EVALUATION OF FRACTURED TIGHT GAS WELLS UTILIZING PRODUCTION DATA

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The purpose of this paper is to show how to evaluate fractured tight gas wells using readily available tools and production data. The paper will primarily deal with the application of coupling conventional analysis, type curve analysis, and a single-phase production simulator to find effective fracture length, fracture conductivity, and reservoir permeability.

INTRODUCTION

The art of hydraulic fracturing has grown from a wellbore extension/clean-up technique to the primary technique in many prospects for economical recovery. As fracturing has matured, numerous products and techniques have been introduced to improve well performance or lower completion costs. These techniques and products are brought in with various amounts of laboratory testing and computer simulation. However, very little well evaluation is ever performed to validate or justify these added or deleted costs. The evaluations are usually left to unspecified well traits as they relate to other wells in an area. These may or may not be representative of how the well is performing.

The process of fracture evaluation has been discussed by many authors, but these usually involve extended shut-in (months-years) or constant rate or pressure production, and are not practical or economical in reality.

The four pieces of production information normally available are production rates and pressures, cumulative production, and time. Any evaluation would have to come from this data.

Evaluation in this paper involves the manipulation of the pressure difference that is rate-normalized and the matching of production data with a production simulator. The widespread use of computers today makes these procedures readily available and quickly performed.

PROCEDURES

The first step is to manipulate the pressure data to a usable form; that is, convert the surface flowing pressure to downhole wellbore sandface pressure. This is shown in Equation #1:

EQ.#1

$$P_{wfs}^2 = P_{whs}^2 Exp(S_) + \frac{25y_q^2 \overline{TZ} f(MD) EXP[(S_2)-1]}{EXP(S_1)+S_2 * d^2}$$

where: P_{wfs}=Pressure sandface
P_{wh}=Tubing pressure
y_g =specific gravity of gas(air=1.0)

S_1 $=0.0375y_g(TVD)/\overline{TZ}$
q =MMscf/d

$\overline{T}$ $={}^0R$

$\overline{Z}$ =gas compressibility at ave. conditions
MD = measured depth
d =in.
f $=N_{re}$ (Reynolds' number)

S_2 $=.0375y_g(MD)/\overline{TZ}$

Next, the pressure data must be rate-normalized; that is, adjust the pressure in to account for the rate variations. This may be adjusted by convoluting or deconvoluting the data as in Equations 2, 3, 4, and 5.

EQ.2 Convolution

$$Pwf(t) = \int_0^t qD'(T)\ P_{sf}(t-T)dT$$

where: P_{wf}=Measured wellbore pressure
qD'=Measured flow rate

$$P_{sf} = \frac{qmuB_o}{141.2Kh}\ Ei\left(\frac{r^2}{0.0264nt}\right)$$

hence EQ.3:

$$\frac{\Delta P_{wf}(t)}{\Delta q_{sf}(t)} = \frac{Bu}{70.6Kh} [t_{scf}+const+s]$$

EQ.4 Deconvolution

$$P_{wf}(t) = \sum_{t=1}^{n} (q_1-q_0)\ P_{sf}(t-t_i-1)$$

Gladfelter Deconvolution (Rate Normalized Pressure)

$$\frac{\Delta P_{wf}(t)}{\Delta q_{sf}(t)} \text{ vs. } t$$

With the pressure rate normalized, it can be plotted P vs. t log-log to identify the different flow periods.

The earlier flow data (1/4 slope) is fracture bilinear flow. If the bilinear flow period is plotted p vs. t 0.25, the slope is mbf and:

EQ.5

$$KK_{fw}^2 = \left(\frac{444.8qT}{hm_{bf}}\right)^4 * \left(\frac{1}{\phi \mu c_t}\right)$$

After the 1/4 slope, a 1/2 slope develops, called "fracture linear flow." When linear flow is plotted p vs. $\sqrt{t}$, a slope called m_{1f} develops and:

EQ.6

$$KX_f^2 = \left(\frac{4.064qZT}{hm_{1f}}\right)\left(\frac{\mu}{\phi c_t}\right)$$

where: K=Formation permeability
K_{fw}=Fracture conductivity
X_f=Fracture length

At this point, K_{fw} and X_f could be found if K were known. To find K, we take the derivative of the pressure convolution and/or the deconvolution. At infinite acting radial flow, K can be calculated:

EQ.7

$$pD=0.5\left(\ln\frac{tD}{cD}+0.809+\ln CDe^{2s}\right)$$

Pressure Derivative Response

$$\frac{tD}{cD}pD'+.5$$

Convolution Derivative Response

$$\frac{d\frac{p_{wf}(t)}{q_{sf}(t)}}{dt_{sfc}}=0.5$$

We have now found our X_f, K_{fw}, and K. However, the quality of data often does not have a unique answer. The next step is to plot the convolution, deconvolution, and respective derivatives against type curves for finite conductive fractures. Their respective axes are:

