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Seismic Amplitude Calibration for Quantitative Interpretation

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Abstract

Significant progress has been made over many decades in improving seismic data quality. However, seismic amplitudes after data processing can be of arbitrary scale relative to corresponding reflection coefficients. Calibration of seismic data to geology, often expressed in terms of well log data, is needed before Quantitative Interpretation (QI) of seismic data can be undertaken for predicting rock and fluid properties. Calibration can be thought of as consisting of many processing and analysis steps, including seismic pre-stack gather offset scaling, wavelet estimation, synthetic-to-seismic tie analysis, and seismic inversion to impedance, among others. Although reservoir characterization has benefited greatly from advances in seismic processing technology, amplitude calibration is still a challenge as there is no single unique method. I will discuss some of the issues in this report.

Background

Seismic data quality is improving every day with advancement in acquisition and processing technologies. We geophysicists want to use seismic data more than simply for structural interpretation of the subsurface. For reservoir characterization and management, we prefer to take advantage of the full waveform, which in addition to travel time, includes amplitude, shape, and frequency content. Seismic amplitude analysis is now often used for 3D, and Time Lapse (4D) quantitative seismic interpretation (Hilterman, 2001; Avseth et al., 2005; Simm and Bacon, 2014). Generally, seismic waves reflected from a reservoir zone and recorded at the surface have propagated down and up through a vast overburden, and partly through the reservoir zone itself. Therefore, the amplitudes associated with these recordings have been affected by several physical factors unrelated to the rock properties of the reservoirs of interest (Sheriff, 1975). The objective of seismic processing for reservoir characterization is to correct the recorded data for all unwanted effects (noise) and preserve the amplitude response due to the reservoir layers themselves (signal). However, seismic data, even after several steps of data processing to mitigate the noise and enhance the signal associated with the primary reflections, has at best *relative* amplitudes. These amplitudes must be calibrated to be consistent with geology, or rock properties expectations (Bee et al, 2006). Calibration typically employs well logs to facilitate wavelet extraction and generation of synthetics, which can then be compared (tied) to the seismic data to assess the level of consistency not just between event travel times but also between amplitudes. After such calibration, QI for rock and fluid properties can be undertaken with greater confidence.

Seismic-well tie

The seismic waveform can be interpreted as geology after we link the waveform “wiggles” to well-log-based synthetics. This process is often called the seismic-well tie. Figure 1 (right-most column) shows an example of a comparison between acoustic-impedance (AI)-based synthetics and seismic data. The seismic-well tie is the starting point for both QI and structural interpretation. A seismic-well tie offers many benefits:

i. it provides a basis for interpreting seismic events in geologic terms;

ii. it helps establish a time-depth relationship between seismic data and the well depths, respectively;

iii. it generally requires the estimation of a wavelet and therefore the phase of the data;

iv. it enables general quality control of both seismic and well logs; and

v. it enables the understanding of seismic resolution and tuning effects.

The quality and usefulness of seismic-well ties can be impacted by various factors. Generally, it is desirable to have “tall” logs that penetrate much of the overburden, if not also below a reservoir zone of interest. This is because the ability to generate good well-ties over a tall section helps to build confidence in the overall interpretation. Accurate synthetic amplitudes generally require P-wave sonic log and density log data. For a non-vertical incidence angle synthetic, we also require S-wave sonic log, but these are often not recorded. A possible mitigation step that can be taken in this case is to generate pseudo-shear logs. Well log quality, and hence seismic-well tie quality, may also be influenced by down hole logging conditions such as hole rugosity and wash out. Nevertheless, we often consider well log data as being closer to the “ground truth” than seismic data, and we endeavor to condition our seismic data and models to be as consistent with the well logs as possible. If seismic-well ties are poor, then one should question both the seismic data and well-log-based synthetics.

