CHAPTER-2

LITERATURE REVIEW

Reservoir simulation is used as a tool to understand the performance of the reservoir all over the world for more than 40 years. The fluid flow mechanism in shale gas reservoir is largely different from fluid flow in conventional reservoirs. Simulation of shale gas reservoirs needs distinctive features to deal with gas desorption, non-Darcy flow, natural fractures and hydraulic fractures and gas adsorption on solid surface.

The goal of this work is to develop a shale gas reservoir simulation model which can be employed to perform sensitivity analysis for several factors that will effect the well performance.

2.1 <u>Flow in Fractured Shale:</u>

For better understanding of the model and the fluid flow in the fractured shale reservoir many researchers (Medeiros et al., 2008, Ozkan et al., 2011, Brown et al., 2011, and Bello and Wattanberger, 2008 & 2010) had extensively used the concept of dual porosity. In dual porosity concept, it assumes that the matrix has large storativity but negligible conductivity but the fracture has less storage capacity but high conductivity.

In dual porosity model, the representation of matrix and fracture media is done by transfer functions, which represents the fluid transfer from the matrix to the fracture network. (Warren & Root, 1963) was the one who introduced the dual porosity model to the petroleum literature. They have assumed a pseudo steady state flow from matrix to fracture to formulate this dual porosity model. (Kazemi et al., 1969) extended the Warren and Root model to unsteady state fluid transfer between matrix and fractures. Matrix-fracture fluid transfers were solved by Kazemi by using multiphase transfer functions. The transient fluid flow assumption between matrix and fractures is more appropriate in shale gas reservoirs (Brown et al., 2011).

2.2 <u>Knudsen Diffusion and Desorption in Shale Matrix:</u>

Shale was characterized as mud rock (Folk et al., 1974). In general mud rocks are named as sedimentary rocks, which are distributed with grains with size lower than 62 μm while pore throat and body distribution are on a smaller scale which makes it very difficult to measure their physical properties (Sodergeld et al., 2010). So, for modeling fluid flow in shale, understanding fluid flow from micro pores to Nano pores is important. This requires understanding the molecular size of the working fluids that can access the small rock conduits.

As shown in Figure 2.1 (Sodergeld et al., 2010), the dominance of Knudsen diffusion and slip flow regimes are more at Nano meter scale. Figure 2.2a, shows the conventional Darcy flow when there is no Knudsen diffusion and slip flow. Figure 2.2b, shows the development of the slip flow regime when the size of the pore channels becomes smaller due to which sufficient pressure drop will occur for the mean free path of the fluid particles to become larger than the pore diameter. Initially, Darcy law was used to model the fluid flow in conventional and un-conventional reservoirs. But due to the different fluid flow mechanism in shale gas reservoirs the use of Darcy law is no more applicable.

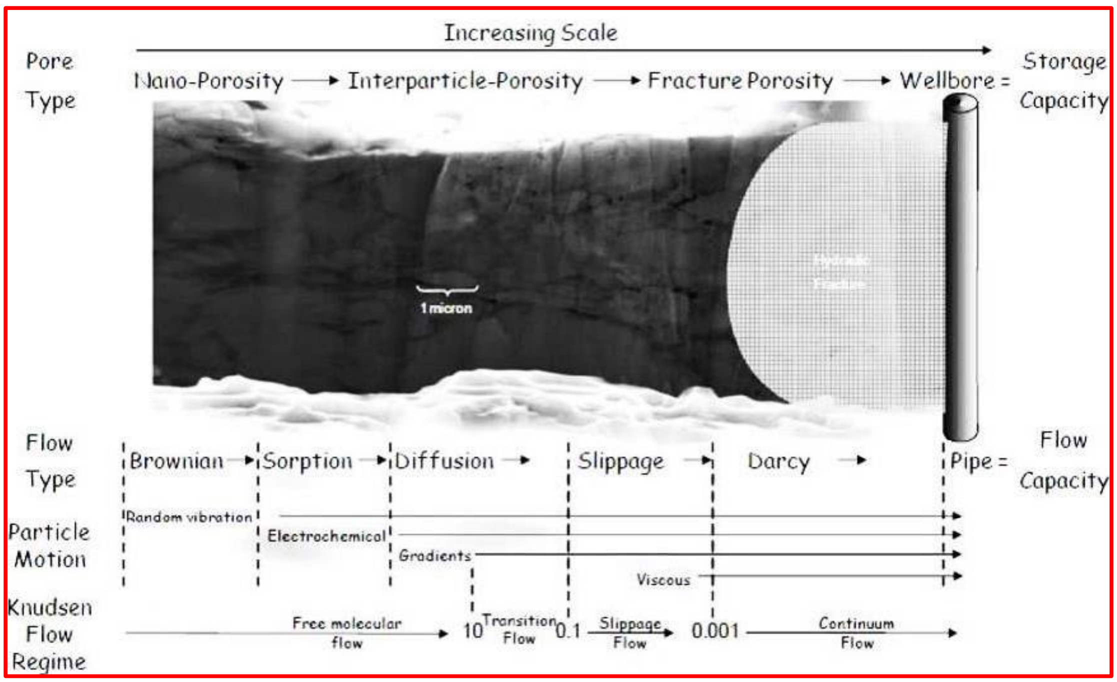

Figure 2.1: Gas Shale storage and flow capacity diagram showing pore type, flow type, dominant particle motion within a given flow regime.(Ion-milled SEM image of Devonian gas shale, Sodergeld et al., 2010).

