VIDEO COURSE INDEX
BASIC CONCEPTS IN DECLINE CURVE ANALYSIS
BY
M. J. FETKOVICH

PRESENTED MAY 24TH - 26TH, 1993
STAVANGER NORWAY

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	- " " " Winfield "	0	44	28
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NTSC TAPE		START TIME		
		HR	MIN	SEC
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	- Chatom Unit - P/Z Plot	1	12	12
	- Updated Performance Plot - From Red Cave	1	14	00
	- Kroth Air Well - Well Log - Texas Hugoton	1	15	00
	- Table Showing Sidetrack Deliverabilities No Areal Variation at All	1	16	00
	- APX Elliot #1 - MHF - Poor work	1	18	51
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		HR	MIN	SEC
6	- Exercise to appreciate Qmax/Gi RATIO	0	05	01
	INFILL DRILL RESPONSE	0	21	30

- END -

New Set
4/16/91

BASIC CONCEPTS IN
DECLINE CURVE ANALYSIS

MIKE FETKOVICH

PHILLIPS PETROLEUM COMPANY

ARPS DECLINE EQUATIONS

EXPONENTIAL $b = 0$

$$q(t) = \frac{q_i}{e^{D_i t}}$$

HYPERBOLIC

$$q(t) = \frac{q_i}{[1 + bD_i t]^{1/b}}$$

LIMIT ON $b \leq 1$

GOOD ONLY FOR DEPLETION.

EM·PIR·I·CAL ADJ. **1. A.** RELYING UPON OR DERIVED FROM OBSERVATION OR EXPERIMENT: EMPIRICAL METHODS. **B.** CAPABLE OF PROOF OR VERIFICATION BY MEANS OF OBSERVATION OR EXPERIMENT. 2. RELYING SOLELY ON PRACTICAL EXPERIENCE AND WITHOUT REGARD FOR SYSTEM OR THEORY.

1-14 Production-rate-decline Curves

Production-rate-decline curves are widely used throughout the producing side of the oil industry in assessing individual well and field performance and in forecasting future behavior. When estimates are based on the mathematical or graphical techniques of production-rate-decline curve analysis, it should always be remembered that this analysis is merely a convenience, a method that is amenable to mathematical or graphical treatment, and it has no basis in the physical laws governing the flow of oil and gas through the formation. Such curves can be drawn for individual wells, for a group of wells within a pool, or for all the wells in a pool taken together: the curve of oil-production rate on the reservoir-performance graph (Fig. 1-32) is a typical example. It will be assumed in what follows that one well only is being considered. However, it must be remembered that the analysis applies equally to a group of wells; the only reason for the assumption is to avoid repeating the qualifying phrase "or group of wells" after every use of the word "well."

NIND
1963 Book

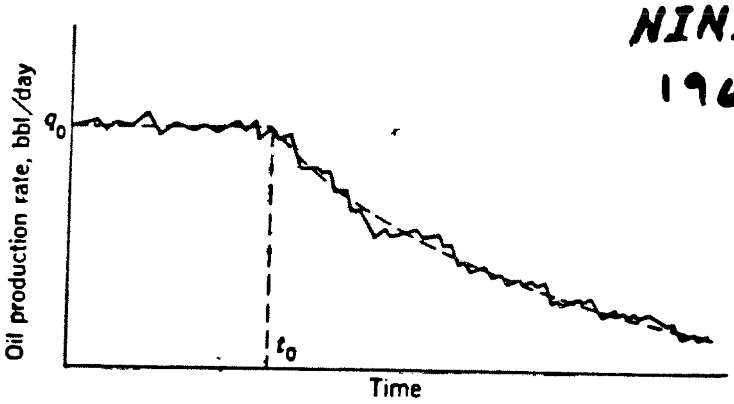


Fig. 1-33 Typical plot of oil-production rate vs time.

Because the obvious way to plot production rate is against time, this was the first method used. It was found that, following a period during which the production rate was steady (at or near the well's allowable, or the market demand), there came a time when the well could no longer make its allowable, and the production rate dropped off fairly regularly, or *declined*, month by month. A typical plot of production rate against time is shown in Fig. 1-33, in which an average curve has been shown by means of the dashed line. Evidently, if some regular (mathematical) form can be given to the curved part of the dashed line, it will be possible to extrapolate this into the future and so make predictions as to what the well will be producing in, for instance, 1, 2, 5, or 10 years' time. If the data are plotted as production rate vs cumulative oil production, it is found that the declining part of the curve becomes a reasonable straight

MUSKAT - PHYSICAL PRINCIPLES OF OIL PRODUCTION (1949)

THE HUNDREDS OF OIL FIELDS THAT WERE DISCOVERED BEFORE 1930 AND THAT ARE NOW DEPLETED HAVE THE ONLY ITEM OF PHYSICAL SIGNIFICANCE THAT CAN BE DERIVED FROM THE AVAILABLE RECORDS OF THE GREAT MAJORITY OF CURRENTLY DEPLETED FIELDS IS THE CURVE OF FIELD PRODUCTION RATE VS. TIME.

THEY (THE FIELDS) WERE GENERALLY PRODUCED "WIDE OPEN" AT MAXIMUM CAPACITY WITH NO CONTROLS. [THE IDEAL SITUATION FOR RATE-TIME DECLINE ANALYSIS.]

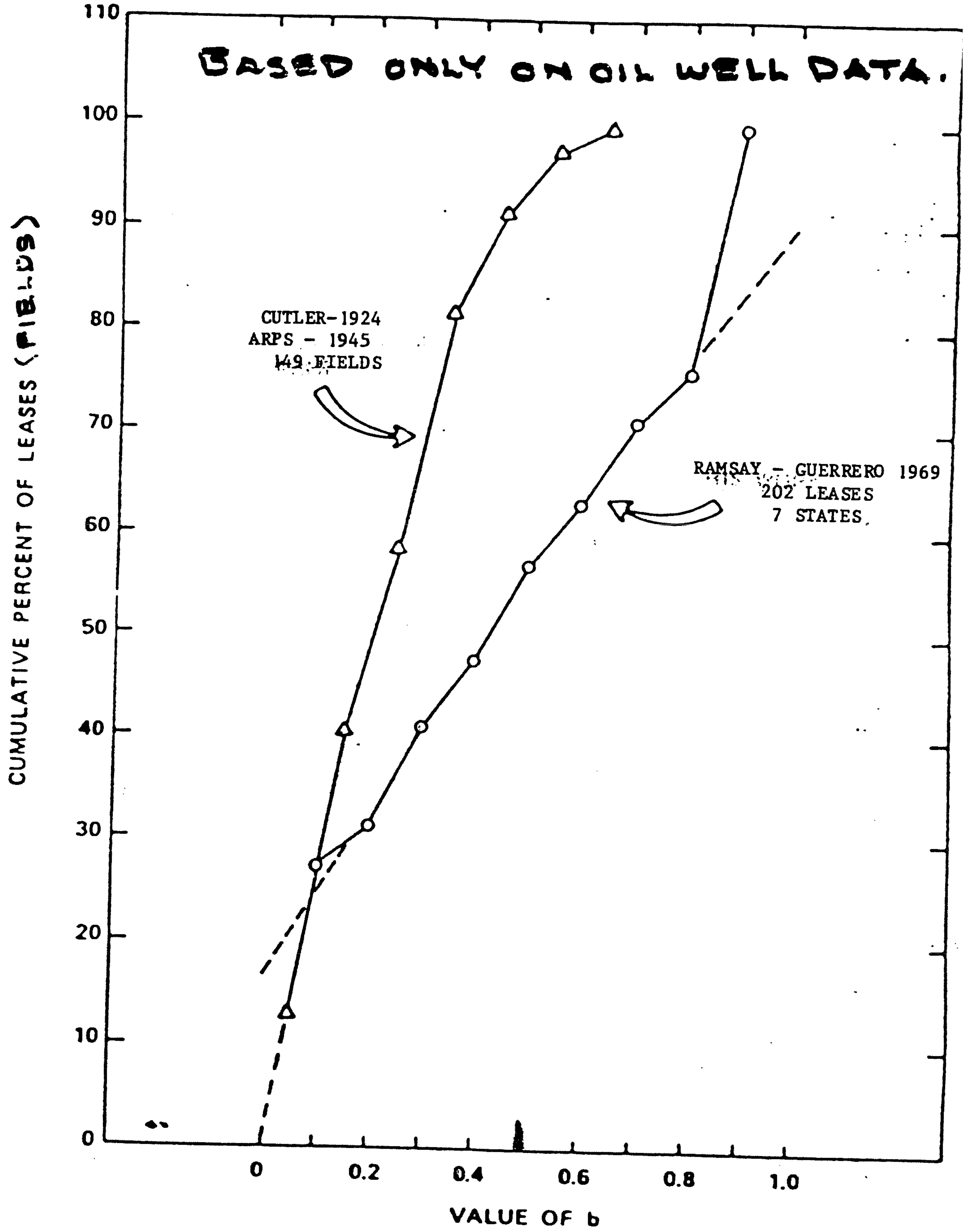
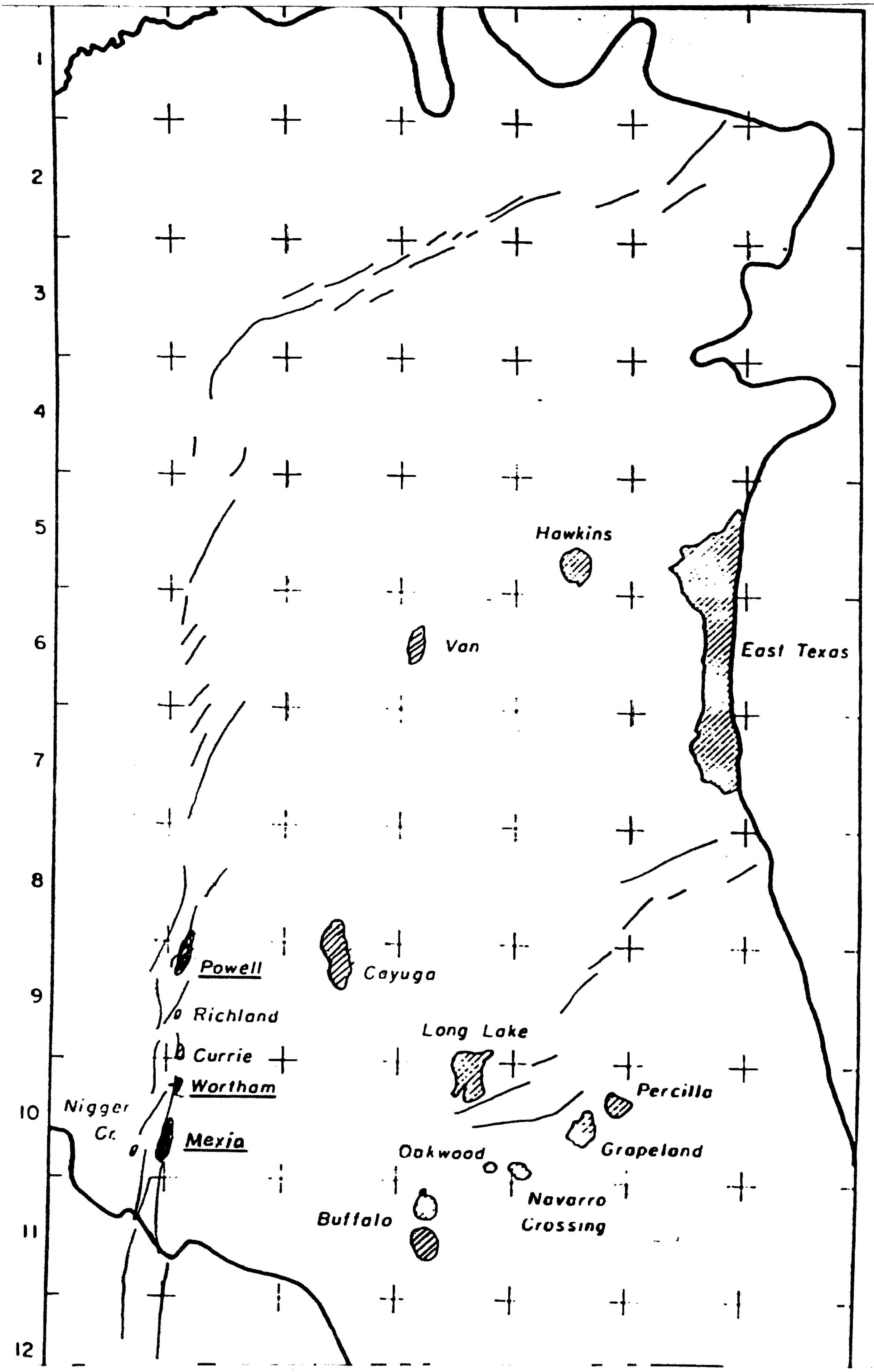


Fig. 2—Distribution of values of *b* for hyperbolic curve.


1
2
3
4
5
6
7
8
9
10
11
12
Hawkins
Van
East Texas
Powell
Cayuga
Richland
Currie
Wortham
Nigger Cr.
Mexia
Long Lake
Percilla
Grapeland
Oakwood
Navarro Crossing
Buffalo

FAULTLINE FIELDS

WOODBINE SAND

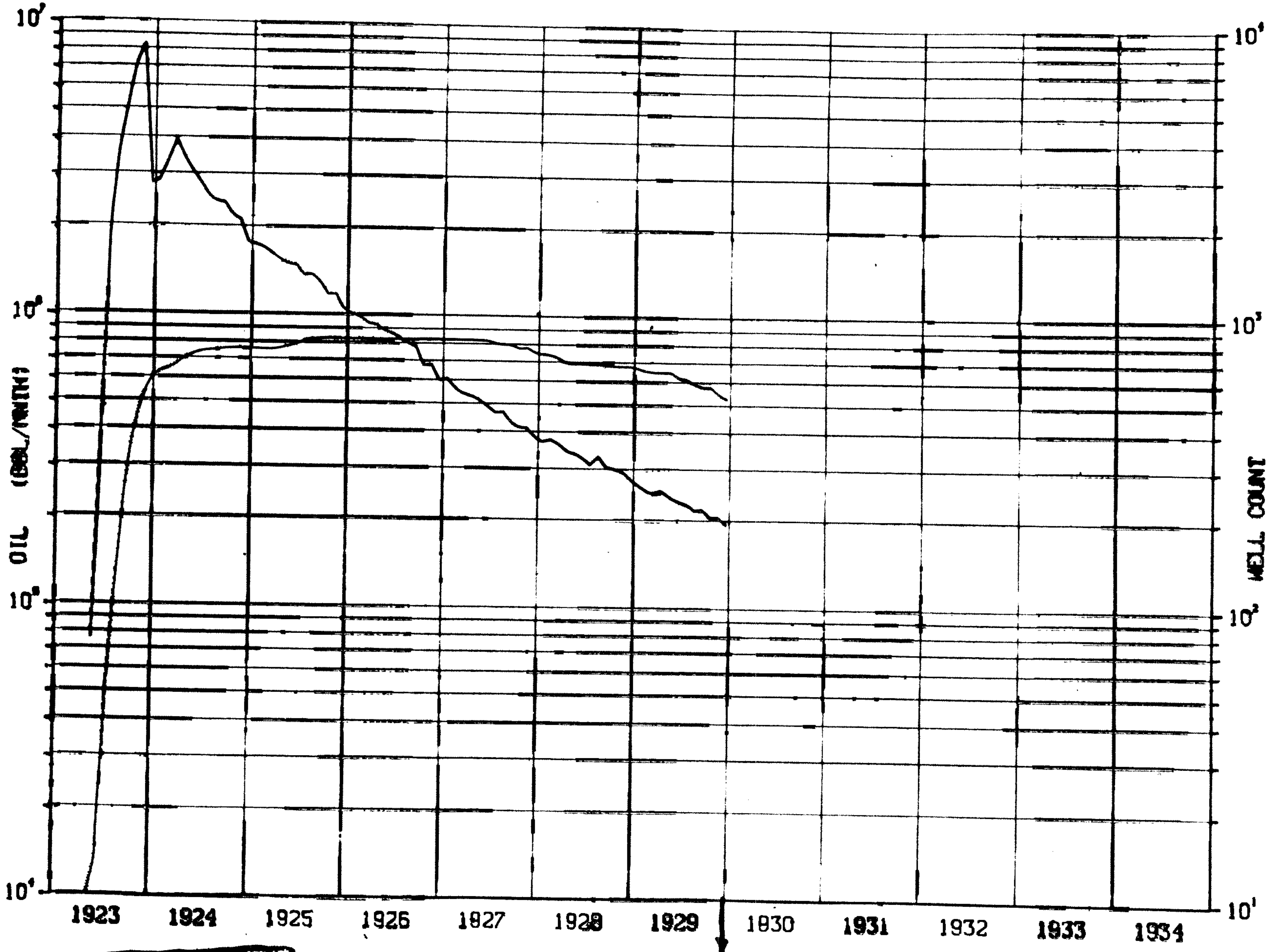
FROM DISCOVERY IN THE EARLY 1920'S, THESE FIELDS WERE RAPIDLY DEVELOPED AND REACHED PEAK PRODUCTION WITHIN 6 MONTHS OF FIRST PRODUCTION.

WATER INTRUDED RAPIDLY INTO THE PAY FORMATION, INDICATING A STRONG [redacted] WATER DRIVE.

BY 1929, WATER CUT WAS NEAR 90% FOR ALL THREE FIELDS. THE POWELL FIELD WAS SUBJECTED TO REPRESSURING BY GAS INJECTION.

	WORTHAM	POWELL	MEXIA
FIRST PRODUCTION DATE	NOVEMBER 1924	MAY 1923	OCTOBER 1921
	2 MO	6 MO	3 MO
PEAK PRODUCTION DATE	JANUARY 1925	NOVEMBER 1923	JANUARY 1922
MAXIMUM NUMBER OF WELLS	322	827	544
PROVED ACREAGE	745	2,600	3,700
ACRES PER WELL	2.3	3.1	6.8
ESTIMATED ULTIMATE RECOVERY (MBO)	23,000	110,000	94,000
ULTIMATE RECOVERY PER ACRE	31,000	42,000	25,000

(FROM U.S. BUREAU OF MINES, REPORT OF INVESTIGATIONS, "DEVELOPMENT AND PRODUCTION HISTORY ON THE SALT FLAT AND OTHER FAULT FIELDS OF EAST CENTRAL TEXAS, BY HILL ET.AL., MARCH 1931.)

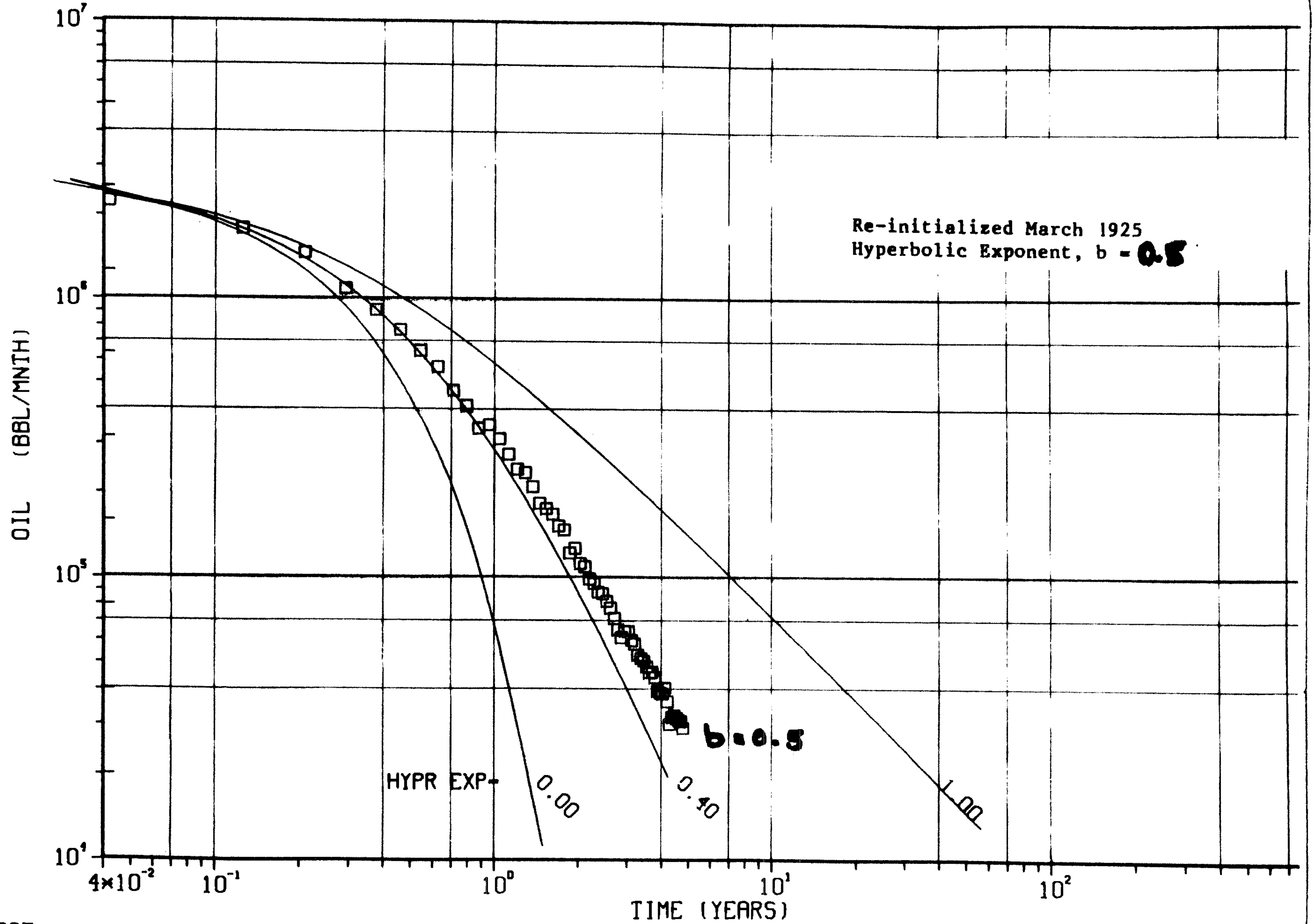


LEASE-
RESVR-

POWELL FIELD
WOODBINE SAND
FAULTLINE

TEXAS
MAX WELLS : 827

AHK



Re-initialized March 1925
Hyperbolic Exponent, b = 0.5

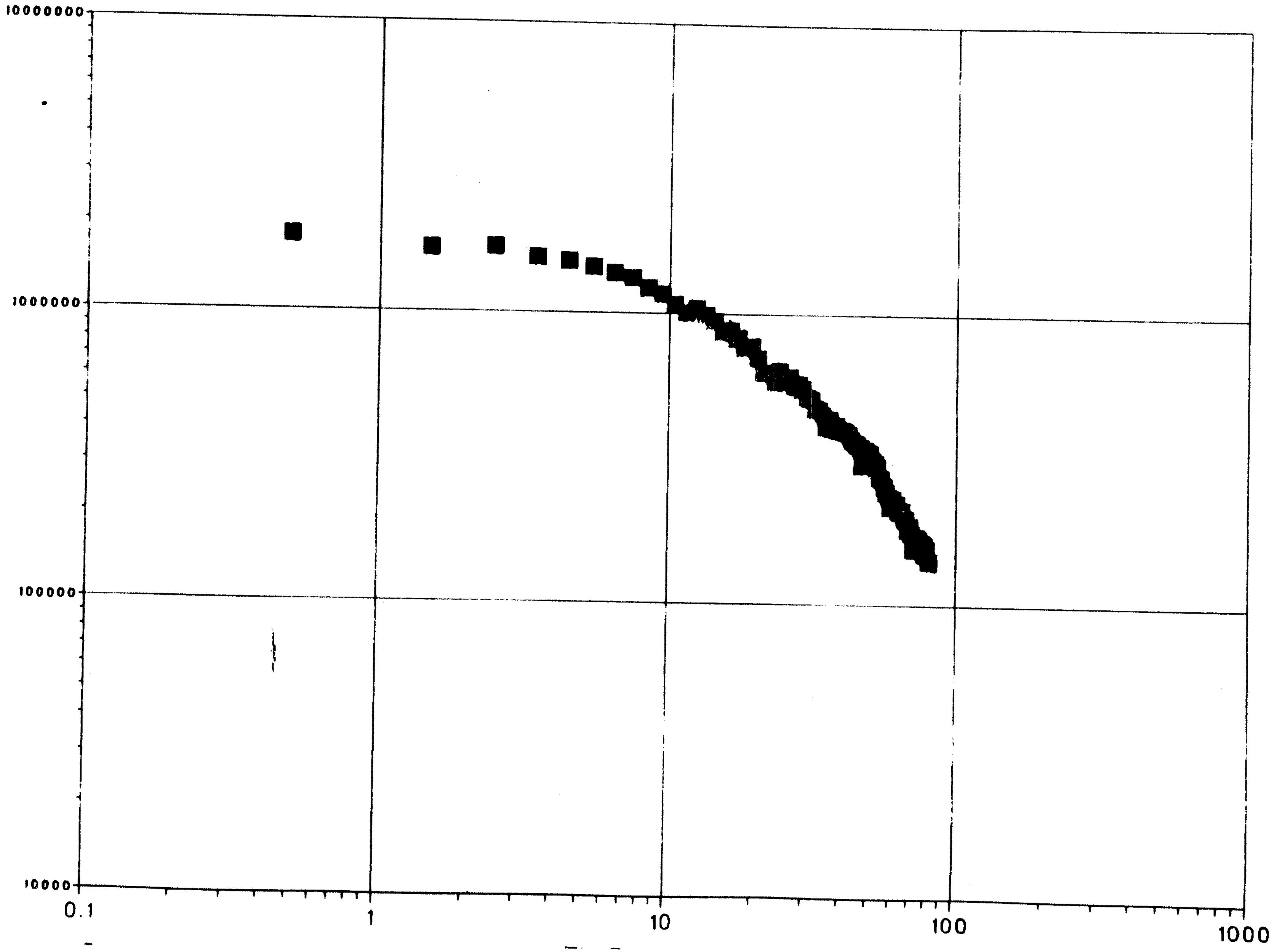
LEASE-
RESVR-

WORTHAM FIELD
WOODBINE SAND
FAULTLINE

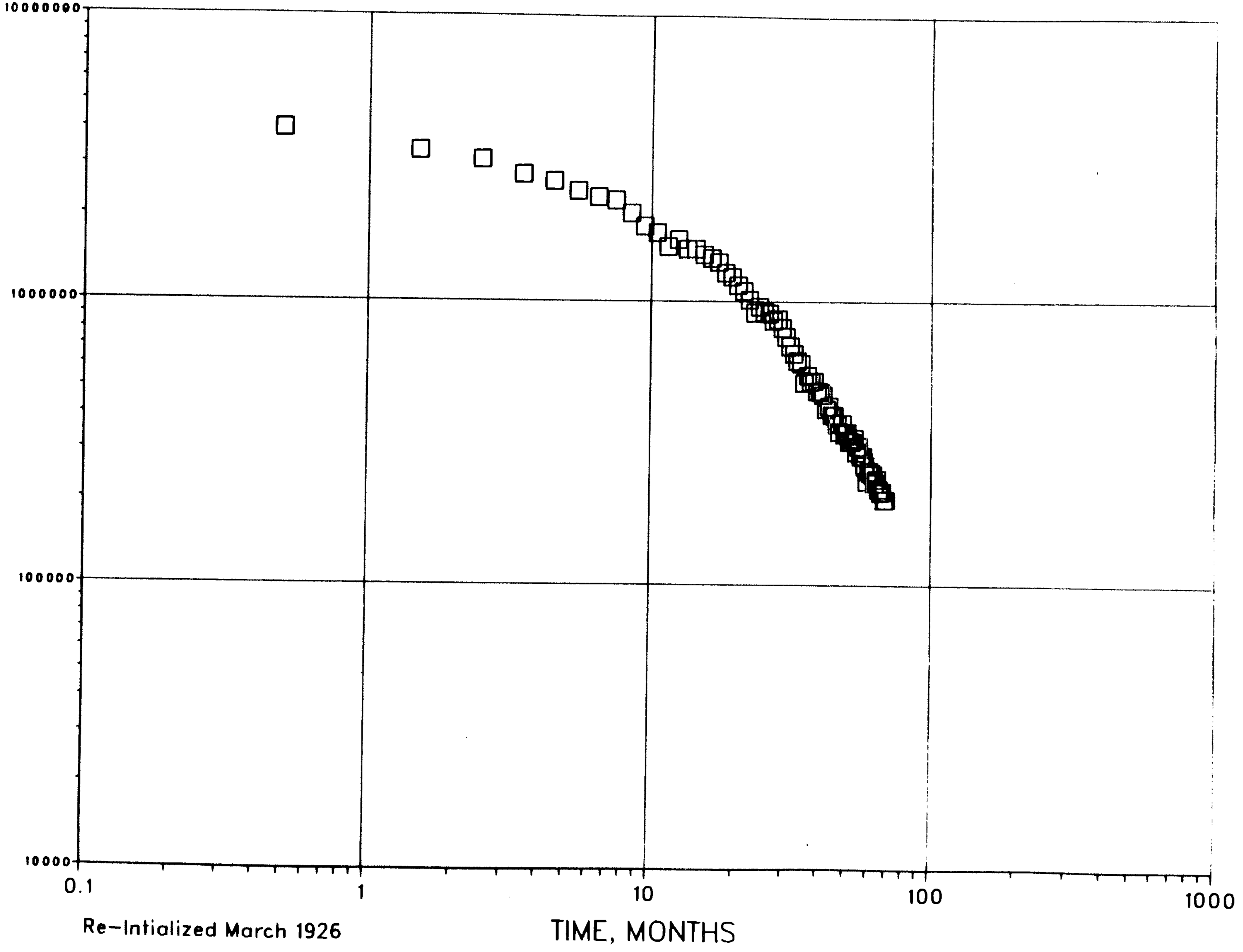
TEXAS
MAX WELLS : 322

AHK

MEXIA FIELD – WOODBINE SAND
FAULTLINE – MAX WELLS : 544

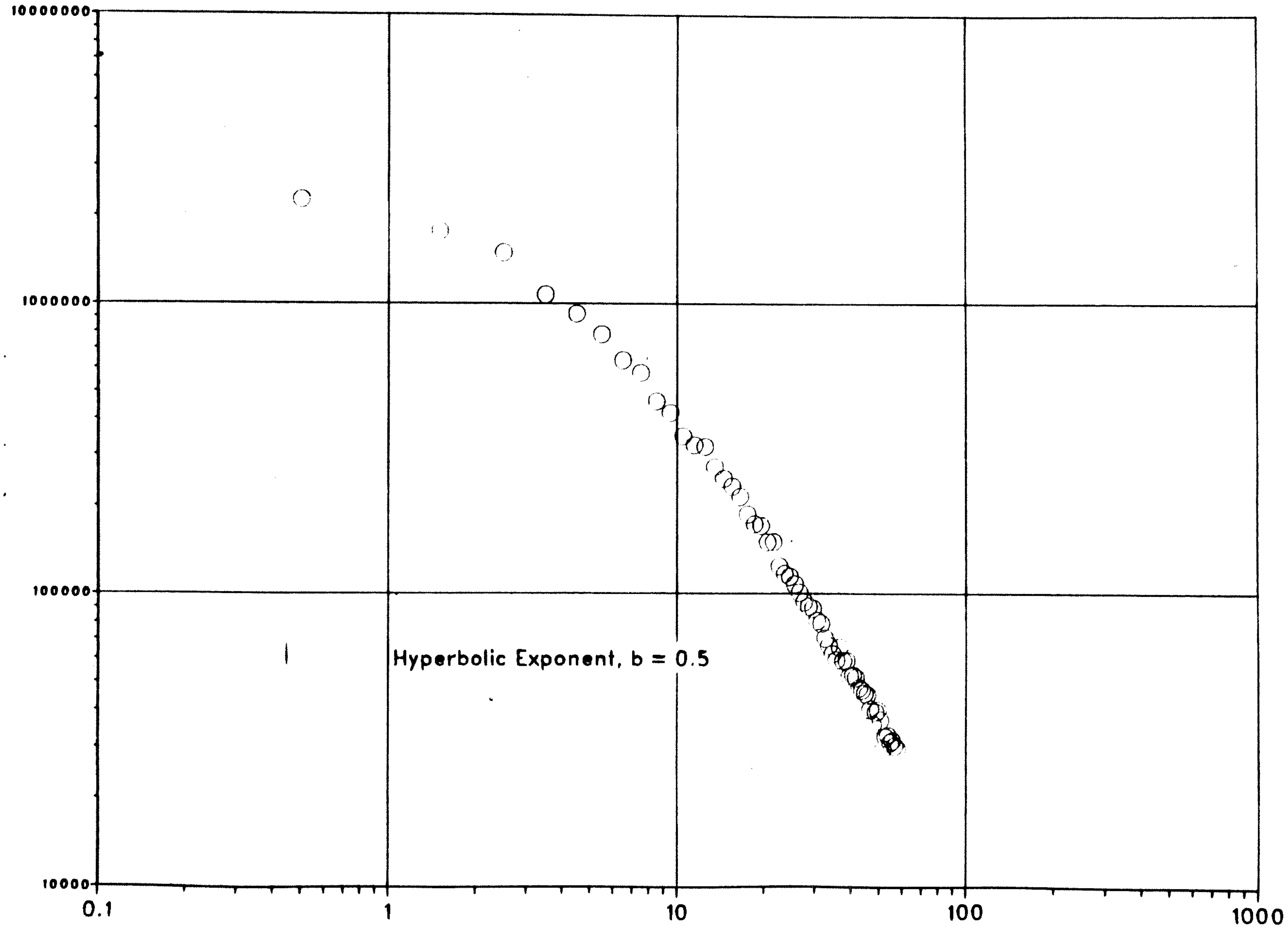


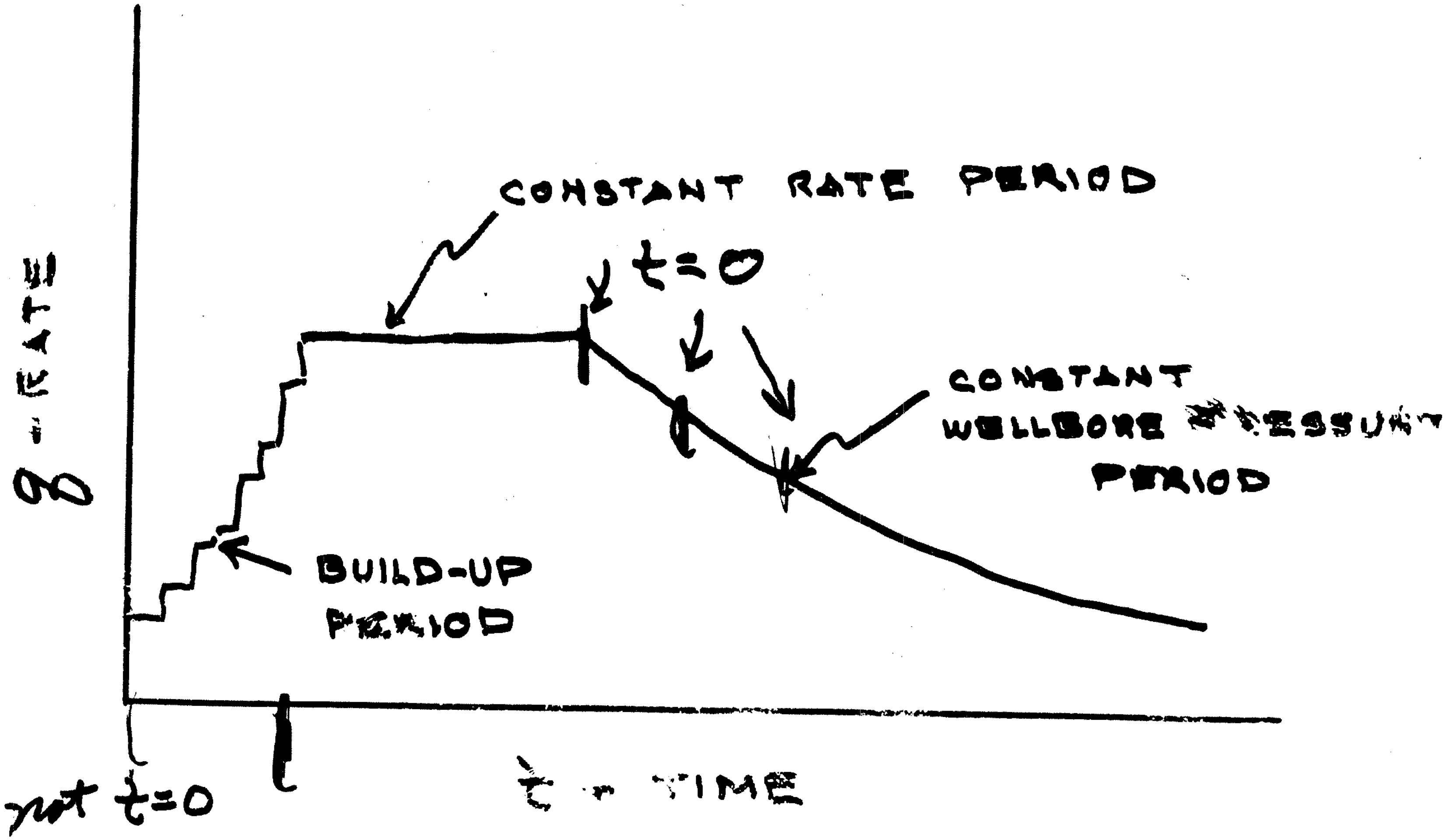
POWELL FIELD – WOODBINE SAND
FAULTLINE – MAX WELLS : 827



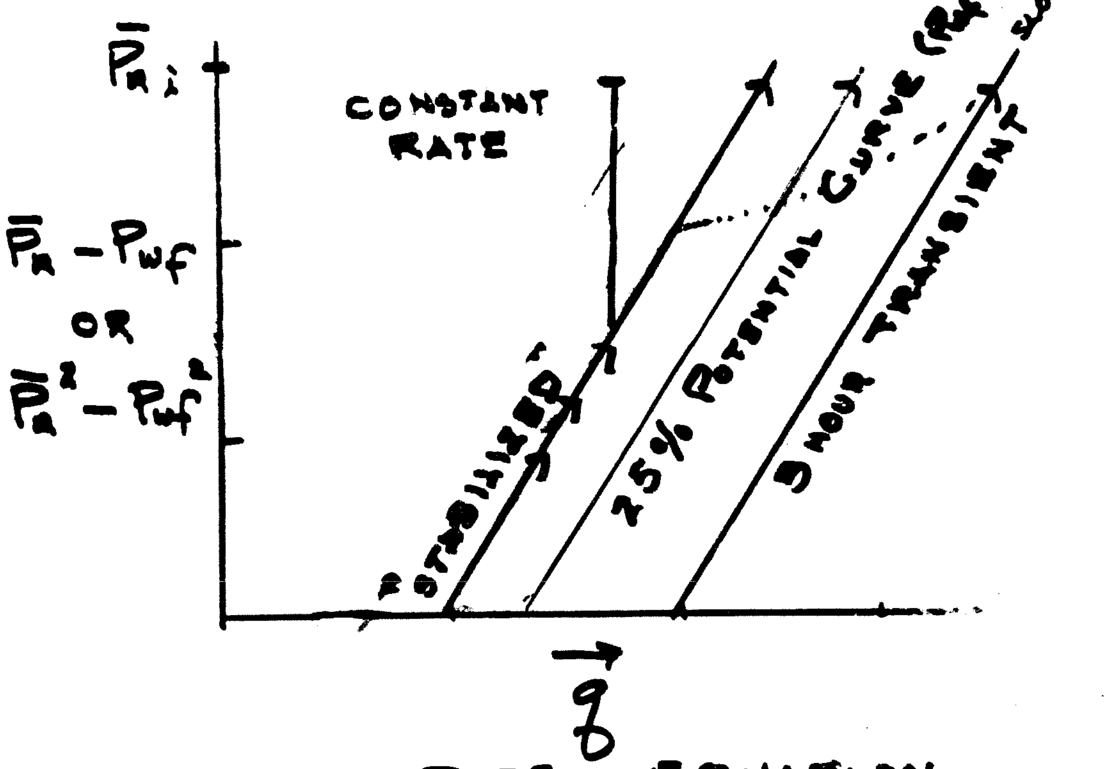
Re-Intialized March 1926

WORTHAM FIELD – WOODBINE SAND
FAULTLINE – MAX WELLS : 322

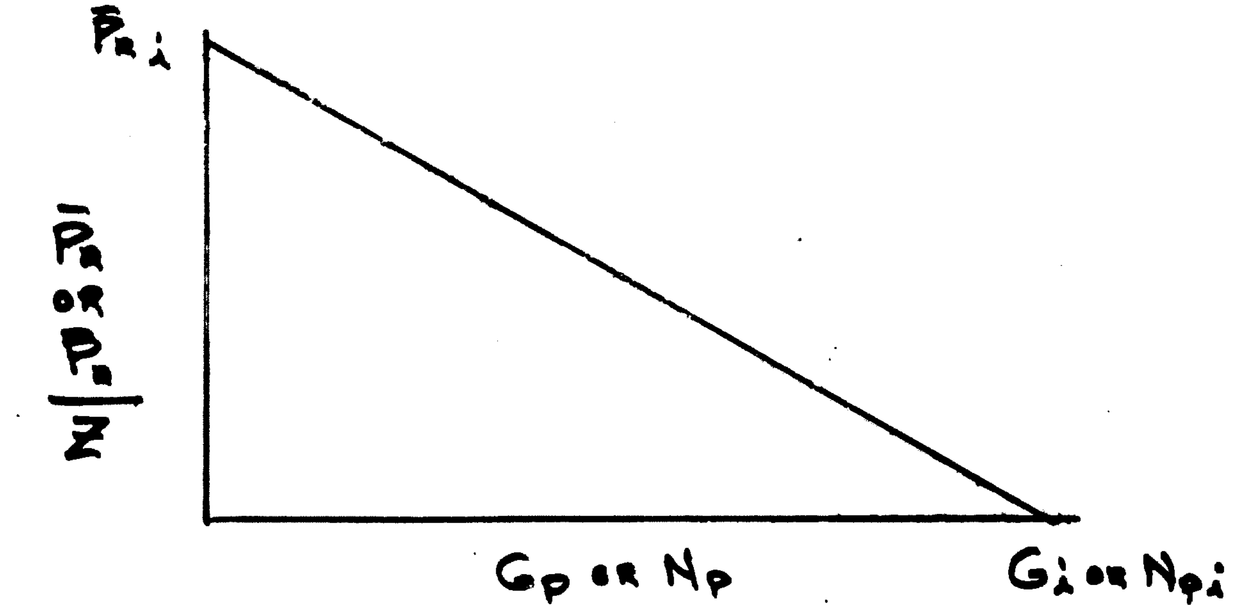



CONSTANT RATE PERIOD
t=0
CONSTANT
WELLBORE PRESSURE
PERIOD
BUILD-UP
PERIOD
q - RATE
not t=0
t - TIME

FIELD OR WELL



RATE EQUATION



MATERIAL BALANCE

GAS WELL DECLINE EQUATIONS ($p_{wf} \cong 0$)

DEPLETION

EXPONENTIAL n=0.5

$$q_{g(t)} = \frac{q_{gi}}{e^{\left(\frac{q_{gi}}{G_i}\right) t}}$$

$$D_i = \frac{q_{gi}}{G_i} \quad \text{or} \quad 2n \left(\frac{q_{gi}}{G_i}\right)$$

HYPERBOLIC n>0.5

$$q_{g(t)} = \frac{q_{gi}}{\left[1 + (2n-1)\, \frac{q_{gi}}{G_i}\, t\right]^{\boxed{\frac{2n}{2n-1}}}} = \frac{1}{b}$$

$$D_i = 2n \left(\frac{q_{gi}}{G_i}\right)$$

* q_{gi} = "STABILIZED" ABSOLUTE OPEN-FLOW POTENTAIL.

G_i = GAS-IN-PLACE AT START OF DECLINE.

n = SLOPE OF STABILIZED BACK-PRESSURE CURVE.

t = TIME FROM START OF DECLINE ANALYSIS

q(t) = FLOW RATE AT TIME t.

* q_{gi} can be <u>substantially</u> less than actual early flow rates for low permeability stimulated gas wells.