Understanding the phase of the seismic data, and hence of the wavelet required to make optimal well-seismic ties, is paramount. Seismic resolution is optimized and interpretation is facilitated when the reflection seismic data has *zero* phase. Zero phase means the underlying wavelet is a symmetric wiggle event with a central peak or trough (depending on the event polarity), located at the event time. The phase of seismic data rotates with increasing depth through the subsurface due to physical principles. Processing steps – from simple rotation to sophisticated time-varying Q compensation can help to produce seismic data that is zero phase at the reservoir zone in which we are most interested. Phase can sometimes be estimated visually by looking at the shape of seismic wiggles at locations where isolated step-changes in subsurface properties are known to exist, such as at the water bottom, or top salt, or the top of a carbonate layer (e.g. the Buda Formation shown in Figure 1). In these cases, we are looking for symmetrical sidelobes about a central peak. However, estimating the phase of the seismic data is generally accomplished by performing the non-trivial task of extracting a wavelet from the seismic data using well-log data and the synthetics generated from them as constraint.

Wavelet

Wavelets are used for generating synthetic seismograms for estimating the phase of seismic data. This allows for interpreting seismic amplitudes, and for inverting seismic data to obtain elastic properties of reservoir layers. Wavelets should have amplitude and phase consistency with seismic for QI applications. One can think of the amplitude component of a wavelet as a seismic-to-synthetic scalar. To learn how this scalar varies throughout a seismic volume, we can estimate, or extract, a wavelet by using seismic and well logs together. We often find that this wavelet scalar varies with time (depth), offset (or angle of incidence), and space. Ideally, we want a stationary wavelet with consistent phase and scalar throughout the seismic volume to simplify the interpretation of amplitude variation with offset/angle (AVO/AVA) in terms of rock properties. A spatially varying wavelet may be an indication of ambiguity in either seismic data quality or wavelet estimation, or both. For QI purposes, the preference is to work with seismic data in which the underlying wavelet can be demonstrated to not vary significantly either spatially or with angle of incidence. Figure 2 shows an example of angle-varying wavelets. Note that if the phase of the seismic data is already known or assumed, then the seismic data alone can be used to estimate the amplitude and frequency content of the wavelet, in which case it is called a statistical wavelet.

AVO attributes

AVO attributes describe how seismic reflection amplitudes from reservoir interfaces vary with surface acquisition offset, or more accurately, vary with reflection angle of incidence (AVA). These variations in amplitude are generally indicative of contrasts in reservoir and overburden rock properties. They can be used to infer rock and fluid properties of the reservoir, including lithology, saturation, porosity, and even Time Lapse (4D) changes in saturation, porosity, and pore pressure. At a minimum, the important step of calibration should be applied to the processed seismic data before reliable angle stacks and AVA attribute volumes (such as Intercept and Gradient) are generated. Figure 3 shows significant difference between the AVA behavior for seismic and synthetic gathers, where in this case the seismic amplitudes decay much more strongly with offset (or angle) than do the synthetic amplitudes. In the calibration process, the seismic AVA pattern is modified to be more consistent with the synthetic. This calibration process is not trivial, owing to many issues unrelated to rock properties that influence seismic and synthetic amplitudes:

i. well logs used in synthetic computation may be inaccurate for a variety of reasons;

ii. forward modelling of the synthetic response may be inaccurate due to certain approximations often invoked in the convolutional method;

iii. the wavelet used in modeling may be inaccurate owing to a variety of amplitude and phase issues, as well as non-stationary spatial and temporal behavior in the seismic data; and

iv. even the choice of analysis time window, or the selection of which wells to use for amplitude computation can lead to different understandings of expected AVA behavior. Generally, a goal of calibration is to arrive at a consensus on a robust understanding of global AVA behavior at the reservoir zone of interest that can be based on analysis of multiple seismic-well ties.

Amplitude interpretation

After application of calibration, seismic amplitudes should be more appropriate for QI applications. In particular, seismic amplitudes can be compared with modeled seismic amplitudes as a function of varying rock and fluid properties, as shown in Figure 4, in which case amplitudes are suitable for QI. Note that the additional phenomenon of tuning needs to be addressed even after calibration has been applied, before seismic amplitudes can be fully utilized. Tuning-related amplitude changes occur due to thinning and thickening of adjacent reflecting stratigraphic layers. Usually a seismic tuning study is needed, as shown in Figure 4. In general, below the tuning thickness, seismic amplitudes are directly proportional to reservoir thickness, and such amplitudes can be used to interpret when a reservoir thins and terminates. Seismic angle stacks or cross-plots of intercept and gradient seismic can also be used for AVA-based QI. Seismic AVA analysis has a proven track record of success in exploration, development, and production management of hydrocarbon reservoirs, but it requires accurate amplitude calibration.

