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A New Methodology to Define Net Pay Zone in Gas Reservoirs

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Abstract

Net pay thickness is defined as that portion of a reservoir which contains economically producible hydrocarbons with today's technology, prices, and costs. This thickness is a key parameter of the volumetric calculation of in-place hydrocarbons, well test interpretation, and reservoir characterization. A reservoir interval is considered as net pay when it contains hydrocarbons that can flow at an economic rate. Therefore, to define net pay, cutoffs of hydrocarbon storage properties besides flow properties of reservoir rock are necessary. Frequently, petrophysical log-derived rock storage properties like porosity and water saturation are linked to core measured properties like permeability to find a relation between them. Then, by use of a fixed limiting value for permeability, log-derived properties cutoffs are determined. The basic problem of these methods is related to permeability cutoff, since in most cases there is no knowledge about it, and the permeability cutoff can differ from field to field or even well to well.

A new methodology has been developed to find a logical permeability cutoff for gas reservoirs which can differ for different wells and/or fields. This technique is based on gas flow through porous media in tight rocks. Accordingly, a relationship between porosity and permeability is derived as a cutoff value at reservoir pressure and temperature, which is considered as a discriminator plot. Then, the core data of the specified reservoir are added to this plot and the data points reflecting net pay zone are identified. This technique has been applied to four real gas reservoirs in Iran and indicated acceptable results confirmed by the drill stem test (DST) and production data. The results show that the proposed procedure is less dependent on experts' experiences and acts as a straightforward and powerful tool for the refinement of net pays. In addition, the cutoff values calculated from this method contain a scientific base supporting the main procedure.

Keywords: Knudsen Number, Net Pay Zone, Porosity and Permeability Cutoff, Tight Gas Reservoirs.

1. Introduction

The concept of net pay relates the rock and fluid properties to the economic aspects of production like completion methods and recovery techniques. The goal of the net pay calculation is to eliminate nonproductive rock intervals for reservoir description and quantitative hydrocarbons-in-place and flow calculations. Therefore, a cutoff value for net pay interval should be defined based on rock properties. In the context of reservoir studies, cutoff is commonly used to set limiting values for

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petrophysical parameters that affect the fluid storage. Different authors have utilized diverse combinations of these parameters in their works. Mostly, storage capacities of rock (porosity and water saturation) are linked to flow properties (permeability and/or capillary pressure) to find a relation and discriminate net pay from non-pay. In conventional methods, a permeability cutoff, nominally 0.1 mD for gas reservoirs and 1.0 mD for oil reservoirs is fixed, and porosity cutoff is determined from permeability-porosity relation (Balbinski et al., 2002; Boyer, 1985). Desbrandes (1985) proposed a range of cutoff values for the estimation of hydrocarbon in place for sandstone and carbonate reservoirs including volume of shale, porosity, and water saturation (Table 1). In his proposed table, the values are not specified (a range of values are involved), and the type of fluid is not considered. These estimations can be used just for prospects or exploration wells where there are no more data than petrophysical logs.

Table 1

Cutoff values proposed by Desbrandes (1985).

Reservoir rock	Parameter	Cutoff value
Sandstone	Shale volume	0.3–0.5
	Porosity	0.06–0.08
	Water saturation	0.5–0.6
Carbonate	Shale volume	0.3–0.5
	Porosity	0.04–0.05
	Water saturation	0.5–0.6

The literature review shows that there is no distinct universally applicable attitude for the definition and application of cutoffs, and consequently the determination of the net pay (Worthington, 2008). Usually, geologists define the net pay as the clean part of the reservoir that contains hydrocarbon, but the reservoir engineers consider the productivity of the reservoir rock to determine the net pay (Saboorian-Jooybari, 2017). There are frequent approaches to calculating cutoffs like empirical correlations (Desbrandes, 1985), porosity-permeability cross-plots (Worthington and Cosentino, 2005), analysis of distribution function curves (Li and Dria, 1997), minimum effective pore-throat radius (Worthington, 2008), mobility-based method (Saboorian-Jooybari, 2017; Xu et al., 2019), flow equations considering economic analysis (Yang et al., 2019), mercury injection tests (Shi et al., 2018), data-driven techniques using fuzzy classifier fusion (Masoudi et al., 2011), Bayesian theory (Masoudi et al., 2012), and artificial neural networks (Masoudi et al., 2014). Empirical correlations are based on experts' experience and may not work for different cases. In porosity-permeability cross-plot methodology and also mercury injection tests, a value for permeability cutoff must be first defined, and mostly there is no basis for the definition of this parameter. The main weakness of the minimum pore throat radius method is related to the porosity values with low pore throats that are considered as net pay. In heterogeneous shaly sands or carbonates reservoirs, the distribution function curve analysis cannot clearly separate pay zone from non-pay zone. Finally, the main drawback of data-driven methods is the use of lower resolution parameters for training (well-test-derived parameters) as a representative of the whole completed interval (Saboorian, 2017).

It is of great importance that any methodology for the definition of cutoff must include the economic concerns which are concealed in dynamic factors. These factors include rock properties, fluid viscosity, completion type, stage of depletion, reservoir thickness, oil price, and so on (Mahbaz et al., 2011; Worthington and Majid, 2014; Yang et al., 2019). Most of the methods assume a cutoff value for permeability, based on which other cutoffs like porosity, water saturation, and shale volume are

determined. The main problem with these approaches is that no logical reason has been introduced for determining the permeability cutoff, and this cutoff could vary from formation to formation and/or from well to well or even can be different for different rock types.

In addition, the relation between permeability and petrophysical parameters is challenging and sometimes rock typing must be performed to get a better relationship (Worthington, 2008). Shariq (2016) worked on porosity-permeability transform in tight reservoirs and showed that Swanson's mean is more accurate than traditional porosity-permeability transformation. It removes the bias and predicts the permeability fairly well within the scope of tight rocks. He also analyzed the impact of the cutoff on hydrocarbon in-place and reserve and suggested that it should be critical to get correct porosity cutoff in the case of tight gas sand reservoirs in order to obtain representative connected hydrocarbon in-place volume and reserve, which is essential for a correct decision on field development planning. Harfoushian and Suriyanto (2016) also worked on in-situ permeability measurement utilizing advanced formation testers (either run on wireline or while drilling) to determine the net pay cutoffs. Formation testers estimate mobility, and, from its correlation with porosity, a value for porosity cutoff is estimated; this method also has a problem. The main problem related to methods using mobility taken from formation tester tools is that the mobility estimated from formation testers, especially in exploration wells, is that of the damaged rock since these tools in exploration wells are run after drilling when reservoir rock is damaged; however, permeability measured from cores is the that of the clean rock. Skalinski et al. (2018) proposed a new robust technique for the determination of net pay using NMR shape analysis, mercury injection capillary pressure (MICP) to predict an entry pore throat radius, and wireline pressure test data like modular dynamic tester (MDT). In their work, first a permeability log is constructed based on advanced logs like nuclear magnetic resonance (NMR) and core data. Then, a cutoff value for permeability is estimated by correlating permeability with the observed flow of in-situ fluids (production logs, derivative of temperature logs, and wireline pressure tests), and pay zones are discriminated as those intervals with permeability higher than this cutoff. The main drawback related to their work lies in the estimation of permeability cutoff since only a value for permeability cutoff is considered. However, in this work, a relationship between permeability and porosity is considered as a cutoff. This relationship is dynamic over the whole reservoir thickness as the fluid properties vary in the well column due to changes in the pressure and/or temperature. In addition, Skalinski et al. used the MDT data for the determination of permeability cutoff. It is noticeable that almost always the MDT data are taken after drilling the well, and these data are from the damaged formation which cannot be considered as the representative of the reservoir.

