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Improved characterization and performance prediction of shale gas wells by integrating stimulated reservoir volume and dynamic production data

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ABSTRACT

Gas flow in shale gas reservoirs occurs primarily from ultra low permeability shale rocks through a complex network of natural and induced hydraulic fractures. Consequently, fracture parameters (conductivity and half length), fracture location and distribution are the dominant factors influencing well drainage volumes and shale gas well performance. Stimulated reservoir volume or SRV, estimated from microseismic event clouds or rate/pressure transient analysis, describes a measurement of overall reservoir volume impacted by fracture treatments. With SRV as well as the dynamic production/pressure response, reservoir simulation models can be calibrated to actual well performance in shale gas reservoirs leading to improved understanding, forecasting and future well placement.

In this paper, we first introduce a novel approach for computing well drainage volume for shale gas wells with multistage fractures and fracture clusters. Next, we calibrate the shale gas reservoir model by matching the drainage volume with the SRV within specified confidence limits. The matching of the SRV is done in addition to the traditional history matching of production/pressure response and further constrains the estimation of fracture parameters. An evolutionary algorithm with design of experiments is used for the assisted history matching. Sensitivities to various parameters such as fracture conductivity, fracture half lengths and rock compaction have also been investigated. The proposed approach has been applied to a generic shale gas well designed after a real field case. The results clearly indicate the benefits of including SRV during history matching, leading to improved fracture/matrix parameter estimation and performance forecasting. Our proposed approach provides an important tool that can be used to optimize well placement, fracture treatments and improve the economics of shale gas plays.

Introduction

The rise in the demand of natural gas globally and the application of more sophisticated production technologies in particular, the creation of multiple hydraulic fractures from horizontal wells (Cramer, 2008; Britt and Smith, 2009; King, 2010) have motivated energy companies to increasingly develop harder-to-access natural gas resources such as tight sands, shale gas and coal bed methane. These unconventional reservoirs with ultra-low permeabilities are known to be more abundant throughout the world and are likely to be the dominant suppliers of future natural gas production (Holditch, 2006).

Fluid flow in tight sand and shale gas reservoirs can be analyzed through numerical simulations of the pressure response and saturation distributions just as for conventional reservoirs. Because of the extremely low matrix permeabilities, much of the fluid movement in shale gas and tight gas reservoirs happen in the interconnected networks of natural fractures. The matrix provides the storage for the gas whereas the fractures are the primary flow conduits. Proper modeling of the orientation, distribution and connectivity of the natural fractures is critical to reservoir simulation and forecasting (Olson, 2008; Cipolla et al., 2009). In particular, the understanding of the interaction between induced hydraulic fractures and naturally existing fractures is an important key in the successful development and exploitation of these reservoirs (Lee and Hopkins, 1994; Cipolla et al., 2011; Weng et al., 2011). Planning an effective field development

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Nomenclature

$\mathbf{m}_i$	a genome of model parameters
T_n	temperature in heat-bath algorithm for generation n
α	diffusivity coefficient, md psi/cp
τ	arrival time of the pressure 'front' or diffusive time of flight, day
Δp	bottom-hole pressure misfit between observed and simulated well responses, psi
ΔV	drainage volume misfit between observed SRV and volume enclosed by pressure front, ft^3
k	permeability, md
ϕ	porosity
μ	viscosity, cp
c_t	reservoir total compressibility, 1/psi
k_M	matrix permeability, md
k_E	enhanced area permeability, md
k_F	fracture permeability, md
C_M	matrix permeability compaction factor, 1/psi
C_E	enhanced area permeability compaction factor, 1/psi
C_F	fracture permeability compaction factor, 1/psi
X_F	half axis of elliptical fracture, ft
BHP	bottom-hole pressure, psi
EUR	estimated ultimate recovery
EPA	enhanced permeability area
DV	drainage Volume, ft^3
FMM	fast marching method
SRV	stimulated reservoir volume, ft^3
GA	genetic algorithm
RSM	response surface methodology
DOE	design of experiments

