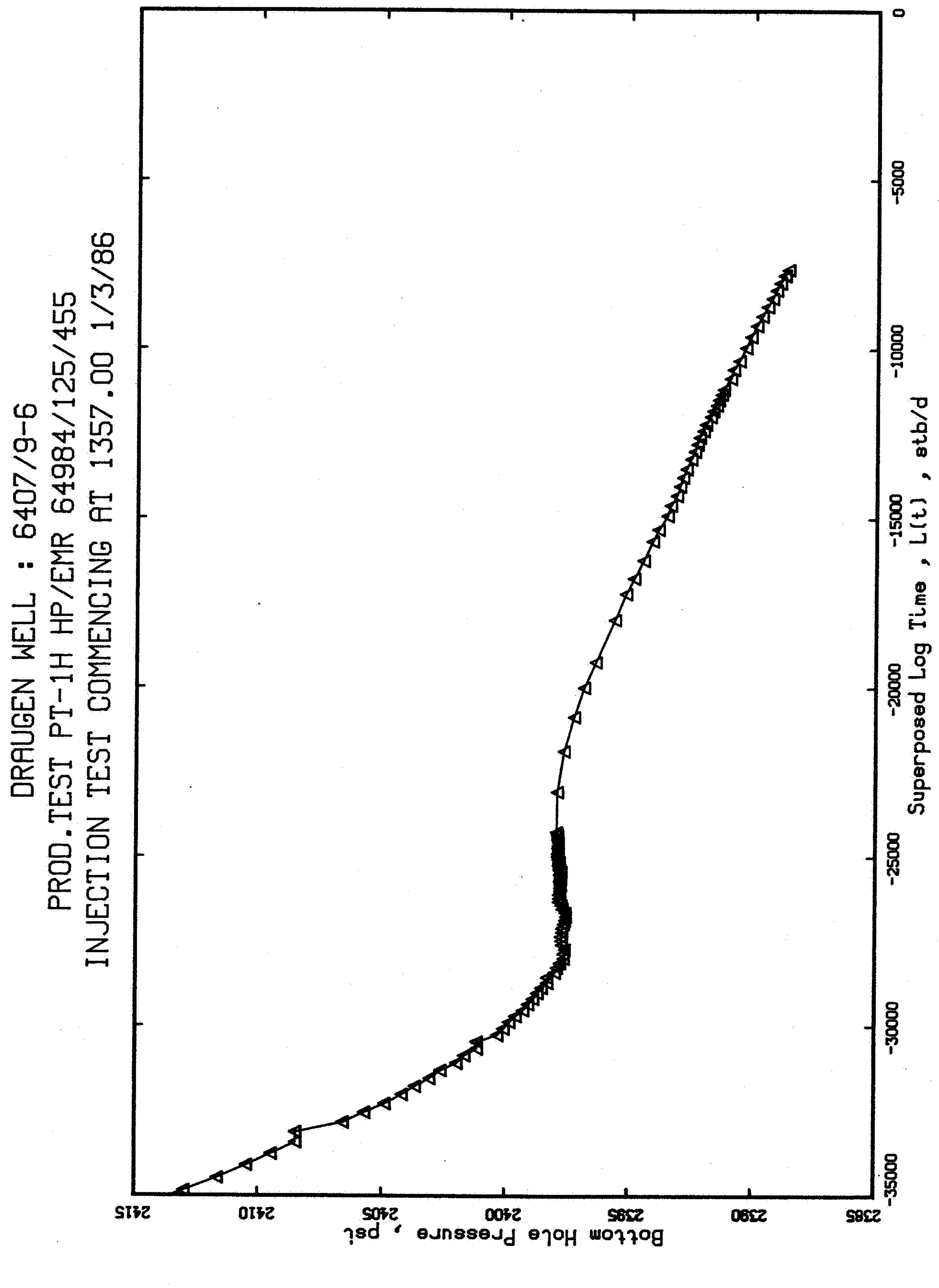
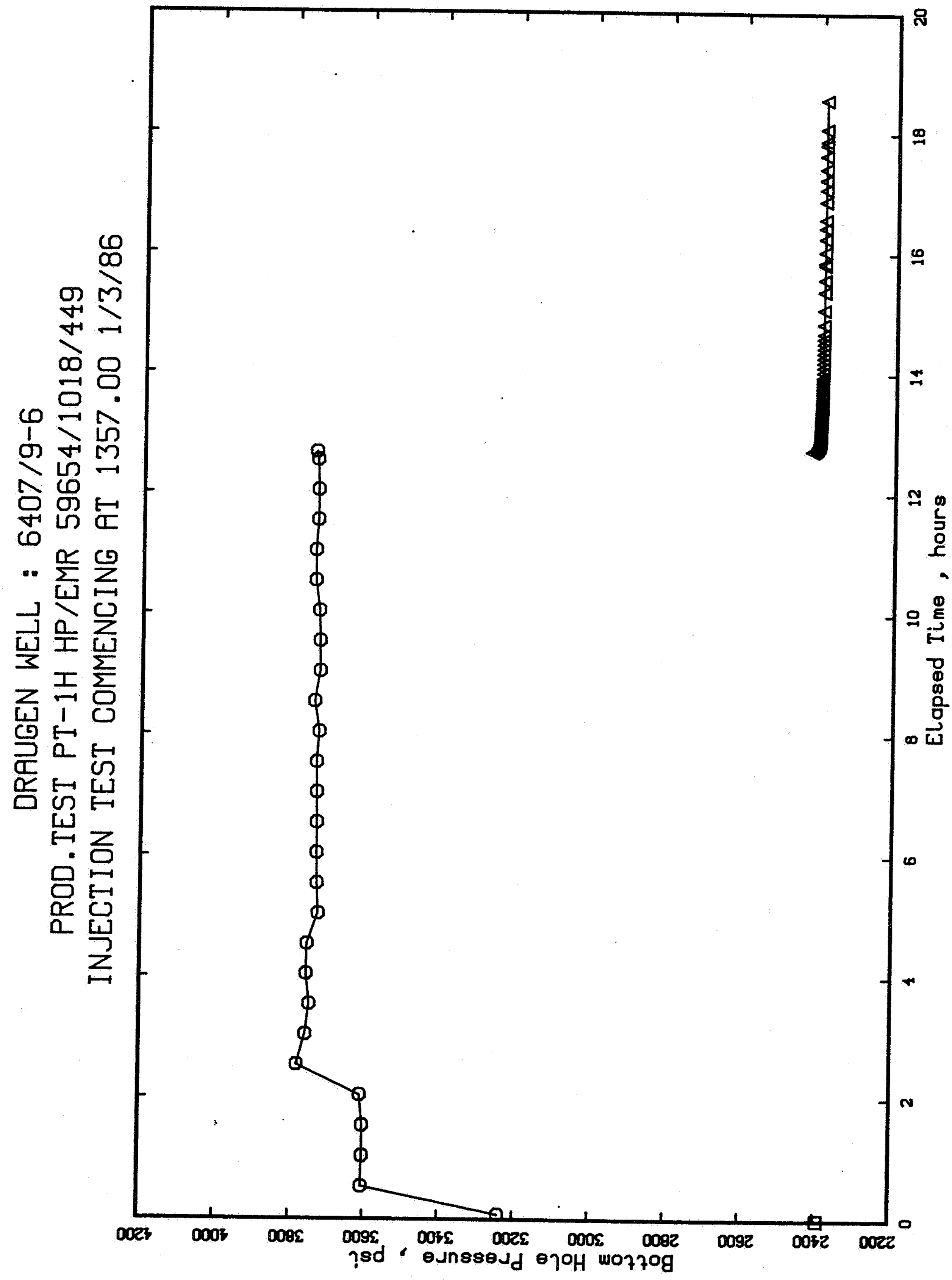
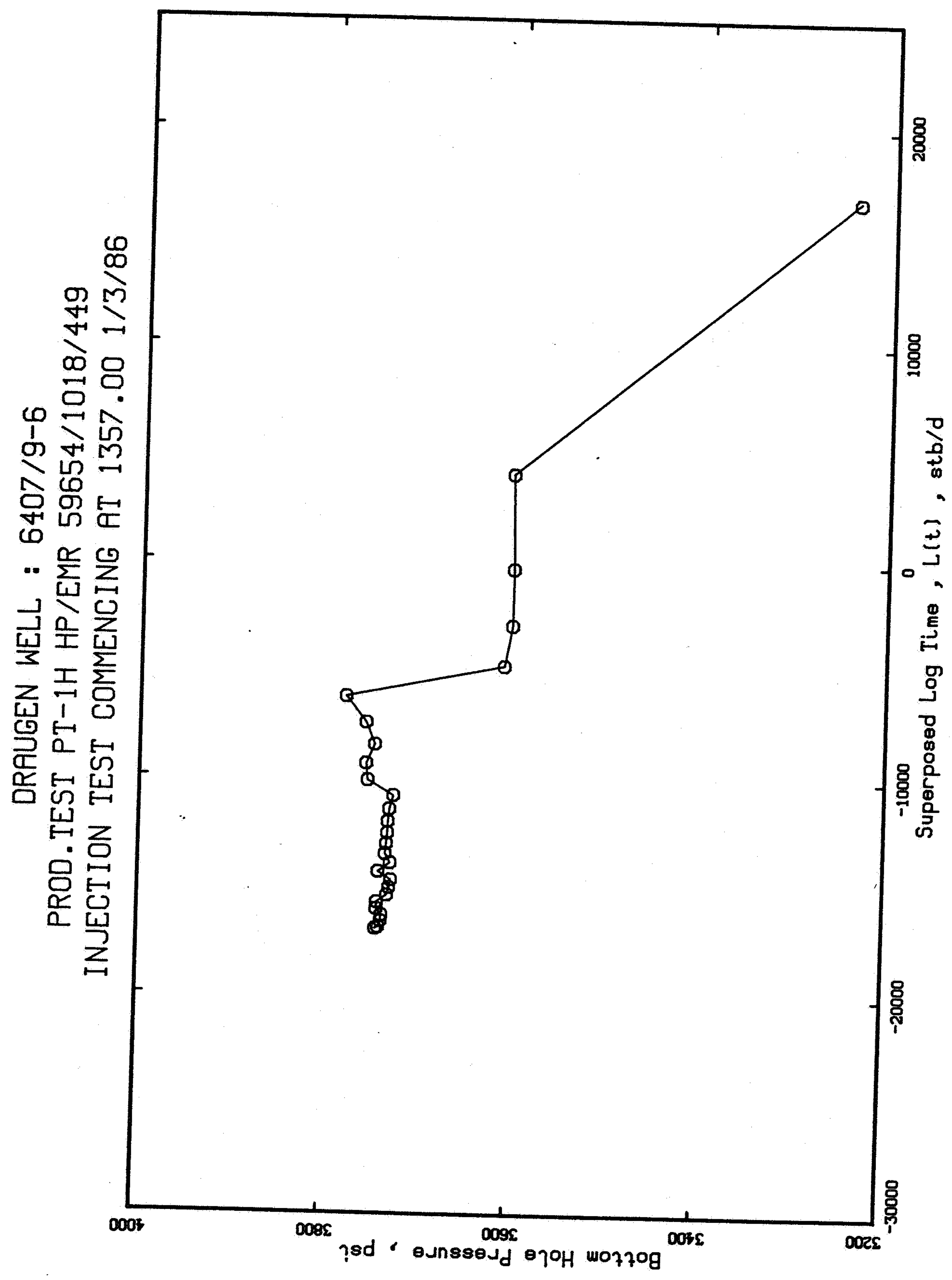
-10000
-15000
-20000
-25000
-30000
-35000
-40000
2350
2400
2450
2500

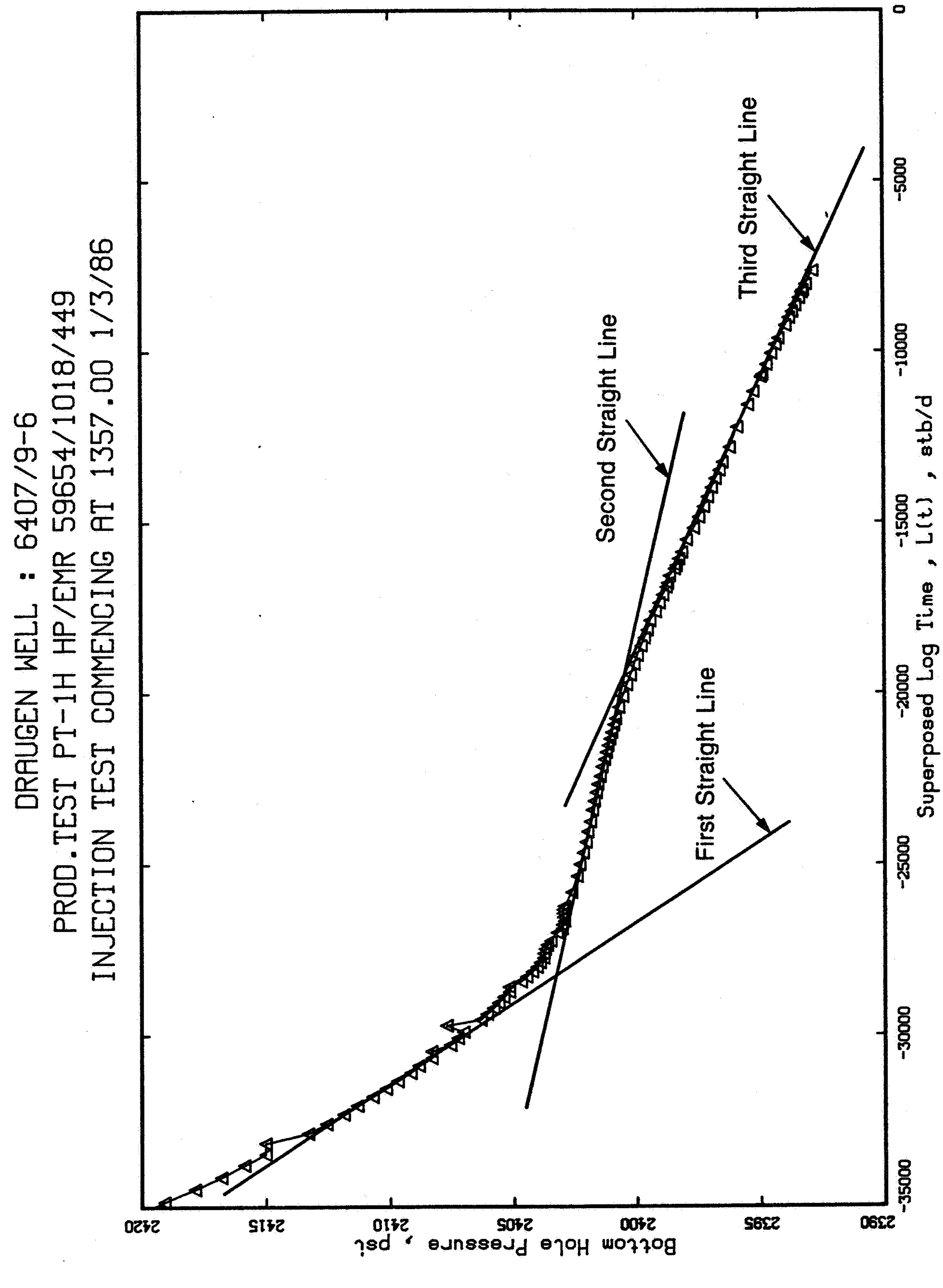

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1G STRAIN GAUGE SDP 83068
INJECTION TEST COMMENCING AT 1800.00 24/2/86
Bottom Hole Pressure , psi
2400
2600
2800
3000
3200
3400
3600
3800
4000
4200
4400
Elapsed Time , hours
0
2
4
6
8
10
12
14
16
18
20


DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1G STRAIN GAUGE SDP 83068
INJECTION TEST COMMENCING AT 1800.00 24/2/86
First Straight Line
Second Straight Line
Superposed Log Time , L(t) , stb/d
0
-10000
-20000
-30000
-40000
Bottom Hole Pressure , psi
2500
2450
2400
2350

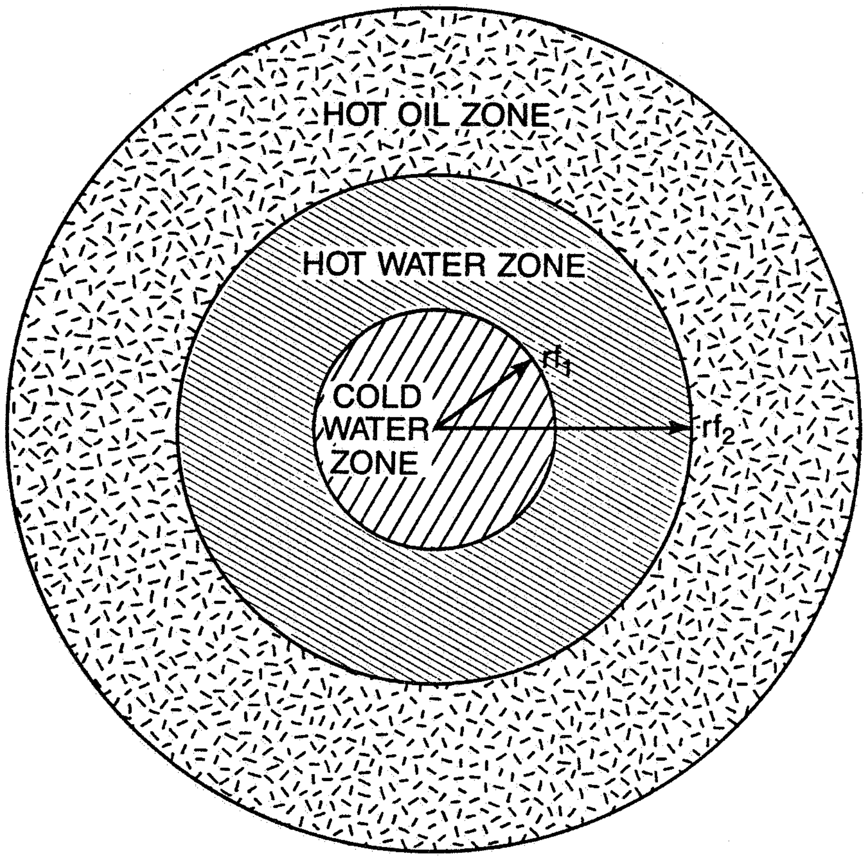

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1H HP/EMR 64984/125/455
INJECTION TEST COMMENCING AT 1357.00 1/3/86
Bottom Hole Pressure , psi
2415
2410
2405
2400
2395
2390
2385
Superposed Log Time , L(t) , stb/d
0
-5000
-10000
-15000
-20000
-25000
-30000
-35000


DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1H HP/EMR 59654/1018/449
INJECTION TEST COMMENCING AT 1357.00 1/3/86
Elapsed Time , hours
0
2
4
6
8
10
12
14
16
18
20
Bottom Hole Pressure , psi
2200
2400
2600
2800
3000
3200
3400
3600
3800
4000
4200


DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1H HP/EMR 59654/1018/449
INJECTION TEST COMMENCING AT 1357.00 1/3/86
Superposed Log Time , L(t) , stb/d
Bottom Hole Pressure , psi
-30000
-20000
-10000
0
10000
20000
3200
3400
3600
3800
4000

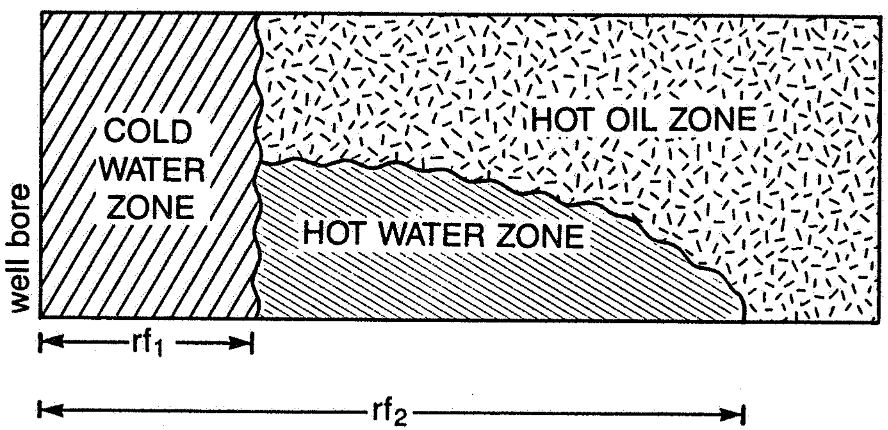

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1H HP/EMR 59654/1018/449
INJECTION TEST COMMENCING AT 1357.00 1/3/86
First Straight Line
Second Straight Line
Third Straight Line
Superposed Log Time , L(t) , stb/d
Bottom Hole Pressure , psi
0
-5000
-10000
-15000
-20000
-25000
-30000
-35000
2390
2395
2400
2405
2410
2415
2420

SCHEMATIC DIAGRAM
OF FLUID DISTRIBUTION AROUND 6407/9-6 DURING PT-1H



SCHEMATIC CROSS-SECTION

VIEW OF FLUID DISTRIBUTION AROUND 6407/9-6 DURING PT-1H (GRAVITY SEGREGATION SCENARIO)



Well:6407/9-6

Gauge Summary Oil Zone Test: PT-1

Perforated Interval 1618-1631 m.ss.

Test	PT-1A	PT-1A	PT-1A	PT-1D	PT-1D	PT-1D	PT-1E
Gauge Type	VALSTAR	HP/VALSTAR	HP/VALSTAR	HP/VALSTAR	HP/VALSTAR	SPD GAUGE	HP/EMR
Serial No.	067/537/163	003/1141/1098	066/784/124	003/1141/1098	067/0928/126	SG 83068	64984/0125/58455
Gauge Depth (m.ss.)	1598	1598	1598	1622.2	1626.9	1629.5	1612.8
No of Data points	7200	7200	7200	7050	7050		300
Scan Interval/Duration	60S/60 hrs	60S/60hrs	120S/60 hrs			5S	.02hr/6hrs
Date/time on	5-2/1500	5-2/1500	5-2/1500	17-2/0200	17-2/0200	17-2/0100	19-2/1056
Date/time off	8-2/0300	8-2/0300	8-2/0300	20-2/1000	20-2/100		19-2/1651
Performance	Bad	Good	Failed	Good	Good	Good	
Comments	Excessive Pressure fluctuations		No Data Reported				

Well:6407/9-6

Gauge Summary Oil Zone Test: PT-1

Perforated Interval 1618-1631 m.ss.

Test	PT-1E	PT-1F	PT-1F	PT-1F	PT-1G
Gauge Type	HP/EMR	HP/EMR	HP/Valstar	SDP Strain Gauge	HP/EMR
Serial No.	64984/0125/58455	64984/0125/455	067/098/126	SG 83068	64984/0125/455
Gauge Depth (m.ss.)	1612.8	1620	1625	1628.3	1620.76
No of Data points	263	1846	7830		1250
Scan Interval/Duration	.02hrs/5.25 hrs			10 S	
Date/time on	19-2/1716	20-2/0300	20-2/300	20-2/0224	24-2/1500
Date/time off	19-2/2235	24-2/0800	24-2/0800	25-2/0818	25-2/1200
Performance		Failed	Good	Failed	Failed
Comments		Increasing Pressure During Falloff		Ran out of memory	Increasing Pressure During Falloff

Well:6407/9-6

Gauge Summary Oil Zone Test: PT-1

Perforated Interval 1618-1631 m.ss.

Test	PT-1H	PT-1H	PT-1H	PT-1G	PT-1G
Gauge Type	HP/EMR	HP/EMR	GRC	HP/EMR	Strain Gauge
Serial No.	64984/125/455	59654/1018/449	59853/58893	63349/1165/935	SG 83068
Gauge Depth (m.ss.)	1620.63	1623.97	1626.16	1622.69	1626.76
No of Data points	1200	1200	1200	1250	
Scan Interval/Duration					10 S
Date/time on	1-3/1230	1-3/1230	1-3/1230	25/2/1500	24-2/1411
Date/time off	2-3/0830	2-3/0830	2-3/0830	25-2/1200	25-2/1440
Performance	Failed	Good	Failed	Failed	Good
Comments	Increasing Pressure During Fall off		No Data Recorded	No Data Reported	

Well 6407/9-6
PT-1 Samples Collected

No.	Test	Time	Date	Fluid	S.G.	Sampling Point	Container (Description /Volume)	Serial Number	Remarks
1	PT-1D	0015 0035	17.2.86	Gas	0.812 (Air=1)	Separator	PVT-gas	1965A	
2	PT-1D	0030 0040	17.2.86	Oil	0.812	"	PVT-oil 675 c.c.	811507	
3	PT-1D	0113 0127	17.2.86	Gas	0.810 (Air=1)			2106A	
4	PT-1D	0113 0137	17.2.86	Oil	0.810	"	PVT-oil 675 c.c.	811090	
5	PT-1D	0154 0210	17.2.86	Oil	0.810	"	PVT-oil 670 c.c.	811976	
6	PT-1D	0154 0210	17.2.86	Gas	0.810 (Air=1)	"	PVT-gas	1012	
7	PT-1D	0610 0615	17.2.86	Oil			Bbl-drum 45 gal		3 Bulk samples taken

Well 6407/9-6
PT-1 Samples Collected

No.	Test	Time	Date	Fluid	S.G.	Sampling Point	Container (Description /Volume)	Serial Number	Shipping Conditions
8	PT-1E	1538	19-2-86	BHS	-	1633.5 m BDF	"	311501	425psig at $58^{O}F$
9	PT-1E	1538	19-2-86	BHS	-	1036 m BDF	600 c.c.	811502	475psig at $65^{O}F$
10	PT-1E	1538	19-2-86	BHS	-	1631.1 m BDF	"	811081	400 psig at $68\ ^{O}$
11	PT-1E	2122	19-2-86	BHS	-	1631.1 m BDF	"	811501	400 psig at $56^{O}F$
12	PT-1E	2122	19-2-86	BHS	-	1633.5 m BDF	"	811079	400 psig at $56^{O}F$

WELL 640796 SURVEY DATE 290186

HP GAUGE DATA

RESERVOIR DATA:-

FLUID CONTACTS (M-TVSS)
DATUM DEPTH = 1630.0
GOC = .0
OWC = 1637.0

FLUID GRADIENTS (PSI/M)
GAS = .000
OIL = 1.066
WATER = 1.425

GEOLOGICAL DATA:-

FORMATION TOP	DEPTH (M-TVSS)
FROYA FORM	1617.0
HALTENBANK	1636.5

PRESSURE DATA:-

GEOLOGICAL ZONE	DEPTH(M) AHBDF	TVSS	PRESSURE (PSIA) MEASURED	DATUM	MUD(PRE-SETTING)	COMMENT
FR	1643.5	1618.5	2383.4	2395.7	2879.0	
FR	1646.0	1621.0	2385.8	2395.4	2883.0	
FR	1648.0	1623.0	2387.6	2395.1	2886.0	
FR	1650.5	1625.5	2391.5	2396.3	2891.0	
FR	1652.5	1627.5	2392.4	2395.1	2894.0	
FR	1655.0	1630.0	2394.9	2394.9	2898.0	
FR	1657.0	1632.0	2397.0	2394.9	2902.0	
HA	1664.5	1639.5	2405.8	2394.8	2915.0	
HA	1666.0	1641.0	2407.9	2394.7	2917.0	
HA	1679.0	1654.0	2426.3	2394.6	2940.0	
HA	1717.0	1692.0	2478.4	2392.6	3003.0	
HA	1719.0	1694.0	2480.5	2391.8	3006.0	

Table 8.4.2

Well: 6407/9-6

Production Test Summary

Test Period/Gauge	Gauge Depth m.ss.	Extrapolated Average Reservoir Pressure at Datum (psia)	koh/kwh D.ft	Average PI/II	Average Skin
PT-1D					
SDP Strain Gauge SG83058	1629.5	2393	276	142 b/d/psi	8.1
HP/Valstar 003/1141/098	1622.2	2393	296	130 b/d/psi	10.0
HP/Valstar 067/0928/126	1626.9	2393	315	140 b/d/psi	10.9
PT-1F					
HP/Valstar 067/0928/126	1625.4	2394	64	8 bwpd/psi	38.0
PT-1G					
SDP Strain Gauge SG83068	1626.8	2406	45	7 bwpd/psi	29.6
PT-1H					
HP/EMR 59654/1018/449	1624	2396	88	10 bwpd/psi	43.0

Well: 6407/9-6
PT-1: Sequence of events

Flow Period	Start Time	End Time	Duration Hrs.	Cum Prod.(bbls)	Final Oil Rate (B/d)	Comments
PT-1A	6-2-86					
	1435 Perforated intervals 1618 - 1631 m.ss. with a 347 psi drawdown					
1Dd	1435	0015	9.7	117	-	Constant rate not maintained for any extended period
2 Dd	0015	0115	1	79.2	459	12/64" Bean
3 Bu	0120	1543				Buildup Survey

Killed well - Pulled String - Gravel Packed - Ran Completion String.

Flow Period	Start Time	End Time	Duration Hrs.	Cum Prod.(bbls)	Final Oil Rate (B/d)	Comments
PT-1B	14-2-86					
1Dd	0821	1045	2.4	45.9	173	Clean up period
2Dd	1050	2400	13.2	569	1196	1st and 2nd gravel pack stabilisation period not well defined

0001 Well Shut-in

Acidised with 100 bbls of 15% HCl.

Flow Period	Start Time	End Time	Duration Hrs.	Cum Prod.(bbls)	Final Oil Rate (B/d)	Comments
PT-1C	15-2-86					
1 Dd	1154	0230	14.6	572	1296	Unloaded well on a 20/64"choke
2 Dd	0256	0845	5.8	1281	3065	32/64" "
3 Dd	0916	1230		1959	4295	40/64" "
4 Dd	1300	1345	0.75	2235	5554	50/64" "
5 Dd	1350	1945		3653	5342	48/64" "
6 Dd	2000	2100	1.0	3949	4877	56/64" "
7 Dd	2217	0100		4936	5735	60/64" "
9 Bu	0104 Well Shut-in					

Flow Period	Start Time	End Time	Duration Hrs.	Cum Prod.(bbls)	Final Oil Rate (B/d)	Comments
PT-1D	17-2-86 18-2-86					
1Dd	0715	0853		127	1056	Opened well on a 28/64" adjustable choke
2 Dd	0853	1900		1100	2363	Flowed over a 28/64" fixed choke
3 Dd	1905	0700		3588	4949	Flowed on 44/64" fixed choke. Separator samples taken during flow-period
	18-2-86 19-2-86					
4 Bu	0705	0700				Well shut-in for main buildup test
PT-1E	19-2-86					
1 Dd	1252	1620		-	307	Running in hole with 3 BHS well flowing over a 19/64" choke when samples were taken
2 BU	1621	1759	Well Shut-in for 2nd sampling run			
3 Dd	1800	2200		-	154	Well opened up on a 12/64" choke increased to 17/64" choke. Well flowing over a 17/64" choke when samples were taken.

PF-1F, PT-1G, PT-1H and PT-1J Water injection tests.

