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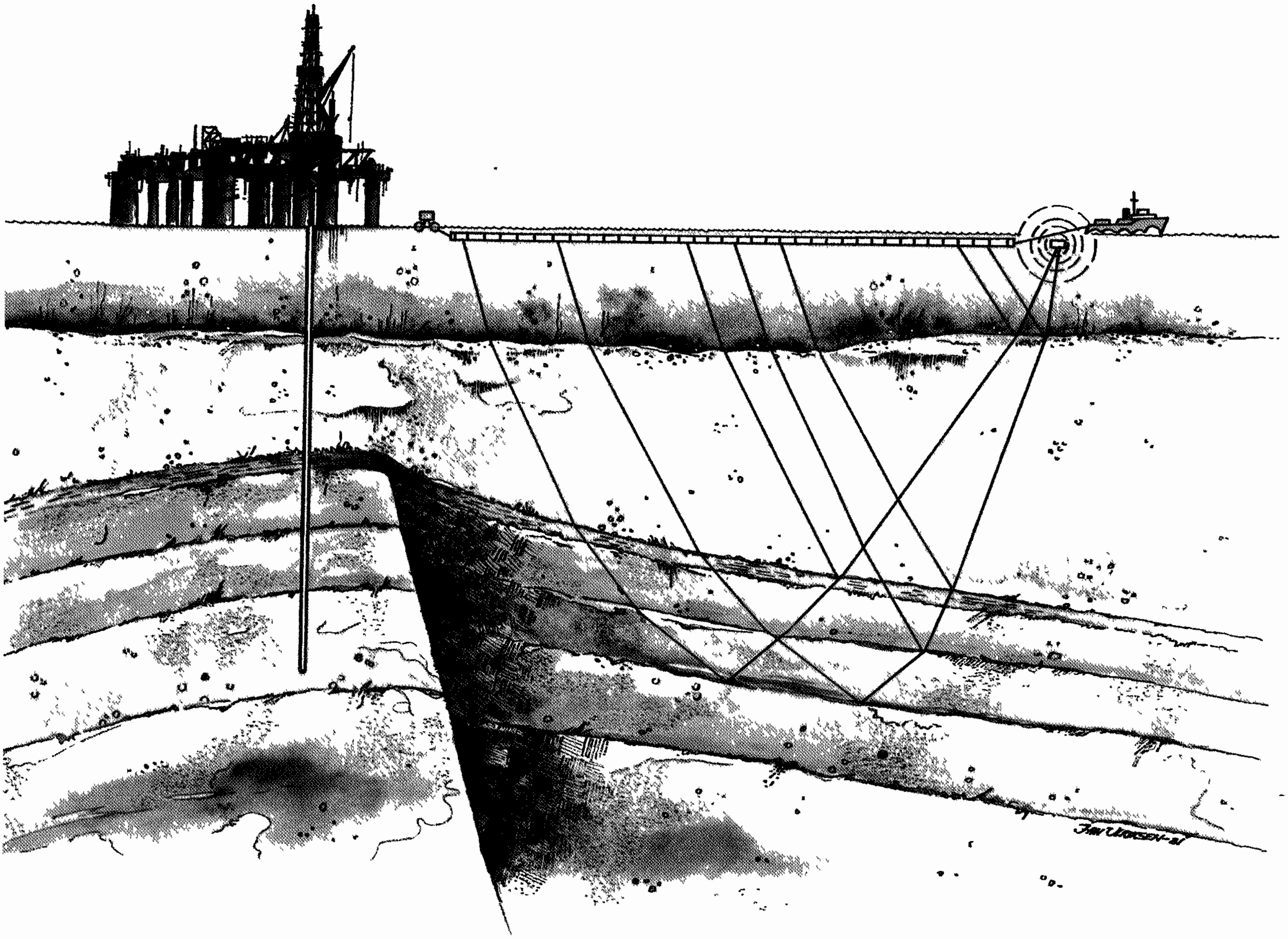

WELL TESTING REPORT

34/10-17

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Den norske stats oljeselskap a.s

CLASSIFICATION

MADE BY

Steinar Lyngroth

SUBTITLE

TITLE

WELL TESTING REPORT

34/10-17

JANUARY 1984

COMPLETED		APPROVED	
6.1.84	St. Lyngroth	25/1 -84	Jon Hanstveit

CONTENTS

1. INTRODUCTION

Well 34/10-17 is the first exploration well drilled on the Beta structure in block 34/10. The structural map on figure 1.1 shows the location of the well.

The well was drilled to a total depth of 3466 mRKB into a formation of Lower Jurassic age.

Hydrocarbon bearing formations were encountered in sands of Middle Jurassic age (Brent).

Four production tests were performed in the gas, oil and water bearing sands in the Brent formation. The tests were designed with conventional downhole and surface equipment.

NOTE: All depths in this report refer to RKB level (measured depth), unless others are indicated.

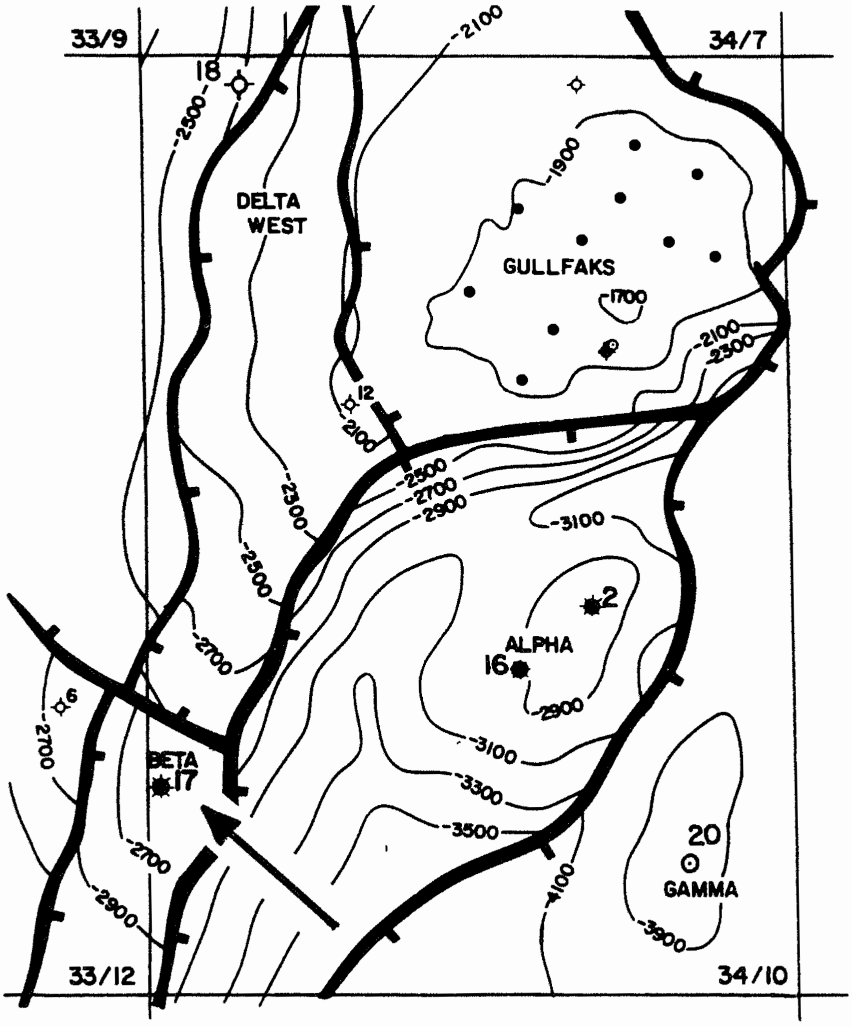


Fig. 1.1 Top Jurassic Structural Map, Block 34/10

2. WELL DATA

Licence:	PL 050
Well:	34/10-17
Location:	61°03'58.93"N 02°00'50.78"E
Classification:	Exploration (Wildcat)
Rig:	Deep Sea Bergen
Spud Date:	23.02.83
Test Period:	27.05.83 - 29.06.83
Completion Date:	08.07.83
RKB Elevation:	25m
Water Depth:	135m
Total Depth:	3466 mRKB
Status:	Plugged and abandoned

3. TESTED INTERVALS

The following intervals were tested:

DST no.	Perf. interval	Formation	Produced fluid
1	2934.0-44.0 mRKB	Etive/Rannoch	Water
2	2880.0-90.0 mRKB	Ness	Oil and Gas
3	2835.0-45.0 mRKB	Ness	Gas and Cond.
4	2754.0-57.0 mRKB 2763.0-65.0 " 2767.5-71.5 " 2773.0-77.0 " 2784.5-90.5 "	Ness	Gas and Cond.

The test intervals are shown on the Well Data Summary, figure 3.1. Figure 3.2 shows the 34/10-17 lithology.

Fig. 3.1

WELL: 34/10-17

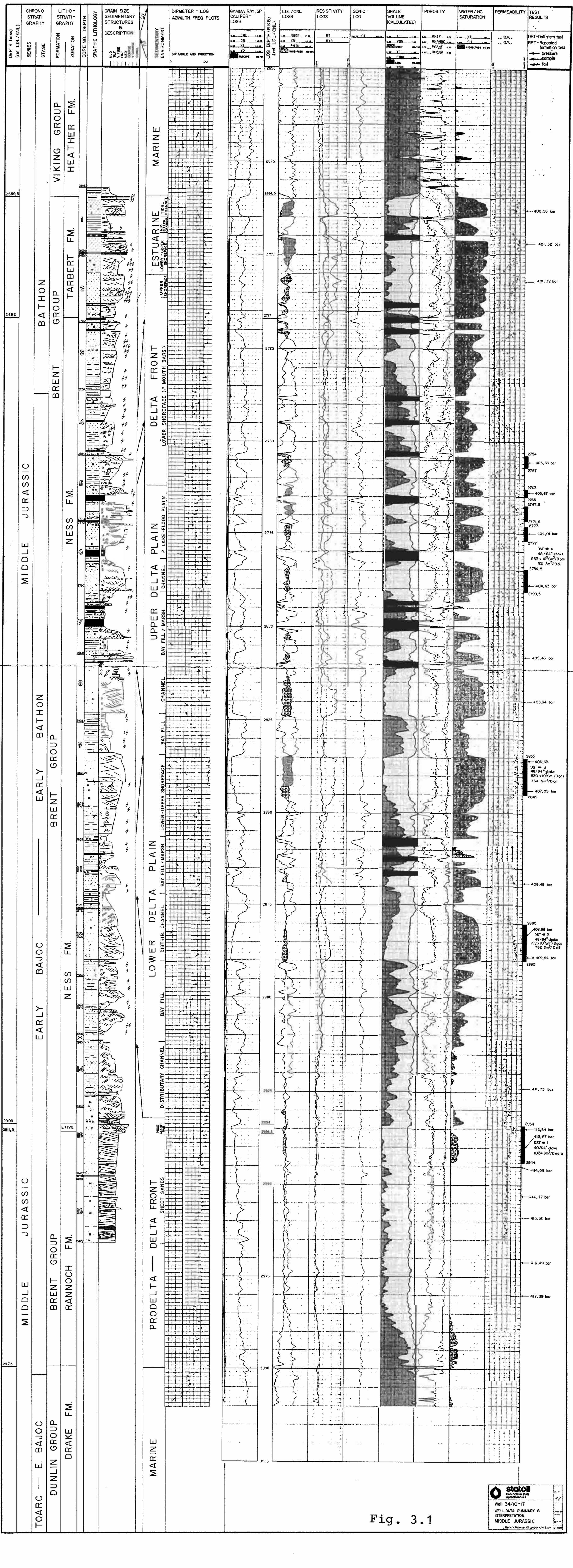
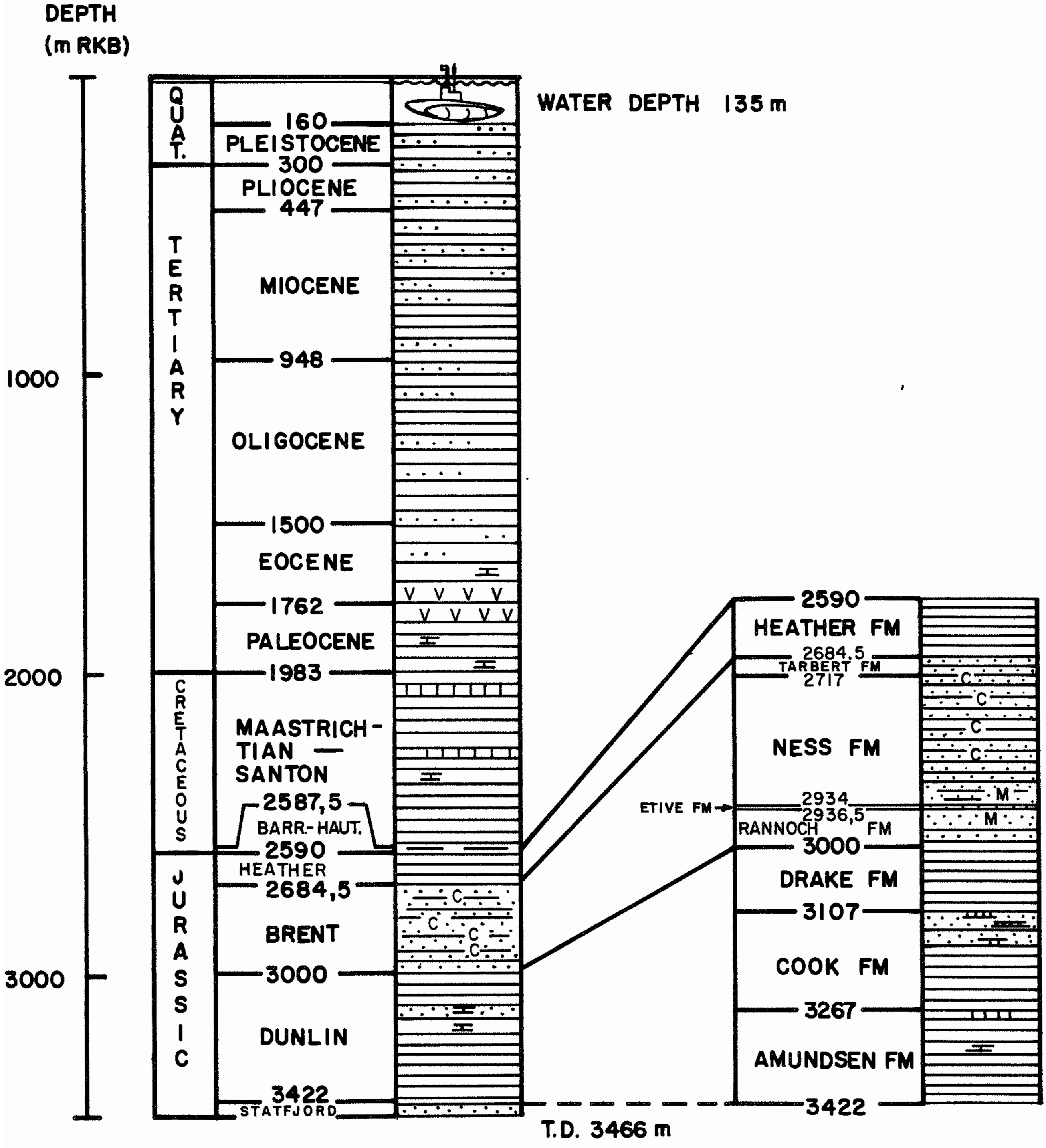


Fig. 3.1

Fig. 3.2

34/10-17 LITHOLOGY



4. OBJECTIVES

The objectives of testing well 34/10-17 were:

1. Obtain representative samples of the reservoir fluids: Gas, oil and water.

2. Evaluate reservoir rock properties and productivity.

3. Determine reservoir pressure and temperature.

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5. RESULTS AND CONCLUSIONS

5.1 Summary of the Test Performance

Table 5.1 shows a summary of the test performance, flow rates, bottom hole pressures etc. for each of the tests.

The given flow rates are average for the last 2 to 3 hours of stabilized flow. It should be noted that the metering practices are questionable, especially for the oil rates, and that the difference in the gas-oil ratio for the different flow periods probably are due to this problem.

More detailed test performance data are shown in chapter 6.

Table 5.1 34/10-17 SUMMARY OF TEST PERFORMANCE

DST no.	FORM.	PERFS. mRKB	OPER.	DURATION mins	CHOKE 1/64"	BHP bar	OIL RATE Sm^3/D	GAS RATE $10^3 Sm^3/D$	GOR Sm^3/Sm^3	WATER RATE Sm^3/D	OIL GRAV. g/cc	GAS GRAV Air= 1
1	Etive/ Rannoch	2934-2944										
			INITIAL FLOW	2.5	48	352						
			INITIAL SHUT IN	65		409						
			SECOND FLOW	511	40	363	0	0		1024		
			SECOND SHUT IN	652		409						
2	Ness	2880-2890	INITIAL FLOW	5	32	398						
			INITIAL SHUT IN	66		407						
			SECOND FLOW	352	48	400	782	192	245	0	0.85	0.74
			SECOND SHUT IN	370		407						
			THIRD FLOW	478	28	403	545	134	246	0	0.85	0.74
			THIRD SHUT IN	475		407						
			BTM HOLE SAMPLING		8	406						

Table 5.1 contd.

DST no.	FORM.	PERFS. mRKB	OPER.	DURATION mins	CHOKE 1/64"	BHP bar	OIL RATE Sm^3/D	GAS RATE $10^3 Sm^3/D$	GOR Sm^3/Sm^3	WATER RATE Sm^3/D	OIL GRAV g/cc	GAS GRAV Air=1
3	Ness	2835-2845	INITIAL FLOW	4	32	399						
			INITIAL SHUT IN	68		404						
			SECOND FLOW	495	48	399	734	530	722	0	0.80	0.72
			SECOND SHUT IN	473		404						
			THIRD FLOW	427	32	401	452	364	805	0		0.72
			THIRD SHUT IN	409		404						
4	Ness	2754 -57 +	INITIAL FLOW	2	32	391						
		2763 -65 +	INITIAL SHUT IN	61		400						
			SECOND FLOW	546	48	395	501	653	1303	0	0.76	0.71
		2767.5 -71.5 +	SECOND SHUT IN	533		401						
			THIRD FLOW	453	32	398	320	428	1338	0	0.76	0.71
		2773 -77 +	THIRD SHUT IN	442		401						
		2784.5 -90.5										

5.2 Reservoir Pressure

A series of pressure samples were obtained by an FMT log (Formation Multi-Tester) throughout the hydrocarbon and water bearing sections prior to the running of the 7" liner. A separate FMT report (ref. 2) discusses the details of that test. The FMT pressures and resulting gradients are shown in figure 5.1.

Reservoir pressure is also obtained by extrapolating pressure build up curves (Horner plot) from the production tests. This extrapolation is believed to give reliable results because of an early start of the semilog straight line and the low value of the slope m (see chapter 6 for details). The extrapolated reservoir pressure was determined for all the gauges on each build up. The pressures were then corrected to the mid perforation depth by applying the pressure gradients obtained from the FMT. The resulting pressures for the build up giving the highest pressure are as follows:

DST no.	Gauge no.		P* at mid perf. depth, bar
1	SS 0151	(s)	412.1
1	SDP 82009		412.4
1	SS 0100		412.2
2	SS 0151	(s)	408.4
2	SDP 82020		407.8
2	SDP 82009		408.1
3	SDP 82003		405.3
3	SS 0222		405.7
3	SS 0181	(s)	405.7
4	SDP 82020		402.5
4	SS 0222	(s)	403.0
4	SS 0151		No reliable data

The small differences between the gauges indicate that the reservoir pressure can be determined within a range of ± 0.5 bar.

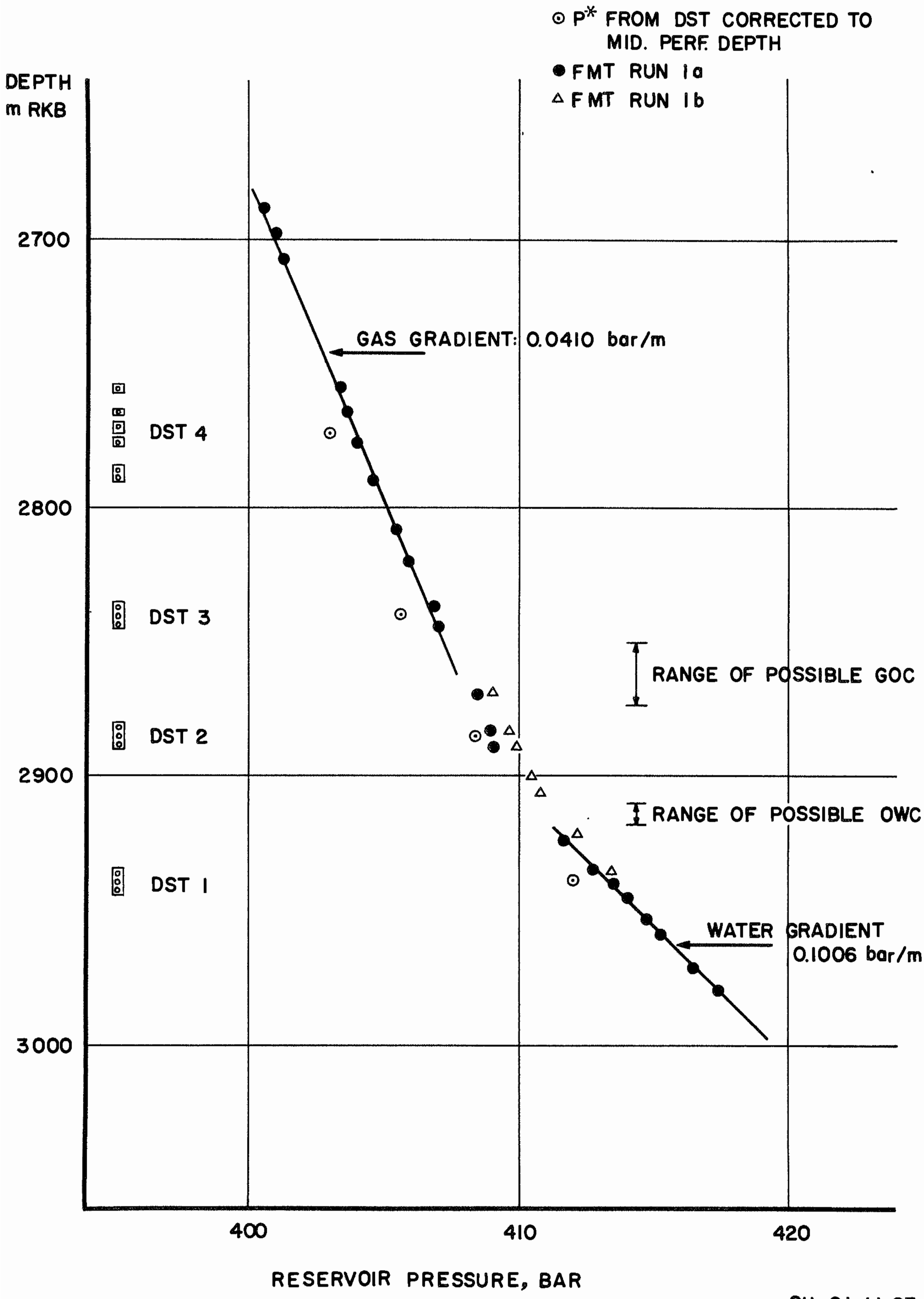
The gauges marked (s) seem to have the best data quality and they are therefore selected for the test analyses. The p* from these gauges are plotted on figure 5.1.

It should be noted that the absolute pressures recorded by the FMT are 1.0 to 1.5 bar high (assuming that the DST pressures are correct).

Fig. 5.1 DST AND FMT PRESSURE VS. DEPTH

WELL 34/10 - 17

(See FMT Report for details)



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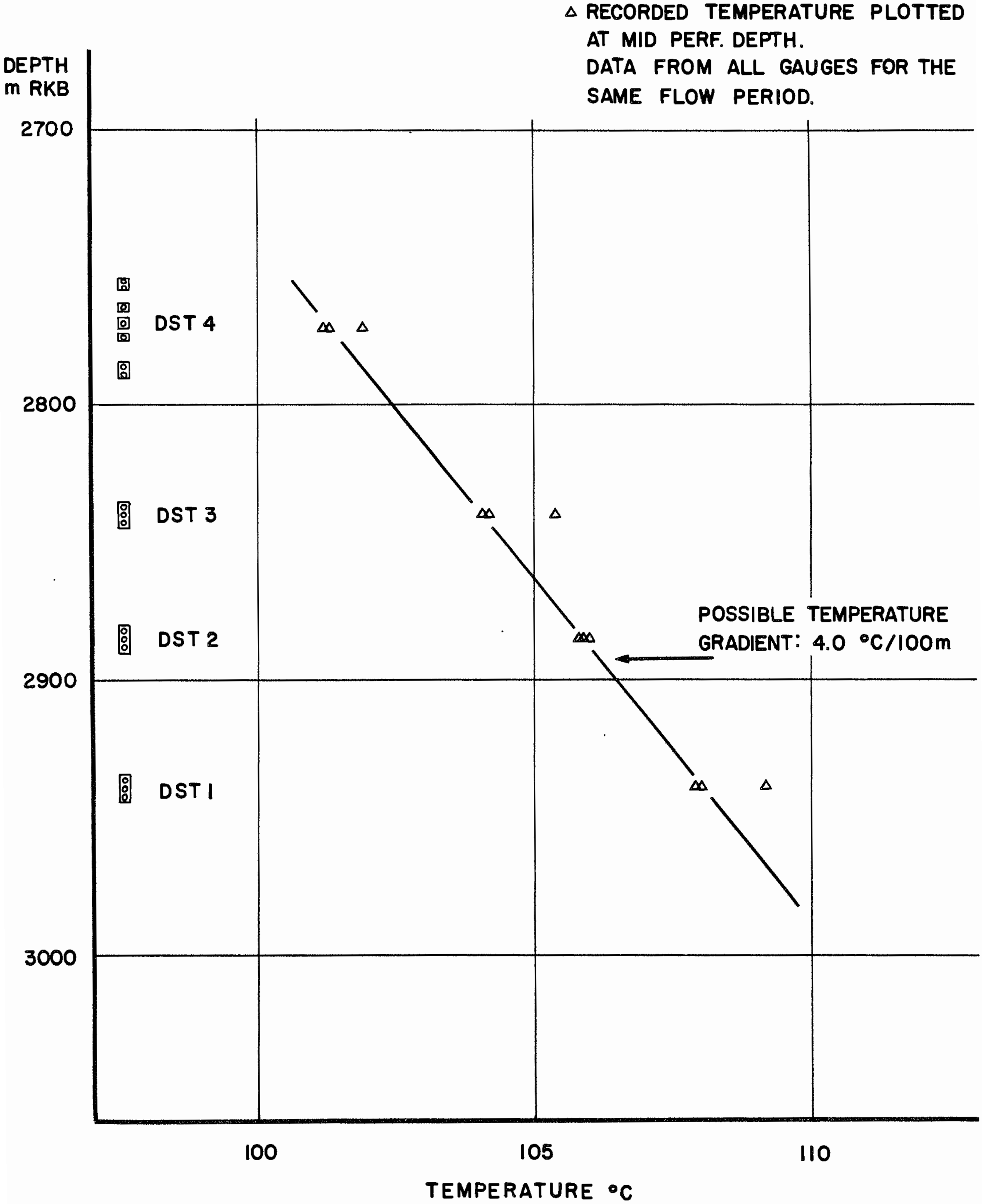
5.3 Reservoir Temperature

The bottom hole temperature was continuously recoreded by three gauges throughout all the tests. A significant difference between flowing and shut in temperatures was observed (5 to 8^{o}C higher flowing temperature). This might be due to cooling through the well media during shut in and possible heating during flow because of pressure loss close to the well bore (skin). No conclusion is made as to which temperature is correct, and for convenience the maximum recorded flowing temperature is considered as the reservoir temperature.

The maximum flowing temperature for each test (and each gauge) is plotted versus depth and shown in figure 5.2. A temperature gradient of 4.0^{o}C per 100 m is drawn through points where two or three gauges read the same temperature.

Fig. 5.2 MAXIMUM FLOWING BOTTOM HOLE TEMPERATURE VS. DEPTH

WELL 34/10-17



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5.4 Permeability and Skin

The permeability of the tested zones have been calculated from the pressure build up data obtained during the tests. The results are as follows:

DST No.	Perf.intv. mRKB	Max.thickness m	Test perm. Darcy
1	2934 - 44	79	0.2
2	2880 - 90	18	2.0
3	2835 - 45	14	0.6
4	2754 - 90	23.5	0.3

The test derived permeabilities for DST no. 3 and DST no. 4 are lower than the permeability measured or core samples, indicating that only a part of the interval has contributed to the test response, and that condensate drop out may have reduced the permeability.

None of the test zones were stimulated and some positive skin, mainly due to formation damage, was observed:

DST No.	Skin factor	Skin pressure loss, bar	Skin press.loss as fraction of drawdown
1	112	43	0.93
2	23	4.9	0.72
3	18	3.8	0.68
4	15	3.9	0.64

5.5 Other Results/Conclusions

Productivity

The hydrocarbon zone tests showed low pressure drawdown in the reservoir at fairly high production rates. This indicates a high productivity. The dewpoint pressure and bubble point pressure in the gas- and oil zones respectively are, however, measured to be close to the reservoir pressure. The productivity will therefore, at lower pressures, be less than what was seen in the tests.

The pressure distribution in the production system for each test production rates are shown in table 5.2. The high increase in tubing pressure loss with rate shows that 3½ inch tubing is not optimal for such high rates. Significant higher production rates (at a given wellhead pressure) can be achieved by using a larger tubing (f. ex. 4½ inch).

Table 5.2 Test production rates & pressure, well 34/10-17

DST no.:	1	2		3		4	
Gas rate, 10^3 Sm^3/d:	0	192	134	530	364	653	428
Oil rate, Sm^3/d:	0	782	546	734	452	501	302
Water rate, Sm^3/d:	1025	0	0	0	0	0	0

Pressure, bar

Wellhead pressure:	42	104	215	177	247	188	257
Pressure loss in tubing:	324	297	189	223	155	209	142
Drawdown:	46	7	4	6	4	6	3
Reservoir pressure:	412	408	408	406	406	403	403

6. TEST PERFORMANCE AND ANALYSIS

6.1 General

All the tests were designed conventionally with a short initial flow period followed by an initial shut in period of about one hour, a main flow and shut in period and for DST 2, 3 and 4 also a third flow and shut in period. At the end of DST 2, bottom hole samples were collected.

Four pressure gauges were run on the test string in all the tests, but one gauge failed in each test. Test analyses are made on the pressure data from all the gauges. The data quality is, however, for some of the gauges rather poor and one gauge has therefore been selected as the most reliable. The test analysis calculations, pressure plots etc. for this gauge are included in the report while the results of the analyses of the other gauges are shown.

All the tested zones have high permeabilities and the pressure drawdown during the production period was therefore low. The pressure stabilized after a short production time and actually showed an increase with time (at a constant flow rate) in all the tests. This effect made reliable drawdown analysis impossible.

Pressure buildup (Horner) analyses were made for all the tests. Because of the excellent reservoir quality, the slope m on the Horner plot is very low. Small errors in the gauge readings (f.ex. because of temperature correction) can therefore affect the slope to some degree. The permeability, skin etc. calculated from these test analyses should therefore be considered as approximate values only.

In the following paragraphs, test analysis and test performance data are shown in this order for each test:

1. Results of the test analysis
2. Comments on the test analysis
3. Data input to the analysis
4. Calculations
5. Pressure plots used in the analysis
6. Comparison of results obtained from all the pressure gauges
7. Diary of events
8. Flow data, graphical illustration
9. Flow data, table
10. Layout of the teststring
11. Gauge arrangement
12. Sampling summary

6.2 DST no. 1, Performance and Analysis

6.2.1 Results of the Test Analysis

The following results are obtained from the test:

Reservoir pressure: 412 bar at 2939 mRKB (mid perf.)

Reservoir temperature: 108°C

Produced reservoir fluid: Water with 32000 mg/l NaCl eq.

Permeability: 190 md average over a total interval of 79 m.
(10 m were perforated)

Skin: Skin factor of 112 corresponding to a pressure loss of 43 bar. Total drawdown was 46 bar. About 3% of the skin was due to partial penetration (perforated 10m of 79m total).

No boundary effects are seen.

6.2.2. Comments to the Test Analysis

The test was evaluated using the conventional Horner analysis of the second shut in period. No significant wellbore storage effects were observed (the well was shut in downhole). The main flow period was disturbed by clean up effects, and drawdown analysis was therefore not performed.

The thickness of the formation interval contributing to the test is somewhat uncertain. No vertical boundaries are seen on the cores below the perforated interval (21m of cores available). The permeability, however, decreases with depth. A tight zone located 56m below the test zone is seen on the logs. It has, for the test analysis, been assumed that this entire interval has affected the test response. The partial penetration skin factor was calculated using a "corrected" total thickness equal to (k h) of the total interval devided by (k) of the perforated interval because of the large permeability variance over the section.

6.2.3 Data Input to the Analysis

Bottom hole pressure data from the pressure gauge SS0151 were selected for the analysis. The quality of these data seems to be good.

The reported water production rate was not constant with time. The flowing BHP and WHP were, however, fairly constant and it was therefore assumed that the rate variations were due to metering problems. An average water rate was used for the analysis.

Water viscosity, water formation volume factor, water compressibility and rock compressibility were derived from standard correlations. Residual oil compressibility was assumed to be as for DST no. 2.

Porosity and saturation data were taken from the log analysis report (ref. 1).

The pressure gradient in the water zone was taken from the FMT report (ref. 2).

The formation thickness contributing to the test response has been estimated using the available core and log analyses data.* Very low vertical permeabilities are measured on plugs from 2901.60m to 2921.10m, and this section is therefore assumed to represent a vertical flow barrier. Some scattered plugs from 2921.10m to 2934m (top perf.) also show low permeabilities, but they might only represent small local barriers. Below the perforated interval (below 2944m), no permeability barriers are seen (core data down to 2965m). The permeability of this section is, however, much lower than in the perforated interval. Log evaluation shows a possible barrier at 3000m.

The maximum thickness will then be 79m (2921m to 3000m). The cement bond log shows a good bond up to 2920m (see Appendix 1), eliminating "behind casing flow" from zones higher in the well.

Arithmetic average horizontal liquid permeabilities from the core analysis are as follows (for comparison with test derived permeability thickness):

Interval, m	Thickness, m	avg. k_{hl}, md	k h, md m
2921-2965 (cored)	44	360	15800
2965-3000	35	30 (est.)	1000
Total:	79	210	16800
2934-44 (perf.int.)	10	916	9160

Test k h = 15265 md m

*Core depths are corrected to log depths.

INPUT TO TEST ANALYSIS

Well no. 34/10-17

DST no. 1 Test Date 02.06.83

Reservoir Parameters

Perforations 2934 - 2944 m RKB

Zone (s) Etive/Rannoch

Wellbore radius 0.11 m

RKB Elev. 25 m

Depth Mid. Perfs: 2939 m RKB 2914 mSS

Pressure Gauge no. SS 0151 Depth 2908.8 m RKB 2883.8 m SS

Pressure Gradient: 0.1006 bar/m

Pressure Correction, Gauge to Mid. Perfs.: 3.0 bar

Formation Volume Factor 1.028 Res.m^3/Sm^3 Viscosity 0.30 cp

Thickness 79 m

Oil Saturation 3.8 %

Water Saturation 96.2 %

Gas Saturation 0 %

Porosity 20.4 %

Oil Compressibility 298 10^{-6} bar^{-1}

Water Compressibility 43 10^{-6} bar^{-1}

Gas Compressibility ____ 10^{-6} bar^{-1}

Formation Compressibility 50 10^{-6} bar^{-1}

System Compressibility $C_t = S_o C_o + S_w C_w + S_g C_g + C_f$

C_t = .038 x 298 10^{-6} + 0.962 x 43 10^{-6} + 0 x ____ 10^{-6} + 50 10^{-6}

C_t = 103 10^{-6} bar^{-1}

Flow Data: Flow Period no. 2

Choke 40 / 64 inches Oil Rate 0 Sm^3/D Gas Rate 0 Sm^3/D

P_{tf} 108 bar Water Rate 1025 Sm^3/D GOR ____ Sm^3/Sm^3

Oil Spec. Grav. ____ Gas Spec. Grav. ____

Cumulative Production Oil ____ Sm^3 Gas ____ Sm^3

Water N/A Sm^3

Equivalent Gas Rate (Gas / Cond System) = qg + qo Vsc = ____ Sm^3/D

Horner Analysis

Well no. 34/10-17
DST no. 1
Build Up no. 2
Gauge no. SS 0151 Test Date 02.06.83

Effective Production Time tp = Cumulative Production / Last Rate

tp = ______ / ______ = 8.5 hrs.

Straight Line Starts at 1.5 hrs Slope: m = 0.445 bar/cycle

P_{wf} = 362.7 bar P_{1hr} 408.6 bar P^* 409.1 bar

Estimated Reservoir Pressure (P^*) at Mid. Perfs. (2914 mSS): 412.1 bar

Permeability:

$$Kh = \frac{21.49\, q\, B u}{m} = \frac{21.49 \cdot 1025 \cdot 1.028 \cdot 0.30}{0.445} = 15265 \text{ md.m}$$

K = Kh / h = 15265 / 79 = 190 md.

