

Improving depth prediction accuracy of quantified drilling hazards

W. SCOTT LEANEY¹ AND WILLIAM H. BORLAND²

¹Wireline & Testing
Jakarta

²Wireline & Testing
Bangkok

Abstract: Under-compacted shales are often associated with over-pressured formations. These shales have excess water and tend to be mechanically weak (or are overlain by mechanically weak formations), thus the safe mud window for drilling the under-compacted interval can be quite narrow. Efficient and safe drilling operations require accurate depth predictions of these over-pressured formations as well as a knowledge of the magnitude of the over-pressure. In this paper we describe a technique which combines the best aspects of conventional Vertical Seismic Profiles (VSP) and Reverse Vertical Seismic Profiles (RVSP) to detect under-compacted shales and predict formation pressures to locate drilling hazards below TD.

The excess water in the under-compacted shales will have a lower acoustic impedance than expected from the compaction trend. Shales that depart from the compaction trend may indicate potential drilling hazards below. Conventional VSPs provide at discrete intervals in the well, high quality reflection data which can be used to accurately predict acoustic impedance below the bit. This acoustic impedance is then interpreted to provide both the location (in time and depth) of the drilling hazard and the mud weight necessary to contain it. The two way time estimate of the hazard location is usually quite accurate but the depth estimate is less certain due to the estimation of formation velocities below TD. The RVSP using the drill bit as a source, provides a continuous time versus depth relationship while drilling. This time versus depth is used to continually update the conventional VSP depth prediction of the drilling hazard and thus provide the most accurate depth of the hazard prior to its penetration.

INTRODUCTION

Predicting the depth to a reservoir target or suspected drilling hazard is important both in exploration and field development settings. The types of problems most often cited relate to the selection of a casing point and/or mud weight prediction. The drilling challenge is always one of maintaining a balance between borehole fluid pressures (mud weight) and formation pore pressures or "geopressure". Drilling under balanced, with insufficient mud weight, can result in borehole failure (sloughing, breakouts) and even blowouts due to excessive pore pressure in permeable formations. Drilling overbalanced may prevent borehole failure in some formations but can cause damage to reservoir or sealing formations, hindering or making it impossible to produce from reservoirs later.

The difficulty is that the mud weight required to maintain pressure balance with the formation can change rapidly as drilling progresses through formations with different pore pressures (Fertl, 1976). It is common for a well to be drilled at a selected mud weight until a certain intermediate depth, casing set, and drilling continued with a

new mud weight to allow balance to be maintained with the new formation pressures. The problem then becomes one of selecting the casing point and predicting the mud weight required to drill balanced through the deeper formations.

This is where borehole seismic can play an important role, since seismic techniques provide the only means to "see" a significant distance away from or below a well bore. Surface seismic data, as they are recorded with sources and receivers at the surface, usually do not provide the accuracy in time-to-depth conversion required for making drilling decisions. VSPs (vertical seismic profiles), on the other hand, as the receivers are located at depth, provide a more accurate technique for predicting the depth to a target. VSPs are not without their limitations either, and integrating measurements while drilling with VSP results has the potential of providing a new accuracy and reliability for drilling decisions (Haldorsen *et al.*, 1965; Carron, 1988).

In the following sections we look at the geopressure problem, review the seismic trace inversion problem and examine the essential components of high resolution VSPs. We then look at the drill bit seismic technique and demonstrate

how VSP and Drill Bit Seismic data can be integrated for an improved look-ahead product.

GEOPRESSURE OVERVIEW

Geopressure refers to formation fluid pressure at depth. It is generally between lithostatic pressure and hydrostatic pressure. Lithostatic pressure refers to the total weight of material in an overlying column, while hydrostatic pressure refers to the pressure due to a column of water extending to the surface. In normally compacting sediments, water escapes through permeable sands or along fractures as overburden sediments build up, and fluid or pore pressure stays close to hydrostatic pressure. But if the formation fluids are not allowed to escape, for example due to the low permeability of shales, then the formation fluid bears part of the overburden load and becomes over pressured.

The hydrostatic pressure at depth h is defined as:

$$P = hG_w, \quad (1)$$

where G_w is the local hydrostatic pressure gradient. G_w varies regionally between the "normal" values of 0.433 psi/ft to 0.5 psi/ft. Lithostatic pressure generally follows a gradient of 1 psi/ft. Geopressure gradients greater than 0.7 psi/ft are considered abnormally high and dangerous (These figures for pressure gradients can be expressed equivalently as mud densities, since the density integrated over the borehole becomes a weight. 0.465 psi/ft = 9.2 lb/gal = 1.1 gm/cc; 1 psi/ft = 20 lb/gal = 2.4 gm/cc; 0.7 psi/ft = 14 lb/gal = 1.68 gm/cc).

ESTIMATING GEOPRESSURE

If formation fluids are impeded from escaping upwards due to low permeability the formation fluid bears more and more of the overburden load as sedimentation progresses. When this happens compaction slows down and effective porosity increases. Thus, if fluid pressures are abnormally high, porosity will also be abnormally high for a given depth of burial. This means that the various geophysical measurements that respond to porosity can be used to estimate geopressure.

The technique to estimate geopressure was proposed by Hottman and Johnson in 1965. They exploited the dependence of the sonic and resistivity log responses on porosity to estimate the expected trend of decreasing porosity with depth of burial. After estimating a trend for normally compacting shales, deviations from the normal trend were transformed to pore pressure gradient and equivalent mud weight using an empirical relation determined for Gulf Coast data.

