Well Tie Tutorial and its importance in Seismic Interpretation and Inversion

Carla, Carvajal, Jorge Fernandez [1] and Joaquin Aristimuno [2]
Ikon Science [1]
Former Ikon Science, currently Paramount Resources [2]

Summary

The well tie is a key step in seismic interpretation and characterization. Despite its importance, it is often overlooked, leading to a lack of understanding of its consequences. This article delves into the basics of the well to seismic tie, including a case of study showcasing the impact of using an inaccurate time-depth relationship (obtained from the well tie process). This article also examines the effects of using different wavelets in a simultaneous inversion and its potential consequences on estimating elastic and geomechanical properties.

Introduction

It is well known that well tie to seismic is a critical step towards the characterization of reservoirs using seismic data. Understanding the real characteristics of the wavelets (amplitude, phase, and frequency) and their variations with each other (e.g. amplitude and frequency and phase and frequency) is paramount to perform an optimal well tie. We agree that a quantitative approach is needed (not just a visual comparison between synthetics and seismic data, assuming at the same time knowledge of the wavelet being analyzed) when doing well ties. It is also important to note that to have a good well tie, a proper wavelet estimation should be performed.

When performing well to seismic ties we want to achieve several things:

- Satisfy ourselves that there is a reasonable match between synthetic and seismic data at the objective level, without which inversion will not be useful.
- Establish the time-depth relation that will be needed for building the starting model.
- Determine the offset (or angle) - dependent wavelets that are needed as input to the inversion.

In general, we should establish the well ties at the start of the inversion preparations, but seismic data conditioning will change the time-depth relations and the wavelets, so the well ties should be repeated on the final conditioned seismic.

We will explain in some detail the Roy-White methodology (White, 1980) as a way to quantify how good a well tie is (and hence, demonstrate improvement after log editing or seismic conditioning) and to put error bars on the seismic wavelet spectrum (so we can see whether the wavelet is well determined).

A quantitative approach for the well tie: the Roy White methodology in practice

The Roy White methodology (White 1980) allows us to quantify how good a well tie is, and hence, demonstrate improvement after log editing or seismic conditioning. It allows us to analyze error bars on the seismic wavelet spectrum so we can see whether the wavelet is well determined.

The Roy White method is essentially a coherence matching technique. The workflow can be summarized as follows:

1. From well log data we estimate the earth reflectivity, albeit with associated noise.
2. A volume of seismic data around the well is scanned for the best statistical fit to the synthetic trace, and a wavelet is estimated at that trace.
3. The filter providing the best match between the earth reflectivity and the seismic is our best estimate of the original seismic wavelet.

There are various things to consider when tying a well and estimating wavelets. The first is the wavelet length or L. Then there is the time window, T, over which the estimation will be performed.

Roy White defined two important concepts useful to quantify the quality of a well tie: the goodness of fit, and the wavelet accuracy. Maximizing these two measures should deliver the best wavelet, with the smallest error bars.

The goodness of fit measurement is called PEP, the proportion of energy predicted from the synthetic. Numerically, it's approximately the square of the cross-correlation, and a value greater than 0.7 is considered good.

Goodness of fit is not a measure of the accuracy of the wavelet. The cross-correlation increases with increase in wavelet length, but the longer the wavelet is, the more chance that noise is also being matched.

If a value of one is achieved, it implies a perfect match between the seismic and the synthetic, using the estimated wavelet (i.e., the residual is zero).

The goodness of fit is defined by equation [1]:

$$\text{PEP} = 1 - (\text{energy in residuals/ trace energy})$$

The maximum PEP value is not necessarily found at the well location or along a composite trace along the well trajectory. In practice, a seismic cube is scanned around the well location in order to find a maximum PEP. This approach is preferable since positioning of seismic energy during migration carries uncertainty, well positioning itself may be uncertain, and lateral stability of the estimation may be better understood with PEP maps.

The wavelet accuracy is given by NMSE, the normal mean squared error, that is calculated using equation [2]:

$$\text{NMSE} = 0.59 / T \times (1 - \text{PEP}) / \text{PE}$$

Where L is the wavelet length and T is the length of the time window from which the wavelet is estimated. A good well tie has NMSE less than 0.2.

