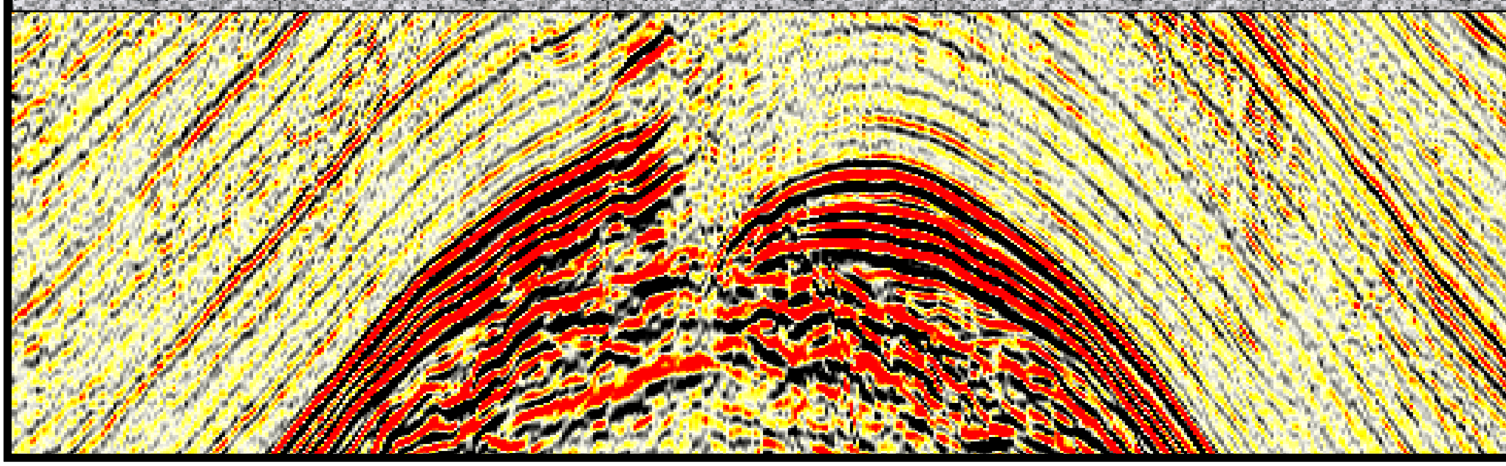
Consortium for
Applied Geosciences and Energy

Seismic Quantification In Reservoir Delineation & Characterization



2004 – 2007 Industry Project

Reservoir Quantification Laboratory
504 Science and Research Bldg 1
Houston, Texas 77204-5006

Seismic Quantification in Reservoir Delineation & Characterization

By

Consortium for Applied Geosciences and Energy
www.agl.uh.edu
Dr. Kurt J. Marfurt, Director

Reservoir Quantification Laboratory

In co-operation with

Allied Geophysical Laboratory
&
Rock Physics Laboratory

Sponsor Contribution	**Amount $35,000/year**
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Proposal prepared by

Dr. Fred Hilterman	**713-743-5802**	**fhilterman@uh.edu**
Dr. Gennady Goloshubin	**713-743-3422**	**ggoloshubin@uh.edu**

This proposal involves wave theory, processing, lab experiments and verification with field data. To accomplish our tasks, a multidisciplinary team has been assembled including geophysicists, geologists, petrophysicists, reservoir engineers, physicists and applied mathematicians. Close alliances have been formed with national labs and other universities working in the same areas.

UH INVESTIGATORS

Dr. John Castagna	Sheriff Professor of Geophysics Seismic exploration and reservoir geophysics
Dr. Gennady Goloshubin	Research Professor of Geophysics Seismic exploration & production
Dr. De-hua Han	Research Professor & Director of Rock Physics Lab Rock physics
Dr. Fred Hilterman	Distinguished Research Professor of Geophysics Seismic exploration and AVO
Dr. Donald Kouri	Cullen Professor of Chemistry, Mathematics and Physics Forward and inverse scattering theory
Dr. Kurt Marfurt	Professor of Geophysics & AGL Director Seismic interpretation, imaging, attributes and processing
Dr. Charlotte Sullivan	Research Assistant Professor of Geology Petroleum geology, carbonates and seismic interpretation
Dr. Bob Wiley	Research Associate Professor of Geophysics Seismic modeling and processing
Dr. Hua-wei Zhou	Associate Professor of Geophysics Seismic tomography, imaging and processing

