

Calibration of Seismic Attributes for Reservoir Characterization

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Abstract

The project, “Calibration of Seismic Attributes for Reservoir Calibration,” is on schedule as planned, with only minor departures from plan. We have been working on multiple data sets, including two public-domain sets, one proprietary data set with a corporate partner, and one other proprietary data set as a member of a consortium. We have expanded the use, on a regular basis, of high-end software well beyond that anticipated in the original work plan. The use of these high-end software packages has greatly enhanced our ability to identify, study, and evaluate potential attributes in the seismic data. In addition, the high-end software has served the purpose of pointing us in the right direction to make simple and straightforward relationships between the rock physical parameters and the seismic data. We required the use of this software to initially discover those relationships, but the understanding of those relationships is, so far, very straightforward, and does not require the use of high-end software.

We are using data from Wyoming, North Texas, South Texas, and the Gulf of Mexico offshore of Louisiana. These environments provide a diverse array of physical conditions and rock types, and a variety of interpretation methods to be applied to them. At this time, in the middle of the second year of the project, we have tentative results from all fields; but most of them are still being tested, verified, and occasionally found in need of revision. These tentative results will not be enumerated in this report; instead, we review some of the procedures we have found to be appropriate for essentially all of the data sets, and describe one set of results that are universal.

We have come to the following (tentative) conclusions in general:

- Inversion of seismic data to acoustic impedance is nearly always beneficial.
- Neural network approaches can identify relationships invisible to the eye.
- The pre-processing of input to the neural network analysis is essential, in order to maximize the likelihood that physically meaningful results will be obtained.

One of our study areas, the Teal South field in the Gulf of Mexico, is also a subject of additional research, in which we are involved through this research contract. Other members of the Teal South Consortium are actively obtaining, processing, and interpreting time-lapse seismic data as the reservoir is being depleted. We are using the original (legacy) streamer data obtained prior to production in this study, and decided to actually test our seismic petrophysical models by predicting a time-lapse response for the field. The details are still being refined as we learn more about the production history of the field, but some fundamental observations have been made and are presented here. These involve the effect of decreasing reservoir (pore) pressure during primary production, and the impact of the associated increasing effective or differential pressure on the seismic velocities in the formation. In short, the increased compressional velocity that results from this pore pressure decline can overwhelm the decrease in compressional velocity expected as a gas cap forms – the seismic response from the reservoir will include a dimming at zero offset, accompanied by an increase in amplitude at far offsets.

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Executive Summary

This project is intended to enhance our ability to use seismic data for the determination of rock and fluid properties through an improved understanding of the physics underlying the relationships between seismic attributes and formation. We have expanded our study to include four data sets, covering a variety of rock types and depositional environments; all of which are host to significant reserves in the domestic United States.

Our project has reached various stages for the different data sets.

- The Wamsutter data from Wyoming has been reinterpreted along several horizons, providing an improved map of the formation, and we are using statistical analyses to detect differences in seismic character. Initial inversion processing has been performed.
- The Stratton data from South Texas has been reinterpreted along several horizons, and has been used in preliminary statistical studies. It has also been processed by our subcontractor, TransSeismic International, under their Dynamic Fluid Method. Detailed well-completion histories were provided by the operator, and association of the seismic features with the producing intervals is underway.
- The Boonsville data from North Texas has been reinterpreted along several horizons, and tentative conclusions have been drawn; a comparison of various interpretations with the results of TransSeismic's technique is underway.
- The Teal South data set from the Gulf of Mexico has been inverted for acoustic impedance, and the reservoir's seismic response under future production has been modeled in a loose sense (additional production data has recently become available, and is being incorporated in the modeling). The importance of changes in pore pressure cannot be over-emphasized; these changes result in a 'dimming' of the brightspot initially associated with the reservoir, even to the point of overwhelming the gas effect as gas comes out of solution. On the other hand, the 'brightening' of reflections at large offsets should increase with production. The overall effect on the stacked amplitudes may still show a brightening, although any interpretation that ignores pore pressure changes will be in error.

