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Seismic Evaluation of Hydrocarbon Saturation in Deep-Water Reservoirs

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QUARTERLY REPORT

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Abstract:

The "Seismic Evaluation of Hydrocarbon Saturation in Deep-Water Reservoirs" (Grant/Cooperative Agreement DE-FC26-02NT15342) began September 1, 2002.

During this second quarter:

- A Direct Hydrocarbon Indicator (DHI) symposium was held at UH
- Current DHI methods were presented and forecasts made on future techniques.
- Dr. Han moved his laboratory from HARC to the University of Houston.
- Subcontracts were re-initiated with UH and TAMU.
- Theoretical and numerical modeling work began at TAMU
- Geophysical Development Corp. agreed to provide petrophysical data.
- Negotiations were begun with Veritas GDC to obtain limited seismic data.
- Software licensing and training schedules were arranged with Paradigm.
- Data selection and acquisition continues.

The broad industry symposium on Direct Hydrocarbon Indicators was held at the University of Houston as part of this project. This meeting was well attended and well received. A large amount of information was presented, not only on application of the current state of the art, but also on expected future trends.

Although acquisition of appropriate seismic data was expected to be a significant problem, progress has been made. A 3-D seismic data set from the shelf has been installed at Texas A&M University and analysis begun. Veritas GDC has expressed a willingness to provide data in the deep Gulf of Mexico. Data may also be available from TGS.

Contents:

Executive Summary:

This project's goal is to develop and test better methods to identify hydrocarbons and estimate in situ fluid saturations under deep water conditions. This requires an integration of rock and fluid data, petrophysics, and surface seismics. The project is now a collaborative effort among the Colorado School of Mines, University of Houston, Texas A & M University, and Paradigm Geophysical. Organizational aspects are now almost complete, and research efforts are underway.

To help asses the current state of the Direct Hydrocarbon Identification "art" and get valuable input from recognized industry leaders, a DHI symposium was held at the University of Houston. Sixteen presentations were made covering current practices, novel uses of data, demonstrations of leading edge work, and predictions of future trends. One prime problem is differentiating low gas saturation "Fizz gas" from economic reservoirs. Additional information is needed. Important suggestions:
- Farther offsets may help extract better density information.
- Effects of anisotropy must be included, especially for far offsets.
- Property distributions should be used to establish fluid identification probabilities
- Attenuation as expressed by frequency effects has strong potential.

Availability of data for the suite of potential sites that were identified for detailed examination and modeling has been investigated. These sites were chosen based on the geologic setting and structural style, and presence of reported seismic hydrocarbon indicators. Veritas has expressed a willingness to provide us with some of their proprietary data. However, Veritas' coverage of the Gulf of Mexico is partial, and our need to acquire appropriate seismic and log data may require that we switch to alternate sites.

Dr. Han is now completing his move from the Houston Advanced Research Center to the University of Houston. Although this move has caused some administrative disruptions, overall, the new environment is more favorable and will benefit all in the long run.

More results will be posted on our websites:

CSM: //crusher.mines.edu/DOE.html
TAMU: //nyssa.tamu.edu/~gibson/Research/Deep_Water_Seismic.html

Results and Discussion*:*

One of the primary accomplishments during this quarter was the holding of a special symposium: "Rock Properties and Seismic Direct Hydrocarbon Indicators (DHI)" at the University of Houston. This symposium was well attended by numerous industry representatives. The meeting agenda is attached as Appendix A. Abstracts from the presentations are attached as Appendix B.

Seismic data is increasingly being used to estimate in situ conditions, lithologies, and fluids. Rock and fluid properties forms a foundation for these interpretation procedures, but a host of other factors influences the actual seismic response. This DHI symposium explored the complexity of how in situ conditions, such as stratigraphy, geometries, heterogeneities, attenuation, wave propagation effects etc. impact the DHI signature. We gained insight on how rock and fluid properties can systematically be used to improve our current technology in seismic evaluation of hydrocarbon saturation.

Some of the topics that were addressed:

What is the current industry practice?

What are the best indicators?

What are the uncertainties and limits on resolution?

Fluid and rock properties at in situ conditions

Core-log-seismic ties (upscaling), primary limitations?