RESEARCH ALLIANCE INVESIGATORS

Dr. Valery Korneev	Staff Geological Scientist, Lawrence Berkeley National Lab Seismic wave propagation
Dr. Tad Patzek	Professor of Geo-engineering, Univ. of California, Berkeley Multiphase flow and hydrofracture dynamics
Dr. Dmitry Silin	Associate Researcher, Univ. of California, Berkeley Reservoir fluid flow and wave propagation
Dr. Dong Hui Zhang	Professor of Computational Science, Univ. of Singapore Seismic wave scattering and dispersion

Preliminary Proposal

Seismic Quantification in Reservoir Delineation and Characterization

Summary

The goal of this research is a better understanding of the physical processes that affect seismic amplitude so that improved delineation and characterization of reservoirs are possible. With a better understanding of the physical processes that effect amplitude, a more accurate estimation of the porosity, permeability, fluid saturation, etc. for the various reservoir compartments will follow.

One physical process that has attracted attention for the delineation of hydrocarbon reservoirs is frequency-dependent amplitude losses. In this study, recently developed theory that produces frequency-dependent amplitude losses in porous fluid-saturated media will be tested. At the heart of this quantification will be the insight gained from measurements in both the rock-physics laboratory (RPL) and the seismic physical-modeling laboratory (SML).

A major goal is to quantitatively evaluate effects of liquid and gas hydrocarbon phases, as well as the effects of reservoir geometry on seismic reflectivity at different incident angles and frequencies (AVAF – *A*mplitude *V*ersus *A*ngle & *F*requency). Physical models that incorporate heterogeneous, permeable zones will be injected with different fluids and gases and then studied at both the RPL and SML. On the numeric side, 3-D elastic models will form the basis for quantifying frequency-dependent attenuation and other physical processes such as wave-front distortion, time-delayed coda, mode conversions and tunneling phenomena associated with thin-bed reservoirs.

As indicated, the loss mechanisms are dependent on frequency and incident angle. In order to provide more quantitative amplitude measurements, the frequency content of the seismic wavelet will be preserved for all offsets (no stretch processing) by applying NMO and migration algorithms in target-oriented processing (TOP).

The processing and interpretation of long-offset seismic data is an important part of this research. Starting with field data, the processing steps to generate AVAF attributes will include with and without TOP. The 3D seismic interpretation will integrate coherency curvature and AVAF attributes to estimate the reservoir structure and composition. At this stage, wave-propagation effects for non-intrinsic attenuation derived from 3-D physical and numerical modeling will be taken into account. An important understanding is to determine how effective the AVAF analyses are in estimating permeability variations and predicting fluid type and mobility. The reservoir interpretation will be calibrated against the geologic model and parameters determined from known petrophysical, engineering and production data from the field.

With the new TOP algorithms, other analyses will be conducted such as cataloging depositional environment to the measured rock properties and seismic signatures. Also, with the high-resolution timing of far-offset events provided by TOP, tomographic inversions for velocity and anisotropy fields has the potential to estimate additional rock properties such as the seal capacity of shale, an important measurement if low-gas saturation is a concern. With the success of the previous steps comes the final goal of integrating inverse scattering theory for verification of the reservoir shape and compartment rock properties.

I. Objective

The objective of this seismic study is the development and application of a methodology that preserves the frequency content of the seismic wavelet during data processing and allows an accurate quantification of seismic reflectivity in terms of the reservoir's structure (delineation) and composition (characterization).

II. Motivation

With a better quantitative understanding of the physical processes that effect the transmission and reflection of seismic amplitude, a more accurate characterization of the porosity, permeability, fluid saturation, thickness, etc. for the various compartments of a reservoir will follow.

III. Introduction

Recently acquired seismic data from both field experiments and physical modeling exhibited amplitude responses that are dependent on the reflection incident angle and frequency. The unusual character of the observed amplitude loss was explained by a recent wave-propagation theory for porous, permeable, fluid-saturated medium. This theory provides promising tools for estimating reservoir structure and composition if amplitude effects in seismic field data can be realistically quantified.

