Three-Phase Flow Simulation in Ultra-Low Permeability Organic Shale via a Multiple Permeability Approach

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Abstract
This paper proposes a novel approach to model multiphase flow of hydrocarbons in unconventional shale reservoirs. Understanding the storage/flow mechanisms from such reservoirs as in the Eagle Ford, Woodford, and Bakken, is crucial in the overall effort to increase the ultimate hydrocarbon production. Based on the geological evidence, three different pore systems with distinctive storage/transport characteristics have been recognized in the shale reservoirs - inorganic medium, kerogen (or organic matter), and natural/hydraulic fractures. Our simulation results show that compared to oil, gas recovery in shale reservoirs can be more efficient due to a dual Darcy/diffusive flow mechanism of the gas phase (as a result of molecule-wall collisions). Darcy flow is considered as the only flow means for the liquid phase transport in such reservoirs. Although oil-wet kerogen is considered to be a rich source of hydrocarbon, nano-darcy permeability of the rock hinders oil production in organic-rich shale. Our sensitivity analysis shows that considering diffusive flow will increase gas recovery by facilitating gas transport in kerogen. On the other hand, although increasing adsorption capabilities in the rock means more hydrocarbon is stored in the organic carbon, the oil-wet nature of the hydrocarbon-saturated kerogen will control the depletion process in this media. Therefore, the limited pressure decrease in the kerogen reduces the effects of hydrocarbon desorption on oil and gas recovery.

1. Introduction
Although concerns regarding ways to fulfill the world’s need for fuel are definitely not new, the ever-increasing global population and subsequent mounting energy demands on limited traditional resources make the subject more pressing. The oil and gas industry is experiencing a period of dramatic changes and uncertainty but one aspect of our business has been constant for more than a century: the development of brilliant new technologies that make possible the discovery and production of new hydrocarbon resources. Expedited by the overwhelming power of such emerging technologies, “unconventional resources”, defined as energy resources that cannot be extracted using “conventional” recovery methods, have attracted a great deal of attention to be viable alternatives that not only help satisfy growing energy demands but do so in a more secure way. The term “unconventional resources” covers a wide range of geologic environments and energy resources from shale gas and oil, to heavy oil, tar sand, coalbed methane, and gas hydrates. The common point between all these resources—besides the challenge these resources pose to the energy industry—is the abundant nature of such resources, which can be a legitimate excuse to see an increasing interest of industry and academia towards this fascinating subject, as evident by a large variety of research projects performed on various aspects of such reservoirs (Clarkson et al. 2011; Arogundade and Sohrabi 2012; Parvazdavani et al. 2012; Farhadi Nia et al. 2013; Jessen and Evazi Yadecuri 2013; Cheng et al. 2014; Fai-Yengo et al. 2014; Li et al. 2014; Sherafati et al. 2014; Yu et al. 2014; Lashgari et al. 2014a; Lashgari et al. 2014b). Among these unconventional resources, shale reservoirs have recently received significant interest and investigations due to numerous success of current shale plays such as Marcellus, Eagle Ford, Bakken, and Woodford. The term “shale reservoir” is referred to as extraordinarily fine-grained sediments with extremely low permeability. Understanding the complex mechanism of multiphase flow plays a key role in improving the recovery of such reservoirs. Modeling studies and field performance are still key factors to estimate and forecast the production of liquid-rich shale reservoirs (Whitson et al. 2014).
The shale matrix is mainly comprised of micro- and nano-scale pores where free and adsorbed gas can play a significant role in contributing the total gas production because of huge gas amount in those small-scale pores (Ambrose et al. 2010). Loucks et al. (2009) also investigated the shale matrix and found two various types of pores, micro- and nano-, co-exist in the shale matrix, where nano-pores are mostly located in the organic matter. Organic matter, typically termed total organic carbon (TOC), is one significant and unique content of shale reservoirs because it has different physical properties with common rock and can greatly affect the hydrocarbon flow and storage in shale. Hydrocarbon in shale reservoirs is usually considered to exist in three forms: compressed in pores and fissures, adsorbed in the organic and inorganic matter, and dissolved in the kerogen (Javadpour 2009; Zhang et al. 2012).

