Research Article

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Production Forecasting of Tight Oil Reservoirs Using Improved Decline Model

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Abstract
Tight oil formation has become interest for many researchers since less than 10% of the OOIP can be obtained from the primary recovery. Other thinking on how to improve the oil recovery is still done. Decline curve analysis is one of the methods commonly used to estimate the ultimate recovery and the production rate profile of tight oil reservoirs. The present work uses the Duong model to overcome the limitations of Arps' model. This study compares the observed values from simulation results to the estimated values from Duong model over 30 years. In our previous work, we demonstrated that some key parameters such as reservoir permeability, number of fractures per stage, fracture permeability, CO_2 injection rate, CO_2 injection time, CO_2 soaking time, number of CO_2 huff-n-puff cycle have a great effect on the improve of oil recovery of tight oil reservoirs while applying CO_2 huff-n-huff. This work also focused on the development of some regression equations that can help to get approximatively the oil recovery factor of any formation, the goal here is to generate a suite of diagnostic plots to estimate oil recovery. These equations have revealed that the best fit is the polynomial regression. Results show the overestimation of oil reserve by Duong model when the flow regime changes from linear flow.

Keywords: Tight oil reservoirs, Decline curve analysis, Simulation, CO_2 injection, Ultimate recovery.

Introduction
During the past decades, liquid-rich unconventional tight oil plays have attracted lots of industry attention due to technology advancements and commodity price. One important quality for different liquid-rich unconventional tight oil plays is that hydrocarbon bearing formations have very low porosity and extremely low permeability compared to conventional hydrocarbon liquid reservoirs [1]. Therefore, recovering hydrocarbon from those tight formations is not easy. Understand what is happening in the reservoir and for improving the oil recovery when CO_2 is injected refers to analyze the different recovery mechanism possible. Several recovery mechanisms have been proposed for gas injection in liquid-rich reservoirs: Gas molecule diffusion, reduction in capillary pressure, vaporization, swelling, viscosity reduction, secondary solution gas drive, wettability changes, and pressure support [2].

These physical mechanisms occur during the CO_2 injection process in unconventional reservoirs. CO_2 EOR Process in the Tight Oil Formation is divided into five steps as illustrated in Figure 1. Step 1: CO_2 flows into and through fracture; During the initial phases of CO_2 injection, the CO_2 flows rapidly through fractures, but not through the rock matrix itself. Step 2: Unfractured rock matrix is exposed to CO_2 at fractures surfaces; The CO_2 begins to permeate the rock matrix driven by the pressure gradient caused by CO_2 injection. Step 3: CO_2 permeates the rock driven by pressure, carrying some hydrocarbon inward; however, the oil swelling and extruding some oil out of the pores. The initial permeation of CO_2 into the rock matrix could potentially reduce oil production by carrying oil near the surface deeper into rock matrix. Conversely, the oil swelling caused by theCO_2 could yield increases of oil during the pressurization process. As CO_2 continues to permeate the rock, the oil will increasingly migrate to the rock surface (and into the fractures) based on swelling and lowered viscosity caused by the CO_2. Step 4: Oil migrates to the bulk CO_2 in the fractures by means of swelling and reduced viscosity; The CO_2 pressure then begins to equalize throughout the rock matrix. At this point, oil swelling and lowered viscosity, and the possible formation of a CO_2/oil miscible phase continue to enhance oil mobilization. Step 5: As the CO_2 pressure gradient becomes smaller, oil production is slowly driven by concentration-gradient diffusion from pores into the bulk CO_2 in the fractures; Finally, as pressure equilibrium is approached, concentration driven diffusion of hydrocarbons in CO_2 from the rock interior to the bulk CO_2 in the fractures may become the dominating process.

Decline curve analysis is known as a technique where production data from a well or reservoir is used to predict the well/reservoir future production. The two main decline analysis goals are the remaining reserve estimation and the remaining life down to a specified economic limit [4]. There are high challenges in forecasting the performance of tight oil reservoirs created by the behavior of fluid flow in extremely tight porous media neighbored by high conductivity induced and/or natural fractures. There are some limitations when applying the Arps' model assumptions to tight reservoirs, therefore, improved models are needed for this kind of unconventional reservoirs [5]. To solve this problem some decline curve analysis models such as Power Law Exponential (PLE), Logistic Growth Analyses (LGA), Duong method have been proposed [6].

