

Patrik Pusztai and Dr. Anita Jobbik

Research Institute of Applied Earth Sciences

INVESTIGATION OF GAS FLOW MODELS IN CASE OF MICRO- AND NANO PORE SIZE RESERVOIRS

INTRODUCTION

The growing requirement for energy and decreasing quantity of fossil fuels are forced the present engineers to find alternative solutions. This phenomenon is valid in case of hydrocarbons too, where the role of unconventional reservoirs is getting more significant at recent times. Natural gas production from these types of reservoirs has been developed remarkably in the past few decades thanks to the technology advancement.

These types of reservoirs (tight gas; shale gas) usually have pore size distribution in the range of micro- to nanometers and the reservoirs are placed in extreme conditions, which influence the equations describing the gas flow and the material balance equations. Appropriate description and modeling of these mechanisms are indispensable for economic exploitation of unconventional natural gas reservoirs.

Conventional continuum-flow equations, such as the well-known Darcy's law, greatly underestimate the fluid-flow rate when applied on nanopore-bearing reservoirs. This paper concentrates on the collection, interpretation and presentation of different flow models which can be used in such conditions. They are utilized on core samples which are originated in a Hungarian reservoir under extreme pressure and temperature (over 1100 bar and 200 °C). As only limited literatures are available which can describe the exact flow behavior of natural gas in these conditions, comparison of the different models under these conditions can provide information for a wider understanding of these types of reservoirs.

Several factors influence gas production from these unconventional formations, so the creation of an adequate material balance equation was necessary to describe pressure depletion and original gas in-place. Integration of this novel material balance equation with the different flow models results a calculation algorithm which enables to investigate the reservoir behavior during production. Through this calculation procedure a simple economic analysis can be performed. Finally the adaptability of this model to real production data is investigated.

MATERIAL BALANCE EQUATION

Investigation of the multiple mechanisms which characterize the tight and shale gas reservoirs are evident. Shale gas reservoirs are organic-rich, fine grained reservoirs in which the pore space can be classified into three main categories: porous in organic matter, interparticle pore system in the organic matrix, and fractures (induced by hydraulic fracture stimulation and natural fractures). Natural gas (mainly methane) in shale gas reservoirs is generally believed to be stored as either free or adsorbed gas; although, solution gas within pore fluids and bitumen may also be important (B. Haghshenas et al., 2014). Strictly speaking, there are multiple mechanisms for gas storage in organic-rich shales including (C.R. Clarkson and B. Haghshenas, 2013):

1. Adsorption upon internal surface area
2. Conventional (compressed gas) storage in natural and hydraulic (induced) fractures
3. Conventional storage in matrix porosity (organic and inorganic)
4. Solution in formation water
5. Absorption (solution) in organic matter

This paper concentrates on the 1., 3. and 4. mechanisms as they represent the greatest effects. In case of tight sand gas reservoirs the application of adsorption can be neglected if the total organic content (TOC) has negligibly small value.

In the previous two subchapters the explanation of the 1. and 4. mechanisms are detailed as they can be investigated in different ways.

Adsorption

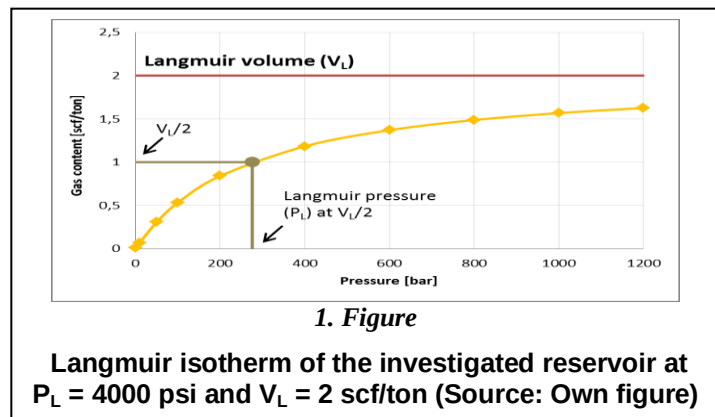
The matrix systems of shale reservoirs (also CBM) have immense capacity for methane storage. The mechanism by which this occurs is called adsorption. In adsorption, molecules of gas become attached to the surface of coal or to organic material in shale (which is obviously proportional to the total carbon content of the formation). Nearly all of the gas stored by adsorption to shale exists in a condensed, near liquid state. In order to simulate gas production in shale gas reservoirs, an accurate model of gas adsorption is very important. There are two different types of adsorption: chemical adsorption and physical adsorption. This paper deals with only the physical adsorption as it is more relevant in case of reservoir engineering.

The expression of adsorption isotherm must be introduced as the temperatures of reservoirs are assumed to be constant in this paper. It is assumed that at a given temperature the volume of adsorbed gas is only pressure dependent in the case of a given gas component and a given adsorbent (J. Pápay, 2013).

This paper suggests the use of the so called Langmuir isotherm, which is one of the most common applied adsorption models for shale gas reservoirs. It is based on the assumption that there is a dynamic equilibrium at constant temperature and pressure between adsorbed and non-adsorbed gas. Also, it is assumed that there is only a single layer of molecules covering the solid surface. The Langmuir isotherm has two fitting parameters the Langmuir volume (V_L) and the Langmuir pressure (P_L). The typical formulation of Langmuir isotherm is shown in the **Eq. 1.**, where V is the adsorbed gas volume at pressure p , V_L is the Langmuir volume or the maximum gas volume of adsorption at infinite pressure, and P_L is the Langmuir pressure, which is the pressure corresponding to one-half Langmuir volume (I. Langmuir, 1918).

$$V = \frac{V_L \times p}{P_L + p} \quad 1$$

In the **Eq. 1.** the V_L [scf/ton] and P_L [psia] values are determined in laboratory tests and the values of them are proportional to temperature, adsorbent material and to adsorbed material. **Fig. 1.** shows the Langmuir isotherm of the investigated reservoir in this paper (detailed later).



