CONOCO

Interoffice Communication

To : E.A. Herring

From : Kurt Thomas

Date : 3 April, 1984

Subject : WELL 7/8-3 UPPER JURASSIC RESERVOIR

Introduction

The purpose of this report is to analyze and accumulate the reservoir engineering data and information obtained from the drilling and testing of well 7/8-3. The well encountered an oil-bearing Upper Jurassic sandstone between 3720.7 m and 3767 m. The top part of the sand is argillaceous, and is too tight and water-saturated to be considered net reservoir. This report deals primarily with the sand unit between 3735.2 m and 3767 m.

The reservoir engineering data obtained from this interval is summarized on attached Table 8. Below is a discussion of the analysis of the data.

Log Analysis

Preliminary log analysis through the sandstone indicated an average porosity of 12.7 % and an average water saturation of 43 %. The highest water saturation of 88 % occurred below ±3765 m, where a possible oil-water contact was seen (see log section, Figure 1). Core data indicate that this zone is relatively tight in comparison to the sand above 3765 m. This could explain why no free water was produced during DST No.1, which included the interval 3762 - 3767 m.

The saturation calculations mentioned above were made using a water resistivity of .016 ohm-m and uncorrected LLD readings for Rt.

The log data has been reanalyzed using the Conoco Log Analysis Module (CLAM). Rw was taken as .014 ohm-m. The main reason for the decrease in Rw was formation temperature, which was measured as approximately 311°F during the drill-stem tests. The temperature had been estimated as 280°F during the logging operations. At 311°F, .014 ohm-m corresponds to on equivalent NaCL concentration of 140,000 ppm. By comparison, formation water in the Ula Reservoir has 170,000 ppm equivalent NaCL and Rw is .0145 ohm-m at reservoir conditions. The lower chloride concentration in the 7/8-3 reservoir might be explained by the fact that it is more overpressured than the Ula Reservoir (13.5 ppg versus 12.0 ppg).

In the CLAM analysis, readings of all three porosity tools were input. MSFL, LLS and LLD resistivity values were input to account for the effects of invasion on Rt. Based on this analysis, average porosity was calculated as 13.3 %. Average water saturation was calculated as 28.2 % through most of the sand, but water saturation below 3765 m was 51.9 %. Net pay in the sand was picked as 23 m in this analysis, whereas 24.6 m were picked in the earlier analysis. The intervals picked as net pay, along with the corresponding porosities and water saturations calculated, are shown in Table 1.

Drill - Stem Test No.1

DST No. 1 was conducted on the interval from 3762 m to 3767 m. The objective was to determine, if possible, whether there was an oil-water contact at 3765 m. It was proposed that, if DST No.1 produced water, no further testing be conducted. If it tested oil or would not flow, DST No.2 would be conducted higher up in the sand.

The well was flowed for 7 minutes and then shut-in for one hour for the initial shut-in period. The pressure data from the buildup period indicate an original formation pressure of 8602 $\pm$ 5 psig.

The final flow period lasted 10 hours and 10 minutes, with oil to surface after 2.5 hours. The final build-up period lasted 13 hours and 24 minutes.

During the final 5 hours of the flow period, the oil rate declined from 1340 BOPD to 1275 BOPD, averaging about 1300 BOPD. GOR was fairly constant at about 177 SCF/STB. BS + W was 1 %, but no free water production was noticed. Flowing bottom-hole pressure during the final 5 hours of flow was 3788 psig, declining to 3736 psig. The productivity index was .27 BOPD/psi, and formation temperature was measured as 312^{o}F.

Horner analysis of the pressure build-up data indicated a Kh of 202 mD-ft, with a skin of -3.2. The negative skin is assumed to be due to the great permeability variations within the perforated interval, which probably caused a pseudo-fracture effect. Therefore, it was further assumed, based on core data, that only $\pm$3 feet of formation were contributing to flow , and the permeability of that three feet was thus calculated as 70 mD.

The above calculations were based on estimated oil properties of .9 cp viscosity, 1.21 bbl/STB FVF, and 5 x 10^{-6} vol/vol/psi compressibility. Preliminary PVT data available since that time indicates that .8 cp, 1.1 bbl/STB, and 10.2 x 10^{-6} vol/vol/psi would be better values for those properties. Recalculation using these values yields Kh = 163mD (K = 54 mD if h = 3ft.) and skin = -2.8.

If the bulk of the production was indeed coming from a three-foot interval, that could explain why the flow rate and the flowing BHP were both dropping during the flow period. But it does not explain why the formation pressure extrapolated from the final build-up was only 8416 ±5 psi, some 186 psi less than the formation pressure indicated by the initial buildup. According to a paper by A.C. Gringarten*, buildup data in a multilayered reservoir with double-porosity behaviour (i.e., a layered reservoir with radical permeability contrasts) can exhibit two semi-log straight lines. One of these corresponds to the most permeable layer and is seen relatively early in the buildup data. If the drawdown and buildup last long enough, a transition period will be seen, and then a second semi-log straight line will be evident that represents the response of the entire reservoir. If the drawdown and /or buildup are too short, only the response of the most permeable layer will be seen. Horner analysis of this data can indicate too low an extrapolated reservoir pressure, and depletion can be erroneously assumed by comparison with previous pressure measurements.

