AFTER CLOSURE ANALYSIS OF THE LINEAR FLOW REGIME IN A FRACTURE CALIBRATION TEST

A Thesis

by

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ABSTRACT

After closure analysis (ACA) of a fracture calibration test designed to provide closure pressure and the fracturing fluid leak-off coefficient can provide estimates for formation permeability and pressure if radial flow is visible before the end of the acquired pressure falloff data. In very low permeability formations, the time required for the fracture calibration test to reach radial flow is likely to be impractically long, but the linear flow regime is likely to appear immediately after closure. The objective of this study is to develop equations for estimation of permeability and fracture half-length from the linear flow regime when the radial flow regime is absent.

The formation permeability can be determined when applying after closure analysis (ACA) of Fracture Calibration Test (FCT). The ACA can also offer a means of determining the initial reservoir pressure, fracture length, and closure pressure which are all crucial parameters of hydraulic fracture design in conventional and unconventional reservoirs.

After closure linear and radial flow regimes are easily identified in the log-log diagnostic plot of pressure change and its derivative with respect to the logarithm of elapsed time. We investigate using a flattening departure from the linear flow regime to estimate permeability when the radial flow is absent. We show how the relationship between reservoir permeability and pore pressure can be used effectively to reduce the uncertainty in the formation permeability estimate when an independent estimate exists for the reservoir pressure. We also show how to estimate the fracture half-length from the linear flow regime once an estimate for permeability has been made. We develop

equations for estimating permeability and fracture half-length using values that can be read directly from the log-log diagnostic plot.

The value of this work is to provide parameters of interest within a reasonable fall-off duration. This work shows the flaws in current analysis techniques for linear flow regime and indicate how this regime can correctly estimate permeability and fracture half-length even in the absence of radial flow.

DEDICATION

To Hao Zeng

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NOMENCLATURE

B	=formation volume factor, L^3/L^3, RB/STB
c_t	=total compressibility, Lt^2/m, psi-1
C_f	=fracture conductivity, m^3, md-ft
FCT	=Fracture Calibration Test
h	= formation thickness, L, ft
h_f	=fracture height, L, ft
ISIP	=instantaneous shut-in pressure
k	=permeability, L^2, md
$k_f w$	=fracture conductivity, md-ft
m'	=constant derivative level in a log-log plot
m_L	=slope of data on pseudo-linear flow plot, m/Lt^2psia
p	=pressure, m/Lt^2, psia
q	=flow rate, m^3/s, bbl/day
Q_i	=injection rate into one wing of the fracture, bbl/min
Rw	=wellbore radius, ft
R_f	=fracture radius, L, ft
T	=temperature, R
T_R	=temperature, R
t_e	=equivalent time, hr
V_i	= the volume of fluid injected into one fracture wing, L^3, bbl
x_f	=fracture half-length, ft

Greek

Δ	=difference, dimensionless
μ	=viscosity, m/Lt, cp
ϕ	= porosity, dimensionless
η	=fracture fluid efficiency, %

Subscript

c	=closure
D	=dimensionless
elf	=end of linear flow
g	=gas
hf	=hydraulic fracture
r	=reservoir
lf	=linear flow
i	=initial
n	=time step
ne	=time step at the end of the injectio

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CHAPTER I

INTRODUCTION

Usually, for conventional reservoirs, Fracture Calibration Test (FCT) refers to three types of tests which include a mini-falloff test, a step rate test and a mini-fracture test (Figure 1.1). It usually consists with three steps(Gulrajani. N. S. and Nolte 2000). The first step is the mini-fall off which means to inject at a very short time with a low flow rate. Followed the Step Rate which is often used to determine fracture extension pressure. The mini-falloff can also be called a Diagnostic Fracture Injection Test (DFIT), and it is designed to estimate fracture treatment design parameters such as fracture geometry, fracture fluid efficiency, formation permeability, and pressure.

