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Analytical Models For Gas Production In A Shale Reservoir: A Review Focusing On Pore Network System

M.V. Abbas^{1*}, M. Shoaib¹, N.A.H. Alshmlh¹, A.S.A. Shahid^{2,3}, H.M. Kim³

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Abstract

Shale gas reservoirs may contain pores with different origins (; natural or induced) and scales. They can be divided into four groups, inorganic porosity, organic porosity, natural micro-fractures porosity and artificially created fractures porosity. The inorganic porosity is the void spaces within matrix of clay, pyrite, silica and other non-organic minerals. The organic porosity is the void space that remains in organic matter after conversion the kerogen to gas and oil. Organic matter in the form of kerogen is finely dispersed within inorganic matrix and contain void spaces (organic porosity). Micro-fractures network contains void spaces (natural micro-fractures porosity) and pore network system is also formed after creation of hydraulically induced fractures (artificially created fractures porosity). Simulating gas production from shale gas is a complex process due to interaction of fluid with various pore scales. In the current research work, shale gas transport through complex porous network is reviewed. Transport mechanism for free and adsorbed gas in dispersed organic nano-pores is combination of both Darcy and non-Darcy phenomena. Slippage of gas molecules occurs in organic pores and desorption of gas molecules occurs as the reservoir pressure depletes. The combined flux from organic pores is transported into inorganic pores then transported into micro-fractures network which can be exploited if hydraulically induced fractures are created in the vicinity of wellbore. It is a huge challenge to model gas production from shales due to presence of multi-scaled porosities. Slippage effects and desorption further add to the complexity in shale gas reservoirs. Analytical models, presented in the current review paper, incorporate complexities in shale gas reservoirs so that production from shale gas can be modeled precisely.

Keywords: Unconventional Gas Reservoirs, Shale Gas Reservoirs, Pore Network, Analytical Simulation Models, Gas Desorption.

1. Introduction:

Natural gas is one of the main sources of energy and with conventional resources depleting, it is high time to exploit unconventional resources in the form of Shale Gas [1], [2] As the energy demand is increasing rapidly, Shale gas has gained world attention as an extra resource to fill the gap of energy demand [3]. Hence, world is moving towards exploiting unconventional deposits which were

considered to be economically unfeasible initially [2]. Technologies have been improving with respect to cost of time and money, and effective horizontal drilling along with hydraulic fracturing techniques have allowed development of shale gas reservoirs at much more economical levels [2], [4][6]. According to Energy Information Administration (EIA), world total gas resources are about 22,600 TCF and 40% of total natural gas is contributed by shale gas [2].

¹⁾ DIATI, Politecnico di Torino, Italy

²⁾ Department of Petroleum and Gas Engineering, University of Engineering and Technology, Lahore, Pakistan

³⁾ Department of Energy and Mineral Resources Engineering, Sejong University, Seoul, South Korea

Corresponding Author: villayat.abbas@gmail.com)

Unconventional gas reservoirs have very low permeability range as compared to conventional gas reservoirs [7].

Pore size of shale gas reservoirs is in nano-meters ranging from 10-200 nm, and therefore permeability is in the range of nano-Darcy [8], [9]. In conventional gas reservoirs, gas resides only in pore spaces while in the case of unconventional gas reservoirs, the gas remains in two different forms, i.e. it is present as adsorbed gas on organic matter and as free gas inside fractures and pores [10].

Development of unconventional gas reservoirs is challenging both economically and operationally due to very low permeability and adsorbed gas presence. Conventional completion (vertical well without hydraulic fracturing) is not economical in unconventional reservoirs so effective horizontal drilling is required along with multi-stage fracturing. It will improve near wellbore conductivity and also improve conductivity of natural fractures by providing a main channel connecting micro-fractures. [4], [11].

Unconventional gas reservoirs can be mainly classified, after excluding gas hydrates, as [12]:

1. Shale Gas (permeability in the range of 10^{-6} to 10^{-3} md)
2. Tight Gas (permeability in the range of 10^{-3} to 1 md)
3. Coal-Bed Methane (gas resides in naturally occurring coal bed)

Gas in shales is most important when compared with other two unconventional resources because of huge resource potential in form of much higher horizontal extent of shales resulting in huge trapped volumes of natural gas [2]. Pore network in shale gas reservoirs is complex and at least contain four distinct pore scales:

- a) Inorganic porosity: Clay, pyrite, silica and other non-organic minerals contains void spaces within matrix [13], [14]
- b) Organic porosity: Organic matter in the form of kerogen is finely dispersed within inorganic matrix. It is assumed to be formed at the time of hydrocarbon generation and act as separate porous medium having pore size in range from

5nm to 1000nm. It can adsorb and store free gas simultaneously [15].

