CONFIDENTIAL

PETROLEUM ENGINEERING

WELL 7/12-4

COMPLETION REPORT

WORK BY: F. MUSGRAVE
J.F.A. RENTON
D.K. WOODWARD

REPORT BY: J.F.A. RENTON

APPROVED BY: D.K. WOODWARD

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WELL SUMMARY

Well 7/12-4 was spudded by the rig 'Nörskald' on 12th September 1977 and reached a TD of 3621 m BRT in the Trias on 9th November 1977. After a period of logging and testing the well was temporarily plugged and abandoned and the rig released on 13th December 1977 having spent 95 days on location.

The well was drilled in order to evaluate the extent and potential of the Upper Jurassic sands in the south eastern flank of the main 7/12 structure. The sands were encountered at a depth of 3445.5 m BRT after which seven full hole cores were cut from 3447.5 to 3556.7 m BRT averaging 98% recovery.

Core analysis and log interpretation indicated an Upper Jurassic sand of net thickness 73 m (89.5 m gross) with porosities ranging from 10% to 23%, permeabilities from a few millidarcy to 1750 millidarcy and water saturations from less than 5 to over 60%. The sand quality deteriorated considerably below 3510 m BRT and the Middle Jurassic sand-shale sequence was encountered at 3529.5 m BRT. This extended for 25.5 m to the top of the Lower Jurassic at 3555 m BRT, the top Trias was picked at 3593 m BRT.

Due to the shaliness of the sands below 3510 m BRT no evident oil-water contact could be seen on the logs. However there were no hydrocarbon shows in either the core or cuttings below 3551 m BRT suggesting a possible oil-water contact at this depth, this compares favourably with the previously determined contact for the structure of 3555 m BRT (3530 mSS).

Production tests were performed on three reservoir intervals. A test in the Middle Jurassic sand-shale sequence below 3536 m BRT produced clean formation water whilst a test six meters higher in the Upper Jurassic produced dry oil indicating a probable producing oil-water contact somewhere between 3536 and 3530 m BRT.

Analysis of the test data showed the lower zone to have a permeability in the region 0.15 md and the second test over the interval 3527 - 3530 m BRT to have a permeability around 1.5 md. The third test was conducted towards the top of the main Upper Jurassic sand between the depths 3453 - 3471.5 m BRT to obtain reservoir data and representative reservoir oil samples.

The test produced approximately 3750 bbls of dry oil from the 49 ft. interval at a final rate of 6974 BOPD (39^{O} API) through a 32/64" choke, the total estimated GOR was 540 SCF/STB. During the test twelve single phase oil samples were collected at the wellhead for PVT studies. Analysis of the build up data indicated the zone to have a permeability of 640 md, though it is unlikely that the test was limited to the perforated interval alone, and the actual permeability is more likely to be in the region of 250 md. The skin factor for the test was calculated to be +12 yielding a productivity index of 19 BOPD/psi, this would be increased to 42 BOPD/psi under ideal conditions.

Using the extrapolated pressures from DST's 2 and 3 it is estimated that the reservoir pressure at a datum of 3500 mSS (3525 m BRT) is approximately 7142 psig within an accuaracy of $\pm$ 30 psi.

1. HYDROCARBON INDICATIONS

Shallow gas was detected and measured using the Exlog gas chromatograph in quantities around 10,000 ppm C_1 for the first 1000 m drilled with levels up to 32,000 ppm C_1 recorded. This dropped to between 2000 - 6000 ppm C_1 in the lower Tertiary down to 2615 m BRT. A small amount of C_2 was noticed in the Palaeocene mudstones between 2615 and 2755 m BRT, through this disappeared in the Danian, a constant 1,500 ppm C_1 was monitored throughout this section.

Traces of C_2 were again noticed in the Cretaceous below 2830 m together with 1,500 ppm C_1. The level of C_1 rose to 3,000 ppm once the Upper Jurassic shale was penetrated at 3345 m BRT rising further to 4500 ppm on encountering the top of the reservoir at 3445,5 m BRT. The level of C_2 rose to 1,000 ppm across the reservoir interval. Below the reservoir 150 ppm C_1 was recorded together with a trace of C_2.

The top of the reservoir was marked by a drilling break and the cuttings being stained by a light brown oil. The cuttings showed a bright yellow fluoresence with a pale straw cut, fast streaming and a milky yellow cut fluorescence.

The full hole cores cut from the reservoir displayed similar hydrocarbon shows together with significant oil bleeding and gas bubbling below 3453 m BRT. A strong odour of sweet hydrocarbons was apparent from the cores. Only the tightly cemented calcarious, argillaceous bands showed no signs of fluorescence. The hydrocarbon shows gradually changed to a pale yellow fluorescence with a milky white cut fluorescence with decreasing sand quality below 3475 m BRT. This turned to increasingly patchy fluorescence below 3490 m BRT resulting from the transition to argillaceous siltstone with correspondingly lower porosities. No shows whatsoever were encountered in the core or cuttings below 3551 m BRT.

2. CORE ANALYSIS

Seven full-hole cores were cut in the Upper Jurassic reservoir interval 3447.5 - 3556.7 m BRT (drilled depth) with an average recovery of 98%. (See Table 1 for details).

TABLE 1. CORE RECOVERY

Core No.	Interval cored (m BRT)	Recovery (m)	% Recovery
1	3447.5 - 3465.8	18.3	100%
2	3465.8 - 3474.5	8.7	100%
3	3474.5 - 3491.5	17.0	100%
4	3492.5 - 3510.7	18.2	100%
5	3510.7 - 3519.7	9.0	100%
6	3519.7 - 3538.4	18.7	100%
7	3538.4 - 3556.7	17.6	96%

3491.5 - 3492.5 was drilled with a rock bit.

Conventional core analysis was performed on plugs cut at approximately 30 cm intervals and the following parameters determined:

a) Helium and saturation porosity

b) Horizontal and vertical air permeability

c) Residual fluid saturations

d) Grain density

Full results of the analysis are available in the Statex A/S report and the horizontal permeability has been plotted on the 7/12-4 Reservoir Composite Log as shown in Fig. 23.

A summary of log and core data over the net pay intervals is given in Table 2, the net pay was calculated using a cut-off of 10% log porosity.

TABLE 2. SUMMARY OF LOG AND CORE DATA FOR NET PAY INTERVALS

UNIT	1	2	3	4	5
Top (m BRT DD)	3445	3452.5	3488	3521	3526
Base (")	3452.5	3488	3521	3526	3530
Thickness (m)	7.5	35.5	33.0	5.0	4.0
Net/Gross ratio	0.93	0.94	0.85	0.0	0.50
Log Ø (arith. mean)	13.8	17.1	14.8	-	14.5
Helium Ø (arith. mean)	18.2	17.7	16.3	-	[illegible].4
Horizontal perm. (k_H)md.					
Max. value	216	1435	419	-	11
Min. value	1.9	6.3	4.0	-	5.2
Arith. mean	28.6	347.2	129.2	-	5.65
Geometric mean	9.7	128.4	83.8	-	5.63
Harmonic mean	4.1	53.2	39.3	-	5.61
Vertical perm. (k_v)md.					
Max. value	70	1765	379	-	8.2
Min. value	1.0	1.6	1.2	-	4.7
Arith. mean	18.0	265.8	64.1	-	6.65
Geometric mean	8.2	57.6	34.1	-	6.47
Harmonic mean	4.1	14.7	14.2	-	6.29

Net/Gross using 10% log Ø cut-off.

The results obtained from the core analysis confirm the pattern derived from lithological descriptions and log analysis.

The helium core porosities tended to be higher than those obtained from the logs, especially in the poorer sands, suggesting that the shale correction applied to the logs was possibly excessive (ref. Section 3). The slight difference in the better sands of Units 2 and 3 might be partially attributed to the overburden effect on the cores, this would account for approximately 0.5 - 0.7 porosity units discrepancy. The comparison between core and log porosities in Unit 1 is slightly misleading since only the better part of Unit 1 was cored.

Sand quality deteriorated in the lower section of Unit 3 below 3510 m BRT resulting in lower average porosities and permeabilities than existed in the majority of Unit 3. Average permeabilities for the upper half of Unit 3 were as follows: -

	kH	kv
Arithmetic mean	156.1	72.2
Geometric mean	114.2	36.7
Harmonic mean	66.3	12.9

Horizontal permeabilities were approximately 100% higher than the vertical permeabilities in the good sands of Units 2 and 3, though were more or less equal in the poorer sands of Units 1 and 5. This might indicate a greater percentage of dispersed clay compared to laminated clay in the shalier sections. The ratio of kv harmonic/kH arithmetic varied between 0.04 (Unit 2) and 1.11 (Unit 5), the kv values will probably be significantly less than indicated in the poorer sands owing to the non-pay intervals.

Horizontal permeabilities varied between a maximum value of 1435 md in Unit 2 down to the cut-off permeability which tended to be in the region of 1 - 4 md.

Porosity in the Unit 2 sand reached 22 - 23% over some sections though decreased with depth to 10% by 3520 m BRT. Unit 4 by definition contained no net pay.

No poroperm analysis was performed on the sidewall cores.

3. LOG INTERPRETATION

The following wireline logs were run in the 8 1/2" open hole: -

TABLE 3. 8 1/2" OPEN HOLE LOGGING SEQUENCE

LOG	DATE	HOLE DIA. INS.	INTERVAL M. BRT
ISF/BHC/GR/SP	9/11/77	8 1/2	3621 - 3350
CNL/FDC/GR/CAL	"	"	3621 - 3350
DLL/MSFL/SP/CAL	"	"	3621 - 3367
HDT	"	"	3621 - 3367
WST	10/11/77	"	3621 - 3367
RFT (4 runs) 5A - 5D. [5B, C & D were sampling runs]	"	"	6 Pressure Points (See Table 5 for depths)
CST	11/11/77	"	24 bullets recovered

For the wellsite log interpretation, a value of 0.014 ohm.m was taken for the resistivity of the Upper Jurassic formation water. This was obtained from the aquifer samples from previous wells on the structure, no adequate aquifer was obvious on the 7/12-4 logs to confirm this value. The shale fraction and corrected porosities were taken from a Neutron-Density cross-plot using a matrix density of 2.65 grms/cc and shale point of $\rho_{sh} = 2.50$, $ØN_{sh} = 30\%$.

The Indonesia equation was used to calculate water saturations with formation resistivities taken directly from the Dual-Laterolog deep reading. Constants used in the equation were as follows: -

$$a = 1$$

$$m = 2$$

$$n = 2$$

$$R_{sh} = 1.5 \text{ ohm.m}$$

$$R_w = 0.014 \text{ ohm.m}$$

For the wellsite interpretation V_{sh} was taken as the lower of the GR and Neutron-Density calculated V_{sh}'s. For the GR calculated V_{sh} the constants used were as follows: -

GRmax = 90 API units
GRmin = 35 API units

In general the calculated porosities were approximately 1 - 2 porosity units lower than those obtained from core analysis. Overburden effects on the cores would account for 0.5 - 0.7 porosity units discrepancy, the remaining difference may be due to the ρ ma value used possibly being slightly too low and/or the ρ shale value also being too low.

A detailed computer processed interpretation of the reservoir logs was carried out by Formation Evaluation Branch, BP Trading Ltd.. The basic data and constants used in the interpretation were identical to those used at the wellsite, additional information used was as follows: -

Rmf = 0.207 ohm. m at 76°F
Δ tma = 48 μs/ft.
Δ tf = 189 μs/ft.
ρ h = 0.8 grms/cc
ρ f = 1.0 grms/cc

The CNL was corrected for borehole effects whilst digitising the log.

Conventional shaly sand techniques were employed for the interval 3430- 3574.75 m BRT and the following parameters obtained from the crossplots.

ØN shale = 30%
ρ b shale = 2.50 for 3430 - 3520.75 m BRT
= 2.55 for 3521 - 3574.75 m BRT
Δ t shale = 95 μs/ft.

V_{sh} values were calculated using the minimum of the sonic/density and gamma ray indicators for the interval 3430 - 3520.75 m BRT and were taken directly from the neutron/density for the interval 3521 - 3574.75 m BRT.

The mica option was not employed in this computer processed interpretation as the mica contents were considered to be low and the core porosities agreed moderately well with those obtained from the logs. (The log derived porosities again being approximately 0.5 - 1% lower than the core porosities corrected to reservoir conditions). A GR vs. P plot confirmed that the mica contents were low and would not significantly affect the log porosities.

Water saturations were calculated using the Indonesia equation taking the formation resistivity values directly from the Dual-Laterolog deep reading without applying a correction for invasion.

No obvious OWC was present on the logs with water saturations in the region of 40 - 60% existing below the anticipated OWC of 3551 m BRT as defined by the disappearance of oil shows. It is unlikely that high residual oil saturations exist at this depth, the discrepancy is thought to be partially due to the determination of Rt.

As the formation resistivities were taken directly from the Dual-Laterolog deep reading without any corrections being made for invasion or thin bed effects, the resistivities used would tend to be higher than the true formation resistivities in zones with high formation water saturation.

On average, a combination of these factors would increase a calculated saturation of 60% to approximately 75%, this being somewhat closer to the expected value. Lower saturation values would not be significantly affected.

For the net pay intervals (defined using a 10% log porosity cut-off) average water saturations were calculated for the various geological units, these are given in Table 4.

TABLE 4. AVERAGE WATER SATURATIONS FOR UNITS 1 - 5

UNIT	1	2	3	4	5
Top of Unit (m BRT)	3430 3445	3427 3452.5	3463 3488	3476 3521	3501 3526
Bottom of Unit	3452.5 3427	3488 3463	3496 3521	3501 3526	3505 3530
Thickness (m)	7.5	35.5	33.0	5.0	4.0
Net/Gross ratio	0.93	0.94	0.85	0	0.50
Average Sw% $\{= \frac{\Sigma \emptyset Sw}{\Sigma \emptyset}\}$	21.19	13.7	20.8	-	37.9

Net pay using 10% log Ø cut-off.

The results of the computer processed interpretation are plotted on the 7/12-4 Composite Log as shown in Fig. 23.

4. FORMATION TESTING

4.1 REPEAT FORMATION TESTS

An RFT was run during the 8 1/2" open hole logging suite to try and establish the formation pressure and producibility of various parts of the reservoir.

The tool was run in the hole a total of four times, once for pressure information, the other three times for sample collection.

Two amerada gauges were run with the RFT to confirm the pressure information given by the RFT gauge. A 33 psi temperature correction was applied to the RFT gauge readings for the six pressure points chosen, the results of which are given below in Table 5.

TABLE 5. RESULTS OF RFT PRESSURE RUN

Run 5A.

No.	Depth (mBRT)	Pressure (psig) RPG3 32328	Pressure (psig) RPG3 34527	Average RPG3 Pressure (psig)	Corrected RFT Pressure (psig)	ΔP (psi) RPG3-RFT
1 6	3551.5	7255	7277	7266	7205	61
2 5	3538.0	7406	7391	7398.5	7320	78.5
3 4	3505.0	7172	7159	7165.5	7080	25.5
4 2	3467.0	7133	7119	7126	7045	81
5 1	3458.0	7213	7203	7208	7124	84
6 3	3481.5	7152	7142	7147	7058	89

+14.5.

It is thought that mud hydrostatic pressure leaked into the chamber for tests 2 and 5 at depths 3538.0 and 3458.0 m BRT respectively, these pressures were therefore considered suspect.

The points remaining in the oil zone confirm an oil gradient of approximately 0.29 psi/ft though there appears to be some conflict as to the absolute value of the pressures, the amerada pressures being consistantly higher than those measured by the RFT gauge (see Table 5).

An increase in pressure gradient is apparent on entering the transition zone though the magnitude of this increase is greater than would be expected using normal formation water gradients. This effect may be due to mud filtrate supercharging the low permeability intervals of the reservoir.

Three sampling runs were carried out at depths of 3467, 3458 and 3528 m BRT, a summary of their recoveries is given in Table 6.

TABLE 6. RECOVERIES FROM RFT SAMPLE RUNS

Run No.	Depth (mBRT)	Chamber (gals)	RECOVERY		
			Gas (ft^3)	Oil (ccs)	Water (ccs)
5B	3467	1 2 3/4	11 --	-- 1500	3000 emulsion 8000
5C	3458	1 2 3/4	28 --	-- --	2900 emulsion 9000 emulsion
5D	3528	1 2 3/4	Small Volume	-- --	3000 4000

The pressures obtained from the RFT's together with those from the DST's are plotted versus depth in Fig. 21.

4.2 DRILL STEM TESTS

Production tests were carried out on three reservoir intervals to establish a producible oil-water contact and to obtain reservoir properties of the Middle and Upper Jurassic sands, results of the successful tests are summarised in Table 10. Plugging and mechanical problems caused the failures of DST's 1 and 1A, the tools were run in the hole a total of five times requiring a period of 20 days to complete the tests.

4.2.1 DRILL STEM TEST 1

Objective:

To investigate the reservoir properties of the Middle Jurassic sand-shale sequence and to establish the movable fluids in the transition zone above the 100% water level. Also to establish whether the productivity of this part of the reservoir, though very tight, might be increased by natural fracturing.

Interval perforated:

3550 - 3552 m BRT 2 m
3536 - 3540 m BRT 4 m

Test string;

The test string run was a standard Halliburton string with an APR-N tester situated above a 7" RTTS packer. The packer was set at 3528.3 m BRT with the base of tail pipe at 3558.5 m BRT. Three Otis gauges were run (2 pressure, one temperature) together with two Sperry Sun gauges and two Halliburton BT gauges. Details of the test string can be seen in Fig. 2.
A 6000 ft. water cushion above the APR-N tester valve was run on this test.

Test operation:

DST 1 failed, due most probably to the plugging of the test tools above the APR-N valve with a compact barite/shale plug. Markings on the APR-N valve ball indicated that the valve had opened though this could not be verified. Both Sperry Sun gauges failed to record during the test because of burst batteries. A graphical diary of events for DST 1 is given in Fig. 3

4.2.2 DRILL STEM TEST 1A

Objective:

as for DST 1

Interval perforated:

The same intervals as for DST 1 were reperforated for this test.

Test string:

A similar string to that used on DST 1 was run on DST 1A. Three slip joints instead of two were finally run to allow the packer to be set in conditions of moderate heave. The packer was set at 3527.3 m BRT with the tail pipe extending down to 3548.1 m BRT. No Sperry Sun gauges were included in the DST 1A test string as adequate reservoir information could be gained from the Otis and Halliburton gauges. Details of the test string can be seen in Fig. 4. A 6000 ft. water cushion was again used for this test.

Test operation:

On the first run in the hole the packer was not set because of bad weather and excessive heave. An additional slip joint was added to the test string and the string rerun. No flow was observed throughout the test despite repeated attempts to open the APR-N tester, and, due to the absence of any plugging material on recovering the test tools, it was assumed that the valve had failed to open.

Examination of the charts from the downhole pressure gauges showed a continuous pressure build up throughout the test. This could be explained in terms of the thermal expansion and compressibility of the borehole fluid, the pressure rise being consistent with the temperature increase as recorded by the Otis RT7 gauge.
A graphical diary of events for DST 1A can be seen in Fig. 5.

4.2.3 DRILL STEM TEST 1B

Objective:

as for DST 1

Interval perforated: 3550 - 3552 m BRT
3536 - 3540 m BRT

as for DST 1

Test string:

To avoid further problems with the APR-N valve DST 1B was conducted with the Ful-Flo hydrospring tester. Otherwise the string was similar to those run on DST's 1 and 1A. The 7" RTTS packer was set at 3523.1 m BRT with the tail pipe extending down to 3543.8 m BRT. The gauges in the string were the same as those run on DST 1A with three Otis (two pressure, one temperature) and two Halliburton gauges, no Sperry Sun gauges were run. Details of the test string can be seen in Fig. 6. A 6000 ft. water cushion was again used for this test.

Test operation:

The test was mechanically successful and consisted of two main flows firstly of 5 hours followed by a 4 1/2 hour build up, then a 3 hour flow with a 3 hour build up. The test was complicated since it was unclear whether the hydrospring was opened or closed

at any given time, flow indications at surface continuing throughout. As the 6000 ft. water cushion did not reach surface, the flow and flowrate were monitored from the air displacement using a domestic gas meter.
A graphical diary of events for DST 1B is given in Fig. 7.

4.2.3.1 FLUID PRODUCTION AND SAMPLING DST 1B

Results from the gas meter calibrated to 0.001 m^3, together with pump strokes during the reversing out period and chloride measurements of the reversed out fluids were used to obtain a best estimate of 27.5 $\pm$ 2 bbls of formation water produced during the test. This consisted of 13.7 bbls produced at an estimated rate of 60.5 bbls/day during the first flow with 13.8 bbls at a rate of 91 bbls/day produced during the second flow. No indications of hydrocarbons were observed.

Fluid samples were caught during the reversing out of the test string, a full analysis of the produced fluid which appears to be mainly formation water is given in Appendix 3. There were no traces of sand on reversing out the test string or breaking down the tools.

4.2.3.2 PBU INTERPRETATION OF INITIAL PBU DST 1B

All four pressure gauges run on DST 1B functioned correctly, the gauge used in the interpretation was the Otis gauge RPG3 113259 as this appeared to give consistently more accurate results than any of the other gauges. To provide a check on the results obtained from this gauge a basic interpretation was carried out using the Halliburton gauge BT 5623, the other Halliburton gauge BT 1846 having a stylus that tended to stick.

A Horner plot as shown in Fig. 8 was constructed with data obtained from the initial PBU. This yielded a good straight line with a slope of 2036 psi/cycle. Fluid properties used in the interpretation were taken from previous 7/12 data.

RESERVOIR PRESSURE (Initial PBU)

Extrapolation of the straight line portion of plot gave a P^* of 7015 psig, which, when corrected to the mid point of the perforations, gave a pressure of 7030 psig at 3544 m BRT. This value appears very much lower than would be expected at this depth (see Fig. 21), though appears a valid result when checked against data from other gauges. (BT 5623 gave a $\bar{P}$ of 7050 psig at 3544 m BRT) and results from the final PBU. One plausible solution is that the test interval is in poor communication with the main sand and was partially depleted as a result of the test. This solution was not confirmed by the final build up which gave a $\bar{P}$ somwhat higher (7066 psig at 3544 m BRT) than that from the initial PBU.

PERMEABILITY (Initial PBU)

The Horner plot showed a very slight increase in slope towards the end of the build up possibly indicating a small decrease in permeability away from the wellbore. The interpretation showed the perforated interval to have a total Kh of 1.79 md ft., which if one considers the perforated interval only as contributing to the test, results in an average permeability to water of 0.09 md. This value is approximately a factor of ten lower than the geometric average core permeability across the interval. Since a residual oil saturation existed in the interval, the difference may be explained in terms of relative permeability in addition to overburden and temperature effects. A Ramey curve match interpretation was also conducted on the initial build up, this gave a kh of 3.17 md ft. and a k of 0.16 md agreeing reasonably closely with the Horner interpretation. The curve match also confirmed that semi-log straight line data does exist for this PBU, afterflow effects becoming negligble after 3 hours.

