Integrated Analysis Seismic Inversion and Rockphysics for Determining Secondary Porosity Distribution of Carbonate Reservoir at “FR” Field

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Abstract. In general, carbonate secondary pore structure is very complex due to the significant diagenesis process. Therefore, the determination of carbonate secondary pore types is an important factor which is related to study of production. This paper mainly deals not only to figure out the secondary pores types, but also to predict the distribution of the secondary pore types of carbonate reservoir. We apply Differential Effective Medium (DEM) for analyzing pore types of carbonate rocks. The input parameter of DEM inclusion model is fraction of porosity and the output parameters are bulk moduli and shear moduli as a function of porosity, which is used as input parameter for creating Vp and Vs modelling. We also apply seismic post-stack inversion technique that is used to map the pore type distribution from 3D seismic data. Afterward, we create porosity cube which is better to use geostatistical method due to the complexity of carbonate reservoir. Thus, the results of this study might show the secondary porosity distribution of carbonate reservoir at “FR” field. In this case, North – Northwest of study area are dominated by interparticle pores and crack pores. Hence, that area has highest permeability that hydrocarbon can be more accumulated.

1. Introduction

Carbonate rocks are main host rock as hydrocarbon reservoir which is proved that make up almost 60% world’s reserves. Carbonate rocks are different from siliciclastic reservoir due to their depositional environments and significant diagenetic processes. Extreme diagenetic processes can change carbonate rocks’ initial texture. Thus, carbonate rocks have many variation of pore types, those are interparticle, intercrystal, vuggy, moldic, and cracks. This complexity can affect seismic wave velocities that propagate through carbonate rocks. Consequently, it causes great adversity of characterization carbonate reservoir.

Pore type inversion can be used for determining carbonate secondary pore types, such as Kuster–Toksoz (KT) and Differential Effective Medium (DEM). In 2016, there is a study that compare between Kuster–Toksoz and DEM method for determining secondary pore types. And the result shows that DEM method is better than Kuster–Toksoz method [1]. Hence, in this paper we apply DEM for analyzing pore types of carbonate rocks. The basic of DEM method is the input parameter is fraction of porosity and the output parameters are bulk moduli and shear moduli as a function of porosity, which is used as input parameter for creating Vp and Vs model [2]. Unfortunately, this kind of method...
is only high precision on longitudinal direction which is exactly at the position of well. For evaluating on lateral direction, we also apply seismic post-stack inversion technique that is used to map the pore type distribution from 3D seismic data quantitatively. We use several standard seismic post-stack inversion methods such as Model-Based, Sparse-Spike, and Band-Limited Inversion. Then, find which one has the best correlation coefficient between the predicted and measured P-Impedance. The best result of post-stack seismic inversion will be used as a trend for mapping the distribution of pore types. Due to the complexity of carbonate reservoir, it is better to use geostatistical method to get detailed result. In this study, the whole approach is using two well logs and post-stack 3D seismic data from carbonate reservoir at “FR” field which is located in the East Java Basin.

2. Methods

2.1. Rock Physics of Carbonate

Rock physics studies have shown that porosity is integrated with rock’s elastic properties. The equation of DEM method can be written as [3]:

\[
(1 - \phi) \frac{d}{d\phi} [K^*(\phi)] = (K_2 - K^*) P^{(2)}(\phi)
\]

\[
(1 - \phi) \frac{d}{d\phi} [\mu^*(\phi)] = (\mu_2 - \mu^*) Q^{(2)}(\phi)
\]

which has the initial conditions \( K^*(0) = K_1 \) and \( \mu^*(0) = \mu_1 \),

where:
- \( K_1 \): Matrix bulk moduli,
- \( \mu_1 \): Matrix shear moduli,
- \( K_2 \): Bulk moduli of inclusion phase,
- \( \mu_2 \): Shear moduli of inclusion phase,
- \( \phi \): Porosity,
- \( \phi_0 \): Incremental change in porosity,
- \( P^{(2)} \) & \( Q^{(2)} \): Geometrical factors depending on the aspect ratios of the initial conditions.

