Wavelets, well ties, and the search for subtle stratigraphic traps

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ABSTRACT
We examine the conventional methodology for tying wells to processed seismic data and show why this methodology fails to allow for reliable interpretation of the seismic data for stratigraphy. We demonstrate an alternative methodology that makes the tie without the use of synthetic seismograms, but at the price of measuring the seismic source signature, the cost of such measurements being about 1% of data acquisition costs. The essence of the well tie is (1) to identify geological and seismic interfaces from the logs and core, (2) to measure the one-way travel time to these interfaces using downhole geophones, and (3) to use the polarity information from (1) and the timing information from (2) to identify the horizons on the zero-phase processed seismic data. Conventional processing of seismic data usually causes the wavelet to vary from trace to trace, and conventional wavelet extraction at a well using the normal-incidence reflection coefficients relies on a convolutional relationship between these coefficients and the processed data that has no basis in the physics of the problem. Each new well introduces a new wavelet and poses a new problem—how should the zero-phasing filter be derived between wells?
Our methodology consists of three steps: (1) determination of the wavelet consisting of all known convolutional effects before any processing using measurements of the source time function made during data acquisition, (2) compression of this wavelet to the shortest zero-phase wavelet within the bandwidth available, and (3) elimination of uncontrolled distortions to the wavelet in subsequent processing. This method is illustrated with data from the prospective Jurassic succession in the Moray Firth rift arm of the North Sea in which we have identified, for the first time on seismic data, a major regional unconformity that cuts out more than 20 Ma of geological time. This method offers two major benefits over the conventional approach. First, all lateral variations in the processed seismic data are caused by the geology. Second, events on the processed seismic data may be identified from well logs simply by their polarity and timing. It follows that events can then be followed on the seismic data from one well to another with confidence, the seismic data can be interpreted for stratigraphy, and subtle stratigraphic traps may be identified.

INTRODUCTION
Interpretation of seismic reflection data for stratigraphy requires precise knowledge of the wavelet (Anstey, 1978). Conventionally, “the wavelet” that “ties” seismic data to the stratigraphy known from a well is determined from both the seismic data and the well logs (e.g., White, 1980). This approach has problems that have not been addressed properly.

Conventionally, the well-tie problem is this. The seismic data are processed to a “known” phase, typically zero phase. This means the phase of the seismic wavelet that was assumed to be in the data has been removed. At the well position, the seismic data should then “tie,” that is, strongly correlate, with the synthetic seismogram calculated by convolving the primary reflectivity series with an appropriate zero-phase wavelet. Normally, there is a mis-tie, and the synthetic seismogram is then adjusted to make the tie. This adjustment has three components: a time shift, or linear phase component in the frequency domain, an adjustment to the amplitude spectrum of the wavelet, and an adjustment to the phase spectrum of the wavelet (e.g., Nyman et al., 1987; Richard and Brac, 1988). This approach essentially admits that the so-called zero-phase seismic data are not

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zero-phase, as pointed out in Nyman et al. (1987). An almost perfect tie can be made at any well with this approach. However, if such a "tie" is made at one well, and a marker horizon is followed from this well to the next well, there is normally a mis-tie of, typically, 30 ms at the next well. A new wavelet must be found to "tie" the seismic data at the new well. It follows that the "wavelet" is unknown unless there is a well and the interpretation of the seismic data for stratigraphy between the wells or beyond well control can be unreliable. Poggioglio et al. (1994) have developed a method that forces the seismic data to tie with the same zero-phase wavelet at every given well, but requires not only time shifts of the synthetic seismograms, but also a space-adaptive operator that changes the amplitude spectrum and phase spectrum of all traces in the seismic data.

There are two problems with these approaches. First, the time-shifts of the synthetic seismograms ignore the constraints imposed by the check-shot data at each well. Second, since the wavelet that makes the tie is, in principle, known only at the well, any interpretation of the seismic data for stratigraphy between the wells or beyond well control is, in principle, unreliable.

Consider the history of hydrocarbon exploration in the North Sea. In more than three decades of exploration, over 70% of all the oil and gas has been found to be reservoir in Jurassic sediments in structural traps (Spencer et al., 1996), most notably those created during the Late Jurassic rift episode including the Brent, Ninian and Statfjord fields. Over 80% of these reserves were discovered in the 1970s in the most obvious seismically defined traps (Spencer et al., 1996). Even though comparatively few readily identifiable major structures have been found subsequently, attention has turned only recently to the deliberate search for subtle stratigraphic traps. Of those found so far, none appears to have been the result of a deliberate search. The Miller Field is a case in point; it is essentially a Late Jurassic stratigraphic trap in an intrabasinal location and was discovered only because of the drilling of a minor structural expression at the base Cretaceous level (Rooksby, 1991; Garland, 1993).

