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A METHODOLOGY TO INTEGRATE RESONANCE AND ACOUSTIC
MEASUREMENTS FOR RESERVOIR CHARACTERIZATION

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San Antonio, Texas

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FOREWORD AND ACKNOWLEDGMENTS

The work reported herein represents the first year of development work on a methodology to interpret magnetic resonance and acoustic measurements for reservoir characterization. Project coordination and supervision as well as the geophysical studies, were performed by Dr. Jorge Parra from the Instrumentation and Space Research Division, Southwest Research Institute. Drs. Chris Hackert and Q. Ni, of the same organization, performed software development/computer modeling of acoustic/seismic data and NMR core analysis, respectively. The petrophysical studies were performed by Dr. Hughbert Collier, Collier Consulting. The ultrasonic and NMR core measurements were performed by Core Laboratories, and the Computed Tomography (CT) was performed by Shell Exploration and Production Technology Company.

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This report contains eight sections. Some individual subsections contain lists of references as well as figures and conclusions when appropriate. The first section includes the introduction and summary of the first-year project efforts. The next section describes the results of the project tasks: (1) implementation of theoretical relations between effective dispersion and the stochastic medium, (2) imaging analyses using core and well log data, (3) construction of dispersion and attenuation models at the core and borehole scales in poroelastic media, (4) petrophysics and a catalog of core and well log data from Siberia Ridge field, (5) acoustic/geotechnical measurements and CT imaging of core samples from Florida carbonates, and (6) development of an algorithm to predict pore size distribution from NMR core data. The last section includes a summary of accomplishments, technology transfer activities and follow-on work for Phase II.

I. INTRODUCTION AND SUMMARY OF THE PROJECT

A. Background

Over the years, traditional reservoir characterization techniques have evolved into multidisciplinary processes. In particular, the integration of engineering, geoscientific, and geological data over multiple scales has been used to characterize reservoirs by honoring petrophysical well log data as well as sedimentological models.

Recently, great effort has been dedicated to the integration of well logs with seismic data. Conventional seismic measurements have been used to delineate reservoir structures in the lateral extent, but vertical resolution is limited. And although seismic data is routinely and effectively used to estimate reservoir structure, it plays no role in the essential task of estimating rock physical properties, which are derived from well logs. Simultaneous analysis of seismic and borehole data leads to better estimates of rock physical property distributions in comparison with estimates generated from seismic or well log data alone.

Accurate reservoir description and simulation are dependent on measures of properties such as porosity, permeability, fluid viscosity, and fluid saturation. Porosity is routinely available from wireline log data, which, in conjunction with 3-D seismic data, can be used to generate excellent reservoir porosity models. Until recently, cores were the only source of permeability data measured on a small enough scale to provide critical reservoir heterogeneity data. Permeability is usually derived from core-based permeability-porosity cross-plots, but such an approach is flawed, as the porosity-permeability correlations are often poor and core data may be sparse and expensive to obtain.

Alternatively, acoustic measurements based on Stoneley wave attenuation have been used to indirectly extract information about formation permeability. In this case, attenuation measurements are affected by the heterogeneity and viscoelasticity of the rock, rather than fluid flow interactions alone (or intrinsic properties of the reservoir such as permeability and porosity). To use attenuation and dispersion measurements to predict flow properties, the effects of scattering must be understood so velocity measurements can be corrected by such effects.

Nuclear magnetic resonance (NMR) logging techniques do provide vertically continuous pore-size distribution, but they do not measure permeability directly, nor are they foolproof in distinguishing the amount of oil in an oil-water mixture. Combined with other measurements (resistivity, etc.), reasonable permeability models can be obtained.

The objective of the proposed project is to develop an advanced imaging method, including pore scale imaging, to integrate magnetic resonance (MR) techniques and acoustic measurements to improve predictability of the pay zone in two hydrocarbon reservoirs. We will accomplish this by extracting the fluid property parameters using MR laboratory measurements and the elastic parameters of the rock matrix from acoustic measurements to create poroelastic models of different parts of the reservoir. Laboratory measurements will be compared with petrographic

analysis results to determine the relative roles of petrographic elements such as porosity type, mineralogy, texture, and distribution of clay and cement in creating permeability heterogeneity.

The project is organized in three phases. Phase I comprises the development/application of theoretical models using random/deterministic seismic solutions at different scales, construction of dispersion and attenuation models based on core and well log data, NMR measurements and analyses of rock samples, and imaging analyses. Phase II includes core measurements and imaging analysis, petrographic and geological analysis of cores and petrophysics at the borehole scale, application of theoretical poroelastic models and simulations of 2D images of fluid properties, and NMR measurements at the pore and core scales. Phase III involves the validation of methodology developed in Phases I and II. This incorporates validation of the ultrasonic models based on pore scale information and the applicability of such models to predict acoustic signatures at the borehole scale. In addition, Phase III includes the validation of models based on borehole scale information and the applicability of such models to predict VSP or seismic signatures at the interwell scale. Algorithms to predict pore size distribution from NMR core data developed in Phases I and II will be adapted to predict pore size distributions from NMR well log data. The pore size distribution, permeability and porosity based on NMR data will be used to construct the poroelastic deterministic and random flow models for simulating data at the core and borehole scales.

In this first year annual report, the research topics have been slightly modified from those originally proposed. Thus, the first year of this project covers: (1) implementation of theoretical relations between effective dispersion and the stochastic medium, (2) imaging analyses using core and well log data, (3) construction of dispersion and attenuation models at the core and borehole scales in poroelastic media, (4) petrophysics and catalog of core and well log data from Siberia Ridge field, (5) acoustic/geotechnical measurements and CT imaging of core samples from Florida carbonates, (6) development of an algorithm to predict pore size distribution from NMR core data, and (7) technology transfer.

B. Summary of Project Efforts

An important part of this study is to explore techniques to image flow units using NMR measurements at the core and borehole scales. Therefore, we have implemented an algorithm to determine pore size distribution for NMR core data and capillary pressure measurements. The algorithm is applied to NMR core measurements and capillary pressure data from a carbonate formation in Florida. The final objective is to apply the algorithm to predict pore sizes from T2 distribution that are obtained from NMR well logs where cores are not available. In addition, the pore sizes, permeability, and porosity determined from core data will be used as input parameters to simulate ultrasonic and acoustic waveforms to verify the poroelastic computer models. This topic is included after the Florida data is addressed.

To simulate ultrasonic/acoustic signatures, we have developed stochastic solution based on models constructed at the pore and core scales. The basic theory was developed and applied to the Buena Vista Hills reservoir, and it was reported in the first semi-annual report. Here we describe the extension of the theory to model ultrasonic/acoustic signatures due to 3D heterogeneities. For this purpose we have rigorously derived a Green's function equation for

describing the ensemble average behavior of acoustic waves in media with random variations in two dimensions. By taking the 2D integral that is the basis of the solution, applying a coordinate transformation, and choosing a particular form of the spectral density, we can use the previously published 1D result to evaluate an integral, leaving only an integral over angle. Similar methods can be applied to extrapolate the result to three dimensions and to include anisotropy in the spatial variability. For multidimensional variability, the endpoints of the angular integral are singular, resulting in the imaginary part of the integral being infinite. This is probably an unavoidable result of the plane wave ensemble average basis of the solution. One method to deal with this problem is to limit the integration to the forward- and back-scattering angles. Similar methods have been applied in single-scattering theory, where forward-scattered energy is not counted as lost.

Applying the solution, we produced curves showing the velocity and attenuation of waves in 2 and 3D stochastic media as a function of frequency for varying degrees of variability, anisotropy, and angle of propagation in the medium. All results can be shown to reduce to the proper 1D result in the appropriate limit. We expect these results to be of particular use in analyzing high frequency wave propagation through the vuggy Florida aquifer cores.

In addition, we have analyzed acoustic and VSP data to relate these two scale measurements with the directional attenuation associated with a shale-sand-coal sequence at the Siberia Ridge field. While analyzing the Siberia Ridge VSP data to extract attenuation or dispersion information, we found that the seismic wave amplitude increases with depth in the reservoir region, while the VSP interval velocities from the checkshot data show occasional large differences from the sonic log velocities. Investigating these phenomena, we produced interval velocities, horizontal and vertical amplitudes, hodograms, and angle of incidence plots for the checkshot VSP and two offset VSPs. By using a detailed model of the bottom 2000 feet of the well, we demonstrate that the increase in amplitude is a direct result of the elastic properties of the Almond Formation, and that the discrepancy between checkshot and sonic velocities can be explained by the soft coal layers in the Almond Formation. Even though the coal makes up less than 10% of the formation, the large density and velocity contrast between the coal and the tight shale and sandstone layers produces a significant effect on the observed waves.

These results demonstrate the importance of accounting for the elastic behavior of the medium when investigating wave attenuation, and how a few relatively thin coal layers need to be incorporated into a scaling model to properly predict wave speeds. By doing so, we can create an elastic model at the reservoir scale from the VSP data and relate it to the borehole logs.

Furthermore we have established a method to relate P-wave attenuation to fluid flow in cracked rocks. This method was applied to the Buena Vista Hills reservoir and reported in the first semi annual report. Here we extend its application by predicting acoustic/seismic responses of flow units in a shale-sands-coal sequence at different azimuths in the Almond Formation of the Siberia Ridge field. The poroelastic anisotropic models were constructed with reservoir parameters based on NMR well logs, cores and sonic logs. The petrophysics and the NMR images are discussed in the next section.

At present, we are assessing the applicability of acoustic/seismic waves in fractured tight sands. For this purpose we have constructed poroelastic models based on core and well log data from the Almond Formation of the Siberia Ridge field, Wyoming. The flow properties were obtained from NMR well log data, and velocities were obtained from monopole/dipole sonic data.

We predicted attenuation responses by varying the permeability and squirt flow lengths in the plane defined by the cracks. We also varied the azimuth and incident angles to predict the appropriate frequency range for detecting cracks using acoustic/seismic measurement techniques. We analyzed the sensitivity of the squirt flow length to attenuation and predicted the contribution of fracture permeability in low permeability tight sands. The modeling results provided for detecting fluid-filled fractures using acoustic or seismic measurements in tight sand reservoirs.

We have modeled scattering and intrinsic attenuation associated with a layer sequence of sands, shales and coals. The model includes the poroelastic properties determined from well logs and cores. The objective of this analysis is to evaluate how much of the intrinsic and scattering attenuation will contribute to total attenuation based on VSP and acoustic data. The VSP and sonic logging data from Siberia Ridge 5-2 is being processed and applied to construct dispersion and attenuation models. The result may provide guidelines on whether it is possible to predict flow properties (e.g., permeability, porosity, saturation, etc.) with acoustic and seismic measurements (e.g., VSP and sonic) in this type of environment.

We are also cataloging and analyzing petrophysical and NMR logs from Siberia Ridge, as well as the Florida data. The Siberia Ridge data set includes core, well log, and VSP data that address different scales to predict flow unit detectibility in fractured rock sands. Alternatively, the Florida data set includes data at the pore, core and borehole scales to verify the proposed scale methodology. This data set, to be completed in the first part of Phase II, will include NMR core measurements, NMRI, sonic, petrography/thin sections, geotechnical measurements, standard well logs, etc.

The last section includes a summary of accomplishments, technology transfer activities, and follow-on work for Phase II.

II. 2D and 3D SOLUTIONS OF THE ACOUSTIC WAVEFIELD IN STOCHASTIC MEDIA

A. Summary

Expanding on the 1D stochastic medium result previously derived, we have rigorously derived a Green's function equation for describing the ensemble average behavior of acoustic waves in media with random variations in two dimensions. By taking the 2D integral that is the basis of the solution, applying a coordinate transformation, and choosing a particular form of the spectral density, we can use the previously published 1D result to evaluate an integral, leaving only an integral over angle. Similar methods can be applied to extrapolate the result to three dimensions and to include anisotropy in the spatial variability. For multidimensional variability, the endpoints of the angular integral are singular, resulting in the imaginary part of the integral being infinite. This is probably an unavoidable result of the plane wave ensemble average basis of the solution. One method to deal with this problem is to limit the integration to the forward- and back-scattering angles. Similar methods have been applied in single-scattering theory, where forward-scattered energy is not counted as lost.

Applying the solution, we have produced curves showing the velocity and attenuation of waves in 2 and 3D stochastic media as a function of frequency for varying degrees of variability, anisotropy, and angle of propagation in the medium. All results can be shown to reduce to the proper 1D result in the appropriate limit. We expect these results to be of particular use in analyzing the high frequency wave propagation through the vuggy Florida aquifer cores.

B. Outline of Solution

The solution of the stochastic wavefield in two dimensions reduces to the solution of the following integral.

$$C_{AA} = 2 \int_{-\infty}^{\infty} \int_{-\infty}^{\infty} \frac{k_{0x}^2 + k_{0z}^2}{(k_x - k_{0x})^2 + (k_z - k_{0z})^2 - k_{0x}^2 - k_{0z}^2} S(k_x, k_z) dk_x dk_z \quad (1)$$

Because the variables of integration extend over the entire k_x, k_z plane, we are free to rotate the plane of integration such that the incident wave is parallel to the z axis. In such a situation, $k_{0x} = 0$, and $k_{0z} = k_p$. We then have the simpler expression

$$C_{AA} = 2 \int_{-\infty}^{\infty} \int_{-\infty}^{\infty} \frac{k_p^2}{k_x^2 + k_z^2 - 2k_z k_p} S(k_x, k_z) dk_x dk_z \quad (2)$$

We will now transform the integration variables to a modified radial coordinate system. This system occupies the space $-\infty < k < \infty$, and $0 < \phi < \pi$. The transforms use the familiar radial expressions

$$\begin{aligned} k_x &= k \cos \phi, \text{ and} \\ k_z &= k \sin \phi; \end{aligned}$$

but because the coordinate k is allowed to be negative, the differential area is $|k| dk d\phi$. In the new coordinates, we now have

$$C_{AA} = 2 \int_0^\pi \int_{-\infty}^\infty \frac{k_p^2}{k^2 - 2kk_p \sin \phi} S(k, \phi) |k| dk d\phi \quad (3)$$

It is demonstrated in Mantoglou and Wilson (1982) that, for an isotropic two-dimensional spectral density function $S(k, \phi)$,

$$|k| S(k, \phi) = \frac{1}{\pi} S_{1D}(k), \quad (4)$$

where S_{1D} is the 1D spectral density function along any straight line in the 2D random medium. Applying this to the problem at hand,

$$C_{AA} = \frac{1}{\pi} \int_0^\pi \int_{-\infty}^\infty \frac{2k_p^2}{k^2 - 2kk_p \sin \phi} S_{1D}(k, \phi) dk d\phi \quad (5)$$

Let us simply multiply and divide the integrand by $\sin^2 \phi$. We then get the useful result

$$C_{AA} = \frac{1}{\pi} \int_0^\pi \frac{1}{\sin^2 \phi} \left[\int_{-\infty}^\infty \frac{2k_p^2 \sin^2 \phi}{k^2 - 2kk_p \sin \phi} S_{1D}(k, \phi) dk \right] d\phi \quad (6)$$

This result is useful because the term in brackets $[\]$ is precisely the equation solved in the 1D case, with the substitution of $k_p \sin \phi$ for k_p . Since it already incorporates the 1D spectral density function, we can use the 1D result derived in Parra et al. (1999b). Under these circumstances, the spectral density function corresponds to a situation in which there are transitions between discrete media along the any line ϕ , with average transition spacing L independent of the angle of the line. The result is

$$C_{AA} = -\frac{1}{\pi} \int_0^\pi \frac{2k_p^2 L^2}{1 + 4k_p^2 L^2 \sin^2 \phi} d\phi - \frac{j}{\pi} \int_0^\pi \frac{1}{\sin \phi} \frac{k_p L}{1 + 4k_p^2 L^2 \sin^2 \phi} d\phi \quad (7)$$

The real part is directly integrable, yielding

$$\Re(C_{AA}) = -\frac{2k_p^2 L^2}{\sqrt{1 + 4k_p^2 L^2}}, \quad (8)$$

which at high frequency, means that the phase velocity increases linearly with frequency. This is not unreasonable, because at higher frequencies rays can follow narrow paths of high velocity material. This unbounded increase is not seen in 1D because the wave must cross all materials, fast or slow.