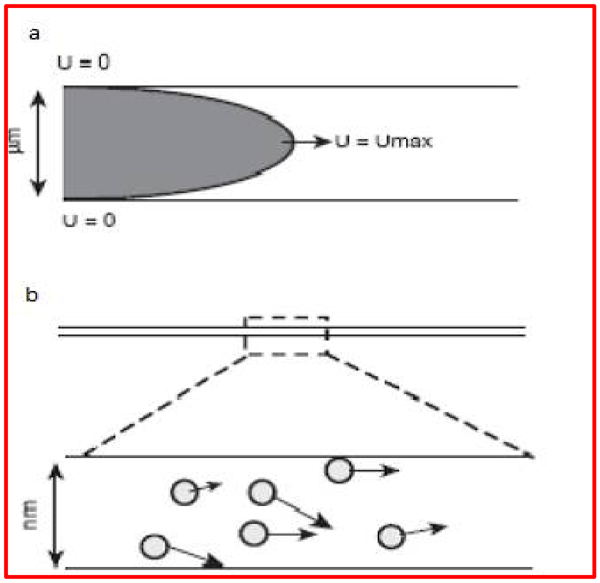

Figure 2.2: Comparison of gas flow (a) in micro pores where the flow is no slip and (b) in nano pores where the flow is slip (Javadpour et al., 2007)

Javadpour et al., (2007) and Javadpour et al., (2009) studies that the Knudsen diffusion and slip flow is followed by fluid flow in the Nano pores of shale matrix, while Darcy flow is followed by fluid flow in micro pores. Desorption occurs from the kerogens surface and at last diffusion occurs in solid kerogen. As shown in Figure 2.3, the authors described that gas fills in pore spaces as compressed gas, adsorbed gas is the remains at the kerogen surface and the dissolved gas is the dispersed gas inside the kerogen.

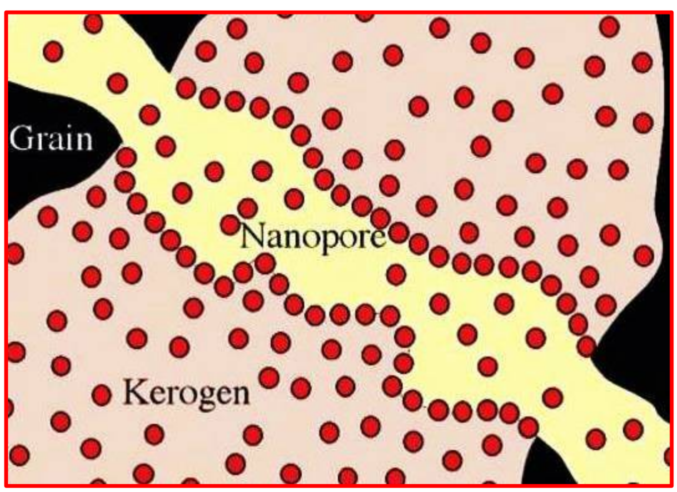

Figure 2.3: Schematic of gas-molecule locations in a small part of a kerogen grain pore system of a mudrock (Javadpour et al., 2009).

Shale rocks have a variety of different size pores, ranging from micro size pores to Nano size pores. In conventional reservoirs, since the larger pores are the main contribution for gas flow, the smaller pores will be considered as under cut-off. In shale gas reservoir, as most of the pores are in the scale of Nano pores, gas in these pores cannot be neglected .So, in shale gas reservoirs, multiple flow mechanisms have to be considered that are prevailing in different sizes of pores. In addition, the existence of kerogen bring the effect of desorption into consideration.

As per the studies of Javadpour et al., (2007) and Javadpour et al., (2009), the gas production from shale starts by creating an equilibrium interruption via a drilled well or by an induced fracture. Now due to the pressure difference, the compressed gas in the pores will be produced, followed by the gas that is adsorbed on the surface of the kerogen due to pressure decrease in the pores of kerogen. Once the gas starts desorbing, a concentration gradient is developed between the bulk of the kerogen and its pore surfaces, which triggers gas diffusion in kerogen. This entire mechanism is illustrated in Figure 2.4 and represented by the following advection-diffusion-desorption equation:

$$\frac{\partial c}{\partial t} + U.\bar{V}c - D\bar{V}^2 c - kc = 0 \tag{2.1}$$

In Eq 2.1, the first term represents concentration change with time, the second term is referred to as advection, the third is Knudsen diffusion, and the last term indicates desorption.

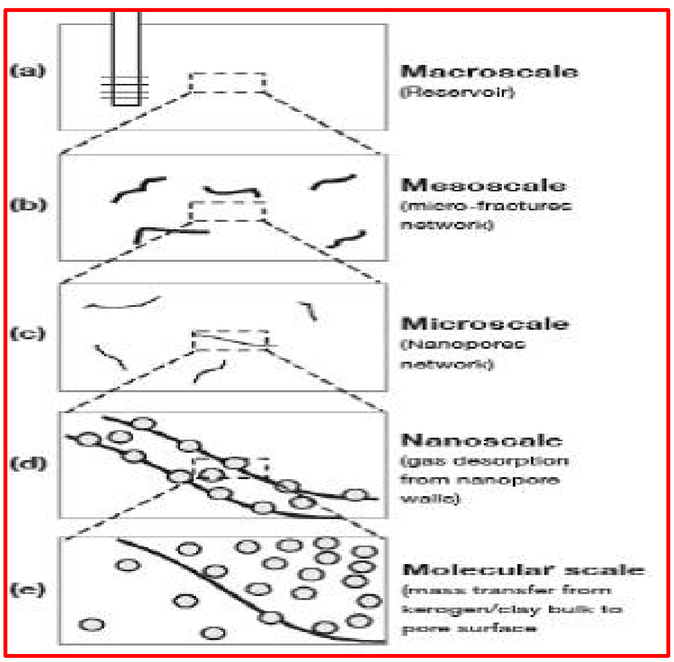

Figure 2.4: Gas evolution and production in shale gas sediments at different length shales (Javadpour et al., 2007).

(Ozkan et al., 2010) used the multi flow mechanisms to generate a dual mechanism, dual porosity formulation for naturally fractured reservoirs, which considers Darcy and Slip flow regimes concurrently. The conclusion reveals that neglecting slip flow in matrix results in significant changes in well productivities (Figure 2.5).

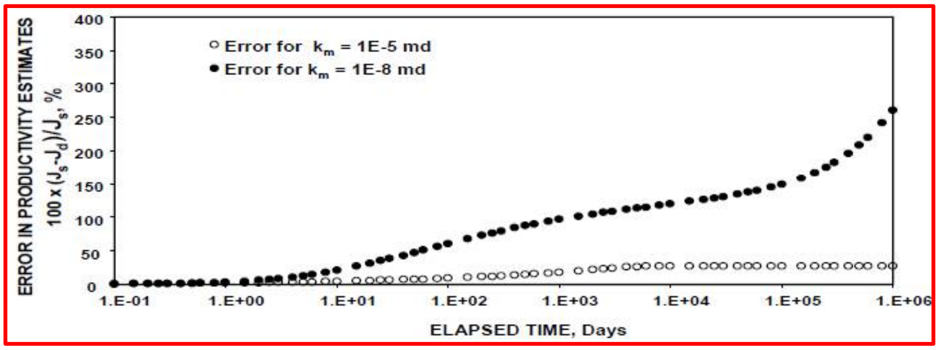

Figure 2.5: Error caused by neglecting the contribution of slip flow on productivity of fracture horizontal wellbore (Ozkan et al., 2010).