Commonly, geoscientists and petroleum engineers consider shale and tight rocks as a non-reservoir part and determine pay zones by eliminating them (Worthington and Cosentino, 2005). These rocks, that were bypassed in the past, are now prospective pay zones due to new technologies and continued demand for hydrocarbons. Therefore, new definition for net pay zone calculations should be applied even in unconventional reservoirs. In this paper, in order to achieve a logical permeability cutoff value which is applicable to all types of reservoir rocks, fluid flow through tight rocks was studied. Then, a new methodology was achieved that resulted in the determination of permeability cutoff at any reservoir temperature and pressure. This study is limited to a single gas phase and is valid for all types of gas reservoirs (dry, wet, and condensate gas) under initial conditions of the reservoir.

2. Consideration of methods used in the industry

The most applicable methods used for cutoff estimations in the industry are permeability-porosity (or mobility-porosity) plot and pore throat diameter-porosity (dp-porosity) plot, which are

comprehensively discussed by Worthington and Cosentino (2005) and Worthington (2008). By applying their approach, there are some data points with porosity more than the estimated cutoff value but with very small pore throat diameters. Small pore throat means lower permeability which cannot be considered as a pay zone. As an example, the core data on a carbonate gas well in Iran (KSH-3) are plotted in Figure 1 using dp-porosity plot.

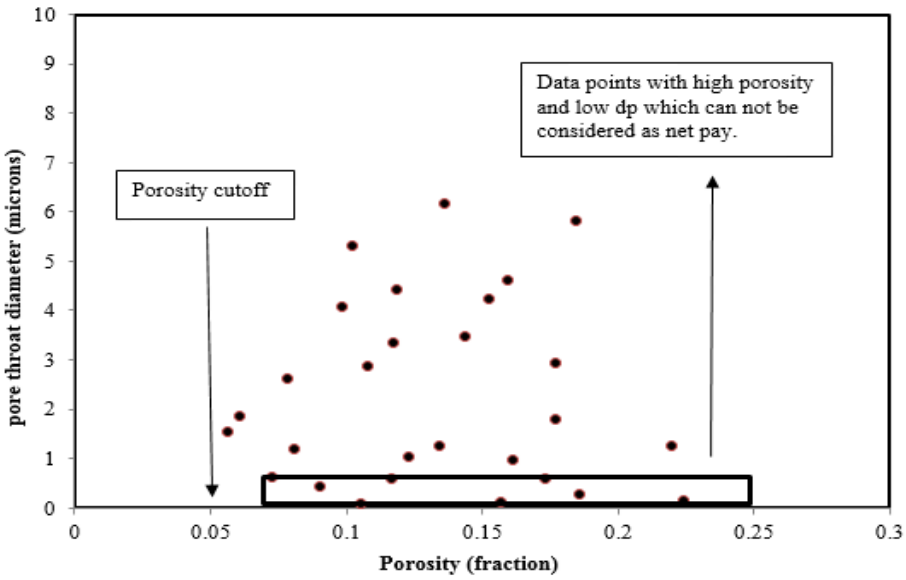

Figure 1

dp-porosity plot to identify porosity cutoff (Well KSH-3).

There are some data points in this plot (shown in the box) which are regarded as a pay zone since their porosities are higher than the porosity cutoff, but their pore throat diameters are very low; they also have low permeability. Although applying rock typing and using different permeability cutoffs can eliminate the above-mentioned weakness, defining different permeability cutoffs for different rock types must be based on a physical logic. In Figure 2, based on a flow unit approach, three different rock types have been realized. For each rock type, a distinct permeability cutoff is to be defined, so three different porosity cutoffs are estimated.

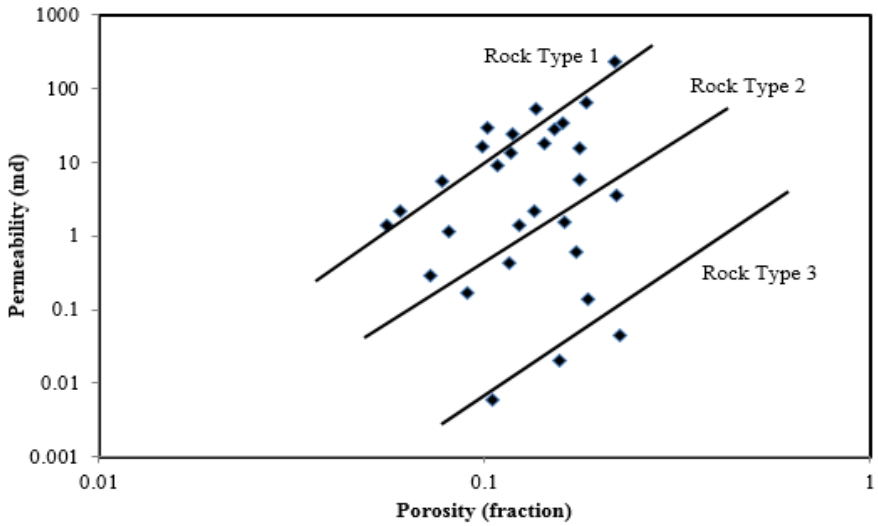

Figure 2

Three different rock types in permeability-porosity data of well KSH-3.

In permeability-porosity plot method, first a permeability cutoff value should be defined. In most cases, 0.1 mD is used for gas reservoirs as a rule of thumb (Saboorian-Jooybari, 2017). However, there are many gas reservoirs with moderate porosity and permeability, which have been produced at the high gas rates. An example is the exploratory well SD-1 in a carbonate reservoir located in Iran. Porosity of the well SD-1 is presented in Figure 3.

