Quantitative application of poststack acoustic impedance inversion to subsalt reservoir development

CHARLES WAGNER, ALFONSO GONZALEZ, VINOD AGARWAL, ADAM KOESOEMADINATA, DAVID NG, STEVEN TRARES, and NORMAN BILES, WesternGeco
KEVIN FISHER, Schlumberger Data & Consulting Services

The cost and complexity of deep-water subsalt development wells is so great that a very limited spatial sampling of the target reservoir is achievable with well data. Thus, the quantitative use of seismic data becomes of paramount importance.

Poststack seismic amplitude inversion, and poststack seismic attribute analysis and modeling, are frequently employed to perform quantitative prediction of reservoir properties from surface seismic data.

Several authors have shown that both absolute and relative acoustic impedance (AAI and RAI, respectively) derived from poststack seismic amplitude inversion can be useful for quantitative estimates of summary reservoir properties such as average porosity, net-to-gross, and others. This includes suprasalt and minibasin clastic reservoirs typically encountered in the Middle and Lower Tertiary plays in the deep-water Gulf of Mexico (several of which are also encountered subsalt), where depth to target can exceed 9000 m and highest frequencies at target are often rather low (20–25 Hz) (Bogan et al., 2003, Vernik et al., 2002).

With sufficient supporting data and appropriate angle of incidence coverage available, prestack inversion for elastic properties is a preferred method for quantitative clastic seismic reservoir characterization. Calibration with mechanical rock properties, and application of sophisticated rock physics models, are both possible with such data. However, this is rarely the case with subsalt plays, partly due to illumination and amplitude normalization uncertainties, and partly due to skepticism regarding the viability of elastic modeling in the subsalt case (Vigh et al., 2011).

Clearly, subsalt amplitude fidelity is of primary concern to quantitative practitioners, whether working with post- or prestack data. Subsalt amplitude data processing is typically directed at a good image for horizon interpretation, and quantitative methods are rarely discussed in literature (see Bui et al., 2011 for an exception).

Published quantitative work in the subsalt regime is largely restricted to low-resolution activities such as pore-pressure prediction. This article describes a study that shows there is reason for optimism regarding the use of quantitative subsalt seismic analysis for reservoir description, and for derisking deep target drilling locations. For deeper targets, limited bandwidth and vertical resolution restricts us to the development of gross seismically derived reservoir statistics.

This study builds on initial, promising, work undertaken in the Green Canyon protraction area in the Gulf of Mexico (Bui et al., 2011), which covered an area of complex salt and minibasin geometry. The intent is to investigate whether the favorable Green Canyon impedance inversion results are achievable elsewhere. Additional inversion work, and a review of processing methodologies, was undertaken to evaluate amplitude fidelity and develop additional results.

For simplicity, we refer to the lower Tertiary Wilcox equivalent rocks in the study area as “Wilcox.” Also, the St. Malo prospect was originally called Dana Point but was renamed after the well was deepened. Some well-log files (and thus, some plots below) retained the Dana Point designation.

Background

A small area—equivalent to about nine blocks (9 × 23 km²) was selected from a much larger spec data volume (~180 blocks) around the Das Bump and St. Malo prospects in the Walker Ridge protraction area—deeper water than Green Canyon, and closer to the outward limits of the salt canopy (Figure 1). Recent operator activity in this area has been focused on the deep (8000 -10,000 m) lower Tertiary Wilcox equivalent play, widespread thick sands with reservoirs characterized by hydrocarbon accumulations over large salt-cored structures. The sands have complex mineralogy, moderate porosity, low permeability, and the reservoirs are often compartmentalized.

A wide-azimuth multiclient seismic survey was acquired over the study area in 2009, processed with 3D generalized surface multiple prediction (GSMP), multiple suppression and an
Seismic inversion for reservoir properties
cally reject plans that call for a full suite of logs from surface to
total depth (TD). In these cases, we are constrained to compar-
ing measured seismic data with a mix of measured, modeled, and
often derived data from well logs, core, pressure measurements,
and measured data from hybrid acquisition methods such as a
vertical seismic profile (VSP). For this study, publically available
well logs were edited and petrophysical analyses were prepared.

Amplitude fidelity
Amplitude preservation during RTM requires proper boundary
conditions and a properly normalized imaging condition (Zhang
and Sun, 2009). In RTM, the image is constructed using Claer-
bourt’s imaging principle by taking the zero-lag crosscorrelation
of extrapolated source and receiver wavefields.

For amplitude preservation, the cross-correlation is normalized
by the shot-by-shot illumination. In practice, the shot-by-shot nor-
malization is unstable in regions of low or no illumination, and
modifications have been proposed to stabilize the image (Cogan et al.,
2011). The modified normalization scheme was used to process the
data set used for this study.

