PL 044

D-19

statoil

1/9-3

TEST REPORT

OCT. - 1978

statoil

KNE/NHC/EAA

31.10.78.

SECTION FOR EVALUATION TECHNOLOGY

PRODUCTION DEPARTMENT

STATOIL

1/9-3

TEST REPORT

OCT. - 1978

TABLE OF CONTENT

1. INTRODUCTION

This is the test report from 1/9-3. The test was carried out on Dyvi Beta from end August to the 22nd of September.

The report is preliminary in the respect that analysis is based on field readings of pressure, the final CPI log was not available and fluid data, for instance, may be refined in the future. However, it is felt that such refinements may only to a very limited degree alter the conclusions derived.

Flopetrol has been the test operator. The test report from Flopetrol was issued on the 23rd of October. In their report the Nm^3 of gas is referred to 1 bar and 0^oC.

The report is organized as follows:

Chapter 2 gives a summary of the test analysis technique applied for 1/9-3. Formulas are referred. Then a summary of ' results derived from each individual test is given.

Chapter 3 represents an integration of the results obtained from the test. Pressure, temperature and permeability profiles are indicated as derived from the test. The stimulation effectiveness and total well productivity is also given.

A complete presentation of each individual test is given in appendix 1 - 4. These appendixes may be read independently of each other and of the main report. At the end of each appendix is given a summary of fluid- and petrophysical properties used in the analysis.

The test analysis is based on STATOIL test analysis program package.

2. INTERPRETED TESTRESULTS.

2.1 Test analysis technique.

The well is analyzed as a single well in an infinite reservoir as no boundary effects have been observed.

The analysis is complicated by the possibility that hydraullic fractures may have developed. Natural fractures, which behave as hydraullic fractures,may also be present. For this reason, one have in the analysis, to watch for indications of linear flow. If such flow pattern in the early time region, the traditional semilog straight line may not always be applied rigorously. Then type curve matching may be the only way to derive formation properties.

In general, these are the steps followed in the analysis:

1) A plot of pressure vs. time to check if the data are smooth without any irregularities.

2) A plot of p vs. $\sqrt{t}$. A straight line in this plot indicates linear flow. This line defines:

   - a slope mvf which may be used to calculate fracture length.

   - the intercept pi with the pressure axis which may be used as estimate of wellbore pressure when the flow started.

   When the Horner slope m is defined, the fracture half length xf is given by:

$$xf = \frac{0.3187}{mvf} \cdot \sqrt{\frac{mqB}{\phi cth\ Fcor}}$$

   Fcor is close to 1 in our cases and are ignored.

   The correct straight line in this plot is generally verified by the log Δp vs. log Δt plot.

3) Then a field plot of log Δp vs. log Δt is generated.

This plot is used to recognize a - 1 slope indicating wellbore storage or a - ½ slope indicating a linear flow pattern. There is a certain pressure inaccuracy in the early period of the field plot which may disturb this recognition.
The field plot is matched on to the type curve giving the best match. The following type curves are applied:

- homogeneous formation with skin effect and wellbore storage.

- vertical fracture with infinite fracture conductivity.

- uniform flux vertical fracture.

Generally we find the uniform flux vertical fracture type curve to be the most applicable one.

The match is used for two reasons:

- to judge if a semilog straight line analysis is applicable. The following rules are used:

  a) the top of the unit slope straight line on a log - log graph is about 1 and ½ log cyde prior to start of the correct semilog straight line.

  b) the dimensionless pressure at the start of the semilog straight is about twice the dimensionless pressure at the top of the one-half slope line.

- to derive kh and xf from a proper match point by the following equations:

$$pd = \frac{kh\Delta p}{141.2\ qB\mu}$$

$$tdxf = \frac{0.000264\ kt}{\phi\mu\ ct\ xf^2}$$

4) A p versus log ($(t+\Delta t)/\Delta t$) is generated. Straight lines are drawn by the least square method between points which according to 3) are on a horner line. The following is calculated:

$$kh = 162.6 \frac{qB\mu}{m}$$

$$s = 1.1513 \left[\frac{p1hr - pwf\ (\Delta t = 0)}{m} + \log \frac{tp + 1}{tp} - \log \frac{k}{\phi \mu ct rw^2} + 3.2275\right]$$

$$\Delta ps = 141.2 \frac{qB\mu}{KH} S = 0.87\ ms$$

Unless otherwise specified, a permeability k is based on a formation thickness equal to the associated perforations.

When fractures have developed and the xf is calculated, the assiciated skin may for 1/9-3 be estimated by:

$$xf = rwe^{-s}$$

The drainage radius rd defines the extent of the pseudosteady-state pressure disturbance:

$$re = 0.029 \sqrt{\frac{kt}{\phi \mu ct}}$$

2.2 DST # 1 results.

Pure water was produced with a cl - content 41000 ppm.
The following results were obtained:

WELL 1/9-3	Build-up no.1	Build-up no.2
p*(psi) at depth 3200.4 m	7026.1	7037
max. temperature ^{o}F	231.4	256.6
kh (md·ft) from Horner	28	338.6
k (md) from Horner	.94	11.5
Skin s	- .4	2.4
rd (ft)	18	310
xf(ft) from square root plot		44
xf(ft) from type curve match		33
kh(md·ft) from type curve match		456
k(md) from type curve match		12
Δps (psi)		648
Flow efficiency		.73

2.3 DST # 2 results.

The well produced water with about 5% oil. It was very difficult to measure oil properties because of emulsion problems, however, the gravity was considered to be at least 35° API.

The formation water produced had a maximum cl- content of 46000 ppm.

The following results were obtained:

	Build-up no.1	Build-up no.2
px (psi at depth 3.125.9 m	7041.3	7045.9
max. temperature (°F)	226.2	252.7
kh (md·ft) from Herner	37.4	104
k (md) from Horner	.5	1.4
Skin s	.5	1.0
rd (ft)	11	84
Δps (psi)		630
Jactual/Jideal		.84
Jactual (BWPD/psi)		.35

2.4 DST # 3 results.

The test gave a daily production less than 20 BBl/D. It is difficult to judge what kind of fluids the interval might produce, but traces of oil and gas were observed.

	Build-up no.1	Build-up no.2
p* (psi) at depth 3114.9 m RKB	7017	
max. temperature (°F)		233.6
kh (md·ft from Horner	.52	
k (md) from Horner	.18	
Skin s	- .17	

2.5 DST # 4 results.

This zone is believed to have the potential of producing hydrocarbons with no watercut. The oil had a gravity 50-53% API and the gas had a spesific gravity .70 relative to air. The gas oil ratio varies between 6.500 and 15.000 SCF/STB.

The following results were obtained:

PRE FRACTURE ACIDIZING

	Build-up no. 1			
	gas is flowing	water is flowing	Drawdown no.2	Build-up no.2
p* (psi) at depth	7026	7026		7126
max. temperature during flow °F				
kh (md·ft) from Horner	12.1	140	84.5	17.2
k (md) from Horner	.21	2.37	1.43	.3
Skin s	10.5	10.3		1.0
rd (ft)	13	15.8		
xf (ft) from square root data plot	.			
Gas in flowing, k = .5 md			3	

POST FRACTURE ACIDIZING

	Drawdown no.3	Build-up no.3	Drawdonw no.4
p* (psi) at depth		6895	
kh (md·ft) from Horner		33	
k (md) from Horner		.56	
Skin s		-4.1	
xf (ft) from square root data plot			
k = .5 md	61		
kh (md·ft) from type match	32.2	77	
k (md) from type match	.55	1.3	
xf (ft) from type match	55		
kh = 26 md·ft			128
kh = 40 md·ft			102

3. INTEGRATION OF THE INDIVIDUAL TEST RESULTS

3.1 Formation pressure.

The initial build-ups have been analyzed. All gauges available have been applied. The results are given below:

Gauge	36405	36396	41611	41677	average
DST no. 1		7024.2			
DST no. 2	7011.1	7021.3	7044.5		7025
DST no. 3	7016.9			7012.6	7015
DST no. 4	6966.2	7030.0		6967.6	6986

p*(psi) from the initial buildup

The avarage valves are plotted versus depth. Only one value is available from the DST no. 1, and this value seems to be a little low.

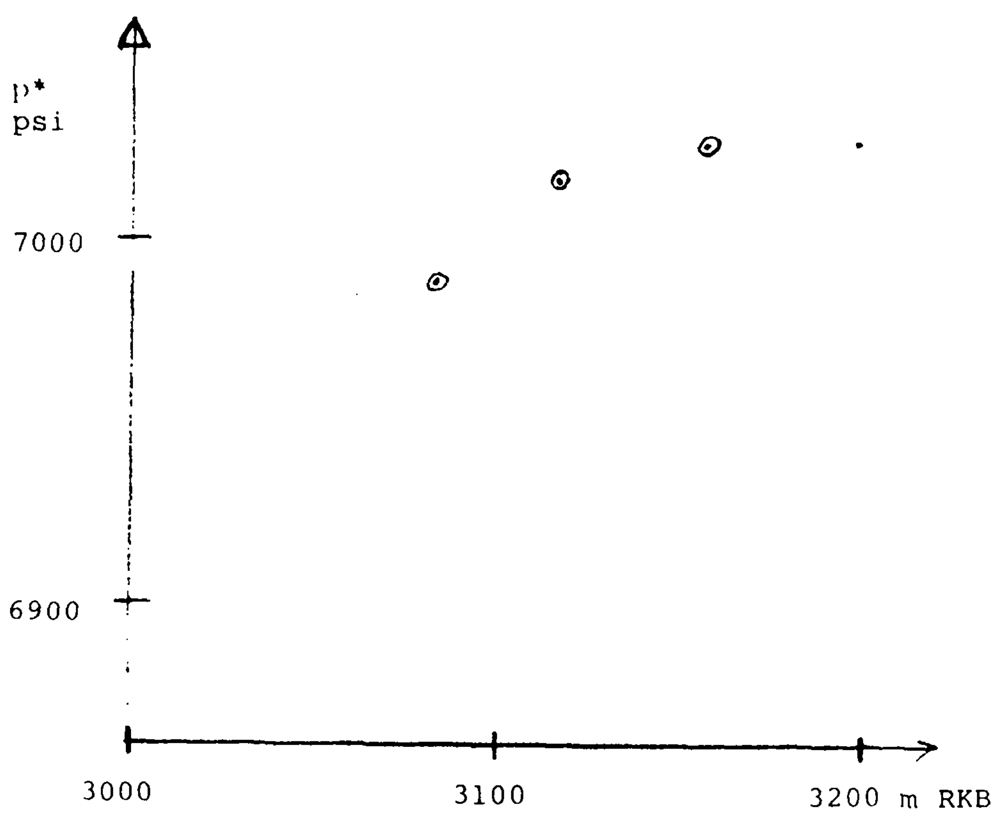


Fig. 1 p*(psi) versus depth (m RKB)

1/9-3 indicates the following formation pressures:

- 7000 psi at 3100 m RKB in the Ekofisk formation

- 7030 psi at 3160 m RKB in Tor formation

There is no reason to believe that there is a pressure barrier between the Tor and the Ekofisk formations.

3.2 Permeability.

The permeability derived form a test is not directly comparable with those from conventional core analysis.

Core permeabilities should be converted to reservoir conditions by the following corrections:

- overburden effect
- reservoir temperature
- saturation distribution in the rock
- averaging of point permeabilities

The derivation of a test permeability from 1/9-3 implies the following problems:

- what is the contributing h
- to what extent does saturation changes (liquid drop out) influence the flow
- what kind of permeability

Throughout this report it is assumed that the height of the producing perforations are contributing to flow. At the end of each appendix, the maximum contributing thickness is indicated. These two values of h defines the followings of permeabilities:

	kh	Perforated thickness		Max. thickness	
	[md·ft]	h[ft]	k[md]	h[ft]	k[md]
DST 1	339	29.5	11.5	89	3.81
DST 2	104	75	1.39	135	.77
DST 3	.52	29.5	0.018	-	-
DST 4	30	59	.5	104	.29

Several factors are involved in the calculation of k which are a little bit conservative, and it is felt that some allowance is already made for a h slightly larger than the perforated interval.

DST 1 and 2 produced water with a fairly large hydrocarbon saturation present. Flow performance, logs and special core analysis suggest that Tor may be a flooded reservoir.

Waterflood tests on plugs from 1/9-1 indicate the following:

- the oil permeability with irreducible water saturation is about 1/3 of the measured air permeability.

- the water permeability at terminal conditions are about 1/10 of the corresponding air permeability, i.e. a further 1/3 reduction of the oil permeability at irreducible water saturation.

- the residual oil saturation at terminal conditions may be in the range 20% - 30%.

The derived permeabilities may now be interpreted in the following way:

DST 1: Pure water was produced and we may assume end point conditions on the relative permeability curve. A krw (Sor) = 11.5 md implies kro (Siw) of the order 35 md. On the other hand, this permeability must imply a certain amount of natural fractures which increases the uncertainty concerning h.

DST 2: About 5% of the liquid stream was oil. This means that we have not completely reached the end point of the waterflood curve.

Thus:
- a factor slightly larger than three should be used to correct from krw (Sor) to kro (Siw).
- analysis is based on water as the single flowing phase which implies that the base krw(Sor) may be a little bit to high.

These two factors work in different directions and a factor of 3 is still used.

A krw (Sor) = 1.4 md implies a kro (Siw) of the order 4.5 md.

It is difficult to judge the permeability derived from DST 3, but it is probable that the same arguments may be applied as for DST 1 and 2.

DST 4 produced hydrocarbons only. If the k from analysis of drawdown no. 2 is ignored, a krg (Siw) of the order .5 md in a gas-water system is apparent.

If both Ekofisk and Tor had been filled with hydrocarbons, the following reservoir capacities might have been expected:

Test interval	DST 1	DST 2	DST 3	DST 4
kh [md·ft]	1017	312	1.5	30

3.3 Reservoir temperature.

The highest reservoir temperatures observed in the wellbore during each DST, is indicated in fig. 2.

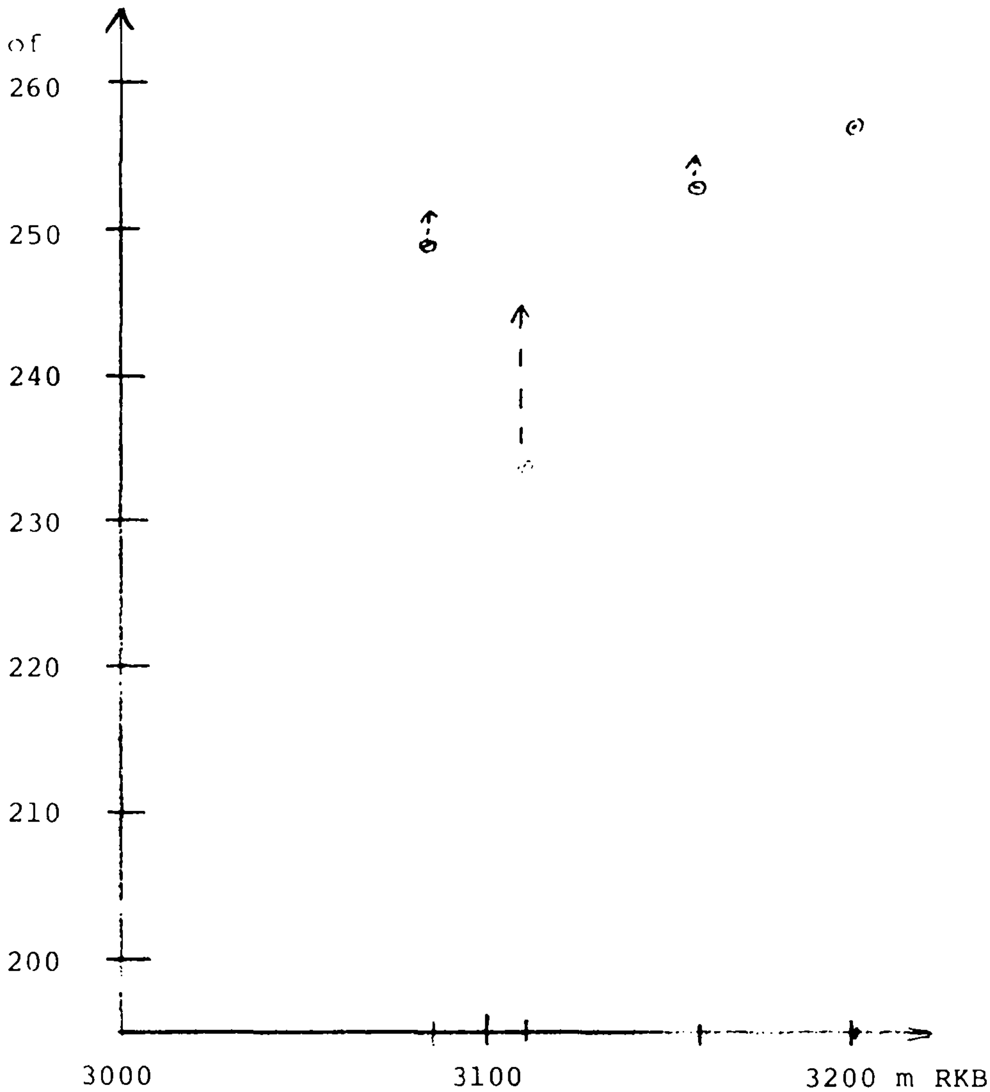


Fig. 2

The base temperature point is the one at depth 3201 m RKB. The following comments are made:

DST no. 1: This temperature is close to stabilized. The temperature increased only 1°F the last 6 hours and .1°F the last hour of flow. Water is a good heat conductor.

DST no. 2: The temperature was increasing .6°F the last hour of flow. It is felt, however, that this temperature is close to a representative level.

DST no. 3: The flow was never sufficient to bring the temperature to a representative level.

DST no. 4: During the 3. flow the highest temperature recorded was 248.2^{O}F in the middle of the flow period. Then the temperature dropped, probably due to cooling by gas expansion.

The shut in temperature was 246^{O}F. Then the temperature increased and reached a high of 248.7^{O}F.

3.4 Skin and total well capasity

On a general basis, the skin observed have the following properties:

- the initial skin may be as high as +10
- after a cleanup and before stimulation, the skin is found to be in the range 1-0
- after frature acidizing, -4.5 is a typical skin.

Capasities for the individual test zones are discussed earlier. The 4 test intervals may, if added together, represent the total well capacity. On the other hand, some of the well capasity may not have been investigated by the 4 test intervals. It is therefore believed, that 473 md·ft represents a minimum estimate of "observed" well capacity, while 1358 md·ft represents a minimum hydrocarbon filled well capacity.

	DST 1	DST 2	DST 3	DST 4	Sum
kh[md·ft]as observed	338.6	104	.52	30	473
kh[md·ft]filled with hydrocarbons	1017	312	1.5	30	1348

3.5 Natural fractures

The following table gives a permeability comparison. There is estimated an arithmetic average of the liquid permeabilities over each perforated interval. This average value is converted to a reservoir matrix average permeability by a factor .5 which is derived as follows (from 1/9-1 data):

kair/k liquid = 1.43
k(Siw)/kair = .33

For low permeabilities, the overburden effect is limited. This correction is ignored. The combined effect:
k (Siw)/k liquid = .47 or.5

The complete test intervals are not covered by core data, and there are considerable relative uncertainties associated with the average liquid permeability for each test interval.

Zone	DST 1	DST 2	DST 3	DST 4
Average liquid perm. [md]	1.8	1.0	-	1.2
Reservoir matrix perm [md]	.9	.5	-	.6
test perm., h equal to perf.[md]	11.5	1.39	0.018	.5
test perm., max. h [md]	3.81	.77	-	.29
hydrocarbon-filled perm.,h equal to per [md]	35	4.5	.05	.5

The table above indicates:

- natural fractures must definitely contribute to flow in the DST 1 interval
- there may be a very slight enhancement of permeabilty over the DST 2 interval.
- no natural fracturing contributes to the flow in DST 3 and 4.

3.6 Fracture acidizing

DST 4 interval was fracture acidized in two steps:

- 1. stimulation: stage 1 only of the planned program due to technical problems

- 2. stimulation: the complete program

A long flow was planned after the stimulation, however, this was not achieved. The following is an extrapolation of the flow performance after stimulation.

From the test analysis:

1. stimulation: x_f = 55ft
2. stimulation: x_f = 105ft

Assume:

q = 20 MMSCFD
$B_g = 750 \times 10^{-6}$ resbbl/SCF
μ_g = .040 cp
ϕ = .321
$C_t = 66.4 \times 10^{-6}$/psi
kh = 35 md·ft

The constant flux hydraullic fracture type curve is used to generate the flowing wellbore pressure as shown in fig. 3.

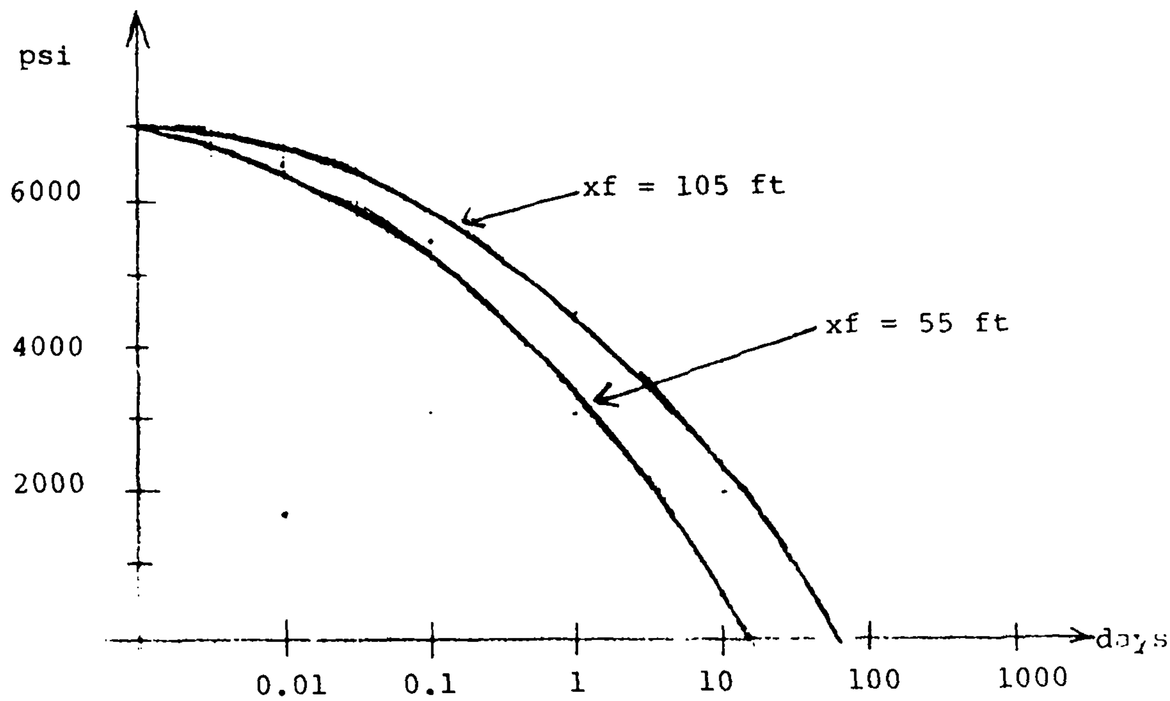


fig. 3

The flowing wellbore pressure is for both fracture half lengths,dropping and is never stabilizing.

If however, the well capacity is increased to 118 md·ft, the wellbore flowing pressure will be as indicated in fig. 4 for a rate 20 MMSCFD.

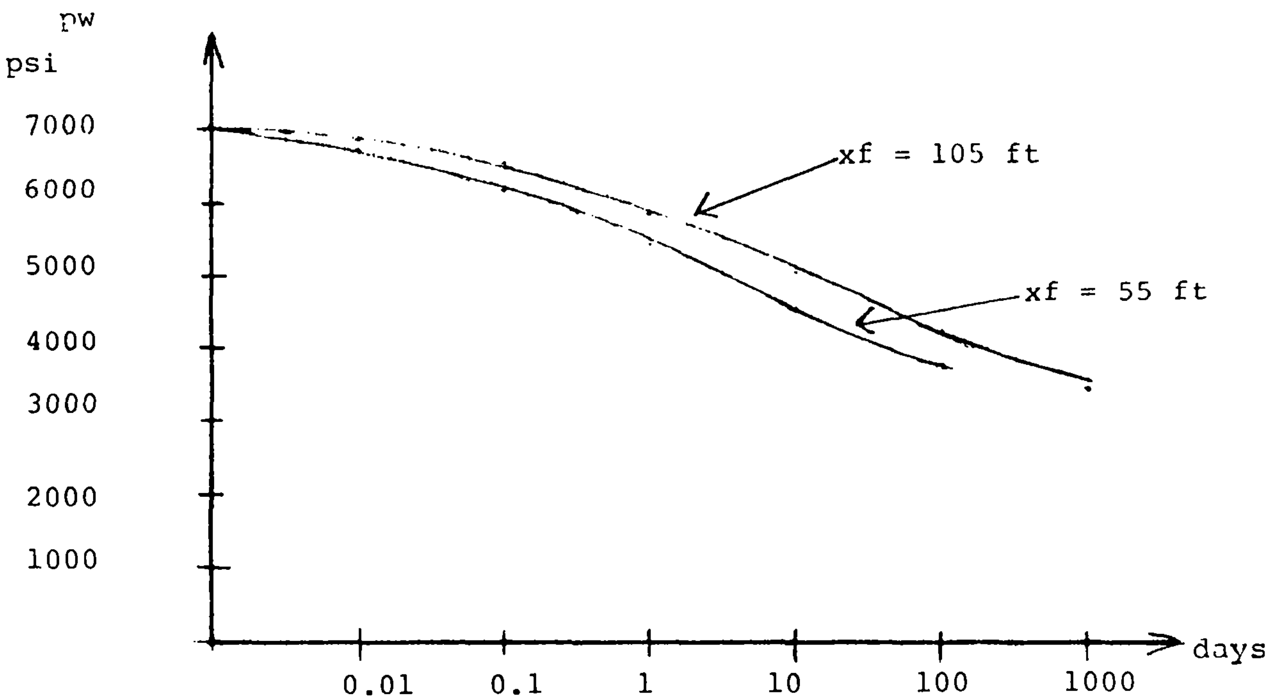


fig. 4

One may conclude:

- 35 md·ft is a too small well capacity even with an xf = 105 ft, to deliver 20 MMSCFD over some time.

- a well capacity of 118 + md·ft with an xf = 105 ft may give a long lasting 20 MMSCFD producer.

3.7 Hydrocarbon GOR

Hydrocarbons were brought to surface from two zones, DST 2 and DST 4.

DST 2 gave small oil and gas rates in conjunction with water. It was difficult to measure the oil rate due to emulsion, but an oil fraction of 5% of the liquid stream is thought to be a representative estimate. The gas rate was in the range .17 MMSCFD. This gives a GOR of 2500 SCF/STB.

After stimulation, DST 4 gave a gas/oil ratio which increased over time. Unfortunately, it was not possible to get a GOR measurement immediately when the well was opened . This complicates th estimate the initial GOR .

Figs 5 and 6 show GOR versus time for flow 3 and 4. It looks like the initial GOR might have a value 5000 SCF/STB or less.

Fig. 7 shows a plot of GOR versus wellbore flowing pressure for flow no 3 and 4. The dotted lines represent an attempt to extrapolate the trend. The extrapolated curves intercept each other at a GOR 4500 SCF/STB.

On this basis, it is thought that the Ekofisk formation fluid might have a GOR in the range 4500-5000 SCF/STB.

1/9-3 test data indicates that the GOR is varying with depth. This is also consistent with 1/9-1 data.

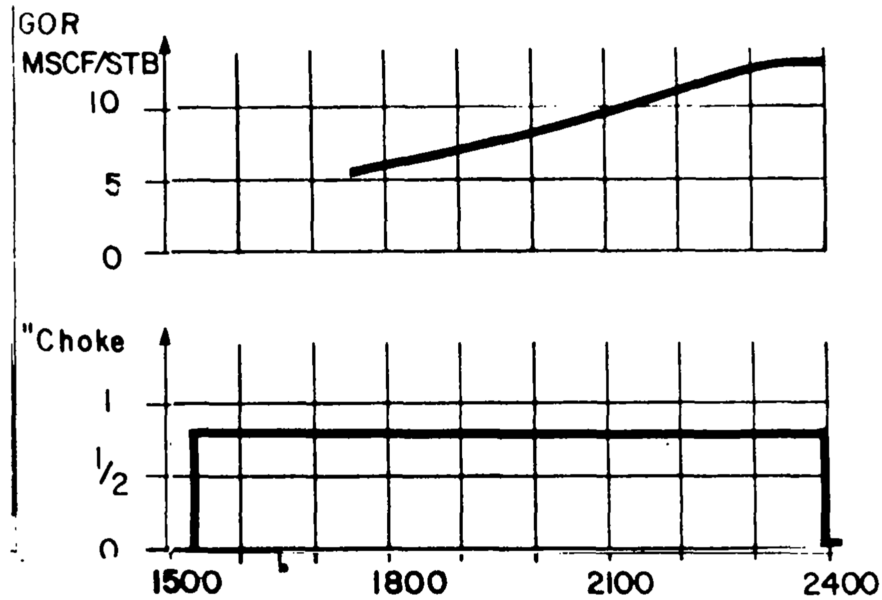


Fig. 5 DST 4 flow 3

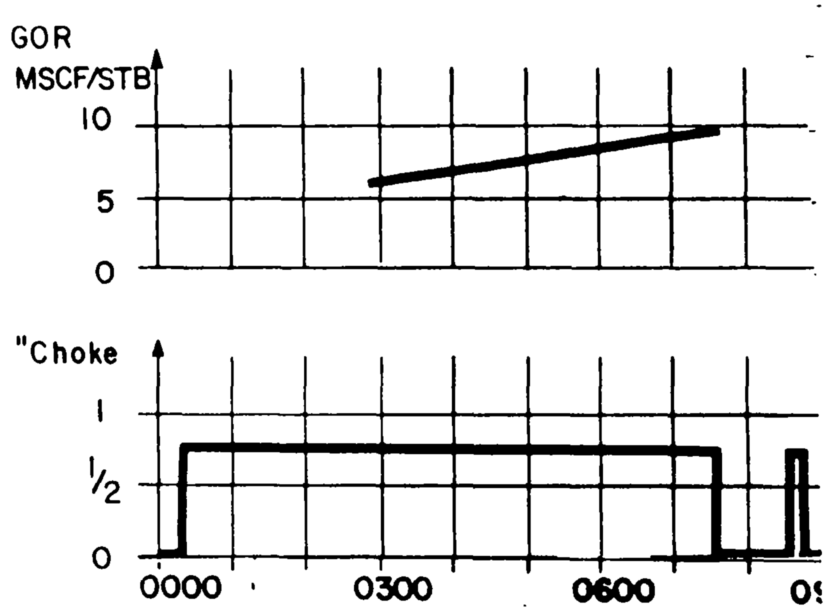


Fig. 6 DST 4 flow 4

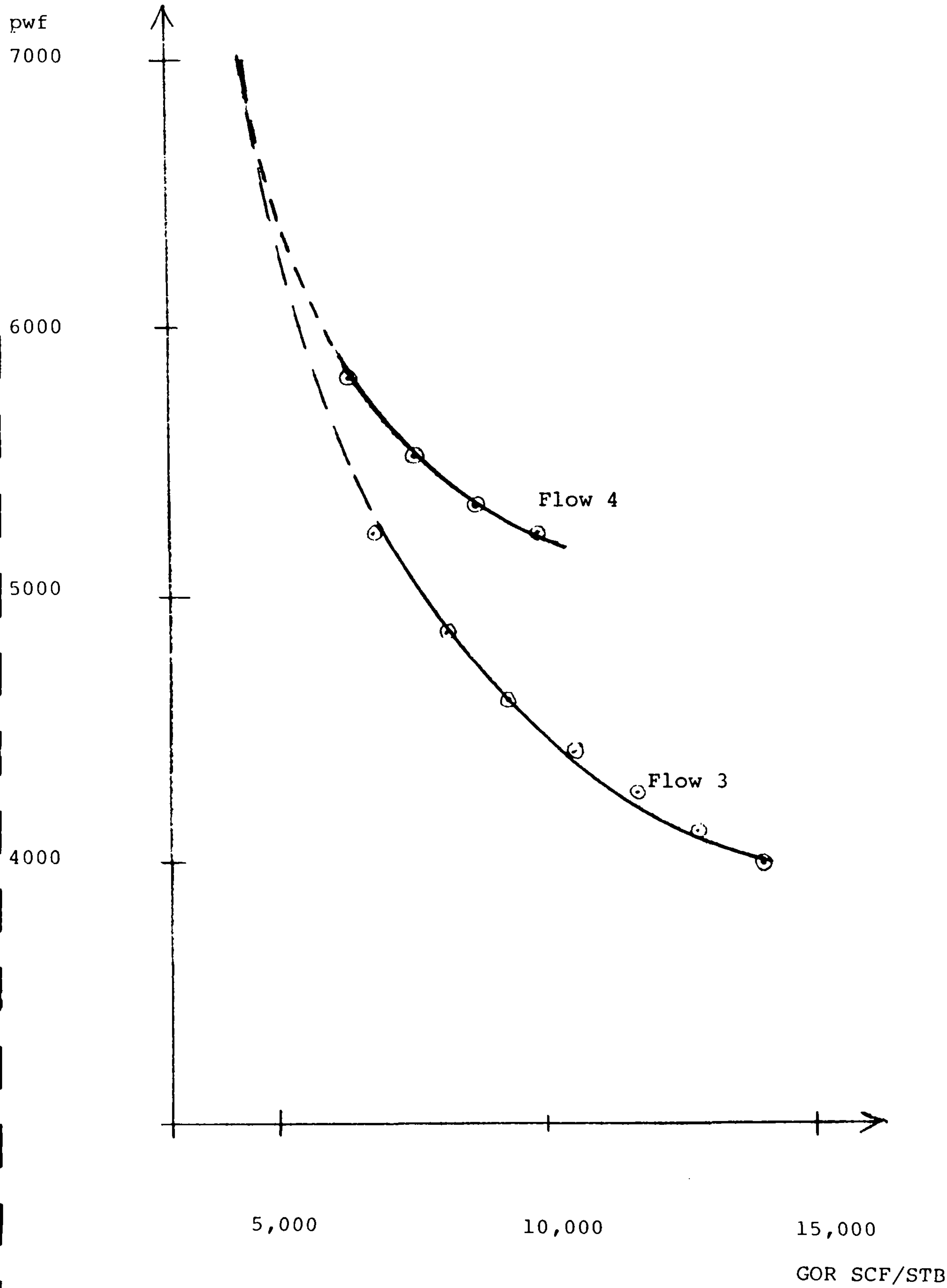

pwf
7000
6000
5000
4000
Flow 4
Flow 3
5,000
10,000
15,000
GOR SCF/STB

Fig. 7

3.8 Fluid distribution

Logs and test data indicates the following:

- there is a transition zone between 3225 and 3230m RKB

- the hydrocarbon saturation in Tor formation above the transition zone is mainly a residual saturation, indicating that the reservoir has been filled with hydrocarbons, but was then flushed with water

- the Ekofisk formation above the tight zone is at the irreducible water saturation.

APPENDIX 1 1/9-3 DST 1

Content

1 1/9-3 DST 1 summary

The main objective of this test was to investigate the kind of fluids which could be produced from right above an obvious transition zone in the Tor formation.

Table 1 gives a summary of test performance. The well was brought to surface without acid stimulation. Only one of the downhole pressure gauges were working properly.

Results were:

- pure water was produced with no measureable traces of hydrocarbons

- the second buildup indicates that a hydraullic fracture has developed with Xf = 35 ft. Only 2.2 bbls were injected back to the formation before the second flow

- the 2. buildup was long enough to develop a semi-log straight line corresponding to a kh = 340 md·ft. This is equiwalent to a k in the range 10 md. This must imply that a certain amount of natural fractures are contributing to the flow.

Table 1

TEST SUMMARY SHEET

Well: 1/9-3 DST no.: 1 Date: 1/9-3/9-78

Formation: TOR Perforations: 3205-3214 m RKB

		Rates			Pressur	
ime [hrs]	event.	oil STB/D	gas MMSCF/D	Water BBL/D	Well-head	bot tom
0.5	1. flow	-	-	360	0	48
3.25	1. build-up	-	-	-	-	69
2.0	2. flow	-	-	1850	40	46
12.0	2.build-up	-	-	-	-	69

2. TESTSTRING AND TESTSEQUENCE

2.1 Teststring

The following is the layout of the teststring:

ID	OD	Description	length (m)	depth (m)
[redacted]		DST 1		
		3½ TDS TBG.		
2.75	6.00	3½ TDS Box-3½ IF Pin	.28	2911.37
[redacted].00	5.00	Slip Joint	5.58	2911.65
[redacted].00	5.00	Slip Joint	4.30	2917.23
2.00	5.00	Slip Joint	4.02	2922.03
[redacted].68	6.12	3½ IF Box-4½ IF Pin	.20	2926.05
2.31	6.50	3 Std of drill	85.16	2926.25
[redacted].12	6.12	9 5/8 RTTS Circulating Valve	.97	3011.41
[redacted].81	6.50	1 Std. of Drill Collars	28.45	3012.38
[redacted].68	6.12	4½ IF Box-3½ IF Pin	.20	3040.83
2.00	5.00	Slip Joint	4.02	3041.03
[redacted].75	6.12	3½ IF Box-4½ IF Pin	.20	3045.05
2.81	6.50	1 Std. Drill Collars	24.85	3045.25
[redacted].75	6.12	4½ IF Box-3½ IF Pin	.20	3070.10
[redacted].00	4.63	APR-A Reverse Valve	.91	3070.30
2.00	4.63	APR-N Tester Valve	4.16	3071.21
[redacted].37	4.63	Big John Jars	1.58	3075.37
2.68	6.12	3½ IF Box-4½ IF Pin	.20	3076.95
[redacted].12	6.12	9 5/8 RTTS Circulating Valve	.97	3077.15
3.12	6.12	9 5/8 RTTS Safety Joint	1.10	3078.12
[redacted].75	8.25	9 5/8 RTTS Packer (Model II)	.68 1.10	3079.22 3181.00
[redacted].50	6.06	4½ IF Box-2 7/8 EUE Pin	.25	3182.10
2.44	2.87	Tubing Pup Joint	1.86	3192.35
[redacted].44	2.87	Perforated Tubing	1.22	3183.57
[redacted].81	2.87	No-Go Nipple	.63	3184.20
2.44	2.87	2 Joint Tubing/W/Plug	18.73	

2.1 Testsequence

DIARY OF EVENTS		WELL No -1/9-3 ZONE TESTED TOR	DST No 1 PERFS 3205-3214m RKB

DATE	TIME	OPERATIONS
31.8.78	1700	Rih w/perf gun, perf 3205-3214m RKB
		w/4sh/ft, no misfire, pooh w/perf gun
	1900	Pick up flopetrol test tree, tighten jts
		w/rightong
	2000	Pick up howco testring with gauges as follows

Gauge	No	Max pressure	Clock hrs	Clock No	Depth m
Amerada	36405	12000 psi	120	6842	3196.5
Amerada	41677	12000 psi	120	17277	3198.4
Amerada	36396	12000 psi	72	5570	3200.4
Kuster	41680	100-200°C	120	17276	3201.3

DATE	TIME	OPERATIONS
1.9.78	0130	Pressure tested howco string to
		4000 psi
	0230	Rih w/test string gatorhawking all connections
		to 8000 psi - 6500 psi
	1700	Made up test tree and surface lines
		set packer at 3181 m
	1830	Pressure tested surface lines, test tree,
		valves, choke manifold and string
	2330	Displaced string with water cushion-74 bbls
2.9.78	00.30	Closed rrts circ. valve and pressure tested
		surface lines and string against apr-n
		to 6000 psi

COMMENTS

PE ____________

DIARY OF EVENTS		WELL No 1/9-3 ZONE TESTED TOR	DST No 1 PERFS. 3205-3214m RKB

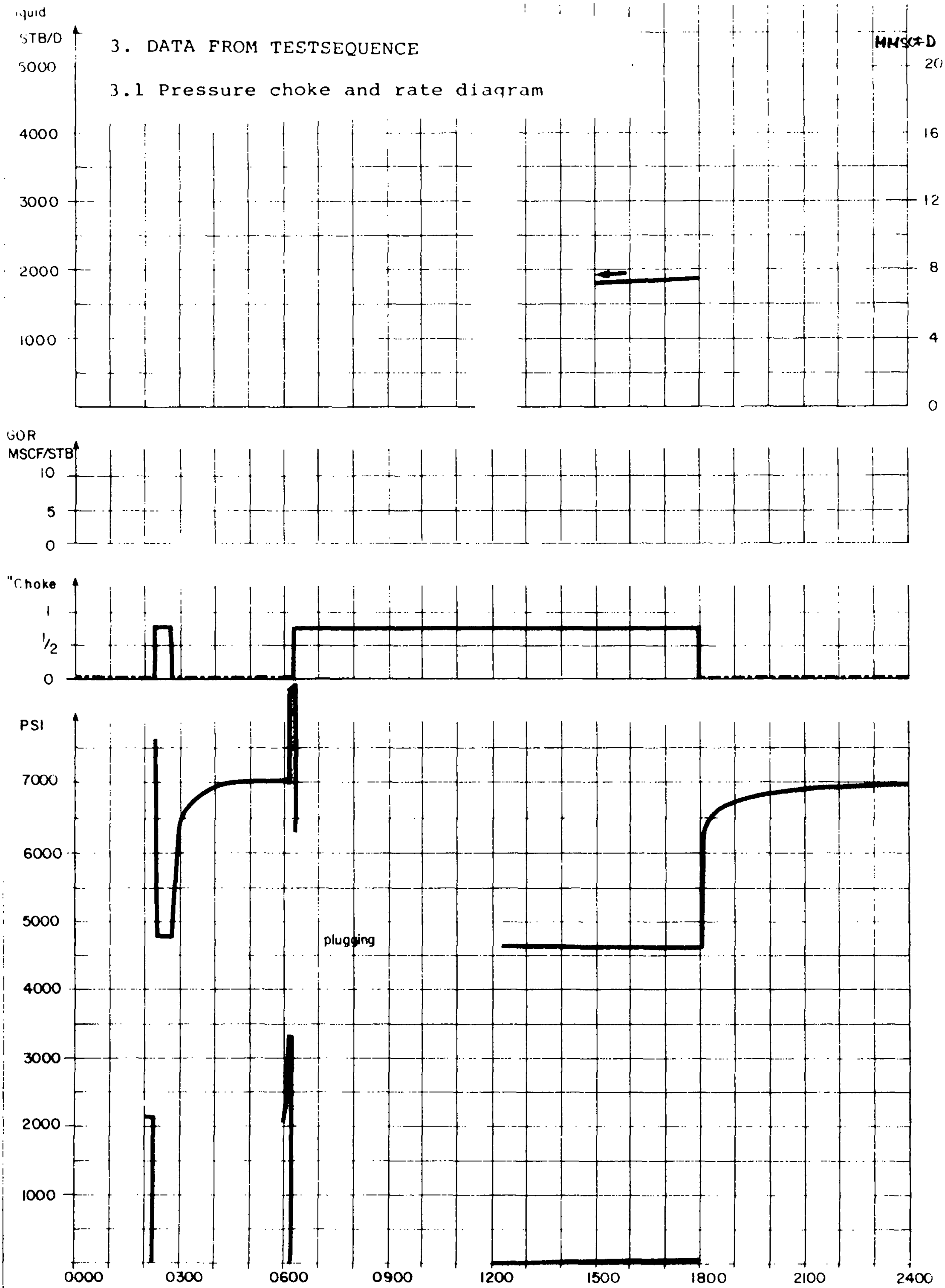
DATE	TIME	OPERATIONS
	0200	Pressured tubing to 1790 psi
	0215	Opened apr-n valve, pressure increased
		to 2100 psi, flowed well to bj-unit.
		wellhead pressure bled down to zero
		flowrate 7.5 bbl/30 mins.
	0245	Closed apr-n, closed on surface for
		1. build-up
	0601	Pressured tubing to 1750 psi
	0604	Opened apr-n valve, positive indication
	0606	Pumped back to the formation, .8 bbl were pumped
		when the formation broke down at 3600 psi, 2.2 bbl
		were injected at a pressure 3500 psi
	0616	Started 2. flow, monitored rates at the bj-unit,
		flowed 13 bbls/21 mins.
		zero wellhead pressure
	0640	Switched flow to burner, clean-up line.
		water cushion was produced
	0800	Mud to surface
	0930	Produced a brownish water phase,well was
		slugging
	1400	Flowed through flopetrol gauge tank
	1759	Closed apr-n valve for 2 build up
		closed on surface.
3.9.78	0613	Opened apr-n valve, good indication
	0623	Started to bullhead well.

