Practical synthetic well ties: an example

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Abstract

This paper highlights the process of tying well synthetics to seismic data for the purposes of seismic interpretation. There are three stages to the well tie process namely a) phase estimation, b) seismic data zero phasing and c) zero phase well tie. As a consequence, it is useful to draw a distinction between a 'phase match' tie and a 'zero phase' tie particularly when the original seismic is not zero phase. A practical example is presented using the RokDoc software.

The understanding of seismic phase is often a key challenge for the interpreter. It has always been so and no doubt will probably continue to be so in the future. For all interpreters the well-to-seismic tie is a basic tool that uses well logs and well velocities to show how reflecting horizons correlate with seismic loops. It is generally understood that for the purposes of seismic interpretation this correlation is made clearest when using a correctly timed zero phase wavelet (e.g. Anstey 1982).

The interpreter needs to be wary of making assumptions about seismic phase and timing. Prior to interpretation seismic and well seismic data require calibration and phase needs to be evaluated. A common assumption is that the seismic data has been processed to zero-phase with the only interpretation issue being the nature of the impedance contrasts corresponding to positive and negative numbers. Unfortunately, seismic data often does not have a symmetrical wavelet (sometimes despite the best efforts of the processor). Given this, it is evident that the well tie comprises three steps:

1. estimation of phase and timing
2. zero phasing of seismic data
3. zero phase well tie

Thus, in the case where the seismic phase is not zero there are essentially two well ties to be made, a 'phase match' tie and a 'zero phase' tie. The phase match tie should be performed in the time domain and this would require depth imaged data to be converted back to time for this part of the process. A practical well tie example is described in the following sections. For the sake of brevity the conditioning of logs and depth to time calibration will not be discussed in this paper (the reader is referred to Simm and Bacon (2014) for an introduction to these topics as well as well tie approaches in general). With respect to the logical basis of the well-seismic matching procedure, including the statistical measures referred to in the following sections, the reader is recommended the work of White (1997) and White and Simm (2003).

Estimating phase

Typically, seismic phase is estimated with commercial synthetics software using one of two techniques:

1. A least squares matching technique (White, 1980; Walden and White, 1992; White, 1997; White and Simm, 2003)
2. An adaptive technique in which an optimum phase match of a synthetic to seismic is determined at the well location

The matching technique provides a scientifically robust approach to the well tie problem, accommodating the fact that migrated seismic (in time or depth) is not precisely positioned with respect to the location of the origin of the reflection. Numerous outputs including statistical measures and map displays help in evaluating the accuracy of the tie (e.g. White, 1997).

Fundamentally, the method relies on an accurate time-to-depth calibration using well-seismic data (checkshots or VSP time/depth points). While the adaptive technique is a less rigorous approach (owing to the fact that phase and timing are not independent) it is appropriate when there are no checkshots and the integrated sonic log is the starting point for the time-depth relationship.

Well tie example

A well tie example is presented below from an offshore well which is slightly deviated (~4° from vertical at the target level) and tied to seismic data of moderate quality. Whilst the presentation of the analysis is to some extent dependent on the software used (in this case RokDoc) the discussion attempts to generalise the key steps in a pragmatic approach to well ties. Equally, the focus is on the analysis of a single well tie and the issues that an interpreter might encounter in a multi-well study (such as averaging wavelets for example) are not addressed.