DEFINITION OF D_i - GAS RESERVOIR

Material Balance Equation

$$\overline{p}_R = -\left(\frac{\overline{p}_{Ri}}{G_i}\right) + p_{Ri}$$

Rate Equation

$$q_g = c_g\ (\overline{p}_R^2 - p_{wf}^2)^n$$

Resulting Rate-Time Equation

$$\frac{q_g(t)}{q_{gi}} = \frac{1}{\left[(2n-1)\left(\frac{q_{gi}}{g_i}\right)\ t + 1\right]^{\frac{2n}{2n-1}}}$$

General Arps Equation

$$\frac{q_g(t)}{q_{gi}} = \frac{1}{[b\ D_i\ t + 1]^{1/b}}$$

Note that:

$$1/b = \frac{2n}{2n-1} \text{ or } b = \frac{2n-1}{2n}\ ;\ also,\ 2n = \frac{1}{1-b}$$

$$and: \quad b\ D_i = 2n-1\left(\frac{q_{gi}}{G_i}\right)$$

Expressing in terms of D_i:

$$D_i = \frac{2n-1}{b}\left(\frac{q_{gi}}{G_i}\right)$$

Substituting for b:

$$D_i = \frac{2n-1}{\left(\frac{2n-1}{2n}\right)}\left(\frac{q_{gi}}{G_i}\right)$$

$$= 2n\left(\frac{q_{gi}}{G_i}\right)$$

Substituting for 2n:

$$D_i = \frac{1}{(1-b)}\left(\frac{q_{gi}}{G_i}\right)$$

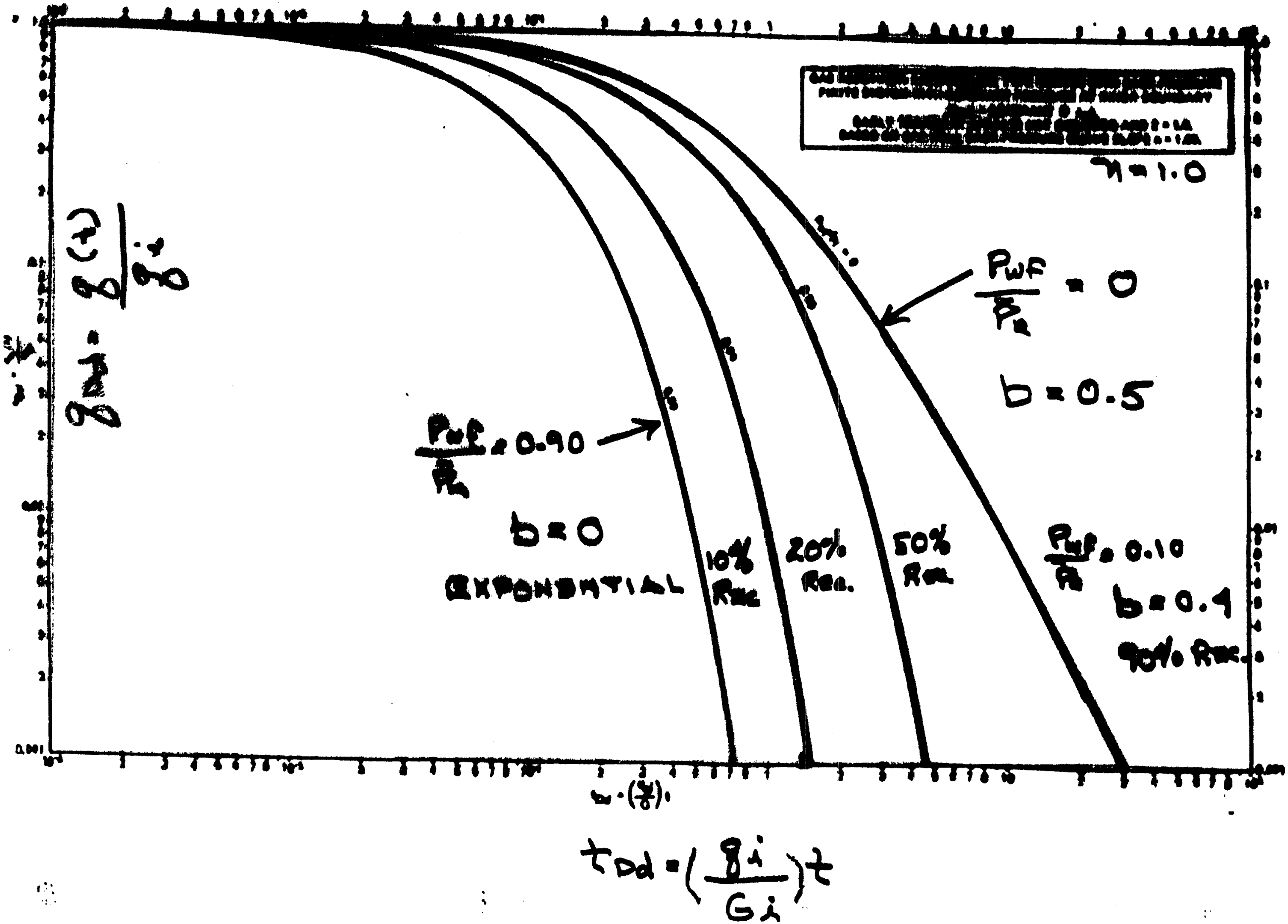
GAS WELL DECLINE EXPONENT - b
IN TERMS OF GAS WELL WELLHEAD
BACK-PRESSURE CURVE SLOPE n ($p_{wf} \cong 0$)

$$b = \frac{2n - 1}{2n}$$

WELLHEAD BACK-PRESSURE SLOPE - n	RATE-TIME DECLINE EXPONENT - b
0.5 HIGH K	0 (EXPONENTIAL)
0.6	0.17
0.7	0.29
0.8	0.38
0.9	0.44
1.0 LOW K	$\boxed{0.50}$

MAX VALUE OF b FOR GAS WELL.

(SINGLE LAYER HOMOGENEOUS)



$q_{Dd} = \frac{q(t)}{q_i}$
$t_{Dd} = \left(\frac{q_i}{G_i}\right) t$
n = 1.0
$\frac{P_{wf}}{\bar{P}_R} = 0$
b = 0.5
$\frac{P_{wf}}{\bar{P}_R} = 0.90$
b = 0
EXPONENTIAL
10% Rec.
20% Rec.
50% Rec.
$\frac{P_{wf}}{\bar{P}_R} = 0.10$
b = 0.4
90% Rec.
0.001

Practical Natural Gas Engineering

R. V. Smith

PENN WELL BOOKS
PENN WELL PUBLISHING CO.
TULSA OKLA.
1983

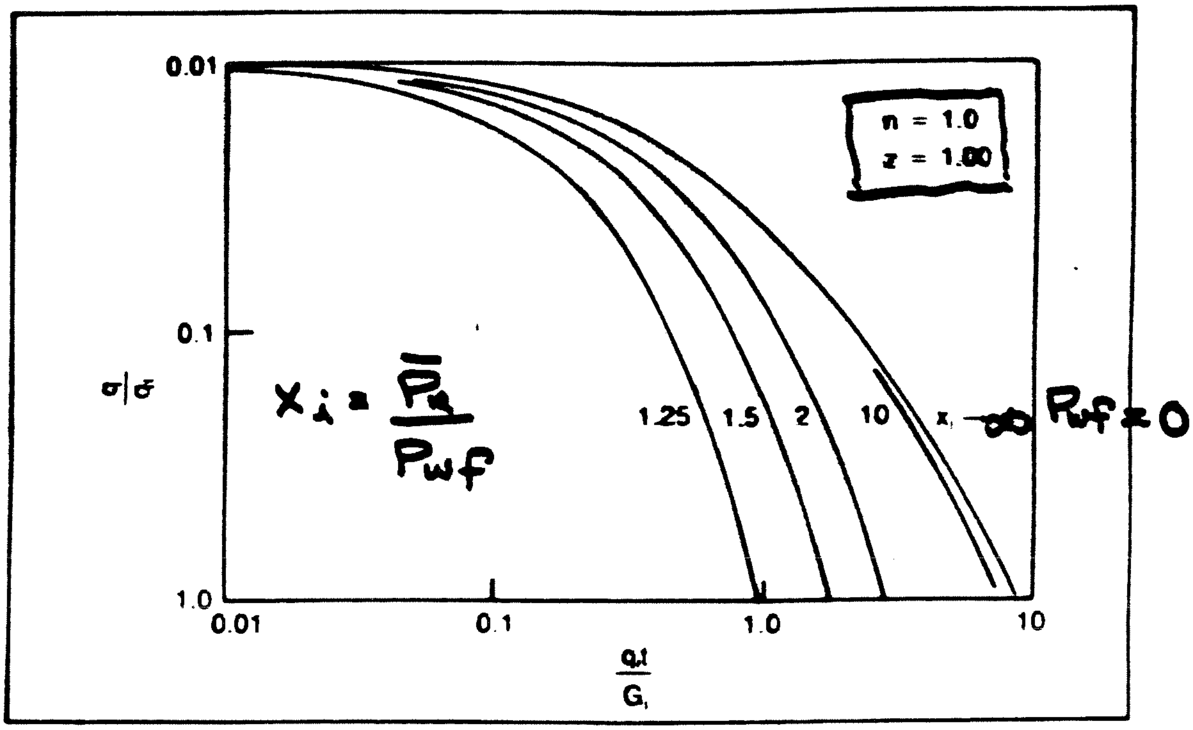


FIGURE 10–6 *Variation of Production Rate with Time for Wells Producing Against Various Constant Back Pressures*, n = *1.0*

same premises regarding the reservoir. Here, assume the well is producing against a constant back pressure of 662 psia in the wellbore at the level of the reservoir. Use the availability integral, A_x, from table 9–3 for an exponent, *n*, value of 0.70, but assume that the compressibility of the gas is 1.000 and use it as such in the material balance. The results are shown in figure 10–7 and are identified as the empirical method.

The difference in the forecast rates is not too bad for the 10 years after stabilization, and at 10 years the instantaneous predicted production rate is 344 for the empirical method versus 315 Mcfd for the theoretical method. Considering the assumptions involved in the empirical method, the chart reading of the theoretical method, and the widely different approaches to the problem, one could consider the agreement to be good. The theoretical method has a serious flaw in that it ignores the additional pressure loss caused by non-Darcy flow near the wellbore. However, the empirical method ignores the compressibility of the gas by assuming it to be 1.000. In the example selected, the exponent, *n*, is taken as 0.70, which indicates a large pressure drop caused by non-Darcy flow. This, in turn, results in a significant difference in the two methods.

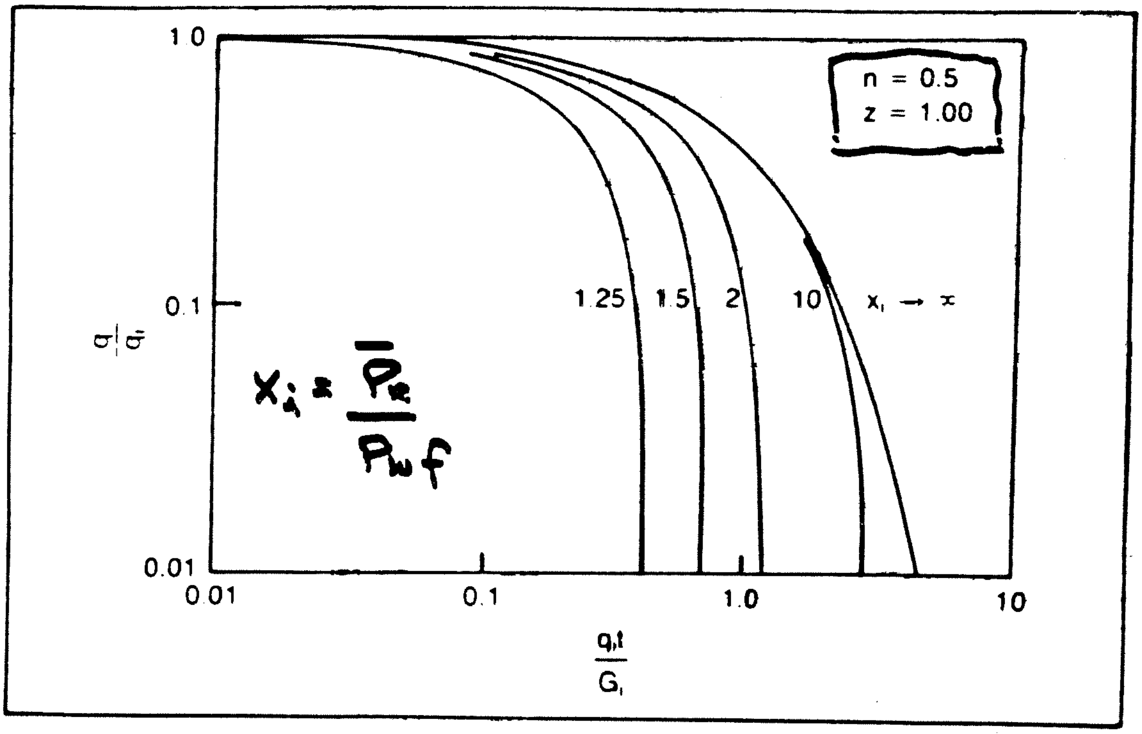


FIGURE 10–1 *Variation of Production Rate with Time for Wells Producing Against Various Constant Back Pressures, n = 0.5*

fraction of the current open-flow potential or against a back pressure that is a constant fraction of the current shutin pressure. This is illustrated in figures 10–1, 10–2, 10–3, 10–4, 10–5, and 10–6 for values of the exponent *n* from 0.5 to 1.0. The dimensionless rate of flow, q/q_i, has been plotted against the dimensionless time, $q_i t/G_i$, on logarithmic coordinates on these six figures. Numerical values for the relationships are given in table 10–1 for the reader who wishes to make plots correspond to figures 10–1 to 10–6, inclusive.* The solutions given in the tables and figures were calculated from analytical solutions when available and otherwise from numerical solutions.

COMPARISON WITH THE THEORETICAL DECLINE CURVE

In chapter 8, a production forecast was made from the theoretical approach to the unsteady-state flow theory for gas wells, but in chapter 9 an empirical approach was developed. Using the same well example that was used in chapter 8, one can start at the stabilization point shown in table 8–9 and make an empirical production forecast for the same gas well using the

---

* The author recommends coordinates with at least 3-in. cycles

Table 10–1, continued

q/q_i	n = 0.9					n = 1.0				
	$x_i \to \infty$	$x_i = 10$	2	1.5	1.25	$x_i \to \infty$	$x_i = 10$	2	1.5	1.25
1.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.95	0.029	0.029	0.022	0.016	0.010	0.026	0.026	0.019	0.014	0.009
0.90	0.060	0.059	0.045	0.033	0.021	0.054	0.054	0.040	0.030	0.019
0.80	0.130	0.129	0.096	0.070	0.045	0.118	0.117	0.087	0.064	0.041
0.70	0.215	0.212	0.157	0.114	0.072	0.195	0.193	0.143	0.104	0.066
0.60	0.319	0.315	0.229	0.165	0.104	0.291	0.288	0.210	0.152	0.096
0.50	0.451	0.445	0.318	0.226	0.141	0.414	0.409	0.294	0.210	0.132
0.40	0.628	0.620	0.432	0.303	0.187	0.581	0.573	0.404	0.285	0.177
0.35	0.743	0.732	0.503	0.350	0.215	0.690	0.681	0.472	0.331	0.204
0.30	0.885	0.870	0.586	0.404	0.246	0.826	0.813	0.555	0.385	0.236
0.25	1.065	1.046	0.686	0.468	0.284	1.000	0.983	0.656	0.450	0.274
0.20	1.306	1.280	0.812	0.547	0.328	1.236	1.213	0.785	0.532	0.321
0.15	1.655	1.615	0.977	0.648	0.385	1.582	1.548	0.960	0.641	0.383
0.10	2.228	2.158	1.212	0.788	0.464	2.162	2.102	1.220	0.798	0.471
0.07	2.826	2.710	1.419	0.909	0.530	2.780	2.682	1.459	0.940	0.550
0.05	3.483	3.298	1.612	1.019	0.591	3.472	3.319	1.692	1.075	0.624
0.03	4.689	4.319	1.897	1.181	0.679	4.774	4.470	2.054	1.283	0.738
0.015	6.832	5.930	2.266	1.389	0.792	7.165	6.419	2.558	1.568	0.893
0.010	8.428	6.965	2.471	1.503	0.854	9.000	7.768	2.857	1.735	0.984

TABLE 10–1.

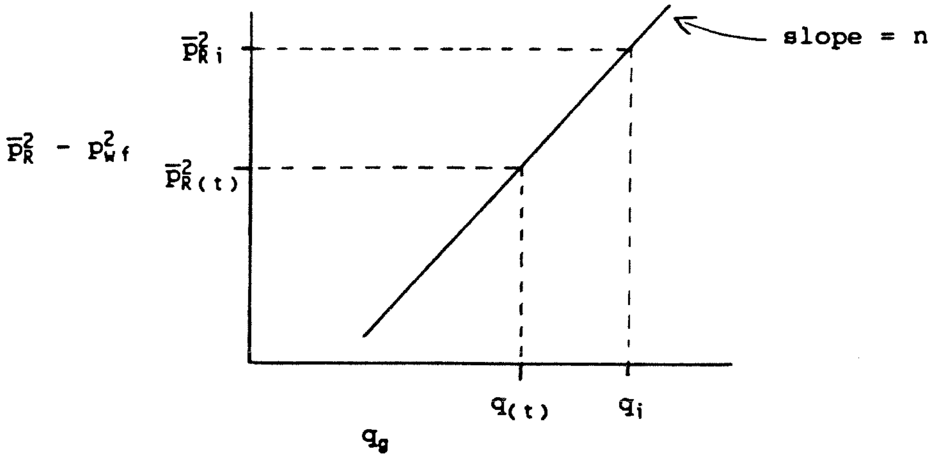
Variation of Producing Rate with Time for Wells Producing against Various Constant Back Pressures and Various n Values, z = 1.00

Values of $(q_i t/G_i)$

	n = 0.5					n = 0.6				
q/q_i	$x_i \to \infty$	$x_i = 10$	2	1.5	1.25	$x_i \to \infty$	$x_i = 10$	2	1.5	1.25
1.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.95	0.051	0.051	0.038	0.028	0.018	0.043	0.042	0.032	0.024	0.01[illegible]
0.90	0.105	0.104	0.078	0.057	0.037	0.089	0.088	0.066	0.048	0.031
0.80	0.223	0.221	0.162	0.118	0.075	0.189	0.187	0.139	0.101	0.0[illegible]
0.70	0.357	0.352	0.254	0.181	0.114	0.306	0.303	0.220	0.158	0.10[illegible]
0.60	0.511	0.504	0.353	0.249	0.154	0.444	0.439	0.312	0.221	0.1[illegible]
0.50	0.693	0.682	0.462	0.320	0.196	0.612	0.603	0.417	0.292	0.18[illegible]
0.40	0.916	0.899	0.580	0.394	0.238	0.825	0.811	0.539	0.370	0.22[illegible]
0.35	1.050	1.027	0.643	0.433	0.260	0.956	0.938	0.608	0.413	0.2[illegible]
0.30	1.204	1.174	0.709	0.472	0.282	1.111	1.088	0.684	0.460	0.2[illegible]
0.25	1.386	1.344	0.776	0.512	0.304	1.300	1.267	0.766	0.510	0.3[illegible]
0.20	1.609	1.546	0.846	0.552	0.326	1.538	1.492	0.858	0.564	0.3[illegible]
0.15	1.897	1.794	0.918	0.593	0.349	1.859	1.785	0.962	0.624	0.3[illegible]
0.10	2.303	2.105	0.991	0.634	0.371	2.339	2.197	1.082	0.692	0.40[illegible]
0.07	2.659	2.332	1.036	0.659	0.384	2.788	2.546	1.165	0.739	0.4[illegible]
0.05	2.996	2.502	1.066	0.676	0.393	3.238	2.853	1.228	0.775	0.44[illegible]
0.03	3.507	2.685	1.096	0.692	0.402	3.970	3.254	1.301	0.815	0.471
0.015	4.200	2.830	1.118	0.705	0.409	5.068	3.662	1.368	0.853	0.4[illegible]
0.010	4.605	2.879	1.126	0.709	0.411	5.772	3.835	1.395	0.868	0.[illegible]

DERIVATION OF THE RATE-CUMULATIVE EQUATION FOR GAS FROM BASIC PRINCIPLES

Beginning with the "stabilized" backpressure curve shown graphically in Figure 1.



The backpressure curve equation can be written for initial conditions as

$$q_i = C_1 \left(\bar{p}_{Ri}^2 - p_{wf}^2\right)^n \tag{1}$$

and at any time t as

$$q_{(t)} = C_2 \left(\bar{p}_{R(t)}^2 - p_{wf}^2\right)^n \tag{2}$$

rearranging (2) and (3) and assuming that for depletion $p_{wf} = 0$.

$$C_1 = \frac{q_i}{\left(\bar{p}_{Ri}^2\right)^n} \tag{3}$$

$$C_2 = \frac{q_{(t)}}{\left(\bar{p}_{R(t)}^2\right)^n} \tag{4}$$

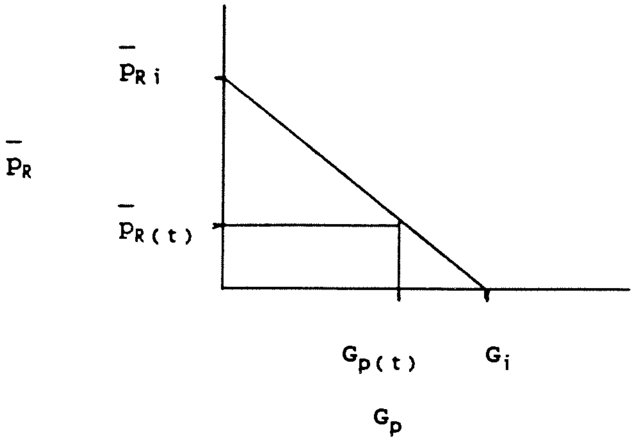
Knowing that $C_1 = C_2$, we can set (3) and (4) equal to each other

$$\frac{q_i}{\left(\bar{p}_{Ri}^2\right)^n} = \frac{q_{(t)}}{\left(\bar{p}_{R(t)}^2\right)^n} \tag{5}$$

rearranging (5)

$$\frac{q_{(t)}}{q_i} = \left[\frac{\bar{p}_{R(t)}}{\bar{p}_{Ri}}\right]^{2n} \qquad (6)$$

The material balance equation is shown graphically in Figure 2.



Using a ratio of similar triangles in Figure 2, we obtain the following relationship.

$$\frac{\bar{p}_{Ri}}{G_i} = \frac{\bar{p}_{R(t)}}{G_i - G_{p(t)}} \qquad (7)$$

rearranging (7)

$$\frac{\bar{p}_{R(t)}}{\bar{p}_{Ri}} = \frac{G_i - G_{p(t)}}{G_i} \qquad (8)$$

substituting (8) into (6) we obtain

$$\frac{q_{(t)}}{q_i} = \left(\frac{G_i - G_{p(t)}}{G_i}\right)^{2n} \qquad (9)$$

rearranging (9) we obtain

$$\frac{q_{(t)}}{q_i} = \left(1 - \frac{G_{p(t)}}{G_i}\right)^{2n} \qquad (10)$$

In order to convince ourselves that Equation (10) is correct, we can check with Arps' empirical hyperbolic rate-cumulative relationship given in his paper as Equation (13).

Arps
$$C = \frac{a_o P_o^b}{1 - b} \left[P_o^{1-b} - P^{1-b} \right] \tag{11}$$

using the nomenclature of Fetkovich, Equation (11) is rewritten as

$$G_{p(t)} = \frac{q_i^b}{D_i\,(1-b)} \left(q_i^{1-b} - q_{(t)}^{1-b} \right) \tag{12}$$

If Equation (10) is correct, using the relationships

$$b = (2n-1)/2n \tag{13}$$

$$D_i = 2n \left(\frac{q_i}{G_i} \right) \tag{14}$$

for hyperbolic gas well decline ($p_{wf} \cong 0$), we should be able to show that Equation (10) is identical to Equation (12). Substituting (13) and (14) into (12) and rearranging we obtain

$$G_{(t)} = \frac{q_i^{1-1/2n}}{(q_i / G_i)} \left[q_i^{1/2n} - q_{(t)}^{1/2n} \right] \tag{15}$$

$$G_{(t)} = G_i \left[\frac{q_i^{1/2n} - q_{(t)}^{1/2n}}{q_i^{1/2n}} \right] \tag{16}$$

$$\frac{G_{(t)}}{G_i} = 1 - \left(\frac{q_{(t)}}{q_i} \right)^{1/2n} \tag{17}$$

$$\left(\frac{q_{(t)}}{q_i} \right)^{1/2n} = \left(1 - \frac{G_{p(t)}}{G_i} \right) \tag{18}$$

$$\frac{q_{(t)}}{q_i} = \left(1 - \frac{G_{p(t)}}{G_i}\right)^{2n} \qquad (19)$$

Equations (19) and (10) are identical and for n = 0.5 (19) becomes

$$q_{(t)} = \frac{q_i}{G_i} \left(G_i - G_{p(t)}\right) \qquad (20)$$

$$q_{(t)} = - \frac{q_i}{G_i} \cdot G_{p(t)} + q_i \qquad (21)$$

Equation (21) results in a straight line when plotted on cartesian paper. This is the same result observed by Arps.

RATE-CUMULATIVE EQUATION

From almost any book dealing with Arp's decline equations, we have

$$N_p \text{ or } G_p = \frac{1}{(1-b)} \cdot \frac{q_i^b}{D_i} [q_i^{(1-b)} - q_a^{(1-b)}]$$

$$\text{set } q_a = 0, \quad \text{then}$$

$$N_p \text{ or } G_p = \frac{1}{(1-b)} \cdot \frac{q_i^b}{D_i} \cdot q_i^{(1-b)}$$

then

$$N_{pi} \text{ or } G_i = \frac{1}{(1-b)} \frac{q_i}{D_i}$$

rearranging and solving for D_i

$$D_i = \frac{1}{(1-b)} \frac{q_i}{G_i} \text{ or } D_i = \frac{1}{(1-b)} \frac{q_i}{N_{pi}}$$

$$\text{where} \quad N_{pi} = OOIP \times R.F. = N(R.F.)$$

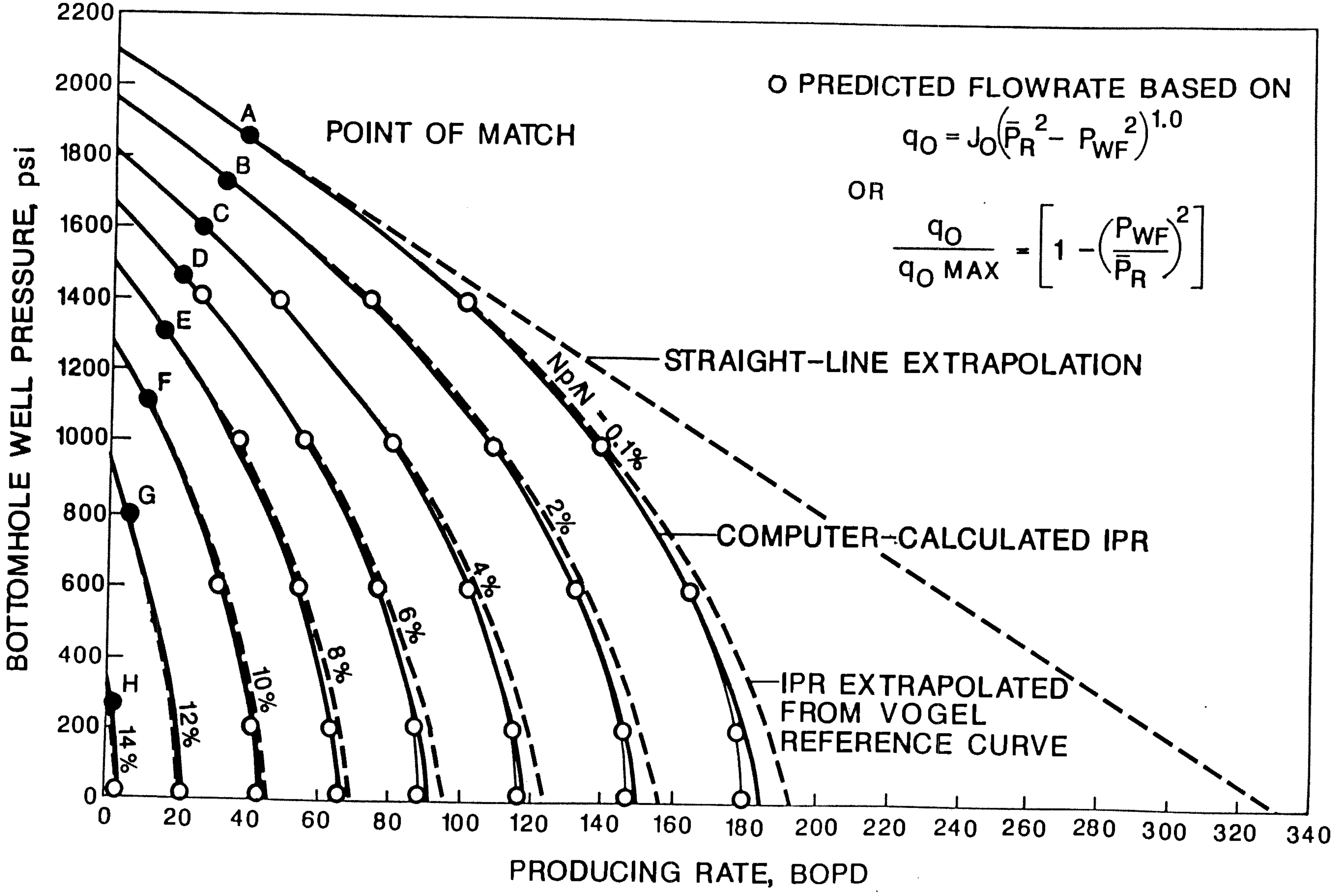
$$\text{and} \quad G_i = OGIP \times R.F. = G(R.F.)$$

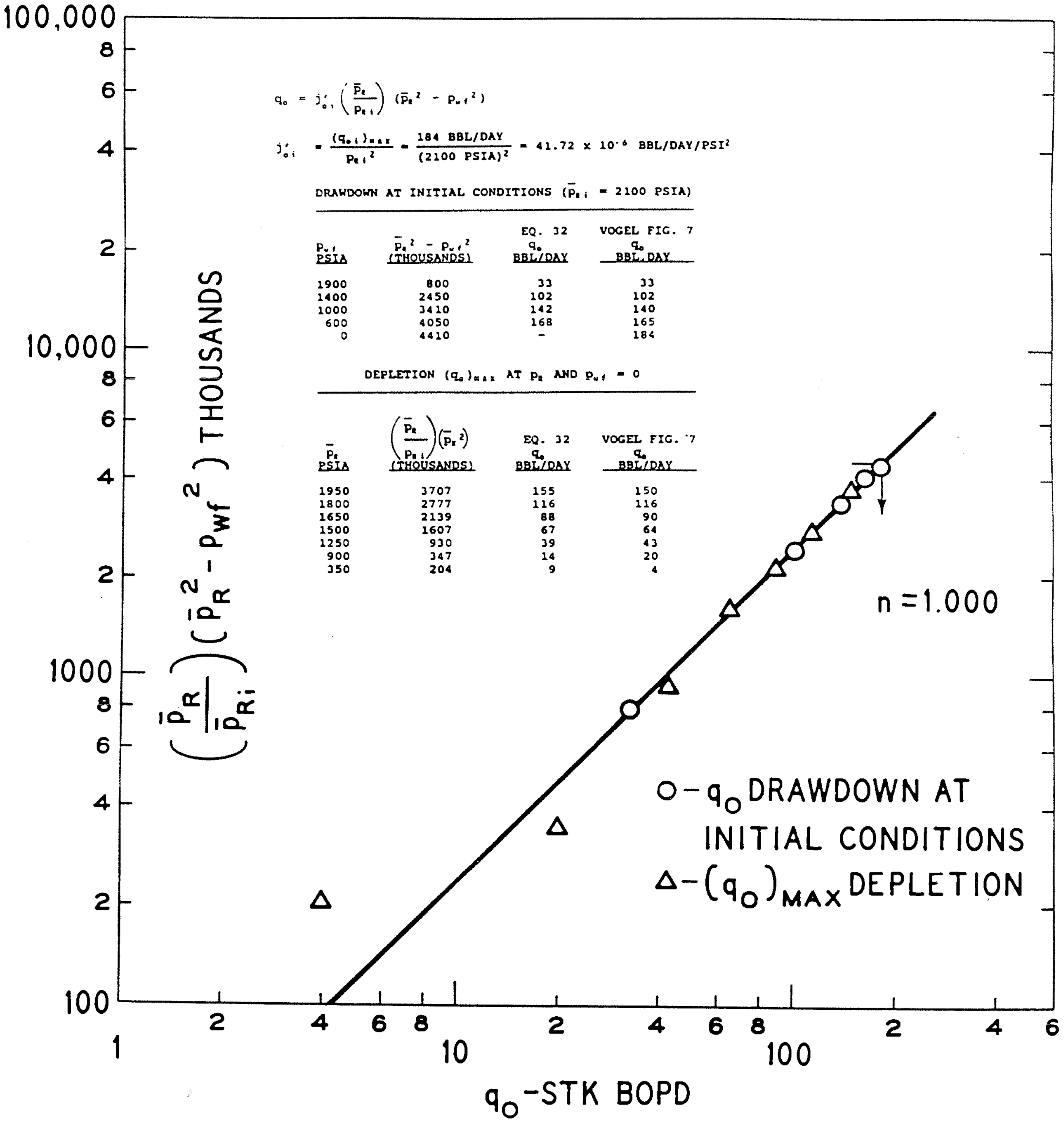
$$\text{where } R.F. = \left(1 - \frac{p_{wf}}{\bar{p}_{Ri}}\right) \text{ ignoring } Z$$

$$G_i = G \text{ for } p_{wf} = 0$$

Remember that $b = f$ *(Drive Mechanism,* $\frac{p_{wf}}{\bar{p}_{Ri}}$ *and*

slope n *of backpressure curves.)*


O PREDICTED FLOWRATE BASED ON
$q_O = J_O(\bar{P}_R^2 - P_{WF}^2)^{1.0}$
OR
$\frac{q_O}{q_{O\,MAX}} = \left[1 - \left(\frac{P_{WF}}{\bar{P}_R}\right)^2\right]$
POINT OF MATCH
STRAIGHT-LINE EXTRAPOLATION
COMPUTER-CALCULATED IPR
IPR EXTRAPOLATED FROM VOGEL REFERENCE CURVE
A
B
C
D
E
F
G
H
Np/N - 0.1%
2%
4%
6%
8%
10%
12%
14%
BOTTOMHOLE WELL PRESSURE, psi
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
PRODUCING RATE, BOPD
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
320
340



$$q_o = j'_{oi}\left(\frac{\bar{p}_R}{p_{Ri}}\right)(\bar{p}_R^2 - p_{wf}^2)$$

$$j'_{oi} = \frac{(q_{oi})_{max}}{p_{Ri}^2} = \frac{184\ \text{BBL/DAY}}{(2100\ \text{PSIA})^2} = 41.72 \times 10^{-6}\ \text{BBL/DAY/PSI}^2$$

DRAWDOWN AT INITIAL CONDITIONS ($\bar{p}_{Ri}$ = 2100 PSIA)

p_{wf} PSIA	$\bar{p}_R^2 - p_{wf}^2$ (THOUSANDS)	EQ. 32 q_o BBL/DAY	VOGEL FIG. 7 q_o BBL.DAY
1900	800	33	33
1400	2450	102	102
1000	3410	142	140
600	4050	168	165
0	4410	-	184

DEPLETION $(q_o)_{max}$ AT p_R AND p_{wf} = 0

$\bar{p}_R$ PSIA	$\left(\frac{\bar{p}_R}{p_{Ri}}\right)(\bar{p}_R^2)$ (THOUSANDS)	EQ. 32 q_o BBL/DAY	VOGEL FIG. 7 q_o BBL/DAY
1950	3707	155	150
1800	2777	116	116
1650	2139	88	90
1500	1607	67	64
1250	930	39	43
900	347	14	20
350	204	9	4

FIG. (25)

DISSOLVED GAS DRIVE DRAWDOWN AND DEPLETION PERFORMANCE CURVE. (AFTER VOGELS(5) FIG. 7)

GAS PRODUCTION FORECAST TABLES

M. J. Fetkovich

The Gas Production Forecast Tables are based on q_i, the initial producing rate, being set at a rate-of-take of 1 MMSCFD/7.3 BSCF of recoverable reserves assuming a recovery factor of 85%. This results in a rate-of-take of 1 MMSCFD/8.59 BSCF gas-in-place. The 1/7.3 rate-of-take defines a producing life of 20 years which is used to determine the actual 20 year recovery factors. In order to include the effect of line pressure, a line pressure of 15% of the initial wellhead shut-in pressure, Pc, was used. (This would allow a well or field having an infinite wellhead open-flow potential to recover 85% of its reserves.) This line pressure is therefore the maximum which should be imposed on the forecast otherwise the 85% recovery factor has no basis. It should be mentioned that the 85% recovery factor is being used only as an initial rate setting and a maximum line pressure setting device. Examination of the forecast tables lists recoveries from 50 to 85% for a 20 year period depending on the wellhead deliverability of the well or field.

Ratios of $\frac{q_i\ (G)}{(q_i)_{max}}$ or $\frac{G}{(q_i)_{max}}$ were selected to obtain increments of approximately one additional year for the constant rate q_i. A base table has been developed which assumes the gas deviation factor Z = 1, and a line pressure of 0 psig. In order to consider the effect of compressibility, three additional tables have been developed; a low pressure table for wellhead shut-in pressures of 0 to 500 psia; a medium pressure table for wellhead shut-in pressures of 500 to 2500 psia, and a high pressure table for wellhead shut-in pressures of 2500 to 6000 psia.

As for the slope of the wellhead back-pressure curve, n, used to develop these tables, our experience shows that n = 0.700 is a normally expected value. Reasonable deviations from n = 0.700 will not significantly affect the forecast.

Nomenclature

G = Initial gas-in-place, Bscf

q_i = Initial producing rate, MMscfd

$(q_i)_{max}$ = Initial stabilized wellhead potential, MMscfd (For a well or total field.)

$q\ (t)$ = Producing rate at time t, MMscfd

EXAMPLE PROBLEM NO. 1

(Forecast for a Well or Total Field)

Given:

Gas-in-place, $G = 6.50$ Bscf

Stabilized wellhead potential, $(q_i)_{max} = 2.300$ MMscfd

Wellhead shut-in pressure, $P_c = 3700$ psia

Ultimate line pressure = .15 x 3700 psia = 555 psia

$$q_i = \frac{6.50 \text{ Bscf}}{8.59 \frac{\text{Bscf}}{\text{MMscfd}}} = .757 \text{ MMscfd}$$

$$\frac{q_i\ (G)}{(q_i)_{max}} = \frac{.757 \text{ MMscfd}}{2.300 \text{ MMscfd}} = 0.329$$

Use Table 1 High Pressure Range (2500-6000 psia) Column 12, $\frac{q_i\ (G)}{(q_i)_{max}}$ of 0.3265

Forecast:

Year	$q\ (t)/q_i$	$q\ (t)$ Mscfd
1-11	1.000	757
12	.922	698
13	.825	625
14	.740	560
15	.666	504
16	.600	454
17	.541	410
18	.489	370
19	.441	334
20	.398	301

Fraction recovered to start of decline = .461 or 2.996 BSCF

Fraction recovery of G at end of 20 years = .708 or 4.602 BSCF

EXAMPLE PROBLEM NO. 2

(Determine the Number of Wells Required to Maintain a 10 Year Constant Rate Period and/or a 15 Year Constant Rate Period)

Given:

Total field gas-in-place, G = 950 Bscf

Average well stabilized wellhead potential, $(q_i)_{max}$ = 10.000 MMscfd

Wellhead shut-in pressure, P_c = 2000 psia

Ultimate line pressure = .15 x 2000 psia = 300 psia

$$q_i = \frac{950 \text{ Bscf}}{8.59 \frac{\text{Bscf}}{\text{MMscfd}}} = 110.6 \text{ MMscfd for total field}$$

$$\frac{q_i\ (G)}{(q_i)_{max}} = \frac{110.6 \text{ MMscfd}}{\text{Wells x } 10.0 \text{ MMscfd}}$$

From Table 2, Medium Pressure Range (500-2500 psia), $\frac{q_i\ (G)}{(q_i)_{max}}$ equals .4335 for 10 year constant rate period and .2300 for 15 year constant rate period.

$$\text{Wells} = \frac{110.6}{.4335 \text{ x } 10.0} = 25.5 \text{ or } 26 \text{ wells (10 year constant rate period)}$$

$$\text{Wells} = \frac{110.6}{.2300 \text{ x } 10.0} = 48 \text{ wells (15 year constant rate period)}$$

A forecast for each case would be determined as in Example 1.

TABLE 1

DIMENSIONLESS PRODUCTION FORECAST TABLE

HIGH PRESSURE RANGE

2500 - 6000 psia

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
$\frac{q_i\ (G)}{(q_i)_{max}}$	1.000	.9307	.8629	.7965	.7317	.6687	.6070	.5475	.4895	.4335	.3790	.3265	.2765	.2300	.1855	.1435	.1050	.0704
$\frac{G}{(q_i)_{max}}$ $\frac{Bscf}{MMscfd}$	8.59	8.00	7.41	6.84	6.29	5.74	5.21	4.70	4.20	3.72	3.26	2.80	2.38	1.98	1.59	1.23	0.90	0.60
Fraction Recovered to Decline	.000	.025	.057	.092	.128	.166	.206	.248	.298	.347	.404	.461	.517	.574	.631	.684	.733	.779
Mid Year									$q(t)/q_i$									
1	.938	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2	.855	.911	.979	1.000														
3	.787	.834	.891	.960	1.000													
4	.729	.770	.818	.876	.947	1.000												
5	.680	.715	.756	.805	.865	.937	1.000											
6	.637	.667	.704	.746	.796	.857	.935	1.000										
7	.599	.626	.657	.693	.736	.788	.853	.936	1.000									
8	.565	.588	.615	.647	.685	.729	.785	.854	.945	1.000								
9	.534	.555	.579	.607	.640	.678	.727	.785	.861	.962	1.000							
10	.506	.525	.547	.571	.601	.634	.676	.726	.791	.875	.991							
11	.481	.498	.518	.540	.566	.595	.631	.675	.729	.799	.895	1.000						
12	.459	.474	.492	.512	.534	.561	.591	.629	.675	.733	.811	.922	1.000					
13	.438	.452	.468	.486	.506	.529	.555	.587	.625	.673	.737	.825	.956	1.000				
14	.419	.432	.446	.462	.480	.499	.522	.549	.580	.620	.670	.740	.842	.996				
15	.402	.413	.426	.440	.455	.472	.491	.514	.539	.571	.611	.666	.743	.858	1.000			
16	.386	.397	.407	.419	.433	.447	.463	.481	.502	.527	.558	.600	.658	.742	.879	1.000		
17	.371	.380	.390	.400	.411	.423	.436	.451	.467	.486	.510	.541	.583	.641	.734	.900	1.000	
18	.356	.365	.373	.382	.391	.401	.412	.423	.436	.450	.467	.489	.517	.554	.613	.714	.914	1.000
19	.343	.350	.357	.365	.373	.380	.389	.397	.406	.416	.428	.441	.458	.480	.513	.566	.662	.886
20	.330	.336	.343	.349	.355	.361	.367	.373	.379	.386	.392	.398	.406	.416	.429	.446	.472	.525
FRACTION RECOVERY OF G	.461	.481	.502	.523	.545	.567	.589	.612	.637	.660	.685	.708	.731	.752	.773	.793	.811	.827

Rate-of-Take: 1/7.300 based on 85% recovery factor
Rate-of-Take: 1/8.590 based on gas-in-place, G
Slope Back-Pressure Curve: 0.700
Line Pressure: 15% of shut-in pressure

TABLE 2
DIMENSIONLESS PRODUCTION FORECAST TABLE
MEDIUM PRESSURE RANGE
500 - 2500 psia

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
$\frac{q_i\ (G)}{(q_i)_{max}}$	1.000	.9307	.8629	.7965	.7317	.6687	.6070	.5475	.4895	.4335	.3790	.3265	.2765	.2300	.1855	.1435	.1050	.0704
$\frac{G}{(q_i)_{max}}$ $\frac{Bscf}{MMscfd}$	8.59	8.00	7.41	6.84	6.29	5.74	5.21	4.70	4.20	3.72	3.26	2.80	2.38	1.98	1.59	1.23	0.90	0.60
Fraction Recovered to Decline	.000	.043	.096	.149	.203	.252	.305	.358	.411	.461	.510	.560	.609	.655	.702	.744	.783	.818
									$q(t)/q_i$									
Mid Year																		
1	.956	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2	.906	.968	1.000															
3	.858	.913	.982	1.000														
4	.813	.863	.923	.997														
5	.771	.815	.869	.934	1.000													
6	.732	.771	.818	.874	.944	1.000												
7	.694	.729	.770	.820	.881	.956	1.000											
8	.660	.690	.727	.770	.823	.888	.972	1.000										
9	.628	.654	.686	.724	.770	.826	.897	.988										
10	.597	.621	.649	.682	.721	.769	.829	.906	1.000									
11	.569	.590	.614	.642	.676	.716	.767	.831	.917	1.000								
12	.542	.560	.581	.605	.633	.668	.710	.763	.833	.927	1.000							
13	.517	.532	.550	.570	.594	.623	.658	.701	.758	.834	.938	1.000						
14	.493	.506	.521	.538	.558	.581	.610	.646	.692	.753	.835	.954	1.000					
15	.470	.481	.493	.507	.523	.543	.567	.596	.633	.680	.744	.834	.968	1.000				
16	.449	.458	.467	.479	.492	.508	.527	.550	.579	.615	.663	.730	.827	.976	1.000			
17	.428	.435	.443	.452	.463	.476	.490	.508	.529	.556	.592	.640	.710	.812	.983	1.000		
18	.409	.414	.420	.428	.436	.445	.456	.467	.484	.504	.529	.563	.609	.675	.782	.978	1.000	
19	.390	.394	.399	.405	.411	.417	.425	.433	.444	.457	.473	.494	.522	.562	.623	.729	.940	1.000
20	.373	.376	.379	.383	.387	.391	.395	.401	.407	.415	.423	.434	.449	.468	.496	.542	.624	.810
FRACTION RECOVERY OF G	.515	.537	.558	.580	.602	.623	.644	.664	.685	.704	.724	.743	.760	.778	.793	.808	.820	.828

Rate-of-Take: 1/7.300 based on 85% recovery factor
Rate-of-Take: 1/8.590 based on gas-in-place, G
Slope Back Pressure Curve: 0.700
Line Pressure: 15% of shut-in pressure

TABLE 3
DIMENSIONLESS PRODUCTION FORECAST TABLE
LOW PRESSURE RANGE
0 - 500 psia

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
$\frac{q_i\ (G)}{(q_i)_{max}}$	1.000	.9307	.8629	.7965	.7317	.6687	.6070	.5475	.4895	.4335	.3790	.3265	.2765	.2300	.1855	.1435	.1050	.0704
$\frac{G}{(q_i)_{max}}$ $\frac{Bscf}{MMscfd}$	8.59	8.00	7.41	6.84	6.29	5.74	5.21	4.70	4.20	3.72	3.26	2.80	2.38	1.98	1.59	1.23	0.90	0.60
Fraction Recovered to Decline	.000	.039	.089	.138	.237	.237	.287	.333	.383	.432	.478	.528	.574	.620	.666	.709	.751	.790
Mid Year	$q(t)/q_i$																	
1	.955	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2	.900	.962	1.000															
3	.850	.904	.971	1.000														
4	.802	.850	.909	.981	1.000													
5	.758	.800	.852	.914	.991													
6	.717	.754	.799	.853	.919	1.000												
7	.679	.711	.750	.797	.854	.925	1.000											
8	.643	.672	.705	.746	.795	.855	.932	1.000										
9	.610	.634	.664	.698	.740	.791	.856	.947	1.000									
10	.578	.600	.625	.655	.690	.733	.788	.856	.947	1.000								
11	.549	.568	.589	.615	.645	.681	.726	.783	.857	.957	1.000							
12	.522	.538	.556	.577	.603	.633	.670	.717	.777	.857	.968	1.000						
13	.496	.509	.525	.543	.564	.589	.620	.658	.706	.770	.857	.983	1.000					
14	.472	.483	.496	.511	.528	.549	.574	.604	.643	.693	.760	.856	.999					
15	.449	.458	.469	.481	.495	.512	.532	.556	.587	.625	.677	.749	.853	1.000				
16	.428	.435	.444	.454	.465	.478	.494	.513	.536	.566	.604	.657	.732	.842	1.000			
17	.408	.413	.420	.428	.437	.447	.459	.473	.491	.512	.540	.578	.629	.704	.825	1.000		
18	.389	.393	.398	.404	.410	.418	.427	.437	.450	.465	.484	.509	.543	.591	.665	.793	1.000	
19	.371	.374	.378	.382	.386	.391	.397	.404	.413	.422	.435	.450	.470	.497	.537	.602	.723	1.000
20	.354	.356	.358	.361	.364	.367	.370	.374	.379	.384	.391	.398	.408	.419	.434	.457	.492	.562
FRACTION RECOVERY OF G	.509	.529	.549	.570	.591	.611	.632	.652	.673	.693	.711	.731	.750	.768	.786	.802	.817	.830

