Introduction to this special section: Seismic inversion for reservoir properties

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Among all possible rock properties, reservoir engineers reserve the distinguished title of “reservoir properties” to pore volume, fluid type, and connectivity because of their direct impact in the economics of hydrocarbon reservoirs. In some reservoirs, engineers may be able to alter the original in-situ properties by applying additional processes to stimulate the matrix (with hydraulic fracturing, for instance) or to push the hydrocarbon out (by injecting some other fluid). Then, the rock and fluid properties that control the outcome of these induced processes become as important as the basic, more traditionally distinguished properties mentioned at the beginning. In any case, it is the geoscientist’s job to understand how these properties vary within the reservoir to fully realize its economic potential.

Structural mapping has been the traditional objective for using seismic technology in exploration and development areas. When the structural problem has been resolved, seismic interpreters usually set more ambitious goals by going after seismic attributes that are either directly related to reservoir properties or give some indication of the “quality” of the rock that helps to separate areas with more or less favorable conditions for economic hydrocarbon accumulations. The seismic response, however, does not depend directly on the reservoir properties. Unlike petrophysical measurements that sample a wide variety of physical properties of the rocks, seismic measurements are sensitive only to the elastic properties and it is up the seismic interpreter to unravel the relations between the worlds of elastic properties and reservoir properties.

For the seismic response to be useful in the estimation of rock quality or reservoir properties, elastic properties and reservoir properties must be related. But this is not enough. The success in the use of seismic data to estimate reservoir properties also depends on how the data were acquired and processed and in our ability to estimate (invert) the relevant elastic parameters from seismic data.

The workflow to estimate reservoir properties from seismic data consists of a series of closely related steps. The first one is a careful petrophysics/rock physics analysis that sets the basis for the relations that may exist between elastic properties and reservoir properties. Petrophysical measurements from a full set of modern logs can be directly and accurately related to reservoir properties because they are designed to detect a wide variety of physical properties. Rock physics analyses may range from simple crossplots that relate elastic properties and petrophysically derived reservoir properties at log or seismic scale to more elaborate models derived from basic theory or laboratory observations. All rock physics models must be locally validated before they are used because each comes with its own set of assumptions. In the second step, seismic data are acquired in a way that favors the estimation of the elastic parameters that are useful in the area of interest. For instance, if density turns out to be an important elastic parameter for the estimation of hydrocarbon saturation or rock brittleness, long offsets should also be recorded. From the processing point of view, relative amplitude preservation is the goal and long offsets and wide azimuths should be adequately treated by taking velocity anisotropy into account. In the third step, elastic properties or some other indicator of rock quality are estimated from the seismic data using algorithms that range from simple attribute extractions from poststack data to more elaborate prestack inversions. In some instances, we may use the estimated elastic properties either to classify groups of rocks with similar properties or geological origin (facies) or to estimate reservoir properties within these units by calibrating with available well data and using rock physics concepts. The steps of prestack inversion and estimation of facies and reservoir properties can sometimes be combined into a single step by assuming a rock physics model. Finally, careful quality control based on well data is crucial to assess our confidence in the seismic-derived results.

When interpreting elastic parameters as a function of variations in reservoir properties, we should keep in mind that not all elastic properties relate to individual reservoir properties in the same way and they are not estimated with the same reliability either. For instance, acoustic impedance may be correlated to porosity variations in some areas but may not be enough to estimate water saturation or to differentiate rock types; on the other hand, density may be more adequate to estimate changes in saturation or rock brittleness but its estimation may be also less reliable if the more expensive long-offset information is not available. The presence of anisotropy in the rocks complicates data processing and parameter estimation even more but, conversely, anisotropy may provide insights about the rocks that cannot be obtained when erroneously assuming that the rocks are isotropic.

Statistical methods are also commonly used to estimate rock properties from elastic properties. These methods range from simple multilinear regressions to more complex geostatistical applications and artificial neural networks are also commonly used. Unlike methods based on rock physics, these methods usually exploit the statistical relations between one or more seismic attributes with a given reservoir property but make no attempt to understand the fundamental reasons behind these relations.

A final, seemingly simple but crucial, step to relate seismic-derived results to the rest of the information in the reservoir is the time-to-depth conversion. Accuracy requirements are different for seismic-well ties and time-to-depth conversion in exploratory settings versus more mature development and production settings. A mis-tie of “a few milliseconds” usually acceptable in exploration environments can be enough to distort the real
correlations that may exist between log and seismic data to the point to make them unusable. Even prestack depth-migrated data need to be additionally depth-corrected to honor all well-log and geological marker information. Inversion results are often used to retie the seismic data to make sure that impedances and density derived from seismic follow their log-scale counterparts as closely as possible.