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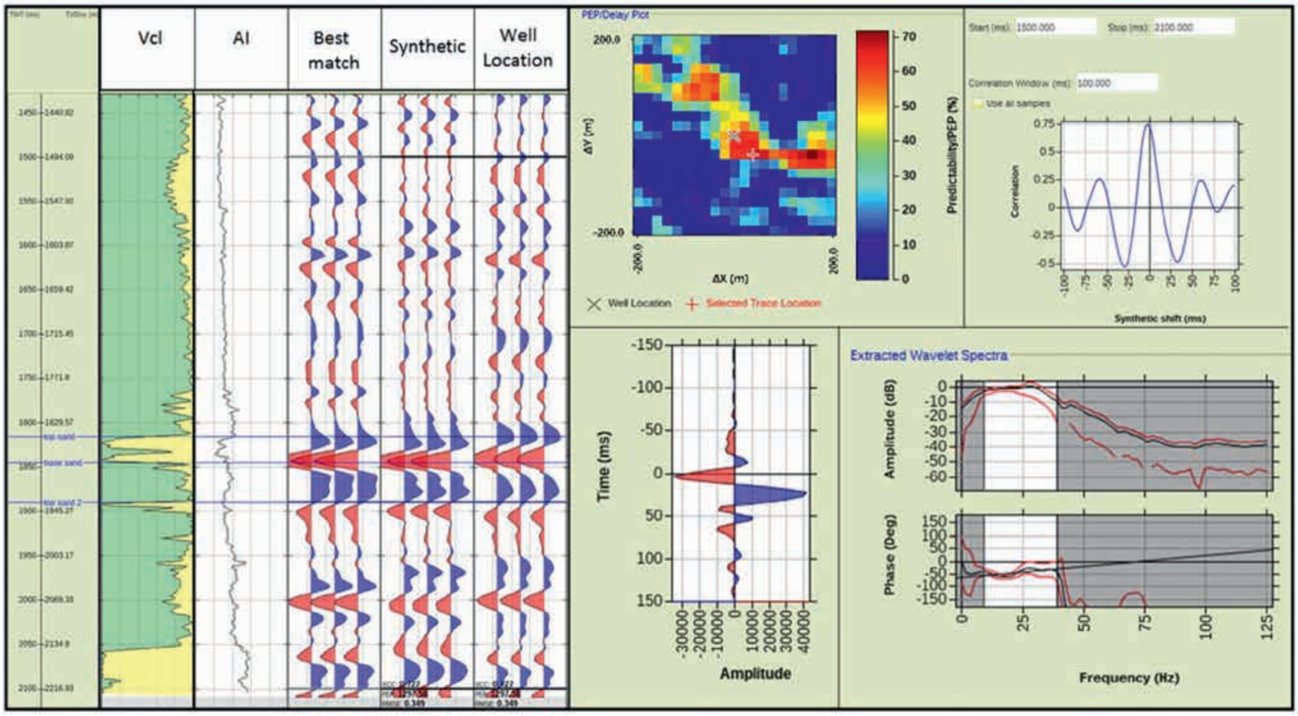

Figure 1 Example of a 'Phase Match' Tie using White's (1980) matching technique. The extracted wavelet is not symmetrical and has a phase intercept of about -60° (see text for discussion). The wavelet lag has been added in the synthetic to illustrate the quality of the tie. Note that owing to the phase rotation and shift the marker horizons are not correctly referenced with respect to the seismic loops.

Wavelet phase from the matching technique

Figure 1 illustrates a 'phase match' tie using the matching technique. The seismic data is a near angle stack with an average incidence angle of 11°, so the reflectivity series has been calculated at this angle using the time-depth function from the sonic log calibration. Matching of the reflection coefficient time series to the seismic data is performed within a particular zone of interest (1500-2100 ms) and within a specified data cube around the well (the option to use the borehole trajectory has been chosen with a search radius of 200 m). The reflection coefficient series is calculated for the average angle of the seismic stack (i.e. 11°). An effective wavelet length of 150 ms was determined after running the software and evaluating the fit statistics described below.

The map display (Figure 1) shows the 'percentage of energy predicted' (PEP) in the synthetic at each location around the well. For readers more familiar with the cross-correlation parameter, PEP is approximately the cross correlation squared (White and Simm, 2003). The band of hot colours on the map effectively indicates the direction of strike of the sand feature encountered by the well. This display is a useful guide to the interpreter in determining an appropriate 'best match' location. The highest PEP calculated (72%) is located ~160 m from the well location (dark red colour at the far right of the display). This is considered a little unreasonable and the best match location was moved to an area of uniform high values (~68%) within ~60 m of the well (+ symbol on the map).