The imaginary part is singular at the integral endpoints. This might be due to the fact that we implicitly assume the ensemble solution is a plane wave propagating parallel to the incident wave. Scattering into angles of $\phi = 0$ and $\phi = \pi$ corresponds to scattered waves orthogonal to the assumed solution. Thus, it might be reasonable to neglect them, and perform the integration from $\phi = \varepsilon$ to $\pi - \varepsilon$. This is not unlike the approach taken by Roth and Korn (1993). In their 2D Born approximation approach to scattering, they found that they had to neglect scattering into forward angles to keep the attenuation bounded for all frequencies. Their integral is not singular, however. Since this solution deals with propagating rather than scattered wavelets, perhaps it is fitting that we only keep the forward propagating wavelets.

C. Reduction to 1D Case

For a stack of infinite parallel horizontal plates, the spectral density is

$$S(k_x, k_z) = \frac{L}{\pi} \frac{1}{1 + k_z^2 L^2} \delta(k_x) \quad (9)$$

We already know that this works with the original integral. Let's look at the radial coordinate version.

$$S(k, \phi) = \frac{L}{\pi} \frac{1}{1 + k^2 L^2 \sin^2 \phi} \delta(k \cos \phi) \quad (10)$$

or

$$S(k, \phi) = \frac{L}{\pi} \frac{1}{1 + k^2 L^2 \sin^2 \phi} \frac{1}{|k|} \delta(\cos \phi) \quad (11)$$

This 2D spectral density function may be substituted into the radial integral to obtain the correct 1D response, recognizing that $\delta(\cos \phi)$ collapses the ϕ integral and sets $\sin \phi = 1$.

We can use a similar technique to find the response of a 1D medium if the medium axis is inclined with respect to the incident wave (or equivalently, if the incident wave is at an angle to the medium). The math is identical to that above, but with a rotation in ϕ . So, if the medium is inclined to the horizontal by an angle ϕ_o , the dispersion in the phase velocity is proportional to

$$- \frac{k_p^2}{1 + 4k_p^2 \cos^2 \phi_o}, \quad (12)$$

while the attenuation is proportional to

$$-\frac{1}{\cos \phi_o} \frac{k_p}{1 + 4k_p^2 \cos^2 \phi_o}. \quad (13)$$

This result is identical to that obtained by Shapiro and Zien (1993) for plane waves at oblique incidence to stacks of parallel plates. Note that the attenuation is singular if the wave is parallel to the bedding planes. Shapiro and Zien note that the result is probably not accurate past the critical angle, and so is confined to small values of ϕ_o . In any case, the velocity of wave propagation along the bedding direction can be multivalued, even for monochromatic waves. Reflection and refraction give rise to an infinite number of modes, each of which may have its own propagation velocity. A unique solution is possible only in the limit of zero frequency, where the wavelength is much longer than the scale of the layering. This zero-frequency solution has been derived by Backus (1962).

D. General Anisotropy in 2D

We have seen how the 2D integral turns out for the isotropic case and the 1D case. It is of practical interest, however, to investigate intermediate degrees of anisotropy. The anisotropy is entirely contained in the spectral density function $S(k, \phi)$. We also know that the limiting 1D case is obtained from the isotropic case by multiplying $S(k)$ by $\delta(\cos \phi)$. Therefore, let's try creating an anisotropic spectral density function by multiplying the isotropic function $S(k)$ by another function $f(\phi)$. This also allows us to continue to evaluate the integral over k in the manner above. Given an anisotropy parameter η , we want $f(\phi)$ to be one when $\eta = 1$, and $f(\phi)$ to be equal to $\delta(\cos \phi)$ as η goes to infinity. Such a function is given by

$$f(\phi) = \frac{\eta}{1 + (\eta^2 - 1) \cos^2 \phi} \quad (14)$$

E. 3D Solution

Having obtained a 2D solution, we find that a 3D solution is a fairly simple extension of the method. Given the 3D integral

$$C_{AA} = 2 \int_{-\infty}^{\infty} \int_{-\infty}^{\infty} \int_{-\infty}^{\infty} \frac{k_p^2}{k_x^2 + k_y^2 + k_z^2 - 2k_z k_p} S(k_x, k_y, k_z) dk_x dk_y dk_z, \quad (15)$$

we can place it into spherical coordinates using the expressions

$$\begin{aligned} k_x &= k \cos \phi \cos \theta \\ k_y &= k \cos \phi \sin \theta \\ k_z &= k \sin \phi \end{aligned}$$

where, as before, k is allowed to range from $-\infty$ to ∞ . This restricts ϕ to the angles from 0 to $\pi/2$. In these spherical coordinates, the integral is

$$C_{AA} = 2 \int_0^{\pi/2} \int_0^{2\pi} \int_{-\infty}^{\infty} \frac{k_p^2 \cos \phi}{k^2 - 2kk_p \sin \phi} S(k, \phi, \theta) k^2 dk d\theta d\phi \quad (16)$$

Following the method outlined by Mantoglou and Wilson (1982), we can obtain a 3D isotropic spectral density function from a 1D spectral density function. Mantoglou and Wilson (1982) demonstrate that the autocorrelation function of an isotropic 3D field is related to the 1D autocorrelation function of a line through the field by the equation

$$\chi(r) = \frac{1}{r} \int_0^r \chi_{1D}(\xi) d\xi. \quad (17)$$

Given that the 1D autocorrelation function we have chosen is $\chi_{1D}(r) = \exp(-r/L)$, we can show that $\chi(r) = [1 - \exp(-r/L)]L/r$. This is a proper 3D autocorrelation function, having the value one at $r = 0$, and decreasing monotonically to zero at large r . However, we are more interested in the spectral density, which is the Fourier (cosine) transform of the autocorrelation function. Using this definition, we can rewrite the equation above to be

$$\chi(r) = \frac{2}{r} \int_0^r \int_0^\infty \cos(k\xi) S_{1D}(k) dk d\xi \quad (18)$$

Evaluating the integral over ξ ,

$$\chi(r) = 2 \int_0^\infty S_{1D}(k) j_0(kr) dk, \quad (19)$$

where j_0 is the spherical Bessel function of zeroth order. The 3D autocorrelation function must also be given by the cosine transform of the 3D spectral density (Shinozuka, 1987), so we can also write that

$$\begin{aligned} \chi(r) &= \iiint \cos(\vec{k} \cdot \vec{r}) S(\vec{k}) d\vec{k} \\ &= \int_0^\infty \int_0^\pi \int_0^{2\pi} \cos(kr \cos \psi) S(k) k^2 \sin \psi d\theta d\psi dk \end{aligned} \quad (20)$$

where the spherical axis $\psi = 90$ degrees is oriented parallel to $\vec{r}$. Evaluating the angular integrals leads to the result

$$\chi(r) = 4\pi \int_0^\infty S(k) k^2 j_0(kr) dk . \quad (21)$$

Considering equations (19) and (21), it is apparent that

$$S(k) = \frac{1}{2\pi} \frac{1}{k^2} S_{1D}(k) . \quad (22)$$

This gives us the 3D spectral density function needed to solve the integral for C. Returning to the previous equation, we can now say that in 3D,

$$C_{AA} = \frac{1}{2\pi} \int_0^{\pi/2} \int_0^{2\pi} \frac{\cos \phi}{\sin^2 \phi} \left[\int_{-\infty}^{\infty} \frac{2k_p^2 \sin^2 \phi}{k^2 - 2kk_p \sin \phi} S_{1D}(k) dk \right] d\theta d\phi \quad (23)$$

As before, the term in square brackets is the 1D integral solved in Parra et al. (1999b). We still have the problem that the imaginary part of the integral is singular for angles perpendicular to the main axis of propagation, i.e., for $\phi = 0$. Therefore, we might exclude the near vicinity of $\phi = 0$ from the integration domain.

F. Anisotropy in 3D

We want to handle the 3D spatial anisotropy as in the 2D case, by introducing a function $f(\phi, \theta)$ so that

$$S(k, \phi, \theta) = \frac{1}{2\pi} \frac{1}{k^2} S_{1D}(k) f(\phi, \theta) \quad (24)$$

which keeps the term inside the brackets above unchanged, and allows us to use the same solution technique. Consider anisotropy parameters η_x and η_y for the x and y directions, where $\eta_x = \eta_y = 1$ corresponds to isotropic symmetry ($f = 1$) and $\eta_x = \eta_y = \infty$ corresponds to the 1D case. Given these parameters, we can construct the function

$$f(\phi, \theta) = \frac{\eta_x \eta_y}{\left(1 + (\eta_x^2 - 1) \cos^2 \phi \cos^2 \theta + (\eta_y^2 - 1) \cos^2 \phi \sin^2 \theta \right)^{3/2}} , \quad (25)$$

which satisfies all constraints. As $\eta_x = \eta_y = \infty$, the expression for f reduces to

$$f(\phi, \theta) = \frac{1}{\cos \phi} \delta(\cos \phi), \quad (26)$$

which is the correct form of the delta function in spherical coordinates. As with the 2D version, oblique incidence of the wave to anisotropic media can be handled by rotating f in space; that is replace $f(\phi, \theta)$ with $f(\phi - \phi_0, \theta - \theta_0)$. Interestingly, the resulting attenuation and dispersion is independent of azimuthal rotations around the main direction of propagation, even for azimuthally anisotropic media ($\eta_x \neq \eta_y$). This is because the only θ dependence is in the f term, and the integral over θ is carried out over the entire circle. Shifts in θ thus are irrelevant to the final result.

G. Calculating Dispersion and Attenuation

Once the C integral is evaluated for 2D or 3D cases, the ensemble average dispersion and attenuation of the plane wave can be determined. A parameter D is defined as

$$D = \frac{\sigma^2}{4}(1 + C), \quad (27)$$

while the plane wave propagates in the random medium as

$$u(x, y, z, t) = U(\omega) e^{j\omega t} e^{-jk_p z(1+D)}. \quad (28)$$

Thus, the real part of D acts to alter the effective phase velocity, while the imaginary part acts as attenuation. For $D = D_R + jD_I$, the effective phase velocity is

$$V_{eff} = V_o (1 - D_R) = \frac{\omega}{k_p} (1 - D_R), \quad (29)$$

and the attenuation due to scattering is

$$Q = \frac{1}{2|D_I|}. \quad (30)$$

H. Results

Applying the 2D and 3D formulas gives rise to several immediate results. First, in the low frequency limit, all solutions regardless of anisotropy or angle of incidence asymptotically approach the Backus (1962) velocity for a plane layered medium with low frequency wave propagation perpendicular to the bedding planes. This velocity, sometimes called the effective medium velocity (Brown and Seifert, 1997), is

$$V_{EM} = \left\langle \frac{1}{V^2} \right\rangle^{-1/2}, \quad (31)$$

for a constant density medium. It is interesting that the wave speed approaches the Backus velocity derived for plane layered media even when 2D or 3D variability is present. The 1D result (Shapiro et al., 1994) already showed that the Backus velocity was independent of angle of incidence, at least for small angles. The Backus velocity for wave propagation parallel to the bedding planes is known to be different (higher) than the perpendicular direction.

In the high frequency limit, the phase velocity approaches a constant value (if $\epsilon > 0$), but this constant value varies with several parameters. It appears that the amount of dispersion increases with decreasing length scale and ϵ , and increases with increasing angle of incidence for horizontally anisotropic variations in the medium. Both the 2D and 3D cases correctly reduce to the known 1D result in the limit of infinite anisotropy.

These effects can be seen in the following figures. For a 2D anisotropic medium with 10% variance in parameters and 6 degree minimum integration angle, the effects of anisotropy on phase velocity and attenuation as a function of frequency are shown in Figure 1. The effects of the angle of incidence on phase velocity and attenuation for 3:1 anisotropy are shown in Figure 2. The effect of changing the minimum angle of integration for the 2D solution given an isotropic medium is shown in Figure 3. For a 3D anisotropic medium with 10% variance in parameters and a 6 degree minimum integration angle, the effects of anisotropy on phase velocity and attenuation are shown in Figure 4. The effects of the angle of incidence on phase velocity and attenuation are shown in Figure 5 for a 3D medium with 10:10:1 anisotropy.

Figure1. Two-dimensional stochastic medium. (a) influence of anisotropy on phase velocity. (b) influence of anisotropy on attenuation. The one-dimensional result is equivalent to infinite anisotropy. Anisotropy is given as the ratio L_x to L_z . Parameters are normal incidence to anisotropy axis, 10% standard deviation in stiffness constant, and 6 degree minimum integration angle.

Figure 2. Two-dimensional anisotropic stochastic medium. (a) influence of angle of incidence on phase velocity. (b) influence of angle of incidence on attenuation. Parameters are 3 to 1 anisotropy, 10% standard deviation in stiffness constant, and 6 degree minimum integration angle.

Figure 3. Two-dimensional anisotropic stochastic medium. (a) influence of minimum integration angle on phase velocity. (b) influence of minimum integration angle on attenuation. Parameters are isotropic medium, 10% standard deviation in stiffness constant.

Figure 4. Three-dimensional stochastic medium. (a) influence of anisotropy on phase velocity. (b) influence of anisotropy on attenuation. The one-dimensional result is equivalent to infinite anisotropy. Anisotropy is given as the ratios of L_x and L_y to L_z . Parameters are normal incidence to anisotropy axis, 10% standard deviation in stiffness constant, and 6 degree minimum integration angle.