The window T we choose is a function of the frequency content of the seismic or the bandwidth. The higher the bandwidth, the smaller the time window.

The wavelet length is then simply calculated from the time window. Usually, L is a value between a 1/3 and a 1/7 of the time windows used.

The longer the ratio L/T is, the better it can fit everything in the time window. But as the wavelet gets longer, the wavelet begins to also fit noise, and the wavelet estimation error goes up. At the opposite end of the axis, the goodness of fit is poor, as we are over-smoothing in the spectral domain. The idea is to find the optimum zone, where the error is low and the goodness of fit is high.

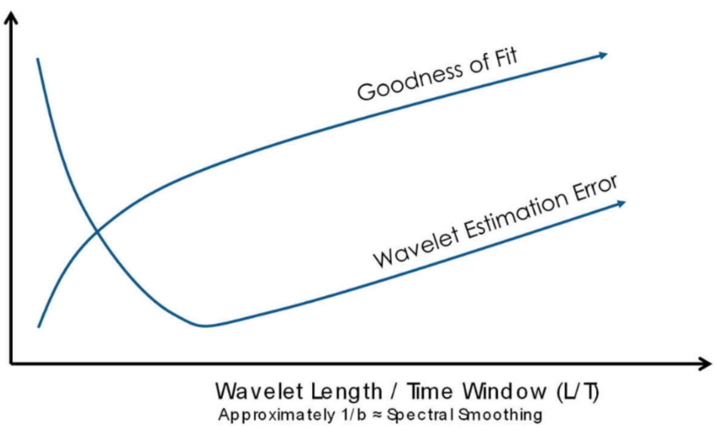

Figure 1. Goodness of Fit and Wavelet Estimation Error vs. L/T ratio. As the (L/T) ratio goes up, or the wavelet length to window length goes up, the goodness of fit, or PEP always increases.

The fairway for good wavelet estimations

In practice, the seismic bandwidth, the wavelet length L, and the seismic time window T are related (Figure 2). The frequency bandwidth 'B' of the seismic data determines the optimum effective wavelet length 'L' required for a synthetic to match, which in turn limits the range of well synthetic time windows 'T' that can be used as input to wavelet estimation. This seismic bandwidth can be determined using a statistical wavelet estimation or by any standard spectral analysis software and checked against any filtering applied by the seismic processing sequence.

The graph shows frequency bandwidth versus optimum wavelet length (red X, Y axes, and red diamond points) and frequency bandwidth versus time window min. and max. (blue X, Y axes, and blue dashed lines).

The more bandwidth the seismic data has, the shorter the wavelet should be, and therefore, the shorter the input seismic data time windows recommended for best results.

Reducing wavelet length, given a fixed seismic data frequency bandwidth, will create smoother wavelets from this wavelet estimation process. The more seismic frequencies that can be included in the input seismic trace, the better the phase estimation, as more points are available to define the wavelet's phase line (see the cartoons beside the B, L, T plot in Figure 2).