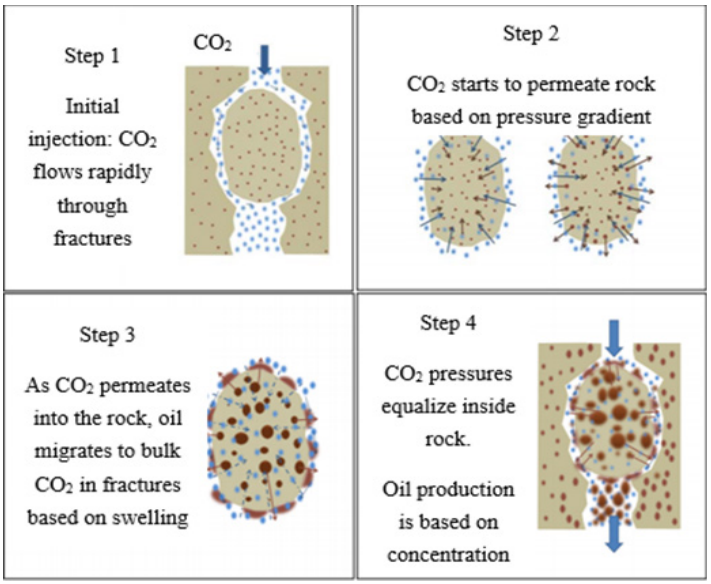

Figure 1: Conceptual steps for CO_2 EOR in fractured tight oil reservoirs [3]

Regression Equations Development

Our job here is to build some regression equations based on results from reservoir simulation. As mentioned previously, some parameters were identified as the best for the increase of oil recovery factor.

CO_2 Injection Time

It is the time recorded for the injection of CO_2 during the whole process. Figure 2 shows the oil recovery factor profile depending on CO_2 injection time. This trend is polynomial and we can notice that the oil recovery factor increases with the increase of the CO_2 injection time.

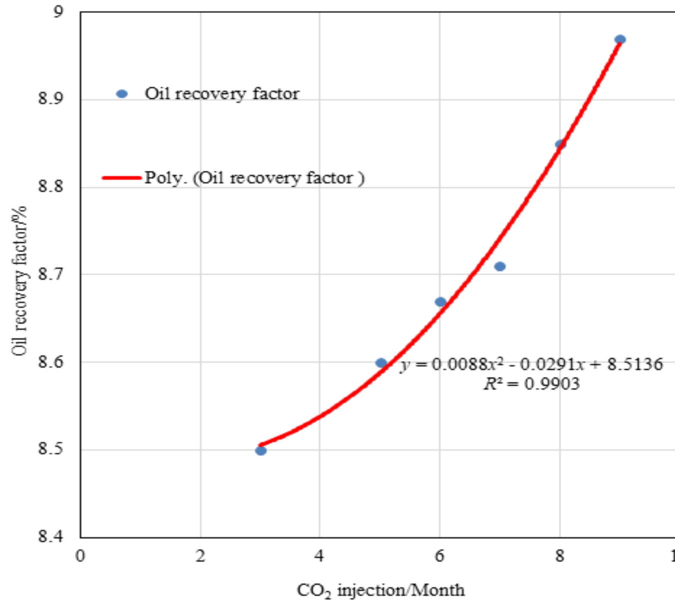

Figure 2: Oil recovery factor trend depending on CO_2injection time

Fracture Permeability

It is the permeability of each fracture set for the stimulation process. Figure 3 shows the oil recovery factor profile depending on fracture permeability. This trend is polynomial and we can notice that the oil recovery factor increases with the increase of fracture permeability.

