MULTI-ZONE METHODS TO
PREDICT GAS WELL PERFORMANCE
BY

LOUIS A. BLANCHARD & JERRY R. NEWHOUSE
PANHANDLE EASTERN PIPE LINE COMPANY

ABSTRACT

This paper explains the contributing elements of a new formula developed for more accurately predicting the performance of those gas wells which include a high permeability zone interbedded with one or more low permeability zones. The theory assumes the existence of three conditions: that the well depletes without water encroachment; that each zone remains discreet from every other--that is, without cross flow among zones when the well is producing; and that each zone has either a hydraulic fracture or some skin effect. As a practical matter in using the model, however, only one of these reservoir conditions need be strictly met: freedom from water encroachment. The model developed herein does adapt to reservoirs that have limited cross flow between zones; it also adapts to those with a hydraulic fracture in only some of the zones. Finally, it includes equations which help to calculate matrix permeability whenever a known hydraulic fracture does exist.

We illustrate the functions of this model by assuming the existence of a shaley-sand, six-zone reservoir and by ascribing to it certain characteristics. We examine how the model uses this data and then discuss the results.

INTRODUCTION

The accurate estimation of future production rates and volumes from gas wells is at present a very important process for any company dependent upon buying or selling natural gas directly from individual gas wells. It will become a crucial process over the next several decades as the gas industry struggles to meet the expected sharp increase in world demand. Any tool, therefore, which better equips the engineer to refine his estimates of gas reserves, should be of interest. It is the purpose of this paper to introduce just such a new tool.

Traditionally, short term flow test data has been used to predict the future performance of any gas well, whether single or multi-zone. Equations (1) & (2) shown below have been used successfully for a long time.

$$BHP/Z = Pi/Zi \times (1 - Gp/Gsc) \qquad \text{-----(1)}$$

$$Qsc = Cs\,(Pws^2 - Pwf^2)^n \qquad \text{-----(2)}$$

To review, equation (1) stands as the basic equation to plot decline curves for volumetric depletion gas wells. The ordinate is plotted as BHP/Z. Cumulative production or Gp is plotted as the abscissa. Theory dictates a straight line function and when Gp = Gsc, then BHP/Z equals zero. Therefore, when BHP/Z = zero, the decline curve will clearly indicate the initial gas in place or Gsc. While these equations have been entirely adequate in describing the IGIP of most single-layer gas wells, experience has shown that the equations underestimate the initial gas in place reserves of multi-layer gas wells. In other words, these equations actually distort the real situation when the area under scrutiny has a high permeability zone interbedded with low permeability zones. The following sections develop a model for more accurately predicting the IGIP for such special cases.

To begin with, let us examine precisely <u>why</u> equation (2) is inadequate for multi-layer well calculations. Equation (2) has been advanced in published literature 1/ in practical oil field units to include:

$$Qsc = \frac{k\ h\ (Pws^2 - Pwf^2)}{1424\ T\ Up\ Zp\ (\ln Re/Rw + S)} \quad \text{------(3)}$$

Prior to stabilization equation (3) can be written as:

$$Qsc = \frac{k\ h\ (Pws^2 - Pwf^2)}{1424\ T\ Up\ Zp\ (Pt + S)} \quad \text{---------(4)}$$

where Pt is a pressure drop function which, after a dimensionless time of 100, may be defined as:

$$Pt = 1/2\ (\ln Tdw + .807) \quad \text{---------(5)}$$

and where

$$Tdw = \frac{.0002635\ k\ t}{Ct\ \emptyset\ Up\ Rw^2} \quad \text{---------(6)}$$

Stabilization of the matrix permeability will occur when:

$$\mathrm{Ln}\ (Re/Rw) = Pt \quad \text{---------(7)}$$

As has been adequately demonstrated in D. G. Russell's article "Methods for Predicting Gas Well Performance," 2/ a model can be constructed for a single zone using a constant pressure Pwf for a given constant time period. A multi-zone model is therefore relatively easy to construct.

Let us assume a six-zone reservoir. Using the general assumption that Pwf (or flowing bottom hole pressure) for each zone in a common well bore will be constant for a given time step, each of the six flow rates can be calculated using equation (4). In a future time step after stabilization, equation (3) can be used until depletion. Total flow from the well would be the partial flow from each zone--1 to 6--for the time step involved. But several problems arise as we attempt to adapt this simple approach to our more complex multi-layer situation: it becomes almost impossible to relate Pt to S, then both to k. The following section explains.