Andrade et al., (2011) developed a “quad porosity” model (Figure 2.6) assuming the reservoir contains four pore spaces: Pores in the organic and inorganic regions of the formation, Natural fractures and hydraulic fractures.

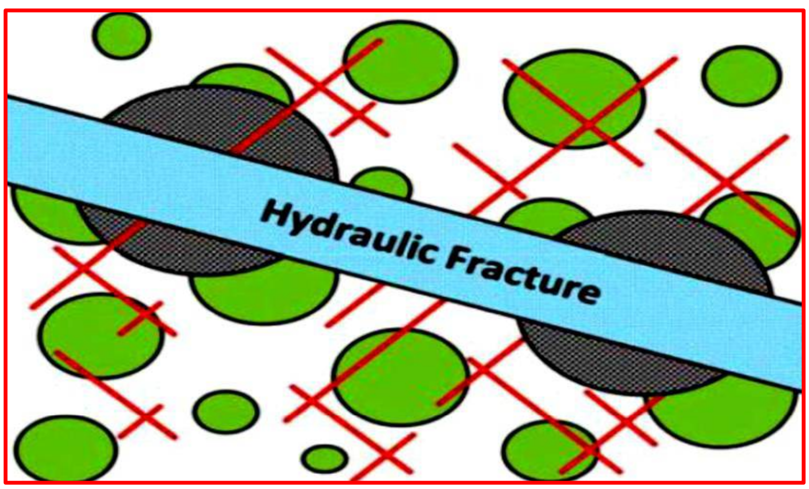

Figure 2.6: Schematic of Quad Porosity Model; Green Circles: Pores in Inorganic, Gray Circles: Kerogen (Organic Matter), tiny dots inside the gravy circles represents the pores within the organics, Red lines: Network of Natural and Induced fractures, Blue bar: Major Hydraulic Fracture (Andrade et al., 2011).

2.3 Modeling Production from Fractured Horizontal Wells:

The effective production of gas from shale reservoirs is done from hydraulically fractured horizontal wells. In unconventional gas reservoirs, this hydraulic fracture can create a pressure drawdown, increase productivity of horizontal wells by increasing the area of contact with formation, and to create high productivity paths for gas flow to the wellbore. The cost of the project in shale reservoirs mainly depends on the well spacing and the number of required hydraulic fracturing stages. Chen and Raghavan (1997) and Raghavan et al. (2007) established a source function to analyze the pressure behavior and production performance of fractured horizontal wells in shale gas reservoirs. From this analysis they concluded that "The purpose of fracturing a horizontal wellbore is to create a network whose long term performance will be similar to that of a single fracture of length equal to the spacing between the outermost hydraulic fractures". With this conclusion the performance of fractured horizontal wells can be correlated with effective fracture conductivity and effective fracture half-length. These parameters depend upon the permeability of the reservoir, distance between the fractures, and conductivity of the hydraulic fractures. The active fracture is intended to produce from the region beyond the tips of the fractures as shown in Figure 2.7.

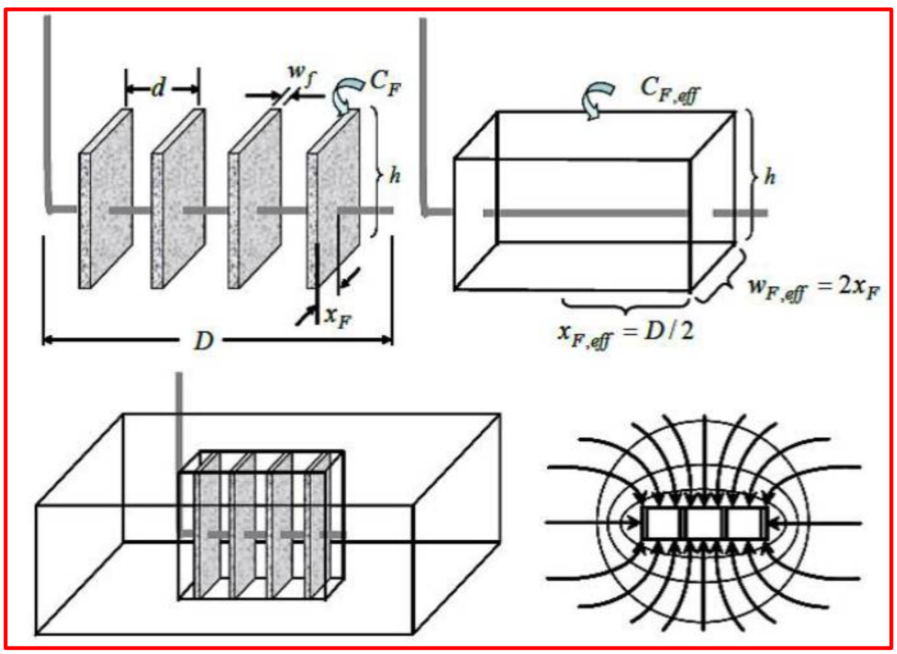

Figure 2.7: Sketch of fractured horizontal well in a shale gas reservoir and the convergence of flow around the well. (Ozkan et al., 2011).

Medeiros et al. (2007) developed a semi-analytical model for a diffusivity equation using Green's function solution, which has the tendency to include local heterogeneities. This model is used for investigating the effectiveness of the horizontal wells with several induced fractures (both transverse and longitudinal).The concept of dual porosity was used to incorporate a stimulated reservoir volume around the wellbore and hydraulic fractures into the model. From this semi analytical model several important things were concluded. The most important one is that the productivity of the well is significantly increased if hydraulic fractures affect the stress distribution to create and regenerate natural fractures around the well. Here, the production of gas was primarily from the natural fractures. The other important conclusion is that transient flow period controls the productivity of these systems.