The study includes the investigation of various physical mechanisms that control frequency-dependent reflectivity near reservoir zones. Before a new intrinsic attenuation theory can be applied to 3-D seismic data, amplitude and frequency losses associated with various other physical processes must be compensated for. To this end, 3-D physical and numerical modeling approaches will be exploited. The Allied Geophysical Laboratories has recently developed the capability to construct physical models that incorporate heterogeneous, permeable zones that can be injected with different fluids and gasses. New hardware and software controls permit acquisition with variable frequency source waveforms and receiver settings that can measure both reflected and transmitted waves. Numerically, 3-D elastic synthetics will be generated across simulations of the physical models. The wave-propagation parameters of the physical models, which are needed for the numerical models, will be measured in the rock-physics laboratory. Then, the physical and theoretical synthetics will be decomposed to quantify the frequency dependency effects associated with physical processes such as subtle mode conversions, tunneling phenomena associated with thin-bed reservoirs and wave-front distortion. By calibrating the amplitude losses from both physical and numeric synthetics, it is anticipated to quantitatively evaluate effects of liquid and gas hydrocarbon phases, as well as the effects of reservoir geometry on seismic intrinsic attenuation and reflectivity at different frequencies.

Attenuation theory in porous media will be introduced to illustrate the characterization of a reservoir's permeability from carefully calibrated reflectivity. Previous field results will be discussed later to illustrate the procedure.

IV. Attenuation Concepts

The principal concepts of wave attenuation in porous fluid-saturated media and the equations governing the mechanical interaction between an elastic skeleton and fluid flow in pore space were introduced by Frenkel (1944), Gassmann (1951) and Biot (1956ab, 1962). This is often called the Biot-Gassmann theory. A discussion about the current state of this theory can be found in Chapman et al., 2002. White (1975) proposed a theory to explain signal attenuation in rocks by the presence of compressible gas-filled pockets. White's theory suggests that attenuation in gas-saturated rock is frequency dependent and has a maximal value. Carcione, et al (2003) used a poroelastic-modeling algorithm to compute numerical experiments of wave propagation based on White's partial-saturation model. They showed the conversation of fast P-wave energy into dissipating slow waves at patches is the main mechanism of attenuation. Mavko and Nur (1975) introduced the concept of squirt flow. Dvorkin and Nur (1993) attempted to incorporate squirt flow into the Biot's model (the so-called BISQ model). This model is more applicable in the case of partial saturation. Pride, et al., (2003) described possible attenuation mechanisms and current state of experimental measurements of absorption. As discussed by Pride, seismic energy is primarily attenuated due to wave scattering from small-scale heterogeneities, frictional flow of the liquid inside rock pores and fractures (squirt flow), and pressure changes in gas-filled pores.

A connection between low-frequency attenuation and permeability of rocks is proposed. Experimental studies have shown that the attenuation can be strongly affected by the properties of the porous media and the fluid saturation. It is well accepted that attenuation (1/Q) is frequency-dependent and it changes dramatically with the liquid saturation. For instance, Q may be less than 10 in sedimentary liquid-saturated rocks (see Jones, 1986 and Sams, et al., 1997). The presence of liquid may lower Q to 14 in metamorphic rocks (Pujol, et al, 1998), and in limestone Q varies from 200 (dry) to 20-40 (water-saturated) (Gadoret, et al, 1998). Experimental findings of Goloshubin and Korneev (2000) showed very low values of Q (<5) for fluid-saturated rocks containing some residual gas. Their model explained low Q by including an additional diffusion dissipation term. Analysis of seismic reflections from thin fluid-saturated porous layers observed in data collected during seismic monitoring at a natural gas storage field allowed Korneev et al. (2004) to propose a model with an analytical solution, which simulates the observed high attenuation and also amplitude and phase dependences at low seismic frequencies.

V. Reservoir Characterization by Reflectivity

The fact that reflection, transmission, and attenuation in fluid-saturated solids are frequency-dependent was discussed in the literature (Geertsma and Smith, 1961, Dutta and Ode, 1983; Santos et al., 1992; Denneman et al., 2002; Pride et al., 2003). Recently, Silin et al (2004) have obtained an asymptotic representation of the seismic reflection from a fluid-saturated porous medium in the low-frequency domain. In their model, the frequency-dependent component of the reflection coefficient is proportional to the square root of the product of frequency of the signal and the mobility of the fluid in the reservoir. In addition, the model establishes a connection of the reflectivity anomalies with reservoir properties, in particular with fluid mobility, and provides a new possibility for seismic reservoir imaging. The expression of the reflection coefficient R as a function of frequency ω, permeability κ and viscosity η is

