Seismic data generation for the UNISIM-I benchmark

This report details the creation of synthetic seismic amplitude cubes with added noise using the UNISIM-I-R model. Here, we briefly describe the main steps performed to calculate those amplitudes, but the full descriptions can be found at de Souza (2018 – Chapter 4: 4D Seismic Bandwidth and Resolution Analysis for Fluid-flow Model Applications).

UNISIM-I-R is a high-resolution fluid-flow model created using publicly data available from the Namorado field of the Campos Basin, located in Brazil. It is a sandstone reservoir with turbiditic origin, dated as Albian-Cenomanian Age (Winter et al., 2007). The structural model, i.e., reservoir limits, top and bottom, horizons, and faults, were interpreted using the public seismic dataset. The flow model was built accounting for small-scale heterogeneities in a corner-point grid, containing 326 x 234 x 157 active cells with lateral spacing of 25 x 25 meters and with 1 meter of thickness. The facies and porosity properties were modeled using geostatistical methods, while permeability was calculated as a function of porosity. For more details on the UNISIM-I-R model please refer to Avansi & Schiozer (2015). The distribution of porosity is shown in Figure 1 for the top and bottom of the reservoir.

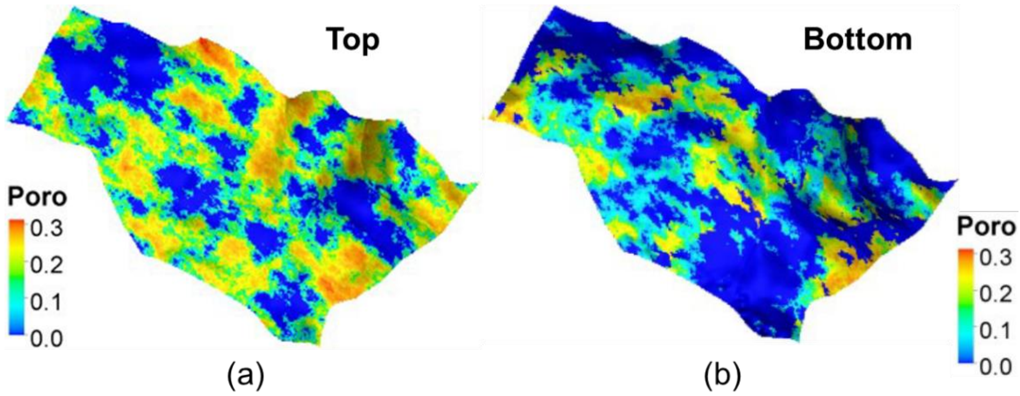

Figure 1. Porosity of the UNISIM-I-R model at the (a) top and (b) bottom of the reservoir. Adapted from Avansi & Schiozer (2015).

After simulating the model, static and dynamic properties (e.g., porosity, net-to-gross, pressure and water saturation) were extracted for two simulation timesteps: t=0 (named baseline survey) and t=2618 days (named monitor 1 survey), which were used as input for the petro-elastic modeling (PEM). For the PEM, the net-to-gross property was used to calculate the shale percentage at each grid cell, the Hertz-Mindlin model to derive dry bulk and shear moduli (Avseth, Mukerji & Mavko 2011), and Batzle & Wang (1992) relationships to model the fluid response to pressure and temperature. Finally, a standard Gassmann fluid substitution procedure was applied to obtain P- and S- impedance values at the simulation scale.

To apply the 1D convolutional model for the synthetic amplitudes' generation, it is necessary to convert the estimated elastic properties to the time domain. For that, a constant P-wave average velocity of 2500 m/s was used to convert PEM outputs from depth to two-way travel time (TWT). Then, reflection coefficients were computed using the normal-incidence plane-wave approximation (Telford et al., 1990), being convolved with a wavelet to generate the synthetic 3D seismic volumes of amplitude for both baseline and monitor 1 surveys. The wavelet considered was an Ormsby wavelet (Figure 2), and had a trapezoidal shape in the frequency spectrum defined by the following frequencies: 0, 20, 60 and 80 Hz, simulating a broadband seismic acquisition technology (Rosa et al. 2020; Souza et al. 2018).