In addition to the spatial appreciation of the correlation coefficient the matching method provides statistics (bT and b/B), related to the spectral content of the data and the window length, to evaluate the robustness of the estimation. For a tie with statistical validity, bT should be >6 and b/B should be in the range 0.25-0.5 (White (1997) and White and Simm (2003)). Table 1 shows values of 6.82 and 0.48 respectively for bT and b/B.

Effective seismic angle	q=11°
Seismic time gate	1500-2100 ms
bT	6.82
b/B	0.48
PEP (percentage energy predicted)	0.68
NMSE	0.07
Estimated phase error	11°
Cross correlation at best match	0.848
Cross correlation at well location	0.727
Best match Rel X	40 m
Best match Rel Y	-40 m
Wavelet lag (added in display)	20 ms
Phase intercept	-60°
Phase gradient	0.862
Potential phase range	-50° to -70°

Table 1 Parameters for Well-Seismic Tie using the Matching Technique.

Related to the bT and PEP statistics is the estimation of phase error, which in this example is estimated at 11° (Table 1). The phase estimation error is calculated via the normalised mean squared error (NMSE) (White and Simm, 2003):

$$NMSE \approx \frac{1}{bT}\frac{1-PEP}{PEP}, \; Std.Err.Phase(radians) \approx \sqrt{NMSE/2}$$

Wavelet time series and amplitude and phase spectra are also shown in Figure 1. The wavelet looks reasonable and comprises two main loops (a trough/peak pair) with a number of secondary oscillations. Wavelet phase is assessed from the phase display by selecting a signal range (using the amplitude spectrum as a guide) and making a linear fit to the phase between the estimated standard errors (note there is no justification in most cases for the phase fit to be anything other than linear). The intercept of the straight line fit gives the (average) phase and the slope of the line represents a residual time shift (White and Simm, 2003). Phase estimation can be quite sensitive to the signal range chosen. In this case a phase of around -60° is determined for a signal range of 8-40 Hz. The phase angle description is referenced to the positive standard polarity convention (Sheriff, 2002) (i.e. time zero is set at the maximum positive amplitude value). Visually varying the linear fit between the estimated standard errors (red curves) gives a potential phase range of -50° to -70° (i.e. this is the range of wavelet phase for which the fit statistics would be similar). This range is consistent with the calculated phase error of 11° described above. Note that a 20 ms time lag has been estimated in the matching process and, in order to appreciate the quality of the tie, the wavelet and synthetic displays have been made with the lag added (Figure 1).

The occurrence of amplitude at zero frequency on the amplitude spectrum (Figure 1) is explained by the fact that it is not possible with only 600 ms of time segment to properly estimate the low frequency roll off. This is not important for the general estimation of seismic phase (even with broadband data) but it is critical for the derivation of wavelets for broadband seismic inversion. Naeini et al. (2016) have determined more advanced well tie procedures that give an estimate of the low frequency roll off.

The synthetic from the best match (i.e. the convolution of the reflection series with the 'extracted' wavelet) is shown in