Illumination compensation below salt is challenging, in particular
because of the strong influence salt geometry has on wave propagation.
This is demonstrated in Figure 2, showing the illumination pattern
from five surface shots in a wide-azimuth (WAZ) data set with a salt
body with complex geometry.

Notice the focusing and defocusing effect that salt has on subsalt
illumination. This example demonstrates that small variations in the
salt geometry have strong effects on subsalt illumination.

Illumination studies are an important part of any quantitative
work that depends on imaging amplitudes; these studies identify
those regions where illumination is good and stable, and those
regions where illumination compensation has high uncertainty,
so proper preconditioning of amplitude is done before inversion
or attribute analysis.

Validation of seismic amplitude data has always been prob-
lematic. Our frugal colleagues in the engineering discipline typi-
cally reject plans that call for a full suite of logs from surface to
total depth (TD). In these cases, we are constrained to comparing
measured seismic data with a mix of measured, modeled, and
often derived data from well logs, core, pressure measurements,
and measured data from hybrid acquisition methods such as a
vertical seismic profile (VSP). For this study, publically available
well logs were edited and petrophysical analyses were prepared.

In addition to direct comparisons, we can also test the re-

Figure 2. (top) Seismic section from a WAZ data set; the arrows show the locations of five shots to
illustrate their contribution to the illumination; top salt (orange), base salt (yellow). (middle) Sum of
illumination weights for the five selected shots. Note, in particular, the complex illumination patterns
below salt, created by focusing and defocusing of energy as it propagates in and out of the salt body.
White indicates no illumination. (bottom) Stack volume formed from APSDM RTM-migrated full-
waveform well synthetic gather. (left) Inverted acoustic impedance from synthetic APSDM RTM stack
with well-log impedance. (center) Log overlay. (right) Red = measured logs, blue = inversion result,
and green = background model.
Seismic inversion for reservoir properties

As part of this study, activities were undertaken to develop synthetic prestack data from logs, to evaluate the preservation of synthetic data through processing and migration, and to evaluate the recovery of acoustic impedance from the migrated synthetic data via poststack inversion.

A forward-modeled elastic full-waveform gather was constructed and run through a production VTI anisotropic prestack depth migration (APSDM) processing flow to produce an angle gather, which was subsequently stacked using near angles (to approximate vertical incidence) and replicated to form a small 3D data set. A wavelet was extracted from that data set using the logs from the model construction process, and a poststack absolute acoustic impedance inversion was performed. The stack data set and inversion results (shown at the bottom of Figure 2) indicate that the workflow recovers acoustic impedance rather well.

Forward models derived from well logs need to be constructed thoughtfully, as they are not without problems, particularly with respect to the effects of velocity anisotropy on well logs. Notably, establishing a depth/time relationship using check shots or VSP data in a deviated well can have high uncertainty. Without a walkaway (or walkabobe) source that keeps as close to vertical incidence as possible, such measurements suffer from the same anisotropy effects as surface seismic acquisition. Only vertical, or near-vertical, wells were used for this study.

Figure 3. Well-to-seismic tie at St. Malo, with synthetic constructed using extracted wavelet (right). Track 1 = well logs (blue = acoustic impedance; pink = bulk density; red = compressional sonic). Track 2 = reflectivity. Track 3 = seismic amplitude, synthetic, seismic amplitude. Track 4 = seismic amplitude and synthetic along borehole trajectory.

Figure 4. Depth-domain relative acoustic impedance volume. Positive = orange, negative = white, zero = black. Approximate thickness of section below base of salt (bright orange at top) is 4000 m.
Seismic inversion for reservoir properties

Parallel construction of a background absolute acoustic impedance model contributes to a low-frequency compensation step that combines a low-frequency component of the model with the rescaled relative acoustic impedance to create the final absolute acoustic impedance volume (Figure 5). A 5-Hz upper cutoff was used to limit the contribution of the well-data background model to the overall absolute acoustic impedance result.

Construction of the background model for this study included interpretation of control surfaces intended to constrain interpolated full-bandwidth well information, and the use of migration velocities as a guide model to augment depth trends and better represent space-variant behavior away from, and undetected by, well control. For example, note the yellow feature between the St. Malo and Das Bump wells (Figure 5), the strength and location of which is driven by the velocity field.

Inversion methodology

Poststack acoustic impedance inversion is based on acoustic (e.g., P-wave only) theory, rather than elastic (P+S-wave) theory. Poststack analysis works in our favor because we have “the power of the stack” helping with noise reduction in the otherwise best-suited RTM amplitude product.

