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Article information:

To cite this document:
Samarth D. Patwardhan, Fatemeh Famoori, Suresh Kumar Govindarajan, (2016) "Quad-porosity shale systems – a review", World Journal of Engineering, Vol. 13 Issue: 6,pp. 529-539, doi: 10.1108/WJE-09-2016-0087
Permanent link to this document:
http://dx.doi.org/10.1108/WJE-09-2016-0087

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Quad-porosity shale systems – a review

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Abstract
Purpose – This paper aims to review the quad-porosity shale system from a production standpoint. Understanding the complex but coupled flow mechanisms in such reservoirs is essential to design appropriate completions and further, optimally produce them. Dual-porosity and dual permeability models are most commonly used to describe a typical shale gas reservoir.
Design/methodology/approach – Characterization of such reservoirs with extremely low permeability does not aptly capture the physics and complexities of gas storage and flow through their existing nanopores. This paper reviews the methods and experimental studies used to describe the flow mechanisms of gas through such systems, and critically recommends the direction in which this work could be extended. A quad-porosity shale system is defined not just as porosity in the matrix and fracture, but as a combination of multiple porosity values.
Findings – It has been observed from studies conducted that shale gas production modeled with conventional simulator/model is seen to be much lower than actually observed in field data. This paper reviews the various flow mechanisms in shale nanopores by capturing the physics behind the actual process. The contribution of Knudson diffusion and gas slippage, gas desorption and gas diffusion from Kerogen to total production is studied in detail.
Originality/value – The results observed from experimental studies and simulation runs indicate that the above effects should be considered while modeling and making production forecast for such reservoirs.

Keywords Flow mechanisms, Multiple porosity, Reservoir characterization, Shale reservoirs

Paper type Research paper

1. Introduction

With the increasing energy consumption throughout the world, it is unlikely that the rate at which conventional hydrocarbons are produced is going to be able to match the demand. The estimates of world energy supply and demand have shown that the total demand in energy will increase by one-third from 2010 to 2035. Additionally, because of environmental concerns with oil and the risks posed due to geopolitical reasons, most countries are looking toward natural gas as the energy solution of the future; natural gas being the cleanest energy resource used so far (World Energy Outlook, 2012). In fact, the USA saw a decrease in their gas imports in 2007 for the first time since the 1970s when a production surge was brought on by shale gas exploitation and that trend has continued. With the discovery of shale gas reservoirs, many energy-hungry but resource-deprived countries are lining up to replicate the shale success story; most notably China, Australia, India and Latin America.

Appalachian Devonian shale was the first shale reservoir found in the state of New York in 1821 (Lancaster *et al.*, 1996) and by the early 1990s, the number of wells that were drilled in it was in the order of thousands. It was only with the advent of the coupled technologies of horizontal drilling and hydraulic fracturing that the production started proving to be economical. Gas production from shale reservoirs has contributed immensely to the USA becoming a net gas exporter since 2012, besides reducing its energy dependency on foreign oil. The gas from shale reservoirs, being environmentally friendly and technically recoverable, has led to several countries looking to explore for shale gas on their own shores.

Because of the lessons learnt over the past two decades, drilling and completion practitioners may have gone beyond the early learning curves, but when it comes to an understanding of transport mechanisms within such reservoirs, a steep curve awaits researchers. Significant amounts of work have been done by researchers, when it comes to characterizing a shale reservoir accurately, and aptly describing the transport mechanisms by which gas gets transported within them. Knudsen diffusion within the existing nanopores, followed by desorption, followed by viscous flow within the existing natural and hydraulic fractures, define the flow regimes in such reservoirs. This detailed characterization of the various transport mechanisms is because of the existence of multiple porosity systems within the reservoir. When shale reservoirs are hydraulically

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World Journal of Engineering
13/6 (2016) 529–539
© Emerald Group Publishing Limited [ISSN 1708-5284]
[DOI 10.1108/WJE-09-2016-0087]

Received 25 September 2016
Accepted 25 September 2016

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fractured, the stimulated reservoir volume adds to the already existing spatial heterogeneity within such reservoirs, thereby making them even more difficult to characterize. An advanced model was constructed (Yan *et al.*, 2015) that allows the simulation of an arbitrary number of porosity types which accurately capture the transient flow in the matrix, which otherwise is not possible with the dual-porosity models that are used to characterize such reservoirs. It has been seen that the multiple-porosity models that have been developed show a good match with the single-porosity models, and the application of matrix subdivisions further increases their accuracy. Lopez and Aguilera (2013) have introduced a quintuple-porosity system for shale gas reservoirs, which discuss the importance of characterizing a shale gas reservoir into multiple porosity types, and the corresponding transport mechanisms within them. Real data from Devonian gas shales are used to illustrate the effect of free gas, adsorbed gas and dissolved gas in a material balance cross-plot of P/Z vs cumulative production. They further conclude that the original gas in place (OGIP) computed without considering additional porosities is less than that computed by considering multiple porosity types in such reservoirs. Work has been done (Hinkley *et al.*, 2013), where all the capabilities of available reservoir simulators were exhausted to explore the advantages and disadvantages of simulating unconventional reservoirs like shales, using one-, two-, three- and four-porosity systems, along with their corresponding flow mechanisms. The authors conclude that the quad-porosity model gave an excellent match with the field data, and Knudsen diffusion and the slip flow phenomenon had a significant impact on both the matrix permeability and gas production. Also, a petro-physical model was built for shale reservoirs (Lopez and Aguilera, 2014), which allows for the quantification of storage capabilities through a determination of adsorbed porosity, organic porosity, inorganic porosity and hydraulic fracture porosity. The authors further used data recognition techniques to delineate various flow regimes, which compared wells against laboratory data. Results from the petro-physical model confirmed that the quantification of all these porosities is important for the numerical simulation of shale reservoirs.

