PetroSI: Petrophysical Seismic Inversion for More Accurate and Precise Reservoir Properties

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Summary

Petrophysical Seismic Inversion, PetroSI, is an innovative stratigraphic inversion scheme that simultaneously integrates any number of seismic volumes with petrophysical and geological data through a petro-elastic model (PEM). We invert directly for key reservoir rock and fluid properties in a 3D geocellular model at different vertical scales to produce an optimal solution. PEM's relate the inverted properties to the seismic response and also maintain consistency between the time, depth and derived velocities throughout the inversion process. These innovations allow us to overcome the limitations faced by many existing techniques regarding resolution, vertical domain and the link between seismic response and reservoir properties. The result is a fine-scale shared earth model that is consistent with both log and seismic data and is especially amenable for flow simulation and reservoir performance prediction.

Introduction

Detailed 3D reservoir models are increasingly relied upon for prediction of reservoir performance, especially with flow simulation. These models commonly contain petrophysical information about lithology, rock properties (such as porosity, permeability, etc) and fluid saturations on a very fine vertical scale, typically of one meter or less. Seismic data provide an extensive areal coverage with dense and regular lateral sampling, however, integration of seismic data into the reservoir characterization poses a number of challenges, e.g., the dimensions of the earth are in lengths while seismic is recorded in time units, seismic amplitudes respond to changes in elastic properties which are only related to petrophysical characteristics in a complex way by many factors, and the vertical resolution that is recoverable from seismic data is low compared to the target geologic resolution. Additionally, most of the techniques published for estimation of porosity from seismic data can be described as a sequential two-step approach, seismic inversion (deterministic or geostatistical) to obtain acoustic or elastic impedance and transformation of impedance into petrophysical properties. Most two-step approaches (with one exception, 8) use the full seismic volumes only in the first step of seismic inversion and are summarized by acoustic or elastic properties in the second step. However, honoring these effective properties is not equivalent to honoring the seismic, which is not sensitive to the absolute values, only the contrasts. There is a risk of reasonably matching the effective properties but significantly departing from the seismic.

This paper presents the result of a two-year collaborative R&D project between CGG and Marathon Oil, designed to overcome these challenges. The deliverable was a petrophysical seismic inversion workflow and tools to generate fine-scale geomodels that are fully consistent with observed seismic data. A key component of the inversion methodology is a PEM, or petro-elastic model, that links the reservoir properties stored in the geomodel (e.g., porosity, rock, and fluid types) to the elastic response.

Petrophysical Seismic Inversion

Petrophysical Seismic Inversion starts with a fine-scale (flow-unit scale) geomodel defined from a 3-D stratigraphic grid in depth. The PEM(s) is applied to calculate elastic properties in each cell of the geomodel from stored values of porosity, lithology and saturation. Angle-dependent reflectivity series are calculated from the elastic properties through the Zoeppritz equation at each trace location. The reflection coefficient series are then converted from depth to time using the velocities stored in the geomodel. Angle-dependent 3-D synthetics are finally generated by wavelet convolution. Perturbations of the properties of the geomodel are introduced using a simulated annealing algorithm to optimize the match between predicted and observed angle stacks. After convergence, the geomodel honors the observed seismic amplitudes, is consistent with the user-specified PEM, and integrates inversion-based velocities that ensure coherence between the depth and time domains.

Changes in the initial model, such as flow unit scale lithology distribution, or the modification of the PEM will lead to different solutions. This allows geologically meaningful alternative solutions in the final models that are consistent with the seismic data. This methodology can be used to build new fine-scale reservoir models as well as to update existing models that are not yet coherent with available seismic volumes.

Petrophysical Seismic Inversion works pre-stack or with partial angle stacks introducing more than one seismic measurement and therefore provides an additional degree of freedom for reservoir property prediction. We can expect to access more than one petrophysical parameter in a meaningful manner. Traditional pre-stack inversion provides either compressional and shear impedances (I_p and I_S) or the triplet V_P, V_S and density (ρ). The last three variables are not independent as they are the elastic expression of various petrophysical variables, for example, porosity, sorting, fluid type and saturations.

Figure 1 shows a simplified illustration of the workflow. This workflow is usually not a single pass through. Iteration between some of the steps to address a problem originating at one stage and diagnosed at a later stage should be expected.