SKIN EFFECT AND PRODUCTIVITY (initial PBU)

From the Horner plot of the initial PBU a skin factor of -2.1 was obtained which is not untypical for a water test of this type. A steady state productivity index and an ideal productivity index were also calculated, these were 0.0044 and 0.0035 BWPD/psi respectively. The Ramey curve match approach gave a skin of -5 which is moderately consistent with the Horner value considering the inaccuracy of the curve match technique and the limited number of possibilities (s = 0, -5, -10).

4.2.3.3 PBU INTERPRETATION OF FINAL PBU DST 1B

RPG 3 113259 was again used for the interpretation of the final PBU. The data from the final build up was affected by transients remaining from the initial flow and build up. A superposition technique was used to calculate f (Δt) to correct for this effect before interpreting the results. A Horner plot of the data from the final PBU together with the superposition plot of P (Δt) vs. f (Δt) is given in Fig. 9.

RESERVOIR PRESSURE (Final PBU)

The reservoir pressure obtained from the superposition analysis was found to be 7066 psig at 3544 m BRT which is in good agreement with those obtained from the initial PBU (7030 psig from RPG 113259 and 7050 psig from BT 5623 at 3544 m BRT). This pressure as previously mentioned is lower than expected.

PERMEABILITY (Final PBU)

A kh of 1.86 md ft. was calculated from the final build up giving an average permeability to water of 0.09 md ft. for the perforated interval agreeing closely with that from the initial PBU.

SKIN EFFECT AND PRODUCTIVITY (Final PBU)

A skin of -2.5 was calculated from the final build up which gave a steady state PI of 0.0048 BWPD/psi and an ideal PI of 0.0036 BWPD/psi. These values are very similar to those obtained from the initial build up.

A summary of the results for DST 1B is given in Table 7.

TABLE 7. A SUMMARY OF DST 1B RESULTS

	INITIAL PBU		FINAL PBU	
	Horner	Ramey	Horner	Ramey
kh (md ft)	1.79	3.17	1.86	3.33
k (md)	0.09	0.16	0.09	0.17
s	- 2.1	- 5	- 2.5	- 5
$\bar{P}$ at 3544 m BRT	7030	-	7066	-
J_{ss} (BWPD/psi)	0.0044	-	0.0048	-
J ideal (BWPD/psi)	0.0035	-	0.0036	-
$r_{inv.}$ (ft)	27	-	27	-

4.2.3.4 CONCLUSIONS DST 1B

DST 1B established that the interval 3536 - 3552 m BRT is at essentially irreducible oil saturation and that the effective producing OWC at this location is above 3536 m BRT. This is to be expected in view of the extremely low permeability (around 0.13 md) existing over this interval. By the fact that the test kh agreed with the core data corrected to reservoir conditions one can conclude there is no significant natural fracture permeability in this part of the Middle Jurassic sand-shale sequence, the ideal productivity being in the region of 0.0035 BWPD/psi The reservoir pressure at this depth was found to be considerbly less than expected, approximately 7050 psig at 3544 m BRT. The reason for this is uncertain though one possibility is that the test interval is in poor communication with the main sand and was partially depleted as a result of the test.

4.2.4 DRILL STEM TEST 2

Objective:

To establish the maximum possible Upper Jurassic oil column in the well and thus confirm the effective producing oil-water contact determined in other wells.

Interval perforated:

3527 - 3530 m BRT

Test string:

The test string used for DST 2 was practically identical to that run on DST 1B. Again the Ful-Flo hydrospring tester was used in place of the APR-N valve. The 7" RTTS packer was set at 3501.7 m BRT with the base of the tail pipe extending down to 3522.5 m BRT. Three Otis gauges were run, two pressure and one temperature, together with two Halliburton gauges. Again no Sperry Sun gauges were run on this test, full details of the string can be seen in Fig. 10. A 6000 ft. water cushion was run above the Hydrospring tester.

Test operation:

DST 2 was mechanically successful and consisted of an initial 13 minute flow and 58 minute shut in, followed by a 66 minute flow and 59 minute shut in and finally a 15 hour flow and 1 hour shut in. As with DST 1B the test was complicated by not knowing whether the Hydrospring was opened or closed at any one time. After one hour of the fianl build up, while attempting to ensure that the well was closed in downhole, the packer was accidentally unseated and the remaining pressure build up lost. The water cushion never reached surface during the test and so flows and flowrates were again monitored using a domestic gas meter at surface.

4.2.4.1 FLUID PRODUCTION AND SAMPLING DST 2

From measurements of displacement when reversing out and volumes obtained in the test tank it was calculated that 26 STB of oil had flowed during the test at an average rate of 37.5 BOPD.

Fluid samples were caught during the reversing out of the test string and breaking down of the tools, no trace of formation water or significant increase in salinity was observed confirming that the produced fluid was dry oil. The average API gravity of this oil was 39.4^{o}. No traces of sand were found either when reversing out the test string or breaking down the test tools.

4.2.4.2 PBU INTERPRETATION OF SECOND PBU DST 2

The interpretation of DST 2 was carried out using the Halliburton gauge BT 5623. This gauge was chosen as it appeared to give consistently more reliable results than the other Halliburton gauge BT 1846. A BT gauge was chosen as the scale employed is larger than that used with the Otis RPG 3 gauges, also both Otis gauges became unreadable during certain stages of the test.

As it was envisaged that the build up data was affected by wellbore storage, both Horner plot analysis and Ramey type curve match techniques were used. Fluid properties used in the interpretation were taken from previous 7/12 data prior to the results from 7/12-4 being made available. The μo used in the calculations was 0.38 cp though 7/12-4 PVT results indicate that the actual viscosity may be closer to 0.48 cp, this would tend to increase the calculated permeabilities by a factor of around 25%. Other parameters used in the calculations are not changed significantly by the latest 7/12-4 PVT results.

RESERVOIR PRESSURE (SECOND PBU)

From the Horner plot shown in Fig. 13 a P^* of 7156 psig was obtained, which, when corrected to the perforations mid point gave a $\overline{P}$ of 7164 psig at 3528.5 m BRT. This is in moderately good agreement with the pressure obtained from the final PBU (7137 psig at 3528.5 m BRT) and in combination with DST 3 confirms an oil gradient of 0.29 psi/foot (see Fig. 21).

PERMEABILITY (SECOND PBU)

From the Ramey type curve match a kh of 12.7 md ft. was obtained, which if one consideres the perforated 10 ft. interval only as contributing to the test, results in an average permeability to oil of 1.3 md. The curve match technique confirmed that semi log straight line data does exist after approximately 17 minutes, the curve match plot can be seen in Fig. 12. A Horner plot analysis yielded a similar kh of 10.1 md ft. giving a k of 1.0 md over the perforated interval. It should be noted that in the light of recent 7/12-4 PVT data the actual permeabilities may be 25% higher than those calculated due to the higher than expected oil viscosity, this would increase the permeability from 1 - 1.3 md to around 1.3 - 1.6 md. Core data from this section gave a geometrical average permeability of 7 md. which is approximately a factor of five higher than that obtained from the test results. Considering the effects of residual oil saturation, overburden and temperature one would only expect a reduction from core to test permeability in the range of 2.5. The lower than expected test permeability may possibly be due to relative permeability effects although no water production was detected.

SKIN EFFECT AND PRODUCTIVITY (SECOND PBU)

Both the Horner plot and Ramey type curve match gave a skin factor of +10 which is considered normal for an oil test of this type. A steady state productivity index and an ideal productivity index were then calculated, these were 0.0067 BOPD/psi and 0.0136 BOPD/psi respectively.

4.2.4.3 PBU INTERPRETATION FINAL PBU DST 2

The Halliburton gauge BT 5623 was again used for the interpretation of the final PBU. Both the Horner plot approach and the Ramey type curve analysis were carried out as it was felt that the data for this PBU was again affected by afterflow. The Horner plot can be seen in Fig. 15 and the type curve match in Fig. 14.

RESEVOIR PRESSURE (FINAL PBU)

From the Horner plot a P^* of 7129 psig was obtained resulting in a $\overline{P}$ of 7137 psig at 3528.5 m BRT, this is in moderately good agreement with the value obtained from the previous PBU (7164 psig at 3528.5 m BRT)

PERMEABILITY (FINAL PBU)

The Ramey type curve match gave a kh of 14.6 md ft. over the 10 ft. interval resulting in an average permeability to oil of 1.5 md. This compares well with the Horner result of 2 md for this build up and 1 - 1.3 md for the previous build up. As previously mentioned this is considerably less than the geometric core average permeability of 7 md, the discrepancy being explained in terms of irreducible water saturation, overburden, temperature and possibly relative permeability effects. The type curve match showed that afterflow effects became negligible after approximately 30 minutes.

SKIN EFFECT AND PRODUCTIVITY (FINAL PBU)

The Ramey type curve match gave a skin of +10, the Horner plot a value of +21. From this it can be seen that considerable formation damage occurred prior to the testing of the zone, though this is to be expected with an oil test of this type. A productivity index of 0.0087 BOPD/psi was calculated which under ideal conditions (s = 0) would yield a productivity index of 0.027 BOPD/psi taking the Horner skin value of +21. The radius of investigation for this test was in the order of 217 ft.

A summary of the results for DST 2 is given in Table 8.

TABLE 8. A SUMMARY OF DST 2 RESULTS

	SECOND PBU		FINAL PBU	
	Horner	Ramey	Horner	Ramey
kh (md ft)	10.07	12.68	20.02	14.65
k (md)	1.0	1.27	2.0	1.46
s	+10	+10	+21	+10
$\overline{P}$ at 3528.5 m BRT (psig)	7164	-	7137	-
J_{ss} (BOPD/psi)	0.0067	-	0.0087	-
J_{ideal} (BOPD/psi)	0.0136	-	0.027	-
$r_{inv.}$ (ft)	42	-	217	-

NB. kh and k values may be 25% higher than those calculated due to the higher oil viscosity obtained from 7/12-4 PVT report.

4.2.4.4 CONCLUSIONS DST 2

DST 2 established that dry oil can be produced down to praci-cally the base of the Upper Jurassic sands. The test, when combined with the results of DST 1B, established the producible OWC to be between 3530 and 3536 m BRT in this well.

The permeability in the poor quality sands between the depths 3527 and 3530 m BRT was estimated to be in the region of 1-2 md which is lower than would be expected from core averaged data corrected to reservoir conditions. This descrepancy might be explained in terms of relative permeability effects though no evidence of formation water production was detected. Considerable formation damage occurred in these low permeability sands prior to testing resulting in a skin factor of between [illegible] and +20. The productivity of this zone was in the region of 0.008 BOPD/psi which might be increased to 0.02 BOPD/psi under ideal conditions. The reservoir pressure at the perforations mid point was estimated to be 7150 psig at 3528.5 m BRT, which when combined with DST 3 results, confirmed an oil gradient in the Upper Jurassic sands of 0.29 psi/ft.

4.2.5 DRILL STEM TEST 3

Objective:

To obtain the maximum amount of reservoir and fluid data from the main Upper Jurassic sands.

Interval perforated:

3471.5 - 3463.5 m BRT

3460 - 3453 m BRT

Test string:

The test string employed for this test reverted back to using the APR tester valve. Below this as usual were the RTTS bypass, safety joint and packer, the packer being set at 3438.9 m BRT. Below the packer and perforated joint was a joint containing three Otis gauges, two pressure and one temperature, and below that a joint containing three Sperry Sun pressure gauges. Two Halliburton BT pressure gauges were also included, the base of the tail pipe was at 3469.4 m BRT. A full water cushion was run with this test, details of the test string can be seen in Fig. 16.

Test operation:

The Halliburton APR-N tester valve failed to close throughout the test, this only became apparent on examining the downhole charts on completion of the test, and consequently actuation of surface valves during the second and third shut in periods interfered slightly with the pressure build ups.

Otherwise the test was successful with four flowing periods and four shut in periods, the details of which are listed below.

1st flow	8 minutes
1st shut in	1 hour
2nd flow	4 hours
2nd shut in	8 hours (to fix a leaking swivel joint)
3rd flow	2 hours
3rd shut in	2 hours (to fix leaking chicksan)
4th flow	6 hours
4th shut in	6 hours

4.2.5.1 FLUID PRODUCTION AND SAMPLING DST 3

A total of approximately 3750 bbls cumulative of dry 39°API oil was produced during the four flowing periods. Initially for each flow the well was opened directly to the burners, then, when the well was partially stabilised, the flow was directed through the test separator and accurate flow rate measurements could be recorded.

The final flowing rates for the three main flow periods are listed overleaf.

	FINAL FLOW RATE (BOPD)
2nd flow	7040
3rd flow	7050
4th flow	6975

Full details of the flow rates and their calculation can be found in the Otis report for 7/12-4. All flows were maintained through a 32/64" choke on the choke manifold.

The final gas rate monitored for DST 3 was 2.6 MMSCF/D giving a separator GOR of 370 corresponding to a total GOR of 540 SCF/STB.

Twelve single phase oil samples were collected at the wellhead during the main flowing periods at wellhead pressures varying between 2330 and 2930 psig. The bubble points of these samples were checked on site and were all in good agreement averaging 1445 psig at 50^{o}F. A comprehensive PVT analysis of some of these samples is available in Corelabs PVT Report. Several atmospheric oil samples including three 55 gallon drums were collected during DST 3 from the test separator. Separator gas samples were also taken at regular intervals for chromatographic and H_2S analysis. Low levels of H_2S were detected using low range Gastec tubes after 5 hours flow and the concentration gradually increased to approximately 9 ppm and stabilised at this value. Full details of the H_2S measurements together with the gas chromatographic analysis of the separator gas can be found in the Production Testing Field Report for 7/12-4, a plot of H_2S concentration vs flowing time can be seen in Fig. 20.

Sand Production:

No trace of sand whatsoever was observed when reversing out the test string, breaking down the tools or flushing out the test separator on completion of the test. However 0.05 ft^3 of sand was recovered whilst conditioning the mud using OEDP prior to plugging back.

4.2.5.2 PBU INTERPRETATION OF FINAL PBU DST 3

Out of the seven pressure gauges run on this test only one functioned correctly, the Halliburton gauge BT 5623. The other Halliburton gauge failed completely, the Otis gauge 113256 suffered a ruptured bellows and on gauge 113259 the clock stopped. All three Sperry Sun gauges failed due to burst batteries.

Only the final PBU was interpreted as this was the only PBU uninterrupted by actuation of surface valves.

It was considered that the effect of the previous flows and PBU's were insignificant on the final PBU and so a standard Horner plot, as shown in Fig. 18 was constructed from the data obtained from BT 5623, this yielded a straight line of slope 19.2 psi/cycle. Fluid properties used in the interpretation were taken from previous 7/12 data prior to the 7/12-4 PVT data being made available. In the light of the higher than expected μo values, permeabilities may be approximately 25% higher than those calculated as was mentioned with DST 2.

Reservoir Pressure:

From extrapolation of the straight line a P^* of 7095 psig was obtained, this, when corrected to the perforations mid point, gave a $\overline{P}$ of 7088 psig at 3462.25 m BRT. This pressure when considered in combination with DST 2 results confirms an oil gradient of 0.29 psi/ft in the Upper Jurassic oil bearing sands (see Fig. 21). The absolute valuc of this pressure is in good agreement with other 7/12 data at this depth.

Permeability:

From the Horner plot a kh of 31339 md ft was calculated, which, if one considers the test to be limited to the 49 ft of perforations, results in a permeability to oil for the zone of 640 md. It is unlikely however that the test was not restricted to the perforated interval, and that the sands below were contributing to the test resulting in a somewhat higher than actual permeability. This is confirmed by the core data which gives a geometrical average permeability across the perforated interval of 344 md. When one considers the effects of overburden and temperature one would expect the test permeability, if restricted to the perforated interval alone, to be less than the core averaged permeability. If the entire sand from 3446 - 3493 m BRT was contributing to the test, this would reduce the net permeability to around 200 - 250 md which is more in line with that expected from the core data corrected to reservoir conditions. Afterflow effects were insignificant during the build up despite the well being shut in at surface.

Skin Effect and Productivity:

From the Horner plot a skin factor of +12 was calculated. This is considered normal for an oil test of this type and indicates some formation damage. Limited entry effects as mentioned above might also contribute to the positive skin. A productivity of 19 BOPD/psi was calculated, which, under zero skin conditions, results in an ideal productivity index of 42.3 BOPD/psi. The radius of investigation for the test was in the region of 1900 ft. A summary of the results for DST 3 is given in Table 9.

TABLE 9. A SUMMARY OF DST 3 RESULTS

kh (md ft)	FINAL PBU
kh (md ft)	31339
k (md)	640
s	+12.2
$\overline{P}$ at 3462.25 m BRT (psig)	7088
J_{ss} (BOPD/psi)	19
J ideal (BOPD/psi)	42.3
$r_{inv.}$ (ft)	1896

NB. In the light of the latest 7/12-4 PVT results kh and k may be 25% higher than those calculated.

CONCLUSIONS DST 3

DST 3 confirmed that high productivity sands exist towards the top of the Upper Jurassic reservoir with permeabilities in the region of 200 - 700 md. The test was unlikely to have been confined to the perforated interval resulting in the test permeability of 640 md being substantially higher than the geometric core average permeability of 344 md over this interval. Flow rates of around 7000 BOPD were maintained through a 32/64" choke at wellhead pressures in excess of 2000 psig. Formation damage and limited entry effects contributed to the skin factor of +12, the productivity index was estimated to be 19 BOPD/psi with an ideal productivity index of 42.3 BOPD/psi. Substantial fluid sampling was carried out during DST 3 and twelve single phase oil samples collected at the wellhead for PVT analysis.

TABLE 10. A SUMMARY OF DST RESULTS

	DST 1B				DST 2				DST 3
Formation	Middle Jurassic				Upper Jurassic				Upper Jurassic
Perforations (m BRT)	3550 - 3552 3536 - 3540				3527 - 3530				3471.5 - 3463.5 3460 - 3453
Water cushion	6000 ft				6000 ft				To surface
Fluid produced	Formation Water				Dry oil				Dry oil
Volume produced (BBLS)	27.5				26				3750
Oil gravity ^{o}API	-				39.4				39
Water SG (at 20^{o}C)	1.178				-				-
Rate (BPD)	60 - 90				37.5				~ 7000
Separator GOR (SCF/BBL)	-				-				370
Total GOR (SCF/BBL)	-				-				540
	Initial PBU		Final PBU		2nd PBU		Final PBU		Final PBU
Method of interpretation	Horner	Ramey	Horner	Ramey	Horner	Ramey	Horner	Ramey	Horner
kh (md ft)	1.79	3.17	1.86	3.33	10.07	12.68	20.02	14.65	31339
k (md)	0.09	0.16	0.09	0.17	1.0	1.27	2.0	1.46	640
s	-2.1	-5	-2.5	-5	+10	+10	+21	+10	+12.2
J_{ss} (BPD/psi)	0.0044	-	0.0048	-	0.0067	-	0.0087	-	19
J_{ideal} (BPD/psi)	0.0035	-	0.0036	-	0.0136	-	0.027	-	42.3
r_{inv} (ft)	27	-	27	-	42	-	217	-	1896
$\overline{P}$ (psig)	7030 at 3544 m BRT		7066 at 3544 m BRT		7164 at 3528.5 m BRT		7137 at 3528.5 m BRT		7088 at 3462.5 m BRT
Reservoir temperature (Q)	284 ^{0}F at 3610 m BRT				- -				- -

5. RESERVOIR FLUID PROPERTIES

5.1 Oil Properties

Twelve single phase oil samples were collected at the wellhead during DST 3. A rig site bubble point check was performed on each sample. Three of the samples were sent to Corelabs of Aberdeen for PVT analysis. The bubble points for the three samples were determined, and, as they were in good agreement with each other and within acceptable agreement of the on site results, the samples were combined for the remainder of the tests.

A summary of the main results is given below, the full report of the analysis can be found in the Corelab PVT report for 7/12-4.

Bubble point at	295°F	2417 psig
" " "	180°F	2087 "
" " "	60°F	1631 "

Compressibility at 180°F,	7000 psig	7.66 psi^{-}
" " 295°F,	" "	11.30 "

Viscosity of oil at 295°F,	" "	0.480 cp
" " " " " "	2417 psig	0.368 "

GOR from single stage flash to 68°F, 0 psig	626 SCF/BBL
Bo " " " " " " " "	1.508 Res. B/BBL
Residual oil stock tank gravity from single stage flash	38.2° API
GOR (total) from 3 stage flash to 60°F, 0 psig	553 SCF/STB
Bo " " " " " "	1.46 Res. B/STB
Residual oil stock tank gravity from 3 stage flash	39.4° API
SG of gas from single stage flash (rel. to air)	1.011

	Mole percent
H_2S	-
CO_2	1.43
N_2	1.64
Methane	30.31
Ethane	7.22
Propane	6.63
i Butane	1.33
n Butane	4.27
i Pentane	1.48
n Pentane	2.59
Hexanes	2.62
Heptanes	3.89
Octanes	5.15
Nonanes	3.91
Decanes plus	27.53
	100.00

The report appears internally consistent when checked against standard correlations. The results obtained must be considered to represent the most reliable results to date since previous analyses were based on recombination or RFT samples.

The only significant discrepancy in the report exists with the oil viscosity. The viscosities measured using the rolling ball viscometer were consistently higher than those predicted from the standard correlations and were considerably higher than obtained from previous 7/12 samples. At 7000 psig the viscometer measured an oil viscosity of 0.48 cp at 295°F whereas previous results indicated it was closer to 0.38 cp. From the correlations a viscosity in the region 0.4 - 0.43 cp was predicted, this must be considered more reasonable than the report value.

5.2 Water Properties

Several samples of formation water were taken while reversing out the test string following the completion of DST 1B.

Four of these samples were sent to Caleb Brett in Ellon, Aberdeenshire for a full analysis, the results of this analysis can be seen in Appendix 2. A summary of the main results is given below: -

Relative density at $20^{o}C$ g/ml			1.1784
pH at $25^{o}C$			5.2
Total dissolved solids mg/l			250870
Chloride	mg/l		153630
Bicarbonate	"		61
Sulphate	"		-
Carbonate	"		-
Bromide	"		158
Sodium	"		72670
Potassium	"		4350
Calcium	"		13800
Magnesium	"		3020
Resistivity at $25^{o}C$	ohm. m		0.0496
" " $40^{o}C$	"		0.0377
" " $60^{o}C$	"		0.0283
" " $80^{o}C$	"		0.0288

The results of the analysis are consistent with the expected results and are similar to previous 7/12 water samples. The concentration of Calcium however was found to be approximately half that encountered on earlier 7/12 wells and is more in line with expected formation water concentrations.

