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Depletion Performance of Layered Reservoirs Without Crossflow

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ABSTRACT

Based on actual field data, this paper presents a study of the depletion performance of a two-layered gas reservoir without crossflow that has produced for over 20 years at effectively a constant wellbore flowing pressure. The study demonstrates that a rate-time decline curve exponent "b" value ranging between 0.5 and 1 (harmonic) is a predicted response of a layered gas reservoir without crossflow. The actual rate-time performance data for the individual wells examined, and the field as a whole, exhibit a decline exponent b of approximately 0.9.

By means of graphical presentations of rate-time and pressure-cumulative production, this paper illustrates some of the depletion performance characteristics that identify no-crossflow layered reservoirs. These graphical presentations show very clearly the effect of changes in the layer volume, permeability, and skin (s) on the depletion performance of no-crossflow layered reservoirs.

Rigorous and simplified approaches to the problem result in essentially the same results. Both constant wellbore pressure and constant rate depletion performance are examined as a part of this study.

INTRODUCTION

Of all the papers written about noncommunicating layered reservoirs, only a few have attempted to deal with the subject of depletion - long term production forecasting. W. Tempelaar-Lietz[1] originally published an internal Shell report in 1953 on the effect of oil production rate from a volumetric reservoir with more than one layer. It was later published in the March 1961 SPEJ along with the classic Lefkovits et al.[2] paper on layered reservoirs. Lefkovits et al. modified the Tempelaar-Lietz constant rate two-layer single phase liquid depletion equations to account for two layers of unequal thickness. Fetkovich,[3] in 1974, applied the constant wellbore pressure single phase liquid solution to rate-time production data from a layered reservoir to demonstrate that when two noncommunicating layers, each characterized by a single phase liquid exponential decline, $b = 0$, were produced commingled, the result was an increase in b to 0.2.

Hypothetical solution gas drive reservoir studies for noncommunicating layers were conducted by Keller et al.[4] in 1949 to investigate the effects of recovery efficiency and gas-oil ratio behavior and by Gentry and McCray[5] in 1978 to study the effects of producing noncommunicating layers on the decline exponent, b. Both studies used single cell models that did not include transient effects. In addition, both used a conventional productivity index relationship, $PI = f(\Delta p)$, for defining a rate equation, instead of an IPR relationship that is a function of the difference in pressures squared, i.e., $PI = f(\Delta p^2)$. By their nature, more sophisticated multiphase flow studies would still have difficulty in assigning realistic k_{ro} and k_{rg} relationships for each layer. Further, the difficulty in obtaining the necessary field data such as individual well measured oil rates, gas rates, frequent bottomhole shutin pressures, and a non-linear $\bar{p}$-N_p relationship presents a serious problem in verification. A similar problem exists for a single phase liquid situation in that few oil reservoirs are totally or even highly undersaturated and produced to abandonment by simple liquid expansion. Those that are highly undersaturated often develop strong water drives because of the large reservoir pressure decline with small production volumes. Such fields are often immediately placed under waterflood. The single phase liquid solutions of Tempelaar-Lietz, however, could find application in very high-pressured gas reservoirs.

To date, we know of no published field case history that illustrates depletion performance characteristics, other than RFT layer pressures, to identify no-crossflow layered reservoir behavior. Single phase volumetric gas fields and wells offer the best opportunity for detection of layered reservoir responses in

References and illustrations at end of paper.

$$q_g(t) = \frac{(q_{gi})_{MAX}}{\left\{\left[\dfrac{(q_{gi})_{MAX}}{G_i}\right] t + 1\right\}^2} \quad . . . (3)$$

Note that the exponent 2 is equal to the Arps[8] exponent 1/b or b = 0.5 for Eq. 3.

The pseudosteady-state backpressure equation with which Eq. 1 was derived is usually written as

$$q_g = C(\overline{p}^2 - p_{wf}^2)^n \quad . . . (4)$$

With n = 1 and $p_{wf} = 0$, Eq. 4, expressed in terms of reservoir variables, becomes

$$(q_{gi})_{MAX} = \frac{kh\,(p_i^2)}{1424\,(\overline{\mu Z})\,T\left[\ln\left(\dfrac{.472\, r_e}{r_w}\right) + s\right]} \quad . . (5)$$

Combining Eqs. 2 and 3 for the rate-time performance of a two-layered system with a common wellbore flowing pressure of zero we have

$$q_{gT}(t) = \frac{(q_{gi})_{MAX1}}{\left\{\left[\dfrac{(q_{gi})_{MAX1}}{G_{i1}}\right] t + 1\right\}^2} + \frac{(q_{gi})_{MAX2}}{\left\{\left[\dfrac{(q_{gi})_{MAX2}}{G_{i2}}\right] t + 1\right\}^2} \quad . . . (6)$$

Only if $(q_{gi})_{MAX1}/G_{i1}$ is equal to $(q_{gi})_{MAX2}/G_{i2}$ will the b value of 0.5 for each layer yield a composite rate-time b value of 0.5.

$$q_{gT}(t) = \frac{(q_{gi})_{MAX1} + (q_{gi})_{MAX2}}{\left\{\left[\dfrac{(q_{gi})_{MAX}}{G_i}\right] t + 1\right\}^2} \quad . . . (7)$$

For the limiting case in which $(q_{gi})_{MAX2}$ approaches 0 in the low permeability layer, the total rate-time profile will, of course, be identical to that of the high permeability layer; each will have a b value of 0.5.

As defined in Reference 3, the ratio of decline curve dimensionless time to real time, t_{dD}/t, is equal to $(q_{gi})_{MAX}/G_i$. Layers having similar values of t_{dD}/t or $(q_{giMAX})/G_i$ will deplete at the same rate and could be treated as a single equivalent layer. We will use the ratio

$$\left[\frac{(q_{gi})_{MAX}}{G_i}\right]_R = \frac{\dfrac{(q_{gi})_{MAX1}}{G_{i1}}}{\dfrac{(q_{gi})_{MAX2}}{G_{i2}}} \quad . . . (8)$$

and the volume ratio

$$V_R = \frac{V_1}{V_2} = \frac{G_{i1}}{G_{i2}} \quad . . . (9)$$

as correlating parameters in our study. By convention, layer 1 is always the more permeable layer.

Assuming for simplicity that $p_{i1} = p_{i2}$ and $(\mu c_t)_{i1} = (\mu c_t)_{i2}$, and substituting reservoir variables as illustrated in Reference 3,

$$\left[\frac{(q_{gi})_{MAX}}{G_i}\right]_R = \frac{k_1/\phi_1\left[\ln\left(\dfrac{.472\, r_{e2}}{r_w}\right) + s_2\right]}{K_2/\phi_2\left[\ln\left(\dfrac{.472\, r_{e1}}{r_w}\right) + s_1\right]} \cdot \frac{r_{e2}^2}{r_{e1}^2} \quad . (10)$$

Similar ratios were also suggested by Raghavan[9] except for the inclusion of the skin and r_e terms. It should be pointed out that the assumption of equal initial pressures is not necessary for the constant wellbore pressure cases since the layer production rates are independent of each other.

<u>Cumulative-Time Equations</u>

The cumulative production-time equation for a gas well producing from any one layer against a constant wellbore pressure of zero is

$$\frac{G_p(t)}{G_i} = 1 - \left\{(2n-1)\left[\frac{(q_{gi})_{MAX}}{G_i}\right] t + 1\right\}^{\frac{1}{(1-2n)}} \quad . . . (11)$$

For n = 1, Equation 11 reduces to

$$\frac{G_p(t)}{G_i} = 1 - \frac{1}{\left\{\left[\dfrac{(q_{gi})_{MAX}}{G_i}\right] t + 1\right\}} \quad . . . (12)$$

<u>Material Balance Equation</u>

The material balance (M. B.) equation for any one layer is

$$\frac{\overline{p}}{z} = \frac{p_i}{z_i}\left[1 - \frac{G_p(t)}{G_i}\right] \quad . . . (13)$$

For a two-layer system with equal initial pressure and fluids, the M. B. equation is

$$\left(\frac{\overline{p}}{z}\right)_T = \frac{p_i}{z_i}\left[1 - \frac{G_{p1}(t) + G_{p2}(t)}{G_{i1} + G_{i2}}\right] \quad . . . (14)$$

For pressure-cumulative production analysis of a layered reservoir, each layer $\overline{p}/z$ and the total system $(\overline{p}/z)_T$ are all plotted versus the total well cumulative production, G_{pT}, where

$$G_{pT}(t) = G_{p1}(t) + G_{p2}(t) \quad . . . . (15)$$

<u>LAYERED RESERVOIR PERFORMANCE FORECASTS</u>

In order to better understand the depletion performance of our noncommunicating layered reservoir, a one well two-layered system was set up using reservoir variables from our field of study. The following data

Constant Rate Cases

To investigate the effect of rate sensitivity on differential depletion, three different constant rate forecasts were made along with a constant wellbore pressure case assuming K_R = 10, V_R = 1, and equal layer skins. Initial rates of 300 Mscfd based on a 1 MMscfd/5 Bscf rate of take, 175 Mscfd based on a 1 MMscfd/8.6 Bscf rate-of-take, and 10 Mscfd representing an economic limit rate were forecast.

The $\overline{p}/z$ vs G_{pT} graph, Fig. 10, demonstrates that differential depletion is not rate sensitive for our practical rates of interest. This is a result of the gas flow rates being a function of kh and a difference in pressures squared, i.e., $q_g = f(\Delta p^2)$. As the flowing pressure approaches reservoir shut-in pressure ($\Delta p \rightarrow 0$), as is the case for the 10 Mscfd forecast, the gas rate becomes a function of a difference in pressures, i.e., $q_g = f(\Delta p)$. Tempelaar-Lietz[1] found that for the single phase liquid case, where $q_o = f(\Delta p)$, differential depletion was sensitive to all rates of flow and that as the constant rate q approaches zero, both layers deplete equally, i.e., layer 1, layer 2, and the total system pressures are all equal. Obviously, very high pressure gas wells will behave like the single phase liquid case, $q = f(\Delta p)$, and solution gas drive reservoirs below the bubble point should behave like the low pressure gas cases since oil well inflow performance[10] yields $q_o = f(\Delta p^2)$.

Figure 11 presents individual layer and composite flow rates for the above cases. Initially, layer rates are a function of kh. When the constant rate cases go on decline, the rates again become a function of kh. The 300 Mscfd case is not shown for clarity of presentation since it lies between 175 Mscfd and the constant p_{wf} case. Note that only for the 10 Mscfd case do the layer rates approach being equal, the constant rate definition of pseudosteady state for two layers of equal pore volume. At practical rates of production that eventually decline to the economic rate of 10 Mscfd, pseudosteady state is never achieved. Also included on this figure are the results obtained using the simple forecasting program based on gas material balance and a stabilized backpressure curve for each layer. The results are identical to the model results.

Field Shut-in Pressures

Routine field data available from layered gas wells consists of monthly commingled production rates, q_T, total system cumulative production, G_{pT}, and commingled shut-in pressures. In our field of study, 72-hr shut-in pressures are taken annually. Based on approximate field reservoir parameters (K_R = 10/1, V_R = 1/2, and $s_1 = s_2 = -3$) annual 72-hour shutin and 48-hour drawdown pressures were simulated using a two-layer radial reservoir model containing 50 cells in each layer. The constant wellbore pressure case results are shown in Fig. 12, and a 175 Mscfd constant rate case, based on a 1 MMscfd/8.6 Bscf rate-of-take, is shown in Fig. 13. As expected, both figures demonstrate that the commingled shut-in pressures, divided by z, basically follow the $\overline{p}/z$ curve of the more permeable layer. The 72-hour pressures for the constant wellbore pressure case are initially somewhat lower than those for the constant rate case because the 72-hour shut-in begins from a much lower flowing pressure prior to shut-in. After about 0.4 Bscf of recovery, the 72-hour pressure begins to exceed the more permeable layer pressure due to interlayer wellbore backflow. Note that trend plotting of the late-time 72-hour shut-in pressure points would overestimate the total original gas-in-place, G_{iT}.

Fig. 14 serves to illustrate the effect of a reduction in p_{wf} on the shape of the pressure-cumulative production plot. In this case, a constant p_{wf} of 192 psia ($\overline{p}/z$ = 200 psia) was maintained for the first 50 years, followed by a constant p_{wf} of 14.7 psia ($\overline{p}/z$ = 15.0 psia) thereafter. With this exception, all forecast assumptions are identical to those employed in Figs. 12 and 13. For a single layer gas reservoir of moderate to high permeability, a change in backpressure will not profoundly affect the shape of the pressure-cumulative production curve. For a layered reservoir without crossflow, however, the effect is dramatic as two distinct differential depletion envelopes become evident. Note that a flattening of the 72-hour shut-in points can be seen both before and after the backpressure change. Eventually, the 72-hour pressures asymptotically approach the minimum flowing wellbore pressure or abandonment pressure. Observed in several wells in our field of study, this flattening of measured shut-in pressures appears to be a characteristic signature of commingled layered reservoirs with contrasting layer permeabilities. It is further magnified when the more permeable layer has a smaller volume than the less permeable layer. Shown in Fig. 15, Well L exhibits a flattening of 72-hour shut-in pressures before and after a line pressure change from 60 psig to 20 psig.

The rate-time companion plot of Fig. 14 is displayed in Fig. 16. The effect of the reduction in p_{wf} is equally pronounced. Interestingly, the total system production response following the backpressure change has the appearance of - but is not - an infinite acting transient spike. Figs. 14 and 16 also demonstrate the excellent agreement between results obtained from the backpressure curve-material balance program, a purely pseudosteady state approach for each layer, and results obtained from the 2-layer 50-cell radial model. As expected, with the ratio of $p_{wf}/\overline{p}$ being different for the two periods, the total system rate-time curve through the first 50 years exhibits a somewhat lower b value than the b value obtained by reinitializing the curve after the decrease in wellbore flowing pressure.

BACKPRESSURE CURVES

A stabilized backpressure curve and a material balance equation are frequently used to prepare long term production forecasts for single layer systems. The stabilized backpressure curve is only utilized during constant wellbore pressure production, i.e., the declining production period. A single stabilized backpressure curve relationship for multi-layer systems has never been defined, mainly because previous investigations of multi-layered systems are based on constant rate production - the rate never experiences decline.

Constant Wellbore Pressure

Depicted in Fig. 17, several different backpressure curves were developed from a radial model forecast, assuming V_R = 1/2, K_R = 10/1, $S_1 = S_2 = -3$, and a constant p_{wf} = 42.8 psia. Annual 72-hour shut-ins, each followed by a 48-hour drawdown, were also simulated to represent typical official test requirements, test of the type curves developed by Da Prat[11] for single layered naturally fractured reservoirs. The early depletion of the high permeability layer appears analogous to fracture volume depletion; the late depletion of the low permeability layer can be considered analogous to matrix depletion. When attempting to identify a naturally fractured reservoir on the basis of double-depletion rate-time behavior, one must therefore consider the possibility of layering with no crossflow. In Monterey reservoirs, for example, the degree of fracturing is highly lithology dependent and any intra-layer fracture-matrix response may be overwhelmed by the layering response among lithologically dissimilar zones of contrasting permeability.

Recall from Fig. 9 that when two separate layered systems have the same gas-in-place, share the same values of V_R, and $(q_{HAX}/G_i)_R$, each system will overlay the same $\overline{p}/z$ - G_{pT} curve. (As long as $(q_{HAX}/G_i)_R$ is constant, each system may have different layer permeabilities, porosities, and skins.) Fig. 20 demonstrates that such systems will also describe similar rate-time curves. In this case, V_R = 1/1 and K_R = 10/1 for both systems. For the system shown using open symbols, S_1 = 0 and S_2 = +5, resulting in $(q_{HAX}/G_i)_R$ = 15.9. For the system represented by closed symbols, S_1 = -3 and S_2 = 0, yielding $(q_{HAX}/G_i)_R$ = 15.5. Log rate versus log time type curves for these systems, based on radial model results, exactly match with a slight shift of both axes due to differing layer skins. Only a minor difference is evident between the profiles of the low permeability layers; the undamaged layer traces a lower r_e/r_{wa} stem during the transient period. Note that the total system profiles, shown with square symbols, exactly overlie, each tracing a b stem of 0.8 through 100 years of production. Similar results are obtained using the pseudosteady state gas deliverability program.

Fig. 21 illustrates similar results for two other systems of equal $(q_{HAX}/G_i)_R$. Both systems assume V_R = 1/2 and K_R = 10/1 approximating the values for our field of study. The open symbols refer to the system in which S_1 = +5 and S_2 = 0, yielding $(q_{HAX}/G_i)_R$ = 6.3. The closed symbols identify the system in which S_1 = 0 and S_2 = -3, resulting in $(q_{HAX}/G_i)_R$ = 6.4. Again, composite profiles exactly coincide, this time approximating a b stem of 0.9.

Figs. 20 and 21 reveal that different values of V_R and $(q_{HAX}/G_i)_R$ produce different values of b. The complete spectrum of possible Arps b values for various differential depletion cases is shown in Table 2. All these results are based on a constant flowing pressure equal to 10 percent of the initial shut-in pressure. Several values of $(q_{HAX}/G_i)_R$, including 1.0, 3.0, 5.0, 10.0, 15.5, 30.0, 100.0, and 1000.0, were investigated in combination with volume ratios of 2/1, 1/1, and 1/2. Predictably, for any given V_R, the b value increases as $(q_{HAX}/G_i)_R$ increases, i.e., as the contrast in layer properties, primarily permeability, becomes more pronounced. For very large values of $(q_{HAX}/G_i)_R$, however, the double depletion decline develops and a constant b stem cannot be maintained. At both ends of the $(q_{max}/G_i)_R$ spectrum, therefore, the composite curve collapses to a single layer profile with a b of 0.4. The highest b values obtained in our study are for (q_{HAX}/G_i) ratios between 10 and 20. Further, for any given $(q_{HAX}/G_i)_R$, b increases as V_R decreases. Assuming $(q_{HAX}/G_i)_R$ = 10.0, for instance, a V_R of 2/1 yields a b of 0.65, a V_R of 1/1 yields a b of 0.80, and a V_R of 1/2 yields a b of 1.0. For very low volume ratios, however, a constant b stem is again impossible to maintain.

Fig. 22 is a type curve overlay of six $(q_{HAX}/G_i)_R$ cases, including 1.0, 3.0, 5.0, 10.0, 15.5, and 30.0, all premising V_R = 1/2. Fig. 23 is a similar overlay of five V_R cases, including 2/1, 1/1, 1/2, 1/5, and 1/10, all assuming $(q_{HAX}/G_i)_R$ = K_R = 10/1. In both figures, the axes of each individual rate-time plot are shifted so that all cases can be presented on a single Arps depletion type curve. Note in Fig. 22 that the radial model results generally begin to fall below a fixed b stem at late time. The higher the b stem indicated by the early depletion performance, the earlier in real time this drop-off occurs. For V_R = 1/5 and 1/10, shown in Fig. 23, the total system profile briefly exceeds a b of 1.0, only to fall back to a lower value of b later in depletion. Eventually, only the low permeability layer contributes to the total flow rate and the b value migrates to that of a single layer. Normal wellbore deterioration, liquid loading, etc., experienced even by a single layer completion, may, in fact, contribute to this migration. With the exception of cases involving low volume ratios, however, our results demonstrate that a fixed b stem will be sufficient for predicting flow rates to a practical economic limit. Nevertheless, caution should be exercised in using a fixed b value to predict reserves at late time for layered systems. We do not advocate the use of b stems greater than 1.0 for forecasting purposes.

A final point concerns the type curve matching procedure used on the curves generated in Figs. 22 and 23. We were unable to analytically predict exactly where to match each composite rate-time curve based on a total system kh. An approximate match could be obtained by first estimating q_{dD} using kh_T and $\overline{\mu B}$, and then shifting the curve from left to right along the time axis in order to match the appropriate early time r_e/r_{wa} stem. The best manual fit q_{dD} was in every case 5 to 10 per cent lower than the calculated q_{dD}. The problem lies in estimating the time to pseudosteady state for a layered system, making the t_{dD} match point difficult to evaluate. Further, the total system pore volume cannot be exactly estimated based on a type curve match of the total rate profile. If a gas well exhibits a b value greater than 0.5, indicating the presence of a layered system, individual layer pore volumes may be estimated by graphically desuperposing the total system curve from the high permeability layer with a b = 0.4 using a trial and error procedure.

DISCUSSION

Most reservoirs consist of several layers with reservoir properties varying to some degree between layers. Whether crossflow exists or does not exist between layers may be of considerable importance in long term forecasting. If crossflow exists, adjacent layers can be combined into a single equivalent layer using the average reservoir properties of the crossflowing layers. Even if crossflow does not exist, layers can still be combined into an equivalent single layer if each has the same diffusivity properties, or q_{HAX}/G_i. It should also be possible to reduce multi-layer systems into equivalent two-layer systems for rate-time analysis or production forecasting. All but the most permeable layer may be combined into a single layer of lesser permeability. We have made a few

8.) Shut in pressures obtained for layered reservoirs will track the pressure of the most permeable layer. Extrapolation of a shut-in $\overline{p}/z$ versus G_{pT} curve may possibly underestimate the gas-in-place, G_{iT}, at early times and overestimate the gas-in-place at late times. Similarly, semilog extrapolation of early rate-time data will underestimate recoverable reserves. Continuing to extrapolate late rate-time data along a fixed high value of b may overestimate recoverable reserves.

9.) The total system stabilized backpressure curve of a layered system is not a straight line. Annual deliverability tests, however, when plotted in the form of a depletion backpressure curve, will define a straight line. The slope of this backpressure curve is less than that of the individual layers.

10.) For our field of study, a simplified approach using a stabilized backpressure curve and a material balance equation for each layer yields the same basic results and conclusions as obtained from a radial model study.

NOMENCLATURE

- b = reciprocal of decline curve exponent
- B = FVF, res vol/surface vol
- c_g = gas compressibility, psi^{-1} [kPa^{-1}]
- c_t = total compressibility, psi^{-1} [kPa^{-1}]
- C = gas-well backpressure curve coefficient
- CAOF = calculated absolute open flow, Mscfd
- e = natural logarithm
- G_i = initial gas-in-place Bscf [std m^3]
- G_p = cumulative gas production Bscf [std m^3]
- h = thickness, ft [m]
- J = productivity index, BOPD/psi [std m^3/kPa]
- k = effective permeability, md
- k_R = layer permeability ratio
- n = exponent of backpressure curve
- N_p = cumulative oil production, STB
- N_{pi} = initial expandable oil-in-place at pressure p_i, STB (Eq. A-5)
- $\overline{p}$ = average reservoir pressure, psia [kPa]
- p_c = wellhead shut-in pressure, psig
- p_i = initial reservoir pressure, psia [kPa]
- p_{wf} = wellbore flowing pressure, psia [kPa]
- $(q_i)_{MAX}$ = initial surface rate of flow from the stabilized curve
- $(q^*)_{MAX}$ = Eq. 16
- q(t) = surface flow rate at time t
- q_T = total constant rate from layers 1 and 2
- r_e = external-boundary radius, ft [m]
- r_{wa} = effective wellbore radius, ft [m]
- r_w = wellbore radius, ft [m]
- s = skin factor, dimensionless
- S.G. = gas specific gravity
- S_w = water saturation, fraction
- t = time, days
- t_{dD} = decline-curve dimensionless time
- T = reservoir temperature, °R
- V_R = layer volume ratio, (Eq. 9)
- z = gas compressibility factor, dimensionless
- μ = viscosity, cp [Pa·s]
- ϕ = porosity, fraction of bulk volume

SUBSCRIPTS

- g = gas
- i = initial
- o = oil
- T = total of layers 1 and 2

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TABLE 1

INITIAL ISOCHRONAL TEST RESULTS

WELL	TEST DATE	WHSIP P_c psig	3 HOUR ISOCHRONAL TESTS CAOF mcfd	Slope n	kh md-ft	h ft	k md	s	*** $h_1/h_2 = 1/2$, $k_1/k_2 = 10/1$ k_1 md	k_2 md
A	10-19-60	384.5	16000	1.00	1498	64	23.4	-4.6	59	5.9
B	12-07-60	383.7	14600	1.00	1761	29	60.7	-5.2	152	15.2
C	01-27-61	386.4	13700	1.00	1332	37	36	-4.8	90	9.0
D	02-27-61	404.4	6200	0.78	1248	47	26.6	-4.0	66	6.6
E	03-06-61	379.9	3600	1.00	332	74	4.5	-3.8	11	1.1
F	03-09-61	408.1	8800	0.83	984	72	13.7	-4.5	34	3.4
G	01-23-63	419.5	3690	0.69*	565	29	19.5	-4.0	49	4.9
H	08-12-63	408.7	5800	1.00	225	39	5.8	-4.8	14	1.4
I	10-02-63	417.9	2000	0.86	215	23	9.3	-4.0	23	2.3
J	09-09-63	416.3	5900	1.00	397	41	9.7	-4.4	24	2.4
Arithmetic Averages		400.9	8029	0.92	856	46	20.9	-4.4	52	5.2
							18.8**			

* Flow after Flow Test

** $\frac{\Sigma kh}{\Sigma h}$

*** $k_1 h_1 + k_2 h_2 = kh_T$ and $h_1 + h_2 = h_T$
$k_1 = 10 k_2$ and $h_2 = 2h_1$

TABLE 2

DECLINE EXPONENT b AS A FUNCTION OF $\left[\frac{(q)_{max}}{G_i}\right]_R$ AND V_g

$\left[\frac{(q)_{max}}{G_i}\right]_R$	V_g 2/1	1/1	1/2
1	.4	.4	.4
3	.5	.55	.6
5	.6	.65	.7
10	.65	.8	1.0
15.5	.65	.8	1.0
30*	.6	.7	.8
100*	.5	.5	.5
1000*	.4	.4	.4

* Double depletion decline b listed in table is for the first depletion decline

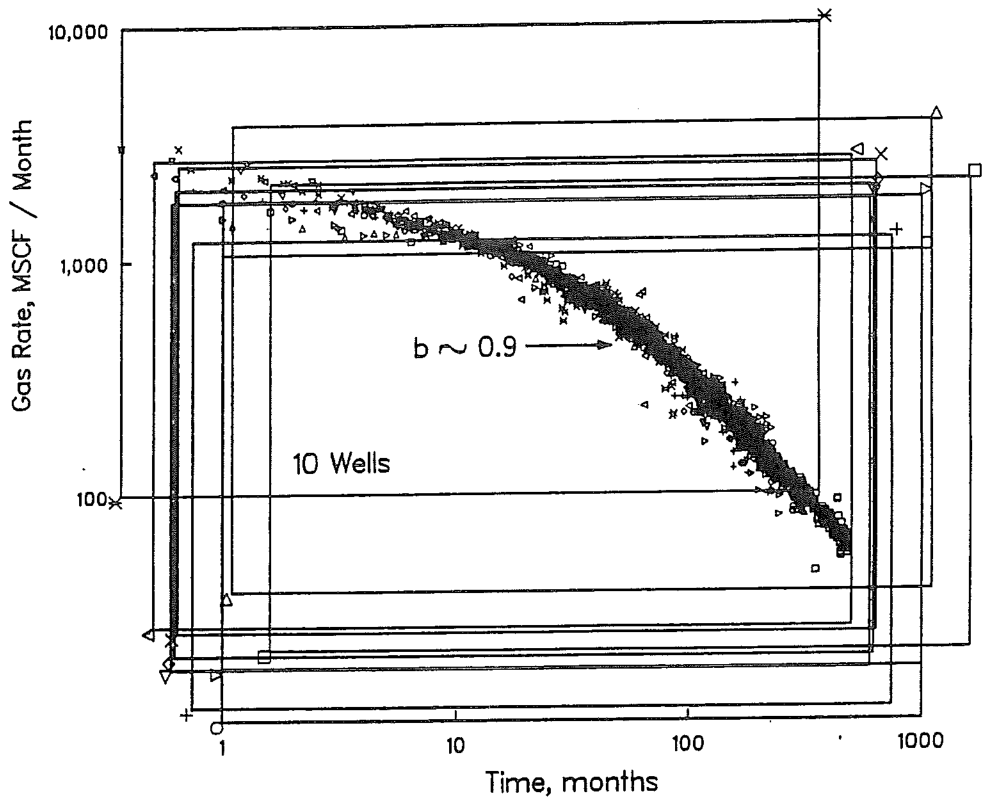

Fig. 1—Overlay of log-rate vs. log-time production data of 10 gas wells.