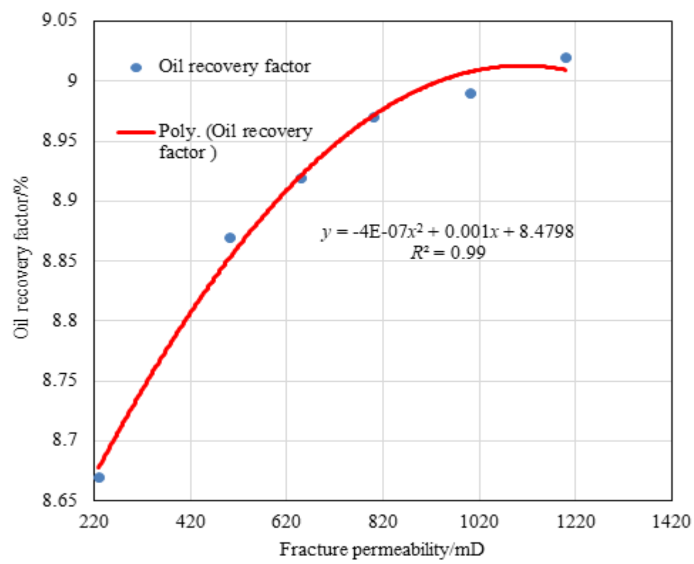

Figure 3: Oil recovery factor trend depending on Fracture permeability

Soaking Time

It is the time recorded for the soaking of the CO_2. During this period, the well is shut in and the process is stopped. Figure 4 shows the oil recovery factor profile depending on soaking time. This trend is polynomial and we can notice that the oil recovery factor increases with the increase of the soaking time until a value at which it starts decreasing. That means a soak period is crucial to recover oil effectively but an extra longer soaking time has no effect on the improvement of recovery factor [7]. We can say that there is an optimum value of soaking time for which the oil recovery is the highest. We have to pay attention on it regarding to the result we want to get.

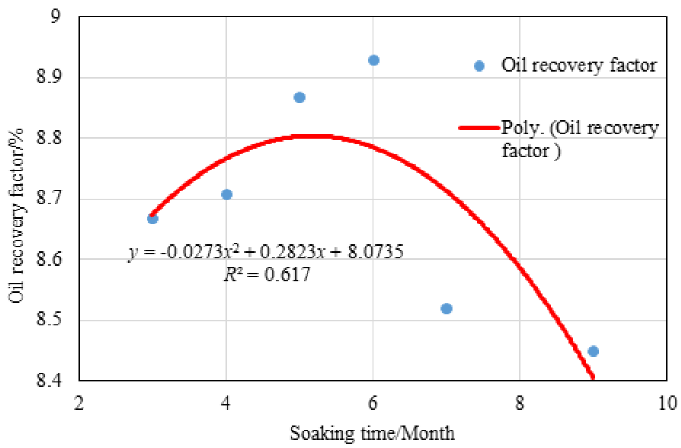

Figure 4: Oil recovery factor trend depending on Soaking time

Fracture Half-length

It is the half-length of each fracture set for the stimulation process. Figure 5 shows the oil recovery factor profile depending on fracture length. This trend is polynomial and we can notice that the oil recovery factor increases with the increase of fracture half-length.

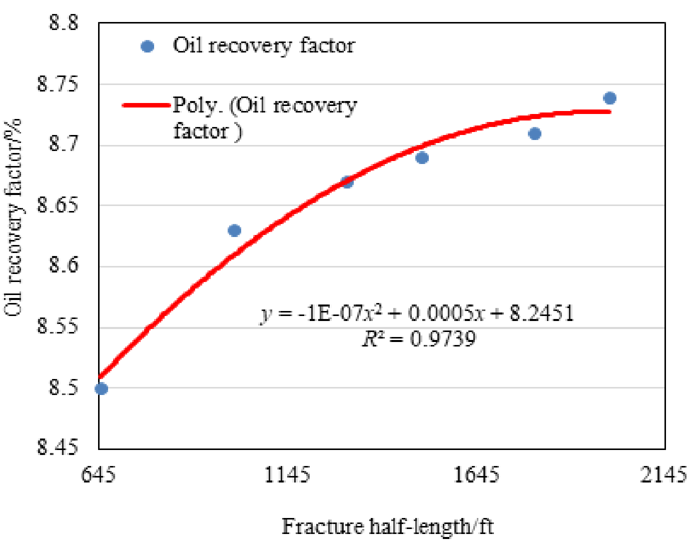

Figure 5: Oil recovery factor trend depending on Fracture half-length

A cycle in this process is constituted by 6 months for injection, 3 months for soaking time and 12 months for the production. Previously, we proved that the increase of injection time increases the oil recovery factor; As the increase of number of cycle means the increase of at least one of those three (injection, soaking or production) elements, we can deduce that the increase of the number of cycle increases the oil recovery factor automatically. Figure 6 shows the oil recovery factor profile depending on number of cycle; this trend is polynomial.