Well 6407/9-6

Summary of Separator Data

Date Time	THP/THT psig/°F	OIL RATE Stb/d	GOR Scf/Stb	Psep/Tsep psig/°F	BHP Psia	Comments
6-2-86						PT - 1A
1440	279/44	-	-	-	2326	2" adjustable choke Backsurge
1443	-	-	-	-	2335	Choke decreased to 40/64"
1445	310/44	-	-	-	2349	Decreased adjustable choke to 22/64"
1450	335/44	-	-	-	2353	22/64" Choke
1455	340/44	-	-	-	2355	20/64" Choke
1500	339/44	-	-	-	2357	24/64" Choke
1530	387/44	-	-	-	2357	17/64" Choke, 40.9 bbls returned since perforating
1600	412/44	-	-	-	2358	21/64" Choke
1630	422/44	-	-	-	2356	25/64" Choke
1745	434/44	-	-	-	2357	21/64" Choke
1830	437/44	-	-	-	2358	21/64" Choke
2130	494/44	-	-	-	2355	27/64" Choke, CO_2 = 0.1% Approx. rate 379 b/d
2245	545/44	-	-	-	2357	12/64" choke, 0% BSW CO_2=0.1%
7-2-86						
0015	544/44	389	208	30/36	2357	12/64" Choke
0030	544/44	473	173	30/39	2357	12/64" Choke
0045	543/44	470	177	30/38	2357	12/64" Choke
0115	544/44	459	181	30/38	2357	12/64" Choke
0200	129/44	-	-	-	2358	Shut-in
11-2-86						PT - 1B
0817	295/-	-	-	-	-	Well opened on 16/64" adjustable choke
0820	270/-	240	-	-	-	20/64" Choke
0825	160/-	720	-	-	-	20/64" Choke
0830	150/43	720	-	-	-	20/64" Choke
0840	126/43	576	-	-	-	20/64" Choke
0900	97/43	504	-	-	-	20/64" Choke. BSW 100% Diesel
0930	80/43	384	-	-	-	20/64" Choke. BSW 100% Diesel
1100	162/43	384	-	-	-	26/64" Choke. Water observed on surface 10%
1120	170/43	-	-	-	-	28/64" Choke. H_2O 57%
1200	120/43	720	-	-	-	28/64" Choke. CO_2 = 1% H_2S = 0 ppm
1215	132/43	950	-	-	-	32/64" Choke. H_2O = 27%
1915	137/43	1039	183	42/36	-	36/64" Choke. H_2O = 1%

Date Time	THP/THT psig/^{o}F	OIL RATE Stb/d	GOR Scf/Stb	Psep/Tsep psig/^{o}F	BHP Psia	Comments
						Emulsion 3%
1930	122/43	1085	179	40/44		40/64" Choke. H_2O 1%. Emulsion 3%
2400	105/44	1196	267	96/37		44/64" Choke
15-2-86						PT - 1C
1154	-	-	-	-	-	Opened Well on 20/64" Choke
1200	334/43	648	-	-	-	20/64" Choke
1205	333/47	642	-	-	-	20/64" Choke
1300	155/44	691	-	-	-	20/64" Choke pH=6, 100% Diesel
1400	171/46	461	-	-	-	20/64" Choke. pH=2
1500	224/45	604	-	-	-	20/64" Choke 100% acid returned
1600	251/45	586	-	-	-	20/64" Choke Trace Oil & Acid
1700	298/45	768	-	-	-	20/64" Choke BSW 1.6% water, 60% oil 38.4% acid/gel
1800	351/46	858	-	-	-	20/64" Choke BSW 6% acid/gel 24% water, 70% oil
0300	499/51	1920	-	-	-	32/64" Choke BSW 7% acid/gel, 0.1% water, 84.9% oil
0500	481/61	3072	-	-	-	32/64" Choke CO_2 = 1%, H_2S = 0 ppm BSW 9% acid gel, 91% oil
0545	485/-	4985	99	146/73	-	32/64" Choke
0700	490/64	2875	159	185/95	-	32/64" Choke
0800	492/65	3087	133	180/98	-	32/64" Choke
0930	455/69	4282	125	140/61	-	40/64" Choke
1245	431/-	4514	112	140/56	-	46/64" Choke
1300	400/72	5259	-	152/58	-	50/64" Choke
1400	419/71	5432	127	181/81	-	48/64" Choke
1500	404/73	5589	122	166/73	-	48/64" Choke
1600	405/70	5689	111	180/71	-	48/64" Choke, BSW = 2% CO_2=0.6%, H_2S = 0
2015	405/-	6140	109	180/70	-	56/64" Choke
2030	405/70	6409	103	180/70	-	56/64" Choke
2230	394/72	6423	-	313/63	-	60/64" Choke, BSW = 2% BSW = 1.7%
16-2-86						
0100	394/62	5735	68	315/64	-	60/64" Choke, BSW = 2.1%

Date Time	THP/THT psig/^{o}F	OIL RATE Stb/d	GOR Scf/Stb	Psep/Tsep psig/^{o}F	BHP Psia	Comments
17-2-86						PT - 1D
0715	554/46	1680	-	-	2373	Opened Well on 28/64" Choke
0745	538/49	2368	-	-	2367	32/64" Choke
0900	545/52	1517	-	-	2368	28/64" Choke
1000	545/53	2150	-	-	2367	28/64" Choke
1215	547/-	2249	153	70/42	2367	28/64" Choke
1300	548/43	2368	145	70/28	2367	28/64" Choke
1900	548/56	2363	144	67/41	2367	28/64" Choke
1930	424/65	5529	106	181/57	2345	46/64" Choke
2100	457/66	4991	112	196/81	2349	44/64" Choke
2200	455/66	4946	113	194/78	2348	44/64" Choke
2400	485/68	4857	115	192/78	2348	44/64" Choke. Commenced taking separator samples Six PVT samples taken, 3 bulk samples
18-1-86						
0700	459/65	4949	114	195/75	2348	44/64" choke
Well Shut In						

Date Time	THP/THT psig/^{o}F	OIL RATE Stb/d	GOR Scf/Stb	Psep/Tsep psig/^{o}F	BHP Psia	Comments
19-2-86						PT - 1E
1252	764/-	-	-	-	-	Opened well on 16/64" positive choke
1300	559/43	-	-	-	-	12/64" Choke
1415	522/-	144	-	-	2362	16/64" Choke
1500	572/43	298	-	-	2361	19/64" Choke
1538	572/-	374	-	-	2361	19/64" Choke. 3 BHS taken
Well Shut In						
1800	-	-	-	-	-	Opened well on 12/64" positive choke
1805	571	374	-	-	-	12/64" Choke
1845	571	374	-	-	2362	16/64" Choke
2100	572	125	-	-	2362	17/64" Choke
2130	571	355	-	-	2360	17/64" Choke 3 BHS taken

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D
DRAWDOWN COMMENCING AT 0853.00 17/2/86

WELL AND RESERVOIR DATA

Formation net thickness	:	50.00 ft
Reservoir fluid	:	oil
Perforated interval	:	5308.0- 5351.0 ft
Wellbore radius	:	.510 ft
Absolute porosity	:	.300

PVT PROPERTIES

FORMATION VOL FACTOR BO bbl/bbl	VISC AT RESV CONDITIONS cP	TOTAL COMPRES SIBILITY ct psi-1
1.2000	.670	.4400-004

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D STRAIN GAUGE SDP 83068
DRAWDOWN COMMENCING AT 0853.00 17/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
1	0	.0	.00000	.00000	2392.2
2	1Dd	2300.0	1.93472	1.93472	2379.0
3	1Dd	2300.0	2.86806	2.86806	2378.0
4	1Dd	2300.0	3.89028	3.89028	2377.6
4	1Dd	2300.0	4.82361	4.82361	2377.6
5	1Dd	2300.0	5.89028	5.89028	2377.4
6	1Dd	2300.0	6.86806	6.86806	2377.3
7	1Dd	2300.0	7.88472	7.88472	2377.2
8	1Dd	2300.0	9.88611	9.88611	2377.2
9	1Dd	2300.0	10.90833	10.90833	2377.1
10	1Dd	2300.0	11.93056	11.93056	2377.1
11	1Dd	2300.0	12.06806	.13750	2357.5
12	2Dd	4900.0	14.88750	2.95694	2358.3
13	2Dd	4900.0	15.90972	3.97917	2358.1
14	2Dd	4900.0	16.88750	4.95694	2358.0
15	2Dd	4900.0	17.90972	5.97917	2357.9
16	2Dd	4900.0	18.88750	6.95694	2357.9
17	2Dd	4900.0	19.90972	7.97917	2357.8
18	2Dd	4900.0	20.88750	8.95694	2357.8
19	2Dd	4900.0	21.90972	9.97917	2357.8
20	2Dd	4900.0	22.88750	10.95694	2357.9
21	2Dd	4900.0	23.90972	11.97917	2357.8
22	2Dd	4900.0	24.01528	12.08472	2357.3
23	2Dd	4900.0			
24	3Bu	.0	24.01667	.00139	2377.1
25	3Bu	.0	24.01806	.00278	2383.8
26	3Bu	.0	24.02083	.00556	2384.6
27	3Bu	.0	24.03194	.01667	2385.7
28	3Bu	.0	24.07639	.06111	2386.9
29	3Bu	.0	24.12083	.10556	2387.4
30	3Bu	.0	24.16528	.15000	2387.7
31	3Bu	.0	24.20972	.19444	2388.0
32	3Bu	.0	24.25417	.23889	2388.1
33	3Bu	.0	24.29861	.28333	2388.3
34	3Bu	.0	24.34306	.32778	2388.5
35	3Bu	.0	24.38750	.37222	2388.6
36	3Bu	.0	24.43194	.41667	2388.8
37	3Bu	.0	24.47639	.46111	2388.8
38	3Bu	.0	24.52083	.50556	2388.9
39	3Bu	.0	24.56528	.55000	2389.0
40	3Bu	.0	24.60972	.59444	2389.0

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D STRAIN GAUGE SDP 830..
DRAWDOWN COMMENCING AT 0853.00 17/2/..

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
41	3Bu	.0	24.65417	.63889	2389.2
42	3Bu	.0	24.69861	.68333	2389.2
43	3Bu	.0	24.74306	.72778	2389.3
44	3Bu	.0	24.78750	.77222	2389.4
45	3Bu	.0	24.83194	.81667	2389.4
46	3Bu	.0	24.87639	.86111	2389.4
47	3Bu	.0	24.92083	.90556	2389.6
48	3Bu	.0	24.96528	.95000	2389.6
49	3Bu	.0	25.00972	.99444	2389.6
50	3Bu	.0	25.05417	1.03889	2389.7
51	3Bu	.0	25.09861	1.08333	2389.7
52	3Bu	.0	25.14306	1.12778	2389.8
53	3Bu	.0	25.18750	1.17222	2389.9
54	3Bu	.0	25.23194	1.21667	2389.9
55	3Bu	.0	25.27639	1.26111	2389.9
56	3Bu	.0	25.32083	1.30556	2390.0
57	3Bu	.0	25.36528	1.35000	2390.0
58	3Bu	.0	25.40972	1.39444	2390.0
59	3Bu	.0	25.49861	1.48333	2390.1
60	3Bu	.0	25.58750	1.57222	2390.2
61	3Bu	.0	25.67639	1.66111	2390.3
62	3Bu	.0	25.76528	1.75000	2390.3
63	3Bu	.0	25.85417	1.83889	2390.4
64	3Bu	.0	25.94306	1.92778	2390.4
65	3Bu	.0	26.03194	2.01667	2390.5
66	3Bu	.0	26.12083	2.10556	2390.6
67	3Bu	.0	26.20972	2.19444	2390.5
68	3Bu	.0	26.29861	2.28333	2390.6
69	3Bu	.0	26.38750	2.37222	2390.7
70	3Bu	.0	26.47639	2.46111	2390.7
71	3Bu	.0	26.56528	2.55000	2390.8
72	3Bu	.0	26.65417	2.63889	2390.8
73	3Bu	.0	26.74306	2.72778	2390.8
74	3Bu	.0	26.83194	2.81667	2390.9
75	3Bu	.0	26.92083	2.90556	2390.9
76	3Bu	.0	27.00972	2.99444	2390.9
77	3Bu	.0	27.09861	3.08333	2391.0
78	3Bu	.0	27.18750	3.17222	2391.0
79	3Bu	.0	27.32083	3.30556	2391.1
80	3Bu	.0	27.58750	3.57222	2391.2

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D STRAIN GAUGE SDP 83068
DRAWDOWN COMMENCING AT 0853.00 17/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
81	3Bu	.0	27.72083	3.70556	2391.1
82	3Bu	.0	27.85417	3.83889	2391.2
83	3Bu	.0	27.98750	3.97222	2391.3
84	3Bu	.0	28.12083	4.10556	2391.3
85	3Bu	.0	28.25417	4.23889	2391.4
86	3Bu	.0	28.38750	4.37222	2391.3
87	3Bu	.0	28.52083	4.50556	2391.4
88	3Bu	.0	28.65417	4.63889	2391.5
89	3Bu	.0	28.78750	4.77222	2391.5
90	3Bu	.0	28.92083	4.90556	2391.6
91	3Bu	.0	29.05417	5.03889	2391.5
92	3Bu	.0	29.18750	5.17222	2391.5
93	3Bu	.0	29.32083	5.30556	2391.6
94	3Bu	.0	29.45417	5.43889	2391.6
95	3Bu	.0	29.58750	5.57222	2391.6
96	3Bu	.0	29.72083	5.70556	2391.7
97	3Bu	.0	29.85417	5.83889	2391.2
98	3Bu	.0	30.07639	6.06111	2391.8
99	3Bu	.0	30.29861	6.28333	2391.8
100	3Bu	.0	30.52083	6.50556	2391.9
101	3Bu	.0	30.74306	6.72778	2391.8
102	3Bu	.0	30.96528	6.95000	2392.0
103	3Bu	.0	31.18750	7.17222	2391.9
104	3Bu	.0	31.40972	7.39444	2392.0
105	3Bu	.0	31.63194	7.61667	2392.0
106	3Bu	.0	31.85417	7.83889	2392.1
107	3Bu	.0	32.07639	8.06111	2392.1
108	3Bu	.0	32.29861	8.28333	2392.1
109	3Bu	.0	32.52083	8.50556	2392.2
110	3Bu	.0	32.74306	8.72778	2392.3
111	3Bu	.0	32.96528	8.95000	2392.3
112	3Bu	.0	33.18750	9.17222	2392.3
113	3Bu	.0	33.40972	9.39444	2392.3
114	3Bu	.0	33.63194	9.61667	2392.3
115	3Bu	.0	33.85417	9.83889	2392.3
116	3Bu	.0	34.07639	10.06111	2392.5
117	3Bu	.0	34.29861	10.28333	2392.5
118	3Bu	.0	35.27639	11.26111	2392.5
119	3Bu	.0	36.29861	12.28333	2392.6
120	3Bu	.0	37.32083	13.30555	2392.7

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D STRAIN GAUGE SDP 83068
DRAWDOWN COMMENCING AT 0853.00 17/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
121	3Bu	.0	38.29861	14.28333	2392.7
122	3Bu	.0	39.09861	15.08333	2392.6
123	3Bu	.0	39.80972	15.79444	2392.7
124	3Bu	.0	40.87639	16.86111	2392.7
125	3Bu	.0	41.23194	17.21667	2392.7
126	3Bu	.0	41.58750	17.57222	2392.7
127	3Bu	.0	41.94306	17.92778	2392.7
128	3Bu	.0	42.29861	18.28333	2392.7
129	3Bu	.0	42.65417	18.63889	2392.8
130	3Bu	.0	43.00972	18.99444	2392.8
131	3Bu	.0	43.36528	19.35000	2392.8
132	3Bu	.0	43.72083	19.70556	2392.8
133	3Bu	.0	44.07639	20.06111	2392.8
134	3Bu	.0	44.43194	20.41667	2392.9
135	3Bu	.0	44.78750	20.77222	2392.9
136	3Bu	.0	45.14306	21.12778	2392.9
137	3Bu	.0	45.49861	21.48333	2392.9
138	3Bu	.0	45.85417	21.83889	2392.9
139	3Bu	.0	46.20972	22.19444	2393.0
140	3Bu	.0	46.56528	22.55000	2393.0
141	3Bu	.0	46.92083	22.90556	2393.0
142	3Bu	.0	47.27639	23.26111	2393.0
143	3Bu	.0	47.63194	23.61667	2393.1
144	3Bu	.0	47.98750	23.97222	2393.0

```
Period range =          24          144
 Horner begin point   (        24) ? ))29

 Horner end   point   (       144) ? ))37

CALCULATED FORMATION AND WELLBORE PARAMETERS
  Period                                                  3
  Selected semi log straight line segment           29 to  37
  Fitted semi-log slope (psi)/(stb/d)             -.41148-003
  Flow Capacity , mD.ft                               275903.
  Permeability , mD                                  5518.053
  Extrapolated (pseudo) pressure psi                .2392+004

  No. of points fitted                                      9
  Correlation coefficient                               -.998

 Period (0 if no more) (         4) ? )  )3

  Period range =          24          144
   Horner begin point   (        24) ? ))41

   Horner end   point   (       144) ? ))95

CALCULATED FORMATION AND WELLBORE PARAMETERS
  Period                                                  3
  Selected semi log straight line segment           41 to  95
  Fitted semi-log slope (psi)/(stb/d)             -.53808-003
  Flow Capacity , mD.ft                               210989.
  Permeability , mD                                  4219.776
  Extrapolated (pseudo) pressure psi                .2393+004

  No. of points fitted                                     55
  Correlation coefficient                               -.999

 Period (0 if no more) (         4) ? )  )0
```

SKIN ANALYSIS FOR DRAWDOWN PERIODS
Permeability, mD (4220.) ?))5518

Period (0 if no more) (1) ?))