For the deliberate search for stratigraphic traps to be successful, it is essential that the data be acquired and processed with this as a major goal, rather than merely as a secondary possibility following the determination of structure. Determination of structure from seismic data is essentially a search for a velocity model that allows the seismic data to be migrated to determine a sharp image. The velocities are found by contouring seismograms, using the rate of change of traveltime with offset. This is a first-order effect. In contrast, determination of stratigraphy from seismic data is essentially the correlation of seismic reflection amplitudes with changes in acoustic impedance in the subsurface. This is a second-order effect and requires more precision.

We argue that this correlation requires the absolute arrival times of the reflections at a well to be known. In the presentation of our argument, we found it necessary to examine what is meant by "a good well tie," "the seismic wavelet," "the convolutional model of the seismogram," the effects of viscoelastic absorption on wave propagation, and the role of conventional predictive deconvolution in seismic data processing. It is shown that conventional processing forces the wavelet to vary uncontrollably from trace to trace.

In our approach, the wavelet is determined from measurements made during acquisition, and then is compressed to the shortest possible wavelet within the bandwidth available. Subsequent processing of the data is constrained to introduce no uncontrolled distortions to the wavelet. In particular, predictive deconvolution with a predictive gap less than the length of the wavelet is eliminated.

The argument is illustrated with data from a seismic survey of exploration wells that targeted the prospective Jurassic reservoir interval in the Inner Moray Firth, at the western end of one of the three main rift arms in the North Sea Basin.

THE CONVOLUTIONAL MODEL OF THE SEISMOGRAM

Consider the modeling of seismic reflection data in a computer, using, for example, a finite-difference scheme in three dimensions. Every element in the earth is parameterized by its density and elastic constants. Absorption can be included by allowing the stress to depend linearly on the strain rate as well as on the strain itself. Each element in the model earth would then be linearly viscoelastic. The source and receivers must also be characterized.

The receivers have the known, measured, characteristics of hydrophone or geophone arrays, together with the known responses of the associated recording systems. Over the bandwidth of interest, and at the signal levels we measure, these devices are linear, and the effects of their responses are strictly convolutional. It is possible that there are severely attenuating zones beneath the geophones. These can be characterized using linear viscoelasticity, as described above. Such zones are, in any case, part of the earth, and not part of the receivers.

The input to the model is the source time function of the source in the right units. For vibroseis vibrators, this is the force applied by the vibrator plate to the surface of the earth, and is not necessarily the same for each vibrator (Baeten and Ziolkowski, 1990). For the dynamite source it is the radial displacement of the cavity generated by the dynamite explosion. For an air gun, it is the displacement of the air-gun bubble.

The signal generated by the computer program at a receiver is the convolution of the source time function with the earth impulse response. This response is the pressure or particle velocity that would be generated at the receiver if the source time function were an impulse. The impulse response at each receiver is different, because the travel paths vary from receiver to receiver. At a given receiver the impulse response is the sum of many different arrivals, each of which has traveled a different path. The viscoelastic absorption of energy along each of these paths is different. As a result, the effects of absorption are different for each arrival in the seismogram and are therefore not convolutional. Therefore, they cannot, in principle, be removed by deconvolution.

In the recorded seismogram there are three convolutional components: the source time function, the receiver response, and the response of the recording system. These components may be removed by deconvolution, provided they are known. In real seismic data, the characteristics of the receivers and recording systems are known with great precision. The source time function can be measured for every major source (Ziolkowski, 1991) and the cost, for marine seismic data, is on the order of 1% of the data acquisition cost (Hones, 1996).
THE WAVELET

What is "the wavelet"? It is impossible to give a simple answer to this question. One reason we find a different wavelet at every well is because conventional seismic data processing can introduce uncontrolled distortions to the wavelet. Another is that conventional methodology (White, 1980) requires the simple normal-incidence synthetic seismogram to "match" the seismic data after stack and migration after stack. However, there is no theory to support this requirement. Therefore, the match tells us nothing about the meaning of this "wavelet," and therefore nothing about the stratigraphy. These claims are discussed further below. At this point we introduce our approach.

Our approach is (1) to determine the wavelet before any processing, using measurements of the source wavefield made during data acquisition, (2) to compress this wavelet to the shortest possible wavelet within the bandwidth available, and (3) to ensure that the subsequent processing introduces no unknown distortions to the wavelet. With this approach, it is possible to say what the wavelet is. It involves measurement of the source signature. This step is indispensable and we consider it to be a small price to pay to get precise well ties, and to be able to interpret stratigraphy reliably between wells.

