AFTERFLOWS AND BUILDUP INTERPRETATION

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ABSTRACT

Field data on pumping well buildup curves illustrate long fluid column stabilization, U-tubing of liquid from tubing into the annulus, gas coning, high-pressure gas stringers, and high-pressure liquid stringers. Examples are given of truncation and of fitting two curves to the afterflow to get a better approximation of main pay and stringer properties, and of estimating unflooded stringer pressure from afterflow changes.

INTRODUCTION

We have been getting buildup curves on pumping wells by determining liquid levels acoustically, measuring surface pressures and calculating sand-face pressures. The measured acoustic velocity permits calculation of the specific gravity and Z factor for the gas, so that its weight can be calculated. The weight of the liquid column is calculated stepwise with the aid of correlations[1-3] of fraction of column that is gas with the gas flow, the pressure, and the annulus area. Data are taken automatically at intervals of 5 minutes to 1 hour in a programmed sequence. The amount of gas and of liquid in the annulus at each data point is determined, which permits calculation of the gas and of the liquid afterflow for each interval.

DISCUSSION

Besides giving buildup curves for the conventional analysis, the changes in liquid level and inflow rates give additional insight into the well's performance. We have recognized several types of situations that we have interpreted to indicate: fluid column stabilization, pump valve leakage, gas coning, and the presence of high pressure stringers of gas or of liquid (water and/or oil).

Note that all wells discussed in this report are pumping wells.

FLUID COLUMN STABILIZATION (CASE 1, TABLE 1)

Pumping wells generally should not have a long fluid column, since the backpressure reduces the flow of oil into the well. However, for various reasons many wells do have - sometimes several thousand feet. Fig. 1 gives an example of a well with about 6,000 ft. of liquid on the formation while pumping. The liquid level falls rapidly during stabilization for two reasons. As the gas comes out from under the liquid, the level drops; and since the separating gas is at an elevated pressure, it raises the well pressure, causing liquid to flow back into the formation.

In this example, after about 12 hours, the fluid column had lost its entrained gas and the reservoir pressure around the well had built up to match the well's bottomhole pressure, so that from that point onward the buildup was normal and could be used for calculating KH and reservoir pressure in the conventional manner.

LEAKY PUMP VALVES (CASE 2, TABLE 2)

Sometimes even when there is very little fluid column, we have an unusually high rate of fluid entry measured in the annulus, followed by a drop in fluid level and then a normal buildup. Fig. 2 and Case 2, Table 2, illustrate such a case. We attribute this to U-tubing of liquid from the tubing into the annulus at shut-in, due to leaking pump valves. In some cases the volume of the tubing above the fluid level in the casing is approximately equal to the volume of the rise in the casing. In Case 2 the tubing volume was about four times the rise. This excess may be because we do not know what the gas content of the tubing was, or just how far the tubing level fell. Also the fall in casing level after the hump peak undoubtedly means backflow of liquid from the casing into the formation. We have not corrected for the backflow during the rise in the hump. These factors could well account for the tubing content being greater than the observed rise in the casing.

GAS CONING (CASE 3, TABLE 3)

Sometimes a well that was producing gas at a high rate shows practically no gas afterflow. This suggests coning of gas from a gas-oil interface above the perforations. In this situation, even a small change in gradients around the well might cause the gas level at the well to rise a little, cutting off gas flow completely. Figs. 3 and 4 show the change in liquid level and surface pressure with time. The rise in gas pressure shown in Fig. 4 was due entirely to compression by the rising liquid; there was no increase in gas content of the annulus. There was a substantial liquid afterflow.

HIGH-PRESSURE GAS STRINGER (CASE 4, TABLE 4)

When a liquid level falls instead of rising after shut-in, it means that liquid is being forced back into the formation. We have seen cases in which the liquid dropped clear down to the perforations. This might happen in a single thick zone with a gas liquid interface in the perforated interval if the liquid flowed back into the lower part of the formation displacing gas that enters the well at the top of the formation. However, if the gas afterflow drops to a low level but then continues almost unabated as the backpressure rises, it suggests the presence of two zones, one the main pay zone making gas and oil, and the other a thin stringer of high-pressure gas.

Fig. 5 shows the liquid level, Fig. 6 the gas afterflow, and Table 4 other information on such a well. The gas afterflow becomes very small compared with the initial gas inflow rate, but since its percentage decline with time is much less in the later stages than it is in the early stages, it has a major effect on the shape of the semilog plot (Fig. 7). The well compressibility is roughly constant, so that constant inflow would give a semilog plot whose slope increases in proportion to time. The upward curvature in Fig. 7 is due to the gas afterflow shown in Fig. 6.

This upward curvature is characteristic of a fractured well in a single zone. A fractured zone also in the later stages reflects a region of less flow capacity and higher pressure than it did in the early part of the buildup. However, in the fracture case, one would expect to see both gas and liquid in the afterflow. A late afterflow of only gas or only liquid suggests the presence of a second zone of gas or liquid of limited KH but higher pressure. Such a two-zone case would give an upward curving semilog plot similar to that of a fractured well.

HIGH-PRESSURE LIQUID STRINGER (CASE 5, TABLE 5)

Frequently, particularly in waterfloods, wells give indications of a high-pressure liquid stringer likely representing direct communication with the injection well. Table 5 gives information on such a well. In the later stages the rise in gas pressure is due to compression by the rising liquid. No gas is entering the annulus. The liquid does not level off, but rises strongly to the end of the buildup (Fig. 8). Gas and liquid afterflows are shown in Figs. 9 and 10, the semilog plot in Fig. 11 and a log-log type curve in Fig. 12.

Not only does a high-pressure stringer with a nearly constant afterflow give a semilog plot that looks like that of a fractured well, but also the plot of pressure vs. square root of time gives a long straight line (Fig. 13). Therefore, the choice of whether we are dealing with a long fracture or with a high-pressure stringer must depend on information other than the buildup curve alone. As suggested above, solely gas or solely liquid in the later afterflow may indicate a stringer. Or if the KH calculated for the formation is unreasonably low compared with earlier values, it may suggest a stringer. Also, the low permeability may result in a reservoir pressure estimate that is unreasonably high, suggesting the presence of a stringer. Afterflow data provide the necessary insight for analyzing these types of problems.

Since the rate of pressure buildup is directly proportional to the afterflow into the well, we felt that truncating the data to a point at which the afterflow (which determines the semilog slope) reflected conditions in the main pay zone rather than in the stringer should give a better estimate of the main pay characteristics. Such a point is indicated by the letter "T" in Figs. 10 and 11. Since the afterflow is dropping rapidly during most of this early part of the curve, it seems advisable to use a variable rate analysis.[4] A comparison of the results of a conventional analysis on the whole curve and on the truncated curve, and of a variable rate analysis on the truncated curve are given in Table 6 for Case 5.

Note that if there is a stringer causing the afterflow at the end, use of a conventional analysis taking the final slope ("full run") would give much too low a KH and too high a pressure.

This is, of course, a rough approach to the problem since several factors are unresolved. For example, the measured liquid inflow is a net figure; undoubtedly there is crossflow back into the lower pressure zone. Also, the farther one slides down the semilog curve, Fig. 11 to truncate, the bigger KH will be.

Since the well storage factor is reasonably constant, the rate of pressure rise at any time is proportional to the afterflow. This means that a hyperbolic decline of afterflow with time will yield a straight-line semilog plot. The curve in Fig. 10 looks as if it might be the sum of two hyperbolic terms - one starting high and dropping rapidly and the other smaller at the beginning, but declining more slowly. To check this, we fitted the equation

$$Q = \frac{Q1}{1+B1xT} + \frac{Q2}{1+B2xT} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

to the four points marked P, Case 5, Table 5. Q1 and Q2 represent the initial afterflow of the main pay and of the stringer, B1 and B2 are the time scale factors, and Q the measured total afterflow (gas + liquid in B/D at the bottom of the well at time T). Since the well storage is approximately constant, for each term of the equation we can write

$$Q = 1440 \times Cw \quad \frac{d(BHP)}{dT} = \frac{Qo}{1+BxT} \quad \ldots\ldots\ldots\ldots (2)$$

$$M = \frac{d(BHP)}{d \log T} = \frac{2.303 \times Qo}{1440Cw(1/T+B)} \quad \ldots\ldots\ldots\ldots (3)$$

where M is the conventional psi/log cycle, ordinarily measured on the semilog plot. Values of Q1, Q2, and M1 and M2 at the final time (7690 minutes) are given in Table 7 together with other factors calculated, assuming that the layer thickness is proportional to Q1 or Q2. Since this is in a waterflood, we assume the stringer was responding rather directly to the injection well, and produced only water.

Values of the truncated-variable-rate method of getting main pay characteristics (Table 6) are not in too good agreement with the main-pay values obtained by fitting two curves to the afterflow (Table 7), but at least are a lot closer together than either is to the unmodified full run (Table 6).

STRINGERS NOT SUPPORTED BY WATERFLOOD (CASE 6, TABLE 8)

Often, particularly in a waterflood, analysis of pressure buildup tests shows gas afterflow completely stopping at some point along the curve. This effect was present in a survey of nine wells in a West Texas San Andres waterflood. Four of the wells were not included in the study for the following reasons: One of the wells (No. 6, Table 8) showed gas coning - the gas production dropped to zero and remained there during the whole buildup. One of the wells (No. 7, Table 8) showed a gas stringer - substantial free gas afterflow continued during the entire buildup. Two of the wells (No. 8 and 9, Table 8) showed coning, but then later the free gas afterflow picked up and continued to the end of buildup - presumably being produced with the oil from a zone that was being flooded.