In such reservoirs, the scales of the fractures are of importance. The natural fractures are on an entirely different scale, as compared to the created hydraulic fractures, thereby affecting the fluid flow through them. A new methodology has been presented by researchers (Legrand *et al.*, 2016), by which they extended the single-fracture-scale dual-porosity models to situations with higher scales. They further investigated the optimum methodology required for the transfer of fluids between different fracture scales.

It is because of the heterogeneity-like fractures, barriers and faults present within such reservoirs, that production becomes difficult. Work has been done, in which such heterogeneities were modeled and responses on the production profile were observed. Zhang *et al.* (2016) have discussed the problems faced when conducting a successful steam-assisted gravity drainage (SAGD) process, when interbedded shales are encountered, as the success of an SAGD process is much more common in a homogeneous reservoir, than in a heterogeneous one. Furthermore, because of the complex fracture network and multiple porosity types within shale reservoirs, it is very difficult to interpret the pressure transient through such reservoirs. Teng *et al.* (2016) have presented a semi-analytical model to study the pressure behavior in such reservoirs, which considers the multiple transport mechanisms that are prevalent in shale reservoirs. Flow regimes are identified using the proposed model.

2. Background

Generally speaking, reservoir and stimulated reservoir volume (commonly called SRV, calculated as a function of fracturing fluid volume injected) is modified to match production data (without much physical support) (Aguilera, 2010). Additionally, a significant amount of shale gas research has focused on understanding and improving the hydraulic fracturing in shale gas production, and comparatively less work has been done concerning the understanding of the flow mechanisms in shale gas matrices (Andrarde *et al.*, 2010). Modeling and simulation of unconventional reservoirs provide us with an approach to study reservoir flow mechanisms and improve production foresight. Shale gas reservoirs are known to be complex systems composed of quartz, pyrite, clay minerals and organic matter known as kerogen (Sondergeld *et al.*, 2010). Several authors (Wang and Reed, 2009; Apaydin *et al.*, 2012; Yan *et al.*, 2016; Patwardhan *et al.*, 2014) have described shale reservoir structures consisting of four porosity types, namely, inorganic matrix, organic matrix, natural fractures and hydraulically induced fractures. Inside the organic matter, kerogen consists of two parts: porous space and kerogen bulk (Javadpour, 2009). For the accurate computation of the OGIP, it is critical that porosity in all of these individual subcategories is considered. This accurate characterization of shale systems helps in correctly identifying the contributions of the individual flow mechanisms, as well as in assisting better forecasting of the recovery.

2.1 Conventional methods

Conventionally, dual-porosity models have been used to model naturally fractured reservoirs, where all fractures are assumed to have identical properties (Apaydin *et al.*, 2012). Many dual-porosity models have been developed (Warren and Root, 1963) using the sugar cube model in which a matrix provides the storage while fractures provide the flow medium. The model assumed a pseudo-steady-state fluid transfer between matrix and fractures. Since then, several models have been developed mainly as a variation of the Warren and Root (1963) model assuming different matrix-fracture fluid transfer conditions (Freeman *et al.*, 2010). However, to assume that all the fractures have similar properties, such as aperture, flow capacity, etc., would be a highly erroneous assumption, and the existing heterogeneity in them needs to be considered. Such assumptions, in the cases of hydraulic fractures, can lead to incorrect productivity estimates. Thus, triple-porosity (organic matrix, inorganic matrix and natural fractures) and quad-porosity models have been developed as more realistic efforts to capture reservoir heterogeneity (Wu *et al.*, 2004). In petroleum literature, however, the first triple-porosity model was introduced by Abdassah and Ershaghi (1986). Two sub-models were considered: the strata model and the uniformly distributed blocks model. In both of these, two matrix systems have different properties and the fluid is

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flowing to a single fracture, which has considerably different properties, under gradient (unsteady state) as inter-porosity flow.