The convolutional wavelet is the combination of all convolutional effects in the shot record. A point source and point receiver it is the source time function convoluted with the receiver response and the recording instrument response. In principle, the surface of the earth is a boundary to the earth and should not be considered part of the source or receiver. Until we have an exact solution to the removal of free-surface effects, however, source ghosts should be included where applicable (air guns and dynamite), and also receiver ghosts, where applicable (marine surveys). Marine source arrays and vibrator arrays are directional, as are the receiver groups. In theory, these directional effects can be removed in common-receiver gathers for source effects (assuming shot-to-shot repeatability) and in common-shot gathers for receiver effects (e.g., Bauten and Ziolkowski, 1990, Chap. 7). In practice, it may be sufficient for most purposes simply to take an average angle of incidence, say 20°, to allow for the nonvertical incidence of the raypath from the source to the target and back to the receiver. This raypath is illustrated in Figure 1 for a marine example. The resulting wavelet, shown in Figure 2 and calculated using source measurements recorded through the same instruments as the seismic reflection data, defines the bandwidth of the data; the data cannot have a bandwidth any greater than the bandwidth of this wavelet.

The method used to calculate the wavelet from measurements is discussed in detail in Ziolkowski and Johnston (1997). The source wavefield of the air-gun array was measured for each shot using near-fall hydrophones. Using the method of Ziolkowski et al. (1982) and Parkes et al. (1984), the measurements were used to decompose the wavefield into the individual spherical waves generated by the oscillating bubbles emitted by the air guns. The spherical waves were then superposed in the frequency domain, taking into account the geometry of the array and the free surface, to compute a far-field signature at 20° to the vertical. A receiver ghost was added in the frequency domain, taking into account the 20° angle of incidence and the measured depth of the streamer. A reflection coefficient of −1 was assumed at the water surface.

The wavelet thus obtained, as shown in Figure 2, contains bubble pulses and is very long. The bubble pulses do not appear to be very significant when the full frequency bandwidth is included. At the target the highest frequency in the data may be 40 Hz. Figure 3 shows the wavelet of Figure 2 filtered with a minimum-phase filter with a high-cut frequency of 40 Hz, and the primary-to-bubble ratio is reduced by a factor of 2.

![Fig. 1. Geometry for calculation of the wavelet.](image1)

![Fig. 2. The 20° wavelet.](image2)

![Fig. 3. The wavelet of Figure 2 after low-pass filtering with 40 Hz high cut.](image3)
The wavelet clearly needs to be shortened to obtain maximum resolution within the bandwidth available.

Figure 4 shows the construction of a signature deconvolution filter that makes the known long unfiltered convolutional wavelet of Figure 2 into a short minimum-phase wavelet with essentially the same bandwidth. The application of the signature deconvolution filter to the data makes the wavelet in the data short, thus increasing the resolution. We now have a known short wavelet, Figure 4b, in the data. If the wavelet changes, for instance because of changes in the source signature detected through continuous monitoring during data acquisition, we must keep the desired short wavelet, Figure 4b, fixed and design a new filter, Figure 4c, to shape this new long wavelet to the same short desired wavelet. This will ensure that, after signature deconvolution, the same known wavelet, Figure 4b, exists throughout the data.

Figure 5 shows the process of Figure 4 in the frequency domain. The air-gun bubble pulses seen in Figure 4a exhibit the characteristic peaks and notches in the amplitude spectrum as shown in Figure 5a. The tuned air-gun array reduces the bubble pulses somewhat, but not completely. Figure 5b shows the amplitude spectrum of the desired wavelet; it is designed to be essentially the same as Figure 5a, but is smooth. The amplitude spectrum of the filter, Figure 5c, that shapes the calculated wavelet into the desired wavelet is essentially flat over the bandwidth of the wavelet, but with superimposed notches and peaks to compensate for the corresponding peaks and notches in the spectrum, Figure 5a, of the wavelet. The result of multiplying Figure 5a by Figure 5c is Figure 5d, which is very similar to the desired spectrum, Figure 5b. Because the filter spectrum, Figure 5c, is essentially flat, the signal-to-random noise level essentially is unchanged.

**Fig. 4.** Signature deconvolution: (a) the wavelet of Figure 2; (b) the delayed desired minimum-phase wavelet; (c) the signature deconvolution filter; (d) the convolution of the wavelet (a) with the filter (c).
Thus the application of the signature deconvolution filter, designed in this way, increases the resolution, by shortening the wavelet, but without decreasing the signal-to-noise ratio.