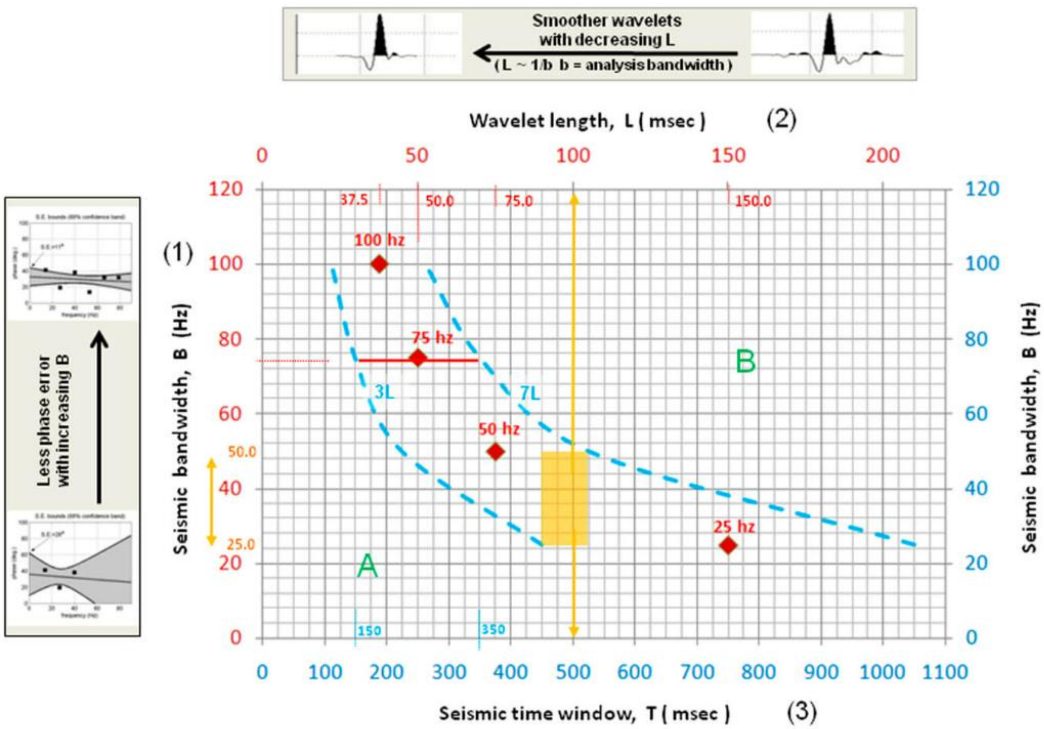

Figure 2. The fairway for good wavelet estimations. Good estimations can be possible inside the fairway between the two light-blue-dashed lines. Zone A is distortion and Zone B is matching noise (White, 1998).

The green A indicates an area on the graph where distortion of the estimated wavelet is likely because the wavelet is too short for the seismic data's restricted frequency bandwidth and B indicates an area where longer wavelets than necessary allow noise to be matched to the synthetic as well as signal.

Well tie example

In this case study, we want to demonstrate the importance of a good well tie for optimal seismic inversion results (Aristimuno and Carvajal, 2022). We estimated wavelets at the five well locations for each partial stack, meaning that we estimated a total of 20 wavelets. Then, we average them to get a wavelet for the nears, the mids, the fars and the ultrafars, and this is what we called a set of wavelets. This process is only possible if there is consistency between the wavelets across the angle range, with only gradual variation in the form of a decrease in bandwidth and modest phase rotation from the near to far stacks. Otherwise, data conditioning is needed to have better results in the seismic inversion.

Figure 3 shows the well tie in the well Norton 1 for the near stack. There are four tracks, from left to right: the first one shows the seismic section with the synthetic trace at zero angle of incidence, the next track is the seismic trace selected at the best PEP location, then the synthetic trace using the estimated wavelet, and the last track is the composite seismic trace estimated at the well location. Visually, we can observe a good well tie, especially at the top of the target in the Jubilee sand. Above the target the section is noisier, but still we have a reasonable tie with a cross-correlation value of 73% in the window from 1590 to 1950 ms.

