Journal of Natural Gas Science and Engineering 103 (2022) 104649

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

journal homepage: www.elsevier.com/locate/jngse

Multiphysics gas transport in nanoporous unconventional reservoirs: Challenges of mathematical modelling

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ARTICLE INFO

Keywords:
Unconventional reservoirs
Multiphysics flow dynamics
Nanoporous media
Modelling and simulation

ABSTRACT

The flow behavior of fluids in nanoporous unconventional gas reservoirs is a multiphysics process making the mathematical modelling of such reservoirs challenging. Several vital forces and mechanisms are simultaneously playing a role in controlling the flow behavior in unconventional reservoirs. This comprehensive review aims to critically investigate the multiphysics flow dynamics in nanopores including viscous flow, diffusive and advective flow, adsorption and desorption phenomena, stress effect, and capillary and inertial effects. It also highlights a need for a combined approach to tackle such complicated fluid transport in unconventional reservoirs. The physics and characteristics of each transport mechanism are analyzed, and their significances are outlined to understand how the consideration of mechanisms is essential for accurately modelling a complex scenario. Finally, the challenges and prospects of unconventional reservoir modelling are discussed, and some suggestions are provided for the study of fluid mechanics of unconventional reservoirs. It is expected that this review will help researchers with a better understanding of the complexity of modelling of unconventional reservoirs.

1. Introduction

Growing energy demand has now forced the oil industry to pay more attention to unconventional energy resources such as oil sands, tight oil, shale gas, coal-bed methane (CBM), and gas hydrate. Unconventional resources hold a giant energy source for the mitigation of future energy demands. However, unlike conventional hydrocarbon reservoirs that consist of micro-pores and possess high permeability (a fraction of Darcy, D), understanding fluid(s) flow behavior in unconventional hydrocarbon reservoirs containing nano-pores and possessing extremely low permeability (a fraction of milliDarcy, mD) is still a challenging task (Wang et al., 2019a, 2019b; Kazemi et al., 2020; Sayed et al., 2017; Adelinet et al., 2013). The hydrocarbon recovery from unconventional reservoirs could not meet the desired amount of production due to the lack of technology development and proper understanding of unconventional reservoirs. Thus, clear understandings, studies on nonlinear physical processes, and effective technologies are still required to examine the science associated with flow in such complex nano-channels for the proper development of unconventional reservoirs which is still behind the actual needs of oil and gas industries. Compared to conventional reservoirs, the major characteristic of unconventional formations is that their permeabilities are low or ultralow that conventional techniques traditionally used for high permeable systems are not applicable. As such, to facilitate the transport of oil or gas in such formations, unconventional production technologies are needed (Salama et al., 2017). Unfortunately, the modelling tasks for unconventional reservoirs are very difficult due to the complex nature of nanoporous media of formation and anomalous fluid flow behavior. Incorporating the modelling approach has shown success in examining such complex behavior of fluid flow in few cases. However, it has been often seen that in most of the cases, a lack of understanding in considering the exact mechanisms and active forces acting on the fluids, actual governing equations, and proper boundaries conditions leads to huge uncertainty in the modelling results (Weng et al., 2014; Sun et al., 2018; Belhaj et al., 2019).

The complex and nonlinear physical processes associated with the unconventional hydrocarbon reservoirs include adsorption or/and desorption of hydrocarbons onto rock's surface, strong interactions between fluids (oil, gas, and aqueous phases) and rock (minerals), complex non-Darcy's fluid flow behavior in tiny pores with heterogeneous

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https://doi.org/10.1016/j.jngse.2022.104649
Received 6 November 2021; Received in revised form 25 April 2022; Accepted 24 May 2022
Available online 26 May 2022

lithologies including fractures (Wu, 2016). Adsorption, diffusion, advection, capillary and viscous forces as well as viscoelastic properties are responsible for abnormal fluid flow behavior within nanoporous media of unconventional reservoirs.

Several modelling approaches have been utilized to simulate mimicking gas flow through nanoporous media of unconventional reservoirs by using nanotube concept (Beskok and Karniadakis, 1999; Cooper et al., 2004; Holt et al., 2006; Hayat et al., 2017). However, all of these methods of modelling approaches are space and time consuming, and these will become impracticable for larger systems. Considering very small grid size and time step when accurate simulations are attempted to produce precise results, convergence often becomes a momentous problem that further raises a crucial situation. Therefore, further research is still required to justify the applicability of these methods. The comparison between these modelling results to real experimental data has also not been provided in the literature. Therefore, further investigations should be continued to accumulate the knowledge of modelling approach of unconventional reservoirs.

The apparent permeability concept is required to simplify the simulation work of unconventional reservoirs with very low permeability, and it was first proposed by Javadpour in 2009. In 2009, Knudsen diffusion and advection flow was considered to propose apparent permeability idea (Javadpour, 2009). The computing complexity can be significantly reduced by expressing the flux vector term in the Javadpour method in the form of Darcy's equation. The concept of apparent permeability has further been adopted in the modelling of shale gas reservoirs at the pore scale (Civan, 2009; Foroozesh et al., 2019; Shabro et al. 2011, 2012). For unconventional reservoirs, researchers have also developed mathematical equation(s) for the apparent permeability in the form of Knudsen number based on a unified Hagen-Poiseuille equation (Ziarani and Aguilera, 2012; Beskok and Karniadakis, 1999; Civan, 2010). It has been found that only a few basic understandings have been explored and employed yet to define the relation between the complicated processes and the flow-driving mechanisms to investigate the flow behavior in unconventional reservoirs. After a comprehensive literature review, no single work has been found where all active mechanisms were considered to model the fluid flow through nanoporous media of unconventional reservoirs. Therefore, quantifying the fluid flow in unconventional hydrocarbon reservoirs has been still a technical and scientific challenge and requires a key focus on developing fundamental understanding, new technologies, qualitative and quantitative methods, and mathematical models. This review paper provides a comprehensive description of the nanoporous unconventional reservoir, governing flow mechanisms, and modelling of fluid flow behavior. Effects of different physics contributing to flow on the modelling of the unconventional reservoirs have been demonstrated accordingly. The challenges and prospects of unconventional reservoir characterization and modelling for mitigation of future energy demand are also presented.

2. Aim and novelty of the review

Literature survey reveals that the proper methodology for modelling unconventional reservoirs should be summarized in a review. At the same time, it also has found that the anomalous nature of pore size distribution (due to heterogeneous and complex mineralogy and lithology of poorly connected nanometer or micrometer-size pore structure) has not been discussed properly considering all the influencing mechanisms in fluid flow. On the other hand, modelling and simulation of unconventional reservoirs play a vital role in understanding the nature of unconventional reservoirs. It is found in the literature that the Lattice Boltzmann method and pore network model are generally applied to simulate the unconventional nanoporous reservoirs (Lilley and Sader, 2008; Rahmanian et al., 2011). Different articles focus on one or two influencing physics to model the fluid flow behavior in unconventional reservoirs. It is difficult to find a single literature where the multiphysics of flow transport has been considered in modelling. Therefore, the present review has taken an attempt to summarize all the works considering improved unconventional reservoir characterization by different modern imaging techniques and different mechanisms responsible for unusual fluid flow behavior in the unconventional reservoirs. There are some review articles available in the literature on unconventional reservoirs and prospects of future energy demand (Taghavinejad et al., 2020; Chong et al., 2016; Lin, 2016; Li et al., 2015; Arogundade and Sohrabi, 2012). However, the present review impulses to convey the message of its novelty based on the combined summary of characterization and modelling, and simulation of unconventional reservoirs. This article first summarizes the different unconventional reservoirs and their worldwide reserves for a basic idea of the energy scenario of unconventional reserves. Later on, the difficulties in the characterization of unconventional reservoirs based on nanopore size distribution by imaging techniques are discussed. No other review has documented this information previously. The most important part of the review is to summarize different fluid transport physics affecting flow behavior in nanoporous rocks and introduce the concept of a combined model, which shows the novelty of the present review.