Skin:

$$S = 1.1513 \left[\left[\frac{P1hr - Pwf}{m}\right] + \text{Log}\left[\frac{tp+1}{tp}\right] - \text{Log}\left[\frac{K}{\emptyset \mu C_t rw^2}\right] + 3.098 \right]$$

$$S = 1.1513 \left[\left[\frac{408.6 - 362.7}{0.445}\right] + \text{Log}\left[\frac{8.5+1}{8.5}\right] - \text{Log}\left[\frac{190}{0.204 \cdot 0.3 \cdot 103 \cdot 10^{-6} \cdot 0.11^2}\right] + 3.098 \right]$$

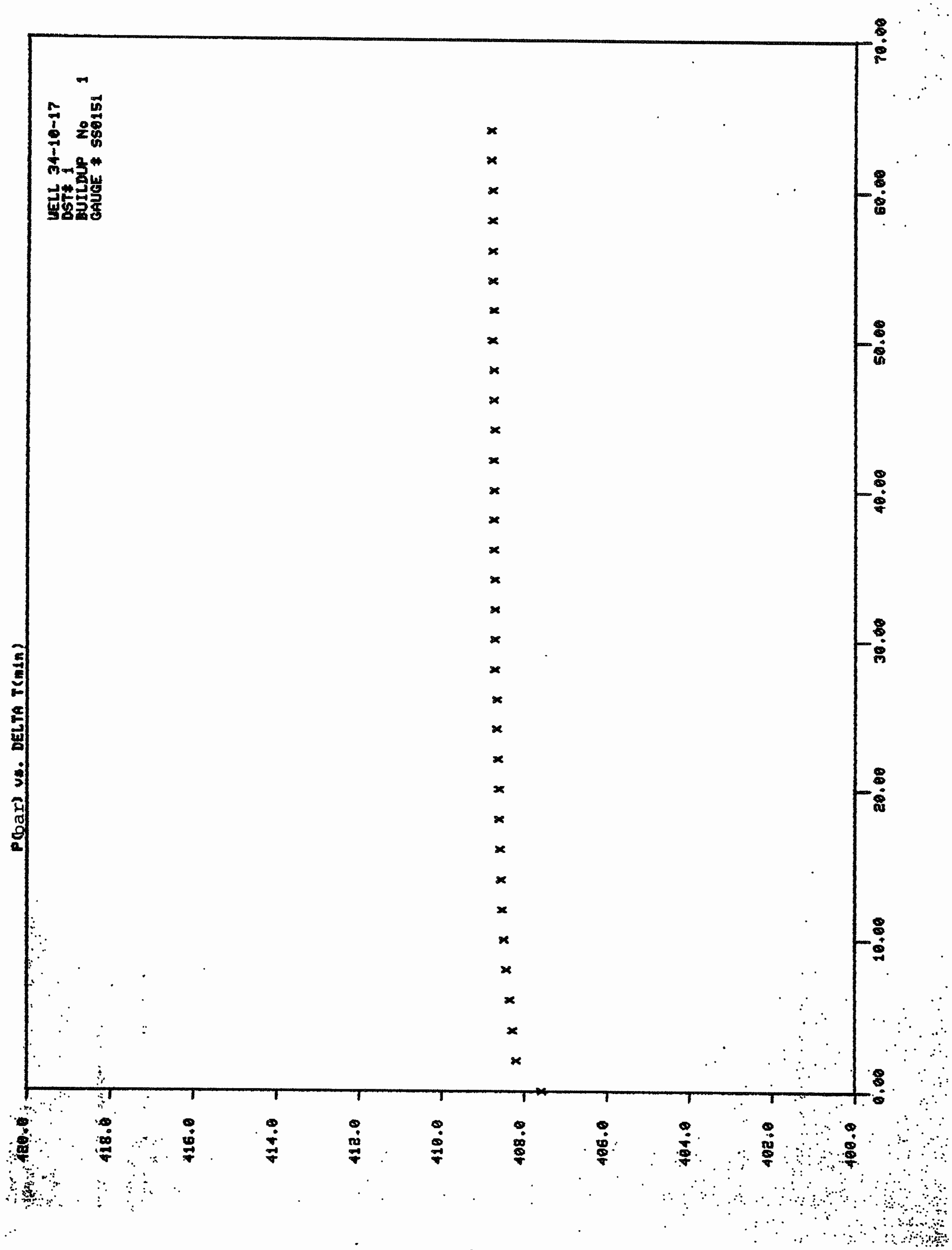
S = 112

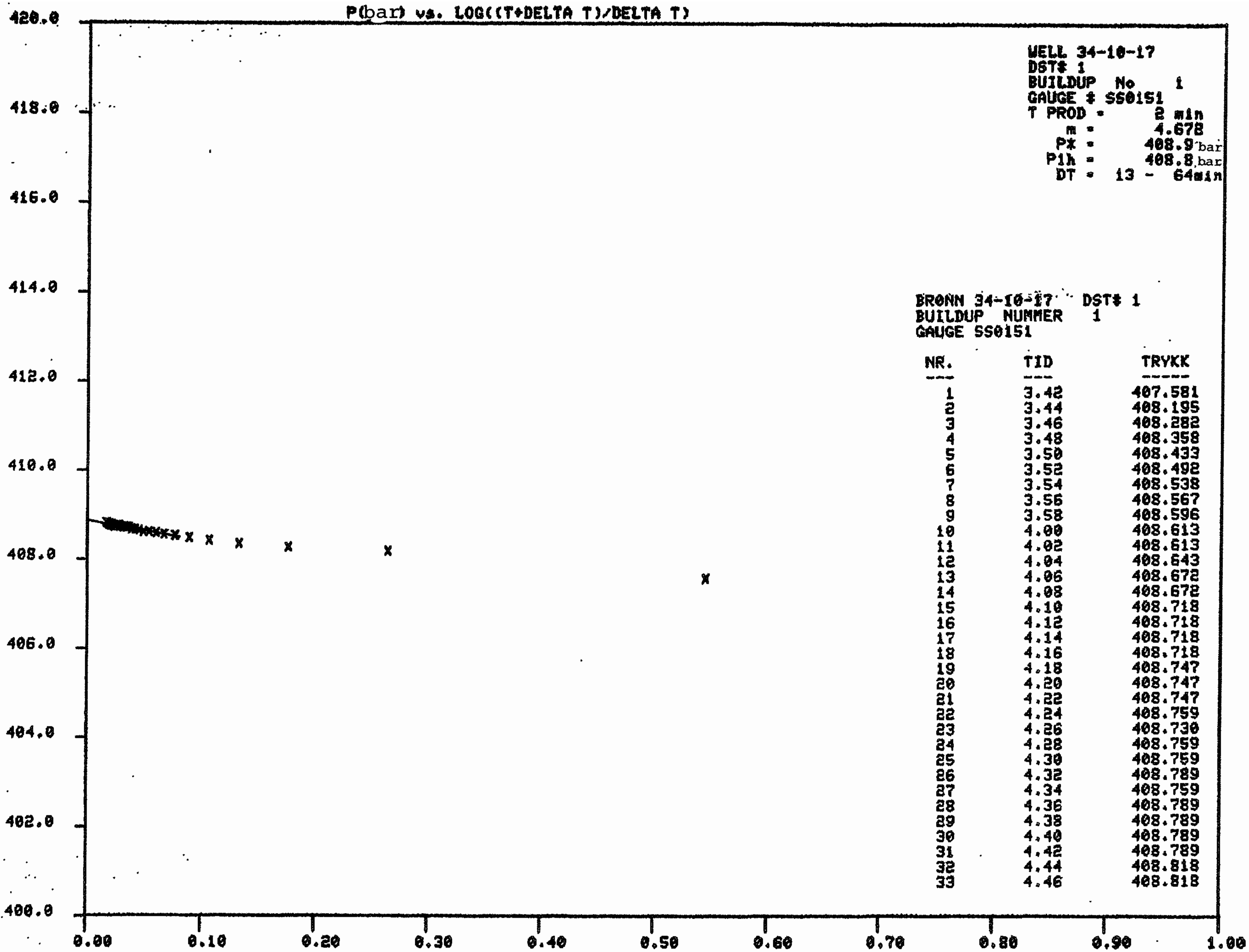
For the Previous Flow Period:

$$\Delta Ps = \frac{18.665 \cdot q\, B\, \mu}{kh} S = \frac{18.665 \cdot 1025 \cdot 1.028 \cdot 0.30 \cdot 112}{15265} = 43 \text{ bar}$$

$\Delta Pdd = P^* - Pwf$ = 46.4 bar

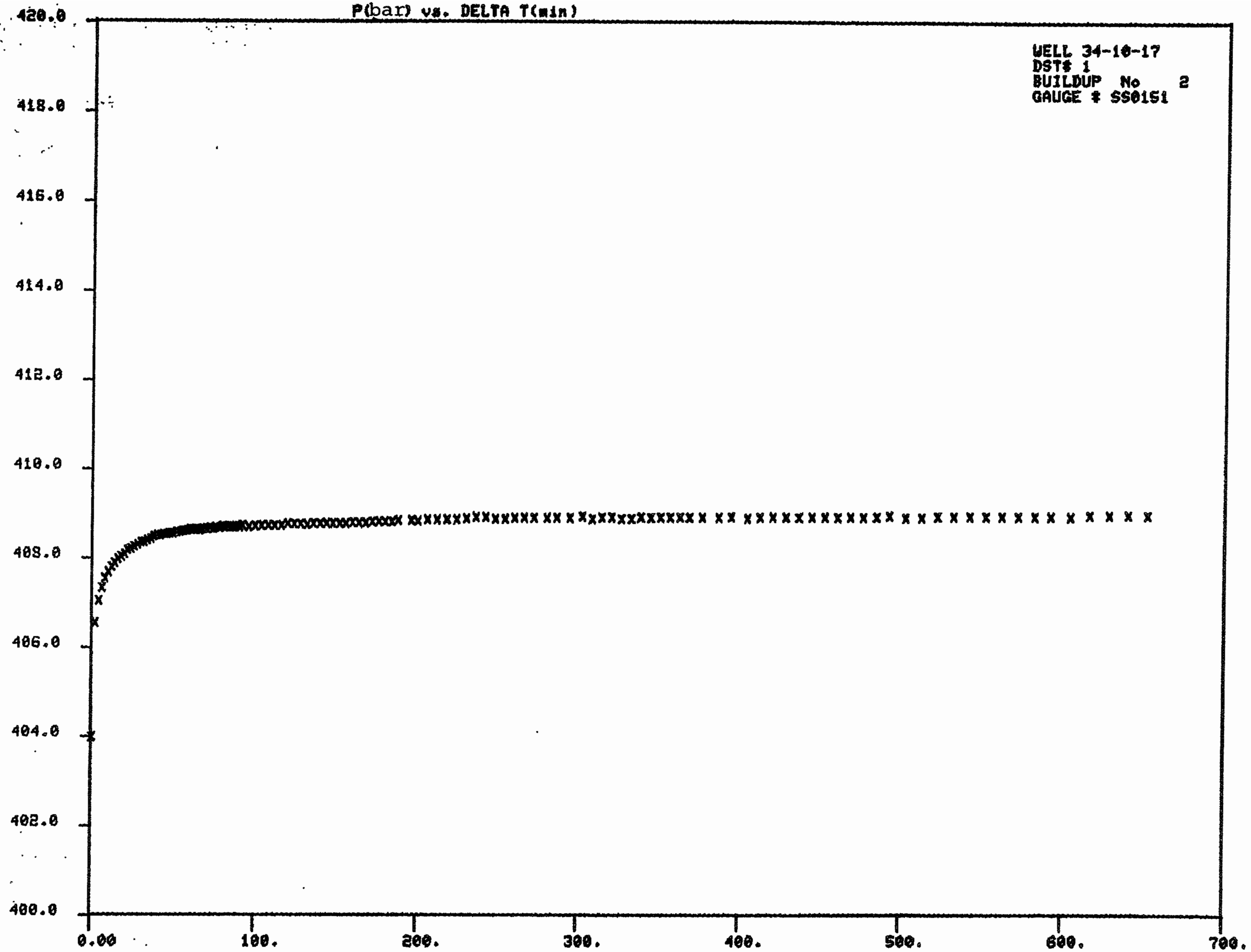
Skin as Fraction of Total Drawdown: $\frac{\Delta Ps}{\Delta Pdd}$ = 0.93

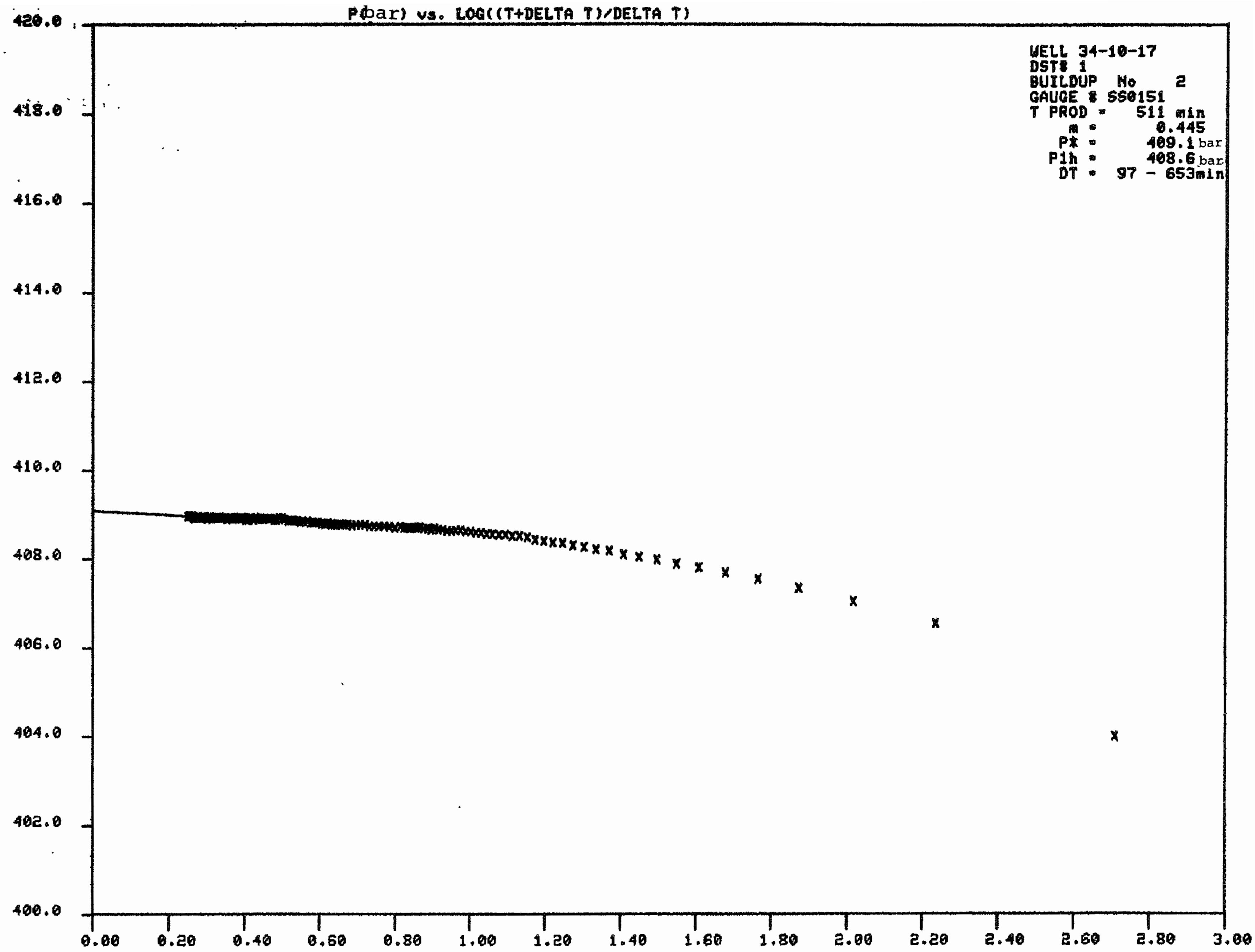

P(bar) vs. DELTA T(min)
WELL 34-10-17
DST# 1
BUILDUP No 1
GAUGE # SS0151
420.0
418.0
416.0
414.0
412.0
410.0
408.0
406.0
404.0
402.0
400.0
0.00
10.00
20.00
30.00
40.00
50.00
60.00
70.00

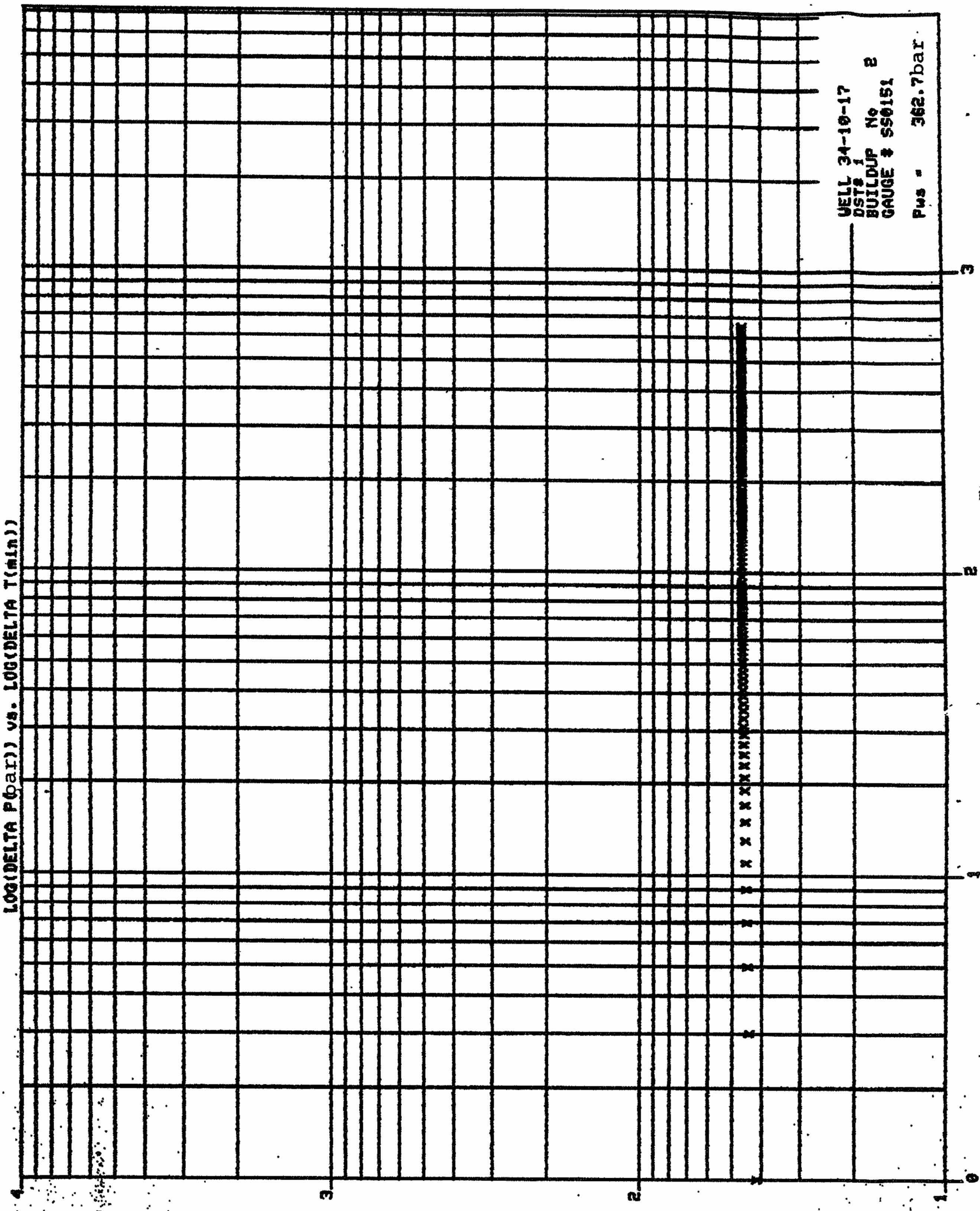


BRØNN 34-10-17 DST$ 1
BUILDUP NUMMER 1
GAUGE SS0151

NR.	TID	TRYKK
1	3.42	407.581
2	3.44	408.195
3	3.46	408.282
4	3.48	408.358
5	3.50	408.433
6	3.52	408.492
7	3.54	408.538
8	3.56	408.567
9	3.58	408.596
10	4.00	408.613
11	4.02	408.613
12	4.04	408.643
13	4.06	408.672
14	4.08	408.672
15	4.10	408.718
16	4.12	408.718
17	4.14	408.718
18	4.16	408.718
19	4.18	408.747
20	4.20	408.747
21	4.22	408.747
22	4.24	408.759
23	4.26	408.730
24	4.28	408.759
25	4.30	408.759
26	4.32	408.789
27	4.34	408.759
28	4.36	408.789
29	4.38	408.789
30	4.40	408.789
31	4.42	408.789
32	4.44	408.818
33	4.46	408.818


P(bar) vs. DELTA T(min)
WELL 34-10-17
DST# 1
BUILDUP No 2
GAUGE # SS0151
420.0
418.0
416.0
414.0
412.0
410.0
408.0
406.0
404.0
402.0
400.0
0.00
100.
200.
300.
400.
500.
600.
700.


P(bar) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-17
DST# 1
BUILDUP No 2
GAUGE # SS0151
T PROD = 511 min
m = 0.445
P* = 409.1 bar
P1h = 408.6 bar
DT = 97 - 653min
420.0
418.0
416.0
414.0
412.0
410.0
408.0
406.0
404.0
402.0
400.0
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
1.60
1.80
2.00
2.20
2.40
2.60
2.80
3.00


LOG(DELTA P(bar)) vs. LOG(DELTA T(min))
WELL 34-10-17
DST# 1
BUILDUP No 2
GAUGE # SS0151
Pws = 362.7bar

BRØNN 34-10-17   DST# 1
BUILDUP NUMMER 2
GAUGE SS0151

NR.	TID	TRYKK
1	13.18	403.989
2	13.20	406.550
3	13.22	407.045
4	13.24	407.336
5	13.26	407.540
6	13.28	407.685
7	13.30	407.802
8	13.32	407.889
9	13.34	407.976
10	13.36	408.035
11	13.38	408.093
12	13.40	408.180
13	13.42	408.209
14	13.44	408.267
15	13.46	408.297
16	13.48	408.355
17	13.50	408.367
18	13.52	408.397
19	13.54	408.426
20	13.56	408.484
21	13.58	408.513
22	14.00	408.513
23	14.02	408.542
24	14.04	408.542
25	14.06	408.555
26	14.08	408.555
27	14.10	408.584
28	14.12	408.584
29	14.14	408.613
30	14.16	408.613
31	14.18	408.648
32	14.20	408.642
33	14.22	408.626
34	14.24	408.626
35	14.26	408.655
36	14.28	408.655
37	14.30	408.684
38	14.32	408.655
39	14.34	408.684
40	14.36	408.684
41	14.38	408.713
42	14.40	408.697
43	14.42	408.697
44	14.44	408.697
45	14.46	408.697
46	14.48	408.697
47	14.50	408.726
48	14.54	408.697
49	14.58	408.726
50	15.02	408.739
51	15.06	408.739
52	15.10	408.739
53	15.14	408.739
54	15.18	408.768
55	15.22	408.768
56	15.26	408.768
57	15.30	408.751
58	15.34	408.780
59	15.38	408.780
60	15.42	408.780
61	15.46	408.780
62	15.50	408.780
63	15.54	408.780
64	15.58	408.810
65	16.02	408.793
66	16.06	408.793
67	16.10	408.822
68	16.14	408.822
69	16.18	408.822
70	16.22	408.822
71	16.26	408.851
72	16.34	408.851
73	16.38	408.835
74	16.44	408.864
75	16.50	408.864
76	16.56	408.864
77	17.02	408.864
78	17.08	408.893
79	17.14	408.922
80	17.20	408.922
81	17.26	408.876
82	17.32	408.876
83	17.38	408.906
84	17.44	408.906
85	17.50	408.906
86	17.58	408.906
87	18.04	408.906
88	18.12	408.906
89	18.20	408.935
90	18.26	408.889
91	18.32	408.918
92	18.38	408.918
93	18.44	408.889
94	18.50	408.889
95	18.56	408.918
96	19.02	408.918
97	19.08	408.918
98	19.14	408.918
99	19.20	408.918
100	19.26	408.918
101	19.34	408.918
102	19.44	408.918
103	19.52	408.931
104	20.02	408.902
105	20.10	408.931
106	20.18	408.931
107	20.26	408.931
108	20.34	408.931
109	20.42	408.931
110	20.50	408.931
111	20.58	408.931
112	21.06	408.931
113	21.14	408.931
114	21.22	408.931
115	21.30	408.960
116	21.40	408.914
117	21.50	408.914
118	22.00	408.943
119	22.10	408.943
120	22.20	408.943
121	22.30	408.943
122	22.40	408.943
123	22.50	408.943
124	23.00	408.943
125	23.10	408.943
126	23.22	408.927
127	23.34	408.972
128	23.46	408.972
129	23.58	408.972
130	0.10	408.972

COMPARISON OF RESULTS OBTAINED FROM ALL GAUGES

WELL no.: 34/10-17

DST no.: 1

	Selected Gauge		Other Gauges			
Gauge no.:	SS 0151		SDP 82009		SS 0100	
Build Up no.:	1	2	1	2	1	2
Data Quality:	Good	Good	Fair	Quest.	Quest.	Poor
Horner Slope,bar/cycle:	4.67	0.445	10.52	0.431	3.23	0.364
Permeability, md:		190		200		236
p* Corrected to mid perf., bar:	411.9	412.1	412.3	412.4	412.1	412.2

Well 34/10-17 DST no. 1	DIARY OF EVENTS	CHP/PG Perfs.: 2934-44 m Zone tested BRENT

1983 Date	Time	OPERATIONS
		PERFORATING
27.05	04.00	Perforated for squeeze at 2925 m. Could not inject at correct rate and pressure.
	06.30	Reperforated at 2926 m.
	13.00	Squeezed 3.5 m^3 cement.
28.05	18.00	Ran CBL, cement good.
31.05	12.00	Perforated for DST no. 1, 4 sh/ft, 120° phasing, 120 shots 2934 - 44 m.
		TEST STRING
	13.04	Started Sperry Sun MK III 0230 4 min mode.
	13.07	Started Sperry Sun MK III 0100 2 min mode.
	13.12	Started Flopetrol DSP 82009 30 sec. mode.
	13.13	Started Sperry Sun MK III 0151, 2 min mode.
	13.26	Placed Sperry Sun gauges 0100 and 0230 in DST hanger.
	13.36	Placed Sperry Sun gauge 0151 and Flopetrol SBP 82009 in XN-nipple. Running in hole with teststring.
01.06	02.00	Discovered leak in teststring, pulled 30 stnds. Found leak, cont. RIH.
	13.30	P.U. SSTT
	15.15	P.U. STT Could not close SSI , pulled OOH
	21.30	Repaired SSTT (check valves on lines)
	23.00	RIH w/SSTT.
02.06	03.23	Sat RTTS packer.
		INITIAL FLOW/BUILD-UP
	03.37	Opened LPR-N valve.
	03.39	Opened choke manifold on 48/64" fixed choke. Produced 7 bbls to surge tank.
	03.41	Closed LPR-N valve and choke manifold for build-up.
		SECOND FLOW/BUILD-UP
	04.46	Opened LPR-N valve
	04.47	Opened choke manifold on 40/64" fixed choke.
	05.06	Rat hole mud to surface.
	05.20	Changed to 40/64" adjustable choke to check for plugging in the fixed choke.
	05.25	Flow directed through 40/64" fixed choke.
	07.06	Flowed through separator.

Remarks :

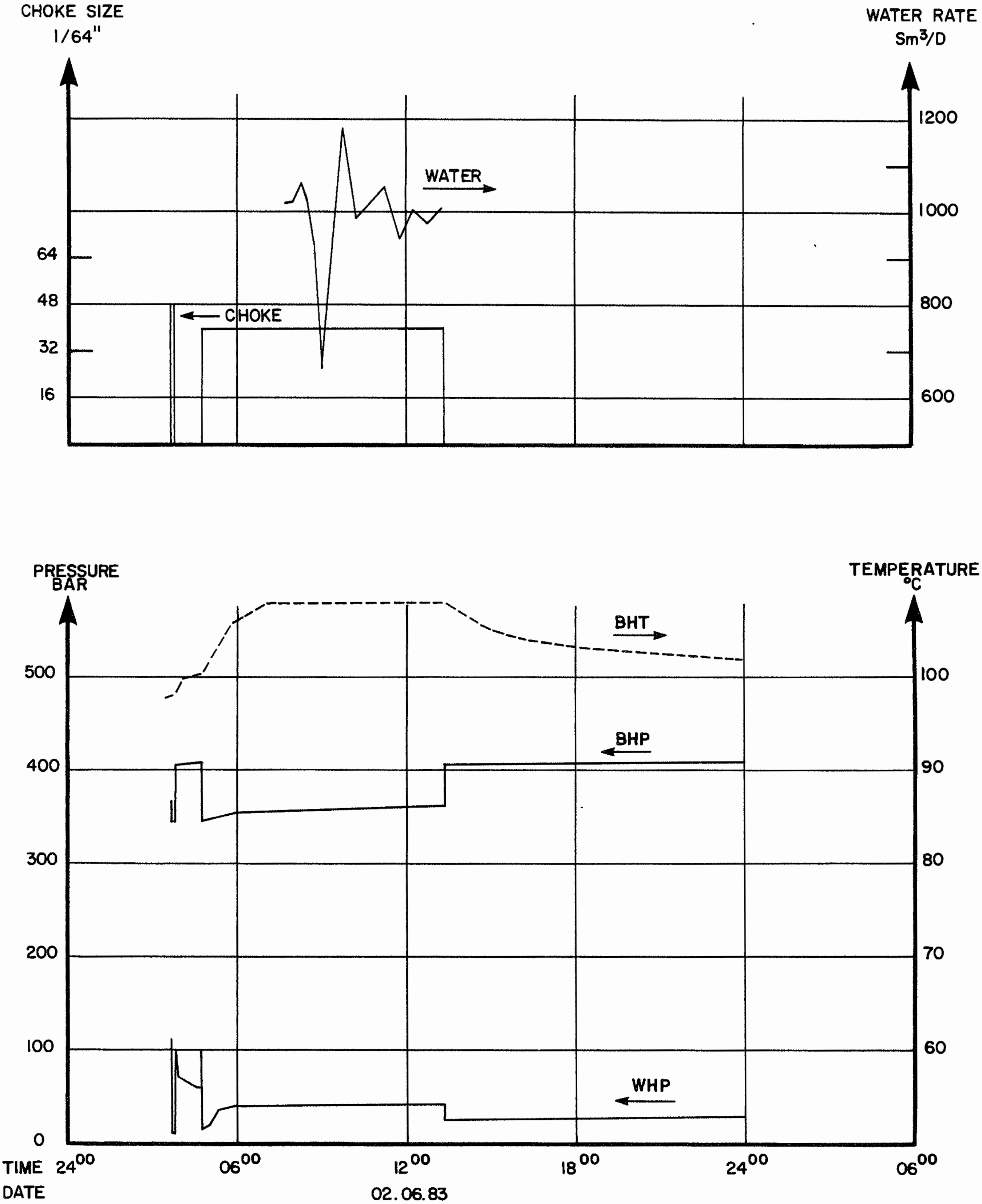
Well 34/10-17 DST no. 1	DIARY OF EVENTS	CHP/PG Perfs.: 2934 - 44m Zone tested BRENT

Date	Time	OPERATIONS
	07.30	Flowed to tank for meter factor.
	07.46	Bypassed tank.
	08.50	Flow directed to port gas flare line.
	08.52	Started to pump out of tank through oil guns.
	09.29	Bypassed separator due to low and variable separator pressure. The separator pressure oscillated (10 bar ± 3 bar) which influenced the water rate. Impossible to get accurate meter factor.
	09.30	Flowed to tank for rate measurements
	09.45	Bypassed and pumped out of tank.
	10.00	Flow directed to tank.
	10.15	Bypassed and pumped out of tank.
	10.30	Flowed to tank.
	10.45	Bypassed and pumped out of tank.
	11.00	Flowed to tank.
	11.55	Bypassed and pumped out of tank.
	11.30	Flowed to tank.
	11.45	Bypassed and pumped out of tank.
	12.00	Flowed to tank.
	12.15	Bypassed and pumped out of tank.
	12.30	Flowed to tank.
	12.45	Bypassed and pumped out of tank.
	13.00	Flowed to tank.
	13.15	Bypassed tank.
	13.18	Closed LPR-N valve and choke manifold for build-up
03.06	00.10	Killed well by bullheading into formation.
		END OF TEST

Remarks :

34/10 - 17 DST no. 1

FLOW, CHOKE, PRESSURE AND TEMPERATURE DIAGRAM



STL. 31.10.83

Well 34/10-17	FLOW DATA	CHP/PG
DST no. 1		Perfs.: 2934-44m
		Zone tested BRENT

1983

Date/ time	Bottom hole		Well head		Chokes 1/64"		Separator data							Liq. and gas analysis					
02.06	press. bar	temp. °C	press bar	temp. °C	manifold	heater	press. bar	temp. °C	gas rate $10^3Sm^3/d$	oil rate Sm^3/d	Water Sm^3/d	sp.gr.oil	sp.gr.gas	Water %	Sedim. %	CO_2 %	H_2S ppm	NaCl g/l	pH
	*	*																	
	SECOND FLOW PERIOD																		
04.47	346.5	99.9	16.3	8.3	40		OPENED WELL FOR CLEAN UP ON 40/64" FIXED CHOKE												
05.06	350.9	103.1	37.5	33.1	40		RATHOLE MUD TO SURFACE												
07.06	356.6	107.4	40.0	68.4	40		SWITCHED FLOW THROUGH SEPARATOR												
07.45	357.0	107.6	40.0	71.2	40		9.6	24.3	0	0	1022			100				33	7.0
08.00	357.1	107.6	40.0	72.4	40		10.7	30.6			1028					3	0	32	7.1
08.15	357.3	107.6	40.0	73.3	40		10.4	35.2			1064								
08.30	357.5	107.7	40.2	71.6	40		10.4	38.5			1027				Trace	3	0		
08.45	357.4	107.8	39.8	73.1	40		9.0	41.1			937							32	7.0
09.00	357.3	107.9	39.7	74.9	40		6.0	42.9			666				Trace	4	0		
09.29	362.5	107.9	42.1	73.4	40		BYPASSED SEPARATOR. STARTED METERING WATER RATE AT TANK.												
09.45	362.9	107.9	41.8	76.2	40						1183							33	7.0
10.15	363.1	107.9	42.0	76.4	40						992					3	0		
11.15	363.2	108.0	41.9	75.6	40						1053				0				
11.45	363.2	107.9	41.9	75.4	40						946					3.3	0	32	6.9
12.15	363.4	108.0	42.0	75.7	40						1007				0				
12.45	363.2	108.0	41.7	75.2	40						977				0	3.0	0		
13.15	363.2	108.1	42.1	75.6	40						1007							32	7.0
13.18							SHUT IN WELL FOR BUILD-UP												

Remarks

* Flopetrol gauge SDP 82009 at 2912.50m.

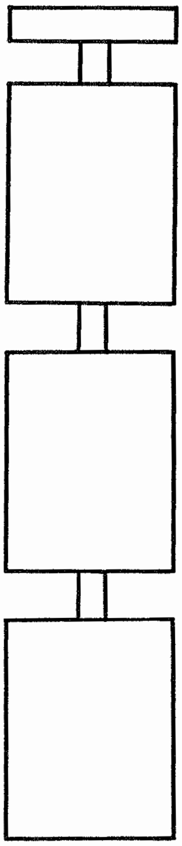
Well 34/10-17	LAYOUT OF TEST-STRING	CHP/PG
DST no 1		Perfs 2934 - 2944 m
		Zone tested BRENT

TEST-STRING	ID inch	OD inch	LENGTH m	DEPTH mRKB
OTIS STT w/X-O 4 3/8" B x 3½" TDS PIN				
TOP FIRST JOINT TUBING				- 7.04
1 JT. 3½ TDS TBG. 12.7 LBS/FT L-80	2.75	3.50	9.45	2.41
J JT. "	"	"	8.93	11.34
X/O 3½ TDS BOX x 4½ ACME PIN	2.80	6.00	0.34	11.68
OTIS LUBRICATOR VALVE	3.00	13/10.75	1.61	13.29
X/O 4½ ACME PIN x 3½ TDS PIN	2.80	6.00	0.38	13.67
5 STANDS 3½ TDS TBG	2.75	3.50	137.88	151.55
PUPJOINT 3½ TDS	"	"	2.02	153.57
X/O 3½ TDS BOX x 4½ ACME PIN	2.80	6.00	0.21	153.78
OTIS SSTT	3.00	13.00	1.78	155.56
SLICK JOINT 3½ TDS	2.25	3.50	2.23	157.79
TOP 18 3/4" WELLHEAD AT 158 M				-
FLUTED HANGER	3.00	12.00	0.30	158.09
X/O 4½ ACME PIN x 3½ TDS PIN	2.80	6.00	0.44	158.53
PUP JOINT 3½ TDS	2.75	3.50	3.21	161.74
269 JOINTS (89 STANDS + 2 SINGLE) 3½ TDS	"	"	2491.63	2653.37
X/O 3½ TDS BOX x 3½" IF PIN	2.75	4.50	0.56	2653.93
SLIP JOINT (OPEN)	2.25	5.00	5.54	2659.47
SLIP JOINT (CLOSED)	2.25	5.00	4.02	2663.49
5 STDS + 2 SINGLES DRILL COLLARS	2.25	4.75	151.62	2815.11
RTTS MECH. CIRC VALVE	2.25	4.625	0.90	2816.01
1 STD DRILL COLLARS	"	4.75	28.43	2844.44
SLIP JOINT (CLOSED)	"	5.00	4.02	2848.46
SLIP JOINT (CLOSED)	"	5.00	4.02	2852.48
1 STD DRILL COLLARS	"	4.75	28.43	2880.91
APR-MSAFETY/CIRC VALVE	"	5.00	2.30	2883.21
DRILL PIPE TESTER VALVE	"	5.00	1.46	2884.67
LPR-N TESTER VALVE	"	4.625	5.10	2889.77
FUL FLO HYD. BYPASS	"	4.625	2.11	2891.88
BIG JOHN JAR	"	4.625	1.59	2893.47
RTTS SAFETY JOINT	2.44	5.00	0.95	2894.42
RTTS PACKER (ABOVE)	2.40	5.75	0.56	2894.98
RTTS " (BELOW)	"	5.75	0.82	2895.80
PERF. 27/8" FULL EUE JNT (PINUP)	2.44	2.88	9.45	2905.25
X/O 2 7/8" EUE PIN x 2 3/8" EUE BOX	2.00	3.25	0.25	2905.50
OTIS "XN"- NIPPLE (PIN x PIN)	1.79	3.25	0.25	2905.75
2 3/8" EUE COLLAR	2.00	2.38	0.14	2905.89
X/O 2 3/8" EUE PIN x 2 7/8" EUE PIN	2.44	4.15	0.18	2906.07
2 7/8" EUE FULL JOINT	2.44	2.88	9.44	2915.51
S.O.S. DST HANGER	-	-	-	
2 7/8" EUE FULL JOINT	2.44	2.88	9.35	2924.86
BULL PLUG w/ CROSS 2 7/8" EUE BOX	2.44	3.25	0.15	2925.01

Remarks.

All measurements to bottom of each item.

Well 34/10-17	GAUGE ARRANGEMENT	CHP/PG
		Perfs.: 2934-44m
DST no. 1		Zone tested BRENT

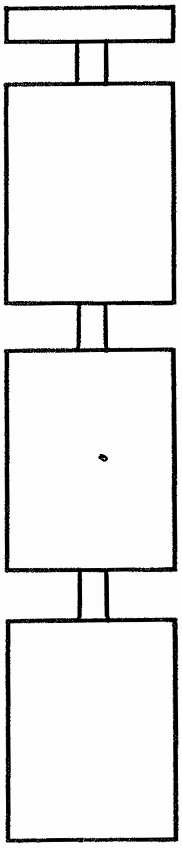


WIRELINE NIPPLE at 2905.75 **mRKB**

Gauge type and number: Sperry Sun MK III 0151
Depth, pressure elemement: 2908.78 m **Range:** 0 - 690 bar
Mode: 2 min **Delay:** 17 hrs
Actuated: time 13.13 **date:** 31.05.83
Will run out: time 14.13 **date:** 03.06.83

Gauge type and number: Flopetrol DSP 82009
Depth, pressure elemement: 2912.50m **Range:** 0-690 bar
Mode: 30 sec. **Delay:** 17 hrs
Actuated: time 13.12 **date:** 31.05.83
Will run out: time **date:**

Gauge type and number:
Depth, pressure elemement: **Range:**
Mode: **Delay:**
Actuated: time **date:**
Will run out: time **date:**



D.S.T. HANGER at 2915.75 **mRKB**

Gauge type and number: Sperry Sun MK III 0100
Depth, pressure elemement: 2918.64m **Range:** 0-690 bar
Mode: 2 min **Delay:** 17 hrs
Actuated: time 13.07 **date:** 31.05.83
Will run out: time 14.07 **date:** 03.06.83

Gauge type and number: Sperry Sun MK III 0230
Depth, pressure elemement: 2921.62 m **Range:** 0-690 bar
Mode: 4 min **Delay:** 17 hrs
Actuated: time 13.04 **date:** 31.05.83
Will run out: time 22.04 **date:** 05.06.83

Gauge type and number:
Depth, pressure elemement: **Range:**
Mode: **Delay:**
Actuated: time **date:**
Will run out: time **date:**

Well 34/10-17	SAMPLING	CHP/PG
DST no 1		Perfs.: 2934-44m
		Zone tested BRENT

SEPARATOR SAMPLES (NONE)

Time/date	Sample no.	Type of sample	Transfer time	Bottle no

BOTTOM HOLE SAMPLES (NONE)

Time/date	Sample depth mRKB	Estimated PB bar/°C	Transfering pressure(bar)	Bottle no

WELLHEAD SAMPLES

Time/date	Sampling point	Sampling equipment	Remarks
		2 x 25l Plastic cans	Water
		10 x 1l Plastic bottles	Water

6.3 DST No. 2, Performance and Analysis

6.3.1 Results of the Analysis

The following results are obtained from the test:

Reservoir pressure: 408 bar at 2885 mRKB (mid. perf.)

Reservoir temperature: 106°C

Produced reservoir fluid: Oil with associated gas at a ratio of 245 Sm^3 gas per Sm^3 oil.

Permeability: 2000 md

Skin: A skin factor of 23 corresponding to a pressure loss of 4.9 bar. Total drawdown was 6.8 bar (for the highest flow rate).

No boundary effects are seen.

6.3.2 Comments on the Test Analysis

The test was evaluated using the conventional Horner analysis of the second and third shut in periods. The LPR-n valve did not close properly at the second shut in, and for the third shut in the well was shut in at the surface only. No significant wellbore storage effectes were, however, observed.

Drawdown analyses were not performed because of the data quality. The bottom hole pressure increased slightly during the flow periods indicating a continuous clean up of the well.

The bottom hole flowing pressure during the second flow period was about 1 bar below the bubble point pressure of 402 bar obtained in the laboratory. For the third flow period the flowing pressure was above the bubble point pressure. The small difference in the analysis results for the two build up periods indicate that no significant gas saturation can have developed in the reserovir during the second flow.

6.3.3 Data Input to the Analysis

Bottom hole pressure data from the pressure gauge SS0151 were selected for the analysis. The quality of these data seems to be good.

Average production rates for the last part of the flow periods are used in the analysis.

Oil viscosity and compressibility were taken from the PVT analysis report made on a bottom hole sample from this test (ref. 3). The oil formation volume factor was derived by simulating a 2 stage separation (test separator conditions), utilizing the results from the PVT analysis.

Connate water compressibility and formation compressibility were derived from standard correlations.

Porosity and saturation data were taken from the log analysis report (ref. 1).

The pressure gradient in the oil zone was taken from the FMT report (ref. 2) and the PVT report (ref. 3).

The formation thickness contributing to the test response has been estimated using the available core and log analyses data*. Low permeability zones are seen from 2869.85m to 2877.45m and from 2890.60m to 2891.95m. These zones are assumed to be laterally continuous.

The thickness of the tested zone will therefore be 13.15 m (2877.45 to 2890.60m). The cement bond log shows a good bond from 2878m to 2904m (see Appendix 1). Because the very top of the permeable section is not covered with a good cement bond, there is a possibility that a permeable zone from 2864.35m to 2869.50m can have affected the test results.

Arithmetic average horizontal liquid permeability from the core analysis are as follows (for comparison with test derived permeability thickness):

Interval, m	Thickness, m	avg. k_{hl}, md	k h, md m
2877.45-90.60	13.15	2220	29200
2864.55-69.50	4.95	980	4800
Total:	18.10	1880	34000
2880-90(perf.int.)	10	2823	28200

Test k h = 34800 md m (analysis of second build up)
= 38200 md m (analysis of third build up)

* Core depths are corrected to log depths.