$$R = R_0 + R_1(1 + i)\,(\omega\,\kappa/\eta)^{1/2}, \qquad (1)$$

where R_0 and R_1 are real coefficients and i is the imaginary number. The coefficients R_0 and R_1 are dimensionless functions of the mechanical properties of the fluid and rock, which include the densities and the elastic coefficients. Taking the derivative of R with respect to frequency implies the following relationship:

$$A = C\,(\kappa/\eta\omega)^{1/2}. \qquad (2)$$

At a given frequency, the unknown constant C, which is a complex function of porous rock parameters, can be found from production data. In the following example, the well production rate is assumed to be proportional to mobility (κ/η). Fig. 1 shows the results of frequency-dependent seismic processing. The seismic map shows the variation of the amplitude of the target horizon at a low frequency relative to the amplitude of the same wave at a high frequency. The imaging results that *predicted* the location of the oil-water contact were confirmed by well data. All wells producing water are outside of the oil-saturated region. The wells with the highest oil production rate (*e.g.*, wells 91 and 86) are found close to the zones of the high deviation of the map attribute at low frequencies.

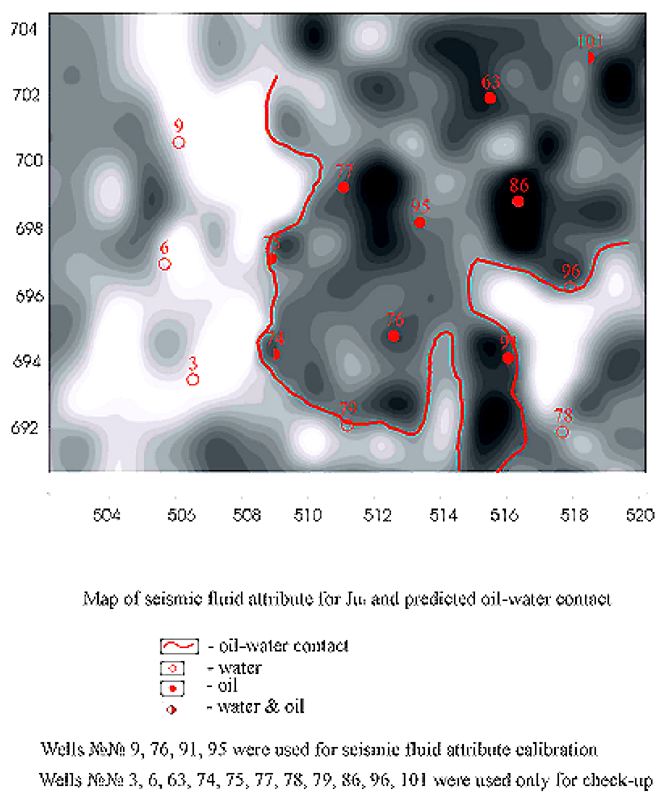

Fig. 1 A blind test of the ability of frequency-dependent processing and interpretation to map the oil-water contact using the low-frequency part of seismic data. The seismic and well data were recorded in Central Siberia. The seismic image shows the difference of low-frequency reflectivity at 12 Hz to the one at 40 Hz

centered frequency, the predicted oil-water contact, and the locations of the calibration wells and the wells used for testing purposes. The data are the courtesy of Surgutneftegas.

For the data in Fig. 1, the imaging attribute is proportional to the derivative of the reflected amplitude A. Figure 2 shows the measured production rates for the oil field from Fig. 1, and the theoretical curve, which was calibrated using just one well data point. The field data and theory correlate quite well.

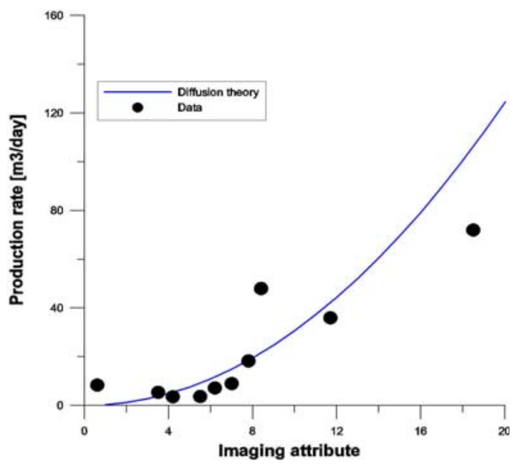

Fig. 2 Oil production rate vs. the imaging attribute. The theoretical line is computed using the low-frequency asymptotic solution in Eq. (2).

