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Unconventional resource's production under desorption-induced effects

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ABSTRACT

Thousands of horizontal wells are drilled into the shale formations across the U.S. and hydrocarbon production is substantially increased during past years. This fact is accredited to advances obtained in hydraulic fracturing and pad drilling technologies. The contribution of shale rock surface desorption to production is widely accepted and confirmed by laboratory and field evidences. Nevertheless, the subsequent changes in porosity and permeability due to desorption combined with hydraulic fracture closures caused by increased net effective rock stress state, have not been captured in current shale modeling and simulation. Hence, it is essential to investigate the effects of induced permeability, porosity, and stress by desorption on ultimate hydrocarbon recovery.

We have developed a numerical model to study the effect of changes in porosity, permeability and compaction on four major U.S. shale formations considering their Langmuir isotherm desorption behavior. These resources include; Marcellus, New Albany, Barnett and Haynesville Shales. First, we introduced a model that is a physical transport of single-phase gas flow in shale porous rock. Later, the governing equations are implemented into a one-dimensional numerical model and solved using a fully implicit solution method. It is found that the natural gas production is substantially affected by desorption-induced porosity/permeability changes and geomechancis. This paper provides valuable insights into accurate modeling of unconventional reservoirs that is more significant when an even small correction to the future production prediction can enormously contribute to the U.S. economy.

1. Introduction

Recoverable reserves of shale gas in the U.S. are estimated to be 862 Tcf [1]. Although challenges associated to exploration and management of shale assets are yet to be resolved, decreased evaluated risk promises a secure gas supply for next decades. The large accumulation of gas shale formations serve as both a hydrocarbon source and a productive reservoir. Most of the gas is stored in organic-rich rock while less portion of gas in place is in pore spaces [2]. Extremely low matrix permeability as well as highly complex network of natural fractures are unique characteristics of shale formations. Permeability of shale rocks is estimated to be between 50 nD (nano-Darcy) and 150 nD [3]. Recent advances and innovations in hydraulic fracturing are key success of shale gas economic production as a viable global energy supply. Nevertheless, complexities associated with flow mechanisms and existence of many pressure dependent phenomena, such as combined hydraulic and natural fracture conductivity losses, Klinkenberg gas slippage effect, desorption/adsorption and Darcy/non-Darcy flow, are not completely understood and need more attentions to reach our industry needs. In this study, desorption-induced porosity and permeability changes of shale matrix as well as closure effect of hydraulic fractures are focused in detail to evaluate their impact on production form four very productive U.S. shale resources.

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Hydraulic fracturing creates highly conductive channels and paths for the reservoir fluid to flow from the reservoir pay zone to the well bore. Moreover, stress-induced natural fractures open with the hydraulic fracturing operation; thus a secondary fracture network is created in addition to hydraulic fractures. This secondary fracture network placed in the stimulated reservoir volume (SRV) area is caused by stress alterations during hydraulic fracturing treatment [4]. Researchers named this secondary fracture network either as natural fractures or secondary fracture network [5]. The main difference between primary fractures, which are hydraulic fractures, and secondary fractures is that the secondary fracture network is unpropped. Typical proppant volumes used in the hydraulic fracture operations are very low to keep fractures open in the propped secondary fracture network. Therefore, these secondary fractures remain unpropped (Since the natural fractures lack proppant, their conductivities are much more pressure dependent compared to hydraulic fractures.). Pressure-dependency of hydraulic fractures and their impact on production are discussed by the researchers [2,6,7] and are combined with desorption-induced porosity/permeability change in this study.

Reservoir simulation and modeling of unconventional resources have been given much more attention over the past years. Many numerical and analytical models are developed and extensive reservoir studies have been conducted. Commercial reservoir simulators are also improved to handle and capture fluid flow behavior and natural gas production from unconventional assets, such as shale. However, the developed models have ignored some of complex physics of shale and integrating the entire phenomena in shale is still a challenging target for the petroleum industry. Further, among analytical and semi-analytical methods, works done by Refs. [8–11] have provided comprehensive progress in the modeling of shale gas reservoirs.

