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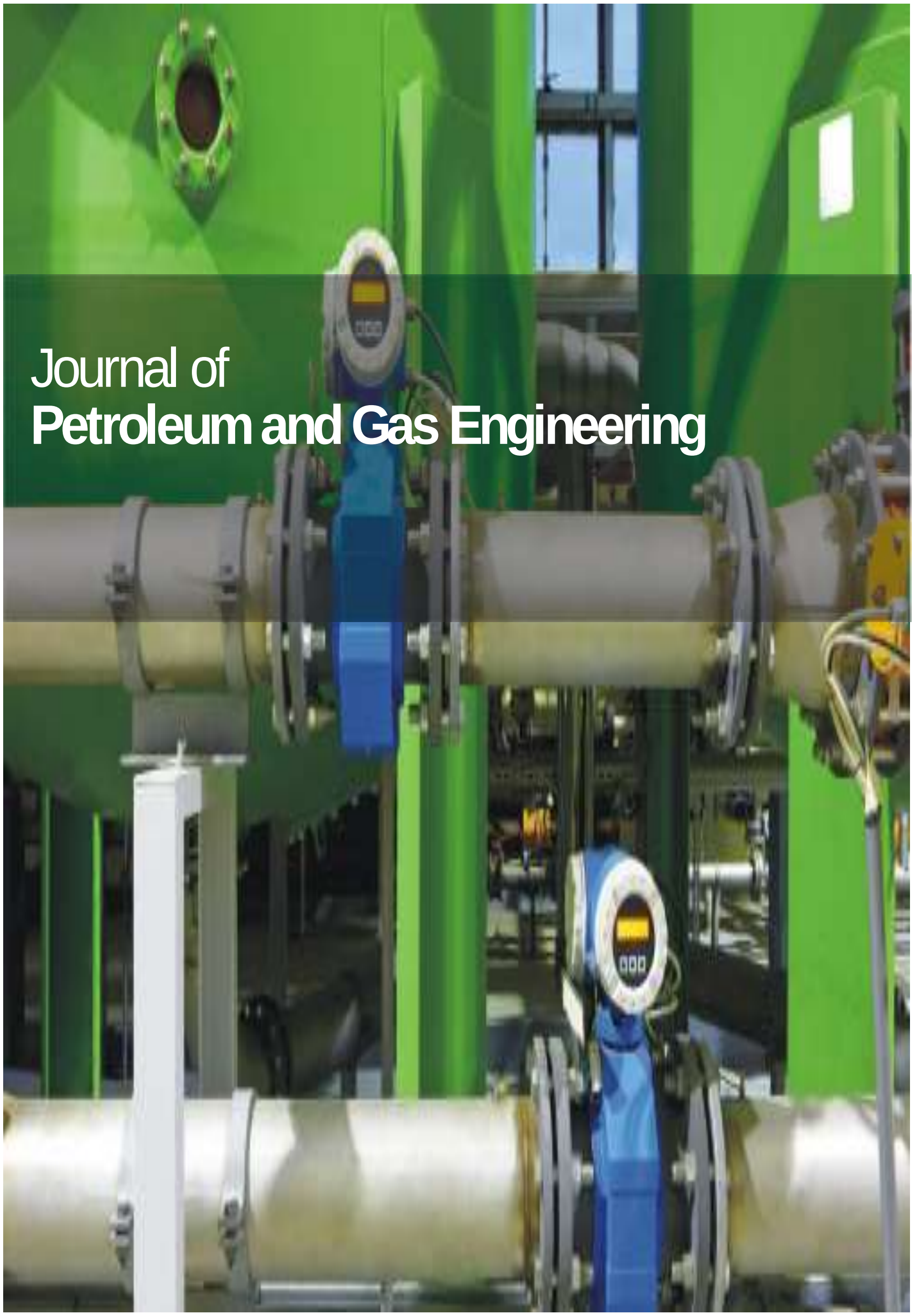

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Review

Review of studies on pore-network modeling of wettability effects on waterflood oil recovery

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Waterflooding has become by far the most widely applied method for enhanced oil recovery, accounting for more than half of oil production worldwide. Changes in the wettability of a porous medium and the chemical composition of the wetting fluid result to changes in oil recovery. In recent time, pore-network modeling has been used increasingly to study the effect of wettability on waterflood oil recovery and multiphase flow properties in different types of petroleum reservoirs. Starting from single pore models of fluid arrangements, computations of relative permeability, interfacial area, mass dissolution rate and many other physical properties have been made. Using realistic representations of the pore spaces of various rock systems, it is now possible to predict many petro-physical properties that govern fluid flow and transport in petroleum reservoir rock systems. Such properties include porosity, permeability, waterflood relative permeability, capillary pressure, phase saturations, and fluid transfer coefficients. This review looks briefly into some of the successes made so far on pore network modeling, with an emphasis on models of wettability trends and oil recovery by waterflooding.

