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A complementary approach for uncertainty reduction in post-flowback production data analysis

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ABSTRACT

A key limitation of conventional post-flowback production data analysis is non-uniqueness of solution. This causes uncertainty in reservoir parameter estimates and hydrocarbon forecasts. This paper proposes a complementary approach, using flowback data analysis to constrain post-flowback data analysis and reduce uncertainty in output results.

This study history-matches two-phase pressure and rate data from seven multifractured Horn River shale-gas wells to investigate the benefits of analysing both flowback and post-flowback data together. The flowback history-match result estimates the pore-volume of active fracture networks, effective half-lengths and initial gas volume in hydraulic fractures during flowback. Also, the field production forecasts from the flowback history-match yield lower gas rates compared to actual post-flowback production data. On the other hand, the post-flowback history-match results overestimate effective half-lengths when compared to flowback history-match results. These observations are due to neglecting the secondary fracture and gas desorption effects on the dual-porosity based flowback model used in this study. The communication interface between secondary fractures and hydraulic fractures significantly increases during post-flowback periods (when most of the water in the active secondary fractures have been displaced by gas influx from the matrix and matrix pressure drops below the critical desorption pressure). Therefore, post-flowback analysis should properly couple flowback history, and account for secondary fracture and gas desorption effects to yield reasonable results.

This paper shows how to perform a complementary flowback and post-flowback data analysis for comprehensive fracture/reservoir characterization. This complementary approach provides engineers with a tool to estimate fracture parameters (such as half length) from flowback analysis and use them as inputs for post-flowback analysis. Although a dual-porosity framework is sufficient for flowback data analysis, proper post-flowback analysis should account for both secondary fracture effects (using a triple-porosity framework) and gas desorption effects.

1. Introduction

Tight reservoirs are formations with very-low permeability. Hence they require a process like hydraulic fracturing to produce economic amounts of oil and gas. Multistage hydraulic fracturing (King, 2012; Cheng, 2012) involves injecting millions of gallons of fracturing fluid (a mixture of $\geq$ 90% water, proppants and chemical additives) through horizontal wells to create multiple fractures. These fractures significantly increase the contact area between the wells and tight reservoirs.

After hydraulic fracturing, a large portion of the fracturing fluid remains in the created fractures. To ensure optimal flow rates from the stimulated well, the water plugging the created fractures needs to be recovered before putting the well on a long-term hydrocarbon production (Crafton and Gunderson, 2007). This is achieved through flowback operations. Flowback is a short process where water (+some oil/gas) in the fractures are allowed to flow to the surface. The duration of this process varies from well to well, depending on the reservoir and operational challenges. Although, the flow rate and pressure of the fluids recovered during flowback are recorded, they are usually of poor quality and typically discarded. However, the industry in recent times have realised that flowback provides the earliest opportunity to characterize both fracture and reservoir. This has prompted improvements in the

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quality and frequency of flowback data measurement. Nevertheless, reliable data recording still faces some practical challenges like quality control, inter-well communication and flowback management. Although flowback is a multiphase process, most existing flowback models (Crafton, 1997, 1998; Clarkson, 2012; Abbasi, 2013; Abbasi et al., 2014) either assume single phase flow or do not properly account for the rapid fluid saturation changes in the hydraulic fractures (HF). These effects and other fluid physics are now accounted for in newer models such as Ezulike and Dehghanpour (2014b). However, the frequent well shut-in periods due to operational challenges (e.g. erosion of chokes and valves) still need to be accounted for in all flowback models for a reliable post-flowback production forecast.

After flowback, the water saturation in the HF becomes minimal such that the stimulated well is ready to be put on production. Although the recovered fluid is mainly gas/oil during post-flowback production, flow from the well is usually multiphase. However, most of the analytic models available for conventional production data analysis (PDA) are single phase. Examples of such models include the (1) radial dual-porosity models (Carlson and Mercer, 1991), (2) linear dual-porosity models (El-Banbi, 1998; Bello, 2009), (3) radial triple-porosity models (Ozkan et al., 2010; Dehghanpour and Shirdel, 2011), (4) linear triple-porosity models (Al-Ahmadi, 2010; Al-Ahmadi and Wattenbarger, 2011; Ali et al., 2013), (5) trilinear flow model (Brown et al., 2011) and (6) quadrilinear flow model (Ezulike and Dehghanpour, 2014a).

One key challenge facing conventional PDA is non-uniqueness of solution. This causes uncertainty in reservoir parameter estimates and hydrocarbon forecasts. Also, the fact that production data is generally multiphase (Alkouh et al., 2013; Alkouh and Wattenbarger, 2013) violates the key assumption of single-phase (Fig. 1a) in most PDA models. Hence, there is a need for an alternative analysis approach.