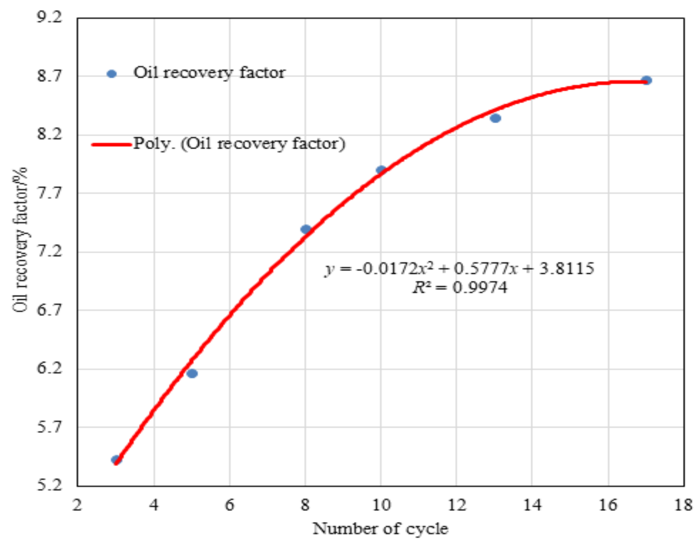

Figure 6: Oil recovery factor trend depending on Number of Cycle

A predictive modeling was built in this part in order to investigate the relationship of the oil recovery with some key parameters. Results have shown that most of them have a polynomial trend means they gradually affect the increase of oil recovery. It is also important to notice that for some of them such as the soaking time, there is an optimal value after which the increase decreases the oil recovery. For this case, we recommend to work with a value less than the optimal value because of economical reason. We should then pay attention on this kind of information before fixing the right methodology scheme.

Comparative Study of Simulation Results and Production Decline Model

In this part we first of all try to compare a production decline model to the observed data (results from simulation) over 10 years. Duong model is chosen here as the appropriate one for our goal. A log-log plot of oil production rate over cumulative oil production versus time was always a straight line for unconventional reservoirs[8]. The parameters (slope, m and intercept, a) obtained from this plot are characteristics of the reservoir rock and fracture stimulation completions. To evaluate rate and cumulative production based on boundary dominated flow, instead of using the traditional Arps' decline method Duong suggested using the constraints of initial production rate at infinity. Duong's work is primarily described by Eq. 1 and Eq. 2

$$\frac{q(t)}{Q(t)} = at^{-m} \qquad 1$$

$$q(t)=q_1 t(a,m)+q_\infty \quad 2$$

where, $$t(a,m)=t^{-m}\exp\left(\left(\frac{a}{1-m}\right)\left(t^{1-m}-1\right)\right)$$

The second aspect investigated in this chapter is to know which result (either by injecting or without injecting CO_2) for the Duong production decline fits the best the observed data from the simulation results. From Figure 7 and Figure 8 we can get a=144.81; m=1.727 for the case without injecting CO_2, and a= 589.46; m=1.89 for the case with injecting CO_2. By performing a linear regression of the observed production rate $q(t)$ against the time function (a,m) based on Eq. 2 we obtain successively Figure 9 and Figure 10 (for the two cases). The estimated values are = 52.782; q_∞= -7.3301 for the case without injecting CO_2, and q_1 = 178.03; q_∞= -16.337 for the case with injecting CO_2. Two other equations are proposed by Duong to estimate the production rate and the cumulative production.

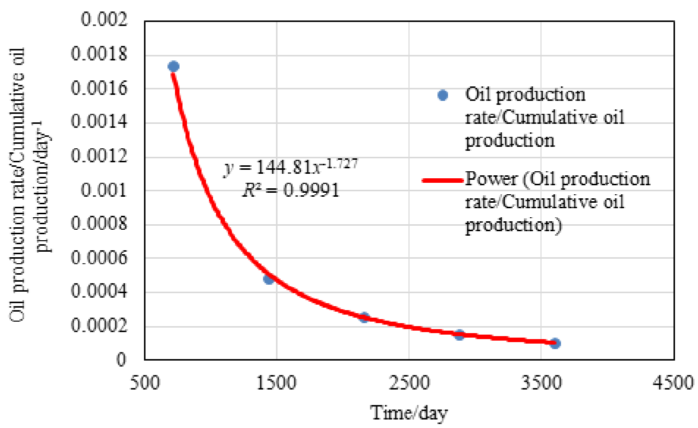

Figure 7: Duong Model fit to the ratio of oil production rate and cumulative oil production (Without CO_2 injection)

