Elastic Property Modeling Related to Pore Type Analysis in Carbonate Reservoir

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Abstract. The reservoir has a significant role as a place of hydrocarbon accumulation in a petroleum system. Therefore, during exploration, a good understanding of the reservoir characterization becomes important to recognize the hydrocarbon migration path. There are several types of reservoirs which are commonly found; one of them renowned as carbonate reservoir. This type of reservoir is hard to be understood due to the heterogeneity of its pore type as a result of intense cementation and diagenesis. Information of pore type can be obtained based on core analysis or rock physics analysis. There are some rock physics approaches commonly used such as Kuster-Toksöz, Self Consistent Approximation (SCA), and Differential Effective Moduli (DEM). On the other hand, there are also other approaches but less famous. Parameters such as spherical porosity ($\phi_s$), pore shape parameters – pore shape factor ($S$) and relative pore shape factor ($\Delta S$) – are sensitive to identify pore type which may be developed in a carbonate reservoir. A positive value of $\phi_s$ and $\Delta S$ is the characteristic of carbonate rocks with the domination of stiff pore (high aspect ratio). These characteristics also can be informed by a value of $S > 1$. On the opposite, a negative value of $\phi_s$ and $\Delta S$ is the characteristics of carbonate rocks dominated by soft pore (low aspect ratio) that also can be informed by a value of $S < 1$. These parameters offer a simpler approach about pore type analysis and easier compared to Kuster-Toksöz in rock physics modeling. This research will use synthetic data to comprehend each parameters and real data to validate a hypothesis based on synthetic data. The results obtained in this study can be used as a first step to do seismic inversion based on the elastic property which is sensitive enough for this condition.

1. Introduction
In the petroleum system, the reservoir is known as a place for hydrocarbon accumulation. To be a good accumulation place, a reservoir must have a good quality of porosity and permeability. The development of porosity in the reservoir needs to be understood because it relates to the amount of hydrocarbon that can be preserved. There are several types of the hydrocarbon reservoir and a carbonate reservoir is known for its uniqueness due to the heterogeneity of porosity. This uniqueness can be simplified by using a parameter named spherical porosity [1]. This parameter can distinguish between spherical porosity and non-spherical porosity. The heterogeneity of porosity is also affecting the rock strength so that the velocity varies along with the composition of porosity. There are several rock physics approaches which can solve this problem such as Kuster-
Toksöz [2], Self Consistent Approximation (SCA) [3], or Differential Effective Moduli (DEM) [3] and they are commonly used.

On the other hand, some empirical approaches can be used to comprehend this problem by using parameters named pore shape factor [4] and relative pore shape factor [5], and these parameters are related to spherical porosity. The strength of these parameters are the required data is easy to acquire because it is commonly found in log data and the mathematical process to obtain the parameters is simple. In this research, the characteristic of these empirical parameters will be deeply discussed and their usage on identifying the variety of pore type in a carbonate reservoir.

2. Pore Geometry in Carbonate Rock
Carbonate rock is known by its variety of pore type due to intensive cementation and diagenesis. This condition is marked by a variety of sonic velocity value. For example, carbonate rock which contains stiff pores (i.e., moldic porosity and vuggy porosity) and interparticle porosity has a higher value of sonic velocity than carbonate rock that contains soft pores (i.e., intraparticle and micro pore) and interparticle porosity. The geometry of pore itself is described by the parameter aspect ratio. Aspect ratio is a comparison between the short axis to the long axis. The aspect ratio of the round pore is 1. As it got flatter, it has an aspect ratio less than 1.

The other way to know pore type in carbonate rocks is by using a parameter called spherical porosity ($\phi_S$). This parameter assumes a typical behavior for the primary host rock like the Wyllie’s time average equation [1]. Spherical porosity is defined as a fractional volume of spherical inclusions. The amount of primary porosity ($\phi_p$) left in the rock after the inclusion is related to the original of primary porosity (figure 1).

![Figure 1. Spherical inclusion model](image)

in terms of spherical porosity, it can be interpreted as,

$$\phi_s = \frac{\phi_B - \phi_p'}{1 - \phi_p'} \quad (1)$$

Bulk porosity ($\phi_B$) can be obtained from calculation of neutron – density log combination and $\phi_p'$ is calculated from Wyllie’s time average equation.

Velocity in carbonate reservoir can be predicted using a modification of Wylie’s time average equation by introducing an empirical parameter named as pore shape factor ($S$) [4]. This empirical parameter is related to spherical porosity. The formula of pore shape factor can be written as:

$$S = 1 + \frac{\phi_s}{\phi_B} \times \frac{6.5}{V_{\text{matrix}}} - 3\phi_s + 2\phi_B\phi_s \quad (2)$$

Sonic velocity of matrix ($V_{\text{matrix}}$) depends on fraction volume of rock minerals composition. Therefore, the modification of Wyllie’s time average equation will be:
As the sonic velocity of rock \((V_{P_{rock}})\) and sonic velocity of fluid \((V_{P_{fluid}})\) can be obtained based on log data.

Other parameter named relative pore shape factor \((\Delta S)\), which is derived from subtraction between pore shape factor to 1, is also introduced [5]. This parameter is able to recognize the continuous variation of pore shape from microcrystalline to spherical porosity with multiple pore structures. As these empirical parameters have a component of porosity, there is a possibility that they can identify pore type variation in a carbonate reservoir. In this paper, their abilities will be identified by comparing with parameter aspect ratio related to pore type analysis. Both synthetic data and real carbonate reservoir data will be used.