INPUT TO TEST ANALYSIS

Well no. 34/10-17

DST no. 2

Test Date 07.06 - 08.06.83

Reservoir Parameters

Perforations 2880 - 2890 m RKB

Zone (s) Ness

Wellbore radius 0.11 m

RKB Elev. 25 m

Depth Mid. Perfs: 2885 m RKB 2860 mSS

Pressure Gauge no. SS 0151 Depth 2858.8 m RKB 2833.8 m SS

Pressure Gradient: 0.058 bar/m

Pressure Correction, Gauge to Mid. Perfs.: 1.5 bar

Formation Volume Factor 1.89 Res.m^3/Sm^3 Viscosity 0.273 cp

Thickness 18.1 m

Porosity 23.1 %

Oil Saturation 68.5 %

Oil Compressibility 298 10^{-6} bar^{-1}

Water Saturation 31.5 %

Water Compressibility 43 10^{-6} bar^{-1}

Gas Saturation 0 %

Gas Compressibility ______ 10^{-6} bar^{-1}

Formation Compressibility 50 10^{-6} bar^{-1}

System Compressibility $C_t = S_o C_o + S_w C_w + S_g C_g + C_f$

C_t = 0.685 x 298 10^{-6} + 0.315 x 43 10^{-6} + 0 x ______ 10^{-6} + 50 10^{-6}

C_t = 268 10^{-6} bar^{-1}

Flow Data: Flow Period no. 2

Choke 48 / 64 inches Oil Rate 782 Sm^3/D Gas Rate 192000 Sm^3/D

P_{tf} 104 bar Water Rate 0 Sm^3/D GOR 245 Sm^3/Sm^3

Oil Spec. Grav. 0.85 Gas Spec. Grav. 0.744

Cumulative Production Oil ______ Sm^3 Gas ______ Sm^3

Water ______ Sm^3

Equivalent Gas Rate (Gas / Cond System) = qg + qo Vsc = ______ Sm^3/D

Horner Analysis

Well no. 34/10-17
DST no. 2
Build Up no. 2
Gauge no. SS 0151

Test Date 07.06 - 08.06.83

Effective Production Time tp = Cumulative Production / Last Rate

tp = ______ / ______ = 5.9

Straight Line Starts at 1.5 hrs Slope: m = 0.249 bar/cycle

P_{wf} = 400.1 bar P_{1hr} 406.7 bar P^* 406.9 bar

Estimated Reservoir Pressure (P^*) at Mid. Perfs. (2860 mSS): 408.4 bar

Permeability:

$$Kh = \frac{21.49\, q\, B\mu}{m} = \frac{21.49 \cdot 782 \cdot 1.89 \cdot 0.273}{0.249} = 34820 \text{ md.m}$$

K = Kh / h = 34820 / 18.1 = 1900 md.

Skin:

$$S = 1.1513 \left[\left[\frac{P_{1hr} - P_{wf}}{m}\right] + \text{Log}\left[\frac{tp+1}{tp}\right] - \text{Log}\left[\frac{K}{\varnothing\mu\, C_t\, r_w^2}\right] + 3.098 \right]$$

$$S = 1.1513 \left[\left[\frac{406.7-400.1}{0.249}\right] + \text{Log}\left[\frac{5.9+1}{5.9}\right] - \text{Log}\left[\frac{1900}{0.231 \cdot 0.273 \cdot 268\text{x}10^{-6} \cdot 0.11^2}\right] + 3.098 \right]$$

S = 23

For the Previous Flow Period:

$$\Delta P_s = \frac{18.665 \cdot q\, B\, \mu}{kh}\, S = \frac{18.665 \cdot 782 \cdot 1.89 \cdot 0.273 \cdot 23}{34820} = 4.9 \text{ bar}$$

$\Delta P_{dd} = P^* - P_{wf}$ = 6.8 bar

Skin as Fraction of Total Drawdown: $\frac{\Delta P_s}{\Delta P_{dd}}$ = 0.72

INPUT TO TEST ANALYSIS

Well no. 34/10-17

DST no. 2

Test Date 07.06 - 08.06.83

Reservoir Parameters As for Flow Period no.2

Perforations ______ m RKB

Zone (s) ______

Wellbore radius ______ m

RKB Elev. ______ m

Depth Mid. Perfs: ______ m RKB ______ mSS

Pressure Gauge no. ______ Depth ______ m RKB ______ m SS

Pressure Gradient: ______ bar/m

Pressure Correction, Gauge to Mid. Perfs.: ______ bar

Formation Volume Factor ______ Res.m^3/Sm^3 Viscosity ______ cp

Thickness ______ m

Oil Saturation ______ %

Water Saturation ______ %

Gas Saturation ______ %

Porosity ______ %

Oil Compressibility ______ 10^{-6} bar^{-1}

Water Compressibility ______ 10^{-6} bar^{-1}

Gas Compressibility ______ 10^{-6} bar^{-1}

Formation Compressibility ______ 10^{-6} bar^{-1}

System Compressibility $C_t = S_o C_o + S_w C_w + S_g C_g + C_f$

C_t = ______ x ______ 10^{-6} + ______ x ______ 10^{-6} + ______ x ______ 10^{-6} + ______ 10^{-6}

C_t = ______ 10^{-6} bar^{-1}

Flow Data: Flow Period no. 3

Choke 28 / 64 inches Oil Rate 545 Sm^3/D Gas Rate 134000 Sm^3/D

P_{tf} 214 bar Water Rate 0 Sm^3/D GOR 246 Sm^3/Sm^3

Oil Spec. Grav. 0.85 Gas Spec. Grav. 0.738

Cumulative Production Oil ______ Sm^3 Gas ______ Sm^3

Water ______ Sm^3

Equivalent Gas Rate (Gas / Cond System) = qg + qo Vsc = ______ Sm^3/D

Horner Analysis

Well no. 34/10-17

DST no. 2

Build Up no. 3

Gauge no. SS 0151

Test Date 07.06 - 08.06.83

Effective Production Time tp = Cumulative Production / Last Rate

tp = ______ / ______ = 8.0 hrs.

Straight Line Starts at 1.0 hrs Slope: m = 0.158 bar/cycle

P_{wf} = 402.6 bar P_{1hr} 406.7 bar P^* 406.8 bar

Estimated Reservoir Pressure (P^*) at Mid. Perfs. (2860 mSS): 408.3 bar

Permeability:

$$Kh = \frac{21.49\, q\, Bu}{m} = \frac{21.49 \cdot 545 \cdot 1.89 \cdot 0.273}{0.158} = 38250 \text{ md.m}$$

K = Kh/h = 38250 / 18.1 = 2100 md.

Skin:

$$S = 1.1513 \left[\left[\frac{P_{1hr} - P_{wf}}{m}\right] + \text{Log}\left[\frac{tp+1}{tp}\right] - \text{Log}\left[\frac{K}{\emptyset \mu\, Ct\, rw^2}\right] + 3.098 \right]$$

$$S = 1.1513 \left[\left[\frac{406.7-402.6}{0.158}\right] + \text{Log}\left[\frac{8.0+1}{8.0}\right] - \text{Log}\left[\frac{2100}{0.231 \cdot 0.273 \cdot 268\text{x}10^{-6} \cdot 0.1^2}\right] + 3.098 \right]$$

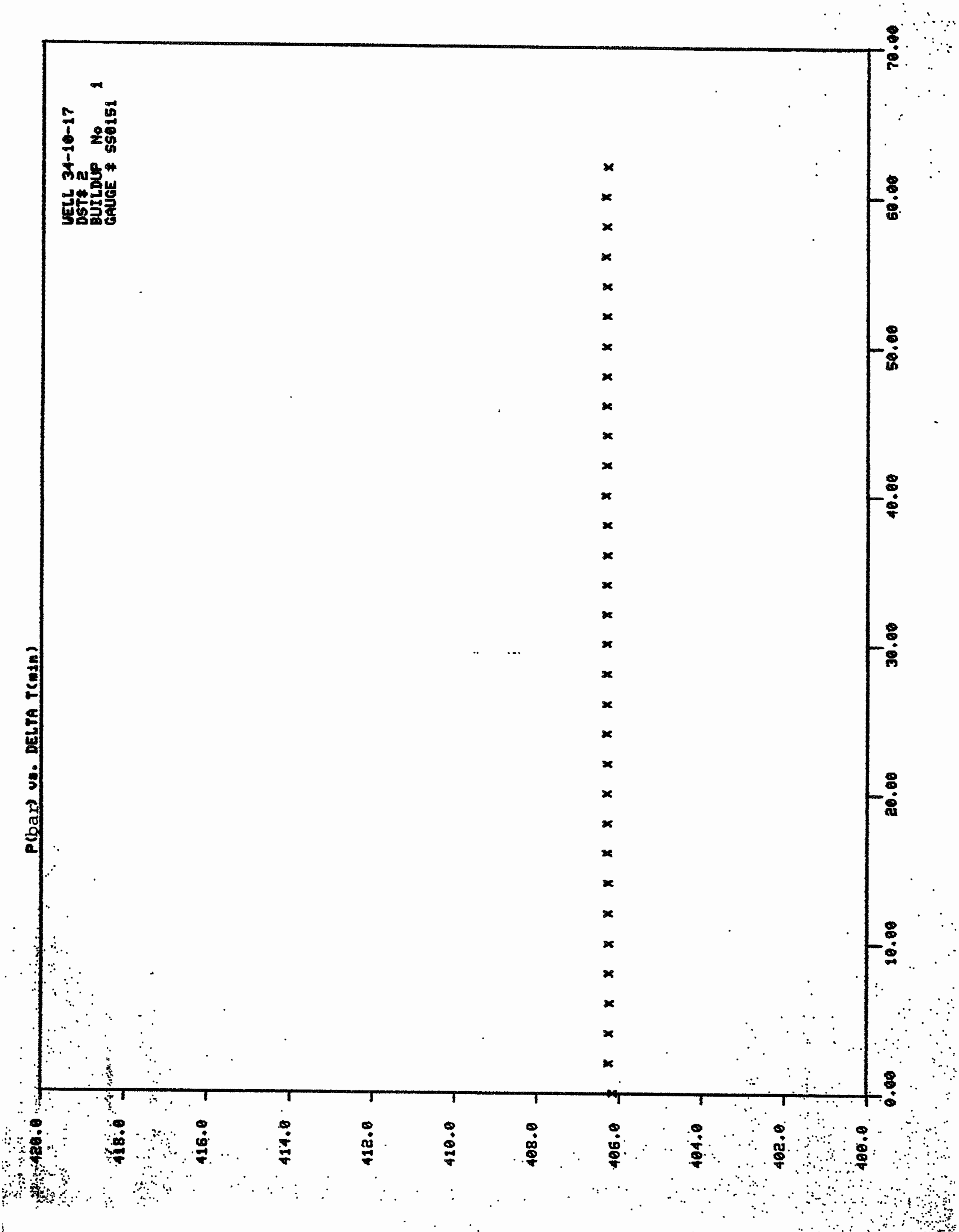
S = 22

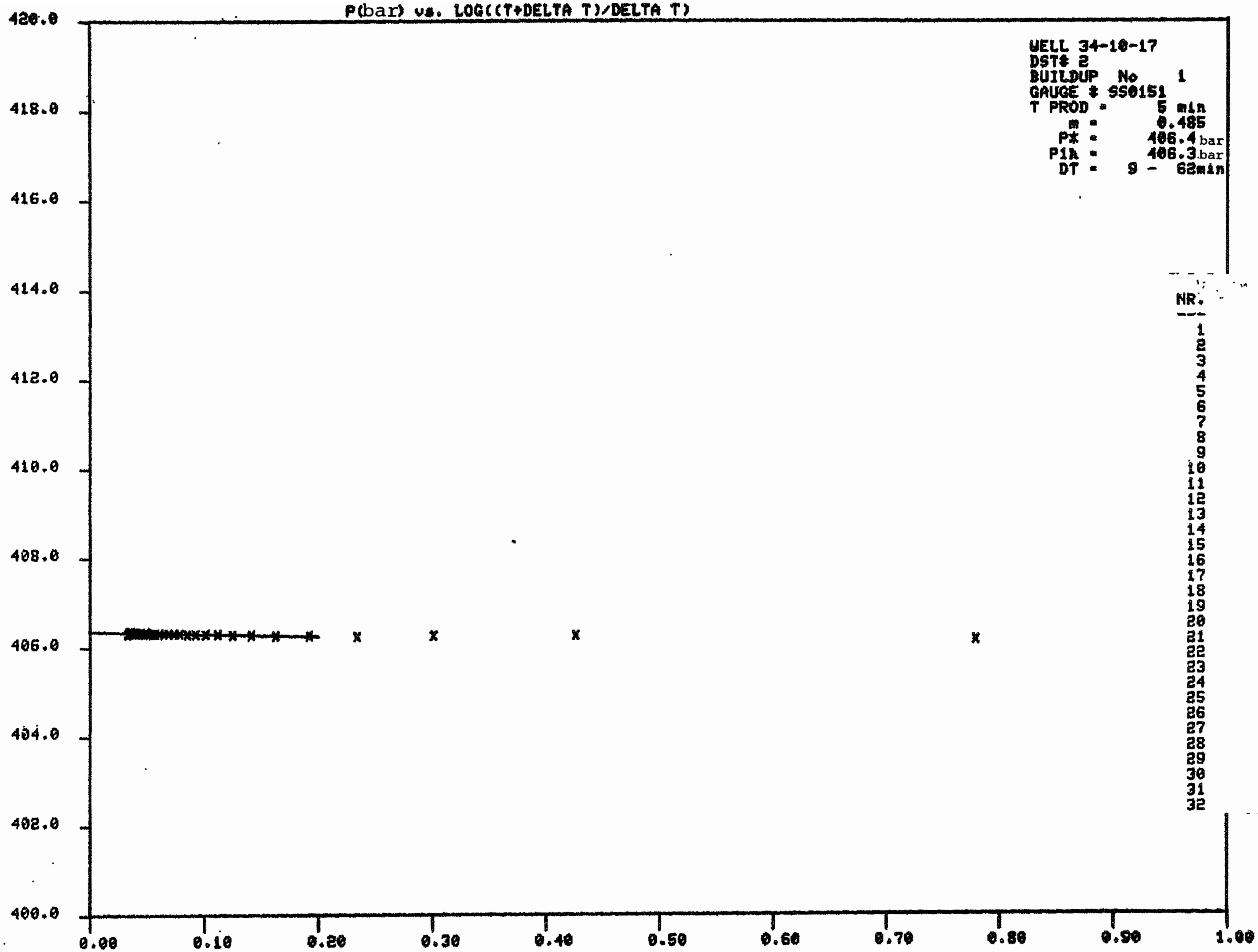
For the Previous Flow Period:

$$\Delta Ps = \frac{18.665 \cdot q\, B\, \mu}{kh}\, S = \frac{18.665 \cdot 545 \cdot 1.89 \cdot 0.273 \cdot 22}{38250} = 3.0 \text{ bar}$$

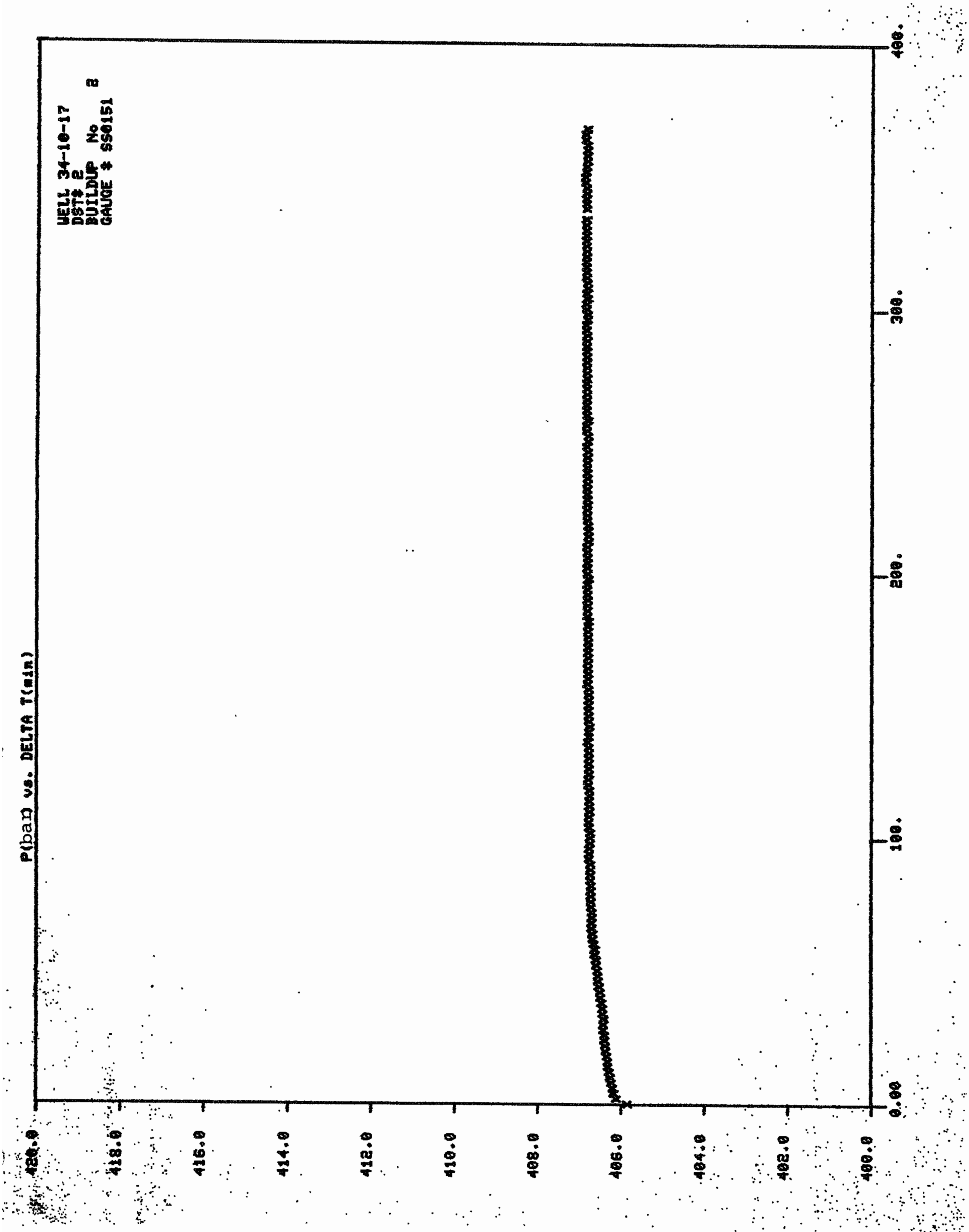
$\Delta Pdd = P^* - Pwf$ = 4.2 bar

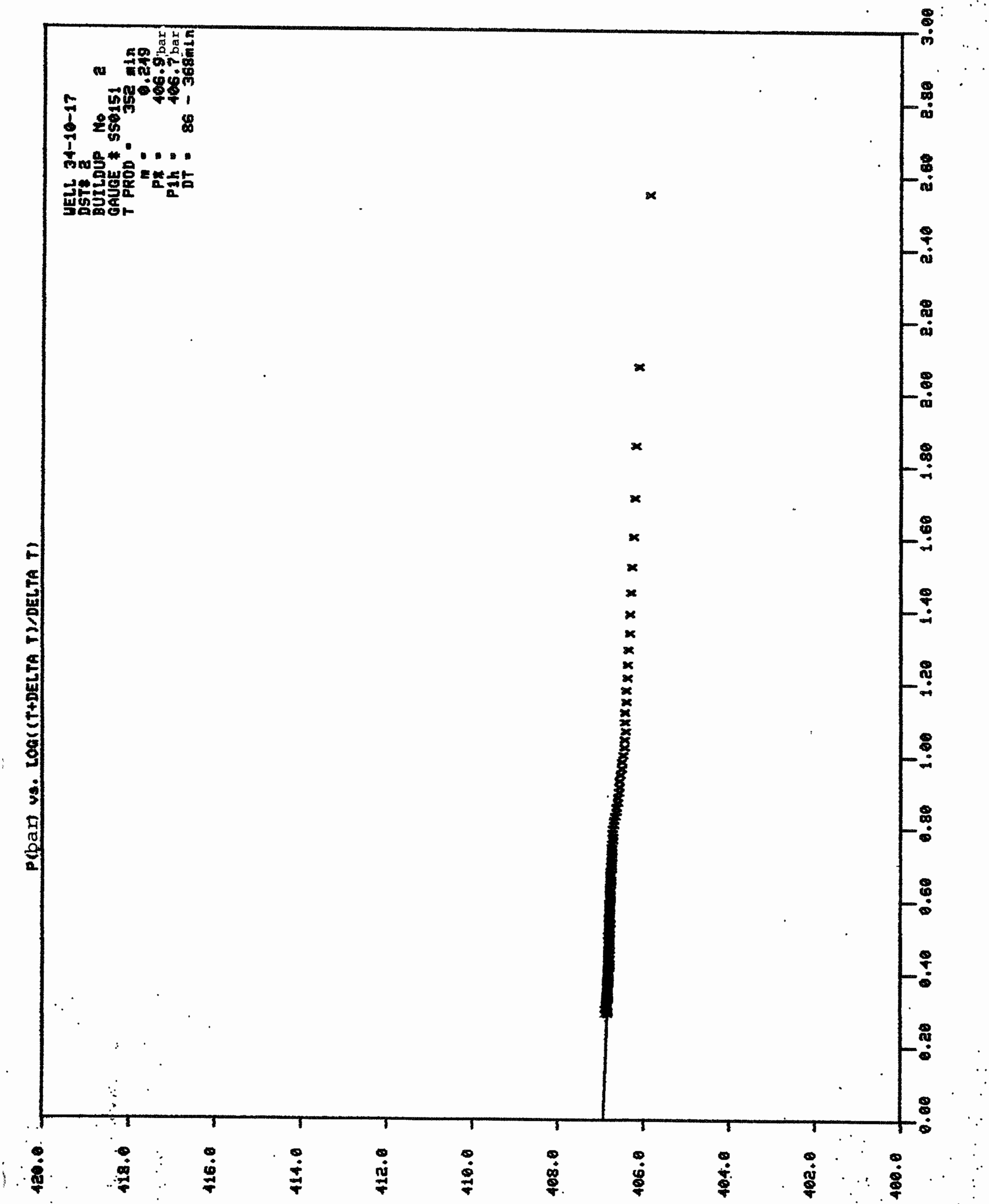
Skin as Fraction of Total Drawdown: $\frac{\Delta Ps}{\Delta Pdd}$ = 0.71

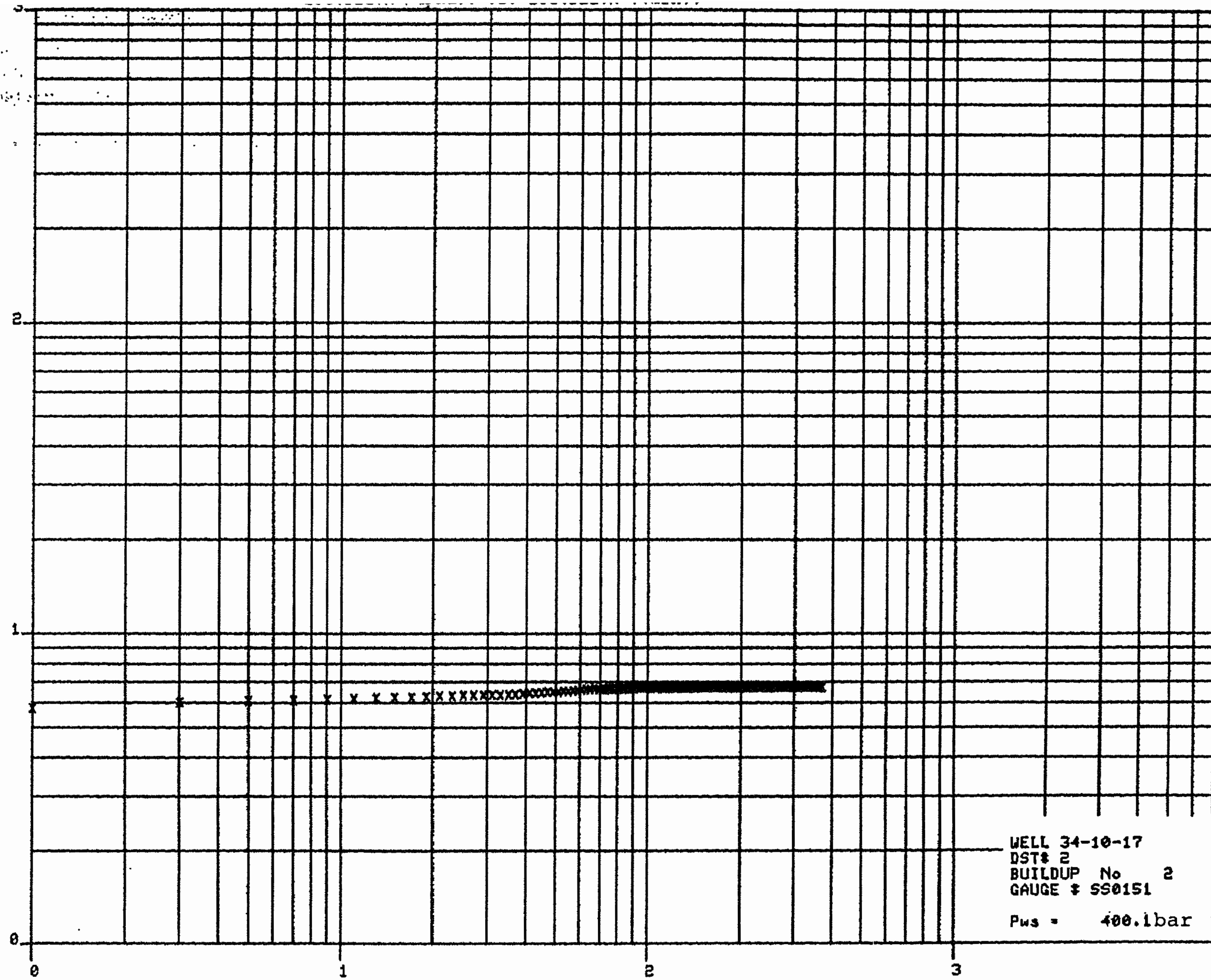

P(bar) vs. DELTA T(min)
WELL 34-10-17
DST# 2
BUILDUP No 1
GAUGE # SS0151
420.0
418.0
416.0
414.0
412.0
410.0
408.0
406.0
404.0
402.0
400.0
0.00
10.00
20.00
30.00
40.00
50.00
60.00
70.00



NR.	TID	TRYKK
1	1.05	406.159
2	1.07	406.264
3	1.09	406.264
4	1.11	406.253
5	1.13	406.271
6	1.15	406.271
7	1.17	406.289
8	1.19	406.289
9	1.21	406.306
10	1.23	406.306
11	1.25	406.306
12	1.27	406.306
13	1.29	406.324
14	1.31	406.324
15	1.33	406.324
16	1.35	406.324
17	1.37	406.324
18	1.39	406.324
19	1.41	406.324
20	1.43	406.324
21	1.45	406.353
22	1.47	406.324
23	1.49	406.324
24	1.51	406.336
25	1.53	406.336
26	1.55	406.336
27	1.57	406.336
28	1.59	406.336
29	2.01	406.365
30	2.03	406.336
31	2.05	406.365
32	2.07	406.306

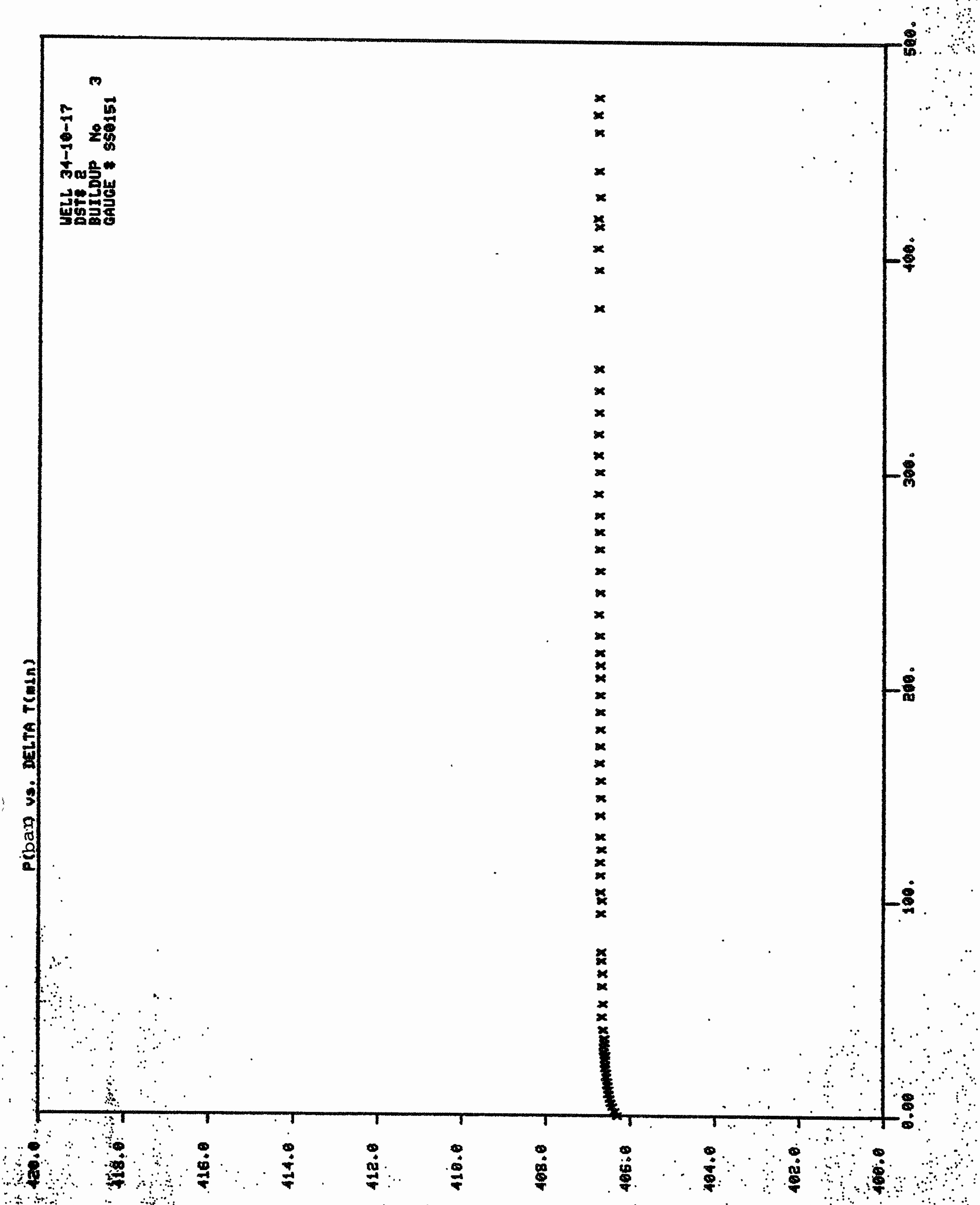

P(bar) vs. DELTA T(min)
WELL 34-10-17
DST# 2
BUILDUP No 2
GAUGE # SS0151
420.0
418.0
416.0
414.0
412.0
410.0
408.0
406.0
404.0
402.0
400.0
0.00
100.
200.
300.
400.

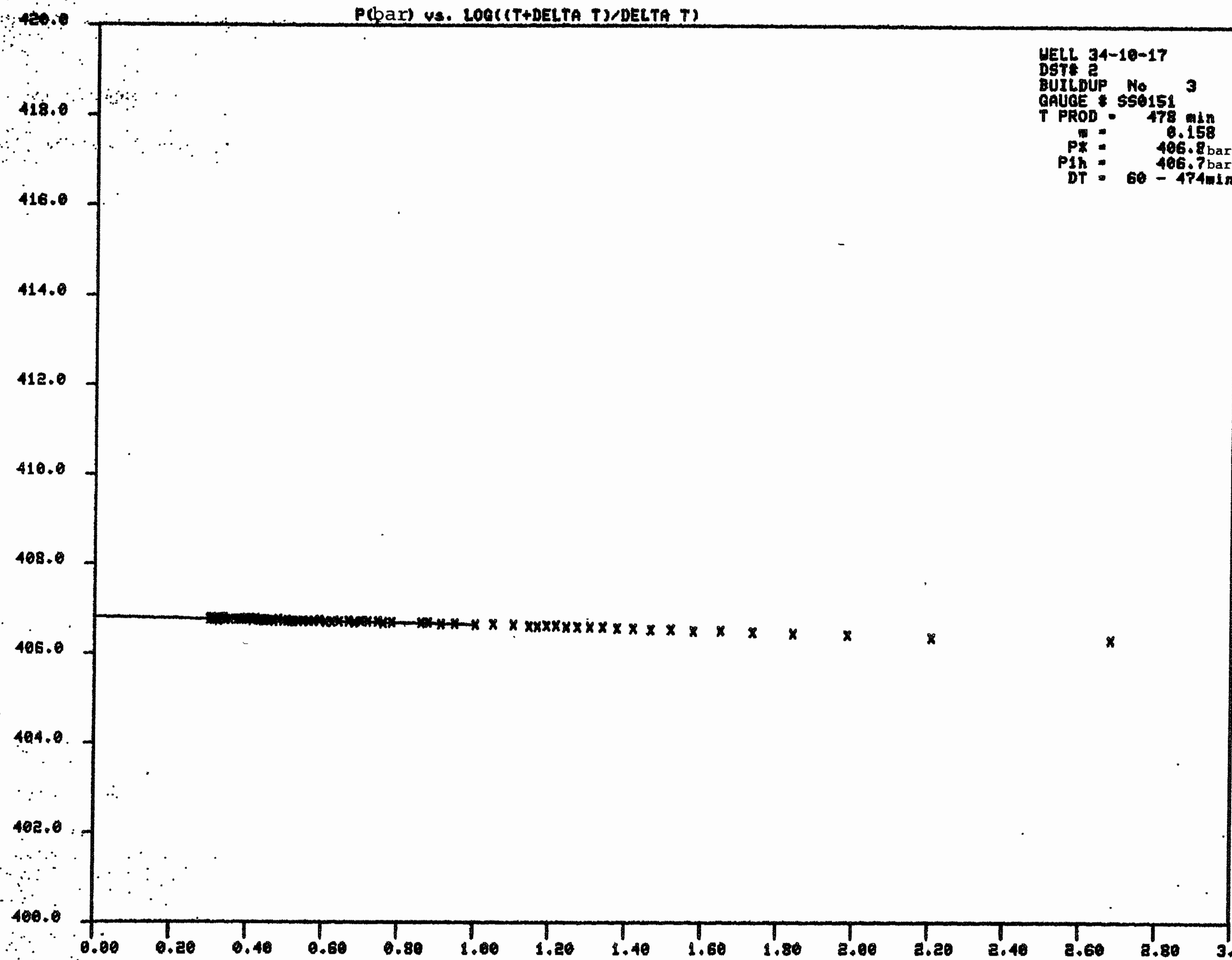

P(bar) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-17
DST# 2
BUILDUP No 2
GAUGE # SS0151
T PROD = 352 min
m = 0.249
P* = 406.9 bar
P1h = 406.7 bar
DT = 86 - 368min
420.0
418.0
416.0
414.0
412.0
410.0
408.0
406.0
404.0
402.0
400.0
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
1.60
1.80
2.00
2.20
2.40
2.60
2.80
3.00

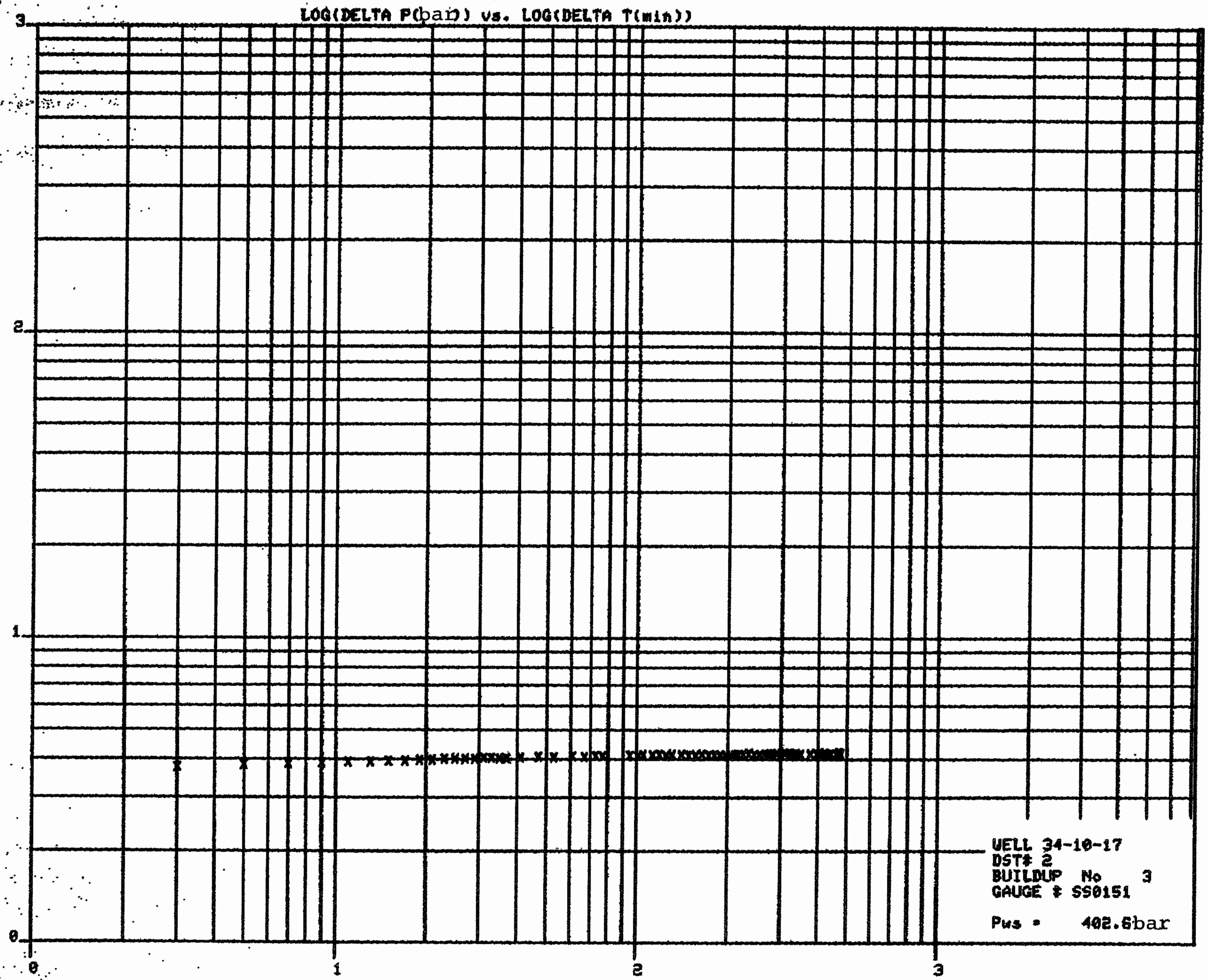

WELL 34-10-17
DST# 2
BUILDUP No 2
GAUGE # SS0151
Pws = 400.1bar
0
1
2
3

BRØNN 34-10-13 DST# 2
BUILDUP NUMMER 2
GAUGE SS0151

NR.	TID	TRYKK
1	8.01	405.854
2	8.03	406.116
3	8.05	406.174
4	8.07	406.204
5	8.09	406.233
6	8.11	406.262
7	8.13	406.291
8	8.15	406.320
9	8.17	406.320
10	8.19	406.349
11	8.21	406.378
12	8.23	406.378
13	8.25	406.408
14	8.27	406.408
15	8.29	406.437
16	8.31	406.437
17	8.33	406.420
18	8.35	406.449
19	8.37	406.449
20	8.39	406.478
21	8.41	406.507
22	8.43	406.507
23	8.47	406.565
24	8.51	406.578
25	8.55	406.607
26	8.59	406.636
27	9.03	406.694
28	9.07	406.723
29	9.11	406.706
30	9.15	406.736
31	9.19	406.736
32	9.23	406.736
33	9.27	406.748
34	9.31	406.748
35	9.35	406.777
36	9.41	406.760
37	9.45	406.789
38	9.51	406.772
39	10.10	406.801
40	10.70	406.784
41	10.17	406.784
42	10.23	406.767
43	10.29	406.796
44	10.39	406.825
45	10.45	406.808
46	10.53	406.808
47	11.03	406.791
48	11.11	406.820
49	11.21	406.820
50	11.31	406.838
51	11.39	406.803
52	11.47	406.838
53	11.57	406.838
54	12.09	406.844
55	12.17	406.844
56	12.27	406.844
57	12.39	406.844
58	12.53	406.856
59	13.05	406.827
60	13.19	406.856
61	13.29	406.856
62	13.49	406.885
63	14.01	406.839
64	14.11	406.868


P(bar) vs. DELTA T(min)
WELL 34-10-17
DST# 2
BUILDUP No 3
GAUGE # SS0151
420.0
418.0
416.0
414.0
412.0
410.0
408.0
406.0
404.0
402.0
400.0
0.00
100.
200.
300.
400.
500.


