4.10.4 RFT Measurements

Schlumberger's repeat formation tester was run in the Triassic to determine formation pressures, identify fluid contacts and where possible obtain original reservoir fluids.

In run 5 A, which was carried out over the reservoir, Triassic Unit 6, a total of 19 pressure recordings and 6 segregated samples were taken. Table 4.20 is a listing of recorded pressures (mud and formation) and calculated permeabilities. The correction applied is approximately 16 psi throughout.

A plot of corrected formation pressure versus depth, fig. 4.8, for the interval 2431.5 to 2762.5 m RKB logged shows that in the oil zone the points plot in a fairly straight line having a gradient of 0.97 psi/m. The bottom points give a gradient of 1.41 psi/m indicating water. The oil water contact is believed to be at 2586 mRKB as shown by the intersection of the two gradients.

In run 7 g which was carried out in the Triassic sequences Unit 5, 4, 3 and 2, 9 pressure recordings were attempted of which 4 were tight. Table 4.21 shows a listing of the pressures, and permeabilities.

Temperature corrections of 15 psi were applied. Fig. 4.9 is a plot of pressures versus depth for the interval 2893.0 - 3491.5 m RKB logged. A water gradient of 1.42 psi/m is obtained.

At the oil water contact the RFT-measurements gave a formation pressure of 5613 psig. This corresponds to a gradient to surface of 2.2 psi/m, which shows the reservoir to be overpressured.

The permeability estimated from the RFT-measurements in Unit 6 have a range of 3 to 1800 mD with a geometric average of 43 mD.

Six segregated samples were taken in the reservoir 5. Three of the samples were in the oil zone and the rest in the water zone. In each case the lower 2 3/4 gallon chamber was bled off at the well site and the top 1 gallon chamber was shipped to Core Lab. Table 4.22 lists the chamber pressures and the fluids recovered.

The water samples recovered are not believed to be representative for the Triassic formation water probably due to contamination by mud-filtrate. For a valid salinity of the formation value, refer to DST 1 section 4.10.5.

Table 4.20: Well 34/4-4, RFT measurements.

Run 5a-f: November 12, 1982, BHT = 190^{O}F

	DEPTH mRKB	MUD PRESSURE TEMP. CORR. psig	FORMATION PRESSURE TEMP. CORR psig	PERMEABILITY mD	REMARKS
5b	2431.5$^{(S2)}$	6018	5482	80	Segregated sample
5a	2432.0	6016	5477	25	
5a	2454.0	6069	5501	100	
5a	2456.0	6074	5503	50	
5a	2485.0	6155	5536	40	
5c	2489.0$^{(S3)}$	6156	5534	50	Segregated sample
5a	2510.0	6205	5556	25	
5a	2525.0	6247	5571	400	
5a	2547.0	6297	5592	10	
5e	2573.0$^{(S5)}$	6354	5611	250	Segregated sample
5a	2575.0	6361	5617	1800	
5a	2585.0	6389	5629	15	
5a	2593.0	6405	5638	10	
5a	2599.5	6416	5656	-	Poor seal
5a	2600.0	6429	5668	5	
5a	2600.0	6421	5656	40	
5d	2606.5$^{(S4)}$	6437	5656	120	Segregated sample
5a	2614.5	6459	5670	120	
5a	2630.0	6497	5693	3	
5f	2643.5$^{(S6)}$	6524	5707	30	Segregated sample
5a	2643.5	6527	5710	12	
5a	2664.0	6575	5739	60	
5a	2715.0$^{(S1)}$	6699	5810	500	Segregated sample
5a	2716.0	6707	5818	-	Plugged
5a	2762.5	6809	5873	200	

During Run's 5a to 5f, six segregated samples (S1 to S6) were recovered from the Triassic, three samples in the oil zone and three samples in the water zone.

Table 4.21: Well 34/4-4, RFT-measurements

Run 7g: December 8, 1982, BHT = 220^{o}F

DEPTH mRKB	MUD PRESSURE TEMP. CORR. psig	FORMATION PRESSURE TEMP. CORR. psig	PERMABILITY mD	REMARKS
2893.0	6735	-	-	Tight
2893.5	6737	-	-	Tight
2984.0	6948	6213	5	
3081.5	7163	6352	2	
3159.0	7350	6464	2	
3222.5	7494	6568	-	Low permeability
3335.0	7745	-	-	Tight
3408.0	7915	6815	40	
3491.5	8101	-	-	Tight

No segregated formation fluid samples were taken in Run 7g.

Table 4.22: Well 34/4-4, RFT-samples

RUN NO.	SAMPLE NO.	DEPTH mRKB	BOTTOM CHAMBER OPENING PRESSURE psig	BOTTOM CHAMBER RECOVERY	TOP CHAMBER* PRESSURE psig
5b	S2	2431.5	1400	8000 cc oil 30 cuft gas	1400
5c	S3	2489.0	0	7000 cc filtrate	1200
5c	S5	2573.0	200	Filtrate mixed with oil	1000
5d	S4	2606.5	200	Filtrate	400
5f	S6	2643.5	0	Filtrate	50
5a	S1	2715.0	0	9500 cc filtrate and water	300

*This chamber was left sealed and retained for PVT-analysis.

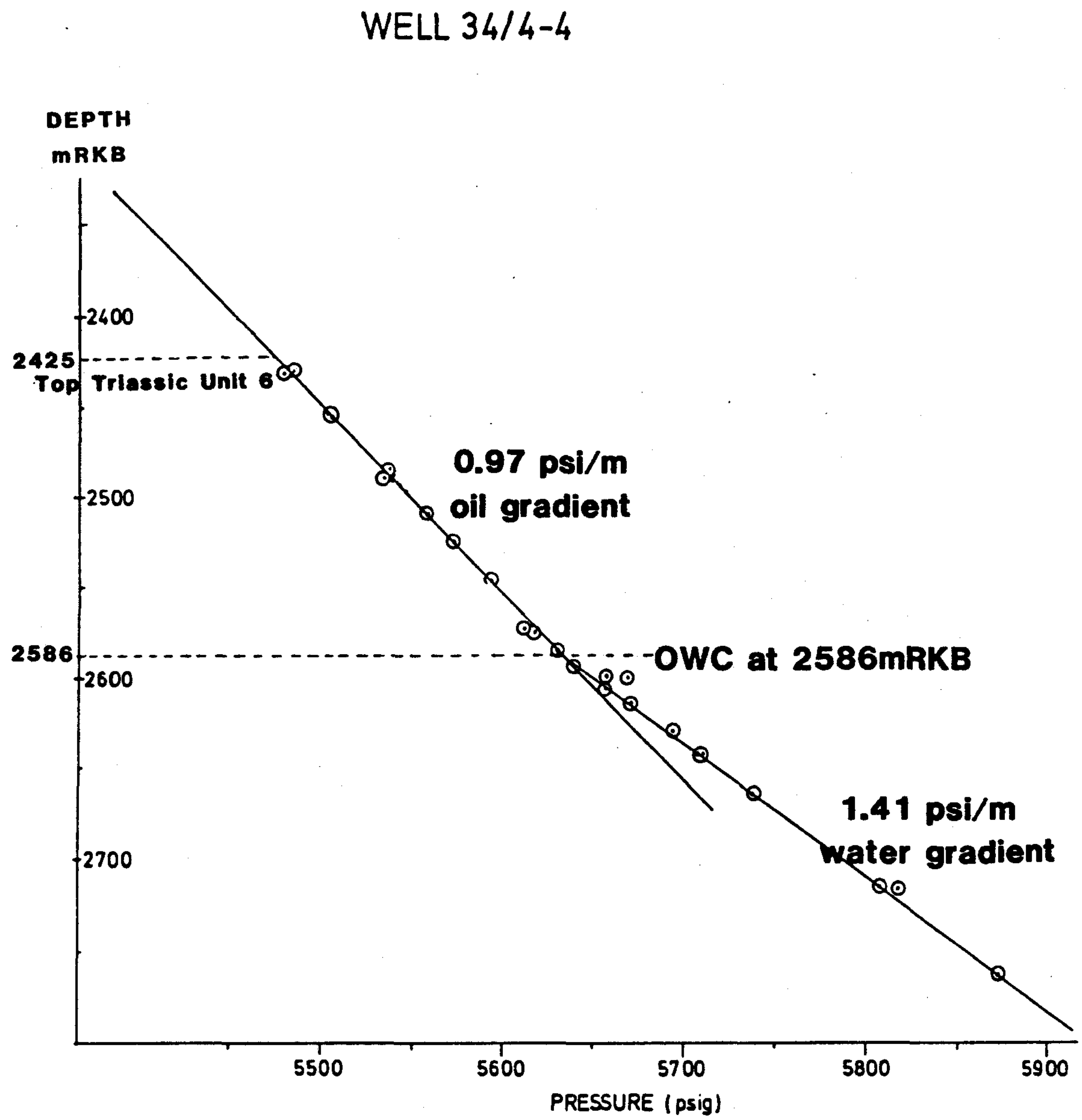


Fig 4.9 RFT-Pressure versus Depth crossplot (2431.5-2762.5 mRKB logged)