- c) Natural micro-fractures porosity: Micro-fractures network are very important in shale gas reservoirs because they have high fluid conductivity which contributes to higher gas rates in shale gas reservoirs. Porosity in micro-fractures network is assumed to be less than 0.5%. Porosity and permeability of these natural fractures can be improved at this pore scale after successful hydraulic fracturing treatment [15].
- d) Artificially created fractures: Pore network system formed after creation of hydraulically induced fractures.

The term artificial fracturing is generally described in terms of both location and geometry. For example, a horizontal well with over 5000ft length can be hydraulically fractured 10-20 times at intervals of hundreds of feet. Fracture half-length may vary from 500 to 800 m in each direction. This geometry explains the area from where the shale gas will be produced after hydraulic fracturing stages are completed [5], [16]. Hydraulic fracturing forms a complex fracturing network by connecting the micro-cracks naturally present in the rock with the main hydraulic fracture and enhances the percolation capacity of reservoir. Due to this complexity, many researchers have studied numerically simulated hydraulic fractures in order to couple them with reservoir simulator to forecast the performance of reservoir in more complete manner [4], [17].

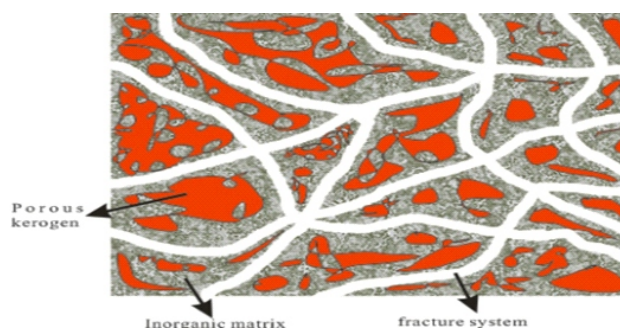


Figure 1: Distribution of multi-scaled pore media in the SRV area of shale gas reservoir [18].

Creating complex pore networks in shale gas reservoirs is one of the most challenging and important tasks in shale resource development. Porosity in shale gas reservoirs is mostly associated with organic kerogen as shown in (Figure 1) and the aim of development of shale gas is to tap into this main porosity to maximize the ultimate recovery.

The gas production from shale gas reservoir and the simulation of this fluid production are also affected by gas slippage and desorption of gas. The gas is absorbed on the pores' surface instead of occupying the pores (void spaces). When the pressure decreases during gas production, the gas is generated in the form of free gas in the natural fractures [7]. When the gas passes through a porous medium with low permeability, the slippage of gas occurs, where the gas layers velocity is not zero near the solid wall, as a result there is significant increase in flow rate of gas in the porous media [19]. In the kerogen filled rock matrixes, the absorbed gas and free gas exits together, the gas begins to desorb from the wall of pores and flow in the direction of matrix system. When the change in pressure occurs inside the rock matrix and fracture system, the gas transfer happens from matrix to fracture. If the reservoir pressure decreases, gas desorption occurs, generating free gas with a large capacity [10]. Once the shale gas reservoir production starts, the gas in the matrix begins to transfer to fractures [20]. Therefore, this leads to a reduction in pressure, which leads to free gas production by the fracture network. Once gas production begins, the flow contribution of fractures is high, and the matrix fill-ups the fractures, and as a result gas start flowing in the direction of wellbore

and brings the natural gas to the surface [21].

2. Problems Faced in Simulating Production from Shale Gas Reservoirs:

Simulating gas production from shale gas is a complex task due to the interaction of flowing fluid with various pore scales. Transport mechanism for free and adsorbed gas in dispersed organic nanopores is combination of both Darcy and non-Darcy phenomena. Slippage of gas molecules occurs in organic pores because mean free path of gas molecules is comparable to pore-throat size [22]. Along with that, desorption of gas molecules occurs as the reservoir pressure depletes. The combined flux from organic pores is transported into inorganic pores present in shale gas. Combined flux from organic and inorganic pore scales is transported into micro-fractures network which have less interconnection and are widely dispersed. Micro-fractures can be exploited if hydraulically induced fractures are created in the vicinity of wellbore as shown in Figure 2. Hydraulic fracturing treatment provides two advantages:

- Micro-fractures are intersected orthogonally to complete flow path from organic matter to wellbore.
- Micro-fractures are opened which increases fluid conductivity.

