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statoil

PETROPHYSICAL EVALUATION
6407/1-2
JANUARY 1984

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Per Seim
Operation Technology
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SUBTITLE

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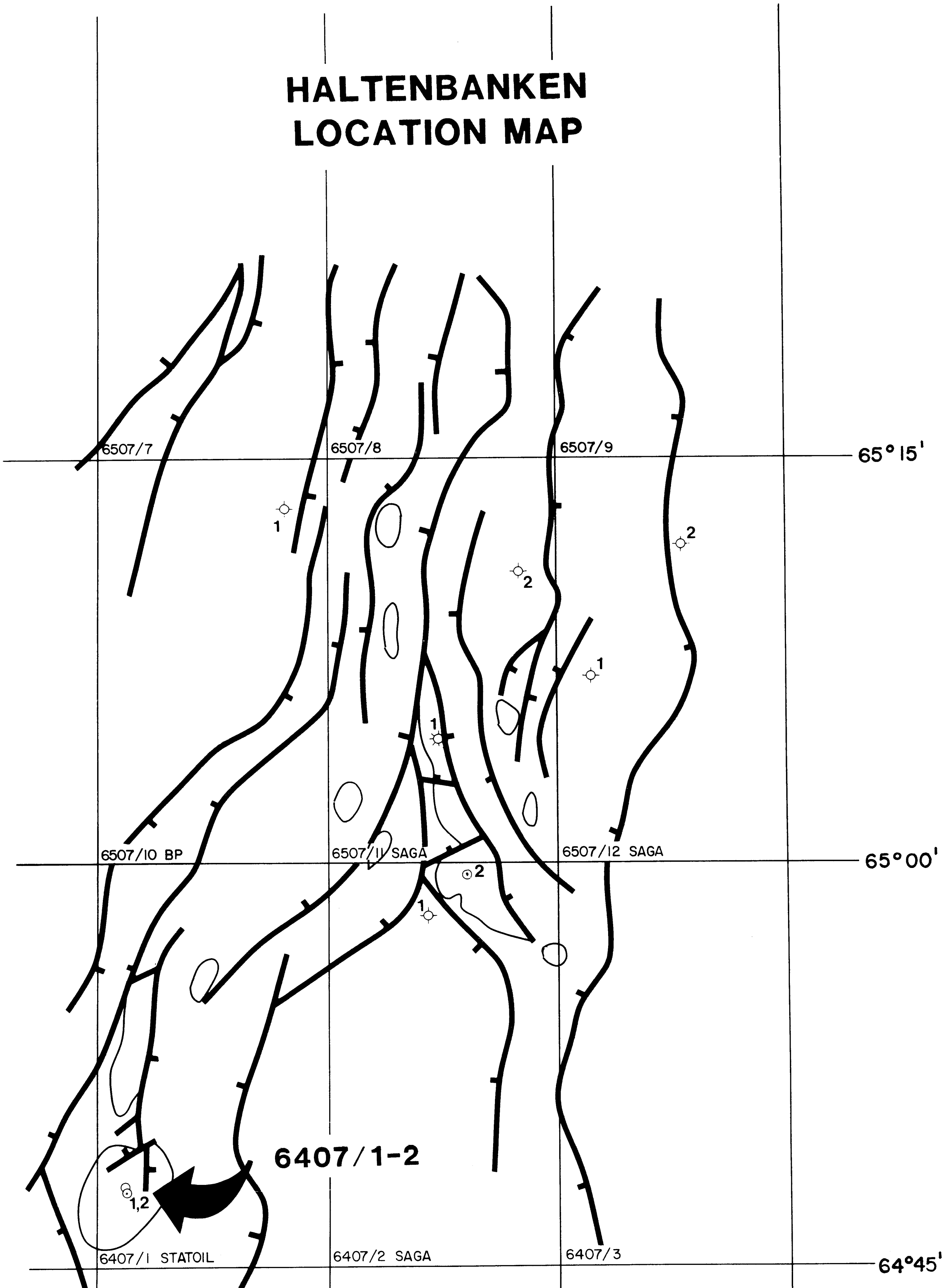
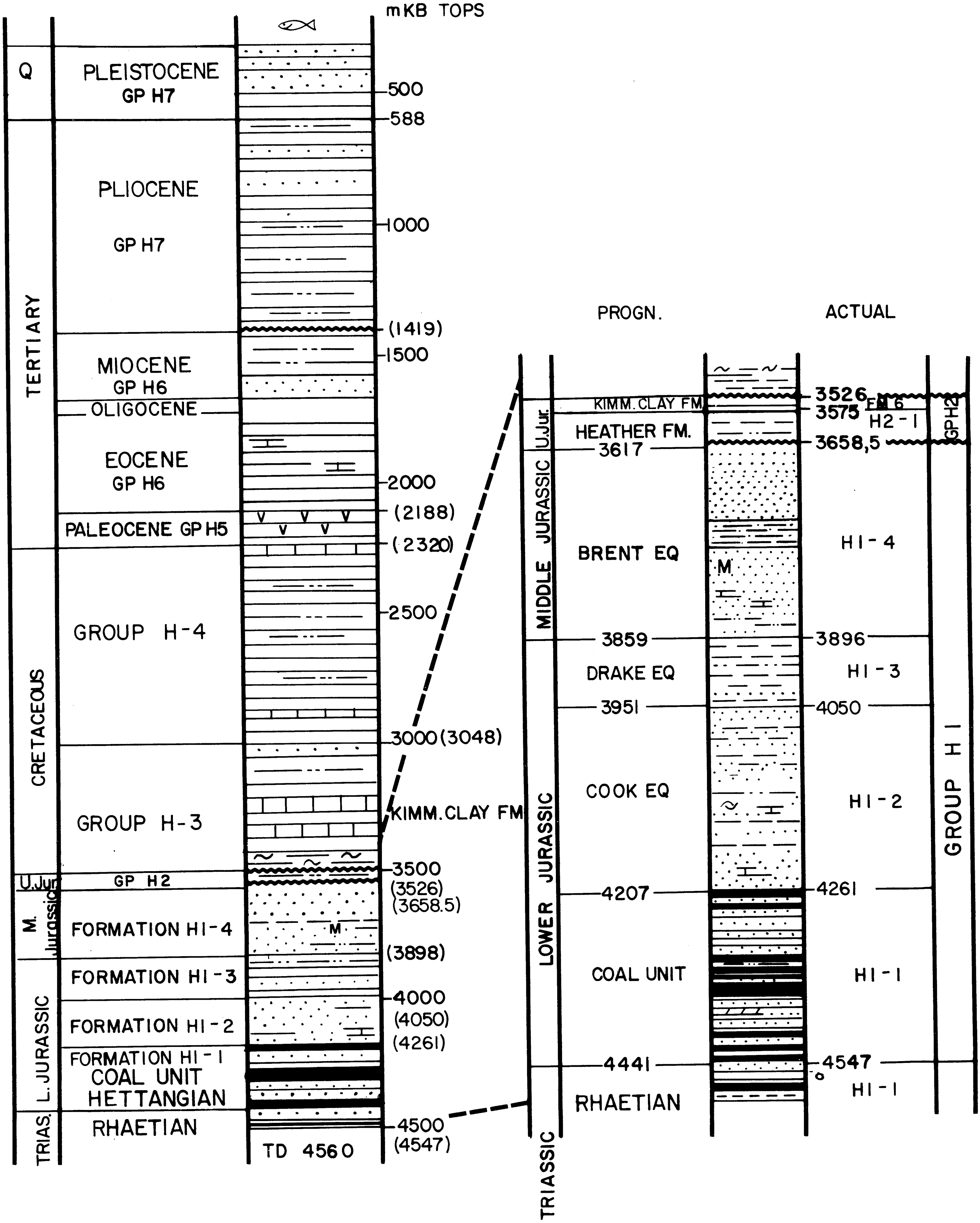
COMPLETED		APPROVED	
16.1.84	Per Seim	24/1-84	J. Hanstveit