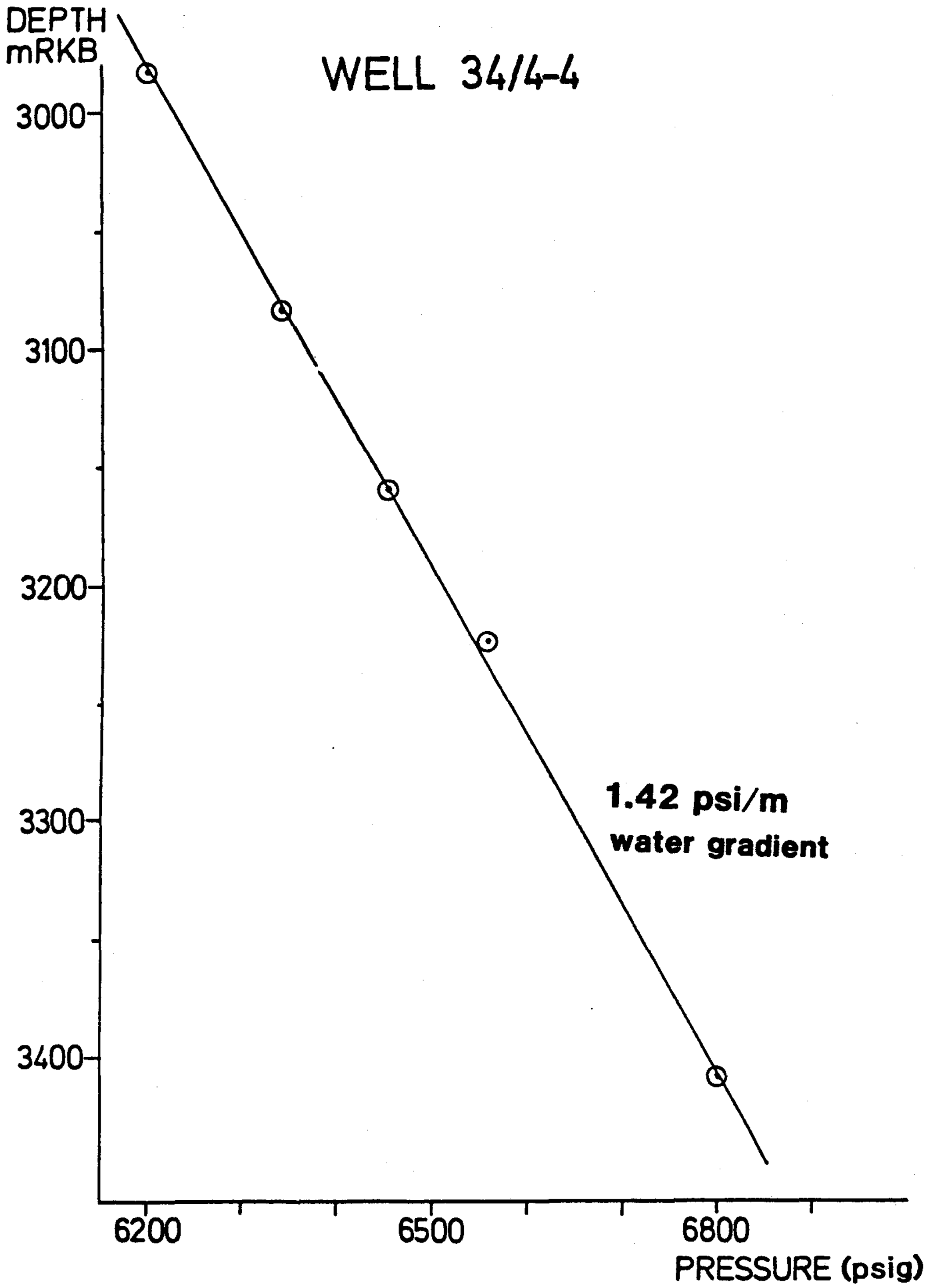


Fig 4.10 RFT - Pressure versus depth
(2893.0 - 3491.5 mRKB logged)

4.10.5 Drill Stem Test

The drill stem testing of the well 34/4-4 was carried on in the period from the 10 December '82 to the 25 January '83, and consisted of three oil tests and one water test.

A summary of the main data from the four tests are given in table 4.23.

Table 4.23: Well 34/4-4, Main results from Drill Stem Tests

	DST 1	DST 2	DST 3	DST 4
Perforated Interval, m RKB logged m RKB drilled	2618.0-2626.0 2627.5-2635.5	2572.5-2577.5 2579.5-2584.5	2512.8-2515.8 2519.3-2522.3	2429.0-2437.0 2433.5-2441.5
Remarks	Water zone	Near OWC	Moderate reservoir sand	Very good reservoir sand
Log porosity, %	21	25	19	27
Water Saturation, %	100	44	55	13
Flow Rate, bbl/d	525	2900	340*	11000
Choke Size, in	32/64	26/64	4/64 - 16/64	44/64
Separator Pressure, psig	-	180	-	795
Separator Temperature, ^{o}F	-	55	-	110
Separator GOR, scf/bbl	-	525	-	393
Well head Pressure, psig	21	1610	250	2000
Well head Temperature, ^{o}F	66	74	43	115
Bottom hole flow Pressure, psig	3744	4710	2120*	4600
Reservoir Pressure, psig	5647	5604	5556	5470
Bottom hole Temperature, ^{o}F	204	205	202	200
Gauge depth, m RKB	2588	2546	2480	2407

*Estimated

DST 1

The test interval 2618.0 - 2626.0 m RKB (LDT-CNL Run 5c of 10 November) was perforated with a 4" Hyper Jet II Casing Gun. The performation fluid was a fresh water based bentonite mud with baryte. The density was 1.64 g/cc and the API water loss 6 cc. A pill with 15 bbl of this fluid was circulated across the interval to be perforated. The mud above the pill had the same density.

Flow rates and bottom hole pressures are shown in fig. 4.11.

The initial flow lasted 12 minutes. The well was opened on a 20/64 adjustable choke. After 7 minutes the choke size was increased to 32/64". 17.8 bbl of cushion water was recovered, which gave an average rate of 2140 bbl/d. At the end of the period the rate was about 2600 bbl/d with a well head pressure of 260 psig.

The initial flow was followed by a build-up of 2 hours and 5 minutes.

The final flow lasted for 18 hours. The well was opened on a 28/64" choke. During a period of 2 hours the rate decreased from 2600 bbl/d to 600 bbl/d and the well head pressure decreased from 750 psig too 25 psig. As the well head pressure reached the low values, no pressure drop was observed over the choke. After 4 hours the choke became plugged by high viscous mud. To clean the choke, the size was increased to 32/64".

After 5 hours of flow, almost clean formation water water was recovered and the well became nearly stable. The average rate of the last 12 hours was 525 bbl/d and the well head pressure 21 psig. In this period the rate declined very slowly. The bottom hole flowing pressure averaged 3744 psia at 2588 m RKB and the temperature 204^{o} F.

After the final flow, the well was shut in at the surfaces. The build-up pressures were monitored at the wellhead and preliminary pressure analyses carried out. After 27 hours it was evident that the straight line of the Horner plot could not be reached within reasonable time, and the test was then concluded.