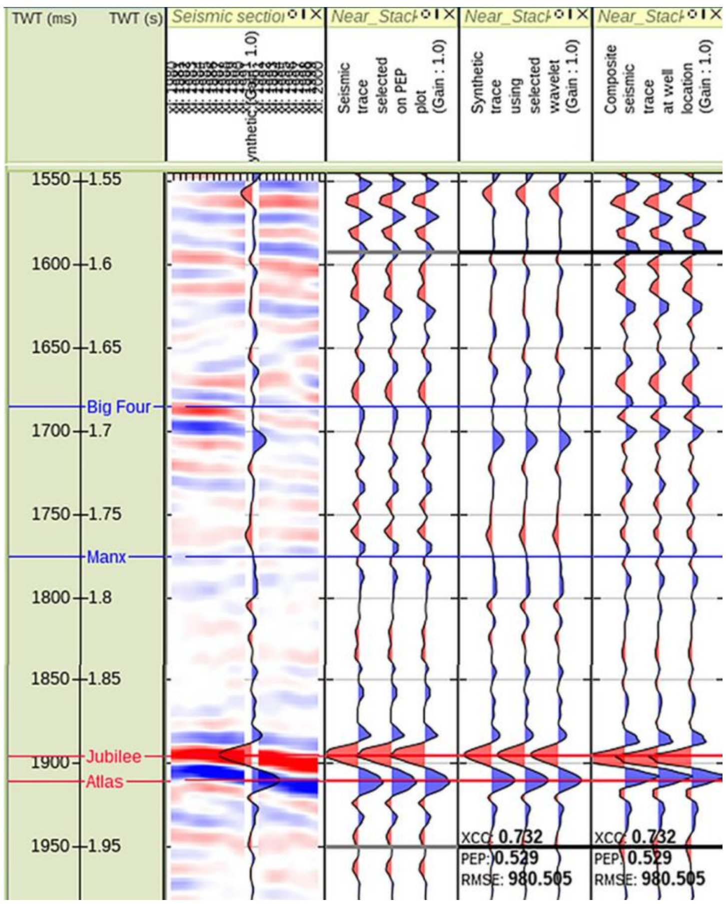

Figure 3. Synthetic well tie for the near stack in well Norton 1.

The quantitative analysis of our synthetic well tie for the near stack is shown in Figure 4. The proportion of energy predicted (PEP) over a 200 m square window around the well location is shown in Figure 4. Note that the best PEP values are observed around 50 m away from the well (identified with a red cross). Although high PEP values indicate a good synthetic tie, we also need to look at the delay. We selected the best well tie that satisfies both a high PEP value with near-zero delay and estimated the wavelet at this location. The NMSE value of our estimated wavelet is 0.07, which meets the criteria of a number below 0.2. The analysis bandwidth times the window length (bt) and the analysis bandwidth of the seismic (b/B) are inside the recommended values. For both parameters, low values indicate the wavelet is under smoothed and the wavelet length should be decreased and high values indicate the wavelet is over smoothed and the wavelet length should be increased. The average phase of the wavelet is -5 degrees and the phase average error is low at 10.38 degrees. We repeated this methodology for all the partial stacks and wells and averaged the wavelets per angle.