Period range = 2 11
Horner begin point (2) ?))

Horner end point (11) ?))

Drawdown period	1
Selected semi log straight line segment	2 to 11
Initial (pseudo) pressure psi	.[illegible]2+004
Extrapolated (pseudo) pressure psi	.[illegible]8+004
Total skin	7.482
No. of points fitted	10

Period (0 if no more) (2) ?))

Period range = 12 23
Horner begin point (12) ?))15

Horner end point (23) ?))

Drawdown period	2
Selected semi log straight line segment	15 to 23
Initial (pseudo) pressure psi	.[illegible]92+004
Extrapolated (pseudo) pressure psi	.[illegible]60+004
Total skin	8.685
No. of points fitted	9

Period (0 if no more) (3) ?))0

SUMMARY OF SKIN ANALYSIS

Total skin fitted for period 1	7.482
Total skin fitted for period 2	8.685
Average skin	4.
No. of points fitted	2

RADIUS OF INVESTIGATION TABLE, Rinv (feet)

nØjØ	1	2	3
1 Ø	25[illegible].		
2 Ø	354[illegible].	2516.	
3 Ø	50[illegible].	4345.	3543.

Rinv (n,j) is the radius of investigation, at the end of period n, of the pressure transient induced by the rate change which took place at the start of period j.

Base Permeability , mD	5518.000
Hydraulic Diffusivity , mD.psi/cP	.624+009

MULTI-RATE PRESSURE TRANSIENT DURATION TABLE, DT (hours)

nØjØ	1	2	3
1 Ø	[illegible].9		
2 Ø	[illegible].0	12.1	
3 Ø	[illegible].0	36.1	24.0

DT (n,j) is the duration, at the end of period n, of the of the pressure transient induced by the rate change which took place at the start of period j. Note that the duration of the last period may have been extended so as to reach beyond the start of semi-steady state (if finite reservoir).

RATE CHANGE HISTORY (INDUCING PRESSURE TRANSIENTS)

Rate change at start of period 1, stb/d	2300.000
Rate change at start of period 2, stb/d	2600.000
Rate change at start of period 3, stb/d	-4900.000

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D HP/VALSTAR 003/1141/098
DRAWDOWN COMMENCING AT 0700 17/2/86

SEQUENCE OF EVENTS

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PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
1	0	.0	.00000	.00000	2382.7
2	1Dd	2300.0	1.93333	1.93333	2368.1
3	1Dd	2300.0	3.06667	3.06667	2367.3
4	1Dd	2300.0	4.06667	4.06667	2367.1
5	1Dd	2300.0	4.13333	4.13333	2367.0
6	1Dd	2300.0	5.13333	5.13333	2366.9
7	1Dd	2300.0	6.13333	6.13333	2367.0
8	1Dd	2300.0	7.13333	7.13333	2366.8
8	1Dd	2300.0	8.13333	8.13333	2367.0
9	1Dd	2300.0	9.13333	9.13333	2366.9
10	1Dd	2300.0	11.93333	11.93333	2366.7
12	2Dd	4900.0	12.06667	.13333	2348.0
13	2Dd	4900.0	13.06667	1.13333	2344.5
14	2Dd	4900.0	14.06667	2.13333	2348.6
15	2Dd	4900.0	15.06667	3.13333	2348.3
16	2Dd	4900.0	16.06667	4.13333	2348.1
17	2Dd	4900.0	17.06667	5.13333	2348.0
18	2Dd	4900.0	18.06667	6.13333	2347.9
19	2Dd	4900.0	19.06667	7.13333	2347.9
20	2Dd	4900.0	20.06667	8.13333	2347.8
21	2Dd	4900.0	21.06667	9.13333	2347.9
22	2Dd	4900.0	22.06667	10.13333	2347.9
23	2Dd	4900.0	23.06667	11.13333	2347.8
24	2Dd	4900.0	23.71667	11.78333	2347.9
25	2Dd	4900.0	24.02083	12.08750	2347.3
26	3Bu	.0	24.02500	.00417	2374.4
27	3Bu	.0	24.02917	.00833	2375.1
28	3Bu	.0	24.03333	.01250	2375.5
29	3Bu	.0	24.03750	.01667	2375.9
30	3Bu	.0	24.04167	.02083	2376.1
31	3Bu	.0	24.04583	.02500	2376.4
32	3Bu	.0	24.05000	.02917	2376.6
33	3Bu	.0	24.05417	.03333	2376.8
34	3Bu	.0	24.05833	.03750	2376.9
35	3Bu	.0	24.06250	.04167	2377.0
36	3Bu	.0	24.06667	.04583	2377.1
37	3Bu	.0	24.07083	.05000	2377.3
38	3Bu	.0	24.07500	.05417	2377.4
39	3Bu	.0	24.07917	.05833	2377.4
40	3Bu	.0	24.08333	.06250	2377.5

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D HP/VALSTAR 003/1141/098
DRAWDOWN COMMENCING AT 0700 17/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
41	3Bu	.0	24.08750	.06667	2377.6
42	3Bu	.0	24.09167	.07083	2377.7
43	3Bu	.0	24.09583	.07500	2377.7
44	3Bu	.0	24.10000	.07917	2377.8
45	3Bu	.0	24.10417	.08333	2377.8
46	3Bu	.0	24.10833	.08750	2377.8
47	3Bu	.0	24.11250	.09167	2377.9
48	3Bu	.0	24.11667	.09583	2377.9
49	3Bu	.0	24.12083	.10000	2378.0
50	3Bu	.0	24.12500	.10417	2378.0
51	3Bu	.0	24.12917	.10833	2378.0
52	3Bu	.0	24.13333	.11250	2378.1
53	3Bu	.0	24.13750	.11667	2378.1
54	3Bu	.0	24.14167	.12083	2378.1
55	3Bu	.0	24.14583	.12500	2378.2
56	3Bu	.0	24.15000	.12917	2378.2
57	3Bu	.0	24.15417	.13333	2378.3
58	3Bu	.0	24.15833	.13750	2378.3
59	3Bu	.0	24.16250	.14167	2378.3
60	3Bu	.0	24.16667	.14583	2378.3
61	3Bu	.0	24.17083	.15000	2378.3
62	3Bu	.0	24.17500	.15417	2378.4
63	3Bu	.0	24.17917	.15833	2378.4
64	3Bu	.0	24.18333	.16250	2378.4
65	3Bu	.0	24.18750	.16667	2378.5
66	3Bu	.0	24.19167	.17083	2378.4
67	3Bu	.0	24.19583	.17500	2378.5
68	3Bu	.0	24.20000	.17917	2378.5
69	3Bu	.0	24.20417	.18333	2378.5
70	3Bu	.0	24.20833	.18750	2378.6
71	3Bu	.0	24.21250	.19167	2378.5
72	3Bu	.0	24.21667	.19583	2378.6
73	3Bu	.0	24.22083	.20000	2378.6
74	3Bu	.0	24.22500	.20417	2378.6
75	3Bu	.0	24.22917	.20833	2378.6
76	3Bu	.0	24.23333	.21250	2378.7
77	3Bu	.0	24.23750	.21667	2378.7
78	3Bu	.0	24.24167	.22083	2378.7
79	3Bu	.0	24.24583	.22500	2378.7
80	3Bu	.0	24.25000	.22917	2378.7

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D HP/VALSTAR 003/1141/098
DRAWDOWN COMMENCING AT 0700 17/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
81	3Bu	.0	24.25417	.23333	2378.7
82	3Bu	.0	24.25833	.23750	2378.7
83	3Bu	.0	24.33333	.31250	2379.0
84	3Bu	.0	24.41667	.39583	2379.3
85	3Bu	.0	24.42083	.40000	2379.3
86	3Bu	.0	24.50000	.47917	2379.4
87	3Bu	.0	24.58333	.56250	2379.6
88	3Bu	.0	24.66667	.64583	2379.8
89	3Bu	.0	24.75000	.72917	2379.9
90	3Bu	.0	24.83333	.81250	2380.0
91	3Bu	.0	24.91667	.89583	2380.2
92	3Bu	.0	25.00000	.97917	2380.2
93	3Bu	.0	25.16639	1.14556	2380.5
94	3Bu	.0	25.33306	1.31222	2380.7
95	3Bu	.0	25.49972	1.47889	2380.8
96	3Bu	.0	25.66639	1.64556	2380.9
97	3Bu	.0	25.83306	1.81222	2381.1
98	3Bu	.0	26.83306	2.81222	2381.6
99	3Bu	.0	27.33306	3.31222	2381.9
100	3Bu	.0	27.83306	3.81222	2382.0
101	3Bu	.0	28.33306	4.31222	2382.2
102	3Bu	.0	28.83306	4.81222	2382.3
103	3Bu	.0	29.33306	5.31222	2382.4
104	3Bu	.0	29.83306	5.81222	2382.6
105	3Bu	.0	30.33306	6.31222	2382.7
106	3Bu	.0	30.83306	6.81222	2382.8
107	3Bu	.0	31.83306	7.81222	2383.0
108	3Bu	.0	32.83306	8.81222	2383.1
109	3Bu	.0	33.83306	9.81222	2383.3
110	3Bu	.0	34.83306	10.81222	2383.4
111	3Bu	.0	35.83306	11.81222	2383.5
112	3Bu	.0	36.83306	12.81222	2383.6
113	3Bu	.0	37.83306	13.81222	2383.7
114	3Bu	.0	38.83306	14.81222	2383.7
115	3Bu	.0	39.83306	15.81222	2383.7
116	3Bu	.0	40.83306	16.81222	2383.7
117	3Bu	.0	41.83306	17.81222	2383.8
118	3Bu	.0	42.83306	18.81222	2383.8
119	3Bu	.0	43.83306	19.81222	2383.9
120	3Bu	.0	44.83306	20.81222	2384.0

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D HP/VALSTAR 003/1141/098
DRAWDOWN COMMENCING AT 0700 17/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
121	3Bu	.0	45.83306	21.81222	2384.1
122	3Bu	.0	46.83306	22.81222	2384.1
123	3Bu	.0	47.83306	23.81222	2384.2
124	3Bu	.0	47.99972	23.97889	2384.2

```
Period range =            26          124
 Horner begin point   (        26) ? ))43

 Horner end   point   (       124) ? ))86


CALCULATED FORMATION AND WELLBORE PARAMETERS
                                                          3
  Period
  Selected semi log straight line segment            43 to  86
  Fitted semi-log slope (psi)/(stb/d)               -.38285-003
  Flow Capacity , mD.ft                                296537.
  Permeability , mD                                   5930.737
  Extrapolated (pseudo) pressure psi                 .2383+004

  No. of points fitted                                      44
  Correlation coefficient                                -.999

Period (0 if no more) (         4) ? )  )3

 Period range =            26          124
  Horner begin point   (        26) ? ))92

  Horner end   point   (       124) ? ))105


CALCULATED FORMATION AND WELLBORE PARAMETERS
                                                          3
  Period
  Selected semi log straight line segment           92 to 105
  Fitted semi-log slope (psi)/(stb/d)               -.62197-003
  Flow Capacity , mD.ft                                182533.
  Permeability , mD                                   3650.668
  Extrapolated (pseudo) pressure psi                 .2385+004

  No. of points fitted                                      14
  Correlation coefficient                                -.999

Period (0 if no more) (         4) ? )  )0
```

SKIN ANALYSIS FOR DRAWDOWN PERIODS
Permeability, mD (5931.) ?))

Period (0 if no more) (1) ?))

Period range = 2 11
Horner begin point (2) ?))

Horner end point (11) ?))

Drawdown period	1
Selected semi log straight line segment	2 to 11
Initial (pseudo) pressure psi	.2383+004
Extrapolated (pseudo) pressure psi	.2368+004
Total skin	9.765
No. of points fitted	10

Period (0 if no more) (2) ?))

Period range = 12 25
Horner begin point (12) ?))15

Horner end point (25) ?))

Drawdown period	2
Selected semi log straight line segment	15 to 25
Initial (pseudo) pressure psi	.2383+004
Extrapolated (pseudo) pressure psi	.2350+004
Total skin	10.202
No. of points fitted	11

Period (0 if no more) (3) ?))0

SUMMARY OF SKIN ANALYSIS

Total skin fitted for period 1	9.765
Total skin fitted for period 2	10.202
Average skin	5.
No. of points fitted	2

RADIUS OF INVESTIGATION TABLE, Rinv (feet)

nØjφ	1	2	3
1 φ	2592.		
2 φ	3677.	2608.	
3 φ	5198.	4506.	3674.

Rinv (n,j) is the radius of investigation, at the end of period n, of the pressure transient induced by the rate change which took place at the start of period j.

Base Permeability , mD	5930.737
Hydraulic Diffusivity , mD.psi/cP	.671+009

MULTI-RATE PRESSURE TRANSIENT DURATION TABLE, DT (hours)

nØjφ	1	2	3
1 φ	11.9		
2 φ	24.0	12.1	
3 φ	48.0	36.1	24.0

DT (n,j) is the duration, at the end of period n, of the of the pressure transient induced by the rate change which took place at the start of period j. Note that the duration of the last period may have been extended so as to reach beyond the start of semi-steady state (if finite reservoir.