In the example presented, frequency-dependent imaging calibrates the fluid mobility (production rate) of the reservoir. The limits and conditions of the applicability of imaging based on intrinsic attenuation are part of this investigation.

It is clear that NMO stretch and other processing procedures that change the frequency content of the propagating wavelet need to be avoided if quantitative analyses of amplitudes that depend on frequency are to be conducted. Target-oriented processing (TOP) provides an avenue to avoid stretch. Currently, no conventional seismic processing software has frequency-preserved and target-oriented processing. Numerous algorithms for processing and interpretation need to be developed to handle this change in processing and interpretation philosophy.

VI. Frequency-Preserved Processing

The calibration of seismic frequency-dependent reflectivity measurements to reservoir properties is based on the assumption that robust amplitudes are obtained for individual frequency components of the propagating wavelet. However, the frequency content of the seismic wavelet is distorted by conventional data processing with NMO providing the most significant distortion. In a conventional CMP gather, the trace associated with an offset equal to depth has a wavelet frequency that is nominally 12 percent lower than the frequency associated with the normal-incident reflection. With the introduction of anisotropic NMO processing, the wavelet frequency content on the very far-offset trace can be one-half that of the normal-incident wavelet. This is not an acceptable condition when calibrating loss mechanisms to reservoir properties as a function of frequency. In addition, AVO attributes are suspect when appreciable NMO stretch is generated. Hilterman and VanSchuyver (2003) introduced a novel-processing scheme based on a migration algorithm that doesn't perform NMO corrections followed by a target-oriented NMO correction. The CDP gather on the right side of Fig. 3 illustrates the retention of wavelet frequency when TOP is applied.

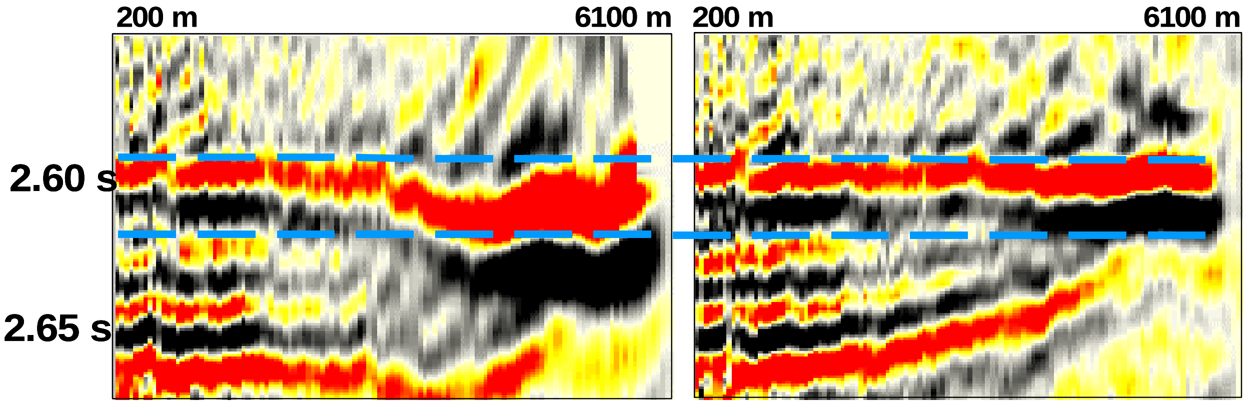

Fig. 3 CMP gathers illustrating target-oriented processing (TOP) (right) versus conventional processing. The frequency content of the propagating wavelet within the dashed target interval has not been distorted by TOP.

Besides the preservation of frequency, the quality of the seismic image is improved significantly with TOP. Figures 4-5 illustrate this point with an obvious improvement in the structural interpretation. The structure shown in Fig. 4 is a faulted anticline and on the angle stack (26°-35°), there is an indication of fault-block compartments near the apex of the structure. In order to observe the frequency content of the signal, the upper surface of the high amplitude reflection was flattened to a constant time and the result is shown in Fig. 5.

