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Petrophysical studies of north American carbonate rock samples and evaluation of pore-volume compressibility models

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ABSTRACT

In this work, we evaluate two pore volume compressibility models that are currently discussed in the literature (Horne, 1990; Jalalh, 2006b). Five groups of carbonate rock samples from the three following sedimentary basins in North America that are known for their association with hydrocarbon deposits were selected for this study: (i) the Guelph Formation of the Michigan Basin (Middle Silurian); (ii) the Edwards Formation of the Central Texas Platform (Middle Cretaceous); and (iii) the Burlington-Keokuk Formation of the Mississippian System (Lower Mississippian). In addition to the evaluation of the compressibility model, a petrophysical evaluation of these rock samples was conducted. Additional characterizations, such as grain density, the effective porosity, absolute grain permeability, thin section petrography, MICP and NMR, were performed to complement constant pore-pressure compressibility tests. Although both models presented an overall good representation of the compressibility behavior of the studied carbonate rocks, even when considering their broad porosity range (~2–38%), the model proposed by Jalalh (2006b) performed better with a confidence level of 95% and a prediction interval of 68%.

1. Introduction

Increasing demand for hydrocarbons has resulted in greater interest in improving techniques for studying the behavior of oil reservoirs, which are complex systems with interacting rock/oil/water/gas and allow for the storage of fluid phases (Sok et al., 2009). Generally, efforts to characterize these reservoirs are based on descriptions of the spatial distribution of petrophysical parameters, such as porosity, permeability and fluid saturation (Harari et al., 1995; Lucia, 2007). These parameters are important for evaluating the properties of rocks regarding their transport of fluids and for improving knowledge of rock-fluid interactions that may influence the flow of hydrocarbons (Tiab and Donaldson, 2004).

In compaction or rock drive reservoirs, the movement of hydrocarbons toward the wellbore can be driven by an increase in the net confining pressure caused by the collapse of pore space (Tiab and Donaldson, 2004; Lucia, 2007; Oliveira et al., 2013). The degree of the resulting compaction depends on the compressibility of the rock. Compressibility is related to changes in volume and changes in applied stress. Rock pore-volume compressibility (C_{PV}; equal to the C_{PC} discussed by Zimmerman et al. (1986)) is a measure of the changes in pore volume caused by a change in applied stress (Chertov and Suarez-Rivera, 2014). For hydrostatic compression with a constant pore pressure (P_P), the pore-volume compressibility can be written as follows:

$$C_{PV} = -\frac{1}{V_P}\left(\frac{\partial V_P}{\partial P_c}\right)_{P_p} \tag{1.1}$$

where Vp = pore volume and P_c = confining pressure.

The compressibility value depends on the rock composition and depositional history. Despite the positive effect of compaction on production, the matrix permeability generally decreases as the pore spaces collapse, the cross-section of the pore throats decrease and the open fractures are closed (Doornhof et al., 2006), resulting in an increased resistance to the passage of fluid (Walsh, 1981).

Studies that estimate the evolution of rock pore-volume compressibility as a function of porosity play an important role in providing continuous C_{PV}-depth profile modeling soon after wireline logging procedures are concluded (Wolfe et al., 2005). A better understanding of its

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spatial variation is important for different aspects that are linked to reservoir management, such as pressure history matching and hydrocarbon production forecasting (Wolfe et al., 2005), geohazard evaluation associated with production and injection (Kvalstad, 2007) and changes in permeability during production (Petunin et al., 2011).

Thus, one central aim of the oil industry is to characterize the structure and dynamics of carbonate reservoirs. Carbonate reservoirs account for more than half of the world's proven oil reserves and have a high potential for gas exploration (Sok et al., 2009; Abdideh and Bargahi, 2012). However, the relationship between geophysical data and rock properties is complex for such lithologies, which is reflected in the elastic properties and conditions of the pore systems (Grechka, 2009; Weger et al., 2009). This complexity is explained by the great variety of textures presented by carbonate rocks, depositional processes, post-depositional diagenesis, and different chemical processes that are related to the formation of their constituent minerals (Sprunt and Nur, 1976; Lucia, 2007; Vanorio et al., 2008). These facts result in systems with pores present in the carbonate rocks, which are much more complex than commonly observed siliciclastic rocks (Moore, 2001; Croizé et al., 2010).

Therefore, studies aimed at estimating the pore-volume compressibility of carbonate rocks are particularly relevant for the oil and gas industry. Such importance can be highlighted by the efforts made over past decades for proposing different predictive analytical methods (e.g., Hall, 1953; Van der Knaap, 1959; Horne, 1990; Jalalh, 2006b). Such approaches could allow indirect assessments of recoverable oil volume and identify the best means for extraction (Laurent et al., 1993; Jalalh, 2006b). These approaches also provide clues for predicting the structural behavior of the reservoir, which can be used to help prevent reservoir collapse due to subsidence (Tiab and Donaldson, 2004; Oliveira et al., 2013). However, one of the most important debates in the literature is the extent of the applicability of such modeling methods due to the different petrophysical considerations that are inherent to each of the proposed formulations, which would be the most reliable method for a particular type of lithology.