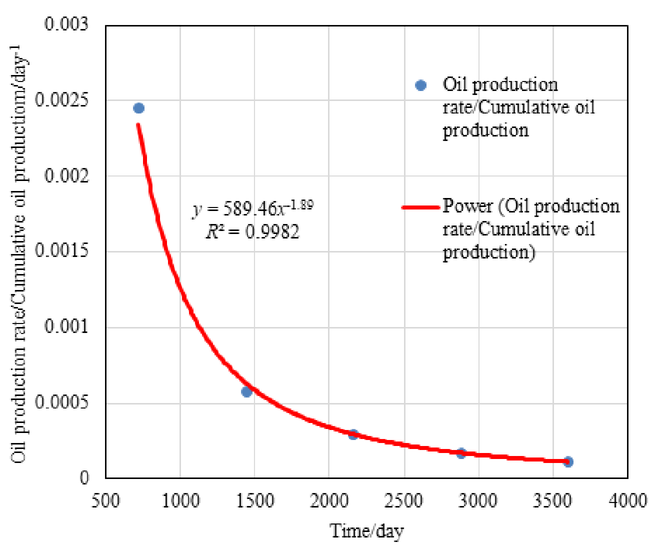

Figure 8: Duong Model fit to the ratio of oil production rate and cumulative oil production (With CO_2 injection)

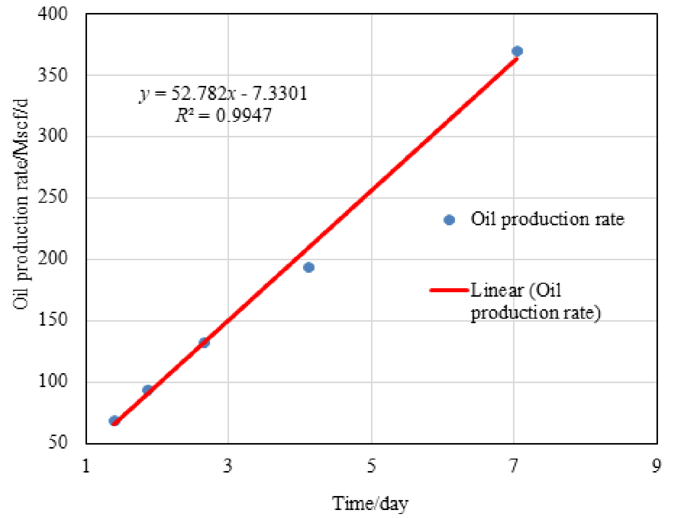

Figure 9: Oil production rate vs. Time for Duong model (Without CO_2 injection)

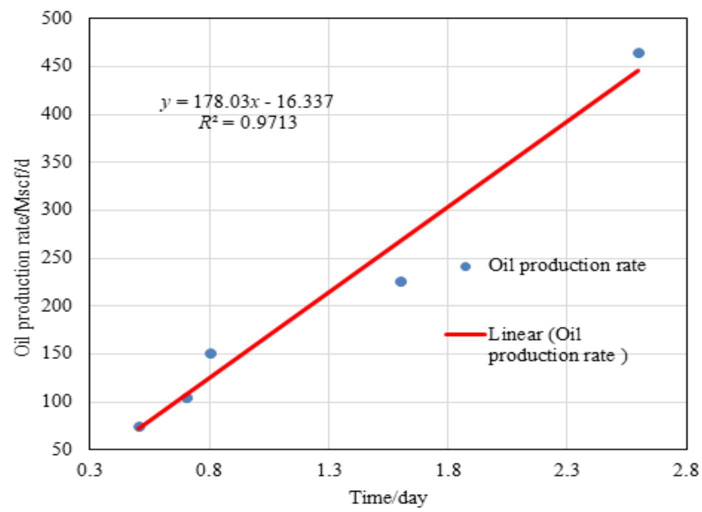

Figure 10: Oil production rate vs. Time for Duong model (With CO_2injection)

$$q(t)=q_1 t^{-m}\exp\left[\frac{a}{1-m}\left(t^{1-m}-1\right)\right]+q_\infty \quad 3$$

$$Q(t)=\frac{q_1}{a}\exp\left[\frac{a}{1-m}\left(t^{1-m}-1\right)\right]+q_\infty t \quad 4$$

