Astero
PL090

Formation Evaluation Report
Well 35/11-13

Operator: **Partners:**

HYDRO

STATOIL revus energy IDEMITSU Gaz de France

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1 Introduction

Well 35/11-13 was spudded just north of the Fram field (see Figure 1-1, Figure 1-2 and Figure 1-3) in 361m water depth. The well was drilled using waterbased mud with the semi-submergible rig "Deepsea Trym" to a total depth of 3266m MD. Both gas and oil were encountered in the reservoir, which is a sandstone reservoir of the Upper Jurassic (Oxfordian) age.

The well results are considered promising since the discovery is in an area where an infrastructure is already in place. The well was also production tested to an oil rate of 500 Sm^3/d. After the DST, the well was permanently plugged and abandoned.

The main objectives with the well were:

- § Test the presence- and type of hydrocarbons in the Oxfordian Turbidites in the Astero prospect
- § Test the Astero prospect within structural closure, close to the top of the structure.
- § Test an area of the Astero prospect with thick J52 reservoir sand thickness.
- § Test the Astero prospect where there is good HC indication.
- § Test the stratigraphic trap component of the Astero prospect.
- § Leave acceptable updip volumes.
- § Provide required information and data for evaluation of the discovery (Ref./1/).

The well attained a maximum deviation of ~2 deg. at around 3024m MD RKB. The general well data are presented in Appendix 12.1. This formation evaluation report summarizes the formation evaluation of the Astero well 35/11-13; petrophysical interpretation, wireline formation tester results, drill stem test results and PVT analysis.

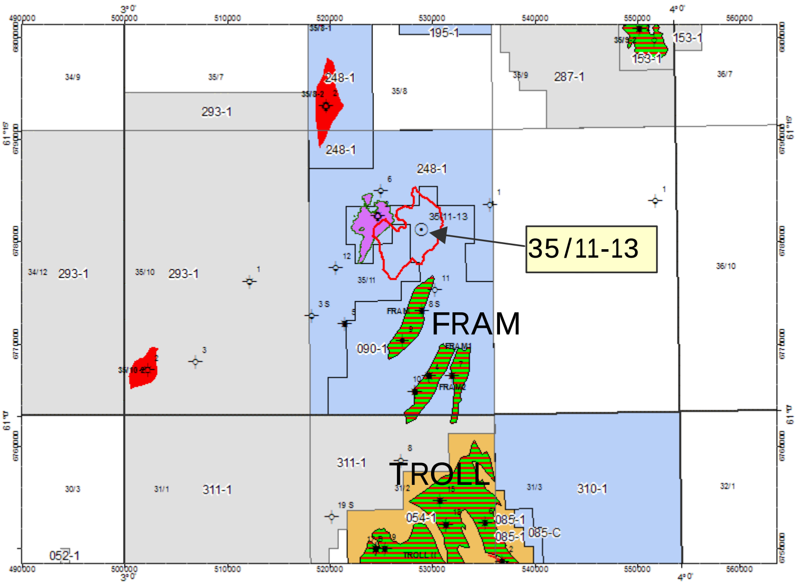


Figure 1-1: Location of Astero -well 35/11-13

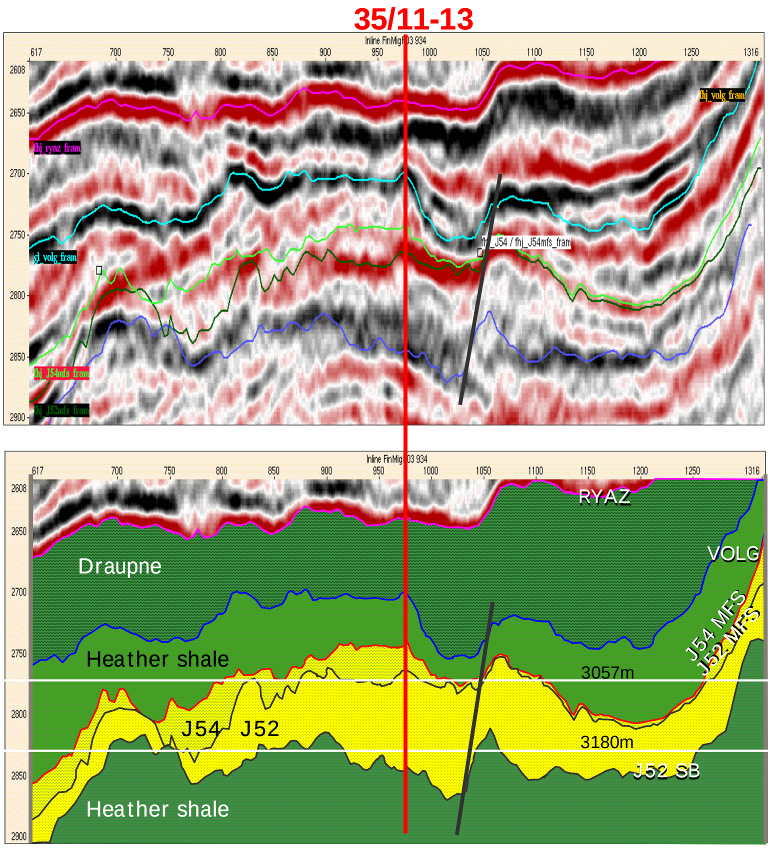


Figure 1-2: Cross-section through 35/11-13

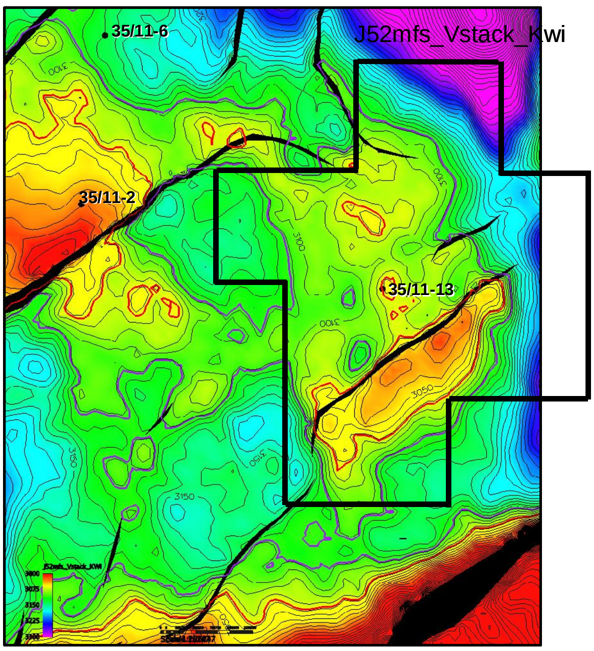


Figure 1-3: Top map of the structure

2 Summary and Conclusions

The formation evaluation data included:

- MWD/LWD and Wireline logs
- Conventional core measurements from whole core and sidewall cores
- Petrographic and special core analysis (SCAL) measurements
- Wireline formation tester (WFT) pressures, samples and fluid scanning
- Production and fluid samples from DST # 1
- PVT analysis
- Mini fracture test

The main results from the formation evaluation from well 35/11-13:

- The middle Oxfordian J52 sandstone, which is split into 7 sub-units (R1 to R7), contains an approximately 38 m oil column with a thin (approximately 2 m) overlying gas cap. The J52 sequence has good reservoir quality. The zone average petrophysical parameters are shown in Table 2-1.

Zone	Top zone (m MD RKB)	Thickness h (m)	Porosity ϕ_L (frac)	Net to gross (frac)	Water sat. S_w (frac)	Permability k_{arith} (mD)
J52-R1	3096.3	11.6	0.20	0.99	0.19	456
J52-R2	3107.9	3.5	0.15	0.25	0.59	-
J52-R3	3111.4	17.8	0.20	0.96	0.34	172
J52-R4	3129.2	2.9	0.13	0.26	0.73	-
J52-R5	3132.1	26.0	0.17	0.92	0.64 / 1.0 *	47
J52-R6	3158.0	7.1	0.13	0.31	1.0	-
J52-R7	3165.1	41.8	0.16	0.75	1.0	-

* above and below OWC

Table 2-1: Main petrophysical average parameters well 35/11-13

- The fluids contacts are estimated from logs, core fluorescence, MDT pressure points and fluid scanning (MDT). There is little uncertainty for the GOC. Also the OWC is well defined. There is relatively large difference between OWC (core fluorescence) and the FWL (MDT pressure points). Ongoing SCAL studies may resolve this. The fluid contacts are presented in Table 2-2.

Contact	m MD RKB	m TVD MSL
GOC	3098.5	3073.1
OWC	3136.8	3111.4
FWL	3138.0	3112.6

Table 2-2: Fluid contacts, well 35/11-13

- The testderived permeability in the Oxfordian sandstone is estimated to 105 mD. There is somewhat lower than the average arithmetical core permeability of 170 mD in the test interval.

- No sign of depletion was observed during the test. However, the test interpretation demonstrated presence of three no-flow boundaries at 100, 180 and 290 m from the well. The main results from the interpretation are presented in Table 7-9.

- The formation temperature is estimated to be between 118 and 120 ^{o}C.

- Note that both the MDT and DST (taken at separator) oil samples were taken while flowing at a pressure below the bubblepoint. A recombined separator sample was analyzed and the main PVT properties are presented in Table 2-3. The oil density from PVT was 652 kg/Sm^3; this compares well with the MDT oil pressure gradient of 0.655 g/cc. Bubble point pressure found from the MDT oil and gas gradients is approximately 314 bar which is 10 bar higher than estimated from the PVT analysis.

GOR oil zone (Sm^3/Sm^3)	184.3
P_b (bar)	304.5
Gas gravity solution gas (kg/Sm^3)	0.73
Oil density at SC (kg/Sm^3)	851.7
Oil density, pycnometer at res. cond. (kg/Sm^3)	651.8
Oil viscosity (cp)	0.289
B_o @ P_r (Rm^3/Sm^3)	1.581
B_{ob} @ P_b (Rm^3/Sm^3)	1.585

Table 2-3: Main PVT results of the oil

- The MDT water sample was of good quality. The water sample had 9 % mud filtrate contamination. The formation water is relatively fresh (Cl^- and TDS (total dissolved solids) content of 7700 and 15000 mg/l respectively) and has little content of Barium (53mg/l) and Strontium (7 mg/l). The resistivity is 0.06Ωm. The main parameters from the water are shown in Table 10-11. More details about the formation water can be found in section 10.3.

- From the mini-frac tests a Formation Propagation Pressure (FPP) of 514 bar was found, no value for the Instantaneous Shut-In Pressure (ISIP) was possible to obtain. Figure 9-1 show the mini-frac sequence.

3 Formation Evaluation Data Acquisition

The formation evaluation program in well 35/11-13 Astero comprised coring, logging and production testing, and an evaluation of the data is found in the following chapters.

The well was logged with MWD/LWD (Table 4-1). Two whole cores were cut in this well with fair recovery as summarised Table 3-1. The coring point was approximately 6 meters below top reservoir. In addition core plugs were cut in the non-cored sections.

Core No.	Reservoir Zone	Core Interval Cut (Drillers Depth m.MD)	Core Length Cut (m.)	Core Interval Recovered (Drillers Depth m.MD)	Core Length Recovered (m.)	Recovery (%)
1	J52-R1 - J52-R3	3100.00-3115.00	15.0	3100.00-3114.40	14.4	96.0
2	J52-R3 - J52-R5	3115.00-3142.00	27.0	3115.00-3134.30	19.3	71.5

Table 3-1: Whole Core recovery in well 35/11-13

A full wireline logging suite was run across the reservoir section (Table 4-2) including petrophysical logs and MDT. Numerous samples of gas, oil and water were taken with the MDT, and in addition scanning was performed to aid estimation of the OWC.

The objectives of the wireline formation testing (WFT) were:

- Obtain formation pressures and the fluid gradients including the contacts
- Secure high quality pressurized HC samples for:
  - PVT analysis
  - Geochemical analysis
- Collect 10ltr dead oil sample for SCAL studies
- Secure representative formation water sample
- Identify presence of different character fluids in reservoirs

The well was thereafter cemented, and a production test (DST) was performed in the lower part of the reservoir (3111.5 – 3130 m MD RKB) just below a shale protecting the pressure response form the influence of the gas. The DST objectives were:

- To measure initial reservoir pressure and temperature
- To determine and measure any contaminants (H_2S, CO_2, etc)
- Determine permeability-thickness and skin
- Obtain reservoir geometry data
- Obtain representative formation fluid samples (bottom hole sampling optional)

The **petrohysical interpretation** (Chapter 4) includes:

- MWD/LWD logs
- Wireline logs
- Conventional core measurements from whole core and sidewall cores
- Petrographic core measurements
- Special core analysis (SCAL) measurements

The **fluid contacts** (Chapter 5) are estimated from :

- Wireline formation tester (WFT) pressure measurements and logs
- MDT scanning data

The **sampling with the MDT** is presented in Chapter 6 – Wireline Formation Sampling. Samples were taken in:

- Gas
- 2 x Oil
- Water

The test and **analytical test interpretation** are presented in Chapter 7, the **analysis of the minifrac** in Chapter 9 and **estimation of reservoir temperature** in Chapter 8. Finally an overview of **PVT results** (hydrocarbons and formation water) is given in Chapter 10.

4 Petrophysical Interpretation

4.1 Log Data Acquisition and Quality

The reservoir section was in favourable condition for logging. The reservoir section was close to vertical; the hole deviation was less than 1.6 degrees. Further, the hole size was very close to bit size. There is a large washout below the casing shoe, however this occurs well above the reservoir section. Waterbased mud was used.

4.1.1 MWD/LWD logs

Baker Hughes Inteq provided MWD/LWD services as summarised in Table 4-1. There were some minor problems as indicated, but overall there are complete gamma ray and resistivity logs over most of the well interval. Some depth shifts were required to match the reference wireline logs; these are documented in the report from Logtek who made the composite logs (refer section 4.1.3).

MWD/LWD Services	Run No.	Interval m. MD RKB	Hole Size	Date	Mud Type	Remarks
VSS (Vibration Stick Slip)	1-2	386.7-474	36"		Sea W.	Drilled with 17.5"x36" bit size to 474m and then cleaned with 26" bit size 474-476m. No logging services.
MPR-VSS-PRESSTEQ (Res./GR/ann. pr., temp.)	3	476-701	9 7/8" pilot	21-22.03.05	Sea W.	Res. failed in this pilot hole section. GR recording ok.
	4	476-701	26"	22-23.03.05	Sea W.	Res. logged in the 26" hole section, (GR from 9 7/8" pilot).
	5-6	701-1757	17.5"	27.03-01.04.05	WBM	No 2 MHz Res. (only 400 kHz Res) 701-1135m. Only Real-Time Res. & GR 1024-1052m due to memory failure.
	7-10	1757-2932	12.25"	07-18.04.05	WBM	Discontinuous GR response 1757-2800m due to different GR sensor type in Runs 7-9.
	11-13	2932-3291.5	8.5"	23-29.04.05	WBM	Cored intervals 3100-3115 and 3115-3142m logged by reaming 60 and 32 hours respectively after being drilled.

Table 4-1: MWD/LWD services run by Baker Hughes Inteq in well 35/11-13

4.1.2 Wireline logs

Schlumberger provided the formation evaluation wireline services as summarised in Table 4-2: Wireline services run by Schlumberger in well 35/11-13. High quality log data were recorded over the entire reservoir section. There was minimal tool sticking from the wireline-conveyed tool string.

Density, neutron and gamma ray measurements (TLD/CNL/GR) were recorded with 8” vertical resolution processing, and these logs together with the laterolog resistivity (HRLA) data were acquired with high-resolution sampling of 0.0508 metres/sample. This high resolution was maintained for the CPI calculations. Sonic (DSI) compressional and shear data were recorded inside the 9 5/8” casing as well as in the open-hole section; these data were subsequently re-processed by Schlumberger for optimal results.

Wireline formation tester services included the successful acquisition of pressures, samples and fluid logging from the MDT tool as summarised in the Table.

Sidewall cores were acquired with the mechanical sidewall-coring tool (MSCT). Initial recovery appeared to be good (41/45) but conventional core measurements could only be made on 28 samples (refer section 4.2.1).

Formation Evaluation Wireline Services	Run No.	Interval m. MD RKB	Hole Size	Date	Mud Type	Remarks
DSI/HRLA/TLD/CNL/ECS/GR (Sonic/Res./Dens./Neut./GR)	1A	2925-3295	8.5"	30.04.05	WBM	Dens./Neut./GR logged with 8" vertical resolution processing. SP failure. Very large washout below CS 2925-2936m. DSI acquired in P&S, Upper & Lower Dipole modes; compressional (DTCO) & Shear (DTSM) from Schlumberger re-processing.
DSI/HRLA/TLD/CNL/ECS/GR (Sonic/Res./Dens./Neut./GR)	1AR	2405-3265	9 5/8" csg. / 8.5"	30.04.05	WBM	Down-log used as Repeat Section, Depth Reference Log (first RIH & stretch correction procedures applied), and for recording DSI through casing (2405-2925m). DSI acquisition modes and data processing procedures as above.
MDT/GR - Pressures	1A	3097-3205.5	8.5"	30.04.05	WBM	Total 29 pressure points; 28 successful, 1 tight. Several points exhibit low mobility (<20 mD/cp).
MDT/GR - Samples	1B	3097-3157.5	8.5"	01-02.05.05	WBM	Multiple samples and fluid scanning at four depth levels; fluid scanning alone at a further three depth levels.
MSCT/GR	1A	2960-3151	8.5"	02.05.05	WBM	Attempted = 45 Sidewall cores. Recovered = 41 including 2 partial (3 empty, 1 aborted).

Table 4-2: Wireline services run by Schlumberger in well 35/11-13

4.1.3 Composite logs

Logtek made composite logs in accordance with NPD requirements. One hybrid composite was made for the entire well (hybrid of MWD/LWD and wireline measurements) where the MWD/LWD data were depth shifted to match the reference wireline logs. Three petrophysical composite logs were generated; one with merged depth matched MWD/LWD data, one with standard 0.1524 metres/sample wireline data (sonic) and one with the high resolution 0.0508 metres/sample wireline data (resistivity, density, neutron and gamma ray).

4.1.4 CPI Input logs - Environment and Invasion corrected data

The wireline contractor performed environment and invasion corrections during acquisition; the corrected data were sourced from the third petrophysical composite log (refer section 4.1.3). The following corrected curves were used in the petrophysical interpretation:

- Gamma ray, corrected for hole size and mud weight (curve 'EHGR')
- Density, corrected for bit size and mud weight (curve 'RHO8')
- Neutron, corrected for hole size, stand-off, mudcake, borehole salinity, formation salinity, mud weight, pressure and temperature (curve 'HTNP')
- Resistivity Rt and Rxo, invasion corrected from the five HRLA laterolog resistivity measurements, (curves 'RT_HRLT' and 'RXO_HRLT')

4.2 Core Data

4.2.1 Conventional core measurements

Conventional core measurements were made on core plugs from both the whole core and from the sidewall cores (Ref. /3/). Only the whole core measurements were used in core-log calibrations in the petrophysical interpretation; results from the sidewall cores were only used qualitatively because these measurements are considered to be of a lower quality due to the possibility of mechanical damage during acquisition. In the CPI result displays, (Figure 4-6 and Figure 4-7), whole core measurements are indicated with “X” symbols whereas sidewall core measurements are shown as “square” symbols.

The conventional core data include porosity, permeability and grain density measurements. Although the mud was doped with Tritium tracer, core saturation measurements were not made due to poor results in trying to correct for mud filtrate contamination in previous wells drilled with similar high salinity water based mud.

The cores were depth shifted to match the wireline logs as summarised in Table 4-3:

Core No.	Reservoir Zone	Core Interval Recovered (Drillers Depth m.MD)	Depth Shift applied to Core (m.)	Core Interval Recovered (Log Depth m. MD)	Remarks
1	J52-R1 - J52-R3	3100.00-3114.40	+3.5	3103.50-3117.90	
2	J52-R3 - J52-R5	3115.00-3134.30			
(2A)		3115.00-3125.73	+3.75	3118.75-3129.48	The core photographs show a distinct break in core #2 at 3125.735 (Drillers Depth m. MD).
(2B)		3125.74-3134.30	+4.5	3130.24-3138.80	

Table 4-3: Whole Core depth shifting in well 35/11-13 – shifts applied for core plugs

The depth shifts in the above Table are those applied to the core plug measurements; the shifts were determined from correlations between core porosity and the density log. Split shifts were required for Core #2 and were implemented at a distinct break seen in the core photographs at 3125.735 Drillers Depth m MD (Ref. /4/).

Slightly different depth shifts were required for the whole core gamma ray measurements; these shifts were determined from correlations between the core and log gamma rays. The different depth shift concerns Core #1 which was shifted of +3.75 metres (compared to the +3.5 metre shift for the core plug measurements). It was concluded that the core plug and the core gamma ray measurements were off-depth with each other by 0.25 metres; this can occur because the gamma ray measurements are made when the core is still inside the aluminium sleeve.

Conventional core measurements were made on 28 sidewall cores that were recovered over the interval 2960.0-3151.0 m MD RKB. Whilst these cores should in principle be on depth with the wireline logs, a depth shift of –0.5 metres was applied to all cores in order to yield an optimum correlation between core porosity and the density log.

4.2.2 Petrographic core measurements

Petrographic XRD analyses and thin section point count measurements were made on selected whole core samples (Ref. /5/). The measurements of most interest concerning clay/shale volume determination are summarised in Table 4-4:

Drillers Depth	Core	Plug	Permeability	Porosity	XRD			Thin Section	
MD RKB (m.)	No.	No.	KHAC (mD)	PHIH (FRAC)	Chlorite (FRAC) (by weight)	Smectite (FRAC) (by weight)	Kaolin (FRAC) (by weight)	Matrix Clay (Counts) (out of 300)	Kaolin (Counts) (out of 300)
3100.00	1	1	296.000	0.212	0.001	0.010	0.032	0.00	18.00
3102.50	1	11	550.000	0.221	0.000	0.008	0.022	0.00	21.00
3104.00	1	17	710.000	0.231	0.000	0.015	0.026	0.00	15.00
3104.75	1	20		0.050	0.002	0.031	0.154		
3105.20	1	22		0.037	0.006	0.039	0.160		
3106.00	1	25	14.700	0.166	0.000	0.024	0.061	11.00	21.00
3106.55	1	27	0.096	0.019	0.006	0.063	0.161		
3107.55	1	31	9.870	0.186	0.000	0.018	0.051	1.00	28.00
3108.75	1	36	196.000	0.229	0.000	0.009	0.030	0.00	29.00
3109.75	1	40	2.390	0.153	0.000	0.021	0.069	0.00	24.00
3111.25	1	46	216.000	0.235	0.000	0.008	0.037	0.00	22.00
3112.00	1	49	135.000	0.216	0.000	0.012	0.038	0.00	32.00
3114.00	1	57	158.000	0.218	0.000	0.013	0.033	0.00	26.00
3116.00	2	63	62.300	0.210	0.000	0.010	0.037	0.00	28.00
3118.00	2	71	75.400	0.215	0.000	0.020	0.045	0.00	31.00
3120.00	2	79	237.000	0.220	0.001	0.008	0.028	0.00	23.00
3122.00	2	87	57.700	0.187	0.001	0.017	0.032	0.00	21.00
3123.55	2	93	0.068	0.056	0.002	0.004	0.009	0.00	9.00
3124.45	2	96	706.000	0.240	0.001	0.018	0.030	1.00	24.00
3125.07	2	99	659.000	0.237	0.000	0.009	0.022	0.00	25.00
3126.06	2	103		0.030	0.005	0.031	0.193		
3127.00	2	107		0.036	0.001	0.054	0.135		
3128.00	2	111	119.000	0.203	0.000	0.006	0.033	0.00	28.00
3130.00	2	118	4.970	0.196	0.001	0.010	0.050	2.00	23.00
3132.00	2	126	22.800	0.181	0.000	0.016	0.041	0.00	23.00

Table 4-4: Petrographic measurements related to clay/shale volume in well 35/11-13

XRD bulk fraction clay measurements also include “illite/mica” which can be problematic because these two minerals (the former clay, the latter part of the rock framework) cannot be distinguished from the XRD spectra. It is fortunate that the thin section point count measurements show that there are minimal occurrences of illite in these middle Oxfordian reservoir sands. Consequently, the XRD clay assessment can be evaluated by excluding the “illite/mica” fraction from the clay components as in the above Table. Total clay fraction (by weight) was determined by summing the chlorite, smectite and kaolin components, and this was then converted to an approximate volumetric fraction by multiplying by (1-PHIH). This gives in an assessment of clay volume, not shale volume; it needs to be considered that most shales contain of the order maximum 40% clay.

Thin section point count measurements were made with 300 counts allowing identification of both detrital (matrix clay) and authigenic (predominantly kaolin) shale components (refer above Table). In thin section point counting it is not possible to distinguish between “clay” and the associated microporosity components;

consequently, the original point counts data reflect the shale rather than the clay volume. Assessment of the shale volume was made by dividing the sum of the matrix clay and kaolin components by 300 (counts).

XRD clay volumes and thin section shale volumes were used to guide parameter selection in the log shale volume calculations (refer section 4.1). The petrographic results are shown in the volumetric analysis track of the CPI result displays, (Figure 4-6 and Figure 4-7); thin section shale volumes are scaled from 0 to 1.0 and are shown with "star" symbols whereas the XRD clay volumes are scaled from 0 to 0.4 and are shown as "circle" symbols.

4.2.3 Special core analysis (SCAL) measurements

A SCAL programme was initiated at Reslab in mid 2005 and is expected to be completed in 2nd quarter of 2006. Evaluations are being performed on 16 plugs selected from the entire cored section, most of the samples are from the oil zone. The measurements include:

- Confining pressure measurements of porosity and formation factor (m)
- Mercury injection capillary pressure
- Porous plate capillary pressure and resistivity index (n) at reservoir conditions

The first item above has been completed with the following results at 170 bar net confining pressure, (the estimated effective reservoir stress in the Astero area):

- Porosity overburden correction factor = 0.979
- Cementation exponent (m) = 2.03 with cementation factor (a) = 1.0

4.3 Log interpretation

Log interpretation includes estimation of porosity from density log, water saturation based on the Indonesia equation, and estimation of net sand and pay.

4.3.1 Porosity

Total porosity PHIT was determined by direct calibration of the density log with overburden corrected core porosity. Separate calibrations were performed for the oil leg above the transition zone (Figure 4-1), and for the combined water and oil transition zones (Figure 4-2). The crossplots yield the fluid density 'ROF' values to be used in calculating PHIT from the density log response equation.

The oil transition zone was treated as an effective "water-bearing interval" for the purposes of the core-log porosity calibrations because analyses show that water rather than oil is the predominant fluid in this interval, i.e. the density log response is influenced more by the water than the oil in the oil transition zone.

Discriminators, (density < 2.45 g/cc, core porosity > 0.1, core permeability > 1mD) were applied in the core-log calibration crossplots to ensure that the calibrations were made over the better quality reservoir samples.

Both core-log calibrations were constrained through the rock matrix/grain density 'ROMA' value of 2.64 g/cc which was determined from a histogram of the conventional core grain density measurements, (refer Figure 4-3). Non-reservoir samples were also excluded from the histogram analysis, (core samples excluded if permeability < 0.1 mD).

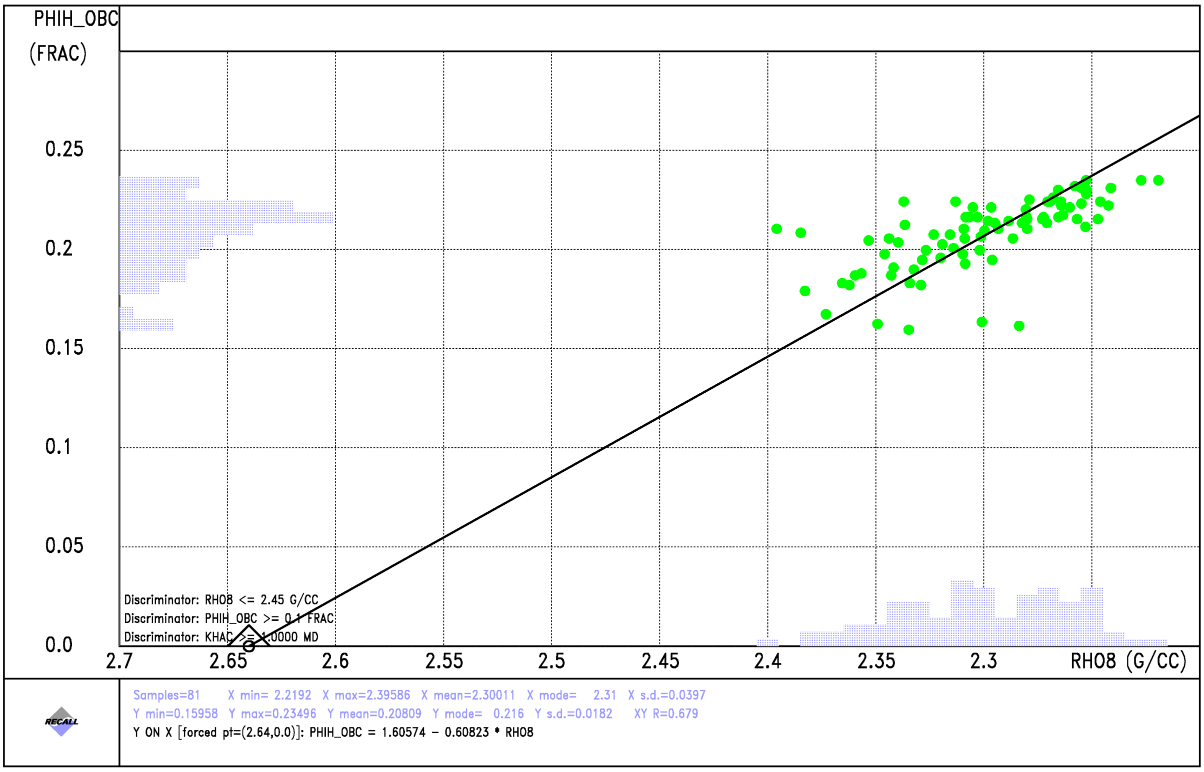


Figure 4-1: Density log calibration to core porosity in the oil leg above the transition zone

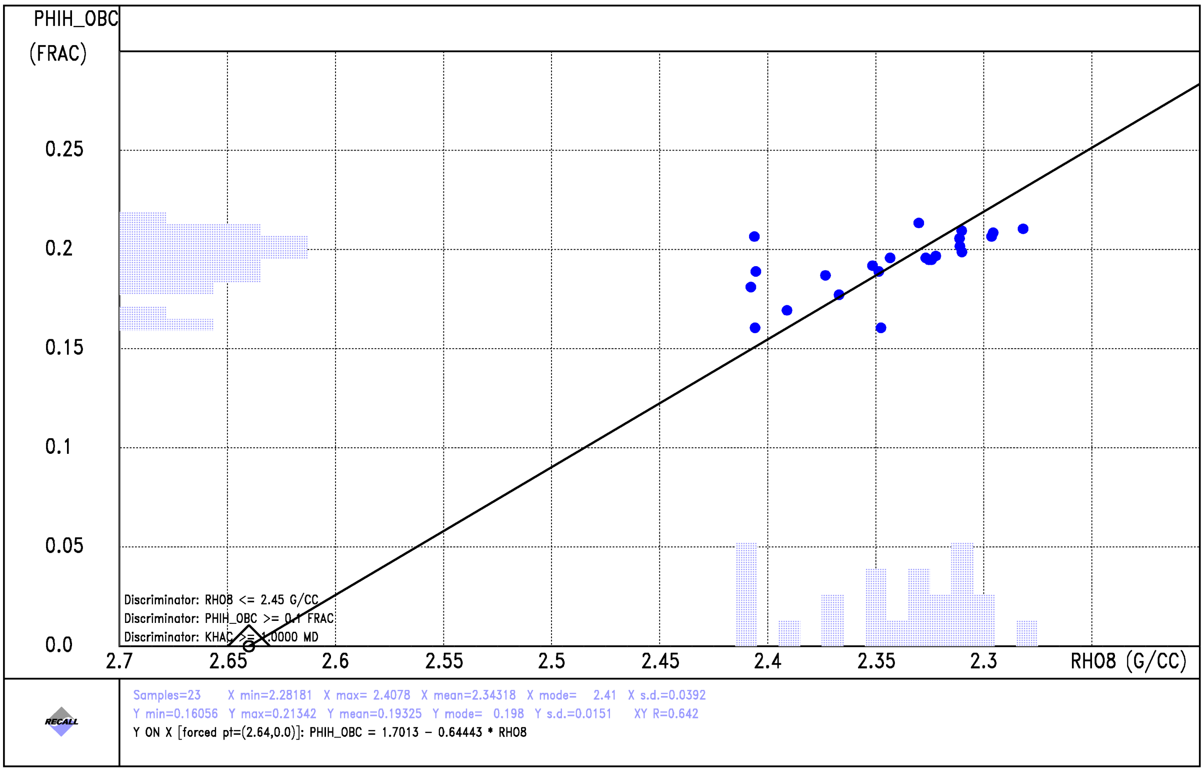


Figure 4-2: Density log calibration to core porosity in the water and oil transition zones

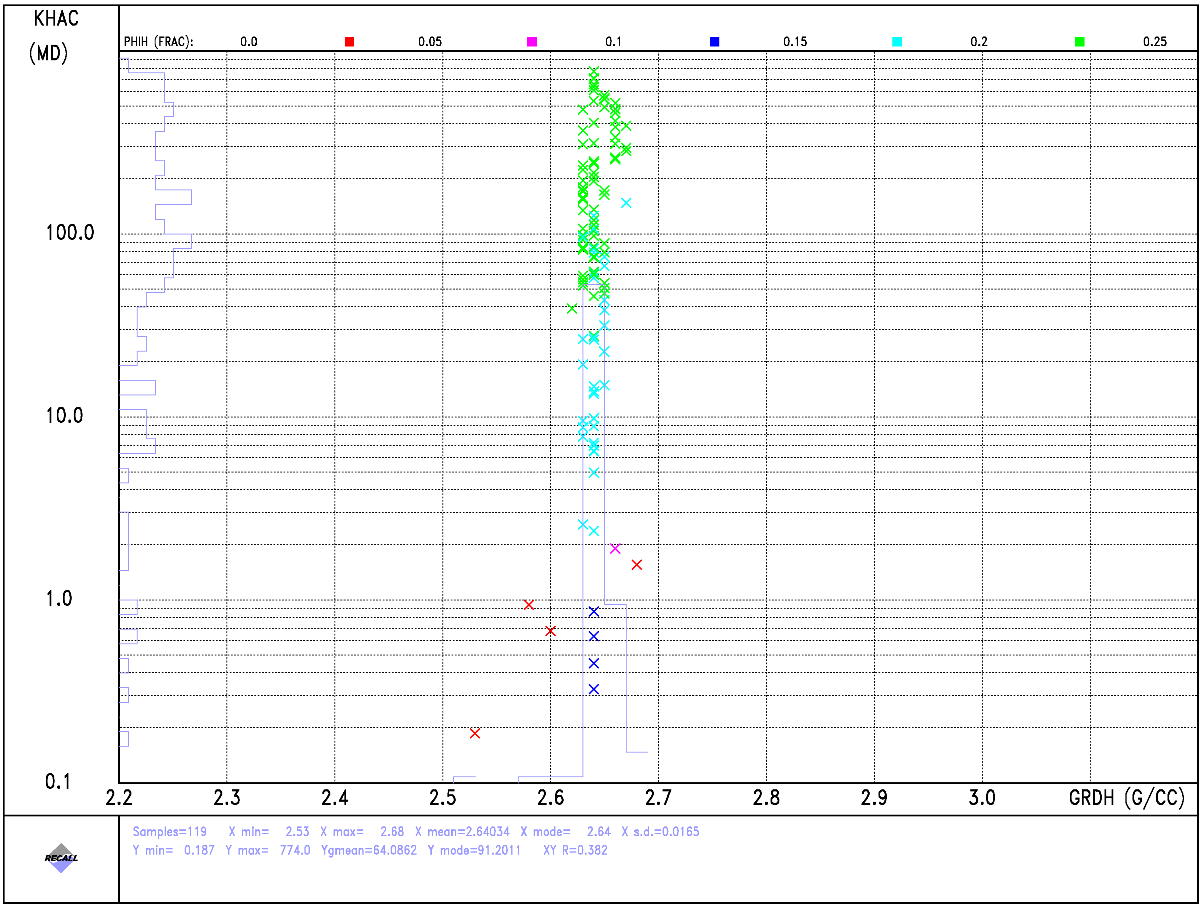


Figure 4-3: Histogram of conventional core grain density measurements

Fluid density ROF values derived from the core-log porosity calibrations are as follows:

- Oil leg above the transition zone: ROF = 0.996 g/cc
- Water and oil transition zones: ROF = 1.088 g/cc

A calibration was not possible in the gas zone since it was not cored; an estimated ROF value of 0.75 g/cc was applied. The suitability of this estimated value is confirmed from comparisons between log total porosity PHIT and the core porosity measurements from sidewall core samples over the gas zone interval, (refer Figure 4-6 and Figure 4-7).