Rate-of-Take: 1/7.300 based on 85% recovery factor
Rate-of-Take: 1/8.590 based on gas-in-place, G
Slope Back-Pressure Curve: 0.700
Line Pressure: 15% of shut-in pressure

TABLE 4
DIMENSIONLESS PRODUCTION FORECAST TABLE
Z = 1.0 LINE PRESSURE = 0

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
$\frac{q_i\ (G)}{(q_i)_{max}}$	1.000	.9307	.8629	.7965	.7317	.6687	.6070	.5475	.4895	.4335	.3790	.3265	.2765	.2300	.1855	.1435	.1050	.0704
$\frac{G}{(q_i)_{max}}$ $\frac{\text{Bscf}}{\text{MMscfd}}$	8.59	8.00	7.41	6.84	6.29	5.74	5.21	4.70	4.20	3.72	3.26	2.80	2.38	1.98	1.59	1.23	0.90	0.60
Fraction Recovered to Decline	.000	.053	.103	.152	.202	.252	.301	.351	.400	.450	.503	.553	.602	.652	.702	.751	.801	.850
Mid Year								$q(t)/q_i$										
1	.971	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2	.916	.980	1.000															
3	.864	.921	.990															
4	.817	.867	.928	1.000														
5	.772	.816	.870	.935	1.000													
6	.731	.770	.817	.873	.943	1.000												
7	.692	.726	.768	.817	.877	.952	1.000											
8	.656	.686	.722	.765	.817	.881	.963	1.000										
9	.623	.649	.680	.717	.762	.816	.886	.975	1.000									
10	.591	.614	.641	.673	.711	.758	.816	.891	.990									
11	.562	.582	.605	.633	.665	.705	.754	.816	.898	1.000								
12	.535	.552	.572	.595	.623	.656	.698	.749	.816	.906	1.000							
13	.509	.523	.540	.560	.584	.612	.646	.689	.744	.816	.916	1.000						
14	.484	.497	.511	.528	.548	.571	.600	.635	.680	.738	.817	.930	1.000					
15	.462	.472	.484	.499	.515	.534	.558	.586	.623	.669	.731	.818	.947	1.000				
16	.440	.449	.459	.471	.484	.500	.519	.543	.571	.608	.656	.723	.819	.965	1.000			
17	.420	.427	.436	.445	.456	.469	.484	.503	.525	.554	.591	.642	.713	.817	.992			
18	.401	.407	.414	.421	.430	.440	.452	.467	.484	.506	.534	.572	.624	.698	.817	1.000		
19	.383	.388	.393	.399	.406	.413	.423	.434	.447	.463	.484	.512	.549	.600	.680	.819	1.000	
20	.366	.370	.374	.378	.383	.389	.396	.404	.413	.425	.440	.459	.485	.519	.571	.657	.819	1.000
FRACTION RECOVERY OF G	.519	.541	.562	.583	.605	.626	.647	.668	.689	.710	.731	.752	.772	.792	.810	.829	.843	.850

Rate-of Take: 1/7.300 based on 85% recovery factor
Rate-of-Take: 1/8.590 based on gas-in-place, G
Slope Back-Pressure Curve: 0.700
Line Pressure: 0

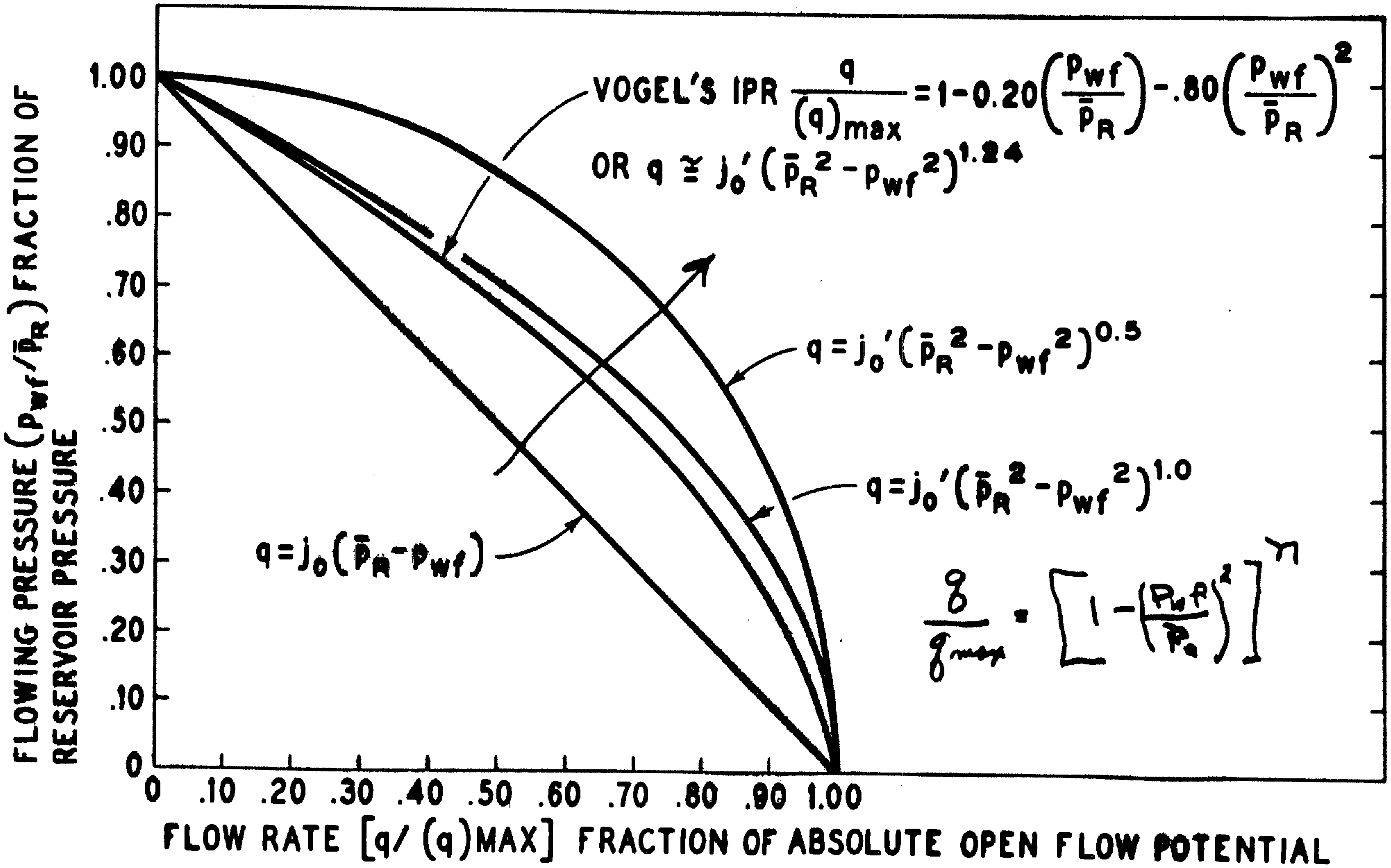


FIG. (1)

INFLOW PERFORMANCE RELATIONSHIPS FOR VARIOUS FLOW EQUATIONS (AFTER VOGEL[5])

OIL WELL DECLINE EQUATIONS ($p_{wf} \cong 0$)

$$q_{oi} = J_o'\left(\frac{\bar{p}_R}{p_i}\right)\left(\bar{p}_R^{\,2}\right)^n \quad \text{AND} \quad \bar{p}_R^{\,2} = -\left(\frac{\bar{p}_{Ri}^{\,2}}{N_{pi}}\right) + \bar{p}_{Ri}^{\,2}$$

EXPONENTIAL $n = 0.5$

$$q_o(t) = \frac{q_{oi}}{e^{-\left(\frac{q_{oi}}{N_{pi}}\right)t}}$$

$$D_i = \frac{q_{oi}}{N_{pi}} \quad \text{OR} \quad \frac{2n+1}{2}\left(\frac{q_{oi}}{N_{pi}}\right)$$

HYPERBOLIC $n > 0.5$

$$q_o(t) = \frac{q_{oi}}{\left[1 + \frac{2n-1}{2}\left(\frac{q_{oi}}{N_{pi}}\right)t\right]^{\frac{2n+1}{2n-1}}} \quad \frac{2n+1}{2n-1} = \frac{1}{b}$$

$$b = \frac{2n-1}{2n+1}$$

$n = 1$; $b = 0.33$

$$D_i = \frac{2n+1}{2}\left(\frac{q_{oi}}{N_{pi}}\right)$$

q_{oi} = "STABILIZED" ABSOLUTE OPEN-FLOW POTENTIAL AT START OF DECLINE

N_{pi} = REMAINING RECOVERABLE RESERVES AT START OF DECLINE

n = SLOPE OF STABILIZED BACK-PRESSURE CURVE, $q_o = f(\Delta p^2)$

t = TIME FROM START OF DECLINE ANALYSIS

$q(t)$ = FLOW RATE AT TIME t

DEFINITION OF D_i - SOLUTION-GAS-DRIVE OIL

Material Balance Equation

$$\overline{p}_R^2 = -\left(\frac{\overline{p}_{Ri}^2}{N_{pi}}\right)N_p + \overline{p}_{Ri}^2$$

Rate Equation

$$q_o = J'_{oi}\,\frac{\overline{p}_R}{\overline{p}_{Ri}}\,(\overline{p}_R^2 - p_{wf}^2)^n$$

Resulting Rate-Time Equation

$$\frac{q_o(t)}{q_{oi}} = \frac{1}{\left[\left(\frac{2n-1}{2}\right)\left(\frac{q_{oi}}{N_{pi}}\right) t + 1\right]^{\frac{2n+1}{2n-1}}}$$

General Arps Equation

$$\frac{q_o(t)}{q_{oi}} = \frac{1}{[b\,D_i\,t + 1]^{1/b}}$$

Note that:

$$1/b = \frac{2n+1}{2n-1} \text{ or } b = \frac{2n-1}{2n+1}\;; \quad \text{also, } \frac{2n+1}{2} = \frac{1}{1-b}$$

and: $$b\,D_i = \left(\frac{2n-1}{2}\right)\left(\frac{q_{oi}}{N_{pi}}\right)$$

Expressing in terms of D_i:

$$D_i = \frac{2n-1}{2b}\left(\frac{q_{oi}}{N_{pi}}\right)$$

Substituting for b:

$$D_i = \frac{2n-1}{2\left(\frac{2n-1}{2n+1}\right)}\left(\frac{q_{oi}}{N_{pi}}\right)$$

$$= \left(\frac{2n+1}{2}\right)\left(\frac{q_{oi}}{N_{pi}}\right)$$

Substituting for $\left(\frac{2n+1}{2}\right)$:

$$D_i = \frac{1}{1-b}\left(\frac{q_{oi}}{N_{pi}}\right)$$

DEFINITION OF D_i — SOLUTION GAS DRIVE OIL

Material Balance Equation

$$\bar{p}_R = -\left(\frac{\bar{p}_{Ri}}{N_{pi}}\right) N_p + \bar{p}_{Ri}$$

Rate Equation

$$q_o = J'_{oi}\,\frac{\bar{p}_R}{\bar{p}_{Ri}}\,(\bar{p}_R^2 - p_{wf}^2)^n$$

Resulting Rate-Time Equation

$$\frac{q_o(t)}{q_{oi}} = \frac{1}{\left[(2n)\left(\frac{q_{oi}}{N_{pi}}\right) t + 1\right]^{\frac{2n+1}{2n}}}$$

General Arps Equation

$$\frac{q_o(t)}{q_{oi}} = \frac{1}{[b\,D_i\,t + 1]^{1/b}}$$

Note that:

$$1/b = \frac{2n+1}{2n} \quad or\ b = \frac{2n}{2n+1}\ ; \quad also,\ 2n+1 = \frac{1}{1-b}$$

and: $$b\,D_i = 2n\left(\frac{q_{oi}}{N_{pi}}\right)$$

Expressing in terms of D_i:

$$D_i = \frac{2n}{b}\left(\frac{q_{oi}}{N_{pi}}\right)$$

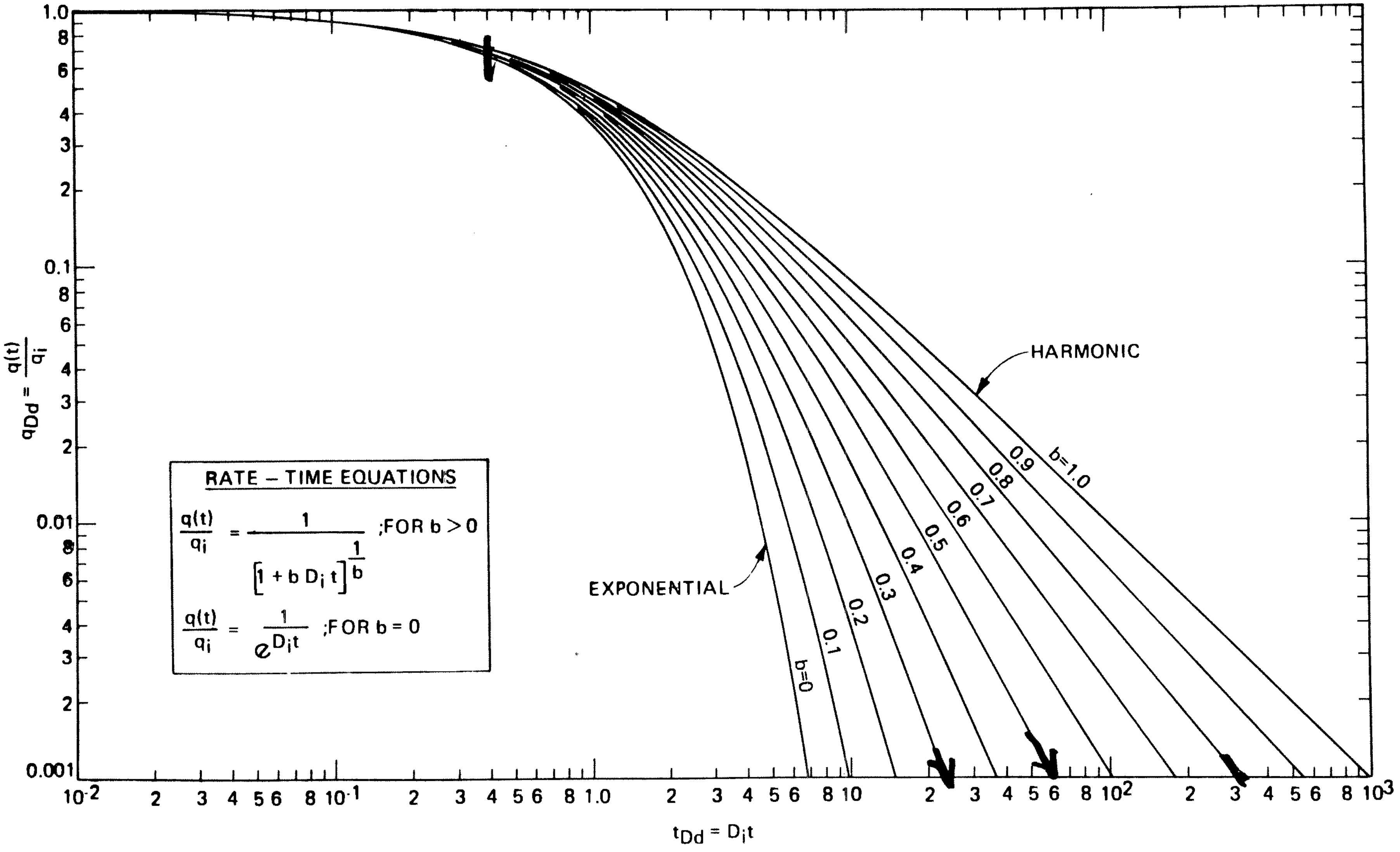
Substituting for b:

$$D_i = \frac{2n}{\left(\frac{2n}{2n+1}\right)}\left(\frac{q_{oi}}{N_{pi}}\right)$$

$$= (2n+1)\left(\frac{q_{oi}}{N_{pi}}\right)$$

Substituting for (2n+1):

$$D_i = \frac{1}{1-b}\left(\frac{q_{oi}}{N_{pi}}\right)$$



RATE – TIME EQUATIONS

$$\frac{q(t)}{q_i} = \frac{1}{\left[1 + b D_i t\right]^{\frac{1}{b}}} \quad ;\text{FOR } b > 0$$

$$\frac{q(t)}{q_i} = \frac{1}{e^{D_i t}} \quad ;\text{FOR } b = 0$$

FIG. 1 TYPE CURVES FOR ARPS EMPIRICAL RATE-TIME DECLINE EQUATIONS, UNIT SOLUTION ($D_i = 1$).

2. External Gas Drive

This type driving energy is the result of an expanding free gas cap. This is basically a displacement type drive, the gas displacing the oil ahead as it expands because of pressure reduction. The recovery efficiency of an external gas drive reservoir is dependent upon the displacing efficiency of the gas and the size of the gas cap because as the gas cap size increases, the actual number of barrels of expansion of the gas cap for a given pressure drop, will also increase accordingly. Therefore, as the gas cap size increases, a smaller pressure drop will be required to produce the oil to economic depletion. This will be discussed more fully in Chapter 5. Typical pressure-production history curves for reservoirs with both small gas caps and large gas caps are shown in Figure 3-1.

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"RESERVOIR ENGINEERING
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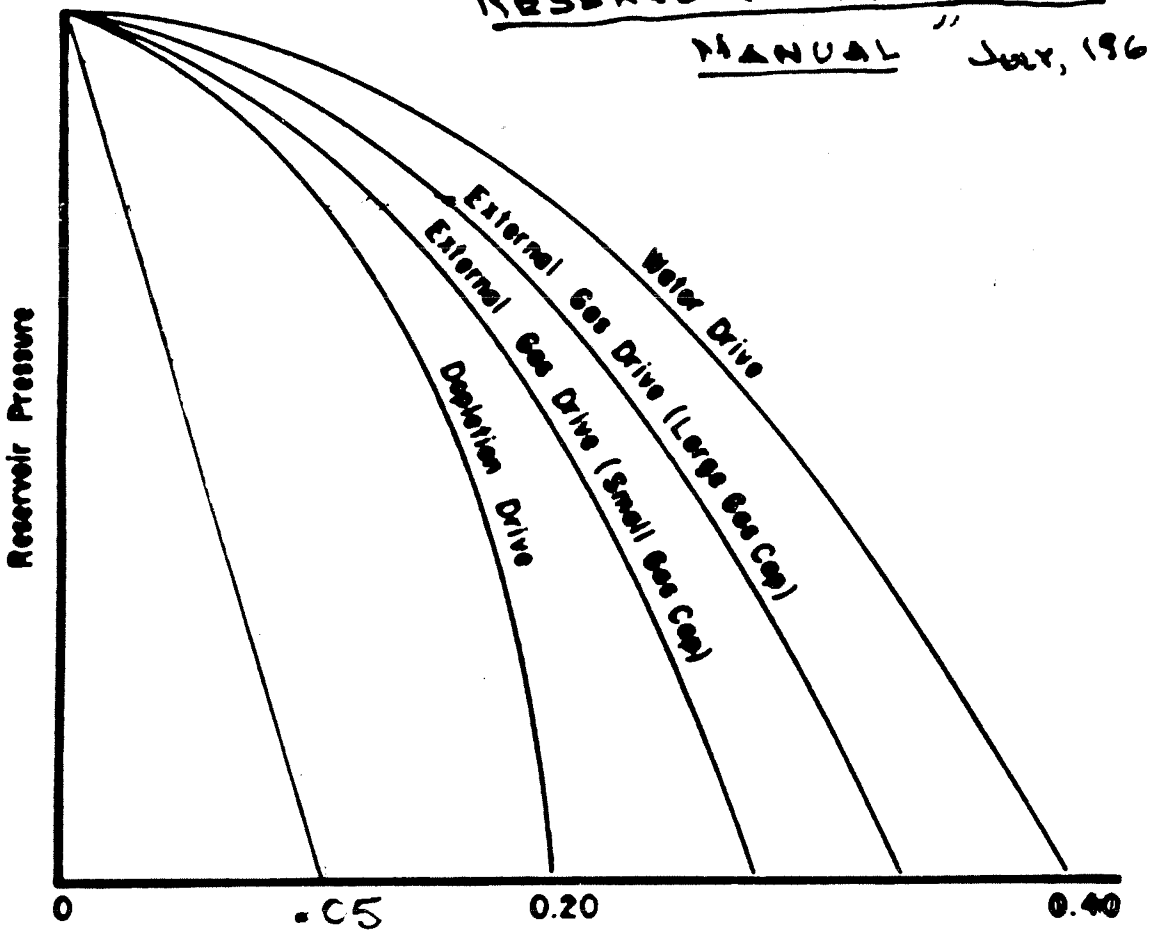
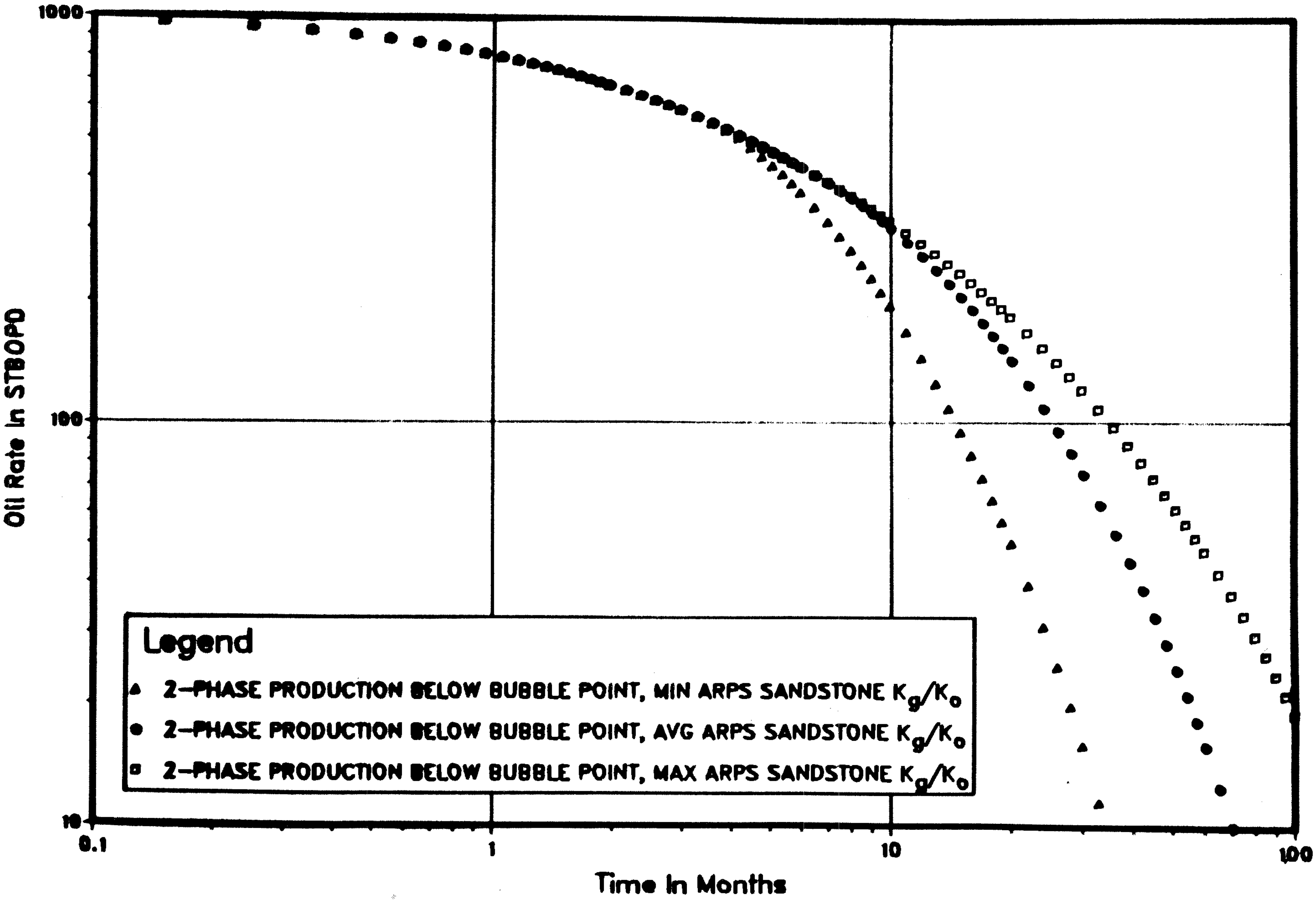
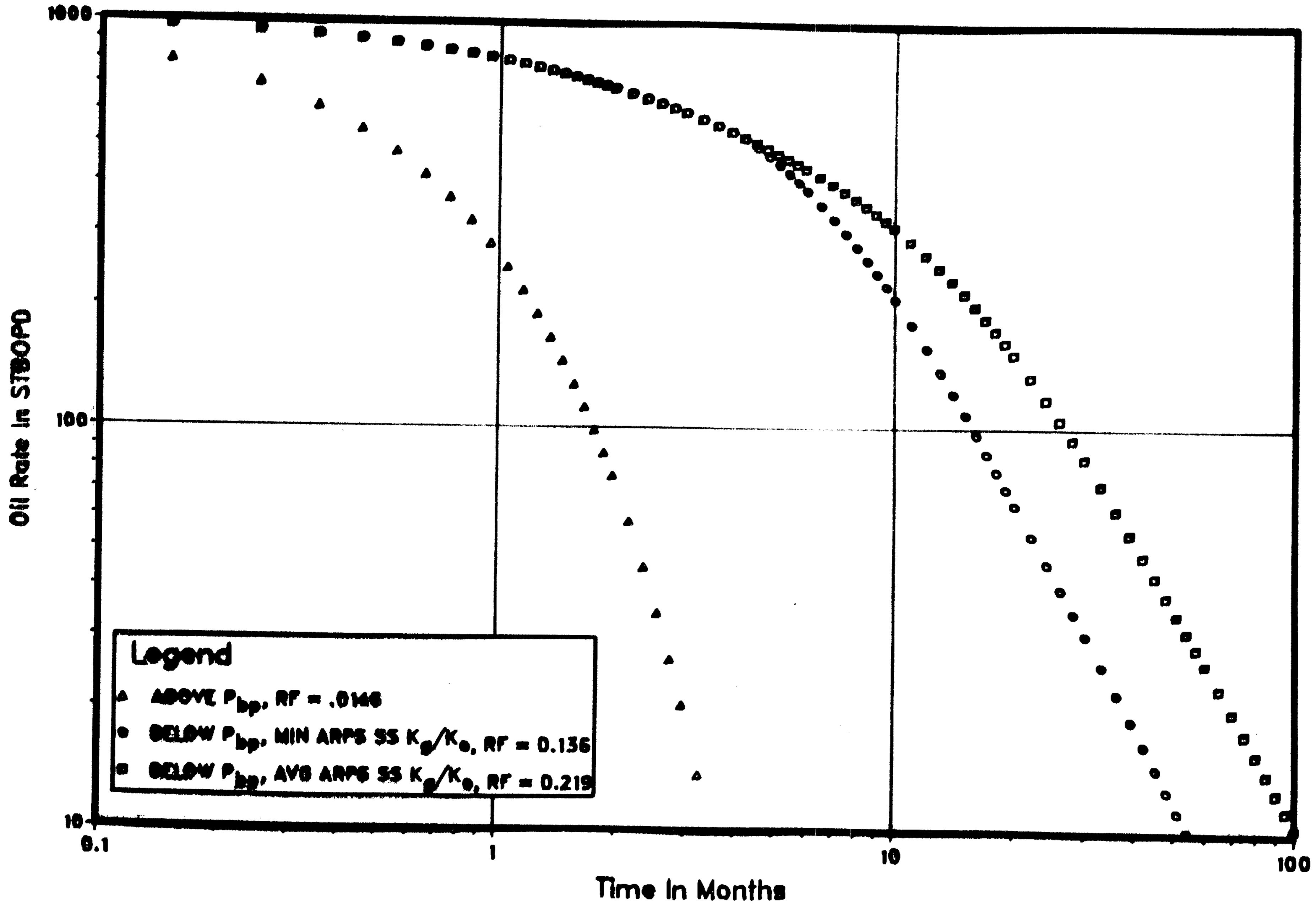


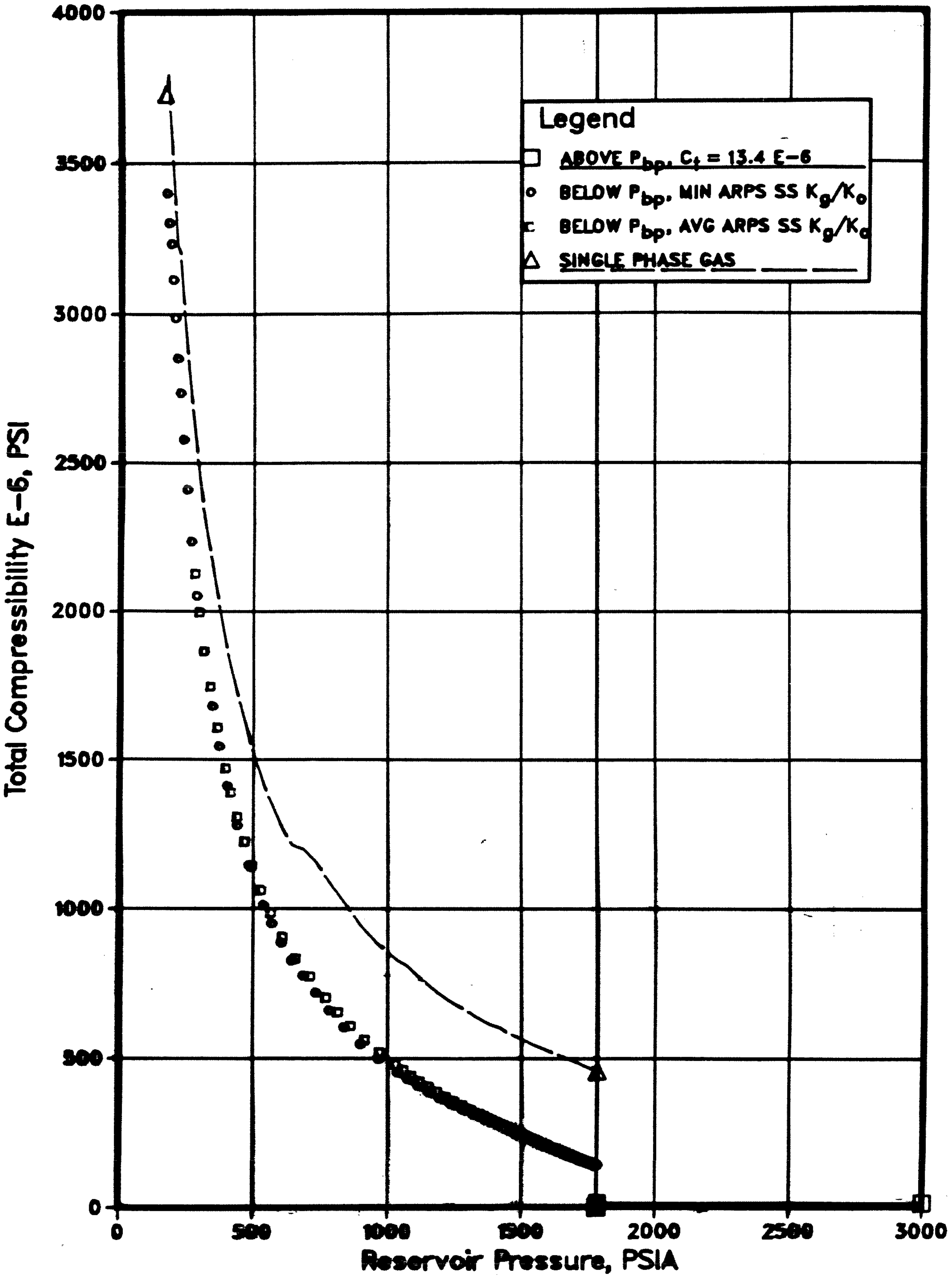
FIGURE 3-1. Ultimate oil recovery-fraction of original oil in place.

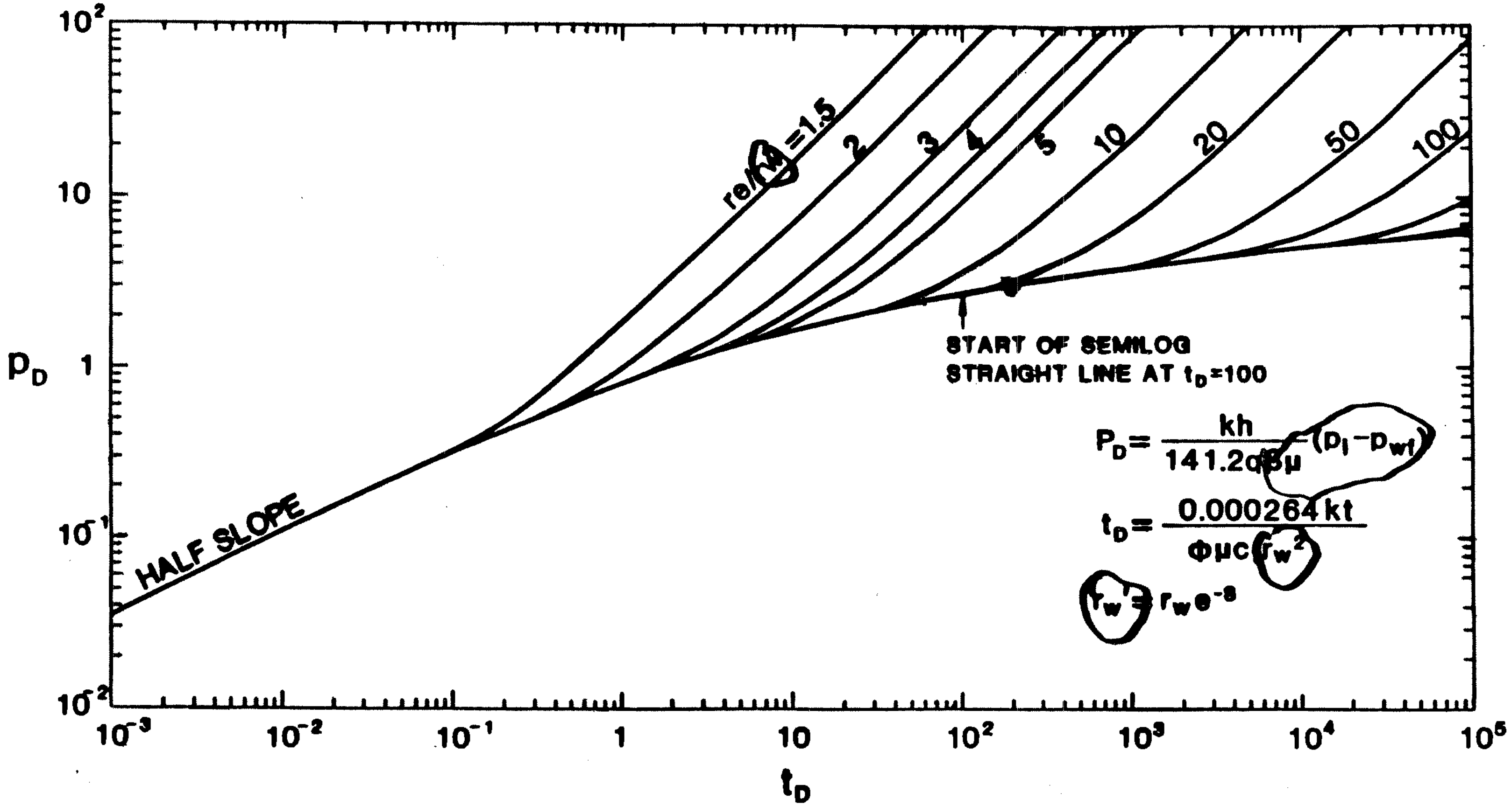
3240 Decline Curve b Value Study

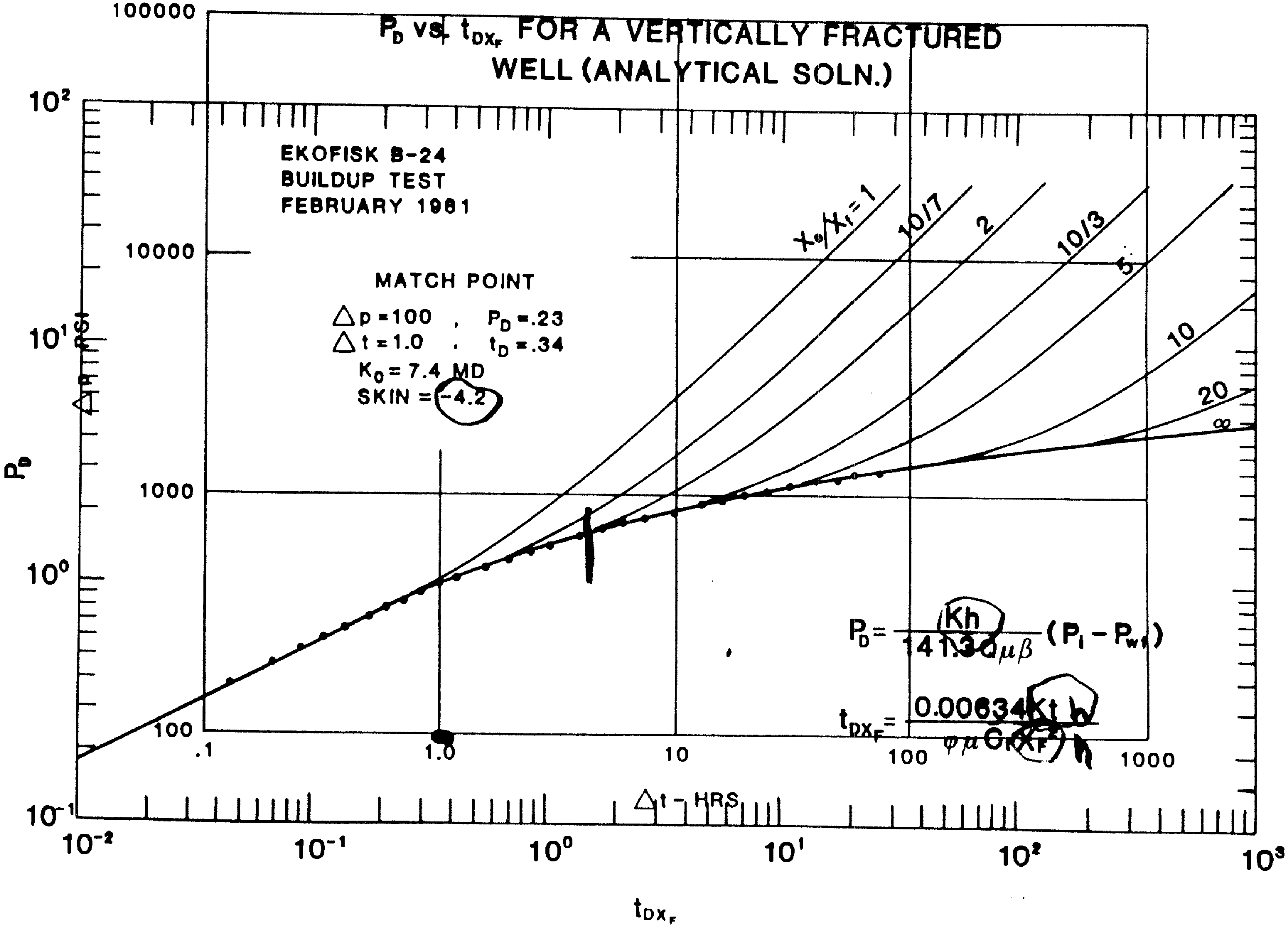


3240 Decline Curve b Value Study




Legend
□ ABOVE Pbp, Ct = 13.4 E-6
○ BELOW Pbp, MIN ARPS SS Kg/Ko
□ BELOW Pbp, AVG ARPS SS Kg/Ko
△ SINGLE PHASE GAS
Total Compressibility E-6, PSI
4000
3500
3000
2500
2000
1500
1000
500
0
0
500
1000
1500
2000
2500
3000
Reservoir Pressure, PSIA


p_D
t_D
10^{2}
10
1
10^{-1}
10^{-2}
10^{-3}
10^{-2}
10^{-1}
1
10
10^{2}
10^{3}
10^{4}
10^{5}
HALF SLOPE
re/rw'=1.5
2
3
4
5
10
20
50
100
START OF SEMILOG
STRAIGHT LINE AT t_D=100
$p_D = \frac{kh}{141.2qB\mu}(p_i - p_{wf})$
$t_D = \frac{0.000264\,kt}{\phi\mu c r_w'^2}$
$r_w' = r_w e^{-s}$



P_D vs. t_{DX_F} FOR A VERTICALLY FRACTURED WELL (ANALYTICAL SOLN.)

BASIS FOR LOG-LOG TYPE CURVE MATCHIN

TAKE THE LOG OF t_D AND P_D AND q_D.

$$\log t_D = \log\left(\frac{0.00634\, Kh}{\phi \mu c_t r_w'^2 h}\right) + \log(t)$$

$$\log P_D = \log\left(\frac{Kh}{141.2\, q \mu B}\right) + \log(\Delta P)$$

$$\log q_D = \log\left(\frac{141.2\, \mu B}{Kh\, \Delta P}\right) + \log(q_t)$$

DISPLACEMENT OF BOTH CO-ORDINATES BY A CONSTANT.

