



Petrophysical Parameters Curves' Calculation for Non-conventional Reservoirs' Modeling and Characterization

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Abstract

The quantitative petroleum reservoir analyses' topic is one of the biggest challenges facing geo-modelers. The difficulty lies in the fact that the constructed model depends on many empirical Archie's law parameters such as tortuosity factor (a), cementation exponent (m), and saturation exponent (n). The most used methodology of choosing the appropriate set values of (a , m , n) is the trial/error technique. The parameters values' sets are calculated empirically based on core data taken from different wells. The main drawback of this method is that these petrophysical parameters are not constant all over the reservoir section and are very variant in non-conventional reservoirs. The objective of this study is to provide curves of the petrophysical parameters (a , m , n) from petrophysical logs based on new equations. The new equations are based on relating tortuosity as a function of the sonic log and other basic logging curves (Gamma Ray, Neutron-density). Then, the calculated curves are used in constructing a more accurate non-conventional reservoir model. The obtained results have been compared to the conventional interpretation where a , m , and n are taken constants for all reservoir sections. Moreover, the obtained results are validated through core data and MDT tests in Algerian Southern non-conventional reservoirs.

Keywords

Tortuosity factor · Cementation exponent · Saturation exponent · Empirical parameters · Reliable reservoir modeling

1 Introduction

The Berkine Basin is a very important region for oil research, where the geological and geophysical studies carried out in the region have mainly been devoted to Triassic Clayey sandstone (TAGI), upper Devonian (Carboniferous), and lower Siegenian (Yisheng et al., 2019). The drilled well is part of the delineation of the central block; the wells in the region are producing oil and gas condensate in the TAGI. From a geological side, the basin is of Intracratonic type, and it is located in the Northeastern part of the Saharan platform (Doghmane & Belahcene, 2019; Doghmane et al., 2019; Eladj et al., 2020; Ouabed & Chegrouche, 2013). It is defined as a flat basin with strongly planed Infra-Cambrian bedrock (Fig. 1).

2 Proposed Methods

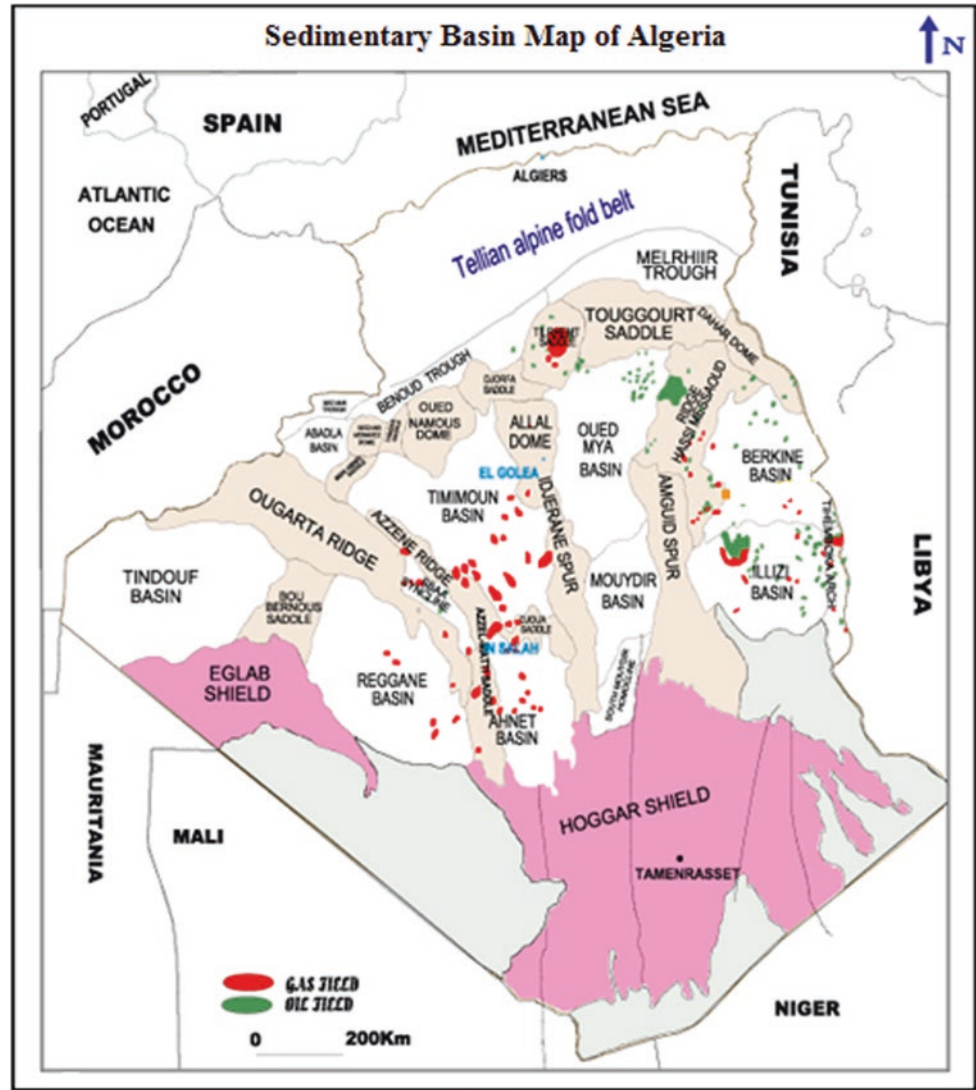
The proposed method is based on extracting tortuosity exponent m , the exponent a , and saturation exponent n as curves from logging curves (GR, Neutron-density, sonic) (Ouabed & Chegrouche, 2013). In the Archie equation, these parameters are considered constant for the whole reservoir section. It is valid only for homogeneous reservoirs, and for unconventional reservoirs with a high degree of heterogeneity, this assumption is misleading not only for the Archie equation but also for others like Simandoux, modified Simandoux, Waxman, Smith, etc. (Mithilesh et al., 2018). The coefficient a can also be called tortuosity factor, cementation intercept, lithology coefficient. It is used to correct for the compaction effect, grain size, and