Figure 5. Three-dimensional anisotropic stochastic medium. (a) influence of angle of incidence on phase velocity. (b) influence of angle of incidence on attenuation. Parameters are 10 to 10 to 1 anisotropy, 10% standard deviation in stiffness constant, and 6 degree minimum integration angle.

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III. ANALYSIS OF VSP AND SONIC LOG DATA FROM THE GREATER GREEN RIVER BASIN: AMPLITUDE AND INTERVAL VELOCITY

A. Summary

While analyzing the Siberia Ridge vertical seismic profile (VSP) data to extract attenuation or dispersion information, we found that the seismic wave amplitude increases with depth in the reservoir region, while the VSP interval velocities from the checkshot data show occasional large differences from the sonic log velocities. Investigating these phenomena, we produced interval velocities, horizontal and vertical amplitudes, hodograms, and angle of incidence plots for the checkshot VSP and two offset VSPs. By using a detailed model of the bottom 2000 feet of the well, we demonstrate that the increase in amplitude is a direct result of the elastic properties of the Almond Formation, and that the discrepancy between checkshot and sonic velocities can be explained by the soft coal layers in the Almond Formation. Even though the coal makes up less than 10% of the formation, the large density and velocity contrasts between the coal and the tight shale and sandstone layers produce a significant effect on the observed waves.

These results demonstrate the importance of accounting for the elastic behavior of the medium when investigating wave attenuation, and how a few relatively thin coal layers need to be incorporated into a scaling model to properly predict wave speeds. By doing so, we can create an elastic model at the reservoir scale from the VSP data and relate it to the borehole logs.

B. Introduction

The relationship between checkshot VSP and sonic logs is an important scaling problem in geophysics. These two methods employ fairly different techniques to measure velocity information around the borehole, often yielding divergent results. Sonic logging data is of better resolution, but is vulnerable to errors arising from washout, fluid invasion, and other borehole effects. Checkshot VSP provides better information on the local formation as a whole, but quality is significantly worse than with sonic logs (although still better than surface seismic). Ideally, checkshot VSP and sonic logs could be integrated to provide a more balanced picture of subsurface velocity profiles. To help reconcile the differences, researchers have examined effects due to dispersion, scattering, anisotropy, and general issues of scale.

Dispersion, which may be the result of scattering or anelasticity, has been suggested as a major contributor to discrepancies between sonic (high frequency) and VSP (low frequency) measurements of velocity, although several other contributing factors are known (Stewart, et al., 1984). De et al. (1994) compared VSP and modern sonic data in several diverse wells and found that sonic log velocities tend to be slightly faster than VSP velocities, consistent with normal dispersion. They found, however, that this bias is best observed as a trend over a range of depths, and that point by point comparison of VSP and sonic velocities may lead to inconsistent interpretations.

Attenuation is mathematically related to dispersion, and strongly attenuating zones may contribute to apparent differences in velocity. The wave amplitude is affected, however, not just by attenuation but also by the local elastic constants of the medium. Ganley and Kanasevich (1980)

suggested that such effects could be corrected for in attenuation measurements. Dietrich and Bouchon (1985) extended this concept when they found that they were better able to extract Q values from VSP checkshot data after using synthetic VSP models to correct for scattering and elasticity.

The primary data for this study is a checkshot and two offset VSPs from the Siberia Ridge field in the Greater Green River Basin, Wyoming. This is a tight gas sand field with most production coming from the Almond Formation. The Almond consists of discontinuous tight sands and fairly continuous thin coals interbedded with shales and siltstones. The coal is thought to be the origin of the reservoir gas, but most long-term production is through the more permeable sand units. Porosity in the sands averages less than 10%, and permeabilities are generally less than one millidarcy in the sand, and microdarcies in the shale. The checkshot VSP is actually run with a 400-foot north offset, but given the reservoir depths are below 9000 feet, this is essentially a zero offset VSP.

C. Checkshot VSP

The raw checkshot VSP data Figure 6 does not show a great deal of structure, with the only significant reflections coming from the top and bottom of the Almond Formation. We will be analyzing the amplitude and interval velocity from the downgoing wave of this and two offset VSP shots at the same well. Because the waveform changes little with depth, the amplitude is measured simply as the magnitude of the first peak in the waveform. The time breaks for the interval velocity calculation are measured by automatic picking of the zero crossing before the first peak in the waveform. Admittedly, this is not the first break, but it is a quantity which can be more accurately determined while considering each trace in isolation.

The zero crossing picking method appears to be fairly robust, and provides consistent results with a cross-correlation technique, which also employs the full waveform. Stewart et al. (1984) discuss several methods of picking VSP arrivals, and conclude that cross-correlation is the best of several automated methods. We chose to use the zero crossing technique because it is simple to interpolate a zero crossing time with greater precision than with the sampling rate, and because the cross-correlation method is more affected by upgoing waves. The zero crossing is affected by phase changes in the observed wave, and so is affected by reflections. It relies on a point relatively close to the leading wavefront, however, and so is only severely affected for receiver locations just above reflectors. Since we will be comparing the VSP arrival times with modeled data, it is more important that a consistent method be used than that the arrival times be strictly correct.

1. Sonic Log + Interval Velocity

The sonic log and the interval velocity derived from the zero-offset VSP are shown in Figure 7. The two curves can be seen to match fairly well in most regions, but there are two zones where large discrepancies between the sonic velocity and VSP velocity occur. One of these is at the base of the Lewis shale. Here, the sonic log indicates velocities of 18,000 ft/s, unusually high. Since there are no obvious reflections in this area on the seismic data and other logs do not indicate a change in lithology, we conclude that this is simply bad data in the sonic log. The other region of discrepancy is in the middle of the producing Almond Formation. Here, more care was taken to ensure the accuracy of the well logs, so the data are probably good. We will be able to

explain this discrepancy through modeling, but first we must fix the hole left in the sonic logs by the bad data.

If the regions of apparently bad logs are disregarded, we can find a strong correlation between resistivity and velocity. Disregarding the extremes of both velocity and resistivity, a correlation of $V_p = 8980 + 4050 \log_{10}(\text{AHT10})$ results (Figure 8). Here, V_p is in ft/s units and AHT10 is in units of ohm-m. The expected error in V_p from using this correlation is about 800 ft/s, or 6% of a typical velocity. We use this correlation with the resistivity data to patch the sections of sonic log that have bad information, roughly 10160 to 10340 ft tvd. The resulting velocities may not be exact, but they are probably close enough so that no major spurious reflections will be predicted by the model.

2. *Model*

We constructed a model for the VSP based on the available log data in this well, from roughly 9000 feet to 10800 feet tvd. The model consists of a stack of planar layers, with elastic constants derived from a Backus average (Backus, 1962) of the well logs. In formations higher than the Almond, we have the block averaging create layers 10 feet thick. In the Almond Formation, the blocked layers are two feet thick, to better capture the fine variability of the formation. Receiver stations are located in the layered model at identical depths to the actual VSP geophone true vertical depths. An initial use of this model to simulate the low frequency VSP response resulted in a fair match to the observed interval velocities, but no improvement in the middle Almond discrepancy noted above.

We were able to have the model match the experimental profile by applying one more correction to the Almond Formation well logs. This formation is marked by thin coal beds, many of which are apparently underresolved by the well logs. If the known coal beds have their properties corrected to $V_p = 9000$ ft/s and density of 1.4 g/cc before applying the Backus averaging, a great improvement in the modeled interval velocity results. (These are typical coal properties found in the literature, e.g. Yu et al. (1993), Ramos and Davis (1997). The density log in particular appears to underresolve the thin coals beds, and measures higher than expected densities.) We can now basically match the magnitude and thickness of the low velocity region in the Main Almond interval velocity profile, as demonstrated in Figure 9.

3. *Amplitudes*

We now examine the amplitude of the direct arrival. Applying a minimal amplitude correction for spherical divergence only, we find that the amplitude of the direct arrival actually has an increasing trend with depth in the logged Lewis and Almond Formations (Figure 10). This trend of increasing amplitude with depth is a strictly elastic phenomenon, but must be accounted for before any measure of attenuation can be made. This includes the spectral ratio method, as well as the method of Hauge (1981).

Extracting amplitudes from the simulated VSP, we find a similar structure with an even steeper increase of amplitude with depth than is seen in the experiment. It seems likely that

this is a result of two causes. First is the lack of attenuation in the model: up to this point we have presumed that each layer is by itself non-attenuating. A possible second cause is that the spreading loss may be slightly greater than spherical. In any case, we can attempt to correct the amplitude depth slope by including attenuation in the model. Figure 11 shows the amplitudes assuming non-attenuating layers ($Q = \infty$), and models where every layer has a natural Q of either 60 or 30. As the attenuation is increased (Q is decreased), the slope of amplitude versus depth drops.

The case of $Q = 30$ from Figure 11 actually matches the experimental amplitudes quite well, as seen in Figure 12. Here, we have normalized the amplitudes to approximately match at a true depth of 9000 feet. Below this point the modeled and experimental amplitudes follow each other fairly closely until the lower part of the Almond Formation is reached. In this zone, we can still observe a similarity of structure, but the magnitude has drifted. This is in large part attributable to the fact that we have no well log information below this point. Because the observed amplitude of the direct wave is influenced somewhat by reflections from slightly deeper boundaries, we cannot absolutely predict the amplitude of the wave at the bottom of the well.

D. Offset VSPs

In addition to the zero-offset VSP, two offset VSP data sets were recorded in the same well. Figures 13 and 14 show the horizontal component of the received wave, and show several upgoing and downgoing converted SV waves. Both offsets are about 5300 feet, but one is northeast of the well head, and one is southeast. The offset VSP data are more difficult to model because of the uncertainty in path length, the changing angle of incidence (due to both the increasing well depth and the refraction of the wave), and the potential for lateral variability in medium properties. Nevertheless, we do model the offset VSP data, assuming an azimuthally isotropic laterally invariant medium. Because we do not have well log or lithology information all the way from the surface to the reservoir, we only model the formations at a 9000-foot depth and below. The presumed angle of incidence of the wave at 9000 feet is 45 degrees, similar to what is observed in the data.

1. Offset Hodo

A sample hodogram from the northeast offset VSP is plotted in Figure 15, together with a corresponding hodogram from the full waveform model. The first primarily vertical motion of the incident P wave is the dominant feature, while a slightly smaller amplitude converted SV reflected wave appears as a primarily horizontal movement. This hodogram covers the range of 1.0 to 1.2 seconds and is recorded at 10400 feet measured depth, just above the top of the Almond Formation. The reflected SV wave is converted from the top of the Almond.

Since the incident P wave is so obvious on the hodogram, we can use the hodogram to estimate the local angle of incidence of the P wave. This will vary with depth, both because of the changing geometric relationship between the source and receiver, and also because of the refraction of the downgoing wave as it passes through media of changing P wave velocity. In Figure 16 we show both the geometric angle of incidence (computed based on a straight line from source location to receiver location) and the hodogram angle of incidence (based simply on the maximum deflection). It is not surprising to see that the hodogram angle of incidence is more

maximum deflection). It is not surprising to see that the hodogram angle of incidence is more horizontal than the geometric angle of incidence since refraction through media where wave velocity increases with depth suggests such behavior. Nevertheless, the two curves follow the same trend, and we can see that angles of incidence at the reservoir depths are only 30 or so degrees from vertical. The well deviation causes a kink in the angle of incidence curve, so that for the southeast offset, the angle of incidence actually begins to decrease with increasing depth.

2. *Offset Interval Velocities*

Meaningful interval velocities from offset VSP can only be computed if one has a good idea of the angle of incidence of the wave. Especially for a case such as this, where the well is deviated, the computed velocity can be very sensitive to the azimuth and incidence angles. We compute the interval velocities based on two methods. First, a crude method based on an assumption of straight rays between source and receiver, and secondly based on the angle of incidence derived from the hodogram plots. Presuming that there are no severe lateral variations, we can still determine the azimuth angle by the vertical plane containing both source and receiver locations.

Interval velocities derived from a straight ray assumption are shown in Figure 17. For this plot, the angle of incidence is assumed to be given by the smooth lines in Figure 16. Because the straight ray assumption results in a more vertical wave than is actually seen, the derived interval velocities are significantly higher. Using this method one finds velocities of 15,000 ft/s at moderate depths and up to 20,000 ft/s in the deeper Lewis shale.

Interval velocities derived from the hodogram angle of incidence are shown in Figure 18. These velocities are more consistent with the sonic log and the zero offset interval velocities. Comparing the offset interval velocities with the zero offset interval velocities, we can see that they are fairly consistent. There is certainly some noise in the magnitude, but the structure is recognizably the same. In particular, we can recognize the low velocity zone at the base of the Lewis shale, which is more consistent with the resistivity-patched sonic log in the offset interval velocities than in the vertical interval velocities. This may be an indicator of TIV anisotropy in the lower velocity shale, since the vertically derived interval velocity is lower than the two offset derived interval velocities. All three interval velocity curves show a peak in the Upper Almond, a velocity low in the Main Almond, and a peak again near the bottom of the well.

3. *Offset Model*

Since it appears that we can obtain a reasonable interval velocity profile from the offset VSP data, we should examine how this is consistent with the plane layer full waveform model. This model covers only the region below 9000 feet (tvd) and so does not extend all the way to the surface. Nevertheless, we can simulate the effect of an offset VSP by specifying that a plane wave is incident to the layered model at a 45 degree angle, approximately equal to the angle of incidence derived from the offset hodogram at a 9000-foot depth. Of course, since the velocity changes in every 10-foot thick layer, refraction immediately changes the observed angles. By computing the angle of incidence of the wave from the hodogram at each receiver station, we can observe how the refraction affects the wave as it travels through the formations, as in Figure 19. In

fact, the behavior of the modeled local angle of the wave is very consistent with the observed profile of angles. As the wave travels deeper into the well, one can observe a drift where the modeled angle tends toward more horizontal than the experiment. This is due to the changing geometric relationship between source and receiver. The modeled wave changes only due to refraction, while in the experiment there is an additional trend towards a vertical wave because of the increasing depth to offset ratio.

We can also compute interval velocities from the plane layer model by using the model hodogram angle to correct the arrival picks, as we did for the experimental offsets. Using this method we derive interval velocities for the modeled offset VSP which are fairly consistent with the experimental offset VSP interval velocities, and very consistent with the modeled vertical interval velocities (Figure 20). This result validates the technique of using the hodogram angle to compute interval velocities from offset VSP.

It is difficult to match quantitative amplitude information from the offset VSP experiment to the model because of uncertainty in the path length and the possibility of lateral variability in the media. Nevertheless, we can observe that the amplitude profiles of both offset VSP shots match each other very well (Figure 21), and both match fairly well to the shape of the model offset amplitudes (Figure 22).

