Session NG -- Natural Gas Technology

Session NG-2

Natural Fractures

NG-2.1 Integrated Seismic Study of Naturally Fractured Tight Gas Reservoirs

CONTRACT INFORMATION

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Schedule and Milestones

FY94 Program Schedule

		S	O	N	D	J	D	M	A	M	J	J	A
NEPA	(complete)												
Feasibility plan	(complete)												
Feasibility test	(complete)												
Verification plan		-----	-----	-----									
Verification		-----	-----	-----	-----	-----	-----	-----					
Interpretation & analysis		-----	-----	-----	-----	-----	-----	-----					

OBJECTIVES

In tight formations, which can include sandstones, shales, limestones, and coal, often the only practical means to extract the gas is by exploiting the increased drainage surface provided by natural fracture zones. The practical difficulties that must be overcome before effectively using these fractures include: locating the position and orientation of fracture zones, determining the intensity of fracturing, and characterizing the spatial relationships of these fractures relative to reservoir heterogeneities which might enhance or inhibit the eventual gas flow.

Reflection seismic methods are, and will continue to be, the key geophysical tool for imaging these heterogeneities in the subsurface of the earth. However, in spite of great advances in field acquisition techniques and computer processing power, the primary product of conventional seismic work is still only the spatial pattern of reflectivity, which is a measure of velocity variations. Most of the amplitude information goes unused. Although fracture zones may have a reflectivity signature, more often they will not, because of steeply dipping angles, limited offset range in the acquisition, a subtle impedance mismatch, or too thin a fractured zone relative to the wavelength.

In fact, there is probably no single seismic attribute that will always tell us what we need to know about fracture zones. Our objective, in the project, is to integrate the principles of rock physics into a quantitative interpretation scheme that exploits the broader spectrum of fracture zone signatures:

- anomalous compressional and shear wave velocities
- Q and velocity dispersion
- increased velocity anisotropy
- amplitude variation with offset (AVO) response

Our goal is to incorporate four key elements:

- Acquisition and processing of seismic reflection field data.
- Theoretical studies of the anisotropic signatures of fractured rocks.
- Laboratory measurements of seismic velocity, velocity anisotropy, and attenuation in reservoir and cap rocks.
- Integration and interpretation of seismic, well log, and laboratory data, incorporating forward modeling.

The effects of attenuation, elastic anisotropy, and attenuation anisotropy on Amplitude Variation with Offset measurements were previously investigated in a theoretical manner, using a full waveform modeling algorithm (Samec, et al., 1990). In particular, it was shown that in viscoelastic solids, the effect of anisotropy and attenuation strongly condition the amplitude of reflected events. The reflection coefficients along an interface depend on the elastic, viscous, and anisotropic properties of the rocks traversed by the seismic waves and are influenced by both elastic anisotropic energy focusing, and by anisotropic dissipation. Therefore, proper characterization of amplitude variations requires that the phenomena affecting the phase and amplitudes of the signal be modeled rigorously.

The previous modeling work and recent advances in computer technology have demonstrated that it is rapidly becoming feasible to account for "all" aspects of wave propagation. However, what is lacking is a systematic petrophysical interface that will serve as the tie between rock properties and seismic properties. Our goal is to integrate currently available tools, new technology, and rock physics to analyze a field data set in a fractured reservoir.

BACKGROUND INFORMATION

The Seismic Velocity Signature of Fractured Rock

The basis for virtually all modern seismic strategies for detecting fractures lies in laboratory studies, such as those performed by Nur and coworkers more than two decades ago (eg., Nur and Simmons, 1969; Nur, 1971). They discovered that cracks and pores almost always decrease compressional and shear velocities in rocks. Cracks, in particular, can have the largest effect by volume, and when oriented either by stress or by rock depositional fabric, they introduce velocity anisotropy.

Typical behavior of P- and S-wave velocities in cracked crustal rocks is illustrated in Figure 1 for a tight gas sandstone. The dry and saturated data for both P and S waves show a large and rapid increase with confining pressure, which is usually attributed to crack and fracture porosity (Nur, 1971; Toksöz et al., 1976; Walsh, 1965). As confining pressure is increased, the most compliant pores (ie., cracks and fractures) are pressed closed, followed by the next less compliant, and so on. Contrast this behavior with velocities for Solenhofen limestone, shown in Figure 2. This rock is relatively free of cracks, and consequently there is very little change of velocity with confining pressure.

Fluid saturation has the greatest effect on the crack portion of the porosity, with the following key features:

- Fluid saturation almost always increases compressional velocity

- Fluid saturation tends to decrease the dependence of compressional velocity on effective pressure
- Fluid saturation has relatively little effect on shear velocity.

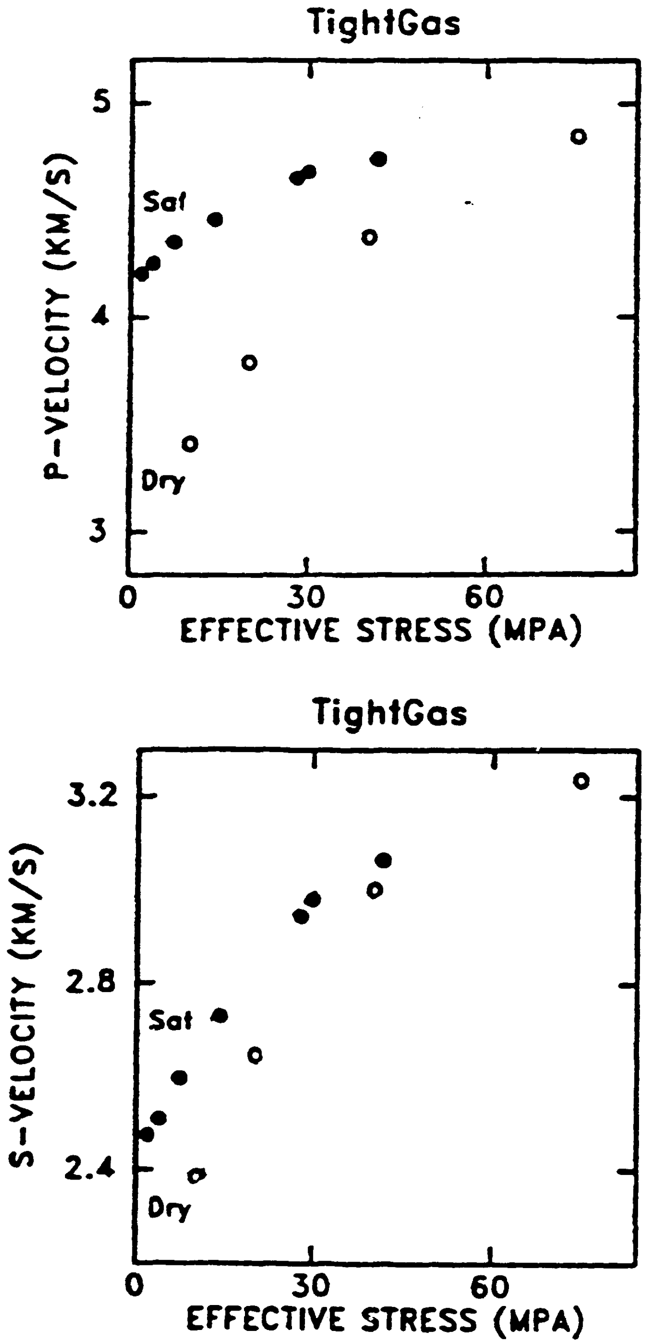

Figure 1. Compressional and shear wave velocities as functions of effective stress in a tight gas sandstone (Coyner, 1984).

The implications of these are that cracks enhance our ability to seismically detect gas vs. water or oil saturation by (1) enhancing the net decrease in Vp with gas, (2) by enhancing the drop in Vp/Vs with gas, and if cracks are aligned, (3) by increasing the degree of velocity anisotropy.

Figure 3 illustrates the effects of crack alignment on seismic anisotropy (Nur, 1971) -- the central feature of seismic strategies for fracture detection. In this case the crack porosity is essentially isotropic at low stress. As uniaxial stress is applied, crack anisotropy is induced by preferentially closing cracks that are perpendicular or nearly perpendicular to the axis of compression. The velocities -- compressional and two polarizations of shear -- clearly vary with direction relative to the stress-induced crack alignment. Similar behavior is expected when cracks are generated by the external stress field or by excess pore pressure.

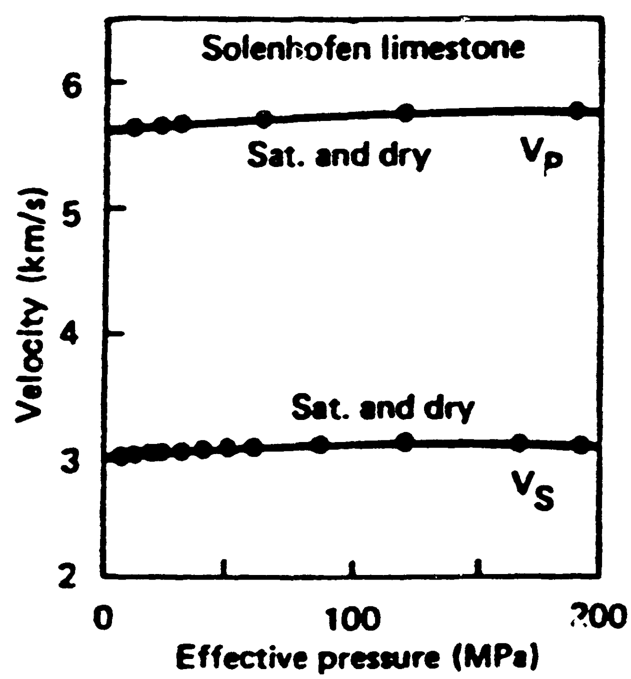

Figure 2. Compressional and shear wave velocities for Solenhofen limestone, which has little crack porosity (Nur and Murphy, 1981).

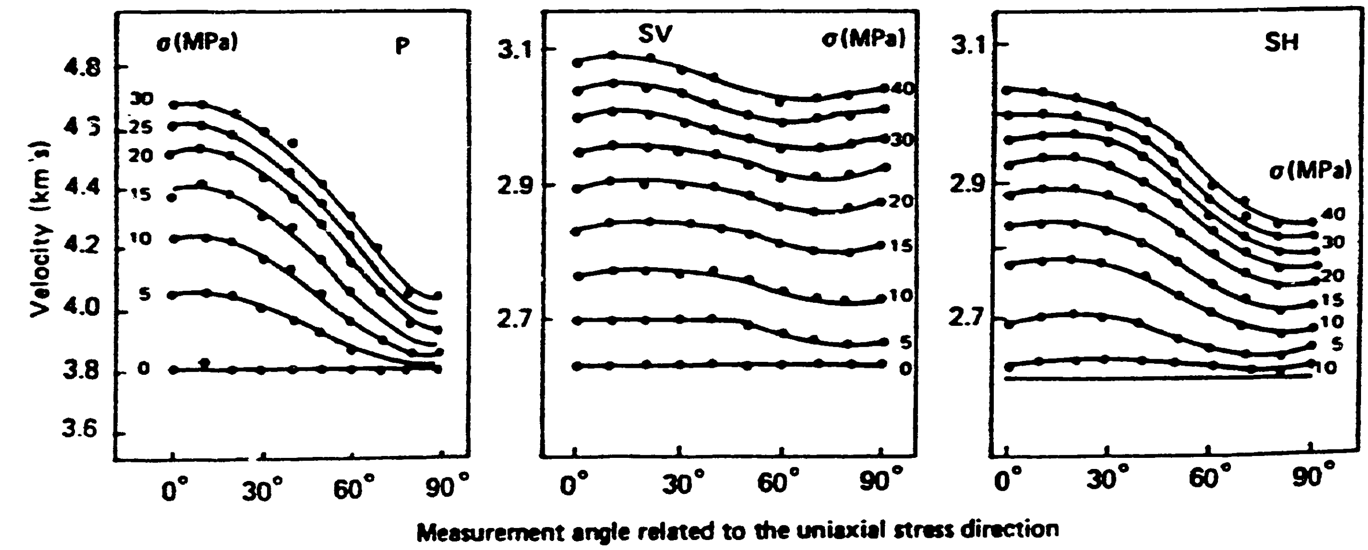

Figure 3. Velocity anisotropy induced on a Barre granite sample by a uniaxial stress. The stress is applied in the direction $\theta=0^o$. The SH wave is polarized perpendicular to the stress direction for any θ. The SV wave is polarized in the plane containing the stress direction (Nur, 1971).

A.V.O. Studies In Isotropic Media

A.G.C. (Automatic Gain Control) can be viewed as a practical tool to raise the seismic S/N ratio in difficult areas and to highlight the structural component of petroleum traps; however, it also destroys the "true" seismic amplitude information, because it applies a time varying amplitude adjustment across the traces. This realization, coupled with care in using AGC, led to numerous works on the analysis of bright spots (Tatham and Stoffa, 1976, Backus and Chen, 1975). Without AGC, proper amplitude balancing of seismic sections becomes essential for comparing reflections at deep and shallow times.

The theory behind A.V.O. analyses in isotropic media is simple. It relies on the fact that the energy of incident P-waves is converted into 4 different waves at each interface. Zoeppritz (1919) was the first to derive a set of equations relating the various displacement amplitudes present at an interface; these were derived from basic physical principles, by using Snells' law, the continuity of displacement, and the continuity of stress across each layer. Using these relations, Koefed (1955) computed amplitudes as functions of changes in the Poisson's ratios His work showed that it is the contrasts in Poisson's ratio across an interface that control the variations in amplitude with offset. In 1982, Ostrander demonstrated that Poisson's ratio had a strong influence on changes in reflection coefficient versus angle of incidence, and that A.V.O. analysis can often distinguish between gas-related amplitude anomalies from other types of amplitude anomalies. In 1961, Bortfeld published a set of equations which approximate the Zoeppritz equations, and which also enhance the importance of the influence of rock properties on reflection amplitudes. As pointed out by Shuey (1985), the Bortfeld approximations remain difficult to interpret in terms of the inverse problem and suggested simplifications - now known as Shueys approximations.

Based on the general relationships between lithology, Poisson's ratio, and effective pressure established by Gregory (1976) and Domenico (1977), gas sands have a significantly lower Poisson's ratio than water or oil sands at shallow depths; this fact can also be verified using Gassmann's relations, so that it can be concluded that the pore fluid type controls Poisson's ratio for a given lithology. However, the contrast in Poisson's ratio is reduced as depth is increased. We conclude that for relatively shallow depths, it should be possible to "see" direct hydrocarbons from seismic data.

Theoretical Studies in Anisotropic Media

Banik (1987) showed that the effects of elastic anisotropy were important in characterizing A.V.O. amplitude anomalies. Based on the hypothesis that most seals in sand-shale sequences are made-up of transversely isotropic shales, it can be said that A.V.O. anomalies in the Gulf Coast cannot be properly modeled by simple elastic isotropic theory. In extreme cases, the A.V.O. trend can even be reversed even more if anisotropy is included. In studying the effects of wave propagation in fully anisotropic media, Samec et al. (1990) showed that it can be inappropriate to neglect anisotropic or anelastic effects, for accurate modeling of pre-stack data. In fact, they showed that the expected trend in reflection coefficient amplitude versus angle of incidence may be reversed from the elastic isotropic case if no special care is taken to compensate for: source radiation pattern, anelastic or anisotropic energy focusing, and phase distorsions, which are due to wave propagation in anelastic anisotropic media.

Anisotropy and anelasticity lead to continuous changes in the phase of the wavelet as it is propagated, and to preferrential focusing of the seismic energy along the wavefront. For these reasons, and because the earth is neither purely elastic nor isotropic, they suggested that displacement amplitude is not the relevant parameter for A.V.O. analysis. Since the amplitude of the displacements is proportional to the energy for a given frequency, they suggested that the total energy within a window around the arrival of interest should be considered instead of picked displacement amplitudes. This new parametrization may not be adequate to place anomalous events correctly in space (migration), but it should allow for a more robust extraction of lithology and fluid content.

The results of the analysis showed that it is both necessary and feasible to correct reflected events for:

- Source radiation pattern,
- Energy focusing, and
- Phase effects

Petrophysical Studies Of Velocity Anisotropy

Recently there has been an increasing amount of empirical evidence of anisotropy, and in particular of transverse isotropy in shales (Tosaya, 1982, Thomsen, 1986, Vernik et al., 1990), and for azimuthal anisotropy in fractured rocks (Thomsen, 1987; Crampin, 1984). Concurrently, the emphasis in seismic petrophysical studies has shifted towards anisotropy (Lo et al, 1985) and anelasticity (Jones, 1986).

Other petrophysical parameters have also been shown to be crucial in the estimation of velocities and anisotropy. In particular, Marion (1990) showed that the location of clays had a strong influence on compressional velocities, Vernik et al.(1990) related the presence of kerogen to velocity and anisotropy measurements in the Bakken shale, and Blangy (1990) showed that it may be possible to map kerogen content directly from seismic measurements.

Theoretical formulations of seismic anisotropy due to aligned cracks and fractures have been given by Hudson (1980, 1981, 1986, 1990a,b), Peacock and Hudson (1990), Nishizawa (1982), and Schoenberg and Douma (1988). Nishizawa's model is based on the solution for an elastic inclusion in an anisotropic medium, and the work of Kinoshita and Mura (1971), Lin and Mura (1973) is valid for all aspect ratios in contrast to the models developed by Hudson and Schoenberg and Douma, which are good for small aspect ratios. Recently Xu et al. (1990) have used Nishizawa's scheme in conjunction with Dienes' (1982) result for permeability of interconnected cracks to model the pressure dependence of wave velocities and hydraulic properties of rock samples containing aligned cracks.

There is a generalized increase in awareness of the importance of reservoir heterogeneities, and this results in the modeling of the effects of microstructure. In the past, the modeling was done by making approximations on the particular geometries of grain shapes or by using networks, but more recently, advances in computer technology has enabled the direct calculation of elastic moduli for any pore geometry (Chen et al, 1990, Dvorkin et al, 1990).

An increasing amount of research is being carried on attenuation and velocity dispersion effects (Jones, 1986, Samec et al, 1990). Recently Jones (1986) showed some of the effects of wave propagation in anelastic media. In particular, he re-introduced a phenomenological model to characterize frequency-absorbtion pairs and related dispersion to wave propagation for shear waves through the product of frequency times fluid viscosity.

At first glance, it may seem that all of these areas of research are unrelated. However, they all converge toward one common goal: the mapping of reservoir heterogeneities, and fracture zones in particular, from high resolution seismic data, and they should be integrated into a common modeling approach.

PROJECT DESCRIPTION

We are involved in an integrated study incorporating four key activities:

- Acquisition and processing of seismic reflection field data.
- Theoretical studies of the anisotropic viscoelastic signatures of fractured rocks.
- Laboratory measurements of seismic properties.
- Integration and interpretation of seismic, well log, and laboratory data, incorporating forward modeling.

Examples of the necessity for integration of methods for accurate reservoir characterization abound in the literature (Hoopes and Aber, 1989, Inouye and Williams, 1988, Robertson, 1989, Brown et al, 1986, among others). Traditional approaches emphasize that the benefits of integration are a better calibration of the seismic and as a result, a better final reservoir description. However, we plan on integrating several methods not only to enable a better calibration of the seismic, but to also enable a better understanding of the petrophysics of wave propagation.

Acquisition And Processing Of Seismic Field Data

A key goal of this study is to develop and demonstrate a practical methodology for locating and characterizing fracture zones using realistic seismic field techniques. Therefore, we have selected a field site with known fracture zones, and acquired surface seismic data that is suitable for our integrated studies.

The study area is located at the southern end of the Powder River Basin in Converse County in east-central Wyoming. It is a low permeability fractured site, with both gas and oil present. Reservoirs are highly compartmentalized due to the low permeabilities, and fractures provide the only practical drainage paths for production. The two formations of interest are:

- The Niobrara: a fractured shale and limey shale to chalk, which is a reservoir rock, but also its own source rock.
- The Frontier: a tight sandstone lying directly below the Niobrara, brought into contact with it by an unconformity.

Theoretical Studies

We are involved with four theoretical aspects of seismic wave propagation in fractured rocks: (1) developing improved formulation relating fracture-induced seismic anisotropy in dry versus saturatured rocks, and at low seismic frequencies versus high seismic frequencies, (2) modeling of the P- and S-wave reflectivities at interfaces between anisotropic formations with arbitrary dips and orientations, (3) forward modeling of propagation in realistic velocity models representing the field site, and (4) exploring the relations between the flow properties of fractures and their seismic signatures.

Laboratory studies

We have begun measuring ultrasonic velocity, velocity anisotropy, and attenuation on a suite of representative cores. The results will be used in all aspects of the modeling and analysis.

Rock physics will play a central role in this project, because it will serve as the basis for integration through deterministic modeling and calibration of rock properties. The manner in which seismic amplitudes are affected by lithology, density, attenuation, frequency dispersion, environmental (in-situ) conditions, fluids, and anisotropy will be addressed systematically.

RESULTS

Data Acquisition

The field portion of this project was undertaken with Amoco Production Co. and ARCO Oil and Gas, in a study area located in east-central Wyoming. Approximately 48 km of 9-component surface seismic data have been acquired, arranged in 4 intersecting 2-D lines. (see Figure 4). The acquistion was done by Amoco's party 45. The P-wave source was four simultaneous P-wave vibrators. The sweep was from 7 to 90 Hz with a duration of 10 seconds. The sweep was repeated four times, and the signals were stacked in the field recorders. Shear wave sources consisted of four rotating base-plate shear-wave vibrators working together, operating in both in-line and cross-line modes. The shear-wave sweep was from 7 to 50 Hz with a duration of 10 seconds. The sweep was repeated eight times and stacked in the field recorders. All sources were recorded by all three receiver components.

