Tying well-log synthetic seismograms to seismic data: the key factors

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Summary

In general terms the prerequisites for a close tie between a well-log synthetic seismogram and a seismic data volume are accurate sonic and density logs and good quality seismic data. This poster discusses the key factors that underlie this generality and illustrates them with practical examples. Q,C. of the well-log and seismic data, timing and log calibration, well tie location, seismic bandwidth and S/N ratio, and the use of well tie diagnostics all play an important part in making close well ties. While attention to these factors generally leads routinely to good well ties, there remain some problem cases and areas that currently defy all attempts to produce a close tie. The poster briefly explores reasons behind these difficult cases.

Introduction

Well ties have become fundamental to the interpretation of modern seismic data. They allow horizons picked by an interpreter to be related directly to a well log and they provide a means of estimating the wavelet needed to invert seismic data to impedance and to rock property indicators. The old practice of making a tie by assigning times and polarities to formation tops is too rough and ready for the demands made of seismic interpretation today. In particular reliance on a polarity convention can easily lead to picking the wrong loop and missing valuable amplitude information. What the interpreter really needs to know is whether the data are processed to zero phase, whether the dominant loop in the resulting seismic wavelet is delayed, whether that loop corresponds to an increase or decrease in acoustic impedance (Simm and White 2002). A well tie makes this correspondence clear. It is often not that expected from the stated polarity convention. Knowledge of the seismic wavelet is even more critical to inversion to impedance since wavelet errors propagate through the whole process.

Figure 1 shows the elements of a well tie. A broadband primaries synthetic seismogram (trace 2) constructed from a calibrated acoustic impedance log (trace 1) is matched to a seismic trace segment (traces 4 and 6). The filter that converts the broadband synthetic to the matched synthetic (trace 5) is the seismic wavelet (trace 3). This shows that the black peak corresponds to an increase in impedance with a delay of 32 ms and allows features from the impedance log to be correlated with the seismic data. Alternatively it is a straightforward matter to remove the delay from the seismic data and convert the wavelet to zero phase. The residuals (trace 7) are the difference between the seismic trace and its synthetic seismogram. They indicate how good the fit is. Some trivial extra calculations can quantify how accurate the well tie is.

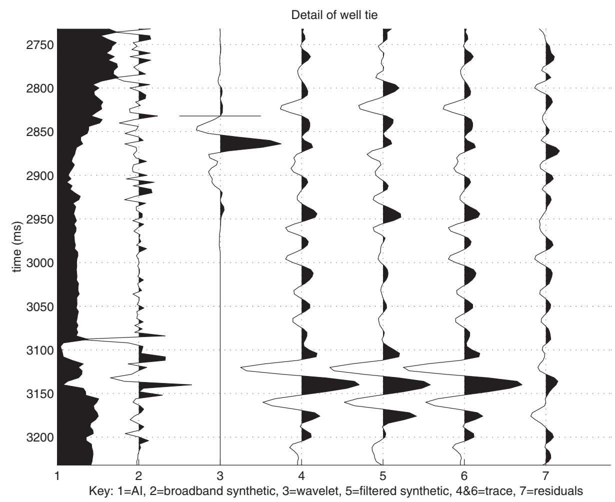

Figure 1: The components of a well tie. Time zero of the wavelet is indicated by the horizontal line.

The approach outlined here emphasises the importance of measuring the wavelet from the data, as in this example, irrespective of any preconceptions about its timing, polarity or what it should look like, Because the first loop of real seismic wavelets, including minimum phase ones, is rarely the dominant loop, a convention that defines the polarity of this first loop is not a reliable guide to the polarity of the main wavelet lobe.

Wavelet accuracy

The poster also emphasises the importance of a quantitative approach to well ties that results in measures of likely wavelet accuracy (White 1997) and not simply measures of synthetic to seismic goodness-of-fit. The matching process that produced the tie of Figure 1 is not, as often stated, a deterministic procedure. By taking account of noise in the seismic data and errors in the synthetic, one can estimate the accuracy of the wavelet.