P(bar) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-17
DST# 2
BUILDUP No 3
GAUGE # SS0151
T PROD = 478 min
m = 0.158
P* = 406.8bar
P1h = 406.7bar
DT = 60 - 474min
420.0
418.0
416.0
414.0
412.0
410.0
408.0
406.0
404.0
402.0
400.0
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
1.60
1.80
2.00
2.20
2.40
2.60
2.80
3.00


LOG(DELTA P(bar)) vs. LOG(DELTA T(min))
3
2
1
0
0
1
2
3
WELL 34-10-17
DST# 2
BUILDUP No 3
GAUGE # SS0151
Pws = 402.6bar

BRØNN 34-10-17 DST# 2
BUILDUP NUMMER 3
GAUGE SS0151

NR.	TID	TRYKK
1	22.09	406.308
2	22.11	406.366
3	22.13	406.425
4	22.15	406.454
5	22.17	406.483
6	22.19	406.512
7	22.21	406.512
8	22.23	406.541
9	22.25	406.541
10	22.27	406.570
11	22.29	406.570
12	22.31	406.599
13	22.33	406.599
14	22.35	406.599
15	22.37	406.599
16	22.39	406.628
17	22.41	406.628
18	22.43	406.612
19	22.45	406.612
20	22.49	406.641
21	22.49	406.641
22	22.55	406.670
23	23.01	406.653
24	23.09	406.682
25	23.15	406.665
26	23.21	406.694
27	23.25	406.694
28	23.43	406.706
29	23.49	406.689
30	23.53	406.719
31	0.01	406.719
32	0.07	406.731
33	0.13	406.702
34	0.19	406.731
35	0.29	406.731
36	0.37	406.714
37	0.45	406.714
38	0.53	406.743
39	1.01	406.726
40	1.09	406.726
41	1.17	406.726
42	1.25	406.726
43	1.33	406.726
44	1.39	406.726
45	1.45	406.738
46	1.53	406.738
47	2.03	406.767
48	2.13	406.738
49	2.23	406.738
50	2.33	406.750
51	2.41	406.750
52	2.49	406.750
53	2.59	406.779
54	3.09	406.750
55	3.17	406.779
56	3.27	406.779
57	3.37	406.768
58	3.47	406.768
59	3.57	406.768
60	4.25	406.768
61	4.43	406.768
62	4.53	406.791
63	5.03	406.768
64	5.07	406.791
65	5.17	406.744
66	5.29	406.774
67	5.47	406.774
68	5.55	406.803
69	6.03	406.774

COMPARISON OF RESULTS OBTAINED FROM ALL GAUGES

WELL no.: 34/10-17

DST no.: 2

	Selected Gauge			Other Gauges					
Gauge no.:	SS 0151			SDP 82009			SDP 82020		
Build Up no.:	1	2	3	1	2	3	1	2	3
Data Quality:	Good	Good	Good	Quest.	Good	Fair	N/A	Quest.	Quest.
Horner Slope, bar/cycle:	0.485	0.249	0.158	3.184	0.169	0.119		0.071	0.074
Permeability, md:		1900	2100		3100	2800		7400	4500
p* Corrected to mid perf., bar:	407.9	408.4	408.3	408.1	408.1	408.0		407.8	407.7

Well 34/10-17 DST no. 2	DIARY OF EVENTS	CHP/PG Perfs.: 2880-90 mRKB Zone tested BRENT

1983 Date	Time	OPERATIONS
		PERFORATING
05.06	23.00	Rigged up Dresser Atlas.
		Ran CBL/VDL, cement O.K.
06.06	02.00	RIH w/perforating gun.
	02.50	Perforated 2880 - 90 mRKB (ref. Density-Neutron log) 4 sh/ft, 120^{o} phasing.
		Out of hole, all 120 shots fired.
		TEST STRING
	03.20	Started to run in hole with tail pipe.
	03.30	Installed gauges in DST-hanger
	03.50	Installed gauges in XN-nipple.
	04.00	RIH with Halliburton BHA and tubing.
	23.00	Started pressure testing surface equipment.
07.06	00.30	Finished pressure testing.
	00.39	Sat packer
	00.52	Closed MPR
		INITIAL FLOW/BUILD-UP
	00.50	Opened LPR-n valve.
	00.58	Opened choke manifold on 32/64" fixed choke.
		Flowed back 2.6 m^3 cushion to surge tank.
	01.03	Closed LPR-n valve and choke manifold.
		2.FLOW/BUILD-UP
	02.06	Opened LPR-n valve.
	02.09	Opened choke manifold on 8/64" adj. choke,increased to 32/64" adj. in 2 min.
	02.18	Mud to surface, adj. choke plugged
	02.19	Changed to 32/64" fixed choke.
	02.25	Burner ignited
	02.48	Changed to 48/64" adj. choke.
	02.57	Changed to 48/64" fixed choke.
	03.37	Flowed through heater to increase temp. for better separation (thick heavy oil).
	03.40	Flowed through seaprator.
	04.29	Indication on surface pressure that LPR-n valve closed few minutes (annulus pressure dropped due to the leak)

Remarks:
Leak in rig standpipe causing dropping annulus pressure. Communication between mudpump no. 1 with water to burner and mudpump no. 2 to annulus. Shut of water pump and isolate annulus. Total of 11 m^3 lost due to the leak.

Well 34/10-17 DST no. 2	DIARY OF EVENTS	CHP/PG Perfs.: 2880-90 mRKB Zone tested BRENT

Date	Time	OPERATIONS
07.06	04.45	Started to take first set of PVT-samples. (one oil and one gas bottle)
	05.15	Finished sampling.
	08.01	Closed LPR-n valve and choke manifold for second build-up. (LPR-n valve leaking.)
		THIRD FLOW/BUILD-UP
	13.58	Started glycol injection to avoid freezing when the gas on top of teststring started to flow.
	14.06	Opened LPR-n valve. No response on surface.
	14.11	Opened choke manifold on 28/64" fixed choke. Directed the flow through heater to burner (heater chokes 2 x 128/64").
	14.28	Stopped glycol injection.
	15.05	Flowed through separator.
	18.25	Started to take 2. set of separator samples.
	19.40	" 3. "
	20.30	" 4. "
	20.50	Separator conditions unstable, oil level and pressure increased.
	22.09	Closed choke manifold for surface shut-in.
		BOTTOM HOLE SAMPLING
08.06	06.00	Started glycol injection to avoid freezing.
	06.04	Opened choke on 20/64" adj. choke.
	06.32	Changed to 10/64" fixed choke.
	06.40	Flowed to separator to tank. Estimated rate.
	06.55	Closed choke manifold, surface pressure 231 bar.
	07.00	Closed lubricator valve. Bled off to 42 bar on choke, test O.K.
	07.18	Bled to zero pressure and closed choke manifold. Test O.K. Recut slick line twice.
	08.15	Started clocks on sample chambers (2.5 hrs).
	08.32	Opened swab valve to install samplers.
	09.00	Flushed line and pressure up to equalize pressure across lubricator valve, leaking in sruffing box. Replaced O-ring seal.
	09.15	Installed samplers again.
	09.25	Increased surface pressure to 224 bar to equalize pressure across the lubricator valve. No leaks.

Remarks :

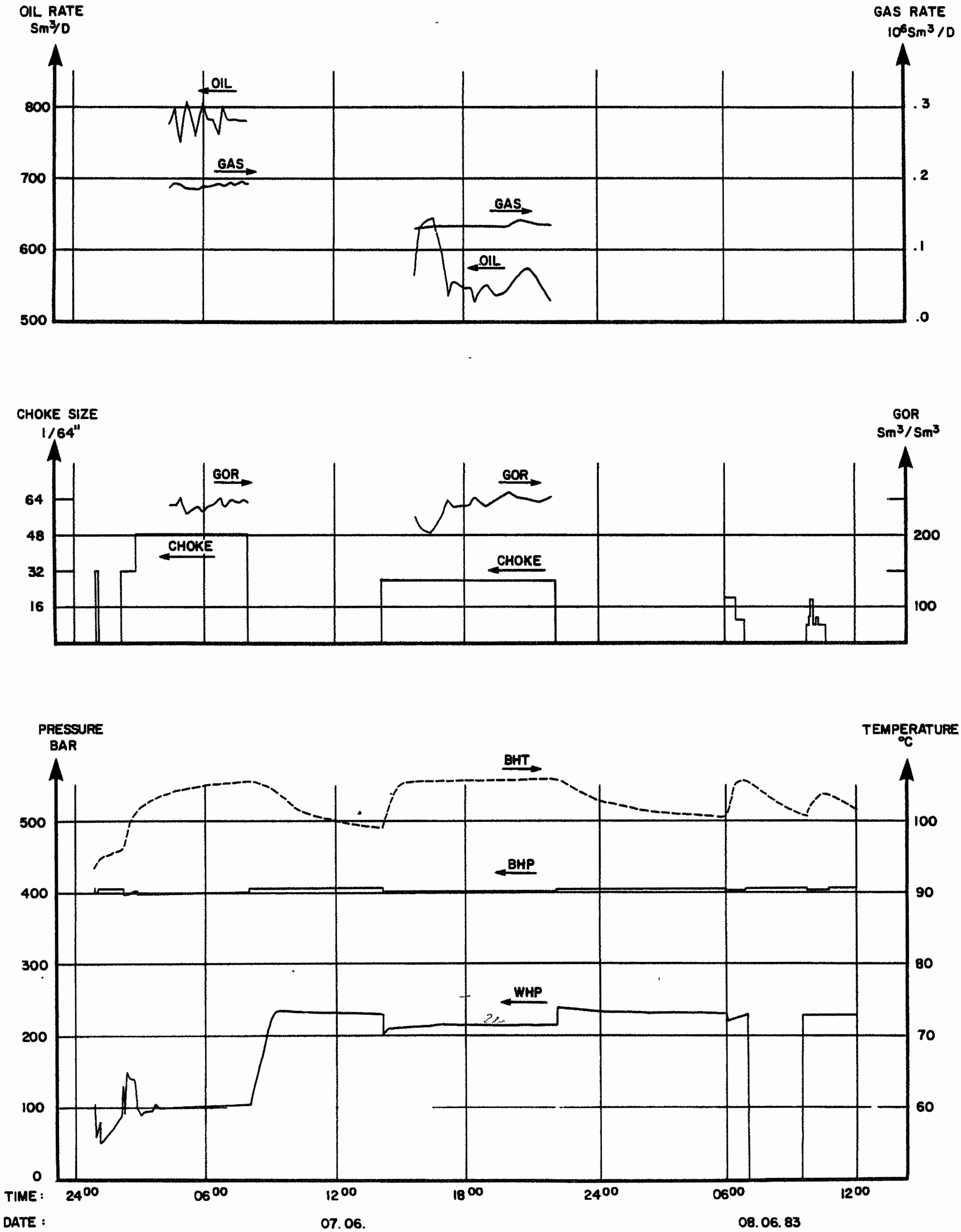
Well 34/10-17 DST no. 2	DIARY OF EVENTS	CHP/PG Perfs.: 2880 - 90m Zone tested BRENT

Date	Time	OPERATIONS
08.06	09.32	Closed kill valve.
	09.36	Opened lubricator valve and RIH with samplers.
	09.45	Opened choke manifold on 8/64" fixed choke.
	09.51	Choke plugged (freezing due to gas).
	09.52	Changed to 12/64" adj. choke.
	09.55	Increased to 20/64" adj.
	09.56	Decreased to 10/64" adj.
	09.58	Changed to 8/64" fixed, plugged again.
	10.03	Back to 10/64" adj.
	10.05	Samplers at bottom (2831.6 m)
	10.14	Back to 8/64" fixed choke.
		Flowed to tank, estimated rate.
	10.35	Closed choke manifold.
	10.45	Samplers closing.
	11.02	Started to POOH with samplers.
	11.53	Closed lubricator.
	11.54	Bled off surface pressure to 35 bar through choke manifold, test O.K.
	12.00	Bled to zero pressure, pull out samplers. Samplers O.K. (No leaks.)
	12.35	Closed choke manifold, opened kill valve, equalize pressure across lubricator valve.
	12.39	Opened lubricator valve and started bullheading with mud.
		END OF TEST

Remarks :

34/10-17
DST no.2

FLOW, CHOKE, PRESSURE AND TEMPERATURE DIAGRAM



STL. 31.10.83.

Well 34/10-17	FLOW DATA	CHP/PG
DST no. 2		Perfs.: 2880-90m
		Zone tested BRENT

1983 Date/ time	Bottom hole press. bar	Bottom hole temp °C	Well head press bar	Well head temp. °C	Chokes 1/64" manifold	Chokes 1/64" heater	Separator data press. bar	Separator data temp. °C	Separator data gas rate $10^3 Sm^3/d$	Separator data oil rate Sm^3/D	Separator data GOR Sm^3/Sm^3	Separator data sp.gr.oil	Separator data sp.gr.gas (Air=1)	Liq. and gas analysis Water %	Liq. and gas analysis Sedim. %	Liq. and gas analysis CO_2 %	Liq. and gas analysis H_2S ppm
07.06	*	*															
	SECOND FLOW PERIOD:																
02.09					8		OPENED WELL FOR CLEAN UP ON 8/64" ADJ. CHOKE.										
02.11	402.6	96.2	78.6	12.8	32		CH. TO 32/64" ADJ.										
02.18	399.5	96.9	139.5	33.3	32		RATHOLE MUD TO SURFACE										
02.19	402.2	97.0	145.3	32.7	32		CH.TO 32/64" FIXED										
02.48	400.9	101.2	139.7	29.6	48		CH. TO 48/64" ADJ.							0	1		
02.57	396.8	101.5	78.9	32.2	48		CH. TO 48/64" FIXED										
03.40	399.7	103.1	105.9	38.7	48		SWITCHED FLOW THROUGH SEPARATOR								Trace		
04.30	401.1	104.1	95.3	44.5	48		19.8	22.2	187.9	776.1	242.2					1.0	0.5
04.45	400.0	104.3	100.9	41.3	48		20.5	23.5	193.2	799.5	241.7	0.853	0.744				
05.00	400.1	104.5	102.3	45.8	48		20.9	24.2	189.9	749.8	253.3	0.847					
05.15	400.2	104.5	103.1	50.4	48		21.1	26.2	186.3	808.2	230.5						
05.30	400.2	104.7	103.1	51.4	48		21.1	28.0	184.9	784.8	235.6	0.847	0.744			0.9	0.7
05.45	400.3	104.8	103.1	51.0	48		21.3	30.1	184.3	756.8	240.7						
06.00	400.3	104.9	103.4	51.8	48		21.4	30.3	188.1	806.8	233.1	0.852	0.744				
06.15	400.3	105.0	103.7	54.2	48		21.4	31.3	187.5	783.4	239.4						
06.30	400.2	105.0	103.6	52.9	48		21.4	31.6	189.9	781.9	242.8	0.847	0.744				
06.45	400.5	105.2	104.0	54.3	48		21.5	31.9	191.2	760.0	251.6						
07.00	400.5	105.3	103.7	55.8	48		21.5	32.9	191.0	803.8	237.6	0.848				0.9	0.7
07.15	400.5	105.3	104.2	55.8	48		21.6	33.1	194.1	780.4	248.7						
07.30	400.5	105.4	104.2	56.9	48		21.4	33.7	192.6	781.9	246.3	0.844					
07.45	400.5	105.5	104.3	56.4	48		21.6	33.8	193.7	779.0	248.6						
08.00	400.5	105.5	104.1	54.6	48		21.4	33.8	193.4	781.9	247.7	0.847					
08.01							SHUT IN WELL FOR BUILD-UP										

Remarks

* Flopetrol gauge SDP 82009 at 2873.17 m.

** at 20.5 ± 1 °C

Well 34/10-17

DST no. 2

FLOW DATA

CHP/PG

Perfs.: 2880-90m

Zone tested BRENT

Date/time 1983	Bottom hole press. bar	Bottom hole temp °C	Well head press bar	Well head temp. °C	Chokes 1/64" manifold	Chokes 1/64" heater	Separator data press. bar	Separator data temp. °C	Separator data gas rate $10^3 Sm^3/d$	Separator data oil rate Sm^3/D	Separator data GOR Sm^3/Sm^3	Separator data sp.gr.oil	Separator data sp.gr.gas (Air=1)	Liq. and gas analysis Water %	Liq. and gas analysis Sedim. %	Liq. and gas analysis CO_2 %	Liq. and gas analysis H_2S ppm		
07.06																			
	THIRD FLOW PERIOD:																		
14.11					28		OPENED WELL ON 28/64" FIXED CHOKE.												
15.45	402.9	105.5	212.8	39.8	28		21.5	18.4	127.8	563.9	226.7			0	Trace				
16.00	402.9	105.5	213.2	40.8	28		21.6	19.2	132.2	633.3	208.7					1.0	1.0		
16.15	402.9	105.5	213.7	43.1	28		21.6	19.7	132.0	641.9	205.7								
16.30	402.9	105.6	214.1	41.1	28		21.7	20.1	131.6	644.8	204.0								
16.45	402.9	105.6	208.5	43.9	28		22.5	20.8	133.1	N/A			0.738						
17.00	402.9	105.6	215.3	45.2	28		22.0	21.8	133.2	589.9	225.8					1.0	1.0		
17.15	402.9	105.7	214.3	46.0	28		22.0	22.4	133.2	536.4	248.4								
17.30	402.9	105.7	214.1	45.6	28		22.0	22.9	133.1	555.2	239.6		0.738						
17.45	403.0	105.8	214.2	46.8	28		22.0	23.6	133.1	549.4	242.2								
18.00	403.0	105.8	214.1	44.8	28		22.1	24.2	132.6	546.5	242.7	0.856				0.9	1.0		
18.15	403.0	105.8	214.1	46.4	28		22.0	24.8	132.6	546.5	242.7								
18.30	402.9	105.8	214.1	46.4	28		22.2	24.9	132.6	524.6	252.7								
19.00	403.0	105.9	214.5	49.3	28		22.0	25.9	132.3	552.3	239.6					0.9	1.0		
19.30	402.9	105.9	214.4	48.6	28		22.3	25.6	133.5	536.4	248.9								
20.00	403.0	105.9	214.5	48.4	28		22.1	25.8	133.5	541.4	261.2	0.848	0.738			0.9	1.0		
20.30	403.0	105.9	214.7	50.1	28		22.2	26.3	141.4	564.6	250.5								
21.00	403.0	105.9	214.6	49.6	28		24.9	26.6	N/A	575.4						0.9	1.0		
21.30	403.0	106.0	214.8	50.7	28		25.4	26.6	136.7	553.0	247.3								
22.00	403.0	106.0	214.9	49.4	28		25.1	27.0	134.7	529.9	254.2	0.850	0.738						
22.09							SHUT IN WELL FOR BUILD-UP												

Remarks

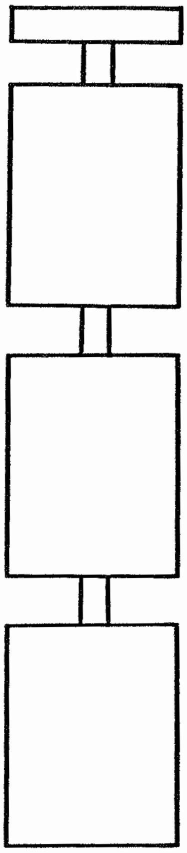
Well 34/10-17	LAYOUT OF TEST-STRING	CHP/PG
DST no 2		Perfs 2880-90 m
		Zone tested BRENT

TEST-STRING	ID inch	OD inch	LENGTH m	DEPTH mRKB
OTIS STT W/O-OVER (4 3/8"B x 3½"TDS P)				
TOP FIRST JOINT TUBING				-7.04
JNT 3½" TDS TBG 12.7 LBS/FT L-80	2.75	3.50	9.45	2.41
JNT 3½" TDS TBG 12.7 LBS/FT L-80	2.75	3.50	8.93	11.34
X-OVER 3½" TDS BOX x 4½" ACME PIN	2.80	6.00	0.34	11.68
OTIS LUBRICATOR VALVE	3.00	10.75	1.61	13.29
X-OVER 4½" ACME PIN x 3½" TDS PIN	2.80	6.00	0.38	13.67
5 stds 3½ TDS TBG	2.75	3.50	137.88	151.55
PUP JNT 3½" TDS	2.75	3.50	2.02	153.57
X-OVER 3½" TDS BOX 4½" ACME PIN	2.80	6.00	0.21	153.78
OTIS SSTT	3.00	13.00	1.78	155.56
SLICK JUNT 3½" TDS	2.25	3.50	2.23	157.79
TOP 18 3/4" WELLHEAD AT 158M				
FLUTED HANGER	3.00	12.00	0.30	158.09
X-OVER 4½" ACME PIN x 3½" TDS PIN	2.80	6.00	0.44	158.53
264 JNTS (88STDS) 3½" TDS	2.75	3.50	2445.12	2603.65
X-OVER 3½" TDS BOX x 3½" IF PIN	2.75	4.50	0.56	2604.21
SLIP JNT (OPEN)	2.25	5.00	5.54	2609.75
SLIP JNT (CLOSED)	2.25	5.00	4.02	2613.77
5 STDS + SINGLE DRILL COLLAR	2.25	4.75	151.62	2765.39
RTTS MECHANICAL CIRC VALVE	2.25	4.625	0.90	2766.29
1 STD DRILL COLLARS	2.25	4.75	28.43	2794.72
1 SLIP JNT (CLOSED)	2.25	5.00	4.02	2798.74
SLIP JNT (CLOSED)	2.25	5.00	4.02	2802.76
1 STD DRILL COLLARS	2.25	4.75	28.43	2831.19
APR-M SAFETY/CIRCULATION VALVE	2.25	5.00	2.30	2833.49
DRILLPIPE TESTER VALVE	2.25	5.00	1.46	2834.95
LPR-N TESTER VALVE	2.25	4.625	5.10	2840.05
FUL FLO HYDRAULIC BYPASS	2.25	4.625	2.11	2842.16
BIG JOHN JAR	2.25	4.625	1.59	2843.75
RTTS SAFETY JOINT	2.44	5.00	0.95	2844.70
RTTS PACKER (ABOVE)	2.40	5.75	0.56	2845.26
RTTS PACKER (BELOW)	2.40	5.75	0.82	2846.08
PERF. 2 7/8" FULL EUE JNT (PIN UP)	2.44	2.88	9.45	2855.53
X-OVER 2 7/8" EUE PIN x 2 3/8" EUE BOX	2.00	3.25	0.25	2855.78
OTIS XN-NIPPLE (PIN x PIN)	1.79	3.25	0.25	2856.03
2 3/8" EUE COLLAR	2.00	2.38	0.14	2856.17
X-OVER 2 3/8" EUE PIN x 2 7/8" EUE PIN	2.44	4.15	0.18	2856.35
1 2 7/8" EUE FULL JOINT	2.44	2.88	9.44	2865.79
S.O.S. DST-HANGER				
1 2 7/8" EUE FULL JOINT	2.44	2.88	9.35	2875.14
BULL-PLUG w/CROSS 2 7/8" EUE BOX	2.44	3.25	0.15	2875.29

Remarks.

All measurements to bottom of each item.

Well 34/10-17	GAUGE ARRANGEMENT	CHP/PG
		Perfs.: 2880-90 m
DST no. 2		Zone tested BRENT

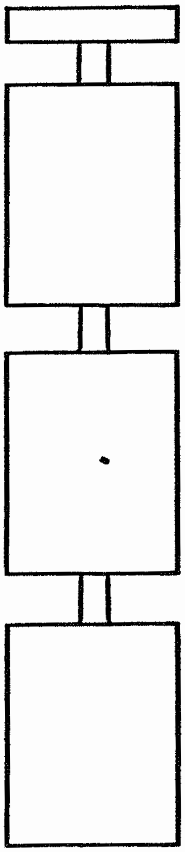


WIRELINE NIPPLE at 2855.78 mRKB

Gauge type and number : Sperry Sun MK III 0151
Depth, pressure elemement : 2858.81 Range : 0-690 bar
Mode : 2 mins Delay : 17 hrs
Actuated : time 3.52 date : 06.06.83
Will run out : time 04.51 date : 09.06.83

Gauge type and number : Flopetrol DSP 82020
Depth, pressure elemement : 2863.24 Range : 0-690 bar
Mode : 10 sec. Delay : 24 hrs
Actuated : time 3.40 date : 06.06.83
Will run out : time date :

Gauge type and number :
Depth, pressure elemement : Range :
Mode : Delay :
Actuated : time date :
Will run out : time date :



D.S.T. HANGER at 2865.79 mRKB

Gauge type and number : Sperry Sun MK III 0100
Depth, pressure elemement : 2868.68 Range : 0-690 bar
Mode : 4 mins Delay : 17 hrs
Actuated : time 03.35 date : 06.06.83
Will run out : time 12.35 date : 11.06.83

Gauge type and number : Flopetrol SDP 82009
Depth, pressure elemement : 2873.11 Range : 0-690 bar
Mode : 30 sec. Delay : 16 hrs
Actuated : time 3.37 date : 06.06.83
Will run out : time date :

Gauge type and number :
Depth, pressure elemement : Range :
Mode : Delay :
Actuated : time date :
Will run out : time date :

Well 34/10-17	SAMPLING	CHP/PG
DST no 2		Perfs.: 2880-90 m
		Zone tested BRENT

SEPARATOR SAMPLES

Time/date	Sample no.	Type of sample	Transfer time	Bottle no
07.06.83			mins	
04.45	1	Oil	20	SOS 108
04.45	2	Gas	20	SOS 1011
18.25	3	Oil	28	SOS 105
18.25	4	Gas	28	SOS 1002
19.40	5	Oil	30	810692
19.40	6	Gas	30	SOS 1022
20.30	7	Oil	35	810222
20.30	8	Gas	35	SOS 1014

BOTTOM HOLE SAMPLES

(One sample chamber contained only gas,- not representative)

Time/date	Sample depth mRKB	Estimated PB bar/°C	Transfering pressure(bar)	Bottle no
08.06.83				
10.45	2831.6	379/10	483	810698

WELLHEAD SAMPLES (NONE)

OTHER SAMPLES:

Time/date	Sampling point	Sampling equipment		Remarks
07.06.83				
07.15	Separator	Glass-jar	2 x 1 l	Oil
07.15	"	Jerry-can	1 x 20 l	"
17.05	"	Glass-jar	1 x 1 l	"
17.20	"	"	"	"
18.00	"	"	"	"
18.10	"	"	"	"
17.25	"	Jerry-can	1 x 20 l	"
17.50	"	"	1 x 10 l	"
	"	Glass-jar	3 x 3 l	Water

6.4 DST No. 3, Performance and Analysis

6.4.1 Results of the Analysis

The following results are obtained from the test:

Reservoir pressure: 405.5 bar at 2840 mRKB (mid.perf.)

Reservoir temperature: 104°C

Produced reservoir fluid: Gas with associated condensate at a ratio of 1250 - 1400 Sm^3 condensate per $10^6 Sm^3$ gas (or 720 - 800 Sm^3 gas per Sm^3 condensate).

Permeability: 570 md

Skin: Skin factor of 18 corresponding to a pressure loss of 3.8 bar for the highest flow rate (total drawdown was 5.6 bar) and a skin factor of 9 corresponding to a pressure loss of 1.6 bar for the lower flow rate (total drawdown was 3.1 bar). The increase of skin with increasing rate is due to turbulent flow.

No boundary effects are seen.

6.4.2 Comments to the Test Analysis

The test was evaluated using the conventional Horner analysis of the second and third shut in periods. No significant well bore storage effects were observed (the well was shut in downhole).

Drawdown analyses were not performed because of the data quality: Clean up disturbance during the second flow and very low pressure drawdown during the third flow period.

The reported producing gas oil ratio is somewhat higher for the low flow rate period than for the high flow rate period. This is believed to be due to inaccurate oil rate metering. No conclusion is made on which ratio is correct.

The test derived permeability thickness is significantly lower than the permeability thickness calculated from core data. This can be due to reduced permeability because of condensate drop out in the reservoir. The laboratory measured dew point pressure (375 bar) is lower than the DST no. 4 dew point (384 bar) and is not considered to be reliable.

6.4.3. Data Input to the Analysis

The bottom hole pressure data from the pressure gauge SS0181 were selected for the analysis. The quality of these data seems to be fairly good.

Average production rates for the last part of the flow periods are used in the analysis. An equivalent (total) gas rate was obtained by adding the condensate rate expressed as gas rate (for the given condensate gravity and separator pressure) to the gas rate.

The gas characteristics were taken from the PVT analysis report made on a recombined sample from this test (ref. 4).

Connate water compressibility and formation compressibility were derived from standard correlations.

Porosity and saturation data were taken from the log analysis report (ref. 1).

The pressure gradient in the gas zone was taken from the FMT report (ref. 2).

The formation thickness contributing to the test response has been estimated using the available core and log analyses data.* Low permeability zones are seen from 2823.6m to 2833.75m and from 2848.0m to 2864.2 m. These zones are assumed to be laterally continuous.

The thickness of the tested zone will therefore be 14.25m (2833.75m to 2848.0m). The cement bond log shows a good bond from 2813m to 2849m (see Appendix 1), eliminating "behind casing flow" from other zones.

Arithmetic average horizontal liquid permeabilities from the core analysis are as follows (for comparison with test derived permeability thickness):

Interval, m	Thickness, m	avg. k_{hl}, md	k h, md m
2833.75-48.0*	14.25	3850	55000
2835-45 (perf.int.)	10	4813	48100

Test k h = 8100 md m (analysis of the second build up)
6500 md m (analysis of the third build up)

*Core depths are corrected to log depths.

INPUT TO TEST ANALYSIS
(GAS / COND. SYSTEM)

Well no. 34/10-17

DST no. 3

Test Date 21.06-23.06.83

Reservoir Parameters

Perforations 2835-2845 m RKB

Zone (s) Ness

Wellbore radius 0.11 m

RKB Elev. 25 m

Depth Mid. Perfs: 2840 m RKB 2815 mSS

Pressure Gauge no. SS 0181 Depth 2825.9 m RKB 2800.9 m SS

Pressure Gradient: 0.041 bar/m

Pressure Correction, Gauge to Mid. Perfs.: 0.6 bar

Formation Volume Factor 0.0036 Res.m^3/Sm^3 Viscosity 0.0387 cp

Thickness 14.25 m

Oil Saturation 0 %

Water Saturation 0.135 %

Gas Saturation 0.865 %

Porosity 0.257 %

Oil Compressibility ______ 10^{-6} bar^{-1}

Water Compressibility 43 10^{-6} bar^{-1}

Gas Compressibility 1400 10^{-6} bar^{-1}

Formation Compressibility 49 10^{-6} bar^{-1}

System Compressibility $C_t = S_o C_o + S_w C_w + S_g C_g + C_f$

C_t = 0 x ______ 10^{-6} + 0.135 x 43 10^{-6} + 0.865 x 1400 10^{-6} + 49 10^{-6}

C_t = 1265 10^{-6} bar^{-1}

Flow Data: Flow Period no. 2

Choke 48 / 64 inches Cond. Rate 734 Sm^3/D Gas Rate 530000 Sm^3/D

P_{tf} 177 bar Water Rate 0 Sm^3/D GOR 722 Sm^3/Sm^3

Cond. Spec. Grav. 0.802 Gas Spec. Grav. 0.720

Cumulative Production Condensate ______ Sm^3 Gas ______ Sm^3

Water ______ Sm^3

Equivalent Gas Rate = qg + qc Vsc + qw · 7390 = 662000 Sm^3/D

Horner Analysis

Well no. 34/10-17

DST no. 3

Build Up no. 2

Gauge no. SS 0181

Test Date 21.06-23.6-83

Effective Production Time tp = Cumulative Production / Last Rate

tp = ______ / ______ = 8.25

Straight Line Starts at 0.5 hrs Slope: m = 0.245 bar/cycle

P_{wf} = 399.2 bar P_{1hr} 404.6 bar P^* 404.8 bar

Estimated Reservoir Pressure (P^*) at Mid. Perfs. (2815 mSS): 405.4 bar

Permeability:

$$Kh = \frac{21.49\,q\,Bu}{m} = \frac{21.49 \times 662000 \times 0.0036 \times 0.0387}{0.245} = 8100 \text{ md.m}$$

$$K = Kh/h = 8100 / 14.25 = 570 \text{ md.}$$

Skin:

$$S = 1.1513 \left[\left[\frac{P_{1hr} - P_{wf}}{m}\right] + \text{Log}\left[\frac{tp+1}{tp}\right] - \text{Log}\left[\frac{K}{\phi \mu C_t r_w^2}\right] + 3.098 \right]$$

$$S = 1.1513 \left[\left[\frac{404.6-399.2}{0.245}\right] + \text{Log}\left[\frac{8.25+1}{8.25}\right] - \text{Log}\left[\frac{570}{0.257 \times 0.0387 \times 1265 \times 10^{-6} \times 0.1}\right] + 3.098 \right]$$

S = 18

For the Previous Flow Period:

$$\Delta Ps = \frac{18.665 \cdot q\,B\,\mu}{kh}\,S = \frac{18.665 \times 662000 \times 0.0036 \times 0.0387 \times 18}{8100} = 3.8 \text{ bar}$$

$\Delta Pdd = P^* - P_{wf}$ = 5.6 bar

Skin as Fraction of Total Drawdown: $\frac{\Delta Ps}{\Delta Pdd}$ = 0.68

INPUT TO TEST ANALYSIS
(GAS / COND. SYSTEM)

Well no. 34/10-17

DST no. 3

Test Date 21.06-23.06.83

Reservoir Parameters As for Flow Period no. 2

Perforations ________ m RKB

Zone (s) ________

Wellbore radius ________ m

RKB Elev. ________ m

Depth Mid. Perfs: ________ m RKB ________ mSS

Pressure Gauge no. ________ Depth ________ m RKB ________ m SS

Pressure Gradient: ________ bar/m

Pressure Correction, Gauge to Mid. Perfs.: ________ bar

Formation Volume Factor ________ Res.m^3/Sm^3 Viscosity ________ cp

Thickness ________ m

Porosity ________ %

Oil Saturation ________ %

Oil Compressibility ________ $10^{-6} bar^{-1}$

Water Saturation ________ %

Water Compressibility ________ $10^{-6} bar^{-1}$

Gas Saturation ________ %

Gas Compressibility ________ $10^{-6} bar^{-1}$

Formation Compressibility ________ $10^{-6} bar^{-1}$

System Compressibility $C_t = S_o C_o + S_w C_w + S_g C_g + C_f$

C_t = ____ x ____ 10^{-6} + ____ x ____ 10^{-6} + ____ x ____ 10^{-6} + ____ 10^{-6}

C_t = ________ $10^{-6} bar^{-1}$

Flow Data: Flow Period no. 3

Choke 32 / 64 inches Cond. Rate 452 Sm^3/D Gas Rate 364000 Sm^3/D

P_{tf} 247 bar Water Rate 0 Sm^3/D GOR 805 Sm^3/Sm^3

Cond. Spec. Grav. 0.777 Gas Spec. Grav. 0.715

Cumulative Production Condensate ________ Sm^3 Gas ________ Sm^3

Water ________ Sm^3

Equivalent Gas Rate = qg + qc Vsc + qw · 7390 = 447000 Sm^3/D

Horner Analysis

Well no. 34/10-17

DST no. 3

Build Up no. 3

Gauge no. SS 0181

Test Date 21.06-23.06.83

Effective Production Time tp = Cumulative Production / Last Rate

tp = ______ / ______ = 7.12

Straight Line Starts at 0.5 hrs Slope: m = 0.207 bar/cycle

P_{wf} = 401.6 bar P_{1hr} 404.5 bar P^* 404.7 bar

Estimated Reservoir Pressure (P^*) at Mid. Perfs. (2815 mSS): 405.3 bar

Permeability:

$$Kh = \frac{21.49\, q\, Bu}{m} = \frac{21.49 \times 447000 \times 0.0036 \times 0.0387}{0.207} = 6500 \text{ md.m}$$

K = Kh / h = 6500 / 14.25 = 455 md.

Skin:

$$S = 1.1513 \left[\left[\frac{P_{1hr} - P_{wf}}{m} \right] + \text{Log} \left[\frac{tp + 1}{tp} \right] - \text{Log} \left[\frac{K}{\emptyset \mu\, C_t\, rw^2} \right] + 3.098 \right]$$

$$S = 1.1513 \left[\left[\frac{405.5-401.6}{0.207} \right] + \text{Log} \left[\frac{7.1+1}{7.1} \right] - \text{Log} \left[\frac{455}{0.257 \cdot 0.0387 \cdot 1265 \cdot 10^{-6} \cdot 0.11^2} \right] + 3.098 \right]$$

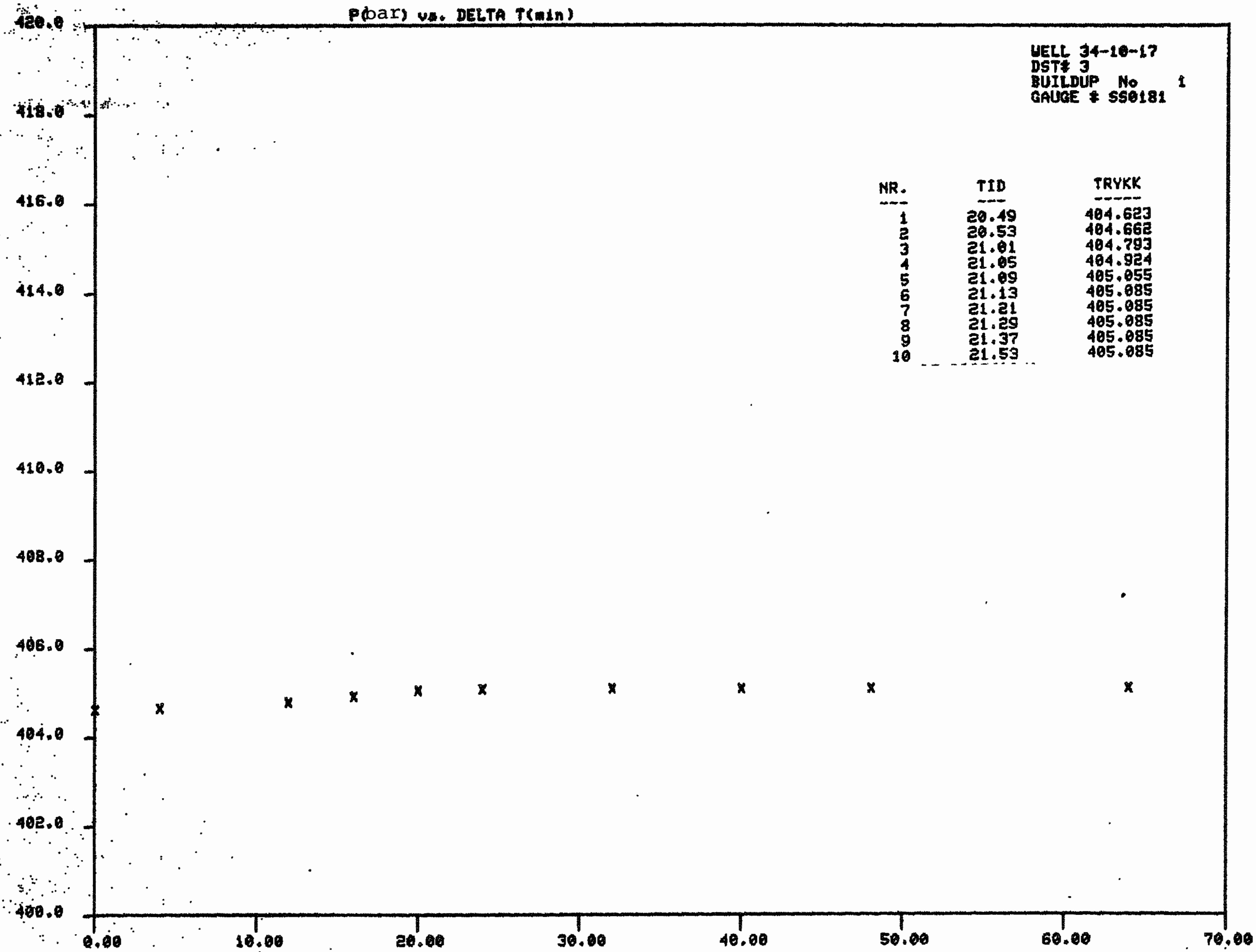
S = 9

For the Previous Flow Period:

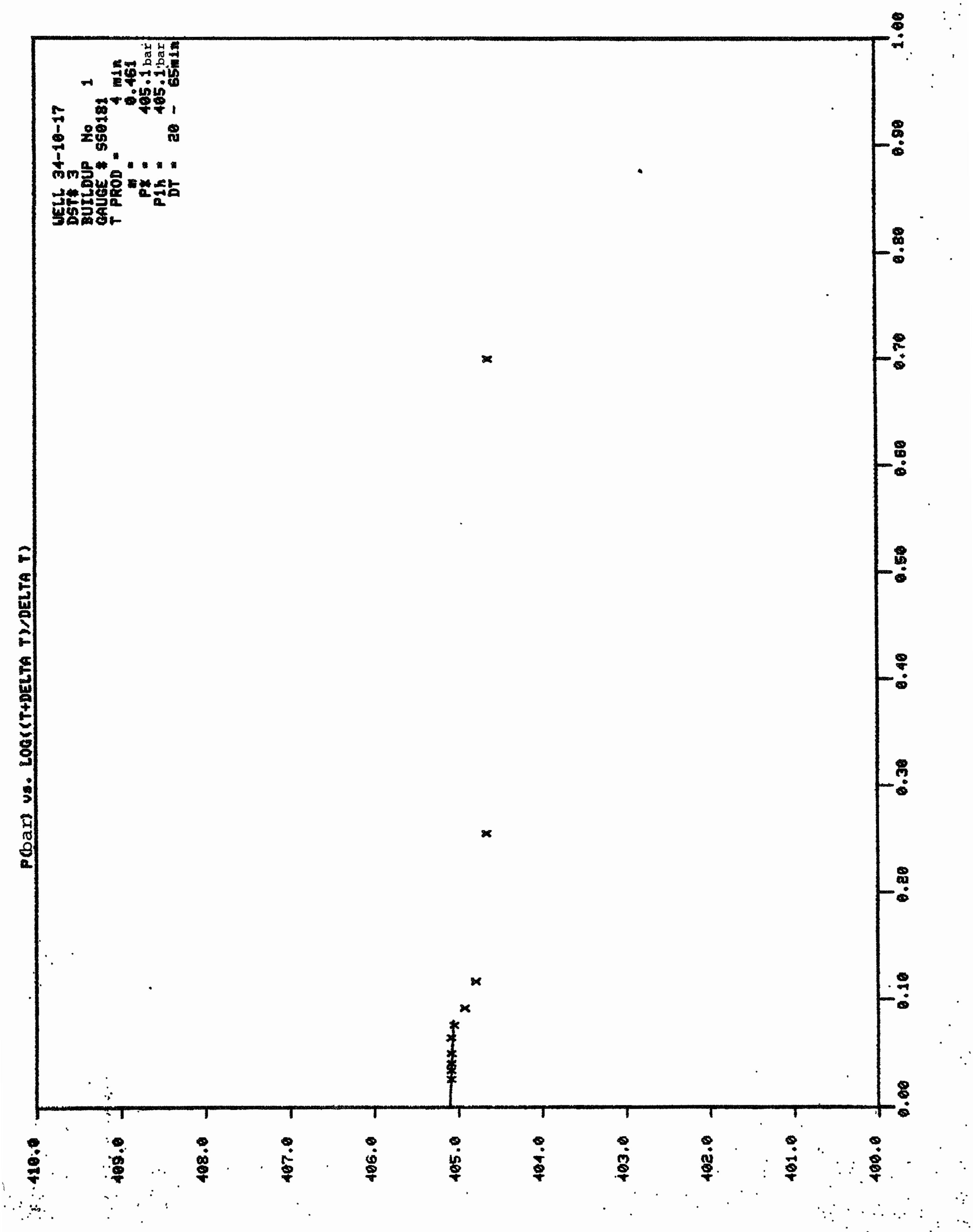
$$\Delta Ps = \frac{18.665 \cdot q\, B\, \mu}{kh}\, S = \frac{18.665 \times 447000 \times 0.0036 \times 0.0387 \times 9}{6500} = 1.6 \text{ bar}$$