DEFINING THE RELATIONSHIP BETWEEN k AND S

Assume for a moment we have a flow test with data as shown on Fig. 1. The relationship which would result between k and S is shown in equation (4). On any flow test, at a given Qsc, Pws, and Pwf with a real time value of t, the calculated k or permeability value would be larger when S represents a small hydraulic fracture and smaller when S represents a large hydraulic fracture. For a single-layered reservoir, it is easy to work directly with one skin value, using present theory. The Pt value can easily be related to S, then both to k. For a multi-layered reservoir, however, it becomes an extremely complicated task to arrive at single Pt and S values which adequately reflect the dynamics of the reservoir, to say nothing of then relating those values to a single k.

NEW THEORY

Introducing The Model

To illustrate our theory, we assume the existence of a sample well. We ascribe to our sample well the following characteristics: it is a shaley-sand, six-zone gas reservoir with volumetric depletion. Its six gas zones deplete over a thirty year time span at various rates and pressures. At the end of thirty years, individual zone recovery ranges from 88.6 percent to 1.7 percent; average recovery is 42.8 percent. It includes a decreasing or lasting hydraulic fracture that becomes less effective with time.

$$Q3 = Q1 + Q2 \qquad \text{--------- (8)}$$

Q1 = flow from the matrix permeability.
Q2 = flow from the hydraulic fracture or skin.
Q3 = total flow from the well with a hydraulic fracture.

From equation (4) with zero skin value:

$$Qsc = Q1 = \frac{\text{Constant}}{Pt} A \qquad \text{--------- (9)}$$

From equation (4) with a negative or positive skin value:

$$Qsc = Q3 = \frac{\text{Constant}}{(Pt + S)} A \qquad \text{--------- (10)}$$

Constant A includes all the identical terms of h, Pws, Pwf, T, Up, Zp, etc., for two flow tests. One test, because it is performed prior to fracturing, assumes a zero skin effect; the other test, taken after fracturing, assumes a minus skin value. Constant A is the same for both tests. Then Q3 will be greater than Q1 because of its hydraulic fracture assumed in equation (10).

After combining equations (9) and (10), we have the following:

$$Q1\ Pt = Q3\ (Pt + S) \qquad \text{--------- (11)}$$

$$Q3\ S = Q1\ Pt - Q3\ Pt$$

$$Q3\ S = -(Q3 - Q1)\ Pt$$

$$Q2 = (Q3 - Q1) \quad \text{from equation (8)}$$

$$S = -(Q2/Q3)\ Pt \qquad \text{--------- (12)}$$

The value of -(Q2/Q3) Pt can now be substituted as an initial skin effect when a hydraulic fracture exists. Therefore, equation (4) for a given time value, assuming the presence of a hydraulic fracture, can be re-written as the following:

$$Qsc = \frac{k \quad h \quad (Pws^2 - Pwf^2)}{1424 \quad T \quad Up \quad Zp \quad (Pt - Q2/Q3\ Pt)} \quad \text{--------}(13)$$

By definition, Q2/Q3 will be the Fraction Flow from the Skin effect, or:

$$FFS = (Q2/Q3) \quad \text{--------}(14)$$

For convenience we will use the term FFS to refer to that fraction throughout the rest of the paper. For some situations, equation (13) can be simplified. Specifically, when a known hydraulic fracture exists for a short term flow test and the dimensionless time is more than 100, equation (13) reduces to this:

$$Qsc = \frac{k \quad h \quad (Pws^2 - Pwf^2)}{1424 \quad T \quad Up \quad Zp \quad Pt\ (1-FFS)} \quad \text{--------}(15)$$

We can then reduce equation (15) to the following:

$$k - \ln k = \text{Constant } B \quad \text{--------}(16)$$

Constant B contains all the variables of the other values in equation (15) such as an assumed value for FFS, and the actual values for Qsc, Pws, Pwf, t, etc.

We next must assume a series of different values for FFS until we obtain a good history match of k to the weighted average core or permeability formula value. As we illustrate below, once this absolute permeability is found, we next must use it with reservoir data to find the effective permeability for each zone. The next two sections discuss these two steps in more detail.

Determine Weighted Average Permeability for All Zones

Please refer again to Fig. 1. The figure shows the actual data calculated from logs or obtained from a flow test; it contains all known values except k and FFS. Now, we must find average k and average FFS values across all zones represented in the flow test.