**THE ROLE OF PREDICTIVE DECONVOLUTION**

Predictive deconvolution is required in conventional seismic data processing to attenuate multiples generated by the free surface (Peacock and Treitel, 1969; Taper et al., 1995). The predictive gap must be shorter than the multiple period. In the case of marine seismic data processing, the predictive gap must be shorter than the two-way traveltime in the water. If the wavelet is shorter than this gap it is unaffected by the predictive deconvolution operator. In other words, if the original long wavelet is compressed to a known wavelet, shorter than the predictive gap, before predictive deconvolution is applied, the wavelet will be the same after predictive deconvolution.

If the wavelet is known to be long, as in marine surveys, performing the signature deconvolution step before predictive deconvolution is critical. If the wavelet is not known, as is usually the case, this critical step cannot be done, and the wavelet will be altered by the predictive deconvolution operator, as discussed below.

**TRUE-AMPLITUDE RECOVERY**

The seismic reflection data are not stationary. That is, the statistical properties of the data are not independent of the time origin. In particular, there are no data before the shot is fired, the biggest amplitudes are usually the first arrivals, the amplitude and bandwidth decreases with time, and there are

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**Fig. 5.** Frequency-domain equivalent of Figure 4: (a) amplitude spectrum of 4(a); (b) amplitude spectrum of 4(b), which is a smoothly interpolated version of (a); (c) amplitude spectrum of 4(c) which is, on average, flat in the bandwidth of the wavelet; (d) amplitude spectrum of 4(d).
no data after recording has stopped. A stationary time series is infinitely predictive. Deconvolution uses a prediction-error filter (Peacock and Treitel, 1969; Taner et al., 1995) to remove the so-called “predictable part” of the data (the multiples) from the seismogram, revealing the so-called “unpredictable part” (the primaries). The “predictable part” is estimated from the autocorrelation of the data, which also contains the primaries. Predictive deconvolution assumes that there are no accidental correlations between primary reflections that can contribute to the autocorrelation of the data. If the data were only a small part of an infinitely long stationary time series, the prediction-error filter could be computed from the autocorrelation function estimated from any suitably long segment in the time series, by definition, including the segment containing the primary reflections we are trying to reveal. Since that segment is the only segment available, the stationarity assumption is critical to the predictive deconvolution process. This argument is discussed in more detail in Ziolkowski (1984, Chap. 5).

Since seismic data clearly are not stationary, the predictive deconvolution step is preceded by a step, usually known as “true-amplitude recovery,” that applies a time-dependent gain to the data to make the data look more as if they are segments of stationary time series. Typically, this gain function is $e^{r_t}$ where $r$ is time and $n$ is approximately 2. This gain correction introduces a time-dependent distortion to the wavelet: that is, after application of this gain correction the wavelet varies down each trace and the convolitional model is violated (Ziolkowski, 1984, Chap. 2). The only gain correction that does not violate the convolitional model is an exponential gain, $e^{r_t}$, typically about 12 dB/s.

Neither $e^{r_t}$ nor $e^{u_t}$ make the data stationary. There is no “true-amplitude recovery” correction that makes the data stationary. If we want to keep track of the wavelet, we should use the exponential gain; if we are more concerned about stationarity than wavelet distortion, it may be better to use $e^{u_t}$. These two operations are equivalent only at one time instant.

ZERO-PHASING

At some point we should like to make the wavelet zero phase, to enable the interpreter to line up known acoustic interfaces with peaks or troughs in the seismic data. Zero-phasing can be done before or after predictive deconvolution. After the exponential gain correction, the wavelet is $w_t$, and is related to the original desired wavelet $d_t$ as

$$w_t = e^{u_t} d_t.$$  \hspace{1cm} (1)

The wavelet $w_t$ has a Fourier transform $W_f$, where $f$ is frequency and

$$W_f = |W_f| \exp[i \phi_w(f)],$$  \hspace{1cm} (2)

in which $|W_f|$ is its amplitude spectrum and $\phi_w(f)$ is its phase spectrum. The zero-phasing filter is simply the multiplication of the Fourier transform of the data by the function $\exp[-i \phi_w(f)]$. The result is to produce a wavelet $w_0$ in the data that has the Fourier transform

$$W_0(f) = |W_f|.$$  \hspace{1cm} (3)

This is the shortest possible wavelet within the bandwidth of the data (Berkhout, 1984, Chap. 1) and is illustrated in Figure 6.