Log effective porosity PHIE was calculated from PHIT by correcting for the shale content (PHIE = PHIT - (VSH x PHISHALE)). The shale porosity 'PHISHALE' value was estimated to be 0.06 from log and core measurements in the shale intervals.

The log porosity calculation parameter values, (rock matrix/grain density ROMA, fluid density ROF and shale porosity PHISHALE), are also summarised in Table 4-6.

4.3.2 Water saturation

The Indonesia equation was used to calculate water saturation from the logs. Formation resistivity (Rt), and the invaded zone resistivity (Rxo) were taken from the Contractor's wellsite invasion corrected laterolog measurements (RT_HRLT and RXO_HRLT). The calculations were made using shale volume VSH and effective porosity PHIE as previously documented in sections 4.1 and 4.3.1 respectively.

Formation temperature of approximately 118^{o}C was determined from DST 1 and is assumed to be from the midpoint depth of the perforated interval, (3120.75 m MD RKB / 3095.35 m TVD MSL). The temperature gradient over the reservoir section was taken from the Hydro report "Well programme 35/11-13, Astero", page 35. The DST 1 temperature and the temperature gradient were combined to make a continuous formation temperature 'FTEM' curve (FTEM = 38.76 + (0.0256 x SSDP)) where 'SSDP' is the TVD MSL depth curve.

Formation water resistivity Rw of 0.12 ohmm at 119.3 ^{o}C was estimated from a Pickett plot over intervals with low shale content in the water zone, (Figure 4-4). The Rw temperature was calculated at the midpoint of the water zone (3172 m MD RKB).

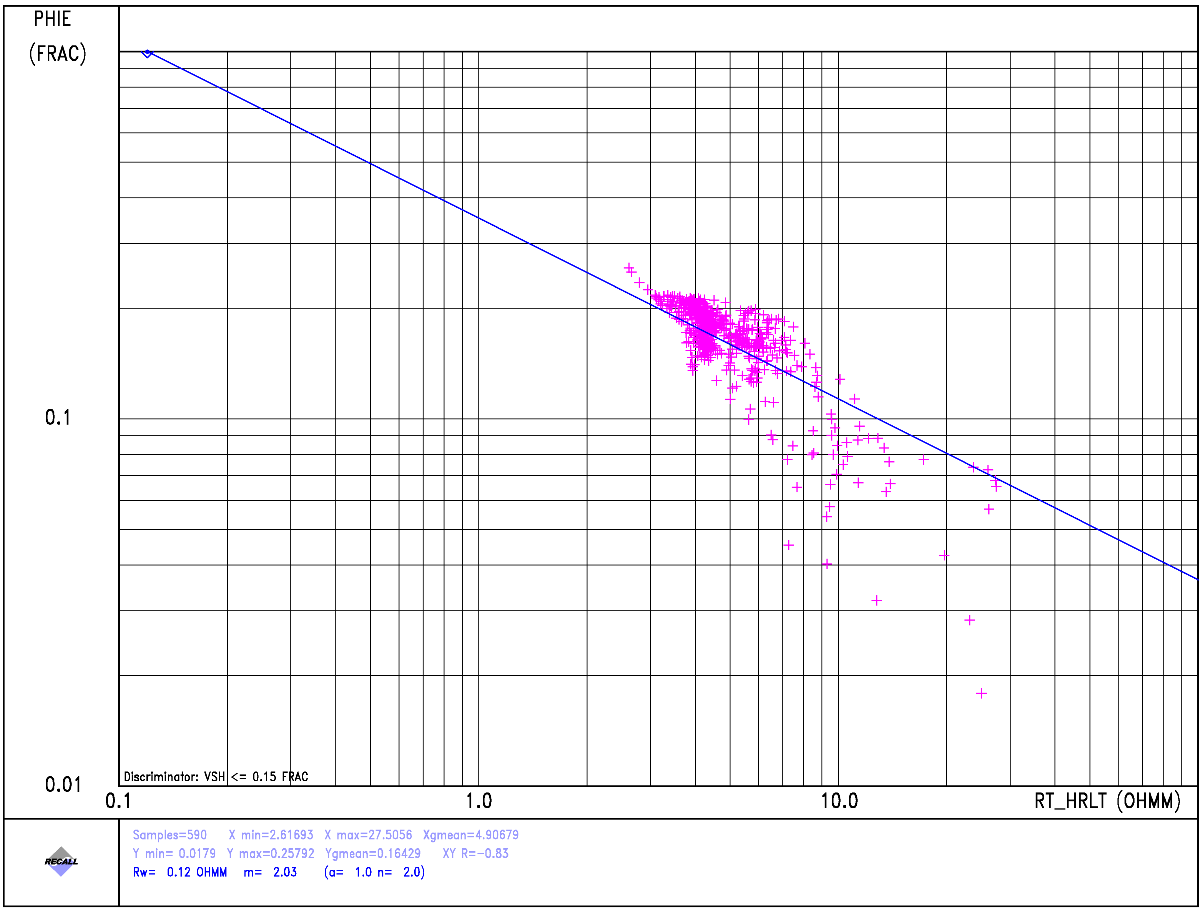


Figure 4-4: Pickett plot over intervals with low shale content in the water zone

The Pickett plot (and the subsequent CPI calculations) incorporated the cementation factor (a=1) and cementation exponent (m=2.03) values determined from SCAL measurements in this well (refer section 4.2.3).

Measurements of synthetic formation water resistivity at elevated temperature are given in Ref./10/. However, the resistivity values indicated in the current version of this report appear to be from the contaminated MDT water sample and not from the synthetic formation water (that was formulated to correct for the 9% mud filtrate contamination in the MDT sample). The report does provide the ion composition calculated by Petrotech for the (synthetic) formation water; the ion compositions are converted to NaCl salinity and then to water resistivity values in Table 4-5:

	WFS corr.[1]			Formation water[2]		
Ions:	Ion composition (mg/l)[3]	Ion multiplier[4]	Equiv. Nacl (ppm)[5]	Ion composition (mg/l)[3]	Ion multiplier[4]	Equiv. Nacl (ppm)[5]
Cl	15782	1.00	15782	7721	1.00	7721
SO4	31	0.42	13	0	0.50	0
Br	44	0.44	19	35	0.44	15
Li	3	2.50	8	3	2.50	8
Na	7621	1.00	7621	5376	1.00	5376
K	6507	0.93	6052	1443	0.90	1299
Mg	17	1.05	18	14	1.20	17
Ca	162	0.82	133	157	0.80	126
Sr	6	1.00	6	7	1.00	7
Ba	53	1.00	53	59	1.00	59
Acetate	559	1.00	559	449	1.00	449
Formate	18	1.00	18	12	1.00	12
	30803 Total Solids		30281 Total Nacl	15276 Total Solids		15088 Total Nacl

Notes

1 - "WFS corr." = Wireline Formation Sample, Ion Composition corrected by Petrotech for barite and sulphate precipitation.
2 - "Formation water" = Formation Water, Ion Composition calculated by Petrotech by correcting for 9% mud filtrate contamination.
3 - Ion compositions from Petrotech Report "Validity checks and analysis of MDT water samples, Report version:2", page 8.
4 - Ion Multipliers from Schlumberger Chart Book, Chart Gen-8. Values for Sr, Ba, Acetate & Formate assumed = 1.0 (not in Chart)
5 - Since ionic concentrations are low, it can be assumed that mg/l = ppm

Resistivity from Nacl concentration:

WFS corr. :	30,281 ppm Nacl concentration corresponds to a resistivity of 0.2231 ohmm at 20 °C; 0.0654 ohmm at 120 °C.
Form. water:	15,088 ppm Nacl concentration corresponds to a resistivity of 0.4211 ohmm at 20 °C; 0.1235 ohmm at 120 °C.

Table 4-5: Estimation of water resistivity from water sample ion composition calculations

The above table shows that the ion composition of the synthetic (contamination corrected) formation water translates to 15088 ppm NaCl concentration corresponding to a resistivity at 120°C of 0.1235 ohmm. This strongly supports the Rw value determined from the Pickett plot analysis. Furthermore, the ion composition of the contaminated MDT sample translates to 30281 ppm NaCl concentration corresponding to a resistivity at 120°C of 0.0654 ohmm which is very similar to the (incorrect) resistivity values presented in the current version of the Petrotech Report.

Mud filtrate resistivity Rmf of 0.052 ohmm at 20°C was taken from the value reported in the HRLA log heading. Rmf is used with Rxo to calculate invaded zone water saturation Sxo.

Shale resistivity 'RSHALE' was estimated at 30 ohmm from Rt log readings in the shale intervals. Default values were used for remaining parameters in the Indonesia equation, including the saturation exponent (n=2.0); a more specific value should be available when the SCAL programme is completed.

All of the water saturation calculation parameters are summarised in Table 4-6.

4.3.3 Net Reservoir / Shale volume

Net reservoir intervals were determined by applying a shale volume cut-off of 0.40 together with a total porosity cut-off of 0.065 in the gas zone and 0.11 in the oil and water zones.

The total porosity cut-off values were evaluated from a crossplot of overburden corrected core porosity versus core horizontal air permeability measurements, refer Figure 4-5:

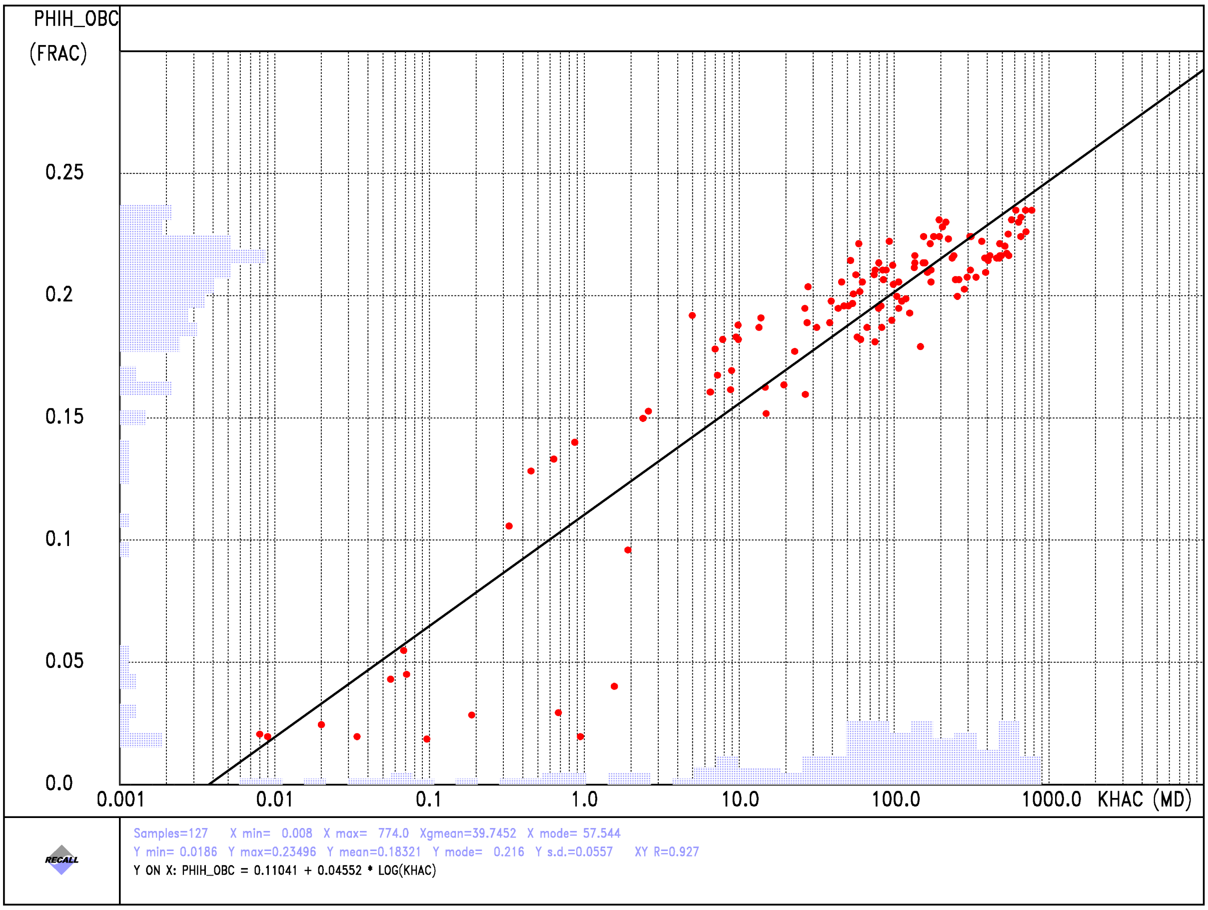


Figure 4-5: Crossplot of the conventional core porosity and permeability measurements

The gas zone porosity cut-off of 0.065 corresponds to a permeability of 0.1 mD whereas the 0.11 porosity cut-off for the oil and water zones corresponds to a permeability of 1 mD. Note that the core-derived porosity cut-offs are applied to log total porosity 'PHIT' (rather than to log effective porosity 'PHIE') since core porosity measurements are more closely represented by PHIT than PHIE. This is because the core preparation procedures (drying at 60^{o}C and 40% humidity) remove most of the capillary and clay bound water.

Shale volume 'VSH' was determined from a minimum of gamma ray and density-neutron log shale indicators. Linear relationships were applied for both indicators. The density-neutron shale indicator was implemented using apparent grain density 'RHGA' which is a triangulated calculation from the density-neutron crossplot involving the matrix, shale and fluid points. RHGA values were calculated using a sandstone matrix and constant fresh water fluid parameters; fluid effects were subsequently accounted for by picking separate shale indicator parameter values in the gas, oil and water zones. The benefit of the RHGA approach is that the shale indicator parameters (minimum and maximum values) can be assessed in a similar manner to the gamma ray. For both shale indicators, the selection of minimum and maximum parameter values was guided by the results from the petrographic clay and shale volume measurements, (discussed in section 4.2.2). The minimum and maximum shale parameter values are summarised in Table 4-6.

The gamma ray 'EHGR' and RHGA curves are shown in the first track of the CPI result displays, (Figure 4-6 and Figure 4-7); both curves have very similar response characteristics indicating good fundamental agreement between the two shale indicators. Shale volume calculations from each indicator ('VGR' and 'VRHGA') together with the final minimum value ('VSH') are shown in the fourth data track of the CPI result displays; this confirms the excellent agreement between the two indicators.

4.3.4 Petrophysical input parameters

Well 35/11-13: Petrophysical input parameters				Parameter values applied over the Petrophysical fluid zonation (depths in m. MD RKB):				
Calculation	Parameter Description	Mnemonic	Units	Shale1 3040.00-3092.00	Gas 3092.00-3098.50	Oil 3098.50-3129.18	Oil transition + Water 3129.18-3206.95	Shale2 3206.95-3260.00
Shale volume	Gamma ray (GR) minimum value	MINGR	GAPI	50				
	Gamma Ray (GR) maximum value	MAXGR	GAPI	136				
	Apparent grain density (RHGA) minimum value	MINRHGA	G/CC	2.67	2.60	2.65	2.67	2.67
	Apparent grain density (RHGA) maximum value	MAXRHGA	G/CC	3.03				
Core Porosity	Horiz. helium porosity - Overburden corrected	PHIH_OBC	FRAC	0.979 x PHIH				
Log Porosity	Rock matrix/grain density	ROMA	G/CC	2.64				
	Fluid density	ROF	G/CC	1.088	0.750	0.996	1.088	1.088
	Shale porosity	PHISHALE	FRAC	0.06				
Saturation (Indonesia eqn.)	Formation temperature at midpoint DST 1		DEGC	118 °C at 3120.75 m MD RKB / 3095.35 m TVD MSL				
	Formation temperature curve	FTEM	DEGC	Calculated from TVDMSL depth curve 'SSDP': FTEM = [38.76 + (0.0256 x SSDP)]				
	Formation water resistivity Rw		OHMM	Rw = 0.12 @ 119.3 °C (from Pickett plot, temperature from midpoint of water zone at 3172 m.MD RKB)				
	Rw curve (at formation temperature).	RW	OHMM	Rw = 0.12 @ 119.3 °C converted to 'Rw at FTEM' = 0.12 x (119.3 + 21.5) / (FTEM + 21.5)				
	Mud filtrate resistivity Rmf		OHMM	Rmf = 0.052 @ 20 °C (from measurement reported in HRLA log heading)				
	Rmf curve (at formation temperature).	RMF	OHMM	Rmf = 0.052 @ 20 °C converted to 'Rmf at FTEM' = 0.052 x (20 + 21.5) / (FTEM + 21.5)				
	Shale resistivity.	RSHALE	OHMM	30				
	Cementation factor	a		1				
	Cementation exponent	m		2.03				
	Saturation exponent	n		2				
	Indonesia equation parameter	ISILT		0				
	Indonesia equation parameter	CVSH		1				
Net Reservoir	Cut-off value for Total Porosity (PHIT)	CO-PHIT	FRAC	> 0.11	> 0.065	> 0.11	> 0.11	> 0.11
	Cut-off value for Vshale (VSH)		FRAC	< 0.40				
Net Pay	Cut-off value for water saturation (SWE)		FRAC	< 0.60				

Table 4-6: Petrophysical input parameters

4.4 Petrophysical results and Net Reservoir zone averages

Depth plots of the wireline logs, core data and CPI Petrophysical evaluation results are presented in Figure 4-6 (J54 section) and Figure 4-7 (J52 section). Both plots are presented at the same scale to give a visual impression of the relative thickness of the two sections.

The J54 section, (Figure 4-6), is dominated by shale facies in this well, but there are several thin sand beds towards the base that are most likely gas-bearing (as at the top of the J52 section).

The main reservoir sands occur in the J52 section (Figure 4-7). There is a thin interval (approximately 2 metres) containing light hydrocarbons at the top of the oil column. The absence of a distinct shale barrier of significant thickness between the oil and the light hydrocarbon interval strongly suggests that the light hydrocarbon interval is most likely a gas cap in communication with the oil column.

The J52 oil column has been analysed as two distinct intervals consisting of an oil zone and an oil transition zone. The oil transition zone is characterised by very high water saturations such that the predominant formation fluid is water rather than oil. The high water saturations may be related to the lower permeability in this interval.

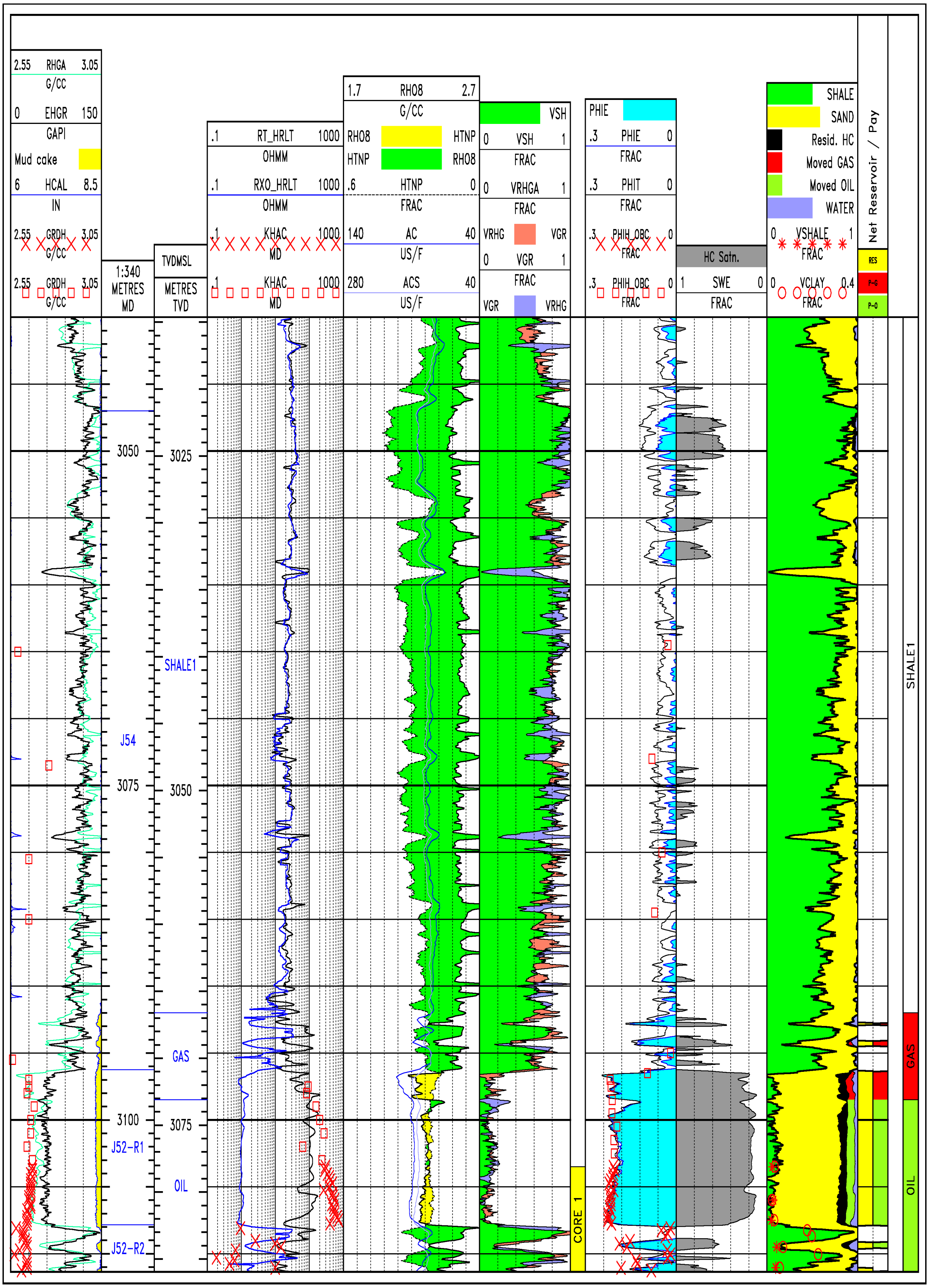


Figure 4-6: Wireline logs, core data and CPI results, J54 section, well 35/11-13

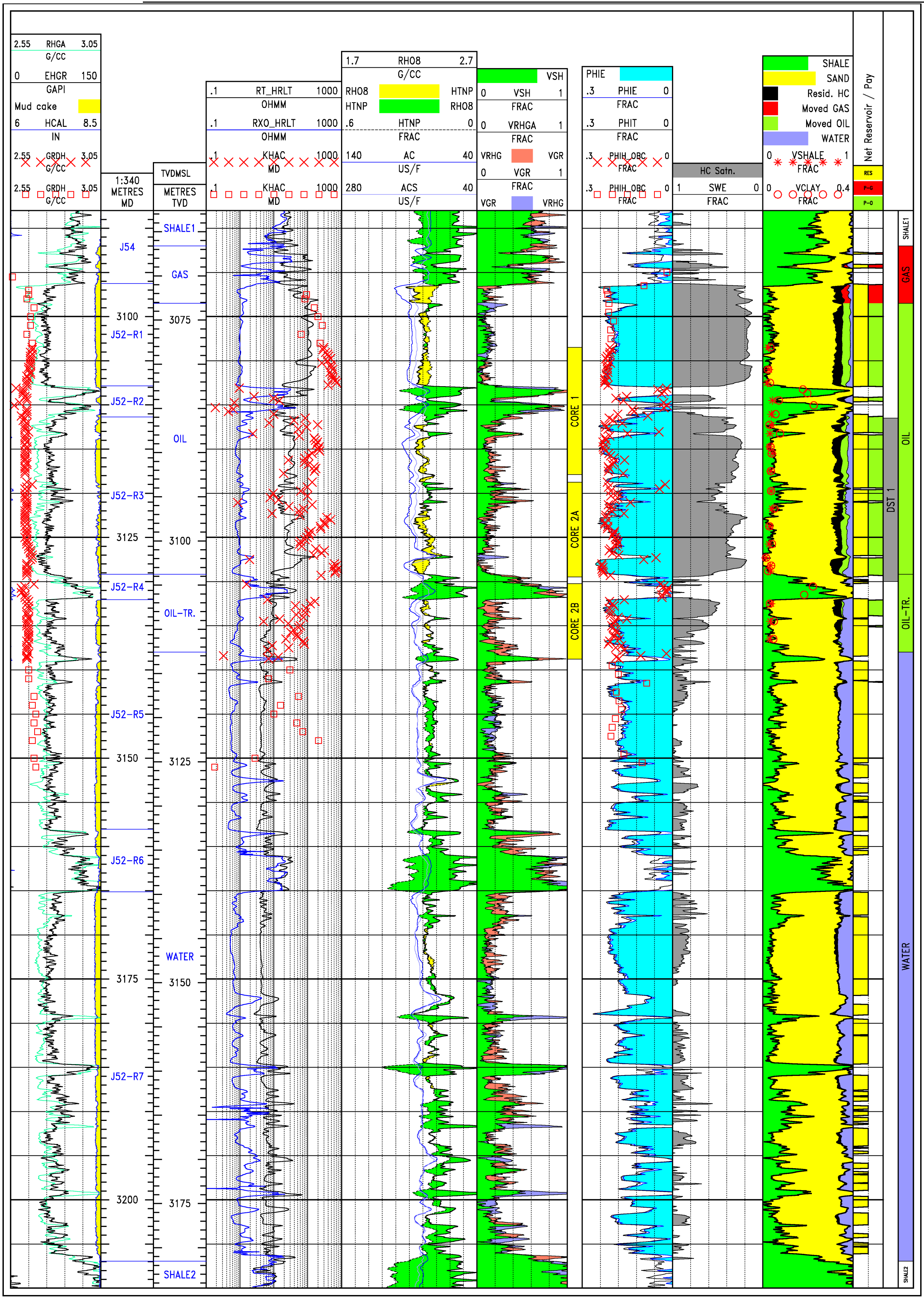


Figure 4-7: Wireline logs, core data and CPI results, J52 section, well 35/11-13

Log and core data zone averages over Net Reservoir intervals are shown in Table 4-7:

Well 35/11-13	Top MD	Top TVD	Base MD	Base TVD	Thickness (TVD) Gross	Thickness (TVD) Net	Thickness (TVD) N/G	Porosity log	Porosity core	Sw log	K (ari) core	K (geo) core
Zone:	RKB [m]	MSL [m]	RKB [m]	MSL [m]	[m]	[m]	[frac]	[1] [frac]	[2] [frac]	[3] [frac]	[4] [mD]	[5] [mD]
J54	3047.00	3021.63	3096.25	3070.86	49.23	0.61	0.012	0.122	***	0.524	***	***
J52-R1	3096.25	3070.86	3107.85	3082.46	11.60	11.49	0.991	0.199	0.216*	0.192	456*	440*
J52-R2	3107.85	3082.46	3111.37	3085.98	3.52	0.88	0.250	0.146	**	0.587	**	**
J52-R3	3111.37	3085.98	3129.18	3103.78	17.80	17.04	0.957	0.196	0.199	0.342	172	76
J52-R4	3129.18	3103.78	3132.05	3106.65	2.87	0.74	0.257	0.127	**	0.730	**	**
J52-R5	3132.05	3106.65	3158.04	3132.63	25.98	23.85	0.918	0.171	0.181*	0.845	47*	21*
J52-R6	3158.04	3132.63	3165.13	3139.72	7.09	2.23	0.314	0.132	***	0.928	***	***
J52-R7	3165.13	3139.72	3206.95	3181.53	41.81	31.18	0.746	0.160	***	0.902	***	***
J52-Total	3096.25	3070.86	3206.95	3181.53	110.67	87.40	0.790	0.174	0.196*	0.654	188*	74*
J52-above FWL	3096.25	3070.86	3138.00	3112.60	41.74	35.99	0.862	0.193	0.199	0.354	191	84
J52-below FWL	3138.00	3112.60	3206.95	3181.53	68.93	51.41	0.746	0.161	***	0.905	***	***
J52- DST 1	3111.50	3086.11	3130.00	3104.60	18.49	17.37	0.939	0.195	0.199	0.347	173	77

Key:

[1]	Log derived effective porosity PHIE - arithmetic average, thickness weighted.
[2]	Core overburden corrected helium porosity PHIH_OBC - arithmetic average.
[3]	Log derived effective water saturation SWE - arithmetic average, porosity and thickness weighted.
[4]	Core klinkenberg corrected horizontal air permeability KHAC - arithmetic average.
[5]	Core klinkenberg corrected horizontal air permeability KHAC - geometric average.
*	Core data values may not be representative due to insufficient core coverage in the zone.
**	Core data values not reported because they are not representative of the zone.
***	Core data values not reported because there are no core data in the zone.

Table 4-7: Zone averages over Net Reservoir intervals in well 35/11-13

5 Fluid Contact Levels

The interpretation of the formation fluid contacts is based on the following information:

- Electrical logs
- Cores analysis
- Formation pressure points (chapter 5.1)
- Fluid logging
- PVT analysis

The data interpreted is discussed in chapters 5.1 and a summary of the fluid scanning is given in chapter 0.

5.1 Pressure measurements

Twenty-nine pressure tests were attempted in MDT Run 1A as listed in Table 5-3 (next page), note all pressure values are from the CQG quartz gauge. Twenty-eight of the pressure tests were considered successful, (only one dry test), but several tests exhibited low mobility.

5.2 Formation Pressure Points, Core analysis and Electrical Log Interpretation

The formation pressure measurements (Table 5-3) were evaluated to determine fluid gradients and fluid contact levels. The results are presented in Figure 5-1; the fluid gradient values and consequent fluid contact levels are shown in Table 5-1:

Fluid Gradients and Fluid Contacts interpreted from the pressure data					
Gradients:	bar/m	g/cc	Contacts:	Depth	
				m. MD RKB	m. TVD MSL
Gas	0.0245	0.25			
Oil	0.0642	0.655	GOC	3098.5	3073.1
Water	0.0951	0.97	FWL	3138.0	3112.6

Table 5-1: Fluid gradients and contacts interpreted from MDT pressures in well 35/11-13

The interpreted oil gradient (0.655 g/cc) is in close agreement with the density determined from PVT analyses on oil samples from DST 1, (0.653 g/cc), Table 5-2. The PVT oil density values are sourced from Ref./9/.

Density from PVT analyses of recombined separator sample from DST 1						
Test	Test interval		PVT analysis method	Density at P_{BP} (304.5 bar)	Est. correction to reservoir pressure	Density at Pi (315 bar)
	m. MD RKB	m. TVD MSL				
DST 1	3111.5-3130.0	3086.1-3104.6	Pycnometer:	0.6518 g/cc	+ 0.0016 g/cc	0.6534 g/cc
			Single stage separation:	0.6530 g/cc	+ 0.0016 g/cc	0.6546 g/cc
			Differential liberation:	0.6480 g/cc	+ 0.0016 g/cc	0.6496 g/cc
			Two stage separation:	0.6540 g/cc	+ 0.0016 g/cc	0.6556 g/cc
Density (average value from the above four methods) at 315 bar reservoir pressure =						0.653 g/cc

Table 5-2: Density from PVT analyses on oil samples from DST 1 in well 35/11-13

The interpreted water gradient (0.97 g/cc) is consistent with the water density calculated from the formation water resistivity Rw value of 0.12 ohmm at 119.3 ^{o}C. The Rw value corresponds to a salinity of 15647 ppm NaCl which converts to a density of 0.962 g/cc at reservoir pressure and temperature.

The gas / light hydrocarbon column is too thin to determine a gradient value from the pressure data. The gas gradient value (0.25 g/cc) presumes that the fluid is gas.

Several pressure tests indicated low mobility, (refer Table 5-3); some occur towards the base of the oil transition zone, and several more occur towards the base of the water zone. The interpreted gradient lines were placed through the higher mobility points; consequently, as might be expected, many of the low mobility tests plot above the gradient lines indicating a small degree of supercharging.

Figure 5-1 also shows the depths and summary results from the fluid sampling and fluid logging (scanning) measurements; the results are also summarised in Table 5-2.

Depth MD RKB [m.]	Depth TVD MSL [m.]	Test No.	File No.	Reservoir Zone	Formation Pressure [bar]	Mud pressure Before [bar]	Mud pressure After [bar]	Mobility [mD/cp]	Remarks
3097.00	3071.6	32	111	J52-R1	313.816	393.595	393.602	235.4	ok
3097.90	3072.5	31	110	J52-R1	313.840	393.715	393.714	309.9	ok
3100.50	3075.1	30	109	J52-R1	313.981	394.034	394.031	462.7	ok
3102.50	3077.1	29	108	J52-R1	314.107	394.288	394.285	488.2	ok
3105.00	3079.6	28	107	J52-R1	314.269	394.597	394.596	450.5	ok
3106.90	3081.5	27	106	J52-R1	314.375	394.839	394.835	537.7	ok
3112.50	3087.1	26	105	J52-R3	314.774	395.532	395.534	3.2	Low mobility
3115.00	3089.6	25	104	J52-R3	314.899	395.844	395.841	287.2	ok
3117.50	3092.1	24	103	J52-R3	315.069	396.168	396.169	203.2	ok
3123.50	3098.1	23	102	J52-R3	315.439	396.916	396.915	328.7	ok
3126.50	3101.1	22	101	J52-R3	315.626	397.299	397.295	207.2	ok
3128.00	3102.6	21	100	J52-R3	315.770	397.562	397.560	166.6	ok
3132.40	3107.0	20	99	J52-R5	316.100	398.110	398.111	25.6	ok
3134.10	3108.7	19	98	J52-R5	316.226	398.244	398.247	7.8	Low mobility
3135.30	3109.9	18	97	J52-R5	316.274	398.432	398.433	12.7	Low mobility
3136.00	3110.6	17	96	J52-R5	316.291	398.520	398.521	16.3	Low mobility
3142.50	3117.1	16	95	J52-R5	316.819	399.318	399.322	53.8	ok
3147.50	3122.1	15	94	J52-R5	317.295	399.934	399.932	39.8	ok
3155.50	3130.1	14	93	J52-R5	318.068	400.937	400.942	23.9	ok
3157.50	3132.1	13	92	J52-R5	318.243	401.181	401.187	95.9	ok
3166.20	3140.8	12	91	J52-R7	319.110	402.264	402.261	34.6	ok
3170.00	3144.6	11	90	J52-R7	319.440	402.728	402.728	45.2	ok
3175.50	3150.1	10	89	J52-R7	319.979	403.405	403.408	20.8	ok
3183.50	3158.1	9	88	J52-R7	320.850	404.383	404.390	0.9	Low mobility
3186.50	3161.1	7	87	J52-R7	321.043	404.750	404.748	26.5	ok
3193.50	3168.1	6	86	J52-R7	321.784	405.621	405.607	7.5	Low mobility
3200.50	3175.1	5	85	J52-R7	322.546	406.492	406.469	3.2	Low mobility
3202.00	3176.6	4	79	J52-R7	322.550	406.657	406.643	21.2	ok
3205.50	3180.1	3	78	J52-R7		407.089	407.049		Dry Test

Table 5-3: MDT pressure measurements in well 35/11-13

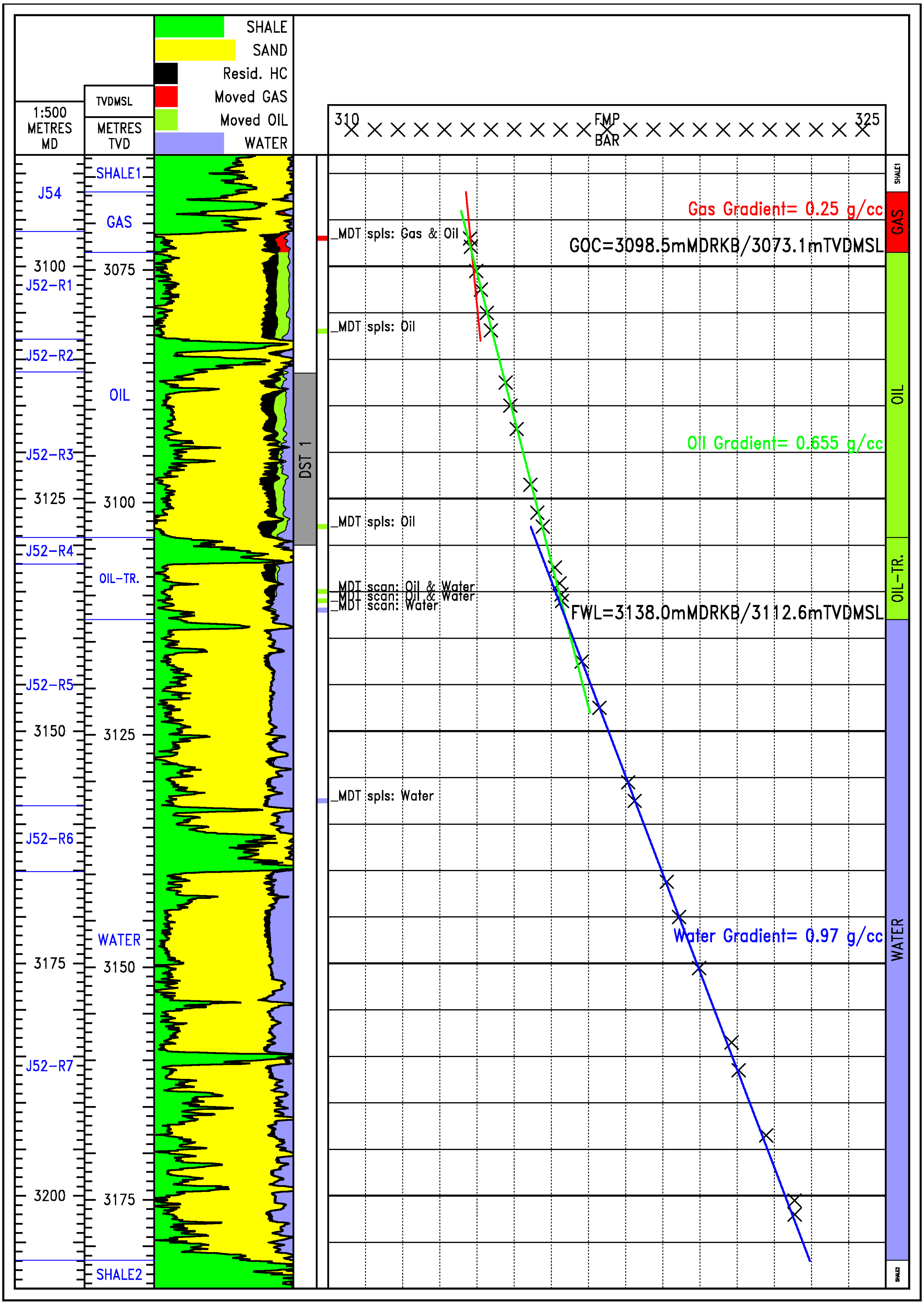


Figure 5-1: Formation pressure and fluids interpretation, J52 section, well 35/11-13

5.3 Fluid Scanning Interpretation (MDT)

The MDT-toolstring was configured with both an LFA and CFA. It was therefore decided to perform a downhole fluid scanning with the MDT in order to verify the FWL in the reservoir. The fluid scanning was performed at three different depths: 3135, 3136 and 3137m MD RKB, see Figure 5-2 below.