In this study, we aim to investigate the petrophysical properties of carbonate rocks from North America from three distinctive geologic backgrounds (which are well known for their association with hydrocarbon reservoirs) and to determine the adequacy of the selected pore-volume compressibility models for modeling the resulting data. This approach could provide insights into the reliability of these predictive analytical models, which are currently used to evaluate the compressibility behaviors of carbonate reservoirs.

2. Compressibility Models

As previously discussed, the importance of C_{PV} assessment as a strategic information source for the oil industry has been highlighted in discussions that have occurred over past decades regarding the establishment of analytical methods for predicting pore compressibility as a function of confining pressure (e.g., Hall, 1953; Van der Knaap, 1959; Horne, 1990; Jalalh, 2006b). In one of the first approaches, Hall (1953) proposed an empirical relationship between C_{PV} and initial porosity (ϕ) based on a petrophysical analysis of reservoir rocks (sandstones and carbonates) using the following relation:

$$C_{PV}^{Hall\ (1953)} = \frac{2.587 \times 10^{-10}}{\phi^{0.4358}}\ Pa^{-1} \tag{2.1}$$

Since 1953, this method has been used in numerical simulations of reservoirs as the primary method for obtaining commercial and laboratory estimates (Li et al., 2004).

Horne (1990) observed behavior patterns of C_{PV} datasets as a function of initial porosity for consolidated sandstones and carbonates and for unconsolidated sandstones. Additionally, Horne (1990) proposed alternative empirical relationships for the different type of lithologies, which were widely adopted (Jalalh, 2006a). For consolidated carbonates, the proposed relationship is as follows:

$$C_{PV_{CARB}}^{Horne\ (1990)} = 1.4504 \times 10^{-10} \cdot \left[e^{4.026-23.07\phi+44.28\phi^2}\right] Pa^{-1} \tag{2.2}$$

However, as discussed by Jalalh (2006b), both methods must be applied with caution. For example, according to the method of Hall (1953), it is possible to obtain similar C_{PV} values for samples from different lithologies because the initial values of porosity are equivalent, despite any differences in the rigidity of the samples. Although Horne (1990) provided empirical relationships for distinctive lithologies, his work was based on estimates provided by Newman (1973), who assumed that the lithostatic pressure was 75% in $C_{PV} \times \phi$ calculations.

More recently, Jalalh (2006b) proposed two new formulations for estimating $C_{PV} \times \phi$ as alternatives to the method proposed by Horne (1990) by using a compilation of data published over past decades for different lithologies (Hall, 1953; Fatt, 1958, Van der Knaap, 1959; Dobrynin, 1962; Kohlhaas and Miller, 1969; Von Gonten and Choudhay, 1969; Laurent et al., 1993; Jalalh, 2006c). Such new methods were named the (i) “Horne modified method” (a variation of what was proposed by Horne (1990) and based on the non-linear regression curve fitting of the compilation data mentioned above) and (ii) a “new formulation” proposed by the author (through curve fitting of the non-linear, Farazdaghi and Harris (1968) method for the compilation dataset discussed above, and given by the following relation for carbonate rocks:

$$C_{PV_{CARB}}^{Jalalh\ (2006)} = 1.4504 \times 10^{-10} \cdot \left[\frac{1}{\frac{1}{(1.022)^2} + \frac{\phi^{1.05}}{(1.681)^2}}\right] Pa^{-1} \tag{2.3}$$

As discussed previously, one of the goals of this work is to verify the adequacy of the formulations proposed by Horne (1990) and Jalalh (2006b) for the patterns of pore-volume compressibility as a function of porosity datasets from carbonate rocks.

3. Geologic Background

Five groups of carbonate rock samples from the three following sedimentary basins of North America (Fig. 2.1) and with high economic interest because of their proven potential for oil exploration (Lona, 2006) were selected for this study: the Guelph Formation of the Michigan Basin (GD samples), the Edwards Formation of the Central Texas Platform (samples EW, EY and DP) and the Burlington-Keokuk Formation of the Mississippian System (BL samples). The general aspects associated with these selected geological settings are discussed below.

3.1. Guelph Formation, Michigan Basin

The Michigan Basin is an intracratonic basin that covers approximately 207,000 km^2 of the north-central portion of the United States and a portion of the province of Ontario, Canada, and comprises approximately 4800 m of predominantly marine sedimentary records (carbonates, evaporites and siliciclastic deposits) ranging from Cambrian to Pennsylvanian (Wylie and Wood, 2005; Dekeyser, 2006). As discussed by Coniglio et al. (2003), the carbonate deposits present in this basin are of particular interest because of their relationship with hydrocarbon reservoirs, which have been exploited for over a century (Zheng, 1999; Wylie and Wood, 2005). More recently, this region includes large aquifers, such as those observed southwest of the province of Ontario (Dekeyser, 2006). Therefore, studies have been conducted since the 1960s at the local and regional scales to obtain a better understanding of facies and diagenetic processes of Silurian reefs in the Michigan