RATE CHANGE HISTORY (INDUCING PRESSURE TRANSIENTS)

Rate change at start of period 1, stb/d	2300.000
Rate change at start of period 2, stb/d	2600.000
Rate change at start of period 3, stb/d	-4900.000

DRAUGEN WELL : 6407 [illegible]
PROD.TEST PT-1D HP/V[illegible]AR 067/0928/126
DRAWDOWN COMMENCING AT 0700.00 17/2/86

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SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
1	0	.0	.00000	.00000	2387.8
2	1Dd	2300.0	2.06667	2.06667	2373.3
3	1Dd	2300.0	3.06667	3.06667	2372.7
4	1Dd	2300.0	4.06667	4.06667	2372.4
5	1Dd	2300.0	5.06667	5.06667	2372.3
6	1Dd	2300.0	6.06667	6.06667	2372.3
7	1Dd	2300.0	7.06667	7.06667	2372.3
8	1Dd	2300.0	8.06667	8.06667	2372.0
9	1Dd	2300.0	9.06667	9.06667	2372.1
10	1Dd	2300.0	10.06667	10.06667	2372.2
11	1Dd	2300.0	11.93333	11.93333	2372.1
12	2Dd	4900.0	12.06667	.13333	2351.5
13	2Dd	4900.0	13.06667	1.13333	2349.4
14	2Dd	4900.0	14.06667	2.13333	2353.7
15	2Dd	4900.0	15.06667	3.13333	2353.2
16	2Dd	4900.0	16.06667	4.13333	2353.0
17	2Dd	4900.0	17.06667	5.13333	2352.9
18	2Dd	4900.0	18.06667	6.13333	2352.8
19	2Dd	4900.0	19.06667	7.13333	2352.8
20	2Dd	4900.0	20.06667	8.13333	2352.7
21	2Dd	4900.0	21.06667	9.13333	2352.8
22	2Dd	4900.0	22.06667	10.13333	2352.8
23	2Dd	4900.0	23.06667	11.13333	2352.8
24	2Dd	4900.0	23.71667	11.78333	2352.8
25	2Dd	4900.0	24.00417	12.07083	2352.8
26	3Bu	.0	24.00833	.00417	2379.7
27	3Bu	.0	24.01250	.00833	2379.9
28	3Bu	.0	24.01667	.01250	2379.9
29	3Bu	.0	24.02083	.01667	2380.2
30	3Bu	.0	24.02500	.02083	2380.6
31	3Bu	.0	24.02917	.02500	2380.9
32	3Bu	.0	24.03333	.02917	2381.2
33	3Bu	.0	24.03750	.03333	2381.5
34	3Bu	.0	24.04167	.03750	2381.8
35	3Bu	.0	24.04583	.04167	2382.0
36	3Bu	.0	24.05000	.04583	2382.1
37	3Bu	.0	24.05417	.05000	2382.3
38	3Bu	.0	24.05833	.05417	2382.4
39	3Bu	.0	24.06250	.05833	2382.5
40	3Bu	.0	24.06667	.06250	2382.6

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D HP/VALSTAR 067/0928/126
DRAWDOWN COMMENCING AT 0700.00 17/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
41	3Bu	.0	24.07083	.06667	2382.7
42	3Bu	.0	24.07500	.07083	2382.7
43	3Bu	.0	24.07917	.07500	2382.8
44	3Bu	.0	24.08333	.07917	2382.8
45	3Bu	.0	24.08750	.08333	2382.9
46	3Bu	.0	24.09167	.08750	2382.9
47	3Bu	.0	24.09583	.09167	2383.0
48	3Bu	.0	24.10000	.09583	2383.0
49	3Bu	.0	24.10417	.10000	2383.0
50	3Bu	.0	24.10833	.10417	2383.1
51	3Bu	.0	24.11250	.10833	2383.1
52	3Bu	.0	24.11667	.11250	2383.2
53	3Bu	.0	24.12083	.11667	2383.2
54	3Bu	.0	24.12500	.12083	2383.2
55	3Bu	.0	24.12917	.12500	2383.3
56	3Bu	.0	24.13333	.12917	2383.3
57	3Bu	.0	24.13750	.13333	2383.3
58	3Bu	.0	24.14167	.13750	2383.3
59	3Bu	.0	24.14583	.14167	2383.3
60	3Bu	.0	24.15000	.14583	2383.4
61	3Bu	.0	24.15417	.15000	2383.4
62	3Bu	.0	24.16250	.15833	2383.4
63	3Bu	.0	24.17083	.16667	2383.4
64	3Bu	.0	24.17917	.17500	2383.5
65	3Bu	.0	24.18750	.18333	2383.5
66	3Bu	.0	24.19583	.19167	2383.5
67	3Bu	.0	24.20417	.20000	2383.5
68	3Bu	.0	24.21250	.20833	2383.6
69	3Bu	.0	24.22083	.21667	2383.6
70	3Bu	.0	24.22917	.22500	2383.6
71	3Bu	.0	24.23750	.23333	2383.7
72	3Bu	.0	24.24583	.24167	2383.7
73	3Bu	.0	24.25417	.25000	2383.7
74	3Bu	.0	24.26250	.25833	2383.7
75	3Bu	.0	24.27083	.26667	2383.8
76	3Bu	.0	24.27917	.27500	2383.8
77	3Bu	.0	24.28750	.28333	2383.8
78	3Bu	.0	24.29583	.29167	2383.8
79	3Bu	.0	24.30417	.30000	2383.9
80	3Bu	.0	24.31250	.30833	2383.9

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D HP/VALSTAR 067/0928/126
DRAWDOWN COMMENCING AT 0700.00 17/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
81	3Bu	.0	24.32083	.31667	2383.9
82	3Bu	.0	24.33750	.33333	2384.0
83	3Bu	.0	24.35417	.35000	2384.0
84	3Bu	.0	24.37083	.36667	2384.1
85	3Bu	.0	24.38750	.38333	2384.1
86	3Bu	.0	24.40417	.40000	2384.1
87	3Bu	.0	24.42083	.41667	2384.2
88	3Bu	.0	24.43750	.43333	2384.2
89	3Bu	.0	24.45417	.45000	2384.3
90	3Bu	.0	24.47083	.46667	2384.3
91	3Bu	.0	24.48750	.48333	2384.3
92	3Bu	.0	24.50417	.50000	2384.4
93	3Bu	.0	24.52083	.51667	2384.4
94	3Bu	.0	24.53750	.53333	2384.4
95	3Bu	.0	24.55417	.55000	2384.5
96	3Bu	.0	24.57083	.56667	2384.5
97	3Bu	.0	24.58750	.58333	2384.5
98	3Bu	.0	24.60417	.60000	2384.6
99	3Bu	.0	24.62083	.61667	2384.6
100	3Bu	.0	24.63750	.63333	2384.6
101	3Bu	.0	24.65417	.65000	2384.6
102	3Bu	.0	24.68750	.68333	2384.7
103	3Bu	.0	24.72083	.71667	2384.7
104	3Bu	.0	24.75417	.75000	2384.8
105	3Bu	.0	24.78750	.78333	2384.8
106	3Bu	.0	24.82083	.81667	2384.9
107	3Bu	.0	24.85417	.85000	2384.9
108	3Bu	.0	24.88750	.88333	2385.0
109	3Bu	.0	24.95417	.95000	2385.1
110	3Bu	.0	24.98750	.98333	2385.1
111	3Bu	.0	25.03333	1.02917	2385.2
112	3Bu	.0	25.04139	1.03722	2385.2
113	3Bu	.0	25.07472	1.07056	2385.3
114	3Bu	.0	25.10806	1.10389	2385.3
115	3Bu	.0	25.14139	1.13722	2385.3
116	3Bu	.0	25.17472	1.17056	2385.4
117	3Bu	.0	25.20806	1.20389	2385.4
118	3Bu	.0	25.24139	1.23722	2385.4
119	3Bu	.0	25.27472	1.27056	2385.4
120	3Bu	.0	25.34139	1.33722	2385.5

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1D HP/VALSTAR 067/0928/126
DRAWDOWN COMMENCING AT 0700.00 17/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
121	3Bu	.0	25.45806	1.45389	2385.6
122	3Bu	.0	25.96639	1.96222	2386.0
123	3Bu	.0	26.46639	2.46222	2386.3
124	3Bu	.0	26.96639	2.96222	2386.5
125	3Bu	.0	27.46639	3.46222	2386.7
126	3Bu	.0	27.96639	3.96222	2386.9
127	3Bu	.0	28.96639	4.96222	2387.1
128	3Bu	.0	29.96639	5.96222	2387.4
129	3Bu	.0	30.96639	6.96222	2387.6
130	3Bu	.0	31.96639	7.96222	2387.8
131	3Bu	.0	32.96639	8.96222	2387.9
132	3Bu	.0	33.96639	9.96222	2388.1
133	3Bu	.0	34.96639	10.96222	2388.2
134	3Bu	.0	35.96639	11.96222	2388.3
135	3Bu	.0	36.96639	12.96222	2388.3
136	3Bu	.0	37.96639	13.96222	2388.4
137	3Bu	.0	38.96639	14.96222	2388.4
138	3Bu	.0	39.96639	15.96222	2388.4
139	3Bu	.0	40.96639	16.96222	2388.4
140	3Bu	.0	41.96639	17.96222	2388.5
141	3Bu	.0	42.46639	18.46222	2388.5
142	3Bu	.0	42.96639	18.96222	2388.5
143	3Bu	.0	43.96639	19.96222	2388.6
144	3Bu	.0	44.46639	20.46222	2388.6
145	3Bu	.0	44.96639	20.96222	2388.6
146	3Bu	.0	45.96639	21.96222	2388.7
147	3Bu	.0	47.99972	23.99556	2388.8

```
Period range =           26          147
 Horner begin point  (        26) ? ))65

 Horner end   point  (       147) ? ))91

CALCULATED FORMATION AND WELLBORE PARAMETERS
  Period                                                    3
  Selected semi log straight line segment             65 to  91
  Fitted semi-log slope (psi)/(stb/d)               -.36056-003
  Flow Capacity , mD.ft                                314870.
  Permeability , mD                                   6297.406
  Extrapolated (pseudo) pressure psi                 .2387+004

  No. of points fitted                                      27
  Correlation coefficient                                -.995

 Period (0 if no more) (       4) ? )  )3

  Period range =           26          147
   Horner begin point  (        26) ? ))98

   Horner end   point  (       147) ? ))130

CALCULATED FORMATION AND WELLBORE PARAMETERS
  Period                                                    3
  Selected semi log straight line segment             98 to 130
  Fitted semi-log slope (psi)/(stb/d)               -.57409-003
  Flow Capacity , mD.ft                                197757.
  Permeability , mD                                   3955.135
  Extrapolated (pseudo) pressure psi                 .2389+004

  No. of points fitted                                      33
  Correlation coefficient                                -.998

 Period (0 if no more) (       4) ? )  )0
```

SKIN ANALYSIS FOR DRAWDOWN PERIODS
Permeability, mD (3955.) ?))6297

Period (0 if no more) (1) ?))

Period range = 2 11
Horner begin point (2) ?))

Horner end point (11) ?))

Drawdown period	1
Selected semi log straight line segment	2 to 11
Initial (pseudo) pressure psi	.2388+004
Extrapolated (pseudo) pressure psi	.2373+004
Total skin	10.510
No. of points fitted	10

Period (0 if no more) (2) ?))

Period range = 12 25
Horner begin point (12) ?))15

Horner end point (25) ?))

Drawdown period	2
Selected semi log straight line segment	15 to 25
Initial (pseudo) pressure psi	.2388+004
Extrapolated (pseudo) pressure psi	.2355+004
Total skin	11.376
No. of points fitted	11

Period (0 if no more) (3) ?))0

SUMMARY OF SKIN ANALYSIS

Total skin fitted for period 1	10.510
Total skin fitted for period 2	11.376
Average skin	6.
No. of points fitted	2

RADIUS OF INVESTIGATION TABLE, Rinv (feet)

nØjφ	1	2	3
1 φ	2670.		
2 φ	3787.	2686.	
3 φ	5356.	4643.	3787.

Rinv (n,j) is the radius of investigation, at the end of period n, of the pressure transient induced by the rate change which took place at the start of period j.

Base Permeability , mD	6297.000
Hydraulic Diffusivity , mD.psi/cP	.712+009

MULTI-RATE PRESSURE TRANSIENT DURATION TABLE, DT (hours)

nØjφ	1	2	3
1 φ	11.9		
2 φ	24.0	12.1	
3 φ	48.0	36.1	24.0

DT (n,j) is the duration, at the end of period n, of the of the pressure transient induced by the rate change which took place at the start of period j. Note that the duration of the last period may have been extended so as to reach beyond the start of semi-steady state (if finite reservoir).

RATE CHANGE HISTORY (INDUCING PRESSURE TRANSIENTS)

Rate change at start of period 1, stb/d	2300.000
Rate change at start of period 2, stb/d	2600.000
Rate change at start of period 3, stb/d	-4900.000

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1F HP/VALSTAR 067/0928/126
INJECTION TEST COMMENCING AT 0608.00 20/2/86

WELL AND RESERVOIR DATA

Formation net thickness	:	50.00 ft
Reservoir fluid	:	
Pre-test reservoir pressure	:	2388.4 psi
Perforated interval	:	5308.0- 5351.0 ft
Wellbore radius	:	.510 ft
Absolute porosity	:	.300

PVT PROPERTIES

FORMATION VOL FACTOR BO bbl/bbl	VISC AT RESV CONDITIONS cP	TOTAL COMPRES SIBILITY ct psi-1
1.0200	1.250	.4400-004

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1F HP/VALSTAR 067/0928/126
INJECTION TEST COMMENCING AT 0608.00 20/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
1	0	.0	.00000	.00000	2388.4
2	1Bu	-12700.0	.06250	.06250	2404.8
3	1Bu	-12700.0	1.04139	1.04139	2713.6
4	1Bu	-12700.0	2.04139	2.04139	2788.7
5	1Bu	-12700.0	3.04139	3.04139	2839.1
6	1Bu	-12700.0	4.04139	4.04139	2821.2
7	1Bu	-12700.0	5.04139	5.04139	2882.8
8	1Bu	-12700.0	6.04139	6.04139	2928.4
9	1Bu	-12700.0	7.04139	7.04139	2970.5
10	1Bu	-12700.0	8.04139	8.04139	3010.6
11	1Bu	-12700.0	9.04139	9.04139	3049.2
12	1Bu	-12700.0	10.04139	10.04139	3085.9
13	1Bu	-12700.0	11.04139	11.04139	3110.4
14	1Bu	-12700.0	12.04139	12.04139	3135.4
15	1Bu	-12700.0	13.04139	13.04139	3158.6
16	1Bu	-12700.0	14.04139	14.04139	3184.9
17	1Bu	-12700.0	15.04139	15.04139	3210.3

18	1Bu	-12700.0	16.93333	16.93333	3247.6
19	2Bu	-16288.0	17.04139	.10806	3292.6
20	2Bu	-16288.0	18.04139	1.10806	3534.7
21	2Bu	-16288.0	18.42889	1.49556	3595.8
22	2Bu	-16288.0	18.90806	1.97472	3656.9
23	2Bu	-16288.0	20.15000	3.21667	3796.8
24	3Bu	-13212.0	21.15806	1.00806	3769.8
25	3Bu	-13212.0	22.15806	2.00806	3765.9
26	3Bu	-13212.0	23.15806	3.00806	3773.9
27	3Bu	-13212.0	24.15806	4.00806	3774.1
28	3Bu	-13212.0	25.15806	5.00806	3786.4
29	3Bu	-13212.0	26.15806	6.00806	3791.2
30	3Bu	-13212.0	27.15806	7.00806	3803.9
31	3Bu	-13212.0	28.15806	8.00806	3817.3
32	3Bu	-13212.0	29.15806	9.00806	3819.8
33	3Bu	-13212.0	30.15806	10.00806	3827.6
34	3Bu	-13212.0	31.15806	11.00806	3836.1
35	3Bu	-13212.0	32.64139	12.49139	3845.0
36	4Bu	-13337.0	33.17472	.53333	3916.8
37	4Bu	-13337.0	34.17472	1.53333	3981.1
38	4Bu	-13337.0	35.17472	2.53333	4026.7
39	4Bu	-13337.0	37.17056	4.52917	4084.4
40	4Bu	-13337.0	39.17472	6.53333	4112.4