Ozkan et al. (2011) and Brown et al. (2011) developed a solution analytical trilinear flow for simulating the pressure transient and production scenario of fractured horizontal wells in shale gas reservoirs. In this model, similar to the work of Chen and Raghavan (1997) and Raghavan et al. (2007), the fractured horizontal well is represented as an equivalent fracture. In shale gas reservoirs, as the flow is mostly from the stimulated reservoir volume, the aggregate length of individual fractures is equal to the length of the equivalent fracture, as shown in Figure 2.8; average conductivity of fractures is equal to the conductivity of the equivalent fracture. As shown in Figure 2.8, the drainage volume can be seen as parallel with the length of the equivalent fracture and the width equal to the average hydraulic fracture spacing.

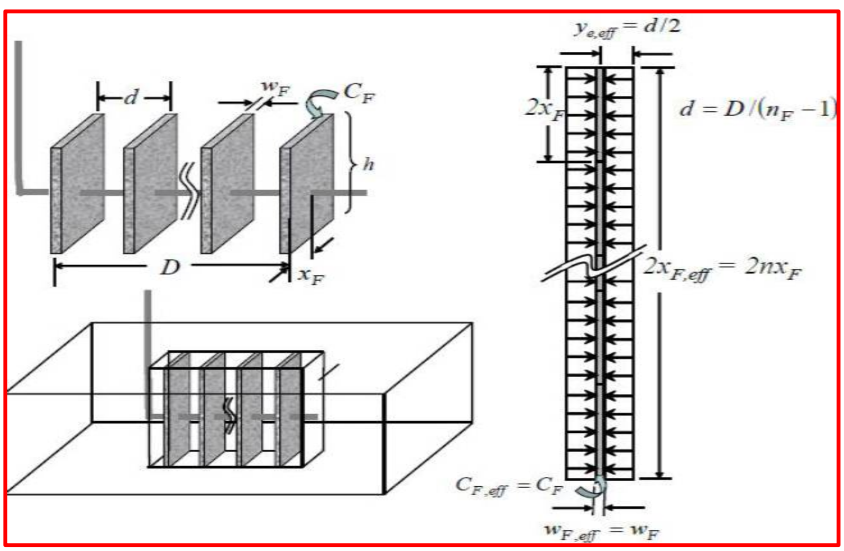

Figure 2.8: Effective fracture concept for multiply fractured horizontal well in an unconventional tight reservoir (Brown et al., 2011).

This trilinear analytical model considers three environments (Figure 2.9), a shale reservoir beyond the tips of the induced fractures i.e. outer reservoir, the natural fractures - inner reservoir, and hydraulic fractures distributed along the length of the horizontal wellbore. The flow convergence is linear in natural and induced fractures. Also, to some extent the flow in outer reservoir is linear. So, combining these three environments illustrates the importance of trilinear analytical flow model (Figure 2.9).

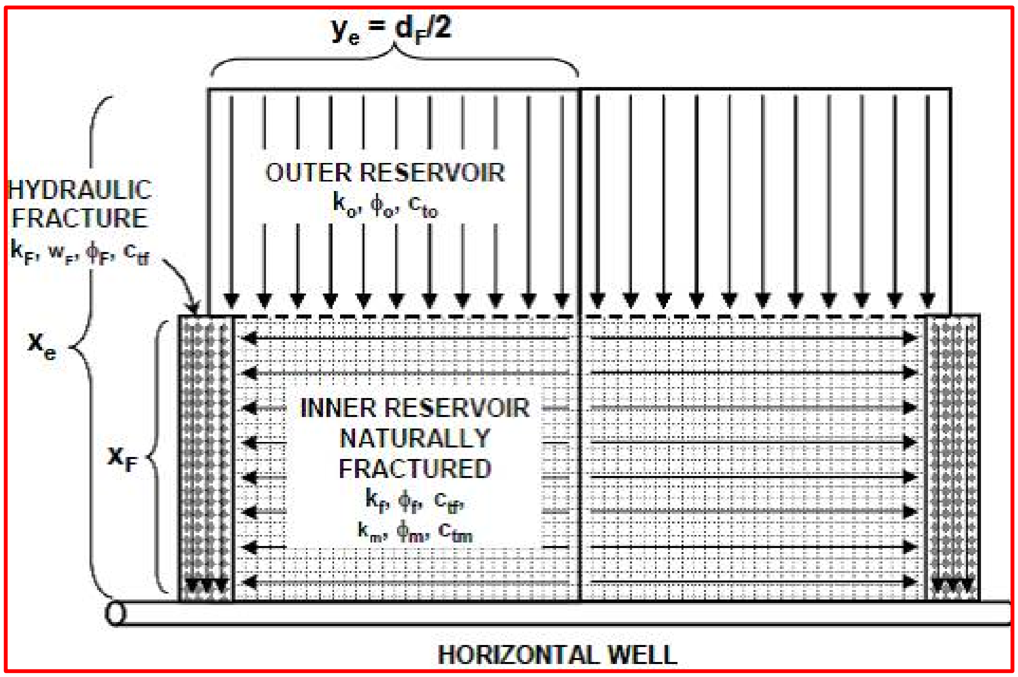

Figure 2.9: Trilinear Flow Model (Ozkan et al., 2011).

Brown et al, (2011) proved that the trilinear model will follow the movement of the actual field data (Figure 2.10).As most of the parameters are unknown; the results in Figure 2.10 were obtained by implementing regression calculations. The pressure and the derivative trilinear model curves are matched with the pressure and derivative field data and the curves obtained are reasonably fine.