COMMENTS

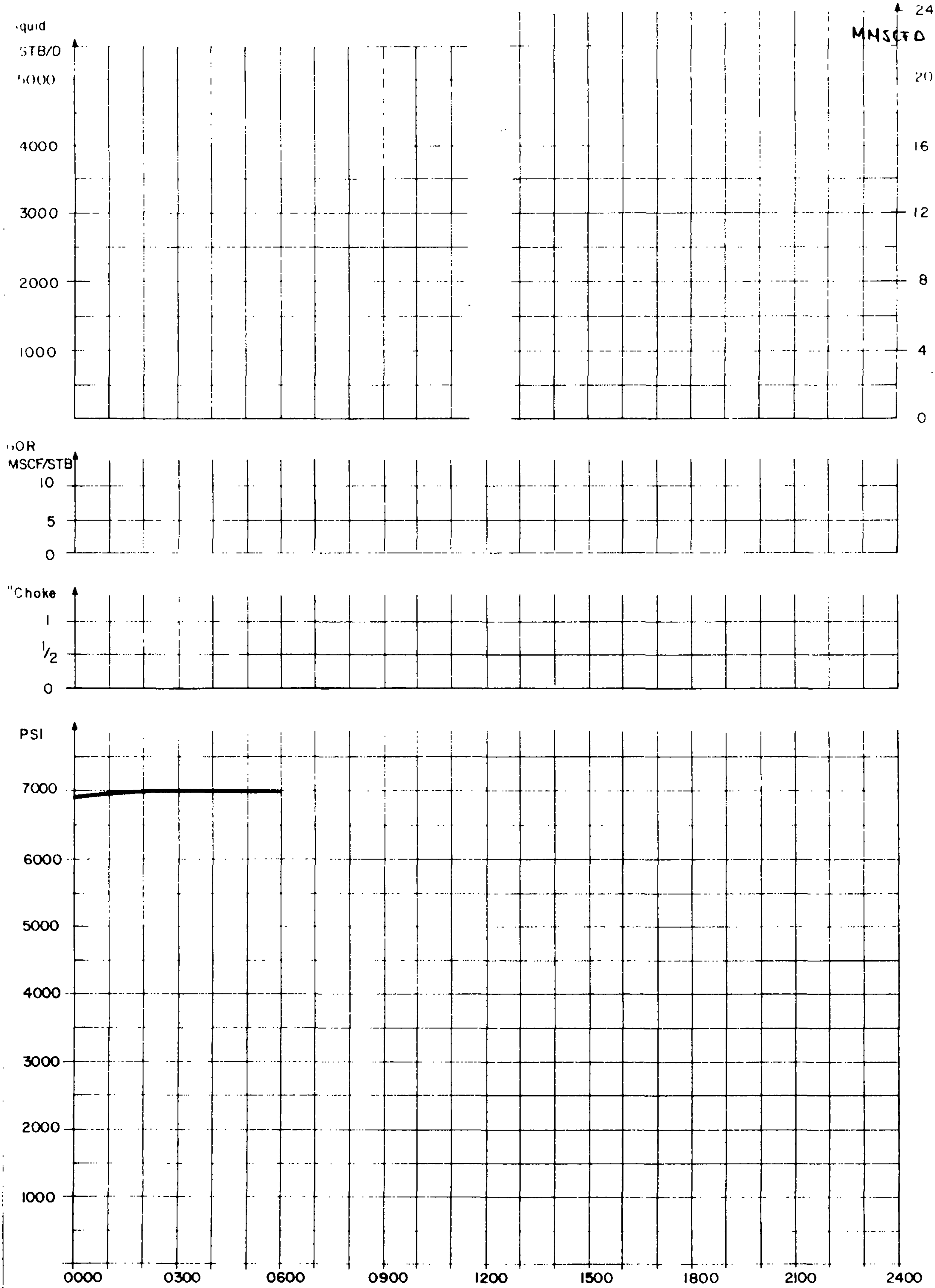
PE ____________

3. DATA FROM TESTSEQUENCE

3.1 Pressure choke and rate diagram



WELL: 1/9-3 DST NO: 1 DATE: 020978



WELL: 1/9-3 DST NO: 1 DATE: 030978

3.2 Flow data

DATO 2.9.73 OPERASJON 2. FLOW Ark nr 1 av 2

BRØNN [illegible] 9-3 DST nr 1 Perforert interval 3205-3214m RKB Trykkmåler dybde

Tid	Operasjon	Choke 64 in	WHP psi	WHT F	BHP psi	BHT F	Sep trykk psia	Sep temp F	Gassrate MMSCFD	Vann STBOPD	GOR SCF STB	Olje API	Gass s.g.	Væskeanalyse på rigg: Sted	Vann %	Sediment %	Cl- ppm	Olje API	Merknad
[illegible]		48	15	90		252.3								b.h.	66	34			
[illegible]		"	12	91										b.h.	64.5	15.5			
[illegible]		"	[illegible]	[illegible]		253.3											[illegible]		
[illegible]		"	12	98										b.h.	[illegible]	[illegible]			
[illegible]		"	12	[illegible]										"	[illegible]	[illegible]			
[illegible]		"	12	96										"	92	8			
[illegible]		"	13	104		255.4								"	85	15.0	22[illegible]		
[illegible]		"	13	107										"	93	7			
[illegible]		"	13	109										"	97.5	2.5	22[illegible]		
[illegible]		"	13	111										"	97	3			
[illegible]		"	19	111		255.6								"	93	7	24[illegible]		
[illegible]		"	2[illegible]	114	4641									"	99	1	24[illegible]		
[illegible]		"	22	117	4639									"	99	1	25[illegible]		
[illegible]		"	22	119	4619									"	98.5	1.5	26[illegible]		
[illegible]		"	21	120	4617	255.6								"	99.2	0.8	[illegible]		
[illegible]		"	[illegible]	[illegible]	4613									"	[illegible]	[illegible]	[illegible]		
[illegible]		"	23	125	4627	255.6								"	99.6	0.4	[illegible]		
[illegible]		"	[illegible]	129	4634					2004				"	99.65	0.35	26[illegible]		
[illegible]		"	[illegible]	[illegible]	4624	255.7				1953				"					
[illegible]		"	[illegible]	[illegible]	4624					1522				"	[illegible]	.25	[illegible]		
[illegible]		"	[illegible]	[illegible]	4635					[illegible]				"					
[illegible]		"	[illegible]	[illegible]	[illegible]					2004				"	[illegible]	[illegible]	[illegible]		
[illegible]		"	[illegible]	[illegible]	[illegible]	255.[illegible]				1927				"					
[illegible]		"	[illegible]	[illegible]	[illegible]					[illegible]				"	[illegible]	[illegible]	[illegible]		
[illegible]		"	[illegible]	[illegible]	[illegible]					[illegible]				"					
[illegible]		"	[illegible]	[illegible]	[illegible]					[illegible]				"	[illegible]	[illegible]	[illegible]		

DATO | OPERASJON | Ark nr 2 av 2

BRØNN 1/9-3 | DST nr 1 | Perforert interval 3205-3214m RKB | Trykkmåler dybde

Tid	Operasjon	Choke 64 th	WHP psi	WHT F	BHP psi	BHT F	Sep trykk psia	Sep temp F	Gassrate MMSCFD	Vann STBOPD	GOR SCF STB	Olje API	Gass r g	Væskeanalyse på rigg: Sted	Vann %	Sediment %	Cl ppm	Olje API	Merknad
1700		"	35	135	4601	256.5				1775									
1715		"	34	135	4639					1699				b.h.	99.9	.1	41000		
1730		"	40	137	4634					1978									
1745		"	40	139	4627					1902				b.h.	99.8	.2	41000		
1759		"	40	140	4627	256.6				1927									

4 TEST ANALYSIS

4.1 Buildup no 1

Horner analysis:

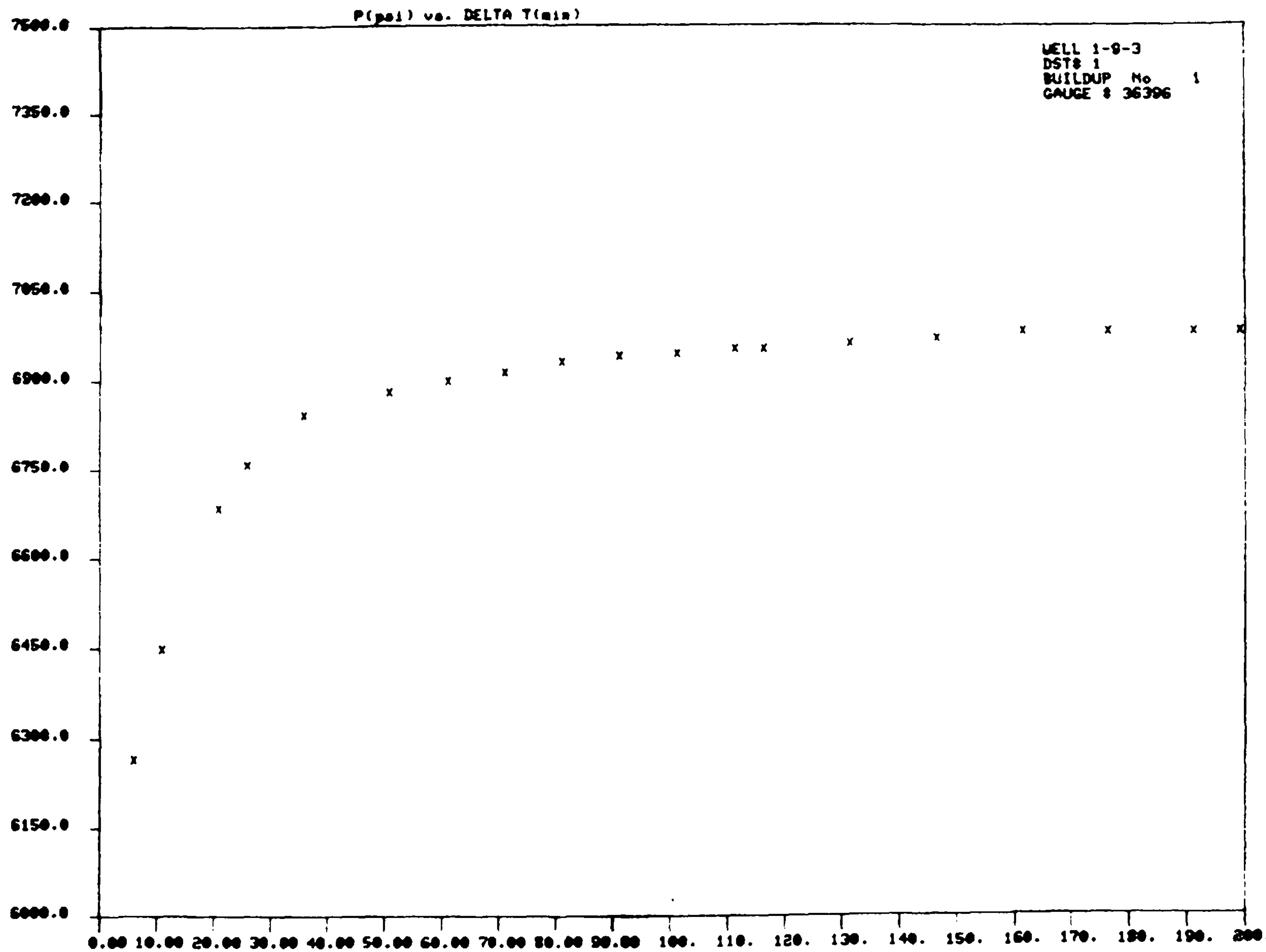
p^* = 7026.1 psi
m = 731 psi/decade
kh = 28 md·ft
s = -.4
rd = 18 ft

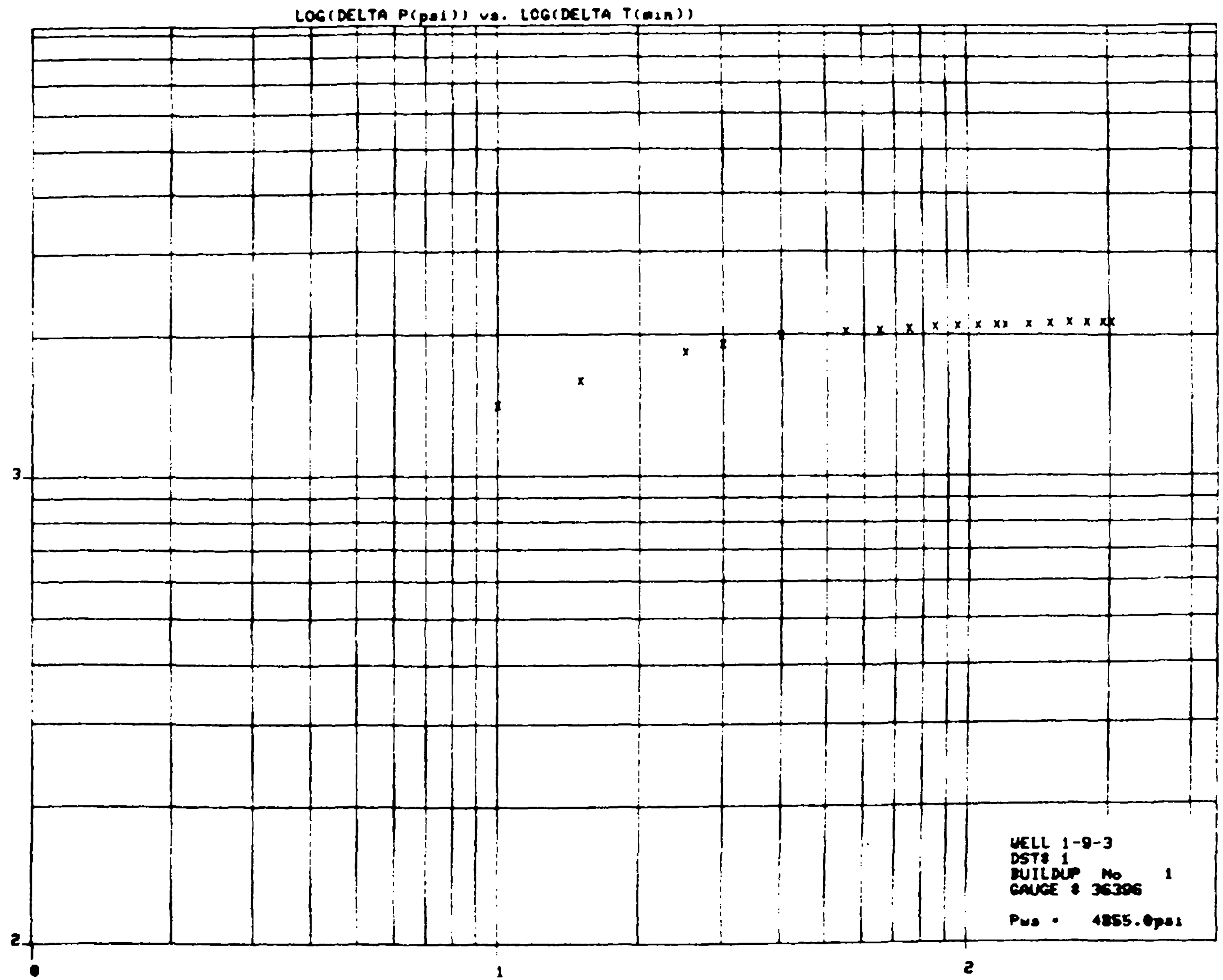
Enclosed:

- pressure point table
- p vs. Δt
- log Δp vs. log Δt
- p vs. log ((t+Δt)/Δt) with straight line

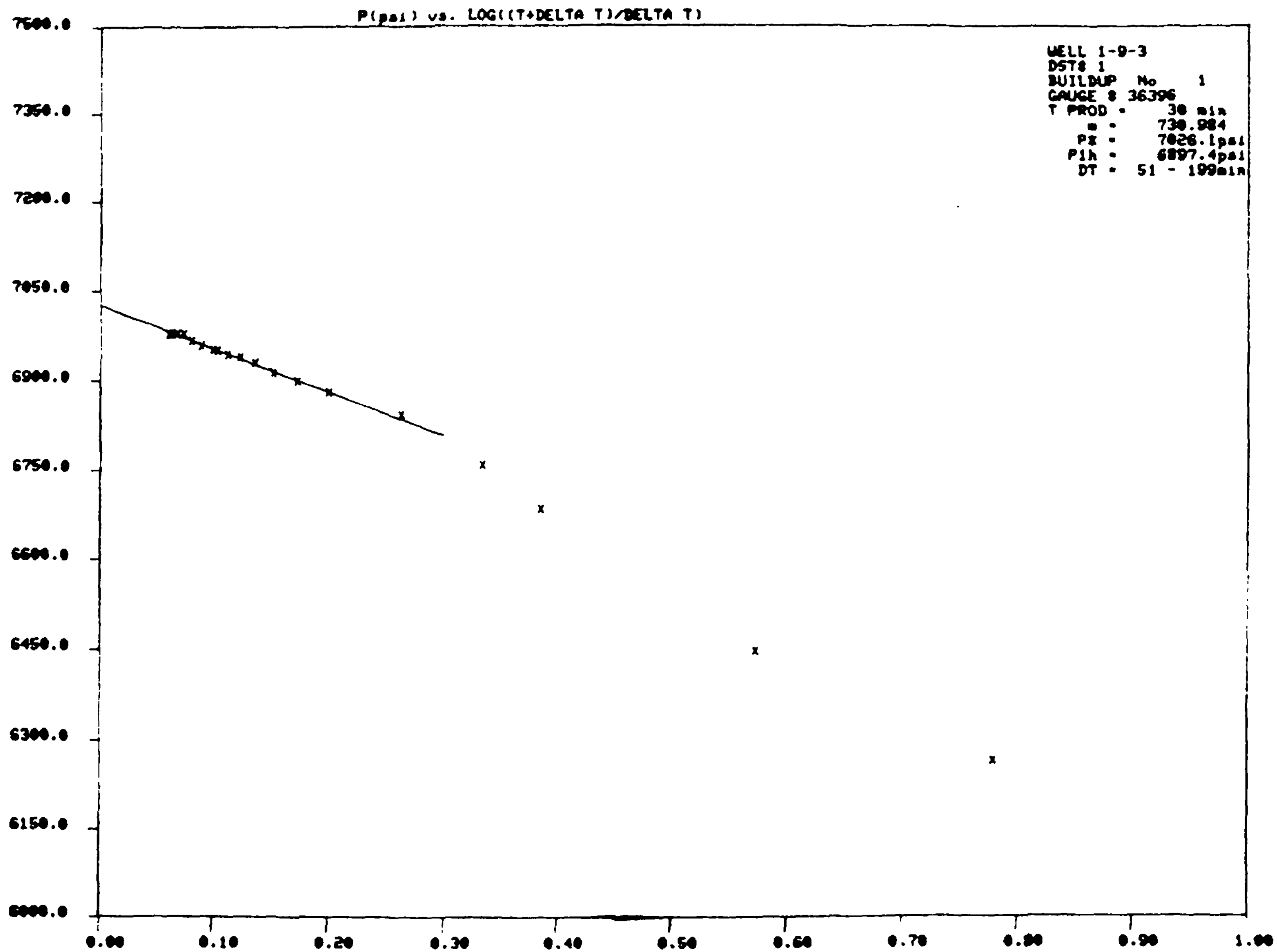
BRØNN 1-9-3   DST# 1
BUILDUP NUMMER   1
GAUGE 36396

NR.	TID	TRYKK
1	2.55	6265.500
2	3.00	6448.700
3	3.10	6684.500
4	3.15	6757.800
5	3.25	6841.600
6	3.40	6879.400
7	3.50	6898.100
8	4.00	6911.700
9	4.10	6929.700
10	4.20	6938.400
11	4.30	6942.800
12	4.40	6950.200
13	4.45	6950.800
14	5.00	6958.300
15	5.15	6966.300
16	5.30	6978.100
17	5.45	6978.100
18	6.00	6978.100
19	6.08	6978.100


P(psi) vs. DELTA T(min)
WELL 1-9-3
DST# 1
BUILDUP No 1
GAUGE # 36396
7500.0
7350.0
7200.0
7050.0
6900.0
6750.0
6600.0
6450.0
6300.0
6150.0
6000.0
0.00 10.00 20.00 30.00 40.00 50.00 60.00 70.00 80.00 90.00 100. 110. 120. 130. 140. 150. 160. 170. 180. 190. 200.



LOG(DELTA P(psi)) vs. LOG(DELTA T(min))
3
2
0
1
2
WELL 1-9-3
DST# 1
BUILDUP No 1
GAUGE # 36396
Pws = 4855.0psi



P(psi) vs. LOG((T+DELTA T)/DELTA T)
WELL 1-9-3
DST# 1
BUILDUP No 1
GAUGE # 36396
T PROD = 30 min
m = 730.984
P* = 7026.1psi
P1h = 6897.4psi
DT = 51 - 199min
7500.0
7350.0
7200.0
7050.0
6900.0
6750.0
6600.0
6450.0
6300.0
6150.0
6000.0
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00

4.2 Buildup no 2

Horner analysis:

$p^* = 7037$ psi
$m = 310.9$ psi/decade
$kh = 338.6$ md·ft
$k = 11.5$ md
$s = 2.4$
$rd = 312$ ft

Square root data plot analysis:

$m^1 = 545$ psi/$\sqrt{hr}$
$xf = 44$ ft

Type curve analysis (matched on a constant flux hydraulic fracture type curve)

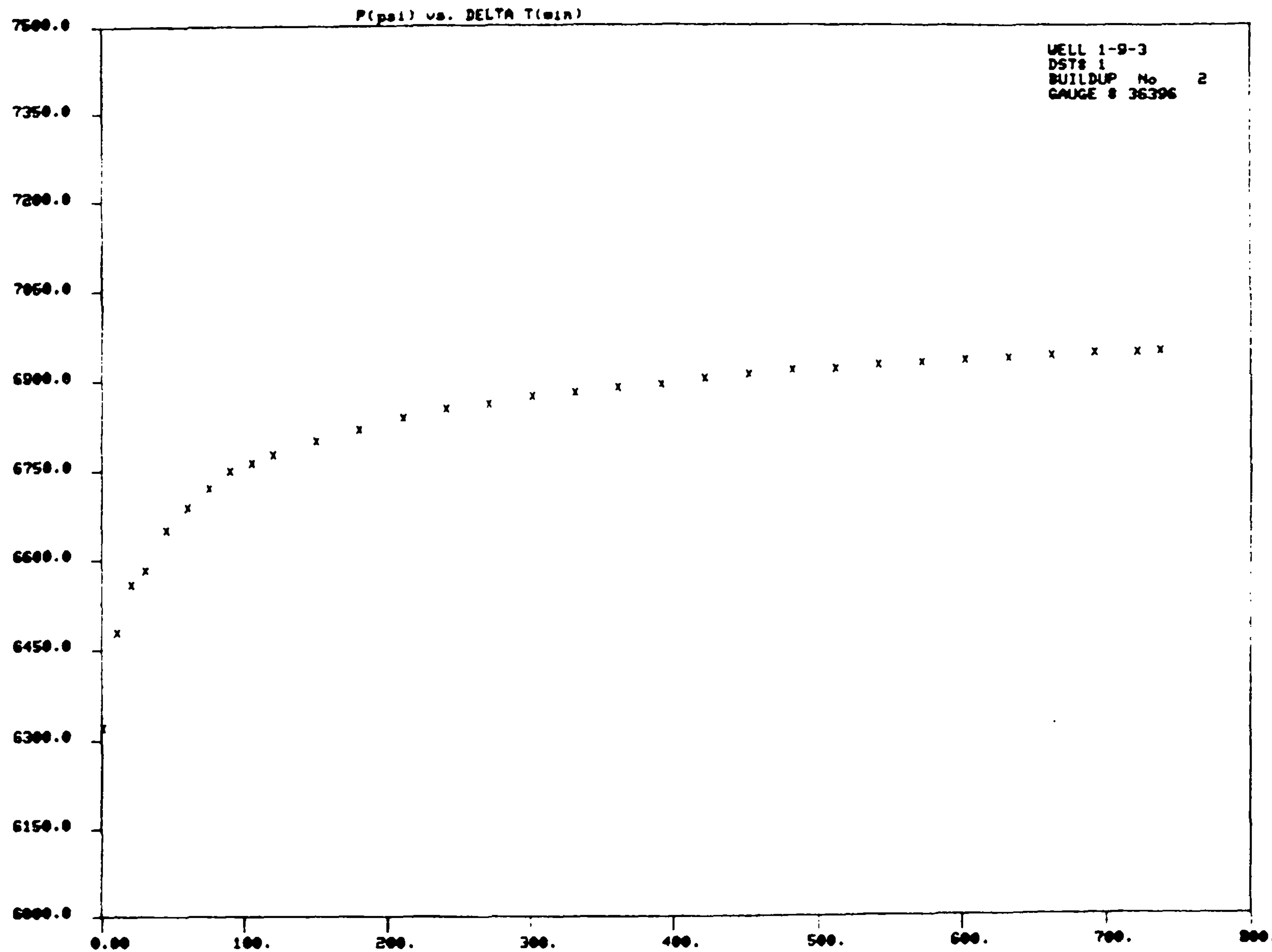
$kh = 356$ md·ft
$k = 12$ md
$xf = 33$ ft

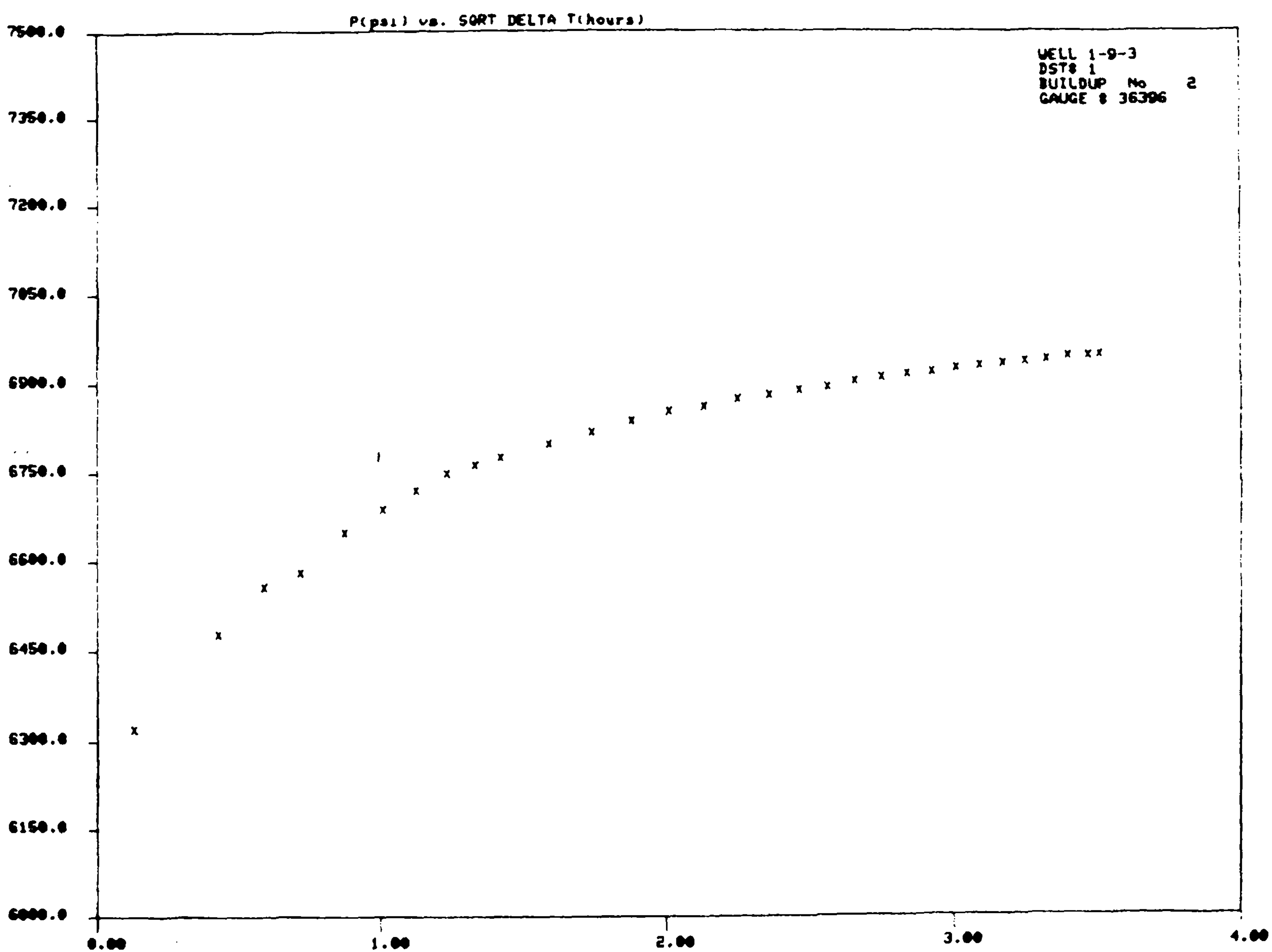
Enclosed:

- pressure point table
- p vs. Δt
- p vs. $\sqrt{\Delta t}$ with straight line
- log Δp vs. log Δt
- type curve match
- p vs. log $((t+\Delta t)/\Delta t)$ with straight line

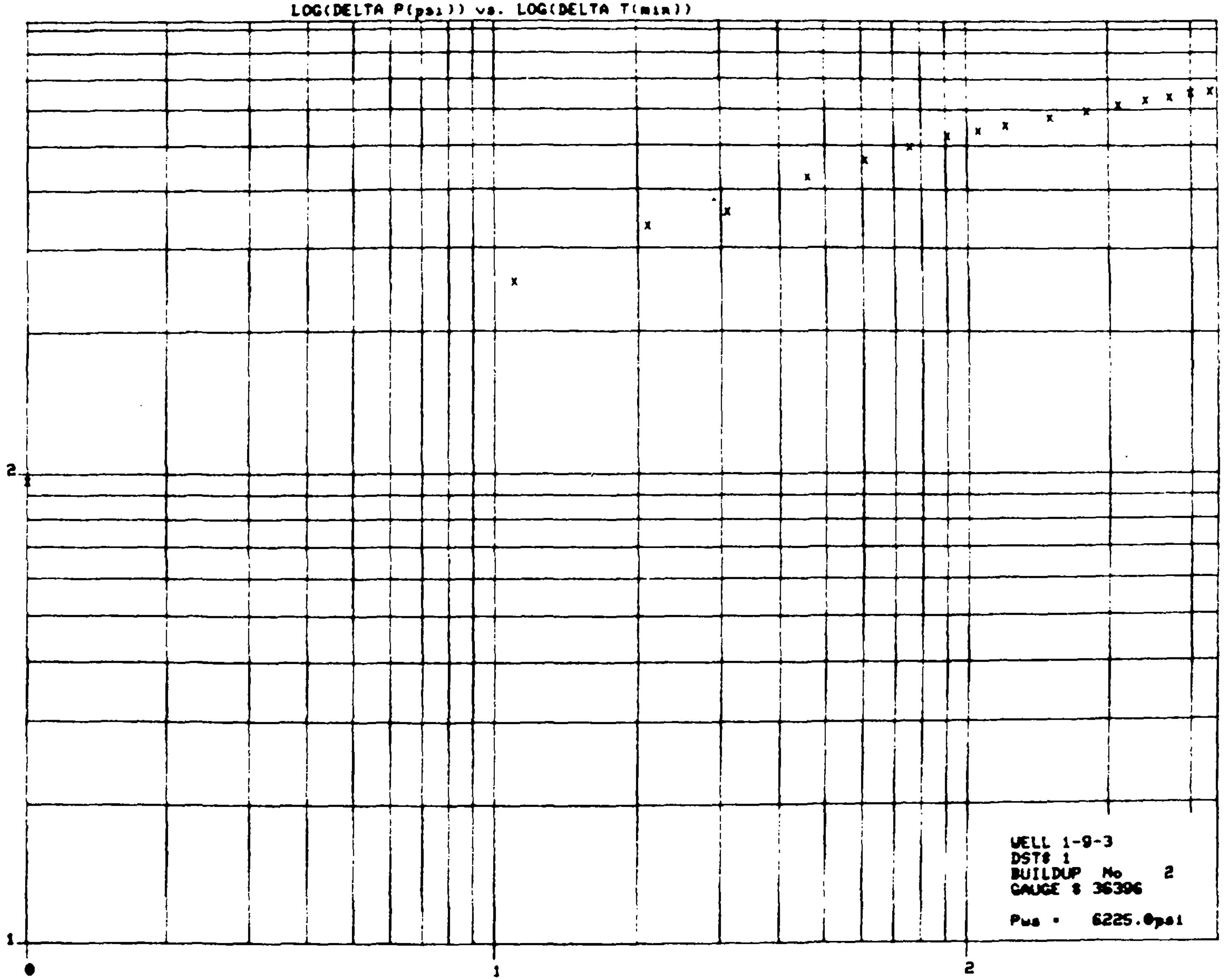
BRØNN 1-9-3 DST# 1
BUILDUP NUMMER 2
GAUGE 36396

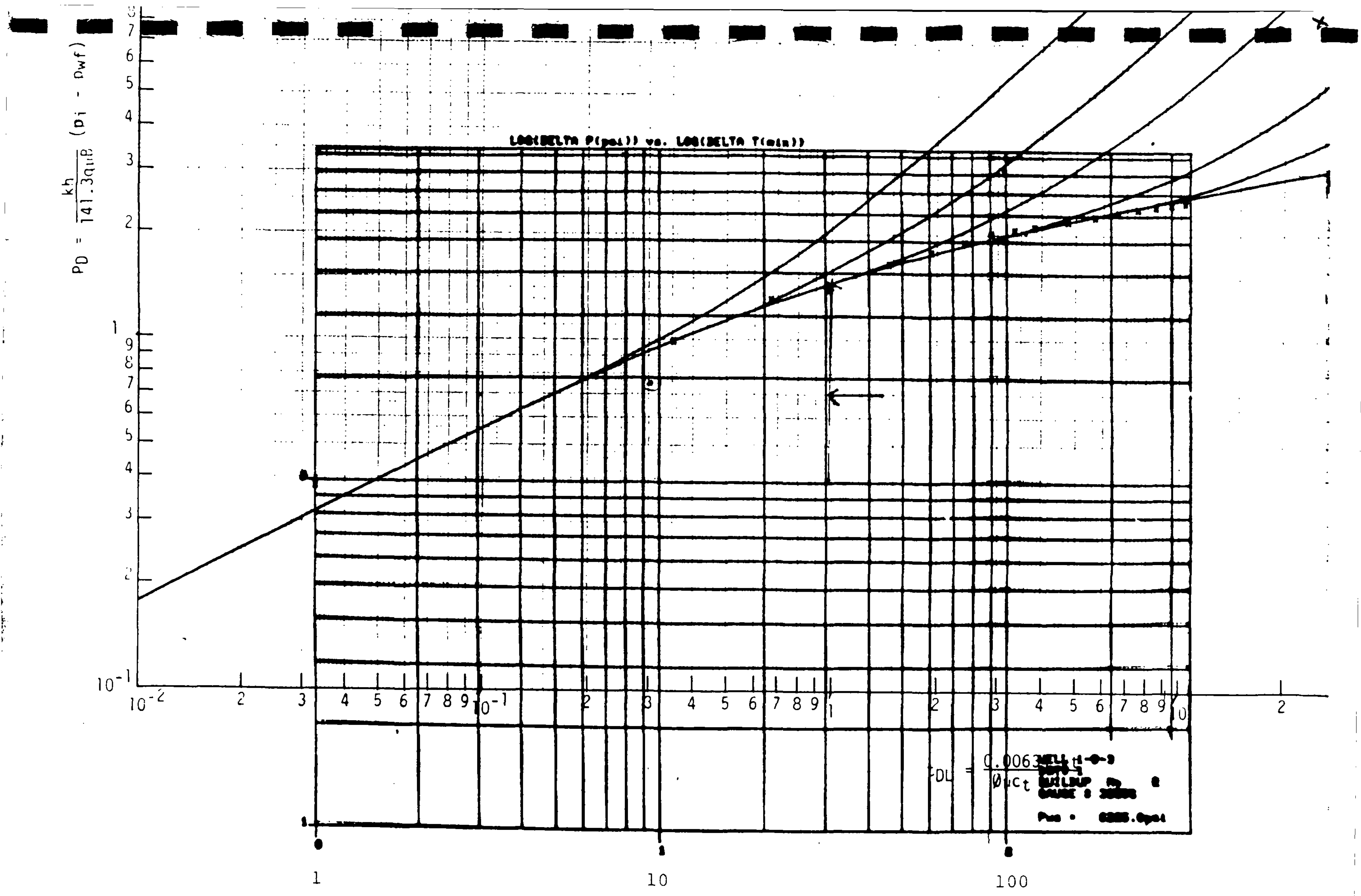
NR.	TID	TRYKK
1	18.00	6321.400
2	18.10	6479.100
3	18.20	6558.500
4	18.30	6582.100
5	18.45	6649.800
6	19.00	6687.600
7	19.15	6719.900
8	19.30	6749.100
9	19.45	6762.100
10	20.00	6775.800
11	20.30	6798.700
12	21.00	6817.900
13	21.30	6836.600
14	22.00	6852.100
15	22.30	6859.600
16	23.00	6872.600
17	23.30	6878.800
18	0.00	6886.900
19	0.30	6891.900
20	1.00	6901.800
21	1.30	6907.900
22	2.00	6914.200
23	2.30	6917.300
24	3.00	6923.500
25	3.30	6927.200
26	4.00	6931.000
27	4.30	6934.100
28	5.00	6937.800
29	5.30	6942.800
30	6.00	6943.900
31	6.16	6945.900

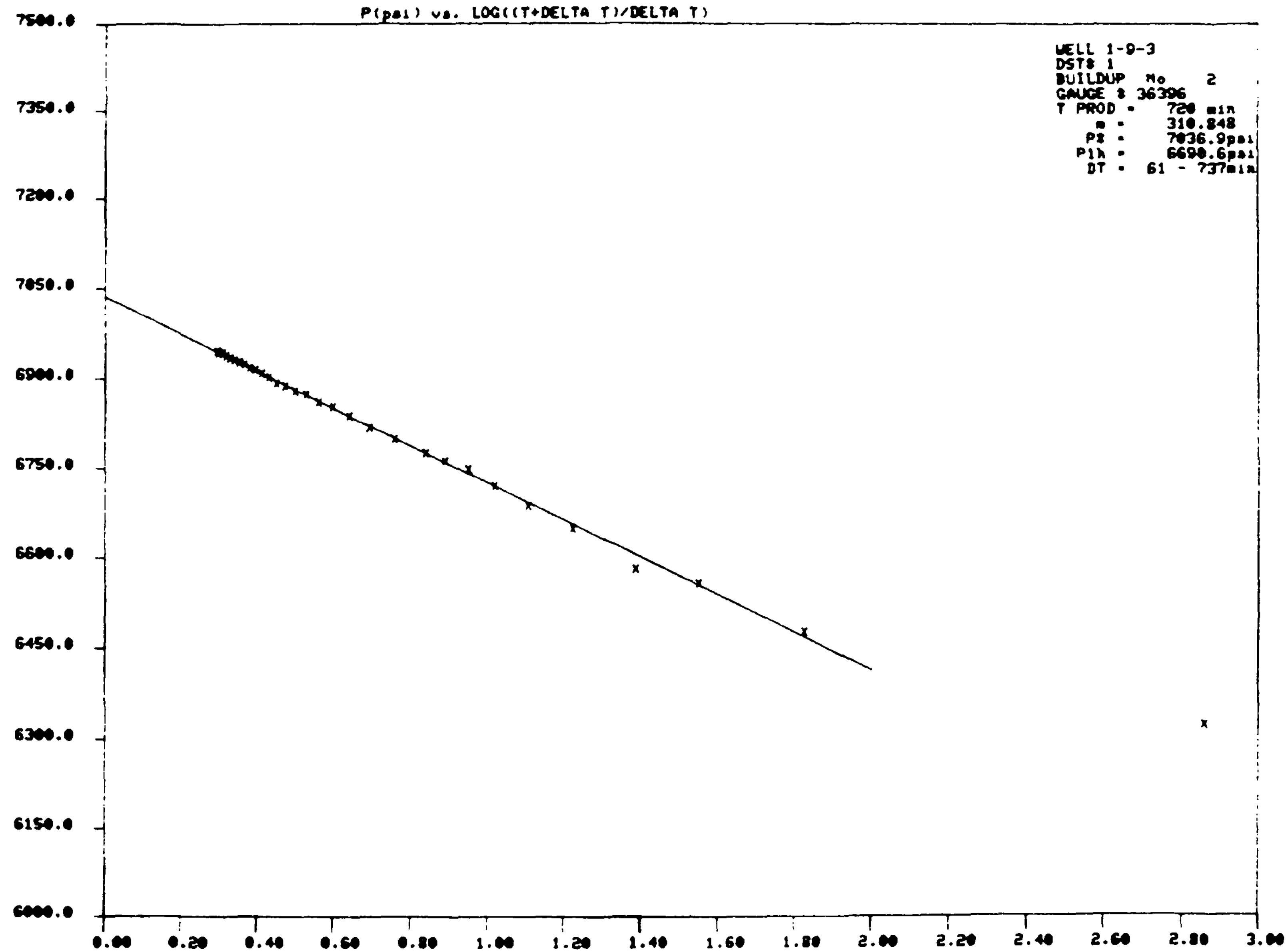

P(psi) vs. DELTA T(min)
WELL 1-9-3
DST# 1
BUILDUP No 2
GAUGE # 36396
7500.0
7350.0
7200.0
7050.0
6900.0
6750.0
6600.0
6450.0
6300.0
6150.0
6000.0
0.00
100.
200.
300.
400.
500.
600.
700.
800.


P(psi) vs. SQRT DELTA T(hours)
WELL 1-9-3
DST# 1
BUILDUP No 2
GAUGE # 36396
7500.0
7350.0
7200.0
7050.0
6900.0
6750.0
6600.0
6450.0
6300.0
6150.0
6000.0
0.00
1.00
2.00
3.00
4.00

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




LOG(DELTA P(psi)) vs. LOG(DELTA T(min))
$P_D = \frac{kh}{141.3 q \mu B} (p_i - p_{wf})$
$t_{DL} = \frac{0.0063}{\phi \mu c_t}$
1
10
100



P(psi) vs. LOG((T+DELTA T)/DELTA T)
WELL 1-9-3
DST# 1
BUILDUP No 2
GAUGE # 36396
T PROD = 720 min
m = 310.848
P* = 7036.9psi
P1h = 6690.6psi
DT = 61 - 737min
7500.0
7350.0
7200.0
7050.0
6900.0
6750.0
6600.0
6450.0
6300.0
6150.0
6000.0
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

5 Miscellaneous data used in the test analysis-DST 1

Completion data:

r_w = .4 ft (9 $^5/_8$" casing)
perforated interval: 3205-3214m RKB = 9m = 29.5ft

Water properties:

B_w = 1.0 res bbl/STBBL
μ_w = .30 cp
$c_w = 3.2 \times 10^{-6}$ vol/vol/psi

Hydrocarbon compressibility:

$c_{hc} = 50 \times 10^{-6}$ vol/vol/psi

Petrophysical properties:

rock compressibility: 3.0×10^{-6} vol/vol/psi

over perforated interval:
ϕ = .207
S_w = .780
S_{hc}= .220
h = 29.5 ft
$C_t = 16.5\ 10^{-6}$ vol/vol/psi

over maximum contributing interval:
ϕ = .20
S_w = .858
S_{hc} = .142
h = 89 ft
$C_t = 12.85\ 10^{-6}$ vol/vol/psi

```
YES

NB!!!  CALCULATIONS MAY TAKE SOME TIME!!!!!!


 S T A T I S T I C S
*********************

FIELD: . . . . . . . . . . .              1-9
WELL:  . . . . . . . . . . .            1-9-3A
DATE:  . . . . . 09.21.20     19 OCTOBER   1978
ENGINEER:  . . . . . . . . . JRA

DEPTH INTERVAL:  . . .  3204.00 TO  3213.00
APPLIED CUTOFFS:
.              VSH:  GREATER THAN       0.40
.             PHIF:     LESS THAN       0.12
:               SW:  GREATER THAN       0.65

 T O T A L    D E P T H
*****************************************
THICKNESS: . . . . . . . . .         9.000
AVERAGE  . . . 'PHIF'  . . .         0.207
AVERAGE  . . . 'VSHALE'  . .         0.024
AVERAGE  . . . 'SW'  . . . .         0.780
W.AVERAGE  . . 'SW' * 'PHIF'         0.773
AVERAGE  . . . 'SH'  . . . .         0.220
VOID VOLUME: . . . ('PHIF').         1.866
HC VOID VOLUME . . ('SH'*) .         0.424
RES HC VOID VOLUME ('SHR'*).         0.009
MOV HC VOID VOLUME . . . . .         0.415
*****************************************

 N E T    P A Y
*****************************************
THICKNESS: . . . . . . . . .         1.250
AVERAGE  . . . 'PHIF'  . . .         0.225
AVERAGE  . . . 'VSHALE'  . .         0.027
AVERAGE  . . . 'SW'  . . . .         0.559
W.AVERAGE  . . 'SW' * 'PHIF'         0.559
AVERAGE  . . . 'SH'  . . . .         0.441
VOID VOLUME: . . . ('PHIF').         0.282
HC VOID VOLUME . . ('SH'*) .         0.124
RES HC VOID VOLUME ('SHR'*).         0.009
MOV HC VOID VOLUME . . . . .         0.115
*****************************************

 N E T    S A N D
*****************************************
THICKNESS: . . . . . . . . .         9.000
AVERAGE  . . . 'PHIF'  . . .         0.207
AVERAGE  . . . 'VSHALE'  . .         0.024
AVERAGE  . . . 'SW'  . . . .         0.780
W.AVERAGE  . . 'SW' * 'PHIF'         0.773
AVERAGE  . . . 'SH'  . . . .         0.220
VOID VOLUME: . . . ('PHIF').         1.866
HC VOID VOLUME . . ('SH'*) .         0.424
RES HC VOID VOLUME ('SHR'*).         0.009
MOV HC VOID VOLUME . . . . .         0.415
*****************************************

 N E T / G R O S S    R A T I O S
*****************************************

HNETPAY /HGROSS SAND :  0.13889
HNETSAND/HGROSS SAND :  1.00000
HNETPAY /HNETSAND    :  0.13889
*****************************************


BROWN                    DYBDE 1     DYBDE 2
1-9-3A                   3204.00     3213.00


GI KOMMANDO?
```

```
YES

NB!!!  CALCULATIONS MAY TAKE SOME TIME!!!!!!


 S T A T I S T I C S
 ####################

FIELD: . . . . . . . . . . .                1-9
WELL:  . . . . . . . . . . .              1-9-3A
DATE:  . . . . . 11.57.15     19 OCTOBER   1978
ENGINEER:  . . . . . . . . . JRA

DEPTH INTERVAL:  . . .  3198.00 TO  3225.00
APPLIED CUTOFFS:
.               VSH:  GREATER THAN       0.40
.              PHIF:     LESS THAN       0.12
.                SW:  GREATER THAN       0.65

 T O T A L    D E P T H
 ########################################
THICKNESS: . . . . . . . . .      27.000
AVERAGE  . . . 'PHIF'  . . .       0.200
AVERAGE  . . . 'VSHALE'  . .       0.013
AVERAGE  . . . 'SW'  . . . .       0.858
W.AVERAGE  . . 'SW' * 'PHIF'       0.826
AVERAGE  . . . 'SH'  . . . .       0.172
VOID VOLUME: . . . ('PHIF').       5.402
HC VOID VOLUME . . ('SH'*) .       1.045
RES HC VOID VOLUME ('SHR'*).       0.009
MOV HC VOID VOLUME . . . . .       1.035
 ########################################

 N E T    P A Y
 ########################################
THICKNESS: . . . . . . . . .       2.000
AVERAGE  . . . 'PHIF'  . . .       0.237
AVERAGE  . . . 'VSHALE'  . .       0.017
AVERAGE  . . . 'SW'  . . . .       0.588
W.AVERAGE  . . 'SW' * 'PHIF'       0.590
AVERAGE  . . . 'SH'  . . . .       0.412
VOID VOLUME: . . . ('PHIF').       0.475
HC VOID VOLUME . . ('SH'*) .       0.195
RES HC VOID VOLUME ('SHR'*).       0.009
MOV HC VOID VOLUME . . . . .       0.185
 ########################################

 N E T    S A N D
 ########################################
THICKNESS: . . . . . . . . .      26.500
AVERAGE  . . . 'PHIF'  . . .       0.202
AVERAGE  . . . 'VSHALE'  . .       0.012
AVERAGE  . . . 'SW'  . . . .       0.848
W.AVERAGE  . . 'SW' * 'PHIF'       0.820
AVERAGE  . . . 'SH'  . . . .       0.175
VOID VOLUME: . . . ('PHIF').       5.344
HC VOID VOLUME . . ('SH'*) .       1.045
RES HC VOID VOLUME ('SHR'*).       0.009
MOV HC VOID VOLUME . . . . .       1.035
 ########################################

 N E T / G R O S S    R A T I O S
 ########################################

HNETPAY /HGROSS SAND =  0.07407
HNETSAND/HGROSS SAND =  0.98148
HNETPAY /HNETSAND    =  0.07547
 ########################################


BRONN                     DYBDE 1     DYBDE 2
1-9-3A                    3198.00     3225.00

GI KOMMANDO?
```

APPENDIX 2 1/9-3 DST 2

Content

1. 1/9-3 DST 2 Summary

The initial objectives of this test were to:

- investigate formation properties
- collect fluid samples
- evaluate acid frac stimulation effectiveness

This was planned to be a fairly long test. We did expect a certain water cut, but were surprised by the amount of water which was produced. For this reason the test was aborted after the second build up.