Key words: Wettability, pore scale modeling, petroleum reservoir, waterflooding, oil recovery.

INTRODUCTION

The world is facing challenges in increasing oil and gas supply rapidly enough to sustain growth in energy demand and the economy. Growth in global population and industrialization in developing countries will result to increase in global energy consumption and hence further pressure on the available oil resources. Oil producing companies are encountering increasing difficulties and challenges in accessing new conventional reserves and are therefore turning to more complex developments, like the deep and ultra-deep offshore, to deliver growth and boost oil and gas production. However, even the huge oil and gas reservoirs discovered in deep and ultra-deep offshore will only yield about 30% recovery by primary reservoir energy. This still leaves with us the problem of recovery of a greater percentage of what is left behind. Waterflooding is by far the most widely applied method of improved oil recovery over the years, with good results in conventional and unconventional (tight oil) as well as shale gas reservoirs (Craft and Hawkins, 1991). Waterflooding, when properly applied, can increase

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production from conventional oil reservoirs by 25 to 45% of the oil originally in place (OOIP) depending on the reservoir fluid and rock properties (Meshioye et al., 2010; Klug-Santner, 2017). By implementing waterfloods, we can lower the declines in most declining oil fields and increase reserves.

Wettability is known to be a major factor influencing oil recovery by waterflooding. It determines the microscopic distribution of fluids in the pore-space which, in turn, determine important multiphase properties such as capillary pressure, relative permeability, residual saturation and resistivity index (Karabakal and Bagci, 2004; Ju and Fan, 2012). Crude oil/water/rock interactions leading to wettability variations can result to large variations in the displacement efficiency of waterfloods. However, wettability in real porous systems remains a poorly understood phenomenon as it is very difficult to measure and characterize. Commonly used single global measures such as the Amott-Harvey and USBM indices (WI) are clearly limited in their ability to describe the rich variety of multi-phase behaviour observed in real reservoir systems (Anderson, 1987a,b; Morrow and Mason, 2001). Hydrocarbon reservoir pore spaces have different orientations and complex geometries (Bear, 1953) and these, combined with complexities in rock-fluid and fluid-fluid interactions, reduce descriptions of wettability to highly simplified model systems, limiting its understanding in real porous systems. Accurate assessment of wetting characteristics of a rock-fluid system is an important aspect that requires consideration before conducting flow experiments. Consideration should be given to the fact that wettability of a given rock sample may change after a series of experiments. Changes in rock structure and adsorbed chemicals on the rock surfaces can also cause changes to the system wettability. Therefore, quantitative and qualitative tests have to be performed after a series of each flow experiments to increase accuracy of results.

A better understanding of wettability and its effect on waterflood oil recovery and multiphase rock and fluid flow properties requires detailed knowledge of the pore-network distribution of fluids. Understanding of multi-phase flow and transport is generally limited by lack of information about the microstructure of porous media and the associated flow processes. Most of the studies in literature have been focused on less complicated rock-fluid systems. While less complexity may be necessary for developing better understanding of the fundamentals of transport and fluid flow, the resulting data may not be able to capture all the complexities needed to fully characterize the reservoir under consideration. Also, the impacts of the rock surfaces and fluid spreading characteristics on wettability trend in a given rock system has not received sufficient attention, despite their importance. Wettability in real porous systems is very difficult to measure and characterize and remains a poorly understood phenomenon. Commonly used single global measurement methods (Amott-Harvey and USBM indices) tend to be limited in their ability to describe accurately, the complex multiphase behaviour observed in real reservoir systems.

Complexity of the pore geometry has led to the development of many experimental, theoretical, analytical and numerical methods for studying transport and fluid flow processes in porous media (Sallès et al., 1993; Liou, 2005; Wang et al., 2016; Meakin et al., 2007; Chatzis and Dullien, 2009; Sun et al., 2012a; Raeini et al., 2012; Karadimitriou and Hassanizadeh, 2012; Miyan and Pant, 2015; Andrew et al., 2015; Noetinger et al., 2016). Measurement techniques involving the use of X-ray and neutron scattering, scanning electron microscopy (SEM), transmission electron microscopy (TEM), focused ion beam milling (FIBM), QEMSCAN imaging, nuclear magnetic resonance (NMR) and others are usually expensive and time consuming, with accuracy of obtained data limited by sample preparation methods, experimental setup, conditions and procedures. Thus, different methods of pore structure characterization may likely yield different results for the same rock sample. Again, there is also the problem of over-idealization or oversimplification of the porous structure geometry that at the end may render the proposed method either incomprehensible or simply too bogus to be meaningful. Understanding the impact of rock wettability on multiphase flow of oil and gas in the reservoir is very important in many secondary and enhanced oil recovery (EOR) processes. This paper gives a brief review of studies that describe the pore-network models used in explaining trends in waterflood oil recovery as a function of wettability of the rock system.