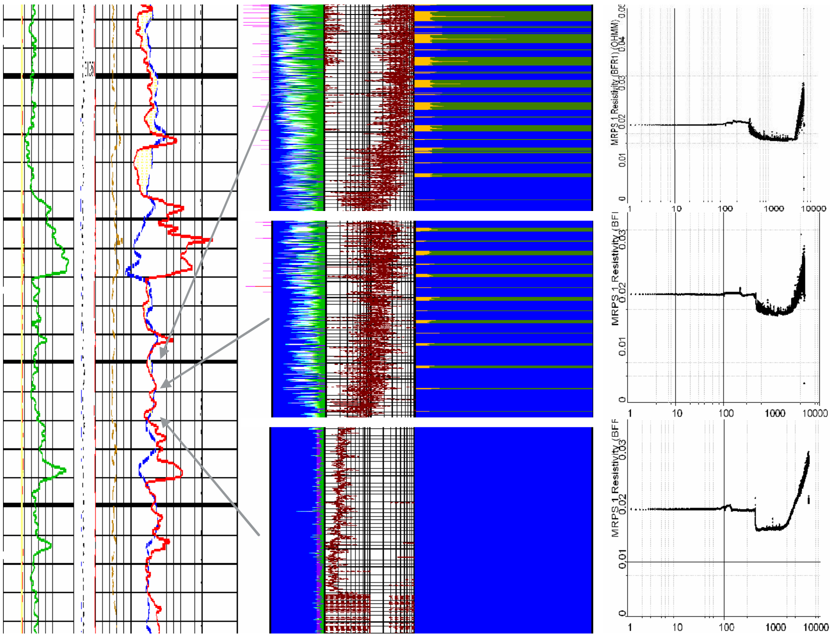


Figure 5-2: Fluid scanning around the FWL, 3135-3137m MD RKB

Summary results from the fluid sampling and fluid logging (scanning) measurements are shown in Table 5-4:

Fluid analysis from MDT fluid logging measurements					Offshore analysis results on two samples		
Depth		Reservoir	Samples or	Fluid	MDT chamber	Oil Density	GOR
m. MD RKB	m. TVD MSL	Zone	Scanning	Analysis	No.	(g/cc)	(m^3/m^3)
3097.00	3071.6	J52-R1	Samples (5)	Gas and Oil	MRSC #172	0.789 @ 14.9°C	3872.7
3107.00	3081.6	J52-R1	Samples (4)	Oil	MRSC #100	0.848 @ 14.3°C	120.1
3128.00	3102.6	J52-R3	Samples (2)	Oil			
3135.00	3109.6	J52-R5	Scanning	Oil and Water			
3136.00	3110.6	J52-R5	Scanning	Oil and Water			
3137.00	3111.6	J52-R5	Scanning	Water			
3157.50	3132.1	J52-R5	Samples (2)	Water			

Table 5-4: Fluid analysis from MDT fluid sampling and fluid scanning

The fluid analysis results from MDT fluid logging measurements (on the left side of Table 5-4) were evaluated, Ref./7/. This report includes summary analyses of the recovered fluid samples together with graphical displays showing the fluid scanning results. The fluid analysis results are not conclusive concerning the nature of the 'gas zone' at 3097m MD RKB since both gas and oil are in evidence. The Offshore analysis results on two samples (on the right side of Figure 6-1) were taken from Ref./6/. These results show a very high GOR for the 'gas zone' sample at 3097 m MD RKB compared to the oil sample at 3107m MD RKB. PVT analyses for the MDT hydrocarbon samples are currently in progress; further information concerning the nature of the 'gas zone' should be available when these analyses are completed.

The GOC, which is estimated at 2073.1 m, TVD MSL (3098.5 m MD RKB), is considered to be relatively well defined from both logs (density-neutron separation) and pressure points. The GOC is located in a thin calcite layer.

The OWC is not well defined from the logs. There is clearly ODT to 3128 m MD RKB and WUT 3139 (maybe 3137) m MD RKB. In between is a 'transition' zone. The FWL from intersection of the oil and water gradients is defined at 3112.6 m TVD MSL (3138 m MD RKB). The fluid scanning at 3135 and 3136 demonstrated presence of mobile oil, while at 3137 m MD RKB only water flowed. At the lowest scanning depth (3137 m MD RKB) the shallow resistivity logs is reading low (the deep resistivity seem to read a calcite), and from this level and up both the resistivity logs are slightly increasing. It is therefore concluded that the OWC must be right above the lower scanning depth. The OWC is set to 3111.4 m TVD MSL (3136.8 m MD RKB, 3132.3 m core depth) which is lowest depth where fluoresce (light colour) can be identified on the core (Figure 5-3). No fluorescence is seen below the OWC, and the water saturation should be 1.0 for the whole water zone (some oil saturation is calculated in the log interpretation).

The difference between the estimated FWL from MDT and the OWC is 1.5 m. This seem to be to large; in the interval 3135 to 37 the core permeabilities are between 50 and 100 mD which is a fairly good formation. The FWL defined from pressure data could be somewhat inaccurate; only small adjustments of the gradients could move the FWL somewhat up. In the SCAL program entry pressure will be measured for several plugs located in the transition zone. This might reduce the uncertainty around the OWC & FWL.

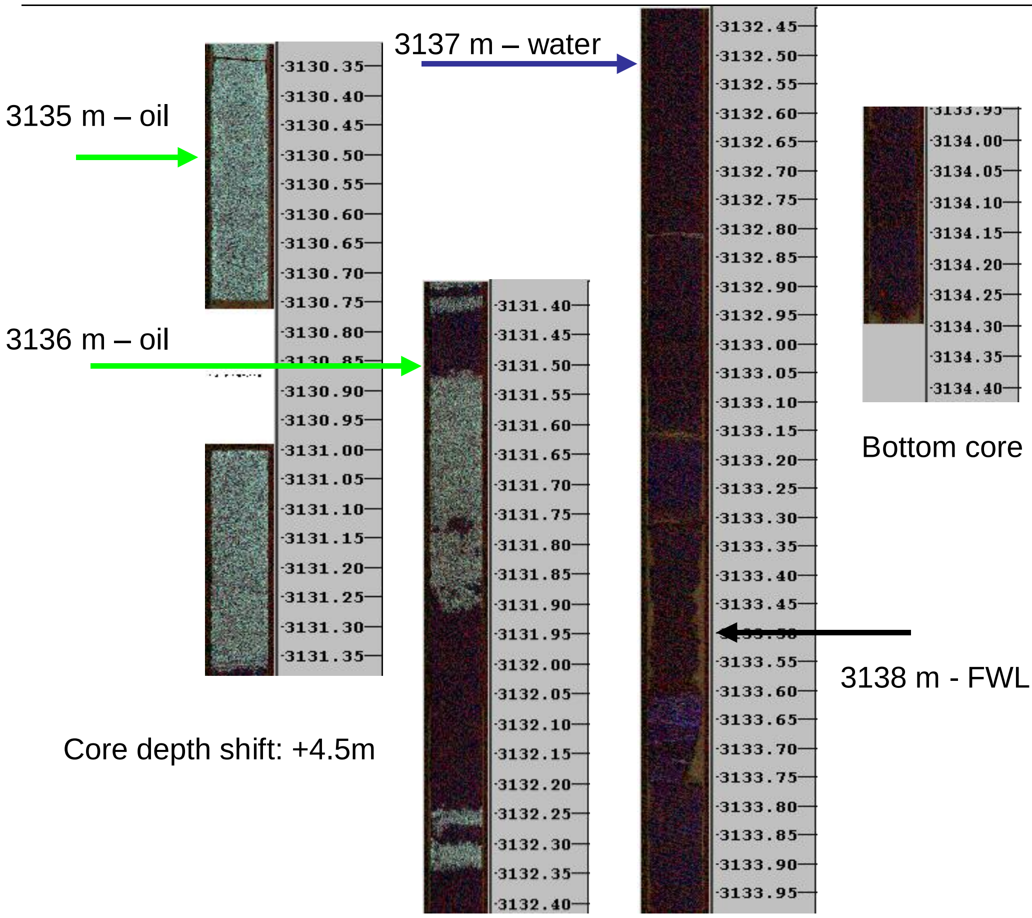


Figure 5-3: Scanning depth on core (light colour is fluoresce, dark no flouresence)

6 Wireline Formation Sampling

This chapter presents the operational aspects of wireline formation sampling. One MDT run (1B) was performed in order to fulfil the sampling objectives. A list of the sampling intervals is given in Table 6-1.

Sampling depth (m MD RKB)	Log run #	Sample type			Sampling probe
		Gas	Oil	Water	
3097	1B	X			Large Diameter
3107	1B		X		Large Diameter
3128	1B		X		Large Diameter
3157.5	1B			X	Large Diameter

Table 6-1: List of all sample intervals and observed fluid type on MDT logs

6.1 Wireline Formation Tester Acquisition

The Schlumberger Modular Dynamic Tester (MDT) wireline tool was used for the both of the two WFT operations. An overview of the MDT-runs is presented in Table 6-2 (next page). A very simple MDT configuration was run for the pressure point run. The MDT-toolstring consisted only of a probe and hydraulic module. The MDT configuration used for the fluid sampling and scanning was more sophisticated and it is shown in appendices 12.2. The complete sequence of events is found in appendices 12.8.1.

The MDT experienced several operational problems. Some of these problems were related to human error and some were tool/ software failures.

6.1.1 Fluid Sampling

All samples were taken during the separate sampling run 1B. The main fluid sampling objective in well 35/11-13 was to retrieve high quality single phase HC samples and representative water samples from the Astero reservoir. Note that no tracer was added to the mud.

13 (out of 14) fluid samples were successfully captured during the wireline formation sampling run. Two of the samples are collected from the water zone in the Astero reservoir while rests of the samples are collected at three different intervals in the gas and oil zone. All samples were captured using the low shock method using the large diameter probe.

Some problems were experienced during the job, but none of them caused any major operational failure. These problems were:

- One MPSR sample bottle was accidentally fired "close"; hence this sample bottle was lost.
- A leaking seal caused one captured SPMC sample to be lost.
- MDT power panel overheated, had to change power supply.
- Some plugging tendency of the Large Diameter Probe; had to reset the probe to cure the plugging of the probe nozzle.
- CFA detected no CO_2 during the oil sampling, while as much as 5% CO_2 was measured during the later production test! No obvious reason has been found for not detecting the CO_2 with the CFA (possibly was the CO_2 sensor turned off during the job).

During the same MDT run 1B, 3 different fluid scanning operations were conducted in order to investigate the FWL in the Astero reservoir. As seen in Figure 12-1, the MDT-string was configured with the both the LFA and CFA modules. The results are discussed in chapter 5.3, but the fluid scanning operations went well and are regarded as a success.

6.1.2 Offshore Fluid Transfer

Oilphase did the offshore fluid transfer. In total, total, 5 MPSR samples were captured and transferred to CSB transport bottles, 6 SPMC samples were sampled and transferred to SSB transport bottles. One SPMC had a cut back-up ring, due to a faulty redress, and the sample leaked out slowly from the top of the rod. One 1 gallon chamber and one 2 ¾ gallon chamber were sampled and flashed while measuring the GOR. Gas were filled in gasbags for offshore GC analysis and delivered to the mud logging unit for GC analysis. The density was measured on extracted oil from both samplers, and the resistivity was measured on water from the 2 ¾ gallon chamber. The offshore analysis results are being reported in chapter 10.1.1.

All samples were labeled and shipped to Oilphase in Stavanger, for onwards shipping to ResLab. A complete list of the samples can be found in the appendices 12.5.

MDT logging run #1A and #1B								
Date	**Log run**	**No. of pre-tests**	**Sampling depth (m MD RKB / TVD MSL)**	**MDT Samples taken**			**Run objectives**	**Operational comments**
				Gas	**Oil**	**Water**		
30.04.05	1A	28	n/a	n/a	n/a	n/a	Pressure points	Got 28 P-points out of 29.
01.05.05	1B	8	3097 / 3071.6	SPMC:2 MPSR:2 MRSC:1	n/a	n/a	Recover samples and identify fluid type	Sampling of a small gas cap seen on top of oil column. Good mobility and low drawdown during sampling.
			3107 / 3081.6	n/a	SPMC:2 MPSR:1 MRSC:1	n/a	High quality and large volume of samples	No special operational problems reported.
			3128 / 3102.6	n/a	SPMC:1 MPSR:1	n/a	High quality samples	Pumpout showing some tendency of seal-failure during shifting of stroke direction. Operation completed successfully.
			3135 / 3109.6	n/a	n/a	n/a	Fluid scanning	The LFA/CGA modules were used at three different depths to investigate the oil water contact in order to back up the FWL depth determined from the MDT pressure gradient.
			3136 / 3110.6	n/a	n/a	n/a	Fluid scanning	
			3137 / 3111.6	n/a	n/a	n/a	Fluid scanning	
			3157.5 / 3132.1	n/a	n/a	SPMC:1 MPSR:1	High quality samples	Some problems encountered both on the pumpout module and the hydraulic pressure in the PS_1 probe. Several "reset probe" commands were executed.

Table 6-2: MDT logging overview

6.2 Sampling Gas at 3097m MD RKB

During the clean-up at 3097m MD, it was noted that the LFA/CFA analysis indicated gas/condensate (which was also the indications from the pressure gradient curve). Both the colorization and GOR-readings were significantly different than the later readings from 3107m MD. The fluid flashed from the 1 gallon chamber (MRSC 172) is shown in Figure 6-1 below.

Figure 6-1: Fluid sample (MRSC 172) from 3097m MD RBK

As seen from the picture below, Figure 6-2, the fluid captured lower in the reservoir at 3107m MD is quite different – both in character and volume - than the sample collected at the top of the reservoir.

Figure 6-2: Fluid sample (MRSC 100) from 3107m MD RBK

All of the fluid identification channels indicated a gas and/or light oil with high GOR. When the gas normalized channel [4] and [5] clearly separates from the other gas normalized data, see Figure 6-3, it is a positive verification of free gas. The reason is that the highest gas normalized channels reads the larger "gas bubbles" which are flowing through the gas sensor. The readings are also significantly higher (on the y-axis) than later seen for the oil and water sampling situation.

The optical densities, shown in Figure 6-4, indicate that a relatively clear liquid is being pumped. This corresponds well with the observed fluid when flashing the 1 gallon chamber at surface, see Figure 6-1. If one also looks at the fluid fraction plot,

Figure 6-5, it is evident that there is a significant volume of gas being pumped at 3097m MD. When the pump rate is increased at ~8000 sec., a much larger volume of gas is produced through the MDT-tool. This can be seen from the CGA plot in Figure 6-6. When the pump is running at 700 rpm, a higher amount of gas and GOR is seen (the lower half of the figure). Also the C_6^+ fraction is lower on the log. The GOR is estimated to be around 2200 – 2400 m^3/m^3 during this period with a higher pump rate. The corresponding pressure and temperature development at 3097m MD is seen in Figure 6-7.

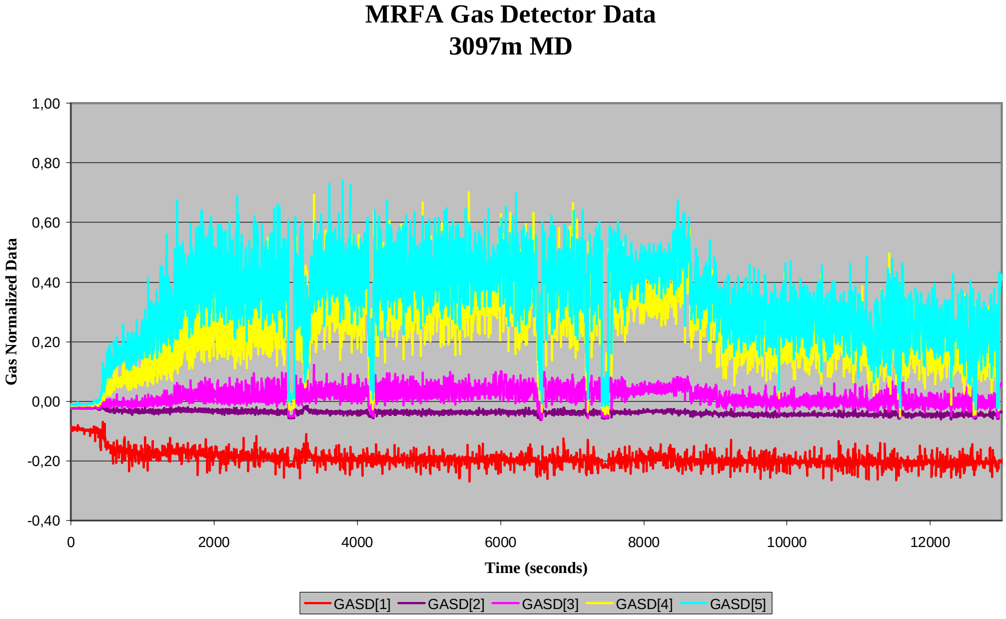


Figure 6-3: Gas normalized data from 3097m MD RKB

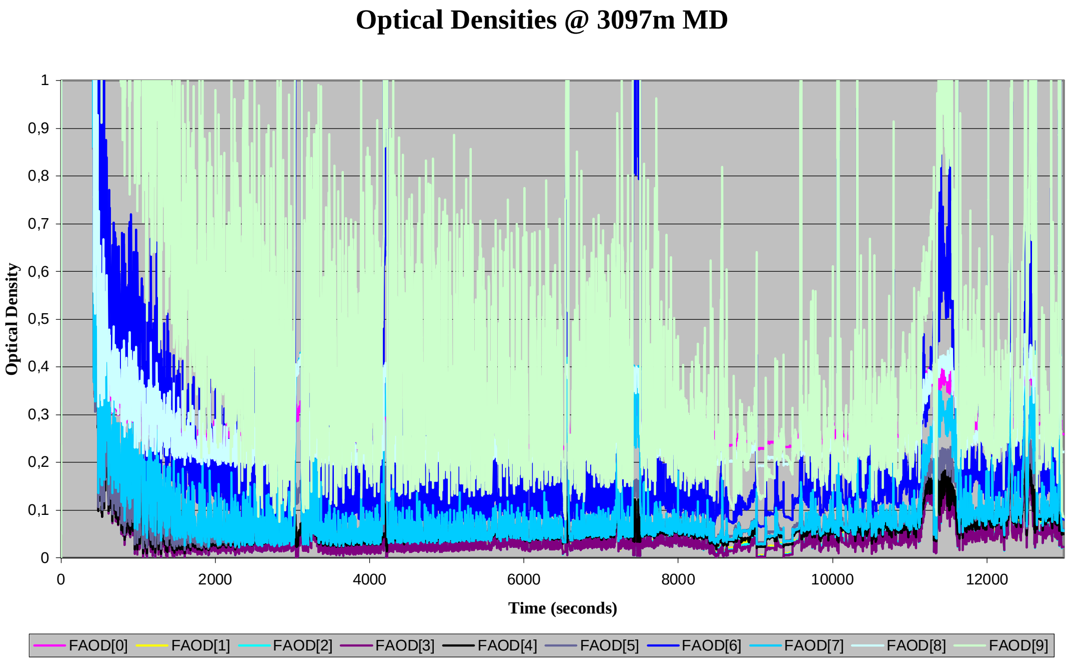


Figure 6-4: Optical densities at 3097m MD RKB

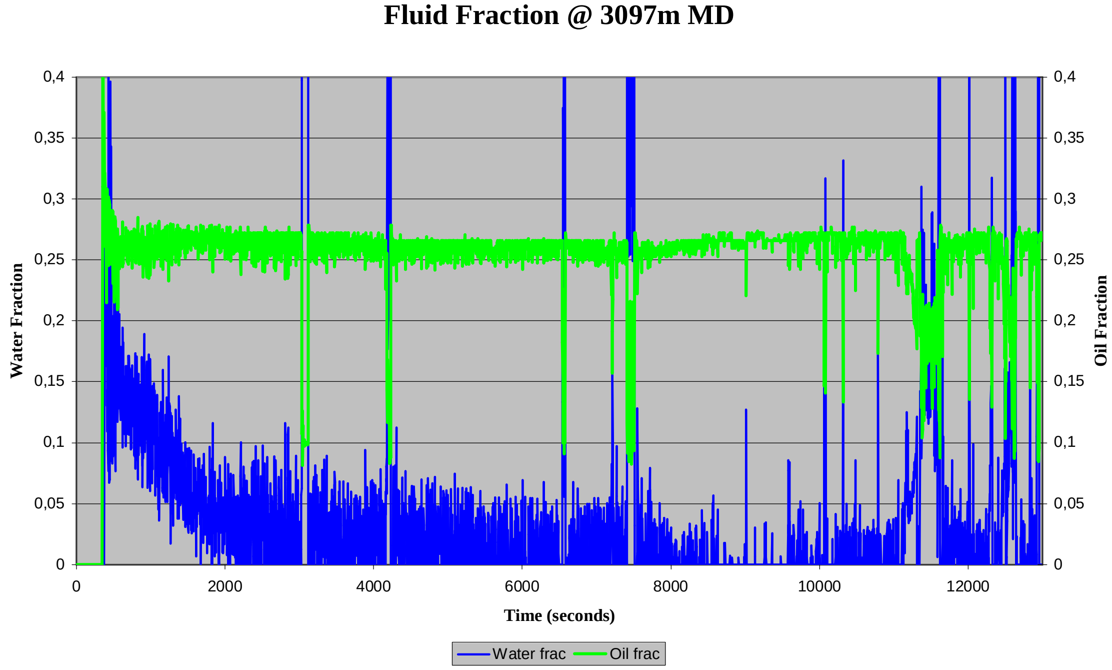


Figure 6-5: Fluid fraction plot from 3097m MD RKB

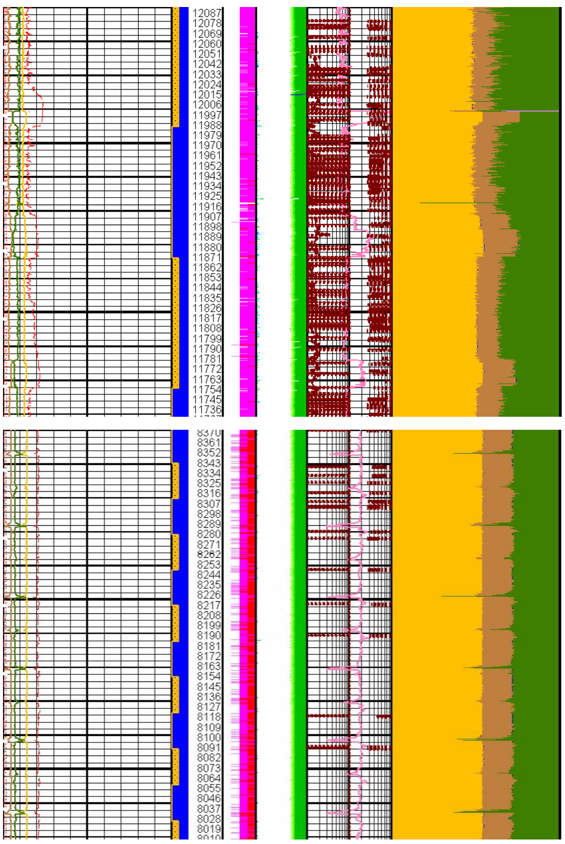


Figure 6-6: CFA plot showing different gas volume depending on pump rate

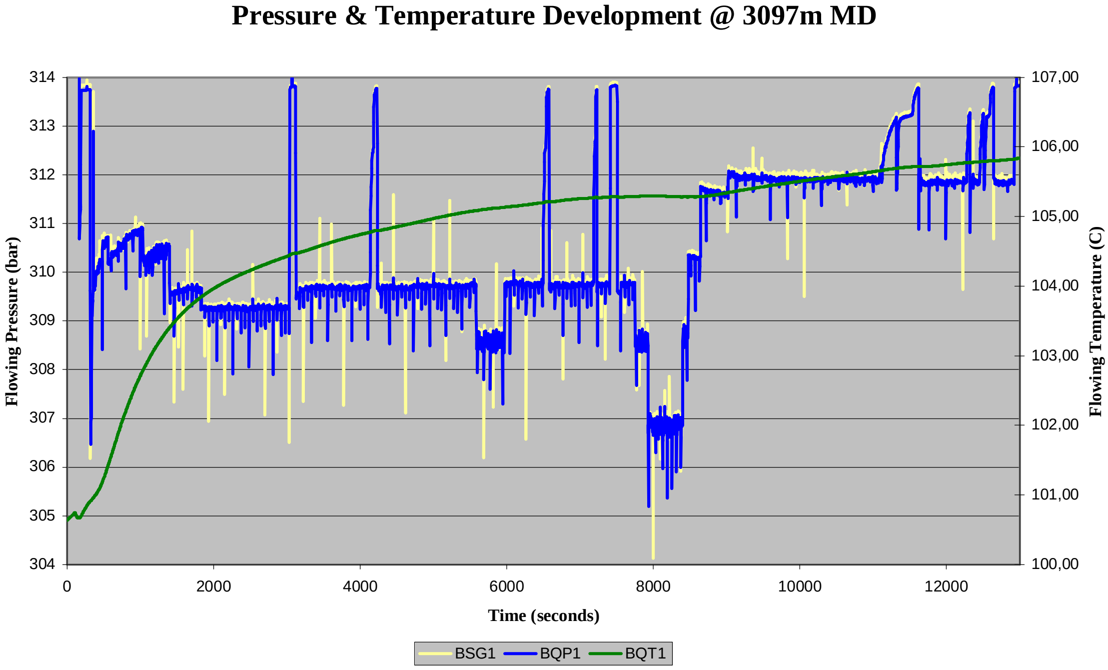


Figure 6-7: Pressure and temperature development at 3097m MD RKB

On interesting observation can be drawn from the resistivity plot, Figure 6-8, with respect to the clean-up of the sampling depth. When the pump rate is increased from 500 rpm to 700 rpm (~8000 sec.), the resistivity is saturated (~24 ohmm) and "stable". Up to this point the resistivity has been erratic and jumping up and down indicating a non-uniform fluid being pumped.

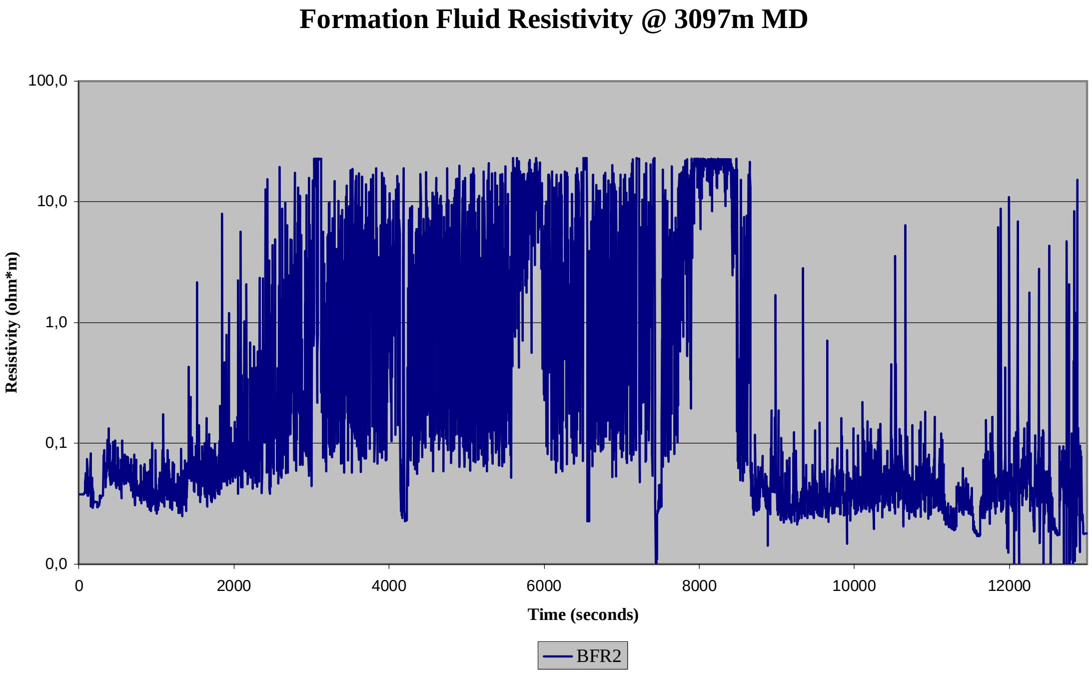


Figure 6-8: Resistivity readings at 3097m MD RKB

When the rate is reduced to 300 rpm, the resistivity is falling back to a significantly lower value and exhibit a more stable reading. This indicates that the fluid which is flowing through the resistivity cell is cleaner and more uniform (less free gas). The last MPSR bottle (#971) sampled at this depth should therefore be of a better quality than the three first ones taken.

A summary of the clean-up and transfer data is presented in Table 6-3 and Table 6-4.

Bottle #	Ref. time (sec)	Cleanup data		Draw-down (bar)	Comments
		Time (hr:min)	Volume (litre)		
MPSR # 73	4073	1:03	n/a	4	
SPMC #123	6445	1:42	n/a	4	
SPMC #103	7114	1:53	45	4	
MPSR #768	-	-	-	-	Accidentally sealed, no sample
MRSC2 #172	10051	2:42	n/a	1.7	1 gallon chamber
MPSR #971	12265	3:20	81	1.6	

Table 6-3:Sampling data at 3097 m (gas)

MDT bottle no.	Opening pressure (bar)	Transport bottle no.	Volum	Comments
MPSR # 73	224 bar @ 10 C	CSB 6286-MA	340 cc	Monophasic
SPMC #123	Atm.	n/a	n/a	Leaking bottle, lost sample
SPMC #103	345 bar @ 11 C	SSB 9283-MA	187 cc	Monophasic
MRSC2 #172	Atm.	n/a - glass	1 ltr	Atmospheric, flashed offshore
MPSR #971	234 bar @ 10 C	CSB 4464-EA	350 cc	Monophasic

Table 6-4: Surface sampling data (3097 m - gas)

6.3 Sampling Oil at 3107m MD RKB and 3128m MD RKB

The two sets of LFA/CFA plots from the oil sampling at 3107m and 3128m MD are relatively similar in behavior. The optical densities and gas normalized data indicate the same type of oil being sampled, see Figure 6-9 and Figure 6-10. The optical density channel [1] is at both depth approaching ~1.3 and the separation of the gas channels is almost identical at the two depths. This correlates well with the pressure gradient over the same interval.

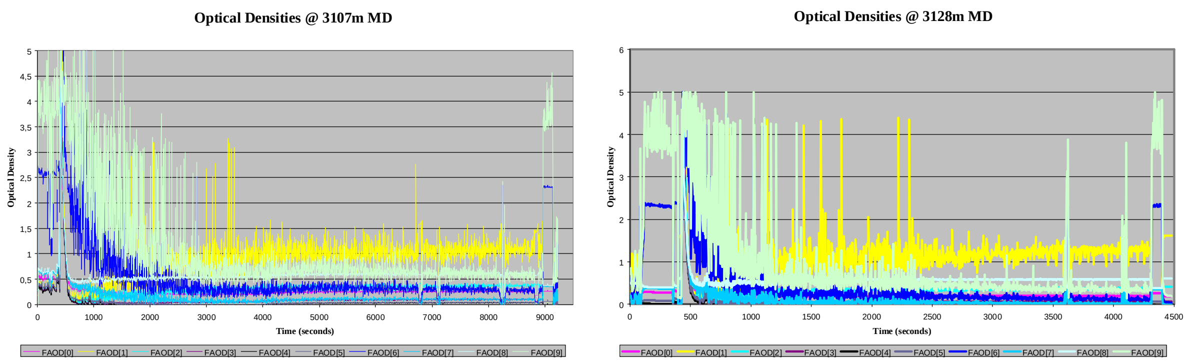


Figure 6-9: Optical densities from 3107 and 3128m MD RKB

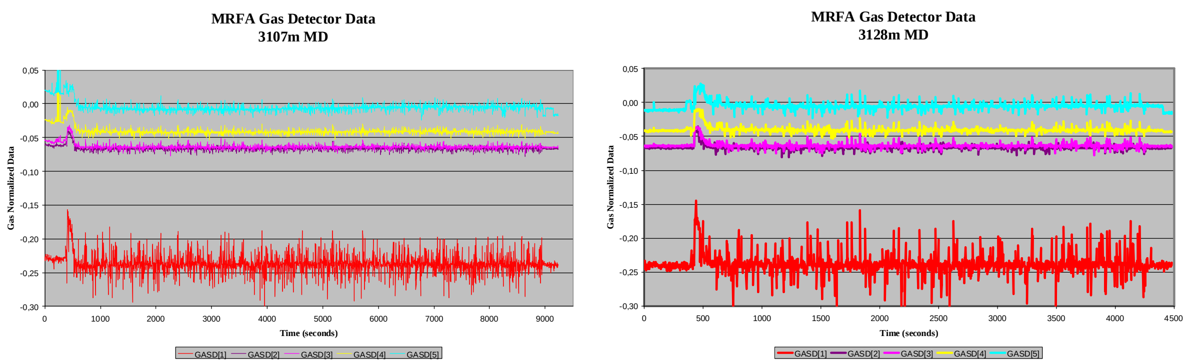


Figure 6-10: Gas normalized data from 3107 and 3128m MD RKB

The samples captured at 3128m MD are possibly of better a quality because they are somewhat less contaminated by mud filtrate. It looks like the clean-up went faster at this depth, see Figure 6-9 and Figure 6-11, and that the curves becomes more stable before the samples are taken.