Using the measured formation water resistivities and extrapolating these to reservoir conditions (295°F) using standard resistivity vs. temperature charts, an Rw value of 0.0145 ohm. m was obtained corresponding to a NaCl concentration of 165,000 ppm. This is very similar to the value of 0.014 ohm. m obtained from previous samples and used in the log interpretation. The extrapolated resistivity vs. temperature plot can be seen in Fig. 19.

6. RESEVOIR PRESSURE AND TEMPERATURE

6.1 RESERVOIR PRESSURE

Initial reservoir pressure measurements for 7/12-4 were taken during the final logging suite using the RFT gauge. These results have been plotted versus depth in Fig. 21 together with the extrapolated pressures obtained from the three DST's.

From the RFT pressures it can be seen that there is a considerable discrepancy between the amerada readings and those given by the RFT gauge, however if one considers the possible gauge errors as indicated by the error bars, the discrepancy is explicable. Past experience has shown the RFT gauge to be less accurate than claimed by Schlumberger.

Above the probable effective OWC the data from DST's 2 and 3 agrees well with previous 7/12 data and lies approximately midway between the amerada readings and RFT gauge results. The reservoir pressure gradient in the Upper Jurassic oil bearing sands appears to be in the region of 0.29 psi/ft which is consistent with the gradient of 0.298 psi/ft. determined from the reservoir oil density. The absolute pressure taken at a datum of 3500 m SS was found to be 7142 psig. This is thought to be accurate within $\pm$ 30 psig considering the accuracy of the gauges (ref. Section 7) and the difference obtained between the initial and final PBU on DST 2. This figure compares well with 7140 psig obtained from previous 7/12 data.

Below the probable effective OWC there is some discrepancy as to the absolute value of the reservoir pressure in this region. The RFT gauge results give pressures higher than those expected and the extrapolated DST results considerably lower. This might be explained in terms of the shaly nature and low permeability of this zone. The sand shale sequence may have become superchanged by invasion of mud filtrate during the drilling of the zone resulting in a higher than normal pressure in the vicinity of the borehole. As the shaly sands may well be in poor communication with the main sands, the DST may have depleted the zone resulting in a locally reduced reservoir pressure.

This explanation was not confirmed on comparison of the results obtained form the initial and final PBU's for DST 1B, the final PBU instead of showing a further reduced reservoir pressure compared to the initial PBU gave a result 36 psi higher.

6.2 RESERVOIR TEMPERATURE

From a Horner type plot using the temperatures obtained during the Run 5 logging suite, a reservoir temperature of 284 ^{O}F at 3610 m BRT was obtained. However due to the approximations of this method, this result is not considered particularly accurate.

The RT 7 temperature gauge run in all three DST's only functioned correctly on DST 1B where it registered a temperature of 286 ^{O}F at 3537 m BRT. This is in good agreement with the logging derived temperature, though is approximately 5 ^{O}F lower than more accurate measurements obtained during higher flow rate tests on previous 7/12 wells.

A discussion of pressure and temperature gauge performance is given in Section 7.

7. GAUGE PERFORMANCE

Three types of pressure gauges were used during the testing of 7/12-4, Otis RPG 3's Halliburton BT's and Sperry Sun gauges. The Sperry Sun pressure gauges failed to produce any useful results due to battery malfunction. It was concluded that the batteries provided were slightly too long for the housing and when making up the housing the batteries were compressed causing them to crack under the high bottom hole temperatures.

During DST 1B and 2 only the Otis and Halliburton gauges were run, these all functioned correctly and produced useful results. However on DST 3 both Otis gauges failed, one due to ruptured bellows, the other because the clock stopped. All three Sperry Sun gauges failed as previously mentioned, and one Halliburton gauge failed to record leaving just one Halliburton gauge functioning correctly.

The agreeement between the gauges was moderate as can be seen in Table 11 though there were occasionally larger than expected discrepancies. For each DST the PBU analysis was conducted with the gauge considered to be giving the most consistent and reliable results.

The main differences between the gauges occurred at early shut in times where a minor error in time measurement resulted in a considerable difference in the pressure reading due to the sharply rising pressure. However at the more important later shut in times, agreement betweeen the gauges was moderately good.

The Otis RT 7 temperature gauge only functioned correctly during DST 1B where it monitored a reservoir temperature of $286^{O}F$ at 3537 m BRT, somewhat lower than expected. On DST 2 the stylus failed to operate, and on DST 3 the clock stopped.

TABLE 11. GAUGE AGREEMENT

DST		Δt (mins)	BT 5623	BT 1846	RPG3 113259	RPG3 113256
1B	1st flow	0 295	2749 3414	2837 3397	2676 3378	2866 3354
	1st CIP	0 435	3441 6613 *	3418 6628	3378 6528 *	3354 6519
	Final flow	0 165	3473 3786	3495 3798	3520 3722	3316 3699
	Final CIP	0 150	3802 6171 *	3813 6228	3737 6119 *	3730 6140
2	2nd flow	0 45	2836 2857	2794 2819	2994 3020	2842 2847
	2nd CIP	0 55	2860 7047 *	2825 7048	3025 7026	2847 7082
	Final flow	0 870	2857 3259	2819 3229	2979 3423	2867 3284
	Final CIP	0 55	3272 6928 *	3241 6942	3423 6924	3285 6949
3	3rd flow	0 110	6815 6721	FAILED	CLOCK STOPPED	BELLOWS RUPTURED
	3rd CIP	0 110	6715 7089			
	Final flow	0 350	6807 6744			
	Final CIP	0 390	6744 7089 *			

* Gauges for PBU analysis

APPENDICES

APPENDIX 1. DIARY OF EVENTS

DIARY OF EVENTS	WELL No : 7/12-4 ZONE TESTED: M/U Jurassic	DST No: RFTs 5A - 5D PERFS. :

DATE	TIME	OPERATIONS
10/11/77	0430	RIH Schlumberger RFT for Pressure data.
	0541	On station at 3551.5 m.BRT. Initial hydrostatic 7485 psi.
	0547	Tool set.
	0602	Pressure steady at 7171 psi.
	0610	Retract tool: Final hydrostatic 7483 psi.
	0613	On station at 3538 m.BRT. Initial hydrostatic 7456 psi.
	0619	Tool set : Formation pressure built up to 7284 psi.
	0636	Tool retracted: Final hydrostatic 7452 psi.
	0640	On station at 3505 m.BRT. Initial htdrostatic 7387 psi.
	0645	Tool set: Formation pressure 7048 psi.
	0653	Tool retracted: Final hydrostatic 7388 psi.
	0659	On station at 3467 m.BRT. Initial hydristatic 7310 psi.
	0730	Tool set: Formation pressure 7015 psi.
	0710	Tool retracted: Final hydrostatic 7315 psi.
	0714	On station at 3458 m.BRT. Initial hydrostatic 7290 psi.
	0718	Tool set: Initial pressure of 7119 psi decreased to 7091 by
		tool retracted.
	0736	Tool retracted: Final hydrostatic 7293 psi.
	0742	On station at 3481.5 m.BRT: Initial hydrostatic 7340 psi.
	0749	Tool set: Formation pressure 7015 psi

COMMENTS :

RFT Depths refer to CNL/FDC 5A

P.E. :

DIARY OF EVENTS		WELL No: 7/12-4 ZONE TESTED:	DST No: RFTs 5A - 5D PERFS.:

DATE	TIME	OPERATIONS
16/11/77	0800	Tool retracted: Final hydrostatic 7339 psi.
		Flopetrol RPG-3 pressure gauges were run with RFT 5A.
		Results are presented below:

RFT Depth (mBRT)	RPG - 32328 (PSI)	RPG - 34527 (PSI)
3551.5	7255	7277
3538.0	7406	7391
3505.0	7172	7159
3467.0	7133	7119
3458.0	7213	7203
3481.5	7152	7142

DATE	TIME	OPERATIONS
	1000	RIH Schlumberger RFT (Run 5B) with 1 gallon and 2 3/4 gallon
		sample chambers.
	1350	On station at 3467 m BRT: Initial hydrostatic 7282 psi.
	1353	Set tool: pretest chamber formation pressure 6982 psi.
	1355	Commence sampling 1 gal chamber: flowing pressure approx.
		6910 psi: chamber full in approx. 2 mins.
	1401	Seal 1 gal. chamber - pressure 6980 psi.
	1402	Sampling 2 3/4 gal. chamber: chamber full in approx. 6 mins;
		flowing pressure approx. 6900 psi.
	1416	Seal 2 3/4 gal. chamber: pressure 6979 psi.
	1418	Tool retracted: Final hydrostatic 7277 psi.

COMMENTS:

RPG-3 Bellows are 3 m. below RFT pad.

P.E.:

DIARY OF EVENTS		WELL No: 7/12-4 ZONE TESTED:	DST No: PERFS.:
DATE	**TIME**	**OPERATIONS**	
10/11/77	1500	Out of hole, bled off 1 gal. chamber.	
		Surface pressure: 800 psi	
		Gas: 11 cu.ft.	
		Emulsion: 3000 cc (approx. 95% water)	
		Water resistivity .405 ohm.m at 64° F, Cl = 10000 ppm.	
		(interpreted as mud filtrate)	
		Gas composition: C_1 83.8 %	
		C_2 11.4 %	
		C_3 3.7 %	
		iC_4 0.4 %	
		nC_4 0.7 %	
		Lines to 2 3/4 gal. chamber have pressure 1000 psi,	
		and contain oil approx. 38°.	
		1 P.V.T. transfer was made from the 2 3/4 gal. chamber:	
		Bottle number: 22400-31 Bubble Point: 2170 psi at 62° F.	
		Following this transfer the remaining fluid in the chamber	
		was depressurised, and proved to be water with:	
		R = 0.362 ohm.m at 62° F.	
		This is interpreted as mud filtrate.	

COMMENTS:

This P.V.T. sample is probably mostly water, although the bubble point is inexplicably high.

P.E.:

DIARY OF EVENTS		WELL No : 7/12-4 DST No : ZONE TESTED: PERFS. :
DATE	TIME	OPERATIONS
10/11/77	1700	RIH Schlumberger RFT (Run 5C) with 1 gallon and 2 3/4
		gallon chambers.
	1808	On station at 3458 mBRT. Initial hydrostatic 7269 psi.
	1810	Set tool: formation pressure from pretest chamber 6981 psi.
	1813	Sampling 1 gallon chamber: flowing pressure approx. 6398 psi.,
		chamber full in approx. 2½ mins.
	1818	Seal 1 gallon chamber: pressure 6980 psi.
	1820	Sampling 2 3/4 gallon chamber: flowing pressure approx. 6421 psi.
	1834	Seal 2 3/4 gallon chamber: pressure 6981 psi.
	1837	Tool retracted: final hydrostatic 7263 psi. POH.
	1920	Out of hole.
		1 gallon chamber: surface pressure 1000 psi.
		28 SCF gas
		2900 cc emulsion
		Gas composition H_2S : no trace
		C_1 : 85.8 %
		C_2 : 9.5 %
		C_3 : 3.9 %
		iC_4 : 0.3 %
		nC_4 : 0.6 %
		After extensive centrifuging emulsion could be separated
		to about 40% water, remainder oil.
		Lines to 2 3/4 gallon chamber. 1100 psi surface pressure.

COMMENTS :

PE :

DIARY OF EVENTS		WELL No: 7/12-4 DST No: ZONE TESTED: PERFS.:
DATE	**TIME**	**OPERATIONS**
10/11/77		2 3/4 gallon segregated sample: transferred two 600 cc samples:
		Bottle No: 22400-107 22226-116
		Bubble Point psig: 430 430
		Temp.° F: 50 50
		Significant amounts of water were observed in the transfer
		lines after the second bottle was transferred, and the remainder
		of the chamber was depressurised, containing a stable emulsion
		which when centrifuged had between 10 & 40% oil.
	2100	RIH Schlumberger RFT (Run 5D) with 1 gallon and 2 3/4 gallon
		chambers.
	2200	On station at 3528 m BRT: Initial hydrostatic 7415 psi.
	2212	Tool set: pretest chambers took 5 mins to fill to initial
		pressure 7097 psi: formation obviously tight.
	2219	Tool retracted.
	2221	Reset tool at 3528.5 m BRT: attempting to find more pereable
		horizon: after 3 mins pressure had only build up to 189 psi:
		retract tool.
	2226	Reset tool at 3527.5 m BRT: in 9 minutes pretest chamber pressure
		built up to 7078 psi.
	2238	Tool retracted: hydrostatic 7411 psi.
	2240	On station at 3528 m BRT for sampling: hydrostatic 7415 psi.
	2241	Tool set: pretest chamber pressure 7068 psi.

COMMENTS:

P.E.:

DIARY OF EVENTS		WELL No : 7/12-4 DST No : ZONE TESTED: PERFS. :
DATE	TIME	OPERATIONS
10/11/77	2247	Sampling 1 gallon chamber.
	2327	Seal 1 gallon chamber: pressure 7050 psi.
	2328	Sampling 2 3/4 gallon chamber: flowing pressure 190 psi.
	2340	Seal 2 3/4 gallon chamber after 1 hr. on station to prevent
		chances of differential stick.
	2343	Tool retracted: hydrostatic pressure 7406 psi. POH.
11/11/77	0045	OOH. Surface pressure in 1 gallon chamber: 0 psi.
		3400 cc water, R = 0.28 ohm.m at 58° F.
		Chloride content 15000 ppm.
		Small volume of gas: C_1 : 79.8 %
		C_2 : 10.0 %
		C_3 : 6.7 %
		iC_4 : 1.0 %
		nC_4 : 2.5 %
		Surface pressure of 2 3/4 gallon chamber: 0 psi.
		No gas.
		4000 cc water. R = 0.22 ohm.m at 58° F.
		Chlorides = 23.500 ppm.
		Assuming formation water to have chlorides content
		approx. 145000 ppm (as in 7/12-3A) 2 3/4 gallon chamber
		must contain mostly mud filtrate with maximum 17%
		formation water.

COMMENTS :

P.E. :

DIARY OF EVENTS	WELL No: 7/12-4	DST No: 1
	ZONE TESTED: M. Jurassic	PERFS.: 3536-40, 3550-52

DATE	TIME	OPERATIONS
16/11/77	01.00	Ran Schlumberger CBL/VDL/CCL/GR over 7" liner.
		Log showed good cement bond over all test intervals, and in overlap.
	05.00	Test overlap to 3000 psi by pressuring up below blind rams. Pressure
		test and Function test BOP stack. Rerun wear bushing.
	12.45	Rig Schlumberger to perforate RIH, gun failed P.O.H. and repair
		connection in head.
		Perforate 3550-52 m, 3536-40 m BRT (FDC/CNL 5A)
	18.15	Start making up tools for DST 1 Gauges Run:
		Gauge — No. — Clock Hrs. — Time Set
		Otis RPG-3 — 37995 — 120 — 1800
		Otis RPG-3 — 37999 — 72 — 1803
		Otis RT-7 — 40263 — 120 — 1810
		Sperry Sun — 214 — 168 — N/A
		Sperry Sun — 70 — 84 — N/A
		Howco BT — 5623 — 72 — 1758
		Howco BT — 1846 — 120 — 1752
	20.40	Run test tools as programmed: pressure test on top of
		tools: leaking.
	21.35	Pull back; find and repair leak on impact reverse sub.
	22.20	Pressure test on top of tools to 5000 psi.
17/11/77	00.00	Pressure test on top of 3½ pipe to 5000 psi.
		Run 5" D.P. with 6000' water cushion, pressure testing on top of
		25 and 50 stands to 5000 psi.

COMMENTS:

P.E.:

DIARY OF EVENTS		WELL No: 7/12-4 DST No: 1 ZONE TESTED: PERFS.:
DATE	**TIME**	**OPERATIONS**
17/11/77	06.55	Made up Subsea Test Tree, check unlatch/relatch mechanism.
	07.35	Made up Lubricator Valve.
	10.55	Made up Surface Tree, flow and kill lines and tested to 7000 psi.
	11.05	Set RTTS packer: lost 28,000 lbs wt. landed SSTT.
	11.20	Pressured to 2000 psi on annulus: opened APR 'N' tester valve.
		No blow: sucking very slightly at bubble hose.
	11.25	Bleed annulus pressure to close APR valve for initial P.B.U.
		No indications of flow at bubble hose.
	12.25	Pressure annulus to open APR tester for main flow. Again very
		slight sucking initially, dying out after a brief time. The well
		was left open for 4 hrs in the hope that it would come in:
		no indications of flow during the entire period.
	16.25	Closing in APR tester: cycle tool twice to check operation: still
		no indications of flow.
	17.00	It was discovered that due to the NRV in the kill line annulus
		pressure had apparently been applied continuously since 11.25,
		and not bled off as thought.
		Cycle tool twice - still no indications of flow.
	17.12½	Close in for main P.B.U.
18/11/77	00.16	Drop bar to shear impact sub for reversing out: circulating
		across wellhead.
	00.22	Bar hits: reversing out to Otis tank collecting samples at
		wellhead: 80 barrels water cushion (chlorides negligible;
		5 barrels mud and water cushion mixed (chlorides 3000 - 11000 ppm);
		uncontaminated mud after 191 Bbls. Circulate and condition mud.
	03.50	Unseat packer.

COMMENTS:

P.E.:

DIARY OF EVENTS		WELL No : 7/12-4 DST No : 1 ZONE TESTED: PERFS. :
DATE	TIME	OPERATIONS
18/11/77	13.05	Pulling test tools: top of APR 'N' test tool and base of first stand of collars were plugged with barite/shale. Fluid from collars below impact reverse sub contained no fluorescent hydrocarbons, with Chloride content of 3500 ppm appears to be a mixture of mud and water cushion.
	15.30	Complete breaking down test tools.

COMMENTS :

P.E. :

DIARY OF EVENTS	WELL No : 7/12-4	DST No : 1A
	ZONE TESTED:	PERFS. : 3050-52, 3536-40

DATE	TIME	OPERATIONS
18/11/77		R.I.H. open ended drill pipe to 3570 m,
		reverse circulated hole 2 cycles: Flushed riser through
		choke and kill lines.
19/11/77	0700	Run Schlumberger Junk Basket to T.D. (3591 m):
		a small amount of sand/shale cuttings collected,
		probably from T.D.
	1000	Reperforate 3550-3552 m, 3536-3540 m, (extra runs required
		due to 2 misfires).
	1830	Pick up test tools: All tools thoroughly cleaned to ensure
		no plugging material remained. Test string dimensions as for DST 1.
		Gauges run:

Gauge	No.	Clock Length	Set	Depth
Howco BT	1846	120 hrs.	1829	3556.93
Howco BT	5623	72 "	1832	3555.71
Sperry Sun	214	84 "	-	3551.54
Sperry Sun	398	168 "	-	3548.54
Otis RPG-3	40263	120 "	1837	3542.39
Otis RPG-3	37999	72 "	1835	3540.03
Otis RT-7	37993	120 "	1830	3538.03

DATE	TIME	OPERATIONS
	2200	Pressure test on top of test tools to 5000 psi.
	2350	Pressure test on top of 3½" pipe - did not hold -
		pulled back tools to locate leak.
20/11/77	0225	Find impact reverse sub leaking - face washed out:
		remachine and test 5000 psi OK.
	0410	R.I.H. with remaining 3½" and 5" pipe: fill two stands above
		APR 'N' tester with gel to prevent solids settling out. Run 6000'
		fresh water cushion, remaining pipe empty.

COMMENTS :

P.E. :

DIARY OF EVENTS		WELL No : 7/12-4 DST No : 1A ZONE TESTED: PERFS. :
DATE	TIME	OPERATIONS (Page 2)
20/11/77	1155	Pick up Otis Subsea Test Tree: check unlatch mechanism.
	1330	Surface tree made up - wind 45 - 50 knots, heave 10-12 ft.,
		too rough to set packer or pick up choke manifold to connect
		surface lines.
	1400	P.O.H., lay down surface tree, lubricator valve and subsurface
		test tree; make up Cameron hang off tool and land string in
		wellhead.
	1530	W.O.W.: winch in Otis burner booms to avoid damage.
	2200	Force 12 forecast: pull back to top of water cushion to avoid
		filling empty string with seawater if hanging off.
21/11/77	1015	P.O.H. to check tools and circulate hole clean while W.O.W.
	1430	Out of hole. Gel in collars above APR had developed extreme
		viscosity, would not run out of bottom collar.

COMMENTS :

P.E. :

DIARY OF EVENTS		WELL No : 7/12-4 DST No : 1A ZONE TESTED: PERFS. : 3550-52, 3536-40
DATE	TIME	OPERATIONS (Page 1)
21/11/77		RIH Open ended pipe, circulated to condition mud.
22/11/77		Circulating with OEDP at 3570 m awaiting forecast of improving
		weather.
23/11/77		Spot pill of treated mud over test interval, POH.
	1820	Picking up test tools. Gauges run:

Gauge	No.	Clock Hrs.	Time Set	Final Depth
Howco BT	14226	120	1810	3547.79
Howco BT	12419	72	1805	3546.57
Otis RT7	40263	120	1820	3541.40
Otis RPG-3	37999	72	1818	3539.04
Otis RPG-3	37993	120	1812	3537.04

DATE	TIME	OPERATIONS
		Spot viscous ge in 2 stands of collars above APR-N tester.
	2030	Test to 5000 psi on top of test tools.
	2240	Test to 5000 psi on top of $3\frac{1}{2}$" D.P.
		R.I.H. with 5" D.P. with fresh water to give 6000'
		water cushion - test to 5000 psi at 25 and 51 stands.
24/11/77	0640	Pick up Subsea Test Tree.
	0820	Land string in wear bushing.
	0925	Test surface lines to choke manifold to 7000 psi,
		lines to separator to 1500 psi.
	0933	Set packer.
	0945	Pressure up to 1900 psi on annulus to open APR tester valve:
		no clear surface indications.
	0950	Shut in well for initial PBU
	1045	Opened APR-N tester tool for main flow period: weak intermittent
		indication at bubble hose; registered 0.001 cu.m. of air flowing
		from pipe in 2 hours. After 3 hrs. 5 mins well appears to be

COMMENTS :

P.E. :

DIARY OF EVENTS		WELL No : 7/12-4 DST No : 1A ZONE TESTED: PERFS. :
DATE	**TIME**	**OPERATIONS** (Page 2)
24/11/77		sucking slightly. Drain remaining water from 3" Chiksans:
		no effect. After 3 hrs. 55 mins increase annulus pressure
		from 1900 to 2200 psi: still no indications.
	1455	Bleed of annulus pressure and close APR-N
	-1501	tool. Pressure up annulus twice to 1900 to check operation of
		APR-N tool. Well seems to be sucking slightly (2 to 3 ins water)
		regardless of annulus pressure.
	1515	Annulus pressure bled off for final P.B.U.
	1746	Drop bar to commence reversing out: no effect.
	1808	Pressure annulus to 3200 psi and activate APR 'A' reversing valve.
		(This would open APR-N test tool instantaneously and distort PBU
		slightly but 50 knot winds and 12 ft. heave left no option.
		Reverse out to Otis tank approx. 78 bbls fresh water cushion
		followed by annulus mud.
	1845	Circulate down drill pipe and up annulus to condition mud prior
		to P.O.H.
	2140	End P.B.U. by unseating packer (pull about 310,000 lbs). P.O.H.
25/11/77		Waiting on weather with drill pipe hung off, test tools in 9 5/8"
		casing above 7" line hanger.
	1600	Relatch drillpipe and continue P.O.H.
	2130	Recover samples of fluid from collars below reversing sub:
		max chlorides 13,000 ppm: mud and water cushion only. Retrieve
		gauges and break down test tools.
26/11/77		R.I.H. O.E.D.P. - reverse circulated bottoms up. 1 unit gas, no
		fluorescence, no increase in chlorides: no evidence of formation
		fluids.

