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Uncertainties Associated with Petroleum Reservoir's Rock and Fluid Properties

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Abstract

The estimation of petroleum reservoir's rock and fluid properties remains fundamental for an efficient characterization of multi-phase hydrocarbon flow in a saturated confined reservoir under high pressure and high temperature conditions. The main reservoir rock property includes porosity, permeability and rock compressibility. The principal fluid properties include density, viscosity and compressibility of hydrocarbon fluids. In addition to this basic properties, the introduction of relative permeability for characterizing multi-phase hydrocarbon flow becomes a complex function of wetting-phase saturation. Further, the fluid-fluid interphase property namely interfacial tension (IFT) arising from the presence of capillary pressure; and fluid-solid interphase property namely contact angle (θ) arising from reservoir wettability plays a very crucial role in dictating the resulting spatial and temporal distribution of hydrocarbon pore fluids within a petroleum reservoir as a function of time, upon hydrocarbon production. Thus, accurate estimation of these fundamental reservoir properties become very crucial towards a successful reservoir characterization. In this context, the objective of the present article is to provide an inherent uncertainties associated with the deduction of each of these reservoir rock and fluid properties towards characterizing a petroleum reservoir. The present study concludes that although very recently developed data-driven forward and reverse models remain mathematically convincing, they still remain to be not geologically trustworthy. Since, addressing reservoir heterogeneity it-self requires a high-end computing facility, the concept of uncertainty quantification of permeability becomes further computationally expensive. In addition, the uncertainties resulting from laboratory-scale experimental investigations, minimum number of core samples from field-scale investigations and the association of reservoir physics at multiple-scales make the measurement of relative permeability to remain to be highly erroneous.

Keywords: *Porosity; Relative permeability; Capillary pressure; Wettability; Uncertainty.*

1. Introduction

Characterization of a petroleum reservoir involves the analysis of various flow regimes and production scenarios associated with multi-phase fluid flow. For this purpose, a lot of field data on both rock and fluid properties of a petroleum reservoir are required. However, in reality, very few remain available and as a result, various deterministic approaches including experimental techniques, analytical techniques and computational methods have been widely employed to estimate reservoir porosity. However, all these approaches still have uncertainties and limitations towards predicting reservoir rock and fluid properties as the field core samples only represent a very small portion of the entire petroleum reservoir. Eve, if the secured field core samples exhibit strong heterogeneity and anisotropy, the estimation of the effective reservoir rock properties will end up with multiple solutions and/or non-unique solutions. Further, all the existing deterministic approaches provide only a single-valued reservoir rock property in the absence providing a range of fluid or rock properties, given the nature of inevitable reservoir heterogeneity at all scales. With such a practice, it becomes extremely complex in arriving a reliable and confident decision-making process.

On the other hand, Bayesian evidential learning (using Canonical Correlation Analysis and/or Kernel Density Estimator), or, a very recent data-driven technique tries to quantify the uncertainties associated with reservoir rock and fluid properties, however, they lack theoretical evidence. In this context, the objective of the present article is to provide an inherent uncertainties associated with the deduction of each of these reservoir rock and fluid properties towards characterizing a petroleum reservoir. In the present article, the uncertainty sources associated with porosity, permeability, relative permeability, capillary pressure and wettability (contact angle) properties have been analysed in detail.

2. Uncertainty associated with porosity

Porosity remains to be one of the fundamental reservoir units that characterizes the storage capacity of a petroleum reservoir. In a confined, saturated petroleum reservoir, each pore is assumed to be completely filled with a pore fluid so that total pore-fluid saturation in pores always remains to be 100%, unlike an unsaturated aquifer associated with vadose zone. Pores can be either hydraulically connected (effective porosity) or isolated. The total porosity includes all kinds of porosity, where, pore fluids either remain to be mobile (effective porosity) or immobile (dead-end porosity or isolated porosity). Thus, porosity being one of the most fundamental parameters for the characterization of a petroleum reservoir, it remains to be very useful for investigating the reservoir's fluid flow properties, reservoir's pore pressure evolution as well as in assessing the reservoir's mechanical and elastic behaviour.

The conventional model-based approaches for estimating porosity involves geophysical inversion of the waveform data towards obtaining the geophysical elastic properties involving P-impedance and V_p/V_s; and then, either using a statistical relationship from logging/core data (statistical rock physics connects reservoir properties to elastic properties), and/or by using geophysics models to translate the elastic properties into an equivalent reservoir porosity [1-3]. Bayesian-based joint inverse problem suffers from the additional dimensionality and excessive computational cost associated with the forward model evaluations. In such exercises, the accuracy of the results might be considerably exaggerated or understated by the inadequate precision of seismic (non-linear) inversion.