HALTENBANKEN LOCATION MAP



6407/1-2

GENERALIZED STRATIGRAPHY



CONTENTS

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1. SUMMARY

Formation H1-4 of Middle Jurassic age was found to contain hydrocarbons. The top of the reservoir was encountered at 3658.5 mRKB, and a well defined hydrocarbon/water contact was found at 3716 mRKB.

The analysis of samples from the production test indicates that the reservoir contains a gas-condensate system.

The well has a net pay thickness of 56.8m, with 14.5% average porosity, 24.9% average water saturation and 10.9% average shale volume. The net sand thickness in formation H1-4, top sandstone member, is 111 m of a total thickness of 113.5 m.

2. INTRODUCTION

Well 6407/1-2 is the first well to reach the objectives in block 6407/1 as well 6407/1-1 was abandoned after setting 20" casing.

The primary ojective was to test the Jurassic sands for hydrocarbon accumulations.

The purpose of this report is to evaluate the petrophysical parameters of the middle Jurassic sands based on information from electrical logging and core measurements. Results from the drillstem test and the RFT logging are presented in separate reports.

The depth reference used in this report is the LDT-CNL-GR log shown in the graphical log presentation.

3. LITHOLOGY

This report is concerned only with formation H1-4, which is divided into three members, the top sandstone member (3658.5 - 3772 mRKB), the siltstone - claystone member (3772 - 3815 mRKB) and the lower sandstone member (3815 - 3898 mRKB).

The top sandstone member was deposited in a shallow water, high energy environment. The sand is homogeneous and contains hydrocarbons in the upper part. It is highly quartz-rich with minor amounts of feldspar, mica and sparse rock fragments. Pore-filling kaolinite is the main clay mineral present.

4. LOG QUALITY

After setting a 9 5/8" casing at 3546 mRKB, driller's depth, the well was drilled to 3701 mRKB, driller's depth, and logged with ISF-DDBHC-MSFL-GR and LDL-CNL-GR (run no. 3). The well was then drilled to 3969 mRKB, drillers depth, and the following open hole logs were run:

ISF-DDBHC-MSFL-GR	Run no. 4
LDL-CNL-GR	Run no. 4
DLL-NGT	Run no. 1
SHDT-GR	Run no. 1
RFT-GR	Run no. 1

Although some values in the master calibrations are questionable, the logs appear to be well calibrated with consistent readings before and after survey. No shifts due to calibration errors are required.

Several operational difficulties were experienced during the logging operations, and although the logs generally show good repeatability in the reservoir section, the hole was badly washed out during the time between the two logging runs. The DLL-NGT would not pass the hydrocarbon/water contact and is only available in the hydrocarbon zone. The LDT-CNL-GR would not enter the reservoir section after the main run, and run no. 3 was utilized as a repeat.

The deep induction curve has an anomalous resistivity peak at the top of the reservoir on both the main and the repeat log of run no. 4. This peak is not present in run no. 3 or in the DLL, and it is assumed that the severe washout above the reservoir causes the anomaly.

During both runs, the logs were severely affected by washouts and a rugose hole from the casing shoe down to the top of the reservoir. The best values in this section are found from run no. 3. Through the reservoir the hole is fairly well in gauge.

Mud properties were varying during drilling of this zone and the reserovir was drilled with varying mud weight. During run no. 4 mud pressure was about 90 bar above formation pressure, causing an anomalous invasion profile affecting log responses.

It can be concluded that, by merging results from the two log runs, a set of technically acceptable logs suitable for interpretation is available.

5. INTERPRETATION METHOD

5.1 Input Parameters

The parameters used in this interpretation is presented in table 5.1. The parameters are based on information from log headings, crossplots, histograms and pressure measurements. No zoning of paramters was performed, as the interval under consideration is relatively short and has a homogenous appearance.

5.2 Resistivity

Down to 3714 mRKB the readings from the DLL together with the MSFL curve from run no. 4 was used for resistivity evaluation. Normal borehole and invasion corrections were applied to get R_t and R_{xo} for this zone.

From 3714 mRKB down, the ISF-MSFL from run no. 4 was utilized. The deep induction and MSFL curves were manually corrected in this interval using standard corrections.

The resulting curves R_t and R_{xo} are presented in the graphical log presentation.

5.3 Formation Water Resistivity

Formation water resistivity was calculated using Hingle plots, SP and the Rwa-method. The apparent Rw were in the range 0.025-0.031 ohm m with SP giving the lowest value. As the SP-deflections are at a maximum in a rather high resistivity section of the log, this indicator was discarded, and the formation water resistivity chosen for this interpretation was taken as Rw= 0.030 ohm at 110^{o}C. This corresponds to a salinity of approximately 90 000 ppm. In well 6407/2-2, Saga reports a salinity of 100 000 ppm in middle jurassic sandstone at 2500 m RKB.

5.4 Shale Indicators

A total of four single curve and three two-curve shale indicators were calculated in both the hydrocarbon and water zone. The shale volume curve presented in the graphical log presentation was taken as the minimum of the indicators based on the GR-log, neutron log and the neutron-density crossplot in the hydrocarbon zone, and the GR-log, neutron-density and sonic-density crossplots in the water zone. The dominating shale indicator for the whole interval is the one calculated from the GR-log.