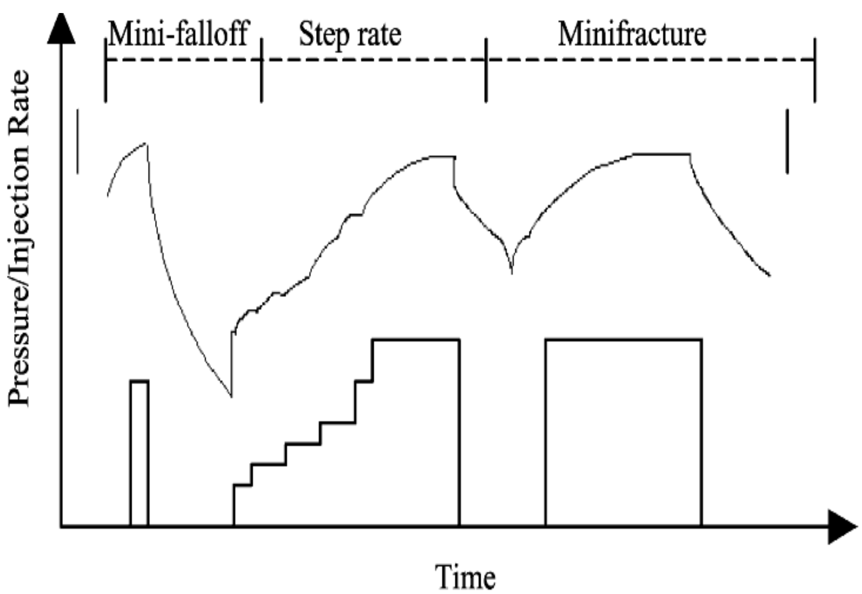

Figure 1.1 Formation Calibration Testing Sequence (Nolte 1997)

This study focuses on the falloff data observed after the fracture closes.

Nolte (1997) used the Carter (1957) expression for leakoff from the fracture face to determine fracture closure pressure and the leakoff coefficient. Barree et al (2009) developed a consistent analysis of the G-function and its derivative with respect to G-function. He demonstrated through field cases the diagnostic approach for 4 different leakoff types, namely normal leakoff, pressure-dependent leakoff, tip extension as well as transverse storage (or height recession). Recently, Liu and Ehlig-Economides (2015) enable matching injection fall off fracture calibration test data exhibiting abnormal leakoff behavior. The model match, in turn, makes it possible to qualify the additional parameters relevant to the main fracture design.

This thesis is focused on the falloff behavior observed after the fracture closes. Chapter II reviews the current literature regarding to after closure analysis. It starts by introducing the FCT pressure response chronology and ends with the log-log diagnostic plot introduced recently for FCT injection falloff analysis.

Chapter III uses the linear flow regime. The logic is to first review the Marongiu-Porcu (2014) model. We then introduce a method to estimate permeability and fracture half-length from the one point at the end of the linear flow trend in the log-log derivative for the injection (or drawdown) response for an effectively infinite conductivity fracture and present new equations to estimate permeability and fracture half length in the FCT injection falloff.

Chapter IV will show field examples illustrating the new method.

CHAPTER II

CURRENT KNOWN METHODS FOR AFTER CLOSURE ANALYSIS

This chapter shows currently known FCT after closure analysis for the pseudo radial flow and linear flow regimes.

2.1 Pseudo-Radial Flow Analysis

Pseudo-radial flow is widely used to estimate permeability.

Nolte et al. (1997) used the classical heat flow in solids and developed the time function for after closure pseudo-radial flow. For the estimation of formation transmissibility, it is obtained by using the radial flow period of the slope of pressure difference and the time function. This is obtained by combining the reservoir pressure and m_R which if the pressure-intercept and its slope of a Cartesian plot of pressure versus the square of radial flow time function.

Soliman et al. (2005) developed after closure analysis technique using analogous technique for conventional well test analysis. . The method uses a log-log specialized plot to estimate the permeability and reservoir pressure during pseudo-radial flow behavior. The permeability calculation assumes the fracture length does not change.

Because usually the injection time is much smaller than the falloff time in these tests, Gu et al. (1993) analyzed the injection falloff after closure behavior as a response to an impulse test.

2.2 Linear Flow Analysis

Between when the fracture closes and the start of pseudoradial flow linear flow to the fracture will likely dominate the transient response, often for a very long time.

Soliman et al. (2005) also proposed analysis of the linear flow regime. If the fracture length is estimated from the before closure transient analysis, Soliman et al. (2005) observed that both permeability and fracture conductivity can be estimated if the bilinear flow regime appears. This paper also comments that while it is not be feasible to calculate the permeability when the end of bilinear or linear flow is not observed, the last point on the straight line may be used to calculate an upper bound for the permeability.

