ABSTRACT

A NEW FLOW-BASED CUT-OFF CRITERION FOR PERMEABILITY IN DRY GAS RESERVOIRS,

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Some reservoirs containing significant regions with very low permeability gas-bearing rock (down to 10^{-2} md.) are currently in production in North America and the UKCS. As the UKCS matures more lower permeability prospects, particularly gas or gas condensate ones, may be considered for development.

A petrophysical cut-off is a commonly applied device used in the process of calculating in place hydrocarbons. In the case of gas fields, which have an element of low permeability reservoir, the particular cut-off value chosen can have a substantial effect on gas-in-place and reserves. Cut-off values for permeability are often selected using ‘rules of thumb’ or experience, without reference to likely flows in the particular reservoir. This paper presents a means of helping guide the choice of permeability cut-off.

Previously a flow-based permeability cut-off criterion for gas reservoirs was advanced by Dr Fishlock of AEA Technology and presented to the London Petrophysical Society. This was derived on the basis of dimensional considerations and normalised for vertical flow conditions. In this paper we report an improved criterion based on an analytic flow solution. The criterion is based on a rectangular gas reservoir model in which a uniform low permeability region laterally connected to a uniform higher permeability region is drained by a well. Although technically the criterion is derived for areal flows, it has a similar form to the earlier criterion normalised for vertical flow and is likely to be more widely applicable. In any case, as wells are drilled in different regions, the new criterion is helpful in estimating which pay might contribute to reserves. Examples of application of the criterion to data relevant to UKCS fields are given.

INTRODUCTION

The use of a petrophysical cut-off to define net pay and exclude unnecessary data, is a traditional practical device used in the industry for many years. Cut-offs may be employed on one or more of several factors including permeability, porosity, net to gross, shale or clay content and water saturation. However, for a reservoir with complex geology, the accurate determination of suitable cut-off values might in principle require simulation modelling of the reservoir including all the data, which would defeat the point of the cut-offs. This is because chosen cut-offs should reflect reservoir flows and realistic timescales for hydrocarbon production.

Partly for this reason, permeability cut-offs, on which we shall focus, are usually chosen by rules of thumb and experience, rather than directly from knowledge of likely flows in the reservoir. However, gas in particular is more mobile than oil, so over the course of a reservoir's lifetime, gas from quite low permeability regions may be producible. One constraint on this is given by the fact that permeability usually correlates with porosity, so that very low permeability may imply insufficient pore volume to contain much gas. However, it is possible for significant gas volumes to exist in rock with permeability lower than the typical rule of thumb cut-off value used for gas of 0.1 mD on the UKCS (see section on UKCS Gas Reservoir Applications). Three relevant examples of UKCS gas reservoirs from the open literature are Hyde [1], Anglia [2] and Ravenspurn North A [3]. The Travis Peak formation in Texas also provides several examples of producing gas sandstone reservoirs with median permeabilities as low as 0.007 mD [4].

One way in which permeabilities may be very low, but porosities are good is through diagenetic illite cementation. This may reduce permeabilities by blocking pore throats without substantially reducing pore volumes. However, there are other ways this may occur including diagenesis in depositional variation or burial history or structural factors. Unfortunately, the effects of the diagenetic processes tend to be reservoir specific, often causing extreme variations in reservoir quality over small spatial distances. This precludes deterministic modelling of the heterogeneities caused by such diagenetic processes for typical cases.

So is it possible to do better than the rule of thumb in estimating permeability cut-offs with a practical method? One way of attempting this is to base a cut-off criterion on an analytic flow solution, that is one which can be expressed as a simple formula. This will introduce a host of approximations and assumptions, but these can at least be checked, for example, using numerical reservoir simulation. An analytic form also provides a quantitative guide as to importance of contributing factors. This is the approach that has been adopted here for gas reservoirs. For these reservoirs, nature is helpful in that gas reservoir flows can be described more simply than oil reservoir flows, facilitating analytic solution. One assumption that is made is that there is a uniform low permeability region connected to a higher permeability region, from which gas is produced. While this may be a good enough assumption for modelling many situations, it is possible to imagine heterogeneous reservoir geologies for which it is not. We shall touch upon this question later, but it is important to recognise the limitations of what can be done with analytic solutions. We may have provided a tool which can help guide the choice of permeability cut-offs, but we do not claim it is uniformly applicable!