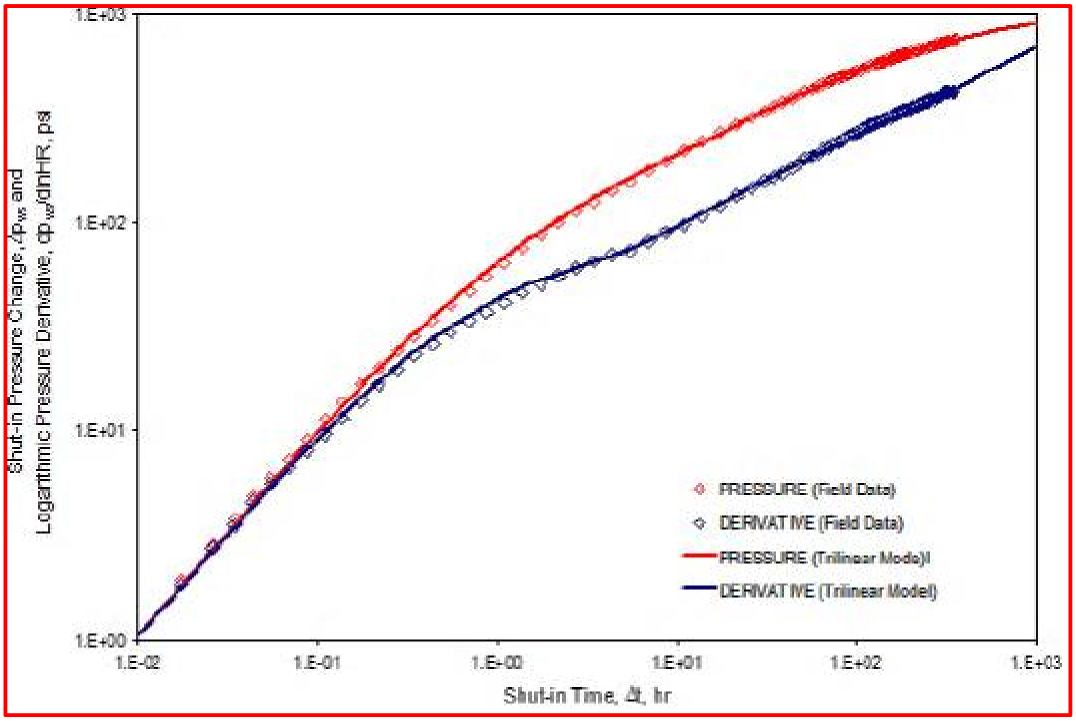

Figure 2.10: Trilinear model match of the field data (Brown et al., 2009).

Ozkan et al. (2011) investigated the effects of stimulated reservoir volume on the behavior of production from horizontal wells. Similar to Mayerhofer et al. (2008), it has been concluded that the production beyond the stimulated reservoir volume is negligible. Considering Ozkan et al. (2011), Figure 2.11 represents the well performance of different sizes of the outer reservoir with two different values of natural fracture permeability. One value of natural fracture permeability is 2,000 mD, at this value the effect of reservoir outside stimulated reservoir volume is not seen even after 100 years. For the second value of natural fracture permeability (20,000 mD) the effect of reservoir outside stimulated reservoir volume is seen after 11 years, which is still not economical. Similar comparison was made with respect to the natural fracture density in Figure 2.12.

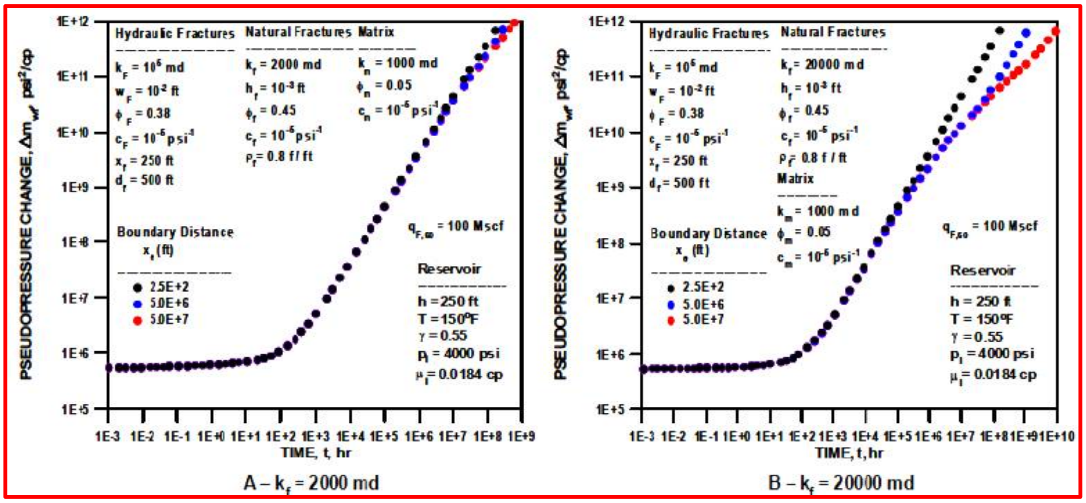

Figure 2.11: Trilinear Model Effect of Outer Reservoir. (Ozkan et al. 2011).

Ozkan et al. (2011) proved that the productivity of fractures horizontal wells are not only sensitive to natural fracture permeability (Figure 2.11) but also sensitive with respect to the density of the natural fractures (Figure 2.12).

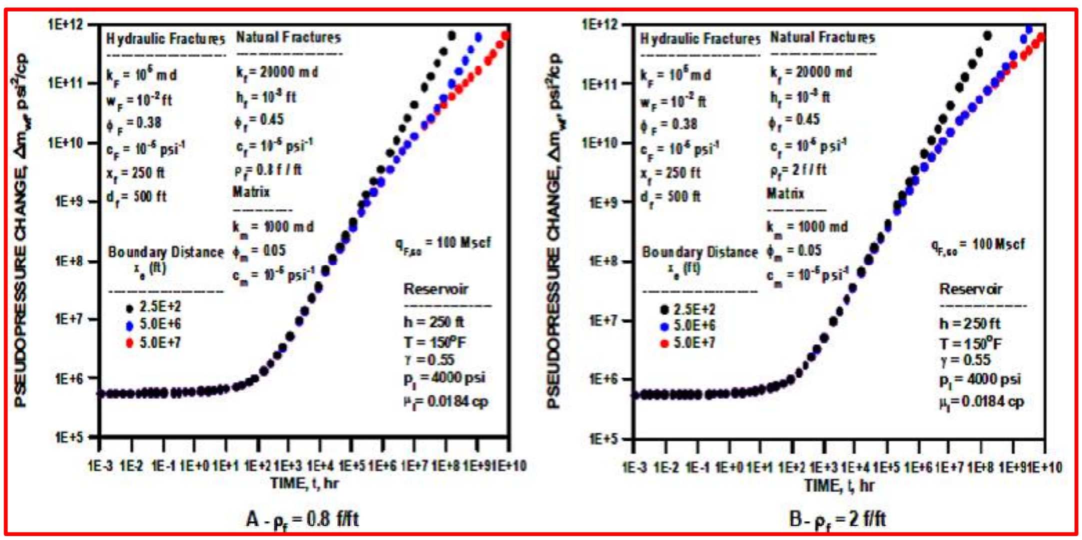

Figure 2.12: Trilinear Model Effect of Outer Reservoir A-ρ_f=0.8f/ft, B- ρ_f=2 f/ft (Ozkan et al. 2011).