Please refer to Fig. 2. For Run #1, we assumed that 10 percent of the flow from the well was caused by the skin effect, i.e., 1975 MCF/D x .10 = 197.5 MCF/D was attributed to flow from the skin effect. Therefore, FFS = 10 percent. (This value serves for illustrative purposes only. As previously discussed, if the assumed fracture is small, as in Run #1, then k is larger than if the fracture is assumed to be larger, as shown in Runs #2 and #3. Run #3 at last matched the weighted average core data permeability using equation (15).)

The importance of using equation (15) rather than equation (4) should become apparent, for as we discuss below, equation (15) allows for fluctuating Ø and k from zone to zone. As a practical matter also, we can adapt equation (15) to accommodate a damaged or positive skin zone. The (1-FFS) we show for a fractured zone simply becomes (1+FFS) for a damaged zone. The derivation of this change in equation (15) involves the assumption that flow rate is impeded by positive skin damage. We mention this adaption only as a footnote, however. No further space will be devoted to its discussion since most completed wells initially have a hydraulic fracture or negative skin effect of some kind.

Determine Permeability For Each Zone

After we once have found the weighted average permeability across all zones, we next must calculate permeability for each zone separately. The most successful approach is to use a formula distributing core permeability for each zone to the bench mark weighted average core permeability found in the previous step. But herein lies a problem; core information is sometimes missing for the very zones which will produce the most easily. Offset wells often are not cored at all. For these reasons, a search of the literature was made to determine whether a permeability formula exists that would lend itself equally well to finding both absolute and effective permeability for any given zone. Such a formula 3/ was found. It is set forth in equation (17).

$$k^{1/2} = C \ \emptyset^{a} / Sw \qquad \text{- - - - - - - - -(17)}$$

To variables C and a we assign these values:

When the gas sand is clean:	C = 100 and a = 2.25
When the gas sand is shaley:	C = 79 and a = 3.0

The above values are not sacred. Certainly other values for C and a should be used if the formation type warrants it. And if the reservoir is sufficiently complex, the reader may even need to select, for some zone(s), a more sophisticated permeability formula than equation (17). The simplicity and adaptability of equation (17), however, make it ideal for our illustrative purposes. The results of using it with the shaley sand values shown above are displayed in Fig. 3. After verifying the base data as correct, we then distribute the permeability from zone to zone using equation (17).

The first three runs charted in Fig. 4 simply represent more detailed results of the data shown in Fig. 2. Please refer now to Fig. 4. Run #1 assumed a fracture flow from the skin effect (FFS) as 10 percent of the total measured well test flow. The resulting permeability factor was too high. Run #2, which assumed 90 percent of the total measured flow from the fracture, results in a too-low permeability factor. Run #3 assumed 50 percent FFS and finally matches the calculated core data closely enough. Run #4 takes us one step further, reducing absolute permeability to effective permeability, using the best estimate of relative permeability data.

Estimated Shut-In Pressure

Because it is so important that this next step be understood, we digress momentarily to explain some physical principles underlying the estimation of shut-in pressure. (We assume here a shut-in time of 72 hours or less, and we assume that the shut-in test under discussion is performed at some point after one-half the estimated producing life of the well.) Whether the well being gauged at this point is in a single- or multi-layer reservoir, the shut-in reading will nearly always most closely reflect the pressure of the lowest pressured gas. To the inexperienced, the previous statement at first will seem entirely erroneous, particularly considering the well-known propensity of gas to move from high pressure to low. The physical explanation really is quite simple.

That zone of gas (in a multi-layer reservoir well) which, after considerable production, registers as the <u>lowest pressure</u> gas, is also, all other conditions being equal, the zone of <u>highest permeability</u>. Conversely, given the same conditions, that gas whose pressure is highest must under these same circumstances be from the zones of the lowest permeability; this high pressure gas is, in effect "locked in." Hence, it moves more slowly toward the well bore. It is the gas with the lowest pressure then that flows most freely toward the well bore. And it is this lowest pressure gas that is the most active contributing factor to the shut-in pressure.

During the shut-in period, some amount of gas present from each of the higher pressure zones begins to move from the well bore into the lowest-pressure zone. The entry pressures of those gases raises slightly the pressure that the low-pressure gas alone would produce.

The actual shut-in pressure of our sample well, then, reflects the unstabilized shut-in pressure of the lowest pressure zone plus the entry pressures of the low permeability zones flowing into it. The model generates an approximation of this phenomenon using an average shut-in pressure for each individual zone.