PORE NETWORK MODELING

Based on experimental data from a broad range of porous materials, it has been shown that most of the shortcomings mentioned earlier can be overcome through the application of pore-scale modeling using real structural representations and surface properties of the rock system. Techniques that have the potential to greatly improve our understanding of wettability in real porous systems have been developed and are increasingly being used. One of the techniques is direct 3-D imaging of the pore-scale distribution of fluids in reservoir pore spaces using X-ray computed tomography. Pore network partitioning methods are then used to define local pore scale fluid distributions and individual pore saturations.

Pore network models

As stated above, wettability has not received much attention despite its significance, and only few studies

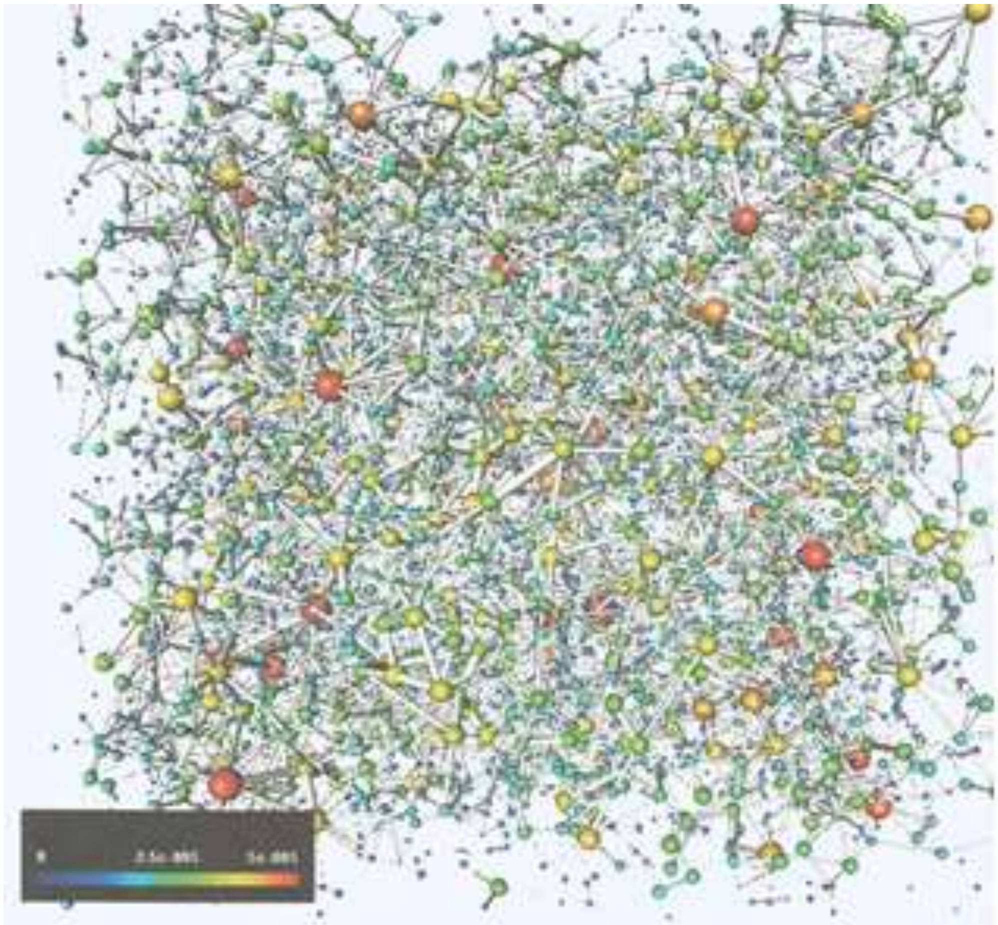

Figure 1. Pore network extracted from 3-D image of a sandstore using Maximal Ball Algorithm.The pores and throats are represented as spheres and cylinders, respectively.
Source: Dong and Blunt (2007).

have been conducted on its impact on oil recovery after waterflooding. Even among these studies, complexities in porous media structure and experimental conditions have made it difficult to develop a global understanding of wettability. Pore networks are simplified representations of the complex geometry of the porous media that show how pore spaces and pore throats are interconnected. This geometric simplification makes network models computationally very efficient and able to handle sizes in the meso-scale. A pore network in which the elements are typically assigned relatively simple shapes amenable to analytical treatment: spheres for pores and cylinders for throats is shown in Figure 1. Pore network models are practical reservoir description and simulation tools used to study a variety of two- and three-phase displacement processes. Pore-scale modeling has been used successfully to predict many different properties, such as two- and three-phase relative permeability and wettability impact on reservoir fluid distributions (Valvatne and Blunt 2004; Valvatne et al., 2005; Thibodeaux et al., 2015; Raeini, 2017). From rock samples methods have been developed to analyze the pore space and extract geologically realistic networks. These methods have been applied to analyze waterflood oil recovery trend as a function of wettability at the field scale, demonstrating the potential of waterflooding in a variety of sandstones, fractured and carbonate reservoirs.

