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Reservoir and fluid characterization of a tight gas condensate well in the Montney Formation using recombination of separator samples and black oil history matching

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A B S T R A C T

Liquid-rich shale (LRS) reservoirs are economically attractive but operationally challenging particularly for cases where multi-phase flow occurs within the reservoir. Proper treatment of PVT and rock properties, as well as rock-fluid interaction, in these unconventional reservoirs is central to providing improved short- and long-term oil and gas production forecasts. In the presence of limited surface sampling, the available analytical models often do not provide satisfactory results due to the uncertainty in the initial *in-situ* fluid system. In such situations, and particularly when there are many unknown parameters, numerical models are ideally suited, using a history matching framework, to assist with reservoir and fluid characterization.

In this paper, production data from a multi-fractured horizontal well completed in a tight gas condensate reservoir in the Montney Formation in western Alberta, Canada is presented and analyzed using black oil numerical simulation. An assisted history-matching routine (i.e. Differential Evolution (DE) algorithm) is used in combination with black oil numerical simulations to characterize reservoir fluids and estimate reservoir and hydraulic fracture properties. The applicability of black oil numerical simulation for accurate prediction of the fluid model and well performance using numerous compositional numerical simulations and various fluid systems is first verified. The *in-situ* fluid is assumed to be a mixture of recombined separator samples with unknown oil-gas recombination ratio. The effect of time of sampling on the produced well stream composition is considered.

Our results show that recombined separator sample mixtures collected early on during production of wells subjected to limited drawdown can successfully represent reservoir fluid properties with the exception of saturation pressure. In other words, the reservoir fluid PVT behavior can be predicted by recombination of an early initial separator fluid sample only by varying the saturation pressure. Hence, the assisted history matching can be performed using black oil numerical simulations with a reduced number of unknowns for the fluid system. The well/reservoir properties and unknown reservoir fluid are characterized in terms of a 12-parameter system. The history-matched results using DE could satisfactorily reproduce the water and hydrocarbon surface flow rates, and flowing bottomhole pressure curves. The quality of results are comparable to those obtained previously (Hamdi et al., 2015) using a fully-compositional numerical model.

The new workflow using assisted history-matching combined with black oil simulation provides a practical yet accurate method for characterizing fluid, reservoir and fracture properties in unconventional gas condensate systems.

1. Introduction

Production data analysis is one of the key tools used for understanding reservoir behavior of unconventional shale and tight formations. Production analysis can be performed using analytical, semi-analytical, empirical and numerical simulation approaches. Numerical simulation approaches are advantageous because they are less restrictive and can include more physics than other methods for

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production analysis (Kalantari Dahaghi et al., 2012). They are better suited for modeling the complex storage/flow behavior often encountered in unconventional reservoirs (i.e. adsorption/desorption, non-Darcy flow, multi-phase flow, reservoir heterogeneities, stress-dependent porosity and permeability and complex fracture network) and can be used to perform realistic sensitivity analysis and parametric study. Traditionally, numerical history matching of tight/shale reservoirs has utilized deterministic approaches for adjusting fracture network properties for prediction of reservoir behavior (Mayerhofer et al., 2006; Cipolla et al., 2009; Bazan et al., 2010). Although assisted history matching techniques are commonly applied to conventional reservoirs, such approaches are less frequently used for unconventional reservoirs. There are a few exceptions, such as the application of Artificial Intelligence and the Ensemble Kalman Filter methods, which have been successfully implemented by some researchers to investigate the impact of rock and fracture uncertainties on the production forecasts (Enyioha and Ertekin, 2014; Ghods and Zhang, 2010; Nejadi et al., 2014).

In tight reservoirs, developing an *in-situ* fluid model from production data is problematic because fluid production at the surface cannot be confidently recombined for this purpose (Whitson and Sunjerga, 2012). The produced fluids are affected not only by the *in-situ* fluid composition, but also by hydraulic fracture and reservoir properties. The impact of hydraulic fracture and reservoir permeability is discussed by Behmanesh et al. (2015b) for volatile oil fluid system and in Behmanesh (2016) for gas condensate fluid system. Hamdi et al. (2015) applied an assisted history-matching approach, combined with compositional numerical simulation, to extract reservoir, hydraulic fracture and *in-situ* fluid properties from a multi-fractured tight gas condensate well in the Montney Formation. Using their workflow, the authors obtained an excellent match of fluid rates and pressures and a reasonable match of separator oil and gas compositions. To achieve this, an equation of state model was tuned to allow matching of surface fluid compositions at a selected production time (i.e. time of sampling). From the twenty parameters that were selected to represent the uncertainty in water saturation, rock and fluid properties, eleven parameters were assigned by Hamdi et al. (2015) to describe the fluid model. Adding extra dimensions to assisted history matching problems in some cases can hinder the convergence to the solution.