Are deep-water conditions substantially different than shallow-water?

What might be the best test cases?

Promising new directions (density extraction, inversion, attenuation, etc.)

This symposium helped establish the limits of the current state of the art, point out specific problems, and explore promising new directions. As examples:

- Farther offsets may help extract better density information.
The density can be better extracted from further offsets (>35 degrees). However, this is problematic is data quality is poor at longer offsets.

- Effects of anisotropy must be included, especially for far offsets.
Including factors such as η (Thomsen, 2002; Tsvankin, 2000) will substantially change the moveout correction in far offsets. Often, offset dependent amplifiers corrupt the fluid signature.

- Property distributions should be used to establish fluid identification probabilities

The indication of hydrocarbons is not a 'yes' or 'no' proposition. A seismic signature can only lead to a probability of hydrocarbons.

- Attenuation as expressed by frequency effects has strong potential.
Extracting frequencies to look for low frequency 'shadows' is becoming more common. However, there is little current understanding of the phenomena.

Initial Model Development

The application of attenuation measurements to the detection and discrimination of hydrocarbons has strong potential for improving reservoir characterization, and, as noted, this was an important point of discussion at the DHI Symposium. To investigate this point, we have begun to design numerical models and compute full waveform synthetic seismograms to gain some insights into relevant phenomena prior to examining field data. The design of the experiments is guided by results published by Golushubin et al. (2000, 2001, 2002), who have analyzed ultrasonic laboratory and seismic field data to detect and possible effects of attenuation. They present basic results for frequency-dependent variations in amplitude at low frequency that might be interpreted in terms of frequency-dependent attenuation. If this effect is real, it could provide a useful means of discriminating between gas and oil-rich reservoirs.

Therefore, our starting models are designed to represent thin reservoirs with varying values of Q. Our analysis has also included the computation of reflection coefficients to calibrate full waveform numerical results, and the next steps will test different values of Q, different frequencies, and different models for how Q depends on frequency. We hope to determine whether our numerical results are consistent with the predictions and observations of Golushubin et al. (2000, 2001, 2002), as well as preparing for simulations of field data obtained from Veritas or other sources.

Current Candidate Fields:

Progress was made evaluating the several fields that were initially proposed as the initial phases of our investigation (see Table 1 below). We chose these fields based on our perception of the data availability, familiarity with the area, geologic structure, and known seismic hydrocarbon signature. The list in Table 1 is preliminary and will likely change as sources of data are contacted and data quality is assessed. For example, Veritas has numerous 3-D data sets in the deep Gulf of Mexico, but the coverage is not complete. Their Mississippi Canyon survey does not include the Mensa, Mars, or Ursa fields. Veritas 2-D lines do cross some of these fields.

Table 1. Status of candidate Deep-water Gulf of Mexico Fields with seismic hydrocarbon indicators

Field	Attribute	Status
Teal South	Shelf, only one well, data available	Post-stack data at TAMU
Mensa	(Shell?) structurally simple	J.T. to examine
Nanson	Core samples & logs available	Kerr-McGee cooperating
Ursa	Multiple real and false HC indicators	Veritas has 2-D lines
Troika	Sample and fluid data already published	Marathon cooperating
Mars	Published data examined, salt confined	Veritas has 2-D lines
Boomvang	Near Nansen	Kerr-McGee cooperating

Plans:

As before, our primary plans at this point involve continuing the acquisition of appropriate seismic and log data.

Responsibilities for some individual tasks are for next period were accepted by members of our research team:

Obren Djordjevic (Paradigm)
– Help establish software platform,
- Organize analysis examples and training

R. Gibson (TAMU) – Check availability of ODP core samples
- Dust off forward modeling programs

D. Han (UH) - Attempt data transfer from Kerr McGee for Nansen field
- Collate sample data

M. Batzle - Complete negotiations with Veritas about data
- Acquire initial log data
- Obtain Troika samples from Marathon

The move of Dr. Han to the University of Houston (UH) from the Houston Advanced Research Center (HARC) was somewhat disruptive, but beneficial in the long run. HARC had changed directions, lost staff and resources. Communications and exchanges with experts in related fields are much better at UH. In fact, UH was pleased to host the DHI symposium. Some considerable administrative mischief was caused, since all subcontracts needed to be rewritten. However, that process is nearly complete (we hope!) and research can continue.