Further, the mode of propagation of errors and uncertainties associated with the employed model essentially leads to a non-unique solution to the inverse problem of estimating the reservoir porosity. The porosity estimation further gets erroneous, when the concerned petroleum reservoir remains to be characterized by significant heterogeneities, even in sandstone reservoirs, particularly with layered formation or with the presence of thin layers in the pay-zone thickness. In the case of carbonate reservoirs, the relationship between velocity and porosity gets still complicated as the pore structures keep evolving/varying caused by physical, chemical and biological changes, not only during initial sedimentation, but also, the pore changes keep happening even during post-depositional diagenesis leading to a strong non-linearity between seismic properties and porosity. In essence, the data gathered from seismic approach remains influenced by ambient and instrumental noise, and thereby presenting uncertainty through model training.

On the other hand, the application of ANNs to get rid-off the gradient instability problem (vanishing or exploding gradients) does not reflect the reality, while the application of recurrent neural networks and convolutional neural networks using relatively small data sets also do not reflect the reality, although, such machine learning methods claim that it offers a semi-automated, non-linear assessment method that utilizes a digital operator to directly transform the seismic trace into porosity. With smaller data set, ensemble learning algorithms tries to reduce the variance by integrating (either sequential/XGBoost or parallel/RF) a number of weak learners into a strong learner. The main problem with data-driven approach is that, it is not practically feasible to secure data with the required volume, and further, the reservoir porosity keeps evolving with time upon hydrocarbon production, and thereby making the already available data to be less reliable for prediction purposes. It should be noted that although, petro-physical methods (experimental analysis) provide the most reliable estimation of porosity, these experiments require very expensive field core samples; and also it remains to be highly time-consuming and mostly not reversible. Further, these cores in many cases do not remain to be representative of the entire reservoir, and hence, this approach is not practical for a larger field-scale reservoir application. On the other hand, the application of empirical methods such as Kozeny-Carman relation (for its simplicity and convenience in practical applications) remains to be applicable only for highly isotropic and homogenous reservoirs. In fact, permeability and porosity cannot be related directly because porosity is a scalar function, while, permeability remains to be a second-order tensor. Further, porosity no more depends on pore-size (porosity depends only on pore-size distribution), while, permeability non-linearly (quadratically) depends on pore-size. Thus, so far, the uncertainty quantification of porosity remained to be not successful and the evolving model developments for porosity estimation alone is no more sufficient to efficiently characterize the reservoir.

3. Uncertainty associated with permeability

Reservoir permeability remains to be the most important reservoir rock property that dictates the ease with which the pore fluid would be able to migrate through a given reservoir. Permeability remains to be strongly affected by the randomness and spatial variations in pore morphology at sub pore-scales, and also by the degree of hydraulic connectivity of the complex three-dimensional pore network. Thus, reservoir permeability remains to be endowed with uncertainty and its quantification becomes a challenging task because even pore-scale uncertainty quantification requires multi-point statistics in order to reflect all the field-scale topological attributes towards describing the long-rage hydraulic connectivity of a low-permeable petroleum reservoir. In essence, reservoir permeability is either measured using cored intervals at the laboratory-scales or it remains estimated using logged intervals at field-scale.

In fact, Turban and Robert [4] estimated permeability using production equation and formation pressure. Since, both cored-interval as well as logged-interval approaches remain to be an indirect method, the scope for uncertainty remains larger. The earlier investigations on permeability estimation involved the conventional deterministic approach, where, the best-fit experimental model (which, ignored uncertainty) were found out towards permeability estimation. Then, probabilistic approaches were employed for permeability estimation, where, the uncertainty was assessed by Probability Distribution Function. Further, the estimation of hydraulic permeability using linear pressurization, oscillating pore pressure and constant-rate flow injection methods are based on fluid flow under steady-state conditions in a closed boundary that dictate the nature transient fluid flow. Thus, direct information on permeability remains deduced from only a small number of boreholes, while, the application of deterministic and stochastic inversion techniques that represent the entire reservoir is widely used. However, it should be clearly noted that the simplifications introduced in order to secure a unique model calibration in an inverse approach would lead to spurious results, which is not acceptable. Thus, with only a small number of parameters involved, the estimation of permeability remains to be under-estimated. On the other hand, the application ensemble Kalman Filter (EnKF) does not result in the same quality of fit as observed in a deterministic inversion for the given ensemble size, although EnKF performs better than Monte Carlo and Bayesian inversion approaches. As far as permeability is concerned, it becomes essential to figure out the sources of uncertainty; and having found the sources of uncertainty, it is critical to delineate the sensitive/dominant parameters that should actually be parametrized. Having parameterized the sensitive parameters, then, it becomes crucial to dissect a given realization (as it is ruled out to replicate the reality completely by a model) that would accurately forecast the relative changes in permeability estimation. Although, addressing reservoir heterogeneity itself requires a high-end computing facility, the concept of uncertainty quantification of permeability becomes further computationally expensive.