In general, we feel that inversion of most seismic data volumes for acoustic impedance is an important step in determining the physical basis for interpretation of seismic attributes. The inverted volume itself can be used as a sort of attribute for input to other statistical processing, including neural network analysis. The two most-common neural network approaches include waveshape classification and multi-attribute analysis; both of these techniques can identify relationships invisible to the eye. We do not feel confident using the results of neural network analyses, however, without also investigating the physical nature of the associations revealed. Our current work is based primarily on searching for these physical bases, and on refining the statistical approaches used to identify them.

Introduction

The objectives of this project are three-fold: To determine the physical relationships between seismic attributes and reservoir properties in specific field studies; to improve the usefulness of seismic data by strengthening the physical basis of the use of attributes; and, in the third year of the project, to test the approaches suggested or developed during the first two years on at least one new data set. In association with these studies, collaboration with corporate partners and technology transfer as ideas are developed and tested are ongoing integral components.

This project is divided into four main tasks, and these are further subdivided into subtasks. The following sections refer to those tasks; when appropriate, the application of each task to each data set is described. The breakdown in the 'Results and Discussion' section of this report will be based not on tasks, but on the data sets and on the concepts derived from those data sets.

Task 1: Project Management

Project management encompasses reporting and project support. Both are essentially on schedule. We continue to obtain additional high-end software suites (most recently adding several programs from Hampson-Russell, Landmark Graphics, and a new component to Stratimagic, NexModel), and incorporate them into our studies. System administration, which was a problem at the start of year one, is now running very smoothly.

Task 2: Borehole Data

Borehole data for this project consists of three types: existing data (of all sorts), new core and outcrop data (to determine fine-scale heterogeneities), and new log data acquired for this project. We have made use of data provided by our corporate partners, have sought out additional data relating to the data sets, and have obtained new data in some instances.

Well log data never seems to be complete, and we are putting a large effort into identifying additional constraints on low-frequency velocity models; these efforts are paying off in improved inversion results and improved insight into reservoir evolution and development. Detailed core data is available only for wells in the neighborhood of one of the study areas, and analogs to fine-scale velocity and density changes are sought for the other fields.

Task 3: Processing

Processing of the seismic data has proceeded on schedule; additional post-stack processing to remove some apparent artifacts will soon be undertaken, using ProMax software from Landmark Graphics. We were initially shocked at the large sizes of multiple data volumes, required by our various software packages, but the continual drop in price of disk drives and tape backup systems has permitted us to keep up with our growing needs within the original budget.

Task 4: Visualization

Our visualization of reservoir properties has proceeded nicely. We use visualization for improved reservoir characterization, for enhancing communication with our corporate partners, and for technology transfer. Lately, we became impressed with the power of visualization

available in some programs for PC use, and will soon obtain a software suite for use on a laptop, greatly enhancing the technology transfer aspect of the project in the next reporting periods.

Technology Transfer

Our web site is complete, and being updated regularly (<http://www.geo.mtu.edu/spot>). A paper has been accepted for presentation at the August convention of the Society of Exploration Geophysicists, and several oral presentations on various aspects of the work have been made to small groups of experts, where feedback and comments were obtained. During the half-year period covered by this report, presentations were made to one corporate partner (BPAmoco, with respect to the Wamsutter area), to the Teal South Time-Lapse Consortium at the Energy Research Clearing House, and to a workshop on Seismic Signatures of Fluid Transport. Abstracts have been approved for presentations to the Summer SEG Development and Production Forum and to the Annual SEG convention in August. A presentation to members of the US Congress and to congressional staffers is scheduled for mid July, 2000.

