AVO for managers: pitfalls and solutions

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ABSTRACT

Amplitude versus offset (AVO) has become an important interpretation tool for the detection of hydrocarbons and reservoir description. It is important to remember when interpreting AVO data the limitations and assumptions behind the approach. This paper explores some of these assumptions and limitations. Further, in interpreting AVO data to make predictions about the geology, it is important to remember there are two inversions or mappings being done. The first inversion is predicting the elastic parameters from the prestack seismic. The second is predicting the rock and fluid properties from the elastic parameter estimates. Each mapping has its own issues of reliability and uniqueness.

Often a linearized approximation of the Zoeppritz equation is used as the model to predict the elastic parameters from prestack seismic. This imposes certain restrictive assumptions. To meet these assumptions the seismic data must be properly processed. Failing to do so will result in AVO anomalies not related to the geology. The elastic parameters that are estimated are bandlimited. This further complicates the analysis of the data and creates a number of pitfalls.

In the literature there are a variety of AVO techniques, which make assumptions about the rock physics and the relationship between the reservoir and the surrounding materials. If these assumptions are incorrect, this can lead to erroneous interpretations. The rock physics of the play must be understood to make reasonable predictions.

Because of these issues, this paper advocates interpreting AVO at various stages; the prestack gathers, the reflectivity sections, and inversions based on the reflectivity sections. This approach includes both forward modeling and inversion.

INTRODUCTION

AVO is a useful tool to help understand the rock and fluid properties of the earth. It has proven itself useful for finding hydrocarbons. Interpretation based on an AVO analysis provides more information than an interpretation based just on conventional stacked seismic.

The stack, used in a conventional interpretation, represents the average amplitude found in the multi-offset data at a particular location. It is an approximation of the bandpassed P-wave impedance reflectivity, where P-impedance is the product of P-wave velocity and density, and the reflectivity is the difference of the P-impedance divided by its sum at each geological layer boundary. In AVO analysis, instead of just looking at the average amplitude, the amplitudes of all the offsets are analyzed. It is possible to summarize the AVO behavior with several parameters that can be output as sections. These sections can be related to the reflectivity of various elastic parameters. For example, after AVO analysis it is possible to generate both the bandpassed P-wave and S-wave impedance reflectivity, where S-wave impedance is the product of S-wave velocity and density. So, instead of just interpreting an approximate form of the P-impedance reflectivity stack as in a conventional interpretation, both the P and S impedance stacks can be interpreted in an AVO analysis allowing the interpreter to more uniquely describe their geologic objective.

This is the promise of AVO. A number of considerations temper the reality. First the relationship between the rock properties and the elastic parameters is non-unique. The elastic parameters are what we can measure with the seismic. There are at most three parameters: P-wave velocity, S-wave velocity, and density. However, there are many rock and fluid variables that influence the elastic parameters. Hence, any predictions made about the rock properties from elastic parameters will be ambiguous.

Secondly, the elastic parameters are not measured directly. Elastic waves are measured which have propagated through the earth. These waves are distorted and must be properly processed in order to get useable estimates of the earth's elastic parameters. If this is not done correctly, there will be errors in the elastic parameter estimates and the subsequent geologic prediction. In fact, it is virtually impossible to recover the true elastic parameters of the earth from seismic measurements due to three fundamental limitations in the seismic method: the effect of the bandpassed seismic wavelet, the distortion of the seismic raypath due to unknown geologic structure and velocity, and the effect of seismic noise.

Therefore, an AVO analysis can be thought of as a two-step inversion. In the first step, the seismic data is processed so as to obtain estimates of the elastic parameters of the earth. These estimates will have error coming from noise in the measurements, and from incorrect processing. The second inversion, is trying to map the elastic parameters to estimates of the rock properties. This second transform again suffers from non-uniqueness, noise and theoretical errors in the mapping.

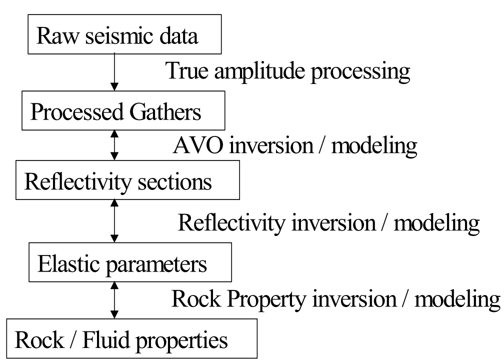


Figure 1: Flow diagram for AVO inversion. The interpretation can occur at any intermediate stage. Moving from the seismic to rock and fluid property estimates, involves processing and inverting the seismic. Moving from the rock and fluid properties to the seismic response involves forward modeling.

This two-step inversion is shown in more detail in Figure 1. The input is prestack seismic, which must be processed to remove the distortions alluded to above. The prestack data is then inverted to generate reflectivity estimates of the elastic parameters that can then be used to predict the rock and fluid properties.

This sequence does not have to be carried out in a top down fashion. The interpretation could be done at any intermediate output. Modeling could be done instead of inversion to link the seismic and rock properties. For example, synthetic gathers or reflectivity sections can be generated based on our knowledge of the rock and fluid properties of the play or local well control. These models can be used as templates for the interpretation of the prestack gathers and reflectivity sections. The components in this figure are somewhat artificial, but serve to highlight key steps in which potential problems arise. These steps and the pitfalls associated with them are the subject of this paper.

AVO Theory

Before discussing the steps in Figure 1 in detail, the AVO model that will be used for the rest of the paper must be defined. Most analysis techniques commercially used today are based on the Zoeppritz equation or a linear approximation of it such as Aki and Richards (1980)

$$r(\theta) = \frac{1}{2}\left(1 - 4\frac{\beta^2}{\alpha^2}\sin^2\theta\right)\frac{\Delta\rho}{\rho} + \frac{1}{2}\frac{\Delta\alpha}{\alpha}\frac{1}{\cos^2\theta} - 4\left(\frac{\beta}{\alpha}\right)^2\left(\frac{\Delta\beta}{\beta}\right)\sin^2\theta \quad , \qquad (1)$$

where α, β, ρ respectively are the average p-wave velocity, s-wave velocity, and density across the interface. θ is the average angle of incidence and $\Delta\alpha$, $\Delta\beta$, $\Delta\rho$ are the change in p-wave velocity, s-wave velocity and density.

If the elastic parameters are known for each layer it is possible to predict how the amplitude will change as a function of angle. Seismic data is recorded as a function of offset so some sort of transform must be performed to change from angle to offset. For a homogenous velocity this is simple to do. We can shoot rays down striking the reflector at different incident angles. From simple geometry we can calculate the relationships between angle and offset. It is possible to do this also for complex velocity fields and calculate a mapping from offset to angle. If there are errors with this transform, this can lead to systematic errors in the predictions from this model.

The Zoeppritz equations are derived for a single interface, separating two isotropic materials, assuming an incident plane wave. Each of these assumptions is potentially problematic and can lead to erroneous conclusions. If one of the layers is anisotropic, then a modified form of the Zoeppritz equations must be used. Note that isotropy implies that the seismic velocity is the same in all directions, whereas anisotropy implies that that the velocity changes as a function of direction. Figure 2 shows the AVO response, first if one assumes the two layers are isotropic, and secondly if the top layer is anisotropic. There is strong evidence that shale can be anisotropic. This is important since seals for gas sands are often shale. If the shale seal is anisotropic, and we use an isotropic model, the conclusions we reach about the elastic parameters and rock properties will be influenced by the use of the wrong model possibly leading to incorrect conclusions and predictions.