Table 1 gives a summary of test performance.

Results from the test were:

- only 5% hydrocarbon were produced
- the formation permeability is about 1 md, hence there are no natural fractures contributing to flow.

Table 1

TEST SUMMARY SHEET

Well: 1/9-3 DST no.: 2 Date: 6.9.78 - 7.9.73

Formation: Tor Perforations: 3157-3180m RKB

		Rates			Pressur	
ime [hrs]	event.	oil STB/D	gas MMSCF/D	Water BBL/D	Well-head	bot tom
[illegible].50	1. flow	-	-	418	0	50
[illegible].02	1. build up	-	-	-	-	69
1[illegible].78	2. flow	50	.17	1100	200	37
11.22	2. build up	-	-	-	-	68

2. TESTSTRING AND TESTSEQUENCE

2.1 Teststring

The following is the layout of the teststring:

ID	OD	Description	length (m)	depth (m)
		DST No 2		
		3½ TDS TBG.		2964.87
.75	6.00	3½ TDS Box-3½ IF Pin	.28	2965.15
2.00	5.00	Slip Joint	5.58	2970.73
.00	5.00	Slip Joint	4.30	2975.53
2.00	5.00	Slip Joint	4.02	2975.55
.68	6.12	3½ IF Box-4½ IF Pin	.20	2979.75
2.81	6.50	3 Std of drill	85.16	3064.91
.12	6.12	9 5/8 RTTS Circulating Valve	.97	3065.88
2.81	6.50	1 Std. of Drill Collars	28.45	3094.33
.68	6.12	4½ IF Box-3½ IF Pin	.20	3094.53
2.00	5.00	Slip Joint	4.02	3098.65
.75	6.12	3½ IF Box-4½ IF Pin	.20	3098.75
2.81	6.50	1 Std. Drill Collars	24.85	3127.20
.75	6.12	4½ IF Box-3½ IF Pin	.20	3127.4
.00	4.63	APR-A Reverse Valve	.91	3128.31
2.00	4.63	APR-N Tester Valve	4.16	3132.47
.37	4.63	Big John Jars	1.58	3134.05
2.68	6.12	3½ IF Box-4½ IF Pin	.20	3134.25
.12	6.12	9 5/8 RTTS Circulating Valve	.97	3135.22
3.12	6.12	9 5/8 RTTS Safety Joint	1.10	3136.32
.75	8.25	9 5/8 RTTS Packer (Model II)	.68 1.10	3137 3138.1
.50	6.06	4½ IF Box-2 7/8 EUE Pin	.25	3138.35
2.44	2.87	Tubing Pup Joint	1.86	3140.21
.44	2.87	Perforated Tubing	1.22	3141.43
1.81	2.87	No-Go Nipple	.63	3142.06
2.44	2.87	2 Joint Tubing/W/Plug	18.73	3160.79

2.2 Testsequence

DIARY OF EVENTS	WELL No - 1/9-3	DST No 2
	ZONE TESTED Tor	PERFS 3157-3180m RKB

DATE	TIME	OPERATIONS
5.9.78		
	0600	Rigged up dresser atlas, made 3 run with
		perforating gun, 4 spf from 3157 to 3180m RKB
	1630	Made up test tree and laid same
		back down
	1730	Made up bottom hole assembly, tested to
		4000 psi. The following gauges were run:
		Gauge — Clock — Depth [m]
		Amerada 36405-12000 psi — 120 hrs — 3154.9
		Amerada 41611-12000 psi — 120 hrs — 3152.9
		Amerada 36396-12000 psi — 72 hrs — 3157.0
		Kuster 41680-100-200^{o}C — 120 hrs — 3158.9
	2200	Rih W/test string
6.9.78		
	0632	Set packer at depth 3137.2m RKB
	0647	Displaced tubing with water
	0721	Close rtts circulating valve, tested
		tubing
	0739	Tubing pressure 1865 psi
	0742	Opened apr-n valve, pressure increased
		to 2300 psi
	0742	Flowed well to b-j unit, 8.7 bbls were produced
		in 30 mins, zero wellhead pressure

COMMENTS

PE

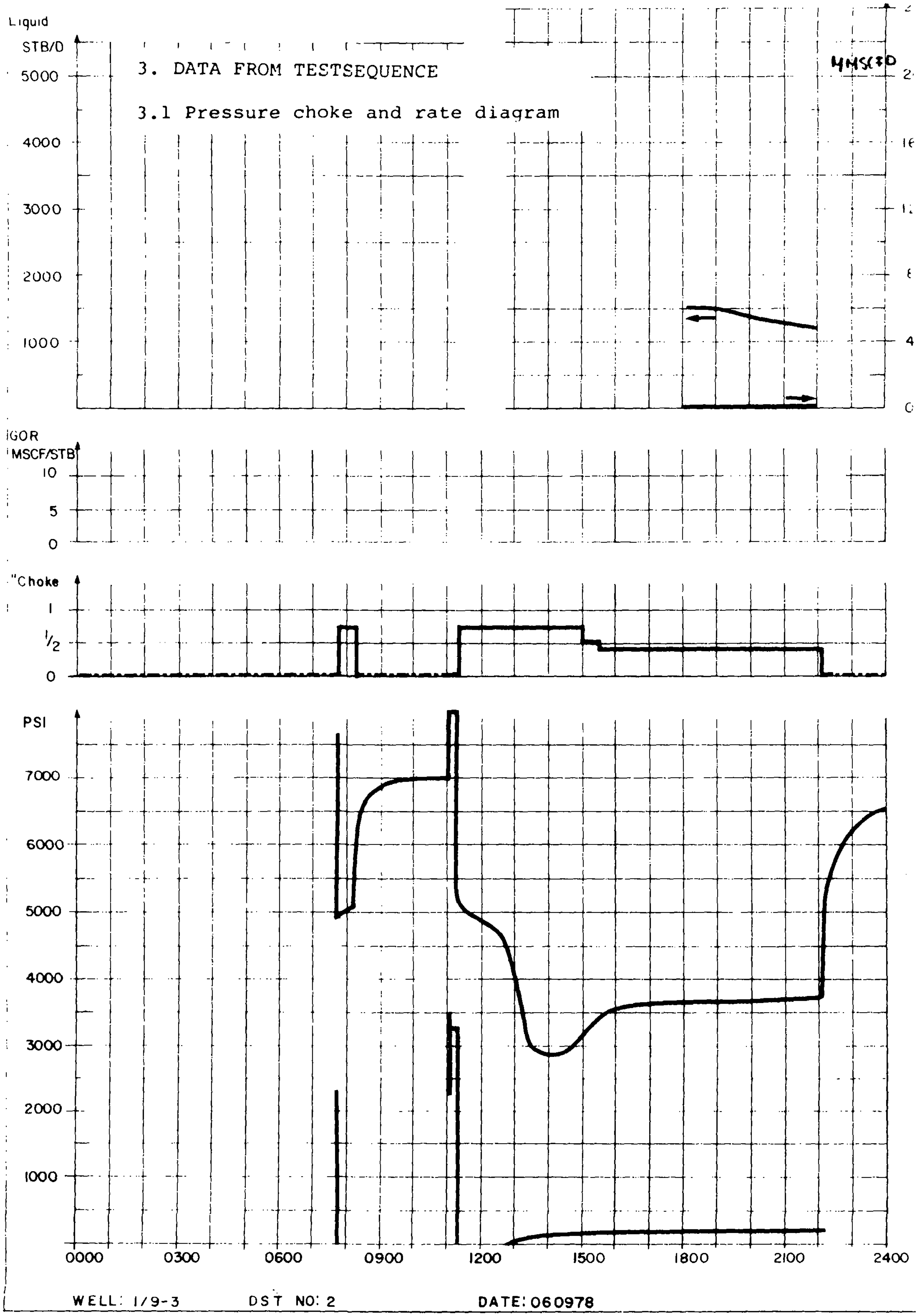
DIARY OF EVENTS		WELL No ______ DST No ______ ZONE TESTED: ______ PERFS ______
DATE	TIME	OPERATIONS
	0812	Closed apr-n for 1. buildup
	1113	Opened apr-n. Injected 5 bbls, formation
		broke down at 3500 psi, injection pressure
		3250 psi
	1120	Started to flow well, monitored rate,
		.52 bbl/min
	1203	Diverted flow to clean up line, 3/4" choke
	1302	Mud to surface
	1330	Gas to surface, well slugging
	1503	½" choke to stabilize well
	1530	Choke to 24/64"
	1700	Flowed through separator
	2207	Closed apr-n for 2. shutin
	2225	Closed choke manifold
7.9.78	0920	Opened apr-n, bull headed capasity of tubing
		into formation, circulated
	1500	Released packer, laid down test tree and
		surface lines
	1600	Observed well, pulled out of hole
8.9.78	0315	Retrieved bombs

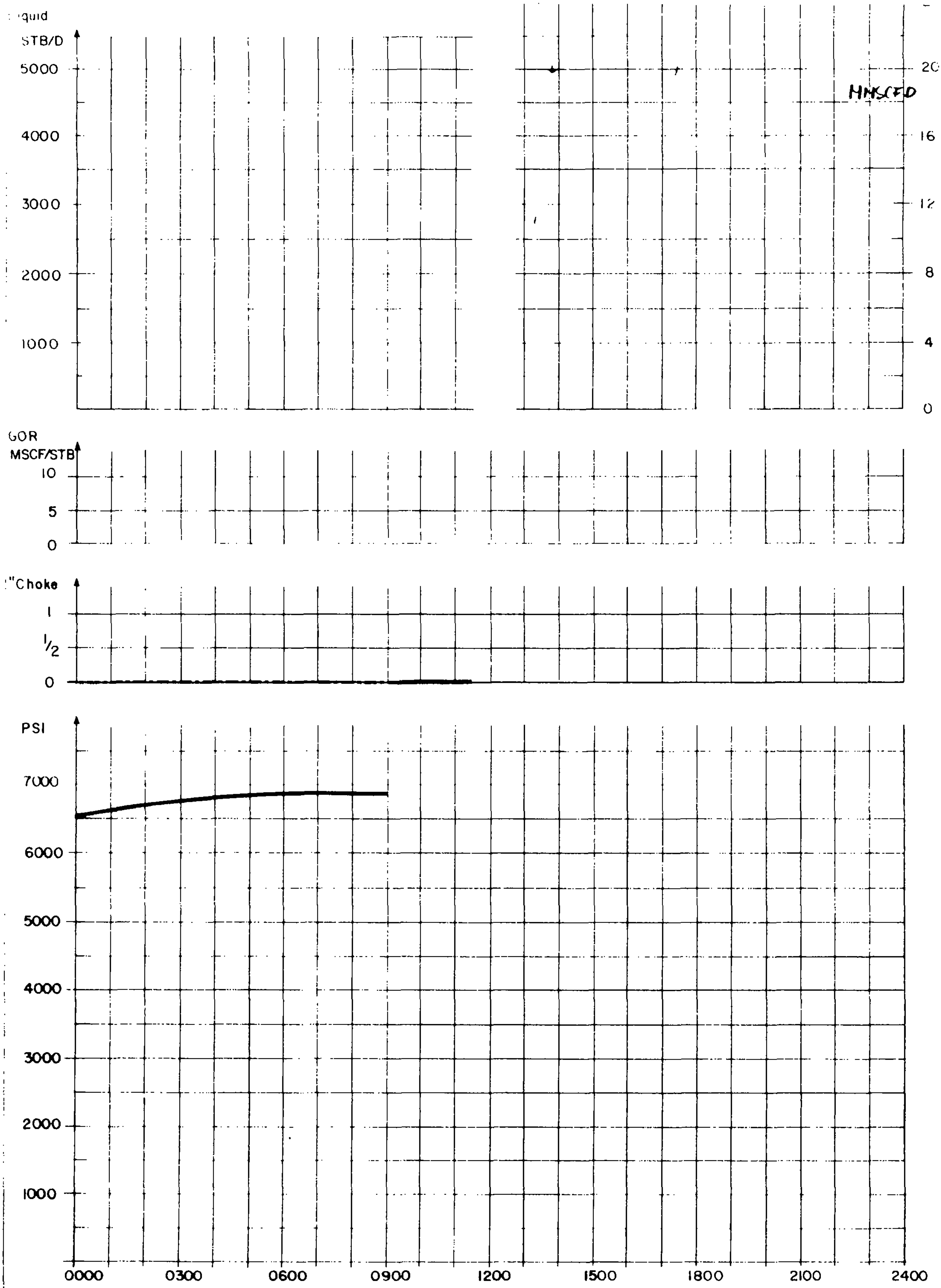
COMMENTS

PE ______

3. DATA FROM TESTSEQUENCE

3.1 Pressure choke and rate diagram





WELL: 1/9-3 DST NO: 2 DATE: 070978

3.2 Flow data

DATO | OPERASJON 2. Flow | Ark nr 1 av 2

BRØNN 1/9-3 | DST nr 2 | Perforert interval 3157-3180m RKB | Trykkmåler dybde

Tid	Operasjon	Choke 64"	WHP psi	WHT F	BHP psi	BHT F	Sep trykk psia	Sep temp. F	Gassrate MMSCFD	Liquid STBOPD	GOR SCF/STB	Olje API	Gass s.g.	Væskeanalyse på rigg: Sted	Vann %	Sediment %	Olje %	Olje API	Merknad
1200		48	<12		4891	239.2													
1300		"	<12		4316	242.6													
1315		"	70		3816														
1330		"	60	88	2901														
1345		"	160	89	2716														
1400		"	150	37	2816	242.4									50	5	45		
1415		"	120	85	3011														
1430		"	195	85	3127										67	5	28		
1445		"	110	81	3087										30	3	17		
1500		"	130	87	3118	247.8													
1515		32	110	87	3237										95.5	2	2.5		
1530		24	95	87	3431														
1545		"	155	88	3567										78.7	1.3	20		
1600		"	209	90	3578										88	2	10		24000 ppm cl-
1615		"	187	91	3619														
1630		"	200	92	3629														
1645		"	156	93	3670														
1700		"	161	93	3712	248.9									90.8	1.2	3		35000 ppm cl-
1715		"	206	96	3694														
1730		"	209	96	3670		75	80	.171				.725		89.5	.5	10		
1745		"	197	96	3667		75	85	.170	1470			"						
1800		"	196	96	3667	250.2	73	90	.174	1490			"		89.6	.4	10		37000 ppm cl-
1815		"	203	98	3673		73	92	.170	1494			.750						
1830		"	213	99	3680		75	93	.171	1448			"		39.5	.5	10		
1845		"	203	99	3666		75	94	.170	1586			"						
[illegible]		"	205	100	3666	250.9	75	94	.169	1505			"		94	1.0	5		39000 ppm cl-

DATO:

OPERASJON

BRØNN

DST nr.

Perforert interval

Trykkmåler dybde

Tid	Operasjon	Choke 64 in	WHP psi	WHT F	BHP psi	BHT F	Sep trykk psia	Sep temp F	Gasrate MMSCFD	Liquid STBOPD	GOR SCF/STB	Olje API	Gass s.g.	Væskeanalyse på rigg: Sted	Vann %	Sediment %	Olje %	Olje API	Merknad
1915			191	100	3666		75	94	.169	1526			.750						
1930			193	100	3666		74	94	.164	1634			"		937	.3	6		
1945			203	101	3660		74	94	.164	1478			"						
2000			205	101	3679	251.6	75	93	.166	1578			"		91.5	.5	8	33.5	40000 ppm cl-
2015			210	103	3685		75	93	.165	1644			"						
2030			210	103	3685		75	92	.166	1371			"		89.6	.4	10		
2045			213	104	3682		75	92	.165	1351			"						
2100			196	103	3682	252.1	75	92	.167	1379			"		89.5	.5	10	34.3	46000 ppm cl-
2115			203	103	3676		75	91	.164	1230			.768						
2130			224	104	3685		75	92	.164	1060			"						
2145			220	105	3714		75	90	.171	1123			"						
2200			212	105	3724	252.7	75	90	.180	1109			"						

4 TEST ANALYSIS

4.1 Buildup no 1

Horner analysis:

$p^* = 7041.3$ psi
$m = 636.3$ psi/decade
$kh = 37.4$ md·ft
$k = .5$ md
$s = .46$
$rd = 11$ ft

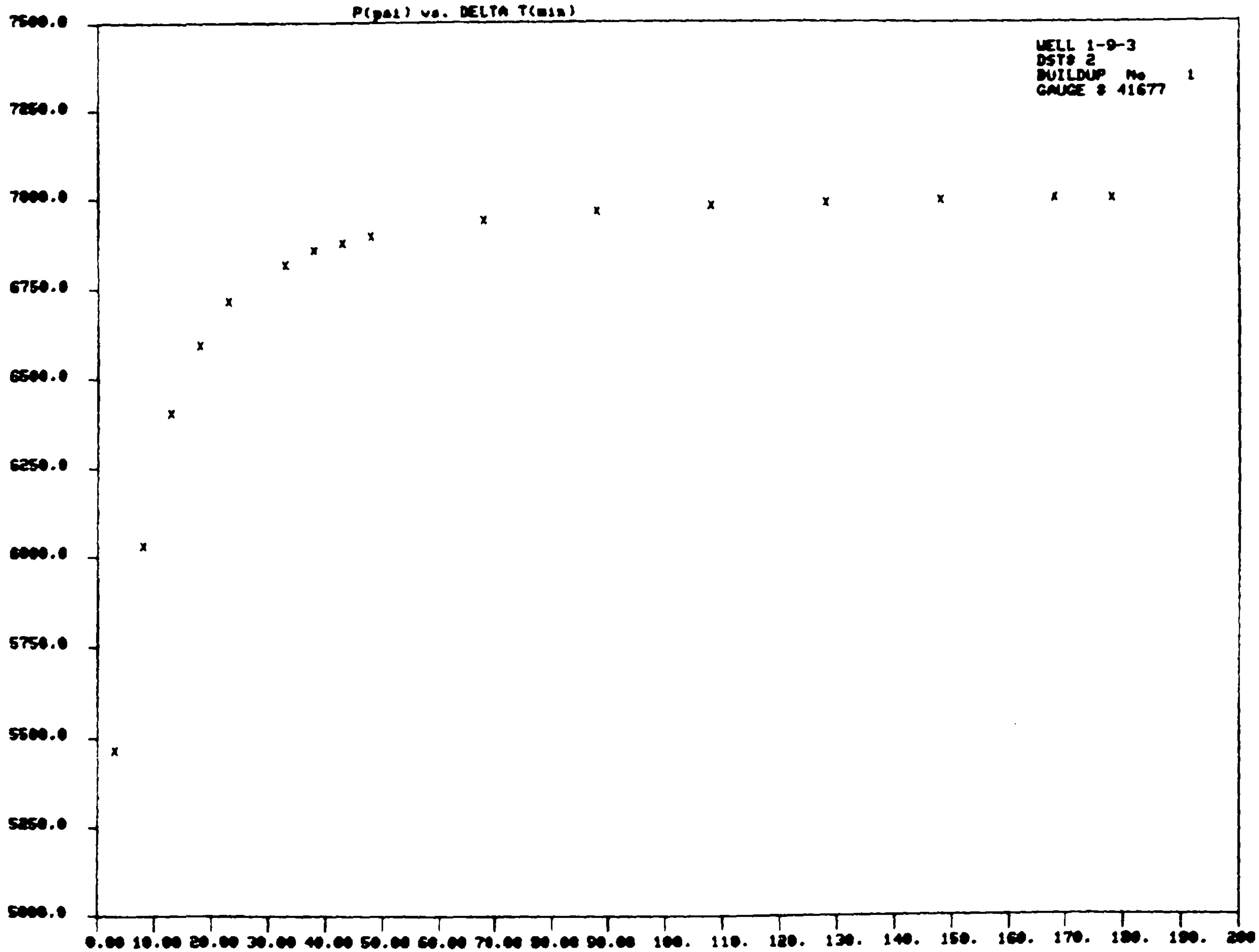
Enclosed:

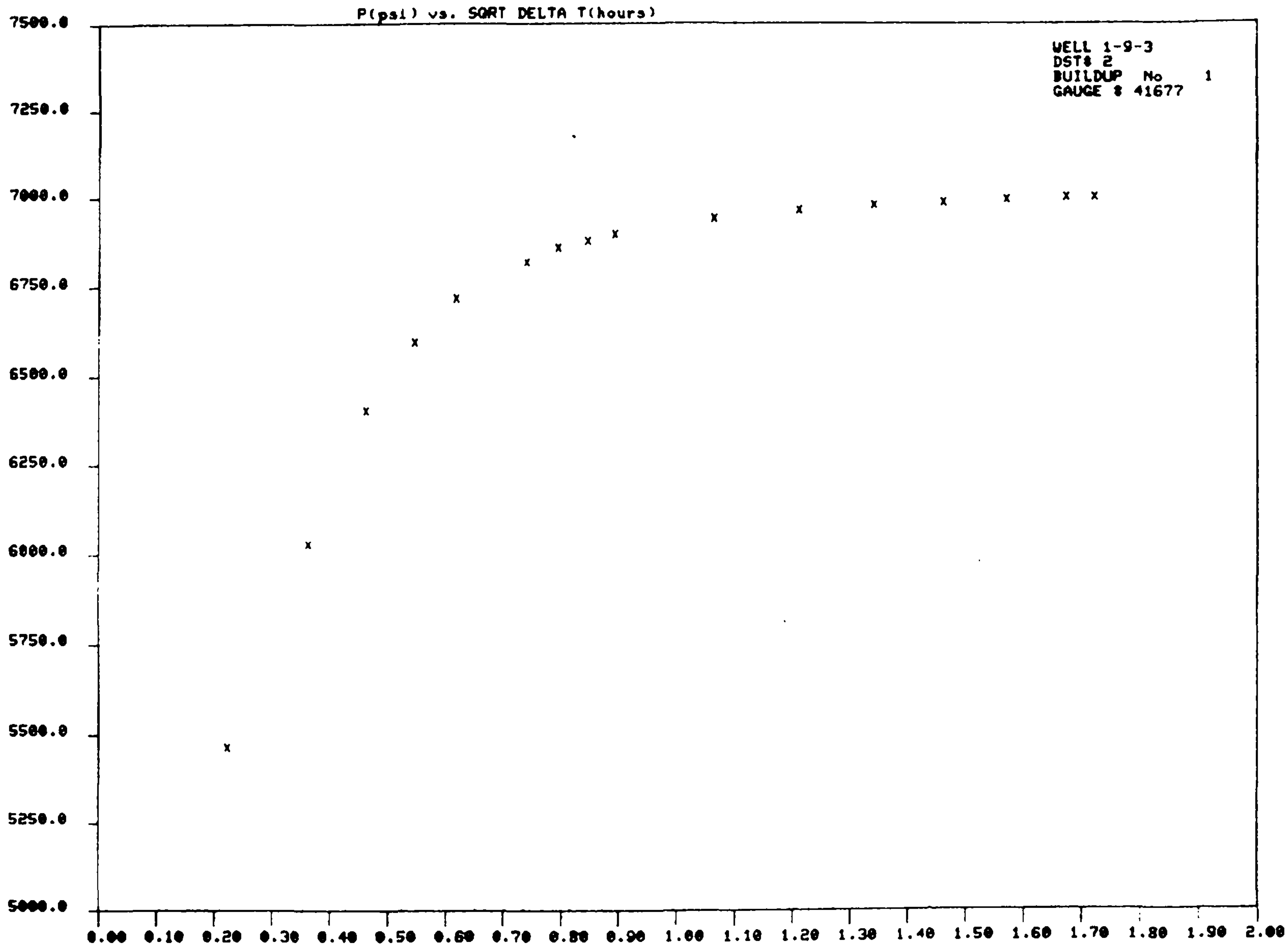
- pressure point table
- p vs. Δt
- p vs. $\sqrt{\Delta t}$
- $\log \Delta p$ vs. $\log \Delta t$
- type curve match
- p vs. $\log ((t+\Delta t)/\Delta t)$ with straight line.

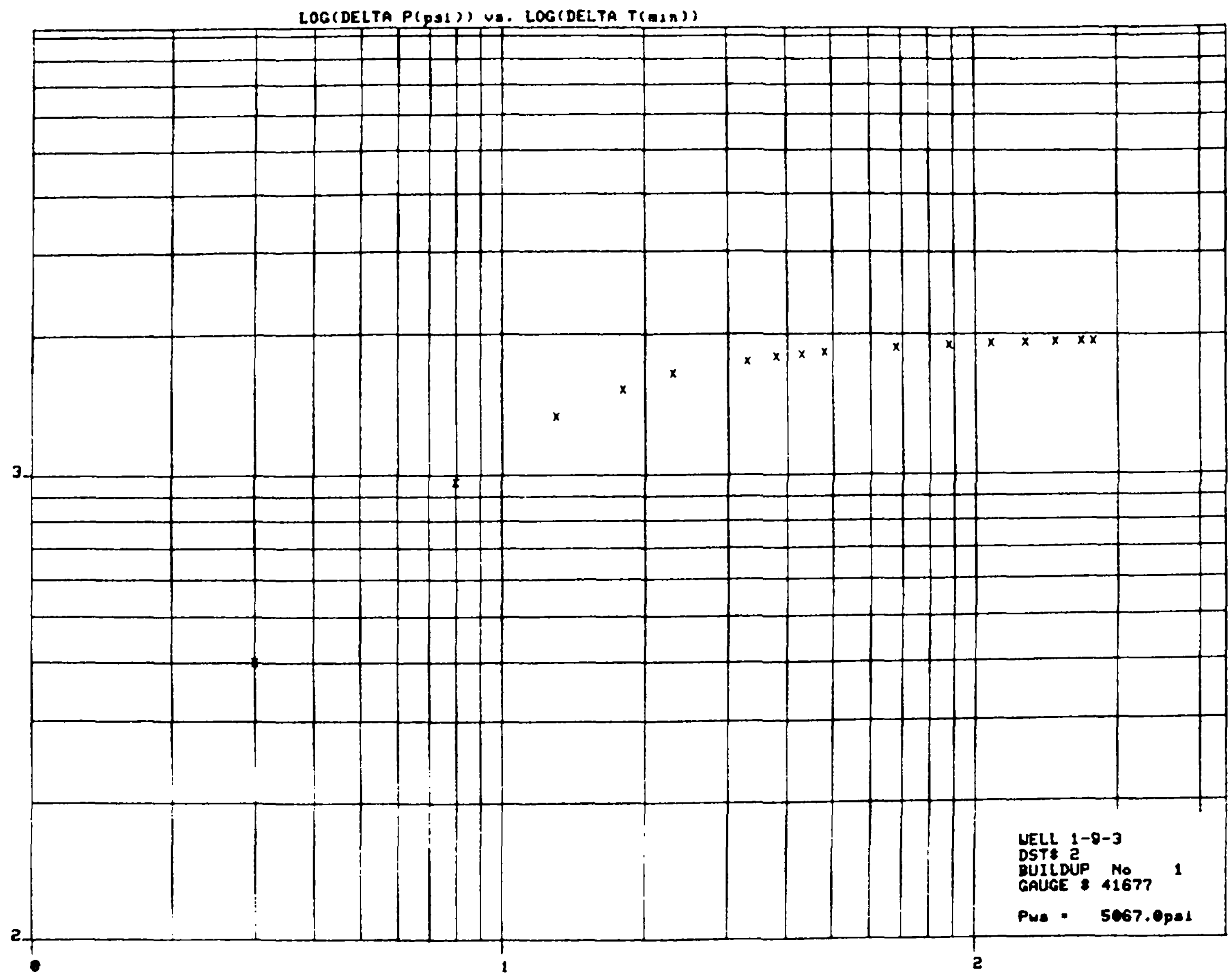
BROWN 1-9-3   DST8 2
BUILDUP NUMMER 1
GAUGE 41677

NR.	TID	TRYKK
1	8.15	5400.900
2	8.20	6031.300
3	8.25	6403.500
4	8.30	6592.600
5	8.35	6714.600
6	8.45	6814.700
7	8.50	6854.400
8	8.55	6873.300
9	9.00	6891.600
10	9.20	6935.500
11	9.40	6960.000
12	10.00	6974.000
13	10.20	6982.500
14	10.40	6990.400
15	11.00	6997.100
16	11.10	6997.100

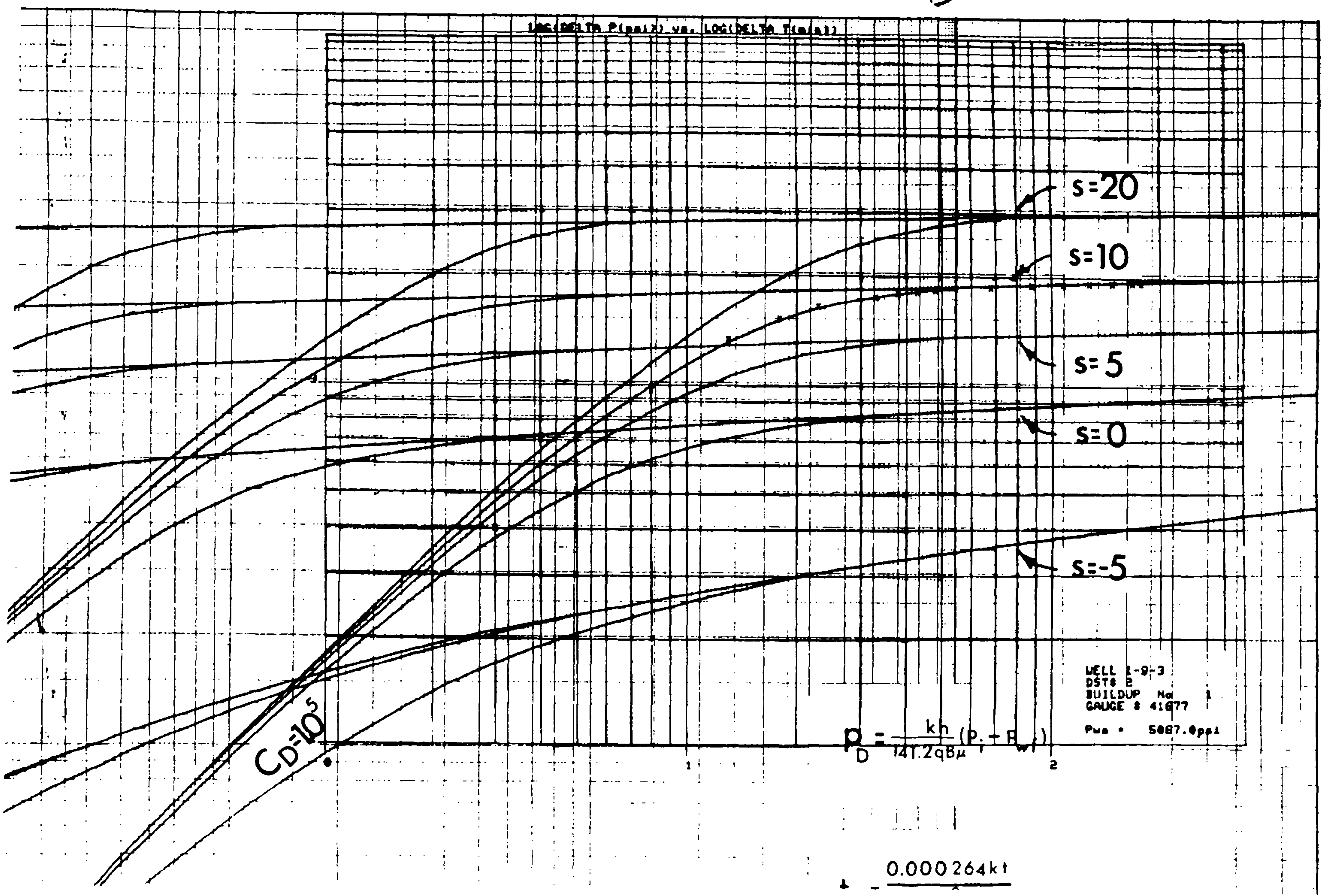
GI TYPE EDITERING
0 - SLUTT
1 - LISTING
2 - SLETTING
3 - ADDERING
4 - ERSTATTING

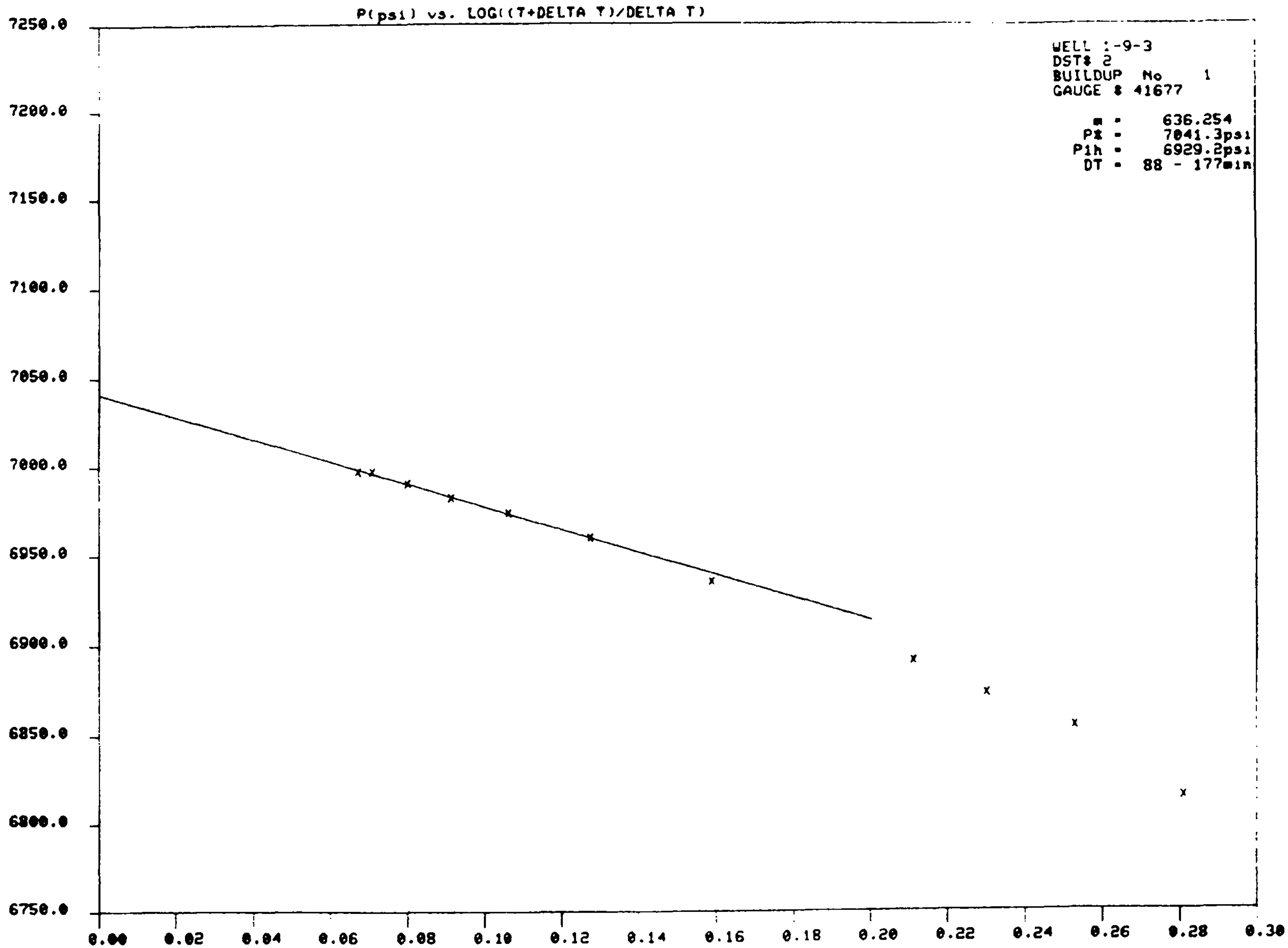

P(psi) vs. DELTA T(min)
WELL 1-9-3
DST# 2
BUILDUP No 1
GAUGE # 41677
7500.0
7250.0
7000.0
6750.0
6500.0
6250.0
6000.0
5750.0
5500.0
5250.0
5000.0
0.00 10.00 20.00 30.00 40.00 50.00 60.00 70.00 80.00 90.00 100. 110. 120. 130. 140. 150. 160. 170. 180. 190. 200.


P(psi) vs. SQRT DELTA T(hours)
WELL 1-9-3
DST$ 2
BUILDUP No 1
GAUGE $ 41677
7500.0
7250.0
7000.0
6750.0
6500.0
6250.0
6000.0
5750.0
5500.0
5250.0
5000.0
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00
1.10
1.20
1.30
1.40
1.50
1.60
1.70
1.80
1.90
2.00


LOG(DELTA P(psi)) vs. LOG(DELTA T(min))
3
2
0
1
2
WELL 1-9-3
DST# 2
BUILDUP No 1
GAUGE # 41677
Pws = 5067.0psi

TORAGE AND SKIN EFFECT




P(psi) vs. LOG((T+DELTA T)/DELTA T)
WELL :-9-3
DST# 2
BUILDUP No 1
GAUGE # 41677
m = 636.254
P* = 7041.3psi
P1h = 6929.2psi
DT = 88 - 177min
7250.0
7200.0
7150.0
7100.0
7050.0
7000.0
6950.0
6900.0
6850.0
6800.0
6750.0
0.00
0.02
0.04
0.06
0.08
0.10
0.12
0.14
0.16
0.18
0.20
0.22
0.24
0.26
0.28
0.30

4.2 Buildup no 2

No fracture indictions. The log-log field plot is matched on to the type curve with wellbore storage and skin.