PERMEABILITY CUT-OFF CRITERION

Introduction

A permeability cut-off criterion has been developed by considering production from a high permeability region connected to a low permeability region, see Figure 1. The flow from the low permeability region has been modelled using an analytic Carter-Tracy linear 'gasifer' type model, based on the Hurst-van Everdingen analytic flow solution. This type of solution has been employed in reservoir simulators for many years to model the behaviour of aquifers in communication with hydrocarbon reservoirs. The term 'gasifer' is used when the invading phase is gas not water.

The model is based on the following assumptions:

1. Flow is always laminar so a one-dimensional model is adequate.
2. Flow is independent of gravitational effects.
3. The gasifer is homogeneous.
4. The gasifer has constant total viscosity-compressibility product.
5. The permeability of the high permeability region is considered to be such that there is no significant pressure drop across it.

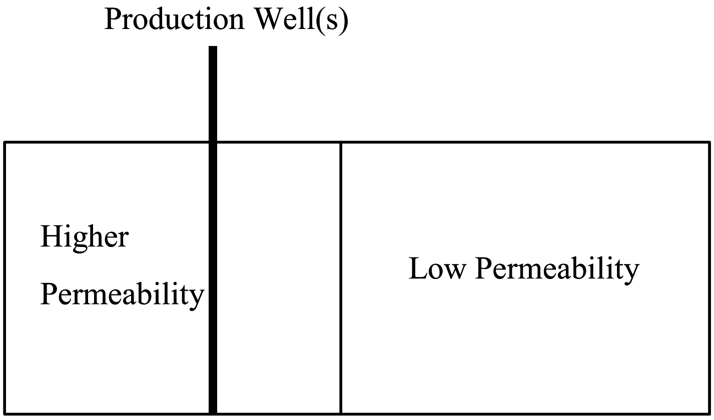

Figure 1: Schematic of Reservoir Model

The first three assumptions are generally well satisfied for gas flow, but the fourth may not be. Even so, the variation in the viscosity-compressibility product may be less than a factor of two, except at low pressures, see Figure 2. We shall see, however, that this is good enough for application of the cut-off criterion. The fifth assumption can be rephrased as the pressure adjacent to the high permeability region is close to the average pressure of the high permeability region and will be satisfied for many reservoirs.

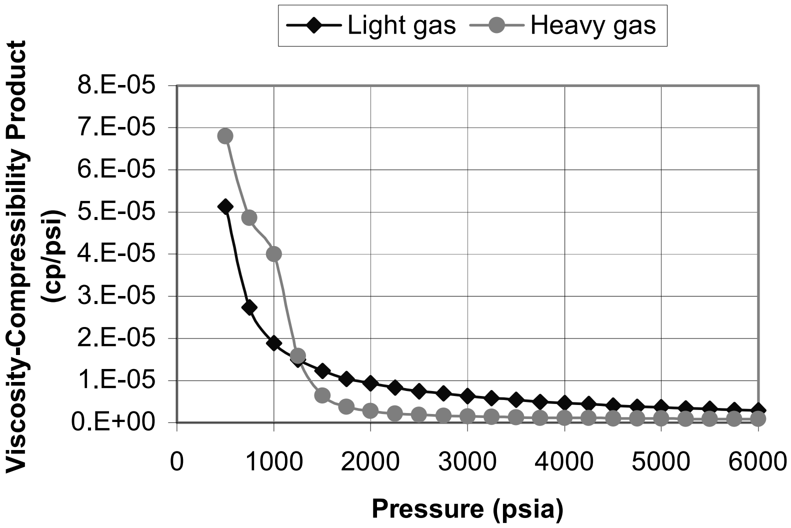

Figure 2: Variation of Product of Gas Viscosity and Compressibility with Pressure

The approximate solution was derived subject to a linear pressure decline in the high permeability region. The solution is therefore no longer valid at the end of plateau production for a reservoir, but this does not provide a restriction to the application of the proposed criterion.