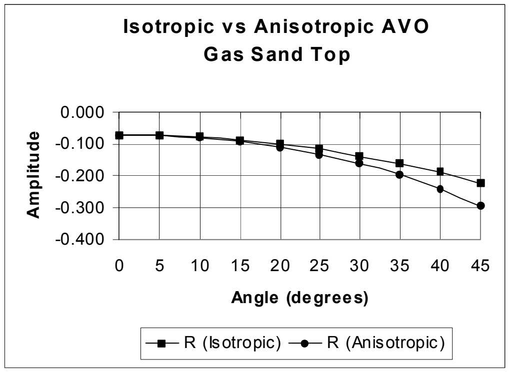


Figure 2: Effect of anisotropy on the AVO response

The assumption that there is only one layer is wrong but can be a useful approximation. When multiple interfaces and layers are included in the model, factors that influence the amplitude such as multiples, converted waves, transmission losses all occur. Since these are not included in our simplistic AVO model arising from equation (1), they must be appropriately processed so as not to influence the estimates of the elastic parameters.

Preparation of the input gathers for the AVO analysis

multiple interference	array effects
temporal tuning	instrumentation
mode conversions	source strength & consistency
transmission losses	receiver coupling
effect of overburden	RNMO
reflector curvature	processing algorithms
spherical divergence	NMO stretch
phase changes with offset	geology
noise and interference	ground roll
attenuation, dispersion, absorption	random noise

Table1: Factors which influence AVO

Many factors influence the amplitude of the reflectivity as a function of offset. A list of these factors is shown in Table 1. Ideally, we would like to isolate the AVO response due to the geology and process the rest out. If there are residual amplitude distortions left after processing, these distortions will introduce error and uncertainty into the final interpretation.

This paper focuses on AVO pitfalls so it is important to point out that these factors exist, but it is beyond the paper's scope to discuss them in much detail. Several factors will be discussed for illustration purposes. The interested reader is referred to papers by Spratt (1993), and Mazotti (1995) for a more detailed discussion of true amplitude processing.

The first AVO distortion considered is due to offset dependent transmission losses. At an interface, part of the energy will be reflected and part transmitted. Due to the conservation of energy, if energy is reflected, the amount of transmitted energy will be less than the input. Each layer will cause losses, but generally most of the energy will be transmitted.

Similar to reflectivity, transmission losses can change as a function of offset governed by Zoeppritz equations. This would introduce a distortion on the AVO response at the target leading to an erroneous AVO analysis. Offset dependent transmission losses are potentially significant if there are large velocity contrasts above the geologic objective. In addition, we would expect that under the most pronounced AVO anomalies, such as a gas sand, we would find the most pronounced transmission loss effects.

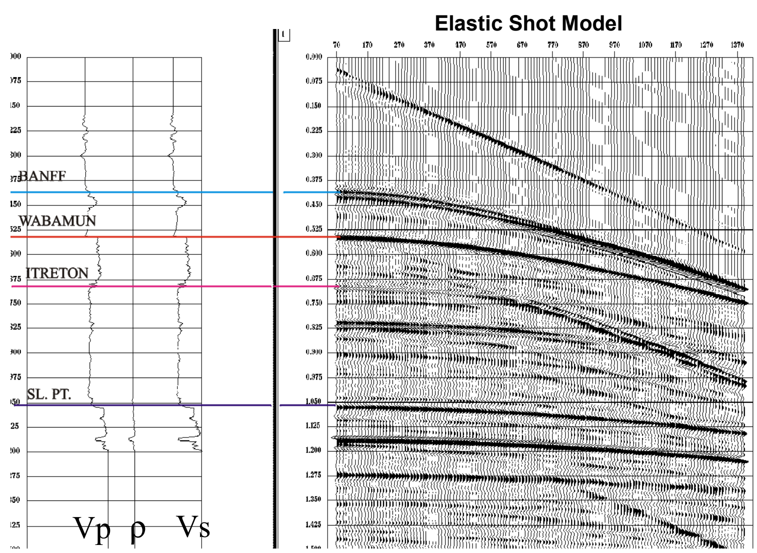


Figure 3: Synthetic gather showing offset dependent transmission losses

Figure 3 shows a finite difference elastic model generated from a well log from northwestern Alberta. The zone of interest is the Slave Point. There are two large velocity contrasts occurring at shallow depths in this particular area. The first occurs at the Banff and the second at the Wabamun. Offset dependant transmission losses occur on both these interfaces. Note that the amplitude of the Banff gets larger as a function of offset. Less energy gets transmitted to subsequent layers for the larger ray paths as a result. This is evident on the Wabamun and Ireton reflections where the amplitude decreases as function of offset. If we wanted to do an AVO analysis on the Slave Point we need to address the amplitude distortions being introduced by the shallow markers. Figure 4 shows a common offset gather of the real data at the same location showing the same distortion.

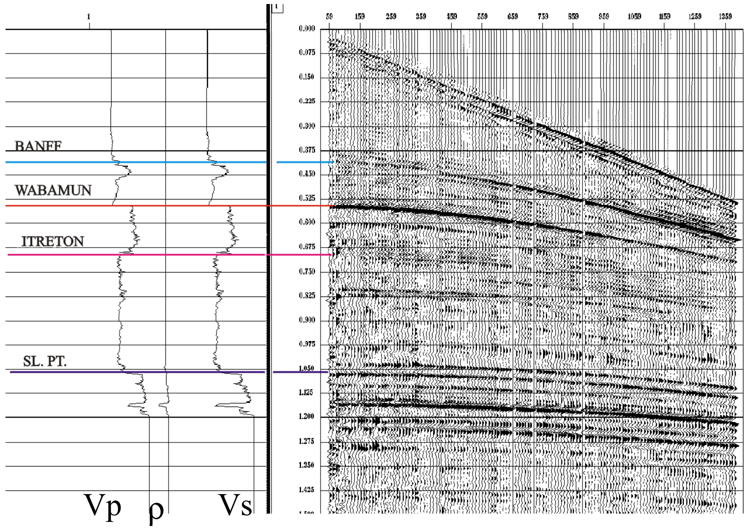


Figure 4: Common offset gather showing offset dependent transmission losses

Data Processing

Data must be processed to meet the assumptions that were listed earlier for the Zoeppritz equation. Often processing done to create an optimal section for conventional interpretation will have processes applied that will make it unsuitable for AVO analysis.

One example of this, is applying trace scaling (trace balancing) to the prestack gathers. On land data, it is performed to correct for trace-to-trace scaling differences introduced by the source and receiver coupling variability. Trace scaling is often implemented by normalizing the RMS energy of the trace over some design window. In the processing sequence, this is often done before and after deconvolution. It is sometimes built right into the deconvolution algorithm. After trace scaling, the gather is better balanced and noisy traces scaled down.