Each receiver group consisted of 6 geophones at 5 m spacing. The group interval was 30 m. The shot interval was generally two group intervals, or 60 m. Shots were centered at the half group. Each repeated source sweep was made after a small move-up, so that the total effective source array was always one group interval or 30 m. Each shot record contained 240 groups, at an asymmetric split spread of 180 and 60 receivers. This gave maximum offsets of +5400m (17,700 ft) and -1800m (5900 ft). Near the ends of each line the source walked through the array giving off-end shooting with a maximum offset of 7200m (23616 ft).

All field traces were recorded at 4 ms sampling rate. Useful recorded signal was generally below 40 Hz for P-waves and 30 Hz for S-waves.

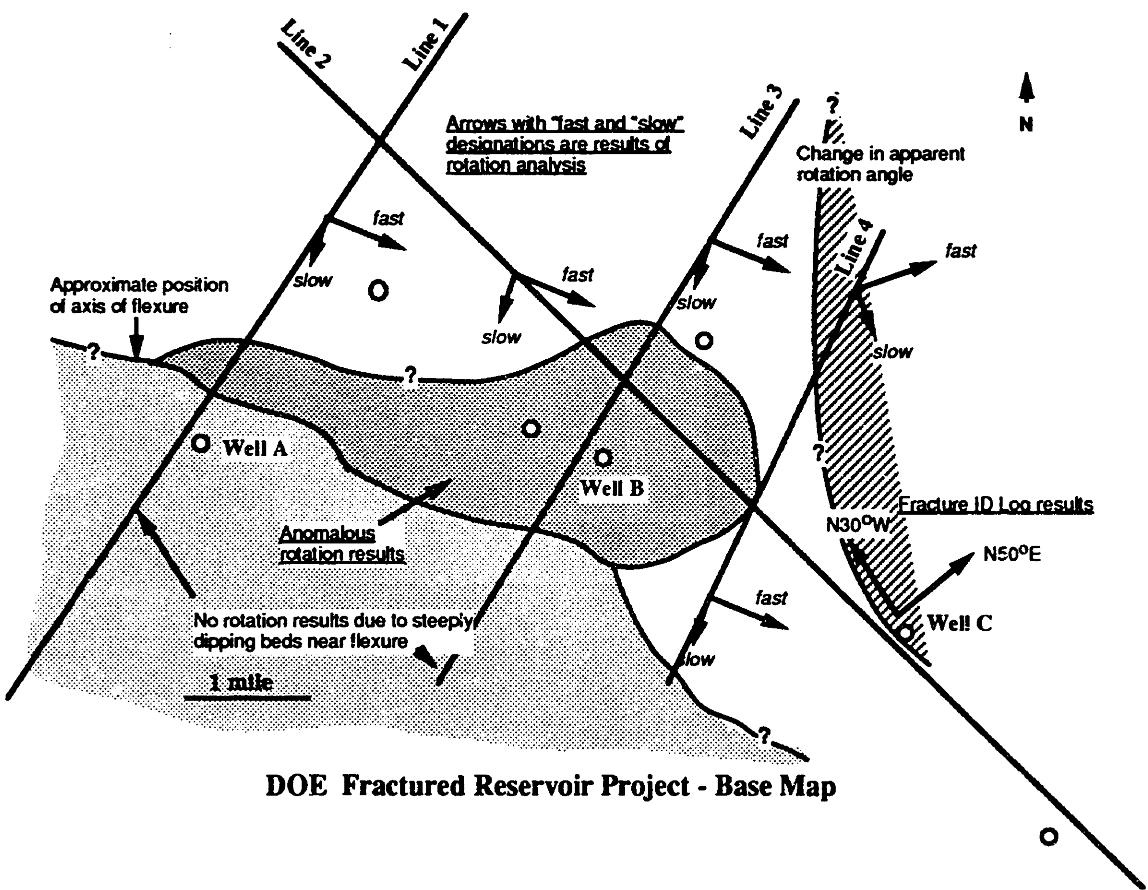

Figure 4. Field Experiment Base Map

Data Processing

It is well known that fractures create S-wave splitting and velocity variations in both P and S wave modes. While we are analyzing shear wave splitting, we will also emphase analysis of P-wave amplitudes, the search for AVO trends, velocity variations, and viscoelastic behavior, as a means to detect fracture characteristics. This approach has several advantages:

- It can be used on conventional P-wave data as well as on S-wave data. The vast majority of existing seismic data is P-wave, and offshore data is (and will continue to be) strictly P-wave. By focusing on shear wave splitting we would limit the range of possible areas that can be characterized.
- Velocity variations can be characterized from conventionally-processed surface seismic lines (either single or multi-component). In contrast, shear-wave splitting requires the development of very specialized particle motion analysis software.
- Envelope amplitude and time delay measurements of reflections are more reliable than measures of reflected event particle motion.

Figure 4 shows the project basemap, with the locations of the four multicomponent lines, and several wells labeled for reference. On this map are superimposed several features. A thin line trending southeast from the western edge of the project marks the beginnings of a steep flexure, beyond which the beds ramp up sharply to the southwest. The flexure marks the southwest edge of the Powder River Basin and can be seen clearly on the seismic lines 1 and 3. At the start of the project, Amoco's geologist speculated that at least some of the fracture sets in the area should trend parallel with the flexure axis, roughly corresponding to the maximum curvature of the beds. We are finding seismic anomalies that are at least qualitatively consistent with this.

The results of rotation analysis of the multicomponent seismic data are marked by arrows designating the fast and slow shear wave polarization directions. Typical analyses suggest that if the seismic anisotropy is related to fractures, then the fractures are trending parallel to the fast axis (which, in fact is roughly parallel to the flexure axis); a conjugate set of fractures is also possible, perpendicular to the main set, but it would be expected (from the typical seismic interpretation) to be less intense. We find the trend of the seismically-inferred primary set of fractures to be fairly consistent over the study area. However there is an anomalous zone trending roughly east-west, shown by the darker shaded region, where the rotation analysis is anomalous and poorly defined, possibly indicating additional fractures superimposed at a different orientation. The northeast end of line 4 shows an anomalous orientation, which is consistent with orientations determined from fracture identification logs from the well labeled "C". The trends from this well are approximately N50°E for the Frontier formation, and N30°W for a group of fractures within the Niobrara. As stated in previous reports, northwest-trending fractures were found by Lewis et al. (1991) for the Niobrara at Silo Field in southeastern Wyoming. Laubach (1992), in a study of the Green River Basin and Moxa Arch area of southwestern Wyoming, noted that Cretaceous and younger deformation has produced north-, northeast- and east-trending fractures in the foreland basins. This latter trend is approximately in agreement with that found in the rotation analysis. However, further work is necessary to reconcile the results from the seismic and those from the well logs, and to interpret the meaning of the interesting "anomalous" (shaded) area.

Figure 5 shows an example of shear-wave mistie between inline-inline and crossline-crossline events after the optimum rotation. There is no observable travel time difference between certain corresponding shallow events, but at greater depth, the mistie is quite large. This indicates that the main sources of anisotropy are in the deeper layers.

In some places, the crosstalk does not vanish for any rotation angle. In fact the events seem to be balanced so perfectly that their relative strength doesn't change much for different rotation angles. We believe that this is caused by either a variable fracture orientation with depth, or a superimposed set of fractures that distorts the symmetry of the material. We have observed several such anomalous zones as mentioned in the previous section.

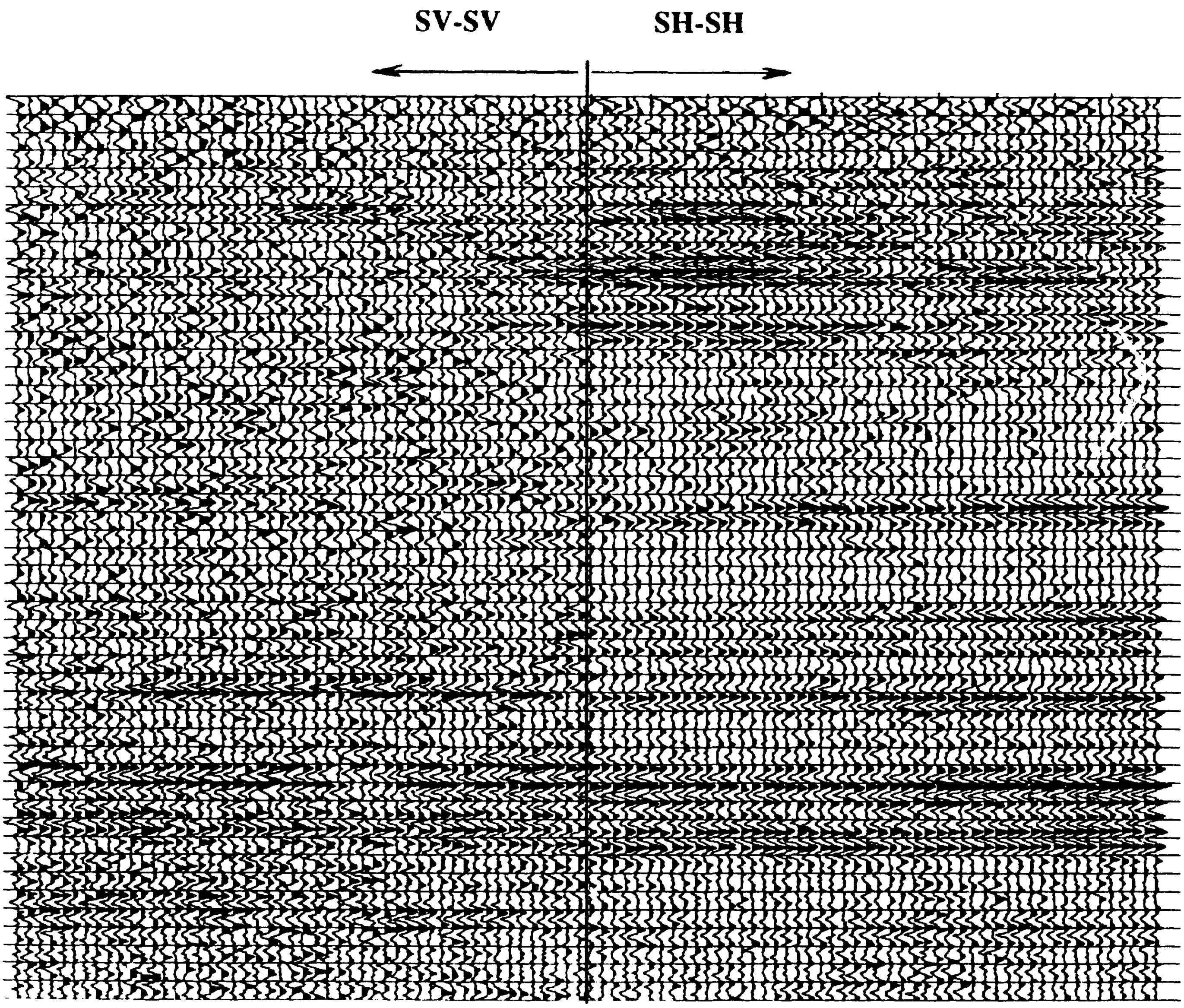

Figure 5. Example of Shear Wave Mistie after Rotation

We are beginning to see large lateral variations in P-wave reflector amplitude. Some of these seem to correlate with areas of anomalous shear-wave polarization. On P-wave true amplitude stacks, the amplitude of theNiobrara decreases dramatically within the anomalous zone. We are in the process of modeling the various causes of P-wave amplitude anomalies: pore fluid changes, fractures, porosity changes, etc.

Theoretical Studies

Most theories of seismic anisotropy due to aligned cracks are inclusion models and have several limitations in common: (1) They are based on idealized pore geometries, such as elliptical cracks, and difficult to determine parameters, such as crack aspect ratio. (2) They are limited to dilute fracture concentrations. (3) Background anisotropy in the mineral fabric is usually ignored. (4) The treatment of the frequency-dependent effects of pore fluids is incomplete or ambiguous.

We have developed a new formulation for analyzing saturation, pressure, and frequency effects in anisotropic rocks with cracks. It is generally independent of idealized crack geometries; it is good for all crack concentrations; it allows for anisotropic backgrounds; and it treats very precisely the effects of pore fluids and frequency. The formulation is an anisotropic extension of the geometry-independent work of Mavko and Jizba (1991).

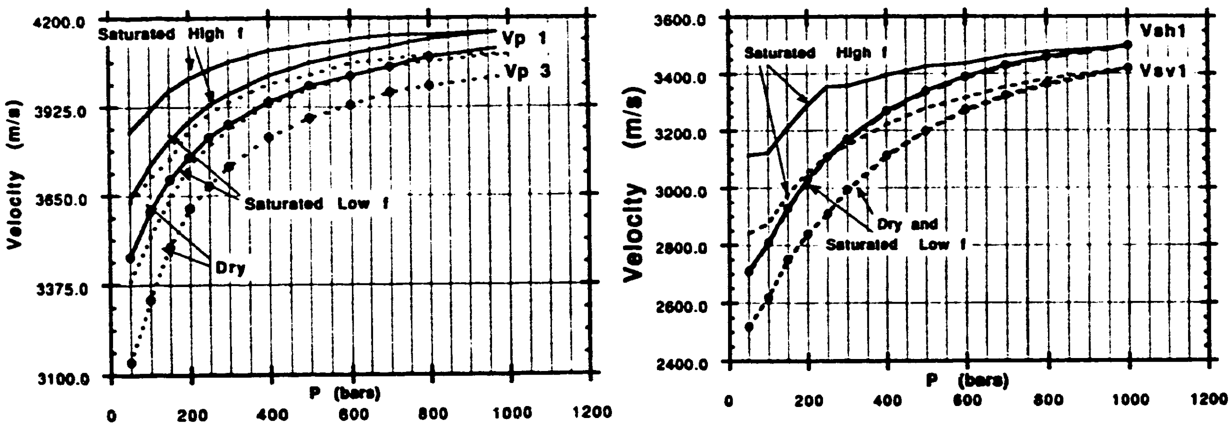

Figure 6. Anisotropic P-velocity in a sandstone (left) and S-velocity in a granite (right). Dots are measured data. Curves are high and low frequency predictions for saturated rocks.

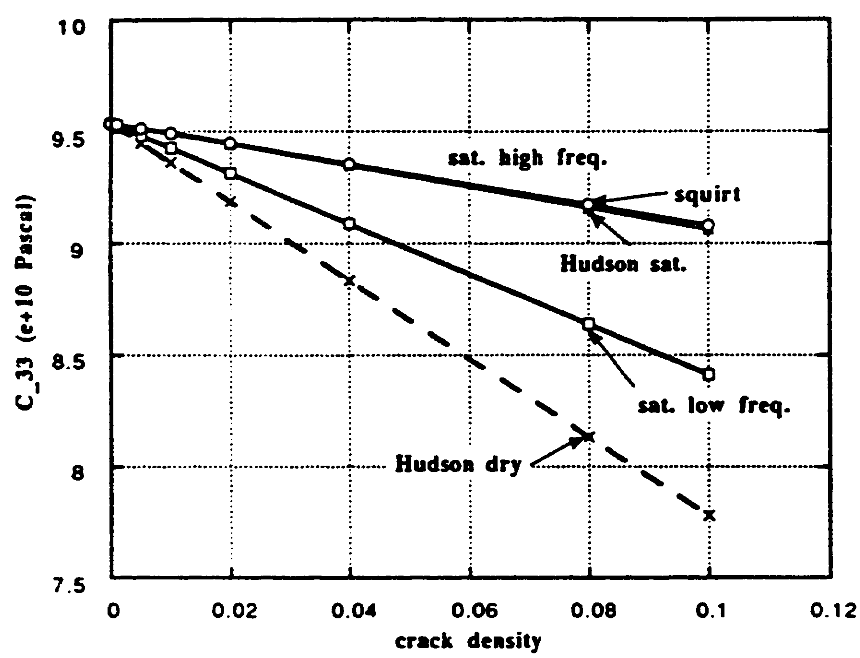

Figure 7. Comparison of dry, low frequency saturated and high frequency saturated moduli for a rock with three mutually orthogonal crack sets.

Under the excitation of a passing wave, pore pressure is induced in the pore space, which stiffens the rock relative to its dry state. At low frequencies the induced pressure is uniform throughout the pore space and the results reduce to those of Brown and Korringa (1971). At high frequencies local pore-scale pressure gradients exist which increse the stiffness further. The pressure distribution and the resulting dispersion depend on the microscopic distribution of crack compliances and orientations. However, all of the information needed to predict this saturated behavior can be determined from measured pressure dependence of dry rock moduli. This is formulated in terms of a generalized pore space compliance tensor, which can be measured from dry data, without the need to assume pore shapes or dilute distributions of cracks.

Using this formulation, we can explore the variations of velocity and velocity anisotropy under different conditions. Figure 6 shows P-wave velocity in a sandstone and S-wave velocity in granite, both of which are approximately transversely isotropic. The solid curves correspond to the "fast" direction and the dashed curves to the "slow" direction. The solid circles are measured dry rock velocities (Coyner, 1984). The additional curves are estimated saturated rock velocities at low (in situ) frequencies and high (laboratory) frequencies. The increase of velocity with pressure indicates the presence of compliant crack-like porosity.

Anisotropy in all cases persists to high pressure, when most of the crack porosity is eliminated. This intrinsic non-crack anisotropy appears to account for most of the total anisotropy, even at lower pressures. Therefore, it would be incorrect to interpret the velocity anisotropy at any particular pressure entirely in terms of aligned cracks, as is often done.

The effects of saturation are variable and depend strongly on frequency. The P velocities in the sandstone are predicted to increase with saturation. At low frequencies, the pressure dependence and the anisotropy are slightly decreased. At high frequencies, the velocities are substantially higher, and the pressure dependence and anisotropy are reduced further. For the S velocities in granite, low frequency saturated velocities are virtually the same as the dry velocities. However, the high frequency saturated velocities are substantially increased, the pressure dependence is reduced, and the anisotropy is increased.

Figure 7 illustrates some frequency effects using a simulation of a rock with three mutually orthogonal crack sets. At low frequencies (such as in the field) pore fluid generally has time to flow and equilibrate under the stresses of a passing wave, while at high frequencies (as in the lab) the induced pore pressures remain unequilibrated. This causes a generally larger effective stiffness and higher seismic velocity in the lab than in the field. The figure shows one element of the effective elastic tensor (C_{33}) as a function of crack density. We show the dry modulus (as predicted by Hudson's, 1991, theory for dry rocks), the saturated high frequency modulus (our new formulation and Hudson's theory for saturated rocks) and the saturated low frequency values. Note the change in going from dry to saturated and when saturated from low frequency to high frequency. Hudson's theory is used in virtually every field study to interpret the observed anisotropy. Yet, this illustrates the very important result that Hudson's is a very high frequency theory which is appropriate for the lab, but must not be applied to the field, without corrections for low frequency.

In summary, our new formalism provides a flexible means to explore saturation, pressure, and frequency effects in anisotropic rocks. We find that: (1) Anisotropy can have a substantial non-crack component which can introduce errors into conventional crack interpretations; (2) Velocities and velocity anisotropy may or may not change between dry and saturated conditions. Fluid saturation sometimes increases anisotropy and sometimes decreases it, depending on the rock, the stress state, and the frequency; (3) Saturation effects are sensitive to the distribution of crack orientations, and in some cases a single set of parallel cracks may not be adequate. (4) Velocities and velocity anisotropy can change dramatically with frequency. Consequently great care must be taken when extrapolating laboratory results to the field or when "validating" a particular model with laboratory data.

FUTURE WORK

Our future activities on the project will involve substantially more processing of the field seismic data with emphasis on amplitudes, analysis of laboratory data to help quantify the seismic signature of the fractured reservoir rocks, and seismic forward modeling and integrated interpretation of the field data to develop improved methods of fracture detection and characterization.

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NG-2.2 Fracture Detection, Mapping, and Analysis of Naturally Fractured Gas Reservoirs Using Seismic Technology

CONTRACT INFORMATION

Contract Number	DE-AC21-92MC28135
Contractor	Coleman Research Corporation 5950 Lakehurst Drive Orlando, FL 32819
Contractor Project Manager	Dr. Pieter Hoekstra
Principal Investigators	Dr. Heloise Lynn, Lynn Incorporated
METC Project Manager	Royal Watts
Period of Performance	09/23/92 - 10/23/94
Schedule and Milestones	FY1993-94 Program Schedule

	(1993)						(1994)					
	S	O	N	D	J	F	M	A	M	J	J	A
Test Plan												
Fabrication	N/A											
Testing							←——→					
Analysis									←————			

OBJECTIVE

There are a number of producing gas fields in the United States where production is controlled by natural fractures. The host rock may consist of low porosity, low permeability formations, and wells completed in the unfractured rock have low productivity. On the other hand, wells intercepting fractured rocks may show good production. The objective of the research under this contract is to improve the technology for detecting fractures by surface geophysical methods. This remote detection of fractures will allow optimum placement of vertical or horizontal wells.

BACKGROUND INFORMATION

Seismic reflection prospecting is the dominant geophysical technique employed in hydrocarbon exploration. Compressional (P-) wave surveys are most common, both historically and at present. From P-wave reflection surveys structural information in sedimentary basins is derived. More recently, from reflection amplitude variation with source-receiver offset, detection from the earth's surface of a change in pore fluid has been achieved. Investigations by major oil companies and academic institutions, mainly in the last ten years, have established that relative fracture density and fracture orientation information are contained in shear-wave reflection seismic data. The specific objectives of the research is to further document and improve deriving fracture information from shear (S-) wave and P-wave multicomponent reflection surveys.