Solution in formation water

As it is known the natural gas cannot dissolve in water effectively. Although under high pressure and temperature the volume which dissolves in water can reach significant amounts. So it is evident to calculate this amount as the investigated reservoirs are under extreme conditions and also the measured connate water saturation of the core samples was significant. Solution depends on pressure, temperature and salinity values. The solution is less effective if the salt content of the formation water is high. As natural gases mostly consist of methane the calculation of methane solubility can provide adequate results. C.W. Blount and L.C. Price in 1982 developed two correlations for calculating the methane solubility in formation water. This work uses the correlation which provides less standard deviation value, **Eq. 2**.

$$\log_e CH_4 = -1,4053 - 0,002332 \times T + 6,3 \times 10^{-6} \times T^2 - 0,004038 \times S - 7,579 \times 10^{-6} \times P + 0,5013 \times \log_e P + 3,235 \times 10^{-4} \times T \times \log_e P \quad 2$$

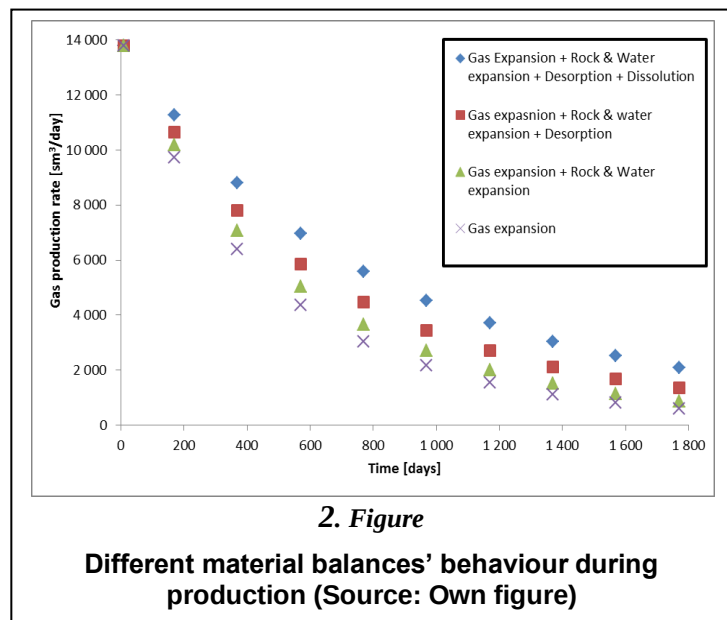
Where standard deviation of residuals is 0,0706 and multiple R is 0,9943. T is the formation temperature [°F], P is the formation pressure [psia] and S is the formation salinity [grams/liter]. CH₄ is in standard cubic feet [SCF] per petroleum barrel at 25 °C and atmospheric pressure. The validation of this correlation is 160 °F - 464 °F temperature and 3500 psi – 22500 psi pressure.

Methane solubility is greater with increasing pressure and temperature. Also it is greater with decreasing salinity values as it is indicated by **Eq. 2**.

Derivation of pressure drop calculation

Material balance equations are one of the most powerful tools for a reservoir engineer to model the reservoir behavior and approximate the original gas in place. The main concept in generating the material balance equation is simply a volumetric balance, which states that the algebraic sum of volume changes of gas in reservoir and the gas produced must be zero. The reservoir temperature is assumed to be constant. In this paper such material balance equation was necessary which deals with the fact of several different mechanisms. Because of the reservoir conditions a closed reservoir is assumed (in

case of tight, compact reservoir this assumption is acceptable) where the gas expansion, formation water expansion and formation rock expansion are the basic mechanisms. As a great deal of unconventional gas reservoirs are shale gas types, dealing with adsorption is indispensable. Also because of the great pressures and temperatures the dissolution of natural gas in the connate formation water is necessary (also the measured connate water saturation of the core samples were extremely high). Due to these phenomena the following connection is stated in this paper where the volumes identified under reservoir conditions.



$$\begin{aligned} \text{Cumm. gas production } [\text{m}^3] &= \text{Gas expansion } [\text{m}^3] + \text{Rock and water expansion } [\text{m}^3] \\ &+ \text{Desorption } [\text{m}^3] + \text{Release from formation water } [\text{m}^3] \end{aligned} \quad 3$$

It is evident due to the mechanisms took into account that the pressure depletion is not as high in case of all mechanisms as in case of only a closed reservoir without desorption or release of natural gas from formation water (**Fig. 2.**).

Identification of the different parts of the above connection can be seen in the following equations, where the Langmuir isotherm was used (**Eq. 1.**) to the desorbed gas volume calculation and for calculation of the release dissolved gas volume, **Eq. 2.** was used. Gas expansion and formation water and rock expansion calculation were calculated by clear equations.

$$\text{Cumm. gas production } [\text{m}^3] = G_p \times B_g \quad 4$$

$$\text{Gas expansion } [\text{m}^3] = G_f \times (B_g - B_{gi}) = A \times h \times \Phi_{ci} \times (1 - S_{wi}) \times \left(\frac{B_g}{B_{gi}} - 1 \right) \quad 5$$

$$\begin{aligned} \text{Rock and water expansion } [\text{m}^3] &= G_f \times B_{gi} \times \frac{S_{wi} \times c_w + c_f}{1 - S_{wi}} \times (p_i - p) \\ &= A \times h \times \Phi_{ci} \times B_{gi} \times (S_{wi} \times c_w + c_f) \times (p_i - p) \end{aligned} \quad 6$$

$$\begin{aligned} \text{Desorption } [\text{m}^3] &= G_a \times \frac{1}{G_{ci}} \times B_g \times \left(\frac{V_L \times p_i}{P_L + p_i} - \frac{V_L \times p}{P_L + p} \right) \\ &= A \times h \times \rho_{bi} \times B_{gi} \times \left(\frac{V_L \times p_i}{P_L + p_i} - \frac{V_L \times p}{P_L + p} \right) \end{aligned} \quad 7$$

$$\text{Release from formation water } [\text{m}^3] = G_s \times B_g \times \frac{1}{V_{si}} \times \Delta V_s = A \times h \times \Phi_{ci} \times S_{wi} \times B_g \times \Delta V_s \quad 8$$