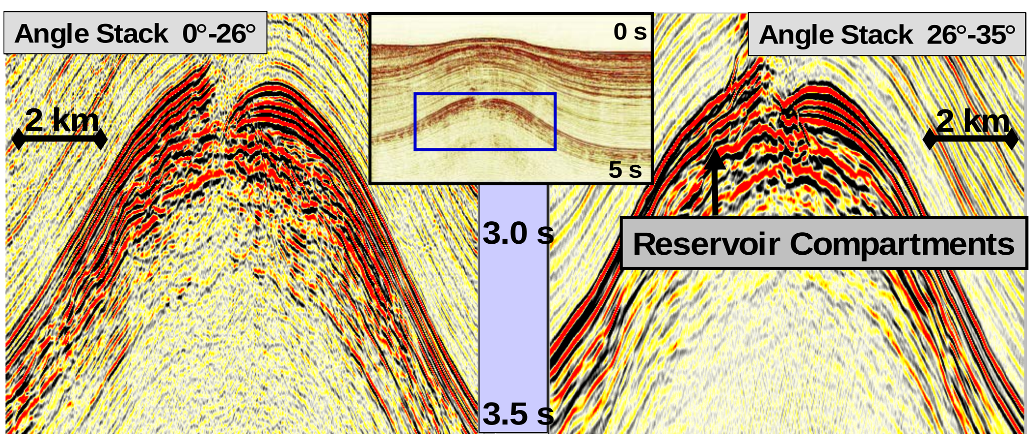

Fig. 4 Pre-stack time migrated sections with conventional angles (0°-26°) and far-offset angles (26°-35°). Structure is a faulted anticline with some indication of fault blocks near the apex. Potential reservoirs are within the high-amplitude band.

With conventional processing (middle of Fig. 5), the 35°-50° angle stack has excessive wavelet stretch and the interpretative value of section becomes questionable.

However, with TOP, the 35°-50° angle stack at the bottom of Fig. 5 exhibits excellent quality. In fact, there are fault blocks illustrated on the 35°-50°angle (bottom portion of Fig. 5) that are difficult to observe in the 0°-16° angle stack.

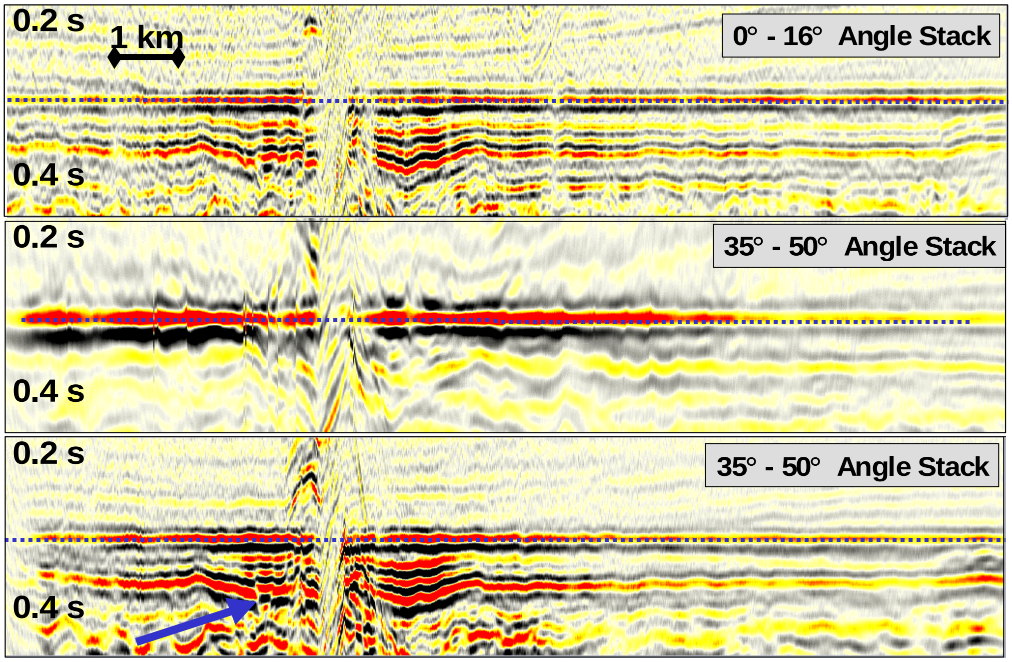

Fig. 5 Migrated angle stacks across anticline with 20° plus dip. The angle stacks have been flattened on the horizon of interest to illustrate wavelet-frequency preservation. The middle angle stack (35°-50°) was processed conventionally while the bottom angle stack was processed with non-stretch NMO and migration (TOP). There is better fault delineation on this far-angle stack (arrow in bottom section) than on near-angle stack (top).

