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The Use of Pressure Buildup Information to Analyze Non-Respondent Vertically Fractured Oil Wells

By

John G. Evans, Member AIME, Amoco International Oil Co.

ABSTRACT

When a hydraulically fractured oil well, with a single vertical fracture, does not respond favorably to the stimulation treatment, and provided that well conditions warranted the frac treatment, the cause of poor response is due to flow restrictions within the propped fracture, an unpropped fracture, or a damaged region in the formation adjacent to the face of a propped fracture. By the proper analysis of pressure buildup data taken from the well, the location of the flow restriction can be determined. Linear flow into the fracture distinguishes formation damage from either an unpropped fracture or from restrictions in a propped fracture. Approximations of the fracture length and thickness of the damaged region near the fracture face are available by using the techniques presented.

INTRODUCTION

The production performance of an oil well following a hydraulic fracturing treatment often continues on pre-stimulation decline trends, does not return to prior levels, or improved rates are not sustained. Providing that well conditions warranted the fracture stimulation, the causes of the unfavorable results are either due to flow restrictions within the propped fracture, an unpropped fracture, or a damaged region in the formation adjacent to the face of a propped fracture.

References and illustrations at end of paper.

When the fracture is vertically oriented and when negligible or zero flow occurs in the fracture, the fluids flow radially into the wellbore from the surrounding formation. If the formation near the fracture face is damaged, then the flow near the propped fracture is essentially linear. Thus, recognition of the type of flow near the well determines the condition causing reduced flow rates, i.e., either 1) plugged propped fractures or unpropped fractures, or 2) formation damage adjacent to the propped vertical fracture.

A method is presented herein for the identification of the flow regime near the well from pressure buildup data. Approximations of the fracture length and thickness of the damaged region near the fracture face are available by using the techniques presented.

CONDITIONS CAUSING LINEAR FLOW

Consider a single, vertical, propped fracture of infinite capacity intersecting the wellbore and extending completely across the square drainage area of a regularly spaced well (Figure 1A). All flow in the reservoir is linear towards the fracture. As the fracture length decreases (Figure 1B), flow towards the fracture extremities becomes radial causing the overall flow regime about the well and fracture region to be somewhat elliptical. At great distances from the wellbore and fracture extremities, the flow is virtually radial. The flow in the rock near the fracture face remains linear and the amount of linear flow depends on the fracture length.

If the flow resistance in the fracture approaches the resistance offered by the formation (i.e., the fracture does not have infinite capacity), the amount of linear flow in the well and fracture region diminishes. However, the presence of formation damage at the fracture face tends to overcome the non-linearizing effects of reduced fracture capacity. The skin reduces the flow rate; hence, there is much less pressure drop through the fracture as compared to the formation, which results in linear flow in the formation towards the fracture. Thus, given a propped fracture of adequate length and a damaged region at the fracture face, linear flow exists in the formation near the fracture and this condition can be detected by the proper interpretation of pressure buildup data.

MATHEMATICAL DESCRIPTION OF THE SYSTEM

Flow in the immediate vicinity of the fracture is linear. As distance from the fracture increases, the nature of the flow phases from linear to elliptical to nearly radial at the drainage boundary of the well.[1] Hence, the early time pressure response from a buildup will represent nearly linear flow and radial flow will govern the late time data. By disregarding the radial flow at the fracture extremities and by assuming infinite fracture capacity, the Diffusivity Equation in linear form will mathematically describe the early time pressure response from a buildup. Commonly known techniques developed from radial models will apply to the late time data. Utilizing the conditions indicated on Figure 2, the following equation is the Diffusivity Equation written in linear form

$$\frac{\partial^2 p}{\partial x^2} = \frac{\phi \mu c}{k} \frac{\partial p}{\partial t} \quad . \quad . \quad . \quad . \quad . \quad . \quad (1)$$

For semi-infinite flow and for constant flow at the fracture,

$$\frac{\partial(0,t)}{\partial x} \quad \frac{q_o' \mu}{k A_{ef}} \quad . \quad . \quad . \quad . \quad . \quad . \quad (2)$$

$$p(\infty,t)=p_i \quad . \quad . \quad . \quad . \quad . \quad . \quad (3)$$

The initial condition is

$$p(x,o)=p_i \quad . \quad . \quad . \quad . \quad . \quad . \quad (4)$$

Using hydraulic fracturing terminology, the fracture length, X_f, represents the distance from the wellbore to one end of the fracture. The fracture height, h, represents only that portion of net pay which is propped and contributing fluid. The effective fracture area, A_{ef}, is

$$A_{ef}=2X_f h \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (5)$$

The use of a semi-infinite model requires that

$$q_o' = q_o/2 \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (6)$$

$$A_{ef}=A_f/2 \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (7)$$

Subject to the assumptions listed above and to the assumptions given in the derivation of the Diffusivity Equation[2], the solution to the above system, written in field units, is

$$P_{wf}=p_i - \left(16.3\right)\left(\frac{q_o}{A_f}\right)\sqrt{\frac{\mu_o t}{C_t K_o}} \quad . \quad . \quad . \quad (8)$$

Equation (8) was originally presented by Clark[3]. Since the solution has not appeared in the petroleum literature, the method is presented in Appendix I.