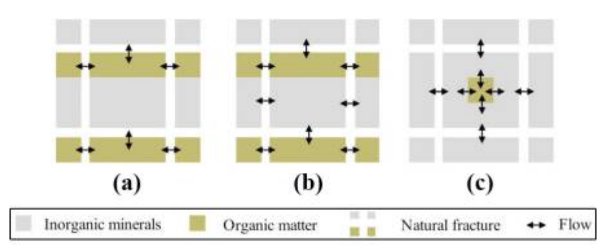
2.2 Triple porosity methods

Al-Ghamdi and Ershaghi (1996) were the first to introduce the dual-fracture triple-porosity model for a radial system. Their model consisted of a matrix and two fracture systems, a more permeable macrofracture and a less permeable microfracture. Two sub-models were presented by them. The first is similar to the triple-porosity layered model where microfractures replace one of the matrix systems. The second is where the matrix feeds the microfractures under pseudo-steady-state flow, which in turn feeds the macrofractures under pseudo-steady-state flow conditions as well. The macrofractures and/or microfractures act as conduits through which fluid flows to the well. Lui (1981) presented a radial triple-continuum model, in which the system consists of fractures, a matrix and cavity media. Only the fractures feed the well, but they receive flows from both the matrix and cavity systems under pseudo-steady-state conditions. Unlike previous triple-porosity models, the matrix and cavity systems are shown to be exchanging flow (under pseudo-steady-state conditions), and thus, it is called a triple-continuum model. Wu *et al.* (2004) used the triple-continuum model for modeling the flow and transport of tracers and nuclear waste in the unsaturated zone of the Yucca Mountains. They represented the system consisting of large fractures, small fractures and a matrix. The authors further validated the analytical solution with numerical simulation for an injection well injecting at a constant rate in a radial system. In addition, they demonstrated the usefulness of the triple-continuum model for estimating reservoir parameters. All the previous models considered pseudo-steady-state flow in the system, until Dreier *et al.* (2004) improved the triple-porosity, dual-fracture model originally developed by Al-Ghamdi and Ershaghi (1996) by considering transient flow conditions between microfractures and macrofractures. However, the flow between a matrix and a microfracture is still considered to be in a pseudo-steady-state condition. His work emphasized the development of a new quadruple-porosity sequential feed and simultaneous feed models. He addressed the need for nonlinear regression to match well test data and estimated reservoir properties in the case of the quadruple-porosity model. Later, a triple-porosity model for shale gas reservoirs was described (Al-Ahmad and Wattenbarger, 2011), in which fractures were considered to have different properties and hence the triple-porosity model was introduced consisting of porous media, less permeable microfractures and more permeable macrofractures. Haghshenas *et al.* (2013) presented a conceptual model with multi-porosity and multi-permeability for fluid flow in shale play. They considered three different configurations for fluid flow through triple-porosity systems (organic matter, inorganic matter and natural fractures). They further proposed a triple-porosity system to characterize a shale system better. Results indicated that the non-Darcy flow component had a significant effect on production behavior in such reservoirs. This effect included additional pressure drop, leading to a loss in productivity from the completed wells. Hudson's (2011) work used a multi-porosity, multi-permeability model in the commercially available reservoir simulation tool, computer modelling group (CMG)-GEM, incorporating the structural details of a typical shale reservoir. With the result from microscopic petro-physical studies such as scanning electron microscopy (SEM), transmission electron microscopy (TEM), etc., the model represented three different permeability conduit networks, including an organic matrix, an inorganic matrix and natural fractures. Three separate configurations were used to investigate the connectivity among the three porous systems, and the impact of each configuration on the expected oil recovery was evaluated. In the first configuration, the organic matter was assumed to be the main gas-bearing porosity system of the shale matrix and the only flow conduit to the natural fractures. Pores within the organic matter were filled with gas and much of the water was likely to be adsorbed on and associated with the surface of clay minerals. In this configuration, the inorganic porosity was assumed to be saturated with water. Under this assumption, the flow was assumed to come only from the organic network feeding the natural fractures. In the second configuration, the organic and inorganic matters simultaneously fed to the natural fractures, and, in the third one, organic porosity fed the inorganic porosity system and inorganic porosity fed the natural fractures. These three configurations are as shown in Figure 1.

2.3 Quad-porosity methods

Swami and Settari (2012) first described a quad-porosity system and developed a theoretical model for shale gas reservoirs. They further segregated the porosity as four storage mechanisms, namely, free gas in natural fractures, free gas in a nonporous organic matrix, adsorbed gas and gas dissolved in kerogen. However, the model only considered two porosities: natural fracture and organic matrix. Knudson diffusion and slip flow were taken into account through the incorporation of apparent permeability. In their work, a shale reservoir was represented by the quadruple-porosity system which was first introduced by Aguilera (2010) and Andrade *et al.* (2010, 2011), namely, as organic and inorganic matrix and natural and hydraulic fractures. Hudson (2011) analyzed the gas transport in shale reservoirs with an explicit differential model. The simulation of Hudson's (2011) work, based on a quad-porosity system, was implemented using a commercial

Figure 1 Conceptual model of three pore-connections configurations



Notes: (a) Configuration 1; (b) Configuration 2; (c) Configuration 3
Source: Haghshenas *et al.* (2013)

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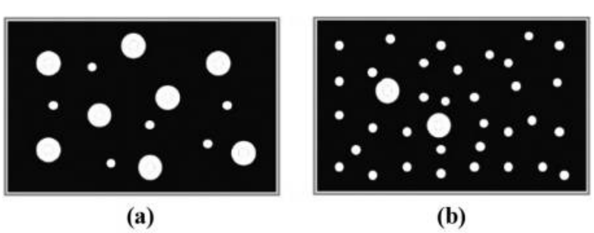
reservoir simulator. The differential equations were derived from a conservation approach and were solved with the help of finite difference approximation which was included in the simulator. Patwardhan *et al.* (2014) described the production history and pressure distribution in shale reservoirs based on a quad-porosity model. The gas transport in porous media was described using the effect of slip flow, Knudson diffusion and Langmuir desorption, and the simulations were carried out using CMG-GEM. According to the results, considerable differences in well productivity and pressure transients were observed when reservoirs were modeled as quad-porosity systems. Also, emphasis was laid on the fact that accurate and appropriate characterization of such reservoirs is important for the estimation of their production potential and for forecasting-related economic scenarios.