We compare the observed production rate $q(t)$ with that estimated (for the two cases) using Eq. 3 as shown Figure 11. We can conclude that the model honors the trend of observed data when the whole process is made without CO_2 injection consideration. A consideration of this parameter reveals an overestimation of the observed data by the Duong decline model. In Figure 12 we compare the observed cumulative production Q(t) with that estimated (for the two cases) using Eq. 4. We can conclude that the model gradually diverges from the observed data but best fits the case without injecting CO_2; the estimated cumulative production is higher than the observed data. Table 1 presents the detailed cumulative oil production over the 10 years for the two cases. For the case of injecting CO_2, the difference with the observed data is believed to be 180497 Mscf. For the case without injecting CO_2, the difference with the observed data is believed to be 40373 Mscf. We conclude that the Duong decline model mostly works when we consider a process without CO_2 injection. Otherwise, it will overestimate the data.

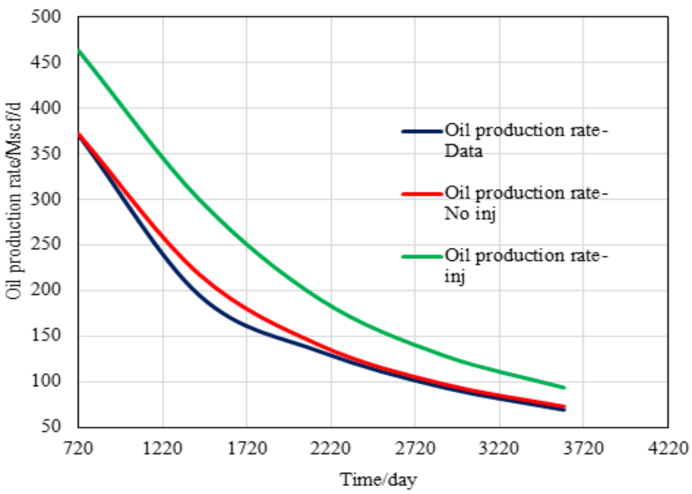

Figure 11: Duong model fit to the oil production rate from simulation (A comparison of the two cases)

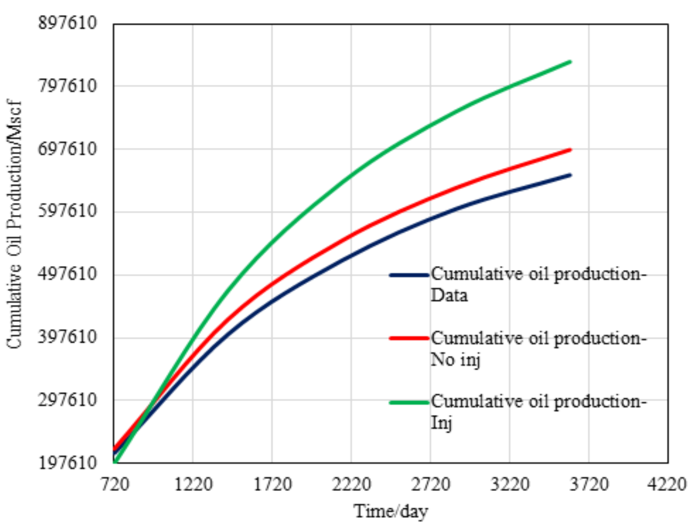

Figure 12: Duong model fit to cumulative oil production from simulation (A comparison of the two cases)

Table 1: Detailed cumulative oil production over 10 years

Time (Year)	Without Injecting CO_2(Mscf)	Simulation Results (Mscf)	With Injecting CO_2(Mscf)
1	-	-	-
2	220842	214044	197610
3	-	-	-
4	427257	403489	473240
5	-	-	-
6	552545	521017	645270
7	-	-	-
8	636571	602904	758120
9	-	-	-
10	697306	656933	837430

Conclusion

1. The existence of fractures aids the transport process of CO_2. CO_2 penetrates from the fracture into the matrix through a diffusive mechanism and mix with oil to achieve miscibility.
2. CO_2 molecular diffusivity is a significant factor in the reservoir simulation model to capture the real physics mechanism during CO_2 injection into the tight oil reservoirs.
3. A comparison of the oil recovery factor with and without gas injection has proved that it is higher when injecting gas.
4. Duong model overestimates oil reserve once flow regime changes from linear flow.

Nomenclature

q Production rate, volume/time
t Time
q(t) Production rate at time t, volume/time
a Intercept constant, 1/time
m Slope
q_1 Oil rate at day 1
q_∞ Oil rate at infinite time
t (a,m) Time function

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