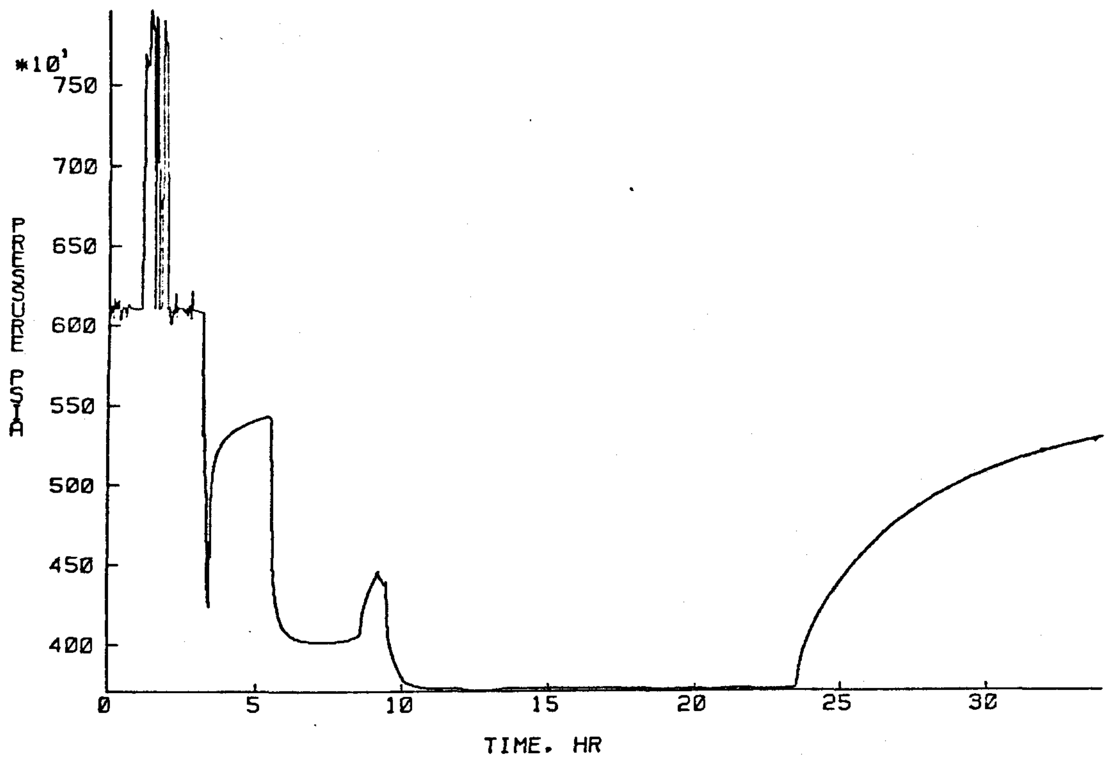
No sand production was noticed during the entire test.

During the water test more than 100 litres of produced water was filled into plastic cans at atmospheric condition. Two 700 cc samples were taken at a well-head pressure of 21 psig.

The produced formation water had a salinity of 44 g/l and a resistivity of 0.22 ohmm at 60° F.

From the pressure development during the main flow period a formation permeability of 128 mD and a very high skin factor of 180 was estimated. Without the effect of this skin, the productivity of the formation would have been about 20 times higher. The extrapolated reservoir pressure is 5647 psi at depth 2588 m RKB.

SPERRY SUN GAUGE 130



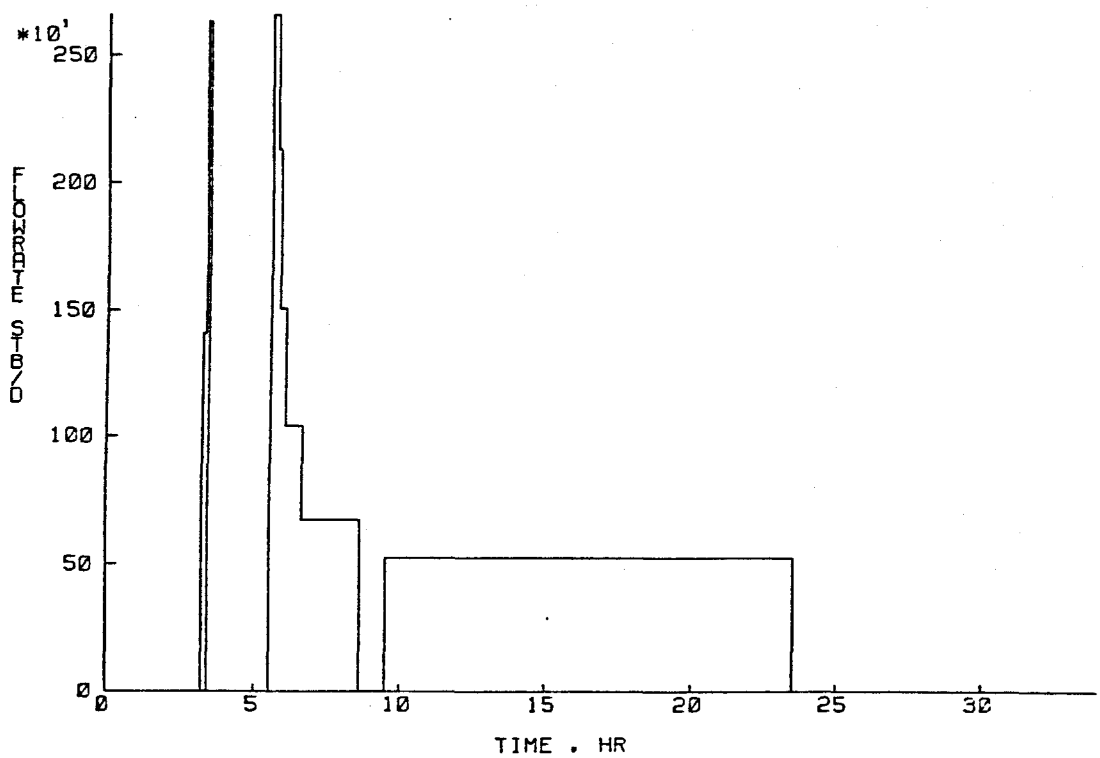


FIG 4.11, Well 34/4-4, Bottom hole pressure and flow rate versus time, DST 1

DST 2

The test interval 2572.5 - 2577.5 m RKB (LDT-CNL Run 5c of 10 November) was perforated with a 4" Hyper Jet II Casing Gun. Prior to perforating, a 30 bbl pill of a salt water polymer mud was circulated across the test interval. This mud had a density of 1.67 g/cc and a API fluid loss of 3.7. The regular mud above the pill had the same density as the pill.

Flow rates and bottom hole pressures are shown in fig. 4.12.

The initial flow lasted for 8 minutes. The well was flowed through a 24/64" fixed choke. A total of 25.0 bbl was produced, which gives an average flow rate of 4500 bbl/d. The well-head flowing pressure was about 1350 psig.

After the initial flow the well was shut in for 2 hours and 28 minutes and the choke manifold.

The main flow lasted for 12 hours and 57 minutes. The well was opened and cleaned up on a 20/64" fixed choke. After about 3 hours the choke size was increased to 24/64" and the flow stabilized at a rate of 2900 bbl/d and a well-head pressure of 1600 psig. The bottom hole flowing pressure stayed at 4710 psia at a depth of 2546 m RKB and the temperature at 205^{o} F. A GOR of 525 scf/bbl was measured at separator conditions of 180 psig and 55^{o} F.

The well was then shut in at the down hole tester valve for 24 hours 45 minutes for final build-up.

The final build-up was followed by a ten hours sampling flow. At a rate of 560 bbl/d the well-head pressure was 2800 psig, well above the estimated bubble point pressure. At these conditions, monophasic well-head samples were taken.

At the end of the last flow period the rate was increased to determine the maximum sand free production rate if possible. Through a 36/64" choke a flow of about 6100 bbl/d at a well-head pressure of 1420 psig was obtained. Finally, the choke size was increased to 52/64" and the rate reached 10100 bbl/d at a well-head pressure of 1100 psig. No sand production was observed.

After the well had cleaned up only clean oil was produced. No water production was registered during this phase.

The LPR-tester valve did not operate properly during this test. The pressure drop in the string was significantly higher in the second flow period than in the other flow periods. The most likely reason for this is that the tester valve was not completely open in this period. As the valve later was closed for pressure build-up it did not seal. An inspection after the test showed the ball of the valve to be badly damaged.

Four sets of gas and oil samples for recombination were taken under separator condition during the stabilized phase of the main sampling flow periods.