$TimeX=td_{xf}=.000264K\ t/\phi\mu c_t X_f^2$
$PressureY=PD=Kh\ m(p)/1424qT$
$Storage\ coefficient=CDf=5.615C/2\pi\phi c_t hX_f^2$
$Fracture\ conductivity=FCD=K_{fw}/K_{Xf}$

When matching the derivatives, infinite radial flow (Eq. 7) will be found earlier than from the pressure -- thus, the best chance to find K.

Once K is agreed upon from both conventional analysis and type curve matching, the less sensitive K_{fw} and X_f should match both ways.

The third method of analysis is to match production with the output of a single-phase simulator. Here, production pressure is set for the various time frames where there is good early production data. Then, using the variables determined earlier, production can be projected.

If the variables are correct, a match should be apparent. Caution should be exercised in the early data due to fluid loading that is unaccounted for in the pressures. The pressure errors will affect the early time production match, but later time s should match accordingly.

EXAMPLE #1

In the first example, the deconvoluted pressure NP has been normalized out over the BHP to account for the rate variations (Chart 1). This puts the pressure on the proper slope and smoothes the data somewhat.

Chart 2 is the diagnostic plot of the BHP, its derivative and convolution derivative. The identification cannot be done on the BHP and derivative because of unaccounted rate variations. The convolution does not follow the recognizable trends. Chart 3 is the deconvolution and its derivative and the 1/4, 1/2, and unit slopes are distinctive. The bilinear period (1/4 slope) yields a KK_{fw}^2 of 6.1018E + 06 md^3-ft^2 on Chart 4. The linear flow (1/2 slope) shows up on Chart 5 as KX_f (7.6356E + 05 md-ft^2. Finally, the flow goes into unit slope. This is an indication of a bounded system; infinite radial flow is not seen. Diagnostic Chart 2 did not pick this up.

Without a K, the next step is to match up the type curve for the time period up until unit slope starts. Care is taken to get the best possible match, for this is where K will be derived. On Chart 6, a good match can be found with the deconvolution on both pressure and derivative. The agreement between conventional and type curve matching can now be found using the K from the type curve.

Now, the K, K_{fw}, and X_f are put into the production simulator for verification. A good match is made. If the K had been off, drastic differences would be seen. The K_{fw} and X_f sensitivities are based upon how they affect the F_{cd}.

EXAMPLE #2

The second example shows a different pressure slope from the actual pressure and deconvolution pressure (Charts 8 and 9). From Charts 11 and 12, we see that KK_{fw} = 6.8895E + md^3-ft^3 and KX_f^2 = 6.7578E + 5 md-ft^2. Since infinite acting radial flow is not showing up, the K cannot be determined.

When reviewing the conventional results to the type curve math on Chart 13, there is a difference of 150 ft of frac length and 190 md-ft conductivity or 0.104 md in permeability. This can be verified by the production simulator. Chart 14 projects production a little lower than actual. When the permeability is raised the 0.104 md, a match is made (Chart 15). Also, when the length and conductivity are adjusted, a match is made. This shows that the results are within the accuracy of the system.

CONCLUSIONS

Production pressure data, when convoluted and deconvoluted with their derivatives, can be used to find K, K_{fw}, and X_f through conventional analysis and type curve matching. The use of readily available computer power makes these techniques practical and simulator modeling verification easy.

ACKNOWLEDGMENTS

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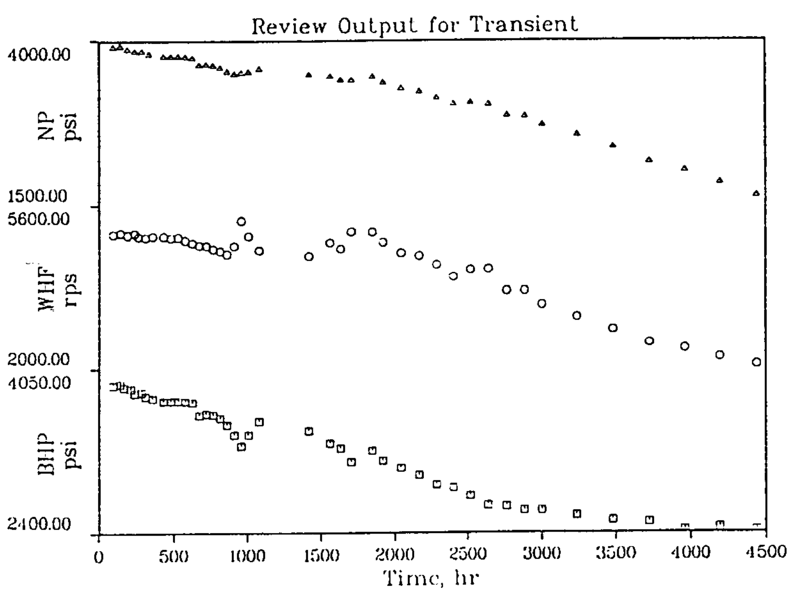