A log-log analysis of the buildup data (Table 2) was made in an attempt to see the transition from the permeable zone to the total reservoir response. As seen in Figure 2, the transition period seems to have appeared, and a valid semi-log straight line representing total system response should have been reached. Calculations are shown in Figure 3. The calculated Kh is 226 mD-ft. (K = 75 mD if h = 3), slightly higher than was calculated from Horner analysis. The calculated wellbore storage constant,C, is 2.87×10^{-5} bbl/psi, which is very close to the 2.83×10^{-5} bbl/psi calculated by multiplying casing volume by oil compressibility. The calculated skin factor of -.19 is significantly higher than the -2.8 calculated from Horner analysis, but these calculations are very sensitive to the permeability or formation thickness input. The -2.8 skin calculated from the Horner plot assumed k=70, which corresponds to h = 3. If h = 3 is used in the skin calculation from the type curve, skin would be -1.1. Matrix permeability is estimated as 0.6 % of "fracture" permeability. If the high-permeability streak has 75 mD, the rest of the zone would have approximately 0.5 mD, which is not unreasonable according to the core data.

Although these results do not conclusively prove that the tested interval was partially depleted during the test, they do indicate that it is possible. Also, the fact that no free water was produced during the test does not disprove the possible water contact at 3765 m. The high permeability streak seems to be centered around 3763.75 m (3761.25 m core depth) which is just above the possible contact.

* Ref.: SPE 10044, Interpretation of Tests in Fissured Reservoirs and Multilayered Reservoirs with Double Porosity Behaviour: Theory and Practice

Drill - Stem Test No. 2

DST No. 2 was conducted on the interval from 3734.5 m to 3740.5 m to further test the reservoir and to establish a flowrate.

From a 5-minute initial flow and 40-minute initial buildup, initial pressure was estimated as 8586 ±5 psig. Estimated formation temperature at mid-perforations is 310°F. The final flow period lasted 9 hours and 17 minutes. The average flowrate was 440 BOPD. No gas rate measurement was obtainable. Average flowing BHP was 4946 psig, but it was trending downward. The calculated P.I. was 0.12 BOPD/psi. Buildup time was 10 hours and 10 minutes.

Parameters calculated from Horner analysis were Kh = 346 mD-ft. (K = 23 mD for h = 15 ft.) and skin of +9. Drawdown due to skin was approximately 54%, so the zone would have theoretically produced ±1100 BOPD with no skin.

If the parameters are recalculated using a viscosity of .8cp and FVF of 1.1, then Kh = 252 mD-ft. (K = 16.8, h = 15) and skin is +10.

Type curve analysis indicates a Kh of 222 mD -ft. (K=14.8 mD.) and a skin of +10.4. Match values and calculations are shown in Figure 4.

The high skin factor seen during this test was probably due to a combination of factors. Although the interval was cored slightly underbalanced, it was exposed to a .8 ppg overbalance with 6.1 water loss mud during subsequent cores. Eventually, the interval was exposed to a 950 psi overbalance as the well neared TD. Time was also a factor; the interval was open for 23 days from the time it was cored until it was cased off. DST No.1 would probably have exhibited a similarly high skin factor had it not been for the pseudo-fracture effect.

Core Data

Core data obtained from the reservoir is contained in Tables 3 through 7. The perforated interval of DST No. 1 is indicated on Tables 6 and 7. As indicated by the three core permeabilities from 3760.9 m to 3761.5 m, the core data supports the existence of a high permeability streak of from .6 to 1.25 m thickness in an otherwise relatively tight matrix.

The perforated interval of DST No. 2 (Table 3) also seems to have a high permeability streak from 3733.2 m to 3733.8 m, but the surrounding matrix values tend to be more uniform and higher than those of the DST No.1 interval. Plotting the horizontal air permeability data from these two intervals on log probability charts, Dykstra-Parsons permeability variation V factors of .908 and .833 are calculated for the DST No.1 interval and the DST No.2 interval respectively. With the oil viscosity of .8 cp, and using the Ula field values of .33 cp water viscosity and relative permeability values at 30 % water saturation of .05 for water and .30 for oil, a mobility ratio of .4 is calculated.

Using the V factors and mobility ratio mentioned above, and assuming that the zones are water-flooded to a water-oil-ratio of 1, vertical coverage of 17 % would be obtained for the DST No.1 interval. Vertical sweep efficiency would be 30 % for the DST No.2 interval. Further assuming that water injection would be set up in a direct line drive pattern, areal sweep efficiency would be 87 %. Total sweep of the DST No.1 interval would therefore be .17 x .87 = 15 % by water injection. Sweep of the DST No.2 interval would be .30 x .87 = 26 %.

Reserves

Based on average porosity of 13.3 %, water saturation of 28.2 %, and formation volume factor of 1.1, oil-in-place is 673.5 STBO/acre-ft. If the recovery factor of 26% calculated above is used, oil recovery would be 175.1 STBO/acre-ft.

Current mapping of the Upper Jurassic sand, showing the location of 7/8-3 and the proposed location for well 7/8-4, is included as Figure 5. Proven reservoir limits are shown on this map by the dashed line. Estimated net sand volume within those limits is 78,100 acre-ft.

Proven oil-in-place is therefore estimated as 673.5 x 78,100 = 52.6 MMSTBO, with recoverable reserves of 175.1 x 78,100 = 13.7 MMSTBO.