However, Marongiu-Porcu (2014) indicated that the possibility of having after closure bilinear flow should be excluded. Marongiu-Porcu (2014) objected to claims by Soliman et al. (2005), Craig and Blasingame (2006), and Barree et al. (2009), that they observed bilinear flow in the after closure behavior. He indicated that after closure bilinear flow should be regarded as an artifact because sufficient pressure gradient to justify bilinear flow in a fracture with no proppant would be a violation of the poroelastic closure model.

Marongiu-Porcu (2014) mentioned the Gringarten et al. (1975) method to determine the upper limit of permeability when there is a departure to a pseudo radial flow after the ½ slope (also found in Earlougher (1977)). The formula they proposed is:

$$k = \frac{(0.2150)(141.2)qB\mu}{h*\Delta p} \tag{2.1}$$

where Δp is the log derivative pressure when the departure toward a radial flow after the after closure flow regime is observed. The injection rate is in bbl/min, B is in RB/STB, μ is in cp, h is in ft and Δp is in psi. Transferring this particular formula from oil into gas gives

$$k = \frac{(0.2150)(141.2)qB\mu}{h*\Delta p} \tag{2.2}$$

and the Δm(p) is the observed pressure change at the moment of departure from the 1⁄2 slope towards the pseudo-radial flow flat logarithmic derivative. The injection rate is in bbl/min, T is in R, h is in ft and Δp is in psi. Marongiu-Porcu (2014) indicates to use $x_f = R_f$ and $h = R_f$ for a radial fracture with $2R_f <$ the formation thickness, h. For a radial fracture with $2R_f >$ the formation thickness h, $x_f = R_f$ and h is the formation height.

However, the same references show the following equation:

$$x_f \geq \sqrt{\frac{0.000237kt}{0.016\emptyset\mu c_t}} \tag{2.3}$$

The inequality applies when the transient data end with a linear flow trend with no evidence of a departure to pseudoradial flow.

2.3 Log-Log Diagnostic Method for After Closure Analysis

The Bourdet et al. (1989) log-log diagnostic plot of the pressure change and the semilog superposition derivative function is widely used in well testing interpretation. It is designed to identify flow regimes from straight derivative trends with characteristic slopes and levels from which important well or reservoir parameters can be directly computed. Mohamed et al. (2011) introduced use of this plot for fracture calibration test injection falloff analysis. Xue, (2012) showed the trends on this plot for commonly-encountered abnormal leakoff behaviors.

2.4 Chapter Summary

There are several approaches for analyzing after closure behavior in the fracture calibration test, and many of them focus on estimating fracture half-length using permeability acquired from pseuroradial flow. However, the next chapter will show that the linear flow regime can be also used to estimate permeability even when pseudoradial flow is absent.

CHAPTER III

ESTIMATION OF PERMEABILITY AND FRACTURE HALF LENGTH FROM THE LINEAR FLOW REGIME

Chapter II described the general permeability estimation using pseudoradial and linear flow.

This chapter starts with explaining the Marongiu-Porcu (2014) global model. Then it uses the linear flow regime to determine permeability and fracture half-length. It also shows and quantifies a shift in the linear flow derivative trend that occurs when the falloff duration is much longer than the time on injection.

3.1 Simplification for the Marongiu-Porcu After Closure Model

Marongiu-Porcu (2014) provided a complete analysis methodology based on the log-log diagnostic plot and a basic global model for the before and after closure analysis. For after closure analysis particularly, he provided the model that matched the after closure part of pressure falloff data and in turn allowed quantifications of reservoir permeability and formation pressure.

The Marongiu-Porcu et al. (2014) model approximates the actual injection sequence as a two-rate injection followed by shut-off, where the first rate is an assumed average leak-off rate during the fracture propagation, and the second rate is an assumed average leakoff rate during closure

The values of the average total leak-off rate during the injection and during the shut-in the following:

$$q_{L(TOT)} = \frac{2V_i(1-\eta)}{t_e} \tag{3.1}$$

$$q_{F(TOT)} = \frac{2V_i\eta}{\Delta t_c} \tag{3.2}$$

with V_i as the volume of fluid injected into one fracture wing (i.e., half of the total injected fluid volume), t_e as equivalent time, Δt_c as closure time, and η as fracture fluid efficiency and is calculated using the formula presented by Nolte (1986).

$$\eta = 1 - \frac{g_0(\Delta t_D = 0, \alpha)}{g_c(\Delta t_{D,c}, \alpha)} \tag{3.3}$$

with the $g_o(\Delta t_D = 0, \alpha)$ as the g-function at shut-in time, and $g_c(\Delta t_{D,c}, \alpha)$ as the g-function of closure time.