Jarvie (2004) conducted laboratory experiments and demonstrated that the amount of adsorbed gas and free gas in the shale matrix linearly rises with TOC content, which was also confirmed by Wang and Reed (2009). Based on these observations and theories, Wang and Reed (2009) stated that four diverse styles of pore systems co-exist in shale reservoirs: inorganic medium, organic matter, natural fractures, and hydraulic fractures, where various flow/storage mechanisms will be applied in each pore system. Moreover, it has been mentioned in a number of research projects that the inorganic medium is water-wet while the organic matter (kerogen) is believed to be hydrocarbon-wet (Wang and Reed 2009; Passey et al. 2010; Sondergeld et al. 2010; Curtis et al. 2012).

In the presence of small pores with permeabilities on the order of nano-darcy, Darcy flow is obviously limited and other non-Darcy flow mechanisms should be also taken into account to explain the complicated multiphase flow mechanism in shale (Javadpour 2009; Civan et al. 2011; Shabro et al. 2011). Although some innovative methods including a dual-mechanism approach and the apparent permeability, either based on mechanisms or a condition of Knudsen number, have been proposed in these works, the complex connection between various porous media still cannot be properly represented by such models, which may affect the understanding of the true dynamic of multiphase flow in shale reservoirs. Therefore, a novel approach to model multiphase flow in both diverse pore systems and connections between them is required and necessary to be developed. These complex models can be coupled with some new methods to reduce the computational cost of the problem (Efendiev et al. 2013; Gildin et al. 2014).

As similar with our previous research (Yan et al. 2013a), the shale matrix is subdivided into the inorganic media and kerogen (or organic matter) with different pore geometries, where appropriate flow mechanisms are employed in each sub-media. The model in this paper focuses on three-phase oil, gas, and water flow with a multi-continua approach in shale. Additionally, the mixed wettability, total organic carbon, and complicated physical change of the liquid and gas phases are also considered in the current model. Sensitivity of hydrocarbon production and pressure depletion to different factors such as total organic carbon, adsorption in organic matter, and diffusive flow are analyzed to enhance the understanding of the dynamic of complex multiphase flow processes in shale reservoirs.

2. Model Description

As previously mentioned, the reservoir heterogeneity in a shale reservoir can extend to the micro- or even nano-scale. This sort of heterogeneity exists in the organic matter (also called kerogen) in shale as well. To better characterize the subtle pore systems in this scenario, Yan et al. (2013a; 2013b) proposed a micro-scale model with a shale subdivision scheme. Basically, in this model shale matrix is partitioned into two sub-systems: inorganic matter and kerogen. Each of these subsystems has its own hydraulic/wettability/transport/storage characteristics. Since in kerogen there exists a diverse pore size distribution, we further subdivided it into two son-types: kerogen with micro-pores and kerogen with nano-pores. Petrophysical and high resolution microscopic data show that kerogen is dispersed in the inorganic matter. As shown in Fig. 1, inside the kerogen, small pores (nano-pores) reside on the walls of larger pores (micro-pores). To an upper level, natural fractures play the role of pathways to deplete the matrix system. To realize the spatial complex of the pore systems in shale matrix, a kerogen unit is designed such that those kerogen grids with nano-pores can only communicate with kerogen with micro-pores, and random kerogen unit distribution in the matrix grid system is used (Yan et al. 2013c). Further, the number of those grid blocks of organic matter is controlled by TOC (the weight of total organic carbon in shale matrix). In this paper, we are using a micrometer-scale model, with the matrix size of 150 μm and fracture aperture of 1 μm, surrounding our matrix, and a TOC value of 10.0 wt%.
Fig. 1—Local pore distribution in kerogen shows smaller pores reside on the wall of larger pores (Curtis et al. 2010).