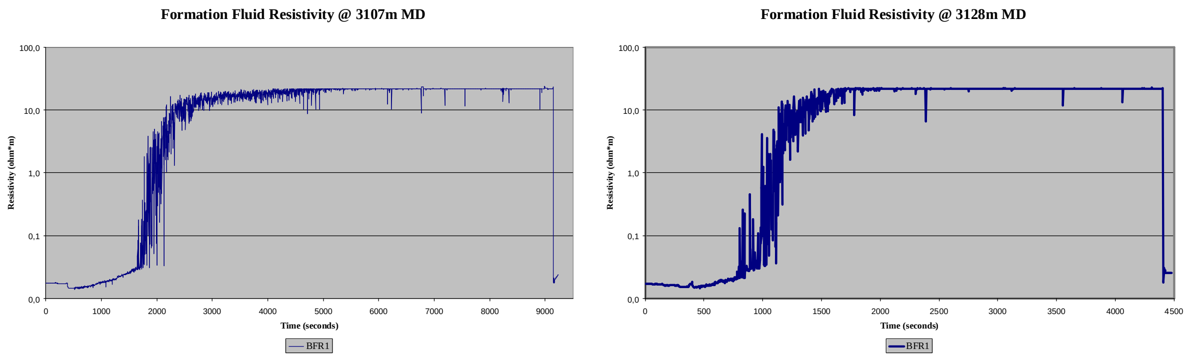
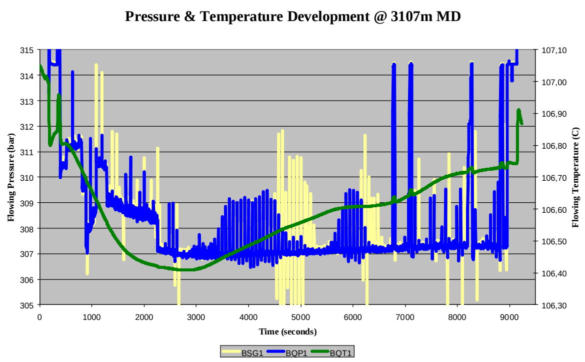


Figure 6-11: Resistivity readings at 3107 and 3128m MD RKB



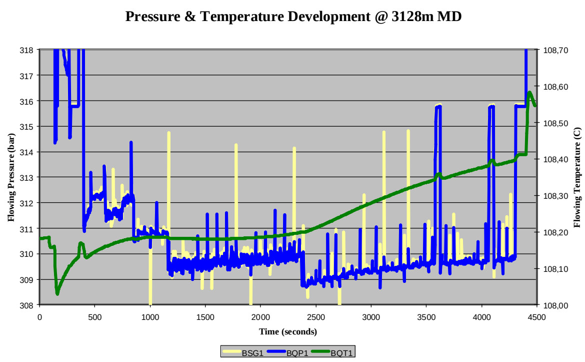


Figure 6-12: Pressure and temperature development at 3107 and 3128m MD RKB

The pressure history is presented in Figure 6-12. We see that we have a drawdown of 6-7 bar at both sampling depths. The slightly reducing drawdown while sampling indicates that the system still is cleaning up.

A summary of the clean-up and transfer data is presented in Table 6-5 to Table 6-8. Note that during sampling at both sampling intervals in the oil zone the pressure was lower than the bubblepoint pressure. Using a bubblepoint gradient of 0.1 bar/m results in a maximum drawdown for gas free production of approximately 0.6 and 2.2 bar for the upper and lower sampling depth respectively. Those limits are exceeded by 6.4 and 3.8 bar.

Bottle #	Ref. time (sec)	Cleanup data		Draw-down (bar)	Comments
		Time (hr:min)	Volume (litre)		
MPSR # 972	6721	1:46	93	7	
SPMC #148	7053	1:51	n/a	7	
MRSC2 #100	7411	1:57	103	7	2 3/4 gallon chamber
SPMC #121	8789	2:20	125	7	

Table 6-5: Sampling data at 3107 m (upper oil)

MDT bottle no.	Opening pressure (bar)	Transport bottle no.	Volum	Comments
MPSR # 972	158 bar @ 10 C	CSB 4753-EA	410 cc	Monophasic
SPMC #148	414 bar @ 11 C	SSB 2149-EA	245 cc	Monophasic
MRSC2 #100	Atm.	IATA Cans	4 +3.5 ltr	Dead oil
SPMC #121	423 bar @ 13 C	SSB 2040-EA	230 cc	Monophasic

Table 6-6: Surface sampling data (3107 m – upper oil)

Bottle #	Ref. time (sec)	Cleanup data		Draw-down (bar)	Comments
		Time (hr:min)	Volume (litre)		
MPSR # 972	3537	0:52	42	6	
SPMC #121	4022	1:01	49	6	

Table 6-7: Sampling data at 3128 m (lower oil)

MDT bottle no.	Opening pressure (bar)	Transport bottle no.	Volum	Comments
MPSR # 972	165 bar @ 12 C	CSB 6949-MA	410 cc	Monophasic
SPMC #121	441 bar @ 14 C	SSB 10334-AA	220 cc	Monophasic

Table 6-8: Surface sampling data (3128 m – lower oil)

6.4 Sampling Water at 3157.5m MD RKB

During water sampling the optical water channels [6] and [9] clearly indicate formation water throughout the sampling operation, see Figure 6-13. No tracer was added to the WBM, it was planned for a longer pumping time than for the HC samples. Unfortunately, some plugging tendency was experienced during the clean-up period, and the probe hade to be reset (see pressure response at ~7500 sec. in Figure 6-14). Since the MDT tool was not moved during the retraction of the probe, it re-set most likely very close the initial position. The clean-up of the formation and the near probe inlet area continued almost without any setback of the clean-up process. By investigating the resistivity plot, Figure 6-15, one see that the resistivity chanced very little after the probe had reset.

The resistivity (for contaminated water) ends at a value of 0.06 ohmm compared to 0.12 ohmm used in the petrophysical analysis.

Plugging tendency occurred during the whole pumping period, and the water samples were captured at a point where one wanted to secure the samples before the nozzle of the probe plugged off completely. However, the water samples should have low mud filtrate contamination.

In Table 6-9 and Table 6-10 presents a summary of the water sampling data.

Bottle #	Ref. time (sec)	Cleanup data		Draw-down (bar)	Comments
		Time (hr:min)	Volume (litre)		
MPSR # 930	14300	3:58	58	13	Max drawdown 50 bar
SPMC #150	15000	4:10	66	13	

Table 6-9: Sampling data at 3157.5 m (water)

MDT bottle no.	Opening pressure (bar)	Transport bottle no.	Volum	Comments
MPSR # 972	48 bar @ 12 C	CSB 6840-MA	420 cc	Monophasic
SPMC #121	490 bar @ 14 C	SSB 1254-EA	230 cc	Monophasic

Table 6-10: Surface sampling data (3157.5 m – water)

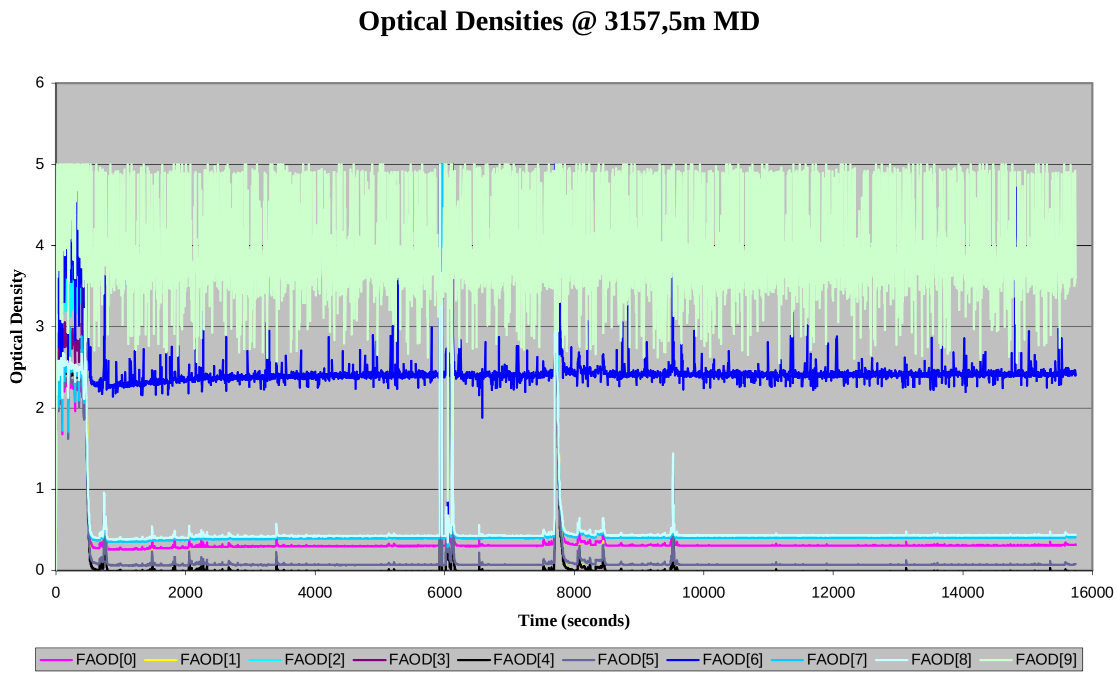


Figure 6-13: Optical densities from 3157.5m MD RKB

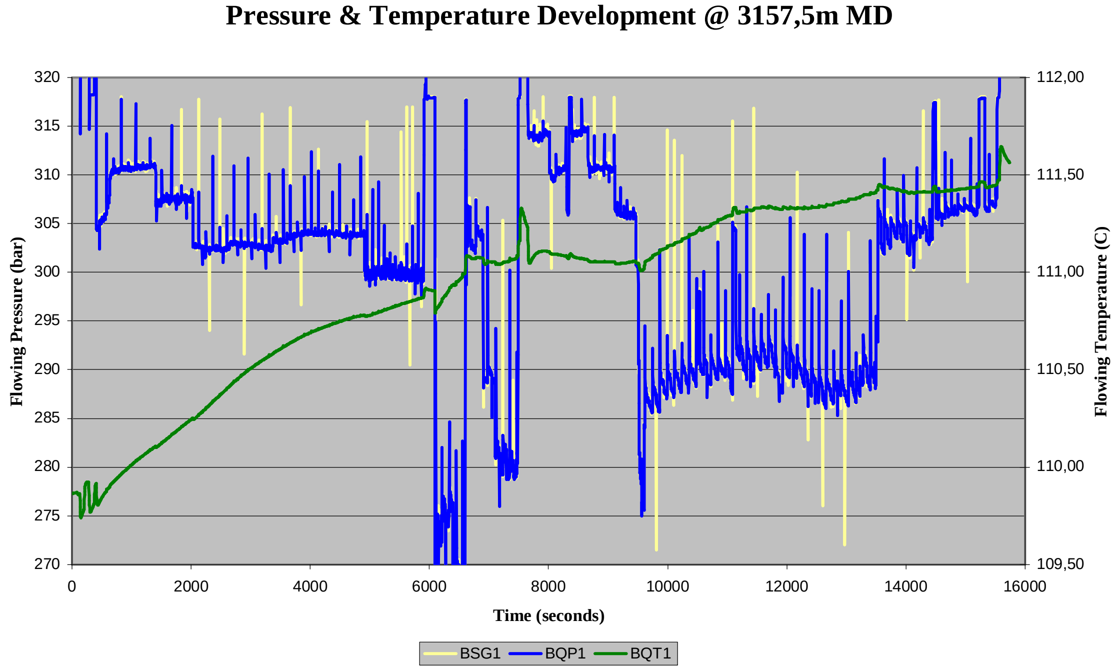


Figure 6-14: Pressure and temperature development at 3157.5m MD RKB

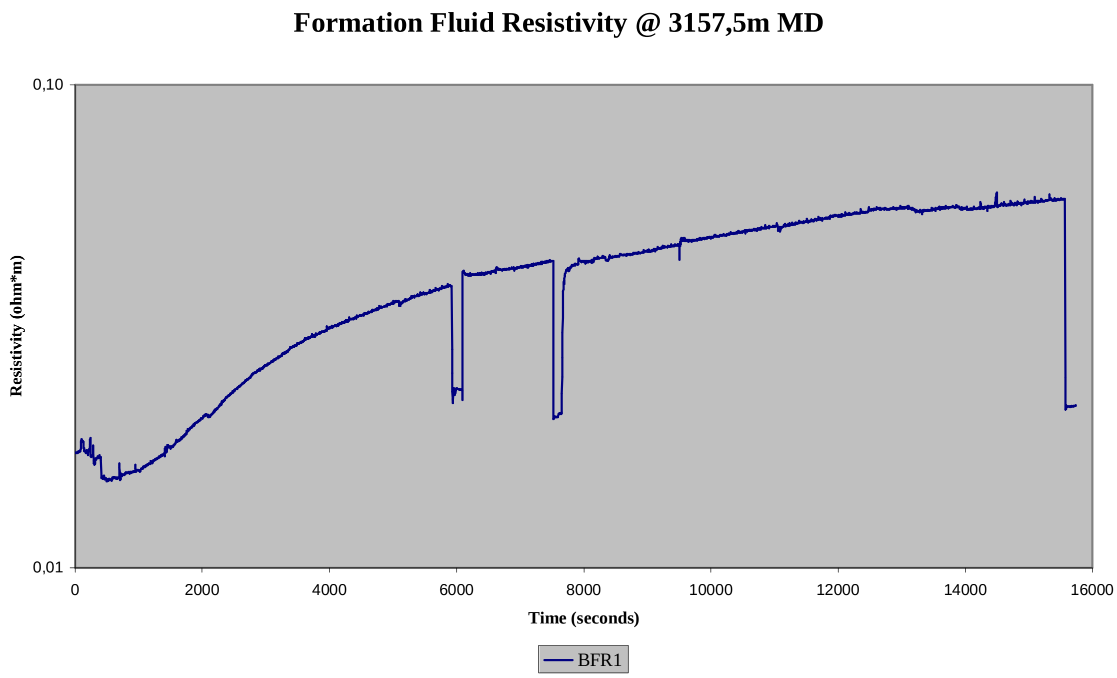


Figure 6-15: Resistivity readings at 3157.5m MD RKB

6.5 Curve Mnemonics for MDT Channels

Curve mnemonics	**Explanation**	**Units**
BSG1	MRPS 1 Strain Gauge Pressure	Bar
BQT1	MRPS 1 Quartz Gauge Temperature	Deg. C
BQP1	MRPS 1 Quartz Gauge Pressure	Bar
B1TR	MRPS 1 Resistivity Cell Temperature	Deg. C
B1TV	MRPS 1 Strain Gauge Temperature	Deg. C
BFR1	MRPS 1 Resistivity	Ohm*m
FAOD [0..9]	Fluid Analyzer Optical Density Data [ch. 0..9]	Unitless
Water frac. (WATF)	Water Fraction	Unitless
Oil frac. (OILF)	Oil Fraction	Unitless
GASD[1..5]	Gas Detector Normalized Data [ch. 1..5]	Unitless

Table 6-11: Curve mnemonics for the MDT channels

7 Drill Stem Test Interpretation

This Chapter contains data acquisition during the test and test interpretation.

7.1 Summary of DST Data Acquisition

One production test was performed in the oil bearing section of the Oxfordian Formation (DST #1). In this chapter the data acquisition during the testing is described. Analysis of the test data is presented in chapters 7, 8 and 9.

Bottom hole sampling was planned, but was cancelled due to PROSPER calculations demonstrated presence of free gas in the lower part of the well. Hence, it would not have been possible to take representative bottom hole samples. A summary of the data acquisition is presented in Table 7-1, the main completion data is found in Table 7-2. The gauges used in DST in Table 7-3 and a summary of the sampling in Table 7-4.

Surface data acquisition	- 'Standard' surface data acquisition system) - Sandec)
Bottom hole gauges (Ref./11/)	- 2 x Spartek quartz; carrier above packer - 2 x Metrolog quartz; carrier above packer
Sampling	- PVT sets at the separator - Trace elements at the separator - Other samples at the separator

Table 7-1: Summary of data acquisition during the DST operation

Perforated interval	3111.5 – 3130.0 (3086.1 – 3104.6) m MD RKB (m TVD MSL)
Perforating guns	Halliburton tubing conveyed guns, 4 5/8" 12 sfp 60 deg phasing HMX Millenium charges
Underbalance	Approximately 45 bar
Packer depth	3089 m MD RKB
Tubing	3 ½ " below seabed, 4 ½ " landing string

Table 7-2: Completion data

Gauge	Sensor depth (m MD RKB (m TVD MSL))	Comments
Spartek quartz # 20397	3082.0 (3056.6)	Worked ok
Spartek quartz # 20398	3081.3 (3055.9)	Worked ok
Metrolog CGM # 7401	3082.1 (3056.7)	No data
Metrolog CGM # 7443	3082.1 (3056.7)	No data

Table 7-3: Gauges used in DST

Sample no.	Bottle no.	Time (12/5-06)	Sampling point	Sample type	Volume	Bottle pressure (bar)	Comment
1,01	N/A	23:00 (11/5)	Test Sep	Water	1L	Atm	
1,02	PT-2075	03:30-04:00	Test Sep	Oil	600cc	11	PVT set-1
1,03	A-1806	03:30-04:00	Test Sep	Gas	20L	20	PVT set-1
1,04	5034A	03:30-04:00	Test Sep	Gas	20L	20	PVT set-1
1,05	N/A	10:30-11:35	Calibration tank	Oil	200 l	200 l Drum	Mixing study sample
1,06	N/A	10:30-11:35	Calibration tank	Oil	200 l	200 l Drum	Mixing study sample
1,07	PT1123	12:20-12:45	Oil outlet Test Sep.	Oil	600 cc	12	PVT set-2
1,08	A1803	12:20-12:50	Gas outlet Test Sep.	Gas	20 l	20	PVT set-2
1,09	4764 A	12:20-12:50	Gas outlet Test Sep.	Gas	20 l	20	PVT set-2
1,10	TS 11518	13:26-13:57	Oil outlet Test Sep.	Oil	600 cc	12	PVT set-3
1,11	A2456	13:26-13:58	Gas outlet Test Sep.	Gas	20 l	20	PVT set-3
1,12	A 1802	13:26-13:59	Gas outlet Test Sep.	Gas	20 l	20	PVT set-3
1,13	PT 2059	14:35-15:05	Oil outlet Test Sep.	Oil	600 cc	12	PVT set-4
1,14	A 2114	14:35-15:05	Gas outlet Test Sep.	Gas	20 l	20	PVT set-4
1,15	A 0166	14:35-15:05	Gas outlet Test Sep.	Gas	20 l	20	PVT set-4
1,16	Geo 151	15:15-15:20	Gas outlet Test Sep.	Gas	150 cc	20	Gechemical # 1
1,17	PT 226	15:22-15:25	Gas outlet Test Sep.	Gas	150 cc	20	Gechemical # 2
1,18	Geo 150	15:28 -15:33	Gas outlet Test Sep.	Gas	150 cc	20	Gechemical # 3
1,19	N/A	17:00	Oil outlet Test Sep.	Oil	1 l	Atm	Plastic Bottle
1,20	N/A	17:00	Oil outlet Test Sep.	Oil	1 l	Atm	Plastic Bottle
1,21	N/A	17:00	Oil outlet Test Sep.	Oil	1 l	Atm	Plastic Bottle
1,22	N/A	17:00	Oil outlet Test Sep.	Oil	1 l	Atm	Plastic Bottle
1,23	N/A	17:00	Oil outlet Test Sep.	Oil	1 l	Atm	Plastic Bottle
1,24	N/A	17:10	Oil outlet Test Sep.	Oil	1 l	Atm	Aluminium Bottle
1,25	N/A	17:10	Oil outlet Test Sep.	Oil	1 l	Atm	Aluminium Botle
1,26	N/A	17:15	Oil outlet Test Sep.	Oil	0,5	Atm	Aluminium Bottle
1,27	N/A	17:15	Oil outlet Test Sep.	Oil	0,5	Atm	Aluminium Bottle
1,28	A 2010	17:00-17:15	Oil outlet Test Sep.	Oil	20 l	~4	For Emulsion study
1,29	5308 A	17:30-17:45	Oil outlet Test Sep.	Oil	20 l	~4	For Crude Assay
1,30	N/A	20:30	Water outlet Test Sep.	Water	0.5 l	Atm	
1,31	N/A	20:30	Water outlet Test Sep.	Water	0.5 l	Atm	
1,32	N/A	20:30	Water outlet Test Sep.	Water	1 l	Atm	
1,33	N/A	20:30	Water outlet Test Sep.	Water	1 l	Atm	
1,34	N/A	20:30	Water outlet Test Sep.	Water	1 l	Atm	
1,35	N/A	20:30	Water outlet Test Sep.	Water	1 l	Atm	

Table 7-4: Summary of sampling during the DST

7.2 Operations summary of DST # 1

Picking up the TCP guns commenced at 08:15 on May 08. The detailed Sequence of Events (as per PWS well test report) is shown in Appendix 12.8.2. Test string configuration is included in Appendix 12.9.

The test string was run without any major problems. The string was displaced to base oil via the OMNI valve to create the required underbalance when **perforating**. The guns fired against closed choke manifold at 10:14 May 11 with a good response at surface. The well was opened on a 16/64” adjustable choke and increased to a final choke setting of 58/64”. The total flowing period was 2 hours and 15 minutes. For the last hour of the **initial flow** the well was diverted through the separator. The well was then shut in downhole for a 9 hours **initial build-up**.

After an initial build up the well was opened on a 12/64" adjustable choke and gradually increased to a 36/64" adjustable choke with flow diverted via the steam heat exchanger and test separator and out to the burners.

The well was then diverted to a 32/64" fixed choke for the remainder of the **main flow** period. An oil rate of around 500 m^3/d was achieved on a 32/64" fixed choke at a GOR of around 160Sm^3/Sm^3.

Four sets of pressurised separator samples were collected (PVT). One set was taken early in the flow period through the separator and 3 more sets were taken towards the end of the flow period. The well was shut in down hole at the tester valve for a 36 hours long **main buildup** at 21:41 on May 12.

Bottomhole sampling was planned after the main build-up. However, the drawdown was estimated to be so large that two-phase flow occurred in the bottom part of the teststring. It is then impossible to obtain representative samples, and hence, bottomhole sampling was cancelled.

After the main build-up a **mini-frac** program was carried out. The string was filled with 1.1 SG brine, pressure up the annulus to open the downhole tester valve and 4.4 m^3 was pumped in four cycles. The well was thereafter killed and permanently plugged and abandoned.

A summary of the main events in the test is found in Table 7-5, and main production data in Table 7-6. Plots of key bottomhole and surface data are presented in Figure 7-1 and Figure 7-2. Listings of main production data and trace element measurements are found in Appendix 12.7.

Event	Start (date& duration)	Duration (hrs:min)
Perforating	11.05.05 10:13	-
Initial flow	11.05.05 10:14	2:17
Initial build-up	11.05.05 12:31	9:00
Main flow	11.05.05 21:42	23:59
Main build-up	12.05.05 21:41	35:47
Minifrac	14.05.05 12:16	5:13

Table 7-5: Main DST events

Parameter	Main flow (12/5 21:40)
Choke size (inch)	32/64
Gas rate, q_g (Sm^3/d)	79270
Oil rate, q_o (Sm^3/d)	497
GCR (Sm^3/ Sm^3)	159
Water rate, q_w (Sm^3/d)	0
BHP (bar) Spartek # 20398	286.5
BHT (°C) Spartek # 20398	117.4
WHP (bar)	93.4
WHT (°C)	20.9
P_{sep} (bar)	20.6
T_{sep} (°C)	54.8
H_2S (ppm)	2.2
CO_2 (%)	5.2
Gas gravity, ρ_g (air = 1)	0.73
Oil density at 15 °C, ρ_o (g/cm^3)	0.851
BSW (%)	0
Sand production – (kg/d) (Sandec)	0

Table 7-6: Key production figures (main flow)

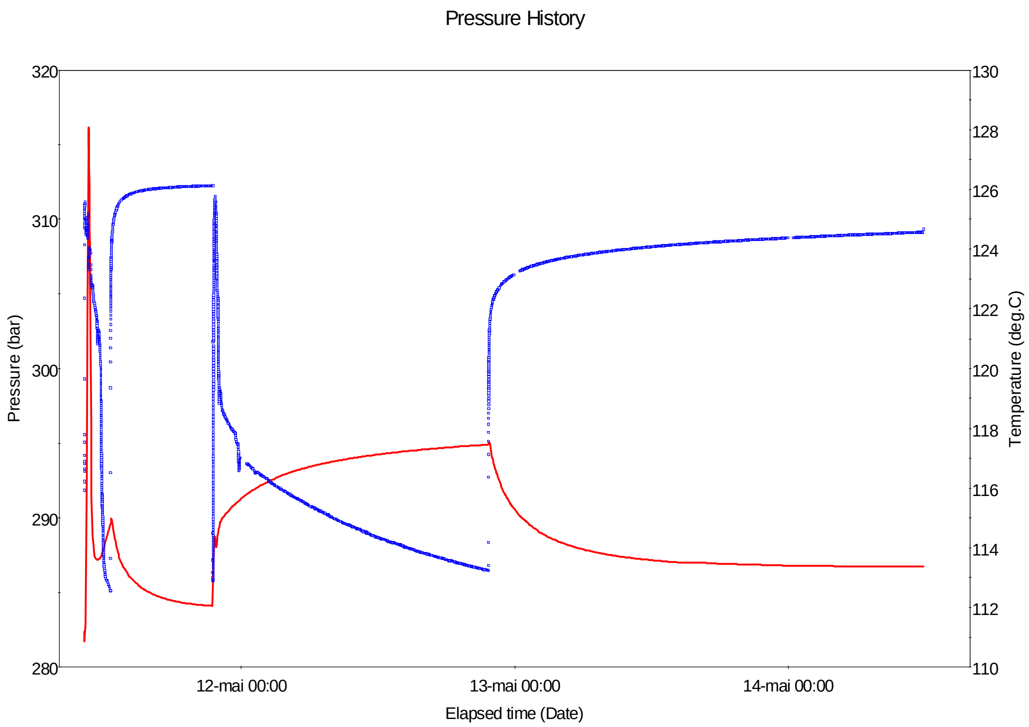


Figure 7-1: Bottomhole pressure and temperature

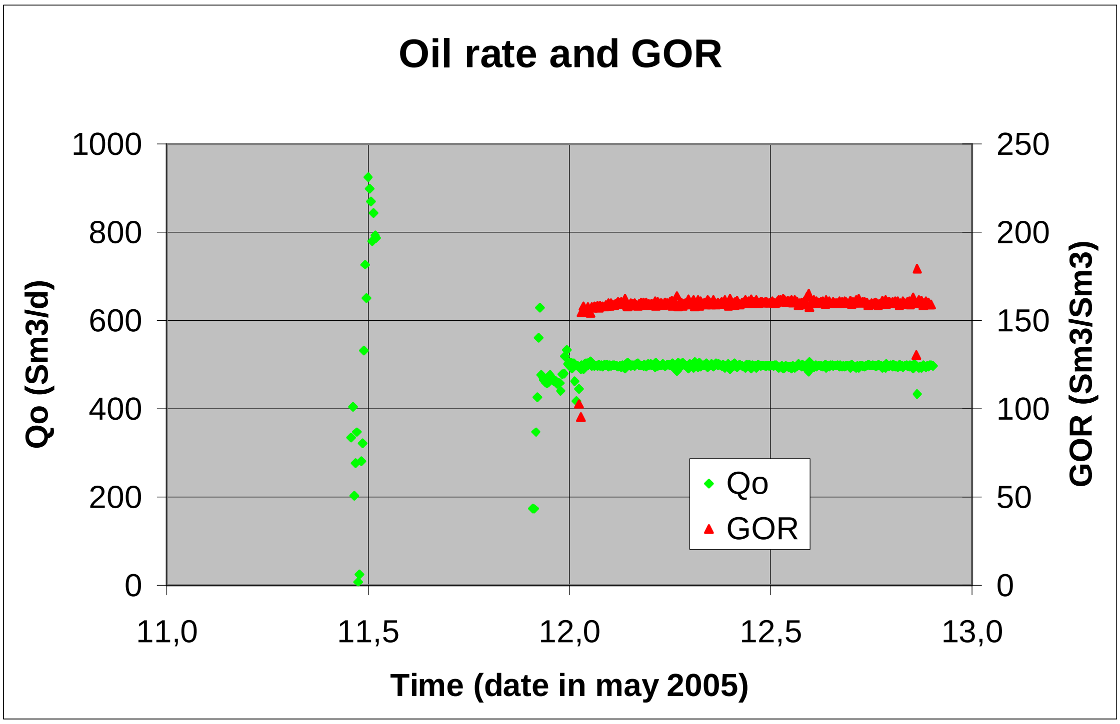


Figure 7-2: Oil rate and GOR

7.3 Test interpretation

This chapter contains test interpretation of DST #1, which includes the memory gauge evaluation, the estimation of initial reservoir pressure and analytical test analysis of the reservoir response. Interpret 2003 test interpretation package was used for the analysis. An overview of the test is presented in Figure 7-3.

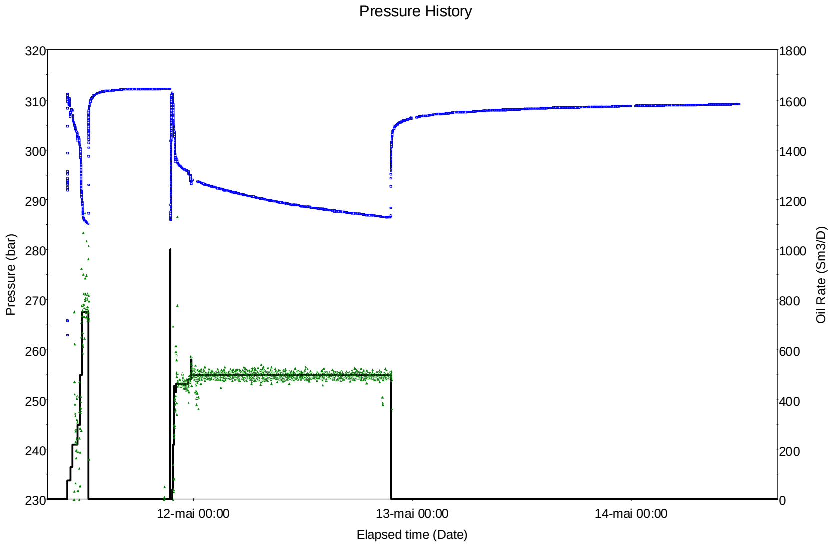


Figure 7-3: Oil rate and bottomhole pressure

7.3.1 Pressure Gauge Evaluation

Four memory gauges were run in a gauge carrier. Both Spartek gauges worked fine throughout the test while the two Metrolog gauges failed. The Spartek gauges were compared and the result is shown in Figure 7-4. The pressure gauge no. 20397 is used as the base line in the figure. There is only a small shift from build-up to flow periods, which can be explained by friction loss. In each flow period the pressure difference is constant. Both gauges are therefore considered good. The pressure gauge 20397 was selected for the analysis as it was programmed to take pressure readings at a higher frequency than 20398.

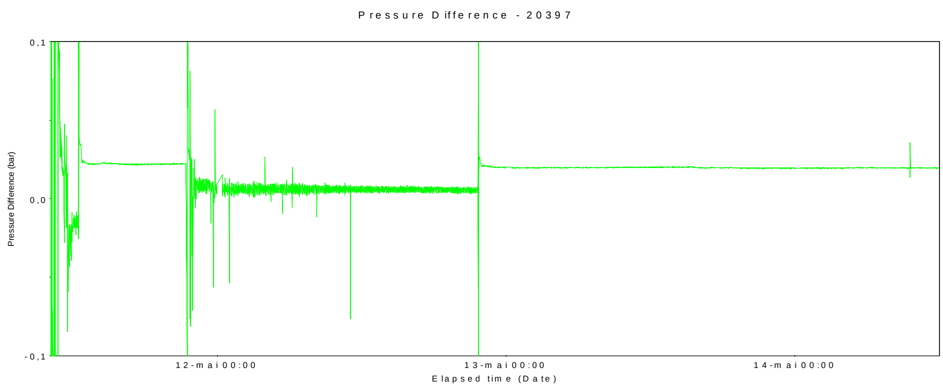


Figure 7-4: Gauge comparison - #20397 and #20398 (ref. gauge is #20398)

7.3.2 Analytical Test Interpretation

The rate history and the bottomhole pressures are given in Figure 7-3. The rate history was prepared using the separator data and is shown in Table 7-7: . Rate data is not available in the early part of the flow period when the separator is bypassed. For these periods the rate was estimated using a PI technique.

Flow period	Start date/time: 08 may 2005 00:00:00		Duration (hrs)	Oil rate, q_o (Sm^3/d)
	Start time	End time		
1	08/05/05 00:00:00	11/05/05 10:13:26	82.2239	0
2	11/05/05 10:13:26	11/05/05 10:31:52	0.3073	75
3	11/05/05 10:31:52	11/05/05 10:48:33	0.2779	130
4	11/05/05 10:48:33	11/05/05 11:19:53	0.5223	220
5	11/05/05 11:19:53	11/05/05 11:38:38	0.3124	300
6	11/05/05 11:38:38	11/05/05 11:46:19	0.1282	500
7	11/05/05 11:46:19	11/05/05 12:32:17	0.7656	750
8	11/05/05 12:32:17	11/05/05 21:31:15	8.9830	0
9	11/05/05 21:31:15	11/05/05 21:31:49	0.0097	1000
10	11/05/05 21:31:49	11/05/05 21:44:12	0.2064	0
11	11/05/05 21:44:12	11/05/05 21:45:44	0.0256	40
12	11/05/05 21:45:44	11/05/05 21:55:27	0.1619	220
13	11/05/05 21:55:27	11/05/05 22:03:26	0.1330	455
14	11/05/05 22:03:26	11/05/05 22:10:34	0.1191	430
15	11/05/05 22:10:34	11/05/05 23:28:24	1.2971	463
16	11/05/05 23:28:24	11/05/05 23:44:01	0.2603	480
17	11/05/05 23:44:01	11/05/05 23:49:22	0.0892	560
18	11/05/05 23:49:22	12/05/05 21:41:57	21.8757	497
19	12/05/05 21:41:57	14/05/05 11:56:46	38.2477	0
20	14/05/05 11:56:46	16/05/05 11:10:50	47.2344	0

Table 7-7: Oil rate history

In the log-log plot of the initial build-up (Figure 7-5) three periods can be observed. It begins with a short wellbore storage period, which is followed by a radial flow period that last for approximately 2.5 log cycle. Finally the build-up is influenced by no-flow boundaries.

In the log-log plot of main build-up (Figure 7-6) the flat part of the derivative is partly disappeared; the permeability closer to the wellbore is decreasing. This is believed to be caused by gas coming out of solution resulting in two-phase flow. We also see that the boundary effect at the end is more dominant. The derivative flattens at the same level giving the same kh-product for both build-ups (Figure 7-7).