TECHNIQUE FOR INTERPRETING BUILDUP DATA

When a pressure buildup test is conducted, the well is usually produced for a short period of time at a constant rate and then shutin while the bottom hole pressure is recorded. This sequence of events is shown graphically in Figure B1, Appendix B, and is handled mathematically by using the Principle of Superposition. The result is

$$P_{ws}=p_i - 16.3 \frac{q_o}{A_f}\sqrt{\frac{\mu_o}{K_o \phi c_t}}\left[\sqrt{t+\Delta t} - \sqrt{\Delta t}\right] \quad (9)$$

If P_{ws} is plotted against , the early time data representing linear flow will plot as a straight line with a slope, m, or

$$m=16.3 \frac{q_o}{A_f}\sqrt{\frac{\mu_o}{K_o \phi c_t}} \quad . \quad . \quad . \quad . \quad . \quad (10)$$

Russell and Truitt[4] did not advocate the use of this analytical scheme in vertically fraced wells, stating that afterflow destroyed the early time data. Formation damage was not considered in their model. The linear flow period phases rapidly to elliptical flow in such a model. However, when a damaged region exists adjacent to the fracture face, the period of linear flow is much longer than in an undamaged situation, and afterflow can be tolerated.

Typically, the shutin pressure versus $\left(\sqrt{t+\Delta t} - \sqrt{\Delta t}\right)$ has two straight line portions, m_1 and m_2, with a curved portion representing radial late time data, as shown in Figure 3. The first slope is of short duration and represents flow through the damaged region. The equation for this slope is

$$m_1 = 16.3 \frac{q_o}{A_f}\sqrt{\frac{\mu_o}{k_s \phi c_{ts}}} \quad . \quad . \quad . \quad . \quad (11)$$

and has two unknowns, namely k_s and A_f. The extrapolation of m_1 to $\sqrt{t}$, i.e., $\Delta t = 0$, should result in a close approximation of P. The second straight line portion, m^2, has a relatively longer duration than m_1. It reflects linear flow throught a portion of formation directly upstream from the damaged region m_2 is given by

$$m_2 = 16.3 \frac{q_o}{A_f}\sqrt{\frac{\mu}{k_o \phi c_t}} \quad . \quad . \quad . \quad . \quad (12)$$

with only A_f being unknown since k_o can be determined by other means. The data representing radial flow should plot as a straight line as either P_{ws} vs log (Δ t), the Horner Method[5], log ($P_{ws} - \bar{p}$) vs Δ t, the Late Time Muskat Technique[6]. The value of k_o can be determined from either method.

The intersection of the extrapolations of the straight line portions, m_1, and m_2, is defined at p_x, as shown on Figure 3. Physically, p_x is the flowing pressure in the undamaged region immediately adjacent to the damaged zone. Hence, the pressure drop across the damaged region is given by

$$\Delta P_s = P_x - P_{wf} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (13)$$

Since the volumetric flow rate through the damaged and undamaged region is constant, Equations (11) and (12) can be equated with the following result:

$$k_s = \left(\frac{m_2^2}{m_1^2}\right)\left(\frac{C_t}{C_{ts}}\right) k_o \quad . \quad . \quad . \quad . \quad . \quad (14)$$

This equation must be used when $P_{wf} \leq BPP \leq p_x$, that is, when free gas exists in the damaged region thus severly affecting C_{ts}. A method for determining C_{ts} is presented in Appendix C. If both p_x and P_{wf} are less than BPP, or if $P_{wf} \geq$ BPP, then $C_t \approx C_{ts}$ and Equation (14) reduces to

$$k_s = \left(\frac{m_2}{m_1}\right)^2 k_o \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (14a)$$

Using the preceding equations, the pressure drop across the skin (Δp_s), the permeability of the skin (k_s), the effective fracture area (A_{ef}), the total flow area (A_f), and the fracture length (X_f) can be determined. If steady state conditions are assumed for flow through the damaged region, the thickness of the damaged region may be approximated by using Darcy's Law. Substitution of A_f, p_s, k_s into the linear form of Darcy's Equation results in

$$d_s = \frac{0.001127 \; A_f \; k_s}{\mu_o \; q_o \; B_o} \quad . \quad . \quad . \quad . \quad . \quad . \quad (15)$$

A_{ef} and X_f are a measure of the fracturing process. A fracturing efficiency can be defined, E_f, which is equal to the effective area of the propped fracture divided by the fracture area computed using Fast and Howard's technique (7), or

$$E_f = \frac{A_{ef}}{A_f} \times 100 \quad . \quad . \quad . \quad . \quad . \quad . \quad (16)$$

FIELD EXAMPLE

A sixty-nine hour pressure buildup was conducted on Well A, a Muddy Sandstone producer in Campbell County, Wyoming. Pertinent data regarding this well is shown in Table 1. This well was producing at 26 BOPD and other wells in the field with less favorable productive indices were producing at higher rates. The well was waterfraced with 45,000 gal of 40 cp frac fluid carrying 1/4 to 1 lb/gal of 8-12 mesh sand at 30 GPM.