CHART I

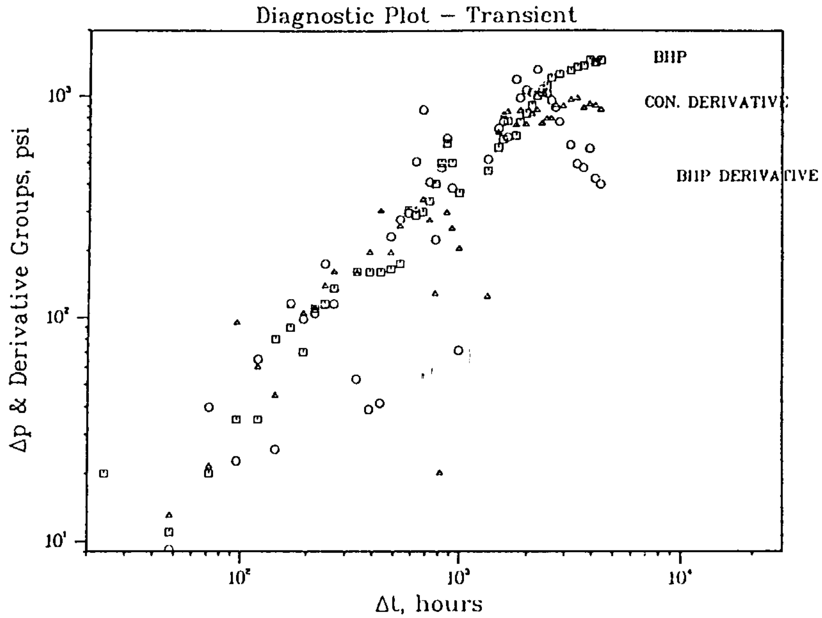


CHART 2

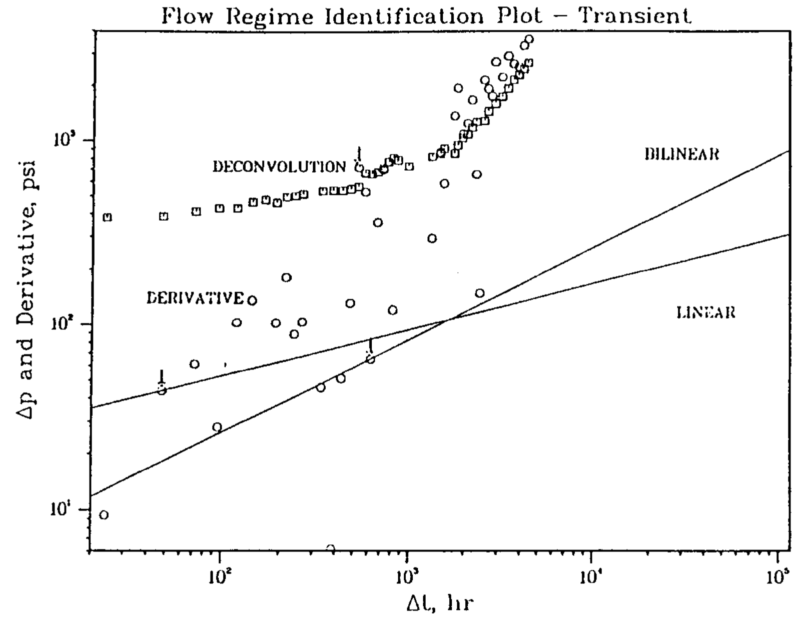


CHART 3

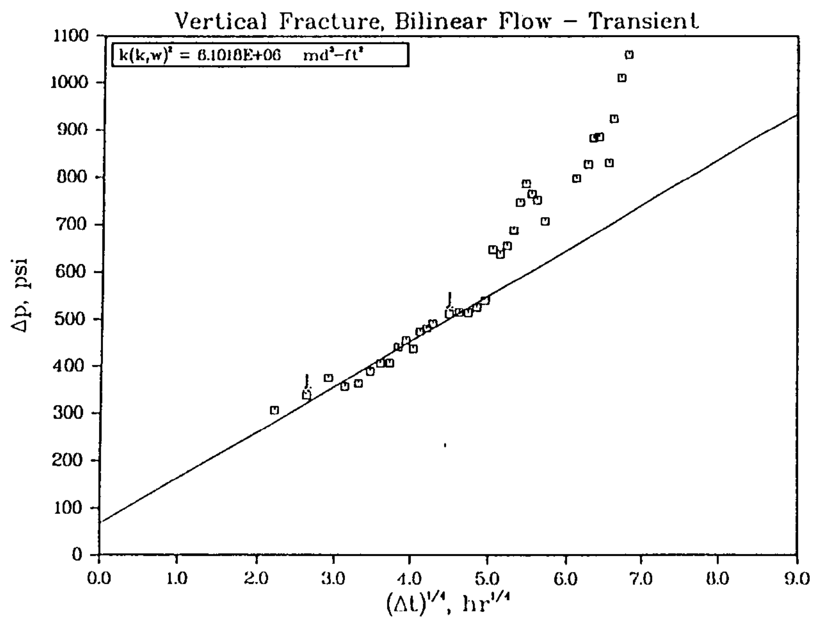