3. Unconventional oil and gas reservoirs

Unconventional oil and gas reservoirs have increasingly been playing a significant role in the worldwide hydrocarbon production which includes the commercial production of tight gas, oil sands, and CBM and the rapid increase of shale gas and tight oil production caused by the revolution of shale gas in the United States of America (Jarvie, 2012; Guangming, 2008; Caineng et al., 2010; Zandong et al., 2011; Zou et al., 2016). Gas hydrate is another giant resource of energy for the coastal countries due to the large volume of reserves. But still, economic production is in the developing stage as the proper characterization and exploration of gas hydrate reservoirs are yet to be completed. Fig. 1 shows the major classes of unconventional resources that have the highest interest for future energy sources to mitigate the continuously increasing energy demand. It is also important to consider the

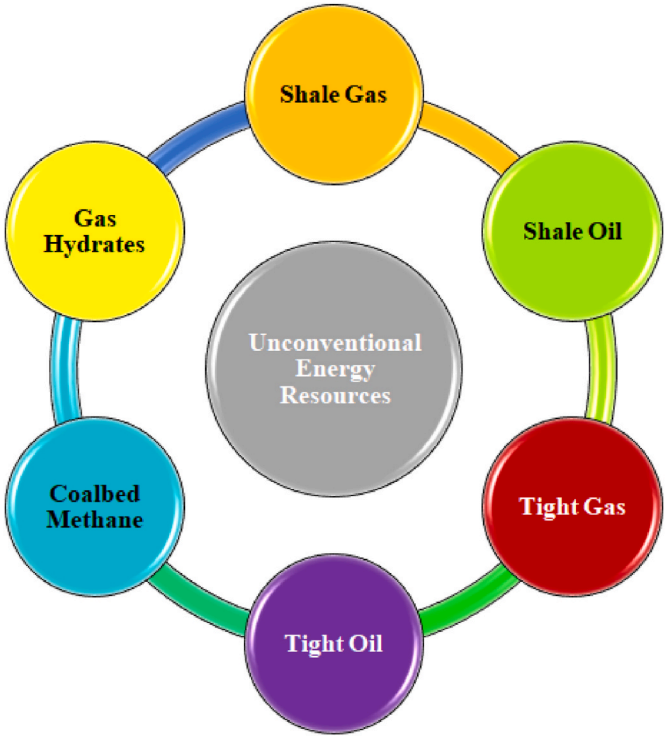

Fig. 1. Classification of unconventional energy resources.

unconventional resources of Alberta's oil sands and heavy oil/bitumen that have a major contribution to Canada's energy supply. Deep gas is also one of the classes of unconventional resources, which is explained by shale gas.

Conventional and unconventional hydrocarbon resources can also be defined with the help of a viscosity-permeability cross-plot. Cander (2012) put forward a similar approach to identify unconventional hydrocarbons and proposed that unconventional hydrocarbon resources are such resources that can be recovered at commercial production levels by altering the permeability of rock or/and viscosity of fluid (suitable permeability-viscosity ratio). Another classification of unconventional resources mainly implies as technology (including development) and economics (including productivity) driven approach (Aminzadeh and Dasgupta, 2013). In other words, such resources fall into a set of continuous (or pseudo-continuous) resources with no natural commercial yield, but that can only be extracted (or recovered) through implementing suitable reservoir stimulations in order to meet the required mobility or ratio between permeability and viscosity.

A schematic characterization of conventional and unconventional hydrocarbon resources is depicted in Fig. 2 based on permeability, pore size, hydrocarbon viscosity, natural productivity, and technology requirement for development to make it commercially viable, including worldwide reserve's percentage of different types of resources.

4. Multiphysics fluids flow through nanoporous media

Various forces such as viscous, inertial and capillary forces, and phenomena such as adsorption and desorption, diffusion and advection and also viscoelastic properties of the medium influence the fluid flow through nanoporous medium of unconventional reservoirs. Transport behavior of gas (containing both free-state and absorbed gas molecules) in nanoporous unconventional reservoirs is critical and yet a challenge for exact estimation of net reserve, transport mechanism, and hence the production management. Moreover, the extreme confinement of the nanoporous media can affect the flow dynamics of the gas molecules specially the mean flow path that promotes existence of different flow-regimes such as slip, continuum, transition, and free molecular (Bhattacharya and Lie, 1991). Thus, it further results a non-linear flow behavior depending on the pore size, reservoir pressure, temperature, stress, mean particle's velocity (of gas molecules), etc. (Fakcharoenphol et al., 2014; Li et al., 2017). In these flow regimes, the flow of gases does not obey continuum assumptions (unless under certain conditions) hence Darcy's law is not satisfactory in illustrating such flow. The transport mechanism of gases in such tiny pores is controlled by a diffusion process (multiscale diffusion mechanism) and characterized by a dimensionless number, Knudsen number (K_n). The probability of collisions or diffusion within the gas molecules is directly associated with an important parameter called mean free path (λ) of a gas molecule, expressed as follows by Eq. (1):

$$\lambda = \frac{\mu_{nw}}{P_m}\sqrt{\frac{\pi RT}{2M}} \tag{1}$$

Different mechanisms usually control the gas molecular flow, depending on the scale of the flow path and pressure of gas (P_m). Moreover, the ratio of λ and 'd_f' is named as Knudsen number (K_n) where, 'd_f' is the characteristic size of the gas flow channel as shown in the below Eq. (2):

$$K_n = \frac{\lambda}{d_f} \tag{2}$$

If the pressure is increased, the average mean free path is decreased, and thus, the Knudsen number reduces (see Fig. 3).

A schematic of gas transport and different flow regions, including adsorbed, Knudsen, and bulk region of an organic nanopore is depicted in Fig. 4. These multi-transport mechanisms consisting of different flow-region for free and adsorbed gas molecules have already been explained somewhere else (Jia et al., 2018a, 2018b; Ning et al., 2017; Medveď and Černý, 2011).

Fig. 5 indicates different flow regimes at different Knudsen numbers. For $Kn < 10^{-3}$, continuum flow (without slip) represented by Darcy or Navier-Stokes equations is applicable. Slip flow (Klinkenberg correction) needs to be coupled to continuum flow for $10^{-3} < Kn < 10^{-1}$, which is applicable to the majority of conventional gas reservoirs and unconventional tight systems. Nevertheless, due to nanoporous

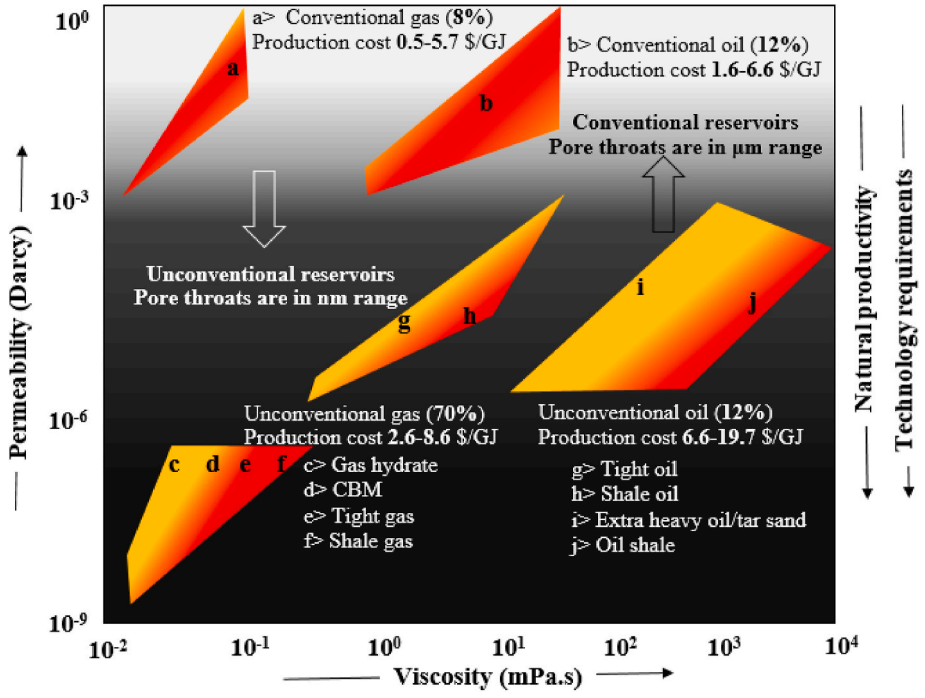

Fig. 2. Properties, global percentage reserves, natural productivity, technology requirements, and production cost associated with conventional and unconventional reservoirs and reserved hydrocarbons (Aminzadeh and Dasgupta, 2013; Caineng et al., 2013; IEA, 2010).