The popular use of pore-network models to represent multi-phase flow was pioneered by Fatt in the 1950s who shifted away from the existing method of representing the porous media using bundle of tubes to the use of a 2-D lattice network to randomly assign throat radii for calculation of various properties of the network (Fatt 1956a, b, c). The subsequent increased interests in using pore-scale network modeling have led to the development of many models with different representations of pore space that are used in the characterization of multiphase flow (Blunt and King 1991; Lowery and Miller 1995; Fenwick and Blunt 1998; Blunt 1998; Koplik et al., 1998; Dixit et al., 1999; Tuller et al., 1999; Hui and Blunt 2000; Dillard and Blunt 2000). Some of these representations, shown in Figure 2, have been

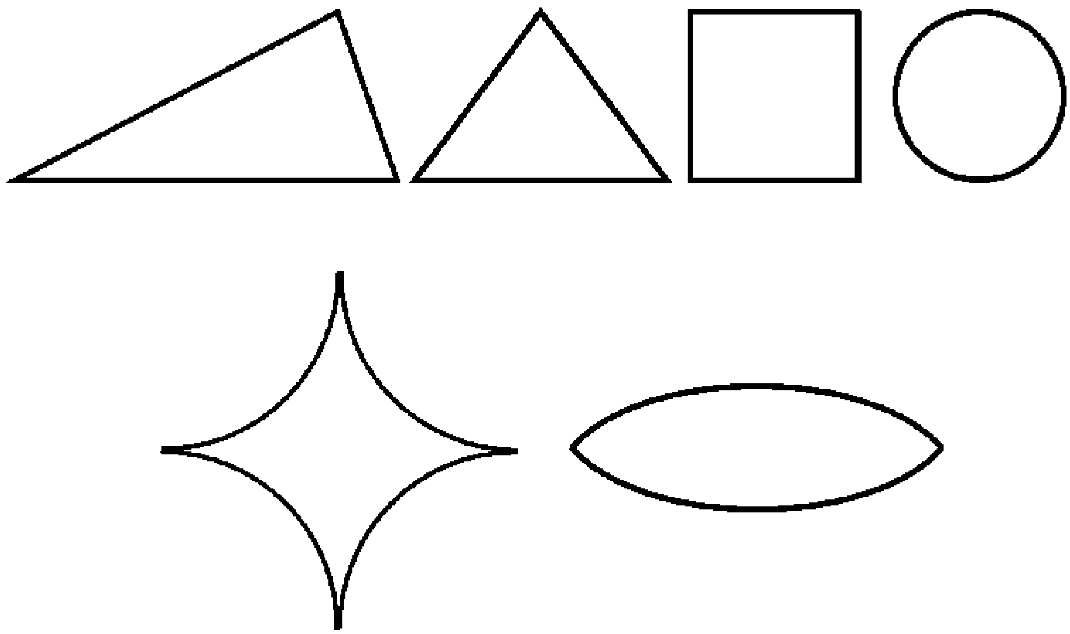

Figure 2. Pore network elements (models) with different cross-sectional shapes.

reviewed by, e.g., Berkowitz and Balberg (1993), Sahimi (1995) and Blunt (2001; Sok et al., 2002; Raoof and Hassanizadeh, 2010).

Pore-network modeling has advanced to a veritable theoretical compliment to special core analysis and has proved to be an efficient tool to study the effect of wettability at the macroscopic scale, especially on oil recovery (McDougall and Sorbie, 1995; Blunt, 1998; DiCarlo et al., 2000; Zhao et al., 2010; Ryazanov et al., 2014). It is being used in the industry to assign multiphase flow properties in reservoir models and to predict how these properties vary with rock type and wettability. Using physically-based properties that properly capture the pore network and wettability variations in the reservoir we can predict variations in oil recovery trends by waterflooding.

It will be necessary to state that a majority of the existing pore network models cited above do not give accurate representations of natural pore space geometry and topology needed for prediction of macroscopic transport of immiscible fluids in porous reservoir systems. They have only succeeded in capturing more of the physics of pore-scale displacement mechanisms of waterflood oil recovery as a function of wettability variation. Less emphasis and efforts were made in capturing the complex pore-scale geometry of a typical real reservoir rock. Hence, although these models give good interpretation of the phenomena observed in experiments, they have not been able to model accurately the physics of fluid flow in real porous media network, and thus have not been truly predictive of waterflood oil recovery as a function of wettability.

However, using advanced imaging techniques we can generate useful information about the microstructure of real formation. Such techniques include micro-focused computed tomography (CT) and serial sectioning (Coles et al., 1994; Hazlett, 1995; Al-Raoushi and Wilson, 2005; Knackstedt et al., 2006; Al-Kharusi and Blunt 2008; Sok et al., 2010; Gharbi and Blunt, 2012; Zhenpeng et al., 2015; Wopara and Iyuke, 2018). The capabilities of pore network model as a tool for understanding the pore structure of reservoir rocks have increased tremendously, thanks to these techniques.