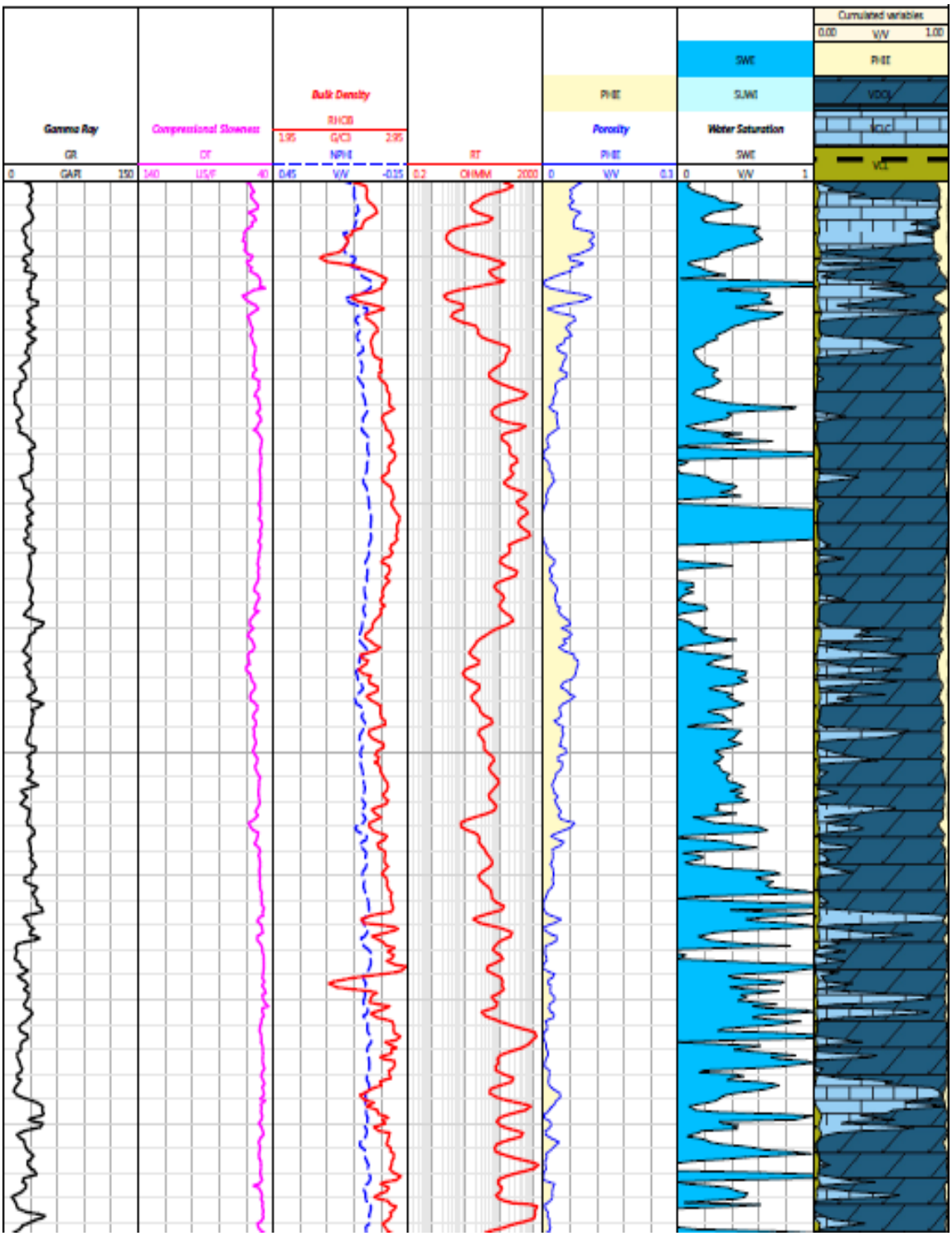

Figure 3

Porosity distribution of Well SD-1.

The mean permeability of the reservoir layer is less than 1 mD. The gas rate was measured as 12.7 MMScf/day at a drawdown pressure of 2000 psi. Running a simple Darcy equation for this well with the net pay thickness calculated from conventional methods will give us just a rate not more than 5 MMScf/day. In this well, no significant mud loss has been observed during the overbalanced drilling of the reservoir, which means fracture makes no contribution to the flow. If conventional cutoff methods are applied to such a well, net pay will be estimated less than reality. Due to the fact that there is a lack of knowledge about permeability cutoff, a new method is required. In this paper, an approach has been implemented based on fluid flow in tight reservoirs to estimate net pay zone. This method has been applied to four different gas reservoirs under initial reservoir conditions, and its results are in perfect agreement with the drill stem test (DST) data.

3. New methodology

Since tight rocks and shale are considered as non-pay zones, in order to find a way to estimate petrophysical parameters of cutoffs, study of fluid flow in shale or tight rocks is essential. Here, only gas flow in gas reservoirs has been studied, and this approach may be extended to oil reservoirs. In the study of gas flow through tight rocks, the ratio of molecular mean free path to pore throat diameter affects the flow regime. Hence, a dimensionless number known as Knudsen Number (K_n) is defined:

$$K_n = \frac{\lambda}{D} \tag{1}$$

where D is pore throat diameter, and λ is the mean free path of gas molecules. The mean free path parameter of ideal gases can be estimated from Equation 2:

$$\lambda = \frac{\kappa_B\, T}{\sqrt{2}\, \pi\, \delta_m^2\, P} \tag{2}$$

where κ_B is Boltzman constant equal to 1.3805×10^{-23} j/K, T is temperature (K), P is pressure (Pa), and δm is collision diameter (m). The mean free path or average distance between collisions for a gas molecule may be estimated from kinetic theory, supported by Serway's approach (1990). According to this approach, z-factor can be used in Equation (2) to find mean free path for real gases:

$$\lambda = \frac{\kappa_B\, z\, T}{\sqrt{2}\, \pi\, \delta_m^2\, P} \tag{3}$$

Equations 2 and 3 are derived for a single component gas phase. A weighted average method can be used to calculate mean free path of the multi-component gases as was applied by Shi J. (2013). Flow regime in gas shale and tight formation is influenced by the ratio of molecular mean free path to pore throat diameter. Roy et al. (2003) showed that different flow patterns are characterized by Knudsen number as shown in Figure 4.

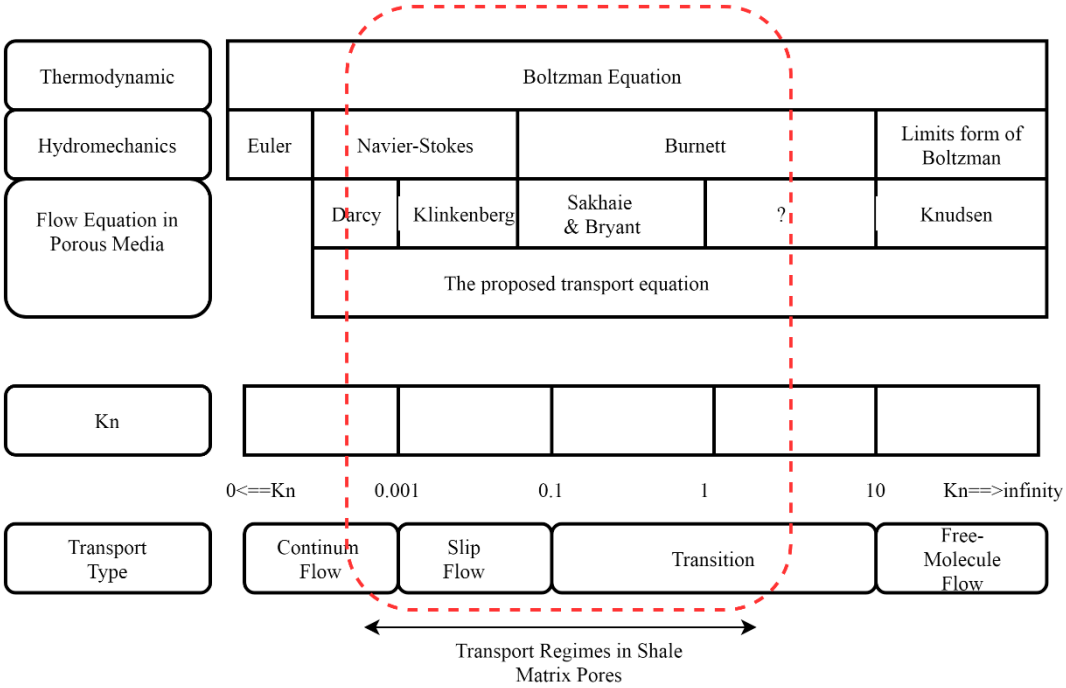

Figure 4

Different flow regimes in the gas flow through shale (Shi et al., 2013).