COMMENTS :

P.E. :

DIARY OF EVENTS		WELL No : 7/12-4A DST No : 1B ZONE TESTED: PERFS. : 3550-52, 3536-40
DATE	TIME	OPERATIONS
26/11/77	1320	Started picking up test tools.
	1345	Ran gauges.

Gauge	No.	Clock (hrs.)	Time set	Final Depth
Otis RPG-3	37993	120	1320	3552.58
Otis RPG-3	37999	72	1322	3534.58
Otis RT7	40263	120	1326	3536.94
Howco BT	5623	72	1321	3542.31
Howco BT	1846	120	1324	3543.53

DATE	TIME	OPERATIONS
	1515	Made up Hydro spring.
	1655	Test on top of APR A to 5000. Slight leak at make up to collar. Ok after tightening.
	2020	Test on top of 3½" d/p. Slight leak observed. Pressured to 5000, leak still evident.
	2110	Test on top of slip joints, leak now slightly worse. Top slip joint differential piston was leaking slowly, however the main leak continued after this was replaced by another slip joint.
	2245	Test on top of drill collars below slip joints, leak now even worse.
	2330	Test on top of APR A, leak still evident.
27/11/77	0005	Tested OK on top of impact reverse sub.
	0040	RIH to APR A tightening joints of the one stand of drill collars. Tested OK on top of APR-A.
	0140	RIH 3 stands of collars, tested to 5000 successfully.
	0225	Tested on top of slip joints OK.
	0300	Tested on top of 3½" OK.
	0505	Tested after 25 stands OK.
	0710	Tested on top of 50 stands OK. Ran water cushion to 51 stands.

COMMENTS :

P.E. :

DIARY OF EVENTS		WELL No : 7/12-4 DST No : 1B ZONE TESTED: PERFS. :
DATE	TIME	OPERATIONS (Page 2)
27/11/77	0920	Picked up SSTT.
	1000	Picked up lubricator valve.
	1105	Pressure tested tree and lines to 7000 psi.
		Swivel on top of kill line leaking. Tested OK after replacement
		fitted.
	1240	Pressure test to separator OK (1500 psi).
	1258	Set RTTS packer and cycle hydrospring open.
	1317	Slight blow on bubble hose.
	1321	Stronger blow on bubble hose.
	1326	Cycled hydrospring closed.
	1350	Blowing strongly - hydrospring appears to be open.
	1621	Cycle again to theoretically open hydrospring.
	1630	Still bubbling at between 80-90 bbls/day.
	1814	Closed hydrospring by lifting string 12 ft. up without letting
		back down. Bubbling on hose ceased more or less immediately.
	2205	Lowered string back to original position - no flow.
	2239	Cycled tool to open position, however, no flow seen.
	2338	Cycled tool to closed position - no flow.
28/11/77	0039	Cycled tool to open position - no flow.
	0138	Cycled tool to closed position - no flow.
	0146	Cycled tool to open position - no flow.
	0244	Cycled tool to closed position lifting string up until actually
		pulling on the packer.
	0245	Weak indications of well flowing.
	0300	Well flowing slowly.
	0545	Well shut in for PBU.
	0813	Dropped bar.

COMMENTS :

P.E. :

DIARY OF EVENTS		WELL No: 7/12-4 DST No: 1B ZONE TESTED: PERFS.:
DATE	TIME	OPERATIONS (Page 3)
28/11/77	0819	Annulus level started to drop, started pumping mud to keep topped up.
	0826	Fluid returns to surface after pumping 542 strokes.
	0838	Closed rams and continued pumping, taking samples approximately every 100 strokes.
	0854	Mud back to surface lines after pumping 1785 strokes. Circulated mud.
	1027	Unset packer and POH.
	1800	Out of hole with gauges.

COMMENTS:

P.E.:

DIARY OF EVENTS	WELL No: 7/12-4	DST No: 2
	ZONE TESTED: U. Jurassic	PERFS.: 3527-30 mBRT

DATE	TIME	OPERATIONS
29/11/77	09.00	Rig Schlumberger. RIH junk basked with gauge ring and tagged cement
		at 3534.8 mBRT.
	11.00	Ran and set Baker model 'N' bridge plug at 3533 mBRT. Pressure
		tested to 2000 psig.
	13.00	RIH and perforated 3527-30 mBRT.
		POH and rig down Schlumberger.
	15.15	Commence picking up test tools for DST No. 2. Following gauges run:

Gauge	No.	Clock Hrs.	Set at
Halliburton BT	5623	72	14.31
Halliburton BT	1846	120	14.30
Otis RPG-3	37999	120	15.16
Otis RPG-3	37993	72	15.19
Otis RT-7	40263	120	15.23

DATE	TIME	OPERATIONS
	17.20	Pressure tested top APR 'A' to 5000 psi.
	19.30	Pressure tested top slip joints to 5000 psi and top 3½ in. pipe
		to 5000 psi. Ran in 5" d/p with 6000 fr. fresh water cushion.
		Pressure tested to 5000 psi after 25 stands and at top of cushion
		(52 stands).
30/11/77	01.15	Picked up SSTT
	02.15	Made up lines to surface test tree.
		Landed string in wellhead and pressure tested surface lines to
		7000 psi to choke manifold and 1500 psi to separator inlet.
	03.30	Waiting on daylight to commence test.
	07.35	Checked hanging weight of string:
		pick-up 240,000 lb wt set down: 230,000 lb wt.

COMMENTS:

3½" IF d/p joint used as gauge carrier filled with fresh water.
1 stand of collars above Fol-Flo tester filled with gel.

P.E. :

DIARY OF EVENTS		WELL No : 7/12-4	DST No : 2
		ZONE TESTED:	PERFS. :

DATE	TIME	OPERATIONS
30/11/77		Picked string up 5.5 m put in six turns to right and set down.
		Loss of ∿ 25000 lb wt indicated packer set.
	07.44	Packer set at 3501.72 mBRT. Ful-Flo hydrospring should have opened
		after ∿ 3 mins. No indication of flows.
	07.57	Cycled tool to closed position to record initial PBU. Hydraulic
		connection to side-arm safety valve damaged.
	08.21	Repaired and reopened sidearm valve.
	08.55	Cycled tool to open position. No indication of flow.
	10.01	Still not slightest sign of flow at bubble hose. Recycled tool in
		case still in closed position. Still no surface indication of flow.
	10.00	Still no sign of flow. Recycled tool in theory to open position.
		Well sucking slightly.
	11.35	Shut side-arm safety valve. Drained all water out of surface lines.
		Remade up lines and opened side arm valve.
	11.45	Steady blow now apparent at bubble hose. Obviously water in lines
		had prevented surface indications. Recorded air displacement rate
		with gas meter.
	12.00	Steady blow: 34 BPD.
	13.00	Rate: 31 BPD. Slight trace of gas:
		C: 154 ppm., C_2 : 17 ppm.
	14.00	Rate: 37 BPD. Gas concentration decreasing.
	15.00	Rate: 40 BPD. Gas concentration negligible. The increasing rate
		suggests that produced oil may be rising through the water cushion
		and releasing gas from solution.
	16.00	Rate: 65 BPD. Trace gas.
	17.00	Rate: 227 BPD. 29 ppm C_1.

COMMENTS :

Maximum gas concentration reading at 13.30:

C_1: 540 ppm, C_2: 65, C_3: 20

P.E. :

DIARY OF EVENTS

WELL No: 7/12-4 DST No: 2

ZONE TESTED: PERFS.:

DATE	TIME	OPERATIONS
30.11.77	18.00	Rate: 1500 BPD. 44 ppm C_1.
	18.30	Total displacement: 84 Bbls (air space volume above water cushion:
		98 Bbls). Gas reaches surface.
		Flow directed through gas meter and back into flare line.
	20.00	Rate: 1159 BPD. Gas SG (calc.) 0.799.
	21.00	Rate: 1349 BPD.
	22.00	Rate: 1431 BPD.
	23.00	Rate: 1429 BPD.
1.12.77	00.00	Rate: 1401 BPD.
	01.00	Rate: 1430 BPD.
	02.00	Rate: 1261 BPD. Picked up string 18 ft to close Ful-Flo tester
		for final PBU. Continued monitoring gas rate at surface.
	03.00	Gas rate showing no sign decreasing so picked string up further
		3 ft and set back down same distance to ensure tool closed.
	04.00	Gas rate showing slight increasing trend.
		Picked up tool once again and held in top position. Sudden ∿ 6 ft
		drop in annulus mud level indicated that packer had become unseated.
		Limited fall in level indicated tester was closed. Waited on day-
		light to commence reverse out.
	07.30	Gas rate still 1400 BPD. Set string down in wellhead and dropped
		bar to commence reversing out.
	07.47	Impact sub-sheared. Contents of test string reversed out to test
		tank. Flow controlled and samples collected at choke manifold.
	08.01	Oil to surface. Samples taken at bubble hose. ∿ 26 Bbls of oil
		flowed to tank when water cushion reached surface.

COMMENTS:

From 18.00 hrs onward the gas rate is essentially stabilized.
Based on the 7/12-2 GOR this represents an oil rate of ∿ 15 STBPD.

P.E.:

DIARY OF EVENTS		WELL No : 7/12-4 DST No : 2 ZONE TESTED: PERFS. :
DATE	TIME	OPERATIONS
1.12.77	09.15	Mud to surface after 180 Bbls total displacement. Mud switched overboard after 195 Bbls displaced and 10 Bbls dumped. Total of 113 Bbls fluid reversed to test tank and separator (of which ∿ 5 Bbl Mud).
	12.00	Completed conditioning mud. Pumped slug and POH.
	13.15	Stood back SSTT in derrick.
	19.00	Test tools out of hole. RIH with OEDP to condition mud and plug back.

COMMENTS :

P.E. :

DIARY OF EVENTS	WELL No: 7/12-4	DST No: 3
	ZONE TESTED: U. Jurassic	PERFS.: 3471.5-63.5, 3460-57 mBRT

DATE	TIME	OPERATIONS
2.12.77	08.30	Rig Schlumberger and RIH with junk basket
		to tag top cement at 3476 mBRT. POH.
	11.00	RIH with Baker model 'N' type bridge
		plug and set at 3475.5 mBRT. Pressure
		tested to 2600 psig.
	13.30	RIH and perforated interval 3471.5 - 63.5
		to 3460 - 53 mBRT.
	20.00	Schlumberger out of hole and rigged down.
	20.30	Commence picking up test tools for DST No. 3.
		Following gauges run:

Gauge	No.	Clock Hrs.	Set at
Halliburton BT	5623	72	20.21
Halliburton BT	1863	120	20.17
Sperry Sun	208	84	-
Sperry Sun	185	84	-
Sperry Sun	68	128	-
Otis RPG-3	28122N	72	20.38
Otis RPG-3	37998	120	20.35
Otis RF-7	40246	120	20.31

DATE	TIME	OPERATIONS
	22.00	Pressure test top APR 'A' reversing valve to 5000 psi.
	23.10	Pressure test at top $3\frac{1}{2}$" pipe to 5000 psi.

COMMENTS:

P.E.:

DIARY OF EVENTS		WELL No: 7/12-4 DST No: 3 ZONE TESTED: PERFS.:
DATE	TIME	OPERATIONS
2.12.77	23.30	RIH 5" d/p pressure testing every 25 stands (first two to 5000 psi
		and thereafter 6000 psi). Fresh water cushion run to surface.
3.12.77	06.40	Make up sub-sea test tree.
	08.00	Make up surface tree plus flowlines.
		Land string in wellhead. Pressure test surface lines to 7000 psi.
		Changed out leaking needle valve. Pressure test liens to separator
		to 1500 psi.
	09.20	Check string hanging wt. Picked up 10 ft, put in to turns to right
		and set down with ∿ 25,000 lb wt loss.
	09.27	Packer set.
	09.38	Pressured annulus and flowed well on 32/64 in. variable choke to
		test tank.
		WHFP = 465 psi.
	09.43	Closed-in downhole.
	09.46	Closed in on surface manifold.
		Total volume tanked: 73 Bbls.
		Rate: 13140 BPD. Wellhead pressure increased rapidly to 2800 psi.
	10.46	Pressured up an annulus to 2000 psi to open APR 'N'.
	10.51	Opened up at surface on 16/64 in. variable choke. WHFP dropped
		to 1950 psig and then started increasing slowly.
	11.02	Mud to surface.
	11.05	Oil to surface. WHFP 2210 psig.
	11.16	Directed flow through separator. Unable to obtain level in sepa-
		rator. Oil rate ∿ 9200 STBPD but oil probably also carried over
		into gas line. Variable choke setting of 1/4 in. obviously not
		true reading and is probably closer to 3/4 in.

COMMENTS: The separator GOR of 150 SCF/STB with gas remaining in solution represents a total GOR of ∿ 350 SCF/STB. This is considerably less than previous results and may be spurious due to oil carry over.

P.E.:

DIARY OF EVENTS	WELL No: 7/12-4	DST No: 3
	ZONE TESTED:	PERFS.:

DATE	TIME	OPERATIONS
3.12.77	11.48	Switched flow through 1/2" positive choke. decreased
		significantly and WHFP increased up to 2900 psi.
	11.55	Level established in separator and rate measured: 7130 STBPD
		with Sep. P: 750 psig, Sep. Temp.: 168° F.
		GOR ∿ 150 SCF/STB.
	12.15	Flowrate: 7140 STBPD. WHFP: 2920 psig.
		WHFT: 184° F. Unable to determine separator volume factor
		owing to blockage in shrinkage tester lines.
		Total shrinkage factor determined by taking PVT sample of
		separator oil and flashing off to volumetric flask.
		Shrinkage factor: 0.91 STB/Sep. Bbl.
		Checked separator pressure with DWT.
		Barton meter correct within 10 psi.
	13.20	BS & W reduced to less than 0.1% water. Commenced collecting
		PVT samples at wellhead.
	14.10	Second PVT sample completed. BS & W now zero. Separator
		gas S.G. determined by Ranarex: 0.774.
	14.55	Bypassed separator.
	14.48	Closed-in well at surface manifold for helicopter arrival.
	15.05	Leak developed in swivel below surface tree. Shut-in at APR 'N'
		and at lubricator valve. Bled off wellhead pressure. Lubricator
		close line lost pressure. Closed SSTT.
		Opened helicopter valve and bled off remaining pressure.
	17.15	Removed STT and installed kelly valve. Broke out swivel and
		remade up STT on kelly valve. Pressure tested system. Leak
		developed at kelly valve.
	20.07	Removed STT and kelly valve. Made up STT directly onto 5" d/p

COMMENTS:

P.E.:

DIARY OF EVENTS		WELL No: 7/12-4 DST No: 3 ZONE TESTED: PERFS.:
DATE	TIME	OPERATIONS
3.12.77		Pressured string to equalize across SSTT balls. Opened SSTT.
		Pressure tested entire system.
	22.45	Commence pressuring annulus to open APR 'N'.
	22.47	Opened up well on 32/64 in. fixed choke. Flow diverted through
		separator. Differential meter off scale, changed from 1" to 1.5"
		orifice plate
	23.45	Oil rate: 7930 STBPD. Sep. P: 790 psig. Sep. T: 135° F.
		Separator GOR: 285 SCF/STB.
4.12,77	00.00	Commence collecting further PVT samples at wellhead.
		Separator gas samples taken every half hour for chromatographic
		analysis and H_2S me-surements - see details enclosed.
	00.47	Chiksan connection on rig floor developed leak. Well shut-in
		on Otis side arm safety valve and separator bypassed.
		Removed half Chiksan swing. Remade up and pressure tested
		system.
	02.38	Open well on 32/64 in. fixed choke. Switched flow to separator.
	02.45	Commence collecting atmospheric oil sample from separator and
		further PVT samples from wellhead.
	03.00	WHFP: 2750 psig, WHFT: 115° F,
		Sep. P: 760 psig, Sep. T: 138° F,
		Rate: 7494 STBPD, Sep. GOR ∿ 275 SCF/STB.
	05.00	Continued stabilized flow. Further atmospheric and PVT samples
		taken. Gas monitorings continued. Second gas SG measured on
		Ranarex: 0.754
	07.00	Obtain final (12) PVT sample at wellhead. Check separator
		shrinkage factor: 0.895 STB/ Sep. Bbl.

COMMENTS:

P.E.:

DIARY OF EVENTS		WELL No 7/12-4 DST No 3 ZONE TESTED: PERFS. :
DATE	TIME	OPERATIONS
4.12.77	08.31	By pass separator.
	08.34	Bleed-off annulus pressure to close APR 'N'. No decrease in
		rate or WHFP.
	08.43	Close-in at choke manifold.
	15.00	Insert bar above swab valve and attempt to bleed-off string
		above APR 'N'.
	15.32	Flowrate appears restricted but not declining.
	15.45	Dropped bar to commence reverse out. No change in annulus
		level or wellhead closed-in pressure noted.
		Pressure annulus slightly and increase in WHCIP noted.
	16.05	Bleed down string to burners maintaining annulus pressure below
		700 psig.
	16.50	Mud to surface after 192 bbls disclosed.
		10 Bbls mud dumped.
	17.10	Commence circulation to condition mud.
	21.30	Unseated packer and POH.
5.12.77	03.30	Breaking down test tools.
	04.45	Recover pressure gauges.
	05.00	RIH open ended d/p to commence suspension programme.
		Circulated two cycles to condition mud.
		$\sim 0.05 ft^3$ sand collected at bottoms up.
		Commenced plugging back.

COMMENTS :

P.E. :

APPENDIX 2. ANALYSIS OF FORMATION WATER

Formation Water Analysis (DST 1B)

An API water analysis was carried out on the following samples: -

Sample No.	Time taken	BBLS pumped during reverse out
79	08.49 (28/11/77)	157.6
80	08.50 - " -	162.7
81	08.51 - " -	170.0
82	08.52 - " -	172.8

Test	Units	Sample No. 79	80	81	82
Relative density at 20°C	g/ml	1.1634	1.1769	1.1803	1.1779
pH at 25°C		6.0	5.4	5.1	5.2
Total dissolved solids	mg/l	228800	247300	255500	249800

Anions	Units	79	80	81	82
Chloride	mg/l	140200	151600	156600	152700
Sulphate	"	-	-	-	-
Carbonate	"	-	-	-	-
Bicarbonate	"	200	55	60	67
Sulphide	"	neg.	neg.	neg.	neg.
Hydroxyl	"	-	-	-	-
Bromide	"	120	130	150	195
Cations					
Sodium	"	63400	70000	73100	74900
Potassium	"	4280	4280	4380	4400
Calcium	"	16740	17140	10960	13310
Magnesium	"	2980	2950	3080	3040
Iron	"	2.8	245	315	255
Barium	"	10.4	24.3	31.0	22.0
Lithium	"	25.3	31.8	27.0	28.6
Strontium	"	740	830	850	845

Resistivity	Units	79	80	81	82
at 25°C	ohm.m	0.0510	0.0500	0.0488	0.0500
at 40°C	"	0.0386	0.0377	0.0374	0.0379
at 60°C	"	0.0294	0.0286	0.0284	0.0278
at 80°C	"	0.0235	0.0227	0.0320	0.0227

BP PETROLEUM DEVELOPMENT OF NORWAY A.S

WATER ANALYSIS REPORT

FIELD: 7/12

WELL: 7/12-4

ZONE: MIDDLE JURASSIC DST 1B

SAMPLE DATE:

DATE OF ANALYSIS:

LABORATORY: CALEB BRETT

SAMPLING DETAILS: AVERAGE OF SAMPLES 80,81 AND 82.

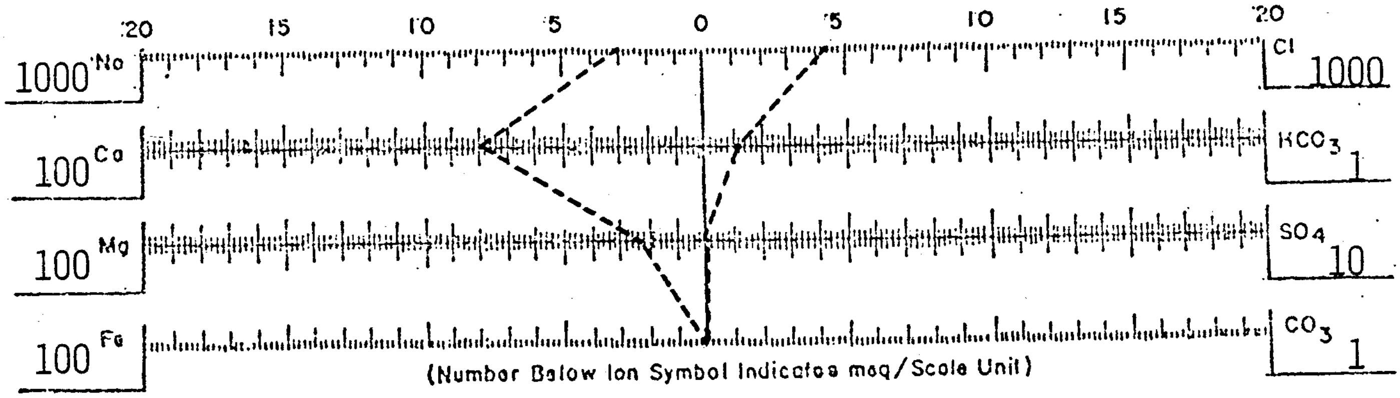
Specific Gravity 1.178 AT 20^{o}C pH 5.2 Resistivity 0.050 OHM AT 25^{o}C

Appearance as recieved ORANGE CLOUDY Appearance on filtration ORANGE CLEAR

Total Dissolved Solids 250,000 Total Suspended Solids N/M

Hydrogen Sulphide N/M

DISSOLVED MINERAL ANALYSIS PATTERN



(Number Below Ion Symbol Indicates meq/Scale Unit)

DISSOLVED SOLIDS ANALYSIS

	mg/l	meq/l	method
Sodium	72700	3161	
Potassium	4350	111	
Calcium	15800	788	
Magnesium	3020	248.5	
Iron	270	14.5	
Barium	26.6	0.4	
Strontium	842	19	
Lithium	29.1	4.2	

	mg/l	meq/l	method
Chloride	153600	4327	
Sulphate	-	-	
Bicarbonate	61	1	
Carbonate	-	-	
Sulphide	NEG.	NEG.	
Hydroxyl	-	-	
Bromide	158-	2	

APPENDIX 3. REFERENCE REPORTS

REFERENCE REPORTS

1. Otis Flowtest Report 7/12-4
2. Otis Gauge Reading Report 7/12-4
3. Flopetrol RFT Amerada Report 7/12-4
4. Core Laboratories PVT Analysis Report 7/12-4
5. Caleb Brett Water Analysis Report 7/12-4
6. Formation Evaluation Branch, BP Trading Ltd., Computer Processed Interpretation 7/12-4
7. Production Field Testing Report 7/12-4
8. 7/12-2 Petroleum Engineering Completion Report
9. 7/12-3 Petroleum Engineering Completion Report
10. 7/12-3A Petroleum Engineering Completion Report
11. 7/12-4 Geological Completion Report
12. Statex Core Analysis Report 7/12-4
13. Halliburton Formation Testing Service Reports DST 1 7/12-4
14. Halliburton Formation Testing Service Reports DST 2 7/12-4
15. Halliburton Formation Testing Service Reports DST 3 7/12-4

LIST OF FIGURES

BP PETROLEUM DEVELOPMENT OF NORWAY A.S.