Pore Pressure

The pore pressure measured in the Upper Jurassic sand was a mud weight equivalent of about 13.5 ppg. This is slightly lower than the 14 ppg estimated before drilling.

Conclusions

DST No.1 tested an average rate of 1300 BOPD with a drawdown of 4836 psi. A negative skin factor was calculated, indicating a pseudo-fracture effect caused by production from a permeable streak of about 226 mD-ft in an otherwise tight matrix. DST No.2 averaged 440 BOPD with 3622 psi drawdown. Type curve analysis indicated a Kh of 222 mD-ft and a skin of +10.4. This positive skin can be attributed to prolonged exposure to relatively high water loss mud in an overbalanced condition. Skin damage on DST No.1 was probably masked by the pseudo-fracture effect.

There is a possible oil-water contact near the base of the sand whose existence was neither proven nor disproven by DST No.1. The possible contact is in the tight matrix below the permeable streak that is thought to have contributed most or all of the production during the test. Pressure data obtained during DST No.1 seem to indicate that the lower portion of the sand, or at least the high permeability streak, might have been partially depleted during the test. This should not be too surprising, considering the lenticular nature of the sand. No signs of depletion were seen during DST No.2.

Although it is difficult, due to the radical permeability variations, to extrapolate what the well would have produced if all of the sand had been perforated, it would probably not be a commercial rate. The low flow rates obtained at maximum drawdown on the two tests show that long-term production at a commercial rate would be unlikely from well 7/8-3.

Oil-in-place proven by the 7/8-3 well is 52.6 million STBO. Of that, 13.7 million STBO is recoverable.