DRAUSEN WELL : 6407/9-6
PROD.TEST PT-1F HP/VALSTAR 067/0928/126
INJECTION TEST COMMENCING AT 0608.00 20/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
41	4Bu	-13337.0	41.17472	8.53333	4133.0
42	4Bu	-13337.0	43.17472	10.53333	4142.6
43	4Bu	-13337.0	45.17472	12.53333	4116.9
44	4Bu	-13337.0	47.17472	14.53333	4148.7
45	4Bu	-13337.0	49.17472	16.53333	4124.0
46	4Bu	-13337.0	51.17472	18.53333	4132.2
47	4Bu	-13337.0	53.17472	20.53333	4147.7
48	4Bu	-13337.0	55.17472	22.53333	4113.6
49	4Bu	-13337.0	57.17472	24.53333	4116.3
50	4Bu	-13337.0	59.17472	26.53333	4143.9
51	4Bu	-13337.0	61.17472	28.53333	4123.6
52	4Bu	-13337.0	63.17472	30.53333	4129.0
53	4Bu	-13337.0	65.17472	32.53333	4094.2
54	4Bu	-13337.0	67.17472	34.53333	4088.2
55	4Bu	-13337.0	69.17472	36.53333	4048.2
56	4Bu	-13337.0	71.90417	39.26278	4066.9
57	5Bu	.0	71.90806	.00389	2788.2
58	5Bu	.0	71.91222	.00806	2447.4
59	5Bu	.0	71.91639	.01222	2444.2
60	5Bu	.0	71.92083	.01667	2441.7
61	5Bu	.0	71.92500	.02083	2439.1
62	5Bu	.0	71.92917	.02500	2436.8
63	5Bu	.0	71.93333	.02917	2434.5
64	5Bu	.0	71.93750	.03333	2432.3
65	5Bu	.0	71.94167	.03750	2430.3
66	5Bu	.0	71.94556	.04139	2428.4
67	5Bu	.0	71.94972	.04556	2426.7
68	5Bu	.0	71.95417	.05000	2425.1
69	5Bu	.0	71.96250	.05833	2422.1
70	5Bu	.0	71.96667	.06250	2420.7
71	5Bu	.0	71.97083	.06667	2419.6
72	5Bu	.0	71.97500	.07083	2418.5
73	5Bu	.0	71.97917	.07500	2417.3
74	5Bu	.0	71.98333	.07917	2416.3
75	5Bu	.0	71.98750	.08333	2415.4
76	5Bu	.0	71.99167	.08750	2414.6
77	5Bu	.0	72.00000	.09583	2413.1
78	5Bu	.0	72.00833	.10417	2411.8
79	5Bu	.0	72.01667	.11250	2410.7
80	5Bu	.0	72.02500	.12083	2409.7

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1F HP/VALSTAR 067/0928/126
INJECTION TEST COMMENCING AT 0608.00 20/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
81	5Bu	.0	72.04167	.13750	2408.6
82	5Bu	.0	72.05833	.15417	2407.7
83	5Bu	.0	72.07500	.17083	2407.1
84	5Bu	.0	72.08333	.17917	2406.9
85	5Bu	.0	72.09167	.18750	2406.6
86	5Bu	.0	72.09583	.19167	2406.5
87	5Bu	.0	72.11250	.20833	2406.2
88	5Bu	.0	72.14583	.24167	2406.0
89	5Bu	.0	72.21250	.30833	2405.4
90	5Bu	.0	72.24583	.34167	2405.1
91	5Bu	.0	72.25417	.35000	2405.0
92	5Bu	.0	72.26667	.36250	2404.9
93	5Bu	.0	72.31667	.41250	2404.6
94	5Bu	.0	72.33333	.42917	2404.4
95	5Bu	.0	72.35000	.44583	2404.2
96	5Bu	.0	72.36667	.46250	2404.2
97	5Bu	.0	72.38333	.47917	2404.0
98	5Bu	.0	72.40000	.49583	2404.0
99	5Bu	.0	72.48333	.57917	2403.5
100	5Bu	.0	72.65000	.74583	2402.7
101	5Bu	.0	72.81667	.91250	2401.9
102	5Bu	.0	72.90000	.99583	2401.8
103	5Bu	.0	72.98333	1.07917	2401.5
104	5Bu	.0	73.06667	1.16250	2401.2
105	5Bu	.0	73.15000	1.24583	2401.0
106	5Bu	.0	73.23333	1.32917	2400.7
107	5Bu	.0	73.31667	1.41250	2400.6
108	5Bu	.0	73.40000	1.49583	2400.4
109	5Bu	.0	73.48333	1.57917	2400.1
110	5Bu	.0	73.56667	1.66250	2400.0
111	5Bu	.0	73.65000	1.74583	2399.8
112	5Bu	.0	73.73333	1.82917	2399.7
113	5Bu	.0	73.81667	1.91250	2399.6
114	5Bu	.0	74.10806	2.20389	2399.2
115	5Bu	.0	74.27472	2.37055	2399.0
116	5Bu	.0	74.44139	2.53722	2398.6
117	5Bu	.0	74.60806	2.70389	2398.4
118	5Bu	.0	74.77472	2.87055	2398.1
119	5Bu	..	74.94139	3.03722	2398.0
120	5Bu	.0	75.10806	3.20389	2397.9

DRAUSEN WELL : 6407/9-3
PROD.TEST PT-1F HP/VALETAR 067/0928/126
INJECTION TEST COMMENCING AT 0608.00 20/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
121	5Bu	.0	76.10000	4.19583	2397.0
122	5Bu	.0	77.13305	5.22889	2396.1
123	5Bu	.0	78.13305	6.22889	2395.6
124	5Bu	.0	79.13305	7.22889	2394.9
125	5Bu	.0	80.13305	8.22889	2394.5
126	5Bu	.0	81.13305	9.22889	2394.1
127	5Bu	.0	82.13305	10.22889	2393.8
128	5Bu	.0	82.79972	10.89555	2393.6
129	5Bu	.0	83.13305	11.22889	2393.4
130	5Bu	.0	84.13305	12.22889	2393.4
131	5Bu	.0	84.79972	12.89555	2393.0
132	5Bu	.0	85.13305	13.22889	2392.9
133	5Bu	.0	85.79972	13.89555	2393.1
134	5Bu	.0	87.13305	15.22889	2392.9
135	5Bu	.0	89.13305	17.22889	2392.6
136	5Bu	.0	91.13306	19.22889	2392.3
137	5Bu	.0	93.13306	21.22889	2392.0
138	5Bu	.0	95.13306	23.22889	2391.7
139	5Bu	.0	95.39972	23.49556	2391.6
140	5Bu	.0	95.46639	23.56222	2391.7
141	5Bu	.0	95.53306	23.62889	2391.6
142	5Bu	.0	95.59972	23.69556	2391.6
143	5Bu	.0	95.66639	23.76222	2391.6
144	5Bu	.0	95.73306	23.82889	2391.7
145	5Bu	.0	95.76639	23.86222	2391.6
146	5Bu	.0	95.79972	23.89556	2391.6
147	5Bu	.0	95.90000	23.99583	2391.6

```
CALCULATED FORMATION AND WELLBORE PARAMETERS
   Period                                                    5
   Selected semi log straight line segment            64 to  76
   Fitted semi-log slope (psi)/(stb/d)          -.[illegible]14-002
   Flow Capacity , mD.ft                                 64498.
   Permeability , mD                                   1289.964
   Extrapolated (pseudo) pressure psi                 .1290+004

   No. of points fitted                                      13
   Correlation coefficient                               -1.000

  Period (0 if no more) (         6) ? >  )0

SKIN ANALYSIS FOR DRAWDOWN PERIODS
  Permeability, mD ( 1290.     ) ? )    )


  Period (0 if no more) (         1) ? )  )

    Period range =             2            18
     Horner begin point   (         2) ? ))

     Horner end   point   (        18) ? ))

    Drawdown period                                           1
    Selected semi log straight line segment            2 to  18
    Initial (pseudo) pressure psi                     .1388+004
    Extrapolated (pseudo) pressure psi                .1944+004
    Total skin                                            9.622
    No. of points fitted                                     17

   Period (0 if no more) (        2) ? )  )

     Period range =            19            23
      Horner begin point   (        19) ? ))

      Horner end   point   (        23) ? ))

     Drawdown period                                          2
     Selected semi log straight line segment          19 to  23
     Initial (pseudo) pressure psi                    .1388+004
     Extrapolated (pseudo) pressure psi               .1324+004
     Total skin                                          18.922
     No. of points fitted                                     5
```

```
Period (0 if no more) (        3) ? )  )

 Period range =          24          35
  Horner begin point   (       24) ? ))

  Horner end   point   (       35) ? ))

 Drawdown period                                              3
 Selected semi log straight line segment               24 to  35
 Initial (pseudo) pressure psi                          .2388+004
 Extrapolated (pseudo) pressure psi                     .3739+004
 Total skin                                                30.577
 No. of points fitted                                          12

Period (0 if no more) (        4) ? )  )

 Period range =          36          56
  Horner begin point   (       36) ? ))

  Horner end   point   (       56) ? ))

 Drawdown period                                              4
 Selected semi log straight line segment               36 to  56
 Initial (pseudo) pressure psi                          .2388+004
 Extrapolated (pseudo) pressure psi                     .4022+004
 Total skin                                                37.837
 No. of points fitted                                          21

Period (0 if no more) (        5) ? )  )0

SUMMARY OF SKIN ANALYSIS
 Total skin fitted for period  1                            9.622
 Total skin fitted for period  2                           18.922
 Total skin fitted for period  3                           30.577
 Total skin fitted for period  4                           37.837

 Average skin                                                  9.
 No. of points fitted                                          4
```

RADIUS OF INVESTIGATION TABLE, Rinv (feet)

n j	1	2	3	4	5
1	1054.				
2	1150.	459.			
3	1464.	1015.	905.		
4	2172.	1899.	1843.	1605.	
5	2509.	2276.	2229.	2037.	1255.

Rinv (n,j) is the radius of investigation, at the end of period n, of the pressure transient induced by the rate change which took place at the start of period j.

Base Permeability , mD	[illegible]89.964
Hydraulic Diffusivity , mD.psi/cP	.[illegible]82+008

MULTI-RATE PRESSURE TRANSIENT DURATION TABLE, DT (hours)

n j	1	2	3	4	5
1	16.9				
2	20.2	3.2			
3	32.6	15.7	12.5		
4	71.9	55.0	51.8	39.3	
5	95.9	79.0	75.8	63.3	24.0

DT (n,j) is the duration, at the end of period n, of the of the pressure transient induced by the rate change which took place at the start of period j. Note that the duration of the last period may have been extended so as to reach beyond the start of semi-steady state (if finite reservoir).

RATE CHANGE HISTORY (INDUCING PRESSURE TRANSIENTS)

Rate change at start of period 1, stb/d	-[illegible]700.000
Rate change at start of period 2, stb/d	-[illegible]588.000
Rate change at start of period 3, stb/d	[illegible]076.000
Rate change at start of period 4, stb/d	-125.000
Rate change at start of period 5, stb/d	[illegible]337.000

```
Period range =          57          147
 Horner begin point   (        57) ? ))92

 Horner end   point   (       147) ? ))

CALCULATED FORMATION AND WELLBORE PARAMETERS
  Period                                                5
  Selected semi log straight line segment       92 to 147
  Fitted semi-log slope (psi)/(stb/d)         -.52003-003
  Flow Capacity , mD.ft                           185568.
  Permeability , mD                              3711.360*
  Extrapolated (pseudo) pressure psi             .2387+004

  No. of points fitted                                 56
  Correlation coefficient                          -1.000

 Period (0 if no more) (       6) ? )  )
```

* Second slope analysed with oil viscosity of 0.67 cp.

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1B STRAIN GAUGE SDP 83068
INJECTION TEST COMMENCING AT 1800.00 24/2/86

WELL AND RESERVOIR DATA

Formation net thickness	:	50.00 ft
Reservoir fluid	:	water
Pre-test reservoir pressure	:	2432.1 psi
Perforated interval	:	5308.0- 5351.0 ft
Wellbore radius	:	.510 ft
Absolute porosity	:	.300

PVT PROPERTIES

FORMATION VOL FACTOR BO bbl/bbl	VISC AT RESV CONDITIONS cP	TOTAL COMPRESSIBILITY ct psi-1
1.0200	1.250	.4400-004

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-16 STRAIN GAUGE SDP 83068
INJECTION TEST COMMENCING AT 1800.00 24/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
1	0	.0	.00000	.00000	2432.1
2	1Bu	-13375.0	.00833	.00833	2626.7
3	1Bu	-13375.0	.17778	.17778	3250.5
4	1Bu	-13375.0	.34167	.34167	3311.2
5	1Bu	-13375.0	.50833	.50833	3327.7
6	1Bu	-13375.0	.68333	.68333	3337.0
7	1Bu	-13375.0	.84444	.84444	3346.1
8	1Bu	-13375.0	1.00833	1.00833	3361.4
9	1Bu	-13375.0	1.01944	1.01944	3362.3
10	1Bu	-13375.0	1.17500	1.17500	3373.3
11	1Bu	-13375.0	1.50833	1.50833	3400.1
12	1Bu	-13375.0	2.01389	2.01389	3451.8
13	1Bu	-13375.0	2.50833	2.50833	3511.6
14	1Bu	-13375.0	3.01111	3.01111	3564.0
15	1Bu	-13375.0	3.51111	3.51111	3581.2
16	1Bu	-13375.0	4.00833	4.00833	3680.3
17	1Bu	-13375.0	4.50833	4.50833	3802.2
18	1Bu	-13375.0	5.00833	5.00833	3841.8
19	1Bu	-13375.0	5.50833	5.50833	3870.8
20	1Bu	-13375.0	6.00556	6.00556	3957.1
21	2Bu	-15080.0	6.09167	.08611	3994.5
22	2Bu	-15080.0	6.25833	.25278	4073.1
23	2Bu	-15080.0	6.34167	.33611	4093.9
24	2Bu	-15080.0	6.50556	.50000	4063.4
25	3Bu	-13260.0	6.51111	.00556	4071.2
26	3Bu	-13260.0	6.67500	.16944	4106.4
27	3Bu	-13260.0	6.84167	.33611	4122.5
28	3Bu	-13260.0	7.00833	.50278	4136.2
29	3Bu	-13260.0	7.17500	.66944	4164.7
30	3Bu	-13260.0	7.67500	1.16944	4226.6
31	3Bu	-13260.0	8.00833	1.50278	4256.8
32	3Bu	-13260.0	8.01111	1.50556	4256.6
33	3Bu	-13260.0	8.17500	1.66944	4174.0
34	3Bu	-13260.0	8.34167	1.83611	4143.7
35	3Bu	-13260.0	8.50556	2.00000	4167.2
36	4Bu	-11315.0	8.67500	.16944	4142.9
37	4Bu	-11315.0	8.67778	.17222	4142.8
38	4Bu	-11315.0	8.84444	.33889	4130.5
39	4Bu	-11315.0	9.00833	.50278	4075.2
40	4Bu	-11315.0	9.17500	.66944	4044.0