E. Conclusions

In this chapter, we have demonstrated that simple plane models based on sonic logs can successfully capture the behavior, including hodogram angle, amplitude, and interval velocity of checkshot and offset VSP data. The anomalous increase in amplitude versus depth of the checkshot VSP is a natural result of the elastic properties of the medium. Using an inelastic model, we showed that a Q of 30 is consistent with the observed amplitude behavior. In examining the offset VSP data, we have demonstrated that hodograms can be used to compute useful and accurate interval velocities. Elastic and scattering effects can combine to yield apparent interval velocities which are not indicative of the underlying structure, but these effects can be captured and reproduced by models. This will in principle allow a model structure true to the underlying lithology to be fit to the observed data.

Figure 6. Zero-offset VSP waveforms, vertical component

Figure 7. VSP interval velocities for the zero-offset experiment and sonic log velocities, both corrected to true vertical depth. Note the bad sonic data from around 10,200 feet to 10,350 feet depth.

Figure 8. Correlation between sonic velocity data and resistivity.

Figure 9. VSP interval velocities for the zero offset experiment, corrected sonic log velocities, and interval velocities from a simulated VSP based on a plane layered model.

Figure 10. Amplitude data from the zero-offset VSP experiment. The green curve is uncorrected and the red curve corrected for geometrical spreading losses in amplitude.

Figure 11. Amplitude data from the simulated VSP using three values for attenuation.

Figure 12. Comparison between simulated VSP amplitudes ($Q=30$) and experimental VSP amplitudes for the zero-offset experiment.

Figure 13. Northeast offset VSP waveforms, horizontal component. Most of the visible reflections are now converted S-waves.

Figure 14. Southeast offset VSP waveforms, horizontal component. Again, most of the reflected waves are converted S-waves.

Figure 15. Hodograms from 10400 feet measured depth from the northeast offset VSP and a model offset VSP.

Figure 16. Angle of incidence computed from hodograms of the offset VSP (black - northeast offset, red - southeast offset) and the geometric angle from source to receiver (green - northeast offset, blue - southeast offset).

Figure 17. Interval velocities for the offset VSP profiles based on geometric angle of incidence. (Black - northeast offset, red - southeast offset).

Figure 18. Interval velocities for all three experimental VSP profiles based on hodogram angle of incidence. (Black - northeast offset, red - southeast offset, green - zero offset).

Figure 19. Angle of incidence computed from hodograms for the offset VSP (black - northeast offset, red - southeast offset) and the model offset VSP (green).

Figure 20. Interval velocities over the reservoir depths computed from the offset VSP (black - northeast offset, red - southeast offset) and the model offset VSP (green).

Figure 21. Amplitudes of the experimental offset VSP (black - northeast offset, red - southeast offset).

Figure 22. Amplitudes over the reservoir depths of the experimental offset VSP (black - northeast offset, red - southeast offset) and the model offset VSP (blue).

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IV. A MODEL TO RELATE P-WAVE ATTENUATION TO FLUID FLOW IN FRACTURED ROCKS

A. Summary

An important issue in reservoir geophysics is to determine whether attenuation/dispersion measurements can be used to predict fluid filled fractures in tight gas sand reservoirs. To address this issue, we assume that fractures in a poroelastic medium can be represented by the permeability, squirt flow and stiffness constants tensors. We also assume that the principal axis of these tensors is aligned with the horizontal x-axis of symmetry. We construct models based on reservoir parameters from the Almond Formation of the Siberia Ridge field, Wyoming. We predict attenuation responses by varying the permeability and squirt flow lengths in the plane of the cracks. We also vary the azimuthal and incident angles to predict the appropriate frequency range for detecting fractures. We analyze the sensitivity of the squirt flow length to attenuation and predict the contribution of fracture permeability in low permeability tight gas sands. The modeling results provide insight for detecting fluid filled fractures using acoustic/or seismic measurements in tight gas sand reservoir environments.

We also analyze the feasibility of detecting flow units associated with fluid filled cracks of a shale-sand-coal layer sequence of the Almond Formation with acoustic/seismic methods.

The analysis provides results of a modeling approach based on borehole data to predict whether flow units can be detected at acoustic and seismic scales. The flow units were constructed using core and borehole data. The model based on these two scales predicts attenuation responses at the borehole and crosswell scales. The model approach can be applied to other reservoirs with different petrophysical characteristics and reservoir parameters. In this application, the permeability and porosity were derived from NMR well logs which were calibrated with core data.

B. Introduction

Detection of fractures using seismic and acoustic measurement techniques has attracted considerable attention in the gas and oil industry. In particular, the detection and prediction of high fracture density in tight gas sands using elastic wave propagation has been addressed by Lynn et al. (1999). In this work the fractures were detected using P-wave reflection seismic data with support of shear wave reflections and VSP data. The main finding was the existence of oriented fracture systems that induce azimuthal anisotropy in the rock matrix that otherwise could be azimuthal isotropy.

In addition, natural fractures and cracks in tight gas sand reservoirs can affect the velocity and attenuation of acoustic and seismic waves. The importance of cracks as fluid-flow pathways in reservoirs has long been recognized. For example, Tichelaar and Hatchell (1997) used four component flexure waves to determinate anisotropy in a carbonate reservoir in northern Oman. The results showed that one of the anisotropy orientations is parallel to the strike of open fractures and to preferential flow directions in the reservoir. In crosswell applications and single well surveys, Majer et al. (1997) successfully detected a fracture zone and confirmed previous hydrological data

that indicated a preferred pathway. In 3D seismic applications, Perez et al. (1999) showed that the P-wave AVO response may depend on the azimuth in the presence of fracture-induced azimuthal anisotropy. They concluded that azimuthal P-wave AVO analysis using surface seismic data can aid in detecting fracture orientation. A recent modeling study by MacBeth (1999) addresses the applicability of the azimuthal variation of P-wave signatures with fluid flow. He concluded that the effect of crack-related attenuation is large, especially when considering that velocity anisotropy induced in the models is at most 5%. This study suggests that it is possible to detect fluid filled fractures using surface seismic measurements. However, to interpret the seismic signatures it will be necessary to simulate full waveforms based on realistic fracture and crack models that can be incorporated in poroelastic heterogeneous earth models. This will provide a way of quantifying the effect of scattering attenuation versus the effect of intrinsic attenuation associated with fluid flow in fractures and the reservoir matrix. In this work we have two major goals: (1) apply the Biot and Squirt flow (BISQ) model to relate the P-wave attenuation to fluid flow in cracked rocks, and (2) determine whether it is possible to detect fluid-filled fractures in tight gas sands using acoustic/seismic measurement techniques. To address these issues we use core data and well logs from the Siberia Ridge Field, Wyoming.

C. Geology and Petrophysics

The Siberia Ridge Field is a stratigraphically trapped gas accumulation on the north flank of the Wamsutter Arch in the Greater Green River Basin, Wyoming. Gas production is from the Almond and overlying Lewis reservoirs. The Almond Formation is alternating sandstones, shales, and coals of Late Cretaceous age. Within the field area, the Almond can be stratigraphically divided into an Upper Almond marine sequence (10,575 to 10,650 feet) and a brackish to non-marine Main Almond sequence (below 10,650 feet). The Main Almond is approximately 450 feet thick and the Upper Almond is 30 to 50 feet thick. Coals occur only in the Main Almond and are the source of the gas. Most of the gas production, however, is from the Upper Almond (assuming horizontal bedding).

The Upper Almond is a transgressive marine sequence, consisting of shore face to foreshore deposits. The sequence is predominately a laterally continuous barrier bar sandstone (the Almond Bar) with a classic coarsening upward profile. It is bounded by shales. The barrier bar sandstone is 50 feet thick on the log and has a true vertical thickness of approximately 30 feet. Borehole fracture data indicate that fractures in the Siberia Ridge Field are systematic regional extension fractures. Mean fracture aperture from FMI data is about 0.3 mm.

Siberia Ridge fracture density ranges from 5.5 fractures per foot. Fracture density markedly increases with depth in the Siberia Ridge wells. This increase coincides with a change in lithology from mostly marine sands and marine shale to a more heterogeneous mixture of sands, muds and coals of the coastal plain. The small porosity and matrix permeability suggest that the source of water is from high permeability fractures. Natural features, as determined by FMI and anisotropic data, distinctly increase in the lower Main Almond and Ericsson sands. The fracture permeability may explain the problematic water production in the wells at the Siberia Ridge field. A petrophysical analysis was made of the cored interval in the well (10,603 to 10,624 feet). Only this part of the Upper Almond was analyzed because this interval is the most homogeneous, shale-free part of the barrier bar, and core analyses were available for this interval. Routine and restored-state

measurements were made on 24 samples, taken at one-foot intervals. This interval has the petrophysical properties given in Table 1 (see the histograms given in Figures 23a-23f):

Table 1. Petrophysical Data

Petrophysical Property	Range of Values	Average Value
P velocity (ft/s)	14,100 to 15,000	14,709
Bulk density (g/cc)	2.44 to 2.53	2.48
Core permeability* (md)	0.0 to 0.12	0.004
Core porosity* (dec)	0.035 to 0.10	0.08
Log porosity (dec)	0.07 to 0.12	0.09
Shale volume (dec)	0.04 to 0.36	0.19
*Made at overburden pressure.		

The selected interval is a low porosity, very low permeability shaly sandstone. Shale laminations are present throughout and it appears that shale is also dispersed in the sands.

Seven cross plots (see Figures 24a-24e) were made to investigate the relationships between compressional velocity and log porosity (PHIT), core porosity at overburden pressure (CPOR_INS), core permeability at overburden pressure (CKINF_IN), bulk density (RHOB), and volume of shale (VSH). These properties were also graphed as Z values on the cross plots as colored data points. Black points signify no Z value; colors signify varying ranges of the Z value (see the scale in the lower left of the cross plot).

Reduced major axis regression was calculated for four of the plots (each of the different y axis variables). Correlation coefficients were low (0.42 to 0.13). However, in some instances, elimination of the shalier intervals (see the Z values on the Bulk Density plot) will improve the correlation.

As would be expected, velocity increases as log porosity decreases. This same relationship can be seen in the core porosity plot, where if the two smallest porosity values are deleted, the slope of the line changes considerably. There is no relationship between velocity and core permeability, but this is because the permeabilities are so very low (0.004 and very similar (0.0 to 0.12 md). The correlation between velocity and bulk density is low but can be improved by eliminating the points with greater than twenty percent shale. Finally, the shale volume-velocity plot has velocity increasing as shale volume increases. This is the opposite of what would be expected. There is no obvious explanation.

The key to interpreting petrophysical relationships, or the lack thereof, in this sandstone is probably the petrographic and diagenetic history of the rock. The low average porosity

(0.08% core and 0.09% log) and permeability (0.09 md) suggest a great deal of compaction and occlusion of porosity from cementation and/or the presence of clay minerals (0.19 average shale volume). The shale is obscuring many of the petrophysical relationships and needs to be accounted for to improve the regression analysis.

D. Method

To simulate a fractured zone containing fluids we use a poroelastic model characterized by the tensor permeability and the squirt flow tensor. The model is based on the work given by Parra (1997) and Dvorkin and Nur (1993). We simulate the system of cracks by assuming that the horizontal x-axis is the axis of symmetry. To relate attenuation and dispersion with the presence of cracks embedded in tight sands, we define the plane of the cracks (yz) as a plane of large permeability and the direction perpendicular to the cracks (x) as a low permeability tight sand. In addition, the model assumes that the principal axis of the stiffness constant tensor ($C_{11}, C_{66}, C_{13}, C_{44}, C_{33}$) is aligned with the permeability tensor (k_x, k_z) and the squirt flow tensor. To simulate the crack system we consider two scales: (1) squirt flow length ($R_z = R_y$) of the order of centimeters to represent cracks, and (2) squirt flow length (R_x) less than or equal to 1 mm to represent grain scales. These scales add some degree of anisotropy to simulations that include directional attenuation. The concept of using two squirt flow lengths to simulate attenuation associated with fluid transport properties in a porous medium has been addressed by Akbar et al. 1994, who considered wave-induced squirt fluid flow at two scales: (1) local microscopic flow at the smallest scale of saturation heterogeneity, and (2) macroscopic flow at a larger scale of fluid-saturated and dry patches. They observed two peaks of acoustic wave attenuation—one at low frequency (caused by global squirt flow) and another at higher frequency (caused by local flow). In the model study described below, the global squirt flow (in the yz-plane characterized by the stiffness constants C_{33}, C_{44} and C_{13}) represents fluid flow within the fracture plane. We believe that the representation of a system of cracks based on global squirt flow is practical since we expect a nonuniform fluid distribution within a fracture plane. Since the stiffness constant in the yz-plane can be related to crack density, the variation of the fluid dynamic pressure due to the crack-related flow can simulate the effect of fluid filled fractures on the attenuation.

E. Modeling Results

1. Analysis

A model was constructed using core and well log data from the Siberia Ridge field, Wyoming. The core data provided the grain density, permeability and porosity. Dipole sonic logs provided the velocities. The fracture orientation and apertures were provided by the FMI data. The squirt flow lengths were estimated from thin section analysis. We calculated dispersion and attenuation curves to analyze the applicability of acoustic/seismic techniques to detect the presence of fractures in tight gas sand environments. Specifically, we wanted to evaluate whether it is possible to detect fluid-filled cracks using acoustic/seismic measurement techniques. Since the attenuation and dispersion of elastic waves are sensitive to the presence of fluids in cracks (Parra, 2000), we analyzed these effects by assuming a plane wave traveling at different azimuths relative to a system of vertical cracks in tight sands. The model parameters were based on the data given in Table 1.

Figure 25a shows attenuation maximums at low and high frequencies for the squirt flow length of 0.2 mm in the tight sands and a system of cracks having a global squirt flow length of 5 cm. Attenuation peaks are observed at 1000 Hz (in the frequency range of 10 to 1500 Hz) at azimuths of 0 (normal to the system of cracks) and 30 degrees. These observations suggest that to squeeze fluid in and out of the cracks will require acoustic or seismic energy in the range of 10-1000 Hz (e.g., crosswell, reverse VSP, and long space logging).

In Figure 25a, attenuation maximums are also observed at higher frequencies at azimuths of 60 and 90 degrees (parallel to the fracture plane). For these azimuths, elastic waves excite fluid motion in the porous matrix, and attenuation is controlled by fluid flow in tight sands (or local squirt flow).