strategy requires estimating the drainage capacity of current wells and optimizing well placement so as to minimize the overlapping of drainage volumes of existing wells. Production decline curves have been widely used to compute drainage volumes and estimate ultimate recoveries (EUR) in tight gas reservoirs (Fetkovich, 1980; Cox et al., 1996; Blasingame and Rushing, 2005; Rushing et al., 2008). Also, pressure transient tests are commonly used in determining the well productivity and the benefits of hydraulic fracturing in tight gas reservoirs (Lee and Hopkins, 1994). Whereas both decline curve analysis and pressure transient tests have played a vital role in the exploitation of tight gas reservoirs, the interpretation of such analytical tools can be considerably complicated in the presence of complex spatial heterogeneity and natural fractures. In particular, the interactions between the hydraulic fracture and natural fractures and their implications on well drainage volumes cannot be adequately accounted for by existing analytic methods. We need to resort to numerical reservoir simulation for these purposes. However, such simulations can be severely limited because of the uncertainty in matrix and fracture parameters.

One of the most common and effective ways to develop and exploit unconventional reservoirs, in particular shale gas reservoirs is horizontal wells with multistage fractures. In fact, improvements in hydraulic fracturing and completion technologies have been the primary driving force behind the economic recovery of shale gas resources. However, in a typical application to develop tight or shale gas reservoirs, the cost of completing a horizontal well can be about half (or sometimes more) of the total well cost. Hence, there is a tremendous need to improve our understanding of the effectiveness of the completion strategy so as to optimize the number of hydraulic fracture stages needed to drain the gas-in-place. In many shale gas reservoirs, natural fractures are healed by calcite cementation (Fan et al., 2010). Hydraulic fracturing with proppant and water will not only create high conductivity primary hydraulic fractures but also stimulate and/or reopen natural fractures in the vicinity of hydraulic fractures. This will ultimately generate a complex fracture network or stimulated reservoir volume (SRV) surrounding each stage of primary hydraulic fracture. The growth and final pattern of SRV, which depends on rock properties and fracturing, are typically complex and unpredictable. Though recently microseismic mapping has been widely used to measure the geometry and location of complex fracture systems (Fisher et al., 2002; Mayerhofer et al., 2010), it does not provide insights into the conductivity of the fracture network or the "effective" drainage volume/area of the stimulated region, mainly due to lack of sufficient data to locate proppant distribution and conductivity distribution in the fracture network. More recently, the use of rate normalized pressure data (Bello and Wattenbarger, 2010; Song and Ehlig-Economides, 2011) have been proposed to obtain estimates of SRV that actually contribute to the flow.

Numerous efforts have been undertaken to optimize hydraulic fracture stages in the past. These have involved a combination of numerical simulation and analytical computations using rate and pressure transient analysis. An important aspect of any simulation study is model calibration, also known as history matching. Previous works related to history matching in shale gas reservoirs has been done by adjusting primarily fracture parameters namely fracture length, fracture density, and fracture conductivity. History matching applications for both the Barnett shale (Mayerhofer et al., 2006; Cipolla et al., 2009) and the Haynesville shale (Wang and Liu, 2011) have involved integration of flowing bottom-hole pressure or phase rates to infer fracture parameters in a manual and deterministic manner. Such deterministic approaches lead to a single set of fracture parameters of unknown reliability. Specifically, no quantification of uncertainty in fracture parameters is available from these deterministic approaches. Stochastic approaches such as genetic or evolutionary algorithms and Ensemble Kalman Filters result in an ensemble of history matched models. By careful analysis of multiple history matched models, we can obtain a sense of non-uniqueness and uncertainty in fracture parameters derived through history matching. Whereas the use of stochastic methods in history matching is now very routine for conventional reservoirs, their applications to unconventional reservoirs have been very few and far between (Ghods and Zhang, 2010; Mohaghegh et al., 2011).

The objectives of this paper are threefolds. First, we draw upon the recent developments in history matching in conventional reservoirs to develop a workflow for calibrating shale gas reservoir models to infer fracture and matrix parameters. Second, we propose a novel approach to estimating well drainage volumes in shale gas reservoirs. Third, we use the drainage volume to calibrate reservoir models with SRV information derived from microseismic or rate/pressure transient analysis. The use of SRV in addition to the production and pressure data provides an additional degree of constraint during history matching and is thus expected to improve estimates of matrix/fracture parameters and reduce associated uncertainties.

2. Methodology

Our goal here is to calibrate static parameters such as fracture conductivity, fracture half length, matrix permeability and geomechanical/compaction parameters in order to match the dynamic