Allowing for Changing Skin Effect

The value of S is of more consequence at short flow intervals than at long flow intervals when the drainage radius is farther from the fracture. For most situations, the value of Pt is normally sufficient to indicate the expanding drainage radius; but for some heavily fractured wells, it appears that we should also take into consideration a negative skin effect; moreover, we should increase that value toward a more positive value with time, particularly if the fracture may heal with time. The model does incorporate a means of adjusting the S value over the time interval for each zone. This adjustment is expressed as a percentage of the inital S value.

Our example assumes an initial negative skin value which becomes steadily more positive over a period of four years until the final skin value for each zone is 65 percent of the original skin for that zone.

Some reservoirs may behave differently, of course--their initial negative skin value becoming increasingly negative over time as the reservoir "cleans up." The model set forth in this paper accommodates that situation also.

Allowing for Cross Flow During Shut-In

The model described in this paper, while it does not address the phenomenon of natural cross flow among zones, does allow for such cross flow--within the well bore--during shut-in. The model assumes that the permeability, thickness, and skin of each zone are properly related to the whole system. 4/ Please refer to Fig. 8. Note that here, at time-step 360 mo, the dramatic shut-in pressure differential among the zones permits us to see this phenomenon clearly at work in the model. Please refer to the column marked "Shut-In Transfer MCF/D." Note here that the production from Zones 2 - 6 have all accumulated and transferred into Zone 1. That is, the MCF/D's of 95, 17, 8, 4 and 2 shown for Zones 2 - 6 add up to the (126) that we find transferred into Zone 1.

To make our cross-flow calculations, we first divide each zone of the reservoir into intervals, each of which measures from 1 ft to 10 ft. Our model uses an interval of 5 ft. What is crucial here is that interval size be dictated by the actual reservoir conditions under description.

With the well shut-in, the Pws of the lowest pressured zone (using equation (4)) is assumed to be the total of all Pwf's for the remaining zones. In other words, the MCF/D we calculated for the higher pressured zones, we transfer to the lowest pressured zones during shut-in.

BASIC USE OF THE MODEL

This model can be used either for a new well (in which case the value of FFS can be estimated from the size fracture treatment of the well or estimated by analogy with similar wells in similar formations); or it can be used for a well with considerable production history (in which case the model should be history matched to actual production). Our theoretical explanation sounds simple. For either of these extremes, however, actual history matching can become elaborate: for a new well, it is simply too difficult to do accurately from core data alone, without some test or production logging to indicate zone flow and shut-in zone pressure; and for the older well, it becomes increasingly complicated the more individual zone data there is that requires intepretation. But even given these difficulties, equation (15) stands as a relatively simple and accurate tool for describing the behavior of extremely complicated multi-zone gas reservoirs.

EXAMPLE OF DATA OUTPUT FROM THE MODEL

Now let us demonstrate exactly how the model works. The sample well we are using is described on page 3; its initial reservoir conditions are described in Fig. 5. The example assumes gas transmissiblity for all zones within a 640 acre drilling and spacing unit. It should be understood that any actual obstruction in the unit (such as shale) which blocks gas from moving to the well bore will cause less recoverable gas to be produced than the model indicates.

Please refer to Fig. 5, specifically to time step 0 which describes initial conditions. Compare those conditions with those for time step 1 (after one month's production). We see that by the end of one month, the model begins to describe changing reservoir pressures within each zone. Any transfer between zones is too small to calculate. Note that the highest flow rate of 2,355 MCF/D is from Zone 1, which has the highest permeability. Zone 6 has the lowest flow rate and the lowest permeability. Total flow at the surface is 3,049 MCF/D. All zones are flowing against a pressure of 867.9 psia.

Please refer now to Fig. 7 and time step 72 months. After six years of production, different pressures from zone to zone become more apparent. When the well is shut in, gas transfers into the lowest pressured zone at the rate indicated under "SHUT-IN TRANSFER MCF/D." Recovery for Zone 1 is 45.50 percent of the initial gas in place estimated for Zone 1. Recovery from Zone 6 is only .32 percent of the initial gas in place estimated for Zone 6. The overall recovery from all six zones is only 18.19 percent. Remaining gas in place for all zones is 12,239 MMCF.

At time step 360 months, or after thirty years, the zones have depleted at varying rates. Note in Fig. 8 that Zone 2 is now producing more than Zone 1. But the significant phenomenon here is that the model indicates the overall recovery for all six zones is still only 42.76 percent of the true total gas in place.

Conventional methods of estimating recoverable reserves would mistakenly put this percentage much higher. Fig. 9 explains why.

