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DARCY BASED PERMEABILITY IN A PETROLEUM RESERVOIR BEFORE AND AFTER WATER-FLOODING: WHAT DOES IT DEPEND ON?

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Abstract: A sound knowledge on the estimation of reservoir permeability becomes fundamental for a precise prediction of production forecasts. The problem becomes further complex for multi-phase fluid flow as observed in a petroleum reservoir. Thus, estimating the magnitude of effective/relative permeability remains very challenging in the context of multi-phase fluid flow. Even in a relatively homogeneous sandstone reservoir, the concept of relative/effective permeability becomes very complex. In the present paper, an attempt has been made in order to discuss the sensitive factors that alter the magnitude of effective/relative permeabilities in a petroleum reservoir between the transition period namely 'at the end of primary recovery' and "during water-flooding'. It has been proposed that the 'pressure' in addition to rock and fluid properties will dictate the resulting effective/relative permeability even in the absence of considering the geo-mechanical aspects of the reservoir. The study is further extended to consider the concept of effective/relative permeabilities in a fractured reservoir. It is proposed that the intensity of the coupling between fracture and rock-matrix will significantly influence the resulting effective/relative permeabilities of oil and water within the fracture and rock-matrix, while the fracture relative permeability will become a complex non-linear function of water-saturation.
Keywords: Effective permeability; Relative permeability; Petroleum reservoir; Fracture; Rock-matrix

INTRODUCTION

Permeability along with porosity forms the fundamental reservoir unit. In reality, the magnitude of single-phase absolute permeability has been characterized by log-normal distribution as against the normal distribution meant for porosity. The extended version of Darcy's law that describes the multi-phase fluid flow through a porous medium is given in equations (1) and (2) for liquids and gases respectively.

Darcy flux = (Volumetric flow rate / Area) = (1/Dynamic viscosity) (Absolute permeability x Relative permeability) (Pressure gradient) (1)

Darcy flux = (Volumetric flow rate @ mean pressure / Area) = (1/Dynamic viscosity) (Absolute permeability x Relative permeability) (Pressure gradient) (2)

For gases, the absolute permeability calculated using Darcy's extension will be larger than the actual absolute permeability and for such cases, slip factor comes into the picture, which is associated with the Klinkenberg effect. The slip factor may be obtained from the values of gas permeability and the reciprocal of average pressure. Relative permeabilities can be generally estimated from Corey curves for a relatively homogeneous porous medium.

The purpose of the present work is to analyze whether the relative/effective permeability of a given geological formation (in a petroleum reservoir) remains constant during primary and secondary recovery or not. If there is a variation in the magnitude of relative/effective permeabilities between primary and secondary recovery, then, what exactly quantifies the resulting permeability. The present work does not the geo-mechanical aspects of a petroleum reservoir. The work is also extended to understand the complexities associated with the estimation of effective/relative permeabilities of a fractured reservoir.