CHART 4

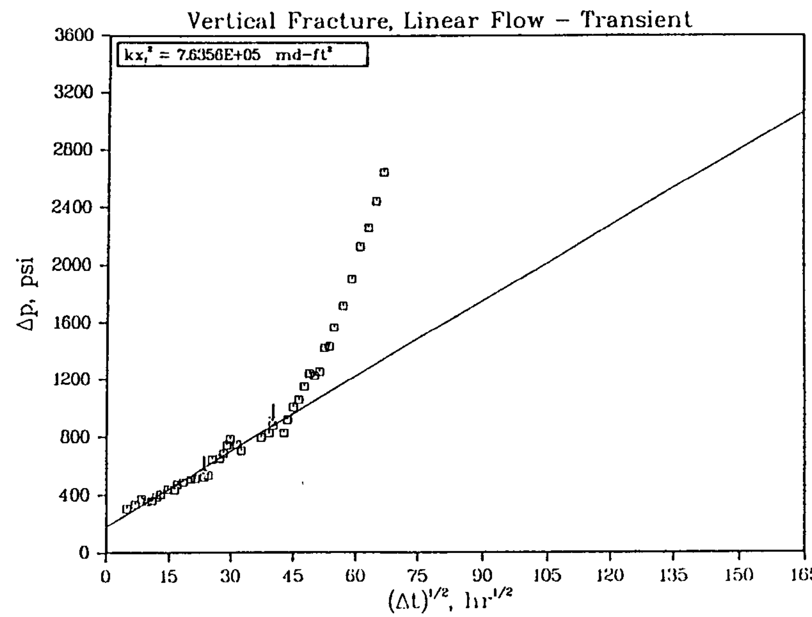


CHART 5

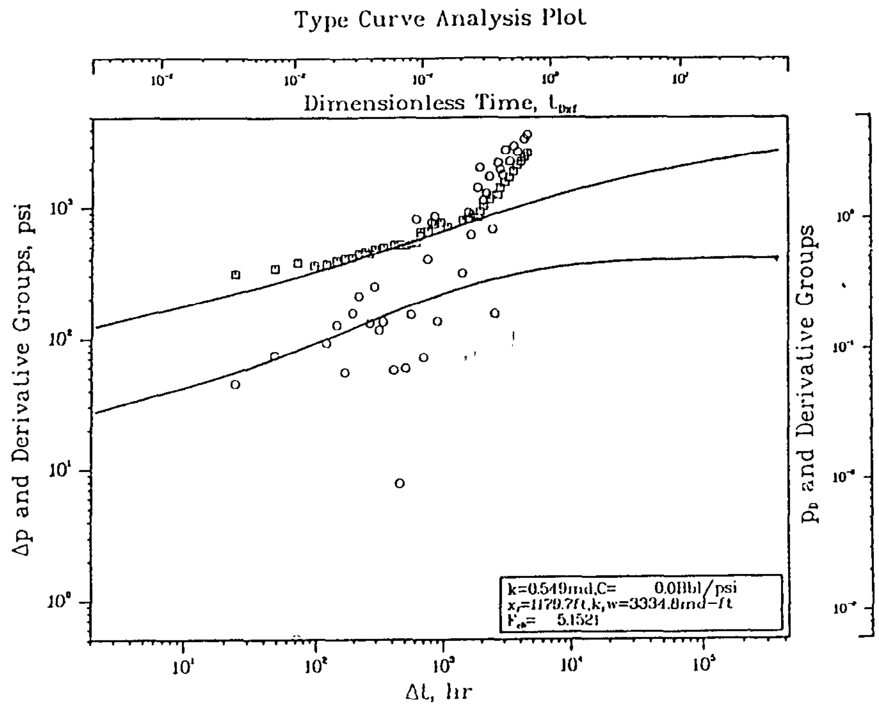


CHART 6