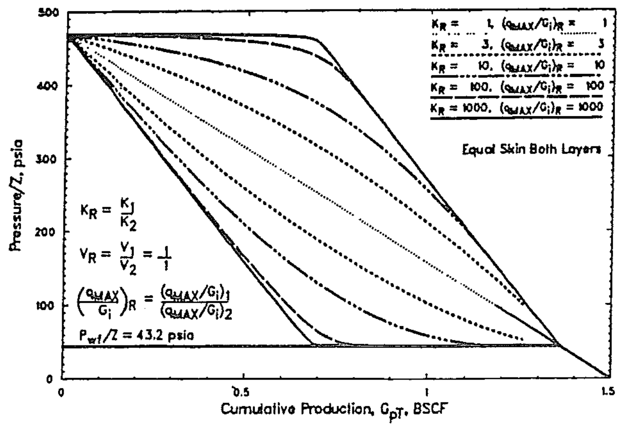

Fig. 8—p/z vs. cumulative production, layer skins equal, $V_R = 1$ and K_R range 1 to 1,000.

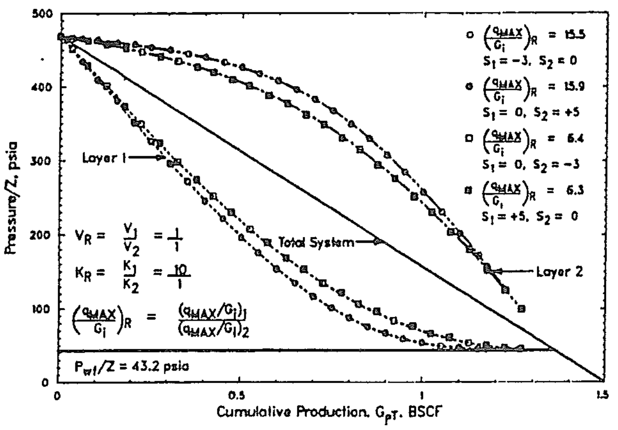

Fig. 9—Effect of different layer skin (S) on p/z vs. G_p curves, $V_R = 1$, $K_R = 10$.

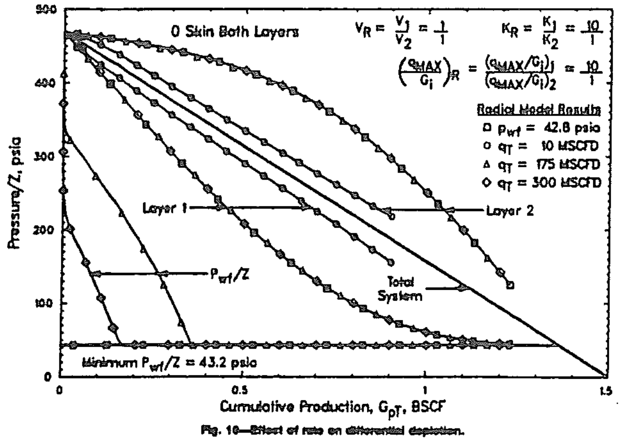

Fig. 10—Effect of rate on differential depletion.

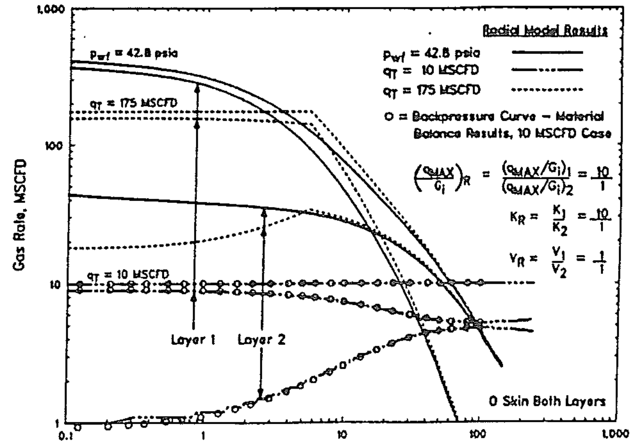

Fig. 11—Layer and composite rates vs. time at constant wellbore pressure and constant rate.

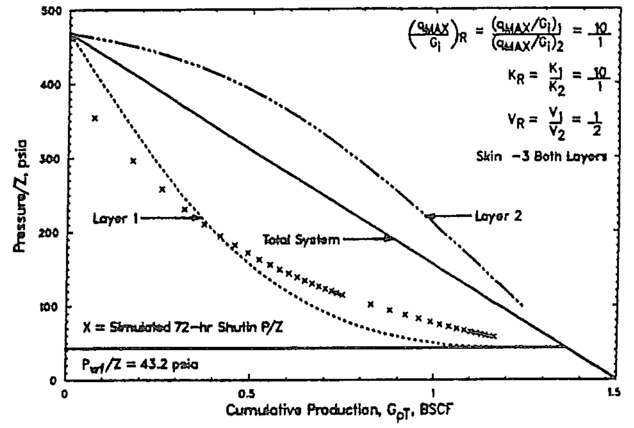

Fig. 12—Simulated 72-hour shut-in p/z compared with layer average pressure p/z, constant wellbore pressure case.

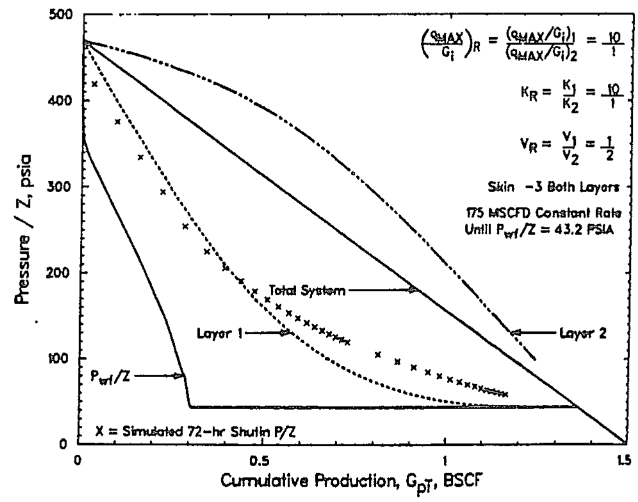

Fig. 13—Simulated 72-hour shut-in p/z compared with layer average pressure p/z, constant rate case.

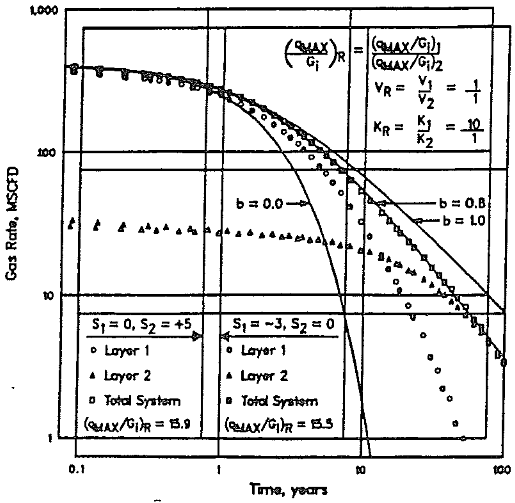

Fig. 20—Effect of layer skins at $V_R = 1$ and $K_R = 10$ on total system decline exponent b.

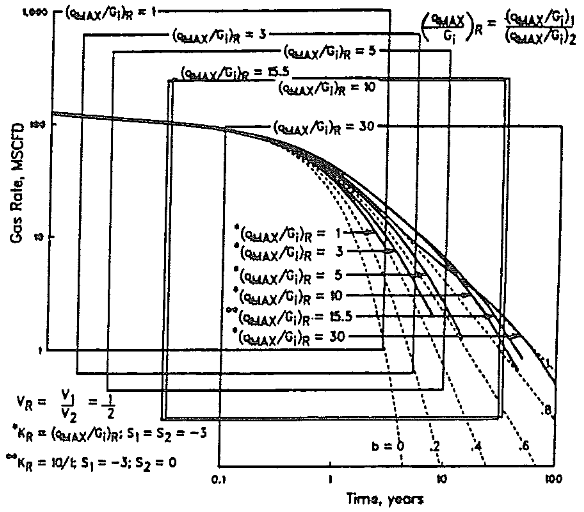

Fig. 22—Composite well declines for $[q_{MAX}/G_i]_R$ between 1 through 30 at $V_R = 1/2$.

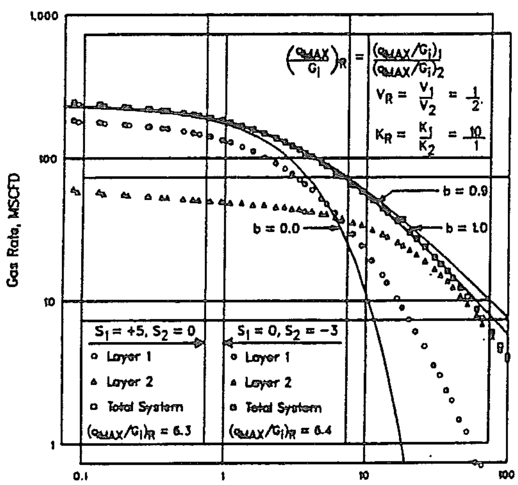

Fig. 21—Effect of layer skins at $V_R = 1/2$ and $K_R = 10$ on total system decline exponent b.

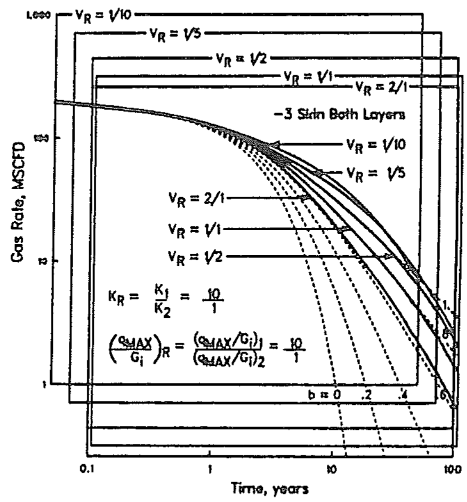

Fig. 23—Composite well declines for V_R between 2/1 through 1/10 at $[q_{MAX}/G_i]_R = 10$.

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DEVELOPMENT OF A MULTIWELL, MULTILAYER MODEL TO EVALUATE INFILL DRILLING POTENTIAL IN THE OKLAHOMA HUGOTON FIELD

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SPE Members

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ABSTRACT

Phillips Petroleum Company conducted a reservoir modeling study as one part of a comprehensive study evaluating the merits of recent infill drilling activity in the Kansas Hugoton Field and evaluating possible infill drilling in the Oklahoma Hugoton Field. This paper describes the development and application of a three-dimensional gas reservoir model in history matching and forecasting the reservoir performance of a layered, no crossflow gas reservoir which has produced at essentially a constant rate over forty years. The multiwell, multilayer model was developed with reservoir variables from twelve contiguous sections within Phillips acreage in the southern portion of the Oklahoma Hugoton Gas Field. Unlike conventional history matching techniques, the model simulated surface shut-ins and flowing pressures from actual tests to history match forty years of official annual shut-in and deliverability test data.

Forecast results show that no additional reserves are added with an additional well on 640 acres. At abandonment, infill wells do not deplete any of the high pressure layers more than that resulting from one producing well per 640 acres. A long producing life (108 years) is predicted for the study area and results from both a low field rate of take and more significantly the depletion behavior of a layered, no crossflow reservoir.

INTRODUCTION

On April 25, 1986, the Kansas Corporation Commission (KCC) issued an order[1] that allows infill drilling in the Kansas portion of the giant Hugoton Gas Field. The order allows producers to drill a second gas well on each of the 4163 six hundred forty (640) acre proration units. Based on geological and engineering testimony, the KCC ruled that an additional 3.5 to 5 Tscf of additional reserves could be recovered by drilling an infill well on most of the current 640 acre proration units. Initial and remaining gas-in-place in the Kansas Hugoton Field, indicated from pressure-cumulative production data presented at the hearing, were 30 and 12 Tscf, respectively.

In view of the infill drilling order in Kansas, the Oklahoma Corporation Commission (OCC) initiated a proceeding to determine whether it should develop a plan to authorize the drilling of increased density wells in the Oklahoma portion of the Hugoton Gas Field. A January 30, 1987, OCC notice of inquiry requested all interested parties to submit answers to 16 questions related to infill drilling potential on the present 640 acre spacing pattern. There are currently 1340 active wells in the Oklahoma Hugoton Field. Cumulative production to March 1, 1989, is 5.0 Tscf with an indicated 1.5 Tscf of remaining recoverable reserves.

Phillips Petroleum Company's investigation of the impact of infill drilling on gas production and the potential of recovering additional reserves from the Oklahoma Hugoton field included four different studies.[2,3,4] One of the more comprehensive studies was a reservoir simulation study which is the subject of this paper. A three-layer, no crossflow, three-dimensional reservoir model was developed to simulate the performance of original and infill wells in a 12 section study area of Phillips Oklahoma Hugoton acreage in the southern portion of the Oklahoma Hugoton Gas Field (see Fig. 1). We demonstrate how a unique history-match of performance data of the original wells on a section was obtained with virtually no adjustment to the log-calculated input variables which determine original gas-in-place and model performance. Any volumetric gas-in-place adjustment would, of course, be crucial to the evaluation of infill drilling potential. The performance data that were history matched in our model study included: 1) over 40 years of official state test annual wellhead shut-in pressure vs. cumulative production data, 2) official state test

References and illustrations at end of paper.

annual 72 hour deliverability test rate and flowing pressure data, 3) individual layer pressure data obtained from an expendable well drilled in the 12 section study area, and 4) pressure-cumulative production and deliverability test performance data of a replacement well in the 12 section study area.

The history matched model was used to 1) calculate the study area's total recoverable reserves and individual layer reserves with and without infill wells and 2) forecast production rates for the study area with and without infill wells at the current market demand and with all wells produced wide open. Study results show that a second well on a 640 acre proration unit does not improve the drainage or recovery compared to the current 640 acre spacing pattern and that the long life, 108 years, associated with the Oklahoma Hugoton field is to be expected because of its layered no crossflow nature.

GEOLOGY

Cyclical sedimentation within the Hugoton Basin produced a Lower Permian section comprised of successive cycles of laterally continuous and mappable, shallow marine carbonate intervals (Florence, Towanda, Ft. Riley, Winfield, Krider, and Herington Limestones), each capped by reddish-brown terrigenous siltstones, mudstones, and shale intervals (Oketa, Holmesville, Gage, Odell, and Paddock Shales).[5] Dolomitization of the carbonates produced a continuous intercrystalline pore system that promotes good areal continuity of reservoir porosity and permeability within each of the dolomitized carbonate intervals. This indicated areal reservoir continuity is supported by our various reservoir studies. Because of their low permeability and high threshold entry pressures, the intervening argillaceous units act as barriers to vertical flow between the carbonate units. Different pressures measured in individual layers by various operators confirm vertical heterogeneity or the layered no crossflow nature of the reservoir. Fig. 2 illustrates N-S and E-W cross-sections through the Phillips 12 section study area showing the basic layering and the continuity of the layers.

In the southern portion of the Oklahoma Hugoton Field where the Phillips study area is located and our geologic studies focused, the principal producing reservoirs are the Herington, Krider, and Winfield members. They constitute three no crossflow gas producing layers in our reservoir simulation model. All other geologic layers below the Winfield and including the lower portion of the Winfield in this portion of the field are wet.

A more in-depth discussion of the geology of the study area and the rest of the Oklahoma Hugoton Field can be found in Ref. 5. The geology and similar Lower Permian layering within the Kansas Hugoton Field can be found in the testimony and exhibits presented in the Kansas Hugoton hearing.

MODEL STUDY AREA

Our model study area includes sections 26-28 and 33-35, T2N, R15E and sections 2-4 and 9-11, T1N, R15E located in Texas County, Oklahoma, (see Fig. 1). In selecting a study area, we looked for a location that was central to our block of acreage in the Oklahoma Hugoton Field and had at least one deep well drilled below the Chase on each of the 30 sections surrounding and including the 12 section study area. The deep wells were drilled in the early 1960's and logged with a suite of modern logs through the Chase formations. Layer correlations and reservoir parameters ϕ, h, and S_w were ultimately developed from log analysis calibrated to core data for input into the reservoir simulation model. The 12 section study area also includes, within its boundaries, one section on which a replacement well was drilled 2259 ft. from the original well in the extreme southwest quarter of its 640 acre section (Fig. 5). History matching of the performance of a previously drilled replacement well with several years of production performance should be equivalent to verifying the ability of our model to realistically predict the performance of any infill wells drilled on a 640 acre section within our study area. A further consideration used to locate a representative study area was to select an area where the outer boundaries of the 12 section study area reasonably coincided with no flow boundaries determined by proportioning offset well producing rates.

LOG ANALYSIS

Logs from the Chase producing wells drilled and logged in the 1940's and 1950's, consisted of SP and resistivity logs only and were not adequate for inclusion in the log analysis. These logs were used, however, in correlating formation tops for cross-sections.

Modern logs from 39 wells from the 30 section region (Fig. 1) were analyzed to define porosity, gross thickness, and water saturation values for input into the model cells. Typical logs from the 39 wells include induction electric, dual induction-laterolog, sonic, and in a few wells, density logs. The Strat No. 2, a replacement well located within the study area, was drilled in 1981 and logged with Dual Induction-SFL, BHC sonic, and density/neutron logs. Two of the wells, the Buf No. 3 and the Shell 2R, both located within the 12 section study area, were drilled and logged in 1987. Logs from these two wells include Dual Induction-SFL, BHC sonic, lithodensity/neutron, and RFT logs. These two wells were cored through the Chase interval. Individual layer DST's were also performed on the Buf No. 3. Figure 3 is a type log which includes individual layer pressures from the DST's. The type log also includes SP, gamma ray, and Dual Induction-SFL traces over the Chase interval from the Buf No. 3.

Core analyses performed on one-inch diameter plugs from the two cores taken in the study area provided data for the calculation of Archie equation parameters a, m, and n for subsequent water saturation calculations. Whole core analyses provided porosity data for the calibration of log porosity to core porosity. Shale travel-time and neutron log shale porosity were both used to correct porosity for shale content. Water resistivity was obtained from water samples produced from study area wells.

The model was constructed as a gross model. Only gross pay thicknesses, excluding thicknesses of the shale formations separating the productive layers, were calculated. The log analyses yield gross thickness values, with porosity reductions for shale content providing the only eventual hydrocarbon pore volume correction. Porosity or water saturation cut-offs were not used to alter the gross thicknesses or gross hydrocarbon pore volumes in the productive layers.

MAPPING OF RESERVOIR PARAMETERS

Porosity, thickness, and water saturation values from log analyses on the 39 wells in the study area were used to generate grid cell values for model input. The mapping extends over thirty 640 acre sections, including the 12 modeled sections and the 18 sections surrounding the modeled sections. See Fig. 4 for the mapped values of porosity for the Krider layer in the 30 section region of our study area.

Permeability values calculated at the 39 well locations for the Herington zone, from core ø-k correlations calibrated to the Herington DST results taken on the Buf No. 3 well, were mapped into the original well locations and also into each of the grid cells for model input. Krider layer permeabilities were then calculated for those wells completed only in the Herington and Krider by subtracting the ϕ-k derived Herington kh from the total well kh obtained from multipoint test analysis. The resulting Krider permeabilities in the 18 (7 in the modeled area, 11 in the perimeter sections) Herington-Krider wells were then mapped and grid point values for model input obtained (see Fig. 4). The resulting map extrapolated Krider well permeabilities at the 12 (5 in the modeled area, 7 in the perimeter sections) Winfield completion wells were used along with the Herington permeabilities and the total well kh from multipoint test to calculate and map Winfield permeabilities for model layer input.

WELL DELIVERABILITY AND LAYER PERMEABILITY DISTRIBUTION

Total well kh and skins for 30 wells were calculated from initial multipoint flow after flow tests obtained on each well after their initial completions in the late 1940's. All layers in each well were separately stimulated thru perforations with an acid frac without proppants, using bridge plugs between each successive treatment. After all layers were stimulated, the bridge plugs were drilled out and a final commingled acid treatment conducted. The well was generally blown for cleanup and rested for at least a week before a commingled multipoint test was conducted. The flow after flow tests generally consisted of three or four 24 hour or 3 hour flows. At the time these initial tests were run, the shut-in pressures within each layer should have been essentially equal at or near their initial values. This is a significant point with regard to pressure transient test interpretation values of kh and skin obtained in no crossflow layered reservoirs when layer pressures are not equal (see Ref. 7).

Our analysis of the multipoint tests consisted of a semi-log drawdown and log-log type curve analysis of the first flow of each of the multipoint tests. The drawdown data for all wells analyzed for kh and skin, s, were found to fit the constant rate infinite conductivity type curve solution. A superposition analysis was then performed to utilize and fit all of the flow after flow test data. A zero non-Darcy flow term was ultimately used in our final superposition analysis; this lack of a non-Darcy flow term will be emphasized again later in this paper. The superposition analysis was most useful with the three hour flows since the semi-log period was not present in a single three hour flow. Table 1 summarizes the pressure transient analysis results in terms of the total well calculated kh and skins for those wells located in the modeled 12 section study area. Eight of the twelve wells required no adjustments in skin to history match all of the 40+ years of official 72 hour deliverability tests. As seen in Table 1, only slight changes in skin were required to match the remaining four wells' deliverability tests. In no case was the total well test kh adjusted in our history matching efforts.

The Herington layer permeability distribution used in our model study was based on a ϕ-k relationship derived from core data taken on two wells drilled and cored in the study area in 1987. The Herington porosity-permeability plot was calibrated with a Herington layer DST pressure buildup calculated permeability conducted on one of the cored wells, the Buf No. 3. This calibrated ϕ-k relationship was then used with the log-derived porosity to obtain Herington layer permeabilities for the 39 wells in the study area. The buildup test calculated permeability was approximately equal to that indicated from the ϕ-k correlation, 0.38 md and 0.37 md, respectively.

MODEL DEVELOPMENT

A review of the various model study testimonies presented in the Kansas Hugoton infill drilling hearing was made. Several one-well multilayer studies fixed in all layers the no flow outer boundaries. All layer volumes were based on a 640 acre proration unit. These fixed drainage boundaries resulted in apparent history matched gas-in-place numbers being less than model input volumetric numbers. This difference in gas-in-place was interpreted to indicate the presence of lenses or pods of trapped and undrained gas. A multiwell, multilayer model study that did account for offset well drainage effects did not attempt to match well deliverability performance, or more crucially, individual layer pressures. By not matching layer pressures, the multiwell study also came up with a similar difference between volumetric and pressure-cumulative history matched volumes as did the one well fixed outer boundary single well model studies. Although the conclusions were the same, the differences were a result of two different effects. This led us to the conclusion that no valid model study was performed to have correctly evaluated the infill drilling potential in the Kansas Hugoton Field.

It was therefore concluded that to realistically evaluate and predict the future performance and production from infill wells in the Oklahoma Hugoton Field, a multiwell, multilayer simulation study must be developed that should attempt to history match all of the following historical performance or reservoir data, including:

1) each well's annual official test shut-in pressure cumulative production data

2) each well's official 72 hour deliverability tests

3) Herington, Krider, and Winfield layer pressures in at least one well in the multilayer study area

4) performance match of (1) and (2) on one or more replacement wells drilled on a 640 acre section in the multiwell study area. We considered that a replacement well's match of several years of performance history would be equivalent to verifying the ability of the model to predict the performance of future infill wells that may be drilled anywhere on a section.

The grid (27 x 36), layering, and number of well locations (12 original wells, 1 replacement and the DST-cored well) used in our Oklahoma Hugoton model study is shown in Fig. 5. Each of the original 12 wells are located in the center of a 640 acre proration unit. Each 640 acre section is modeled with 81 cells (9 x 9) for each of the three (3) layers. The number of cells per 640 acre section, 81, was what was required to correctly simulate the official 72 hour shut-in and subsequent 72 hour drawdown tests. Model verification used a single well on a 50-cell per layer radial model with identical reservoir properties. Both the radial and 9 x 9 one well test models were developed with three no crossflow layers and were able to handle, without instability, the interlayer wellbore backflow that occurred between differentially depleted layers during surface shut ins. The negative skins obtained from well stimulations were treated similarly in both models by including the skin, s, in the well cell productivity index.

HISTORY MATCH

As previously discussed, layer thickness, h, porosity, ϕ, and water saturation, S_w, input into the model for each layer were obtained from core calibrated log analysis. There were never any changes required to ϕ, h, or S_w to obtain the final history match. Layer permeability, k, skin, s, and total well deliverabilities were developed from initial completion commingled well pressure transient tests. Since each layer in all wells was individually stimulated using bridge plugs, all layers were assumed to have been successfully stimulated and skins for each layer completed in a given well were assumed equal to that obtained from the commingled well test analysis. Three wells in the 12 well study area were completed in all three layers, Herington, Krider, and Winfield. Most of the other wells initially were tested and stimulated in the upper few feet of the Winfield, but were then plugged off because following stimulation the Winfield was considered too wet to commingle with the Herington and Krider layers. Only a minor adjustment in skin was required in four of the 12 wells to match individual well deliverability curves (see Table 1). Monthly production rates for individual wells were also basic input into the model.

We have found that in layered no crossflow reservoirs the most critical aspect in confirming a unique history match is to match layer pressures. Layer pressures obtained at the Buf No. 3 expendable well located 1780 ft. NW of the Buf No. 1 and layer pressures at the Buf No. 1 well were:

Layer	Buf No. 3 DST Pressures psia	Buf No. 1 Packer Test 11 Day Shut-In Pressure psia	Model Layer k-md
Herington	314	222	0.1
Krider	121	118 (Krider and Winfield)	9.0
Winfield	141		3.3

The 193 psi difference in pressure between the Herington and Krider layers at the Buf No. 3 location clearly demonstrates differential depletion in our layered no crossflow reservoir. The gradient pressure between the Buf No. 1 and No. 3 over the 1780 ft. is commensurate with the layer permeabilities. Initial reservoir pressure in our study area was 490 psia in all layers.

PRESSURE-CUMULATIVE AND DELIVERABILITY CURVE MATCHING

With the multiwell model we history match individual well 72 hour (96 hour after 1975) surface shut-in pressures calculated to bottomhole and the subsequent final 72 hour drawdown flow rate and flowing pressure, calculated to bottomhole. The shut-in and drawdown periods represent annual official tests taken at mid-year and used by the Oklahoma Corporation Commission to allocate allowables within the Oklahoma Hugoton Field. In the model study, all wells are simultaneously shut-in then flowed at their official test rates using eight 9-hour time steps to simulate the actual 72 hour shut-in and drawdown as conducted in the field.

