A Case Study of Subsurface Uncertainty Analysis in Modelling Carbonate Reservoir

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Abstract. High risks exist in the development of the offshore carbonate oilfield which is discovered by two wells and complicated by fractures. Quantification of the impact of various subsurface uncertainties in the carbonate oilfield is crucial for decision-makers to carry out any field development. A comprehensive modelling methodology is documented to capture a range of subsurface uncertainties of dual-medium reservoir. Matrix porosity model is created constrained by seismic inversion. The macro- and micro-discrete fracture models are built based on the seismic data, core sample and FMI data and are upscaled into the matrix model to generate dual-medium model. Sensitivity analysis and uncertainty workflow are conducted to evaluate the impact of parameters (such as structure, fluid contact and fracture aperture) on reservoir volume and to generate multiple static model realizations. The probabilistic STOIIP of these models is performed and the high, middle and low case geological models are selected for the further reservoir simulation. Sensitivity analysis shows that oil–water contact and structure have the most impact on STOIIP in the field and the matrix water saturation, fracture aperture, and matrix porosity have moderate impact. The minor parameters are fracture water saturation and Bo. It seems that more new data should be gathered and structure interpretation needs to be refined to narrow the OWC, structure and fracture uncertainties. The practice in the carbonate reservoir conducts an integrated uncertainty workflow and

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provides a useful reference to the subsurface uncertainty analysis on dual-medium reservoir.

Keywords: Uncertainty · Sensitivity analysis · Fracture model · Stochastic model · Carbonate · Volume calculation

1 Introduction and Background

The oilfield is located in Song Hong basin, offshore Vietnam and the water depth between 25 and 30 m. It is a proven pre-Tertiary carbonate play with two wells discovered in 2008. The pre-Tertiary carbonate is eroded at the top and overlayed mudstone, siltstone and coal of lacustrine deposition of Eocene/Oligocene (Fig. 1). The structure is formed as the results of a number of tectonic events such as regional uplift and extension creating a series of horst and grabens. It is a carbonate anticline hold by normal faults in NE–SW trend. The oilfield covers the area of 5.3 km^2 and the carbonate thickness is about 470 m.

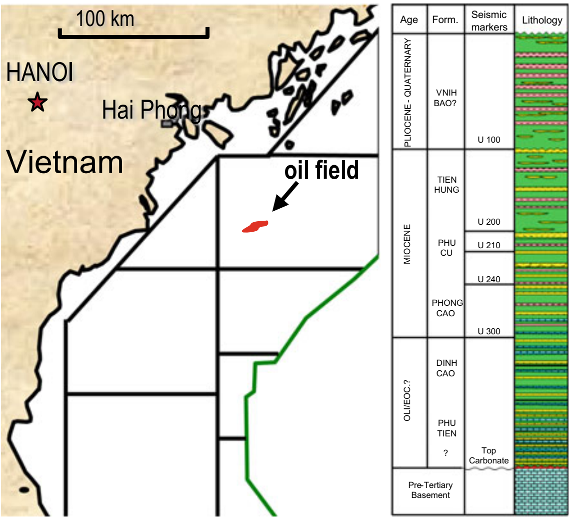

Fig. 1. Location map of the oilfield and generalized stratigraphic column

By now, only two wells are in this oilfield. Well R1 is drilled 3 m into the top of carbonate and then abandoned. The test oil is 4859 bbls/d and gas 170,000 scm/d. Well R2 is drilled 382 m carbonate and 20 m shale down without water encountered. The test oil is 5938 bbls/d and gas 222,000 scm/d after acidizing. Side wall core (SWC) samples show that the reservoir characteristic is tight, fractured carbonate reservoir with muddy facies dominant and the main lithology is dolomite and limestone.

Dolomite and limestone can be clearly distinguished using PEFZ log (Fig. 2). RHOB shows reduction in density spikes where impurities such as carbonaceous materials are present. Internal variations are expected in the reservoir where some may act as flow barriers.