In general, steps of DEM method are the same with KT method which is needed the geometrical factors, matrix, and elastic moduli of inclusion as the input of DEM method. In this method, we follow Xu and Payne’s [4] extended Xu-White model of carbonate rocks, which the total pore space is divided into four components. Those are clay-related pores, reference pores, stiff pores, and crack pores. The first step, we obtain the elastic moduli of the solid rock matrix by using Voigt-Reuss-Hill average method. In this step, we mix minerals in the rock which the clay-related pores with water will be included in the solid material. The second step is we add three geophysical pore types using DEM method. Then, we obtain the dry bulk and shear moduli. The difference between KT and DEM method is DEM do not need to loop aspect ratio, but need to determine it as the input. Zhao Classification is used as fundamental of the determination of three value of aspect ratios. The aspect ratio of interparticle pores (reference pores) is range from 0.12 – 0.15. The aspect ratio of stiff pores is range from 0.7 – 0.8, and the aspect ratio of crack pores is range from 0.01 – 0.02. In this step, we also model the fluid modulus using Wood’s suspension model which the fluid saturation effect is also considered. Afterward, Gassmann’s method is discharged to substitution the fluid and the elastic response of saturated rock be calculated. The schematic rock physics modelling steps are shown in figure 1. The final step is calculating the Vp-reference that the result of DEM equation is as the input.
Vp-reference plays an important role on determining between stiff pores and crack pores. If the Vp-measured is higher than Vp-reference, stiff pores are presented. But if the Vp-measured is lower than Vp-reference, crack pores are performed. If all the process has been done, then compare Vp-reference with Vp-measured. Then find the best correlation coefficient which is presented the best illustrative model. Those models will be changed continuously as parameters are adjusted. The output of this process will be used as the input of the petrophysical modeling process for mapping the distribution of the carbonate’s pore types.

2.2. **Post Stack Seismic Inversion**

In general, seismic inversion is defined as a technique that helps to build model of physical characteristics of rocks and fluids by using seismic data and well data as the input. The output of the inversion process are acoustic impedance model, pressure velocity (Vp) model, and density model. The acoustic impedance model is determined by approximating acoustic impedance over the whole seismic section by using Kriging interpolation technique. Generally, the workflow all of the post stack seismic inversion are the same. We extract wavelet from seismic data statistically. Seeing that seismic data has negative polarised which shows increasing acoustic impedance as trough, so the wavelet is decreased polarised.

2.3. **Petrophysical Modeling**

The best result of post stack seismic inversion is used as the secondary variable or trend for mapping the distribution of carbonate’s pore types. It is better to use geostatistical method due to the complexity of carbonate reservoir. Sequential Gaussian Simulation (SGS) method is used for distributing the porosity. SGS method calculates statistically to predict undefined points. Before we apply the petrophysical modeling process, there are several steps that we must do. First step is conduct each of horizons to make map structure. Then, make a simple grid based on the map structure that have been made. The next step makes a zone between horizons as a reservoir zone. Afterward, apply layering process to the zone that have been made. This process is needed to make a lot of thinned layers on the reservoir zone. Therefore, the detailed property distribution will be achieved. The thickness of the layering is performed as the thickness of cell, in which that thickness is as the average interval of property well log that will be modeled later. Afterward, apply scale up well logs process to property well log that will be modeled. The objective of this process is to input the property data from well log into 3D grid model. Then, we need to analysis the direction of distribution of the porosity which the azimuth of the direction of distribution will be used as the input on petrophysical modeling process later. The next step is resample the result of post stack seismic inversion that will be used as the secondary variable for mapping the distribution of carbonate’s pore types. The final step is apply petrophysical modeling for distributing the porosity log and also the pore types log that we got from rock physics inversion process. The input is upscaled property well log, the azimuth of the direction of...
distribution, and post stack seismic inversion as the secondary variable. Then, the map of distribution of carbonate’s pore types is achieved.