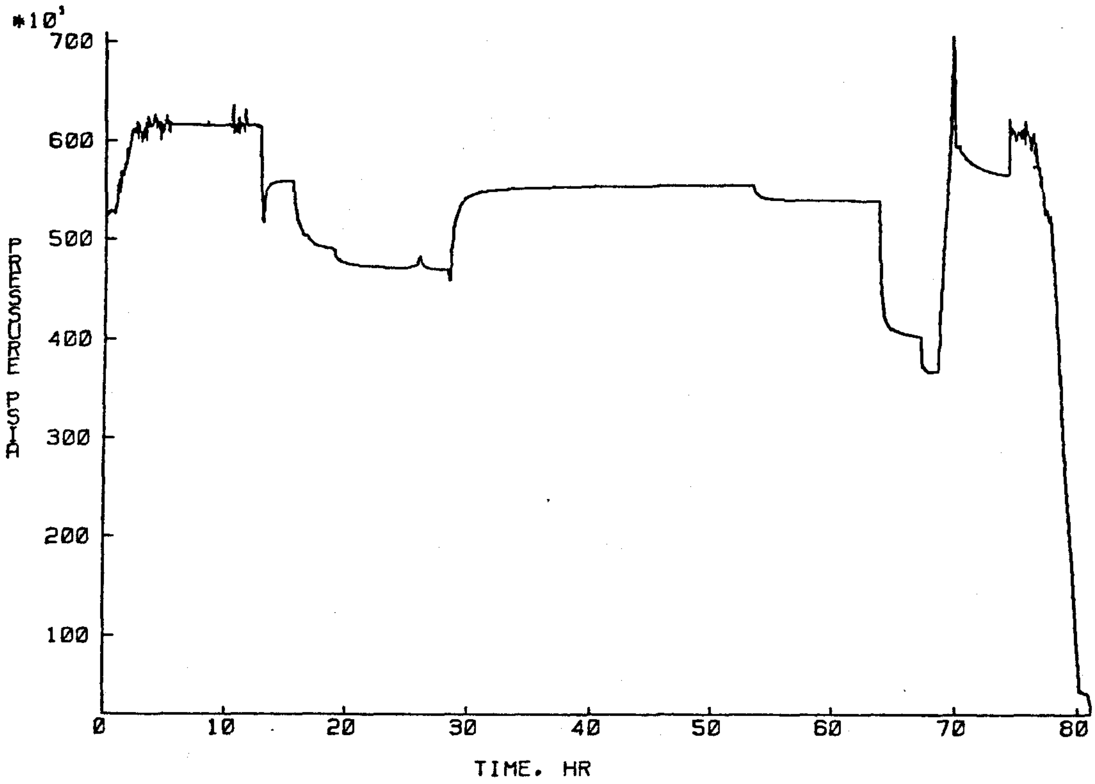
Two oil samples were taken at the well head during the sampling flow at a pressure of 2785 psig.

Oil samples were taken from the separator under atmospheric conditions. A preliminary measurement gave a density of 0.82 g/cc for the dead oil.

During the entire test, fluid samples were regularely taken from the separator and the well stream. No sand or water was noticed in these samples after the well had been cleaned up.

From the pressure build-up analysis a formation permeability of 140 mD an a skin factor of 0.7 was calculated. A reservoir pressure of 5604 psia was determined at depth 2552 m RKB. The maximum temperature measured for the tested formation was 205^{0} F.

SPERRY SUN GAUGE 0100



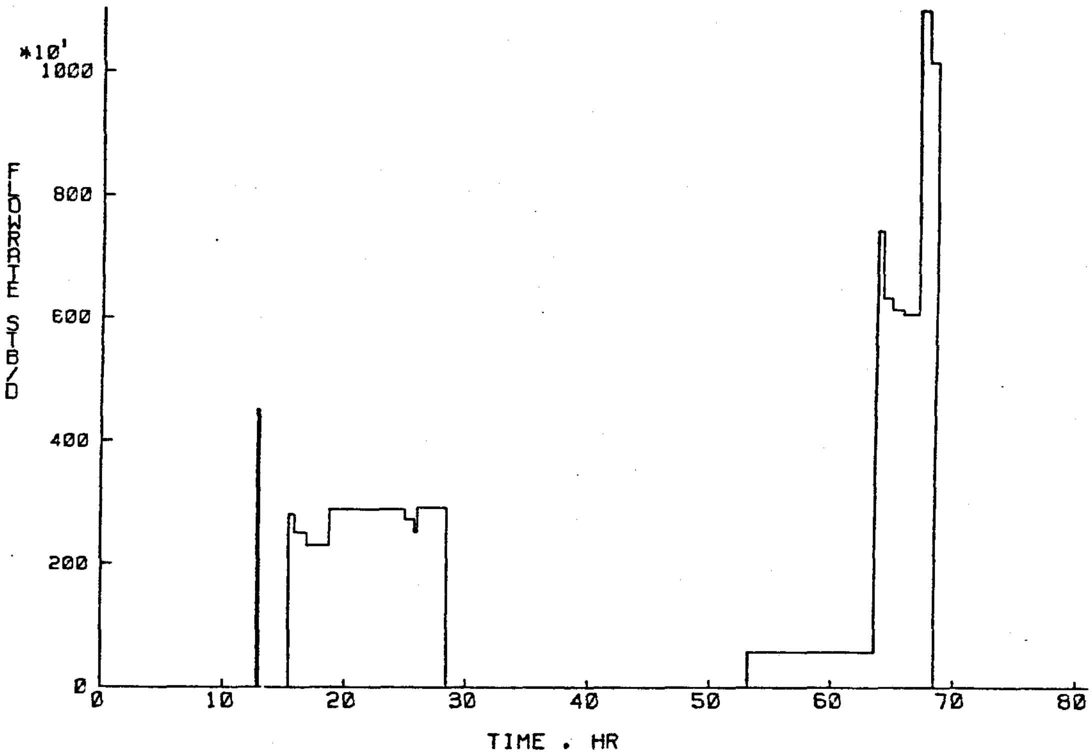


FIG 4.12, Well 34/4-4, BOTTOM HOLE PRESSURE AND FLOW RATE VERSUS TIME, DST 2.

DST 3

In the original test program the DST no. 3 was planned for the interval 2513.0 - 2521.5 m RKB. Because the CBL indicated poor cement in the lower part of this interval, it was decided only to test the upper 3 m.

The test interval 2512.8 - 2515.8 m RKB (LDT-CNL, Run 5c of 10 November 1983) was first perforated 4 January 1983 with a 4" Hyper Jet II Casing Gun. Prior to perforating a 30 bbl pill of a sea water based polymer mud with a density of 1.67 g/cc and an API fluid loss of 4 was circulated across the test interval.

Shortly after perforating, the test procedure had to be suspended for approximately a week due to bad weather. During this period the formation around the perforation could have been somewhat damaged by the contact to the external fluid in the borehole. To minimize this effect, the test interval was reperforated on January 14, 1983. A new pill was circulated across the test interval before the reperforating. The same kind of equipment and perforation fluid was used as for the original perforation.

Bottom hole pressures and flow rates are shown graphically in fig. 4.13. It should be noted that the given average rates are estimated and not actually measured.

The initial flow lasted for 13 minutes. The well was opened on a 12/64" adjustable choke, which soon was increased to 18/64". After this the well head pressure was nearly zero and the well flowed free. A total of 1.32 bbl of cushion water was produced, giving an average flow rate of 146 bbl/d.

After the initial flow, the well was shut in for 2 hours at the down hole LPR tester valve for pressure build-up.

The main flow period lasted for 20 hours totally. The well was initially opened for free flow. Over a period of 51 minutes the rate stabilized at 180 bbl/d. In an attempt to improve the productivity, 5 bbl of water was pumped into the well at a rate of 2 bbl/min. At 3140 psig well head pressure the formation was fractured and 2 bbl injected into the reservoir. The corresponding bottom hole pressure was 6660 psia at 2490 m RKB, giving a frac gradient of 2.7 psi/m. When the well was opened up for production again the rate was 360 bbl/d. A second injection of 7 bbl, at approximately the same pressure and rate, did not improve the productivity further.