4. Uncertainty associated with relative permeability

The concept of relative permeability remains to be central in dictating the flow of oil and gas in a petroleum reservoir. Relative permeability values are generally obtained from experimental investigations that involves the measurement of pressure drop at various cross sections of the core samples for varying physical conditions and subsequently applying the measured pressure drop values in Darcy's equation. The magnitudes of relative permeability to oil and water are expressed as a function of wetting phase saturation. However, the practical difficulties associated with the measurement of relative permeability values through experimental investigations have been reported by several authors including Moghadasi *et al.* [5]. In fact, Silpngarmlers et al Moghadasi *et al.* [6] have concluded that the laboratory experiments towards securing relative permeability values remain to be very complicated and time consuming. Boukadi *et al.* [7] have discussed the various disadvantages and limitations associated with the measurement of relative permeability values through steady-state, transient and centrifuge methods; and the authors have clearly concluded that the relative permeability values remain subjected to errors and uncertainties, with maximum errors near the residual water saturation.

In case of relative permeability model application, there are four unknown parameters (A, L, B & M) with Chierici's model for the estimation of relative permeability [8], while, there are six unknown parameters (L_w, E_w, T_w, L_o, E_o & T_o) with LET relative permeability model [9]; thus, the extent of uncertainty towards estimating relative permeability to oil and water remains larger. Thus the uncertainties resulting from laboratory-scale experimental investigations, minimum number of core samples from field-scale and the association of reservoir physics at multiple-scales make the measurement of relative permeability to remain to be highly erroneous. For example, William *et al.* [10] concluded that the laboratory-based relative permeability to water requires to be lowered, while, the laboratory-based residual oil saturation to water is required to be enhanced in order to match the water cut in the absence of affecting the pressure match. The problem becomes serious for the reservoir fields having insignificant history, where, a single relative permeability curve cannot be generated from averaging the normalized raw data and from averaging end-points (and then, subsequently generating a single de-normalized curve). Thus, the current application of parameterizing the relative permeability values using curve shapes and end-points have a larger uncertainty towards forecasting the oil recovery. Given the field-scale complexities, it becomes challenging to get rid-off geological uncertainties (associated with the estimation of relative permeability) either by a field geologist or by a formation evaluation specialist, leaving reservoir simulation engineer. Also, scaling up of relative permeability value from core-scale to larger simulation scale remains associated with a large uncertainty as the numerical results are mostly associated with numerical dispersion. Further, at the core-scale, the physical system may be dominated by capillary forces that dictate the resulting flow regime, while, at the field-scale, it could be the viscous forces that dictate the resulting flow regimes in a petroleum reservoir. Thus, the estimation of relative permeability is no more straight-forward, even, in a sandstone reservoir.

5. Uncertainty associated with capillary pressure

The application of capillary pressure concept using Darcian approach remains to be extremely erroneous. To start with, the term 'capillary pressure' should not be used as such in petroleum reservoir applications as such. By default, the concept of capillary pressure remains associated with pore-scale, where, Young-Laplace equation can comfortably be applied in order to estimate capillary pressure as a function of interfacial tension (IFT), contact-angle and radius of curvature of the pore. However, this equation remains applicable only at the pore-scale, and it is no more valid at the (larger) Darcy-scale, which is continuum-based using Representative Elementary Volume (REV) approach. Thus, we are forced to handle the concept of capillary pressure at the larger Darcy-scale. In fact, the concept of capillary pressure vanishes if the pore-size remains greater than 1-10 microns; and there is no concept of capillary pressure for larger pores or at the larger scale. However, the concept of 'macroscopic capillary pressure' has been introduced in petroleum reservoir applications, in order for this capillary parameter to get along with larger Darcian-scale. However, the concept of macroscopic capillary pressure is volume averaged over all oil-phases (p_o) and over all the water-phases (p_w); and essentially, it destroys the very fundamental concept of capillary pressure that exists at the interface between a wetting-phase and a non-wetting-phase. Thus, if capillary pressure is defined as the pressure difference between wetting and non-wetting-phase fluid pressures, then, it no more represents the interfacial pressure (along a line or over an interfacial area), while, it represents an averaged value over an hypothetical volume-based approach. Thus, physically, the concept of macroscopic capillary pressure does not represent the field reality, while, the concept of microscopic capillary pressure is no more valid. Further, the extension of Darcy's law for characterizing multi-phase fluid flow remains valid, only when, the physical system of interest remains dominated by capillary forces, with the assumption that one of immiscible fluids take the velocity of the solid during the flow of the other immiscible fluid. In other words, both the immiscible fluids cannot flow simultaneously. And, this assumption fundamentally violates the application of multi-phase fluid flow through petroleum reservoirs. Thus, as far as capillary pressure is concerned, the magnitude of capillary pressure deduced either from models or from experiments (porous plate, mercury injection, conventional centrifuge, high-speed overburden centrifuge, vapour desorption, ultra-centrifuge, semi-dynamic method) remains to be completely uncertain, when these values are applied under Darcian approach, unless a pore-scale characterization of multi-phase hydrocarbon flow through a petroleum reservoir remains possible. Thus, if capillary pressure estimation itself is erroneous, then, it becomes challenging to determine the displaceable fluid saturation end points for multi-phase flow.