3. Results and Discussion

3.1. Rock Physics Inversion

The aspect ratio of interparticle pores, crack pores, and stiff pores are 0.15, 0.02, and 0.8, respectively. Crossplot between Vp-measurement and Vp DEM for each wells are required for making sure that the effective moduli using DEM has closed to the real data. The crossplots are given RMS error under 0.03. The lowest RMS error value prove that the effective moduli using DEM method has closed to real data. Afterward, secondary pore types of carbonate rocks have been analyzed for each wells. It is shown in figure 2, figure 3, and figure 4. Red colour is presented as crack pores, white colour is presented as interparticle pores, and blue colour is presented as stiff pores. At FR-01 well, the log clay indicate that rock formation still contains clays. On the other hand, the log clay content curves of FR-02 and FR-03well indicate that rock formations do not contain clays. It may say clean formation. Only a few thin layers of clay exist in the FR-02 well. Figure 2 shows that crack pores are more dominant than stiff pores at FR-01 well. At depth 9200 – 9400 ft, it is indicated the presence of thick layer of stiff pores. Thus, hydrocarbon will not be accumulated in that layer. At FR-02 well are performed that crack pores are more dominant than stiff pores as well. Stiff pores also exist at depth 8400 – 8650 ft, but they are not as much as crack pores. Figure 4 shows pore types of FR-03. Unlike FR-02, at FR-03 well stiff pores are more dominant than crack pores. Percentange of stiff pores at FR-03 is extremely high. Due to FR-02 and FR-03 well are exactly at the same crossline, so we assume that distribution of pore types will be complex at that crossline. The pore type estimation of both wells is confirmed by the identical and almost matching of the curve of log Vp model and log Vp measurement (see the Log Vp curves in figure 2, figure 3, and figure 4).

![Figure 2](image_url)

*Figure 2. Pore types of FR-01 well which are dominated by crack pores rather than stiff pores.*
Figure 3. Pore types of FR-02 well which are dominated by crack pores rather than stiff pores.

Figure 4. Pore types of FR-03 well which are stiff pores more dominant than the crack ones.

3.2. Seismic Inversion

Before we apply inversion process, we need to make sure that correlation between real seismic trace and synthetic seismic trace has already achieved the lowest misfit between two traces. The correlation is applied using two wells available in the study area and shows good result. FR-03 well cannot be applied this step. Due to FR-03 well is shallow, only 100 – 200 ft in depth, it cannot be applied seismic-well tie. Therefore, we use geostatistical method for distributing porosity on petrophysical modeling, in which calculates statistically to predict undefined points. For FR-01 well, its correlation is about 0.586, and for FR-02 well, its correlation is about 0.685. The correlation is applied from ± 100 ms above the upper of the well tops until the base depth of well. The initial acoustic impedance
model is built using the interpolation along the seismic horizons as a guide and each well locations into the crosslines and inlines. The initial model is applied by using 10/15 Hz filter. It means that impedance above 15 Hz will be cut. Only impedance in range frequency below 15 Hz is required for building the initial model. Thus, high frequency is not allowed while building initial model process, in which seismic only concern impedance with low frequency.

The correlation coefficient of each inversion methods are compared to get the best result of post-stack seismic inversion. The correlation coefficient is controled by input parameters of each inversion methods until the trace of predicted and measured P-Impedance is fit. All of post-stack seismic inversion methods generate reliable results and clearly confirm the presence of reservoir. Model based hard constraint inversion method shows higher correlation coefficient (0.994) than soft constraint inversion (0.952). On the other hand, sparse-spike inversion method shows 0.966 of correlation coefficient and band-limited inversion method shows only 0.908 of correlation coefficient. Therefore, the inversion that is used for the secondary variable of petrophysical modeling is model based hard constraint. We use model based hard contraint instead of soft constraint, since that correlation coefficient is higher and the hard constraint method is more accurate seeing that well log plays a role in inversion process. The result of model based hard constraint is shown in figure 5.