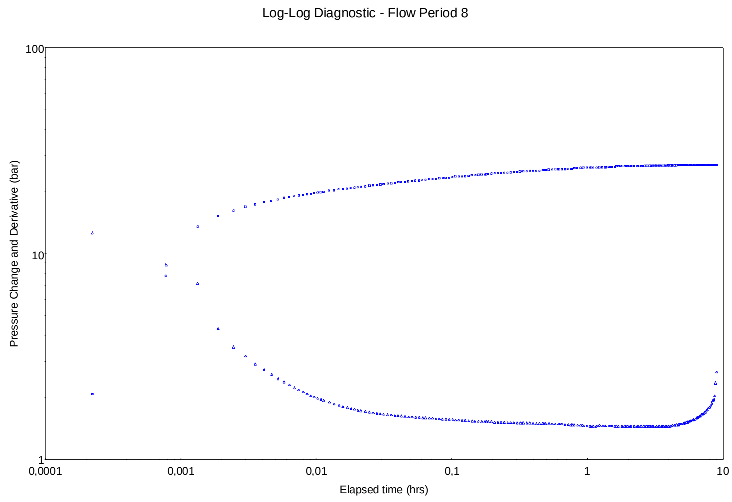


Figure 7-5: Diagnostic log-log plot of initial build-up

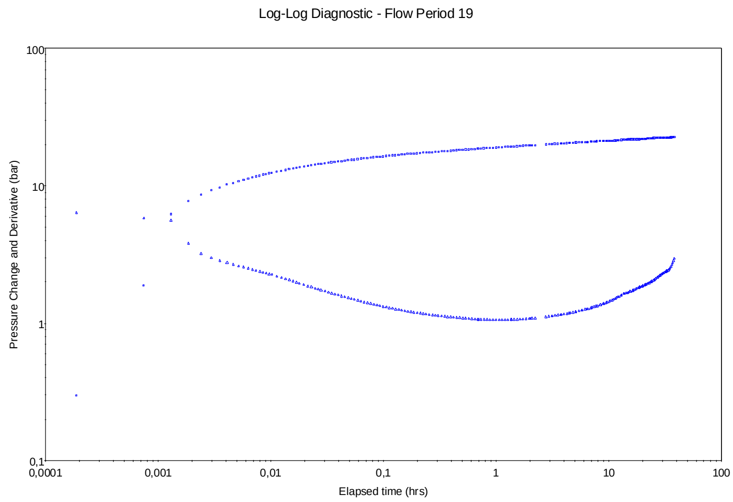


Figure 7-6: Diagnostic log-log plot of main build-up

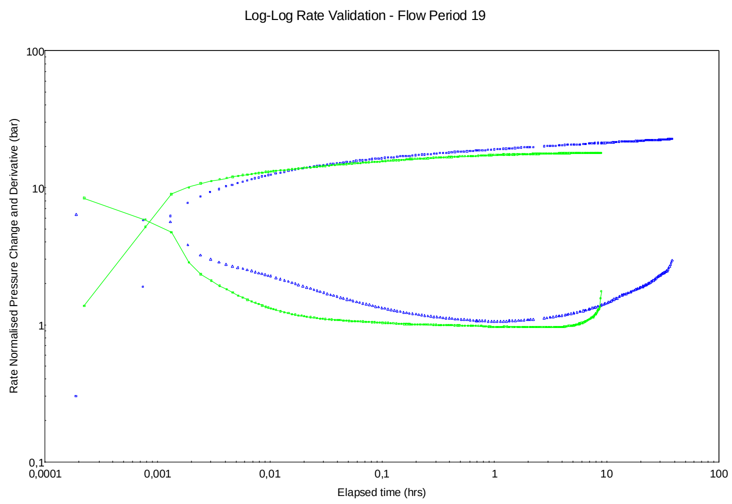


Figure 7-7: Log-log comparison between initial and main build-up

The main build-up is analyzed (Figure 7-8, Figure 7-9 and Figure 7-10) with a radial composite model with reduced properties in closest to the well in order to reflect the relative permeability effect due to two phase flow. A 10 m radius with a kh, which equals 60% of the reservoir kh, was introduced. Infinite acting radial flow is taken at the flat part of the derivative (Figure 7-8). The lower flat part of the radial flow period gives a permeability thickness of 1880 mDm and a permeability of 105 mD when using the net pay thickness between the shale barriers for height. The input parameters for the test interpretation are presented in Table 7-8.

The late time period of the main build-up was used for modeling reservoir geometry. The reservoir response can be modeled using an opened ended rectangle (distances 100, 180 and 290m). The simulated bottom hole pressure using this model is shown together with the measured bottom hole pressures in Figure 7-10.The simulated pressures agree fairly well with the observed bottom hole pressures. It should however be kept in mind that this is a rough model of the reservoir only and that similar models like parallel boundaries/intersecting boundaries also give simulated bottom hole pressures which fit the observed data reasonably well. The analysis shows that the well is in a reservoir with flow restrictions but with no depletion. The main results are presented in Table 7-9.

Parameter	**Value**
Porosity, ϕ (fraction)	0.195
Net pay, h (m)	17.9
Well radius, r_w (m)	0.108
Oil formation factor, B_o (rm^3/Sm^3)	1.58
Oil viscosity, μ_o (cp)	0.29
Total compressibility, c_t (bar^{-1})	0.00023

Table 7-8: Input parameters

Parameter	**Value**
Initial reservoir pressure, P_i (bar) @ 3081.3 m MD RKB,	312.7
Well flowing pressure, P_{wf} (bar) [gauge # 20397]	286.5
Permeability thickness product, kh (mDm)	1880
Permeability, k (mD)	105
Skin, s	1.8
Inner radius (m)	10
Permeability in inner radius (mD)	65
Distance to first no-flow boundary, d_1 (m)	100
Distance to second no-flow boundary, d_2 (m)	180
Distance to third no-flow boundary, d_3 (m)	290
Radius of investigation, r_i (m)	530
Pressure drop due to skin, Δp_s (bar)	6

Table 7-9: Main results from test interpretation

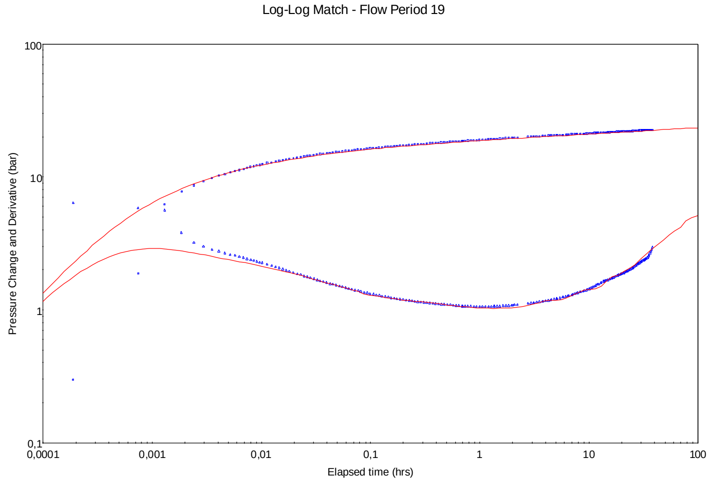


Figure 7-8: Log-log match of the main build-up

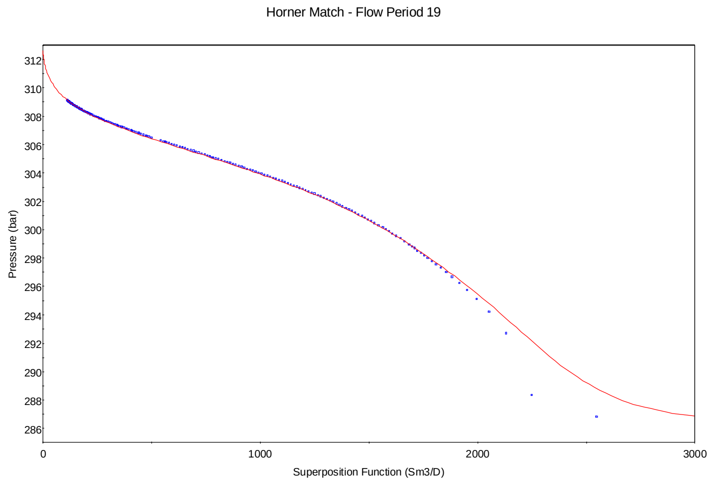


Figure 7-9: Superposition plot match of main build-up

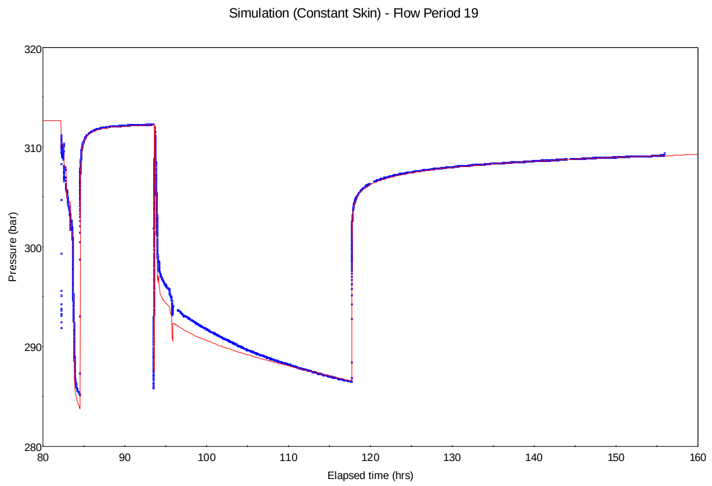


Figure 7-10: Simulation plot of the whole test

7.3.3 Initial Reservoir Pressure

Normally the initial pressure can be defined accurately by extrapolating the superposition data in the initial build-up to infinite time. Due to the complex no-flow boundary system, the initial pressure will then be somewhat underestimated. Therefore the value of initial pressure defined in the test interpretation is used.

The initial pressure is estimated for both the pressure gauges 20397 and 20398. The extrapolation gives the same value for the initial pressure: 312.7 bar @ 3056.3m MSL. A Horner plot of the initial build-up is shown in Figure 7-11.

Extrapolation of the initial pressure from the DST, using the pressure gradient from the MDT measurements, 0.064 bar/m, gives a pressure of 314.6 bar at top perforation, 3086.5m MSL. This compares well with the MDT pressure data at the same depth which is 314.7 bar.

The initial flow had duration of approximately 2.25 hrs, and the following build-up lasted for 9 hrs. The completion fluid (base oil and brine) was produced out of the well during this flow period. Therefore the well was full of oil, and hence, there is little uncertainty when extrapolating from the gauges to the perforations.

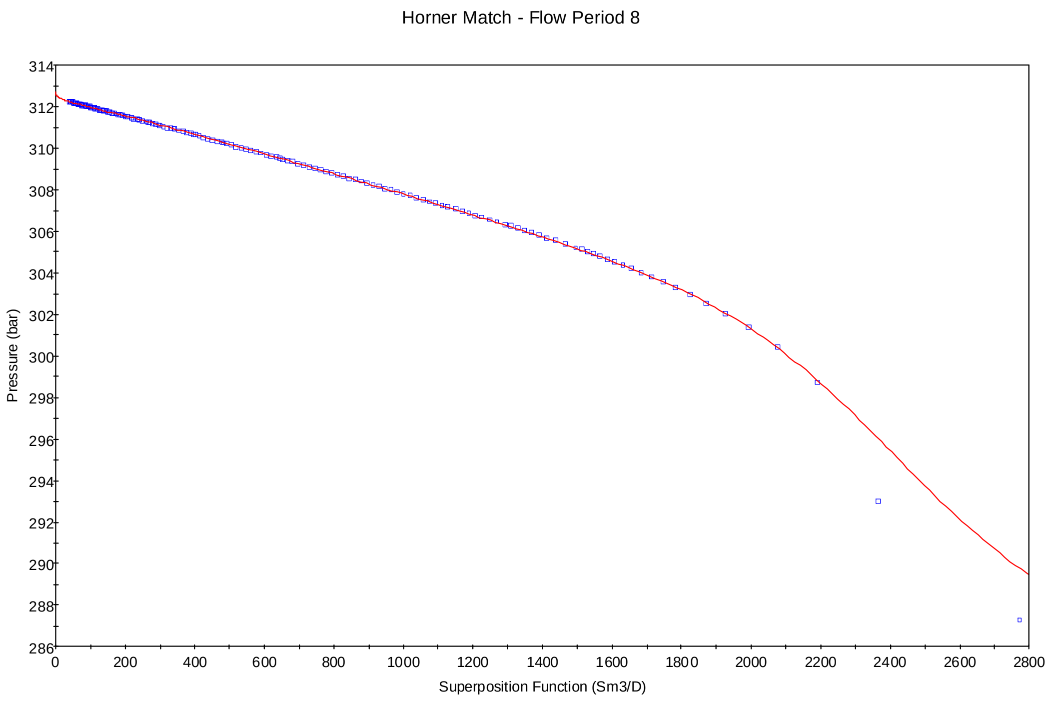


Figure 7-11: Horner plot of the initial build-up

8 Formation Temperature Interpretation

The temperature data was recorded both during wireline logging (Table 8-1), sampling with the MDT (Table 8-2) and the in the DST (Figure 8-1). The logging temperatures is not unexpected lower than for the DST. Hence, temperature data from the DST gives the best basis for estimation of the reservoir temperature.

Log	Run no.	Depth (m MD RKB)	Temperature (^{o}C)
PEX	1A	3295	100
MDT	1A	3206	105
VSP	1A	3230	105
MDT	1B	3158	110
MSCT	1A	3151	112

Table 8-1: Well temperatures from wireline logging

Depth (m MD RKB)	Temperature (^{o}C)	Comments
3097	105.8	Sampling
3107	106.8	Sampling
3128	108.5	Sampling
3135	109.9	Scanning
3136	110.6	Scanning
3137	109.5	Scanning
3157.5	111.4	Sampling

Table 8-2: Well temperatures from MDT sampling

In Figure 8-1 the temperatures from the two working bottom hole gauges are presented. The two temperature gauges have almost identical (0.04 ^{o}C difference) temperature readings. During flowing, the maximum recorded temperature was 117.6 ^{o}C but the temperature was still increasing when the well was shut-in for the main build-up. The reservoir temperature is estimated to be between 118 and 120 ^{o}C. The vertical temperature gradient in the tubing while flowing is uncertain but is believed to be small. Hence, the temperature readings have a reference depth of 3081m MD RKB, which is in the middle of the perforated interval.

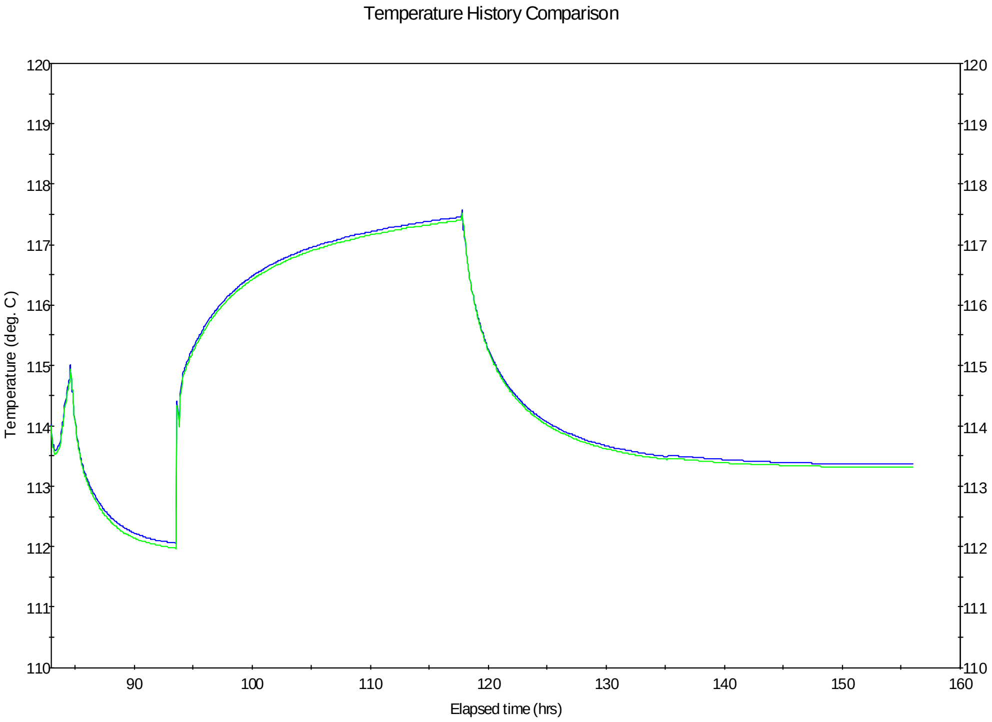


Figure 8-1: Bottomhole temperatures recorded in the DST

9 Mini Fracture Test

After the production test in well 35/11-13, a mini-frac test was performed. The mini-frac test was conducted with 1.1 g/cc brine in the tubing. The mini-frac was completed with six cycles at 80 l/m, 100 l/m, 115 l/m and 360 l/m, respectively. A plot of the bottomhole pressures plots during the mini-frac can be seen in Figure 9-1.

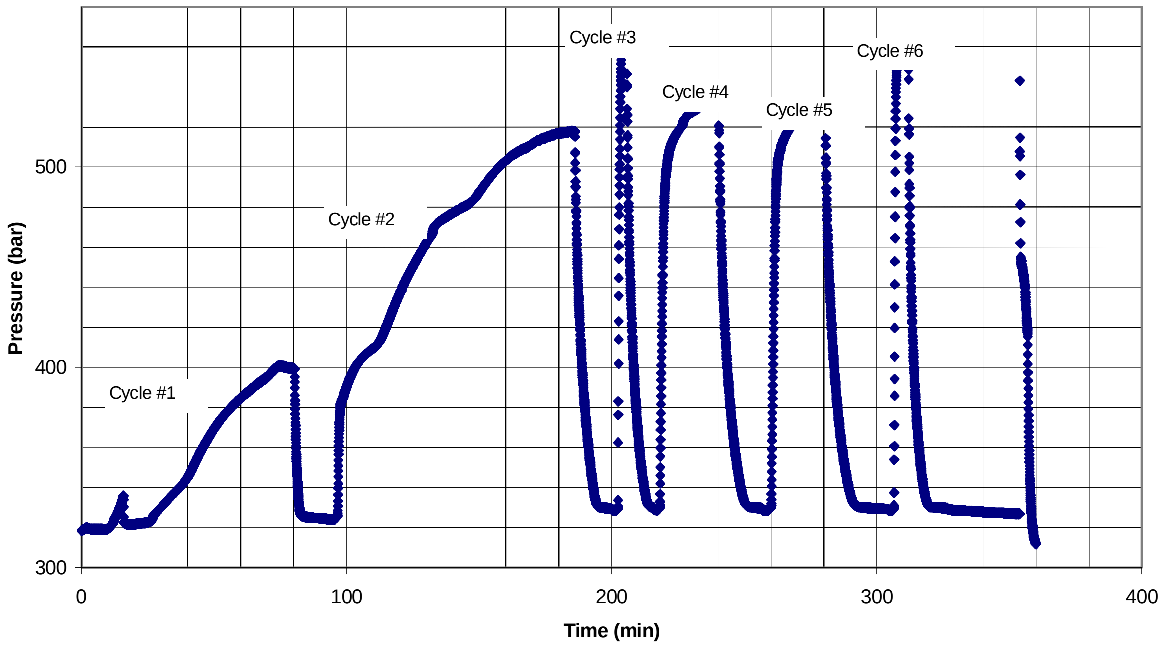


Figure 9-1: Bottomhole pressures for all minifrac cycles

9.1.1 Cycle #1 and cycle #2

From Figure 9-2 and Figure 9-3 it is clear that no real fractures are created during these cycles, although the injected volumes are quite high. However due to the relative high permeability and the low rate, all the injected fluid are believed to be injected into the matrix. The rates for these two tests are 80 l/min and 100 l/min respectively. From Figure 9-8 it is clearly that the increase in pressure vs. volume from cycle #1 and #2 are almost identical (same slope of both curves)

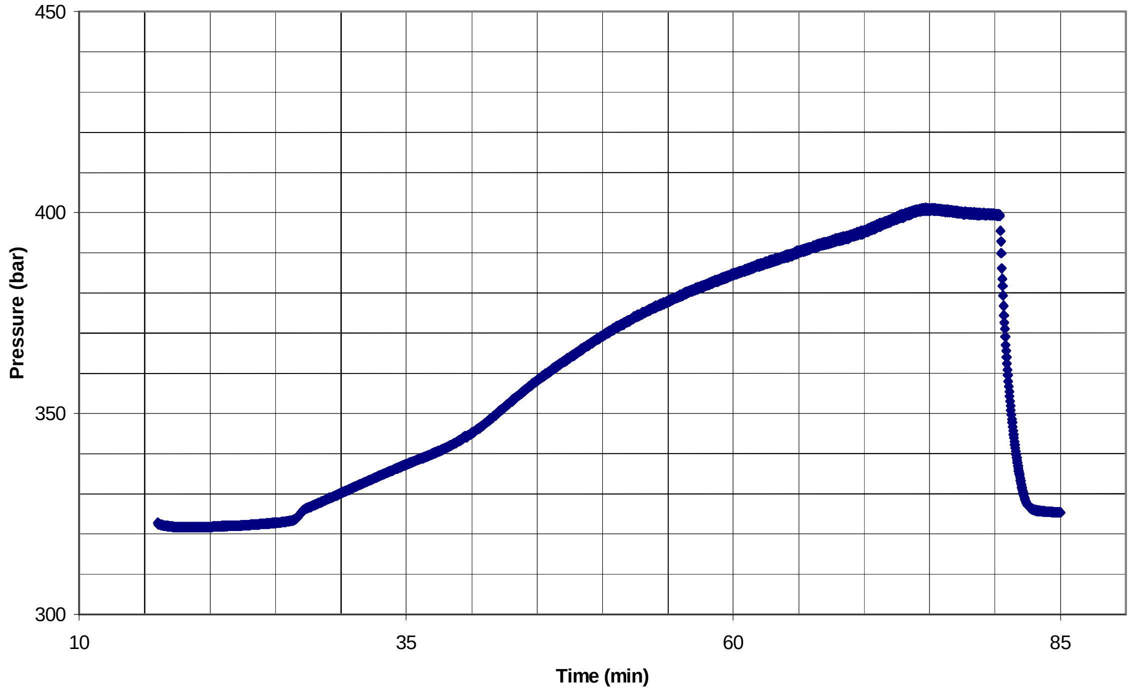


Figure 9-2: Bottomhole pressure during mini-frac cycle no.1 (80 l/min)

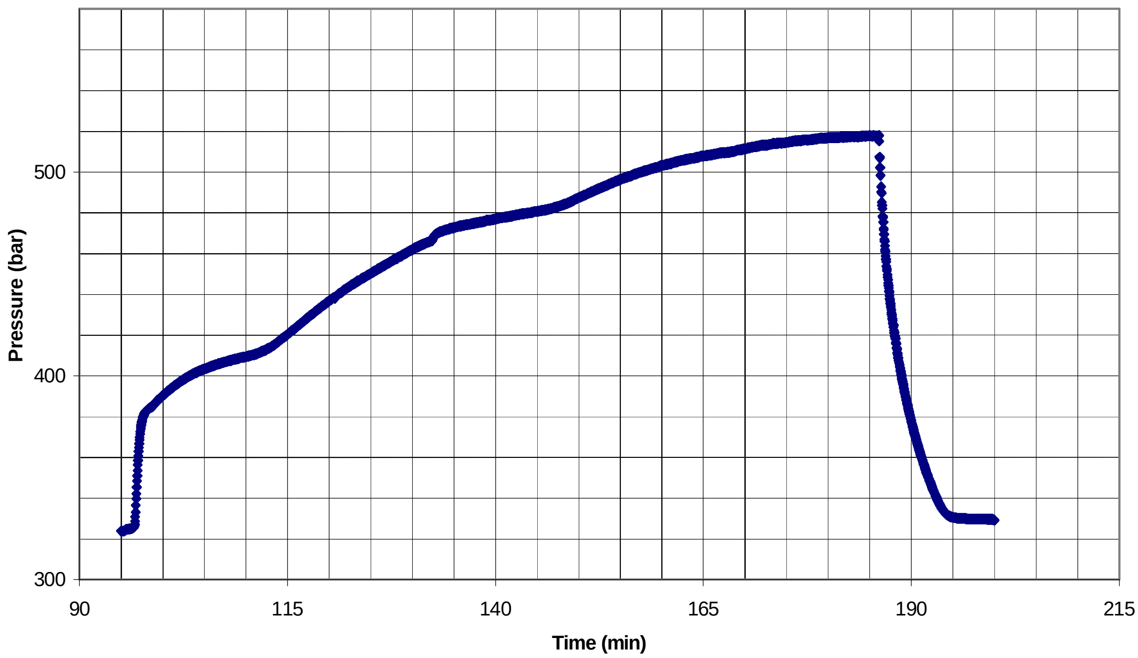


Figure 9-3: Bottomhole pressure during mini-frac cycle no. 2 (100 l/m)

9.1.2 Cycle #3

This cycle is a high rate test. From Figure 9-4 it is clear that fractures are created during this test. The rate is not known, but assumed to be equal to the rate used in cycle #6 (360 l/min). The fracture propagation pressure (FPP) is 562 bar at this rate.

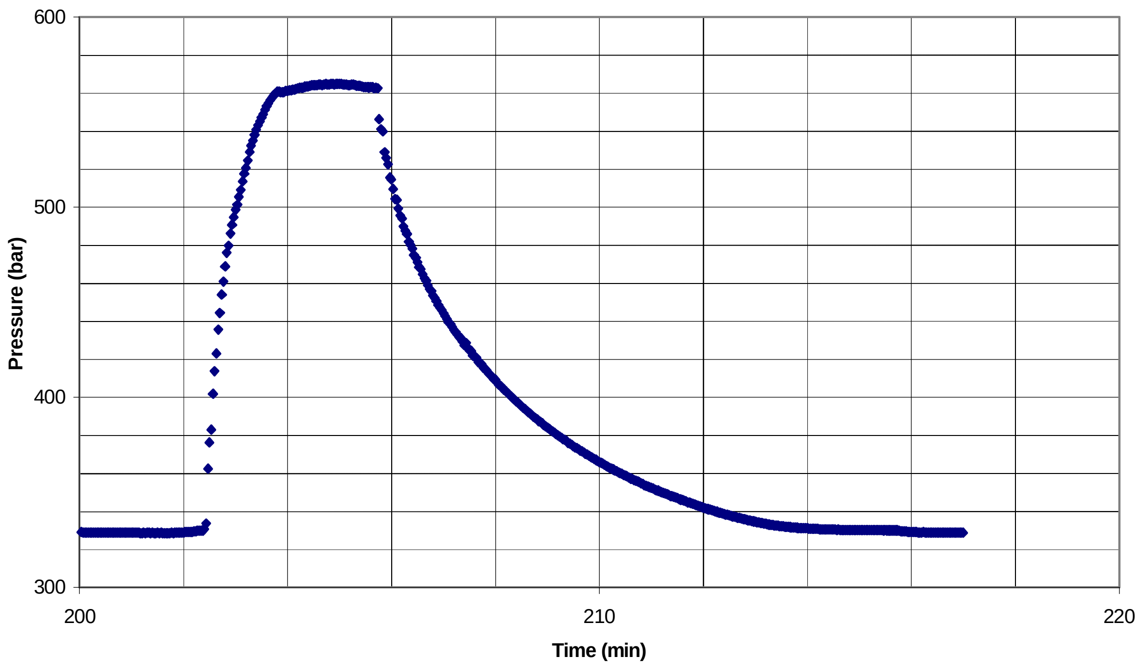


Figure 9-4: Bottomhole pressure during mini-frac cycle no. 3

9.1.3 Cycle #4

This cycle is carried out using 115 l/min, and also here there is evidence that fractures are created (see Figure 9-5), and the pressure stabilizes at 531 bars at this rate.

9.1.4 Cycle #5

This cycle is carried out using 100 l/min, and also here there is evidence that fractures are created (see Figure 9-6), and the pressure stabilizes at 522 bars at this rate.

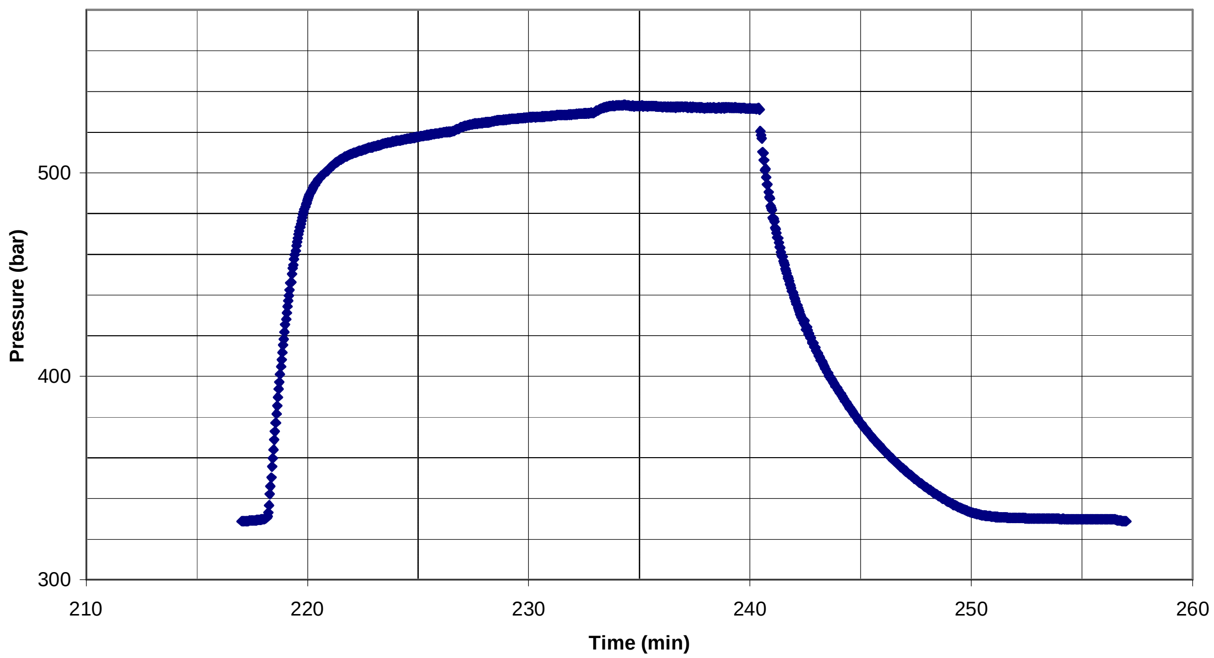


Figure 9-5: Bottomhole pressure during mini-frac cycle no.4 (115 l/m)

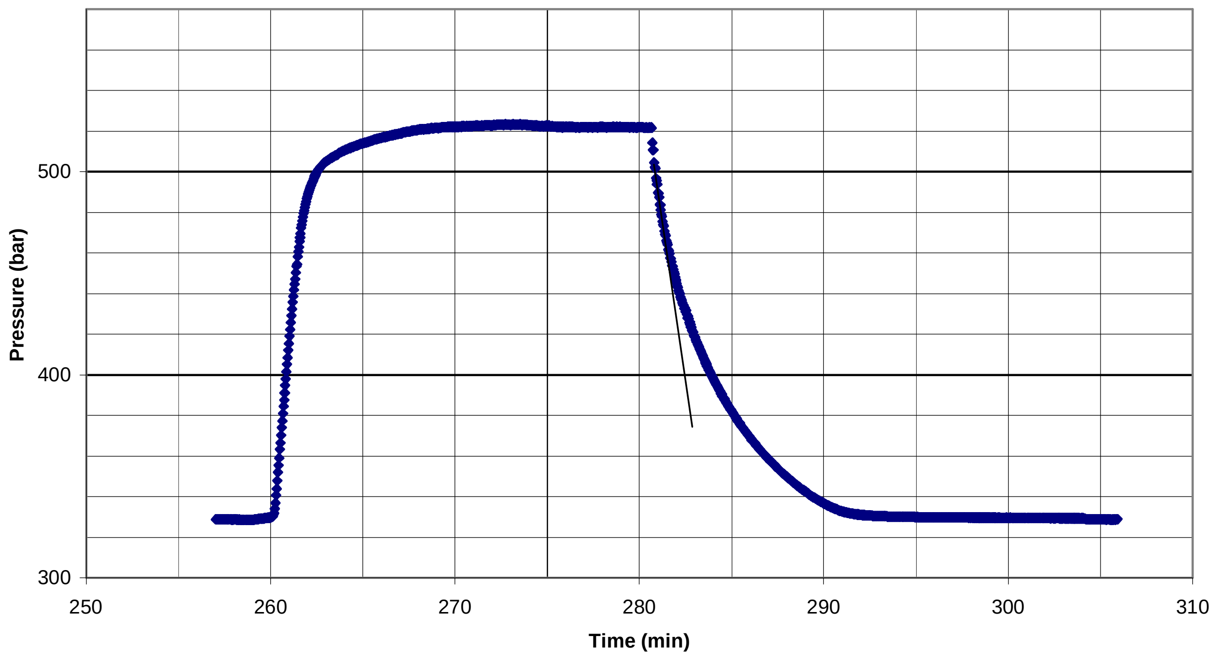


Figure 9-6: Bottomhole pressure during mini-frac cycle no.5 (100 l/m)

9.1.5 Cycle #6

This is a second high rate test using 360 l/min. and the pressure stabilizes at 548 bars at this rate.

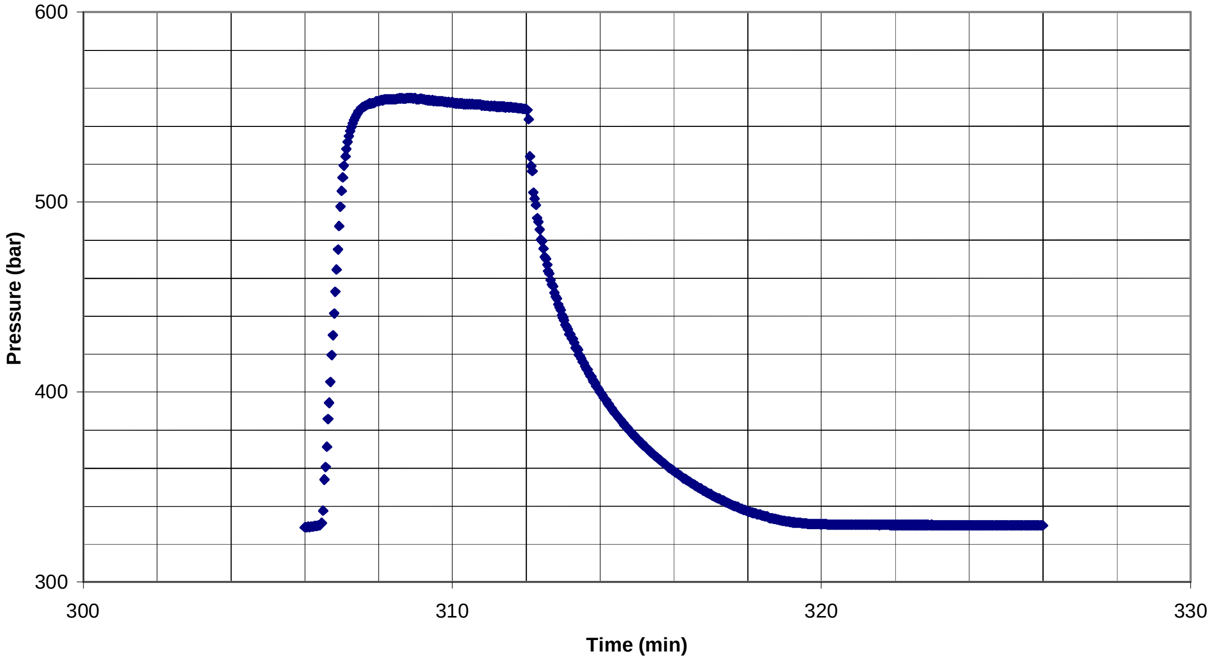


Figure 9-7: Bottomhole pressure during mini-frac cycle no. 6 (360 l/m)

9.1.6 Pressures during pump up

A comparison of the pressure build up during the cycles #3 - #6 is seen on Figure 9-8. It is evident that the pressure builds up at an almost constant rate during these tests, although using different rates (100-360 l/min).