In shale gas reservoirs, the matrix permeability ranges in the order of Nano darcies (Javadpour et al., 2007, Sondergel et al., 2010, Orangi et al., 2011). The effect of matrix permeability is observed during the production period by reducing the pressure drop (Figure 2.13). As the permeability of matrix is high, the drop in pseudo pressure is observed at intermediate time periods. At latter times all the results will merge concluding that the matrix permeability doesn't have a significant role in fractured horizontal wellbore. But, for longer production periods the matrix permeability will influence the gas production.

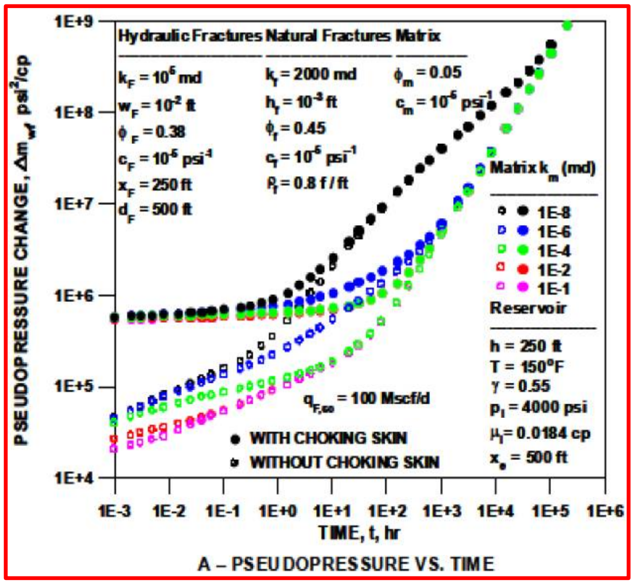

Figure 2.13: Trilinear Model-Effect of inner Reservoir Matrix Permeability km=1E-8 mD until km=1E-1 (Ozkan et al., 2011).

Brown et al., (2011) studied the pressure drop in both conventional gas reservoirs and unconventional gas reservoirs, which state that productivity drop is almost similar, In fact, unconventional reservoirs will have a uniform pressure drop (Figure 2.14).From this it is clear that the understanding of expected performance of potential completion designs is very essential for better productivity in a stimulated reservoir zone.

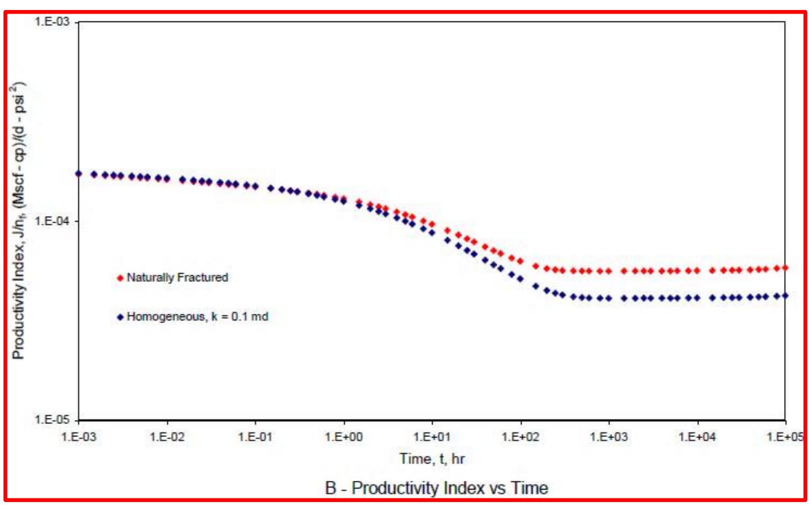

Figure 2.14: Trilinear Model-Effect of Inner Reservoir Matrix Permeability between Unconventional reservoir vs homogeneous tight conventional reservoir (Browm et al., 2011).

2.4 Pressure Dependent Natural Fracture Permeability:

As natural fractures are helpful in providing efficient drainage for the stimulated reservoir volume, under stress and strain these fractures will open and close. So, a separate analysis has to be performed for predicting the effect of stress on natural fracture permeability. Cho et al. (2012) performed an experimental study of pressure dependent natural fracture permeability in shale gas reservoirs, which concludes that the effect of pressure dependent, natural fracture permeability on shale gas production is a function of matrix permeability.

2.5 Reservoir Simulation Models for Gas Shales:

2.5.1 Single Porosity model:

In this model, the fractures in the shale reservoir is discretized and represented as grid cells which will be a single planar planes or system of planar planes. (Li et al.2011).

Finely gridded system i.e a single porosity model is used to produce a reliable result and in general it is used as a reference model for checking the accuracy of newly developed models. But, the main drawback of this single porosity system is that it requires longer computational time which is not feasible for some systems. (Cipolla et al. 2009).

2.5.2 Dual Porosity Model:

In 1963, Warren and Root developed Dual Porosity model which is mostly used in induced fractured shale gas reservoirs.

In a conventional double Porosity model, the shale gas reservoir is a collection of matrix blocks and natural fractures (Figure 2.15). In single porosity model, the gas flows directly from the reservoir to the well. But, in this model, the gas flow into the well through the natural fracture system. This natural fracture system is continuously recharged with the gas desorbing from the matrix. (Carlson and Mercer, J.C. 1991).

The matrix blocks which occupy the major portion of the shale reservoir contains both free gas and the adsorbed gas. The natural fracture system which conquers small volume in the shale reservoir contains only free gas and contributes very less to the shale gas production. The purpose of the natural fracture system is to provide a main path for flow of gas.