After application of the zero-phasing filter, each seismogram in the data is now the earth impulse response (with exponential gain applied) convolved with this wavelet, with its peak exactly at the arrival time of the event. The polarity is our choice. In this example, the polarity is chosen to give a black peak in the seismogram data to correspond to a step increase in acoustic impedance in the well. This is SEG normal polarity (Sheriff and Geldart, 1995, 183). If it is required that a black peak should correspond to a step decrease in acoustic impedance, for instance to show gas, the polarity of the data should be reversed after zero-phasing.

It should be noted that the zero-phasing step can be combined with the signature deconvolution step. Instead of the minimum-phase wavelet $d_t$, the wavelet $e^{-u_t} w_0$ is used as the desired wavelet. A different signature operator would be designed and applied, causing this wavelet to be present in the data after signature deconvolution. After the exponential gain correction, the wavelet in the data would then be $w_0$ and no further operations to the wavelet would be required.

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**THE EFFECT OF CONVENTIONAL PROCESSING ON THE WAVELET**

Consider what happens to the wavelet with conventional processing. First the conventional $e^{r_t}$ process of “true amplitude recovery” applies a distortion to the wavelet that varies along each trace of the data, thus violating the convolitional model. Next, predictive deconvolution is applied with a gap that is shorter than the wavelet. The predictive deconvolution operator is derived from the autocorrelation of the trace, which is different for each trace in the gather in the 1-D case (Peacock and Treitel, 1969) and different for each gather in the 2-D case (Taner et al., 1995). This is partly because the so-called “predictable part” of the trace, including the wavelet and the multiples, is expected to vary with offset, but it is also because the so-called “unpredictable part,” the response of the earth, is not white (Fokkema and Ziolkowski, 1987) and contributes to the autocorrelation function in a way that must vary with offset and from gather to gather. The operator is therefore different for each trace of the data. After predictive deconvolution there is therefore a different wavelet on every trace of the data. Even if the quality control in data acquisition ensured perfect repeatability of the wavelet.

**Fig. 6.** Zero-phase equivalent of 4(b).
from trace to trace, the predictive deconvolution step would destroy it. There is, therefore, no such thing as "the wavelet" after conventional prestack predictive deconvolution.

The data are stacked. Then, after stack, predictive deconvolution is often applied again, usually with different parameters, again with a different operator on every trace, thus ensuring that there are further differences in the wavelet from trace to trace. The conventional use of predictive deconvolution thus guarantees that lateral variations in the data cannot be attributed solely to lateral variations in the geology, thus rendering the data unreliable for the interpretation of stratigraphy.

**THE WELL TIE BY CHARACTER-MATCHING AND THE CONVOLUTIONAL MODEL.**

The goal of seismic data processing is to render the seismic data interpretable. The interpreter attempts to correlate reflections seen in the data with known acoustic impedance contrasts in the earth. The processed seismic reflection data are presented to the interpreter as if they contain primary normal-incidence reflections only, with all unwanted multiples, refractions, diffractions, surface waves, compression-to-shear conversions, etc., having been removed successfully by the processing.

The convolutional model described above for each recorded trace of a shot gather is valid because of the linearity of the viscoelastic earth model and the linear response of both the receiver and the recording system. After the shot records have been combined in conventional processing to produce stacked sections, the resulting seismic traces are not the convolution of some physically meaningful wavelet with the primary reflection coefficient series.

If, nevertheless, this convolution is assumed (e.g., White, 1980; Nyman et al., 1987; Richard and Brac, 1988; Poggiagliolmi and Alfred, 1994), each well introduces a new wavelet and a new question is now posed—how should the zero-phasing filter be derived between wells? This approach does not solve a problem; it simply creates a new one.

**PRECISE SYNTHETIC SEISMOGRAMS.**

Precise synthetic shot records could in principle be computed properly using finite differences, as outlined above, provided a completely faithful 3-D anisotropic viscoelastic model of the earth existed, and provided all receiver and source effects were included, as discussed above. To calculate these synthetic shot records would require much more knowledge of the earth than can be obtained from a single well and also would require knowledge of the source that is usually not available. If all the required knowledge were available, the synthetic shot records would resemble the recorded data. Then there would be a reasonable match to the processed data only if the synthetic shot records were processed in the same way as the real data.

**DETERMINISTIC WELL-TIE METHODOLOGY.**

The best match we can hope to get by the simple convolution of a wavelet with the normal-incidence reflection coefficients obtained from a limited part of the well is for the timing and polarity of the principal reflections.

