Geostatistical reservoir modeling issues, how seismic can help: a typical case study.

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Abstract

3D earth modeling is a key issue for Reservoir Characterization. Fluid flow simulations based on a reliable model of reservoir heterogeneities will provide better prediction of hydrocarbon production. Moreover the uncertainty on the reservoir structure, the rock properties and the contacts may be assessed by means of simulations that preserve the geological features of the reservoir.

This paper deals with a geostatistical workflow of a 3D reservoir modeling applied to real data of a siltstone reservoir. The first key issue is the optimal use of the available data: the wells with information on markers of key horizons, lithofacies and porosity and an acoustic impedance cube that brings relevant information for constraining the porosity model and facies proportions.

The second point is related to the comparison of different geostatistical methods. The main steps of the workflow are:

- Surfaces simulations delimiting the top and bottom of the reservoir, using the information from wells.

- Facies simulations (Sequential Indicator Simulation, Truncated Plurigaussian Simulation). It requires the building of a flat stratigraphic grid (Flattening) within which variograms calculations and simulations are performed. After the flattening, the 3D vertical proportions curves (VPC) are computed. A 2D proportion constrained by a seismic attribute is used to constrain the 3D VPC. These proportions are used for the facies simulation.

- 3D porosity simulations are achieved independently for each facies, then a cookie cutting procedure constrained by the facies simulations provide the final porosity simulations.

- Finally, simulations are transferred from the stratigraphic space to the real space.

Several types of simulations are used (Surfaces simulations, SIS, TPGS, 2D porosity simulations, 3D porosity simulations, contact). To evaluate the different available models, volumetric calculations based on simulations of the different parameters provide stochastic distributions of volumes.

Case Study

The North Cowden Unit (NCU) is located on the eastern edge of the Central Basin platform in the west Texas Permian basin (Yarus et al. 1994). Production is from the Guadalupian Grayburg Formation (Permian).

The formation is composed of alternating dolomite and siltstone for a total thickness of about 140 meters. Dolomites range from anhydritic skeletal wackestones through mudstones. It is divided into five dolomite intervals (D1-D5), each separated by a siltstone interval (S1-S4). The most productive interval is S2.

The elevations of the markers of top and bottom horizons limiting the reservoir of interest are known on 32 vertical wells. At a regular one foot interval we have the following information:

- facies of the three main lithotypes (siltstone-anhydrite-dolomite),
- porosity,
- horizontal permeability.

Besides a seismic cube with acoustic impedance attribute is available for improving the modeling of the rock properties.

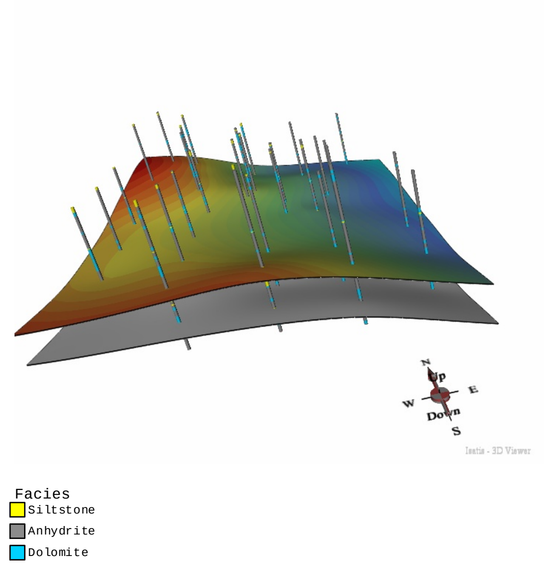

Figure 1: Top and bottom reservoir surfaces and wells with facies.

Methodology

Different methods will be used in order to calculate reservoir volumes. The uncertainty will be quantified from the distribution of volumes calculated on simulations of the reservoir unit. The simulations concern the reservoir structure, i.e. the top and bottom surfaces, and the rock properties, namely the porosity. In order to better take into account the reservoir heterogeneity a two step procedure is carried out. It consists of simulating the facies then populating them by simulations of porosity with specific features per facies. At each stage the simulations are achieved by generating random outcomes reproducing the spatial variability represented by the variogram, which constitutes a clear advantage over classical Monte Carlo approaches.