Surface seismic – derived stacking velocities have also been used to map over pressure, and in recent years more sophisticated approaches have emerged to estimate pore pressure which make use of a suite of five or six logs, including those recorded in real time by MWD and LWD. The shortcoming of the latter approach is that prediction ahead of the bit is not possible, so a sudden onset of over pressure is not easily anticipated. The shortcoming of the former surface seismic approach is that it is inaccurate.

A seismic trace is an indication of variations in acoustic impedance within the earth. Conventional surface seismic has sources and receivers at surface and data acquisition involves summing reflections in a substantial range of angles. Inverting surface seismic for acoustic impedance may give indications of over pressuring but due to the lack of specific knowledge of the downgoing wave train, the uncertainty in amplitude due to reflection angles, and increased noise; seismic data obtained in a well (in the form of a Vertical Seismic Profile — VSP) itself is generally preferable for a more quantitative interpretation.

VSPs can be inverted below an intermediate TD for acoustic impedance, and since acoustic impedance depends on porosity through both velocity and density, over pressure can be inferred for zones of anomalous low acoustic impedance. Drillers want predictions in depth, however, and the output of VSP inversion is acoustic impedance in two-way time. Thus, a velocity profile must be determined below intermediate TD for a depth transform. This problem can be solved approximately through an empirical velocity-density relation, optionally calibrated using the local data base. Gardner's relation (Gardner, 1971) puts bulk density in terms of velocity raised to some power. It was originally determined for brine-saturated sediments composed predominantly of shales. It takes the form:

$$\rho = aV^b, \quad (2)$$

with coefficients $a = 0.23$ and $b = 0.25$ for Gulf Coast data. The above relation says that the inverted acoustic impedance, $Z = \rho V$ is proportional to V^{1+b} , so with a regionally determined estimate of the coefficients a and b , inverted acoustic impedance is easily transformed to velocity. From the interval velocity at each two-way time sample below the intermediate TD a time versus depth profile is then obtained.

Once velocity versus depth is estimated below the intermediate TD the Hottman-Johnson approach for sonic transit time can be used to estimate the pore pressure gradient and provide a recommended minimum mud weight. The critical

point in the Hottman-Johnson approach is the empirical relation between reservoir fluid pressure gradient (or equivalent mud weight) and observed minus expected or normal slowness. Ideally one would want a local data base of formation pressure test and sonic data over a sufficient depth interval. Unfortunately, we have not yet built up a large enough data set for regions in South East Asia, although we are working on this project. In the absence of sufficient pressure test and sonic data, we use the published relation in the Hottman and Johnson paper. We fit a curve of the form:

$$ppg = 0.465 + cD^d \quad (6)$$

to the H-J data, where ppg = pore pressure gradient in psi/ft and D = differential slowness (observed minus normal slowness) in $\mu\text{s}/\text{ft}$. The coefficients for the Hottman-Johnson relation are found to be: $c = 0.057$ and $d = 0.523$

The strategy for estimating geopressure from inverted VSP data is summarized as follows:

- Using (a preferably calibrated) Gardner's relation or an assumed density function, transform acoustic impedance in two-way time to interval velocity.
- Using the interval velocity versus two-way time below intermediate TD, transform the time index of either velocity or acoustic impedance to depth.
- Using an estimated normal decrease of slowness with depth (for example from a nearby well) and the Hottman-Johnson relation, map abnormally high slowness values to pore pressure gradient and mud weight.

The above interpretation strategy starts from a reliable acoustic impedance pseudo-log obtained from the VSP data. Unfortunately, there are several factors conspiring against being able to achieve a reliable VSP inversion (Carron, 1988). We now review the fundamental problems of look-ahead VSPs.

It should be noted at this point that there are many geologic scenarios, both post- and syn-depositional, that can lead to excess pore pressure in a given lithology. In addition, there may be several of these processes in effect in the same formation. It is important, therefore, to understand that there are a number of scenarios which can introduce over pressuring in a formation that are not associated with under compacted shales. Absence of under compacted shales does not necessarily mean an absence of over pressuring.

INVERSION

There can be no inverse problem without a forward problem, and the forward problem underlying seismic trace inversion is the convolutional model. A processed seismic trace in

two-way time, s , is assumed to be the result of a wavelet, w , convolved with a reflectivity series, r , plus noise, n :

$$s = w \otimes r + n \quad (3)$$

The reflectivity is related to acoustic impedance, Z as:

$$r_{i-1} = \frac{Z_i - Z_{i-1}}{Z_i + Z_{i-1}} \quad (4)$$

where the subscript i denotes a discrete acoustic impedance layer of thickness equal to the time sampling rate. Such an acoustic impedance log averaged in layers of equal travel time is referred to as a Goupillaud model. It is apparent from the above equation that the acoustic impedance at any layer index I can be obtained by the product:

$$Z_I = Z_0 \prod_{i=1}^I \frac{1 + r_{i-1}}{1 - r_{i-1}} \quad (5)$$

If the reflection coefficients are small, then this recursive product can be approximated by an exponentiated integration. It is useful to think of inversion as scaled trace integration, since a 90 degree phase rotation occurs in the transform from reflectivity to acoustic impedance.

If the wavelet w were a spike or delta function, then the recorded seismic data would be the impulse response of the earth plus noise and could be inverted for the acoustic impedance profile save for a starting impedance scale factor. The wavelet is not a spike, though, due to source and recording limitations and to filtering during wave propagation.

As already discussed the problem of seismic trace inversion is one of somehow filling in the missing low and high frequency information. The more important of the two is the low frequency information, since over pressure and an accurate time-depth curve below TD require the trends in acoustic impedance.