In this work, the same well as analyzed by Hamdi et al. (2015), but using a different approach for handling the multi-phase flow problem is presented. In order to reduce the complexity of the problem (i.e. nonlinearity and high dimensionality) solved by Hamdi et al. (2015), a similar history matching routine with a reduced set of parameters is made possible by the use of faster black-oil numerical simulations. In the current work, the *in-situ* fluid model is assumed to be a mixture of recombined separator samples with an unknown oil-gas recombination ratio. This simplification can help reduce the dimensionality of the fluid model to only one uncertain parameter (i.e. saturation pressure) and hence allows for history matching with a reduced number of descriptive input parameters. Previous work (Whitson and Sunjerga, 2012) has demonstrated the difficulty of properly representing the *in-situ* reservoir fluid through recombination of separator samples for liquid-rich shales (LRS) producing with large drawdowns. The recommended guidelines provided in this work propose a solution to tackle this problem.

The paper is organized as follows: in the next section, recommended strategies for separator sampling from liquid-rich shale reservoirs are discussed. In the "History Matching Procedure" section, the implementation of the Differential Evolution (DE) algorithm within a black-oil numerical simulation framework is outlined.

2. Recombination Strategy in Liquid Rich Shale Reservoirs

For multi-fractured horizontal wells producing from liquid-rich shale reservoirs, recombining the separator gas and the separator oil, or direct sampling from openhole formation tester may not ensure producing a consistent *in-situ* reservoir fluid (Whitson and Sunjerga, 2012). The producing OGR rapidly drops as the flowing bottomhole pressure decreases below the saturation pressure. To obtain a

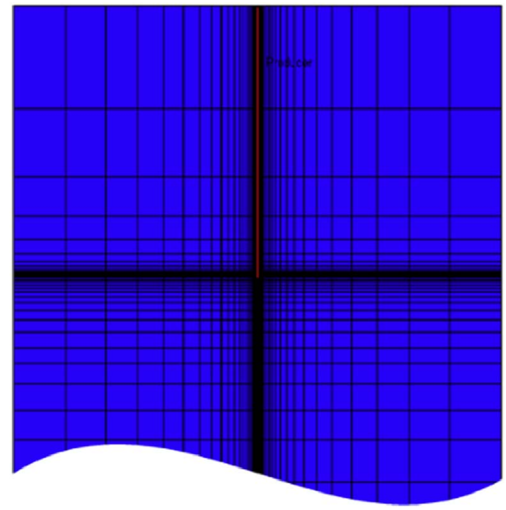

Fig. 1. Schematics of 2D planar model used for modeling a single hydraulic fracture in tight or shale gas reservoirs.

Table 1
Simulation model properties.

Property	Value	Unit
Matrix Permeability, k	1.0E-3	md
Reservoir Thickness, h	250	ft
Rel-perm exponents $n_g = n_{og} = n_{ow} = n_w$	2.5	–
End point relperm	1	–
Critical saturation	$S_{wc} = S_{orw} = S_{org} = 0.2$, $S_{gc} = 0.1$	–
Matrix porosity, ϕ	0.05	
Fracture spacing	250	ft
Well spacing	250	ft
Initial reservoir pressure, p_i	4850	psia
Reservoir temperature, T	162	°F
Fracture half-length, x_f	150	ft
Wellbore diameter	0.25	ft
Fracture conductivity	50	md-ft
Fracture width	1	ft
Fracture porosity	0.25	–
Separator pressure	100	psia
Separator temperature	80	°F

Table 2
PVT properties of Gas Condensate and Volatile Oil Fluid.

Fluid	Gas Condensate	Volatile Oil
OGR/CGR (STB/MMscf)	95	300
Saturation Pressure (psia)	3560	3670
Surface oil/condensate API	49	38
Composition(Mole%)		
C1	75.2	69.4
C2	7.80	7.6
C3	3.55	4.2
C4	2.10	3.1
C5	1.20	1.22
C6	1.10	1.75
C_{7+}	9.05	12.73
C_{7+} Properties		
γ_{C7+}	0.81	0.86
MW_{C7+}	174	205
Producing CGR/OGR at the time of Sampling (STB/MMscf)		
t = 50 days	73	280
t = 150 days	25	123