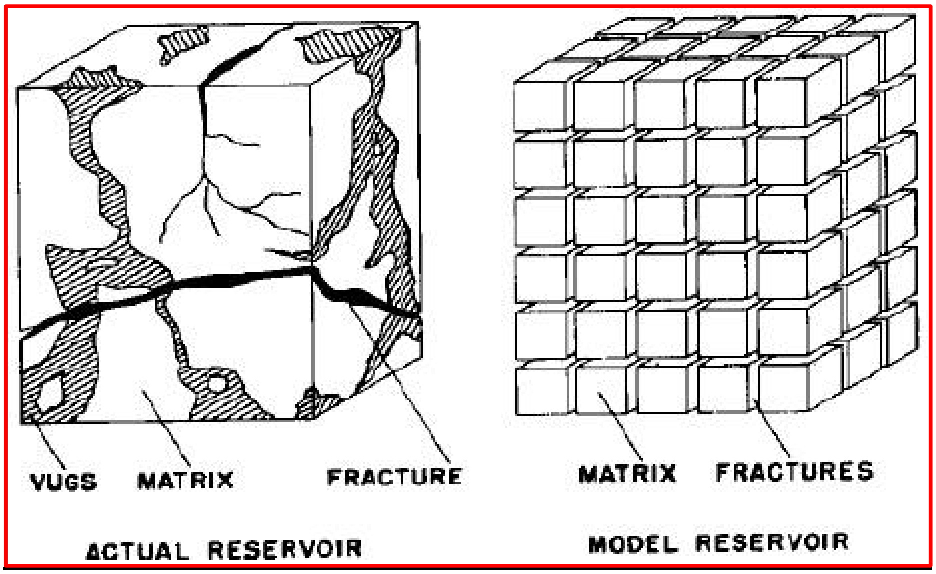

Figure 2.15: Explanation of Dual Porosity Model (Carlson et al. 1991).

The Dual porosity model is very popular in the area of shale gas reservoirs, as most of the shale gas reservoirs are naturally fractured. Several studies have done in the same area.

Some researchers, Du et al. (2010) have considered induced or hydraulic fractures in place of natural fractures in dual porosity model. For analyzing the performance of the dual porosity model, the data obtained from micro-seismic responses, hydraulic fracture treatments and production data history matching is performed. The extent of proppant propagation during hydraulic fracturing and the conductivity of the hydraulic fracture were discussed. Several parameters like rock compressibility, water holdings in hydraulic fracture network, fracture system conductivity and micro-seismic intensity were considered for performing sensitivity analysis.

Zhang et al. (2009) developed a updated dual porosity simulation model for studying the effect of different parameters to the simulation of single horizontal well. This updated dual porosity model is developed by upscaling the discrete fracture network (DFN) model. ECLIPSE (Reservoir Simulator) was used to study the effect of thirteen different parameters on cumulative gas production.

Li et al. (2011) performed a study on the similarities and differences between single porosity model and Dual porosity model. During their study, it is proven that the production responses were similar in both the models. They also stated that though the production results from both the models satisfy the history matching data for shale gas reservoirs, they cannot give the production predictions for future performances. But, for achieving the same accuracy of history matching, dual porosity model is the best when compared to single porosity model as it takes much more time for simulation

2.5.3 **<u>Multiple Interaction Continua Medium:</u>**

Pruess et al. (1985) developed Multiple Interaction Continua Medium Model which is an extension to the previously developed dual porosity model. In MINC model, the fractured shale gas reservoir is discretized into several grid blocks; these grid blocks are divided into two porous zones- natural fracture porosity and matrix porosity. Now, in MINC method the matrix block is further subdivided into a system of nested rings which helps in calculating the fluid flow between the rings, as shown in Figure 2.16.

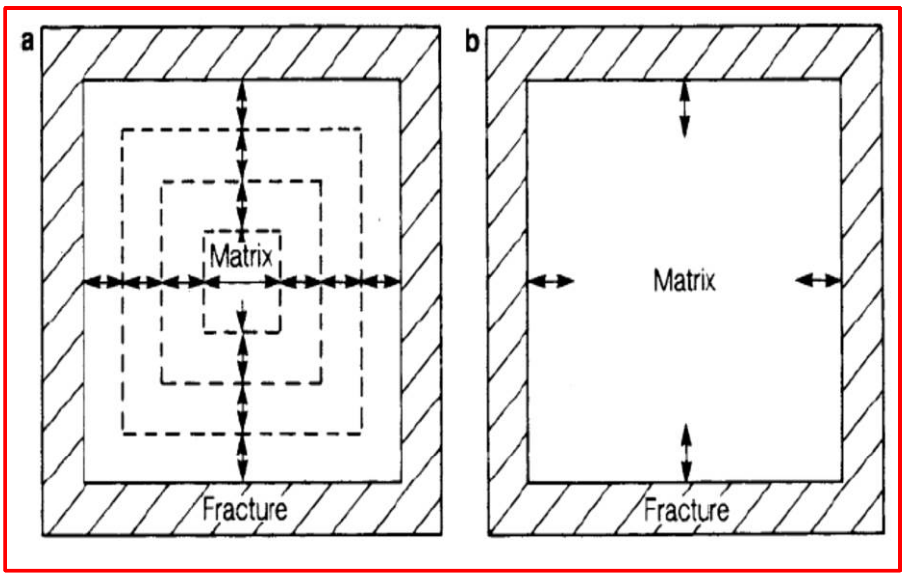

Figure 2.16: Discretization of Matrix Blocks: a. MINC, b. Dual Porosity Model (Yu-Shu Wu et. al. 1988).

2.5.4 **<u>Dual Permeability Model:</u>**

Similar to conventional dual porosity model, dual permeability model also consists of matrix and fracture systems. Each of this system will be having their own reservoir and fracture properties like matrix porosity, natural fracture porosity, matrix permeability, natural fracture permeability, saturation etc. So, each grid block contains one matrix porosity and one natural fracture porosity.

As shown in Figure 2.17, the flow inside each grid block is represented as the flow of gas from matrix to matrix block and from matrix to fracture network. The properties of matrix will dominate the matrix to fracture flow. For the flow between grid blocks, which is different from conventional dual porosity model, the matrix porosities in the dual permeability model is also connected with the porosities of the surrounding matrix blocks similar to fracture porosities.

Moridis (2010) developed a dual permeability model and compared with dual porosity model and effective continuum model (ECM). In order to check the effectiveness of the different model, Moridis (2010) has created a sample case with very fine discretized grid blocks, complex descriptions of the fracture-matrix interactions in several subdomains of the producing systems, and considering this as a reference for evaluating the perfection of different models. The results obtained from dual permeability model gives the best performance from the other two developed models. They also stated that, at later stage of production the deviation between dual permeability and sample case model is more apparent.