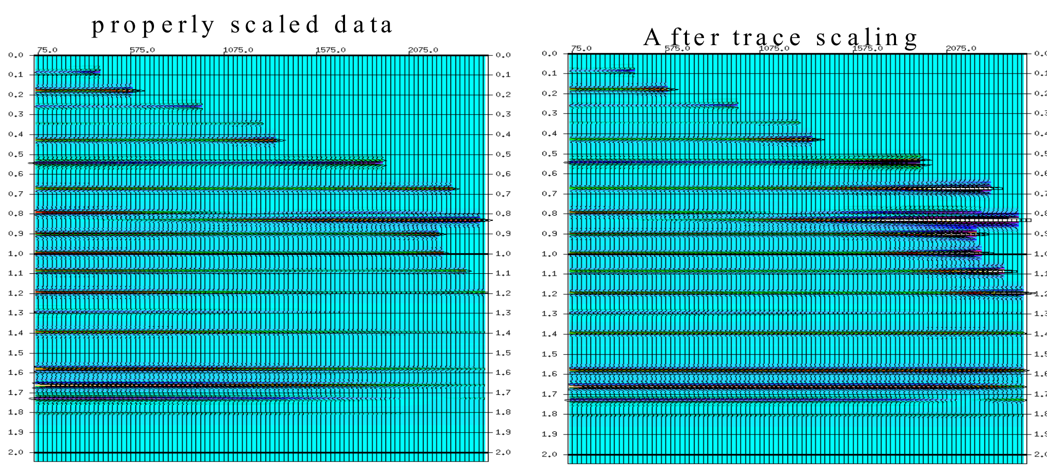


Figure 5: The effect of trace balancing on gathers. The left hand gathers are properly scaled. The right hand gathers have been trace balanced. Note the change in gradient.

If trace scaling is done, the amplitude with offset relationship is distorted. Figure 5 shows a model gather before and after trace balancing. Note that the amplitudes on the trace balanced gathers are much stronger on the far offsets than on the reference gather. The AVO relationship has been changed, resulting in a systematic AVO distortion. This results in incorrect estimates of the elastic parameters if an AVO inversion is performed. Figure 6 shows the AVO inversion for S-impedance reflectivity. On the left side of Figure 6 is the correct S-impedance reflectivity section. The right side shows the effect of the trace balance on the estimate S-impedance reflectivity. The anomalies are still evident, but the background reflectivities have been severely distorted. If a fluid stack or a poststack inversion is performed on this section, these distortions will have a severe negative impact on the interpretation of the final result.

Ideally, instead of doing trace scaling, one should do surface consistent scaling. Surface consistent scaling is a processing algorithm, which corrects for the source and receiver coupling variability using a statistical model. Figure 7, shows an S-impedance reflectivity section extracted on gathers which had trace balancing and Figure 8 shows the same section on gathers which had surface consistent scaling. The AVO inversion result based on the surface consistent scaled gathers has better continuity and a better signal to noise ratio. Interestingly, the input gathers with surface consistent scaling appeared noisier than the trace balanced gathers.

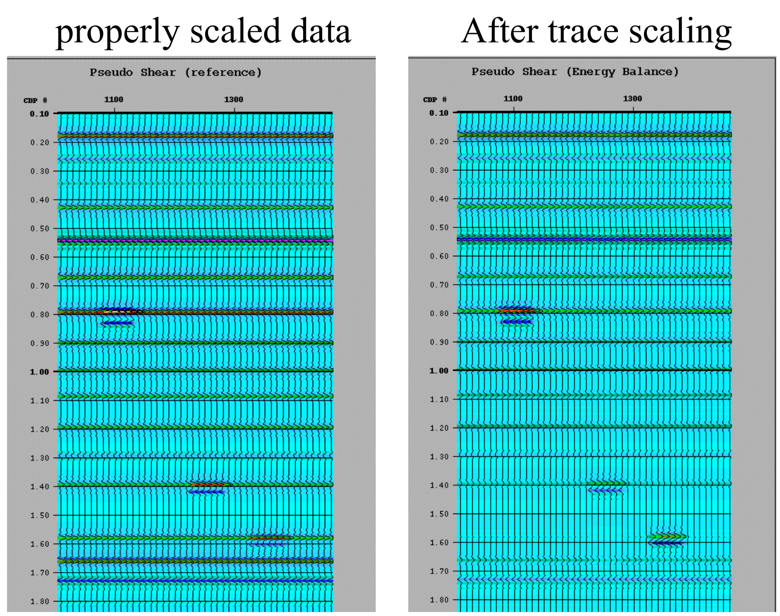


Figure 6: The effect of trace balancing on AVO inversion. The left hand S-impedance section is properly scaled. The right hand section was trace balanced prior to inversion. Note the change in amplitudes.

The main point that we would like to make before leaving this section is that the gathers must be properly prepared prior to doing an AVO analysis. The saying ”garbage in, garbage out” applies here. The requirements for AVO are often at odds with what makes for a good-looking section used in conventional interpretation. Ideally, when the data is initially processed it should be dual streamed, creating a section optimal for interpretation, and gathers optimal for AVO. If AVO is being considered after the initial conventional processing has been done, then the data should be reprocessed.

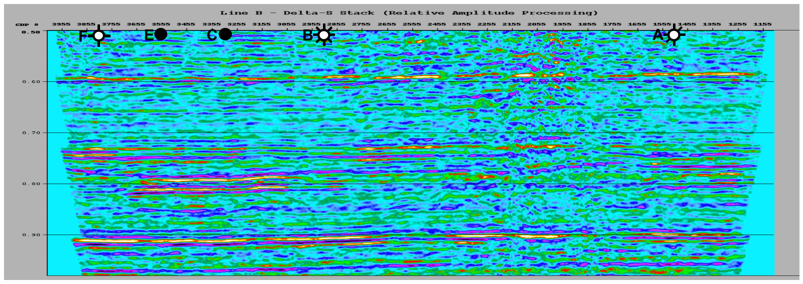


Figure 7: Effect of prestack scaling on AVO inversion. The S-impedance AVO section was inverted using trace balanced gathers as input.

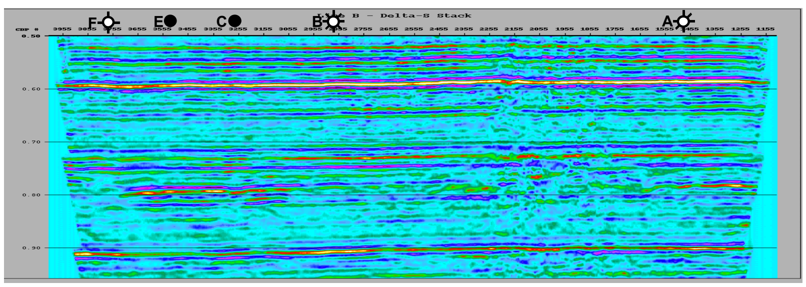


Figure 8: S-impedance AVO inversion based on gathers with surface consistent scaling. This is the same line as shown in figure 7. Note the improved signal-to-noise ratio and continuity of this section compared to figure 7.