Horner analysis:

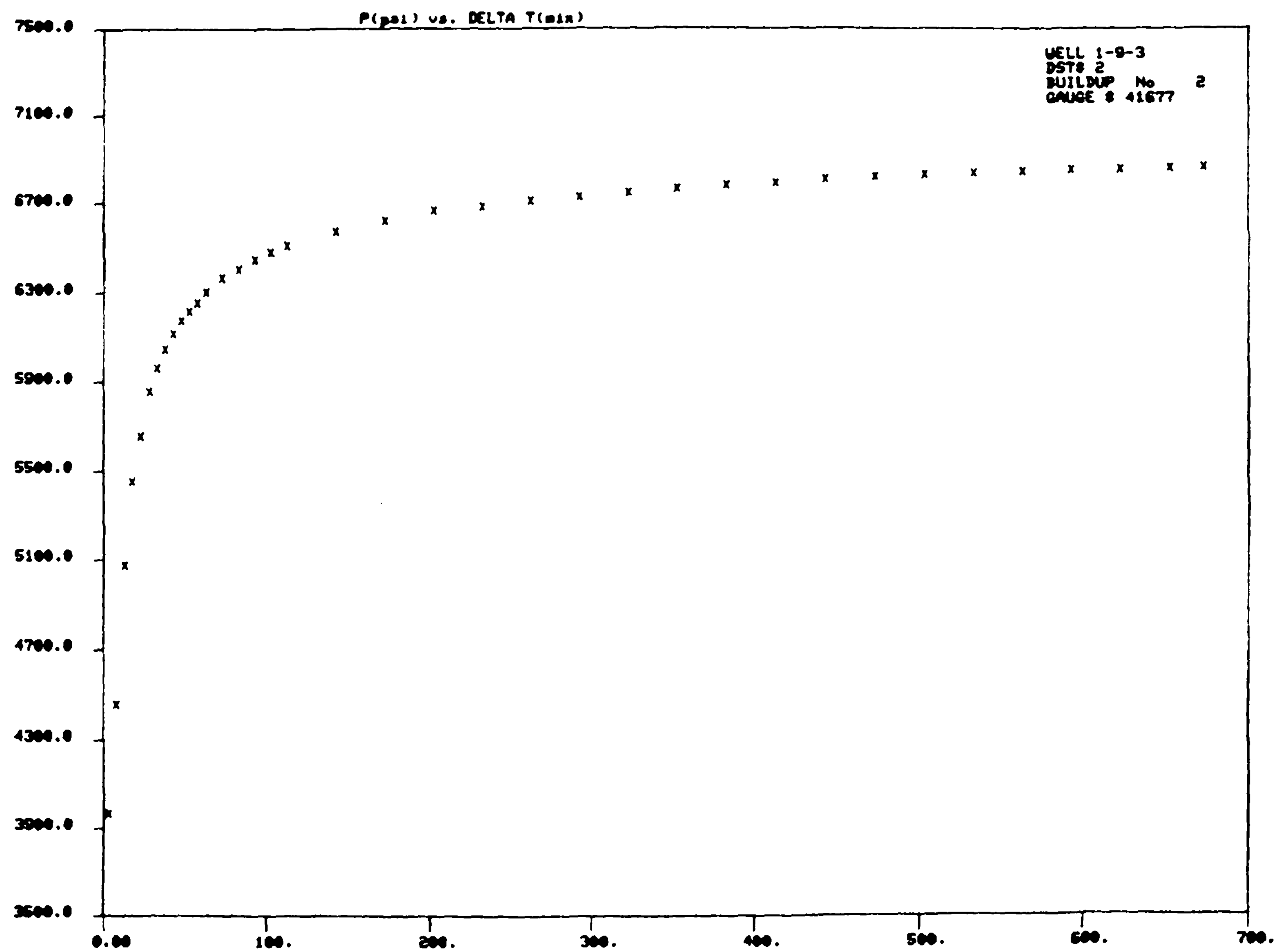
p^* = 7045.9 psi
m = 631.3 psi/decade
kh = 104 md·ft
k = 1.37 md
s = 1.0
rd = 84 ft
Δps = 630 psi
Jactual/Jideal = .84

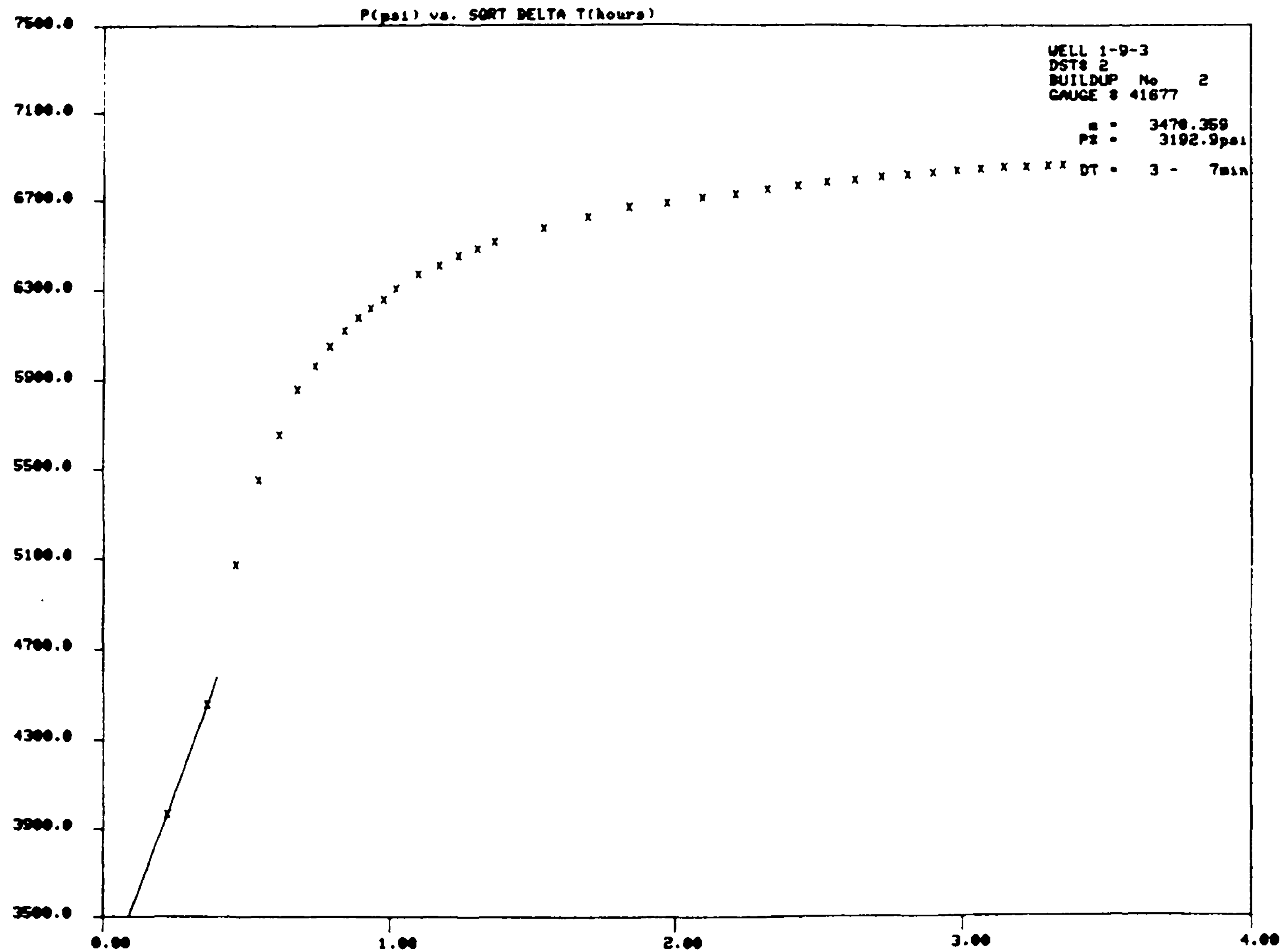
Enclosed:

- pressure point table
- p vs. Δt
- p vs. $\sqrt{\Delta t}$
- log p vs. log Δt
- type curve match
- p vs. log $((t+\Delta t)/\Delta t)$ complete plot
- p vs. log $((t+\Delta t)/\Delta t)$ with straight line

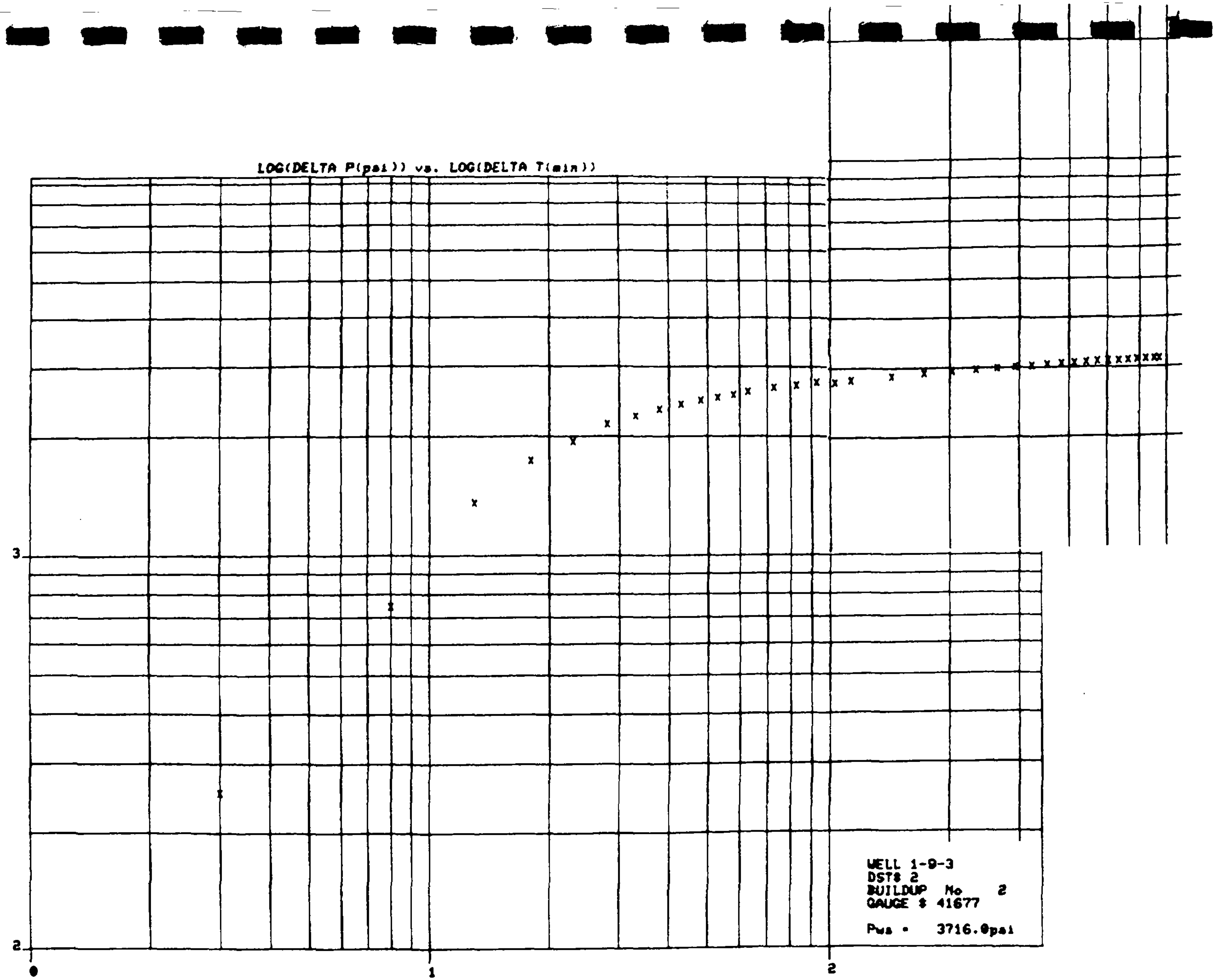
BRONN 1-9-3 DST# 2
BUILDUP NUMMER 2
GAUGE 41677

NR.	TID	TRYKK
1	22.10	3968.900
2	22.15	4460.100
3	22.20	5075.800
4	22.25	5452.800
5	22.30	5656.000
6	22.35	5857.400
7	22.40	5961.100
8	22.45	6046.500
9	22.50	6116.700
10	22.55	6174.000
11	23.00	6215.500
12	23.05	6254.000
13	23.10	6301.600
14	23.20	6365.600
15	23.30	6403.500
16	23.40	6446.200
17	23.50	6476.700
18	0.00	6507.200
19	0.30	6568.200
20	1.00	6617.000
21	1.30	6659.700
22	2.00	6678.000
23	2.30	6702.400
24	3.00	6720.700
25	3.30	6742.100
26	4.00	6760.400
27	4.30	6775.700
28	5.00	6785.400
29	5.30	6800.000
30	6.00	6811.000
31	6.30	6821.400
32	7.00	6830.600
33	7.30	6836.700
34	8.00	6845.800
35	8.30	6848.900
36	9.00	6855.000
37	9.20	6858.600

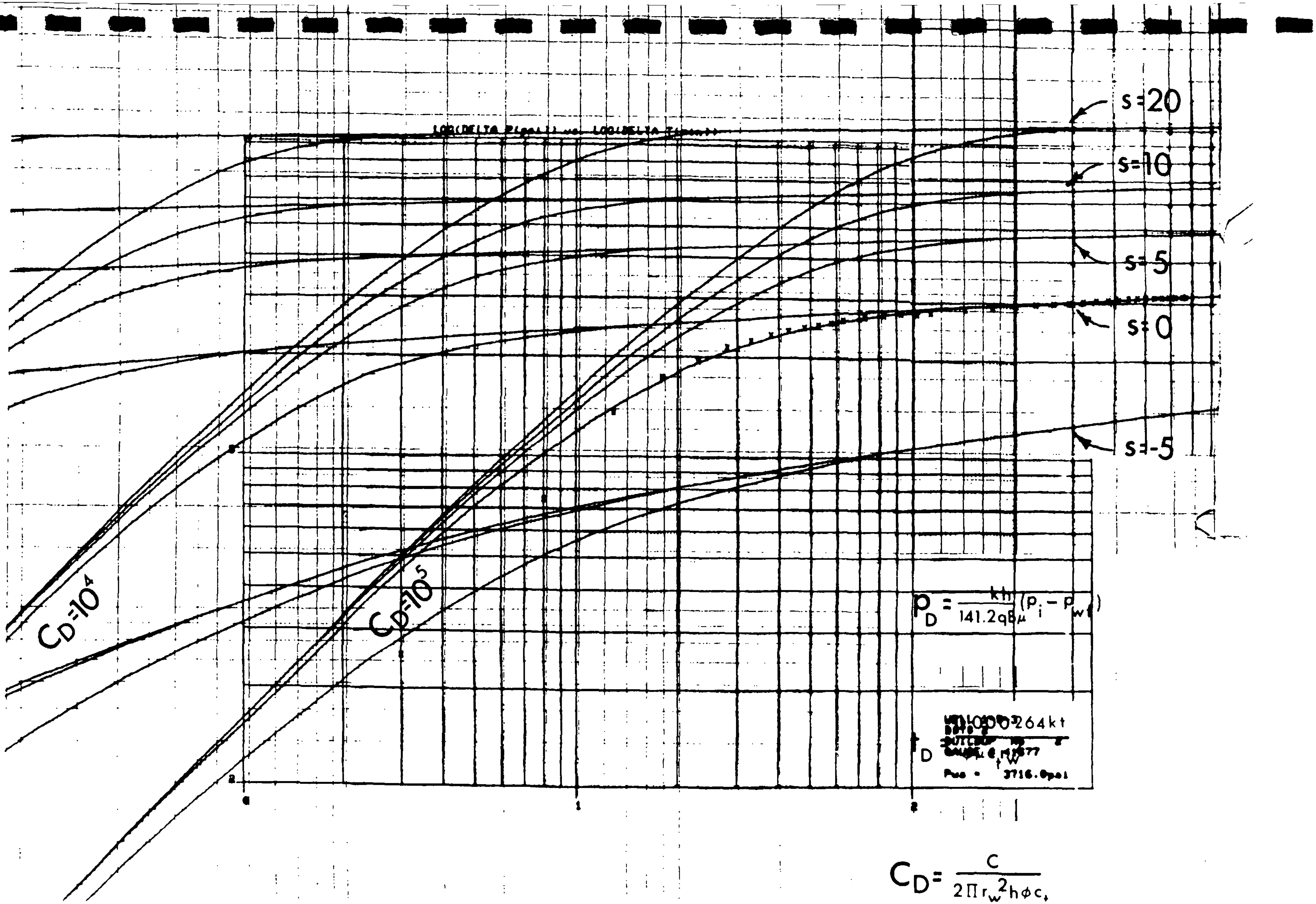

P(psi) vs. DELTA T(min)
WELL 1-9-3
DST# 2
BUILDUP No 2
GAUGE # 41677
7500.0
7100.0
6700.0
6300.0
5900.0
5500.0
5100.0
4700.0
4300.0
3900.0
3500.0
0.00
100.
200.
300.
400.
500.
600.
700.

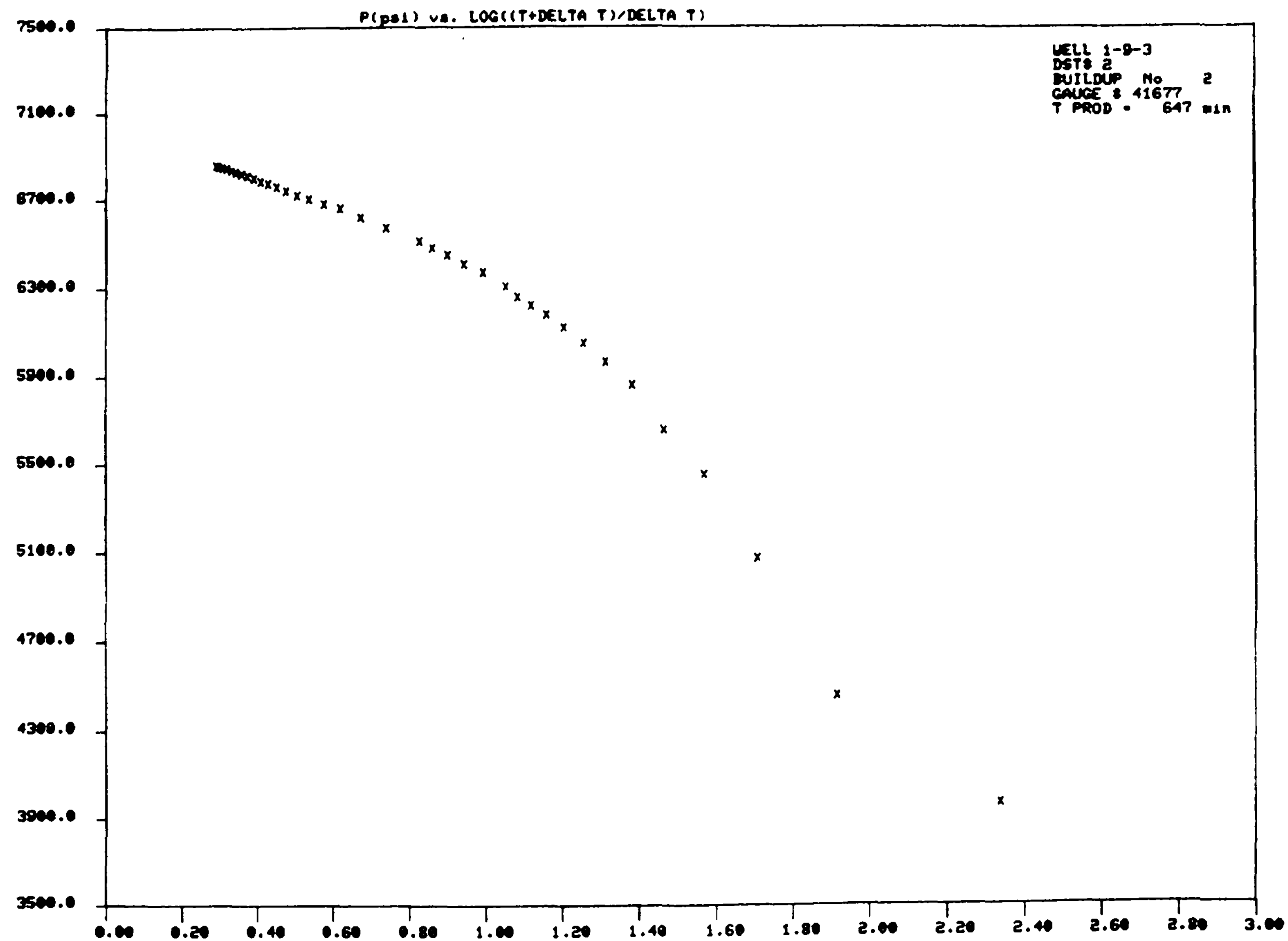


P(psi) vs. SQRT DELTA T(hours)
WELL 1-9-3
DST# 2
BUILDUP No 2
GAUGE # 41677
m = 3470.359
P* = 3192.9psi
DT = 3 - 7min
7500.0
7100.0
6700.0
6300.0
5900.0
5500.0
5100.0
4700.0
4300.0
3900.0
3500.0
0.00
1.00
2.00
3.00
4.00

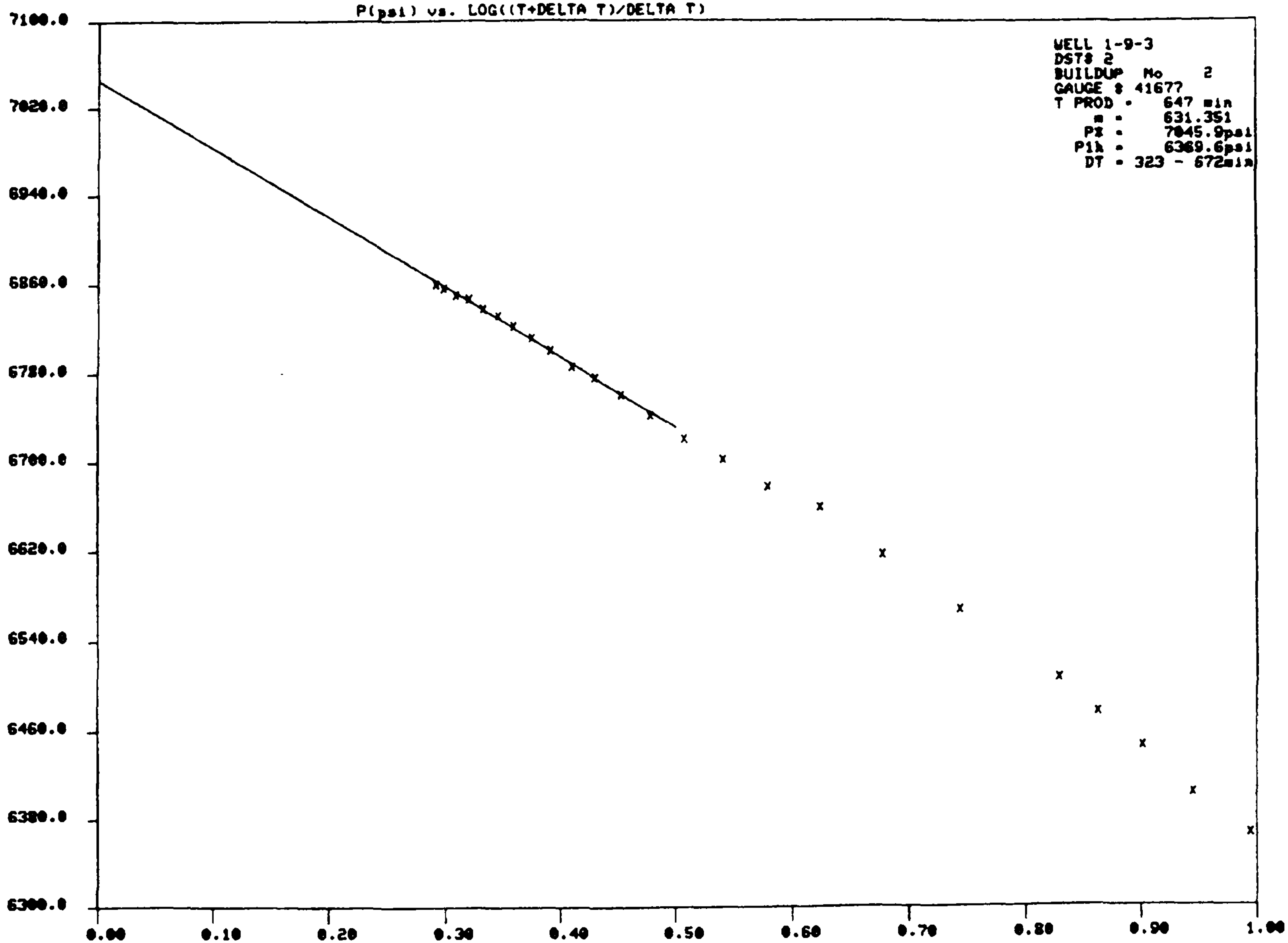


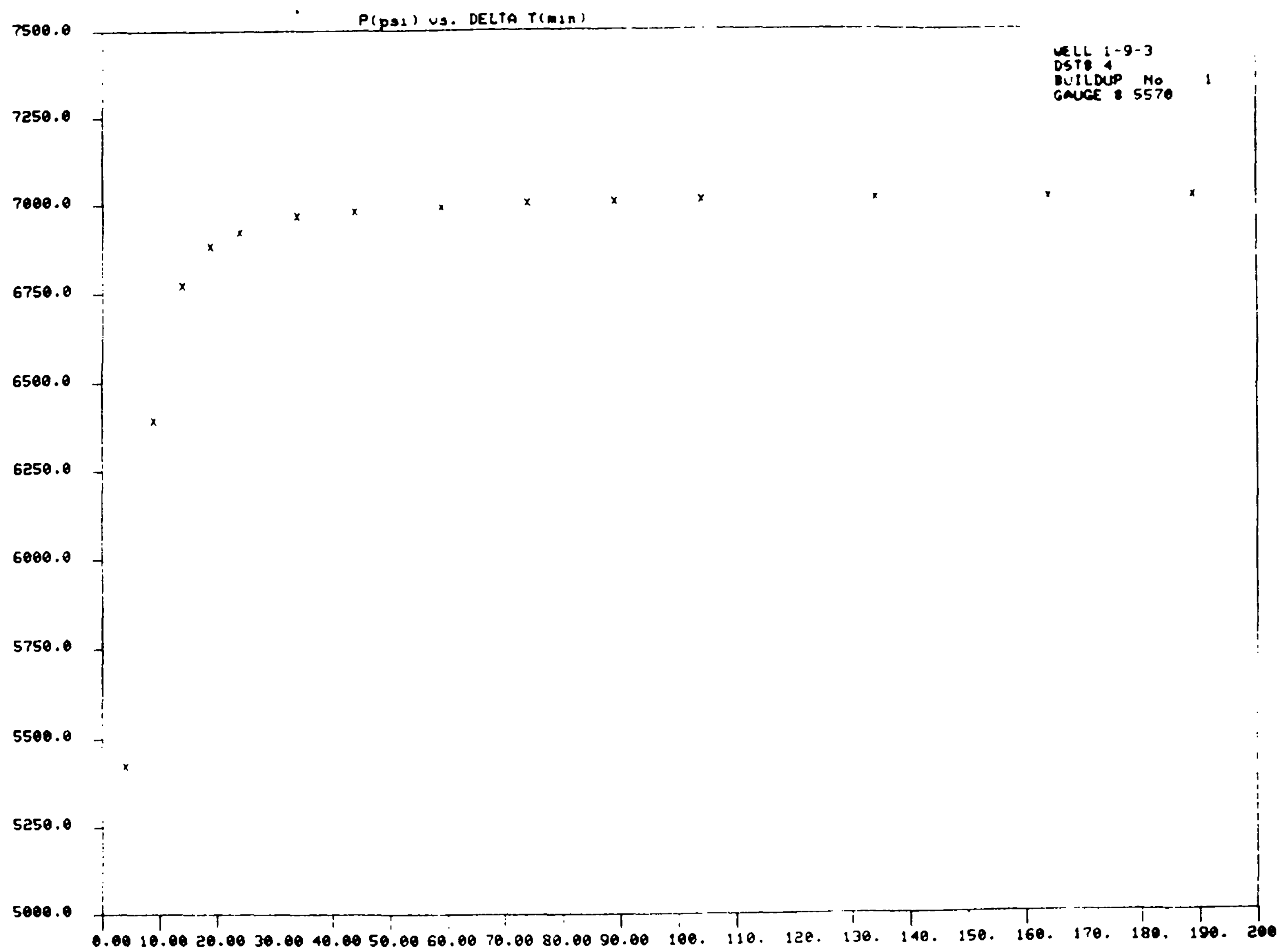
LOG(DELTA P(psi)) vs. LOG(DELTA T(min))
3
2
0
1
2
WELL 1-9-3
DST# 2
BUILDUP No 2
GAUGE # 41677
Pws = 3716.0psi

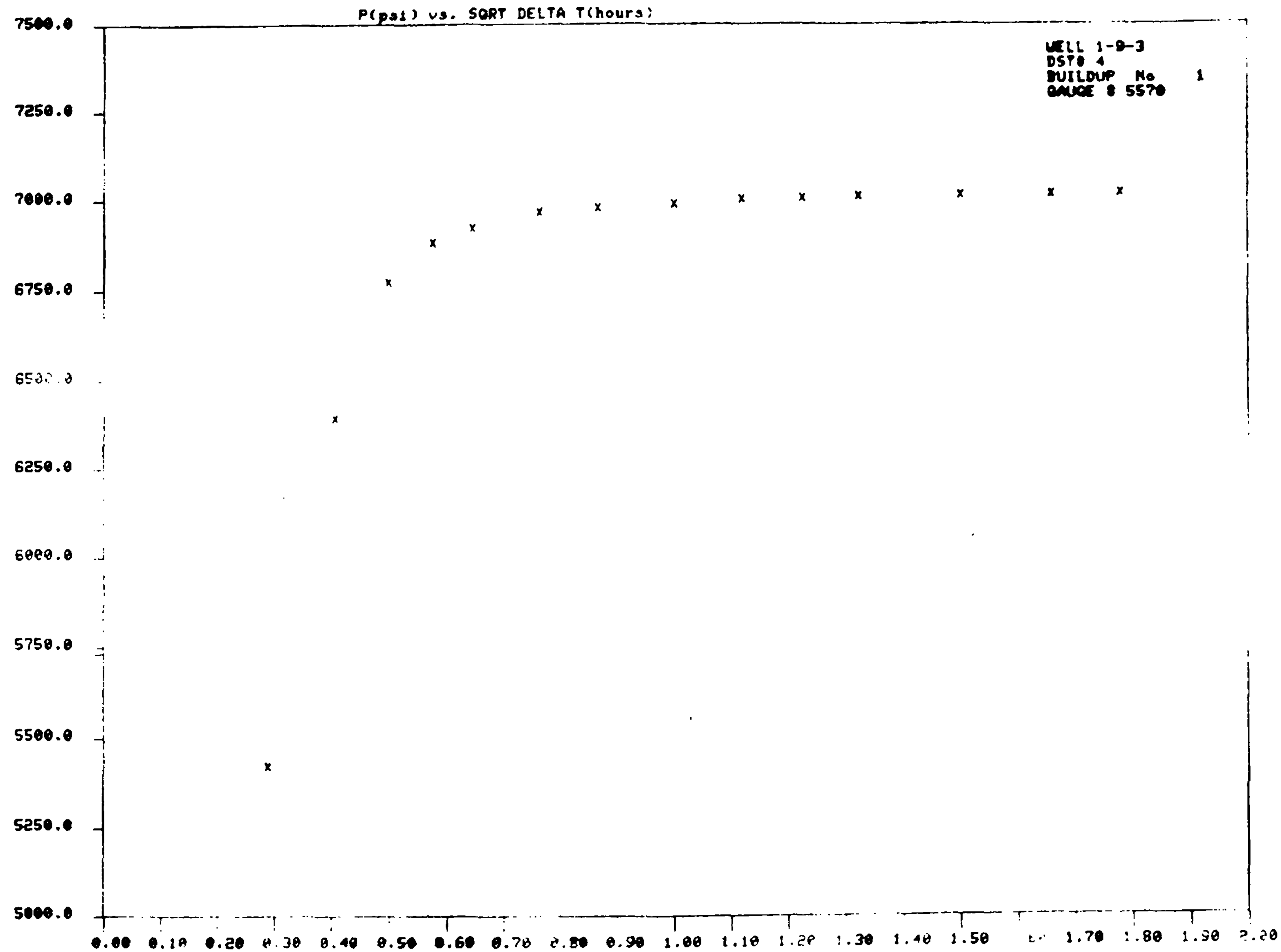

s=20
s=10
s=5
s=0
s=-5
$C_D=10^4$
$C_D=10^5$
$p_D = \frac{kh}{141.2 qB\mu}(p_i - p_{wf})$
$t_D = \frac{0.000264 kt}{\phi\mu c_t r_w^2}$
$C_D = \frac{C}{2\pi r_w^2 h\phi c_t}$

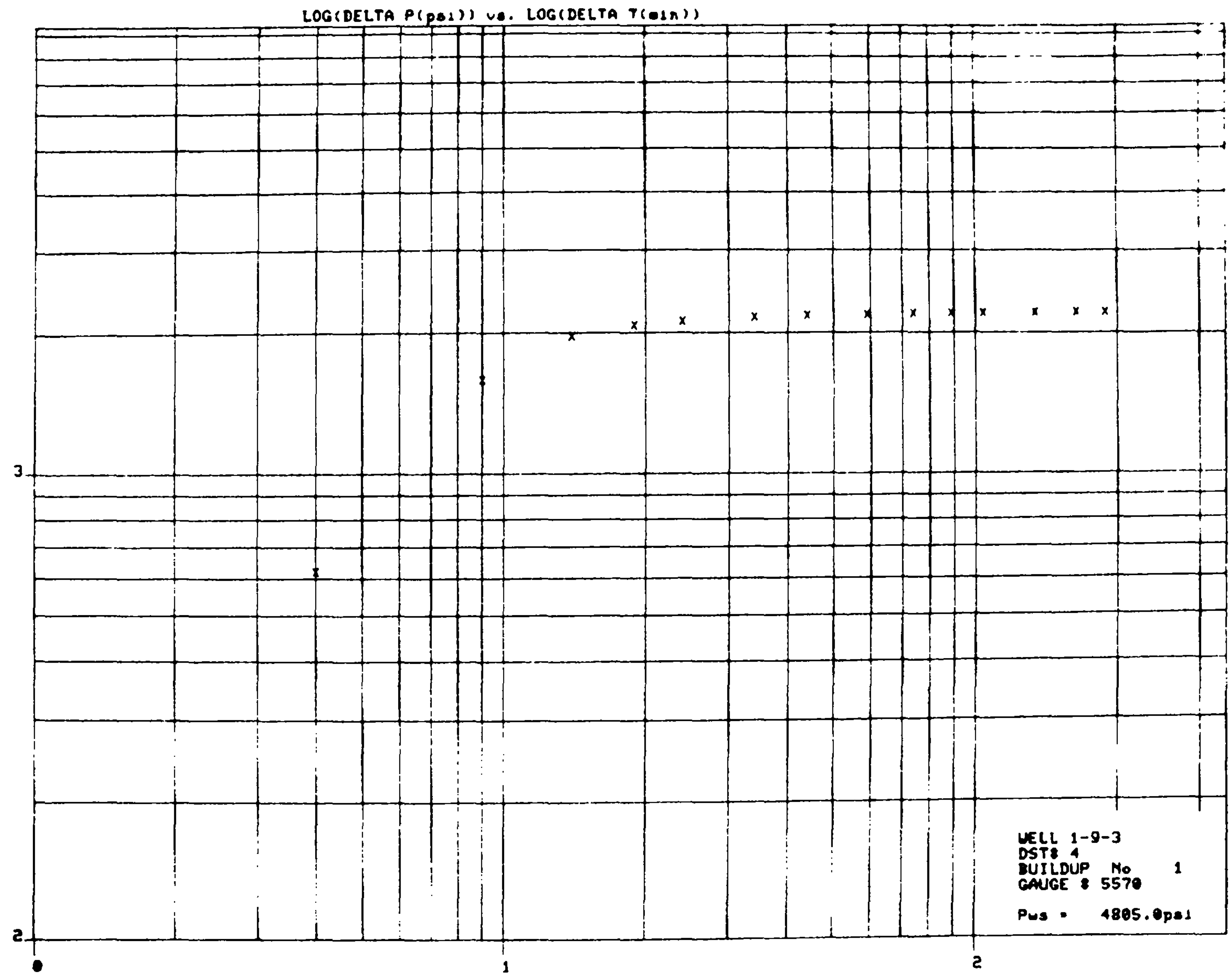

P(psi) vs. LOG((T+DELTA T)/DELTA T)
WELL 1-9-3
DST# 2
BUILDUP No 2
GAUGE # 41677
T PROD = 647 min
7500.0
7100.0
6700.0
6300.0
5900.0
5500.0
5100.0
4700.0
4300.0
3900.0
3500.0
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
1.60
1.80
2.00
2.20
2.40
2.60
2.80
3.00

P(psi) vs. LOG((T+DELTA T)/DELTA T)




P(psi) vs. DELTA T(min)
WELL 1-9-3
DST# 4
BUILDUP No 1
GAUGE # 5570
7500.0
7250.0
7000.0
6750.0
6500.0
6250.0
6000.0
5750.0
5500.0
5250.0
5000.0
0.00 10.00 20.00 30.00 40.00 50.00 60.00 70.00 80.00 90.00 100. 110. 120. 130. 140. 150. 160. 170. 180. 190. 200.


P(psi) vs. SQRT DELTA T(hours)
WELL 1-9-3
DST# 4
BUILDUP No 1
GAUGE # 5570
7500.0
7250.0
7000.0
6750.0
6250.0
6000.0
5750.0
5500.0
5250.0
5000.0
0.00
0.10
0.20
0.40
0.50
0.60
0.70
0.90
1.00
1.10
1.30
1.40
1.50
1.70
1.80
1.90


LOG(DELTA P(psi)) vs. LOG(DELTA T(min))
3
2
0
1
2
WELL 1-9-3
DST$ 4
BUILDUP No 1
GAUGE $ 5570
Pws = 4805.0psi

4 TEST ANALYSIS

4.1 Buildup no 1

No indication of linear flow. Both gas and water may have flowed.

Horner analysis:

$p^* = 7026.4$ psi
$m = 185.6$ psi/decade

Assume gas was flowing:

kh = 12.1 md·ft
k = 0.20 md
rd = 13 ft
s = 10.5

Assume water was flowing:

kh = 140 md·ft
k = 2.3 md
rd = 16 ft
s = 10.3

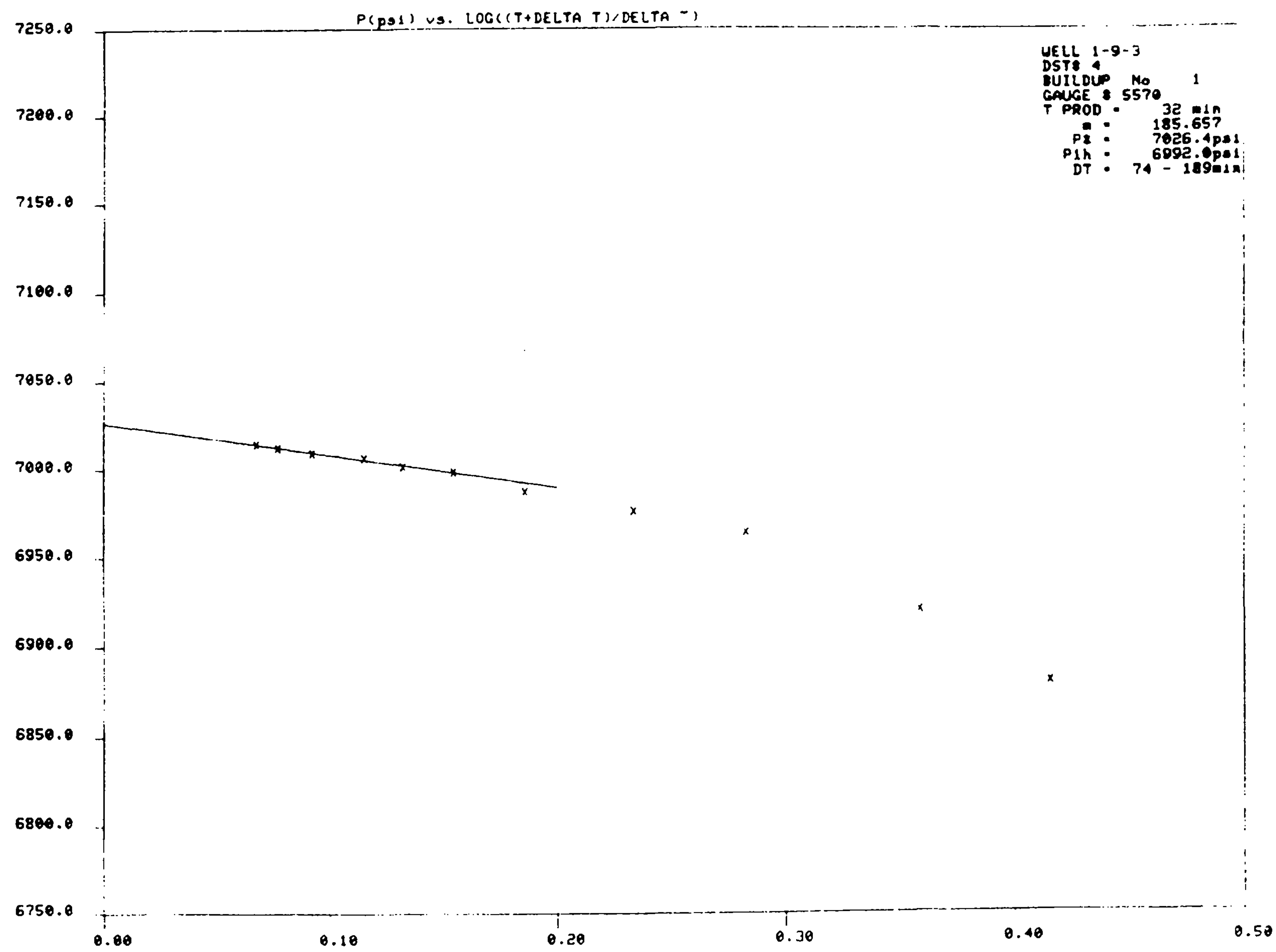
It is felt from later analysis that the gas case is the most probable one.

Enclosed:

- pressure point table
- p vs. Δt
- p vs. $\sqrt{\Delta t}$
- log Δp vs. log Δt
- p vs. log $((t+\Delta t)/\Delta t)$ with straight line

BRØNN 1-9-3 DST# 4
BUILDUP NUMMER 1
GAUGE 5570

NR.	TID	TRYKK
1	12.20	5424.000
2	12.25	6393.000
3	12.30	6771.000
4	12.35	6880.000
5	12.40	6920.000
6	12.50	6964.000
7	13.00	6976.000
8	13.15	6987.000
9	13.30	6998.000
10	13.45	7001.000
11	14.00	7006.000
12	14.30	7009.000
13	15.00	7012.000
14	15.25	7014.000


P(psi) vs. LOG((T+DELTA T)/DELTA ~)
WELL 1-9-3
DST# 4
BUILDUP No 1
GAUGE # 5570
T PROD = 32 min
m = 185.657
P* = 7026.4psi
P1h = 6992.0psi
DT = 74 - 189min
7250.0
7200.0
7150.0
7100.0
7050.0
7000.0
6950.0
6900.0
6850.0
6800.0
6750.0
0.00
0.10
0.20
0.30
0.40
0.50

4.2 Drawdown no 2

The pressure data show some irregular behavior during the early part of the flow.

From the square root data plot:

$pi = 5245$ psi
$mvf = 1265$ psi/$\sqrt{hr}$

Under the assumption of flowing gas and
k = .5 md:

xf = 3 ft

The pi from the square root data plot is used to generate the field type curve. This plot indicates linear flow for 10-20 mins.

The p vs. log t is showing quite a bit of scattering, never the less, a drawdown analysis is made:

m = 265.8 psi/decade
kh = 84.5 md·ft
k = 1.43 md

This is not considered to be a very reliable estimate of k.

Enclosed:

- pressure point table

- p vs. t

- p vs. $\sqrt{t}$ with a straight line

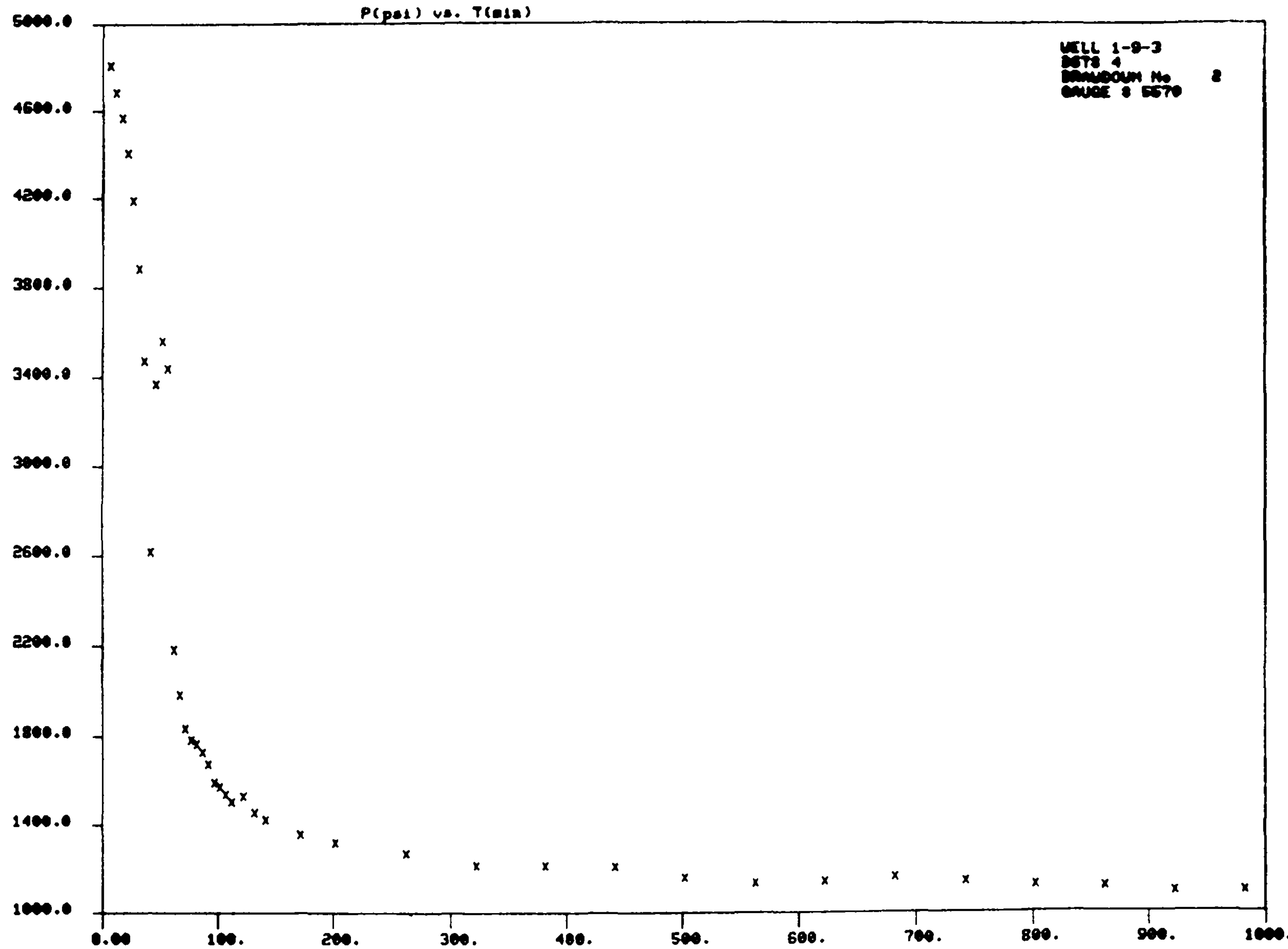
- log p vs. log t

- p vs. log t

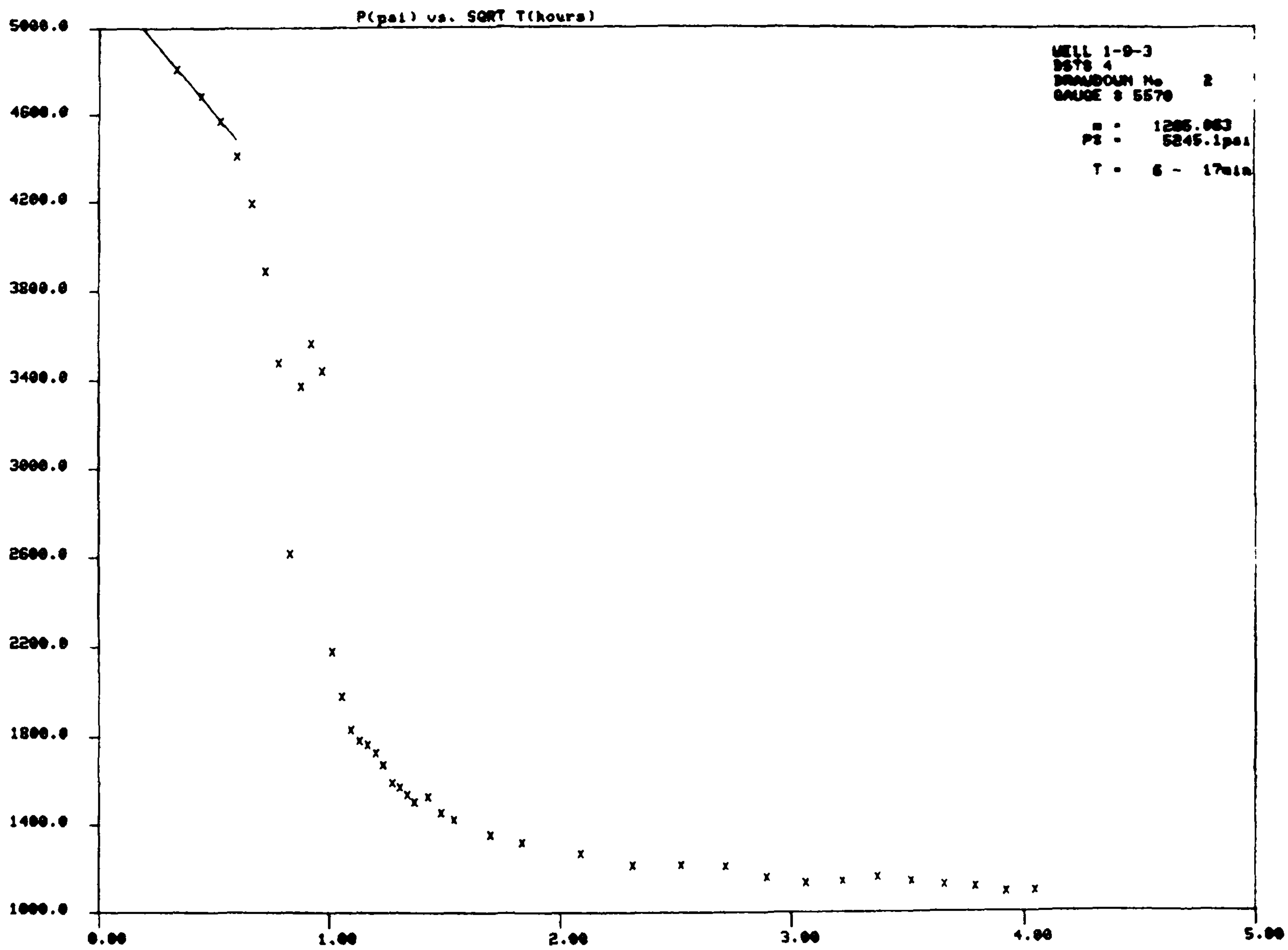
- p vs. log t with a straight line

BRØNN 1-9-3 DST# 4
DRAWDOWN NUMMER 2
GAUGE 5570

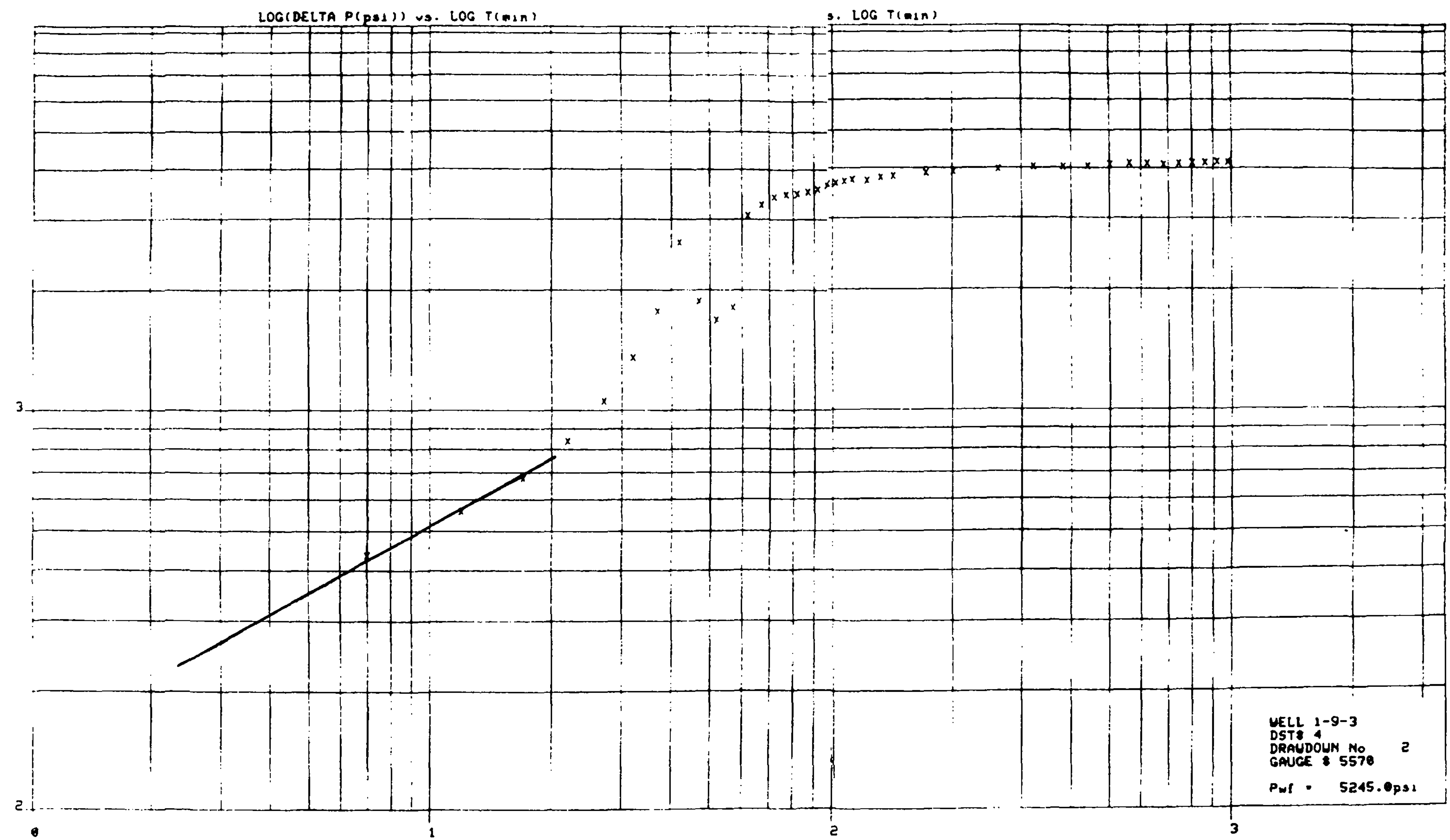
NR.	TID	TRYKK
1	15.45	4810.000
2	15.50	4688.000
3	15.55	4568.000
4	16.00	4406.000
5	16.05	4189.000
6	16.10	3885.000
7	16.15	3475.000
8	16.20	2619.000
9	16.25	3370.000
10	16.30	3562.000
11	16.35	3438.000
12	16.40	2184.000
13	16.45	1986.000
14	16.50	1837.000
15	16.55	1787.000
16	17.00	1768.000
17	17.05	1731.000
18	17.10	1678.000
19	17.15	1595.000
20	17.20	1576.000
21	17.25	1542.000
22	17.30	1507.000
23	17.40	1533.000
24	17.50	1458.000
25	18.00	1427.000
26	18.30	1359.000
27	19.00	1321.000
28	20.00	1272.000
29	21.00	1216.000
30	22.00	1216.000
31	23.00	1210.000
32	0.00	1160.000
33	1.00	1135.000
34	2.00	1141.000
35	3.00	1160.000
36	4.00	1141.000
37	5.00	1123.000
38	6.00	1115.000
39	7.00	1092.000
40	8.00	1095.000