In 1985, Dr. Stuart Crampin published a theoretical treatment of seismic wave propagation in anisotropic media. His work stated that in a medium with vertical aligned fractures, only two polarizations of the vertically propagating S-wave can exist: (1) the S-wave polarized parallel to the fractures (that is, with particle motion parallel to the fractures), which travels at approximately the uncracked rock shear-wave velocity; and (2) S-wave polarized perpendicular to the fractures, which travels at a lower velocity dependent upon fracture density. These two shear waves are commonly designated as S1 and S2, respectively. When a shear wave is polarized at an intermediate orientation to the principal axis of the fractures, the shear wave will split in the fractured medium into the two allowed polarizations. The time delay between the two "split" shear waves is proportional to the fracture density. These statements have been verified by experimental observations in the field and in the laboratory.

Oil industry field data experience of shear wave splitting dates from the earliest 1980's, later published in 1986 by Amoco (Thomsen, 1986; Ral and Hanson, 1986; Lynn and Thomsen, 1986; Alford, 1986; Willis, Rethford, and Bielanski, 1986) and subsequently by other oil companies. To interpret the seismic anisotropy observed in a field data set in terms of fracture orientation and relative fracture density, requires the acquisition of a multicomponent VSP (Vertical Seismic Profile), with input from the geologic data (cores, wireline logs), knowledge of the in-situ stress field, and production data (including evidence on the preferred flow direction within the reservoir).

PROJECT DESCRIPTION

The critical components of the project are:

1) Selection of a gas field with known production from naturally occurring fractures. The project scope does not allow for drilling of wells, so that evidence for occurrence of fractures and gas production from fractures must be obtained from existing wells' field production history, and other data.

2) Acquisition of both surface and downhole seismic P-wave and S-wave data. The project will acquire one 9-component (9-C) VSP. In a 9-C VSP survey, seismic events are recorded by 3-C geophones from one P-wave, and two perpendicular oriented S-wave sources (SH and SV). Also, approximately 12 miles of 9-C surface seismic data will be acquired.

3) Processing and interpretation of 9-C VSP and 9-C surface seismic data, and correlating the seismic anomalies observed to all available geologic and production information to show how the variations in seismic response is related to fracture density, fracture orientation, lithology, structure, and production history.

RESULTS

The project goals were announced to the oil and gas industry, and they were encouraged to submit their field for the investigations. Five companies prepared a submittal, and Table 1 is a listing of the fields and their rating in terms of technical criteria. Table 2 is a listing of all the criteria applied to site selection.

Table 1. Rating According to Technical Criteria of Five Sites

Gas Field Proposed	Company	Evidence for 2-D Structure	Risk of Obtaining Low Quality Surface Seismic Data	Evidence of Production from Natural Fractures
Bluebell-Altamont Uinta Basin, UT	Pennzoil	Good	Low	Excellent
Madden Field Wood River Basin, WY	LL&E	Poor, likely 3-D structure	High (shale layer overlies producing horizon)	Excellent
Wight Unit in Texas	Conoco	Good	Low	Good
Giddings Field, Austin Chalk, Central TX	Union Pacific Resources Company	Good	Moderate (may be too deep)	Good
Mayberry Field, NW Colorado	Coastal Oil & Gas	Good	Moderate (may be too deep)	Good

Table 2. Criteria Applied to Site Selection

Technical Criteria

- Probability of acquiring high quality P-wave and S-wave reflection data at depth of occurrence of producing horizon.
- Strength of evidence of gas production from natural fractures.
- Complexity of geologic structure (2-D structures preferred over 3-D structures).

Government Benefit Criteria

- Cost-sharing by industry.
- Release of proprietary information.
- Federal lease.

The field selected was Pennzoil's Bluebell-Altamont Field, Upper Green River gas production, northern Uinta Basin, northern Utah. The Upper Green River gas field has established production from the last major lacustrine deposition within the Uinta Basin. Natural gas is being produced from the upper Green River formation between 6,500 - 8,500 ft. Producing rates from these zones ranges from 100 MCFPD to over 5000 MCFPD. Prior lacustrine deposits comprise the Wasatch (oil) and Lower Green River (oil and gas). Gas reservoirs within the upper Green River are trapped by updip pinchouts of the prograding lake margin. Producing intervals consist of fractured lake-margin sandstones encased within tight shales and carbonates of the lacustrine deposits. The evidence of fractures are seen in: (1) cores, (2) FMS, (3) sonic logs, and (4) production rates from perforated zones whose core matrix permeability and porosity would not support observed production rates. The sandstones which produce gas have matrix porosity of < 8% and permeability of < 1 md. Production has been enhanced in several wells with hydraulic sand fracturing. Sandstones in non-fractured wellbores are capable of producing at rates of 100 to 300 MCFPD, whereas wells from naturally or artificially fractured wellbores produce at rates from 1000 to 5000 MCFPD. There is concurrent Class I Reservoir DOE work in the Bluebell-Altamont field being conducted by the Utah State Geological Survey, Salt Lake City, Utah. It is planned to examine this data and to evaluate its potential use within this project.

The terrain is believed to be accessible to vibroseis (seismic sources), and seismic reflection crews are operating in this part of the Rocky Mountains. Crew mobilization fees could thus be kept to reasonable levels. The quality of previously acquired P-wave seismic data is good to excellent, showing minimal problems with either statics or near surface velocity anomalies. An on-going drilling program will use the results of the DOE study to help pick well locations. Identification of by-passed pay might also be established by this study, and Pennzoil would be interested to test this information.

In July 1993 a site visit was made to the field. During this visit the existence of orthogonal joints and fracture sets in outcrops were verified, and locations of approximately 12 linear miles of seismic lines were selected parallel and perpendicular to the fracture trends. During this visit it was also determined that access for use of vibrators along the seismic lines was good. A NEPA report for the investigation was submitted to DOE.

FUTURE WORK

The acquisition of the 9-C surface seismic and 9-C VSP's is planned for the spring of 1994. An important incentive for acquiring both S-wave and P-wave reflection data is that P-wave amplitude variation with offset (AVO) data is available for hundreds of thousands of P-wave reflection surveys. Knowledge about the location of the fractures, as determined from the S-wave analyses, will highlight zones of interest within the P-wave data set for detailed study. Thus, a way for reprocessing and re-interpreting the P-wave data for fracture information may be achieved.

Also, S-wave reflection surveys are more expensive (≈ $30,000 per mile) to acquire than P-wave reflection surveys (≈$10,000 per line mile). Therefore, if it can be proven that fracture information can also be derived from special processing of P-wave surveys, there is a large cost advantage.

In processing and interpretation of the 9-C VSP and 9-C surface seismic line, emphasis will be placed on correlating four diverse data sets. These are (1) the seismic anisotropy, (2) the in-situ horizontal stress field orientation, (3) the natural fractures' orientation and magnitude from cores, FMS, borehole televiewer, etc., and (4) the direction of preferred flow direction in the reservoir. All four items are necessary to add to the reservoir characterization.

Since this research offers an unique opportunity to directly correlate anomalies in seismic data to known fracture information, the data set will be carefully processed to bring out special events in P-wave and S-wave data, such as:

1) A change in P-wave velocity (decrease) in zones identified to be fractured in S-wave data.

2) Information about relative fracture density from P-wave AVO data, and the influence on AVO of orientation of the seismic line with respect to the fracture. This is the impetus for acquiring data both parallel and perpendicular to the fracture.

3) Changes in seismic polarization in highly fractured zones. These changes can be documented by the borehole VSP.

4) Information from the mode-converted (P-S) seismic data sets.

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NG-2.3 Geotechnology for Low Permeability Gas Reservoirs

CONTRACT INFORMATION

Contract Number	DE-AC04-76DP00789 (FEW-2086)	
Contractor	Sandia National Laboratories P.O. Box 5800 Albuquerque, NM 87185-5800	
Contractor Project Manager	David A. Northrop (505) 844-2302	Department 6112
Principal Investigators	John C. Lorenz Norman R. Warpinski Lawrence W. Teufel	Department 6117 Department 6114 Department 6117
METC Project Manager	Royal J. Watts	
Period of Performance	April 1, 1992 to September 30, 1993	
Schedule and Milestones	**FY93 - FY94 Tasks**	

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                              |        FY93          |          FY94          |
                              O N D J F M A M J J A S O N D J F M A M J J A S
Slant Hole Completion Test    -------|
Fractured Reservoirs:
           Green River Basin  ------------------------------------------------
         Support to Industry  ------------------------------------------------
Geomechanics:
                 Lab Studies  ------------------------------------------------
   Effective Stress Analyses  ------------------------------------------------
        Methodology Report    -----------------------|
Geophysical Data Set                                  |----------------------|
Support to METC               ------------------------------------------------
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OBJECTIVES

The objectives of this program are (1) to use and refine a basinal analysis methodology for natural fracture exploration and exploitation, and (2) to determine the important characteristics of natural fracture systems for their use in completion, stimulation and production operations.

BACKGROUND INFORMATION

Natural fractures are the critical production mechanism in most of the low permeability gas reservoirs in the western United States. Of particular interest are the regional fracture systems that are pervasive in western US tight sand basins. Regional fractures are created by anisotropic stress fields, usually under conditions of high pore pressure (Lorenz et al., 1991). In such systems, fractures tend to be primarily unidirectional, and thus poorly interconnected (Lorenz and Finley, 1991). This facet of western US tight gas reservoirs has been one of the primary causes of poor success in obtaining economic production from these tight reservoirs.

If these fracture systems are to be economically exploited, it is necessary to determine where fractures exist, what their characteristics are, and how the fractures interact with the reservoir geometry, in situ stresses, and other factors. Natural fracture basinal analysis, which integrates core, log, outcrop, and well test data into a tectonic and fracturing framework, provides a means for obtaining a useful characterization of the natural fracture system. Results from seismic analyses, if proven to be effective in detecting fracture systems, can also be incorporated within this framework.

Successful stimulation and production of these reservoirs also requires a knowledge of the properties of the fracture systems, such as the stress sensitivity and damage propensity. The factors need to be evaluated through a combination of field and laboratory studies, in which individual fractures (lab) and fracture systems (field) are studied. Such studies provide the necessary information for optimizing reservoir management strategies.

PROJECT DESCRIPTION

Continuing work (Lorenz et al., 1993) on this project has demonstrated that natural fracture systems and their flow characteristics can be defined by a thorough study of well and outcrop data within a basin. Outcrop data provides key information on fracture sets and lithologic controls, but some fracture sets found in the outcrop may not exist at depth. Well log and core data provide the important reservoir information to obtain the correct synthesis of the fracture data. In situ stress information is then linked with the natural fracture studies to define permeability anisotropy and stimulation effectiveness. All of these elements require field data, and in the cases of logs, core, and well test data, the cooperation of an operator.

Such a systematic study has been performed in the southern Piceance basin, with the Multiwell Experiment (MWX) providing the key subsurface information. Other wells in the surrounding region have confirmed the MWX data and supported the findings. Currently, a similar effort is ongoing in the Green River basin and in other fractured reservoirs. Through such studies, these procedures can be refined, but a key need is access to more and better field data. Thus, cooperating with industry to obtain non-routine, extra data on "wells of opportunity" are an important part of this project. The result is a better understanding of the dynamics of fractured reservoir behavior.

Laboratory studies of the stress sensitivity and permanent damage to natural fractures have aided in interpreting reservoir response. Such lab studies require conductivity measurements of single natural fractures under a wide range of stresses and pore pressures. Matrix poroelastic studies are also required to estimate the stress change within a reservoir as pressure drawdown occurs. Special laboratory procedures were developed previously in this project, and are now being applied to a wide variety of rocks. These detailed lab measurements are required to understand the flow characteristics of the matrix rock and fracture system throughout the life of a reservoir.

RESULTS

The following three sections present brief examples of the types of information gained from some different parts of this project.

Natural Fracture Characterization

Figure 1 shows data on natural fracture orientations and locations as revealed in horizontal core from the Slant Hole Completion Test (SHCT) core. This fracture system is a

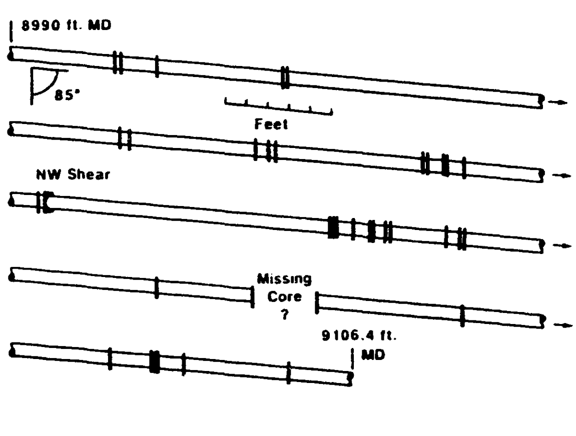

Figure 1. Fractures in SHCT-1 Core

regional, unidirectional, system, whose existence was essentially inferred during MWX and confirmed in this SHCT core. Of note are the non-regular spacings of fractures, which appear in a series of groups or swarms. Thus "Average Fracture Spacing" is not a useful number. Rather, the typical spacings of fracture groups is a better number to use in simulation models, as these give a more realistic value for the distribution of the permeable fracture conduits for gas. This spacing seen in core is similar to the spacing of gas shows observed while drilling (Lorenz and Hill, 1991).

These natural fractures are vertical and thus they have a minimum probability of being intersected by the typical vertical well. So little information is gained about the fracture system. This project addressed how to optimize the amount of natural fracture data from a pilot well. If the pilot well is deviated by 30 degree from vertical, the probability of intersecting a vertical fracture in a 35-ft thick pay increases by up to 6200% where the wellbore's azimuth is oriented normal to the fracture strike. However, even if the fracture strike is unknown, there is a two-thirds chance of intersecting at least half of this percentage with a randomly oriented wellbore azimuth (Lorenz, 1992). A company, based on Sandia recommendations, recently drilled a 30-degree deviated pilot well in order to assess natural fracture orientation and characterization at a site in the Green River basin. This slanted pilot well was successful in providing the data required to determine the regional fracture system's azimuth, and the company confidently drilled a horizontal well at this location.

Effective Stress

The effective stress law of a material defines a relation for the interplay of confining stress and internal pore pressure on a given property or process. The stress law is usually expressed in the form:

$$P = G(\sigma - \alpha p),$$

where the property or process, P, may include, for example, permeability or deformation, G( ) is some generalized function that describes the effect of stress on P, σ is the external confining stress on the sample, p is the internal pore pressure, and α is the poroelastic parameter that relates stress and pore pressure. Generally, α is assumed to be a constant and equal to 1.0. However, an accurate knowledge of α as a function of σ and p is required for confident understanding and modeling of reservoir behavior during such normal operations as drawdown, water flooding, and stimulation. Unfortunately, few studies of α are available. This project has focused upon determinations of α for tight sandstones and carbonates (e.g., Warpinski and Teufel, 1992).

An experimental apparatus and analytical procedures have been developed that allow for the routine determination of α. Figure 2 shows the measured permeability (k)-stress (σ)-pore pressure (p) relationships, as well as the resulting α for permeability, for a Mesaverde Cozzette sandstone. Of note is the large decrease in α at high effective stress. This shows that the common assumption of α=1 is not very good for such low permeability rocks.

Figure 3 shows the α for deformation as a function of depth at the MWX site. Again, the divergence between measured and theory indicates that α needs to be measured for tight rocks as simple theory is not adequate.

Similar measurements have been made on samples containing single natural fractures. The experimental procedures are complicated by the need to correct for turbulence and to note any irreversible closure behavior. Two Mesaverde Cozzette samples showed relatively little stress sensitivity, and nearby mudstones showed irreversible closure behavior.

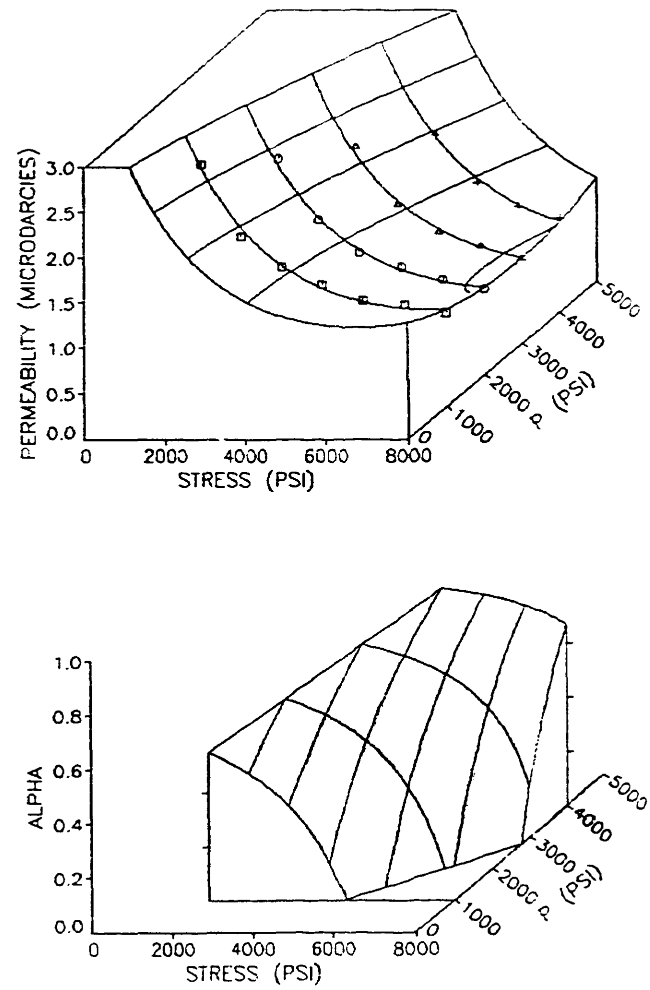

Figure 2. Effective Stress for Permeability

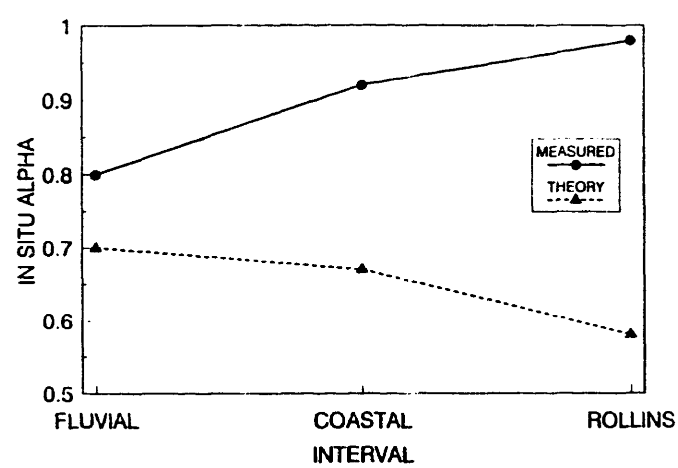

Figure 3. Alpha for Deformation vs. Depth

Stress Path

Knowledge of in situ stress and how stress changes with reservoir depletion and pore pressure drawdown is important in a multi-disciplinary approach to reservoir characterization and management. Stress affects nearly all petrophysical properties and hence the measurement and interpretation of laboratory, well test, and geophysical data. Hydrostatic (isotropic) loading is the conventional test procedure followed by the petroleum industry to determine the stress dependence of reservoir properties. However, hydrostatic tests do not truly reflect the stress anisotropy and deviatoric stress state that exists in most reservoirs and do not adequately simulate the changing stresses in a reservoir during production (e.g., Teufel et al., 1993) In situ stress measurements made in wells during pore pressure drawdown show that many reservoirs follow a stress path (defined as the change in effective horizontal stress/change in effective overburden stress from initial reservoir conditions) that is significantly different than either a constant total-stress boundary condition (hydrostatic loading) or a uniaxial-strain boundary condition (i.e., no lateral displacement of the reservoir boundaries).

Triaxial compression laboratory tests on a variety of reservoir rocks show that compressibility, permeability, and sonic velocity vary markedly with stress path (Rhett and Teufel, 1992). Thus, changes in properties measured under hydrostatic loading conditions to predict reservoir response during production and pore pressure drawdown can be inaccurate and very misleading if applied to a reservoir that follows a non-hydrostatic stress path. Realistic predictions of reservoir behavior require petrophysical property measurements of reservoir matrix rock and fractures made in the laboratory under loading paths that duplicate the stress path followed by the reservoir during production.

For example, analysis of MWX data shows that this reservoir (in the Rulison field) followed a relatively high stress path of 0.76 (Figure 4). This path is less than isotropic loading (K=1.0) and considerably greater than K=0.25 predicted by uniaxial strain tests. Fracture closure and large reductions in reservoir permeability and productivity can occur in reservoirs that follow high stress paths. In sharp contrast, permeability and productivity are maintained in reservoirs with low stress paths (Figure 5), such as the Ekofisk field, because there is only a relatively small increase in the horizontal stress across steeply dipping fractures.

FUTURE WORK

Future work in FY 94 will consist of three main efforts:

- We will continue its geologic field work and its efforts with industry on wells-of-opportunity in order to obtain high-quality information on natural fractures and stresses and reservoirs of interest.

- We will also continue our geomechanics-related measurements and analyses (stress sensitivity, damage, poroelasticity, stress path, etc.) on appropriate reservoir rocks where information is lacking.