AVO inversion

The linearized approximation of the Zoeppritz equation can be used to invert the prestack gathers, to get estimates of the p-wave velocity, s-wave velocity and density reflectivity. This inversion is ill-conditioned, meaning that a small amount of noise will lead to large uncertainty in the reflectivity estimates. To get around this, equation (1) is often rearranged to make it more stable. This usually involves solving for two unknowns rather than three (Lines, 2000). One popular rearrangement of this is to describe the amplitudes vs. angle as a line with intercept A and slope B. This is two term Shuey equation (Shuey, 1985)

$$R(\theta) = A + B\sin^2\theta \quad . \tag{2}$$

B is called the Gradient stack and represents the slope of the line defined by equation (2). The intercept section, A, is the bandpassed P-impedance reflectivity.

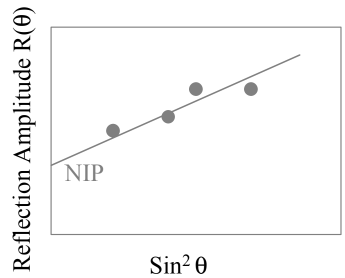


Figure 9: AVO inversion is similar to linear regression. The fitting procedure for amplitudes for a single time at one CMP. Fitting equation (2) is just a simple linear regression where the intercept and slope are calculated. This process is done for every time sample within a CMP gather generating an intercept trace and a gradient trace. This is done for every CMP gather resulting in intercept and gradient sections.

These sections are useful to the interpreter since they summarize the AVO behavior of the gather so the interpreter does not have to look at all the prestack gathers. However, these sections are not necessarily intuitive in understanding how the elastic parameters themselves are behaving. There are other rearrangements of equation (1), which solve for reflectivity sections in terms of elastic reflectivities. One such method is due to Fatti et al., (1994), which directly solves for P and S impedance reflectivity. It is often more intuitive to work with reflectivity sections based on elastic properties. If we conceptually understand how the P and S impedance will react to gas, we can predict how these AVO sections will also react.

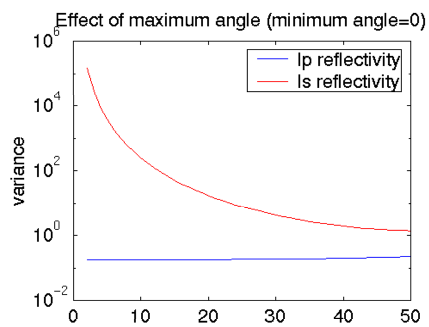


Figure 10: Effect of the range of angle used in the AVO inversion on the stability of the problem.

In generating these sections, noise in the prestack gathers will lead to uncertainties in the parameter estimates. Generally, the estimate of the P-impedance reflectivity will have an uncertainty about that of the stacked data. The second AVO section such as S-impedance reflectivity or the gradient stack will have much greater uncertainty. This uncertainty can be predicted. Figure 10 shows the predicted uncertainty for the P and S impedance reflectivity at a signal to noise ratio of one. These curves show how the AVO inversion process amplifies noise. The uncertainty decreases as the angle range for which AVO inversion increases. To decrease the uncertainty, one can increase the fold of the data acquired to increase the signal to noise ratio or try to increase the range of angles used in the AVO inversion. If the signal to noise ratio is poor, the estimates from the AVO inversion could be erroneous

It is possible to design quality controls for these issues (Downton, 2000). The top panel in Figure 11 shows an S-impedance AVO extraction. Under this is a panel showing how the noise gets amplified similar to Figure 10. The bottom most panel shows the fractional uncertainty in the parameter estimate. At the beginning and end of the line there are not many offsets resulting in a small angle range over which to do the AVO inversion. Since the angle range is small, there is not enough information to do a reliable AVO inversion and the results will be unreliable. This effect is correctly identified on the middle and bottom quality control stacks in Figure 10. The fractional uncertainty in this area is greater than one. Many people shoot 2D or 3D surveys so they tie well control just at the edge of the survey. This practice is insufficient for AVO and erroneous conclusions can result.

Note that it is also possible to see where the missed shots are in the middle panel of Figure 10. At these points, the line is missing the near offsets, and consequently the range of angles available for the AVO analysis is poor leading to noise magnification. Some of the shallow anomalies are related to this acquisition issue.

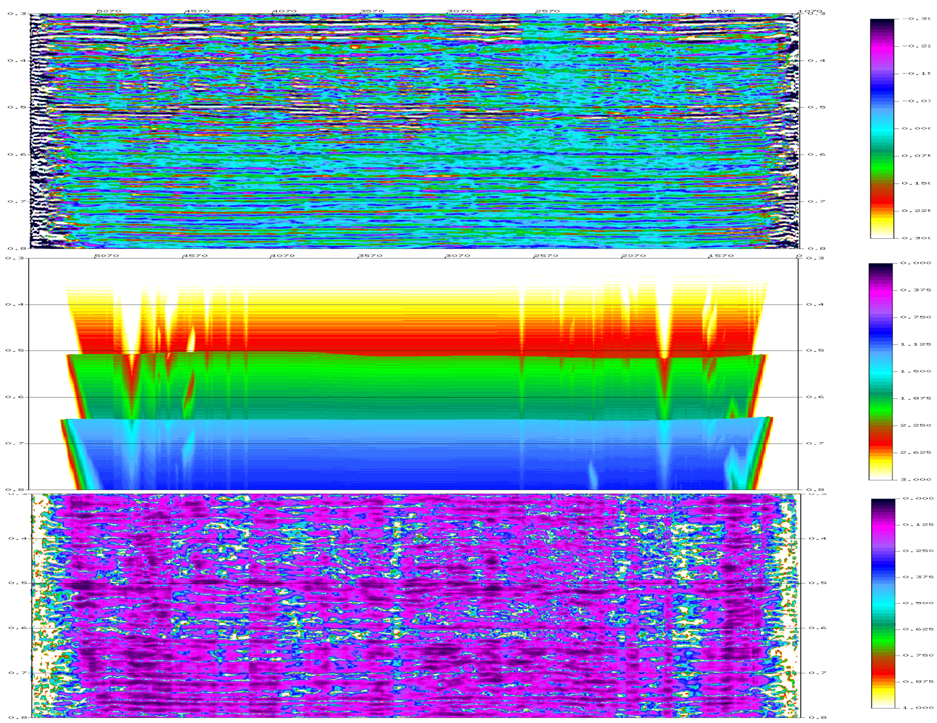


Figure 11: The top panel is the S-impedance AVO inversion. The middle panel is the variance assuming unit noise and the bottom panel is the fractional uncertainty. Note the large fractional uncertainty at the end of the line where there are no far offsets.

Reflectivity inversion

It is often desirable to work with the elastic parameters rather than the bandpassed reflectivity associated with the elastic parameter. For example, it is more intuitive to work with velocity rather than velocity reflectivity. Geologists are familiar with working with velocity logs through the use of sonic logs. There are well known relationships describing how velocity changes as a function of porosity or lithology.

Reflectivity depends on the contrast in velocities between two adjacent layers. Since both layers can change, it is much more difficult to relate changes in the reflectivity than to changes in rock properties. Further, we are interpreting bandpassed reflectivity. There is some wavelet convolved with the reflectivity spreading the reflectivity response temporally. It can be quite complex to understand what the physical significance of a particular amplitude is.

