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Containing data noise in unconventional-reservoir-performance forecasting

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ABSTRACT

Many decline-curve analysis methods have emerged for forecasting the future performance of unconventional reservoirs. However, severe noise in field data, coupled with the low-frequency rate in monitoring/reporting and the unknown behavior of many completion and reservoir parameters, collectively present serious challenges in obtaining correct model parameters in many settings.

To address the complexity of this multitude of issues, performance forecasting is approached in two steps. First, we attempt to circumvent the data noise and frequency issues with a global cumulative production profile for a group of wells exhibiting similar performance characters, leading to the estimation of global model parameters. Second, we compare error trends amongst all methods for a basis of selecting well groups. Finally, a simple rule-of-thumb is developed to get an estimate of the allowable time for extrapolating performance prediction within 10% error.

1. Introduction

Many forecasting tools have been proposed over the last few years for the shale plays where micro- to nano-darcy formations govern fluid flow. These tools can be grouped in two areas. One approach involves the use of type curves generated from the simplified analytical or numerical models. This approach demands many assumptions including uniform reservoir properties, identical performance of induced fractures over life span, infinitely conductive wellbores, among others. Some of the studies belonging to this category include those of Clarkson and Pedersen (2010), Nobakht et al. (2012), among others. This approach although theoretically elegant demands the knowledge of flowing-bottomhole pressure to normalize the rate. Because wells in shale reservoirs are rarely instrumented downhole, reliable pressure data from oil wells poses a practical challenge after the installation of an artificial-lift system. In this context, the wellhead pressures monitored in gas and gas-condensate wells lend themselves for relatively easy downhole conversion.

The second approach involves the use of empirical or semi-analytical methods. Methods proposed by Ilk et al. (2008, 2010), Valko (2009), Duong (2011), Kabir and Lake (2011), and Clark et al. (2011) offer modern analysis tools for long-term performance forecasting. Because the production history has been relatively short in unconventional assets, the maximum being about ten years in the Barnett shale, the absolute accuracy of these tools is open to debate. However, that the Arps (1956) method provides optimistic solutions in all cases has been demonstrated by many studies.

Published production data from the shale plays that are available in the public domain are typically associated with monthly frequency. These data are used frequently by various investigators for testing many predictive tools. Among many pursuing data-driven discovery, the seminal studies of Valko (2009) and Valko and Lee (2010) are worthy of note. However, questions arise whether all data are amenable to simple fitting, or do they require prior treatment before any such fitting is attempted. This point is worthy of considerations because both data noise and frequency of reported data may skew the outcome of fitting and the consequent solutions. Of course, the rate-decline model used has a significant impact on the solutions so generated.

As noted by Mohagheh (2013), most numerical modeling studies in shale reservoirs pertain to single-well scenario, presumably because of the complexity in well completions demanding large number of grid cells. Accordingly, Mohagheh (2013) proposed data-driven empirical methods for handling large number of wells in a shale play. Citing many of his field studies, encouraging results were reported at both the asset and individual-well level. As expected, this empirical approach is unsuitable for explaining storage and transport processes in the shale, and that robustness of long-term predictions are not assured.

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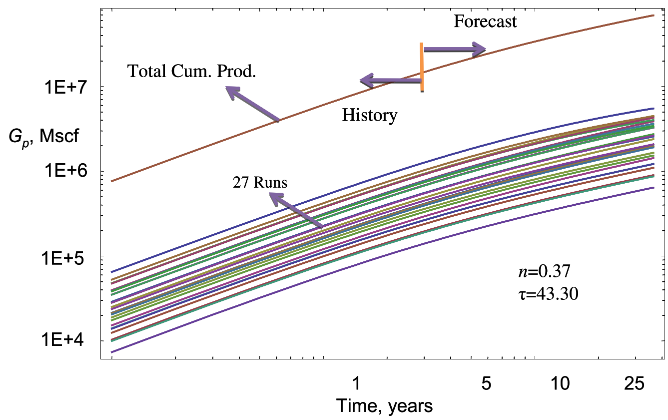

Fig. 1. Cumulative production history for the 27 simulated cases.

This study explores the merit of handling a large number of wells using some of the leading-edge empirical tools. In this context, the data smoothing question is handled by working with the cumulative production curve for a group of wells, along with the noisy rate–time curves. To this end, we considered four different models. These included the stretched-exponential decline model or SEDM (Valko, 2009), logistic model (Clark et al., 2011), long-term linear-flow (LTLF) model (Duong, 2011), and Arps (1956). The Arps model is included for the sake of comparison. We also considered the two-tank model (Shahamat and Aguilera, 2010) and its extension to three-tank formulation, and the capacitance-resistance model (CRM) at early stage of this investigation. We recognize the need for bottomhole-flowing pressure corresponding to rate data for a holistic analysis, such as the one shown by Kabir et al. (2011). However, the public data bases are generally devoid of such information. Therefore, this study is confined to traditional decline-curve analysis with modern tools.