There are an infinite number of solutions to the seismic trace inversion problem because arbitrary low and high frequencies can be added to the solution without altering the quality of fit to the band limited data. The simplest way to fill in the missing low frequency information is by taking it from other sources. One way is to take it from the sonic and VSP information from nearby wells, interpolated to the new well location, perhaps guided by seismic horizons picked on a workstation. This approach is useful in a field with several nearby wells but is of little use for deeper targets or in an exploration setting. Another way is to make use of interval velocities obtained from surface seismic stacking velocities. This option is attractive because information is available anywhere along a seismic line (or in a 3D seismic cube), and deep in the section. However, stacking velocities are often of

poor accuracy and should be calibrated with well data where possible. For VSP inversion still another approach is to extrapolate the time-depth curve based on a compaction law. Once the low frequency trend is determined, a comparatively simple least squares inversion is possible which will find the solution that remains as close as possible to the starting low frequency model. Deviations from the starting or background model will only be recovered if the data contain low frequency information.

There are other more complex inversion algorithms which attempt to fill in the missing frequencies by making assumptions about the underlying model. Such algorithms fall into the sparse spike or minimum entropy categories. These inversion algorithms seek a model with simple structure – one that contains a few, well separated contrasts or reflection coefficients. This type of model is quantifiable by a norm or functional related to the entropy of the reflectivity sequence (Wiggins, 1986). Minimizing an entropy-like norm while fitting the data and other prior constraints selects one out of the possible infinity of models, and because a spike requires all frequencies for its representation, a sparse spike solution is wide band and has “filled in” the missing low and high frequencies. The processing sequence might contain the following steps:

- Unconstrained acoustic impedance recovery from corridor stack by minimizing an entropy norm.
- Construction of an acoustic impedance log from the time-depth curve and constraints.
- Merging the above two acoustic impedance logs to include the low frequency component from above.
- Update the merged acoustic impedance to assure the data fit.

Another inversion algorithm that is implicitly “sparse spike” uses autoregressive modeling in the frequency domain (Walker and Ulrych, 1983). This algorithm relies on the fact that a spike at some time will Fourier transform to a harmonic (complex sinusoid) that is defined at all frequencies. Strictly speaking, harmonics are modeled by ARMA (autoregressive - moving average) processes, but they are well approximated by higher order AR processes, the coefficients of which are simpler to determine. The autoregressive algorithm solves for the complex AR coefficients that model the frequency domain data within a band of high SNR. The low frequencies can then be predicted with a constraint on conjugacy between positive and negative frequencies, and acoustic impedance constraints, with bounds, can be included (Ulrych and Walker, 1984).

SURFACE SEISMIC, VSP AND RVSP DATA

Seismic acquired in the well (sources at surface receivers downhole or vice-versa) is preferable to Surface seismic (sources and receivers on surface) for quantitative inversion for the following reasons:

- Both the upgoing and the downgoing wavefield is acquired in wellbore seismic where as in surface seismic only the upgoing wave train is recorded. In wellbore seismic this downgoing wavefield is used to deterministically deconvolve the upgoing wavefield allowing suppression of multiples and collapse of the wavelet into a known ideal wavelet. In surface seismic the downgoing wavefield is not recorded and therefore statistical and modeling processes are usually done to suppress multiples and shape the wavelet.
- The bandwidth of wellbore acquired seismic is generally broader, especially in the high frequency range, than surface seismic, due to the one way travel path wellbore seismic has through the generally highly attenuative shallow formations whereas surface seismic waves must make a two way path.
- The wellbore seismic is normally designed to have a single reflection angle, usually close to zero. This means that the reflectivity is easily related to acoustic impedance. The surface seismic, on the other hand, is a stack of reflections at different angles, usually in a range of zero to thirty degrees or more. The amplitude of this stack is related to both the acoustic impedance and Poisson’s ratio making it much more complicated to interpret.

From the above we can see wellbore seismic would appear to have the best chance for a quantitative inversion. What about the differences in source receiver geometry for wellbore seismic? Conventional Wireline VSP surveys places a source at surface and receivers downhole. Figure 1 illustrates the setup for the case of a vibroseis source. It is possible, in theory, to reverse the configuration, that is receivers on surface and source downhole, and obtain the same measurements (RVSP). In practice, however, it has proven quite difficult to design powerful enough sources to operate in downhole conditions and not destroy the well.

An alternative to deploying a source in the hole with wireline is to use the roller cone drill bit as a source. As a working roller cone drill bit destroys the rock at the bottom of the hole, it acts like a dipole source, radiating acoustic energy into the

surrounding formation. Some of this energy travels directly to the surface where it can be detected by geophones, or hydrophones if the well is offshore. Some of the energy radiates downwards ahead of the bit where it may be reflected by impedance contrasts in the earth. This reflected energy can also be detected at surface.

If a roller cone bit is being used then axial vibrations are generated in the drill string. These vibrations are correlated with the energy radiating into the formation. The vibrations travel up the drill string as axial waves. They can be detected by placing a sensor, such as an accelerometer, on the swivel.

Although the bit radiates energy continuously while drilling, timing information can be extracted, (Fig. 2).

The acoustic energy is transmitted along the drill string to the accelerometer, and through the formation to the geophone array. These two transmission paths usually have different acoustic velocities. Cross correlation of the accelerometer signal with the geophone signal gives the relative travel time difference between the drill string path and the formation path. In order to find the absolute travel time from the bit to the geophones through

the formation, i.e. the checkshot time, the travel time along the drill string must be established.