Reflectivity inversion (Russell, 1988) converts the bandpassed reflectivity to its corresponding elastic parameters. An example would be converting bandpassed P-impedance reflectivity to P-impedance. AVO methodologies such as LMR (Goodway et al., 1997), include reflectivity inversion as part of the AVO processing sequence. LMR stands for lambda-mu-rho, the basic three elastic constants which define the P- and S-wave velocity.

In doing reflectivity inversion certain assumptions must be made. Since the seismic data is bandlimited, there is information missing for both the low and high frequencies. The reflectivity inversion must be constrained with external information from another source to properly estimate the elastic parameter such as velocity. The low velocity trend from well control is often used as an external source of information for reflectivity inversion. If this information is wrong it can lead to systematic error in the elastic parameter estimates. This is problematic in frontier basins with sparse well control.

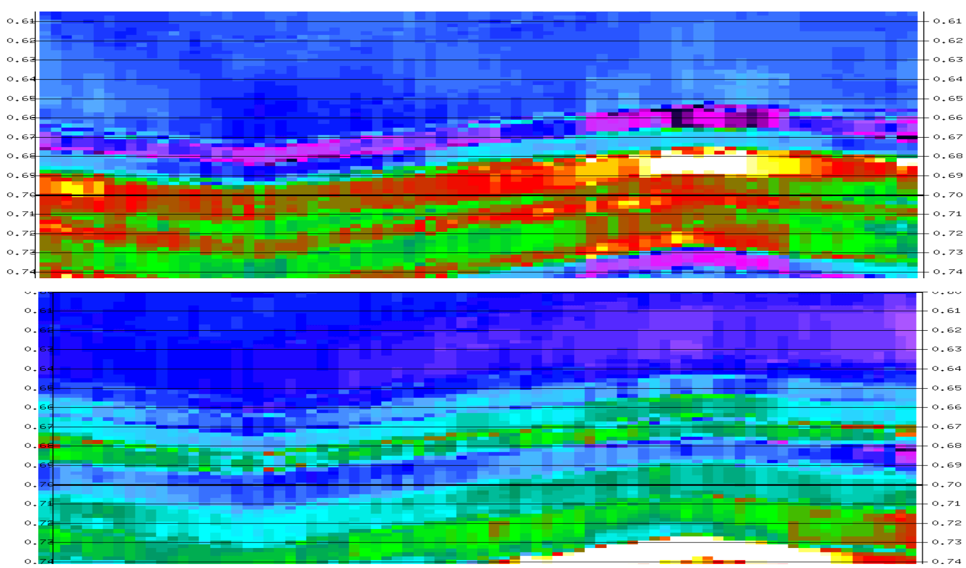


Figure 12: Lambda*rho inversions with two different phase rotations. The top panel is rotated 0 degrees and the bottom panel 180 degrees. Low values of Lambda*rho are in violet. Note the low Lambda*rho anomalies at station 1200, 0.65 seconds and 0.73 seconds are high after the 180 degree rotation changing the interpretation.

Additionally, the inversion process needs the knowledge of the wavelet. Certain simplifying assumptions can be made, such that the wavelet has a flat amplitude spectrum and zero phase. If these assumptions are wrong, this can lead to error. For example, Figure 12 shows the effect of varying the phase of the input section prior to inversion. This is a Lambda-rho section where low values can indicate a gas.

(Actually, we can think of the parameter lambda as being sensitive to the fluid and mu as being sensitive to the rock matrix, but since it is difficult to estimate lambda or mu unambiguously from the seismic data, we estimate the products lambda x rho and mu x rho, where rho stands for density.) High values of Lambda-rho indicate a tight rock.

On the top Lambda*rho section (0 degree rotation), there is a good anomaly at station 1300 at both 0.66 seconds and 0.735 seconds. On the lower panel, which is rotated 180 degrees, both anomalies have high lambda*rho and appear tight! Two different interpretations result from two different phases. It is essential to get the phase right.

Mapping Elastic Parameters to Rock / Fluid Properties

Ultimately, we want to be able to predict the rock and/or fluid properties from the elastic parameters derived from the seismic. There are many rock physics variables influencing the elastic properties of the rock. For example, the fluid content, pressure, temperature, mineralogy, porosity, the number of cracks, the orientation of the cracks all influence the elastic properties of the rock. Since there are at best only three elastic parameters, any inferences made from them, about the rock variables are going to be non-unique and probabilistic.

This is perhaps too pessimistic a viewpoint. Often knowledge of the local geology can be used to help constrain the rock and fluid property predictions. For example it might be known that the porosity of some sand does not vary and this variable can be excluded in the analysis. In addition, not all of the variables listed above will affect the rocks to the same degree. Some variables might influence the rock quite significantly and others not at all.

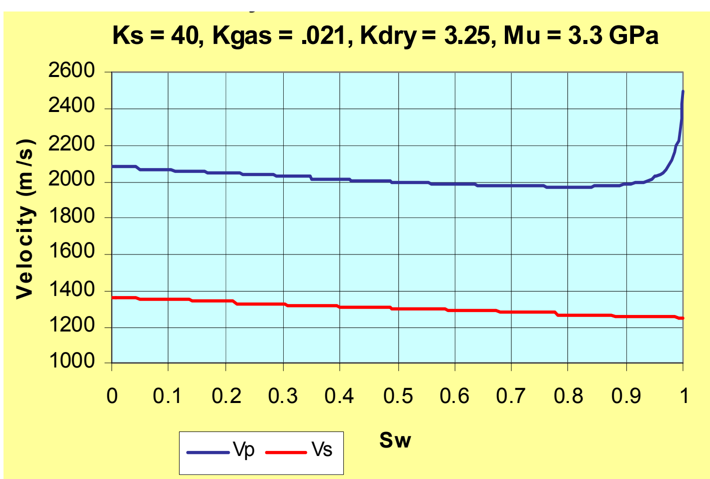


Figure 13: The effect of gas saturation on the P and S wave velocity

The effect of gas on sandstones is often very pronounced. The influence of this is shown in Figure 13 where the introduction of a small amount of gas changes the P-velocity significantly. The S-velocity remains largely unaffected. In this example a gas sand and a brine sand have significantly different elastic parameters, so it should be possible to differentiate the two using AVO. However, a low saturation gas sand (e.g. 5%) has almost the same elastic parameters as high saturation gas sand (e.g.100%). Thus it will be difficult to tell if the reservoir is economic from the elastic parameters and AVO.

The usual situation when making a prediction about rock and fluid properties from AVO is that several geologic variables are changing simultaneously. For example, if our geologic objective is trying to identify a gas filled dolomite, there is a good chance that at the zone of interest the mineralogy is also variable. There might be the potential for limestones, anhydrites or some mixture of the above, each with different elastic parameters. The porosity and their aspect ratios are also variable, influencing the elastic parameters. Lastly the variable we are interested in the fluid content will influence the elastic parameters. If only two elastic parameters are used to predict the rock properties the estimates of the geologic variables will be non-unique. Figure 14 shows a cross-plot (Li and Downton, 2000) of some carbonate core measurements displayed with the elastic parameters $\lambda\rho$, $\mu\rho$. Superimposed on top of this is an interpretation based on a statistical analysis of how each variable influences the rocks elastic parameters. Note that there are areas of non-uniqueness.