5.5 Porosity

In the hydrocarbon zone, the density and neutron logs were crossplotted using a sandstone-limestone model. Corrections for borehole effects, shale and hydrocarbon saturation in the invaded zone were applied, giving the final porosity.

In the water zone, porosity was evaluated using density, neutron and sonic porosities corrected for borehole effects and shale volume, with emphasis put on the density derived porosity. The final porosity is presented as PHIF in the graphical log presentation.

5.6 Water Saturations

Both invaded zone and virgin zone saturations were calculated using the Nigeria method presented in Schlumberger's Well Evaluation Conferences on Nigeria 1974 and North Sea 1974.

In view of the encountered porosity and depth of the sediments, the lithology factor a and saturation exponent n were taken as 1 and 2, respectively. Preliminary results from the core analysis indicated the cementation exponent m to be 1.9 when using a forced fit. The shale exponent c was taken as 1.6.

6. CORING SUMMARY

A total of four cores were cut in the interval 3661 - 3719.5 mRKB, drillers depth. 57.1 m of core was recovered. Preliminary results from the core analysis is presented in table 6.1.

In order to match the log depth, the results from the core analysis had to be depth shifted + 7.5 m.

Based on the reported values it is difficult to establish a relationship between porosity and permeability. The permeability seems to be a function mainly of grain size and the amount of porefilling material. Plots of porosity versus permeability are presented as figure 6.1 and 6.2.

7. DISCUSSION

In the cored interval there is generally good agreement between core measurements and log derived parameters. The average porosity from the log evaluation is approximately one percent lower than the average core porosity. This could be due to the influence of overburden pressure, and will be investigated in a special core analysis program.

The relatively high permeability values reported at porosity values of approximately 12% led to an adjustment of the cut-off values used for calculating the statistics. The porosity cut-off used in this evaluation is 10%. This has little influence on the net pay statistics, but does increase the net sand thickness. The cut-off values for water saturation and shale volume has very little influence on the statistics, and standard values of $Sw < 65\%$ and $Vsh < 40\%$ have been used.

The cores show that no shale is present in the cored interval, and the shale volume curve in this evaluation should rather be called a clay volume curve. Picking parameters from the adjacent shale beds for use in the shale correction routines are probably not correct, but the chosen values seem to be within the ranges given in the literature for the clay minerals present. The "shale volume" curve is also influenced by the presence of mica. The average "shale volume" of 10.9% in the net sand section seems to be be representative of the clay and mica concentration in this interval, and the resulting uncertainty in the final results are considered acceptable.

There are several indications of an anomalous invasion profile in the reservoir section. The density and neutron porosity curves does not show any gas effects in the hydrocarbon zone, apart from the top 1.5 meters where the porosity is higher. The spontaneous potential curve has a very gradual transition at the top of the reservoir, with the maximum deflection in the hydrocarbon zone, and a reduced deflection in the water zone. A segregated sample was taken with the RFT at 3665 m RKB, but only mud filtrate was recovered. The gradual increase in the calculated water saturation with depth over a rather long interval, could be due to a long transition zone or invasion effects, or both. Capillary pressure measurements from the core could give an indication here. All these effects are not fully understood, but a combination of gravity segregation and deep invasion could be possible. Hopefully, further core analysis could give some useful information.

At the top of the reservoir there is a 1.5 m zone with slightly higher porosity than the rest of the interval. The density and neutron curves are clearly affected by hydrocarbons in this section, and this is probably due to a very shallow invasion. This zone is also very clean.

The rest of the hydrocarbon zone, from 3660 to 3716 mRKB, has a homogeneous log response, although the core analysis indicates a change of facies at approximately 3688 mRKB.

The hydrocarbon-water contact has been defined as the bottom of the calcite cemented zone at 3715 - 3716 mRKB. The hydrocarbon saturation is reduced from 55% to residual saturations across this zone.

The residual saturations in the water zone down to 3745 m RKB are coinciding with weak shows reported from the wellsite sample description. The small amounts shown from 3745 m RKB to the bottom of the reservoir are probably due to statistical variations and within the accuracys expected, and this zone should be considered as containing only water.

The main statistics from this evaluation is presented in table 7.1, and detailed statistics in table 7.2.