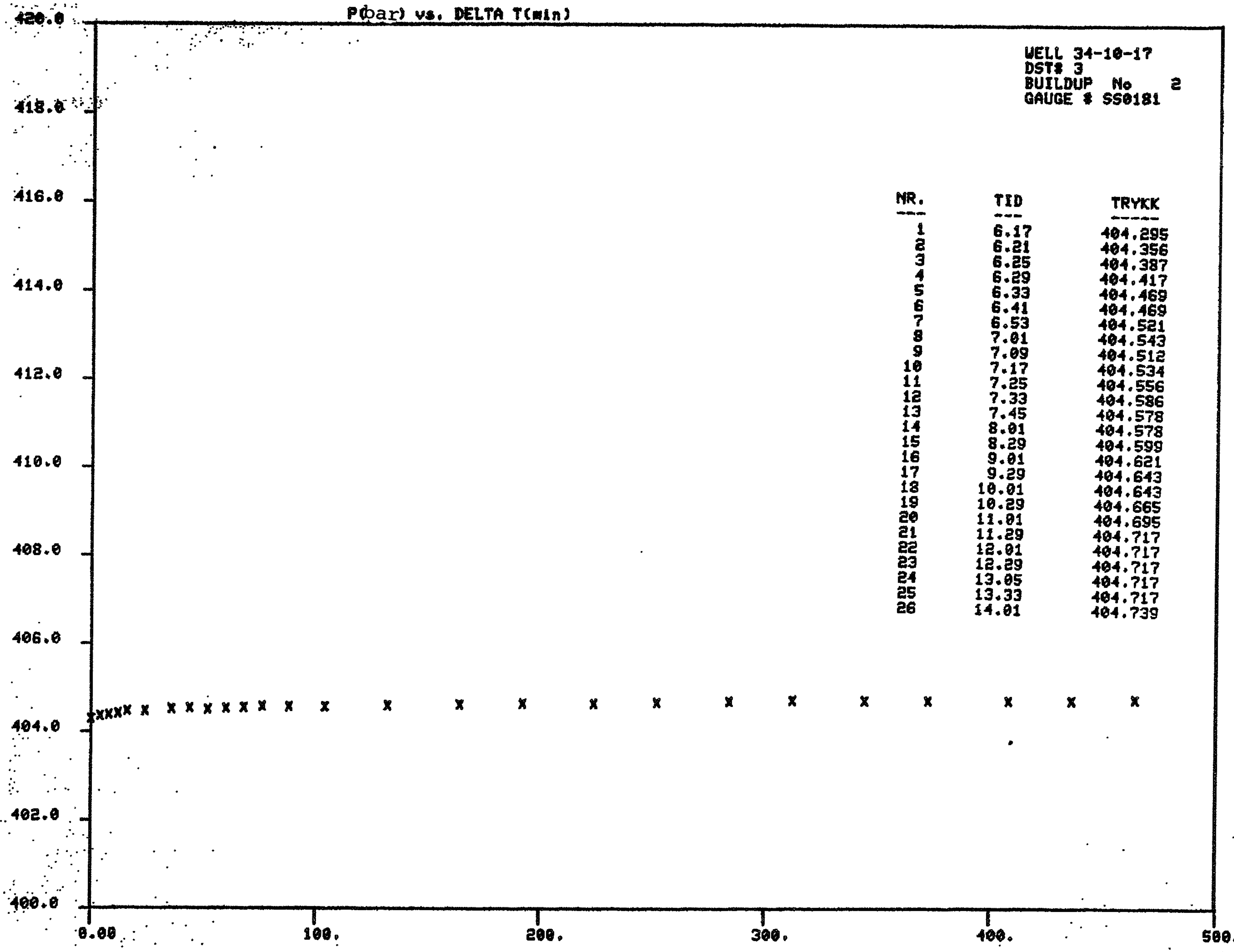
$\Delta Pdd = P^* - Pwf$ = 3.1 bar

Skin as Fraction of Total Drawdown: $\frac{\Delta Ps}{\Delta Pdd}$ = 0.52

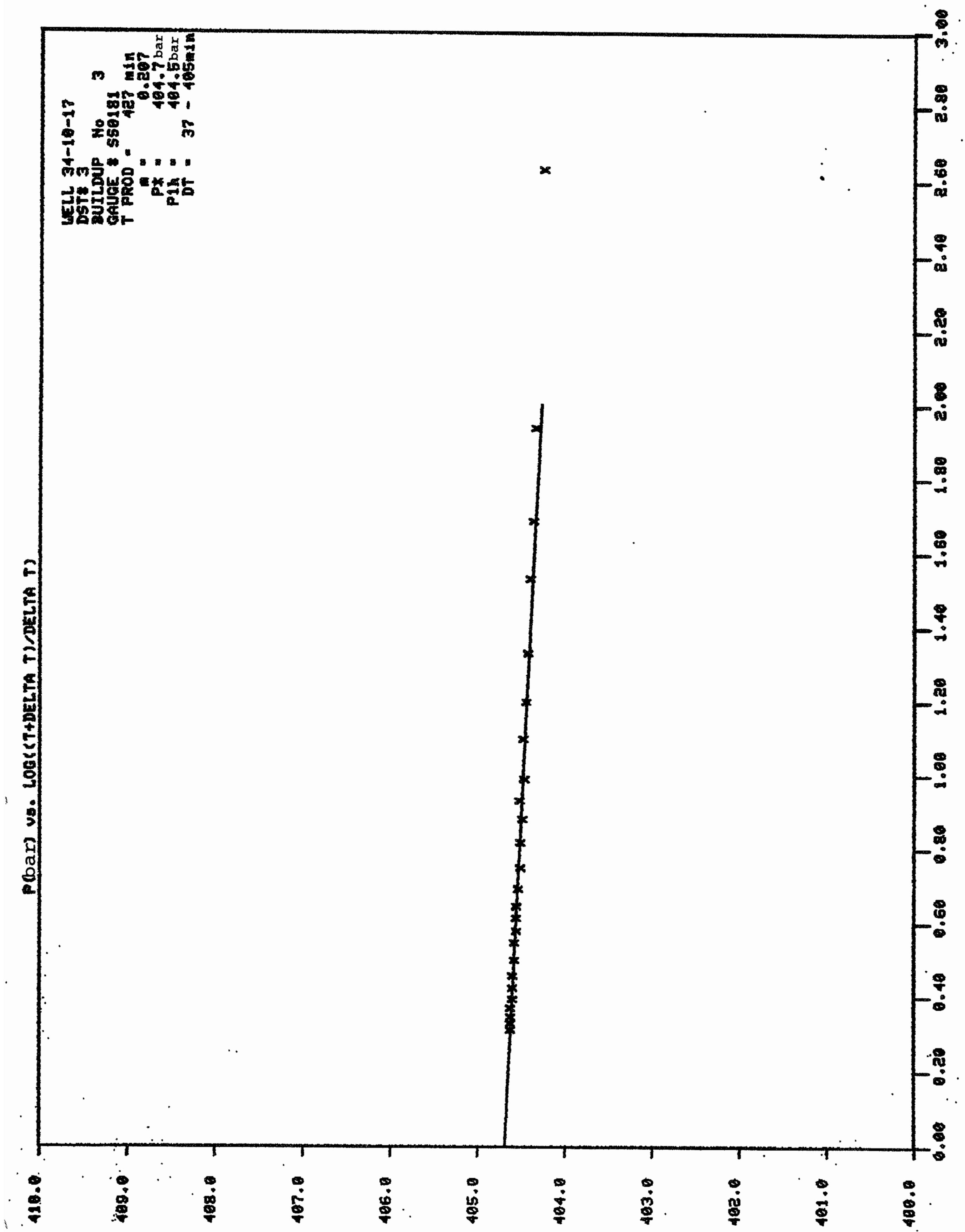


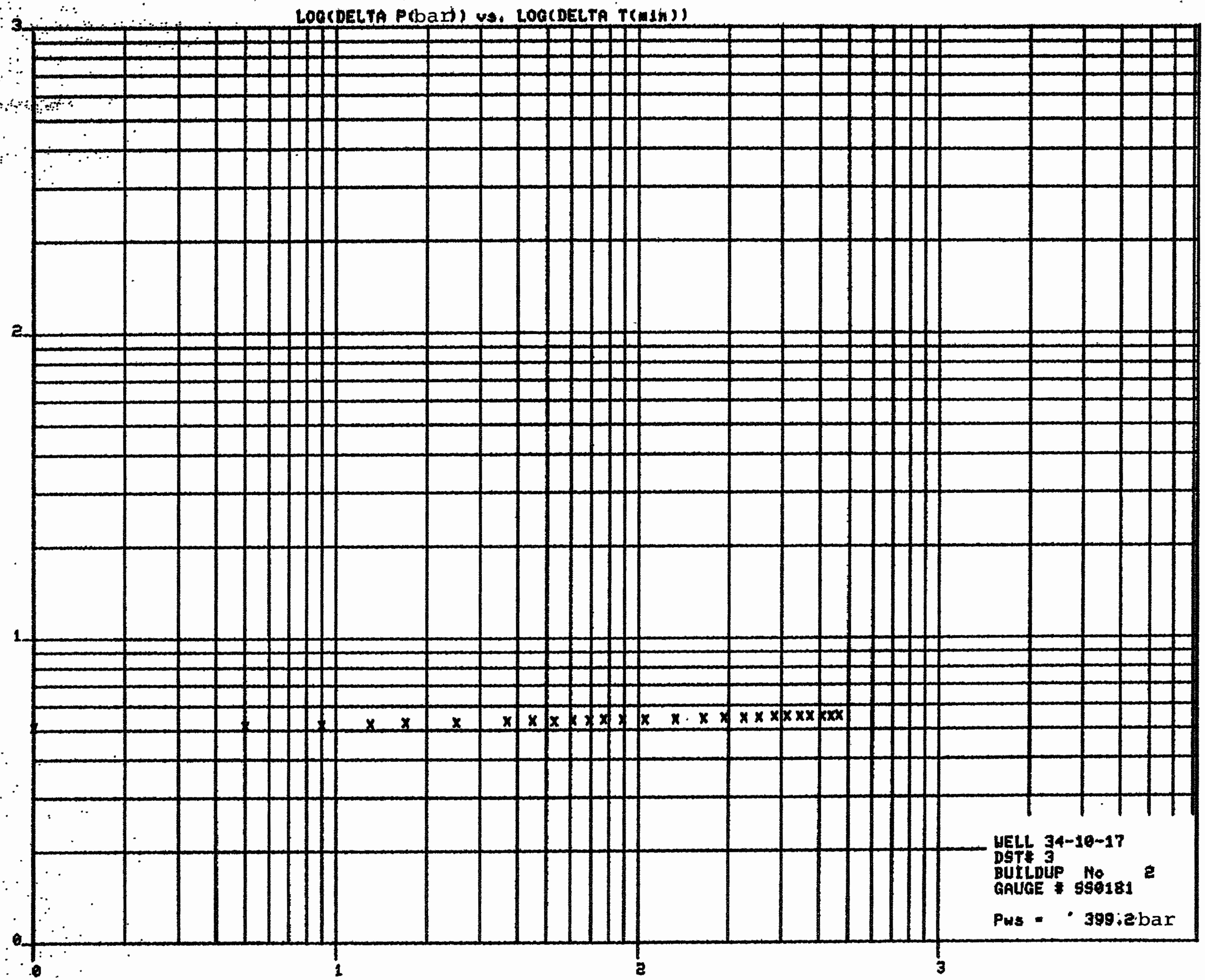
NR.	TID	TRYKK
1	20.49	404.623
2	20.53	404.662
3	21.01	404.793
4	21.05	404.924
5	21.09	405.055
6	21.13	405.085
7	21.21	405.085
8	21.29	405.085
9	21.37	405.085
10	21.53	405.085

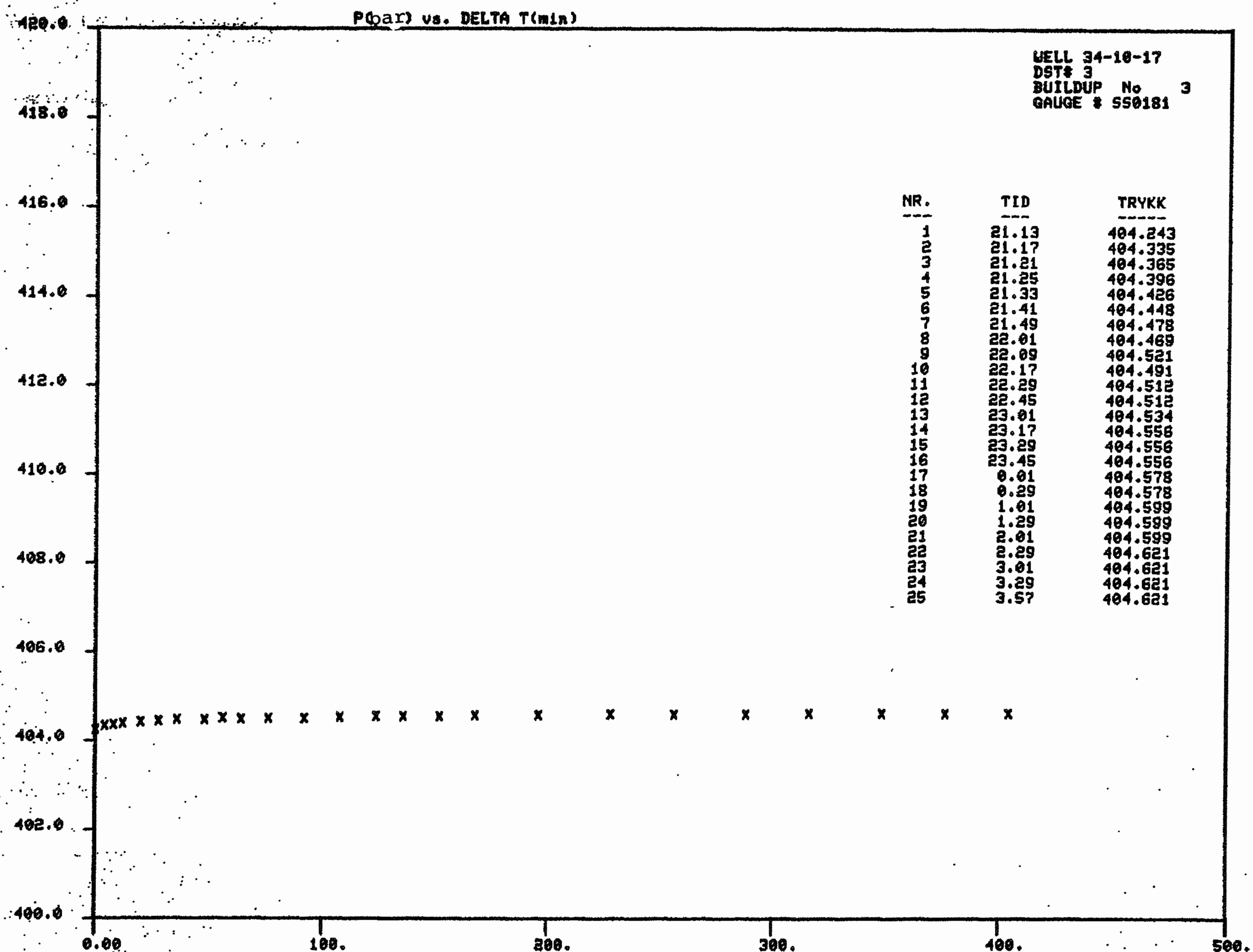

P(bar) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-17
DST# 3
BUILDUP No 1
GAUGE # SS0181
T PROD = 4 min
m = 0.461
PX = 405.1 bar
P1h = 405.1 bar
DT = 20 - 65min
410.0
409.0
408.0
407.0
406.0
405.0
404.0
403.0
402.0
401.0
400.0
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00



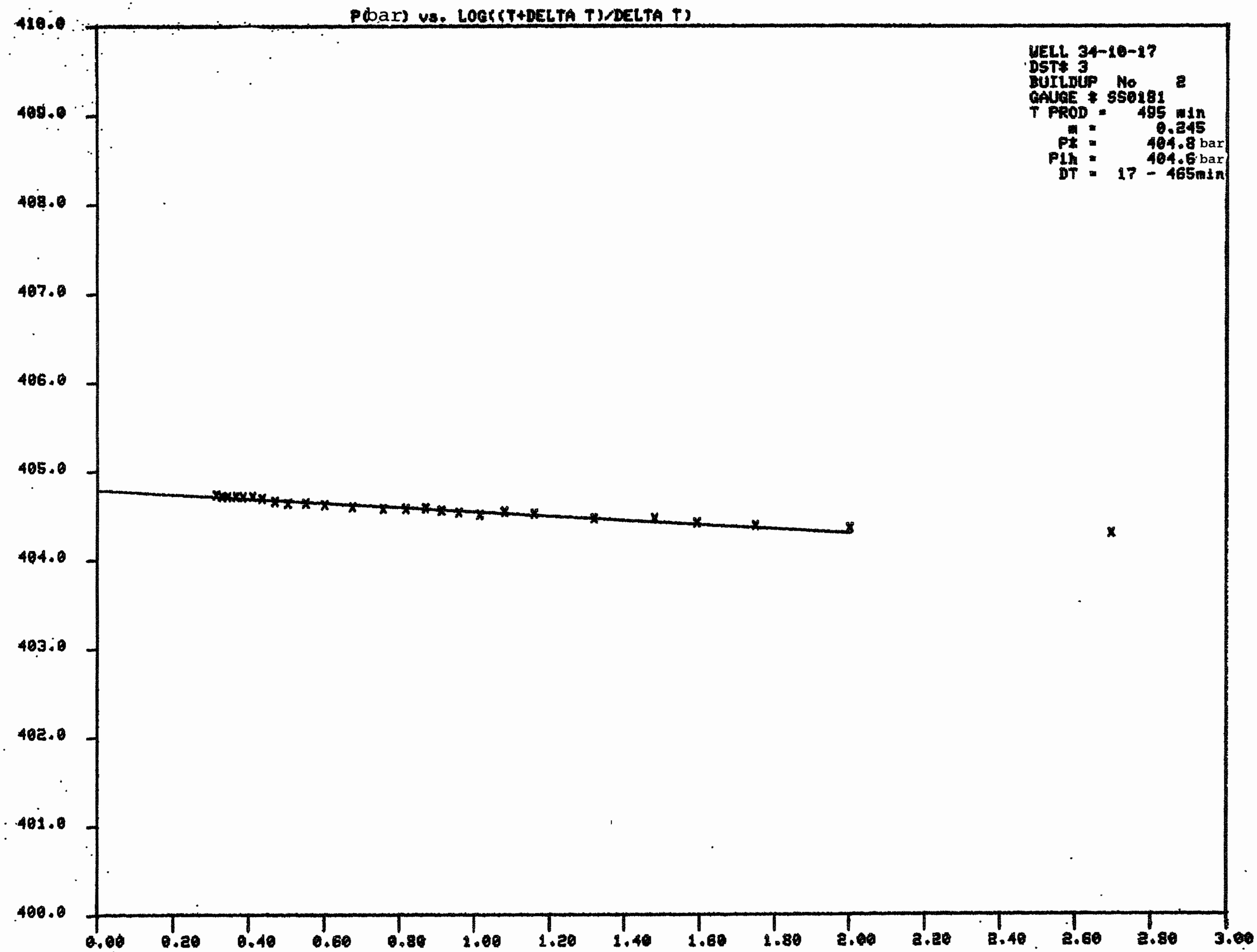
NR.	TID	TRYKK
1	6.17	404.295
2	6.21	404.356
3	6.25	404.387
4	6.29	404.417
5	6.33	404.469
6	6.41	404.469
7	6.53	404.521
8	7.01	404.543
9	7.09	404.512
10	7.17	404.534
11	7.25	404.556
12	7.33	404.586
13	7.45	404.578
14	8.01	404.578
15	8.29	404.599
16	9.01	404.621
17	9.29	404.643
18	10.01	404.643
19	10.29	404.665
20	11.01	404.695
21	11.29	404.717
22	12.01	404.717
23	12.29	404.717
24	13.05	404.717
25	13.33	404.717
26	14.01	404.739

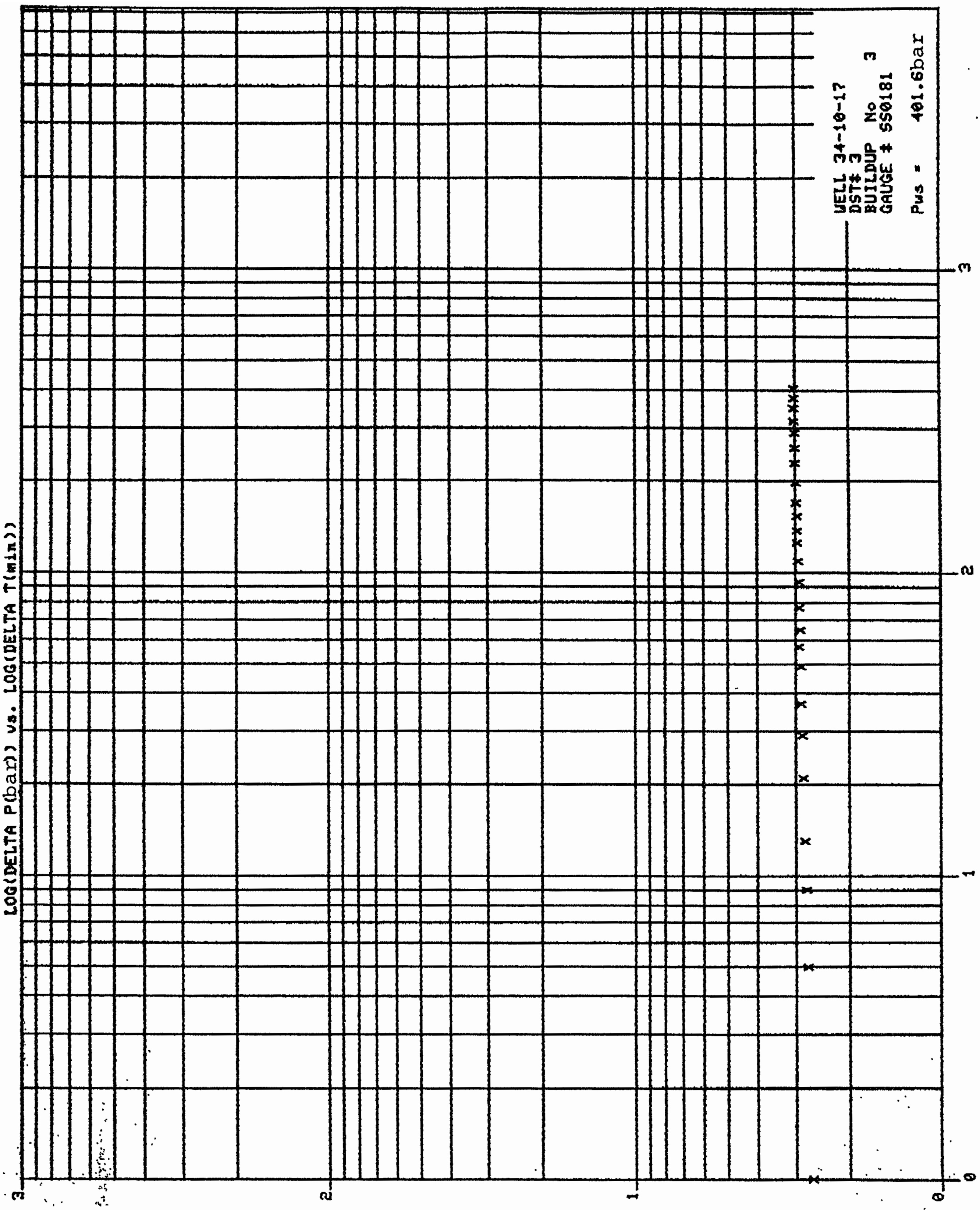

P(bar) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-17
DST# 3
BUILDUP No 3
GAUGE # 550181
T PROD = 427 min
m = 0.207
P* = 404.7bar
P1h = 404.5bar
DT = 37 - 405min
410.0
409.0
408.0
407.0
406.0
405.0
404.0
403.0
402.0
401.0
400.0
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
1.60
1.80
2.00
2.20
2.40
2.60
2.80
3.00


LOG(DELTA P(bar)) vs. LOG(DELTA T(min))
0
1
2
3
WELL 34-10-17
DST# 3
BUILDUP No 2
GAUGE # 990181
Pws = ' 399.2bar



NR.	TID	TRYKK
1	21.13	404.243
2	21.17	404.335
3	21.21	404.365
4	21.25	404.396
5	21.33	404.426
6	21.41	404.448
7	21.49	404.478
8	22.01	404.469
9	22.09	404.521
10	22.17	404.491
11	22.29	404.512
12	22.45	404.512
13	23.01	404.534
14	23.17	404.556
15	23.29	404.556
16	23.45	404.556
17	0.01	404.578
18	0.29	404.578
19	1.01	404.599
20	1.29	404.599
21	2.01	404.599
22	2.29	404.621
23	3.01	404.621
24	3.29	404.621
25	3.57	404.621


P(bar) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-17
DST# 3
BUILDUP No 2
GAUGE # SS0181
T PROD = 495 min
m = 0.245
P* = 404.8 bar
P1h = 404.6 bar
DT = 17 - 465min
410.0
409.0
408.0
407.0
406.0
405.0
404.0
403.0
402.0
401.0
400.0
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
1.60
1.80
2.00
2.20
2.40
2.60
2.80
3.00



LOG(DELTA P(bar)) vs. LOG(DELTA T(min))
WELL 34-10-17
DST# 3
BUILDUP No 3
GAUGE # SS0181
Pws = 401.6bar
0
1
2
3
3
2
1
0

COMPARISON OF RESULTS OBTAINED FROM ALL GAUGES

WELL no.: 34/10-17
DST no.: 3

	Selected Gauge			Other Gauges					
Gauge no.:	SS 0181			SS 0222			SDP 82003		
Build Up no.:	1	2	3	1	2	3	1	2	3
Data Quality:	Fair	Fair	Good	Quest.	Quest.	Quest.	Quest.	Poor	Poor
Horner Slope, bar/cycle:	.461	.245	.207	.244	.262	.252	.139	.204	.322
Permeability, md:		570	455		530	370		680	290
p* Corrected to mid perf., bar:	405.7	405.4	405.3	405.7	405.4	405.3	405.3	405.3	405.2

Well 34/10-17	DIARY OF EVENTS	CHP/PG
DST no. 3		Perfs.: 2835-45 m
		Zone tested BRENT

1983 Date	Time	OPERATIONS
		PERFORATING
20.06	20.30	Rigged up Dresser Atlas. Ran CBL.
	23.00	RIH with perforating gun. Perforated 2835-45 m. (ref. Density-Neutron log) 4 sh/ft, 120^{o} phasing.
21.06	00.55	POOH perf. gun.
		TEST STRING
	01.30	Started RIH wtih test string BHA
	01.47	Installed gauges in test string.
	18.00	Started pressure testing of string and surface eq.
	20.24	Set packer.
		INITIAL FLOW/BUILD-UP
	20.34	Opened LPR-n valve.
	20.44	Opened choke manifold on 32/64" fixed choke. Flowed back 2.8 m^3 to surge tank.
	20.48	Closed choke manifold and LPR-n valve.
		SECOND FLOW/BUILD-UP
	21.55	Opened LPR-n valve.
	21.56	Opened choke manifold on 32/64" adjustable choke.
	22.00	Mud to surface.
	22.03	Gas to surface.
	22.10	Adjustable choke plugged.
	22.19	Changed to 32/64" fixed choke.
	22.36	Changed to 44/64" adjustable choke.
	22.48	Changed to 48/64" fixed choke.
	23.10	Flowed through separator.
22.06	01.05	Flowed to surge tank for meter tactor.
	04.35	Started to sample 1. set of PVT samples.
	05.40	" 2. "
	06.06	By-passed separator.
	06.11	Closed choke manifold and LPR-n valve.
		THIRD FLOW/BUILD-UP
	14.03	Opened LPR-n valve.
	14.04	Opened choke manifold on 32/64" fixed choke.
	14.11	Flowed through separator.
	15.00	Flowed to surge tank for meter factor.

Remarks :

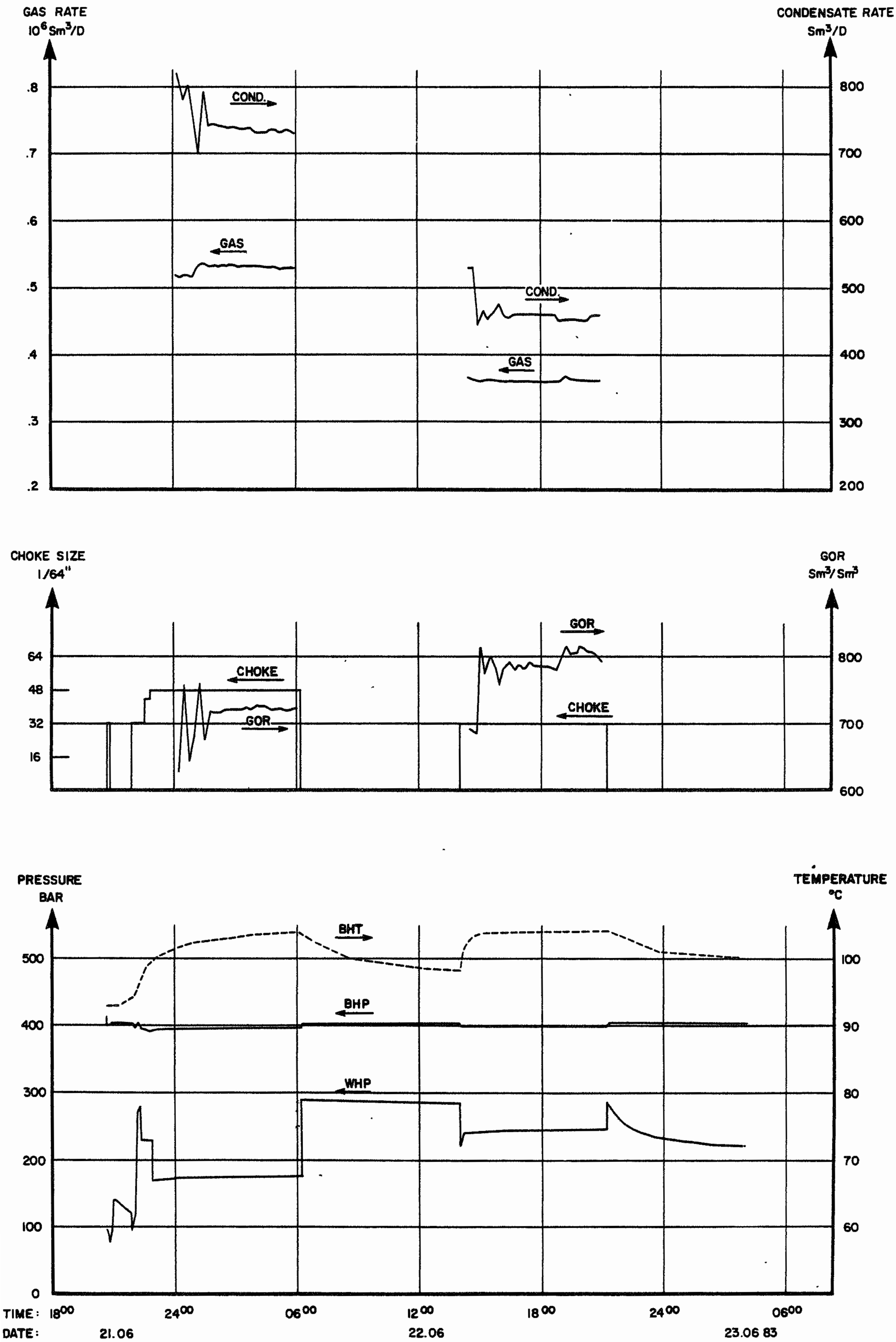
Well 34/10-17 DST no. 3	DIARY OF EVENTS	CHP/PG Perfs.: 2835-45 m Zone tested BRENT

1983 Date	Time	OPERATIONS
22.06	19.00	Started to sample 3. set of PVT samples.
	19.10	Unstable separator pressure, progably due to failure in pressure controller.
	20.14	Started to sample 4. set of PVT samples.
	21.11	By-passed separator.
	21.13	Closed choke manifold and LPR-n valve.
23.06	04.00	Opened LPR-n valve and killed well by bullheading into formation.
		END OF TEST

Remarks :

34/10-17
DST no. 3

FLOW, CHOKE, PRESSURE AND TEMPERATURE DIAGRAM



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Well 34/10-17	DST no. 3

FLOW DATA

CHP/PG
Perfs.: 2835 - 45m
Zone tested BRENT

Date/ time (1983)	Bottom hole press. bar	Bottom hole temp °C	Well head press bar	Well head temp. °C	Chokes 1/64" manifold	Chokes 1/64" heater	Separator data press. bar	Separator data temp. °C	Separator data gas rate $10^3 Sm^3/d$	Separator data oil rate Sm^3/D	Separator data GOR Sm^3/Sm^3	Separator data sp.gr.oil	Separator data sp.gr.gas (Air=1)	Liq. and gas analysis Water %	Liq. and gas analysis Sedim. %	Liq. and gas analysis CO_2 %	Liq. and gas analysis H_2S ppm		
21.06																			
	*	*																	
	SECOND FLOW PERIOD																		
21.56					32		OPENED WELL FOR CLEAN UP ON 32/64" ADJ. CHOKE												
22.00	398.9	94.6	121.9	23.7	32		RATHOLE MUD TO SURFACE												
22.10	403.8	96.0	279.3	30.5	32		CHOKE PLUGGING												
22.19	403.8	97.1	281.6	20.6	32		CHOKE TO 32/64" FIXED												
22.36	397.2	98.5	232.6	30.8	44		CHOKE TO 44/64" ADJUSTABLE									0.5			
22.48	393.5	99.4	171.6	35.6	48		CHOKE TO 48/64" FIXED												
23.10	396.2	100.4	170.9	48.3	48		SWITCHED FLOW THROUGH SEPARATOR												
22.06 00.15	397.9	101.8	174.1	56.4	48		60.4	30.4	517.2	820.2	630.5	0.795	0.790		Trace	0.5	0		
00.30	398.2	102.0	174.7	58.2	"		60.7	31.7	515.6	681.8	756.3								
00.45	398.3	102.2	174.7	58.2	"		60.4	32.5	518.3	803.2	645.3								
01.00	398.4	102.4	175.0	59.0	"		60.9	33.7	516.1	752.4	685.9	0.795	0.790			0.5	0		
01.15	398.3	102.5	175.5	60.6	"		60.2	34.6	532.7	703.0	757.7								
01.30	398.4	102.6	174.9	58.4	"		60.0	35.3	535.6	790.5	677.6								
01.45	398.4	102.6	175.4	61.3	"		60.2	34.9	533.5	742.5	718.5								
02.00	398.6	103.0	175.2	60.2	"		60.2	34.8	534.2	745.3	716.8	0.795	0.720			0.5			
02.15	398.6	102.8	176.0	62.7	"		60.5	35.5	532.8	742.5	717.6			0	0		0		
02.30	398.6	103.0	176.0	62.8	"		60.7	35.6	532.8	739.7	720.3								
02.45	398.6	103.1	175.7	61.1	"		60.6	36.7	532.8	738.3	721.7								
03.00	398.6	103.1	176.0	62.9	"		60.7	36.6	532.8	739.7	720.3	0.802	0.720						
03.15	398.7	103.3	175.8	63.1	"		60.7	37.0	531.5	736.9	721.2								
03.30	398.7	103.3	176.0	62.6	"		60.8	37.5	531.5	735.8	722.6								
03.45	398.7	103.4	176.4	63.7	"		60.9	37.5	531.5	736.9	721.2								

Remarks

* Flopetrol gauge SDP 82003 at 2817.03 m.