The remaining five wells are the first five wells in Table 8. At first it was thought that the gas afterflow might be stopping at about the same place along the buildup curve, but the times varied widely - from 1% to 82% of the total buildup time of approximately four days (Column 6, Table 8). However, if the pressure at which the free gas afterflow drops to zero is noted (Column 7, Table 8), there is a remarkable consistency in the pressure for the first four wells, the free gas afterflow stopping at about 40% of the reservoir pressure at the radius of drainage in this waterflood.

This suggests that there is a significant part of the production coming from zones of lower pressure, probably representing stringers not in communication with the injection well, which are therefore still producing by depletion drive. It would be expected that they would produce free gas along with the oil, while in general zones repressured by the flood would usually produce only dissolved gas. Thus the pressure at which free gas afterflow stops - especially when it is confirmed in a number of wells, should give an indication of the pressure in the part of the reservior still producing by natural depletion.

CONCLUSIONS

1. Afterflow studies often show the presence of high pressure stringers which cause errors in estimating reservoir properties by conventional buildup analysis.
2. Conventional analysis when such stringers are present gives too low a KH, too high a reservoir pressure and too negative an S value.
3. Sometimes afterflow results reveal operating problems.
4. Afterflow data provide the possibility of separating out and estimating the main pay properties, in the presence of a high pressure stringer.
5. When afterflow data are obtained on a number of wells in a

waterflood, characteristic changes in afterflow often reveal the pressure in oil stringers not being supported by the flood.

NOMENCLATURE

B = hyperbolic time scale factor (Eq. 2) minutes^{-1}
$B1$ = B for main pay Eq. 1, minutes^{-1}
$B2$ = B for high-pressure stringer Eq.1 minutes^{-1}
BHP = Pressure in well at datum, psia
Cw = well storage factor, bbl/psi BHP increase
KH = permeability x thickness, md x ft.
Log = logarithm to the Base 10
M = semilog slope, psi/log cycle
M1 = M for main pay, psi/log cycle
M2 = M for high-pressure stringer, psi/log cycle
ΔP = pressure differential from final measured pressure to pressure at radius of drainage, psi
Q = afterflow, B/D or Mcf/D
Qo = Q at T = 0
Q1 = Qo for main pay
Q2 = Qo for high-pressure stringer
RD = radius of drainage (based on pattern area), ft.
RI = radius of investigation[5]
S = skin effect[6]
T = time, minutes
TF = final time, minutes
TH = production time, minutes (Horner time)

REFERENCES

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TABLE 1—CASE 1, FLUID COLUMN STABILIZATION

WELL PARAMETERS

Formation: Deyler "C"

Top of Perforations	8496	Feet
Bottom of Perforations (Datum)	8533	Feet
Net Pay	11	Feet
Casing ID	3.966	Inches
Tubing OD	2.375	Inches
Oil Production Rate	51.	Bbl/D
Water Production Rate	1.	Bbl/D
Gas Production Rate	12.	MCF/D

Data below are smooth data used in Calculations. Raw data are shown as X in Figure 1 along with the smoothed curve.

Shut-in Time Minutes	Liquid Level Feet	Surface Pressure psig	Bottom Hole Pressure at 8533 ft	Afterflows into Well Gas MCF/D	Afterflows into Well Liquid bbl/D
0	2749	21.3	1710.82	8.40	98.07
5	2715	24.4	1740.01	7.98	82.66
10	2686	27.4	1753.88	7.96	71.91
20	2636	33.6	1780.32	7.89	61.49
30	2593	39.7	1806.79	7.74	50.83
45	2539	48.8	1841.04	7.60	41.90
60	2512	57.9	1845.56	8.05	19.16
90	2476	76.0	1880.68	8.04	13.27
135	2450	102.9	1914.50	8.27	4.53
191	2569	137.5	1844.38	10.80	-25.17
333	2864	212.5	1844.06	11.03	-24.70
514	3321	286.9	1765.66	12.55	-31.45
734	4025	346.0	1647.92	11.98	-36.63
858	3924	363.2	1965.48	1.90	11.04
1291	3582	390.6	2222.31	0.00	10.12
2004	3256	412.6	2361.36	0.00	4.76
3115	3040	436.1	2356.75	0.03	1.92
4153	2932	453.2	2510.01	0.06	1.29

TABLE 2—CASE 2, LEAKY PUMP VALVES

WELL PARAMETERS

Formation: Upper Clearfork

Top of Perforations	4012	Feet
Bottom of Perforations (Datum)	4120	Feet
Net Pay	30	Feet
Casing ID	5.009	Inches
Tubing OD	2.375	Inches
Oil Production Rate	32.	Bbl/D
Water Production Rate	3.	Bbl/D
Gas Production Rate	3.2	MCF/D

Data below are smoothed data used in Calculations. Raw data are shown as X in Figure 2 along with the smoothed curve.

Shut-in Time Minutes	Liquid Level Feet	Surface Pressure psig	Bottom Hole Pressure at 4120 ft	Afterflows into Well Gas MCF/D	Afterflows into Well Liquid bbl/D
0	4120	53.6	77.97	20.12#	39.37
5	4110	55.8	82.78	18.89	33.55
10	4102	58.0	87.30	18.62	29.60
20	4087	62.3	95.73	18.03	24.86
30	4075	66.4	103.60	17.45	21.98
45	4058	72.4	114.50	17.95	18.90
60	4043	78.2	125.79	16.07	20.53
90	4012	88.6	146.71	13.79	19.67
135	3971	101.8	174.78	11.55	18.35
215	3887	121.4	223.53	9.55	22.93
313	3873	139.4	250.47	8.07	3.26
430	3933	154.0	250.40	6.68	-11.85
565	3906	166.8	277.08	4.01	4.88
891	3855	188.0	321.79	2.18	3.87
1292	3800	200.6	358.53	0.96	3.49
2030	3721	214.0	404.21	0.37	2.69
2935	3639	223.6	445.84	0.18	2.34
4400	3520	234.9	502.70	0.08	2.10
6601	3370	245.9	570.56	0.00	1.64
6992	3347	247.2	580.43	0.00	1.59

TABLE 3—CASE 3, GAS CONING

WELL PARAMETERS

Formation: Sims "A" Sand

Top of Perforations	7311	Feet
Bottom of Perforations (Datum)	7434	Feet
Net Pay	123	Feet
Casing ID	6.365	Inches
Tubing OD	2.875	Inches
Oil Production Rate	120	Bbl/D
Water Production Rate	135	Bbl/D
Gas Production Rate	48	MCF/D

Shut-in Time Minutes	Liquid Level Feet	Surface Pressure psig	Bottom Hole Pressure at 7434 ft	Afterflows into Well Gas MCF/D	Afterflows into Well Liquid bbl/D
0	7358	69.3	136.49	0.00	105.40
10	7336	69.5	146.06	0.00	99.97
20	7314	69.7	155.58	0.00	99.56
60	7226	70.4	193.20	0.00	98.59
110	7117	71.2	239.97	0.00	98.34
150	7034	71.8	275.60	0.00	93.29
240	6878	73.0	342.54	0.00	72.17
360	6724	74.3	408.72	0.00	54.25
540	6542	76.1	487.33	0.00	42.52
840	6311	78.5	587.47	0.00	31.10
1246	6083	81.3	686.14	0.00	22.93
1947	5794	85.2	812.25	0.00	15.63
2995	5551	89.9	917.61	0.06	8.48
4456	5347	94.9	1009.21	0.05	4.95
5690	5234	98.2	1059.35	0.09	3.53

TABLE 4—CASE 4, HIGH PRESSURE GAS STRINGER

WELL PARAMETERS

Formation: Viola

Top of Perforations	1988	Feet
Bottom of Perforations (Datum)	2290	Feet
Net Pay	302	Feet
Casing ID	6.336	Inches
Tubing OD	2.875	Inches
Oil Production Rate	16.	Bbl/D
Water Production Rate	26.	Bbl/D
Gas Production Rate	30.(est)	MCF/D

Shut-in Time Minutes	Liquid Level Feet	Surface Pressure psig	Bottom Hole Pressure at 2290 ft	Afterflows into Well Gas MCF/D	Afterflows into Well Liquid bbl/D	Afterflows into Well Total bbl/D	Well Storage bbl/psi
0	2142	36.2	88.3	29.85	42.0	927.	
5	2140	39.7	94.2	25.74	9.3	724.	.43
10	2139	42.9	99.1	23.05	6.3	615.	.44
15	2140	45.7	102.7	21.44	-6.6	540.	.52
20	2141	48.4	106.1	19.86	-5.8	484.	.50
30	2142	53.2	112.1	17.54	-4.8	405.	.49
45	2144	59.3	120.3	13.54	-3.4	291.	.35
60	2145	64.0	126.4	11.13	-2.4	228.	.42
90	2147	71.6	135.6	8.68	-1.63	166.	.40
135	2148	80.2	145.7	6.65	-1.23	118.	.42
236	2150	92.5	159.7	4.62	-0.71	75.	.38
364	2151	101.0	170.2	2.53	-0.32	39.	.33
521	2152	107.8	178.0	1.67	-0.25	24.3	.34
706	2153	114.4	185.0	1.36	-0.21	19.1	.35
918	2154	120.8	191.7	1.16	-0.15	15.7	.34
1427	2155	133.2	204.8	0.84	-0.09	10.7	.32
2399	2156	148.8	221.2	0.55	-0.06	6.5	.30
3623	2157	163.0	236.0	0.40	-0.04	4.4	.29
5098	2159	175.5	248.9	0.31	-0.03	3.2	.28