It is a huge challenge to model gas production from shales due to presence of multiple porosities. Slippage effects and desorption further add to the complexity. Physics of these effects need to be incorporated correctly and completely, so that production from shale gas can be simulated precisely.

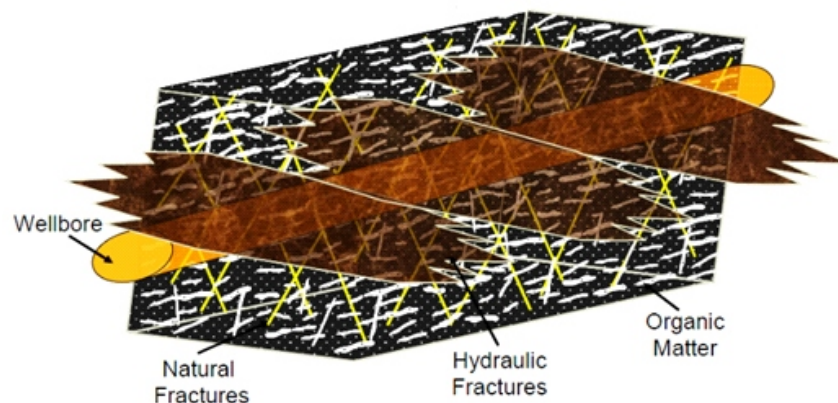


Figure 2: Schematic of gas transport from organic matter to wellbore [15].

Figure 3 shows the schematic of production fair-ways in shale gas reservoirs having multiple porosities. Shale gas (free and adsorbed) in organic pores is transported to inorganic pores. Combined flux from both organic and inorganic pores is transported into micro-fractures. Hydraulic fractures intersect micro-fractures orthogonally and allow transport of shale gas to wellbore. The model to be used to simulate the fluid flow from shale gas reservoirs should take into account these flow fair-ways in right order as well to be able to completely describe the fluid flow behavior.

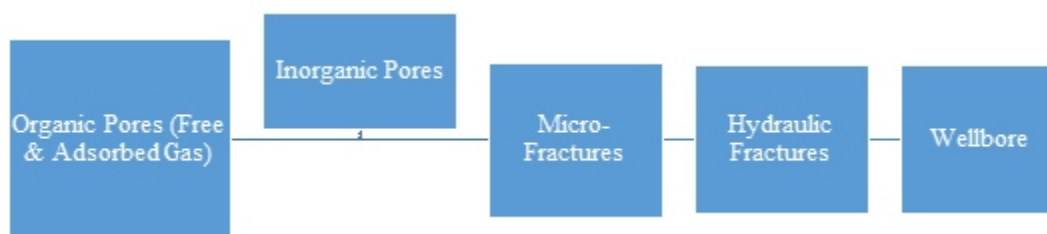


Figure 3: Schematic of production fair-ways in shale gas

2.1. Desorption of Gas in Organic Pores:

Desorption of gas in organic pores can be tackled by adsorption model which provides a relationship for the adsorbed gas amount on solid surface at given pressure and temperature. If the temperature is constant, then adsorbed gas amount on solid surface is only a function of pressure and relationship is known as “Adsorption Isotherm”. There are five types of adsorption models for single component [23]:

a) Type (I) Langmuir's Isotherm which is used

for single layer coverage of gas molecules on solid surface [24].

b) Type (II) and (III) allow multilayer coverage and have infinite pore spaces for adsorption [25].

c) Type (IV) and Type (V) additional constraint of finite adsorption capacity on solid surface [26].

Figure 4 shows five types of adsorption models for single component where p^0 is the saturation pressure.