The simulations of surfaces and porosity are obtained by Gaussian methods (Turning Bands or Sequential Gaussian simulations). In the case of the porosity two approaches have been followed (Figure 2). Firstly considering the limited variations of the reservoir unit thickness, we have simulated directly the average porosity, ignoring the variability due to the facies heterogeneity. Secondly we have applied the two step procedure mentioned above. For the second step three porosity simulations have been achieved on all cells located within the reservoir envelope. The combination of facies and porosity simulations has finally been realized by using a cookie cutting procedure.

100 simulations have been performed independently for each item (surfaces, facies, porosity per facies). The full combinatory of all simulations is huge (10^{10}). Hence we have only kept 100 scenarios by linking the simulations of the different items to the other items of same rank.

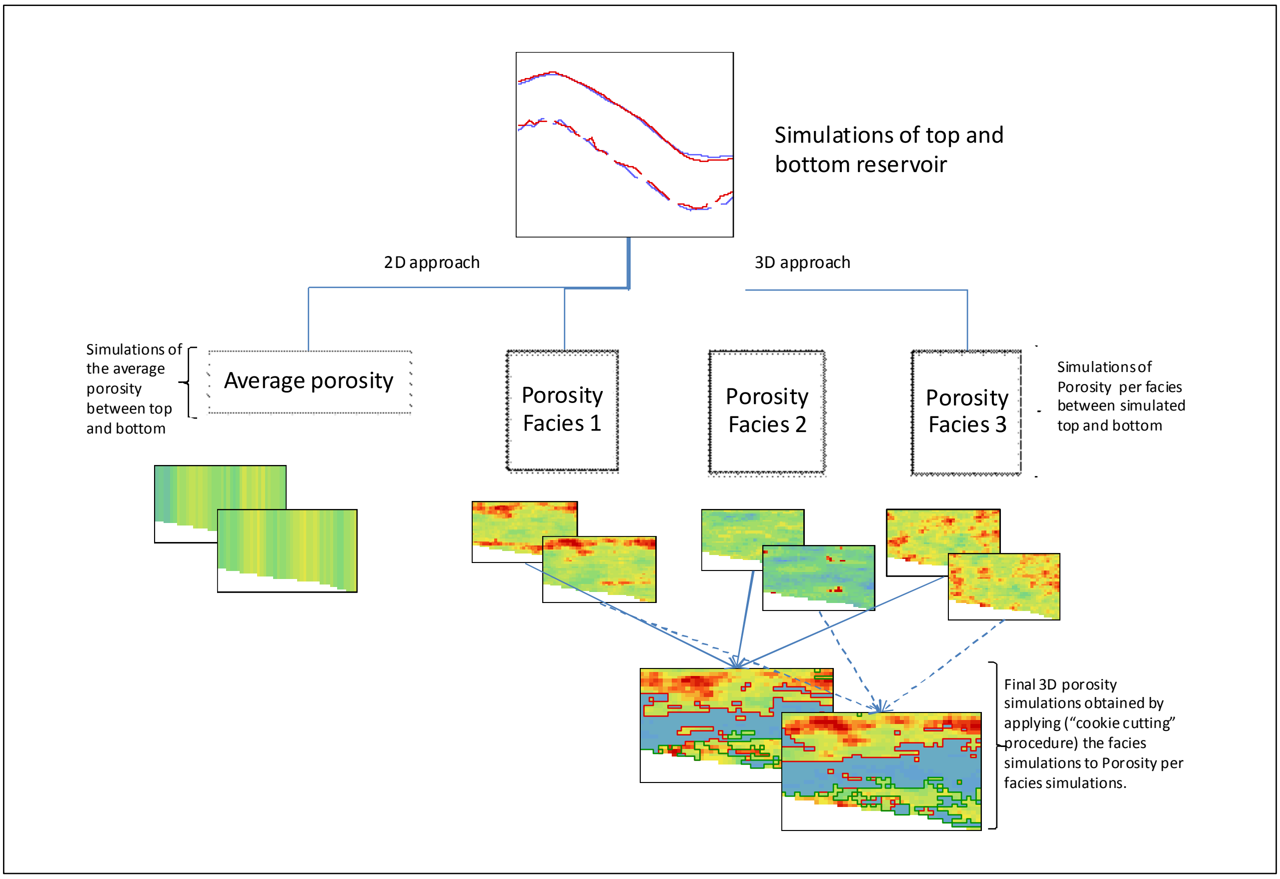

Figure 2: Organigram of 2 different approaches for simulating the porosity in the reservoir layer.