Figure 25b illustrates attenuation curves for the model parameters given in Table 1. In this example we increase the global squirt flow length to 7 cm, and the attenuation peaks shift to the low frequency range. In this case, the attenuation peaks computed at azimuths of 0 and 30 degrees are observed at 600 Hz. Since the local squirt flow in the tight sands was kept fixed, the positions of the attenuation peaks in the higher frequency range remain the same as those in Figure 24 at azimuths of 60 and 90 degrees. It is clear that, as the global squirt flow length is increased, the attenuation peak will shift to the lower frequencies. This can be justified, because to move fluid in and out of large, thin cracks requires wavelengths comparable to those associated with crack lengths. On the other hand, if we keep increasing the global squirt flow length, the local cracks in the zy plane that cause squirt flow phenomena disappear, and the flow becomes 1D, as given by the Biot model (Dvorkin and Nur, 1993). So far, squirt flow lengths between 5 and 7 cm produce realistic attenuation in the range of acoustic/seismic measurements. In fact, the attenuation peaks correspond to quality factors of about 40. These results show that attenuation can be strongly affected by wave-induced squirt flow in the plane of the fracture. We also observe in Figure 25 that attenuation due to the tight sands is associated with a Q of 80 at high frequencies. That is, fluid flow in tight sands is not causing attenuations as strong as those in environments with lower velocity and high porosity (Parra, 1999; and Hackert et al., 1999). In fact, in cracked formations with porosities on the order of 20 percent and permeability on the order of 10 md, we have observed quality factors in the range of 20-40 (Hackert et al., 1999). In this environment, the results predict that as long as there is fluid flow in the rock matrix towards the cracks, the fluid motion will attenuate the acoustic/seismic waves. In the event that there is no crack induced fluid flow, we cannot expect high attenuation for waves traveling perpendicular to the fracture system. In this case the Biot mechanism will control any fluid interaction between the pore fluid and the rock matrix in the direction parallel to the direction of P-wave propagation. Since the permeability in the tight sands is about 0.01 md, the Biot flow will be practically zero in the direction normal to the fracture plane.

2. *The seismic coal-shale-sand layer sequence response of Siberia Ridge*

To assess the applicability of acoustic/seismic waves in fractured tight sands, it is important to determine the scattering attenuation associated with a layer sequence of sands, shales and coals. The model includes poroelastic properties obtained from well logs and core information. The objective of this analysis is to determine whether flow units can be detected and

delineated with acoustic and seismic measurements in tight sand formations. Specifically, it provides the attenuation associated with elastic scattering effects such as the layering and intrinsic effects due to flow units. The model responses are calculated at different azimuths and angles of incidence as well as a broadband frequency range to simulate vertical fractures induced anisotropy.

The medium is formed by sands having the properties given in Table 1, and shales are assumed to be isotropic without fractures. Also, the model is assumed to have isotropic unfractured coal beds. The lithology and rock physical properties used for the modeling are given in Table 2.

Table 2. Rock Physical Properties for Layer Model

Lithology	Vp	porosity	perm
coal	2.7 km/s	2%	1 microdarcy
shale	3.9 km/s	1%	0.1 microdarcy
sand	4.2 km/s 4.4 km/s	8.4%	10 microdarcy/50 millidarcy

The modeling method to accomplish the objectives is based on the use of elastic and poroelastic plane wave computer codes. The programs are used with a stack of 114 layers representing the Almond Formation. These layers have a true vertical thickness of 358 feet. Q values are determined by running the plane wave programs and obtaining the frequency dependent amplitude on the bottom side of the layer stack. This amplitude is converted to a transmission coefficient, which is related to Q through the frequency and distance traveled. For simplicity, the distance traveled is the vertical thickness, divided by the cosine of the incident angle. We have observed that this approach is fine, except that for angles closer to horizontal, refraction can significantly change the path length. Measured attenuation for the 75 degree incidence data (and to a lesser extent, the 45 degree data) is probably too low because the path length is overestimated. We don't think we can really correct this too much because the critical angle for the coal layers is 45 degrees. We may be able to apply a correction for the sand layers.

In addition, to simulate interwell seismic measurements we consider incidence angles that are measured from vertical so that 75 degree incidence is near horizontal. Azimuth is measured relative to the fracture system, so 0 degree azimuth is normal to the fractures, while 90 degree azimuth is parallel to the fractures. Remember that normal incidence to the layers is also parallel to the vertical fractures, so that the largest effect from the fractures will come at 0 degree azimuth and near horizontal angles.

In the modeling method we also include the stochastic representation of the layer sequence. For example, Figure 26 shows the Q^{-1} derived from the normal incidence elastic model (including coal layers), and a prediction of Q^{-1} based on stochastic medium theory. Agreement is not so good between the deterministic (solid line) and stochastic response (dash lines). To see whether this difference is due to the coal, we replaced all coal layers with shale or sand by merging with the layer above (see Figure 27). This new no-coal model has an elastic Q^{-1} in good agreement with stochastic medium theory. Note too, that when coals are present, the attenuation is higher by an roughly an order of magnitude for both the elastic and stochastic models. This means

that the few coal layers in the full model cause the medium statistics to no longer be described by a Gaussian probability distribution. Thus, the stochastic model underpredicts the attenuation when coals are present. In Figures 26 and 27, the attenuation is predicted in the frequency range of 0.01-10 kHz, to evaluate the applicability of acoustic/seismic techniques for predicting flow units. These results demonstrate that the presence of the coal beds are the main cause of high attenuation in the Almond Formation.

In Figure 28, we present the elastic and poroelastic attenuation response for the same coal-sand-shale layer model used in Figure 26. The elastic attenuation is represented by a solid line and the poroelastic attenuation is represented by dashed lines. The figure shows that the poroelastic attenuation is about the same as the elastic attenuation for seismic and crosswell seismic frequencies. On the other hand, the poroelastic attenuation is greater than the elastic attenuation for frequencies in the range of sonic logs and long space logging (i.e., for frequencies greater than 2000 Hz). Thus, real attenuation effects can be seen at high frequencies.

In the next series of examples we analyze the effect of the angle of incidence and azimuths on the attenuation response. We analyze angles of incidence of 45° and 75° for azimuths of 0° and 90°. Figures 29 and 30 show the attenuation response of the same layer model used in the previous example in the presence of a plane wave incident at 45° at azimuths of 0° and 90°, respectively. In both cases the elastic (solid line) and poroelastic (dashed lines) responses are presented. In the direction normal to the fracture system, the poroelastic response is greater than the elastic response in the frequency range of 200 to 700 Hz.

In direction of the fracture system the elastic and poroelastic attenuation responses are similar. In addition, there appears to be a greater elastic amplitude response in the direction parallel to the fracture system rather than in the direction perpendicular to the fracture system. In fact, in Figures 31 and 32, the angle of incidence was increased to 75° to show that the elastic attenuation is greater in the direction of the fracture system than in the direction normal to the fractures. This difference is caused by the induced anisotropy associated with the fractured tight sands. This effect can be observed between 150-1000 Hz. In the same frequency range, frequency the poroelastic attenuation is greater than the elastic attenuation for waves traveling perpendicular to the fracture system. That is, fluid movement can occur when waves are traveling perpendicular to the fractures. This suggests that losses in the direction of the fractures is caused mainly by the crack conditions of the rock and not by the presence of fluids.

F. Conclusions

The modeling results indicate that cracks in tight gas sands may be detected using seismic methods in the range of 10 to 1000 Hz at azimuths between 15-30 degrees at angles of incidence near 90 degrees. Also, the results suggest that attenuation is sensitive to fluid flow in the tight sands above 1000 Hz at azimuths greater than 60 degrees. These results indicate that any attempt to map fractures in low permeability and low porosity environments will require multiple frequency measurements in the range of sonic logs and long space logging or high frequency VSP measurements. To separate intrinsic effects from scattering effects associated with the shale-sand-coal layer sequence in the Siberia Ridge field will require measurements at a minimum of two frequencies (e.g., sonic and VSP data).

Well Name: SIB 5-2
 Depth: 10603 to 10624 by 0.50 feet
 Constraints: None
 Total values: 43
 Within range: 43
 Geometric mean: 14707.848
 Standard deviation: 209.105

Skewness: -0.707
 Variance: 43724.918
 Kurtosis: 0.191

Arithmetic mean: 14709.338
 Median: 14728.821
 Mode: 14650.000

Figure 23a. Histogram of P-wave velocity (Vp) based on the core interval between 10,603 and 10,625 ft. in well SIB 5-2.

Well Name: SIB 5-2
Depth: 10603 to 10624 by 0.50 feet
Constraints: None

Total values: 43
Within range: 43
Geometric mean: 2.479
Standard deviation: 0.020

Skewness: 0.401
Variance: 0.000
Kurtosis: -0.035

Arithmetic mean: 2.479
Median: 2.476
Mode: 2.475

Figure 23b. Histogram of bulk density (RHOB) based on the core interval between 10,603 and 10,625 ft. in well SIB 5-2.

Well Name: SIB 5-2
 Depth: 10603 to 10624 by 0.50 feet
 Constraints: None
 Total values: 21
 Within range: 21
 Geometric mean: undefined
 Standard deviation: 0.017

Skewness: -1.501
 Variance: 0.000
 Kurtosis: 1.599

Arithmetic mean: 0.078
 Median: 0.084
 Mode: 0.085

Figure 23c. Histogram of core porosity (CPOR) based on the core interval between 10,603 and 10,625 ft. in well SIB 5-2.

Well Name: SIB 5-2
 Depth: 10603 to 10624 by 0.50 feet
 Constraints: None
 Total values: 43
 Within range: 43
 Geometric mean: undefined
 Standard deviation: 0.013

Skewness: -0.177
 Variance: 0.000
 Kurtosis: -0.479

Arithmetic mean: 0.093
 Median: 0.096
 Mode: 0.105

Figure 23d. Histogram of log core porosity (PHIT) based on the core interval between 10,603 and 10,625 ft. in well SIB 5-2.

Well Name: SIB 5-2

Depth: 10603 to 10624 by 0.50 feet

Constraints: None

Total values: 43

Within range: 43

Geometric mean: undefined

Standard deviation: 0.078

Skewness: 0.171

Variance: 0.006

Kurtosis: -0.724

Arithmetic mean: 0.191

Median: 0.189

Mode: 0.210

Figure 23e. Histogram of volume of shale (VSH) based on the core interval between 10,603 and 10,625 ft. in well SIB 5-2.

Well Name: SIB 5-2
 Depth: 10603 to 10624 by 0.50 feet
 Constraints: None
 Total values: 21
 Within range: 21
 Geometric mean: undefined
 Standard deviation: 0.004

Skewness: 0.881
 Variance: 0.000
 Kurtosis: -0.395

Arithmetic mean: 0.004
 Median: 0.003
 Mode: 0.000

Figure 23f. Histogram of core permeability (CKINF_IN) based on the core interval between 10,603 and 10,625 ft. in well SIB 5-2.

Well Name: SIB 5-2 UWI: 43037239560000
 Depth: 10603 to 10624 by 0.50 feet
 Constraints: None
 21 out of 43 points plotted.

Figure 24a. Cross plot between P-wave velocity and log porosity logs (PHIT)

Well Name: SIB 5-2 UWI: 49037239560000

Depth: 10603 to 10624 by 0.50 feet

Constraints: None

21 out of 43 points plotted.

Figure 24b. Cross plot between P-wave velocity and porosity logs (CPOR)

Well Name: SIB 6-2 UW: 49037239560000
 Depth: 10603 to 10624 by 0.50 feet
 Constraints: None

21 out of 43 points plotted.

Well Name: SIB 5-2 UWI: 49037239560000

Depth: 10603 to 10624 by 0.50 feet

Constraints: None

21 out of 43 points plotted.

Figure 24d. Cross plot between P-wave velocity and volume of shale logs (VSH)

Well Name: SIB 5-2 UWI: 49037239560000

Depth: 10603 to 10624 by 0.50 feet

Constraints: None

21 out of 43 points plotted.

Figure 24e. Cross plot between P-wave velocity and permeability logs (CKINF)

Figure 25a. The effect of frequency and azimuths for a global squirt flow length=5 cm (representing fluid flow in cracks) and a local squirt flow length = 0.2 mm (representing fluid flow in tight sands).

Figure 25b. The effect of frequency and azimuths for a global squirt flow length = 7 cm (representing fluid flow in cracks) and a local squirt flow length = 0.2 mm (representing fluid flow in tight sands).

Figure 26. Normal incidence. Solid line is elastic, dotted line is stochastic medium prediction. This is a full model with coal layers. The coals cause a large increase in attenuation, but are too sparse and too different to have a good match from stochastic theory.

Figure 27. Normal incidence. Solid line is elastic, dotted line is stochastic medium prediction. This is a modified model without coal layers. This model (using sand and shale only) shows a good match with a stochastic medium theory result.

Figure 28. Normal incidence. Solid line is elastic only, dotted line is poroelastic. Vertical incidence is parallel to fractures, so only real effect is at high frequencies.

Figure 29. 45 degree incidence, 0 degree azimuth. Solid line is elastic only, dotted line is poroelastic.

Figure 30. 45 degree incidence, 90 degree azimuth. Solid line is elastic only, dotted line is poroelastic.

Figure 31. 75 degree incidence, 0 degree azimuth. Solid line is elastic only, dotted line is poroelastic.

Figure 32. 75 degree incidence, 90 degree azimuth. Solid line is elastic only, dotted line is poroelastic.

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V. SIBERIA RIDGE DATA

We have received the following data on Siberia Ridge well 5-2 from Schlumberger Geoquest with the permission of GRI. This is a well recently drilled in the tight gas sands of the Green River Basin, Wyoming. To maximize contact between the well and the fracture network, the well deviates at about 48 degrees from vertical in the producing Almond Formation. The Almond sandstones are generally about 10% porosity, with permeability around 20 microdarcies.

A. Well Log Data

We have over 30 different logging curves. This includes several resistivity measurements, gamma ray, SP, P velocity from sonic logging, and neutron porosity, as well as several derived parameters like water saturation, % shale and % coal by volume, and computed permeability. We also have NMR logging data including the Schlumberger processed T2 distribution curve, and NMR measured porosity. From the given T2 values we can use several techniques to obtain the NMR permeability. Additional information includes a fracture log and the well deviation path.

All well logs cover the Almond Formation in this well, approximately 10600 feet to 11000 feet in depth. Some well logs cover part of the overlying Lewis shale and include about 2000 feet of wellbore (9000 - 11000 feet in depth). We are also expecting to receive FMI resistivity data and dipole sonic data from this well.

B. Core Data

Cores were obtained from the 5-2 well over a distance of about 24 feet, and an extensive analysis of these cores led by Schlumberger Geoquest was undertaken. Core plugs were taken at one-foot intervals. Some of the analysis is available for all cores, and some for a subset of cores.

Data from all cores

This includes photographs, porosity, permeability, and grain density. The lithology covered by the 24-foot cored section is analyzed and found to cover several types of sandstone deposition environments and span several fractures.

Data from a subset of cores

Generally the same subset of core plugs is used for each test, but occasionally nonoverlapping or different subsets are used. Data includes:

- SEM images
- Formation factor for resistivity including regression vs. porosity
- Formation resistivity index vs. brine saturation
- Mercury porosimetry including capillary pressure curves and pore throat radius
- Point count data including mineralogy, porosity, permeability, compaction, etc.

- Stress dependence of porosity and permeability
- NMR from cores including T2 distribution, surface relaxivity, and FFI/BVI cutoff

The core NMR data is courtesy of Dr. George Hirasaki of Rice University.