LOCATION PLAT WELL 7/12-4

COUNTRY - NORWAY

AREA - NORTH SEA

CO-ORDINATES - LAT. 57° 05' 36.66" N

LONG 02° 51' 36.96" E

LICENCE NO. 019

BLOCK NO. 7/12

GRID REFERENCE E 6327953.7

N 488502.4

ELEVATION OF ROTARY TABLE 25m metres AMSL

REFERENCE - U.T.M INTERNATIONAL SPHEROID, ZONE 31

Scale: 1:250,000

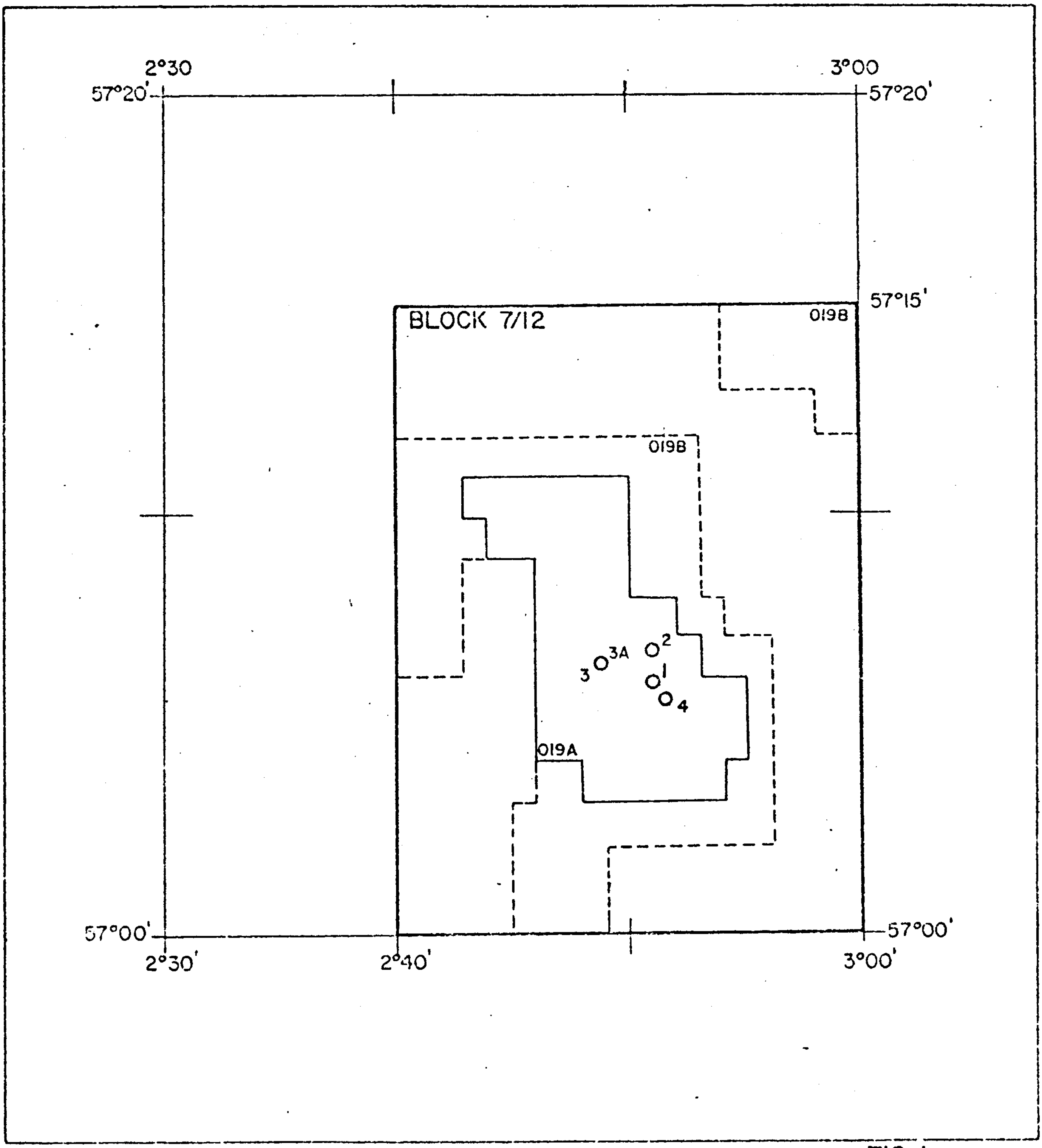
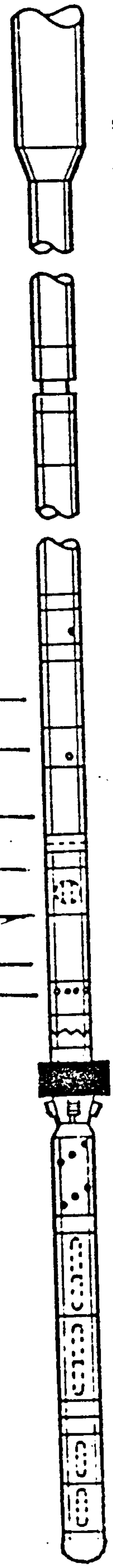


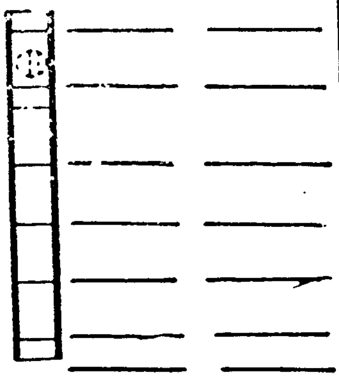
FIG. 1

HALLIBURTON TEST STRING WELL 7/12-4 DST 1

APR STRING



FUL-FLO STRING.



TOOL	BOX	PIN	LENGTH	DEPTH
HANG-OFF POINT				93.25
HANGER BELOW H/O			0.18	93.43
STANDS 5" DRILLPIPE			3077.03	3170.46
CROSSOVER	$4\frac{1}{2}$"IF	$3\frac{1}{2}$"IF	0.51	3170.97
STANDS $3\frac{1}{2}$" DRILLPIPE			117.96	3288.93
SLIP JNT. (OPEN)			6.10	3295.03
SLIP JNT. (CLOSED)			4.57	3299.60
6" STANDS $4\frac{3}{4}$" DRILL COLLARS			164.54	3464.14
CROSSOVER	$3\frac{1}{2}$" IF	$2\frac{7}{8}$" EUE	0.3	3464.44
APR REVERSE VLV.			0.74	3465.18
CROSSOVER	$2\frac{7}{8}$"EUE	$3\frac{1}{2}$"IF	0.46	3465.84
1 STAND $4\frac{3}{4}$" DRILLCOLLARS			27.04	3492.68
IMPACT SUB			0.30	3492.98
1 STAND $4\frac{3}{4}$" DRILLCOLLARS			26.94	3519.92
BAR CATCHER			0.21	3520.13
CROSSOVER	$3\frac{1}{2}$" IF	$2\frac{7}{8}$" EUE	0.24	3520.37
APR TESTER			4.05	3524.42
BIG JOHN JARS			1.52	3525.94
RTTS BY-PASS			0.84	3526.78
RTTS SAFETY JNT.			1.01	3527.79
RTTS PACKER			0.52	3528.31
			0.81	3529.12
PERF. TAIL PIPE			6.71	3535.83
CROSSOVER	$2\frac{7}{8}$"EUE	$3\frac{1}{2}$"IF	0.2	3536.03
1 JOINT $3\frac{1}{2}$" IF D/P (OTIS GAUGES)			9.61	3545.64
1 JOINT $3\frac{1}{2}$" IF D/P (SPERRY SUN GAUGES)			9.37	3555.01
CROSSOVER	$3\frac{1}{2}$ IF	$2\frac{7}{8}$" DP	0.70	3555.71
BT CARRIER			1.22	3556.93
BT CARRIER			1.22	3558.15
BULL PLUG			0.30	3558.45

FIG. 2

GRAPHICAL DIARY OF EVENTS DST 1

7/12 -4

16 - 18th inc. NOVEMBER 1977

EVENT	HRS	DOWNHOLE PRESSURE RECORD PSIG
RIH pressure testing string.		
Landed test string.		
Set packer and opened APR.		
Cycled APR to try and obtain flow.		
Closed APR for PBU.		
Dropped bar and reversed out.		
Unset packer and POH		

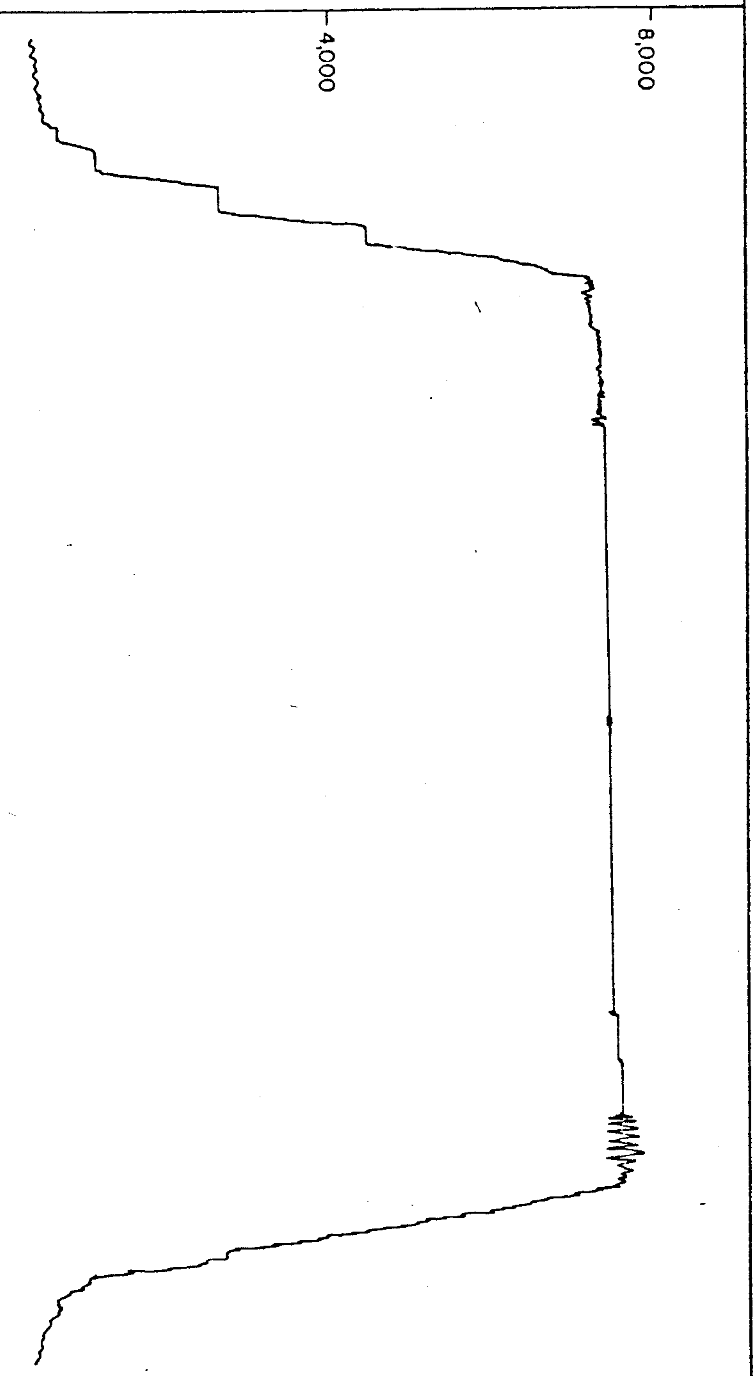
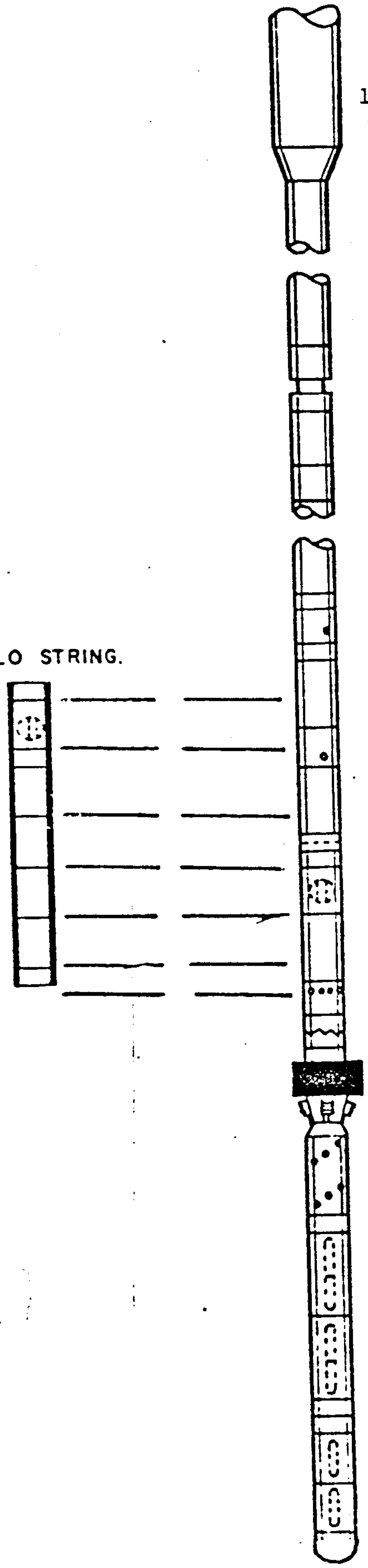


FIG. 3

Drwg No 0718

HALLIBURTON TEST STRING WELL 7/12-4 DST NO. 1A



TOOL	BOX	PIN	LENGTH	DEPTH
HANG-OFF POINT				93.25
HANGER BELOW H/O			0.18	93.43
107 STANDS 5" DRILLPIPE			3077.03	3170.46
CROSSOVER	4½"IF	3½"IF	0.51	3170.97
3 STANDS 3½" DRILLPIPE			111.63	3282.60
SLIP JNT. (OPEN)			6.10	3288.70
SLIP JNT. (½ OPEN)			5.34	3294.04
SLIP JNT (CLOSED)			4.57	3298.61
6" STANDS 4¾" DRILL COLLARS			164.54	3463.15
CROSSOVER	3½" IF	2⅞" EUE	0.30	3463.45
APR REVERSE VLV.			0.74	3464.19
CROSSOVER	2⅞" EUE	3½" IF	0.46	3464.65
1 STAND 4¾" DRILLCOLLARS			27.04	3491.69
IMPACT SUB			0.30	3491.99
1 STAND 4¾" DRILLCOLLARS			26.94	3518.93
BAR CATCHER			0.21	3519.14
CROSSOVER	3½" IF	2⅞" EUE	0.24	3519.38
APR TESTER			4.05	3523.43
			1.52	3524.95
BIG JOHN JARS				
RTTS BY-PASS			0.84	3525.79
RTTS SAFETY JNT.			1.01	3526.80
			0.52	3527.32
RTTS PACKER ℄				
			0.81	3528.13
PERF. TAIL PIPE			6.71	3534.84
CROSSOVER	2⅞" EUE	3½" IF	0.20	3535.04
1 JOINT 3½" IF D/P (OTIS GAUGES)			9.61	3544.65
CROSSOVER	3½ IF	2⅞" DP	0.70	3545.35
BT CARRIER			1.22	3546.57
BT CARRIER			1.22	3547.79
BULL PLUG			0.30	3548.09

FIG. 4

GRAPHICAL DIARY OF EVENTS DST 1A
7/12-4
22 - 25th NOVEMBER 1977

EVENT	HRS	DOWNHOLE PRESSURE RECORD PSIG
Pressure tested tools		
RIH topping up d/p		
RIH rest of 5" d/p		
WOW		
continued in hole		
landed tree		
Set packer and opened APR for 5 min flow and 1 hr shut in		
Final flow period		
Cycled APR		
Shut in period		
Opened APRA		
POH to 9 5/8" shoe		
Hung off		
WOW		
POH		

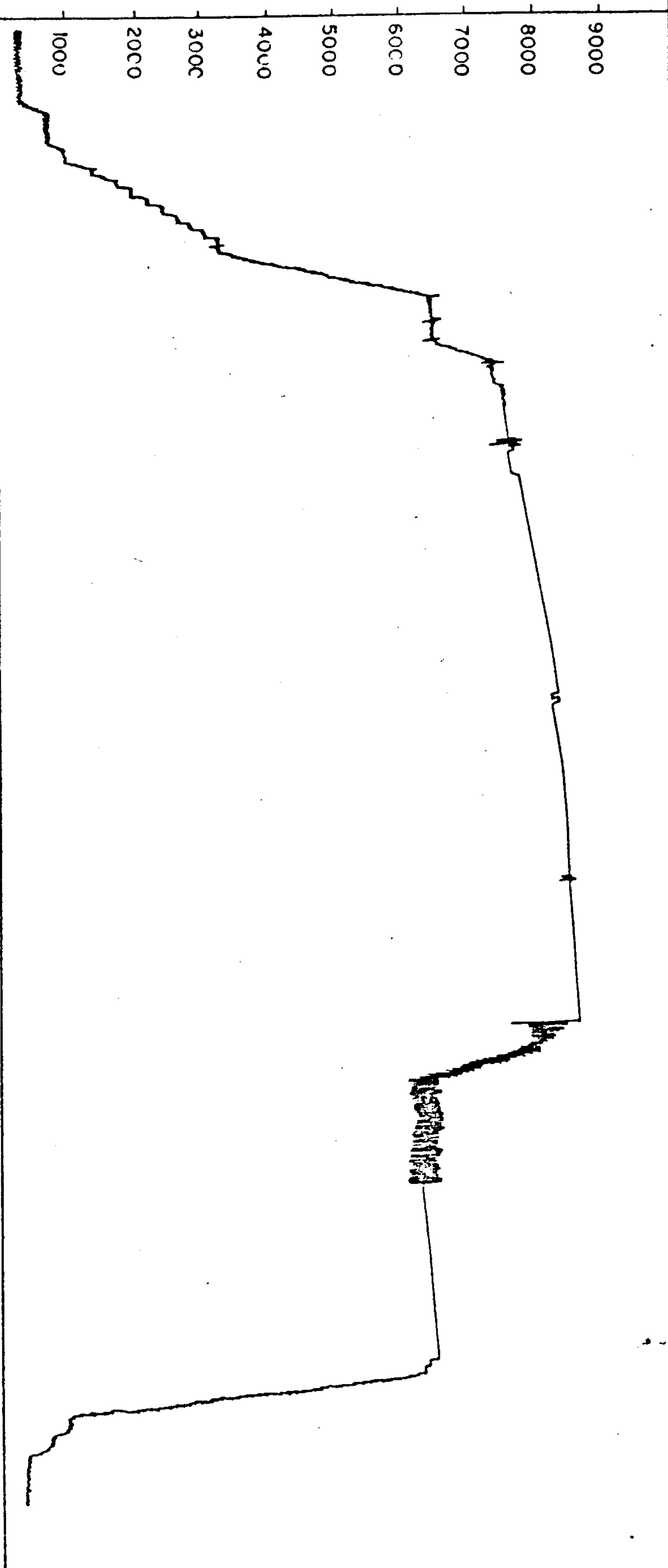
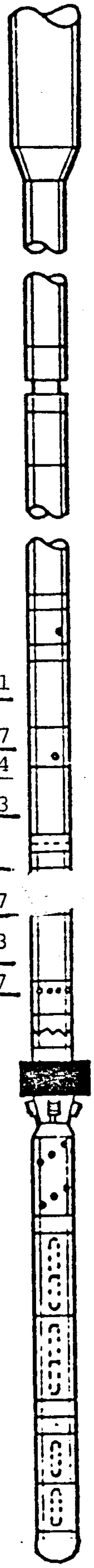


FIG. 5

Drwg.No. 0717

DRILL STRING DST 1B (7/12-4)

APR STRING



TOOL	BOX	PIN	LENGTH	DEPTH
HANG-OFF POINT				93.25
HANGER BELOW H/O			0.18	93.43
STANDS 5" DRILLPIPE			3077.03	3170.46
CROSSOVER	4½"IF	3½"IF	0.51	3170.97
STANDS 3½" DRILLPIPE			47.37	3218.94
SLIP JNT. (OPEN)			6.10	3224.44
SLIP JNT. (CLOSED)			4.57	3229.01
6" STANDS 4¾" DRILL COLLARS			164.54	3393.55
CROSSOVER	3½" IF	2⅞" EUE	0.30	3393.85
APR REVERSE VLV.			0.74	3394.59
CROSSOVER	2⅞"EUE	3½"IF	0.46	3395.05
1 STAND 4¾" DRILLCOLLARS			27.04	3422.09
IMPACT SUB			0.30	3422.39
1 STAND 4¾" DRILLCOLLARS			26.94	3449.33
BAR CATCHER			0.21	3449.54
CROSSOVER	3½"IF	2⅞"EUE		
BIG JOHN JARS			1.52	3520.69
RTTS BY-PASS			0.84	3521.53
RTTS SAFETY JNT.			1.01	3522.54
RTTS PACKER ℄			0.52	3523.06
			0.81	3523.87
PERF. TAIL PIPE			6.71	3530.58
CROSSOVER	2⅞"EUE	3½"IF	0.20	3530.78
1 JOINT 3½"IF D/P (OTIS GAUGES)			9.61	3540.39
CROSSOVER	3½ IF	2⅞" DP	0.70	3541.09
BT CARRIER			1.22	3542.31
BT CARRIER			1.22	3543.53
BULL PLUG			0.30	3543.83

FUL-FLO STRING.