Kurt Thomas

cc: RKH

KOT/mlo-3-84

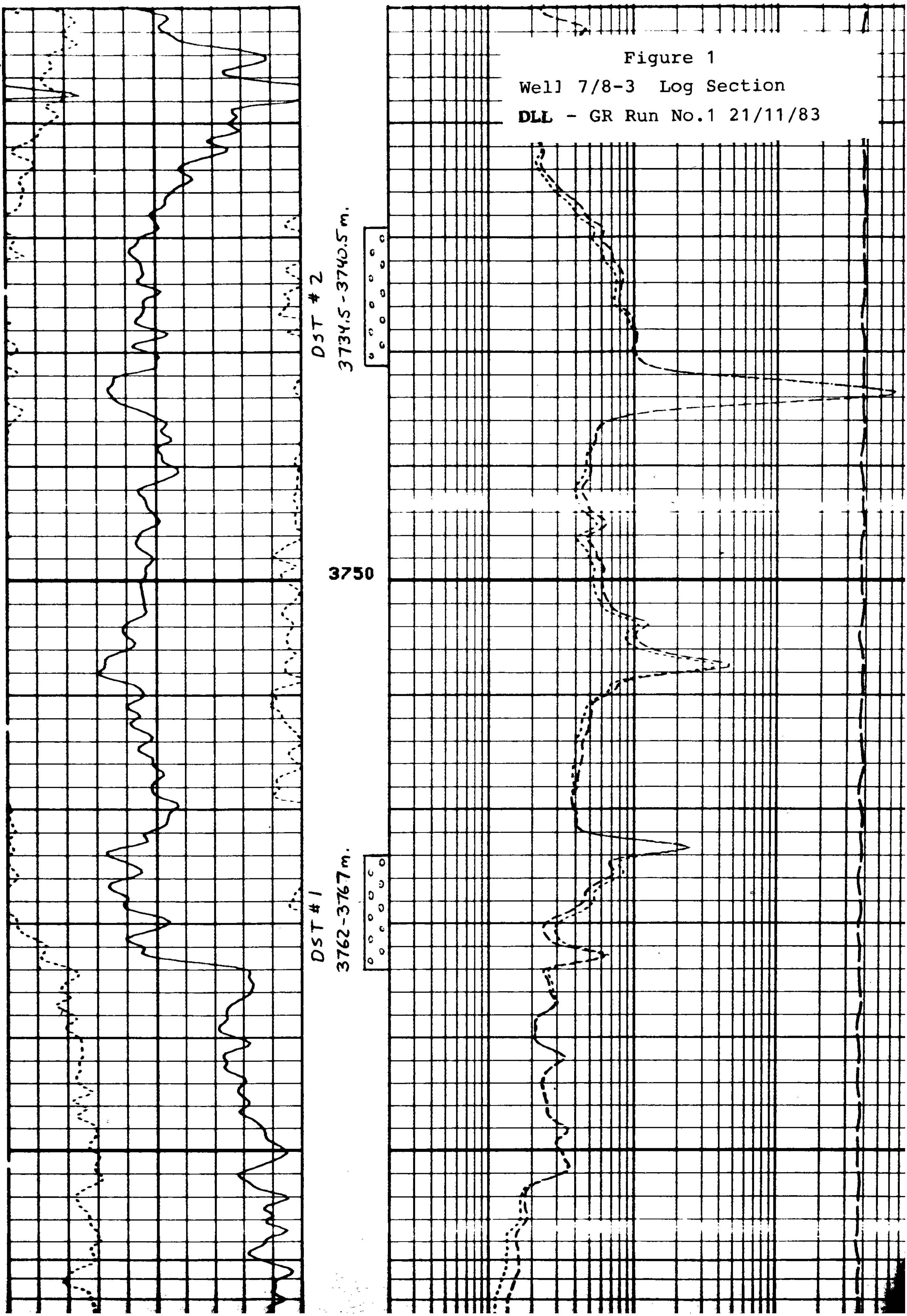
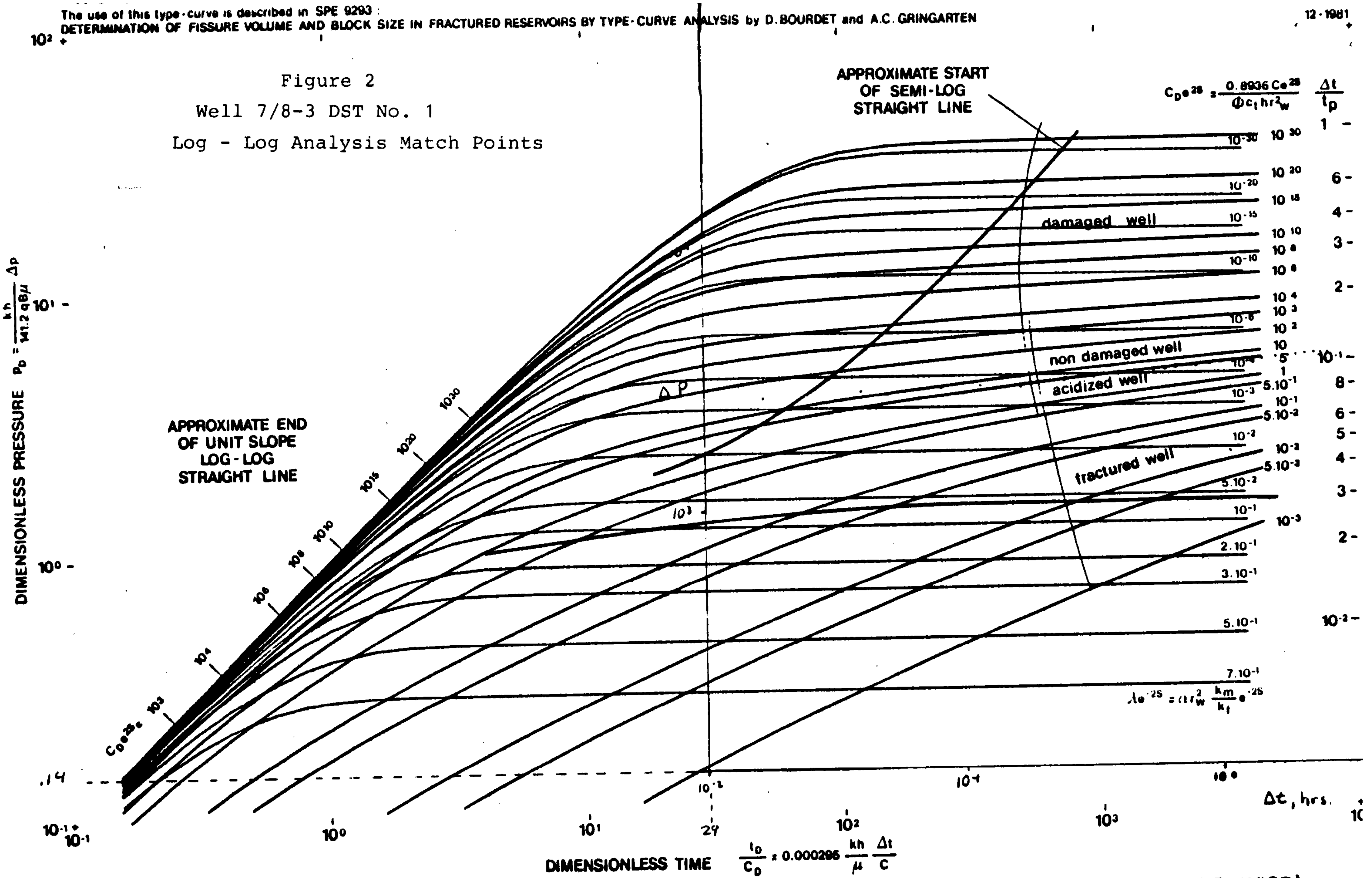


Figure 1
Well 7/8-3 Log Section
DLL - GR Run No.1 21/11/83



TYPE-CURVE FOR A WELL WITH WELLBORE STORAGE AND SKIN (RESERVOIR WITH DOUBLE POROSITY BEHAVIOR)

Figure 3

DST No.1 - Type Curve Analysis

Porosity = .12
Formation thickness = 20ft
Flow rate = 1300 BOPD

Oil Viscosity = 0.8cp

Formation Volume Factor = 1.1bbl/STB

Total Compressibility = 12×10^{-6} vol/vol/psi

wellbore Radius = .35ft
Casing Volume = .37bbl/ft x 75ft = 2.775bbls
(packer to bottom of perfs.)