PERMEABILITY IN A PETROLEUM RESERVOIR

A petroleum reservoir represents a geological formation that is completely/fully saturated with the multi-phase fluids that include hydrocarbons (oil and/or gas) along with the formation water [1]. In addition, a petroleum reservoir is supposed to store as well as transmit these hydrocarbons under the confined conditions using the natural energy available within the reservoir (primary hydrocarbon recovery). It should be clearly noted that the reservoir becomes incapable of transmitting significant quantities of oil and/or gas at the end of primary oil recovery, despite, still having significant storage of residual hydrocarbons. Thus, at the end of the primary recovery, a petroleum reservoir replicates a geological formation that is similar to an impervious formation (like clay, having significant storage in the absence of significant transmissivity/ permeability/hydraulic-conductivity). In other words, the relative permeability to oil/gas and water at the end of primary recovery is nearly zero/insignificant; and hence, a secondary recovery method (water/gas flooding) and/or a tertiary recovery method (thermal/chemical/microbial EOR) is applied in order to extract the residual/left hydrocarbons, where the relative permeability, and in turn, the mobility; and subsequently, the production of the concerned multi-phase fluids (oil & gas) gets enhanced. At this point, it is interesting to note that the term 'intrinsic permeability' (or single-phase 'absolute permeability') is a function of rock property alone; and it does not depend on fluid properties at all (unlike 'hydraulic conductivity'). Thus, since, 'intrinsic permeability' is a function of 'rock property' alone, we will not be able to bring in the concept of "hydraulic gradient' (for single-phase fluid flow) or 'pressure gradient' (for multi-phase fluid flow) into the picture. However, it can be clearly understood that the magnitude of 'pressure gradient' becomes insignificant or the same tends to approach zero; and hence, the fluid (oil or gas) ceases to flow within the reservoir; and subsequently, there is no fluid flow towards the production well at the end of primary recovery. Now, the depleted pressure of the reservoir is enhanced 'externally' (and not naturally) by means of secondary recovery (water or gas flooding) technique. By external injection of water and/or gas, the relative/effective permeability of the reservoir fluids is increased; and this results in an improved oil/gas production. And, this sequence of events clearly tells us that the 'effective/relative permeability' associated with the oil, gas and water flow of a petroleum reservoir has indirectly become a function of 'reservoir pressure' as well in addition to its dependence on rock and fluid properties. Strictly speaking, 'intrinsic permeability' is no more a function of fluid for Darcy's law to be valid. On top of it, in a typical petroleum reservoir, the 'relative/effective permeability' becomes a function of 'reservoir pressure'.

DEPENDENCE OF PERMEABILITY

Permeability in a petroleum reservoir has several complexities; and as a result, quantifying permeability has become more and more approximated without solid fundamental theory. In this paper, the author has made an attempt to raise some of the fundamental queries that would help to better understand the dependence of permeability in a typical petroleum reservoir.

(a) Whether the single-phase 'absolute permeability' of the same reservoir has undergone a significant transformation during the periods between 'the end of primary recovery' and 'during secondary/tertiary recovery'?

(b) Whether the pore geometry of the reservoir gets restructured; and in turn, the nature of the 'connected interstices' gets modified during this transition period?

(c) What exactly caused the changes in the magnitude of the relative permeabilities of oil, gas, and water, during the periods between 'the end of primary recovery' and 'during secondary/tertiary recovery'?

(d) Whether Darcy's law accommodates such changes in permeability resulting from the factors that are beyond 'the continuity of the fluid migration by means of well-connected pores'? If so, under what conditions?

(e) If the 'relative/effective permeability' becomes a function of 'pressure'; what does it pertain to? Is it Oil pressure or Gas pressure or Water pressure or Average Reservoir Pressure? If it is 'Average Reservoir Pressure', then, how will it be feasible to provide a link/upscaling between local-scale oil/gas/water pressure to the Darcy-scale 'average reservoir pressure'?

(f) For Darcy's law to be valid, the fluid flow within the reservoir should be essentially 'horizontal'. Under such conditions, the one-dimensional fluid flow essentially indicates the ability of the reservoir to transmit oil, water and/or gas through its entire thickness called the 'reservoir transmissivity'. For a one-dimensional problem, the 'entire thickness' of the reservoir becomes 'a single point' on a single line. If so, how come, the 'permeability' associated with a 'petroleum reservoir' becomes a function of different 'fluids' as well?

(g) The storativity of a petroleum reservoir provides the correlation between the changes in the quantity of oil, water and/or gas stored within the reservoir and its associated changes in the elevations of the 'piezometric surface'. The storativity of a petroleum reservoir should represent the volume of the pore fluids (oil, water and/or gas) released from or added to a vertical column of a reservoir of unit horizontal cross-section, per unit of decline or rise of the piezometric head. However, in a petroleum reservoir, during water flooding, there will be an addition of water only in the absence of adding oil and/or gas. If so, how exactly, can we quantify the concept of 'storativity' associated with an oil reservoir? Further, whether 'storativity' has any correlation with the 'permeability' during the transition period? Because, it should be clearly noted that the storativity of a petroleum reservoir is caused by the compressibility of oil, water and/or gas; and also, by the elastic properties of the bulk reservoir.