Conclusions:

We are moving ahead with this project. The well-attended DHI symposium clarified the current 'state-of-the-art'. Despite the administrative difficulties caused by the move of Dr. Han to the University of Houston, progress has been made obtaining data and samples. The project is approximately on schedule.

Further information can be obtained from:

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Colorado School of Mines
Phone: 303-384-2067 email: mbatzle@mines.edu

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APPENDIX A: AGENDA - Direct Hydrocarbon Indicator (DHI) Symposium
At the University of Houston

Time		
8:30	**Introduction, structure, scope**	D-h Han
8:40	**Basic rock and fluid properties**	M. Batzle
9:05	**Rock physics in the time-lapse seismic workflow**	G. Gist
9:25	**Gassmann's equation: Frame property models and effective application to wireline log data**	Tad Smith
9:45	**Shear Wave Velocity Prediction for AVO/DHI Applications***	R. Keys & S. Xu
10:05	**Research Directions in Fluid Properties Determination**	J. Castagna
10:30	**-- Break --**	
10:45	**Recent Example of Seismic Attenuation as a Gas Indicator**	J. Wall
11:05	**Scientific Success, Commercial Failure**	J. Hooper
11:25	**Some comments on AVO, anisotropy and laminated shaly sands**	K. Katahara
11:55	**How Anisotropy can distort AVO: a Mississippi Canyon example**	B. Devault
12:05	**-- Lunch --**	
1:00	**Scaling issues related to physical parameters & geological heterogeneity**	D-h Han
1:15	**Velocity Upscaling and Dispersion**	S. Dolan
1:40	**How deterministic can we downscale well-log into seismic volumes**	H-w Zhou
2:00	**Sensitivity Analyses for Time-Lapse Seismic Studies**	R. Gibson & S-h Yuh
2:20	**-- Break --**	

2:35 **The Nansen Discovery, East Breaks 602, deepwater Gulf of Mexico - A geophysicist's perspective** J. Pan

2:55 **Seismic anomalies and pore fluid ambiguities offshore West Africa** P. Avseth

3:20 **What's Next for Pore-Fluid Estimation?** F. Hilterman

3:50 **Open discussion**

APPENDIX B: Abstracts from the Direct Hydrocarbon Indicator (DHI) Symposium

M. Batzle, CSM: mbatzle@mines.edu

Title: **Basic rock and fluid properties**

The combination of rock and fluid properties controls any seismic hydrocarbon indicator. Variations in the background rock properties may be responsible for false indicators. Hydrocarbons range from heavy tar-like liquids to light oils with high gas content, condensates to light gases. The composition and saturation determine the excursion of an indicator from the background brine saturated trend. Many types of indicators have been proposed, but most measure approximately the same thing. Despite the effort that has gone in to defining and calibrating and seismic fluid indicators, false indicators are common and often remain unexplained.

R

De-hua Han, HARC, dhan@harc.edu

Title: **Scaling issues relate to physical parameters and geological heterogeneity**

Discussing scaling issues related to nature of physical parameters, geological heterogeneity of lithology and fluid distribution and their correlations. Talk will forcus on scaling issues of seismic velocities.

4D

Grant Gist, Exxonmobil Upstream Research Co: grant.a.gist@exxonmobil.com

Title: **Rock physics in the time-lapse seismic workflow**

The 4D workflow must be grounded in rock physics to effectively optimize a portfolio of 4D projects. This optimization should include modeling that can inform everything from acquisition to interpretation. Through this modeling we want to create the conditions for business success by managing the technical risk inherent in 4D projects. I'll offer three particular topics on this theme, with more questions than answers:
(1) How rock physics fits into the 4D workflow, and its use in modeling response and evaluating uncertainty,
(2) The spatial distribution of multiphase fluids and the role of patchy saturation models,
(3) The role of rock physics in evaluating the potential for 4D in fractured reservoirs.