Results and Discussion

Because most of the current and new results for this project are of such tentative nature, and currently undergoing rigorous testing and verification, we will only report those results that have passed this testing and are worthy of public dissemination. These consist of one overall conclusion regarding the value of different general analysis procedures, and one specific conclusion on the significance of reservoir pressure in determining seismic response.

General Analysis Procedures: Inversion, neural networks, physical interpretation.

Inversion: We have come to appreciate the power of seismic inversion for acoustic impedance, and strongly encourage this process on all data volumes. There are three reasons for our support for this technique. First, it requires extreme attention to estimation of the seismic wavelet present in the data, and this exercise alone is essential for interpretation of seismic attributes (see Figure 1 for a comparison of possible wavelets in the Teal South data). Second, it provides a good estimate of lithologic properties, through seismic impedance. And third, it enables one to view an image of the reservoir itself, in a broadband (not frequency-limited) sense, something that is much more physically meaningful than conventional reflection volumes (as shown in Figure 2 for the Teal South data, for example).

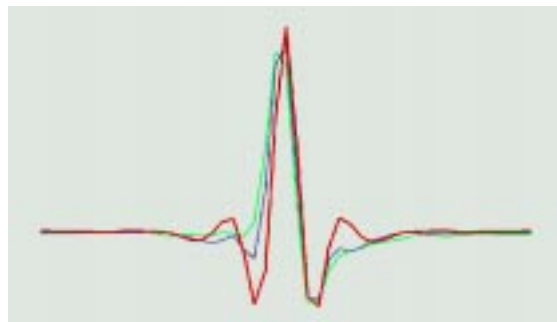


Figure 1: Three different possible wavelets estimated (in a preliminary step) from the Teal South data.

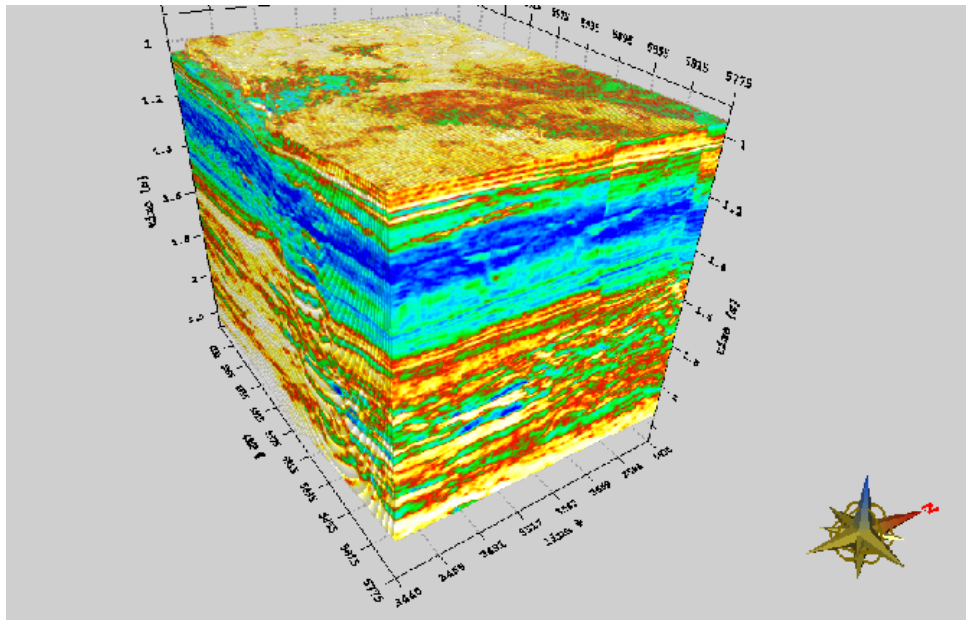


Figure 2: Visualization of the acoustic impedance volume obtained for the Teal South data.