TABLE 5.1

INPUT PARAMETERS

MUD PROPERTIES

Mud density	1.3 g/cm^3
Mud filtrate density	1.0 g/cm^3
Average mud pressure	470 bar
Mud resistivity at 110°C	0.11 ohm m
Mud filtrate resistivity at 110°C	0.075 ohm m
Mudcake resistivity at 110°C	0.20 ohm m
Mud salinity	15000 ppm Cl^-

SHALE PARAMETERS

Shale exponent c	1.6
Shale resistivity	3.5 ohm m
Density response in shale	2.56 g/cm^3
Neutron response in shale	0.41
Sonic response in shale	86 $\mu s/ft$
Gamma ray response in shale	100 API

FORMATION PARAMTERS

Lithology factor (a)	1
Cementation exponent (m)	1.9
Saturation exponent (n)	2
Average temperature	110°C
Matrix density	2.65 g/cm^3
Matrix transit time	54 $\mu s/ft$
Hydrocarbon density	0.4 g/cm^3
Gamma ray response	20 API

TABLE 6.1

CORE ANALYSIS, 6407/1-2

Cored interval	3661.0 - 3719.5 M RKB (driller)
Number of cores	4
Recovered	57.1 M
Average recovery	98%
Porosity range	6.3% - 19.0%
Average porosity	15.4%
Average porosity of net sand (PORHE > 10%)	15.6%
Average grain density	2.652 G/CM^3
Permeability range	
Horizontal	2.5-853 MD
Vertical	0.29-459 MD
Average air permeability	
Arithmetic horizontal	161.5 MD
Arithmetic vertical	85.5.MD
Geometric vertical	41.8 MD
Harmonic vertical	10.7 MD

TABLE 7.1

LOG ANALYSIS 6407/1-2

FORMATION H-1-4, TOP SANDSTONE MEMBER
INTERVAL 3658.5 - 3772.0 M RKB

	Thickness (M)	PHIF (%)	SW (%)	VSH (%)
Gross sand	113.5	13.4	60.1	10.9
Net sand	111.0	13.5	59.3	10.9
Net pay	56.8	14.5	24.9	10.9

Ratios:

Net pay/Gross sand	0.500
Net sand/Gross sand	0.978
Net pay/Net sand	0.516

Cut off:

Net pay	10% < PHIF < 100%
	0% < SW < 65%
	0% < VSH < 40%
Net sand	10% < PHI < 100%
	0% < VSH < 40%

Table 7.2

S T A T I S T I C S

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FIELD:	TYRIHANS
WELL:	6407-1-2
ENGINEER:	PS
DATE:	14.57 3 NOV 1983

DEPTH INTERVAL: . . . 3658.50 TO 3772.00

APPLIED CUTOFFS:

. USH:	GREATER THAN	0.40
. PHIF:	LESS THAN	0.10
. SW:	GREATER THAN	0.65

T O T A L   D E P T H

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THICKNESS:	113.500
AVERAGE . . . 'PHIF' . . .	0.134
AVERAGE . . . 'VSHALE' . .	0.109
AVERAGE . . . 'SW'	0.601
W.AVERAGE . . 'SW' * 'PHIF'	0.573
AVERAGE . . . 'SH'	0.405
VOID VOLUME: . . . ('PHIF').	15.259
HC VOID VOLUME . . ('SH'*) .	6.598
RES HC VOID VOLUME ('SHR'*).	3.293
MOV HC VOID VOLUME	3.305

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N E T   P A Y

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THICKNESS:	56.750
AVERAGE . . . 'PHIF' . . .	0.145
AVERAGE . . . 'VSHALE' . .	0.109
AVERAGE . . . 'SW'	0.249
W.AVERAGE . . 'SW' * 'PHIF'	0.248
AVERAGE . . . 'SH'	0.751
VOID VOLUME: . . . ('PHIF').	8.207
HC VOID VOLUME . . ('SH'*) .	6.170
RES HC VOID VOLUME ('SHR'*).	3.026
MOV HC VOID VOLUME	3.144

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N E T   S A N D

****

THICKNESS:	111.000
AVERAGE . . . 'PHIF' . . .	0.135
AVERAGE . . . 'VSHALE' . .	0.109
AVERAGE . . . 'SW'	0.593
W.AVERAGE . . 'SW' * 'PHIF'	0.567
AVERAGE . . . 'SH'	0.413
VOID VOLUME: . . . ('PHIF').	15.034
HC VOID VOLUME . . ('SH'*) .	6.581
RES HC VOID VOLUME ('SHR'*).	3.283
MOV HC VOID VOLUME	3.297

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N E T / G R O S S   R A T I O S

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HNETPAY /HGROSS SAND =	0.50000
HNETSAND/HGROSS SAND =	0.97797
HNETPAY /HNETSAND =	0.51126