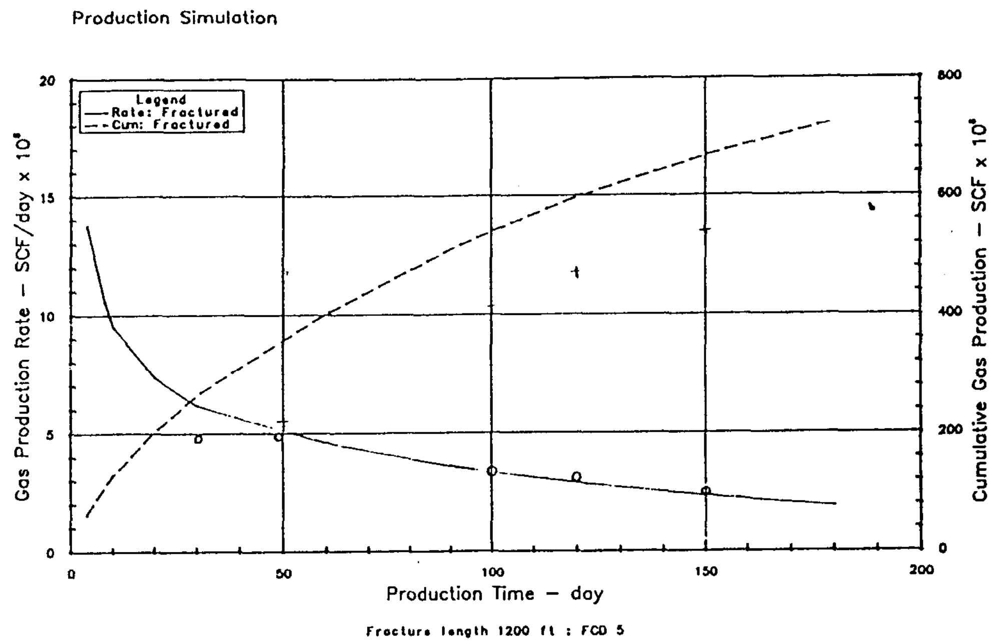


CHART 7

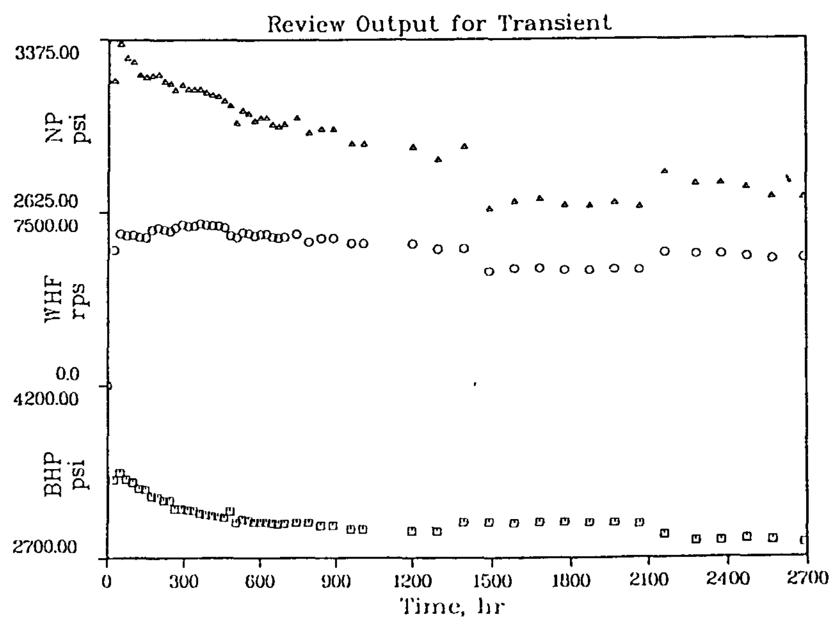


CHART 8

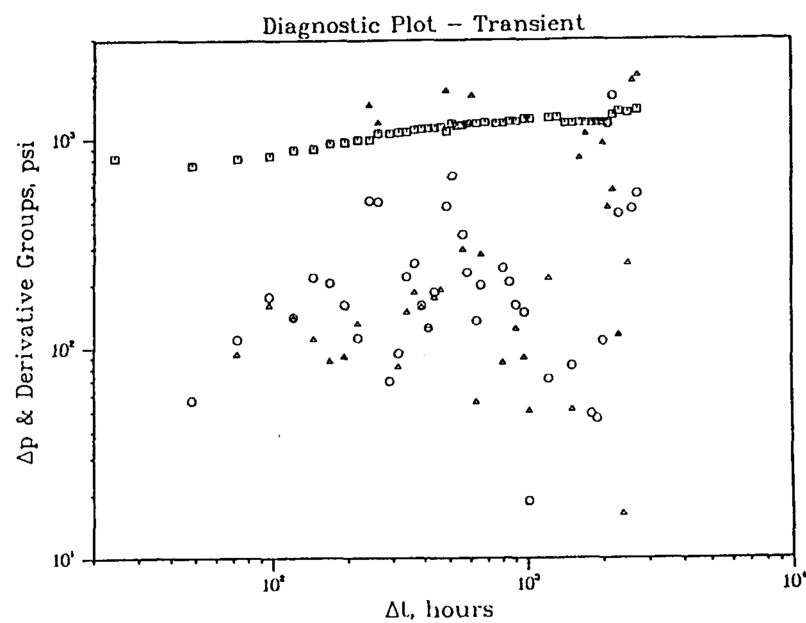


