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Screening improved recovery methods in tight-oil formations by injecting and producing through fractures

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ABSTRACT

Tight-oil reservoirs exhibit two characteristic behaviors that limit potential for improved recovery: (i) limited fluid movement from the unfractured matrix limits the potential to sweep additional oil towards the production wells with injection of a displacing fluid, (ii) the wettability of these reservoirs tend to be oil-wet which holds oil in relatively smaller pores, as compared to gas or water, making it difficult to mobilize that trapped oil. Primary oil production from these formations can decline to half of initial rates in the first year due to low permeability in the unfractured reservoir matrix, and a large amount of unrecovered oil remains in smaller pores that is not able to move out. To address these challenges, this study investigates the potential to improve oil recovery from tight-oil reservoirs by a method that includes injecting a fluid into the fractured reservoir to produce hydrocarbons from adjacent fractures intersecting the same wellbore. The injection and production through fractures has a potential economic advantage over huff-n-puff scheme such that there is no lag-period between injection and production. We compare the estimates of incremental oil recovery obtained by injecting water, immiscible CO_2, and surfactant over the oil recovered by primary depletion (with no injection). The results suggest that injection of fluids may not always improve recovery from tight-oil reservoirs, especially in a heterogeneous reservoir (having different rock types) whose average matrix permeability is lower than 0.01 mD. In cases where recovery is improved over primary depletion, water flood and surfactant flood perform almost equally well with no noticeable difference between the two. Although, surfactant results in favorable fluid properties to mobilize oil, the reason surfactant did not perform well in tight-oil formation studied here is because the unswept oil is inaccessible due to small permeability, and not because of high capillary pressure.

1. Introduction

Oil and gas production from unconventional tight-oil resources has become an important source of energy security in the United States (US) and it is emerging to be as important in other countries, especially in China. The contribution of oil produced from unconventional shale resources has jumped from 0.5 million barrels per day (BPD) in 2005 to ~5 million BPD in 2015, i.e. ~52% of the total US crude oil production [36]. This increase in production from unconventional shale resources has been mainly due to advancements in drilling efficiency and well configuration [29]. However, similar improvements have not been achieved for well performance; it has been observed [29] that year after year wells in mature plays (e.g. Eagle Ford and Bakken) have shown almost similar initial rates and decline trend. Production from tight-oil resources has two drawbacks with a potential for improvement: (i) low recovery factor [7,8], and (ii) decline in daily production rate by more than 50% within the first year of production from an average well in Bakken [25,37] and Eagle Ford [2,10]. For instance, estimated oil resources in the Bakken formation is estimated to be 300 billion barrels [6], out of which 7.38 billion barrels is technically recoverable [7,8], i.e. just ~2% of the original oil in place (OOIP). In addition to low recovery factor, the production rate of a new well from tight-oil reservoirs have been reported to decline by more than half within a year [2,10,25,37], primarily because of fast depletion from fractures and slow fluid movement from low matrix permeability.

To arrest the declining production rates and recover additional oil from tight-oil resources, traditional methods of improved oil recovery (IOR) can be considered (e.g. water/gas/surfactant flooding, etc.). However, unlike IOR in conventional reservoirs with relatively high permeability, unconventional tight-oil resources present two major challenges to IOR: (i) negligible fluid movement

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outside the fractures limits the possibility of an efficient sweep between the wells, and (ii) the wettability of these reservoirs tend to be oil-wet that keeps the oil in the smallest pores compared to gas or water, making it difficult to drive most of the oil out.

We investigate the potential of IOR from tight-oil reservoirs by a method that includes injecting a fluid through a set of fractures and producing hydrocarbons from a different set of fractures intersecting the same wellbore [4] as shown in Fig. 1. This injection-production scheme is less expensive compared to IOR using several injection and production wells in tight-oil reservoir e.g. [9,15], and unlike huff-n-puff, does not require shutting-in the well.

To investigate the potential of improving recovery in tight-oil reservoirs, we study the injection of three different fluids (water, immiscible CO_2, and surfactant) in a single wellbore that is intersected by three injection-fractures and three recovery-fractures. We compare the estimates of oil recovery obtained by injecting water, immiscible CO_2, and surfactant with the oil recovered by primary depletion (from all six fractures) with no injection. The impact of fluid injection on oil recovery is assessed for three different average permeabilities (very low, low, and relatively high), three different injection rates (low, high, and very high), and when injection is constrained by constant bottom-hole pressure in a homogeneous and heterogeneous medium with rock characteristics representative of a typical tight-oil reservoir.