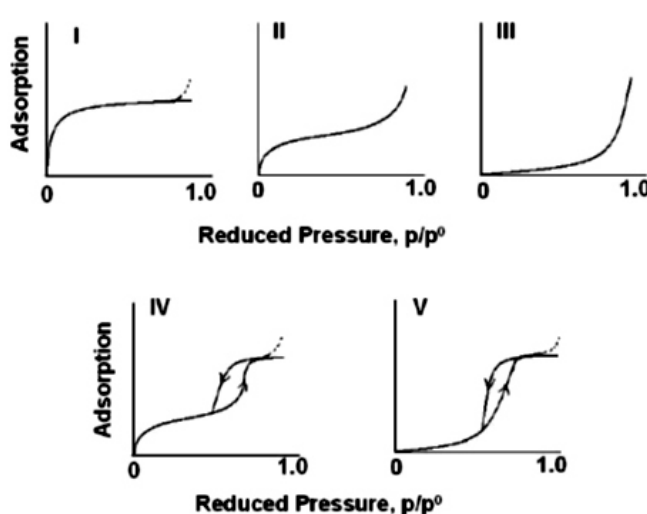


Figure 4: Adsorption isotherms for single component [27], [28]

Langmuir's Isotherm assume single layer coverage of gas molecules [24] but BET Adsorption model [29] can be used to tackle infinite number of adsorbed layers.

Extended Langmuir's Isotherm [24] and Gibbs

Approach [25] are the two approaches used to model multicomponent adsorption.

2.2. Gas Slippage:

Slippage of gas molecules occurs in organic pores

because mean free path of gas molecules is comparable to pore-throat size [22]. To model gas production from shale gas, Klingenberg's apparent permeability concept is mostly used. Apparent gas permeability is given by Equation (1):

$$k_{kl} = k \left(1 + \frac{b_{kl}}{P} \right) \quad (1)$$

Gas slippage factor is assumed constant [22], [30] introduced pressure dependency on gas slippage factor by providing Equation (2):

$$b_{kl} = \frac{P c_g \mu_g D}{\alpha k} \quad (2):$$

Here, D is the slip coefficient, α is the conversion factor, c_g is the gas compressibility and μ_g is the gas viscosity.

3. Methodology to Estimate In-Place of Shale Gas Reservoirs:

Conventional volumetric and material balance methods are not directly applicable for shale gas reservoirs to calculate the recoverable reserves. When calculating the reserves of shale gas without taking into account the impact of adsorption hysteresis, certain calculation errors will occur. So that, conventional volumetric and material balance methods need modifications to be more effective for shale gas reservoir to do a dynamic analysis [31].

Hence, modifications are introduced to tackle desorption in shale gas reservoirs.

3.1. Volumetric Calculation for Shale Gas Reservoirs:

Ambrose et al. (2010) provided the procedure to accurately quantify shale gas in place. Total shale gas in place includes adsorbed gas, free gas in place (adsorbed gas corrected), gas dissolved in oil and gas dissolved in water. Total shale gas in place expressed in scf/ton is given by Equation (3) [32]:

$$V_t = V_g + V_f + V_{so} + V_{sw} \quad (3)$$

Adsorbed gas from Langmuir isotherm (V_g), free gas in place (V_f), gas dissolved in oil (V_{so}) and gas dissolved in water (V_{sw}) are given by Equations (4) - (7):

$$V_g = \frac{V_L P}{P + P_L} \quad (4)$$

$$V_f = \frac{32.0368}{B_g} \left[\frac{\phi(1 - S_w)}{\rho_s} - \frac{1.318 \times 10^{-6}}{\rho_s} \left(\frac{V_L P}{P + P_L} \right) \right] \quad (5)$$

$$V_{so} = \frac{32.0368}{5.6146} \left(\frac{\phi S_o R_{so}}{\rho B_o} \right) \quad (6)$$

$$V_{sw} = \frac{32.0368}{5.6146} \left(\frac{\phi S_w R_{sw}}{\rho B_w} \right) \quad (7)$$

Here, V_L is Langmuir's volume constant (scf/ton), P_L is Langmuir's pressure constant (psia), P is given gas phase pressure (psia), ρ_s is density of adsorbed gas (gm/cm³), ρ is density of fluid (gm/cm³), ϕ is porosity (fractions), S_w is water saturation (fractions), R_{sw} is solution gas-water ratio (scf/stb), B_w is formation volume factor of water (bbl/stb), S_o is oil saturation (fractions), R_{so} is solution gas-oil ratio (scf/stb) and B_o is formation volume factor of oil (bbl/stb).