Neural-networks: Over the past few years, a series of new neural-network techniques have been developed and applied to a variety of seismic data types. We are most interested in those approaches that work on classification of the seismic wavelet into different ‘facies’ based on waveshape; these incorporate thin-bed effects as well as lithologic changes, as shown by example in Figure 3 (from the Stratton field). New modeling approaches help identify the origin of the waveshapes as classified. Another approach take various volumetric attributes, including conventional seismic attributes, inversion results, and other information as may be available, and finds associations with, for example, well-log data.

Physical Interpretation: The results of any statistically based procedure, and particularly those of neural network types of analyses, should be interpreted in terms of the physical cause of the relationship found. This implies tying back to well data (see Figure 4), to production data, and to geologic interpretations, and then performing modeling on those data to determine the relationship to the observed seismic waves.

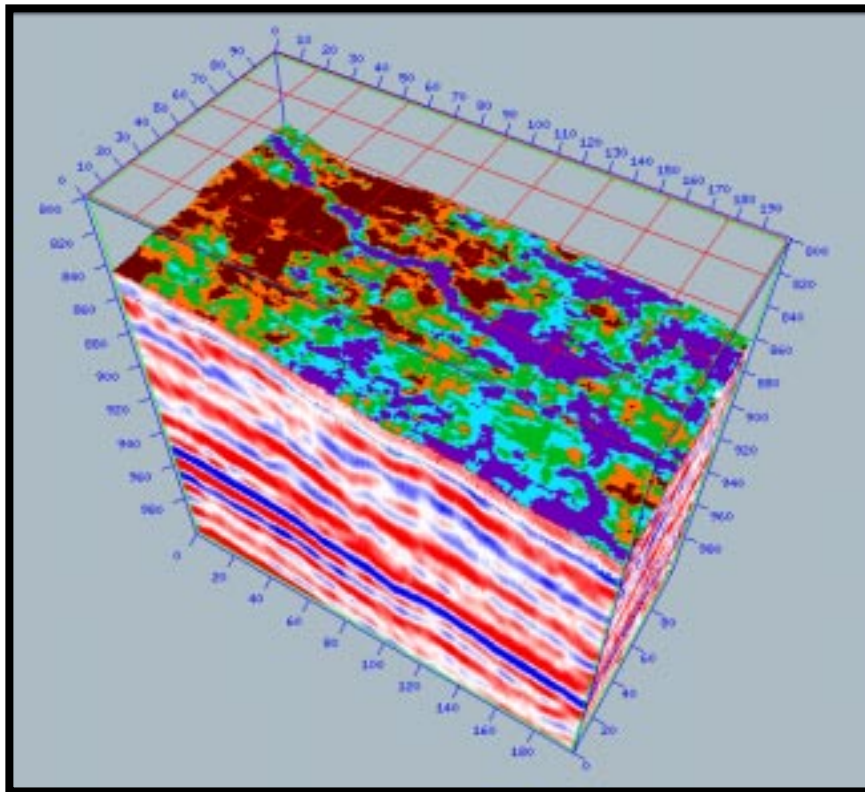


Figure 3: Seismic 'facies' as interpreted using a neural network, Stratton data set.