A proprietary convolutional poststack inversion methodology was utilized for this study (see Bui et al., 2011). The APS-DM RTM data set is first stretched from depth to time using the migration velocity volume. This is followed by well-to-seismic tie and development of a wavelet suitable for use with inversion using the extended Roy White wavelet extraction methodology (Figure 3).

A pre-inversion data conditioning step is then introduced, where signal is analyzed and enhanced within the measured seismic bandwidth, and subsequently stabilized and zero-phased trace-by-trace with a frequency-dependent dephasing operator. The method also takes into account certain space-variant behavior beyond that contained in the estimated global embedded wavelet (Poggiagliolmi and Allred, 1994). The next step is an iterative discrete spike inversion, which generates relative acoustic impedance (Figure 4).

Parallel construction of a background absolute acoustic impedance model contributes to a low-frequency compensation step that combines a low-frequency component of the model with the rescaled relative acoustic impedance to create the final absolute acoustic impedance volume (Figure 5). A 5-Hz upper cutoff was used to limit the contribution of the well-data background model to the overall absolute acoustic impedance result.

Construction of the background model for this study included interpretation of control surfaces intended to constrain interpolated full-bandwidth well information, and the use of migration velocities as a guide model to augment depth trends and better represent space-variant behavior away from, and undetected by, well control. For example, note the yellow feature between the St. Malo and Das Bump wells (Figure 5), the strength and location of which is driven by the velocity field.

The development of surfaces for our background modeling methodology sometimes differs from traditional horizon picking in that the surfaces may not always rigorously follow obvious features such as base salt. Indeed, this is an interpretive step, wherein surfaces may be driven through features like salt keels, or across reflectors, in order to reflect a specific desired scenario. Similar decisions are required regarding the use of parallel, onlap,
offlap, or other interpolation truncation style against base salt or other features.

The guide model methodology used in this study requires a linear, or linear-inverse, relationship between the guide model volume and the interpolated well property. A reasonably linear relationship between smoothed well log acoustic impedance and migration velocity exists within the study area, visible in the inset in Figure 5. The methodology also allows for adjustment of bias between well data and the guide model; in this case a moderately high bias toward the velocity cube was used.
The methodology provides significant flexibility with respect to scaling seismic, impedance, and model data, in addition to the degree of influence incorporated from the guide model. Sophisticated rescaling capability (such as the ability to match gross package reflectivity to that of an equivalent package of interpolated full-bandwidth log data) is critical for testing impedance response scenarios such as gas cloud versus poor illumination in dim zones, and others.

Evaluating the comparison between smoothed well logs and inverted impedance (Figure 6), we observe a quite reasonable match at a high level. Some mismatch of thicknesses and position is probably due to migration velocity mis-tie, and might be resolved with a locally derived velocity field. Local rescaling may be required for a better match in certain intervals. A higher migration frequency cutoff could conceivably reveal more detail from the amplitude data.

Reservoir properties and petrophysics

The link between the exploration and reservoir development processes is largely based on seismic data. The presence of wells and well data, at the target, makes the difference between the two. When well data are added to the knowledge base, the number of assumptions is reduced, and the breadth of uncertainty becomes better constrained. Neither is entirely eliminated. Well information (logs, core, PVT analysis, fluid chemistry analysis, pressure tests, etc.) serves to constrain the parameterization ranges of empirical relationships that can be used to calibrate seismically derived information to well-derived information.

In this article, we suggest that a quantitative relationship can be established between seismically derived acoustic impedance, and well-log-derived porosity. The applicability of such relationships, by means of industry-standard computations such as Archie’s equations, to reservoir development will likely vary from prospect to prospect and from one producing interval to another within a prospect. As nonoperators, our observations and interpretations are necessarily broad.

Poststack acoustic impedance is known to have limited capability for sand/shale discrimination when applied to sands...
Seismic inversion for reservoir properties with complex mineralogy, and to shales that have undergone significant compaction. Such is the case with onshore south Texas Wilcox-aged rocks, and equally so with the Wilcox equivalent rocks in the study area (Stromboe et al., 2007). Stochastic rock physics classification methods have been used with some success (Bui et al., 2011).

Operators have subdivided the Wilcox into upper and lower sections, with a shaly interval as the dividing zone (referred to as the middle Wilcox Shale, or WC 2, in this article). In this study, the gamma-ray log was used as a sand/shale cutoff log, using 80 GR API units or higher as a shale indicator. While somewhat problematic in detail, gamma ray appears to be a reasonable proxy for shale content in this setting.