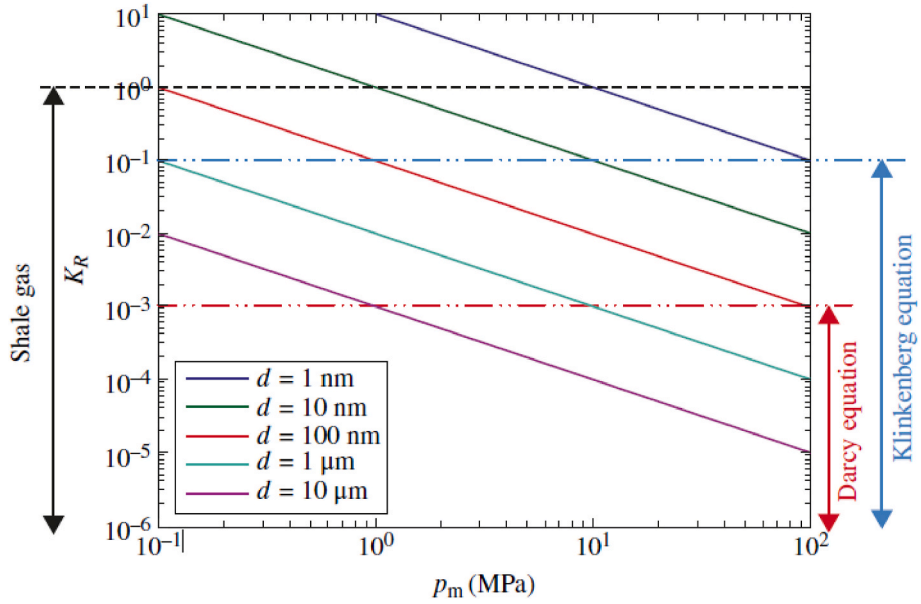

Fig. 3. Knudsen number (*Kn*) versus mean reservoir pressure for a porous system at different mean pore sizes (Rezaee, 2015).

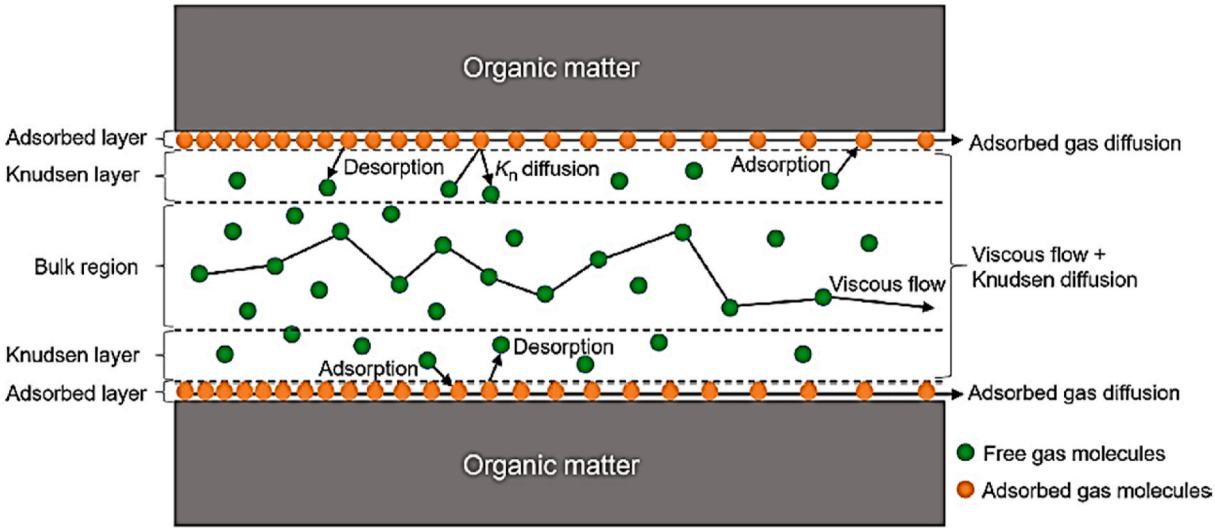

Fig. 4. A schematic of different flow types of the gas molecules in different layers of an organic pore of unconventional nanoporous reservoirs during gas transport (Ning et al., 2019).

structure of shale systems, *K*n could be larger than 0.1, leading to have Knudsen diffusion flow (Transitional flow) and *K*n even becomes higher than 10 where free molecular flow is developed.

4.1. Viscous flow

For understanding the proper effect of viscous force on fluid flow within unconventional reservoirs, the concept of water movement within nanopores can be considered. The governing equation for viscous flow is explained based on the modified Hagen-Poiseuille equation. The pore size flow theory can be used for modelling fluid flow through nanoporous media of unconventional reservoirs only when the dimension of characteristic flow is large enough.

The variation in the value is common, and the extent of departure value predicted by Hagen-Poiseuille equation is very significant, and that fails to illustrate the fluid flow through nanoporous media (Majumder et al., 2005; Holt et al., 2006) due to a "velocity jump" at the walls and the water migration and hydrogen bonding at the boundary region. For accurate modelling of fluid flow through nanopores, a pressure gradient ∂p/∂z in nanoporous media, the true slip, and effective velocity must be considered, and a volumetric flow flux can be expressed as (Holt et al., 2006):

$$Q_s = \frac{\pi}{8\mu(d)}\left[(d/2)^4 + 4(d/2)^3 l_{s,t}\right]\frac{\delta p}{\delta z} \tag{3}$$

where, μ(d) refers to the bulk viscosity of the fluid, d is pore diameter, and $l_{s,t}$ is the path-length.

A predicted flow flux (Q_n) can also be derived based on the Hagen-Poiseuille equation in terms of infinite viscosity (μ_∞), bulk viscosity with a no-slip boundary condition. The enhancement factor can be defined as the ratio of the measured (Q_s) to the predicted (Q_n) flow fluxes expressed in Eq. (4) (Holt et al., 2006; Majumder et al., 2005).

$$\varepsilon = \frac{Q_s}{Q_n} = \left[1 + 8\frac{l_{s,t}}{d}\right]\frac{\mu_\infty}{\mu(d)} \tag{4}$$

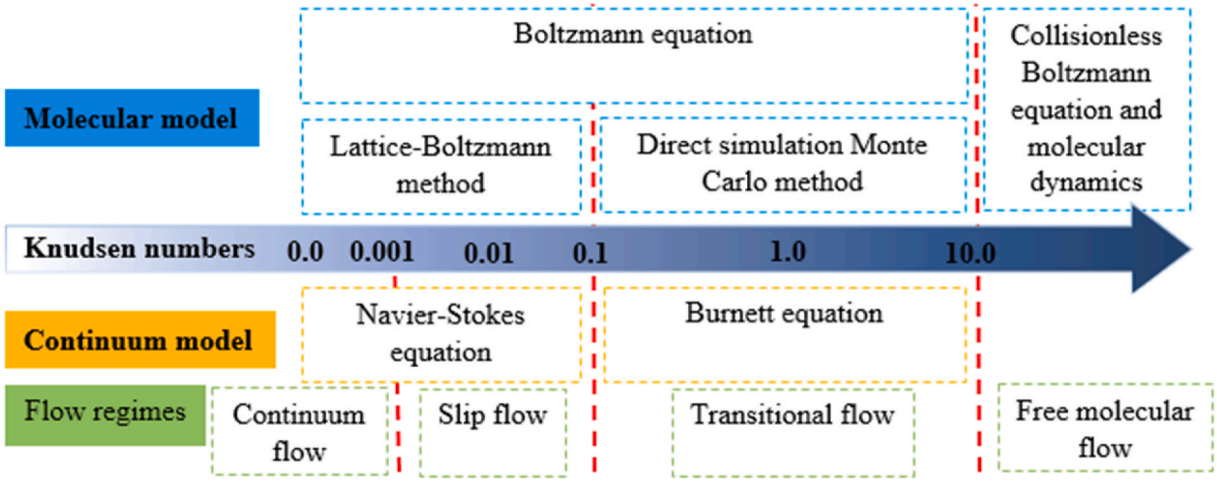

Fig. 5. Typical governing flow models for different flow regimes (Modified from Wang et al., 2017 and Taghavinejad et al., 2020).