The p/z vs. Total G_p plot of the Buf No. 1 well (Fig. 6) illustrates one of the key well matches from the final history match of our multiwell model. The 34 triangles represent 44 years of field shut-in pressure performance data. The model shut-in is effectively a wellhead shut-in that allows wellbore backflow between the differentially depleted layers during the period the well is shut-in. The simulated shut-in pressure values obtained with the model are shown as circles on the figure.

The solid lines shown on the p/z vs. G_p plot represent the volumetric average layer pressures and the total system average pressure over the 640 acre unit plotted against the total cumulative production, G_p produced from all layers. The lowest curve represents the layer average pressure, $\overline{P}$, of the most permeable Krider layer followed by the Winfield layer, the total system volumetric average pressure of all three layers, and finally, the uppermost curve that represents the low permeability Herington layer average pressure. Also shown on this figure is the excellent match of layer pressures at the model location of the Buf No. 3 expendable well located 1780 feet from the Buf No. 1 producing well.

The total well 72 hour transient deliverability curve match of the Buf No. 1 well is shown in Fig. 7. The 34 triangles represent 44 years of field well performance test data presented as a bottomhole backpressure curve plot. No reservoir or stimulation deterioration since initial completion is indicated from this data. The circles represent the model simulation of the actual test sequence durations and test flow rates. The quality of the overall match is reflected by a model point to test point overlay. Because the total well kh and s are now correct in the model, model points will also lie along the backpressure curve established by field data even if a poor match of reservoir shut-in pressures, $\bar{p}$, is obtained.

This matching of the 72 hour test based on model input variables developed from an analysis of initial 3 hour and 24 hour flow after flow tests, with only a minor adjustment of skin in a few wells, is quite remarkable. It speaks highly of modern well test analysis methods applied to high quality test data taken in the mid-1940's. A significant point to note from the backpressure curve plots of field and model data is that a backpressure curve slope of n = 0.886 is obtained, even though the model has no non-Darcy flow component in any of the layers for any well in the model. The Mutual No. 1 well offsetting the Buf No. 1 has the lowest value of slope n = 0.799 (see Fig. 11).

REPLACEMENT WELL MATCH

A history match of the performance of the Strat No. 1 and 2 wells located on a 640 acre proration unit in the south central portion of our model study area was an attempt to demonstrate the ability of the history matched model to accurately predict the results of drilling an infill well. The Strat No. 2 well was drilled in 1981, some 2259 ft southwest of the Strat No. 1 well, as a deep test. The No. 2 well was completed as a replacement well for the No. 1 well in the Herington and Krider layers. The Strat No. 1 well was plugged and abandoned upon the completion of the No. 2 well. The permeabilities, thicknesses, porosities, and water saturations at the No. 2 well cell were those previously assigned from our initial model description, (no pressure transient testing was conducted on the No. 2 well after it was completed). The skin used for the No. 2 well was that value previously assigned to the No. 1 well, s = -4.66. At the completion of the Strat No. 2 well, a pumping unit was installed for continuous dewatering of the well. The replacement well was completed in the Chase because the No. 1 well was beginning to load up with water, as was seen on the backpressure curve performance plot (Fig. 9) and its rate-time plot (not shown).

The p/z vs. G_p match of both the Strat Nos. 1 and 2 with a combined 44 years of history is shown on Fig. 8. Note the match of the change in slope and excellent match of the No. 2 well test pressures compared with the model test value. No changes or adjustments to any of the reservoir parameters of the No. 2 well were made. This matching of the No. 2 well constituting 8 years of performance data since its replacement of the No. 1 well, tends to confirm the model's ability to predict the performance of a well drilled within our history matched 12 section study area.

The history matched deliverability curve(s) of the Strat No. 1 and 2 are illustrated in Fig. 9. The early 72 hour performance of the No. 1 well and the current 72 hour performance of the No. 2 well, with pumping jack, show essentially the same deliverability curve location for both wells. This indicates that the replacement well, equivalent to drilling an infill well within the 640 acre section, is no better or worse than the original well. Ref. 3 compares the results of infill drilling to date in the Kansas Hugoton Field, showing that the <u>average</u> infill well backpressure performance curve is approximately 10 percent better than the original well. Based on a frequency distribution, however, the <u>most probable</u> result is that the infill well will be only 85 percent as good as the original well. Ref. 4 similarly illustrates that when the original well has been properly stimulated, or restimulated, the infill well performance will be virtually identical to the original well.

In our early attempts to estimate the deliverability performance curves of infill wells, it had been assumed that modern stimulation technology could possibly result in a 3- or 4-fold increase in the deliverability curve of an infill well when compared to an original well. Considering the relatively successful negative skins we later found on the Phillips 12 well study area wells, averaging -5.0, it is highly unlikely that new infill wells can improve on the stimulation results obtained on our original wells. Furthermore, with the differential layer depletion currently existing, diversion techniques other than mechanical bridge plugs would tend to be less successful than when all layer pressures were equal.

12 SECTION STUDY AREA MATCH

An excellent history match was obtained on all wells with the multiwell no crossflow three layered model. There were virtually no changes to the original reservoir input variables. There was absolutely no adjustment to the pore volume input data. A slight departure in observed vs. slightly lower calculated shut-in pressures was evident on the Christine, Princess, and Oella wells on the east side. Attempts to fine tune the match on these three wells were made using the concepts and equations in Ref. 6, including investigating the effect of expanding the size of the study area. It was noted that the magnitude of kh in the Princess and Oella wells, 999 md-ft and 850 md-ft, respectively, was much higher than the other Herington Krider completions and closer in magnitude to those wells perforated and completed in the Winfield. (Use of the equations of Ref. 6 also confirmed the need for five completions in the Winfield.) Fig. 10 shows the final p/z vs. G_p match of all 12 wells with five wells having Winfield production, including the Princess and Oella. Recall that the Buf lease also matched the model layer pressures to the layer DST data. The overall match covers a period of 44 years of performance data.

The 72 hour official deliverability test matches for each of the wells are shown in Fig. 11. The matches are excellent on all wells. As mentioned previously, minor adjustments to skin values were made in four wells to obtain the deliverability curve matches (see Table 1). Note that the slopes of backpressure curves range from a low of n = 0.799 to a high of n = 0.908. <u>Recall that there is no non-Darcy flow term in any of the model layers</u>. The average of all the backpressure curve slopes n is equal to 0.872. This compares to that of 0.850 assigned by the Oklahoma Corporation Commission original field rules order of 1943 to be used for all wells for deliverability and allowable calculations.

CLOSING OF THE SECTION LINE BOUNDARIES

To illustrate the danger of attempting to study the infill drilling potential of a layered reservoir using single well model studies or single well analytical solutions, no flow boundaries were placed between all of the section lines. This converts the matched 12 well model into twelve separate one well studies, anyone of which could have been selected to study infill drilling. Because flow rates from each individual layer are not available to proportion no-flow boundaries for each layer, one must assume for individual well studies that the drainage radius, r_e, for each layer are equal and most likely to be that of the proration unit spacing.

Fig. 12 shows the results of closing all section line boundaries. The history match is destroyed. Recall that input data are based on and consistent with all known reservoir data and geological interpretations. The results clearly show that there was areal communication throughout the study area. Only the Mutual, Princess, Oella, and Strat leases appear to have preserved their match with the original basic reservoir description, and a layered no crossflow system. The Mayoe, Buf, and Luman leases could have been exactly matched by assuming crossflow between all layers, whereas the Vantine and Christine leases would have required an increase in pore volume and the Dakar and Atar would have required a decrease in pore volume to have obtained a match. Any decrease in pore volume could then have been interpreted as an indication of trapped or bypassed gas, thus justifying a need for infill drilling as was concluded from the Kansas Hugoton one well studies.

CROSSFLOW CASE

A seemingly good history match of p/z vs. G_p was also obtained assuming crossflow between all layers. A kv/kh of 0.005 between all the layers was used. This case illustrates the necessity of obtaining and matching layer pressures in a no crossflow layered reservoir. Fig. 13 shows the p/z vs. G_p match obtained on all wells with crossflow and a 20 percent reduction in pore volume. The pressure-cumulative production match on all wells appears excellent. Similarly, the individual well deliverability curve matches, not shown, appear to be as good as those obtained for the final no crossflow history match. There are, however, no point to point matches of the test and model data. Layer pressures for each of the three layers and the total system pressure are indistinguishable on Fig. 13 because they are equal and all overlay each other.

Layer pressures at the Buf No. 3 well location for the crossflow case are:

Layer	Model Pressure psia	DST Pressures psia
Herington	100	314
Krider	97	121
Winfield	98	141

It may be coincidental, but the 20% pore volume reduction necessary to match the p/z vs. G_p data is identical to that found in a Kansas Hugoton Field multiwell study that matched only pressure vs. cumulative production data. It was the 20 percent difference between volumetric derived gas-in-place and history matched gas-in-place (referred to as "target" or "bypassed" gas) that was used as a basis to justify infill drilling in the Kansas Hugoton Field.

FUTURE PERFORMANCE PREDICTIONS

The history matched multiwell model (with lateral communication and no crossflow) was used to forecast future production with and without an infill well drilled on each of the twelve 640 acre proration units. Infill wells were located in the center of the NW quarter of each of the 12 sections and completed in the same layers as the original wells. The same stimulation skin as was used for the original well was used for the infill well. All infill wells were premised to begin producing January 1, 1990. The average allowable production was specified as a constant rate for each well until they eventually went on decline producing against a limiting line pressure of 20 psia. For the infill well case, the section allowable remained the same, i.e., each well produces half of the single well section allowable. The Oklahoma Hugoton Field well allowable is based on acres times deliverability. It is unlikely that the field market demand will substantially increase in the future.

The total 12 section production rate used for prediction was 1740 Mscfd, which corresponds to a rate-of-take of 1 MMscfd/29 Bscf of original gas-in-place. This rate-of-take defines a time period of 79 years. A limiting case assuming the original well and infill well are both being permitted to produce wide-open was also run. Based on the 3-D model predictions, economic analyses were performed to evaluate the economics of infill drilling. Even with the very optimistic production schedule of producing wide-open, the economic analysis results of accelerated recovery from drilling infill wells were found to be unacceptable.

The most surprising result of our studies is that there is no increase in recoverable reserves as a result of each unit containing an infill well. Further, the high abandonment pressure of the low permeability Herington layer remains unchanged as a result of drilling an infill well on the section. Table 2 summarizes the principal results obtained from the 12 section model study forecasts projected to a per well abandonment rate of 10 Mscfd. The results indicate a cumulative production of 45.12 Bscf to the year 2055 for current operations and current spacing and 45.05 Bscf to the year 2023 where each unit contains an infill well. This represents a recovery of 88.6% and 88.5%, respectively, indicating no increase in recoverable reserves as a result of drilling an infill well. Note also from Table 2 that, to an abandonment rate of 10 Mscfd/well, an infill well does not deplete the low permeability Herington layer (average pressure of 142 psia at abandonment) any more than that resulting from one producing well per 640 acres.

Continuing the current method of operations results in a total producing life for our study area of 108 years, or 65 years beyond 1989. Drilling an infill well will reduce the remaining life by half to 33 years, but this is not economical and will result in no additional recoverable reserves. As for the potential of contacting isolated pods or pockets of undrained gas, neither the geological studies,[5] our replacement well study,[2] nor our comprehensive model history match support such a concept as was postulated in the Kansas Hugoton hearings.

With the history matched model we were able to test two limiting cases - 1) produce the study area with one well per section wide open from the start of production (1946), and 2) drill an infill well in each section and produce both wells wide-open starting from 1946. Table 2 summarizes the results obtained for these two cases. Both cases result in recoveries that are slightly less than that obtained by current operations (88.6%): 88.2% and 88.3% recovery producing wide-open since 1946 without and with infill drilling, respectively. Further, at wide-open production starting in 1946, the total producing life for one well per 640 acres would have only been reduced from 108 years to 82 years. No crossflow layered reservoirs that have contrasting layer permeabilities will always have unusually long producing lives. The most significant observation to be made from the wide-open production results is that the Herington layer pressure at abandonment is some 10 psi higher, 2 to 3% less recovery, than constant rate or current operation results. This indicates that the current operations with one well per 640 acres is effectively and efficiently draining the Oklahoma Hugoton field. The layer p/z vs. cumulative production of the study area is sensitive to the rate of production (see Fig. 14).

EFFECT OF LAYERING ON DEPLETION AND TIME TO ABANDONMENT

Two significant characteristics of no crossflow layered reservoirs having layers of contrasting permeabilities are 1) the low permeability layer(s) at well abandonment can have relatively high abandonment pressures and 2) the producing life of these types of layered reservoirs can appear to be excessively long. Either one or both of these characteristics can be misleading in terms of appearing to justify infill drilling. Table 3 summarizes depletion times and abandonment pressure results calculated for the Buf No. 1 well utilizing the simple rate-time and cumulative-time equations of Ref. 6. The 3-D model parameters used for the Buf No. 1 well and 640 acre drainage for each layer are used for these calculations. The calculated times of 78, 24, and 21 years for the Herington, Krider, and Winfield, respectively, are the producing times to an abandonment rate of 10 Mscfd. For this calculation, each layer is assumed to be produced separately and wide-open against a 0 psia flowing pressure. For a commingled well producing all three layers and produced wide-open against 0 psia flowing pressure, it would take 89 years to reach the 10 Mscfd abandonment rate. Clearly, the long producing time of 89 years for the commingled well is dictated by the low permeability layer. The calculated abandonment pressures of the Krider and Winfield layers are 10 and 15 psia, respectively, while the Herington layer abandonment pressure is relatively high at 211 psia. The initial layer pressure was 490 psia for all three layers. Because of the different pressures in each layer and because field measured shut-in pressure usually reflects that of the high permeability layer, it is difficult to define an "abandonment pressure." Abandonment rate is therefore used to define recoverable reserves for no crossflow layered reservoirs.

The simple equations in Ref. 6 (for single well application) are readily applied to multiwell problems with good engineering accuracy by simply summing the pseudosteady state $(q_{gi})_{max}$ values of each well in a layer and using the total layer gas-in-place, G_i. The calculated depletion times to an abandonment rate using the simple equations compared to 3-D model results for the limiting case of wide-open production are shown in Table 4. Also shown in this table are the times to an abandonment rate after the 43 years of constant rate production or current operations. Note that the total life of 108 years is only 26 years longer than what the life would have been under completely wide-open production from the beginning. The long producing life, therefore, is primarily due to the no crossflow layered nature of the reservoir and not simply the low rates-of-take set for the field.

Limiting case calculations using simple equations can be easily made for any number of layers in a no crossflow layered reservoir to obtain initial estimates of producing times and layer abandonment pressures. Also, the effect of infill drilling on times to abandonment and layer pressures can be readily calculated by representing $(q_{gi})_{max}$ as the sum of 2 wells on 320 acre spacing. This will result in reducing the time to abandonment to half of that achieved with one well on 640 acres; however, the layer abandonment pressures will be identical to those obtained for one well as the $[(q)_{max}/G_i]$ ratio does not change with an infill well.

CONCLUSIONS

All of the following conclusions are applicable to our study area. Based on other studies that are fieldwide[2,5] or even in the Kansas Hugoton,[3,4] it appears that most of the conclusions would be applicable to other areas within the Hugoton Fields.

1. To realistically predict the future performance and production from infill wells in the Oklahoma Hugoton Field, a multiwell multilayer simulation study has been used to history match:
   A. each well's official test shut-in pressure cumulative production data
   B. each well's official 72 hour deliverability tests
   C. layer pressures in one well in the multiwell study area
   D. performance match of one or more replacement wells drilled on a 640 acre section in the multiwell study area.

2. Because of wellbore backflow between layers, a valid history match of a layered no crossflow reservoir should provide for the actual simulation of the shut-in pressures for p/z vs. G_p performance matching. Also, the flow periods and rates should be simulated for well productivity performance matching.

3. A single well reservoir simulation model cannot realistically be used to evaluate the infill drilling potential in the Oklahoma Hugoton Field because of drainage effects from offset wells. No flow boundaries between wells cannot be reasonably assigned to each individual layer. Each layer can have a different radius of drainage, r_e.

4. No trapped or bypassed gas exists due to areal heterogeneity in the 12 section study area since we successfully history matched layer pressures, all test performance data of the original wells, and one replacement well without any adjustment to the log calculated input variables which determine original gas-in-place.

5. Forecast results show that no additional reserves are added by infill drilling an additional well per 640 acres starting in 1990. This conclusion also applies even if infill drilling were to have been initiated in 1946 and the wells produced wide-open from the beginning of production. Although infill wells do accelerate production, the shortened life is of no significance if the infill well is not economic to drill.

6. Study results demonstrate that the indicated long life of the study area (108 years) is a characteristic of a layered no crossflow reservoir having contrasting layer permeabilities. In addition, this unusually long life is due, in part, to the low historical rate of take from the field.

7. The basic heterogeneity of the Oklahoma Hugoton Field is that of layering, with no crossflow between layers. This layering effect may result in significant differences between layer pressures and in the reservoir recovery being rate sensitive.

8. The $\bar{p}/z$ vs. G_p curves developed for the full 12 section study area under current operating conditions and producing wide-open from the beginning show that effective and efficient drainage of the reservoir layers has been occurring. The layer pressure differences are less under current operating conditions than they would have been under wide-open production.

NOMENCLATURE

G_i	= initial gas-in-place Bscf
G_p	= cumulative gas production Bscf
h	= thickness, ft
k	= effective permeability, md
kv	= effective vertical permeability, md
kh	= effective horizontal permeability, md
n	= exponent of backpressure curve
p	= pressure, psia
$\bar{p}$	= average reservoir pressure, psia
p_{wf}	= wellbore flowing pressure, psia
q_g	= surface rate of flow, Mscfd
$(q_{gi})_{max}$	= initial surface rate of flow from the stabilized curve, Mscfd
q_a	= abandonment flow rate, Mscfd
r_e	= external-boundary radius, ft
s	= skin factor, dimensionless
S_w	= water saturation, fraction
t_a	= time, years to abandonment rate
z	= gas compressibility factor, dimensionless
ϕ	= porosity, fraction of bulk volume

SUBSCRIPTS

g	= gas
i	= initial
a	= abandonment

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TABLE 1

INITIAL FLOW AFTER FLOW TEST RESULTS, 12 SECTION STUDY AREA

First Gas	Well	Date of Test	No. Flows	Length of Each Flow (hrs)	Pressure Transient Analysis Results Commingled Well kh md-ft	s	72 Hour Deliverability Curve History Match Skins s
10/46	Mayoe	10/46	3	24	637	-5.15	-5.55
11/46	Buf	10/46	4	24	589	-5.44	(-5.44)
11/46	Mutual	9/46	4	24	436	-5.33	(-5.33)
9/47	Vantine	4/47	4	3	1340	-5.05	(-5.05)
6/48	Sheil	9/47	4	3	489	-5.08	(-5.08)
11/46	Christine	9/46	4	24	615	-4.69	-5.15
8/47	Dakar	8/47	4	3	395	-5.42	-5.00
1/47	Luman	1/47	3	24	650	-5.24	(-5.24)
11/46	Princess	3/47	4	3	999	-4.49	(-4.49)
8/47	Atar	4/48	4	3	703	-4.65	(-4.65)
8/46	Strat	1/47	4	24	527	-4.66	(-4.66)
1/47	Oella	3/47	4	3	850	-4.49	-4.70

( ) indicates no change in skin, s

TABLE 2

SUMMARY OF 12 SECTION MODEL STUDY RESULTS

Layer	G_i Bscf	1/89 G_p Bscf	1/89 Rec. %	Current Operations (Constant Rate to p_{wf} = 20 psia): No Infill Well: Layer $\bar{P}$, psia	G_p Bscf	Rec. %	Current Operations: w/Infill Well: Layer $\bar{P}$, psia	G_p Bscf	Rec. %	Wide-Open Production (Constant p_{wf} = 20 psia at t = 0) from 1946: No Infill Well: Layer $\bar{P}$, psia	G_p Bscf	Rec. %	Wide-Open Production: w/Infill Well: Layer $\bar{P}$, psia	G_p Bscf	Rec. %
Herington	15.09	6.30	41.7%	144	10.90	72.2%	142	10.94	72.5%	155	10.55	69.9%	153	10.62	70.4%
Krider	25.40	19.03	74.9%	23	24.28	95.6%	25	24.21	95.3%	21	24.38	96.0%	21	24.37	95.9%
Winfield	10.44	7.70	73.8%	25	9.94	95.2%	27	9.90	94.8%	23	9.98	95.6%	24	9.97	95.5%
Total System	50.93	33.03	64.9%		45.12	88.6%		45.05	88.5%		44.91	88.2%		44.96	88.3%
Time to Abandonment; Rate - 10 Mscfd/well, (t_a) from 1946						108 yrs			76 yrs			82 yrs			41 yrs
(t_a) from 1989						65 yrs			33 yrs						

TABLE 3

BUF #1 WELL
EFFECT OF LAYERING ON DEPLETION AND TIME TO ABANDONMENT RATE OF 10 MSCFD

Layer 640 acres	k md	h ft	kh md-ft	skin	$(q_{gi})_{max}$ Mscfd	G_i MMscf	$\frac{(q_{gi})_{max}}{G_i}$ x 10^{-6}	$\left[\frac{(q_{gi})_{max}}{G_i}\right]_R$
Herington	0.1	58	6	-5	47	1144.7	41.1	50.4
Krider	9.0	50	452	-5	3581	1728.9	2071	1.00
Winfield	3.3	40	131	-5	1038	884.1	1174	1.76
Total	4.0	148	589	-5	4666	3757.7		

	@ 10 Mscfd *		Commingled Well			
Layer	t_a yrs	G_p/G_i fraction	t_a yrs	q_{layer} Mscfd	G_p/G_i fraction	$\bar{P}_{R\,layer}$ psia
Herington	78	0.54	89	8.5	0.57	211
Krider	24	0.95	89	0.8	0.98	10
Winfield	21	0.90	89	0.7	0.97	15
				10.0	0.85	

* Times and fraction recoveries as if each layer produced separately to an abandonment rate of 10 Mscfd

TABLE 4

12 SECTION STUDY AREA DEPLETION TIMES TO ABANDONMENT RATE OF 120 Mscfd PER LAYER

Layer	Comple-tions	G_i Bscf	$\Sigma\ (q)_{max}$ Mscfd	$\Sigma\ (q)_{max}/G_i$ x 10^{-6} (days^{-1})	Produced Wide-Open From 1946: PSS Eq. P_{wf} = 0 t_a (yrs)	Produced Wide-Open From 1946: 3-D model P_{wf} = 20 psia t_a (yrs)	Current Operations: 3-D Model $(P_{wf})_{min}$ = 20 psia t_a (yrs)
Herington	12	15.09	1,184	78.5	75	76	94
Krider	12	25.40	50,129	1,974	27	25	67
Winfield	5	10.44	12,406	1,188	21	20	61
		50.93					
Commingled Well, t_a (yrs) from 1946					86	82	108

Rate-time equation, PSS, P_{wf} = 0 and backpressure curve slope n = 1.0

For each layer:

$$q_g(t) = \frac{(q_{gi})_{max}}{\left\{\left[\frac{(q_{gi})_{max}}{G_i}\right] t + 1\right\}^2}$$

Time to abandonment rate, $q_g(t)_a$

$$t_a = \frac{\sqrt{\frac{(q_{gi})_{max}}{q_g(t)_a}} - 1}{\left[\frac{(q_{gi})_{max}}{G_i}\right]}$$