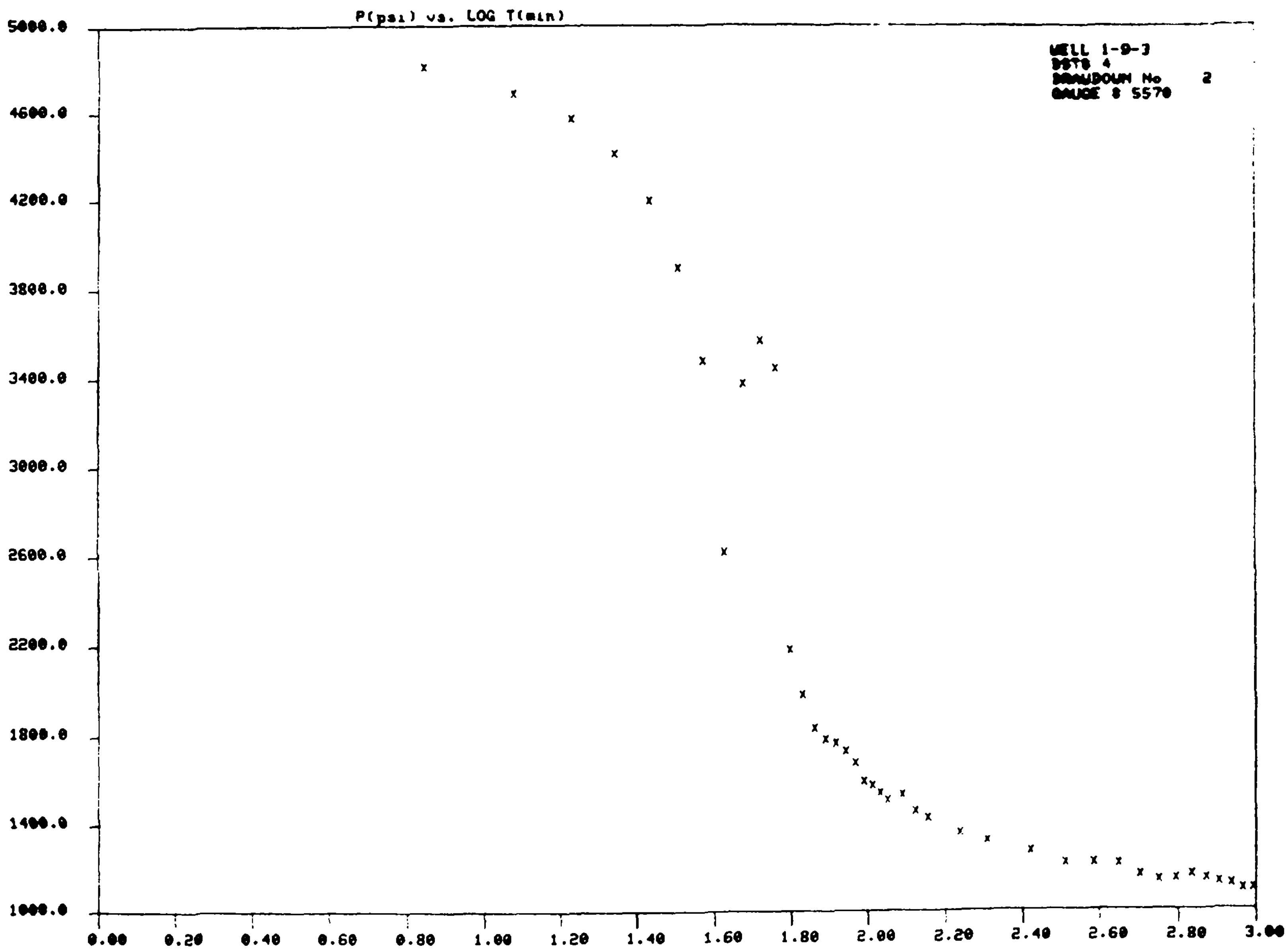
P(psi) vs. T(min)
WELL 1-9-3
DSTS 4
DRAWDOWN No 2
GAUGE S 5570
5000.0
4600.0
4200.0
3800.0
3400.0
3000.0
2600.0
2200.0
1800.0
1400.0
1000.0
0.00
100.
200.
300.
400.
500.
600.
700.
800.
900.
1000.

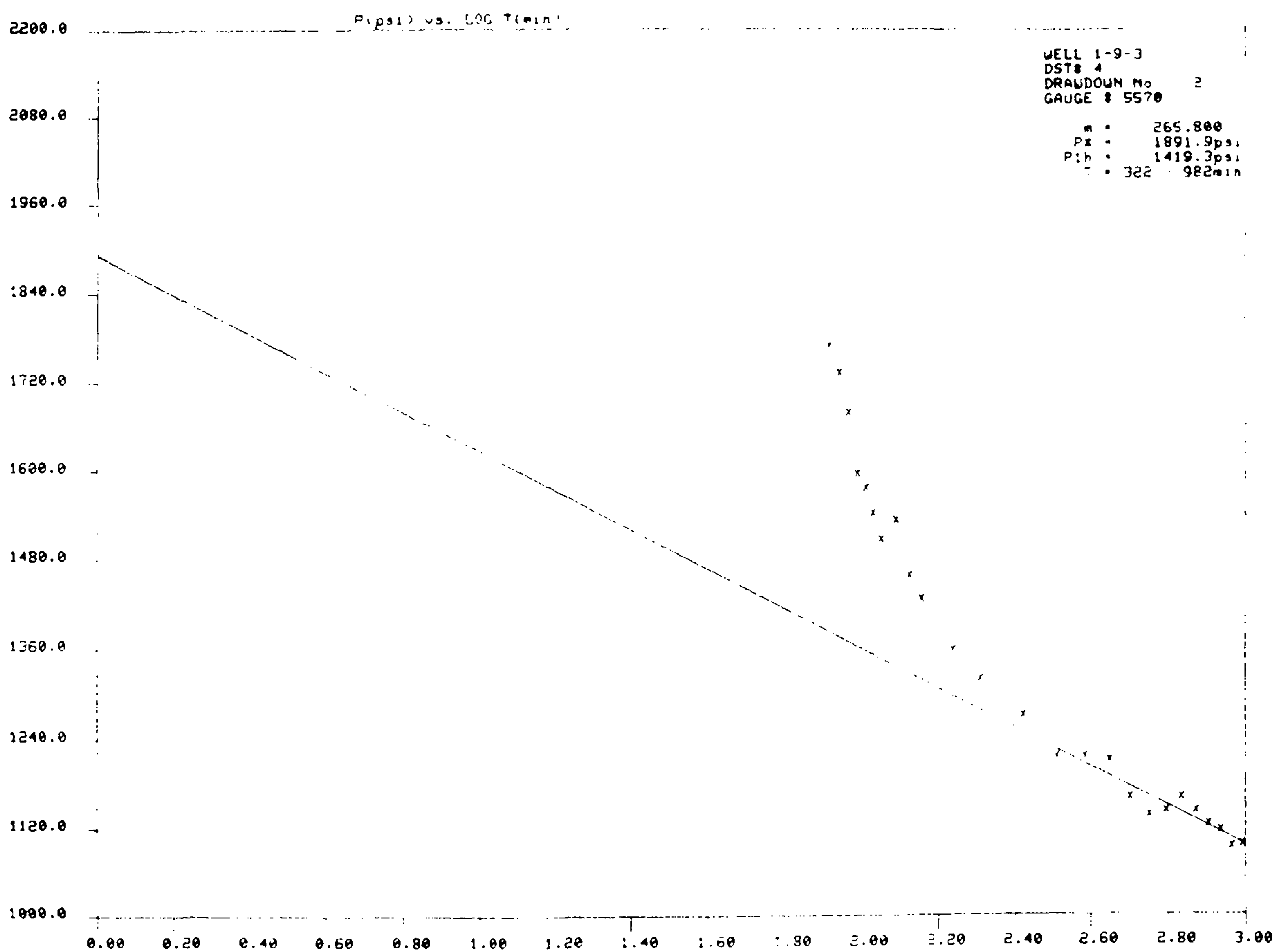


P(psi) vs. SQRT T(hours)
WELL 1-9-3
DST# 4
DRAWDOWN No 2
GAUGE # 5570
m = 1205.083
Pi = 5245.1psi
T = 6 - 17min
5000.0
4600.0
4200.0
3800.0
3400.0
3000.0
2600.0
2200.0
1800.0
1400.0
1000.0
0.00
1.00
2.00
3.00
4.00
5.00



LOG(DELTA P(psi)) vs. LOG T(min)
s. LOG T(min)
3
2
0
1
2
3
WELL 1-9-3
DST# 4
DRAWDOWN No 2
GAUGE # 5570
Pwf = 5245.0psi


P(psi) vs. LOG T(min)
WELL 1-9-3
DST8 4
DRAWDOWN No 2
GAUGE 8 5570
5000.0
4600.0
4200.0
3800.0
3400.0
3000.0
2600.0
2200.0
1800.0
1400.0
1000.0
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



P(psi) vs. LOG T(min)
WELL 1-9-3
DST# 4
DRAWDOWN No 2
GAUGE # 5570
m = 265.800
P* = 1891.9psi
P1h = 1419.3psi
T = 322 982min
2200.0
2080.0
1960.0
1840.0
1720.0
1600.0
1480.0
1360.0
1240.0
1120.0
1000.0
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

4.3 Buildup no 2

Indications of linear flow for 10-20 mins. The late part of the log-log field curve may be matched on to a type curve with skin and wellbore storage.

The Horner line is well developed. Analysis:

p^* = 7126.7 psi
m = 117 psi/decade
kh = 17.2 md·ft
k = .3md
s = 1.0

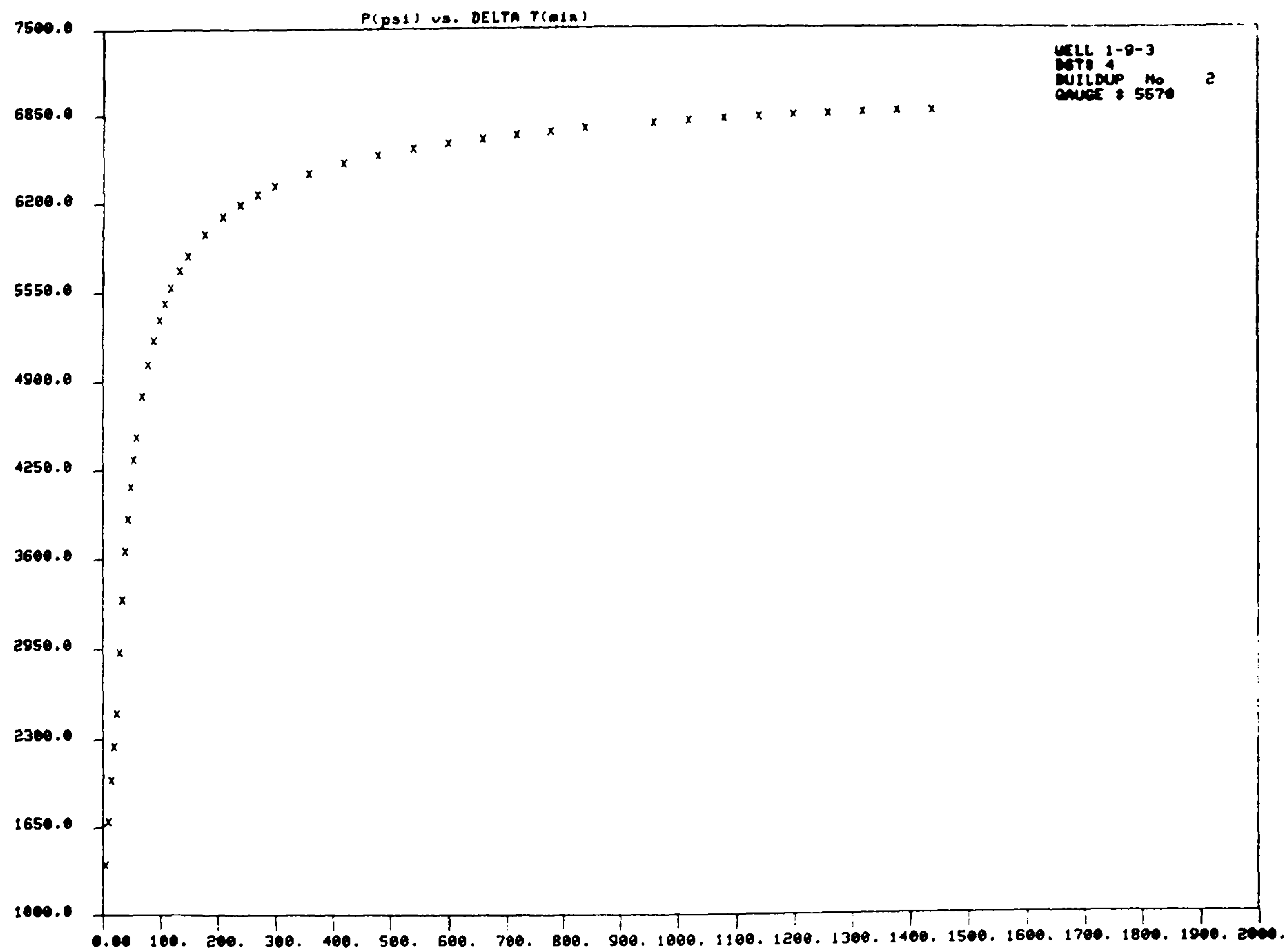
This is not considered to be a very representative analysis (pwf low, p^* too high)

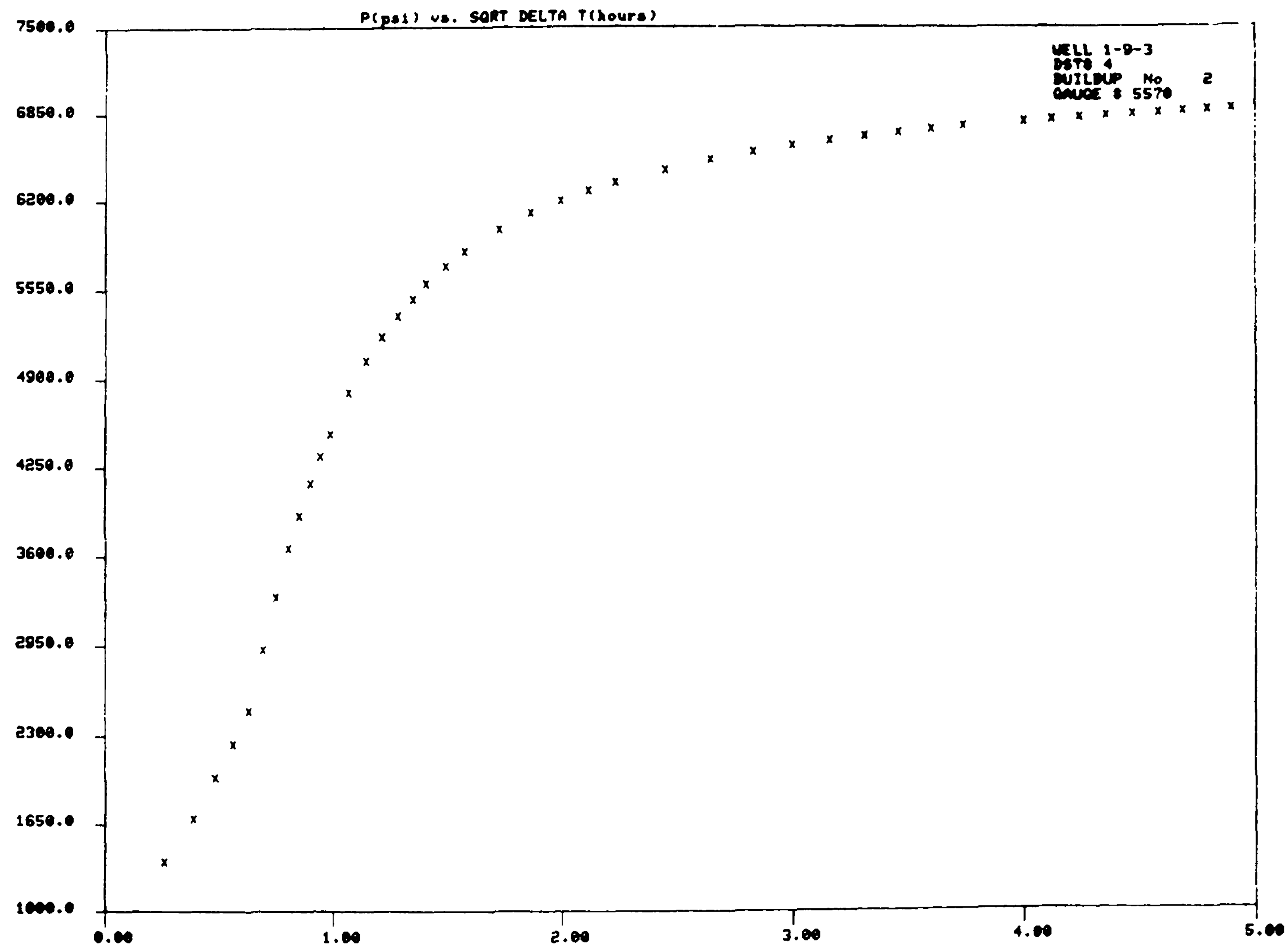
Enclosed:

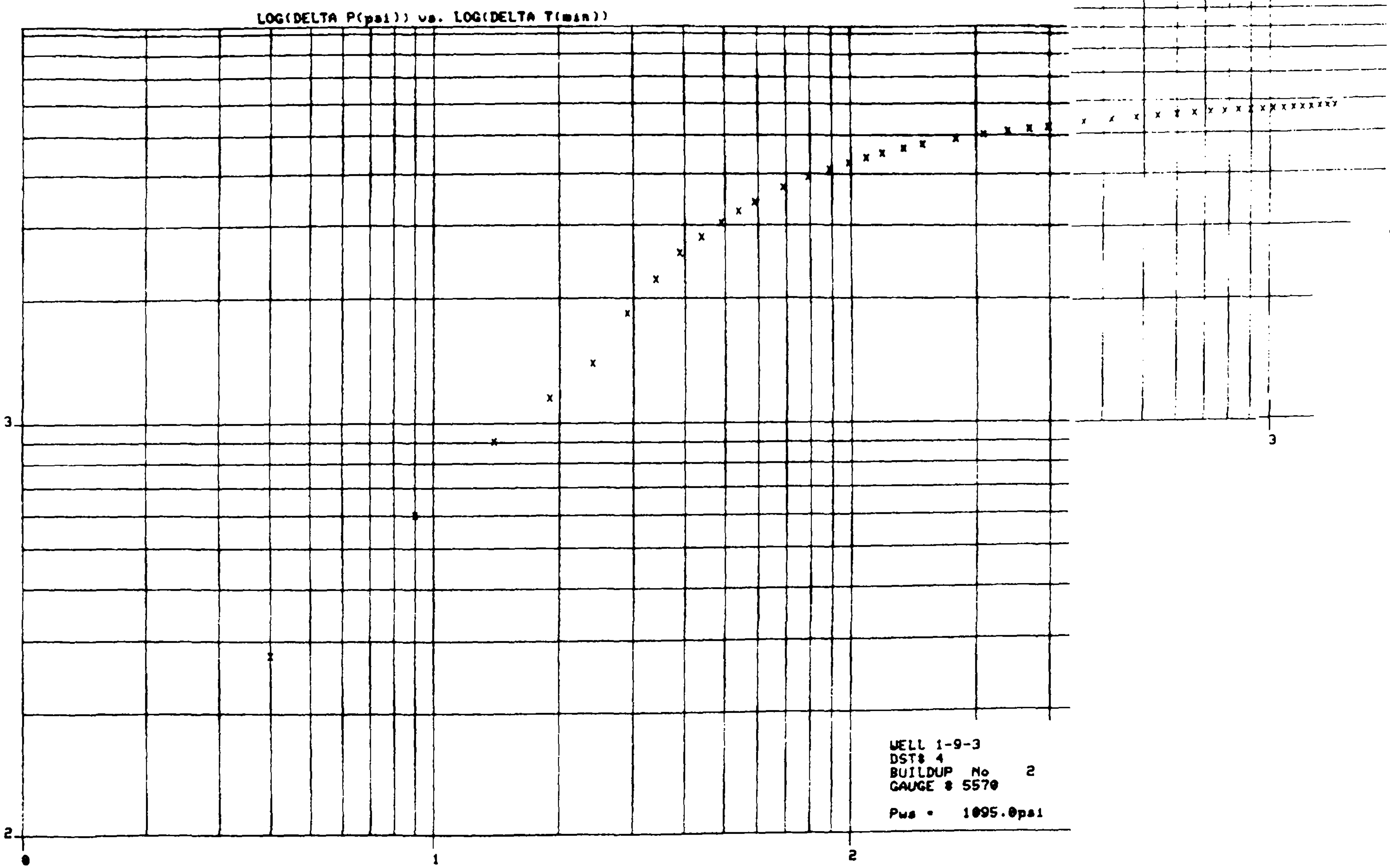
- pressure point table
- p vs. Δt
- p vs. $\sqrt{\Delta t}$
- log p vs. log Δt
- p vs. log $((t+\Delta t)/\Delta t)$ complete curve
- p vs. log $((t+\Delta t)/\Delta t)$ with straight line

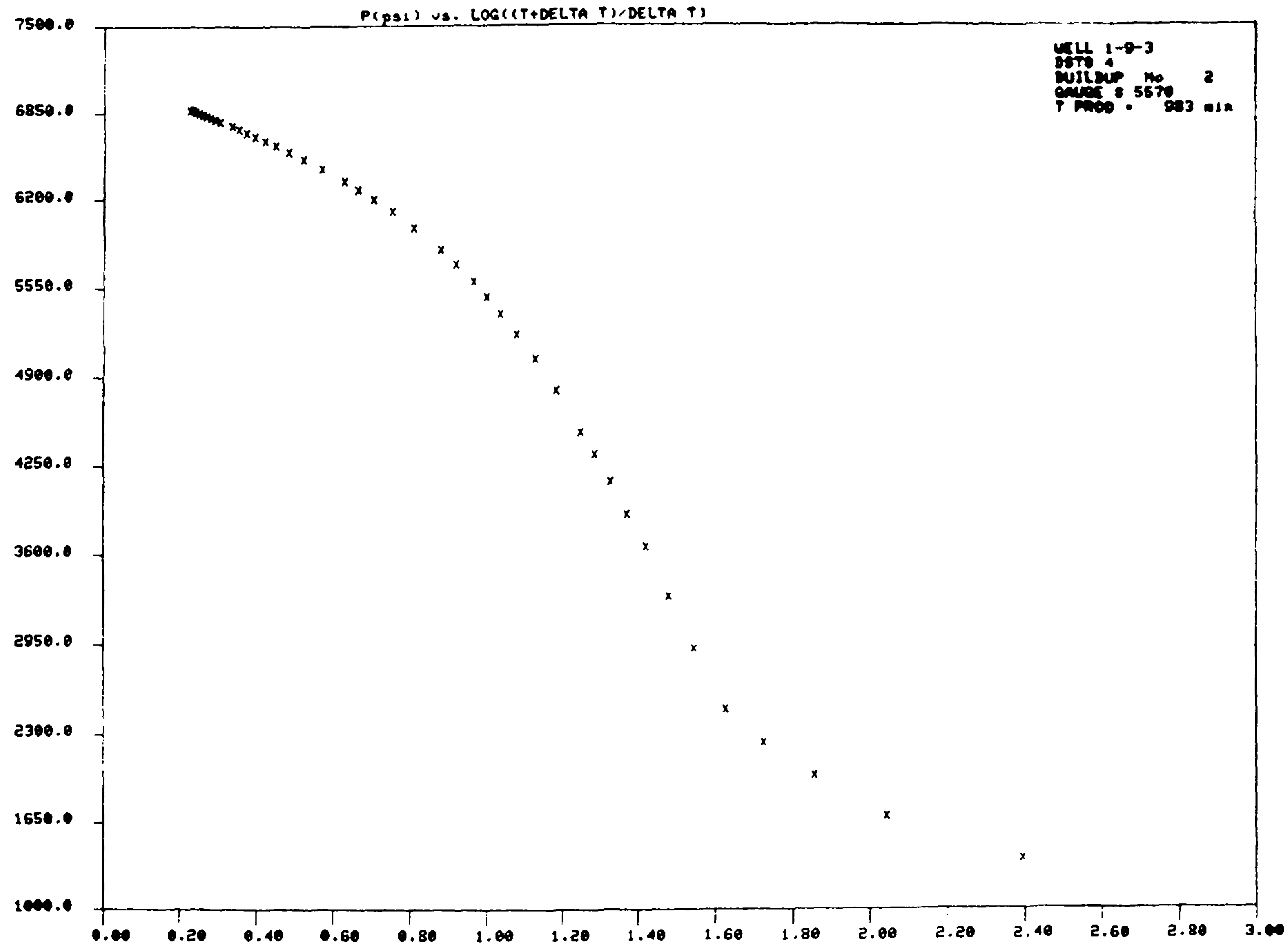
BRØNN 1-9-3 DST# 4
BUILDUP NUMMER 2
GAUGE 5570

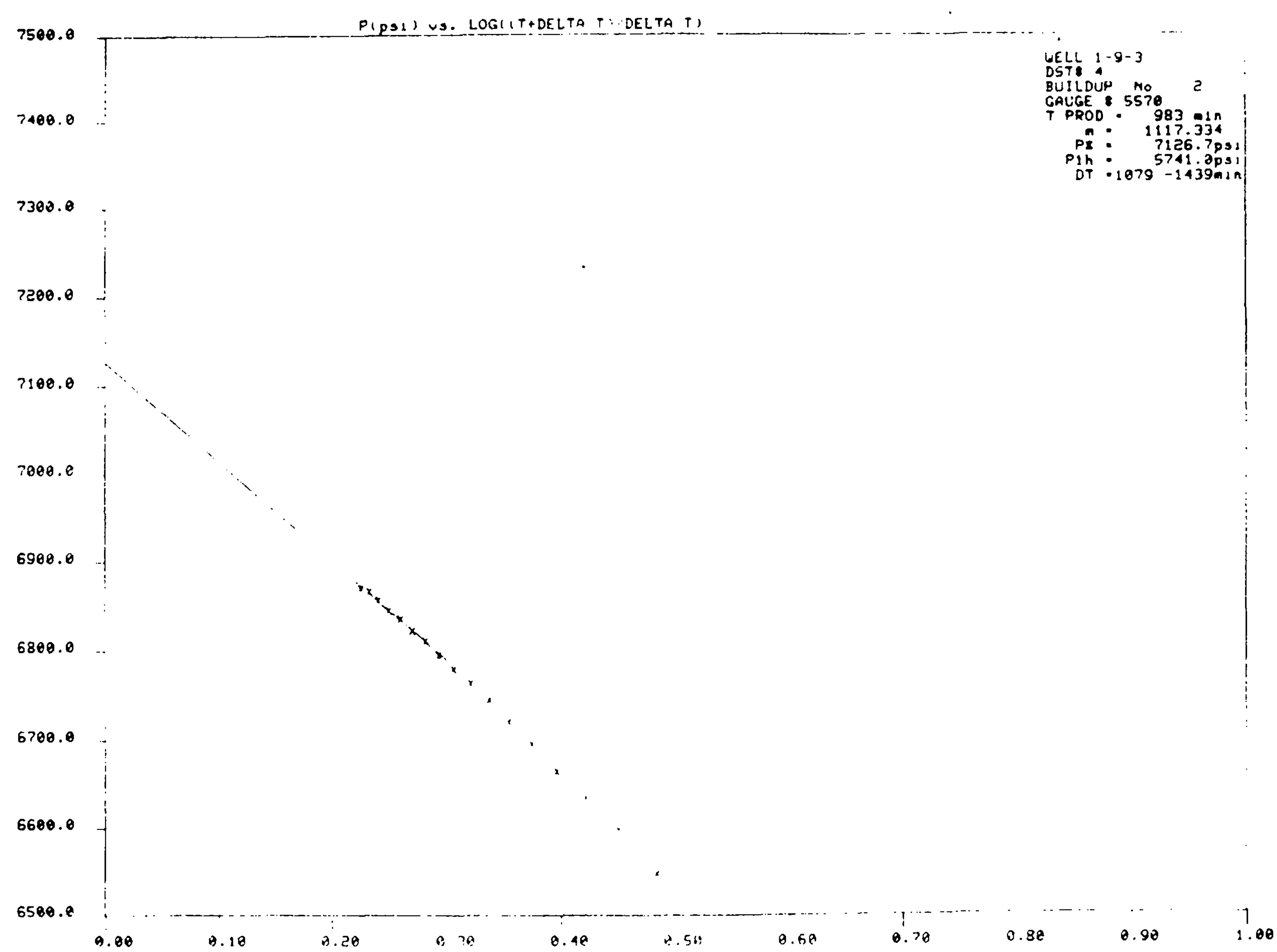
NR.	TID	TRYKK
1	8.05	1371.000
2	8.10	1694.000
3	8.15	1998.000
4	8.20	2246.000
5	8.25	2488.000
6	8.30	2929.000
7	8.35	3308.000
8	8.40	3662.000
9	8.45	3897.000
10	8.50	4133.000
11	8.55	4332.000
12	9.00	4493.000
13	9.10	4798.000
14	9.20	5027.000
15	9.30	5201.000
16	9.40	5353.000
17	9.50	5474.000
18	10.00	5586.000
19	10.15	5710.000
20	10.30	5816.000
21	11.00	5977.000
22	11.30	6101.000
23	12.00	6188.000
24	12.30	6262.000
25	13.00	6325.000
26	14.00	6418.000
27	15.00	6492.000
28	16.00	6548.000
29	17.00	6598.000
30	18.00	6635.000
31	19.00	6656.000
32	20.00	6697.000
33	21.00	6722.000
34	22.00	6747.000
35	23.00	6765.000
36	0.00	6781.000
37	1.00	6796.000
38	2.00	6812.000
39	3.00	6824.000
40	4.00	6837.000
41	5.00	6846.000
42	6.00	6858.000
43	7.00	6868.000
44	8.00	6871.000


P(psi) vs. DELTA T(min)
WELL 1-9-3
DST# 4
BUILDUP No 2
GAUGE # 5570
7500.0
6850.0
6200.0
5550.0
4900.0
4250.0
3600.0
2950.0
2300.0
1650.0
1000.0
0.00 100. 200. 300. 400. 500. 600. 700. 800. 900. 1000. 1100. 1200. 1300. 1400. 1500. 1600. 1700. 1800. 1900. 2000.


P(psi) vs. SQRT DELTA T(hours)
WELL 1-9-3
DST8 4
BUILDUP No 2
GAUGE $ 5570
7500.0
6850.0
6200.0
5550.0
4900.0
4250.0
3600.0
2950.0
2300.0
1650.0
1000.0
0.00
1.00
2.00
3.00
4.00
5.00


LOG(DELTA P(psi)) vs. LOG(DELTA T(min))
3
2
0
1
2
3
WELL 1-9-3
DST$ 4
BUILDUP No 2
GAUGE $ 5570
Pws = 1095.0psi


P(psi) vs. LOG((T+DELTA T)/DELTA T)
WELL 1-9-3
DST# 4
BUILDUP No 2
GAUGE # 5570
T PROD = 983 min
7500.0
6850.0
6200.0
5550.0
4900.0
4250.0
3600.0
2950.0
2300.0
1650.0
1000.0
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


P(psi) vs. LOG((T+DELTA T)/DELTA T)
WELL 1-9-3
DST# 4
BUILDUP No 2
GAUGE # 5570
T PROD = 983 min
m = 1117.334
P* = 7126.7psi
P1h = 5741.0psi
DT =1079 -1439min
7500.0
7400.0
7300.0
7200.0
7100.0
7000.0
6900.0
6800.0
6700.0
6600.0
6500.0
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00

4.4 Drawdown no 3

The well has changed properties. No semilog straight line has developed, the well is dominated by linear flow.

Square root data plot analysis:

p^* = 6903.1 psi
mvf= 1189.1 psi/$\sqrt{hr}$

Assume k = .5 md
xf = 61 ft

The log-log field plot is generated by the extrapolated pressure from the square root data plot. The field plot is matched on to a constant flux hydraullic fracture type curve:

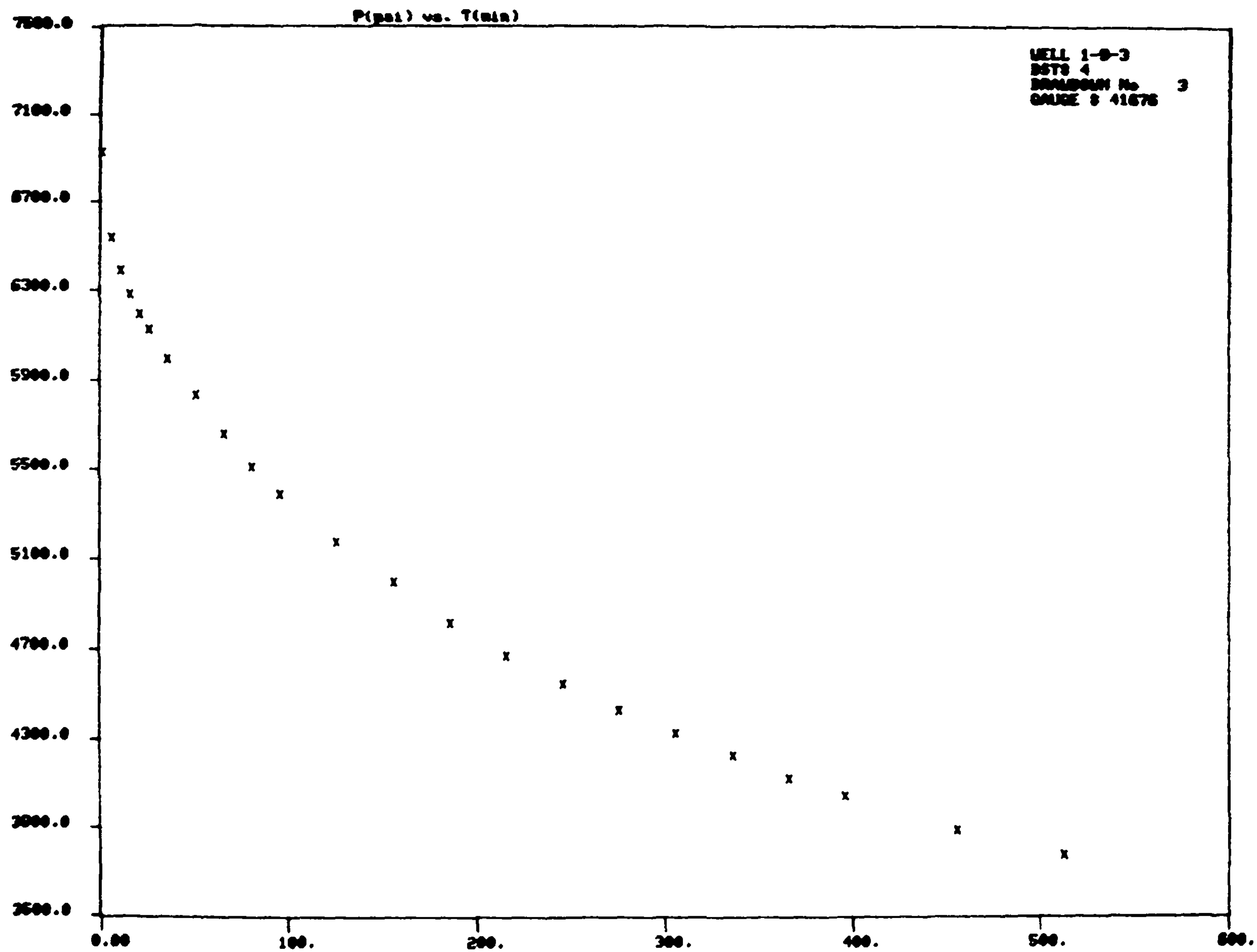
kh = 32.2 md·ft
k = .55 md
xf = 55 ft

Enclosed:

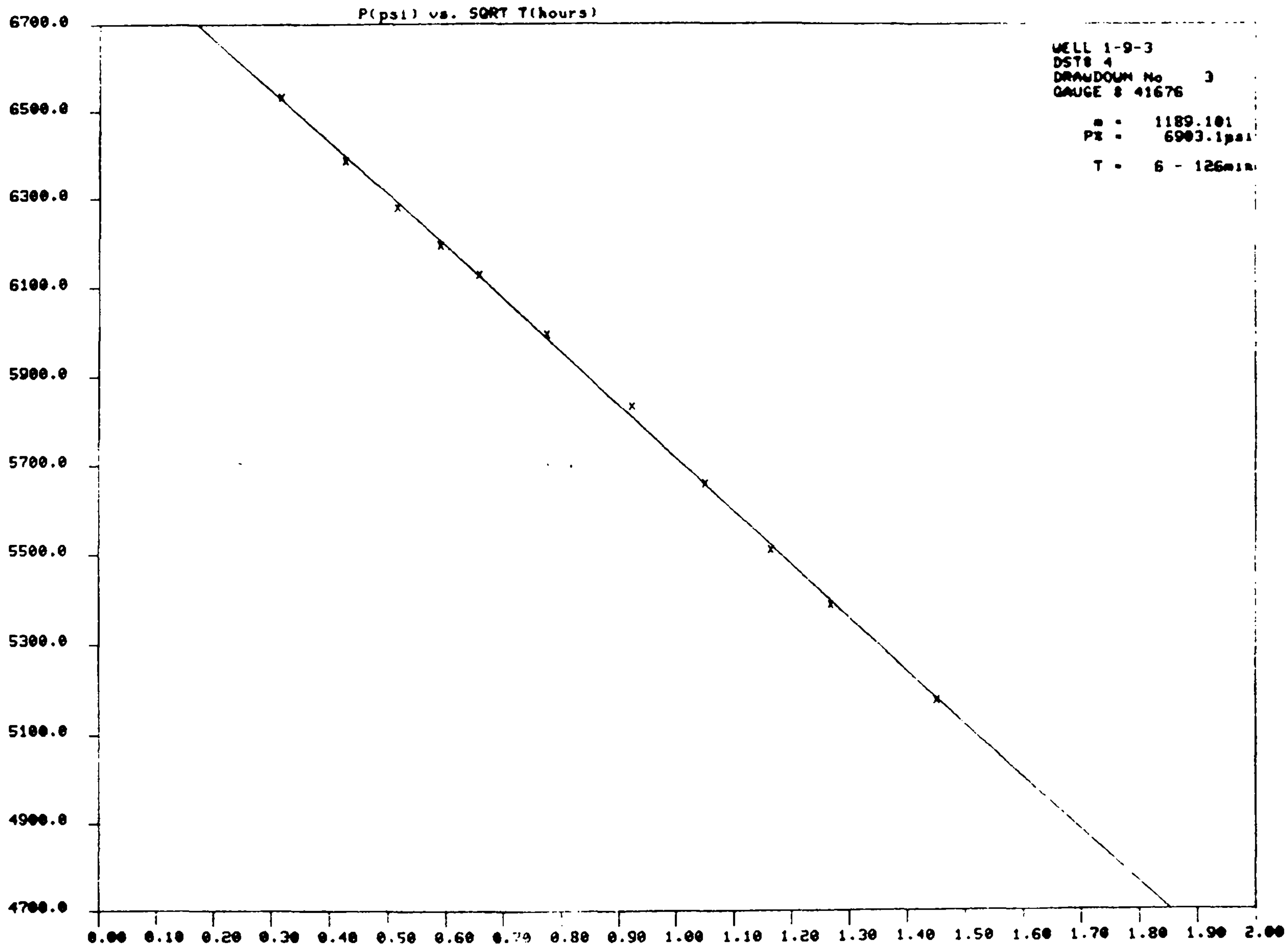
- pressure point table
- p vs. t
- p vs. $\sqrt{t}$ with a straight line
- log p vs. log t
- type curve match

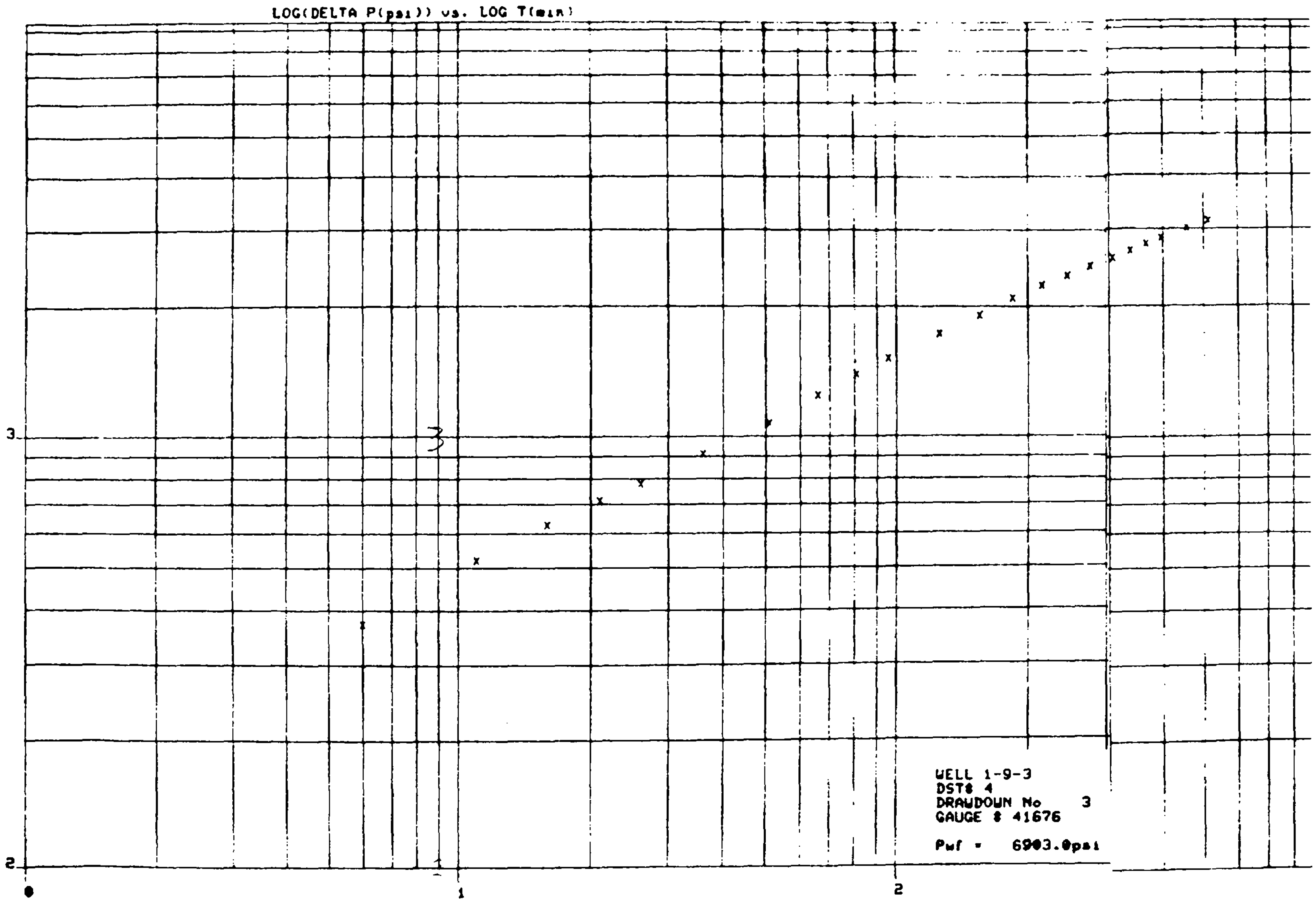
BRØNN 1-9-3 DST# 4
DRAWDOWN NUMMER 3
GAUGE 41676

NR.	TID	TRYKK
1	15.35	6384.000
2	15.40	6278.000
3	15.45	6191.000
4	15.50	6125.000
5	16.00	5993.000
6	16.15	5833.000
7	16.30	5660.000
8	16.45	5512.000
9	17.00	5390.000
10	17.30	5177.000
11	18.00	5000.000
12	18.30	4818.000
13	19.00	4675.000
14	19.30	4550.000
15	20.00	4435.000
16	20.30	4330.000
17	21.00	4231.000
18	21.30	4127.000
19	22.00	4047.000
20	23.00	3890.000
21	23.57	3773.000

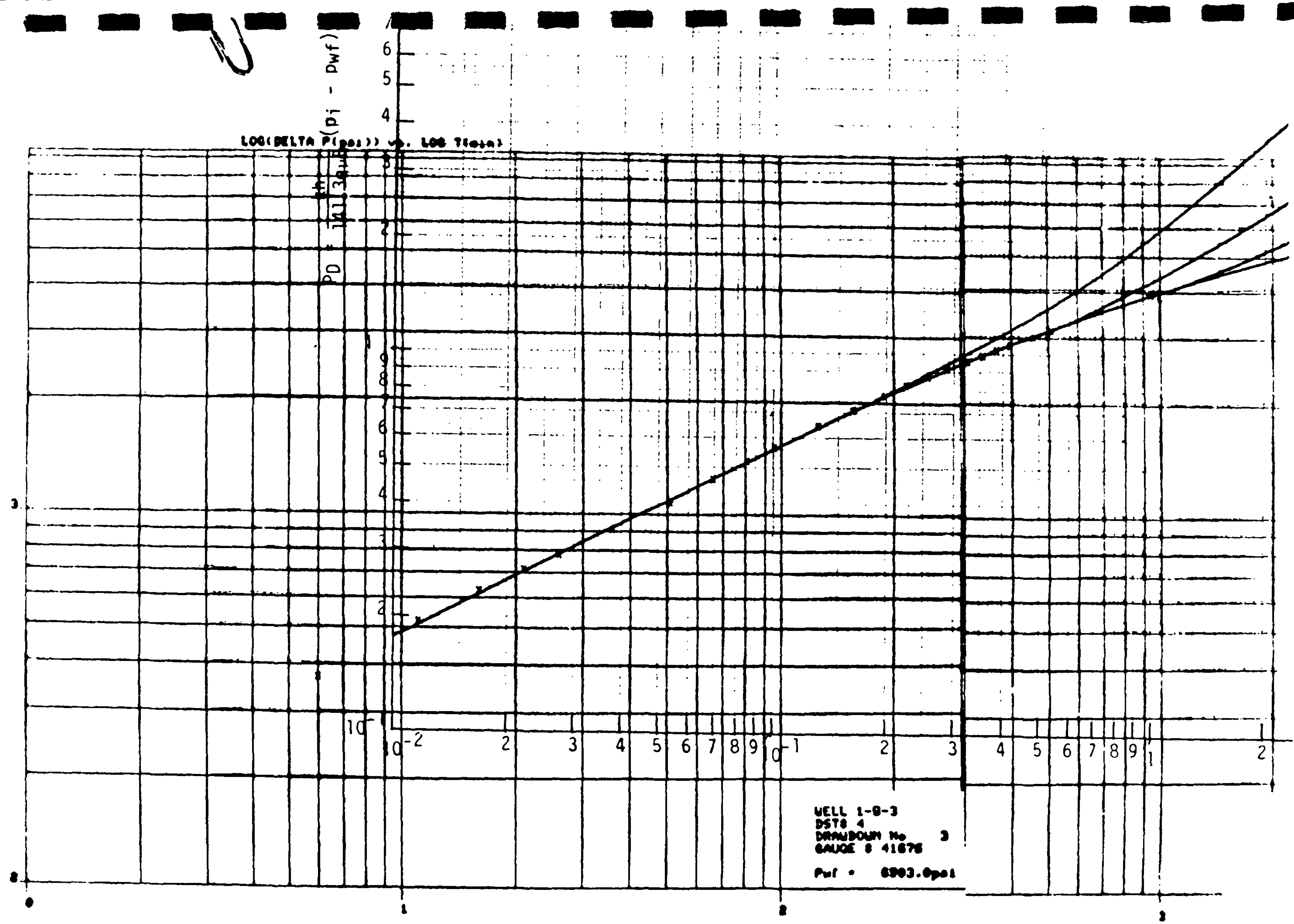


P(psi) vs. T(min)
WELL 1-B-3
DST# 4
DRAWDOWN No 3
GAUGE # 41676
7500.0
7100.0
6700.0
6300.0
5900.0
5500.0
5100.0
4700.0
4300.0
3900.0
3500.0
0.00
100.
200.
300.
400.
500.
600.