A huge wide range (over six orders of magnitude) of the enhancement factors may appear due to diverse dimensions and verities of the fluid confinement in nanoporous media. The model could simulate accurately these fluids' confined flows and successfully predict or capture the governing multi-physics associated with the different flow behaviors. Three different boundary conditions such as (i) the multilayer sticking, (ii) slip, and (iii) no-slip at the pore's surface should be considered in the aforementioned model (Zhang et al., 2012). Moreover, it also demonstrates that the wettability is indeed one of the governing factors that control the flow behavior of the confined fluid.

On the other hand, the viscous flow will take a different form in the case of the slip flow coupled with the Knudsen number. In this regard, Stops (1970) stated that the motion of gas molecules can be estimated by using the collision of the molecules with each other if the pore throat diameter is bigger than the mean free path (of gas molecules). As a result, the molecules have less time to collide with the wall. Therefore, viscous flow takes place due to the pressure gradient developed within single-component gas molecules.

However, the mass flux 'N_v' (kg/(m^2·s)) of viscous flow with gas density 'ρ_g' (kg/m^3) can be determined using Darcy's law as expressed below (Kast and Hohenthanner, 2000):

$$N_v = -\frac{\rho_g k_i}{\mu_g}(\nabla p) \tag{5}$$

where, k_i and ∇p are the intrinsic permeability (m^2) of the nano-capillary and differential pressure (Pa) across the capillary.

4.2. Diffusive flow

Generally, three major types of diffusion of the gas molecules may co-exist in a pore throat viz., surface, bulk, and Knudsen as shown in Fig. 6. Surface diffusion appears for the gas molecules that are adsorbed along the pore's surface (Lanetc et al., 2021; Karim et al., 2018). The flow mechanism involved with the surface diffusion can be examined through (i) Fick's law-based surface diffusion models coupled with Langmuir adsorption isotherm and (ii) chemical potential concept related Maxwell-Stefan approach. It should be noted that Maxwell-Stefan formulation (non-Fickian mass transfer) has been used for unconventional reservoirs in the literature for modelling mass transfer of multicomponent systems (Karim et al., 2018; Santiago and Kantzas, 2020). Knudsen diffusion becomes significant in the flow regime at higher Knudsen numbers. As a matter of fact, Knudsen number could be larger than one necessitating the consideration of mechanisms such as Knudsen diffusion and slip flow at which rock permeability demonstrates to be pressure dependent (Salama et al., 2017). Knudsen

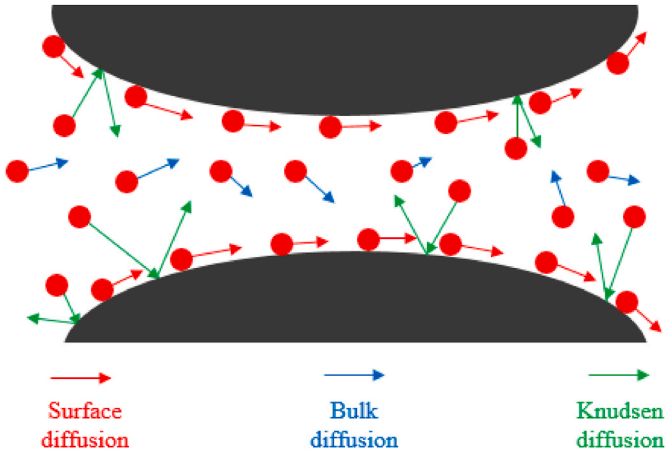

Fig. 6. Schematic of different kinds of diffusion (surface diffusion: red arrow, bulk diffusion: blue arrow, Knudsen diffusion: green arrow) of gas molecules in a pore throat.

diffusion happens due to the fact that the collisions between gas molecules and walls are more than intramolecular collisions, so "resistances in series" approach is assumed in the literature for capturing the competition between Knudsen diffusion and molecular diffusion (Zhao et al., 2003).

Knudsen diffusion is dedicated only to the movement of free gas molecules raised due to their collision on the pore surface shown in Fig. 6 (green arrows). It has been found that the Knudsen diffusion coefficient is proportional to the differential pressure along the pore channel. The flux associated with the Knudsen diffusion of free gas can be calculated using Eq. (6).

$$N_k = \frac{\varphi}{\tau}\frac{2r}{3}\sqrt{\frac{8ZRT}{\pi M}}\frac{P}{ZRT}C_g\nabla P \tag{6}$$

where, N_k indicates the flux for Knudsen diffusion of free gas (mol/m^2.s); φ represents the effective porosity; τ is the correction factor for tortuosity; Z accounts for the compression factor; T is the absolute temperature of formation (K); R is the universal gas constant (8.314 J/(K mol)); P is pore pressure (MPa); M represents molecular weight (kg/mol); and C_g provides the value of gas compressibility (MPa^{-1}).

The migration of gas molecules along the pore wall is known as surface diffusion (Fig. 6; red arrows) that is due to the chemical potential gradient as a result of changes in production pressure. The flux for

surface diffusion of gas molecules can be calculated by Eq. (7).

$$N_s = \varepsilon_{ks}(1-\varphi)D_{s,0}\frac{P}{ZRT}\frac{C_{\mu s}P}{P_L^2+P_LP}\nabla P \tag{7}$$

where, N_s is the flux for surface diffusion of adsorbed gas (mol/(m^2. s)); ε_{ks} is the quantity of solid organic matter, φ represents the total interconnected pore volume of matrix; $D_{s,0}$ is the surface diffusion coefficient of organic matter at zero loading (m^2/s); P_L is the Langmuir pressure (MPa) and $C_{\mu s}$ is the Langmuir volume of the organic matter surface (mol/m^3).

Contrary to the classical fluid mechanics, experimental studies showed that the slip flow occurs at the surface of the micro-pores regardless of the surface wettability (Yoshio, 2012; Wang et al., 2019a, 2019b). Moreover, the ratio of the pore size to the Knudsen layer's thickness varies with Knudsen number (*Kn*) and different slip boundary conditions are used to describe (Karniadakis et al., 2006; Wang et al., 2019a, 2019b; Zhang et al., 2012). The slippage viscous flow's flux, 'N_{vs}' (mol/(m^2. s)) of free gas can be estimated by considering the slip factor associated with the changes of the apparent viscosity, nanofluid viscosity, and surface velocity slip given in Eq. (8).

$$N_{vs} = \frac{\varphi}{\tau\mu_g}\frac{r^2}{8}\frac{P}{ZRT}(1+F)\nabla P \tag{8}$$

where, μ_g and r refer to the gas viscosity (mPa s) and effective pore radius (m), and F refers to the slip factor.

If we consider the diffusion in the matrix, then the governing equation is the mass conservation equation. The mass of the gas in the matrix per unit volume of matrix (m_m) consists of both free phase and adsorbed phase gases, as shown in the below Eq. (9):

$$\frac{\delta(m_m)}{\delta t} - \nabla\cdot\left(\frac{k_k}{\mu_{nw}}\rho_{gk}\nabla p_k\right) = -Q_{mf} \tag{9}$$

where, t is the time, p_k is the gas pressure in the matrix, μ_{nw} is the viscosity of the gas (non-wetting phase) in the matrix. Q_{mf} means the gas exchange between matrix and micro fractures of the matrix. k_k is the permeability of matrix which is obtained by the following Eq. (10) as:

$$k_k = \frac{D\mu_{nw}}{p_m} \tag{10}$$

where D is the effective diffusion coefficient of the matrix and has three components as follows:

$$D = D_c + D_e + D_{es} \tag{11}$$

where, D_c is the viscous flow-induced diffusion coefficient, D_e is the effective molecular-Knudsen diffusion coefficient, and D_{es} is the effective surface diffusion coefficient (Wang et al., 2018).