3.2 Material Balance for Shale Gas Reservoirs

Material balance equation is one of the most important reservoir engineering tools to estimate initial gas in place from the production data. Material balance equation for shale gas reservoirs should include desorption phenomenon [33] provides generalized material balance Equation (8) which incorporates desorption term.

$$G B_{gi} = (G - G_p) B_g + \Delta V_{wip} + \Delta V_{ep} + \Delta V_d \quad (8)$$

Net water encroachment (ΔV_{wip}), rock and water expansion (ΔV_{ep}) and desorption term (ΔV_d) are given by Equations (9) - (11):

$$\Delta V_{wip} = 5.615 (W_e - W_p B_w) \quad (9)$$

$$\Delta V_{ep} = \frac{B_{gi} G}{S_{gi}} (c_t + c_w S_{wi} + c_o S_{oi}) (P_i - P) \quad (10)$$

$$\Delta V_d = \frac{\rho_b B_{gi} V_f G}{S_{gi} \phi} \left[\left(\frac{V_L P_i}{P + P_L} \right) - \left(\frac{V_L P}{P + P_L} \right) \right] (P_i - P) \quad (11)$$

Here, G is initial gas in place (scf), B_g is formation volume factor of gas (ft³/scf), W_e is cumulative water encroached from aquifer into reservoir (bbl), W_p is cumulative water produced from reservoir (stb), B_w is formation volume factor of water (bbl/stb), S_g is gas saturation (fractions), S_w is water saturation (fractions), S_o is oil saturation (fractions), ϕ is reservoir porosity (fractions), P is reservoir pressure (psia), P_i is initial reservoir pressure (psia), ρ_b is bulk density (gm/cm³), V_f is free gas in place (scf/ton), c_t is total compressibility (1/psi), c_w is water compressibility (1/psi), c_o is oil compressibility (1/psi), S_{wi} is initial water saturation (fractions), S_{oi} is initial oil saturation (fractions), S_{gi} is initial gas saturation (fractions), V_L is Langmuir volume constant (scf/ton), P_L is Langmuir pressure constant (psia), P is reservoir pressure (psia), ϕ is reservoir porosity (fractions), S_w is water saturation (fractions), R_{sw} is solution gas-water ratio (scf/stb), B_w is formation volume factor of water (bbl/stb), S_o is oil saturation (fractions), R_{so} is solution gas-oil ratio (scf/stb) and B_o is formation volume factor of oil (bbl/stb).

ρ_b is bulk density of rock (gm/cm^3), V_f is adsorbed gas corrected free-gas in place (scf/ton), C_t is total compressibility (psi^{-1}), C_w is water compressibility (psi^{-1}), C_o is oil compressibility (psi^{-1}) and subscript i indicates initial conditions.

4. Interpretation of Analytical Simulation Models:

Analytical simulation models are available in literature with the purpose to simulate gas production from shale gas reservoirs. Interpretation of four analytical simulation models is include as below:

4.1. Linear-to-Boundary (LTB) Model:

This model was developed initially with an assumption that primary hydraulic fractures have

same fracture half-length and distance between consecutive fractures is also equal [34] as shown in Figure 5. This assumption was later removed, and the improved model is valid for heterogeneous completion [35]. Drainage of well is restricted to volume between hydraulic fractures. Transient linear flow occurs initially due to infinite conductivity hydraulic fractures and later on pressure transient reaches boundary dominated flow. Reservoir volume between fractures also known as stimulated reservoir volume (SRV) has high permeability (k_1) when compared with formation permeability (k_2). Higher permeability of SRV is due to reactivation of natural fractures when high pressure fluid is injected to create hydraulic fractures.