This two-rate injection, however, can be simplified as a one-step injection at the leakoff rate during closure (Eq. 3.2) for the material balance time duration. The material balance time is computed by dividing the total injected volume, V_i, by the leakoff rate during closure. This approach is analogous to the time adjustment recommended by Horner (1950) to approximate the flow history before a buildup test.

3.2 Permeability and Fracture Half-length Estimation from the Injection Transient Response

This section explains how to use the modern Bourdet log-log diagnostic plot for identification of linear flow and estimation of the product of the fracture half-length and the square root of permeability. The following equation describes the pressure change, Δp, during linear flow to a fracture:

$$\Delta p = m_{lf}\sqrt{\Delta t} + (\frac{\pi}{3})(\frac{m}{1.151})\frac{kx_f}{k_f w} \tag{3.4}$$

where m_{lf} is the slope of a graph of pressure versus the square root of time, m is the slope of a graph of pressure versus log time, k_f is fracture permeability, and w is fracture width. The Bourdet, et al. (1989) derivative for this function is

$$\Delta p' = \frac{1}{2} m_{lf}\sqrt{\Delta t} \tag{3.5}$$

During linear flow, the Bourdet derivative is straight with a ½ slope trend. Ehlig-Economides has indicated (Ehlig-Economides, 2013) that for any point $(\Delta p', \Delta t)_{lf}$ found in the ½ slope derivative trend

$$m_{lf} = 2\Delta p' / \sqrt{\Delta t}, \tag{3.6}$$

and

$$x_f\sqrt{k} = \left(\frac{4.064\Delta qB}{m_{lf}h}\right)\left(\frac{\mu}{\phi c_t}\right)^{1/2} \tag{3.7}$$

Therefore, for oil,

$$x_f = (\frac{4.064qB_o}{2\Delta p' h})(\frac{\mu\Delta t}{\phi c_t k})^{1/2} \tag{3.8}$$

and for gas,

$$x_f = \left(\frac{41.046qT_R}{2\Delta m(p)' h}\right)(\frac{\Delta t}{\phi \mu_g c_t k})^{1/2} \tag{3.9}$$

where the $\Delta p'$ and Δt is the point in the pressure derivative where exhibits a $1/2$ slope has been observed. The values of h, formation thickness and x_f, fracture half-length depend on the injection rate and volume, heterogeneity and rock stress and mechanics (Ewens 2012).

The inequality in Equation 2.3 becomes an equality when the departure from linear flow toward pseudoradial flow is observed as a downward or rightward deflection from the 1/ 2 slope trend at a time, t_{elf}, marking the end of linear flow. Solving for the permeability, k:

$$k = \frac{0.016\emptyset\mu c_t x_f^2}{0.0002637 t_{elf}} \tag{3.10}$$

Combining Eqns. 3.7 and 3.8 or Eqns. 3.7 and 3.9 enables estimation of both permeability and fracture half-length using the derivative point marking the end of linear flow. The onset of actual pseudoradial flow occurs at least $100t_{elf}$. That is, if the end of linear flow is at 10 hours, the start of pseudoradial flow will be after about 1000 hours. Therefore, this method for estimating permeability and fracture half-length greatly shortens the time sufficient for the analysis.

3.3 Distortion in Linear Flow Behavior for Short Injection Duration

The previous discussion related to pressure behavior during constant rate injection or production. Buildup or falloff transients are frequently distorted by superposition. In particular, when the injection time is much smaller than t_{elf} for a given reservoir fracture model case, we observe an 'S' shaped half slope. We use the Cotton Valley tight well case as an example to simulate this situation.

For this case, t_{elf} is 2.27 hours. Figure 3.1 compares the derivative behavior of the falloff following injection for 0.1 hours to the injection derivative response for the same injection rate. The falloff derivative shows an "S" shape including a downward (or rightward) shift during the linear flow portion.