Match Values:

$C_D e^{2S} = 5$

$t_{D/CD} = 29$ at $\Delta t = .01$

$P_D = .14$ at $\Delta p = 100$

$\lambda e^{-2S} = .0003$

Calculations:

$$\frac{Kh}{MB} = 141.2\ q \frac{PD}{\Delta p} = 141.2\ (1300)\ \frac{.14}{100} = 257$$

Kh = 257 MB = 257 (.8)(1.1) = 226mD-ft
K = 75mD if h = 3ft

$$C = \frac{.000295(Kh)}{M} \frac{\Delta t}{t_D/c_D} = \frac{.000295(226)(.01)}{.8 \quad (29)} = 2.87 \times 10^{-5} \text{ bbl/psi}$$

C = Casing volume x oil compressibility
C = 2,775 bbls x (10.2×10^{-6} bbl/bbl/psi)
= 2.83×10^{-5} bbl/psi

$$S = \frac{1}{2} \text{In} \left((C_D e^{2S}) \frac{\emptyset C_t h r_w^2}{.8936\ C} \right)$$

= -.19

$$\lambda = \frac{\lambda e^{-2S}}{e^{-2S}} = \frac{.0003}{e^{-2(-.19)}} = 2.1 \times 10\text{-}3$$

$$\frac{K_m}{K_f} = \frac{\lambda h_f h_m^2}{12hrw^2} = \frac{(2.1 \times 10^{-3})\ (3)\ (17)^2}{12(20)(.35)^2} = 6.1 \times 10^{-3}$$

$K_m = 6.1 \times 10^{-3} K_f = 6.1 \times 10^{-3} (75\text{mD}) = .46\text{mD}.$

Figure 4

DST No. 2 - Type Curve Analysis

Porosity = .12

Formation h = 15ft.

Flow Rate = 440 BOPD

Oil Viscosity = .8cp

Formation Volume Factor = 1.1bbl/STB

Total Compressibility = 12×10^{-6} vol/vol/psi

Casing Volume = .37 bbl/ft x 82.5 ft = 3.05 bbls.

Wellbore radius = .35 ft

Match Valves:

$C_D e^{2S} = 10^{10}$

$t_D/c_D = 27$ at $\Delta t = .01$

$P_D = .405$ at $\Delta P = 100$

Calculations:

$$\frac{Kh}{MB} = 141.2q \frac{P_D}{\Delta p} = 141.2\ (440)\ \frac{.405}{100} = 252$$

Kh = 252 MB= 252 (.8)(1.1) = 222mD-ft.

K = 14.8mD if h = 15ft.

$$C = \frac{.000295\ Kh}{M} \frac{\Delta t}{t_D/C_D} = \frac{.000295(222)(.01)}{.8\quad (27)} = 3.03 \times 10^{-5} \text{ bbl/psi}$$

C = Casing Volume x oil compressibility

C = 3.05 bbls x 10.2×10^{-6} bbl/bbl/psi = 3.11×10^{-5}bbl/psi

$$S = \frac{1}{2} \ln\ (\ C_D e^{2S})\ \frac{\emptyset Cthrw2}{.8936C}$$

$$= +\ 10.4$$

TABLE 1

Well 7/8-3 Upper Jurassic Sand

Log - derived Reservoir Properties

Interval (m.,md)	Porosity (%)	Water Saturation (%)
3735 - 40	12.7	26.5
3743 - 48	12.9	29.4
3748 - 51	14.6	25.3
3755 - 61.5	14.2	29.3
3762.5 - 65	11.6	29.7
3765 - 66	12.2	51.9

TABLE 2

DST No. 1 Type curve analysis

Pressure Data

t, hours	Pwf = 3750 psig (P -Pwf), psi
.017	2701
.050	2846
.083	2933
.117	2996
.183	3089
.250	3161
.317	3220
.383	3271
.450	3316
.517	3357
.617	3408
.717	3456
.817	3499
.917	3536
1.017	3571
1.150	3612
1.317	3658
1.483	3700
1.650	3737
1.817	3770
1.981	3801
2.15	3828