Fig. 9 depicts the gap in volume between the conventionally-estimated IGIP and the new-model estimation of IGIP for all six zones of the model well. Note that at the end of 30 years' depletion, the conventional method of estimating IGIP for this well sets the figure at a maximum of 7.8 BCF; the multi-layer model would, however, at the end of 30 year's depletion, set the IGIP at 14.961 BCF--a difference of 7.161 BCF. The crux of this discrepancy, as explained earlier, lies in the model's underlying assumption that the bottom-hole pressure of a mid-life, short-term shut-in test most nearly reflects the pressure of the lowest- rather than of the highest-pressured gas flowing into the well bore.

The ramifications of this discrepancy are obvious. Reservoir, production and research engineers have for years observed this phenomenon of multi-layer wells steadily producing reserves at a constant low pressure for some time beyond the well's expected life.

Not all multi-layer gas wells behave in this manner, it is true. But many will. With this type of model, engineers have at least one new tool to help them in their decision-making. Now, at the point where engineers face potentially costly workovers and must decide whether to abandon a producing well or to spend large sums to regain production, they can use this tool as they initialize pilot research programs to discover how best to recover more gas from low permeability zones.

To refer again to Fig. 10, some explanation is in order. The flowing bottom hole pressure is held constant at 868 psia from beginning year 1 to year end 4. Beginning year 5 to the end of year 10, Pwf is gradually reduced from 741 psia to 121 psia. From beginning year 11 to ending year 23, Pwf is held constant at 60 psia and reduced to 30 psia beginning year 24 for the remainder of the thirty years.

The rapid decline in production for years 1 to 4 is attributed to a more rapid depletion of the highest permeability Zone 1, a healing fracture to 65 percent of initial value, and the normal function of the transient equation used. In years 5 to 10 the scheduled production is maintained by lowering Pwf gradually. After year eleven, Pwf is maintained at surface limitations of pressure reduction. Note that lowering Pwf from 60 psia to 30 psia by changing surface equipment beginning year 24 does not increase production immediately, but does establish more cumulative production by year 30 than would have been possible without the pressure reduction.

CONCLUSIONS:

1. A multi-zone model such as the one set forth herein is a much more reliable tool for describinq the actual production behavior of most reservoirs containing high permeability zones interbedded with low permeability zones than is the single-zone model described at the first of this paper.

2. Characteristically, in multi-zone wells which have been considerably produced, the bottom hole pressure for a short term shut-in test will reflect the pressure of the lowest pressured zone plus the entry pressure of gases from the other zones flowing into it.

3. For many multi-zone volumetric depletion fields, the plot of BHP/Z vs

Cummulative Production underestimates the true initial gas in place. Use of this standard method of calculating initial gas in place for these wells may result in their premature abandonment when actual reservoir conditions warrant research to find the best method for further recovery.

4. For the sample well described, a plot of rate vs time on semi-log paper shows a rapid drop in production followed by a stabilized rate decline. Three conditions account for this steep drop: 1) a decreasing skin effect; 2) faster depletion from the highest permeability zone; and 3) the normal function of the transient flow as described in the transient flow equation.

NOMENCLATURE

a -	Empirical exponent to relate Ø to permeability.
C -	An empirical factor to relate Ø and Sw to permeability.
Cs -	Stabilization factor used as a constant.
Ct -	Total compressibility of the rock, fluid, and gas - vol/vol/psia.
Cg -	Gas compressibility factor - vol/vol/psia.
FFS -	Fractional flow from the skin value, i.e., the part of total flow from a well caused by the skin value.
Gp -	Cummulative gas produced - cubic ft.
Gsc -	Total initial gas in place - cubic ft.
h -	Net pay thickness - ft.
IGIP -	Initial Gas In Place - MMCF.
k -	Permeability used interchangeably with calculated, absolute, and effective permeability - md.
MCF/D -	Thousand cubic feet per day at standard conditions.
n -	Exponent of the back pressure equation.
Ø -	Porosity of the rock - fraction.
Pi -	Initial pressure - psia.
Pt -	Pressure drop function (see text) - dimensionless.
Pwf -	Bottom hole pressure, flowing - psia.
Pws -	Bottom hole pressure, static - psia.
Qsc -	Total gas produced at standard conditions - MCF/D.
RGIP -	Remaining gas in place - MMCF.
Re -	Radial distance to external drainage radius - ft.
Rw -	Radius of inside diameter of casing - ft.
S -	Skin factor - dimensionless.
SIBHP -	Shut-in bottom hole pressure - psia.
Sw -	Water saturation of the rock - fraction.
T -	Temperature of reservoir - degrees Rankine.
Tdw -	Dimensionless time - (see text).
t -	Real time - hours.
Up -	Gas viscosity dependent upon pressure - cp.
Zi -	Initial Z.
Zp -	Gas deviation factor dependent upon pressure.