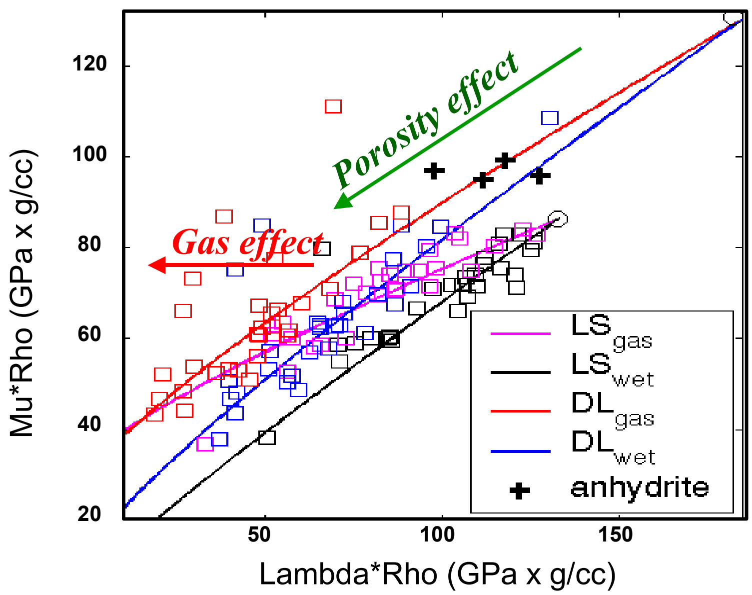


Figure 14: How the elastic parameters react to changes in rock and fluid variables: The underlying symbols are core measurements. Note the potential non-uniqueness of interpreting rock and fluid properties using elastic parameters

There is significant scatter between the model of how the variables should behave and where the data points actually lie. In this case it could be coming from the fact that the influence of fractures is not taken into account. It is extremely difficult to account for all the potential variables influencing the rock and account for them. This will introduce additional uncertainty into any prediction of rock properties from elastic parameters.

Interpretation

Up to this point we have followed Figure 1 moving in a top down fashion. As mentioned in the introduction, each of the intermediate outputs can be interpreted. For example, the reflectivity sections can be interpreted to predict rock and fluid properties. Modeling can be done rather than inversion to understand the significance of the reflectivity section. The modeling would be based on well control, or empirical rock physics relationships to help understand how varying the rock properties will influence the seismic signature.

Based on this understanding, various transformations can be performed on the multiple AVO sections to try and highlight the desired geologic objective. Adding or multiplying the two stacks together are examples of these transformations. The result of these transformations is often called an indicator stack. One of the oldest indicator stacks is the product stack. It is simply the product of the A and B stack from equation 2. It highlights low velocity gas sands surrounded by high velocity regional units. These are called class III sands (Rutherford and Williams, 1989). This is the most common type of AVO anomaly, but Rutherford and Williams also discuss class I, or high impedance contrast gas sands, and class II, or near-zero impedance contrast gas sands. The class II sands cannot be seen on a product stack.

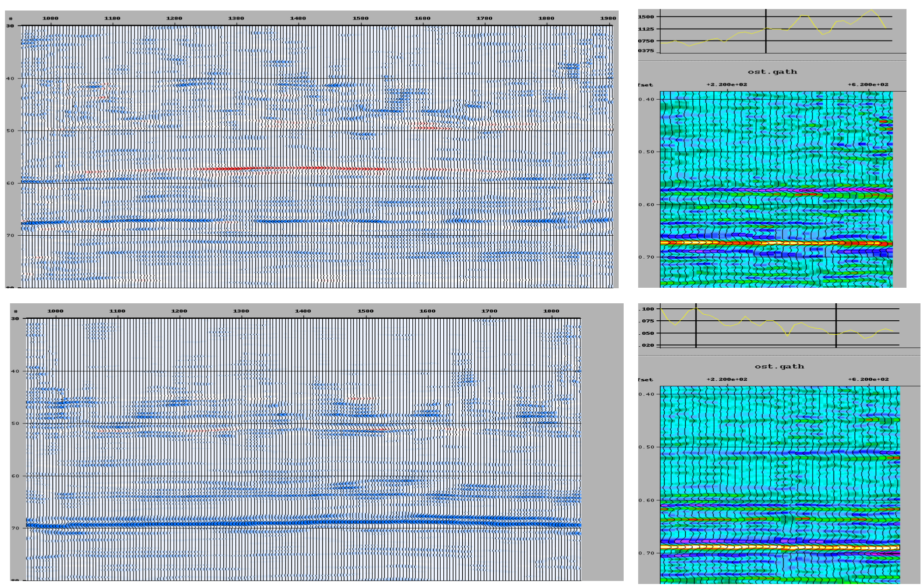


Figure 15: The top left panel shows the product stack over a known gas field. To the right is an Ostrander gather at the well location. Note the increase with amplitude as a function of offset. The bottom panel shows a product stack over a bright spot created by a very porous wet sand. The Ostrander gather shows a decrease with offset.

From simple rock physics relationships and forward modeling, it is possible to see that for a class III gas sand, the interface between the higher velocity regional material and the low velocity gas sand will generate a negative value for both A and B. The interface between the base of the gas sand and the unit below will generate positive values for both A and B. Multiplying the A and B sections results in a positive value at both the top and base of the gas sand. If the sand is wet, the product stack is negative. Figure 15a shows a product stack anomaly over a known gas field. The positive values are displayed in red and the negative values displayed in blue. The red values here correspond to the known gas pool. Figure 15b is a product stack over a line with a bright spot. The bright spot turned out to be a high porosity wet sand. The product stack of this correctly indicates it as wet.

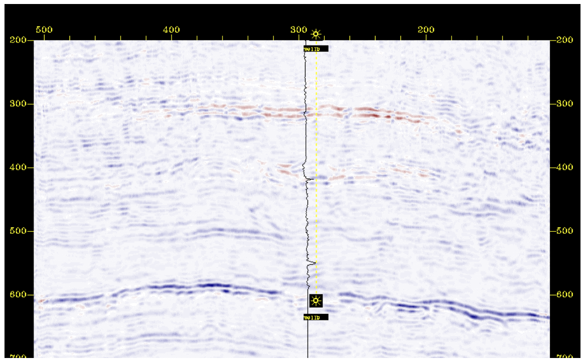


Figure 16: Product stack over a known gas field. The product stack correctly identifies the top anomaly at 0.32 seconds at the well bore, but fails to identify the anomaly at 0.42 seconds.

This method is not used all that often now for several reasons. The results seem to be sensitive to the frequency content of the seismic and tuning. Secondly, the method only works for a specific class of gas sands. There are more robust and general methods available. Figure 16 shows a product stack over another line. The product stack correctly identifies the anomaly for the top sand at 0.320 seconds, but misses the thick low velocity gas sand at 0.420 seconds. Probably, the issue here is tuning. This well was the best well in the project area, so it is disconcerting that the product stack did not work. However, another indicator stack, the fluid stack, did.