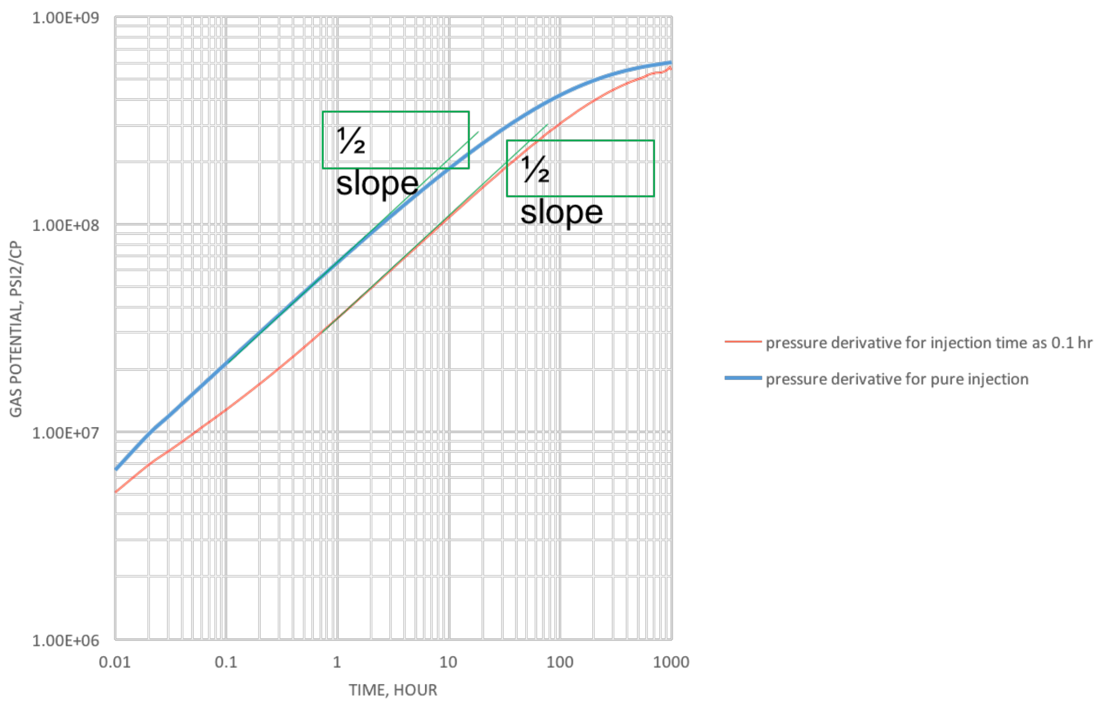

Figure 3.1 Single Rate Injection Pressure Derivative and 0.1-hour Injection Pressure Derivative

Figure 3.2 shows sensitivity to the injection duration. The ½ slope derivative behavior appears for sufficiently small injection time, but shifted downward as in Figure 3.1. As the injection time increases, the falloff is dominated by a transition between the first and second ½ slope trends, but a clear linear flow appears for sufficiently small injection time. The shift in the ½ slope appears to be about a factor of 2, and the end of linear flow in the falloff is about 10 times larger than that seen in the injection response.