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BASIC DATA

LOGS		FLOW TEST	INITIAL GAS CHARACTERISTICS
Ø = .118	a/	Pws = 3,212.9	Ui = .02180
h = 30'		Pwf = 2,611.5	Zi = .822
Sw = .363	a/	Qsc = 1975 MCF/D	Cg = .00024
T = 610 ^{O}R		t = 24 hr	
a/ = Weighted Average		Casing = 5-1/2" O.D.	

FIGURE #1

Using equation (15), and ignoring the rock and water compressibility, then all values are known except k and FFS. Assume FFS is .10 for Run #1 as shown below. Equation (15) reduced to equation (16) is:

$$k - \ln k = 1.22$$

$$k = 1.82 \text{ md}$$

Weighted Average k and S for all Zones
Represented by Flow Test

Run #	FFS %	S (skin)	k md
1	10	-0.696	1.82
2	90	-5.190	.17
3*	50	-3.321	.97

*Run #3 matches weighted average permeability of core data.

FIGURE #2

	BASE DATA FOR ALL RUNS				
	ZONE #	Net Pay (ft.)	Ø	SW	Calculated Core Permeability k a/
	1	5	.18	.22	4.3857
	2	5	.15	.26	1.0516
	3	5	.11	.36	.0853
	4	5	.10	.40	.0390
	5	5	.09	.44	.0171
	6	5	.08	.50	.0065
Weighted Average			.118	.363	.93 md

a/ From Equation (17): $k = [\,79\,\text{Ø}^3/\,Sw]^2$

FIGURE #3

CALCULATED ZONE PERMEABILITY

ZONE #	RUN 1 % FFS	RUN 1 k	RUN 2 % FFS	RUN 2 k	RUN 3 % FFS	RUN 3 k	RUN 4 % FFS	RUN 4 k
1	10	8.5942	90	.7913	50	4.5569	70	2.6203
2	10	2.0607	90	.1897	50	1.0927	70	.6283
3	10	.1672	90	.0154	50	.0886	70	.0510
4	10	.0764	90	.0070	50	.0405	70	.0233
5	10	.0336	90	.0031	50	.0178	70	.0102
6	10	.0128	90	.0012	50	.0068	70	.0039
Weighted Average		1.82		.17		.97		.56

Run #1 - Calculates k too high to BASE DATA.
Run #2 - Calculates k too low to BASE DATA.
Run #3 - Matches BASE DATA calculated absolute permeability.
Run #4 - Matches best estimate of effective permeability.

FIGURE #4

TIME STEP 0 WITH WELL SHUT-IN

ZONE NO.	FFS VALUE %	VALUE VALUE k	SIBHP PSIA	IGIP MMCF	PERCENT RECOVERY %
1	70	2.6203	3,212.9	4,448	0
2	70	.6283	3,212.9	3,517	0
3	70	.0510	3,212.9	2,231	0
4	70	.0233	3,212.9	1,901	0
5	70	.0102	3,212.9	1,597	0
6	70	.0039	3,212.9	1,267	0
TOTAL				14,961	

FIGURE #5

TIME STEP 1 MONTH WITH 867.9 psia Pwf

ZONE NO.	SIBHP VALUE	FLOW MCF/D	RGIP MMCF	SHUT-IN TRANSFER MCF/D	PERCENT RECOVERY %
1	3,161.7	2,355	4,378	0	1.57
2	3,196.5	597	3,499	0	.51
3	3,210.6	54	2,229	0	.09
4	3,211.6	26	1,900	0	.05
5	3,212.2	12	1,597	0	.00
6	3,212.5	5	1,267	0	.00
TOTAL		3,049	14,870	0	
OVERALL RECOVERY					.61

FIGURE #6

TIME STEP 72 MONTHS WITH 614.5 psia Pwf

ZONE NO.	SIBHP VALUE	FLOW MCF/D	RGIP MMCF	SHUT-IN TRANSFER MCF/D	PERCENT RECOVERY %
1	1,736.7	566	2,424	(144)	45.50
2	2,589.1	216	2,918	119	17.03
3	3,111.6	21	2,175	14	2.51
4	3,156.1	10	1,875	7	1.37
5	3,180.9	5	1,584	3	.81
6	3,197.1	2	1,263	1	.32
TOTAL		820	12,239	0	
OVERALL RECOVERY					18.19