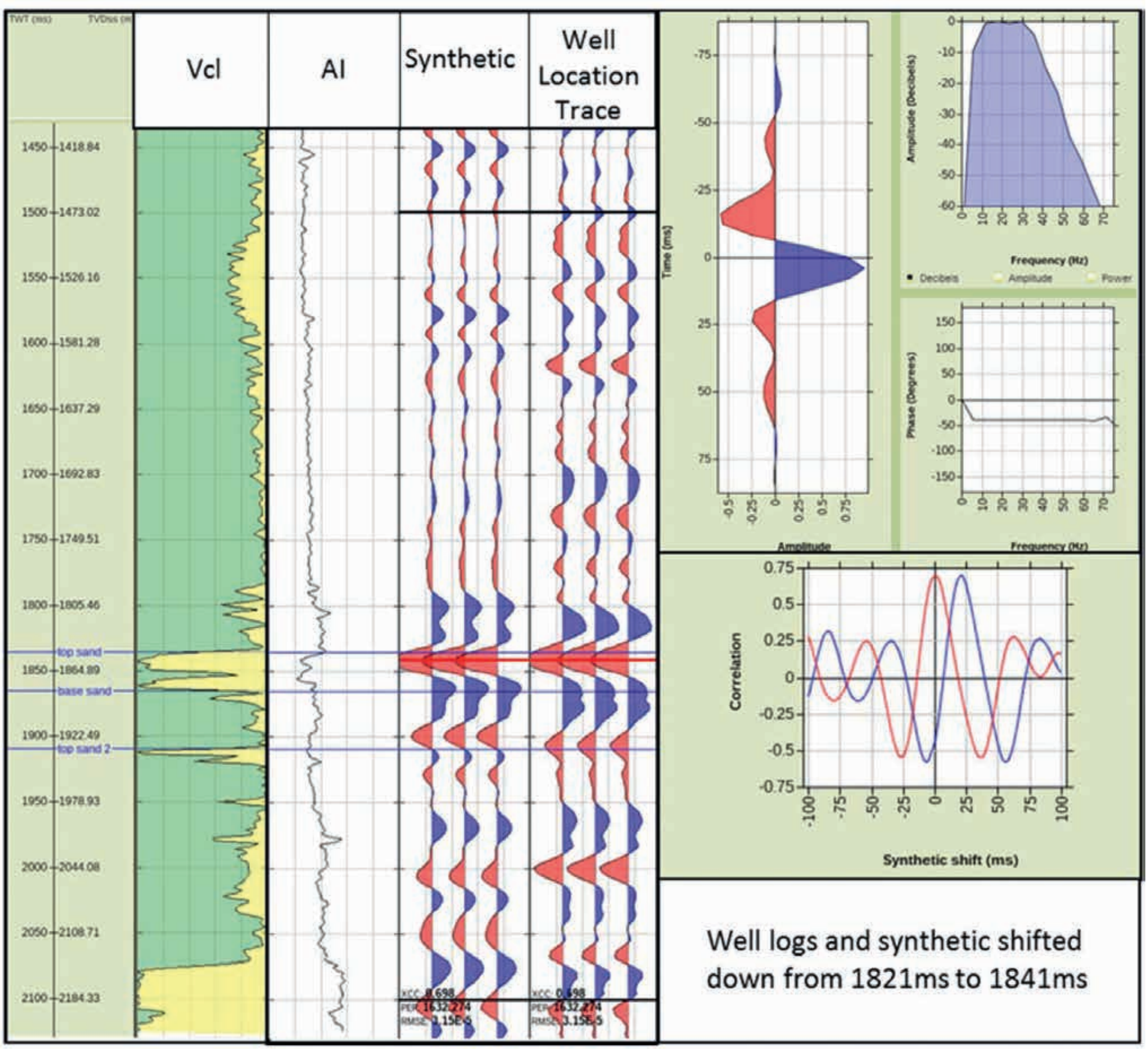

Figure 2 'Phase match' well tie at the well location using the Adaptive Technique. (Note colours for the correlogram are blue=pre-shift, red=post shift).