The results of the pressure buildup are plotted on Figures 4 and 5. Note that the early time data does not plot as a straight line on the log plot, Figure 4. However, the late time data representing late time flow is a straight line, and the formation permeability and static pressure can be computed. When the buildup data is plotted as P_{ws} vs $\sqrt{t+\Delta t} - \sqrt{\Delta t}$, Figure 5, two straight lines are noted in the early time data. This reveals that a damaged condition exists adjacent to the propped vertical fracture.

Computations show that the permeability of the undamaged formation surrounding Well A is 3.0 md and that the static reservoir pressure is approximately 1,525 psig. The pressure drop across the skin damage area is 883 psi and the permeability of the skin is 0.00005 md. The effective area of the fracture is 4,500 ft^2 and the fracture length is 120 ft. The skin thickness is 0.37 in. According to the fracturing calculations, the fracture area should be 80,000 ft^2. The resulting fracturing efficiency is approximately 5.6%. These calculations are shown in Appendix D.

CONCLUSIONS

If linear flow can be distinguished from radial flow in a vertically fractured well, the condition causing reduced flow rates can be determined. Knowledge of its position will indicate the probable cause of the flow problem and also suggest the type of remedial action to undertake.

A method is given for distinguishing linear flow from radial flow. More specifically, a method of analyzing pressure buildup data recorded in a vertically fractured well with formation damage adjacent to the face of a propped fracture is given. If the early time pressure buildup response plotted against $\sqrt{t+\Delta t} - \sqrt{\Delta t}$ is a straight line, then the flow during that period is linear and damage is indicated.

Equations are derived for computing the fracture area, the fracture length, the thickness of the formation damage and the pressure drop across the skin from a pressure buildup test conducted in a well with formation damage adjacent to the vertical fracture face. If the fracture area, as computed from fracturing design calculations is known, then the efficiency of the fracturing process can be estimated from knowledge of the effective fracture area computed from the buildup data.

NOMENCLATURE

A_f = fracture area from fracture calculations (area of one face), ft^2
A_{ef} = effective fracture area, ft^2
A_f = total area of fracture available to flow, ft^2
B_g = gas formation volume factor, Res Bbl per SCF
B_o = oil formation volume factor, Res Bbl per STB
C_t = total formation compressibility, psi^{-1}
C_{ts} = compressibility of the damaged region, psi^{-1}
d_s = thickness of the damaged region, ft
h = net pay thickness, ft
k = permeability, md
k_g = effective gas permeability, md
k_o = effective oil permeability, md
k_s = effective permeability of the damaged region, md
μ_g = gas viscosity, cp
μ_o = oil viscosity, cp
m_1 = slope of pressure vs square root of time curve for flow through the damaged region, psi/
m_2 = slope of pressure vs square root of time curve for flow through the undamaged region, psi/
p = pressure, psia
p_i = initial reservoir pressure, psia
p_x = pressure at undamaged-damaged zone interface, psia
P_{ws} = shutin wellbore pressure, psia
P_{wf} = flowing wellbore pressure, psia
ΔP_s = pressure drop across the damaged region, psi
BPP = bubble point pressure of oil, psi
q = flow rate, STBPD
R = instantaneous gas-oil ratio, SCF/STB
R_s = solution gas-oil ratio, SCF/STB
t = time, hrs
X_f = fracture length, ft
ϕ = fractional porosity

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APPENDIXES

APPENDIX A: SOLUTION OF THE LINEAR DIFFUSIVITY EQUATION FOR CONSTANT FLOW RATE AT THE FRACTURE AND A SEMI-INFINITE RESERVOIR

For this system, we have Equations (1), (2), (3), and (4), or

$$\frac{\partial p}{\partial t} = \alpha \frac{\partial^2 p}{\partial x^2} \quad (1)$$

where $\alpha = \frac{k}{\phi \mu c}$

$$\frac{p(o,t)}{x} = \beta \quad (2)$$

where $\beta = \frac{q'}{k A_{ef}}$

$$p(\infty,t) = p_i \quad (3)$$

$$p(x,o) = p_i \quad (4)$$

Taking the LaPlace Transform of expressions (1), (2), and (3)

$$s\,\bar{p}(x,s) - p(x,o) = \alpha \frac{d^2\bar{p}(x,s)}{dx^2} \quad (A1)$$

$$\frac{d\bar{p}(o,s)}{dx} = \frac{\beta}{s} \quad (A2)$$

$$\bar{p}(\infty,s) = \frac{p_i}{s} \quad (A3)$$

Substituting (4) into (A1) and rearranging

$$\frac{d^2\bar{p}}{dx^2} - \frac{s}{\alpha}\bar{p} = -\frac{p_i}{\alpha} \quad (A4)$$