One advantage of the current micrometer-scale model is that with the diverse distribution of different pore systems in the model, different physics could be considered in various porosity types we observe in shale (i.e. inorganic matter or kerogen). Typically, in pore systems with relatively larger scale pore geometry, such as natural fracture continuum and inorganic matter, Darcy flow is considered to be the only flow mechanism for the liquid (oil and water) and gas phase. On the contrary, in the kerogen, due to the fact that pore size is close to the size of gas molecules, diffusive flow is considered as a mass transport mechanism in addition to the Darcy flow for the gaseous phase. As for the liquid phase, its flow in the kerogen is merely characterized as Darcy flow. The state of complexity also lies in the gas storage mechanism in shale matrix. Usually, those substances with a higher surface volume ratio and strong electrochemical attraction are much easier to adsorb gas, and in shale reservoirs, kerogen could be considered as such medium, similar to coal. In this paper, the classic Langmuir model is applied to calculate the adsorption and desorption of gas molecules in the kerogen. However, in other media, the adsorption effect is neglected because of the relatively large pore size there and the less affinity to gas molecules. Note that there are some other types of complexity related with shale reservoirs like changing in fluid properties as a result of pore proximity effects and those effects can also be incorporated into the current model if required (Didar and Akkutlu 2013a; Didar and Akkutlu 2013b). If multiple phase flow occurs in the shale matrix, relative permeability and capillary pressure are complex issues to handle. In our current model, we consider the inorganic matter (mainly composed of clay minerals, quartz, calcite, etc.) to be water wet and kerogen (composed of organic matter) to be oil wet. Mass transfer is achieved through a three-phase model in which oil, gas, and water form three separate phases, where organic components can transfer between oil and gas phases. Kerogen is considered to be mostly saturated with oil and gas and inorganic has an initial water saturation of 0.3. The modified Stones I model (Aziz and Settari 1979) is adopted for three-phase relative permeability calculations, and Brooks and Corey formulation (Brooks and Corey 1964) is used to calculate capillary pressure. A detailed explanation of the formulation used for hydraulic properties is discussed by Yan et al. (2013b). Table 1 provides more information about the model, hydraulic properties, diffusivities, initial pressures and saturations, etc.

Table 1—Properties of different media (fracture, inorganic, and kerogen) in the base case model

<table>
<thead>
<tr>
<th>Porosity system</th>
<th>Fracture</th>
<th>Inorganic</th>
<th>Kerogen</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Micro-pores</td>
<td>Nano-pores</td>
</tr>
<tr>
<td>Initial pressure, MPa</td>
<td>13.7 (constant)</td>
<td>64.3</td>
<td>64.3</td>
</tr>
<tr>
<td>Initial water saturation, fraction</td>
<td>0.98 (constant)</td>
<td>0.3</td>
<td>0.02</td>
</tr>
<tr>
<td>Initial oil saturation, fraction</td>
<td>0.01 (constant)</td>
<td>0.25</td>
<td>0.30</td>
</tr>
<tr>
<td>Initial gas saturation, fraction</td>
<td>0.01 (constant)</td>
<td>0.45</td>
<td>0.68</td>
</tr>
<tr>
<td>Permeability, nD</td>
<td>84×10⁶</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Diffusivity, m²/s</td>
<td>NA</td>
<td>NA</td>
<td>7.09×10⁻⁶</td>
</tr>
<tr>
<td>Desorption</td>
<td>Langmuir pressure, MPa</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>Langmuir volume, m³/Kg</td>
<td>NA</td>
<td>NA</td>
</tr>
</tbody>
</table>
3. **Results and Discussion**

In this part, we will briefly present the results from base the case simulation scenario. An attempt is made to analyze these results based on the current hypothetical porosity model. These results are then followed by sensitivity analysis runs in which the effect of different variables on our results is analyzed. Ultimately, this step-wise procedure provides a better understanding of the water and hydrocarbon flow mechanisms in the shale matrix and important factors affecting the hydrocarbon production process.

3.1. **Base Case Simulation**

The model described in the previous section was used to perform simulation runs and investigate different aspects of hydrocarbon flow in organic rich shale. Fig. 2 shows the average pressure in matrix. We can see from the graph that pressure in the inorganic matter decreases as time goes on. This is because inorganic matter is water-wet and has a higher pressure compared to the fracture media. In fact, inorganic matter is upstream for gas and oil when these grids sit adjacent to oil-wet kerogen grids (with a lower oil and gas phase pressure due to capillarity) and fracture (with a lower constant pressure—no capillary pressure). Consequently, hydrocarbon will leave inorganic grid blocks toward fracture (this part is considered as the recovered hydrocarbon) or kerogen, resulting in a decrease in inorganic matter pressure with time. However, water-wet inorganic matter tends to pull water toward itself. At the late time of the simulation, water is able to make its way into the matrix, saturating inorganic grid blocks. This results in an increase in the pressure of the inorganic matter later in the course of simulation. Such behavior becomes clearer when we look at the average water saturation with time (Fig. 3). According to the figure, water saturation in the inorganic matter starts to increase gradually in the middle stages of the production process. This behavior is attributed to the high capillary pressure in the shale matrix because of very small pores’ radii in such reservoirs. At later times, water saturation increases in the inorganic media, causing a pressure build up in that media. On the other hand, kerogen is considered to be oil-wet and is mostly saturated with oil and gas with a low water saturation. Looking at Fig. 3, we can see water saturation level at kerogen stays at very low value of 0.02 and does not change with time. Therefore, the main flow behavior in the kerogen corresponds to hydrocarbon flow in and out with a net result of producing hydrocarbons (mostly gas) form kerogen and a decrease in pressure at later production times.