FOR ARP'S EQUATION

$$\frac{q(t)}{q_i} = \frac{1}{\left[1 + b D_i t\right]^{1/b}}$$

WHERE $t_{Dd} = D_i t$

$$\log t_{Dd} = \log \overset{=1}{D_i} + \log t$$

AND

$$q_{Dd} = \frac{q(t)}{q_i}$$

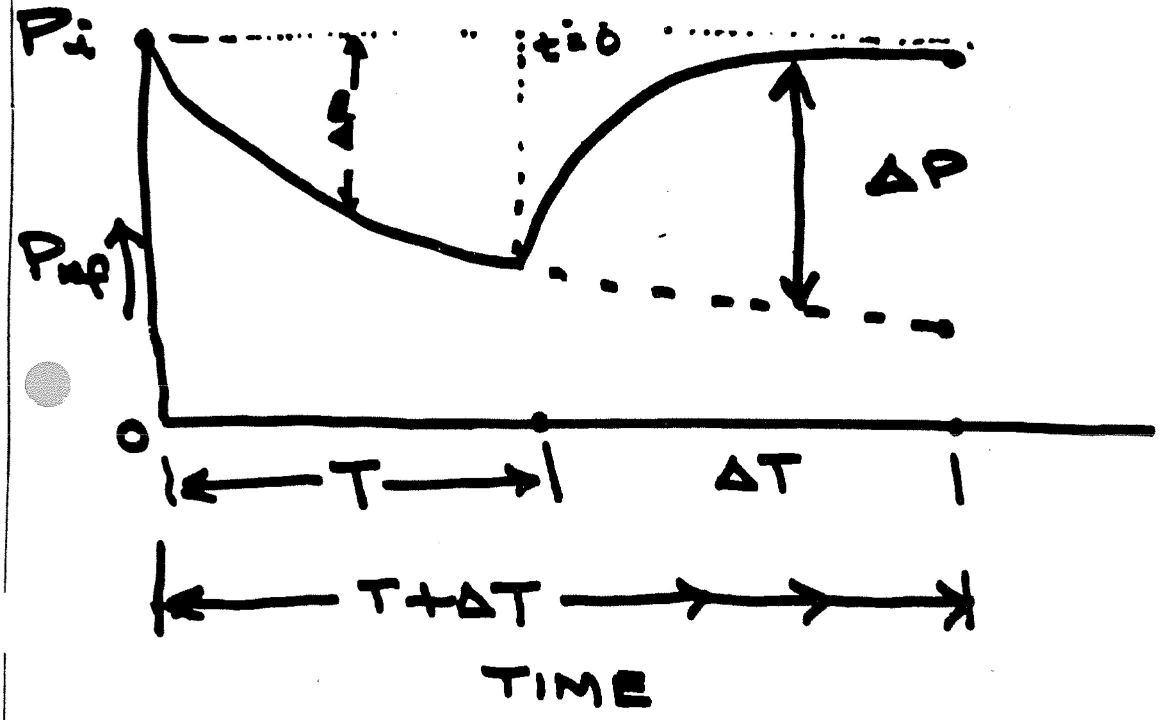
$$\log q_{Dd} = \log q(t) - \log q_i^{=1}$$

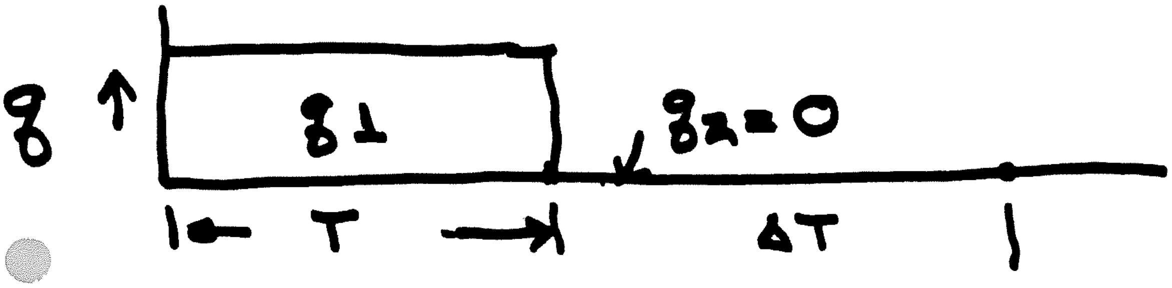
OR

$$\log q_{Dd} = -\log q_i + \log q(t)$$

SUPERPOSITION

CONSTANT RATE CASE (DRAWDOWN AND BUILD-



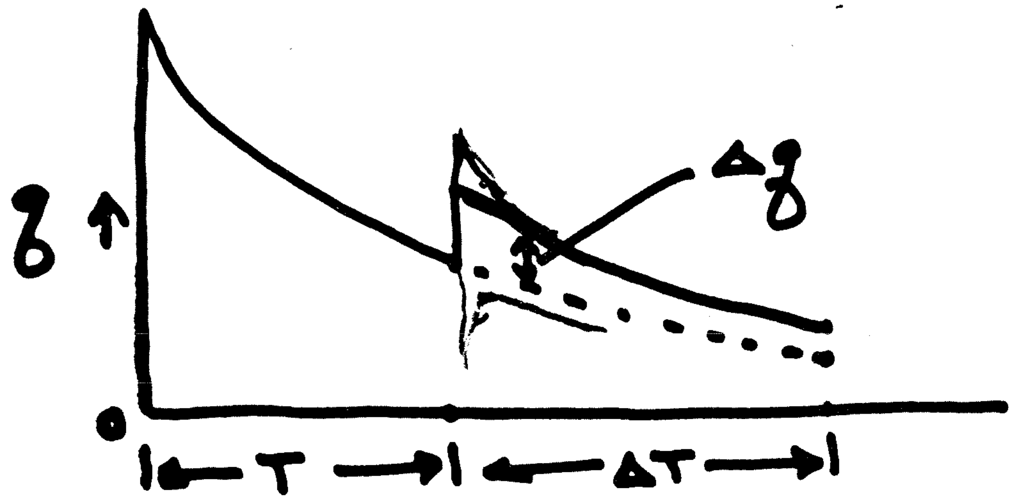


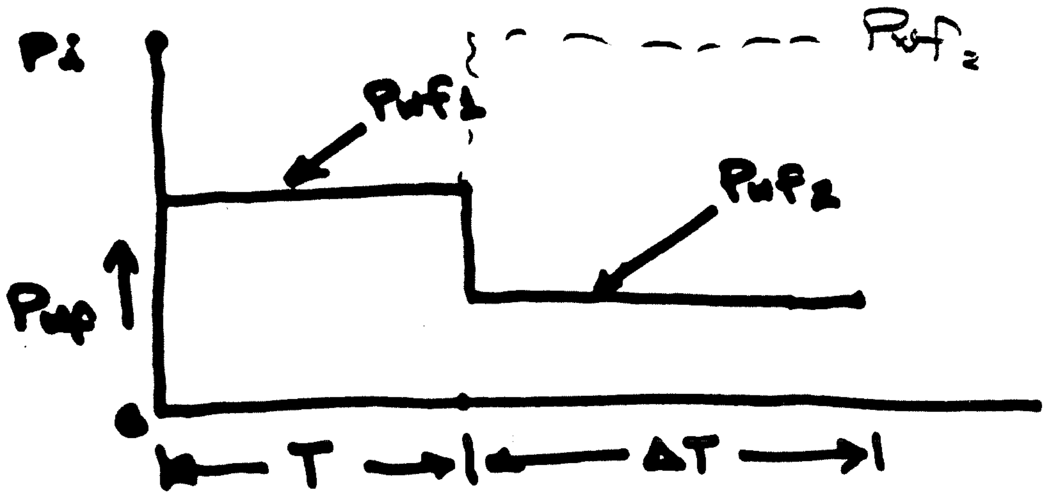
$$P_i - P_w(t) = \frac{141.2\,\mu B\,(q_1 - 0)}{kh} \cdot P_D(T+\Delta T)_D$$

$$+ \frac{141.2\,\mu B\,(\overset{0}{q_2} - q_1)}{kh} \cdot P_D(\Delta T)_D$$

SUPERPOSITION

CONSTANT WELLBORE PRESSURE (RATE DECLINE)





$$q(t) = \frac{Kh\,(P_i - P_{wf_1})}{141.2\,\mu B} \cdot q_D\,(T+\Delta T)_D$$

$$+ \frac{Kh\,(P_{wf_1} - P_{wf_2})}{141.2\,\mu B} \cdot q_D\,(\Delta T)_D$$

TABLE 9

EXAMPLE OF EFFECT OF BACKPRESSURE CHANGE ON DECLINE AND RECOVERY FEDERAL A-1

$\bar{p}_R = 3500$ psi; $p_b = 2705$ psi

Match Point, $b = 0.30$:

$q(t) = 1000$ BOPM; $q_{Dd} = 0.220$

$t = 1$ mo; $t_{Dd} = 0.212$

$$q_i = \frac{1000 \text{ BOPM}}{0.220} = 4545.5 \text{ BOPM}; \quad \boxed{D_i} = \frac{0.212}{1 \text{ mo}} = 0.212 \text{ mo}^{-1}$$

$$q(t) = \frac{q_i}{[1 + bD_i t]^{1/b}} = \frac{4545.5 \text{ BOPM}}{[1 + 0.0636t]^{3.333}}$$

First backpressure change 1400 psia to 1069 psia @ t = 11 months

q_1 @ t = 1 mo = 3701 BOPM (See Figure 9)

$$\Delta q_1 = q_1 \frac{\left[\dfrac{p_{wf_1}{}^2 - p_{wf_2}{}^2}{2p_b}\right]}{\left[(\bar{p}_R - p_b) + \dfrac{(p_b{}^2 - p_{wf_1}{}^2)}{2p_b}\right]} = 3701 \frac{\left[\dfrac{1400^2 - 1069^2}{2(2705)}\right]}{\left[(3500 - 2705) + \dfrac{(2705^2 - 1400^2)}{2(2705)}\right]} = 313 \text{ BOPM}$$

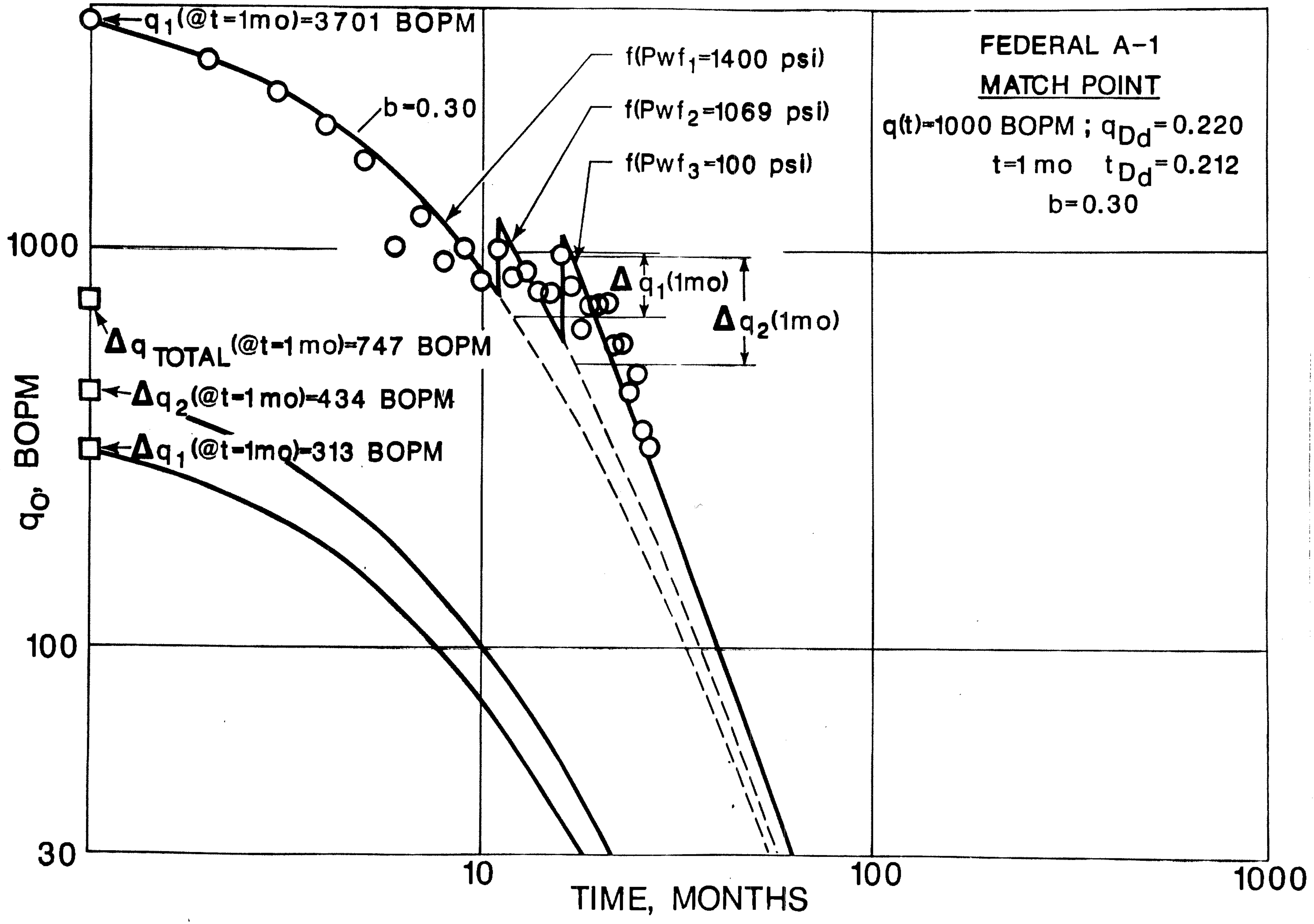
Second Backpressure change 1069 psia to 100 psia @ t = 16 months

$$\Delta q_2 = q_1 \frac{\left[\dfrac{p_{wf_2}{}^2 - p_{wf_3}{}^2}{2p_b}\right]}{\left[(\bar{p}_R - p_b) + \dfrac{(p_b{}^2 - p_{wf_1}{}^2)}{2p_b}\right]} = 3701 \frac{\left[\dfrac{1069^2 - 100^2}{2(2705)}\right]}{\left[(3500 - 2705) + \dfrac{(2705^2 - 1400^2)}{2(2705)}\right]} = 434 \text{ BOPM}$$

TABLE 9-A

EXAMPLE OF EFFECT OF BACKPRESSURE CHANGE ON DECLINE AND RECOVERY FEDERAL A-1

	[1] t mo	[2] q_1 BOPM	[3] Δq_1 $\left\{\frac{313}{3701} \times [2]\right\}$ BOPM	[4] Δq_2 $\left\{\frac{434}{3701} \times [2]\right\}$ BOPM	[5] Column [3] @ t = 12 mo BOPM	[6] Column [4] @ t = 17 mo BOPM	[7] q Total [2]+[5]+[6] BOPM
P_{wf_1}	1	3701	313	434			3701
	2	3050	258	358			3050
	3	2540	215	298			2540
	4	2135	181	250			2135
	5	1811	153	212			1811
	6	1548	131	181			1548
	7	1332	113	156			1332
	8	1154	98	135			1154
	9	1006	85	118			1006
	10	881	75	103			881
P_{wf_2}	11	776	66	91			776
	12	687	58	81	313		1000
	13	610	52	72	258		868
	14	544	46	64	215		759
	15	487	41	57	181		668
P_{wf_3}	16	438	37	51	153		591
	17	395	33	46	131	434	960
	18	357	30	42	113	358	828
	19	324	27	38	98	298	720
	20	295	25	35	85	250	630
	.	.	.	.	.	.	.
	.	.	.	.	.	.	.
	.	.	.	.	.	.	.
	58	26	2	3	4	7	37
	59	25	2	3	4	7	36
	60	24	2	3	4	6	34
	61	23	2	3	3	6	32
	62	22	2	3	3	6	31
Cum (BO):		27,714	2,344	3,250	2,320	3,191	33,225


q₁(@t=1mo)=3701 BOPM
b=0.30
f(Pwf₁=1400 psi)
f(Pwf₂=1069 psi)
f(Pwf₃=100 psi)
FEDERAL A-1
MATCH POINT
q(t)=1000 BOPM ; q_Dd=0.220
t=1 mo t_Dd=0.212
b=0.30
Δq₁(1mo)
Δq₂(1mo)
Δq TOTAL(@t=1 mo)=747 BOPM
Δq₂(@t=1 mo)=434 BOPM
Δq₁(@t=1mo)=313 BOPM
q_o, BOPM
1000
100
30
10
100
1000
TIME, MONTHS

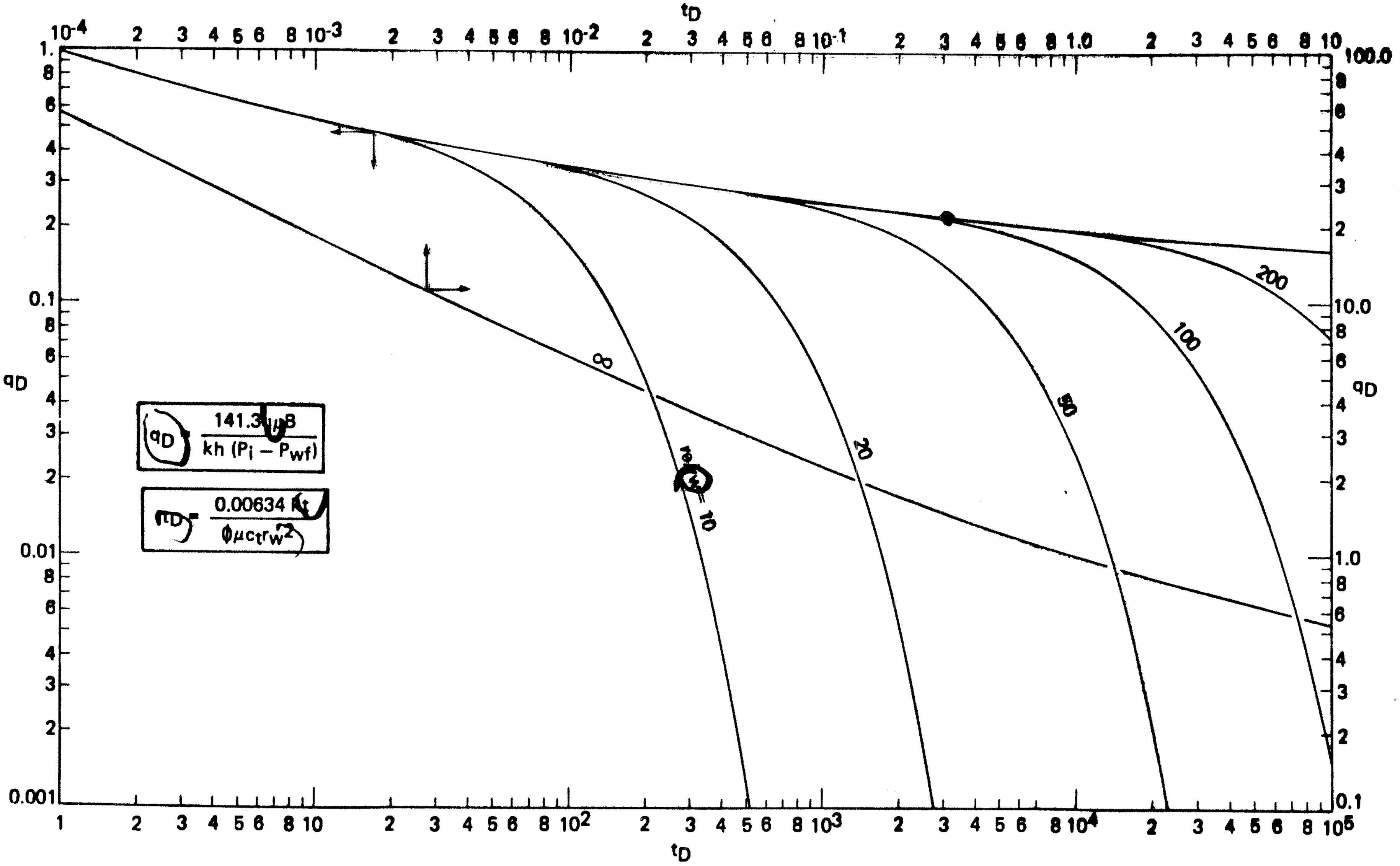


FIG. 2A

DIMENSIONLESS FLOW RATE FUNCTIONS PLANE RADIAL SYSTEM, INFINITE AND FINITE OUTER BOUNDARY, CONSTANT PRESSURE AT INNER BOUNDARY. 10, 11, 15 & 16

Tests indicate limited reservoir at slope well

DECLINING flow rates during test periods indicate a limited reservoir at a high-producing North Slope well drilled 2 years ago to the Lisburne formation.

Sohio Petroleum Co.'s 1 Sag Delta, 6 miles northeast of the edge of Prudhoe Bay field, had an initial flow rate of 9,380 b/d, but during a 10½-hr test, the flow declined to 6,700 b/d with increasing gas production.

Sohio retested the well in 1977 with similar results. During a 56-hr test, the flow dropped to 5,000 b/d without stabilizing.

Drilling at the time was conducted by BP Alaska, which became a Sohio division this year.

Operators at Prudhoe Bay have been testing the Lisburne for several years in an effort to supplement production from the shallower Sadlerochit formation, which provides the current flow of more than 1 million b/d.

Significant tests. The Lisburne tests are doubly significant because the formation apparently extends northward into the Beaufort Sea, where the Alaska and U.S. governments plan a joint lease sale in late 1979.

Sohio released test data on the Sag Delta well after the State of Alaska's department of oil and gas conservation disclosed other well data under a state law which makes such information available to the public after 25 months.

Sohio said the decline in the flow rate was "attributable to a variable and erratic nature of porous zones in the Lisburne formation.

"This characteristic has been noticed in exploratory wells drilling through this formation on the North Slope," the company said. "Future appraisal wells will be needed to evaluate the extent and distribution of this hydrocarbon accumulation."

Well history. The Sag Delta well was spudded Feb. 6, 1976, from an onshore location in 4-11n-16e and bottomed in the Beaufort Sea in 33-12n-16e.

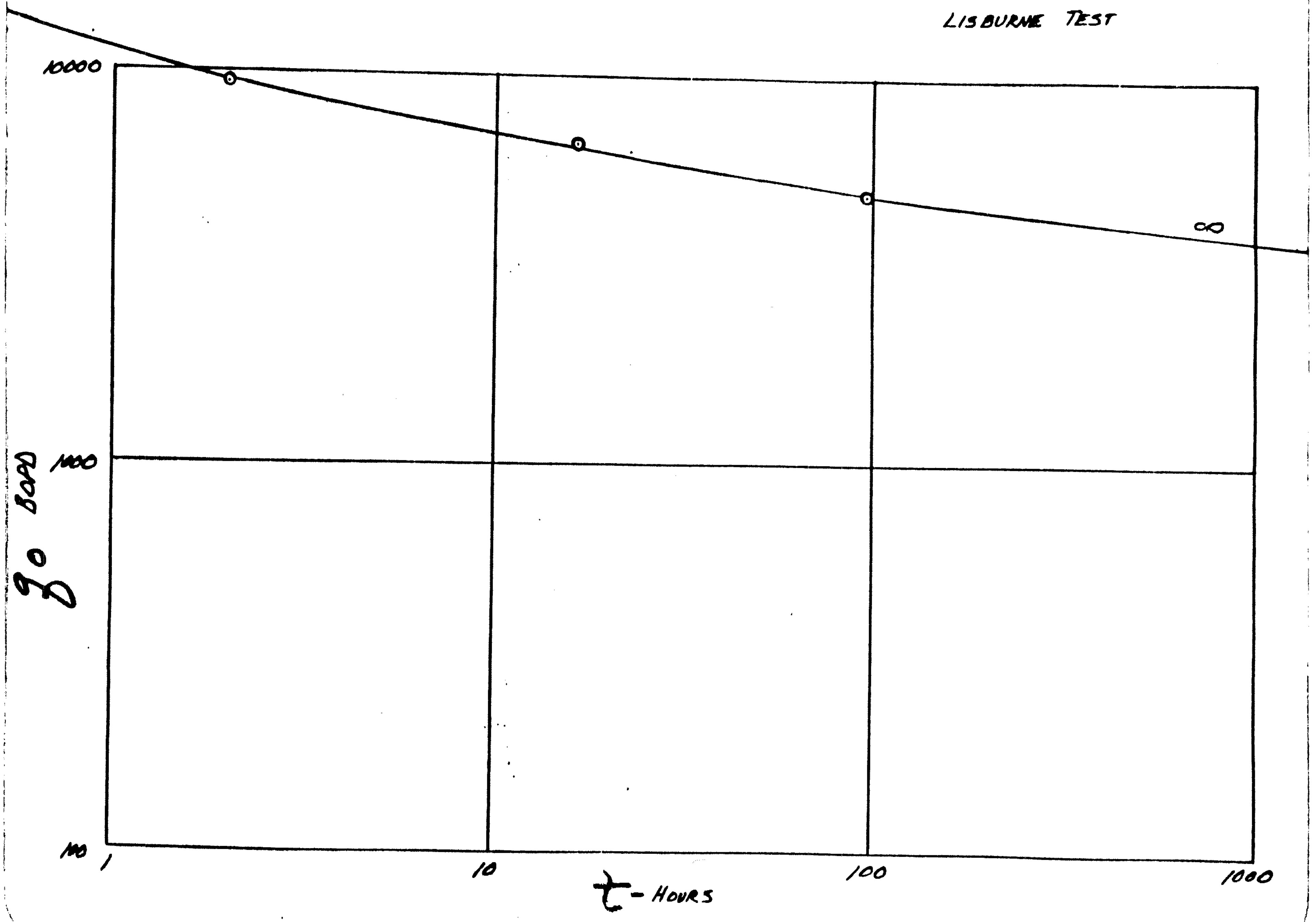
Perforations for testing were at 9,134-9,261 ft vertical depth (9,424-9,555 ft measured).

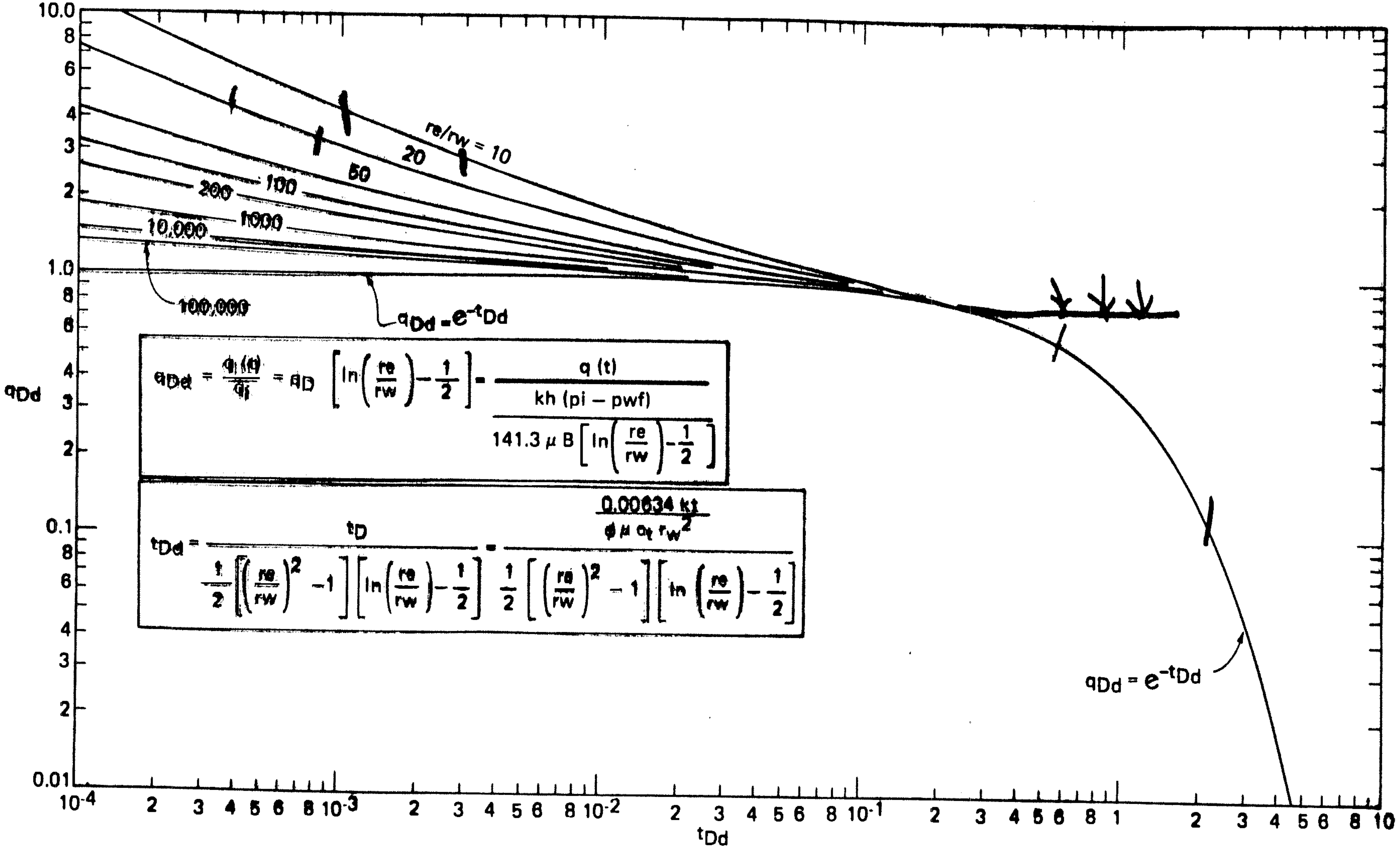
Total depth was 9,806 ft vertical (10,216 ft measured).

Location is about 3 miles south of open acreage which will be available at the lease sale.

The company said that if its appraisal of current data indicates more drilling is needed, additional wells may be drilled during the coming winter season in advance of the sale.

No. 1 SAG DELTA
SOHIO PETROLEUM
LISBURNE TEST

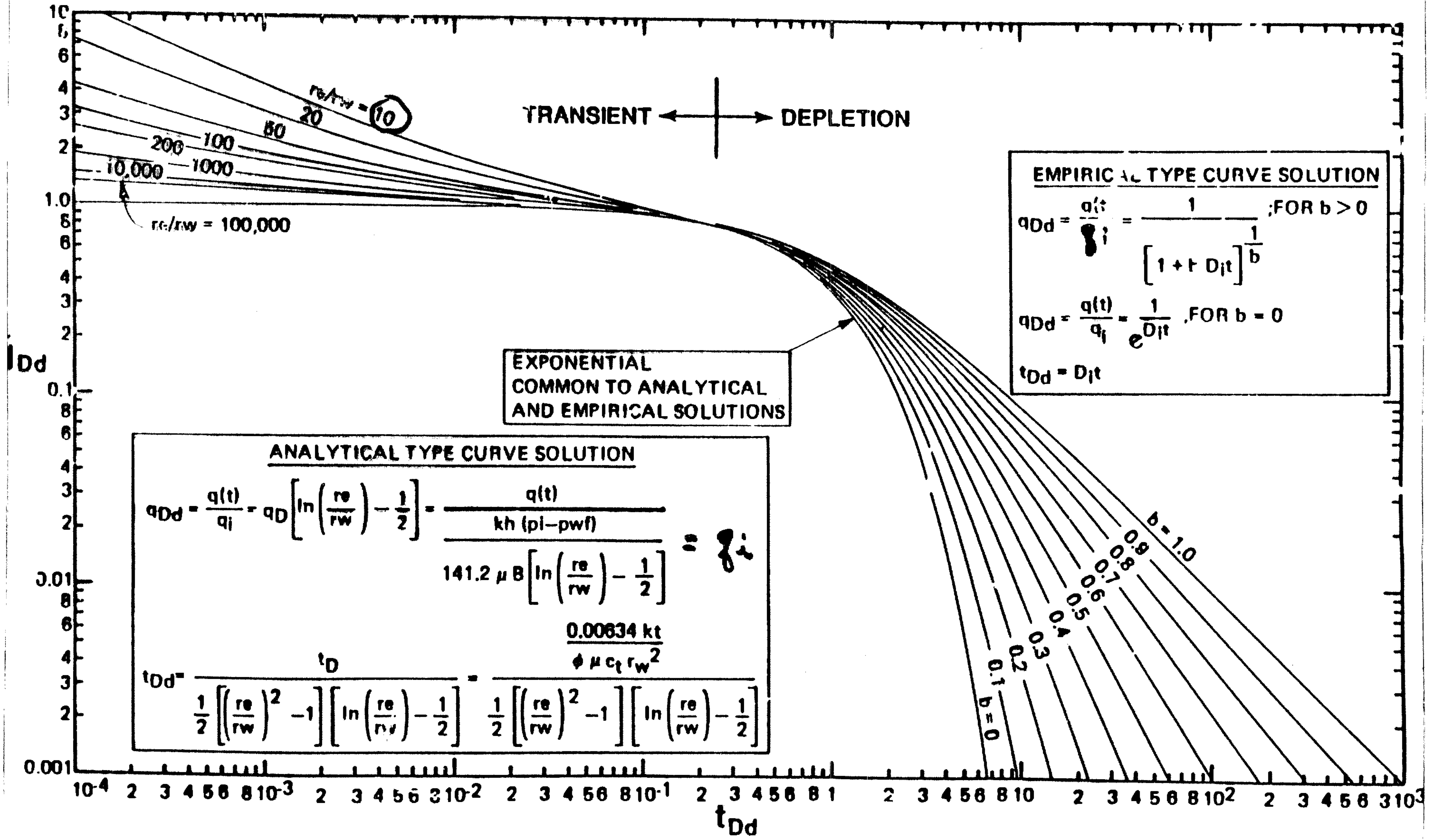




$$q_{Dd} = \frac{q_i(t)}{q_i} = q_D \left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2} \right] = \frac{q\,(t)}{\dfrac{kh\,(pi - pwf)}{141.3\,\mu\,B\left[\ln\left(\dfrac{re}{rw}\right) - \dfrac{1}{2}\right]}}$$

$$t_{Dd} = \frac{t_D}{\frac{1}{2}\left[\left(\frac{re}{rw}\right)^2 - 1\right]\left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2}\right]} = \frac{\dfrac{0.00634\,kt}{\phi\,\mu\,c_t\,r_w^2}}{\frac{1}{2}\left[\left(\frac{re}{rw}\right)^2 - 1\right]\left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2}\right]}$$

FIG. 3
DIMENSIONLESS FLOW RATE FUNCTIONS FOR PLANE RADIAL SYSTEM, INFINITE AND FINITE OUTER BOUNDARY, CONSTANT PRESSURE AT INNER BOUNDARY.



EMPIRICAL TYPE CURVE SOLUTION

$$q_{Dd} = \frac{q(t)}{q_i} = \frac{1}{\left[1 + bD_i t\right]^{\frac{1}{b}}} \text{ ;FOR } b > 0$$

$$q_{Dd} = \frac{q(t)}{q_i} = \frac{1}{e^{D_i t}} \text{ ,FOR } b = 0$$

$$t_{Dd} = D_i t$$

ANALYTICAL TYPE CURVE SOLUTION

$$q_{Dd} = \frac{q(t)}{q_i} = q_D\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right] = \frac{\dfrac{q(t)}{kh\,(p_i - p_{wf})}}{141.2\,\mu B\left[\ln\left(\dfrac{r_e}{r_w}\right) - \dfrac{1}{2}\right]} = q_i$$

$$t_{Dd} = \frac{t_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_w}\right)^2 - 1\right]\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right]} = \frac{\dfrac{0.00634\,kt}{\phi \mu c_t r_w^2}}{\frac{1}{2}\left[\left(\frac{r_e}{r_w}\right)^2 - 1\right]\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right]}$$

EXAMPLE PROBLEM

The following example problem is quite informative. It's an example from Arps' original paper "Analysis of Decline Curves" which can be found in SPE Petroleum Transactions Reprint Series No. 3 "Oil and Gas Property Evaluation and Reserve Estimates". Three plots are made from this example:

The first is a basic plot and interpretation of match points. See page 6 of SPE 4629 for match point evaluation that can be used in decline equation, or you can use step 3 (page 6) to get your forecast.

From Arps

Table 2 - Loss Ratio for Lease Producing From Arbuckle Lime in Kansas

(Typical Case of Hyperbolic Decline)

	(1) Month	(2) Year	(3) Time t (Mo)	(4) Time +100 (Mo)	(5) Monthly Production Rate, P (Curve JB, Fig. 3) (BOPM)	(6) Reinitialized Time (Mo)	(7) Loss in Production Rate During 6 Months Interval ΔP	(8) Loss Ratio on Monthly Basis $a = 6 \frac{P}{\Delta P}$	(9) First Derivative of Loss Ratio $b = \frac{\frac{6P}{\Delta P}}{6}$
History	Jan.	1937	.5	100	28,200				
	July	1937	6.5	106	15,680		-12,520	- 7.52	
	Jan.	1938	12.5	112	9,700		- 5,980	- 9.72	-0.37
	July	1938	18.5	118	6,635		- 3,065	-12.97	-0.54
	Jan.	1939	24.5	124	4,775		- 1,860	-15.39	-0.40
	July	1939	30.5	130	3,628		- 1,147	-18.96	-0.59
	Jan.	1940	36.5	136	2,850	New	- 778	-21.96	-0.50
	July	1940	42.5	142	2,300	t	- 550	-25.08	-0.52
	Jan.	1941	48.5	148	1,905	.5	- 395	-28.95	-0.64
	July	1941	54.5	154	1,610	6.5	- 295	-32.76	-0.63
	Jan.	1942	60.5	160	1,365	12.5	- 245	-34.43	-0.28
	July	1942	66.5	166	1,177	18.5	- 188	-36.97	-0.42
	Jan.	1943	72.5	172	1,027	24.5	- 150	-41.15	-0.70
Forecast	July	1943	78.5		904		- 123	-44.20	-0.508
	Jan.	1944	84.5		802		- 102	-47.25	-0.508
	July	1944	90.5		717		- 85	-50.30	-0.508
	Jan.	1945			644		- 73	-53.35	-0.508
	July	1945			582		- 62	-56.40	-0.508
	Jan.	1946			529		- 53	-59.45	-0.508
	July	1946			483		- 46	-62.50	-0.508
	Jan.	1947			442		- 41	-65.55	-0.508
	July	1947			406		- 36	-68.60	-0.508
	Jan.	1948			375		- 31	-72.65	-0.508
	July	1948			347		- 28	-74.70	-0.508

First derivitive of loss ratios approximately constant; average b = 0.508.
Extrapolation until July 1948 by means of this average b value of -0.508.

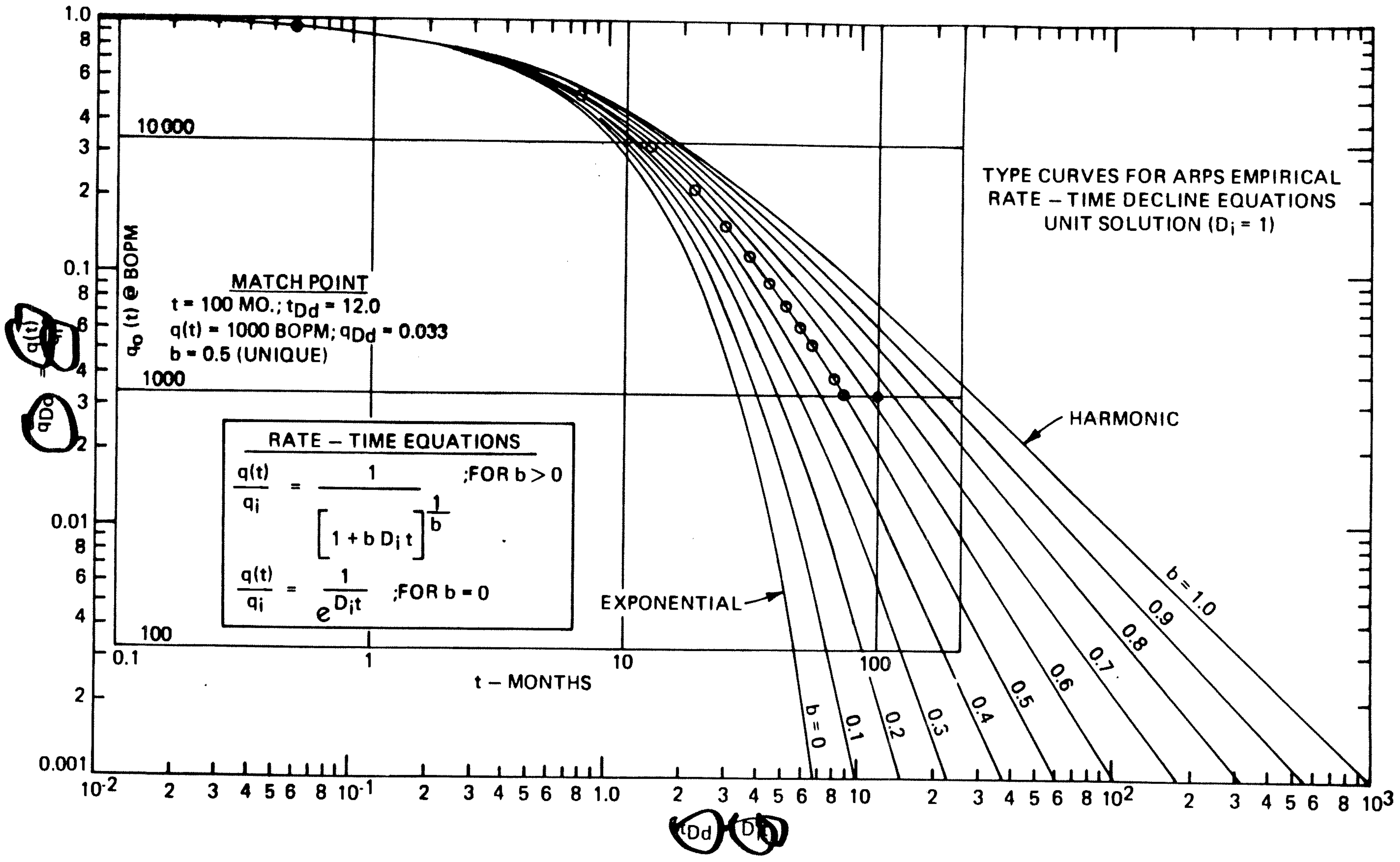
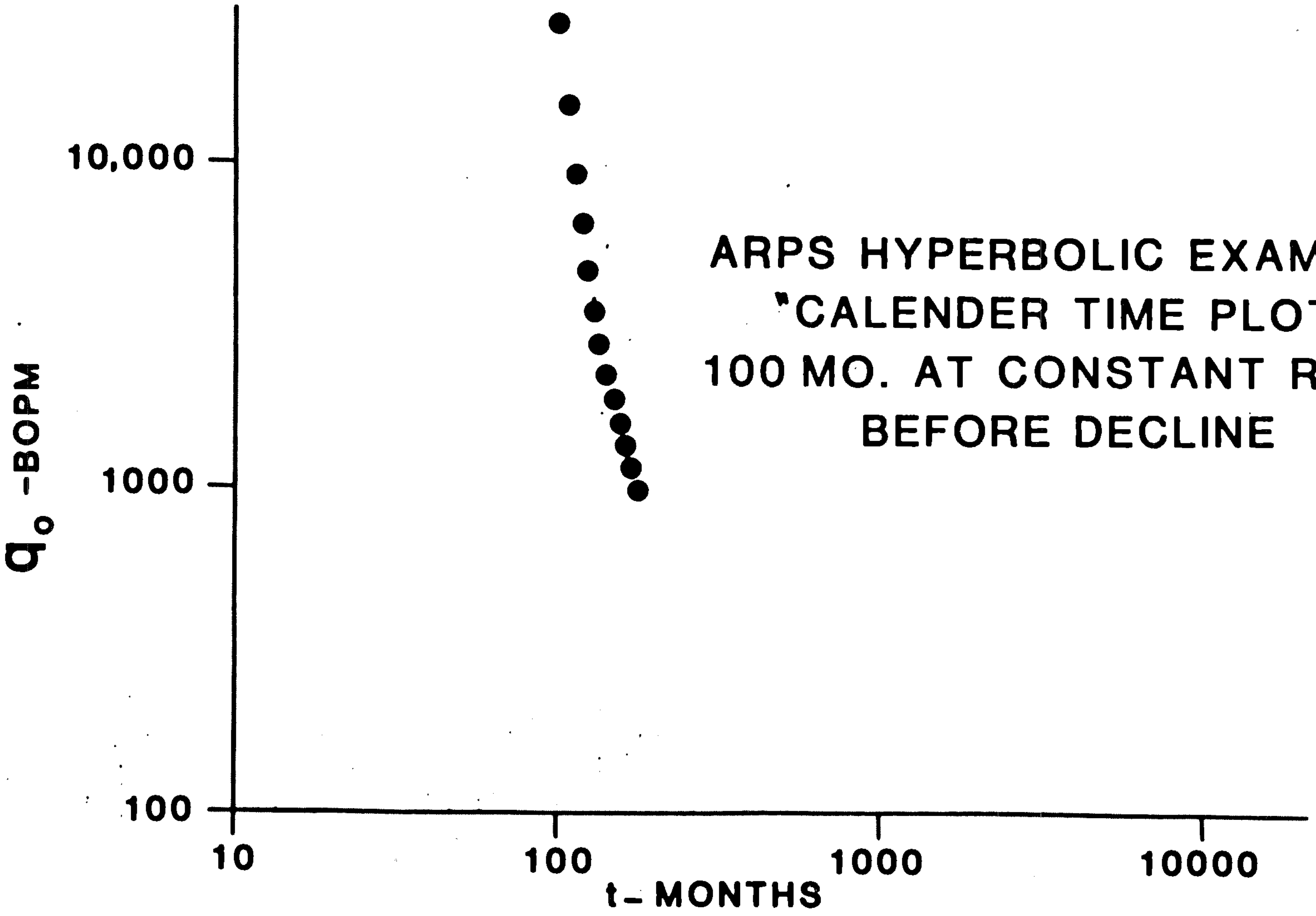


FIG. 10

TYPE—CURVE MATCH OF ARPS' HYPERBOLIC DECLINE EXAMPLE[4] ,(UNIQUE MATCH).

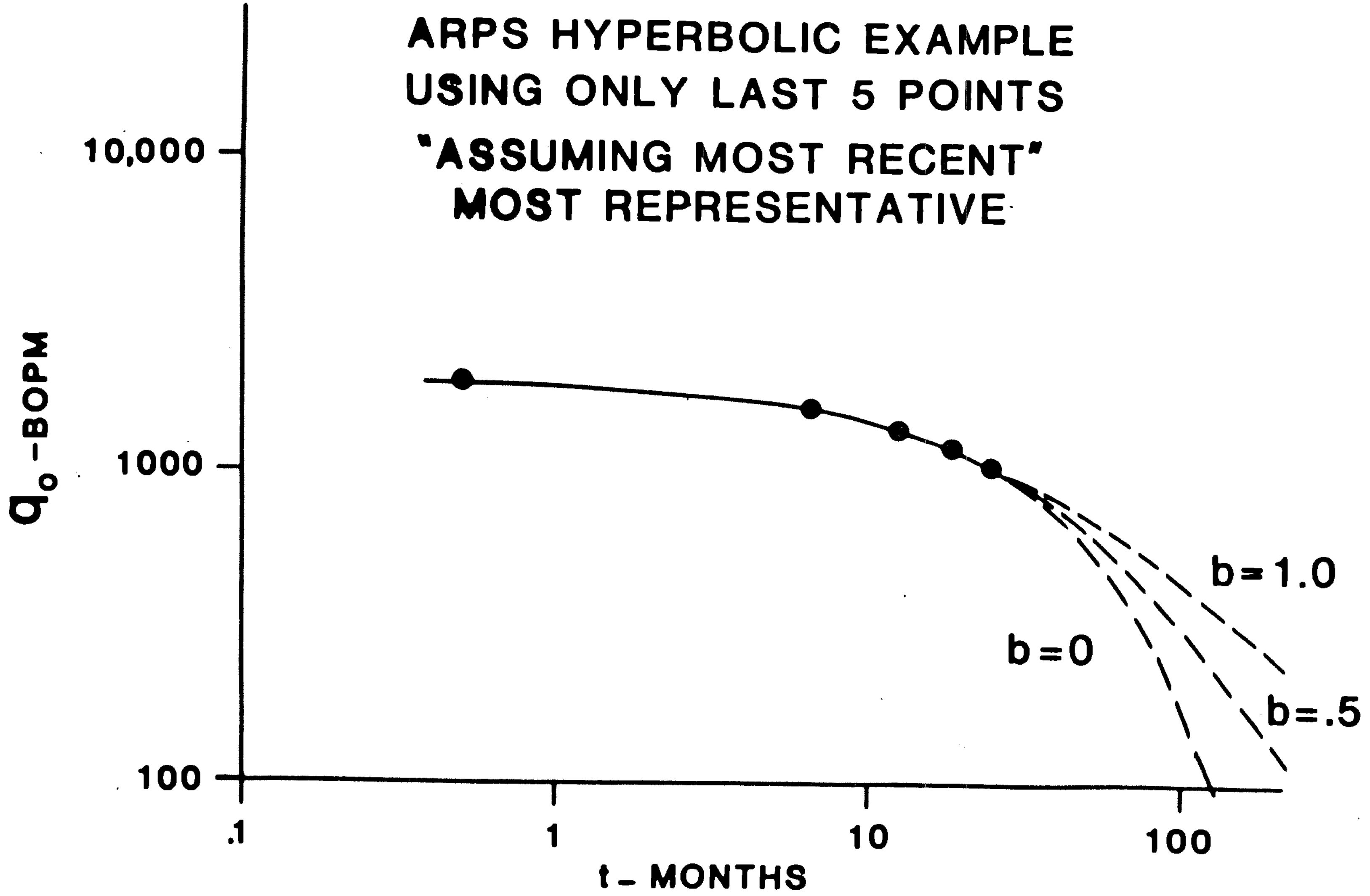
The next plot is a calendar time plot which brings out the most important point of all, "you can't start decline analysis unless the well is on decline". Adding the time when a well is really not on decline, is producing at a constant rate, or was on proration totally distorts the rate time plot. It tends always to force it to an exponential.