The general solution of (A4)

$$\bar{p}(x,s) = C_1 e^{\sqrt{\frac{s}{\alpha}}x} + C_2 e^{-\sqrt{\frac{s}{\alpha}}x} + \frac{p_i}{s} \quad (A5)$$

where C_1 and C_2 are arbitrary constants of integration. Applying the transformed boundary conditions, (A3) to (A5), it is found that $C_1=0$ so that

$$\bar{p}(x,s) = C_2 e^{-\sqrt{\frac{s}{\alpha}}x} + \frac{p_i}{s} \quad (A6)$$

Taking the derivative of (A6) and applying (A2)

$$\frac{d\bar{p}}{dx} = -\sqrt{\frac{s}{\alpha}}\, C_2 e^{-\sqrt{\frac{s}{\alpha}}x} \quad (A6)^1$$

and

$$\frac{\beta}{s} = -\sqrt{\frac{s}{\alpha}}\, C_2 e^0$$

or

$$C_2 = -\frac{\beta\sqrt{\alpha}}{s^{3/2}}$$

Therefore, substituting C_2 into (A6)

$$\bar{p}(x,s) = -\beta\sqrt{\alpha}\,\frac{e^{-\frac{x}{\sqrt{\alpha}}\sqrt{s}}}{s^{3/2}} + \frac{p_i}{s} \quad (A7)$$

Taking the inverse LaPlace Transform of (A7),

$$p(x,t) = p_i - 2\beta\sqrt{\alpha}\left[\sqrt{\frac{t}{\pi}}\, e^{-\frac{x^2}{4\alpha t}} - \frac{x}{\sqrt{\alpha}}\,\mathrm{erfc}\left(\frac{x}{2\sqrt{\alpha t}}\right)\right] \quad (A8)$$

Only the pressures recorded at the fracture face, i.e., x=0, are of interest; Equation (A8) reduces to

$$P_{wf} = p_i - \frac{q'\mu}{k A_{ef}}\sqrt{\frac{k}{\phi \mu C_t}}\sqrt{\frac{t}{\pi}} \quad (A9)$$

Since $q' = q/2$ and $A_{ef} = A_f/2$,

$$P_{wf} = p_i - \frac{2}{\sqrt{\pi}}\frac{q}{A_f}\sqrt{\frac{\mu t}{\phi k C_t}} \quad (A10)$$

In field units, Equation (A10) is

$$P_{wf} = p_i - 16.3\,\frac{q_o}{A_f}\sqrt{\frac{\mu_o t}{k_o C_t}} \quad (A11)$$

APPENDIX B: APPLICATION OF THE PRINCIPLE OF SUPERPOSITION

On a pressure buildup test, it is assumed that the well is produced at a constant rate for a time (t) until the well is shutin. As in all pressure buildup work, t=(24) Np/q_o, where q_o is constant production rate prior to shutting in the well. The time recorded after the well has been shutin is denoted by Δ t, as shown in Figure B1. The Principle of Superposition states that the resultant pressure distribution in a reservoir upon making a change in the flow rate of a well at time (t) is equal to the previous pressure drop caused by the flow rate (q_o) for the time (t + Δ t) plus the pressure drop caused by the rate change (q_1-q_o) for time (Δ t), where (q_1) is the new flow rate. Since the flow rate on a pressure buildup test is changed from (q_o) to zero, the rate change as expressed above is (0-q_o). The Principle of Superposition expressed in mathematical terms for a pressure buildup is

$$p_i - p_{ws} = 16.3\,\frac{q_o}{A_f}\sqrt{\frac{\mu_o}{\phi k_o C_t}}\sqrt{t+\Delta t} + 16.3\left(\frac{0-q_o}{A_f}\right)\sqrt{\frac{\mu_o}{\phi k_o C_t}}\sqrt{\Delta t}$$

$$p_i - p_{ws} = 16.3\,\frac{q_o}{A_f}\sqrt{\frac{\mu_o}{\phi k_o C_t}}\left(\sqrt{t+\Delta t} - \sqrt{\Delta t}\right) \quad (B1)$$

APPENDIX C: ESTIMATING C_t AND C_{ts}

Using the well known equation for predicting field gas-oil ratios from laboratory derived relative permeability and fluid properties,

$$R = \frac{kg}{ko}\,\frac{\mu o}{\mu g}\,\frac{Bo}{Bg} + Rs$$

compute the gas-oil relative permeability ratio using a field measured GOR, or

$$\frac{kg}{ko} = \frac{R - Rs}{\frac{Bo}{Bg}\,\frac{\mu o}{\mu g}}$$

Arbitrarily assuming that the relative permeability relationships in the damaged region are identical to those in the undamaged zones, then the procedure for finding the gas saturation in the damaged area and in the remainder of the drainage area, which is needed to compute the compressibility terms, is

(1) Find kg/ko @ $\frac{p_x + p_{wf}}{2}$ for the damaged region.