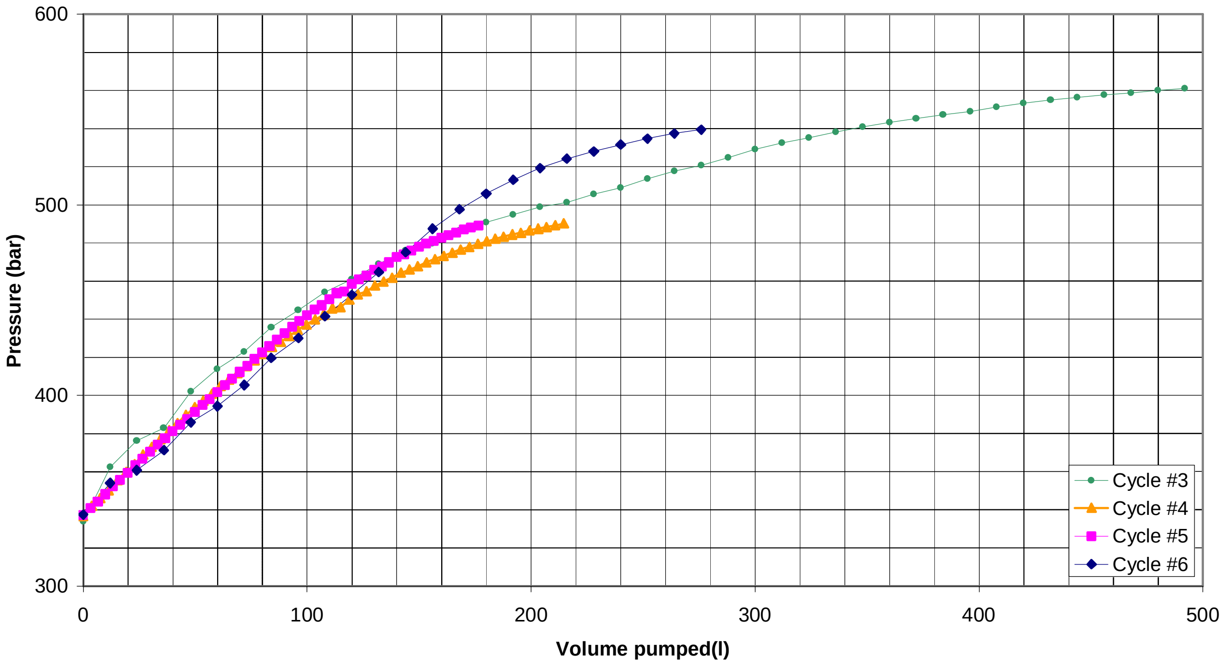


Figure 9-8: Bottomhole pressure build-up during pumping

9.1.7 Pressure during fall off

Due to the high permeability the pressure rapidly decreases to hydrostatic pressure during shut in. Due to this rapid decrease no further interpretation of the instantaneous shut-in pressure (ISIP), which in terms equals the minimum horizontal stress, has been carried out.

9.1.8 In-situ stress determination

The minimum horizontal stress at the depth cannot be determined from the shut-in period, due to the highly permeable formation.

Fracture propagation pressure for zero rate is determined to be approx. 514 bars using linear regression of the above rates and FPP.

10 Fluid Analysis and Results

Laboratory measurements have been performed on both the MDT (gas, oil and water) and DST (oil) fluid samples from well 35/11-13. The results are discussed in the following sub-chapters. In addition, quicklook analyses on MDT and DST samples were performed offshore, which are also reported below.

10.1 Offshore Analysis Results

10.1.1 Offshore Analysis Results of MDT samples

Two MDT samples were analysed offshore by Oilphase (Ref./6/); one which was taken at 3097m MD RKB and one which was taken at 3107m MD RKB. Both samples were captured in large sampling container, i.e. 1 gallon and 2 ¾ gallon chambers, respectively. The analyses were done as a part of the transfer operation to proper storage bottles. The results of the analysis are listed in Table 10-1.

MDT chamber	Formation	Formation Depth	GOR (m^3/m^3)	Oil Density (g/cc)
MRSC-#172	Oxfordian	3097m MD RKB	3872.7	0.789 @ 14.9°C
MRSC-#100	Oxfordian	3107m MD RKB	120.1	0.848 @ 14.3°C

Table 10-1: Quicklook offshore analysis of MDT samples

The two samples had also a very different colour and appearance. Picture of the two samples from 3097m and 3107m can be seen in Figure 6-1 and Figure 6-2, respectively.

10.1.2 Offshore Analysis Results of DST samples

During the production test well 35/11-13, Petrotech (Ref./8/) performed offshore analysis of the gas, oil and water collected. The samples were taken from the separator outlet lines. In Table 10-2 to Table 10-4 below, a summary of the offshore analysis results from the DST samples is given.

Parameter	Result
Gas gravity (SG Air=1)	0.730
H_2S (ppm)	2.5
CO_2 (vol%)	5.2

Table 10-2: Offshore analysis results of DST gas sample

Parameter	Result
Density (g/cc @ 15 deg.C)	0.851

Table 10-3: Offshore analysis results of DST oil sample

Parameter	Result
pH	6.45
Total alkalinity (mg/l)	2440
Dissolved CO_2 (mg/l)	900
Chloride (mg/l)	53000
Resistivity (Ohm-m @ 20deg.C)	0.1835
Density (g/cc)	1.081
Sulphate (mg/l)	550
Ba/Sr (mg/l)	0

Table 10-4: Offshore analysis results of DST water sample

10.2 Onshore Analysis Results

The onshore laboratory analyses were performed by ResLab (Ref./9/). The most representative sample from the gas zone is the single phase MDT sample captured in bottle SPMC #103. This sample was collected after about 7500 sec with clean-up, and the temperature was exhibiting a semi steady state behavior, see Figure 6-7. The most representative oil sample is the 3rd PVT set collected during the DST test. The quality check done on the four PVT sets indicates that the 3rd PVT set gives best consistency of the data. For more details, reference is made to Ref./9/.

The following PVT analyses have been performed:

Analysis	Number of samples	Number analyzed
Quality check of separator oils	4	4
Quality check of separator gases	8	8
Composition analysis of separator gas	8	1
Single stage separation of separator oil including compositional analyses of stock tank gas and oil. C_{10}^+/C_{30}^+	4	1
Physical recombination of reservoir fluid	1	1
Constant mass expansion of reservoir fluid at reservoir temperature	1	1
Single stage separation of reservoir fluid including compositional analyses of stock tank gas and condensate. C_{10}^+/C_{30}^+	1	1
Differential liberation of reservoir fluid at reservoir temperature.	1	1
Viscosity of reservoir fluid at reservoir temperature.	1	1
Two stage separator test.	1	1

Table 10-5: List of PVT analyses performed on DST samples from well 35/11-13

The analyses have been performed at reservoir temperature, i.e. 118 ^{o}C. A summary of the measured main fluid properties and fluid composition are given in Table 10-6 to Table 10-10 below.

Main results of gas cap gas	
P_d @ T_r	308.0 Bar
GCR gas cap	4800 Sm^3/Sm^3
Condensate dropout	4.1%
Gas gravity	0.991 kg/Sm^3
Gas gravity, solution gas	0.8 kg/Sm^3

Table 10-6: Main PVT results of gas analyses from gas cap

T_r (^{o}C)	P_b (Bar)	Isotherm. compr. at $P_{b.}$ (Bar^{-1})	Viscosity at $P_{b,}$ (mPas)
118.0	304.5	2.540×10^{-4}	0.289

Table 10-7: Constant mass expansion and viscosity of separator oil sample

PVT analysis	GOR/R_S Sm^3/Sm^3	B_o at P_b m^3/Sm^3	Density of Stock Tank Oil kg/m^3	Molecular weight of oil	Density at P_b kg/m^3
SF	184.3	1.585	851.7	218.5	653.0
DL	203.0	1.671	856.2	228.6	648.0
2 stage sep. test	173.6	1.546	848.1	212.8	654.0

Table 10-8: Main PVT properties of separator oil sample

SF = Single stage separation
DL = Differential Liberation
Standard condition:
Gas samples : 15 ^{o}C and 1.01325 bar = 1 atm
Oil samples : 15 ^{o}C and laboratory atmospheric pressure

The accuracy of the measurements has been defined to be:

- Determination of dew point pressure.
    - Estimated accuracy of bubble point pressure determination: +/- 2 bar
    - Pressure readings: +/- 1 bar
    - Resolution, pressure readings: 0.1 bar
    - Temperature readings: +/- 0.5 ^{o}C
    - Resolution temperature readings: 0.1 ^{o}C
- Volume readings: +/- 1 %
- Gas Oil Ratio: +/- 1 %
- Pycnometer Density of reservoir fluid: Est. accuracy: +/- 1 %

It should be noted that the bubble point, P_b, and dew point, P_d, are slightly lower than the reservoir pressure, consistent with the reservoir being at saturation pressure at the gas oil contact 3073m TVD MSL (3099m MD RKB).

COMPONENT	Composition of reservoir fluid			
	Mole %	Weight %	Molar Weight	Density kg/m^3
Nitrogen	0.286	0.325	28.02	804.0
Carbon Dioxide	3.740	6.672	44.01	809.0
Hydrogen Sulphide	0.000	0.000		
Methane	80.102	52.091	16.04	300.0
Ethane	5.926	7.224	30.07	356.7
Propane	3.463	6.190	44.09	506.7
iso-Butane	0.424	0.998	58.12	562.1
n-Butane	1.235	2.911	58.12	583.1
Neopentane	0.004	0.012	72.15	597.0
iso-Pentane	0.355	1.038	72.15	623.3
n-Pentane	0.490	1.434	72.15	629.9
Hexanes, C_6 total	**0.529**	**1.818**	**84.7**	**667.5**
n-Hexane	*0.249*	*0.870*	*86.2*	*662.7*
iso-Paraffins	*0.233*	*0.813*	*86.2*	*660.7*
Naphtenes	*0.048*	*0.136*	*70.1*	*748.1*
Heptanes, C_7 total	**0.822**	**3.011**	**90.4**	**743.0**
n-Heptane	*0.159*	*0.647*	*100.2*	*686.9*
iso-Paraffins	*0.162*	*0.657*	*100.2*	*690.2*
Naphtenes	*0.390*	*1.355*	*85.8*	*769.9*
Aromatics	*0.111*	*0.352*	*78.1*	*883.1*
Octanes, C_8 total	**0.733**	**3.096**	**104.2**	**767.2**
n-Octane	*0.110*	*0.508*	*114.2*	*707.0*
iso-Paraffins	*0.089*	*0.414*	*114.7*	*706.7*
Naphtenes	*0.378*	*1.593*	*103.9*	*771.5*
Aromatics	*0.156*	*0.581*	*92.1*	*872.0*
Nonanes, C_9 total	**0.429**	**2.071**	**119.0**	**777.7**
n-Nonane	*0.097*	*0.502*	*128.3*	*723.0*
iso-Paraffins	*0.094*	*0.490*	*128.2*	*723.6*
Naphtenes	*0.100*	*0.484*	*119.0*	*793.8*
Aromatics	*0.138*	*0.595*	*106.2*	*872.8*
Decanes plus, C_{10}^+	**1.462**	**11.110**	**187**	**822**
Sum	100.000	100.000		

Table 10-9: Composition of MDT gas sample, bottle 9283-MA

COMPONENT	Mole %	Weight %	Molar Weight	Density kg/m^3
Nitrogen	0.117	0.037	28.02	804
Carbon Dioxide	3.132	1.557	44.01	809
Hydrogen Sulphide	0	0		
Methane	49.624	8.995	16.04	300
Ethane	5.842	1.985	30.07	356.7
Propane	4.3	2.142	44.09	506.7
iso-Butane	0.63	0.414	58.12	562.1
n-Butane	2.015	1.323	58.12	583.1
Neopentane	0.008	0.007	72.15	597
iso-Pentane	0.696	0.568	72.15	623.3
n-Pentane	1.035	0.844	72.15	629.9
Hexanes, C_6 total	**1.459**	**1.395**	**84.6**	**668.2**
n-Hexane	*0.708*	*0.689*	*86.2*	*662.7*
iso-Paraffins	*0.606*	*0.59*	*86.2*	*660.9*
Naphtenes	*0.146*	*0.115*	*70.1*	*748.1*
Heptanes, C_7 total	**3.126**	**3.17**	**89.8**	**748**
n-Heptane	*0.575*	*0.651*	*100.2*	*686.9*
iso-Paraffins	*0.545*	*0.617*	*100.2*	*690.8*
Naphtenes	*1.522*	*1.475*	*85.8*	*770.9*
Aromatics	*0.484*	*0.427*	*78.1*	*883.1*
Octanes, C_8 total	**3.555**	**4.148**	**103.3**	**774.3**
n-Octane	*0.472*	*0.609*	*114.2*	*707*
iso-Paraffins	*0.368*	*0.478*	*114.9*	*707*
Naphtenes	*1.783*	*2.091*	*103.8*	*772.3*
Aromatics	*0.932*	*0.97*	*92.1*	*872*
Nonanes, C_9 total	**2.212**	**2.937**	**117.5**	**786.6**
n-Nonane	*0.428*	*0.621*	*128.3*	*723*
iso-Paraffins	*0.416*	*0.602*	*128.2*	*723.7*
Naphtenes	*0.518*	*0.694*	*118.6*	*793.6*
Aromatics	*0.85*	*1.02*	*106.2*	*873*
Decanes plus, C_{10}^+	**22.249**	**70.481**	**280**	**875**
Sum	100	100		

Table 10-10: Composition of recombined oil sample, bottle TS-11518 & A-1802

10.3 Formation Water Analysis

Petrotech performed validity checks and analysis on a water sample collected with the MDT. Petrotech performed the following analyses:

- Contamination analysis
- pH at reservoir conditions
- Resistivity at reservoir conditions
- Density at reservoir conditions

- GWR of flashed sample
- pH / Alkalinity
- Anions/cations/organic acids
- Conductivity
- Density at standard conditions
- Suspended solids
- TDS

In addition, Analytica, BTEX, performed the following analyses:

- Organic acids (Analytica)
- BTEX (Analytica)
- Sr87/ Sr86 (IFE)

The bottle selected for the analyses, was the MDT bottle MPSR #930 (transfer bottle no. 6840-MA). By comparing the mud filtrate ions and the formation water ions, it was found that the formation water sample was contaminated with 9% mud filtrate. (The estimated value from the MDT-log was ~5%). A water sample under 10% mud filtrate contamination is regarded to be of good quality and the corrected synthetic formation water should be representative.

The following main results of the Petrotech analyses are valid (Table 10-11):

Component (mg/l)	Formation water
Cl	7721
SO_4	0 *)
Br	35
Li	3
Na	5376
K	1443
Mg	14
Ca	157
Sr	7
Ba	59 **)
SCN	0
Acetate	449
Formate	12

Table 10-11: Main formation water analysis results

*) Assume no sulphate in the formation water. Some sulphur has precipitated with barium
**) Assume that some barium has precipitated with sulphate

The above results are from the analysis on the flashed water sample. The corrected Water Formation Sample assumes that some barium has precipitated with sulphate. The formation sample has been corrected for the 9% contamination. After correcting for the mud filtrate contamination, the resistivity and density versus temperature was calculated, see Table 10-12.

Temperature °C	Pressure bar	Resistivity Ωm	Density g/ml
20	1	0.2294	1.00814
112	318	0.0848	0.97281
115	318	0.0741	0.96992
120	318	0.0623	0.96577

Table 10-12: Synthetic formation water resistively and density vs. temperature

The GWR was measured to 4.3 Sm^3/Sm^3 at 21.5 °C. Analytica (Ref./10/) measured organic acids (Table 10-13) and BTEX (Table 10-14) on the water sample. The result from the IFE $^{87}Sr/^{86}Sr$ measurement was 0.714 (Ref. /10/).

Component	Content (mg/L)
Formate	<5
Acetate	247
Propionate	20
Butyrate	<7
Valerate	<6

Table 10-13: Organic acids in the formation water

Component	Content (µg/L)
Benzene	610
Toluene	280
Etylbenzene	6.5
m/p Xylene	24
O -Xylene	18

Table 10-14: BTEX for the formation water

11 References

Ref./1/ Well "programme 35/11-13, Astero", Hydro, 25.01.2005
Ref./2/ "Final Well Report, Well 35/11-13", Norsk Hydro ASA.
Ref./3/ "Conventional Core Analysis, Well 35/11-13", ResLab, 17.08.2005
Ref./4/ "Core Photographs 35/11-13, White and UV light", ResLab, 2005
Ref./5/ "Standard Core Description, Well 35/11-13", Hydro Research Centre Bergen, 2005
Ref./6/ "Field Operation Report, Well 35/11-13", Oilphase, May 2005.
Ref./7/ "Modular Formation Dynamics Tester - Field Report", Schlumberger, May 2005.
Ref./8/ "Well 35/11-13, PVT Sampling and Trace Analysis", Petrotech, May 2005.
Ref./9/ "PVT Analysis of reservoir oil from recombined separator sample, well 35/11-13, Astero field", Reservoir Laboratories AS, September 2005.
Ref./10/ "Validity checks and analyses of MDT water samples", Petrotech, September 2005.
Ref./11/ "Down Hole & Surface Data Acquisition", PWS-31-O-RP-001, Power Well Services, June 2005.

12 Appendices

In the following chapters operational details of well 35/11-13 can be found.

12.1 General Well Data

Well name:	35/11-13	
Drilling operator name:	Norsk Hydro Produksjon AS	
Geodetic datum:	ED50	
Coordinates:	61° 9` 44.10`` N	3° 32` 21.40`` E
UTM coordinates:	6781140.46 N	529019.63 E
UTM zone:	31	
Drilled in production licence:	090	
Area:	NORTH SEA	
Drill permit:	1092-L	
Drilling facility:	DEEPSEA TRYM	
Drilling days:	57	
Wellbore entry date:	18.03.2005	
Wellbore completion date:	13.05.2005	
Original wellbore purpose:	WILDCAT	
Wellbore purpose:	WILDCAT	
Wellbore status:	P&A	
Wellbore contents:	OIL/GAS	
Discovery wellbore:	YES	
Seismic location:	MN92001R03:inline934, crossline 976	
Kelly bushing elevation (KB) [m]:	25	
Water depth [m]:	388	
Total depth (MD) [m]:	3266	
Deepest penetrated age:	LATE JURASSIC	
Last updated by NPD:	18.05.2005	

12.2 MDT Sampling Configurations - Run 1B

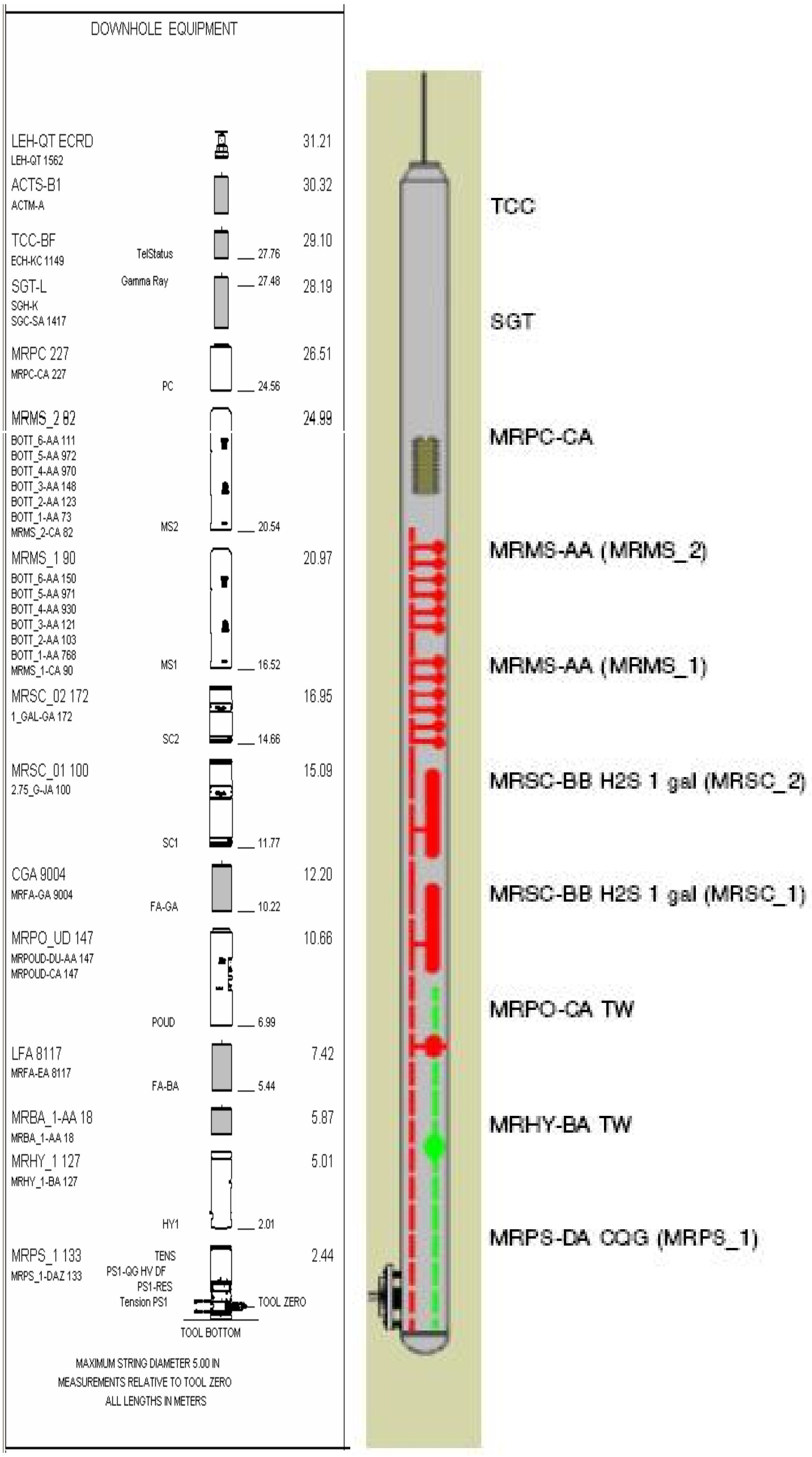


Figure 12-1: MDT-configuration used during sampling run 2A

12.3 Sampling Summary of the MDT run 1B (from Schlumberger)

Sample	DLIS	Depth	Formation Fluid	P(form)	P(hyd)	Mobility	Cleanup (l/mns)	Temp(form)	Temp(hyd)	
=====	====	====	===========	=====	=====	=====	===========	=========	=======	
[1]	143	3097	Gas/Oil	313.72	393.101	252.7				
[2]	146	3107	Oil	314.39	394.442	423.3	125 L	107.4 degC	107.7degC	
[3]	149	3128	Oil	315.76	396.870	341.8	52 L	108.68 degC		
[4]	153	3135	Scanning	316.19	397.665	12.2		109.8degC	110degC	***(operation aborted)***
[5]	156	3157.5	Water	318.177	400.481	78.9	63 L	109.8degC	110.4degC	
[6]	159	3135	Scanning	316.195	397.659	11.6	24 L/79min	109.9degC	110.6degC	
[7]	163	3137	Scanning	316.268	397.968	36.6	43 L/84min	110.6degC	110.7degC	
[8]	170	3136	Scanning	316.171	395.518	17.5	22 L/72min	109.5degC	110.0degC	

ETIM Chamber-Serial(s)	Temp (degC)	Open Drawdown (bar)	Max. Shut-in Pressure (bar)	OCM Predicted Contam.(%)	GOR (sm^3/sm^3)
==============	======	=========	========	=========	==================
1(a) MRMS2 MPSR-1 #73	104.96	4	588	13%	2170
1(b) MRMS2 SPMC-2 #123	104.96	4	588	9%	2170
1(c) MRMS1 SPMC-2 #103	105.1	4	588	9%	2170 ***(Back up ring had been cut by the upper sleeve. Sample leaking out of bottle.)***
1(d) MRSC-2 #172	105.13	1.7	588	7.4%	2170
1(e)MRMS1 MPSR-5 #971	105.3	1.6	588	6.4%	2170
==============	======	=========	========	=========	==================
[2a] MRMS2 MPSR-5 #972	106.8		588	N/A	
[2b] MRMS2 SPMC-3 #148	106.89		588	N/A	
[2c] MRSC-1 #100	107.0		588	N/A	137 m^3/m^3
[2d] MRMS1 SPMC-3 #121	107		588	N/A	137 m^3/m^3

ETIM Chamber-Serial(s)	Temp (degC)	Open Drawdown (bar)	Max. Shut-in Pressure (bar)	OCM Predicted Contam.(%)	GOR (sm^3/sm^3)
[3a] MRMS2 MPSR-4 #970	108.6		590Bar	2.5%	144 m^3/m^3
[3b] MRMS2 SPMC-6 #111	108.6		590 Bar	2.5 %	144 m^3/m^3
[5a] MRMS1 MPSR-4 #930	111.71	13Bar	589Bar	5%	n/a
[5b] MRMS1 SPMC-6 #150	111.71	13Bar	589Bar	4%	n/a

MRMS Bottle	Dead Volume
3	7.2 cc
2	10.2 cc
6	10.3 cc
1	11.1 cc
5	12.0 cc
4	12.5 cc

* Hydrocarbon Samples - Dead volume filled with Distilled water
* Water Samples - Dead volume filled with Air

12.4 Real-time LFA/CFA plots from the different HC sampling interval (Schlumberger)

12.4.1 3097m MD RKB

11-May-2005 13:25

Output DLIS Files

DEFAULT MDT_OFA_202PTP FN:12 PRODUCER 13-May-2005 11:00 3097.0 M 33.6 M

Elapsed Time (s)	Event Summary
13136.7	Retract Single Probe Module (MRPS) 1
13038.6	Vert Pretest 8.7 cc @ 60 C3/M Single Probe Module (MRPS) 1
12927.3	Pumping Stopped 35685.0 C3 Dual Up-down Pumpout Module (MRPOUD)
12627.9	Seal Multi-Sample Module (MRMS) 1, bottle 5
12265.2	Open Multi-Sample Module (MRMS) 1, bottle 5, sample number = 4
11594.4	Seal Sample Chamber Module 2 (1 Gallon, H2S)
10051.2	Open Sample Chamber Module 2 (1 Gallon, H2S), sample number = 1
7505.1	Pump Out Started Dual Up-down Pumpout Module (MRPOUD)
7409.7	Pumping Stopped 45045.0 C3 Dual Up-down Pumpout Module (MRPOUD)
7305.6	Seal Multi-Sample Module (MRMS) 1, bottle 2
7113.9	Open Multi-Sample Module (MRMS) 1, bottle 2, sample number = 3
6572.1	Seal Multi-Sample Module (MRMS) 2, bottle 2
6445.2	Open Multi-Sample Module (MRMS) 2, bottle 2, sample number = 2
4215.0	Seal Multi-Sample Module (MRMS) 2, bottle 1
4072.2	Open Multi-Sample Module (MRMS) 2, bottle 1, sample number = 1
3116.4	Pump Out Started Dual Up-down Pumpout Module (MRPOUD)
3064.5	Probe Set @ 3097.0 M Single Probe Module (MRPS) 1
3035.7	Pumping Stopped 23985.0 C3 Dual Up-down Pumpout Module (MRPOUD)
3031.5	Auto Reset Single Probe Module (MRPS) 1
313.2	Pump Out Started Dual Up-down Pumpout Module (MRPOUD)
160.8	Vert Pretest 20.0 cc @ 60 C3/M Single Probe Module (MRPS) 1
65.4	Probe Set @ 3097.0 M Single Probe Module (MRPS) 1

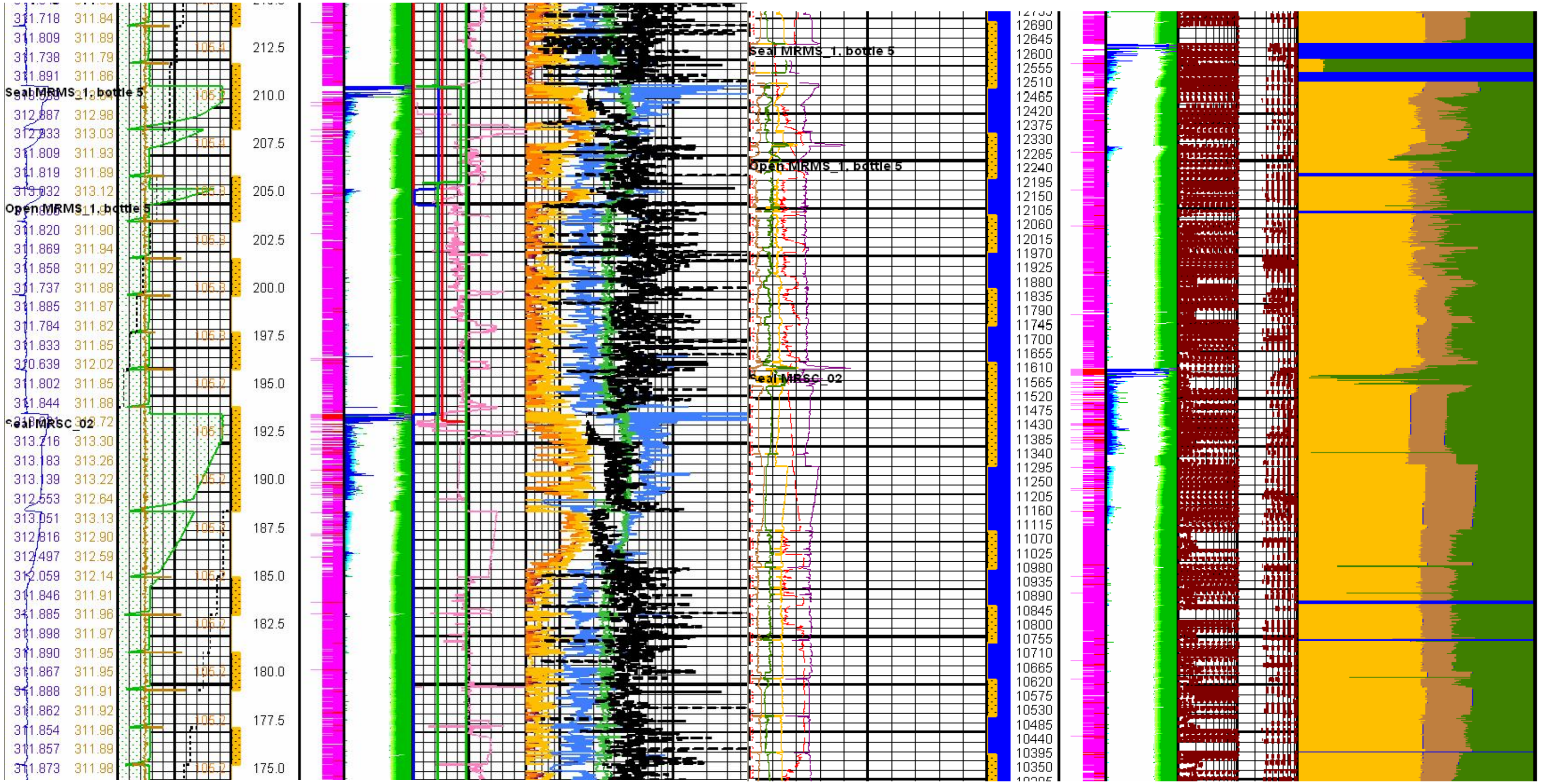


Figure 12-2: LFA and CFA plot of the last sample capture at 3097m MD RKB

12.4.2 3107m MD RKB

Input DLIS Files

11-May-2005 13:26

Output DLIS Files

DEFAULT	MDT_OFA_203PTP	FN:13	PRODUCER	13-May-2005 11:34	3107.0 M	23.5 M

Elapsed Time (s)	Event Summary
9144.6	Retract Single Probe Module (MRPS) 1
9036.3	Vert Pretest 10.9 cc @ 60 C3/M Single Probe Module (MRPS) 1
8954.7	Pumping Stopped 125190.0 C3 Dual Up-down Pumpout Module (MRPOUD)
8862.3	Seal Multi-Sample Module (MRMS) 1, bottle 3
8788.5	Open Multi-Sample Module (MRMS) 1, bottle 3, sample number = 7
8266.2	Seal Sample Chamber Module 1 (2.75 Gallon, H2S)
7410.6	Open Sample Chamber Module 1 (2.75 Gallon, H2S), sample number = 2
7111.2	Seal Multi-Sample Module (MRMS) 2, bottle 3
7053.3	Open Multi-Sample Module (MRMS) 2, bottle 3, sample number = 6
6792.9	Seal Multi-Sample Module (MRMS) 2, bottle 5
6721.2	Open Multi-Sample Module (MRMS) 2, bottle 5, sample number = 5
369.9	Pump Out Started Dual Up-down Pumpout Module (MRPOUD)
162.0	Vert Pretest 9.9 cc @ 60 C3/M Single Probe Module (MRPS) 1
58.5	Probe Set @ 3107.0 M Single Probe Module (MRPS) 1

PIP SUMMARY

Time Mark Every 60 S

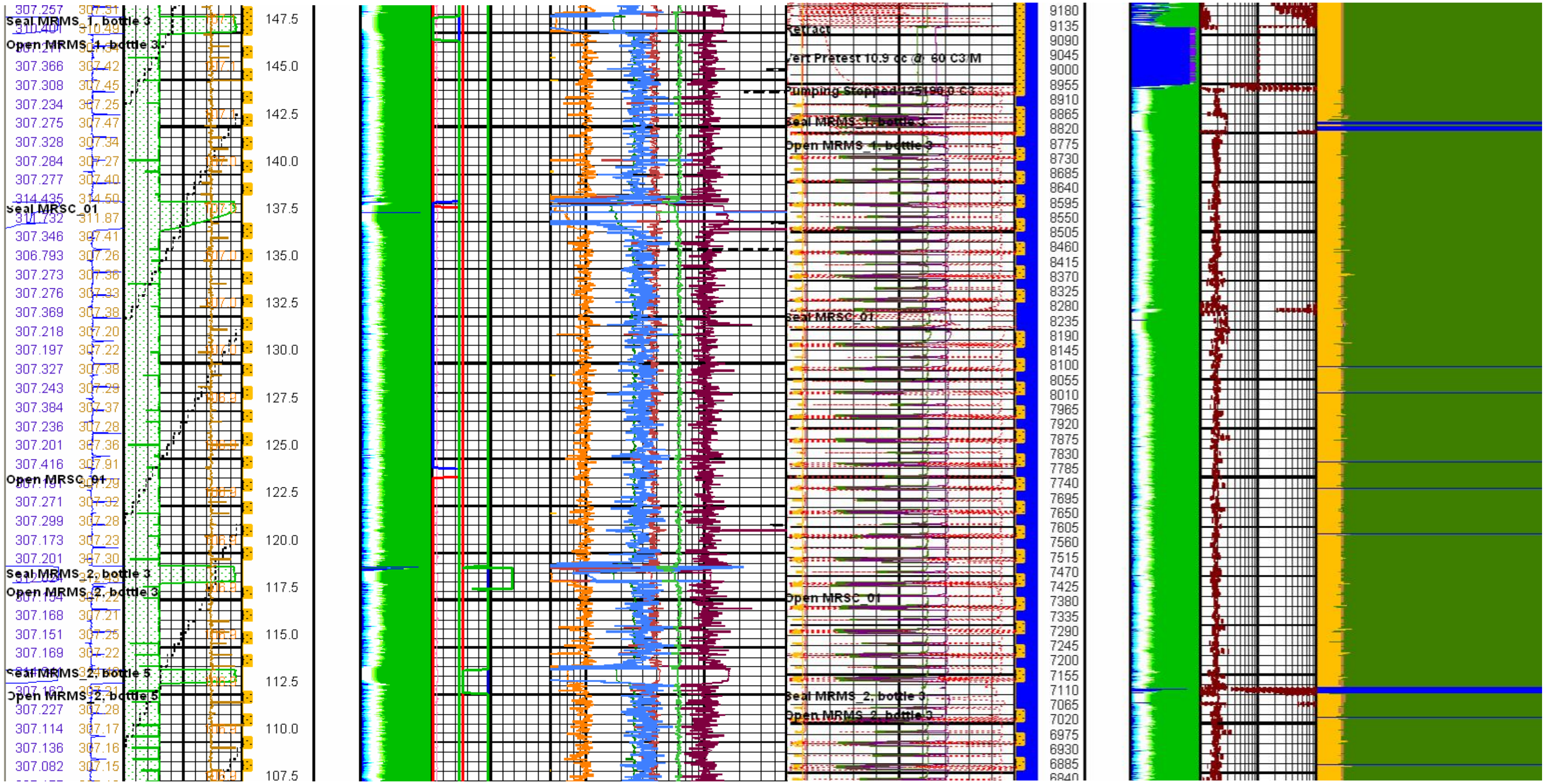


Figure 12-3: LFA and CFA plot of the samples capture at 3107m MD RKB

12.4.3 3128m MD RKB

Input DLIS Files

11-May-2005 13:26

Output DLIS Files

DEFAULT	MDT_OFA_206PTP	FN:14	PRODUCER	13-May-2005 11:57	3128.0 M	11.4 M

Elapsed Time (s)	Event Summary
4402.5	Retract Single Probe Module (MRPS) 1
4305.6	Pumping Stopped 52065.0 C3 Dual Up-down Pumpout Module (MRPOUD)
4097.4	Seal Multi-Sample Module (MRMS) 2, bottle 6
4022.1	Open Multi-Sample Module (MRMS) 2, bottle 6, sample number = 9
3615.0	Seal Multi-Sample Module (MRMS) 2, bottle 4
3536.7	Open Multi-Sample Module (MRMS) 2, bottle 4, sample number = 8
391.2	Pump Out Started Dual Up-down Pumpout Module (MRPOUD)
263.7	Vert Pretest 10.0 cc @ 60 C3/M Single Probe Module (MRPS) 1
131.4	Vert Pretest 9.9 cc @ 60 C3/M Single Probe Module (MRPS) 1
52.2	Probe Set @ 3128.0 M Single Probe Module (MRPS) 1