TABLE 5—CASE 5, HIGH PRESSURE LIQUID STRINGER

WELL PARAMETERS

Formation: San Andres

Top of Perforations	4976	Feet
Bottom of Perforations (Datum)	5003	Feet
Net Pay	27	Feet
Casing ID	4.953	Inches
Tubing OD	2.375	Inches
Oil Production Rate	7.	Bbl/D
Water Production Rate	89	Bbl/D
Gas Production Rate	1.0	MCF/D

Shut-in Time Minutes	Liquid Level Feet	Surface Pressure psig	Bottom Hole Pressure at 5003 ft	Afterflows into Well Gas MCF/D	Liquid bbl/D	Total bbl/D	Well Storage bbl/psi
0	4788	49.6	154.53	0.80	98.41	P111.92	
5	4771	49.9	162.65	0.63	86.20	96.36	0.0412
10	4756	50.1	169.46	0.66	78.69	88.95	0.0454
15	4742	50.4	175.83	0.68	72.83	82.93	0.0452
20	4728	50.7	181.84	0.68	68.18	77.96	0.0450
30	4704	51.1	193.00	0.66	61.07	70.07	0.0446
45	4672	51.8	207.05	0.73	50.06	59.28	0.0478
60	4644	52.4	220.32	0.64	47.55	P55.18	0.0440
90	4592	53.5	244.82	0.49	42.86	48.12	0.0426
135	4524	54.9	276.62	0.41	36.43	40.29	0.0439
326	4319	58.7	376.75	0.00	25.87	25.87	0.0364
452	4220	60.4	422.71	0.00	20.86	20.86	0.0397
767	4032	63.4	509.43	0.00	14.49	14.49	0.0397
956	3947	65.1	548.95	0.00	11.86	11.86	0.0394
1646	3707	71.0	660.06	0.04	8.72	8.87	0.0393
2209	3521	75.8	749.12	0.01	8.73	8.76	0.0384
3979	2989	90.1	1000.90	0.00	7.37	P 7.37	0.0388
5767	2528	103.4	1219.28	0.00	6.53	6.53	0.0387
6378	2376	107.8	1290.86	0.00	6.17	P 6.17	0.0387
7690	2157	116.8	1397.32	0.00	3.55	3.55	0.0370

TABLE 6—COMPARISON, CASE 5: FULL RUN, TRUNCATED RUN AND TRUNCATED RUN WITH VARIABLE RATE ANALYSIS

QUANTITY	FULL RUN	TRUNCATED	TRUNCATED VARIABLE RATE
Final time, minutes	7690	1033	1033
KH, millidarcy feet	57.4	187.7	253.2
S, Skin Effect	-4.5	-2.9	-2.3
Final measured bottom hole pressure PSIA	1389	561	561
Drainage Area Pressure* PSIA	3693	1776	1429

* Gradient at end of buildup from final measured pressure to pressure at radius of drainage calculated from steady state radial flow.

$$\Delta P = M \times \log \frac{(RD)^2}{(RI)^2} + .25068 \times M$$

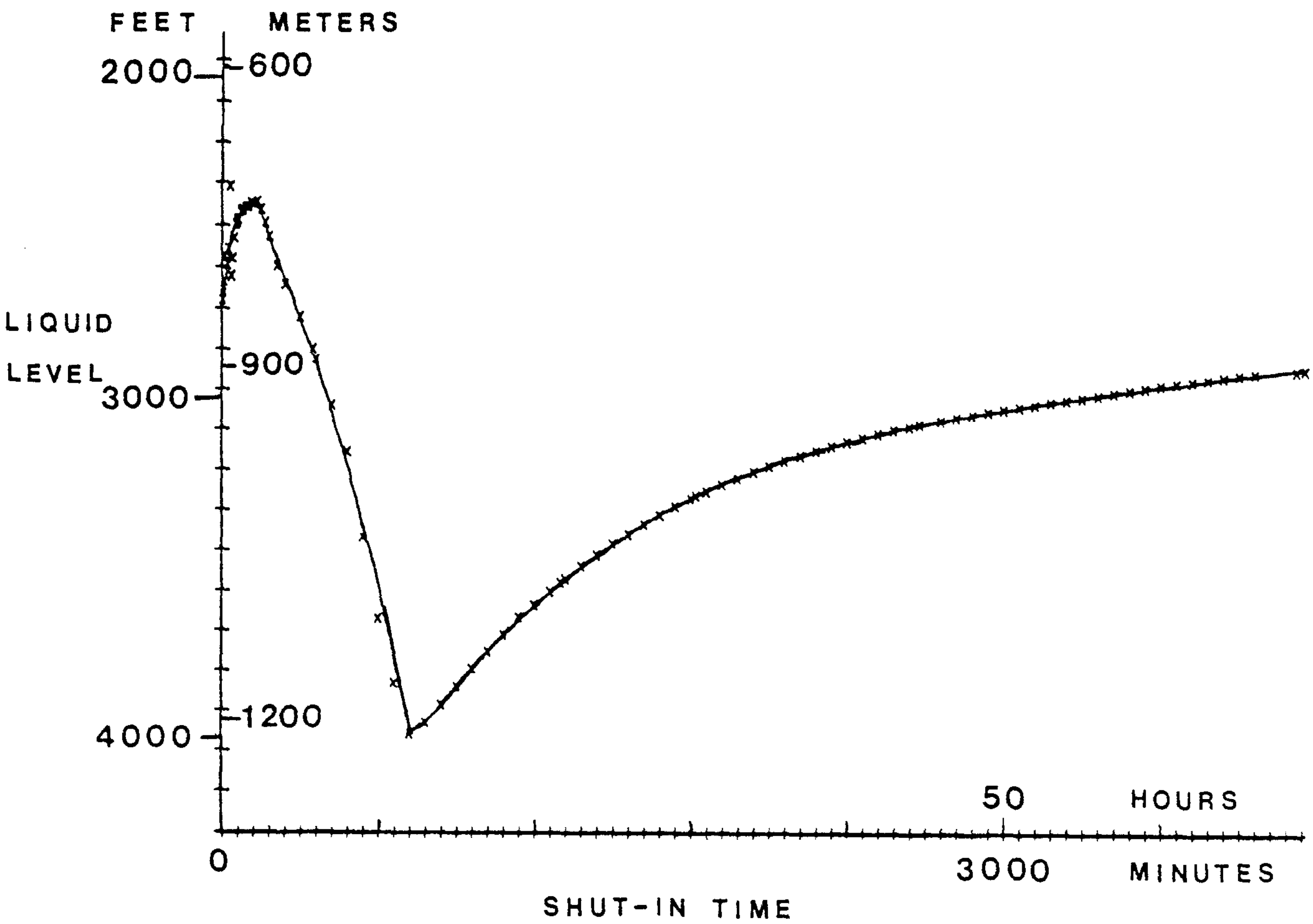
TABLE 7—FITTING TWO CURVES TO AFTERFLOW TO GET PRESSURE CURVES FROM WHICH MAIN PAY AND STRINGER PROPERTIES CAN BE ESTIMATED

	Main Pay	Stringer
Initial Flow, gas + liquid, Qo, bbl/D	104.1	7.8
Time Scale Factor, B, Minutes^{-1}	1.994×10^{-2}	7.2×10^{-5}
Oil, bbl/D	7.0	0
Water, bbl/D	81.2	7.8
Gas, MCF/D	1.0	0
Pay thickness, feet	25.1	1.89
M, psi/log cycle	212.9	1405.
KH, MD x ft.	431	.6
S	+ .6	-5.4
Drainage area pressure, psia	1710	3051