FINAL REPORT

COMPANY : CONOCO
WELL : 7/8-3
FIELD : 7/8
STATE : NORWAY

CORE NO.: 1

DATE: DECEMBER 1983

GECO
GEOPHYSICAL COMPANY OF NORWAY A/S
Petroleum laboratory

Plug No.	Depth (meter)	Permeability (mD), horizontal K_a	K_1	vertical K_a	K_1	Porosity (%) He	Sum.	Pore saturation S_o	S_w	Grain dens. g/cc	Formation Description
	3731.00										
1	3731.05	0.32	0.25	0.16	0.12	17.1	5.1	0	5.2	2.68	Sst.Lt-gry.VF-gr.Sbang.VW-cmt.w/Calc.
2	3731.35	1.2	0.96	1.9	1.5	11.8				2.68	A.A.W-srt.w/Clauc.ltl-Mic.
3	3731.65	3.5	2.9	7.1	6.1	19.2				2.67	A.A.F-gr.
4	3732.00	1.3	0.99	0.23	0.18	10.6	5.2	2.7	49.4	2.69	A.A.VF-gr.w/Pyr.
5	3732.30	4.2	3.6	13.3	11.7	13.5				2.68	A.A.F-gr.w/o Pyr.
6	3732.60	9.4	8.2	0.70	0.54	13.2				2.67	A.A.
7	3732.90	3.7	3.1	0.49	0.38	12.7	10.2	10.5	21.0	2.66	A.A.
8	3733.20	356	342	245	235	14.4				2.70	A.A.M-gr.
9	3733.50	162	154	42.5	39.0	15.0				2.65	A.A.F/M-gr.ltl-Calc.
10	3733.80	134	127	135	128	14.7	10.2	12.0	14.4	2.65	A.A.
11	3734.10	16.4	14.6	2.6	2.1	12.2				2.65	A.A.F-gr.
12	3734.40	12.7	11.2	10.8	9.5	13.2				2.65	A.A.
13	3734.70	12.2	10.7	6.6	5.6	13.1	9.1	7.9	2.6	2.65	A.A.
14	3735.00	14.3	12.6	9.4	8.2	13.4				2.65	A.A.
15	3735.30	26.4	23.9	35.3	32.1	12.5				2.65	A.A.
16	3735.60	nmp		19.6	17.6	18.7	12.8	7.8	11.7	2.66	A.A.fis.
17	3735.90	6.3	5.4	0.50	0.38	10.8				2.66	A.A.VF-gr.w/o fis.
18	3736.20	58.8	54.5	5.9	5.1	13.5				2.65	A.A.F-gr.
19	3736.50	5.4	4.6	2.2	1.7	10.9	14.0	15.6	8.7	2.66	A.A.VF-gr.
20	3736.80	0.81	0.63	0.17	0.13	6.9				2.65	A.A.C-lam.
21	3737.10	4.6	3.9	3.5	3.0	10.6				2.65	A.A.
22	3737.40	1.5	1.1	0.89	0.70	9.6	12.4	4.2	16.6	2.67	A.A.
23	3737.70	1.1	0.87	1.2	0.93	9.2				2.66	A.A.
24	3738.00	0.79	0.61	1.7	1.3	9.5				2.65	A.A.
25	3738.30	0.070	0.052	0.064	0.047	3.0	6.3	9.5	4.7	2.69	A.A.F-gr.Calc-mtrx.
26	3738.60	0.076	0.056	0.058	0.042	3.2				2.69	A.A.
27	3738.90	0.079	0.058	0.059	0.044	2.6				2.69	A.A.
28	3739.20	0.067	0.049	0.053	0.039	2.1	6.6	0	4.1	2.69	A.A.
	3739.50										

DST #2 3734.5 - 3740.6 m. Log Depth
(3732 - 3738.1 m. Core Depth)

TABLE 3

FINAL REPORT

COMPANY : CONOCO
WELL : 7/8-3
FIELD : 7/8
STATE : NORWAY

CORE NO.: 2

PAGE: 1

DATE: DECEMBER 1983

GEOPHYSICAL COMPANY OF NORWAY A/S
Petroleum laboratory

Plug No.	Depth (meter)	Permeability (mD), horizontal K_a	K_1	vertical K_a	K_1	Porosity (%) He	Sum.	Pore saturation S_o	S_w	Grain dens. g/cc	Formation Description
	3739.80										
29	3739.85	0.057	0.042	0.057	0.042	2.8	1.6	0	16.8	2.71	Sst.Lt-gry.F-gr.Sbang.VW-cmt.Calc-mtrx.
30	3740.15	0.089	0.066	0.060	0.044	3.2				2.70	A.A.W-srt.w/C.Clauc.
31	3740.45	0.48	0.37	0.096	0.072	8.6				2.70	A.A.Gry.F-gr.w/o Calc-mtrx.w/Calc.
32	3740.75	101	95.4	65.8	61.1	15.0	8.2	6.4	19.3	2.67	A.A.F-gr.ltl.Calc.Clauc.
33	3741.05	26.0	23.5	19.9	17.8	15.0				2.66	A.A.
34	3741.35	2.0	1.6	0.70	0.54	13.0				2.67	A.A.
	3741.50										