,where G_p is the cumulative gas production under standard conditions [sm^3], G_f is the initial free gas volume under standard conditions [sm^3], G_a is the adsorbed gas volume under standard conditions [sm^3], G_s is the dissolved gas volume under standard conditions [sm^3], G_{ci} is the initial adsorbed gas content of the reservoir [sm^3/kg rock], V_{si} is the initial dissolved gas content [sm^3/m^3], ΔV_s is the initial dissolved gas volume minus the dissolved gas volume under depleted reservoir pressure [sm^3/m^3], A is the reservoir area [m^2], h is the reservoir height [m], B_{gi} is the initial formation volume factor [m^3/sm^3], B_g is the formation volume factor under depleted reservoir pressure [m^3/sm^3], Φ_{ci} is the corrected porosity [-], S_{wi} is the initial water saturation of the reservoir [-], V_L is the Langmuir volume [sm^3/kg], P_L is the Langmuir pressure [Pa], c_w is the water compressibility assumed to be equal with $45,8 \times 10^{-11}$ [$1/\text{Pa}$], c_f is the formation compressibility [$1/\text{Pa}$] factor which can be calculated by the Hall's correlation (H.N. Hall, 1955) who investigated 12 samples (7 limestones and 5 sandstones) to develop a c_f correlation, **Eq. 9.**

$$c_f = 1,86 \times 10^{-6} \times \Phi_m^{-0,415} \times \frac{1}{6894,75729} \quad 9$$

The use of corrected porosity is necessary because in this model the free gas volume is less than in case the adsorbed phase volume is ignored. The adsorbed gas is placed on the surface of the pores so it decreases the effective porosity. As the pressure decreases the adsorbed phase vaporizes (due to Langmuir isotherm) and makes a vacant space that is instantly occupied by free gas. So the pore volume available for free gas is allowed to increase as pore pressure decreases in this case during production. J. Williams-Kovacs et al., 2012 suggest a correction factor for this phenomena, it is presented in field unit, **Eq. 10**. It should be corrected with a Φ_{cm} term, suggested by this paper as the measured porosity (measured in laboratory conditions) is required in reservoir conditions, **Eq. 11.**, suggested by T. W. Engler, 2010.

$$\left(\frac{\Phi_{ac}}{\Phi_{cm}} \right) = \frac{\Phi_{cm} \times (1 - S_{wi}) - 1,318 \times 10^{-6} \times M \times \frac{\rho_b}{\rho_a} \times V_L \times \frac{p}{p + P_L}}{\Phi_{cm} \times (1 - S_{wi})} \quad 10$$

$$\Phi_{cm} = \frac{e^{c_f \times (p_i - p_m)}}{\frac{1}{\Phi_m} - [1 - e^{c_f \times (p_i - p_m)}]} \quad 11$$

Where Φ_{ac} is the corrected porosity due to adsorption [-], Φ_{cm} is the corrected measured porosity [-], M is the gas molar mass [lb/lbmol], V_L is in [scf/t] and P_L is in [psi], ρ_b / ρ_a is the reservoir bulk density over adsorbed phase density under initial conditions [-], where the adsorbed gas density is assumed to be equal with liquefied methane density which is approximately 420 kg/m³. Bulk density can be measured by laboratory circumstances (ρ_{bm}) and corrected by the formation compressibility under reservoir conditions, **Eq. 12**.

$$\rho_b = \rho_{bm} + \rho_{bm} \times c_f \times p_i \quad 12$$

where p_m is the pressure during porosity measurement [Pa]. Finally the initial corrected reservoir porosity is given by the following equation.

$$\Phi_{ci} = \Phi_{cm} \times \left(\frac{\Phi_{ac}}{\Phi_{cm}} \right) \quad 13$$

Finally the enhanced material balance equation suggested by this paper is presented below.

$$\begin{aligned} G_p \times B_g &= A \times h \times \Phi_{ci} \times (1 - S_{wi}) \times \left(\frac{B_g}{B_{gi}} - 1 \right) + A \times h \times \Phi_{ci} \times B_{gi} \times (S_{wi} \times c_w + c_f) \times (p_i - p) \\ &+ A \times h \times \rho_{bi} \times B_g \times \left(\frac{V_L \times p_i}{P_L + p_i} - \frac{V_L \times p}{P_L \times p} \right) + A \times h \times \Phi_{ci} \times S_{wi} \times B_g \times \Delta V_s \end{aligned} \quad 14$$

Where B_g , B_{gi} , can be calculated by **Eq. 15**. (in case of B_{gi} the equation is used by the initial deviation factor and with the initial reservoir pressure) and ΔV_s by the use of **Eq. 2**.

(where its value is equal with the volume under initial reservoir pressure minus the volume under depleted reservoir pressure).

$$B_g = \frac{P_{st} \times z \times T_i}{T_{st} \times p} \quad 15$$

Where P_{st} is the standard pressure (101325 [Pa]), T_{st} is the standard temperature (298,15 [K]), z is the deviation factor of the gas under reservoir pressure [-], the i lower index stands for values under initial reservoir conditions. The terms in ΔV_s is determined by SI units so a C_1 correction factor is necessary to convert it back to psi and its value is 0,000145037738.

As pressure drop calculation is required to predict the gas production during several years this paper suggests a method based on the above presented novel material balance equation. The **Eq. 14.** is not a linear equation, so it is suggested by this paper to solve the equation for depleted reservoir pressure (p) using Newton's method which is an iterative calculation method. For this purpose the function **Eq. 16.** is determined by rearrangement and simplification and also the derivative of this function **Eq. 17.** is determined.

$$f(p) = \frac{\beta_{11}}{p} + \beta_{14} - \beta_3 \times p + \frac{\beta_{13}}{p} - \frac{\beta_4}{p} \times \frac{V_L \times p}{P_L \times p} + \frac{\beta_5}{p} \times \left[\beta_6 - e^{\beta_7 - \beta_8 \times (p \times C_1) + \beta_9 \times \ln(p \times C_1) + \beta_{10} \times (p \times C_1)} \right] - \frac{\beta_{15}}{p} \quad 16$$

$$f'(p) = \frac{V_L \times \beta_4}{(p + P_L)^2} - \frac{\beta_5 \times \left(\frac{\beta_{10}}{p} + \frac{\beta_9}{p} - \beta_8 \times C_1 \right) \times e^{\beta_{10} \times \ln(p \times C_1) + \beta_9 \times \ln(p \times C_1) - \beta_8 \times C_1 \times p + \beta_7}}{p} \quad 17$$

$$- \frac{\beta_5 \times \left(\beta_6 - \beta_{10} \times \ln(p \times C_1) + \beta_9 \times \ln(p \times C_1) - \beta_8 \times C_1 \times p + \beta_7 \right)}{p^2} + \frac{\beta_{15}}{p^2} - \frac{\beta_{13}}{p^2} - \frac{\beta_{11}}{p^2} - \beta_3$$