![Average Pressure](image)

Fig. 2—Average pressure in the inorganic matter decreases as hydrocarbon leaves this media toward fracture or kerogen; and at the late production time, increases because water imbibes into the system.

To evaluate the dynamics of mass transfer in our model, Fig. 4 provides the average oil saturation in the shale matrix. As explained before, inorganic matter serves as the upstream for oil and gas so oil saturation decreases with time in the inorganic matter. One the other hand, kerogen can be upstream or downstream to oil and gas, depending on the characteristics of neighboring cells and also the production time. At the early stages of the production, when matrix pressure is well above that of the fracture pressure, the difference in matrix and fracture pressure is high enough to move oil and gas from kerogen to the fracture. At the same time, oil and gas phase pressure in the kerogen (oil-wet) is less than that in the inorganic matter (water-wet). This causes hydrocarbon to move from inorganic into kerogen. As the oil outflux from kerogen to fracture is larger than its influx from inorganic to kerogen at the early
production time, we can see oil saturation decreases in kerogen at beginning. As time goes on, matrix depletes and kerogen pressure decreases, getting closer to the fracture pressure and the oil flow rate from kerogen to fracture decreases. At the same time, oil is still entering kerogen from inorganic grid blocks, causing a net increase in oil saturation of kerogen at the late production time. Gas saturation in the inorganic matter follows a trend similar to oil saturation (Fig. 5). In kerogen, however, gas saturation slightly increases due to oil production from kerogen and gas expansion. During the late production period, gas saturation in kerogen decreases again with a gentle slope. Looking at the production profile of hydrocarbons, we can see an ultimate gas recovery of 34% will be achieved at late times of production (Fig. 6). This ultimate gas recovery is attributed to two main gas flow mechanisms we have observed in shale reservoirs. The first one is the conventional Darcy flow and the other one is diffusive flow due to narrow pore throat radii and molecule-wall interactions in ultra-low permeability shale reservoirs. Fig. 6 shows the ultimate oil recovery is approximately 4%. Although kerogen is a rich source of hydrocarbons, this low oil ultimate recovery is the result of extremely reduced oil flow in the tight reservoir with an oil-wet kerogen of a small pore size and flow restrictions due to high capillary pressures.

![Fig. 3](image1.png)

**Fig. 3**—Average water saturation increases in the inorganic matter as time goes on resulting in an increase in pressure of the inorganic matter at the late production time. Water saturation in the oil wet kerogen remains at low levels.

![Fig. 4](image2.png)

**Fig. 4**—Although average oil saturation decreases in the inorganic matter, oil saturation in the kerogen decreases first (oil production from kerogen to fracture) and increases after that (some oil will move from inorganic to the oil-wet kerogen).
Fig. 5—Average gas saturation in the inorganic follows a similar trend as oil. In kerogen, however, gas saturation slightly increases due to oil production and gas expansion.

Fig. 7 and Fig. 8 show pressure and water saturation map in the 2nd and 4th layer of matrix during early and late production periods (the crosses in the distribution maps represent kerogen dispersed in the inorganic frame). As we can see, pressure starts to decrease in the inorganic matter and after that kerogen will deplete. If we look at the saturation map for the same times, we will see water is not able to enter the system at the beginning of production. Later, water finds its way into the matrix and invades the system from the sides where we have water-saturated fracture. Notice the slight pressure increase in the inorganic at the end of simulation due to water imbibition. Comparing Fig. 7 and Fig. 8, one can say although pressure depletion in the matrix starts at sooner times, water saturation in the system does not increase substantially until after a longer production period. This can be explained considering the fact that the extremely low permeability of the matrix (100 nD) will delay water imbibition into the system.