FIGURE #7

TIME STEP 360 MONTHS WITH 30.1 psia Pwf

ZONE NO.	SIBHP VALUE	FLOW MCF/D	RGIP MMCF	SHUT-IN TRANSFER MCF/D	PERCENT RECOVERY %
1	417.8	59	506	(126)	88.62
2	1,379.3	110	1,471	95	58.17
3	2,820.0	19	2,001	17	10.31
4	2,986.2	9	1,792	8	5.73
5	3,089.1	4	1,548	4	3.00
6	3,141.3	2	1,245	2	1.74
TOTAL		203	8,563	0	
OVERALL RECOVERY					42.76

FIGURE #8

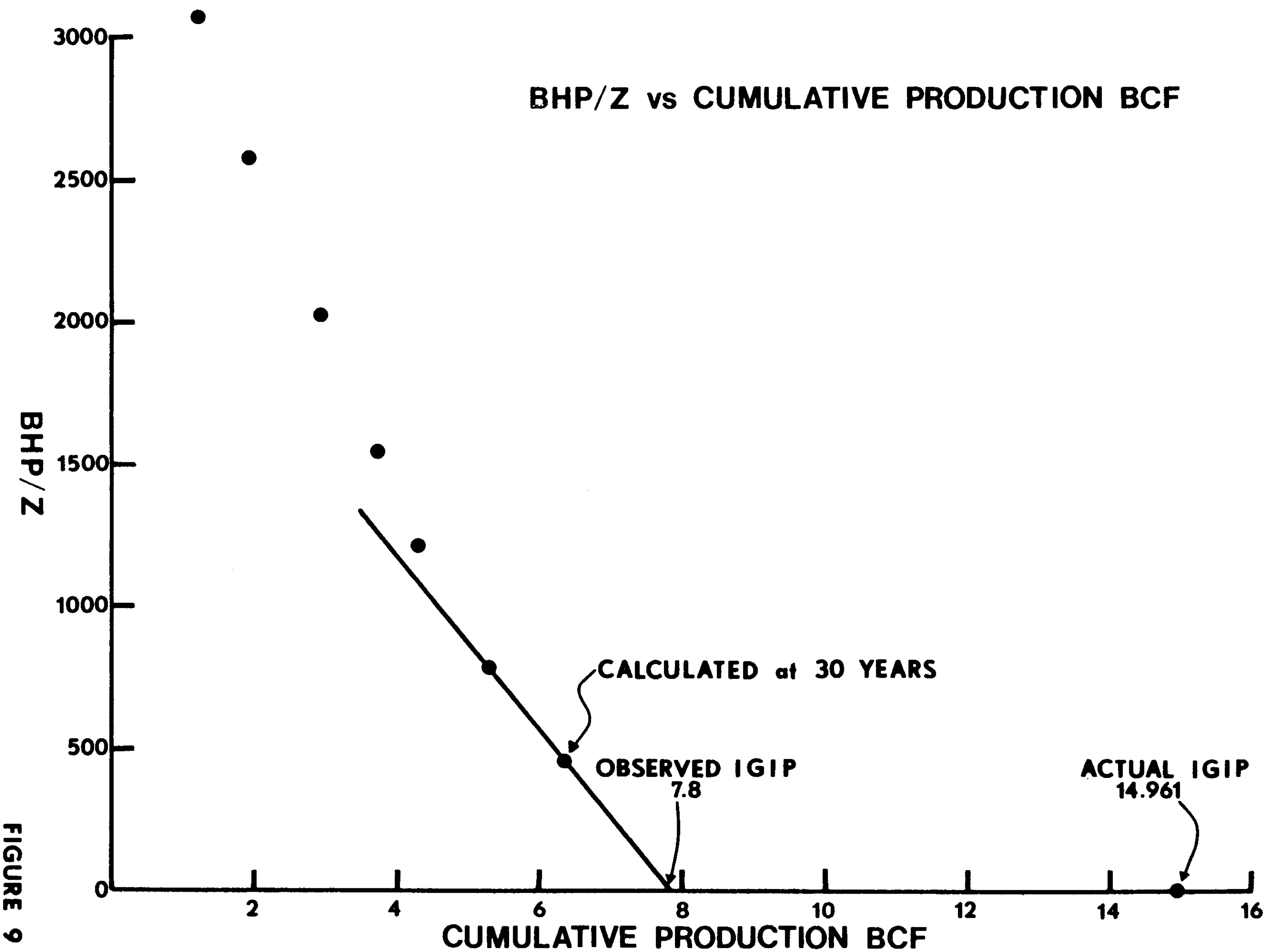