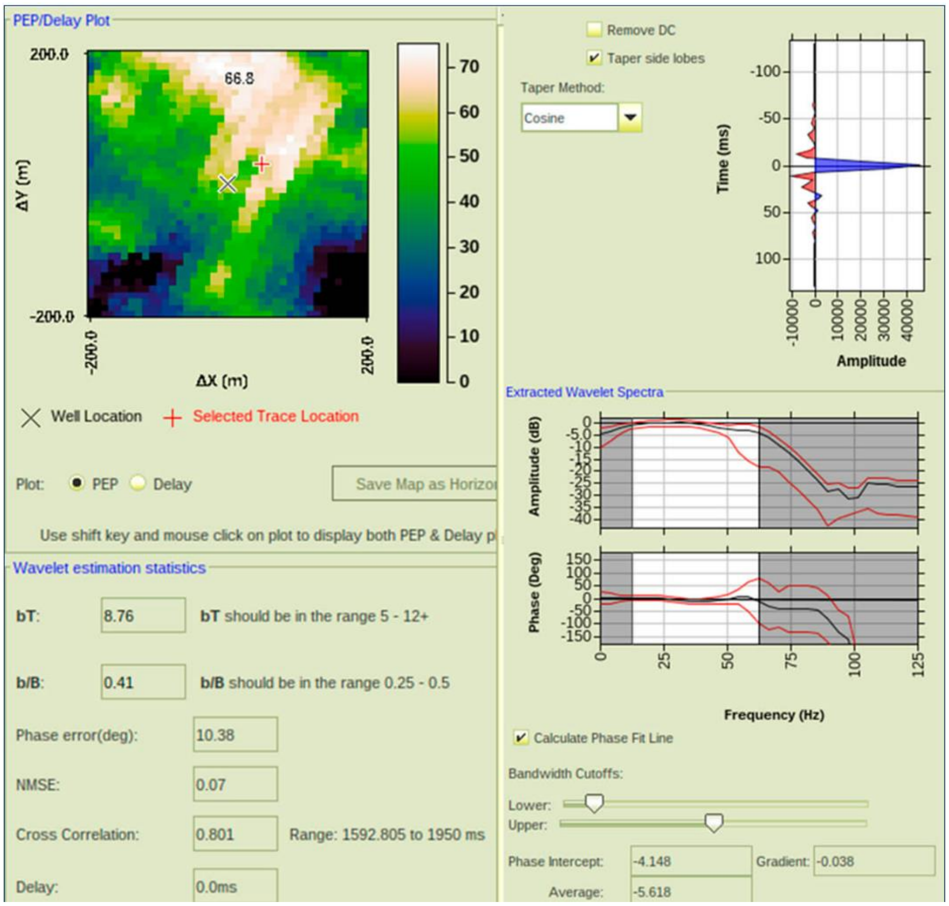

Figure 4. Quantitative well tie analysis (Norton 1) and estimated wavelet at the red cross location.

The effect of a qualitative well tie in seismic inversion

To evaluate quantitatively the effect of a qualitative well tie, e.g., tying a well based on how good it 'looks', we proceed to phase rotate all the average wavelets estimated using the Roy White methodology we used on our previous example -42 degrees.

Figure 5 shows that qualitatively speaking both wavelets (estimated and estimated rotated -42 degress) show a relatively similar 'tie' around the reservoir of interest (between the Jubilee and Atlas markers). However, when performing seismic inversion (in this case we calculated a quick Simultaneous Seismic Inversion), it shows two different results.

Figure 6 shows the results of simultaneous seismic inversion using the estimated average wavelets per angle and when rotating them -42 degrees for compressional velocity (Vp) and Young's modulus (E).

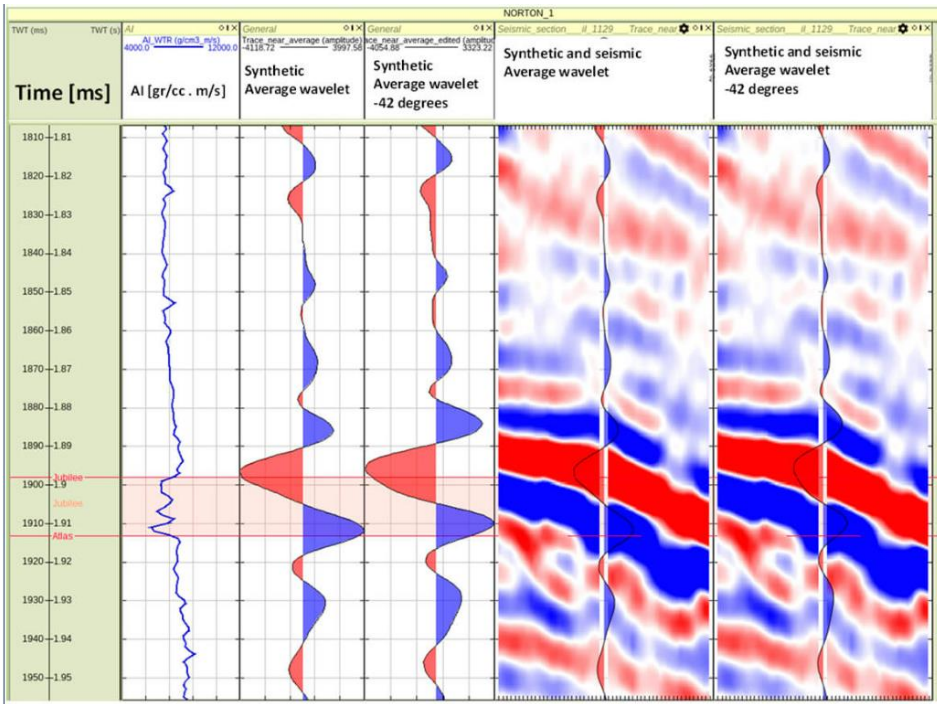

Figure 5. Qualitative well tie using two wavelets: estimated and estimated rotated -42 degrees.