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Fig. 1 Map of sedimentary map of Algeria containing Berkine Basin



pore structure. The stratigraphic study indicated that the lithology of the TAGI is very varying, thus considering the tortuosity as a constant factor which is not a practical assumption in this case due to strong diagenetic affinity and complex pore structures (Yisheng et al., 2019).

Many studies before have used an average value of tortuosity factor ranging from 1.8 to 2; however, due to the need for more precision, it was necessary to obtain the variation of this parameter all over the TAGI sections. The proposed equations are based on relating the arrival time of P and S waves to pore geometry, which can be quantified by its tortuosity; tortuosity values higher than one indicate non-regular geometry, while values close to one indicate regular geometry and homogeneous reservoirs. Based on the velocity calculated from sonic logs, and compensated for mud thickness and borehole geometry given by Eq. (1) (Nordahl et al., 2005).

$$\frac{1}{V} = \frac{\emptyset}{V_f} + \frac{1 - \emptyset}{V_{mat}} \quad (1)$$

where V is the sonic velocity calculated by measuring the travel time from the piezoelectric transmitter to the receiver, normally with the units microsecond per foot (a measure of slowness). V_f is the formation fluid velocity, V_{mat} is the matrix velocity, and \emptyset is the total porosity obtained from neutron-density logs. The mathematical equation used to calculate the petrophysical curves is given by Eq. (2) (Huawei et al., 2015; Ouabed & Chegrouche, 2013).

$$m = f(d, \Delta T_s, \Delta T_p, \emptyset_e) \quad (2)$$

where d is the depth, ΔT_s is the travel time of S waves, ΔT_p is the travel time of P waves, and \emptyset_e is the effective porosity calculated from logging data (Bacetti & Doghmane, 2020).

The proposed method has been applied to many wells in the basin; important results have been given in order to demonstrate the importance of the approach.

3 Results and Discussion

Figure 2 shows the matrix volume calculated by using the classical method (on the left) and the matrix volume after tortuosity corrections (on the right). The obtained matrix volumes have been compared to core data obtained from the laboratory, and it is clear that the corrections based on considering variable tortuosity have allowed obtaining more precise results in terms of reservoir evaluation since the volume was much more similar to the one obtained from core data and laboratory tests. Moreover, the model obtained using the three curves' generation was better representative and its usefulness was much more important than the model obtained by classical interpretation techniques.

4 Conclusions

The main goal of this research work was to generate the curves' tortuosity, cementation, and saturation exponents rather than considering them constant in a heterogeneous reservoir of Berkine Basin. This goal leads us to propose a mathematical approach that relates the logging curves to pore geometry; then, by extracting these curves, the evaluation of thin heterogeneous layers in the reservoir becomes more precise and not time-consuming. Moreover, the obtained matrix volume has been compared to the one obtained from core data and laboratory tests, and it has demonstrated the superiority of the proposed approach for such types of non-conventional reservoirs. Hence, based on the obtained results, it is highly recommendable to consider the tortuosity as a variable in evaluating other similar reservoirs in Algerian hydrocarbons fields.