The last decade has witnessed significant advances in the use of seismic data to estimate reservoir properties. Even though conventional interpretations of raw poststack amplitudes as a function of porosity or possible presence of hydrocarbons are useful and still commonly used, geoscientists now have at their disposal a variety of tools that allow more comprehensive integrations of different data types into single models of the subsurface. Seven excellent papers illustrate these advances in this special section.

In the first paper, Wagner et al. make a compelling argument for the efficacy of poststack inversion in the subsalt domain. They suggest that, through a careful combination of data preparation and processing, it may be possible to recover meaningful rock properties from subsalt seismic data. Additional analyses of the inversion results are also used by the authors to shed insight into reservoir compartmentalization.

In the second poststack inversion paper, Singh proposes a technique for performing poststack seismic inversion in the depth domain. This scheme overcomes the issue of wavelet estimation and convolution in the depth domain by using a pseudodepth transformation, with constant interval velocities derived through seismic-well tie analysis. Analyses of the inversion results show that depth-domain results are comparable or slightly better than time-domain results. It should be noted that this workflow in the depth-domain inversion can use PSDM output directly and therefore avoid depth-to-time and time-to-depth conversion steps.

Brouwer et al. deal with the difficulties in creating accurate subsurface models for use as a background for inversion, rock properties for reservoir characterization, and geology for stratigraphic interpretation. Common methods based on seismic such as stratal slicing break down for complex geology, such as in the case of shelf-to-basin clinofoms, deep-water fans, delta lobe switching, and salt provinces. The authors describe how these shortcomings may be mitigated through the use of high-resolution inversion incorporating a stratigraphically consistent low-frequency model (called HorizonCube) generated through mapping seismic horizons. They demonstrate the advantages and increased accuracy of the final inversion by using this approach with two case histories, one from the North Sea and the other from Brazil.

Then, Close et al. introduce a workflow for quantitative inversion to characterize unconventional tight shale gas. Through the use of AVO-LMR methods, they demonstrate the advantages of interdisciplinary integration by combining increasing quantities of log-calibrated seismic and engineering data to map the heterogeneity of these shales. Understanding this heterogeneity is critical in avoiding costly misplacement of large multiwell horizontal “gas factory” pads.

Fiedner et al. use stochastic methods such as genetic algorithms and simulated annealing for seismic inversion. They show the advantage of these methods, over more standard deterministic gradient-descent approaches, is in avoiding the need for a starting model and the calculation of gradients. Stochastic methods require only forward modeling for the objective function to generate a single “best” model and can also provide statistical ranges of acceptable models for a given error tolerance. From this, an assessment of the reliability and resolution of various inversions can be made with respect to prior geological constraints as opposed to just comparing a single “best” model. Their approach is successfully demonstrated through the application of these stochastic methods to the SEG SEAM Earth model.

Two papers about estimation of properties in anisotropic media close this special section. In the first one, Behura et al. innovatively combine the attenuation effect on the seismic response for gas reservoirs with azimuthal anisotropy in P-wave travel times or NMO. They describe a new method to extract interval NMO and attenuation coefficients through a layer-stripping approach that is velocity-independent. This new algorithm is successfully applied to a wide-azimuth 3D survey over a known gas field in the Coronation area of Alberta, Canada. The resulting mapping is confirmed by existing production and predicts new locations for horizontal wells to optimally intersect natural gas-filled fractures.

The final paper by Shekar and Tsvankin presents a case study where they use crosswell data to develop a technique for estimating the P-wave angle-dependent attenuation coefficient. In this study, a string of receivers in a vertical borehole was used to record the wavefield excited by perforation shots set in a horizontal wellbore. The inversion results show that taking attenuation anisotropy into account reduces the data misfit and reveals variations of the attenuation coefficient between perforation stages. Interpretation of these results is complex, but it may provide an indication of temporal changes related to hydraulic fracturing.

Despite these advances, the road ahead is not without challenges and we still have a lot to learn in all aspects related to the problem of mapping reservoir properties in three dimensions, from our basic understanding of rock physics concepts in reservoirs of complex lithologies, to seismic data acquisition and processing, to inversion for reservoir properties. Our understanding of how rock physics concepts derived from log scale translate into seismic scale, in particular in complex lithologies, carbonate reservoirs or low-permeability resource plays, is still in its infancy. Seismic acquisition of low frequencies, fully sampled wide azimuths, and long offsets is still prohibitively expensive for many operators, not to mention the use of the promising 3C-3D technology. The estimation of reservoir properties in structurally complex areas is still in question because processors face enormous challenges in the preservation of true relative amplitudes in this kind of geological setting. Much more work will be needed before seismic inversion and calibration methods that make consistent use of different kinds of measurements (from geological to petrophysical and geomechanical) become the norm.

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