We have derived a cut-off criterion by calculating, ε, the ratio of the cumulative gas volume which has flowed from the low permeability region to the cumulative gas production. This can be approximated by (see Appendix on CD)

$$\varepsilon = \frac{F}{cV\Delta P} \tag{1}$$

where

F is the cumulative volume flow from the low permeability region
c is the compressibility of the gas

V is the volume of the high permeability region
ΔP is the pressure drop during production

The CD Appendix also contains an analytic expression for the cumulative flow (equation A1.8), which depends on whether the outer boundary of the low permeability region has been experienced, which in turn depends on the properties of the low permeability region and the duration of production.

Infinite Acting Solution
The infinite acting solution applies before the impact of the outer boundary of the low permeability region has been experienced, and in field units is given by

$$\begin{aligned} K_L &= \frac{1}{0.006497}\varepsilon^2 \frac{25\phi_h^2 L_h^2 \mu c}{4\pi\phi_L t} \\ L_L &\geq \sqrt{\frac{0.006497 K_L}{0.15\phi_h \mu c}} \end{aligned} \qquad t_D \leq 0.15 \qquad (2)$$

where

$$t_D = \frac{0.006497 K_L t}{\phi \mu c L_L^{\ 2}} \qquad (3)$$

This yields the minimum permeability capable of delivering the required fraction, ε, of gas from the low permeability region during the field lifetime and is what we propose as a flow-based criterion. It also provides a minimum length corresponding to this permeability. To use the criterion requires specification or knowledge of the factors on the right hand side of (2). This includes ε, which we have taken as 10%, the duration of production and the extent of the high permeability region, which we recommend estimating from well spacing.

Late Time Solution
The late time gasifer influx is given by

$$\varepsilon = \frac{\phi_L L_L}{\phi_h L_h t_D}\left(t_D - 0.15 + \tfrac{1}{3}\left(1 - \tfrac{3}{5}\sqrt{0.15\pi}\right)\left(e^{-3(t_D - 0.15)} - 1\right)\right) \qquad t_D > 0.15 \qquad (4)$$

This is a non linear equation that can be solved either graphically or numerically using a spreadsheet. There are a number of different K_L-L_L pairings that satisfy it. To solve this equation, a value is chosen for either K_L (greater than or equal to the infinite acting value) or L_L (less than or equal to the infinite acting value) and the other value is then determined. The following table gives typical data used in example calculations.

Table 1: Typical Example Data Used

Property	Value
L_h	3800 feet
ϕ_h	0.1
ϕ_L	0.1
μ	0.02 cp
c	0.01 psi^{-1}
t	3650 days (10 years)
ε	0.1

The following table gives typical results for the variation of the minimum extent of the low permeability region with permeability. The extent of the low permeability region from the infinite acting solution is 1392 ft for 0.02 mD.

Table 2: Application of Late Time Solution

K_L (mD)	L_L (feet)
0.02	579
0.05	413
0.1	396
0.5	385
1	384

The late time solution gives a smaller length for the minimum permeability than the infinite acting length. Increasing the permeability further results in even shorter lengths, the minimum length being bounded by volumetric considerations i.e. sufficient gas in the low permeability region to satisfy the criterion.

Note that one doesn't need to use (4) to apply the cut-off criterion unless one wants to estimate the extent of the low permeability region. The practical application of the cut-off criterion can therefore be limited to (2), which is easier to apply than (4).

Validation of the Criterion

Figure 3 shows a comparison of the approximate analytic solution and three simulation calculations assuming permeabilities ranging by two orders of magnitude. The analytic solution does not vary with permeability when plotted against dimensionless time because it impacts the cumulative flow and dimensionless time equally. The simulated data shows only a small spread, which shows that the analytic solution is good enough for application of the cut-off criterion.