Geostatistical simulations

The complete workflow is made of a set of nested simulations for:

1. the reservoir structure;
2. the average porosity over the reservoir layer thickness;
3. the lithological facies in the 3D space;
4. the porosity of each facies.

The step 2 is achieved in case of the 2D approach. In case of the 3D approach steps 3 and 4 are performed instead.

Simulations of the reservoir structure

The top and bottom surfaces of the reservoir have been simulated independently by means of the Turning Bands method. Each surface is simulated by adding to a linear trend depending on X coordinate a residual characterized by a cubic covariance of range 1800m.

This model is justified by the correlation between the elevation and X coordinate measured on the 32 wells and the variogram of the residuals (Figure 3).

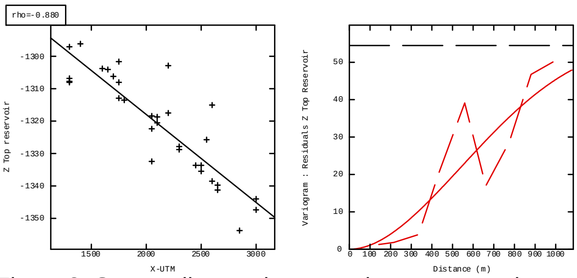

Figure 3: Scatter diagram between the top reservoir elevation and the X coordinate (left), experimental and modelled variogram of the residuals.

Simulations of the average porosity

Although the thickness of the reservoir is not constant (it is lying between 20 and 30m) the average porosity has been simulated directly using sequential gaussian simulation (SGS). No gaussian transform is necessary since the distribution of porosity is close to gaussian (Figure 4).

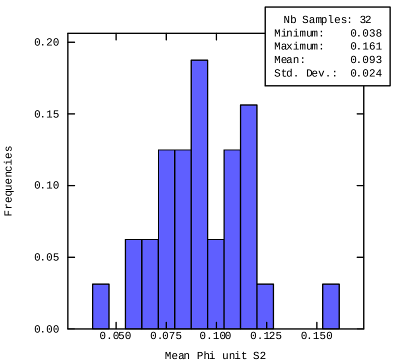

Figure 4: Histogram of the average porosity on the reservoir thickness.

The variogram shows a structure of correlation with a range of 600m.

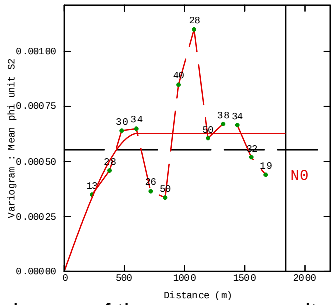

Figure 5: Variogram of the average porosity.

Simulations of the lithological facies

The 3 facies have been simulated using truncated plurigaussian method (Armstrong et al., 2003) in the stratigraphic space. The simulated facies are obtained by applying thresholds on the simulated Gaussian function. These thresholds are calculated in order to correspond to the proportion of facies at each node of a regular grid. The model is then controlled by the variations of the facies proportions vertically and laterally by means of the vertical proportion curves (VPC) calculated from the facies observed along the wells. These proportions are interpolated from the VPC calculated on groups of wells on the grid (Figure 6).

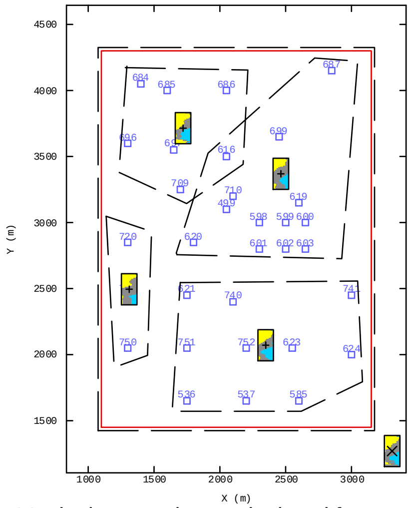

Figure 6: Vertical proportions calculated from wells put in 4 groups.