Impedance interpretation

Inversion of seismic data, including AVA data, for impedance is a fundamental and popular way to further calibrate and optimize the use of seismic amplitudes. Many common seismic inversion methods for impedance require an extracted wavelet from near the target reservoir zone, and these approaches may not yield good results depending on the quality of that wavelet. Another common approach, Colored Inversion (CI, Lancaster and Whitecombe, 2000), does not require such an explicit wavelet, and therefore does not necessarily suffer from wavelet-specific issues. In both inversion methods, well logs are used to enable the recalibration of seismic amplitudes to impedances. For example, in CI a scalar is estimated based on comparing the zero-phase seismic amplitudes with the well log impedance values within the seismic frequency bandwidth. The scalar used in CI is essentially a wavelet (Figure 5) that has a -90 degrees phase and enables matching the seismic amplitude spectrum to the bandlimited (relative) well log impedance spectrum. Estimated seismic impedance can be used for rock and fluid property estimation. The quality of estimated reservoir properties will depend on the favorability of rock physics relationships. Figure 6 shows an example of correlating impedance to porosity. The 3rd panel in Figure 1 compares the porosity from a well log with a prediction from inverted seismic impedance.

The Seismic Net Pay (SNP) method to estimate net reservoir thickness from seismic amplitudes is another example of amplitude calibration in QI. In this approach seismic amplitudes, whether in reflectivity or impedance domain, are essentially recalibrated to measures of net or net-to-gross (NTG). The SNP technology as proposed by Connolly (2007) assumes that the integral of the bandlimited impedance data is proportional to the net pay once the gross interval response is detuned. SNP analysis requires seismic time thickness and seismic average amplitude maps for the gross interval of interest as input, as well as an estimation of the bandwidth of the impedance data – in this case CI – so that the tuning effects can be modeled. Output maps of seismic NTG can be multiplied by the mapped depth thickness maps to produce estimates of seismic net pay.

Conclusions

Seismic amplitudes after processing can have arbitrary scaling that needs to be calibrated with geology before undertaking Quantitative Interpretation (QI) to obtain the rock and fluid properties of a reservoir. The wavelet itself can be treated as a calibration scalar, but this scalar can vary with time, angle, and CDP location. In practice, at best, we use an angle varying wavelet to calibrate AVA data for seismic amplitude interpretation and for inverting data to impedance. Under ideal conditions, a single scalar is consistent across time, angle, and space. Seismic inversion for impedance is another common approach to amplitude calibration, as impedance is a layer property directly related to rock and fluid properties. Seismic calibration is a must for QI, but it is a non-trivial process, and therefore uncertainty estimation in QI also needs to be considered.

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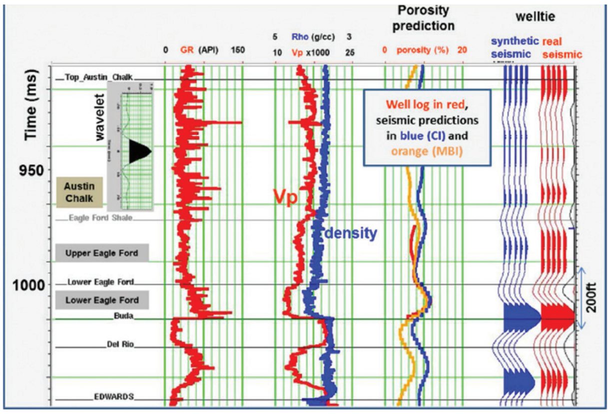

Figure 1: Seismic-well tie (presented at the 2014 SEG Conference by Kumar et al.). First track shows well tops and wavelet in time; second track shows Gamma Ray log; third track shows Vp (red) and density (blue) logs; fourth track compares porosity from well log and those derived from inverted seismic impedances; and the last track shows a comparison of seismic (red) to Synthetic (blue) traces at the well – the same trace is plotted 5 times for better visualization.