Since the 'true' synthetic is an abstraction, we cannot measure the accuracy of the well tie directly. White (1997) gives equations for computing the normalised mean square error ($NMSE$) in the synthetic seismogram and the average phase error within the seismic bandwidth from the 'predictability' P, a measure of goodness-of-fit defined by $P = 1 -$ (energy in the residuals/trace energy). The correlation coefficient R also measures goodness-of-fit but implicit in it is the assumption of an error-free synthetic seismogram. If the assumption holds, then $P = R^2$. R^2 is a less deceptive measure of correlation generally than R. The $NMSE$ of the tie in Figure 1 is 0.022, corresponding to a $\pm 10\%$ error in amplitude and $\pm 6°$ error in phase across the seismic bandwidth. The error bars expand outside this bandwidth.

The tie of Figure 1 was obtained using the matching technique of Walden and White (1998), which can allow for a noisy synthetic. A simpler approach is to filter the synthetic to the bandwidth of the seismic data and time and phase shift the filtered synthetic to match the data. Correcting a misprint in White and Simm (2003), the standard error in phase rotation θ in this case is:

$$SE\{\hat{\theta}\} \simeq \sqrt{\left(1 + \frac{12 f_c^2}{B^2}\right) \frac{(P^{-1} - 1)}{2BT}}$$

where BT is the bandwidth-duration product of the data segment and f_c is the centre frequency.

The key factors

The key factors in tying a well-log synthetic seismogram to seismic data can be identified by working through the steps of the well tie process.

Seismic data Q.C.: S/N and bandwidth
A poor S/N (signal-to-noise) ratio obviously degrades the fit of a well tie. Although data bandwidth is also well recognised as key components of seismic data quality, the extreme dependence of accurate phase and timing on seismic bandwidth is often not recognised. A lack of bandwidth can in principle be compensated by extending the duration of the tie but this is rarely a practical option.

The problem is illustrated in Figure 2. In the left hand panel a synthetic seismogram has been zero-phase filtered to match the spectrum of the seismic data and then time and phase shifted to optimise the fit. In the right hand panel a delay of 4 ms and phase advance of 42° was applied to this optimum match. The two ties are visually indistinguishable; the predictablities of the two ties are 0.647 and 0.639. A 4 ms advance and 40° phase lag also produces an equivalent tie. In seismic inversion this ambiguity of almost 90° in phase would turn a step in impedance into a thin bed and vice versa. The problem stems from the 400 ms segment of data. The well-log reflectivity in this time window has a bandwidth of only ~ 20 Hz which is transmitted into the data. This bandwidth is inadequate for determining timing and phase accurately and produces standard errors in time and phase of ± 3.5 ms and $\pm 38°$. Fortunately the ~ 40 Hz bandwidth in a deeper time window (2.9-3.4s) produces an excellent tie ($P = 0.81$) with standard errors of ± 1.0 ms and $\pm 10°$.

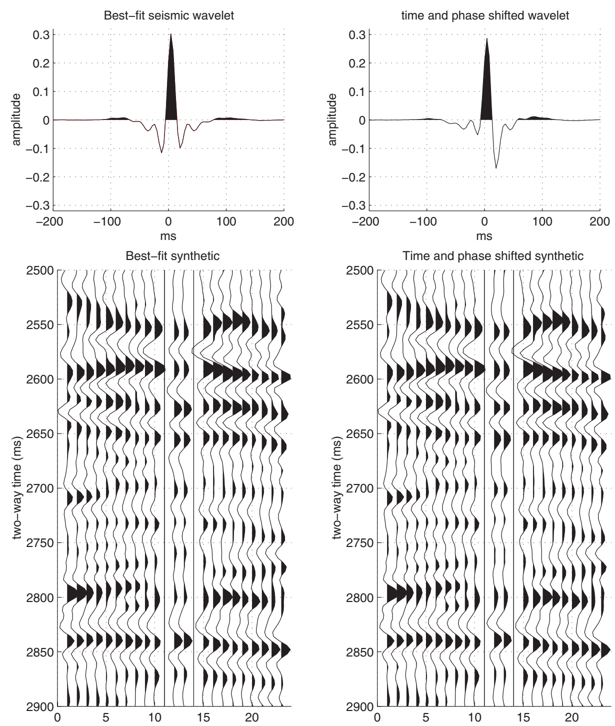

Figure 2: Two equally good well ties constructed from a calibrated impedance log using the two wavelets shown. The wavelets have the same amplitude spectra. The phase and timing of the synthetic in the left hand panel optimally match the data; in the right hand panel the best match synthetic was delayed by 4 ms and phase advanced by 42°.