- We will analyze a unique in-situ, seismic data set that will be obtained as part of the DOE-Gas Research Institute's M-Sites Experiment to determine the ability of seismic techniques to define a typical regional fracture system.

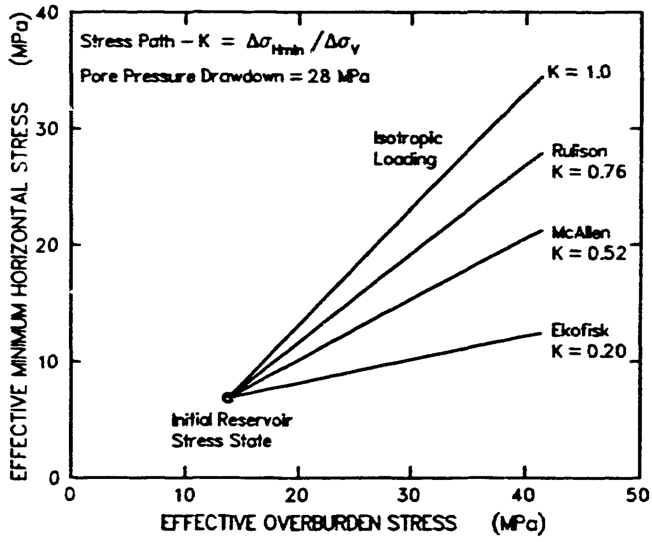

Figure 4. Examples of Different Stress Paths (from Teufel et al., 1993)

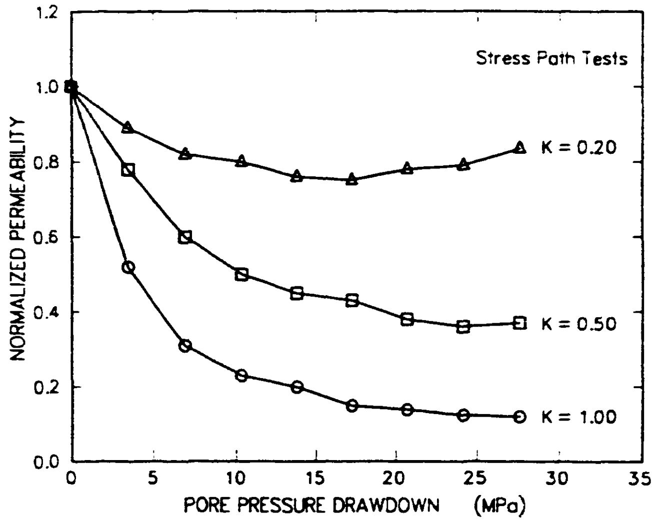

Figure 5. Effect of Stress Path on Permeability (from Teufel et al., 1993)

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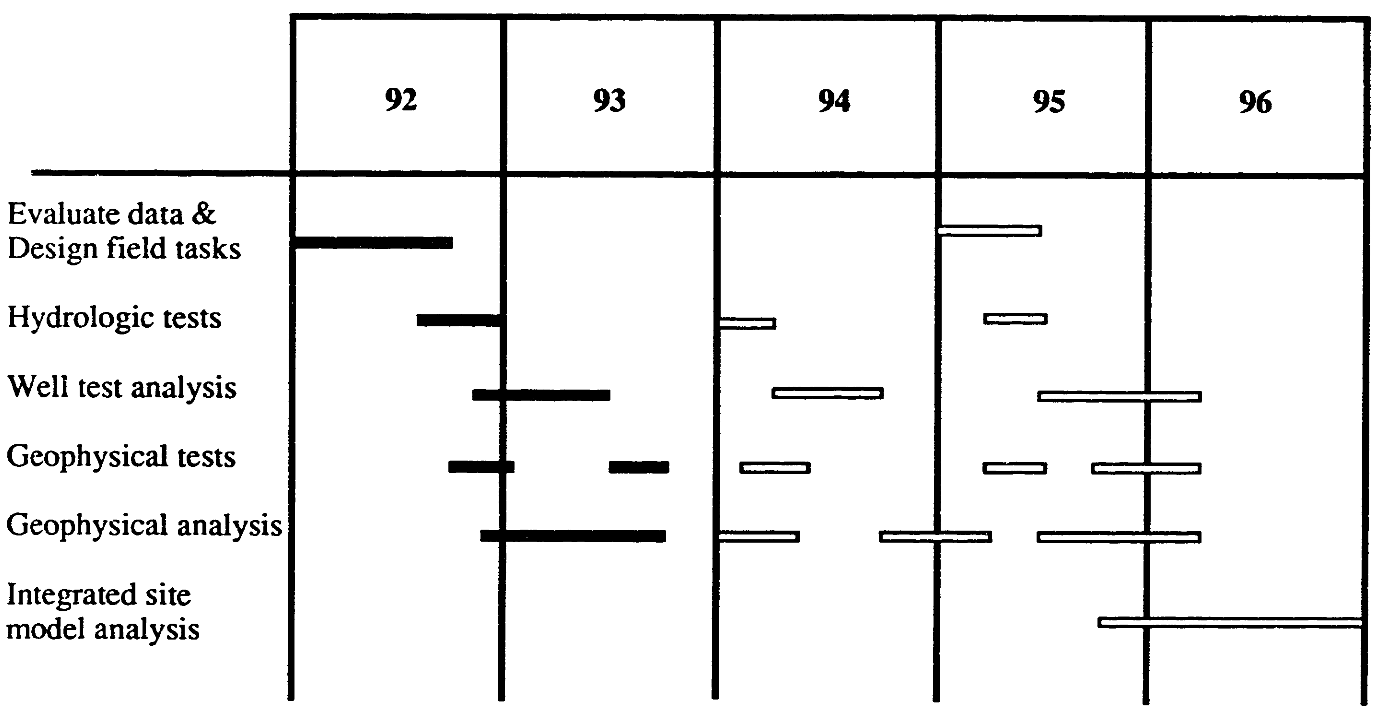
NG-2.4 LBL/Industry Heterogeneous Reservoir Performance Definition Project

CONTRACT INFORMATION

Progress Report:	October 1, 1993
Contract Number	DE-AC03-76SF00093
Contractor	Lawrence Berkeley Laboratory 1 Cyclotron Road Berkeley, CA 94720
Contractor Project Manager	Sally M. Benson
Principal Investigators	Ernest L. Majer Jane C.S. Long
METC Project Manager	Royal J. Watts
Period of Performance	Sept. 10, 1991 to Sept. 10, 1996



Introduction

One of the problems facing the petroleum industry is the recovery of oil from heterogeneous, fractured reservoirs and from reservoirs that have been partially depleted. In response to this need, several companies, notably British Petroleum USA, (BP) and Continental Oil Company (Conoco), have established integrated reservoir description programs. Concurrently, LBL is actively involved in developing characterization technology for heterogeneous, fractured rock, mainly for the DOE's Civilian Nuclear Waste Program and Geothermal Energy programs. The technology developed for these programs was noticed by the petroleum industry and resulted in cooperative research centered on the petroleum companies test facilities. The emphasis of this work is a tightly integrated interdisciplinary approach to the problem of characterizing complex, heterogeneous earth materials. In this approach we explicitly combine the geologic, geomechanical, geophysical and hydrologic information in a unified model for predicting fluid flow. Described here is a comprehensive program between DOE and industry that uses this philosophy through an integrated field testing effort that focuses on realizing techniques for providing an integrated petroleum reservoir description. The work described here is the work being carried out at Conoco's Newkirk test facility. Later phases of the work will involve actual application at a production field.

Under DOE funding, LBL participates in the geologic and geophysical investigations at the test facility. LBL scientists work cooperatively with Conoco personnel in both the exploration and production departments. Amoco and Phillips Petroleum are also involved with the Conoco test facility and are contributing to this effort. The basic concept of the work is to develop and integrate the various geophysical and hydrologic methods through a focused research effort at a few well calibrated and characterized sites. The first phase of the work involved modeling and planning field experiments by applying the techniques described above adapted from the technology developed in DOE nuclear waste and geothermal programs to existing seismic and hydrologic data. The second stage, described here, is to actually carry out joint DOE/Conoco field experiments at the industry sites. To date the work has focused on using high resolution crosshole seismic imaging and (VSP) for fracture detection in both shallow and deep test holes. This is being combined with the development and application of the hydrologic inversion methods for fractured reservoirs.

Conoco Facilities

Conoco has established a borehole test facility (BHTF) near Newkirk, Oklahoma. There is a set of shallow wells, the GW series, and a set of deeper wells, 33 series, at this test facility. The shallow 5 wells range from 100 to 200 foot separation, all approximately 150 feet deep (see Figure 1). This shallow site is in an aquifer confined by shale layers. A series of deep test wells, the 33 series wells in Figure 1, have been drilled and used by Conoco for geophysical tests and are planned for use in hydrologic and tracer tests. These wells are up to 2300 feet deep in a fractured shale and limestone sequence. These boreholes at the test site have been well characterized in order to have a calibrated test site for technique development and research fluid flow through fractured rock. Also, a short distance

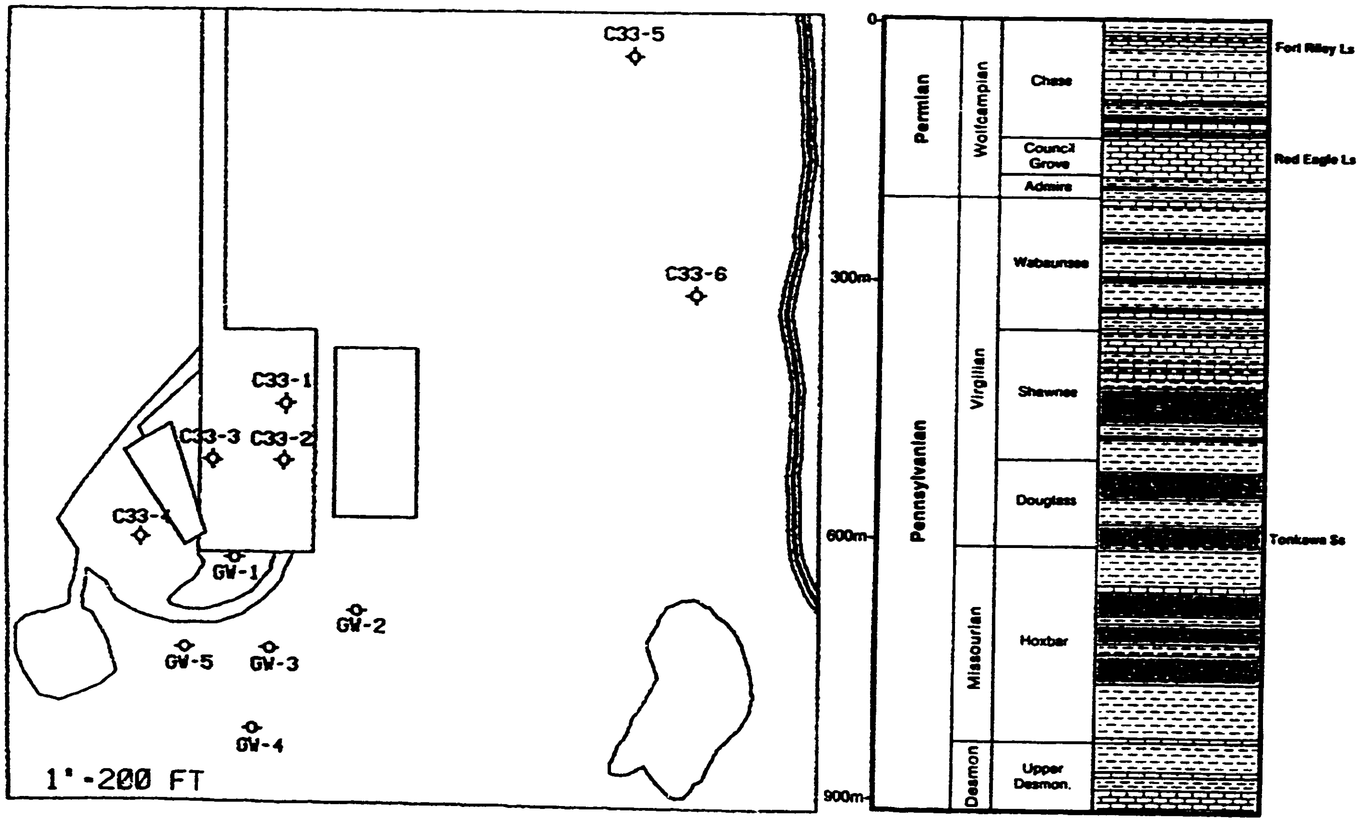


Figure 1. Conoco borehole test facility

away, there is a shallow limestone formation that has extensive exposure which is ideal for geologic investigations. To date Conoco has carried out extensive geophysical and geologic studies on the site to characterize the geologic structure that may influence the hydrology. The first step was the design of the hydrologic and additional geophysical studies for determining the properties that influence the details of the hydrologic behavior in fractured rock. We are currently applying high resolution seismic crosshole imaging in both the deep and shallow wells and developing hydrologic inversion techniques for integration of geologic and geophysical information.

Seismic Imaging

The seismic portion of this project to date has consisted of data acquisition, processing and analysis for three different data sets. The data sets were all acquired at Conoco's Newkirk, OK test facility, and each had different goals. First was a Vertical Seismic Profile (VSP) survey, acquired by Conoco and processed/analyzed by LBL. Second was a set of cross-well surveys in the ground water wells (gw1, gw2, gw3, gw4, gw5). Third was a cross-well survey in deep wells 33-5 and 33-6.

VSP

The 9-component VSP data (Figure 2) was used to understand the seismic response as a function of depth over the 3000 ft. depth of well 33-1. Analysis of the 9-component VSP data for well 33-1 focused on indications of seismic anisotropy as indicated by shear-wave splitting (a difference in travel-time between orthogonally

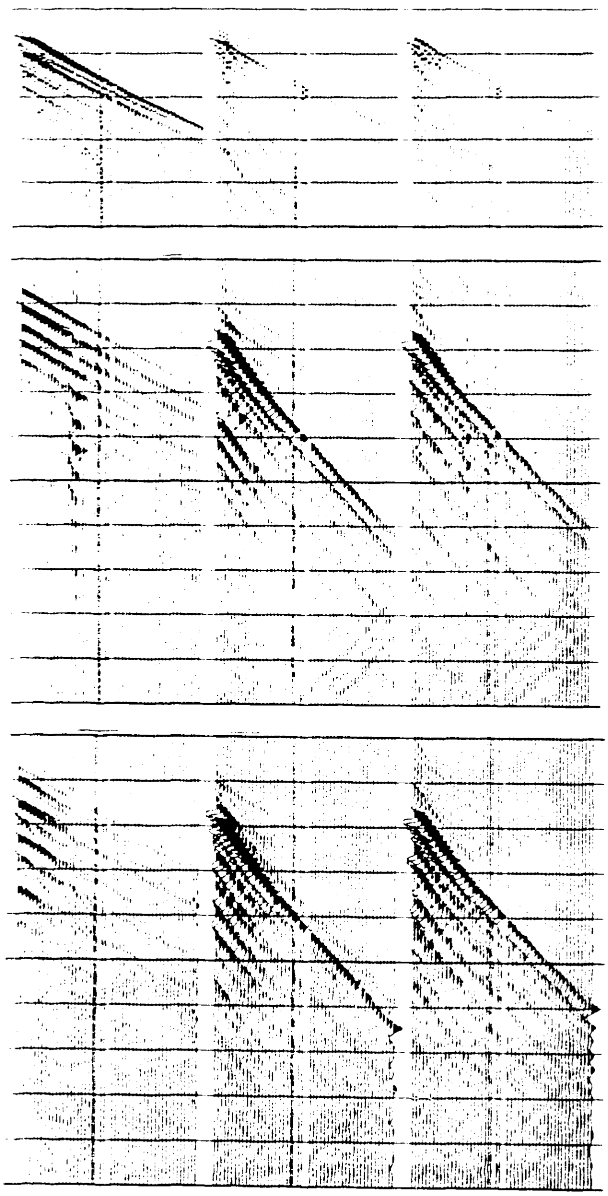


Figure 2. 9-component VSP data from Conoco well 33-1. The 9 data sets are arranged in a 3x3 matrix. Each row is a source polarization (vertical, radial and transverse) and each column is a receiver polarization (vertical, radial and transverse). The timing lines are spaced 100 ms apart. The traces are spaced every 50 ft. from 500 to 2950 ft.

polarized shear-waves). The analysis of shear-wave VSP data for transversely isotropic media with a vertical axis of symmetry can be improved by the application of a 4-component rotation technique. This rotation, often termed an Alford rotation (Alford, 1986) gives the angles, at each recording depth, which best decompose the 4 horizontally polarized seismic traces into two traces. These are the two traces which best represent data recorded in the natural polarization direction of a transversely isotropic media. For vertically propagating, orthogonally polarized shear-waves, the 4-component rotation can give an azimuthal orientation of the vertical axis of symmetry of anisotropy (and by implication, the orientation axis of natural fractures). Figure 3 shows the results of this analysis for the 33-1 VSP. They agree well with the previously inferred fracture orientation (Queen and Rizer, 1990), and they show remarkable consistency as a function of depth. We feel this result is accurately portraying the dominant fracture orientation as a function of depth. Note that the S-wave splitting is clearly measurable at the shallowest receiver depth of 500 feet. This agrees with other studies at the Conoco test facility which show fracturing in shallow formations such as the Ft. Riley limestone.

Groundwater Well Surveys

The Ft. Riley formation was the focus of cross-well surveys in the groundwater wells. An initial survey was conducted in FY 1992. This was a preliminary test so that the source/receiver spacing was relatively large. Receivers were recorded 4 at a time and spaced at 6 ft.. intervals while the source was used at 2 ft. intervals. The distance between the wells (~150 ft.) was such that for each well pair all the ray lengths were within a few feet, and all the incidence angles were small (near horizontal). Analysis of this data

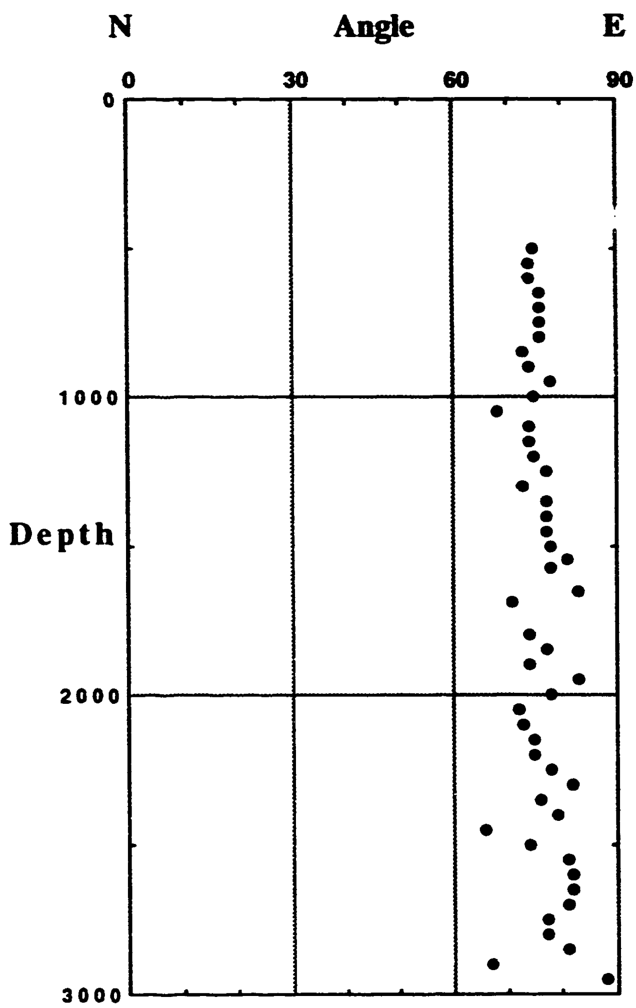


Figure 3. Estimated dominant fracture orientation. The estimate at each depth is taken from the rotation angle for the horizontal VSP data.

set provided a guide for acquisition and analysis of the 1993 data set. The FY1993 data set, acquired in September 1993, was more comprehensive with 5 cross-well surveys using 1/4 m source/receiver spacing over a 16 m depth range. This 1993 data set has superior signal-to-noise ratio and coverage and will provide much improved imaging of the geologic structure.

In addition, we acquired a set of single well reflection surveys from well GW1, GW3 and GW5. These single well surveys were designed with large input from Conoco personnel who have begun assessing this new type of survey. Single well surveys are promising because they have potential to image vertical fractures near a single well with reflection imaging. The problem is the large amount of seismic energy trapped in the well by tube waves and other borehole waves. Our 1993 field experiment proved very promising because we had low amplitude borehole waves. This low noise level implies a much improved potential for identifying vertical fractures.

The 1993 data, both cross-well and single well, has not yet been processed or analyzed as of this writing (October 1993), so we will report on the 1992 data analysis which is representative of the approach we will use for fracture detection in the superior 1993 data set.

While the 1992 data were not conducive to tomography because of the small aperture of acquisition (~150 ft. horizontal to a maximum of ~60 ft. vertical) and large station spacings, some sense of the horizontal layering can be identified. More importantly, relative differences in the velocities between well pairs may be identified. A complete set of travel times were picked and inverted for velocity. The results show only general structure; higher velocities Ft. Riley. Fractures in a homogeneous medium can be detected in cross-well seismic surveys by observing changes in travel time and wave amplitude as the angle between ray paths and dominant fracture orientation varies between perpendicular and parallel. The number and stiffness of the fractures can be determine by the magnitude of the travel time and amplitude changes. The fractures may also be detected by reflected waves since fractures which cause the greatest time delay and wave attenuation will produce the largest reflections.