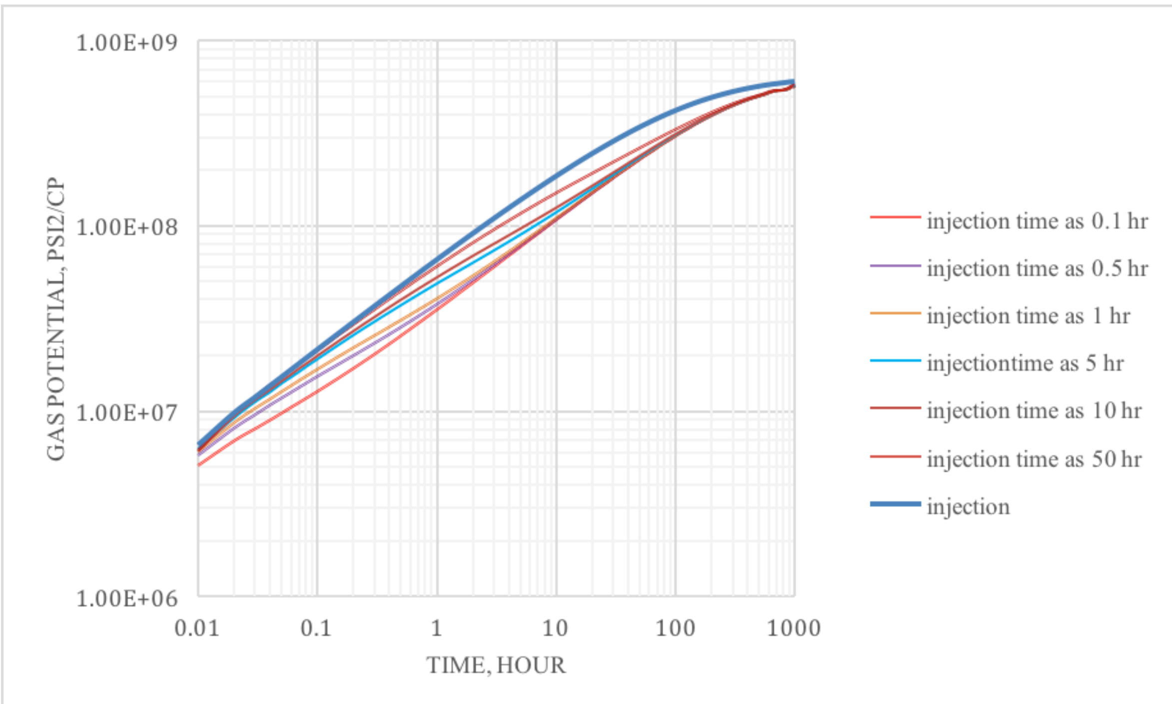

Figure 3.2 Family Curve of Pressure Derivative for Different Injection Time

The following analysis explains the downward shift of about 2. Eq. 3.11 is a generalization of Eq. 3.4:

$$\Delta p = C_1\sqrt{t} + C_2 \tag{3.11}$$

For injection falloff with $t_e + \Delta t << t_{elf}$, (for t_e the previously explained material balance time adjustment for the injection time)

$$\Delta p = C(\sqrt{t_e + \Delta t} - \sqrt{t}) \tag{3.12}$$

Taking the Bourdet derivative of both sides of the equation gives

$$\Delta p' = \frac{d(\Delta p)}{d(\ln(\frac{t_e+\Delta t}{\Delta t}))} = \frac{\frac{d(\Delta p)}{d(\Delta t)}}{\frac{d(\ln(\frac{t_e+\Delta t}{\Delta t}))}{d(\Delta t)}} \tag{3.13}$$

$$\frac{d(\Delta p)}{d(\ln(\frac{t_e+\Delta t}{\Delta t}))} = \frac{C}{2}\frac{\frac{1}{\sqrt{t_e+\Delta t}} - \frac{1}{\sqrt{\Delta t}}}{\frac{1}{t_e+\Delta t} - \frac{1}{\Delta t}} \tag{3.14}$$

$$\frac{d(\Delta p)}{d(\ln(\frac{t_e+\Delta t}{\Delta t}))} = \frac{C}{2}\left(\frac{1}{\frac{1}{\sqrt{t_e+\Delta t}} + \frac{1}{\sqrt{\Delta t}}}\right) \tag{3.15}$$

$$\frac{d(\Delta p)}{d(\ln(\frac{t_e+\Delta t}{\Delta t}))} = \frac{C}{2}\frac{\sqrt{\Delta t}}{\sqrt{\frac{\Delta t}{t_e+\Delta t}}+1} \tag{3.16}$$

For constant rate injection

$$\Delta p' = \frac{C}{2}\sqrt{t} \tag{3.17}$$

For an injection falloff with $\Delta t >> t_{elf}$, the pressure derivative is approximately

$$\frac{d(\Delta p)}{dln(\mathrm{t})} = \frac{C}{2(1.9)}\sqrt{t} \tag{3.18}$$

which indicates that for the cases when injection time is much less than the ½ slope departure time, 1.9 times of the slope can be used in Eq. 3.7 and Eq. 3.8 to estimate fracture half length.

The equation of 3.8. and 3.9 becomes

$$x_f = \frac{4.064 q B_o}{2\left(\sqrt{\frac{\Delta t}{t_e+\Delta t}}+1\right)\Delta p' h})(\frac{\mu \Delta t}{\phi c_t k})^{1/2} \tag{3.19}$$

for oil,

$$x_f = \left(\frac{41.046 q T_R}{2\left(\sqrt{\frac{\Delta t}{t_e+\Delta t}}+1\right)\Delta m(p)' h}\right)(\frac{\mu \Delta t}{\phi c_t k})^{1/2} \tag{3.20}$$

for gas. However, both of these equations require a value for the permeability, *k*.

3.4 New Equations for Analysis of Linear Flow after a Short Injection Duration

Marongiu-Porcu et al. (2014) proposed that FCT design use small injection volume to ensure that fracture closure and, ideally after closure transient behavior, will occur within a practical falloff duration. In fact, frequently these tests do employ small injection volumes over an injection time of a few minutes. The Cotton Valley injection duration was 19 minutes, which is approximately 15% of the t_{elf} for the created fracture.