(2) From kg/ko, determine S_g from relative permeability data.

(3) Then $C_t = S_o C_o + S_g C_g + S_w C_w$ where the appropriate values are used for either the damaged or undamaged regions.

APPENDIX D: EXAMPLE CALCULATION FOR WELL A PRESSURE BUILDUP INTERPRETATION

Late Time, Radial Flow Analysis

$\bar{p} \approx 1525$ psig

$$k_o h = \frac{162.6\ q_o\ \mu o\ Bo}{m} = \frac{(162.6)(26)(.39)(1.49)}{43}$$

$= 57.1$ md-ft.

$k_o = 57.1/19 = 3.0$ md

Since $\bar{p} >$ BPP, $C_t = C_o S_o + C_w S_w + C_f$

$C_t = 11.6 \times 10^{-6}\ psi^{-1}$

Early Time, Linear Flow Analysis

$P_x = 1343$ psi

$\Delta P_s = P_x - P_{wf} = 1343 - 460 = 883$ psi

Since $\bar{p} > P_x >$ BPP and $P_{wf} <$ BPP, it is necessary to compute C_{ts}. Use fluid properties at average pressure in skin, or

$$pavg = \frac{P_x + P_{wf}}{2} = \frac{1343 + 460}{2} = 902 \text{ psi}$$

At 902 psi, Bo = 1.415 Res Bbl/STB, B_g = 0.00297 Res Bbl/SCF, μ_o = 0.422 cp, μ_g = 0.0126 cp

$$\frac{kg}{ko} = \frac{R - Rs}{\frac{Bo}{Bg}\,\frac{\mu o}{\mu g}} = \frac{3200 - 550}{\frac{1.415}{0.00297}\,\frac{0.422}{0.0126}} = 0.166$$

From relative permeability ratio vs gas saturation curve,

$S_g = 20\%$ @ kg/ko = 0.166

From Trube's Correlations*, $Cg = 1370 \times 10^{-6}$ psi

$C_{ts} = Co\ So + Cw\ Sw + Cg\ Sg + Cf = 284 \times 10^{-6}\ psi^{-1}$

$$k_s = \left(\frac{m_2^2}{m_1^2}\right)\left(\frac{C_t}{C_{ts}}\right)(k)$$

$$= \frac{(12.0)^2}{(603)^2} \times \frac{11.6 \times 10^{-6}}{284 \times 10^{-6}} \times 3.0$$

$k_s = 0.5 \times 10^{-4}$ md

$$A_f = 16.3\ \frac{q_o}{m_1}\sqrt{\frac{\mu o}{ks\ \phi\ C_{ts}}} = 9000 \text{ ft}^2$$

$A_{ef} = A_f/2 = 4500$ ft^2

$X_f = A_{ef}/2h = 120$ ft

$$d_s = \frac{1.127 \times 10^{-3}\ A_f\ ks\ \Delta P_s}{q_o\ B_o\ \mu o}$$

$= 0.0292$ ft $= 0.36$ inch

From fracture calculations, the area of fracture, A_f, induced by the fracturing process was 80,000 ft^2, or

$$E_f = \frac{A_{ef}}{A_f} = \frac{4500}{80,000} = 5.6\%$$

*Trube, A. S.: "Compressibility of Natural Gases", TRANS AIME 210, (1957), 355-357.

TABLE 1 - ROCK AND FLUID DATA FOR WELL A, MUDDY SANDSTONE, CAMPBELL COUNTY, WYO.

ϕ = 16.9%	P_{wf} = 460 psig
h = 19 ft	μ_o = .39 cp @ BHT
S_w = 30%	BHT = 175 °F
q_o = 26 STBPD	BPP = 1,250 psi
B_o = 1.49 Res Bbl/STB	R = 3,200 SCF/STB
Depth = 7,000 ft	R_s = 550 SCF/STB
t = 59,300 hrs	

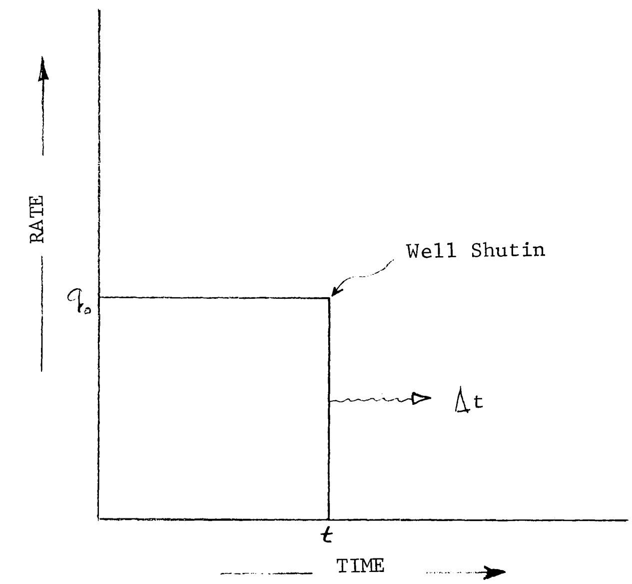

Fig. B1 - Graphical representation of a pressure buildup test.