The component of the effective diffusion coefficient can be determined using different empirical equations. m_m can be expressed as follows in Eq. (12):

$$m_m = \rho_{gk}\varnothing_m + \rho_{ga}\rho_s\frac{V_Lp_m}{p_m+P_L} \tag{12}$$

where, ρ_{gk} is the gas density in the matrix, $\varnothing_m$ is the porosity of the matrix, ρ_{ga} is the density of the adsorbed gas, ρ_s is the matrix rock density, V_L is the Langmuir volume, P_L is the Langmuir pressure, p_m is the pressure of the adsorbed gas on the matrix.

4.3. Advective flow

Advection refers to the transport of molecules (solute) by the movement of bulk fluid (solvent). It is affected by the sum of the i) surface force active on the elemental fluid's volume (a reference volume) and ii) the body force on the mass contained in the reference volume. During the fluid flow through nanoporous media, advection also has a key role in the anomalous behavior of the flow. In this case, the complex nature of nanopores changes the flow path of the fluid through porous media. Advection is most common in fractured zones of a porous medium and can be of different types depending on the conditions of gas-water-rock systems. It can be continuous gas-phase advection where gas flows through pressure drive in the interstitial or fissure space of the dry porous or fractured media (Brusseau, 1991). If the gas dissolves (gas in solution) and is transported by water phase (*in-situ* or groundwater), known as water-phase advection, while when gas phase pushes (or displaces) the aqueous phase (or water) through pressure or/and density drive, called gas-phase advection. Fig. 7 shows gas advection in water-saturated and dry fractured media.

Experience shows that advection takes place at all points within a channel occupied by fluid if a finite advection is obtained at a particular point in that channel within a permeable medium. Advection and diffusion also play important roles in solute transport. The following equation shows the advection-diffusion transport of solute:

$$D\frac{\partial^2 c}{\partial x^2} - v\frac{\partial c}{\partial x} = R\frac{\partial c}{\partial t} \tag{13}$$

where, advection term is $v\frac{\partial c}{\partial x}$ and $D\frac{\partial^2 c}{\partial x^2}$ is the diffusion/dispersion term. c is the concentration of solute in the bulk fluid. v is the bulk velocity as shown below:

$$v = -\frac{K}{n_e}\frac{dh}{dx} \tag{14}$$

where, n_e is effective porosity. $R\frac{\partial c}{\partial t}$ is the retardation term. Solid phase interaction can be observed when solutes flow through a porous or even nanoporous medium. In particular, they can sorb and desorb. The whole process is called retardation which effectively slows down the transportation of a solute through a permeable medium. In the above equation "R" depends on the brine chemistry, nature of solute, and geochemical composition of the porous medium.

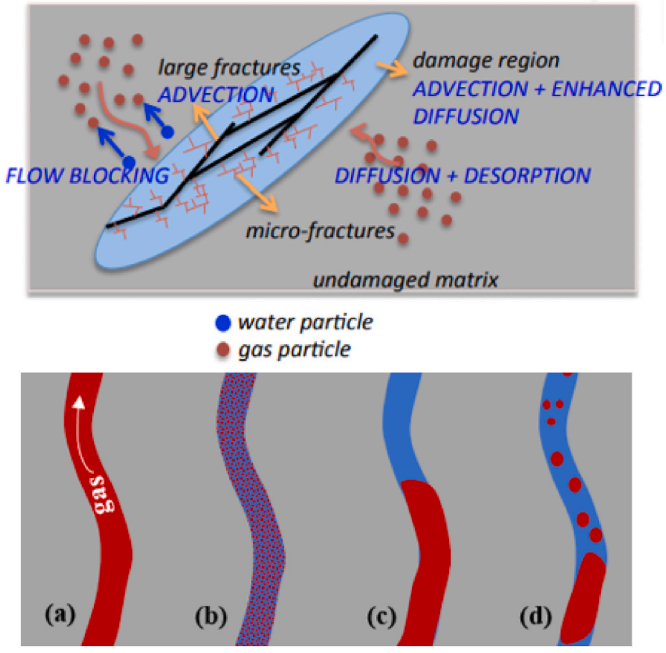

Fig. 7. Schematic of gas advection process (upper) (Karra et al., 2015) in dry and water-saturated fractures (lower); (a) uninterrupted gas-phase flow continuously through the fractures (dry), (b) water-phase advection, (c) gas-phase advection, and (d) movement of gas bubbles through buoyancy effect (buoyant flow) in the fractures (water-saturated) (Etiope, 2015).

Spreading of the solute spiral can be taken place during dispersion. As the dispersion in gas flow through nanoporous media is composed of both molecular dispersion (D_{mol}) and mechanical dispersion (D_{mech}) that cannot be distinguished on the Darcy scale. Mechanical dispersion indicates that average water flow speed cannot be acquired by all types of flow particles in the porous media. There is always variation in flow at a particular path. They can be varied from shorter to longer and slower to faster. Therefore, a total spreading of the solute plume occurs and it looks very much like a diffusion behavior. However, it is expected to raise the diffusion with rising flow speed as the mechanical dispersion depends on the flow. The most common expression for the mechanical dispersion is given by as follows:

$$D_{mech} = \alpha v \tag{15}$$

where, α is the dynamic dispersivity and v is the average linear velocity.

In some cases, advection or dispersion can be neglected. This consideration is based on the Peclet number (ratio of advection to dispersion/diffusion) as given below:

$$P_e = \frac{UL}{D} = L \Big/ \propto \tag{16}$$

when, the Peclet number is large, advection process dominates and we often neglect the dispersion term. On the other hand, when P_e term is small we neglect advection.

4.4. Adsorption and desorption effect

In shale gas reservoirs, the gas can be stored in three states, as described in Table 1.

Adsorption of a component of gas onto the surface of nanoporous media plays a vital role in fluid flow behavior. Proper modelling of adsorption during fluid flow through nanoporous media is very important for unconventional reservoirs. The computational and theoretical characterization and modelling of the coupling of transportation and adsorption during fluid flow through nanoporous media is gaining utmost interest in the industrial applications of hierarchically porous materials to properly understand the basic flow behavior of gases in unconventional reservoirs.

The modelling and simulation of adsorption during fluid transportation through nanoporous media of unconventional reservoirs face considerable challenges counting the complex pore structure of nanoporous media rock formation. Atomistic molecular dynamics and Monte Carlo simulations at the microscopic scale help to simulate the adsorption and diffusion of fluid in unconventional nanoporous media (Bird, 1994; Bird et al., 2009). However, the computational technique is not cost-effective for may be mesoscopic or macroscopic hierarchical materials with largest pores in both solid and fluid.

Computational fluid dynamics can address the transportation of fluids in such hierarchical materials for larger-scale methods but do not readily permit for a description of adsorption (Lilley and Sader, 2008). The Lattice Boltzmann method, known as a mesoscopic lattice-based fluid simulation technique has recently been extended to consider the tracer particles adsorption at the interface of solid and fluid considering the migration of fluid through nanoporous media (Succi, 2001; Agarwal et al., 2005; Levesque et al., 2012, 2013a, 2013b).

Recently, researchers have also paid attention to the mathematical modelling study of physisorption in permeable media by Lattice Boltzmann theory. But there are only a few research works available in the literature. In this regard, Agrawal et al. (2005) developed the adsorption model of toluene on nanosilica gels using Lattice Boltzmann model (LBM) for one-dimensional curves. Here toluene is considered the fluid and nanosilica gel is as the nanoporous media with complex structure. This study mimics the adsorption of fluid onto a nanoporous medium which is an unconventional reservoir in the proposed work.

On the other hand, Anderl et al. (2014) have examined the adsorption and bubble interaction through simulation using LBM in protein foams, whereas Manjhi et al. (2006) applied it for packed bed adsorbents in order to simulate the unsteady state (two-dimensional) concentration profiles. Zalzale and McDonald (2012) adopted a similar approach to examine the permeability of cement pastes (representing porous microstructures). A similar approach has been adopted by Pham et al. (2014) and Hlushkou et al. (2013) for examining the adsorption in packed beds.