ARPS HYPERBOLIC EXAMPLE
"CALENDER TIME PLOT"
100 MO. AT CONSTANT RATE
BEFORE DECLINE



The final plot is a reinitialization of the data using only the last 5 points (one can restart). This will theoretically give you the same answer but the data falls in the region where a b = 0 or even b = 1.0 can appear to match also. Need as much data as possible to help get unique fit.

ARPS HYPERBOLIC EXAMPLE USING ONLY LAST 5 POINTS "ASSUMING MOST RECENT" MOST REPRESENTATIVE



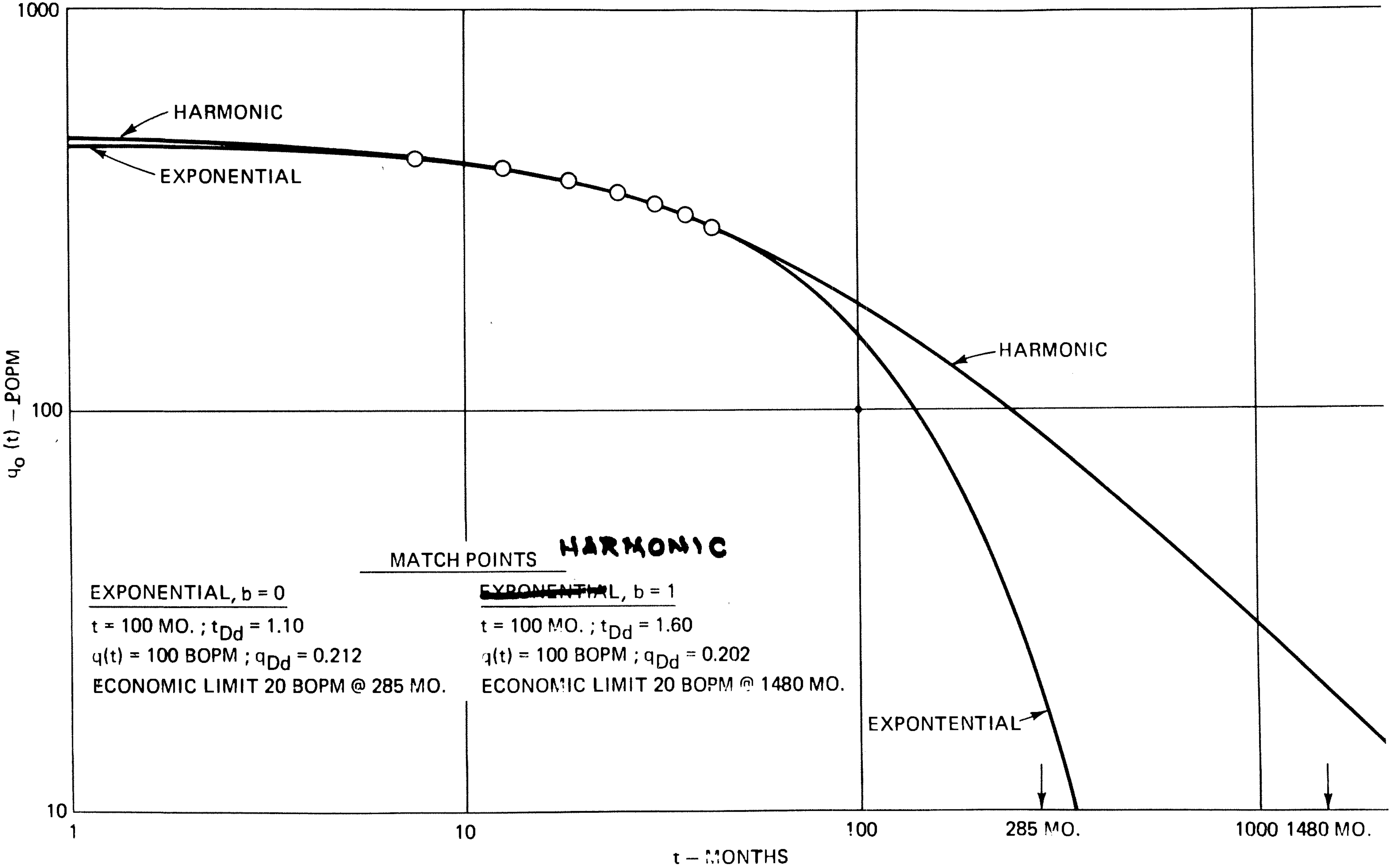
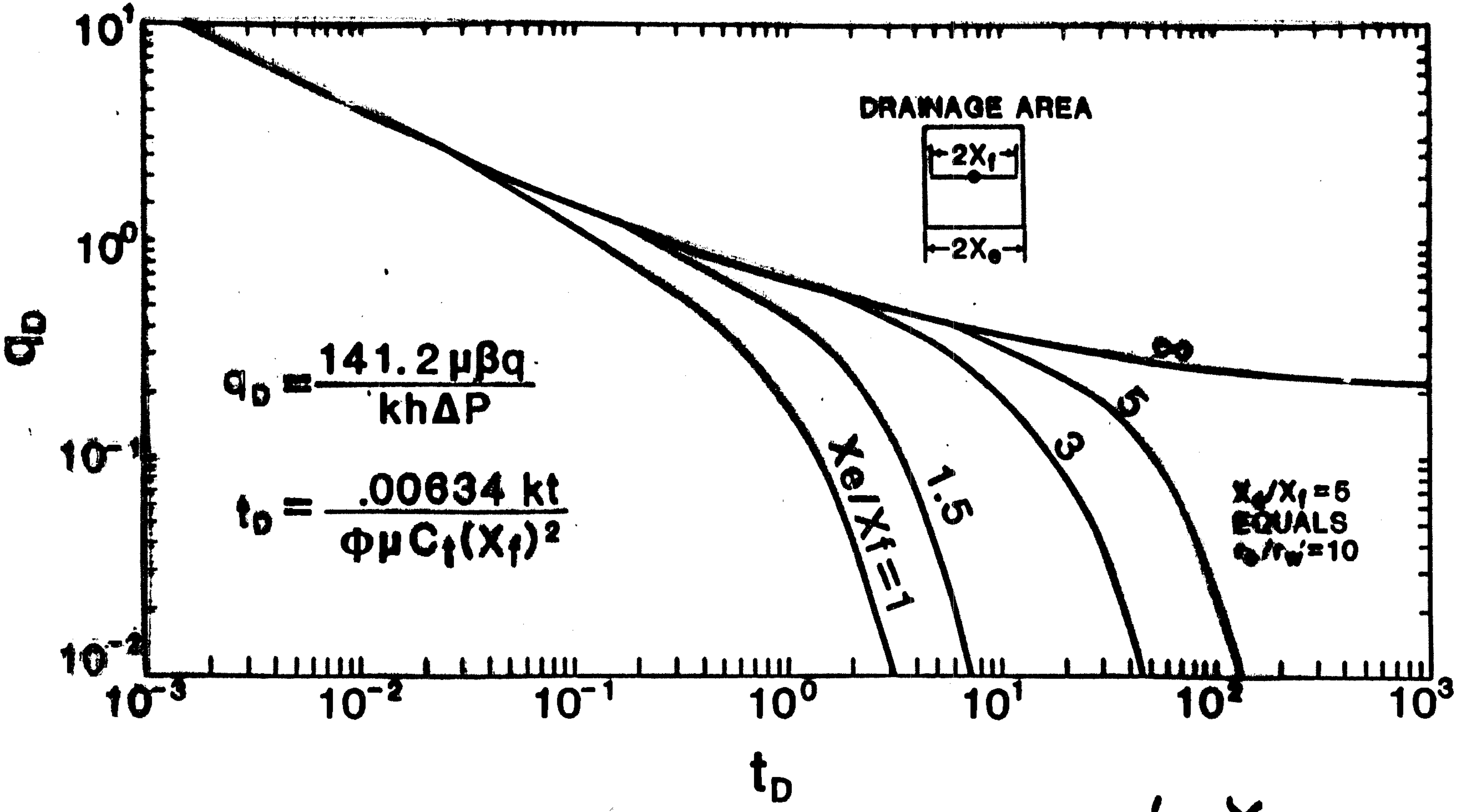
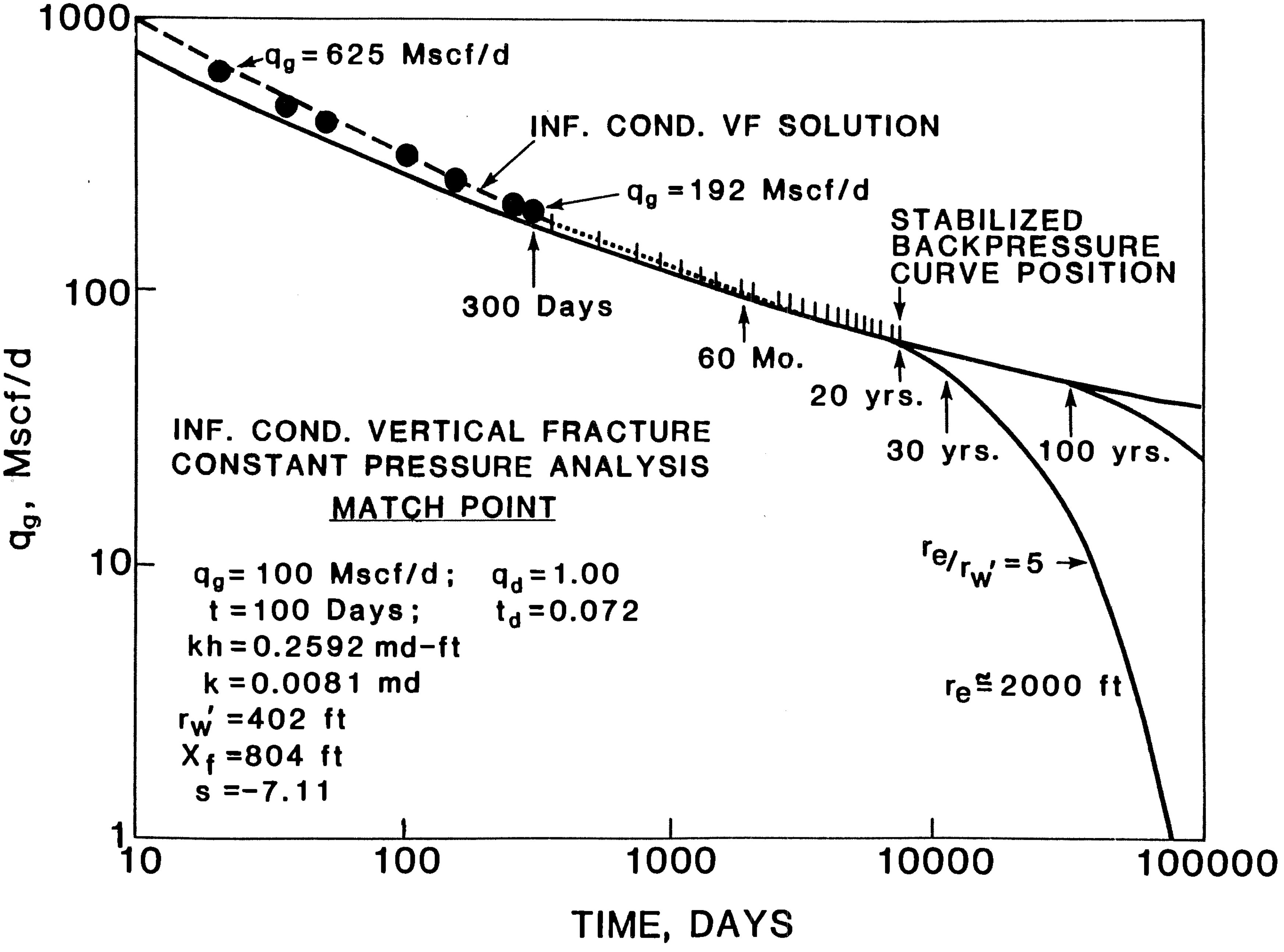


FIG. 11 TYPE – CURVE ANALYSIS OF ARPS' EXPONENTIAL DECLINE EXAMPLE (4)

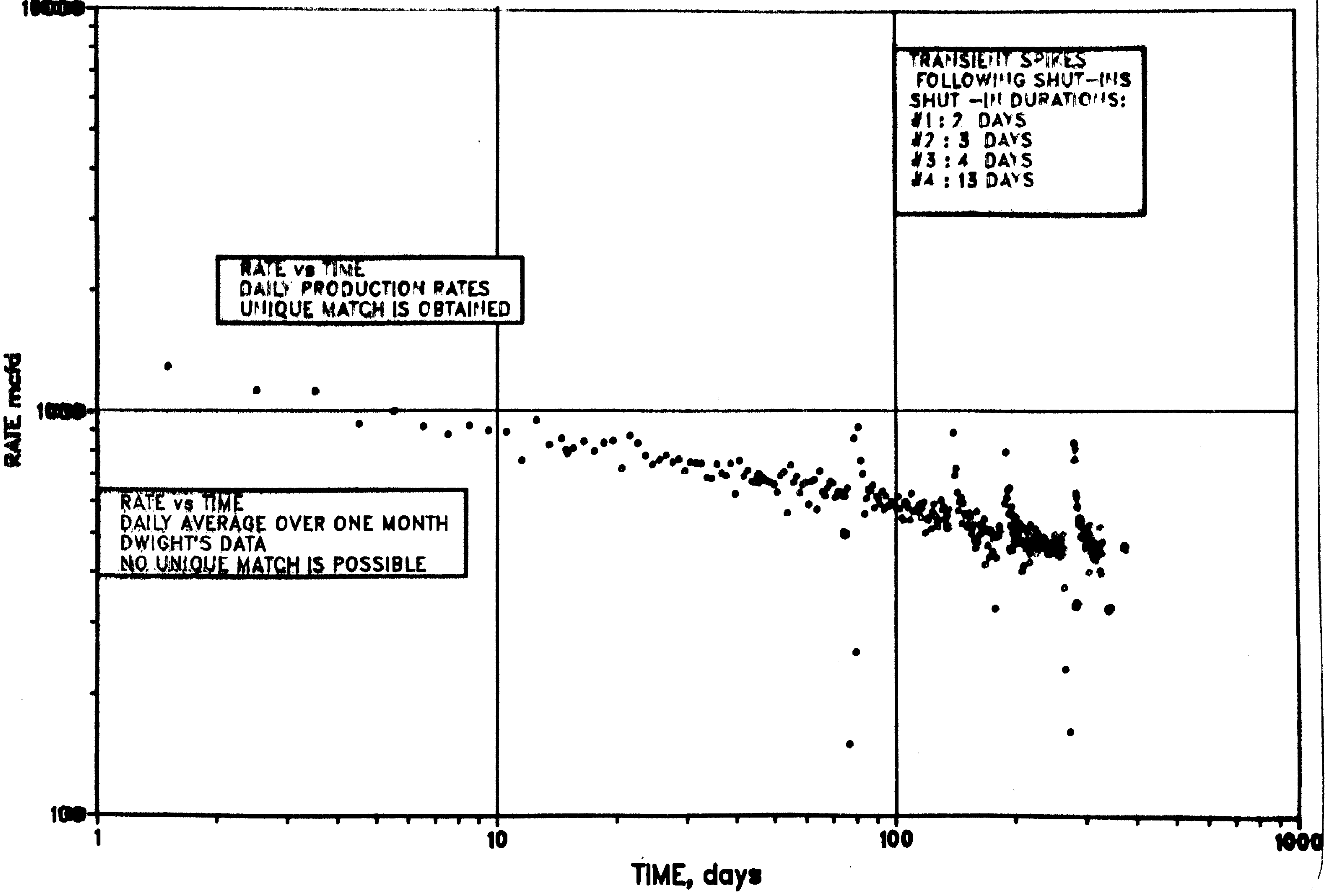
LOCKE & SAWYER 1975



$r_w' = \frac{X_f}{2}$


q_g = 625 Mscf/d
INF. COND. VF SOLUTION
q_g = 192 Mscf/d
300 Days
STABILIZED BACKPRESSURE CURVE POSITION
60 Mo.
20 yrs.
30 yrs.
100 yrs.
INF. COND. VERTICAL FRACTURE CONSTANT PRESSURE ANALYSIS
MATCH POINT
q_g = 100 Mscf/d; q_d = 1.00
t = 100 Days; t_d = 0.072
kh = 0.2592 md-ft
k = 0.0081 md
r_w' = 402 ft
X_f = 804 ft
s = -7.11
r_e/r_w' = 5
r_e ≅ 2000 ft
1000
100
10
1
10
100
1000
10000
100000
q_g, Mscf/d
TIME, DAYS

BEASLEY 3 # 4
CARTHAGE COTTON VALLEY FIELD
PANOLA COUNTY, TEXAS

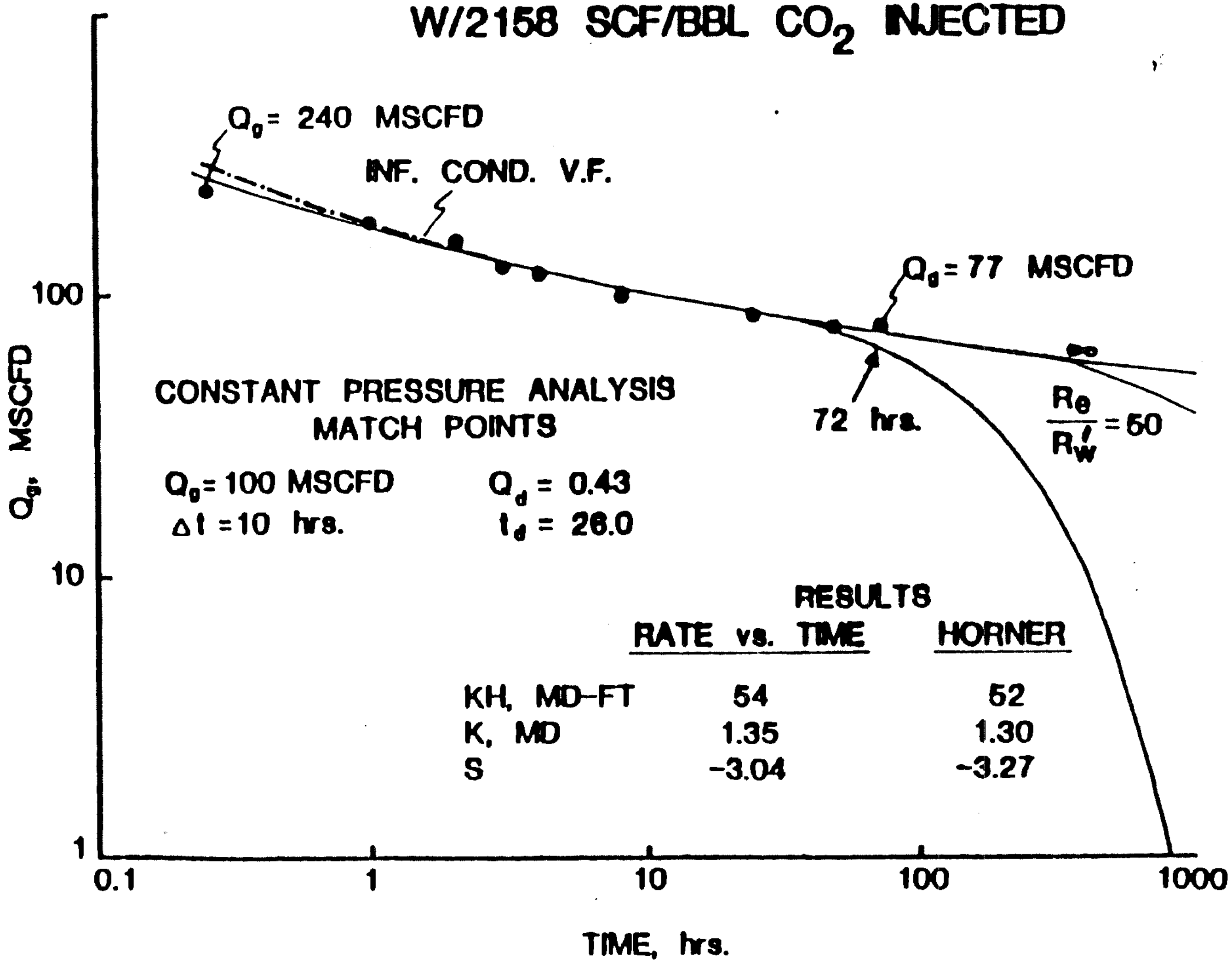


KANSAS LOW PRESSURE GAS WELL

$\overline{P_R}$ = 213 psia

TREATED W/3000 gals. ACID

W/2158 SCF/BBL CO_2 INJECTED



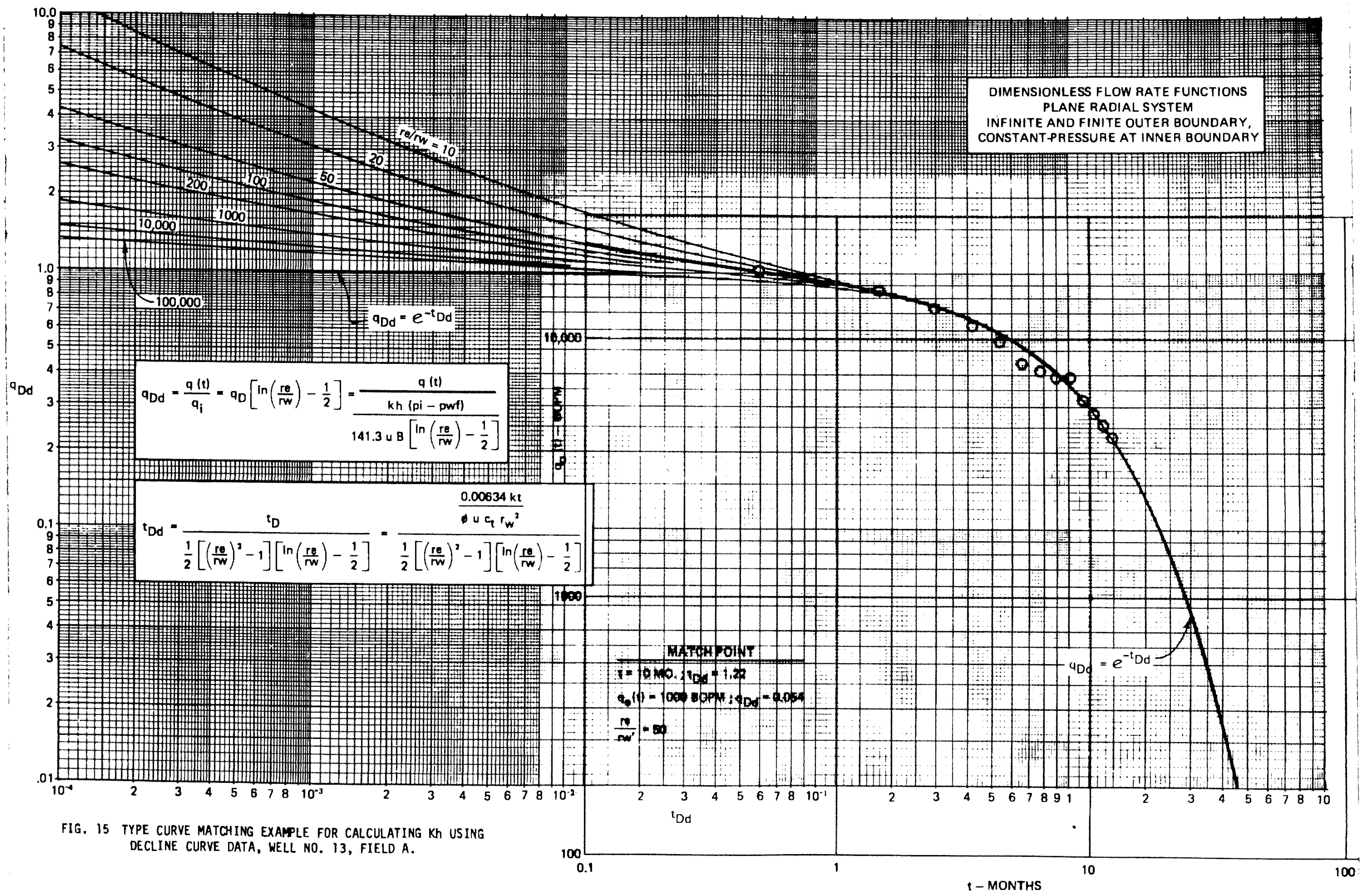
CONSTANT PRESSURE ANALYSIS
MATCH POINTS

Q_g = 100 MSCFD
Δt = 10 hrs.

Q_d = 0.43
t_d = 26.0

RESULTS

	RATE vs. TIME	HORNER
KH, MD-FT	54	52
K, MD	1.35	1.30
S	-3.04	-3.27



DIMENSIONLESS FLOW RATE FUNCTIONS
PLANE RADIAL SYSTEM
INFINITE AND FINITE OUTER BOUNDARY,
CONSTANT-PRESSURE AT INNER BOUNDARY

$$q_{Dd} = \frac{q\,(t)}{q_i} = q_D\left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2}\right] = \frac{q\,(t)}{\dfrac{k\,h\,(pi - pwf)}{141.3\,u\,B\left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2}\right]}}$$

$$t_{Dd} = \frac{t_D}{\frac{1}{2}\left[\left(\frac{re}{rw}\right)^2 - 1\right]\left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2}\right]} = \frac{\dfrac{0.00634\,kt}{\phi\,u\,c_t\,r_w{}^2}}{\frac{1}{2}\left[\left(\frac{re}{rw}\right)^2 - 1\right]\left[\ln\left(\frac{re}{rw}\right) - \frac{1}{2}\right]}$$

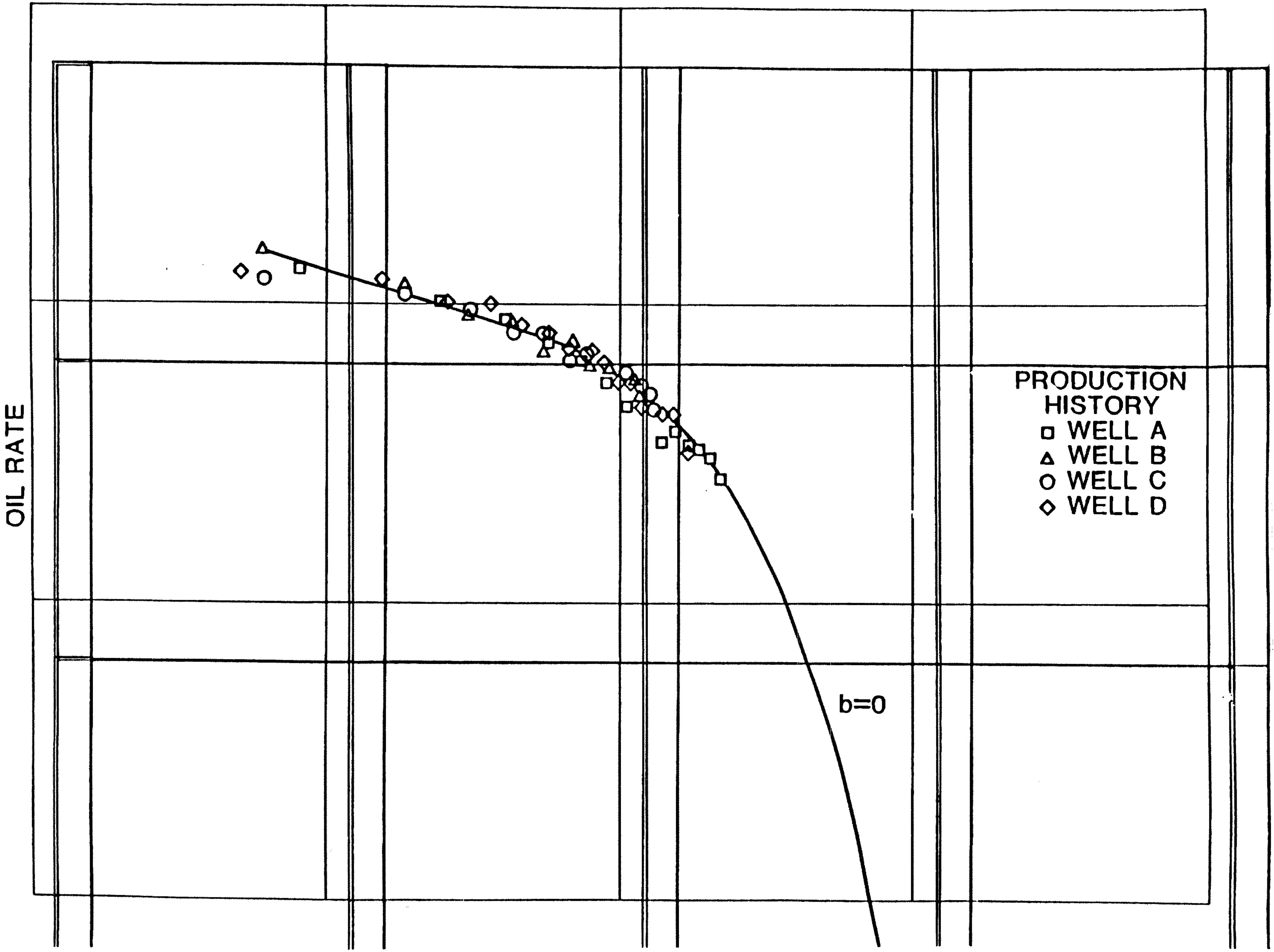
MATCH POINT

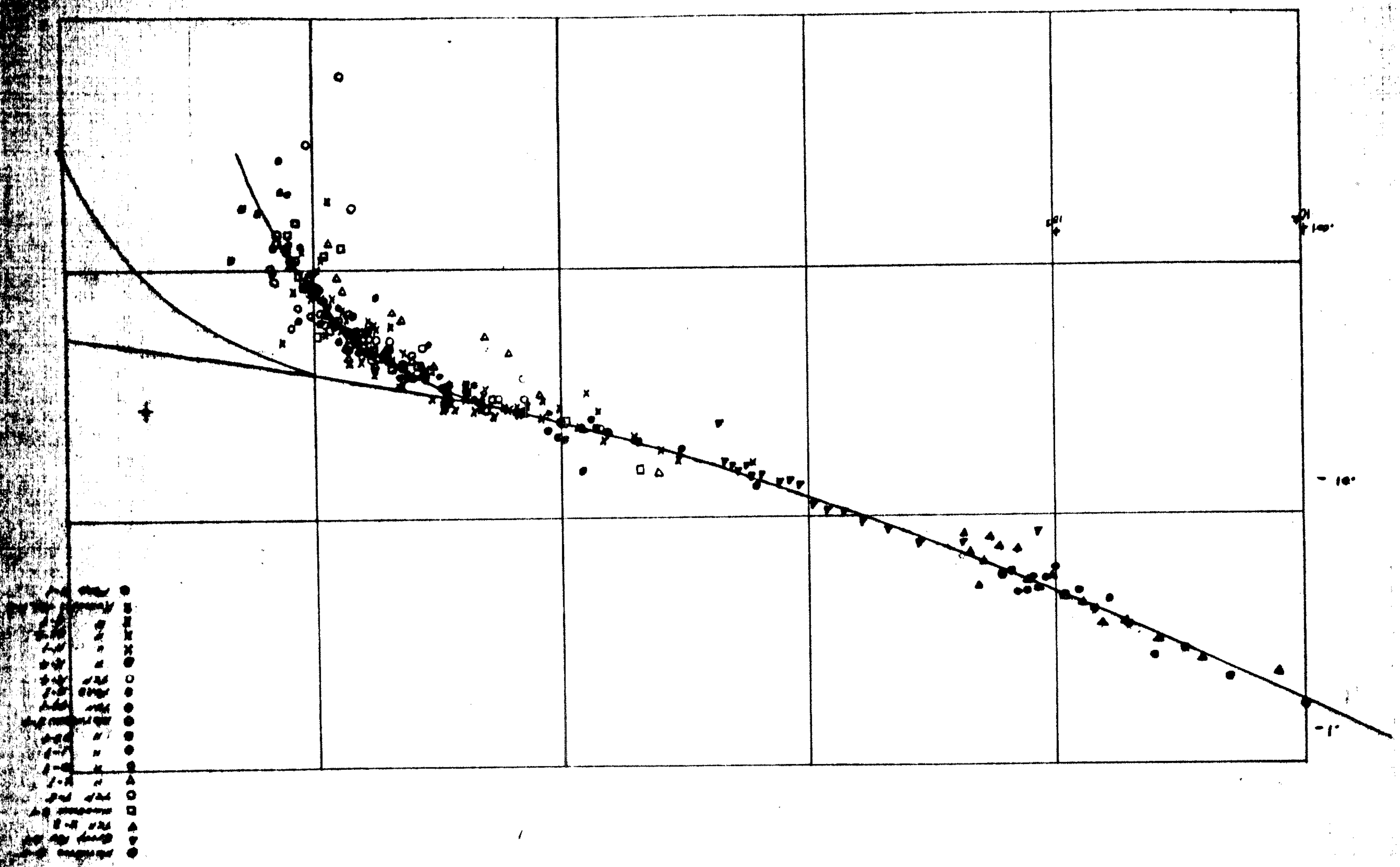
$t = 10$ MO. ; $t_{Dd} = 1.22$

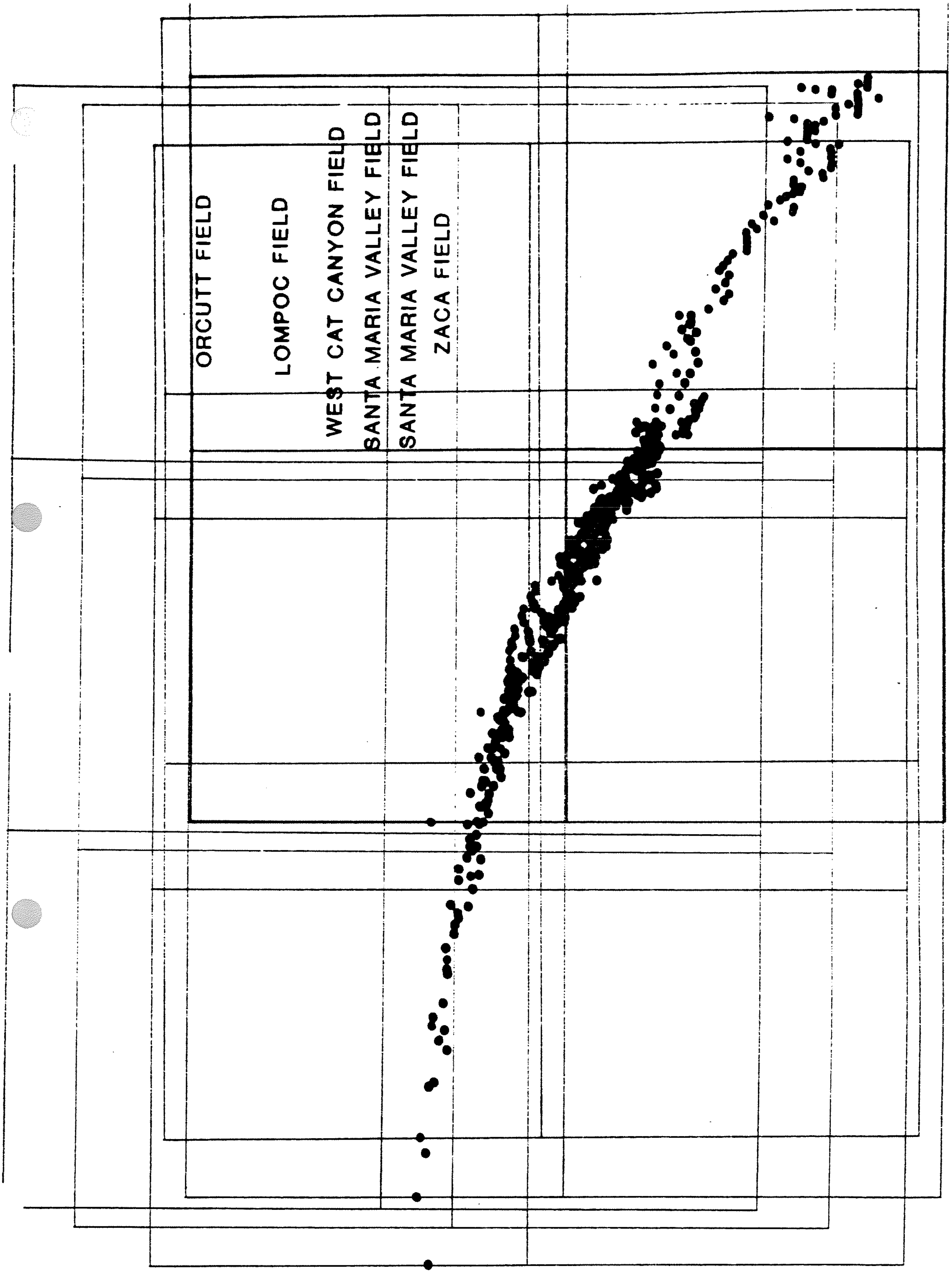
$q_a(t) = 1000$ BOPM ; $q_{Dd} = 0.054$

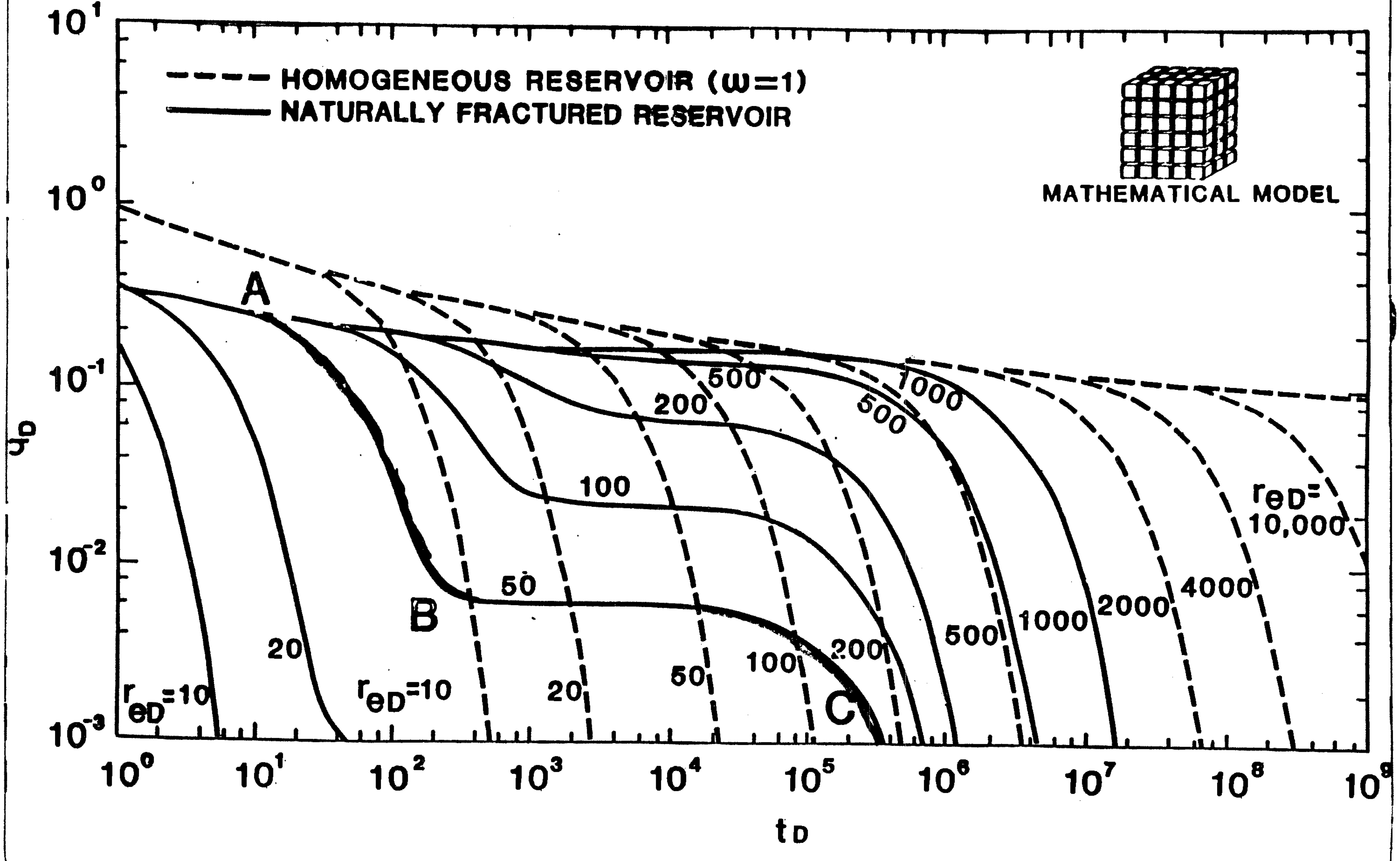
$\frac{re}{rw'} = 50$

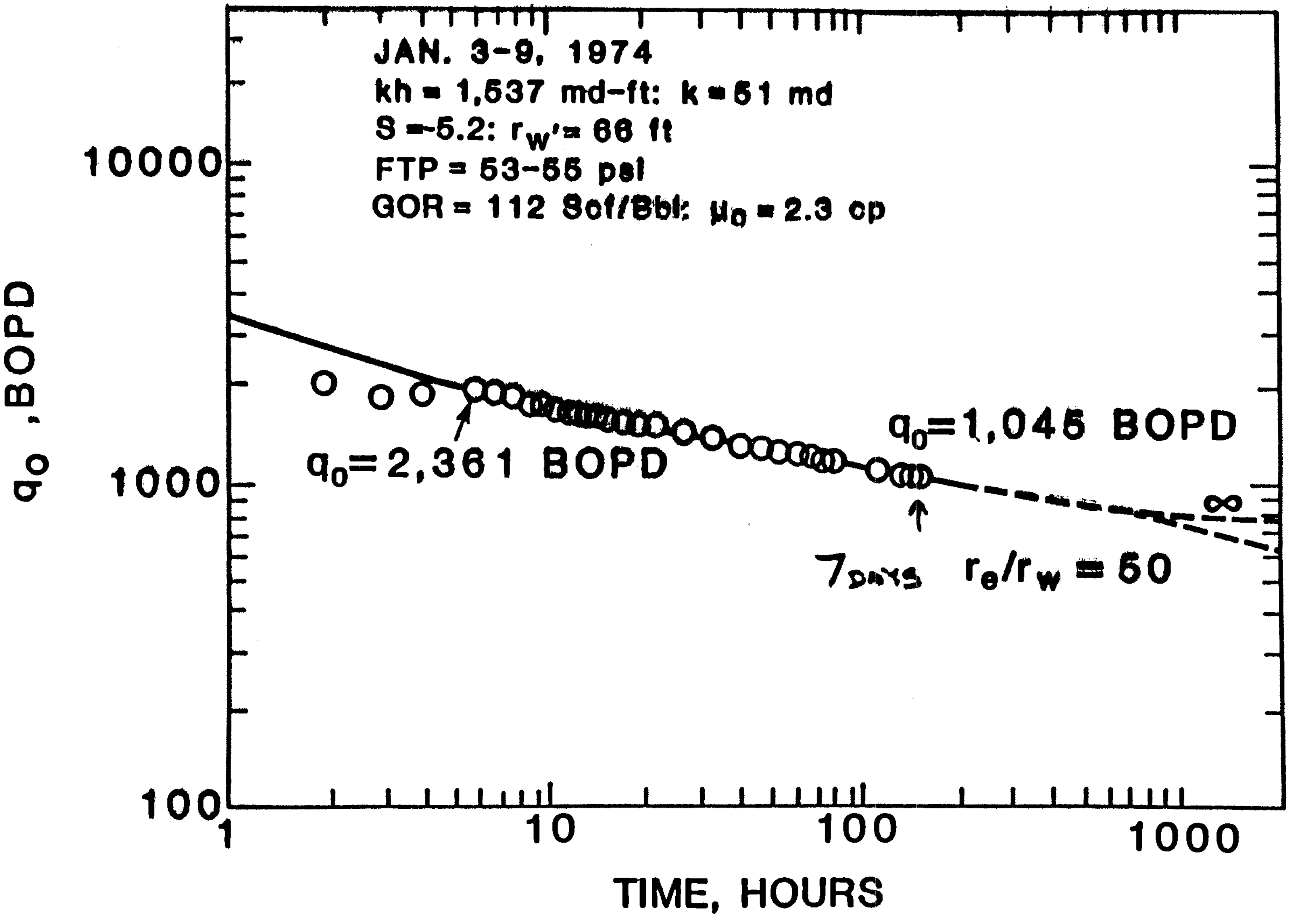
FIG. 15 TYPE CURVE MATCHING EXAMPLE FOR CALCULATING Kh USING DECLINE CURVE DATA, WELL NO. 13, FIELD A.