Well 34/10-17	FLOW DATA	CHP/PG
DST no. 3		Perfs.: 2835-45m
		Zone tested BRENT

1983

Date/time	Bottom hole press. bar	Bottom hole temp °C	Well head press bar	Well head temp. °C	Chokes 1/64" manifold	Chokes 1/64" heater	Separator data press. bar	Separator data temp. °C	Separator data gas rate $10^3Sm^3/d$	Separator data oil rate Sm^3/D	Separator data GOR Sm^3/Sm^3	Separator data sp.gr.oil	Separator data sp.gr.gas (Air=1)	Liq. and gas analysis Water %	Liq. and gas analysis Sedim. %	Liq. and gas analysis CO_2 %	Liq. and gas analysis H_2S ppm		
22.06 04.00	398.8	103.4	176.4	63.9	48		60.9	37.2	531.5	731.3	726.7	0.802	0.720			0.5			
04.15	398.7	103.5	176.4	65.0	"		60.9	37.7	530.8	731.3	725.8								
04.30	398.7	103.5	176.5	64.7	"		60.9	37.8	530.1	731.3	724.9								
04.45	398.7	103.6	176.0	63.3	"		60.9	37.7	530.1	735.5	720.8								
05.00	398.8	103.7	176.6	65.2	"		60.9	37.7	530.1	735.5	720.8	0.802	0.720						
05.15	398.7	103.7	176.6	65.6	"		61.1	38.4	528.8	731.2	723.1								
05.30	398.7	103.6	176.8	65.2	"		61.1	38.4	528.8	734.1	720.3								
05.45	398.7	103.7	177.0	65.1	"		61.1	38.9	528.8	734.1	720.3								
06.00	398.8	103.7	177.0	66.0	"		61.2	39.4	528.8	731.2	723.1	0.802	0.720			0.5	0.		
06.11	398.8	103.8					SHUT IN WELL FOR BUILD-UP												
	THIRD FLOW PERIOD:																		
14.04					32		OPENED WELL ON 32/64" FIXED CHOKE												
14.30	401.3	103.1	241.8	42.2	"		49.3	17.1	366.8	528.6	693.6	0.777	0.715	0	0				
14.45	401.3	103.6	243.2	47.7	"		48.9	16.7	362.6	530.1	684.0			↓	↓				
15.00	401.3	103.7	244.2	51.2	"		47.6	18.0	360.2	443.3	812.5	0.777	0.715						
15.15	401.3	103.9	245.1	54.7	"		47.8	19.4	360.7	465.7	774.5								
15.30	401.3	103.9	244.6	55.7	"		47.4	21.2	363.1	455.2	797.7								
15.45	401.3	103.9	244.6	55.2	"		47.3	22.2	363.1	461.7	786.3								
16.00	401.3	104.0	244.7	55.6	"		47.3	22.7	362.1	476.2	760.4	0.777	0.715			0.5			
16.15	401.3	104.0	245.0	56.8	"		47.3	23.4	360.7	460.4	783.4								
16.30	401.3	104.0	245.7	57.3	"		47.3	24.1	361.6	456.5	792.2								
16.45	401.2	104.0	245.8	57.2	"		47.3	24.1	361.1	461.7	782.2								
17.00	401.2	104.1	245.7	56.4	"		47.4	24.3	361.1	459.1	786.6	0.777	0.715						
17.15	401.3	104.1	245.8	57.2	"		47.3	24.1	361.1	461.7	782.2								

Remarks

Well 34/10-17	FLOW DATA	CHP/PG
DST no. 3		Perfs.: 2835-45m
		Zone tested BRENT

1983

Date/ time		Bottom hole press. bar	Bottom hole temp °C	Well head press bar	Well head temp. °C	Chokes 1/64" manifold	Chokes 1/64" heater	Separator data press. bar	Separator data temp. °C	Separator data gas rate $10^3 Sm^3/d$	Separator data oil rate Sm^3/D	Separator data GOR Sm^3/Sm^3	Separator data sp.gr.oil	Separator data sp.gr.gas (Air=1)	Liq. and gas analysis Water %	Liq. and gas analysis Sedim. %	Liq. and gas analysis CO_2 %	Liq. and gas analysis H_2S ppm		
22.06	17.30	401.3	104.1	246.0	58.2	32		47.3	24.5	361.6	457.8	789.9								
	17.45	401.3	104.1	245.9	57.3	"		47.4	24.6	361.1	459.1	786.6								
	18.00	401.3	104.1	245.8	56.4	"		47.3	24.4	361.6	460.4	785.4	0.777	0.715						
	18.15	401.3	104.1	246.2	58.6	"		47.3	24.5	361.3	460.4	785.4								
	18.30	401.3	104.2	246.2	58.8	"		47.4	24.4	360.7	460.4	783.4								
	18.45	401.2	104.2	246.1	57.9	"		47.4	25.1	360.7	461.7	781.1								
	19.00	401.2	104.2	246.3	58.7	"		47.4	25.3	359.7	449.9	799.6	0.777	0.715						
	19.15	401.2	104.2	246.4	59.6	"		44.6	25.9	367.5	451.2	814.4								
	19.30	401.2	104.2	246.3	58.3	"		46.0	26.1	364.6	452.5	805.7								
	19.45	401.2	104.4	246.6	60.2	"		46.1	26.6	364.2	452.5	804.7								
	20.00	401.2	104.3	246.6	59.6	"		46.2	27.0	364.2	447.3	814.2	0.777	0.715						
	20.15	401.2	104.3	246.7	59.9	"		46.2	27.1	363.7	449.9	808.4								
	20.30	401.2	104.3	247.0	61.1	"		45.9	27.5	363.2	449.9	807.3				Trace				
	20.45	401.2	104.3	246.9	61.0	"		46.0	28.2	367.7	457.8	803.3								
	21.00	401.2	104.3	247.1	62.1	"		45.7	28.2	362.7	457.8	792.4	0.777	0.715		Trace				
	21.13							SHUT IN WELL FOR BUILD-UP												

Remarks

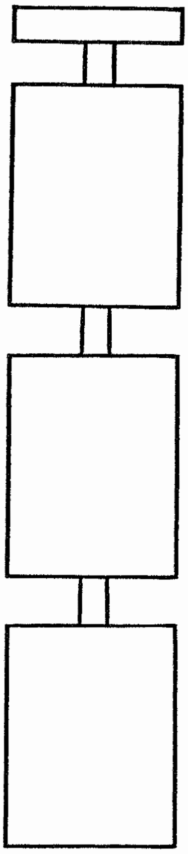
Well 34/10-17	LAYOUT OF TEST-STRING	CHP/PG
		Perfs 2835-45 m
DST no 3		Zone tested BRENT

TEST-STRING	ID inch	OD inch	LENGTH m	DEPTH mRKB
OTIS STT W/X-OVER (4-3/8" B x 3-½" TDS P)				
TOP FIRST TUBING				-7.04
1 JNT 3-½" TDS TBG 12.7 LBS/FT L-80	2.75	3.50	9.45	2.41
1 JNT 3-½" TDS TBG 12.7 LBS/FT L-80	2.75	3.50	8.93	11.34
X-OVER 3-½" TDS BOX x 4-½" ACME PIN	2.80	6.00	0.34	11.68
OTIS LUBRICATOR VALVE	3.00	13/10.75	1.61	13.29
X-OVER 4-½" ACME PIN x 3-½" TDS PIN	2.80	6.00	0.38	13.67
5 STDS 3-½" TDS TBG	2.75	3.50	137.88	151.55
PUP JNT 3-½"TDS	2.75	3.50	2.02	153.57
X-OVER 3-½" TDS BOX x 4-½" ACME PIN	2.80	6.00	0.21	153.78
OTIS SSTT	3.00	13.00	1.78	155.56
SLICK JNT 3-½" TDS	2.25	3.50	2.23	157.79
TOP 18 3/4" WELLHEAD AT 158 m.				
FLUTED HANGER	3.00	12.00	0.30	158.09
X-OVER 4-½" ACME PIN x 3-½ TDS PIN	2.80	6.00	0.44	158.53
258 JTS (86 STDS) 3-½" TDS	2.75	3.50	2390.06	2548.59
1 JNT 3-½"TDS	2.75	3.50	9.30	2557.89
X-OVER 3-½" TDS BOX x 3-½" IF PIN	2.75	4.50	0.56	2558.45
SLIP JNT (OPEN)	2.25	5.00	5.54	2563.99
SLIP JNT (CLOSED)	2.25	5.00	4.02	2568.01
5 STDS + 2 SINGLES DRILLCOLLARS	2.25	4.75	151.62	2719.63
RTTS MECHANICAL CIRC VALVE	2.25	4.625	0.90	2720.53
STD DRILL COLLARS	2.25	4.75	28.43	2748.96
SLIP JNT (CLOSED)	2.25	5.00	4.02	2752.98
SLIP JNT (CLOSED)	2.25	5.00	4.02	2757.00
1 STD DRILL COLLARS	2.25	4.75	28.43	2785.43
SPR-M SAFETY CIRC.VALVE	2.25	5.00	2.30	2787.73
DRILLPIPE TESTER VALVE	2.25	5.00	1.46	2789.19
LPR-N TESTER VALVE	2.25	4.625	5.10	2794.29
FUL FLOW HYDRAULIC BYPASS	2.25	4.625	2.11	2796.40
BIG JOHN JAR	2.25	4.625	1.59	2797.99
RTTS SAFETY JOINT	2.44	5.00	0.95	2798.94
RTTS PACKER (ABOVE)	2.40	5.75	0.56	2799.50
RTTS PACKER (BELOW)	2.40	5.75	0.82	2800.32
PERF. 2-7/8"FULL EUE (PIN UP).	2.44	2.88	9.45	2809.77
X-OVER 2-7/8" EUE PIN x 2-3/8" EUE BOX	2.00	3.25	0.25	2810.02
OTIS XN-NIPPLE (PIN x PIN)	1.79	3.25	0.25	2810.27
2-3/8" EUE COLLAR	2.00	2.38	0.14	2810.41
X-OVER 2-3/8" EUE PIN x 2-7/8" EUE PIN	2.44	4.15	0.18	2810.59
2-7/8" EUE FULL JOINT	2.44	2.88	9.44	2820.03
S.O.S. DST- HANGER	-	-	-	
2-7/8" EUE FULL JOINT	2.44	2.88	9.35	2829.38
BULL-PLUG w/CROSS 2-7/8" EUE BOX	2.44	3.25	0.15	2829.53

Remarks.

All measurements to bottom of each item.

Well 34/10-17	GAUGE ARRANGEMENT	CHP/PG
DST no. 3		Perfs.: 2835-45 m
		Zone tested BRENT

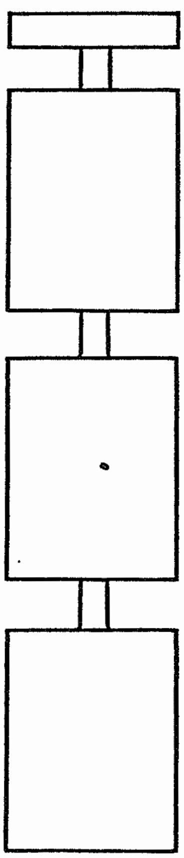


WIRELINE NIPPLE at 2810.27 mRKB

Gauge type and number : Sperry Sun, MK III 0221
Depth, pressure element : 2813.64 m   Range : 0-690 bar
Mode : 2 min   Delay : 17 hrs.
Actuated : time 01.09   date : 21.06.83
Will run out : time 02.07   date : 24.06.83

Gauge type and number : Flopetrol, SDP 82003
Depth, pressure element : 2817.03 m   Range : 0-690 bar
Mode : 30 sec.   Delay : 15 hrs.
Actuated : time 01.05   date : 21.06.83
Will run out : time –   date : –

Gauge type and number :
Depth, pressure element :   Range :
Mode :   Delay :
Actuated : time   date :
Will run out : time   date :



D.S.T. HANGER at 2820.03 mRKB

Gauge type and number : Speery Sun, MK III 0222
Depth, pressure element : 2823.16 m   Range : 0-690 bar
Mode : 2 min.   Delay : 17 hrs.
Actuated : time 01.08   date : 21.06.83
Will run out : time 02.08   date : 24.06.83

Gauge type and number : Sperry Sun, MK III 0181
Depth, pressure element : 2825.90 m   Range : 0-690
Mode : 4 min.   Delay : 17 hrs.
Actuated : time 01.07   date : 21.06.83
Will run out : time 08.00   date : 26.06.83

Gauge type and number :
Depth, pressure element :   Range :
Mode :   Delay :
Actuated : time   date :
Will run out : time   date :

Well 34/10-17	SAMPLING	CHP/PG
DST no 3		Perfs.: 2835-45m
		Zone tested BRENT

SEPARATOR SAMPLES

Time/date	Sample no.	Type of sample	Transfer time	Bottle no
22.06.83			mins	
04.30	1	Condensate	35	SOS 104
04.30	2+3	Gas	35	SOS 1012+1006
05.35	4	Condensate	25	SOS 103
05.35	5+6	Gas	25	SOS 1000+1020
18.55	7	Condensate	40	SOS 110
18.55	8+9	Gas	40	SOS 1003+1005
20.10	10	Condensate	30	SOS 106
20.10	11+12	Gas	30	SOS 1010+1007

BOTTOM HOLE SAMPLES (NONE)

Time/date	Sample depth mRKB	Estimated PB bar/°C	Transfering pressure(bar)	Bottle no

WELLHEAD SAMPLES (NONE)

OTHER SAMPLES:

Time/date	Sampling point	Sampling equipment		Remarks
22.06.83				
07.00	Separator	Jerry-can	1 x 20 l	Condensate
07.00	"	Jerry-can	2 x 10 l	"
07.30	"	Plastic-bottle	1 x 1 l	Water
07.30	"	Glass-jar	6 x 1 l	Condensate
07.30	"	Barrel	1 x 200 l	"
19.00	Mud Pit	Plastic-bottle	1 x 1 l	Mud

6.5 DST No. 4, Performance and Analysis

6.5.1. Results of the Analysis

The following results are obtained from the test:

Reservoir pressure: 403 bar at 2772 mRKB (mid. perf.)

Reservoir temperature: 101.5^{o}C

Produced reservoir fluid: Gas with associated condensate at a ratio of about 750 Sm^3 condensate per 10^6 Sm^3 gas (or 1330 Sm^3 gas per Sm^3 condensate)

Permeability: 270 md

Skin: Skin factor of 15 corresponding to a pressure loss of 3.9 bar. Total drawdown was 6.0 bar (for the highest flow rate).

Productivity: Fairly high flow rates with low corresponding pressure drawdowns were observed indicating a high well productivity (at initial reservoir pressure), see fig. 6.5.2.

No boundary effects are seen.

6.5.2. Comments on the Test Analysis

The test was evaluated using the conventional Horner analysis of the second and third shut in periods. No significant well bore storage effects were observed (the well was shut in downhole).

Drawdown analysis were not performed because of the data quality; clean up disturbance during the second flow and very low pressure drawdown during the third flow period.

The variations in the reported producing gas-oil ratio are probably due to inaccurate metering.

The test derived permeability thickness is significantly lower than the permeability thickness calculated from core data. One reason for this can be that only one or two of the perforated zones have contributed to the test. The others might have limited areal extent or poor clean up of the perforation.

Anomalies in the pressure build up data:

The pressure data obtained during the early part of the second shut in period were examined in more detail to evaluate the reason for a strange pressure build up behavior. Figure 6.5.1 shows the pressure data for all the gauges for the first 3 hours of the shut in period.

The data from the gauges SS0051 and SDP82020 might at first sight indicate a special reservoir characteristic (f.ex. a multilayer system). The gauge SS0222 does not show this effect, neither do any of the gauges during the third shut in period. SS0222 does, however, show a slight pressure drop for about 10 minutes before the other two gauges show a pressure increase.

It has, based on these facts, been concluded that the anomalies in the pressure data are due to some mechanical or hydraulic effects in the well. This could be a slight movement of the packer, a change in annulus pressure or partial plugging of the communication between the perforations and the gauges. The latter seems most likely because the three gauges show different pressure behaviors. The gagues SS0051 and SDP82020, hanging in the xn-nipple, could have been plugged partially off while the gauge SS0222, hanging in the DST hanger below, had communication with the well through the open ended bull plug. The pressure drop at 07.20 hours can be due to a slight pressure release as a result of unplugging of the entrance to the xn-nipple gauges.

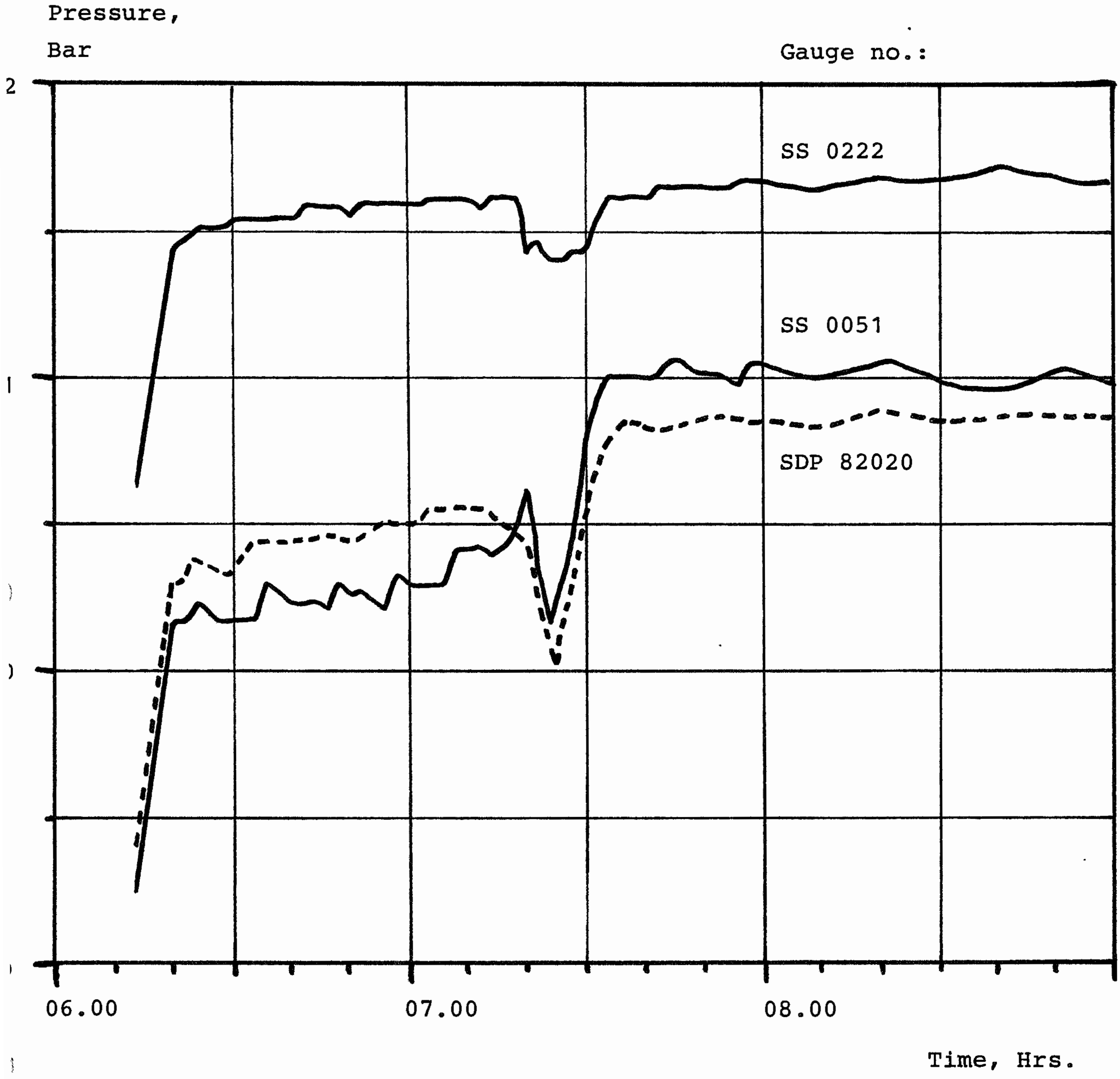
Fig. 6.5.1

DETAILED PLOT OF PRESSURE VS TIME

EARLY PART OF SECOND SHUT IN

DST no. 4

34/10-17



6.5.3 Data Input to the Analysis

The bottom hole pressure data from the pressure gauge SS0222 were selected for the analysis. The quality of the data seems to be fairly good.

The average production rates for the last part of the flow periods are used in the analysis. An equivalent (total) gas rate was obtained by adding the condensate rate expressed as gas rate (for the given condensate gravity and separator pressure) to the gas rate.

The gas characteristics were taken from the PVT analysis report made on a recombinded sample from this test (ref. 5).

The connate water compressibility and formation compressibility were derived from standard correlations.

The porosity and saturation data were taken from the log analysis report (ref. 1).

The pressure gradient in the gas zone was taken from the FMT report (ref.2).

The formation thickness contributing to the test response has been estimated using the available core and log analyses data*. Five intervals were perforated and the thickness of each of these and other zones contributing to the test have been determined:

Perforated interval,m	Perforated thickness,m	Total interval,m	Total thickness,m
2754.0-57.0	3.0	2753.9-58.0	4.1
2763.0-65.0	2.0	2763.0-64.6	1.6
2767.5-70.5	3.0	2767.4-71.3	3.9
2773.0-77.0	4.0	2773.0-77.0	4.0
2784.5-90.5	6.0	2784.3-91.3	7.0
		2801.4-02.6	1.2
		2806.6-08.3	1.7
	18.0m		23.5m

The cement bond log shows a good bond above the top perforation and below 2813m, eliminating "behind casing flow" from other zones than those listed above (see Appendix 1).

Arithmetic average horizontal liquid permeabilities from the core analysis are as follows (for comparison with test derived permeability thickness):

	Thickness,m	avg.k_{hl},md	k h,md m
Total intv.:	23.5	1500	35300
Perf. intv.:	18.0	1730	31100

Test k h = 6400 md m (analysis of the second build up)
5100 md m (analysis of the third build up)

* Core depths are corrected to log depths.

INPUT TO TEST ANALYSIS
(GAS / COND. SYSTEM)

Well no. 34/10-17

DST no. 4 | Test Date 27.06-29.06.83

Reservoir Parameters

Perforations 2754-2757 m RKB | Zone (s) Ness

2763-2765 | Wellbore radius 0.11 m

2767.5-2770.5 | RKB Elev. 25 m

2773-2777

2784.5-2790.5

Depth Mid. Perfs: 2772.3 m RKB 2747.5 mSS

Pressure Gauge no. SS 0222 Depth 2745.6 m RKB 2720.6 m SS

Pressure Gradient: 0.041 bar/m

Pressure Correction, Gauge to Mid. Perfs.: 1.1 bar

Formation Volume Factor 0.0034 Res.m^3/Sm^3 | Viscosity 0.0339 cp

Thickness 23.5 m | Porosity 23.5 %

Oil Saturation 0 % | Oil Compressibility ______ 10^{-6} bar^{-1}

Water Saturation 27.5 % | Water Compressibility 43 10^{-6} bar^{-1}

Gas Saturation 72.5 % | Gas Compressibility 1400 10^{-6} bar^{-1}

Formation Compressibility 49 10^{-6} bar^{-1}

System Compressibility $C_t = S_o C_o + S_w C_w + S_g C_g + C_f$

C_t = 0 x ______ 10^{-6} + 0.275 x 43 10^{-6} + 0.725 x 1400 10^{-6} + 49 10^{-6}

C_t = 1076 10^{-6} bar^{-1}

Flow Data: Flow Period no. 2

Choke 48 / 64 inches | Cond. Rate 501 Sm^3/D | Gas Rate 653000 Sm^3/D

P_{tf} 188 bar | Water Rate 0 Sm^3/D | GOR 1303 Sm^3/Sm^3

Cond. Spec. Grav. 0.758 | Gas Spec. Grav. 0.714

Cumulative Production Condensate ______ Sm^3 Gas ______ Sm^3

Water ______ Sm^3

Equivalent Gas Rate = qg + qc Vsc + qw · 7390 = 757000 Sm^3/D

Horner Analysis

Well no. 34/10-17
DST no. 4
Build Up no. 2
Gauge no. SS 0222

Test Date 27.06-29.06.83

Effective Production Time tp = Cumulative Production / Last Rate

$tp = \_\_\_\_ / \_\_\_\_ = 9.1$ hrs

Straight Line Starts at 1.5 hrs Slope: m = 0.293 bar/cycle

$P_{wf} = 395.9$ bar P_{1hr} 401.6 bar P^* 401.9 bar

Estimated Reservoir Pressure (P^*) at Mid. Perfs. (2747.5mSS): 403.0 bar

Permeability:

$$Kh = \frac{21.49\, q\, Bu}{m} = \frac{21.49 \times 757000 \times 0.0034 \times 0.0339}{0.293} = 6400 \text{ md.m}$$

K = Kh/h = 6400 / 23.5 = 270 md.

Skin:

$$S = 1.1513 \left[\left[\frac{P_{1hr} - P_{wf}}{m}\right] + \text{Log}\left[\frac{tp+1}{tp}\right] - \text{Log}\left[\frac{K}{\emptyset \mu\, C_t\, rw^2}\right] + 3.098 \right]$$

$$S = 1.1513 \left[\left[\frac{401.6-395.9}{0.293}\right] + \text{Log}\left[\frac{9.1+1}{9.1}\right] - \text{Log}\left[\frac{270}{0.235 \times 0.0339 \times 1076 \times 10^{-6} \times 11^2}\right] + 3.098 \right]$$

S = 15

For the Previous Flow Period:

$$\Delta Ps = \frac{18.665 \cdot q\, B\, \mu}{kh}\, S = \frac{18.665 \times 757000 \times 0.0034 \times 0.0339 \times 15}{6400} = 3.9 \text{ bar}$$

$\Delta Pdd = P^* - Pwf = 6.0$ bar

Skin as Fraction of Total Drawdown: $\frac{\Delta Ps}{\Delta Pdd} = 0.64$

INPUT TO TEST ANALYSIS
(GAS / COND. SYSTEM)

Well no. 34/10-17
DST no. 4

Test Date 27.06-29.06.83

Reservoir Parameters As for Flow Period no. 2

Perforations ______ m RKB

Zone (s) ______

Wellbore radius ______ m

RKB Elev. ______ m

Depth Mid. Perfs: ______ m RKB ______ mSS

Pressure Gauge no. ______ Depth ______ m RKB ______ m SS

Pressure Gradient: ______ bar/m

Pressure Correction, Gauge to Mid. Perfs.: ______ bar

Formation Volume Factor ______ Res.m^3/Sm^3 Viscosity ______ cp

Thickness ______ m

Porosity ______ %

Oil Saturation ______ %

Oil Compressibility ______ 10^{-6} bar^{-1}

Water Saturation ______ %

Water Compressibility ______ 10^{-6} bar^{-1}

Gas Saturation ______ %

Gas Compressibility ______ 10^{-6} bar^{-1}

Formation Compressibility ______ 10^{-6} bar^{-1}

System Compressibility $C_t = S_o C_o + S_w C_w + S_g C_g + C_f$

C_t = ______ x ______ 10^{-6} + ______ x ______ 10^{-6} + ______ x ______ 10^{-6} + ______ 10^{-6}

C_t = ______ 10^{-6} bar^{-1}

Flow Data: Flow Period no. 3

Choke 32 / 64 inches Cond. Rate 320 Sm^3/D Gas Rate 428000 Sm^3/D

P_{tf} 257 bar Water Rate 0 Sm^3/D GOR 1338 Sm^3/Sm^3

Cond. Spec. Grav. 0.760 Gas Spec. Grav. 0.714

Cumulative Production Condensate ______ Sm^3 Gas ______ Sm^3

Water ______ Sm^3

Equivalent Gas Rate = qg + qc Vsc + qw · 7390 = 494000 Sm^3/D

Horner Analysis

Well no. 34/10-17

DST no. 4

Build Up no. 3

Gauge no. SS 0222

Test Date 27.06-29.06-83

Effective Production Time tp = Cumulative Production / Last Rate

tp = ______ / ______ = 7.55 hrs

Straight Line Starts at 1.0 hrs Slope: m = 0.239 bar/cycle

P_{wf} = 398.5 bar P_{1hr} 401.5 bar P^* 401.7 bar

Estimated Reservoir Pressure (P*) at Mid. Perfs. (2747.5 mSS): 402.8 bar

Permeability:

$$Kh = \frac{21.49\, q\, B u}{m} = \frac{21.49 \times 494000 \times 0.0034 \times 0.0339}{0.239} = 5100 \text{ md.m}$$

K = Kh / h = 5100 / 23.5 = 220 md.

Skin:

$$S = 1.1513 \left[\left[\frac{P_{1hr} - P_{wf}}{m} \right] + \text{Log} \left[\frac{tp + 1}{tp} \right] - \text{Log} \left[\frac{K}{\varnothing \mu\, C_t\, r_w^2} \right] + 3.098 \right]$$

$$S = 1.1513 \left[\left[\frac{401.5 - 398.5}{0.239} \right] + \text{Log} \left[\frac{7.55 + 1}{7.55} \right] - \text{Log} \left[\frac{220}{0.235 \cdot 0.0039 \cdot 1076 \cdot 10^{-6} \cdot 0.11^2} \right] + 3.098 \right]$$

S = 6

For the Previous Flow Period:

$$\Delta Ps = \frac{18.665 \cdot q\, B\, \mu}{kh}\, S = \frac{18.665 \times 494000 \times 0.0034 \times 0.0339 \times 6}{5100} = 1.5 \text{ bar}$$

$\Delta Pdd = P^* - Pwf$ = 3.2 bar

Skin as Fraction of Total Drawdown: $\frac{\Delta Ps}{\Delta Pdd}$ = 0.47

Productivity/Deliverability

One of the objectives of this test was to evaluate the productivity of the Ness formation.

Plotting of pressure versus rate for the two flow rates on back pressure curve gives an n exponent of 0.77, indicating some pressure drop due to turbulence flow. By assuming radial semisteady state gas flow in the reservoir, the turbulent and laminar parts of the total drawdown has been calculated to be:

Rate no.	q_g, $10^3 Sm^3/D$	ΔPturb.	ΔPlam.	ΔPtot.
1	653	2.0 bar	3.9 bar	5.9 bar
2	428	0.9 bar	2.5 bar	3.4 bar

Pressure drawdown at higher rates can be calculated by the following formula (assuming insignificant change in viscosity and z-factor with pressure, and no change in saturation):

$$pwf = (p^{*2} - Cq_g - D\, q_g^{2})^{0.5}$$

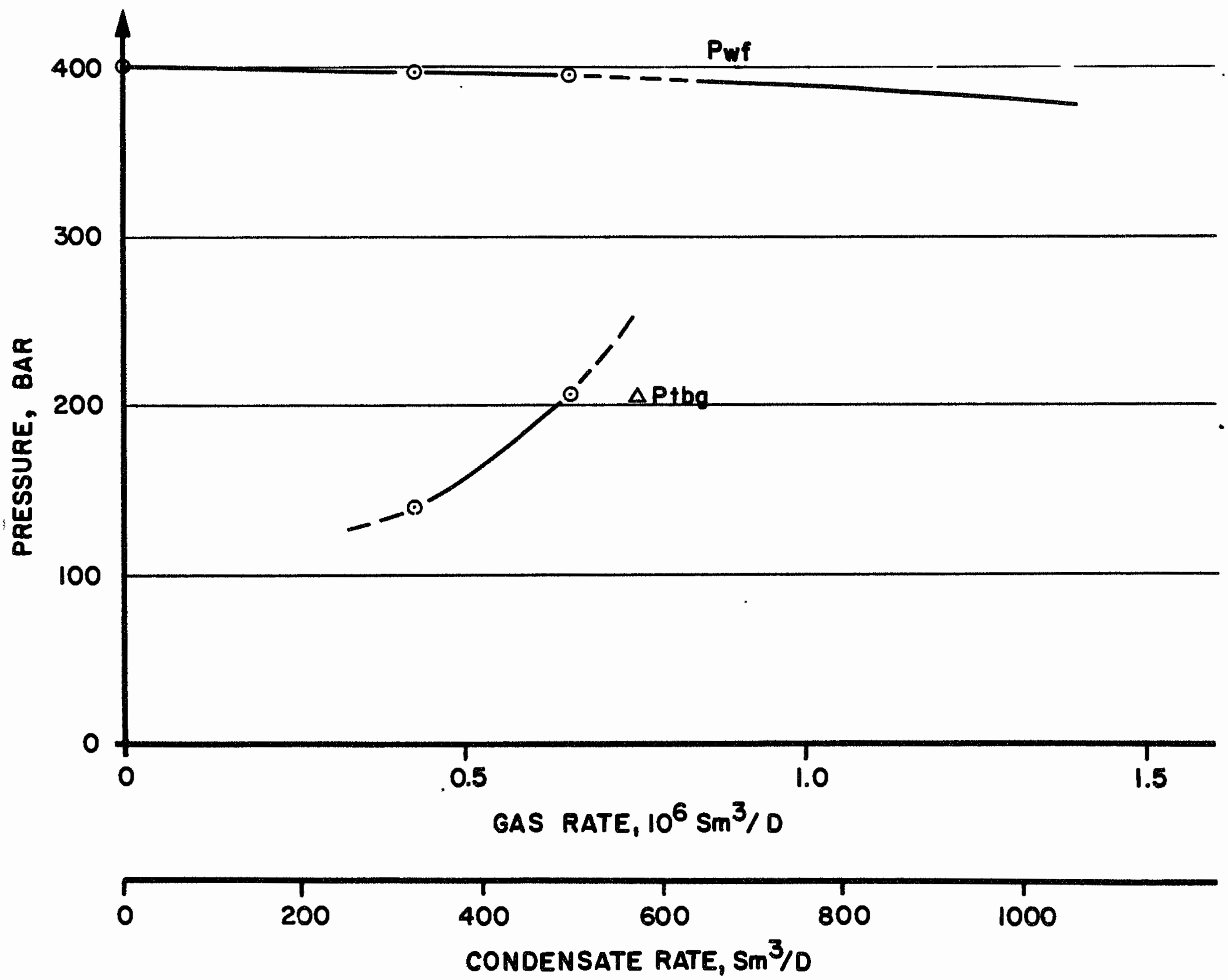
The constants C (for laminar flow) and D (for turbulent flow) have, by using the test results, been calculated to:

$C = 4.74$
$D = 0.0038$

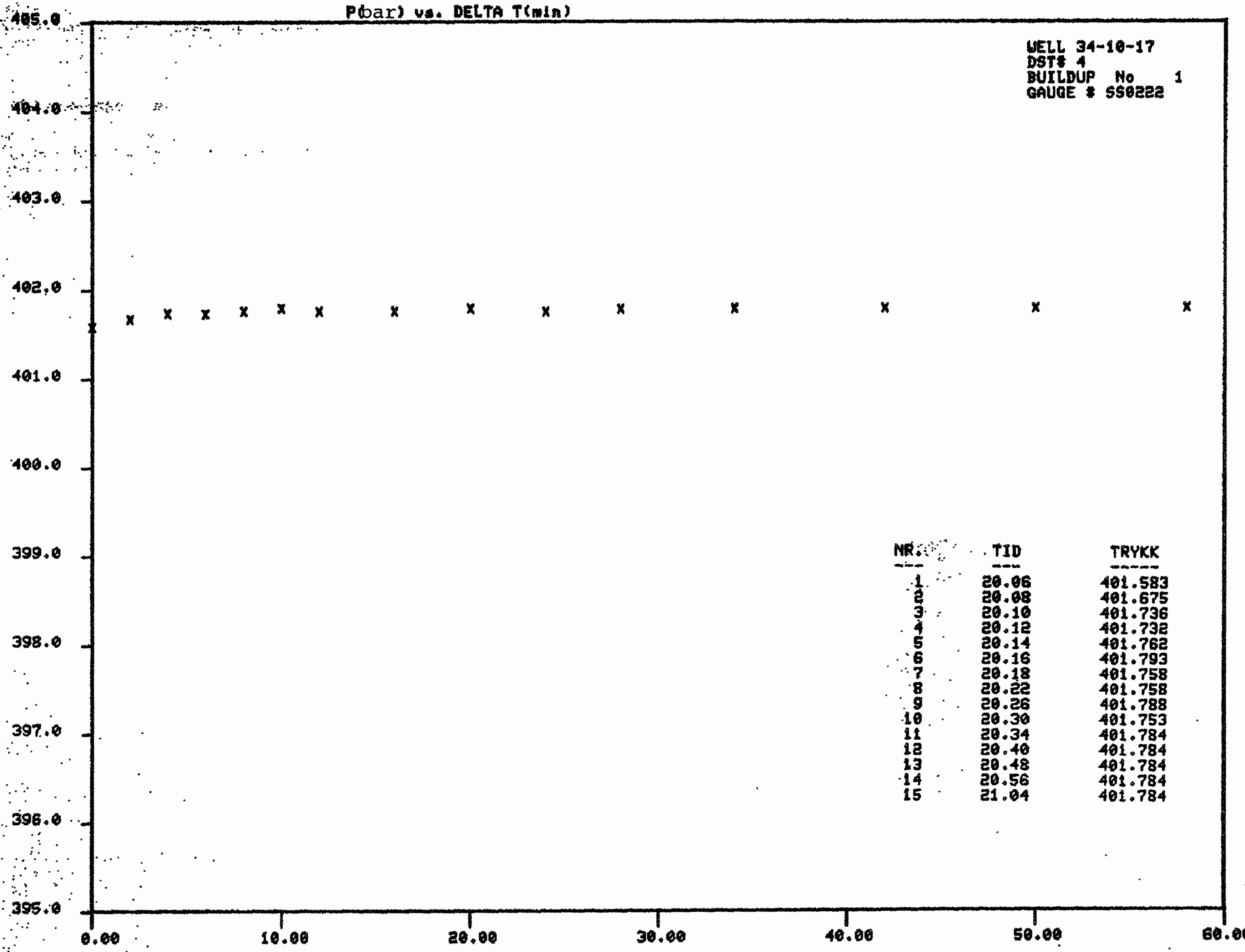
Bottom hole pressure for higher rates have been estimated as shown in figure 6.5.2. At pressures below the dew point (384 bar) more detailed reservoir studies are required to estimate the productivity. Figure 6.5.2 also shows the pressure drop in the 3½" test tubing. This pressure drop shows a large increase with a rate above $0.5 \times 10^6 Sm^3/D$ and it is obvious that much higher production rates could be obtained by using a larger tubing.

Fig. 6.5.2

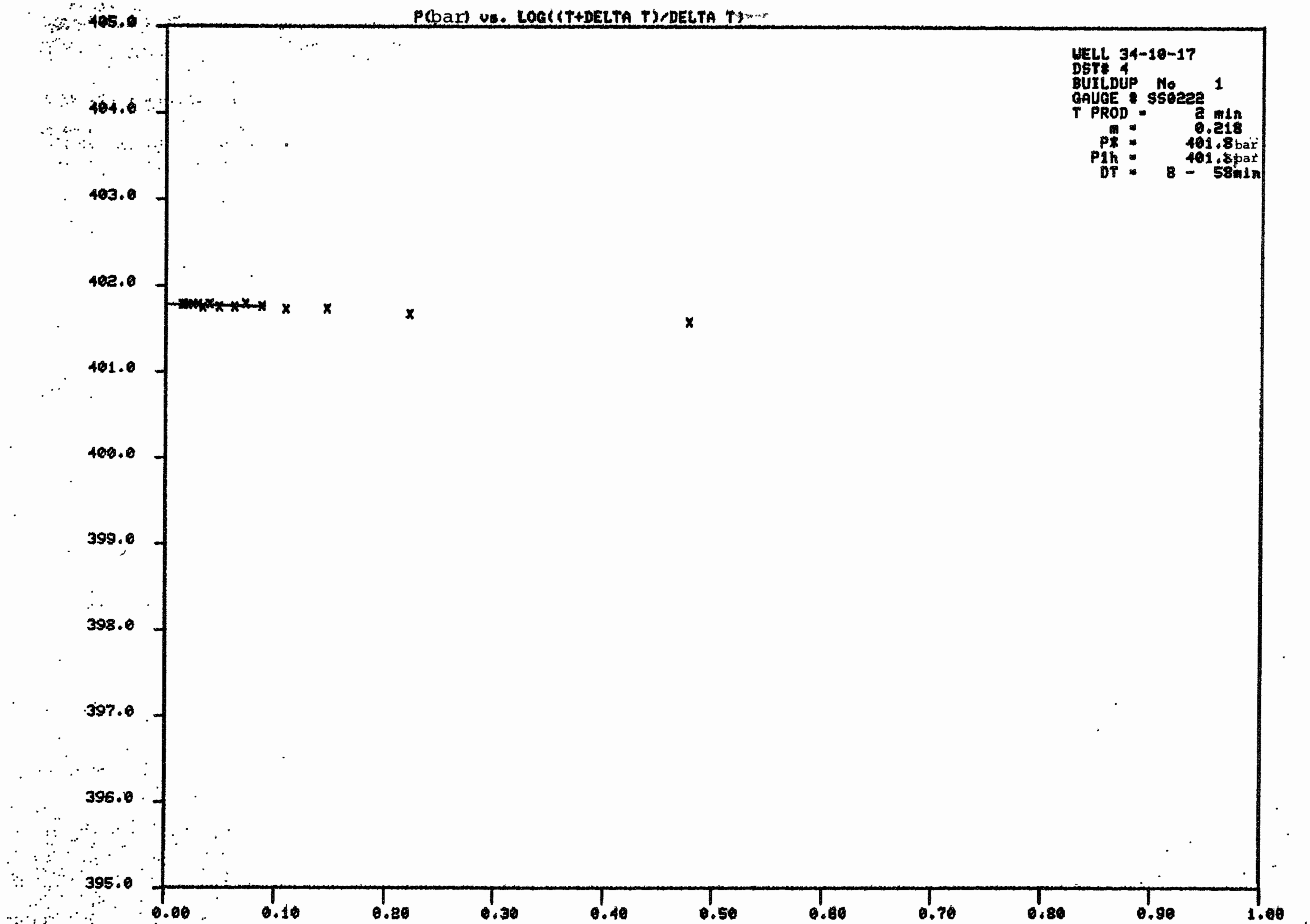
BOTTOM HOLE PRESSURE
AND
TUBING PRESSURE LOSS
VS. RATE
34/10-17, DST 4

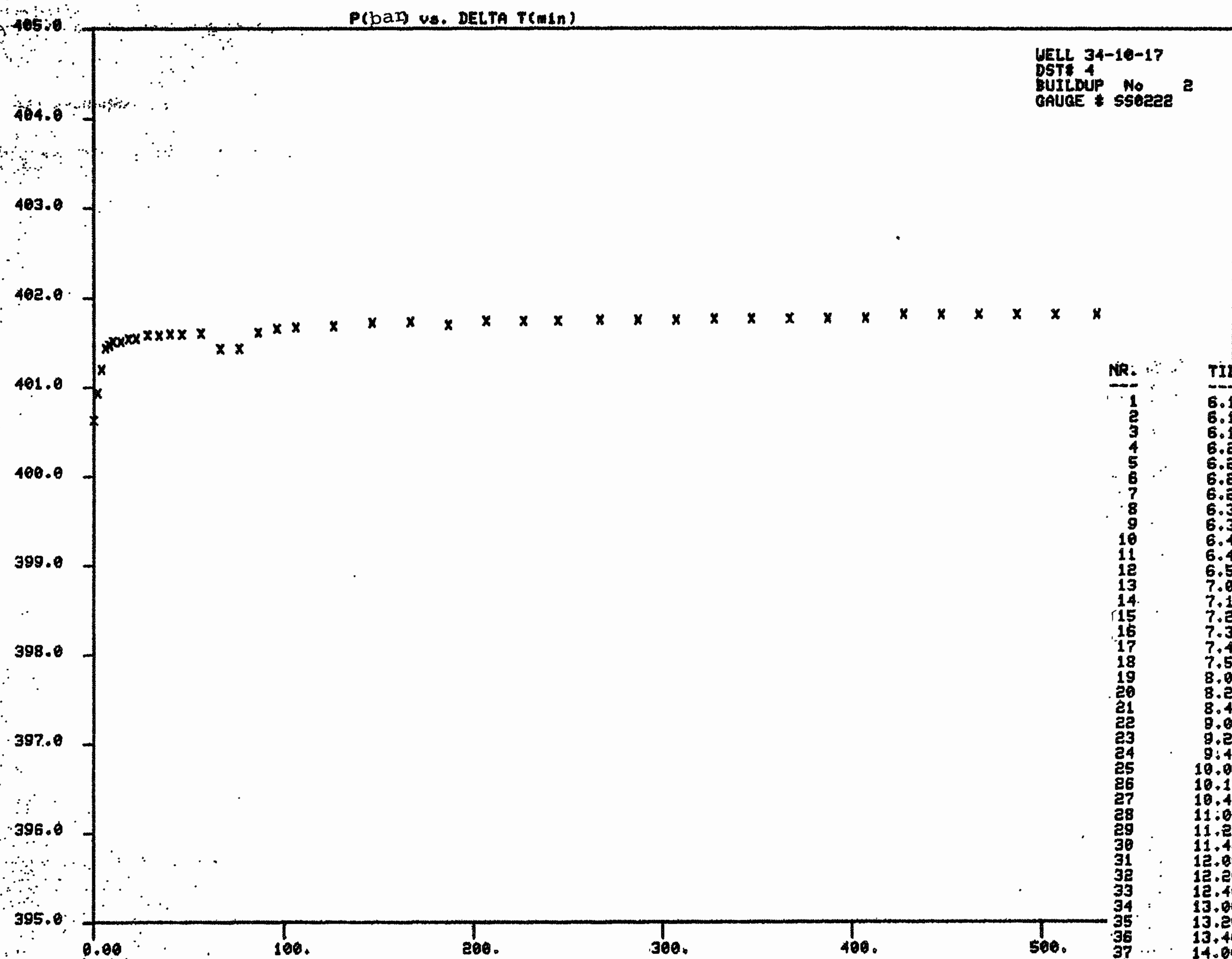


StL 04.11.83

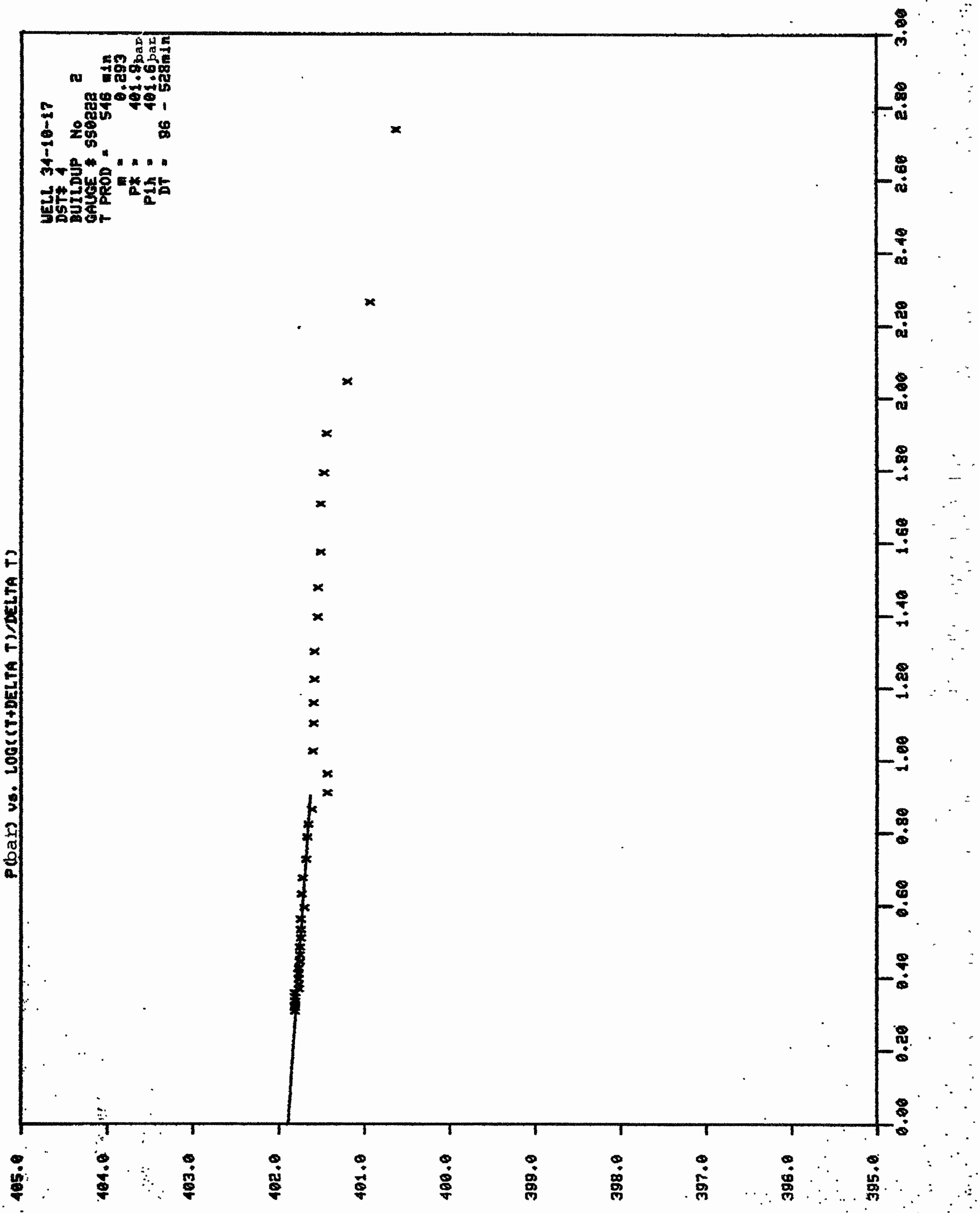


NR.	TID	TRYKK
1	20.06	401.583
2	20.08	401.675
3	20.10	401.736
4	20.12	401.732
5	20.14	401.762
6	20.16	401.793
7	20.18	401.758
8	20.22	401.758
9	20.26	401.788
10	20.30	401.753
11	20.34	401.784
12	20.40	401.784
13	20.48	401.784
14	20.56	401.784
15	21.04	401.784