Fig. 6—Simulation results show an ultimate gas recovery of 34%, which is the result of convective and diffusive flow of the gas phase in shale matrix. Oil ultimate recovery barely reaches 4% meaning that oil flow in such tight reservoirs with discussed dynamics is extremely difficult.
Fig. 7—Pressure distribution in 2nd and 4th layers of matrix at different times (for a better visibility, just half of each layer is shown here—the squares in the 4th layer and crosses in the 2nd layer represent the kerogen and the rest is the inorganic matter).
Fig. 8—Water saturation distribution in 2nd and 4th layers of matrix at different times (for a better visibility, just half of each layer is shown here—the squares in the 4th layer and crosses in the 2nd layer represent the kerogen and the rest is the inorganic matter).
3.2. Effect of Different Shale Properties on Hydrocarbon Production

In this section, we have investigated the effect of different factors such as diffusion coefficient, desorption parameters, and Total Organic Carbon (TOC) on oil and gas production from shale reservoirs. This will help us to understand the fluid flow/storage mechanism in organic-rich shale. To easily analyze hydrocarbon productions of different sensitivity cases and be able to compare various cases, all hydrocarbon production values here are reported as “Relative Cumulative Gas (or Oil) Production” in which actual production is normalized to gas (or oil) in place of the base case presented in section 3.1.

3.2.1. Diffusivity Coefficient

Diffusion can affect hydrocarbon transfer in shale reservoirs by increasing the gas phase flow rate through molecule-wall collisions. In fact, as the pore diameter in shale reservoirs is very small, the mean free path of the molecules becomes comparable to the hydraulic pore diameter and we cannot simply ignore molecule-wall interactions and have to account for that. In our current model, based on the geological evidence, we consider diffusive flow to occur only in kerogen. However, due to the broad range of reservoir characteristics, pore size distribution, and heterogeneity we have observed in different shale plays, this assumption can be modified and further extended to other porosity systems as well. Note that this sort of diffusion only happens in the gas phase; the liquid phase will not show such behavior as molecules in the liquid phase are close to each other and the continuum flow assumption holds true there.

We consider five different cases with no diffusion, low, and high diffusivity coefficients and analyze the diffusion effect on the pressure distribution in the kerogen in addition to the hydrocarbon production. Fig. 9 shows average pressure in the kerogen for five different cases in which we consider no diffusion mechanism (Case 1), low diffusivity coefficients (Cases 2 and 3), mid-range and high diffusion coefficients (Cases 4 and 5 respectively). Comparing Case 1 with the other cases, one can conclude that considering diffusion as a gas flow mechanism will help to more efficiently deplete gas stored in kerogen. The same thing is also observed in Fig. 10 when we plot gas production for different cases in which ultimate gas cumulative production is Case 1 is less than the other cases with diffusion. This is attributed to the fact that diffusion will facilitate gas transport in the kerogen and improves its recovery. On the other hand, both Fig. 9 and Fig. 10 show that although having a higher diffusivity coefficient will accelerate the gas depletion process, it will not change the ultimate gas production and Cases 2 through 5 exhibit similar ultimate gas cumulative production. Note that diffusion effects are reflected only in kerogen average pressure and gas recovery while the other properties like gas, oil, and water saturation, in the kerogen and inorganic media, along with oil cumulative production stay the same for the case with and without diffusion.

![Pressure in Kerogen](image)

Fig. 9—Diffusion mechanism helps to better deplete gas in the kerogen (compared to the case without diffusion). However, higher diffusivity coefficients just accelerate the depletion process and final pressure would be the same for cases with different diffusion coefficients.
3.2.2. Hydrocarbon Desorption
One of the important characteristics of kerogen that distinguishes it from inorganic matter with high mineral content is the fact that kerogen is mainly made up of organic matter, which is the main source of hydrocarbon production during diagenesis. Organic matter is a rich source of hydrocarbon, with a considerable hydrocarbon adsorption capability. Adsorption of hydrocarbon molecules on organic rock surface is generally a physical process with weak rock-fluid bonds. These bonds can break as pressure in the reservoir decreases or temperature increases, resulting in hydrocarbon desorption. In this section we will sensitize desorption capability of the kerogen (through changing Langmuir volume—\(V_L\)) and see how it would affect hydrocarbon production. The current model considers hydrocarbon desorption to occur only as gas phase. Similar to the diffusion case, Case 1 here represents a model without hydrocarbon desorption while Case 2 (\(V_L = 1.25\times10^{-2}\) m\(^3\)/kg) has a low desorption capability, Case 3 (\(V_L = 1.71\times10^{-2}\) m\(^3\)/kg) has a medium desorption capability, and Case 4 (\(V_L = 1.95\times10^{-2}\) m\(^3\)/kg) has the highest desorption capacity. For all the cases, Langmuir pressure is considered to be 10.34 MPa. Fig. 11 shows that cumulative gas production does not change considerably for the cases with and without desorption. Even higher Langmuir volumes do not improve gas production substantially. This behavior can be investigated further by analyzing average pressure in the kerogen. Our results show for different desorption volumes, average kerogen pressure follows a similar pattern; consequently, the pressure effect on gas desorption is similar in all the cases. Because of the oil-wet nature of kerogen and the fact that kerogen is originally filled with oil and gas, pressure in the kerogen grid blocks is not likely to drop significantly. This implies that the quantity of desorbed hydrocarbon in the kerogen will be minimal with little effect on the associated cumulative gas production.