Accurate phase and timing is unlikely to be established from seismic data whose bandwidth barely exceeds the centre frequency (White and Simm 2003). The Ricker wavelet, with a 6 dB bandwidth equal to 1.15 of its centre frequency, falls into this category. Thus, apart from any concerns about their physical reality (Hosken 1988), the use of Ricker wavelets in well-log synthetic seismograms generally yields sub-optimal phase and timing estimates.

Running well ties during processing can bring considerable benefits to seismic data quality (Barley 1985). So too can reprocessing. The outstanding well tie of White and Hu (1998) came about after some 2D lines were reprocessed.

Well-log Q.C.
Some editing and conditioning of the logs is normally required before constructing a synthetic seismogram from them. White, Simm and Xu (1998) documented an example where log conditioning contibuted as much as reprocessing to improving a well tie. Often only a relatively small portion of the log is affected so that the overall effect on the well tie is rather minor. Of course, from the prespective of analysing the seismic response of a reservoir, log editing and conditioning is of paramount importance.

Comparison of observed logs and log crossplots with predictions from empirical or petrophysical model is a valuable Q.C. tool, especially when one cannot call on the services of an experienced log analyst and when monitoring S-wave logs. Discrepancies can highlight log values to be investigated (always remembering that models as well as logs can be unreliable).

Calibrate the sonic and density logs
Errors in timing of the well-log synthetic seismogram are more damaging than errors in amplitude, particularly at higher frequencies. Log calibration using times from a VSP optimises the timing of seismic and well-log ties. The table below demonstrates this for the well tie of Figure 1. Arbitrary 'stretch and squeeze' merely to beautify the fit to a seismic trace is unscientific and definitely not good practice since it propagates errors in the data or well log synthetic into the seismic wavelet (White 1998).

$Stretch$	0.98	0.99	1.00	1.01	1.02	1.03
PEP	0.74	0.83	0.86	0.83	0.77	0.71

Table 1: Variation of the proportion of trace energy predicted (P) in the well tie of Figure 1 with the stretching or squeezing of the calibrated sonic log.

Construct the synthetic seismogram from the calibrated well-logs
This is usually straightforward. The conversion from depth to time resamples the logs and is often combined with a log blocking step. The synthetic seismogram generally benefits from some blocking of the logs and it is mostly safe to block to a fine sample interval (say 0.5 ms) and then anti-alias filter and resample the synthetic to the sample interval of the seismic data. With highly fluctuating logs it pays to optimise the blocking length (Francis 2002).

Converting the logs to elastic impedance (Connolly 1999) offers a quick and convenient way of computing synthetics for well ties on angle stacks using standard normal incidence code. This procedure becomes seriously inaccurate at any sudden change in lithology. Alternatively computing angle or offset-dependent primary reflection series is a straightforward task.

Pilot analysis: the right time and place
Well ties are generally made with time-migrated data. Because velocity tends to increase with depth, image points normally move up dip from the well. Figure 3 shows the scan for best match that preceded the tie of Figure 1 and the time surface of a prominent reflector just above the match gate. The location of best match moves up dip to the SW. Routine scanning for best match between the well-log synthetic and the seismic data shows ample evidence of this up-dip movement. It is not certain that depth migration would always obviate the need to scan for best match. Attempting to tie the well at the wrong location could instigate 'stretching and squeezing' the synthetic seismogram to force a fit.

Generally a data segment long enough to yield a bandwidth-duration product of 25 or more (e.g. 0.5 s for 10-60 Hz North Sea data) is needed to ensure a reliable well tie. If a longer synthetic is available, it also pays to scan for an optimum time gate as the example of Figure 2 shows. The pilot analysis can also investigate the choice of analysis parameters.

