Evaluating Unconventional Reservoir Based on DFIT Analysis, Actual Field Cases

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Abstract

Reservoir properties become critical key parameters to optimize the hydraulic fracture treatment which play an important role to develop unconventional reservoirs. The most valuable and commonly tool used to quantify the reservoir and hydraulic fracture characterizations is Diagnostic fracture injection test (DFIT). The pressure decline response of DFIT test reflects the process of fracture closure and the flow capacity of the reservoir. DFIT test could be provide valuable estimation of reservoir properties and fracturing parameters, including interaction with natural fractures and heterogeneous rock properties. This result could be used to build simulation model to forecast these reservoirs before performing the actual frac job.

The objective of this paper is to investigate and analyze the behavior of non- ideal DFIT and factors which affect the DFIT data. The paper also explains the analysis of DFIT before and after closure and how to identify the flow regimes under complex reservoir conditions. The fall-off period is analyzed using the diagnostic plots and leak-off modeling to determine the reservoir and fracture characterization such as pressure, reservoir permeability, mobility, and transmissibility, flow regime before and after closure and fracture half-length ...etc.). This result could be used to build simulation model to forecast these reservoirs before performing the actual frac job and predict the reservoir productivity index.

The paper explains different mechanisms affecting the pressure behavior during DFIT and leak-off process in order to observe the reservoir response and get more realistic reservoir and fracture

Introduction

DFIT is considered one of the most important tests performed on-site before the main hydraulic fracture injection job in order to determine the critical parameters for stimulation design and provide critical reservoir and rock parameters. DFIT is known by different names such as Fracture-Injection/ Fall-off test. DFIT is performed without proppant to break down the formation and create a short fracture during the injection period (Wang et al., 2017a)., and then, observe the closure of the fracture system and the fracture propagation during the ensuing fall-off period.

One of the main advantages of DFIT is the information similarity gained from the drawdown or buildup tests which are very expensive and impractical to run in unconventional reservoirs. In addition to, DFIT is simple and inexpensive method to estimate reservoir and rock parameters. Consequently,

DFIT or

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minifrac test has become a valuable and commonly used method to analyze the recorded falloff and postfrac data in unconventional, tight-oil and shale-gas reservoirs, however, DFIT analyzing methods can't work in most reservoir cases which leads to an incorrect interpretation (Barree et al. 2015). Figure 1 shows a typical pressure trend from DFIT test (Mohamed 2019).



Figure 1: Rate and pressure measurements from a DFIT (Mohamed 2019).

After shut-in the injection pump, the fall-off pressure data is divided into two main regions, before closure and after closure. The accurate value of closure pressure value is very important to separate between the two regions. The incorrect closure pressure value leads to incorrect DFIT interpretations.

Before closure analysis (BCA) was pioneered by Notle (1979, 1986, 1988) based on Carter (1957) leakoff model. His approach is based on a simple material balance consideration, assumed that the fluid injected during the minifrac test is either leaked into the formation through the fracture face or contribute to the fracture growth into the formation, to verify the fracture fluid efficiency, fracture closure pressure and fracture fluid leak-off coefficient.

G-function derivative plots were introduced by Mukherjee (1991) and Barree and Mukherjee (1996) which included the G dp/dG plot. In this approach, the G-function represents the elapsed time after shut-in normalized to the duration of fracture extension. It is defined as:

$$G(\Delta t_D) = \frac{4}{\pi} [g(\Delta t_D) - g(0)]$$
1

The dimensionless time Δt_D is defined by:

$$\Delta t_D = \frac{t - t_e}{t_e} = \frac{\Delta t}{t_e}$$
 2

The g-function time is defined by:

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$$g_0(\Delta t_D) = (1 + \Delta t_D) \sin^{-1}(1 + \Delta t_D)^{-\frac{1}{2}} + \Delta t_D^{\frac{1}{2}}$$
 for $\alpha = \frac{1}{2}$ "Low fluid effection of β and β and β and β are the second sec

$$g_0(\Delta t_D) = \frac{4}{3} \left[(1 + \Delta t_D)^{3/2} - \Delta t_D^{3/2} \right] \quad for \quad \propto = 1 \text{ "High fluid effeciency"} \qquad 4$$

Castilli (1987) confirmed the fracture closure pressure is determined using Notle's G-function. On the G-function plot, the pressure is expected to appear as a straight line for before the closure, then, deviate from the straight-line at closure point. The fracture closure pressure is picked by the departure of the data from the straight-line trend. The G-function derivative plots were introduced by Barree et al. (1996) that included the plot.

Nolte (1997) provided another dimensionless time function (F-function) for after closure pressure analysis for linear and pseudo-radial flow regime to able to estimate reservoir properties.