In reality the situation is more complicated than the above description implies. Both the accelerometer and the geophone signals are influenced by their respective transmission paths, and the signal radiated into the formation by the bit is influenced by the drill string geometry. This is because some of the energy that travels up the drill string is reflected back down by impedance changes (e.g. the transition between drill pipes and drill collars) and is re-radiated at the bit. We also see that changes in the lithology, bit wear, and weight on bit cause variations in the source wavelet. In addition there is the problem of signal to noise ratio as drilling operations generate a large amount of noise at the surface that is not related to drill bit noise.

The main advantages of conventional wireline VSPs over drill bit source RVSPs are the ability to control the source and the low noise environment associated with wireline acquisition. The wireline VSP acquisition can only be conducted a discrete intervals in the well during which drilling operation are suspended. The drill bit source RVSP

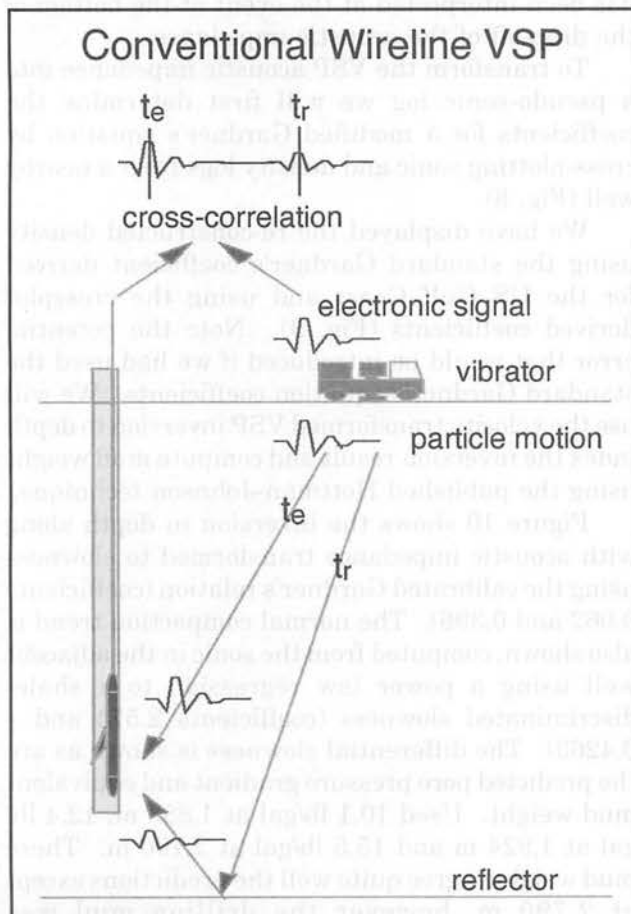


Figure 1. Conventional wireline VSP acquisition geometry.

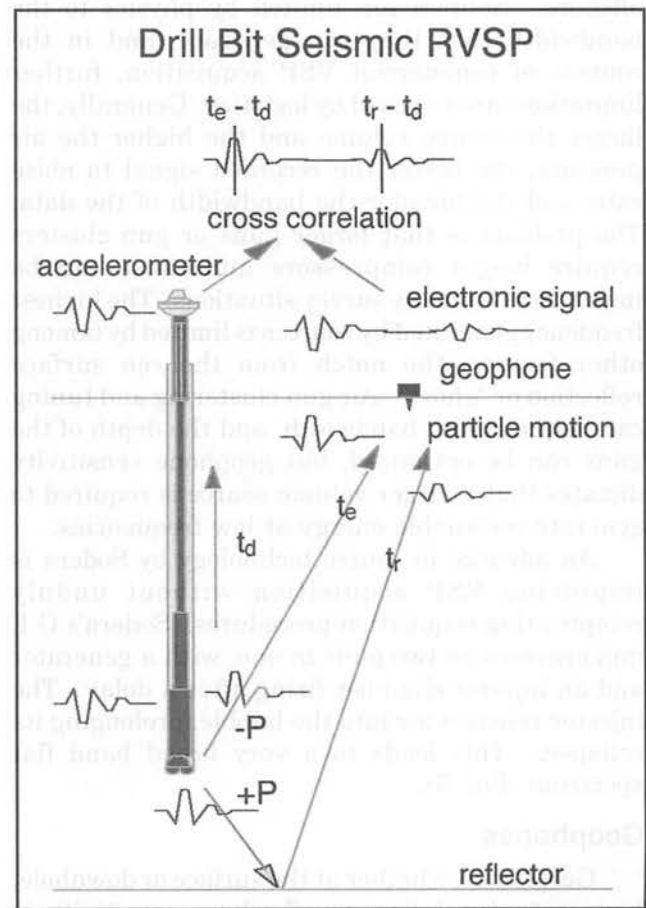


Figure 2. Drill bit seismic RVSP acquisition geometry.

acquisition is done continuously during drilling operations thus providing real-time information.

We will now show how we can combine the advantages of wireline VSP with drill bit seismic RVSPs to provide an accurate depth prediction of a drilling hazard.

VSPs FOR INVERSION

The recovery of acoustic impedance from seismic data is commonly referred to as "seismic trace inversion". The problem is that seismic data are severely band limited, while acoustic impedance data, like sonic and other log data, are wide band. That is, it is difficult to use seismic data alone to reconstruct an accurate acoustic impedance profile. Even VSP data, although usually wider band than surface seismic data, are deficient in both low and high frequencies. We first look at what can be done to record broader band VSP data.