Applications of pore-network modeling

Strongly water-wet hydrocarbon reservoirs are not common and many soils change their water-wet condition to oil-wet state (or mixed wettability state) once contacted by oil (spills). This is as a result of long contact between the oil and the solid surface that allows surface-active oil components to adhere to the solid surface, thus altering wettability (Buckley et al., 1998). Micro-model studies (Lenormand et al., 1983) have explained different displacement mechanisms for multiphase flow in strongly water-wet media, and have been used in pore-scale models to explain a variety of phenomena, including relative permeability hysteresis, and trends in residual oil saturations (Jerauld and Salter, 1990; Blunt, 1997).

The wetting condition of a crude oil/brine/rock system plays a significant role in determining transport properties such as capillary pressure, relative permeability and oil recovery. Since wettability cannot be measured by direct methods, but indirectly by measurements of macroscopic behavior in the rock medium, pore-scale modeling that simulates fluid displacement behavior through pores and throats is used to predict microscopic fluid distribution, which is then related to the macroscopic parameters of wettability index and oil recovery (Jadhunandan, 1990; Morrow, 1990; Dunsmoir et al., 1991; Fassi-Fihri et al., 1995; McDougall and Sorbie, 1997; Dixit et al., 2000; Al-Futaisi and Patzek, 2003; Zhao, 2010; Dodd et al., 2014; Wopara, 2016; Farrad et al., 2016; Alhammadi et al., 2017). It is therefore a useful tool for understanding the impact of rock structure and wettability on multiphase flow properties and oil recovery.

Sandstone reservoirs

Kovscek et al. (1993), basing on the concept of thin films coating on the rock surfaces, proposed a theoretical model for wettability alteration after primary drainage where areas of the pore space in direct contact with oil changed their oil/water contact angle for waterflooding, while water-filled regions remained water-wet. They stated that wettability is controlled by the stability of the thin film, which in turn depends on the fluid system, the mineralogy of the rock surface, the local pore geometry, and the prevailing capillary pressure. They incorporated this scenario in a capillary bundle model with star-shaped pore cross sections. However, they did not indicate the portion and fraction of the pores that we need to change the wettability, neither is it certain the distributions of the contact angle, since they are not likely to be uniform throughout the region of altered wettability. The effect of the reservoir temperature was not considered. It has been shown that temperature and oil viscosity also affect the distribution of fluids in the pore spaces, and hence wettability distribution (Alhammadi et al., 2017). McDougall and Sorbie (1995) investigated trends in relative permeability and oil recovery efficiency as functions of wettability with a regular cubic network. Recovery was shown to be maximum in a network where half the pore space was oil-wet. They also stated that in a mixed-wet system, wettability is either distributed according to pore size where large (MWL) and small (MWS) pores respectively are oil-wet, or fractionally wet (FW) where wettability is uncorrelated to pore size. In simulations of hydrocarbon reservoir behaviour assumptions are that wettability distribution strongly influence many petrophysical functions such as capillary pressure, relative permeability trend, electrical properties and oil recovery efficiency by waterflooding, For examples, Salathiel (1973), Jadhunandan and Morrow (1995) and Jackson et al. (2003), using a series of Berea sandstone cores and crude oil as a wettability-altering agent, applied pore-scale modeling to investigate the relationship between wettability and waterflood oil recovery. Their respective investigations showed that oil recovery by waterflooding initially increased and then decreased as the wettability changed from strongly water-wet to oil-wet, with maximum recovery observed at weakly water-wet conditions. This is corroborated by Wopara (2016) and Wopara and Iyuke (2018). Rostami et al. (2008) carried out an experimental study of wettability effects on oil recovery and residual saturations during gas assisted gravity drainage and subsequent water flooding mechanisms. Analysis and interpretation of the results obtained in terms of saturation profile, oil recovery at break through time, final oil recovery and residual saturations showed that fluid injection rate and wettability played a major role on fluid distribution and displacement mechanism. In line with the work of Rostami and co-workers above, Al-Raoushi and Wilson (2009) investigated the impact of wettability of porous media on pore-scale characteristics of residual non-aqueous phase liquids (NAPLs). Findings indicate that spatial variation in wettability of porous media surfaces has a significant impact on pore-network characteristics of residual NAPL blobs in saturated porous media systems.