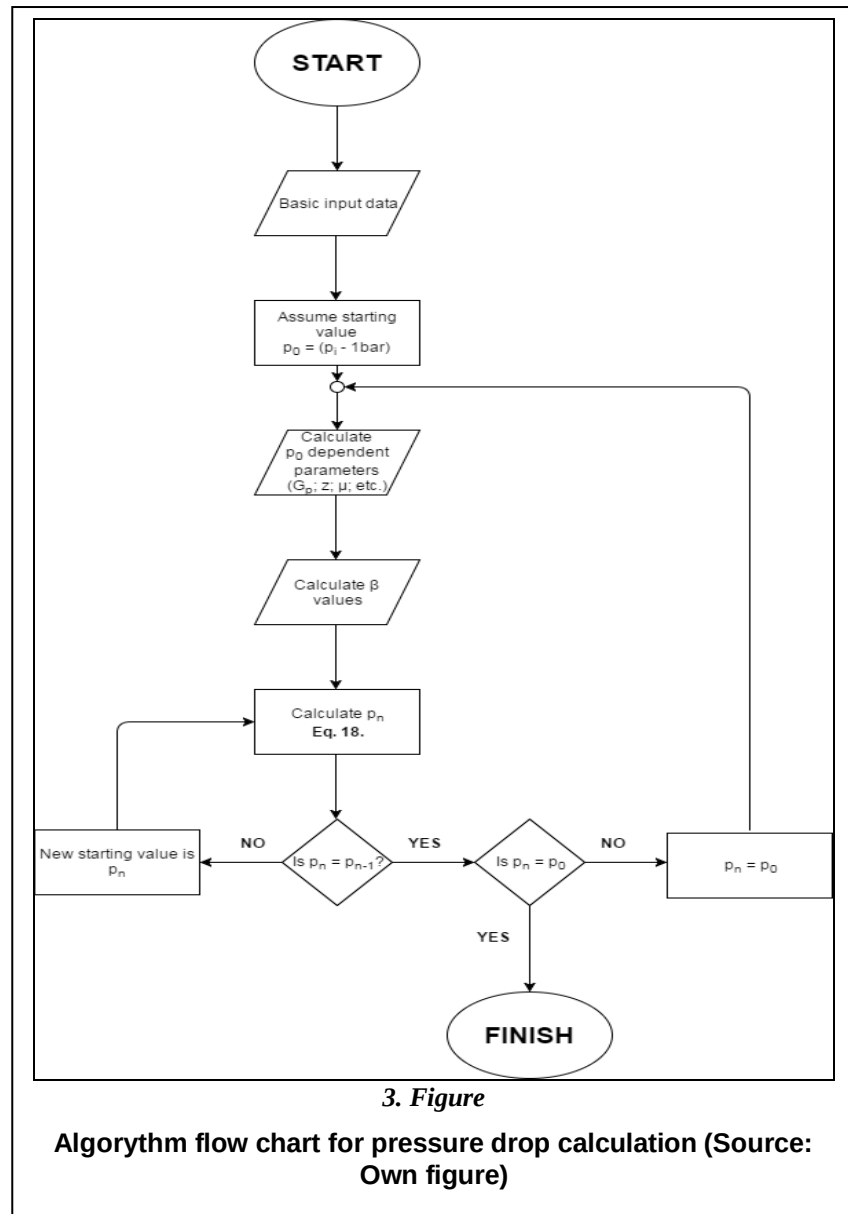
To find the solution a starting p_0 value should be chosen less than the initial formation pressure (assumed to be less with 1 bar). Then with **Eq. 18.** the calculation of a new p value should be done. The procedure has to be continued until the difference between p_n and p_{n-1} is acceptably small.

$$p_n = p_{n-1} - \frac{f(p)}{f'(p)} \quad 18$$

But the deviation factor and the cumulative gas production also depend on the reservoir pressure (p). So after finding an acceptable p_n value the whole procedure should be recalculated with the recalculation of the deviation factor (z) and G_p (gas production rate calculations with different apparent permeability values – detailed in a later section) which now should be calculated with the new p_n pressure instead of the assumed p_0 pressure. So the whole procedure is a double iteration method which can be easily understood with the flow chart illustrate in **Fig. 3.**

The first step is to identify the constant values which are the basic input parameters during the calculations including measured porosity, reservoir area, absolute permeability, reservoir height, Langmuir pressure and temperature, initial reservoir pressure and reservoir

temperature, average pore radius, produced gas specific gravity, etc. Then if the calculation is the first iteration we have to choose a starting depleted reservoir pressure where a 1 bar depletion from initial reservoir pressure is a good assumption in most cases. Otherwise if the iteration is not the first one we have to use the previously calculated depleted pressure (p_n). Next step is the calculation of the pressure dependent parameters (where the depleted pressure is necessary), such as the apparent permeability, gas deviation factor, and the cumulative gas production (where we have to identify the required time step). Then we need to calculate the initial values (corrected initial porosity, formation compressibility, initial reservoir bulk density etc.) and the β parameters that are necessary for **Eq. 16.** and **Eq. 17.** Next the calculation of **Eq. 18.** is necessary where the starting pressure is the assumed depleted pressure (in the first iteration) or the depleted pressure determined in the previous iteration step. Then we have to determine if the resulted pressure is close enough to the starting pressure. If not we have to recalculate **Eq. 18.** with the previously determined pressure (this iteration proceeds until two consecutive calculated pressures are close enough). If we get an acceptable value for depleted pressure we have to determine if this pressure are close enough for the initial assumed (or previously determined pressure by the previous iteration process). If yes we are finished with this process, if not we have to attach back the calculated depleted pressure (after basic input data) and continue the whole process until we get a suitable depleted reservoir pressure.