3. Flow mechanisms

Traditionally, shale gas reservoirs have been represented as a dual-porosity, dual-permeability system, and it has been perceived (Boyer *et al.*, 2006) that in such reservoirs, gas is stored only in pores' spaces (matrix and natural fracture) and adsorbed on pores' surfaces. However, with recent visualization and measurement techniques, additional gas has been found to be dissolved in organic matter as well. Many studies have shown that in shale gas reservoirs, natural gas is generated from organic matter; hence, compositional variation in organic matter makes such reservoirs highly heterogeneous (Javadpour, 2009). Therefore, a conventional dual-porosity system cannot be used for accurately describing such systems. Sondergeld *et al.* (2010) stated that the porosity that occurs within organic matter, pyrite and minerals exists in the form of microcracks. Therefore, advanced reservoir engineering methods are necessary to model gas flow in shale reservoirs. Conventional methods, using Darcy's law, underestimate actual production from shale (Lu *et al.*, 1995; Freeman *et al.*, 2010; Javadpour, 2009; Shabro *et al.*, 2011; Ambrose *et al.*, 2010).

Javadpour (2009) stated that gas flow in nanopores cannot be described simply by the Darcy equation. Processes, such as Knudson diffusion and slip flow at the solid matrix, separate gas flow behavior from Darcy-type flow. Conventional methods note that the amount of gas dissolved in kerogen bulk is negligible and further to that, even if there is any gas at all, the rate of diffusion is extremely low, thereby making this quantity even more insignificant. Figure 2 compares the pore distributions in conventional and unconventional shale reservoirs.

Figure 2 Pore distribution of conventional and shale gas reservoirs



Notes: (a) Conventional; (b) shale gas
Source: Javadpour (2009)

As shown in Figure 2, the number of nanopores is seen to be higher in unconventional shale gas reservoirs. The diameter of pores in shale gas sediments ranges from nanopores to a few micropores.

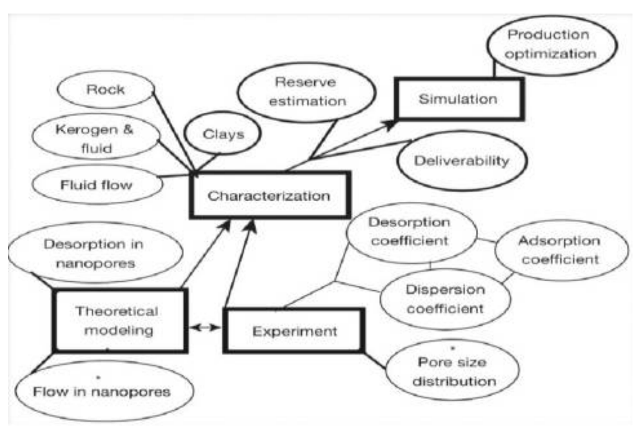
4. Impact of shale gas physics in gas production

Understanding the physical aspect of gas production from shale gas sediments is important for reservoir development and production optimization. Javadpour *et al.* (2007) presented a research study of shale gas reservoirs, in which the research was divided into experimental and theoretical studies. From experimental research, pores' size distribution and characteristics coefficients, such as the permeability and dispersion coefficients, have been determined, and from theoretical modeling, the flow and desorption in nanopores were studied. Combining these two studies led to better shale gas sediment characterization for deliverability analysis and reserve forecasting. Figure 3 shows the spider diagram of the study undertaken.

In the study, the authors presented the experimentally obtained permeability values of 152 samples from several reservoirs with pore-sized distribution of several shale gas samples at a specific 6,000 psi mercury injection pressure, as well as desorption data for a representative shale sample. In the theoretical section, descriptions of gas flow in nanopores and gas evolution curves using probability density functions were presented. From these results, the authors stated that gas storage and flow in shale gas sediments are a combination of different controlling processes. Gas is stored as compressed gas in pores, as adsorbed gas in the pores walls and as soluble gas in solid organic materials, i.e. kerogen and clays. Gas flows through a network of pores with different diameters ranging from nanometers (nm $= 10^{-9}$) to micrometers (μm $= 10^{-6}$). In shale gas systems, nanopores play two important roles:

1 For the same pore volume, the exposed surface area in nanopores is larger than in micropores. This is because the surface area is proportional to 4/d where d is the pore diameter. This large area lets large volumes of gas desorb from the surface of the kerogen in nanopores. Therefore,

Figure 3 Spider diagram of experimental and simulation work undertaken



Source: Javadpour *et al*. (2007)

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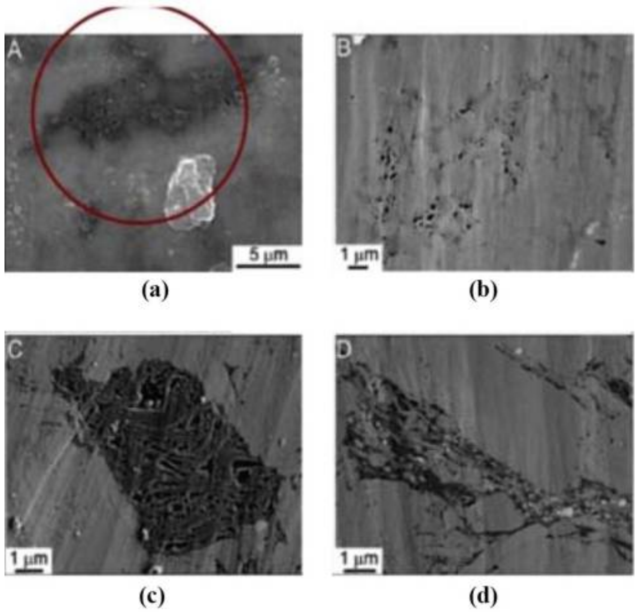
a higher mass transfer of gas molecules occurs inside the bulk kerogen.
2 Gas flow in nanopores is different from Darcy's law, which has been discussed in an earlier section.