CROSSOVER	0.27	3449.81
FUL-FLO HYDROSPRING	3.66	3453.47
CROSSOVER	0.27	3453.74
1 STD D/C	28.09	3481.83
SLIP JNT	4.57	3486.4
SUP JNT.	4.57	3490.97
1 STD. D/C	27.96	3518.93
CROSSOVER	0.24	3519.17

FIG. 6

GRAPHICAL DIARY OF EVENTS DST IB

7/12-4

26-28th NOVEMBER 1977

EVENT	HRS	DOWNHOLE PRESSURE RECORD PSIG

RIH pressure testing test tools.

Pulling back to dind leak.

RIH topping up 5" d/p.

RIH rest of 5" d/p.

Landed SSTT.

Set packer and opened hydrospring.

Attempted to close hydrospring.

Attempted to close hydrospring.

Closed hydrospring.

Attempted to open hydrospring.

Cycled hydrospring 3 times to try and open.

Opened hydrospring by picking up further.

Closed hydrospring.

Dropped bar and reversed out.

Unset packer.

POH.

Breaking down test tools.

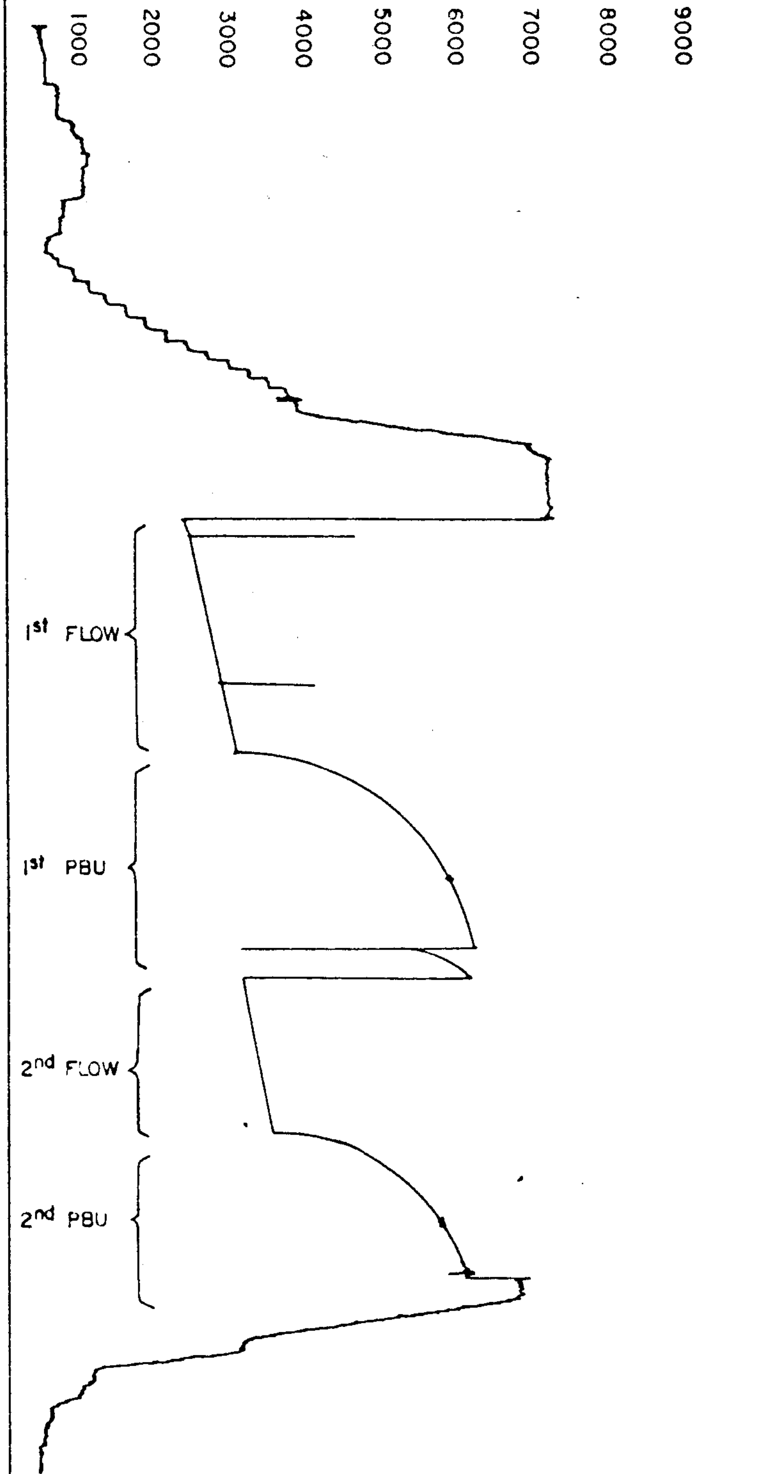


FIG. 7

Dwg. No. 0721

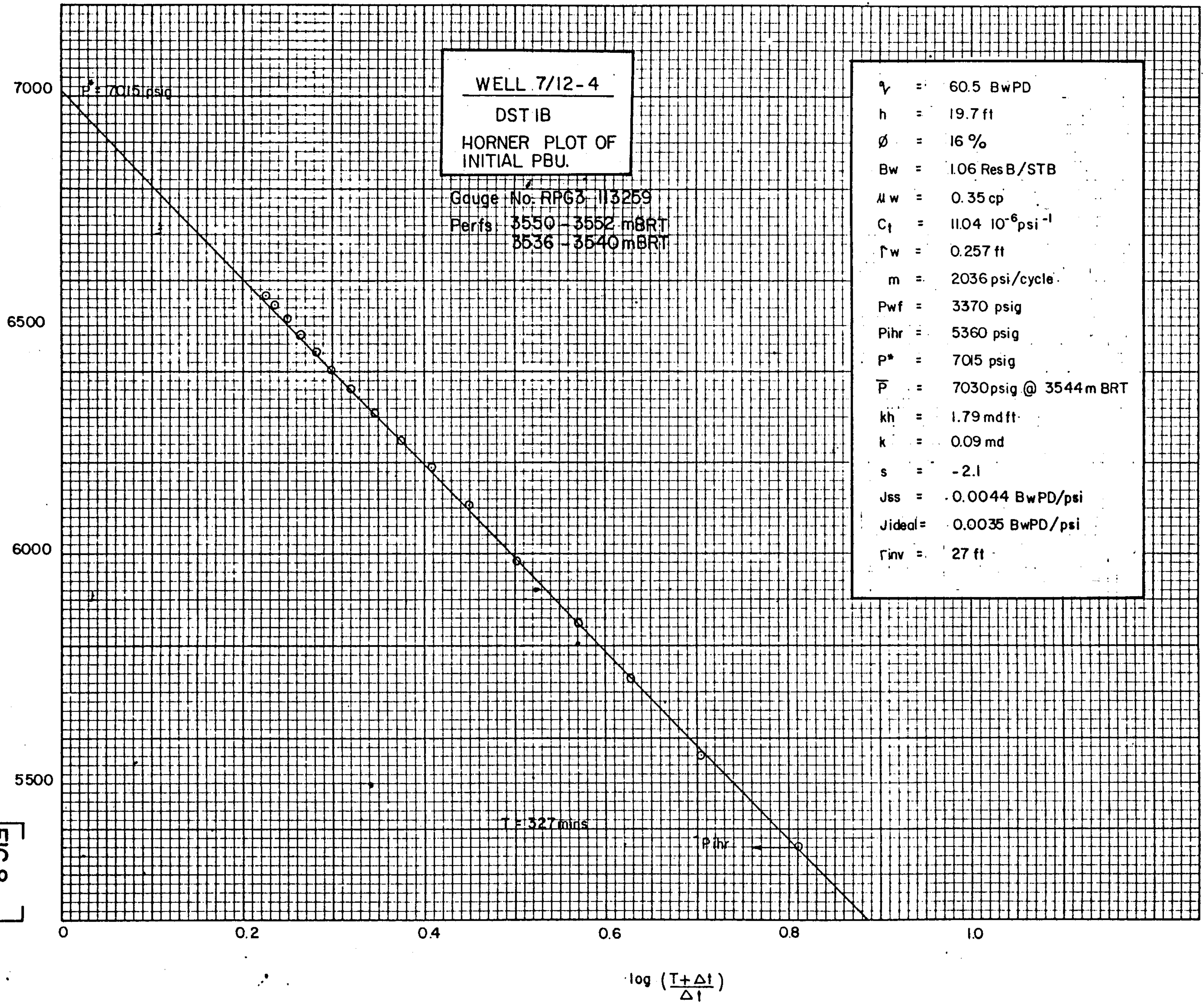
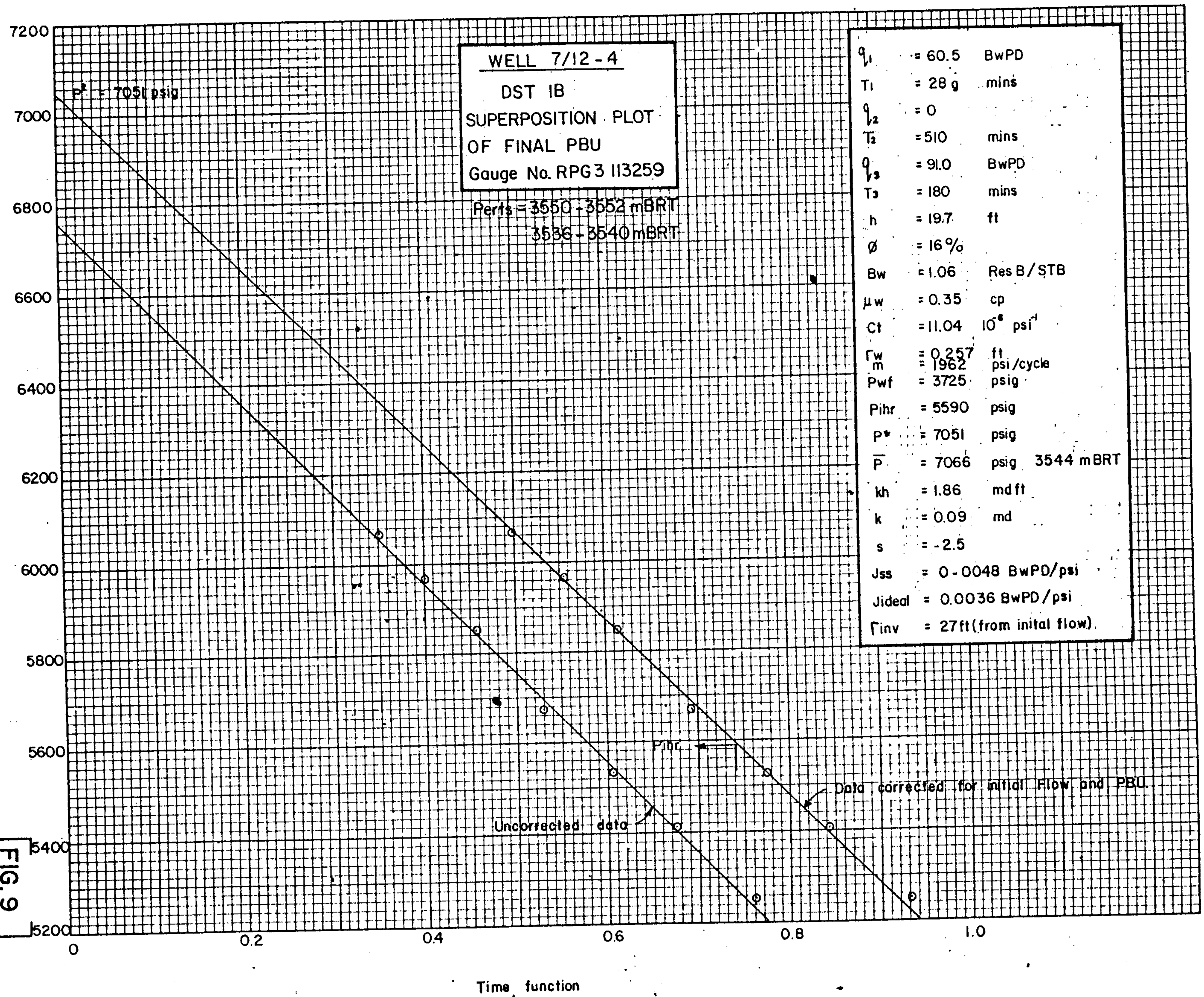

P (psig)
WELL 7/12-4
DST IB
HORNER PLOT OF
INITIAL PBU.
Gauge No. RPG3 113259
Perfs 3550 - 3552 mBRT
3536 - 3540 mBRT
P* = 7015 psig
T = 327 mins
P ihr
7000
6500
6000
5500
0
0.2
0.4
0.6
0.8
1.0
log $\left(\frac{T+\Delta t}{\Delta t}\right)$
q = 60.5 BwPD
h = 19.7 ft
Ø = 16 %
Bw = 1.06 Res B/STB
μw = 0.35 cp
C_t = 11.04 10^{-6} psi^{-1}
rw = 0.257 ft
m = 2036 psi/cycle
Pwf = 3370 psig
Pihr = 5360 psig
P* = 7015 psig
$\overline{P}$ = 7030 psig @ 3544 m BRT
kh = 1.79 md ft
k = 0.09 md
s = -2.1
Jss = 0.0044 BwPD/psi
Jideal = 0.0035 BwPD/psi
rinv = 27 ft

FIG.8



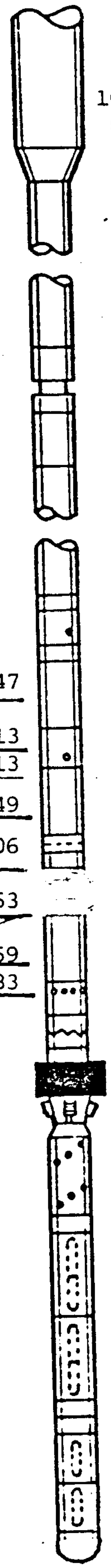
P (psig)

FIG. 9

BP. 1.(JAN. 62)
R 731
RS 4880

HALLIBURTON TEST STRING WELL 7/12-4 DST NO. 2

APR STRING



TOOL	BOX	PIN	LENGTH	DEPTH
HANG-OFF POINT				~~93.25~~
HANGER BELOW H/O			0.18	93.43
107 STANDS 5" DRILLPIPE			3077.03	3170.46
CROSSOVER	4½"IF	3½"IF	0.51	3170.97
3½" DRILLPIPE			26.03	3197.00
SLIP JNT. (OPEN)			6.10	3203.1
SLIP JNT. (CLOSED)			4.57	3207.67
6" STANDS 4¾" DRILL COLLARS			164.54	3372.21
CROSSOVER	3½" IF	2⅞" EUE	0.30	3372.51
APR REVERSE VLV.			0.74	3373.25
CROSSOVER	2⅞" EUE	3½" IF	0.46	3373.71
1 STAND 4¾" DRILLCOLLARS			27.04	3400.75
IMPACT SUB			0.30	3401.05
1 STAND 4¾" DRILLCOLLARS			26.94	3427.99
BAR CATCHER			0.21	3428.20
CROSSOVER	3½" IF	2⅞" EUE		
BIG JOHN JARS			1.52	3499.35
RTTS BY-PASS			0.84	3500.19
RTTS SAFETY JNT.			1.01	3501.20
RTTS PACKER ℄			0.52	3501.72
			0.81	3502.53
PERF. TAIL PIPE			6.71	3509.24
CROSSOVER	2⅞"EUE	3½"IF	0.20	3509.44
1 JOINT 3½" IF D/P (OTIS GAUGES)			9.61	3519.05
CROSSOVER	3½ IF	2⅞" DP	0.70	3519.75
BT CARRIER			1.22	3520.97
BT CARRIER			1.22	3522.19
BULL PLUG			0.30	3522.49

FUL-FLO STRING.

TOOL	LENGTH	DEPTH
CROSSOVER	0.27	3428.47
FUL-FLO HYDROSPRING	3.66	3432.13
CROSSOVER	0.27	3432.13
1 STD D/C	28.09	3460.49
SLIP JNT	4.57	3465.06
SLIP JNT.	4.57	3469.63
1 STD. D/C	27.96	3497.59
CROSSOVER	0.24	3497.83

FIG. 10

GRAPHICAL DIARY OF EVENTS DST 2

7/12 - 4

29th NOV - 1st DEC. 1977

EVENT

RIH pressure testing string

Make up SSTT

Make up surface lines

Land string and wait
on daylight.

Initial flow and PBU

Second flow and PBU

(attempting to establish if
tools open or not)

Final flow

Gas to surface

Final PBU

Packer unseated

(attempting to ensure tool
closed)

Reverse out

POH

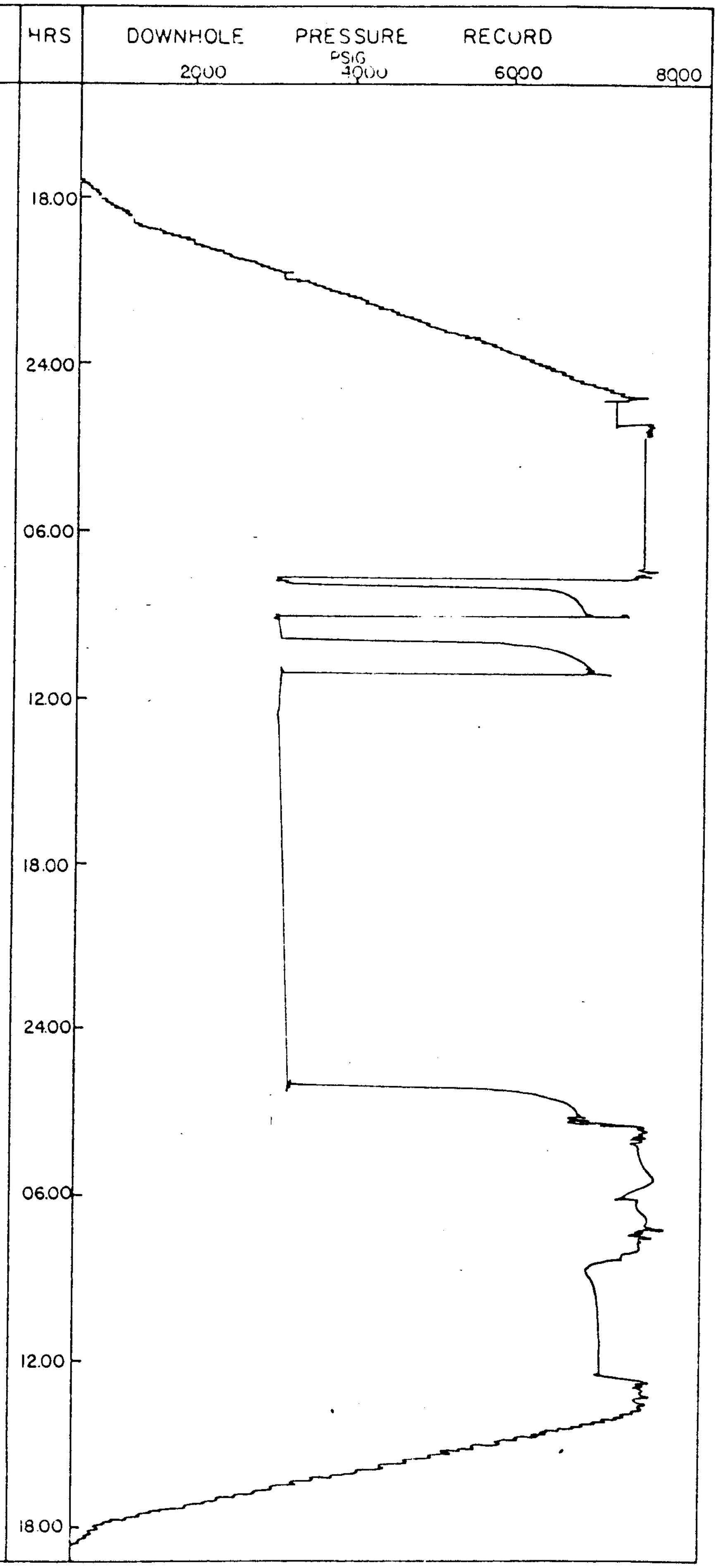


FIG. 11

Dwg. No 0719

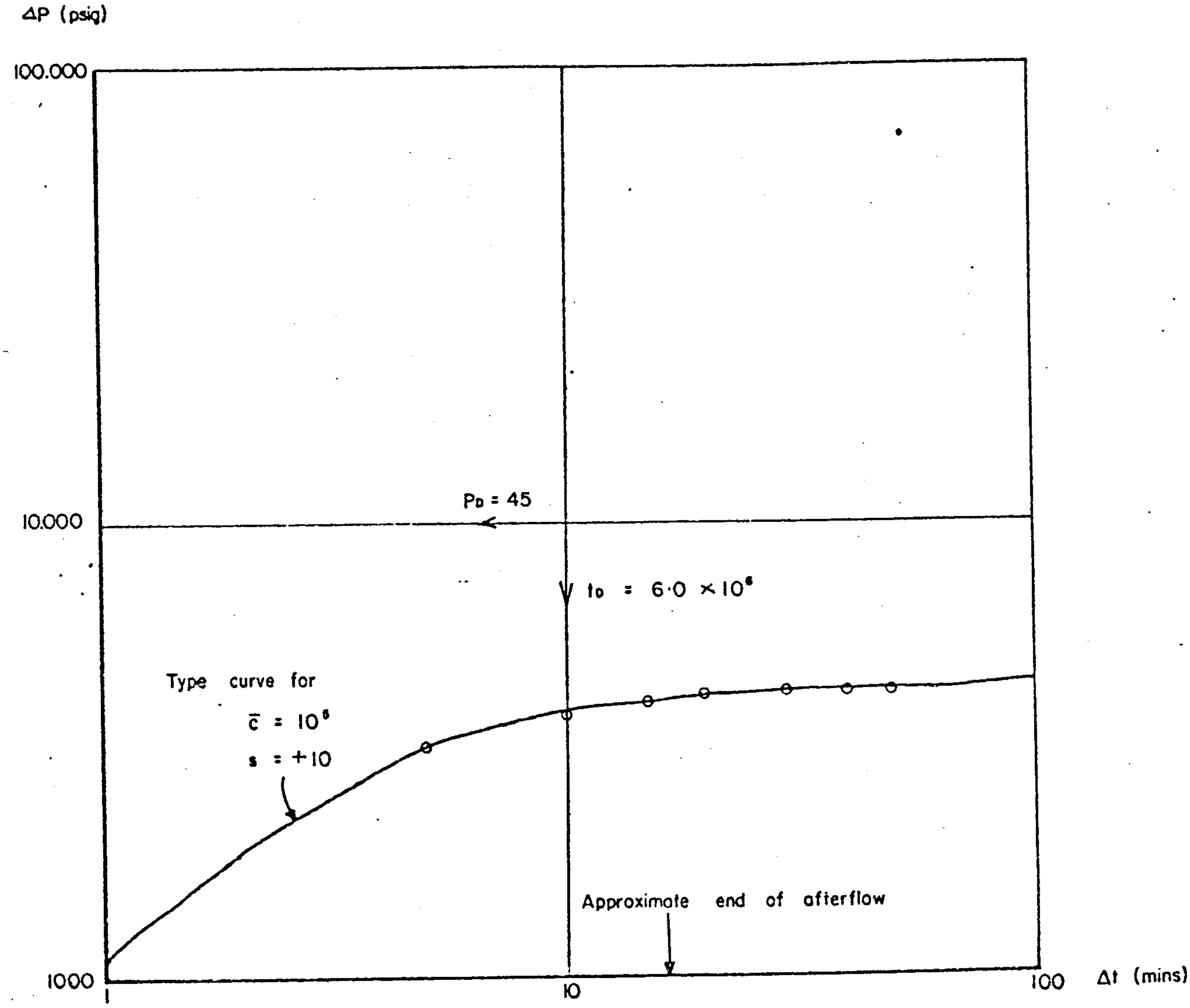
WELL 7/12 - 4

DST 2

RAMEY TYPE CURVE MATCH FOR 2nd PBU.