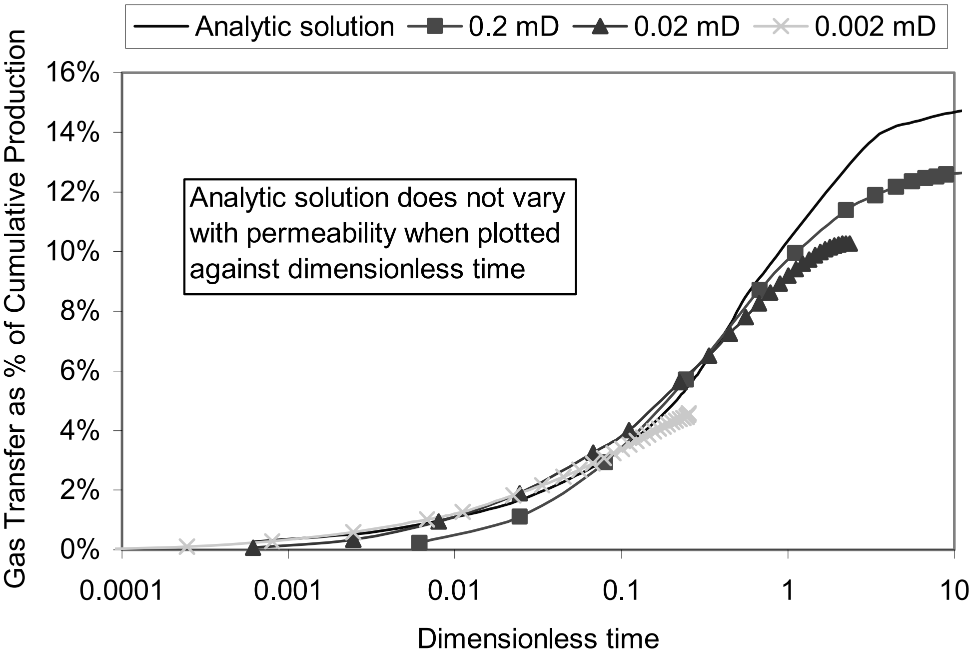

Figure 3: A Comparison of the Analytic Solution and Three Simulations with Different Permeabilities

As well as permeability, the analytic solution also depends on gas compressibility and viscosity, both of which vary with pressure. Here we have entered values at the initial pressure, which gives the best match overall. Figure 2 shows how the product of gas compressibility and viscosity typically varies with pressure, large variations only occur at lower pressures. The low permeability region is likely to have higher average pressure than the main reservoir which supports using the initial values.

In order to check how well the minimum length of the low permeability region is predicted by the analytic solution, we firstly:

- calculate the minimum permeability and associated length using the infinite acting criterion (2) and then
- use the predicted permeability to determine the length of the low permeability region from (4).

Varying the extent of the low permeability region resulted in good agreement between analytic and simulated data as can be seen from Figure 4, which compares three different cases.