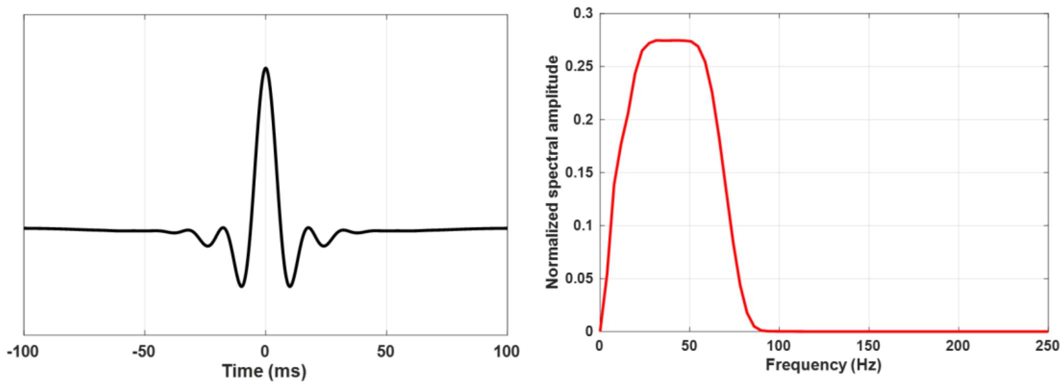

Figure 2. Wavelet used to generate synthetic seismic data (left) and its frequency spectrum (right). From Rosa et al. (2020).

Posteriorly, Gaussian random noise traces were created and filtered using the same frequencies as the wavelet above, being added to the noise-free traces, thereby generating noisy seismic data with a signal-to-noise ratio (S/N) of 3. This S/N value is equivalent to a streamer-type seismic acquisition. The amplitude differences between monitor 1 and baseline are shown in Figure 3 in a map and vertical section. The map corresponds to values of dRMS ($RMS_{monitor}$ - $RMS_{baseline}$).

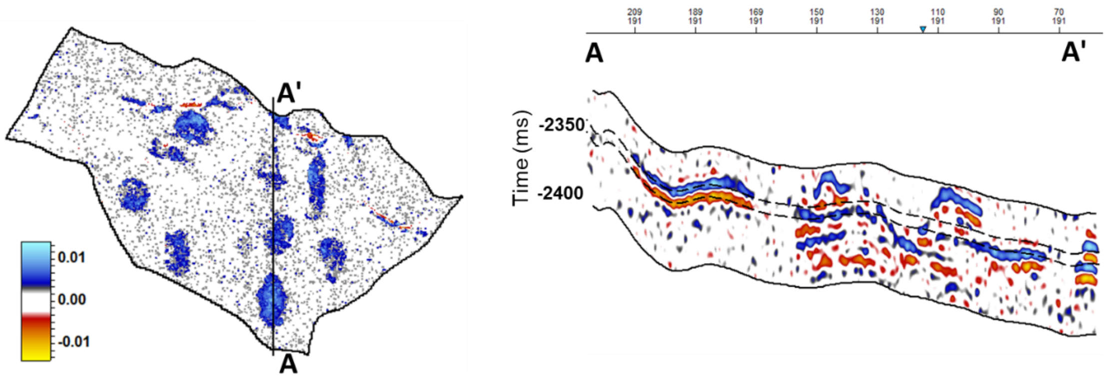

Figure 3. Left: the dRMS map. Right: vertical section of the difference in seismic amplitudes (monitor 1 minus baseline). The solid black lines in the vertical section indicate the top and base of the reservoir and the dashed lines indicate the window of RMS maps extraction. The blue anomalies in the map represent increased acoustic impedance values caused by water injection from the wells.

Overall, such data are likely to provide to geoscientists a state-of-the-art benchmark model for methodology validation, whose high-resolution results in a more realistic synthetic seismic data thereby allowing the integration of seismic attributes into fluid-flow model data studies.

References

Avansi, G. D., & Schiozer, D. J. 2015. UNISIM-I: synthetic model for reservoir development and management applications. International Journal of Modeling and Simulation for the Petroleum Industry, 9(1), 21-30.

Souza, R. M. 2018. Quantitative Analysis of 4D Seismic and Production Data for Saturation Estimation and Fluid-flow Model Assessment. Doctoral thesis, University of Western Australia in partnership with Unicamp.

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