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The effect of fluid pressure on the pore volume compressibility of carbonate reservoir samples using hydrostatic pressure

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ABSTRACT

Rock compressibility is directly affects the hydrocarbon production process in the reservoir and is controlled by elastic properties so for rocks with porosity values.

There are three different methods for measuring the pore volume compressibility. In the CMS (Core Measurement System) method, the pores are filled with helium gas; in the Overburden Rig method are in non-pressure brine saturated condition and in the RCS (Rock Compressibility System) method are in pressure brine saturated condition. In this study, pore volume compressibility was measured for three selected samples in all these methods.

As seen in all compressibility, a lower porosity has a higher compressibility ratio and sample with a higher porosity has a lower compressibility value in three instruments. Condensation in CMS and Overburden Rig by states is in a non-fluidized state and less than RCS method. Also the Overburden rig's compressibility is slightly higher than to the CMS method. The main result of this study is due to oil production and reduced of pore pressure, pore volume compressibility of reservoir have fast reduce in the initial productions and against to scale down to production flow.

Keywords: Compressibility, Carbonate, CMS, RCS, Fluid Pressure, Asmari Formation

INTRODUCTION

The rock compressibility is directly controlled by the elastic properties of the rock and the resistance of the rock matrix which also depends on the shape of the pores. Therefore for different rocks with the same initial porosity a rock that has a harder and more durable matrix has a lower compressibility than a rock with a weak skeleton. In the case of tensions beyond the yield of rock matrix compressibility is comprised of matrix compressibility and pore compressibility. In many cases the compressibility of the matrix at different levels of enclosing stress versus the compressibility of the pores can be neglected. This is especially true for rocks where intergranular porosity predominates.

The difference in overburden pressure and pressure of the reservoir fluid is called effective pressure which is the reduction of formation pressure due to the extraction of fluid from the reservoir thereby increasing the effective pressure and thus the compression of the reservoir so the reservoir rock always becomes denser with the pressure drop of the cavities. This reservoir condensation property which provides the necessary energy for the outflow of oil is of great importance in reservoir engineering studies.

Concerning the reservoir compressibility many theoretical and experimental studies have been carried out. Hall (1953) has described the reservoir rock congestion as an important factor in reservoir engineering calculations which in some cases is neglected.

Newman et al. (1973) have studied the compressibility of pore volume of reinforced and unconsolidated reservoir cavities under hydrostatic conditions.

Geertsma (1979) stated that there are three types of compressibility in the reservoir including matrix, bulk and pores rock. In the rock mass matrix C_S compression the rock mass volume change due to the application of unit pressure at the constant matrix compressibility temperature. And can be shown by equation (1):

$$C_S = -\frac{1}{V_S}\left(\frac{\partial V_S}{\partial P}\right)_T \quad (1)$$

In which, C_S is the compressibility of rock matrix, V_S its volume, and P is the pressure at the constant temperature of T.

Also for the bulk compressibility C_B the amount of rock bulk changes due to the application of unit pressure at constant temperature is defined by the rock bulk compressibility and can be shown by equation (2):

$$C_B = -\frac{1}{V_B}\left(\frac{\partial V_B}{\partial P}\right)_T \quad (2)$$

In which, C_B is the rock bulk compressibility and V_B is the bulk volume, and P is the pressure at the constant temperature of T.

ROCK PORE VOLUME COMPRESSIBILITY C_P

The highest pressure affected on rock pores. In all reservoirs, According to the definition of the amount of change in the volume of stone pores due to the application of unit pressure at constant temperature they are called the rock pore volume compressibility. In other words the porosity of the porous volume in any amount of effective pressure is the volume change per unit volume for a change in pressure of one unit. Because pore changes are directly related to porosity therefore we can show the equation (3):

$$C_P = -\frac{1}{V_P}\left(\frac{\partial V_P}{\partial P}\right)_T = \frac{1}{\Phi}\left(\frac{\partial \Phi}{\partial P}\right)_T \tag{3}$$

In which, C_P is the pore volume compressibility and V_P is the pore volume, Φ is porosity, and P is the pressure at the constant temperature of T.

One of the factors influencing rock compressibility is Poisson's ratio; it is a dimensionless quantity and can be obtained by using the velocity of V_P and V_S waves as follows:

$$\nu = \frac{0.5\times\left(V_P/V_S\right)^2 - 1}{\left(V_P/V_S\right)^2 - 1} \tag{4}$$

In general compressibility decreases with increasing Poisson’s ratio

EMPIRICAL CONJUGATION RELATIONSHIPS

If there is no access to precise data on congestion empirical relationships can be used so the choice of a close relationship to the reservoir conditions which minimizes the errors caused by this estimate should be considered. These relations are often presented as a function of rock porosity.

Hall (1953) presented an empirical relation for compressibility and porosity:

$$C_P = \left(\frac{1.782}{\Phi^{0.438}}\right)\times 10^{-6} \tag{5}$$

In which, C_P is the pore volume compressibility and Φ is porosity.

Newman (1973) presented an empirical relationship using data from 79 limestones and hardened sandstone:

$$C_P = \frac{a}{\left[1 + cb\Phi\right]^{\left(\frac{1}{c}\right)}} \tag{6}$$

In which, C_P is the pore volume compressibility, Φ is porosity and a,b and c are constants.