Adsorption on interfacial sites during the fluid flow through nanoporous media is described as equilibrium between adsorbed and non-adsorbed species. The adsorption kinetic constant (k_a; probability of being adsorbed per unit surface) and desorption kinetic constant (k_d; probability of being desorbed per unit surface) can reveal the status of local equilibrium adsorption between adsorbed species and non-adsorbed species. Vanson et al. (2015) studied the adsorption and transportation of fluid onto solid surface considering the major effect of adsorption and desorption. For example, a short theoretical aspect of the study is explained here. If the additional propagated adsorbed solute quantity, P_{ads}, will couple with the free solute P, then the following equations can represent the interplay between adsorption and transportation.

$$P_{ads}(r, t+\Delta t) = P(r,t)p_a + P_{ads}(r,t)(1-p_d) \tag{17}$$

$$P(r, t+\Delta t) = P(r,t)(1-p_a) + P_{ads}(r,t)p_d \tag{18}$$

where, $p_a = k_a \Delta t/\Delta x$ and $p_d = k_d \Delta t$. At the initial condition $(t = 0)$, the propagated adsorbed quantity is initialized from the densities of free and adsorbed solutes at steady-state condition estimated from a preceding calculation. This concept can be utilized in unconventional porous media where hydrocarbon fluids are flowing under the obstacle of influencing forces.

Now, an attempt can be made to mathematically derive the fraction of particles adsorbed during the flow. In the case of steady state, the fraction of adsorbed particles (Fa) can be determined analytically as follows:

$$F_a = \left(1 + \frac{p_d N_f}{p_a N_{ads}}\right)^{-1} \tag{19}$$

where, N_f indicates the number of fluid lattice nodes and N_{ads} represents the number of adsorption sites on interfacial nodes considering the desorption and adsorption coefficients. In addition, the only idea about the net fraction of the adsorbed species, the spatial distribution of these adsorbed species is also important specifically for non-homogeneous systems. Thus, the computation of the adsorbed density $D_{ads}(r,t)$ term and free density $D_{free}(r,t)$ term of tracers have been introduced here. For the computation of P and P_{ads} the same rules is applied. In particular, at interfacial nodes they obey the followings:

$$D_{ads}(r, t+\Delta t) = D_{free}(r,t)p_a + D_{ads}(r,t)(1-p_d) \tag{20}$$

Table 1
Gas storage methods in shale reservoirs (Usman Ahmad, 2016).

	Gas type in shale reservoirs		
Storage method	Free gas In the pore space of rock matrix and inside the natural fractures	Sorbed gas Adsorbed (chemically and physically) onto the organic matter (kerogen) and mineral surfaces within the natural fractures and matrix rocks	Dissolved gas In the liquid hydrocarbons if present in the system

$$D_{free}(r,t+\Delta t) = D_{free}(r,t)\ (1-p_a) + D_{ads}(r,t)p_d \tag{21}$$

At the initial condition (t = 0), D_{free} is set equivalently in the fluid to $1/N_f$ while D_{ads} is set to zero.

A second-order reversible rate expression for Langmuir rate-controlled adsorption (also known as bilinear adsorption kinetics) is expressed as follows:

$$\frac{\partial q}{\partial t} = k_1 c(q_{max} - q) - k_2 q \tag{22}$$

where, q is amount of matter adsorbed, $q_{\max}$ is the maximum adsorptive capacity of the adsorbent, and the rate constants of adsorption and desorption are denoted as k_1 and k_2 respectively.

At equilibrium, $\frac{\partial q}{\partial t} = 0$, Eq. (22) becomes the Langmuir adsorption isotherm as follows:

$$q = \frac{q_{max}\left(\frac{k_1}{k_2}\right)c}{1+\left(\frac{k_1}{k_2}\right)c} = \frac{ac}{1+bc} \tag{23}$$

where, $a = q_{\max}\ (k_1/k_2)$ and $b = (k_1/k_2)$ indicate the Langmuir constants.

Adsorption has a significant contribution to the fluid flow modelling of unconventional reservoirs. Different specific models can be used to see the effect of adsorption on fluid flow behavior within unconventional nanoporous reservoirs. More fundamental study is required to develop the concept of the adsorption effect on fluid flow behavior within the nanoporous unconventional reservoirs.

Adsorption and desorption usually start after the completion of one process to transfer another one. Once all the specific surface of the porous medium is covered with fluid molecules by adsorption method, the process of desorption begins to make free the molecules.

The onset of the oscillations is attributed to the processes of sorption and desorption of gas micronuclei on the surfaces of the pore space (Yu and Sepehrnoori, 2014). In the process of flow through nanoporous medium of unconventional reservoirs, the fluid/gas molecules are adsorbed on the rock surfaces, changing the type of wettability and thus leading to slippage of the liquid with respect to the pore walls. Therefore, wettability also plays a vital role in fluid flow through nanoporous media where adsorption-desorption acting as major factors. Gas desorption has much contributions to additional gas production from unconventional reservoirs. Cipolla et al. (2010) examined the gas adsorption and desorption in Marcellus and Barnett Shale's samples and it was stated that desorption of gas may contribute up to 15% of the total gas production. Depending on the flowing BHP (bottom-hole pressure), reservoir permeability, and fracture spacing, it was also noticed that the influence of desorption of the gas molecules was noticeable in the later period of the well production. Another study by Thompson et al. (2011) investigated the gas desorption in a Marcellus shale (North-East Pennsylvania, USA). Based on the forecasted data (thirty years) of the well production accomplished with hydraulic-fracturing in twelve successive stages, it was found that desorption of gas molecules can contribute to 17% increase in the ultimate recovery.

Seidle and Arri (1990) developed a technique based on the implemented black oil model in the CMG simulator (2011), which is used to model the gas desorption effect from a coalbed reservoir. However, Langmuir isotherm can be used to calculate the solution gas-oil ratio used in this model. Basically, the Langmuir isotherm can be used for modelling purpose of the gas desorption from the solid surface. Therefore, a desorption model is utmost necessary to predict the fluid flow behavior within the nanoporous unconventional reservoirs.

4.5. Effect of inertial force

Inertial force has an impact on the fluid flow behavior within unconventional nanoporous reservoirs. In this regard, a fundamental equation derived from Newton's second law of motion to a fluid, called Navier-Stokes equations (NSE), can predict the flow behavior of the fluid through nanoporous media. The NSE describes any fluid flow through a fracture (Brush and Thomson, 2003; Al-Yaarubi et al., 2005; Cardenas et al., 2007; Madadi et al., 2003; Waite et al., 1998; Choe and Kim et al., 2003; Brown et al., 1995). For a single-phase flow subjected to a steady and incompressible fluid through a channel (fracture), the NSE is summarized to below equations:

$$\rho \boldsymbol{u} \cdot \nabla \boldsymbol{u} = -\nabla p + \mu \nabla^2 \boldsymbol{u} \tag{24}$$

$$\nabla \cdot \boldsymbol{u} = 0 \tag{25}$$

where, μ, ρ, and p refer to dynamic viscosity, density, and the total pressure, respectively and $\boldsymbol{u} = [u, v, w]$ is the velocity vector. If inertial forces are neglected and a nominal acceleration (or, when the viscous forces are significant thus dominant) is considered, the inertial term on left hand side of Eq. (24) can be cancelled, resulting in the Stokes equation (SE):

$$\nabla p = \mu \nabla^2 u \tag{26}$$

Eqs. (24) and (25) describe the fluid dynamics in fractures in two different ways, and the solutions of the equations would lead to flow fields. The simplified form of Eq. (24) should be selected proper way so that physics and flow fields can be accurately captured. In this case, Reynolds number (R_e) can be used as one of the criteria as expressed below:

$$R_e = \frac{\rho UL}{\mu} \tag{27}$$

where, U and L are velocity and length of flow path. For flow in fractures, an equal length (L) and aperture or width (a) of mean fracture is typically assumed. Although Eq. (24) is the governing equation that precisely describes the fluid flow in fracture across all values of R_e, while Eq. (26) which is comparatively simple, is appropriate only at low value of R_e.

However, it is necessary to inspect local aspects of the nanoporous pore morphology and relate them with the pertinent mechanisms of momentum transfer through viscous and inertial forces for understanding the interplay between the nanoporous structure of the unconventional reservoir rock and fluid flow. Therefore, mathematical modelling and simulation of inertial force and its influence on the anomalous behavior of fluid flow through nanoporous media should be considered for the complete model of unconventional reservoir model in terms of fluid flow behavior.