After 8 hours the well cleaned up. Before this the flow had been directed through an adjustable choke. Stabilized flow was never obtained. Instead, separate slugs of oil and gas were produced. The choke was plugged twice by hydrate build-ups during gas slugs. The choke size had to be changed several times within a range of 4/64" - 16/64" to keep the well head pressure within reasonable limits. The continuously changing gas and oil rates caused problems and errors in the separator measurements. An average oil rate of 340 stb/d has been estimated. The corresponding well head pressure was in the order of 250 psig. At the end of the flow period an impression block was run down to the F-nipple to check that the flow was not choked by any obstruction in the DST string. No obstruction was found.

After the main flow the well was shut-in down hole at the LPR tester valve for nearly 38 hours to record for pressure build-up.

The build-up was followed by a sampling flow of approx. 13 hours. At the beginning of this period the well was kept closed at the surface. In this phase (1 hour 45 minutes) reservoir fluid flowed into the well and the bottom hole pressure increased far above the bubble point. After the well had been opened, the well head pressure was kept at 800 - 1000 psig. The choke size was adjusted accordingly. The average flow rate was 210 stb/d. Two wireline runs, each with two bottom hole samplers in tandem were made. Three samples were successfully collected.

No water production was monitored after the well had cleaned up. During the entire test no sand was produced.

The bottom hole samples were successfully taken at 2465 mRKB during the sampling flow. Before the first sample was collected, 80 bbl of fresh reservoir fluid had flowed into the well. The sampling pressure was approximately 3550 psia.

Oil samples were taken from the separator under atmospheric conditions. Preliminary measurements gave a density of 0.83 g/cc for the dead oil After the main flow period samples were taken from the bottom of the separator.

Field analyses showed that these samples only contain mud mixed with oil. No formation water was discovered.

During the entire test fluid samples were regularly taken from the separator and the well stream. No sand or formation water was observed in these samples.

From the pressure build-up a formation permeability of 35 mD and a skin factor of 32 was calculated. The high skin may be a result of formation damage created in the relatively long period from the perforation to the beginning of the initial flow. Without the effect of the skin, the productivity would have been five times higher.

A reservoir pressure of 5556 psia was determined at 2488 m RKB. The maximum bottom hole temperature measured during the test was 202^{o} F.

SPERRY SUN GAUGE 100

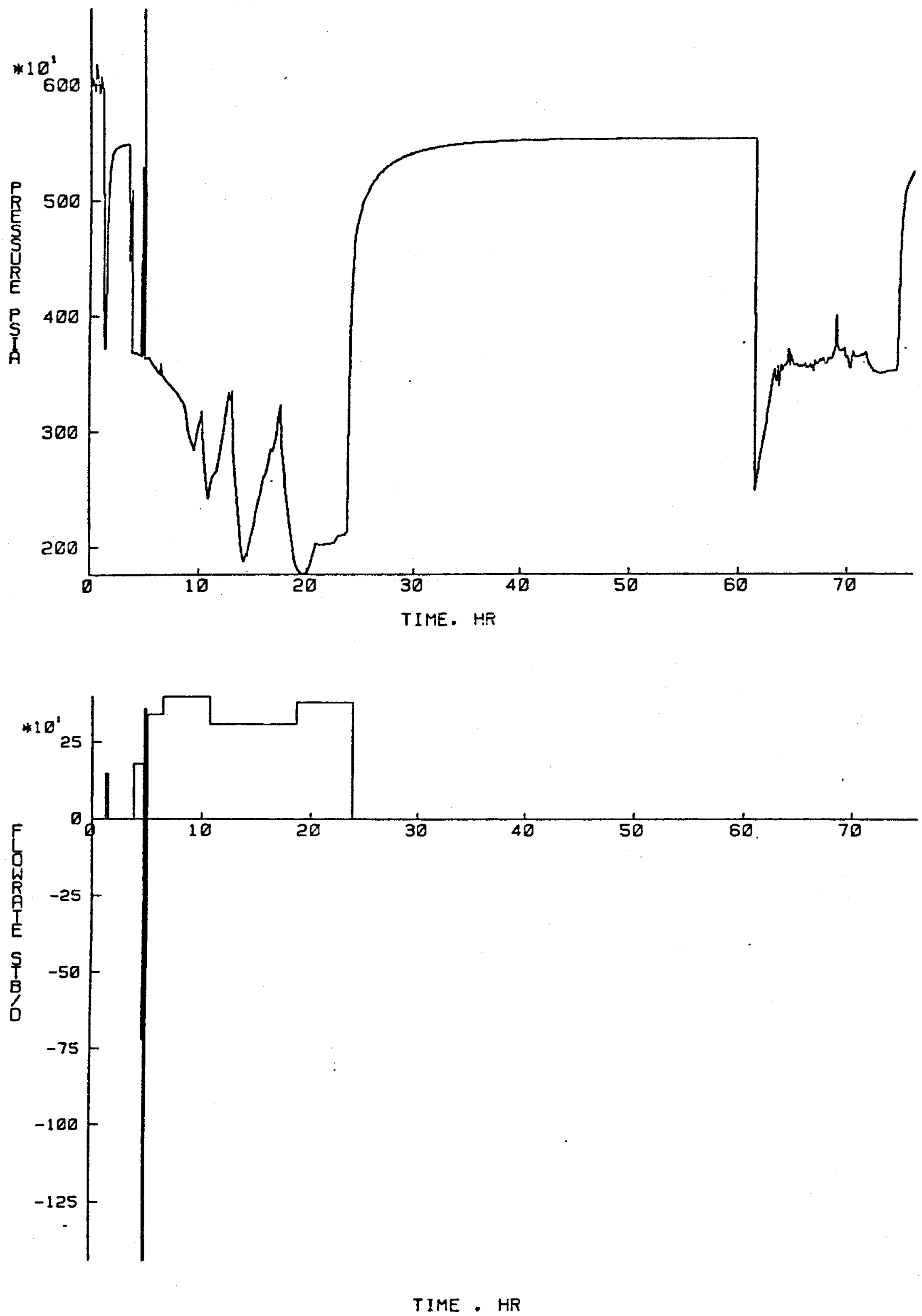


Fig. 4.13 Well 34/4-4, BOTTOM HOLE PRESSURE AND FLOW RATE VERSUS TIME; DST 3.

DST 4

The test interval 2429.0 - 2437.0 m RKB (LDR-CNL Run 5c of 10 November 1983) was perforated with a 4" Hyper Jet II Casing Gun. Prior to perforating, a 35 bbl pill of a sea water polymer mud with a density of 1.67 g/cc and an API fluid loss of 4.5 was circulated across the test interval. The mud above had the same density as the pill.

Flow rates and bottom hole pressures are shown graphically in fig. .

The initial flow lasted 10 minutes. The well was flowed through a 24/64" fixed choke. A total of 34.6 bbl of cushion water was produced, which gave an average flow rate of 4980 bbl/d. The well head flowing pressure increased continuosly from 1430 psig to 1690 psig.

After the initial flow the well was shut-in for 2 hours and 50 minutes down hole at the LPR tester valve for pressure build-up.

The well was then opened on a 28/64" choke for the main flow period. The well cleaned up in about 30 minutes and the choke size was increased to 36/64". At this stage the burners became partly plugged, and after 55 minutes of flow the well had to be shut in. The shut-in lasted 2 hours and 15 minutes, during which the burners were cleaned up.

The well was reopened on a 20/64" choke. This third or main flow period lasted 10 hours and 10 minutes. The choke size was stepwise increased to 44/64" and the well flowed through this choke for more than 8 hours. The production was high but declined slowly. The rate decreased from 11600 bbl/d to 10800 bbl/d and the well head pressure from 2025 psig to 1960 psig over the last 6 hours. The bottom hole flowing pressure reached 4600 psia and the temperature 200^{o} F at 2407 mRKB. A GOR of 393 scf/bbl was measured at separator conditions of 795 psig and 110^{o} F.

After the main flow period the well was shut in for nearly 22 hours at the LPR tester valve to record pressure build-up.

After the main build-up a sampling flow was performed. Bottom hole samples and wellhead monophasic oil samples were taken during this period. The well was flowed on a 12/64" choke at a stable rate of 875 bbl/d and a well head pressure of 2880 psig.

The flow was interrupted for approx. 2 hours while the bottom hole sampler were placed in the test string. The sampling flow was followed by a build-up period of approximately 10 hours.

No sand or water production was observed during the entire test.

Two bottom hole samples were successfully taken at depth 2381 m RKB during the sampling flow period. Before the sampling 140 bbl of fresh reservoir fluid had flowed into the well. The sampling pressure was 5290 psia.