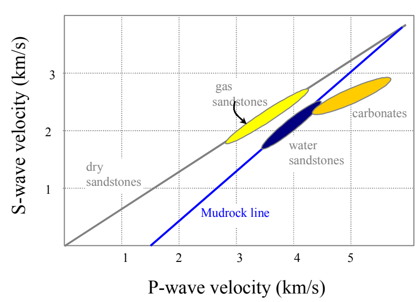


Figure 17: Sketch showing the linear relationship in Vp, Vs space for clastics

The fluid stack (Smith and Gidlow, 1987) is again derived for detecting gas sands in a clastic sequence. It is derived based on the premise that that both the P and S velocity react to porosity in a similar fashion. Both react roughly linearly. Ignoring other factors, the fact that both Vp and Vs react to porosity linearly describes a line in Vp, Vs space. This work was based on the experimental work done by researchers at ARCO (Castagna et al., 1985) and the empirical relationship is called the mudrock line. This implies that the S-impedance section is a scaled version of the P-impedance reflectivity section. If the scaled version of the S-impedance section is subtracted from the P-impedance section then the result should be zero with the following exception.

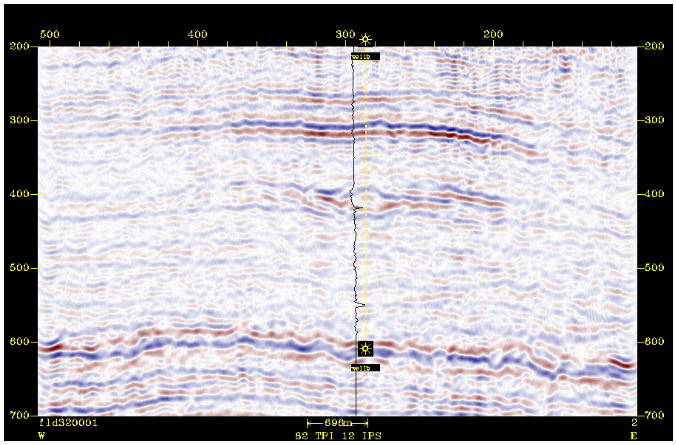


Figure 18: Fluid stack over a known gas field. This is the same line as figure 16. Note that the fluid stack correctly identifies both the top (0.32 seconds) and bottom (0.42 seconds) gas sands at the well bore

If the rock is gas filled, the P-velocity will be lower than if it was brine filled. The S-velocity is largely uninfluenced by the presence of gas or water. In the situation, when there is gas present, subtracting the scaled version the S-velocity reflectivity from the P-reflectivity, will be non-zero. The result of subtracting the scaled S-impedance reflectivity from the P-impedance reflectivity is called the fluid stack. Figure 18 shows the fluid stack for the same line for which the product stack previously failed. Note the fluid stack shows anomalies for both gas sands.

The fluid stack works well for clastic sections but fails when its assumptions are violated. This occurs if there are carbonates. Carbonate rocks do not follow the same linear relationship (Figure 17) as clastics. This implies that a different scale factor should be used in the calculation of the fluid stack. If the wrong scale factor is used, this will result in an anomalous fluid factor response not related to hydrocarbons. This is seen in Figure 18 where the carbonate at 0.620 seconds shows a fluid factor response. It is possible to distinguish the response due to a gas sand versus that due to a carbonate since they are opposite in polarity. In frontier basins this response can be used for phase identification if there is a known carbonate. However, this can also be a potential pitfall. If the phase is guessed wrong, it is possible to think that the anomaly is gas sand when it is actually a carbonate. There have been more than a few dry holes drilled for this reason.

Perhaps even more problematic is the situation where there are inter-fingered clastics and carbonates. The changes in lithology create fluid stack responses of both polarities. Often there is the additional issue of tuning in this situation.

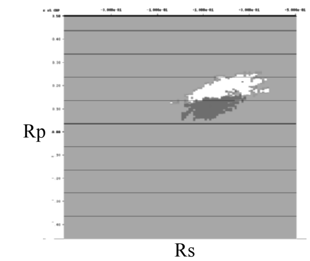


Figure 19: Cross-plot of P and S wave reflectivity sections at gas well (grey) and wet well (white). Note the separation of the two clusters

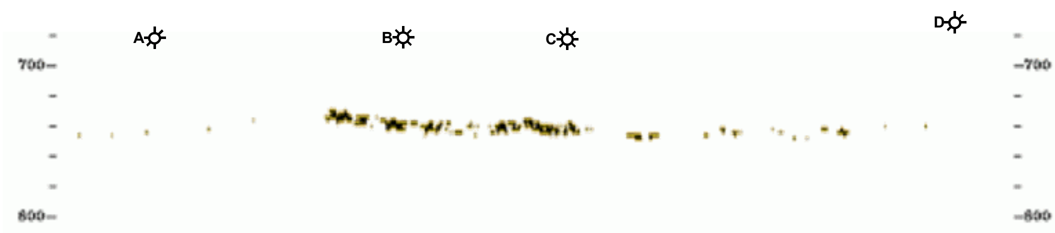


Figure 20: Indicator stack based on cross-plot in figure 19. Filter designed on gas cluster highlights gas pool on seismic section corresponding to known well control

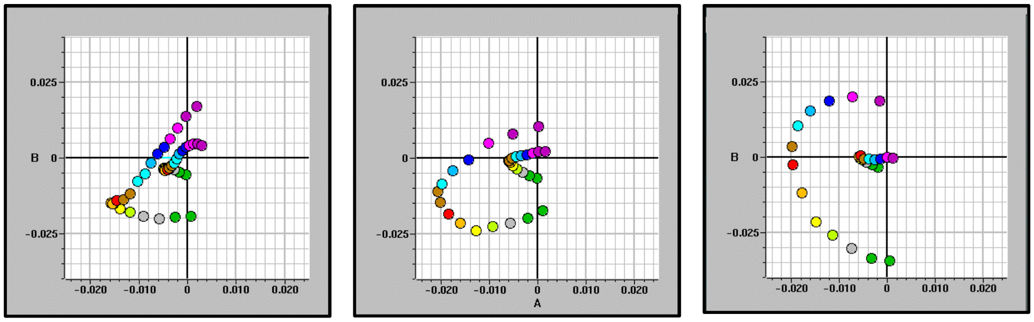
Cross-plotting reflectivity data

Most indicator stacks make assumptions about the rock properties. When those assumptions are violated the indicator will give misleading predictions. In general it is more flexible to try and interpret the reflectivity data in cross-plot space. Hopefully, the geologic objective will occupy a distinct area in cross-plot space and can be identified there.

To understand how the geologic objective will behave in reflectivity cross-plot space a number of strategies are employed. If there is suitable well control, each well can be modeled and cross-plotted to understand how the zone of interest responds. The issue with this approach usually is one of sampling. Have all the possible geologic situations been modeled to understand the response of each in cross-plot space? Usually some significant geologic situations are missed, resulting in unexpected drilling results somewhere in the drilling program.

Rock physics relationships can be used to model the response of geologic situations that are not represented by well control. Again forward models can be generated and studied to understand the influence of various geologic variables.