The disadvantage of this method is the huge computational quantity but it has a great advantage as most of the influential mechanisms are contained in the calculation. **Fig. 2.** shows how different material balances behave with different mechanisms accounted in them. The data used in them are listed in **Table 2.** except V_L is assumed to be equal with 10 [scf/t] and the reservoir is assumed horizontally fractured with 40 m fracture half-length and 10 stages also the basic Darcy's model was used. It can be identified that production rate does

not drop as significantly in case of MBE which accounts for all of the detailed mechanisms as in case of other MBE because of the release of the dissolved natural gas in the connate water and desorbed gas during pressure depletion. All of the MBE can be reached with the presented model by neglecting the unnecessary terms as it can be seen in **Fig. 2**.

GAS FLOW MODELS

The Darcy equation, which was derived from the Navier-Stokes equation based on continuum theory, has been used for more than 150 years to linearly relate fluid-flow rate and pressure gradient across a porous system. The linearity of the Darcy equation makes it easy and practical to use in reservoir engineering analysis and numerical reservoir simulations. Darcy's equation correctly models the flow behavior at macrometrical and micrometrical scale where the main forces interacting are viscous. However, physics of fluid flow in shale and tight reservoirs cannot be predicted from standard flow or mass transfer models because of the presence of nanopores, ranging in size from one to hundreds of nanometers. Conventional continuum flow equations, such as Darcy's law, greatly underestimate the flow rate when applied to nanopore-bearing reservoirs (F. Javadpour et al., 2007).

This phenomena can be described by the fact that with decreasing pore sizes the interacting forces between the pore walls and gas molecules are getting more significant than between gas molecules (which is typical in case of viscous Darcy's flow). As this effect becomes more significant the flow will alter increasingly from the Darcy's flow. Also as the pore sizes are small enough (comparable to molecule size) the main driving force becomes the concentration difference (diffusion) instead of pressure difference.

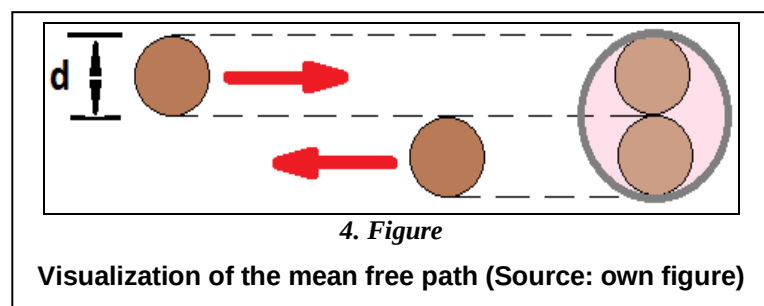
To specify the magnitude of the alteration from Darcy type flow, different flow regimes are introduced. But before the characterization of the flow regimes, introduction of new expressions such as mean free path and Knudsen number are essential.

Mean free path

In a closed system, the molecules are constantly colliding with each other as they are not geometrical points. The average distance between the collisions is the mean free path (R. D. Knight, 2004). A good visualization is on the **Fig. 4**, where the molecules diameter is presented by d [m], so the collision area, A [m^2] can be calculated by the **Eq. 19**.

$$A = d^2 \times \pi \quad 19$$

In time the collision area will sweep out a cylindrical volume where n number of molecules is presented (treated as point masses). The molecules move with a constant speed along straight lines so the mean free path, λ [m] can be calculated as the length of the path divided by the number of collisions (volume of the cylinder, V [m^3] times the number of molecules per unit volume n), **Eq. 20**.



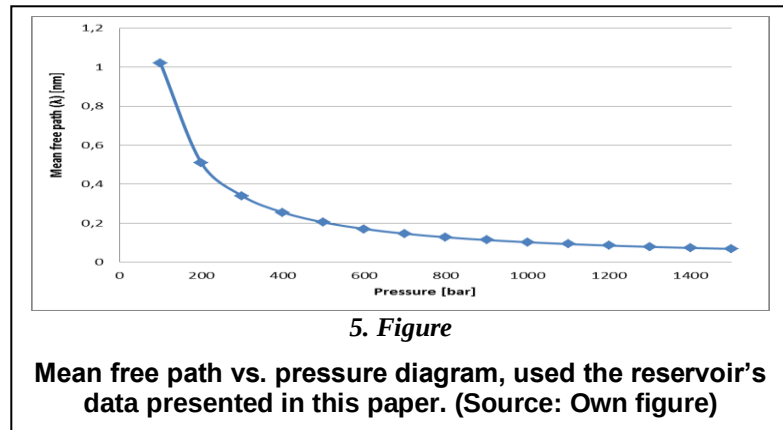
$$\lambda = \frac{l}{V \times n} = \frac{\bar{v} \times t}{\bar{v} \times t \times d^2 \times \pi \times n} = \frac{1}{d^2 \times \pi \times n} \quad 20$$

The problem with this expression is that the average molecular velocity is used, but the target molecules are also moving, so the frequency of collisions depends upon the average relative velocity of the randomly moving molecules. The magnitude of the relative velocity is the square root of the scalar product of the velocity with itself **Eq. 21**. The number of molecules per volume can be given by the Avogadro's number, N_A ($6,022 \times 10^{23}$ [mol⁻¹]) and the ideal gas law. The ratio of the universal gas constant, R ($8,314$ [J/(mol*K)]) and the Avogadro's number is the Boltzmann number, K_B ($1,38 \times 10^{-23}$ [J/K]). Finally the corrected mean free path equation is given by **Eq. 22**.

$$\bar{v}_{rel} = \sqrt{2} \times \bar{v} \quad 21$$

$$\lambda = \frac{R \times T}{\sqrt{2} \times d^2 \times \pi \times N_A \times p} = \frac{K_B \times T}{\sqrt{2} \times d^2 \times \pi \times p} \quad 22$$

This is evident that the mean free path is proportional to pressure because at higher pressure, greater amount of gas molecules can be present into a unit volume, so the collisions between the molecules will be more common and decreasing the value of mean free path, **Fig. 5**.