If Knudsen number is less than 0.001, Darcy flow dominates, and when K_n is in the range of 0.1–0.001, the slippage effect is not negligible, and apparent gas permeability is defined which is higher than that measured by liquid. In this case, Roy et al. (2003) proposed an equation similar to Klinkenberg (1941) to relate absolute permeability (K_L) to apparent gas permeability:

$$(k_g)_{slip} = K_L\,(1 + 5\,K_n) \tag{4}$$

In cases where K_n is larger than 0.1, transition flow and free molecular flow dominate. Sakhaee-Pour and Bryant (2012) investigated transition flow mechanism and proposed an equation to calculate apparent gas permeability:

$$(k_g)_{transition} = K_L\,(0.8453 + 5.4576\,K_n + 0.1633\,K_n^2) \tag{5}$$

In order to calculate Knudsen number in porous media, pore throat diameter can be estimated form the equation proposed by Leverret (1941):

$$d_P(nm) = 0.31416\sqrt{\frac{k}{\varphi}} \tag{6}$$

where k is permeability (mD), φ is porosity in fraction, and d_P is pore throat diameter (nm). Also, other formulas relating permeability to pore throat radius can be used, similar to what has been proposed by Lala et al. (2017). Now the flow regime in gas flow through a porous media can be evaluated using Figure 5 by knowing rock pore throat and reservoir pressure and temperature.

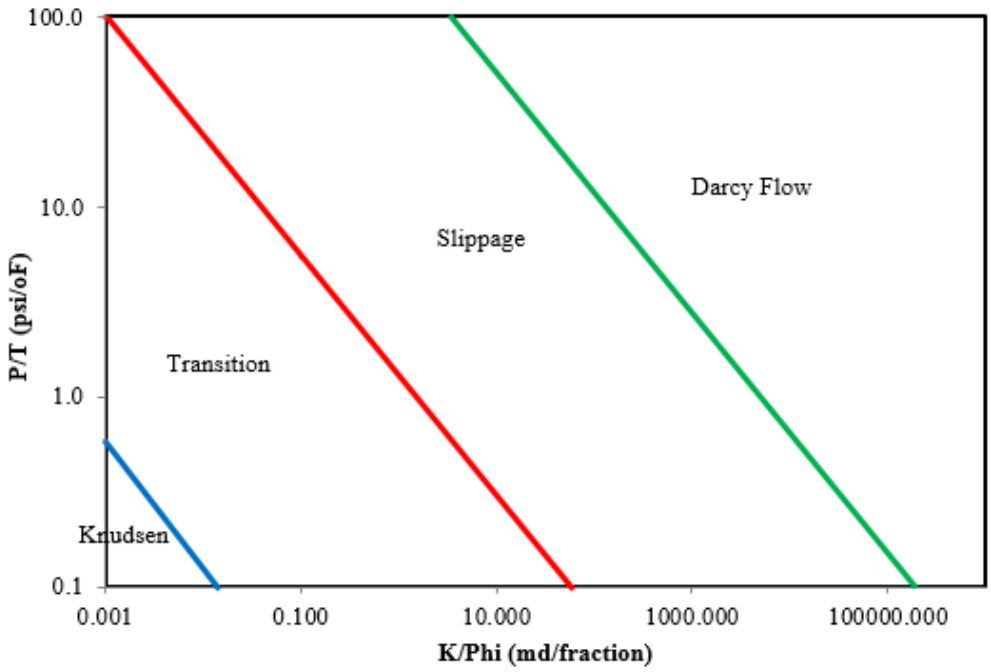

Figure 5

Different flow regimes for gas flow under different reservoir conditions.

As observed in Figure 5, for transition and Knudsen flow regime, the permeability of porous media should be very low, so the gas rate in such reservoirs will not be economic. To illustrate the idea, a vertically heterogeneous reservoir layer with an initial pressure and temperature is regarded as shown in Figure 6.

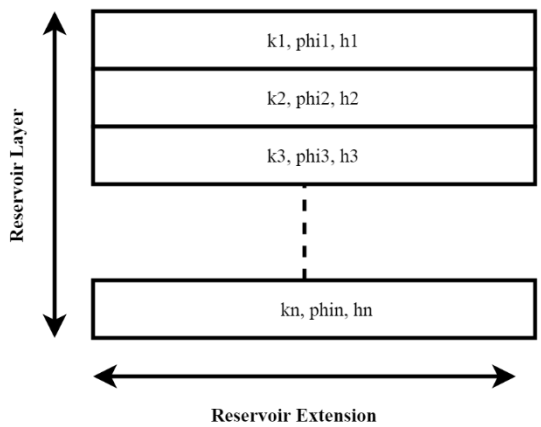

Figure 6

A vertically heterogeneous reservoir layer.

In this example, P/T is simply calculated in each interval in a reservoir layer although it can be considered to be constant, and only k/ϕ is considered a variable. Therefore, based on Figure 5, any of those flow regimes can happen in each interval, but just Darcy flow and slippage can lead to an economic rate. This means that for gas flow in a reservoir rock interval, there is a value for Knudsen number, above which the gas rate is not economic in conventional reservoirs.

By combining Equations 3 and 6, the following equations are derived:

$$K_n = \frac{\lambda}{d} \Rightarrow d = \frac{\lambda}{K_n} \; then \; 3.1416 \times 10^{-8} \sqrt{\frac{k}{\varphi}} = \frac{\lambda}{K_n} \tag{7}$$

where

$$\frac{k}{\varphi} = 1.0132 \times 10^{15} \left(\frac{\lambda}{K_n}\right)^2 \tag{8}$$

The above equation shows that by having the mean free path of gas and a cutoff value for K_n (below which Darcy flow dominates), a relationship between permeability and porosity is derived. This equation will be a cutoff relationship for permeability and porosity, and all k/φ data more than this cutoff value are considered as those related to the pay zone; others are related to non-pay zones. It should be noted that in this method, the volume of shale is not considered as a cutoff property since porosity and shale volume are coupled and pore throat is included. In addition, water saturation cutoff is calculated from porosity-saturation plot after determining porosity cutoff. Using the abovementioned method, net reservoir is identified, and after applying water saturation cutoff, net pay is established.

4. Results and discussion

To clarify the new method, a real lean gas condensate sample (KSH field) of Kangan/Dalan (Khuff) formation is presented. The Kangan/Dalan formation is the main reservoir for natural gas in the southwest of Iran and the northern Persian Gulf and contains some of the world's biggest gas reserves. The composition of the gas in KSH field is presented in Table 2.

Table 2

Gas composition of KSH field.