Spectra are taken from windowed data, which is corrected for radiation pattern and geometric spreading, from the P-wave onset for 64 samples (1.28 msec). This includes 2 or 3 (or more) wave cycles. The background noise was subtracted out of the spectra as it was very channel dependent and large. Spectra were taken for every source-receiver path. The spectra show that the GW5-GW3 and GW3-GW2 well pairs produce the largest amplitudes. However, the GW3-GW1 well pair also produces relatively higher amplitudes. The GW5-GW1 and GW5-GW4 well pairs both produce very low amplitudes. If the GW3-GW1 well pair is ignored the conclusion would be that there exists one or more fractures parallel to the GW5-GW3 and GW3-GW2 well pairs, so that signals from the GW5-GW1 and GW5-GW4 well pairs would pass through them. Explanations, assuming that the amplitudes changes are primarily due to fractures, are:

1) The fracture(s) thin out between GW3 and GW1. Fractures do have a tendency to do this, but it seems fairly unlikely that it would thin out consistently with depth as the data shows. One would more likely expect more variation with depth.

2) The fracture(s) either end or form an echelon so that the miss GW3-GW1. The echeloned fracture may continue north of GW1 or south of GW3. The data from the other borehole offsets should help determine this behavior.

Guided Waves

Frequency dispersion in the first arrival and an increase in high frequency (12 kHz) energy at certain depths provide evidence for guided waves. These guided waves appear to be produced in very thin (on the order of a few feet) velocity zones, e.g. at ~90 feet down boreholes GW3 and GW1. Low velocity zones can produce dispersive arrivals (low frequencies faster), while high velocity zones can produce high frequency arrivals. Examples of high frequency guided waves are seen in both the shallow and deep cross-well experiments.

1992 Deep Cross-Well Survey

In August of 1992, the LBL high-frequency piezoelectric seismic cross-hole system was used in wells 33-5 (source) and 33-6 (receivers). The initial test performed was a high frequency sweep of the piezoelectric source. Previously, this source had been pulsed, but development of frequency control of the high voltage source electronics has allowed us to use vibroseis type sweeps in the sonic frequency band. We feel that a swept source has the potential to increase the distances we can survey between wells by allowing us to put more energy in the bandwidth which is most useful. For example, if no energy above 3000 Hz will propagate in a particular formation, we will only operate the source below 3000 Hz. In this way all the available energy goes into a useful frequency band. Alternately, if we are trying to image a thin fracture, we may want to sweep at high frequencies, above 5000 Hz, to provide resolution of thin features. Because of various field difficulties, we were only able to acquire data for a few test levels. However, this data was good quality and demonstrated the usefulness of the high-frequency source in oil field conditions at distances of 400 ft.. In addition, we learned from our field problems, and we should have a much improved system for the FY1993 field work.

The sweep mode of data acquisition was shown to give better frequency content, with significantly more energy in the 2000 - 3000 Hz range. A correlation with a synthetic sweep

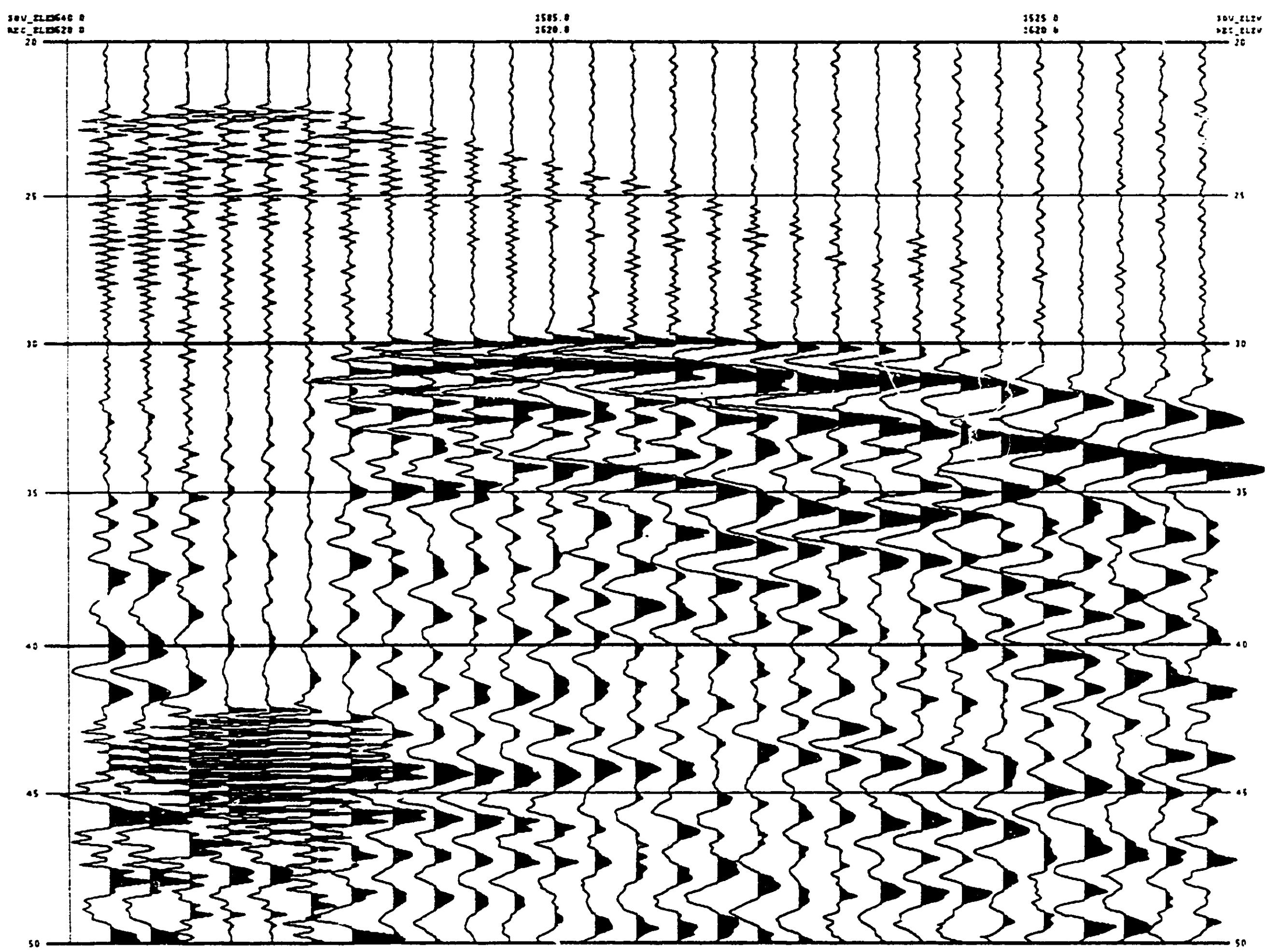


Figure 4. A single cross-well data receiver gather from wells 33-5 and 33-6. The traces show source locations from 1640 to 1505 ft. for a receiver at 1620 ft. The high frequency energy from 22 to 27 ms shows reflections and multiple arrivals. With a frequency content of 3000 Hz, reflections have the possibility of imaging zones of 3 feet or less. This resolution is an order of magnitude better than traditional cross hole surveys.

worked best because of various problems with the source signal (voltage) recorded in the field.

A small amount of data acquired with the pulse mode showed some vary unusual wave propagation characteristics in the 1620 - 1640 ft. depth range (Figure 4). While the typical pulse arrival had a frequency content of 500 Hz, we found 3000 Hz energy arriving in this depth range. This high-frequency arrival had a much higher velocity, agreeing with well log (sonic) data which showed alternating high and low velocities in the 1600 - 1620 ft. zone. There does appear to be a depth mistie between the sonic log and our cross-hole data of about 10 or 20 feet. The high frequency data we acquired in the 1620 - 1640 ft. zone shows reflections and it is possible that we can image very thin layering in this depth zone. Future data acquisition will focus on obtaining maximum resolution in this region.

We have demonstrated the ability of our high frequency source to operate in oil and gas field conditions and acquire good quality data at distances of 400 feet between wells. The use of sweep mode for an entire survey should provide excellent high frequency data and maximize resolution.

1993 Deep Cross-Well Survey

In September 1993 we acquired a full tomography survey in wells 33-5 and 33-6. We covered the depth range from 225 m to 450 m (about 750 to 1500 ft.). We had planned to survey to greater depth (about 2000 ft.) but well conditions prevented deeper recordings. Our survey interval did include a possible fracture zone which was imaged with 1m resolution and frequency content up to 3000 Hz. As with the 1993 shallow well surveys, this data has not yet been analyzed, but significant improvements were made in source and receiver hardware. Therefore, we see greatly improve data quality which should be reflected by improved analysis. We also have demonstrated that LBL's high frequency piezoelectric cross-well system can function in oil and gas field conditions (i.e. depths over 1000 ft. and cross-well distances of 400 ft.).

Hydrologic Inversion

The inverse approach to characterizing fracture zones has the advantage that the method can incorporate flow as well as transport data in deriving the fracture networks. Thus the approach naturally emphasizes the underlying features that impact the fluid flow and transport. However, a network of flow channels, which may be rather elaborate, is likely to be poorly constrained by limited data. Thus, hydrologic models derived by inversion are likely to be non-unique. We have addressed such non-uniqueness by shifting the focus of the problem from the search of a single model that fits the data best to inferences about properties which are shared by the ensemble of acceptable models. We can then determine a most likely model and quantify the associated uncertainties (Vasco et al., 1993).

Fracture Zone Characterization Through Inverse Modeling

The fracture zone is represented as a network of one dimensional conductors having either fixed or variable apertures. The network itself may be partially or fully connected. Depending upon the convention used, the fracture zone models are termed 'equivalent discontinuum' or 'variable aperture continuum' model. The steps involved in generating these model are discussed below.

Equivalent Discontinuum Model. These models represent the fracture zone as a network of partially connected conductors having equal apertures and hence, conductivity. Equivalent discontinuum models are derived starting from a specified lattice or template of conductors. The approach involves searching for a configuration of conductors that will satisfy observed data. We have used a derivative-free optimization scheme called simulated annealing for inversion of hydrologic data. An objective function is defined to reflect the mismatch between the data and the predicted response. A lattice element is randomly chosen and if the element is present or 'on,' it is turned off and vice versa. A change in mismatch, also known as energy, is computed due to the perturbation. If the energy decreases, then the perturbation is accepted; otherwise the perturbation is accepted with a probability P(De) = exp (-De/T) where T is analogous to temperature in Gibbs distribution. By accepting changes which result in an increase in energy, the simulated annealing approach to optimization provides a mechanism of probabilistic hill climbing which allows the method to escape from local extrema (Kirkpatrick et al., 1983).

Once the initial template has been 'annealed' to a sufficiently low energy level, a configuration of conductors representing a conceptual model for the fracture zone is obtained. Since a network of conductors can be rather elaborate, there are several possible configurations that will satisfy limited data. However, all such models being conditioned with respect to the observed data, will represent the major features of the flow field. By examining an ensemble of possible configurations, we can arrive at a conceptual model that incorporates the underlying features shared by all models.

Variable Aperture Continuum Model. In this approach, the fracture zone is represented as a network of fully connected conductors having variable apertures and hence conductivities. The optimization problem consists of searching for a spatial pattern of apertures that satisfy the available data. The steps involved are similar to the ones in constructing equivalent discontinuum models. However, instead of simply turning on or off, the conductors are assigned apertures sampled uniformly from a specified aperture distribution. We have chosen a log-normal distribution of apertures that is consistent with field data (Gale et al., 1990). Such an approach generates preferential flow paths by selectively placing high apertures and thus creates a set of variable aperture channels. Such variable aperture channel models have been successfully used to interpret field tracer data by Tsang et al. (1991).

Well Tests and Pressure Data

The inverse approaches discussed above have been applied to a set of interference test data from the Ft. Riley formation underlying the Conoco bore hole test facility located in Kay County, Oklahoma. The facility consists of five wells, GW-1 through GW-5 as shown in Figure 1. The wells were drilled in a skewed five-spot pattern to provide maximum azimuthal coverage for both seismic and hydrologic experiments. Several well tests were conducted out of which two were chosen for detailed analysis. These tests will be denoted as Pump 58 and Pump 27.

During the test Pump 58 water was produced from the well GW-5 and pressure responses were observed at the wells GW-1, GW-2, GW-3 and GW-4. The pumping rate was fairly constant during this test, starting at about 0.5 gpm and dropping to about 0.46 gpm by the end of the test. Background data collected before the beginning of the test indicated that the wells were recovering from rainfall when the test was started; hence, the drawdown data was corrected for rainfall before further analysis. This correction was accomplished by simply subtracting the additional drawdown due to the recovery from the rainfall. The final drawdown and recovery curves during Pump 58 are shown in Figure 5a.

The test Pump 27 immediately followed test Pump 58. During this test, water was produced from well GW-2 and pressure response was observed in wells GW-1, GW-3, GW-4 and GW-5. The pumping rate during this test varied considerably, starting with about 0.40 gpm and gradually decreasing to 0.23 gpm by the end of the test. This decrease most likely was caused by progressive clogging of a water filter in the flow stream. The filter was installed to protect the flow meter. The drawdown and recovery curves during Pump 27 are shown in Figure 5b.

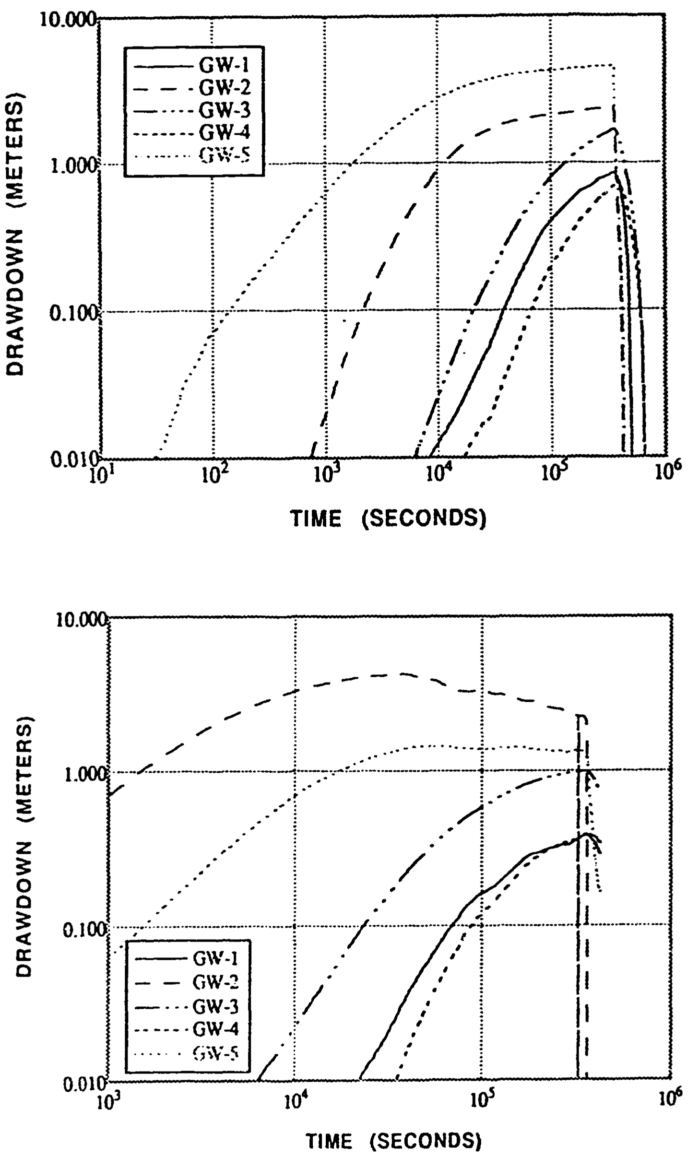


Figure 5. Drawdown and recovery data during tests Pump 58 and Pump 27

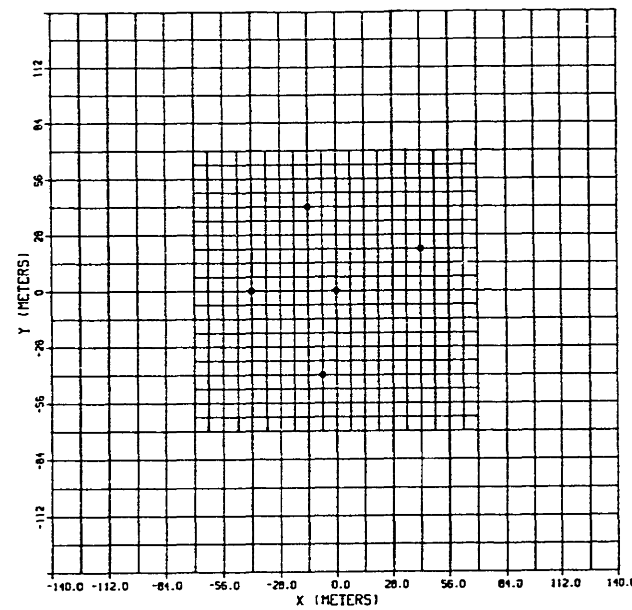
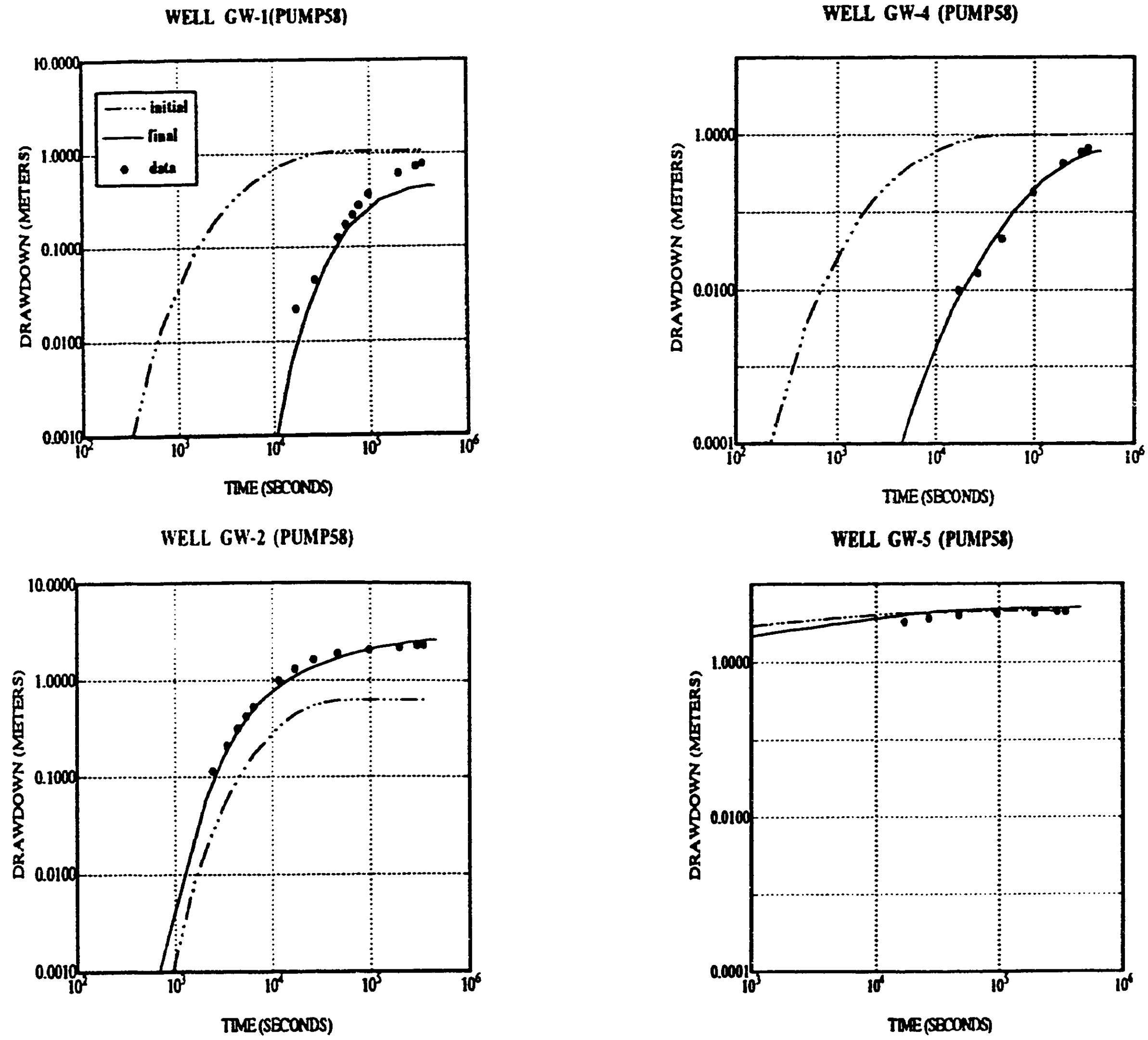


Figure 6. Template for numerical inversion

Development of Conceptual Models by Stochastic Inversion

In this section we discuss numerical inversion of the transient pressure response at the wells during the tests Pump 58 and Pump 27. A channel model consisting of a network of one-dimensional conductors (Karasaki, 1986) was used to simulate the well tests. The flow field was obtained using Galerkin finite element. The template used for inversion is shown in Figure 6. It consists of two regions — an inner dense region to obtain greater resolution of the flow field and a coarse outer region. A sensitivity study was performed to establish the distance to the boundary to have minimal impact of the boundary conditions. A constant head outer boundary conditions was imposed on all four sides. The inner region where the wells are located has an element spacing of 7 meters and the spacing was doubled in the outer region adjacent to the boundary. During the inversion, a criterion was imposed whereby the probability of altering an element decreased exponentially with distance beyond the inner region.