Suppose we have measured the signature and have followed the recommended processing scheme described above, making sure that no uncontrolled distortions have been applied to the wavelet. The wavelet in the data is some known, short, zero-phase wavelet $w_{0}(t)$, as shown in Figure 6. Both the polarity and the arrival time of events in the real data are now the same as the normal-incidence reflection coefficient series converted to two-way traveltime using the measured check-shot data at the well locations. With this processing scheme known interfaces in the wells may therefore be correlated with reflections in the seismic data without synthetic seismograms. We illustrate this method with data from the Inner Moray Firth of the North Sea.

**THE STRATIGRAPHIC SETTING OF THE INNER MORAY FIRTH BASIN.**

The Jurassic stratigraphy of the Inner Moray Firth Basin is well known from nearby onshore outcrops, drilling, and seismic exploration (e.g., Sykes, 1975; Andrews et al., 1990; Underhill, 1991a and b; Stephen et al., 1993; Wignall and Pickering, 1993; Davies et al., 1996). Regional uplift during the Tertiary (Thomson and Underhill, 1993; Hillis et al., 1994) has left the Jurassic relatively shallow in the Inner Moray Firth, and the seismic resolution of Jurassic stratigraphy is therefore generally much better here than elsewhere in the North Sea.

Seismic stratigraphic studies, based on the recognition and correlation of surfaces defined by reflector terminations, enable the Jurassic to be subdivided into two main megasequences J1 and J2 (Underhill, 1991a and b). The boundary between the two megasequences is marked by regional onlap onto a strong reflector that corresponds to a unit known locally as the Alnsc Spiculite. Analysis of well logs enables the J1 megasequence to be subdivided further into genetic stratigraphic sequences through the identification and correlation of through-going marine shale horizons, or maximum flooding surfaces, as shown in Figures 7 and 8 (Stephen et al., 1993, Parington et al., 1993).

A regional correlation of these events has led to the identification of the Middle-Cimmerian Unconformity that allows the J1 seismic megasequence to be subdivided into two parts J1a and J1b (of Underhill, 1991a and b). This unconformity is a significant, but subtle, gentle surface of truncation and onlap, which records an episode of thermal doming and subsequent deflation of the North Sea area (Underhill and Parington, 1993 and 1994). The best sequence-stratigraphic definition of the top of the J1 megasequence and of the Middle-Cimmerian Unconformity occurs in the central areas of the Inner Moray Firth (Stephen et al., 1993).

**RESULTS OF THE NEW WELL-TIE METHODOLOGY.**

The methodology we propose provides two benefits over the conventional approach: (1) accurate stratigraphic correlation between wells and (2) detection of subtle stratigraphic truncations. We illustrate these benefits with examples from a speculative well-tie seismic survey shot in October 1992 by the Seismograph Service Limited (SSL) Seiventer in the Inner Moray Firth of the North Sea. The layout of the survey is shown in Figure 9. The source wavefield was measured according to the method in Ziolkowski et al. (1982) and Parkes et al. (1984), and the seismic reflection data were processed to zero phase according to our method, described above. Wells 12/22-2 and 12/22-3 are connected by a seismic line, as shown in Figure 9, and lie in the area where the top of the J1 megasequences truncated (Figure 7) and hence where the Middle-Cimmerian Unconformity might best be resolved.
Fig. 7. Well correlation panel from the Inner Moray Firth Basin depicting the occurrence and truncation of Lower Jurassic sediments belonging to the Dunrobin Bay Group (modified from Stephen et al., 1993). The progressive truncation enables the Mid-Cimmerian Unconformity to be identified. Subcrop of the lower reservoir in the Beatrice Field, the Orrin Formation, occurs between wells 12/22-2 and 12/22-3.
Fig. 8. Detection of the Mid-Cimmerian Unconformity as defined by onlap and pinchout of Middle and Upper Jurassic units (modified from Stephen et al., 1993). The diagram emphasizes that the most pronounced onlap occurs not between wells 12/22-3 and 12/22-2, but between 12/21-3 and 12/22-3 and between 12/27-1 and 12/30-1. The lithostratigraphy follows the nomenclature recently introduced by Richards et al. (1993).
Accurate correlation of stratigraphy between wells

Figure 10 shows part of the well completion log from 12/22-2. At a depth of 4205 ft bkb (below kelly bushing), 4123 ft ss (sub sea), there is a sharp decrease in the gamma-ray log (extreme left) and a sharp increase in the sonic velocity log (extreme right) that marks the top of the J1 megasequence of Underhill (1991a and b). This is the top of the Alness Spiculite, a porous sandstone containing oil, but with very poor permeability, and therefore it is not currently a producible reservoir. The sharp increase in sonic velocity indicates that the top of this sandstone should provide a clear seismic reflection with a positive reflection coefficient for the measured pressure.