Gauge No. BT 5623 at 3520.97mBRT.

Perfs = 3527 - 3530 mBRT.



kh = 12.68 md ft

k = 1.27 md

s = +10

FIG. 12

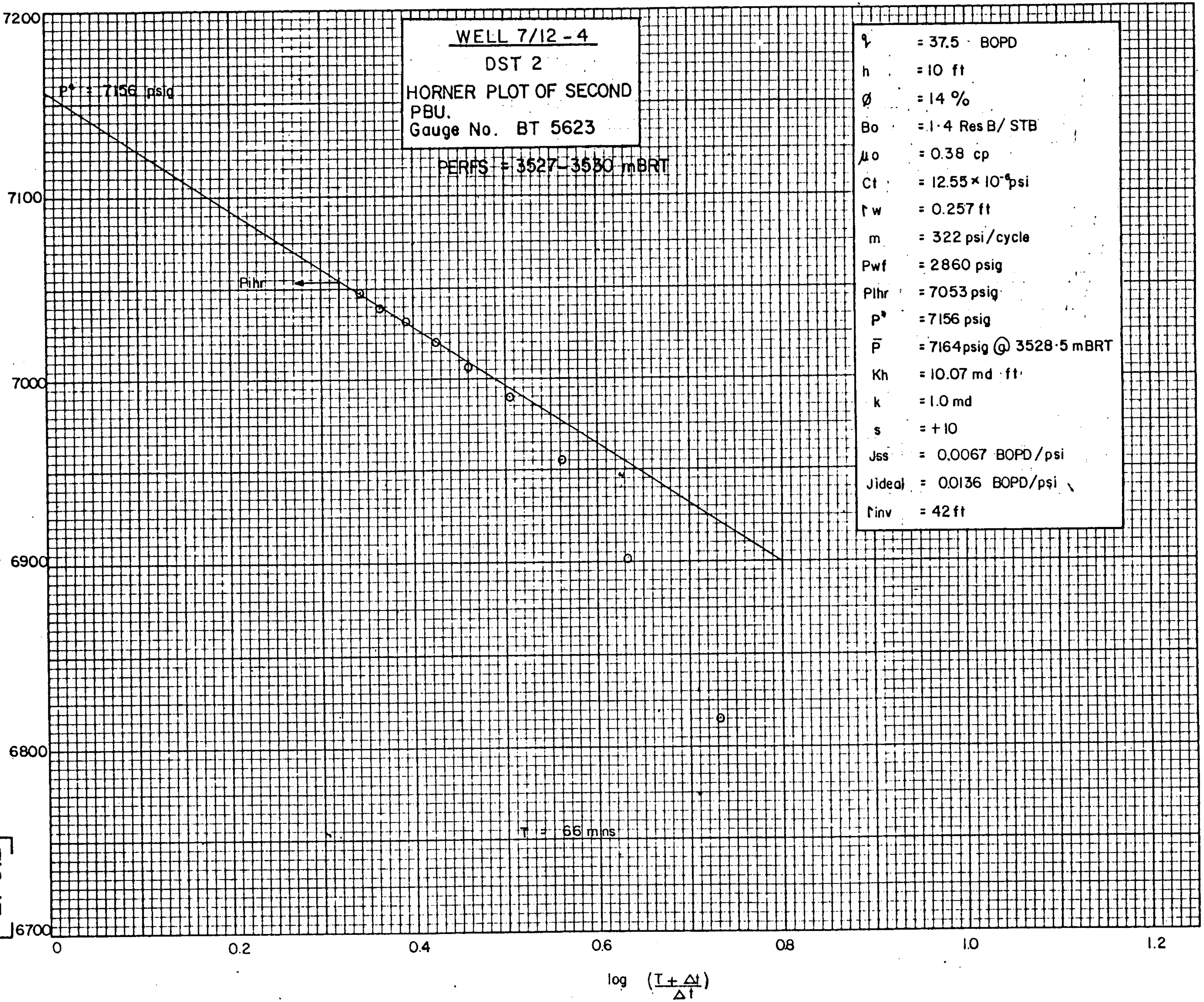

WELL 7/12 - 4
DST 2
HORNER PLOT OF SECOND PBU.
Gauge No. BT 5623
PERFS = 3527-3530 mBRT
P* = 7156 psig
P1hr
T = 66 mins
q = 37.5 BOPD
h = 10 ft
Ø = 14 %
Bo = 1·4 Res B/ STB
µo = 0.38 cp
Ct = 12.55 × 10⁻⁶ psi
rw = 0.257 ft
m = 322 psi/cycle
Pwf = 2860 psig
P1hr = 7053 psig
P* = 7156 psig
P̄ = 7164 psig @ 3528·5 mBRT
Kh = 10.07 md · ft
k = 1.0 md
s = + 10
Jss = 0.0067 BOPD/psi
Jideal = 0.0136 BOPD/psi
rinv = 42 ft
P (psig)
7200
7100
7000
6900
6800
6700
0
0.2
0.4
0.6
0.8
1.0
1.2
log ((T + Δt)/Δt)

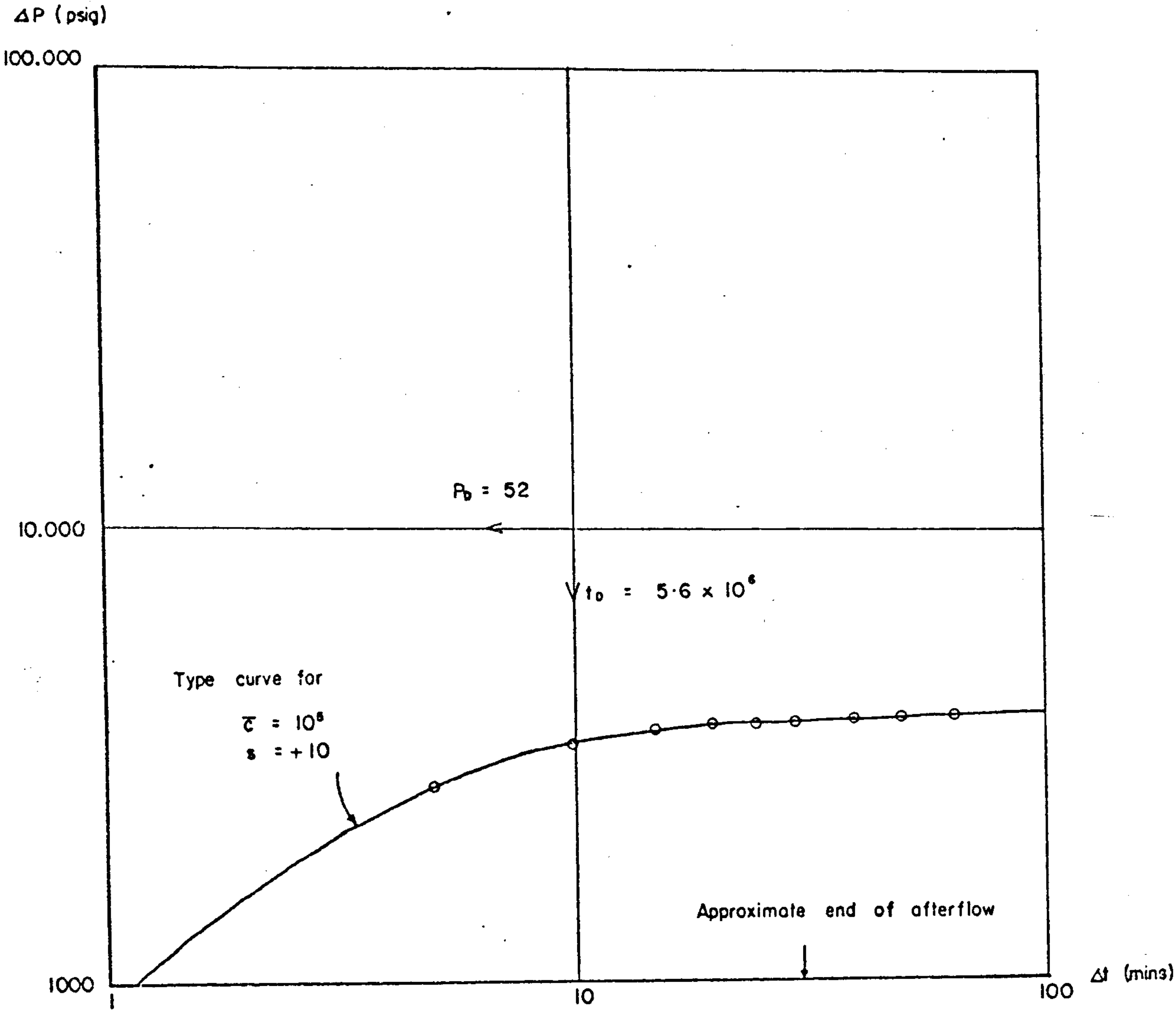
FIG. 13

WELL 7/12 - 4

DST 2

RAMEY TYPE CURVE MATCH
FOR FINAL PBU.
Gauge No. BT 5623 at 3520.97 mBRT.

Perfs = 3527 - 3530 mBRT.



kh = 14.65 md ft

k = 1.46 md

s = +10

FIG. 14

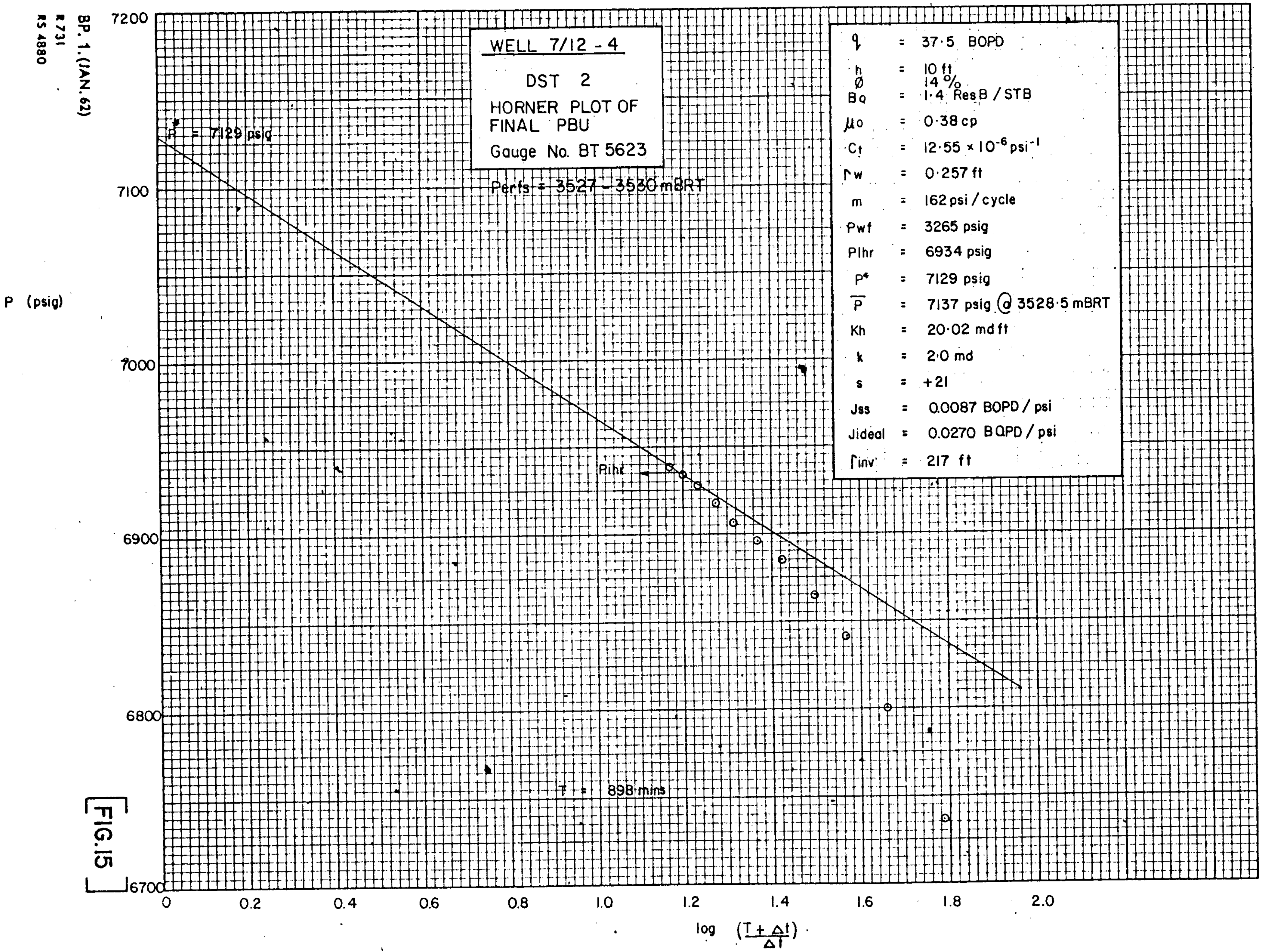
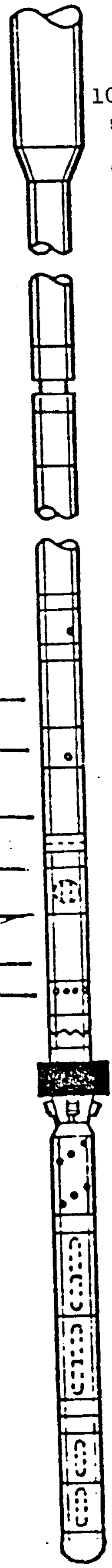


FIG.15

BP. 1. (JAN. 62)
R731
RS 4880

HALLIBURTON TEST STRING WELL 7/12-4 DST NO. 3

APR STRING



TOOL	BOX	PIN	LENGTH	DEPTH
HANG-OFF POINT				93.25
HANGER BELOW H/O			0.18	93.43
107 STANDS 5" DRILLPIPE			3077.03	3170.46
CROSSOVER	4½"IF	3½"IF	0.51	3170.97
1 STANDS 3½" DRILLPIPE			28.51	3199.48
SLIP JNT. (OPEN)			6.10	3205.58
SLIP JNT. (CLOSED)			4.57	3210.15
6" STANDS 4¾" DRILL COLLARS			164.54	3374.69
CROSSOVER	3½" IF	2⅞" EUE	0.30	3374.99
APR REVERSE VLV.			0.74	3375.73
CROSSOVER	2⅞"EUE	3½"IF	0.46	3376.19
1 STAND 4¾" DRILLCOLLARS			27.04	3403.23
IMPACT SUB			0.30	3403.53
1 STAND 4¾" DRILLCOLLARS			26.94	3430.47
			0.21	3430.68
BAR CATCHER			0.24	3430.92
CROSSOVER	3½" IF	2⅞" EUE		
APR TESTER			4.05	3434.97
BIG JOHN JARS			1.52	3436.49
RTTS BY-PASS			0.84	3437.33
RTTS SAFETY JNT.			1.01	3438.34
			0.52	3438.86
RTTS PACKER ℄			0.81	3439.67
PERF. TAIL PIPE			6.71	3446.38
CROSSOVER	2⅞"EUE	3½"IF	0.20	3446.58
1 JOINT 3½" IF D/P (OTIS GAUGES)			9.61	3456.19
1 JOINT 3½" IF D/P (SPERRY SUN GAUGES)			9.75	3465.94
CROSSOVER	3½ IF	2⅞" DP	0.70	3466.64
BT CARRIER			1.22	3467.86
BT CARRIER			1.22	3469.08
BULL PLUG			0.30	3469.38

FUL-FLO STRING.

FIG. 16

GRAPHICAL DIARY OF EVENTS DST 3

7/12-4

3-4th December, 1977

EVENT	HRS	DOWNHOLE PRESSURE RECORD PSIG

Made up test tools

RIH 4" d/p

Set packer, opened APR

Shut in well for 1 hr PBU

Flowed well

Well shut in for helicopter

Tried bleeding off string

Shut in well at SSTT
Fixed leaking swivel joint

Opened well to burner

Well shut in in due to leaking Chicksan

Opened surface valves
Well reopened

Well shut in at choke manifold

Tried bleeding off string

Dropped bar and reversed out

POH

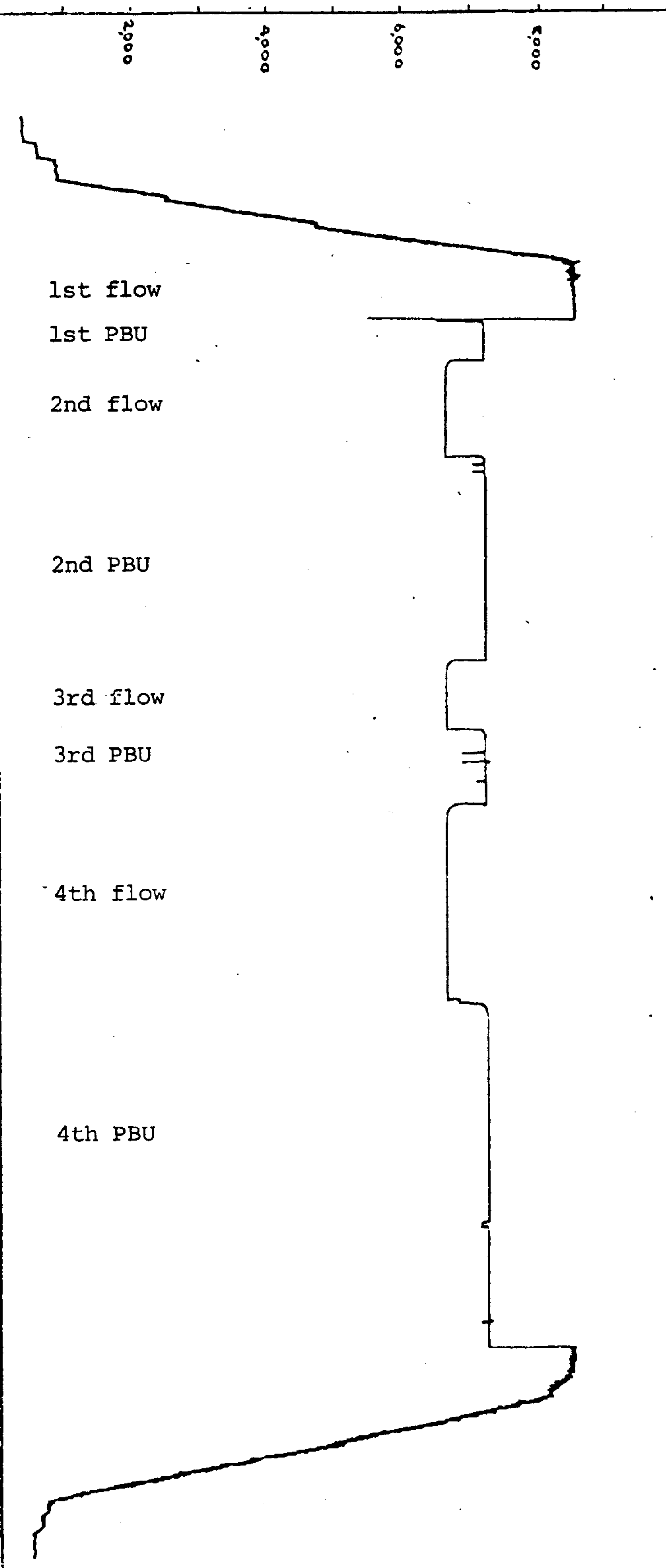


FIG. 17

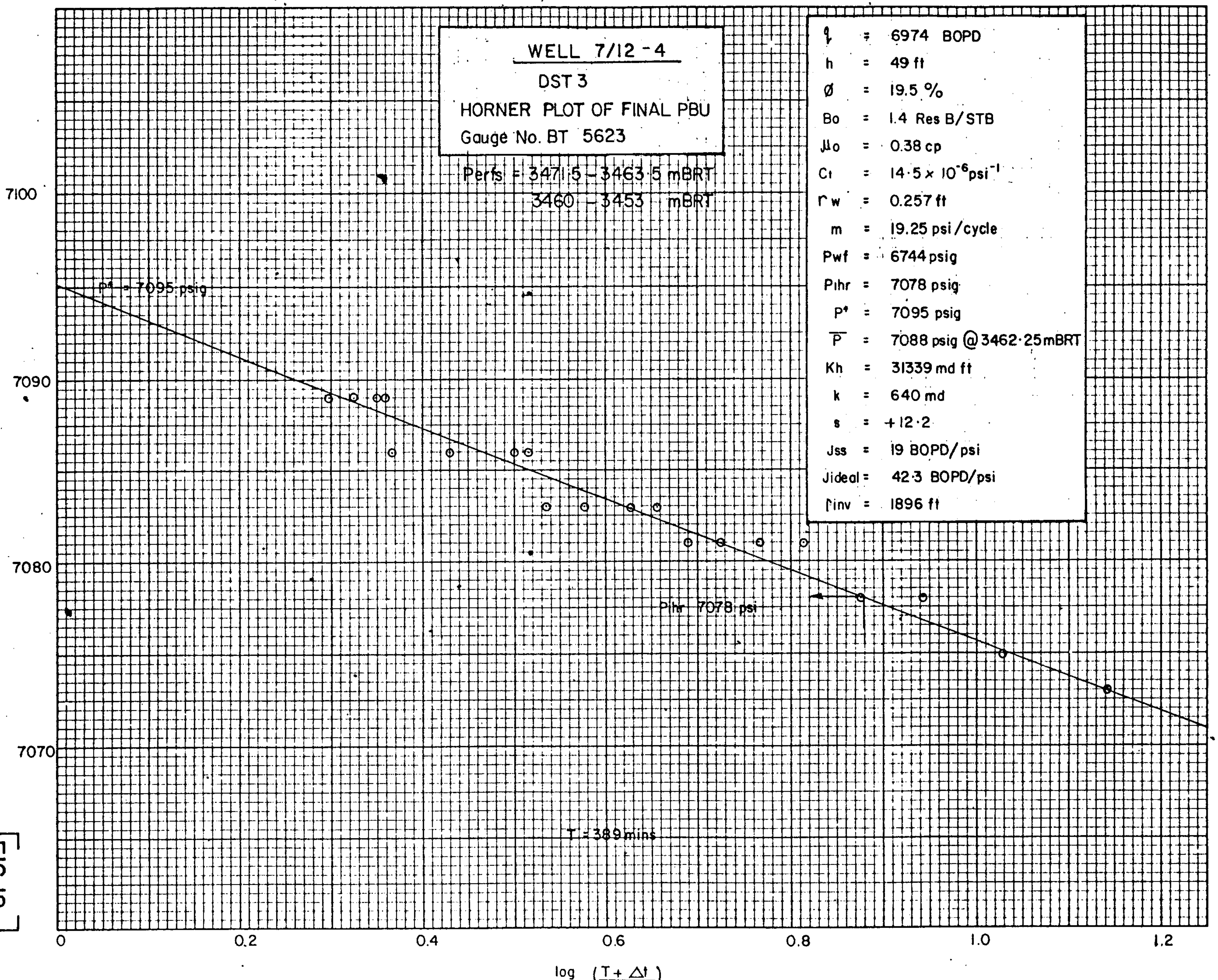

WELL 7/12 - 4
DST 3
HORNER PLOT OF FINAL PBU
Gauge No. BT 5623
Perfs = 3471.5 - 3463.5 mBRT
3460 - 3453 mBRT
q = 6974 BOPD
h = 49 ft
Ø = 19.5 %
Bo = 1.4 Res B/STB
μo = 0.38 cp
Ct = 14.5 x 10⁻⁶ psi⁻¹
rw = 0.257 ft
m = 19.25 psi/cycle
Pwf = 6744 psig
P1hr = 7078 psig
P* = 7095 psig
P̄ = 7088 psig @ 3462.25 mBRT
Kh = 31339 md ft
k = 640 md
s = +12.2
Jss = 19 BOPD/psi
Jideal = 42.3 BOPD/psi
rinv = 1896 ft
P* = 7095 psig
P1hr 7078 psi
T = 389 mins
P (psig)
7100
7090
7080
7070
0
0.2
0.4
0.6
0.8
1.0
1.2
log (T + Δt)