### 3. Methodology

As a way to understand the characteristic of every parameter on identifying pore type in carbonate reservoir, synthetic data about limestone is made. The data consists of several parameters such as the percentage of clay mineral, the percentage of non-clay mineral, porosity, density, the percentage of the soft/stiff pore. The assumptions are the rocks itself consist of two types of minerals; calcite and clay, and there is an oil presence. Data will be modeled using Kuster-Toksöz method [2] to obtain velocity reference using vary of aspect ratio as:

1. Aspect ratio of stiff pore = 0.9, Aspect ratio of reference pore = 0.1
2. Aspect ratio of stiff pore = 0.5, Aspect ratio of reference pore = 0.1
3. Aspect ratio of stiff pore = 0.3, Aspect ratio of reference pore = 0.1
4. Aspect ratio = 0.1 (100% reference pore)
5. Aspect ratio of soft pore = 0.05, Aspect ratio of reference pore = 0.1
6. Aspect ratio of soft pore = 0.03 Aspect ratio of reference pore = 0.1

Then, the reference velocity will behave as \(V_{P_{rock}}\) and is used to obtain parameters such as primary porosity, spherical porosity, pore shape factor and relative pore shape factor. As a result, there will be an information on how they interpret the changing of aspect ratio in carbonate rocks. Later, pore type analysis from real data is used to validate their ability.

### 4. Result and Discussion

Based on synthetic data modeling, primary porosity responses the changing of aspect ratio (figure 2). Primary porosity has a lower value if the rocks are composed of stiff pore (high aspect ratio value) and vice versa. Spherical porosity is also able to identify aspect ratio changing and has a better look than primary porosity. If spherical porosity has a positive value, it responses to stiff pore and vice versa. (figure 3).

Pore shape factor and relative pore shape factor also have a good sensitivity on identifying pore type changing. If the value of the pore shape factor is higher than 1 \((S > 1)\), it refers to stiff pore and if the value of the pore shape factor is lower than 1 \((S < 1)\), it refers to soft pore (low aspect ratio value). Positive value of the relative pore shape factor refers to stiff pore and vice versa. Although both parameters have the same sensitivity like spherical porosity to identify pore type, it is more difficult to obtained. A good correlation between reference velocity and modeled velocity is required to get these parameters. That is why, the weight factor used (Eq.2) need to be adjusted. Different condition has a different weight factor combination. This information will be use to analyze the type of pore in real data situation.
Figure 2. Comparison between porosity and primary porosity in different aspect ratio

The real data is carbonate reservoir which is dominated by bioclastic limestone, has a variety type of pore and has an oil presence. The compositions are dominated by calcite, dolomite, and quartz. The data is modeled using Kuster-Toksöz method to obtain the aspect ratio and compared
with the empirical parameters that are received from modified Wylie’s time average equation. The result shows that these empirical parameters have the same response as aspect ratio in identifying pore type as pore type in the research area is dominated by stiff pore (high aspect ratio) (figure 4).

![Figure 3](image1.jpg)

**Figure 3.** Parameters’ sensitivity in pore type analysis based on synthetic data with an aspect ratio (AR) as the color key

![Figure 4](image2.jpg)

**Figure 4.** Parameters’ sensitivity in pore type analysis based on real data with an aspect ratio (AR) as the color key

This result is also supported by petrography analysis, as the research area is dominated by the presence of moldic porosity and vuggy porosity (high aspect ratio), and less occurrence of intraparticle porosity (low aspect ratio). This domination does not continue vertically which is likely happen due to intense cementation and diagenesis as a result of sea level changes. These empirical parameters also can be used to identify some elastic moduli which are sensitive to pore type variation. Note that different research area or formation may have different elastic moduli which are sensitive to pore type development. Several elastics moduli that are sensitive to pore type variation (figure 5) are:

1. Comparison between bulk modulus dry over bulk modulus mineral \( (K_{dry}/K_{min}) \)
2. Shear modulus dry \( (\mu_{dry}) \)
3. Comparison between bulk modulus dry over shear modulus dry ($K_{dry}/\mu_{dry}$)

![Figure 5. Elastic Moduli’s Sensitivity in Pore Type Development in Research Area](image)

Although these parameters offer easiness on identifying pore type in carbonate rocks, the information that is gathered is only about the presence of stiff pore and soft pore. Information about the geometry cannot be predicted which is vital on pore type analysis. Therefore, the aspect ratio is still the best parameter to recognize pore type in carbonate rocks. But, as a beginning, spherical porosity, pore shape factor, and relative pore shape factor can be used as a quick view to identifying pore type development in the research area.

5. Conclusion
As a conclusion, the variation of pore type in carbonate rock can be recognized using several empirical parameters such as spherical porosity, pore shape factor, and relative pore shape factor, as the spherical porosity is the easiest parameter to be obtained. The others can be used to identify the pore type variation after adjusting the weight factor as a way to achieve a good correlation between reference velocity and modeled velocity. If the spherical porosity and relative pore shape factor have a positive value, and the pore shape factor is higher than 1, it refers to stiff pore (high aspect ratio) and vice versa. These parameters are also able to recognize the vertical continuity of specific type of porosity, as in the research area there is a vertical discontinuity which is likely happened due to sea level changing. They also can be useful to identify some elastic moduli which are sensitive to pore type changing although they may be different in other area or formation. Even though aspect ratio offers more information than the empirical parameters, they are useful as a quick look to identify pore type which is developed on the carbonate reservoir.

6. References
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