CHART 9

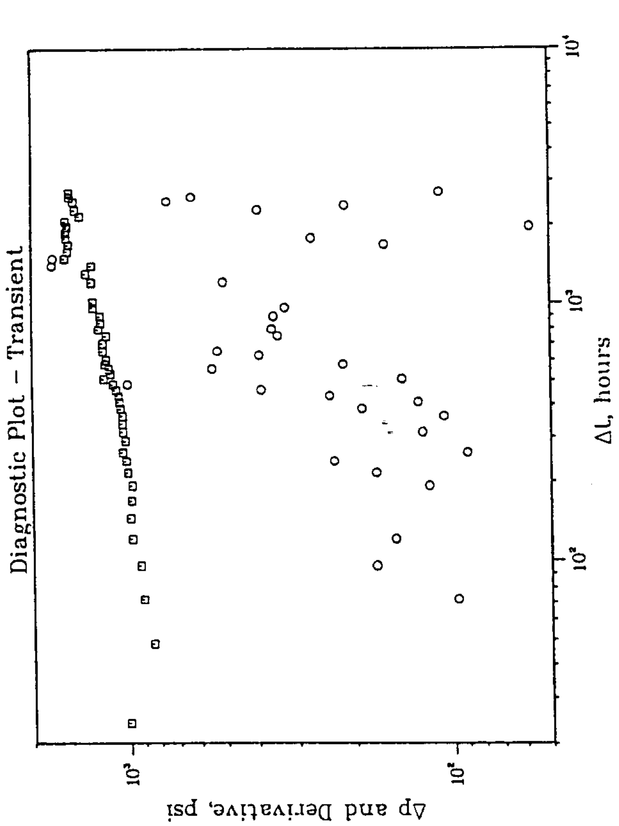


CHART 10

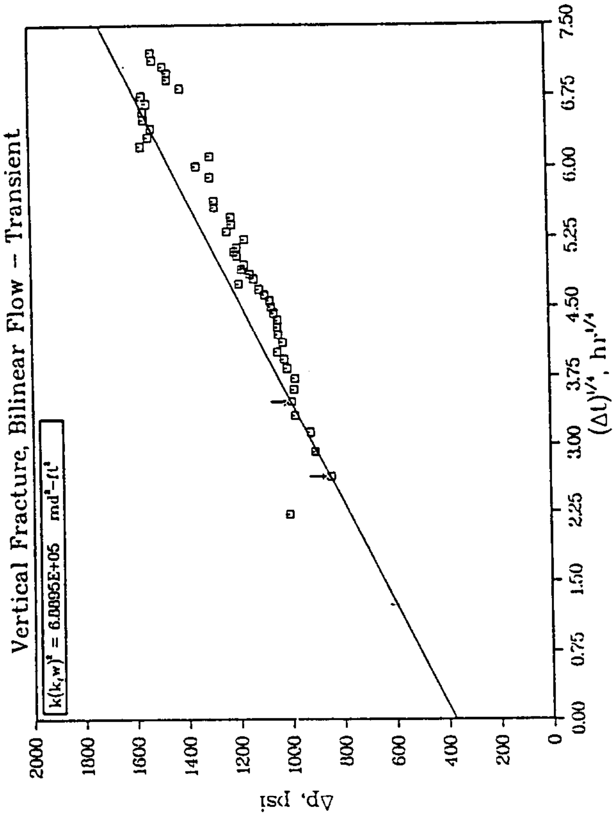


CHART 11