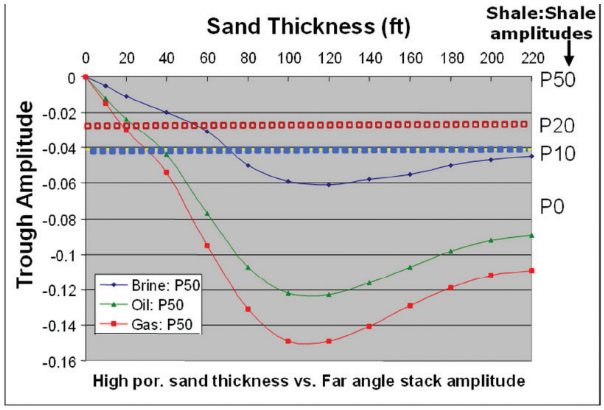

Figure 4: Seismic modelling (probabilistic) of a far angle stack used in QI of seismic amplitudes (example from Thompson et al., 2009). Background response (P10 and P20 in blue and red dotted lines) of shale over shale is constant over reservoir thicknesses. The P50 (median) tuning amplitudes of brine sand (blue), oil sand (green) and gas sand (red) for a high porosity AVA class III sand are plotted.

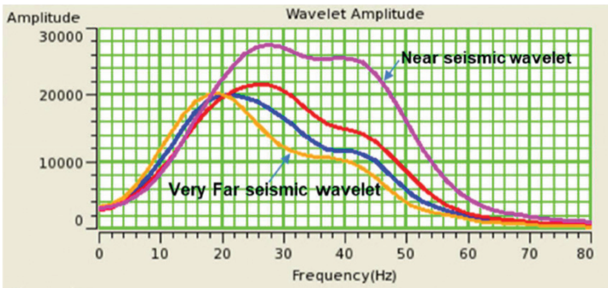

Figure 2: Example of wavelets (displayed in frequency domain) estimated from near (100), mid (200), far (300), and very far (400) angle seismic stacks.

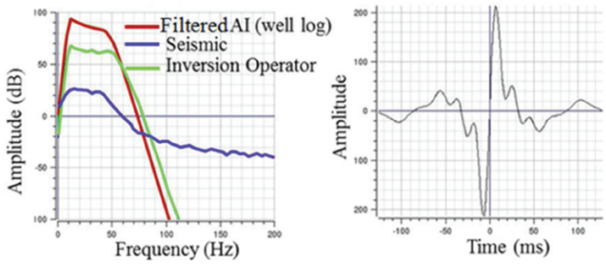

Figure 5: Colored inversion operator (example from Chen et al., 2015). Left plot shows average seismic amplitude spectrum (blue), desired spectrum derived from well log impedance (red), and estimated operator (green) to scale seismic data to the desired spectrum. Inversion operator (wavelet) in time domain is shown on the right, (Lancaster and Whitecombe, 2000)

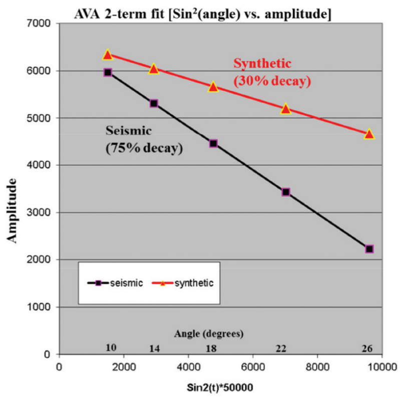

Figure 3: AVA 2-term plot showing amplitude versus sin2θ for seismic and synthetic data. Before one generates AVO attributes (intercept and gradient) or angle stacks for QI, the seismic AVA response needs to be scaled to synthetic data.

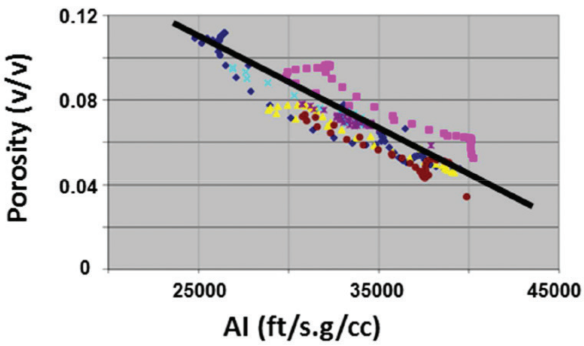

Figure 6: Rock physics relationship from well logs between acoustic impedance (AI) and porosity (Kumar et al., 2014). Color in the plot represents different wells. Often AI has a good relationship with porosity. Seismic inversion can provide AI, which in turn can be used to derive porosity using this relationship. Porosity volumes are used for reservoir model building.