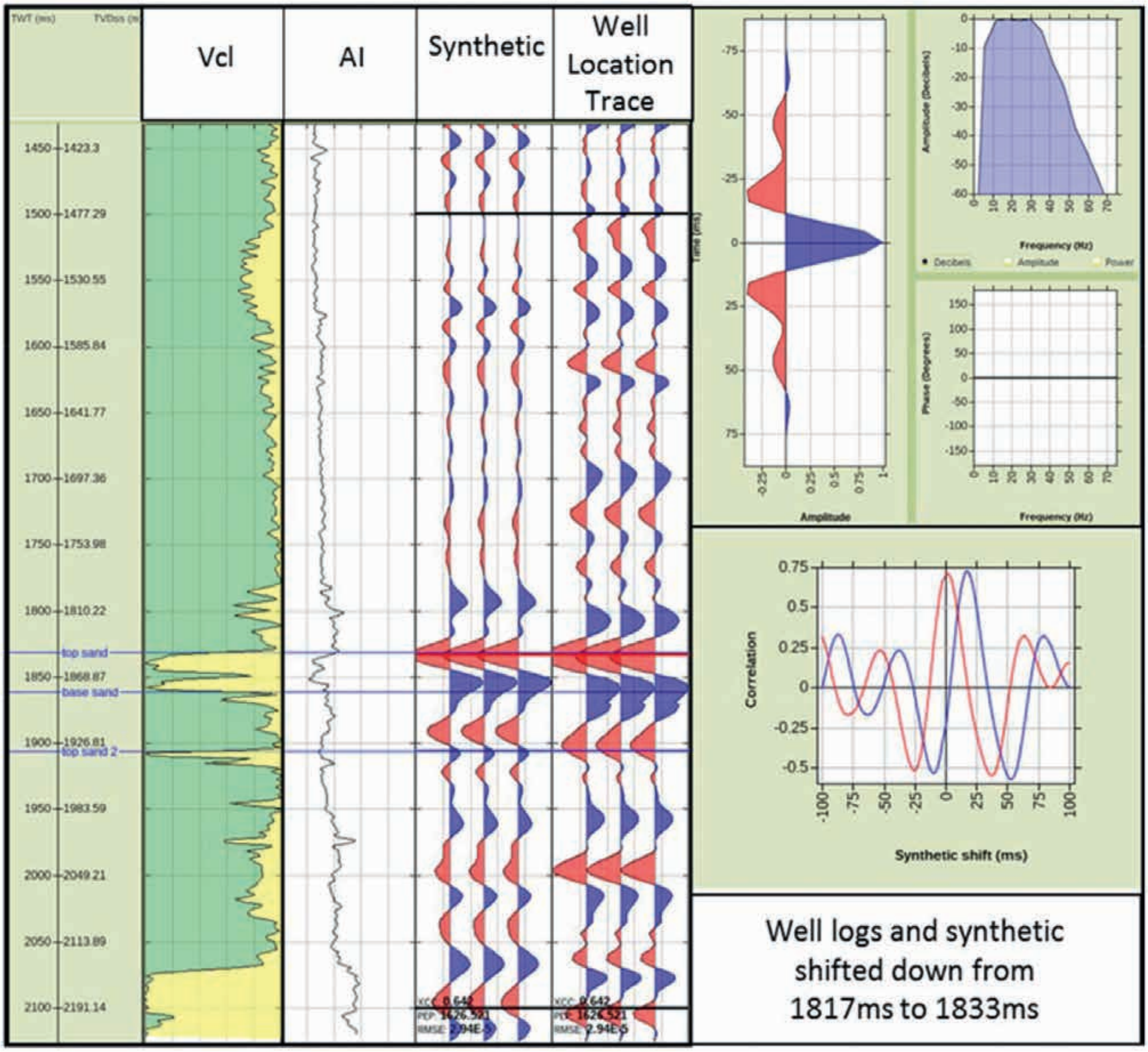

Figure 3 Zero phase tie (with positive standard polarity wavelet) at the well location after phase rotation of +60°. The top and base of the low impedance sand now correlate clearly with a trough and peak respectively.

Figure 1 along with the seismic traces at the best match and well locations. In the case of relatively flat lying geology a large degree of similarity would be expected between the traces at the best match and well locations. Comparing the best match trace and the synthetic shows that there is a reasonable character and amplitude match, particularly in the lower half of the synthetic where the key reflecting interfaces are situated. The symmetrical correlogram (or cross correlation), determined at the well location with a correlation window of 100 ms, suggests that the wavelet phase has been accurately determined. Given the phase rotation and the time lag it is clear that this 'phase match' synthetic display should not be used to correlate the well markers to the seismic loops.