C. Seismic Data

We have VSP data from the 5-2 well for three offsets. The first is a close to zero offset profile including 291 waveforms from 97 three-component receiver locations, extending down to 11,000 feet in measured depth. The other two offsets are approximately 5300 feet, one northeast of the well head and one southeast. The northeast profile consists of 276 waveforms from 92 receiver locations, and the southeast profile consists of 261 waveforms from 87 receiver locations. The receiver locations are spaced at approximately 50 feet in measured depth in the lower part of the well (near the formations of interest) and are more widely spaced at shallower depths. This data may be coupled with the measured P velocity from sonic logs to gain additional insight on the acoustic behavior of the rock formations.

D. Summary of Natural Fracture Analysis at Siberia Ridge

Fractures in the Siberia Ridge Field dip near vertical and strike near 60 - 70 degrees. Typical field-wide fracture apertures are 30 microns. Fracture density increases with depth in the Almond Formation.

Core data:

The 24.5 feet of core from the deviated Almond 5-2 well intersects 12 natural fractures. Nine are in the bottom four feet, in which the lithology transitions from channel to more tightly cemented shoreface sands. The fractures have a mean strike of N55E degrees, and dip 80 to 85 degrees to the northwest. Core measurements indicate minimum horizontal stress is aligned N50W. Mean fracture spacing is about one per 2.0 feet, and mean width is 14 microns. Based on these numbers, fracture permeability k_f averages 4 md, while the mean fracture permeability k_2 averages 2 md in the Almond Bar.

Image data:

Dip and strike information is largely similar to the core fracture data. In the 5-2 well, fracture spacing is one per 7.4 feet from top Almond through Almond 300 (10,600 - 10,880 feet). The rate of fractures increases markedly in the Almond 500 (10,940 to 11,000 feet), at one fracture per 1.4 feet, and continues at this rate through the Almond 600. This increase is not seen in the vertical wells, possibly a sign of fracturing from a nearby lineament. A fracture swarm in the Almond 300 averages one fracture per 0.7 feet.

Core and FMI data suggest that only fractures in sandstones are open, while fractures in shale and coal are healed. The increase in fracture density in the lower intervals may be strongly correlated with an increase in net sandstone. In the 5-2 well, the fracture density averages three fractures/foot of sandstone, while nearby vertical wells average 0.5 fracture/foot of sandstone. This is not corrected for well deviation. When a correction is made, the deviated and vertical wells show

similar fracture spacings: about 4 inches in the horizontal direction, and 23 inches in the vertical direction. The 5-2 well has slightly more fractures because of proximity to a fault, and the vertical wells slightly fewer. In any case, well deviation is a much more dominant factor in fracture density than fault proximity.

It is estimated that fracture porosity is at most 0.03%, so that fractures comprise at most 0.3% of the total sandstone porosity. There may still be a large impact from fracturing on permeability however. See Aguillera (1995), pp, 18-19, 194-202. Mean aperture is the mean width, while mean hydraulic aperture is the cubic mean width. This more closely relates to the flow equations. Mean aperture appears to be around 20 microns, while mean hydraulic aperture appears to be around 50 microns. The variance is high, with a standard deviation of about 20 micrometers.

The single point fracture permeability is related to the aperture by (Aguillera, 1995) $k_f = 8.35 \times 10^6 w^2$, where k_f is in Darcies and w (the aperture) is in cm.

The bulk permeability for a fracture set of uniform spacing is $k_2 = k_f w / D$, where D is the fracture spacing.

Based on the borehole image fracture data, the fracture permeability is lowest in the upper Almond, around 5 md, and highest in the Almond 500 and lower sections, varying from 10 to 50 md. A distinction should be made between the true fracture spacing and the fracture spacing along the well. Permeabilities based on the former are perhaps more true for bulk fluid movement, while permeabilities based on the latter may be more relevant to actual production.

Fractures and production:

Most long term field production (90%) is from the Almond Bar. This is a relatively thin sandstone, so the chances for a vertical well to intersect a fracture is small. Thus, it seems unlikely that fractures play a large role in current field production. Early production is often predominantly from the Almond 300 - Almond 500 sandstones, and this production may be fracture enhanced. The sandstones in these regions are less laterally continuous and may be rapidly depleted. Natural fractures in the lower Almond do contribute a great deal of water production, and for this reason many wells are plugged back above the lower Almond Formations.

E. Illustrations of the Data

Several figures show examples of the available data. Figure 33 is a lithological column interpreted from the core data by Schlumberger GeoQuest. This is in the main producing member of the Almond Formation, and consists of some of the most permeable and highest porosity sands. Figure 33 shows a lithological column and sample well logs through the entire Almond Formation, along with NMR well log measurements. Note the correlation between high T2 values and the more porous sand units. Figures 34 and 35 are not depth matched, so the cores in Figure 34 actually come from the section in Figure 35 extending from about 10,600 to 10,630 feet in measured depth. Figure 35 compares three permeability measurements: computed permeability from log porosity, permeability from core plugs, and NMR log permeability from standard sandstone correlations. All three measurements show significant differences.

Figure 33: Lithological environment of cored area. Depths are not matched to well logs, see figures 34 and 35.

Figure 34: A lithological column interpreted from well logs, together with some of the well logs and core data. Cores were taken from the relatively high porosity, high permeability sandstones slightly deeper than 10,600 feet. The final column shows the processed NMR T2 data. In general, the higher the T2 value, the larger the pores and the greater the permeability. Red indicates a high concentration of pores with that T2 value, while blue indicates a low concentration.

Figure 35: Comparison of permeability measurements. Red: computed permeability based on well log porosity and water saturation calibrated to field core measurements. Green: actual core measurements. Black: NMR well log permeability, using standard SDR method and total NMR porosity. The permeability estimates span roughly two orders of magnitude, but are reasonably consistent in trend.

Reference:

Aguillera, R. (1995) Naturally fractured reservoirs, 2nd ed., PennWell Publishing Co., Tulsa.

VI. FLORIDA WATER MANAGEMENT DISTRICT DATA

The petrophysics, core data, and well log data from selected reservoirs are being gathered, evaluated and cataloged for the data analysis addressed in the previous Sections. In this section, we provide the current status of the data required to accomplish current and future phases of the project.

Core measurements from a Florida carbonate water reservoir were performed by Core Laboratory. Most of these measurements were paid for by the Florida Water District, and selected core samples were paid for by our project. Specifically, we paid for the dry ultrasonic measurements. We also paid for the CT image of the selected samples, which was produced by Shell Oil Company. The ultrasonic and NMR core measurements from Florida will be completed by Core Lab at the end of April of this year. The data that will be available for Phase II includes ultrasonic, NMR and geotechnical core measurements, together with thin section analysis and CT tomography for selected cores. The data set also includes NMR, acoustic and standard logs. In fact, existing data from the Florida reservoir have been used to develop the algorithm to extract pore size distribution from NMR core data. In the following, we describe the procedure to perform ultrasonic measurements for several core samples and we provide tables containing P and S wave velocities and geotechnical data.

South Florida Core Samples

Samples from south Florida were analyzed and prepared for the Phase II. The samples are 4-inch and 1 7/8-inch diameter cores from the PBF #10 well, Hillsboro County, Florida. The well belongs to the South Florida Water Management District. It was drilled mud rotary with a 9.875-inch bit in January-April, 1999. TD is 2,352 feet.

The borehole penetrates Miocene, Oligocene, and Eocene carbonates: Hawthorn Group, Suwannee Limestone, Ocala Group, and Avon Park Limestone. Lithologies are dolomite and limestone. The rocks contain a variety of lithofacies, pore types, pore geometries, and permeabilities.

The following data set is available for the PBF #10 well. All of the data has been released for use in the project.

- Logs: Baker Atlas NMR, multipole array acoustic, high definition induction, density-neutron, spectra gamma ray, and 4-arm caliper. Digital data for all logs is available. Baker is processing the NMR and acoustic data.
- Core: Fifty-three feet of 4-inch and 1 7/8-inch diameter core was cut from 970-1172 feet. Core Labs has performed routine core analyses on 50 full diameter samples. The core has a wide range of pore types and pore geometries. Porosities for the 50 samples range from 6 to 49%, and permeabilities range from 0.14 to 12,280 md. Vertical perms were measured on all the cores. The core has been photographed with regular light and thin sectioned. Also, 224 minipermeameter measurements were made (see Table 3).

Analysis in progress

At a meeting on December 1, 1999 we examined the core at the Core Lab facility in Midland, Texas. The core and core analysis was compared to the NMR and Stoneley wave permeability logs. Samples from a wide range of rock types, pore geometries, permeabilities, and porosities were selected for special core analyses. Twenty-four samples were picked for P and S wave measurements by Core Labs and three of these (two samples have vuggy-moldic porosity and one is a calcareous sandstone) were also earmarked for CT scanning by Shell's Petrophysical Services Laboratory in Houston (see Table 4).

CT scans were made every 2 mm for two cores. 3D images were then constructed. The calcareous sandstone was not imaged because the pores are too small to be adequately resolved by CT. Shell is preparing the final images. The three samples were sent to Core Labs for P and S wave velocity measurements to be analyzed somewhat differently. The P and S waves were recorded according to the following procedures:

P and S wave measurements for all 24 samples were made at one overburden pressure. Core Labs determined the appropriate pressure based on the sample depth and noted the pressure in the report. Note: All saturated measurements were made with tap water.

- P and S wave measurements were made separately on each sample. As much of the wave trains were recorded as was possible (64,000 points per measurement).
- Measurements were made at 250 kilohertz.
- All 1 7/8-inch diameter cores were measured full diameter, with the entire core length (except for ends that needed to be trimmed).
- All due care was taken to keep the cores intact during trimming.
- Of the 21 samples, the five that were 4 inches in diameter were plugged for the P and S wave measurements.
- The 21 samples were measured under saturated conditions, then three of the samples were selected for unsaturated measurements.
- The three samples were measured under unsaturated and saturated conditions, using the full diameter core. (One of the three samples is a 4-inch diameter core and it was not plugged.)
- NO PLUGS WERE CUT FROM ANY CORES, EXCEPT THE FIVE THAT WERE 4 INCHES IN DIAMETER, UNTIL WE LOOKED AT THE DATA AND DECIDED WHICH CORES TO PLUG AND HOW TO PLUG THEM.
- Procedures for the cap pressure measurements will be decided after the P and S data are examined.
- All core pieces (trim edges and residue from plugging) will be retained, identified as to sample number, and returned.

P and S wave measurements were completed and they are given in Table 5. For the next step, we selected approximately 12 samples for NMR measurements. Core Labs, Houston is currently performing the measurements under saturated and unsaturated conditions, along with capillary pressure measurements. The twelve samples are from varying pore types, porosities, and permeabilities.

Table III

COMPANY: South Florida Water Management District
 WELL: PBF No. 10

Sample #	DEPTH TOP feet	DEPTH BOTTOM feet	K(max) md	K(90) md	K(vert) md	POR %	GD gm/cc	Description
	1.0	1000.2	1000.4	-999.0	-999.0	135.3	30.0	2.7 Sd, gry, slt-vfgr, calc
A	2	1015.5	1015.7	0.1	0.1	0.5	6.0	2.7 Lim, foss, sndy, tr moldic
	3.0	1016.3	1016.5	0.1	0.0	0.0	7.2	2.7 Lim, foss, sndy, sl moldic
A	4	1018.3	1018.6	1235.7	640.4	107.9	13.4	2.7 Lim, foss, sl sndy, sl moldic
	5.0	1019.3	1019.4	488.3	134.5	206.1	25.4	2.7 Lim, foss, sl sndy, sl moldic
A	6	1020.7	1020.9	0.7	0.3	0.7	11.4	2.7 Lim, foss, sl moldic
A & CT	7	1021.7	1022.0	869.9	818.0	6.9	16.6	2.7 Lim, foss, sl moldic
A	8	1022.2	1022.4	2740.2	2216.9	1419.3	26.6	2.7 Lim, foss, moldic
	9.0	1023.6	1024.0	2059.5	1853.1	1900.7	32.4	2.7 Lim, foss, moldic
	6.0	1028.4	1028.6	-999.0	-999.0	-999.0	33.7	2.7 Lim, foss, moldic
A	11	1029.0	1029.3	3015.6	2938.9	2496.6	32.3	2.7 Lim, foss, moldic
	12.0	1030.0	1030.3	5144.6	5144.6	4973.9	31.1	2.7 Lim, foss, moldic
A	13	1042.7	1043.0	4979.6	4873.0	3907.9	30.1	2.7 Lim, foss, moldic
	14.0	1043.6	1043.8	6156.7	4676.8	4740.5	33.4	2.7 Lim, foss, moldic
A	15	1044.3	1044.6	1991.3	1701.5	1158.4	27.9	2.7 Lim, foss, sl sndy, moldic
A	16	1045.3	1045.6	425.8	372.9	414.7	26.6	2.7 Lim, foss, sndy, sl moldic
A	17	1046.5	1047.0	62.9	58.6	66.7	31.2	2.7 Sd, gry, vfgr, calc
A	18	1047.2	1047.6	101.7	92.1	58.8	31.4	2.7 Sd, gry, vfgr, calc
A	19	1048.0	1048.5	25.8	24.8	34.2	21.3	2.7 Sd, gry, vfgr, calc
A & CT	20	1049.6	1050.0	69.0	61.5	83.8	29.7	2.7 Sd, gry, vfgr, calc
A	21	1050.4	1050.8	86.3	86.3	58.1	31.9	2.7 Sd, gry, vfgr, calc
A	22	1051.1	1051.4	170.2	155.6	91.0	32.4	2.7 Sd, gry, vfgr, calc
	23.0	1052.2	1052.5	-999.0	-999.0	-999.0	32.8	2.7 Sd, gry, vfgr, calc
	24.0	1057.0	1057.2	-999.0	-999.0	-999.0	31.5	2.7 Sd, gry, vfgr, calc
A	25	1058.0	1058.2	102.3	94.0	42.4	31.0	2.7 Sd, gry, vfgr, calc
A	26	1059.2	1059.5	44.5	32.1	6.3	24.0	2.7 Lim, foss, sndy, brec
A	27	1060.3	1060.5	398.0	376.3	293.6	29.0	2.7 Sd, gry, vfgr, foss, calc
	28.0	1125.6	1126.0	2444.7	1668.3	1232.6	44.7	2.7 Lim, foss, moldic

Table III (cont'd)