P(psi) vs. SQRT T(hours)
WELL 1-9-3
DST# 4
DRAWDOWN No 3
GAUGE # 41676
m = 1189.101
P* = 6903.1psi
T = 6 - 126min
6700.0
6500.0
6300.0
6100.0
5900.0
5700.0
5500.0
5300.0
5100.0
4900.0
4700.0
0.00 0.10 0.20 0.30 0.40 0.50 0.60 0.70 0.80 0.90 1.00 1.10 1.20 1.30 1.40 1.50 1.60 1.70 1.80 1.90 2.00



LOG(DELTA P(psi)) vs. LOG T(min)
3
2
0
1
2
WELL 1-9-3
DST# 4
DRAWDOWN No 3
GAUGE # 41676
Pwf = 6903.0psi



LOG(DELTA P(psi)) vs. LOG T(min)
$P_D = \frac{kh}{141.3q\mu B}(p_i - p_{wf})$
WELL 1-9-3
DST# 4
DRAWDOWN No 3
GAUGE # 41876
Pwf = 6903.0psi

4.5 Buildup no 3

Linear flow is dominating the buildup. The straight line in this square root data plot is not as evident as for drawdown no 3.

The log-log field plot is not very easy to match, however, some sort of a match is found on an infinite conductivity vertical fracture type curve:

$kh = 77$ md·ft
$k = 1.3$ md

This is not considered to be a very representative value for k.

The Horner analysis is made, although the proper straight line has not developed:

$m = 3339.6$ psi/decade
$p^* = 6895.5$ psi
$kh = 33$ md·ft
$k = .56$ md
$s = -4.1$

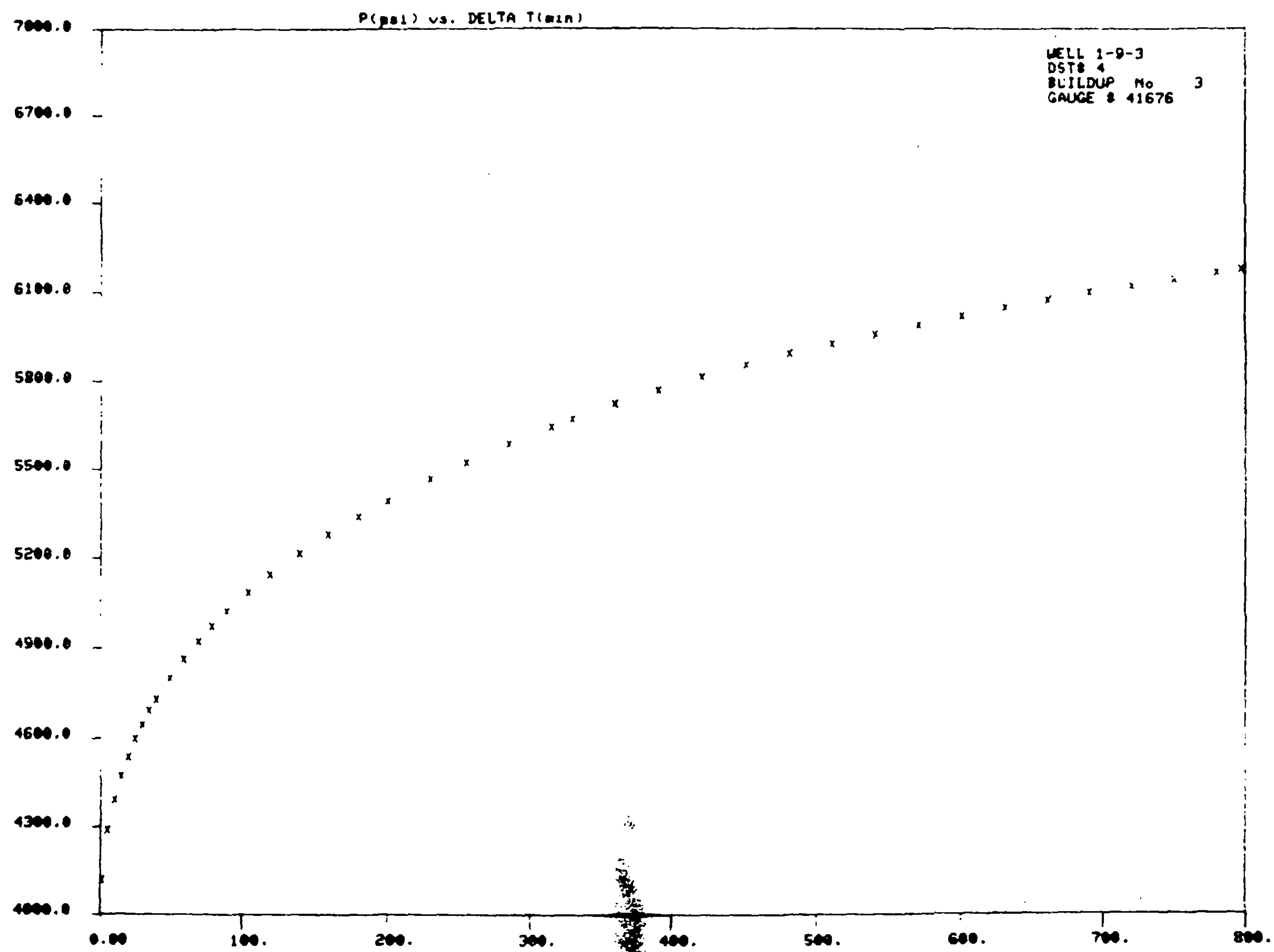
It is expected that the correct semi-log straight line would give on: a slightly lower value of k.

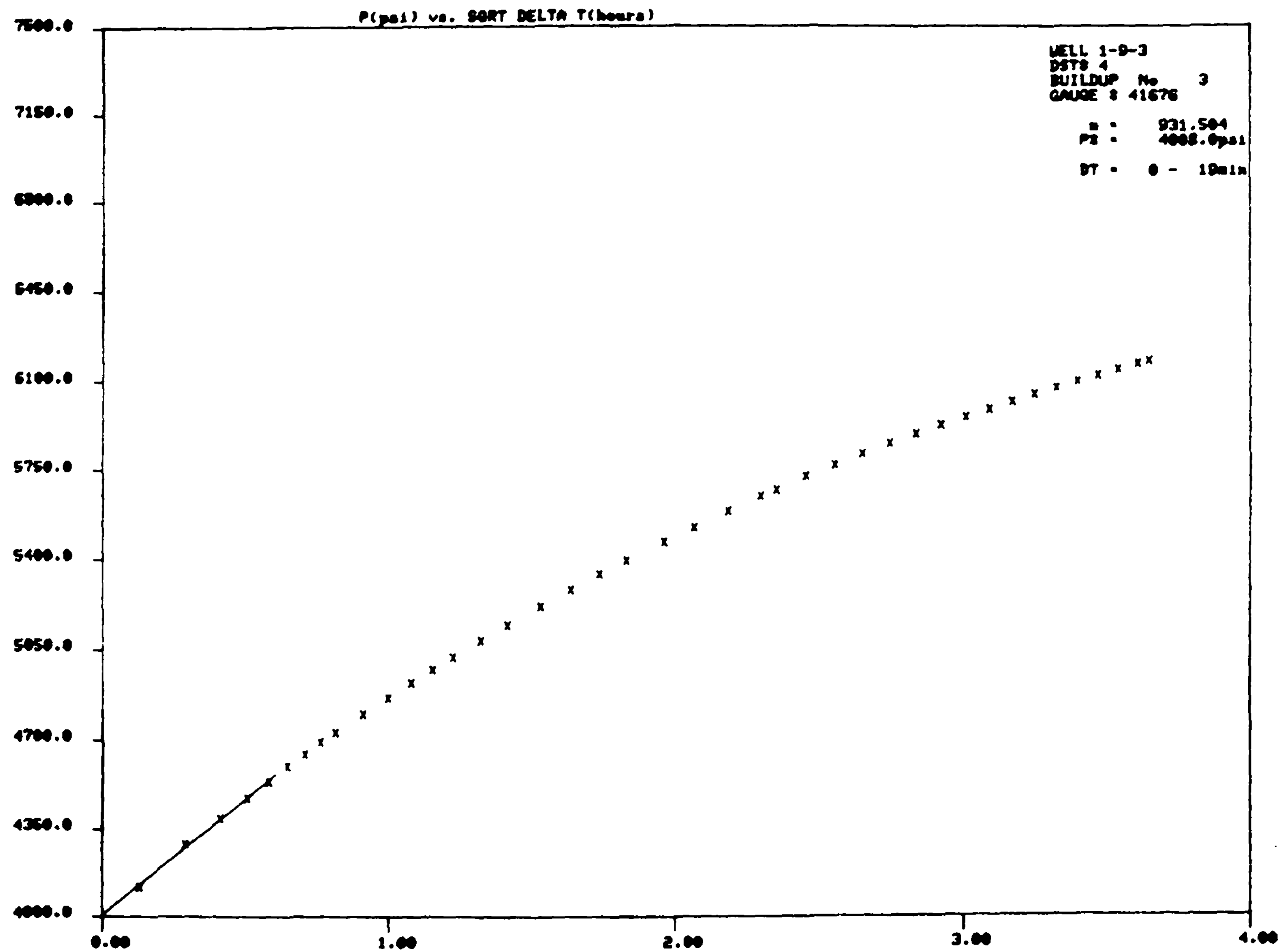
Enclosed:

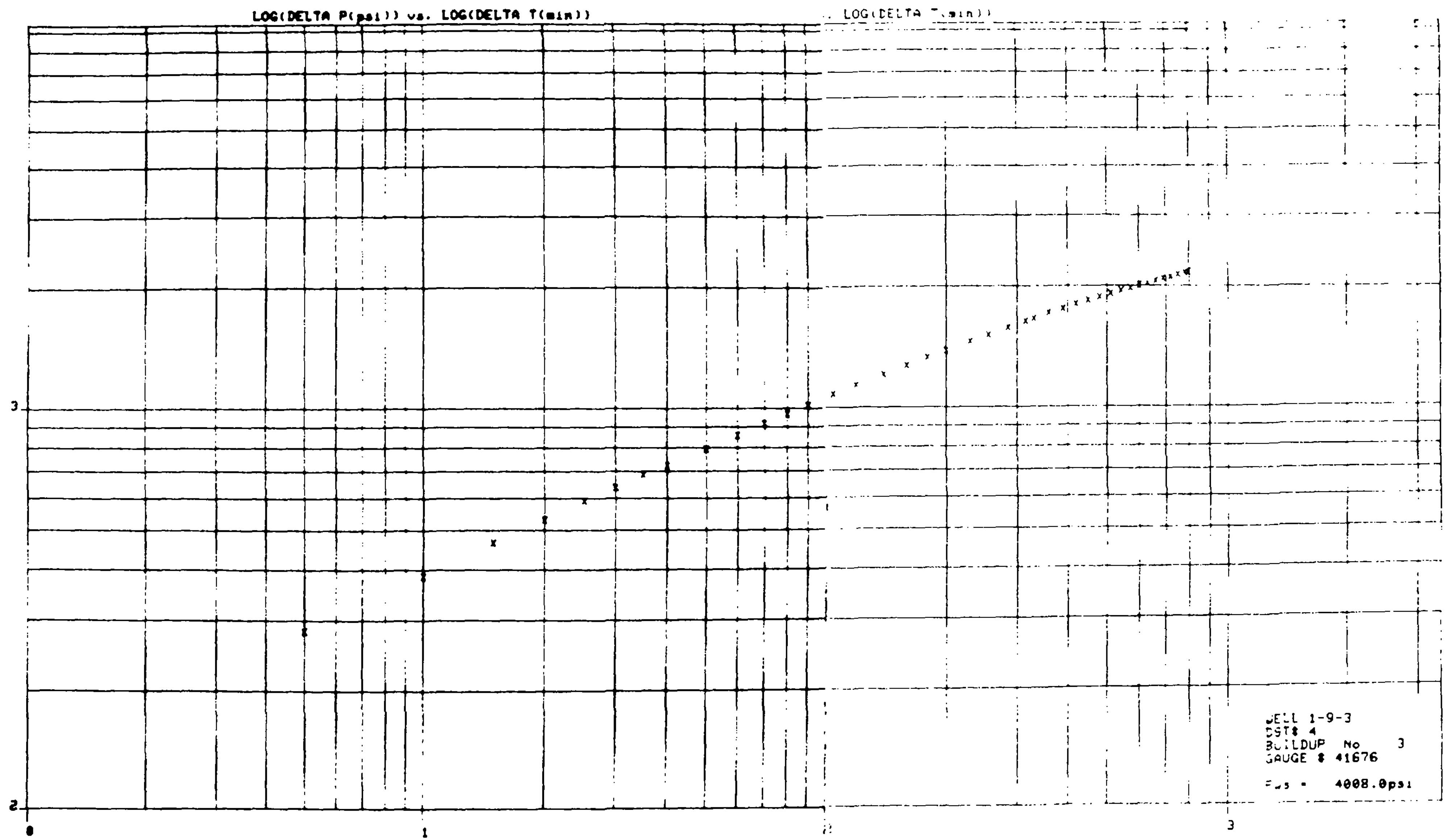
- pressure point table
- p vs. Δt
- p vs. $\sqrt{\Delta t}$
- log p vs. log Δt
- type curve match
- p vs. log $((t+\Delta t)/\Delta t)$
- p vs. log $((t+\Delta t)/\Delta t)$ with straight line

BRØNN 1-9-3 DST# 4
BUILDUP NUMMER 3
GAUGE 41676

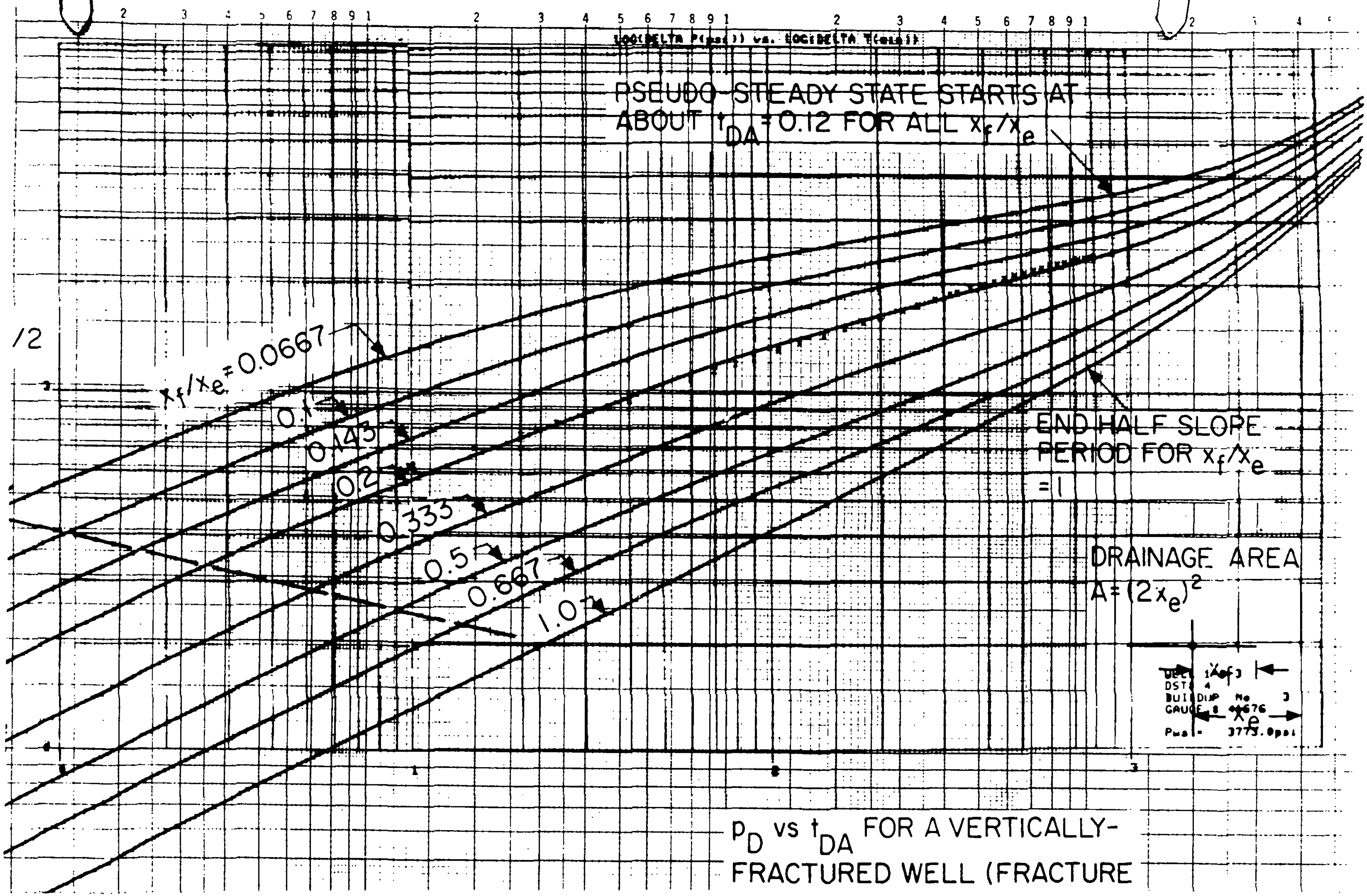
NR.	TID	TRYKK
1	0.01	4118.000
2	0.05	4290.000
3	0.10	4393.000
4	0.15	4474.000
5	0.20	4538.000
6	0.25	4599.000
7	0.30	4646.000
8	0.35	4694.000
9	0.40	4731.000
10	0.50	4803.000
11	1.00	4866.000
12	1.10	4925.000
13	1.20	4975.000
14	1.30	5025.000
15	1.45	5088.000
16	2.00	5148.000
17	2.20	5219.000
18	2.40	5282.000
19	3.00	5342.000
20	3.20	5395.000
21	3.50	5469.000
22	4.15	5524.000
23	4.45	5586.000
24	5.15	5645.000
25	5.30	5670.000
26	6.00	5722.000
27	6.30	5766.000
28	7.00	5810.000
29	7.30	5851.000
30	8.00	5888.000
31	8.30	5921.000
32	9.00	5952.000
33	9.30	5983.000
34	10.00	6013.000
35	10.30	6041.000
36	11.00	6067.000
37	11.30	6093.000
38	12.00	6115.000
39	12.30	6137.000
40	13.00	6161.000
41	13.17	6172.000


P(psi) vs. DELTA T(min)
WELL 1-9-3
DST# 4
BUILDUP No 3
GAUGE # 41676
7000.0
6700.0
6400.0
6100.0
5800.0
5500.0
5200.0
4900.0
4600.0
4300.0
4000.0
0.00
100.
200.
300.
400.
500.
600.
700.
800.

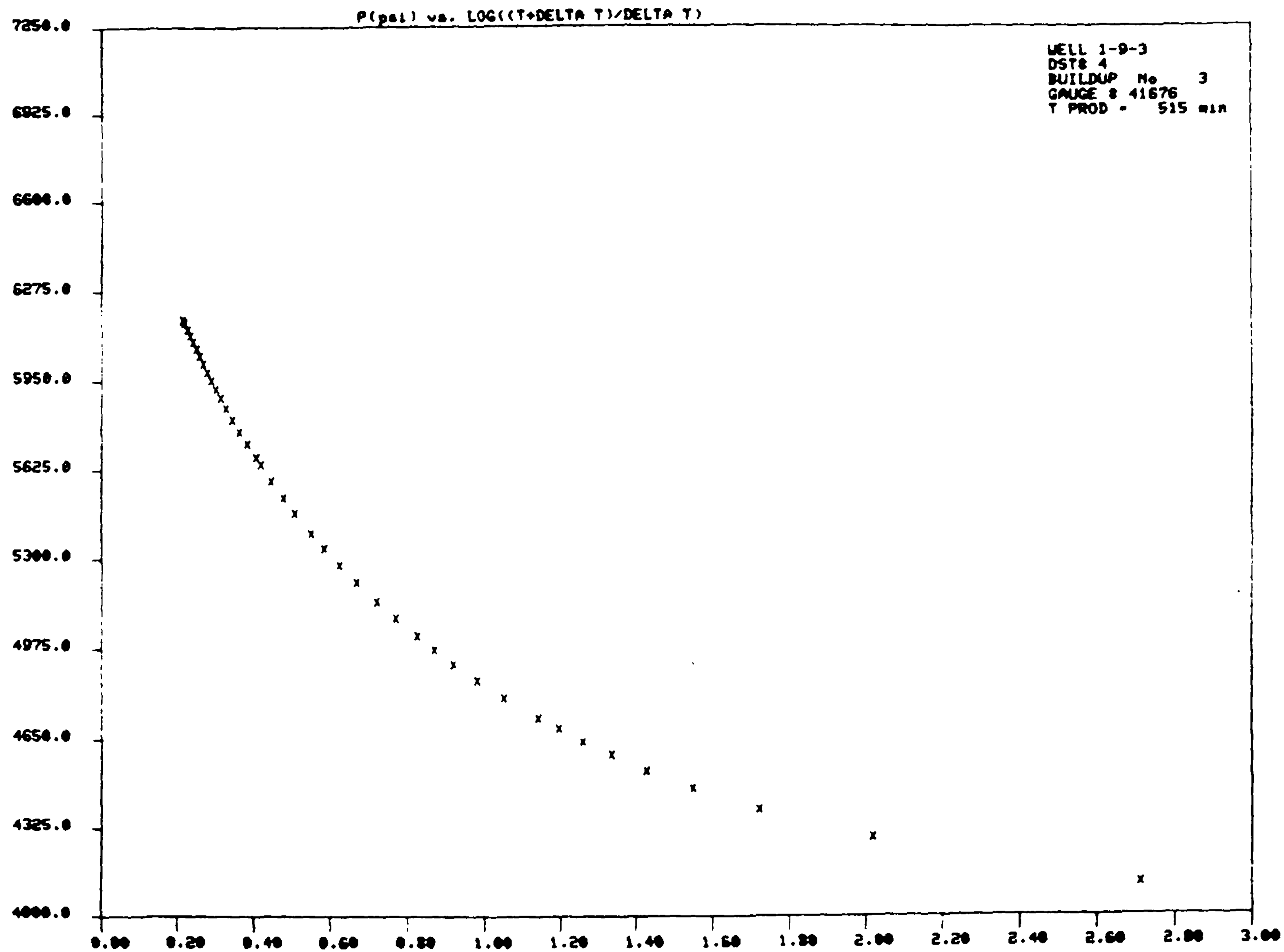

P(psi) vs. SQRT DELTA T(hours)
WELL 1-9-3
DSTS 4
BUILDUP No 3
GAUGE # 41676
m = 931.504
PZ = 4008.0psi
DT = 0 - 10min
7500.0
7150.0
6800.0
6450.0
6100.0
5750.0
5400.0
5050.0
4700.0
4350.0
4000.0
0.00
1.00
2.00
3.00
4.00

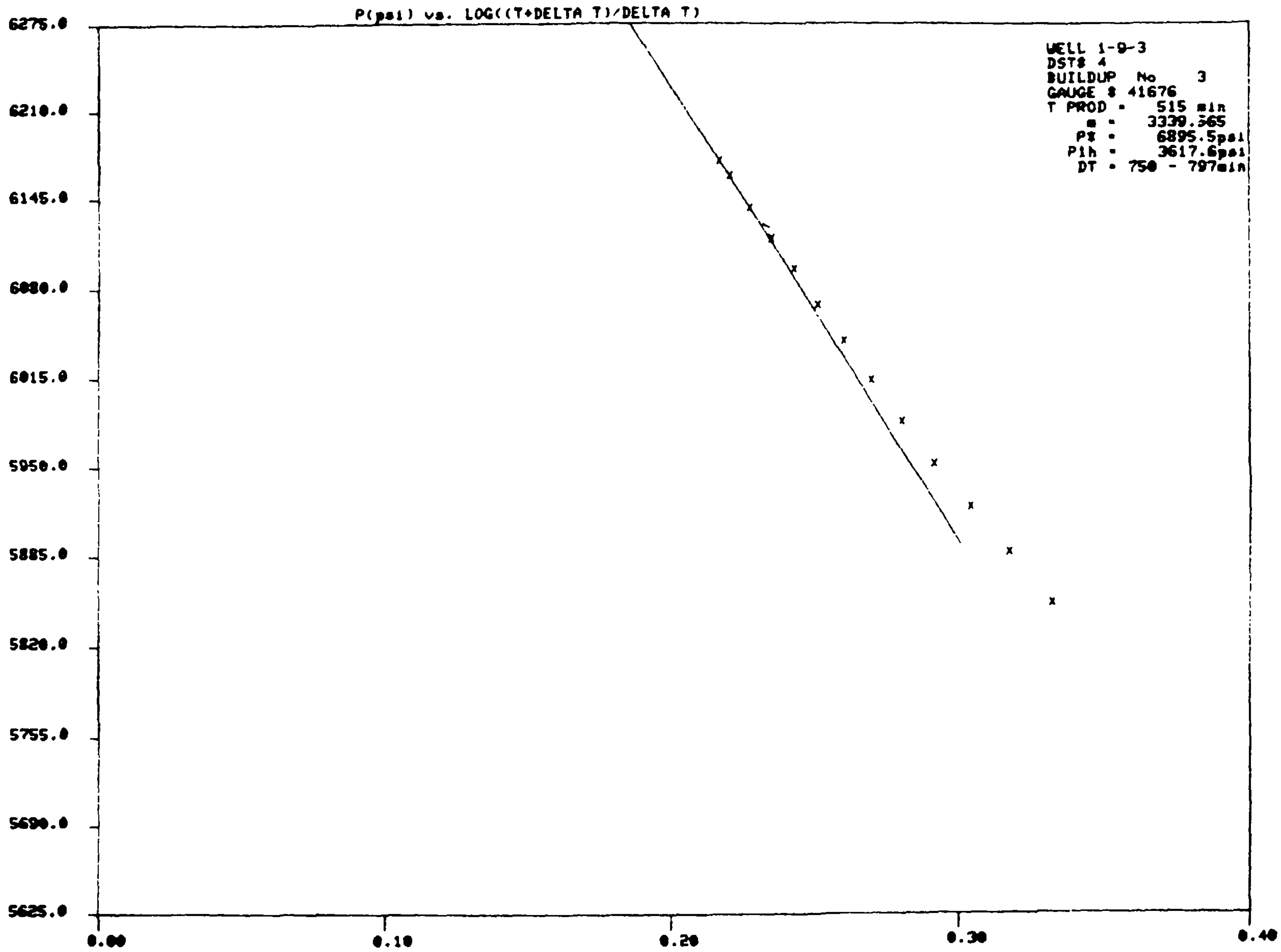


LOG(DELTA P(psi)) vs. LOG(DELTA T(min))
LOG(DELTA T(min))
3
2
0
1
2
3
WELL 1-9-3
DST# 4
BUILDUP No 3
GAUGE # 41676
Pws = 4008.0psi



LOG(DELTA P(psi)) vs. LOG(DELTA T(min))
PSEUDO-STEADY STATE STARTS AT ABOUT t_{DA} = 0.12 FOR ALL x_f/x_e
x_f/x_e = 0.0667
0.1
0.143
0.2
0.333
0.5
0.667
1.0
END HALF SLOPE PERIOD FOR x_f/x_e = 1
DRAINAGE AREA $A = (2x_e)^2$
x_f
x_e
GAUGE
Pwsi = 3773.0psi
p_D vs t_{DA} FOR A VERTICALLY-FRACTURED WELL (FRACTURE


P(psi) vs. LOG((T+DELTA T)/DELTA T)
WELL 1-9-3
DST# 4
BUILDUP No 3
GAUGE # 41676
T PROD = 515 min
7250.0
6925.0
6600.0
6275.0
5950.0
5625.0
5300.0
4975.0
4650.0
4325.0
4000.0
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



P(psi) vs. LOG((T+DELTA T)/DELTA T)
WELL 1-9-3
DST# 4
BUILDUP No 3
GAUGE # 41676
T PROD = 515 min
m = 3339.565
P* = 6895.5psi
P1h = 3617.6psi
DT = 750 - 797min
6275.0
6210.0
6145.0
6080.0
6015.0
5950.0
5885.0
5820.0
5755.0
5690.0
5625.0
0.00
0.10
0.20
0.30
0.40

4.6 Drawdown no 4

The early flow conditions were disturbed by leaks. The flow was then aborted due to technical problems.

No semi-log straight line has developed. The flow is even to short to define a type curve match.

A reservoir capasity kh is assumed and the log-log field plot is slided horizontally to define the new fracture half length xf.

Assume kh = 26 md·ft
xf = 128 ft

Assume kh = 40 md·ft
xf = 102 ft

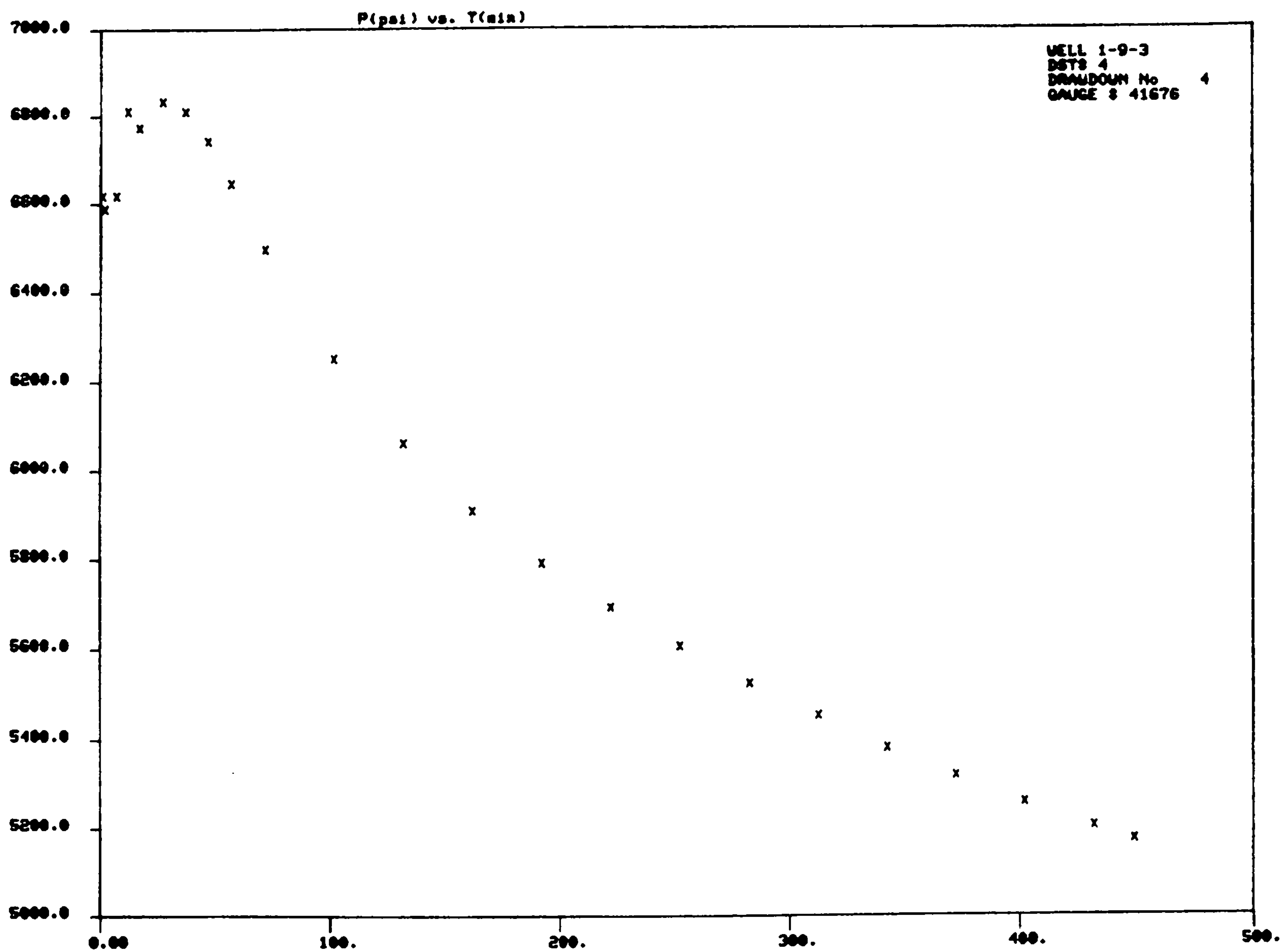
We see that the complete fracture acidizing doubled the fracture length.

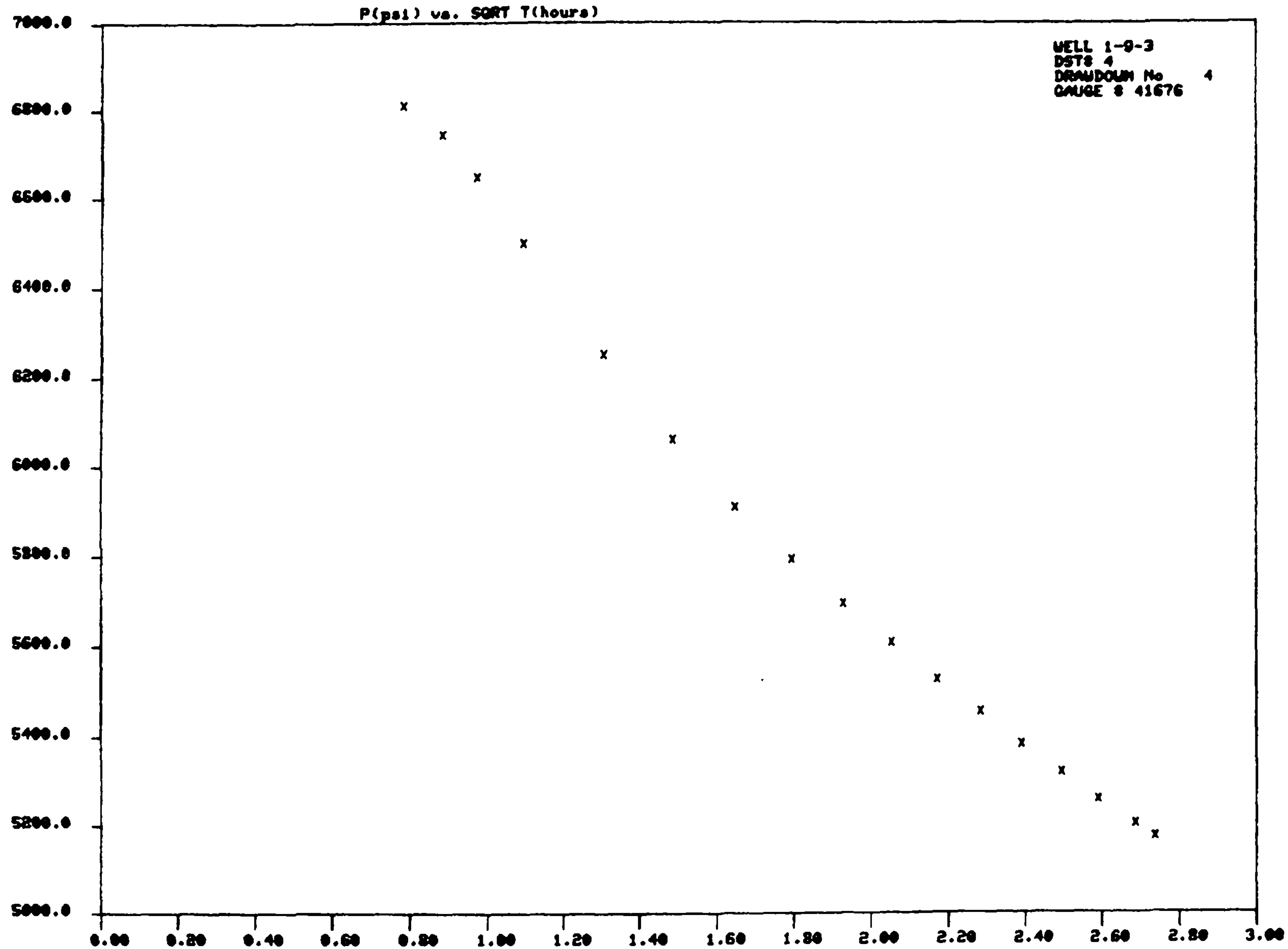
Enclosed:

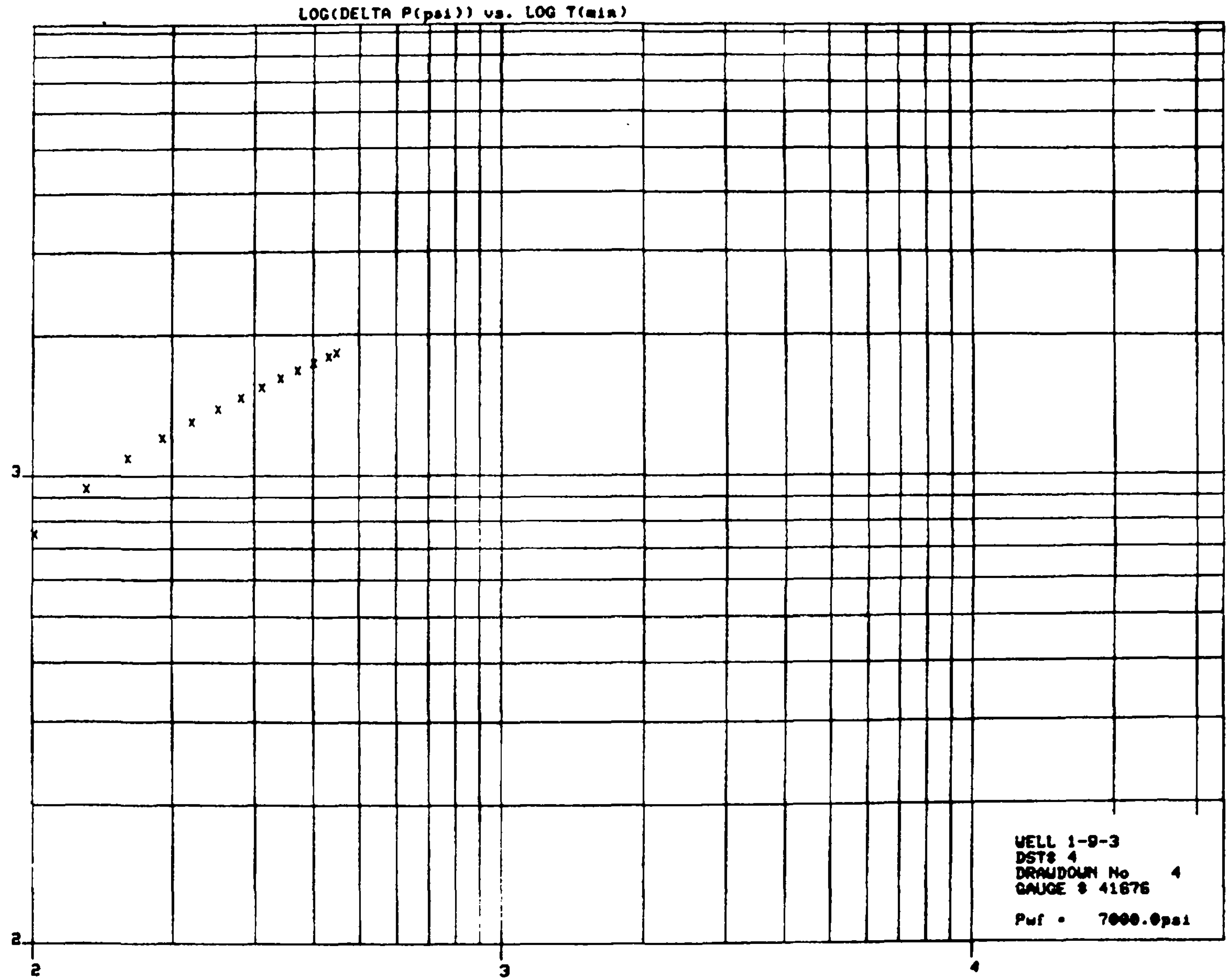
- pressure point table
- p vs. t
- p vs. $\sqrt{t}$
- log p vs. log t

BRØNN 1-9-3 DST# 4
DRAWDOWN NUMMER 4
GAUGE 41676

NR.	TID	TRYKK
1	0.19	6618.000
2	0.20	6588.000
3	0.25	6618.000
4	0.30	6812.000
5	0.35	6774.000
6	0.45	6834.000
7	0.55	6811.000
8	1.05	6742.000
9	1.15	6645.000
10	1.30	6495.000
11	2.00	6250.000
12	2.30	6060.000
13	3.00	5909.000
14	3.30	5793.000
15	4.00	5694.000
16	4.30	5608.000
17	5.00	5526.000
18	5.30	5454.000
19	6.00	5382.000
20	6.30	5319.000
21	7.00	5258.000
22	7.30	5203.000
23	7.47	5172.000


P(psi) vs. T(min)
WELL 1-9-3
DSTS 4
DRAWDOWN No 4
GAUGE $ 41676
7000.0
6800.0
6600.0
6400.0
6200.0
6000.0
5800.0
5600.0
5400.0
5200.0
5000.0
0.00
100.
200.
300.
400.
500.