This paper proposes an integrated approach which reduces the uncertainty in reservoir parameter estimates and hydrocarbon forecast. This approach uses flowback data analysis (FDA) as a constraint to guide the conventional PDA. This study has three main parts; independent flowback data analysis, independent psot-flowback data analysis and complementary flowback and post-flowback data analysis.

2. Methodology

The models used to investigate the benefits of analysing both flowback and post-flowback data together are the linear dual-porosity model (DPM, Bello (2009)) and the flowback analysis model (FAM, Ezulike and Dehghanpour (2014c)). These models use the linear dual-porosity static framework shown in Fig. 2. DPM is a single-phase dual-porosity model which accounts for reservoir depletion from both matrix and hydraulic fractures under the assumption of negligible secondary fracture effects. FAM is a model which extends the existing single-phase DPM by incorporating a dynamic relative permeability function (an explicit relationship between relative-permeability and time which captures the rapidly changing fluid-phase saturations in hydraulic fractures) into its static model framework. Details of the implementation of DPM and FAM are provided in the results section of this work.

The dimensionless wellbore pressure equation for FAM in Laplace space under variable rate inner boundary conditions is given in Eq. (1) (Ezulike and Dehghanpour, 2014c). Eq. (1) simplifies to the dimensionless wellbore pressure equation for DPM when $\beta_2 = 1$ and $\beta_3 = 0$ for $0 \le t_{D_{AC}} \le t_{D_{AC}inf}$, and $\beta_1 = 1$ and $\beta_2 = 0$ for $t_{D_{AC}} > t_{D_{AC}inf}$.

$$\overline{P}_{wDL} = \frac{f^*(s)}{\sqrt{f(s)}}\left\{\coth\left(\sqrt{f(s)}y_{De}\right) + I_D\sqrt{f(s)}\right\} \tag{1}$$

$$\text{where } I_D = \frac{r_w}{\sqrt{A_{cw}}}I \tag{2}$$

$$\text{and } f(s) = \begin{cases} \dfrac{1}{\beta_2}\left[\omega_F(s+\beta_3^*) + \dfrac{\lambda_{AC,Fm}}{3}\sqrt{f_m(s+\beta_3^*)}\tanh\left(\sqrt{f_m(s+\beta_3^*)}\right)\right] & 0 \le t_{D_{AC}} \le t_{D_{AC}inf} \\ \dfrac{1}{\beta_1}\left(\omega_F[s+\beta_2(s+\beta_3^{**})] + \dfrac{\lambda_{AC,Fm}}{3}\left[\sqrt{f_m(s)}\tanh\left(\sqrt{f_m(s)}\right) + \beta_2\sqrt{f_m(s+\beta_3^{**})}\tanh\left(\sqrt{f_m(s+\beta_3^{**})}\right)\right]\right) & t_{D_{AC}} > t_{D_{AC}inf} \end{cases} \tag{3}$$

$$\text{and } f^*(s) = \begin{cases} \dfrac{1}{\beta_2}\left[\dfrac{1}{(s+\beta_3^*)}\right] & 0 \le t_{D_{AC}} \le t_{D_{AC}inf} \\ \dfrac{1}{\beta_1}\left[\dfrac{1}{s} + \dfrac{\beta_2}{(s+\beta_3^{**})}\right] & t_{D_{AC}} > t_{D_{AC}inf} \end{cases} \tag{4}$$

$$\text{and } f_m(s) = \frac{3s\omega_m}{\lambda_{AC,Fm}} \tag{5}$$

This study is done under three key steps (Fig. 3). Step 1 handles data processing, Step 2 involves independent flowback and post-flowback data analyses and Step 3 deals with constrained post-flowback data analysis.

Step 1 entails gathering and preparing quality controlled flowback and post-flowback production data from the same wells for analyses. This is achieved by ensuring that there are no spurious discontinuities between the trends of fluid flow rates and cumulative production data recorded during flowback and post-flowback production periods.

Step 2 starts with an independent flowback data analysis using FAM (Ezulike and Dehghanpour, 2014c) to history-match flowback data from Step 1, estimate key fracture parameters (e.g. effective half-length and pore volume of interconnected fracture networks) and forecast hydrocarbon production. It continues with an independent production data analysis using DPM (Bello, 2009) to history-match post-flowback data from Step 1. Finally, it ends with a comparison of the results from independent flowback and post-flowback data analyses.

Step 3 involves a flowback-guided production data analysis. It tests the accuracy of FAM to predict post-flowback gas production in the field by comparing the hydrocarbon forecast from FDA in step 2 against field production data. The results of this accuracy test would make a case for combining both flowback and post-flowback