Component	Composition (%)
Nitrogen	2.7
Carbon dioxide	3.8
Methane	89
Ethane	2.54
Propane	0.65
Iso-Butane	0.18
n-Butane	0.2
Iso-Pentane	0.11
n-Pentane	0.08
Hexane plus	0.74

Mean free path of the gas molecules can be calculated by Equation (9) in field units:

$$\lambda = \frac{2.14 \times 10^{-20} [T(°\mathrm{F}) \times 0.55 + 255.2]}{\delta_m^2 \, z \, P(\mathrm{psi})} \tag{9}$$

For KSH gas reservoir with the composition given in Table 2, at the initial temperature of 279 °F and the pressure of 7372 psi, the mean free path of the reservoir gas is calculated by the weighted average

method. Considering 0.001 as the K_n cutoff, the cutoff value for the ratio of permeability to porosity will be 17.2×10^{-15} m^2, which is equivalent to 17.2 mD/fraction. Therefore, a diagram is plotted as shown in Figure 7.

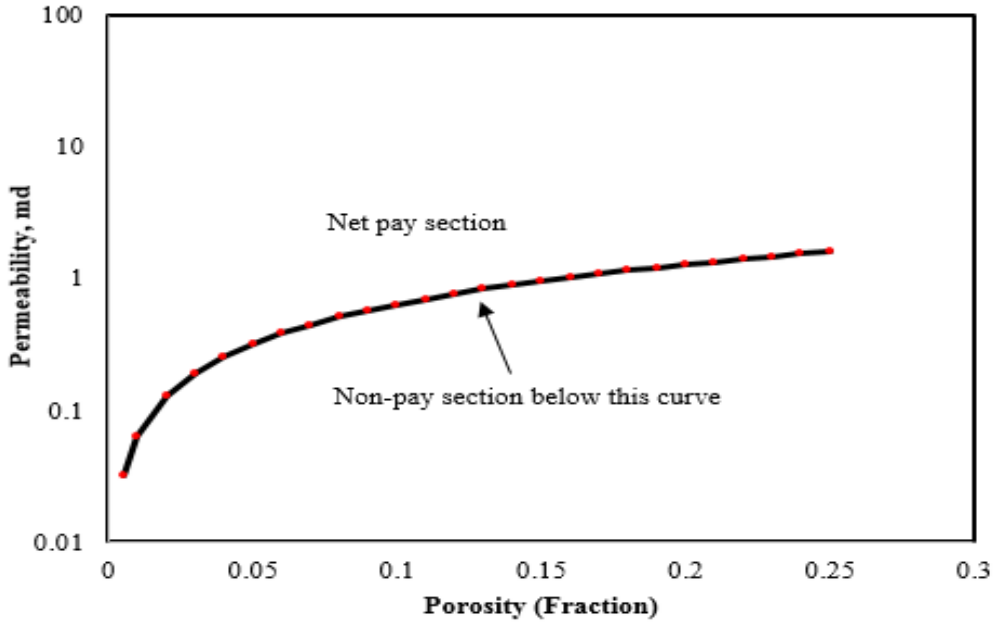

Figure 7

Permeability-porosity cutoff discriminator plot in KSH field.

This diagram can be considered as a discriminator plot to separate pay zones from non-pay zones in the Khuff reservoir of KSH field. The core data on porosity and permeability of this reservoir in well KSH-3 are listed in Table 3.

Table 3

Core poro-perm data in KSH field (Well #3).

Porosity (fraction)	Liquid permeability (mD)	Porosity (fraction)	Liquid permeability (mD)
0.1228	1.36	0.1165	0.435
0.1772	15.419	0.0905	0.167
0.1344	2.206	0.056	1.378
0.0725	0.288	0.161	1.513
0.2186	232.12	0.0781	5.495
0.1846	63.515	0.081	1.156
0.0984	16.507	0.1434	17.545
0.1767	5.72	0.1523	27.679
0.1569	0.02	0.1022	29.165
0.2199	3.479	0.1185	23.626
0.173	0.591	0.1079	9.071
0.2243	0.045	0.1592	34.58
0.1858	0.14	0.0606	2.136
0.1051	0.006	0.1173	13.397
0.1362	52.769		

Adding these data points to the discriminator plot of Figure 7, data points representing pay zones will be separated from those representing non-pay zones (Figure 8).

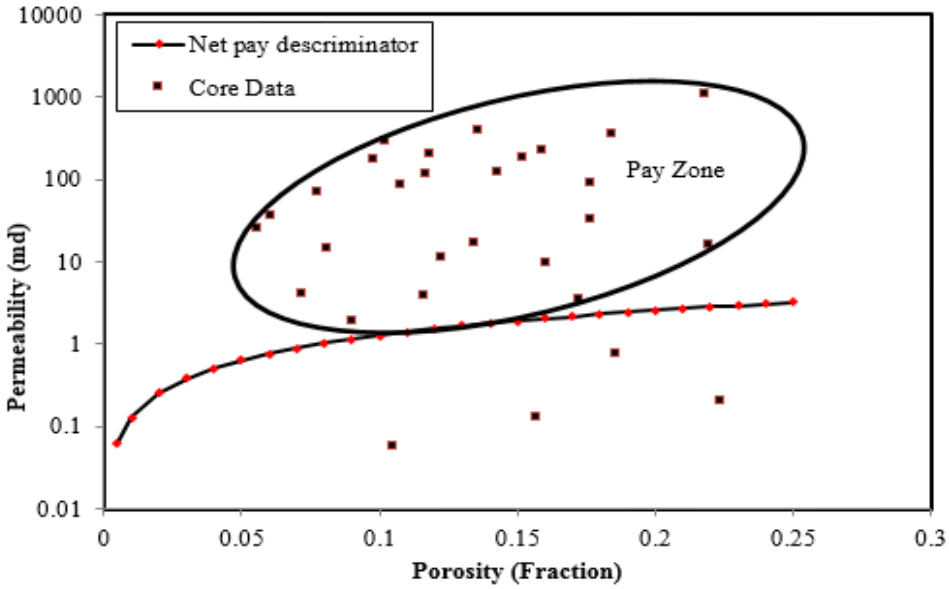

Figure 8

Poro-perm plot in Well KSH-3 for identifying pay zones.

Therefore, the problem mentioned earlier and illustrated in Figure 1 does not occur using the new method. Looking at Figure 8, porosity points with lower permeability than cutoff value will not be in pay zones, but by use of conventional cutoff methods, these porosities are reflected as pay zones. It is important to note that this technique is used for the determination of pay zones, and users can grade the pay zones for other applications by utilizing rock typing methods.

Another field example is the exploration GN Field in Khuff formation with an initial reservoir pressure and temperature of 6550 psi and 242 °F respectively. The composition of reservoir fluid obtained from the first exploration well is tabulated in Table 4. Using CVD experiment, the fluid in this field is characterized as wet gas since no liquid was dropped at the reservoir temperature during the CVD test, but liquid was observed under the separator conditions.

Table 4

Gas composition of Well GN-1.

Component	Composition (%)
Nitrogen	6
Carbon dioxide	2
Methane	86.5
Ethane	2.5
Propane	0.75
Iso-Butane	0.21
n-Butane	0.3
Iso-Pentane	0.18
n-Pentane	0.14
Hexane plus	1.42

The mean free path of molecules using the average weighted method under reservoir conditions is calculated as 1.49 angstroms. Therefore, k/φ cutoff curve based on Equation (8) is 22.2 mD/fraction. The plot of $k-\varphi$ for Well #1 of this reservoir is shown in Figure 9.