Knudsen number

When the average mean free path of the gas molecules begins to be comparable or greater than the pore size containing it, the result is a break in the continuum theory. The degree of deviation from this theory is measured with the Knudsen number. The Knudsen number is calculated by the ratio of the mean free path and the pore diameter **Eq. 23**. The value of this number is directly proportional to the mean free path so as the average distance between the collisions of the molecules are getting smaller the Knudsen number decreased as well.

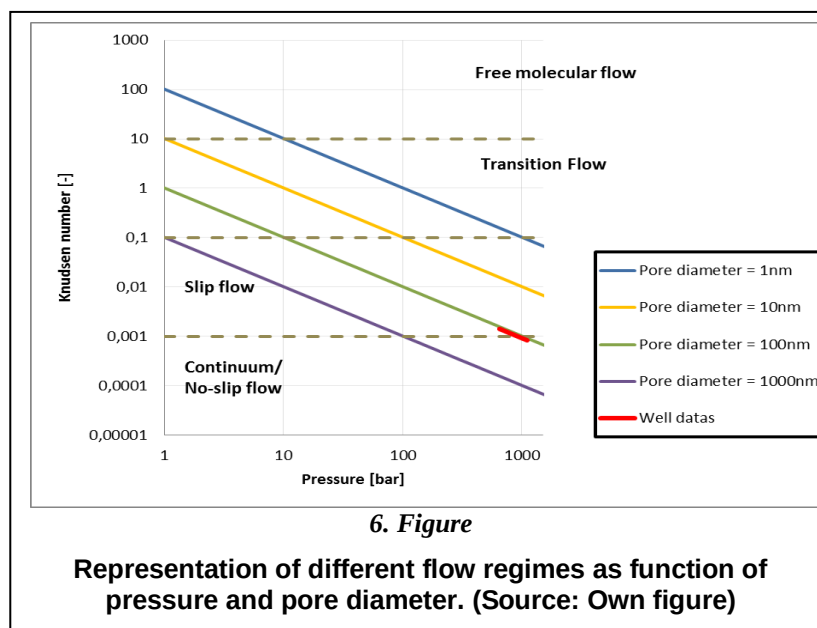
$$K_n = \frac{\lambda}{d} \quad 23$$

If the pore diameter is much greater than the mean free path of the contained gas molecules, the value of Knudsen number is between 0 to 10^{-3} [-] and the flow behavior does not differ from the continuum flow (E.L. Cussler, 2009). In case of the mean free path is getting comparable to the pore diameter or exceeds it the flow becomes to alter from the Darcy's flow and different type of flow regimes can be distinguished depending on the magnitude of the deviation. **Table 1.** represents flow regimes corresponding to Knudsen number ranges (R. Rezaee, 2015).

Types of different flow regimes as a function of Knudsen number (Source: R. Rezaee, 2015)

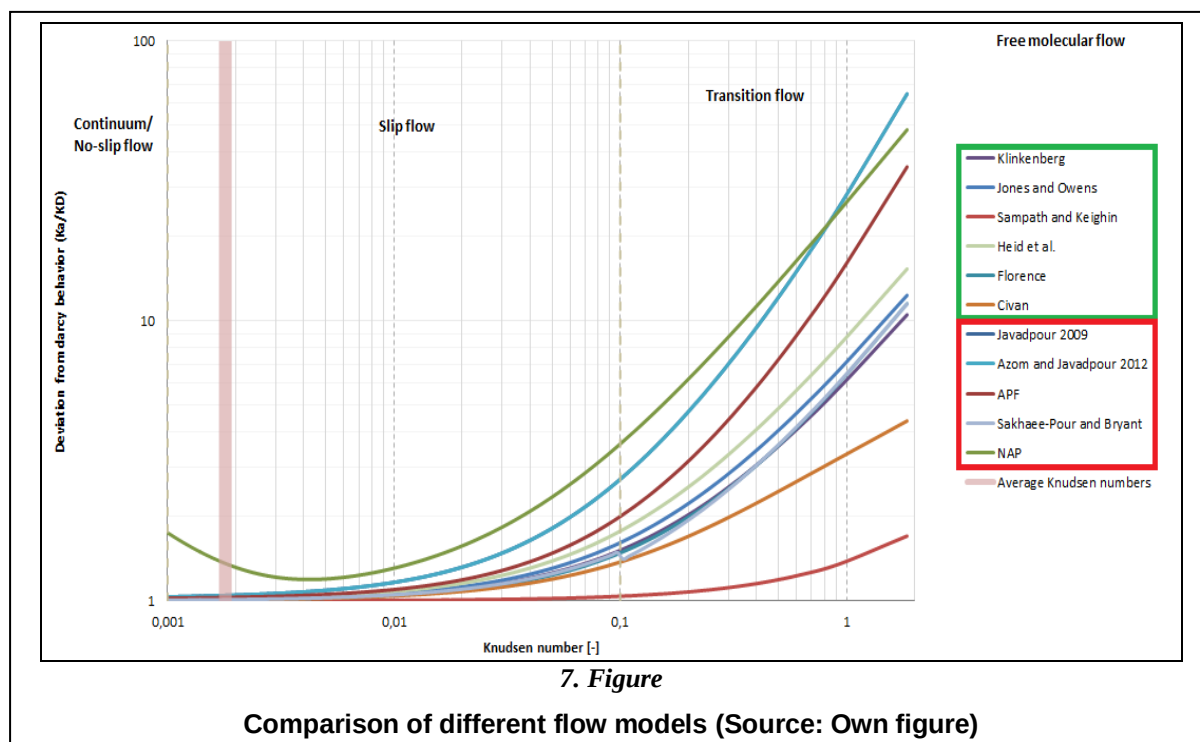
Knudsen number [-]	Flow regime
$0 - 10^{-3}$	Continuum/darcy flow (no-slip flow)
$10^{-3} - 10^{-1}$	Slip flow
$10^{-1} - 10^1$	Transitional flow
$10^1 - \infty$	Free molecular flow/Knudsen diffusion

The different flow regimes are presented as a function of pressure in the **Fig. 6.** where different pore diameters are also investigated and the examined formation's properties, presented in **Table 2.**, are shown as a red line. It can be observed that the flow regimes of the later investigated formation are between the continuum flow and the slip flow regime. It is a quite interesting fact, because as the investigated reservoir's properties are in extreme conditions, a very non-continuum flow behavior can be presumed. This controversial observation can be explained by the fact that the value of Knudsen number is proportional to the pressure inversely, resulting that **Eq. 24.** is not very accurate at high pressures. That is why it is predicting a mean-free-path smaller than the collision diameter at very high pressures (F. Javadpour et al., 2007).