OIL RATE
PRODUCTION
HISTORY
□ WELL A
△ WELL B
○ WELL C
◇ WELL D
b=0


100
10
1


ORCUTT FIELD
LOMPOC FIELD
WEST CAT CANYON FIELD
SANTA MARIA VALLEY FIELD
SANTA MARIA VALLEY FIELD
ZACA FIELD

HOMOGENEOUS RESERVOIR (ω=1)
NATURALLY FRACTURED RESERVOIR
MATHEMATICAL MODEL
q_D
t_D
10^1
10^0
10^-1
10^-2
10^-3
10^0
10^1
10^2
10^3
10^4
10^5
10^6
10^7
10^8
10^9
A
B
C
r_eD=10
20
r_eD=10
20
50
100
200
500
1000
2000
4000
r_eD=10,000
50
100
200
500
500
1000
500
1000


JAN. 3-9, 1974
kh = 1,537 md-ft: k = 51 md
S = -5.2: r_w' = 66 ft
FTP = 53-55 psi
GOR = 112 Scf/Bbl: μ_o = 2.3 cp
q_o = 2,361 BOPD
q_o = 1,045 BOPD
7 DAYS
r_e/r_w = 50
∞
q_o, BOPD
10000
1000
100
1
10
100
1000
TIME, HOURS

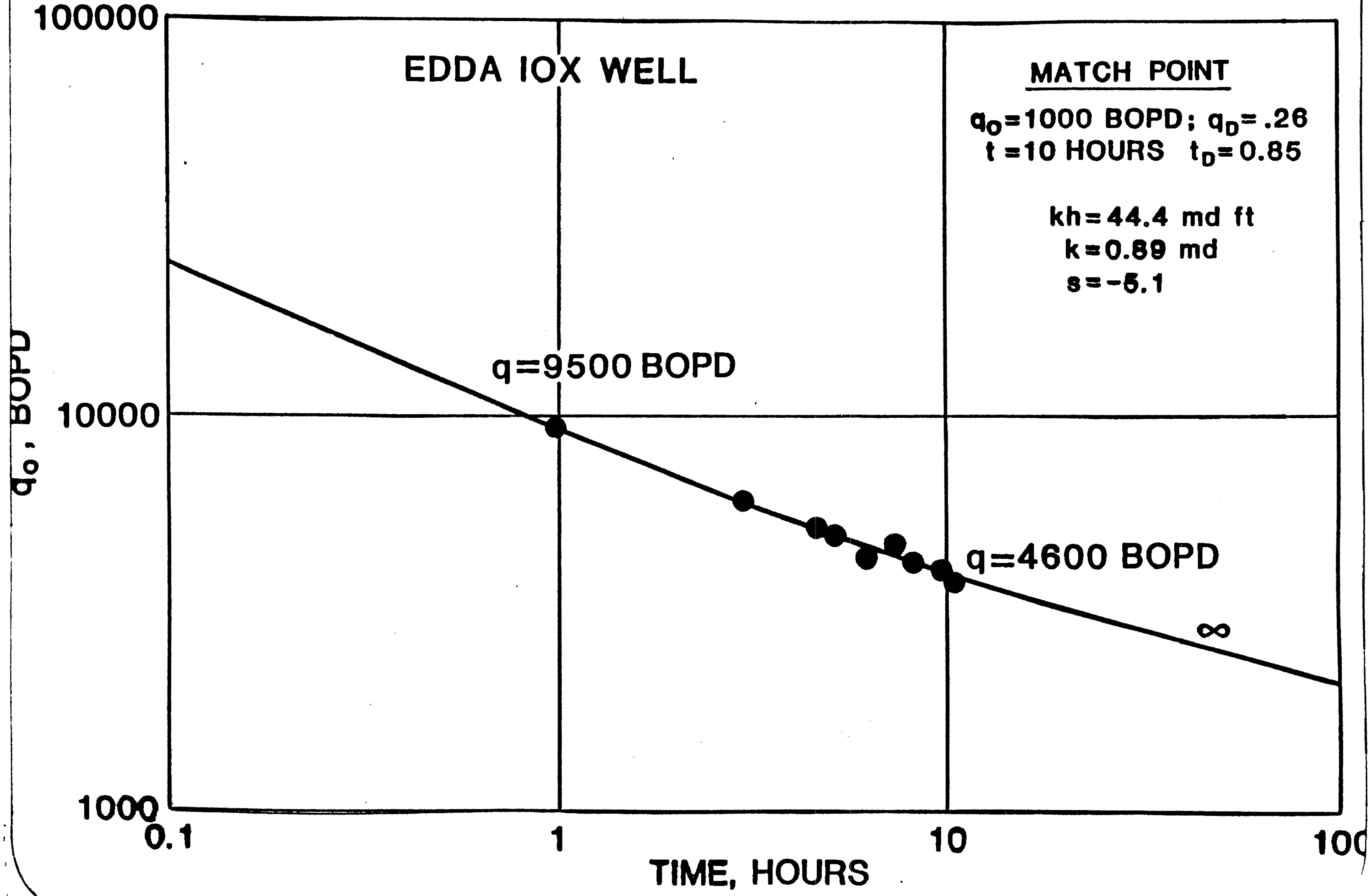

EDDA IOX WELL
MATCH POINT
q_o=1000 BOPD; q_D=.26
t =10 HOURS t_D=0.85
kh=44.4 md ft
k=0.89 md
s=-5.1
q=9500 BOPD
q=4600 BOPD
∞
q_o, BOPD
100000
10000
1000
0.1
1
10
TIME, HOURS

TABLE 1

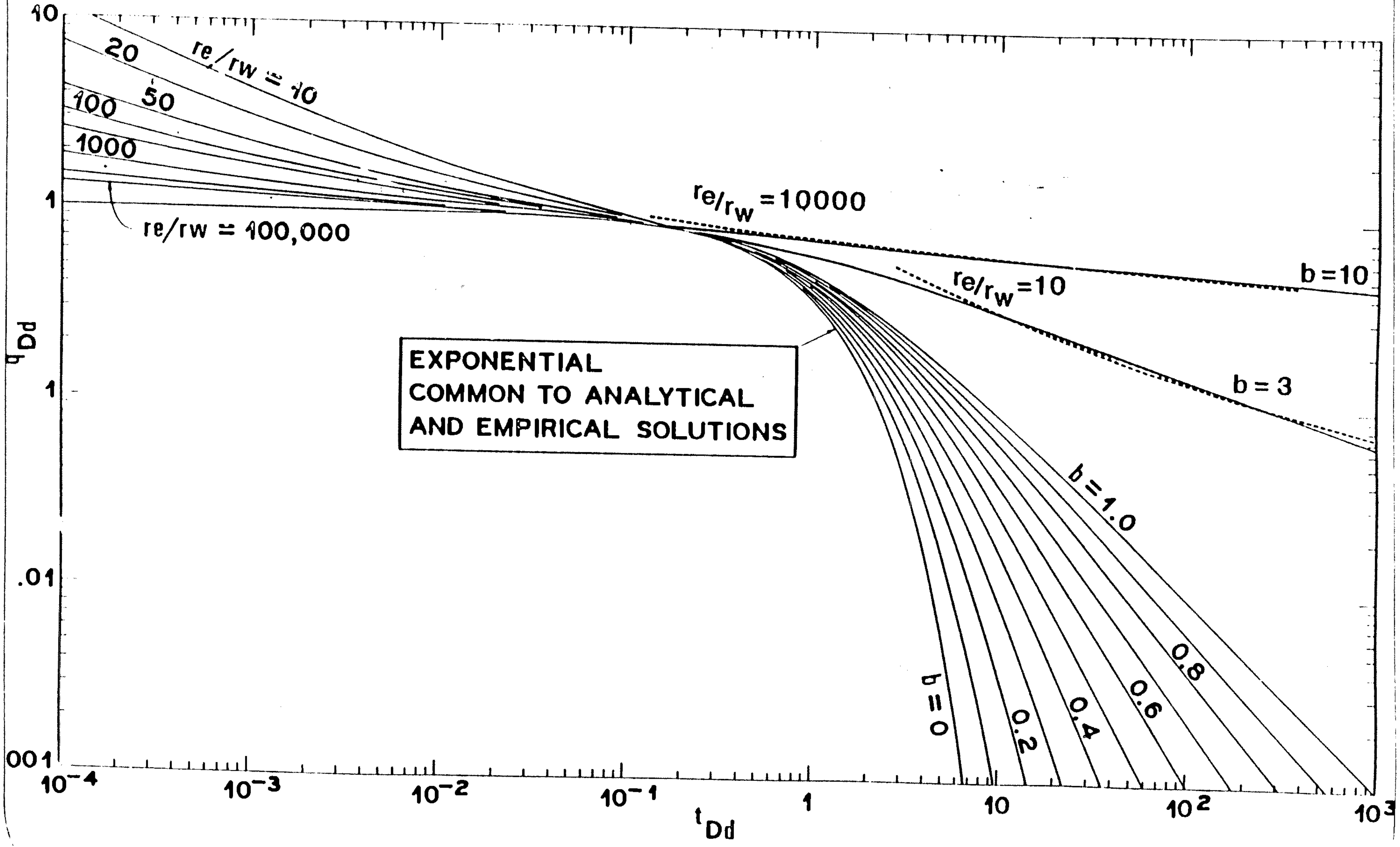
EDDA 10X WELL

DST 2 SUMMARY OF ANALYSIS RESULTS (POST ACID) AND RESERVOIR DATA

	Horner	$q_D - t_D$ Constant p_{wf} Plane Radial System
k, md	0.95	0.89
s	-4.8	-5.1
r_w', ft	40	54

Reservoir Data

ϕ = 0.25
S_w = 0.35
μ = 0.167 cp
p_i = 7043 psia
β_o = 1.992 RBL/STB
h = 50 ft
c_t = 21.6×10^{-6} psi^{-1}



10
1
1
.01
001
q_{Dd}
10^{-4}
10^{-3}
10^{-2}
10^{-1}
1
10
10^2
10^3
t_{Dd}
re/rw = 10
20
50
100
1000
re/rw = 100,000
r_e/r_w = 10000
r_e/r_w = 10
b = 10
b = 3
b = 1.0
0.8
0.6
0.4
0.2
b = 0
EXPONENTIAL
COMMON TO ANALYTICAL
AND EMPIRICAL SOLUTIONS

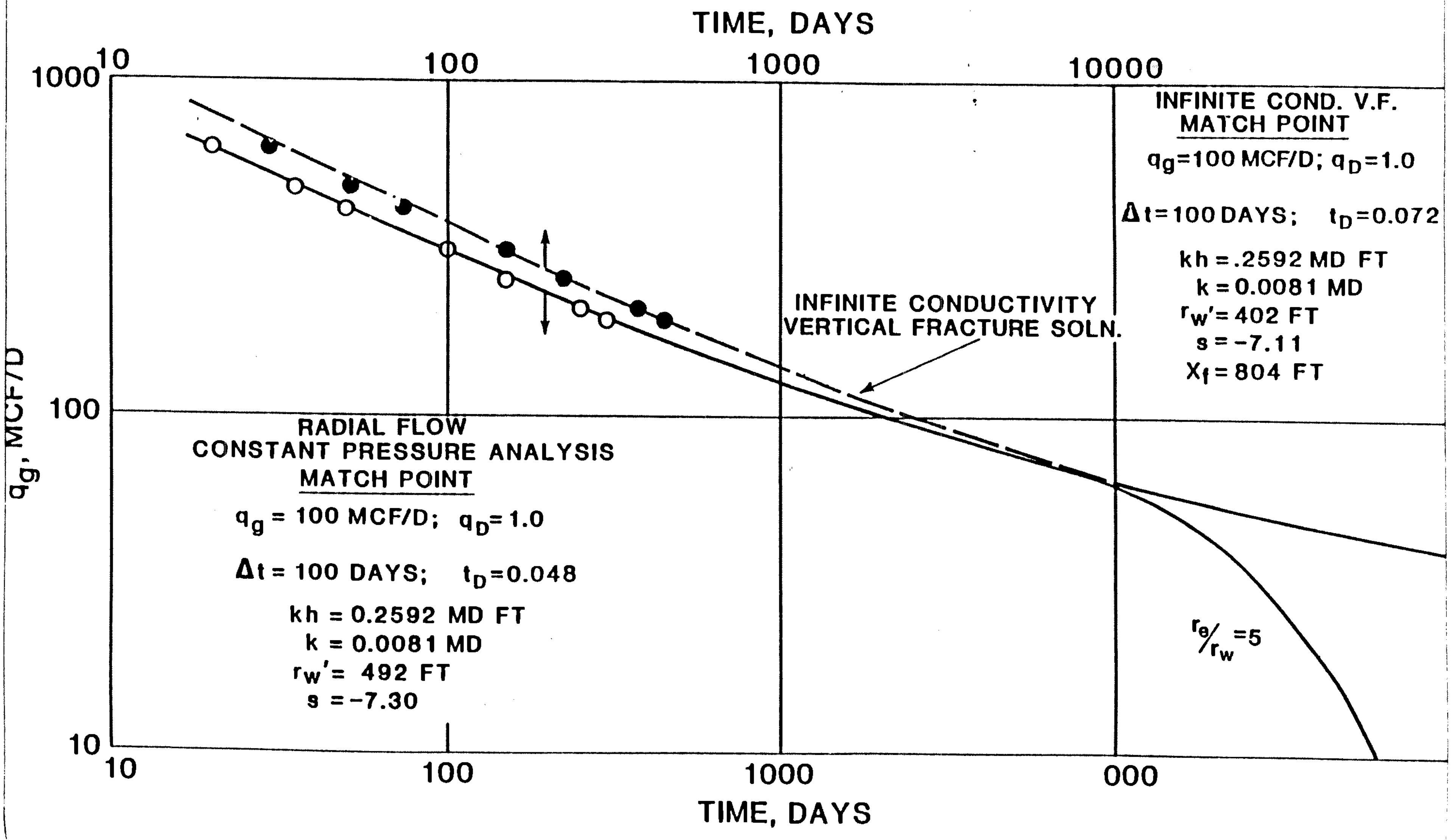

TIME, DAYS
10
100
1000
10000
1000
100
10
q_g, MCF/D
INFINITE COND. V.F.
MATCH POINT
q_g=100 MCF/D; q_D=1.0
Δt=100 DAYS; t_D=0.072
kh =.2592 MD FT
k = 0.0081 MD
r_w'= 402 FT
s = -7.11
X_f = 804 FT
INFINITE CONDUCTIVITY
VERTICAL FRACTURE SOLN.
RADIAL FLOW
CONSTANT PRESSURE ANALYSIS
MATCH POINT
q_g = 100 MCF/D; q_D= 1.0
Δt = 100 DAYS; t_D=0.048
kh = 0.2592 MD FT
k = 0.0081 MD
r_w'= 492 FT
s = -7.30
r_e/r_w=5
10
100
1000
000
TIME, DAYS

TABLE 2

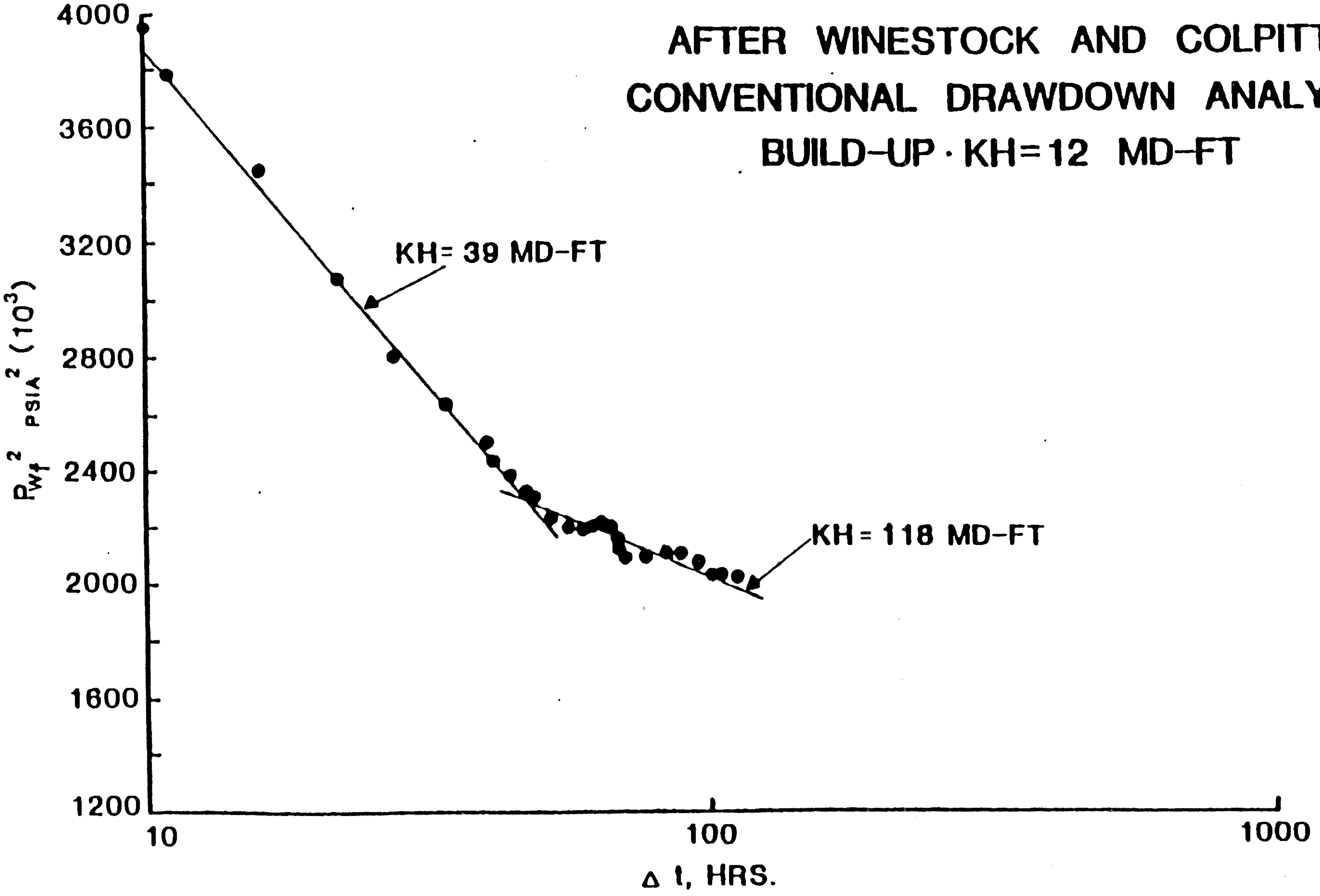
MHF GAS WELL A

COMPARISON OF PRODUCTION FORECASTS

TIME (MO.)	CONSTANT PRESSURE SOLUTION (Mscf/D)	INF. COND. V.F. SOLUTION (Mscf/D)	SPE 6838 SIMULATOR RESULTS (Mscf/D)
12	182	182	190
18	157	157	165
24	140	136	150
30	130	128	140
36	122	120	135
42	117	112	130
48	110	108	120
54	108	103	110
60	104	100	105
YR.			
6	100	95	
7	96	89	
8	92	86	
9	89	83	
10	86	80	
11	84	78	
12	82	75	
13	80	73	
14	79	71	
15	77	69	
16	76	68	
17	74	67	
18	73	66	
19	72	65	
20	71	64	

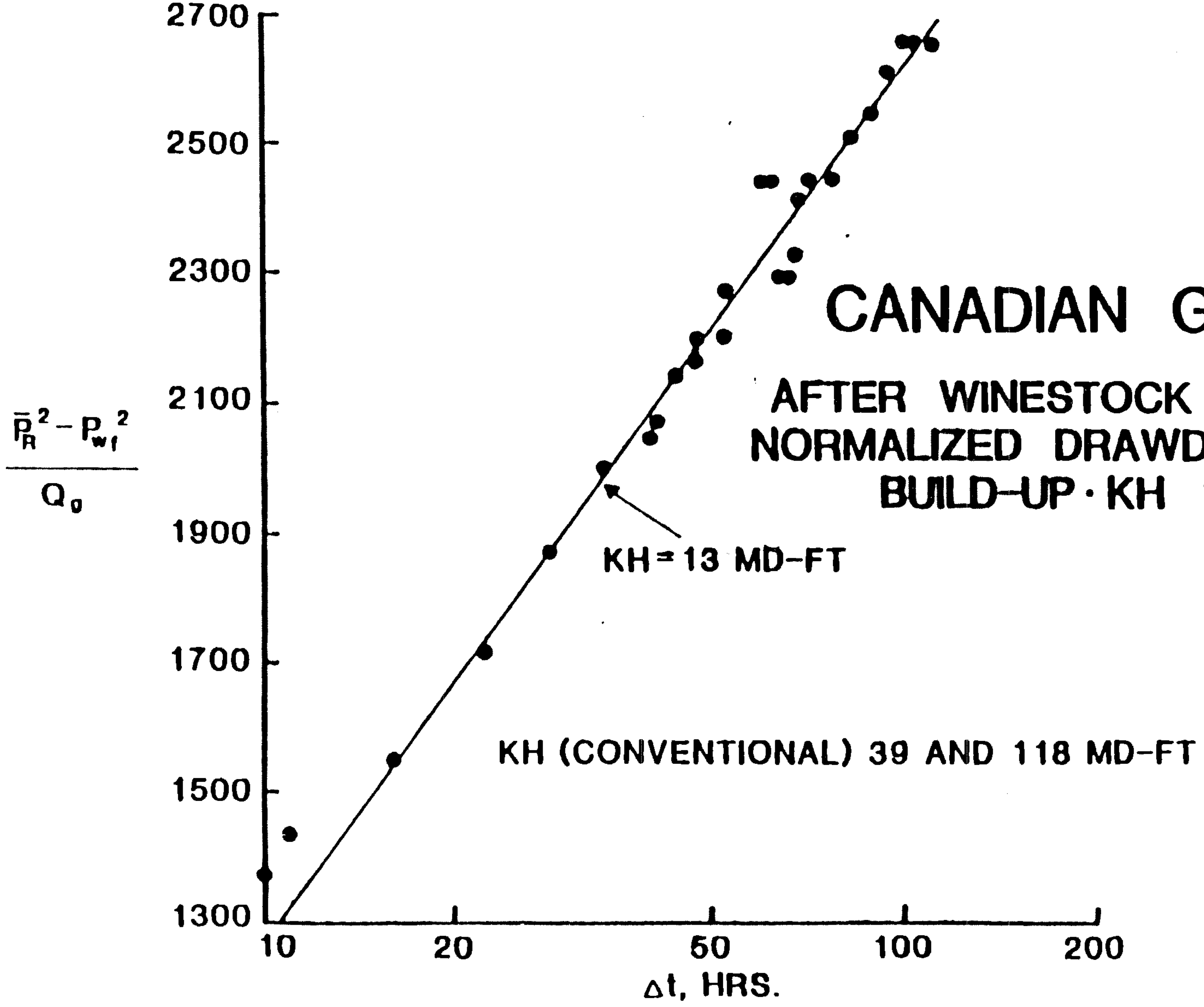
CANADIAN GAS WELL

AFTER WINESTOCK AND COLPITTS
CONVENTIONAL DRAWDOWN ANALYSIS
BUILD-UP · KH=12 MD-FT



CANADIAN GAS WELL

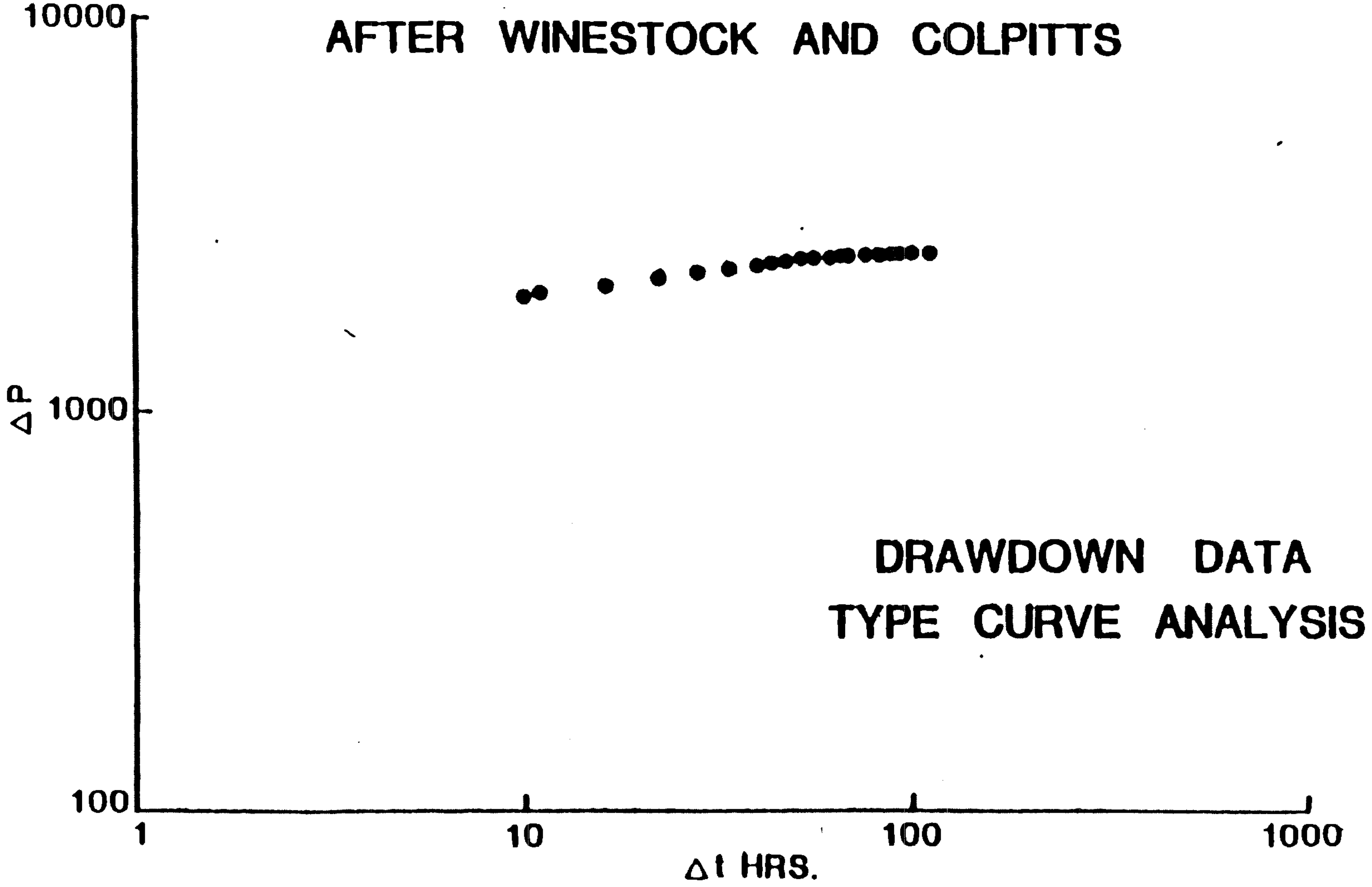
AFTER WINESTOCK AND COLPITTS
NORMALIZED DRAWDOWN ANALYSIS
BUILD-UP · KH 12 MD-FT



KH (CONVENTIONAL) 39 AND 118 MD-FT

CANADIAN GAS WELL

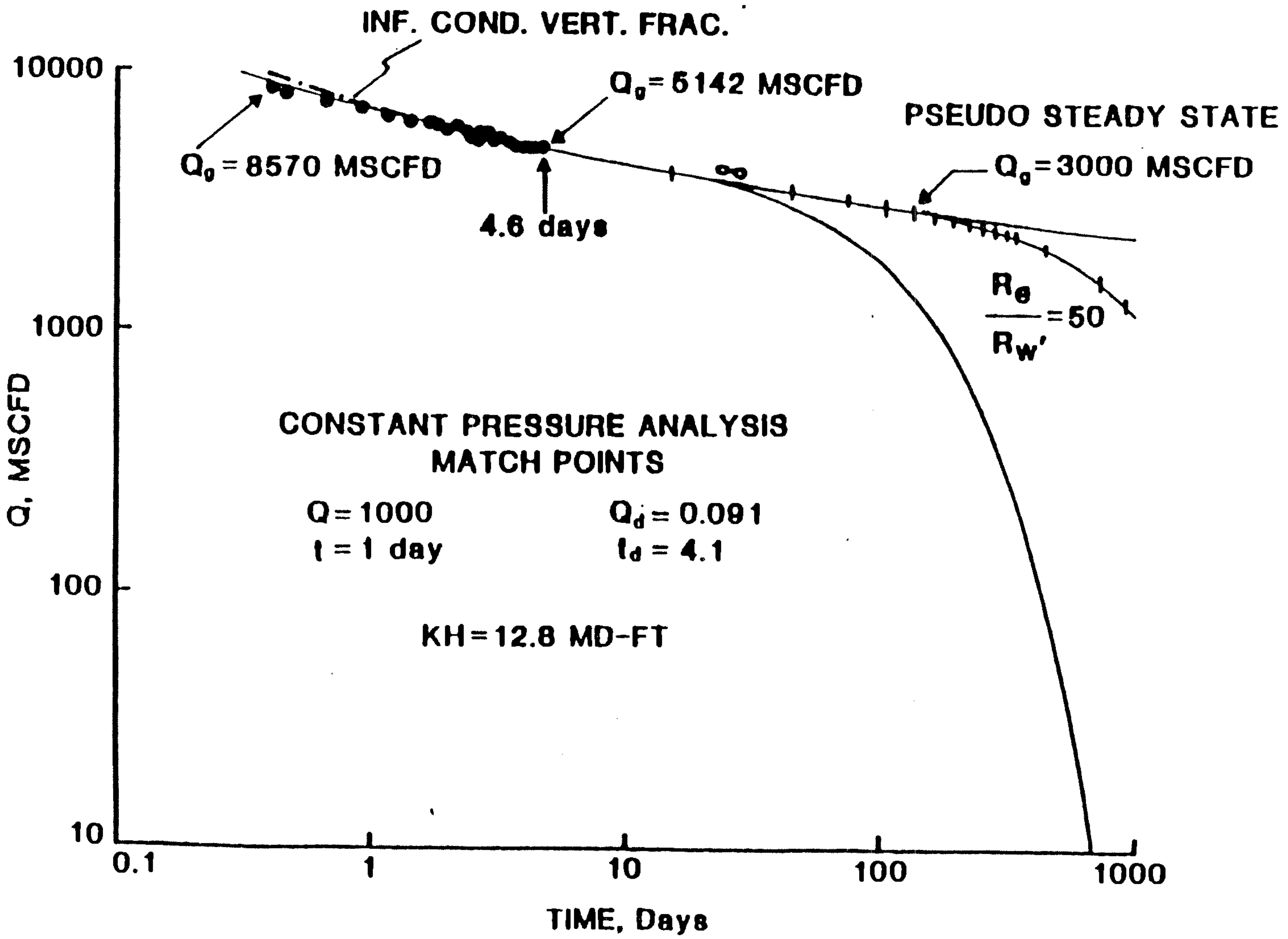
AFTER WINESTOCK AND COLPITTS



DRAWDOWN DATA
TYPE CURVE ANALYSIS

CANADIAN GAS WELL

WINESTOCK AND COLPITTS DATA
CONSTANT PRESSURE ANALYSIS
BUILD-UP · KH 12 MD-FT



WINESTOCK AND COLPITTS DATA CONSTANT PRESSURE ANALYSIS OF (Q vs. t)

PRODUCTION FORECAST READ DIRECTLY FROM CURVE

TIME MO.	RATE MSCFD
1	4200
2	3550
3	3300
4	3125
5	3000
6	2875
7	2775
8	2675
9	2575
10	2500
11	2450
12	2375
YR.	
2*	2100
3*	1600
4*	1325
5*	1125

* MID YEAR READINGS

TABLE 1

WEST VIRGINIA GAS WELL B
72 HOUR DRAWDOWN DATA

TIME (HR)	P_{wf} (psia)	GAS RATE (Mscfd)	m(p) (psia^2/cp) MILLIONS	Δ m(p) (psia^2/cp) MILLIONS	Δ m(p)/q (psia^2/cp Mscfd) THOUSANDS
0.0	4185	0	1202.50	0	0
0.25	4079	1757	1153.95	48.55	27.63
0.75	4025	1468	1129.32	73.18	49.85
1.00	4000	1482	1117.95	84.55	57.05
2.00	3926	1494	1084.38	118.12	79.06
3.00	3888	1443	1067.20	135.30	93.76
6.00	3794	1443	1024.91	177.60	123.07
24.00	3650	1141	960.73	241.80	211.89
48.00	3562	1054	921.90	280.60	266.22
72.00	3478	1019	885.14	317.36	311.44

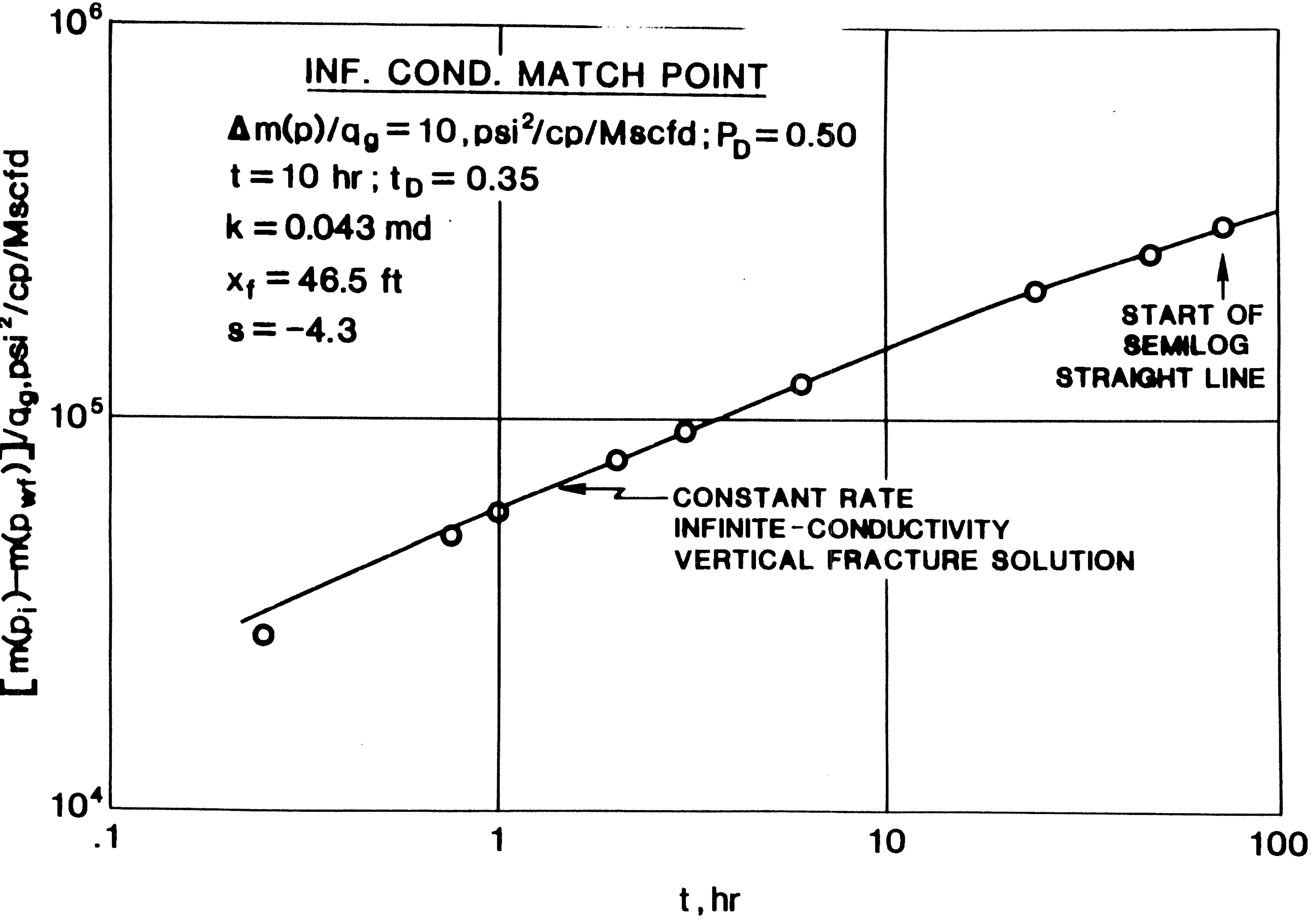
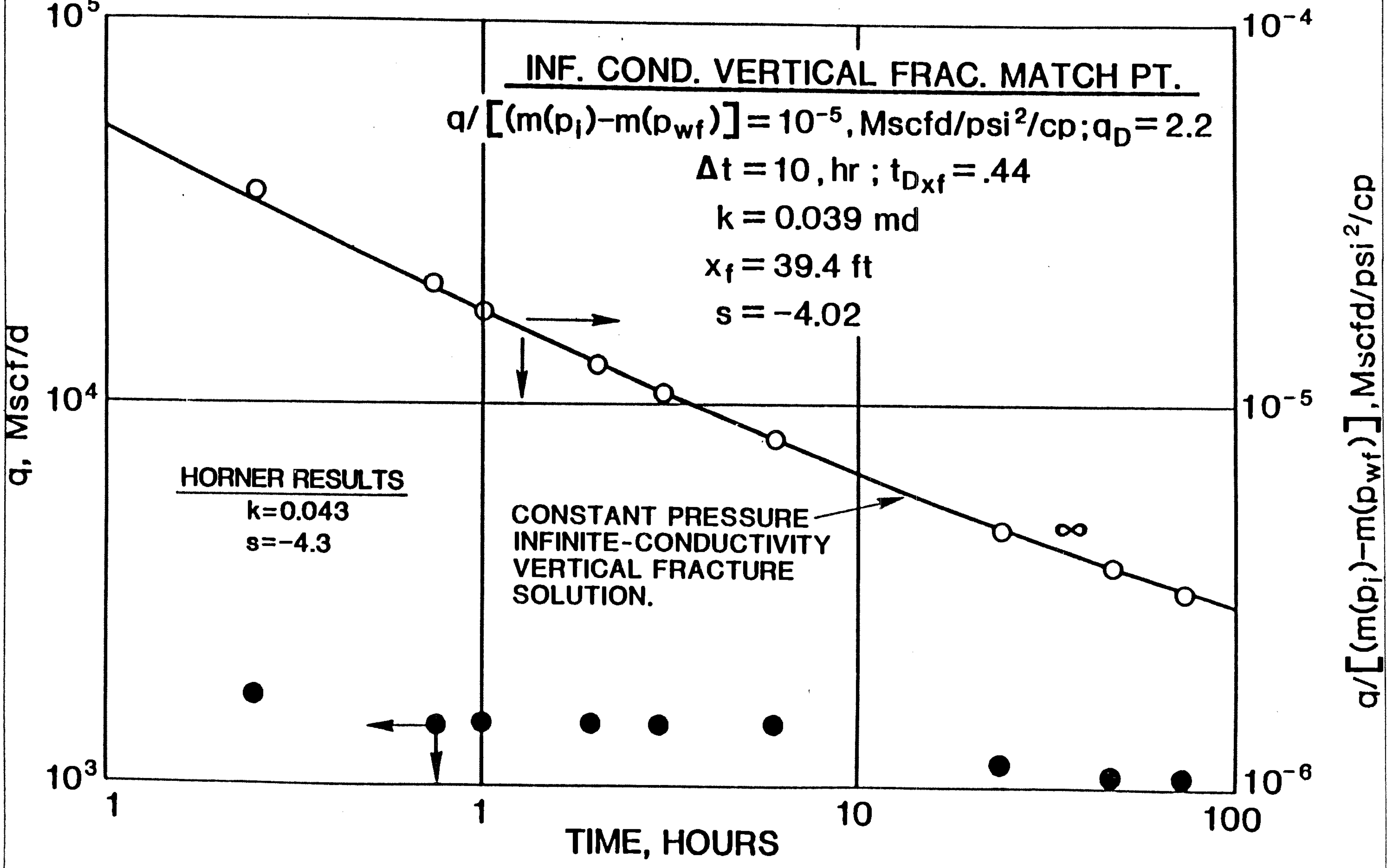
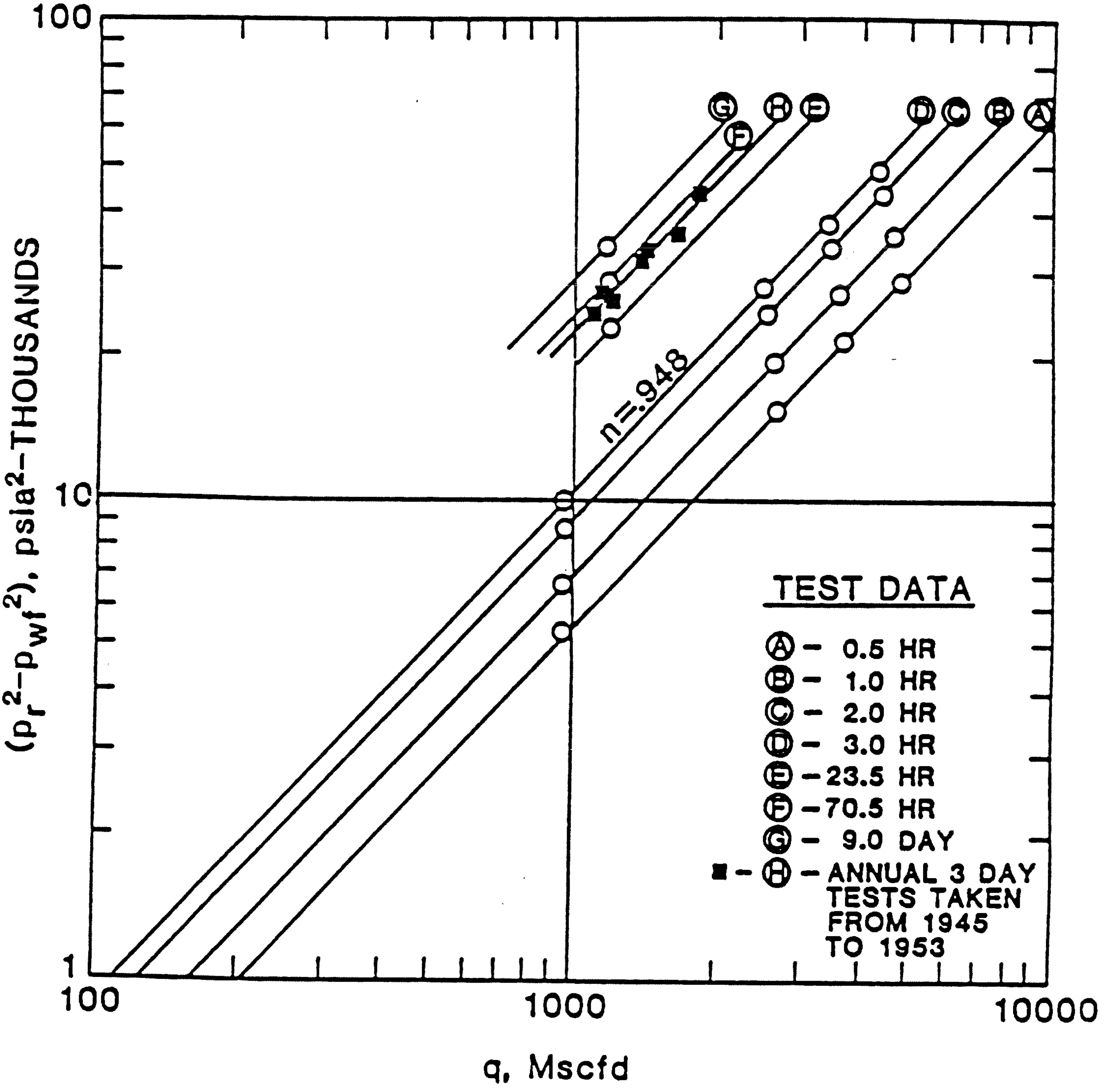
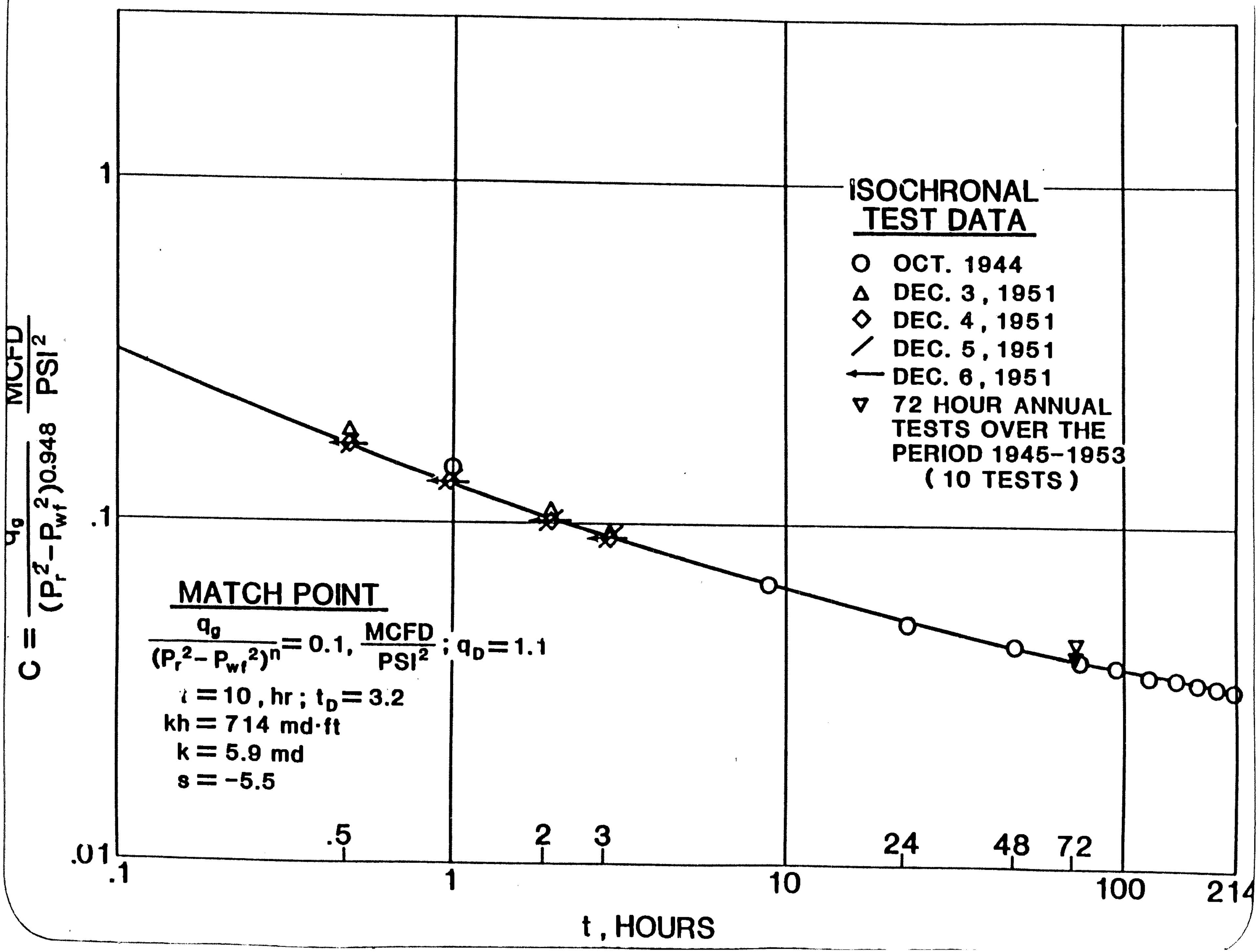
INF. COND. MATCH POINT
Δm(p)/q_g = 10, psi²/cp/Mscfd ; P_D = 0.50
t = 10 hr ; t_D = 0.35
k = 0.043 md
x_f = 46.5 ft
s = −4.3
START OF SEMILOG STRAIGHT LINE
CONSTANT RATE INFINITE-CONDUCTIVITY VERTICAL FRACTURE SOLUTION
10⁶
10⁵
10⁴
.1
1
10
100
t, hr
[m(p_i)—m(p_wf)]/q_g, psi²/cp/Mscfd