Estimate the wavelet and its accuracy
The matching technique of Figure 1 requires data segments with a bandwidth-duration product of 25 or more. Provided the preceding groundwork was adequate, this step is also straightforward. Bandpass filtering followed by optimum time and phase shifting is more suitable for noisy data or shorter data segments, Whatever the method, a well tie without some indication of its accuracy is an incomplete tie. In particular a tie from a short data segment or narrow bandwidth data is generally inaccurate and an interpreter needs to be aware of its impact on, say, impedance inversion.

Measures of accuracy become very useful when comparing or combining seismic wavelets estimated at different wells within the same seismic survey (White 1997). Examples are presented to show that wavelets estimated from marine seismic data are mostly consistent within the same survey.

Problem cases.

What do you do when a well tie is poor? There is no prescription for improving it beyond the general one of going back to q.c. the seismic data and calibrated logs. In general effort spent on practical investigation of the logs and seismic data is more likely to improve a well tie than worrying about theoretical niceties such as the time variance of the seismic wavelet.

Some problem cases and areas currently defy all attempts to produce a close tie. One is in tying seismic data to synthetic seismograms from deviated wells. Uncertainties in the well path and structure relative to the seismic data make it very difficult to time the synthetic accurately enough. Ties to well logs from finely layered sequences with strongly fluctuating velocities are also generally poor. These sequences generate strong internal multiples that are notoriously difficult to model accurately. There are no easy remedies to these problems.

Conclusion

Adopting a rigorous but pragmatic and data-driven approach converts the making of well ties from an art to a science. It establishes a work flow that consistently yields dividends in better well ties. Measuring accuracy is an important part of the process. It quantifies the reliability of the tie and, in the long term, helps build experience on what matters in making a good well tie. A third reason for always measuring accuracy is the need to compare and combine wavelets.

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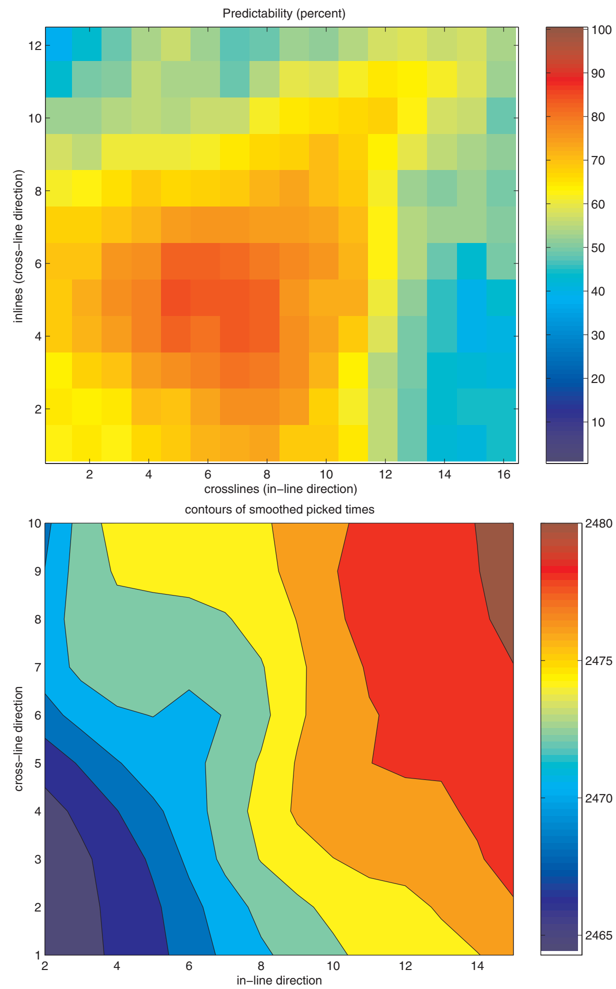

Figure 3: Top: Contours of goodness-of-fit from matching a 2.7-3.2s segment of well-log synthetic seismogram with a cube of data centred on the well. The well is at the centre of the displays. The goodness-of-fit is measured by P, the proportion of trace energy in the seismic trace predicted by the match, which is approximately the square of the cross-correlation coefficient between the matched synthetic seismogram and data. Bottom: time contours of a prominent reflection above the match gate showing NE-SW dip.