Discontinuum Models. As discussed before, the discontinuum models are created by randomly selecting elements and turning them on or off to minimize the difference between computed and observed values. Figure 7 shows the matching of drawdown data from the test Pump



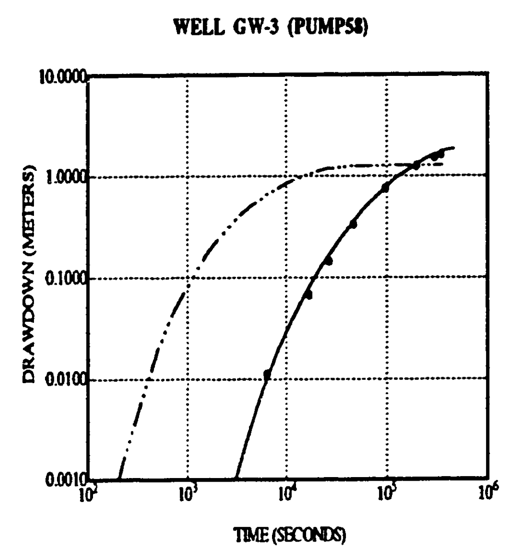


Figure 7. Inversion of drawdown data from test Pump 58

58. The dotted lines correspond to pressure response from the initial template. For the producing well GW-5, early time data were excluded from matching since they were affected by wellbore storage. Overall, the inversion scheme is able to reproduce the drawdown data reasonably well. The early pressure response observed at well GW-2, the farthest well from the producing

well, is indicative of a preferential flow path or fracture in that direction. The final configuration of elements obtained after inversion is shown in Figure 8a. The solid lines represent connected pathways whereas the dead ends have been shown with dotted lines. The fracture patterns appear to suggest the presence of a single fracture extending from well GW-5 to GW-2 to the north of GW-3.

The fracture pattern obtained after inversion of test Pump 27 is shown in Figure 8b. Again we observe a direct pathway between the wells GW-2 and GW-5 to the north of GW-3. In addition, on comparing Figures 8a and 8b, we observe that both the patterns exhibit sparse fracture density in the vicinity of the central well GW-3.

We carried out an inversion whereby annealing was performed simultaneously on the drawdown data from both the tests discussed above. Such coannealing is computationally intensive but should help better constrain the inverse problem. The final configuration resulting from the coannealing is shown in Figure 8c. On comparing with Figures 8a and 8b, we observe that coannealing has reproduced many of the common features. The direct pathway between GW-2 and GW-5 to the north of GW-3 is also present here. However, the fracture density has been substantially reduced in the vicinity of well GW-1.

In summary, the fracture pattern emerging from all the inversions exhibit a direct pathway between the wells GW-2 and GW-5 as might be expected from the early pressure response observed in these wells. The pathway consistently appears to the north of the well GW-3. Also, there is low fracture density in the vicinity of the central well GW-3 and it is connected to the rest of the wells through long tortuous pathways which explain the relatively low sensitivity of well GW-3 to production from nearby wells.

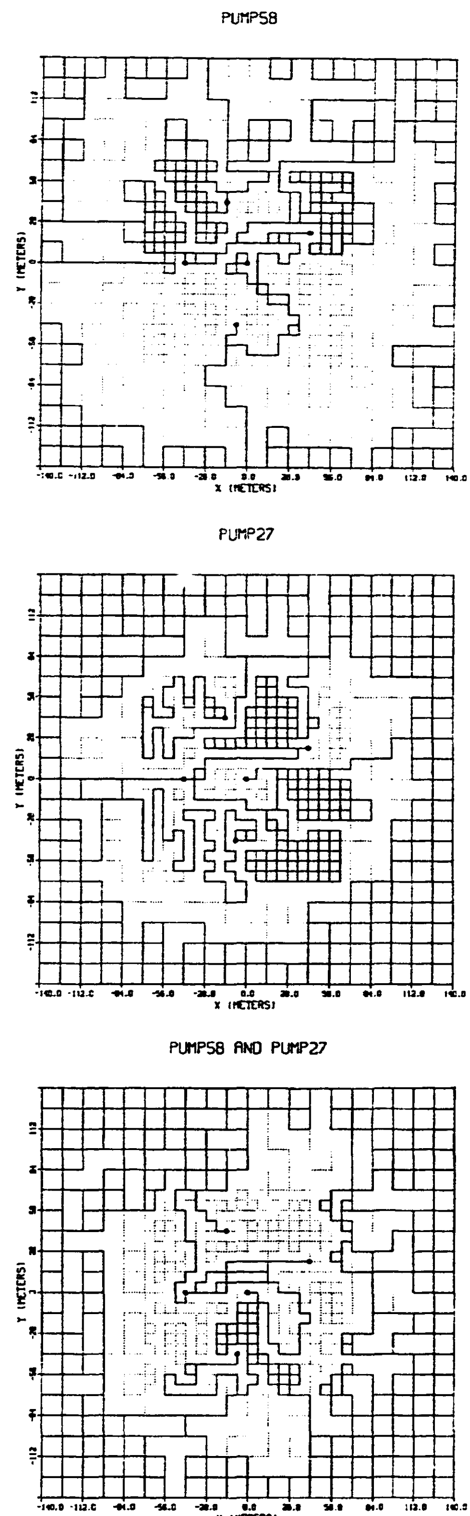


Figure 8. Equivalent discontinuum models derived by inversion

Continuum Models. The continuum models were generated through variable aperture annealing whereby apertures were sampled uniformly from a log normal distribution with a mean of 0.00065 m. The mean aperture was chosen using cubic law based on the parameters estimated using analytical models (Barker, 1988). The convergence of simulated annealing was found to be quite sensitive to the selection of log aperture variance and a value of 0.5 worked the best for the transient pressure data. A series of inversions were performed on the pressure data from the test Pump 58. Specifically, several variable aperture annealing runs were conducted and concluded when the misfit was reduced to a specified level. Figure 9 shows the energy vs. iterations for all these models. When a sufficient number of models were accumulated, various statistical quantities were extracted from the ensemble. Figure 10a shows the median model derived from the ensemble. Again, the preferential flow path between the wells GW-5 to GW-2 is apparent here. The ensemble mean is shown in Figure 10b. The mean model appears smoother compared to the median model and thus, appears

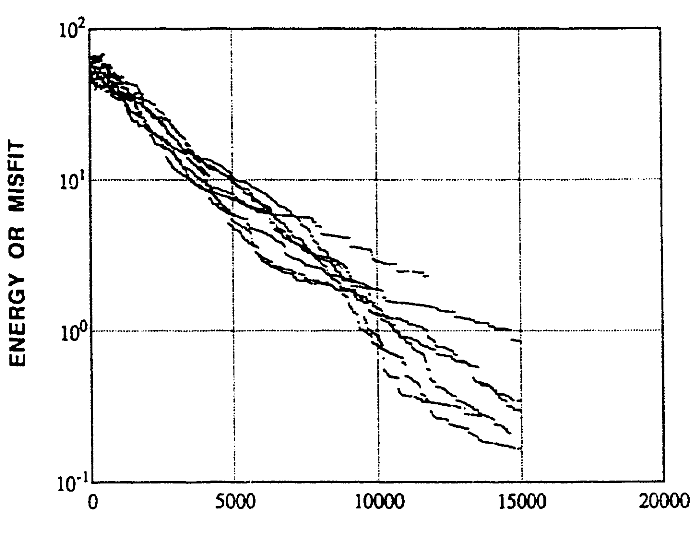


Figure 9. Energy vs. iterations for an ensemble of variable aperture models

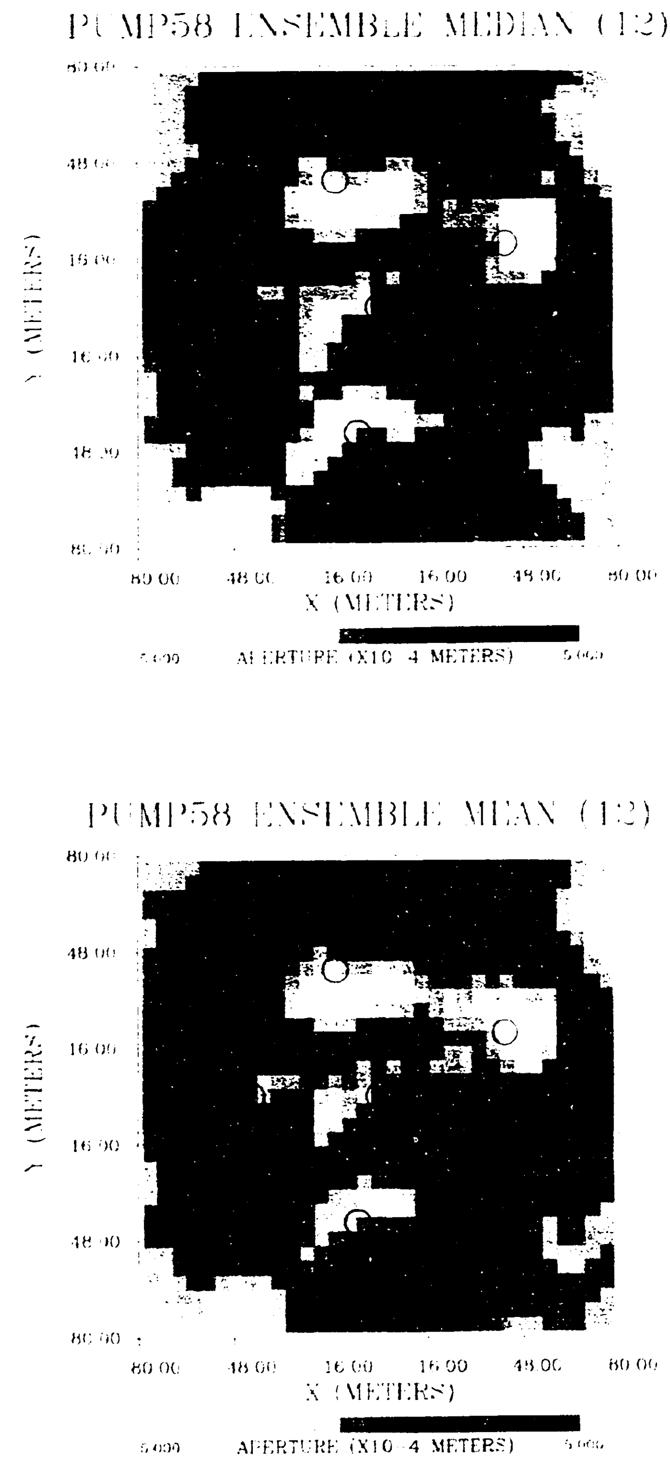
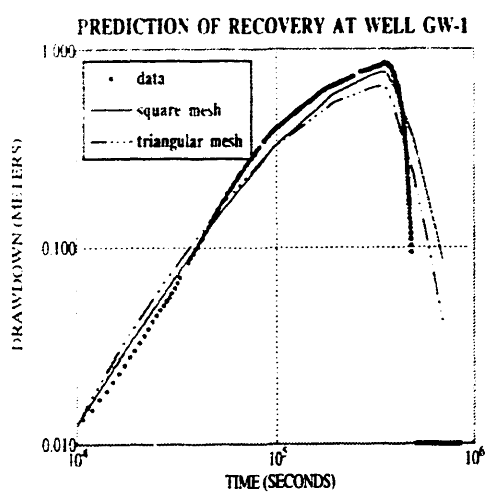
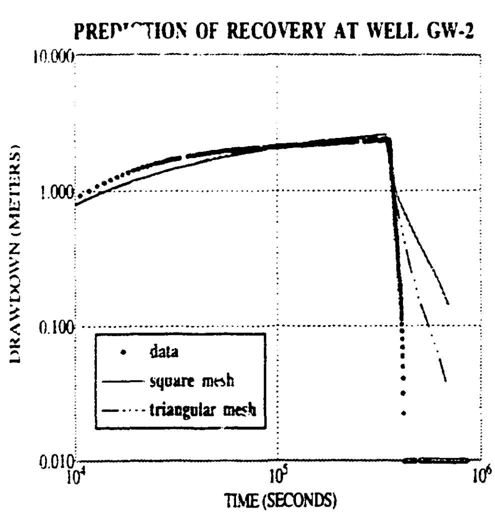


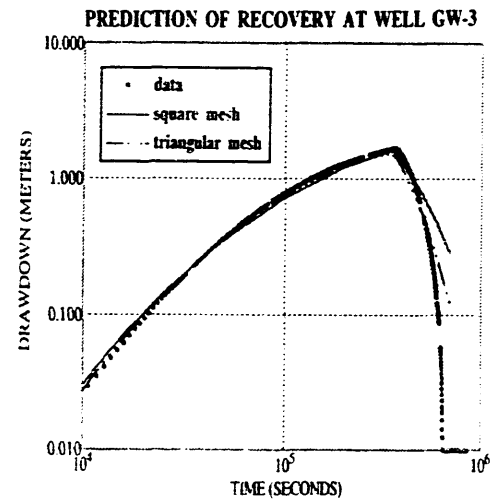
Figure 10. Ensemble median and mean of variable aperture continuum models

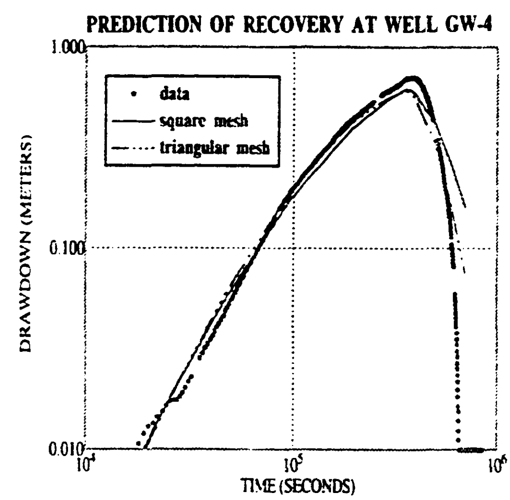
to emphasize the long-range correlation. The median model, on the other hand, is less sensitive to the presence of outliers and thus, overall may be a better representation of the reality.

Prediction of Build-up Data. In order to verify the conceptual models derived through inversion, an attempt was made to predict the build-up data using these models. Only the data from the test Pump 58 was used for this purpose due to lack of sufficient build up data from the other test. Even the data from Pump 58 was affected due to rainfall just before the beginning of the build up phase. Figure 11 shows the data versus prediction using discontinuum models. The early recovery of the field data can be attributed to the rainfall.









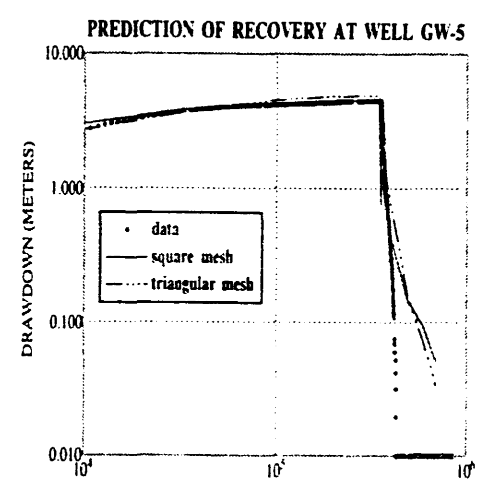


Figure 11. Prediction of build-up data based on conceptual models

Summary, Conclusions and Future Work

In this paper we have discussed hydrologic and seismic characterization of a fractured limestone and shale/sandstone formations based on a set of interference test data and VSP/tomographic imaging. Numerical inversions have been carried to build conceptual models for the Ft. Riley formation based on 'equivalent discontinuum' and 'variable aperture continuum' approaches. The analysis suggests the following conclusions:

- Stochastic inverse approaches were successful in reproducing the transient pressure behavior at the pumping and observation wells and appear to be viable means for characterizing fractured formation.

- The conceptual models for the Ft. Riley formation derived based on both continuum as well as discontinuum approaches indicate presence of a preferential pathway between wells GW-2 and GW-5 to the north of well GW-3.

- An attempt was made to verify the conceptual models by predicting the build data during the test Pump 58. The field data was affected by rainfall; however, the conceptual models appear to generate the expected trend.

- Multi-component VSP is useful for determining fracture orientation.

- High frequency (up to 5000 hz) imaging of the subsurface is possible at moderate scales (few hundred meters).

- P-wave imaging of fractured rocks using traveltime and amplitude studies give useful information on fracture density, location, and orientation.

Future work will involve one more year of work at the Newkirk test facility. This will include experiments focusing on the effect of desaturation of fractured rock and the validation of the inversion models. The out years of this project will this shift to the application of the technology to actual gas reservoirs.

Acknowledgments

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Session NG -- Natural Gas Technology

Session NG-3

Resource Assessments and Modeling

NG-3.1 Preliminary Results on the Characterization of Cretaceous and Lower Tertiary Low-Permeability (Tight) Gas-Bearing Rocks in the Wind River Basin, Wyoming

CONTRACT INFORMATION

Contract Number	DE-AT21-93-MC30139
Contractor	United States Geological Survey Branch of Petroleum Geology MS 934, Denver Federal Center Denver, Colorado 80225-0046
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METC Project Manager	Karl-Heinz Frohne
Period of Performance	October 1, 1992 to September 30, 1993

This report is preliminary and has not been reviewed for conformity with the U.S. Geological Survey editorial standards or with the North American Stratigraphic Code.

OBJECTIVES

The Wind River Basin is a structural and sedimentary basin in central Wyoming (Figure 1) that was created during the Laramide orogeny from Late Cretaceous through Eocene time. The objectives of the Wind River Basin tight gas sandstone project are to define the limits of the tight gas accumulation in the basin and to estimate in-place and recoverable gas resources. The approximate limits of the tight gas accumulation will be defined from available drillhole information. Geologic parameters, which controlled the development of the accumulation, will be studied in order to better understand the origins of tight gas accumulations, and to predict the limits of the accumulation in areas where little drillhole information is available. The architecture of sandstone reservoirs will be studied in outcrop to predict

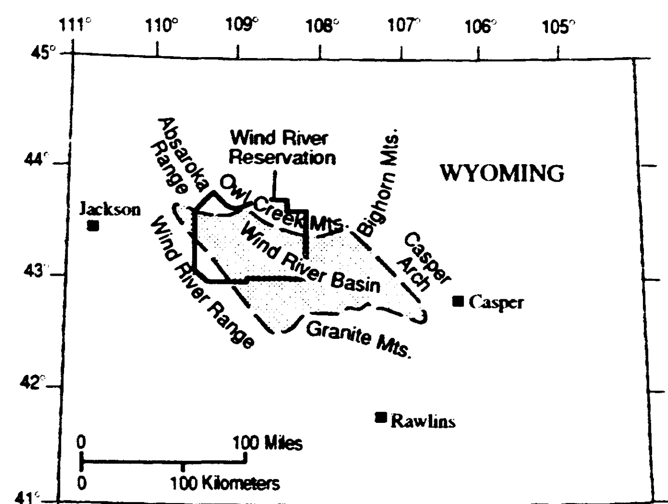

Figure 1. Index map showing location of Wind River Basin and surrounding uplifts. Location of Wind River Reservation is shown by heavy black line.

production characteristics of similar reservoirs within the tight gas accumulation. Core and cuttings will be used to determine thermal maturities, quality of source rocks, and diagenetic histories.

Our work thus far has concentrated in the Wind River Indian Reservation in the western part of the basin. The U.S. Geological Survey has has just completed a Bureau of Indian Affairs-funded three-year project with the Shoshone and Arapaho Tribes of the Wind River Indian Reservation to study the oil and gas and coalbed methane resources of the Reservation. The Reservation project culminated in August and provided three important products: 1) a field trip to the Reservation; 2) a special session highlighting our results at the Wyoming Geological Association Meeting in Casper Wyoming; 3) and the publication of a Wyoming Geological Association guidebook on the Wind River Basin. Many of the studies published in the guidebook were jointly funded by the Bureau of Indian Affairs and the U.S. Department of Energy funded tight gas sandstone project.

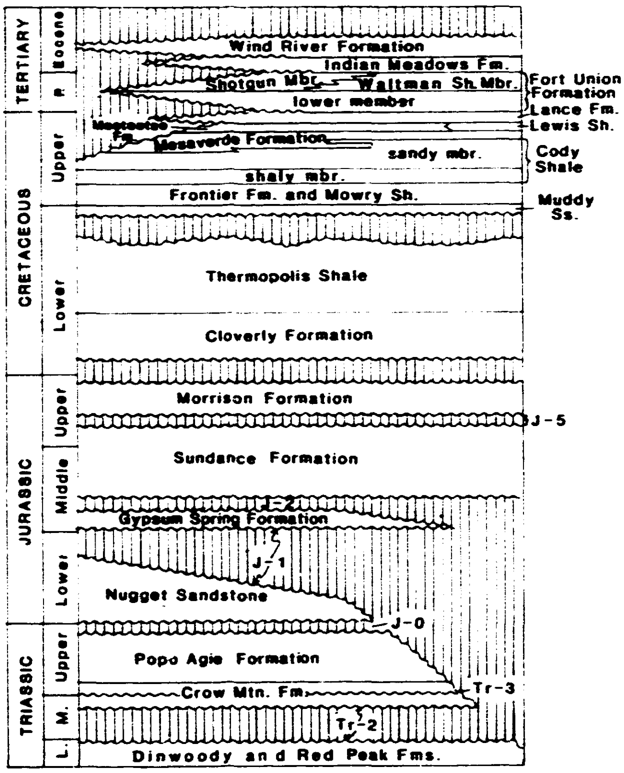

Figure 2. Generalized stratigraphic chart of Mesozoic age and Cenozoic age rocks, Wind River Basin, Wyoming. Patterns of vertical lines indicate hiatuses. Locations of Triassic unconformities (Tr-3, Tr-3) and Jurassic unconformities (J-0, J-1, J-2, J-5) from, Pipiringos and O'Sullivan (1978).