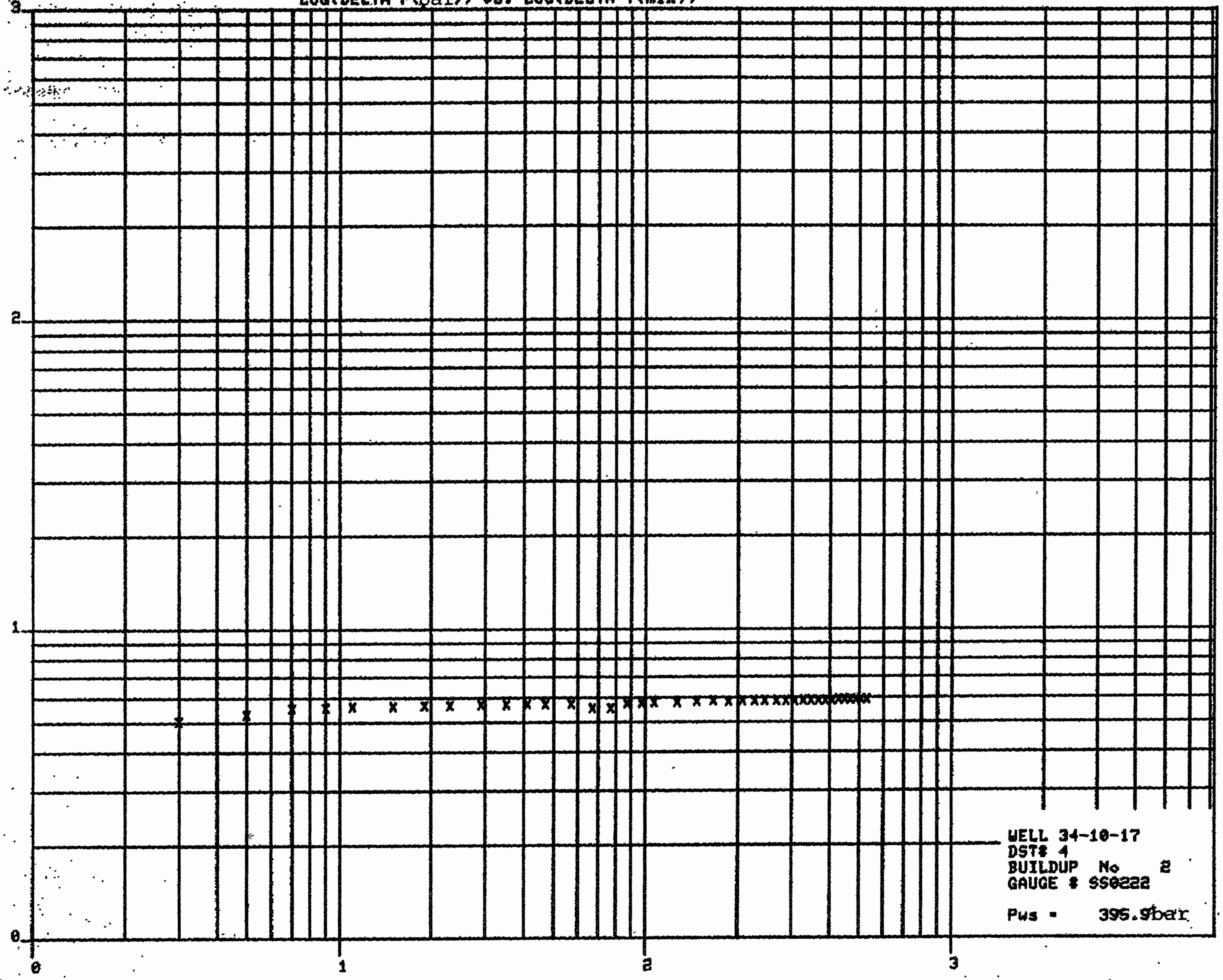

P(bar) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-17
DST# 4
BUILDUP No 1
GAUGE # SS0222
T PROD = 2 min
m = 0.218
P* = 401.8bar
P1h = 401.8bar
DT = 8 - 58min
405.0
404.0
403.0
402.0
401.0
400.0
399.0
398.0
397.0
396.0
395.0
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00

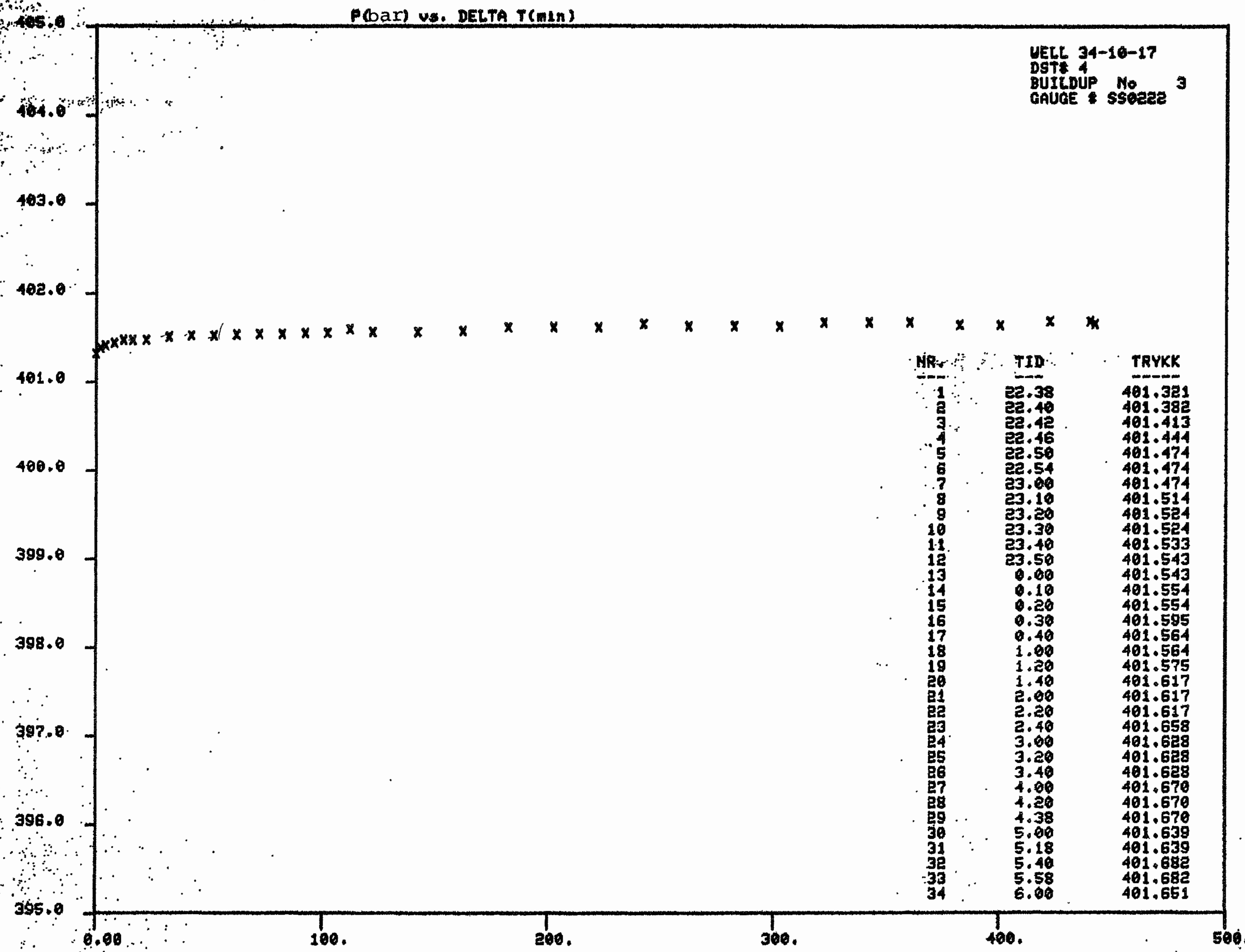


NR.	TID	TRYKK
1	6.14	400.628
2	6.16	400.934
3	6.18	401.199
4	6.20	401.444
5	6.22	401.474
6	6.24	401.514
7	6.28	401.514
8	6.32	401.545
9	6.36	401.545
10	6.42	401.585
11	6.48	401.585
12	6.54	401.595
13	7.00	401.595
14	7.10	401.605
15	7.20	401.431
16	7.30	401.431
17	7.40	401.615
18	7.50	401.656
19	8.00	401.667
20	8.20	401.678
21	8.40	401.720
22	9.00	401.731
23	9.20	401.701
24	9.40	401.743
25	10.00	401.743
26	10.18	401.743
27	10.40	401.755
28	11.00	401.755
29	11.20	401.755
30	11.40	401.768
31	12.00	401.768
32	12.20	401.768
33	12.40	401.768
34	13.00	401.768
35	13.20	401.811
36	13.40	401.811
37	14.00	401.811
38	14.20	401.811
39	14.40	401.811
40	15.02	401.811

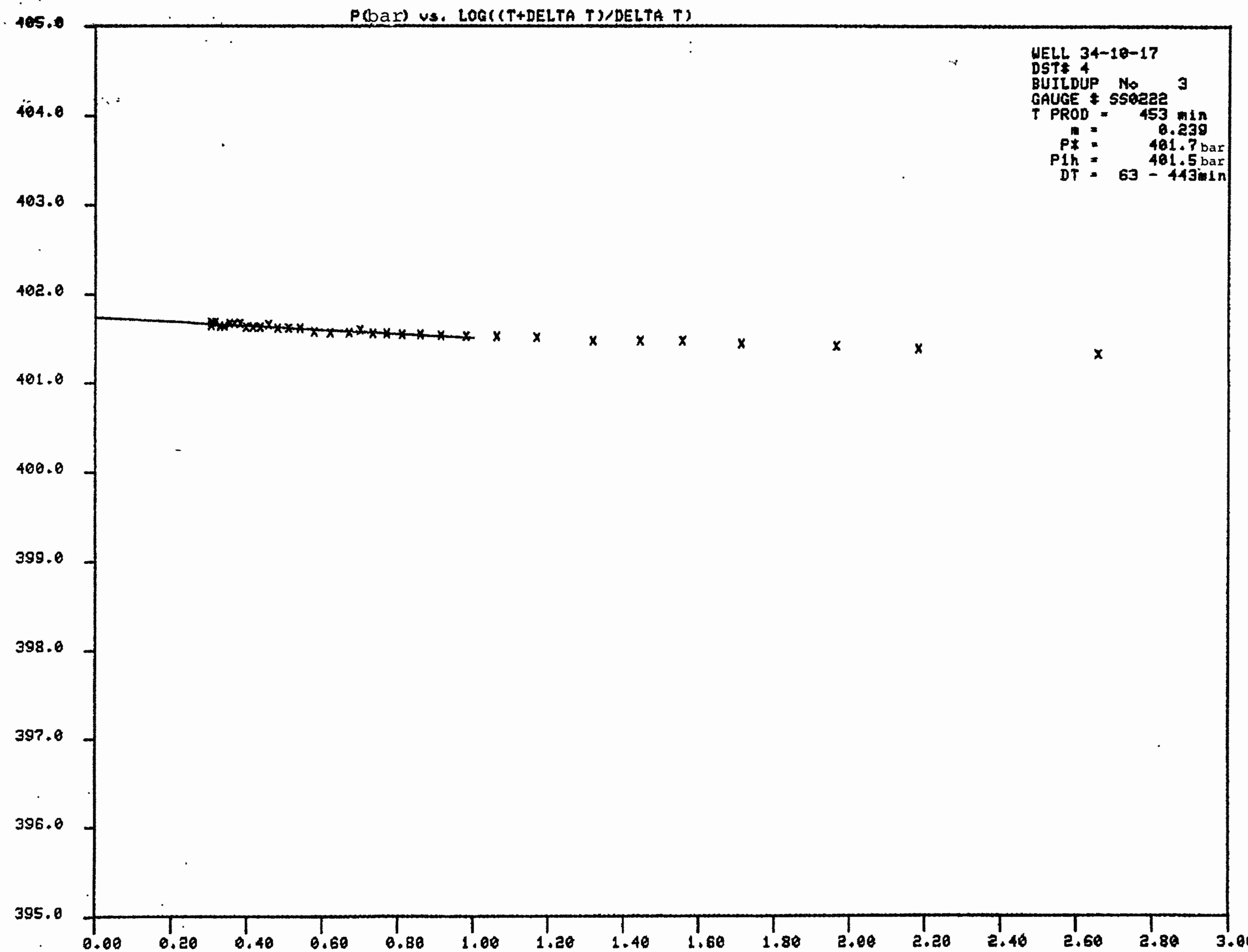

P(bar) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-17
DST# 4
BUILDUP No 2
GAUGE # SS0222
T PROD = 546 min
m = 0.293
PX = 401.9bar
P1h = 401.6bar
DT = 96 - 528min
405.0
404.0
403.0
402.0
401.0
400.0
399.0
398.0
397.0
396.0
395.0
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
1.60
1.80
2.00
2.20
2.40
2.60
2.80
3.00

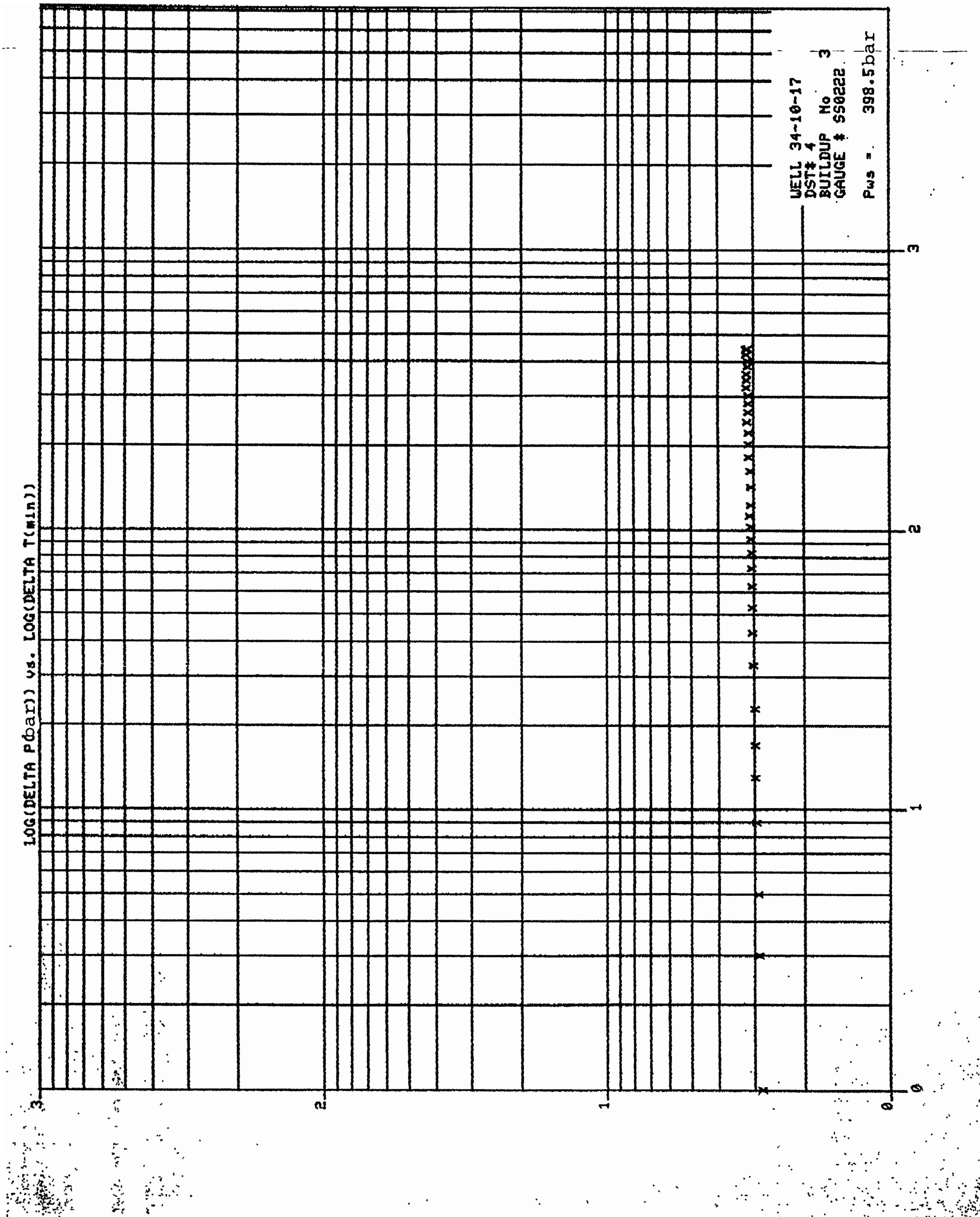
LOG(DELTA P(bar)) vs. LOG(DELTA T(min))





NR	TID	TRYKK
1	22.38	401.321
2	22.40	401.382
3	22.42	401.413
4	22.46	401.444
5	22.50	401.474
6	22.54	401.474
7	23.00	401.474
8	23.10	401.514
9	23.20	401.524
10	23.30	401.524
11	23.40	401.533
12	23.50	401.543
13	0.00	401.543
14	0.10	401.554
15	0.20	401.554
16	0.30	401.595
17	0.40	401.564
18	1.00	401.564
19	1.20	401.575
20	1.40	401.617
21	2.00	401.617
22	2.20	401.617
23	2.40	401.658
24	3.00	401.628
25	3.20	401.628
26	3.40	401.628
27	4.00	401.670
28	4.20	401.670
29	4.38	401.670
30	5.00	401.639
31	5.18	401.639
32	5.40	401.682
33	5.58	401.682
34	6.00	401.651


P(bar) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-17
DST# 4
BUILDUP No 3
GAUGE # SS0222
T PROD = 453 min
m = 0.239
P* = 401.7 bar
P1h = 401.5 bar
DT = 63 - 443min
405.0
404.0
403.0
402.0
401.0
400.0
399.0
398.0
397.0
396.0
395.0
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
1.60
1.80
2.00
2.20
2.40
2.60
2.80
3.00


LOG(DELTA P(bar)) vs. LOG(DELTA T(min))
WELL 34-10-17
DST# 4
BUILDUP No 3
GAUGE # SS0222
Pws = 398.5bar
0
1
2
3
0
1
2
3

COMPARISON OF RESULTS OBTAINED FROM ALL GAUGES

Well no.: 34/10-17
DST no.: 4

	Selected Gauge			Other Gauges					
Gauge no.:	SS 0222			SDP 82020			SS 0151		
Build up no.:	1	2	3	1	2	3	1	2	3
Data Quality:	Fair	Fair	Fair	Quest.	Fair	Fair	Poor	Poor	Poor
Horner Slope, bar/cycle:	.218	.293	.239	5.14	.247	.168	No analysis possible		
Permeability, md:		270	220		320	310			
p* Corrected to mid perf., bar:	402.9	403.0	402.8	401.5	402.5	402.3			

Well 34/10-17 DST no. 4	DIAREY OF EVENTS	CHP/PG Perfs.: 2754 - 90.5 m * Zone tested BRENT

1983 Date	Time	OPERATIONS
		PERFORATING
25.06	15.30	Rig up Dresser Atlas and perforate 4 shots around 2754 mRKB.
	17.30	RIH with RTTS packer and squeeze cmt.
26.06	05.30	RIH with bit and scraper drlg cmt and cond. mud.
	18.00	Rig up Dresser and run CBL/VDL. Good cementbond 2766.5 - 2741 mRKB. Fair bond from 2741 - 2734 mRKB.
	20.00	RIH and perforate selective 1) 2790.5-2784.5mRKB 2) 2777-2773 mRKB (Ref. Density - Neutron log)
	22.30	RIH and perforate selective 1) 2770.5-2767.5mRKB and 2765 - 2763 mRKB 2) 2757-2754 mRKB.
	23.55	Perforation job complete.
27.06	00.10	Started gauges.
	00.13	Started rigging bottom hole assembly.
	00.21	Started RIH.
	00.25	Gauges set in DST hanger.
	00.36	Gauges set in XN-nipple, cont. RIH.
	19.55	Set packer.
		INITIAL FLOW/BUILD-UP
	20.02	Open LPR-valve WHP = 132 bar.
	20.03	Open choke-manifold on 32/64" fixed choke. WHP=67 bar Produced 1.3 m^3 cushion to surge tank (8 Bbls)
	20.05	Close LPR-valve and choke manifold.
		SECOND FLOW/BUILD-UP
	21.05	Open LPR-valve, WHP=132 bar, no indication of opening Start glycol injection.
	21.06	Open choke manifold on 16/64" adj. choke. Gradually increase choke:
	21.08	28/64" adj.
	21.09	32/64" adj.
	21.16	Mud to surface. Plugging on adj. choke. WHP=172.6 bar.
	21.17	Gas to surface. Working on adj. choke. Increase to 52/64" still plugging. WHP= 253.0 bar.
	21.18	Change to 48/64" fixed choke. WHP = 213.1 bar.
	21.42	Stop glycol injection. WHP = 175.86 bar.
	22.00	Drop in wellhead pressure due to slug of mud. High readings on sand detector. B.S.W. = 35%. Mostly mud + mudfiltrate. No sand detected. WHP = 174.8 bar.

Remarks:

* 5 intervals perforated : 2790.5 - 2784.5 m
2773.0 - 2777.0 m
2770.5 - 2767.5 m
2765.0 - 2763.0 m
2757.0 - 2754.0 m

Well 34/10-17 DST no. 4	DIARY OF EVENTS	CHP/PG Perfs.: 2754 - 90.5m Zone tested BRENT

1983 Date	Time	OPERATIONS
	23.52	Direct flow through separator, WHP= 184.3 bar.
28.06	00.00	Drained water outlet from separator to remove all water.
	00.45	Started flowing to tank for correction factor.
	01.15	Finished flowing to tank.
	01.45	Started condensate sampling from goose-neck.
	02.15	Measured shrinkage.
	03.18	Started PVT-sampling from separator.
	04.34	Finished PVT-sampling. 2 sets, each containing 1 condensate + 2 gas, taken.
	04.45	Continue condensate sampling on rig floor.
	06.05	Bypassed separator.
	06.12	Closed LPR-valve for second build-up.
	06.13	Closed choke-manifold Sampled 1 20 1 jerry can + 1 10 1 jerry can condensate from separator. No water produced.
		THIRD FLOW/BUILD-UP
	15.04	Opened LPR-valve, started glycol-injection.
	15.05	WHP = 274.8 bars. Opened choke manifold on 32/64" fixed choke. Directed flow through heater and separator.
	15.15	Adjusted separator pressure to 55 bars. WHP = 249.2 bars.
	15.34	Bypassed heater.
	15.38	Stopped glycol-injection.
	16.15	Malfunction on 2" flow-meter. Swithced to 3" flow while repairing 2" meter.
	16.30	Switched flow back to 2" flow and directed flow to tank for correction factor. Took shrinkage measurements.
	19.06	Started PVT-sampling from separator.
	20.52	Finished PVT-samling. 2 sets taken (1 cond + 2 gas each)
	21.08	Started condensate-sampling at goose-neck.
	22.00	Finished wellhead sampling, 6 litre glasses taken.
	22.32	Closed oil outlet to raise condensate level in separator.
	22.35	Bypassed separator.
	22.38	Closed LPR-valve and choke manifold for final shut-in period.
	22.45	Sample one barrel and two 10 1 jerry cans condensate from separator. No water produced.
	05.06	Open choke manifold on 32/64" fixed choke and bleed pressure above LPR-N valve.
	05.30	Close choke-manifold, WHP = 220 psig. Open kill valve, close failsafe. Pump 1 m^3 water and 51 bbls mud.

Remarks :

Well 34/10-17 DST no. 4	DIARY OF EVENTS	CHP/PG Perfs.: 2754-90.5 Zone tested BRENT

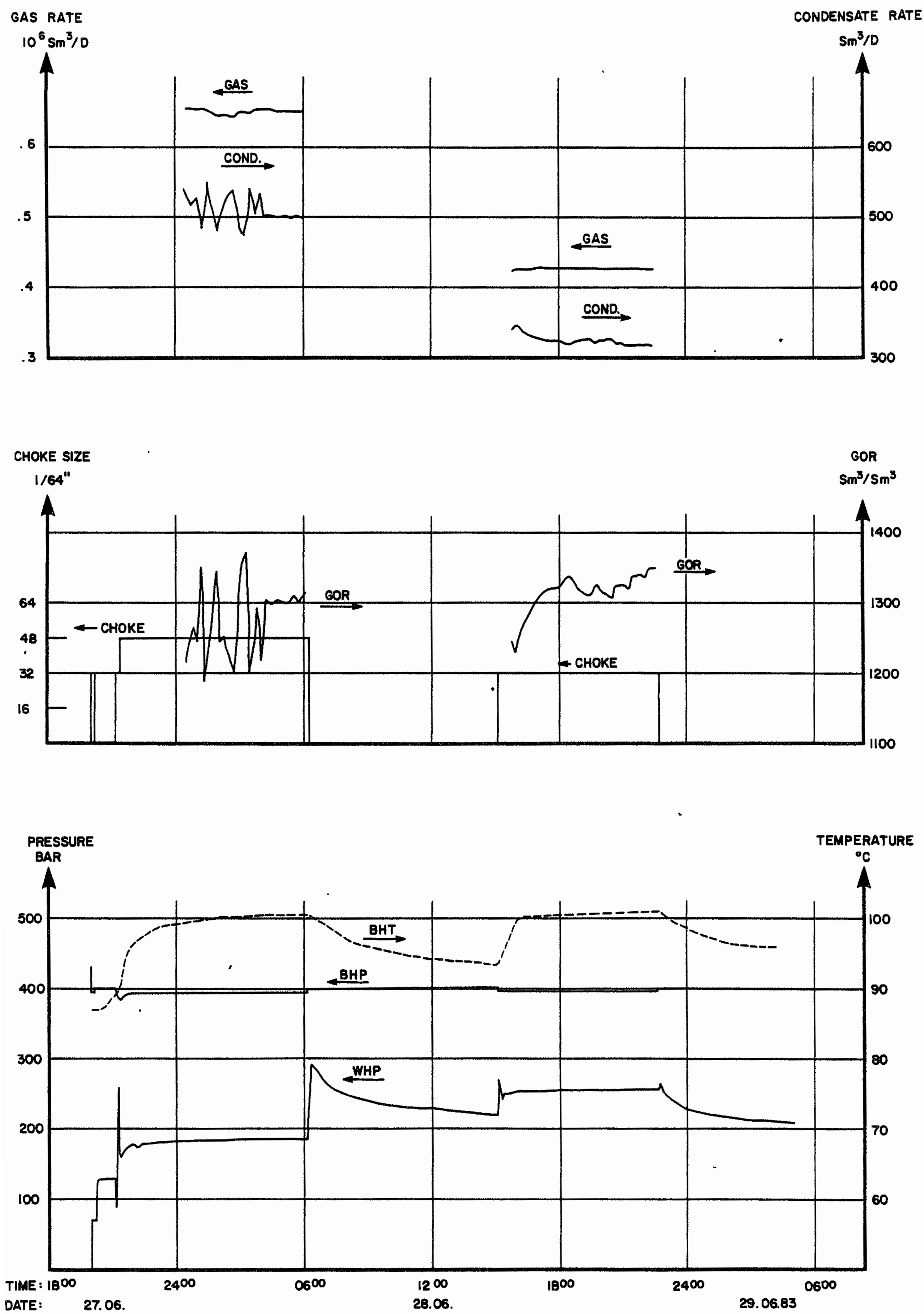
1983 Date	Time	OPERATIONS
28.06	06.00	Open LPR-valve, start bullheading.
	06.18	Finished bullheading. Close lubricator valve. Open failsafe valve and choke manifold. Flush lines to burner.
	10.05	Release packer.
	22.12	XN-nipple gauges up.
	22.18	DST hanger gauges up.
		END OF TEST

Remarks :

34/10-17

DST no. 4

FLOW, CHOKE, PRESSURE AND TEMPERATURE DIAGRAM



STL. 31.10.83

Well	34/10-17	FLOW DATA	CHP/PG
DST no.	4		Perfs.: 2754 - 90.5m**
			Zone tested BRENT

1983 Date/	time	Bottom hole press. bar	Bottom hole temp °C	Well head press bar	Well head temp. °C	Chokes 1/64" manifold	Chokes 1/64" heater	Separator data press. bar	Separator data temp. °C	Separator data gas rate $10^3 Sm^3/d$	Separator data oil rate Sm^3/D	Separator data GOR Sm^3/Sm^3	Separator data sp.gr.oil	Separator data sp.gr.gas (Air=1)	Liq. and gas analysis Water %	Liq. and gas analysis Sedim. %	Liq. and gas analysis CO_2 %	Liq. and gas analysis H_2S ppm
		*	*															
		SECOND FLOW PERIOD:																
27.06	21.06					16		OPENED WELL FOR CLEAN UP ON 16/64" ADJ. CHOKE										
	21.08	390.4	89.0	96.7	11.3	28		CH. to 28/64" ADJ.										
	21.09	387.7	89.0	88.1	17.7	32		CH. TO 32/64" ADJ.										
	21.16	387.0	89.2	189.2	35.6	32		RATHOLE MUD TO SURFACE.										
	21.17	395.9	89.4	241.3	38.6	52		CHOKE PLUGGING. CH. to 52/64" ADJ.										
	21.18	391.9	89.6	213.1	39.7	48		CH. to 48/64" FIXED.										
	23.52	394.1	99.2	184.3	56.4	48		SWITCHED FLOW THROUGH SEPARATOR								0.4		
28.06	00.30	394.3	99.5	185.4	59.1	48		57.6	24.9	655.4	539.7	1214.3	0.758	0.714				
	00.45	394.3	100.0	185.0	57.6	"		57.1	26.8	657.1	519.2	1265.6						
	01.00	394.3	99.8	184.8	56.6	"		57.4	27.7	656.3	525.6	1248.6					1.0	
	01.15	394.3	99.9	184.9	57.0	"		57.4	28.3	656.3	485.6	1351.5						
	01.30	394.3	100.0	185.6	59.4	"		56.9	28.3	654.5	552.6	1184.5					1.0	<0.5
	01.45	394.4	100.0	185.7	60.1	"		57.1	28.8	650.0	517.7	1255.7						
	02.00	394.3	100.2	186.2	60.9	"		57.2	29.6	647.5	481.2	1345.5						
	02.15	394.7	100.1	185.3	62.3	"		57.1	30.2	647.5	517.7	1250.7	0.758	0.714				
	02.30	394.6	100.1	185.9	60.9	"		57.1	30.7	645.3	533.0	1210.7						
	02.45	394.6	100.2	186.1	61.2	"		57.3	31.0	644.5	537.7	1198.5						
	03.00	394.7	100.2	186.6	61.8	"		57.1	31.2	652.0	483.6	1348.2					1.1	<0.5
	03.15	394.7	100.3	187.0	63.2	"		57.3	31.5	473.0	473.	1374.8	0.758	0.714		0.2		
	03.30	394.7	100.4	187.0	63.1	"		57.1	31.8	650.3	541.3	1201.5						
	03.45	394.7	100.4	187.4	64.0	"		57,2	32.3	654.7	506.0	1294.0						
	04.00	394.8	100.4	187.7	64.6	"		57.1	32.4	654.7	535.4	1222.9					1.1	

Remarks

* Flopetrol gauge SDP 82020 at 2736.50 m.
** 5 intervals perforated. See Diary of events for details.

Well 34/10-17	FLOW DATA	CHP/PG
DST no. 4		Perfs.: 2754-90.5 m
		Zone tested BRENT

1983

Date/ time		Bottom hole press. bar	Bottom hole temp °C	Well head press bar	Well head temp. °C	Chokes 1/64" manifold	Chokes 1/64" heater	Separator data press. bar	Separator data temp. °C	Separator data gas rate $10^3 Sm^3/d$	Separator data oil rate Sm^3/D	Separator data GOR $Sm^3/Sm3$	Separator data sp.gr.oil	Separator data sp.gr.gas (Air=1)	Liq. and gas analysis Water %	Liq. and gas analysis Sedim. %	Liq. and gas analysis CO_2 %	Liq. and gas analysis H_2S ppm
28.06	04.15	394.8	100.4	187.7	64.4	48		57.1	33.1	654.7	502.4	1303.1	0.758	0.714				
	04.30	394.8	100.5	187.7	64.7	"		57.1	33.6	654.7	503.6	1300.1					1.0	<0.5
	04.45	394.8	100.8	187.8	65.0	"		57.1	33.9	653.0	500.1	1305.9						
	05.00	394.9	100.6	188.1	65.6	"		57.2	33.9	653.0	501.3	1302.8					1.0	
	05.15	394.9	100.6	187.9	64.8	"		57.1	33.6	653.0	501.3	1302.8	0.758	0.714		0.9		
	05.30	394.9	100.7	188.2	65.5	"		57.1	34.0	653.0	497.8	1312.1					1.0	
	05.45	394.9	100.7	188.2	65.9	"		57.0	34.0	653.0	502.4	1299.8						
	06.00	394.9	100.8	188.3	66.1	"		57.0	34.6	653.0	497.8	1312.1						
	06.12	394.9	100.8	188.3	66.3			SHUT IN WELL FOR BUILD-UP										
		THIRD FLOW PERIOD:																
	05.05					32		OPENED WELL ON 32/64" FXD CHOKE. FLOWED THROUGH SEPARATOR										
	15.45	397.7	99.5	253.2	51.5	"		56.0	28.1	425.7	341.8	1245.4	0.762	0.714		0.1		
	16.00	397.8	100.0	254.7	55.2	"		55.3	25.4	427.5	347.4	1230.6						<0.5
	16.15	397.7	100.2	255.4	57.3	"		55.1	24.6	427.6	339.6	1259.4						
	16.30	397.8	100.4	255.8	58.9	"		CHANGED METER										
	16.45	397.7	100.4	256.0	60.0	"		55.1	25.6	428.0	331.7	1290.5	0.762	0.715		0.0	1.2	
	17.00	397.7	100.5	256.2	60.8	"		54.9	26.2	430.8	329.5	1307.6						
	17.15	397.7	100.6	256.3	61.4	"		54.9	26.7	429.6	326.1	1317.5						
	17.30	397.8	100.8	256.5	62.1	"		54.9	27.3	429.0	325.0	1320.2					1.1	
	17.45	397.8	100.9	256.6	62.5	"		55.0	28.0	429.2	325.0	1320.7	0.760	0.714			1.2	
	18.00	397.8	100.8	256.7	63.0	"		55.0	28.4	429.7	325.0	1322.2						
	18.15	397.7	100.8	256.9	63.2	"		55.0	28.9	429.7	321.6	1336.0						
	18.30	397.7	100.9	257.0	63.7	"		55.0	29.4	429.1	320.5	1338.9					1.0	
	18.45	397.7	100.9	257.1	63.9	"		55.1	29.9	429.1	322.7	1329.6	0.760	0.714				

Remarks

Well 34/10-17	FLOW DATA	CHP/PG
DST no. 4		Perfs.: 2754 - 90.5m
		Zone tested BRENT

1983 Date/ time	Bottom hole		Well head		Chokes 1/64"		Separator data							Liq. and gas analysis					
	press. bar	temp °C	press bar	temp. °C	manifold	heater	press. bar	temp. °C	gas rate $10^3 Sm^3/d$	oil rate Sm^3/D	GOR Sm^3/Sm^3	sp.gr.oil	sp.gr.gas (Air=1)	Water %	Sedim. %	CO_2 %	H_2S ppm		
28.06 19.00	397.7	100.9	257.2	64.3	32		55.1	30.5	428.5	325.0	1318.7					1.0	0.6		
19.15	397.7	101.0	257.3	64.5	"		55.2	30.4	428.5	326.1	1314.1								
19.30	397.7	100.9	257.3	64.7	"		55.1	30.2	428.0	326.1	1312.4					1.0	0.7		
19.45	397.7	100.9	257.3	64.8	"		55.1	30.2	428.0	322.7	1326.0								
20.00	397.7	101.0	257.4	64.9	"		55.0	30.4	428.0	325.0	1316.8	0.760	0.714			1.0	0.6		
20.15	397.7	101.0	257.4	65.1	"		54.9	30.1	428.0	326.1	1312.4								
20.30	397.7	101.0	257.5	65.2	"		54.9	30.3	428.0	327.2	1307.9					1.1	0.6		
20.45	397.7	101.9	257.6	65.3	"		54.9	30.4	428.0	322.7	1326.0								
21.00	397.7	101.9	257.6	65.4	"		54.8	30.6	428.0	322.7	1326.0	0.760	0.714			1.0	0.7		
21.15	397.7	101.0	257.6	65.6	"		54.8	30.3	428.0	323.9	1321.5								
21.30	397.7	101.1	257.7	65.8	"		54.9	30.7	427.4	319.4	1338.2					1.0	0.6		
21.45	397.7	101.2	257.7	65.8	"		54.8	30.7	427.4	318.3	1342.9								
22.00	397.6	101.1	257.8	65.7	"		54.8	30.7	427.4	319.4	1338.2	0.760	0.714						
22.15	397.6	101.1	257.8	65.9	"		53.7	30.6	429.4	318.3	1349.3					1.0			
22.30	397.6	101.2	257.8	66.0	"		53.7	30.5	429.4	318.3	1349.3								
22.38							SHUT IN WELL FOR BUILD UP.												