Models

Different flow models investigated in this paper are collected and presented in **Fig. 7.** All of them are expressed in an apparent permeability parameter divided by the absolute (or Darcy - constant) permeability. These apparent permeability values are functions of the pressure in all models. This is different than the Darcy's model where a constant value of permeability is determined. These models expressed in different forms as their applicability is usually acceptable in one or two flow regimes. The derivations of the different models are not detailed in this paper nor the apparent permeability equations of them (the corresponding literatures are listed in the references). Two types of flow regimes are investigated in this paper (in addition to the continuum regime). There are 6 types of models which deal with the slip flow regime and 4 types which deal with mainly transitional regime. Also a model which uses individual equations in case of different regimes is presented. It has to be mentioned that most of the models which accounts for Knudsen diffusion (typical mechanism in transitional regime besides slip phenomenon) are also suggested in case of slip regime, except the NAP (non-empirical analytical permeability) model which neglect the slip term. This is the reason why it cannot describe appropriately the flow in this regime (see in **Fig. 7.**). The models usually suggested to describe slip phenomenon are framed with green and models suggested in case of transitional regime are framed with red.



Also the Knudsen range (different during production) of the investigated reservoir is marked with rose color. We can identify that the apparent permeability values are constantly increasing with increasing Knudsen number. These models do not underestimate the gas flow rate as it was earlier mentioned in case Darcy's flow. Also the models which accounts for Knudsen diffusion result higher apparent permeability values, so higher gas flow rates are expected. These results were anticipated as the literature states (H. Singh and F. Javadpour, 2015). The investigated reservoir data are listed in **Table 2**. The investigated formation was at the depth 5470-5478,5 m and 43 core samples were derived the whole interval on which the measurements for most basic input data were performed by the Research Institute of Applied Earth Sciences at the University of Miskolc. The Langmuir constants were assumed relatively low based on corresponding literature (B. Badics et al., 2011).

2. Table:

Investigated reservoir's parameters

Name	Symbol	Value	Unit
Absolute permeability	k_{∞}	0,0035	mD
Average porosity	Φ	2,29	%
Average pore radius	r_{av}	55,22	nm
Reservoir temperature	T	229	°C
Initial reservoir pressure	P_i	1104,2	bar
Reservoir height	h	8,16	m
Wellbore radius	r_w	5,5	inch
Initial water saturation	S_{wi}	86,1	%
Flowing bottom hole pressure	P_{wf}	650	bar
Drainage radius	r_e	50	m
Langmuir volume	V_L	2	scf/tons
Langmuir pressure	P_L	4000	psia
Bulk density	ρ_{bi}	2,63	g/cm ³
Average collision diameter	δ_{av}	0,39	nm

RESULTS

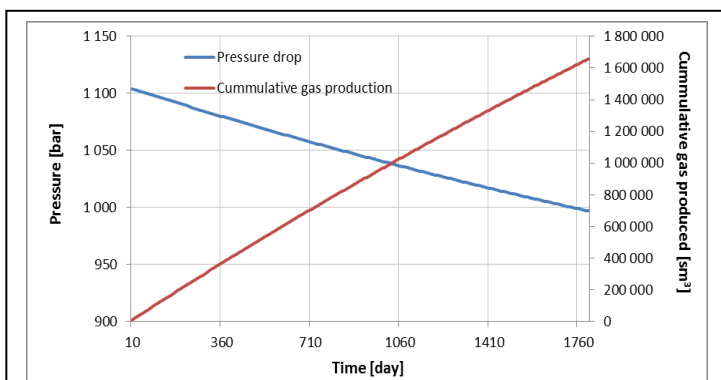
During production calculation this paper investigated a 5 years interval. Because the very small permeability values no high production rates were forecasted, which were proven by the calculations. The initial production rates and the cumulative gas productions for each model are presented in **Table 3**. Also, its deviation from the Darcy permeability's values is examined with percentages to the Darcy values. The pressure drop calculations were based on the algorithm presented earlier and an open-hole production (radial flow) was assumed.

3. Table

Comparison of the different models' results in case of initial gas production rate and cumulative gas production during 5 years interval (Source: Own figure)

Model	Initial production rate [m ³ /day]	Deviation from Darcy [%]	Cumulative gas production [m ³]	Deviation from Darcy [%]
H. Darcy, 1856	1 044,4	0,00	1 650 517	0,00
L.J. Klinkenberg, 1941	1 048,9	0,43	1 657 087	0,40
F.O. Jones and W.W. Owen, 1979	1 049,8	0,51	1 658 349	0,47
K. Sampath and C.W. Keighin, 1981	1 044,8	0,03	1 651 003	0,03
J.G. Heid et al, 1950	1 051,2	0,65	1 658 349	0,47
F. A. Florence et al, 2009	1 048,1	0,35	1 655 882	0,33
F. Civan, 2010	1 048,0	0,34	1 655 657	0,31
F. Javadpour, 2009	1 063,8	1,86	1 677 526	1,64
P. Azom and F. Javadpour, 2012	1 063,8	1,85	1 677 500	1,63
H. Darabi et al., 2012 (APF)	1 062,8	1,76	1 676 472	1,57
A. Sakhaee-Pour and S.L. Bryant, 2012	1 048,8	0,42	1 656 902	0,39
H. Singh et al., 2014 (NAP)	1 994,6	90,97	2 714 736	64,48

The initial production rate values are so low that they make the formation impossible for economical production in case of through an open-hole section. The necessity of an enhanced gas recovery treatment is evident. But the deviation from the Darcy production is higher in all cases (as it was presumed by the models). In case of NAP; APF; F. Javadpour, 2009 and P. Azom and F. Javadpour, 2012 the models provide higher production rates than other ones. This phenomenon can be



8. Figure

Pressure depletion and cumulative gas production during 5 years interval in case of L.J. Klinkenberg, 1941 model (Source: Own figure)

elucidated by the fact that the reservoir is at the continuum – no-slip boundary (**Fig. 7.**) so the necessity of Knudsen flow is not required and the validity of these models during this conditions are questionable. Also, the NAP model results very high production rates compared to other models, which can be accounted for the fact that the model does not work properly in the Knudsen range of the reservoir. The other models are come with very similar results in case of initial gas rate and cumulative gas production. As the flow type of the reservoir is very close to the continuum flow regime it was expected that the Darcy's flow calculations will result almost acceptable production values. This assumption was proven by the calculations.