TABLE 8—CASE 6, STRINGERS NOT SUPPORTED BY WATERFLOOD

Formation: San Andres

Well No.	Production Rate Oil B/D	Water B/D	Gas MCF/D	Flowing Pressure psia	Free Gas After-flow Stops Minutes	At psia	Final Measured Pressure psia	Reservoir Pressure At Radius of Drainage psia
1	1	64	1	114	4916	573	612	1251
2	34	0	47	94	1592	446	590	1259
3	18	506	33	209	176	469	1018	1354
4	32	3	23	94	4195	664	702	1385
5	49	489	37	103	77	150	877	1224
6	115	458	58	561	0	561	1475	1551
7	116	0	57	121	>5606	>317	317	750
8	57	349	36	304	>6800	>563	563	862
9	53	133	28	498	>7162	>1089	1089	1247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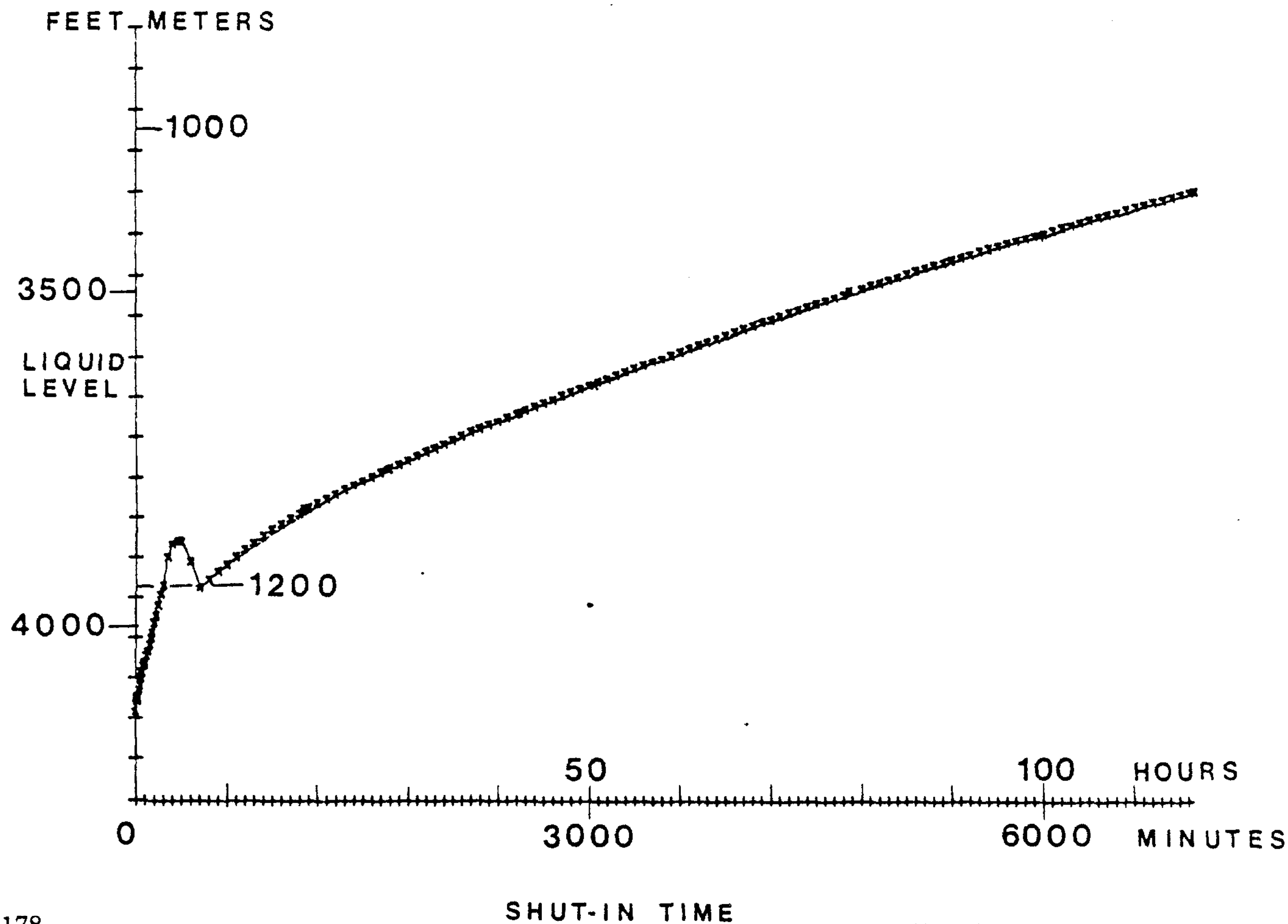
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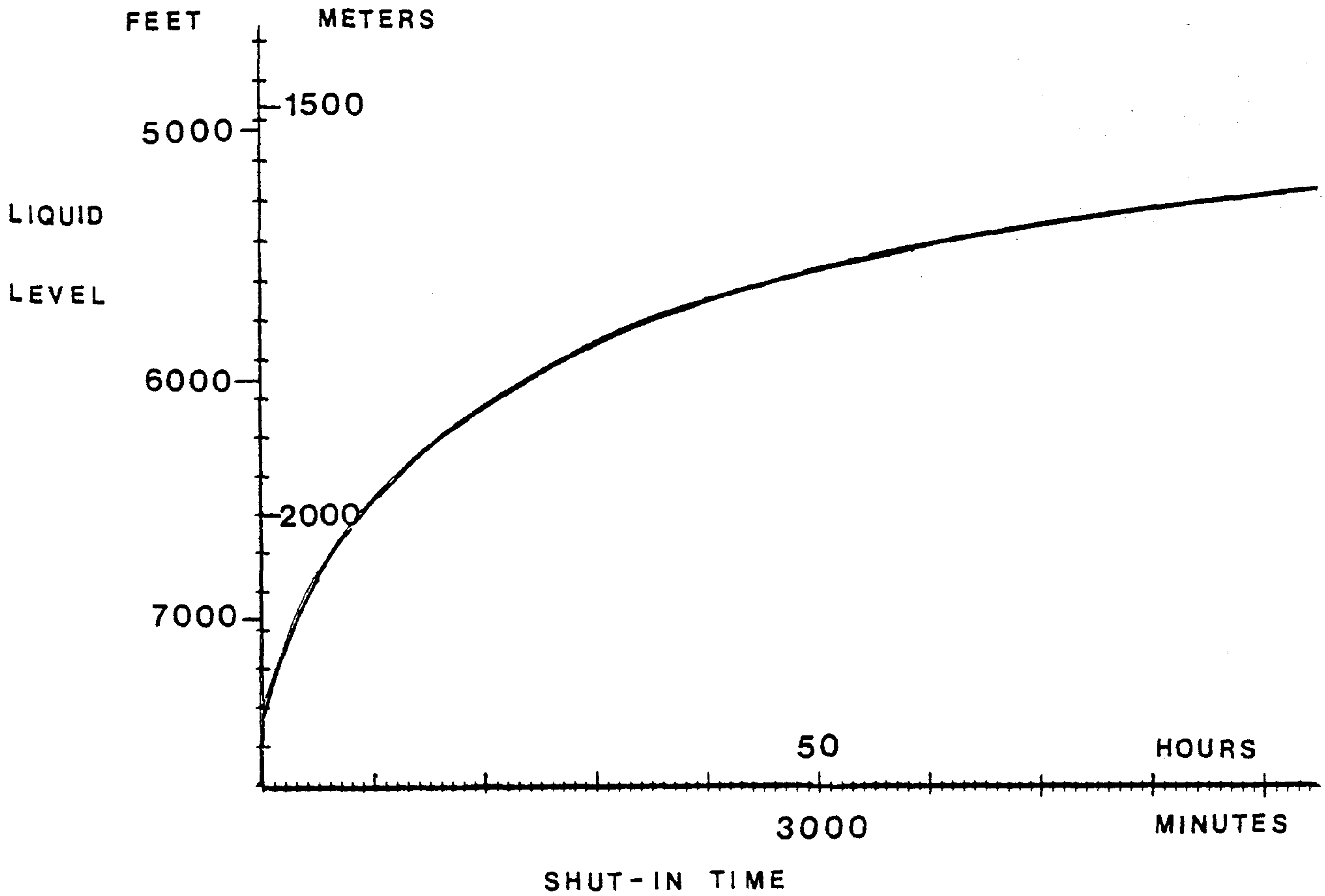