Contrary to the trend observed in two-phase flow, Suicmez et al. (2008), using a three-dimensional mixed-wet random network model representing Berea sandstone to investigate the effects of wettability and pore-level displacement on hydrocarbon trapping, showed that the amount of oil that is trapped by water in the presence of gas increases as the medium becomes more oil-wet. The role played by the presence of a third phase (gas) in this contradictory result is not well defined. Raeesi and Piri (2009) used a model 3-D network of interconnected pores and throats of various geometrical shapes, representing the pore space of Berea and Saudi Arabia reservoir sandstone to investigate the impact of wettability and trapping on the relationship between interfacial area, capillary pressure and saturation in two-phase drainage and imbibition processes. Changing wettability of the system from strongly water-wet to strongly oil-wet resulted in a significant decrease in trapped oil saturation. The implication of this is that as the system wettability changes from strongly water-wet to neutral-wet condition oil recovery by waterflooding increases. By applying pore-network modeling Wopara and Iyuke (2017) validated this trend in oil recovery by waterflooding, using core plugs from Agbada sandstone reservoir in the Niger delta of Nigeria. Zhao et al. (2010) investigated the impacts of wettability on waterflood oil recovery using a capillary pore-scale network model derived from micro-CT images of different rock types. They reproduced the experimental results obtained by Jadhunandan and Morrow, and validated the pore-scale model used to simulate flooding cycles. From the results of their investigation they concluded that for a uniformly-wet system, oil recovery increases as the system becomes less water-wet and reaches a maximum for oil-wet conditions where recovery is approximately constant for contact angles greater than 100°. In water-wet systems oil recovery decreases as initial water saturation increases whereas in oil-wet systems oil recovery initially increases and then decreases. Their findings also, to some extents, confirm the results obtained by Raeesi and Piri (2009). Optimal recovery occurs when a small fraction of the system is water-wet.

Carbonate reservoirs

Carbonate reservoirs are estimated to hold more than 50% of global remaining recoverable conventional oil (Trieber et al., 1971). Experimental studies and field data have shown that many carbonate reservoirs generally have a moderate to strong oil-wet (heterogeneous) character of wettability, resulting from the presence of micro- and macro- pores (Ioannidis and Chatzis, 2000). It is generally known that oil recovery from a rock having a heterogeneous pore size distribution (e.g. carbonates) is typically poor when compared to that from one with a homogeneous pore size distribution (sandstones). Specific characteristics of carbonate reservoirs such as complex texture and pore network structure create complex challenges in reservoir characterization, production and management. There are 3 types of porosities seen in carbonate reservoirs: porosity between the carbonate grains (connected porosity); porosity due to the dissolution of calcite during diagenesis (unconnected porosity or vugs); and porosity due to fractures caused by depositional stresses. Together with wettability heterogeneity, these 3 types of porosities create very complex paths for fluids flow and directly affect recovery from carbonate reservoirs.

During immiscible displacement, as in waterflooding, water will be diverted into connected pathways of larger pores with higher permeability, resulting to significant bypass of oil and poor recovery. Understanding this structural-controlled recovery efficiency is very important in the modeling of carbonate reservoirs with micro-pores. Due to increasing efforts to improve hydrocarbon recovery from carbonate reservoirs, improving traditional network modeling techniques to study carbonates has been the subject of many investigations (Knackstedt et al., 2006; Dong et al., 2008; Al-Kharusi and Blunt 2008, Sok et al., 2010; Al-Dhahli et al., 2011; Gharbi and Blunt 2012; Blunt et al., 2013; Al-Dhahli et al., 2013; Gibrata et al., 2014; Kallel et al., 2015; Nunes et al., 2016; Xu et al., 2017). Gharbi and Blunt (2012) in a study used pore network modeling to study the impact of wettability and connectivity on waterflood relative permeability for a set of six carbonate samples. They used x-ray micro-tomography of a few microns resolution to image the pore space in three dimensions and extracted a topologically representative network of pores and throats from these images. Representing mixed-wet behavior by varying the oil-wet fraction of the pore space they simulated quasi-static displacement in the networks. The results of their work indicate the efficiency of waterflooding as an oil recovery process in carbonate reservoirs.

This is validated by a recent experimental study by Ruidiaz et al., (2018) in which they used two types of carbonate rock, dolomite and limestone, to investigate the effect of wettability alteration on oil recovery by spontaneous imbibition.

Fractured reservoirs

Fluid flow and storage in naturally fractured reservoirs are largely influenced by the geometry, complexity and heterogeneity of the reservoir, e.g., large permeability difference between the rock matrix and fracture, wettability, and porosity, fracture aperture, and grain shape, permeability pathways and/or impermeable barriers formed by the fracture network and their interaction with the host rock matrix (Rezaveisi et al., 2012; Leu et al., 2016; Jafari et al., 2017). The complex multiphase fluid flow behaviour of fractured reservoirs has traditionally proved difficult to predict, resulting in high degree of uncertainty in their characterization and economic development. Adequate knowledge of the influence of fractures on fluid flow has been very challenging. This is due to difficulties associated with proper detection and characterization of the fracture properties that affect fluid flow through the fracture channels. These include fracture network orientations and spatial configuration of fluids, fracture lengths and heights, fracture density, stratigraphic distributions, spacing, apertures, and fracture-surface topography.