HARDWARE

Sources

Air guns are the most commonly used source offshore. Sources are limited by physics to the bandwidth that they can generate, and in the context of commercial VSP acquisition, further limitations are imposed by logistics. Generally, the larger the source volume and the higher the air pressure, the better the recorded signal to noise ratio and the broader the bandwidth of the data. The problem is that larger guns or gun clusters require bigger compressors and these can be impractical for many survey situations. The highest frequency generated by sources is limited by (among other factors) the notch from the sea surface reflection or "ghost". Air gun clustering and tuning can help increase bandwidth, and the depth of the guns can be optimized, but geophone sensitivity dictates that a larger volume source is required to generate recordable energy at low frequencies.

An advance in source technology by Soderer is improving VSP acquisition without unduly complicating acquisition procedures. Soderer's G.I. gun operates as two guns in one, with a generator and an injector chamber firing after a delay. The injector releases air into the bubble, prolonging its collapse. This leads to a very broad band flat spectrum (Fig. 5).

Geophones

Geophones, whether at the surface or downhole, have a "natural frequency" where sensitivity is greatest to particle velocity. This is commonly between 10 Hz and 14 Hz, with no response below

5 Hz (Fig. 3). Geophones also have a "spurious" response at high frequency. The effect is that standard geophones are limited in the bandwidth that they can record and so even if sources could generate a broad-band pulse, low and high frequencies would not be recorded.

In the late 80s an advance was made in the development of a broader band geophone, capable of recording data down to as low as 3 Hz and as high as 200 Hz. This geophone, which is actually a damped accelerometer and called a "GAC" can be fitted into several well seismic tools (Fig. 4).

Field tests and modeling carried out by Soderer given the specifications of our GAC geophone indicate that the G.I. gun should generate significant energy at 4 Hz.

CASE STUDY VSP

The vertical component of conventional wireline VSP data through deterministic deconvolution and corridor stack and is shown in Figure 6. The leftmost three traces of the corridor stack have been corrected to true amplitude. This is the input to inversion.

Figure 7 shows the VSP inversion results with the corridor stack. The over pressure formation has been interpreted at the event at the bottom of the drop-off of the acoustic impedance.

To transform the VSP acoustic impedance into a pseudo-sonic log we will first determine the coefficients for a modified Gardner's equation by cross-plotting sonic and density logs from a nearby well (Fig. 8).

We have displayed the re-constructed density using the standard Gardner's coefficient derived for the US Gulf Coast and using the crossplot derived coefficients (Fig. 9). Note the potential error that would be introduced if we had used the standard Gardner's equation coefficients. We will use the velocity transformed VSP inversion to depth index the inversion result and compute mud weight using the published Hottman-Johnson technique.

Figure 10 shows the inversion in depth along with acoustic impedance transformed to slowness using the calibrated Gardner's relation (coefficients 0.062 and 0.396). The normal compaction trend is also shown, computed from the sonic in the adjacent well using a power law regression to a shale-discriminated slowness (coefficients 2,574 and -0.4263). The differential slowness is shown as are the predicted pore pressure gradient and equivalent mud weight. Used 10.1 lb/gal at 1,883 m, 12.4 lb/gal at 1,924 m and 15.5 lb/gal at 2,790 m. These mud weights agree quite well the predictions except at 2,790 m, however the drilling mud was overbalanced on purpose because of the danger of a blowout.

As mentioned earlier, the depth transform is a crucial issue. In the next section we show how integration with time measurements from drill bit seismic can improve depth predictions.

DRILL BIT SEISMIC

The drill bit Seismic technique makes use of the noise generated by the bit while drilling, essentially treating it as a Vibroseis-type source commonly used in seismic exploration. The drill noise is recorded by accelerometers mounted on the swivel after it has propagated within the drill string, and is recorded by a surface array of hydrophones or geophones after propagation through the earth. As drilling proceeds the accelerometer data is cross-correlated with the receiver data and auto-correlated with itself. This is repeatedly done for 8 second records which are in turn continuously stacked. The stacked cross- and auto-correlations

are indexed at a depth corresponding to individual lengths of drill pipe. The correct arrival time is the relative geophone-accelerometer time plus the drill string travel time. A second processing sequence is initiated after stacked data for several lengths of drill pipe have been acquired. The main steps of this sequence are:

- Drill string multiple removal (utilizing drill string imaging of the accelerometer data).
- Surface (rig) noise attenuation through adaptive beamforming of digitally grouped surface sensors.
- Time picking, geophone edit and stack.
- Stationary noise removal.
- Drill string travel time determination and addition.
- VSP processing.

Although the data are recorded by receivers on or near the surface from a source at depth, the data can be viewed in a reciprocal way as VSP data

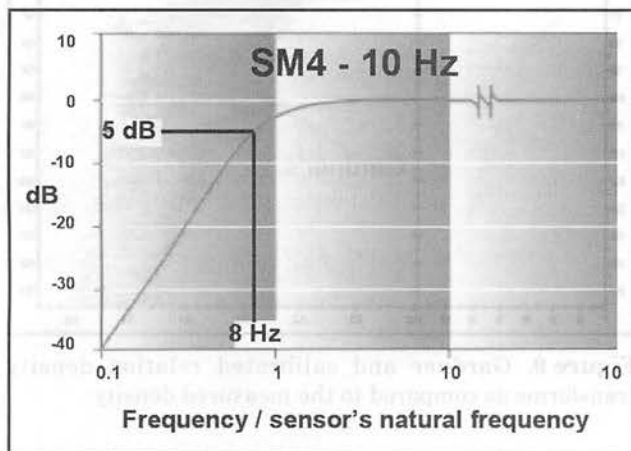


Figure 3. Conventional Geophone.