In the present case it has been possible to improve the estimation of the proportions by using the information indirectly contained in the seismic acoustic impedance. The correlation between the average proportion of the siltstone facies and the acoustic impedance at a given time within the reservoir thickness is significant. It leads to use the seismic attribute as a trend to constrain the average porosity. Figure 7 shows the correlation after having removed noise from the seismic data by filtering techniques.

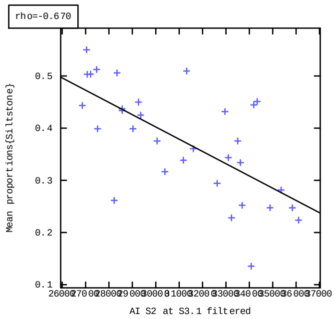

Figure 7: Scatter diagram between the average proportion of siltstone facies of the reservoir and the acoustic impedance filtered at the depth of a given intermediate horizon.

The average siltstone proportion is estimated by non stationary kriging using the acoustic impedance (Figure 8) as external drift.
The estimated siltstone proportion map (Figure 9) is honouring at wells the average proportion of the siltstone facies and reproduces some features of spatial continuity contained in the seismic attribute.

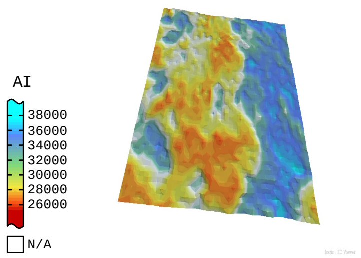

Figure 8: Map of the acoustic impedance after filtering.

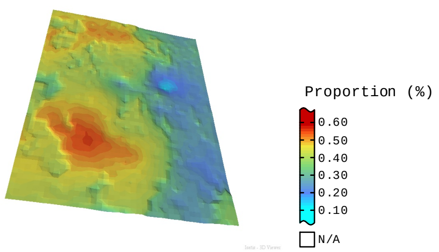

Figure 9: Map of the average siltstone proportion kriged from the wells and the acoustic impedance as external drift.

At the stage of interpolating the facies proportion at each grid node of the 3D grid, the weights assigned to the VPC data are modified in order that the cumulated siltstone proportion on the reservoir thickness matches the interpolated average proportion (Moulière et al., 1997)

The influence of the use of the seismic data on the 3D facies proportions is visualized on Figure 10. Incorporating the seismic constraint gives a higher siltstone proportions for some levels at particular locations.

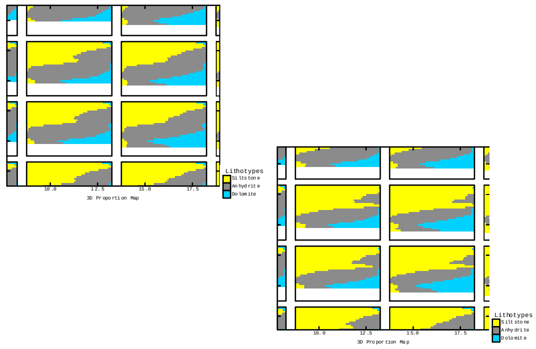

Figure 10: Comparison of the interpolated vertical proportions curves constrained by the seismic (bottom right) or not (top left).

The impact on the simulated facies is visible on Figure11. The use of seismic introduces more variability in the facies spatial distribution.

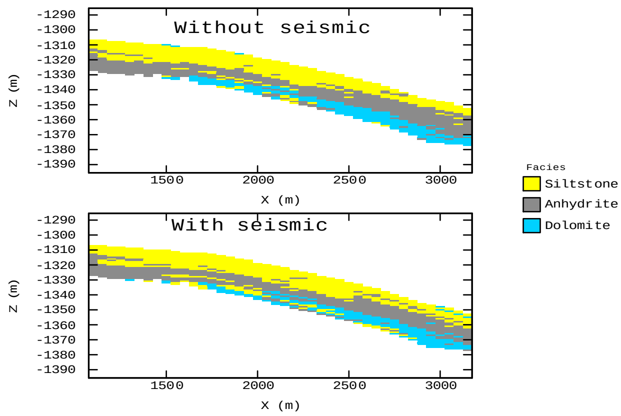

Figure 11: XOZ section of simulated facies constrained by seismic or not.