However, spontaneous water imbibition into the matrix blocks is known as the main mechanism for increased oil recovery from naturally fractured oil reservoirs. The rate of oil recovery and its ultimate value is mostly affected by wettability of the rocks and their pore structure. This has been shown by Rezaveisi et al. (2010) who utilized a novel experimental model to study the imbibition mechanism under different wettability conditions in naturally fractured formations. The results obtained show that presence of a small fraction of oil-wet rock grains drastically affects oil recovery by capillary imbibition

Understanding rock wettability, among other petrophysical properties, is very important in the prediction of fluid transport within the rock matrix in fractured reservoirs (Arns et al., 2004; Blunt et al., 2013; Liu et al., 2017). Pore network structures of fractured reservoir matrix rocks, idealized from 3D X-ray tomography images of core plugs, are useful in efficient calculation of storage capacity and multiphase fluid transport in the formation (Jiang et al. 2007; Ryazanov et al., 2009; Bauer et al., 2012; Al-Dhalhi et al., 2013; Ahmadpour et al., 2016; Liu et al., 2017; Ding et al., 2017). The extension of pore-network models to include explicit fractures (Jiang et al., 2012; Ding et al., 2017) provides an important approach in understanding the rock matrix-to-fractures fluid transfer process and in the modeling of the effects of wettability on waterflood oil recovery.

Oil recovery pattern during gravity drainage processes in heterogeneous porous media depends strongly on wettability. Some studies have investigated the effects of wettability in fractured and homogeneous porous media during free-fall gravity drainage (FFGD) and controlled gravity drainage (CGD) conditions (Zendehboudi et al., 2011; Zendehboudi et al., 2012; Maroufi et al., 2013; Saedi et al., 2015). These studies have shown that different wettability conditions govern the oil recovery mechanism during FFGD and CGD processes. Also, obtained results showed that the wetting properties of the test fluid considerably affected the matrix-to-fracture transfer and the fluid saturation, with the water-wet conditions favoring oil recovery for both FFGD and CGD processes.

Impact on gas-assisted drainage process

Gas Assisted Gravity Drainage (GAGD) has proved to be an effective method of oil recovery. In gas assisted gravity drainage (GAGD) oil recovery is influenced by reservoir rock and fluid specific properties, such as heterogeneity of the formation, wettability, oil and gas density, oil and gas viscosity, viscous force, capillary force, gravity, gas injection rate, and gas-oil miscibility or interfacial tension (Catalan et al., 1994; Caubit et al., 2004; Parsaei and Chatzis, 2011; Wu et al., 2013; Ameri et al., 2015; Khorshidian et al., 2017)

Parsaei and Chatzis (2011) through a systematic experimental study investigated the impact of reservoir wettability variations at the macroscopic scale on oil recovery efficiency in gravity-assisted inert gas injection (GAIGI) process for tertiary recovery of residual oil by waterflooding. Obtained experimental results showed that for a positive oil-spreading coefficient, the continuity of water-wet portions of the heterogeneous porous medium favors the tertiary oil recovery through the film flow mechanism. In addition, owing to the high waterflood residual oil content of the heterogeneous media tested, the oil bank formation occurred much earlier and grew faster, resulting in a higher oil recovery factor. Also, Ameri et al. (2015) carried out laboratory experiments and numerical simulation to study the effect of matrix wettability on the efficiency of gravity drainage by gas (CO_2) injection. They concluded that for a system with an effectively oil-wet matrix, water is the most non-wetting phase while CO_2 is the intermediate-wetting phase. However, with a strongly water-wet matrix, CO_2 is always the least wetting phase. Thus, when water is displaced by the gravity drainage process part of the oil is also produced, leading to improved recovery.

Significance of pore-network modeling

The studies mentioned above have been very successfully in improving our understanding of large-scale natural phenomena taking place in the porous rock system and in investigating the effects of wettability on waterflood oil recovery. The stated models have proved to be of importance due to the fact that they are rather cost-effective and can give accurate predictions for local transport processes. More so, they are amenable to systematic tuning of parameters that influence fluid flow behavior (Meakin and Tartakovsky, 2009). With these pore-scale models we can make improved predictions of macroscopic transport properties by tuning the pore space structure parameters. This helps to understand the scale dependence of continuum transport parameters which are difficult or impossible to capture effectively by the Darcy flow approach. However, in the models stated above, the pertinent issues to resolve are; 1) whether in reservoir rock containing oil and brine, a water film separates the oil phase from the rock, or the oil is in direct contact with the rock; 2) what is the actual configuration of oil and water phases around their contacts. Answers to these questions, among other things, require an accurate representation or description, in terms of the physical and chemical properties, of the real porous medium of interest.