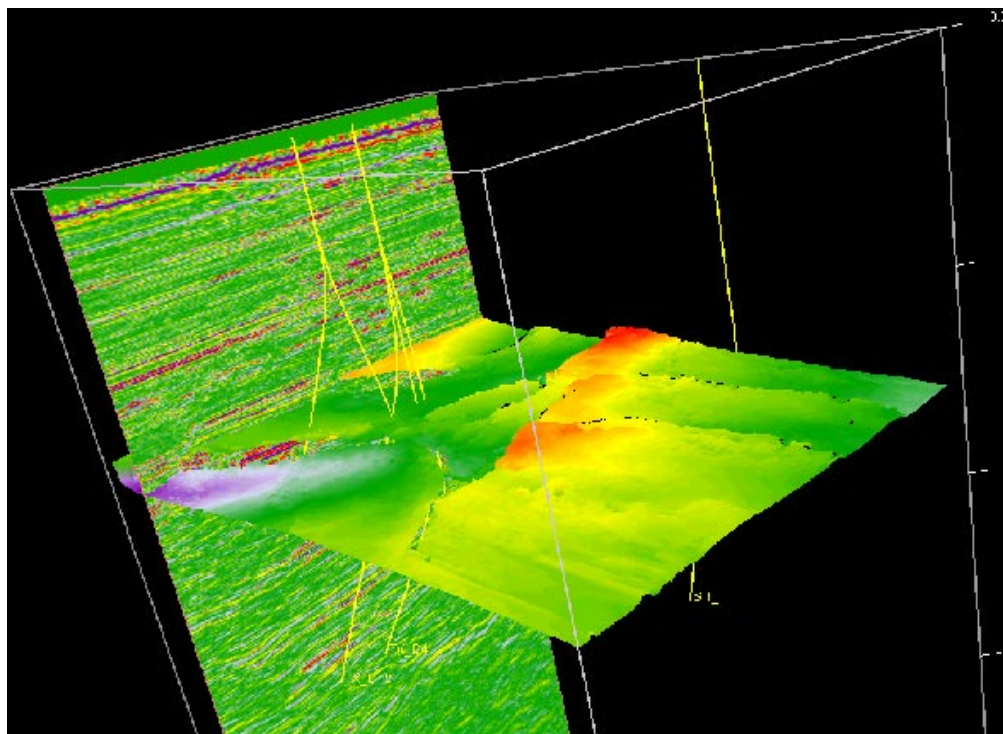


Figure 4: Visualization of the well locations with inverted acoustic impedance volume, Teal South.

The importance of pore pressure on seismic velocities:

As part of the Teal South study, we investigated the effect of changing pore pressure (during reservoir production) on seismic velocities. The results were surprising; so surprising, that we presented them to a variety of small groups of experts before deciding to publish them more openly. The following, based on an abstract accepted for presentation at the annual Society of Exploration Geophysicists meeting, describes the observations.

For the purposes of this study, we will assume two different reservoir rocks under different reservoir conditions; these rocks and conditions are designed to closely model a set of reservoirs that are a subject of a detailed study in the Gulf of Mexico, and are in no way pathologically unique. Both are highly porous sands, under conditions which will tend to maximize the points we wish to make in this study.

Reservoir A (overpressured):

▪ Depth	5600 ft	1706 m
▪ Temperature	139° F	59° C
▪ Pressure	3700 psi	25.5 MPa
▪ Pressure gradient .	0.66 psi/ft	14.9 kPa/m
▪ Oil Gravity	37° API	
▪ GOR	970 scf/stb	173 l/l
▪ Logged Vp	7350 ft/s	2240 m/s
▪ Logged density	2.03 g/cc	

Reservoir B (normally pressured):

▪ Depth	4500 ft	1372 m
▪ Temperature	130° F	54° C
▪ Pressure	2000 psi	13.8 MPa
▪ Pressure gradient ..	0.44 psi/ft	9.95 kPa/m
▪ Oil Gravity	28° API	
▪ GOR	340 scf/stb	61 l/l
▪ Logged Vp	10500 ft/s	3200 m/s
▪ Logged density	2.14 g/cc	

Notice that Reservoir A consists of an overpressured, under-compacted sand, while Reservoir B hosts a normally pressured, normally compacted sand. For the purposes of this exercise, we will assume that the logged Vp/Vs ratio is 2.0 (Poisson's ratio is 0.33) in each reservoir. We also assume the overlying shale is higher velocity and higher Vp/Vs. Neither reservoir had free gas at time of discovery.