3.2.3. Total Organic Carbon (TOC)
Total Organic Carbon (TOC) is a measure of the current quantity of kerogen or organic richness. TOC is defined as the mass percent of organic matter in the shale matrix and is calculated using the density and porosity of kerogen and inorganic matter. In this section, we will try to analyze the effect of TOC on hydrocarbon production from the shale matrix by using three different TOC values of 6\% (Case 1), 10\% (Case 2), and 12\% (Case 3). Our results show that other than gas production and—to some extent—oil production, cases with different TOC values exhibit very similar average pressure and saturation profile in kerogen and inorganic. Therefore, we will not discuss those changes in the matrix and will focus more on gas and oil production. According to Fig. 12, total gas production increases as TOC increases in shale matrix. In fact, higher TOC cases have more kerogen grids in the matrix where kerogen is considered a rich source of gas and presence of Darcy and diffusive flow, as gas transport mechanisms in kerogen, improves gas recovery. On the other hand, if we look at oil production for the same cases (Fig. 13), one can claim that oil recovery will technically stay constant for low and high TOC cases (and even slightly decreases for higher TOC’s). Even though higher TOC values mean more kerogen in the matrix, and consequently higher oil in place; oil production does not match what we are expecting from higher TOC cases. To explain this behavior, we
should remember that kerogen is considered to be an oil-wet medium and because of its small pore throat size, capillary pressure can be very high there. Indeed, at very late production time, when pressure level in matrix falls, oil flow from kerogen into fracture vanishes and oil can only move from water-wet inorganic block to the oil-wet kerogen (with a lower oil-phase pressure). Thus, the kerogen system pulls the oil in the inorganic matter toward itself, preventing that oil to be produced in the fracture. As a result, oil production decreases slightly as number of kerogen grid block increases in the matrix (higher TOC).

Fig. 11—Amount of ultimate gas production does not change for the cases with higher adsorbed gas. This is because kerogen will not deplete effectively (it has an oil-wet nature with a high initial oil and gas saturation) and pressure in kerogen does not fall substantially.

Fig. 12—Higher TOC values increases gas production from shale matrix as kerogen is considered a rich source of gas and presence of conventional Darcy flow and diffusive flow as gas transport mechanisms in kerogen improves its recovery.
Fig. 13—Although higher TOC values mean more oil in place; despite the gas production case, total oil production does not increase with increase of TOC.

Conclusions
Inspired by numerous studies on the geological characteristics of organic-rich shale, we have presented a method of subdividing shale matrix into three different porosity systems with distinctive characteristics (inorganic matter, kerogen, and fractures). By considering the fact that each of these media can respond differently in similar situations, our model captures the complex dynamics in shale. Inorganic matter, as a water-wet system, contains both hydrocarbon and initial water, and water is able to further imbibe into this pore system and replace hydrocarbon. On the other hand, organic carbon in kerogen gives this media oil-wet characteristics with a high initial hydrocarbon saturation and hydrocarbon storage capability. Being able to produce the stored hydrocarbon from kerogen depends on the mass transfer mechanisms for different hydrocarbon phases. Gas flow, as opposed to oil, is considered to be easier due to a dual Darcian/diffusive flow mechanism. However, oil flow is limited to conventional Darcy flow. Our results show that considering diffusion as a gas transport means in kerogen will increase gas recovery from the shale. Nevertheless, smaller or larger diffusivity coefficients do not change the ultimate gas production and just accelerate/decelerate the gas depletion process. Desorption can increase the hydrocarbon in place in shale but its effect on cumulative hydrocarbon production is not significant because of the limited pressure drop in the kerogen. Although total gas production increases as TOC increases in the shale matrix (higher TOC cases have more kerogen grids in the matrix, which means higher oil and gas in place because kerogen is mostly saturated with hydrocarbon), oil production does not change considerably due to the oil-wet nature of kerogen and high capillary pressure in shale.

References