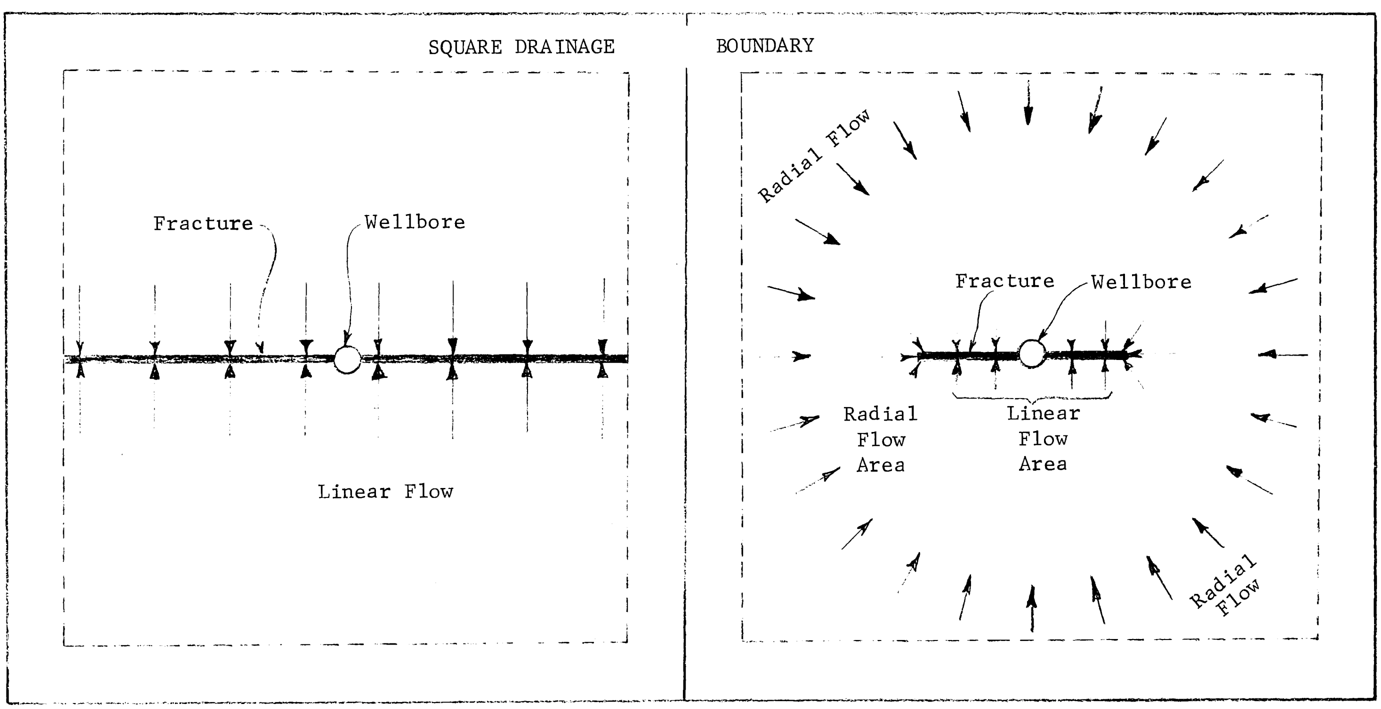

Fig. 1A - Fracture length extending completely across area.

Fig. 1B - Partially penetrating fracture.

Fig. 1 - Flow directions in a square drainage area with a vertical fracture.

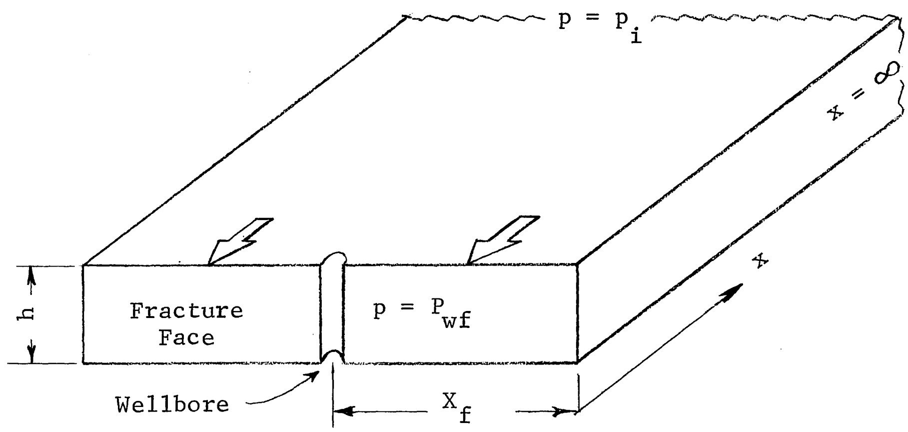

Fig. 2 - Semi-infinite reservoir with a propped vertical fracture.