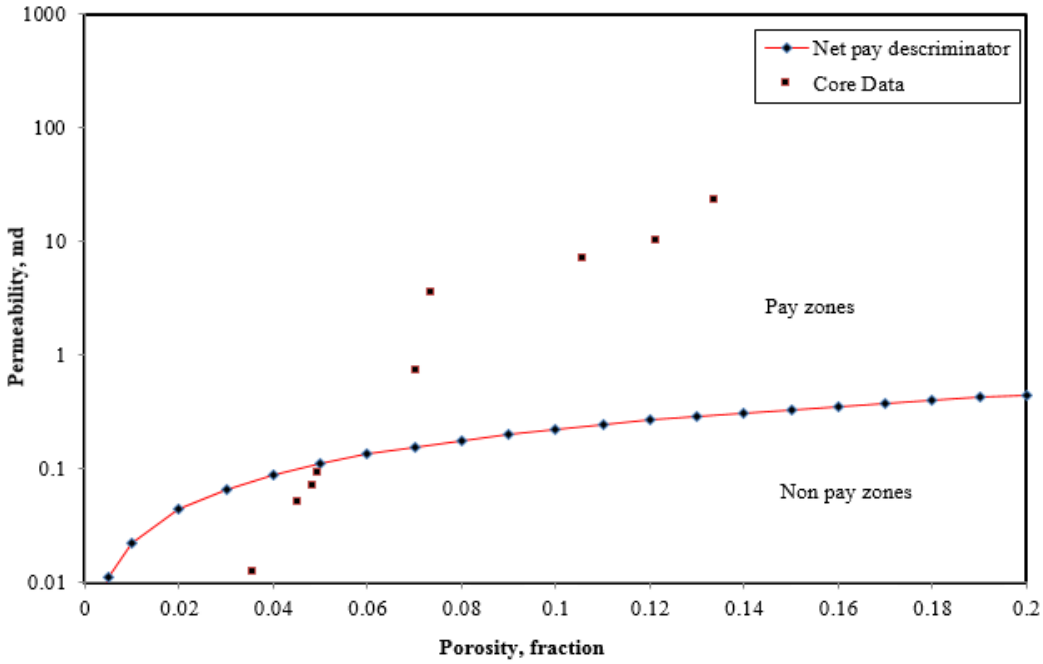

Figure 9

Poro-perm plot in Well GN-1 for identifying pay zones.

Porosity distribution in well GN-1 is depicted in Figure 10 which shows that most of the porosities range from 1 to 6%.

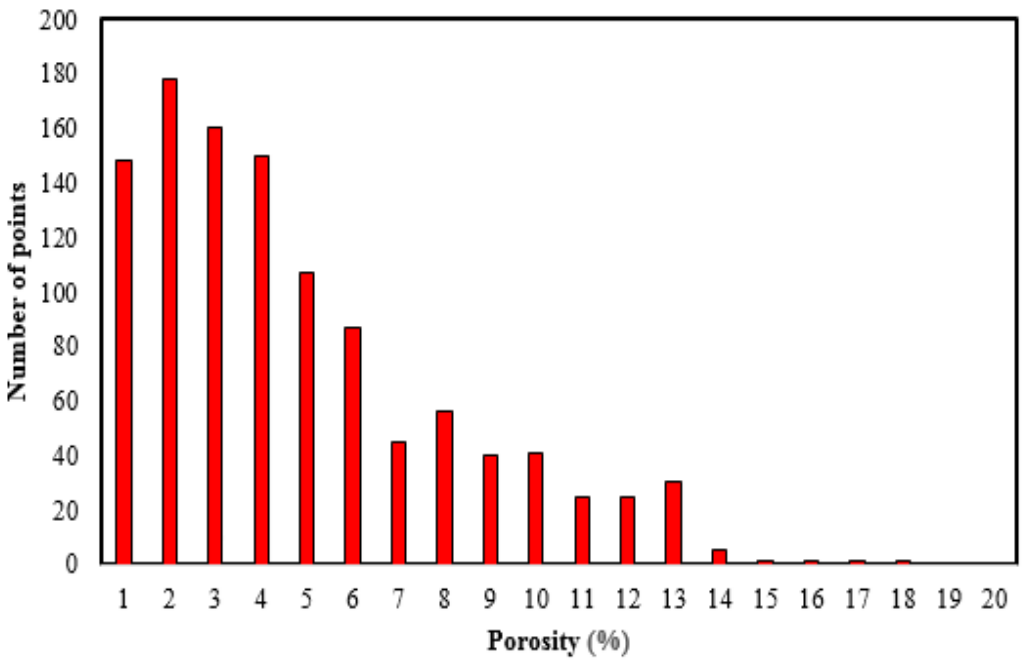

Figure 10

Porosity distribution in Well GN-1.

Also, the interpretation of petrophysical logs extracted from well GN-1 is presented in Figure 11:

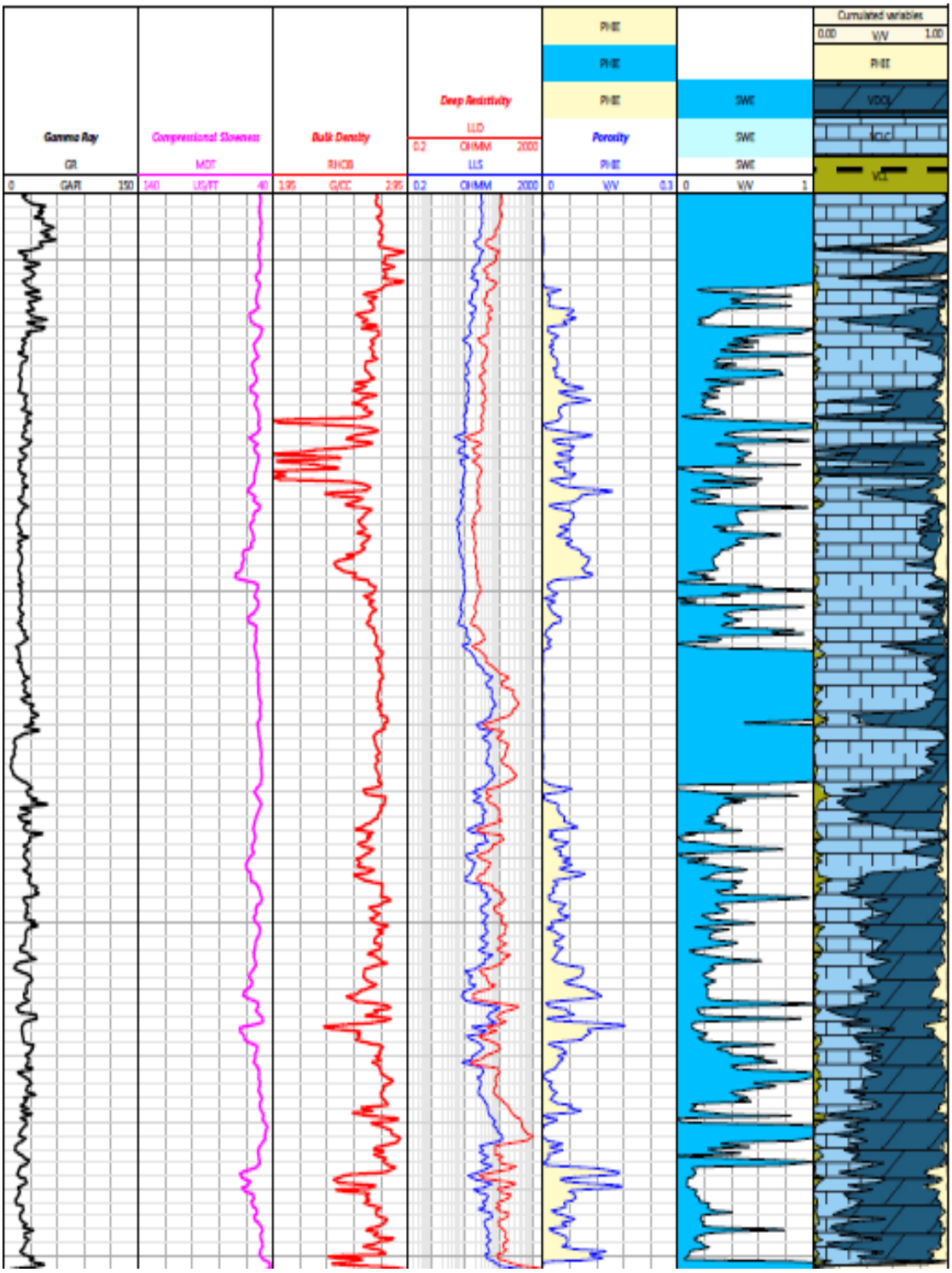

Figure 11

Interpretation of the petrophysical logs of in well GN-1.

Around 9 m of a uniform porous interval with a porosity of 6–8% was tested in this well, and a gas rate of 18 MMSCF/day was obtained at a drawdown pressure of 2400 psi. Pressure transient analysis showed that the average permeability of the interval is 1.4 mD. As observed in Figure 9, porosities between 6 and 8% should have permeability higher than 0.1 mD to be considered as pay zones, which satisfies DST results done in well GN-1. Another example of a gas reservoir in Khuff formation is NP

field with an initial reservoir temperature of 268 °F and a reservoir pressure of 8150 psi. Poro-perm data taken from well NP-1 are plotted in a discriminator plot calculated by Equation (8) as displayed in Figure 12.

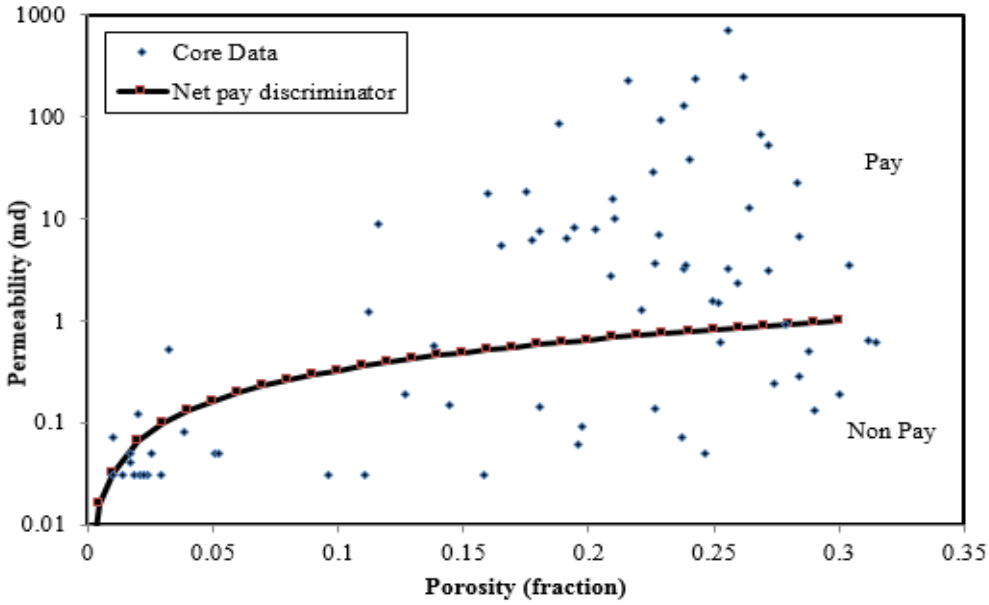

Figure 12

Poro-perm plot in Well NP-1 for identifying pay zones.

In addition, in this example, there are some high porosity points with low permeability which will be regarded as pay zones by applying conventional cutoff methods. To show it, conventional dp-porosity plot for NP-1 data is presented in Figure 13. Looking at this Figure, all porosities greater than 10% are included in pay zones, but some of the high porosities have a very low pore throat diameter and cannot contribute to flow under conventional completion methods.

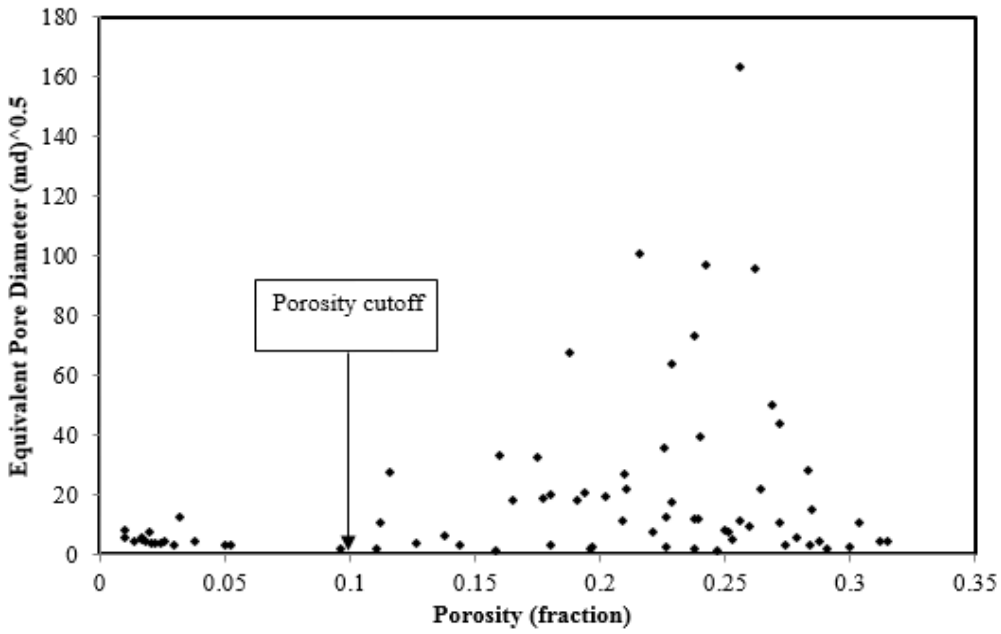

Figure 13

dp-porosity plot method for well NP-1.

Also, the poro-perm plot of Well TBK-1 in field TBK with an initial reservoir temperature and pressure of 192 °F and 3368 psi respectively is shown in Figure 14.