8	A	29	1126.4	1126.9	1896.0	1028.1	1100.0	47.2	2.7 Lim, foss, interpartical
		30.0	1127.2	1127.8	4274.1	4103.0	2982.9	43.0	2.7 Lim, foss, interpartical
		31.0	1128.0	1128.4	2290.0	2290.0	1762.5	40.3	2.7 Lim, foss, interpartical
	A	32	1129.4	1129.8	1805.1	1775.8	2064.0	43.5	2.7 Lim, foss, interpartical
		33.0	1130.4	1130.7	2216.7	2041.5	682.9	42.0	2.7 Lim, foss, interpartical
	A	34	1131.5	1131.8	1135.5	1085.7	632.0	46.6	2.7 Lim, chlky, interpartical, lam
		35.0	1132.4	1132.9	4514.9	3556.3	1624.7	45.6	2.7 Lim, interpartical-moldic
		36.0	1133.3	1133.8	3001.0	2875.8	3259.3	44.7	2.7 Lim, interpartical-moldic
		37.0	1134.2	1134.7	3410.2	2841.1	141.4	41.5	2.7 Lim, interpartical-moldic, lam
		38.0	1135.2	1135.6	12280.3	11461.1	4473.0	40.7	2.7 Lim, interpartical-moldic
		39.0	1136.6	1137.0	5862.9	5862.9	9363.9	49.2	2.7 Lim, interpartical-moldic
		40.0	1137.4	1137.6	8007.9	8007.9	4180.3	47.7	2.7 Lim, interpartical-moldic
	A & CT	41	1138.4	1138.8	3097.4	903.6	4389.3	32.1	2.7 Lim, chlky, rootlet
		42.0	1155.5	1155.8	-999.0	81.9	-999.0	40.9	2.7 Lim, chlky, rootlet
		43.0	1156.7	1156.9	11.4	10.7	10.4	43.3	2.7 Lim, chlky
	A	44	1157.0	1157.4	44.0	33.5	60.3	44.9	2.7 Lim, chlky
		45.0	1158.3	1158.5	17.3	16.9	6.9	41.6	2.7 Lim, chlky
		46.0	1159.1	1159.3	377.6	10.2	27.5	34.1	2.7 Lim, broken frac, chlky
		47.0	1160.0	1160.3	26.4	24.5	12.0	41.7	2.7 Lim, foss, chlky, sl spar
		48.0	1161.2	1161.4	3464.1	3156.9	3453.9	37.3	2.7 Lim, foss, moldic
9	A	49	1162.0	1162.4	98.4	47.3	25.4	41.3	2.7 Lim, foss, chlky, sl spar
		50.0	1170.1	1170.4	7137.5	7137.5	5125.2	40.3	2.7 Lim, foss, moldic

A - sample selected for p & s wave measurements

CT - sample selected for cat scan imaging

SUMMARY OF ULTRASONIC VELOCITY AND DYNAMIC MODULI

South Florida Water Management District
PBF No. 10 Well
File: DAL-99246

Temperature, °F: 72
Sample Condition: Saturated

Sample Number	Depth, feet	Net Stress, psi	Bulk Density, gm/cc	Acoustic Velocity				Bulk Modulus, 1.00E+06	Young's Modulus, 1.00E+06	Shear Modulus, 1.00E+06	Poisson's Ratio
				Compressional		Shear					
				ft/sec	µs/ft	ft/sec	µs/ft				
2	1015.50	310	2.587	16680	59.95	8650	115.63	6.223	6.864	2.608	0.316
4	1018.30	320	2.411	16340	61.20	7750	129.06	6.077	5.288	1.951	0.355
6	1020.70	320	2.464	14560	68.68	7660	130.51	4.441	5.103	1.950	0.308
7	1021.70	320	2.370	13323	75.06	6754	148.06	3.728	3.868	1.458	0.327
8	1022.20	320	2.092	10090	99.07	4650	215.29	2.062	1.662	0.608	0.366
11	1029.00	320	1.919	9870	101.29	4590	217.91	1.795	1.484	0.545	0.362
13	1042.70	320	1.863	10220	97.86	4450	224.95	1.961	1.373	0.496	0.383
14	1043.60	320	1.812	11194	89.33	5484	182.33	2.081	1.972	0.735	0.342
15	1044.30	320	2.016	10060	99.42	4460	224.10	2.028	1.491	0.541	0.377
16	1045.30	320	2.169	12480	80.15	6110	163.73	3.097	2.928	1.091	0.342
17	1046.50	320	2.104	10230	97.73	5630	177.47	1.769	2.310	0.901	0.282
18	1047.20	320	2.182	11240	88.97	6460	154.92	2.082	3.073	1.226	0.254
19	1048.00	320	2.345	13550	73.82	7220	138.57	3.605	4.286	1.646	0.302
20	1049.60	330	2.092	11633	85.96	6327	158.05	2.311	2.913	1.129	0.290
21	1050.40	330	2.148	13070	76.50	7430	134.54	2.814	4.034	1.599	0.261
22	1051.10	330	2.132	11160	89.62	6760	147.94	1.828	3.179	1.313	0.210
25	1058.00	330	2.086	10770	92.82	5440	183.98	2.155	2.208	0.831	0.329
26	1059.20	330	2.064	10447	95.72	6507	153.67	1.466	2.788	1.178	0.183
27	1060.30	330	2.122	11820	84.62	6280	159.11	2.488	2.944	1.130	0.303
29	1126.40	350	1.871	9840	101.63	5048	198.12	1.585	1.698	0.643	0.321
32	1029.40	320	1.913	10219	97.86	5840	171.22	1.520	2.212	0.880	0.257
34	1131.50	350	1.884	9524	105.00	4915	203.45	1.485	1.618	0.613	0.318
41*	1138.40	350	2.449	14848	67.35	7193	139.03	5.000	4.599	1.708	0.347
49	1162.00	360	1.992	9730	102.78	5360	186.57	1.514	1.979	0.772	0.282

Table IV (cont'd)

SUMMARY OF ULTRASONIC VELOCITY AND DYNAMIC MODULI

South Florida Water Management District
PBF No. 10 Well
File: DAL-99246

Temperature, °F: 72
Sample Condition: Dry

Sample Number	Depth, feet	Net Stress, psi	Bulk Density, gm/cc	Acoustic Velocity				Bulk Modulus, 1.00E+06	Young's Modulus, 1.00E+06	Shear Modulus, 1.00E+06	Poisson's Ratio
				Compressional		Shear					
				ft/sec	µs/ft	ft/sec	µs/ft				
7	1021.70	320	2.201	12239	81.71	6928	144.34	2.545	3.600	1.424	0.264
20	1049.60	330	1.849	9809	101.94	6241	160.22	1.104	2.253	0.971	0.160
41*	1138.40	350	1.850	13570	73.69	6871	145.55	3.023	3.126	1.177	0.328

* 4 inch diameter whole core

VII. NMR Method for Estimation of Pore Size Distribution

A. Introduction

During this period we used existing core data from the Florida Data Set Project to develop the model for estimation of pore size distribution from the T_2 distribution data. In fluid saturated porous media, T_2 values are shorter for pore fluids than for the bulk fluids if the fluids interact with the pore surface to promote NMR relaxation. In the fast diffusion limit, the T_2 relaxation rate $1/T_2$ is proportional to the surface-to-volume (S/V) ratio of the pore (Brownstein and Tarr, 1979):

$$1/T_2 = \rho (S/V)_{\text{pore}} \quad (32)$$

where ρ is the surface relaxivity, which is a measure of the pore surface's ability to enhance the relaxation rate. It falls within a reasonably narrow band for a rock, from nanometers to microns per second.

For a rock saturated with a fluid, the T_2 relaxation time distribution can be transformed to the pore size distribution of the rock if surface relaxivity is known. NMR T_2 relaxation is known to depend on surface-to-volume ratio with the proportionality of the surface relaxivity constant (see Equation 32). The model for estimating relaxivity is under development. This model relates to cumulative T_2 distributions and the pore capillary pressure curves (the pore fluid saturation vs. capillary pressure). From the capillary pressure and the water saturation of the core sample, combined with the T_2 relaxation distributions, the relaxivity of the core can be calculated.

B. Surface Relaxivity Determination and Pore Size Distributions

The pore size distribution can be estimated from digital analysis of thin-section images, mercury injection (capillary pressure), and air-brine capillary pressure curves (Kenyon, 1997; Straley, et al., 1995; Loren et al., 1970). The capillary pressure curve is commonly used to measure the pore throat size distribution.

Capillary pressure curve is obtained by drainage, i.e., displacement of a wetting fluid by a non-wetting fluid. The relationship between the capillary pressure and the pore throat size is described by

$$P_c = 2\sigma \cos\theta / r_t \quad (33)$$

Where r_t is the pore throat radius, σ is non-wetting fluid/wetting fluid surface tension, and θ is the contact angle between wetting fluid and non-wetting fluid on the solid surface.

The most often used fluids in drainage are mercury/air and air/brine. The use of the air/brine combination can achieve the irreducible water saturation S_{wir} , while mercury/air does not ensure this state.

For a rock saturated with a single fluid, the T_2 relaxation time distribution can be transformed to the pore size distribution of the rock if the surface relaxivity ρ is known as Equation (32).

In Equation (32), NMR T_2 relaxation depends on surface-to-volume ratio with proportionality constant ρ when the effect of the internal field gradient is negligible.

To estimate relaxivity, if we assume the pores are isolated pores with tube-like shapes and that they act independently, then Equation (33) becomes

$$T_2 = (1/2\rho)r_b \quad (34)$$

Given the above assumptions, T_2 is now proportional to the radius of the pore body. The combination of Equations (32) and (33) leads to the relationship between T_2 and P_c as follows:

$$1/P_c = CT_2 \quad (35)$$

where

$$C = (\rho/\sigma\cos\theta)r_t/r_b \quad (36)$$

Now we introduce another important assumption: the pore-throat to pore-body ratio r_t/r_b does not vary from pore to pore. According to this assumption, the universal constant C may be determined by minimizing the merit function χ^2 as

$$\chi^2 = \sum_{i=1}^n (\log_{10} CT_{2,i} - \log_{10} 1/P_{c,i})^2$$

Given C , σ and θ , we have

$$\rho' = \rho r_t/r_b = C(\sigma\cos\theta) \quad (38)$$

where ρ' is the effective T_2 surface relaxivity which includes the contributions from ρ and r_t/r_b . From now on, we will omit the superscript in effective relaxivity for convenience. Here, $\sigma\cos\theta$ is 64 dyne/cm in used for air-brine capillary pressure curves.

Five core sample T_2 data received from the BICY-PW well in South Florida, with correlations between capillary pressure and core saturation, are listed in Table 5. Figure 36 plots the relationship between the capillary pressure and the core saturation for sample #10. Using the relaxivity determination method, the calculated relaxivity of the different core samples are also shown in Table 5. By the obtained surface relaxivity, the pore size distributions of these five samples are estimated. Figure 37 (a and b) to Figure 41 (a and b) plot their T_2 distributions and pore size distributions, respectively. In addition, the obtained pore size ranges are listed on Table 6. Table 6 indicates that in general the pore size distributions can reflect the permeability ranges from the

samples. These five samples can be divided into two groups from the pore size ranges. Group 1 is the pore size less than 10 μm (samples of #3, #7 and #10); group 2 is the pore size above 10 μm (samples of #12 and #16). In Table 6, all the samples with larger pores (for example above 10 μm) may have the larger permeabilities (see below).

C. Permeability Determinations and Comparisons

Table 7 lists the comparison of the permeability obtained from the Kinkenberg method and the NMR measurements. There are several empirical models used to estimate permeability in literature. Here, two models are used in Table III to estimate the permeability from NMR measurements. The first is the Kenyon Equation (Kenyon, 1997):

$$k = \phi^4 T_{2,LM} \quad (39)$$

where $T_{2,LM}$ is the logarithmic mean of T_2 distribution in ms and ϕ is the porosity in fraction. The second permeability model based on NMR is to estimate a T_2 cutoff value parameter that partitions pore volume into free-fluid and bound-fluid volume index as (Coates et al., 1993)

$$K = 10^4 \phi^4 (FFI/BVI)^4 \quad (40)$$

where porosity is also in fraction, and FFI and BVI are free-fluid index (volume) and bound-fluid index (volume), respectively. Figure 42 illustrates the meaning of FFI, BVI and the relaxation cutoff from T_2 relaxation spectrum.

Here the saturation components of free-fluid and bound-fluid are used to estimate the permeability. The technique is as follows. We seek a T_2 cutoff value parameter that partitions pore volume into free-fluid and bound-fluid volume. These two quantities calibrated as a total fluid volume will be FFI and BVI.

In the laboratory, we make NMR measurements before and after air/brine drainage. The cutoff value is determined by best agreement between bound-fluid volume in a relaxation time distribution of 100% water saturation samples and remaining water volume after centrifuging. The cutoff values are used to estimate the irreducible water saturation from NMR well logging. The results from the second model (Equation 9) seem better than the first model (Equation 8), however, the cutoff values are varied from 40 to 601 ms (40, 99 and 601ms) among these five samples.

D. Discussion

NMR well logging is believed to be the most significant advance in formation evaluation in recent time. The pulsed NMR technique provides important petrophysical information about the reservoir rock such as total fluid content, porosity, pore size distribution, permeability, and potential wettability.

The data analysis demonstrate that the capillary pressure curve combined with the T_2 distribution can be used to determine surface relaxivity. Thus, the pore size distribution can be

estimated by using the surface relaxivity and the T_2 distribution data. The data suggest that the core with the larger pores may have the larger permeability. Among the five samples, the T_2 cutoff values above 600 ms are considered as vuggy samples (#10). The T_2 cutoff model also indicates that the log mean relaxation model is correct in general, because the estimated values from the log mean method are consistent with the T_2 cutoff method except for vuggy sample #10. It suggests that the log mean model is suitable for most NMR relaxation data, except for the vuggy samples. For example, the core with a longer T_2 log mean (or larger porosity) and lower permeability should be considered as a vuggy case. In a vuggy case, the pores connect inside but are isolated outside. Thus, the calculated log mean permeability is less than the real permeability.

The log mean method is faster and easier to use than the second method (Equation 9), since the cutoff values could be different and require more calculations. Incorrect cutoff values affect the FFI/BVI ratio, and hence lead to incorrect permeability values. Like surface relaxivity, cutoff values are not expected to be universal. However, using individual cutoff values, improved permeability estimates particularly for vuggy samples, can be obtained. Only limited data are shown above; more samples are needed for further tests to provide more detailed conclusions.