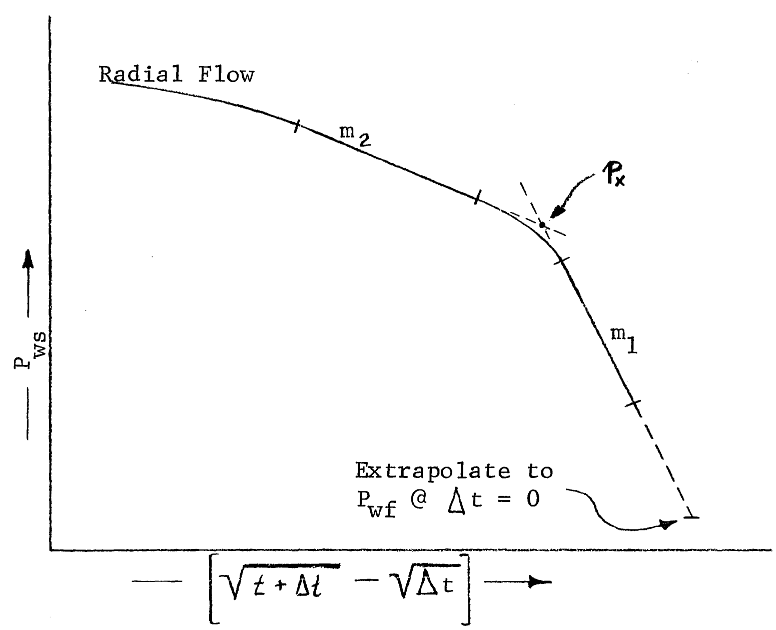

Fig. 3 - Idealized buildup curve from damaged vertically fractured well.