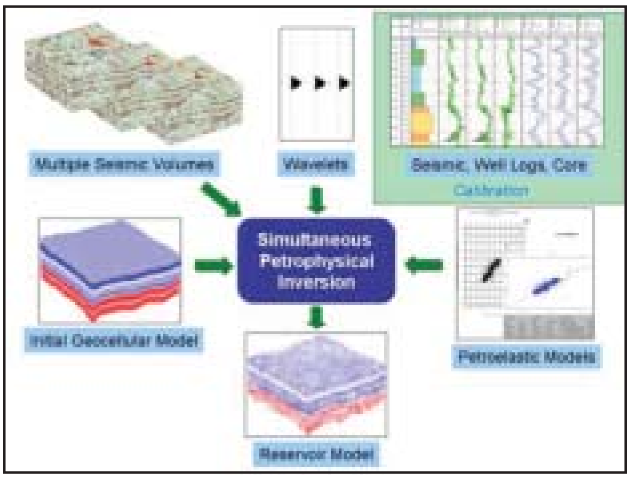

Fig. 1: Petrophysical Seismic Inversion workflow.

Initial ties to the seismic are investigated as a quality control step of the seismic, petrophysics, and PEM. An acceptable well-to-seismic tie is obtained when the time-based synthetic seismic forward modeled from the depth-based fine-scale reservoir properties at the well location using the PEM reasonably matches the recorded traces, Figure 2.

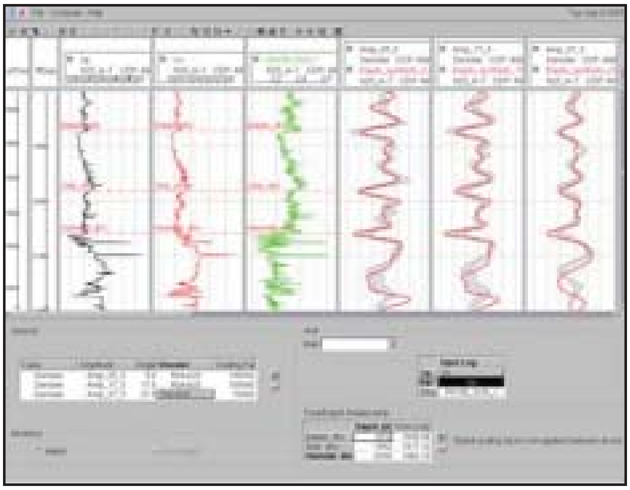

Fig. 2: Well calibration. Measured V_P, V_S, r, and, on the right, synthetic seismic (blue) and real traces surrounding the well (grey) for three angles.

The forward modeling is of particular importance because one of the primary tasks in seismic/well calibration is to bring the times derived from the modeled synthetic into line with the seismic times. Conventionally, this is achieved with the use of tie points and drift curves. Our method requires all time and velocity values are consistent with the reservoir properties from which they are derived in order to maintain the link through the petro-elastic models.

In our stratigraphic framework, the finest scale, V3, is the target scale and is defined by the geologic layering of the initial model with a typical layer thickness of one meter or less, Figure 3. It is the scale at which the petro-elastic models are considered valid. The intermediate V2 scale is the scale at which acoustic or elastic inversions are commonly performed. A V2 layer consists of a stack of V3 layers with geological significance, typically within two sequence boundaries or maximum flooding surfaces. The order of magnitude scale for V2 layers is about ten meters.The coarsest scale, V1, is defined by “macro-horizons”, such as the interpreted seismic events, which are calibrated to well markers and give the structural framework of the geomodel. These three vertical scales provide nested partitions of the

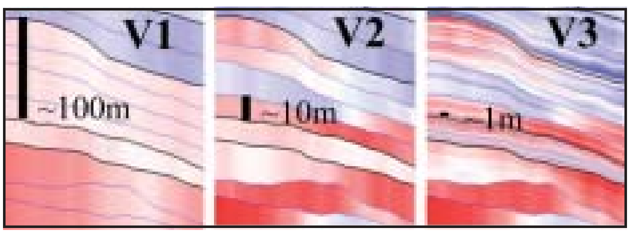

Fig. 3: Velocity section at different scales inside the same geomodel.

subsurface in such a way that a fine-scale layer belongs to a single layer at coarser scale.

There are several reasons to use a layered model during the inversion instead of the regular time sampling of the seismic data. First, the stratigraphy is better modeled, both for geological description and flow unit definition, as internally similar layers with property contrasts between layers. Also, seismic amplitude, despite being regularly sampled in time, is better modeled with accurate positioning of important contrasts beyond the seismic samples. Another reason is that in depth, as well as two-way time (TWT), the stratigraphic layering system is preserved. This is true irrespective of the data acquisition domain, PP or PS time. Finally, a layered model enables small position adjustments, often smaller than a seismic sample, in the different seismic cubes to compensate for residual NMO or to model time shifts and eventually compaction-induced depth shifts between 4D vintages.