Successful reproduction of experimental results is possible using a combination of representative networks and an improved understanding of pore-scale displacement processes. However, several studies have used either cubic networks or a relatively homogeneous network that represent mainly a few sandstone and carbonate rocks. Since the pore structure of a wide range of rock samples can now be determined using Micro-CT imaging, previous studies have to be extended to investigate the effects of wettability on waterflood oil recovery using networks derived from micro-CT image of more different reservoir rock systems. By extending the analysis of the effects of wettability on the macroscopic descriptors of transport of fluids in porous media using a faithful representation of the pore space of various sandstone rocks we can understand the dynamics of multi-phase flow in the rock systems. This understanding is very essential for designing projects for enhanced oil recovery by waterflooding and/or gas injection, optimizing oil recovery, and remediation of oil spills.

One major shortcoming of pore network modeling compared to other methods like lattice-Boltzmann method (LBM) is that it is based on an approximation of pore geometry and physics, lacks generality and does not take into account the effect of resistance to flow within the pore bodies. This may cause overestimation of calculated transport properties, particularly relative permeability values compared to values obtained from experiments. We do not yet have models that will adequately handle fluid flow behaviors in a wide range of variations in pore structures of porous media with different geological conditions

The pore-scale modelling is dominated by particle-based methods. These include the promising lattice

Boltzmann method (Shan and Chen 1993; Martys and Chen 1996; Chen and Doolen 1998; Guo and Zhao 2000; Kang et al., 2002; Pan et al., 2006; Hao and Cheng 2010; Aidun and Clausen 2010; Zhang et al., 2014; Wopara 2016) and smoothed particle hydrodynamics (Zhu and Fox 2002; Tartakovsky and Meakin 2006; Tartakovsky et al., 2007a; Shadloo et al., 2016; Zhang et al., 2017). The particle methods, while suitable for pore-scale analyses, become inefficient at the meso-scale, e.g. when the system requiring analysis has tens or hundreds interconnected pores in each direction (Tartakovsky et al., 2007b; Gong et al., 2016). Further, these methods are time consuming and only very limited pore volumes can be addressed.

Future modeling approaches

To accurately model the effects of wettability on oil recovery and the complex fluid transport phenomena, a physically-based transport network that adequately captures the pore structure must be extracted from the rock of interest. An accurate digital rock model depends on an accurate and detailed digital characterization and analysis of the rock pore system. The heterogeneity of many reservoir rock systems over many length scales create complexities in structural orientation and distribution and in the spatial configuration of fluids in the pore spaces, thus exerting great influence on fluid flow and transport.

However, assessing and quantifying a wide range of parameters, such as size, distribution, location, and orientation of pores, and rock wettability is a daunting task. The variation in spatial characteristics across many orders of magnitude poses a challenge for the determination of a representative microscopic pore network for such systems. Conventional analysis and characterization methods generally give volume-averaged properties while high-resolution imaging techniques are limited in spatial resolution and thus represent small range of pore sizes. Therefore, a detailed and accurate description and characterization of the rock pore network is possible to achieve by the application of a multi-scale imaging approach that involves FIB-SEM, SEM, TEM, HIM, and μ-CT analysis, with each technique focusing on a respective size range. This, however, raises the issue of cost of analyzing a given rock sample.

Also promising are the adaptive and hybrid and hybrid models developed in recent years take advantage of the speed of a quasi-static algorithm for flows that are dominated by capillary forces, and that can handle viscous effects when they are significant (Sun et al., 2012; Tang et al., 2015; Regaieg and Moncorgé 2016, 2017; Costa et al., 2018). These models act as two-way links between the pore and the macro scales by merging their models into a proper computational domain. As multi-scale imaging techniques develop further, with pore-network and adaptive/hybrid models, it is expected that the efforts made so far will lead to a better and deeper understanding of the pertinent pore-level processes that give accurate prediction modeling of wettability influence on rock petrophysical properties, particularly on oil recovery by water flooding.

CONCLUSION

Pore-network modeling has come to stay as a very useful tool for understanding results obtained in experiments on waterflooding of core samples obtained from different reservoir rock systems and for explaining and predicting trends in oil recovery as a function of wettability both at the laboratory and field-scale levels. Using a realistic representation of the pore spaces of various rock systems derived either by statistical or explicit method or through network tuning, we can quickly predict many physical processes such as waterflood relative permeability and fluid transfer coefficients. There is the need to carry out more research in as many hydrocarbon reservoir rock systems as possible, especially in shale gas-oil-systems in order to characterize the pore space and wettability trends. This, together with pore network modeling, will help us to design projects for improved hydrocarbon recovery from such systems by waterflooding.

In the years to come and until a better process and more reliable technologies are developed, waterflooding will continue to remain the most viable and widely applied method for improved oil recovery in both conventional hydrocarbon reservoirs onshore, offshore and in deep/ultra-deep water oilfields. Therefore, an understanding of the pertinent pore-level fluids displacement processes is necessary for obtaining accurate prediction of wettability effects on oil recovery by waterflooding. This is also very important for such globally pressing and highly challenging issues as the capture and safe storage of CO_2, vadoze zone remediation of oil spills and soil contaminants, and natural gas recovery.

CONFLICT OF INTERESTS

The authors have not declared any conflict of interests.

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