Table V

Sample Number	Depth Feet	Capillary pressure (psi)									Calculated
		0	5	10	20	50	100	200	300	400	
		Water saturation (fraction)									Relaxivity (cm/s)
3	851.6	1.000	0.862	0.835	0.835	0.785	0.712	0.593	0.499	0.423	0.5036
7	855.2	1.000	0.765	0.748	0.717	0.640	0.547	0.440	0.384	0.352	1.002
10	861.4	1.000	0.912	0.775	0.653	0.514	0.423	0.342	0.299	0.271	0.6516
12	880	1.000	0.729	0.613	0.508	0.383	0.298	0.221	0.179	0.151	2.605
16	901.6	1.000	0.529	0.439	0.361	0.274	0.218	0.170	0.145	0.129	2.971

Table VI

Depth (m)	Sample I.D.	Relaxivity (μ) cm/s	Pore size range (cm)	Comments
851.6	3	0.5036	0.01 to 5	Neglect < 0.001
855.2	7	1.002	0.01 to 9	Neglect < 0.001
861.4	10	0.6516	0.03 to 5	Neglect < 0.001
880.1	12	2.605	0.03 to 10	Neglect < 0.002
901.6	16	2.971	0.02 to 20	

Table VII

Sample Number	Depth feet	Permeability (Kinkenberg) mD	Porosity (He) fraction	T _{2LM} (ms)	NMR Permeability K=1 ⁴ T _{2LM}	T ₂ cut off (ms)	NMR Permeability K=10 ^{4.4} (FFI/BVI) ⁴
3	851.6	38.0	0.199	66.8	7.0	40	62.9
7	855.2	18.5	0.2000	69.8	7.8	40	43.1
10	861.4	0.10	0.082	290.7	3.8	601	0.18
12	880.1	150	0.332	141.0	241	99	495
16	901.6	302	0.245	350.4	442	99	368

Gas-Water Capillary Pressure (#10)

Figure 36. The correlation between the gas-water capillary pressure with the water saturation fraction of sample # 10.

T₂ Distribution (sample #3)

Figure 37. (A) T₂ distribution for sample # 3.

Pore size distribution (sample #3)

Figure 37. (B) The estimated pore size distribution for sample # 3.

Figure 38. (A) T₂ distribution for sample # 7.

Pore size distribution (sample #7)

Figure 38. (B) The estimated pore size distribution for sample # 7.

Figure 39. (A) T₂ distribution for sample # 10.

Pore size distribution (sample #10)

Figure 39. (B) The estimated pore size distribution for sample # 10.

T_2 Distribution (sample #12)

Figure 40. (A) T_2 distribution for sample # 12.

Pore size distribution (sample #12)

Figure 40. (B) The estimated pore size distribution for sample # 12.

T_2 Distribution (sample #16)

Figure 41. (A) T_2 distribution for sample # 16.

Pore size distribution (sample #16)

Figure 41. (B) The estimated pore size distribution for sample # 16.

Figure 42. Illustration of FFI, BVI and cutoff in T_2 relaxation spectrum.

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VIII . ACCOMPLISHMENTS, TECHNOLOGY TRANSFER, AND PHASE II WORK PLAN

A. Summary of Accomplishments

1. *Algorithm to Estimate Pore Size Distribution from NMR Core Measurements*

Cores from the South Florida Water Management District project were used to develop a model for estimation of pore size distribution. The model requires the cumulative T_2 distribution and pore capillary pressure curves. Thus, the relaxivity parameter combined with the T_2 relaxation distribution generates the pore size distribution associated with each core sample. We have tested the model using core carbonate samples containing vuggy and matrix porosity as well as connected large pores.

2. *Theoretical Relations Between Effective Dispersion and Stochastic Medium*

The 2D random medium solution of heterogeneous wave equation was implemented to produce attenuation and dispersion 2D images.

We have rigorously derived a Green's function equation for describing the ensemble average behavior of acoustic waves in media with random variations in two dimensions. By taking the two dimensional integral which is the basis of the solution, applying a coordinate transformation, and choosing a particular form of the spectral density, we can use the previously published one dimensional result to evaluate an integral, leaving only an integral over angle. Similar methods can be applied to extrapolate the result to three dimensions and to include anisotropy in the spatial variability. For multidimensional variability, the endpoints of the angular integral are singular, resulting in the imaginary part of the integral being infinite. This is probably an unavoidable result of the plane wave ensemble average basis of the solution. One method to deal with this problem is to limit the integration to the forward- and back-scattering angles. Similar methods have been applied in single-scattering theory, where forward-scattered energy is not counted as lost.

Applying the solution, we have produced curves showing the velocity and attenuation of waves in 2- and 3-dimensional stochastic media as a function of frequency for varying degrees of variability, anisotropy, and angle of propagation in the medium. All results can be shown to reduce to the proper one-dimensional result in the appropriate limit. We expect these results to be of particular use in analyzing the high frequency wave propagation through the vuggy Florida aquifer cores.

3. *Imaging Analysis using Existing Core and Well Log Data*

While analyzing the Siberia Ridge VSP data to extract attenuation or dispersion information, we found that the seismic wave amplitude increases with depth in the reservoir region, while the VSP interval velocities from the checkshot data show occasional large differences from the sonic log velocities. Investigating these phenomena, we produced interval velocities, horizontal and vertical amplitudes, hodograms, and angle of incidence plots for the checkshot VSP and two offset VSPs. By using a detailed model of the bottom 2000 feet of the well, we demonstrate that the increase in amplitude is a direct result of the elastic properties of the Almond formation, and that the discrepancy between checkshot and sonic velocities can be explained by the soft coal layers in the Almond formation. Even though the coal makes up less than 10% of the formation, the large density and velocity contrast between the coal and the tight shale and sandstone layers produces a significant effect on the observed waves.

These results demonstrate the importance of accounting for the elastic behavior of the medium when investigating wave attenuation, and how a few relatively thin coal layers need to be incorporated into a scaling model to properly predict wave speeds. By doing so, we can create a elastic model at the reservoir scale from the VSP data and relate it to the borehole logs.

4. *Construct Dispersion and Attenuation Models at the Core and Borehole Scales in Poroelastic Media Using Real Rock and Fluid Property Parameters*

We have constructed poroelastic models based on core and well log data from the Almond formation of the Siberia Ridge field, Wyoming. The flow properties were obtained from NMR well log data, and velocities were obtained from monopole/dipole sonic data.

We predicted attenuation responses by varying the permeability and squirt flow lengths in the plane defined by the cracks. We also vary the azimuth and incident angles to predict the appropriate frequency range for detecting cracks using acoustic/seismic measurement techniques. We analyzed the sensitivity of the squirt flow length to attenuation and predict the contribution of fracture permeability in low permeability tight sands. The modeling results provided insight for detecting fluid filled fractures using acoustic/ or seismic measurements in tight sands reservoirs.

We modeled the scattering and intrinsic attenuation associated with a layer sequence of sands, shales and coals. The model includes the poroelastic properties determined from well logs and cores. The models can be used to evaluate whether acoustic/seismic

measurements techniques can map fluid filled fractures or non-fractured flow units in a tight sands.

5. *Petrophysics and Catalog of Core and Well Log Data:*

(a) Ultrasonic and NMR core measurements from a Florida carbonate water reservoir were performed and cataloged. In addition, 3D and 2D CT images of the selected samples were produced. NMR and sonic logs acquired by Western Atlas were gathered and being cataloged for further analysis. These data will be used to perform most of the tasks of Phase II.

(b) A complete data set from the Siberia Ridge well 5-2 was cataloged and analyzed. This data set was used to test a model-based interpretation algorithm to extract quality factors from sonic and VSP data. Also, the data set was used to build poroelastic models to relate P wave attenuation and velocity with permeability anisotropy

B. Technology Transfer Activities

We have created a home page for the project on the SwRI web site. The home page will include this Annual Report on a .pdf file. Also the home page includes presentations and the resulting papers of Phase I. Below we have manuscripts and articles that can be accessed at the home page, located at <http://www.space.swri.edu/geophysics>.

The manuscript titled, "Attenuation of Acoustic Waves from Multi-scale Scattering and Pore Flow in Heterogeneous Permeable Media, was accepted for publication in the *Journal of the Acoustical Society of America*. The paper will be published this year in the July issue of JASA.

Two papers will be presented at the 70th Annual Meeting and International Exposition of the Society of Exploration Geophysicists, Calgary, Canada in August 2000.

1. A model to relate P-wave attenuation to fluid flow in fractured tight gas sands
2. Relating VSP with well logs in the Greater Green River Basin: amplitude and interval velocity

The analysis of the core/well log data from Buena Vista Hills reservoir was completed. The results of this work was submitted for publication to *Geophysics*. This manuscript can also be accessed at the project home page.

C. Work Plan for Phase II

1. *Modeling, Processing and Interpretation of Ultrasonic Data to Characterize Carbonate Rocks Containing Vuggy Porosity*

The objective of this study will be to devise methods for extracting flow properties from acoustic data and to understand how vuggy porosity affects the attenuation and dispersion mechanism.

(a) Analyze ultrasonic waveforms recorded under saturated and unsaturated conditions in cores from the Florida Project. The data will be processed to extract the signatures associated with the pore structure.

(b) Conduct ultrasonic and acoustic modeling of vuggy porosity in carbonate rocks. Models will be constructed from 3D images based on CT measurements. Random media solutions will be used to predict ultrasonic signatures associated with 3D variability at the pore scale in the cores. Also, deterministic modeling based on 3D finite difference calculations will be used to predict the heterogeneity observed in the cores. The synthetic waveforms will be compared with selected observed ultrasonic data addressed in (a).

(c) Once the models at the core scale are verified, we will calculate dispersion and attenuation signatures at a broad band frequency range to include acoustic and seismic frequencies. The calculations will be done to simulate unsaturated and saturated carbonate rocks containing vuggy porosity.

2. *Catalog and Evaluate Core and Well Log Data from Selected Reservoirs*

We will catalog and evaluate Florida and Siberia Ridge data and will use the information in preparing for poster presentations and related meetings. We will also construct a project web page.

3. *Measurements and Analysis of NMR Data at the Core and Borehole Scales*

The same cores used to record ultrasonic waveforms will be used to conduct NMR and capillary pressure laboratory measurements. These data will be processed to extract permeability, porosity and pore size distribution. The pore size distribution derived from cores containing vuggy porosity will be compared to the corresponding CT image. The objective is to verify if the NMR core data can capture the pore structure of the selected cores. In this case

the optimum application will be to extract pore size distributions from NMR well log data to map the pore structure associated with vuggy porosity.

Cores without vuggy porosity will be selected to analyze the NMR responses at the core and log scales. Pore size distribution, permeability and porosity will be derived from such measurements, and flow parameters based on NMR core data will be used to construct poroelastic models.

NMR signatures of cores with and without vuggy porosity will be compared with petrographic analyses based on thin sections and CT slides. The objective is to understand how flow parameters are related to pore structure and how mineralogy affects fluid flow in the porous matrix. The optimum application is to improve the relationships used to determine permeability from NMR well log data.

4. *Validate Flow Mechanisms Using Poroelastic Models and Applications*

Ultrasonic data from selected cores without vuggy porosity will be processed and analyzed. Flow parameters based on NMR core measurements will be input to the poroelastic modeling program. Synthetic ultrasonic signatures will be predicted and compared with observed signatures. The squirt-flow mechanism and other flow mechanisms will be considered to explain the intrinsic attenuation due to fluid flow. Squirt-flow length will be determined from thin section and pore structure analysis.

The poroelastic models will be used to produce acoustic and seismic signatures for unsaturated and saturated carbonate formations. In particular, attenuation and phase velocity responses will be calculated and interpreted for several angles of incidence and squirt flow lengths. One important issue to be addressed is whether we can predict flow parameters (permeability, viscosity, fluid density, and porosity) using acoustic measurements at two scales (cores and well logs) based on models of acoustic waves in fluid-filled porous media.

The petrophysics column produced will be used to construct earth models characterized by flow units of different lithological properties. In this case, full waveforms will be calculated at the borehole and interwell seismic scales. The main point of such a modeling approach is to simulate and predict those attributes associated with flow units of different properties, and to evaluate whether flow units can be imaged with existing seismic measurement techniques.

After the signatures are evaluated for saturated and unsaturated conditions, we will construct a high-resolution velocity model based on ultrasonic data and petrography. Once the high resolution velocity model is established at the core scale, an association of reservoir

heterogeneity with the elastic scattering component of the signal (based on dry core measurements) can be used to image the important reservoir rock properties related to depositional environments. Once we understand the distribution of reservoir rock properties and relevant fluid properties (derived from NMR measurements), we can map the intrinsic component of velocity dispersion and possibly use it to monitor fluid movement throughout the reservoir.

The goal of the above analysis is to relate the microscopic rock pore structure to observed large-scale fluid flow characteristics in cores and well logs, to define flow units for use in reservoir models. Accurately predicting reservoir fluid flow characteristics will improve the computer simulations used to develop more efficient oil recovery processes.

5. *Petrography from Cores and Petrophysics from Well logs*

A petrographic analysis will be made of thin sections from selected cores to include the characterization and identification of pore geometry, grain mineralogy, grain size and geometry, nature and distribution of cements, clay distribution, etc. The thin sections will also be analyzed with epifluorescent microscopy to identify microporosity and will be compared with the CT images. The data will be analyzed statistically and integrated into the lithofacies and depositional framework of the reservoir. This result will be used to construct high resolution velocity models.

Lithological columns will be produced from the formations the carbonate aquifer. The petrophysical units will be derived from well logs (porosity, gamma ray, resistivity, etc.) using Terra-science software. The column will be correlated with velocity and NMR well logs and used to identify flow units at the borehole scale. It will also be used to simulate earth models to produce acoustic and interwell seismic signatures.

APPENDIX A

EXPERIMENTAL PROCEDURE

Acoustic Velocity

1. The samples were shaped into right cylinders.
2. The specimens were pressure saturated with tap water.
3. Each sample was loaded into a Viton sleeve, then placed into a hydrostatic vessel.
4. Appropriate hydrostatic confining stress was applied while pore pressure lines were left open to the atmosphere.
5. Compressional and shear wave acoustic signals were transmitted through each sample while the confining pressure was being applied. 250 kHz piezoelectric transducers were used to transmit and receive acoustic signals.
6. Transit times indicated by the waveforms were monitored on a high speed, digital oscilloscope. The samples remained in this state until ultrasonic travel time stabilized, indicating pressure equilibrium.
7. Acoustic signal transit times at equilibrium conditions were determined and recorded and saved to a disk using the digital oscilloscope. Arrivals were corrected for the system travel time to determine the travel time through the length of each sample.
8. Sample lengths were divided by transit times to calculate compressional and shear acoustic velocity.
9. Velocity and bulk density values were used to calculate the dynamic moduli as follows:

Poisson's Ratio, ν

$$\nu = \frac{\left(\frac{V_p}{V_s}\right)^2 - 2}{2\left[\left(\frac{V_p}{V_s}\right)^2 - 1\right]}$$

Shear Modulus, G

$$G = C_1 \rho V_s^2$$

Bulk Modulus, K

$$K = C_1 \rho \left[V_p^2 - \left(\frac{4}{3} \right) V_s^2 \right]$$

Young's Modulus, E

$$E = \frac{9 C_1 \rho V_s^2 \left(\frac{K}{C_1 \rho V_s^2} \right)^2}{3 \left(\frac{K}{C_1 \rho V_s^2} \right)^2 + 1}$$

Where:

C_1	=	$1.3480 \cdot 10^{-2}$	=	Conversion factor for ρ (gm/cm ³)
ρ	=	Bulk Density		
V_p	=	P-Wave Velocity		
V_s	=	S-Wave Velocity		