The sonic log is calibrated with a check-shot survey, part of which is shown in Figure 11, in which a geophone is put at known interfaces in the well and measures the downgoing seismic wave from a seismic source just below the sea surface. The vertical traveltine of the sound wave from sea level to the geophone placed at the top of the Alness Spiculite is measured 0.5390 s, corrected for offset, datum, picking errors, etc. Two-way time is thus 1078 ms.

In his mind’s eye the interpreter has the following idea of the reflection process, as illustrated in Figure 12. The sharp increase in acoustic impedance gives a reflection, and the peak of the zero-phase seismic wavelet occurs exactly at the two-way traveltine to the interface. Figure 13 shows the relevant portion of the seismic line at its intersection with 12/22-2. A clear black reflection can be seen in the zero-phase data at 1078 ms, centered on the top Alness Spiculite event.

The synthetic seismogram was obtained by convolving the reflection coefficient series (obtained from the density and sonic logs) with the same zero-phase wavelet, shown in Figure 6. For the best visual comparison with the seismic data, the synthetic seismogram was filtered with the same time-varying band-pass filter and displayed with the same AGC and plotting parameters as the seismic data. The synthetic seismogram shows that the timing and polarity of the seismic reflection data are correct. As discussed above, we do not expect there to be an especially good character match between the synthetic and real seismic data, because the processed seismic data are not equal to a convolution of the wavelet with the normal-incidence reflection coefficient series.

Note that the synthetic seismogram is not required to identify the events on the seismic section: it simply corroborates the identification already made from the well completion logs and the check-shot survey.

Figure 14 shows the complete seismic line linking 12/22-2 and 12/22-3. The top Alness Spiculite reflection can be followed confidently between these two wells as a prominent black positive reflection. Many other events (not marked) can be followed on the seismic section with equal confidence. This can be checked at 12/22-3.

Figure 15 shows part of the well completion log from 12/22-3. The top of the Alness Spiculite is seen here at a depth of 6250 ft bkb (6168 ft ss), where there is a sharp decrease in the gamma-ray log and a sharp increase in the sonic velocity log. The relevant portion of the check-shot survey for this well is shown in Figure 16, in which the traveltine of the sound wave from sea level to the geophone placed at the top of the Alness Spiculite is measured to be 0.7210 s, giving a two-way traveltine of 1442 ms.

Figure 17 shows the relevant portion of the same zero-phase processed seismic line at its intersection with 12/22-3. The top of the Alness Spiculite can be seen as the clear black reflection at 1442 ms, thus confirming the interpretation of the seismic data.

Detection of subtle stratigraphic truncations

An application of this methodology to the interpretation of seismic data has also enabled a subtle stratigraphic truncation, the Mid-Cimmerian Unconformity, to be detected and mapped. The existence of this truncation had been recognized previously through a stratigraphic and sedimentological analysis of over 2000 North Sea biostratigraphically calibrated electrical well logs (Underhill and Partington, 1993 and 1994). Figure 7 shows the truncation in the Inner Moray Firth.

Regional well correlation panels across the basin indicate that the Mid-Cimmerian Unconformity is marked by sudden truncation below and onlap above (Figures 7 and 8). Furthermore they demonstrate that the most pronounced truncation occurs in different places from the most pronounced onlap. The seismic line connecting wells 12/22-2 and 12/22-3 (Figure 14) corresponds to the area in which truncation, but no onlap, is noted from well correlations. Interpretation of the line following a correct well tie of a Lower Jurassic marker bed, The Lady’s Walk member, indicates where the truncation occurs between the wells. This demonstrates the power of iteration between the electrical well-log correlations, the well ties, and the seismic data to define the point of truncation more precisely.

The most pronounced onlap seen from the electrical well-log correlations is in more southerly regions. With our seismic data

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acquisition and processing methodology, we can now identify it on seismic data. Figure 18 shows part of the well completion log from 12/27-1 in which part of the well has actually been cored, including the Mid-Cimmerian Unconformity identified at 3566 ft ss. Figure 19 shows a portion of a seismic line from the same survey, intersecting 12/27-1. The unconformity is indicated by the arrows; the onlap of reflectors onto it from above, and truncation of reflectors against it from below can be seen clearly. Although this is a major regional event, cutting out more than 20 Ma of geological time, this is the first time this unconformity has been convincingly demonstrated on seismic data in this part of the North Sea. Its successful identification on this 2-D survey suggests that subtle truncations and onlaps are likely to be readily identifiable in this and other basins if our approach is adopted with 3-D data.