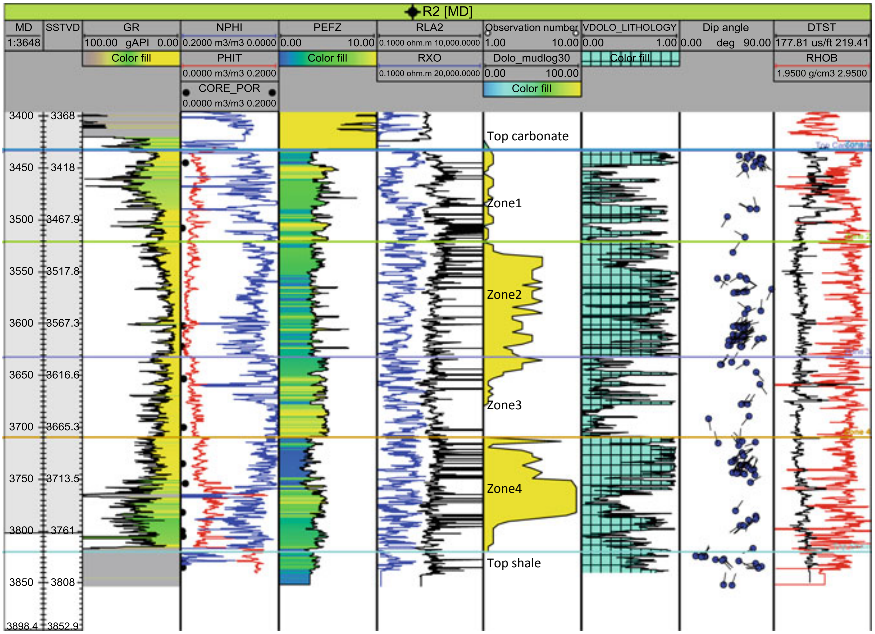

Fig. 2. Wireline log characters of well R2

Four zones are interpreted from the well logs. Zone 1 is mainly limestone with some dolomite layers. Zone 2 is predominantly dolomite. Zone 3 is predominantly limestone. Zone 4 is mainly dolomite with some thick succession of limestone and possible exists permeability barriers.

Well-log interpretation shows that the matrix porosity is between 2.6–3.7% with the average of 3.1%. The matrix water saturation is between 22.3–49.2% with the average of 35.1%. Permeability is 0.47 mD before acid and 14.7 mD after acid. FMI in carbonate reservoir shows that the fractures are abundance with NW–SE trend and medium high angle. The dual-medium reservoir belongs to low porosity, low permeability and thick carbonate.

3D seismic data are gathered but have relative poor resolution in the carbonate reservoir. The main frequency is lower and the seismic events are broken which is difficult to identify the zone interfaces (Fig. 3).

Due to the complex reservoir architecture, seismic imaging difficulties and data shortage, the qualitative and quantitative evaluation of the pre-Tertiary carbonate reservoir is the essential for the field develop plan. The paper summarized a comprehensive workflow to evaluate the subsurface uncertainties for this dual-medium reservoir.

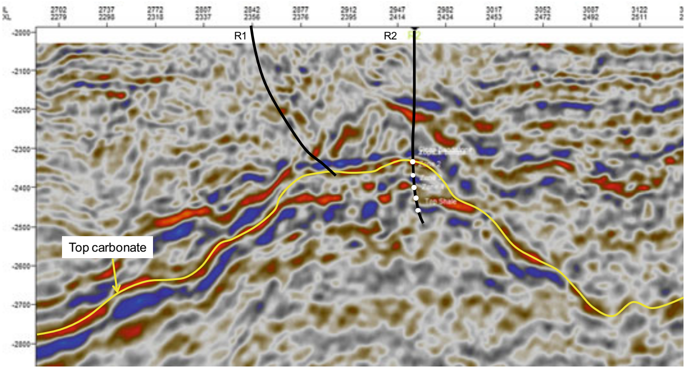

Fig. 3. Seismic section between two wells

2 Methodology and Workflow

The methodology is carried out in two steps. A static model including matrix and fracture is constructed in the first step and, in order to obtain results with less errors, uncertainty analysis of the resulted model is carried out in the second step.

2.1 Matrix Model Building

The lithology percentage model is generated constrained by the seismic impedance inversion.

The porosity log is interpreted using sonic and/or density logs. The porosity model is generated using sequential Gaussian simulation (SGS) method constrained with the impedance data for each lithology [1].

The matrix SW data are interpreted using Archie formula in the well log interpretation, and a constant value is set for the matrix SW in the geological modelling just for simplification in this study. The matrix permeability is generated using the formula considering the porosity and irreducible water saturation [2].