5. Theory and model development

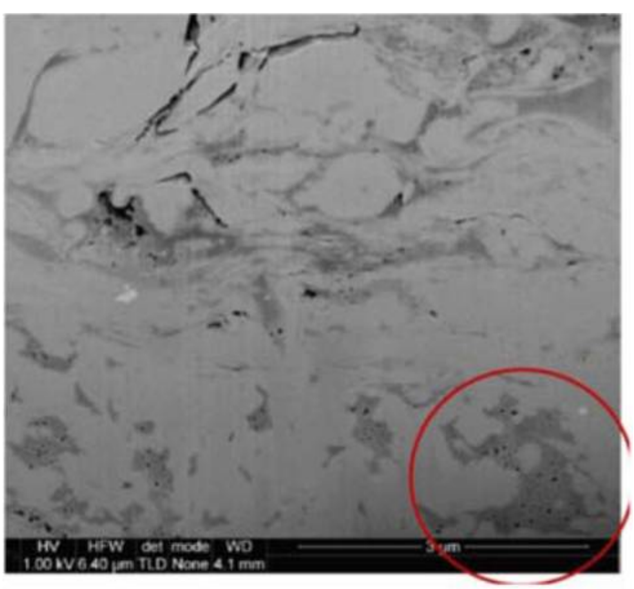
With the current knowledge and advancements, it is possible to look at such reservoirs at nanoscales. Figures 4 and 5 show scanning electron microscope (SEM) images for different shale samples. As can be seen from the sections in red circles, the reservoir matrix is composed primarily of clay/silica, organic matter and some mineral like feldspar. It is important to note that all the pores are exclusively located inside the kerogen.

Figure 4 SEM images of shale gas reservoirs showing the location of pores and kerogen



Source: Loucks *et al*. (2009)

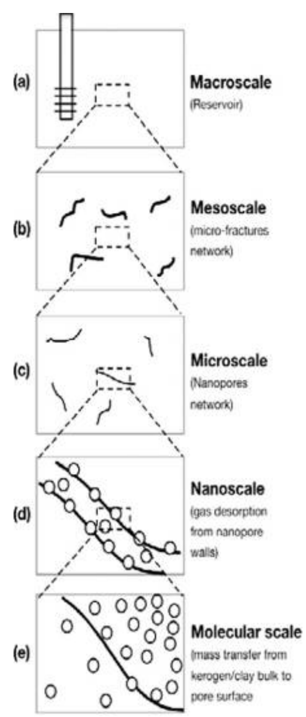
Figure 5 SEM images of shale gas reservoirs



Source: Ambrose *et al*. (2010)

Figure 6 shows the simplified view of shale gas reservoirs at different scales. At the nano- and molecular scale, it is depicted that gas is present as free gas (compressed) in the pore spaces, adsorbed at the pore walls and also diffusing out from kerogen. Studies (Javadpour, 2009) have confirmed that the amount of gas dissolved in the kerogen is negligible and furthermore, the rate of diffusion is extremely low, making this quantity even more insignificant. Based on the work (Javadpour, 2009; Swami and Settari, 2012) presented that was based on classic continuous accumulation, shale gas is a self-sourcing rock and, over the geological period of time, the organic matter gets converted into gas and builds up pressure in the system. This gas is liberated into the nanopores and is stored as free/compressed gas and is also adsorbed on the pore walls. The authors theorized that the kerogen has to be saturated with gas at a particular pressure before it can be able to liberate gas into the pores. In the laboratory, it may be practically impossible to determine gas solubility in kerogen at particular pressures and temperatures. Hence, in their work, corresponding values of bitumen were used. It is known that bitumen is the product of kerogen diagenesis, hence making it very similar to bitumen, chemically speaking. Therefore, in their work, because of the lack of data on kerogen, the authors used the saturation and diffusivity constant values corresponding to bitumen.

Figure 6 From micro- to nanoscale



Source: Javadpour *et al*. (2007)

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6. Sub-systems of the quad-porosity

In this section, a detailed description of various aspects of shale gas reservoirs is emphasized. The four porosity systems within the shale gas reservoir consist of organic and inorganic matter, along with natural and hydraulic fractures. Adsorption/desorption is observed from organic pores and diffusion from organic matter (kerogen) takes place.

6.1 Inorganic matrix

A mineral matrix or inorganic matrix, because of its composition of clay minerals, silica, etc., shows significantly small pore size, in the order of micrometers (Moghanloo *et al.*, 2013). Hence, in this case, viscous flow is not the dominant gas transport mechanism. Additionally, mechanisms such as slip flow and Knudson diffusion are too significant to be ignored. Several authors (Swami and Settari, 2012; Swami *et al.*, 2013) have proposed that inorganic pores are in the range of micropores, while flow within the inorganic matrix can be represented by viscous flow. These two observations are in conflict with each other, and experimental validity would be required to assess the actual flow condition.

6.2 Organic matrix

In the organic matrix, the pores' sizes are in the range of nanopores, and the gas transport deviates from viscous flow behavior. Hence, non-Darcy flow mechanisms such as slip flow and Knudson diffusion should be taken into account. Additional mechanisms are considered in the definition of apparent permeability (Civan, 2010; Javadpour, 2009; Swami and Settari, 2012).