At St. Malo, acoustic impedance from logs shows a good linear relationship to total porosity from logs in the sand intervals of the Wilcox equivalent section (Figure 7). Both porosity and acoustic impedance exhibit a relatively narrow range of values. We expect acoustic impedance \( (V_p \cdot \rho) \) to show some correlation with porosity—many authors have proposed relationships between porosity and velocity, such as the well-known Raymer, Hunt, and Gardner (1980) relationship:

\[
V_p = \left(1 - \phi\right)^2 \cdot V_p^{\text{solid}} + \left(\phi \cdot V_p^{\text{fluid}}\right),
\]

where \( V_p \) is velocity and \( \phi \) is porosity. The mass balance density porosity equation is equally well known:

\[
\rho = \left(\rho_{\log} - \rho_{\text{fluid}}\right) / \left(\rho_{\text{matrix}} - \rho_{\text{fluid}}\right),
\]

where \( \phi \) is porosity and \( \rho \) is density.

Comparison of well-log and inversion-derived porosity (Figure 7) shows a need for local residual scaling and bias adjustment, and fine tuning of trend management. Again, a higher migration frequency cutoff and local velocity control might improve feature correlation. Correlation error is also introduced via the least squares linear transform which compresses population response onto a line and reduces overall point-to-point correlation. A detailed statistical approach using cloud transforms would be more appropriate in this case, and would better support uncertainty analysis.

As mentioned previously, the limited bandwidth of the data set and inherent error in the impedance-to-porosity transform process make it more appropriate to use the results for gross summary statistics. An example map is shown in Figure 8.

Compartmentalization and fracture mapping

The identification and evaluation of possible reservoir compartmentalization is critical to a successful development program. Faults and fracture indicators must be integrated with pressure and other well data to evaluate their impact on drilling and production planning.

Compartmentalization is a known issue in several deepwater Wilcox reservoirs (Figure 9, top). With individual sand unit thicknesses often exceeding 30 m, the resolution of data sets such as those used in this study is sufficient to suggest that spatial characterization of compartment extent from seismically derived data may be feasible. Using a combination of attribute volume
Seismic inversion for reservoir properties and discrete discontinuity products, compartment geometry may be better understood.

The restricted migration bandwidth of this multiclient data set did not create an initial sense of optimism amongst the authors when the topic of fault and fracture mapping was brought up. Still, several significant faults are clearly visible on amplitude and impedance data sets—a few of which penetrate the Wilcox. Major faults were interpreted, and an Ant Track discontinuity analysis was performed on attributes of the relative acoustic impedance volume.

The discontinuity analysis identified several features within the Wilcox that were not picked by the interpreter. Figure 9 (bottom) shows these features superimposed on the relative acoustic impedance volume. To evaluate potential compartmentalization and better optimize the development drilling program, such discontinuities must be extracted as boundary planes and included in reservoir modeling cases.

Some long discontinuities were not connected as well as those interpreted manually. Still, the overall results of the discontinuity analysis were rather comprehensive and quite thought-provoking as a significant number of discontinuities penetrate the reservoir interval.

For example, the mid-Wilcox shale break just above the Zone 2 boundary marker in Figure 9 (immediately above the dashed black interpretation line) is roughly 20 m thick. Based on the difference in pressure trends visible in Zone 1 and Zone 2, we may suspect that this shale forms part (or all) of a seal mechanism between the two zones. This low-impedance unit can be mapped and shows significant spatial heterogeneity within the relative acoustic impedance volume (which is relatively insensitive to long period compaction trends associated with significant structure). In many cases, the relative impedance variations appear to be fault-bounded (Figure 9).

Should supporting petrophysical studies demonstrate that acoustic impedance can be used to help estimate shale seal quality, we may use the absolute acoustic impedance data set as part of a calibrated model of potential seal capacity. Because relative impedance can also reflect heterogeneity above the unit under study, some caution is warranted. Relative and absolute data should be combined to make a complete interpretation.

Summary
We have entered the era of quantitative seismic analysis of reservoirs beneath salt in the Gulf of Mexico. Clearly, there is still much work to be done to bring our confidence up to the point where we are in the suprasalt environment today. However, these results show that with thoughtful data processing and preparation, and even more thoughtful application of the various tools and methods available to us, seismic data can provide calibrated insight into our subsalt reservoirs.

References

Acknowledgments: The authors thank the management of WesternGeco for permission to show WesternGeco multiclient data and to publish this article. Discussions with several WesternGeco staff members helped significantly with this effort, including Everett Mobley, Mark Egan, and Shantanu Singh. We also thank a gracious client who wishes to remain anonymous, for allowing the use of the log displays. This work includes data supplied by IHS Energy Log Services, Inc.

Corresponding author: CWagner2@slb.com