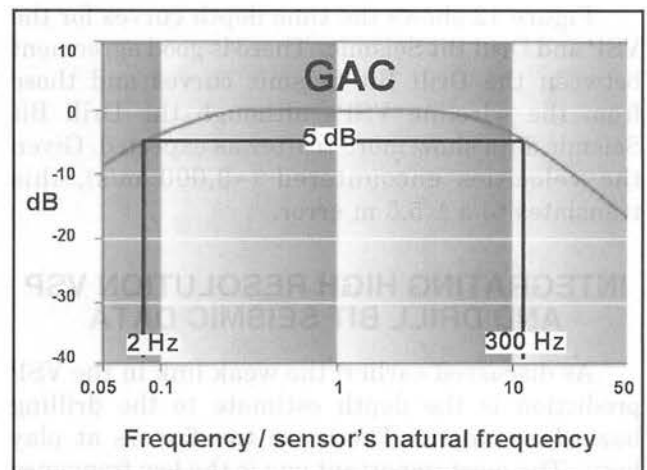


Figure 4. Geophone Accelerometer — GAC.

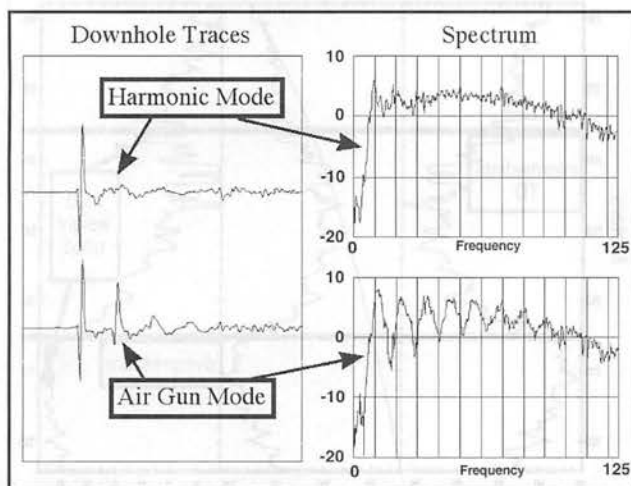


Figure 5. GI gun VSP shot data.

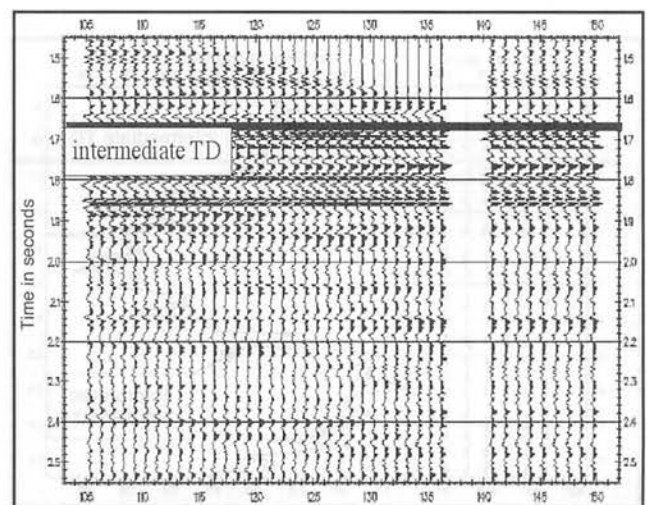


Figure 6. Upgoing deconvolved VSP wavefield and corridor stack in two way time.

having been recorded at depth from an array of sources at the surface.

Figure 11 shows a set of drill bit RVSP data from the same offshore well plotted in true relative amplitude. The data comes from processing 12 surface sensors, in this case hydrophones. The top section shows every second level out of 90 levels of data just before VSP processing. It is therefore comparable to z-axis stacks from a wireline VSP. Clearly visible are the direct arrival and first and second sea bottom multiples. Notice that the first sea bottom multiple has a larger amplitude than the direct arrival. This is expected because the hydrophones, sitting on the sea floor and measuring pressure, receive the downward propagating signal reflected off the sea surface simultaneously with a second upward traveling signal reflected off the sea floor. These signals constructively interfere to produce a larger amplitude. The noise amplitude level is seen to be approximately 1/3 of the direct arrival, but a break time curve is easily picked. Picks are on the trough as with Vibroseis data.

Figure 12 shows the time depth curves for the VSP and Drill Bit Seismic. There is good agreement between the Drill Bit Seismic curves and those from the wireline VSPs although the Drill Bit Seismic data show more scatter as expected. Given the velocities encountered (~3,000 m/s), this translates to a ± 5.5 m error.

INTEGRATING HIGH RESOLUTION VSP AND DRILL BIT SEISMIC DATA

As discussed earlier, the weak link in the VSP prediction is the depth estimate to the drilling hazard or target. There are two factors at play here. The most important one is the low frequency trend recovered by the inversion. This is because

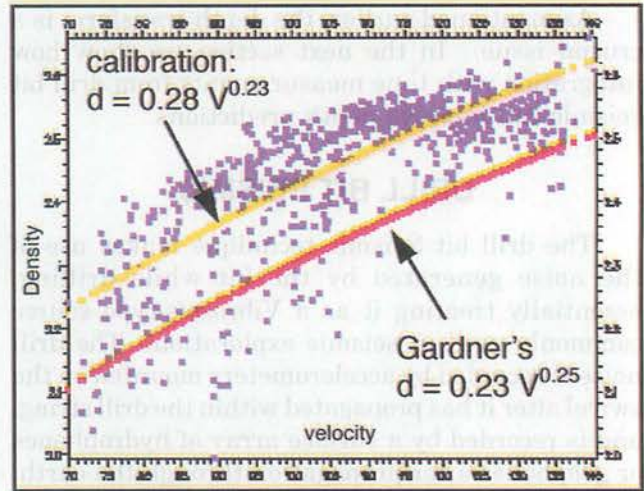


Figure 8. Density/Sonic X-plot.