The matrix volume of oil in place (STOIIP) is calculated with the following formula adding the contributions of each cell in the model.

$$\mathrm{STOIIP} = \sum_{i=1}^{n} \left(V_i * \mathrm{NTG}_i * \varphi_i * (1 - \mathrm{SW}_i)/\mathrm{Bo} \right) \tag{1}$$

where V_i is the rock volume above oil–water contact (OWC), φ_i is the porosity, n is the number of cells, NTG is net to gross, SW is the water saturation and *Bo* is the oil formation volume factor. The NTG is determined based on the cut-offs of the porosity parameter.

2.2 Fracture Model Building

From the tadpole and polar frequency plot analysis on the fracture data interpreted from the FMI data, the classification of fracture sets and the dip, orientation and aperture of each fracture set can be acquired.

Fracture intensity log is then calculated from the FMI interpreted data and the intensity model is built considering the seismic impedance, structure curvature, variance, fault distance and ant tracking data [3]. This intensity model is used to constrain the distribution of fracture sets in the fracture modelling. Fisher model is used to describe the distribution of the fracture dip and azimuth. Log-normal distribution is set for the distribution of fracture aperture with specified mean and standard deviation.

Together with the orientations, geometries and fracture apertures of each fracture set, the discrete fracture networks (DFN) model of all fracture sets is generated and the correspondence fracture porosity and permeability can be also calculated.

2.3 Dual-medium Model

The dual-medium model is generated by upscaling the DFN model into the matrix model. Fracture porosity, permeability and sigma factor are calculated by applying the filtration theory between matrix and fracture when upscaling. The fracture SW is defined as a lower constant value for the fewer irreducible water in the fracture. With the matrix porosity and permeability, the three-dimensional integrated geological model of the dual-medium reservoir is obtained. The STOIIP of the reservoir is the summary of the volume in matrix and the volume in fracture sets. The STOIIP of fracture sets is calculated using the same formula as that of matrix, but with the upscaling fracture porosity, fracture water saturation, and fracture NTG which is 1 for fracture sets.

2.4 Uncertainty Analysis

For the limited data and complex heterogeneities, great risk and high challenge exit in the geological modelling procession. In the procession of building, a geological model a thorough subsurface evaluation is necessary including seismic data interpreting, time-to-depth conversion, well-log data interpreting, 3D property model building and fluid contacts estimating [4]. It is important to acknowledge that at each step there are uncertainties, not only in the data that are used, but also in the interpolation of the data.

In this study, the main uncertainties included in the reservoir volume analysis are structural uncertainty, fluid contact uncertainty and properties uncertainty.

1. Structural uncertainty

The main sources of structural depth uncertainty are related to the seismic data interpretation and time-to-depth conversion using the velocity model [5].

Time interpretation uncertainty for horizons and faults is usually defined by small time shifts of horizon and fault interpretation. The time shift can vary laterally to reflect varying quality of the seismic response.

Uncertainty in the velocity model is referred to the parameters used when building the velocity model (i.e. v0, k, etc.). Different parameters used in the velocity model may change the structure intensely.

In this study, the structural uncertainty can be handled in a simplified method by creating stochastic error surfaces, which in turn will be added to the base case surface. Typically, for the uncertainty on a surface, the uncertainty is essentially zero at the control points (well locations) and varies smoothly away from the wells. The variance depends on the quality of the data and the distance from the wells (Fig. 4).

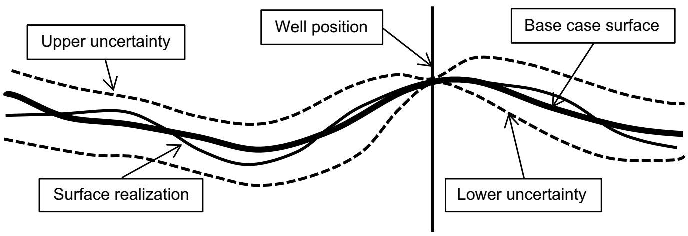

Fig. 4. Structural uncertainty analysis

The stochastic structural uncertainty is based on the equation:

$$Sr = Sbc + U1s * Ug \tag{2}$$

where

Sr is the surface realization to be used in model building.

Sbc is the base case surface calculated without uncertainty.

$U1s$ is the one standard deviation depth error on the base case.

Ug is the random surface created by SGS with mean = 0, std. dev = 1 and has zero value at control points.