4D

Richard Gibson (Texas A&M University) and **Sung Hwan Yuh** (TotalFinaElf)

gibson@geo.tamu.edu

Sensitivity Analyses for Time-Lapse Seismic Studies

Time-lapse seismic surveys can be difficult to interpret quantitatively when interwell reservoir properties are poorly constrained. Similar problems arise when attempting to predict the effectiveness of time-lapse surveys prior to conducting field experiments. For this reason, we have examined the sensitivity of time-lapse seismic data to several important reservoir parameters using analytic and numerical methods. Calculations suggest that the sensitivity of amplitude changes to porosity depend on the type of sediment comprising the reservoir. Specifically, time-lapse changes in seismic reflections from consolidated and unconsolidated sandstone reservoirs can show different dependence on porosity. Our rapid numerical modeling schemes for simulation of time-lapse surveys allow statistical analysis of the uncertainty in seismic response associated with poorly known values of reservoir parameters such as permeability and dry bulk modulus. The results show that for permeability, the maximum uncertainties in time-lapse seismic signals occur at the water front, where saturation is most variable. For the dry bulk modulus, the uncertainty is greatest near the injection well, where the maximum saturation changes occur. Applications to the Teal South data set illustrate the utility of these results.

R

Tad Smith, Newfiled: Tad Smith TMSmith@newfld.com

Title: **Gassmann's equation: Frame property models and effective application to wireline log data**

Application of Gassmann's equation has become a routine and integral part of AVO modeling and analysis. Although the use of these equations can sometimes be problematic (e.g., in shaley sands or in low porosity rocks), the approach often works remarkably well. Typical application involves calculating the frame properties of the rock, and mathematically replacing one fluid with another. Unfortunately, the calculated frame properties are not routinely evaluated for correctness or consistency. Failure to do so may sometimes lead to erroneous (and potentially costly) results. In this talk, an approach is discussed whereby the ratio of the drained frame moduli ($K_{drained}$ /G)are compared against expected ratios (calculated from published laboratory measurements and effective medium theory). This approach yields a reliable technique for evaluating the quality of a fluid substitution, as well as for correcting wireline log data for invasion effects.

U

Seán Dolan et al., Shell: sdolan@shellus.com

Title: **Velocity Upscaling and Dispersion**

Abstract
Accurate calibration of seismic data is essential for the successful quantitative interpretation of amplitudes/attributes, whether it is for 4D seismic, amplitude versus offset (AVO), seismic inversion, etc. Velocity data measured at the well provide a means of linking subsurface geology to its seismic expression. Rock physics models are generally constructed from core plug and wire-line sonic data, but we wish to apply these models at the seismic interval velocity scale. The large difference in resolution and frequency between well/core and surface seismic data leads to mismatches in velocity or travel time estimates, commonly referred to as "drift". Therefore we must upscale models/relationships derived from well data to make them applicable to low resolution, low frequency seismic data.
Here we will present some of the common sources of "drift" and suggest some possible solutions and "best practices".

U

Hua-wei Zhou, Allied Geophysical Laboratories, University of Houston, hzhou@uh.edu

How deterministic can we downscale well-log into seismic volume?

Downscaling of well-log traces into seismic volume encounters difficulties from the difference in the frequency content between well-log and seismic volume, as well as from lateral heterogeneity of medium properties. Within its application domain, the convolution theory may be used to examine the first-order relationship in the downscaling process. The well-log trace may be viewed as a convolution of a high-frequency wavelet with the reflectivity function plus noise, and the seismic trace may be viewed as another convolution of a low-frequency wavelet with the same reflectivity function plus another noise. It is the easy to see that the main obstacle for the downscaling is the handling of the noise terms. To handle the noise term and hence the downscaling deterministically, we need to understand the signal and noise properties deterministically using rock physics and physical modeling. Complementarily, we need to improve the processing to better calibrate the signal in the well-log and seismic traces. We are developing an extrapolation by deterministic deconvolution (EDD) algorithm which, depends on the noise level, may improve the frequency content of seismic volume using well-log data.