The following equations define the diffusion component of the shale gas transport mechanism:

For Knudson diffusion and slip flow, the corrected equation is as follows:

$$K_a/K_D = F_K + F_S \tag{1}$$

Where F_K is the factor because of Knudson diffusion and F_S is the factor because of slip flow:

$$F_K = C_1 \frac{\mu M D_K}{RT\rho} \frac{8}{r^2} \tag{2}$$

Where C_1 is a conversion factor, and ρ is the gas density:

$$F_S = 1 + C_2 \left[\left(\frac{8\Pi RT}{M} \right)^{0.5} \frac{\mu}{pr} \left(\frac{2}{\alpha} - 1 \right) \right] \tag{3}$$

Where C_2 is another conversion factor, and α is the tangential momentum accommodation coefficient. The value of α varies, theoretically, from 0 to 1, depending on the wall surface smoothness, the gas type, temperature and pressure. Javadpour *et al.* (2007) suggested that the value of $\alpha = 0.8$. The Knudson diffusion factor D_K is defined as:

$$D_K = \frac{2r}{3} \left(\frac{8RT}{\pi M} \right)^{0.5} \tag{4}$$

Diffusion flow becomes a function of pressure gradient instead of compositional gradient by the assumption of single-phase flow. The velocity in the x-direction because of the single component diffusion can be expressed as:

$$v_D = \frac{M_g D_K}{\rho_g} \frac{\partial c}{\partial M} \tag{5}$$

The molar concentration for single-phase flow can be expressed as:

$$v_D = \frac{M_g D_K}{\rho_g RT} \frac{\partial p}{\partial x} \tag{6}$$

6.3 Natural and hydraulic fractures

Gas transport within natural and hydraulic fractures is modeled by considering viscous flow and Darcy's law (Al-Ahmed *et al.*, 2011). The viscous flow of free gas is modeled by Darcy's law and is the assumed transport mechanism in hydraulic fractures. Hydraulic fractures are placed in shale reservoirs to connect with a larger section of the reservoir. When fractures are placed, they connect with the natural fractures, and create a pathway for the gas to flow to the wellbore.

7. Discussion

Over the past few years, several studies have been undertaken to try to provide a better understanding of shale gas production forecasting and gas transport within organic nanoporous media. They all provide innovative alternatives to unconventional methods, and the main differences between these models are related to methods considered in characterizing the total quad-porosity shale gas system. Each one of these studies is summarized briefly in the following table. In this section, a critical analysis of the existing formulations has been undertaken with a view to identify similarities and differences between them.

From Table I, it is clear that these mentioned authors with different approaches have proved that shale gas reservoirs should be characterized as multiple-porosity systems, to predict accurately from it. In a study (Hudson *et al.*, 2012), it has been assumed that each porosity system has different physical properties. Organic matrix has gas-wet nanopores with adsorptive properties and the inorganic matrix has an ultra-low permeability that is most likely water-wet but could have more complex wettability. Two alternative approaches for describing gas transport in shale have been suggested, namely, a lumped tank model and a continuum model. The lumped tank model treats the porosity systems within shale as tanks interacting with each other such that, the relevant physical phenomena, such as adsorption, are described by rate equations. The continuum approach describes gas transport in a manner analogous to the methods used by commercial simulators. Comparison has been made between these two models and the new proposed model by Hudson *et al.* (2012), which shows the inherent complexities of transport processes occurring in shale gas reservoirs. The tank model approach is a rapid simulation of reservoir production and can be accomplished without knowing the details of the reservoir. However, a history match must be made using production history. Therefore, they proposed the lump tank model as the better approach to simulate such reservoirs. Forecasting a

World Journal of Engineering
Volume 13 · Number 6 · 2016 · 529–539

Table I Summary of methodologies used for characterizing quad-porosity shale gas reservoirs

No.	Work done by authors	Characterizations of quad system	Method used
1	Hudson *et al.* (2012)	Organic matrix Inorganic matrix Natural fracture Induced fracture	Two approaches used Lumped tank model Continuum model
2	Aguilera (2010)	Porosity of matrix scaled to the bulk volume Porosity of organic materials in shale scale Porosity of the hydraulic fracture scaled to the bulk of the quadruple-porosity system Fracture porosity scaled to the bulk volume of the quadruple-porosity system	Delivery speed: the ratio of permeability and porosity This relationship provides a relative indication of storage and how quickly fluids can move through porous media
3	Ambrose *et al.* (2011)	Total gas in place A volumetric component, G_f involving hydrocarbons stored in pore space as free gas A sorbed component, G_a, with the gas physically stored on the large surface area of the micro-mesopores A volumetric component G_{so}, involving gas dissolved into the liquid hydrocarbon A volumetric component, G_{sw} involving gas dissolved into the formation water	Volumetric method Using numerical molecular modeling approach
5	Wang and Reed (2009)	Organic matrix Nonorganic matrix Natural fracture Hydraulic fracture	Using recent pore images and geochemical data for the Barnett shale in Fort Worth Basin, north Texas to investigate potential effects of organic matter on petrophysical properties, pore network and shale gas-in-place
6	Patwardhan *et al.* (2014)	Organic matrix Nonorganic matrix Natural fracture Hydraulic fracture	Using sensitivity analysis by constructing a model from Barnett shale gas data, using a commercial simulator. Dependent permeability on hydraulic fractures is also considered in assessing impact on production

reservoir's performance based on limited data, though, could be dangerous, as aspects like reservoir heterogeneities drive mechanisms, and cross-flow through faults could lead to highly erroneous results. Therefore, a lumped model should be used with the utmost caution.