PIP SUMMARY

Time Mark Every 60 S

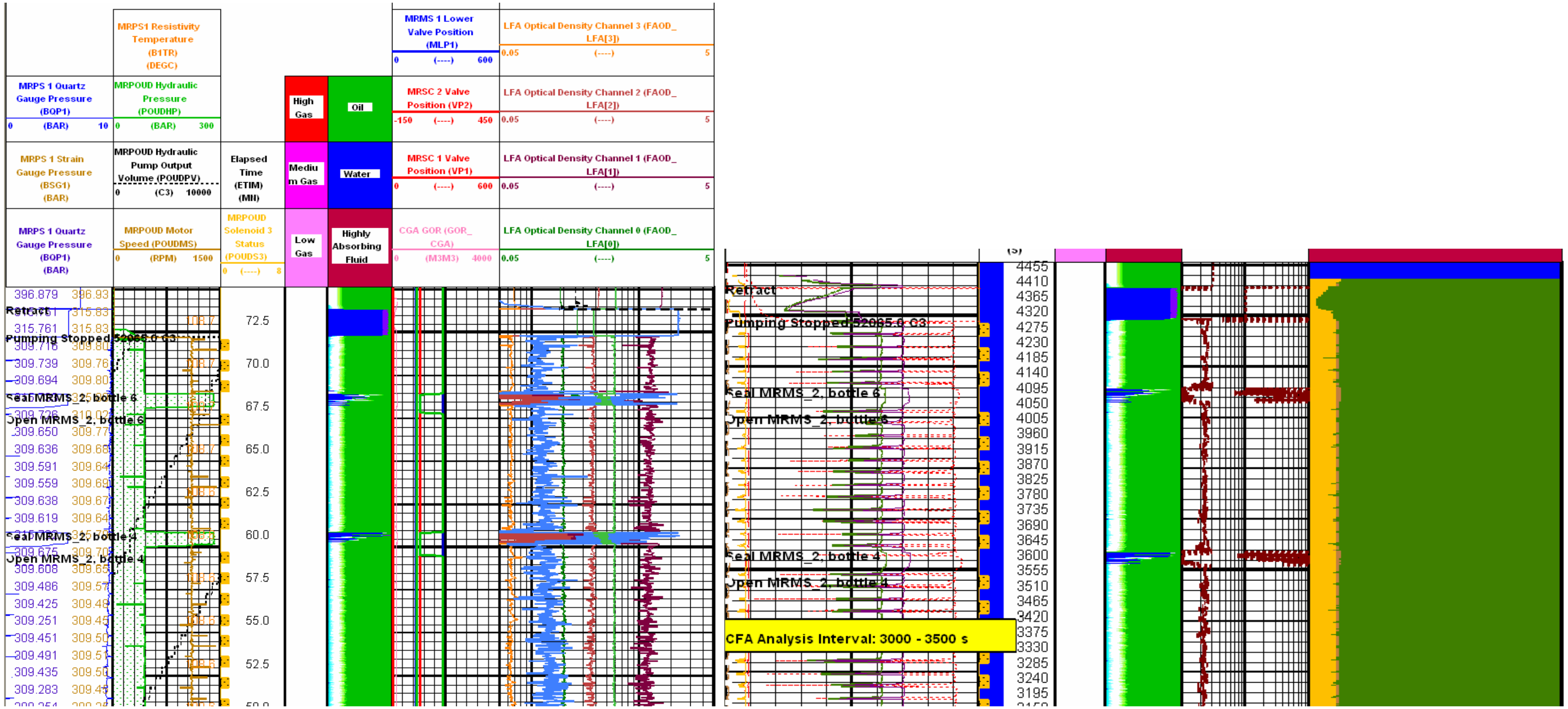


Figure 12-4: LFA and CFA plot of the samples capture at 3128m MD RKB

12.5 Oilphase Sample Listing from MDT Operation

MDT Run	Sample No.	Sample Date	Sample Time	Sample Point (m MD RKB)	Chamber MDT No.	Chamber Size (cc)	Opening Pressure	Bottle No.	Bottle Type	Bottle Size	Amount Sample	Sample Type	Fluid Type	Comments
1B	1.01	28/4-05	15:20	Mud Pit	n/a	n/a	n/a		Metal Can	2 ltr	2 ltr	Mud sample	n/a	
1B	1.02	1/5-05	15:15	3097	MPSR 73	450	224 bar @ 10 C	6286-MA	CSB	700 cc	340 cc	Monophasic	PVT Gas	
1B	1.03	1/5-05	15:50	3097	SPMC 123	250	Atm.	n/a	n/a	n/a	n/a	n/a	n/a	Leaking bottle, lost sample
1B	1.04	1/5-05	16:04	3097	SPMC 103	250	345 bar @ 11 C	9283-MA	SSB	820 cc	187 cc	Monophasic	Gas/oil	
1B	1.05	1/5-05	16:55	3097	MRSC 172	1 gallon	Atm.	n/a	Glass	1 ltr	1 ltr	n/a	Condensate	Flashed offshore
1B	1.06	1/5-05	17:30	3097	MPSR 971	450	234 bar @ 10 C	4464-EA	CSB	700 cc	350 cc	Monophasic	PVT Gas	
1B	1.07	1/5-05	20:04	3107	MPSR 972	450	158 bar @ 10 C	4753-EA	CSB	700 cc	410 cc	Monophasic	Oil	
1B	1.08	1/5-05	20:10	3107	SPMC 148	250	414 bar @ 11 C	2149-EA	SSB	820 cc	245 cc	Monophasic	Oil	
1B	1.09a	1/5-05	20:16	3107	MRSC 100	2 ¾ gallon	Atm.	n/a	IATA Can	5 ltr	4 ltr	Dead oil	Oil	
1B	1.09b	1/5-05	20:16	3107	MRSC 100	2 ¾ gallon	Atm.	n/a	IATA Can	5 ltr	3,5 ltr	Dead oil	Oil	
1B	1.10	1/5-05	20:38	3107	SPMC 121	250	423 bar @ 13 C	2040-EA	SSB	820 cc	230 cc	Monophasic	Oil	
1B	1.11	1/5-05	22:11	3128	MPSR 970	450	165 bar @ 12 C	6949-MA	CSB	700 cc	410 cc	Monophasic	Oil	
1B	1.12	1/5-05	22:19	3128	SPMC 111	250	441 bar @ 14 C	10334-AA	SSB	820 cc	220 cc	Monophasic	Oil	
1B	1.13	2/5-05	03:40	3157,5	MPSR 930	450	48 bar @ 12 C	6840-MA	CSB	700 cc	420 cc	Monophasic	Water	
1B	1.14	2/5-05	03:53	3157,5	SPMC 150	250	490 bar @ 14 C	1254-EA	SSB	820 cc	230 cc	Monophasic	Water	

12.6 Petrotech Sample Listing from DST Operation

Sample no.	Petrotech bottle no.	Date	Time	DST no.	Flow period	Sampling point	Sample type	Volume	Bottle press. Barg	Comments
1.01	N/A	11.05.2005	23:00	1	Main	Test Sep	Water	1L	Atm	
1.02	PT-2075	12.05.2005	03:30-04:00	1	Main	Test Sep	Oil	600cc	11	PVT set-1
1.03	A-1806	12.05.2005	03:30-04:00	1	Main	Test Sep	Gas	20L	20	PVT set-1
1.04	5034A	12.05.2005	03:30-04:00	1	Main	Test Sep	Gas	20L	20	PVT set-1
1.05	N/A	12.05.2005	10:30 - 11:35	1	Main	Calibration ank	Oil	200 l	200 l Drum	Mixing study sample
1.06	N/A	12.05.2005	10:30 - 11:35	1	Main	Calibration ank	Oil	200 l	200 l Drum	Mixing study sample
1.07	PT1123	12.05.2005	12:20-12:45	1	Main	Oil outlet Test Sep.	Oil	600 cc	12	PVT set-2
1.08	A1803	12.05.2005	12:20-12:50	1	Main	Gas outlet Test Sep.	Gas	20 l	20	PVT set-2
1.09	4764 A	12.05.2005	12:20-12:50	1	Main	Gas outlet Test Sep.	Gas	20 l	20	PVT set-2
1.10	TS 11518	12.05.2005	13:26-13:57	1	Main	Oil outlet Test Sep.	Oil	600 cc	12	PVT set-3
1.11	A2456	12.05.2005	13:26-13:58	1	Main	Gas outlet Test Sep.	Gas	20 l	20	PVT set-3
1.12	A 1802	12.05.2005	13:26-13:59	1	Main	Gas outlet Test Sep.	Gas	20 l	20	PVT set-3
1.13	PT 2059	12.05.2005	14:35-15:05	1	Main	Oil outlet Test Sep.	Oil	600 cc	12	PVT set-4
1.14	A 2114	12.05.2005	14:35-15:05	1	Main	Gas outlet Test Sep.	Gas	20 l	20	PVT set-4
1.15	A 0166	12.05.2005	14:35-15:05	1	Main	Gas outlet Test Sep.	Gas	20 l	20	PVT set-4
1.16	Geo 151	12.05.2005	15:15-15:20	1	Main	Gas outlet Test Sep.	Gas	150 cc	20	Gechemical # 1
1.17	PT 226	12.05.2005	15:22-15:25	1	Main	Gas outlet Test Sep.	Gas	150 cc	20	Gechemical # 2
1.18	Geo 150	12.05.2005	15:28 -15:33	1	Main	Gas outlet Test Sep.	Gas	150 cc	20	Gechemical # 3
1.19	N/A	12.05.2005	17:00	1	Main	Oil outlet Test Sep.	Oil	1 l	Atm	Plastic Botle
1.20	N/A	12.05.2005	17:00	1	Main	Oil outlet Test Sep.	Oil	1 l	Atm	Plastic Botle
1.21	N/A	12.05.2005	17:00	1	Main	Oil outlet Test Sep.	Oil	1 l	Atm	Plastic Botle
1.22	N/A	12.05.2005	17:00	1	Main	Oil outlet Test Sep.	Oil	1 l	Atm	Plastic Botle
1.23	N/A	12.05.2005	17:00	1	Main	Oil outlet Test Sep.	Oil	1 l	Atm	Plastic Botle
1.24	N/A	12.05.2005	17:10	1	Main	Oil outlet Test Sep.	Oil	1 l	Atm	Aluminium Botle
1.25	N/A	12.05.2005	17:10	1	Main	Oil outlet Test Sep.	Oil	1 l	Atm	Aluminium Botle
1.26	N/A	12.05.2005	17:15	1	Main	Oil outlet Test Sep.	Oil	0.5	Atm	Aluminium Botle
1.27	N/A	12.05.2005	17:15	1	Main	Oil outlet Test Sep.	Oil	0.5	Atm	Aluminium Botle
1.28	A 2010	12.05.2005	17:00-17:15	1	Main	Oil outlet Test Sep.	Oil	20 l	~4	For Emulsion study
1.29	5308 A	12.05.2005	17:30 - 17:45	1	Main	Oil outlet Test Sep.	Oil	20 l	~4	For Crude Assay
1.30	N/A	12.05.2005	20:30	1	Main	Water outlet Test Sep.	Water	0.5 l	Atm	
1.31	N/A	12.05.2005	20:30	1	Main	Water outlet Test Sep.	Water	0.5 l	Atm	
1.32	N/A	12.05.2005	20:30	1	Main	water outlet Test Sep.	Water	1 l	Atm	
1.33	N/A	12.05.2005	20:30	1	Main	Water outlet Test Sep.	Water	1 l	Atm	
1.34	N/A	12.05.2005	20:30	1	Main	Water outlet Test Sep.	Water	1 l	Atm	
1.35	N/A	12.05.2005	20:30	1	Main	water outlet Test Sep.	Water	1 l	Atm	
1.36	N/A	12.05.2005	20:30	1	Main	Water outlet Test Sep.	Water	1 l	Atm	

12.7 Summary of Production and Trace element Data from DST

Date	Time	BHP bar	WHP bar	WHT Deg C	Oil rate Sm3/d	Gas rate Sm3/d	Sep P bar	Sep T Deg C.
11.05.05	12:15	285.6	65.8	11.9	780	N/A	36.5	26.4
	12:30	285.2	66.2	13.1	787	N/A	36.1	21.1

Table 12-1: Initial Flow - Choke size: 58/64”

Date	Time	BHP bar	WHP bar	WHT Deg C	Oil rate Sm3/d	Gas rate Sm3/d	Sep P bar	Sep T Deg C.	GOR Sm3/Sm3
12.05.05	01:00	293.3	92.7	15.1	502	77788	19.5	47.1	155
	02:00	292.7	93.1	16.8	495	78357	19.7	48.8	158
	03:00	292.1	93.3	17.6	497	79656	19.9	49.1	160
	04:00	291.7	93.8	18.1	501	79440	20.0	49.9	159
	05:00	291.2	94.0	18.4	498	79355	20.1	51.8	159
	06:00	290.8	94,0	18,9	499	80125	20.2	52.2	161
	07:00	290.4	94.1	19.8	498	79629	20.3	52.7	160
	08:00	290.0	94.2	19.9	499	79716	20,4	53.1	160
	09:00	289.6	94.0	21.2	498	79659	20.4	53.8	160
	10:00	289.3	94,1	21,2	494	79679	20,5	54.5	161
	11:00	289.0	94.1	21.1	496	79585	20.3	54.9	160
	12:00	288.7	94,1	21,0	497	79729	20.4	53.8	160
	13:00	288.4	94.1	21.5	495	79663	20.3	54.9	161
	14:00	288.2	94.2	21.6	495	79580	20.0	55.2	161
	15:00	287.9	93.9	21.5	496	79682	20.4	55.5	161
	16:00	287.7	93.7	21.6	498	79563	20.4	55.4	160
	17:00	287.4	93.9	21.8	495	79362	20.3	55.2	160
	18:00	287.2	93.8	21.2	498	79495	20.4	53.4	160
	19:00	287.0	94.0	21.4	496	79745	20.5	55.5	161
	20:00	286.8	93.8	20.9	498	79588	20.6	55.0	160
	21:30	286.5	93.5	20.8	498	79249	20.6	53.8	159

Table 12-2: Production Data, Main Flow - Choke size: 32/64”

Petrotech KNOWLEDGE

ON-SITE MEASUREMENTS OF CONDENSATE

Client	Norsk Hydro
License No.	PL090
Formation	
Well	35/11-13 Astero
Sample point	Oil outlet Test Separator

Date	Time	Density (g/cm^3)	Temp (°C)	Density* (g/cm^3)	Temp (°C)
2005-05-11	11:48	0.846	16.3	0.847	15
"	12:12	0.842	19.6	0.845	15
"	12:25	0.842	20.7	0.846	15
"	22:00	0.853	19.4	0.856	15
"	23:00	0.870	19.4	0.873	15
2005-05-12	0:00	0.861	19.4	0.864	15
"	1:00	0.856	19.0	0.859	15
"	2:00	0.851	19.6	0.854	15
"	3:00	0.848	21.1	0.852	15
"	4:00	0.846	20.0	0.850	15
"	5:00	0.844	19.0	0.847	15
"	6:00	0.848	18.0	0.850	15
"	7:00	0.845	19.4	0.848	15
"	8:00	0.848	20.1	0.852	15
"	9:00	0.848	20.2	0.852	15
"	10:30	0.847	19.7	0.850	15
"	11:00	0.846	20.6	0.850	15
"	12:00	0.844	22.0	0.849	15
"	14:00	0.850	19.1	0.853	15
"	15:00	0.841	21.4	0.846	15
"	18:20	0.842	22.5	0.847	15
"	19:00	0.843	20.5	0.847	15
"	20:00	0.845	17.0	0.846	15
"	21:00	0.849	17.3	0.851	15

*Density at 15 °C is calculated.

Petrotech KNOWLEDGE

ON-SITE MEASUREMENTS OF TRACE ELEMENTS IN GAS

Client	Norsk Hydro
License No.	PL090
Formation	
Well	35/11-13 Astero
Sample point	Gas outlet Test separator

Date	Time	Gas Gravity Sg Air =1	H_2S * (ppmv)	CO_2 (vol %)
2005-05-11	11:15		0.0	0.0
"	11:30		0.0	4.0
"	11:35		0.0	4.0
"	11:45		0.0	4,2
"	11:48	0.670		
"	12:00		0.0	5.0
"	12:10		0.0	5,1
"	12:12	0.670		
"	12:20		0.0	5,1
"	12:25	0.670		
"	22:00	0.692	0.0	5.0
"	23:00	0.725	1.0	5.0
2005-05-12	0:00	0.726	1.8	6.0
"	1:00	0.724	1.5	5.8
"	2:00	0.730	2.0	5.5
"	3:00	0.728	2.0	5.5
"	4:00	0.728	2.0	5.5
"	5:00	0.726	2.0	5.5
"	6:00	0.729	2.0	5.5
"	7:00	0.729	2.0	5.2
"	8:00	0.728	2.8	5.0
"	9:00	0.728	2.0	5.5
"	10:00 Meter Factor			
"	10:35	0.727	2 / (5 by Mærsk)	5.0
"	11:00	0.730	2/(4 by Mærsk)	5.0
"	12:00	0.730	2.2	5.0
"	14:00	0.730	2.4	5.0
"	15:00	0.734	2.3	5,2
"	18:20	0.738	2.5	5.0
"	19:00	0.728	2.5	5.0
"	20:00	0.730	2.2	5.3
"	21:00	0.730	2.5	5.2
"				

* In case of temperatures between 0°C and 10 °C, the H2S reading has to be multiplied by 1.5.

12.8 "Sequence of Events"

The section is divided into two parts: 12.8.1, Wire line Logging and 12.8.2, Well Test Operations.

12.8.1 8 ½" Wire line Logging

The Sequence of Events is based on Schlumberger SOE.

COMPANY: Hydro ASA

WELL: 35/11-13

FIELD: Astero

Rig: Deepsea Trym **Country:** NORWAY

Schlumberger

MDT-GR
Modular Dynamic Tester
Pressure Test - Sampling - Scanning

Rig: Deepsea Trym
Field: Astero
Location: North Sea
Well: 35/11-13
Company: HydroASA

Location:
North Sea
Norwegian Sector
UTME 6 791 139.0mN, UTME 5 29 019.4mE

Elev: K.B. 25.0 m
G.L. -361.7 m
D.F. 25.0 m

Permanent Datum:	MSL	Elev: 0.0 m
Log Measured From:	DF	25.0m above Perm. Datum
Drilling Measured From:	DF	

Country:	Max Deviation	Latitude	Longitude
NORWAY	2.05 deg	3° 32' 21.38"E	61° 09' 44.05"N

Logging Date		4/29/2005					
Run Number		1B					
Depth Driller		3291.5 m					
Schlumberger Depth		3304.0 m					
Bottom Log Interval		3205.5 m					
Top Log Interval		3097.0 m					
Casing Drilling Size	@ Depth	9.63 in		2924.4 m			
Casing Schlumberger		3304.0 m					
Bit Size		8.50 in					
Type Fluid in Hole		KCL					
Mud Density	Viscosity	0.16 g/cc		54.000 cp			
Mud Fluid Loss	PH	3.00 ml		8.40			
Mud Source of Sample		Mud Pit					
RM	@ Measured Temperature	0.07		@ 20.0 °C			@
RMF	@ Measured Temperature	0.05		@			@
RMC	@ Measured Temperature	0.21		@ 20.0 °C			@
Source RMF	Source RMC	Press		Press			
RM @ MRT	RMF @ MRT	0.02	110.0 °C	0.02	110.0 °C		
Maximum Recorded Temperatures		110.0 °C		110.0 °C	110.0 °C		
Circulation Stopped	Time	4/29/2005					
Logger On Bottom	Time	4/30/2005		3:55			
Unit Number	Location	3802	NOBO				
Recorded By		Ihab Girgis/Sarochinee Paweenawat					
Witnessed By		Mike Henderson/Magne Tillung					

23-April-2005

14:30	Crews arrived rig.
15:15	Safety trip on rig.
16:15	Start to locate Schlumberger equipment and power up unit
18:20	Meeting with crane operator.

24-April-2005

07:00	Cable checked during night, some bad insulation in trolex plug (500 Mohms). New rope socket made up.
07:30	Morning meeting, logging will start earliest at 12:00 Thursday. MDT container and toolrack reorganized. Spudding the MSCT generator.
09:30	Head ready with ECRD weakpoint.
09:45	Moving tools around with crane.
13:00	Starting to connect MDT tools.
16:00	Power up with Appkit 2753 - no go. Troubleshooting done.
17:00	Swapped to Appkit 2682 and tools powered up as normally.
17:30	Drilling of crew.
18:30	Continuing checking MDT tools.

25-April-2005

08:00	Continuing checking MDT tools.
14:15	Main MDT toolstring checked, - ok.
19:00	Back up MDT tools checked, - ok.
22:00	Schlumberger engineer and seismic specialist arriving the rig.

26-April-2005

07:00	Seismic tools checked and started to rig up logging run #1 and #2.
08:00	Checking certificate and trying to sort out which maintenance sheet needs to be delivered to rig. Going thru Hydro hazard identification sheet.
11:30	Problems with MSCT generator, leaking oil and motor brackets damage during transport. Starting to repair generator with help from rig mechanical. Ordering new generator and filter from town.
17:30	MSCT tool checked with power supply in unit, no core has been cut. Tool, ok.
19:00	Setting up software and going thru logging program.

27-April-2005

07:00	All tools checked.
11:00	Fit list for unit and tool house done and delivered to rig office.
11:10	Got new parts for generator. Starting to repair the generator.
13:50	Starting up generator, - everything looks ok.
16:30	MSCT tools checked and a core is cut.
17:00	Troubleshooting on line 8 Fish
19:00	Intermittent/open circuit found in safety switch

28-April-2005

07:00 Building new rope socket and doing a test of cable. Sorting out explosives and radioactive material.
09:00 Rigging up MDT string with booster.
15:30 Booster and new MRMS checked in toolstring, - ok.
16:00 Preparing MDT hardware.

29-April-2005

08:50 Checked logging tool for run #1 main and measured maximum induced voltage between lines 1-7 = 13.5V.

30-April-2005

02:30 Start pre-job meeting on the drill floor.
02:50 Start lifting rig-up equipment to the drill floor.
03:30 Finish rigging up wireline.
04:00 Start rigging up the tools.
04:40 Finish rigging up the tools.
04:45 Check the tools at surface. Zero the tool on DF.
04:55 Lift the sources from radioactive pit.
05:15 Finish loading the sources. Start RIH.
05:30 Mark RULS @ 100.01m. RULS = 71.89m. Continue RIH.
06:20 Start down log File#062. DSI logged in casing.
07:10 Stop the log due to OP crash, stream meter go to 7.
07:12 Mark RULB @ 2340.01m. RULB = Correct depth at WFDD.
07:20 Start down log File#065. DSI logged in casing.
08:10 Start down log File#066. Open hole logging.
08:40 Tag TD. Tension down = 3900lbf, Tension up = .4600lbf.
08:43 Start up log File#67. Main log.
09:40 Stop main log. Start RIH for repeat section.
09:43 Tool hang up at 2953m. Try to go up and down, couldn't pass.
10:15 Inside the casing shoe. Wait for decision from town.
10:45 Decide to POOH.
11:35 Tool arrive at 170m. Prepare for unloading the radioactive sources.
12:25 Finish unloading source.
12:30 Rig down toolstring. Preparing for MDT logging run 1A.
13:10 Rig down logging run #1 completed. T1=T2=T3=100 degC
13:20 Starting to pick up MDT tools from deck.
13:40 Rig up MDT.
13:50 Testing og tools. Ac main 250/156 and PP 334/0.57 Run Folder PS1
14:10 Zero and RIH
14:20 Activating compensator and RIH, Toolweight in mub 600 lbs.
15:30 At shoe, pick up weight 3400 lbs.
15:40 Hang up at 3009 m.
15:55 At 3250 m , starting correlation up. Tension 3800 lbs. 0.6 m shallow.
17:23 Taking P-Point at 3183.5m.
18:00 Taking P-Point at 3157.5m. (Point #10)
21:19 POOH. Pressure survey completed.

23:00 Finish rigging down MDT. Prepare for the 3rd logging run.
23:30 Start rigging up VSP.

01-May-2005

00:05 Finish rigging up. RIH with VSP.
09:45 Finish laying down VSP. Prepare for the 4th run.
10:00 Start lifting MDT to the drill floor.
10:20 Start rigging up MDT.
11:05 Starting to check MDT tools.
11:25 AC main 250/419 and PP 335/0.57
11:45 Tool checked and depth set to 29.9 m with head at drill floor. Tool weight in mud 2200 lbs/ACTS 2400 lbs
11:55 At 100 m activating compensator.
12:00 RIH with MDT.
13:02 Pick up at casing shoe = 5050lbf, Run into open hole.
13:22 Correlate at 3150 m Pickup weight = 5400lbf.
14:00 At Sampling depth 3097m, Start set probe.
14:09 Start Pumping.
14:58 Pump stopped, reached auto reset pressure, start pump again.
15:15 Sample into MRMS2 MPSR #73 at 3097 m
15:50 Sample into MRMS2 Slot 2 SPMC #123 at 3097m
16:00 Sample MRMS1 into Slot 2 SPMC #103 at 3097m
16:08 Accidentally sealed an empty sample chamber MPSR #768 in MRMS1
16:55 Decide to sample one extra chamber at this depth. Sample into SC2 #172 at 3097m.
17:26 Sample into MRMS2 Slot 1 MPSR # 971 at 3097m.
17:30 Retrack probe and move off, no overpull experienced.
17:50 Start correlating from 3200m.
18:03 Arrive at 3107m for sampling. Taking a pretest.
18:15 Set the probe again. Ready for sampling operation.
18:20 Start pumping at 400 rpm for clean up at 3107m. Increased rate in steps 600, 800, 1000 and 1200 rpm.
19:22 52ltr pumped.
20:04 93ltr pumped.
20:05 Sampled in MRMS2 MPSR5 #972 at 3107m.
20:10 Sampled in MRMS2 MPSR3 #148 at 3107m.
20:16 Sampled in MRSC 1# 100 at 3107m, 102,96ltr pumped.
20:29 Finished filling MRSC1 #100 (2 ¾ gallon).
20:38 Sampled in MRMS1 SPMC3 # 121, 124ltr pumped.
20:44 Stop pumping and perform final pretest.
20:47 Retract probe.
20:50 Moved off sampling depth, no extra drag experienced.
20:58 Started correlating (dlis #147).
21:03 On next sampling depth 3128m, setting probe for P-Point. Mobility ok.
21:11 Setting probe for sampling.
21:18 Start pumping at 3128m.
21:52 Increased pump rate in steps from 400 rpm to 1200 rpm. Drawdown increased from 2 to 6,7bar.

22:11 Starting to sample in MRMS2 MPSR4 #970 at 3128m. 41,51ltr pumped.
22:20 Starting to Sample in MRMS2 SPMC6 #111 at 3128m. 48,51ltr pumped.
22:28 Stop pumping after 52ltr.
22:30 Retracted probe and move off location.
22:32 Going down to 3215m for correlation.
22:35 Correlating up file #150 0,9m shallow.
22:43 Correlating up file #151on depth.
22:49 On scanning depth 3135m. Set probe and taking pretest, file #152.
23:02 Scanning file #153 started.
23:08 Start fluid scanning/pumping. 65bar drawdown with 400rpm!
23:17 Aborted test due to fear of plugging pump without meeting primary objectives.
23:27 Correlate up to water sampling depth at 3157,5m. Correlation file#154. On depth.
23:31 Set probe and start file#155 for mobility calculation. Mobility ok.
23:42 Start file#156.
23:46 Start clean-up of formation.

02-May-2005
00:05 Increased pump rate to 600rpm, drawdown = 11 Bar.
01:02 Increased pump rate to 1000rpm, drawdown = 18 Bar.
01:15 50V power supply running hot.
01:20 Stop pump and change power supply. Operation took only 10sec., thus avoiding auto retract of probe.
01:22 Restart pump, but drawdown with 1200 rpm is increased from 18 to 42bar! Reduced and vary speed.
01:42 Stop pump, retract the probe.
01:45 Reset probe immediately without moving MDT-tool. Start pump rate to 300rpm, drawdown = 4bar.
01:53 Increased pump rate to 600rpm. Drawdown = 8bar.
01:58 Increased pump rate to 800rpm. Drawdown = 10bar.
02:00 Auto reset pump stop, restart pump with 300rpm. Drawdown = 3.5bar.
02:04 Increased pump rate to 600rpm. Drawdown = 8bar.
02:12 Increased pump rate to 900rpm. Drawdown = 12bar.
02:17 Increased pump rate to 1200rpm Drawdown = 18bar.
02:19 Drawdown increases to 40bar. Decreased pump rate to 900rpm. Drawdown = 30bar.
03:40 Starting to sample in MRMS1 MPSR4 # 930 at 3157.5m @ 900rpm. 57,9ltr pumped.
03:52 Starting to sample in MRMS1 SPMC6 # 150 at 3157.5m @ 900rpm. 65,5ltr pumped.
04:00 Stop pump after 67,8ltr. Retract probe and move off.
04:04 Going down to 3200m for correlation.
04:07 Correlating up (file #157), on depth.
04:12 Start station log #158 at 3135m.
04:15 Setting probe for P-Point.
04:25 Start station log #159 at 3135m for fluid scanning.
04:27 Setting probe for sampling.

04:32	Start pump rate at 300rpm. Drawdown = 32bar.
04:38	Increased pump rate to 400rpm. Drawdown = 40bar.
04:48	Increased pump rate to 500rpm. Drawdown = 43bar.
04:51	Increased pump rate to 600rpm. Drawdown = 46bar.
05:00	Decreased pump rate to 400rpm. Drawdown = 40bar.
05:10	Decreased pump rate to 300rpm. Drawdown = 30bar.
05:20	Increased pump rate to 500rpm. Drawdown = 40bar.
05:23	Increased pump rate to 700rpm. Drawdown = 50bar.
05:30	Increased pump rate to 900rpm. Drawdown = 68bar.
05:50	Stop pump, retract the probe.
05:55	Going down to 3200m for correlation.
06:00	Correlating up (file #160), +0.1 off depth
06:07	Correlating up (file #161), on depth and move to next fluid scanning depth 3137m.
06:13	Start station log #162 at 3137m.
06:14	Setting probe for P-Point.
06:21	Start station log #163 at 3137m.
06:22	Setting probe for sampling
06:28	Start pump rate at 300rpm. Drawdown = 23bar.
06:35	Increased pump rate to 500rpm. Drawdown = 26bar.
06:44	Increased pump rate to 700rpm. Drawdown = 36bar.
06:48	Increased pump rate to 900rpm. Drawdown = 41bar.
06:57	Increased pump rate to 1100rpm. Drawdown = 46bar.
07:15	Decreased pump rate to 800rpm. Drawdown = 38bar.
07:28	Increased pump rate to 1100rpm. Drawdown = 50bar.
07:36	Increased pump rate to 1200rpm. Drawdown = 55bar.
07:55	No indication of oil, only water seen. Stop pump, retract the probe.
07:58	Start POOH.
08:35	At 1300m. Decide to do fluid scanning at 3136m. RIH.
09:05	Reach 3220m. Correlation up (file #166), 2m off. Max Tension up 5500lbf.
09:10	Correlation up (file #167), 0.4m off.
09:15	Correlation up (file #168), on depth.
09:24	Start station log #169 at 3136m.
09:27	Setting probe for P-Point
09:34	Start station log #170 at 3136m.
09:39	Setting probe for fluid scanning.
09:42	Start pump rate at 300rpm. Drawdown = 40bar.
09:48	Increased pump rate to 500rpm. Drawdown = 48bar.
09:57	Increased pump rate to 700rpm. Drawdown = 54bar.
10:17	Decreased pump rate to 500rpm. Drawdown = 48bar.
10:21	Increased pump rate to 700rpm. Drawdown = 68-80bar. After rate increase oil is appearing with similar characteristic as the oil seen at 3135m, but smaller fraction.
10:54	Stop pumping. Retract probe.
11:03	Start POOH.
12:35	Tools arrived at surface. Start rigging down. Maximum recorded temperature = 110 degC

13:50 Rig down MDT finish. Picking up MSCT from deck
14:00 Rig up MSCT and test the tool.
15:00 Zero MSCT at the bit.
15:10 Compensator activated at 100m. Tool weight in mud = 650 lbs
15:15 RIH. Weakpoint in head 6000-6700lbs. Weak point shaft 2700 lbs.
16:00 Test at 1500m.
16:30 Test at 2900m. Pick up weight 3300 lbs.
16:59 Starting correlation for first core. 0,3 m shallow (File #178).
17:15 Cutting core no. 1. On depth (File #179).
17:45 Core 3 at 3149m, aborted due to stalling without any penetration.
19:45 0,1 m deep.
19:50 File #181 on depth.
22:05 Some problems with retracting the bit after core 27.
22:40 0,4 m deep.
22:45 File #183 on depth.

03-May-2005
00:15 Last core taken at 2960m.
00:20 Start POOH.
02:10 Tool arrived at surface.
02:30 Finish removing the cores. Start rigging down the tools.
02:50 Finish rigging down the tools. Start rigging down wireline.
03:20 Finish rigging down wireline equipment.
Maximum recorded temperature = 112,111,112degC.