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Figure 5.5.1

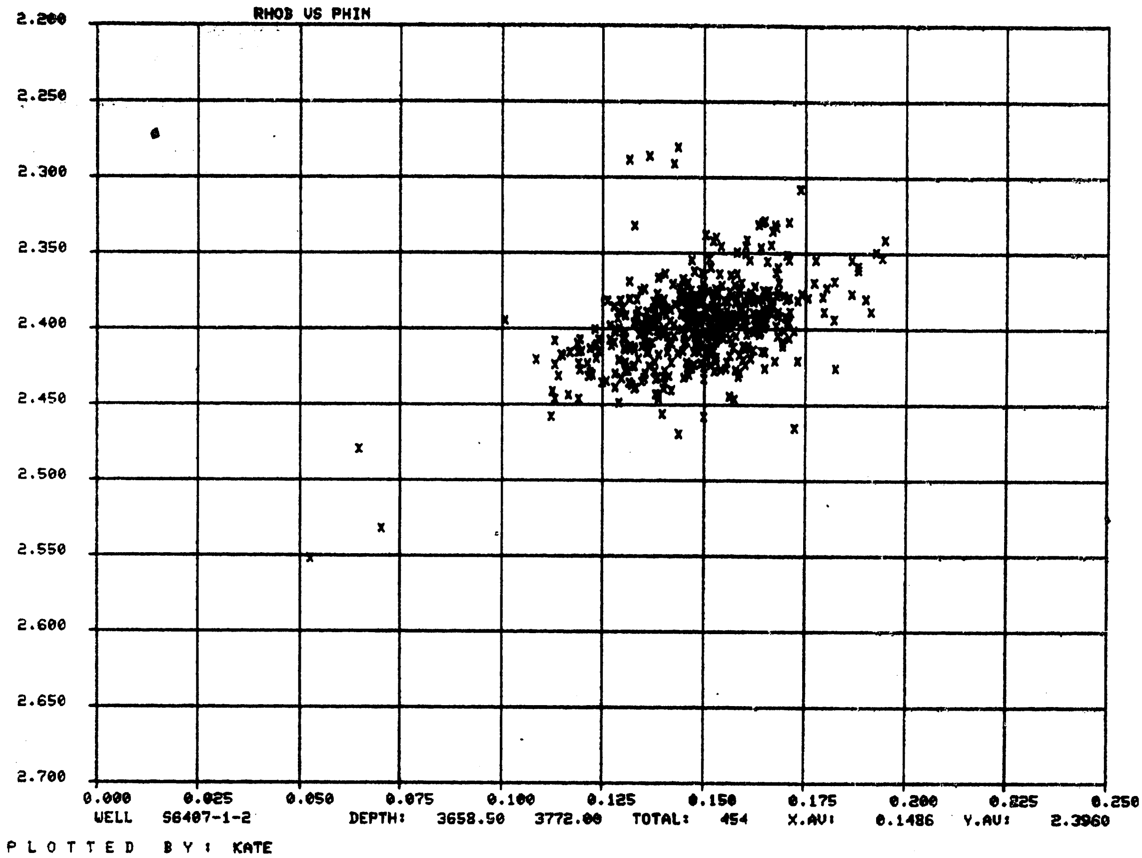