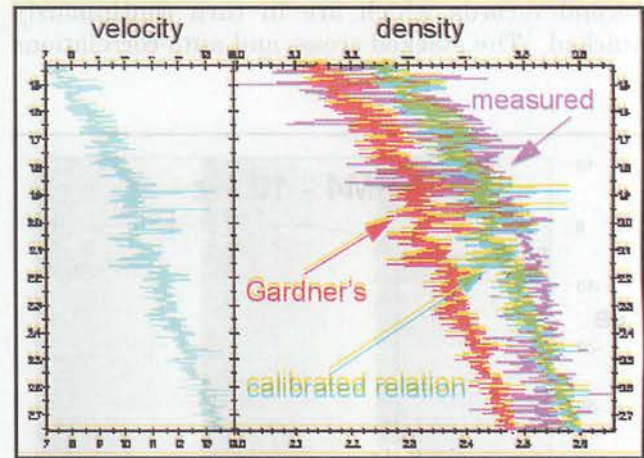


Figure 9. Gardner and calibrated relation density transforms as compared to the measured density.

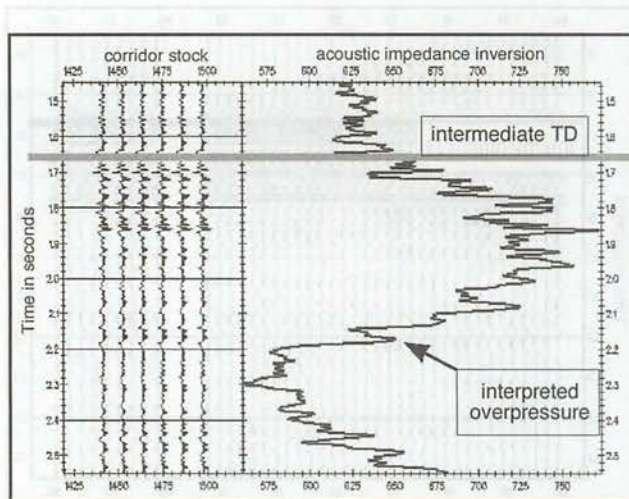


Figure 7. VSP corridor stack and VSP acoustic impedance derivation.

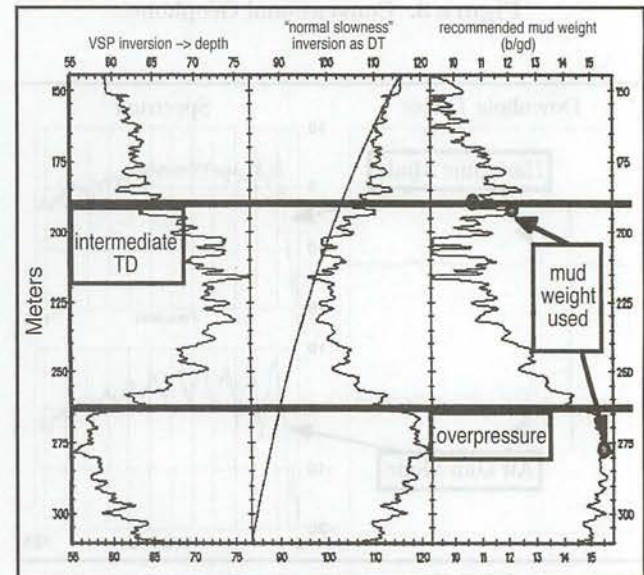


Figure 10. Mud weight derivation determined from and depth indexed by the VSP inversion.

the slowly varying component of the velocity function controls the time-depth curve. The second factor is the need for a density function because the VSP inversion recovers acoustic impedance, not velocity.

Drill Bit Seismic data provide time-depth information below the bottom VSP receiver level as drilling progresses. Thus, the depth index of the acoustic impedance and mud weight prediction can be continuously updated as drilling proceeds, showing clearly when the suspected drilling hazard is about to be hit.

Figure 13 shows a plot of actual bit depth versus predicted depth of an anticipated pore pressure gradient increase. The over pressured zone was interpreted to be at 2.2 seconds on Figure 7. The initial predicted depth to the over pressured zone from the intermediate VSP was at 2,677 m and is

seen to increase to just over 2,700 m as the bit approaches. What is happening is that the predicted time-depth curve from inversion is being continuously updated by the real time time-depth measurements.

DISCUSSION AND CONCLUSIONS

In this paper we reviewed the problem of over pressure — a common reason for acquiring look-ahead VSPs, and the seismic trace inversion problem — a fundamental issue in look-ahead prediction. We examined the essential components of intermediate VSPs from acquisition through processing to inversion and showed recently acquired real data indicative of the advances being made towards the end of an exclusive high resolution VSP service. We presented a simple interpretation method and an end product of predicted mud weight versus depth, which we obtained from the inverted acoustic impedance and empirical relations. The nature of over pressured formations, however, due to their wide range of causes, dictates that a “black box” product is impossible and that interpretation of the inversion is needed.