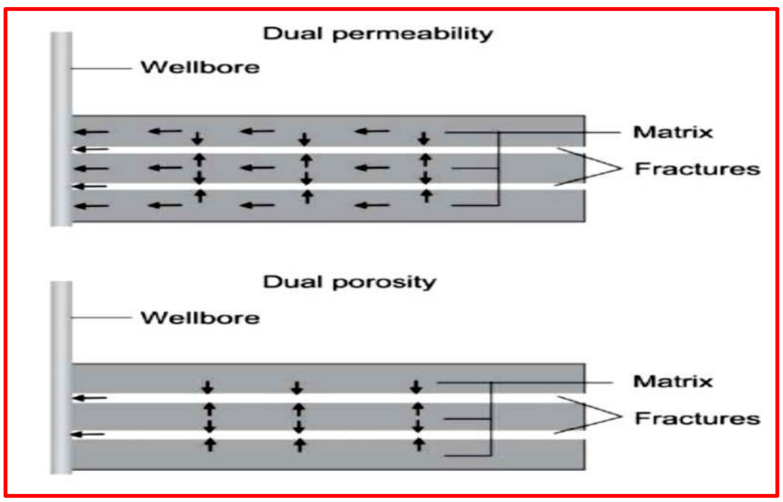

Figure 2.17: Illustration of Flow in Dual Porosity Model and Dual Permeability Model (Pereira et al. 2006).

2.5.5 <u>Multiple Porosity Model:</u>

In dual porosity model, it has assumed that the entire shale reservoir is classified into two parts; the matrix and the natural fracture. But in Multiple Porosity Model, it has been assumed that the reservoir is divided into different parts i.e two or three parts based on different properties like porosity, organic and inorganic rock types.

Dehghanpour et al. (2011) thinks in advance manner and assumes that the matrix blocks in dual porosity model is collection of sub-matrices with Nano Darcy permeability and micro fractures with milli or micro Darcy permeability. Performing sensitivity analysis on this model has proven that by considering micro fractures, the rate of pressure drop in the reservoir is decreased.

Yan et al. (2012) has developed an advanced micro-scale model. Here, the shale matrix bulk was further divided into organic and inorganic matrix. Further, the organic matrix was further divided into organic matter with Nano pores and organic matter with Vugs. Altogether, there are four different cases in their model: Nano Organic Matrix, Vugs Organic matrix, inorganic matrix and natural fracture. In comparison with conventional dual porosity model, the micro scale model is more producible as the pressure drop is much faster. They also developed an advanced model, the Triple Permeability model in which all the fractures, the organic and inorganic porosity systems were considered for flow among these systems.

2.6 Gas Desorption:

The most important aspect in shale gas study is Gas desorption. For the analysis of gas desorption and adsorption, adsorption isotherm which gives the relation between adsorbed gas volume and pressure at constant temperature is generally used.

Though it is accepted internationally that the gas desorption mechanism plays an important role in the production of shale gas from shale reservoirs, the extent of effect of gas desorption on shale gas production and its effect on economics is still controversial.

Bumb et al. (1988) generated an appropriate analytical solution for gas flow in shale reservoirs where the free gas and the adsorbed gas is considered. This analytical solution was used to check the effect of gas desorption on gas production. The obtained result shows that when compared with conventional gas reservoirs the cumulative gas production in reservoirs where the gas desorption takes place is high.

Cipolla et al. (2009) studied the effect of gas desorption by performing simulation study using real shale gas reservoir data of Marcellus and Barnett Shales. The results shows that in Barnett Shale the impact of gas desorption mainly occur in the latter period of the well when the matrix block pressure becomes low. In a period of 30 years gas production, an increase of 5-15% has been observed. Similar trends were also observed in Barnett shale, and observe a 10% increase during a period of 30 year production. From the obtained results, they have concluded that the gas desorption may not give significant impact on economics.

Moridis et al. (2010) had analyzed the effect of desorbed gas on gas production using multi-component Langmuir isotherm equation. Different values of Langmuir volume were selected from 0 to 200 scf/ton and the results shows that the desorbed gas will have a greater impact on prediction of gas production.

Yu et al. (2015) sated that an overall increase in EUR of 20% has been observed at 30 years of gas production for New Albany Shale and Marcellus Shale; for Haynesville Shale an increase of below 10 % has been observed; for Barnett Shale and Eagle ford shale it is observed that an EUR increase of 10% and 20%. They also observed that the gas desorption is very important when the hydraulic fracture spacing is decreasing at later period of the well.

2.7 Flow Mechanisms in Shale Gas Reservoirs:

In shale reservoirs, there are large variations in the scales of pore radius. On one side, hydraulic or induced fractures have macro scale pores; on other side, the matrix pores are in Nano scale. This huge variation of pore scale in the shale reservoir makes the gas flow very complex.

Javadpour et al. (2007) states that the flow in Nano pores is either in continuum or in molecular approach. They also explained about different flow regimes based on Knudsen number (K_n) and also developed an procedure for describing gas flow in Nano pores. Table 2.1 describes different flow regimes based on the Knudsen number (K_n).

Table 2.1: Flow Regimes based on Knudsen Number (Javadpour et al. 2007).

Navier Strokes Equation	
Flow with No slip ((K_n) < 10^-2)	Flow with slip (0.001<(K_n) <10^-1)
Continuous flow	Flow under slip conditions.
Darcy's flow	Knudsen Diffusion

Freeman et al. (2010) describes that the shale gas flows in three different mechanisms: convective flow, Knudsen diffusion, and molecular diffusion. For solving Knudsen diffusion they used Klinkenberg's method, and for estimating molecular diffusion they use Chapman-Enskodd Model.

Swami et al. (2012) identified four different flow regimes based on Knudsen number in shale reservoirs. The types of flow regimes and the Knudsen number ranges are: Viscous flow ((K_n) ≤0.001), Slip flow (0.001<(K_n) <10), Transitional flow (0.1<(K_n) <10), and Knudsen's flow ((K_n) ≥10). They have compared 10 different theories and concluded that Javadpour's model is the most reasonable approach, but needs some validation against real time data.