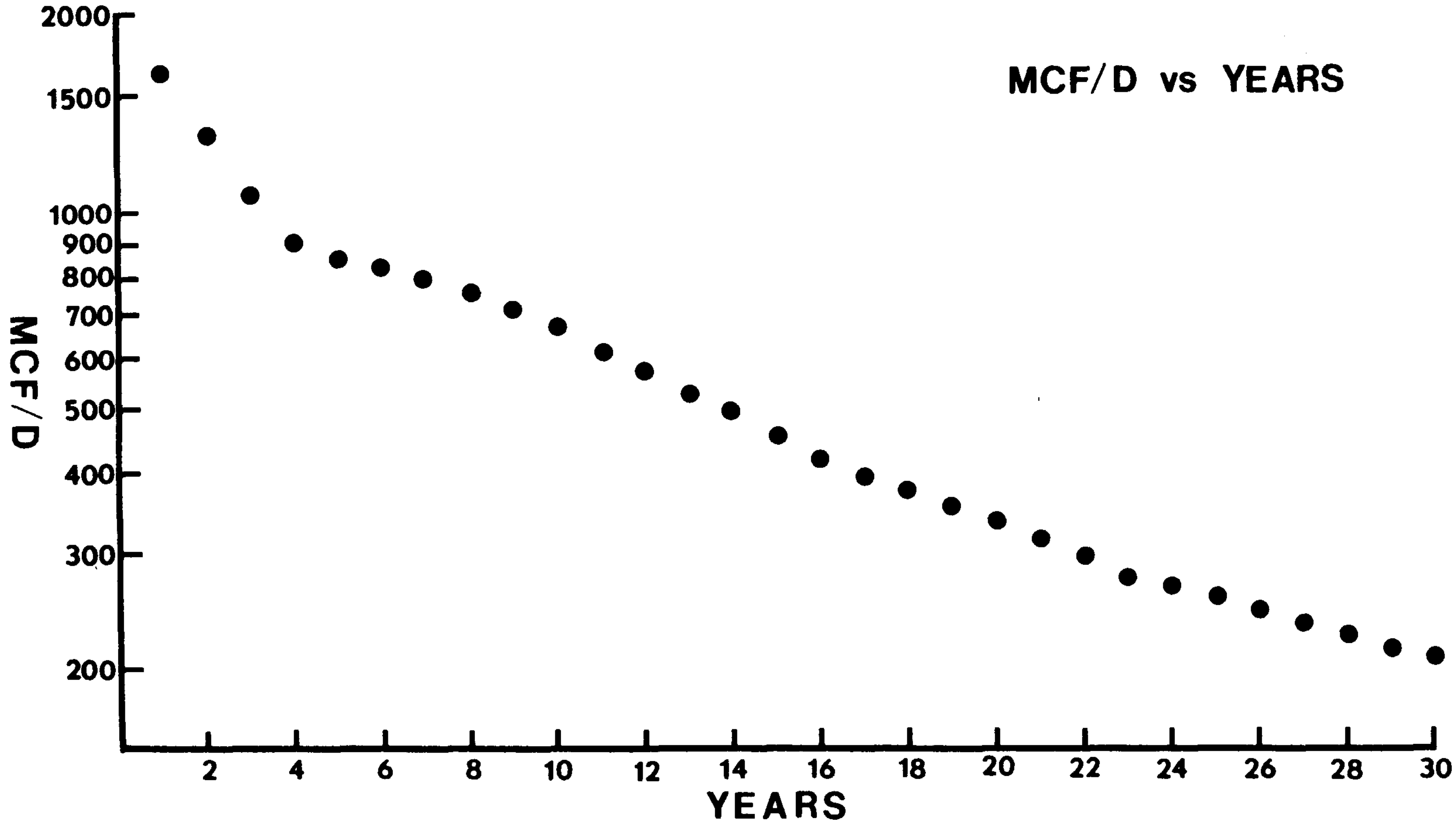

BHP/Z vs CUMULATIVE PRODUCTION BCF
3000
2500
2000
1500
1000
500
0
BHP/Z
2
4
6
8
10
12
14
16
CUMULATIVE PRODUCTION BCF
CALCULATED at 30 YEARS
OBSERVED IGIP
7.8
ACTUAL IGIP
14.961

FIGURE 9



MCF/D vs YEARS
MCF/D
2000
1500
1000
900
800
700
600
500
400
300
200
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
YEARS

FIGURE 10