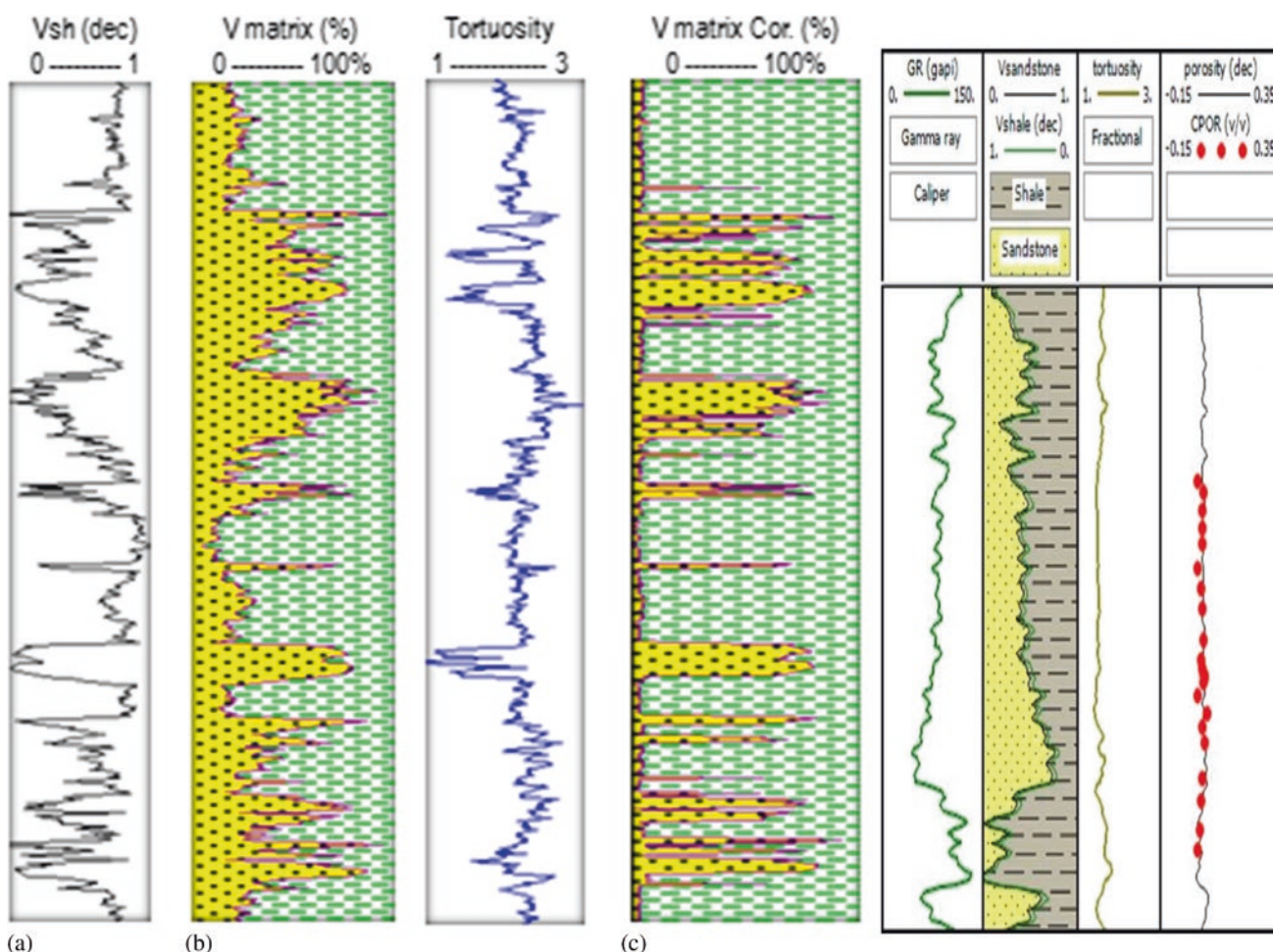


Fig. 2 Matrix volume: **a** without parameters curves' calculation, **b** with and without parameters curves' calculation, **c** porosity estimation with the proposed method

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