Soliman et al. (2005) developed the analysis of after-closure DFIT analysis to determine the reservoir properties, flow regieme and quantify reservoir pressure and permeability. Sometimes the curves of G-Function appear with multi-inflection points that refer to non-ideal leak-off behavior, therefore, the interpretation of fall-off pressure slope changing and fracture closure pressure identifying is too difficult. Marongiu-Porcu et al. (2011) and Mohamed et al. (2011) analyze the fall-off pressure data for normal leak-off using log-log diagnostic plots as shown in Figure 2. They concluded the normal leak-off appears as 3/2 slope using Bourdet method and the closure pressure is picked at deviation from 3/2 slope trend which represents the deviation from straight-line on G-function plot (Bachman et al., 2012).



Figure 2: DFIT Diagnostic Analysis

Methodology

The following diagnostic plots are used to analyze the BCA and ACA pressure decline data:

- 1) Log-Log of pressure and derivative Bourder et al (1989)
- 2) Square Root Time plot
- 3) G Function Plot
- 4) G dp/dG plot

The Log-Log plot is used to determine the flow regimes for both before closure and after closure regions. Bourdet (1989) identifies flow regimes along with characteristic slopes as shown in Figure 2:

- 0.5 slope, Fracture Linear flow
- 3/2 or Unit Slope, defining the Before closure region;
- 0.5 slope, formation Linear flow from the ¹/₂ slope; and
- 0 slope, Radial flow.

After closure analysis (ACA), analyzing the pressure decline after the fracture has closed, was introduced by Nolte et al (1997). The flow regimes of interest in this time span are the linear and pseudo-radial flow profiles. The unconventional shale evaluation is more rigorous and time consuming. Stemming from the extended periods of time needed for pseudo-radial flow to be achieved versus a conventional tight gas or play with drastically higher permeability. The extended shut-in period is necessary and careful attention should be taken with respect to the design and equipment selections.

Well-A_Case_1

The DFIT test is conducted before a stimulation treatment for well-A at formation depth 11000 ft. the procedure involves pumping of 20 bbls of water with 2% KCL. The pressure rises linearly until reaches to the initial break down at 15,200 psi. after observing the breakdown pressure, the pump rate is held constant for 3-5 minutes at the maximum rate allowed by the available pumps. The well is shut-in, and the pressure fall-off is monitored with time. The pressure is monitored by downhole gauge as shown in Figure.3.



Figure 3: Rate and pressure gauges _ Well-A_ Case_1

Before closure section is analyzed using the diagnostic plots such as log-log typical plot, G-function method, square root time in order to determine and confirm the closure pressure and closure time with more than one method. Before starting the analysis, the estimated ISIP is 7800 psi.

The log-log plot (Bourdet et al. 1989) is used to identify the flow regimes before and after closure analyses. Figure 4 indicates the closure pressure and time is picked by the deviation from the 3/2-slope behavior. The closure pressure and time values are 6700 psi and 9.096 hrs. The inspection of this figure provides the following:

- showing the effect of wellbore storage and near wellbore that is ended at circle-1
- after Circle-2 the derivative has a gentle roll down through a ¹/₂-log cycle indicating a residual tortuosity effect.
- Circle-3 represents the fracture extension pressure for a purely vertical plane fracture.
- Nolte leak-off is represented by the 3/2 slope that is shown in the middle of the plot at Circle 4.



Figure 4: Log -log plot_Well-A_Case_1

G-function analysis has been one of the most commonly used method to analyze the recorded fall-off and post-frac data. Figure 5 shows the leak-off type is a fracture height recession leak-off signature that identified by a belly below the straight line through the origin and tangent to the semi-log derivative of pw vs. G-time at the point of fracture closure. The fracture closure pressure and time values are confirmed after using G-Function technique which give closure pressure and time at 6719 psi and 8.942 hrs. respectively.

Traditionally this signature "fracture height recession" assumes that leak-off occurs only through a thin permeable bed and that the fracture extends in height to cover impermeable strata with no leak-off. At shut-in there is a large volume of fluid stored in the fracture and the leak-off rate relative to the stored volume is small, hence the rate of pressure decline is likewise small. As the fracture empties, the rate of leak-off relative to the remaining stored fluid accelerates and the pressure declines more rapidly.

dP/dG

40

dP/dG G*dP/dG, psi

0

0

0

140

7



80

G*dP/dG

G-Function

100

120

Square root time method is also used to confirm the closure pressure and time and confirm the leak-off type. The results confirmed the leak-off type "fracture height recession leak-off signature" and the closure pressure by the deviation from the straight-line behavior passing through the origin. The fracture closure pressure and square time are obtained using the DFIT developed model is 6719 psi and 2.95 hrs., respectively as shown in Figure 6.