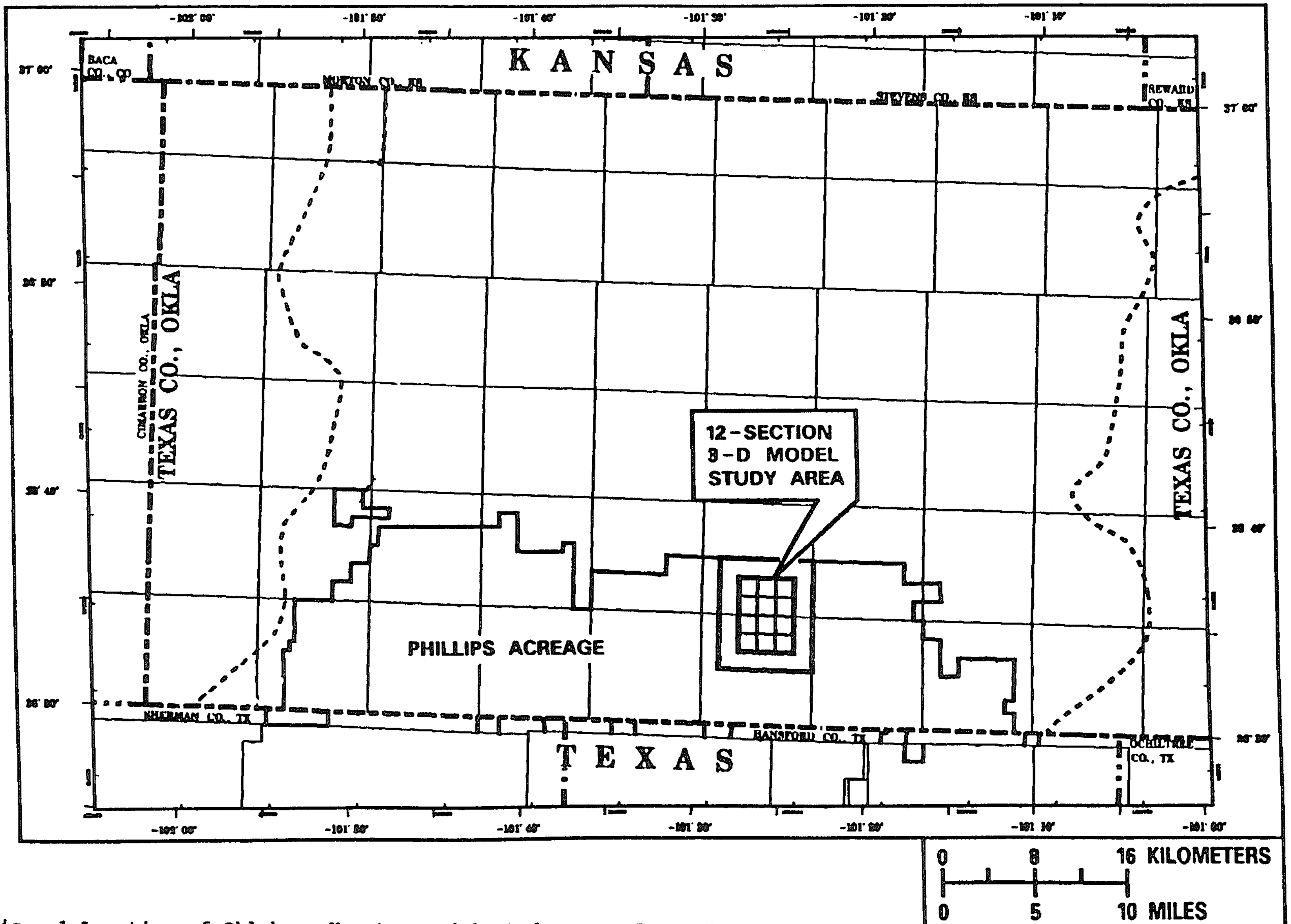

Fig. 1 Location of Oklahoma Hugoton model study area, Texas County, OK

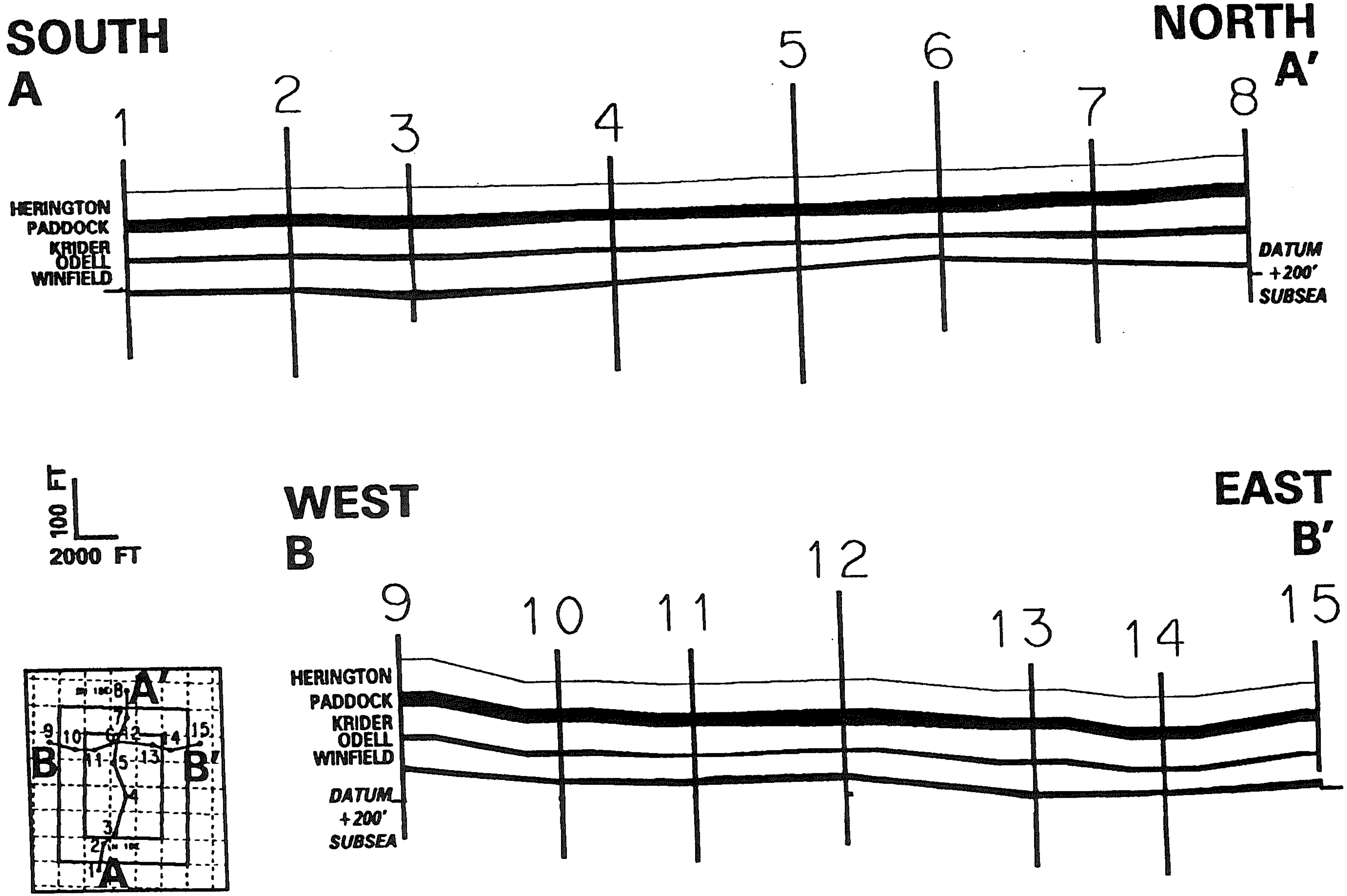

Fig. 2 North-South and East-West cross-sections through model study area

HERINGTON
$P = 314$ psia
$K = 0.10$ md
$\phi = 0.06$
$h = 58$ft
$S_w = 0.76$

KRIDER
$P = 121$ psia
$K = 9.0$ md
$\phi = 0.08$
$h = 50$ft
$S_w = 0.60$

WINFIELD
$P = 141$ psia
$K = 3.3$ md
$\phi = 0.08$
$h = 40$ft
$S_w = 0.67$

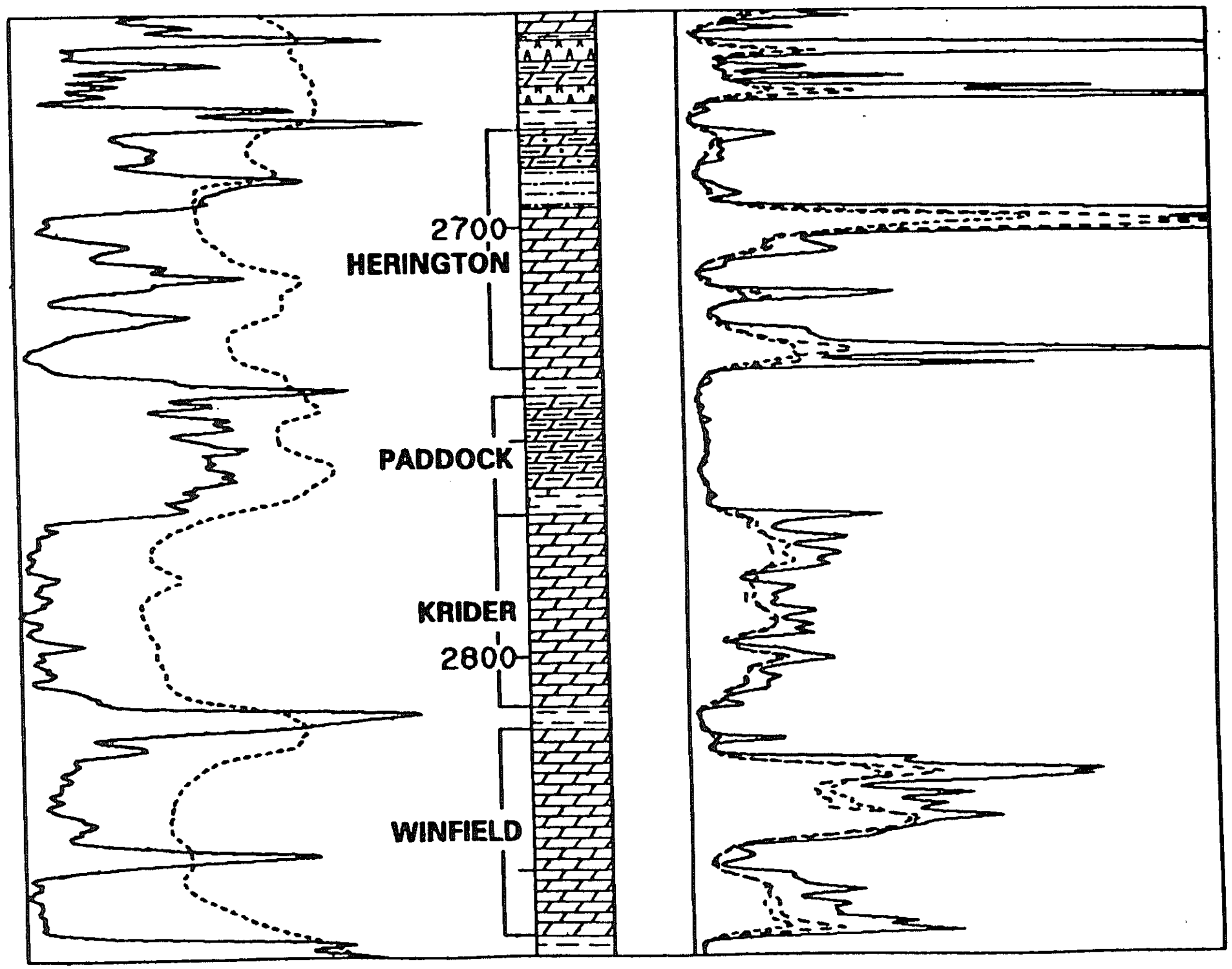

Fig. 3 Type log, Oklahoma Hugoton study area

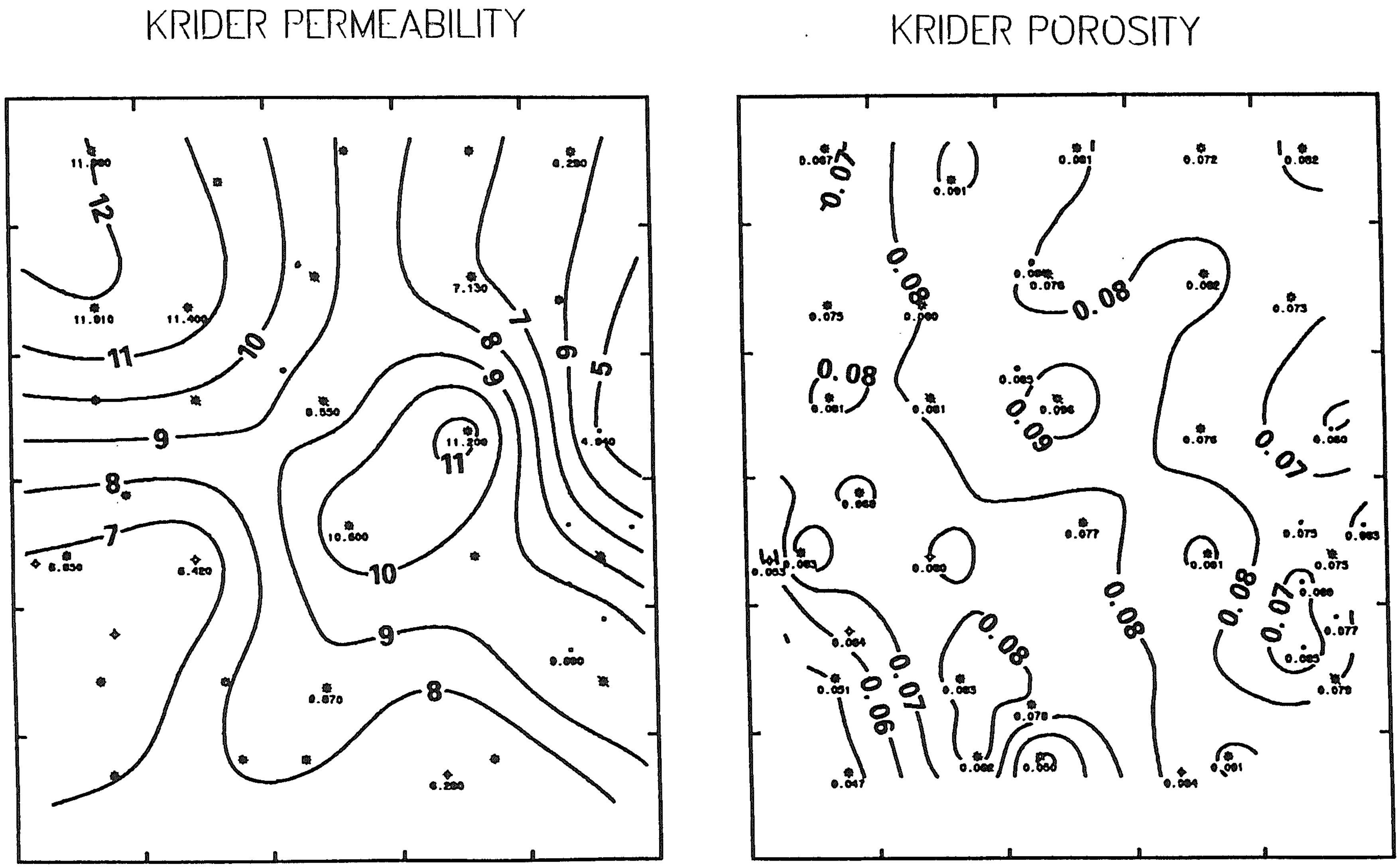

Fig. 4 Study area (30 sections) permeability and porosity maps of the Krider layer

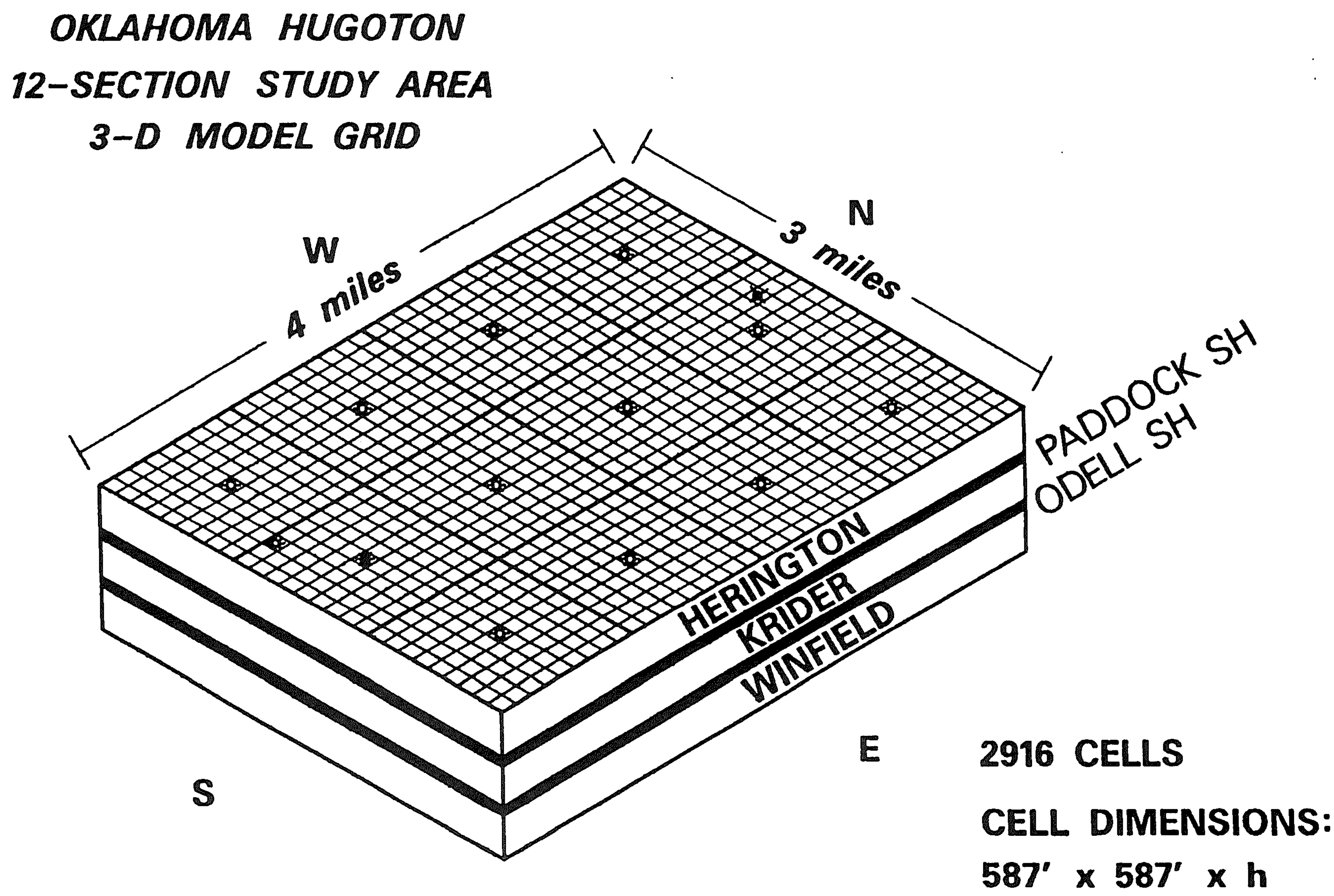

Fig. 5 Study area model grid with original and replacement well locations

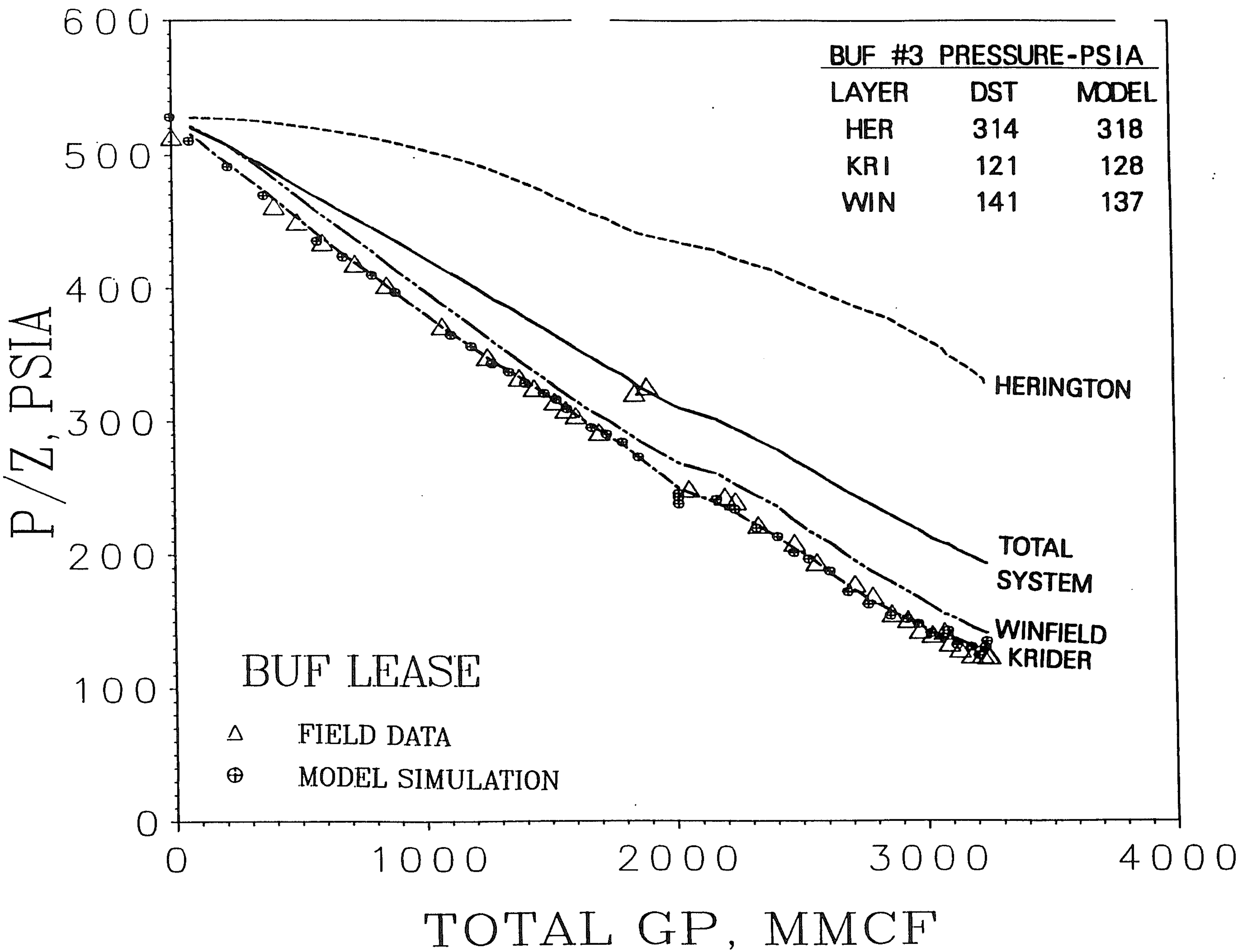

Fig. 6 P/Z vs. cumulative production history match of the Buf No. 1 well with layer pressure match at Buf No. 3 location

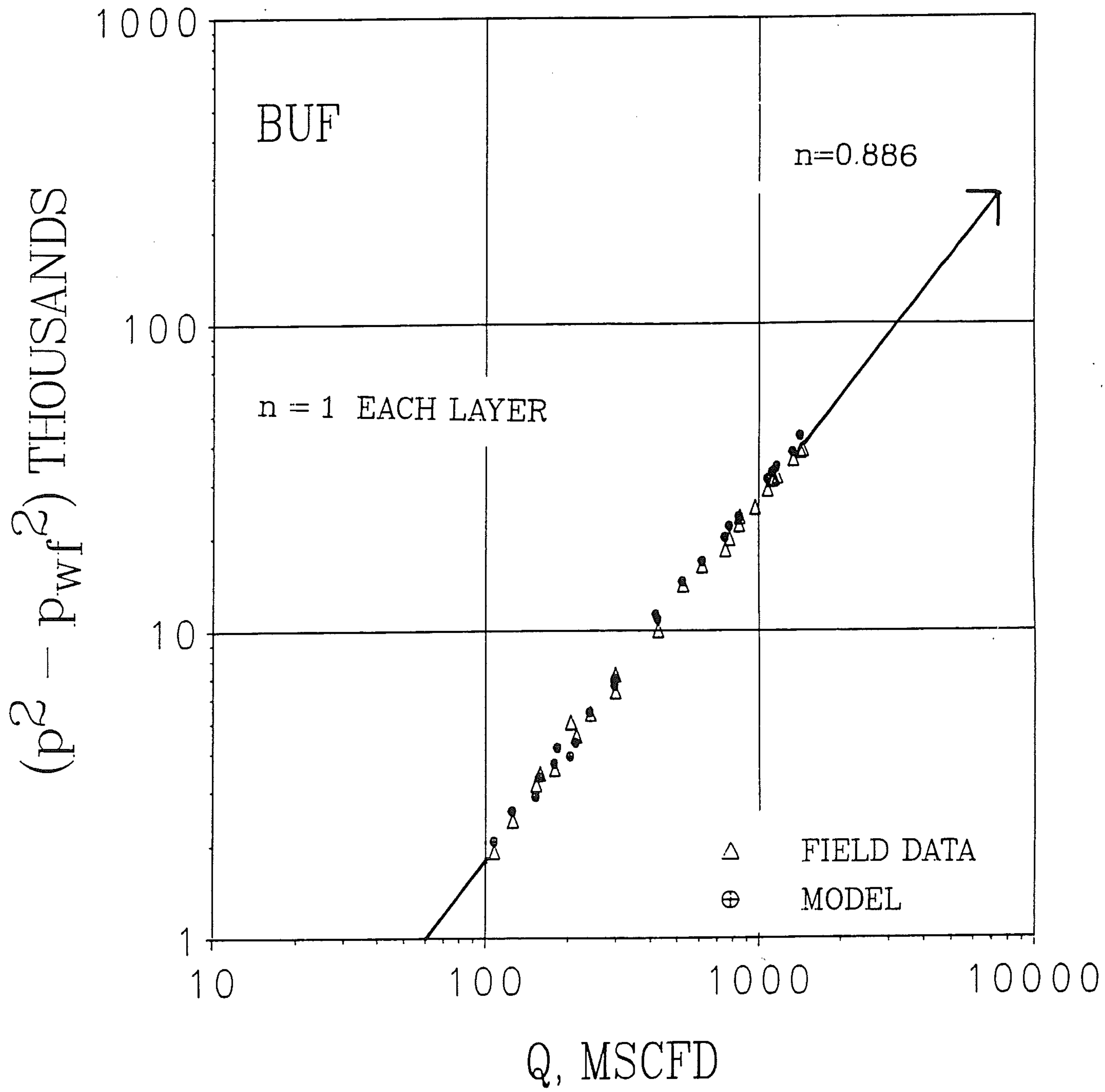

Fig. 7 Deliverability test history match of Buf No. 1 well

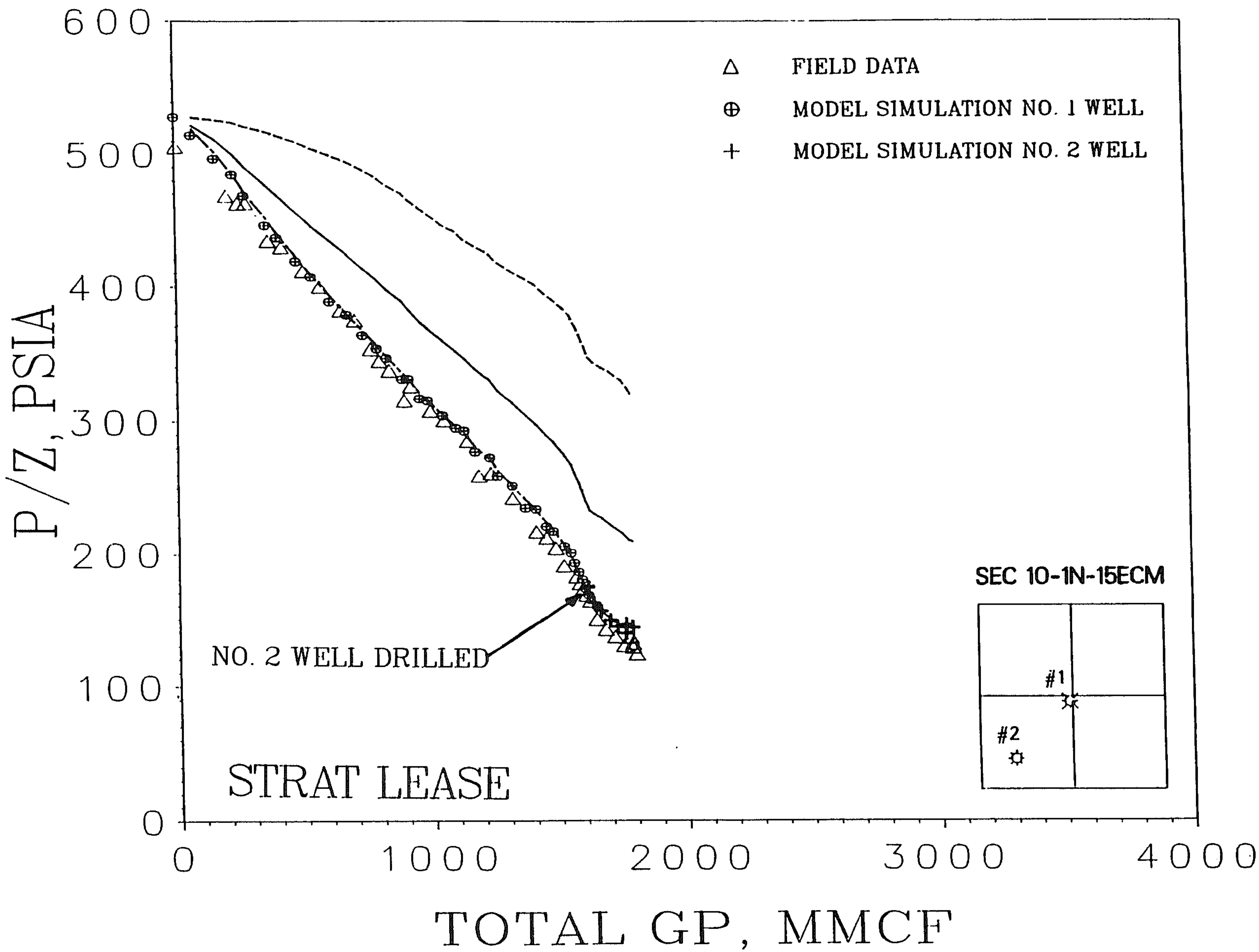

Fig. 8 P/Z vs. cumulative production history match of the Strat No. 1 and Strat No. 2 replacement well

