New Methodology of classification Ultra-low Permeability for Unconventional Reservoir Based on DFIT Analysis

D. Shaker, North Bahariya Petroleum Company, H. Kattab, M. Tantawi and A. Gawish, Suez University

Abstract

Reservoir properties become critical key parameters to optimize the modern hydraulic fracture treatment which play an important role to develop tight and/or unconventional gas 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. This paper present method will be beneficial in classifying new reservoir during appraisal stage based in the result from DFIT test. The key reservoir and hydraulic fracture characterizations will be classified based on Bourdet derivative type before closure region. We identified two types of reservoirs have different value of kh value. Also, our DFIT program has the ability to investigate the factors that affect DFIT data and interpretation including interaction with natural fractures, heterogeneous rock properties, variable storage.

The results of the developed DFIT model after applying on actual field cases are classifying the characterizations of ultra-low permeability unconventional reservoir (such as reservoir pressure, reservoir permeability, mobility, and transmissibility, fracture half-length and flow regime before and after closure...etc.). The key parameters will be used to design the proper hydraulic fracture stimulation. The novel of this paper is how to classify the characterizations of ultra-low permeability unconventional reservoir using new methodology, evaluate shale and tight wells productivity.

Introduction

Unconventional reservoirs became an important worldwide resource which identified by lower permeability (less than 0.1 md) and couldn't be produced at economic flow rates without stimulation. Unlike the conventional resources which contain small volumes of hydrocarbon and easy to produce. Up to date, there isn't available method used to evaluate unconventional reservoirs. Recently, the field development for unconventional reservoir is dependent on economics which rely on

completions and effective contact with the hydrocarbon. Well and completions design parameters play an effective role on the economic success of field development which include well orientation, perforation, no of stage, cluster spacing, fluid volume viscosity, pumping rate.... etc. The main goal is built a new tool to evaluate unconventional reservoir and how to determine the reservoir properties.

Mini-Frac tests can be used to estimate hydraulic fracturing parameters and gain a valuable reservoir pressure data. Different methods can be used to analyze the pressure fall-off data fore before closure analysis (BCA) and after closure analysis (ACA).

BCA technique was first introduced by Nolte (1979) based on the Carter leak-off (1957) to determine the closure pressure. The time function "G-time" was an additional product for his work. Barree and Mukherjee (1996) provided the G function derivative plots that included the G dp/dG plot. This workflow was used in generating the closure pressure. 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:

$$g_0(\Delta t_D) = (1 + \Delta t_D) \sin^{-1}(1 + \Delta t_D)^{-\frac{1}{2}} + \Delta t_D^{-\frac{1}{2}} \text{ for } \propto = \frac{1}{2}$$
 "Low fluid effeciency" 3

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

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

- 1) Log-Log of pressure and derivative Bourdet 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:

- 0.5 slope, Fracture Linear flow
- 3/2 or Unit Slope, defining the Before closure region;
- 0.5 slope, formation Linear flow from the $\frac{1}{2}$ 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.

Volume 24, Issue 8, August - 2022

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.

Methodology

The work flow begins with building a new DFIT program as shown in Figure 1 by:

- Gathering function time (G-function, F-function, square root time and log log) modeling and other models applied for before and after closure.
- Determining the required input data to build the model.
- Proposing an algorithm for the DFIT model structure.
- Programming the required model then developing it by:
 - Modifying G-Function equation to apply for radial flow directly.
 - Applying the developed model for different regime to optimize different parameters (ISIP, PC, ...etc.) in order to estimate the reservoir and rock properties accurately.
 - Predicting and optimizing the well performance, productivity index and EUR.





Figure 1: Flow chart shows the work flow of the developed model

Effect of Reservoir Complexity on DFIT Analysis

In some cases, multiple closures may be observed due to the complexity of the natural fractures. Often time, this leak-off behavior is referred to pressure dependent leak-off. This type of leak-off is considered as a dual-porosity model that assumed the permeability and porosity of natural fractures are different from matrix porosity and permeability.

In many field cases, it is observed that the 3/2 slope trendline may be disappeared and appeared a unit slope trendline directly or the 3/2 slope trendline may be appeared after a unit slope trendline behavior. The unique behavior "unit slope" gives an indication of the composite flow behavior before closure that is observed in Bourdet plot. The before-closure composite flow is attributed to enhanced leak-off due to the opening of existing natural fractures and connecting to the hydraulic fractures, resulting in a larger total fracture surface area. The composite flow regime occurs when the matrix to fracture permeability ratio is greater than or equal to 10. Warpinski (1991) interpreted this behavior for before closure setting as a pressure dependent leak-off.

Consequently, the G-function method doesn't work in such cases with its exponents (3/2, for high fluid efficiency, Eq. 4) which is applied for linear flow and incompressible fluid.

Well-A_Case_1

A real case shows the effect of reservoir complexity on the defining reservoir properties. Figure 2 shows trends of the pressure and injection rate from DFIT test for well-A which is completed in shale reservoir. The pressure rises linearly until reaches to the initial break down at 11,336 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.