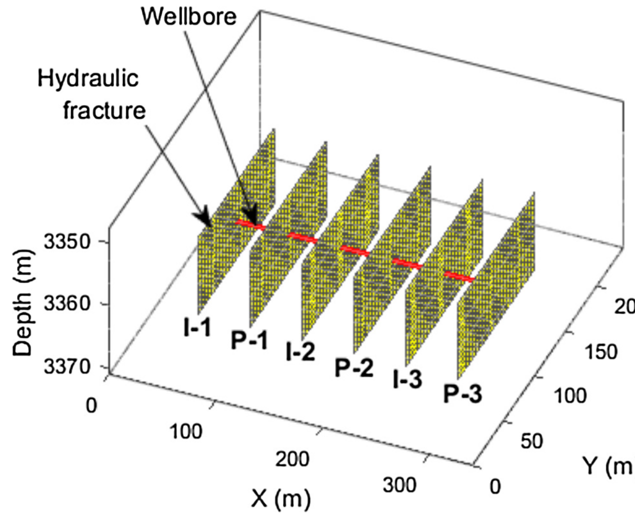

Fig. 2. Computational domain for fractured tight-oil reservoir with six hydraulic fractures intersecting the lateral. After 1800 days (∼5 years) of production by primary depletion, three existing hydraulic fractures are used to inject fluid (I-1, I-2, I-3) and the remaining three fractures are used for production (P-1, P-2, P-3).

2. Method

Below, we discuss the development of the reservoir model and the fluid model used in simulations. The reservoir model is composed of discrete hydraulic fractures that are connected with the matrix grid by a nearest neighborhood connection approach [23]. The flow simulations are performed using Matlab Reservoir Simulation Toolbox (MRST), a full-physics reservoir simulator [23], with fully implicit solutions of blackoil model.

2.1. Reservoir model

2.1.1. Injection and production in tight-oil reservoirs

A schematic of a single horizontal well (henceforth referred to as *lateral*) intersecting six hydraulic fractures in a tight-oil reservoir is depicted by Fig. 2. The conventional approach of recovering hydrocarbons from tight reservoirs would lead to low injection rates and negligible fluid movement due to extremely low permeability, therefore this drawback can be addressed by either having extremely long fractures between injection and production wells (which is not technically possible at present) or drilling additional wells that are closely spaced. The former option is practically impossible with current state of fracturing technology where fracture half-length is few hundred feet [47], while the option of drilling closely spaced additional wells may prove uneconomical for reservoirs with low rates of production. Dombrowski et al. [4] proposed an economical approach that addresses these concerns by a method that includes injecting a fluid through a set of fractures and producing hydrocarbons from a different set of fractures within the same wellbore. As the gravity forces have relatively small impact on light oil in tight reservoirs compared to viscous forces, the hydrocarbons can be recovered from both above and below the fractures.

In this study, we use a single horizontal wellbore intersecting six hydraulic fractures to investigate the injection of fluids as a measure to improve recovery after production rate drops significantly. Initially, all six fractures are used for production by primary depletion (without any injection) for ∼1800 days when the production rate is significantly lower than its initial value.

Although complex fracture geometries (including interaction of hydraulic and natural fractures) are common in tight-oil reservoirs, such geometries are not considered here in order to control the number of variables and to avoid the complexity beyond necessary.

2.1.2. Reservoir properties

The reservoir and fracture properties are taken from other studies [30,46,47] on Bakken tight-oil. The parameters for reservoir

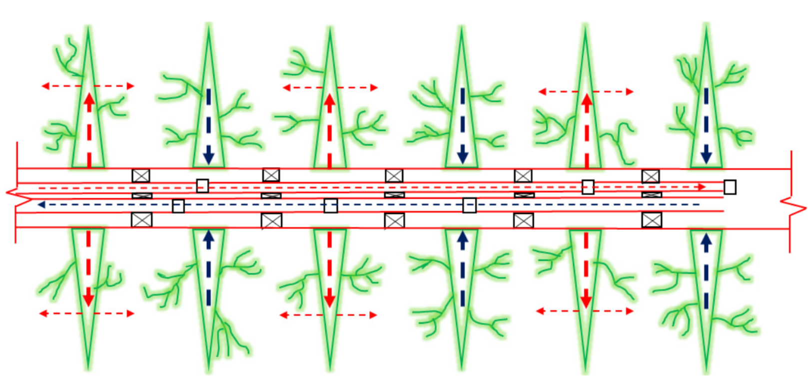

Fig. 1. Schematic for fluid injection and production through hydraulic fractures in tight-oil reservoir. Dashed red and black colored arrows represent the direction of the injected and produced fluids, respectively. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)