Figure 5: G-Function plot_Well-A_Case_1

60



Figure 6: Square root shut-in time plot_ Well-A_ Case_1

After closure region is also analyzed using F-Function method (Talley and Notle 1999) in order to identify flow regimes to confirm reservoir parameters such as reservoir pore pressure, formation flow capacity, mobility and permeability.

The log-log plot of bottomhole flowing pressure minus the assumed reservoir pressure versus the square of the linear flow time function is commonly used to identify the after-closure flow regimes. The analysis of after-closure depends on the accuracy of closure pressure/time picking. The pressure difference curve is dependent on the assumed value of reservoir pressure used but the pressure derivative is independent on the pressure estimate. Figure 7 shows the pressure difference pressure derivative vs. the square of the linear flow time function. The linear and pseudo-radial flow regimes can be identified by a ½-slope and unit-slope behavior of the pressure derivative respectively.



Figure 7: After Closure Analysis- Square Linear Flow Time Function_Well-A_Case_1

Once the linear flow regime is observed, the cartesian plot of pressure versus the linear flow time function can be constructed as shown in Figure 8. After observing the pseudo-radial flow regime, the cartesian plot of pressure versus the pseudo-radial flow time function can be constructed. The estimated reservoir pressure is 5690 psi. The slope (mR) is used to calculate the transmissibility and permeability from Eq. 5, knowing the net pay is 30 ft and reservoir fluid viscosity is 0.2 cp. The estimated reservoir Transmissibility and permeability is 0.84 md*ft and 0.028 md respectively.



Figure 8: Linear Flow Time Function_ Well-A_ Case_1



Figure 9: Radial Flow Time Function_Well-A_Case_1

Well-B_ Case_2

Actual DFIT test is conducted before a stimulation treatment for well-B at formation depth 6000 ft. The pressure rises linearly until reaches to the initial break down at 9,500 psi. After observing the breakdown pressure, the pump rate is held constant for 3-5 minutes at the maximum rate allowed by the available pumps. The well is shut-in, and the pressure fall-off is monitored with time as shown in Figure.10. The estimated ISIP is 8522 psi.



Figure 10: Rate and pressure (results) from DFIT_Well-B_Case_2

The logarithmic derivative in the log-log diagnostic plot shows a steep upward trend, and the closure time and pressure can be picked when the tangent to the derivative has a slope of 3/2. In this case, the closure time and pressure are difficult to pick but it will be confirmed using G-Function and square root methods. The flow regime after closure point couldn't be detected as shown in Figure 11.



Figure 11: Log -log validation plot_Well-B_Case_2

The G-function plot shows the derivative signature of a belly below the straight-line through the origin and tangent to the semi-log derivative of pw vs. G-time at the point of fracture closure as shown in Figure 12. The fracture closure occurs at the G-time and closure time and pressure at 68 hrs., 154 hrs. and 8140 psi.

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Figure 12: G-Function plot_Well-B_Case_2

The closure pressure, time and leak-off type are confirmed using square root time method. The results are confirmed the leak-off type is fracture height recession leak-off signature as shown in Figure 13. The closure pressure is also confirmed by the deviation from the straight-line behavior passing through the origin. The fracture closure pressure and square time is 8145 psi and 12.3 hrs., respectively.



Figure 13: Square root plot_Well-B_Case_2

Figure 14 shows the Δp vs. the square of the linear flow time function, where no clear linear flow presents but the pseudo-radial flow regime is identified properly. Figure 15 presents the cartesian plot of the pressure vs. the radial flow time function. The vertical intercept of the straight line through the appropriate data in the pseudo-radial flow period gives a pore pressure estimate of 7971 psi. Using the slope of the straight line, fluid viscosity of 0.2 cp, and the fracture height of 30 ft, the effective reservoir permeability and mobility can be calculated as 0.04 md and 0.2 respectively.







Figure 15: Radial Flow Time Function _ Well-B_ Case_2

Summary

The most significant findings in this research includes the following:

- G-Function analysis has become a valuable and commonly used method to analyze the DFIT data in unconventional reservoirs.
- G-Function can identify the natural fracture which will help to design the hydraulic fracture job. However, the interpretations from G-function cannot solely describe reservoir properties.
- QC should be applied on pumping and recording data to make sure the results are representative.
- Short shut-in period which does not allow the well to reach to either linear or radial flow
- Quality of pressure gauge is crucial so recommended to use downhole pressure gauge instead of surface gauge.
- DFIT could be pumped in natural fracture which make the closure and reservoir pressure under estimation.
- Rock heterogeneity can create multi closure pressure value.

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