The reservoir pressure drop is not significant during the examined period because of the very low gas production rates. **Fig. 8.** shows the reservoir pressure depletion and the cumulative gas production during the 5 years interval in case of the L. J. Klinkenberg, 1941 model.

MODEL ADAPTABILITY FOR REAL PRODUCTION DATA

Results show that the calculation method suggested by this paper work well in case of the investigated reservoir but comparison of the results was not feasible because there were no available production data from the well. This is why another Hungarian natural gas well was built into the model to analyze the behavior of the model. The basic data of the investigated reservoir are shown in the **Table 4.** As the reservoir is not a shale gas reservoir but a tight gas reservoir the value of Langmuir pressure and Langmuir volume were chosen to 0. There are three different productive zones in this formation and each of them was hydraulically fractured (vertical fracturing treatment). After test geophysical investigation and production tests it was set that the three different fracture system connect to each other and behave like one vertical fracture. This is why basic data were interpreted in this way. During test production 2 810 800 sm³ natural gas and negligible amount of condensate and water were produced. Then the initial gas production rate was about 36 000 sm³/day, which result coincide the results forecasted by the model (suggested this paper). The basic data and the production data were provided by the MOL Nyrt. company.

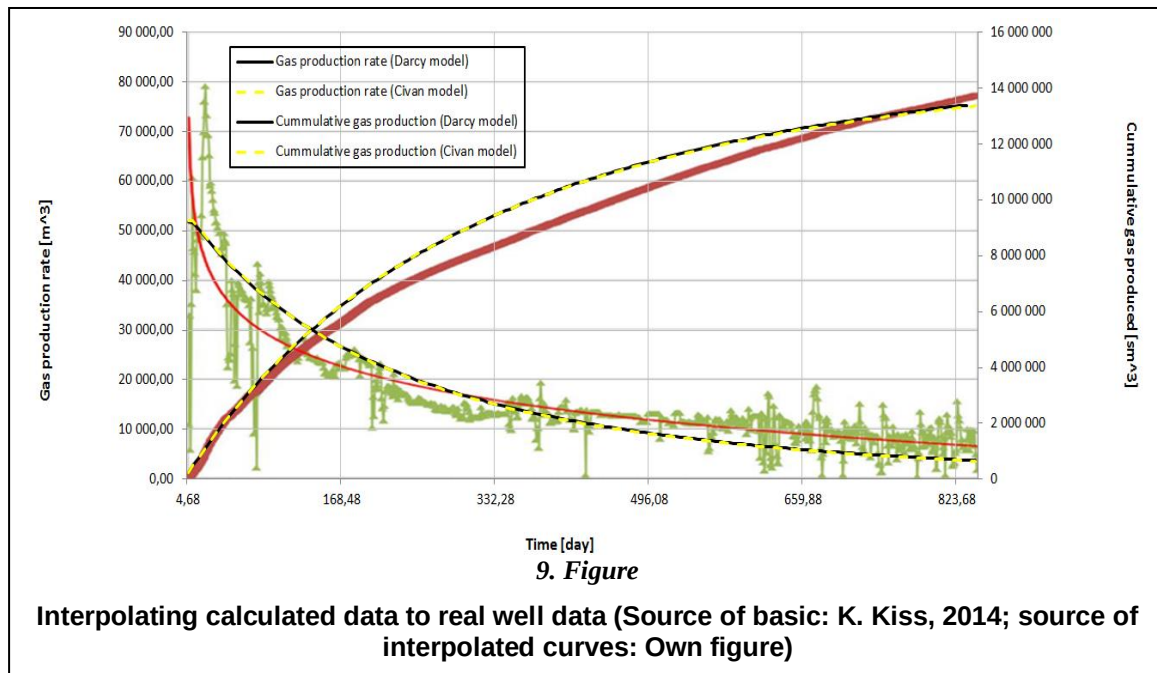
4. Table

Basic parameters of the investigated reservoir (Source: Mol Nyrt. company)

Name	Symbol	Value	Unit
Absolute permeability	k_{∞}	0,008	mD
Average porosity	Φ	8,22	%
Reservoir temperature	T	473,15	K
Initial reservoir pressure	P_i	561	bar
Reservoir height	h	180	m
Area of the reservoir	A	0,02	km ²
Wellbore radius	r_w	0,14	inch
Initial water saturation	S_{wi}	55,4	%
Flowing bottom hole pressure	P_{wf}	266	bar
Fracture half length	x_f	50	m
Length of the flow	L	130	m

The investigated reservoir was in the continuum – slip boundary as well so the simple Darcy's model and the F. Civan, 2010 model (slip model) was interpolated on the production data, **Fig. 9.** As it can be identified there is no excessive deviation between the two models. The interpolated graph fitted acceptably on the measured values so the model suggested by this paper work in a practicable range.

Although in case of reservoirs where flow regimes are in different than continuum regime can be calculated by different models.



CONCLUSION

This paper described the different unconventional gas reservoirs. Also, it described the different flows which come into prominence due to micro and nanopore regimes. Through the introduced flow equations and a new material balance equation a Hungarian formation was characterized. The material balance which involves the detailed role of adsorbed gas in the porous matrix provides reliable calculation of pressure depletion during production and original gas in place.

The performed measurements on the core samples (performed by the Research Institute of Applied Earth Sciences of the University of Miskolc) provide the basic input parameters in the calculations. The reservoir is under extreme conditions so the different models had to be evaluated to get a wider understanding from the reservoir behavior. As the reservoir is in the slip flow regime the most reliable data are assumed to provide by the slip flow models.

The reservoir production was investigated in a 5 year interval in case of all models by the presented calculation algorithm. As no production data were available from the well another Hungarian well was used to investigate the application and adaptability of the model. The results proved the model works in a practicable range.

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