Three oil samples were taken at the well head during the sampling flow. The sampling pressure was 2880 psig.

Four sets of gas and oil samples for recombination were taken at the separator during the main flow period.

Oil samples were taken from the separator under atmospheric conditions. The field measurement gave densities of 0.82 - 0.83 g/cc for the dead oil.

During the entire test, fluid samples were regularly taken from the separator and the well stream. No sand or water was observed in these samples after the well had cleaned up.

From the pressure build-up analysis a formation permeability of 400 mD and a skin factor of -1 was calculated. The pressure analysis also indicates some flow barriers or reductions in the formation flow capacity at various distances from the well. The closest heterogenity is found about 30 m from the well.

A reservoir pressure of 5470 psia was estimated at depth 2407 mRKB. The maximum temperature recorded in the test was 200^{o} F.

SPERRY SUN GAUGE 128.

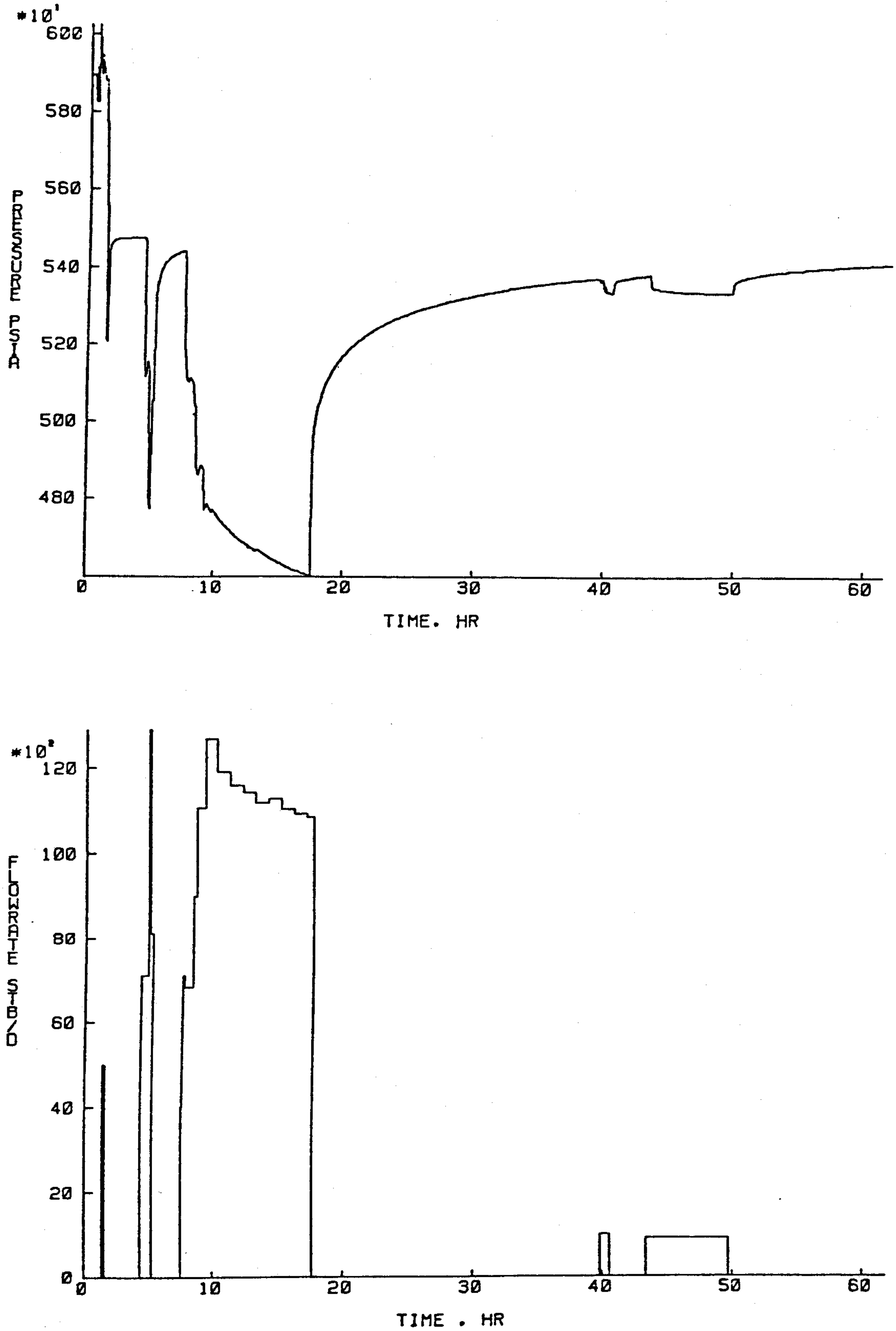


Fig. 4.14 Well 34/4-4, BOTTOM HOLE PRESSURE AND FLOW RATE VERSUS TIME, DST 4.

4.10.6 Formation Fluids

Table 4.24 presents some of the PVT-data of the produced oil. At the top of the reservoir (DST4) the bubble point was measured to 2660 psig. Near the bottom of the oil column (DST2) the bubble point was 2460 psig, 200 psi less. Both Corelab, Aberdeen and Flopetrol PVT-lab in Melun agree upon this difference.

A total gas oil ratio of approximately 1000 scf/STB was measured. The oil gravity was found to be 0.84 g/cc.

Table 4.25 gives the ion-contents of the produced water from the water test. In table 4.26 the composition at the gas assosiated with the water is given. The water has a salt content of 44 g/l and a measured resistivity of 0.22 ohm-m at 60^{o} F.

Table 4.24: Well 34/4-4, PVT-analysis (Analysis performed by Flopetrol Lab., Melun)

Component	DST 2	DST 3	DST 4
N_2	0.91	1.05	1.06
CO_2	0.23	0.21	0.24
C_1	35.84	38.04	37.41
C_2	8.98	9.04	9.02
C_3	7.39	7.42	7.44
IC_4	1.25	1.26	1.25
NC_4	3.94	3.95	3.89
IC_5	1.31	1.30	1.26
NC_5	1.90	1.88	1.81
C_6	2.47	2.37	2.34
C_7+	35.78	33.48	34.28
Molecular weight	95.2	91.1	90.8
Molecular weight of C_7+	211.5	213.0	207.7
Bubble point at 200^0 F, psig	2460	2665	2660
STO Gravity at $60/60^0$ F	0.838	0.841	0.837
GOR scf/STB	913	1017	984

Table 4.25: Well 34/4-4, Water analysis (Performed by CoreLab, Aberdeen)

APPEARANCE BEFORE FILTRATION: Hazy yellow water.

APPEARANCE AFTER FILTRATION: Clear colourless water.

TOTAL DISSOLVED SOLIDS MG/L (CALCULATED):	44330
SPECIFIC GRAVITY AT 60/60^{o}F:	1.029
RESISTIVITY. OHM-METRES AT 60^{o} F (DETERMINED):	0.217
HYDROGEN SULPHIDE:	None Detected
pH:	7.0

CONSTITUENTS:		Mg/L:	Meq/L:
CATIONS:	SODIUM	12630	549.40
	POTASSIUM	175	4.48
	CALCIUM	3760	187.62
	MAGNESIUM	165	13.57
	BARIUM	4.0	0.06
	STRONTIUM	330	7.53
	TOTAL IRON	22	-
	DISSOLVED IRON	L 0.1	L 0.01
			= 762.66
ANIONS:	CHLORIDE	26660	752.08
	SULPHATE	155	3.23
	BICARBONATE	450	7.38
	CARBONATE	Nil	Nil
	HYDROXIDE	Nil	Nil
			= 762.69

L = Less than

Table 4.26: Well 34/4-4, Analysis of gas from water sample (Performed by CoreLab, Aberdeen)

Data pertaining to the transfer of the sample is as follows:

Separator Pressure:	0 psig
Separator Temperature:	58^{0} F
Separator Gas/Water Ratio:	5.3 cubic feet of gas at 60^{0} F and 14.7 psi absolute per barrel of stock tank water at 60^{0} F.
Shrinkage Factor:	0.9985 Vr/Vsat - barrels of stock tank water at 60^{0} F per barrel of saturated water at 2000 psig and 58^{0} F.
Specific Gravity of Flashed Gas:	0.935

Composition of Flashed Gas:

	MOL Per cent	GPM
Hydrogen Sulphide	NIL	
Carbon Dioxide	1.44	
Nitrogen	0.07	
Methane	65.18	
Ethane	10.38	
Propane	10.23	2.814
iso-Butane	2.91	0.952
n-Butane	4.77	1.503
iso-Pentane	1.72	0.629
n-Pentane	1.94	0.703
Hexanes	0.92	0.375
Heptanes Plus	0.44	0.200
	100.00	7.176

Calculated Gross Heating Value: 1568 BTU per cubic foot of dry gas at 14.73 psia and 60^{0} F.