Figure 5. The seismic section as result of model based hard constraint.

Arbitrary line is build from South to North of the study area. The result shows that acoustic impedance is increased by increased depth. The increasing acoustic impedance is due to the density of carbonate rocks (2.3 – 2.8 gr/cm³) are higher than shale (1.9 – 2.7 gr/cm³). Hence, P-wave propagate faster through carbonate rocks since wave needs medium to propagate. Futhermore, due to the high chemical reactivity of carbonate material, carbonate rocks constantly experience cementation, dissolution and dolomitization, which are influenced by pressure, water depth, and temperature. Cementation process is also influenced the increasing acoustic impedance which makes carbonate rocks tighter. Moreover, the arbitrary line result shows acoustic impedance at North of study area is higher than South area.

3.3. Petrophysical Modeling
The pores distribution is divided into three categories. They are interparticle pores, stiff pores, and crack pores. From figure 6 that shows PHIT (total porosity) variance contour map, we can know the distribution of porosity at our study area is from Southwest to Northeast with angle 66 degrees. PHIT as a total porosity describes clay content inside the pores of carbonate rocks. Vertical distribution of PHIT along the section is shown in figure 7. It shows that North to North West of study area has highest porosity. The permeability at that area is good, so hydrocarbon will be more accumulated inside the pores of rocks. On the other hand, Southeast to Northeast of study area is indicated that
porosity are decreased. It shows that the area are dominated with tight carbonate which has been compacted due to the diagenesis process. Therefore, hydrocarbon might be rarely found around that area.

![Figure 6. PHIT variance contour map.](image)

![Figure 7. Distribution of PHIT along the line.](image)

As mentioned above, the objective of this research is not only determine the secondary pore types in carbonate reservoir, but also map the distribution of each secondary pore types. The distributions are shown in figure 8. It shows that North to Northwest of study area are dominated with interparticle pores and crack pores. Stiff pores are not found at that area. Therefore, that area has highest permeability that hydrocarbon can be more accumulated. At West to South West of study area, it shows interparticle pores and crack pores are still dominant. But, stiff pores has already existed. Hence, it is indicated that hydrocarbon accumulation is less than North to North West area. On the other hand, interparticle pores and crack pores are slightly decreased at South to North East of study area. We assume that area has slowly cemented. Thus, rarely found the presence of hydrocarbon in that area due to poor permeability.

![Figure 8. Distribution of the secondary pore types of (a) Interparticle; (b) Crack; and (c) Stiff.](image)

Figure 9 shows the distribution of interparticle pores, crack pores, and stiff pores at crossline of FR-02 and FR-03 well. As mentioned above, due to FR-02 and FR-03 well are exactly at the same crossline, so we assume that distribution of pore types will be complex at that crossline. The
distribution result prove our assumption. In one layer of carbonate reservoir can contain several kind of secondary pores. Interparticle pores and crack pores are found at the upper side of reservoir. But the lower side is dominated by stiff pores. It shows that hydrocarbon will be accumulated at the upper side of the reservoir, due to higher permeability and porosity.

![Image showing distribution of secondary pore types at crossline FR-02 and FR-03 well: (a) interparticle; (b) crack; and (c) stiff.](image)

**Figure 9.** Distribution of secondary pore types at crossline FR-02 and FR-03 well: (a) interparticle; (b) crack; and (c) stiff.

4. Conclusion
In one layer of carbonate reservoir can contain several kind of secondary pores. Therefore, determination and mapping of distribution of secondary pores are important process for identifying good reservoir where has higher porosity and permeability. In this case, North to Northwest of study area are dominated by interparticle pores and crack pores. Thus, that area has highest permeability that hydrocarbon can be more accumulated.

5. References
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