U

Shiyu Xu, Exxonmobil: shiyu.xu@exxonmobil.com

Title: **Some key issues on core-log-seismic integration**

To interpret seismic quantitatively it is essential to calibrate seismic data using lab measurements and log data. However, there are many pitfalls in this important integration process. In this short presentation, I'll focus on the following key issues on core-log--seismic integration:

(1) What are the commonly used techniques for upscaling? Are there any problems for these techniques?
(2) Why do we need down scaling?
(3) What is the frequency effect? Can we model it? Can we separate it from the scaling effect?
(4) What is the uniform fluid model and what is the patchy model? When should we use the uniform fluid model and when should we use the patchy model? Are these two models adequate? Do we need more complicated models?

S

R. Keys & S. Xu, Exxonmobil: r_g_keys@email.mobil.com

Title: **Shear Wave Velocity Prediction for AVO/DHI Applications***

Xu and White (1995) developed a method for estimating compressional and shear wave velocities of shaley sandstones from porosity and shale content. Their model was able to predict the effect of increasing clay content on compressional wave velocities observed in laboratory measurements. A key step in the Xu-White method is to estimate dry rock bulk and shear moduli for the sand/shale mixture. This step is performed numerically by applying the Differential Effective Medium method to the Kuster-Toksöz equations for ellipsoidal pores. Using reasonable assumptions about dry rock elastic properties, we found that we can replace this step with approximations for dry rock bulk and shear moduli that yield an extremely close match to compressional and shear wave velocities computed with the Differential Effective Medium method. These formulas simplify the application of the Xu-White method. They make the Xu-White method more efficient, and they also provide insight into the Xu-White method. For example, these formulas show how the Xu-White model is related to the Critical Porosity Model.

*Presented at the 2000 Annual SEG Meeting, Calgary.

F

Per Avseth, Norsk Hydro: Per.Avseth@hydro.com

Title: **Seismic anomalies and pore fluid ambiguities offshore West Africa**

A turbidite prospect defined by a 4-way closure and a seismic bright spot was predicted to be turbidite channel-sands containing commercial amounts of oil. The prospect was supported by a strong class III AVO anomaly. However, the drilled well revealed sands with residual amounts of gas. Rock physics modeling conducted after the well was drilled showed that, under the given pressure and temperature conditions, uniform distribution of about 10 % gas mixed with 90% brine would cause the same acoustic impedance and Vp/Vs ratio as about 80% oil mixed with 20% brine.

Probabilistic AVO classification conducted prior to the drilling was successful in discriminating the lithologies as well as predicting the zones where hydrocarbons where present. However, it failed in discriminating residual gas from commercial amounts of oil. This pore fluid ambiguity is a well-known problem in hydrocarbon detection from seismic, but the scenario was excluded as an option prior to the well as no cases with residual gas had been encountered in the area.

The future challenge is to find out if residual gas is a regional problem in the area, and if so, how can we possibly discriminate seismic anomalies related to residual gas from seismic anomalies related to oil? Possible solutions include 3-term AVO analysis and/or Q-attribute analysis.

C

J. Hooper, Conocophillips: John.M.Hooper@conoco.com

Title: '**Scientific Success, Commercial Failure**"

Seismic data have been used with reasonable success to quantify the volume of rock related to a particular seismic attribute. Further refinements allow progress determining net to gross and porosity. Therefore to a degree, pore volume can be estimated directly from the seismic data. Production volumes are subsequently determined from a formation recovery factor. Oil recovery is more complicated than gas, but the input for determining gas recovery factor is nearly identical to that required to estimate gas density and compressibility. It is a best practice to work closely with a reservoir engineer to determine the recovery factor, but back-of-the envelope calculations can provide a quick check using a consistent gas/fluid model.

C

Jeff, Pan, Kerr McGee: jpan@kmg.com

Title: **"The Nansen Discovery, East Breaks 602, deepwater Gulf of Mexico - A geophysicist's perspective"**

The Nansen Field was discovered in May 1999 by Kerr-McGee Corporation and Ocean Energy, on East Breaks block 602, deepwater Gulf of Mexico. The field is located in 3,700 ft of water. After successful delineation of the field, the total reserves were estimated at 140-180 MMBOE. The field was fast-tracked and the first production commenced on January 28, 2002, with the world's first truss spar. Daily production of the field is expected to ramp up to a peak of about 40,000 barrels of oil and 80 million cubic feet of gas.