Wavelet phase from the adaptive technique

The process for tying the data using the adaptive technique can be outlined:

1. Amplitude spectrum extracted from the seismic (i.e. using the Fourier transform). (This has been done as an integral part of the wavelet extraction process described above).
2. Zero phase time series wavelet derived from the amplitude spectrum. In this case the low and high frequency slopes were edited to simplify the wavelet and give realistic trough/peak ratios. An alternative would be to fit an idealised wavelet (such as a Butterworth or Ormsby wavelet to the spectrum; for example a 5-10-25-48 Hz Ormsby wavelet would provide a good fit to this extracted spectrum).
3. Depth-to-time conversion (log calibration) – in this case the well seismic calibration employed in the matching section above has been used. (Note that if there were no checkshots the sonic log would be integrated and tied using the depth of a prominent geological boundary and the time from the assumed reflection in the seismic. Pseudo-velocities (i.e. from well depths and seismic times) are not advised as they

pre-suppose a wavelet shape, as does 'stretch and squeeze' to force a match).
4. Reflection coefficients calculated for 11° incidence angle
5. Correlogram of synthetic and seismic at the well location evaluated for symmetry (time gate 1500-2100 ms)
6. Phase rotation to achieve symmetrical correlogram
7. Apply single bulk shift to account for the time lag

Figure 2 illustrates the 'phase match' tie using the adaptive technique at the well location. The phase rotation required to give a symmetrical correlogram is -40°. A lag of 20 ms is clearly defined and the cross correlation is 0.7. The answer is good enough for the purposes of seismic interpretation. The phase difference between the two techniques is not something it would be possible to appreciate by visual inspection. A clear drawback to the adaptive technique is the lack of any assessment of accuracy or potential phase ambiguity. It is argued that the phase accuracy requirements for seismic inversion necessitate the use of the matching technique for understanding the wavelet.

Zero phasing

There are effectively two options for zero phasing. The first is to derive a convolution operator based on the extracted wavelet so that the output has the same amplitude spectra but is zero phase (Robinson and Treitel, 1967). Sometimes this is referred to as 'zero phase deconvolution'. Such an approach effectively assumes that the extracted wavelet is noise free. Often, however, the interpreter can be fairly confident about the general phase of the data but uncertain as to the exact wavelet shape. For example, some of the secondary loops in the wavelet may be the result of noise having been incorporated into the estimation. Equally, slight errors in the logs could lead to uncertainties in wavelet shape. If possible,