Since Ug has values around zero, the product of $U1s$ and Ug will vary across the surface, sometimes being positive, sometimes negative. When this stochastic error level is added to the base case surface, it will produce a new version of that surface, which in some places is shallower, and in other places deeper, than the base case surface.

The initial seed input in the SGS algorithm is defined as the uncertainty parameter. Variable seeds can result in variable surface realizations to evaluate the structural uncertainty analysis.

2. Fluid contact uncertainty

Fluid contact is a common key parameter for the volume calculation. The "oil down to contact" (ODT) or the lowest hydrocarbon contact (LKH) can be identified from DST or PLT data. The volume above these values is defined as the STOIIP in the volume calculation.

Often the fluid contact is different in different wells in the same segments, thus the fluid contact may be set as a range to define the fluid uncertainty.

For this anticline reservoir, the structure spill point can be regarded as the possible lowest fluid contact when no water is encountered in the wells. However, modelling of the structural uncertainty would introduce the uncertainty in the corresponding spill point depth. Thus, the spill point should be picked just following a generated realization of structure model and this spill point data should be set as maximum fluid contact in the whole uncertainty analysis.

3. Property uncertainty

The properties (porosity, SW, Bo, etc.) uncertainties are occurred not only by well data interpretation, but also by modelling the areal distributions of these properties [6].

In the matrix porosity modelling procession, SGS method is used and constrained by other property cubes such as facies model or impedance model. Many parameters input in the SGS can be set as variables for uncertainty analysis (i.e. variogram types, anisotropy ranges, orientation, seed number) [7]. In this study, the seed number is set for matrix porosity uncertainty. The seed defines the start for the random number generation in the algorithms and the changing of the arbitrary seed values in the SGS will generate numerous realizations for the uncertainty analysis.

Fracture porosity is obtained by upscaled DFN model in which the aperture has directly impact on the porosity. So in the fracture modelling, the variable fracture aperture can be an uncertainty parameter to analyse the fracture uncertainty.

The matrix SW is calculated using Archie formula in the well interpretation, in which the cementation exponent, the saturation exponent and tortuosity factor are difficult to define for the complex pore structure and types. For the fracture SW, it is considered that fewer irreducible water exists in the fracture and the fracture is filled with oil with high oil saturation above oil–water contact. Thus, the range of the matrix and fracture SW can be defined for the volume uncertainty analysis.

For the Bo from PVT data, the uncertainty is relatively small and mainly due to the uncertainties in the lab results. Usually, it is set as a constant value and a range can be defined for the uncertainty analysis.

4. Sensitivity analysis

The purpose of sensitivity analysis is to identify the parameters which strongly influence on results of the given model and further analyse the trends of these correlations. An integrated workflow for sensitivity analysis is put forward in commercial three-dimensional geomodelling software in this study. The workflow includes structural modelling, matrix property modelling, DFN modelling, fracture model upscaling and volume calculation. The workflow is run by successively selecting one variable at a time from the set of all uncertain variables and changing its value while keeping the others fixed at their base values. This is done for each uncertain variable in turn. The results are shown in tornado chart in which the major elements can be identified.

5. Uncertainty analysis

The uncertainty analysis uses almost the same workflow of sensitivity analysis. Instead varying one parameter in one loop in sensitivity analysis, the uncertainty analysis varies all parameters in a workflow run. Each parameter gets value from its assigned distributions. The uncertainty analysis investigated the effect of the various variables simultaneously in the series of experimental runs. The volume distribution can be generated from the volume reports of the numerous stochastic realizations. The probabilistic models can also be selected from the total model outputs to represent low, middle and high cases for reservoir simulation [8].

3 Results and Discussion

The reference-case static geological model is firstly constructed to model an interpretation of the most likely distributions of reservoir geological properties and parameters.

3.1 Structural Model

Although four zones are interpreted in the well R2, no clear events can be picked for the zones from the poor seismic data. Only the interpreted top carbonate surface and the top shale surface are introduced in the structural modelling for the reference-case model in Petrel software. Four zones are then built in the zonation procession. A total of eight faults are modelled. The structure is an anticline striking nearly northeast to southwest steepened in the south and north, and a spill point exists in the east (Fig. 5). The geological model contains 99 cells *65 cells in horizontal with 50 m * 50 m