Figure 5.5.2

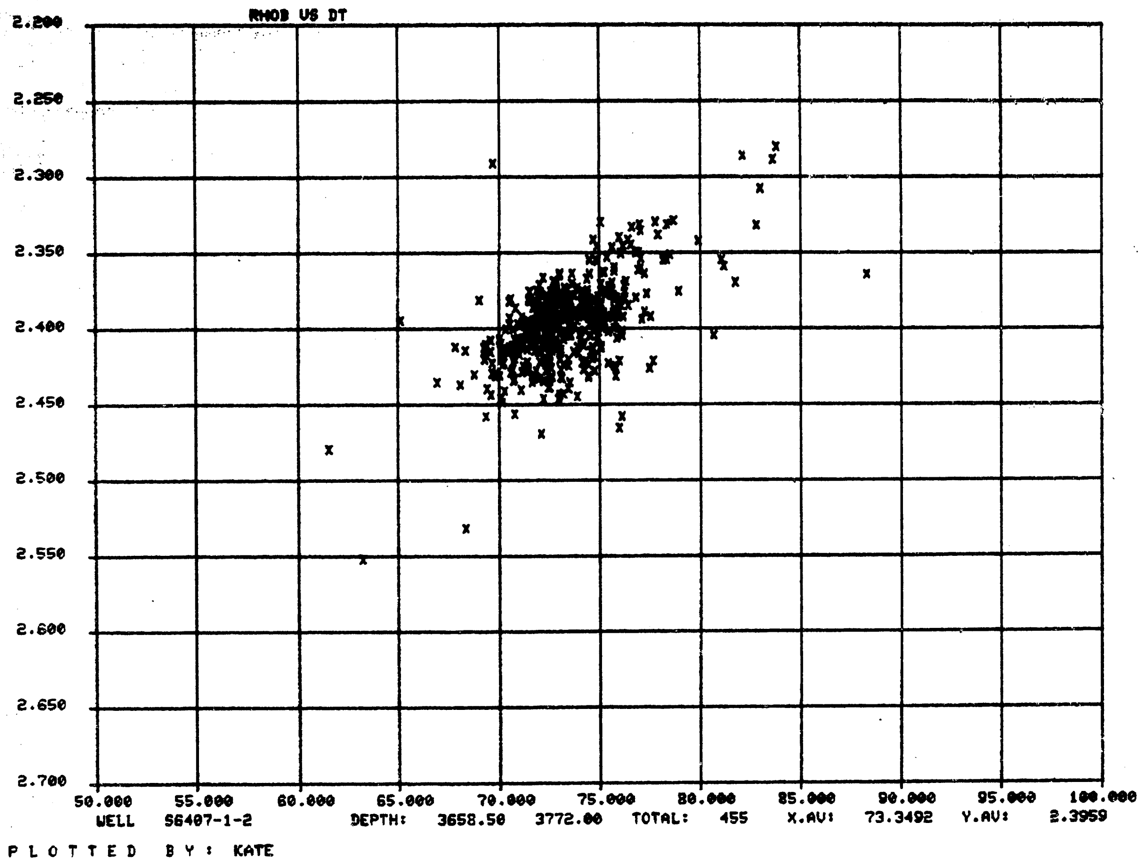
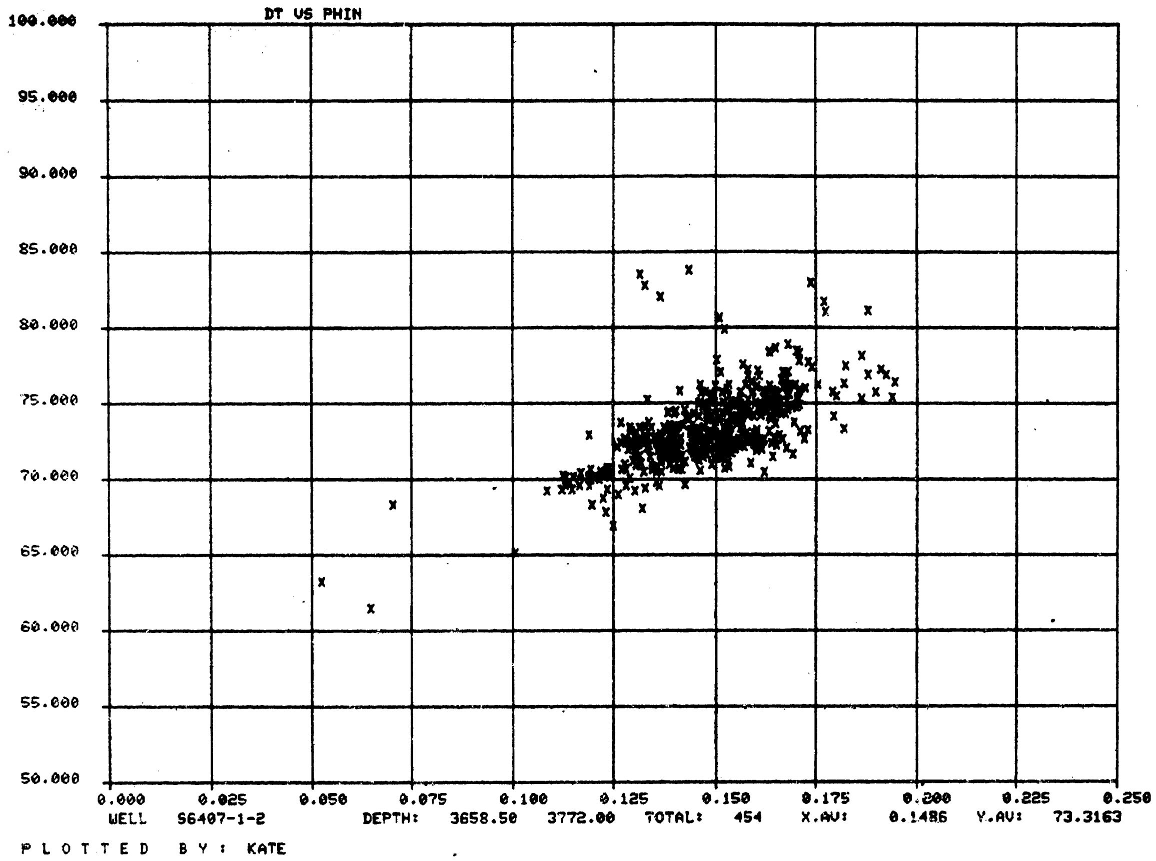