FIG.18

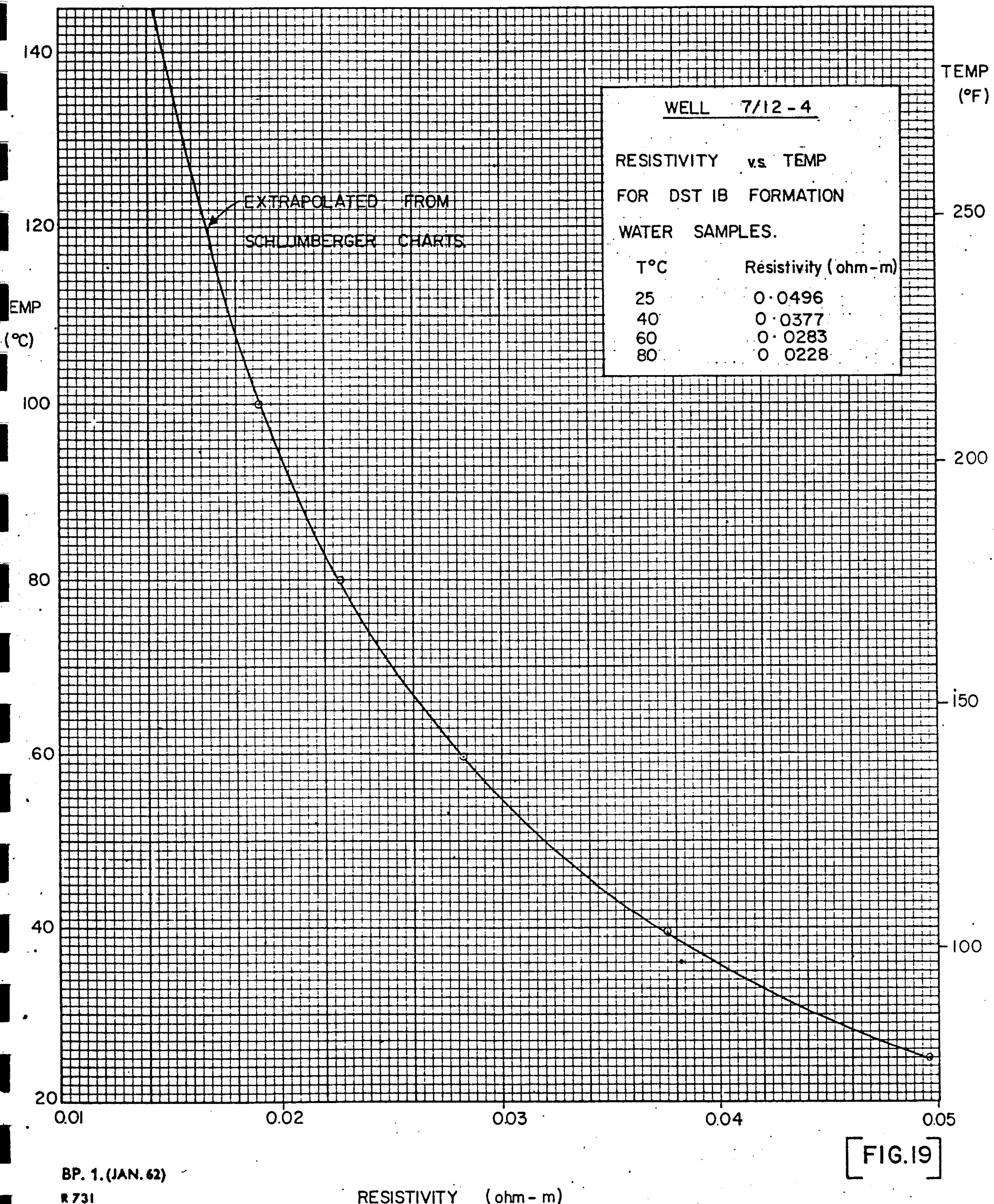


FIG.19

BP. 1. (JAN. 62)
R 731
RS 4880

No. 1086

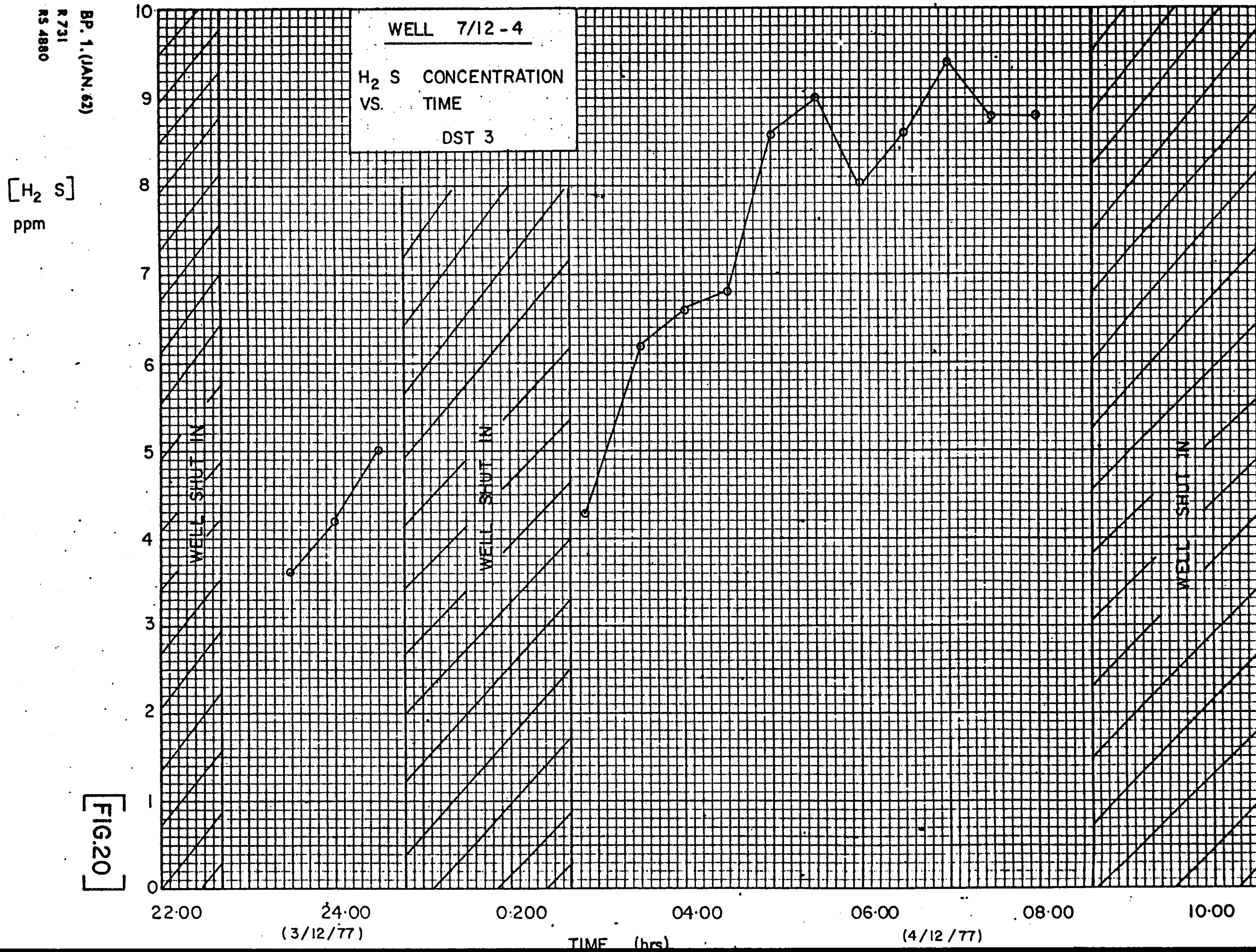

WELL 7/12-4
H_2 S CONCENTRATION
VS. TIME
DST 3
[H_2 S]
ppm
10
9
8
7
6
5
4
3
2
1
0
WELL SHUT IN
WELL SHUT IN
WELL SHUT IN
22:00
24:00
(3/12/77)
0:200
04:00
06:00
(4/12/77)
08:00
10:00
TIME (hrs)

FIG.20

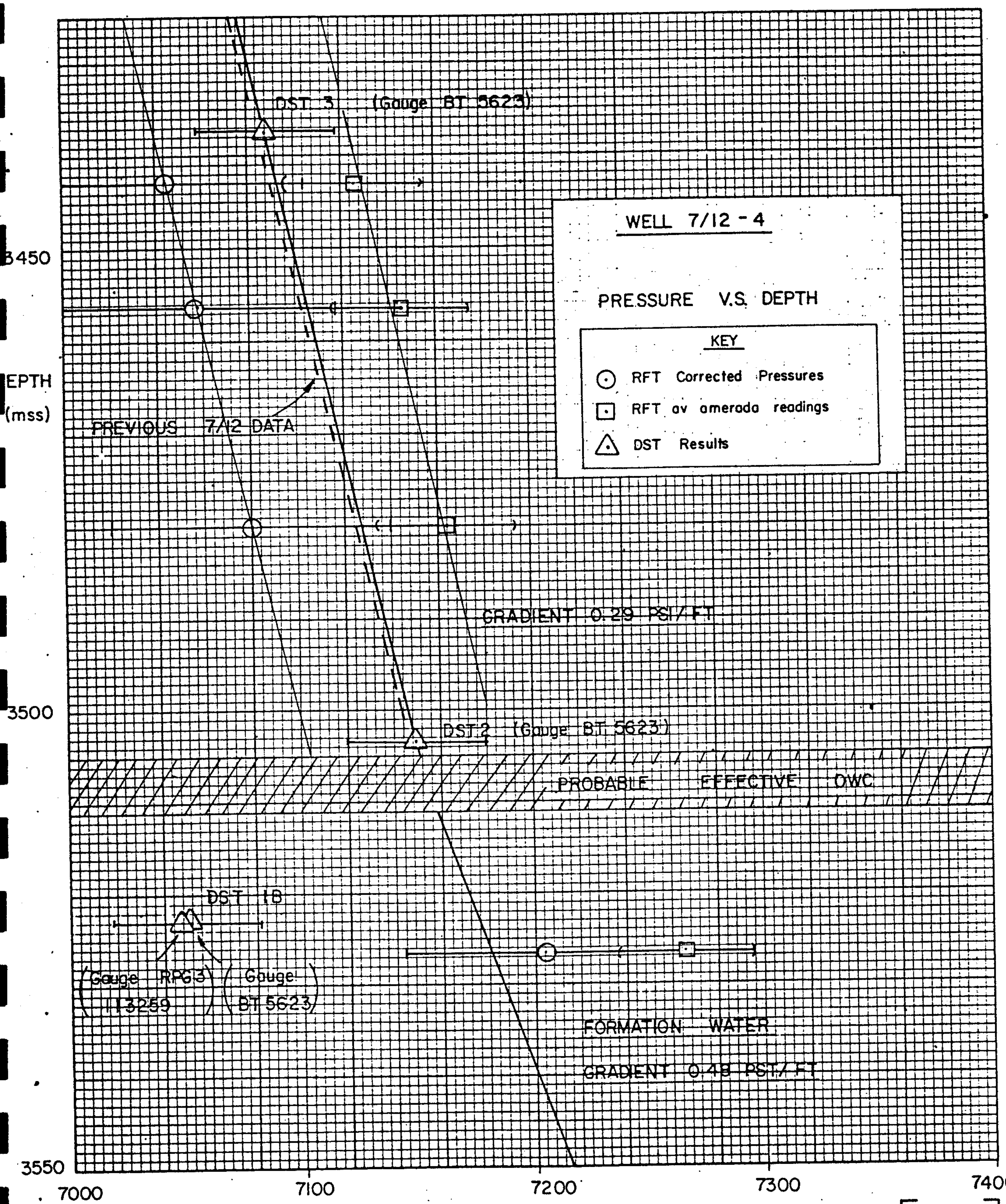


FIG. 21

BP. 1. (JAN. 62)
R 731
RS 4880

Drwg. No. 1095

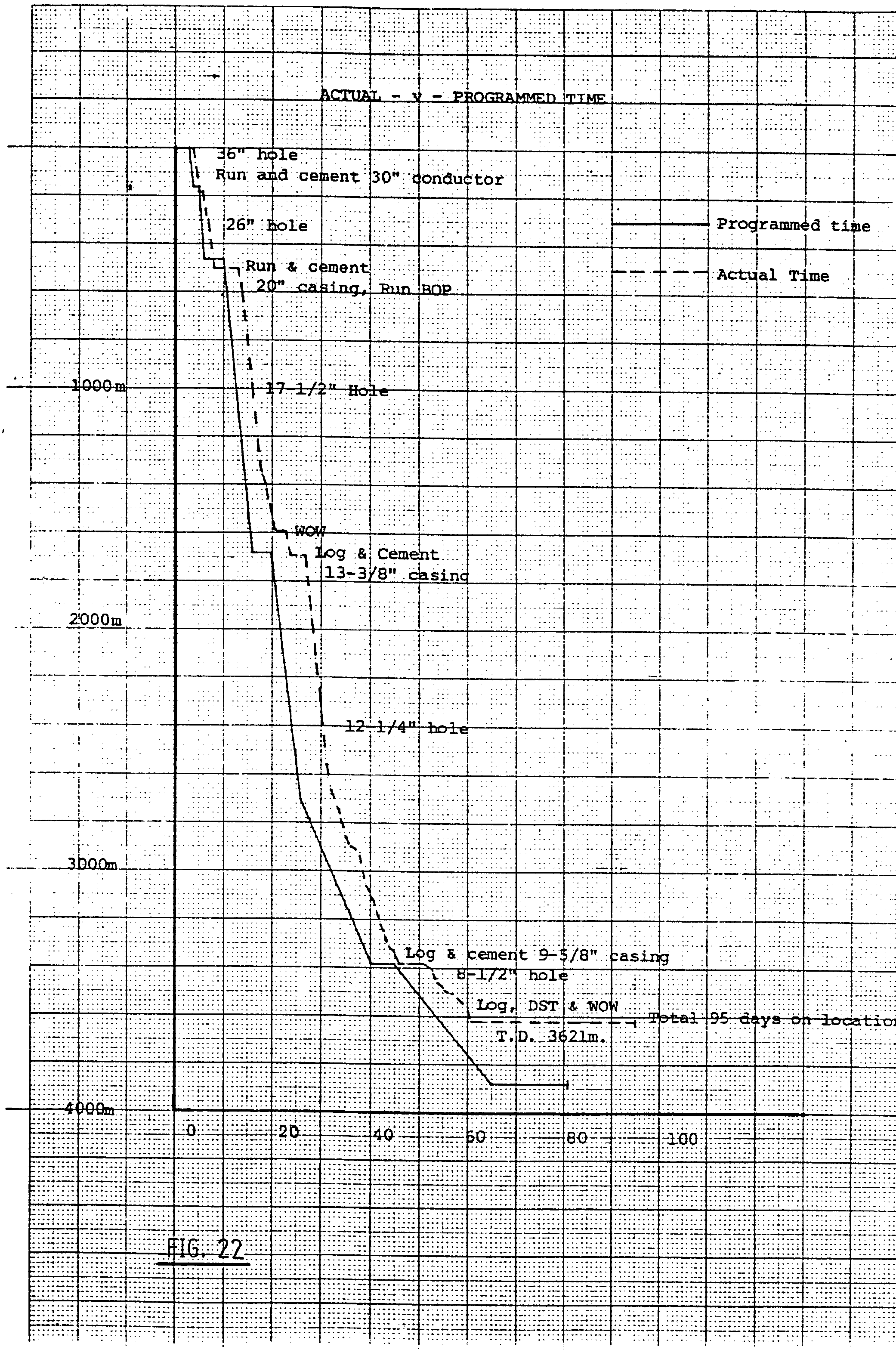
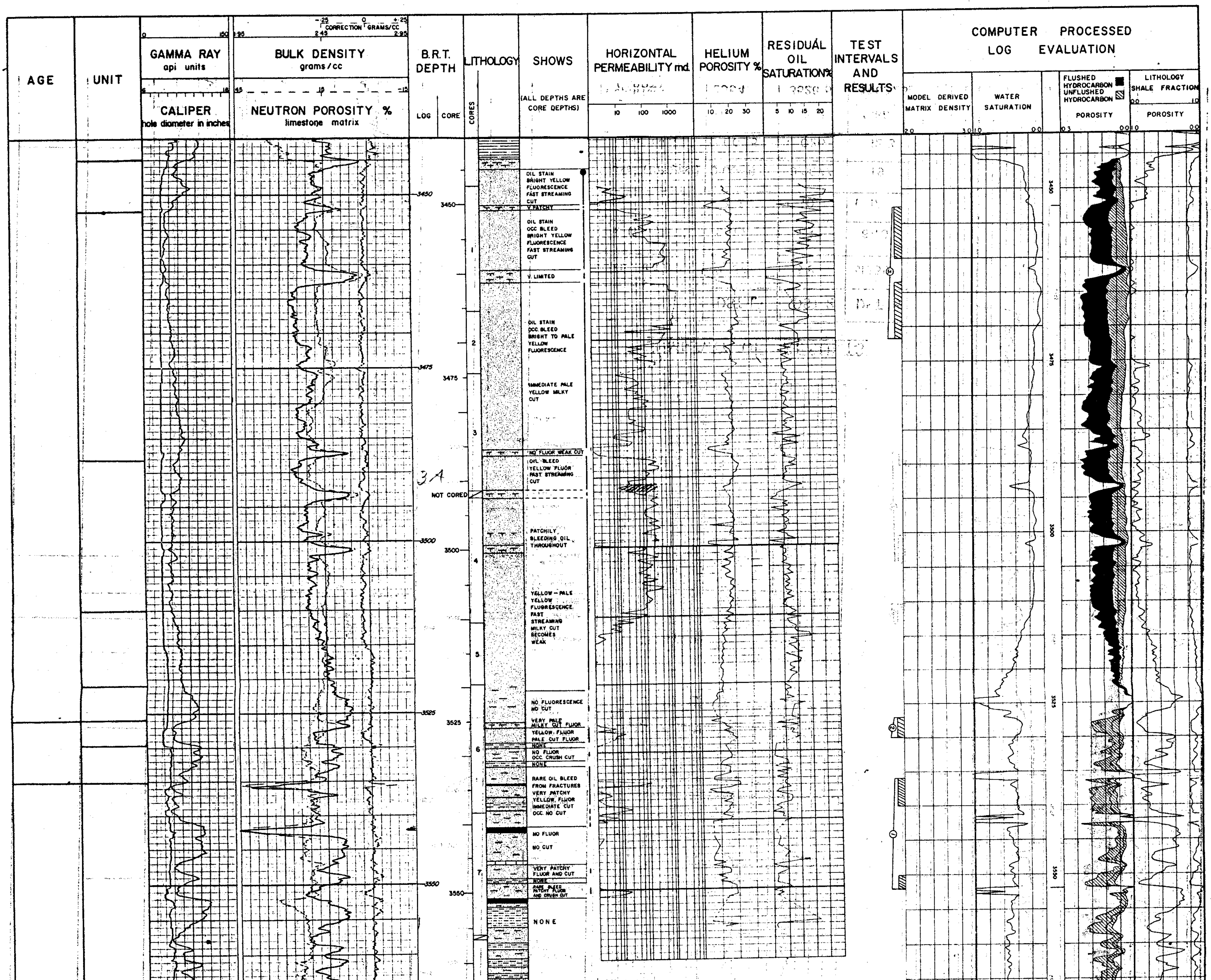

ACTUAL - v - PROGRAMMED TIME
36" hole
Run and cement 30" conductor
26" hole
Run & cement
20" casing, Run BOP
17-1/2" Hole
WOW
Log & Cement
13-3/8" casing
12-1/4" hole
Log & cement 9-5/8" casing
8-1/2" hole
Log, DST & WOW
Total 95 days on location
T.D. 3621m.
Programmed time
Actual Time
1000m
2000m
3000m
4000m
0
20
40
60
80
100

FIG. 22

7/12-4 RESERVOIR COMPOSITE LOG



SUMMARY OF RESULTS

	DST 1B	DST 2	DST 3
kh (md ft)	2.54	13.8	31339
k (md)	0.13	1.4	640
s	− 3.6	+ 10	+ 12
Jss (BPD/psi)	0.0046	0.0077	19
Jideal (")	0.0035	0.020	42.3
$\bar{P}$	7048	7150.5	7088
Depth for $\bar{P}$ (mBRT)	3554	3528.5	3462.25
r_{inv} (ft)	27	217	1896

Drwg. No. 0730

FIG. 23

FIGURE 1