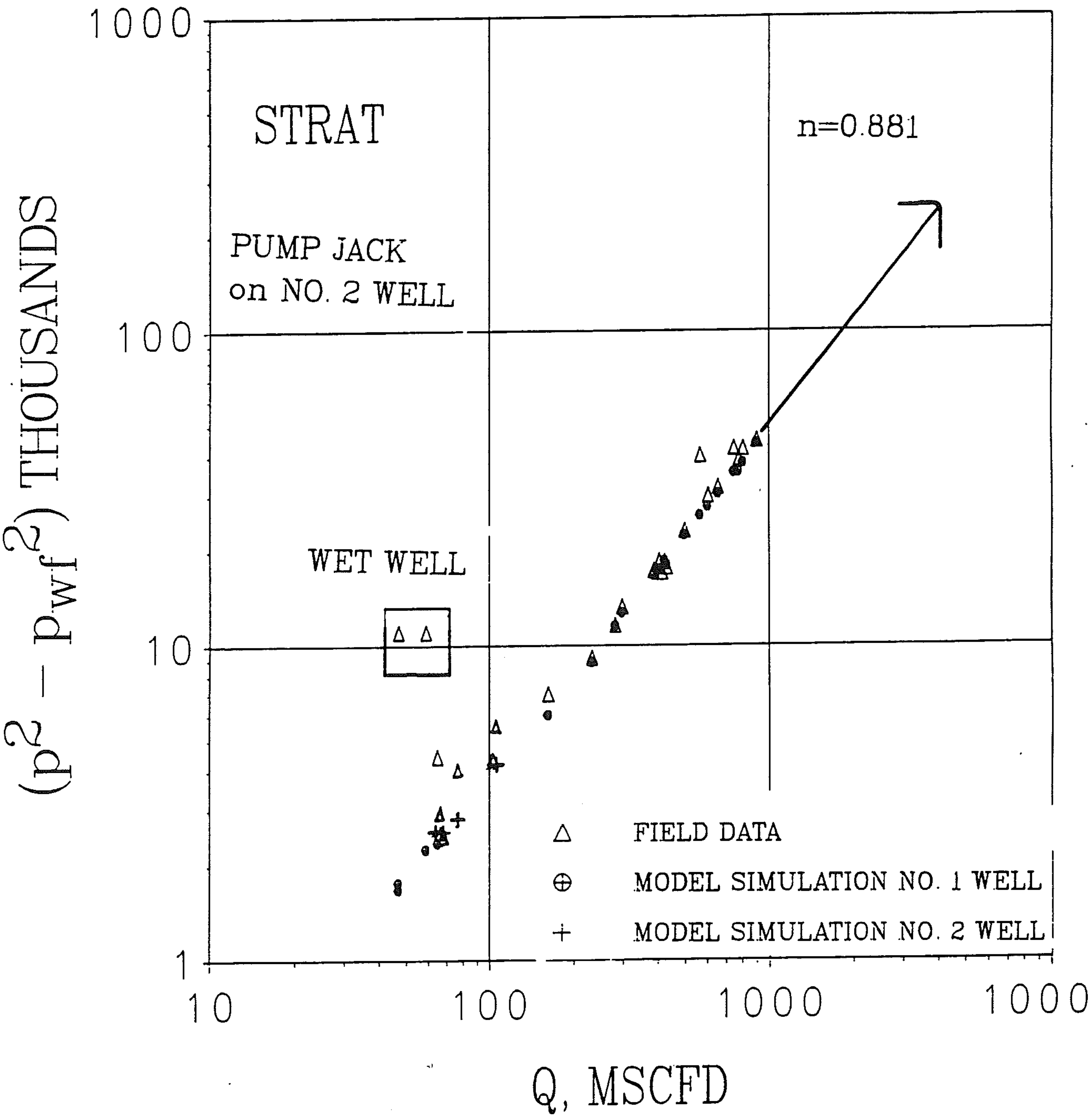

Fig. 9 Deliverability test history match of Strat No. 1 and the Strat No. 2

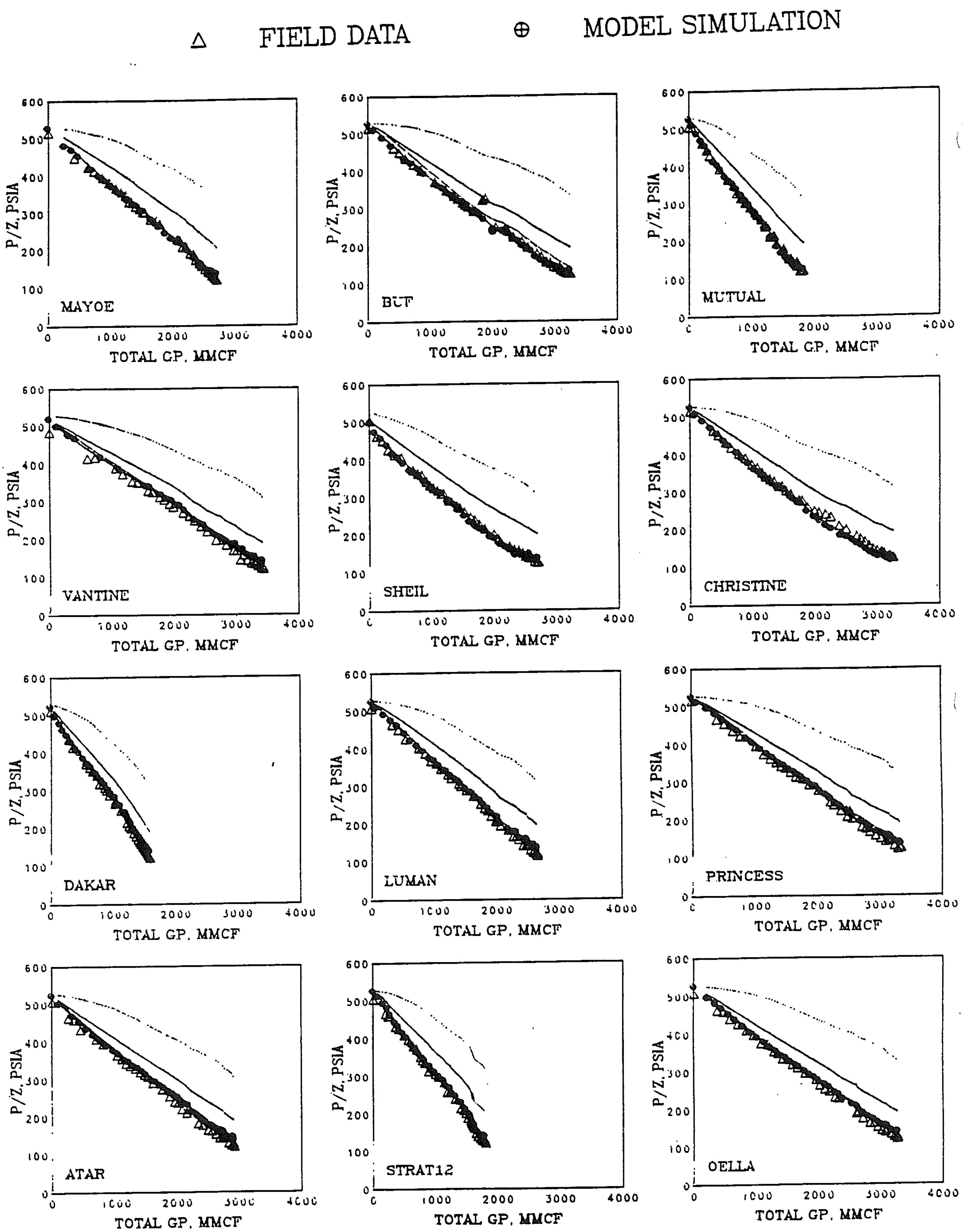

Fig. 10 Final history match of P/Z vs. cumulative production

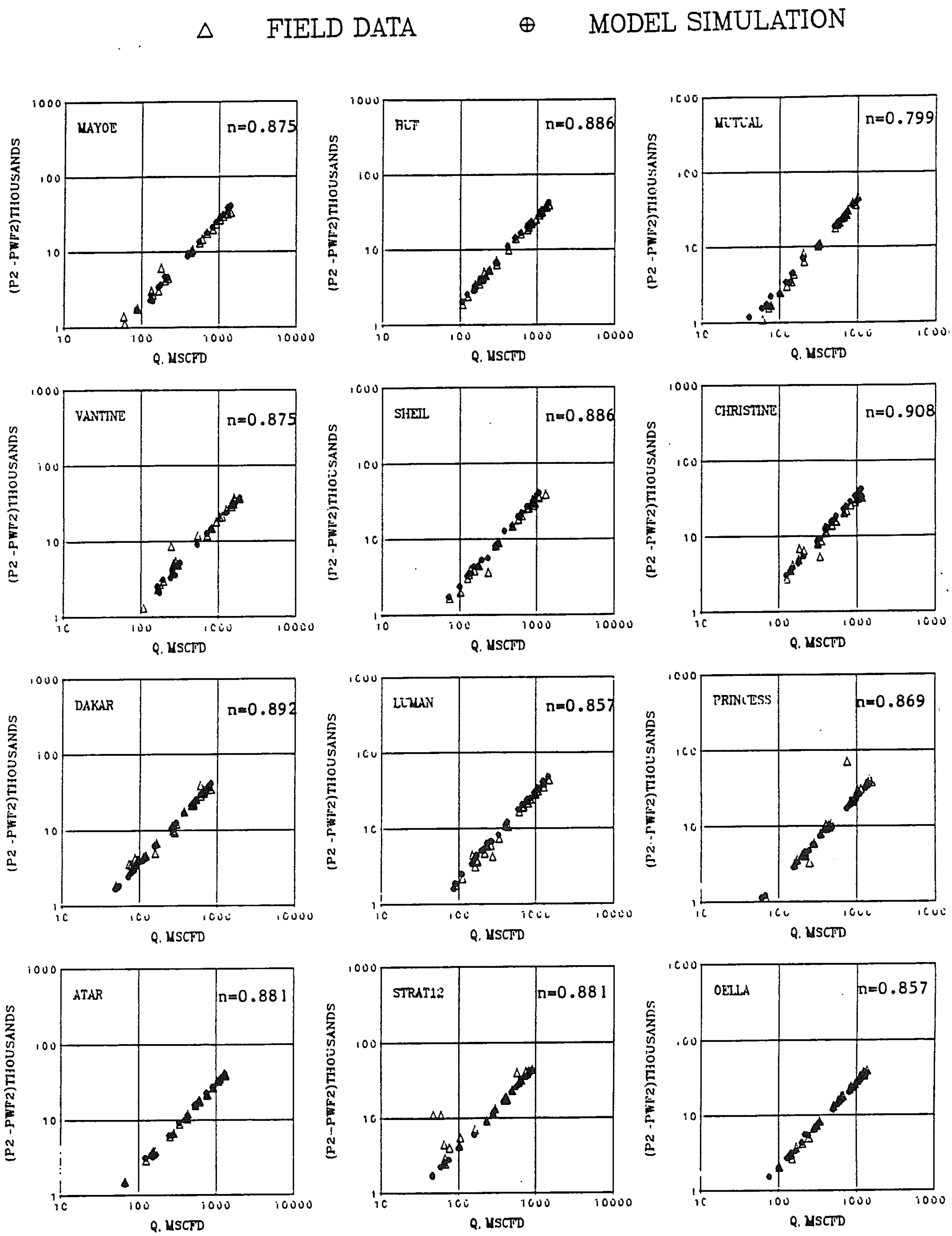

Fig. 11 Final history match of official 72-hr test data

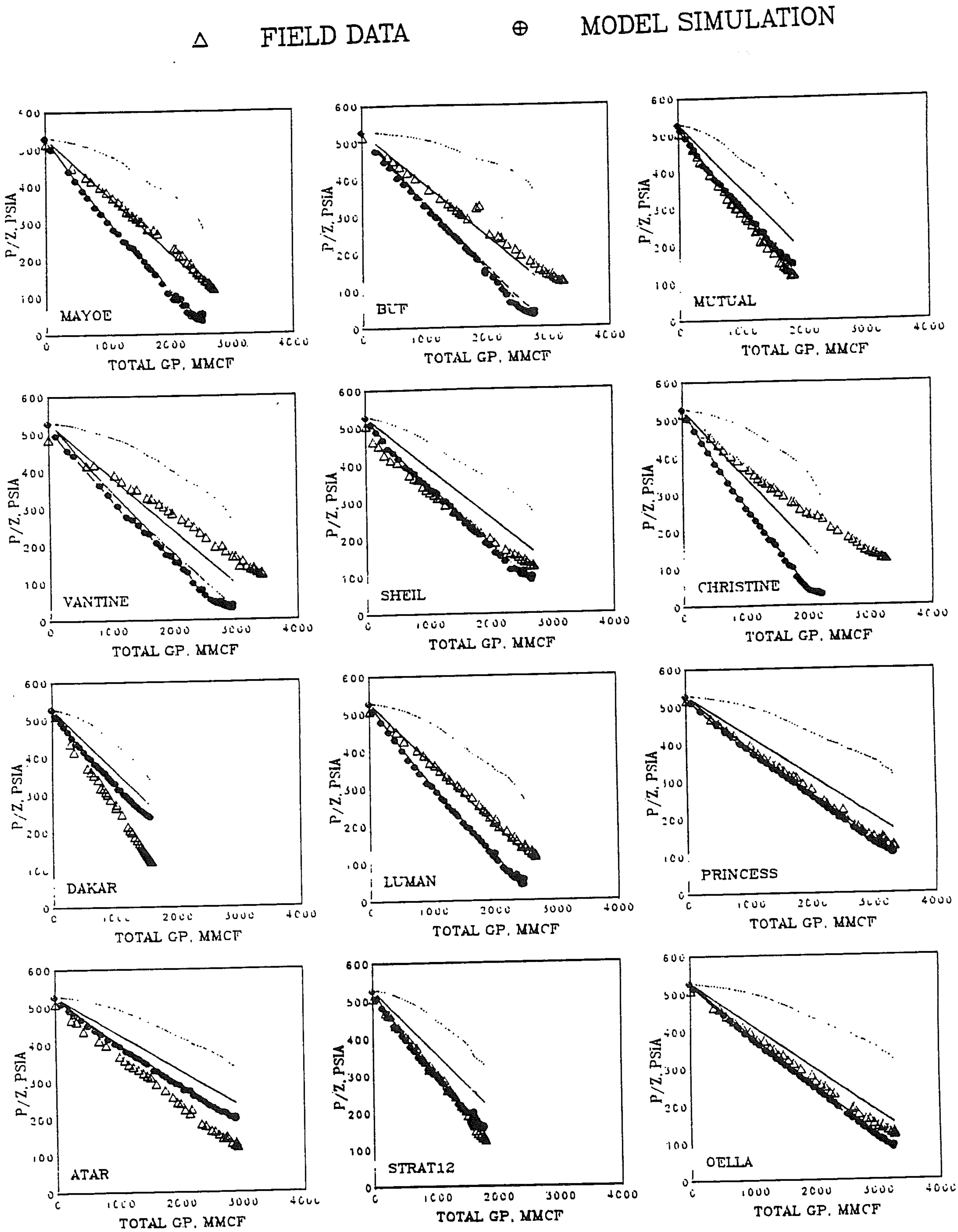

Fig. 12 Effect of closing all section line boundaries

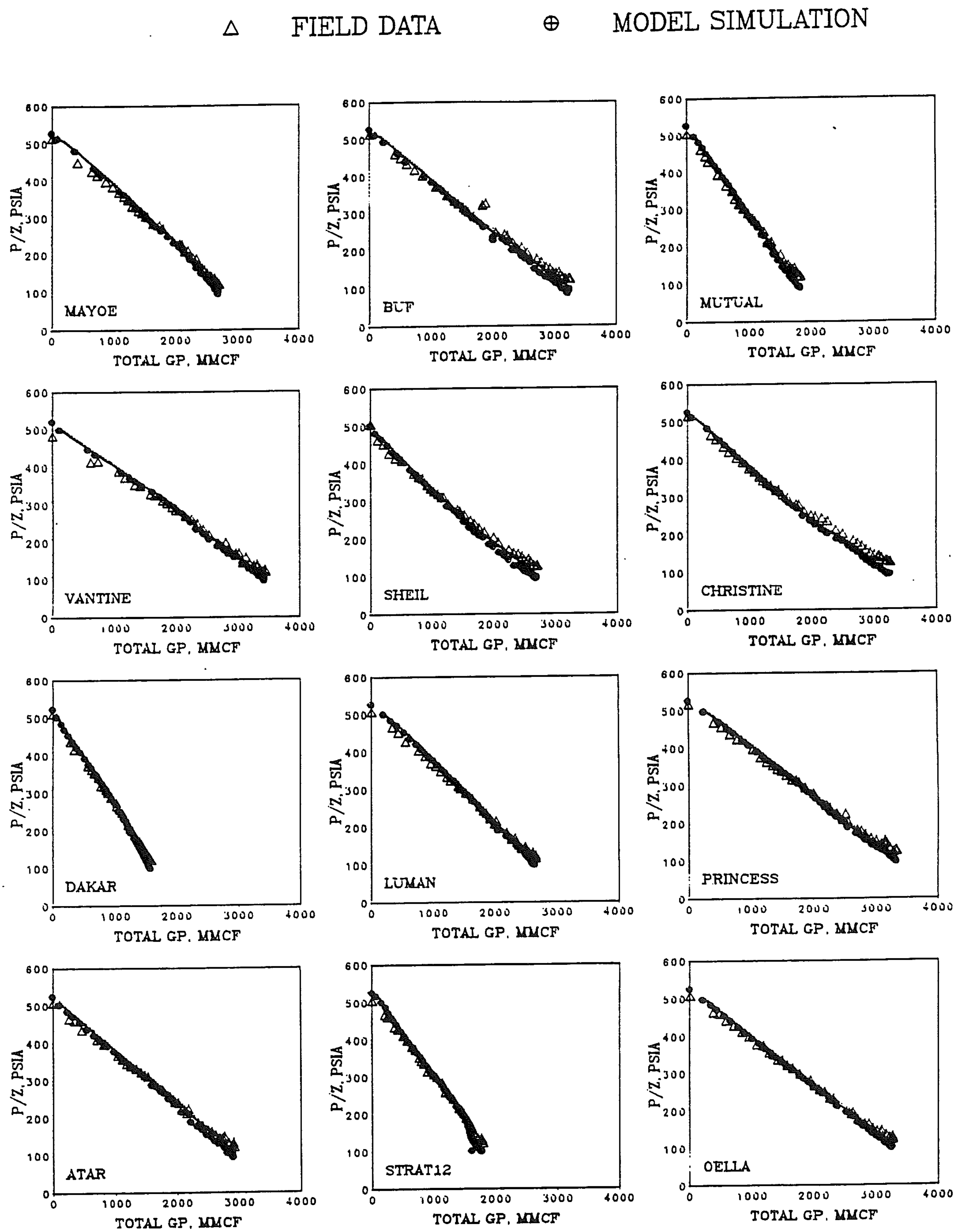

Fig. 13 Complete crossflow (0.005 kv/kh), 20% pore volume reduction (all layer pressures are equal)

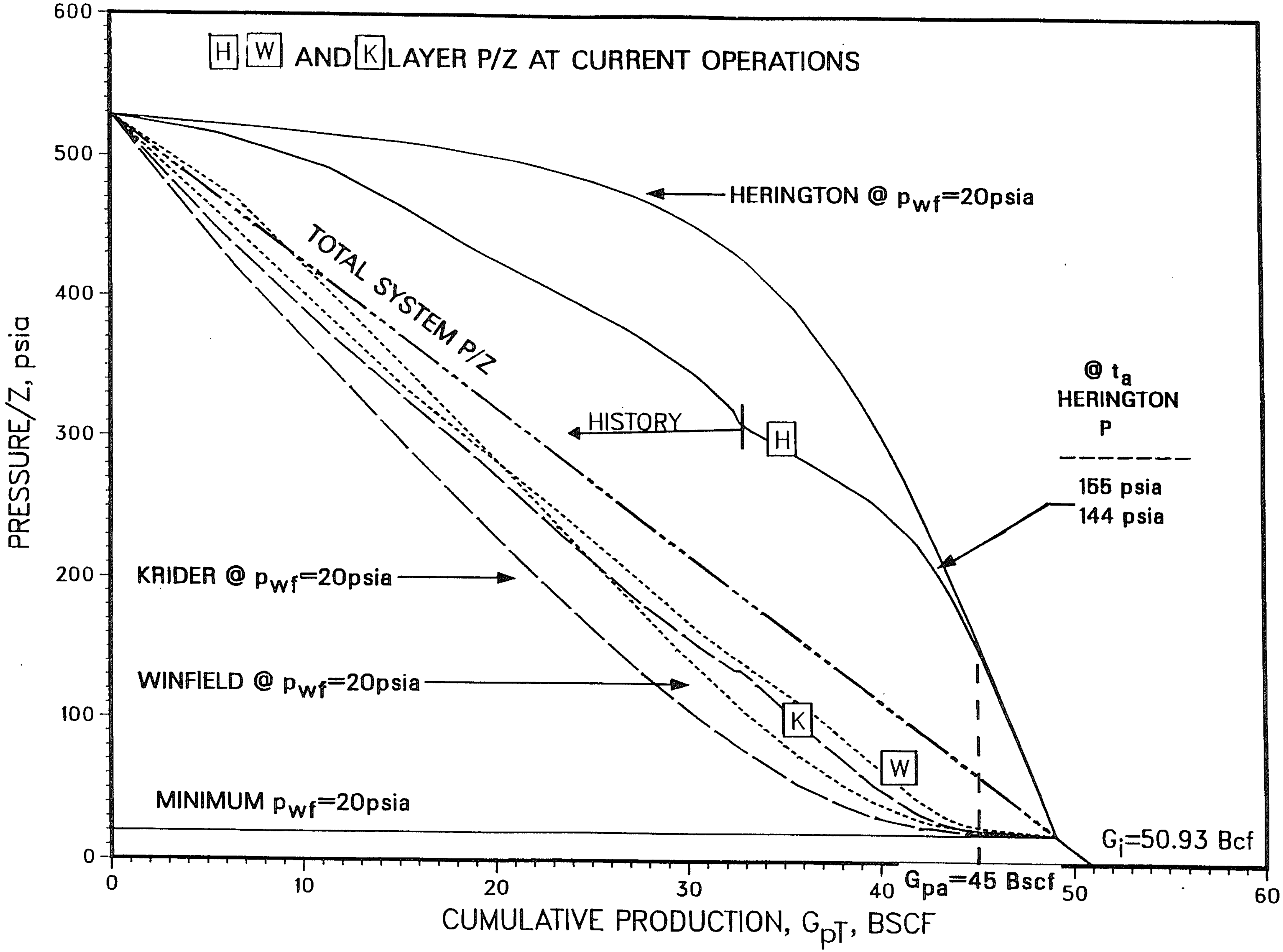

Fig. 14 P/Z vs. cumulative production history and predictions for total model study area

SPE

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ANALYSIS OF KANSAS HUGOTON INFILL DRILLING, PART II: TWELVE YEAR PERFORMANCE HISTORY OF FIVE REPLACEMENT WELLS

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SPE Members

This paper was prepared for presentation at the 65th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in New Orleans, LA, September 23–26, 1990.

ABSTRACT

This paper reviews the performance of five replacement wells drilled in 1977 in the Kansas Hugoton gas field located in southwest Kansas. The purpose of the test program was to determine if increased reserves and deliverability could be obtained by drilling an additional well on each of the five 640-acre spacing units. This paper analyzes the 10 years of data obtained on performance between the original and replacement wells. Advances in the theory of the production performance of no-crossflow, layered reservoirs with contrasting layer properties allow for a better understanding of the data obtained and reported on these 5 replacement and original well pairs.

INTRODUCTION

In 1977, Mesa drilled and completed 5 replacement wells in the Kansas Hugoton Field to establish the performance of these wells in relation to the original wells.[1,2] Specifically, the operator was interested in determining if increased deliverability and reserves could be achieved with the replacement wells by: 1) encountering undrained pay stringers within the Chase group, 2) encountering a higher reservoir pressure in a different part of the 640-acre section, and 3) improving stimulation procedures by selectively perforating and controlling hydraulic fracture treatments. The location of these 5 test wells is shown in Figure 1. Cross sections were generated by the operator using porosity logs for each replacement well and the adjacent wells. These cross sections indicated laterally continuous producing zones with little discontinuity between wells. From individual layer pressure and flowmeter data, the operator concluded that the Krider, Winfield, Upper and Lower Fort Riley zones are separate and distinct producing horizons within the Chase formation, having different reservoir pressures and depleting at different rates. Using the results from flowmeter tests, it was determined that wellbore backflow between zones occurs when a well is shut in. It was also concluded that a commingled wellhead shut-in pressure on these wells reflects the pressure in the layer with the lowest pressure. One unique aspect of the replacement well study was that the original wells were shut-in for an extended period of time and used as observation wells. Monthly wellhead shut-in pressures were recorded and reported to the Kansas Corporation Commission for almost 10 years. The initial wellhead shut-in pressure for the replacement wells averaged 14.4 psi higher than the original wells. Initial official deliverability tests averaged 753 Mscf/day per well higher in the replacement wells when compared to the original wells. No conclusions were presented in Mesa's original work[1] indicating that the replacement wells had encountered any additional gas-in-place.

During the Kansas Hugoton infill drilling hearings in 1985, several witnesses presented their interpretation of various aspects of the performance of Mesa's 5 replacement wells. Opponents of infill drilling concluded: 1) that the replacement wells did not encounter any additional gas-in-place that wasn't already in pressure communication with the original well, 2) the 14.4 psi higher pressure observed in the replacement wells was due to the pressure gradient caused by flow toward the original well, and 3) the initial "official deliverability" increase of 753 Mscf/day per well was temporary. Proponents of infill drilling concluded that the 5 replacement wells would increase the total recovery for the 5 proration units and that, due to the heterogeneous nature of the reservoir and the different layer pressures, infill drilling would increase the recovery of gas from the Kansas Hugoton.

References and illustrations at end of paper.

As part of an extensive reservoir study to evaluate the infill drilling possibilities of the Guymon-Hugoton gas field,[3,4,5] we undertook a study of Mesa's 5 replacement wells because of the large amount of high quality data collected and the similar geologic and producing characteristics between the Oklahoma and Kansas portions of the Hugoton Field. Recent advances in the theory and understanding[6] of the production performance of no-crossflow, layered gas reservoirs allow for a better analysis and understanding of the reported long time performance data on these 5 replacement and original well pairs.

This paper applies basic no-crossflow, layered reservoir concepts to the interpretations of the history of the 5 replacement well proration units. The effect of variations in rate, shut-in periods, and restimulation on the shape of the 72 hour wellhead shut-in pressure vs. cumulative production curve are presented. The observation well pressures allow for an analysis of the continuity of the most permeable layer between the producing well and the observation well. We used our history matched Guymon-Hugoton 12 section multiwell, multilayer model,[3] to simulate the Mesa replacement-observation well experiment. The simulated observation well calculated behavior is virtually identical to that obtained in the Mesa observation original well experiment. Using the simple analytical equations of Ref. 6, the effect of layering on layer abandonment pressures and the long producing times to an abandonment rate are calculated. No evidence is found indicating that new gas-in-place was encountered by the replacement wells. Due to the long producing life of a layered no-crossflow reservoir, infill wells produced to the same abandonment rate as the original wells do not add any incremental reserves.