Aguilera's (2010) approach was based on core data from various North American basins. His approach was to differentiate between viscous flow and diffusion-dominated flow, using the process of speed as a part of a flow unit characterization of unconventional process delivery speed. Process or delivery speed is represented by a ratio of permeability and porosity to provide a continuum between conventional, tight and shale reservoirs. Its aim is to provide a relative indication of storage with respect to how quickly fluids can move through porous media. This concept has been used in conventional reservoirs for several decades. However, in his studies, this concept was presented for tight gas and shale gas reservoirs. He concluded that there is a significant potential to use process speed as a part of the flow unit characterization of an unconventional gas reservoir and the flow unit of conventional, tight gas and shale gas reservoirs (unconventional gas) can be estimated from delivery speed method. Ambrose *et al.* (2011) proposed a volumetric method which accounted for the volumes taken up by the free gas and by the adsorption layer. In their work, they combined the extended-Langmuir adsorption isotherm with volumetric and free gas composition to formulate a new gas-in-place equation accounting for the pore space taken up by a multi-component sorbed phase. SEM has discovered nanopores in organic-rich shale with sizes in the 3-100 nm ranges. However, pores of less than 3 nm could not be captured with SEM technology. At this scale, the adsorption layer thickness is infinitesimally small. Thus, a portion of the total volume would be occupied by a finite-size adsorption layer and not available for free gas molecules. The work of Ambrose *et al.* (2010) was based on a single-component Langmuir adsorption model that they modified (Ambrose *et al.*, 2011) to become a multi-component natural gas with sorption model which became known as extended-Langmuir. It has been shown that because of the lack of material and voidage balance in the calculation of gas-in-place, the resource is often seen to be overestimated, where there is a considerable sorbed-phase component (Shabro *et al.*, 2011). Hence, Ambrose *et al.* (2011) proposed a simple conceptual model that shows the pore and matrix system of shale gas, which is illustrated in Figure 7.

The hashed region represents the effect that the sorbed phase has on the porosity. However, in reality, the nature of gas in a multi-component fluid consists of a number of chemical species, each with a distinct sorption affinity and varying contribution to make to the phase densities. Hence, it is oversimplified (Ambrose *et al.*, 2010). However, work by

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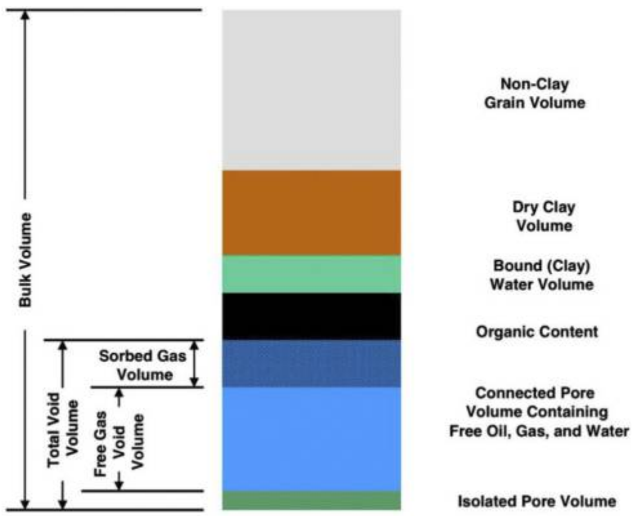
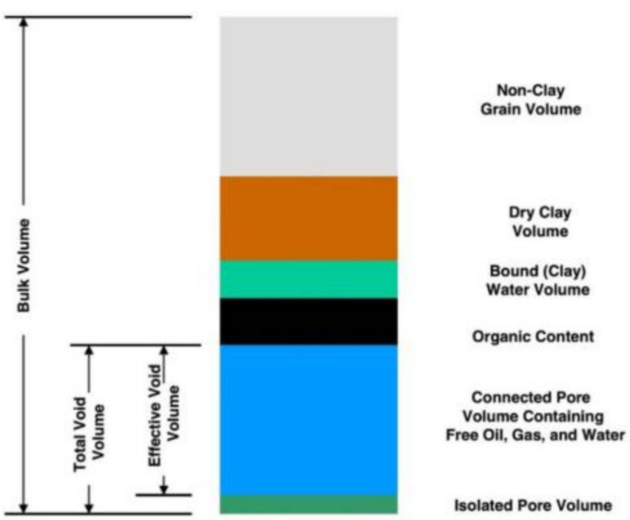
Figure 7 Petrophyscial model from Ambrose *et al.* (2010), showing volumetric constituents of a typical shale gas matrix



Note: The hashed region described the interplay between the sorbed phase and the total porosity
Source: Ambrose *et al.* (2011)

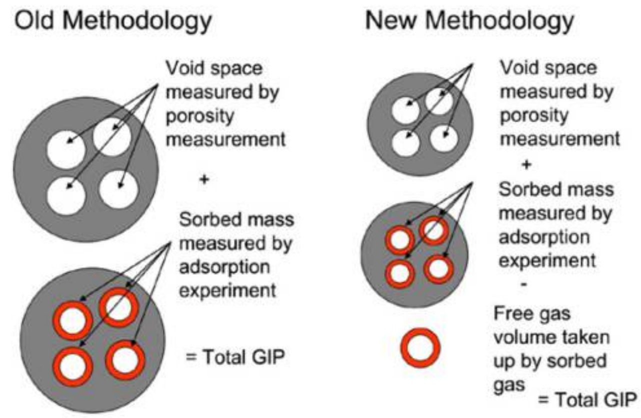
Figure 8 Petro-physical model conceptually showing the volumetric constituents of shale gas matrix



Source: Ambrose *et al.* (2010)

Ambrose *et al.* (2011) has corrected their concept from being a single-component to becoming a multi-component sorbed phase for the void volume, for which the diagram is shown in Figure 8. The simple diagram, that is Figure 9, depicts the new methodology used to determine gas-in-place vs the old methodology. The figure derives information from SEM images, and explains in a simple manner, how the errors get incorporated into calculations, by assuming that the sorbed gas takes up no volume. This method yields a more accurate total gas-in-place prediction, and it is suggested that an adjustment is necessary in volume calculation, especially for shale gas which has high C_2^+ composition and total organic

Figure 9 Comparison of the old and new methodologies in estimation of shale gas-in-place



Source: Ambrose *et al.* (2011)

content. The results indicate that a multi-component nature for shale gas introduces new implications into the gas-in-place estimations. It has been found that a significant sorbed amount could be predicted incorrectly by considering the gas-in-place as pure methane and by not considering the adsorption layer effect.