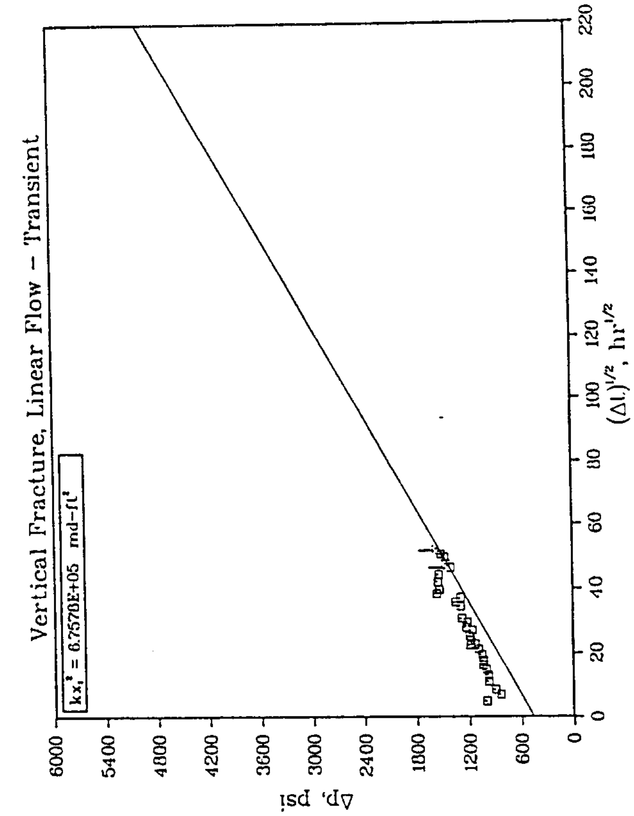


CHART 12

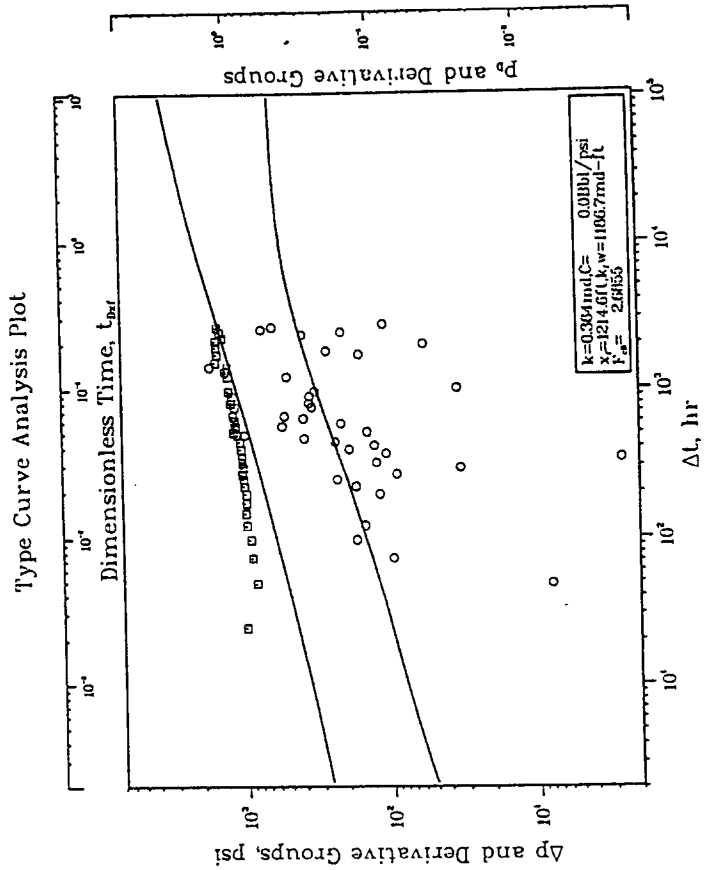
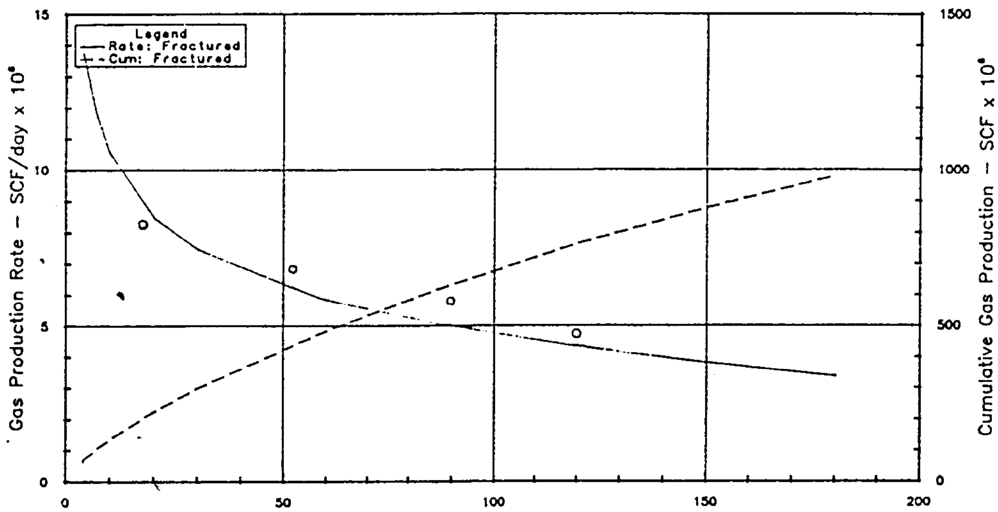