The Nansen prospect is located on a series of structure highs along a salt hinge line. It is on the western edge of a large minibasin. The target amplitudes are situated between a series of NNE-SSW, down to the east faults (Figure 1). All the faults have significant displacement; some of them reach more than 1000 ft dip slip, and therefore facilitate large vertical separations down into the minibasin. The reservoir rocks were prognosis to be multi-lobed channel levee complex sands.

To ensure exploration success, the importance of thorough basic geological work and detailed seismic mapping can never be overstressed. In addition to these efforts, there are important geophysical technologies, such as: DHI/AVO, pressure prediction/column height estimation, and seismic Acoustics/Elastic Inversions (AI/EI), which provide extra information to mitigate exploration risks, increase exploration chance factors, and reduce the range of uncertainty. In this paper, the emphasis will be on these specific geophysical technologies applied to enable the discovery and delineation of this field.

D

Fred J. Hilterman, Geophysical Development Corporation <fred@geodev.com>

Title: **What's Next for Pore-Fluid Estimation?**

Twenty years ago, SEG's Delphi Survey stated that by 1995 low gas saturation would be accurately estimated. Unfortunately, this has not occurred. Our limited success can be related to the PP and PS Zoeppritz equations with respect to gas saturation, AVO class and empirical rock-property relationships. Class 3 AVO anomalies appear to be the best candidates for estimating gas saturation. Of course, this sensitivity analysis is predicated on a solid understanding of the fluid properties for each AVO class, which is an ongoing research topic for DHI studies.

Conventional methods for evaluating fluid properties are normally based on some form of the thin-bed model and Zoeppritz's equation. From these, seismic attributes are extracted such as lambda-rho and the third-term density component that estimate the pore-fluid saturant. Unfortunately, small values of NI_S in Class 3 environments introduced large errors in these attributes and subsequent estimation of gas saturation.

With regard to error, petrophysicists are concerned about upscaling measurements made at laboratory frequencies to the seismic range. However, there are additional scaling problems when the reflection coefficients from log data are extended to band-limited seismic. Seismic amplitude measurements of A/B from 270 deep-water reservoirs illustrate the difficulty in predicting a reasonable NI value.

In an effort to provide additional information about pore-fluid content, seismic offsets that are greater than twice the target depth are being acquired. These new data provide independent measurements of bed thickness and surprisingly also provide a more detailed view of the structure. While still in the research phase, additional interpretation tools will be introduced and more are anticipated as interpreters examine very-long offset data.

D

John Castagna, University of Oklahoma: castagna@ou.edu

Title: **Research Directions in Fluid Properties Determination**

Various ideas have been proposed to distinguish partial and full gas saturation. These include evaluation of AVO curvature to separate velocity and density variations, attenuation measurement, and differences in anisotropic effects in and around targets. Whatever approach is taken, quantification of uncertainty in derived results is a necessity. We are currently investigating stochastic fluid properties inversion as a way of properly accounting for noise and parameter uncertainty in fluid properties determination.

AVO

Keith Katahara, Spinnaker Exploration Company: kkatah@spinexp.com

Title: **Some comments on AVO, anisotropy and laminated shaly sands**

Homogeneous sands often have little anisotropy while bounding shales often have substantial polar anisotropy. The contrast in anisotropy at such shale/sand interfaces can strongly affect AVO response. Laminated shaly sands are anisotropic and will have a different AVO response than homogeneous sands.

AVO

Bryan Devault, Anadarko: bryan_devault@anadarko.COM

How Anisotropy can distort AVO: a Mississippi Canyon example

As pointed out by Andreas Rueger (1997) and most recently by Hilterman (2001), anisotropy has a first-order influence on observed reflection coefficients. Vertical transverse isotropy (VTI) is the most commonly observed form of anisotropy in the Gulf of Mexico and other soft-rock basins worldwide where AVO is most frequently used as a direct hydrocarbon indicator. For typical real-world VTI media, combinations of observed anisotropy parameters and background shale and sand parameters often conspire to produce false (but usually weak) AVO anomalies reminiscent of Class II hydrocarbon signatures. This unfortunate result comes from the VTI reflection coefficient, which can be approximated as

$$R(\theta) = A + B_{iso} \sin^2\theta + C_{iso} \sin^2\theta \tan^2\theta + \Delta\delta \sin^2\theta + \Delta\varepsilon \sin^2\theta \tan^2\theta$$