12.8.2 Sequence of events ; Well Test Operations

Based on Power Well Services SOE

Date	Time	Sequence of Events
08-mai-05	01:30:00	***
08-mai-05	01:30:00	**** ASTERO 35/11-13 ****
08-mai-05	01:30:00	***
08-mai-05	01:30:00	Start Spartek gauge 20397
08-mai-05	01:35:00	Start Spartek gauge 20398
08-mai-05	02:00:00	Start Metrolog gauge 7401
08-mai-05	02:04:00	Start Metrolog gauge 7443
08-mai-05	03:00:00	Installed gauges into gauge carrier.
08-mai-05	03:45:00	Pressure tested gauge carrier to 370 bar.
08-mai-05	08:15:00	Start to RIH with TCP guns
08-mai-05	08:50:00	Perform Toolbox talk prior to RIH with BHA
08-mai-05	09:30:00	Change elevator. Lift X-overs to rig floor
08-mai-05	09:46:00	Lift Champ Packer assembly to rig floor
08-mai-05	10:10:00	RIH with Champ packer assembly
08-mai-05	10:30:00	RIH with LPR-N and gauge carrier
08-mai-05	10:57:00	Make up 1st joint of drill collar
08-mai-05	11:10:00	RIH with OMNI, RD and RA-sub
08-mai-05	11:30:00	Start to RIH with 18 joints of 4 3/4"" drill collars
08-mai-05	13:30:00	Pick up Slip joint # 1 and 2
08-mai-05	14:10:00	Finish BHA. BHA weight = 13 tons
08-mai-05	15:04:00	Make up 1st joint of tubing
08-mai-05	15:54:00	Start to pressure test BHA against TST-valve to 70/370 bar for 5/15 min
08-mai-05	16:15:00	Good test. Bleed off pressure
08-mai-05	16:20:00	Continue RIH
09-mai-05	07:27:00	Pressure up line to 17 Bar to check line-up to annulus
09-mai-05	07:30:00	Line-up OK
09-mai-05	07:33:00	Start to reverse circulate with 158 l/min and 3 bar
09-mai-05	07:41:00	Increase circulating rate to 400 l/min
09-mai-05	08:04:00	Finish reverse circulating. Total pumped 11,3 m3 (704 strokes). OpenMPR
09-mai-05	08:10:00	Dummy hanger to drill floor
09-mai-05	08:25:00	Start to pressure test tubing to 370 bar/15 min. Pump 1150 litres
09-mai-05	08:43:00	Good test. Bleed off pressure
09-mai-05	09:12:00	Stabbed dummy hanger onto tubing
09-mai-05	09:40:00	Start RIH with dummy hanger
09-mai-05	19:00:00	Start POOH with dummy hanger
09-mai-05	19:56:00	Start calibration check of separator differential recorders
09-mai-05	21:00:00	Finish calibration check

09-mai-05	21:30:00	Hanger at surface
09-mai-05	21:58:00	Broke out dummy hanger
09-mai-05	22:05:00	Laid out dummy hanger
10-mai-05	00:04:00	Lifted subsea reel to drill floor
10-mai-05	00:25:00	Lifted SSTT to drill floor
10-mai-05	00:51:00	Stabbed SSTT onto tubing
10-mai-05	01:10:00	Restarted scan lab with purge system activated
10-mai-05	01:30:00	Problem with power supply in lab. Rig electrician working on problem
10-mai-05	01:55:00	SSTT through rotary table
10-mai-05	02:30:00	Start function testing latch
10-mai-05	02:41:00	Finish function testing latch
10-mai-05	02:45:00	Start test on balance line
10-mai-05	02:59:00	Good test. Start test on control line
10-mai-05	03:10:00	Good test
10-mai-05	04:35:00	Start pressure testing string to 370 bar. Function tested chemical injection line on SSTT
10-mai-05	04:58:00	Inflow tested check valve on chemical injection line
10-mai-05	05:00:00	Closed SSTT
10-mai-05	05:02:00	Good test on string. Bled down pressure to 50 bar to inflow test SSTT
10-mai-05	05:11:00	Equalize pressure across SSTT to 370 bar and opened SSTT
10-mai-05	05:20:00	Continue RIH with landing string
10-mai-05	05:30:00	Problem with power supply fixed
10-mai-05	08:53:00	Pick up lower lubricator valve
10-mai-05	10:12:00	Pick up upper lubricator valve
10-mai-05	12:08:00	Pressure test lock line LSSLV to 275 bar
10-mai-05	12:14:00	Good test. Pressure test control line to 206 bar
10-mai-05	12:19:00	Good test. Pressure test lock line on USSLV to 275 bar
10-mai-05	12:27:00	Good test. Open USSLV. Pressure test string to 310 bar
10-mai-05	12:43:00	Good test. Close LSSLV. Inflow test LSSLV
10-mai-05	12:51:00	Good test. Equalize pressure across LSSLV to 385 bar. Release lock line pressure
10-mai-05	12:53:00	Close USSLV. Start inflow test on USSLV to 30 bar
10-mai-05	13:02:00	Good test.
10-mai-05	13:20:00	Pressure test chemical injection on LSSLV to 370 bar
10-mai-05	13:25:00	Good test. Bleed down pressure to 50 bar to inflow test check valve on chemical injection line
10-mai-05	13:29:00	Good test
10-mai-05	13:30:00	Bleed off pressure on string. Closed USSLV
10-mai-05	13:26:00	Start pressure USSLV to 300 bar from above.
10-mai-05	13:45:00	Good test. Release lock line pressure
10-mai-05	13:47:00	USSLV open. Rig down test line
10-mai-05	13:54:00	Run last joint of landing string
10-mai-05	14:00:00	Start rigging up flow head

10-mai-05	19:00:00	Start rigging up coflexip hoses to flow head
10-mai-05	20:30:00	Function test flow head wing valves and surface panels
10-mai-05	21:00:00	Start flushing surface lines
10-mai-05	21:05:00	Finish flushing
10-mai-05	21:07:00	Close kill valve
10-mai-05	21:14:00	Start pressure testing kill valve
10-mai-05	21:23:00	Good test
10-mai-05	21:28:00	Open kill valve
10-mai-05	21:30:00	Start pressure testing against choke, master and swab valves
10-mai-05	21:55:00	Good test
10-mai-05	22:00:00	Start pressure testing flow wing valve
10-mai-05	22:50:00	Close SSV
10-mai-05	23:05:00	Open flow wing and master valves on flow head
10-mai-05	23:06:00	Start pressure testing USSLV and SSV
10-mai-05	23:45:00	Good test. Close master valve. Bleed down pressure to 70 bar to inflow test master valve
11-mai-05	00:05:00	Good test. Open master valve. Close kill valve. Start pressure testing kill valve
11-mai-05	00:10:00	Good test. Bleed down pressure to 70 bar to inflow test kill valve
11-mai-05	00:25:00	Good test
11-mai-05	00:27:00	Open kill valve. Bleed off pressure
11-mai-05	00:32:00	Open SSV. Close choke
11-mai-05	01:08:00	Open choke
11-mai-05	01:25:00	Problem setting packer. Suspect SSTT hanging up in Hydril.
11-mai-05	03:51:00	Start setting packer
11-mai-05	03:55:00	Packer set at 3090m
11-mai-05	04:21:00	Close choke
11-mai-05	04:25:00	Start pressure testing annulus to 39 bar
11-mai-05	04:47:00	Good test. Bleed off pressure
11-mai-05	05:15:00	Function test PSD1 (button 3) on drill floor
11-mai-05	05:50:00	Start cycling OMNI to circulating position
11-mai-05	06:15:00	OMNI in circulating position
11-mai-05	06:22:00	Close wing valve on flow head
11-mai-05	06:25:00	Start circulating tubing to base oil
11-mai-05	07:03:00	Finish circulating
11-mai-05	07:05:00	Close kill wing valve
11-mai-05	07:25:00	Open flow wing valve on flow head
11-mai-05	07:30:00	Perform toolbox talk prior to perforating the well
11-mai-05	07:46:00	Start cycling OMNI to welltest position
11-mai-05	08:08:00	Start steam to heater
11-mai-05	08:13:00	Put compressors on load to port burner. Lit pilots and jets on burner
11-mai-05	08:24:00	Equalised pressure across kill wing valve to 110 bar
11-mai-05	08:27:00	Open kill wing valve
11-mai-05	08:28:00	Function test PSD1 (button 2) at choke manifold. Wing valve

		close very slowly
11-mai-05	08:38:00	Function test PSD1 (button 2) at choke manifold. Wing valve close very slowly
11-mai-05	08:40:00	Close kill valve
11-mai-05	08:41:00	Change out surface panel on rig floor
11-mai-05	09:00:00	Open kill valve
11-mai-05	09:05:00	Function test PSD1 (button 2) at choke manifold. Good test
11-mai-05	09:13:00	Function test PSD1 (button 3) on drill floor
11-mai-05	09:16:00	Function test PSD1 (button 5) at company mans office
11-mai-05	09:21:00	Function test PSD1 (button 4) at test separator
11-mai-05	09:27:00	Function test PSD1 in scan lab
11-mai-05	09:30:00	Wait on helicopter before perforating
11-mai-05	09:31:00	Put compressors on standby
11-mai-05	10:00:00	Put compressors on load to port burner. Light pilots and jets on burner
11-mai-05	10:05:00	Tank level = 2.8M3
11-mai-05	10:06:00	Pressure up tubing to 350 bar to fire guns
11-mai-05	10:08:00	Bleed off pressure to 0 bar
11-mai-05	10:12:00	Bleed down kill line pressure to 30 bar
11-mai-05	10:13:00	Indication at surface that guns fired
11-mai-05	10:13:00	**************************************
11-mai-05	10:13:00	******* INITIAL FLOW *******
11-mai-05	10:13:00	**************************************
11-mai-05	10:14:00	Open well on 12/64ths adjustable choke flowing through heater to calibration tank
11-mai-05	10:15:00	Increase choke to 16/64ths adjustable
11-mai-05	10:16:00	Increase choke to 20/64ths adjustable
11-mai-05	10:17:00	Increase choke to 24/64ths adjustable
11-mai-05	10:19:00	Start injecting MEG at SSLV
11-mai-05	10:20:00	Start injecting methanol at choke manifold
11-mai-05	10:21:00	Start injecting MEG at SSTT
11-mai-05	10:28:00	Increase choke to 26/64ths adjustable
11-mai-05	10:32:00	Increase choke to 28/64ths adjustable. Base oil at surface. Fluid returns = 1 M3
11-mai-05	10:33:00	Divert flow through test separator flowing through 2"" oil meter
11-mai-05	10:35:00	Bypass tank. Divert flow to port burner
11-mai-05	10:48:00	Increase choke to 30/64ths adjustable
11-mai-05	10:50:00	Divert flow to calibration tank
11-mai-05	11:01:00	Bypass tank. Divert flow to port burner
11-mai-05	11:02:00	Increase choke to 32/64ths adjustable
11-mai-05	11:05:00	Start dumping water from separator to calibration tank
11-mai-05	11:06:00	Stop dumping water
11-mai-05	11:07:00	Start dumping water from separator to calibration tank
11-mai-05	11:13:00	Stop dumping water
11-mai-05	11:19:00	Divert flow to cal. tank. Bypass sep.

11-mai-05	11:29:00	Divert flow trough sep.
11-mai-05	11:33:00	Increase choke to 34/64ths adjustable
11-mai-05	11:34:00	Start dumping water from separator to calibration tank
11-mai-05	11:37:00	BS&W = 30 % Base oil
11-mai-05	11:37:00	Co2 = 4%
11-mai-05	11:39:00	Increase choke to 38/64ths adjustable
11-mai-05	11:41:00	Increase choke to 42/64ths adjustable
11-mai-05	11:41:00	BS&W = 10 % Base oil
11-mai-05	11:42:00	H2S = 0 CO2 = 4.2%
11-mai-05	11:43:00	Stop dumping water
11-mai-05	11:44:00	Increase choke to 46/64ths adjustable
11-mai-05	11:46:00	Increase choke to 50/64ths adjustable
11-mai-05	11:49:00	Increase choke to 54/64ths adjustable
11-mai-05	11:52:00	Increase choke to 58/64ths adjustable
11-mai-05	12:00:00	BS&W = 2 % Water
11-mai-05	12:00:00	H2S = 0 CO2 = 5.0%
11-mai-05	12:00:00	Gas SG = 0.67 Oil SG 0.846 @ 16.3 degC
11-mai-05	12:10:00	H2S = 0 CO2 = 5.0%
11-mai-05	12:12:00	Gas SG = 0.67 Oil SG = 0.842 @ 19.6 degC
11-mai-05	12:15:00	BS&W = 1 % Water
11-mai-05	12:20:00	H2S = 0 CO2 = 5.0%
11-mai-05	12:24:00	Start shrinkage 15 DegC
11-mai-05	12:25:00	Gas SG = 0.67 Oil SG 0.842 @ 20.6 degC
11-mai-05	12:31:00	Close LPR-N
11-mai-05	12:34:00	Close Choke
11-mai-05	12:39:00	Stop Chemical inj. SSLV SSTT and at Choke Manifold
11-mai-05	12:40:00	Close burner nozzles
11-mai-05	21:00:00	Held toolbox talk on drill floor
11-mai-05	21:12:00	Start steam to heater
11-mai-05	21:20:00	Compressors on load to burner
11-mai-05	21:27:00	Start injecting MEG at SSTT and LSSV
11-mai-05	21:27:00	**
11-mai-05	21:30:00	***** CLEANUP AND MAIN FLOW *****
11-mai-05	21:27:00	**
11-mai-05	21:31:00	Open LPR-N
11-mai-05	21:42:00	Open well on 12/64ths adjustable choke flowing through heater and separator to port burner
11-mai-05	21:46:00	Increase choke to 20/64ths adjustable
11-mai-05	21:47:00	Increase choke to 24/64ths adjustable
11-mai-05	21:50:00	Increase choke to 28/64ths adjustable
11-mai-05	21:55:00	Increase choke to 32/64ths adjustable
11-mai-05	21:57:00	Increase choke to 36/64ths adjustable
11-mai-05	22:00:00	BS&W = 0.2% water
11-mai-05	22:15:00	BS&W = 0.2% water. Trace of solids. H2S = 0 ppm
11-mai-05	22:30:00	H2S = 0 ppm

11-mai-05	22:45:00	BS&W = 0.1% water
11-mai-05	23:00:00	BS&W = 0.4% water
11-mai-05	23:00:00	Oil SG = 0.845 @ 15 degC
11-mai-05	23:15:00	BS&W = 0.25% water
11-mai-05	23:43:00	Divert flow through 36/64ths fixed choke
11-mai-05	23:50:00	Divert flow through 36/64ths adjustable choke
12-mai-05	00:15:00	Divert flow through 32/64ths fixed choke
12-mai-05	00:19:00	Stop injecting MEG at SSTT and LSSV
12-mai-05	00:26:00	Insert 2.0"" orifice plate
12-mai-05	00:30:00	BS&W = trace of water. Raise 2.0"" orifice plate
12-mai-05	00:35:00	Insert 1.625"" orifice plate. Gas rates are reported in M3/Day. Gas Volumes are reported in M3
12-mai-05	01:00:00	BS&W = 0% water
12-mai-05	01:00:00	Gas SG= 0.724 Oil SG= 0.852 H2S= 1.5 ppm CO2= 5.8 %
12-mai-05	01:15:00	BS&W = 0% water. H2S = 1.5 ppm. CO2 = 5.8%
12-mai-05	01:30:00	BS&W = 0% water
12-mai-05	01:30:00	Gas SG= 0.724 Oil SG= 0.852 H2S= 1.5 ppm CO2= 5.8 %
12-mai-05	02:00:00	BS&W = 0% water
12-mai-05	02:00:00	Gas SG= 0.728 Oil SG= 0.852 H2S= 2 ppm CO2= 5.5 %
12-mai-05	02:30:00	Gas SG= 0.728 Oil SG= 0.852 H2S= 2 ppm CO2= 5.5 %
12-mai-05	02:30:00	BS&W = 0% water
12-mai-05	02:40:00	Start Meter factor . Initial Tank= 4.3 m3 Initial Scan Pulses = 2154420
12-mai-05	02:55:00	Stop Meter factor. Final Tank= 9.6 m3 Final Scan Pulses= 2235728. Tank temp 22.7 DegC
12-mai-05	02:55:00	Combined Meter and Shrinkage factor = 0.925
12-mai-05	03:00:00	BS&W = 0% water
12-mai-05	03:00:00	Gas SG= 0.728 Oil SG= 0.852 H2S= 2 ppm CO2= 5.5 %
12-mai-05	03:13:00	Start Shrinkage 99.5% @ 24 DegC
12-mai-05	03:30:00	Gas SG= 0.728 Oil SG= 0.852 H2S= 2 ppm CO2= 5.5 %
12-mai-05	03:30:00	Petrotech start PVT 1
12-mai-05	03:55:00	Start pump out cal. tank to burner
12-mai-05	03:56:00	Divert sep.oil from burner to cal. tank
12-mai-05	04:00:00	BS&W = 0% water
12-mai-05	04:00:00	Gas SG= 0.728 Oil SG= 0.850 H2S= 2 ppm CO2= 5.5 %
12-mai-05	04:00:00	Petrotech stop PVT 1
12-mai-05	04:01:00	Stop pump out cal. tank to burner.
12-mai-05	04:01:00	Divert sep.oil from cal. tank to burner
12-mai-05	05:00:00	BS&W = 0% water
12-mai-05	05:00:00	Gas SG= 0.728 Oil SG= 0.850 H2S= 2 ppm CO2= 5.5 %
12-mai-05	05:05:00	Start Meter factor . Initial Tank= 1.95 m3 Initial Scan Pulses= 2943906
12-mai-05	05:24:00	Stop Meter factor. Final Tank= 8.80 m3 Final Scan Pulses= 3047673. Tank temp 30 DegC
12-mai-05	05:24:00	Combined Meter and Shrinkage factor = 0.937

12-mai-05	05:30:00	Finish Shrinkage 96% @ 12DegC
12-mai-05	06:00:00	BS&W = 0% water
12-mai-05	06:00:00	Gas SG= 0.729 Oil SG= 0.850 H2S= 2 ppm CO2= 5.5 %
12-mai-05	06:24:00	Start pump out cal. tank to burner
12-mai-05	06:25:00	Divert sep.oil from burner to cal. tank
12-mai-05	06:30:00	Stop pump out cal. tank to burner.
12-mai-05	06:30:00	Divert sep.oil from cal. tank to burner
12-mai-05	07:00:00	Gas SG= 0.729 Oil SG= 0.850 H2S= 2 ppm CO2= 5.2 %
12-mai-05	07:00:00	BS&W = 0% water
12-mai-05	07:30:00	BS&W = 0% water
12-mai-05	08:00:00	BS&W = 0% water
12-mai-05	08:00:00	Gas SG= 0.728 Oil SG= 0.852 H2S= 2.8 ppm CO2= 5.0 %
12-mai-05	08:30:00	BS&W = 0% water
12-mai-05	09:00:00	BS&W = 0% water
12-mai-05	09:00:00	Gas SG= 0.728 Oil SG= 0.852 H2S= 2.0 ppm CO2= 5.5 %
12-mai-05	09:30:00	BS&W = 0% water
12-mai-05	09:40:00	Start Shrinkage 100% @ 26 DegC
12-mai-05	10:00:00	BS&W = 0% water
12-mai-05	10:00:00	Start Meter factor . Initial Tank= 1.70 m3 Initial Scan Pulses= 4553286
12-mai-05	10:28:00	Stop Meter factor. Final Tank= 11.6 m3 Final Scan Pulses= 4706041. Tank temp 32.6 DegC
12-mai-05	10:28:00	Combined Meter and Shrinkage factor = 0.919
12-mai-05	10:30:00	BS&W = 0% water
12-mai-05	10:30:00	Gas SG= 0.727 Oil SG= 0.852 H2S= 2.0 ppm CO2= 5.0 %
12-mai-05	11:00:00	BS&W = 0% water
12-mai-05	11:00:00	Gas SG= 0.730 Oil SG= 0.852 H2S= 2.0 ppm CO2= 5.0 %
12-mai-05	11:30:00	BS&W = 0% water
12-mai-05	11:43:00	Finish Shrinkage 96% @ 18DegC
12-mai-05	11:39:00	Start fill barrel with sample oil
12-mai-05	12:00:00	BS&W = 0% water
12-mai-05	12:00:00	Gas SG= 0.730 Oil SG= 0.849 H2S= 2.2 ppm CO2= 5.0 %
12-mai-05	12:09:00	Stop fill barrel with sample oil
12-mai-05	12:10:00	Start pump out cal. tank to burner
12-mai-05	12:11:00	Divert sep.oil from burner to cal. tank
12-mai-05	12:16:00	Stop pump out cal. tank to burner. Tank level 5.05 m3
12-mai-05	12:16:00	Divert sep.oil from cal. tank to burner
12-mai-05	12:22:00	Petrotech start PVT samples
12-mai-05	12:45:00	BS&W = 0% water
12-mai-05	13:30:00	BS&W = 0% water
12-mai-05	14:00:00	BS&W = 0% water
12-mai-05	14:00:00	Gas SG= 0.730 Oil SG= 0.853 H2S= 2.4 ppm CO2= 5.0 %
12-mai-05	14:30:00	BS&W = 0% water
12-mai-05	15:00:00	BS&W = 0% water
12-mai-05	15:00:00	Gas SG= 0.734 Oil SG= 0.846 H2S= 2.3 ppm CO2= 5.2 %

12-mai-05	15:23:00	Start Shrinkage 100% @ 29 DegC
12-mai-05	15:30:00	BS&W = 0% water
12-mai-05	16:00:00	BS&W = 0% water
12-mai-05	16:30:00	BS&W = 0% water
12-mai-05	17:00:00	BS&W = 0% water
12-mai-05	17:05:00	Finish Shrinkage 96.5% @ 19DegC
12-mai-05	17:30:00	BS&W = 0% water
12-mai-05	18:00:00	BS&W = 0% water
12-mai-05	18:15:00	Petrotech finish with PVT samples
12-mai-05	18:19:00	Start pump out cal. tank to burner
12-mai-05	18:20:00	Divert sep.oil from burner to cal. tank
12-mai-05	18:20:00	Gas SG= 0.738 Oil SG= 0.847 H2S= 2.5 ppm CO2= 5.0 %
12-mai-05	18:25:00	Stop pump out cal. tank to burner. Tank level 0 m3
12-mai-05	18:25:00	Divert sep.oil from cal. tank to burner
12-mai-05	18:30:00	BS&W = 0% water
12-mai-05	19:00:00	BS&W = 0% water
12-mai-05	19:00:00	Gas SG= 0.728 Oil SG= 0.847 H2S= 2.5 ppm CO2= 5.0 %
12-mai-05	19:30:00	BS&W = 0% water
12-mai-05	19:35:00	Start Meter factor . Initial Tank= 2.05 m3 Initial Scan Pulses= 7685409
12-mai-05	19:51:00	Stop Meter factor. Final Tank= 8.1 m3 Final Scan Pulses= 7772826. Tank temp 34.1 DegC
12-mai-05	19:51:00	Combined Meter and Shrinkage factor = 0.982
12-mai-05	20:00:00	BS&W = 0% water
12-mai-05	20:00:00	Gas SG= 0.730 Oil SG= 0.846 H2S= 2.2 ppm CO2= 5.3 %
12-mai-05	20:34:00	Start pump out cal. tank to burner
12-mai-05	20:34:00	Divert sep.oil from burner to cal. tank
12-mai-05	20:40:00	Stop pump out cal. tank to burner. Tank level 0 m3
12-mai-05	20:40:00	Power supply to ignition system failed due to deluge water
12-mai-05	20:40:00	Bled down barton manifold on separator
12-mai-05	20:53:00	Rig electrician repaired ignition cable
12-mai-05	20:54:00	Divert sep.oil from cal. tank to burner
12-mai-05	21:00:00	BS&W = 0% water
12-mai-05	21:00:00	Gas SG= 0.730 Oil SG= 0.851 H2S= 2.5 ppm CO2= 5.2 %
12-mai-05	21:20:00	Start injecting MEG at SSTT. Turn PSD low low override on
12-mai-05	21:30:00	BS&W = 0% water
12-mai-05	21:40:00	Raise 1.625"" orifice plate. Final flowing wellhead pressure = 93 bar
12-mai-05	21:41:00	Close LPR-N
12-mai-05	21:41:00	********************************
12-mai-05	21:41:00	***** MAIN BUILD-UP *****
12-mai-05	21:41:00	********************************
12-mai-05	21:43:00	Close choke
12-mai-05	21:45:00	Close burner heads
12-mai-05	21:52:00	Stop injecting MEG at SSTT

12-mai-05	22:57:00	Close in annulus at autochoke on drill floor
13-mai-05	01:34:00	IA real-time data not sending. Data queued at remote PC.
13-mai-05	02:23:00	Start sending IA real-time data.
13-mai-05	04:00:00	Stopped logging data in order to recalculate data with no correction factors applied
13-mai-05	04:28:00	Restarted scan system. Restarted IA data exchange
13-mai-05	13:10:00	Bleed down separator to tank. Flush meters
14-mai-05	09:20:00	Start Methanol injection upstream Choke manifold
14-mai-05	09:28:00	Open Choke. Bleed off to zero
14-mai-05	09:42:00	Stop Methanol injection upstream Choke manifold
14-mai-05	10:02:00	Close choke
14-mai-05	10:02:00	Close burner heads
14-mai-05	10:07:00	Close Lower Master valve
14-mai-05	10:14:00	Open burner head
14-mai-05	10:14:00	BJ start pump base oil
14-mai-05	10:18:00	Open choke
14-mai-05	10:21:00	BJ stop pumping
14-mai-05	10:22:00	Close choke
14-mai-05	10:22:00	Close burner heads
14-mai-05	10:24:00	Divert flow to cal. tank
14-mai-05	10:25:00	BJ start pump base oil
14-mai-05	10:25:00	Open choke
14-mai-05	10:32:00	BJ stop pumping
14-mai-05	10:32:00	Close choke
14-mai-05	11:04:00	Open choke
14-mai-05	11:04:00	BJ start pump base oil / sea water to cal. tank
14-mai-05	11:25:00	BJ stop pumping
14-mai-05	11:25:00	Close choke
14-mai-05	11:26:00	Close wing valve on flow head
14-mai-05	11:28:00	Open Lower Master
14-mai-05	11:28:00	Start fill string with base oil/ brine
14-mai-05	11:40:00	Open wing valve
14-mai-05	11:57:00	Open Tester Valve
14-mai-05	11:58:00	Start pump to minifrac and kill well
14-mai-05	12:16:00	********************************
14-mai-05	12:16:00	******** MINIFRAC *******
14-mai-05	12:16:00	********************************
14-mai-05	12:16:00	Start minifrac cycle 1
14-mai-05	13:14:00	Stop pumping WHP starts to drop
14-mai-05	13:23:00	Pressure starts to stabilize below 2 bar
14-mai-05	13:35:00	Start minifrac Cycle 2
14-mai-05	15:05:00	Stop pumping WHP starts to drop
14-mai-05	15:14:00	Pressure starts to stabilize around 2 bar
14-mai-05	15:21:00	Start minifrac cycle 3
14-mai-05	15:25:00	Stop pumping WHP starts to drop

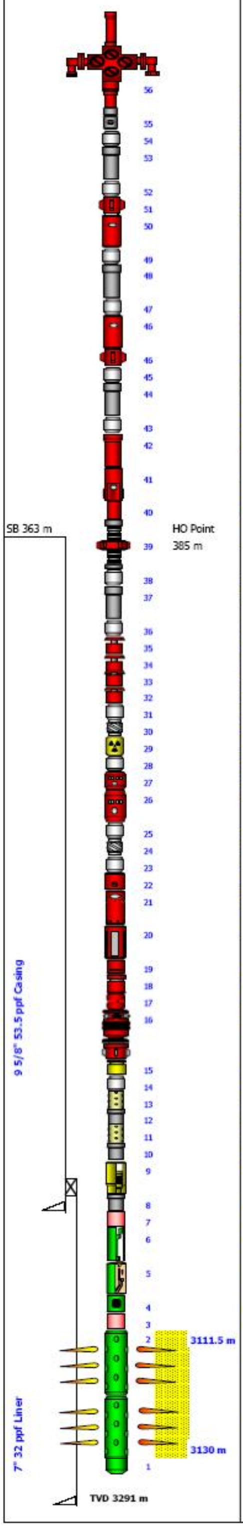
14-mai-05	15:34:00	Pressure starts to stabilize around 2 bar
14-mai-05	15:37:00	Start minifrac cycle 3
14-mai-05	15:59:00	Stop pumping WHP starts to drop
14-mai-05	16:11:00	Pressure starts to stabilize around 2 bar
14-mai-05	16:17:00	Start minifrac cycle 3
14-mai-05	16:40:00	Stop pumping WHP starts to drop
14-mai-05	16:51:00	Pressure starts to stabilize around 2 bar
14-mai-05	17:06:00	Start minifrac cycle 4
14-mai-05	17:11:00	Stop pumping WHP starts to drop
14-mai-05	17:20:00	Pressure starts to stabilize around 2 bar
14-mai-05	17:29:00	Close kill valve
14-mai-05	17:30:00	Open choke. Line up to PWS calibration tank to monitor well
14-mai-05	17:48:00	Close choke
14-mai-05	17:50:00	Pump up annulus to shear RD-valve
14-mai-05	17:54:00	Shear RD-valve
14-mai-05	18:13:00	Start circulating long way
14-mai-05	18:35:00	Finish circulating
14-mai-05	18:36:00	Start 15 min flow check
14-mai-05	19:15:00	Attempt to unseat Champ SSTT hang up in rig BOP. Reposition rig using anchors
14-mai-05	22:30:00	Packer unseated
14-mai-05	22:42:00	Start bullheading kill fluid into formation
14-mai-05	23:45:00	Commence circulate down tubing 1.5 times well volume
15-mai-05	03:30:00	Finish circulating
15-mai-05	04:00:00	Commence rigging down surface tree
15-mai-05	08:05:00	Tool box talk on rig floor prior to pull test string
15-mai-05	08:10:00	Start pull landing string
15-mai-05	09:00:00	Upper SSLV OOH and laid out
15-mai-05	09:30:00	Lower SSLV OOH and laid out
15-mai-05	13:05:00	SSTT OOH
15-mai-05	13:30:00	SSTT laid out

12.9 Test string diagram

HALLIBURTON

Astero - Downhole Test String Diagram - DST#1

Prepared For:	Nick Jensen Visser	Company:	Hydro
Date:	1-May-05	New Well	Y
Field Name	Aster0	Well No.	35/11-13
Rig Name	Deepsea Trym	Revision:	1
BHP (est)	324 bar	BHT (Max)	122 C
Landing Tubing Size & Thread Type:	4 1/2" 24 ppf L80 PH4	Main Tubing Size & Thread Type:	3 1/2" 12.95 #/ft KO-110SS PH6
Casing Size:	9 5/8"	Weight:	53.5
Grade:			
Liner Size:	7"	Weight:	32
Grade:			



No.	Description	Co.	Top Connection	Lower Connection	OD (in)	ID (in)	Length (m)	Depth (m)
56	Surface Test Tree	PWS	5 3/4" Acme Box	5 3/4" Acme Pin	3.06	n/a		
55	LMW	PWS	5 3/4" Acme Box	5" 4th 2G RH Pin	3.06	n/a		-4.84
54	Crossover	Odfjell	5" 4th 2G RH Box	4 1/2" PH4 Pin	8.25	3.38	0.36	-4.84
53	4 1/2" 24 ppf Test Tubing	Odfjell	4 1/2" PH4 Box	4 1/2" PH4 Pin	4.50	3.38	35.31	-4.48
52	Crossover	Odfjell	4 1/2" PH4 Box	4 1/2" 4 Acme Pin	6.25	3.63	0.48	30.83
51	Centraliser	PWS	4 1/2" 4 Acme Box	4 1/2" 4 Acme Pin	16.00	3.00	1.30	31.31
50	Upper Lubricator Valve	PWS	4 1/2" 4 Acme Box	4 1/2" 4 Acme Pin	10.75	3.63	1.82	32.61
49	Crossover	Odfjell	4 1/2" 4 Acme Box	4 1/2" PH4 Pin	6.25	3.63	0.76	34.43
48	4 1/2" 24 ppf Test Tubing	Odfjell	4 1/2" PH4 Box	4 1/2" PH4 Pin	4.50	3.38	2.98	35.19
47	Crossover	Odfjell	4 1/2" PH4 Box	4 1/2" 4 Acme Pin	6.25	3.00	0.56	38.17
46	Lower Lubricator Valve	PWS	4 1/2" 4 Acme Box	4 1/2" 4 Acme Pin	10.75	3.63	1.82	38.73
46	Centraliser	PWS	4 1/2" 4 Acme Box	4 1/2" 4 Acme Pin	16.00	3.00	1.40	40.55
45	Crossover	Odfjell	4 1/2" 4 Acme Box	4 1/2" PH4 Pin	6.25	3.00	0.76	41.95
44	4 1/2" 24 ppf Test Tubing	Odfjell	4 1/2" PH4 Box	4 1/2" PH4 Pin	4.50	3.38	335.16	42.71
43	Cross Over	Odfjell	4 1/2" PH4 Box	4 1/2" 4 Acme Pin	6.25	3.00	0.57	377.87
42	Shearable Handling Sub	PWS	4 1/2" 4 Acme Box	4 1/2" 4 Acme Pin	4.90	3.00	1.54	378.44
			5" 563 Hydr Box					
41	Sub Surface Test Tree	PWS	4 1/2" 4 Acme Box	4 1/2" 4 Acme Pin	13.00	3.00	1.72	379.98
40	Slick Joint	PWS	4 1/2" 4 Acme Box	4 1/2" 4 Acme Pin	5.00	3.00	2.04	381.70
39	Adjustable Mandrel	PWS	4 1/2" 4 Acme Box	4 1/2" 4 Acme Pin	5.00	3.00	1.63	383.74
38	Crossover	Odfjell	4 1/2" 4 Acme Box	3 1/2" 533 Hydr Pin	6.25	2.25	0.81	385.37
37	3 1/2" 12.95 ppf Test Tubing	Odfjell	3 1/2" 533 Hydr Box	3 1/2" 533 Hydr Pin	3.50	2.75	2,482.32	386.18
36	Crossover	Odfjell	3 1/2" 533 Hydr Box	3 7/8" CAS Pin	4.29	2.75	0.73	2,868.50
35	Slip Joint (full open)	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	6.10	2,869.23
34	Slip Joint (full open)	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	6.10	2,875.33
33	Slip Joint (full closed)	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	4.58	2,881.43
32	Slip Joint (full closed)	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	4.58	2,886.01
31	Crossover	Odfjell	3 1/2" PH6 Box	3 1/2" PH6 Pin	5.00	2.25	0.53	2,890.59
30	4 3/4" Drill Collars	Odfjell	3 1/2" PH6 Box	3 1/2" PH6 Pin	4.75	2.25	167.29	2,891.12
29	RA Marker Sub	Halliburton	3 1/2" PH6 Box	3 1/2" PH6 Pin	4.75	2.25	0.30	3,058.41
28	Crossover	Halliburton	3 1/2" PH6 Box	3-7/8" CAS Pin	5.00	2.25	0.38	3,058.71
27	RD Circulating Valve	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	1.09	3,059.09
26	OMNI (reversing) Valve	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	6.52	3,060.18
25	Crossover	Odfjell	3 7/8" CAS Box	3 1/2" PH6 Pin	5.00	2.25	0.38	3,066.70
24	4 3/4" Drill Collar Joint	Odfjell	3 1/2" PH6 Box	3 1/2" PH6 Pin	4.75	2.25	9.35	3,067.08
23	Crossover	Odfjell	3 1/2" PH6 Box	3 7/8" CAS Pin	5.00	2.25	0.39	3,076.43
22	Sliding Sleeve Drain Valve	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	1.05	3,076.82
21	LPR-N Tester Valve	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	4.83	3,077.87
20	Instream Gauge Carrier	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	2.35	3,082.70
19	Tubing String Testing Valve	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	1.22	3,085.05
18	Big John Jar	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	1.59	3,086.27
17	Safety Joint	Halliburton	3 7/8" CAS Box	3 7/8" CAS Pin	5.03	2.25	1.04	3,087.86
16	7" Champ Packer (mech set)	Halliburton	3 7/8" CAS Box	3 1/2" IF Pin	5.70	2.25	1.70	3,088.90
	Packer Rubber						1.00	3,090.60
15	5" Vetrical Shock Absorber	Halliburton	3 1/2" IF Box	3 1/2" IF Pin	5.00	2.25	1.49	3,091.60
14	Crossover	Halliburton	3 1/2" IF Box	2 7/8" EUE Pin	5.00	2.25	0.34	3,093.09
13	2 7/8" Perforated Pup	Halliburton	2 7/8" EUE Box	2 7/8" EUE Pin	3.50	2.44	0.22	3,093.43
12	2 7/8" Tubing	Halliburton	2 7/8" EUE Box	2 7/8" EUE Pin	3.67	2.44	3.09	3,093.65
11	2 7/8" Perforated Pup	Halliburton	2 7/8" EUE Box	2 7/8" EUE Pin	3.50	2.44	0.22	3,096.74
10	2 7/8" Tubing	Halliburton	2 7/8" EUE Box	2 7/8" EUE Pin	3.67	2.44	3.07	3,096.96
9	2 7/8" MTR 2,125 Latch	Halliburton	2 7/8" EUE Box	2 7/8" EUE Pin	3.38	2.13	0.52	3,100.03
8	2 7/8" Tubing	Halliburton	2 7/8" EUE Box	2 7/8" EUE Pin	3.67	2.44	6.16	3,100.55
7	Collar	Halliburton	2 7/8" EUE Box	2 7/8" EUE Box	3.67	n/a	0.13	3,106.71
6	Time delay Firing Head	Halliburton	2 7/8" EUE Pin	2 7/8" Acme Box	3.38	n/a	0.76	3,106.84
5	Multi Action Firing Head	Halliburton	2 7/8" Acme Pin	2 7/8" Acme Box	3.38	n/a	1.04	3,107.60
4	3 3/8" DID Safety Sub	Halliburton	2 7/8" Acme Pin	2 7/8" Acme Box	3.38	n/a	0.93	3,108.64
3	Collar	Halliburton	2 7/8" Acme Pin	4 5/8" Acme Box	4.63	n/a	0.13	3,109.57
	Safety Spacer	Halliburton			4.63	n/a	1.80	3,109.70
2	4 5/8" 12 spf 60 deg HMX Millenium Charges	Halliburton	4 5/8" Acme Pin	4 5/8" Acme Box	4.63	n/a	18.50	3,111.50
1	4 5/8" Bull Plug	Halliburton	4 5/8" Acme Pin		4.63	n/a	0.06	3,130.00
	Bottom of BHA							

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