Horne (1993) gained the process of pore volume compressibility against initial porosity for consolidation limestone reinforced sandstone and unconsolidated sandstones:

For consolidated limestone:

$$C_P = \exp\left(4.026 - 23.07\Phi + 44.28\Phi^2\right)\times 10^{-6} \tag{7}$$

For consolidated sandstone:

$$C_P = \exp\left(5.118 - 36.26\Phi + 63.98\Phi^2\right)\times 10^{-6} \tag{8}$$

For un-consolidated sandstones (which is $\Phi \geq 0.2$):

$$C_P = \exp\left(534.01(\Phi - 0.2)\right)\times 10^{-6} \tag{9}$$

Jalalh (1981) conducted a study on 1-inch diameter and 3-inch lengths of rock plug samples measuring porosity of all samples by helium gas:

$$C_{P-Limestone} = \left(\frac{1}{1.022^{-2} + 1.681^{-2}\Phi^{1.05}}\right)\times 10^{-6} \tag{10}$$

$$C_{P-Sandstone} = \left(\frac{1}{2.141^{-2} + 4.064^{-2}\Phi^{0.4652}}\right)\times 10^{-6} \tag{11}$$

In which, C_P is the pore volume compressibility and Φ is porosity.

LABORATORY METHODS OF COMPRESSIBILITY

The application of force to the core of the reservoir rock can be applied to three style, one side (Uni-axial) three-sided (Tri-axial) or equal three-sided (hydrostatic) modes. The relationship between hydrostatic stress and uniaxial stress in rock samples is expressed in terms of equation (12):

$$\sigma_Z = \frac{\sigma_H}{3}\left(\frac{1+\nu}{1-\nu}\right) \quad (12)$$

In which, ν ισ the Poisson ratio, σ_Z is the uni-axial stress and σ_H is hydrostatic stress.

In this study three types of measuring instruments have been used to determine the compressibility although the basis of their measurement is based on the porosity variation (pores volume) according to the pressure on the sample. But the measurement method in these three devices is different under the following three methods are briefly explained. In order to compare the compressibility data in three experimental methods three carbonate samples with low porosity (6%) moderate (11%) and high (28%) of Asmari formation were selected from southwest of Iran.

Then each sample was prepared for porosity measurements under hydrostatic pressure conditions for Overburden Rig, CMS, and RCS instruments. It should be noted that the measurement of samples in the CMS instrument is a dry sample and the volume of the pores is measured using helium gas injection.

Then each sample was prepared for porosity measurements hydrostatic pressure conditions for Overburden Rig saturated with brine without any pore pressure and RCS instruments is pressurized saturated with brine.

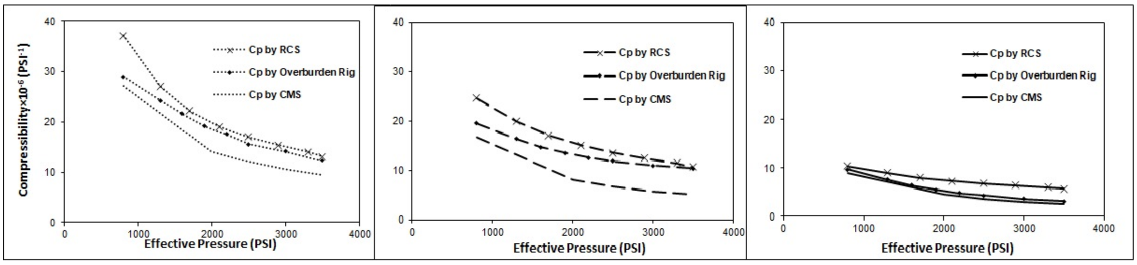

Figure 1. Comparison of the compressibility of sample number (a) 1 with porosity of 6.06% (b) 2 with porosity of 11.11% (c) 3 with porosity of 28.43%

CONCLUSION(S)

As shown in Figures 2(a), 2(b) and 2(c), sample No.1 with a lower porosity has a higher compressibility ratio and Sample No. 3 with higher porosity has a lower compressibility value.

Also in Figures 2(a, b and c) comparing the compressibility of a sample with all three methods shows that the amount of compressibility in RCS method has the highest value due to the presence of fluid pressure. Condensation in CMS and Overburden Rig wise modes is in a non-pressure fluid state and is less than RCS mode. Also amount of Overburden Rig is slightly higher than the CMS method because the sample is saturated with brine and the volume of effective pores is less than in comparison with the CMS method (dry sample).

The main result of this study is due to oil production and reduced of pore pressure, pore volume compressibility of reservoir have fast reduce in the initial productions and against to scale down to production flow.

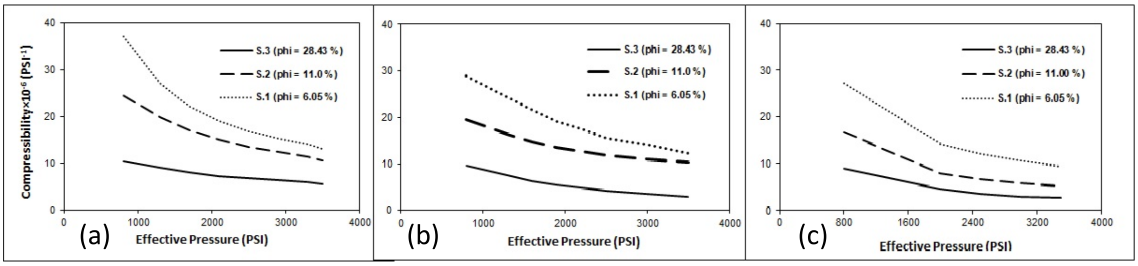

Figure 2. Condensation curve of three carbonate samples of Asmari formation using the results of (a) RCS (b) Overburden Rig (c) CMS instrument.

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