6. Uncertainty associated with wettability

The measurement of contact angle associated with reservoir wettability remains to be a very challenging task as it has clearly recognised that even the wettability of clastic reservoir rock experiences weakly wetting behaviour (as against the generally assumed strongly water-wet behaviour) and in general, these kind of reservoir rocks provide no strong preference either to oil or water due to the adsorption of oil components on the pore surface, resulting from the breaking of the thin water film that is present between the (fluid) oil-phase and (solid) rock surface. Thus, in a real field scenario, there hardly exists either strongly oil-wet or strongly water-wet reservoirs; and from this perspective, the so called macroscopic measurements (either using sessile drops or a Wilhelmy tensiometer) of contact angle associated with a well-defined, specific wettability does not reflect the field reality. In fact, it remains to be challenging to locate the point of contact, to locate the position of the baseline and to construct a tangent line to the drop profile using sessile drop method of direct measurement (particularly, when the contact angle remains to be either too low or too high); and hence, the amount of uncertainty increases extensively. The concept of contact angle remains to be associated with sub-pore-scale phenomena; and hence, its application under larger Darcian-scale poses many uncertainties. Further, most of the laboratory-scale measurements of contact angle are carried out on a flat surface, which is completely far away from reality, because, a field-scale reservoir remains to be characterized by a complex three-dimensional pore network structure. And, in fact, the actual distribution of the irreducible, thin water-film is not clearly known; and also, there is no clarity on the pore-scale details on local-scale wettability in pore-spaces, pore-throats, pore-body as well as in pore necks. In addition, the experiments (with varying cleaning conditions) are mostly not performed under native reservoir wettability and under original reservoir conditions. In the absence of core samples taken from the same reservoir layer; from the same production-well, and from the same reservoir (sandstone or a carbonate reservoir), it becomes extremely challenging to measure the contact angle, given the reservoir core samples filled with impure sand and remain to be relatively unconsolidated. The problem becomes further complex, when the pore fluid remains to be either a medium or light oil and the respective wettability estimation by relative permeability curves poses multiple uncertainties.

7. Conclusions

The analysis of uncertainty in reservoir rock and fluid properties are supposed to be used for investigating the way, the laboratory-based measurement errors keep propagating from input parameters to the model forecast. However, none of the earlier studies remained to be successful in getting rid-off the uncertainties associated with rock and fluid properties due to the inherent reservoir heterogeneity associated with multiple-scales. The present study has made an attempt to highlight the practical complications as well as limitations associated with measurements either at laboratory-scale or at the larger field-scale; and their associated uncertainty quantification. The following conclusions have been deduced from the present study.

1. The uncertainty quantification of porosity remained to be not successful and the evolving model developments for porosity estimation alone is no more sufficient to efficiently characterize the reservoir. And, data-driven forward and inverse models may be mathematically convincing in the absence of geological trustworthy, even for a sandstone reservoir.
2. Since, addressing reservoir heterogeneity it-self requires a high-end computing facility, the concept of uncertainty quantification of permeability becomes further computationally expensive, resulting from the fact that it becomes essential to figure out the actual sources of uncertainty; and having found the sources of uncertainty, it is critical to delineate the sensitive/dominant parameters that should actually be parametrized. Having parameterized the sensitive parameters, it then becomes crucial to dissect a given realization (as it is ruled out to replicate the reality completely by a model) that would accurately forecast the relative changes in permeability estimation.
3. The uncertainties resulting from laboratory-scale experimental investigations, minimum number of core samples from field-scale and the association of reservoir physics at multiple-scales make the measurement of relative permeability to remain to be highly erroneous. Thus, the current application of parameterizing the relative permeability values using curve shapes and end-points have a larger uncertainty towards forecasting the oil recovery.
4. The magnitude of capillary pressure deduced either from models or from experiments remains to be completely uncertain, when these values are applied under Darcian approach; and it requires a pore-scale characterization of multi-phase hydrocarbon flow through a petroleum reservoir to get rid-off uncertainty associated with capillary pressure.
5. The concept of contact angle remains to be associated with sub-pore-scale phenomena; and hence, its application under larger Darcian-scale poses many uncertainties. Further, most of the laboratory-scale measurements of contact angle are carried out on a flat surface, which is completely far away from reality, because, a field-scale reservoir remains to be characterized by a complex three-dimensional pore network structure.

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