The time function in Eqns. 3.19 and 3.20 approaches 2. For $\Delta t = 10t_e$, the value is about 1.9. Therefore, Eqns. 3.19. and 3.20 become

$$x_f = (\frac{4.064qB_o}{3.8\Delta p^{'}h})(\frac{\mu\Delta t}{\phi c_t k})^{1/2} \quad (3.21)$$

for oil and

$$x_f = \left(\frac{41.046qT_R}{3.8\Delta m(p)^{'}h}\right)(\frac{\Delta t}{\phi \mu_g c_t k})^{1/2} \quad (3.22)$$

for gas.

As well, noting that the end of linear flow occurs at about $10t_{elf}$ for injection at constant rate, Eq. 3.7 becomes

$$k = \frac{0.16\emptyset\mu c_t x_f^2}{0.0002637t_{elf}} \quad (3.23)$$

when $t_e << t_{elf}$ for injection.

By combining the new equations of eq 3.23 and eq 3.22 for oil or eq 3.23 and eq 3.21 for gas, the real permeability and fracture half-length can be determined.

Plugging Eq. 3.23 into Eq. 3.22 gives the following equations are for gas:

$$k = \frac{266.07\ qT\mu}{\Delta m(p)^{'}h}\sqrt{\frac{1}{\phi\mu_g}} \quad (3.24)$$

$$x_f = 0.66[\frac{qTt_{elf}}{\mu\Delta m(p)^{'}h}\left(\frac{1}{\phi c_t \mu_g c_t}\right)^{1/2}]^{1/2} \quad (3.25)$$

and the following equations are for oil:

$$k = 26.34\frac{q\mu B_o}{\Delta p^{'}h} \quad (3.26)$$

$$x_f = 0.208\sqrt{\frac{\Delta t q B_o}{\phi c_t \Delta p' h}} \tag{3.27}$$

3.5 Discussion

The analysis provided in Section 3.4 relies on an assumption that $t_e << t_{elf}$, where t_{elf} is the departure time for simple constant rate injection. Hence, the analyst should confirm that this is the case once the analysis is done.

Technically, the Marongiu-Porcu after closure model assumes that the behavior after closure will mimic falloff behavior that would occur when the fracture is present during the entire injection period. In reality, the fracture propagates during injection, and up to now there is no falloff model that specifically takes this into account. All of the analysis techniques discussed in Chapter 2 also make this assumption.

Frequently in field data examples usually the closure time is from one to two times the injection time. During closure the transient behavior is dominated by the poroelastic closure behavior, and the falloff behavior described in this chapter is observed only after closure.

Actual observance of pseudoradial flow in the after closure response typically requires an impractical falloff duration. The analysis in this chapter enables a 100-fold reduction in the time necessary to estimate permeability, and hence, as well fracture half-length.

3.6 Chapter Summary

When radial flow is absent in the flow regime and this is usually happening because the flow is too short or the permeability is too small or in some cases, both. Linear flow regime can be used to estimate permeability and fracture half-length by applying the combination of Earlougher (1977) and Ehlig-Economides (2013) equations. However, for drawdown or falloff, the distortion of the time shift should be considered and the correct results can be determined by using the new equations for analysis of linear flow after a short injection duration.

CHAPTER IV

CONCLUSIONS

The utility of linear flow regime enables a better estimate of upper-limit of permeability than assuming an apparent radial flow when radial flow is absent. This approach can be applied both on fracture calibration test analysis and on conventional buildup test. The longer the falloff/buildup period (or the more approach to radial flow), the more accurate the estimation.

It is possible to estimate of permeability and fracture half-length from the one point at the end of the linear flow trend in the log-log derivative for the injection (or drawdown) response for an effectively infinite conductivity fracture with the condition of the injection time is shorter than the ½ slope departure time from the pure injection case.

Using linear flow regime to determine formation transmissibility will shorten the time that need when using radial flow which is more practical in the real world.

The shift in the linear flow derivative trend from the pure injection curve to a falloff curve can be quantified with a fixed coefficient.

Two new equations to use for the one point in the derivative found at the end of linear flow enable estimation of permeability and fracture half-length. This is applicable only when linear flow is observed with a departure toward radial flow and enables the estimate for the maximum possible permeability a corresponding minimum fracture half-length.

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