PERMEABILITY IN A FRACTURED CARBONATE RESERVOIR

Fluid flow through a fractured reservoir is modelled using multiple continuum as the fundamental entities associated with a fractured reservoir namely fracture and rock-matrix have completely varying reservoir properties. In other words, the concept of the single continuum cannot be applied for a fractured reservoir as it violates the fundamental principle of calculus, which says that the spatial distribution of primary dependent variables and parameters (constant/ varying coefficients) should vary smooth and continuous. However, in a fractured reservoir, the porosity and permeability vary by orders of magnitude at the interface between high-permeable fracture and low-permeable rock-matrix. And, for this reason, a fractured reservoir is generally modelled using a dual continuum approach, where fracture and rock-matrix are treated as separate continuum, while a coupling term at the fracture-matrix interface ensures the continuity of the fluid mass fluxes ([2-32]). On the other hand, deducing the average permeability value for the entire reservoir as a function fracture and rock-matrix permeability would not be correct; and thus, the concept of Equivalent Porous Medium (EPM) should be handled with utmost care, even for a single-phase fluid flow. Now, for multi-phase fluid flow in a fractured carbonate reservoir, the concept of relative/effective permeability becomes far more complex for the following reasons:

(a) For an oil-water system, any fractured reservoir has the following permeabilities: fracture-permeability; matrix-permeability; effective-permeability of the bulk reservoir; effective-permeability of oil in the matrix; effective-permeability of water in the matrix; effective-permeability of oil in fracture; and effective-permeability of water in fracture. It is not easy to determine the magnitude of all these permeability values. On top of it, how exactly to compute the value of interfacial tension and the maximum capillary pressure for this oil-water system? Since, the recovery factor in a fractured reservoir depends on the magnitude of effective-permeabilities of both fracture and matrix, the estimation of these permeability values deserves special attention.

(b) Estimating the ratio between the effective permeabilities of water and oil against the water saturation remains completely different when the fractured reservoir is treated either as a single or multi-continuum. On top of it, the extent of weathering of rocks, the fracture density, the fracture spacing, the fracture orientation, the fracture length dictates the resultant ratio between the effective permeabilities of water and oil as well as the water saturation. In the absence of all these data, characterizing multiphase fluid flow using the concept of effective/relative permeability would remain highly approximate.

(c) Considering the influence of saturation endpoints within a fracture gets seriously affected by the fracture wall geometry; and hence, the fracture relative permeability becomes a complex non-linear function of water-saturation.

(d) Based on the thickness of the fracture aperture, the rate of fluid mass transfer, i.e., the intensity of coupling between fracture and matrix will vary. For example, when the thickness of the fracture aperture is closer to 10 microns, the intensity of coupling will be very high, while for a 1000 micron and greater aperture thickness, the intensity of coupling between fracture and matrix will be very low. Thus, the intensity of the coupling between the high-permeable fracture and low-permeable rock-matrix significantly influences the resulting effective permeabilities of oil and water within the fracture and rock-matrix.

CONCLUSIONS

The following conclusions have been drawn from the present study.

1. There is no clarity in defining the term 'permeability' associated with a typical petroleum reservoir as in petroleum engineering, neither the term 'intrinsic permeability' nor the term 'hydraulic conductivity' is used.
2. Permeability associated with a petroleum reservoir seems to depend on 'reservoir pressure' as well in addition to the rock and fluid properties during the transition period between 'the end of primary recovery' and 'during secondary/tertiary recovery'.
3. It is concluded that the magnitude of storativity before and after water flooding may be completely different as the storativity of a petroleum reservoir is caused by the compressibilities of oil, water and/or gas, along with the elastic properties of the bulk reservoir. This variation in storativity values before and after water flooding may indirectly influence the resulting reservoir permeability.
4. It is concluded that the estimation of effective permeabilities of oil and water in high-permeable fracture and the low-permeable matrix also depend on the extent of weathering of rocks, the fracture density, the fracture spacing, the fracture orientation, and the fracture length.

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