FIG. 10

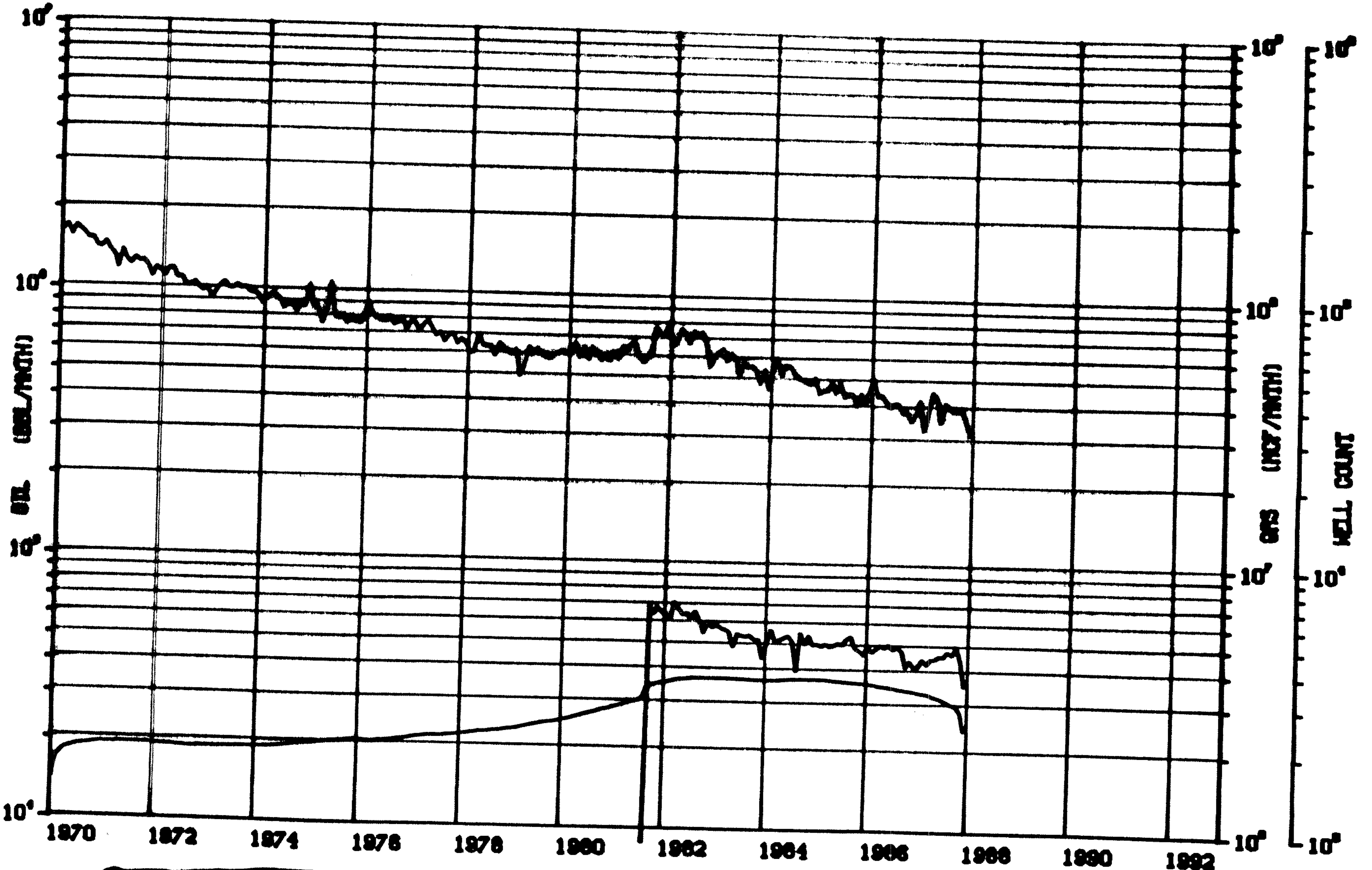

INF. COND. VERTICAL FRAC. MATCH PT.
$q/[(m(p_i)-m(p_{wf})] = 10^{-5}$, Mscfd/psi²/cp; $q_D = 2.2$
$\Delta t = 10$, hr ; $t_{Dxf} = .44$
$k = 0.039$ md
$x_f = 39.4$ ft
$s = -4.02$
HORNER RESULTS
k=0.043
s=-4.3
CONSTANT PRESSURE INFINITE-CONDUCTIVITY VERTICAL FRACTURE SOLUTION.
∞
q, Mscf/d
10^5
10^4
10^3
$q/[(m(p_i)-m(p_{wf})]$, Mscfd/psi²/cp
10^{-4}
10^{-5}
10^{-6}
1
1
10
100
TIME, HOURS


100
10
1
100
1000
10000
q, Mscfd
$(p_r^2 - p_{wf}^2)$, psia^2-THOUSANDS
n=.948
Ⓖ
Ⓗ
Ⓔ
Ⓕ
Ⓓ
Ⓒ
Ⓑ
Ⓐ
TEST DATA
Ⓐ – 0.5 HR
Ⓑ – 1.0 HR
Ⓒ – 2.0 HR
Ⓓ – 3.0 HR
Ⓔ – 23.5 HR
Ⓕ – 70.5 HR
Ⓖ – 9.0 DAY
■ – Ⓗ – ANNUAL 3 DAY TESTS TAKEN FROM 1945 TO 1953


ISOCHRONAL TEST DATA
○ OCT. 1944
△ DEC. 3, 1951
◇ DEC. 4, 1951
／ DEC. 5, 1951
← DEC. 6, 1951
▽ 72 HOUR ANNUAL TESTS OVER THE PERIOD 1945–1953 (10 TESTS)
MATCH POINT
$\frac{q_g}{(P_r^2 - P_{wf}^2)^n} = 0.1, \frac{MCFD}{PSI^2}; q_D = 1.1$
$t = 10$, hr; $t_D = 3.2$
$kh = 714$ md·ft
$k = 5.9$ md
$s = -5.5$
$C = \frac{q_g}{(P_r^2 - P_{wf}^2)^{0.948}} \frac{MCFD}{PSI^2}$
1
.1
.01
.1
.5
1
2
3
10
24
48
72
100
214
t, HOURS

75

8



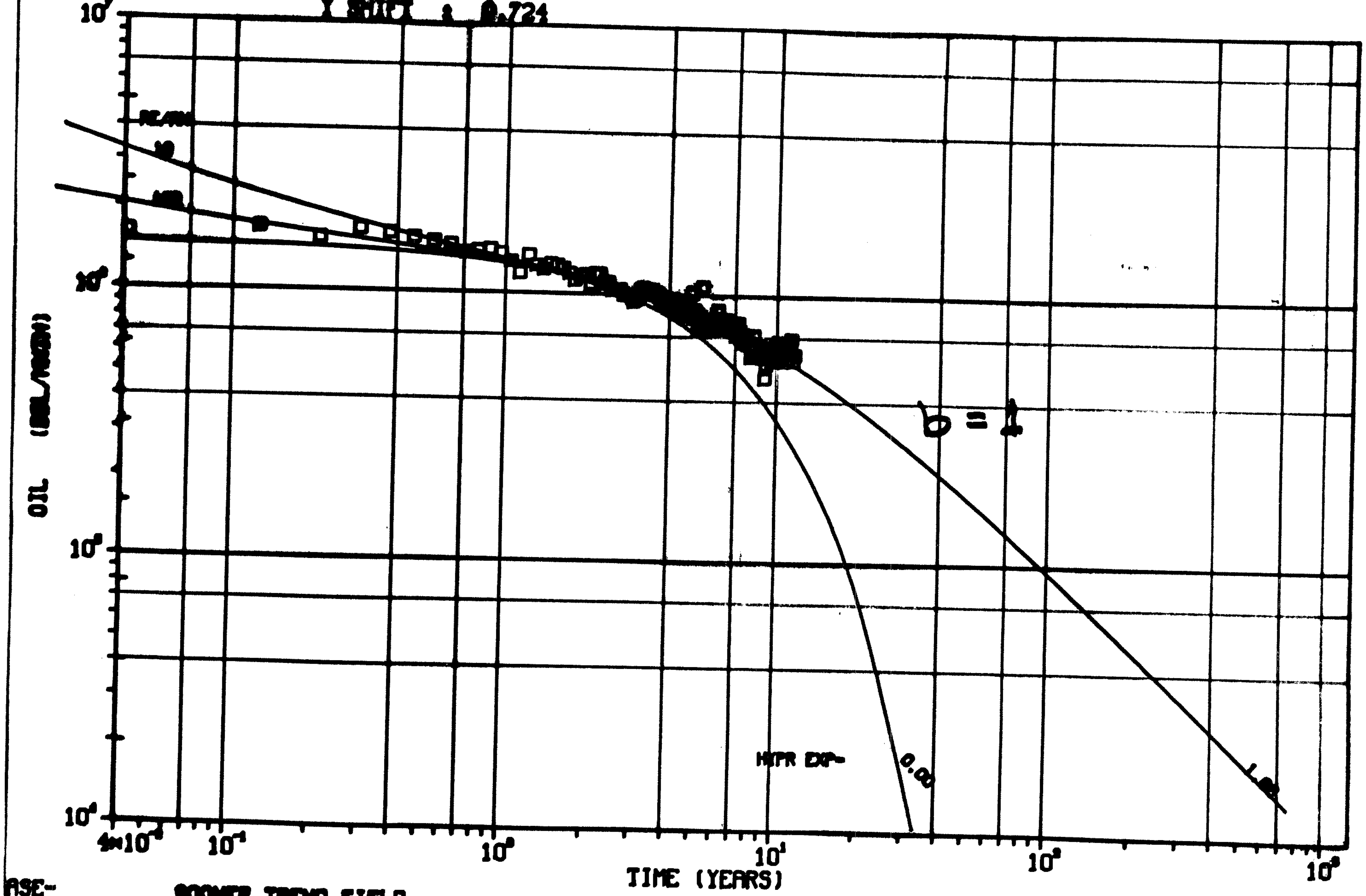
SOONER TREND FIELD

CUM GAS - 398933248.

DWIGHTS
COMPOSITE OF TOTAL

8864 WELLS

TIME ZERO 970 1
HYPR EXP : 1.000
RE/RW : 100.0
X CYCLE1 : -2.230
Y SHIFT : 0.724



ASE-

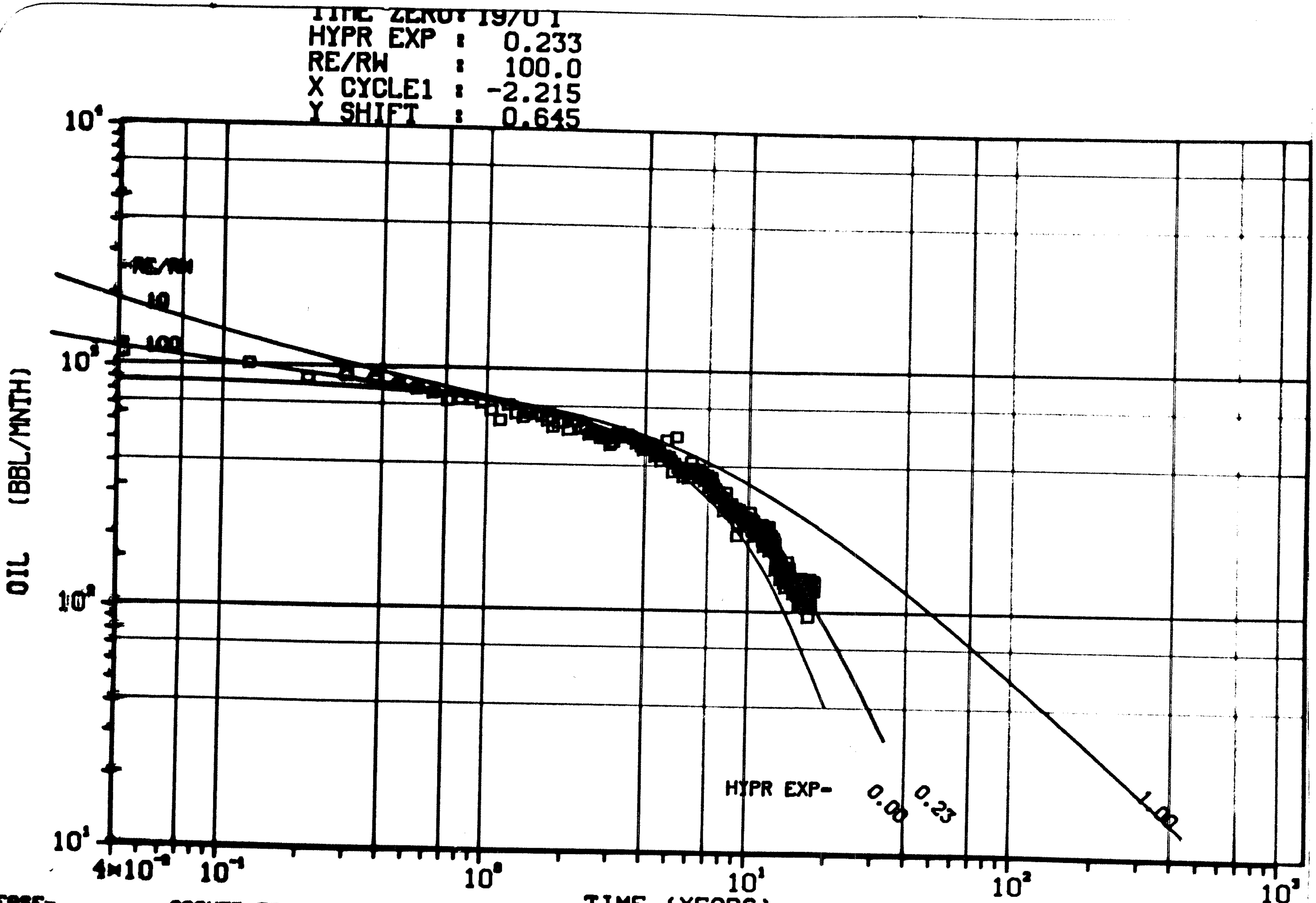
SOONER TREND FIELD

CUM GAS = 300033248.

DWIGHTS
COMPOSITE OF TOTAL ,6064 WELLS

8

TIME ZERO: 1970 1
HYPR EXP : 0.233
RE/RW : 100.0
X CYCLE1 : -2.215
Y SHIFT : 0.645



LEASE-
RESVR-

SOONER TREND FIELD
AVERAGE WELL PRODUCTION
CUM [illegible] = [illegible]33248.

DWIGHTS
AVERAGE FOR TOTAL ,6064 WELLS

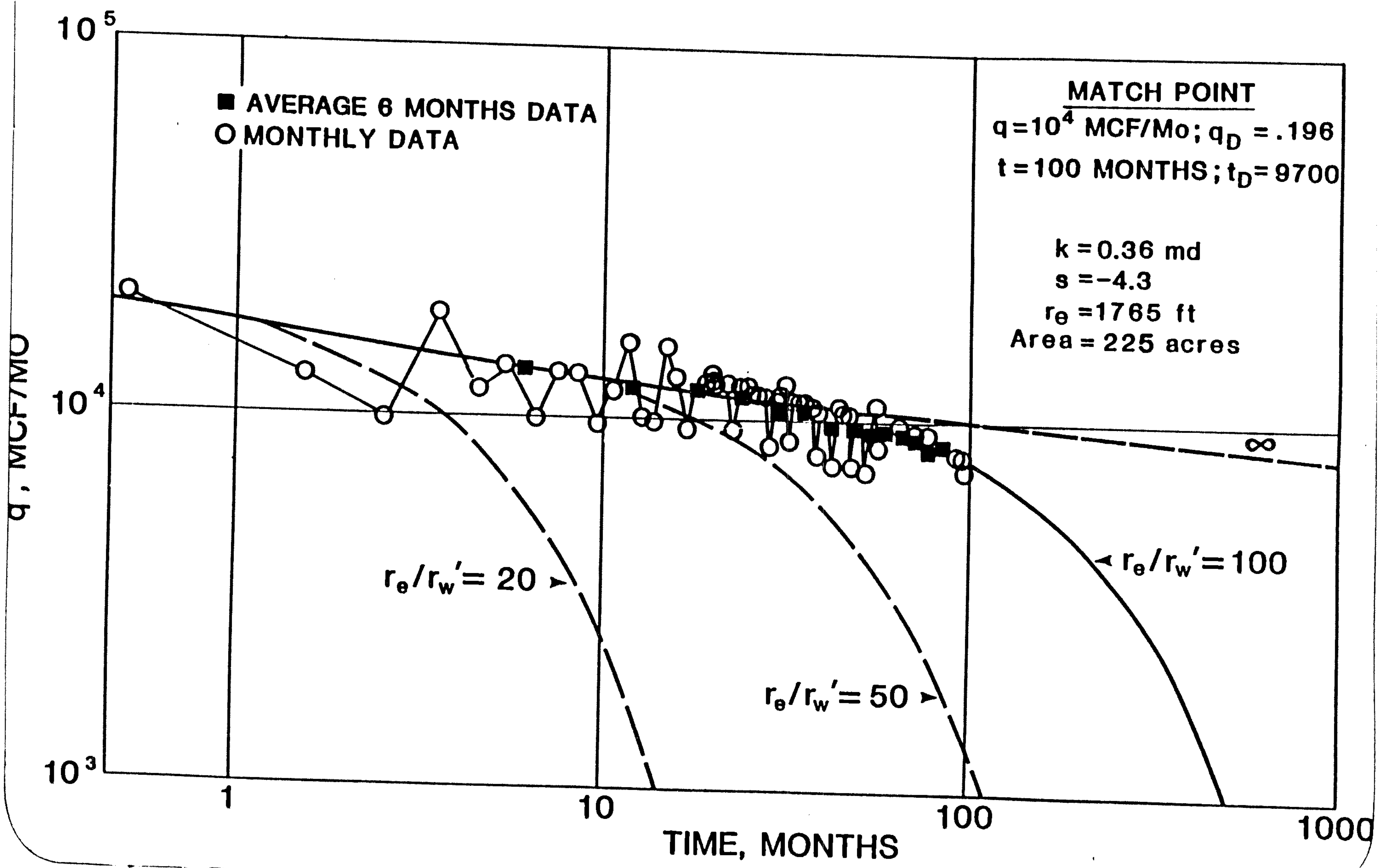
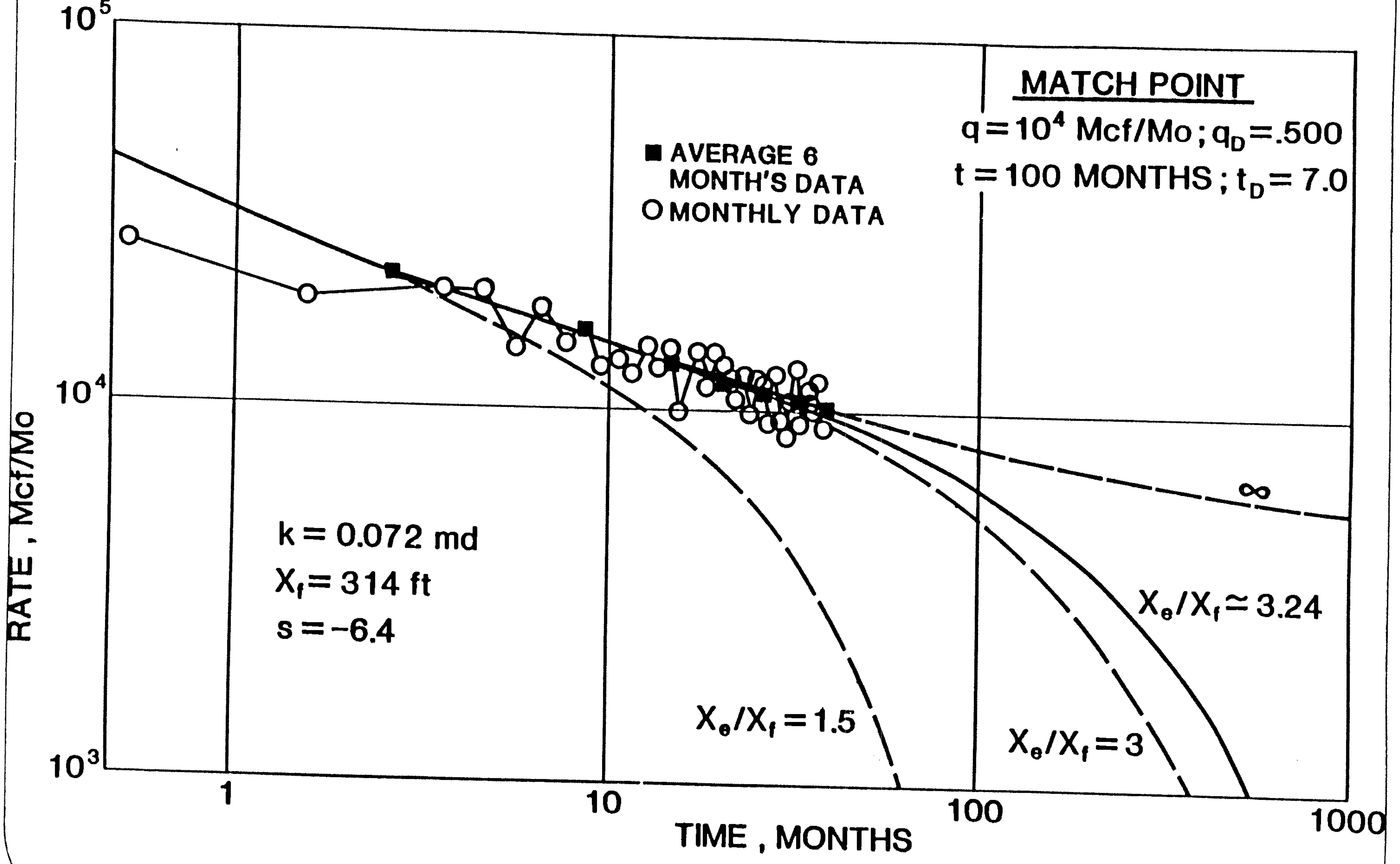

■ AVERAGE 6 MONTHS DATA
O MONTHLY DATA
MATCH POINT
q=10^4 MCF/Mo; q_D = .196
t=100 MONTHS; t_D=9700
k = 0.36 md
s = −4.3
r_e = 1765 ft
Area = 225 acres
∞
r_e/r_w′= 20
r_e/r_w′= 50
r_e/r_w′= 100
q, MCF/MO
10^5
10^4
10^3
1
10
100
1000
TIME, MONTHS

TABLE 6

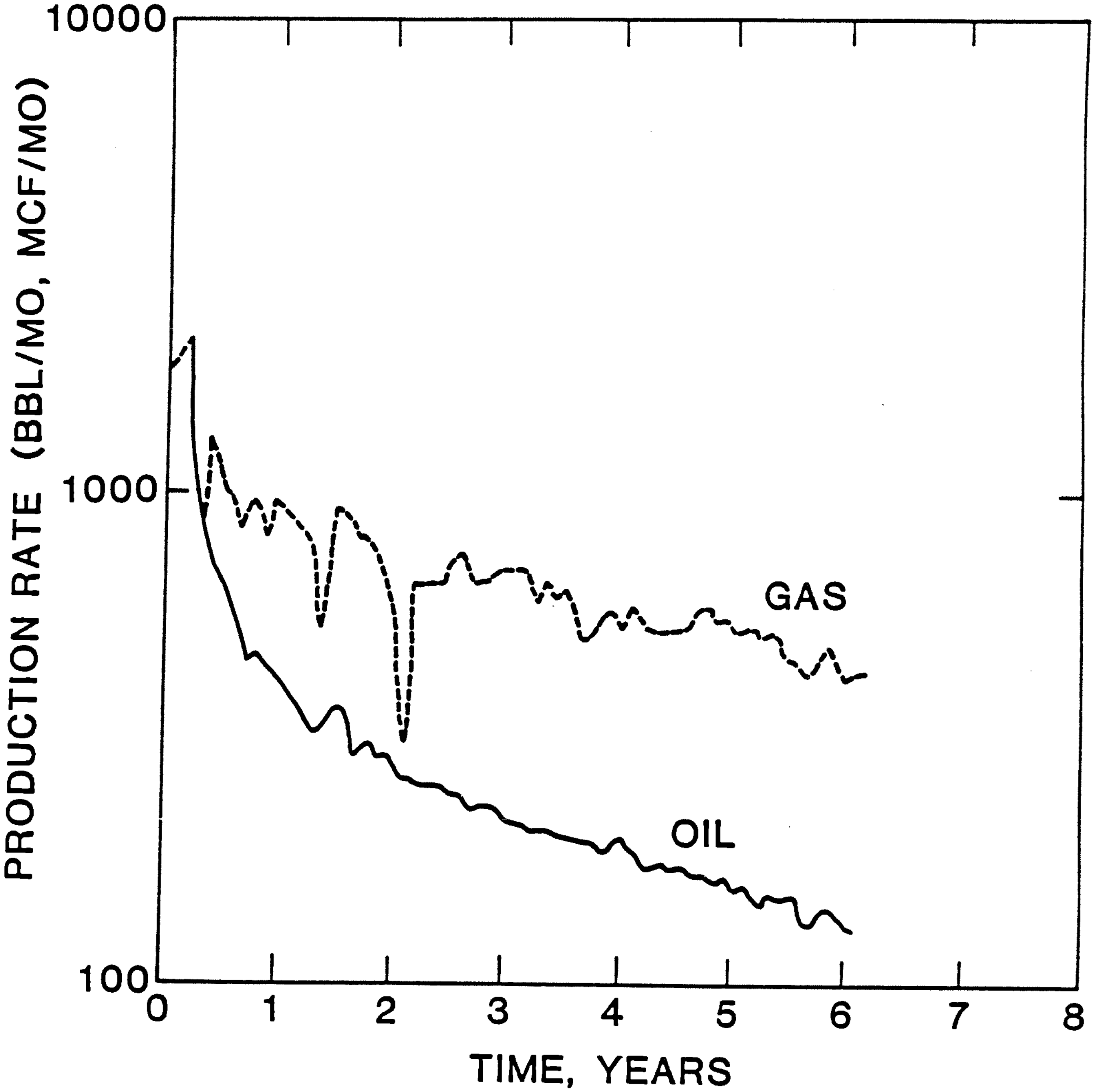
SAN JUAN WELL 58: SENSITIVITY TO r_e/r_w

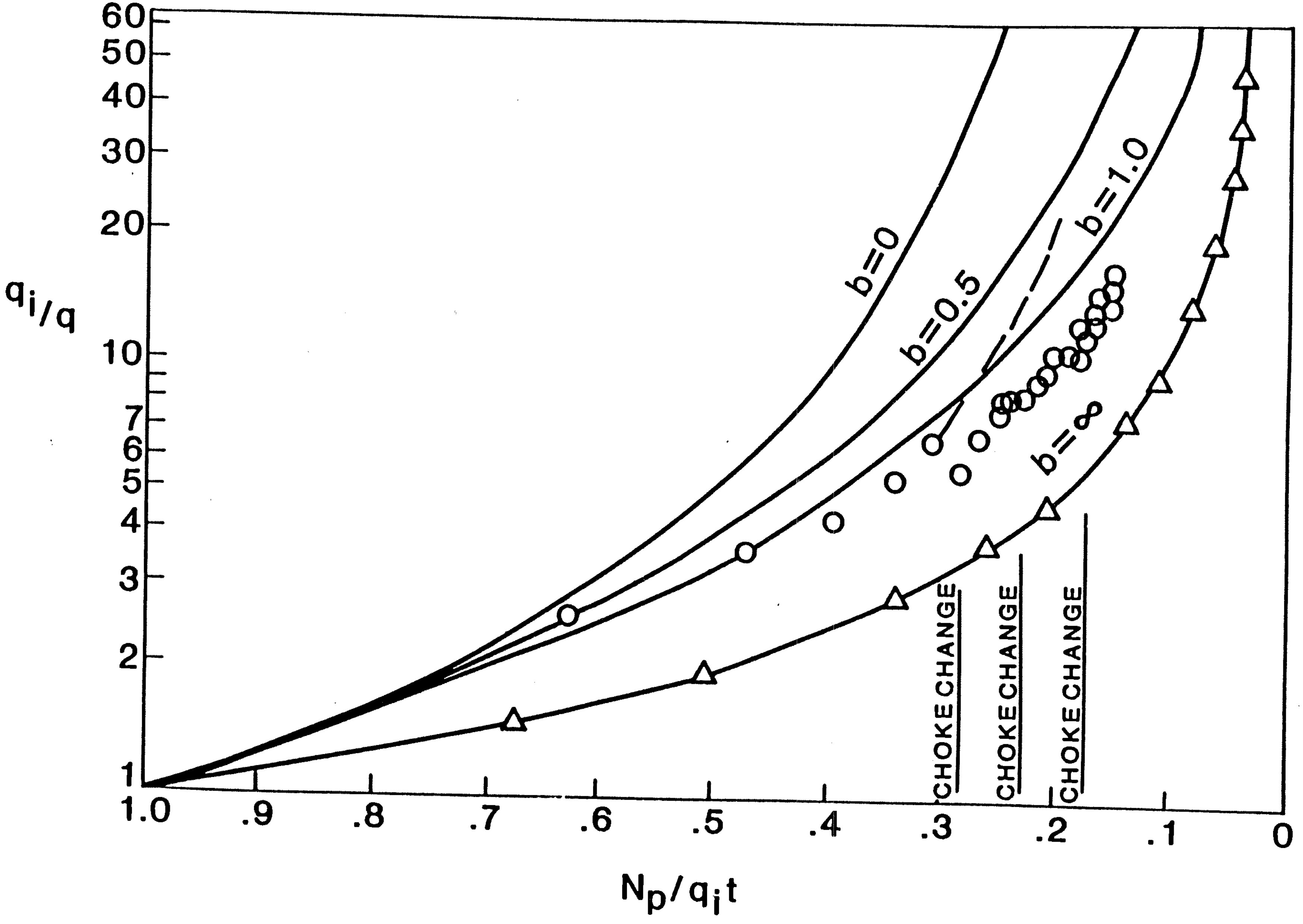
	$r_e/r_{wa} = 100$	$r_e/r_{wa} = 200$
k, md	0.34	0.40
s	-4.3	-3.6
r_e, ft	1,765	1,776

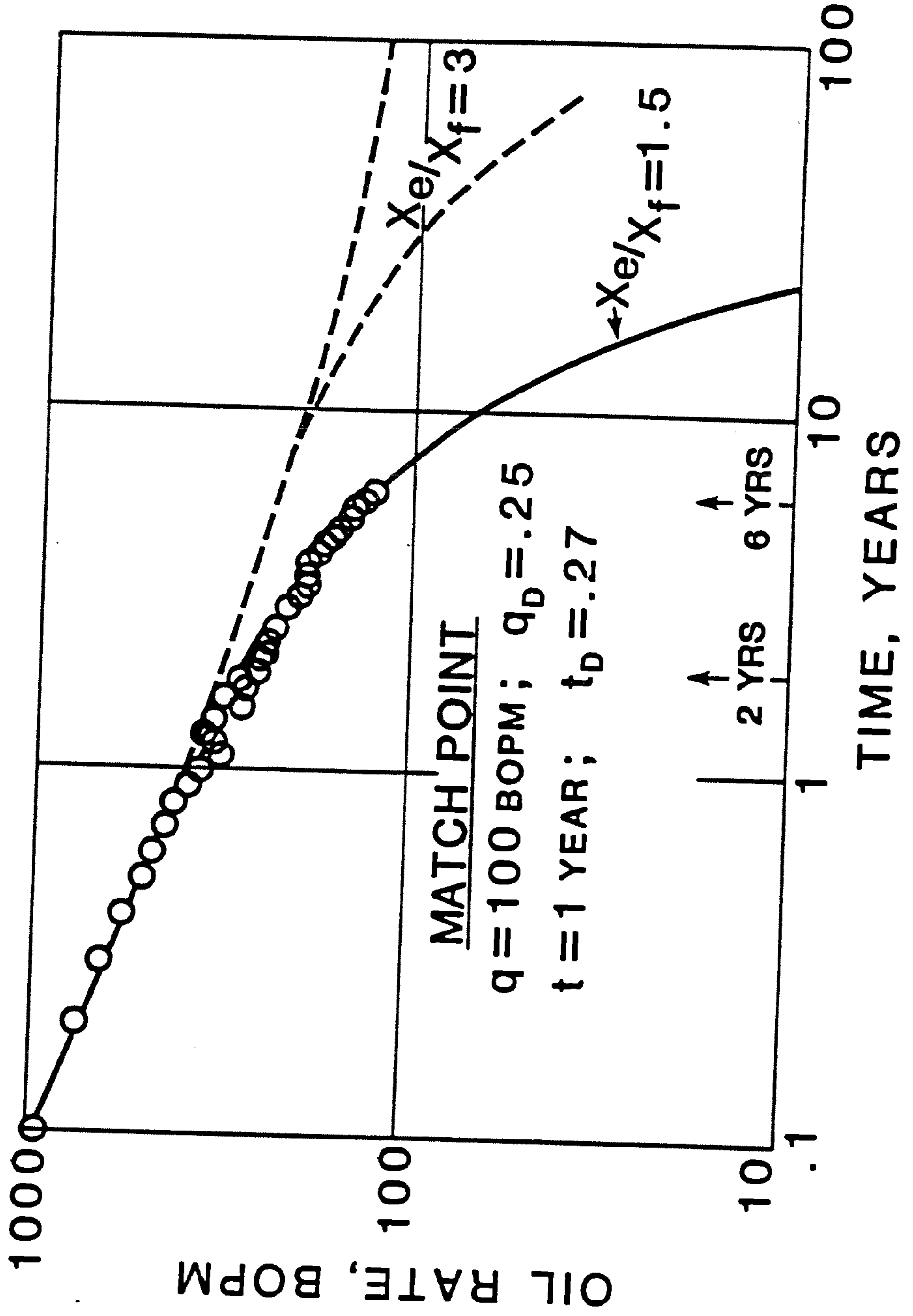

MATCH POINT
q = 10^4 Mcf/Mo ; q_D = .500
t = 100 MONTHS ; t_D = 7.0
■ AVERAGE 6 MONTH'S DATA
○ MONTHLY DATA
k = 0.072 md
X_f = 314 ft
s = −6.4
∞
X_e/X_f ≃ 3.24
X_e/X_f = 3
X_e/X_f = 1.5
RATE , Mcf/Mo
10^5
10^4
10^3
TIME , MONTHS
1
10
100
1000

9

FIG. 2c


PRODUCTION RATE (BBL/MO, MCF/MO)
10000
1000
100
0
1
2
3
4
5
6
7
8
TIME, YEARS
GAS
OIL

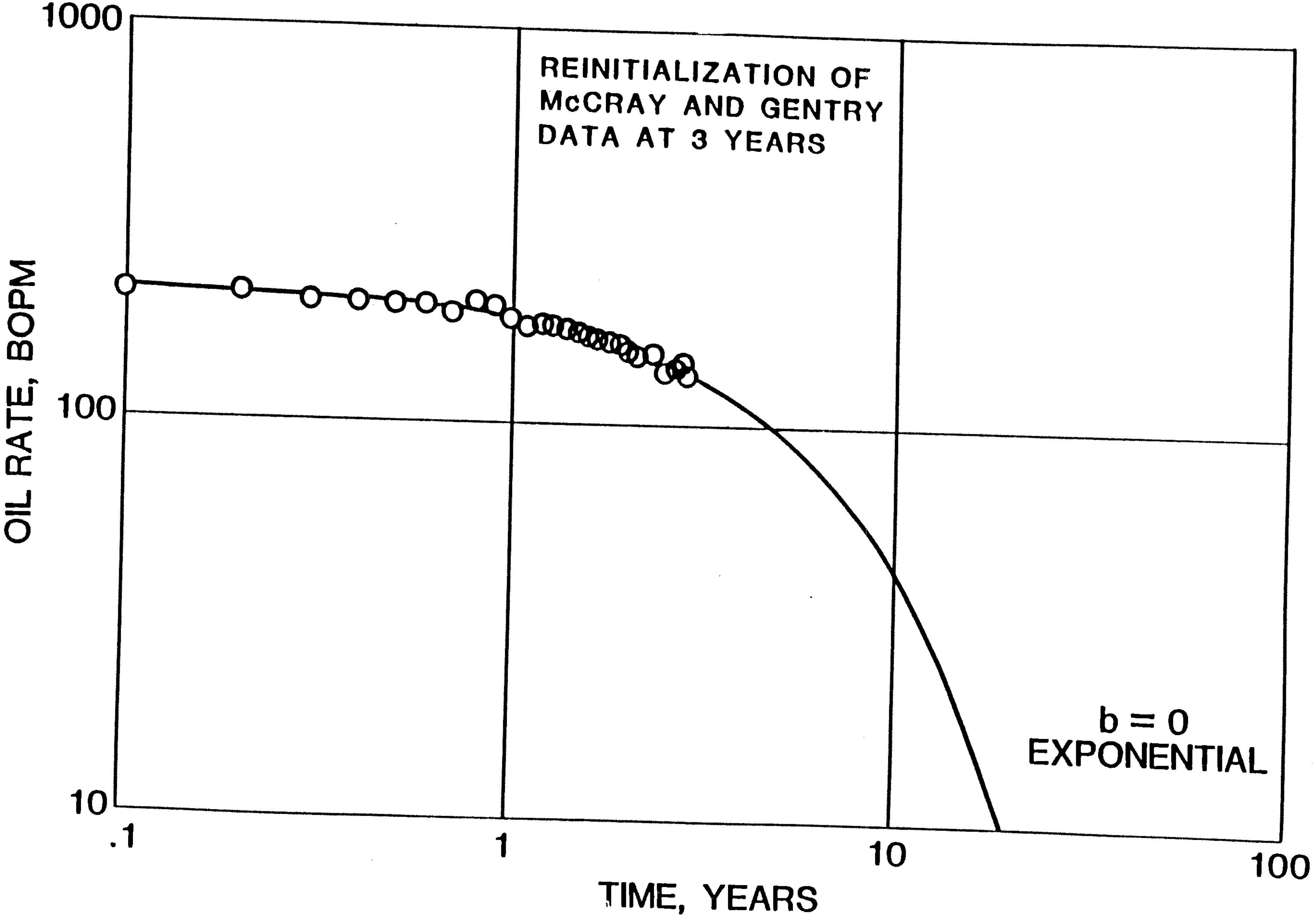

qi/q
60
50
40
30
20
10
7
6
5
4
3
2
1
1.0
.9
.8
.7
.6
.5
.4
.3
.2
.1
0
Np/qit
b=0
b=0.5
b=1.0
b=∞
CHOKE CHANGE
CHOKE CHANGE
CHOKE CHANGE

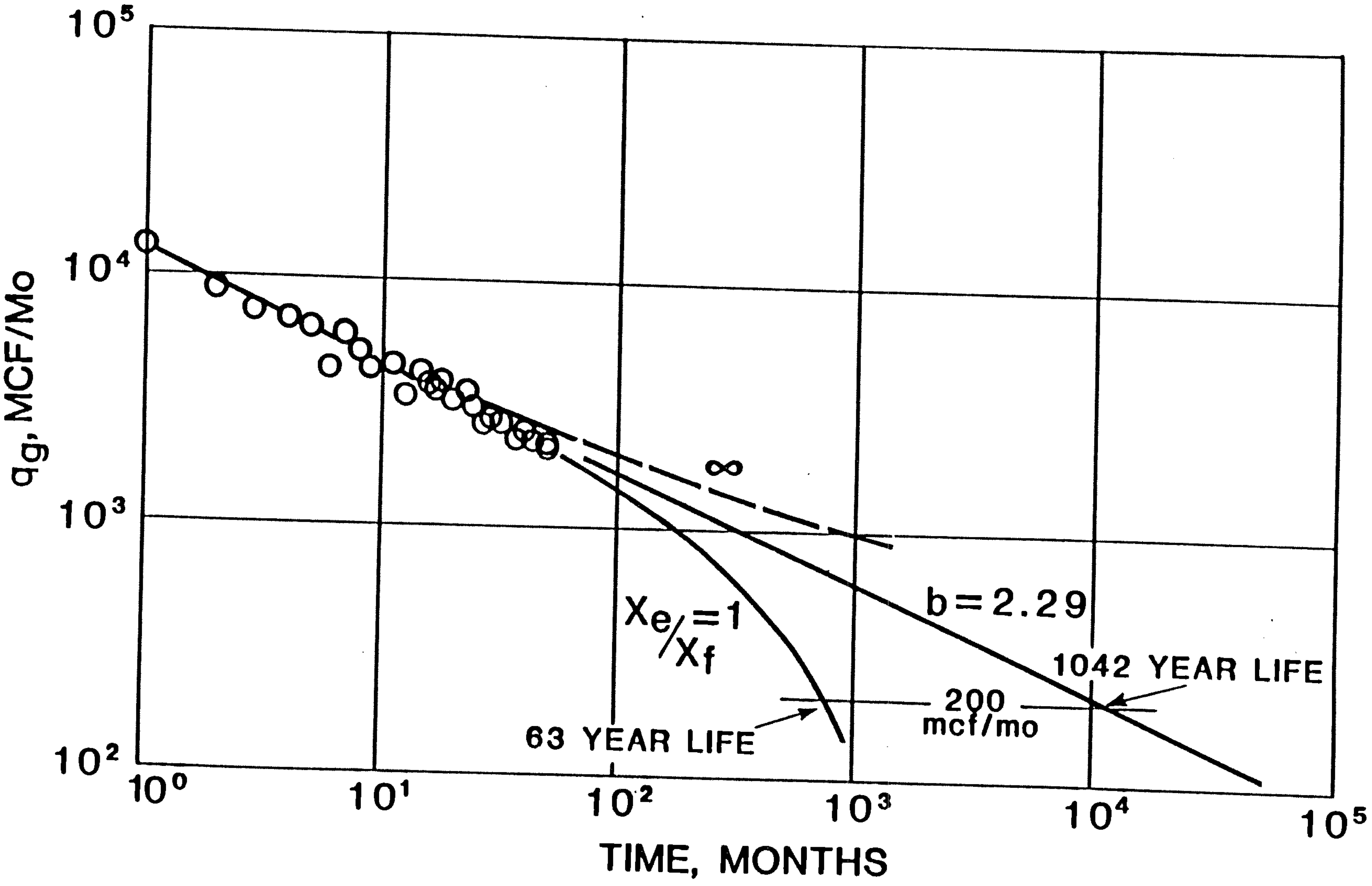


MATCH POINT

$q=100$ BOPM ; $q_D=.25$

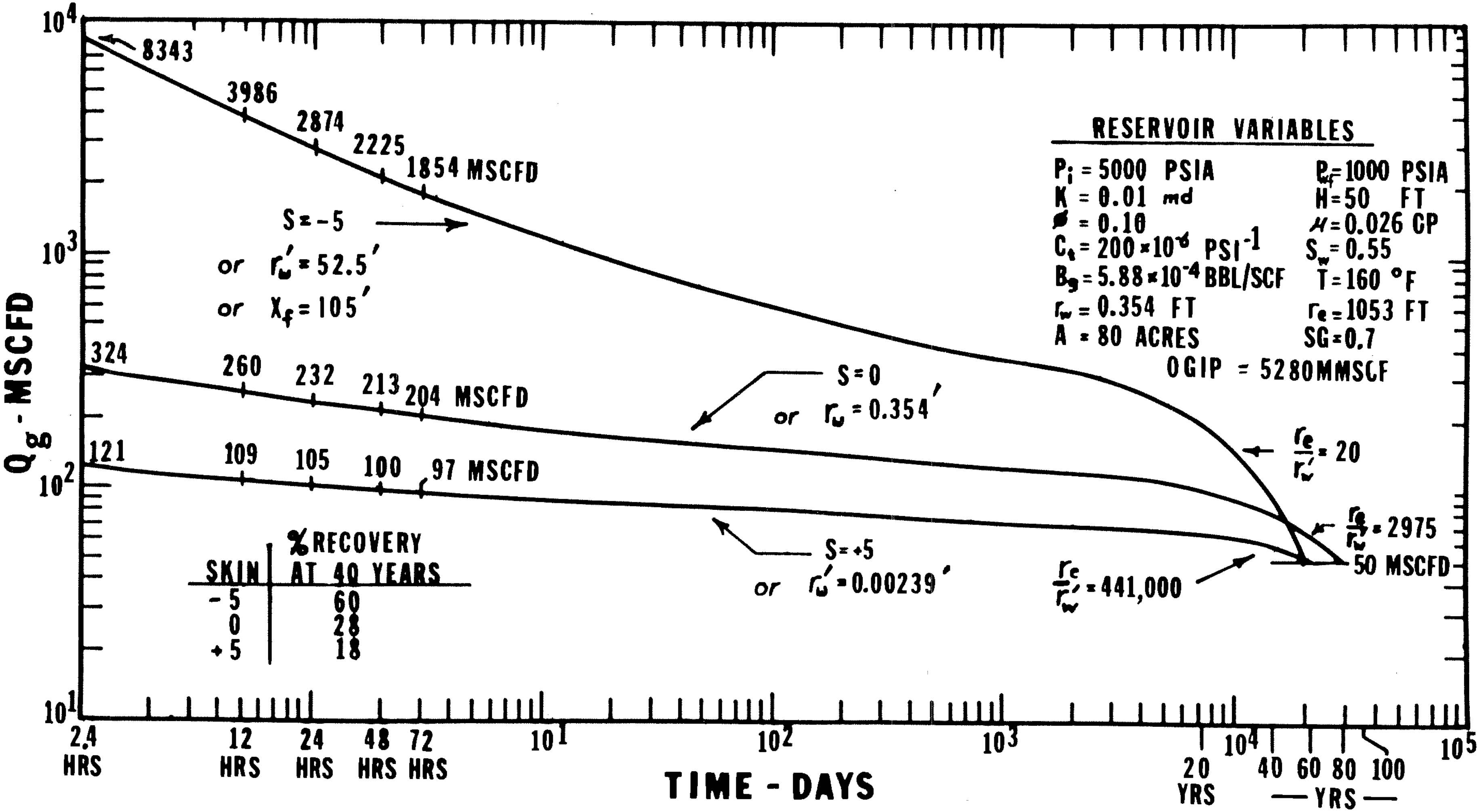
$t=1$ YEAR ; $t_D=.27$


REINITIALIZATION OF
McCRAY AND GENTRY
DATA AT 3 YEARS
b = 0
EXPONENTIAL
OIL RATE, BOPM
1000
100
10
TIME, YEARS
.1
1
10
100



10^5
10^4
10^3
10^2
q_g, MCF/Mo
10^0
10^1
10^2
10^3
10^4
10^5
TIME, MONTHS
∞
$b = 2.29$
$X_e/X_f = 1$
1042 YEAR LIFE
200 mcf/mo
63 YEAR LIFE