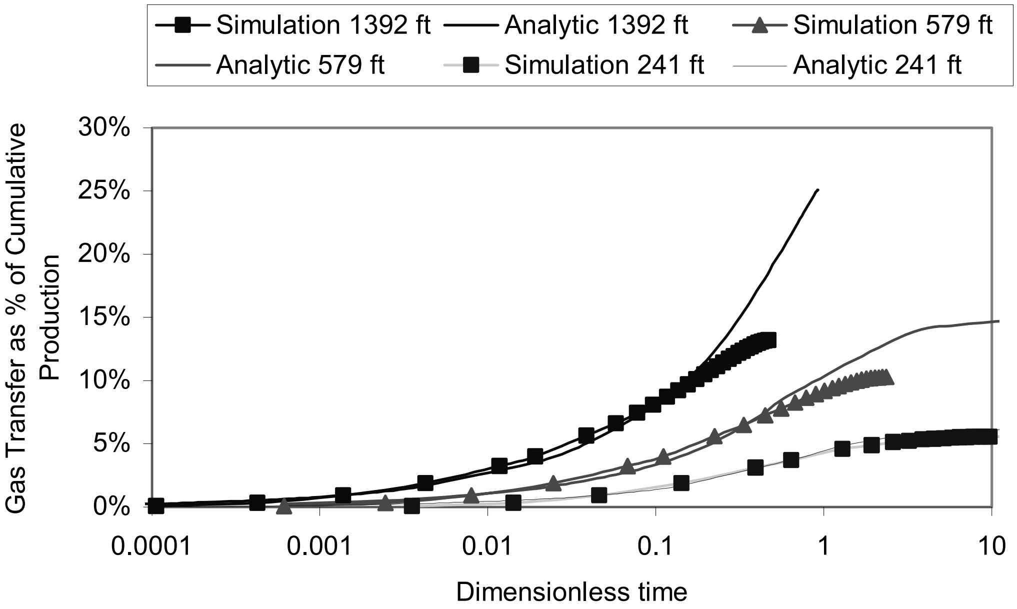

Figure 4: A Comparison of the Analytic Solution and Three Simulations with Different Extents for the Low Permeability Region.

Heterogeneous reservoirs

The criterion was derived for horizontal flow between low and high permeability regions, but it is of interest to know whether it is of use in more heterogeneous situations. This has been investigated using a single well radial model in a layered reservoir, see Figure 5. The model consists of a low permeability layer sandwiched between two high permeability layers. The layered reservoir satisfies many of the assumptions used to derive the analytic solution. The primary flow path consists of migration from low to high permeability layers from which it is produced i.e. the flow is one-dimensional. Gravity does not play a significant role over the short distances typically involved. All other aspects of the modelling are basically similar to the homogeneous model.

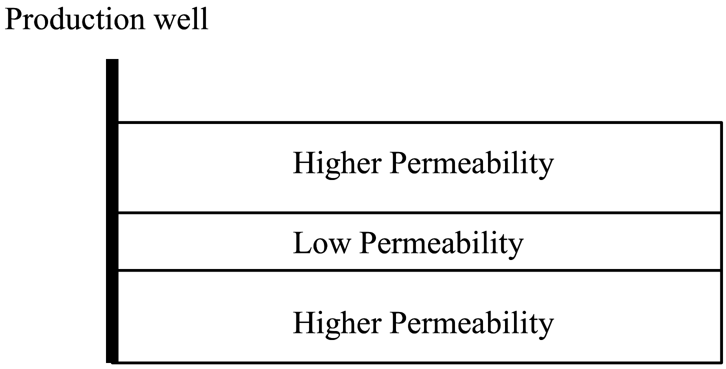

Figure 5: Schematic of Layered Simulation Model

The analytic solution was used to predict the thickness of the low permeability region. The length of the high permeability region was taken to be the thickness of one of the layers, whilst the low permeability length corresponds to half the thickness of the low permeability region. The other data was as in Table 1.

The infinite acting analytic solution predicts an extremely low permeability, of the order of 10^{-6} mD and a thickness greater than 9 feet. The gas has only to only migrate a short distance to the higher permeability layer to be produced over the lifetime of the reservoir and so may flow at a very low rate. If the late time solution is used to vary the permeability, then the following lengths can be calculated. A value of 2.5 feet represents the minimum possible length. Shorter lengths imply insufficient gas to satisfy the assumed 10% value of ε.

Table 3: Variation of Length With Permeability

Permeability (mD)	Length (feet)
$8.8 * 10^{-7}$	3.50
$8.8 * 10^{-6}$	2.54
$8.8 * 10^{-4}$	2.50
0.088	2.50
0.88	2.50

This example has been verified by simulation. The flow is largely linear in the vertical direction and the impact of gravity over the distances involved is not significant. The pressure decline in the high permeability region is approximately linear in time.

The application of the analytic solution to the heterogeneous layered reservoir predicted results comparable to those for the homogeneous model indicating that it should be applicable to a wide range of heterogeneities. However, the timescale for production of gas from the thin low permeability layer was very short, giving an extremely low permeability cut-off. This suggests that no cut-off may be appropriate for sands with small-scale heterogeneities of the order of a few feet.