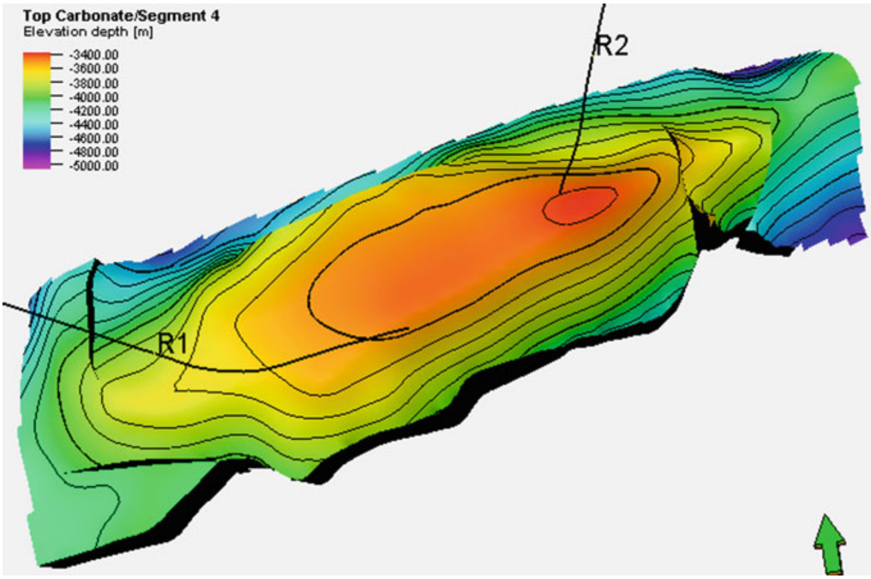

Fig. 5. Structural model

resolution. In the vertical direction of the model, the four zones are divided into 500 layers proportionally with the average cell thickness of 0.75 m. The total number of the model cells is 3,217,500.

3.2 Matrix Model

Based on the lithology interpretation results, the impedance inversion data have been conducted to get the trend distribution of the dolomite and limestone at first. Then the reference-case matrix porosity model is generated using SGS method constrained with the impedance data to delineate the porosity distribution for each lithology (Fig. 6). It can be seen that higher porosity presents in the Zone 4 and Zone 1 and lower in Zone 3.

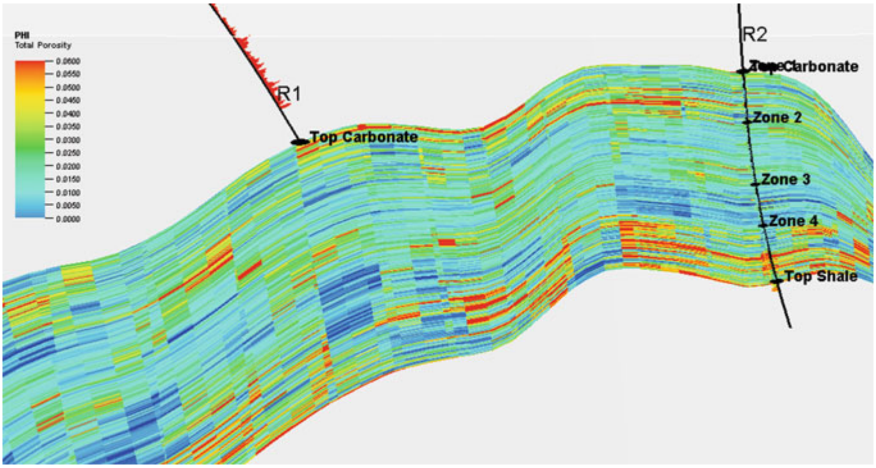

Fig. 6. Matrix porosity section between two wells

The NTG model is determined based on the cut-off value of the porosity parameter. Here the cutoff value is 2% which is defined from flow studies. SW is 25% and Bo is 1.68 for the reference-case matrix geological model.

3.3 Fracture Model

Two-scale fractures are classified in the study. The macro-facture is referred to the faults which could be interpreted from seismic data or some faults which can be identified by ant tracking in Petrel. Ant tracking shows lineaments mostly trend NW–SE and a few trend E–W, which correlate with regional faulting trends as well as fracture orientation from FMI. These macro-factures can be modelled by deterministic method in the structural modelling [9].

The micro-fracture is related to the interpreted fractures from FMI data. The FMI interpretation results show that fractures are well developed in the carbonate reservoir and the dolomite is fractured more intensively than limestone. Tadpole and polar frequency plot show that four micro-fracture sets exit in the reservoir (Fig. 7).