BACKGROUND INFORMATION

Geologic Setting

The principle tight gas sandstone interval in the Wind River Basin extends from the the Lower Cretaceous Muddy Sandstone through the lower member of the Paleocene Fort Union Formation (Figure 2). All of the formations in this interval have received tight formation designation in the basin, and abnormally high formation pressures, a common characteristic of tight sandstone intervals, were encountered throughout this interval at Madden anticline near the deep trough of the basin (Bilyeu, 1978).

The Wind River Basin is one of several large structural and sedimentary basins that formed in the Rocky Mountain region during Laramide deformation. The basin is surrounded by folded and faulted strata of Paleozoic and Mesozoic ages which form the flanks of the adjacent mountain ranges and anticlinal uplifts (Figure 1). Most of the basin interior is covered by rocks of early Eocene age, which mask the stratigraphic and structural relations of older underlying rocks throughout most of the basin interior (Keefer, 1970).

Until Late Cretaceous time, the present site of the Wind River Basin was part of the foreland or stable shelf region which lay to the east of the main miogeosynclinal trough area. Rocks representing all systems, except possibly the Silurian, were deposited during repeated transgressions and regressions of the epicontinental seas across central Wyoming.

Beginning in Late Cretaceous time, the main sites of sedimentary accumulation shifted eastward into the Wind River Basin area because of uplift west of the present Wyoming-Idaho boundary. The last major episode of marine deposition in central Wyoming is represented by the Cody Shale and the basal marginal marine part of the overlying Mesaverde Formation. The remainder of the Mesaverde reflects deposition of chiefly clastic sediments in broad floodplains, coastal swamps, deltas and lagoons. Similar conditions prevailed during deposition of the overlying Meeteetse Formation except in the easternmost part of the Wind River Basin where it intertongues with the marine Lewis Shale. In contrast, during deposition of the Lance Formation in latest Cretaceous time, local tectonic activity was recorded by accumulations of coarse clastic debris near highlands being actively uplifted and eroded, by incipient basin downwarping, and by the development of unconformities along the basin margins. These initial phases of the Laramide deformation were followed in Paleocene time by a period of mountain-building and basin subsidence of increasing intensity. This deformation culminated in early Eocene time in the uplift of high mountains along reverse faults of large magnitude that overrode the basin margins.

Coarse-grained detritus continued to accumulate along the flanks of the rising highlands during deposition of both the Lance and Fort Union Formations, but in the central part of the basin, thick sequences of fine-grained sands, silts, clays, and carbonaceous sediments were deposited in the subsiding syncline. A large lake, "Waltman Lake", covered much of the Wind River Basin in late Paleocene time.

RESULTS

Six detailed cross sections showing lithologies, correlations of lithologic units, and results from drillstem tests and perforations, were constructed and published. Four of these were on the Wind River Reservation (Keefer and Johnson, 1993), and two were east of the Reservation in the eastern part of the basin (Finn, 1993, Szmajter, 1993). Several more cross sections are being constructed and will be submitted for review in the next few months. These cross sections establish basin-wide correlation (Figure 3) and help define the limits of the limits of the tight gas accumulation.

Hydrocarbon generation from source rocks is directly related to thermal maturity, hence, thermal maturity studies can be used to define areas where hydrocarbons have been generated in the past. Subsurface and surface studies using vitrinite reflectance show variations in thermal maturity in the Wind River Basin (Figure 4) (Pawlewicz, 1993; Nuccio and others, 1993).. Comparison of calculated paleotemperatures with present temperatures demonstrates that significant cooling has occurred. Optimum areas for tight-gas generation and accumulation have been defined utilizing these data.

The environments of deposition of the uppermost part of the Cody Shale and the Mesaverde and Meeteetse Formations of Late Cretaceous age were studied on outcrop in the Shotgun Butte area in the north-central part of the Wind River Reservation (Johnson and Clark, 1993). A marginal marine shoreface sandstone occurs in the lower part of the Mesaverde Formation at all localities studied, and is directly overlain by a coaly sequence. Repetitive coarsening-upward cycles of mudstone, siltstone, and sandstone occur in the 200 ft interval of the upper part of the Cody Shale below the shoreface sandstone. These Cody sandstones are typically hummocky cross stratified with symmetrical ripples near the top, indicating that they are largely storm surge deposits that were later reworked by less intense current and wave processes. Channel-form sandstones from 10 to 20 ft thick, with abundant locally derived clayey clasts, occur in a 75 ft thick interval below the shoreface at one locality. These unusual sandstones are

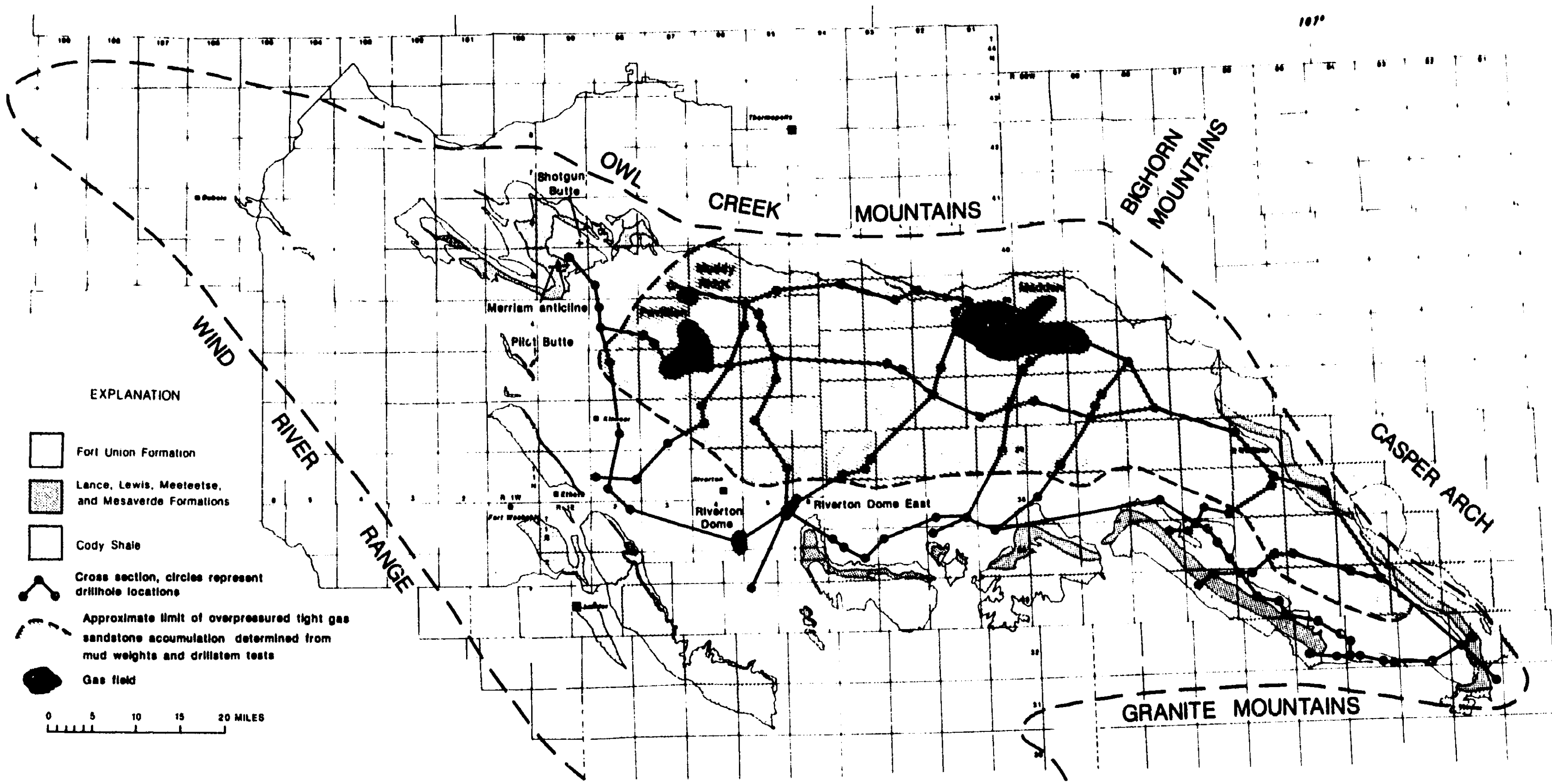

Figure 3. Map showing areas where tight gas formations crop out, approximate outline of overpressured tight gas accumulation, and locations of detailed cross sections.

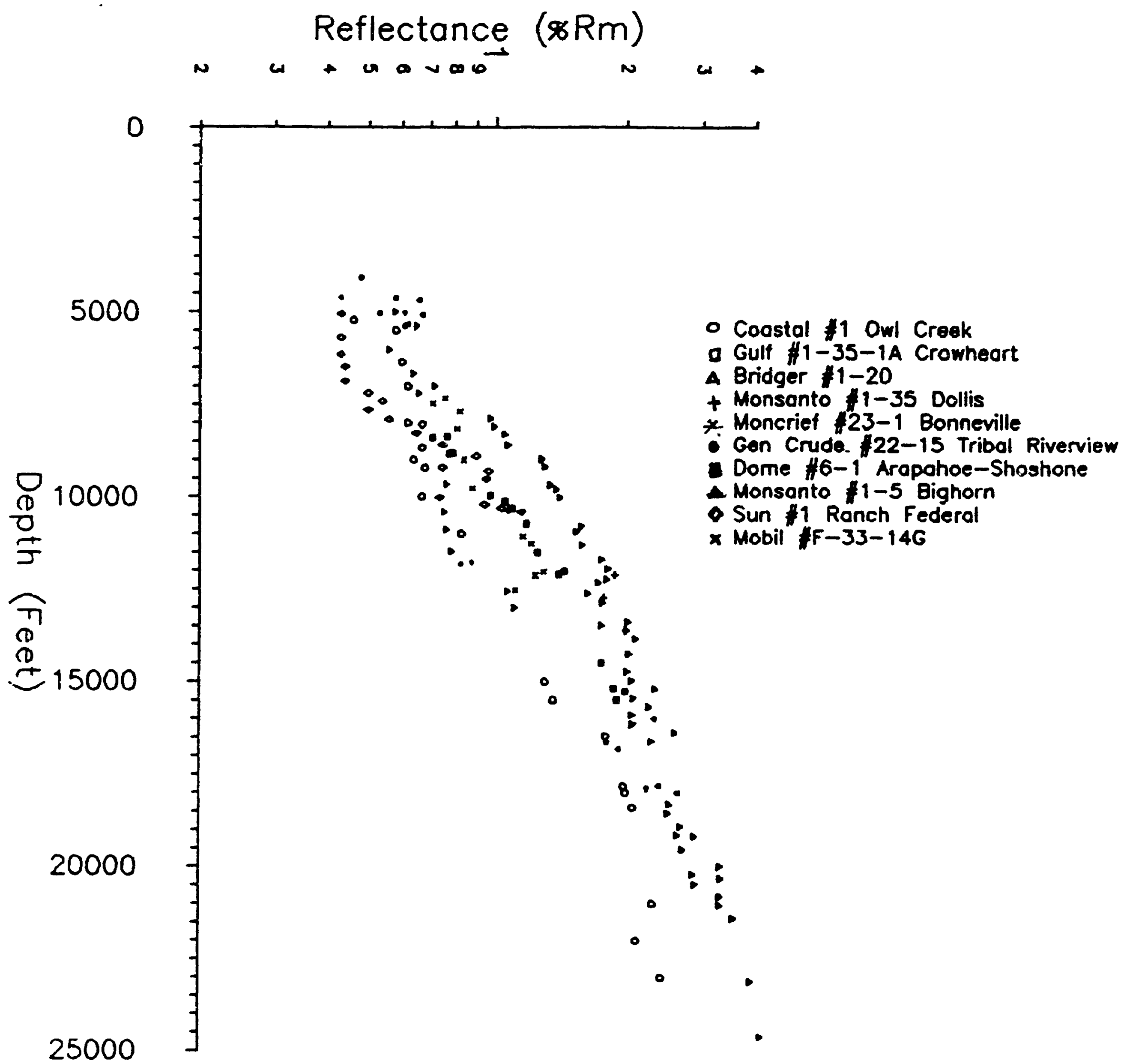

Figure 4. Composite depth versus Rm plot for ten boreholes from the Wind River Basin. From Pawlewicz (1993).

largely confined to a narrow area of the outcrop and grade laterally into more typical tabular shaped storm surge deposits. They may represent unusually large storm surge channels created when high-energy flow conditions were localized to a limited area of the shelf.

The Mesaverde Formation above the shoreface sandstone is divided into a middle member and the Teapot Sandstone Member. The lower part of the middle member is everywhere coaly. Erosional-based sandstones in the middle member are highly variable in thickness and architecture. Thin, single channel sandstone bodies were deposited by moderate to high sinuosity stream channels that were abandoned after a comparatively brief period of time. Thick, multistorey channel sandstone bodies, in contrast, were deposited by fluvial channel systems that

Figure 5. Photograph of multistory fluvial channel sandstone with several highly irregular zones of ripup clasts (outlined with dashed lines), Eagle Point measured section, Wind River Reservation. From Johnson and Clark (1993).

remained relatively stationary for extended periods of time (Figure 5). The multistorey sandstones occur at different stratigraphic levels at different localities suggesting long term stability of fluvial channel systems followed by major avulsion events.

The Teapot Sandstone Member consists of fairly continuous to lenticular white multistory sandstone units as much as 85 ft thick which contain trough cross beds as much as 5 ft high. These sandstone units are interbedded with gray mudstones and carbonaceous shales. Paleosols are preserved at the tops of individual sandstones in the multistory units in some places. It is suggested that these sandstones were deposited largely by low-sinuosity to braided streams.

The Meeteetse Formation consists of alternating coal and sandstone-rich intervals. The coal-rich intervals have relatively thin fluvial channel sandstones probably deposited by medium to high sinuosity streams whereas the sand-rich intervals have thick (to 105 ft) multistorey fluvial channel sandstones possibly deposited by low-sinousity to braided streams.

The geometry of Paleocene-age Fort Union Formation sandstone reservoirs was studied in detail near the town of Hudson (Flores and others, 1993) and in the Shotgun Butte area (Flores and Keighin, 1993) in the western part of the Wind River Basin (Figures 3 and 6). Four types of reservoirs were recognized in the Shotgun Butte area. Type I reservoirs consist of a sandstone, as

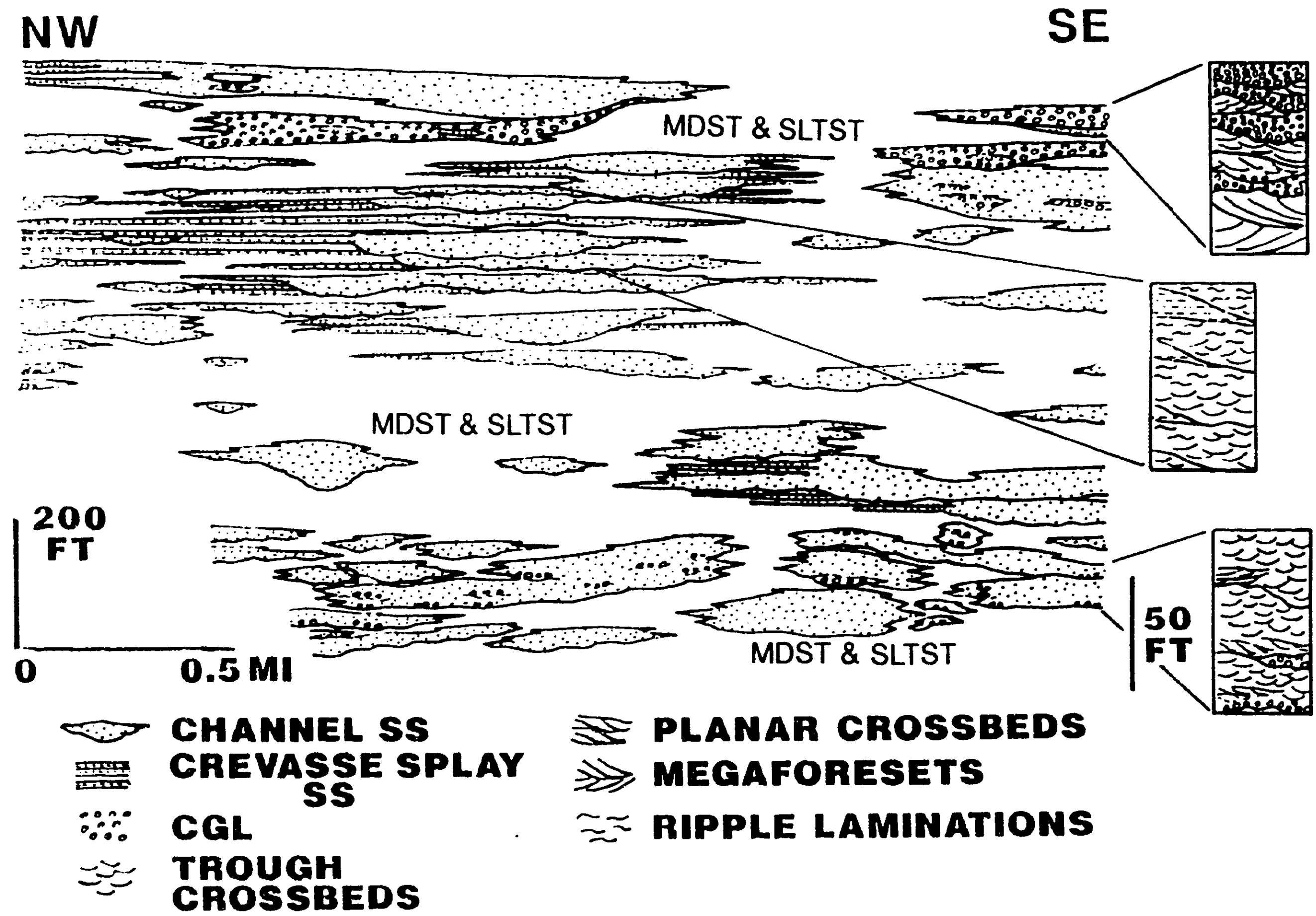

Figure 6. Cross section showing facies stratigraphic framework of sandstone and conglomerate reservoirs and associated seal rocks of mudstones, siltstones, silty sandstones, carbonaceous shales, and coals in outcrop at Merriam anticline, Wind River Reservation.

much as 58 ft thick and as much as 0.6 miles in lateral extent, that is probably basally erosional, and with internal scours marked by lag conglomerates. Large trough crossbeds (as much as 2 ft in height) and planar crossbeds (as much as 1.5 ft in height) internally compartmentalize the individual reservoir units bounded by scour surfaces. Type II reservoirs consist of sandstone, 12 to 30 ft thick, separated by siltstone and mudstone seal rocks, 3 to 20 ft thick. The sandstones form multistorey reservoir complexes to 80 ft thick and 0.25 miles in lateral extent. Type III reservoirs consist of sandstones, 8 to 45 ft thick, interbedded with siltstones and mudstones, 5-40 ft thick. Sandstones are stacked into multistorey sequences as much as 100 ft thick and 0.8 miles in lateral extent. Within the multistorey sequence, individual sandstones are laterally offset and separated by siltstone and mudstone interbeds. These interbeds thin and pinch out toward the direction of amalgamated sandstones and thicken toward their margins. Type IV reservoirs consist of tabular sandstones, as much as 20 ft thick and 1 mile in lateral extent, capping an interval of interbedded mudstone and siltstone. Stacked tabular sandstone reservoirs, as much as 100 ft thick are commonly laterally juxtaposed against type III sandstone reservoirs. This association makes type III and type IV reservoirs the most continuous reservoir system.

Variations in the chemical and isotopic compositions ($\delta^{13}C_1$) of gases from the Wind River Basin were studied in order to better understand the origins of the gases (Johnson and Rice, 1993). Gases from all producing intervals in conventional reservoirs at depths ranging from 2,321 to 18,050 ft are predominantly thermal in origin (C_1/C_{1-5} of 0.82 to 1.0, $\delta^{13}C_1$ of -31.12 to -47.40‰). Most gases sampled from conventional reservoirs appear to have migrated from deeper, more mature source rocks (Figure 7). Gases were collected from three fields where reservoirs from several stratigraphic levels are productive: the Madden field along the deep basin trough, and the Pavillion and East Riverton Dome fields in the western part of the basin. Considerable vertical migration has occurred at all of these fields (Figure 8). At Madden, for example, gases become only slightly heavier isotopically ($\delta^{13}C_1$ of -34.81 to -31.82‰) and chemically drier (C_1/C_{1-5} of 0.95 to 1.0) through more than 12,000 ft of section (5,556 to 18,050 ft). At Pavillion, gases from the shallow (3,437 to 3,564 ft), immature reservoirs (R_m 0.5 percent) in the lower Eocene Wind River Formation are isotopically heavy ($\delta^{13}C_1$ of -39.24 to -40.20‰) and were generated by mature to post-mature source rocks.