It would be nice if a single number can be calculated for flow considering both laminar and turbulent for a given flow geometry. Osborne Reynolds introduced such type of number and it can be expressed as follows:

$$R_e = \frac{\rho(\Delta v)(\Delta y)}{\mu} \tag{28}$$

Here, Δv is the difference in velocity between two regions of the fluid separated by a distance Δy, μ is the viscosity of the fluid, and ρ is the density of the fluid. The higher value of Δv indicates the larger difference in momentum of the different regions and viscosity value will help to maintain the laminar flow. Obviously, if the viscosity increases, the rate of momentum transfer will be increased, and the resulting flow will be smoother. Likewise, if the density is considered, the viscosity and Δv will be the same, but if Δy is decreased, the difference in velocities between nearby molecules will become greater and rapid momentum transfer from collisions will be happened. Therefore, it results in a smoother laminar flow. In this way, the consideration of inertial force in fluid flow through nanoporous media can be utilized for modelling and simulation.

4.6. Stress dependent flow in unconventional hydrocarbon reservoirs

Due to the very small (order of nanometers) pore size of unconventional reservoir rock a large capillary pressure exists. As a consequence of larger capillary pressure, the thermodynamic behavior of hydrocarbons (*in-situ*) in these tiny pores is considerably different from the hydrocarbons staying in the large pores of conventional reservoirs (Jerauld and Salter, 1990; Li et al., 2016; Hassanizadeh and Gray, 1993; Firincioglu et al., 2012). Moreover, such a higher capillary pressure significantly affects the multiphase flow, especially nearby the wellbore and results in liquid holdup (capillary end effect) by inhibiting the fluid entering the hydraulic fractures from the matrix (Moghaddam and Foroozesh, 2017). Such consequence has been recognized in tight and shale oil reservoirs where a shift in the phase envelop and suppressed bubble-point pressure often appear (Xiong et al., 2015). Over the time of production period, fluid depletion from over-pressurized unconventional reservoirs leads to rock deformation, thus alteration in the effective stress on the rock matrix that results in expected decreased pore (pore throat) size and permeability. This reduction in the pore size affects the thermodynamic behavior of reservoir fluids as a consequence of the increased capillary pressure. In addition, such systems are subjected to in-situ stresses due to the combined effects of overburden pressures, pore pressure, and tectonic stresses (Ali and Sheng, 2015). This stress dependent capillary pressure that is enormously sensitive to the effective stress, severely affects the production rate (hydrocarbon recovery rate) and well-deliverability of unconventional hydrocarbon reservoirs. Nano-size pore and large fraction of lighter components are the key features that lead to pronounced effects of pore confinement, while ultra-low permeability and high initial reservoir pressure lead to rock compaction in unconventional hydrocarbon reservoirs (Xiong et al., 2015; Li et al., 2016). Depending on the ratio of the molecule size to the pore size, thermodynamic phase behaviors as well as the associated critical properties of the retained (confined) fluids (in smaller pores) vary accordingly (Brusilovsky, 1992; (Danesh, 1998); Zarragoicoechea and Kuz, 2004; Firincioglu et al., 2012).

Substantial drop in the pore pressure can be seen during the production period specifically in tight oil reservoirs. It is noted that, this substantial drop in the pore pressure as a consequence of the increased effective stress leads to an additional rock compaction. The depressurization of shale-gas reservoirs through production initiates several stress-induced deformations and fractures that, in turn, would imact the permeability. In order to model such complicated processes at the macroscopic level, the dual-continuum approaches and the discrete fractures model are suggested to be applied (Salama et al., 2017).

Shale gas reservoirs behave as a dual porosity/permeability system in which matrix, natural and hydraulic fractures contribute to gas transport in very complex manner (Ali and Sheng, 2015).

Fractures are the key source of flow capacity and changes in fracture flow capacity and conductivity dramatically influence the performance of the unconventional reservoirs. Fractures are characterized mainly by their length, aperture, orientation, density, spacing, and porosity. It is expected that, the alteration or amount of loss in permeability depends on the rock type; in soft rock systems the loss in permeability is much higher as compared to the hard rock. It has been found that the permeability changed in a soft rock system was 95% (from 350 nD to 5–9 nD) with a change in the effective stress from 2000 psi to 6500 psi, while it was 20% for a hard rock system (from 300nD/2000 psi to 255nD/3850 psi) (Rosen et al., 2014). It should be noted that, in the low permeability rocks, the stress-dependency is more noticeable than those in high permeability reservoirs (Xiong et al., 2015). Fracture apertures and fractures transmissivity will change due to two key mechanics: normal stress induced closing/opening and shear-induced dilation. The normal stress is the key factor that controls uniformity of the aperture along the fracture length. The shear dilation is not significant with a low horizontal to vertical stress ratio in most cases (Min et al., 2004). As a result of the closure of fracture apertures, the stresses may be redistributed.

However, maintaining a high fracture conductivity is extremely difficult that significantly hampers the economics of the unconventional hydrocarbon production (mainly during large drawdown) and development. Thus, it is crucial to identify the stress-dependent fracture permeability and to correlate rock deformation and the stress-dependent capillary pressure.

The magnitude of the effective pressure and the effective stress can be evaluated in terms of confining pressure and pore pressure. Wyllie et al. (1958) have carried out experimental studies in a Berea sandstone and realized that at a constant confining pressure (P_{conf}), the velocity of compressional-wave through the block decreases as the pore pressure (P_{pore}) increases. They have shown that an increase in compressional-wave velocities due to an increase in P_{conf} can be offset by an equal increase in P_{pore} for the water-saturated Berea sandstone. Thus, they have postulated that the velocity will be constant for a particular differential pressure (effective pressure) across the core body. However, this assumption encounters a previous theoretical analysis carried out by Brandt (1955) for the elastic wave velocity that propagates in spherical objects as functions of the pore and confining pressure, and found to be dependent upon an effective pressure as given in Eq. (29).

$$P_{eff} = P_{conf} - nP_{pore} \tag{29}$$

where 'n'is the coefficient of internal deformation (its value is less than one).

Furthermore, Christensen and Wang (1985) have presented the compressional and shear wave velocities as functions of in P_{conf} and P_{pore} in Berea sandstones. They have considered the compressibility of the solid grains β_s and compressibility of the bulk material 'β' (Biot and Willis, 1957; Geertsma, 1957; Christensen, 1984), thus n also varies with the differential pressure.

$$n = 1 - \frac{\left(\frac{\partial Q}{\partial P_{Pore}}\right)_{P_d}}{\left(\frac{\partial Q}{\partial P_d}\right)_{P_{Pore}}} = 1 - \frac{\beta_s}{\beta} \tag{30}$$

where Q is any physical quantity, P_d is differential pressure or effective pressure ($P_{conf} - nP_{pore}$). A value of n equals to 1 implies that the increment in pore pressure and confining pressure entirely will cancel out each other. However, a value of n either lesser or greater results an effective pressure. Further, the effective stress can be evaluated through following equations (Terzaghi, 1923; Taghavinejad et al., 2020).

$$\sigma_{eff} = P_{conf} - \chi P_{pore} \tag{31}$$

$$\chi = \frac{\partial k / \partial P_{pore}}{\partial k / \partial P_{conf}} = \frac{\partial \varphi / \partial P_{pore}}{\partial \varphi / \partial P_{conf}} \tag{32}$$

where 'χ' is a constant known as the effective stress coefficient (can either be equal to unity, larger than unity, or smaller than unity depending on the effects of confining and pore pressures on the of the rock's properties specifically porosity, 'φ', or/and permeability,'k').

In the case of $\chi > 1$, the rock deformation becomes more sensitive to pore pressure reduction than the variations in confining pressure while it is opposite in the case of $\chi < 1$. However, an equality exists at $\chi = 1$, where the rock deformation due to pore pressure reduction and confining pressure increment would be equal and cancelled out.

Mathematical modelling of stress/pressure dependent permeability in unconventional reservoirs such as tight oil (Zhang et al., 2019; Xiong et al., 2015; Wijaya and Sheng, 2020), shale gas (Taghavinejad et al., 2020; Moghaddam et al., 2015; Foroozesh et al., 2021; Mokhtari et al., 2013; Ali and Sheng, 2015; Sang et al., 2016; Javadpour et al., 2007), and coal bed methane (CBM) (McKee et al., 1988; Meng et al., 2011) has been studied extensively (Wang and Aryana, 2016; Rosen et al., 2014; Yu and Sepehrnoori, 2013; Feng et al., 2019; Wang et al., 2019a, 2019b).