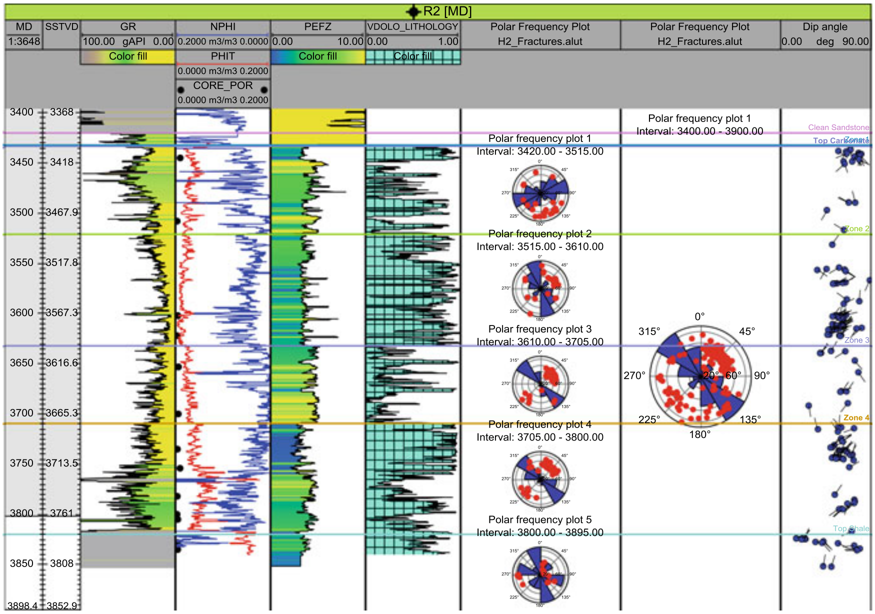

Fig. 7. Well log interpretation and polar frequency plot

1. Fracture set 1 is developed in Zone 2, Zone 3 and Zone 4. The fracture dip angle varies from 30° −70°, and azimuth from 15° −80°. This fracture set 1 is more observed in FMI than other sets.
2. Fracture set 2 is developed in Zone 1 and Zone 4 with the dip angle from 20° −80° and azimuth 300°−340°.
3. Fracture set 3 is presented in Zone 1, Zone 2 and Zone 3. The dip angle ranges from 50°−80°, and azimuth is from 120° −180°.
4. Fracture set 4 is developed in all the four zones. The dip angle is from 45°−75°, and azimuth is from 180°−270°.

The fracture aperture can also be calculated from the FMI considering the SWC data. The average aperture is 0.03 mm and can be maximum to 2 mm or even bigger.

The DFN model is generated for all the four fracture sets. The fracture plane is treated as rectangle in geometry and the elongation ratio is set to 2. The fracture length is defined to follow the log-normal distribution with mean of 50 m. The fracture orientation follows the Fisher model with the mean dip and azimuth. The fracture aperture follows log-normal distribution with the mean of 0.03 mm. Figure 8 is the intersection cut through the fracture planes of the generated DFN model. The well log is the interpreted dolomite percentage. The background is dolomite percentage model, in which the warm colour means high dolomite percentage. The red sticks are fracture planes of the four fracture sets. It can be seen that more fractures are presented in the high dolomite percentage area and more fractures developed in the Zone 2 and Zone 4.

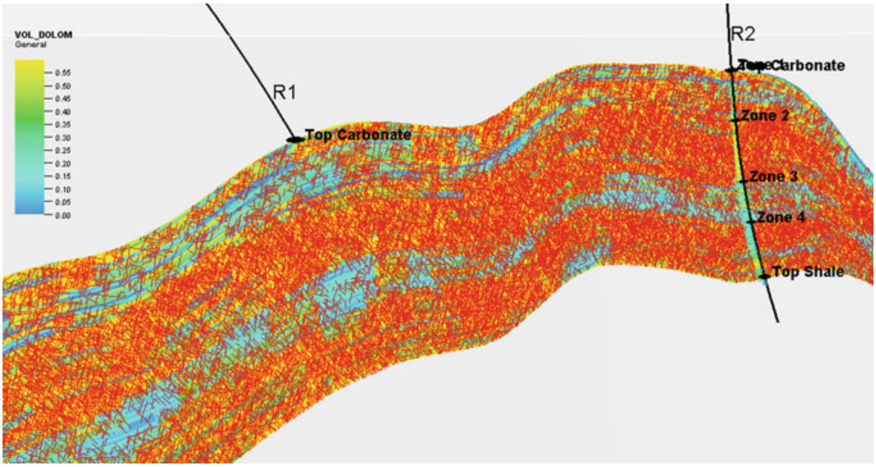

Fig. 8. Well intersection of DFN model

3.4 Sensitivity Analysis

The summary of the input distribution types and their ranges addressed in this paper is presented in Table 1.