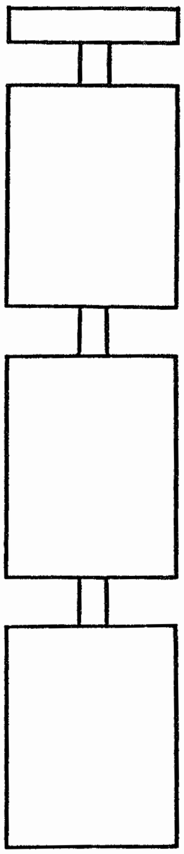
Remarks

Well 34/10-17	LAYOUT OF TEST-STRING	CHP/PG
		Perfs 2754 - 2790.5m
DST no 4		Zone tested BRENT

TEST-STRING	ID inch	OD inch	LENGTH m	DEPTH mRKB
OTIS STT W/X-O 4 3/8" BOX x 3½" TDS PIN				
TOP FIRST JNT TUBING				-7.04
1 JNT 3½" TDS TBG 12.7 LBS/FT L-80	2.75	3.50	9.45	2.41
1 JNT 3½" "	"	"	8.93	11.34
1 X/O 3½" TDS BOX x 4½ ACME PIN	2.80	13/10.75	0.34	11.68
1 OTIS LUBRICATOR VALVE	3.00	6.00	1.61	13.29
1 X/O 4½" ACME PIN x 3½" TDS BOX	2.80	13.00	0.38	13.67
5 STDS 3½" TDS TBG	2.75	3.50	137.88	151.55
1 PUPJOINT 3½" TDS	"	"	2.02	153.57
1 X/O 3½"TDS BOX x 4½ ACME PIN	2.80	6.00	0.21	153.78
1 OTIS SSTT	3.00	13.00	1.78	155.56
1 SLICK JOINT 3½" TDS	2.25	3.50	2.23	157.79
TOP 18 3/4" WELLHEAD 158 M.				-
1 FLUTED HANGER	3.00	12.00	0.30	158.09
1 X/O 4½" ACME PIN x 3½" TDS PIN	2.80	6.00	0.44	158.53
1 PUPJOINT 3½" TBG	2.75	3.50	2.79	161.32
249 (83 STDS) 3½" TBG	"	"	2306.74	2468.06
1 JNT 3½" TBG	"	"	9.30	2477.36
1 X/O 3½" TDS BOX x 3½" IF PIN	"	4.50	0.56	2477.92
1 SLIP JOINT (OPEN)	2.25	5.00	5.54	2483.46
1 SLIP JOINT (CLOSED)	"	"	4.02	2487.48
5 STDS + 1 SINGLE DRILL COLLARS	"	4.75	151.62	2639.10
1 RTTS MECHANICAL CIRC. VALVE	"	4.625	0.90	2640.00
1 STD DRILL COLLARS	"	4.75	28.43	2668.43
1 SLIP JOINT (CLOSED)	"	5.00	4.02	2672.45
1 SLIP JOINT (CLOSED)	"	"	"	2676.47
1 STD DRILL COLLARS	"	4.75	28.43	2704.90
1 APR-M SAFETY CIRC VALVE	"	5.00	2.30	2707.20
1 DRILL PIPE TESTER VALVE	"	5.00	1.46	2708.66
1 LPR-N TESTER VALVE	"	4.625	5.10	2713.76
1 FUL FLOW HYDRAULIC BYPASS	"	"	2.11	2715.87
1 BIG JOHN JAR	"	"	1.59	2717.46
1 RTTS SAFETY JOINT	2.44	5.00	0.95	2718.41
1 RTTS PACKER (ABOVE)	2.40	5.75	0.56	2718.97
1 RTTS PACKER (BELOW)	2.40	"	0.82	2719.79
1 PERF. 2 7/8" FULL EUE (PINUP)	2.44	2.88	9.45	2729.40
X-O 2 7/8 " EUE PIN x 2 3/8" EUE BOX	2.00	3.25	0.25	2729.49
1 OTIS XN-NIPPLE (PIN x PIN)	1.79	"	"	2729.74
1 2 3/8" EUE COLLAR	2.00	2.38	0.14	2729.88
1 X-O 2 3/8" EUE PIN x 2 7/8" EUE PIN	2.44	4.15	0.18	2730.06
1 2 7/8" EUE FULL JOINT	"	2.88	9.44	2739.50
1 S.O.S DST-HANGER	-	-	-	-
1 2 7/8" EUE FULL JOINT	2.44	2.88	9.35	2748.85
Remarks. 1 BULL-PLUG w/CROSS 2 7/8" EUE BOX	"	3.25	0.15	2749.00

All measurements to bottom of each item.

Well 34/10-17	GAUGE ARRANGEMENT	CHP/PG
		Perfs.: 2754-90.5m
DST no. 4		Zone tested BRENT

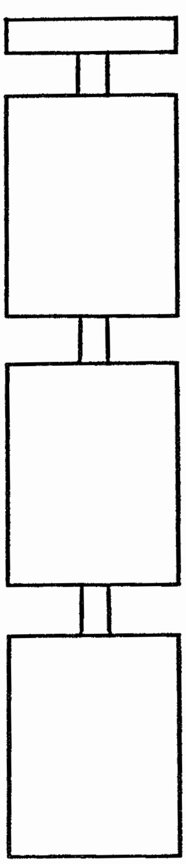


WIRELINE NIPPLE at 2729.74 **mRKB**

Gauge type and number : Sperry Sun MK III 0051
Depth, pressure elemement : 2732.77 m   Range : 690 bar
Mode : 2 min   Delay : 17 hrs.
Actuated : time 00.13   date : 27.06.83
Will run out : time 01.13   date : 30.06.83

Gauge type and number : Flopetrol SDP 82020
Depth, pressure elemement : 2736.50 m   Range : 690 bar
Mode : 30 sec.   Delay : 17 hrs
Actuated : time 00.10   date : 27.06.83
Will run out : time   date :

Gauge type and number :
Depth, pressure elemement :   Range :
Mode :   Delay :
Actuated : time   date :
Will run out : time   date :



D.S.T. HANGER at 2739.50 **mRKB**

Gauge type and number : Sperry Sun MK III 0184
Depth, pressure elemement : 2742.63 m   Range : 690 bar
Mode : 4 min   Delay : 17 hrs.
Actuated : time 00.10   date : 27.06.83
Will run out : time 09.10   date : 02.07.83

Gauge type and number : Sperry Sun MK III 0222
Depth, pressure elemement : 2745.61   Range : 690 bar
Mode : 2 min   Delay : 17 hrs.
Actuated : time 00.11   date : 27.06.83
Will run out : time 01.11   date : 30.06.83

Gauge type and number :
Depth, pressure elemement :   Range :
Mode :   Delay :
Actuated : time   date :
Will run out : time   date :

Well 34/10-17	SAMPLING	CHP/PG
DST no 4		Perfs.: 2754-90.5m
		Zone tested BRENT

SEPARATOR SAMPLES

Time/date	Sample no.	Type of sample	Transfer time	Bottle no
28.06.83			mins	
03.18	1	Condensate	30	SOS 112
03.18	2+3	Gas	30	SOS 1004+1009
04.06	4	Condensate	26	SOS 107
04.06	5+6	Gas	26	SOS 1001+1008
19.07	7	Condensate	41	SOS 109
19.06	8+9	Gas	43	SOS 1023+1047
20.10	10	Condensate	41	SOS 102
20.11	11+12	Gas	41	SOS 1048+1034

BOTTOM HOLE SAMPLES (NONE)

Time/date	Sample depth mRKB	Estimated PB bar/°C	Transfering pressure(bar)	Bottle no

WELLHEAD SAMPLES/OTHER SAMPLES

Time/date	Sampling point	Sampling equipment		Remarks
28.06.83				
02.20 to 05.17	Goose-neck	Glass-jar	6 x 1 l	Condensate
06.20	Separator	Jerry-can	1 x 10 l	"
06.30	"	Jerry-can	1 x 20 l	"
21.00 to 21.30	Goose-neck	Glass-jar	6 x 1 l	"
23.00	Separator	Jerry-can	1 x 10 l	"
23.05	"	"	"	"
23.30	"	Barrel	1 x 200 l	"

7. REFERENCES

1. Petrophysical Evaluation Report Well 34/10-17, Statoil
2. FMT Report Well 34/10-17, Statoil
3. PVT Analysis of BHS Well 34/10-17 DST No. 2, Statoil
4. Condensate Study (PVT) Well 34/10-17 DST No. 3, Expro
5. Condensate Study (PVT) Well 34/10-17 DST No. 4, Expro

Other reports used:

Otis: Well 34/10-17, DST 1,2,3 and 4

Flopetrol: High Accuracy Pressure Temperature Measurements Reports for
DST No. 1 (gauge SDP 82009)
DST No. 2 (gauge SDP 82020)
DST No. 2 (gauge SDP 82009)
DST No. 3 (gauge SDP 82002)
DST No. 4 (gauge SDP 82020)

Sperry Sun: Pressure Survey Reports for
DST No. 1 (gauges 0151 and 0100)
DST No. 2 (gauge 0151)
DST No. 3 (gauges 0222 and 0181)
DST No. 4 (gauges 0151 and 0222)
DST No. 1 Surface Pressures
DST No. 2 Surface Pressures
DST No. 3 Surface Pressures
DST No. 4 Surface Pressures

Corelab: Wellsite Gas and Water Analysis, Well 34/10-17

Statoil: Water Analysis Reports, Well 34/10-17 DST No. 1

Geco: Routine Core Analysis, Well 34/10-17

APPENDIX 1

Cement Bond Quality

The cement bond log ran after the setting and cementing of the 7" liner showed fair to poor bond between the liner and the formation in all the intervals to be production tested.

To improve the cement bond and thereby isolate the test zones from other permeable zones, four block squeezes were performed:

Block squeeze no.	Depth
1	2926m (above DST 1 interval)
2	2893m (below DST 2 interval)
3	2845m (at btm. of DST 3 intv.)
4	2754m (at top of DST 4 intv.)

Cement bond logs were run after each of the block squeezes. Figures A1-1 through A1-8 show the cement bond logs ran before and after the block squeeze for Block squeeze/DST zone no. 1,2,3 and 4 respectively. The logs show that the block squeezes improved the cement bond substantially for all the zones of interest.

Excellent bond is observed across, above and below the test zones 1 and 3. These zones are then isolated and it is therefore assumed that no production or pressure response from other zones occured during the test. Also for test zone 2 a good bond is seen across, above and below the tested zone. However, the very top of the zone (2777.5 - 78.0) is not covered with a good cement bond. Flow from zones above is therefore possible. The block squeeze at the top of test zone 4 also resulted in a good bond at the top and above this zone while the bond quality below the zone is questionable (figure A1-8). It is therefore possible that the produciton zones between 2790.5m (lowest DST 4 perforation) and 2813m (top of good cement above DST 3 zone, see figure A1-6) could have contributed to the DST 4 production and pressure reponses.

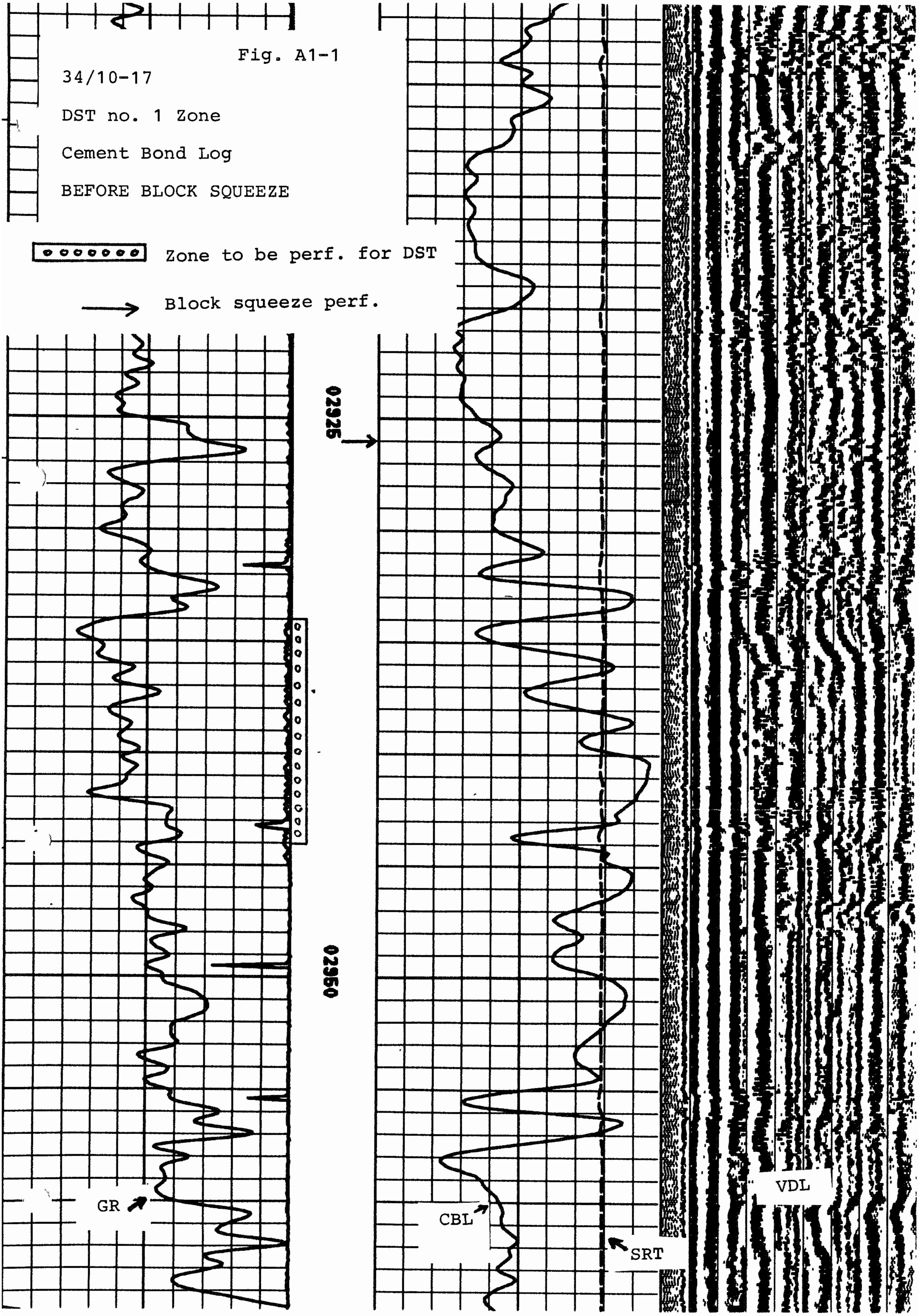


Fig. A1-1
34/10-17
DST no. 1 Zone
Cement Bond Log
BEFORE BLOCK SQUEEZE
Zone to be perf. for DST
Block squeeze perf.
02925
02950
GR
CBL
SRT
VDL

34/10-17

Fig. A1-2

DST no. 1 Zone

Cement Bond Log

AFTER BLOCK SQUEEZE

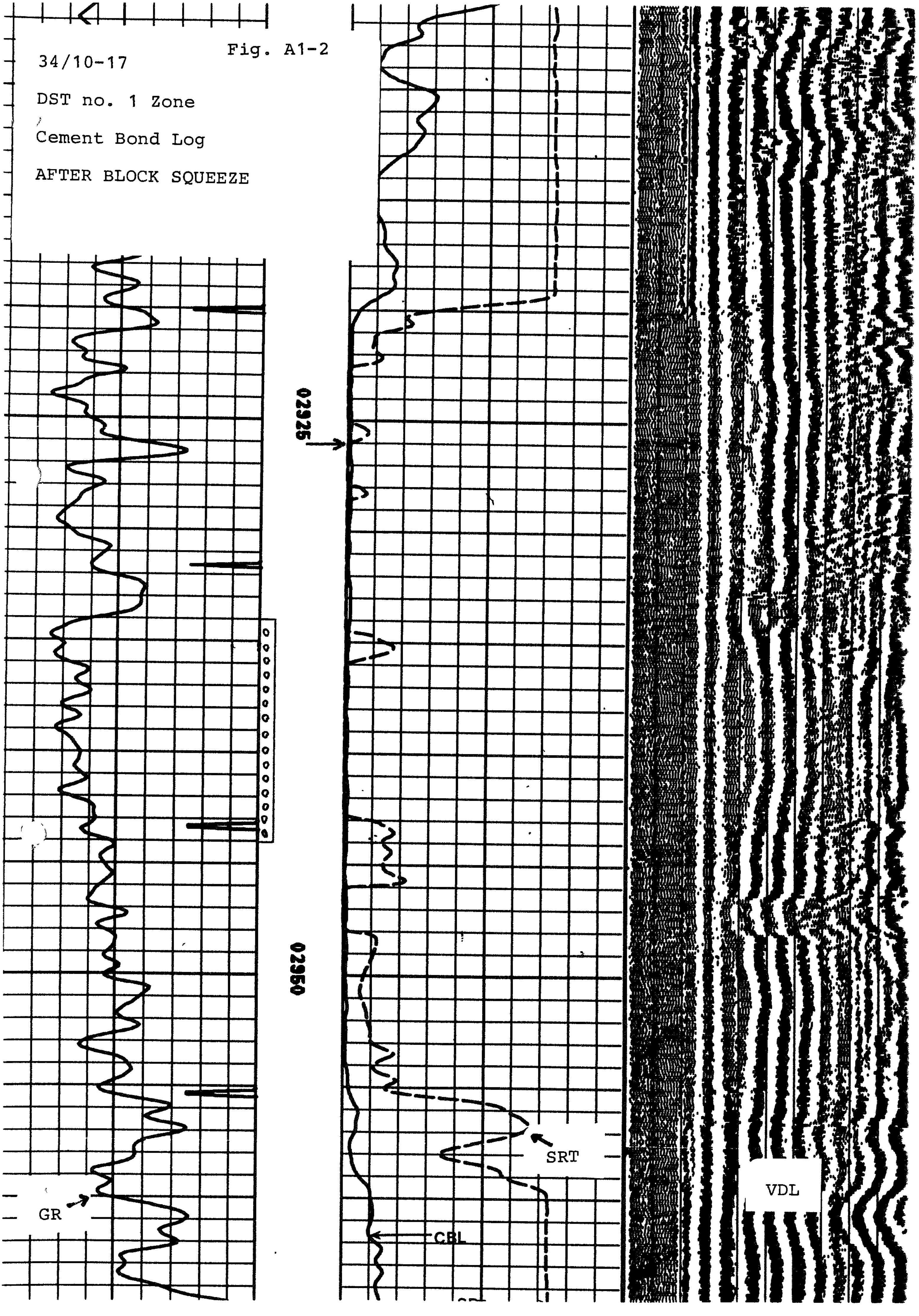


Fig. A1-3

34/10-17

DST no. 2 Zone

Cement Bond Log

BEFORE BLOCK SQUEEZE

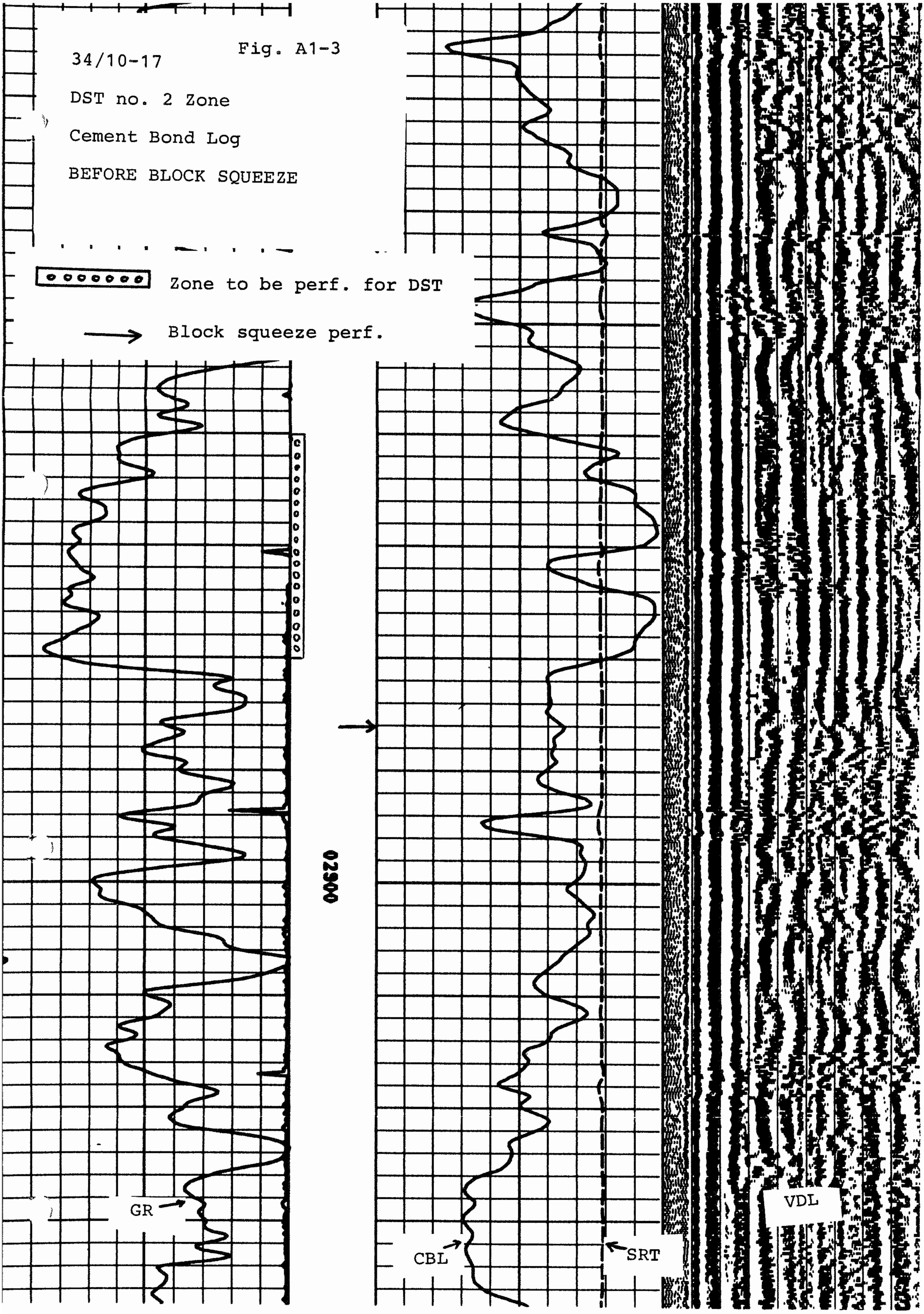


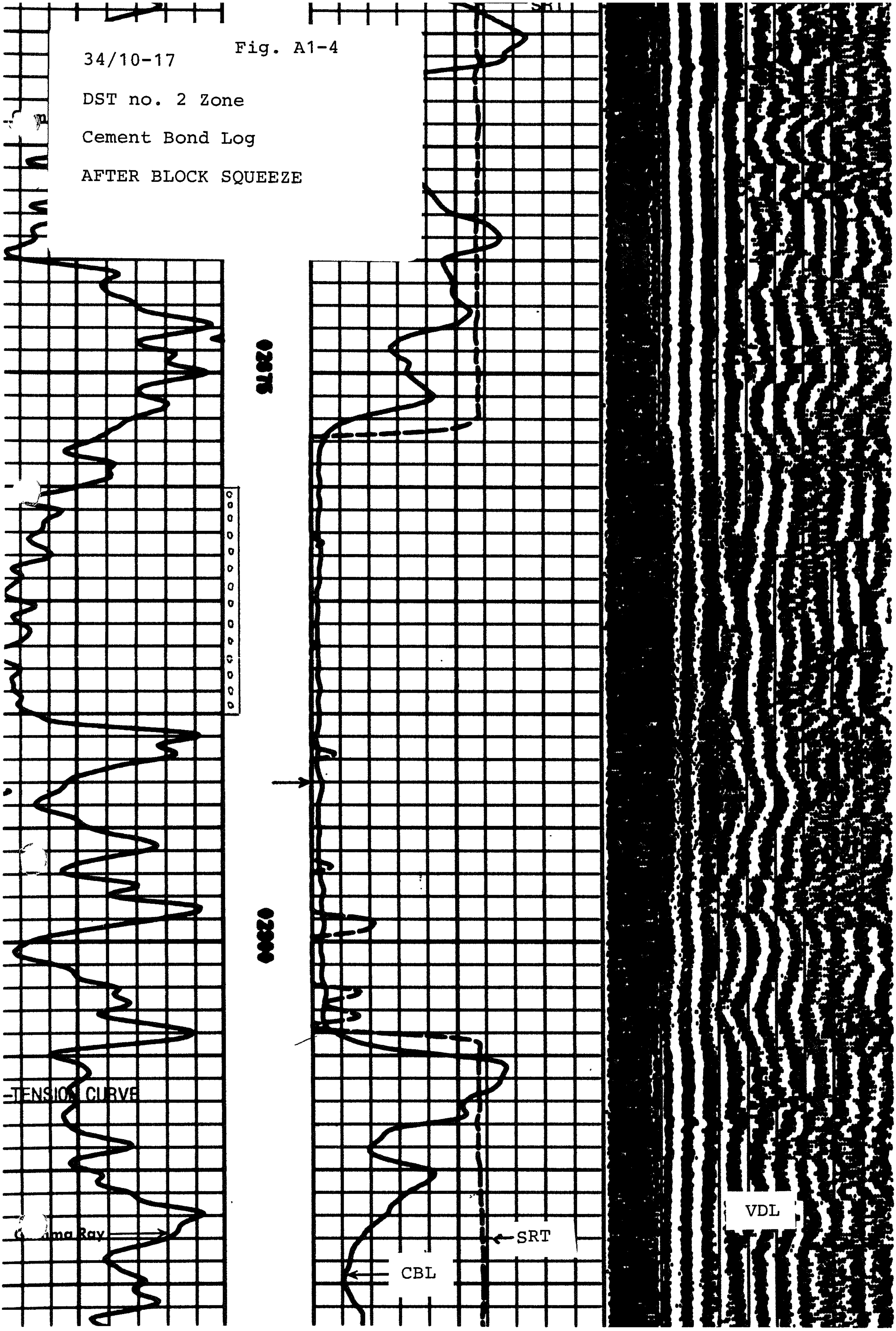
Fig. A1-4

34/10-17

DST no. 2 Zone

Cement Bond Log

AFTER BLOCK SQUEEZE



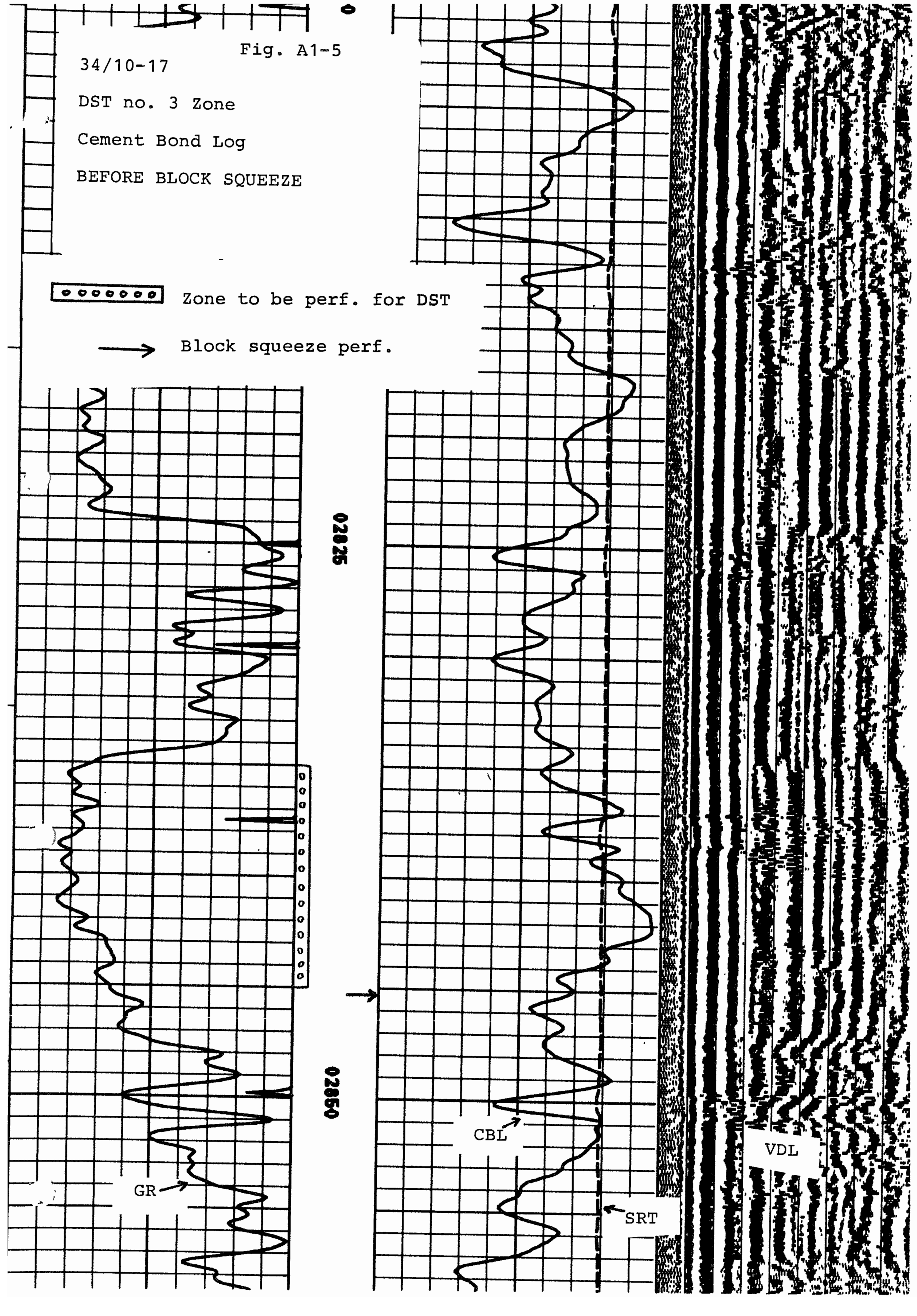


Fig. A1-5

34/10-17

DST no. 3 Zone

Cement Bond Log

BEFORE BLOCK SQUEEZE

Zone to be perf. for DST

Block squeeze perf.

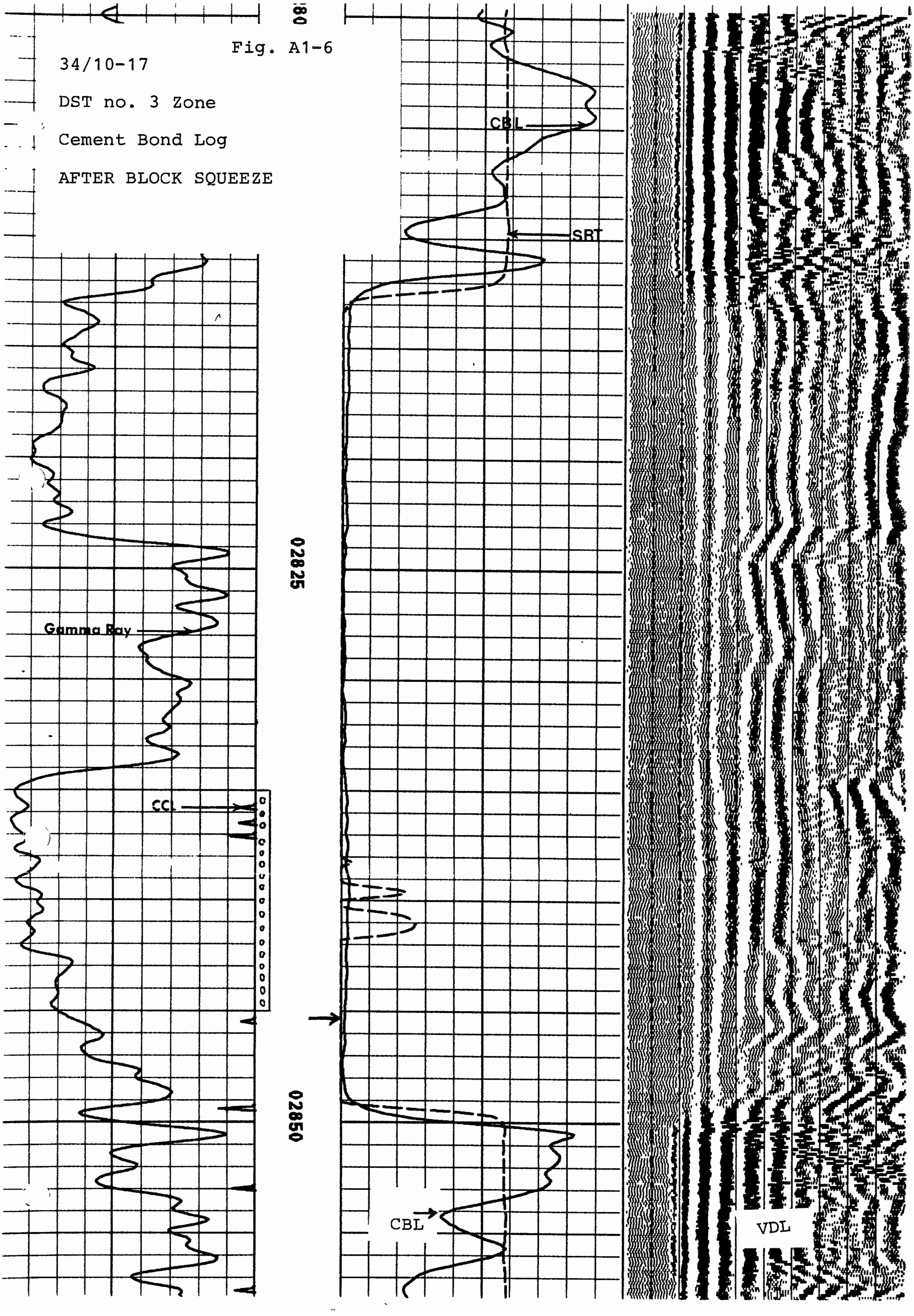


Fig. A1-6
34/10-17
DST no. 3 Zone
Cement Bond Log
AFTER BLOCK SQUEEZE
02825
02850
Gamma Ray
CCL
CBL
SBT
CBL
VDL

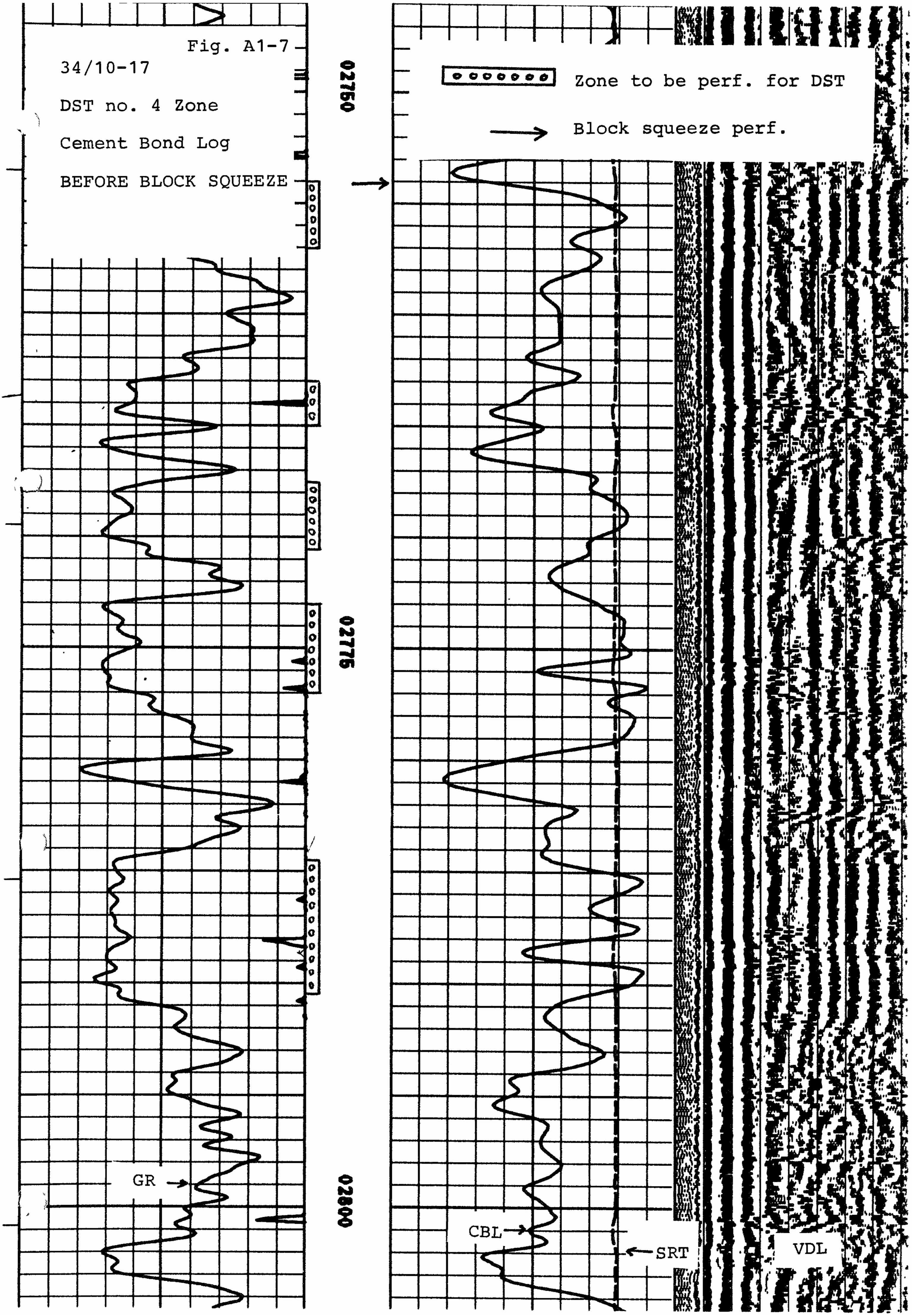


Fig. A1-7
34/10-17
DST no. 4 Zone
Cement Bond Log
BEFORE BLOCK SQUEEZE
Zone to be perf. for DST
Block squeeze perf.
02750
02775
02800
GR
CBL
SRT
VDL

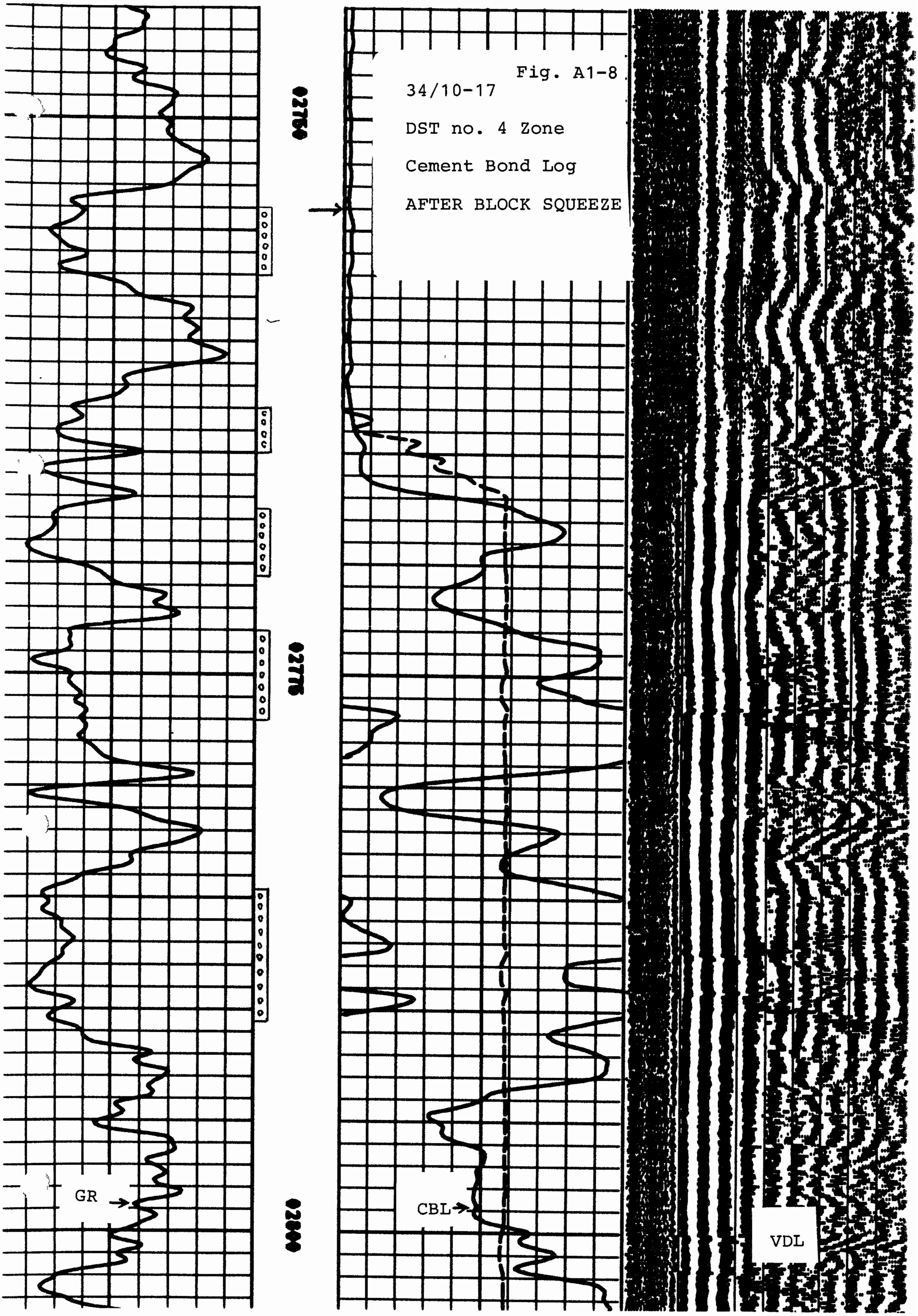


Fig. A1-8
34/10-17
DST no. 4 Zone
Cement Bond Log
AFTER BLOCK SQUEEZE
GR
CBL
VDL