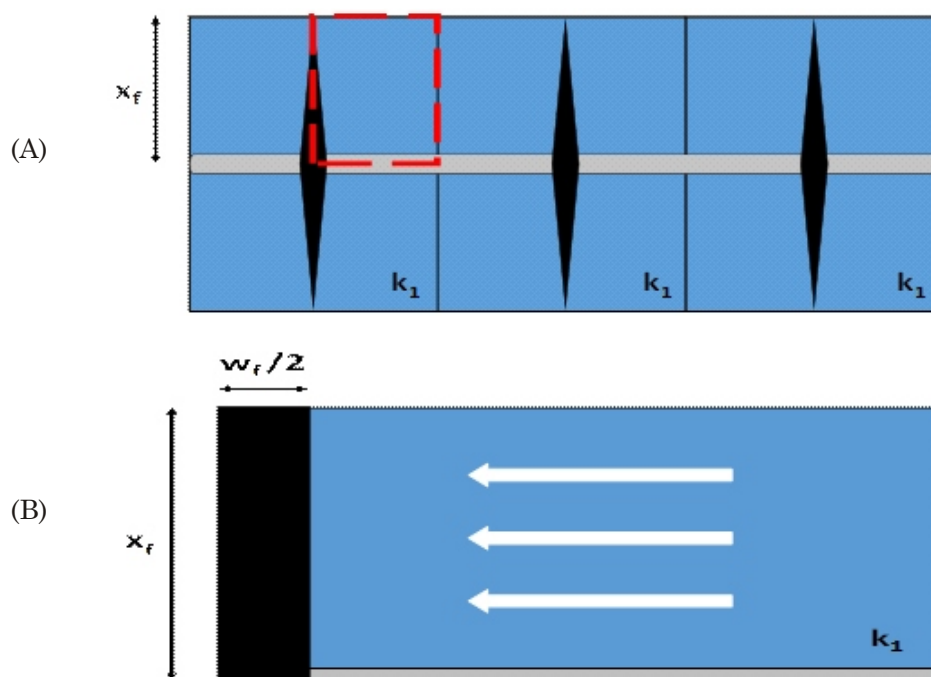


Figure 5: Linear-to-Boundary (LTB) model

4.2. Tri-linear Flow Model:

Linear-to-Boundary model assumes no flow from the region outside SRV. Assumption is reasonable for shale gas reservoirs which has matrix permeability in the order of 10^{-9} Darcy. To tackle flow from region outside SRV, tri-linear flow model was introduced [36]. Tri-linear flow model couples linear flow in three adjacent flow regimes: outer reservoir beyond SRV, inner reservoir between

fractures and hydraulic fractures. All three regions have distinct permeabilities k_2 , k_1 and k_f respectively. Schematic of linear flow regimes is shown in Figure 6. In tri-linear flow model, hydraulic fractures can be considered to have finite conductivity. Along with that, inner reservoir can be treated either homogenous or naturally fractured. Dual-porosity assumption can be used to simulate naturally fractured inner reservoir.