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1B STRAIN GAUGE SDP 83068
INJECTION TEST COMMENCING AT 1800.00 24/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
41	4Bu	-11315.0	9.34167	.83611	4080.7
42	4Bu	-11315.0	9.50833	1.00278	4078.5
43	4Bu	-11315.0	10.00833	1.50278	4074.0
44	4Bu	-11315.0	10.51667	2.01111	4100.8
45	4Bu	-11315.0	11.00833	2.50278	4121.6
46	4Bu	-11315.0	11.51111	3.00556	4086.3
47	4Bu	-11315.0	12.00833	3.50278	4073.3
48	4Bu	-11315.0	12.01111	3.50556	4071.8
49	4Bu	-11315.0	12.19444	3.68889	4013.8
50	5Bu	.0	12.19722	.00278	2907.9
51	5Bu	.0	12.20000	.00556	2644.4
52	5Bu	.0	12.20278	.00833	2525.5
53	5Bu	.0	12.20556	.01111	2472.7
54	5Bu	.0	12.20833	.01389	2462.9
55	5Bu	.0	12.21389	.01944	2458.2
56	5Bu	.0	12.21944	.02500	2456.0
57	5Bu	.0	12.22500	.03056	2451.5
58	5Bu	.0	12.22778	.03333	2446.1
59	5Bu	.0	12.23333	.03889	2443.7
60	5Bu	.0	12.24444	.05000	2437.9
61	5Bu	.0	12.25556	.06111	2433.4
62	5Bu	.0	12.26667	.07222	2429.5
63	5Bu	.0	12.27778	.08333	2426.7
64	5Bu	.0	12.28889	.09444	2424.4
65	5Bu	.0	12.31111	.11667	2421.3
66	5Bu	.0	12.33333	.13889	2419.1
67	5Bu	.0	12.37778	.18333	2416.8
68	5Bu	.0	12.42222	.22778	2414.9
69	5Bu	.0	12.46667	.27222	2413.8
70	5Bu	.0	12.55556	.36111	2412.5
71	5Bu	.0	12.64444	.45000	2412.0
72	5Bu	.0	12.73333	.53889	2411.4
73	5Bu	.0	12.82222	.62778	2411.0
74	5Bu	.0	12.91111	.71667	2410.6
75	5Bu	.0	13.00000	.80556	2410.3
76	5Bu	.0	13.08889	.89444	2410.0
77	5Bu	.0	13.17778	.98333	2409.8
78	5Bu	.0	13.26667	1.07222	2409.6
79	5Bu	.0	13.35556	1.16111	2409.2
80	5Bu	.0	13.44444	1.25000	2409.0

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-16 STRAIN GAUGE SDP 83068
INJECTION TEST COMMENCING AT 1800.00 24/2/86

SEQUENCE OF EVENTS

PAGE- 3

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
81	5Bu	.0	13.53333	1.33889	2408.9
82	5Bu	.0	13.62222	1.42778	2408.7
83	5Bu	.0	13.71111	1.51667	2408.5
84	5Bu	.0	13.80000	1.60556	2408.4
85	5Bu	.0	13.88889	1.69444	2408.2
86	5Bu	.0	13.97778	1.78333	2408.0
87	5Bu	.0	14.06667	1.87222	2407.9
88	5Bu	.0	14.15556	1.96111	2407.9
89	5Bu	.0	14.24444	2.05000	2407.6
90	5Bu	.0	14.33333	2.13889	2407.6
91	5Bu	.0	14.42222	2.22778	2407.5
92	5Bu	.0	14.51111	2.31667	2407.5
93	5Bu	.0	14.60000	2.40556	2407.4
94	5Bu	.0	14.68889	2.49444	2407.1
95	5Bu	.0	14.77778	2.58333	2407.1
96	5Bu	.0	14.86667	2.67222	2407.0
97	5Bu	.0	14.95556	2.76111	2406.9
98	5Bu	.0	15.04444	2.85000	2406.9
99	5Bu	.0	15.13333	2.93889	2406.8
100	5Bu	.0	15.22222	3.02778	2406.6
101	5Bu	.0	15.31111	3.11667	2406.6
102	5Bu	.0	15.40000	3.20556	2406.5
103	5Bu	.0	15.48889	3.29444	2406.5
104	5Bu	.0	15.57778	3.38333	2406.4
105	5Bu	.0	15.66667	3.47222	2406.3
106	5Bu	.0	15.75556	3.56111	2406.3
107	5Bu	.0	15.84444	3.65000	2406.2
108	5Bu	.0	15.93333	3.73889	2406.2
109	5Bu	.0	16.02222	3.82778	2406.1
110	5Bu	.0	16.11111	3.91667	2406.0
111	5Bu	.0	16.20000	4.00556	2405.9
112	5Bu	.0	16.28889	4.09444	2405.9
113	5Bu	.0	16.37778	4.18333	2405.9
114	5Bu	.0	16.42222	4.22778	2405.8
115	5Bu	.0	16.43333	4.23889	2405.8
116	5Bu	.0	16.43889	4.24444	2405.9
117	5Bu	.0	16.44444	4.25000	2405.9
118	5Bu	.0	16.53333	4.33889	2405.8
119	5Bu	.0	16.62222	4.42778	2405.7
120	5Bu	.0	16.71111	4.51667	2405.7

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-16 STRAIN GAUGE SDP 83068
INJECTION TEST COMMENCING AT 1800.00 24/2/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
121	5Bu	.0	16.80000	4.60556	2405.6
122	5Bu	.0	16.88889	4.69444	2405.6
123	5Bu	.0	16.97778	4.78333	2405.5
124	5Bu	.0	17.06667	4.87222	2405.5
125	5Bu	.0	17.15556	4.96111	2405.5
126	5Bu	.0	17.24444	5.05000	2405.4
127	5Bu	.0	17.33333	5.13889	2405.4
128	5Bu	.0	17.42222	5.22778	2405.2
129	5Bu	.0	17.51111	5.31667	2405.2
130	5Bu	.0	17.68889	5.49444	2405.2
131	5Bu	.0	17.86667	5.67222	2405.1
132	5Bu	.0	17.95556	5.76111	2405.0
133	5Bu	.0	17.98056	5.78611	2405.1
134	5Bu	.0	18.02500	5.83056	2405.0

```
   Period range =          50          134
    Horner begin point   (        50) ? ))59

    Horner end   point   (       134) ? ))63


 CALCULATED FORMATION AND WELLBORE PARAMETERS
   Period                                                    5
   Selected semi log straight line segment             59 to  63
   Fitted semi-log slope (psi)/(stb/d)               -.39695-002
   Flow Capacity , mD.ft                                45356.
   Permeability , mD                                    907.110
   Extrapolated (pseudo) pressure psi                 .2309+004

   No. of points fitted                                      5
   Correlation coefficient                              -1.000

  Period (0 if no more) (         6) ? )  )0

SKIN ANALYSIS FOR DRAWDOWN PERIODS
  Permeability, mD ( 907.1     ) ? )   )


  Period (0 if no more) (         1) ? )  )

   Period range =           2           20
    Horner begin point   (         2) ? ))

    Horner end   point   (        20) ? ))

   Drawdown period                                           1
   Selected semi log straight line segment              2 to  20
   Initial (pseudo) pressure psi                      .2432+004
   Extrapolated (pseudo) pressure psi                 .3466+004
   Total skin                                           13.608
   No. of points fitted                                     19
```

```
Period (0 if no more) (         2) ? )  )

 Period range =            21          24
  Horner begin point   (        21) ? ))

  Horner end    point   (        24) ? ))

 Drawdown period                                                2
 Selected semi log straight line segment                21 to  24
 Initial (pseudo) pressure psi                          .2432+004
 Extrapolated (pseudo) pressure psi                     .4012+004
 Total skin                                                20.526
 No. of points fitted                                           4

Period (0 if no more) (         3) ? )  )

 Period range =            25          35
  Horner begin point   (        25) ? ))

  Horner end    point   (        35) ? ))

 Drawdown period                                                3
 Selected semi log straight line segment                25 to  35
 Initial (pseudo) pressure psi                          .2432+004
 Extrapolated (pseudo) pressure psi                     .4109+004
 Total skin                                                25.997
 No. of points fitted                                          11

Period (0 if no more) (         4) ? )  )

 Period range =            36          49
  Horner begin point   (        36) ? ))

  Horner end    point   (        49) ? ))

 Drawdown period                                                4
 Selected semi log straight line segment                36 to  49
 Initial (pseudo) pressure psi                          .2432+004
 Extrapolated (pseudo) pressure psi                     .4027+004
 Total skin                                                29.641
 No. of points fitted                                          14

Period (0 if no more) (         5) ? )  )0

SUMMARY OF SKIN ANALYSIS
 Total skin fitted for period  1                           13.608
 Total skin fitted for period  2                           20.526
 Total skin fitted for period  3                           25.997
 Total skin fitted for period  4                           29.641

 Average skin                                                  7.
 No. of points fitted                                           4
```

RADIUS OF INVESTIGATION TABLE, Rinv (feet)

nØj∮	1	2	3	4	5
1 ∮	526.				
2 ∮	548.	152.			
3 ∮	626.	340.	304.		
4 ∮	750.	534.	512.	413.	
5 ∮	912.	745.	729.	663.	519.

Rinv (n,j) is the radius of investigation, at the end of period n, of the pressure transient induced by the rate change which took place at the start of period j.

Base Permeability , mD	907.110
Hydraulic Diffusivity , mD.psi/cP	.550+008

MULTI-RATE PRESSURE TRANSIENT DURATION TABLE, DT (hours)

nØj∮	1	2	3	4	5
1 ∮	6.0				
2 ∮	6.5	.5			
3 ∮	8.5	2.5	2.0		
4 ∮	12.2	6.2	5.7	3.7	
5 ∮	18.0	12.0	11.5	9.5	5.8

DT (n,j) is the duration, at the end of period n, of the of the pressure transient induced by the rate change which took place at the start of period j. Note that the duration of the last period may have been extended so as to reach beyond the start of semi-steady state (if finite reservoir).

RATE CHANGE HISTORY (INDUCING PRESSURE TRANSIENTS

Rate change at start of period 1, stb/d	-13375.000
Rate change at start of period 2, stb/d	-1705.000
Rate change at start of period 3, stb/d	1820.000
Rate change at start of period 4, stb/d	1945.000
Rate change at start of period 5, stb/d	11315.000

```
Period range =            50          134
 Horner begin point   (        50) ? ))71

 Horner end   point   (       134) ? ))110

CALCULATED FORMATION AND WELLBORE PARAMETERS
  Period                                                          5
  Selected semi log straight line segment                 71 to 110
  Fitted semi-log slope (psi)/(stb/d)                  -.52761-003
  Flow Capacity , mD.ft                                    182899.
  Permeability , mD                                       3657.978*
  Extrapolated (pseudo) pressure psi                      .2401+004

  No. of points fitted                                           40
  Correlation coefficient                                     -.999

 Period (0 if no more) (        6) ? )  )
```

* Second slope analysed with oil viscosity of 0.67 cp.

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1H
INJECTION TEST COMMENCING AT 1357.00 1/3/86

WELL AND RESERVOIR DATA

Formation net thickness	:	50.00 ft
Reservoir fluid	:	
Pre-test reservoir pressure	:	2340.6 psi
Perforated interval	:	5308.0- 5351.0 ft
Wellbore radius	:	.510 ft
Absolute porosity	:	.300

PVT PROPERTIES

FORMATION VOL FACTOR BO bbl/bbl	VISC AT RESV CONDITIONS cP	TOTAL COMPRES SIBILITY ct psi-1
1.0200	1.250	.4400-004

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1H HP/EMR 59654/1018/449
INJECTION TEST COMMENCING AT 1357.00 1/3/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
1	0	.0	.00000	.00000	2390.6
2	1Bu	-13325.0	.08000	.08000	3239.6
3	1Bu	-13325.0	.54000	.54000	3605.0
4	1Bu	-13325.0	1.04000	1.04000	3603.0
5	1Bu	-13325.0	1.54000	1.54000	3603.4
6	1Bu	-13325.0	2.04000	2.04000	3611.0
7	1Bu	-13325.0	2.54000	2.54000	3780.4
8	1Bu	-13325.0	3.04000	3.04000	3758.2
9	1Bu	-13325.0	3.54000	3.54000	3748.5
10	1Bu	-13325.0	4.04000	4.04000	3757.3
11	1Bu	-13325.0	4.54000	4.54000	3755.3
12	1Bu	-13325.0	5.04000	5.04000	3727.6
13	1Bu	-13325.0	5.54000	5.54000	3731.4
14	1Bu	-13325.0	6.04000	6.04000	3732.8
15	1Bu	-13325.0	6.54000	6.54000	3733.2
16	1Bu	-13325.0	7.04000	7.04000	3734.1
17	1Bu	-13325.0	7.54000	7.54000	3735.2
18	1Bu	-13325.0	8.04000	8.04000	3729.6
19	1Bu	-13325.0	8.54000	8.54000	3742.2
20	1Bu	-13325.0	9.04000	9.04000	3728.7
21	1Bu	-13325.0	9.54000	9.54000	3730.3
22	1Bu	-13325.0	10.04000	10.04000	3732.4
23	1Bu	-13325.0	10.54000	10.54000	3742.9
24	1Bu	-13325.0	11.04000	11.04000	3743.2
25	1Bu	-13325.0	11.54000	11.54000	3738.0
26	1Bu	-13325.0	12.04000	12.04000	3738.5
27	1Bu	-13325.0	12.54000	12.54000	3740.9
28	1Bu	-13325.0	12.67194	12.67194	3744.1
29	2Bu	.0	12.73000	.05806	2423.0
30	2Bu	.0	12.73194	.06000	2421.5
31	2Bu	.0	12.73583	.06389	2420.3
32	2Bu	.0	12.74000	.06806	2419.1
33	2Bu	.0	12.74389	.07194	2417.9
34	2Bu	.0	12.74778	.07583	2416.8
35	2Bu	.0	12.75194	.08000	2415.9
36	2Bu	.0	12.75583	.08389	2415.0
37	2Bu	.0	12.76000	.08806	2415.0
38	2Bu	.0	12.76389	.09194	2413.3
39	2Bu	.0	12.76778	.09583	2412.6
40	2Bu	.0	12.77194	.10000	2411.?