Wang and Krupnick (2013) provided a model using Barnett shale gas basin data. They investigated the potential effect of organic matter on petro-physical properties, pore network and fluid in shale gas systems. From gas content and adsorption data from Barnett shale, it was suggested that a significant amount of free gas is stored in organic matter. Organic matter is oil-wet and associated pores work as nanofilters of hydrocarbon flow and water-blocking. It was concluded that fluid flow in organic matter is single-phase. The reason is that most pores in organic materials are 10 to 1,000 times larger than the mean free path of gas molecules in reservoir conditions. Hence, owing to high porosity and single-phase flow, the gas slippage effect in organic matter is considerably higher than that in the inorganic matrix and equal or larger than that in the fracture. It could be the hidden pathway to high gas production in gas shales when further connected with natural or hydraulic fractures. Patwardhan *et al.* (2014) indicated that production from wells completed in a quad-porosity reservoir is dependent on the placement of hydraulic fractures and the degree of connectivity to the existing natural fractures. Using a fracture-completed horizontal well in different configurations of quad-porosity shale gas reservoirs, the work used a model to evaluate the effect of gas flow and storage in such systems on production parameters. Additionally, sensitivity analysis is carried out on critical parameters such as permeability, fracture half-length, fracture conductivity, fracture spacing, etc. to observe its impact on well performance.

From the above-cited work, it can be concluded that shale reservoirs are highly heterogeneous rocks with multiple porosities and storage mechanisms. Through various discussed approaches and formulations, almost all authors have recommended that to quantify the actual gas-in-place

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accurately and predict production performance in such reservoirs, these should be considered as multiple and/or most likely quad-porosity systems.

8. Summary and conclusions

A detailed review regarding previous work performed on the topic of shale systems as quad-porosity reservoirs was given in this study. A critical assessment of the previous work that was performed leads us to the following conclusions:

- Containment of gas in shale reservoirs is done in four storage mechanisms – a nonorganic matrix, an organic matrix, natural fractures and hydraulically induced fractures.
- Various flow mechanisms that characterize flow in shale reservoirs have been discussed in detail. Also, ways of improving transport mechanisms in such reservoirs were discussed.
- It is seen that if the simulation model for shale gas is built with separate matrix and fracture characterization, then the model results have a higher chance of validating the corresponding field observations.
- Slippage and Knudsen diffusion are critical phenomena, when it comes to gas flow mechanisms in such reservoirs. These should not be ignored, as it increases the matrix's apparent permeability, which should be considered when accurately representing a reservoir in reservoir simulation.
- It would be highly incorrect not to consider shale as a quad-porosity system, while estimating the oil-in-place. With this incorrect estimate, all future prediction models would, in turn, paint a wrong economic scenario.
- Literature discusses various types of mathematical models that describe fluid flow through nano-Darcy shale gas reservoirs.
- Micro- and macrofractures within the matrix need to be handled differently than the created hydraulic fractures. A significant difference in flow through these systems affects the overall cumulative production capability.
- Many complexities are associated with shale gas sub-systems, and further investigations, both on the experimental and the modeling levels, need to be done to improve the understanding of such reservoirs.

9. Way forward

A critical review of the quad-porosity nature of shale gas systems has led us to some future directions/recommendations about ways in which this work could be extended:

- The laboratory experiment for gas evolution has been used to calibrate the shale gas model (Javadpour *et al.*, 2007). Further, different flow regimes were suggested based on this calibration and the observed production profiles were justified with statistics models. It still remains to be seen whether the different flow regimes and production profiles will be validated with an actual numerical model, which is built from field data, and which captures the actual flow physics.
- It has been seen in all the experimental studies that have been undertaken, that all lost gas is ignored and is not considered. Lost gas is the amount of gas which is released while transporting a core from wellbore to surface. A detailed analysis of the captured lost gas could help develop a better insight into the storage and flow mechanisms in such reservoirs.
- Work done shows that the simulation models perform reasonably well with field data, if the matrix is subdivided. To what extent can the matrix be subdivided/finely gridded, to reach the desired accuracy and exact field-data match? Focusing on the solution obtained from the model as opposed to the computational cost required needs to be investigated.
- Methodology has been developed in the literature, where the authors have extended the single-fracture-scale dual-porosity to fractures of higher scale. Investigations need to be done for situations where the scaling of fractures is taken to much higher levels for a leaky fault, for example, which also acts like a fracture for fluid flow.
- It can be suggested that someone should endeavor to estimate quad-porosity gas-in-place, adding delivery speed (permeability/porosity) methodology to compare the difference.
- Usually in all studies, gas flow is taken to be single-phase in nature. But, there is bound to be some production of water along with gas. The impact of a multi-phase flow on storage and flow characteristics of a quad porosity shale reservoir would be interesting to see.

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