Figure 5.5.3



DT VS PHIN
100.000
95.000
90.000
85.000
80.000
75.000
70.000
65.000
60.000
55.000
50.000
0.000
0.025
0.050
0.075
0.100
0.125
0.150
0.175
0.200
0.225
0.250
WELL 56407-1-2
DEPTH: 3658.50 3772.00
TOTAL: 454
X.AV: 0.1486
Y.AV: 73.3163
P L O T T E D B Y : KATE

Figure 6.1

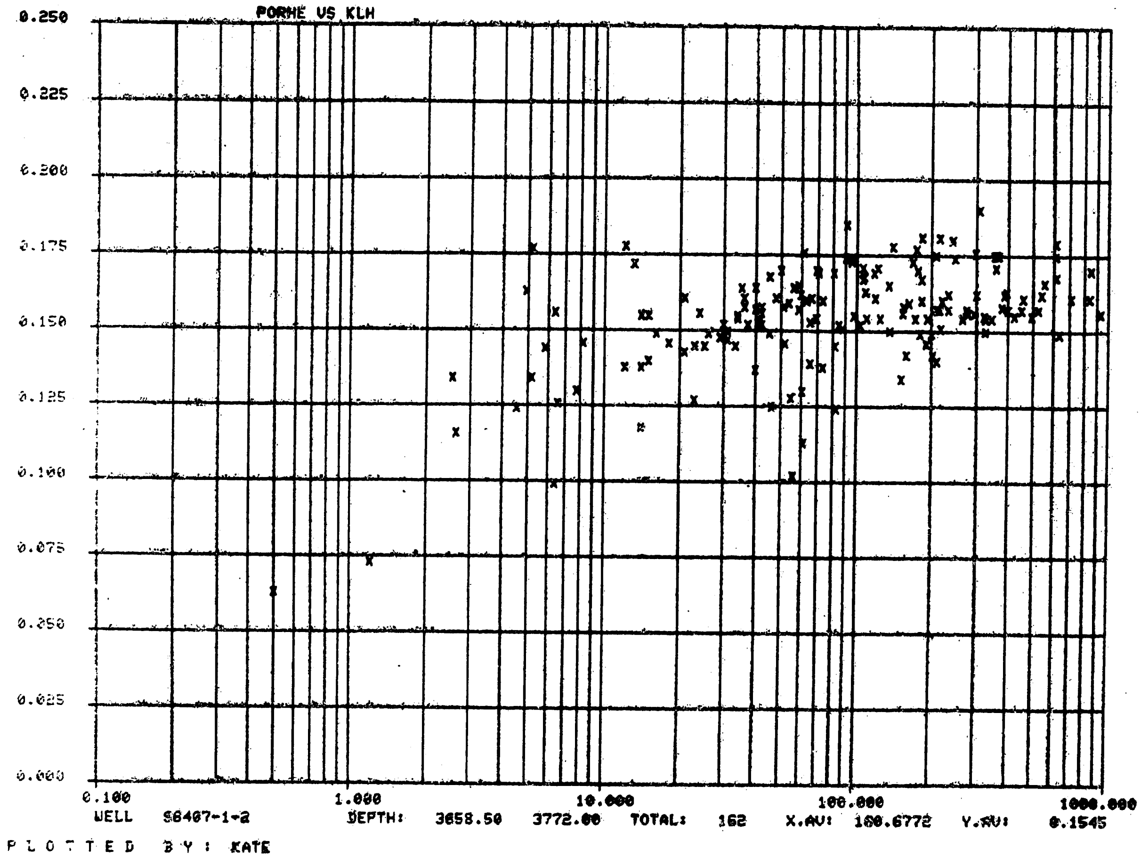


Figure 6.2