A better definition of faults on oblique reflection data is an expected result once wavelet stretch is removed. In target-oriented processing and interpretation, the reservoir time horizon is picked first. Then, the final NMO is applied to block shift the offset traces within a CMP gather to the horizon time for the specified CMP gather. Because of the block shift, interpretation and data analyses are normally limited to a time window about 100 ms on either side of the reservoir event.

VII. Project Tasks

Seismic Data Processing

Task 1. Select 3-D seismic field data set that has sufficient borehole control to facilitate validation of interpretation. Preference will be given to data sets that exhibit events near the reservoir that exhibit frequency-dependent amplitude variations.

Task 2. Perform preliminary processing of 3D field data with conventional anisotropic and pre-stack time migration for *Stage 1 Output*.

Task 3. Perform preliminary attribute processing for known reservoir.

Task 4. Start TOP of 3-D field data

Computer Programming
Task 1. Develop non-stretch pre-stack 3-D time migration and target-oriented NMO.
Task 2. Develop CMP static correction for far-offset traveltimes not define by anisotropic NMO equation. Static corrections might be softly related to parabolic curvature.
Task 3. Develop links between TOP processing package and interpretation workstation.
Task 4. Develop multi-channel programs for the recognition, quantification and decomposition of seismic amplitude variations to different physical processes.
Task 5. Develop slant stack process and impulse response of wave front distortion to define structure caused by lateral heterogeneities.

Wave Propagation
Task 1. Develop the asymptotic model and governing equations describing seismic wave propagation in fluid-saturated porous and fractured rocks. Investigate the interaction between the solid skeleton and the fluid at the transition between permeable and impermeable zones.
Task 2. Describe the reflectivity equations for AVAF imaging of reservoir properties for models with:

- Porous (micro porous) medium
- Fractured medium, and
- Dual-porosity / Dual-permeability medium (Dual = matrix + fractures)

Task 3. Formulate the algorithms for the numerical modeling, AVAF imaging and quantitative analysis of the AVAF images.

Physical and Numerical Modeling
Task 1. Calibrate source and receiver for directionality and water attenuation.
Task 2. Conduct physical modeling to investigate wave attenuation by frequency-dependent reflectivity on long-offset 3D seismic for the following models:

- Porous (micro porous) medium
- Fractured medium, and
- Dual-porosity / Dual-permeability medium.

Task 3. Conduct numerical modeling for the three physical models with and without loss-mechanism parameters.
Task 4. Process physical and numerical data conventionally and with TOP.
Task 5. Extend conventional PP ray theory to include PPSP, PPPP and other modes for long offset.

Rock-Physics Measurements
Task 1. Measure rock properties from borehole data.
Task 2. Measure properties of physical model for inclusion in numerical modeling.

Imaging
Task 1. Create and investigate a new technique of seismic reservoir imaging based on the AVAF models of

- Porous (micro porous) medium
- Fractured medium, and
- Dual-porosity / Dual-permeability medium.

Task 2. Extend reservoir-imaging techniques from AVAF models to 3-D filed data.

Inversion
Task 1. Develop tomographic estimations of velocity and weak-anisotropy fields above, within and below reservoir zones from TOP processing.
Task 2. Estimate attenuation field with tomographic inversion of TOP data.
Task 3. With best estimate of reservoir structure, apply inverse scattering theory to estimate reservoir compartment properties.
Task 4. Investigate possibility of applying forward scattering theory to model the three porous reservoirs.

Borehole to Seismic Calibration
Task 1. Generate 1D and AVO synthetics, ray-theory, reflectivity (SOLID) and anisotropic from available borehole data.
Task 2. Estimate the weak anisotropic trends from seismic and borehole data.
Task 3. Develop rock-property trend statistics and anomalous lithology statistics.
Task 4. Catalog rock properties as function of reservoir and depositional environment.

Interpretation
Task 1. Develop methodology for the interpretation based on TOP data. Build initial structural and stratigraphic geologic models. Calibrate seismic attributes against the geologic models and reservoir parameters determined from petrophysical and engineering data. Map fluid contacts and permeability variation and/or production rate of hydrocarbons.
Task 2. Examine physical, numerical and field data with various coherency and curvature algorithms with conventional and TOP processing.