Table 1. Summary of the input parameter uncertainties

Uncertain parameter	Base value	Distribution	Arguments					
Structure	Seed1							
Porosity	Seed2							
OWC	−3774	Triangular	Min	Spill point	Mode	−3774	Max	−3583
SW_Frac	0.15	Triangular	Min	0.1	Mode	0.15	Max	0.2
SW_Matrix	0.35	Triangular	Min	0.2	Mode	0.35	Max	0.5
Bo	1.68	Triangular	Min	1.63	Mode.	1.68	Max	1.8
Aperture	0.00003	Log-normal	Min	0.00001	Std.	0.0002		

The structure and porosity models are generated both using the SGS algorithm in which the changing of the arbitrary seed values can create numerous realizations to evaluate the structure and porosity uncertainties. Figure 9 is the structural realizations which show the changing of the structural surfaces and corresponding spill points. The blues are reference-case horizons of top carbonate and top shale. The purples and blacks are two structural stochastic realizations of the top carbonate and top shale. All the horizons match well with the well picks in the well locations, and the horizon realizations fluctuate around the reference-case horizons away from wells. The spill points are also changed for the different realizations which will modify the OWC distribution.

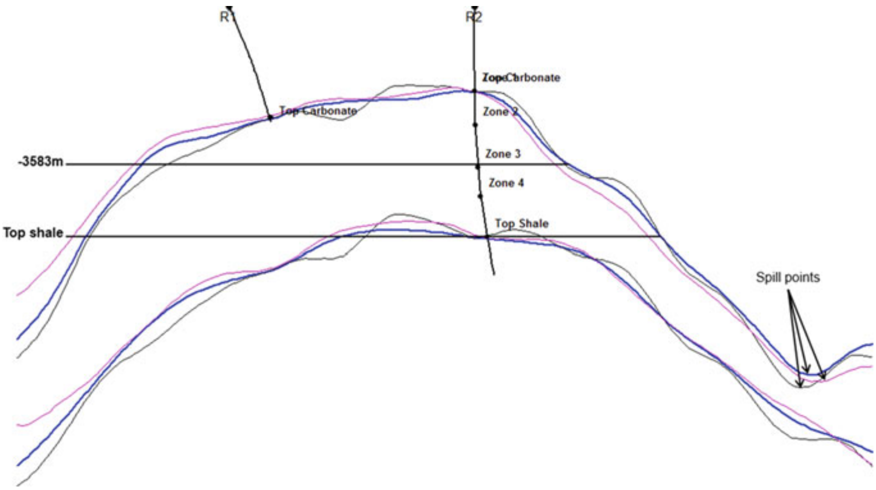

Fig. 9. Structure uncertainties and their spill points

A triangular distribution is used to define contact uncertainty. The PLT data before acidizing show that hydrocarbon flow in Zone 2 at the depth intervals of −3499 to −3538 m TVDSS, −3570 to −3573 m TVDSS and −3579 to −583 m TDVSS. So the minimum depth value is defined by the ODT depth of −3583 m TVDSS. No water encountered, the maximum value is defined to be the spill point of the top carbonate surface which is calculated in each structure uncertainty modelling loop (Fig. 9). The mode is defined at the top of shale (depth of −3774 m TVDSS) for the abundance fractures developed in the reservoir and good flow behaviour in Zone 4 after acidizing.

Using a triangular distribution implies that the highest probability is associated with the carbonate and shale contact and the probability decreases in a linear manner towards the ODT and the spill point depths.

The fracture in the reservoir is considered filled with oil and has fewer irreducible water, so the fracture SW value is set to 0.1–0.2 with triangular distribution.

The matrix SW is interpreted by Archie formula and the ranges are from 0.2 to 0.5 for the uncertainty analysis.

Bo is determined by laboratory results and the ranges are 1.63–1.8.

Fracture aperture is interpreted from FMI. The various ranges are from 0.01 to 2 mm and defined as log-normal distribution.