P(psi) vs. SQRT T(hours)
WELL 1-9-3
DST# 4
DRAWDOWN No 4
GAUGE # 41676
7000.0
6800.0
6600.0
6400.0
6200.0
6000.0
5800.0
5600.0
5400.0
5200.0
5000.0
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(psi)) vs. LOG T(min)
3
2
2
3
4
WELL 1-9-3
DST# 4
DRAWDOWN No 4
GAUGE # 41676
Pwf = 7000.0psi

5 Miscellaneous data used in the test analysis-DST 4

Completion data:

r_w = .4 ft (9 5/8" casing)
perforated interval: 3094-3112m RKB = 18m = 59 ft

Water properties:

B_w = 1.0 res bbl/STBBL
μ_w = .30 cp
$c_w = 3.2 \times 10^{-6}$ vol/vol/psi

Petrophysical properties:

rock compressibilty: 3.0×10^{-6} vol/vol/psi

over perforated interval:
ϕ = .321
S_w = .277
S_{hc} = .723
h = 59 ft
$C_t = 40 \cdot 6 \times 10^{-6}$ vol/vol/psi at 7000 psi
$C_t = 66 \cdot 4 \times 10^{-6}$ vol/vol/psi at 5000 psi

over maximum contributing interval:
ϕ = .290
S_w = .337
S_{ch} = .663
h = 104 ft

Condensate PVT properties:
The following properties are assumed:

γ_g = .71 (air 1.0)
γ_o = separator condensate gravity 49^{o}API = .78(water 1.0)
P_{sep} = 5400 psi
GOR = 7500 SCF/STB
T = 250^{o}F = 710^{o}R

Equivalent gas volume of stock tank condensate (according to Leshikar, 1961) Vc = 1000 cuft/STB

Reservoar fluid gravity:

$$G = \frac{g + \frac{4608x\ c}{GOR}}{1+Vc/Gor} = 1.04$$

Critical properties of this gas:

pc = 709.491-58.718xG = 648.4 psi
Tc = 170.491+307.344xG = 490.1°R

Reservoar conditions of 7050 psi and 250°F (710°R) implies a gas deviation factor (after Standing and Katz) Z = 1.25. This number is also supported by data from 1/9-1, DST 6

Atmospheric gas viscosity is found to be μga = 0.0119 cp (after Carr, Kobayashi and Burrows)

$$Bg = 5.02\ (10^{-3})\ \frac{ZRTR}{PR} = \frac{4.45525}{PR(psi)}$$

Gas compressibility is determined according to Trube by cr = cgx pc

p(psia)	pr	Bg(resbbl/SCF)	Cr	Cg[$10^{-6}psi^{-1}$]	μg/μga	μg(
7000	10.80	$636.5x10^{-6}$	0.033	50.9	3.68	0.0
6500	10.02	$685.5x10^{-6}$	0.035	54.0	3.50	0.0
6000	9.25	$7420.6x10^{-6}$	0.042	64.8	3.35	0.0
5500	8.48	$810.1x10^{-6}$	0.046	70.9	3.15	0.0
5000	7.71	$891.1x10^{-6}$	0.056	86.4	2.95	0.0
4500	6.94	$990.1x10^{-6}$	0.066	102	2.77	0.0
4000	6.17	$1.114x10^{-3}$	0.085	131	2.57	0.0
3500	5.40	$1.273x10^{-3}$	0.12	185	2.35	0.0
3000	4.63	$1.485x10^{-3}$	0.16	247	2.12	0.0
2500	3.86	$1.782x10^{-3}$	0.23	355	1.87	0.0

```
YES

NB!!!  CALCULATIONS MAY TAKE SOME TIME!!!!!!


 S T A T I S T I C S
**********************

FIELD: . . . . . . . . . . .                1-9
WELL:  . . . . . . . . . . .              1-9-3A
DATE:  . . . . . . 09.13.49     19 OCTOBER    1978
ENGINEER:  . . . . . . . . . JRA

DEPTH INTERVAL:  . . .  3095.00 TO  3113.00
APPLIED CUTOFFS:
.                 VSH:  GREATER THAN       0.40
.                PHIF:     LESS THAN       0.12
.                  SW:  GREATER THAN       0.65

 T O T A L     D E P T H
*******************************************
THICKNESS: . . . . . . . . .         18.000
AVERAGE  . . . 'PHIF'  . . .          0.321
AVERAGE  . . . 'VSHALE'  . .          0.004
AVERAGE  . . . 'SW'  . . . .          0.277
W.AVERAGE  . . 'SW' * 'PHIF'          0.276
AVERAGE  . . . 'SH'  . . . .          0.723
VOID VOLUME: . . . ('PHIF').          5.782
HC VOID VOLUME . . ('SH'*) .          4.186
RES HC VOID VOLUME ('SHR'*).          0.217
MOV HC VOID VOLUME . . . . .          3.970
*******************************************

 N E T     P A Y
*******************************************
THICKNESS: . . . . . . . . .         18.000
AVERAGE  . . . 'PHIF'  . . .          0.321
AVERAGE  . . . 'VSHALE'  . .          0.004
AVERAGE  . . . 'SW'  . . . .          0.277
W.AVERAGE  . . 'SW' * 'PHIF'          0.276
AVERAGE  . . . 'SH'  . . . .          0.723
VOID VOLUME: . . . ('PHIF').          5.782
HC VOID VOLUME . . ('SH'*) .          4.186
RES HC VOID VOLUME ('SHR'*).          0.217
MOV HC VOID VOLUME . . . . .          3.970
*******************************************

 N E T     S A N D
*******************************************
THICKNESS: . . . . . . . . .         18.000
AVERAGE  . . . 'PHIF'  . . .          0.321
AVERAGE  . . . 'VSHALE'  . .          0.004
AVERAGE  . . . 'SW'  . . . .          0.277
W.AVERAGE  . . 'SW' * 'PHIF'          0.276
AVERAGE  . . . 'SH'  . . . .          0.723
VOID VOLUME: . . . ('PHIF').          5.782
HC VOID VOLUME . . ('SH'*) .          4.186
RES HC VOID VOLUME ('SHR'*).          0.217
MOV HC VOID VOLUME . . . . .          3.970
*******************************************

 N E T / G R O S S     R A T I O S
*******************************************
HNETPAY /HGROSS SAND  =  1.00000
HNETSAND/HGROSS SAND  =  1.00000
HNETPAY /HNETSAND     =  1.00000
*******************************************


BRONN                    DYBDE 1     DYBDE 2
1-9-3A                   3095.00     3113.00

GI KOMMANDO?
```

```
YES

NB!!!  CALCULATIONS MAY TAKE SOME TIME!!!!!!


 S T A T I S T I C S
*********************

FIELD: . . . . . . . . . . .                  1-9
WELL:  . . . . . . . . . . .                1-9-3A
DATE:  . . . . . 11.53.10     19 OCTOBER    1978
ENGINEER:  . . . . . . . . . JRA

DEPTH INTERVAL:  . . .   3087.00 TO  3119.00
APPLIED CUTOFFS:
.              VSH:  GREATER THAN       0.40
.             PHIF:     LESS THAN       0.12
.               SW:  GREATER THAN       0.65

 T O T A L    D E P T H
******************************************
THICKNESS: . . . . . . . . .       32.000
AVERAGE  . . . 'PHIF'  . . .        0.290
AVERAGE  . . . 'VSHALE'  . .        0.013
AVERAGE  . . . 'SW'  . . . .        0.337
W.AVERAGE  . . 'SW' * 'PHIF'        0.327
AVERAGE  . . . 'SH'  . . . .        0.663
VOID VOLUME: . . . ('PHIF').        9.290
HC VOID VOLUME . . ('SH'*) .        6.256
RES HC VOID VOLUME ('SHR'*).        0.590
MOV HC VOID VOLUME . . . . .        5.666
******************************************


 N E T    P A Y
******************************************
THICKNESS: . . . . . . . . .       32.000
AVERAGE  . . . 'PHIF'  . . .        0.290
AVERAGE  . . . 'VSHALE'  . .        0.013
AVERAGE  . . . 'SW'  . . . .        0.337
W.AVERAGE  . . 'SW' * 'PHIF'        0.327
AVERAGE  . . . 'SH'  . . . .        0.663
VOID VOLUME: . . . ('PHIF').        9.290
HC VOID VOLUME . . ('SH'*) .        6.256
RES HC VOID VOLUME ('SHR'*).        0.590
MOV HC VOID VOLUME . . . . .        5.666
******************************************

 N E T    S A N D
******************************************
THICKNESS: . . . . . . . . .       32.000
AVERAGE  . . . 'PHIF'  . . .        0.290
AVERAGE  . . . 'VSHALE'  . .        0.013
AVERAGE  . . . 'SW'  . . . .        0.337
W.AVERAGE  . . 'SW' * 'PHIF'        0.327
AVERAGE  . . . 'SH'  . . . .        0.663
VOID VOLUME: . . . ('PHIF').        9.290
HC VOID VOLUME . . ('SH'*) .        6.256
RES HC VOID VOLUME ('SHR'*).        0.590
MOV HC VOID VOLUME . . . . .        5.666
******************************************

 N E T / G R O S S    R A T I O S
******************************************

HNETPAY /HGROSS SAND =  1.00000
HNETSAND/HGROSS SAND =  1.00000
HNETPAY /HNETSAND    =  1.00000
******************************************


BRONN                    DYBDE 1    DYBDE 2
1-9-3A                   3087.00    3119.00

GI KOMMANDO?
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APPENDIX 5 - TEST PROGRAM

TEST PROCEDURES:

DST 1 (3205 - 3214 m)

Objectives: Hydrocarbon content for maximum pay thickness, samples, flow rates, pressure and temperature data.

1. Initial flow, 20-30 bbls recovered or 30 min. flow 3/4" choke. Try to inject if no flow. Proceed to stimulation if the injection fails to produce a proper flow response.

2. Initial build-up, 6 times the initial flow period.

3. Evaluate the initial flow response. Possible to surface the well within 4-6 hrs?

   a) Yes -

      Second Flow, clean up and try to stabilize flow, measure water content and rates if possible. Rev. circulate if flow dies and check for oil-content. Proceed with 6.

   b) No -

      If not done during 1., try to inject and flow back to observe the effect. Proceed as outlined in a) if response is good, else try to get at least 10-20 bbls of produced liquid above the RTTS circulation valve and circulate it out checking for oil. Proceed with 6. If this is impossible, then proceed with stimulation.

4. Stimulation: matrix-job to keep volumes and time down.

5. Second flow, clean-up, try to stabilize, measure water content and rates.

6. Second build-up (optional, depending on flow performance. Terminate the test.

DST 2 (3157 - 3180 m)

Objectives: Formation properties, samples, pressure and temperature data.

1. Initial flow, as in DST 1.

2. Initial build-up, as in DST 1.

3. Evaluate the initial flow response. Possible to surface the well within 4 - 6 hrs?

   a) yes - Second Flow: Clean up and try to stabilize on a fairly large choke. Evaluate the flow rate.

      i. if possible to stabilize well, stabilized flow 4-6 hrs, sampling.

      ii. if difficult to stabilize well, flow well 2-3 hrs after clean up, 1 set of samples.

      If the well ceases to flow at a reasonable rate, then proceed as outlined in b) or go to stimulation.

   b) No -

      Try to inject and flow back to observe the effect. Proceed as outlined in a) if response is good, else go to stimulation.

4. Build-up: 1.5 times flow period.

5. Stimulation.
   Fracture acidizing.

6. Cleanup and then flow as long as indicated necessary from the data, 15-30 hours.

7. Build-up: 1.5 times flow period.

DST 3 (3126 - 3135 m)

Objectives: Check for maximum pay. Fluid content. Procedures as for DST 1.

DST 4 (3094 - 3112 m)

Objectives: Formation evaluation of the Danian Zone which was insufficiently tested in 1/9-1 due to technical problems. Flow rates, samples, pressure and temperature data. Procedures as for DST 2.

5 Miscellaneous data used in the test analysis-DST 2

Completion data:

rw = .4 ft ($9^5/8$" casing)
perforated interval: 3157-3180m RKB = 23m = 75 ft

Water properties:

Bw = 1.0 res bbl/STBBL
μw = .30 cp
$cw = 3.2 \times 10^{-6}$ vol/vol/psi

Hydrocrbon compressibility:

$chc = 50 \times 10^{-6}$ vol/vol/psi

Petrophysical properties:

rock compressibility: 3.0×10^{-6} vol/vol/psi

over perforated interval:

$\phi = .225$
$Sw = .638$
$Shc = .362$
h = 75 ft
$Ct = 23.1 \times 10^{-6}$ vol/vol/psi

over maximum contributing interval:

$\phi = .246$
$Sw = .671$
$Shc = .329$
h = 135 ft
$Ct = 21.6 \times 10^{-6}$ vol/vol/psi

```
YES

NB!!!  CALCULATIONS MAY TAKE SOME TIME!!!!!!


 S T A T I S T I C S
*********************

FIELD: . . . . . . . . . . .                 1-9
WELL:  . . . . . . . . . . .               1-9-3A
DATE:  . . . . . . 09.18.13    19 OCTOBER    1978
ENGINEER:  . . . . . . . . . JRA

DEPTH INTERVAL:  . . .  3156.00 TO  3179.00
APPLIED CUTOFFS:
.               VSH:  GREATER THAN       0.40
.              PHIF:      LESS THAN      0.12
.                SW:  GREATER THAN       0.65

 T O T A L    D E P T H
******************************************
THICKNESS: . . . . . . . . .       23.000
AVERAGE  . . . 'PHIF'  . . .        0.225
AVERAGE  . . . 'VSHALE'  . .        0.021
AVERAGE  . . . 'SW'  . . . .        0.638
W.AVERAGE  . . 'SW' * 'PHIF'        0.635
AVERAGE  . . . 'SH'  . . . .        0.362
VOID VOLUME: . . . ('PHIF').        5.186
HC VOID VOLUME . . ('SH'S) .        1.891
RES HC VOID VOLUME ('SHR'S).        0.119
MOV HC VOID VOLUME . . . . .        1.772
******************************************

 N E T     P A Y
******************************************
THICKNESS: . . . . . . . . .       12.500
AVERAGE  . . . 'PHIF'  . . .        0.227
AVERAGE  . . . 'VSHALE'  . .        0.013
AVERAGE  . . . 'SW'  . . . .        0.580
W.AVERAGE  . . 'SW' * 'PHIF'        0.581
AVERAGE  . . . 'SH'  . . . .        0.420
VOID VOLUME: . . . ('PHIF').        2.842
HC VOID VOLUME . . ('SH'S) .        1.189
RES HC VOID VOLUME ('SHR'S).        0.049
MOV HC VOID VOLUME . . . . .        1.140
******************************************

 N E T    S A N D
******************************************
THICKNESS: . . . . . . . . .       23.000
AVERAGE  . . . 'PHIF'  . . .        0.225
AVERAGE  . . . 'VSHALE'  . .        0.021
AVERAGE  . . . 'SW'  . . . .        0.638
W.AVERAGE  . . 'SW' * 'PHIF'        0.635
AVERAGE  . . . 'SH'  . . . .        0.362
VOID VOLUME: . . . ('PHIF').        5.186
HC VOID VOLUME . . ('SH'S) .        1.891
RES HC VOID VOLUME ('SHR'S).        0.119
MOV HC VOID VOLUME . . . . .        1.778
******************************************

 N E T / G R O S S     R A T I O S
******************************************

HNETPAY /HGROSS SAND =  0.54348
HNETSAND/HGROSS SAND =  1.00000
HNETPAY /HNETSAND    =  0.54348
******************************************


BRONN                  DYBDE 1    DYBDE 2
1-9-3A                 3156.00    3179.00


GI KOMMANDO?
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YES

NB!!!  CALCULATIONS MAY TAKE SOME TIME!!!!!!


 S T A T I S T I C S
*********************

FIELD: . . . . . . . . . . .                 1-9
WELL:  . . . . . . . . . . .               1-9-3A
DATE:  . . . . . 11.55.19    19 OCTOBER    1978
ENGINEER:  . . . . . . . . . JRA

DEPTH INTERVAL:  . . .  3157.00 TO  3198.00
APPLIED CUTOFFS:
.               VSH:  GREATER THAN       0.40
.              PHIF:     LESS THAN       0.12
.                SW:  GREATER THAN       0.65

 T O T A L    D E P T H
*****************************************
THICKNESS: . . . . . . . . .        41.000
AVERAGE  . . . 'PHIF'  . . .         0.246
AVERAGE  . . . 'USHALE'  . .         0.021
AVERAGE  . . . 'SW'  . . . .         0.671
W.AVERAGE  . . 'SW' * 'PHIF'         0.675
AVERAGE  . . . 'SH'  . . . .         0.329
VOID VOLUME: . . . ('PHIF').        10.068
HC VOID VOLUME . . ('SH'*) .         3.276
RES HC VOID VOLUME ('SHR'*).         0.227
MOV HC VOID VOLUME . . . . .         3.049
*****************************************

 N E T    P A Y
*****************************************
THICKNESS: . . . . . . . . .        12.750
AVERAGE  . . . 'PHIF'  . . .         0.227
AVERAGE  . . . 'USHALE'  . .         0.013
AVERAGE  . . . 'SW'  . . . .         0.581
W.AVERAGE  . . 'SW' * 'PHIF'         0.583
AVERAGE  . . . 'SH'  . . . .         0.419
VOID VOLUME: . . . ('PHIF').         2.898
HC VOID VOLUME . . ('SH'*) .         1.209
RES HC VOID VOLUME ('SHR'*).         0.049
MOV HC VOID VOLUME . . . . .         1.160
*****************************************

 N E T    S A N D
*****************************************
THICKNESS: . . . . . . . . .        41.000
AVERAGE  . . . 'PHIF'  . . .         0.246
AVERAGE  . . . 'USHALE'  . .         0.021
AVERAGE  . . . 'SW'  . . . .         0.671
W.AVERAGE  . . 'SW' * 'PHIF'         0.675
AVERAGE  . . . 'SH'  . . . .         0.329
VOID VOLUME: . . . ('PHIF').        10.068
HC VOID VOLUME . . ('SH'*) .         3.276
RES HC VOID VOLUME ('SHR'*).         0.227
MOV HC VOID VOLUME . . . . .         3.049
*****************************************

 N E T / G R O S S    R A T I O S
*****************************************

HNETPAY /HGROSS SAND =  0.31098
HNETSAND/HGROSS SAND =  1.00000
HNETPAY /HNETSAND    =  0.31098
*****************************************


BRONN                  DYBDE 1    DYBDE 2
1-9-3A                 3157.00    3198.00

GI KOMMANDO?
```

APPENDIX 3 1/9-3 DST 3

Content

1. 1/9-3 DST 3 Summary

The objective of this test was to evaluate if the hydrocarbons in the tight zone of the Ekofisk formation, might be included in the pay zone.

Table 1 gives a summary of test performance. The well was not really brought to surface. It was decided not to stimulate this well because one felt one might create communication with the DST 4 interval.

Results are:

- slight indications of hydrocarbons
- absolutely no natural fractures
- formation permeability in the range .015 md
- no contribution to the pay from the tight zone in Ekofisk formation

Table 1

TEST SUMMARY SHEET

Well: 1/9-3 DST no.: 3 Date: 9-14.9

Formation: Ekofisk Perforations: 3126-3135m RKB

		Rates			Pressur	
ime [hrs]	event.	oil STB/D	gas MMSCF/D	Water BBL/D	Well-head	Lot tor
0.50	1. flow			19.2	0	46
3.40	1. buildup			-	-	68
29.80	2. flow			16.2	0	47

2. TESTSTRING AND TESTSEQUENCE

2.1 Teststring

The following is the layout of the teststring:

ID	OD	Description	length (m)	depth (m)
		DST 3		
		3½ TDS TBG.		
[illegible].75	6.00	3½ TDS Box-3½ IF Pin	.28	2926.73
2.00	5.00	Slip Joint	5.58	2927.01
[illegible]00	5.00	Slip Joint	4.30	2932.59
2.00	5.00	Slip Joint	4.02	2937.39
[illegible]68	6.12	3½ IF Box-4½ IF Pin	.20	2941.41
2.81	6.50	3 Std of drill	85.16	2941.61
[illegible]12	6.12	9 5/8 RTTS Circulating Valve	.97	3026.77
2.81	6.50	1 Std. of Drill Collars	28.45	3027.74
[illegible]68	6.12	4½ IF Box-3½ IF Pin	.20	3056.28
2.00	5.00	Slip Joint	4.02	3056.48
2.75	6.12	3½ IF Box-4½ IF Pin	.20	3060.20
2.81	6.50	1 Std. Drill Collars	24.85	3060.70
2.75	6.12	4½ IF Box-3½ IF Pin	.20	3089.24
2.00	4.63	APR-A Reverse Valve	.91	3089.44
2.00	4.63	APR-N Tester Valve	4.16	3090.35
2.37	4.63	Big John Jars	1.58	3094.51
2.68	6.12	3½ IF Box-4½ IF Pin	.20	3096.09
3.12	6.12	9 5/8 RTTS Circulating Valve	.97	3096.29
3.12	6.12	9 5/8 RTTS Safety Joint	1.10	3097.26
3.75	8.25	9 5/8 RTTS Packer (Model II)	.68 1.10	3098.36 3099.04
2.50	6.06	4½ IF Box-2 7/8 EUE Pin	.25	3100.14
2.44	2.87	Tubing Pup Joint	1.86	3100.39
2.44	2.87	Perforated Tubing	1.22	3102.25
1.81	2.87	No-Go Nipple	.63	3104.10
2.44	2.87	2 Joint Tubing/W/Plug	18.73	3122.83

2.2 Testsequence

DIARY OF EVENTS		WELL No - 1/9-3 DST No 3 ZONE TESTED Ekofisk PERFS 3126-3135 RKB			
DATE	TIME	OPERATIONS			
12.9.78					
	1030	Rigged up Dresser Atlas, perforated w/4spf			
		from 3126-3135m RKB, rigged down			
	1430	Made up bottom hole assembly with the			
		following gauges:			
		Gauge	No	Clock no/hrs	Depth (m)
		Amerada 12000psi	36405	1942/120	3116.9
		Amerada 12000psi	41677	1943/120	3114.9
		Amerada 12000psi	36396	5570/72	3118.9
		Kuster 100-200°C	41680	17276/120	3112.9
		Tested against apr-n to 4000 psi, rih with			
		teststring			
13.9.78					
	0200	Rigged up test tree and surface lines,			
		pressure tested to 8000 psi			
	0230	Set packer, closed circulating valve and			
		tested string to 4000 psi. Displaced			
		string with water, closed circulating			
		valve and tested string to 7000 psi.			
	0500	Tubing pressure 2200 psi			
	0522	Opened apr-n, tubing pressure			
		increased to 2360 psi			
	0526	Flowed through 3/4" choke to Flopetrol			
		surge tank, pressure decreased to			
		zero in 20 sec.			

COMMENTS

PE

DIARY OF EVENTS	WELL No	-1/9-3	DST No	3
	ZONE TESTED	Ekofisk	PERFS	3126-3135 RKB

DATE	TIME	OPERATIONS
	0529	Closed choke manifold, flowed through
		bubble hose, rate .4 bbl/30 mins
	0557	Closed apr-n valve for 1. buildup
	0921	Opened apr-n
	0925	Injected back to formation, formation broke
		down at 4650 psi, injected 1.5 bbl at a
		pressure of 4000 psi, injection rate
		0.3 bbl/min
	0942	Tubing pressure 3750 psi, opened well
		for flow through 3/4", pressure
		dropped to zero
	0943	Flowed through bubble hose to
		a barrel on the floor
	1800	Run in hole with bottom hole sampler, run no 1
	1940	Sampler closed at -1530m, pooh. Content
		drillwater and 2-3 ml oil
	2025	Rih with sampler, run no 2
	2210	Sampler closed at -3075m, pooh. Content
		mud, drillwater and 1-3 ml crude oil
14.9.78	0800	Rih with sampler, run no 3
	0950	Sampler closed at -3075m, pooh. Content
		mud, drillwater and traces of oil
	1200	Rih with sampler, run no 4
	1330	Sampler closed at -3075m,
		pooh. Content mud bleeding gas
	1515	Closed apr-n valve
	1530	Reverse circulated content of tubing

COMMENTS

PE ____________

DIARY OF EVENTS		
WELL No - 1/9-3	DST No 3	
ZONE TESTED Ekofisk	PERFS 3126-3135m RKB	

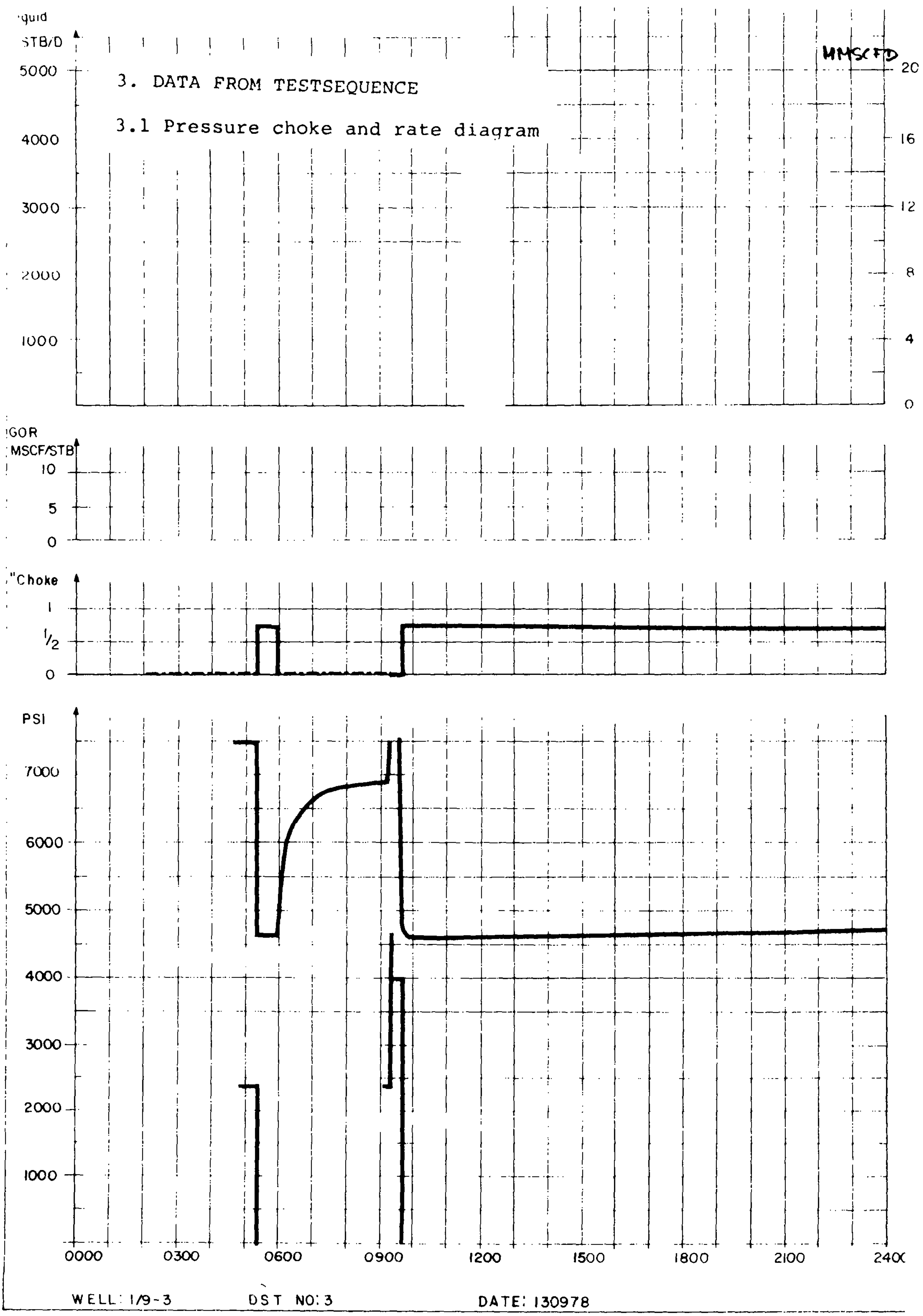
DATE	TIME	OPERATIONS
		Traces of oil. Gas was bleeding during
		the last 50 bbls.
	1745	Completed reverse circulation
	1800	Attempted to inject into formation
	2100	Opened ciculating valve, released packer,
		rigged down test tree and surface lines.
		Observed well. Pooh and broke down test
		tools
15.9.78	0600	Laid down howco test tools, retrieved
		flopetrol recorders.

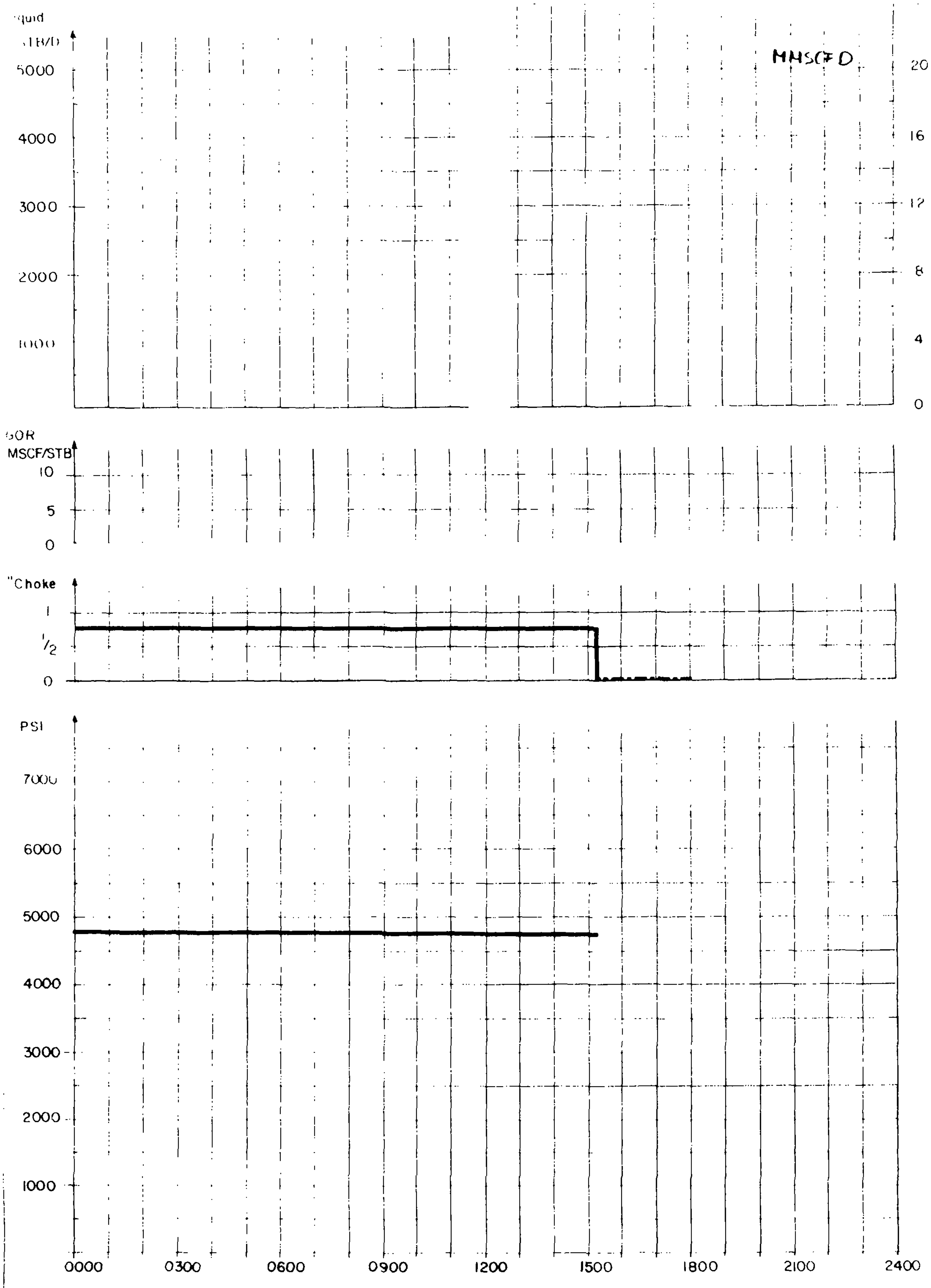
COMMENTS

PE

3. DATA FROM TESTSEQUENCE

3.1 Pressure choke and rate diagram





WELL: 1/9 3 DST NO: 3 DATE: 140978

3.2 Flow data

DATO | OPERASJON 2. Flow | Ark nr | av

BRØNN. 1/9-3 | DST nr | Perforert interval 3126-3115m RKB | Trykkmåler dybde

Tid	Operasjon	Choke 64 in	WHP psi	AHT F	BHP psi	BHT F	Sep trykk psia	Sep temp F	Gasrate MMSCFD	Ltr. min	Cumul. bbl	Olje API	Gas s.g.	Væskeanalyse på rigg: Sted	Vann %	Sediment %	Olje %	Olje API	Merknad
0944										6.7									
0946										9.6									
0955			"							5.0									
1016			"		4617					3.5									
1100			"		4640	288.4				2.3									
1200			"		4655	230.4				2.2									
1300			"		4674	229.3				2.1	3.4								
1400			"		4690	229.6				2.2									
1500			"		4699	230.2				2.1									
1600			"		4710	230.5				1.8									
1700			"		4725	230.7				1.7	11.1								
0100			"		4759	232.0				1.5									
0300			"		4762	232.3				1.5									
0500			"		4765	232.7				1.6									
0600			"		4765	232.9					14.8								
0755			"		4765	233.1					16.1	35.3							
1000			"		4765	233.2					17.4								
1230			"		4736	233.4					19.7								traces of gas to surface
1513			"		4749	233.6					20.1								

4 TEST ANALYSIS

4.1 Buildup no 1

Less than 20 BBL/D were produced. There are no fracture indications. The semi-log straight line is developed.

Horner analysis:

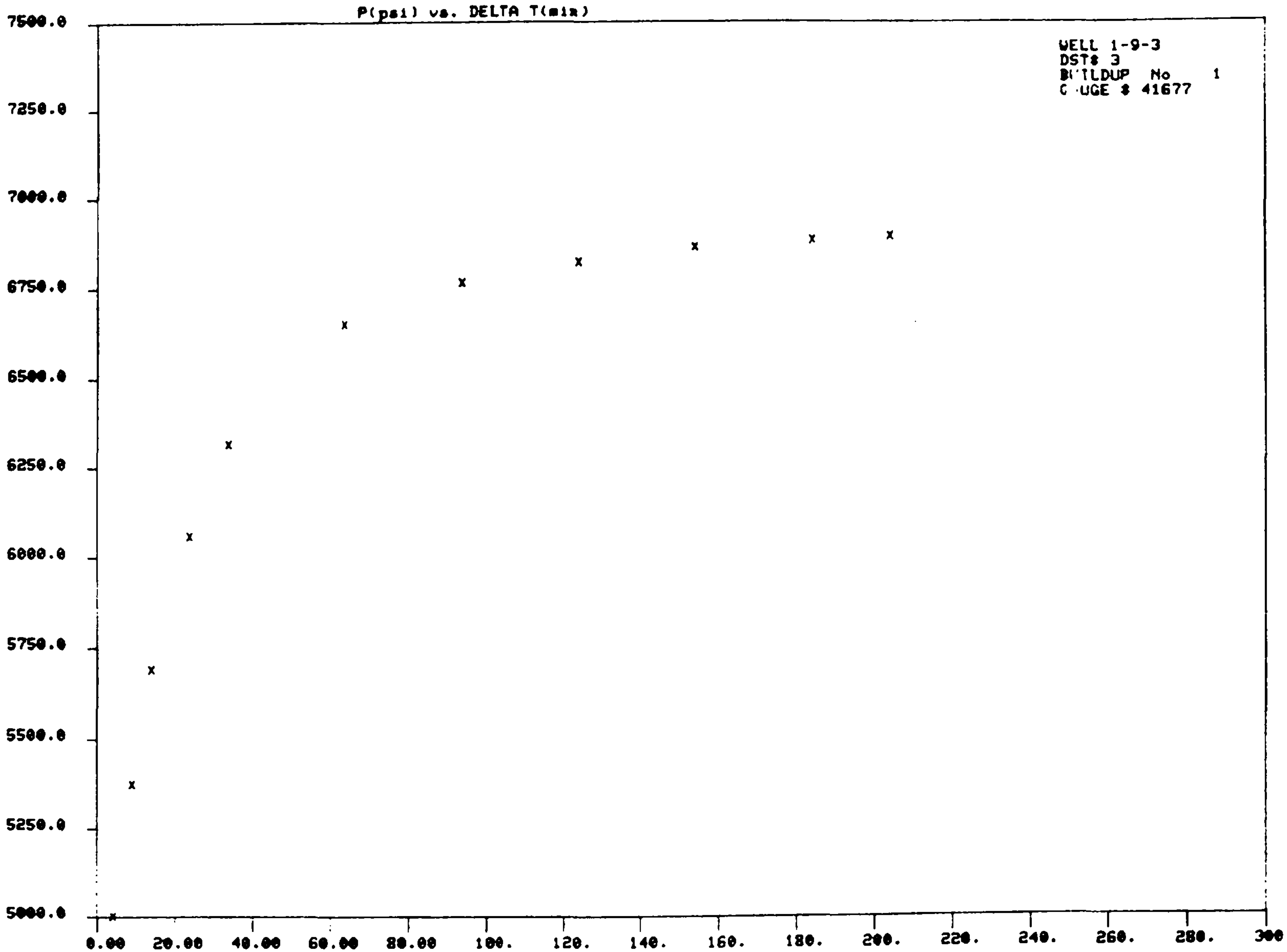
$p^* = 7017$ psi
$m = 2100$ psi/decade
$kh = .52$ md·ft
$k = .018$ md
$s = -.17$

Enclosed:

- pressure point table
- p vs. Δt
- p vs. $\sqrt{\Delta t}$
- log p vs. log Δt
- p vs. log $((t+\Delta t)/\Delta t)$
- p vs. log $((t+\Delta t)/\Delta t)$ with a straight line.

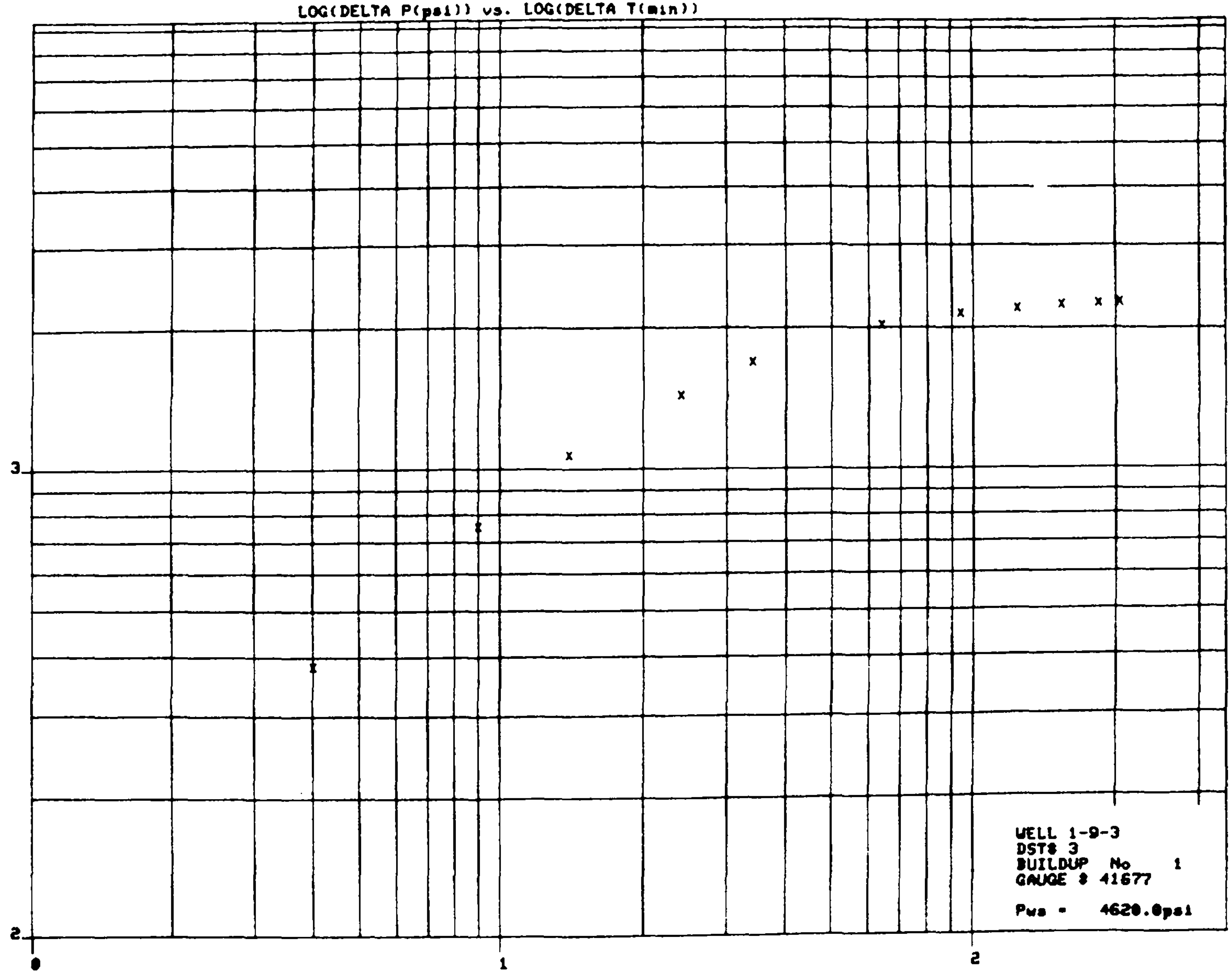
BRØNN 1-9-3   DST# 3
BUILDUP NUMMER   1
GAUGE 41677

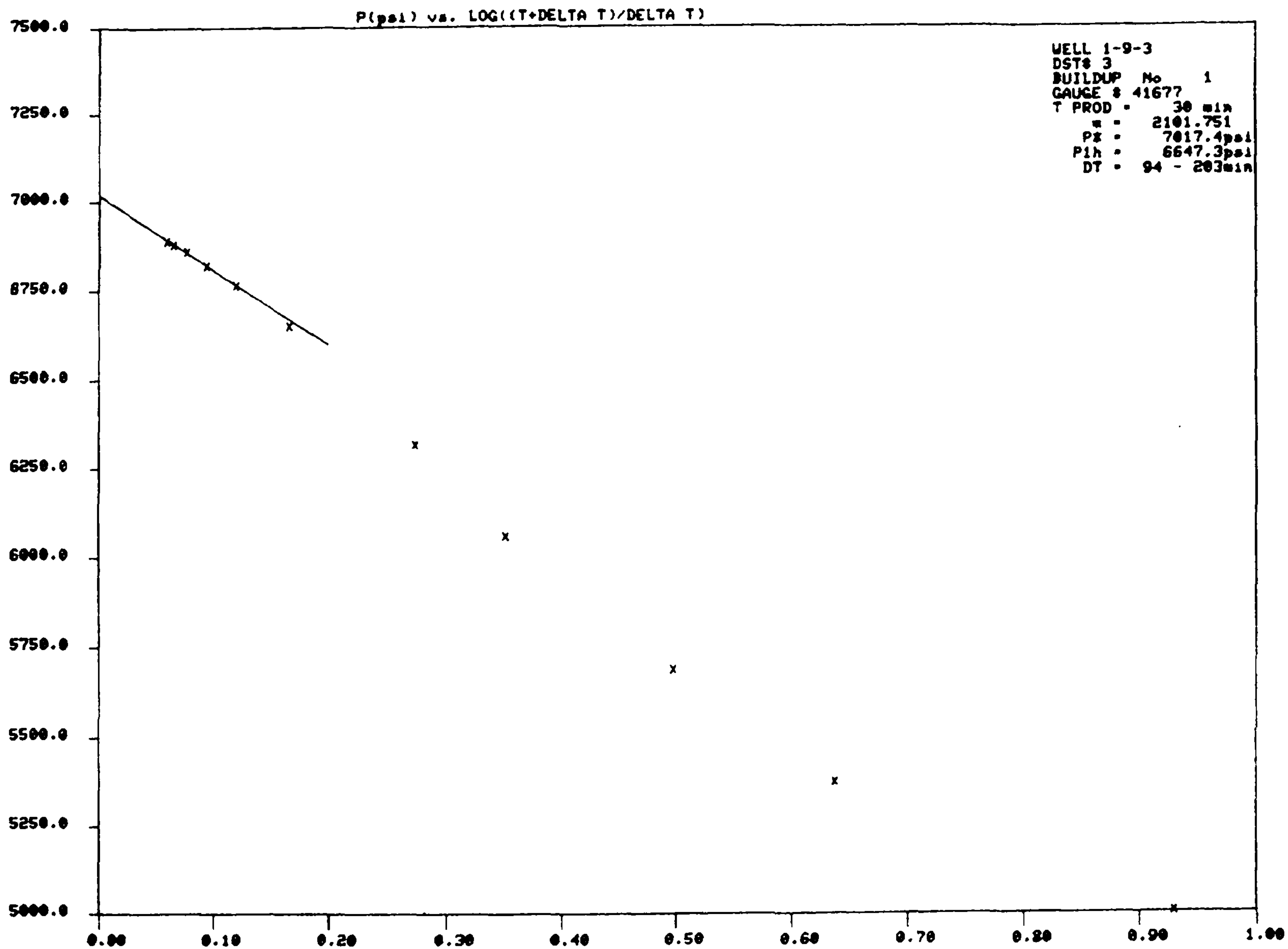
NR.	TID	TRYKK
1	6.00	5002.000
2	6.05	5375.000
3	6.10	5691.000
4	6.20	6060.000
5	6.30	6316.000
6	7.00	6649.000
7	7.30	6763.000
8	8.00	6820.000
9	8.30	6860.000
10	9.00	6879.000
11	9.20	6889.000



P(psi) vs. DELTA T(min)
WELL 1-9-3
DST# 3
BUILDUP No 1
GAUGE # 41677
7500.0
7250.0
7000.0
6750.0
6500.0
6250.0
6000.0
5750.0
5500.0
5250.0
5000.0
0.00
20.00
40.00
60.00
80.00
100.
120.
140.
160.
180.
200.
220.
240.
260.
280.
300.

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




P(psi) vs. LOG((T+DELTA T)/DELTA T)
WELL 1-9-3
DST# 3
BUILDUP No 1
GAUGE # 41677
T PROD = 30 min
m = 2101.751
P* = 7017.4psi
P1h = 6647.3psi
DT = 94 - 203min
7500.0
7250.0
7000.0
6750.0
6500.0
6250.0
6000.0
5750.0
5500.0
5250.0
5000.0
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00

5 Miscellaneous data used in the test analysis-DST 3

Completion data:

r_w = .4 ft (9 5/8" casing)

perforated interval: 3126-3135m RKB = 9m = 29.5ft

Water properties:

B_w = 1.0 res bbl/STBBL

μ_w = .30 cp

$c_w = 3.2 \times 10^{-6}$ vol/vol/psi

Hydrocarbon compressibility:

$c_{hc} = 50 \times 10^{-6}$ vol/vol/psi

Petrophysical properties:

rock compressibility: 3.0×10^{-6} vol/vol/psi

over perforated interval:

ϕ = .207

S_w = .625

S_{hc} = .375

h = 29.5 ft

$C_t = 23.75 \times 10^{-6}$ vol/vol/psi

```
YES

NB!!!  CALCULATIONS MAY TAKE SOME TIME!!!!!!