APPLICATION TO UKCS GAS RESERVOIRS

A survey was made of twelve UKCS gas reservoirs, covering a range of different geologies, put forward for development in the last few years. In five reservoirs, developed by three different operators, permeability cut-offs were either not applied, or have been used only for distinguishing between sand and shale. Of the seven examples for which permeability cut-offs were applied, all were at least 0.1 md and three were greater, though some included additional cut-offs on clay volume and/or water saturation, see Table 4.

The flow criterion was used to define a permeability cut-off for these twelve UKCS reservoirs. Specific field data were used to compute the flow criterion cut-offs where available. Typical values were used for the few exceptions. The percentage of gas required to be recovered from the low permeability region was again set at 10%. The extent of the high permeability region was estimated from the mean area per well in each reservoir, typically a few thousand feet.

The practice of not applying a cut-off for some UKCS southern basin fields is supported by the flow criterion which gives cut-offs of the order of 10^{-3} md for these fields. We see however from Table 4 that the predictions from the flow criterion are typically about an order of magnitude less than the commonly used value of 0.1 md and are substantially less than the chosen operator cut-off, where there is one. This suggests that significant reserves may not be accounted for. For example, for one field, the operator estimated that a reduction in permeability cut-off from 0.1 to 0.01 md would increase the initial-gas-in-place by about a quarter.

Table 4: A Comparison of Operator Cut-offs with Flow Criterion Cut-offs.

Reservoir	Operator Cut-off (md)	Flow Criterion Cut-off (md)	Ratio of flow criterion to operator cut-off
A	None	2.2E-03	-
B	None	3.6E-03	-
C	None	5.1E-03	-
D	None applied	1.8E-02	-
E	0.75	4.3E-02	0.06
F	1	7.1E-04	0.0007
G	0.1	2.8E-02	0.28
H	(Porosity, Vclay) 0.1 to 1	5.2E-02	0.5 to 0.05
I	0.1	3.1E-02	0.3
J	Only sand/shale distinction	2.1E-02	-
K	sand/shale distinction 0.1	2.5E-02	0.3
L	Vclay < 20% and S_w < 70% 0.1	4.8E-03	0.05

CONCLUSIONS

Diagenesis can give rise to very low permeabilities, but still preserve the capacity of the rock to store significant volumes of gas. The effects of diagenetic processes tend to be reservoir specific, often causing extreme variations in reservoir quality over small spatial distances. This precludes deterministic modelling of the heterogeneities caused by such diagenetic processes for typical cases.

A selective survey of more recent UKCS gas field developments shows that most operators are still using fixed permeability cut-offs of about 0.1 md, though some modify this by including constraints on clay or shale content or water saturation. However, no permeability cut-off was applied to a significant minority of fields.

A permeability cut-off criterion based on an analytic solution for gas flow from a uniform low permeability region into a uniform higher permeability region has been derived. Assumptions made in the derivation and application of the analytic solution have been verified using simulation.

The flow criterion was derived assuming uniform low and high permeability regions, but has been applied to a simple heterogeneous case where a thin low permeability layer separates higher permeability sands. The prediction from the analytic solution agreed with simulation, but the timescale for production of gas from the thin low permeability layer was very short, suggesting an extremely low permeability cut-off. This suggests that no cut-off may be appropriate for sands with small-scale heterogeneities of the order of a few feet.

Application of the flow based criterion to the UKCS fields included in the selective survey shows that chosen operator cut-offs are typically an order of magnitude greater than indicated by the flow-based criterion. The flow-based criterion also suggested very low permeability cut-offs for those fields for which no cut-offs had been applied. This suggests that UKCS gas reserves could be systematically underestimated.

ACKNOWLEDGEMENTS

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NOMENCLATURE

c	compressibility of gas
F	cumulative volume flow from the low to the high permeability region
K	permeability
L	characteristic flow length
t	time
t_D	dimensionless time
V	characteristic volume of the high permeability region
ΔP	pressure drop during production
ε	ratio of the cumulative gas volume which has flowed from the low permeability region to the cumulative gas production
ϕ	porosity
μ	viscosity

subscripts

h	denotes property of the high permeability region
L	denotes property of the low permeability region