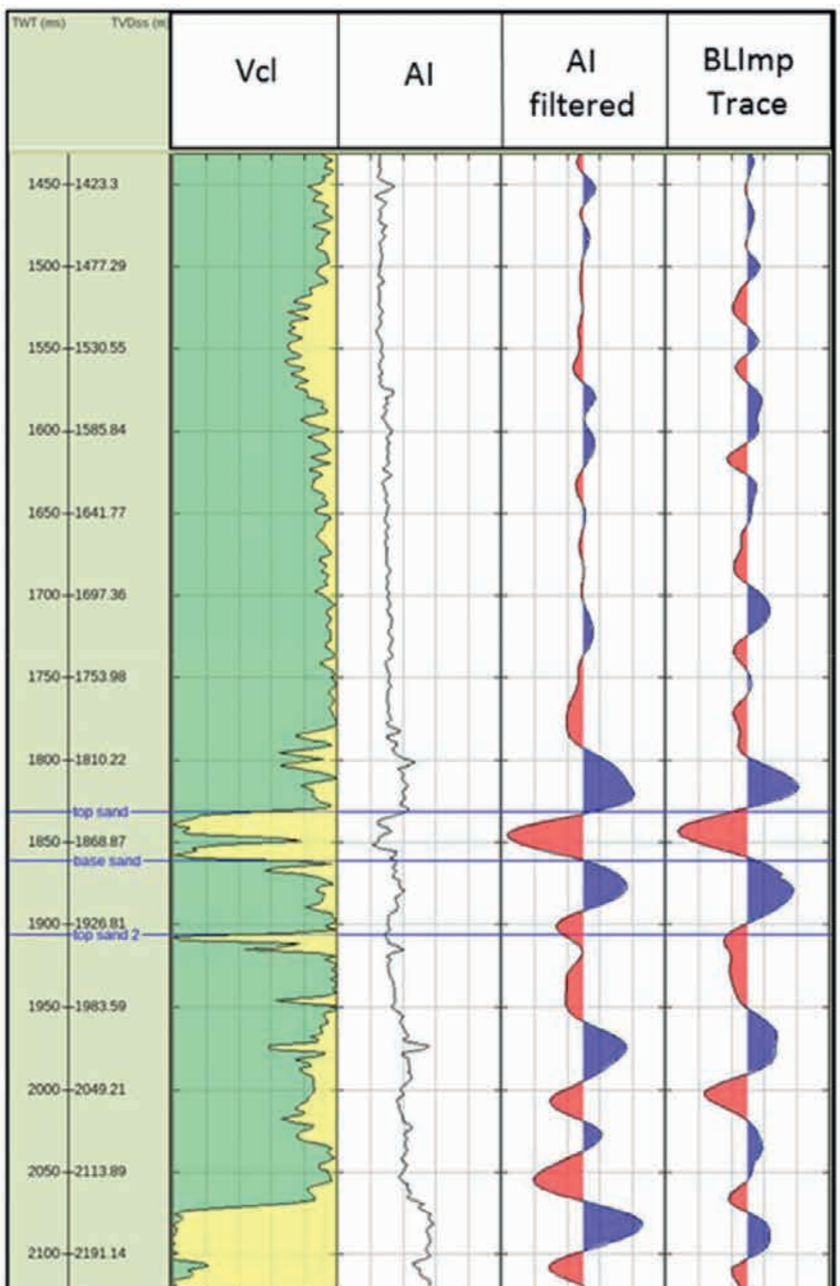

Figure 4 Bandlimited impedance tie. The sand is evident as a low impedance layer (trough) with the top and base of the sand located close to the upper and lower zero crossing of the trough.

wavelet extractions should be performed on multiple wells in order to determine the correct generalised form of the wavelet.

In this example the 'phase match' tie is simply used to estimate a single phase rotation that might be applied to the seismic data to make it broadly zero phase. A phase rotation of +60° has been applied so that the data is zero phase and positive standard polarity (i.e., positive numbers represent a downward increase in impedance). This polarity convention is the most practical when the seismic is to be used for detailed amplitude analysis. For example, it ensures that reflections will plot in the appropriate sector of the AVO plot as well as giving the correct sense of impedance change after application of trace integration-based processes such as band-limited and coloured inversion.

Interpreter's Zero phase tie

Figure 3 shows the final zero phase and correctly time registered tie at the well location. The markers now make sense in terms of the seismic loops, with the top of the low impedance sand being a trough and the base is a peak as would be expected from positive standard polarity.

Once the data can be shown to be zero phase, the interpreter can confidently generate attributes such as quadrature (+90° phase rotation) or bandlimited impedance and perform well ties in these domains. For example, Figure 4 shows a bandlimited impedance tie in which the impedance log from the well has been filtered with a bandpass filter and compared to a bandlimited impedance trace generated by trace integration followed by a high pass Butterworth filter. At higher angles, of course, the filtered quantity would be Elastic Impedance (Connolly, 1999) or Extended Elastic Impedance (Whitcombe et al., 2002) calculated at the appropriate angle.

Conclusions

A robust approach to the tying of well synthetics to seismic comprises three steps: phase estimation, seismic zero phasing and zero phase tie. Although an adaptive technique for estimating phase gives similar results, the practical example presented highlights the benefits of White's (1980) matching technique in providing a range of metrics which are useful in evaluating the nature of the tie, including the range of possible phase ambiguity (an important issue if seismic inversion is being contemplated). This is subject of course to the availability of good quality well seismic time-depth data. For most interpretation requirements a simple phase rotation of the seismic is usually appropriate, enabling the final step of a zero phase tie at the well location.

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