For most shales, the parameters δ and ε are positive (and may reach values as high as 0.2), while both are nearly zero for sands. This means that for sands that are slightly softer than their encasing shales, the contribution from anisotropy will be of the same sign and possibly even the same magnitude as the impedance and poisson's ratio contrasts in B_{iso} and C_{iso}. This is particularly true for low-contrast wet sands, where all three isotropic reflection coefficients are likely to be small and $\Delta\delta$ and $\Delta\varepsilon$ can reach values of greater than -0.15. The perverse result may be behavior such as phase reversals and increasing (negative) amplitude with offset that is mistaken for low-contrast Class II hydrocarbon signatures.

The White Ash prospect (MC 392), drilled in Mississippi Canyon to test a Class II ultrafar-stack anomaly, provides an interesting if inconclusive illustration of anisotropic pitfalls in AVO analysis. The well encountered over 350' of clean wet sand in 3 individual blocky sand members. Postdrill fluid substitution indicated that the sands would be very bright on the full stack if gas-charged. Anisotropic modeling was performed using the well log, check shot, stacking velocities, and an η term estimated from seismic processing. (The latter two items were needed to estimate the parameters ε and δ). Preliminary results indicate that a wet upper sand indeed produces a moderate Class II anomaly because of anisotropy, while the thick (>200') lower sand has a more ambiguous, flat to slightly decreasing response due to anomalous shales above it. The anisotropic anomalies are somewhat weaker than the anomalies observed on the data, possibly reflecting errors in estimation of the anisotropic coefficients and processing decisions such as whole-trace balancing. The modeled isotropic response from both sands shows a strong decrease with offset which is not reflected in the seismic. It should be noted that the observed increases with offset seen on the seismic can also be obtained by modeling edited well logs, particularly in the shale intervals.

Because of the false AVO anomalies VTI anisotropy can create, it should always be considered as an AVO risk, particularly for low-contrast sands. Seismic responses that are weak in both the near and mid range and which strengthen only in the ultrafar region are particularly suspect. Weak Class II behavior is also suspect. Unfortunately, predrill modeling is difficult because a checkshot is needed to accurately estimate the parameter δ that determines the mid-angle anisotropy contribution. The parameter η, which is approximately equal to $\varepsilon - \delta$, can be estimated during processing if sufficiently long offsets are available. It may be possible to combine estimates of this term with empirical relationships between ε and δ to model predrill the relative contribution of anisotropy to the AVO response if enough nearby well control exists to model the isotropic sand and shale parameters accurately.

Joel Walls, M.T. Taner, Jack Dvorkin, Gary Mavko: Rock Solid Images: j.walls@rocksolidimages.com

Title: **Recent Example of Seismic Attenuation as a Gas Indicator**

We have computed anomalous seismic energy absorption on a 3D data volume from a deep water GOM field. The results appear to show a strong correlation between high energy loss and the location of known gas sands. There are three wellbores in the analyzed volume. Attenutation anomalies occur at the location of gas pay zones in all three wells. No anomalies are observed at wet sand locations. A weak anomaly may be present at one oil sand zone. The seismic results were confirmed by Q calculations in the wellbore and synthetic seismic modeling with Q effects included.

F

Charles L. West Marathon Oil Co. <CLWest@MarathonOil.com>

Title: **"Several case studies where risk of residual hydrocarbon amplitude anomalies is apparently predicted from trap analysis"**

Hydrocarbon saturation has been an important issue from the onset of seismic "bright spot" detection. Mitigating this risk will remain an issue with legacy seismic data sets and until technologies for saturation detection are fully developed and deployed. Noncommerical wellbores thought to contain residual hydrocarbons seem to have critical failures in trap elements. The indicated failures have large pressure gradients across the top seal, multiple apparent flat spots, and faulting that postdates the timing of hydrocarbon migration.