ANALYSIS OF REPLACEMENT WELLS

A summary of the development history and geological description for the Kansas Hugoton Field is presented in Part I[7] of this study. The first of the 5 replacement wells drilled was the Gano 1A located in Sec. 20 T29S R37W in Grant Co., KS. Since this was the only replacement well with complete individual layer pressure buildups and flowmeter test results, its performance was analyzed in detail.

Gano 1, Original Well

The Gano 1 was spudded on August 1 and completed on August 28, 1951, by Hugoton Producing Company. This well was completed open-hole in the Krider, Winfield, and Upper and Lower Fort Riley layers with a 5½" slotted liner. The original stimulation treatment consisted of 14,000 gallons of 15% HCl over the entire open hole interval. Initial shut-in wellhead pressure was 434 psia with an absolute open flow potential of about 33,000 Mscf/day. In 1969, Mesa Petroleum Co. purchased the Gano 1 from Hugoton Producing Co. and in 1970 restimulated the well with 150,000 lbs. of sand and 150,000 gallons of water. This restimulation resulted in a four-fold increase in productivity. When the well was shut in as an observation well on April 13, 1977, the cumulative production was approximately 6 BSCF.

Gano 1A, Replacement Well

The Gano 1A was spudded on April 4, and reached a total depth of 2960' on April 7, 1977. Seven inch casing was set and cemented at 2677' through all of the productive intervals. Starting with the Lower Fort Riley, each layer was individually acidized using 3600 to 8000 gals. of 15% HCl and ball sealers. After each layer was acidized, the well was flowed to clean up and obtain stabilized test flow rates. A bottomhole pressure bomb was run and the well shut-in for a pressure buildup test. After each layer had been individually perforated, acidized, and tested, a final commingled pressure buildup was run. All four layers were then sand frac'd together using 200,000 gallons of gelled water with 200,000 lbs. of sand.

Calculated permeability and bottomhole pressure from the individual layer pressure buildup tests for the Gano 1A are indicated on Fig. 2. Log calculated porosities also appear on the figure. The individual layer buildup tests clearly indicate that each layer has different permeabilities and pressures. The most permeable layer, Krider, has the lowest pressure, 188 psia, and the lowest permeable layer, Lower Fort Riley, has the highest pressure, 284 psia. The greatest amount of depletion has occurred in the more permeable layers. From a commingled buildup test with all layers open to the wellbore, the buildup pressure of 190 psia reflects the pressure in the most permeable Krider layer. During the commingled buildup the operator indicated[1] that wellbore backflow was occurring from the lower permeability layers to the high permeability layer during the test.

In order to assess the contribution of flow from each layer and confirm that wellbore backflow between layers was occurring during shut-in, the operator ran a Differential Temperature Log and Flowmeter Survey on the Gano 1A. The production was stabilized at 1200 Mscf/day for seven days prior to the survey with a flowing wellhead pressure of 158.4 psia. (The survey tool was run into the well without shutting the well in.) The flowrates from each layer determined from the flowmeter are shown on Fig. 2. The Krider layer contributed 47% of the total flow while the Lower Fort Riley only contributed 2%. After the flowing well survey was completed, the well was shut in to check for wellbore backflow. This survey indicated that during shut in, the lower two layers, the Upper and Lower Fort Riley, continue to produce gas into the wellbore, backflowing into the upper two layers, the Winfield and the Krider.

Figure 3 is a plot of wellhead shut-in pressures vs. cumulative production with a wellhead backpressure curve and a location plat insert for the Gano Lease. The solid circles represent 72 hour shut-in pressures for the original well, the open circles represent 72-hour shut-in pressures for the replacement well. The plus signs represent well pressures when the original well was kept shut-in as an observation well. The location map in the upper right hand corner of Fig. 3 shows the relative location of the two wells. The distance between the two wells is 2150 feet. The wellhead backpressure curve is a plot of the 72 hour official deliverability test data. The shift to the right in the backpressure curve for the original well corresponds to a sand frac restimulation performed in 1970. The backpressure curve for the replacement well lies slightly to the right of that of the original well restimulation indicating slightly better stimulation results in this replacement well. The wellhead shut-in pressure vs. cumulative production curve has several apparent slope changes making it difficult to properly extrapolate to a gas-in-place. The producing rate and/or duration of shutting a well in prior to the official deliverability test, the overall production rate and the no crossflow, layered nature of the reservoir all play important roles in interpreting and evaluating the wellhead shut-in pressure vs. cumulative production curve.

Figure 4 is a plot of wellhead shut-in pressure and monthly production rates vs. cumulative production for the Gano 1 and 1A lease. Plotting the monthly rates on the wellhead shut-in pressure vs. cumulative production curve aids in evaluating the pressure response. The sand frac conducted in 1970 on the original well substantially increased the official deliverability resulting in a much higher allowable for this well. The increased downward slope represented by the two wellhead shut-in pressure points after the frac job appear to indicate a decrease in remaining gas-in-place for this well. Nearly all of the wells in this part of the field were frac'd during this time, therefore, the drainage area for this well should not have dramatically changed. Although the wellhead shut-in pressure typically reflects the pressure in the more permeable layer, the cumulative production from the well reflects production from all layers.[6] The <u>shape</u> of the wellhead shut-in pressure vs. cumulative production in a no crossflow layered reservoir with a significant contrast in layer properties is rate sensitive. If there is a significant contrast in layer volume, the wellhead shut-in pressure vs. cumulative production plot will have some curvature (concave up). On the other hand, regardless of the contrast in layer properties, as the rate of production approaches zero, all of the layers will deplete at the same rate and the wellhead shut-in pressure vs. cumulative production plot will result in a straight line.[6] The change in slope of the wellhead shut-in pressure vs. cumulative production plot after the frac job in Fig. 4 is caused by the change in the rate of production due to the increased allowables as a result of the restimulation and does not reflect a change in the drainage volume for this well.

Another important consideration in evaluating the shape of the wellhead shut-in pressure vs. cumulative production plot is the effect of any large rate changes, including extended shut-ins, prior to the official deliverability test. The rate of production decreased prior to the 1976 official deliverability test with the well also being shut in during the month for an extended period of time immediately prior to the official test. The effect of rate and a "rest period" can be more clearly seen in the rate, pressure vs. time plot of Fig. 5. The resulting wellhead shut-in pressure in 1976 is clearly higher than that of the previous test in 1974. In the Kansas Hugoton, an official deliverability test consists of a 72 hour flow followed by a 72 hour shut-in with the rate and flowing pressure being recorded at the end of the flow and the wellhead shut-in pressure being recorded at the end of the shut-in. Resting a well prior to an official deliverability test will allow the 72 hour shut-in pressure to build up from a higher pressure than if the well had been producing prior to the test. The wellbore backflow from the high pressure layer(s) to the low pressure layer(s) that occurs during shut-in also causes the well to build up to a higher pressure. (In the Kansas Hugoton, wellhead shut-in pressure is an important factor in the calculation of allowables, the higher the wellhead shut-in pressure, the higher the allowable will be.)

Taking into account the expected curvature of the wellhead shut-in pressure vs. cumulative production curve in a layered no-crossflow reservoir with contrasting layer properties and the effect of the rate and shut-in periods on the shape of this same curve (see Figs. 3 and 4), it is concluded that the replacement well is producing from the same drainage area as the original well. The wellhead shut-in pressures for the replacement well fall on the wellhead shut-in pressure trend started by the original well (Fig. 3).

<u>Observation Well Pressures</u>

The observation well pressures provide a great deal of insight into the behavior of the pressure gradient in the most permeable layer connecting the two wells. Fig. 6 details the production and pressure history for the Gano Lease after the replacement well was drilled. The first pressure on the observation well is 148.5 psig and was taken after the well had been shut-in for one week. Wellhead shut-in pressures taken on the replacement well for several weeks after the sand frac while the well was waiting for an official deliverability test are denoted by inverted triangles. Note that through time, prior to the start of production from the replacement well, the observation well pressure builds up to the pressure in the replacement well. This indicates that prior to any production from the replacement well that the pressure in the most permeable layer is basically the same between these two wells.

Once the replacement well begins to produce, the subsequent 72 hour wellhead shut-in pressures from the official deliverability tests fall below the observation well pressures. The difference between the first observation well pressure on the original well and the first pressure on the replacement well is 10 psi. Approximately one year later, at the time of the official deliverability test for the replacement well, the pressure difference between the two wells is 12.9 psi. Although the absolute pressure difference is basically the same, the pressures for the two wells have traded positions with the replacement well pressure being lower than that of the original well. Or inversely the pressure of the original well is now higher than that of the replacement well. This confirms that the pressure difference is simply a reflection of the pressure gradient between the two wells in the most permeable layer while one is shut-in and the other producing.

Using the steady state, radial flow equation in a bounded system (Eq. 1) and the results from the layer buildups and the flowmeter test, we can attempt to calculate the pressure at the observation well, P_{obs}.

$$P_{obs} = \left[\frac{q_g \ \mu_g \ Tz}{703 \times 10^{-3} \ kh} \left(\ln (r_{obs}/r_{ws}) - \frac{r_{obs}^2}{2r_e^2} + \frac{r_{ws}^2}{2r_e^2} \right) + P_w^2 \right]^{1/2} \qquad (1)$$

Comparing the calculated observation well pressure using Eq. 1 to the measured wellhead shut-in pressures at the replacement well, we can confirm that we are dealing with a pressure gradient. The best point in time to make this comparison is in 1985 as the well was not "rested" that year prior to the official deliverability test. The wellhead shut-in pressure for the replacement well in October 1985 was 127.6 psia while the pressure at the observation well was 142.7 psia. The difference in pressure between these two wells is 15.1 psi. Assuming the wellhead shut-in pressure reflects the pressure in the most permeable layer, we use the properties of the most permeable layer (Krider) for this calculation. The data used in this calculation are summarized in Table 1. The rate presented in Table 1 is 47% of the average rate for the replacement well for the first 9 months of 1985. The flowmeter test indicated that 47% of the total rate comes from the Krider. Using the data in Table 1 with Eq. 1, we calculate an observation pressure of 143.8 psia. This compares very well to the measured observation pressure of 142.7 psia at the same point in time.

Another interesting point on Fig. 6 relates to the effect of the resting of the original well upon the observation well pressures. In 1978, 1979, 1981, and 1983, the replacement well was "rested" for approximately one month prior to the official deliverability test. The slope of the observation well pressures flattens out after each of these resting periods. This subtle change in slope indicates pressure communication between these two wells in the most permeable layer.

In late 1986, Mesa filed an application for the transfer of allowables from the five replacement wells back to the five original wells that were designated as pressure observation wells. The replacement wells were then shut-in until they later could be brought back on production as infill wells. On December 12, 1986, the KCC granted Mesa's request. The replacement well (Gano 1A) was shut-in in September 1986 and the original well (Gano 1) began producing again in December 1986. In January of 1988, the replacement well was placed back into production as an infill well. The wellhead shut-in pressures for both wells at the start of 1987, after several months of no production from either well, are nearly identical. Note that in Fig. 6, the 1987 wellhead shut-in pressure for the original well falls back onto the pressure trend of the replacement well while it was producing.

Carter 1A, Cornwell 1A, Shaw 1A, Thurow 1A

The performance of the other four replacement original well pairs is very similar to that of the Gano well pair. Figs. 7-10 are wellhead shut-in pressure vs. cumulative production plots with wellhead backpressure curves and a location plat for each of the other four well pairs. The observation well pressure detail for each of these four remaining well pairs is presented in Figs. 11-14. The observation well pressures for the Thurow, Shaw, and Carter all begin with the <u>flowing pressure</u> immediately prior to shut-in followed by 24, 48, and 96 hour shut-in pressures. Upon reviewing these figures, one can only conclude that the behavior of these other four replacement well original well pairs is similar to that of the Gano well pair.

OBSERVATION WELL SIMULATION

Using the three-layer, no crossflow, three-dimensional, history matched 12 section model developed in Ref. 3, an attempt is made to simulate the Mesa replacement-observation well experiment. A replacement well was assumed to be drilled in 1977 in the northwest quarter of the northern interior section of the 12 section model. The original well was shut-in and used as an observation well with wellhead shut-in pressures calculated just like the Mesa experiment. The production history from the original well is transferred to the replacement well when the original well is shut-in in the 3D model. A type log for the original well is presented in Fig. 15 with the input porosity and permeability at the replacement well. The layer pressures, percent depletion, layer flow rates, and percent of the total rate for each layer in the model when the replacement well was drilled are also presented in Fig. 15.

Figure 16 is a calculated wellhead shut-in pressure vs. cumulative production plot and a location plat for the replacement well section. The location plat in the upper right hand corner of Fig. 16 shows that the distance between the original and replacement well in the model is 1867 feet. The solid circles represent the 72 hour shut-in pressures for the original well, the open circles represent the replacement well 72 hour shut-in pressures. The plus signs represent the observation well pressures. In this simulation, the skins for the original well and the replacement wells are assumed equal. The general behavior of these 3D model simulated observation well pressures in relation to the replacement well pressures is identical to those observed in the Mesa replacement well field experiment.

The calculated wellhead shut-in pressure and rate vs. time for the 3D model simulated replacement well section is presented in Fig. 17. Interference effects between the two wells can be seen as the shut-in of the replacement well in 1983 causes a flattening and then a slight rise in the observation well pressures. The same effect can be seen during the periods of reduced production and the shut-in period at the end of 1987. The reversal of pressure between the replacement and original well is again clear evidence that the higher initial wellhead shut-in pressure in the replacement well is caused by the pressure gradient due to flow.

EFFECT OF LAYERING ON DEPLETION AND TIME TO ABANDONMENT

In this section, we use the simple rate-time and cumulative-time equations of Ref. 6 to illustrate the effect of layering on individual layer pressure depletion and time to abandonment for the Gano 1A. Assuming equal skins for all layers, the permeability for each layer was adjusted to be in proportion with the rates obtained from the flowmeter survey. Water saturations for each layer are calculated from the layer gas-in-place estimates provided by the operator[2] using log derived porosity, thickness and a 640 acre drainage area. Table 2 gives the calculated depletion times and abandonment pressures for the Gano 1 well assuming to be produced wide-open from 1977 at a flowing bottomhole pressure of 0 psia. The equations used to calculate the time to an abandonment rate and layer pressures at abandonment are summarized in the Appendix. The Krider, Winfield, Upper Ft. Riley, and the Lower Ft. Riley layers assumed to be produced separately take 60, 63, 91, and 108 years respectively to reach an abandonment rate of 10 Mscf/day. For a commingled well, producing all four layers, and produced wide-open against 0 psia flowing bottomhole pressure, it would take 162 years to reach the 10 Mscf/day abandonment rate. This time to an abandonment rate of 10 Mscf/day is almost double the time to the same abandonment rate for the Buf #1 well calculations given in Ref. 3. These much longer calculated times are caused by the addition of a fourth productive layer in this portion of the Hugoton Field. The calculated layer abandonment pressures for the Krider, Winfield, and Upper Ft. Riley are 5, 10, and 20 psia, respectively, while the abandonment pressure for the Lower Ft. Riley is 112 psia.

Table 3 presents the effect of layering on depletion and time to an abandonment rate when we have two wells per section but the second well is drilled when the layer pressure distribution is identical to that measured in 1977 on the Gano 1A. All of the layer properties used in this example calculation are identical to those of the previous example. The abandonment rate now becomes 20 Mscf/day since we have two wells producing in this section. Both wells are assumed to produce wide-open starting in 1977. The times to an abandonment rate of 20 Mscf/day for each layer are reduced by half, starting when the infill well is drilled, but the layer pressures at abandonment do not change compared to the single well case. The fractional recoveries for the one and two well cases are identical at an abandonment rate of 10 Mscf/day/well. The infill well will accelerate production but it will not change the recovery to the same per well abandonment rate. These results assume identical layer completions and completion efficiencies between the infill and original well.

CONCLUSIONS

Although the following conclusions specifically apply to the Mesa replacement well study area, most would also apply to other areas of the Hugoton Field and other similar layered, no-crossflow gas reservoirs with contrasting layer properties.

1. The pressure performance data on the five (5) replacement wells did not show evidence of encountering any additional gas-in-place.

2. The observation well pressures demonstrate that: a) the replacement well and original well are in pressure communication and b) the pressure difference between each set of original and replacement wells is caused by the pressure gradient in the most permeable layer between the two wells. The pressure difference does not reflect any additional gas-in-place.

3. Using the Phillips history matched, 12 section model in the Guymon-Hugoton Field, the Mesa observation-replacement well field experiment results were duplicated by simulating with the model a replacement well and using the original well as an observation well.

4. A simple method can be used to calculate time to an abandonment rate and layer abandonment pressures for a layered, no-crossflow reservoir. These calculations can be made for any number of layers and wells within a drainage area. A long producing life can be expected for wells in a layered, no-crossflow reservoir. Infill wells produced to the same abandonment rate as the original wells do not add any incremental reserves.

NOMENCLATURE

B_{gi}	= gas formation volume factor, SCF/RCF
G_i	= initial gas-in-place, Bscf
G_p	= cumulative gas production, Bscf
G_r	= remaining gas-in-place, Bscf
h	= thickness, ft
k	= effective permeability, md
n	= number of layers
p	= pressure, psia
q(t)	= surface rate of flow, Mscfd
$(q_{gi})_{max}$	= initial surface rate of flow from the stabilized curve, Mscfd
q_a	= abandonment flow rate, Mscfd
r_e	= external boundary radius, ft
r_w	= wellbore radius, ft
r_{wa}	= apparent wellbore radius, ft
S	= skin factor, dimensionless
S_w	= water saturation, fraction
t_a	= time, years to abandonment rate
z	= gas compressibility factor, dimensionless
ϕ	= porosity, fraction of bulk volume
μ_g	= gas viscosity, cp

SUBSCRIPTS

g	= gas
i	= initial
a	= abandonment
n	= layer number
obs	= at observation well
w	= wellbore

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APPENDIX

Equation Summary

Rate time equation

$$q(t) = \frac{(q_{gi})_{max}}{\left(\left[\frac{(q_{gi})_{max}}{G_i}\right] t_a + 1\right)^2} \quad \text{(A1)}$$

Rate time equation for 4 layers

$$q(t) = \sum_{n=1}^{4} \frac{(q_{gi})_{max}}{\left(\left[\frac{(q_{gi})_{max}}{G_i}\right] t_a + 1\right)^2} \quad \text{(A2)}$$

q_{max} equation, pseudosteady state

$$(q_{gi})_{max} = \frac{kh\,\bar{P}}{1424\,\overline{\mu z}\,T\left[\ln\left(\frac{.472\,r_e}{r_w}\right) + s\right]} \quad \text{(A3)}$$

Material balance equations

$$G_p/G_i = 1 - \left(\frac{p}{z} \Big/ \frac{p_i}{z_i}\right) \quad \text{(A4)}$$

$$G_p = \pi\, r_e^2\, B_{gi} \sum_{n=1}^{4} \phi_n\,(1 - S_{wn}) \left(\frac{G_p}{G_i}\right)_n \quad \text{(A5)}$$

Time to abandonment rate, q_a

$$t_a = \frac{\sqrt{\frac{(q_{gi})_{max}}{q_a}}}{\left[\frac{(q_{gi})_{max}}{G_i}\right]} \quad \text{(A6)}$$

Fractional recovery for each layer at abandonment

$$\left[G_p/G_i\right]_a = 1 - \frac{1}{\left[\frac{(q_{gi})_{max}}{G_i}\right] t_a + 1} \quad \text{(A7)}$$

TABLE 1

μ_g	= 0.01 cp	T	= 560 °R
k	= 28.9 md	z	= 0.98
h	= 34 ft	S	= - 5
r_w	= 0.2539 ft	r_{wa}	$= r_w e^{-s} = .2539\ e^5 = 37.68$ ft
r_{obs}	= 2150 ft	q_w	= (0.47)(311,173 Scf/day) = 146,251 Scf/day
r_e	= 2918 ft	P_w	= 127.6 psia

TABLE 2

EFFECT OF LAYERING ON DEPLETION AND TIME TO AN ABANDONMENT RATE
FLOWING BHP = 0
ONE PRODUCING WELL PER SECTION
P_i = 463 psia, B_{gi} = 31.98 SCF/RCF

Layer 640-acres	k md	h ft	kh md-ft	skin	ϕ	S_w	G_i MMSCF	$\bar{P}$* psia	G_p/G_i	G_r MMSCF	1 Well $(q_{gi})_{max}$ MSCFD	$\left[\frac{(q_{gi})_{max}}{G_r}\right]$ x 10^{-6}	$\left[\frac{(q_{gi})_{max}}{G_r}\right]_R$
Krid	21.8	34	741	-5	0.148	0.235	3432	188	0.610	1284	889	692	1.0
Winf	12.6	28	353	-5	0.150	0.285	2676	210	0.563	1123	528	470	1.47
UFR	5.4	42	227	-5	0.149	0.312	3840	238	0.503	1830	436	238	2.91
LFR	0.53	26	14	-5	0.128	0.308	2052	284	0.402	1178	38	32	21.6
Total	10.3	130	1335	-5			12000			5415	1795		

Layer	Time before being produced wide open, yrs	Each layer produced separately to an abandonment rate of 10 MSCFD: t** yrs	t_a yrs	G_p/G_i fraction	Commingled Well: t** yrs	t_a yrs	q_{layer} MSCFD	G_p/G_i fraction	$\bar{P}_{layer}$ psia
Krid	27	33	60	0.96	135	162	0.72	0.99	5
Winf	27	36	63	0.94	135	162	0.90	0.98	10
UFR	27	64	91	0.92	135	162	2.70	0.96	20
LFR	27	81	108	0.69	135	162	5.68	0.77	112
							10.0	0.94	

* Pressure distribution of layers at time = 27 years (1977)
** Time to abandonment producing wide-open beginning in 1977
t_a = total producing life including the first 27 years of commingled production

TABLE 3

EFFECT OF LAYERING ON DEPLETION AND TIME TO AN ABANDONMENT RATE
FLOWING BHP = 0 PSIA
TWO PRODUCING WELLS PER SECTION - INFILL WELL DRILLED
WHEN LAYER PRESSURE DISTRIBUTION IS IDENTICAL TO THAT
MEASURED IN 1977

P_i = 463 psia, B_{gi} = 31.98 SCF/RCF

Layer 640-acres	k md	h ft	kh md-ft	skin	ϕ	S_w	G_i MMSCF	$\bar{P}$* psia	G_p/G_i	G_r MMSCF	2 Well $(q_{gi})_{max}$ MSCFD	$\left[\frac{(q_{gi})_{max}}{G_r}\right]$ x 10^{-6}	$\left[\frac{(q_{gi})_{max}}{G_r}\right]$ R
Krid	21.8	34	741	-5	0.148	0.235	3432	188	0.610	1284	1968	1533	1.0
Winf	12.6	28	353	-5	0.150	0.285	2676	210	0.563	1123	1169	1041	1.47
UFR	5.4	42	227	-5	0.149	0.312	3840	238	0.503	1830	965	527	2.90
LFR	0.53	26	14	-5	0.128	0.308	2052	284	0.402	1178	83	70	21.9
Total	10.3	130	1335	-5			12000			5415	3950		

Layer	Time before being produced wide open, yrs	Each layer produced separately to an abandonment rate of 20 MSCFD: t** yrs	t_a yrs	G_p/G_i fraction	Commingled Well: t** yrs	t_a yrs	q_{layer} MSCFD	G_p/G_i fraction	$\bar{P}_{layer}$ psia
Krid	27	16	43	0.96	65	92	1.4	0.99	5
Winf	27	17	44	0.94	65	92	1.8	0.98	10
UFR	27	31	58	0.92	65	92	5.3	0.96	20
LFR	27	40	67	0.71	65	92	11.5	0.77	112
							20.0	0.94	

* Pressure distribution of layers at t = 27 years (1977)