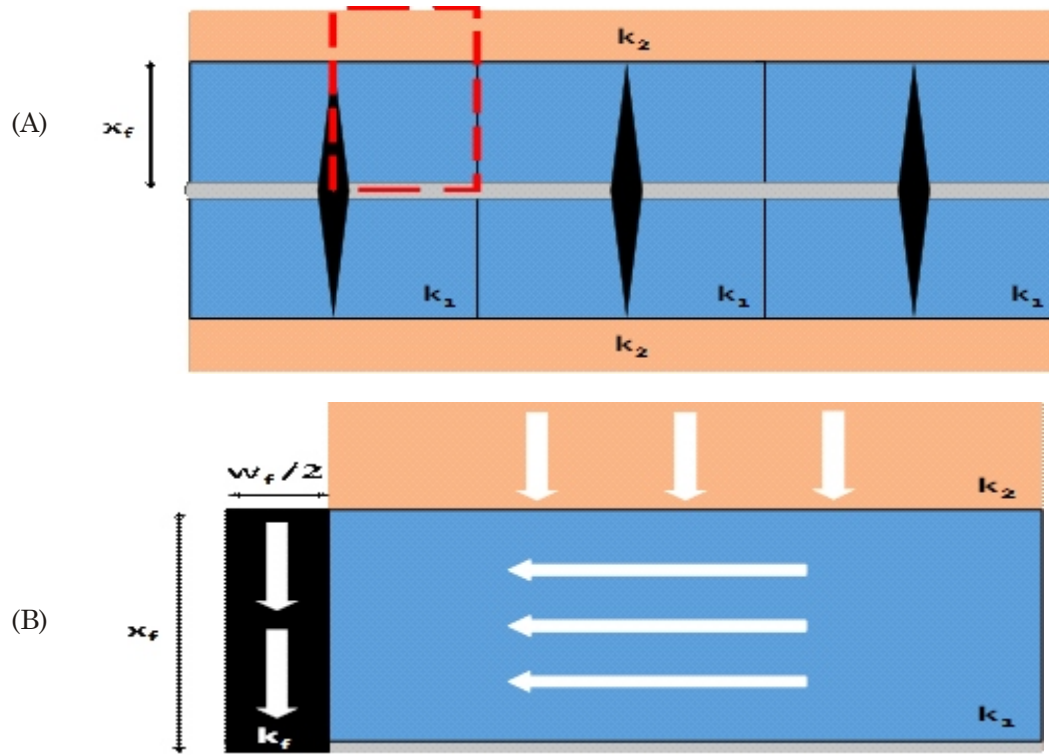


Figure 6: Tri-linear flow model

4.3 Enhanced Fracture Region Model:

Similar to tri-linear flow model, enhanced fracture region model was introduced which comprises of three distinct linear flow regions: low permeability region, high permeability region and fracture region [37]. Although, location of regions and interaction among regions are different. Branched

pattern of fractures is assumed due to which high permeability (k_i) region is present only around the hydraulic fractures as shown in Figure 7. Between stimulated high permeability regions, region of low permeability (k_i) is present. Drainage was assumed till the tips of fracture, so no flow occurs beyond fracture tips.

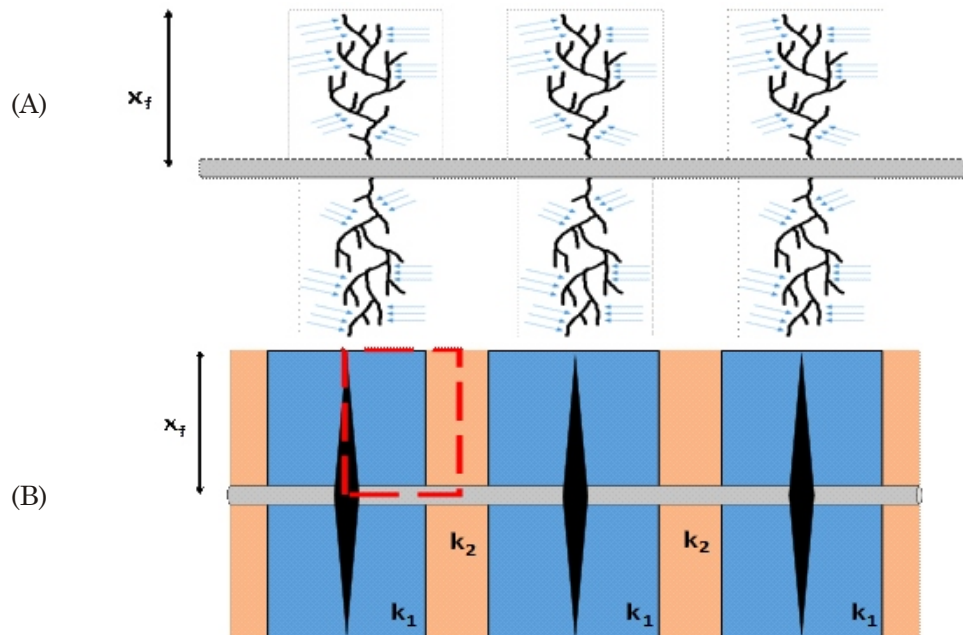




Figure 7: Enhanced fracture region model

4.4 Five Regions Model:

Enhanced fracture region model was extended beyond fracture tips and reservoir was sub-divided into five linear flow regions instead of three [38] as

shown in Figure 8. Distinct permeabilities can be defined for regions 2, 3 and 4 but they are mostly considered equal to native formation permeability. Region 1 is stimulated and has high permeability (k_1).