The lacustrine Waltman Shale Member of the Paleocene Fort Union Formation, which is present throughout much of the eastern two-thirds of the basin, appears to inhibit the vertical migration of gas from deeper sources. Few gas fields produce from the marginally mature reservoirs above the Waltman Shale Member, and the gas that is produced from this interval appears to have originated in the Waltman. At Fuller Reservoir field, in the central part of the basin, gas from shallow (2,500-3,500 ft), marginally mature (R_m 0.60 to 0.65 percent) reservoirs in the Fort Union Formation above the Waltman Shale Member is associated with waxy oil, is wet chemically (C_1/C_{1-5} of 0.84) and is isotopically light ($\delta^{13}C_1$ of -46.99‰). This gas and oil appears to have been generated in the Waltman Shale Member deeper in the basin. Gases from below the Waltman

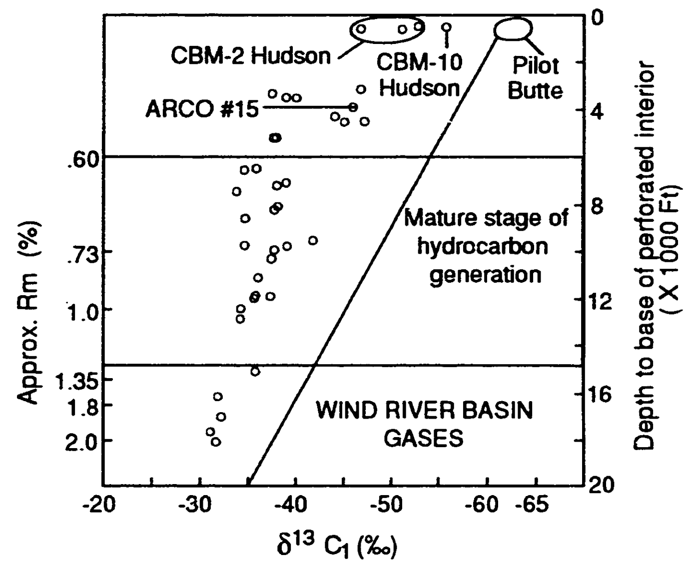

Figure 7. Depth to base of producing interval versus methane carbon isotopic composition (δ13C1) for gases, Wind River Basin, Wyoming. Approximate vitrinite reflectance (R_m) of reservoir rock is also shown. Gases from coalbed methane reservoirs are labeled. Locations of coalbed methane tests are shown on Figure 3. A line showing approximate changes in δ13C1 with increasing thermal maturity is shown. Gases which plot to the left of the line have probably migrated from deeper, more mature source rocks.

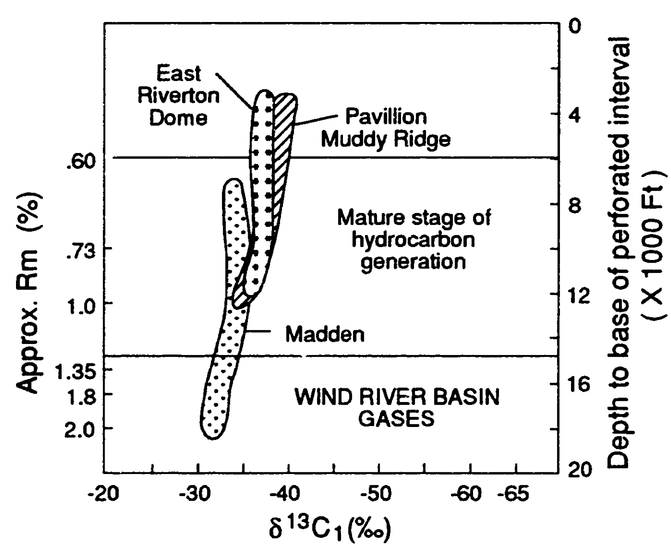

Figure 8. Depth to base of producing interval versus methane carbon isotopic composition (δ13C1) for gases from over wide depth ranges at Pavillion-Muddy Ridge, East Riverton Dome, and Madden fields.

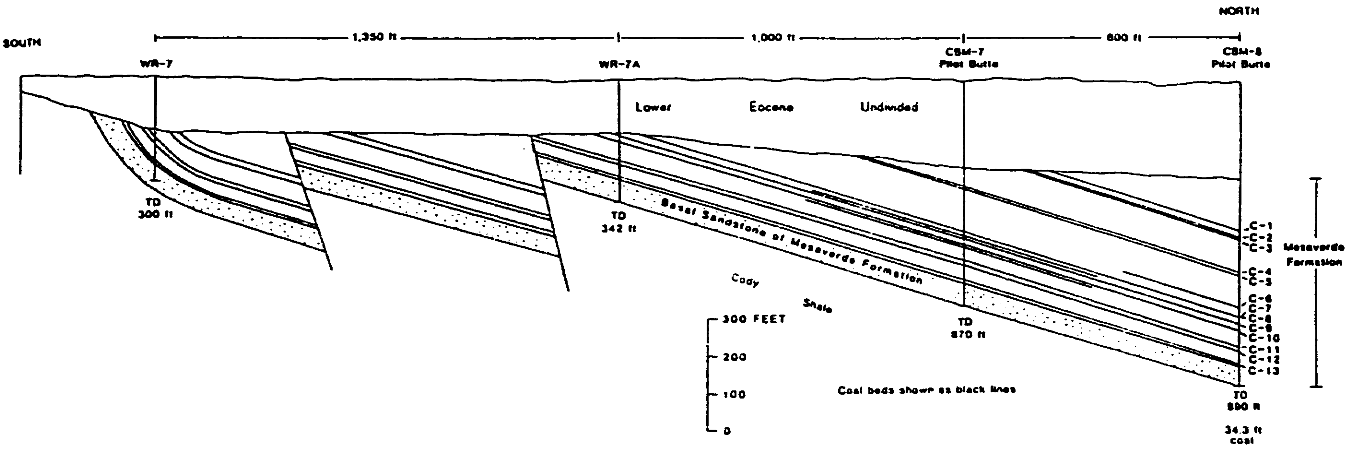

Figure 9. Generalized cross section through Pilot Butte coalbed methane test site, Wind River Reservation, showing coal beds in the Upper Cretaceous Mesaverde Formation truncated and sealed beneath younger strata. Coal beds sealed in this fashion typically contained significant methane in the shallow subsurface. Location of Pilot Butte site on Figure 3. From Johnson and others (1993). Drillholes CBM-7 and CBM-8 from U.S. Geological Survey coalbed methane drilling program. Drillholes WR-7 and WR-7A are from Windolph and others (1982).

Shale Member are chemically dry ($C_1/C_{1\text{-}5}$ of 0.94 to 0.95) and isotopically heavy ($\delta^{13}C_1$ of -34.79 to -36.19‰) and probably migrated from underlying Upper Cretaceous source rocks. In contrast, at Pavillion field, west of the pinchout of the Waltman Shale Member, mature gases from probable Upper Cretaceous source rocks were able to migrate into the shallow marginally mature reservoirs of the lower Eocene Wind River Formation.

A single coalbed methane well is producing in the western part of the basin, at Riverton Dome in the southeast corner of the Wind River Reservation. Gas from this well, which is completed in Upper Cretaceous Mesaverde Formation coals at depths of 3,270 to 3,839 ft., appears to be of thermogenic origin ($\delta^{13}C_1$ -46.15‰, $C_1/C_{1\text{-}5}$ 0.98). Shallow coalbed gases (307 to 818 ft) desorbed from cores of the thermally immature (R_m 0.40 to 0.54 percent) Mesaverde Formation in the Wind River Reservation have highly varied chemical and isotopic compositions and appear to have complex and varied origins. Coalbed gases from the Hudson area in the southeastern corner of the Reservation have the isotopic compositions of a thermally generated gas ($\delta^{13}C_1$ -47.0 to -55.91‰). Coalbed gases from the Pilot Butte area about 25 miles to the northwest (Figure 9) appear to be a mixture of biogenic and thermogenic gas. The methane fraction is isotopically light ($\delta^{13}C_1$ -61.85 to -66.21‰) and is probably largely biogenic, but the gases contain as much as 5.6 percent C_{2+} and this fraction is probably of thermogenic origin. These coals appear to be too thermally immature to have generated significant quantities of thermogenic gas, and it is suggested that the thermogenic component of these gases migrated into the coals from a deeper, more thermally mature source.

FUTURE WORK

Our studies, which have concentrated in the western part of the Wind River Basin, will be extended into the eastern part of the basin. We will continue to work with drillstem test, perforation recoveries, and mudweights to help better define the extent of the tight gas accumulation. This subsurface information will be used in conjunction with reservoirs architecture studies in order to define the production characteristics of various types of sandstone reservoirs within the tight gas interval.

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NG-3.2 Reserves in Western Basins

CONTRACT INFORMATION

Contract Number	DE-AC21-91MC28130
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Contractor Project Manager	Robert H. Caldwell
Principal Investigators	Robert H. Caldwell Bill W. Cotton
METC Project Manager	Karl-Heinz Frohne
Period of Performance	October 01, 1991 to September 30, 1995

Schedule and Milestones

Program Schedule

	Year 1 1991-1992	Year 2 1992-1993	Year 3 1993-1994	Year 4 1994-1995
Greater Green River Basin	**Completed**			
Uinta Basin			----------------	
Piceance Basin				---------------

OBJECTIVES

The objective of this project is to investigate the reserves potential of overpressured tight (OPT) gas reservoirs in three Rocky Mountain basins. These are the Greater Green River Basin (GGRB), Uinta Basin and Piceance Basin.

By documenting productive characteristics in these basins and characterizing the nature of the vast gas resources in place, the reserves potential may be understood and quantified. Through this understanding, it is hoped that the oil and gas industry will be encouraged to pursue exploitation of this resource.

At this point in time, the GGRB work has been completed and the final report submitted for publication. Work on the Uinta basin has just commenced and work on the Piceance basin will commence next year. Since the GGRB portion of this project has been completed, further discussion will center upon this Basin.

BACKGROUND INFORMATION

The starting point for this study is the resource estimate made for each basin by the USGS (Law et al, 1989). The USGS work has characterized a vast resource, with a mean value of over 5,000 Tcf in the GGRB alone.

The question as to how much of this enormous resource is potentially recoverable at commercial rates and hence may be regarded potentially as reserves, is one of the key questions that must be answered by this project. The ability to formulate an answer to that question required that the in place resource itself be independently quantified, characterized and broken down into its areal, vertical, and formation related components, and that reservoir properties be quantified. In addition, key factors controlling the productivity of OPT gas reservoirs had to be quantified and understood in order to formulate a reserves model for the basin.

PROJECT DESCRIPTION

The approach to this project was relatively straightforward: study all productive OPT gas wells in the basin and relate their performance and ultimate recovery back to the USGS resource estimate. In order to complete this task, an extensive data collection program was instigated to assemble relevant geological, petrophysical and engineering data necessary to support the reserves estimation procedure. This data collection exercise included available public domain sources and an approach to local operators to volunteer base information not available within the public domain. As a result, a significant database of information was developed and this database, particularly core information, will be included in digital form with the final GGRB report.

The first task completed was splitting the data into formational units representing the five formation groupings (plays) under consideration. These are as follows:

- Cloverly Frontier
- Mesaverde
- Lewis
- Lance Fox-Hills
- Fort Union

For each play, the first step was assembling a grid of well control correlating to the USGS grid of available cross-section data to ensure that well logs and log interpretation were conducted with a representative coverage within each play. Formal tight gas log interpretation was performed on this dataset and correlated to core information corrected to in-situ conditions. This allowed calibration of the log analysis to productive intervals within each play and the ability to identify pay cutoff parameters.

From this work, each play was isopached and a volumetric in place gas resource calculated. Since a technical approach to resource estimation was adopted, the results of this exercise differed significantly from those by the USGS who used a Delphi methodology. A downward revision of total in place resource from the USGS mean value of 5,064 Tcf to a mean value of 1,968 Tcf was determined by this study. The reasons for this significant downward revision can be related principally to a more sophisticated porosity model that is skewed heavily towards the lower porosities, higher water saturations, and a more sophisticated formation volume factor handling as compared to the USGS analysis.

RESULTS

An extremely important result of this study was a characterization and breakdown of the original resource into components. Of the total evaluated base resource of 1,968 Tcf, 1,127 Tcf is contained within sandstones that are of extremely poor reservoir quality, having estimated in-situ permeabilities of less than 0.001 md. Such resources are termed *technologically nonviable* since they are contained in reservoirs that are considered too tight for commercial exploitation using today's hydraulic fracturing technology. Portions of this resource will only become accessible via future cost reduction and improvement in massive hydraulic fracturing technology.

The remaining 841 Tcf represents resources that are contained in reservoirs considered to have in-situ permeabilities greater than 0.001 md and are termed *technologically viable*. Of this resource, 233 Tcf (12% of the total) is termed *nondemonstrated* since it is contained in reservoirs that have not been shown to be commercially productive. *Nondemonstrated* resources commonly occur in particular facies such as alluvial and other nonmarine depositional systems that are characterized by a high degree of lenticularity. New developments in well completion and stimulation will be required to access these resources.

The remaining 608 Tcf represents *demonstrated* resources. These are in place volumes that are potentially available for conversion into reserves by application of an appropriate recovery factor. Of this volume, 68 Tcf (3% of the total) is considered to be *established* resource characterized by favorable expectations in terms of recovery and drilling risk. A further 191 Tcf (10% of the total) is considered *nonestablished* resource characterized by less favorable expectations in terms of recovery and a higher drilling risk and drilling cost. The differentiation of the *established* and *nonestablished* resource categories is based upon a drill depth criterion termed *economic basement*. *Economic basement* is a conceptual depth that depends upon drilling and completion costs, expected reserves, gas price, and success ratios. Changes in these parameters will cause dynamic movement of resources from one category to the other. The remaining 349 Tcf of *demonstrated* resources are considered *speculative*. *Speculative* resources are those occurring in deeply buried locations, characterized by poor well control and being deeper than any established commercial production. Such volumes are inferred by extrapolation of mapping into the deep basinal areas and are defined as being below the *deepest commercial production*. *Speculative* resources have a high degree of uncertainty associated with their quantification and are thus excluded from consideration from a reserves quantification perspective. Figure 1 is a diagramatic representation of the resource subdivision using a modified McKelvey box format.

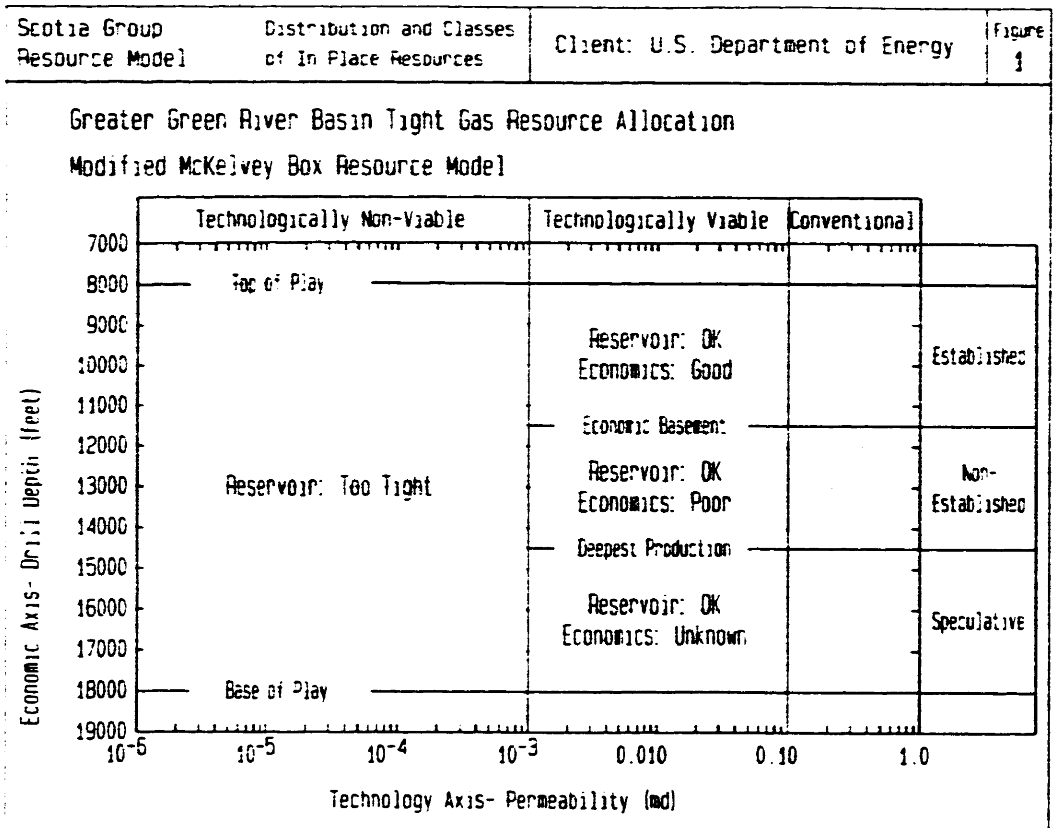

Figure 1. Modified McKelvey Box Resource Model

The following table summarizes the resource high-grading procedure:

Table 1. Breakdown of Revised Resource Estimate (Mean Values)

USGS Mean Resource Estimate	**5,064 Tcf**
Scotia Revised Mean Resource Estimate	**1,968 Tcf**
Minus *Technologically Nonviable* Resources	**1,127 Tcf**
Subtotal *Technologically Viable* Resources	**841 Tcf**
Minus *Nondemonstrated* Resources	**233 Tcf**
Subtotal *Demonstrated* Resources	**608 Tcf**
Subdivision:	
***Speculative* Resources**	**349 Tcf**
***Nonestablished* Resources**	**191 Tcf**
***Established* Resources**	**68 Tcf**

Only *established* and *nonestablished* categories are considered for the purpose of estimating recoverable reserves.

The demonstrated resources identified by the study are mapped and are considered to be distributed in accordance with isopachs at the basinal scale. It is recognized that the entire regional isopached volume will not all be uniformly productive. Dry holes exist within the mapped area as to productive wells, some of which are commercial (have reserves) and some of which are noncommercial (not qualifying as reserves). The recovery factor model thus requires not only a recovery percent of original GIP but also must take into account a factor representative of dry holes and a factor representing commercial considerations. This latter "nonreserves" factor represents that proportion of the resources isopached volume that will not be commercially productive for a variety of reasons. Such reasons could include lateral discontinuity of the reservoirs, unfavorable stress conditions for frac treatments, absence of natural fractures and other difficult to quantify situations. As such, the resulting recovery factor combines three components. These are a base volumetric recovery factor, a dry hole factor, and a commerciality factor. Values assigned to each factor are based upon an analysis of experience within each area and each play based upon analysis of drilling results, driling costs, and EURs.

Recoverable reserves, inclusive of probable, possible and potential categories, are estimated at 21 Tcf and 12 Tcf respectively for the *established* and *nonestablished* categories. These represent MAXIMUM recoverable volumes assuming a variable drilling pattern that leaves NO bypassed gas. The estimated ultimate recoveries (EUR) for existing OPT gas wells are not included in these figures.

Because OPT gas wells are characterized by significant variation in average drainage radius and due to large pay thicknesses, OPT gas wells may drain comparatively small areas. Development on a regulatory 640 or 320 acre spacing can result in significant bypassed gas. This gas remains in inter-drainage area locations at or near original reservoir pressure and is available for exploitation via infill drilling. It is common to have bypassed gas on the order of 50 to 90% of gas in place (GIP) on an initial 640 acre spaced development.

The Lewis play and Almond formation of the Mesaverde play contain the *established* resources and are the principal producing units in the basin with a combined EUR of 1,239 Bcf for existing OPT wells. *Nonestablished* resources are contained in the Frontier and Lewis plays, and in portions of the Almond and Ericson formations of the Mesaverde play. These units represent a combined EUR of 319 Bcf for existing OPT wells. The Lance-Fox Hills and Fort Union plays have no commercial production from the OPT section in the basin. Sub commercial production with an EUR of 0.9 Bcf is recorded from these two plays. The following table summarizes the reserves breakdown by play.

Table 2. Estimated Probable, Possible and Potential Reserves by Play

Play	**Recoverable Tcf**
Fort Union	**0.0**
Lance Fox-Hills	**0.0**
Lewis	**11.8**
Mesaverde	**18.7**
Clovery Frontier	**3.0**
TOTALS	**33.5**

For all existing OPT gas wells in the GGRB, cumulative production to January 1, 1992 is 861 Bcf with an EUR of 1,559 Bcf. This represents proved developed producing (PDP) reserves developed mainly since 1975 in 667 producing wells. These EURs are log normally distributed with the average EUR for a GGRB OPT gas well being 2.3 Bcf and the median well being 0.5 Bcf.

The best producing areas have a distinct "sweet spot" character that involves favorable development of rock properties, diagenetic effects, sand body geometry, natural fracturing, and the optimal conditions for performing a successful hydraulic fracture treatment.

FUTURE WORK

With the completion of the GGRB study and final report, work has commenced on the Uinta basin. It is planned that a similar approach to the GGRB be adopted and that the GGRB methodology be utilized as a work plan for the other basins. The Uinta basin work is scheduled to be completed by September 1994 and the Piceance basin completed by September 1995.

REFERENCES

Law, B.E., C.W. Spencer, R.R. Charpentier, R.A. Covelli, R.F. Mast, G.D. Dolton, and C.J. Wandrey (1989), "Estimates of Gas Resources in Overpressured Low-Permeability Cretaceous and Tertiary Sandstone Reservoirs, Greater Green River Basin, Wyoming, Colorado and Utah." Wyoming Geological Association Guidebook, Fortieth Field Conference, p. 39-61.