Our petrophysical inversion process is stratigraphic and model-driven. This initial model is iteratively updated by perturbing the position of the layers and the values of the properties until all data and constraints are honored. Once a time-depth reference has been defined (usually at a major seismic horizon), the geologic model is known both in depth and time: while it is originally defined in the depth domain, a velocity can be derived for each cell from its associated reservoir properties and PEM and can be used to compute two-way times. In this way, the geologic model is handled simultaneously in time and depth and depth-specific constraints can be incorporated into the inversion process. An important point of the process is that no upscaling of reservoir or elastic properties needs to be performed to compute the synthetic seismic: it is directly computed from the fine-scale series of reflection coefficients.

Results

Our petrophysical inversion algorithm has been validated on synthetic and "live" datasets. The synthetic dataset presented was constructed to make it as realistic as possible and was based on an actual field. It represents a clastic reservoir with oil and gas trapped in a sand bed surrounded by shale. Sand and shale are accordingly assigned slightly different petro-elastic models. Real wavelets with a dominant frequency of 25Hz were used to create the synthetic seismic provided as input to the inversion. The "ground-truth" geologic model was used to generate the seismic and serves as the expected "ideal" result to which actual inversion results are compared.

Figure 4 illustrates the solution to an initial model which was filled with porosity values that are laterally constant along the layers. All of the values were significantly elevated above the true values.

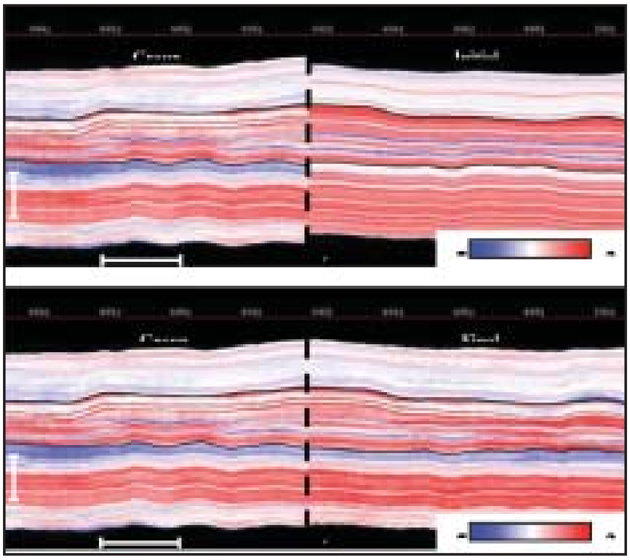

Fig. 4: The known answer is in the left two panels, the input model is the upper right panel, and the inversion results are in the bottom right panel. Five percent porosity is blue and 31% is red.

Figure 5 presents a second synthetic model which used a homogeneous model of 20% porosity. The correct trend has been properly recovered but the vertical pattern inside all seismic-scale layers remains constant. This clearly illustrates the fact that with the proposed inversion scheme, information at sub-seismic resolution comes from the initial model. For this reason, an inversion without any prior fine-scale information in the initial model is equivalent to a seismic-scale petrophysical inversion.

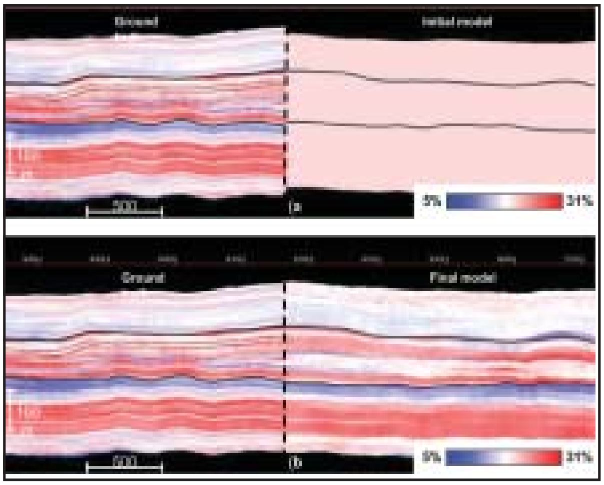

Fig. 5: Homogenous input cube of 20% porosity (top right) and "seismic-scale" result (lower right).

Figure 6 illustrates the input seismic angle stacks at 15, 22 and 30 degrees, left column, the "residual" or difference between the initial model's forward-predicted seismic response for each angle, center column, and the residual of the inversion results for the case of Figure 4.