Even though we could see that the average wavelet rotated -42 degrees showed a 'good' match to the seismic stack at the reservoir level (Figure 5), it is clear now that after removing the effect of the wavelet through the seismic inversion process the elastic properties will be different from those estimated using the right wavelets. This effect is seen not only on the position in time of the maximum values but also the magnitude itself is different.

Because there was a phase rotation applied to the estimated wavelets, the values of elastic and geomechanical properties appear to be shifted in time (Figure 6).

Changes in Young's modulus values, are shown to be as high as ±40%. We know this is due to the fact that the properties appeared to be shifted when using the rotated wavelets, but it is important to mention, as we know, that position in time will affect the position in depth and therefore may affect drilling planning. Moreover, in this example, the extreme changes in E (+40% and -40%) seems to be linked with the presence of gas. This fluid effect may increase even more the uncertainties of elastic properties calculated from seismic inversion when the wavelets are not the correct ones.

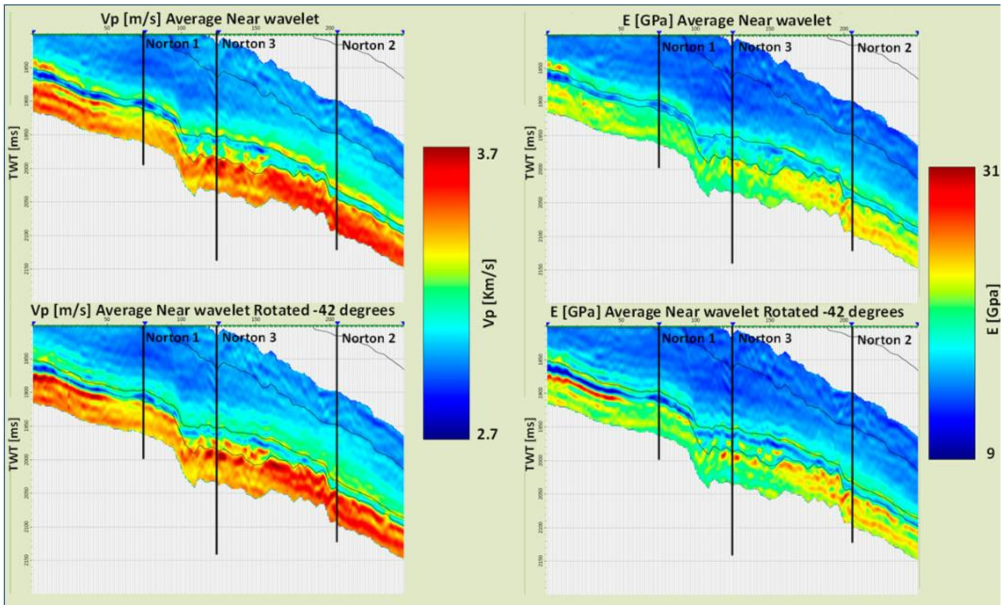

Figure 6. Results of simultaneous seismic inversion applying the estimated average wavelets per angle (top) and when rotating them -42 degrees (bottom) for compressional velocity (Vp) and Young's modulus (E).

Conclusions

Well tie is a very important and often overlooked step in seismic interpretation and seismic inversion. The process of well tie involves the process of wavelet estimation, from which we obtain the different angle-dependent wavelets that are used in the seismic inversion process. Qualitative wavelet estimations can affect the estimated elastic parameters from seismic inversion in a negative way. Quantitative methods, on the other hand, can provide a way of measuring uncertainties of amplitude and phase of the wavelets. Concepts such as PEP and NSME provide additional information as a way of evaluating and demonstrating good wavelet estimates and the wavelet estimation parameters can be determined using the "fairway for good wavelet estimations" from Figure 2. Finally, it was shown that predictions of geomechanical properties could be significantly affected by the estimated phase.

References

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