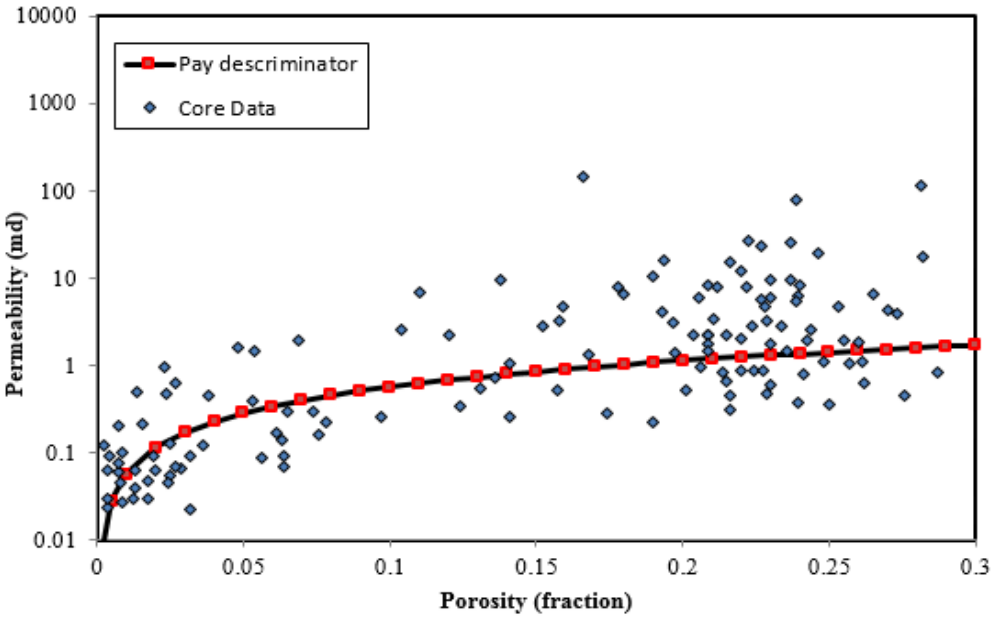

Figure 14

Poro-perm plot of Well TBK-1 for identifying pay zones.

A conventional permeability-porosity method has been devised to estimate porosity cutoff in well TBK#1. The results with adopting no rock typing are presented in Figure 15. In this method, permeability cutoff of 0.1 mD has been chosen to predict porosity cutoff from Figure 15, which is 1.5%. Consequently, all the porosity points higher than 1.5% are deemed to be net pay, even their permeability levels are less than 0.1 mD (permeability cutoff). Therefore, by application of the new method, this weakness is omitted.

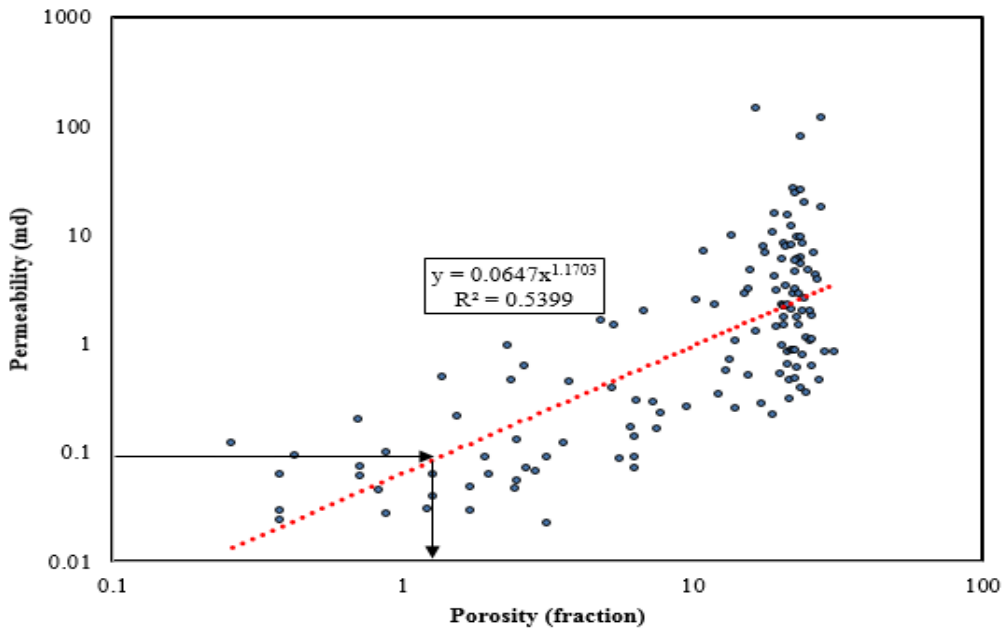

Figure 15

A conventional permeability-porosity method to estimate porosity cutoff in Well TBK#1.

It should be noted that one of the most powerful data for confirming the results of any cutoff estimation method is the results obtained from production tools like production logging tools (PLT). Unfortunately, in the abovementioned field examples, there were no PLT data available; therefore, just DST results have been utilized. On the other hand, in the above examples, DST's are conducted over a thin interval with a homogenous porosity distribution. Therefore, permeability obtained from the transient pressure analysis can be deemed to be a uniform permeability over the tested interval.

To apply the new method, permeability data should be available along the reservoir thickness. For this reason, laboratory-measured core permeability has to be correlated with other properties like porosity or water saturation. The correlation is then extrapolated to uncored intervals or either uncored wells for permeability estimation. Moreover, advanced petrophysical logs such as dipole sonic imager (DSI) or combinable magnetic resonance (CMR) can be used for permeability estimation in the whole interval of a reservoir. Permeability data estimated from these logs should be corrected by the core data if core data are available in any interval. Finally, it is important to notice that although the proposed methodology is restricted to single gas phases, it is valid for all types of gas reservoirs (dry, wet and condensate gas) under initial reservoir conditions. In addition, permeability and porosity data in the whole reservoir interval are needed which can be prepared from the combination of core and advanced logs.

5. Conclusions

The concept of net pay determination is firmly tightened to the permeability cutoff value since minimum economic flow rate under the availability of existing technologies is considered in pay zone definition. Hence, many researchers have utilized permeability cutoff in the first step of their work, but almost all the time this value is determined based on experience. After studying the flow of gases in tight rocks, a new approach has been adopted to determine net pay zones. This method, unlike many other cutoff methods, has a supporting theory behind it which makes it logical for the determination of permeability cutoff. In addition, the main drawbacks related to the previous methods using permeability and porosity from core data are not enclosed in the proposed approach. Finally, this technique has been applied to four wells of different gas fields which agreed well with production and DST data. The confirmation of the results obtained from this technique with production data makes it a powerful tool for the identification of pay zones in gas reservoirs under initial reservoir conditions.

Nomenclature

CMR	Combinable magnetic resonance
$\boldsymbol{d}$	Mean diameter of the pore (m)
$\boldsymbol{d_p}$	Pore throat diameter
DSI	Dipole sonic imager
DST	Drill stem test
$\boldsymbol{\delta_m}$	Molecular collision diameter (effective diameter) of the gas molecules (m)
$\boldsymbol{k}$	Rock permeability (mD)
$\boldsymbol{\kappa_B}$	Boltzmann constant, which is equal to 1.3805×10^{-23} J/K
$\boldsymbol{\lambda}$	Mean free path of gas molecules (m)
$\boldsymbol{\varphi}$	Porosity (fraction)
$\boldsymbol{P}$	Pressure (psi)
$\boldsymbol{T}$	Temperature (°F)

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