Implementation of sensitivity analysis on reference-case model using uncertain parameters described in Table 1 will yield the tornado chart of Fig. 10. The *x*-coordinate is the relative volumes of each loop to the volume of reference-case model (STOIIP base of 100%). The figure shows that OWC and structure have the largest impact on the STOIIP calculation, and the matrix SW, fracture aperture and matrix porosity have moderate impact. The fracture SW and Bo have the least impact. Thus, more work such as fine seismic procession and interpretation should be done or new wells may be drilled to reduce the structure, the spill point or fluid contact uncertainties.

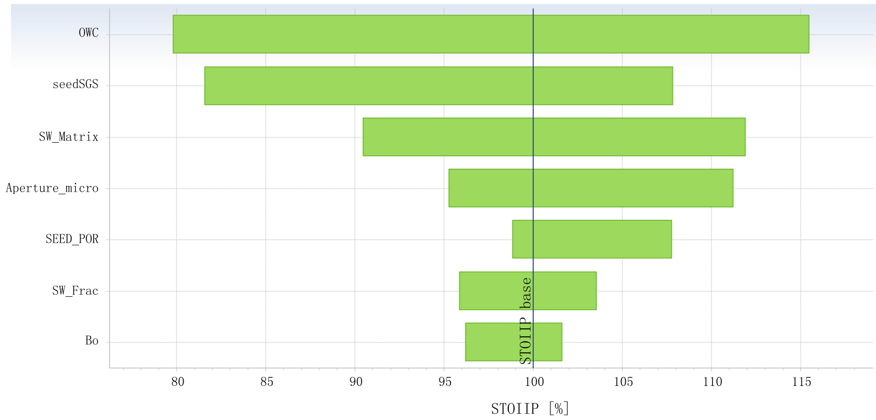

Fig. 10. Sensitivity analysis

3.5 Uncertainty Analysis

The uncertainty analysis workflow is executed 1000 loops with the variables selected randomly from their assigned distributions. It investigates the effect of the various variables simultaneously in a series of experimental runs. The results are the volume reports related to the combination of input variables at different levels.

Figure 11 shows the volume distribution of the numerous models generated by the uncertainty analysis workflow. The probability level of 10%, probability level of 50% and probability level of 90% have been identified and CDF curve can be depicted. It can be seen that the volumes have a relative wide range and the P10:P90 ratio is around 3 which meant that higher risks exist in the project. The probabilistic models can be drawn from those numerous geological models whose volumes are closely to these probabilistic volumes. These probabilistic models are then inputted as low, middle and high case models in the reservoir simulation for the field development plan.

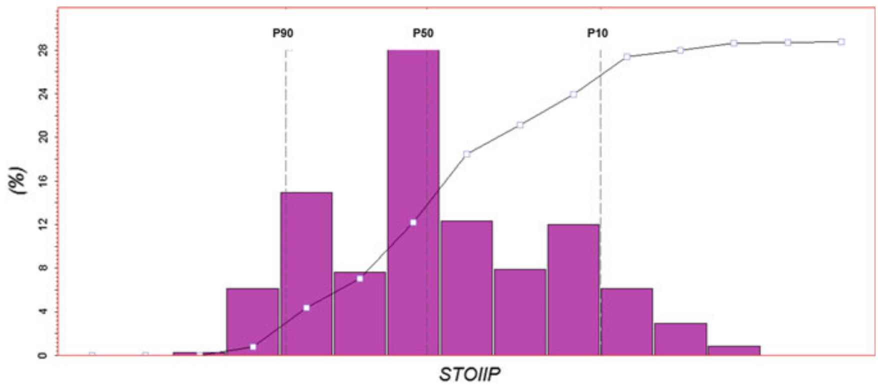

Fig. 11. Volume histogram from uncertainty analysis

4 Conclusions

A comprehensive uncertainty workflow is conducted to analyse the geological risks of the dual-medium carbonate reservoir in this paper. The workflow includes the structure modelling, matrix modelling, fracture modelling and uncertainty modelling. For the oilfield in this paper, the major impact factors from the sensitivity analysis are OWC, structure, matrix SW and fracture aperture. The low, middle and high probabilistic models are generated based on the volume results from uncertainty analysis. More works (such as seismic data reprocessing and fine interpretation, fluid detection and new data collection, etc.) should be carried out to reduce the high risks for this field.

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