Porosity, permeability and gas desorption of shale are considered the key parameters that affect shale ultimate gas recovery. However, least amount of simulation studies is conducted to account for porosity and permeability change due to desorption and rock compaction. In this paper, we first derived the porosity changes due to compaction and desorption, second, we plot the porosity and permeability versus the pressure for Marcellus, Barnett, New Albany and Haynesville shale. Afterward, we introduce a physical model of a horizontal well and the appropriate nonlinear partial differential equations created from governing equations are solved numerically through fully implicit method. The gas production from a single pair of hydraulic fractures is then scaled up to the entire horizontal well for each specific reservoir.

2. Shale desorption isotherms

Large portion of shale rock consists of organic matter, kerogenic media. Natural gas methane molecules are adsorbed on the organic rich strata (also they are stored in pore spaces and natural fractures). Thus, significant amount of natural gas can be produced from the surface of kerogen, which is also known as total organic carbon, TOC [12]. By its very nature, in order to release methane stored within the shale, it is necessary to enhance fluid pathways (create fractures) and deplete the surrounding pressure. As the pressure decreases due to production, more and more adsorbed gas is released from the surface of matrix; this contributes to the total amount of gas produced. Therefore, an adsorption model is required to predict the gas desorbed from shale matrix that will also be served to determine the first objective of this study, calculating the desorption-induced porosity/permeability.

Langmuir adsorption model [13] is the most common empirical mathematical model used to quantify the amount of desorbed gas as a function of pore pressure at constant temperature. This analogy comes from the developments made in modeling coal bed methane (pre-shale technology), but it must be noted that sorptive characteristics of shale might not necessarily serve the same way as it does in shale [14].

Langmuir model simply represents a nonlinear relationship between the potential amount of releasable-gas and the pore pressure given by Eq. (1). This equation represents that the potential amount of releasable-gas is only a function of reservoir pressure.

$$G = \frac{V_L P}{P + P_L} \tag{1}$$

where G is the potential releasable-gas content in scf/t, P is reservoir pressure (assumed to be the average reservoir pressure) in psi, and V_L (Langmuir volume) in scf/t and P_L (Langmuir pressure) in psi are Langmuir constants. Laboratory tests are necessary to determine V_L and P_L from core samples. Langmuir pressure is defined as the pressure at which 50% of gas is desorbed. By this definition, it is clear that the higher the Langmuir pressure reaches, more released-gas from the organic shale matter. Langmuir volume is the gas volume at infinite pressure representing the maximum storage capacity of gas, which is a function of TOC of the particular shale sample.

Fig. 1 shows the capability of four U.S. shale formations in releasing gas that is characterized through Langmuir model. These assets are, Marcellus, New Albany, Barnett and Haynesville shale.

Table 1 provides the common values of properties used in this study for the aforementioned assets. All of them are gathered from the numerical modeling literature except the critical pressure that is calculated using Eq. (2), that is also explained in detail in the subsequent section.

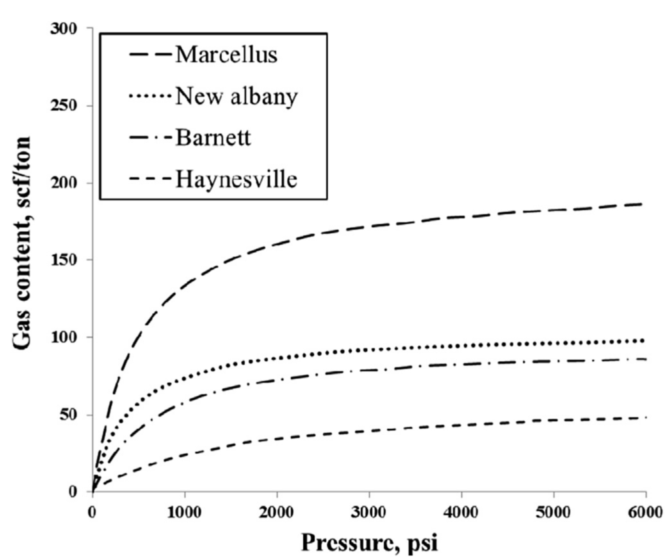

Fig. 1. Desorption isotherms for four U.S. shale formations.