Several assumptions are required to complete the models. These will be explained as we encounter them, but none of them are 'rigged' to make the results fit a certain set of conclusions. In order to model the evolution of each reservoir precisely, we would need to know and understand the drive mechanisms, the relative permeabilities, and other parameters that will, for this exercise, be ignored. Instead, we will assume that the percentage of pore volume occupied by gas increases by 10 percentage points for every decrease of 300 psi in reservoir pressure until it reaches 50% gas saturation. Whether or not this is reasonable depends on many things, including the time scale of production. For example, if the reservoir pressure is slowly drawn

down, and the relative permeability to gas sufficiently high, a gas cap will form and increase the gas saturation at the top of the reservoir, where we are most interested in the seismic properties. On the other hand, if vertical permeability is low, or the reservoir is drawn down rapidly by production, the gas may not have moved, and the seismic response corresponds to a lower gas saturation. Yet again, gas may be produced more rapidly than oil due to its higher relative permeability, and the gas remaining in pore spaces would be lower than assumed.

In the absence of reservoir modeling, we are making the simple assumption that gas saturation correlates directly with pressure decline for the purposes of this exercise alone.

In all of the scenarios, we recognize that as gas comes out of solution, the remaining oil phase has a lower GOR, and increased bulk modulus; that is, the remaining oil has become ‘stiffer’ as the gas is removed from solution. We use Batzle and Wang’s (1992) relationships to predict the properties (GOR and bulk modulus) of the oil phase. Comparisons with PVT analyses on a fluid sample taken from one of the reservoirs confirm the applicability of these relationships.

Naïve Model

In the first model, we simply take the values as provided, solve for the dry-frame moduli using Gassmann’s equation, and then solve Gassmann’s equation again, assuming gas has come out of solution (as the reservoir pressure declined during production) to occupy varying percentages of the pore volume. We also assume the log values represent the formation conditions, where $S_w=0.3$ (irreducible water saturation) in order to obtain the dry-frame moduli (including a dry-frame Poisson’s ratio) for each reservoir. Then we substitute gas for oil (but not water) in the pore space, and solve Gassmann’s equation for the reservoirs. We obtain the following velocities and Poisson’s ratios (see Figure 5).

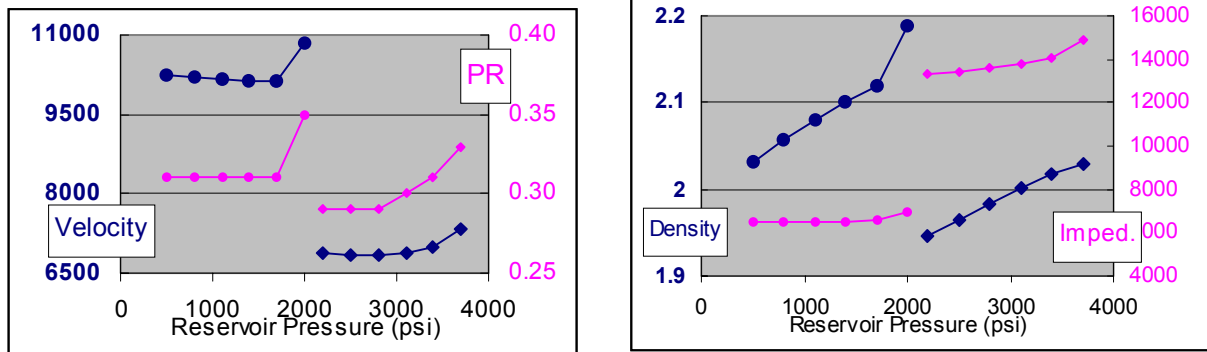


Figure 5: Left side: The predicted seismic properties as the reservoir is produced under this simple model. Diamond symbols represent Reservoir A and circles represent Reservoir B. The thinner curves use the PR (Poisson’s Ratio) axis; the darker curves represent Velocity (ft/s). Right side: The predicted densities and impedances from the simple model. Darker lines represent density (g/cc), and the lighter lines represent impedance (in ft/s * g/cc).

As we might have expected, in both reservoirs we predict a brightening of the reflection and an increase in the AVO response as the reservoir is produced.