** Time to abandonment producing wide-open beginning in 1977

t_a = total producing life including the first 27 years of commingled production

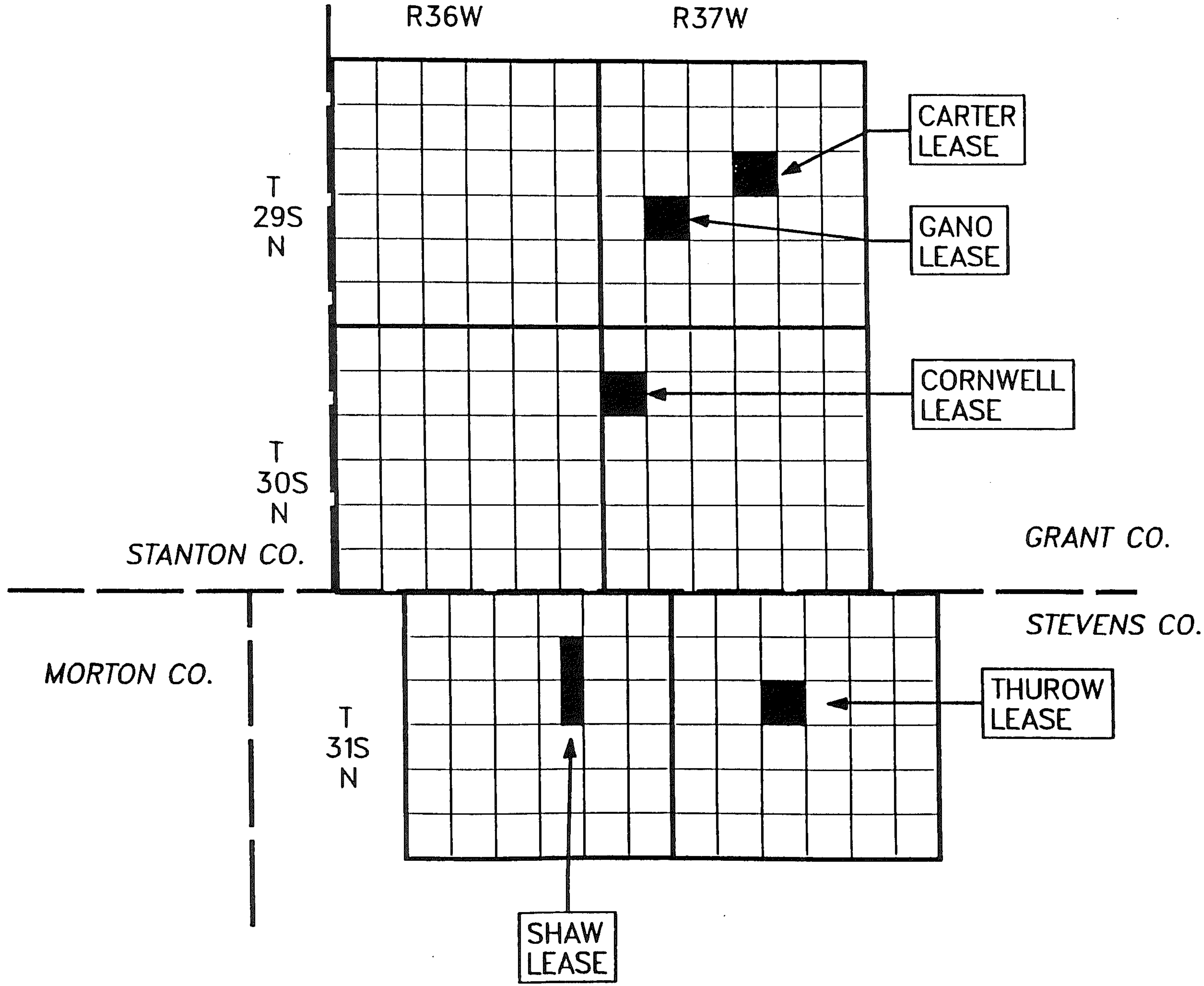

Fig. 1 Location of the five replacement wells

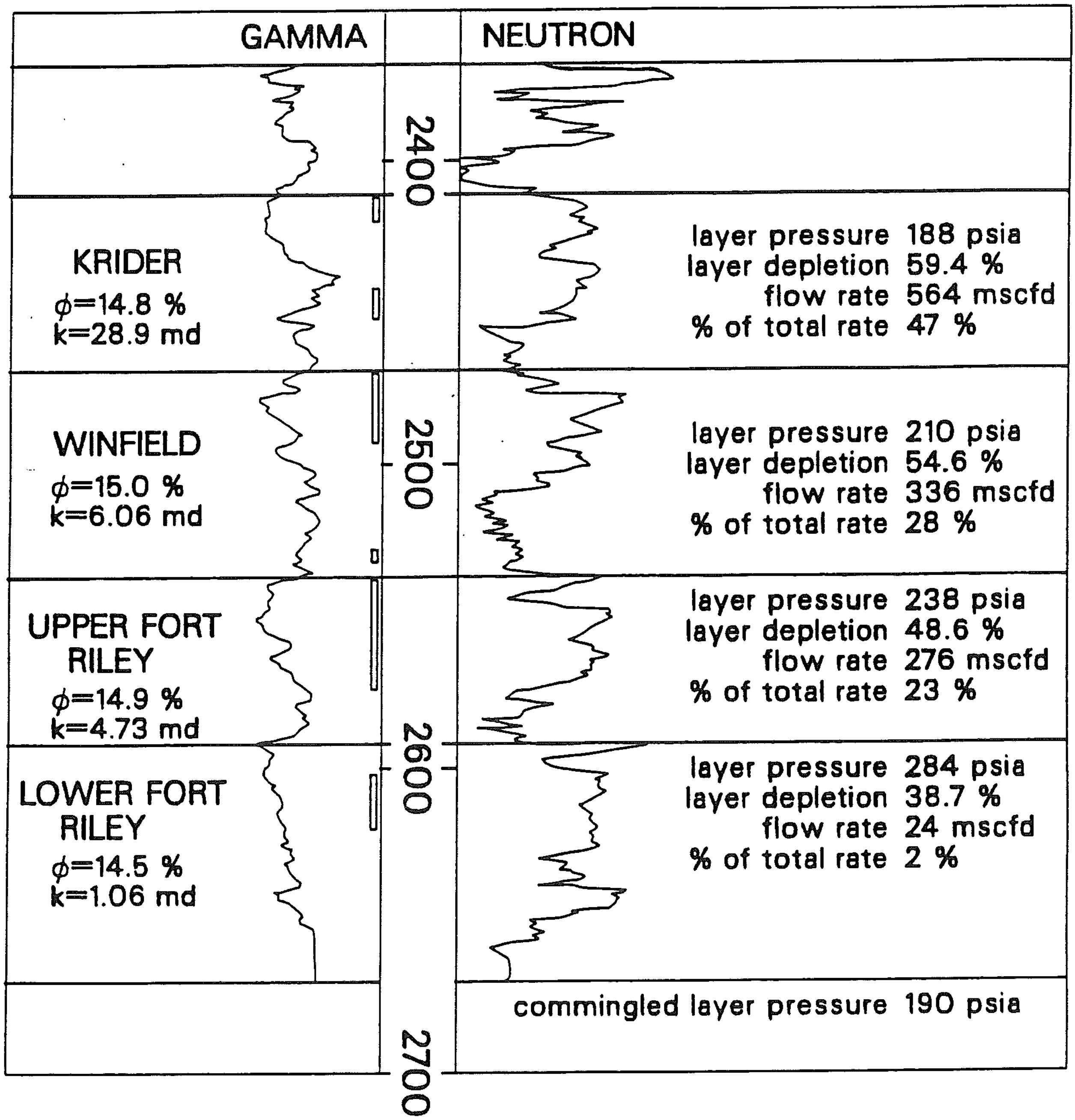

Fig. 2 Type log for the Gano 1A with individual layer pressures and flowrates

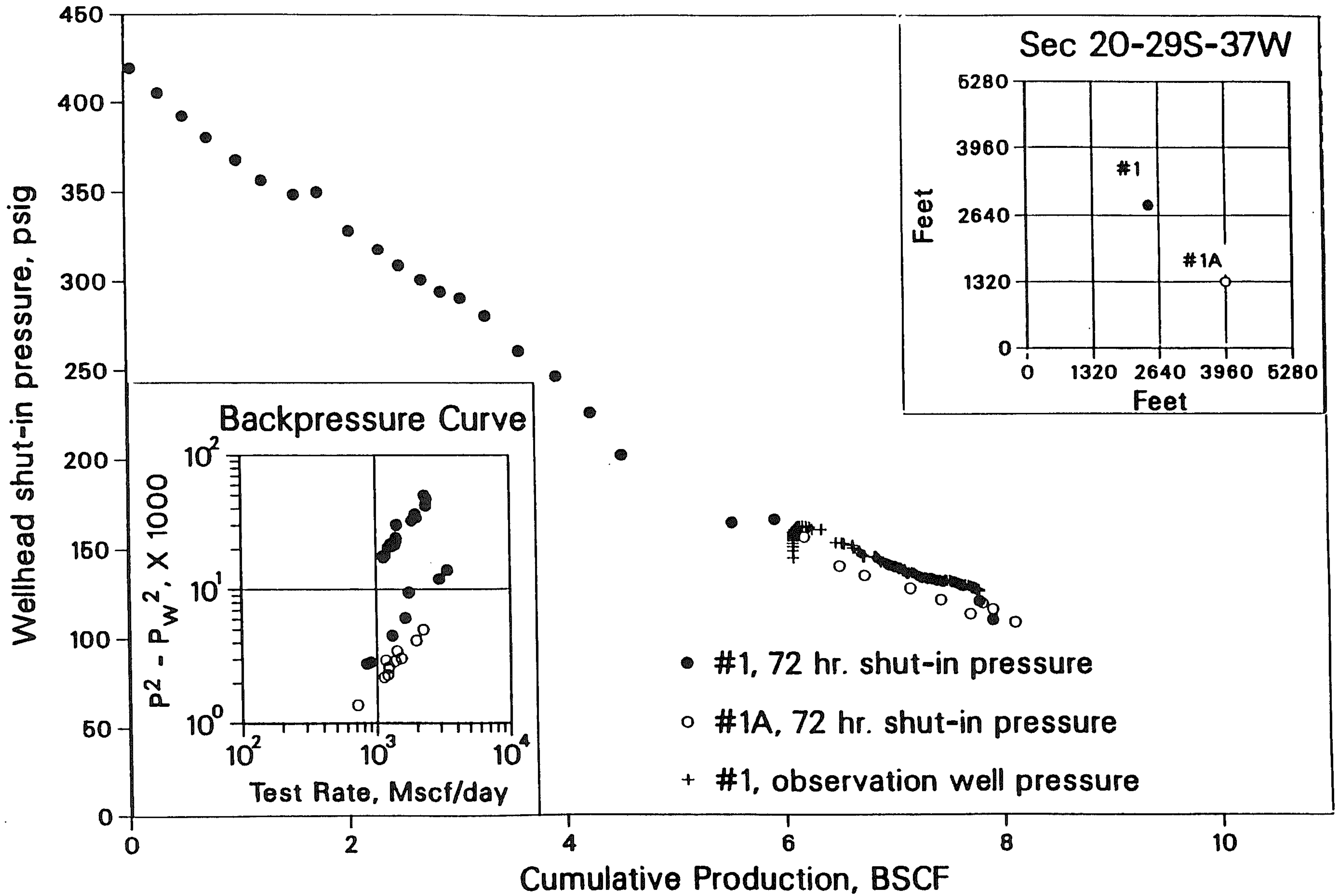

Fig. 3 Wellhead shut-in pressure vs. cumulative production with a wellhead backpressure curve and location plat for the Gano Lease

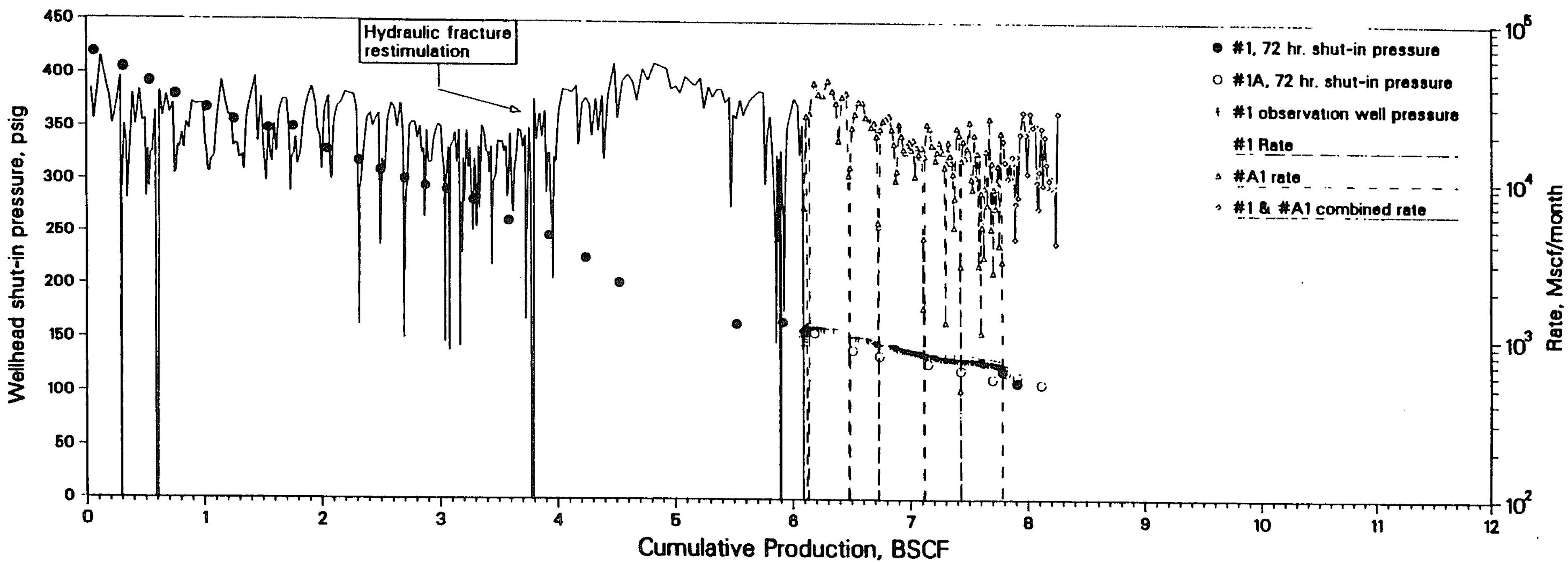

Fig. 4 Wellhead shut-in pressure and monthly rate vs. cumulative production for the Gano Lease

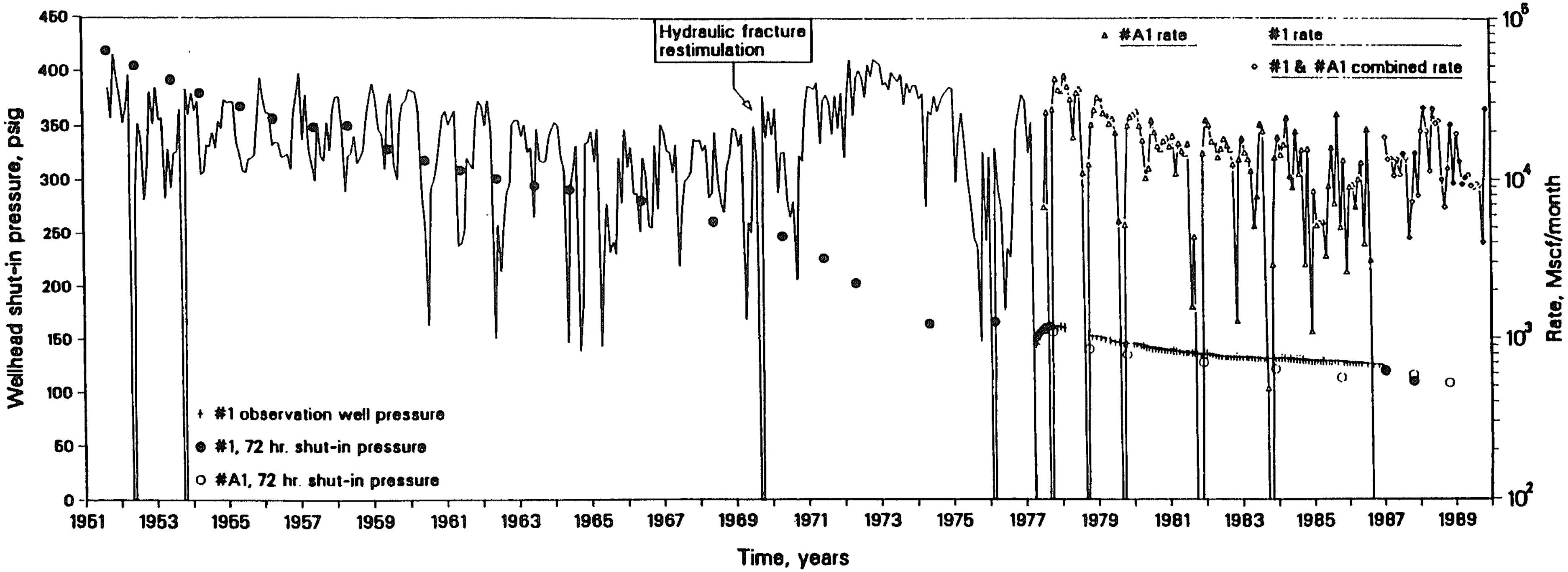

Fig. 5 Wellhead shut-in pressure and monthly rate vs. time for the Gano Lease

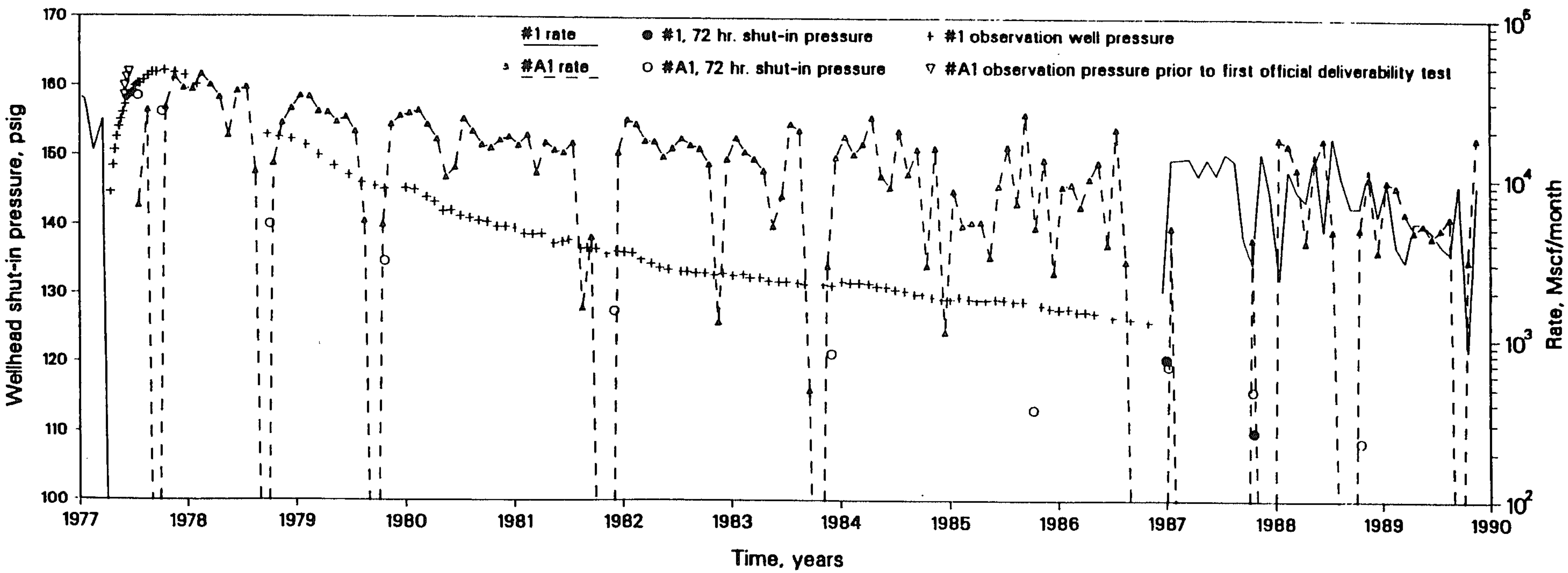

Fig. 6 Wellhead shut-in pressure and monthly rate vs. time since 1977 for the Gano Lease

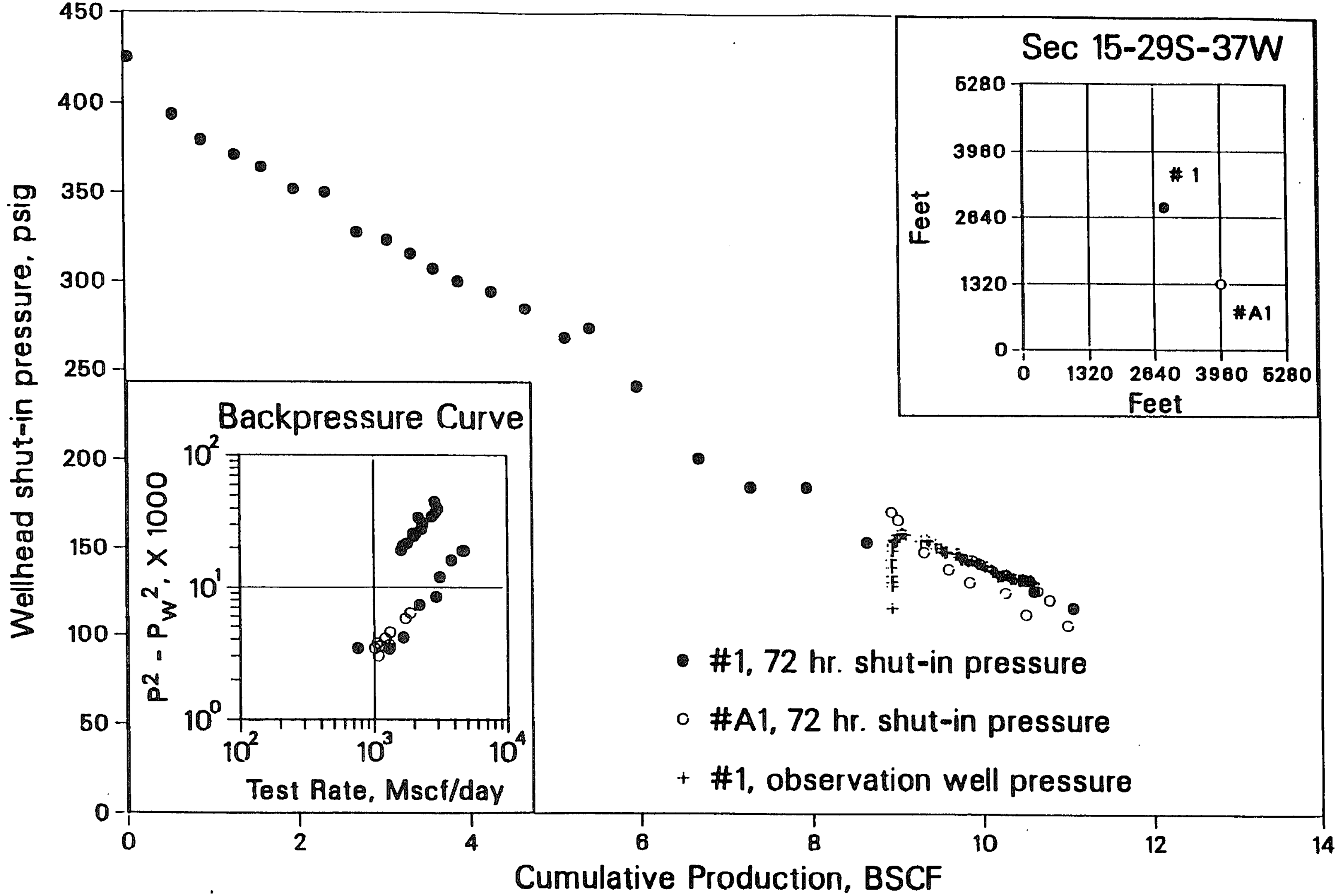

Fig. 7 Wellhead shut-in pressure vs. cumulative production with a wellhead backpressure curve and a location plat for the Carter Lease

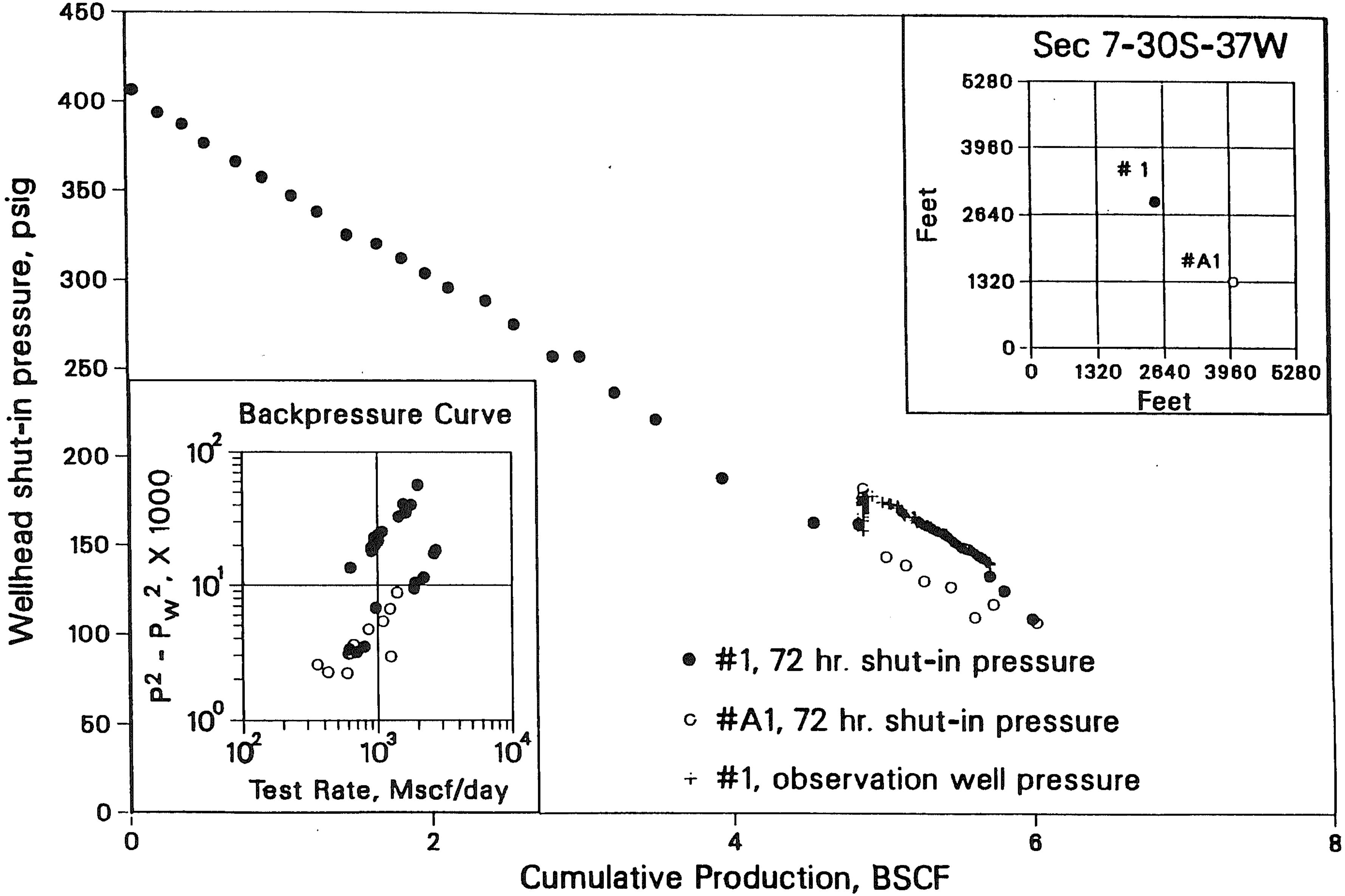

Fig. 8 Wellhead shut-in pressure vs. cumulative production with a wellhead

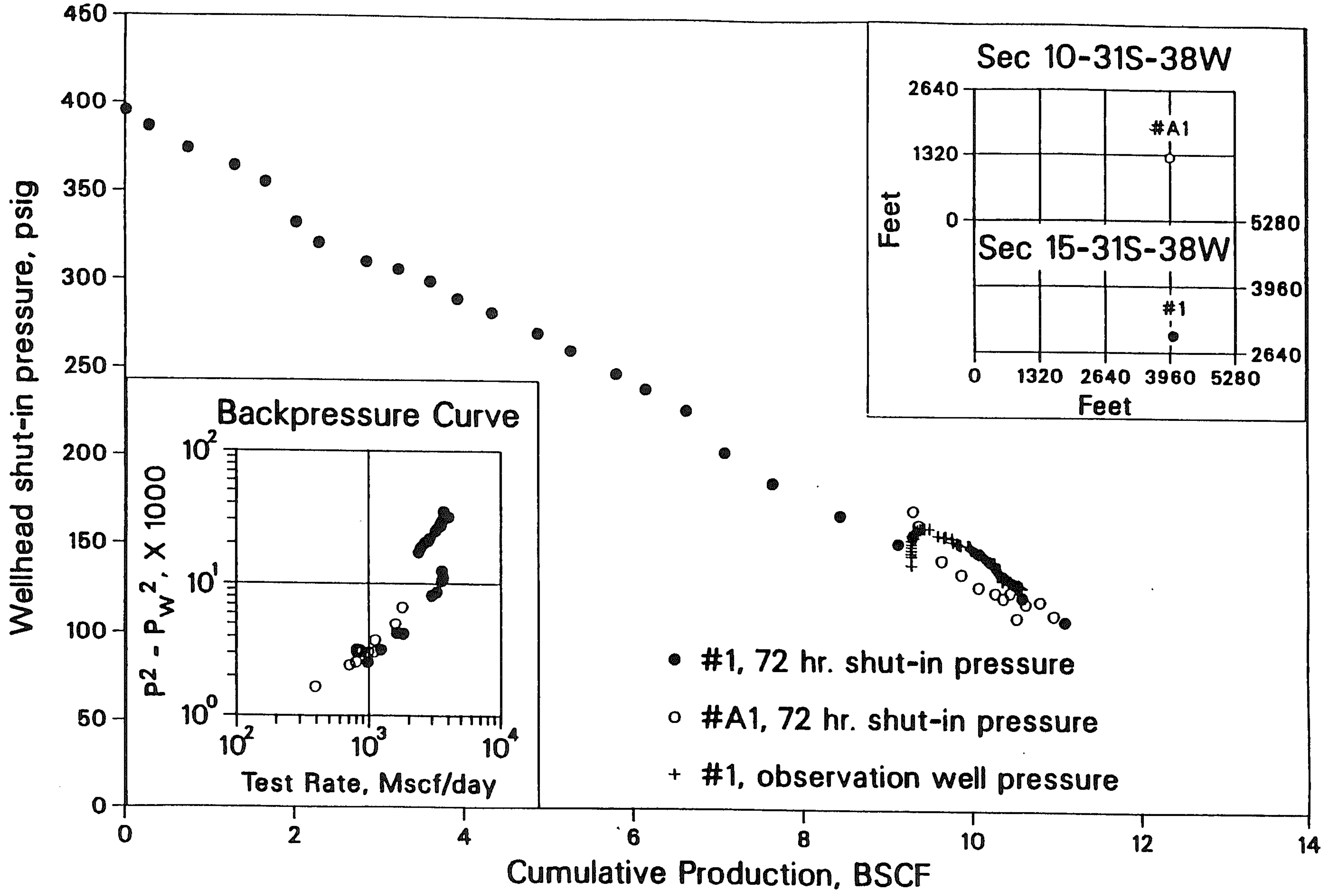

Fig. 9 Wellhead shut-in pressure vs. cumulative production with a wellhead backpressure curve with a location plat for the Shaw Lease