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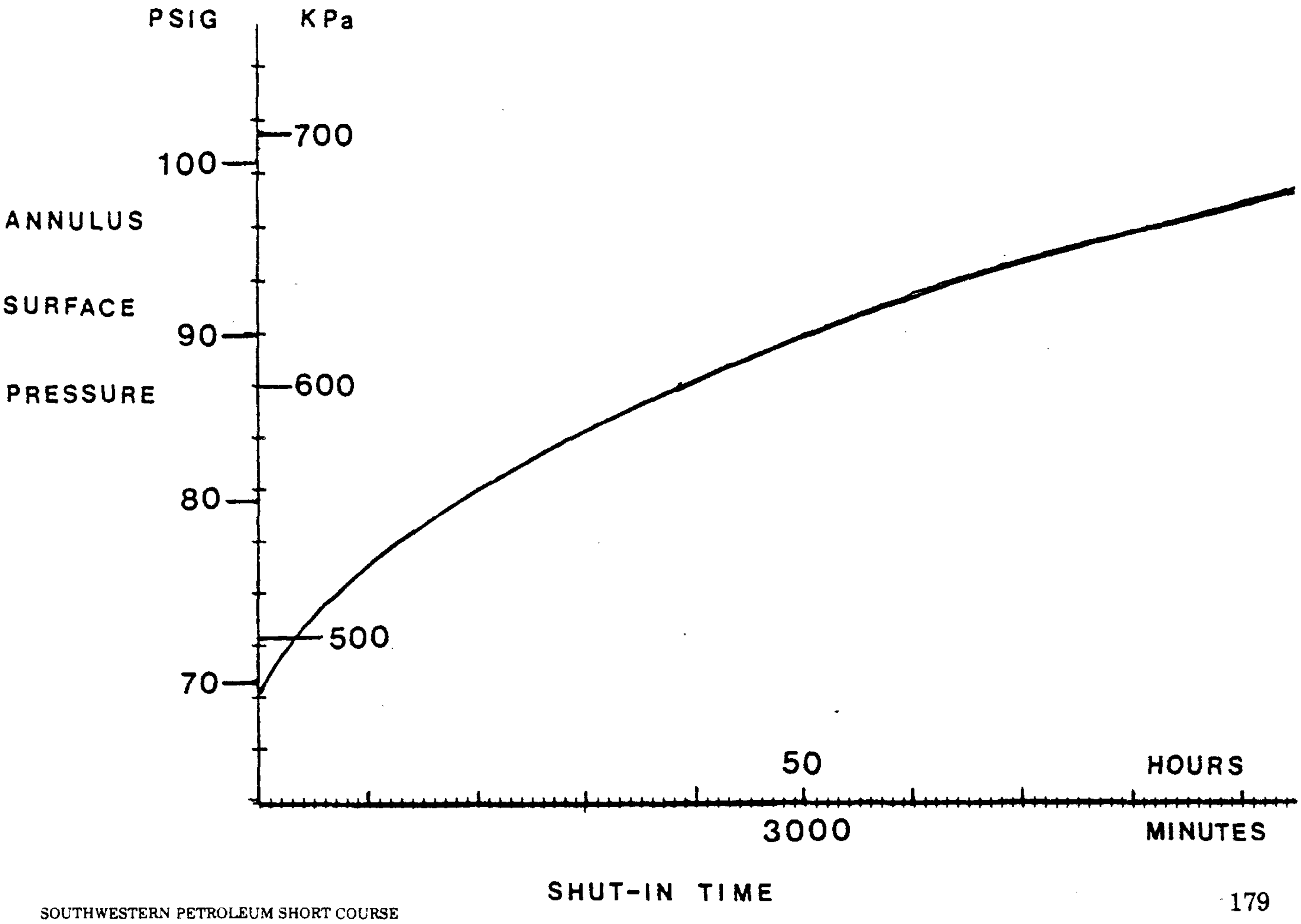
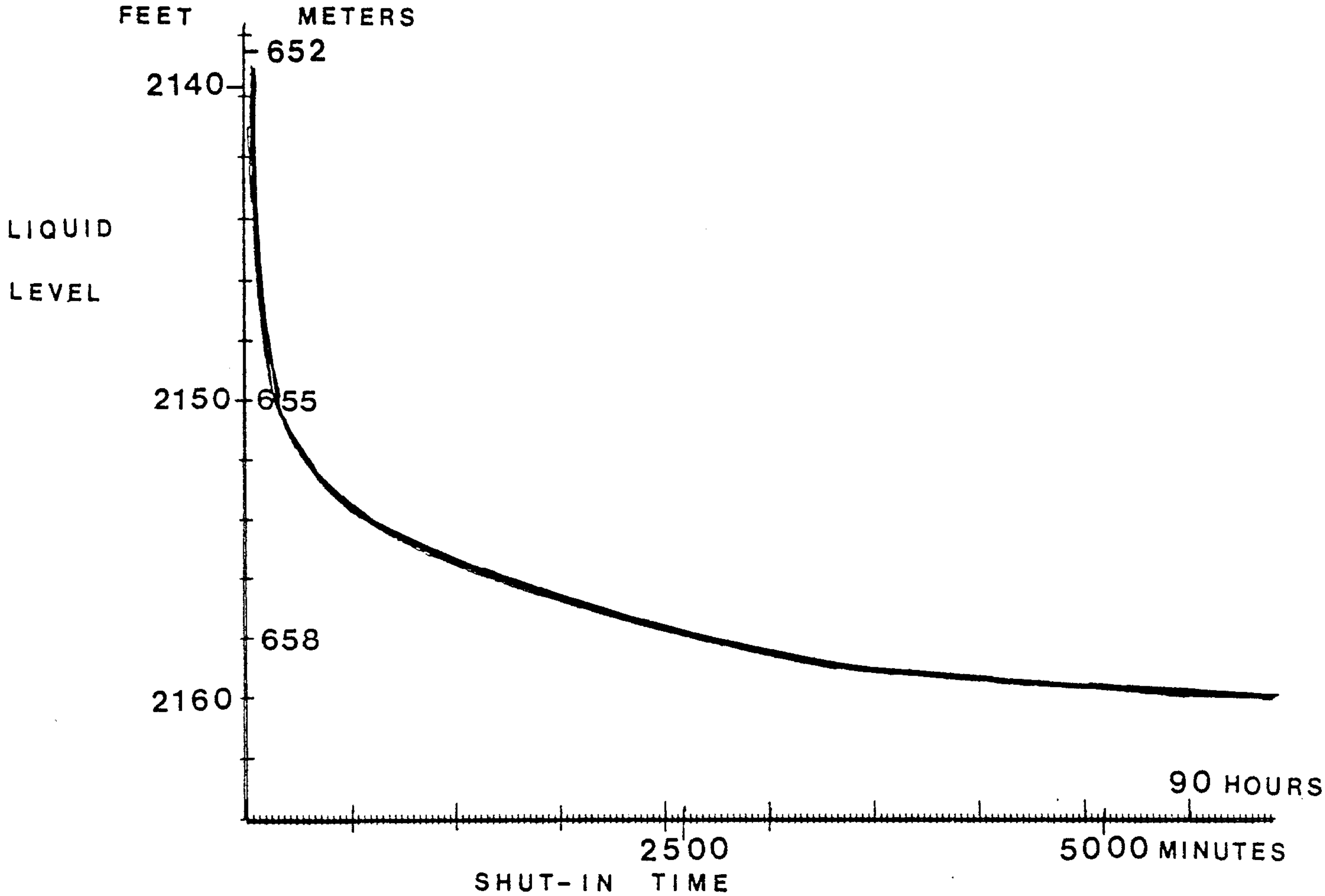
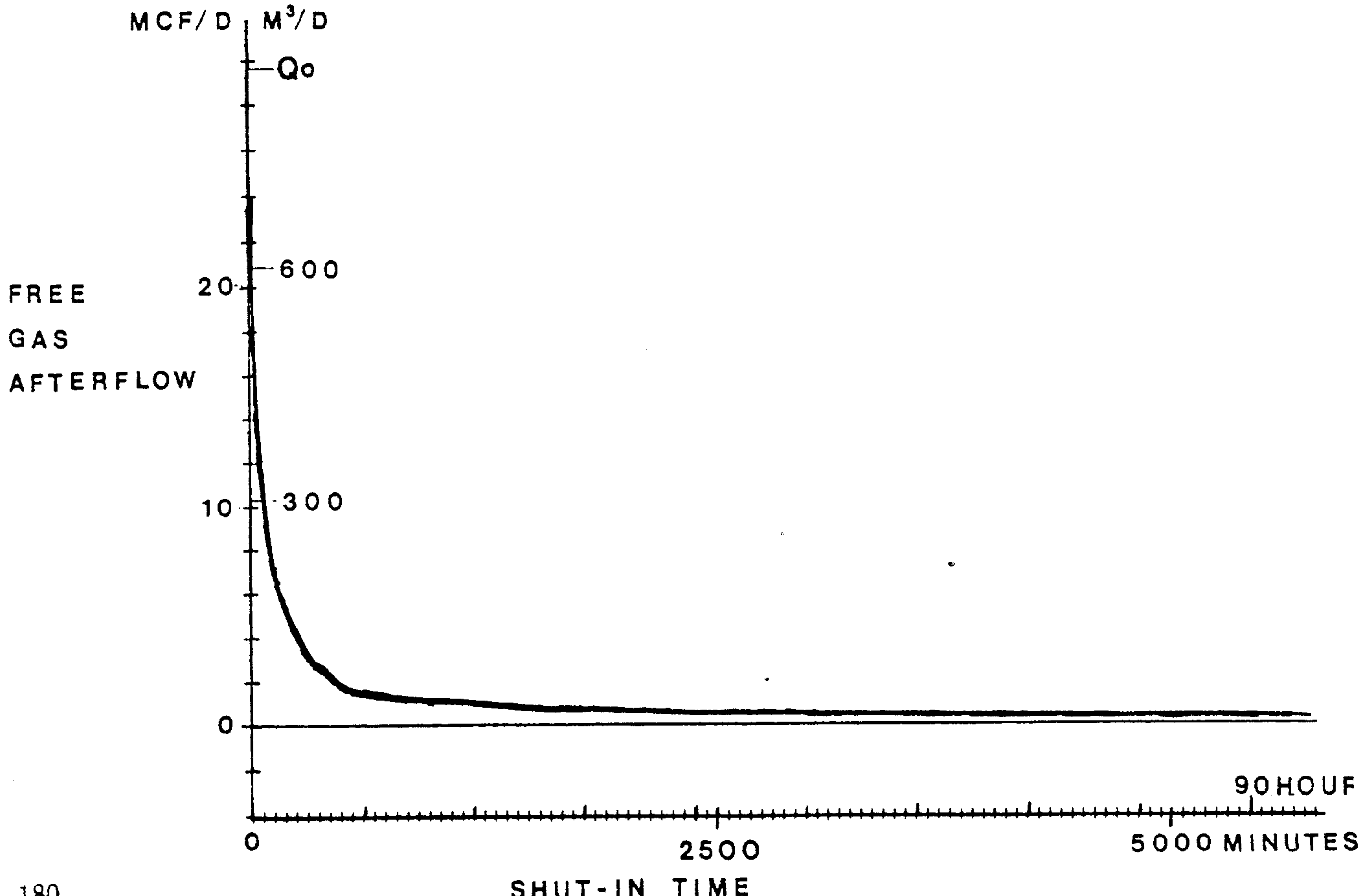
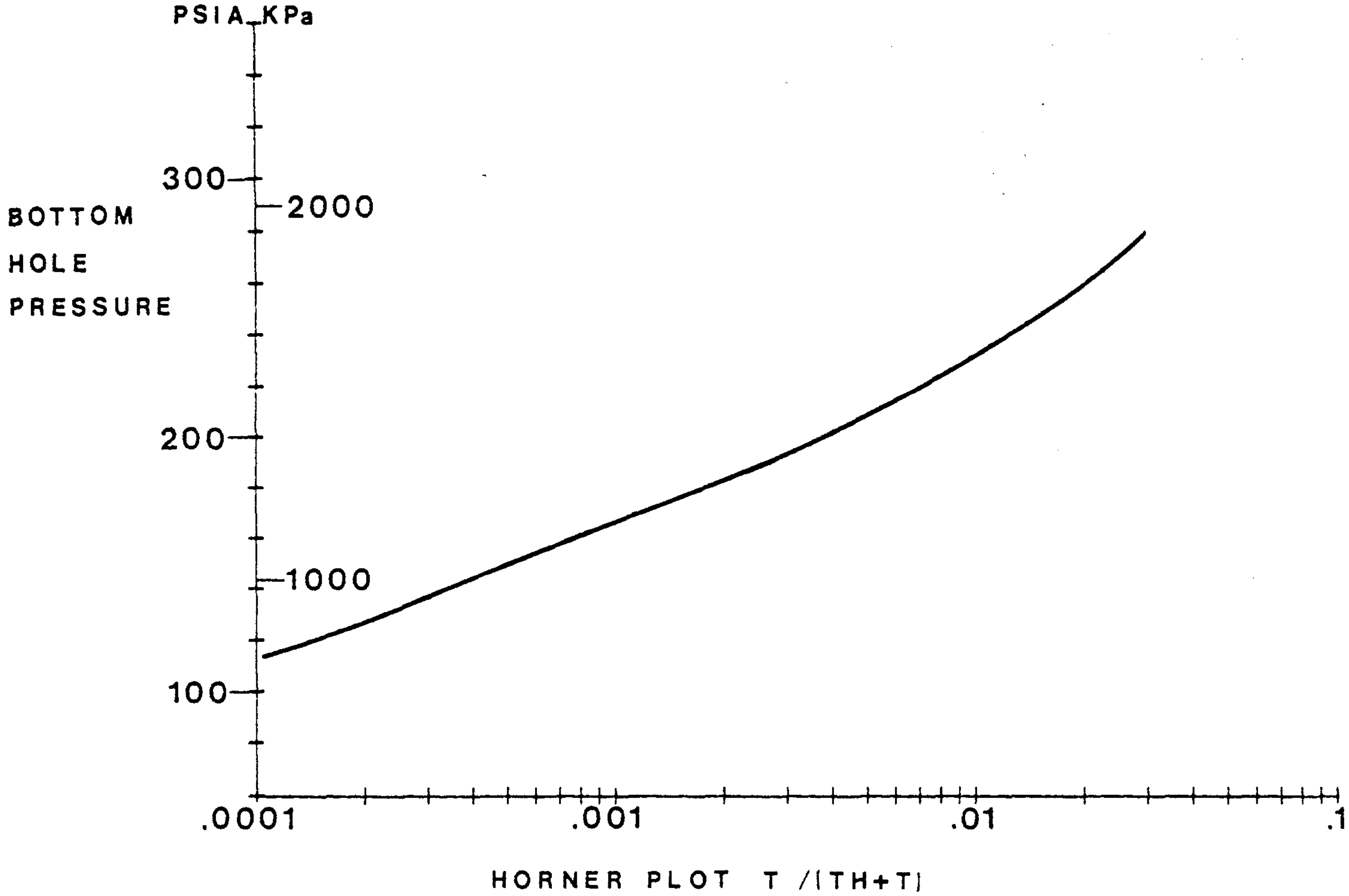
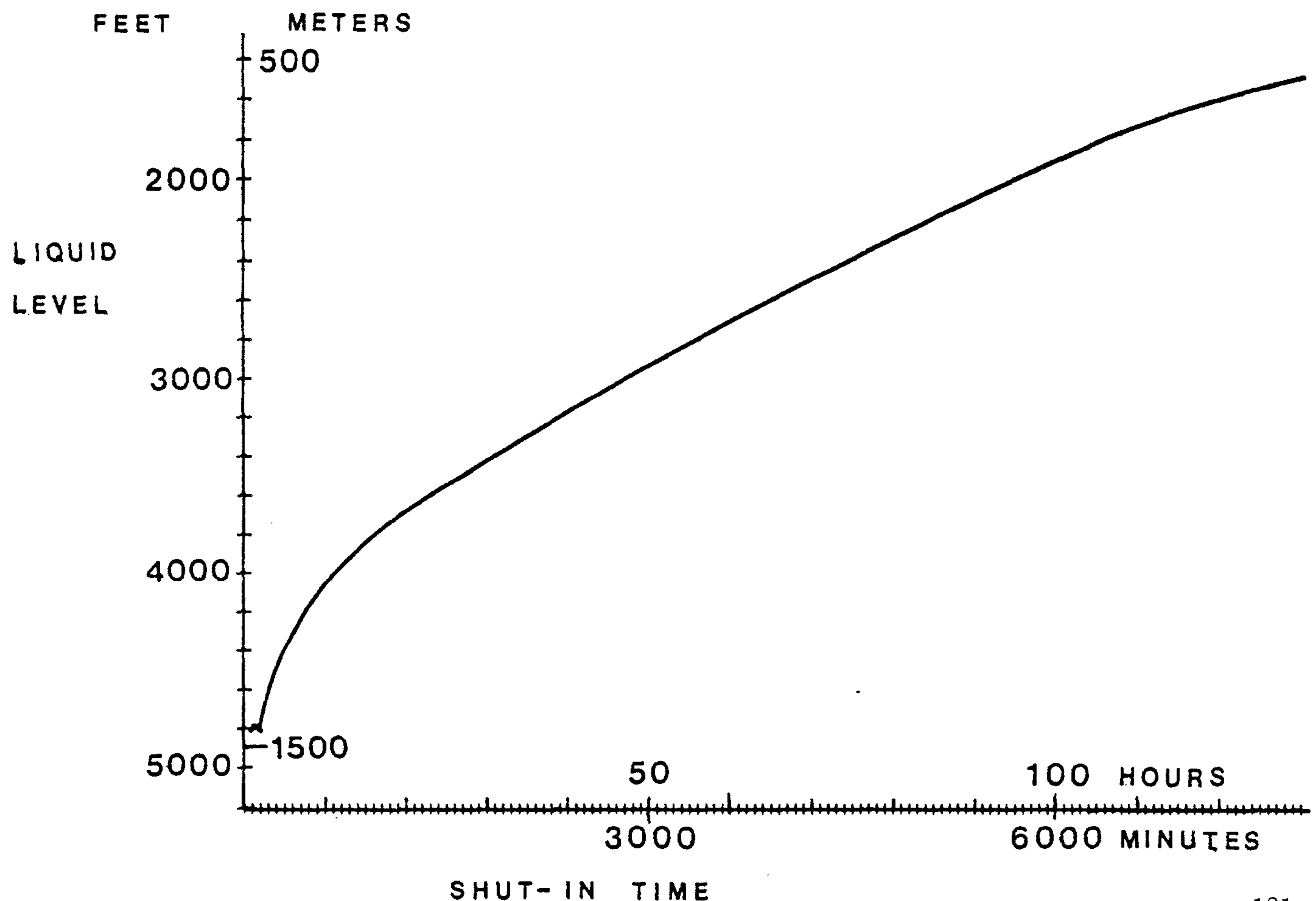
LEVEL
6000
2000
7000
50
HOURS
3000
MINUTES
SHUT-IN TIME