Simulations of porosity per facies

The porosity of each facies is simulated at each node of the grid located between the top and bottom of the reservoir layer, as if these nodes were in the facies of interest. In the final model only the porosity of the facies simulated at each node will be kept.

While the average porosity on the total thickness was close to Gaussian, the porosity of each individual facies is not (Figure 12). The simulations have then been achieved in the Gaussian space after normal score transforms (Chilès et al., 1999).

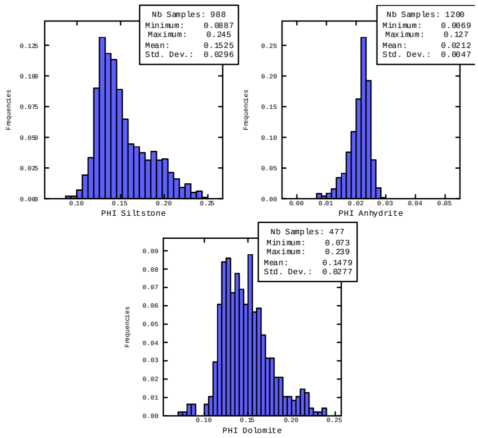

Figure 12: Histogram of the porosity of 1 m intervals along the wells for each facies.

Results

The distribution of Gross and HCPV volumes have been calculated from 100 simulations generated with the different approaches.

The oil water contact is supposed to be known and given as a surface interpolated with the same resolution as the simulated grid.

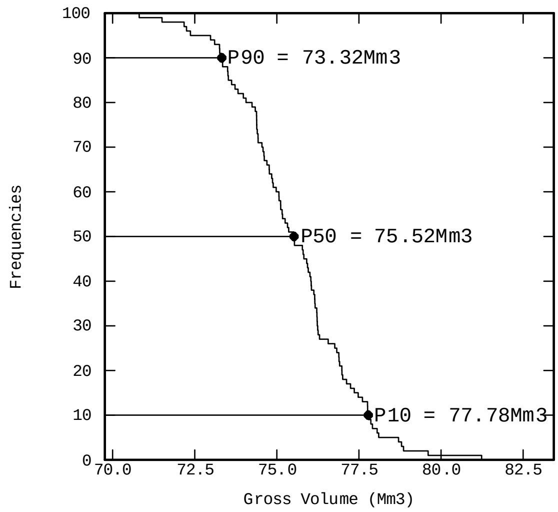

Figure 13: Inverse cumulated histogram of the gross volume of the reservoir from 100 simulations of top and bottom surfaces.

The difference in HCPV volumes is significant between the 2D and 3D approaches (Figure 14). As the most oil bearing facies (siltstone) is preferentially located at the top of the reservoir layer, the HCPV volumes calculated from the average 2D porosity are necessarily under-estimated.

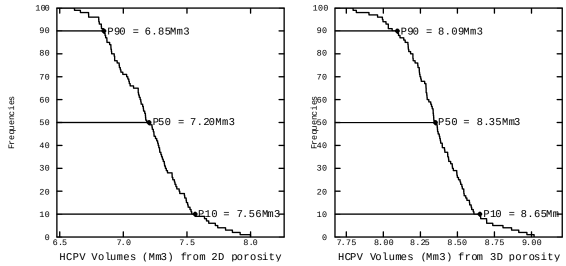

Figure 14: Histograms of HCPV volumes calculated from 100 simulations based on 2D or 3D porosity models.

Conclusions

The recovery of oil resources depend on many factors that interact with each other. Geostatistics and its stochastic framework contribute to the reservoir characterization by providing a static model of the reservoir heterogeneity. Two main advantages of a stochastic approach compared to a deterministic approach are:

- The capability of geostatistical models to integrate different types of information and particularly wells measures and seismic.
- The uncertainty assessment achieved by combining many realizations of the key reservoir parameters obtained by simulation techniques.

The choice of the specific geostatistical technique is of secondary importance. The most important is to choose the right modeling approach. In this paper the simplified 2D approach results in a global under-estimation of the volume by 15%. The model using seismic has little consequence on the global volumes, but it may change the recovered oil volumes because of the more realistic facies variability it provides.

Acknowledgments

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