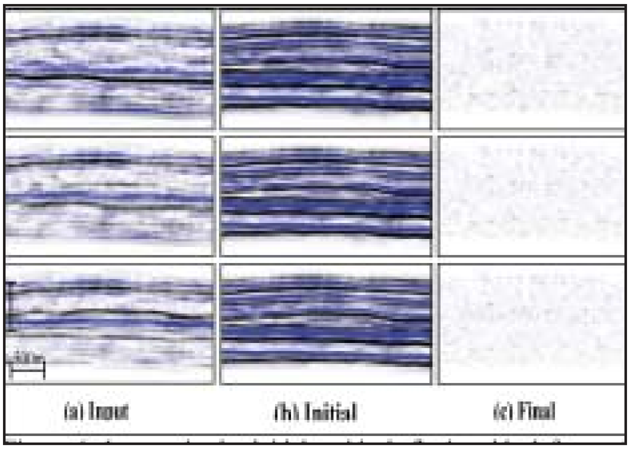

Fig. 6: Input seismic, initial residual, final residual for angle stacks of 15, 22, and 30 degrees

A field example from offshore Norway is provided below. Figure7 shows the predicted response lines of the PEM's superimposed on a crossplot of log data.

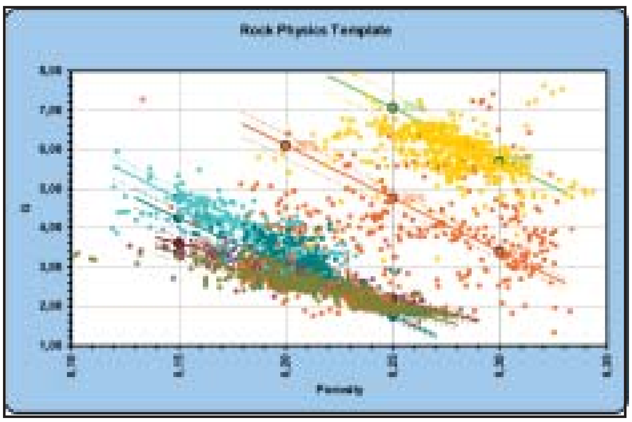

Fig. 7: PEM's of the field example

The result of the inversion is a finely stratified depth model that best represents the six seismic cubes. In this specific case, the input geological model was an areally constant extrapolation of the well data by layer (lower right cube of Figure 8). Figure 8 shows two resulting porosity cubes, the smaller shallower cube above the reservoir and the broad thin cube from within the reservoir interval. Although the seismic is satisfactorily reproduced after inversion, residuals are not small: they contain all the uncorrelated energy due to artifacts such as multiples and residual NMO.

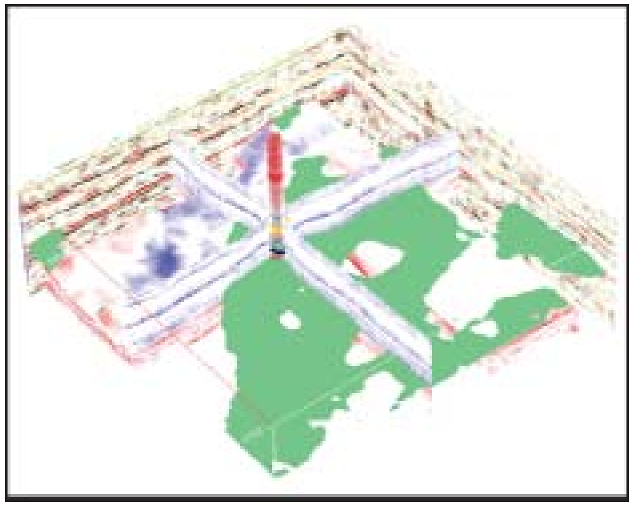

Fig. 8: Comparison of inversion input geo-cube, 1 of the 6 input angle-stack seismic cubes, and 2 resulting porosity cubes. The reservoir interval cube is built at flow unit scale of approximately 1 meter thickness.

Conclusion

Simultaneous petrophysical inversion is a step further towards more accurate and precise reservoir characterization. It is possible to obtain a shared earth model which takes advantage of well and seismic data at their respective resolutions and honors them in their respective domains. Different stratigraphic inputs will yield alternative results reproducing the seismic observations, allowing testing of scenarios and sensitivities and, through flow simulation, to assess their economic implications. In our approach, it is crucial to correctly understand and model the dependencies between all involved properties. Reconciliation of seismic and log measurements within a physically plausible petro-elastic model also challenges the seismic processing and model building practices to provide more quantitative results.

It is reasonable to address the challenges of time-lapse seismic with the same approach. Using a model consistent in depth and time is the natural way to address seismic monitoring. The repeated measurement is in two-way time but production changes lead to constraints that are naturally expressed in depth. Different production changes in pressure and saturation may induce individually opposing elastic responses. Directly working with reservoir properties through a petro-elastic model would reduce potential interpretation problems.

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