TABLE 4

COMPANY : CONOCO
WELL : 7/8-3
FIELD : 7/8
STATE : NORWAY

FINAL REPORT

CORE NO.: 3

PAGE: 1

DATE: DECEMBER 1983

GECO
GEOPHYSICAL COMPANY OF NORWAY A/S
Petroleum laboratory

Plug No.	Depth (meter)	Permeability (mD), horizontal K_a	K_l	vertical K_a	K_l	Porosity (%) He	Sum.	Pore saturation S_o	S_w	Grain dens. g/cc	Formation Description
	3741.70										
35	3742.00	0.91	0.71	0.60	0.46	10.9	5.7	0	4.8	2.65	Sst.Lt-gry.VF-gr.Sbang.VW-cmt.C-lam.
36	3742.30	1.1	0.87	1.1	0.87	11.4				2.64	A.A.W-srt.
37	3742.60	3.9	3.1	0.49	0.38	11.7				2.63	A.A.M-gr.ltl-Mic.
38	3742.95	0.91	0.71	0.52	0.40	10.9	6.5	0	4.4	2.63	A.A.VF-gr.
39	3743.30	2.8	2.2	0.63	0.49	12.0				2.64	A.A.F-gr.
40	3743.60	8.9	7.7	4.4	3.8	13.9				2.63	A.A.
41	3743.95	1.9	1.5	0.82	0.64	12.1	11.6	6.8	40.6	2.63	A.A.
42	3744.30	1.6	1.3	1.3	1.0	12.6				2.62	A.A.
43	3744.65	3.3	2.6	1.6	1.3	12.8				2.63	A.A.
44	3745.00	0.36	0.27	0.36	0.27	9.1	5.9	0	5.0	2.66	A.A.w/Calc.
45	3745.30	2.2	1.7	0.80	0.62	12.3				2.64	A.A.w/o Calc.
46	3745.65	1.9	1.5	1.5	1.2	12.3				2.63	A.A.
47	3746.00	2.6	2.0	1.1	0.87	13.0	10.0	5.2	25.9	2.63	A.A.
48	3746.30	0.052	0.038	0.18	0.14	5.1				2.67	A.A.w/Calc.
49	3746.65	3.5	3.0	1.1	0.89	12.4				2.63	A.A.w/o Calc.
50	3747.00	7.1	6.1	1.6	1.3	13.1	8.0	0	10.0	2.63	A.A.
51	3747.30	32.6	29.7	29.9	27.1	15.3				2.64	A.A.
52	3747.65	9.4	8.2	6.3	5.4	12.4				2.63	A.A.
53	3748.00	40.8	37.4	15.2	13.5	15.5	9.6	5.4	10.9	2.64	A.A.
54	3748.30	0.26	0.20	0.16	0.12	10.0				2.64	A.A.VF-gr.
55	3748.65	19.6	17.5	15.4	13.7	14.0				2.64	A.A.F-gr.
56	3749.00	37.6	34.4	8.3	7.2	13.8	7.5	0	3.4	2.65	A.A.
57	3749.30	322	309	143	135	18.5				2.66	A.A.F/M-gr.
58	3749.65	31.4	28.5	1.1	0.84	13.0				2.66	A.A.F-gr.
59	3750.00	24.9	22.5	2.5	1.9	12.2	8.4	6.3	3.2	2.65	A.A.
60	3750.30	204	194	17.5	15.6	16.0				2.67	A.A.F/M-gr.
61	3750.65	45.4	41.7	7.3	6.3	14.0				2.64	A.A.

TABLE 5

FINAL REPORT

CORE NO.: 3 (cont.)

DATE:

GECO
GEOPHYSICAL COMPANY OF NORWAY A/S
Petroleum laboratory

Plug No.	Depth (meter)	Permeability (mD), horizontal K_a	K_1	vertical K_a	K_1	Porosity (%) He	Sum.	Pore saturation S_o	S_w	Grain dens. g/cc	Formation Description
62	3751.00	0.057	0.042	0.050	0.037	2.1	1.8	0	15.9	2.68	A.A.Calc-mtrx.
63	3751.30	0.087	0.065	0.094	0.070	2.4				2.68	A.A.
64	3751.65	0.041	0.030	0.061	0.045	1.5				2.68	A.A.
65	3752.00	36.3	33.5	5.2	4.4	11.2	9.2	8.7	5.8	2.65	A.A.w/o Calc-mtrx.
66	3752.30	20.2	18.5	142	135	12.0				2.66	A.A.w/Pyr.
67	3752.65	10.9	9.8	14.0	12.4	13.6				2.64	A.A.w/o Pyr.
68	3753.00	14.0	12.7	7.5	6.5	15.1	10.3	5.5	11.0	2.64	A.A.
69	3753.30	4.1	3.5	8.2	7.1	12.2				2.65	A.A.
70	3753.65	11.1	10.0	4.3	3.6	14.3				2.63	A.A.
71	3754.00	128	121	4.2	3.6	13.9	10.2	4.6	18.3	2.63	A.A.
72	3754.30	27.1	24.8	6.1	5.2	14.2				2.63	A.A.
73	3754.65	nmp		9.8	8.6	15.1				2.68	A.A.
74	3755.00	83.1	77.7	1.7	1.4	13.7	9.1	5.6	28.1	2.63	
75	3755.35	npp									
76	3755.65	5.1	4.4	0.85	0.66	13.3				2.63	A.A.
77	3756.00	4.4	3.7	nmp		13.3	15.5	9.3	40.7	2.64	A.A.
78	3756.30	8.9	7.8	2.6	2.0	14.0				2.64	A.A.
79	3756.65	4.2	3.5	2.4	1.8	13.7				2.64	A.A.
80	3757.00	6.2	5.4	3.0	2.5	14.0	10.2	5.0	20.1	2.64	A.A.
81	3757.30	5.1	4.3	2.5	1.9	13.8				2.64	A.A.
82	3757.65	3.2	2.7	0.51	0.39	13.4				2.65	A.A.
83	3758.00	19.5	17.4	0.70	0.54	14.9	11.4	8.5	36.2	2.65	A.A.
84	3758.30	2.9	2.4	0.69	0.54	12.8				2.65	A.A.
85	3758.65	3.4	2.7	1.2	0.91	7.3				2.68	A.A.F/M-gr.Fr-srt.w/Calc.
86	3759.00	0.072	0.053	0.96	0.75	2.8	2.9	0	31.0	2.69	A.A.F-gr.W-srt.Calc-mtrx.
87	3759.30	0.073	0.054	0.076	0.057	2.1				2.69	A.A.
88	3759.65	1.6	1.3	5.6	4.8	10.9				2.64	A.A.w/o Calc-mtrx.
89	3760.00	4.0	3.4	0.17	0.12	10.3	7.0	0	4.0	2.64	A.A.F/M-gr.
	3760.10										

DST #1

TABLE 6

COMPANY : CONOCO
WELL : 7/8-3
FIELD : 7/8
STATE : NORWAY

FINAL REPORT

CORE NO.: 4

PAGE: 1

DATE:

GECO
GEOPHYSICAL COMPANY OF NORWAY A/S
Petroleum laboratory

Plug No.	Depth (meter)	Permeability (mD), horizontal K_a	K_1	vertical K_a	K_1	Porosity (%) He	Sum.	Pore saturation S_o	S_w	Grain dens. g/cc	Formation Description
	3760.10										
90	3760.25	47.6	40.5	4.5	3.8	12.7	11.1	0	43.4	2.66	Sst.Lt-gry.F-gr.Sbang.VW-cmt.fis.ltl-Mic
91	3760.55	2.7	1.9	0.35	0.27	11.2				2.64	A.A.W-srt.w/o fis.
92	3760.90	68.6	59.4	19.5	15.5	13.4				2.66	A.A.F/M-gr.Fr-srt.
93	3761.25	325	311	314	302	14.8	12.7	4.1	24.4	2.67	A.A.w/Calc.
94	3761.50	95.0	84	109	103	12.4				2.68	A.A.M-gr.
95	3761.80	2.3	1.6	0.36	0.27	9.1				2.65	A.A.
96	3762.10	14.2	11.3	15.1	13.4	14.8	14.5	5.4	41.2	2.64	A.A.F-gr.w/o Calc.
97	3762.40	2.8	2.0	0.55	0.43	13.4				2.66	A.A.w/Calc.
98	3762.75	0.41	0.26	0.20	0.15	10.9				2.65	A.A.C-lam.w/Pyr.
99	3763.10	0.75	0.50	0.58	0.45	12.4	14.0	5.6	42.8	2.65	A.A.
100	3763.40	1.2	0.83	0.90	0.70	13.1				2.66	A.A.
101	3763.75	0.70	0.46	0.43	0.33	11.9				2.66	A.A.
102	3764.10	0.15	0.094	0.07	0.052	4.2	5.6	0	47.8	2.69	A.A.Calc-mtrx.
103	3764.40	0.11	0.071	0.042	0.031	9.0				2.64	A.A.VF-gr.w/o C-lam.Pyr.Calc.w/Mic-abd.
104	3764.70	0.14	0.083	0.062	0.046	10.0				2.63	A.A.
105	3765.10	0.058	0.031	0.064	0.047	8.4	4.7	0	28.3	2.64	A.A.Gn-mott.w/Calc.
106	3765.40	0.22	0.13	0.069	0.051	8.6				2.65	A.A.w/Glauc.
107	3765.70	0.091	0.053	0.047	0.034	6.7				2.66	A.A.
108	3766.00	0.046	0.021	0.063	0.047	5.7	4.1	0	48.6	2.67	A.A.
109	3766.35	0.063	0.044	0.063	0.046	6.2				2.66	A.A.
110	3766.65	0.090	0.053	0.10	0.078	10.4				2.64	A.A.
111	3767.00	0.17	0.10	0.088	0.065	11.2	5.9	0	26.7	2.63	A.A.
112	3767.30	0.19	0.12	0.14	0.10	9.9				2.64	A.A.
113	3767.65	0.095	0.053	0.074	0.055	9.7				2.65	A.A.
114	3768.00	0.099	0.062	0.11	0.083	9.9	8.5	0	63.9	2.64	A.A.
	3768.20										

DST#1 3762-3767m. Log Depth
(3759.5-3764.5m Core Depth)

TABLE 7

TABLE 8

RESERVOIR ENGINEERING DATA SUMMARY

Net sand thickness	- 23 m (75.5 ft.)
average porosity	- .133
average water saturation	- .282
Reservoir pressure	- 8595 $\pm$ 5 psig at 3750 m
Reservoir temperature	- 311 ^{o}F
Oil formation volume factor	- 1.1 bbl/STB
Solution GOR	- 177 scf/STB
Oil Gravity	- 32 ^{o}API
DST No. 1	
flow rate	- 1300 BOPD
productivity index	- 0.27 BOPD/psi
DST No. 2	
flow rate	- 440 BOPD
productivity index	- 0.12 BOPD/psi
Average core permeability	- 29 mD. (in net sand)
Proven oil-in-place	- 52.6 MMSTBO
Recovery factor	- 26 %
Proven recoverable reserves	- 13.7 MMSTBO
Pore pressure	- 13.5 ppg

CONOCO

Interoffice Communication

To: R.K. Hammond

From: E.A. Herring

Date: 9 April, 1984

Subject: ENGINEERING ANALYSIS OF WELL 7/8-3

Attached to this letter is an evaluation of the 7/8-3 well by Kurt Thomas. Kurt's report is an excellent analysis and compilation of the engineering data obtained from the well. The main conclusions of the report are:

1. The existence of an oil-water contact near the base of the sand was neither proven nor disproven by DST No.1.

2. Pressure measurements during DST No.1 indicate that the lower portion of the sand or a high permeability sand lens could have been partially depleted during the test.

3. Recoverable oil from a reservoir volume down to the base of the sand in the well is 13.7 million barrels.

I agree with these conclusions, all of which reflect the poor sand quality encountered in the well.

EA Herring

cc: J.I. Horning - Stavanger
R.H. Koenig - Stavanger
O.G. Kiel - Houston
A.R. Thyssen - Houston

Attachment

EAH/mlo-7-84