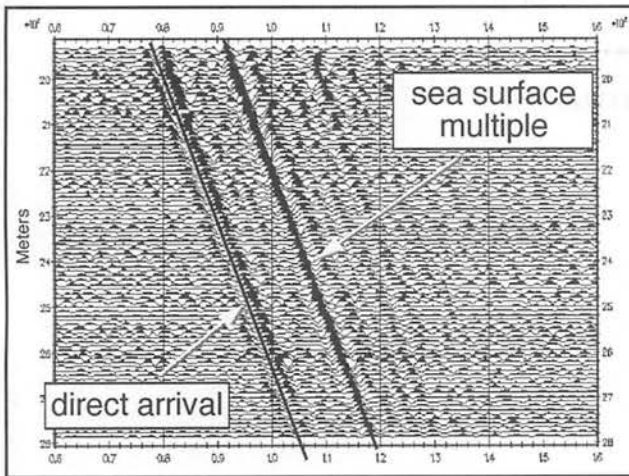


Figure 11. Offshore drill bit seismic stacks of cross-correlated surface sensors.

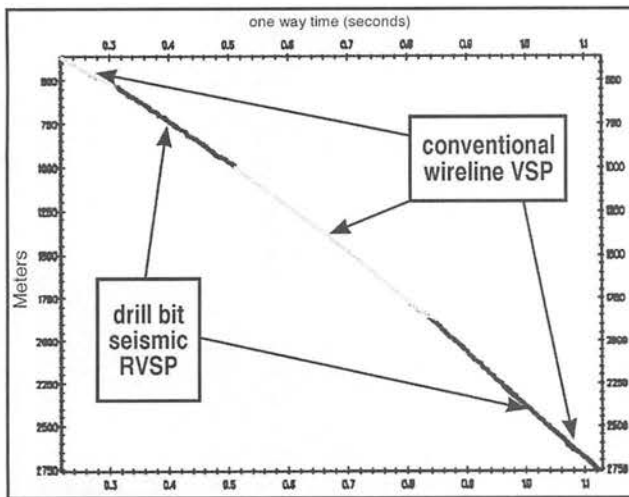


Figure 12. Time/depth comparison between VSP and RVSP acquisition.

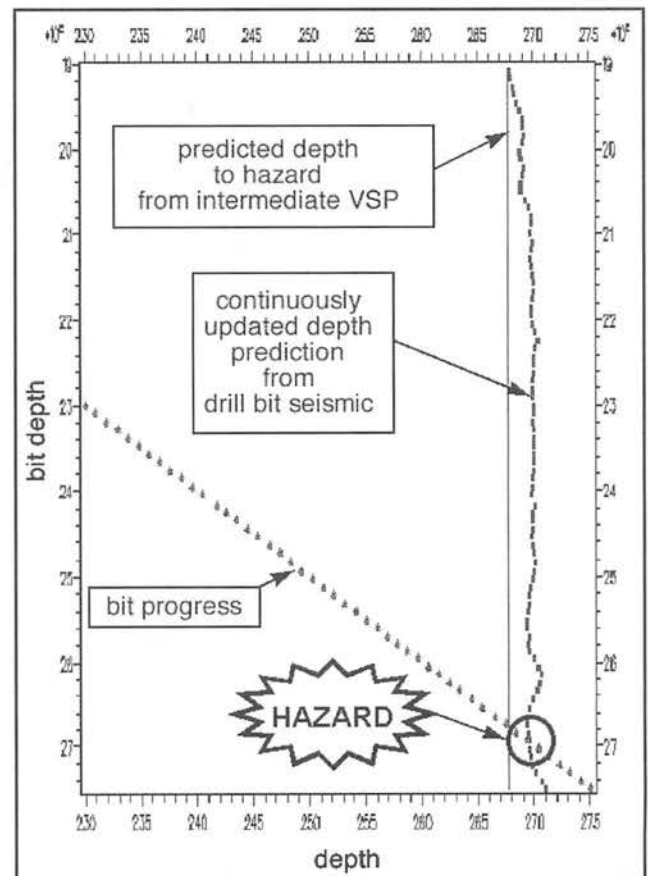


Figure 13. Drilling hazard prediction.

Of paramount importance in predicting the depth to a target is the velocity function used below the intermediate TD. The use of empirical or assumed density functions is an obvious weak link in the procedure. The advent of real time time-depth measurements from drill bit seismic allows a continuously updated predicted depth below the present bit depth. The geophysicist can follow the position of the bit on the seismic section as drilling progresses, and one or more acoustic impedance contrasts interpreted to be drilling hazards or casing point targets can be tracked. A plot of anticipated mud weight versus depth and of actual depth versus predicted depth is easily used by the driller to make timely decisions.

ACKNOWLEDGMENTS

Thanks to: Soichi Nakanishi, Richard Meehan, Masahiro Kamata, Bill Underhill, Aung Than Oo, and Tom McDonald of Schlumberger for help in

acquisition and processing of the data. Appreciation to Professor Tadeusz Ulrych and Mauricio Sacchi at the University of British Columbia for kindly letting us test the AR inversion algorithm.

REFERENCES

- CARRON, D., 1988. *Simultaneous VSP and surface seismic stratigraphic inversion with a minimum entropy algorithm*. SEG abstracts.
- FERTL, W.H., 1976. *Abnormal Formation Pressure*. Elsevier Scientific Publishing Company.
- GARDNER, 1971. *Geophysics*.
- HALDORSEN, J.B.U. ET.AL., 1995. Walk-away VSP Using Drill Noise as a Source, *Geophysics*, 60(4), 978.
- HOTTMAN AND JOHNSON, 1965. *Transactions of the SPE*, 234, 719.
- ULRYCH, T.J. AND WALKER, C., 1984. On a modified autoregressive recovery of the acoustic impedance. *Geophysics*.
- WALKER, C. AND ULRYCH, T.J., 1983. Autoregressive recovery of the acoustic impedance. *Geophysics*.
- WIGGINS, R., 1986. Minimum Entropy Deconvolution. *GeosExploration*.

Manuscript received 15 June 1996