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1H HP/EMR 59654/1018/449
INJECTION TEST COMMENCING AT 1357.00 1/3/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
41	2Bu	.0	12.77583	.10389	2411.3
42	2Bu	.0	12.78000	.10806	2410.7
43	2Bu	.0	12.78389	.11194	2410.2
44	2Bu	.0	12.78778	.11583	2409.7
45	2Bu	.0	12.79194	.12000	2409.2
46	2Bu	.0	12.79583	.12389	2408.9
47	2Bu	.0	12.80000	.12806	2408.3
48	2Bu	.0	12.80389	.13194	2408.3
49	2Bu	.0	12.80778	.13583	2407.6
50	2Bu	.0	12.81194	.14000	2407.3
51	2Bu	.0	12.81583	.14389	2407.0
52	2Bu	.0	12.82000	.14806	2407.7
53	2Bu	.0	12.82389	.15194	2406.3
54	2Bu	.0	12.82778	.15583	2406.1
55	2Bu	.0	12.83194	.16000	2405.8
56	2Bu	.0	12.83583	.16389	2405.6
57	2Bu	.0	12.84000	.16806	2405.4
58	2Bu	.0	12.84389	.17194	2405.2
59	2Bu	.0	12.84778	.17583	2405.2
60	2Bu	.0	12.85194	.18000	2404.7
61	2Bu	.0	12.85583	.18389	2404.5
62	2Bu	.0	12.86000	.18806	2404.3
63	2Bu	.0	12.86389	.19194	2404.1
64	2Bu	.0	12.86778	.19583	2404.0
65	2Bu	.0	12.87194	.20000	2403.8
66	2Bu	.0	12.87583	.20389	2403.8
67	2Bu	.0	12.88000	.20806	2403.7
68	2Bu	.0	12.88389	.21194	2403.7
69	2Bu	.0	12.88778	.21583	2403.5
70	2Bu	.0	12.89583	.22389	2403.3
71	2Bu	.0	12.90000	.22806	2403.0
72	2Bu	.0	12.90389	.23194	2403.0
73	2Bu	.0	12.90778	.23583	2403.0
74	2Bu	.0	12.91194	.24000	2403.0
75	2Bu	.0	12.91583	.24389	2403.0
76	2Bu	.0	12.92000	.24806	2403.0
77	2Bu	.0	12.92389	.25194	2403.0
78	2Bu	.0	12.94000	.26806	2402.7
79	2Bu	.0	12.96000	.28806	2402.4
80	2Bu	.0	12.97583	.30389	2402.3

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1H HP/EMR 59654/1018/449
INJECTION TEST COMMENCING AT 1357.00 1/3/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
81	2Bu	.0	12.99194	.32000	2402.2
82	2Bu	.0	13.00778	.33583	2402.1
83	2Bu	.0	13.02389	.35194	2402.0
84	2Bu	.0	13.04000	.36806	2401.9
85	2Bu	.0	13.06000	.38806	2401.8
86	2Bu	.0	13.07583	.40389	2401.7
87	2Bu	.0	13.09194	.42000	2401.6
88	2Bu	.0	13.10778	.43583	2401.6
89	2Bu	.0	13.12389	.45194	2401.5
90	2Bu	.0	13.14389	.47194	2401.4
91	2Bu	.0	13.16000	.48806	2401.3
92	2Bu	.0	13.17583	.50389	2401.2
93	2Bu	.0	13.19194	.52000	2401.2
94	2Bu	.0	13.20778	.53583	2401.1
95	2Bu	.0	13.22389	.55194	2401.0
96	2Bu	.0	13.24389	.57194	2400.9
97	2Bu	.0	13.26000	.58806	2400.9
98	2Bu	.0	13.29194	.62000	2400.7
99	2Bu	.0	13.32389	.65194	2400.6
100	2Bu	.0	13.36000	.68806	2400.4
101	2Bu	.0	13.39194	.72000	2400.2
102	2Bu	.0	13.42778	.75583	2400.1
103	2Bu	.0	13.46000	.78806	2400.0
104	2Bu	.0	13.49583	.82389	2399.8
105	2Bu	.0	13.52778	.85583	2399.7
106	2Bu	.0	13.56000	.88806	2399.5
107	2Bu	.0	13.60000	.92806	2399.4
108	2Bu	.0	13.64000	.96806	2399.2
109	2Bu	.0	13.68000	1.00806	2399.1
110	2Bu	.0	13.72000	1.04806	2398.9
111	2Bu	.0	13.76000	1.08806	2398.8
112	2Bu	.0	13.78000	1.10806	2398.7
113	2Bu	.0	13.82000	1.14806	2398.6
114	2Bu	.0	13.86000	1.18806	2398.5
115	2Bu	.0	13.88000	1.20806	2398.4
116	2Bu	.0	13.92000	1.24806	2398.3
117	2Bu	.0	13.96000	1.28806	2398.1
118	2Bu	.0	14.04000	1.36806	2398.0
119	2Bu	.0	14.12000	1.44806	2397.7
120	2Bu	.0	14.20000	1.52806	2397.5

DRAUGEN WELL : 6407/9-6
PROD.TEST PT-1H HP/EMR 59654/1018/449
INJECTION TEST COMMENCING AT 1357.00 1/3/86

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
121	2Bu	.0	14.28000	1.60306	2397.3
122	2Bu	.0	14.36000	1.68306	2397.1
123	2Bu	.0	14.44000	1.76306	2396.9
124	2Bu	.0	14.52000	1.84306	2396.8
125	2Bu	.0	14.60000	1.92306	2396.6
126	2Bu	.0	14.68000	2.00306	2396.5
127	2Bu	.0	14.84000	2.16306	2396.2
128	2Bu	.0	15.08000	2.40306	2395.9
129	2Bu	.0	15.38000	2.70306	2395.5
130	2Bu	.0	15.58000	2.90306	2395.2
131	2Bu	.0	15.82000	3.14306	2394.9
132	2Bu	.0	15.86000	3.18306	2394.9
133	2Bu	.0	16.04000	3.36306	2394.7
134	2Bu	.0	16.26000	3.58306	2394.5
135	2Bu	.0	16.44000	3.76306	2394.3
136	2Bu	.0	16.58000	3.90306	2394.2
137	2Bu	.0	16.88000	4.20306	2393.9
138	2Bu	.0	17.08000	4.40306	2393.8
139	2Bu	.0	17.24000	4.56306	2393.7
140	2Bu	.0	17.42000	4.74306	2393.5
141	2Bu	.0	17.64000	4.96306	2393.4
142	2Bu	.0	17.82000	5.14306	2393.3
143	2Bu	.0	17.88000	5.20306	2393.2
144	2Bu	.0	18.08000	5.40306	2393.1
145	2Bu	.0	18.56000	5.88306	2392.9

```
  Period range =            29          145
   Horner begin point   (         29) ? ))35

   Horner end   point   (        145) ? ))61


CALCULATED FORMATION AND WELLBORE PARAMETERS
  Period                                                    2
  Selected semi log straight line segment             35 to  61
  Fitted semi-log slope (psi)/(stb/d)                -.20258-002
  Flow Capacity , mD.ft                                  88872.
  Permeability , mD                                    1777.438
  Extrapolated (pseudo) pressure psi                  .2347+004

  No. of points fitted                                       27
  Correlation coefficient                                 -.990

 Period (0 if no more) (          3) ? )  )0

SKIN ANALYSIS FOR DRAWDOWN PERIODS
 Permeability, mD ( 1777.     ) ? )   )


 Period (0 if no more) (          1) ? )  )

  Period range =             2           28
   Horner begin point   (          2) ? ))6

   Horner end   point   (         28) ? ))

  Drawdown period                                             1
  Selected semi log straight line segment              6 to  28
  Initial (pseudo) pressure psi                       .2391+004
  Extrapolated (pseudo) pressure psi                  .3710+004
  Total skin                                             42.666
  No. of points fitted                                       23

 Period (0 if no more) (          2) ? )  )0

SUMMARY OF SKIN ANALYSIS
 Total skin fitted for period  1                         42.666

 Average skin                                               43.
 No. of points fitted                                        1
```

RADIUS OF INVESTIGATION TABLE, Rinv (feet)

nØjø	1	2
1 ø	1070.	
2 ø	1295.	730.

Rinv (n,j) is the radius of investigation, at the end of period n, of the pressure transient induced by the rate change which took place at the start of period j.

Base Permeability , mD 1777.432
Hydraulic Diffusivity , mD.psi/cP .108+009

MULTI-RATE PRESSURE TRANSIENT DURATION TABLE, DT (hours)

nØjø	1	2
1 ø	12.7	
2 ø	18.6	5.9

DT (n,j) is the duration, at the end of period n, of the of the pressure transient induced by the rate change which took place at the start of period j. Note that the duration of the last period may have been extended so as to reach beyond the start of semi-steady state (if finite reservoir).

RATE CHANGE HISTORY (INDUCING PRESSURE TRANSIENTS)

Rate change at start of period 1, stb/d -13325.000
Rate change at start of period 2, stb/d 13325.000

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SIDEWALL SAMPLES

WELL 6407/9-6

Encl. 2

RUN 1, GUN 1

TOP NO.	GUN DEPTH (M)	RECOVERY (MM)	LITHOLOGY				
1	1787.4		MISSING				
2	1785.4	40	SLTST:	DK GY, FRM - (HD), MIC.	NIL	NIL	NIL
3	1780.9	34	SLTST:	MED (GN) GY, FRM, MIC, (CALC)	NIL	NIL	NIL
4	1775.4	21	S:	MED (GN) GY, FSL, MIC, PRLY CMTD, - CALC CMT.	NIL	NIL	NIL
5	1772.9		MISSING				
6	1765.9	24	S:	MED (GN) GY, FSL- FSU, (ANG), LSE, PRLY CMTD, CALC CMT.	NIL	NIL	NIL
7	1762.4	30	S:	MED GY, FSU-FSL; (ANG), LSE.	NIL	NIL	NIL
8	1755.9	34	S:	MED GY, FSL-FSU, (ANG), LSE, PRLY CMTD, CALC CMT.	NIL	NIL	NIL
9	1751.9	30	S:	MED DK GY, FSU, (ANG), LSE PRLY CMT, CALC CMT.	NIL	NIL	NIL
10	1747.4		MISSING				
11	1738.4	37	S:	MED-DK GY, FSU-FSL, LSE, (ANG), PRLY CMTD, CALC CMT.	NIL	NIL	NIL
12	1737.4		EMPTY				
13	1733.4		MISSING				
14	1730.9	31	S:	LT-MED GY,OCC (BRN) GY, FSL-FSU, (ANG) - (RND), SRTD, PRLY CMTD, CALC CMT, MIC.	NIL	NIL	NIL
15	1729.9		EMPTY				
16	1726.4	30	S:	LT-MED GY, FSL-FSU, (ANG) (RND), SRTD. PRLY CMTD, CALC CMT, MIC.	NIL	NIL	NIL
17	1724.4		MISSING				
18	1722.9		EMPTY				
19	1720.9		EMPTY				
20	1717.9	35	S:	WH-LT (BRN) GY, FSU-MSU, (ANG) - (RND), SRTD, PRLY CMTD, CALC, CMT, (SLTY),MIC	NIL	NIL	NIL
21	1715.4		MISSING				
22	1712.9		MISSING				
23	1710.4		MISSING				
24	1708.2	24	S:	MED-DK (BRN) GY, FSL-FSU, (ANG), PRLY CMTD, PRLY SRTD, SLTY, MIC,(CARB)	NIL	NIL	NIL
25	1705.9		MISFIRE				

Encl. 2

RUN 1, GUN 2

TOP NO.	GUN DEPTH (M)	RECOVERY (MM)	LITHOLOGY		SHOW S/F	C/C	C/F
1	1704.4	23	S:	MED DK GY, FSL, W SRTD, LSE, (ANG)	NIL	NIL	NIL
2	1702.4	35	S:	MED GY, MSL-MSU, SRTD, LSE, (ANG)	NIl	NIL	NIL
3	1697.4	29	S:	MED-LT GY, FSU-MSL, SRTD, V LSE, (ANG)-(RND)	NIL	NIl	NIL
4	1695.4	35	S:	MED GY, FSU-MSL,SRT, LSE, ANG.	NIL	NIL	NIL
5	1692.4	29	S:	DK GY FSU, SRTD, LSE, ANG, MIC, SLST STRKS, (GY) BLK, FRM, FISS.	NIL	NIL	NIL
6	1691.4	33	S:	MED GY, FSL, MO SRTD, LSE, ANG, MIC.	NIL	NIL	NIL
7	1688.9	34	S:	MED DK GY, FSL-FSU, MO SRTD, LSE, ANG, MIC.	GOOD	YL	PA YL
8	1687.4		MISSING				
9	1658.4	40	S:	MED DK GY, FSU-MSL,SRTD LSE, ANG, MIC.	DULL YELL NAT FLUOR, SLOW PALEBL STM CUT, BRT BLUE C/CUT.		
10	1657.9	34	S:	DK (GN) GY, FSU-MSL, MO SRTD, LSE, ANG, MIC.	BRT YELL NAT FLUOR, BRT BL YELL C/CUT.		
11	1645.4	34	S:	DK (GN) GY, MSL; MO SRTD, LSE, (ANG), MIC	BRT YELL NAT FLUOR, PALE BL SOLV CUT, BRT MLKY BLU C/CUT.		
12	1644.4		MISSING				
13	1643.4	36	S:	OLV GY, FSU-MSL, MO SRTD, LSE, (ANG)-(RND), MIC	BRT YELL NAT FLUOR, BRT MLKY BL SOLV CUT, BRT MLKY BL C/CUT.		
14	1642.4		MISSING				
15	1641.9		MISSING				
16	1641.4		MISSING				
17	1640.9		MISSING				
18	1640.4		MISSING				
19	1639.4		MISSING				
20	1638.4	32	CLST:	(GY) BLK, (HD), (FISS), MIC.	NIL	NIL	NIL
21	2637.4		MISSING				
22	1633.6		MISSING				
23	1629.9	41	CLST:	(GY) BLK, (HD), (FISS), MIC.	NIL	NIL	NIL
24	1628.2		MISSING				
25	1623.9	31	CLST:	(GY) BLK; (HD), (FIS), MIC, (CALC).	NIL	NIL	NIL

RUN 2, GUN 1

TOP NO.	GUN DEPTH (M)	RECOVERY (MM)	LITHOLOGY		SHOW S/F	C/C	C/F
1x	1787.6	39	SLTST:	BLK, FRM, (FISS)MIC, CARB, NON CALC.	NIL	NIL	NIL
2x	1772.6	16	S:	WT-LT GY, FSL,(ANG)-(RND), LSE, PRLY, CONS; CALC CMT.	NIL	NIL	NIL
3x	1746.9	22	S:	WT-LT GY, FSL-FSU, (ANG), LSE, PRLY CONS, CALC CMT.	NIL	NIL	NIL
4x				EMTY			

RUN 3, GUN 1

TOP NO.	GUN DEPTH (M)	RECOVERY (MM)	LITHOLOGY		SHOW S/F	C/C	C/F
1	1736.9		EMTY				
2	1733.2	20	S:	LT-MED GY, FSL-FSU, (ANG)-(RND), LSE, PRLY CONS, CALC. CMT.	NIL	NIL	NIL
3	1730.1	19	S:	LT-MED GY,FSL-FSU,(ANG)-(RND), LSE, PRLY, CONS, CALC CMT.	NIL	NIL	NIL
4	1724.7	19	SLTST:	BLK GY, FRM, (FISS), (MIC) (CALC)	NIL	NIL	NIL
5	1722.4		LOST				
6	1720.4		LOST				
7	1714.9		EMPTY				
8	1713.4		LOST				
9	1710.9		LOST				
10	1706.4	19	S:	MED-DK GY, FSL-FSU, (ANG),FRM, MOD SRTD, PRLY CMTD, (PY) (CARB).	NIL	NIL	NIL
11	1687.9	21	S:	LT-MED GY,FSU-FSL,PRLY CONS, MOD SRTD, (ANG)-(RND),CALC CMT.	NIL	NIL	NIL
12	1644.2		EMPTY				
13	1643.9	18	S:	WT-(YEL) GY, FSU-MSL, PRLY CONS, WELL SRTD	BR YEL	NIL	STRW YEL
14	1643.2	35	S:	WT-LT GY,FSU-FSL,PRLY CONS, SRTD, (ANG)-RMD, CALC CMT	BR YEL	NIL	STRW YEL
15	1642.9		EMPTY				
16	1642.2	19	SLTST:	BLK_GY, FRM, (FISS), (MIC), NON CALC, CARB.	NIL	NIL	NIL
17	1641.6		EMPTY				
18	1641.2		LOST				
19	1640.7	30	SLST:	MED-DK GY, FRM, (FISS), (MIC) NON CALC, CARB.	NIL	NIL	NIL
20	1639.9	25	SLTST:	MED-DK GY, FRM, (FISS), (MIC), NON CALC, CARB.	NIL	NIL	NIL
23	1637.9		LOST				
22	1633.6		LOST				

Encl. 2