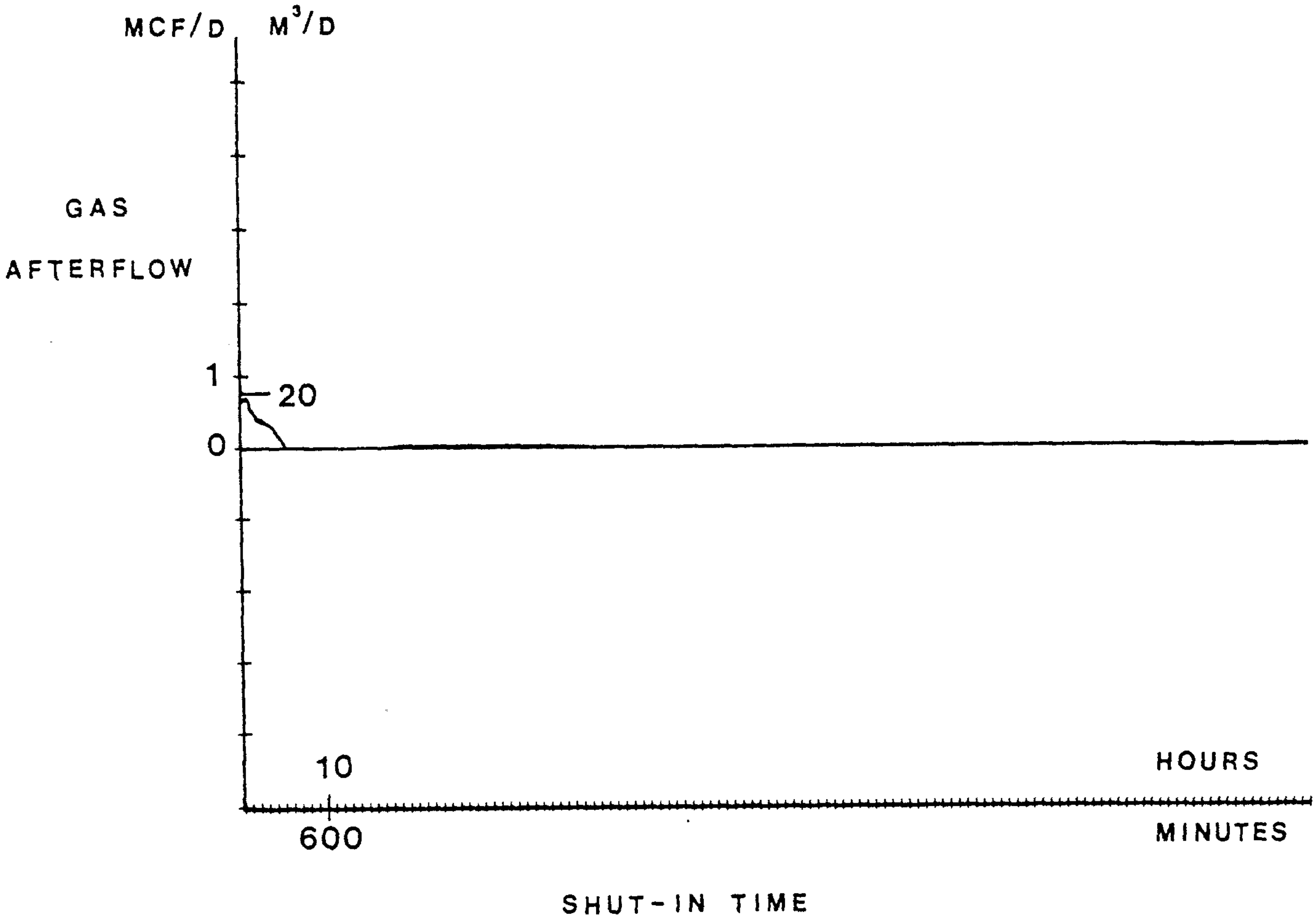

PSIG
KPa
700
100
ANNULUS
SURFACE
PRESSURE
90
600
80
500
70
50
HOURS
3000
MINUTES
SHUT-IN TIME

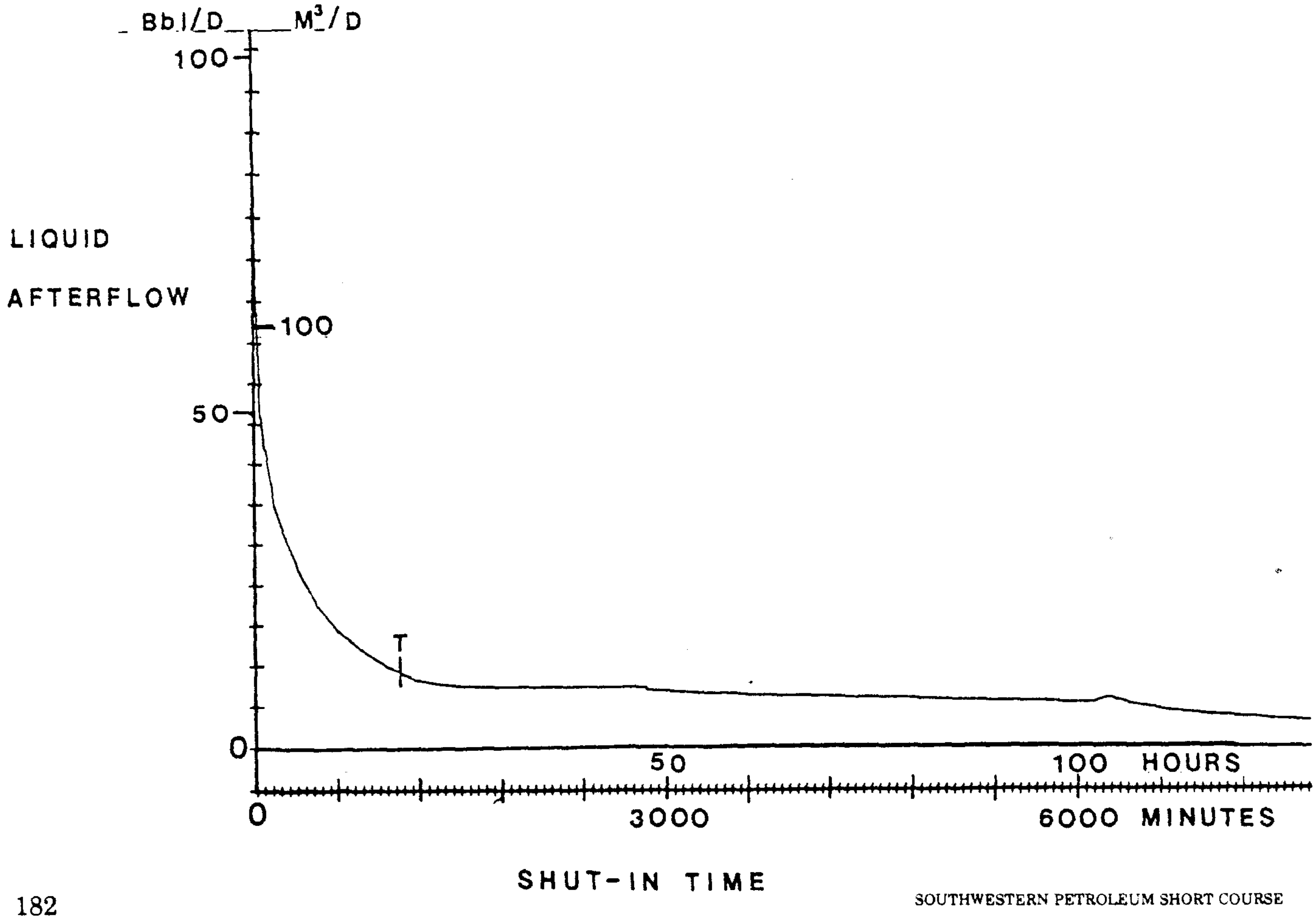

FEET
METERS
652
2140
LIQUID
LEVEL
2150
655
658
2160
90 HOURS
2500
5000 MINUTES
SHUT-IN TIME

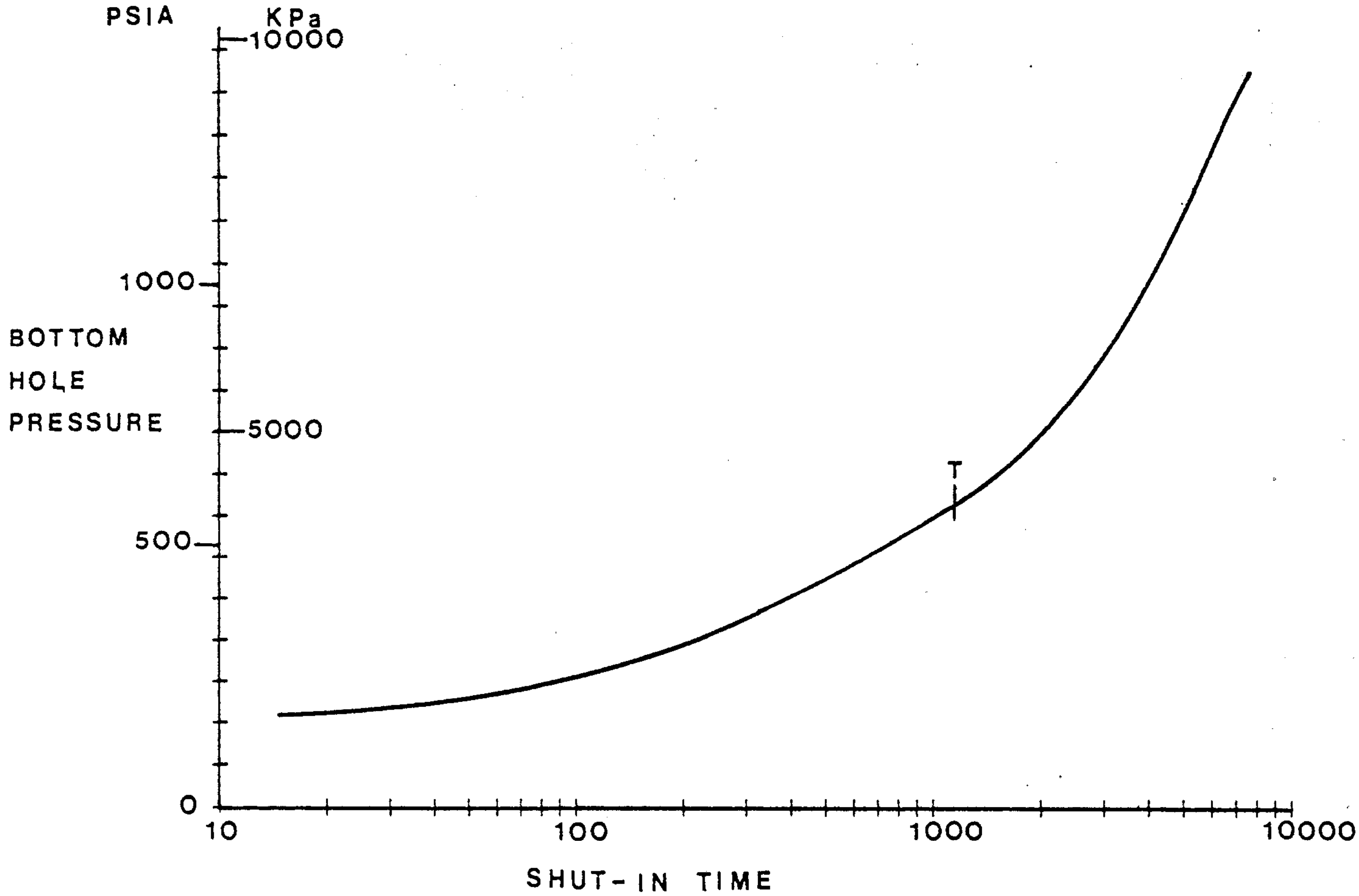

MCF/D
M³/D
Qo
FREE
GAS
AFTERFLOW
20
600
10
300
0
90HOUF
0
2500
5000 MINUTES
SHUT-IN TIME

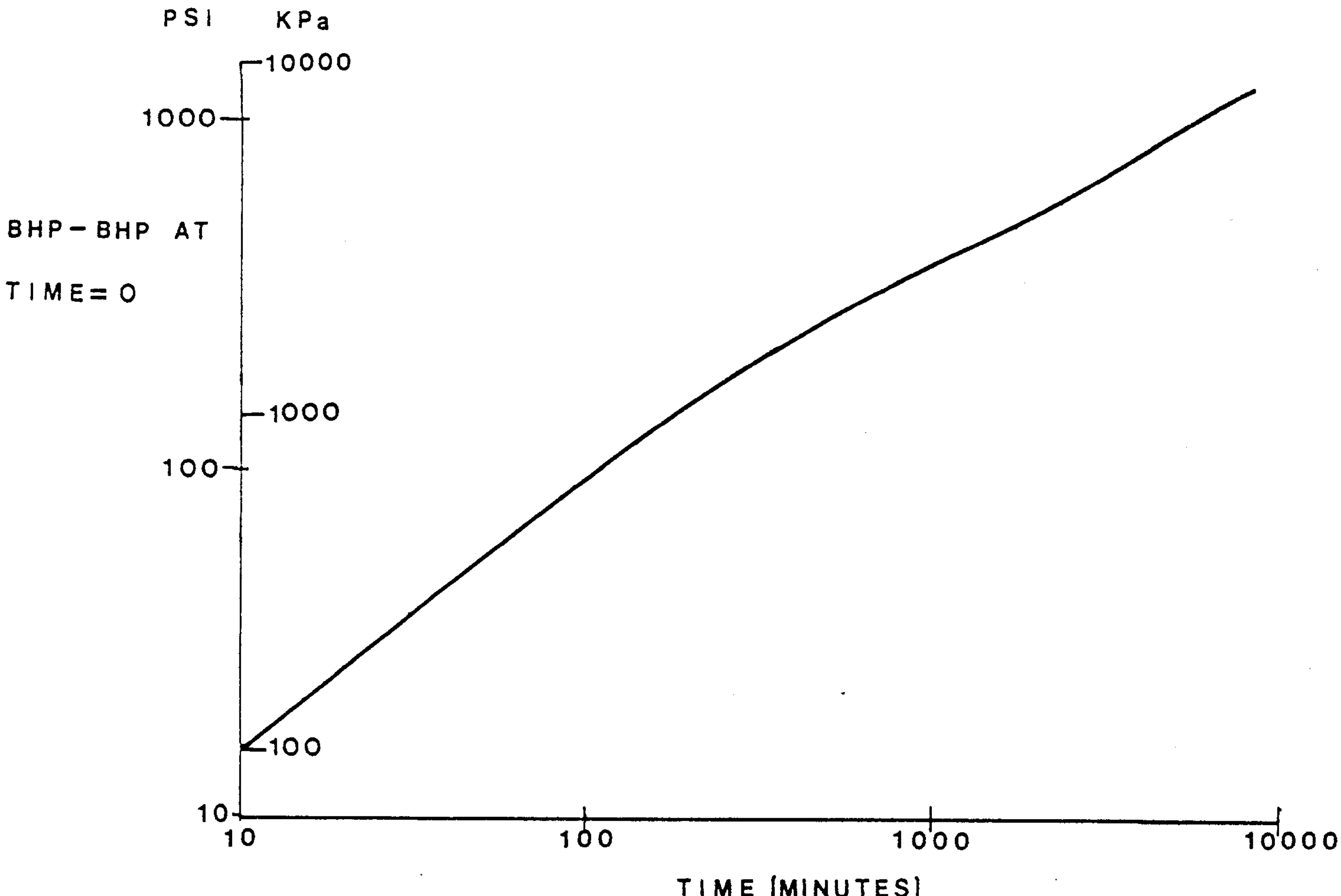

PSIA KPa
300
2000
BOTTOM
HOLE
PRESSURE
200
1000
100
.0001
.001
.01
.1
HORNER PLOT T /(TH+T)