5.2.1. Mud Properties,Daily Report

Well no: 34/4-4

Saga Petroleum a.s.

DATE	HOLE SIZE INCHES	DEPTH METERS	MUD WEIGHT ppg	P.V.	Y.P.	GEL STRENGHT	n	K	WATER LOSS	pH	ALKALINITY Pf/Mf	Ca+ ppM	CL- ppM	SAND %	SOLIDS %	COMMENTS
10.09	36	0	8.7	30	80	34/45	.35	12.5	NA	11.0	.6/.7	0	1200	0	2.7	Spud Mud
11.09	36	Wait on	wather	not drlg. wait on weather												Spud Mud
12.09	36	493	8.7				.35	12.5	N/A	11.0	.6/.7	0	1200	0	2.7	Spud Mud
13.09	36	493	8.7				.35	125	N/A	11.0	.6/.7	0	1200	0	2.7	Spud Mud
14.09	30"CSG	493	8.7	Building sea water Bentonite mud. Run B.O.P.								300		0	2.7	Make up
15.09	30"CSG	493	8.7	Wait on B.O.P valves								300	15000	0	2.7	"
16.09	30"CSG	493	8.7	Drill cmt. & shoe w/sea water								300	15000	0	2.7	"
17.09	17 1/2	735	8.9	7	26	10/13	.277	5.852	N/C	9.1	.05/015	400	11000	25	4	Gel-Mud
18.09	17 1/2	1060	9.5	7	35	16/20	.222	10.503	N/C	9.5	.07/.15	480	8000	.25	7	"
19.09	17 1/2	1213	9.4	7	36	12/18	.217	11.079	N/C	9.3	.07/.15	300	8000	.25	7	"
20.09	26	750	9.5	7	35	12/20	.217	11.079	28	9.2	.1/.2	240	6500	.5	9	"
21.09	26	904	9.4	8	34	17/20	.251	8.758	28	9.4	.1/.2	240	7000	TR	8	"
22.09	26	1120	9.6	7	31	20/25	.244	8.309	30	9.2	.1/.2	240	6500	TR	9	"
23.09	26	1212	11.0	8	34	21/26	.246	9.272	30	9.0	.1/.2	240	7000	TR	15	"
24.09	26	1212	12.0	8	18	15/16	.387	2.330	-	9.1	.15/.28	200	4000	-	20	"
25.09	26	1212	12.0	8	18	13/15	.387	2.330	-	9.0	.1/.2	160	1000	-	17	"
26.09		Mixing up gypsum/mil polymer				302 mud										
27.09	-	1212	9.4	6	5	3/4	.627	.219	28	9.0	.07/.12	1600	19000	-	6	Gyp/polymer mud
28.09	-	1212	9.3	6	9	3/4	.485	.782	20	9.1	.1/.2	1400	19000	-	7	"
29.09	-	1212	9.3	6	9	3/5	.485	.728	20	9.1	.1/.2	1400	19000	-	7	"
30.09	17 1/2	1212	9.3	6	9	3/5	0.49	0.7	20	9.1	.1/1.2	1400	19000	-	7	"
01.10	17 1/2	1302	9.3	9	11	5/7	0.53	0.7	17	9.5	.1/.2	1200	20000		7	"
02.10	17 1/2	1513	9.5	9	12	4/6	0.51	0.85	22	10	.1/.2	1500	21000	-	8	"
03.10	17 i/2	1770	9.5	11	22	9/17	0.41	2.5	22	9.7	.1/.2	1520	21000	-	11	"
04.10	17 1/2	1880	10.5	18	28	13/25	0.47	2.36	18	9.6	.2/.5	1400	21000	-	12	"
05.10	17 1/2	1984	10.6	18	29	13/25	0.47	2.5	17	9.4	.15/.25	1400	21000	-	12	"
06.10	17 1/2	2115	11.5	21	34	17/28	0.47	3.0	16	9.4	.15/.25	1600	21000	-	13	"
07.10	17 1/2	2115	12.0	22	29	12/23	0.51	2.02	16	9.4	.1/.25	1400	21000	-	15,5	"
08.10	17 1/2	2116	11.9	22	29	12/24	0.51	2.02	16	9.4	.1/.15	1400	21000	-	15,5	"
09.10	17 1/2	2116	11.9	20	28	12/23	0.5	2.09	16	9.3	.1/.15	1400	21000	-	15,5	"
10.10		2116	11.9	19	26	12/23	0.5	1.89	16	9.0	.1/.15	1400	21000	-	15,5	"
11.10		2116	11.6	18	24	11/21	0.51	1.7	16	9.0	.1/.15	1400	21000	-	15,5	"

5.2.1. Mud Properties,Daily Report

Well no: 34/4-4

Saga Petroleum a.s.

DATE	HOLE SIZE INCHES	DEPTH METERS	MUD WEIGHT ppg	P.V.	Y.P.	GEL STRENGHT	n	K	WATER LOSS	pH	ALKALINITY Pf/Mf	Ca+ ppM	CL- ppM	SAND %	SOLIDS %	COMMENTS
12.10	12 1/4"	2116	12.	19	22	5/9	0.55	1.34	8	9.4	.2/.5	1600	21000	-	16	Gyp/Polymer
13.10	12 1/4"	2116	12.	28	14	3/6	0.73	0.42	7	10.5	.3/.55		19000	.75	16	Gel/Barite
14.10	12 1/4"	2119	12.	27	22	4/9	0.63	0.95	7.5	9.5	.1/.4	1320	15000	.TR	15	Lignosulfonate
15.10	12 1/4"	2120	12.	27	17	4/19	0.69	0.6	8.5	10.5	.3/.7	1020	12000	.TR	15	"
16.10	12 1/4"	2253	12.3	25	17	6/23	0.67	0.63	8.0	11.0	.3/.8	600	12000	.4	16	"
17.10	12 1/4"	2350	12.3	26	18	5/19	0.67	0.67	7.0	10.3	.2/.7	330	12000	.5	17	"
18.10	12 1/4"	2397	13.5	29	21	5/26	0.66	0.82	6.6	9.5	.1/.5	400	13000	.3	18.5	"
19.10	12 1/4"	2412	13.5	29	22	6/25	0.65	0.89	6.8	10.0	.2/.7	350	12000	.3	20	"
20.10	12 1/4"	2442	13.5	28	23	5/24	0.63	1.0	6.4	9.7	.1/.9	250	12000	.5	21	"
21.10	12 1/4"	2458	13.5	32	20	4/16	0.69	0.7	6.0	10.2	.1/.9	200	12000	.4	21	"
22.10	12 1/4"	2475	13.5	28	18	4/16	0.68	0.64	5.7	10.0	.1/1.1	180	10000	.4	22	"
23.10	12 1/4"	2495	13.5	30	23	4/12	0.65	0.94	4.0	11.0	.4/1.4	160	10000	.5	21.5	Ligno/Chem-X
24.10	12 1/4"	2520	13.5	18	10	2/11	0.71	0.32	3.6	10.4	.4/1.5	150	10500	.5	21	Rheology 120ºF
25.10	12 1/4"	2549	13.5	18	9	2/11	0.73	0.27	3.2	10.4	.4/1.6	160	10500	.5	22	Ligno/Chem-X
26.10	12 1/4"	2566	13.5	18	10	2/10	0.71	0.32	3.0	10.2	.4/1.5	160	10600	.5	22	"
27.10	12 1/4"	2585	13.5	17	10	2/10	0.70	0.33	2.9	10.5	.6/1.8	160	10000	.5	22	"
28.10	12 1/4"	2595	13.5	23	9	3/10	0.86	0.15	2.8	10.0	.5/1.6	140	11000	.5	22	"
29.10	12 1/4"	2595	13.5	18	9	3/9	0.86	0.27	2.8	9.7	.5/1.4	140	10500	.5	22	"
30.10	12 1/4"	2595	14.9	23	11	3/9	0.74	0.24	4	10.1	.6/1.5	140	11000	.5	23	"
31.10	12 1/4"	2595	14.2	24	12	3/9	0.74	0.36	3	10.4	.6/1.4	120	10000	.5	24	"
1.11	12 1/4"	2595	14.2	23	9	3/9	0.78	0.25	3	10.4	.6/1.6	120	10000	.5	26	"
2.11	12 1/4"	2595	14.2	23	9	3/9	0.78	0.25	3	10.3	.6/1.6	120	10000	.5	26	"
3.11	12 1/4"	2595	14.2	20	8	3/9	0.75	0.26	3	10.3	.6/1.6	120	10000	.5	23	"
4.11	12 1/4"	2595	14.2	20	8	3/9	0.75	0.26	3	10.2	.6/1.6	120	10000	.5	23	"
5.11	12 1/4"	2614	14.2	19	9	3/10	0.75	0.27	3.1	10.1	.6/1.5	140	10500	.5	22	"
6.11	12 1/4"	2614	14.2	20	9	3/10	0.74	0.26	3.2	10.1	.5/1.5	140	10500	.5	22	"
7.11	12 1/4"	2624	14.2	23	11	3/11	0.78	0.25	2.8	10.1	.6/1.5	120	10000	.5	22	"
8.11	12 1/4"	2630	14.2	20	11	3/12	0.72	0.35	2.9	10.0	.6/1.5	120	9800	.5	23	"
9.11	12 1/4"	2800	14.2	24	12	3/12	0.73	0.36	3.5	10.5	.6/1.6	100	9500	1	22,5	"
10.11	12 1/4"	2800	14.2	23	12	3/12	0.73	0.37	3.4	10.5	.6/1.6	100	9500	1	23	"
11.11	12 1/4"	2800	14.2	23	12	3/12	0.73	0.37	3.4	10.5	.6/1.6	100	9500	1	23	"
12.11	12 1/4"	2800	14.2	23	12	3/12	0.73	0.37	3.4	10.5	.6/1.6	100	95000	1	23	"