2. Methodology and case studies

Besides the usual noise associated with any production data, installation of artificial-lift, lowering of wellhead pressures, and restimulation often introduce a step change in the production trend, prompting reassessment of decline profile. Although daily production rates are highly desired from the standpoint of frequency, the attendant noise presents another challenge. We present a methodology that circumvents much of the noise, regardless of the source. By grouping wells, preferably with similar formation and completion characteristics, one can significantly dampen noise by treating production with integrated cumulative curves. This treatment allows generation of model parameters for the grouped wells, thereby paving the way for forecasting.

We adopted a pragmatic approach to group existing wells in accord with initial rates because often times the flowing-bottomhole pressures of wells are unavailable, thereby preventing estimation of productivity index. Ideally, the objective of well grouping is to obtain common model parameters for similar wells in terms of productivity index. Instead of calculating one global set of model parameters, assigning individual parameter sets to groups provides the opportunity to reduce uncertainty of model parameters and leads to smaller errors in forecasting. This approach has been shown to work well in the context of probabilistic performance forecasting (Can and Kabir, 2012).

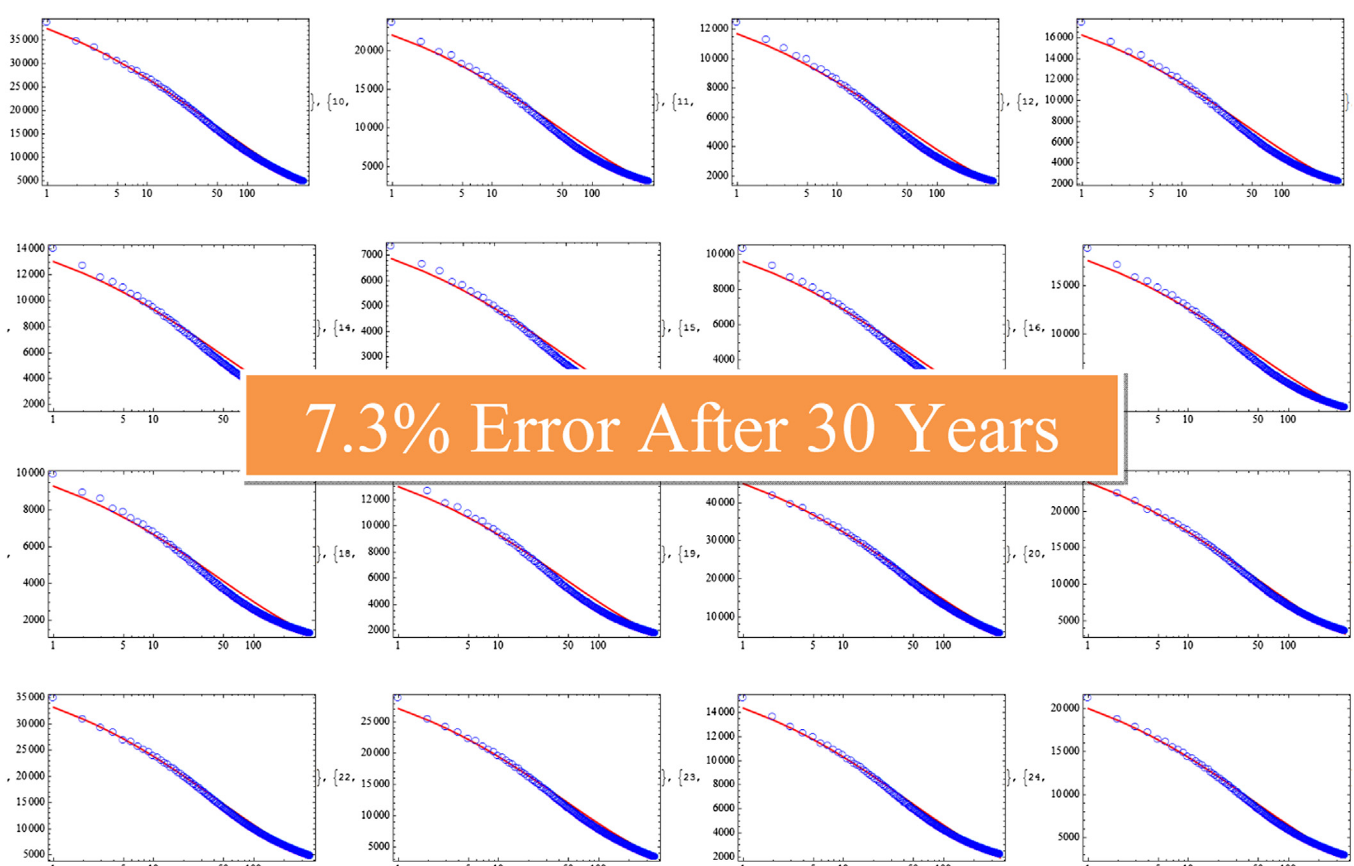

Fig. 2. Robust rate forecasting for the 27 simulated cases with global model parameters.