CHART 13

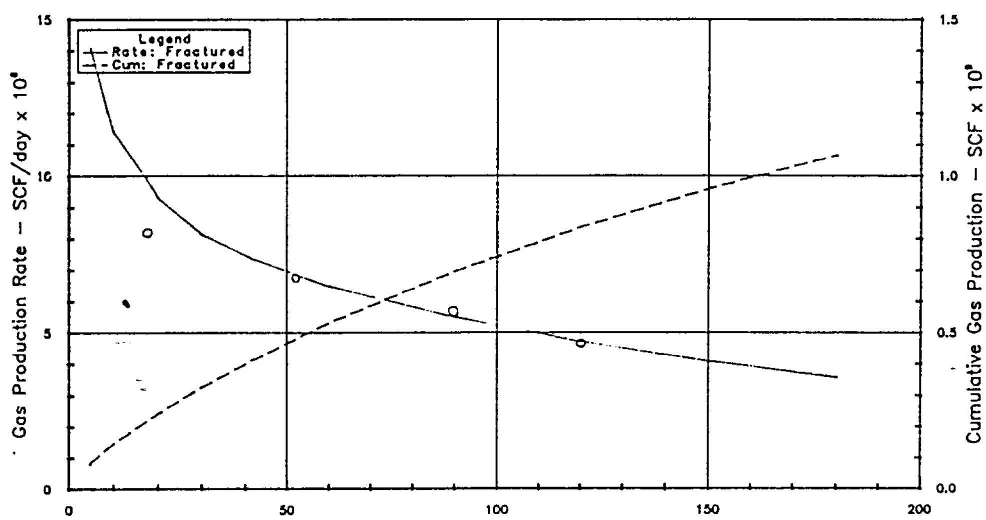
Production Simulation



Fracture length 1200 ft : FCD 2.7

CHART 14

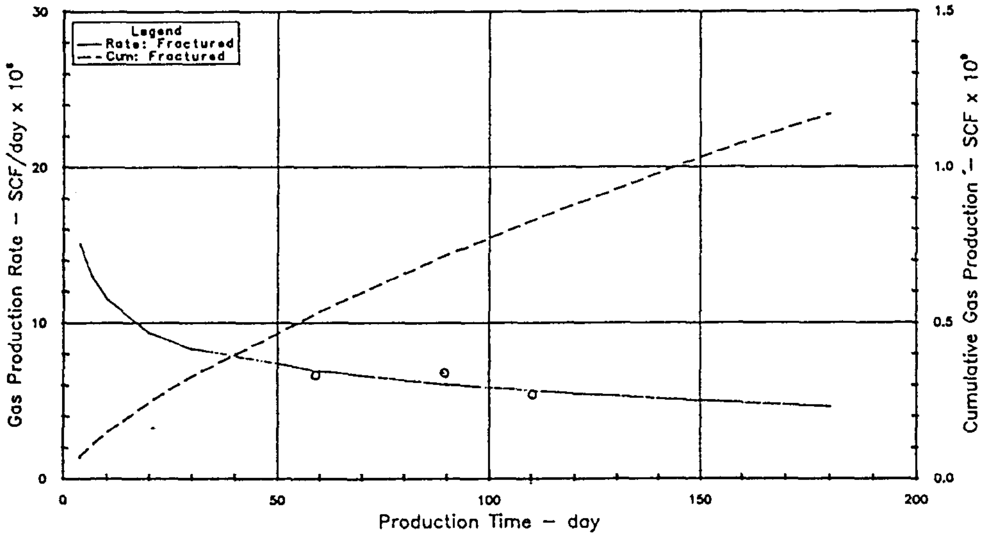
Production Simulation



Fracture length 1200 ft : FCD 2.1

CHART 15

Production Simulation



Fracture length 1350 ft : FCD 2.8

CHART 16