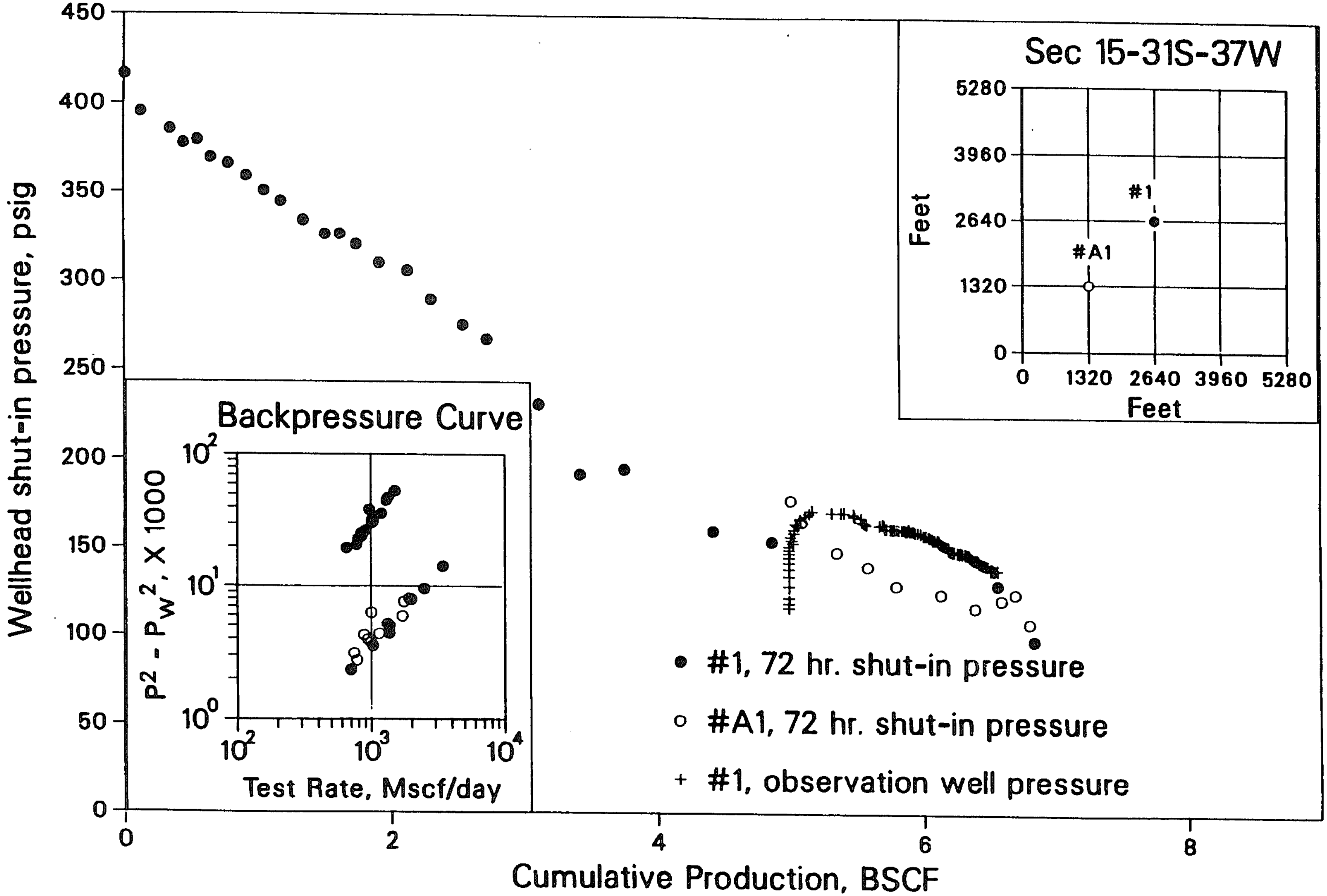

Fig. 10 Wellhead shut-in pressure vs. cumulative production with a wellhead backpressure curve with a location plat for the Thurow Lease

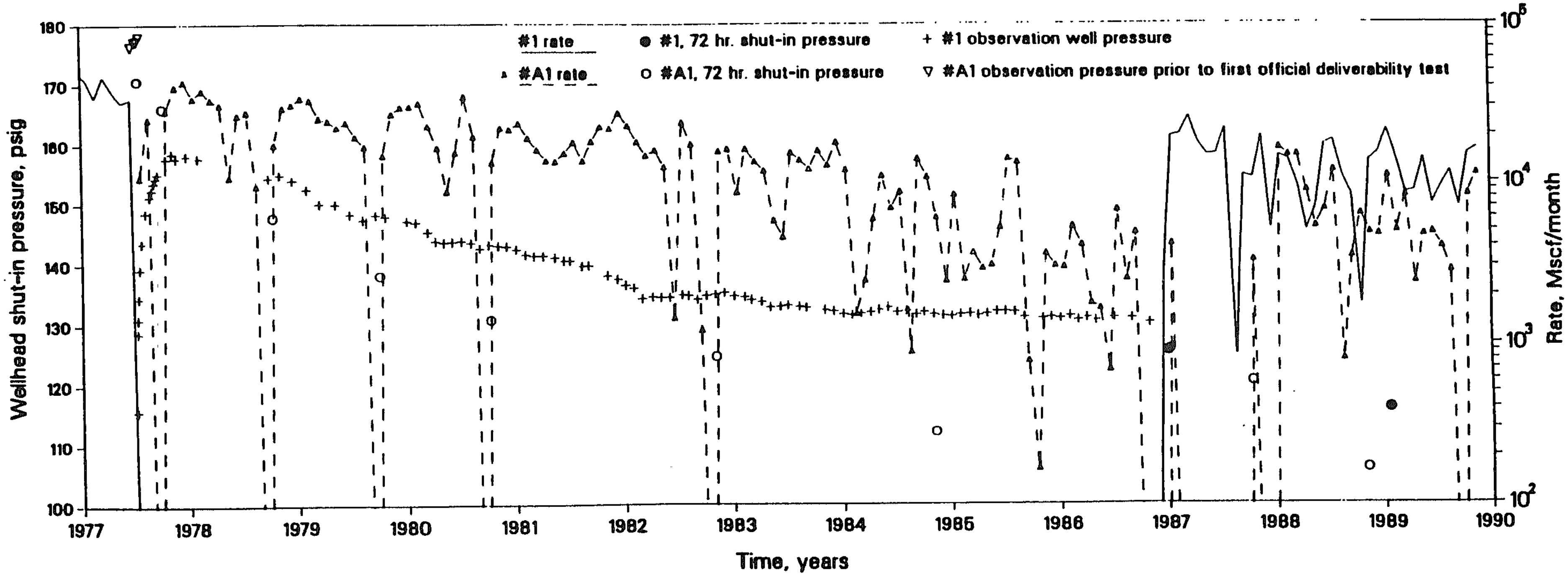

Fig. 11 Wellhead shut-in pressure and monthly rate vs. time since 1977 for the Carter Lease

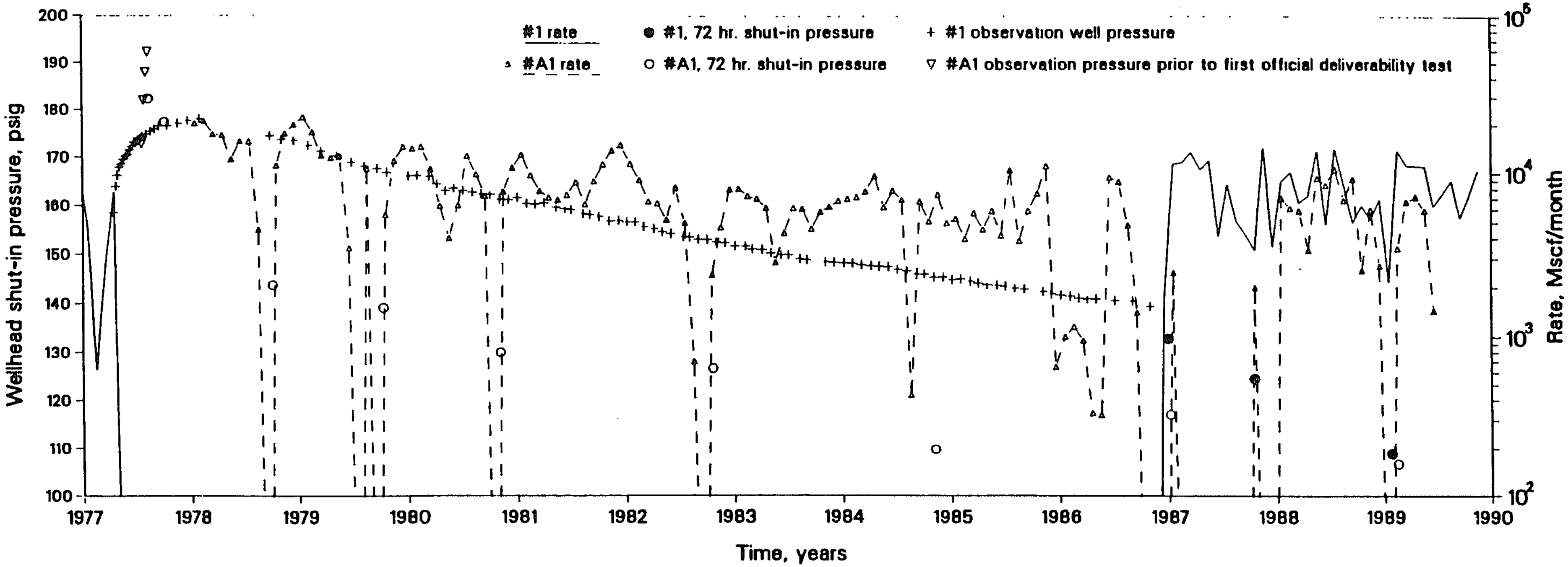

Fig. 12 Wellhead shut-in pressure and monthly rate vs. time since 1977 for the Cornwell Lease

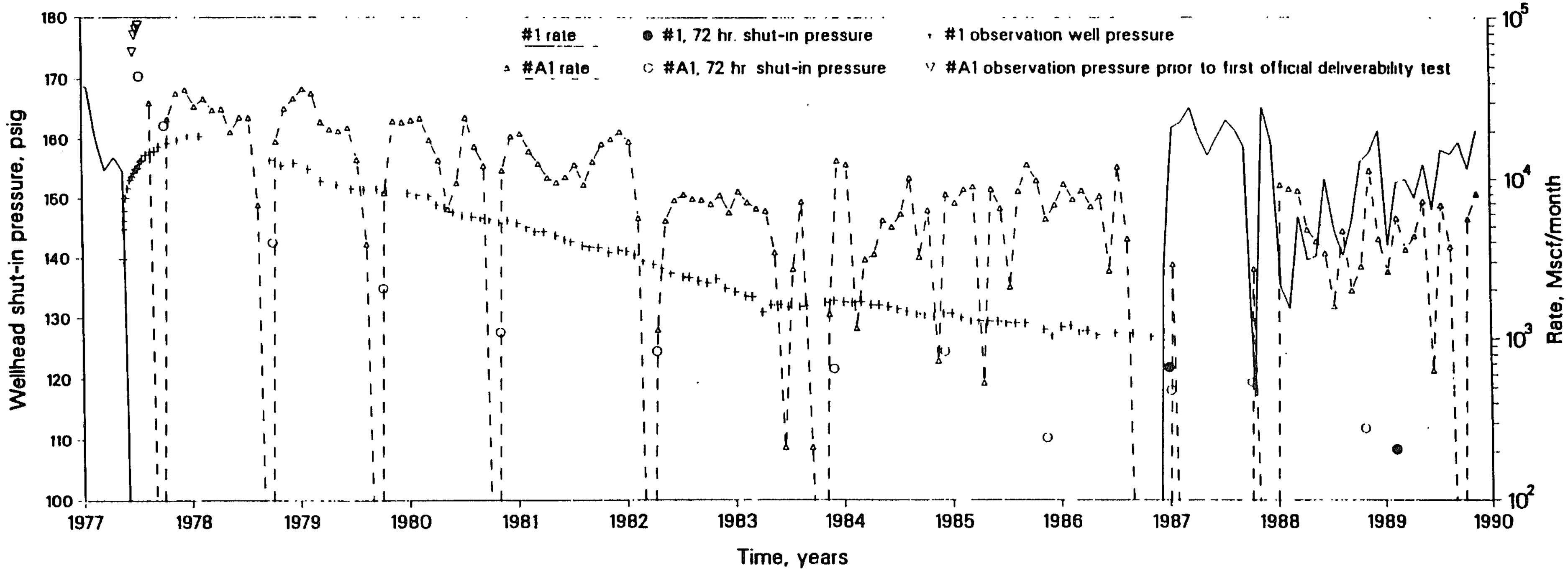

Fig. 13 Wellhead shut-in pressure and monthly rate vs. time since 1977 for the Shaw Lease

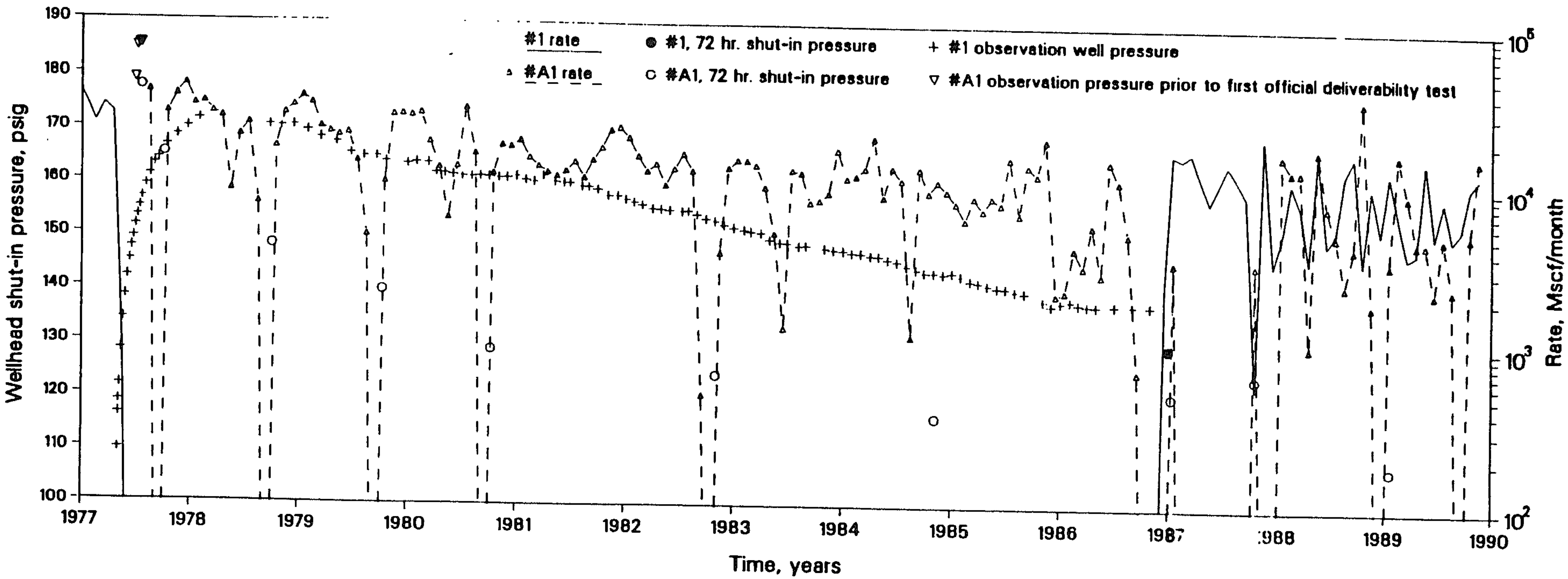

Fig. 14 Wellhead shut-in pressure and monthly rate vs. time since 1977 for the Thurow Lease

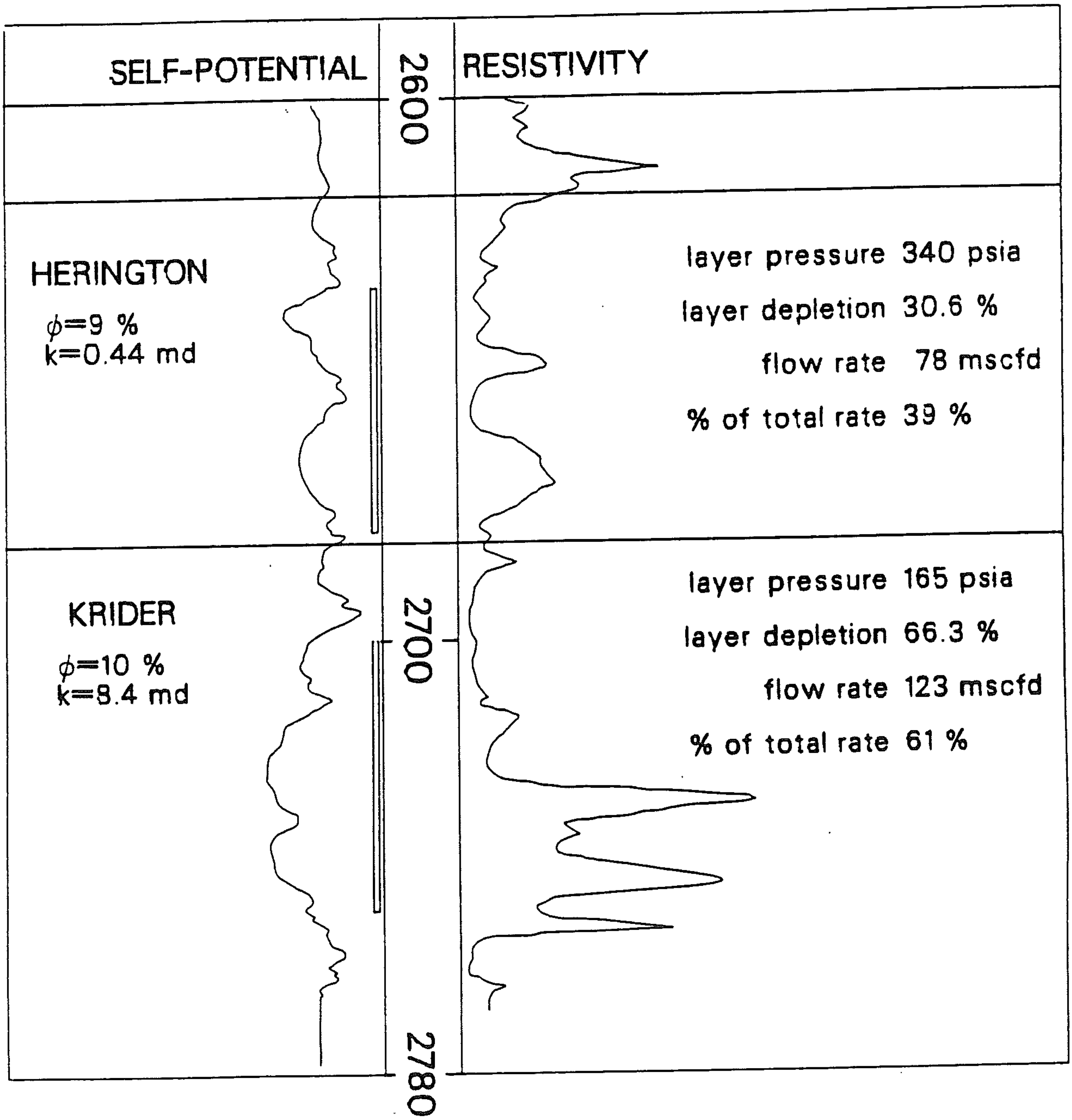

Fig. 15 Type log for the Sheil #1 with simulated individual layer pressures and flowrates

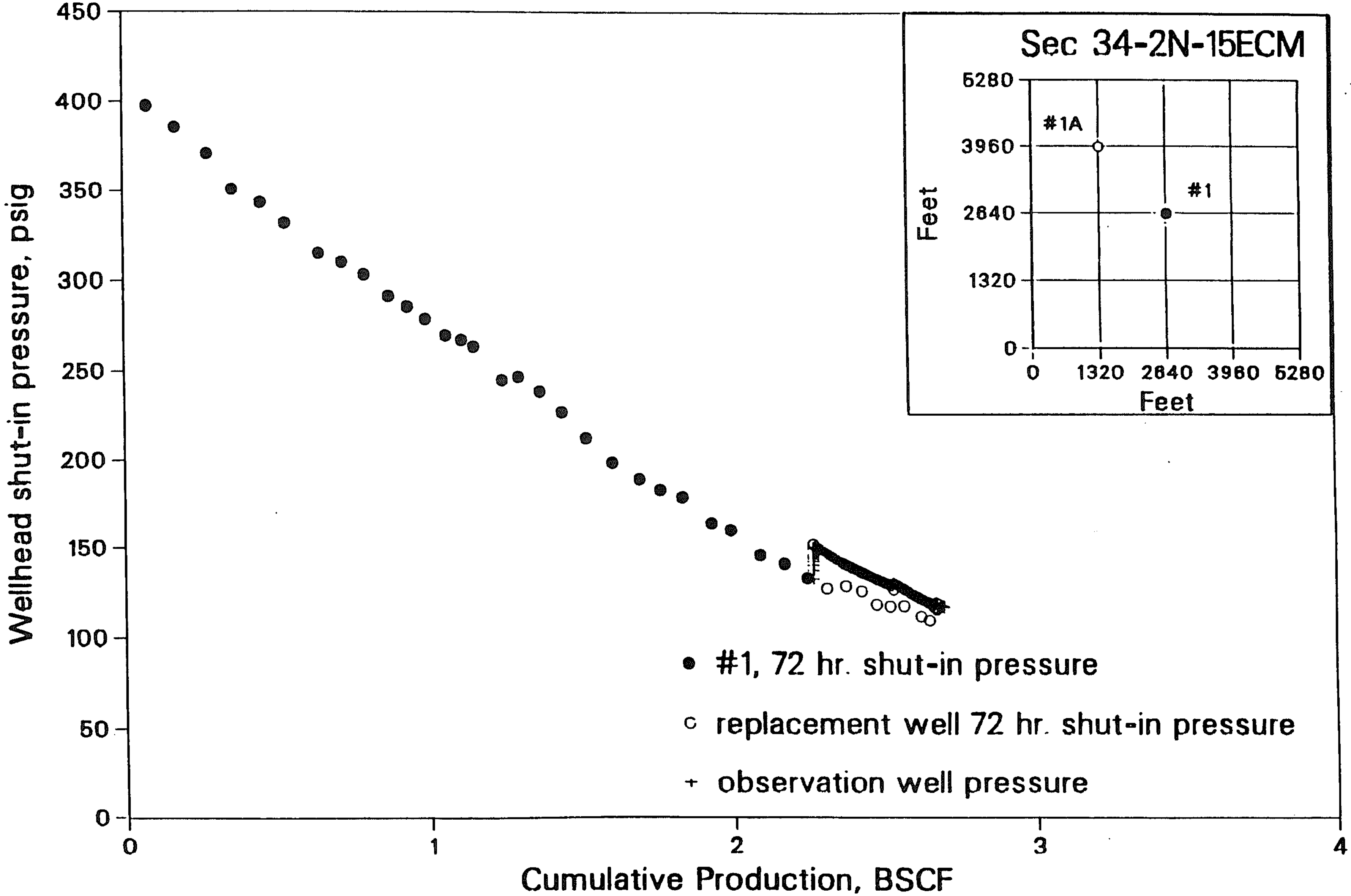

Fig. 16 Calculated wellhead shut-in pressure vs. cumulative production with a location plat for the simulated replacement-observation well experiment

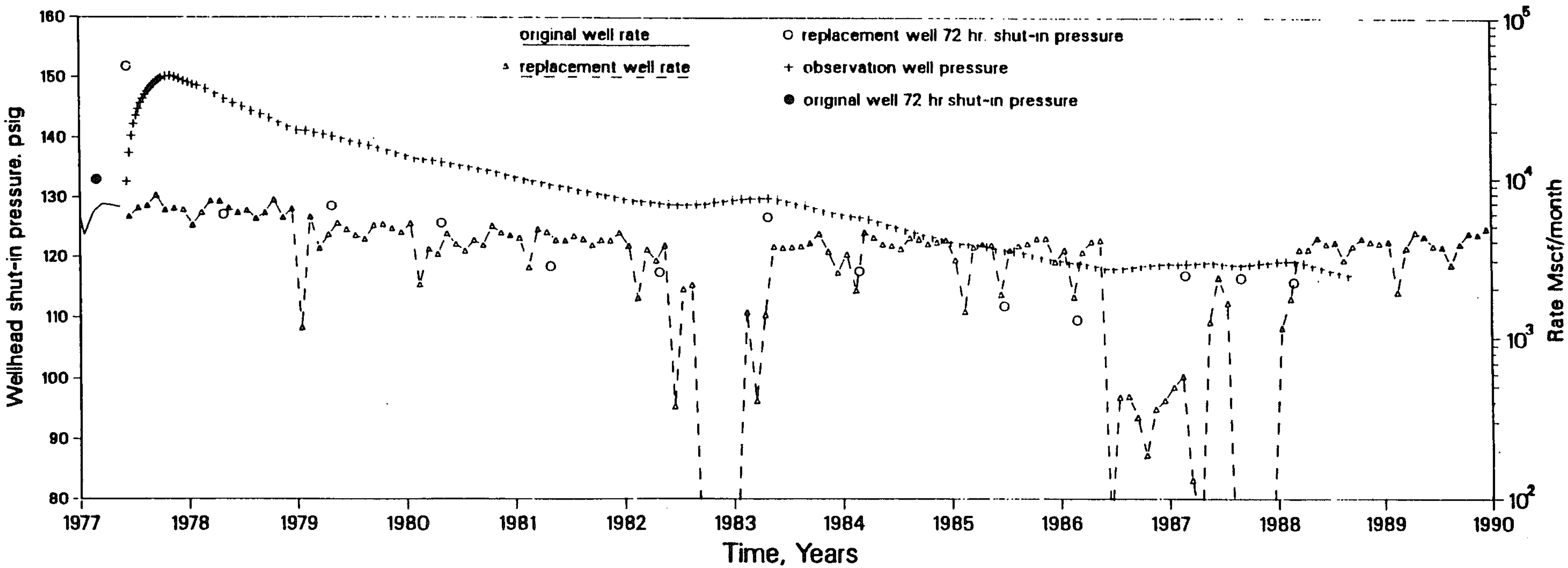

Fig. 17 Calculated wellhead shut-in pressure and monthly rate vs. time for the simulated replacement-observation well experiment