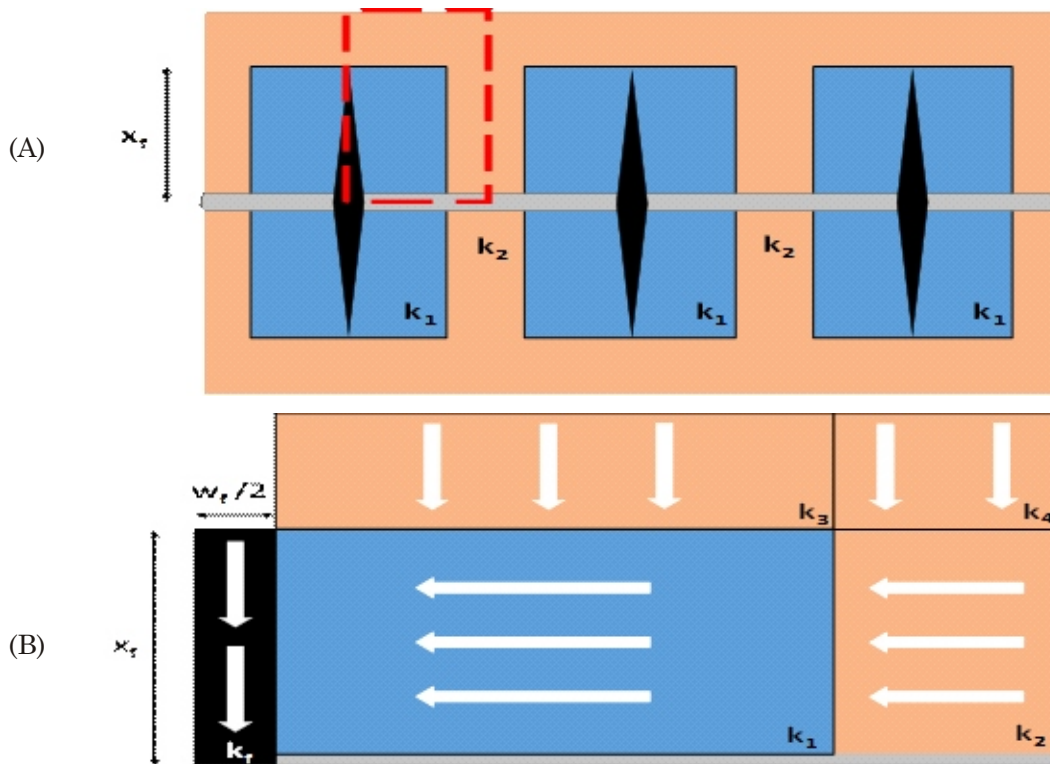


Figure 8: Five regions model

5. Conclusions and Recommendations:

Different analytical simulation models have been being adopted to simulate gas production from shale reservoirs, in which incorporating the presence of multiple porosities, slippage effects and desorption are incorporated. In this paper, we have reviewed four different models, Linear-to-Boundary model, tri-linear flow model, enhanced

fracture region model and five regions model, with which production from shale gas can be simulated precisely, and summarized pros and cons of each model

Acknowledging that choice of analytical model depends upon the scope of work and the final objective, Linear-to-Boundary model is the easiest to implement but least accurate. Tri-linear flow

model is the most commonly used in a commercial software thanks to its robustness. Five regions model is the most complex covering flow from all possible regions, but complexity does not guarantee accuracy. Hence, choice of the model is based on

users' judgement depending on objective at hand. Further comparative studies with theoretical and actual case are needed to give more insight into the merits and demerits of each selected method which is the objective of the ongoing research.

6. Nomenclature

K_{kl} = Klengenberg apparent gas permeability

B_{kl} = Gas slippage factor

P = Pressure

c_g = Gas compressibility

μ_g = Gas viscosity

D = Slip coefficient

γ = Conversion factor

K = Permeability

V_g = Langmuir isotherm

V_f = Free gas in place

V_{so} = Gas dissolved in oil

V_{sw} = Gas dissolved water

V_L = Langmuir's volume constant (scf/ton)

P_L = Langmuir's pressure constant (psia)

ρ_s = Density of adsorbed gas

ρ = Density of fluid

ϕ = Porosity

S_w = Water Saturation

R_{sw} = Solution gas-water ratio

B_w = Formation volume factor of water

S_o = Saturation of oil

R_{so} = Solution gas-oil ratio

B_o = Formation volume factor of oil

G = Initial Gas in place

B_g = Formation volume factor of gas

W_e = Cumulative water encroached from aquifer into reservoir

W_p = Cumulative water produced from reservoir

ΔV_{wip} = Net water encroachment

ΔV_{ep} = Water expansion

Δ_{vd} = desorption term

S_g = Saturation of gas

ρ_b = Bulk density of rock

c_t = Total compressibility

c_w = Water compressibility

c_o = Oil compressibility

i = represents initial conditions

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