Figure 2: Injection rate and pressure trends for Case_1, Well-A

The unit slope behavior is observed instead of 3/2 slope behavior which is considered an indication of reservoir complexity. The unit slope can be interpreted as fracture closing. The fracture closure is picked at the deviation from the unit slope as shown in Figure 3. After identifying the flow regime and fracture closure, a G-function plot is used to confirm the closure pressure.



Figure 3: Log -log plot_ Case_1, Well-A

The G-function plot shows Pressure Dependent Leak-off behavior (PDL) which is characterized by a hump signature above 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 4. The fracture closure occurs at closure pressure and G-time is 5308 psi and 3.58 hrs. respectively.



Figure 4: G-Function plot Case_1, Well-A

Novel Iterative G-Function Exponent Determination Approach

According to the new approach used to determine the new exponent of G-Function that is used in complex reservoirs, the new exponent of G-function is close to one which gives the same slope of pressure derivative using Bourdet method (Figure 3).

The new exponent can be verified by examining the semi-log derivative of G-Function. The semi-log derivative should be appeared as a hump above the straight line extrapolated to the derivative origin, then a direct straight-line matched to the tangent. The following steps give the correct exponent which is matched with Bourdet method slopes, 3/2 slope gives G-function exponent "3/2" and unit slope gives G-function exponent close to one "0.9894":

- 1. Start with initial guess for G-function exponent as an input e.g., 3/2.
- 2. This value is used to construct the semi-log derivative plot.
- 3. Check hump curve, if yes, select the start point of straight-line.
- 4. If the slope is close to one (≤ 1.05 and ≥ 0.97 "), continue to choose closure.
- 5. If the slope out of constraints, go to step 1.

After using the new approach, the closure pressure is 5350 psi and closure G-time is 3.32 hrs. The leakoff type is confirmed as a strong PDL using the new exponents shown in Figure 5.



Figure 5: G-Function plot_Case_1, Well-A using new approach

Figure 6 shows the Δp vs. the square of the linear flow time function, the pseudo-radial flow regime is identified properly. Figure 7 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 reservoir pressure estimate of 3230 psi. Using the slope of the straight line, fluid viscosity of 0.3 cp, and the fracture height of 25 ft, the reservoir permeability can be calculated as 0.003 md.



Figure 6: Log-Log ACA plot _ Case_1, Well-A



Figure 7: Radial Flow Time Function_Case_1, Well-A

Summary

DFITs can provide important information that helps in designing hydraulic fracture treatments and characterization of different reservoirs. The developed DFIT program can be used to improve the analysis of actual fall-off data. The developed model can be used to analyze the complex reservoir which gives unit slope before closure instead of 3/2 slope. Consequently, it can be used in most reservoir cases that the G-function couldn't work in by estimating a new G-Function exponent using the new iteration approach. The reservoir results of actual cases are matched with the real actual reservoir data.

Acknowledgements

I would like to thank my supervisors for their aid in conducting this study. Specifically, I would like to thank Dr. Mazher for his advice and support.

References

- Barree, R., and H. Mukherjee, 1996, Determination of pressure dependent leakoff and its effect on fracture geometry: SPE Annual Technical Conference and Exhibition.
- Bourdet, D., J. Ayoub, and Y. Pirard, 1989, Use of pressure derivative in well test interpretation: SPE Formation Evaluation, v. 4, p. 293–302.
- Carter, R., 1957, Derivation of the general equation for estimating the extent of the fractured area: Appendix I of "Optimum Fluid Characteristics for Fracture Extension", Drilling and Production Practice, GC Howard and CR Fast, New York, New York, USA, American Petroleum Institute, p. 261–269.
- Marongiu-Porcu, M, Ehlig-Economides, C.A., and Economides, M.J., 2011. Global model for fracture falloff analysis. Paper SPE 144028 presented at the North American unconventional gas conference and exhibition, The Woodlands, Texas USA, 14-16 June.
- Mohamed, I.M., Nasralla, R.A., Sayed, M.A., Marongiu-Porcu, M., and Ehlig-Economides, C.A. 2011. Evaluation of after closure analysis techniques for tight and shale gas formations. Paper SPE 140136 presented at the hydraulic fracturing technology conference and exhibition, The Woodlands, Texas, USA, 24-26 January.
- Mohamed, I. Mohamed S., Mazher I., 2019. Investigation of Non-Ideal Diagnostic Fracture Injection Tests Behavior in Unconventional Reservoirs. Paper SPE 194332 presented at Hydraulic Fracturing Technology Conference and Exhibition held in The Woodlands, Texas, USA, 5-7 February.
- M. Ibrahim: "Development of New Well Index Equation for Fracture Wells," SPE paper SPE 164017-MS presented at 2013 SPE Middle East Unconventional Gas Conference and Exhibition held in Muscat, Oman, 28–30 January 2013

 Nolte, K. G., 1979. Determination of Fracture Properties from Fracturing Pressure Decline. Presented at the 54th SPE Annual Technical Conference and Exhibition, Las Vegas, Nevada, 23-26 September, SPE-8341-MS.