VIII. Deliverables, Intellectual Property and Budget

Deliverables

- Copies of seismic data from numerical and physical modeling.
- Petrophysical measurements from borehole and physical models.
- Synthetics and anisotropic measurements derived from field data.
- Algorithms for wave-propagation in porous media
- Methodology (model and field data)
    - ❖ Target-oriented frequency-preserved seismic data processing (TOP)
    - ❖ Identification of impulse response for various physical processes
    - ❖ Tomographic inversion for velocity, attenuation and anisotropic parameters.
    - ❖ Interpretation of structure and composition based on TOP data and seismic reflectivity at different frequencies and incident angles (AVAF)
    - ❖ Forward and inverse scatter theory
- One final report per year

Deliverables will be presented in form of annual reports in digital format. In addition to the report and annual review meeting, we will make visits to sponsor work sites for shorter presentations to a wider audience.

Intellectual Property

New software developments are officially owned by the State of Texas. Our current consortium agreement provides a royalty free license (with no time limit) to our sponsors to use this technology commercially in their search for oil and gas (including work done for partners and host governments) or in the case of service companies for commercial data processing. In addition, commercialization through software sales is allowed by our current agreement. Previously developed computer codes are proprietary.

Budget

Sponsor contribution amount is $ 35,000/year. Service companies providing data are eligible for first-year in-kind sponsorship. Total expenses include expenses for support students and research, for purchases of software, hardware and materials that will be used for construction of 3D physical models. Current members of the Rock Physics Laboratory or AGL Consortia will be given a $10,000/year discount.

IX. Project Time Schedule

		Year 1						Year 2						Year 3					
		2	4	6	8	10	12	2	4	6	8	10	12	2	4	6	8	10	12
Seismic Data Processing																			
Task 1	Select 3-D data	■	■																
Task 2	First 3-D processing			■	■	■	■	■											
Task 3	First attribute processing					■	■	■	■	■									
Task 4	TOP on 3-D data					■	■	■	■	■	■	■	■	■	■	■	■		
Computer Programming																			
Task 1	TOP NMO and migration	■	■	■	■														
Task 2	Trim parabolic NMO stactic				■	■	■												
Task 3	Link TOP to Workstation		■	■	■	■	■	■											
Task 4	Recognize, quantify, decompose amplitude				■	■	■	■	■	■	■	■	■	■	■	■	■	■	
Task 5	Wavefront distortion impulse response				■	■	■	■	■	■	■	■	■						
Wave Propagation																			
Task 1	Develop wave propagation - porous media	▒	▒	▒	▒	▒	▒	▒	▒	▒									
Task 2	Develop AVAF reflectivity eqs. - 3 models				▒	▒	▒	▒	▒	▒	▒	▒	▒						
Task 3	Numeric AVAF synthetics						▒	▒	▒	▒	▒	▒	▒	▒	▒	▒	▒		
Phys. & Numeric Modeling																			
Task 1	Calibrate source-receiver & H2O attenuation	■	■	■															
Task 2	Physical 3-D seismic for 3 models		■	■	■	■	■	■	■										
Task 3	Numerical 3-D seismic for 3 models				■	■	■	■	■	■	■	■	■	■	■	■	■		
Task 4	TOP of seismic from 3 models			■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	
Task 5	Develop extended ray theory	■	■	■	■														
Rock-Physics Measurements																			
Task 1	Measure borehole rock properties			■	■	■	■	■	■	■	■								
Task 2	Measure physical model properties			■	■	■	■												
Imaging																			
Task 1	Develop imaging based on AVAF models					▒	▒	▒	▒	▒	▒	▒	▒	▒	▒	▒	▒		
Task 2	Extend AVAF imaging technique to field										■	■	■	■	■	■	■		
Inversion																			
Task 1	Velocity and anaisotropy inversion							■	■	■	■	■	■	■	■	■	■		
Task 2	Attenuation inversion							■	■	■	■	■	■	■	■	■	■		
Task 3	Characterization by inverse scattering													■	■	■	■	■	■
Task 4	Forward modeling of 3D by scattering				■	■	■	■	■	■	■	■	■						
Calibrate Borehole to Seis																			
Task 1	1D and AVO synthetics			■	■	■	■	■	■	■									
Task 2	Weak anisotropy parameter estimation							■	■	■	■	■	■						
Task 3	Trend and anomaly rock-property modeling				■	■	■	■	■	■	■								
Task 4	Rock properties vs depositional environment							■	■	■	■	■	■	■	■				
Interpretation																			
Task 1	Build structure abd strat models +++					■	■	■	■	■	■	■	■	■	■	■	■	■	
Task 2	Coherency - Conventional vs TOP					■	■	■	■	■	■	■	■	■	■	■	■	■	

▒ Univ. Cal. and National Lab Work

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