Correct the Log Data for Invasion

In this model, we realize that the log data we are using represents an invaded zone, and not the true reservoir conditions. We first must ‘correct’ our velocities and V_p/V_s ratios to the reservoir conditions, again using Gassmann’s equation and simple fluid substitution (and assuming homogeneous saturation, not ‘patchy’). This time, we assume that the logged conditions represent 30% oil (residual oil saturation) and 70% brine (invaded mud). We then arrive at the following production scenario (the differences in densities from those computed in the simple scenario are small, and not shown):

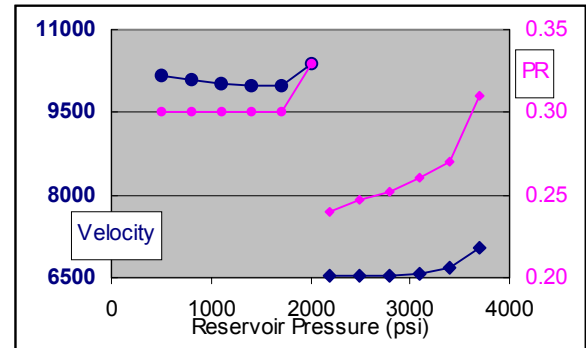


Figure 6: The velocities and Poisson’s ratios (PR; note scale change) for the two reservoirs, with the assumption that the logged values represented invaded conditions.

There are some differences to be noted between the results predicted for this model, and the one in which we assumed the logged values represent formation conditions, but they are not enough to cause us alarm.

Dry-Frame Moduli Increase

The next scenario builds on the last, and further assumes that the frame of the rock ‘stiffens’ as the reservoir pressure decreases. That is, we account for the stress-dependence of velocities in the rock framework; this is usually expressed in terms of changes in the dry-rock or dry-frame moduli as they are used in Gassmann’s equation. For the purposes of this exercise, we will use a set of relations developed by L. Bentley and colleagues (personal communication, 1999), for which we have calibrated some of the constants using the properties of these specific reservoirs. We obtain the following results:

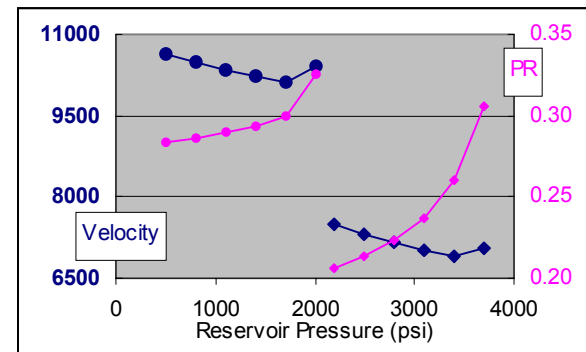


Figure 7: Velocities and Poisson’s Ratios for model in which the dry-frame moduli of the formation rock changes with increased effective pressure during production.

Notice that the bright-spot effect from the gas has been overwhelmed by the stiffening effect of the dry frame in both reservoirs. It is important to realize that the specific relationship used for

the dry-frame stress sensitivity will very strongly determine the degree to which the gas-effect may be overcome.

If the Gas is Produced or Migrates Away

In the above scenarios, we always assumed that the gas did not migrate away from the volume element of the reservoir in which it was released. But this is rarely the case, once a critical gas saturation has been reached and the gas becomes mobile. The gas typically exhibits a greater mobility than the oil or water after it reaches some saturation, and moves readily throughout the reservoir, upwards (gravity segregation) and/or toward a producing well. In the event that all of the gas has moved away from a particular location in the reservoir, leaving only a residual gas saturation (taken here to be 0.1), the following conditions are predicted:

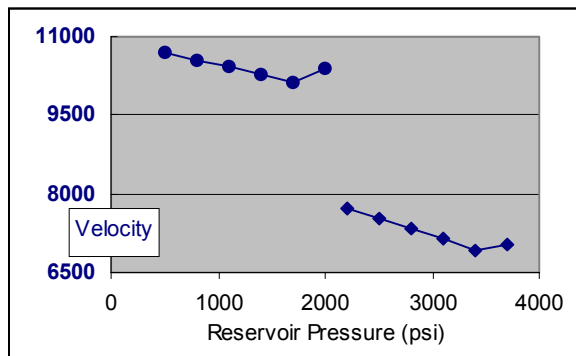


Figure 8: The velocities (Poisson's ratio is not shown) for the scenario in which gas is liberated and remains in the local part of the reservoir until it exceeds 0.1 saturation, after which all gas in excess of 0.1 moves away, either updip or to a producing well.

Summary of Production and Pore Pressure Changes

Figure 9 summarizes all of the velocities observed in the preceding scenarios. We observe that an assumption of simple fluid substitution (either the 'naïve scenario' or the 'corrected for invasion' curves) will lead to extremely optimistic predictions for reservoir monitoring, whereas the more-complete scenarios, including dry-frame stress effects and migration of gas, will likely result in considerable ambiguity for interpretation of time-lapse seismic observations.

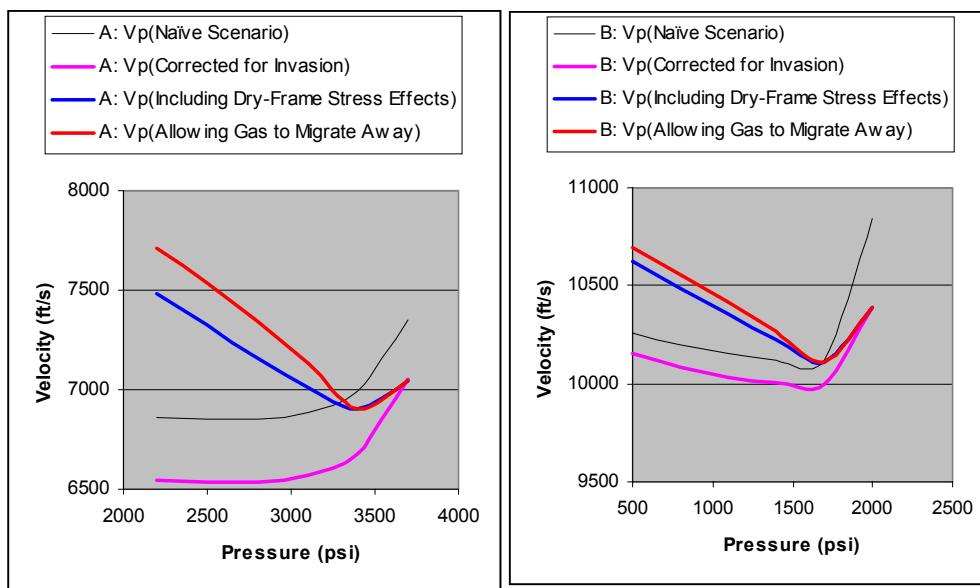


Figure 9.

Conclusions

The project, “Calibration of Seismic Attributes for Reservoir Characterization,” is on schedule as planned. We have reached a number of tentative conclusions, and some firm ones. The firm conclusions include general analysis procedures and the importance of pore pressure in seismic attributes.

The general analysis procedures are designed to include all the rock properties information that can be determined prior to statistical processing or the use of neural networks. One of these, and perhaps the most important, is the inversion of seismic data to acoustic impedance. Following any statistical process, we feel that it is critical to determine the physical cause of the relationships found between seismic attributes and formation properties.

Seismic velocities are extremely sensitive to pore pressure, and highly mistaken predictions can be made if pore pressure is not properly accounted for in analysis. Guidelines are being established to enable an accurate assessment of this effect.

The project has marked its half-way point, and several avenues of additional investigation are being pursued. We see no obstacles to completing the project in the manner proposed, and are confident that significant results are being obtained.