5. Combined effect of all influencing physics and model prediction

The aforementioned physics and phenomena (viscous force, diffusion and advection, adsorption and desorption, inertial and capillary forces, and viscoelastic flow) could all affect flow behavior of fluids and it is necessary to identify the active mechanisms and consider them in the model for the fluid flow study through nanoporous medium of unconventional reservoirs. Therefore, the ensemble of active mechanisms/forces contributing to the flowing fluid in nanoporous media can be written as follows in Eq. (33):

$$F_m = f\left(f_{vis},\ f_{diff},\ f_{adv},f_{ads},f_{des},\ f_{iner},\ f_{cap},\ f_{vise},\ f_{str}\right) \tag{33}$$

where, F_m is the group resultant effect, f_{vis} is the viscous effect, f_{diff} is the diffusion effect, f_{adv} is the advection effect, f_{ads} is the adsorption effect, f_{des} is the desorption effect, f_{iner} is the inertial effect, f_{cap} is the capillary effect, f_{str} is the stress effect, and f_{vise} is the viscoelastic effect. The combined model needs to only include the active mechanisms and it does not intend to have all the forces presented in Eq. (33). It is necessary to incorporate all the influencing factors in the model as far as they have major and perhaps minor impacts on the fluid flow behavior. It should be noted that the combined model just suggests to have all the active mechanisms included and the way the mechanisms combined needs a further study. It is a challenging task to incorporate all the active physics in a single model to predict the fluid flow behavior in unconventional nanoporous media. However, the current need for modelling of an unconventional reservoir requires the development of this type of simulator to build a final single combined model including all the influencing mechanisms. It is necessary to summarize different research works on modelling of fluid flow through nanoporous media for instant knowledge to explore the status of the progress on this challenging topic of unconventional reservoirs. Table 2 shows the aspects of different research works on fluid flow through nanoporous media of unconventional reservoirs considering different influencing physics and models.

6. Challenges and prospects of unconventional reservoir modelling

Several developments have been made on unconventional reservoir modelling in the past few years. Proper modelling of unconventional reservoirs is utmost important for recovery of unconventional energy. However, many critical challenges need to be addressed to understand the unconventional reservoirs. The recent advances have been proposed on the characterization of fluids confined within nano-pore's walls and pore network of unconventional reservoirs. Nano-pore network can be characterized by using modern imaging techniques. However, understanding the connection between pore network and macroscopic observation is still challenging. Sophisticated instrumental techniques for capturing images in nano-pore level is now easy but the proper characterization and anomalous behavior of fluid flow through the tight rock media cannot be yet addressed properly. Stress dependent nature of fluid behavior in ultra-tight unconventional reservoirs together with complicated fluid-rock interaction through diffusion and absorption physics and unusual capillary effect have made it difficult to present a mechanistic based comprehensive model. Developing a combined theoretical model capturing all physics contributing to fluid flow through the nanoporous media help with understanding the unique behavior of fluids in such systems. Statistical mechanics and thermodynamics approaches including molecular dynamics simulation coupled with pore network modelling that considers geomechanics and poroelasticity principles applying computational fluid dynamics (CFD) can essentially improve the flow behavior modelling in nanoporous systems. Such molecular and pore scale approaches will help to learn about actual flow behavior in such nano-pores while they have not been applied in a wide scope to study multiphysics flow behavior of fluids in

Table 2
Research works on modelling of unconventional reservoirs based on fluid flow concept.

Type of unconventional reservoirs	Influencing mechanism (s) considered	Focused research area	Reference
Shale reservoirs	Fracture modelling	Discrete Fracture Model (DFM) and Multiple Interacting Continua (MINC) approaches were used model and simulate the transient effects and fracture networks.	Farah et al. (2019)
Unconventional reservoirs	Compressibility (elastic and inertial effects)	An attempt has been taken to develop a three-dimensional unified pipe-network method (3D UPM) to comprehend flow behavior of oil by considering the compressibility of both fluids and solids in fractured unconventional reservoirs.	Chen et al. (2019)
Shale oil reservoirs	Adsorption	Density function was utilized to model two-phase flow of non-wetting (gas) and wetting (oil) phases in a multiporosity shale formation composed of three types of porosity ranging from micro to nano pores sized pores.	Le et al. (2018)
Tight gas reservoir	Sorption (Adsorption)	Conventional and optimized Transient techniques were used to develop a mathematical model to numerically study fluid flow behavior in time and space domain.	Feng (2017)
Shale oil and gas reservoirs	Diffusion and adsorption	A model was developed for understanding of fluid flow behavior based on the multicomponent mass transport in the nanopores of unconventional reservoirs, such as Eagle Ford, Niobrara, Woodford, and Bakken. The influences of long-term economic development of such reservoirs are also depicted.	Alharthy et al. (2016)
Shale gas reservoirs	Adsorption/desorption	An attempt has been taken to model and simulate the gas production of unconventional reservoirs for prediction of well performance and comprehend the critical parameters related to gas production.	Ding et al. (2014)

(continued on next page)

Table 2 (*continued*)

Type of unconventional reservoirs	Influencing mechanism (s) considered	Focused research area	Reference
Shale oil and gas reservoirs	Adsorption, desorption, and diffusion	A micro-scale model for gas flow in unconventional reservoir (shale) was established that considers kerogen, natural fractures, and inorganic minerals as three separate porosity systems.	Yan et al. (2013)
Shale gas reservoirs	Adsorption and desorption	Integrated workflows were developed to demonstrate effective methodologies for capturing the essential characteristics of shale reservoirs for simulating in an innovative way.	Fazelipour (2011)
Shale gas reservoir	Adsorption and desorption	A generalized numerical and mathematical model was used to simulate the performance of unconventional shale gas reservoir.	Wu et al. (2014)
Shale gas reservoirs	Adsorption and desorption	Effects of positive input of gas desorption and negative contribution of geomechanics on production of the Barnett shale, Marcellus Shale gas fields were analyzed by history matching for identifying the dominant process for gas production.	Yu and Sepehrnoori (2014)
Shale gas reservoirs	Diffusion and convection	A new motion equation related to diffusion, convection, and Lattice Boltzmann method was applied to develop a model for the gas flow to acquire the important parameters in the derived new general equation for fluid flow through shale gas reservoirs.	Song et al. (2015)

unconventional reservoirs.

7. Conclusions

Governing mechanisms and physics such as viscous flow, diffusion, adsorption/desorption, advection, capillary and inertial effect, and viscoelastic properties control the fluid flow behavior in nanoporous media. Considering only a few of them to investigate the exact flow behavior can often yield an inappropriate result. Thus, proper mathematical modelling coupled with most of the governing phenomena (mechanisms) is required to convey the actual physics of the complex behavior of unconventional reservoirs. It is expected that the current discussion in this article will bring a new opening of the unconventional reservoir modelling scenario based on the fluid flow concept. A combined model is required to show the effect of all the active physics on fluid flow behavior in unconventional reservoirs. It should also be noted that some of the mechanisms dominate over other factors and therefore not all the mechanisms to be considered when modelling fluid flow in such reservoirs. Challenges of modelling of unconventional reservoirs are still significant. All effects such as viscous, adsorption and desorption, diffusive and advective flow, stress, capillary and inertial significantly contribute as influential factors in fluid flow through nanoporous unconventional reservoirs. Molecular and pore scale study is suggested to be applied to better understand the flow behaviors in nanoporous systems and understand the contribution of each individual mechanism. Further research works are yet required to reasonably study the complex fluid flow behaviors in nanoporous unconventional reservoirs using mathematical tools.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgment

The first author (AB) gratefully acknowledges Drilling, Cementing, and Stimulation Research Center, School of Petroleum Technology, Pandit Deendayal Energy University, Raisan, Gandhinagar, Gujarat, India and the other individuals those who directly or indirectly associated with this work. The second (SK) gratefully acknowledge the support of Universiti Teknologi PETRONAS under YUTP grant (Grant No: 015LC0-319).

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