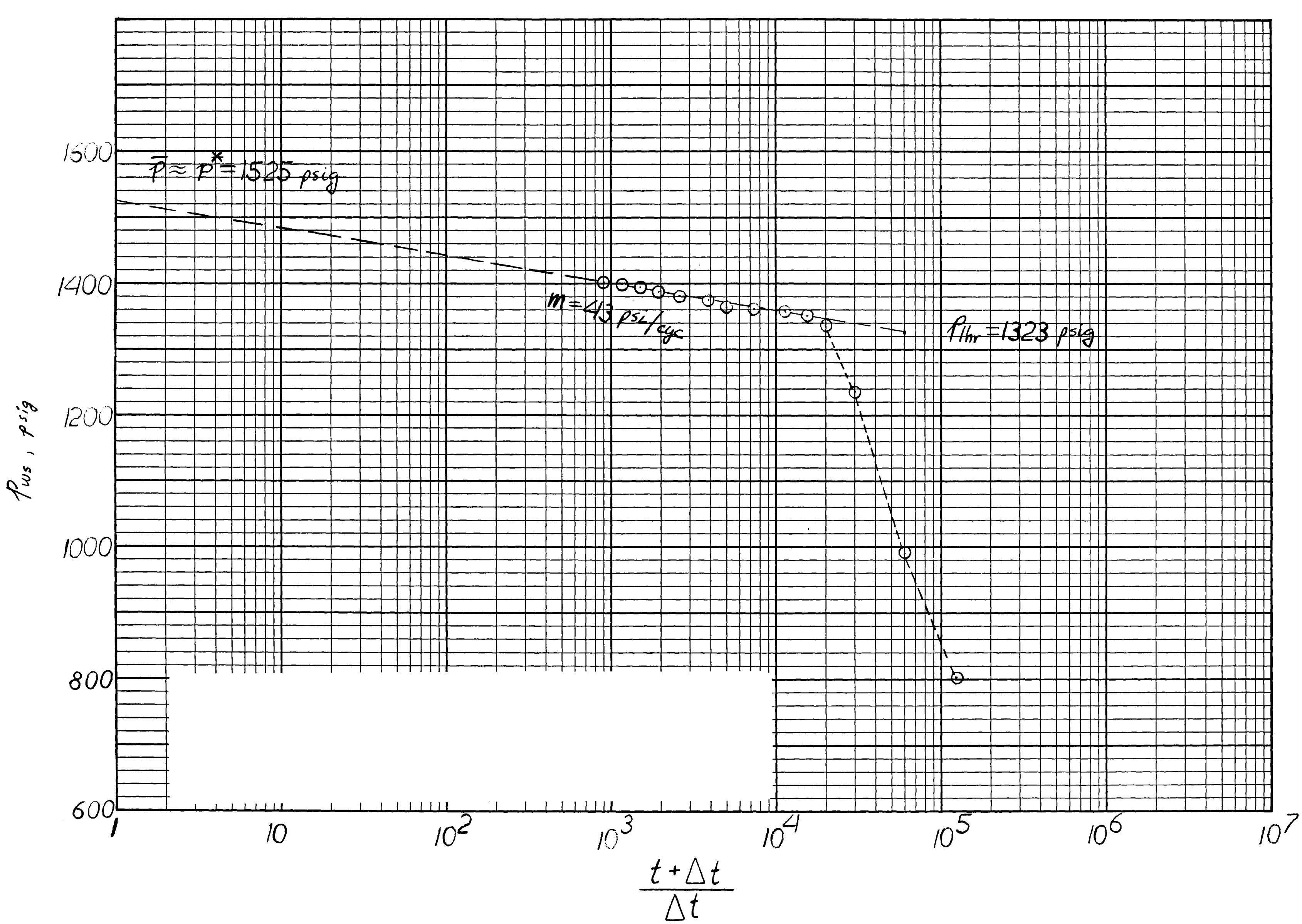

Fig. 4 - Shutin pressure vs ln $\frac{t + \Delta t}{t}$ pressure buildup, Well A, muddy sandstone, Campbell County, Wyo.

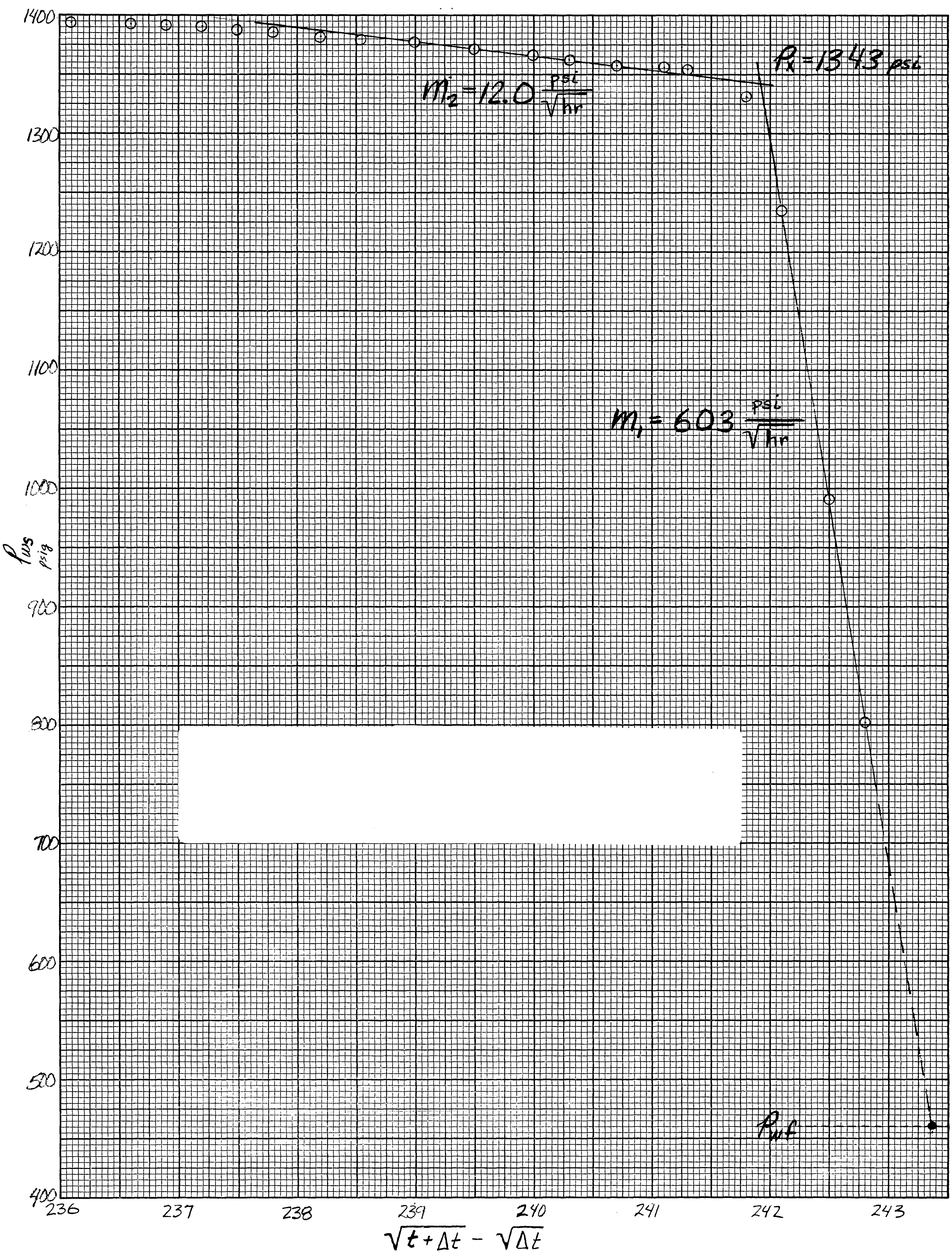

Fig. 5 - Shutin pressure vs $\sqrt{t + \Delta t} - \sqrt{\Delta t}$ pressure buildup, Well A, muddy sandstone, Campbell County, Wyo.