 S T A T I S T I C S
*********************

FIELD: . . . . . . . . . . .                1-9
WELL:  . . . . . . . . . . .              1-9-3A
DATE:  . . . . . . 00.16.06     19 OCTOBER    1978
ENGINEER:  . . . . . . . . . JRA

DEPTH INTERVAL:  . . .  3125.00 TO  3135.00
APPLIED CUTOFFS:
.              VSH:  GREATER THAN       0.40
.             PHIF:     LESS THAN       0.12
.               SW:  GREATER THAN       0.65

 T O T A L    D E P T H
*****************************************
THICKNESS: . . . . . . . . .        10.000
AVERAGE   . . . 'PHIF'  . . .        0.207
AVERAGE   . . . 'VSHALE'  . .        0.050
AVERAGE   . . . 'SW'  . . . .        0.625
W.AVERAGE  . . 'SW' * 'PHIF'         0.622
AVERAGE   . . . 'SH'  . . . .        0.375
VOID VOLUME:  . . . ('PHIF').        2.073
HC VOID VOLUME  . . ('SH'*) .        0.784
RES HC VOID VOLUME ('SHR'*).         0.082
MOV HC VOID VOLUME . . . . .         0.702
*****************************************

 N E T    P A Y
*****************************************
THICKNESS: . . . . . . . . .         7.000
AVERAGE   . . . 'PHIF'  . . .        0.214
AVERAGE   . . . 'VSHALE'  . .        0.045
AVERAGE   . . . 'SW'  . . . .        0.587
W.AVERAGE  . . 'SW' * 'PHIF'         0.586
AVERAGE   . . . 'SH'  . . . .        0.413
VOID VOLUME:  . . . ('PHIF').        1.499
HC VOID VOLUME  . . ('SH'*) .        0.620
RES HC VOID VOLUME ('SHR'*).         0.069
MOV HC VOID VOLUME . . . . .         0.551
*****************************************

 N E T    S A N D
*****************************************
THICKNESS: . . . . . . . . .        10.000
AVERAGE   . . . 'PHIF'  . . .        0.207
AVERAGE   . . . 'VSHALE'  . .        0.050
AVERAGE   . . . 'SW'  . . . .        0.625
W.AVERAGE  . . 'SW' * 'PHIF'         0.622
AVERAGE   . . . 'SH'  . . . .        0.375
VOID VOLUME:  . . . ('PHIF').        2.073
HC VOID VOLUME  . . ('SH'*) .        0.784
RES HC VOID VOLUME ('SHR'*).         0.082
MOV HC VOID VOLUME . . . . .         0.702
*****************************************

 N E T / G R O S S    R A T I O S
*****************************************

HNETPAY /HGROSS SAND =  0.70000
HNETSAND/HGROSS SAND =  1.00000
HNETPAY /HNETSAND    =  0.70000
*****************************************


BRONN                    DYBDE 1    DYBDE 2
1-9-3A                   3125.00    3135.00


GI KOMMANDO?
```

APPENDIX 4 1/9-3 DST 4

Content

1 1/9-3 DST 4 Summary

The objectives of this test were:

- evaluate productitivity of the Ekofisk formation

- collect samples from Ekofisk formation

- evaluate the feasibilty of acid frac stimulation

Table 1 gives a summary of test performance. The stimulation equipment broke down after the first stage, the well was then flowed with a buildup and a new stimulation job was performed the next day. A long flow and a long buildup after the complete acid frac job was not achieved due to leaks on surface flow lines, but we feel that the results from the analysis are conclusive.

Results are:

- the Ekofisk formation have no natural fractures

- the average formation permeability is of the order .5 md

- the first incomplete acid frac job created a hydrallic fracture of the order Xf = 55 ft. The complete acid frac job created a fracture with Xf larger then 105 ft.

Table 1

TEST SUMMARY SHEET

Well: 1/9-3 DST no.: 4 Date: 18.9-21.9 1978

Formation: Ekofisk Perforations: 3094-3112m RKB

		Rates			Pressur	
ime [hrs]	event.	oil STB/D	gas MMSCF/D	Water BBL/D	Well-head	bot tom
.53	initial flow	-	-	456	0	480
3.20	initial buildup					695
6.38	2. flow	300	4.1	-	300	109
24.18	2. buildup					680
7.22	stimulation, wirelinework					
8.53	3. flow	1400	18.5	-	1100	380
3.18	3. buildup					620
13.00	wireline work, complete stimulation program					
2.20	Opened/closed well, leaks					
7.50	4. flow	2500	23.0	-	1500	517
2.0	Closed/opened well, leaks					

2. TESTSTRING AND TESTSEQUENCE

2.1 Teststring

The following is the layout of the teststring:

ID	OD	Description	length(m)	depth (m)
		DST 4		
		3½ TDS TBG.		
[illegible]75	6.00	3½ TDS Box-3½ IF Pin	.28	2893.36
2.00	5.00	Slip Joint	5.58	2893.64
[illegible]00	5.00	Slip Joint	4.30	2899.22
2.00	5.00	Slip Joint	4.02	2904.02
[illegible]68	6.12	3½ IF Box-4½ IF Pin	.20	2908.04
2.81	6.50	3 Std of drill	85.16	2908.24
[illegible]12	6.12	9 5/8 RTTS Circulating Valve	.97	2993.40
2.81	6.50	1 Std. of Drill Collars	28.45	2994.32
[illegible]68	6.12	4½ IF Box-3½ IF Pin	.20	3022.82
2.00	5.00	Slip Joint	4.02	3023.02
[illegible]75	6.12	3½ IF Box-4½ IF Pin	.20	3027.04
2.81	6.50	1 Std. Drill Collars	24.85	3027.24
[illegible]75	6.12	4½ IF Box-3½ IF Pin	.20	3055.69
[illegible]00	4.63	APR-A Reverse Valve	.91	3055.83
2.00	4.63	APR-N Tester Valve	4.16	3056.80
2[illegible]37	4.63	Big John Jars	1.58	3060.95
2.68	6.12	3½ IF Box-4½ IF Pin	.20	3062.54
3[illegible]12	6.12	9 5/8 RTTS Circulating Valve	.97	3062.74
3.12	6.12	9 5/8 RTTS Safety Joint	1.10	3063.71
3[illegible]75	8.25	9 5/8 RTTS Packer (Model II)	.68 1.10	3064.81 3066.59
2[illegible]50	6.06	4½ IF Box-2 7/8 EUE Pin	.25	3066.84
2.44	2.87	Tubing Pup Joint	1.86	3068.70
2[illegible]44	2.87	Perforated Tubing	1.22	3069.92
1.81	2.87	No-Go Nipple	.63	3069.92
2[illegible]44	2.87	2 Joint Tubing/W/Plug	18.73	3089.28

2.2 Testsequence

DIARY OF EVENTS		WELL No 1/9-3 — DST No 4 — ZONE TESTED Ekofisk — PERFS 3094-3112m RKB
DATE	TIME	OPERATIONS
16.9.78	1230	Rigged up. Dresser Atlas wire line head and
		perforated from 3094 to 3112m RKB in two
		runs. Rigged down
	1900	Made up howco bttm hole assemby with the
		following gauges
		Gauge — No — Clock hrs — Clock no — Final depth
		Amerada — 36405 — 120 — 1942 — 3082.9
		Amerada — 41677 — 120 — 1943 — 3080.9
		Amerada — 36396 — 72 — 5570 — 3084.9
		Kuster — 41680 — 120 — 17276 — 3086.9
		Rih with teststring
17.9.78	0730	Picked up test tree, rigged up and
		tested surface lines
	0916	Set packer at 3065.5m RKB
		Closed rtts circulating valve and
		tested tubing
	1044	Opened rtts circulating valve and
		displaced mud in tubing with water.
	1123	Closed rtts circulating valve and tested
		tubing, bled down pressure to 1800 psi
	1142	Opened apr-n valve,
		tubing pressure 2300 psi
	1143	Opened flopetrol choke to 48/64", flowed
		to gaugetank. Produced 9.3 bbls in 30 mins

COMMENTS

PE

DIARY OF EVENTS		WELL No 1/9-3 DST No 4 ZONE TESTED Ekofisk PERFS 3094-3112m RKB
DATE	TIME	OPERATIONS
	1215	Closed choke on surface, then apr-n
		was closed. 1. shut in for 3 hours
	1515	Repaired leak on bubblehose,
		pressured tubing to 1800 psi.
	1527	Opened apr-n, injected 5bbls back
		Formation broke down at 3400 psi, injection rate
		1bbl/min at a pressure 3200 psi,
		closed wing valve on kill side
	1538	Opened choke on 3/4", flowed to
		gauge tank, rate 3bbls/5 mins
	1600	Flowed to clean-up line
	1645	Mud to surface, wellhead pressure increasing,
		gas to surface
	1715	Flare lit
	2237	Flowed through 7/8" adjustable choke
	2307	Increased to 1" choke as an attempt to
		improve the well's capacity to
		lift mud
18.9.78	0210	Switched flow through separator, had
		problems with the Barton gas meter.
		Monitored rates from 0500
	0801	Shut well in on surface, surface pressure
		slowly increased.
	0822	Surface pressure 1725 psi, closed
		apr-n, 2. shut in for 24 hours

COMMENTS

PE

DIARY OF EVENTS	WELL No - 1/9-3	DST No 4
	ZONE TESTED Ekofisk	PERFS 3094-3112m RKB

DATE	TIME	OPERATIONS
19.09.78	0812	Opened apr-n
	0830	Started acid job, bj equipment
		failed after the first stage of the
		acid program, displaced the acid
		in the tubing with seawater
	1115	Rigged up Flopetrol lubricator, run
		the following gauges
		Gauge / Pressure / Clocks / Final depth (m RKB)
		32328 / 10.000 psig / 72 hrs / 3073.8
		41676 / 10.000 psig / 72 hrs / 3071.8
		41675 / 10.000 psig / 120 hrs / 3075.8
	1435	Latched bombs in Baker no-go nipple,
		p.o.o.h
	1520	Rigged down lubricator
	1525	Opened the well slowly to 3/4" adjustable,
		gauged rate, 20bbls/5 min. Flowed to clean-up
		line, pressure increase
	1533	Gas to surface
	1620	Bypassed heater, not required
	1655	Flowed through separator
	2355	Bypassed separator
	2357	Closed choke on surface, pressure
		increased to 2520 psi, closed apr-n for
		3. build-up
20.9.78	1307	Opened master valve, pressure 2035 psi
	1318	Opened apr-n, pressure in tubing
		increased to 4430 psi

COMMENTS

PE ____________

DIARY OF EVENTS	WELL No - 1/9-3	DST No 4
	ZONE TESTED Ekofisk	PERFS 3094-3112m RKB

DATE	TIME	OPERATIONS
	1325	Displaced content in tubing with 117 bbls,
		2100 psi on surface
	1400	Rigged up Flopetrol lubricator to recover
		bombs in Baker nipple
		1. run: didn't recover bombs
		2. run: latched on to the bombs,
		jarred for approx. 1 hour, sheared
		of and r.o.o.h. No bombs recovered.
	1900	Fracture acidizing according to program
	2202	Closed wing valve on kill side
	2207	Opened the well slowly on floor
		manifold
	2210	Closed well on choke due to a leak
		in flowline between choke and heater,
		wellhead pressure 2285 psi.
		Repaired leak, pressure tested lines
		to 5000 psi
	2251	Opened the floor choke again
		very slowly
	2253	3/4" adjustable choke
	2300	Gas to surface, lit the flare
	2315	Closed the well in on the choke due to
		a leak in flowline to burner,
		repaired leak, wellhead pressure 3950 psi
	2329	Opened well to 3/4" adjustable
	2338	Sudden gas leak developed in chicksans (swiwel)
		between test tree and flopetrol choke

COMMENTS

PE

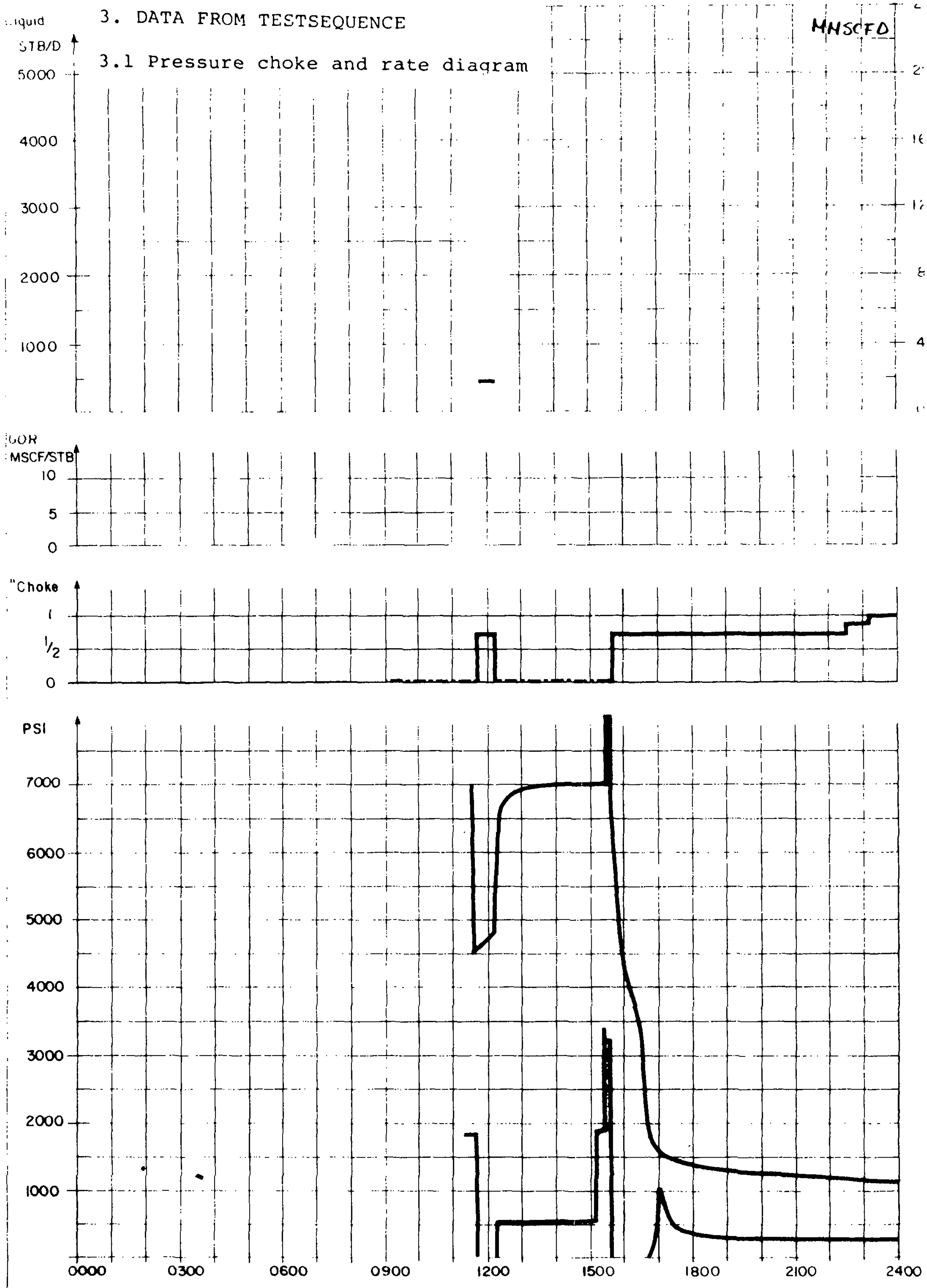
DIARY OF EVENTS		WELL No - 1/9-3 · DST No 4 · ZONE TESTED Ekofisk · PERFS 3094-3112m RKB
DATE	TIME	OPERATIONS
		closed apr-n valve, circulated
		Could not open apr-n valve again,
		opened bottom rtts circulating
		valve, pumped mud, observed well
22.09.78	0700	Well stable, released packer, rigged
		down test tree and surface lines
		p.o.o.h
	1900	Laid down howco test string and
		retrieved pressure recorders.

COMMENTS

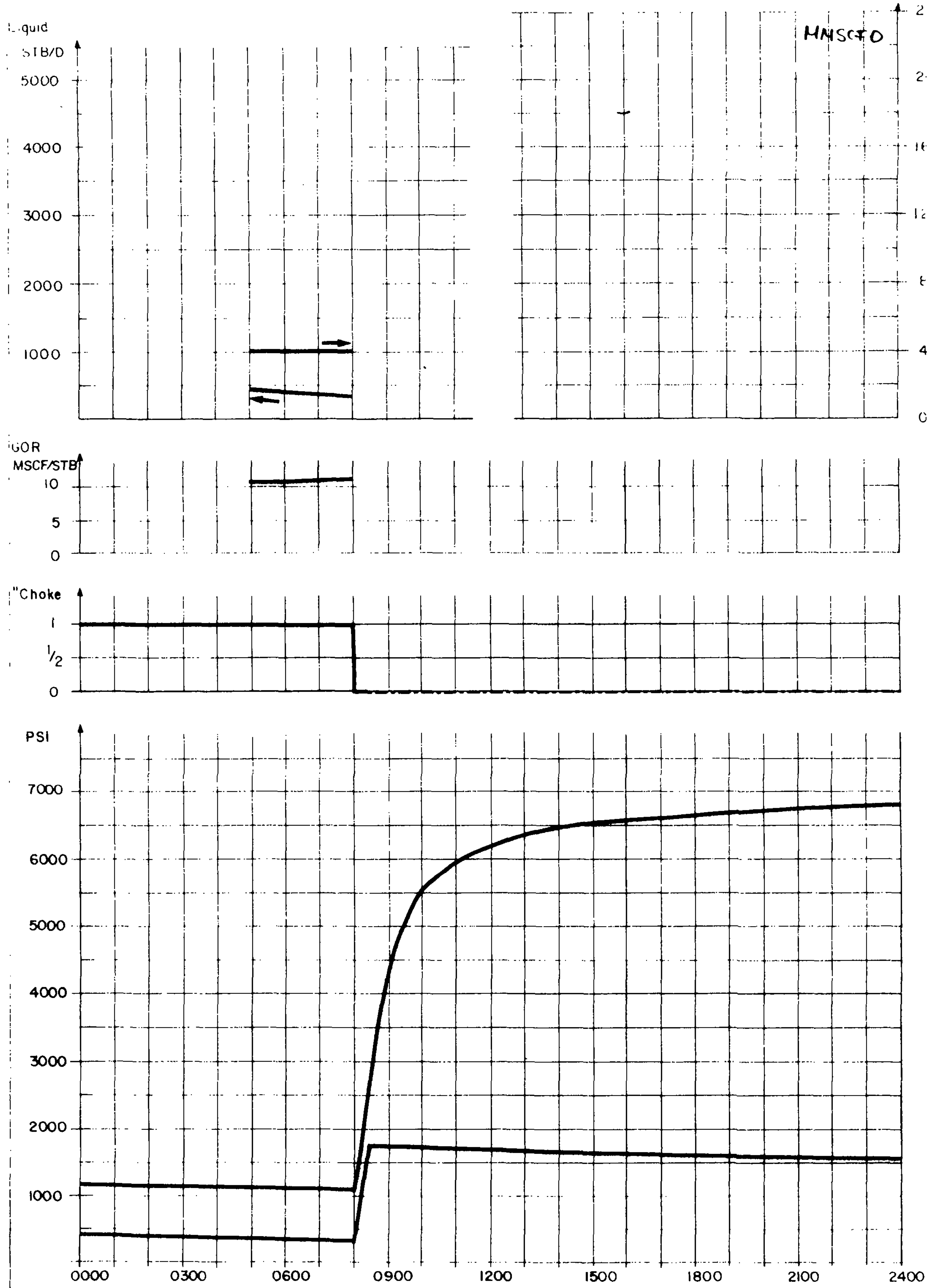
PE

3. DATA FROM TESTSEQUENCE

3.1 Pressure choke and rate diagram



WELL 1/9-3 DST NO: 4 DATE: 170978



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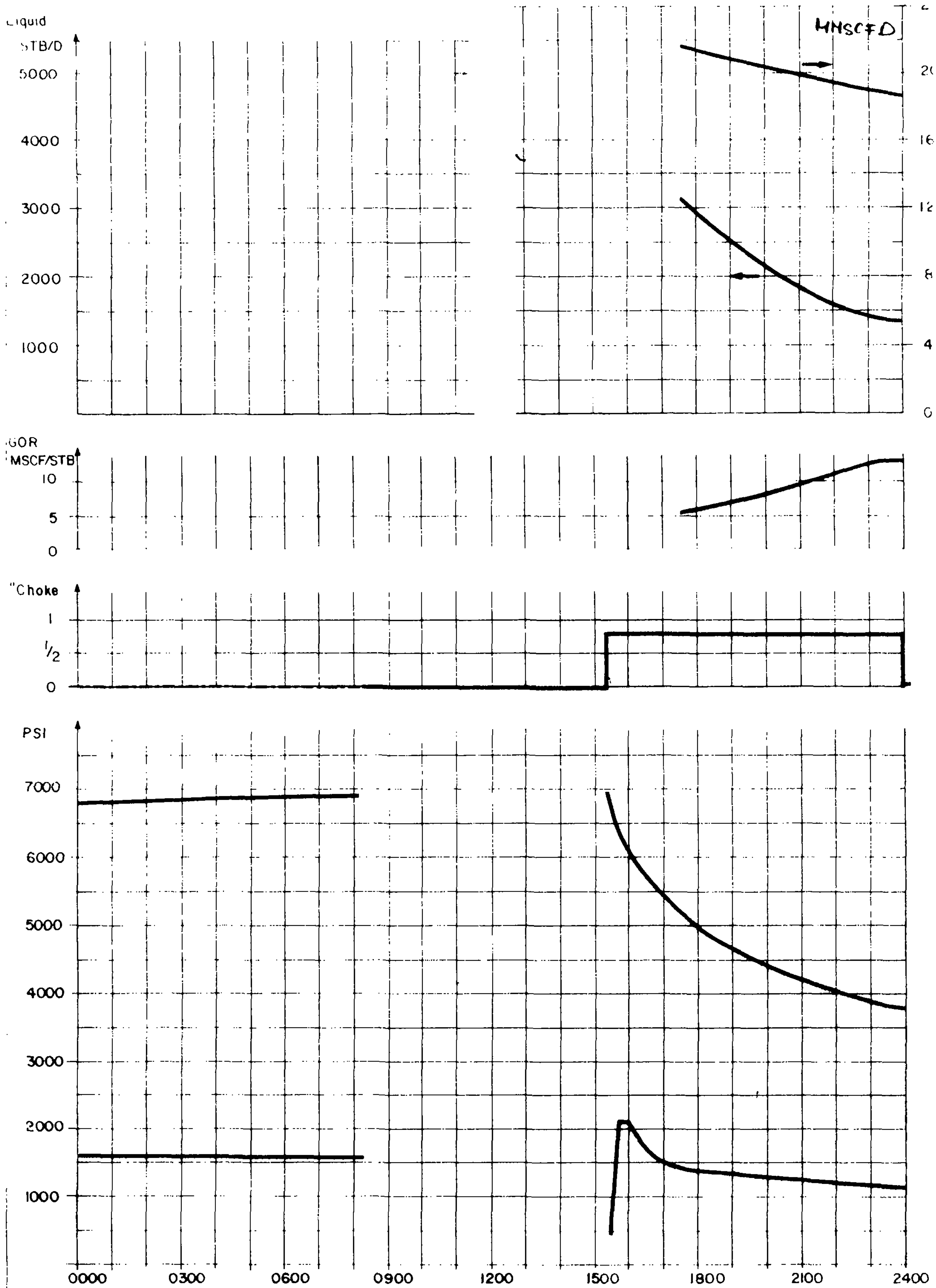

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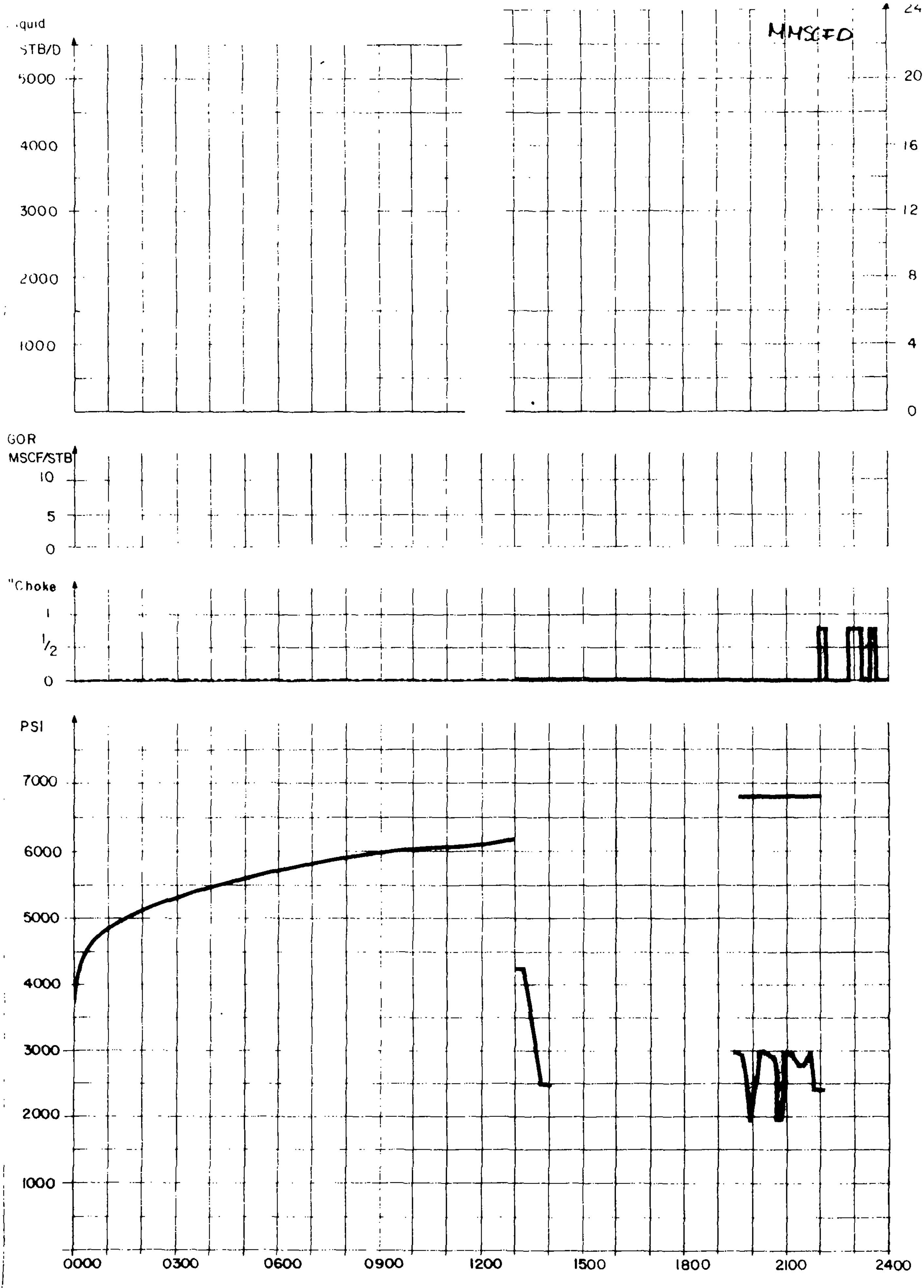

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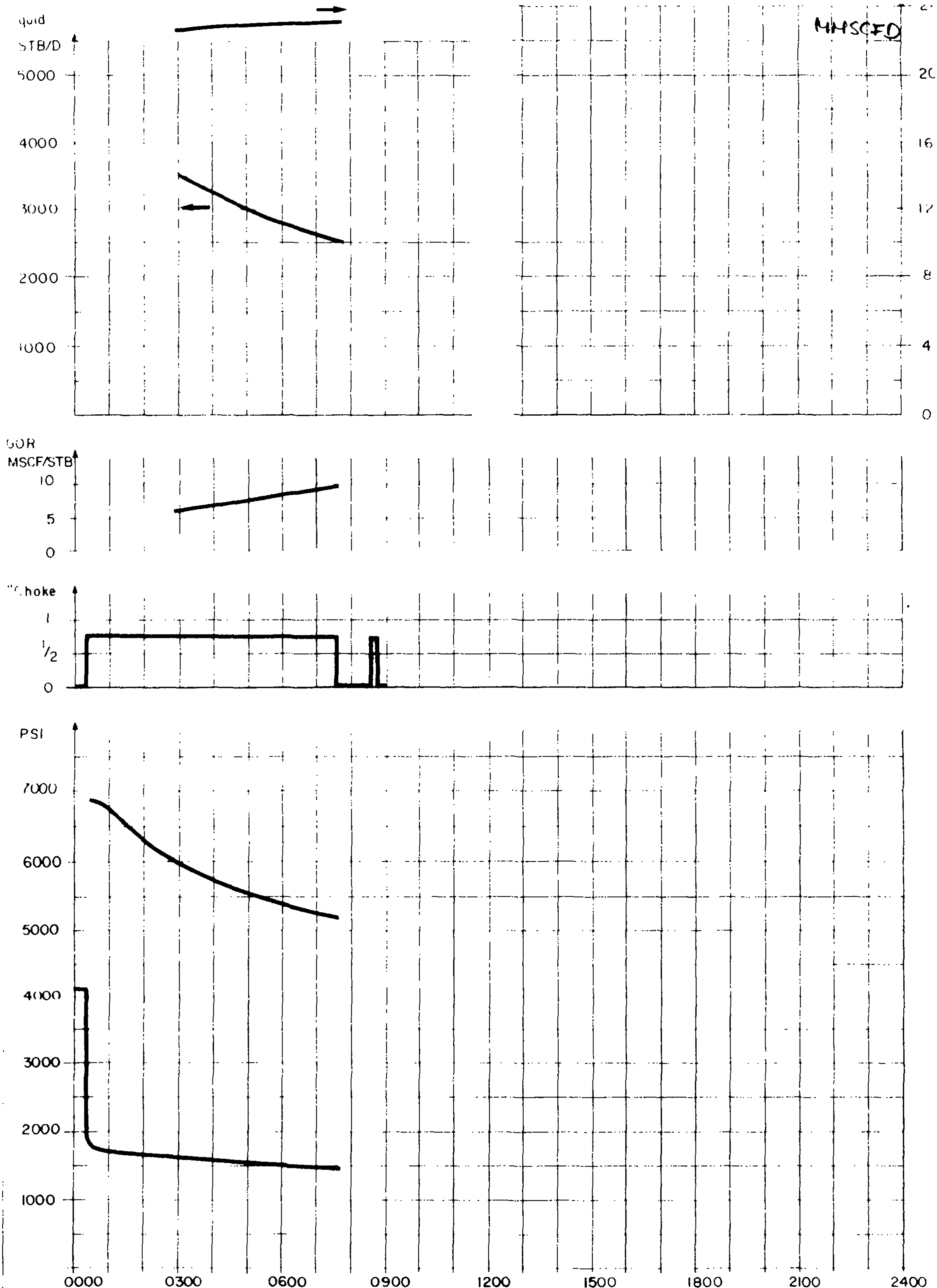

WELL: 1/9-3 DST NO: 4 DATE: 210978

3.2 Flow data

DATO. 17-18/9 1978 | OPERASJON 2. Flow (Cleanup before acid) | Ark nr 1 av 3

BRØNN. | DST nr.: | Perforert interval: | Trykkmåler dybde.

Tid	Operasjon	Choke 64th	WHP psi	WHT F	BHP psi	BHT F	Sep trykk psia	Sep temp F	Gassrate MMSCFD	Oljerate STBOPD	GOR SCF/STB	Olje API	Gass s.g.	Væskeanalyse på rigg: Sted	Mud %	Vann %	Olje %	Olje API	Merknad
1540		48	<12																
1630		"	<12	74															
1645		"	50	81															
1700		"	660	105	1763	227.8													
1705		"	1050	103															
1710		"	730	93															
1715		"	580	90															
1730		"	400	87	1507														
1745		"	430	89															
1800		"	410	87	1427	228.0								b.h.	30	10	60		cl- 18000 ppm
1815		"	400	87										b.h.	2	18	80		
1830		"	377	87	1359														
1845		"	370	90										b.h.	6	15	79		cl- 13000 ppm
1900		"	360	88	1321	228.6													
1915		"	300	88										b.h.	14	4	82		
1930		"	340	89															
1945		"	325	89										b.h.	17	3	89	49.1	cl- 13000 ppm
2000		"	310	90	1272	228.7													
2015		"	300	90										b.h.	3	17	80		
2030		"	310	90															
2045		"	290	90										b.h.	14	1	85		cl- 15000 ppm
2100		"	310	90	1216	229.1													
2115		"	295	90										b.h.	15	5	80		
2130		"	310	91															
2145		"	305	91										b.h.	11	1	8		
2200		"	290	90	1216	229.3													

DATO 17-18/9 1978 OPERASJON 2. Flow Ark nr 2 av 3

BRØNN: 1/9-3 DST nr. 4 Perforert interval: 3094-3112 m RKB Trykkmåler dybde

Tid	Operasjon	Choke 64 in	WHP psi	WHT F	BHP psi	BHT F	Sep trykk psia	Sep temp F	Gassrate MMSCFD	Oljerate STBOPD	GOR SCF/STB	Olje API	Gass s.g.	Væskeanalyse på rigg: Sted	mvd%	vann%	Olje %	Olje API	Merknad
2215		"	300	91										b.h.	8	5	87	48.9	cl^- 14500 ppm
2230		"																	
2245		56	380	95										b.h.	14	1	85		
2300		"	360	94	1210	229.0													
2315		64	335	92										b.h.	9	1	90		
2330		"	300	92															
2345		"	345	92										b.h.	19	1	80		
2400		"	345	92	1160	229.8													
0015		"	310	92										b.h.	14	1	84	48.4	
0030		"	310	92															
0045		"	330	93										b.h.	7	1	92		
0100		"	300	93	1135	230.0													
0115		"	330	92										b.h.	11	.5	88.5		
0130		"	310	92															
0145		"	320	93										b.h.	8.5	1.5	90	48.7	
0200		"	315	92	1141	230.2													
0215		"	360	93										b.h.	7	.5	92.5		
0230		"	360	93															
0245		"	370	93										b.h.	7.5	.5	92.0		
0300		"	370	93	1160	230.4													
0315		"	370	92										b.h.	7	0	93.0	48.9	
0330		"	355	92															
0345		"	390	92										b.h.	7	.5	92.5		
0400		"	370	94	1141	230.7													
0415		"	385	94										b.h.	7	.2	92.8	49.5	
0430		"	370	94						372		49.9							

DATO 17-18/9 1978 OPERASJON 2. Flow (cleanup before acid) Ark nr 3 av 3

BRØNN 1/9-3 DST nr. 4 Perforert interval 3094-3112 m RKB Trykkmåler dybde

Tid	Operasjon	Choke 64 in	WHP psi	WHT F	BHP psi	BHT F	Sep trykk psia	Sep temp F	Gassrate MMSCFD	Oljerate STBOPD	GOR SCF/STB	Olje API	Gass s.g	Væskeanalyse på rigg: Sted	mud%	vann%	Olje %	Olje API	Gas analysis, bubble hose (%): C1	C2	C3	C4	C5
0445		"	365	94						395		49.9											
0500		"	320	93	1123	230.9				441		"		b.h.	8	.5	91.5	49.8					
0515		"	365	93			225	108	4.1	383	10680	"	.692	b.h.	5.8	.2	94.0						
0530		"	360	94			"	108	4.1	407	10050	"	"						78.11	12.00	5.11	3.46	2.06
0545		"	375	95			"	106	4.1	363	11430	"	"	b.h.	7.0	.5	92.5						
0600		"	350	95	1115	231.1	230	109	4.2	338	12400	"	"										
0615		"	340	95			"	"	4.1	436	9350	"	.715	b.h.	5.0	.5	94.5						
0630		"	335	96			"	"	4.1	401	10160	50.4	"					49.7	78.66	11.96	5.00	3.01	1.37
0645		"	355	96			"	"	4.1	361	11290	"	"	b.h.	6.0	.3	93.7						
0700		"	330	96	1092	231.3	"	"	4.1	351	11570	"	.700										
0715		"	340	96			"	"	4.0	342	11700	"	"	b.h.	7.0	.5	92.5						
0730		"	340	96			"	"	4.1	454	8950	"	"						77.88	12.17	5.24	3.59	1.12
0745		"	335	96			"	"	4.1	298	13820	"	"										
0800		"	360	96	1095	231.4	"	"	4.1	279	14770	"	"										
							Cumulativ waterproduction 5.2 bbl																
0804		0	875																				
0805		0	940																				
0806		0	1005																				
0808		0	1125																				
0810		0	1225																				
[illegible]		0	1465																				
0820		0	1660																				
0822		0	1725																				

DATO 19/9 1978 OPERASJON 3. Flow (after 1. acid job) Ark nr 1 av 2

BRØNN: 1/9-3 DST nr 4 Perforert interval 3094-3112m RKB Trykkmåler dybde

Tid	Operasjon	Choke 64 in	WHP psi	WHT F	BHP psi	BHT F	Sep trykk psia	Sep temp F	Gasrate MMSCFD	Oljerate STBOPD	GOR SCF/STB	Olje API	Gass s.g.	Væskeanalyse på rigg: Sted	Vann %	Sediment %	Olje %	Olje API	Gas analysis bubble hose [•] C1	C2	C3	C4	C5	
1530		48	530		6532																			
1545		"	2145	116																				
1600		"	2110	128	5993	239.0																		
1615		"	2080	135		242.6																		
1630		"	1620	141	5660	243.9																		
1645		"	1510	140		245.3									12	.2								
1700		"	1482	143	5390	246.6									6	.2			74.92	12.84	6.24	3.65	2.28	
1715		"	1467	144		247.6	525	102	21.5				.700		4	.2								
1730		"	1445	145			"	104	21.4	3135	6839	50.4	"											
1745		"	1428	145		248.0	"	106	21.4	2601	8228	"	"											
1800		"	1404	145	5000		515	105	21.1	2912	7260	"	"						75.29	12.67	6.10	3.62	2.31	
1815		"	1390	146			"	106	21.0	2720	7710	"	.705											95 BWPD
1830		"	1375	146			525	"	20.9	2582	8110	"	"											
1845		"	1362	147			"	"	20.9	2634	7920	"	"											
1900		"	1343	147	4675	248.2	"	"	20.6	2411	8557	"	"											
1915		"	1328	147			"	"	20.6	2212	9326	"	"						73.65	12.15	5.88	4.59	3.74	2.5-3.0 ppm H_2S
1930		"	1317	147			"	"	20.6	2291	9044	"	"											82 BWPD
1945		"	1305	147			"	"	20.6	2201	9373	"	"											
2000		"	1290	147	4435	248.0	"	"	20.6	2105	9300	51.36	"											
2015		"	1280	147			515	"	20.0	2068	9691	"	"											
2030		"	1268	147			"	"	19.9	1915	10336	"	"											65 BWPD
2045		"	1255	147			"	"	19.8	2014	9336	52.72	"											
2100		"	1242	147	4231	247.6	"	"	19.6	1794	10953	"	"											
2115		"	1235	147			"	"	19.6	1794	10953	"	"						73.68	12.97	5.89	4.16	3.30	2.5 ppm H_2S
2130		"	1222	147			"	"	19.5	1760	11073	"	"											60 BWPD
2145		"	1207	147			"	107	19.5	1735	10924	53.06												

DATO. 19/9 1978 OPERASJON 3. Flow (after 1. acid job) Ark nr 2 av 2

BRØNN 1/9-3 DST nr 4 Perforert interval 3094-3112m RKB Trykkmåler dybde

Tid	Operasjon	Choke 64 th	WHP psi	WHT F	BHP psi	BHT F	Sep trykk psia	Sep temp F	Gassrate MMSCFD	Oljerate STBOPD	GOR SCF/STB	Olje API	Gass s.g.	Væskeanalyse på rigg: Sted	Vann %	Sediment %	Olje %	Olje API	Gas analysis, bubble hose [%] C_1	C_2	C_3	C_4	C_5	
2200		"	1202	147	4047	246.9	515	107	19.4	1504	12906	53.06	.705											
2215		"	1192	147			"	"	19.4	1679	11548	"	"						79.61	10.09	4.63	3.84	2.35	1.5 ppm H_2S
2230		"	1180	147			500	"	19.3	1497	12899	"	.700											57 BWPD
2245		"	1172	147			"	"	18.8	1689	11137	"	"											
2300		"	1162	147	3890	246.4	"	"	18.8	1334	14055	"	"											54 BWPD
2315		"	1152	146			"	"	18.8	1386	13528	"	"						75.92	12.27	5.71	3.71	2.40	1.5-2.0 ppm H_2S
2330		"	1142	146			"	"	18.5	1404	13234	"	"											44 BWPD
2345		"	1135	146		246.0			18.5	1438	12844	"	"						76.91	11.06	5.04	3.81	3.18	3.0 ppm H_2S

DATO. 21/9 1978 OPERASJON 4. flow (after 2. acid frac. job) Ark nr 1 av 2

BRØNN. 1/9-3 DST nr 4 Perforert interval 3094-3112m RKB Trykkmåler dybde

Tid	Operasjon	Choke 64 in	WHP psi	WHT F	BHP psi	BHT F	Sep trykk psia	Sep temp F	Gasrate MMSCFD	Oljerate STBOPD	GOR SCF/STB	Olje API	Gass s.g	Væskeanalyse på rigg: Sted	Vann %	Sediment %	Olje %	Olje API	Gas analysis, bubble hose [%]: C_1	C_2	C_3	C_4	C_5	
0018		0	4125																					
0020		48	1750																					
0030		"	1605	97																				
0045		"	1655	131																				
0100		"	1672	141		230.0													63.52	9.35	5.39	20.1	1.07	1 ppm H_2S
0115		"	1670	145		232.2																		
0130		"	1660	148		234.0																		
0145		"	1655	149		235.4								b.h.	10		90							
0200		"	1645	150		236.7								b.h.	4		96		72.25	11.27	6.10	3.53	1.86	1 ppm H_2S
0215		"	1630	152																				
0230		"	1625	153		238.6	555	113	22.5				.722											
0245		"	1617	153			"	"	22.6	3470	6516	48.3	.714											
0300		"	1612	154		240.3	"	115	22.6	3504	6441	"	"						76.74	12.41	5.76	3.31	1.78	12 ppm H_2S
0315		"	1602	155			"	"	22.6	3453	6536	"	"											
0330		"	1592	154		241.5	"	"	22.6	3317	6804	"	"											
0345		"	1585	155			553	"	22.8	3308	6898	"	"											
0400		"	1577	156		242.8	555	"	22.9	3282	6965	49.0	"						75.98	12.82	5.75	3.38	2.06	1.3 ppm H_2S
0415		"	1570	156			"	"	22.9	3146	7266	"	"											
0430		"	1565	156		243.7	"	"	22.9	3069	7449	"	"											239 BWPD
0445		"	1558	156			"	"	22.9	3120	7327	"	"											
0500		"	1550	156		244.4	"	"	22.9	2956	7733	49.5	"						77.24	13.12	3.86	3.69	2.09	1.5 ppm H_2S
0515		"	1545	156			"	"	22.9	2973	7639	"	"											
0530		"	1537	157			"	116	22.8	2794	8182	"	"											136 BWPD
0545		"	1530	157			"	"	23.0	2922	7323	"	.705											
0600		"	1525	157		245.7	"	"	23.0	2794	8181	"	"											168 BWPD
0615		"	1520	157			"	117	23.0	2716	8417	"	"											

DATO. 21/9 1978 OPERASJON 4. Flow Ark nr 2 av 2

BRØNN. 1/9-3 DST nr. 4 Perforert interval 3094-3112m RKB Trykkmåler dybde.

Tid	Operasjon	Choke 64"	WHP psi	WHT F	BHP psi	BHT F	Sep trykk psia	Sep temp F	Gasrate MMSCFD	Oljerate STBOPD	GOR SCF/STB	Olje API	Gass s.g	Væskeanalyse på rigg: Sted	Vann %	Sediment %	Olje %	Olje API	Merknad
0630		48	1512	158			555	117	22.9	2700	8474	50.6	.71						157 BWPD
0645		"	1507	158			"	117	22.9	2684	8525	"	"						
0700		"	1502	158		246.6	"	117	22.9	2590	8834	"	"						134 BWPD
0715		"	1495	158			"	117	22.9	2366	9670	"	"						
0730		"	1490	159			"	117	22.9	2480	9226	"	"						
0745		"	1485	159		247.1	"	117	22.9	2496	9167	"	"						