GAS WELL EXAMPLE TEST DESIGN
FLOWRATE VS TIME
FOR DIFFERENT SKIN FACTORS



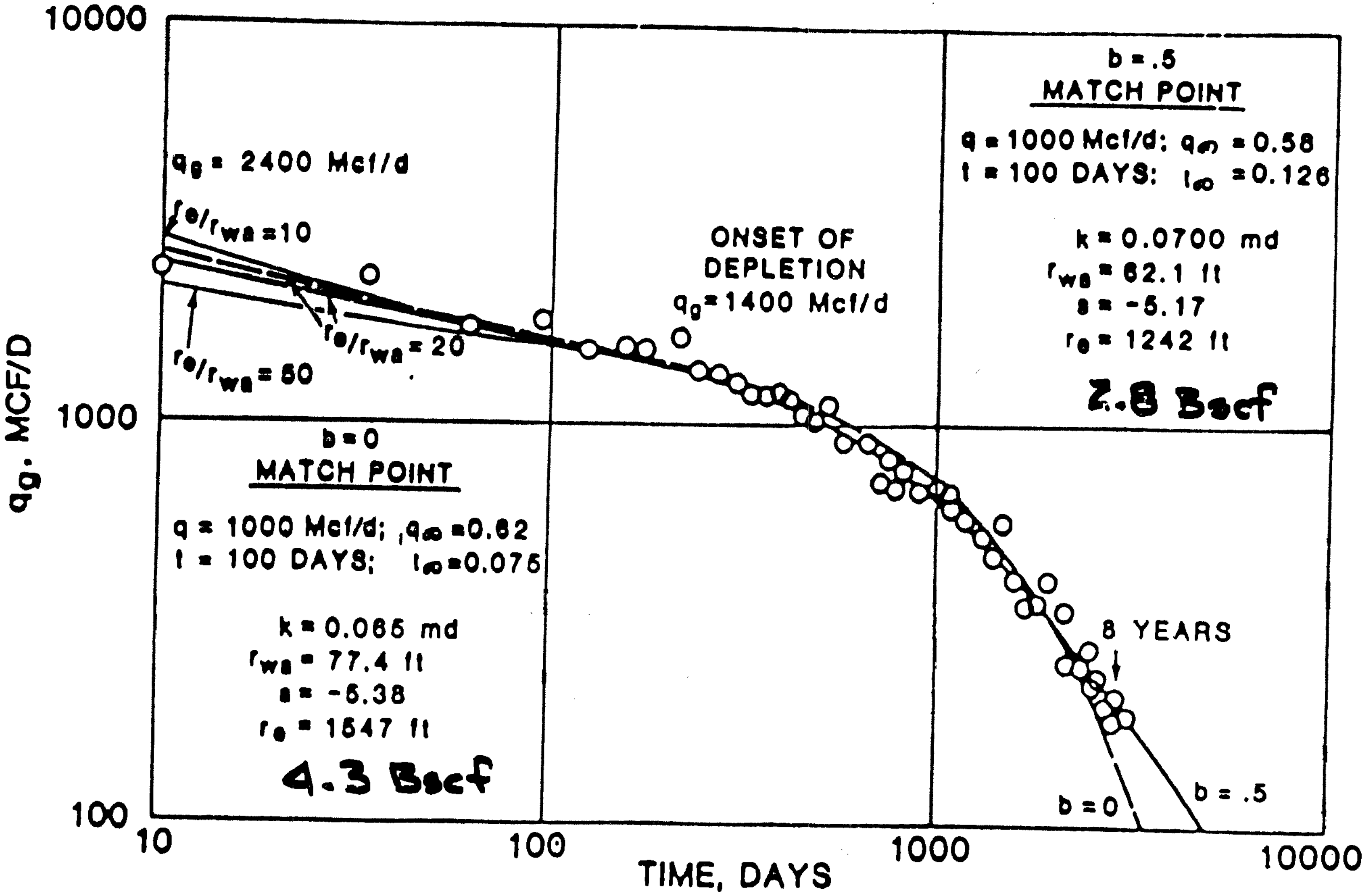
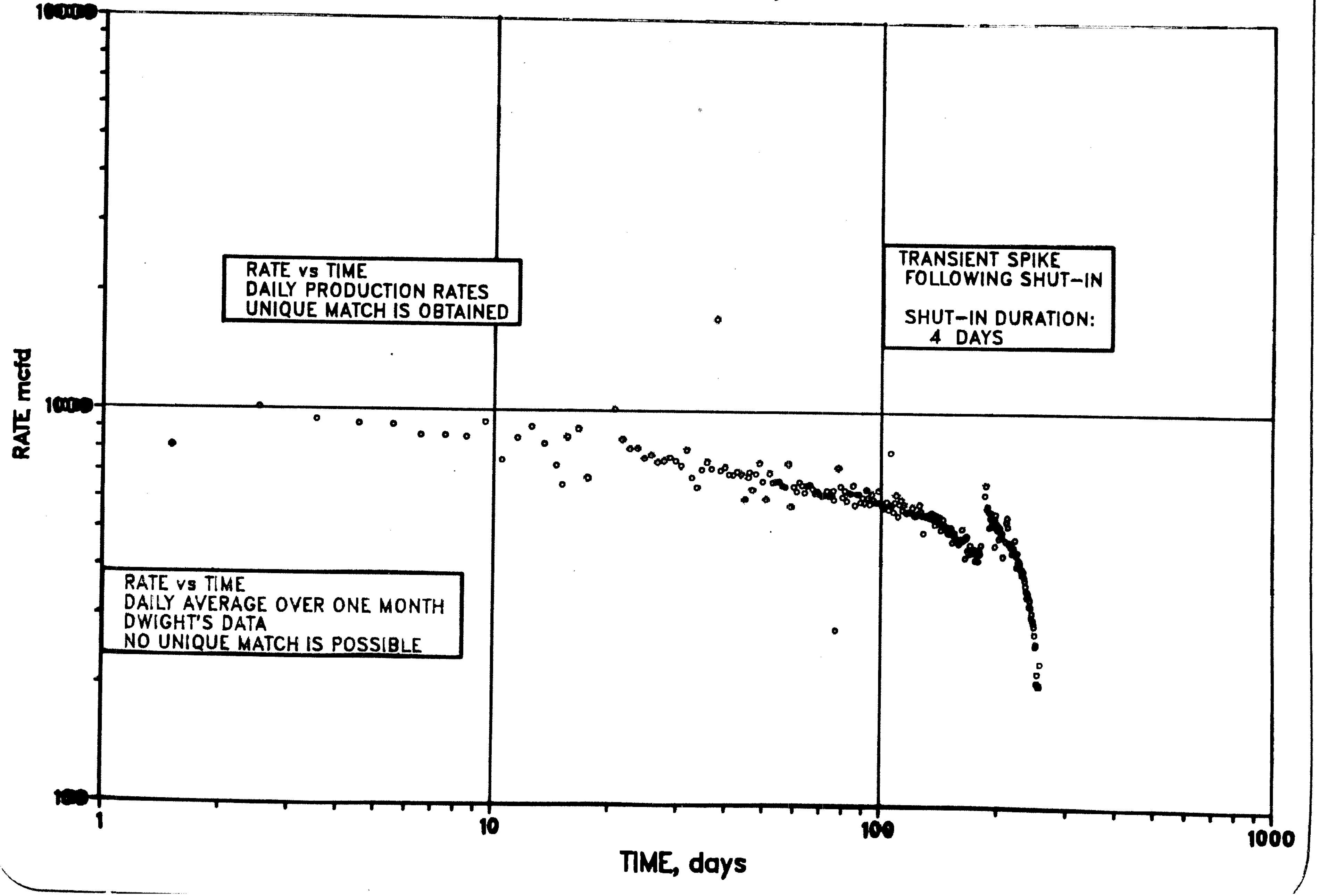


Fig. 17—West Virginia Gas Well A type-curve fit of 8 years of production data fit to a $b=0$ and $b=0.5$.

TABLE 4—WEST VIRGINIA GAS WELL A: SENSITIVITY TO r_e/r_w

	$r_e/r_{wa} = \boxed{10}$	$r_e/r_{wa} = \boxed{20}$	$r_e/r_{wa} = \boxed{50}$	Horner Analysis p_p Basis
kh, md-ft	3.542	4.902	6.705	5.635
k, md	0.0506	0.0700	0.0958	0.0805
V_p, 10^6 ft^3	20.36	20.36	20.36	
r_e, ft	1,242	1,242	1,242	
r_{wa}, ft	124.2	62.1	24.8	
s	−5.86	−5.17	−4.25	−5.52
G at 3,268 psia, Bscf	2.763	2.763	2.763	
G_i at 4,175 psia, Bscf	$\boxed{3.360}$	$\boxed{3.360}$	$\boxed{3.360}$	

NAOMI 3 # 3
CARTHAGE COTTON VALLEY FIELD
PANOLA COUNTY, TEXAS

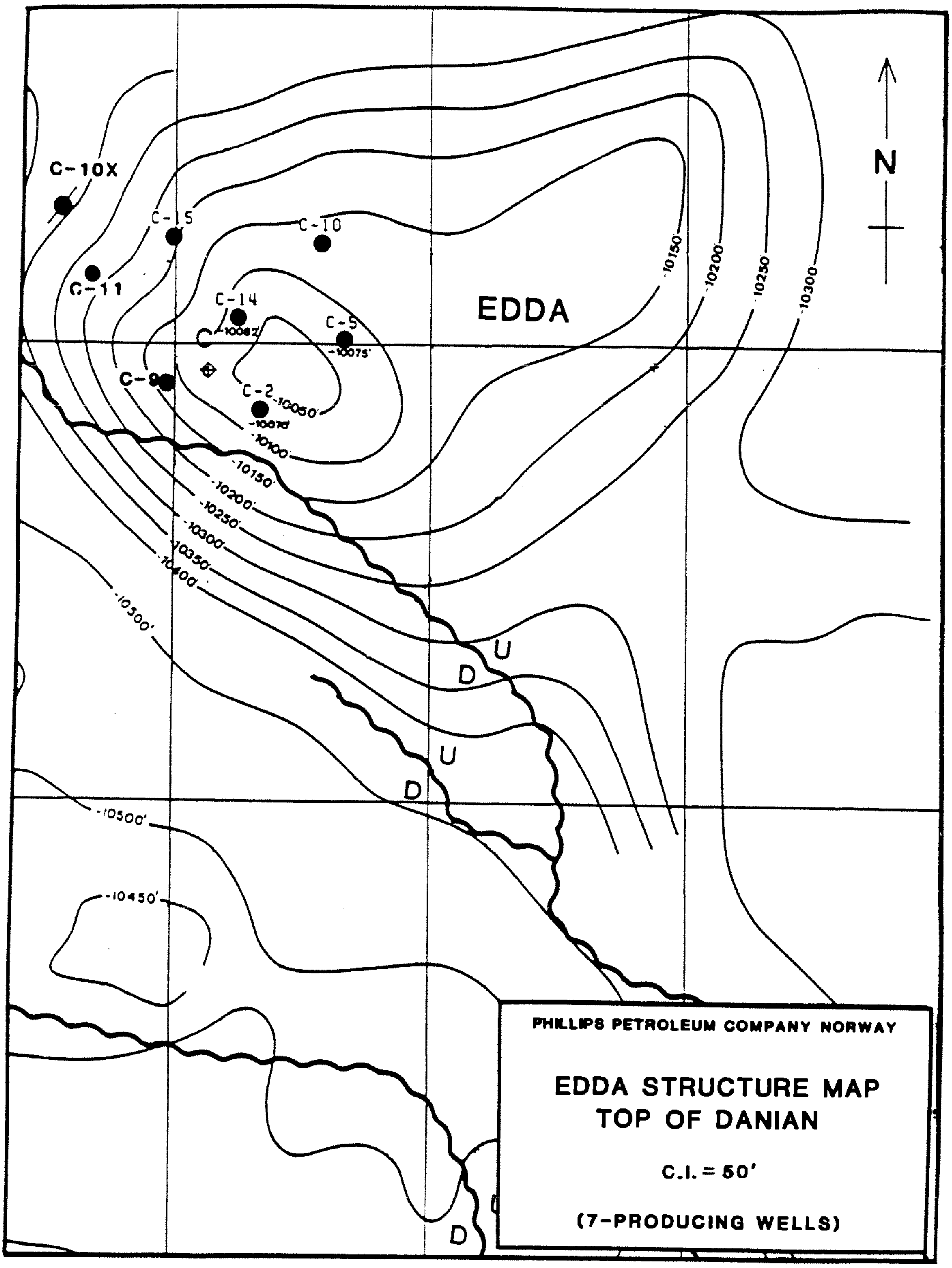


RATE vs TIME
DAILY PRODUCTION RATES
UNIQUE MATCH IS OBTAINED

RATE vs TIME
DAILY AVERAGE OVER ONE MONTH
DWIGHT'S DATA
NO UNIQUE MATCH IS POSSIBLE

TRANSIENT SPIKE
FOLLOWING SHUT-IN

SHUT-IN DURATION:
4 DAYS



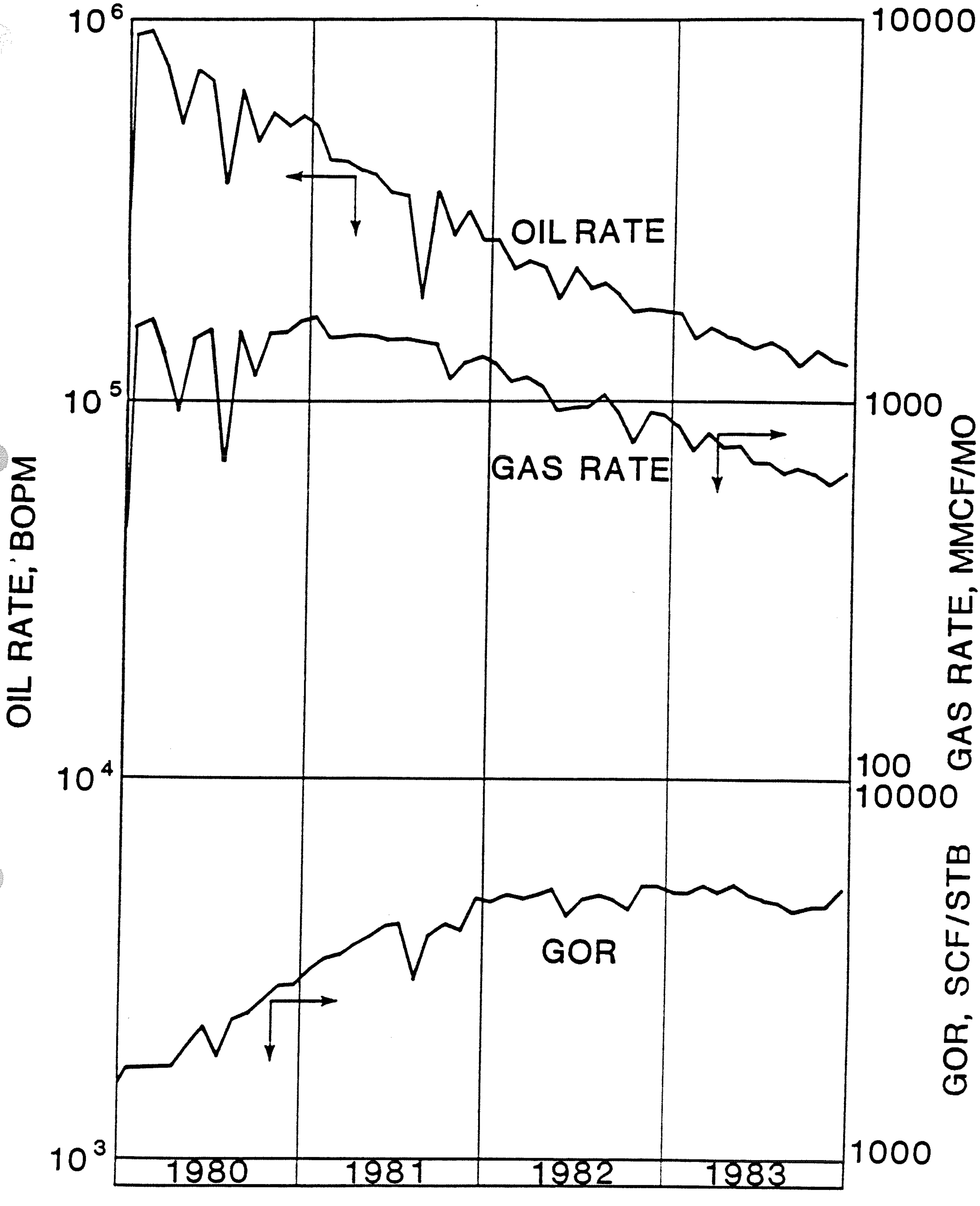
PHILLIPS PETROLEUM COMPANY NORWAY

EDDA STRUCTURE MAP
TOP OF DANIAN

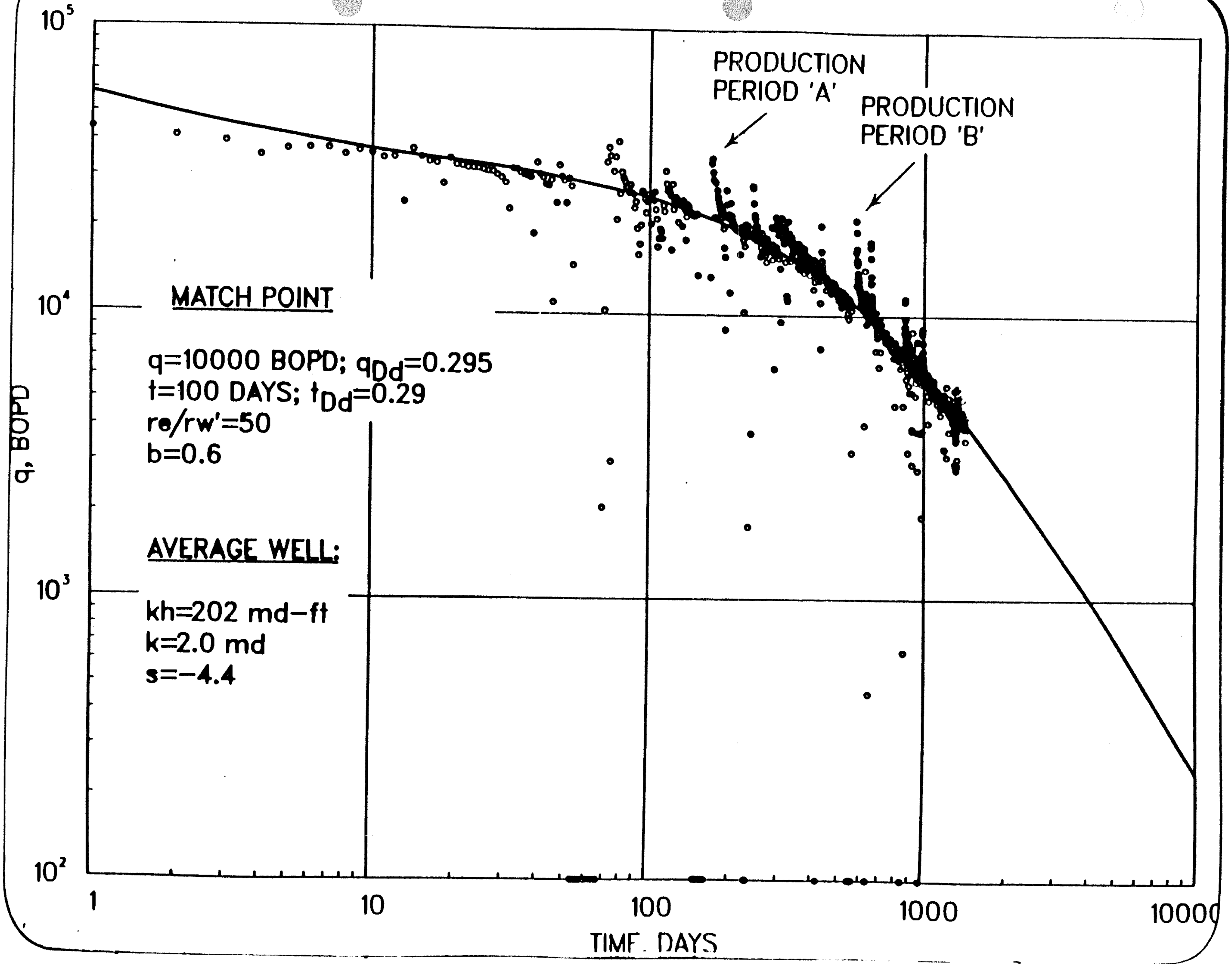
C.I. = 50'

(7-PRODUCING WELLS)

EDDA



OIL RATE, BOPM
10^6
10^5
10^4
10^3
10000
1000
100
10000
1000
GAS RATE, MMCF/MO
GOR, SCF/STB
OIL RATE
GAS RATE
GOR
1980
1981
1982
1983


PRODUCTION
PERIOD 'A'
PRODUCTION
PERIOD 'B'
MATCH POINT
q=10000 BOPD; q_{Dd}=0.295
t=100 DAYS; t_{Dd}=0.29
re/rw'=50
b=0.6
AVERAGE WELL:
kh=202 md–ft
k=2.0 md
s=–4.4
10^5
10^4
10^3
10^2
q, BOPD
1
10
100
1000
10000
TIME, DAYS

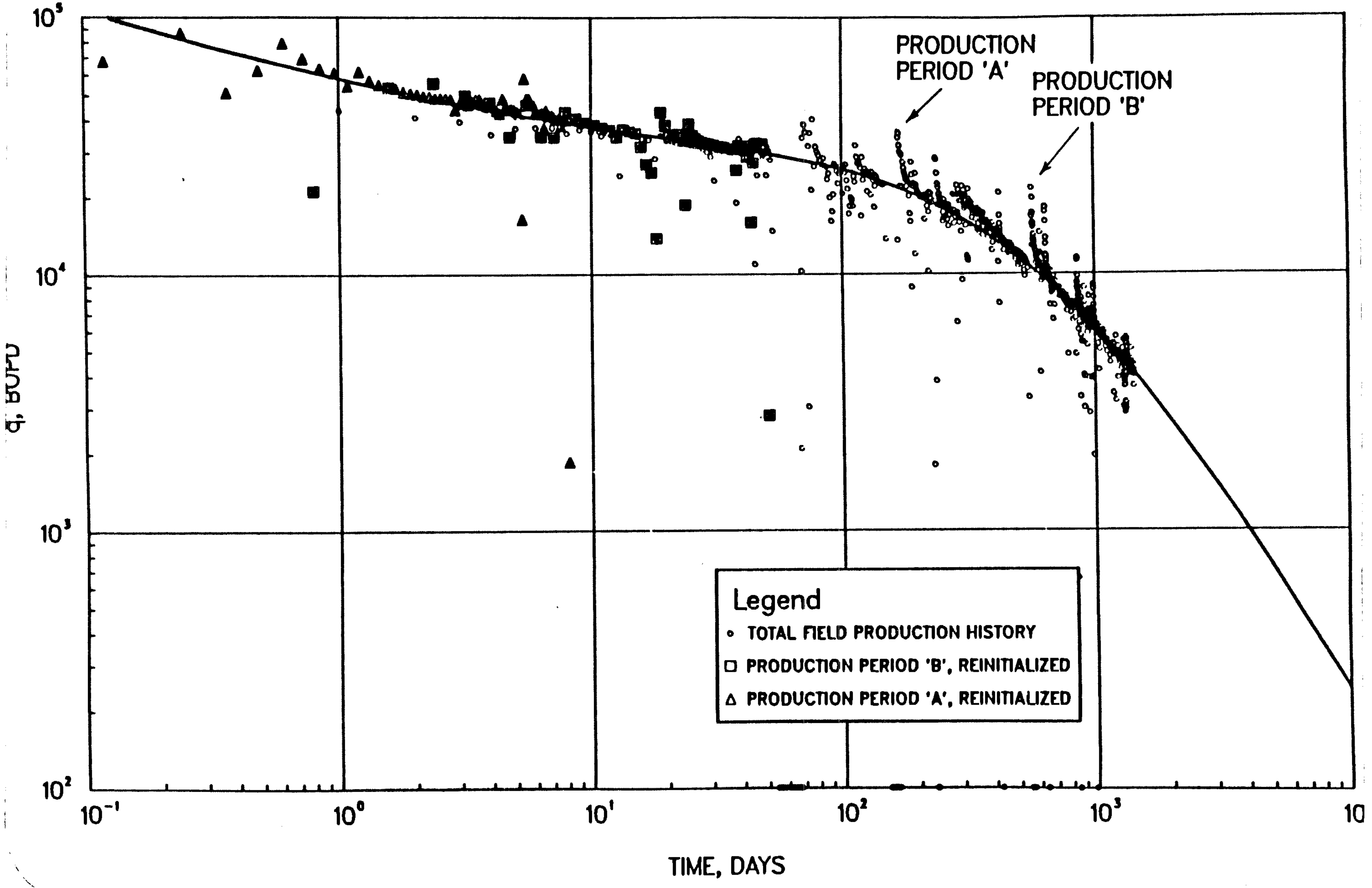

PRODUCTION PERIOD 'A'
PRODUCTION PERIOD 'B'
Legend
TOTAL FIELD PRODUCTION HISTORY
PRODUCTION PERIOD 'B', REINITIALIZED
PRODUCTION PERIOD 'A', REINITIALIZED
q, BOPD
10^5
10^4
10^3
10^2
10^-1
10^0
10^1
10^2
10^3
10
TIME, DAYS

TABLE 8

EDDA SENSITIVITY TO r_e/r_w'

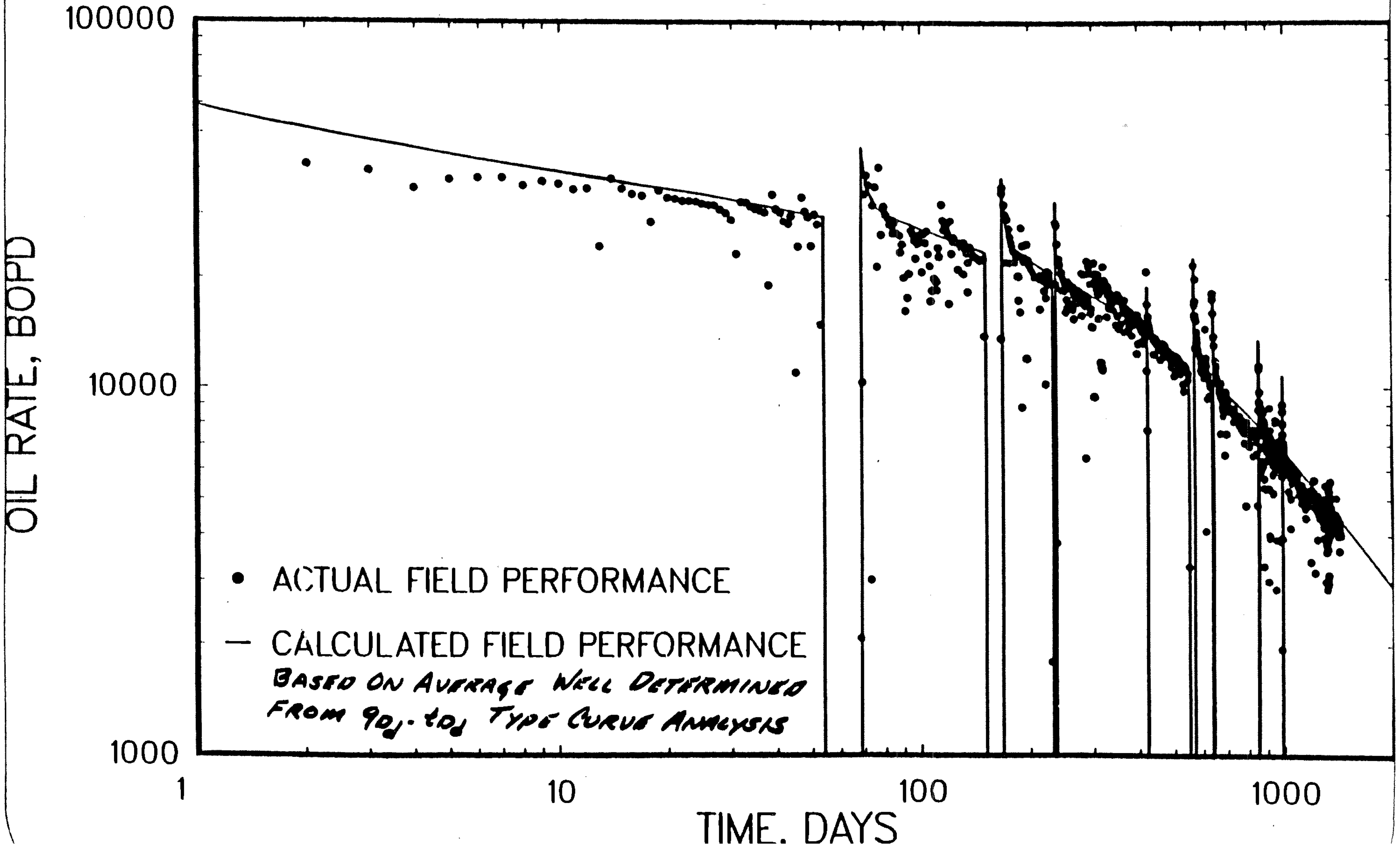
	$r_e/r_w' = 20$		$r_e/r_w' = 50$		$r_e/r_w' = 100$		Average Wel Based on Initial Well Test
	Total Field	Average Well	Total Field	Average Well	Total Field	Average Well	
kh, md-ft	1035.2	147.90	1415.4	202.2	1702.9	243.3	186
k, md	10.35	1.48	14.15	2.02	17.03	2.43	1.86
V_p, MM BBL	202.8	29.0	202.8	29.0	202.8	29.0	
r_e	3919	1481	3919	1481	3919	1481	
r_w'	195.95	74.05	78.38	29.62	39.19	14.81	
s Field[1]	-5.34	-	-4.43	-	-3.73	-	-4.4
s	-	-5.34	-	-4.43	-	-3.73	
OIP, MMSTB	67.1	9.6	67.1	9.6	67.1	9.6	
OOIP, MMSTB	68.3	9.8	68.3	9.8	68.3	9.8	
Material Balance OOIP, MMSTB	67.4	9.6	67.4	9.3	67.4	9.5	

[1] Field $r_w = \sqrt{\text{No. of wells } (r_w^2)}$

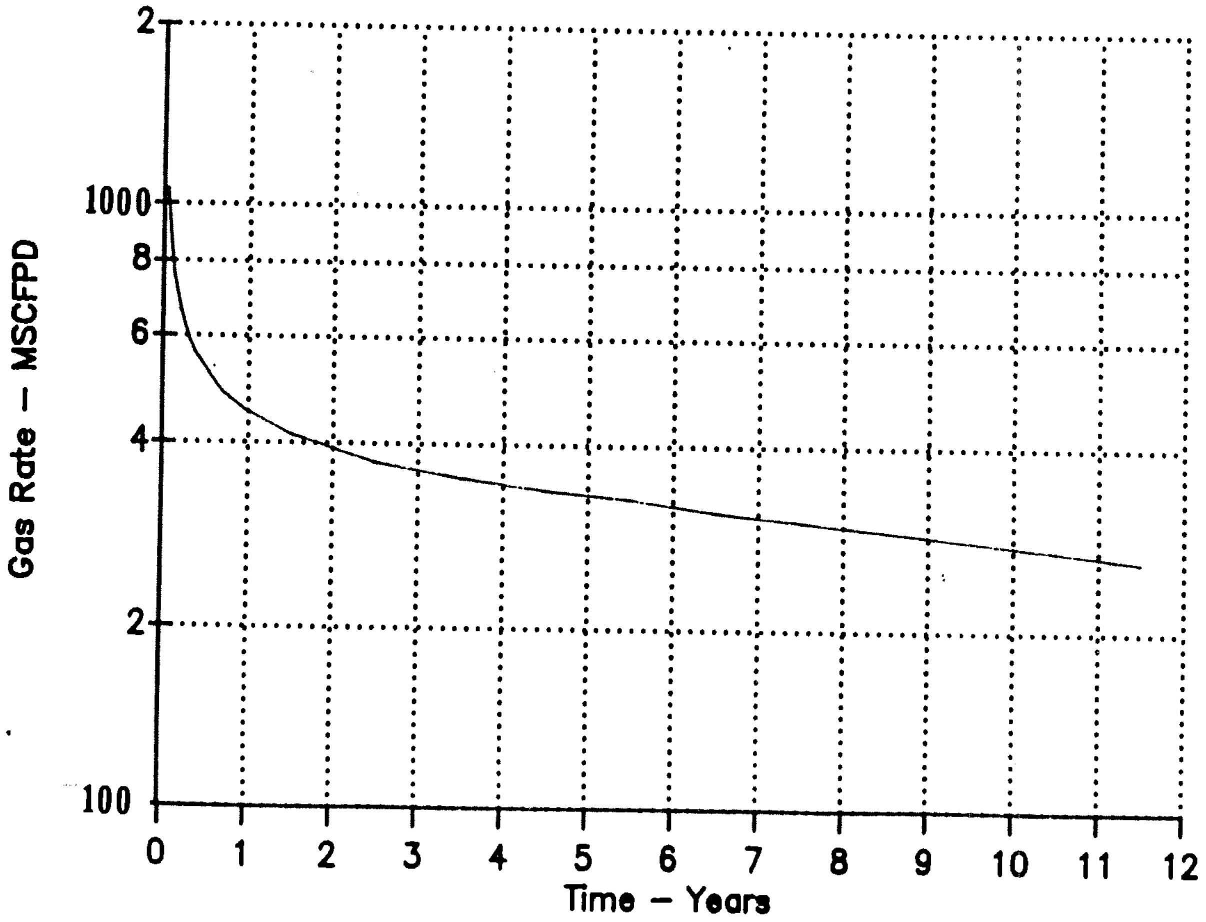
$r_w = \sqrt{7\ (.354\ \text{ft})^2}$

$r_w = 0.9366$ ft

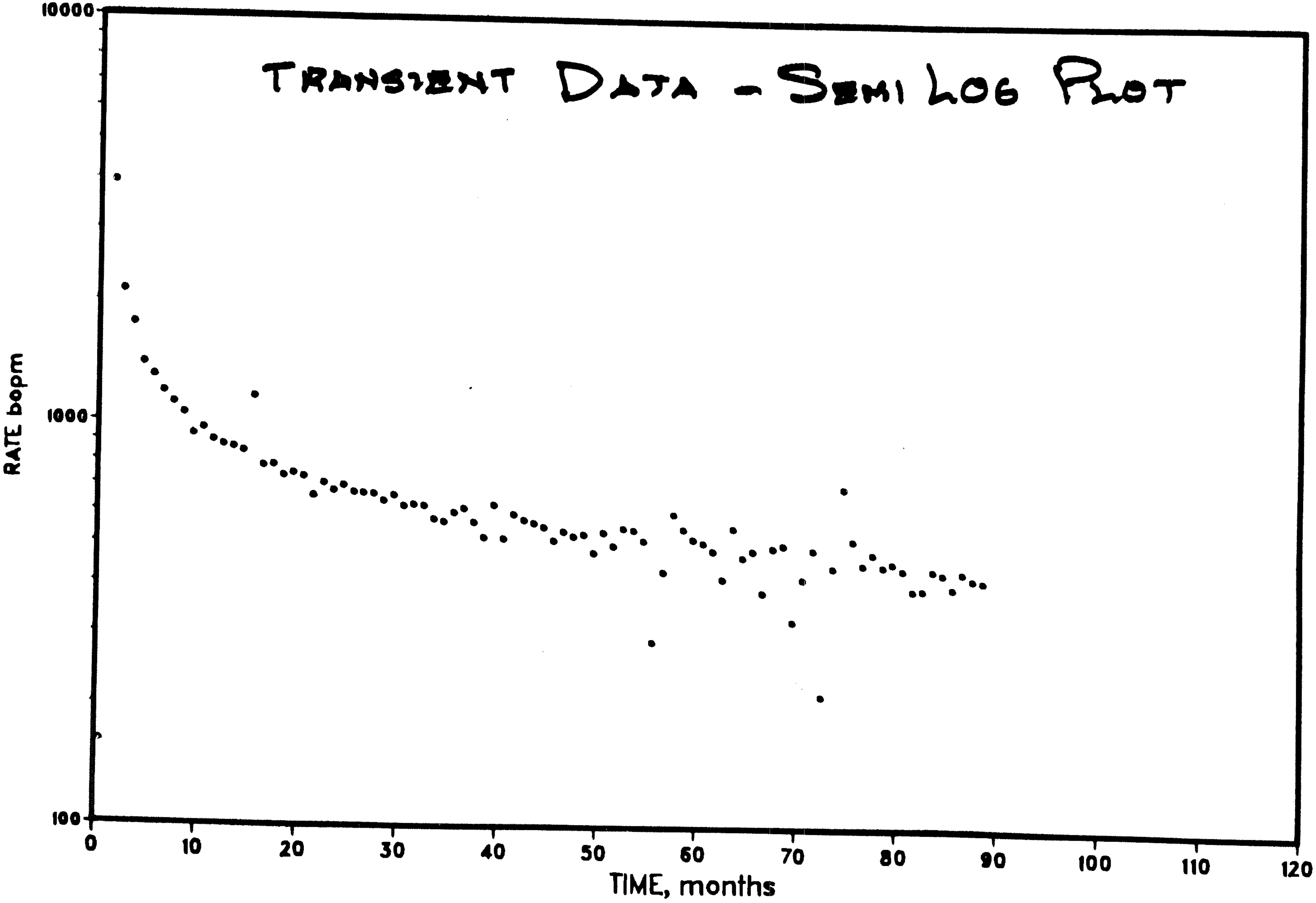
[illegible]


OIL RATE, BOPD
100000
10000
1000
1
10
100
1000
TIME. DAYS
● ACTUAL FIELD PERFORMANCE
— CALCULATED FIELD PERFORMANCE
BASED ON AVERAGE WELL DETERMINED
FROM q_D - t_D TYPE CURVE ANALYSIS

Gas Well Test Design With a Minus Five Skin
Production Forecast From Log–Log Plot (Q vs T)



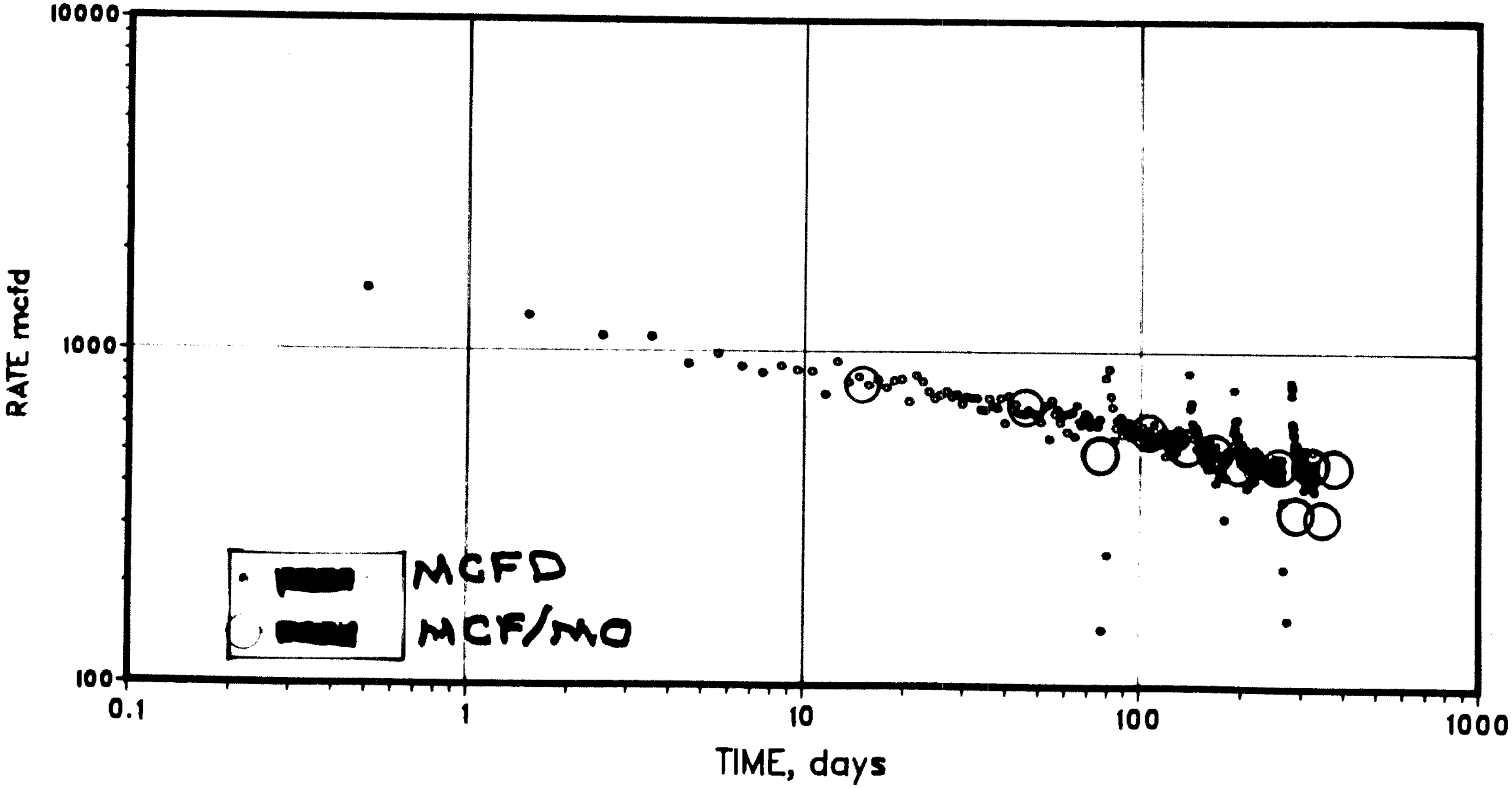
FEDERAL # 1
CONVERSE CO, WYOMING

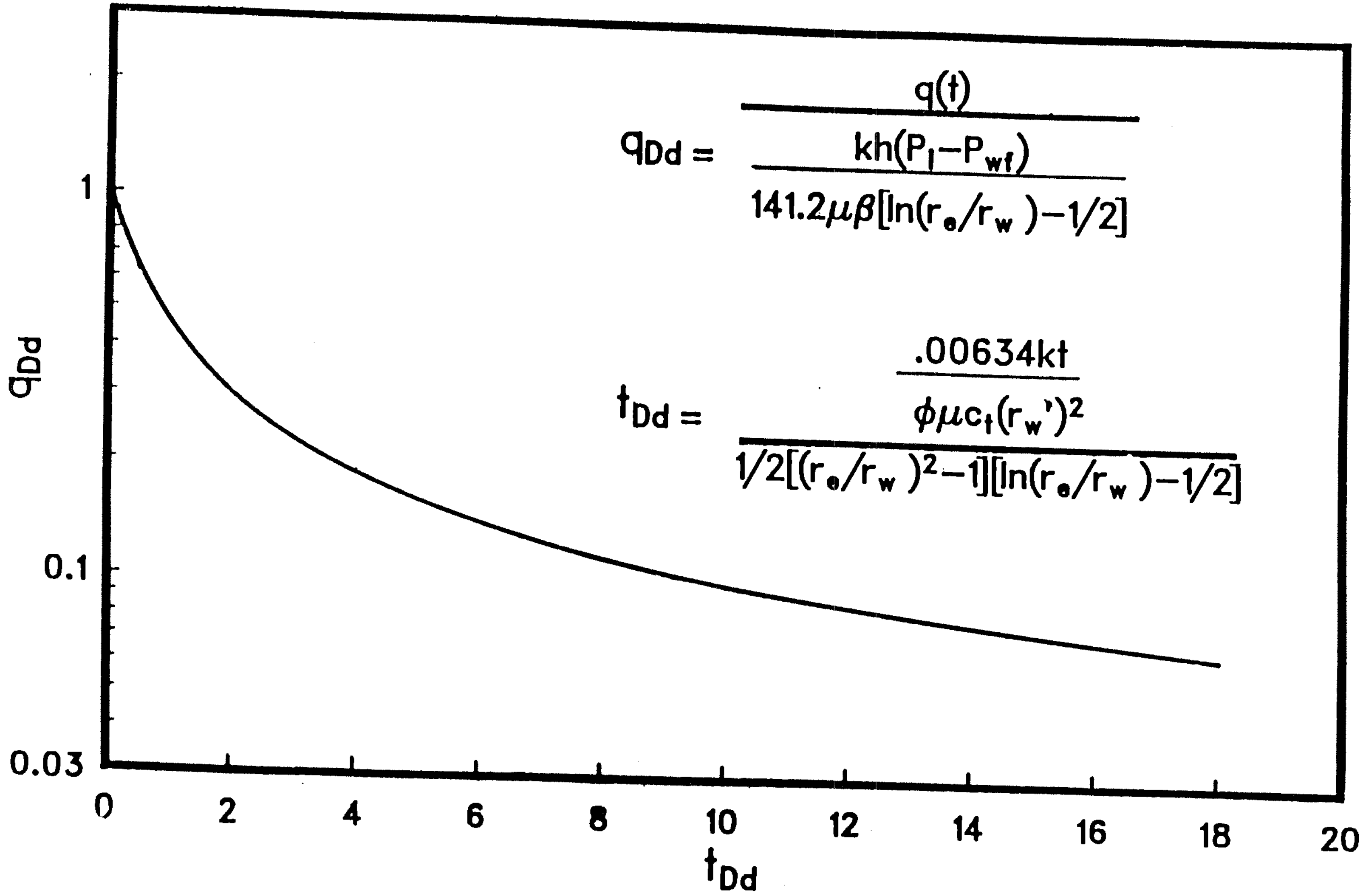


STUDY

STIMULATION EVALUATION & INFILL DRLG.

BEASLEY 3 # 4
CARTHAGE COTTON VALLEY FIELD
PANOLA COUNTY, TEXAS
RATE vs TIME





$$q_{Dd} = \frac{q(t)}{\dfrac{kh(P_i - P_{wf})}{141.2\mu\beta[\ln(r_e/r_w) - 1/2]}}$$

$$t_{Dd} = \frac{\dfrac{.00634kt}{\phi\mu c_t(r_w')^2}}{1/2[(r_e/r_w)^2 - 1][\ln(r_e/r_w) - 1/2]}$$