Cross-plotting reflectivities is more complex to analyze than cross-plotting elastic parameters. This arises because of the interaction of the seismic wavelet and the reflectivity series. If we were analyzing the cross-plot response due to a single layer, at the exact time of the layer boundary the response would be a single point in cross-plot space. If the cross-plot was done over a broader window including the effect of the wavelet, the response becomes a line in cross-plot space. If there is offset-dependent tuning in the data, this line becomes a cartoid in cross-plot space. This becomes further complicated, if instead of dealing with one layer we have multiple layers. The wavelets from these layers will interfere creating a complex pattern in cross-plot space.



(a) Zoom of crossplot of the trough in the unaltered sand.

(b) Zoom of crossplot over trough in sand that has been thinned by 50%.

(c) Zoom of crossplot over trough in sand that has been thinned by 75%.

Figure 21: Effect of sand thickness on cross-plot response

If the zone changes its overall thickness, there will be tuning and this will manifest itself in cross-plot space. Figure 21 shows the influence of tuning on a sand when the overall thickness of the sand is thinned by up to 75% (Ross, 2000). The analysis window is over the trough of the wavelet. Note the spread of the response in cross-plot space and how it changes due to tuning.

Over a wide time window this creates quite a bit of scatter or noise. To see geologic changes among this noise or scatter, the anomaly has to be large. Small anomalies will be drowned out in the noise. More realistically the analysis of the data needs to be restricted to the zone of interest to restrict the amount of scatter.

Figure 19 shows the cross-plot of the P and S impedance reflectivity for an AVO study of the Bluesky sand. This is a high velocity sand with porosity of around 15%. The cross-plot is that of the P and S impedance reflectivity for the Bluesky horizon. Two clusters are evident, one corresponding to a wet well on the line and the other corresponding a gas well on the line. The area around the gas well was highlighted in the cross-plot domain and then displayed on the seismic (Figure 20). The highlighted area corresponds nicely to the known gas field and correctly ignores the wet wells along the line. All four wells are correctly identified.

In the previous example it is possible to discriminate the gas and wet wells by cross-plotting the amplitude of the target horizon. However, this did not work in a general fashion for the play. As the target became deeper in the basin the anomaly became more of a character anomaly. It was found that cross-plotting amplitudes no longer discriminated the gas and wet sands. Other seismic attributes such as instantaneous frequency were needed to discriminate the gas. With limited well control, questions start arising about how statistically significant geologic predictions are, if many attributes have to be studied to accurately map the geology.

Interpreting gathers

Returning to Figure 1, it is possible to interpret the NMO corrected prestack gathers without doing AVO inversion. Modeling can be done to understand the response of various fluid and rock properties by generating synthetic gathers in a similar fashion as the previous section. Predictions can be made about the geology by comparing the prestack gathers to various template synthetic gathers. Figure 22 shows a gas and wet model generated based on well control for the proceeding Bluesky example. Displayed at the bottom is the prestack seismic gather at the gas well. It is possible to see a good correspondence between the model and the actual data. The gas sand is a class II sand anomaly (Rutherford and Williams, 1989). For this type of gas sand, the amplitude is a small peak at zero offset and decreases with offset. If the sand is wet it does not decrease as fast with offset.

Subtle plays with small changes in gradients are sometimes quite difficult to correctly identify on the prestack gathers. When interpreting gathers it is important to understand the class of anomaly you are looking for. Each class will react differently to gas. Figure 15c shows an example of the prestack gather for a class III gas sand corresponding to the gas well shown in Figure 15a. Figure 15d shows the wet response of the prestack gather corresponding to the product stack in Figure 15b.

To interpret these gathers the interpreter must have a good understanding of how various geologic situations will manifest themselves in the prestack domain. There are many variables that change the prestack response. Both the rock physics and the seismic response influence the prestack response.

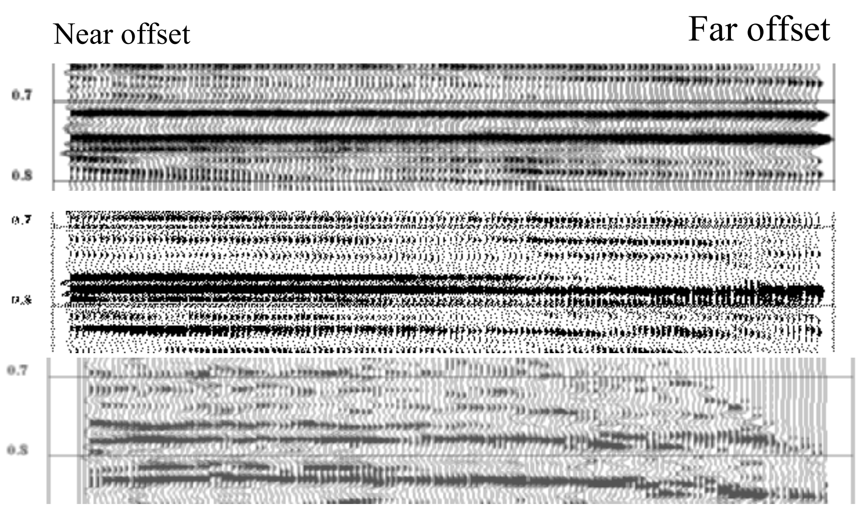


Figure 22: The top panel is a synthetic gather based on a wet Bluesky well. The middle panel is a synthetic gather based on a gas well. Note the decrease with offset of the peak at 0.77 seconds. The bottom panel is the seismic gather corresponding to the gas well.

There are major operational issues in interpreting gathers on a large data volume. One strategy that it is sometimes used, is to identify anomalies using reflectivity stacks and then examine selected gathers at these anomalies and the well control. Examining the gathers in this limited fashion can be quite beneficial. Tying synthetic gathers to the prestack gathers can help identify processing issues and help the interpreter understand the data better. Prestack gathers are perhaps the best way of understanding the random and coherent noise issues in the data. Regardless of which method is preferred by the interpreter, the visualization software provided by many geophysical software vendors makes the analysis of large volumes of data much faster and more efficient. But, as with any analysis tool, such visualization must be used with care, and with an understanding of the inherent limitations of each method.

CONCLUSIONS

Throughout, this paper, we have discussed the many ways AVO analysis can lead to the erroneous predictions of hydrocarbons. The reader might be left with the impression that with so many things that can go wrong, AVO is not worth doing. This would be the wrong impression. AVO has proven itself as a useful tool in finding hydrocarbons but care must be taken in its application. Here are some of the main points to remember when applying AVO.

First, it is important to remember that amplitude variation with offset anomalies can arise which has nothing to do with the geology. It is a result of the propagation of the seismic wavefield. The accuracy of the AVO and geologic predictions become subject to how well the processing deals with these factors. It is important to process the data in an AVO friendly fashion.

For every play, the elastic parameters of the geologic objective must be understood and suitable interpretation methods employed. Thus, it is often advisable to perform AVO modeling before performing AVO analysis on real data. And, when processing the data for analysis, it is appropriate to interpret at all the various output stages. Each output has its own pitfalls and advantages. Often potential pitfalls can be recognized at another output stage and addressed.

The mapping from elastic parameters to rock and fluid properties is non-unique. The implication of this is that, even if all the wave propagation effects are accounted for, and the processing including the AVO inversion is done perfectly, hydrocarbon predictions made will not be perfect, but they should be more accurate than just using a single stack.

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