5.2.1. Mud Properties,Daily Report

Well no: 34/4-4

Saga Petroleum a.s.

DATE	HOLE SIZE INCHES	DEPTH METERS	MUD WEIGHT ppg	P.V.	Y.P.	GEL STRENGHT	n	K	WATER LOSS	pH	ALKALINITY Pf/Mf	Ca+ ppM	CL- ppM	SAND %	SOLIDS %	COMMENTS
13.11	12 1/4	2800	14.2	23	13	3/12	.73	.37	4	10.3	0.6/1.6	100	9500	1	23	
14.11	12 1/4	2800	14.2	23	12	3/12	.73	.37	4	10.3	0.6/1.6	100	9500	1	23	"
15.11	12 1/4	2800	13.9	18	12	3/11	.68	.44	4.5	10.1	.6/1.6	100	9500	1	21	"
16.11	8 1/2	2800	13.9	18	12	3/11	.68	.44	4.5	10	.6/1.6	100	9500	1	21	"
17.11	8 1/2	2804	13.3	22	14	4/10	.69	.49	6	10.5	.4/1.1	150	14000	1	22	"
18.11	8 1/2	2845	13.4	23	14	4/15	.70	.48	6	10.5	.5/1.0	150	14500	0.5	22	"
19.11	8 1/2	2963	13.4	22	14	5/15	.69	.49	6.2	10.5	.5/1.0	150	14500	.5	21	"
20.11	8 1/2	3079	13.4	23	14	5/14	.70	.48	6	10.5	.4/1.0	170	15000	.5	21	"
21.11	8 1/2	3164	13.4	22	13	4/18	.70	.44	5.6	9.7	.2/.7	375	14500	.25	21	"
22.11	8 1/2	3196	13.4	23	12	3/15	.73	.37	5.2	10.1	.3/1.0	300	14500	.25	21	"
23.11	8 1/2	3248	13.4	21	12	4/15	.71	.39	4.8	10	.2/.7	200	14500	.25	21	"
24.11	8 1/2	3248	13.4	21	12	4/15	.71	.39	4.8	10	.2/.7	200	14500	.25	21	"
25.11	8 1/2	3248	13.4	21	12	4/14	.71	.39	4.9	9.8	.2/.7	350	14000	.25	22	"
26.11	8 1/2	3248	13.4	21	12	5/14	.71	.39	4.9	9.8	.2/.7	350	14000	.25	22	"
27.11	8 1/2	3276	13.5	15	12	4/14	.64	.50	5.1	9.7	.2/.6	300	13500	.4	23	"
28.11	8 1/2	3342	13.5	18	12	4/14	.67	.46	5.0	9.9	.1/.8	240	13000	.4	23	"
29.11	8 1/2	3404	13.4	17	11	4/14	.68	.40	5.2	10.4	.2/.8	200	13500	.25	23	"
30.11	8 1/2	3514	13.4	19	12	3/14	.74	.30	5.2	10.4	.2/.8	200	13500	.25	23	"
1.12	8 1/2	3609	13.4	18	12	4/14	.67	.46	6.0	9.8	.1/.7	240	14500	.25	23	"
2.12	8 1/2	3667	13.4	20	12	3/15	.70	.41	6.8	9.9	.1/.7	240	13500	.25	23	"
3.12	8 1/2	3728	13.4	20	12	4/18	.70	.41	6.6	10.1	.1/.8	200	13000	.25	23	"
4.12	8 1/2	3754	13.4	20	12	4/18	.70	.41	6.2	10.3	.1/.7	240	13500	.25	23	"
5.12	8 1/2	3799	13.4	20	11	4/17	.72	.35	5.8	10.2	.1/.7	160	13000	.2	23	"
6.12	8 1/2	3800	13.4	20	11	4/16	.72	.35	5.8	10.1	.11.8	160	13000	.2	23	"
7.12	8 1/2	3800	13.4	20	12	4/16	.70	.41	5.8	10.1	.11.8	160	13000	.2	23	"
8.12	8 1/2	3800	13.4	20	12	4/21	.70	.41	6.1	9.9	.11.8	200	13000	.2	23	"
9.12	8 1/2	3800	13.7	20	12	4/20	.70	.41	6.0	9.0	.1/1.0	240	13000	.2	24	"
10.12	9 5/8	3800	13.7	20	11	4/18	.72	.35	5.7	9.5	.05/.8	160	1300	.25	24	"
11.12	9 5/8	3800	13.7	20	11	4/18	.72	.35	6.0	9.5	.05/.8	160	13500	.25	23	"
12.12	9 5/8	3800	13.7	20	11	4/18	.72	.35	6.0	9.5	.05/.8	160	13500	.25	23	"
13.12	9 5/8	3800	13.7	20	11	4/18	.72	.35	6.0	9.5	.05/.8	160	13500	.25	23	"
14.12	9 5/8	3800	13.9	21	11	4/17	.71	.35	6.0	9.8	.1/.8	160	14500	.25	24	"

5.2.2. Mud Materials used
Well no: 34/4-4

Saga Petroleum a.s.

MATERIAL	UNIT	36" HOLE	26" HOLE	17 1/2" HOLE	12 1/4" HOLE	8 1/2" HOLE	P & A	TOTAL
Bentonite	50 kg sxs	333	804	230	605	115	138	2 225
Canstic Soda	25 kg sxs	10	50	96	137	60	26	379
Soda Ask	50 kg sxs	3				4	1	8
MD Delergent	55 gal drums		3	2	1			6
Barite	MT		325	462	790	149	383	2 109
Unical	25 kg sxs		10	143	166	198	5	522
Gypsum	40 kg sxs		37	183				220
Chemtrol	50 kg sxs				246	61	31	338
CMC Lo-Vis	25 kg sxs			57	16			73
CMC Hi-Vis				1			26	27
Bicarbonate	50 kg sxs			9	30		8	47
Drispac Regular	50 lbs sxs			13	9		8	30
Drispac Superlo	50 lbs sxs			14	21	15	9	59
Pro Pol	25 kg sxs			91		2	10	103
Ligcon	50 lbs sxs			16	376	74	35	501
Milpolymer 302	25 kg sxs			111				111
Promud Defoamer	25 ltr			3	3	5		11
LD - 8 Defoamer	5 gal			3				3
Carbomul	55 gal				3			3