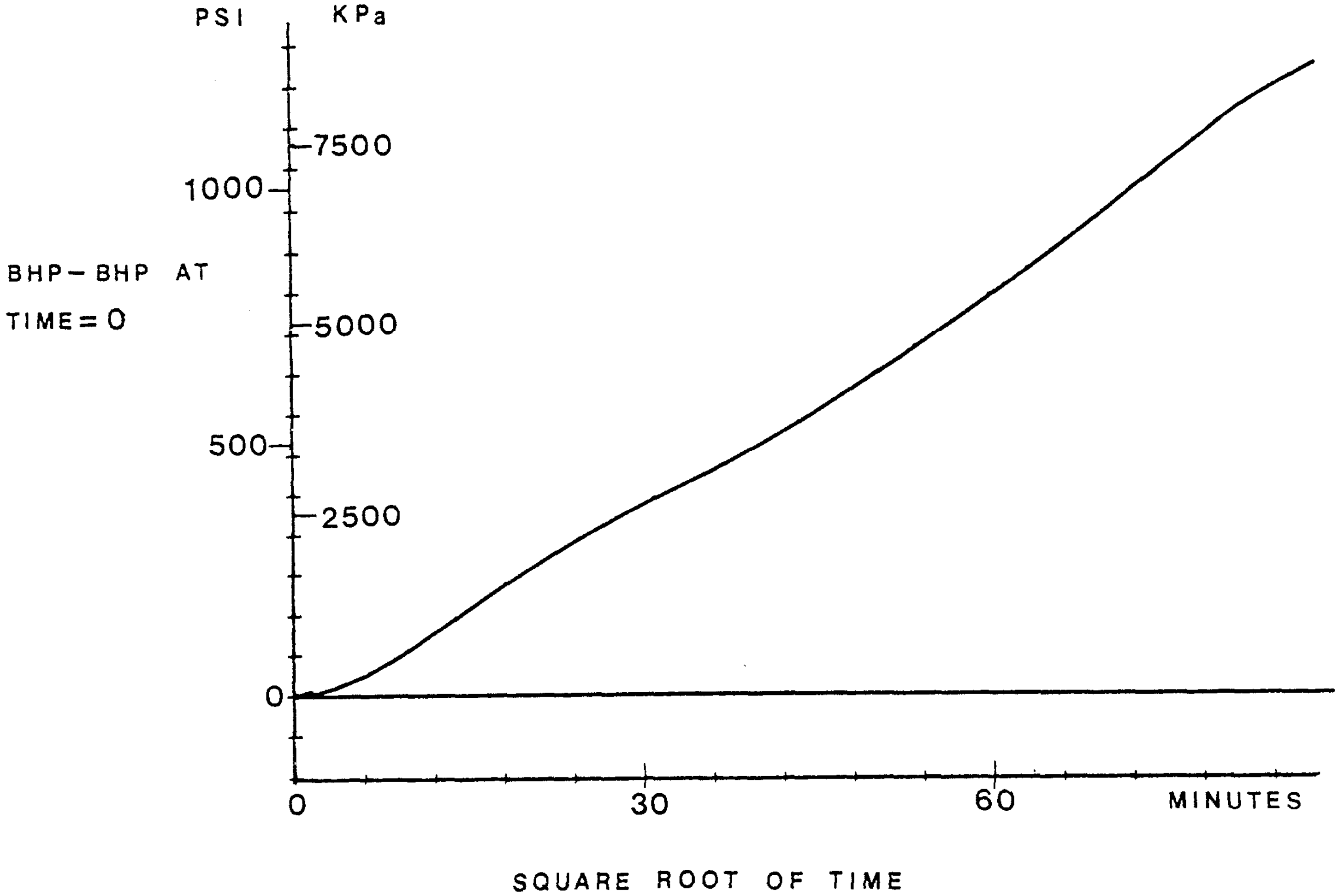

FEET
METERS
500
2000
LIQUID
LEVEL
3000
4000
5000
1500
50
100 HOURS
3000
6000 MINUTES
SHUT-IN TIME


MCF/D
M³/D
GAS
AFTERFLOW
1
20
0
10
HOURS
600
MINUTES
SHUT-IN TIME


Bbl/D
M³/D
100
LIQUID
AFTERFLOW
100
50
T
0
50
100
HOURS
0
3000
6000
MINUTES
SHUT-IN TIME


PSIA
KPa
10000
1000
BOTTOM
HOLE
PRESSURE
5000
T
500
0
10
100
1000
10000
SHUT-IN TIME


PSI
KPa
10000
1000
BHP-BHP AT
TIME=0
1000
100
100
10
10
100
1000
10000
TIME (MINUTES)


PSI
KPa
7500
1000
BHP — BHP AT
TIME = 0
5000
500
2500
0
0
30
60
MINUTES
SQUARE ROOT OF TIME