CONCLUSIONS

Compared with the spectacular success in finding structural hydrocarbon traps, the success in finding subtle stratigraphic traps is poor. In the North Sea, for example, any success has occurred by accident rather than by design. The poor success rate is a consequence of the conventional approach to the problem of tying wells to seismic data. Now that few structural traps remain to be drilled, the deliberate search for subtle stratigraphic traps is of paramount importance for extending the life of the basin. Seismic methodology has not kept pace with this need.

**Fig. 10.** A portion of the well completion log for 12/22-2.
The conventional approach suffers from three shortcomings. First, conventional acquisition and processing of seismic reflection data in general guarantees that the convolutional wavelet varies from trace to trace. This follows from the use of predictive deconvolution both before and after stack with predictive gaps that are shorter than the wavelet. Second, events on the processed seismic data are conventionally identified from well logs via the construction of a synthetic seismogram that is the best match, in some sense, to the processed data at the well position, and is simply the convolution of "a wavelet" with the normal-incidence reflection coefficient series. This convolutional model has no basis in the physics of the problem, and the wavelet thus derived is not related to the convolutional wavelet in the data. Each well introduces a new wavelet and raises a new problem: How should the zero-phasing filter be derived between wells? Third, the synthetic seismograms derived to ensure a good "match" often require time-shifts that are inconsistent with the check-shot data at the wells.

An alternative scheme that has two major benefits is presented. First, all lateral variations in the processed seismic data are caused by the geology. Second, events on the processed seismic data may be identified from well logs simply by their polarity and timing. It follows that events can than be followed on the seismic data from one well to another, with confidence, and the seismic data can be interpreted for stratigraphy. This is demonstrated with data from the prospective Jurassic succession in the Inner Moray Firth of the North Sea.

The proposed method consists of three steps: (1) determination of all known convolutional effects before any processing, using measurements of the source wavefield made during data acquisition, (2) compression of this wavelet to the shortest zero-phase wavelet within the bandwidth available, and

**Fig. 11.** A portion of the calibrated sonic log for 12/22-2.
(3) elimination of uncontrolled distortions to the wavelet in subsequent processing.

The known convolutional effects are the source time function, the receiver response, and the response of the recording system. Absorption is not a convolutional effect in seismic data and cannot be removed by deconvolution. The receiver response and recording system response are normally known with great precision. The measurement of the source time function for all major seismic sources is within the capability of most seismic contractors.

The determination of stratigraphy from seismic data requires precise knowledge of the wavelet, which is not obtained with conventional acquisition and processing methods. We propose that the source time function be measured during data acquisition. The cost is on the order of 1% of the cost of seismic data acquisition. With appropriate data processing the benefits are (1) direct identification of seismic events from well logs on the basis of timing and polarity, (2) correlation of seismic events from well to well, and (3) reliable interpretation of stratigraphy.

Our approach has allowed us to tie all the wells in the Inner Moray Firth without changing the phase of the wavelet at the wells and to map the stratigraphy on these lines. The work has demonstrated that a hitherto undetected subtle, regional unconformity can be detected on seismic data. The impact of this approach on the acquisition, processing, and interpretation of 2-D and especially 3-D seismic data in any part of the world could be very significant and allow the identification of previously undetected stratigraphic hydrocarbon traps.

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**REFLECTION COEFFICIENT**

\[ R_p = \frac{\rho_2 v_2 - \rho_1 v_1}{\rho_2 v_2 + \rho_1 v_1} \]

**SEISMOGRAM**

**POSITIVE REFLECTION**

**INCREASE IN ACOUSTIC IMPEDANCE**

**t = 2 \int \frac{dz}{u(z)}**

**FIG. 12.** The essence of the well tie.

**FIG. 13.** Seismic section of line 1D1R at well 12/22-2, showing the synthetic seismogram and tie to the seismic data.
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REFERENCES


![Fig. 14. Line 1D1R, processed to zero phase and linking wells 12/22-2 and 12/22-3. The top of the Alness Spiculite is indicated with the arrows. The vertical scale is milliseconds; the timing lines are 100 ms.](image-url)
Fig. 15. A portion of the well completion log for 12/22-3.

Fig. 16. A portion of the calibrated sonic log for 12/22-3.
Fig. 17. Seismic section of line 1D1R at well 12/22-3, showing the synthetic seismogram and tie to the seismic data.

Fig. 18. A portion of the well log from 12/27-1.
FIG. 19. A part of seismic line 3D4-D5 tieing with well 12/27-1 and imaging the Mid-Cimmerian Unconformity. The vertical scale is seconds; the timing lines are 100 ms. This line was processed by Geoco-Prakla along the lines described in this paper and is reproduced with their permission.


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